INTEGRATED DISTRIBUTION PLAN (2020-2029)

NOVEMBER 1, 2019

Docket No. E002/M-19-666

EXECUTIVE SUMMARY

On August 30, 2018, the Minnesota Public Utilities Commission ordered Northern States Power, doing business as Xcel Energy to file an Integrated Distribution Plan (IDP) annually beginning on November 1, 2018. The Commission accepted our first IDP, modified the filing requirements, and ordered that we submit our next IDP November 1, 2019. This IDP is the result of the Commission's requirements and input and feedback from our stakeholders.

This IDP presents a detailed view of our distribution system and how we plan the system to meet our customers' current and future needs. The backbone of our distribution planning is keeping the lights on for our customers, safely and affordably. For over 100 years, we have delivered safe, reliable electric service to our customers, and, through our robust planning process and strong operations, we will continue to do so.

We are also planning for the future, and with this IDP we propose to significantly advance our distribution grid and planning capabilities. We have a vision for where we and our customers want the grid to go, and we are taking measured and thoughtful action to ensure our customers receive the greatest value, and that the fundamentals of our distribution business remain sound.

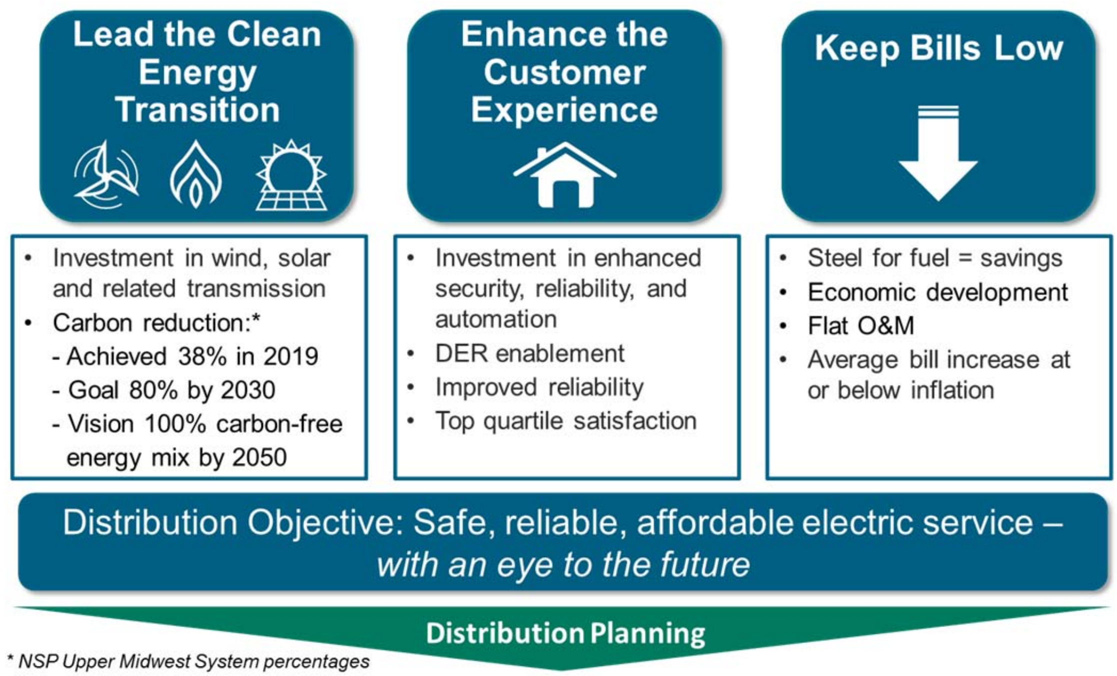
I. PLANNING LANDSCAPE

The electric utility industry is in a time of significant change. Increasing customer expectations and technological advances have reshaped what customers expect from their energy service provider, and how those services are delivered. Technologies that customers can use to control their energy usage, such as smart thermostats, electric vehicle (EV) chargers, smart home devices, and even smart phones, are evolving at a fast rate. Influenced by other services, customers have come to expect more now from their energy providers than in the past, including greater choices and levels of service, as well as greater control over their energy sources and their energy use.

At the same time, major industry technological advances provide new capabilities for utility providers to manage the electric distribution grid and service to customers. Electric meters are now equipped to gather more detailed information about customer energy usage, which utilities can leverage to help customers better understand and manage their usage. Other advanced equipment on the grid is able to sense, communicate, and respond in real time to circumstances that would normally result in power outages. Grid operators can also get improved data to better and more proactively plan and operate the grid. These advancements form the foundation for a flexible grid environment that helps support two-way power flows from customer-connected devices or generating resources (such as rooftop solar) and provides utilities with a greater ability to adapt to future developments.

The foundation on which these capabilities rest is safe, reliable energy. Our strategic priorities of enhancing the customer experience, leading the clean energy transition, and keeping customer bills low are embedded in everything that we do – including the way that we plan our distribution system.

Figure 1: Xcel Energy Strategic Priorities – Applied to Distribution



Distribution planning has historically – and still largely today –involved analyzing the electric distribution system's ability to serve existing and future electricity loads by evaluating the historical and forecasted load levels, and utilization rates of major system components such as substations and feeders. Customers traditionally have had limited information about their energy usage and few choices in how they received information, had questions answered, and paid utility bills or conducted other necessary business with their utilities. For the most part, customers were content to receive a monthly paper bill from their utilities and were unaware and unengaged in whether the energy came from renewable or non-renewable sources.

Now however, customers increasingly want choices, control, and actionable information. And utilities, instead of planning just for load, need to analyze the system for future connections that may be load *or* generation. Also, utilities increasingly need to view their operations and customer tools from their customers' perspectives. This step change in the distribution utility business requires utilities to plan their systems differently, which involves new processes and methodologies and also new and different tools and capabilities.

Like other aspects of the industry that are transitioning and advancing, we are on the forefront of integrated distribution planning and, as such, are taking steps to align and integrate our distribution, transmission, and resource planning processes. We have been in the process of evaluating the next generation of distribution planning tools to increase our forecasting and analysis capabilities – and the advanced planning tool we propose to procure and implement will also aid our integration of planning processes.

II. XCEL ENERGY IDP SUMMARY AND HIGHLIGHTS

With this background, we note that Minnesota is unique from other states implementing integrated distribution planning, in that we are not currently undergoing sizable additions of DER on our system. Rather, Minnesota remains ahead in its planning and therefore able to take a measured approach and pace to IDP that allows the requirements to be implemented in a cost-effective, systematic manner that is in the public interest for all Minnesota customers.

It is in this context that we prepared Minnesota's first IDP – and this now second IDP for Xcel Energy. In advance of this IDP filing, we conducted four stakeholder workshops – the first was in the wake of our first IDP, to overview the filed plan and facilitate a Q&A forum with stakeholders; the second and third were on the topics of greatest interest in our first IDP – non-wires alternatives (NWA) analysis and the cost benefit framework for advanced grid investments, respectively; and, our fourth workshop presented the load and DER forecasts, investment plans, and 5-year action plan contained in this IDP. In addition to complying with IDP requirements – these workshops served to educate and build a better understanding of both our work and stakeholders' needs and expectations. Our goal for the workshops was to continue an iterative and ongoing dialogue to build a mutual understanding of our processes and the IDP, specific to this report as well as in general for future reports.

Our IDP recognizes the emergent state of the industry and availability of enhanced distribution planning tools, Minnesota's specific circumstances, and the building-block approach we are taking to modernize and equip our system to increase our visibility, control, and planning capabilities. We believe this report is robust and meaningful and provides substantial transparency into our distribution function and planning.

Our report provides historical actual and budgeted expenditures, discusses many of our planning practices, and outlines present and forecasted levels of DER. One of the major focuses of this IDP is our request for certification – pursuant to Minn. Stat. § 216B.2425 – of an array of investments to modernize the Company's distribution system. Specifically, we are seeking certification of an Advanced Distribution Planning Tool (APT) and of a number of grid modernization investments that are part of what is collectively referred to as the Advanced Grid Intelligence and Security (AGIS) Initiative.

To highlight some of the key aspects of our report, we summarize below our advanced grid plans, capital investment and O&M budgets, and the current state and in-queue DER on our system.

A. AGIS Initiative

While we have made incremental modernization efforts on the distribution system over many years, the time is now to begin a more significant advancement of the grid. This modernization begins with foundational advanced grid initiatives that both provide immediate benefits and new customer offerings while also enabling future systems and customer value.

We are on the forefront of many of the issues and changes underway in the industry and have developed our AGIS initiative to address them. In addition to the significant steps we have taken to implement and improve our hosting capacity analysis, we are on the cusp of implementing an Advanced Distribution Management System (ADMS). The ADMS is foundational to advanced grid capabilities that will provide the visibility and control necessary for enhanced planning and significant DER integration. We are also implementing a Time of Use (TOU) pilot that involves the installation of Advanced Metering Infrastructure (AMI) meters in two communities in the Twin Cities metropolitan area, and that tests a new residential TOU rate.[1]

Today, Xcel Energy customers have access to numerous energy efficiency and demand management programs, renewable energy choices, billing options, a mobile app, and outage notifications that include estimated restoration times. Customers also receive confirmations when our records reflect that the outages have been resolved – and they receive these via their preferred communication channel – text, email, or

[1] This pilot also provides participants with increased energy usage information, education, and support to encourage shifting energy usage to daily periods when the system is experiencing low load conditions.

phone. We have made advances on our grid and with the service we offer our customers – and these and other products and services have provided our customers with significant value over many years.

However, technologies are advancing, as are customer expectations. Customers want access to actionable information, more choice and greater control of their energy use – and they expect a smarter, simpler and more seamless experience. Enhancing the customer experience is critically important, and is one of our three strategic priorities, along with leading the clean energy transition and keeping bills low. We plan to integrate modern customer experience strategies with advanced grid platforms and technologies to enable intelligent grid operations, smarter networks and meters, and optimized products and services for our customers.

1. *Advanced Grid Proposal*

We are proposing to implement the following advanced grid capabilities:

- *Field Area Network (FAN).* A private, secure two-way communication network that provides wireless communications across Xcel Energy's service area – to, from, and among, field devices and our information systems.
- *Advanced Metering Infrastructure (AMI).* AMI is an integrated system of advanced meters, communication networks, and data processing and management systems that is capable of secure two-way communication between Xcel Energy Energy's business and operational data systems and customer meters.
- *Fault Location, Isolation, and Service Restoration (FLISR).* A form of distribution automation that involves the deployment of automated switching devices that work to detect issues on our system, isolate them, and restore power, thereby decreasing the duration of and number of customers affected an outage.
- *Integrated Volt Var Optimization (IVVO).* An application that uses selected field devices to decrease system losses and optimize voltage as power travels from substations to customers.

In addition to transforming the customer experience, these foundational and core investments will allow us to advance our technical capabilities to deliver reliable, safe, and resilient energy that customers value.

Fundamentally, we must act to replace our current Automated Meter Reading (AMR) service to ensure we continue to provide our customers with timely accurate bills; our current vendor is sun-setting its AMR technology in the mid-2020s. While this system has provided value to customers for many years through efficient meter reading, we have an opportunity now to seize AMI technologies that are becoming available to maximize value for our customers. As we deploy advanced grid infrastructure, platforms, and technologies we expect three outcomes: (1) a transformed customer experience, (2) improved core operations, and (3) facilitation of future capabilities, which we discuss below.

Transformed customer experience. Our planned advanced grid investments combine to provide greater visibility and insight into customer consumption and behavior. We will use this information to transform the customer experience through new programs and service offerings, engaging digital experiences, enhanced billing and rate options, and timely outage communications.

We will offer options that give customers greater convenience and control to save money, provide access to rates and billing options that suit their budgets and lifestyles, and provide more personalized and actionable communications. As our system more efficiently manages energy flows, we can save customers money by reducing line losses and conserving energy. Smarter meters will be the platform that enables smarter products and services and contributes to improved reliability for our customers. Our customers will have more information to make more effective decisions on their energy use.

We will know more about our customers and our grid – and we will use that information to make more effective recommendations and decisions and continually use new information to develop new solutions. This will serve to help keep our bills low, as customers save money through both their actions and ours. It will also help ensure that our transition to a carbon-free system occurs efficiently – and harnesses the vast potential of all energy resources, from utility-scale to local distributed generation.

Improved core operations and capabilities. Smarter networks will form the backbone of our operations, and our investments will more efficiently and effectively deliver the safe and reliable electricity that our customers expect. We will have the capability to communicate two ways with our meters and other grid devices, sending and receiving information over a secure and reliable network in near-real time.

Our current service is reliable; however, we need to continue to invest in new technologies to maintain performance in the top third of U.S. utilities, particularly as we deliver power from more diverse and distributed resources and as industry standards continue to improve. Our advanced grid investments provide the platform and capabilities to manage the complexities of a more dynamic electric grid through additional monitoring, control, analytics and automation.

Our systems will more efficiently and effectively restore power when outages do occur using automation without the need for human intervention. For those outages that cannot be restored through automation, our systems will be better at identifying where the outage is and what caused it – benefitting customers through less frequent, shorter, and less impactful outages; more effective communication from the Company when they are impacted by an outage; and reduced costs from our more efficient use and management of assets.

Facilitation of future capabilities. The backbone of our investments will also support new developments in smart products and services; in the short term by supporting the display of more frequent energy usage data through the customer portal – and over the long term, allowing for the implementation of more advanced price signals. Designing for interoperability enables a cost-effective approach to technology investments and means we can extend our communications to more grid technologies, customer devices, and third-party systems in a stepwise fashion, which unlocks new offerings and benefits that build on one another. We have planned our advanced grid investments in a building block approach, starting with the foundational systems, in alignment with industry standards and frameworks. By doing so, we sequence the investments to yield the greatest near- and long-term customer value, while preserving the flexibility to adapt to the evolving customer and technology landscape. By adhering to industry standards and designing for interoperability, we are well positioned to adapt to these changes as the needs of our customers and grid evolve.

In planning our advanced grid initiative, we have considered the long-term potential of our ability to meet our obligations to serve and our customers' expectations and needs – ensuring we extract cost-effective value from our investments and remain nimble enough to react to a dynamically changing landscape. The principles we applied to our advanced grid planning include the ability to remotely update hardware and software, security, reliability and resilience, and flexible, standards-based service components. We are planning our grid advancement with the future in mind, and to provide both immediate and increasing value for our customers over the long-term.

We are on the forefront of many of the issues and changes underway in the industry and have developed our advanced grid initiative and our customer strategy to address them and harness value for our customers. In addition to transforming the customer experience, these foundational investments will allow us to advance our technical capabilities to deliver reliable, safe, and resilient energy that customers value. These foundational investments also lay the groundwork for later years. The secure, resilient communication networks and controllable field devices deployed today through these investments will become more valuable in the future as additional sensors and customer technologies are integrated and coordinated.

Now is the time to modernize the interface where we connect directly with our customers – the distribution system. Technologies have evolved and matured; our peers have successfully implemented these technologies; and, the industry landscape is evolving. We must ensure our system has the necessary capabilities to meet our customers' expectations and needs – and, the flexibility to adapt to an uncertain future.

We are taking a measured and thoughtful approach to advancing the grid to ensure our customers receive the greatest value, the fundamentals of our distribution business remain sound, and we maintain the flexibility needed as technology and our customers' expectations continue to evolve.

2. *Our Customer Strategy is Informed by Customer Expectations*

Our customer strategy aims to transform the customer experience by implementing capabilities, technologies, and program management strategies to enable the best-in-class customer experience that our customers now expect. It is focused on shifting the customer experience dynamic to one where little action is required from customers around their basic service and where we offer personalized "packages" that customers can select from to meet their needs – similar to what customers experience when purchasing cable and internet services today. These packages may include options such as demand-side management, renewable energy, rate design, and non-energy services.

Figure 2: Customer Strategy Informed by Customer Expectations

Our implementation of the ADMS in early 2020 is preparing the grid for increasing levels of DER. It is also paving the way for further grid advancement with AMI and our ability to leverage the underlying and necessary FAN to reduce customers' energy costs through IVVO, improve customers' reliability experience through FLISR, and more.

Customers will have access to granular energy usage data from our AMI through a customer portal, which we expect to pair with informed insights and helpful tips on how to change their behavior to save energy. Further, the AMI meters we propose include a Distributed Intelligence platform, which essentially provides a computer in each customer's meter that will be able to "connect" usage information from the customer's appliances for further insights – and be updated with new software applications, much like customers can currently update their mobile devices with applications.

Figure 3: Customer Value through Lifecycle

		Awareness	Start/Stop/ Transfer	Billing & Payments	Ongoing Use	Support & Service	Lifestage & Lifestyle
What do customers expect?		A **trusted, responsible source** helping customers learn more about environmental initiatives, energy programs and regulations	An **intuitive, frictionless** experience that doesn't contribute to the stress of moving	**Flexibility** and **options** (i.e., variety of payment methods), **transparency** around monthly costs	**Monthly usage insights** allowing customers to manage costs; a **robust offering of energy efficiency programs** aligned to customers' interests	**Increased visibility** during electric outages and delivery of other services; a service organization that **advocates for the customer**	A **go-to resource** for information and solutions regarding **renewable energy** and **smart homes** Energy management technology
Examples	AGIS Enabled Experience	**Integrated communication plan** across channels and timeline.	**Remote Connect / Disconnect** **Real-time meter reads**	**Bill forecasting** **Bill prepayment**	High bill alerts Energy usage goals TOU alerts Disaggregation	**Outage ERT accuracy** **Arch detection**	Distributed Energy Resources Home automation/remote monitoring
	Customer Value	A feeling of comfort with the changes and timely and relevant communications.	Avoid gaps in service Easier moving experience	Increased bill predictability. Payment flexibility. Better understanding of their monthly bill.	Timely alerts and messages to guide their energy use and add predictability to their bill.	More timely and accurate ERT messages. Predictable home health and safety.	EV, Battery, Solar installation readiness and reduced friction Control over usage in the home.
	Business Value	Customer satisfaction Reduced call volume	Reduced truck rolls Accurate meter reads Reduced call volume	Customer satisfaction Reduced B&P call volume	Customer satisfaction Energy savings More predictable load	Customer satisfaction Reliability Reduced call volume	Customer satisfaction Reliability

To develop the customer strategy, we committed to understanding customers' preferences, considerations, and thoughts regarding the benefits and value of an advanced grid investment. We gathered this information through primary research, such as focus groups and surveys. We also supplemented our research with information from secondary sources including the Smart Energy Consumer Collaborative, and GTM Research and other utilities' advanced grid plans.

Our key takeaways from these sources are as follows:

- *Consumers care more about technology and enabling improvements than process.* Safety and energy savings rated most highly.
- *Addressing service interruptions are important to all customer classes.* Improved reliability will allow the Company to focus more on other customer priorities.
- *Customers expect that service interruptions will be less frequent in scope and duration.*

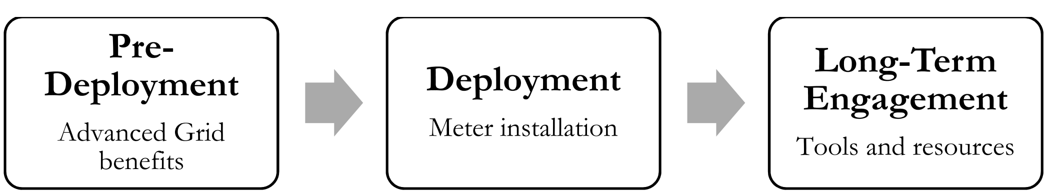
- *Customers expect to receive detailed information from their utility*. They expect this information to be personal and frequent.
- *Customers expect more tools and information for them to make decisions about their energy usage*. Customers indicated more information allowed them to better identify opportunities and strategies to save energy and reduce their costs.
- *Business customers have more awareness and familiarity with advanced rate designs*. Residential customers expect the utility to provide them with rate comparison tools and information about new rate designs.
- *Building trust is a key component to unlocking value*. Trust is best built by identifying solutions and showing results specific to the customers
- *Customers expect that there will be a cost associated with the advanced meter but that the meter will also provide benefits over time.*

We have incorporated customer feedback and insights into our customer transition and communication plans – and the work we are doing to develop new and enhanced products and services as enabled by the advanced grid.

3. Our Advanced Grid Implementation will Educate, Inform, and Ensure a Smooth Implementation

During this transition to the advanced grid, we will take exceptional care of our customers to educate, inform, and ensure a smooth implementation. We are already developing processes that will ensure accurate, timely bills as customers change over to AMI. We are also developing dedicated, hands-on customer care processes that will provide our customers a single point of contact during implementation – and that will phase customer communications relative to our geographic deployment of AMI meter installation. Meter deployment and advanced meter capabilities will be phased in over the next several years, and communications strategies, messages and tactics will be executed in three phases to match the customer journey.

Figure 4: Customer Communications Journey Phases



For example, our customer communications will begin pre-implementation to educate on the possibilities enabled by AMI, as well as customers' ability to opt-out of an AMI meter. As the AMI installation date gets closer, we will inform customers about what to expect with the AMI meter changeover at their homes or businesses. Finally, we will communicate post-AMI installation to reinforce early AMI messaging regarding possibilities and options – also providing practical steps to take advantage of the customer portal or other new or enhanced services available day one.

B. Advanced Planning Tool

In recognition that distribution planning needs were beginning to change and our existing tools could not accommodate all of the analysis we would need or want to do going forward, we began assessing options to upgrade our planning capabilities. We began this assessment in 2015 – and given market trends, our current software's lifecycle, evolving planning requirements, and changes to our grid, the time is ripe to implement a new, more dynamic forecasting tool.

The Advanced Planning Tool (APT) will enable us to meet our planning and regulatory requirements and we believe, result in incremental benefits for our customers. As we have discussed in relation to our advanced grid investment proposal, our customers are increasingly exercising more choice around their use of energy. Some of these choices, including DER and beneficial electrification such as electric vehicles (EV) make granular load forecasting a much more complex and important undertaking than it was only a few years ago. It is essential for our distribution planning tools to better assess how these technologies interact with the grid and how they may change potential distribution system needs.

Further, the Commission has instituted new planning and reporting requirements the Company must meet. These requirements include conducting load and DER scenario analysis and NWA analysis. Finally, our existing tool will no longer be supported in the near future. These factors all require the Company to implement a new solution. These tools will equip our system planners with enhanced capabilities to consider DER adoption scenarios and non-wires alternatives (NWA) in the analyses we perform to ascertain the best way to meet system capacity needs. Further, the APT will enable us to deliver additional benefits in the form of more efficient planning, enhanced load forecasting capabilities, and better integration with the Company's other planning efforts.

Given the capabilities and benefits the APT will enable for our distribution planning processes, we are confident that the investment is in the interest of both customers and the Company and will help the Company meet our regulatory requirements. We expect to procure and integrate the APT in early 2020, at an all-in upfront cost of approximately $9.3 million Xcel Energy-wide. We estimate that the proportional

Northern States Power-Minnesota (NSPM) operating company upfront costs will amount to approximately $4 million, with minimal ongoing costs for the annual software hosting fee and internal maintenance.

In this IDP, we request the Commission certify our request to procure the APT for distribution planning purposes.

C. Five-Year Budgets – Capital and O&M Expenditures

Distribution budgets are evolving based on the future of electric distribution and customers' increasing expectations for control, options, and ease of doing business. Additionally, our capital investment plans generally reflect our advanced grid initiative, as we have discussed it above. Historically, however, the overwhelming majority of our distribution budgets have been dedicated to the immediacy of customer reliability impacts and the dynamic nature of the distribution system. This includes building and maintaining feeders, substations, transformers, service lines, and other equipment – as well as restoring customers and our system in the wake of severe weather, and responding to local and other government requirements to relocate our facilities.

The distribution budget process prioritizes projects based on the Company's goal of providing our customers with smart, cost-effective solutions, recognizing that customers want reliable and uninterrupted power. Although the immediacy of customer safety and reliability is a reality and our primary focus, in addition to these core activities, our investment plan now reflects strategic investments to advance distribution grid capabilities, increase our system visibility and control, and enable expanded customer options and benefits. As noted above, we are planning investments to advance our grid and to procure an enhanced distribution planning tool are in our five-year action plan and budgets.

Table 1 below provides an overview of our 5-year capital budget in the IDP categories.

Table 1: Distribution Capital Expenditures Budget State of Minnesota Electric (Millions)

	Bridge Year	Budget					Budget Ave
IDP Category	2019	2020	2021	2022	2023	2024	2020-2024
Age-Related Replacements and Asset Renewal	$72.5	$87.2	$79.5	$78.3	$79.7	$81.0	$81.1
New Customer Projects and New Revenue	$34.8	$35.6	$39.3	$39.3	$39.4	$39.4	$38.6
System Expansion or Upgrades for Capacity	$19.5	$44.4	$40.1	$32.3	$32.9	$37.9	$37.5
Projects related to Local (or other) Government-Requirements	$31.3	$28.9	$29.4	$28.5	$29.0	$29.2	$29.0
System Expansion or Upgrades for Reliability and Power Quality	$19.8	$21.5	$114.7	$117.4	$117.3	$117.3	$97.6
Other	$26.7	$38.3	$39.7	$43.2	$35.4	$35.1	$38.3
Metering	$6.7	$5.5	$4.3	$3.5	$2.3	$2.3	$3.6
Grid Modernization and Pilot Projects	$4.6	$19.9	$49.3	$141.7	$152.4	$76.7	$88.0
Non-Investment	($4.9)	($3.7)	($3.7)	($3.8)	($3.8)	($3.8)	($3.8)
TOTAL	$210.9	$277.5	$392.6	$480.3	$484.6	$415.2	$410.0

Notes: Excludes Grid Modernization –Other includes Fleet, Tools, Communication Equipment, Locating,Transformer Purchases and the Advanced Planning Tool; Reliability includes placeholder investments for a new reliability program (Incremental System Investment); and Non-investment includes Contributions In Aid of Construction (CIAC), which partially offset total project costs and 3rd party reimbursements for system upgrades due to interconnections and Solar, which is 100% reimbursable by the developers, annual totals will vary based on payment and project timing.

Significant investments in the Distribution 5-year budget include our incremental system investment, or ISI initiative, which is included in the System Expansion or Upgrades for Reliability and Power Quality category. The ISI initiative focuses primarily on the heath, reliability, and resiliency of the portions of our system that are closest to our customers such as feeder and tap lines. The advanced planning tool for which we seek certification in this IDP is in the Other category, which involves approximately $4 million of upfront costs associated with the initial purchase. Finally, our Distribution budget reflects our commitment to advancing EVs in Minnesota, with over $25 million budgeted in the Grid Modernization and Pilots category associated with approved and pending EV proposals.

Also significant are our grid modernization, or AGIS, investments, which we also seek certification for and present separately, because the overall project costs involve both Distribution and Business Systems amounts. See Table 2 below.

Table 2: Grid Modernization Capital Expenditures Budget – NSPM Electric (Millions)

	MYRP Case Period			5-Year Period	10-Year Period
Component	**2020**	**2021**	**2022**	**2023-2024**	**2025-2029**[2]
ADMS[3]	$6.5	$1.0	$3.0	$7.5	-
AMI[4]	$14.0	$28.9	$144.0	$185.2	$15.0
FAN[5]	$14.7	$37.3	$36.8	$3.8	-
FLISR	$3.5	$8.6	$6.6	$18.8	$29.7
IVVO	$0.1	$6.5	$9.8	$18.6	-
Total	**$38.8**	**$82.3**	**$200.2**	**$233.9**	**$44.7**

In terms of grid modernization, ADMS represents approximately $18.0 million in the 2020-2024 timeframe. Our full AMI deployment is planned to begin in 2021 and continue through 2024, with projected capital costs for AMI and FAN of approximately $275.7 million through 2022, and approximately $204 through the 2029 IDP period, for a total of approximately $480 million.[6] FLISR implementation is planned to begin in 2021 and continue at a relatively steady rate through 2028, with projected capital costs of approximately $18.7 million through 2022, and approximately $48.5 through the 2029 IDP period, for a total of approximately $67 million. Finally, IVVO implementation is planned to begin in 2019 and continue through 2024, with projected capital costs of approximately $16.4 million through 2022, and approximately $18.6 million through the 2029 IDP period, for a total of approximately $35 million.

In terms of O&M, large planned projects and programs to support our ongoing provision of regulated utility service are budgeted by function, and are key drivers of the O&M budgets. Programs include operational activities such as: *Vegetation Management,* which includes the work required to ensure that proper line clearances are maintained, maintain distribution pole right-of-way, and address vegetation-caused outages; *Fleet* represents costs associated with the Distribution fleet (vehicles, trucks, trailers, etc.) and miscellaneous materials and tools necessary to build out, operate, and maintain our electric distribution system. The O&M component includes annual fuel costs plus an allocation of fleet support. The *Damage Prevention* category includes

[2] Period may include additional assumptions, including inflation and labor cost increases that are not part of the capital budget in periods 2020-2024.
[3] Eligible for cost recovery through the TCR Rider.
[4] Includes the TOU Pilot.
[5] Includes the TOU Pilot.
[6] Note: Table 3 includes the AGIS O&M budgets as outlined in more detail in the AGIS section.

costs associated with the location of underground electric facilities and performing other damage prevention activities. This includes our costs associated with the statewide "Call 811" or "Call Before You Dig" requirements, which helps excavators and customers locate underground electric infrastructure to avoid accidental damage and safety incidents. And finally, we include AGIS O&M here as well, which represents the Distribution-only portion of the O&M expenditures needed to support the deployment of AGIS devices in the field – along with maintaining those devices.

Table 3 below provides a snapshot of our 2020-2024 O&M Distribution budget by Cost Element.

Table 3: Distribution O&M Expenditures Budget – NSPM Electric (Millions)

Expenditure Category	Bridge 2019	Budget 2020	2021	2022	2023	2024	Budget Avg 2020-2024
Labor	$53.8	$58.3	$59.8	$60.5	$61.6	$63.6	$60.8
Cont. Outside Vendor/Contract Labor	$17.1	$8.9	$12.9	$9.7	$8.7	$8.6	$9.8
Damage Prevention Locates	$8.3	$8.5	$8.6	$8.6	$8.6	$8.6	$8.6
Vegetation Management	$29.0	$28.2	$28.9	$28.4	$30.2	$30.1	$29.2
Materials	$5.9	$6.9	$6.8	$6.8	$6.8	$6.8	$6.8
Transportation Costs	$7.4	$6.9	$6.8	$6.8	$6.8	$6.8	$6.8
AGIS	$0.6	$2.8	$4.5	$6.8	$8.8	$6.5	$5.9
Misc. Other	(0.2)	($3.9)	($3.6)	($3.6)	($3.4)	($3.5)	($3.6)
TOTAL	**$121.9**	**$116.6**	**$124.7**	**$124.0**	**$128.1**	**$127.5**	**$124.2**

– Capital and O&M expenditures associated with the advanced grid initiative are presented separately as a holistic initiative; Misc Other includes employee expenses, first set credits, bad debt, use costs, office supplies, janitorial, dues, donations, permits, etc.

Significant O&M expenditures in the Distribution 5-year budget include O&M to support the AGIS and Incremental System Investment (ISI) deployments.

Consistent with how we present the capital budget for our grid modernization investments, we separately present the O&M to provide a complete view of both Distribution and Business Systems amounts. See Table 4 below.

Table 4: Grid Modernization O&M Expenditures Budget – NSPM Electric (Millions)

	Rate Case Period			5-Year Period	10-Year Period
Component	**2020**	**2021**	**2022**	**2023-2024**	**2025-2029**[7]
ADMS[8]	$1.9	$2.5	$2.5	$6.9	$5.2
AMI[9]	$6.6	$16.4	$14.1	$25.2	$67.2
FAN[10]	$0.1	$2.3	$1.5	$0.5	$8.6
FLISR	$0.2	$0.4	$0.3	$3.3	$2.5
IVVO	$0.0	$0.4	$0.8	$0.6	$0.8
Total	**$8.8**	**$22.0**	**$19.2**	**$36.5**	**$84.3**

In terms of grid modernization, ADMS represents approximately $19 million of O&M in through the 2029 period of this IDP. AMI and FAN comprise approximately $41 million of O&M through 2022, and approximately $101 million through the 2029 IDP period, for a total of approximately $142 million.[11] FLISR has projected O&M costs of approximately $0.9 million through 2022, and approximately $5.8 through the 2029 IDP period, for a total of approximately $6.7 million. Finally, IVVO has projected O&M costs of approximately $1.2 million through 2022, and approximately $1.4 million through the 2029 IDP period, for a total of approximately $2.6 million.

Finally, we clarify that in the IDP context, while our budget process has generally proven to be an accurate gauge of overall budget levels, it is important to understand that plan details – exclusive of large and strategic investments approved for implementation by the Commission, when needed, and our internal governance process, will be inconsistent year-to-year. As we have explained, the Distribution budget is an ongoing and iterative process that is largely driven by the immediacy of reliability and other emergent circumstances that are the practical reality of the Distribution business. The distribution system is the connection to our customers, and we must respond to these circumstances to meet our obligation to serve and ensure we provide adequate service. This means that long-term plans, which, in a distribution context, include five-year action plans, have a much shorter shelf-life.

[7] Period may include additional assumptions, including inflation and labor cost increases that are not part of the O&M budget in periods 2020-2024.
[8] Eligible for cost recovery through the TCR Rider.
[9] Includes the TOU Pilot.
[10] Includes the TOU Pilot.
[11] Includes the TOU Pilot

D. Existing and In-Queue DER

For purposes of IDP in Minnesota, DER is defined as supply and demand side resources that can be used throughout an electric distribution system to meet energy and reliability needs of customers, whether it is installed on the customer or utility side of the electric meter. The definition further clarifies that for the IDP, DER may include, but is not limited to distributed generation, energy storage, electric vehicle, demand side management, and energy efficiency resources.

Xcel Energy has one of the longest-running and most successful Demand Side Management (DSM) programs in the country. Our annual DSM achievements have often outpaced Minnesota's 1.5 percent of sales goal. Our Demand Response programs have 824 MW of registered, controllable customer load under contract in Minnesota, which is one of the largest portfolios of DR in the Midcontinent Independent System Operator (MISO) footprint – and we are on track to add an additional 400 MW to our portfolio by 2023. We have the largest community solar gardens program in the country, with 585 MW from 208 projects online. We anticipate this growing to over 650 MW by the end of 2019. Customer adoption of other DER in our Minnesota service area is otherwise relatively nascent. However, non-CSG distributed solar nearly doubled from last year's level to approximately 86 MW.[12] Distributed wind grew from 4 MW to 16 MW, and distributed storage projects interconnected to our system significantly increased from six to 35. Tables 5 and 6 below summarize current levels of distribution-interconnected DER and how much is in the queue.

Finally, we note that we have launched, or will soon, several pilots to build on our clean energy leadership by investing in infrastructure to increase access to electric vehicles (EV) and help drivers and fleet operators start driving electric. Our pilots include a Fleet EV Service Pilot, which is studying Company investment in EV infrastructure for fleet operators, such as Metro Transit, the Minnesota Department of Administration, and the City of Minneapolis. In addition we are launching a Public Charging Pilot, which is studying investment in EV infrastructure for public charging stations along corridors and community mobility hubs to reduce the upfront cost of public charging. For residential customers we are studying ways to reduce upfront costs for customers through our Residential EV Service Pilot and studying a flat charging rate through our Residential EV Subscription Service Pilot. In addition, we have proposed to expand our Residential EV Service Pilot into a permanent offering, called EV Home Service. The Commission is considering that proposal at this time.

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[12] As of July 2019.

In total, these efforts expand upon our vision for supporting the growth of EVs that will benefit drivers, customers, the environment, and the state.

Table 5: Distribution-Connected Distributed Energy Resources – State of Minnesota
(as of July 2019)[13]

	Completed Projects		Queued Projects	
	MW/DC	# of Projects	MW/DC	# of Projects
Small Scale Solar PV				
Rooftop Solar	67	4,391	61	1,101
RDF Projects	19	25	1	2
Wind	16	61	<1	8
Storage/Batteries[14]	N/A	35	N/A	20

	Completed Projects		Queued Projects	
	MW/AC	# of Projects	MW/AC	# of Projects
Large Scale Solar PV				
Community Solar	585	208	313	286
Grid Scale (Aurora)	100	16	0	0

Table 6: Minnesota Distributed Energy Resources – Demand Side Management and Electric Vehicles

	Completed Projects		Queued Projects	
	Gen. MW	# of Projects	Gen. MW	# of Projects
Energy Efficiency	1,120	N/A	N/A	N/A
Demand Response	824	413,783	N/A	N/A
Electric Vehicles	N/A	7,081-8,500[15]	N/A	N/A

Note: Energy efficiency is cumulative since 2005.

At a system level, tools and methodologies to forecast DER adoption are similarly nascent in the industry. These forecasts rely on predicting customer behavior based on macro-economic factors, understanding potential based on topography and weather, and incorporating policy- and rate-based incentives or disincentives.

All of this supports the conclusion that Minnesota is unique from other states

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[13] Energy Efficiency and Demand Response are as of December 31, 2018.
[14] All current battery projects are associated with other generation projects, such as solar. As such, the interconnection application does not capture gen. MW, as it is accounted for in other categories.
[15] We do not have information that ties our customer accounts to electric vehicle users. *See* IDP Requirement 3.A.21 below for the sources of this range.

implementing IDP in that we are not currently experiencing sizable additions of DER on our system. Rather, Minnesota is ahead in its planning and therefore able to take a measured approach and pace to IDP that allows the requirements to be implemented in a cost-effective, systematic manner that is in the public interest for all Minnesota customers.

The IDP requirements that are emerging in various states often require some form of DER analysis and forecasting – and incorporation of the results into distribution planning analyses. Traditional distribution planning involves forecasting loads for each feeder and each substation transformer, which for our system in Minnesota equates to approximately 1,700 individual forecasts. DER must be forecast by type because each type of DER has different characteristics and differing impacts on the grid. Forecasting DER penetration at a granular *feeder* level for purposes of informing distribution planning is exponentially more complex than doing so at a *system* level. We are unsure about the level of accuracy provided by any tools in such a nascent market and how refined we can get geographically without losing accuracy.

Like traditional load forecasting, DER forecasting requires utilities to use the best information about what has happened in the past and what may happen to develop a picture of what is likely to happen in the future. But DER forecasting diverges from traditional load forecasting when it comes to the inputs; the historical data used for traditional load forecasting is simply not available or necessarily accurate for most DERs. Industry tools and methodologies to incorporate DER into annual distribution plans and planning processes are emergent and immature. Nationally, regulators, utilities, stakeholders, service providers, and others are working to determine methodologies, processes, and tools that will meet the forecasting needs that are emerging in states such as California, New York, and Hawaii.

While we used our present tools and methodologies to inform overall system DER forecasts in this IDP, as we have noted, we are in the process of procuring an advanced planning tool that will help the Company better understand the locational and temporal impacts of DER. The good news from a distribution planning perspective is that Minnesota is presently at comparatively low levels of DER penetration that can reasonably be expected to remain stable in the near-term. Further, our present tariffs require interconnecting parties to mitigate adverse impacts identified in the interconnection application process.

III. ACTION PLAN SUMMARY

The first five years of our action plan will be busy – focused on providing customers with safe, reliable electric service, advancing the distribution grid with foundational and core capabilities including AMI, FAN, FLISR, and IVVO – and procuring and integrating an advanced system planning tool to improve our distribution load forecasting, planning, and DER and NWA analysis capabilities. As discussed further below, all of these investments will provide our customers with value, which is why we are asking the Commission to certify them in connection with this IDP.

IV. PROCEDURAL PROPOSAL

As we have noted, we are seeking to certify an array of investments to modernize the Company's distribution system, pursuant to Minn. Stat. § 216B.2425. Specifically, we are seeking certification of an advanced distribution planning tool and a number of investments that are part of what is collectively referred to as the AGIS initiative: Advanced Metering Infrastructure, a private secure Field Area Network, a form of distribution automation that decreases the duration of and number of customers affected an outage (FLISR), and Integrated Volt Var Optimization, which decreases system losses and optimizes voltage as power travels from substations to customers.

These investments expand on the advanced grid investments previously approved by the Commission, namely the ADMS that will go into service in 2020. Each of these investments will take years to fully implement, and we are requesting that the Commission certify the AGIS projects so that the Company may request recovery of costs in concurrent or subsequent filings, as necessary. This is consistent with other requests for certification for grid modernization investments, where certification enables the opportunity for the Company to request recovery of costs in a subsequent rider filing.

We are also filing a General Rate Case (Docket No. E002/GR-19-564) today with a three-year plan through which we seek cost recovery for much – but not all – of these AGIS investments. Because the span of the AGIS investments goes beyond the 2020 test year and 2021-2022 plan years identified in our MYRP filing, and in light of the concurrent submission of this 2019 IDP, our AGIS rate case testimony provides support for our AGIS investments beyond the term of the rate case and addresses Commission requirements that pertain to both certification and cost recovery for grid modernization investments. In light of this support for our long-term strategy, we believe certification of the full scope of the AGIS investments alongside a rate case cost recovery determination is critical, so that we may complete our AGIS investments at an appropriate pace and potentially include the out-year costs in a rider. Consideration of our certification request in tandem with our rate request will also be most efficient for all stakeholders. The Commission would, of course, have another opportunity for review and approval of specific costs if the Company were to seek rider cost recovery in the future.

Because of this dual filing approach, and in order to minimize duplication, we have provided the support for our AGIS certification request in a testimony format within the rate case, and we are including relevant portions of the testimony as attachments to this filing. We have excised unrelated portions from some witness testimony in order to provide only the relevant material. For instance, Company Witness Mr. David C. Harkness provides testimony regarding our 2020-2022 Business Systems investments for purposes of the MYRP, but not all of them are related to AGIS; we have therefore included only those sections and attachments that relate to AGIS in this IDP filing.

In addition, today we also have filed a Petition for Approval of True-Up Mechanisms. This filing requests the approval of certain true-ups for 2020 which, if approved, would result in the withdrawal of our General Rate Case. In that event, we would no longer request AGIS cost recovery through base rates until the Company's next general rate case is filed. We would, however, ask the Commission to make the more limited determination to certify the AGIS investments and Advanced Distribution Planning Tool in this IDP, so that we may plan for the implementation of our AGIS initiative, and preserve the option to put the costs of these investments in a rider between general rate case filings.

Overall, the filing requirements related to grid modernization investments, as well as for certification, are extensive, and our supporting documentation is likewise extensive and thorough. We have therefore taken several steps to facilitate review of these materials, and make them as digestible and easy to read as possible for the Commission and our stakeholders. These steps include development of executive summaries, compliance matrices, and extractions from larger pieces of testimony as noted above.

The normal procedural schedule for certification under Minn. Stat. § 216B.2425 would require a determination by June 1, 2020, and under normal circumstances, we believe the process leading to certification should resemble a resource acquisition proceeding under the Commission's normal notice and comment procedures that could, in the Commission's discretion and depending on the scope of the investment, include one or more public hearings. We recognize, however, that the schedule in the General Rate Case does not align with that timing. In addition, the AGIS initiative includes large investments and is supported by a sizeable filing that may require analysis beyond the six-month certification timeframe, even if the General Rate Case is withdrawn. Thus, we offer to work with the Commission and stakeholders to set an appropriate deadline and procedural schedule for consideration of these investments.

On a further procedural note, we respectfully request the Commission move to a biennial filing cadence for the IDP, consistent with other Minnesota utilities and the grid modernization statute filing requirements. We believe a biennial filing would better allow time to fully engage with stakeholders on the Commission's planning objectives between IDP filings, as well as to address important issues such as distributed energy resources (DER) planning, a comprehensive approach to non-wire alternatives (NWA), and our advanced grid plans. The present annual filing schedule also does not allow the Company to make significant, meaningful progress on its objectives between these extensive filings. We therefore specifically request the Commission require our next IDP be submitted on or before November 1, 2021, and biennially thereafter.

Finally, with respect to our ADMS initiative, we will be submitting an initial and ongoing annual reports in accordance with the Commission's September 27, 2019 Order in the Company's Transmission Cost Recovery (TCR) Rider Docket.[16] We propose to submit a single ADMS report by January 25, 2020 in the TCR docket and this IDP docket that contains all of the required information. We also respectfully request that the Executive Secretary establish the same January 25th due date for the ongoing annual ADMS reports beginning January 25, 2021 – and that these annual ADMS reports be filed in most recent docket of future IDPs.

[16] Docket No. E002/M-17-797.

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ATTACHMENTS

Number	Name
A1	Attachments List with Non-Public Designations
A2	Compliance Matrix
B	Correlation of IDP Content to Commission’s IDP Planning Objectives
C	IDP Grid Modernization Content Roadmap
D1	Advanced Distribution Planning Tool (APT)
D2	APT Cost Benefit Analysis Summary
E	Distribution Risk Scoring Methodology
F1	Capital Project List by IDP Category
F2	Risk Scored Project Details
G1	Capital Profile Trend
G2	O&M Profile Trend
H	Non-Wires Alternatives Analysis
I	MISO Response to FERC Data Request Docket RM-18-9-000
J	Action Plan Roadmap
K	Planning Area Load Growth Assumptions
L	Distribution Function NPV
M1	AGIS Direct Testimony – Gersack
M2	AGIS Direct Testimony – Bloch
M3	AGIS Direct Testimony – Harkness
M4	AGIS Direct Testimony – Cardenas
M5	AGIS Direct Testimony – Duggirala
N1	RFP – APT
N2	RFP – AMI
N3	RFP – WISUN
N4	RFP – IVVO
O1	AGIS Combined CBA Summary
O2	AGIS AMI CBA Summary
O3	AGIS FLISR CBA Summary
O4	AGIS IVVO CBA Summary
Workpapers	Executable CBA Model – APT
Workpapers	Executable CBA Model – AGIS

GLOSSARY OF ACRONYMS AND DEFINED TERMS

Acronym/Defined Term	Meaning
ADMS	Advanced Distribution Management System
AGIS	Advanced Grid Intelligence and Security
AMI	Advanced Metering Infrastructure
AMR	Automatic Meter Reading
ANSI	American National Standards Institute
BTM	Behind the Meter
BYOD	Bring your Own Device
CAIDI	Customer Average Interruption Duration Index
CIP	Conservation Improvement Program
CPE	Customer Premise Equipment
CPUC	California Public Utilities Commission
CRS	Customer Resource System
CVR	Conservation Voltage Reduction
DA	Distribution Automation
DER	Distributed Energy Resource
DERMS	Distributed Energy Resource Management System
DG	Distributed Generation
DG-PV	Photovoltaic Distributed Generation
DOE	Department of Energy
DR	Demand Response
DRIVE	EPRI's Distribution Resource Integration and Value Estimation tool (for Hosting Capacity Analysis)
DRMS	Demand Response Management System
DSIP	Distribution System Implementation Plan
DSM	Demand Side Management
DSPx	DOE's Next Generation Distribution System Platform
EE	Energy Efficiency
EPRI	Electric Power Research Institute
ESB	Enterprise Service Bus
ERT	Estimated Restoration Time
EV	Electric Vehicle
FAN	Field Area Network
FERC	Federal Energy Regulatory Commission
FLISR	Fault Location, Isolation, and Service Restoration
FLP	Fault Location Prediction
GIS	Geospatial Information System
HAN	Home Area Network
HECO	Hawaiian Electric Company
HEM	Home Energy Management
HPUC	Hawaii Public Utilities Commission
ICT	Innovative Clean Technology
IDP	Integrated Distribution Plan
IEEE	Institute of Electrical and Electronics Engineers

IP	Internet Protocol
ISO	Independent System Operator
IT	Information Technology
IVVO	Integrated Volt VAr Optimization
LBNL	Lawrence Berkeley National Laboratory
LCR	Local Capacity Resource
LTC	Load Tap Changers
MAIFI	Momentary Average Interruption Frequency Index
MDMS	Meter Data Management System
MISO	Midcontinent Independent System Operator
MPUC, PUC, or Commission	Minnesota Public Utilities Commission
M&V	Measurement and Verification
NIC	Network Interface Card
NIST	National Institute of Standards and Technology
MCOS	Marginal Cost of Service
NMS	Network Management System
NSPM or Company	Northern States Power Company-Minnesota Operating Company
NWA	Non-Wire Alternatives
NYPSC	New York Public Service Commission
OMS	Outage Management System
PSCo	Public Service Company of Colorado
PSIP	Power Supply Improvement Plan
PTMP	Point-to-Multi-Point
PV	Photovoltaic
QoS	Quality of Service
REV	New York's Reforming the Energy Vision initiative
RTO	Regional Transmission Operator
R&D	Research and Design
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SCE	Southern California Edison
SEPA	Smart Electric Power Alliance
SVC	Static VAr Compensators
TOU	Time of Use
VEE	Validation, Estimation, Editing
WAN	Wide Area Network
WiMAX	Worldwide Interoperability for Microwave Access
WiSUN	Wireless Smart Utility Network
Xcel Energy	Xcel Energy Inc.

I. INTRODUCTION

On August 30, 2018, the Minnesota Public Utilities Commission ordered Northern States Power, doing business as Xcel Energy to file an IDP annually beginning on November 1, 2018. We submitted our first IDP that included the information required in the Commission's August 30, 2018 Order in Docket No. E002/CI-M-18-251. We continue to provide that information in this second IDP, as well as the additional information required in the Commission's July 16, 2019 Order. As it relates to the advanced grid aspects of this IDP and the rate case filed concurrently with this IDP, the Commission's September 27, 2019 Order in Docket No. E002/M-17-797 also guided the information that we provide.

The IDP presents a detailed view of our distribution system and how we plan the system to meet our customers' current and future needs. The first five years of our action plan are focused on providing customers with safe, reliable electric service, advancing the distribution grid with foundational and core capabilities including:

- AMI, advanced metering technology which will expand the use of our meter system beyond basic billing functions for the benefit of our customers,
- A robust FAN communications network that will facilitate communications between and among advanced distribution grid equipment and AMI meters,
- FLISR, fault detection technology which will deliver significant reliability experience improvements for our customers, and
- IVVO, voltage optimization technology to realize energy savings and increase our DER hosting capacity.

We will also procure and implement an advanced planning tool that will enhance our ability perform NWA analysis, and DER and load forecast scenario analysis; it will also help to facilitate a greater alignment and integration of our distribution-transmission-resource planning.

A. Planning Landscape

The electric utility industry is in a time of significant change. Increasing customer expectations and technological advances have reshaped what customers expect from their energy service provider, and how those services are delivered. Technologies that customers can use to control their energy usage, such as smart thermostats, electric vehicle (EV) chargers, smart home devices, and even smart phones, are evolving at a fast rate. Influenced by other services, customers have come to expect more now from their energy providers than in the past, including greater choices and levels of service, as well as greater control over their energy sources and their energy use.

At the same time, major industry technological advances provide new capabilities for utility providers to manage the electric distribution grid and service to customers. Electric meters are now equipped to gather more detailed information about customer energy usage, which utilities can leverage to help customers better understand and manage their usage. Other advanced equipment on the grid is able to sense, communicate, and respond in real time to circumstances that would normally result in power outages. Grid operators can also get improved data to better and more proactively plan and operate the grid. These advancements form the foundation for a flexible grid environment that helps support two-way power flows from customer-connected devices or generating resources (such as rooftop solar) and provides utilities with a greater ability to adapt to future developments.

IDPs continue to be an emerging industry practice intended to give regulators and other stakeholders a more transparent view into the planning process of the distribution grid through a standardized process. Integrated distribution planning first appeared in states where public policies were driving substantive changes to distribution business models and grids, including the need for utilities to integrate greater and significant levels of DER. Although individuals and developers are installing DER in Minnesota, present levels and the adoption rate continues to be lower than other states that have adopted integrated distribution planning. This gives utilities and stakeholders the time to take a measured approach to implement the tools, models, and processes that ensure the grid is prepared for a more distributed future – while also balancing the costs and other implications associated with such a future.

Distribution planning has historically – and still largely today –involved analyzing the electric distribution system's ability to serve existing and future electricity loads by evaluating the historical and forecasted load levels, and utilization rates of major system components such as substations and feeders. Customers traditionally have had limited information about their energy usage and few choices in how they received information, had questions answered, and paid utility bills or conducted other necessary business with their utilities. For the most part, customers were content to receive a monthly paper bill from their utilities and were unaware and unengaged in whether the energy came from renewable or non-renewable sources.

Now, instead of planning just for load, utilities also need to analyze the system for future connections that may be load *or* generation. Also, utilities will increasingly need to view their operations and customer tools from their customers' perspectives. This step change in the distribution utility business requires utilities to plan their systems differently, which involves not only new processes and methodologies but also new and different tools and capabilities.

Over time, integrated distribution planning in Minnesota is intended to facilitate scenario-based, integrated resource-transmission-distribution planning to ensure a reliable, efficient, robust grid that will flexibly meet the challenges of a changing and uncertain future. Like other aspects of the industry that are transitioning and advancing, we are on the forefront of integrated distribution planning and, as such, are taking steps to align and integrate our distribution, transmission, and resource planning processes.

Increasing DER penetration levels will drive integrated resource planning and distribution planning closer together, however today there are fundamental differences in how these two planning activities assess and develop plans to meet customers' needs that will need to evolve over time. Distribution planning is primarily concerned with location, and resource planning is primarily concerned with size, type and timing of resources – with transmission planning somewhere in the middle. Before a greater integration of these planning processes can occur, distribution planning tools and distribution system capabilities will need to advance.

We have begun this transition. This IDP presents a detailed view of how we plan our system to meet our customers' current needs and how we intend to evolve for the future. The backbone of our planning is keeping the lights on for our customers, safely and affordably. For over 100 years, we have delivered safe, reliable electric service to our customers, and, through our robust planning process and strong operations, we will continue to do so.

We are however, also planning for the future. With this IDP, we propose to procure the next generation of distribution planning tools, which we need to increase our forecasting and analysis capabilities and help integrate our planning processes. We also propose to implement AMI, a robust and secure FAN, technology to improve customers' reliability experience – FLISR, and IVVO, which will result in energy savings and increased hosting capacity on our system.

We have a vision for where we and our customers want the grid to go, and we are implementing and installing new technologies to support our vision. We are taking a measured and thoughtful approach to ensure our customers receive the greatest value, and that the fundamentals of our distribution business remain sound.

B. Background

In 2015, the Commission opened an investigatory docket on grid modernization (Docket No. E999/CI-15-556) and issued the *March 2016 Staff Report on Grid Modernization*. Of various potential options outlined in the Staff Report, the Commission supported examining distribution system planning as the most reasonable and actionable way to assist in the forthcoming grid evolution. In doing so, the Commission also supported the staff-proposed principles as its Planning Objectives to guide further work, as follows:

- Maintain and enhance the safety, security, reliability, and resilience of the electricity grid at fair and reasonable costs, consistent with the state's energy policies,
- Enable greater customer engagement, empowerment, and options for energy services,
- Move toward the creation of efficient, cost-effective, accessible grid platforms for new products, new services, and opportunities for adoption of new distributed technologies, and
- Ensure optimized utilization of electricity grid assets and resources to minimize total system costs.

In August 2016, the Commission received the ICF International report, *Integrated Distribution System Planning*, and in October 2016, held a workshop seeking stakeholder input and discussion on a Minnesota-based distribution system planning framework. In April 2017, the Commission issued a Notice to utilities and stakeholders seeking to understand (1) how utilities currently plan their systems, (2) the status of current-year utility plans, and (3) recommendations for improvements to present planning practices. Xcel Energy submitted comments responsive to the Notice and stakeholder comments June 21, 2017, August 21, 2017 and September 21, 2017.

In January 2018, Commission staff proposed next steps to the Commission at a planning meeting – and in April 2018, established individual utility dockets and released proposed individual utility IDP filing requirements for Commission review; requirements for Xcel Energy were developed in Docket No. E002/CI-18-251. The Commission directed Staff to meet with each utility to discuss and clarify the proposed filing requirements – and afterward, release draft utility-specific IDP filing requirements for comment in June 2018. Xcel Energy submitted its comments June 20, 2018 and reply comments on July 20, 2018. The Commission determined final IDP requirements for Xcel Energy at its August 9, 2018 Agenda Meeting, and issued its Order containing the final requirements on August 30, 2018.

We submitted our first IDP November 1, 2018. Like development of the IDP requirements, the Order acknowledged integrated distribution planning as envisioned by the planning objectives will be an iterative process – set in motion with the Company's initial IDP. In setting the requirements, the Commission acknowledged the compressed timeline between the determination of final IDP requirements and the Company's initial report – and included an option for the Company to explain any gaps in its ability to fulfill each requirement. We held two stakeholder meetings – on September 12th and 26th, 2018 – that addressed the required: (1) load and DER forecasts, (2) proposed 5-year distribution system investments, and (3) anticipated capabilities of system investments and customer benefits derived from proposed actions in the next five years, including consistency with the Commission's Planning Objectives. We also held a post-filing stakeholder workshop to provide an overview of our 2018 IDP and answer questions.

The Commission considered and accepted our 2018 IDP, and issued its Order Accepting Report and Amending Requirements on July 16, 2019. The Order required the Company to submit its next IDP November 1, 2019. The amended requirements clarified the cost-benefit analysis requirements for grid modernization projects and require the Company to:

- Discuss in future filings how the IDP meets the Commission's Planning Objectives (Order Point No. 5, *See* Attachment B),
- Provide additional information on the Incremental Customer Investment Initiative and the System Expansion or Upgrade for Reliability and Power Quality increases beginning in 2021 (Order Point No. 6, *See* Asset Health Section VII.B),
- Make the development of enhanced load and DER forecasting capabilities and tracking and updating of actual feeder daytime minimum loads a priority in 2019 (Order Point No. 7, *See* Section V.D.2 and Attachment D),
- Provide all information, analysis, and assumptions used to support the cost/benefit ratio for AMI, FAN and FLISR; and IVVO and CVR cost-benefit analysis as part of its 2019 IDP filing or other future filings (Order Point No. 8, *See* Grid Modernization Content Roadmap, Attachment C),
- Provide the results of its annual distribution investment risk-ranking and a description of the risk-ranking methodology in future IDPs (Order Point No. 9, *See* Attachments E and F1),
- Provide information on forecasted net demand, capacity, forecasted percent load, risk score, planned investment spending, and investment summary

information for feeders and substation transformers that have a risk score or planned investment in the budget cycle in future IDPs (Order Point No. 10, *See* Attachment F2), and

- File any long-range distribution studies the Company conducted in the time since the last IDP (Order Point No. 11, for which we note there are none for the 2018-2019 period).

The Commission additionally specified a number of requirements associated with cost recovery of future grid modernization proposals in our Transmission Cost Recovery rider proceeding in Docket No. E002/M-17-797, which are included in the Grid Modernization Content Roadmap provided as Attachment C.

We held four stakeholder meetings leading up to our 2019 IDP: (1) a December 12, 2018 presentation of our 2018 IDP and forum for questions and feedback; (2) a Non-Wires Alternatives analysis workshop on April 10, 2019; (3) a grid modernization project cost benefit analysis framework workshop on May 17, 2019; and (4) on September 25, 2019, the workshop required by the Commission's August 30, 2018 IDP Order to present the load and DER forecasts, budgets, and 5-year action plan.

C. Report Outline

This report is organized as follows:

Section	Title	Content Summary
I.	Introduction	Overview of the planning landscape and genesis of IDP in Minnesota.
II.	Distribution System Plan Overview	Summary of our near- and long-term distribution system plans, including summary-level budget information and drivers.
III.	Budget Development Framework	Provides snapshot of budget history and forecast.
IV.	System Overview	Provides snapshot of system statistics.
V.	System Planning	Describes the process of analyzing the distribution system's ability to serve existing and future loads. Also summarizes our proposed advanced planning tool.
VI.	Non-Wires Alternatives Analysis	Discusses project types, timelines, and screening process considerations for NWA as well as related analysis.
VII.	Asset Health and Reliability Management	Describes annual capacity planning and roadmap to mature capacity planning capabilities. Outlines reliability statistics, ongoing system health assessment processes, and ISI initiative.
VIII.	Distribution Operations	Discusses operational processes, such as vegetation management and escalated operations/storm response.
IX.	Grid Modernization	Summarizes our grid modernization strategy and plans.
X.	Customer Strategy	Outlines our customer strategy and plans.
XI.	Distributed Energy Resources	Explains how DER is treated in load forecasts, present and forecasted DER levels, DER scenario analysis, and DER integration considerations.
XII.	Hosting Capacity, System Interconnection, and Advanced Inverters/IEEE 1547	Summarizes our hosting capacity analysis in the context of our overall interconnection processes. Provides interconnection statistics and related discussion.
XIII.	Existing and Potential New Grid Modernization Pilots	Outlines grid modernization and EV pilots.
XIV.	Action Plans	Outlines 5-year and long-term action plans.
XV.	Procedural Proposal	Summarizes the Company's requests and offers to work with the Commission and stakeholders to set an appropriate deadline and procedural schedule for consideration of our proposed AGIS and APT investments.
XVI.	Stakeholder Engagement	Describes stakeholder efforts related to the preparation of this IDP.
XVII.	Integrated Distribution-Transmission-Resource Planning	Discusses present state of D-T-R planning and longer-term view of deeper process alignment.
	Conclusion	

We provide as Attachment A to this IDP, a summary table of the Order Requirements that references locations in the IDP document where we provide the information responsive to each requirement. Some of these are more specific than others, which depends on the nature of the requirement. We also embedded the various requirements throughout this IDP, to signal to the reader when we would be generally or specifically responding to that requirement.

With respect to our grid modernization report, we include in the body of this IDP an executive summary of our plan and our related customer strategy. We provide as Attachment C, a roadmap of where in the attached AGIS Direct Testimony (Attachments M1 through M5) from our rate case filed concurrently with this IDP we meet the grid modernization investment and report requirements. Finally, we also provide a compact disk of the AGIS and advanced planning tool Requests for Proposals and live cost-benefit analysis models.

II. DISTRIBUTION SYSTEM PLAN OVERVIEW

In this Section, we provide a summary of our near- and long-term distribution system plans, including summary-level budget information and drivers. We first begin with a discussion of the policy goals underlying the development of our distribution system plan. We then discuss the Company's objectives in developing a distribution system plan and the framework of the Company's distribution system plan, and the development of the budget for the distribution system plan. Finally, we provide a summary of the distribution system plan, including the five-year and long-term action plans.

A. Distribution System Policy Goals

Federal and state policies and requirements – and customers – determine the key goals of regulated utilities. We believe the regulatory construct and the attributes of our service that our customers value are aligned around reasonable and affordable rates, reliable service, customer service and satisfaction, and environmental performance.

The principal source of state policy with respect to energy, utilities, and the environment are Minnesota statutes. Indeed, in the Legislative Findings section of Minn. Stat. Chapter 216B, the legislature provided a topline summary of state policy with respect to utility regulation:

> It is hereby declared to be in the public interest that public utilities be regulated as hereinafter provided in order to provide the retail customers of natural gas and electric service in this state with adequate and reliable services at reasonable rates, consistent with the financial and economic requirements of public utilities and their need to construct facilities to provide such services or to otherwise obtain energy supplies, to avoid unnecessary duplication of facilities which increase the cost of service to the consumer and to minimize disputes between public utilities which may result in inconvenience or diminish efficiency in service to the consumers.[17]

We have a strong record on reliability, ranking in the first or second quartile nationally in terms of System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) – and have received national recognition for our storm response efforts. Also, significantly, we are achieving these outcomes with total residential electric customer bills that are nearly 20 percent below the national average.

Xcel Energy has one of the longest-running and most successful demand side management (DSM) programs in the country. Between 1990 and 2018, the Company spent $1.5 billion (nominal) on Minnesota DSM efforts and saved nearly 9,700 GWh of energy and 3,600 MW of demand. We are finding new and better ways to communicate with our customers, including redesigning our website to be customer-centric, developing a state-of-the-art storm center and outage notification system, and rolling out a mobile application. Finally, we are building on our clean energy leadership through significant capital investments to increase access to EVs and help drivers and fleet operators start driving electric.

As we discuss below, the goals of our Distribution business are aligned with the regulatory construct, Minnesota state policy objectives, and our customers' interests.

B. Distribution System Plan Objectives

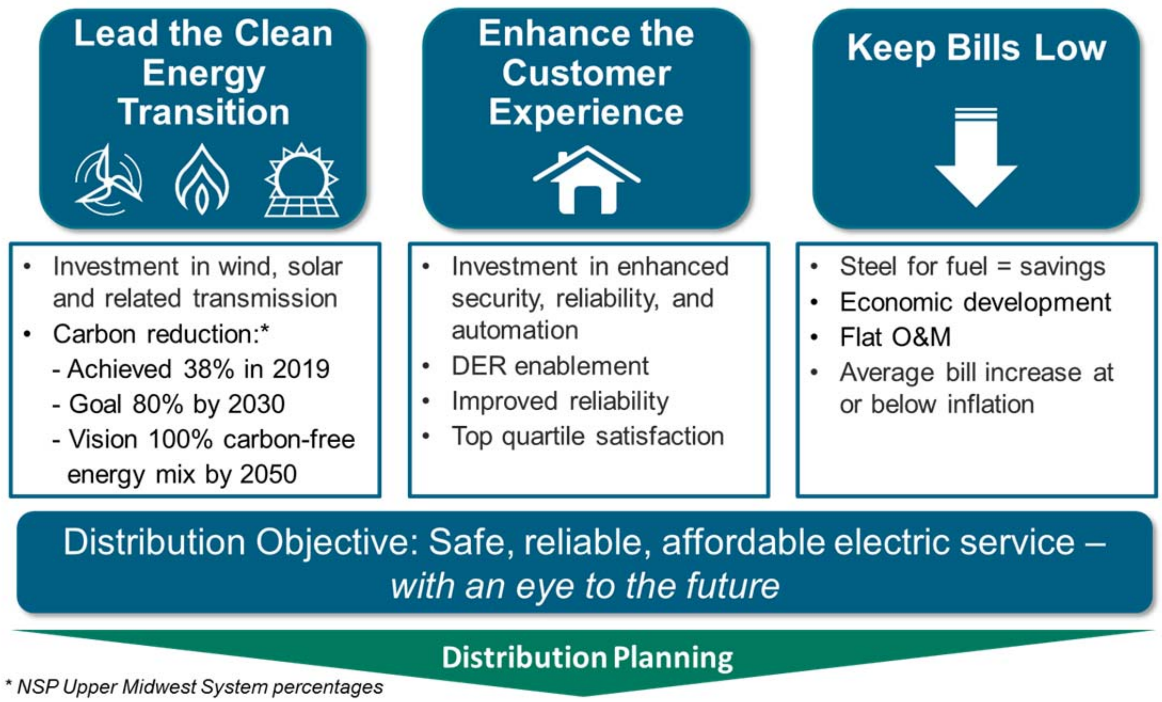
The energy landscape is evolving. Supply resources are becoming less carbon-intensive and more diverse; decentralization is accelerating – driven by advances in technology and new business models. While this evolution has been occurring at a system level, distribution systems – the portion of the system that connects directly with each and every customer – have also begun to advance. We are correspondingly planning for the future. We have a vision for where we and our customers want the grid to go, and we are implementing and installing new technologies to support our vision. We are taking a measured and thoughtful approach to ensure our customers

[17] Minn. Stat. § 216B.01

receive the greatest value and that the fundamentals of our distribution business remain sound.

Xcel Energy's strategic priorities of enhancing the customer experience, leading the clean energy transition, and keeping customer bills low are embedded in everything that we do – including the way that we plan our distribution system.

Figure 5: Xcel Energy Strategic Priorities – Applied to Distribution



The Company's Distribution organization is responsible for operating, maintaining, and constructing the distribution system to ensure that the delivery of power to our customers is safe and reliable. In fact, the Distribution organization is the frontline group out in the field implementing the key Company priorities that drive our operations on a daily basis; namely reliability, safety, and customer focus.

In terms of reliability, customers want quality, uninterrupted power – and their expectations continue to evolve and increase. To address this priority, we regularly evaluate the overall health of our system and make investments where needed to reinforce our system. This includes an asset health analysis of the overall performance of key components of the distribution system such as poles and underground cables. Based on this analysis, we develop programs and work plans to both support our customers' needs for reliable service today – and also to lay groundwork for the grid of tomorrow.

We also must make significant investments to support system capacity needs due to increased loads from existing or new customers. For example, each year we evaluate substation transformer and feeder loads to identify overload risks and potential reliability issues, which drives the capacity-related projects that we plan. We update existing infrastructure, such as our recent initiative to install new energy-efficient LED streetlights – and we respond to increases in new business such as extending service to new housing developments, which are often driven by factors outside of our control.

In terms of safety, we make investments that support both the safety of our workforce and our customers. For example, our capital investments in fleet, tools, and equipment ensure our workers have the necessary provisions and support to do their job safely and efficiently. Other examples include:

- Our vegetation management program that helps reduce preventable tree-related service interruptions and address public and employee safety,
- Our damage prevention program that helps the public identify and avoid underground electric infrastructure,
- Our pole replacement program that ensures our lines and equipment are supported by quality wood poles, and
- Our LED street lighting program improves nighttime visibility, which in turn improves overall safety for both drivers and pedestrians.

Finally, we focus on service to our customers. For example, with certain investments in our distribution system such as in System Control and Data Acquisition (SCADA) capabilities and AMI, we enhance our capabilities to better monitor and respond to system conditions such as outages – and we can provide customers more choices related to their energy use. Additional examples are our industry-leading storm response, and our efforts to improve the estimated restoration times (ERT) we provide to customers.

The Distribution business area's goal is to provide safe, reliable, and affordable electricity to our customers in the near- and long-term. As such, our distribution investment and maintenance plans are designed to reduce risk, improve reliability, manage costs, and advance the grid at the speed of value to our customers. As discussed below, we plan and budget our distribution system investments in alignment with these goals.

C. Distribution System Planning Framework

The Distribution system is the portion of the electric system that delivers energy from the transmission system to our approximately 1.5 million electric customers across the Northern States Power Company-Minnesota (NSPM) operating company service area, including approximately 1.3 million customers in Minnesota. The distribution system is the final link that allows electricity to safely and reliably reach our customers' homes and businesses. The NSPM distribution system is comprised of approximately 1,200 feeders, approximately 15,000 circuit miles of overhead conductor on over 500,000 overhead poles and over 11,000 circuit miles of underground cable. This network of feeders and lines connects 240 distribution-level substations in Minnesota.

The work performed by Distribution is essential to ensuring that the electric service our customers receive is safe, reliable, and affordable. We extend service to new customers or increase the capacity of the system to accommodate new or increased load, repair facilities damaged during severe weather to quickly restore service to customers, and perform regular maintenance and repairs on poles, wires, underground cables, metering, and transformers. Distribution is also at the forefront of working to transform the distribution grid as part of the larger AGIS initiative to enhance security, efficiency and reliability, to safely integrate more distributed resources, support electrification, and to enable improved customer products and services.

The Distribution organization is one of the Company's business units whose investments and work directly impact the daily lives of our customers. As a result, it is important that our investments are focused on achieving the Company-wide priorities of leading the clean energy transition, keeping customer bills low, and enhancing the customer experience.

D. Distribution Financial Overview

Distribution budgets are evolving based on the future of electric distribution and customers' increasing expectations for control, options, and ease of doing business. Additionally, our capital investment plans generally reflect our advanced grid initiative, as we have discussed it above. Historically, however, the overwhelming majority of our distribution budgets have been dedicated to the immediacy of customer reliability impacts and the dynamic nature of the distribution system. This includes building and maintaining feeders, substations, transformers, service lines, and other equipment – as well as restoring customers and our system in the wake of severe weather, and responding to local and other government requirements to relocate our facilities.

These three requirements are intertwined, and we respond to them by providing the following capital and O&M discussion, historical actuals, and 5-year budgets that respond to the related IDP requirements.

1. *Overview*

Historically, the overwhelming majority of Distribution's capital budget has been dedicated to maintaining the health and reliability of our facilities through replacement of aging or damaged equipment. Our planned investments continue to demonstrate a commitment to the Company's priorities of safety, reliability, and enhancing the customer experience. Our focus on the customer experience has been demonstrated through our timely response to customer electrical needs. For instance as the economy grew over the past several years, we met our customers' expectations for timely electrical connections. We also responded to customer demands to relocate our facilities due to an increased number of road construction projects in the metro area driven by the strong economy.

In the area of reliability, our capital budgets reflect a focus on maintaining the health of our existing facilities through established asset health and reliability programs with increasing investments in pole replacements. However, additional investment is needed and our capital budgets during this time period also include investments in our ISI initiative. The ISI initiative focuses primarily on the heath, reliability, and resiliency of the portions of our system that are closest to our customers such as feeder and tap lines.

Our capital budgets also show increasing strategic investments in the Company's AGIS initiative to advance distribution grid capabilities, increase our system visibility and control, and to enable expanded customer options. We will invest in the foundational elements of AGIS such as advanced meters, a FAN communication network, FLISR outage detection and restoration, and IVVO voltage improvement. These foundational elements, in concert with future investments, will provide cumulative benefits that will improve the operation and maintenance of the distribution system while also providing an improved customer experience. While we do not know exactly what the future will hold in terms of new technology or customer adoption rates of EVs and solar, we do know that the set of investments that we are proposing here are the right first building blocks.

We are also responding to customer expectations by expanding our EV programs. This includes several pilot programs that were recently approved by the Commission, a fleet EV service pilot, a public charging pilot, and a residential subscription service pilot, as well as our Petition to expand our existing successful residential service pilot and our work to develop further pilots and programs highlighted in the Company's recently filed Transportation Electrification Plan. These investments will provide the infrastructure necessary to promote greater EV use and to meet the demands of the growing EV market.

The budget process that we utilize has generally proven to be an accurate gauge of the routine work that will be performed each year. However, sometimes there are storms or new business fluctuations that can lead to unexpected increases in our routine work. When these circumstances arise, we seek to actively control our expenditures to stay as close to budget as reasonably practicable by prioritizing our work and allocating funds accordingly. In this way, the Distribution organization is unique from many other business units. While we are confident in our overall level of budgeting and our ability to manage within those annual budgets, the realities of our business require some flexibility within those budgets to respond to changing economic conditions, weather events, and evolving priorities. That being said, we are proud of our successful storm response efforts, reputation for reliable service, and our ability to manage our budget within its bounds and react and reprioritize as necessary each year to ensure our customers continue to receive safe and reliable electric service.

Our capital projects fall into eight capital budget groupings depending on the primary purpose of the project as follows: (1) Asset Health and Reliability; (2) AGIS (3) New Business; (4) Capacity; (5) Mandates; (6) Tools and Equipment; and (7) Electric Vehicle Program; and (8) Solar Gardens.

For purposes of the IDP, we are required to report and discuss distribution system spending in the following categories: (1) Age-Related Replacements and Asset Renewal, (2) System Expansion or Upgrades for Capacity, (3) System Expansion or Upgrades for Reliability and Power Quality, (4) New Customer Projects and New Revenue, (5) Grid Modernization and Pilot Projects, (6) Projects related to local (or other) government-requirements, (7) Metering, and (8) Other.

In the following sections, we portray our capital costs in the IDP categories. We note that we are unable to similarly portray our O&M costs in these categories, which we discuss in more detail below.

2. *Specific Budget Information*

IDP Requirement 3.A.26[18] requires the following:

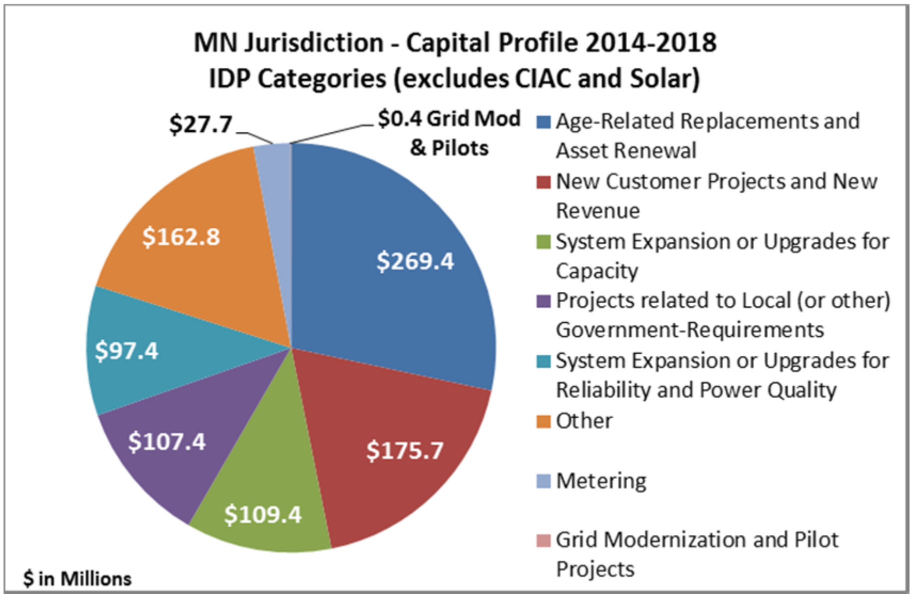
> *Historical distribution system spending for the past 5-years, in each category:*
> *a. Age-Related Replacements and Asset Renewal*
> *b. System Expansion or Upgrades for Capacity*
> *c. System Expansion or Upgrades for Reliability and Power Quality*
> *d. New Customer Projects and New Revenue*
> *e. Grid Modernization and Pilot Projects*
> *f. Projects related to local (or other) government-requirements*
> *g. Metering*
> *h. Other*
>
> *For each category, provide a description of what items and investments are included.*

a. Capital – Historical Actual and Budgeted Expenditures

As noted above, we have categorized our historical actuals and 5-year budgeted amounts into the IDP categories. Figures 6 and 7 below provide a summary of historical actual and budgeted capital expenditures in the IDP categories. We discuss these categories in more detail in below.

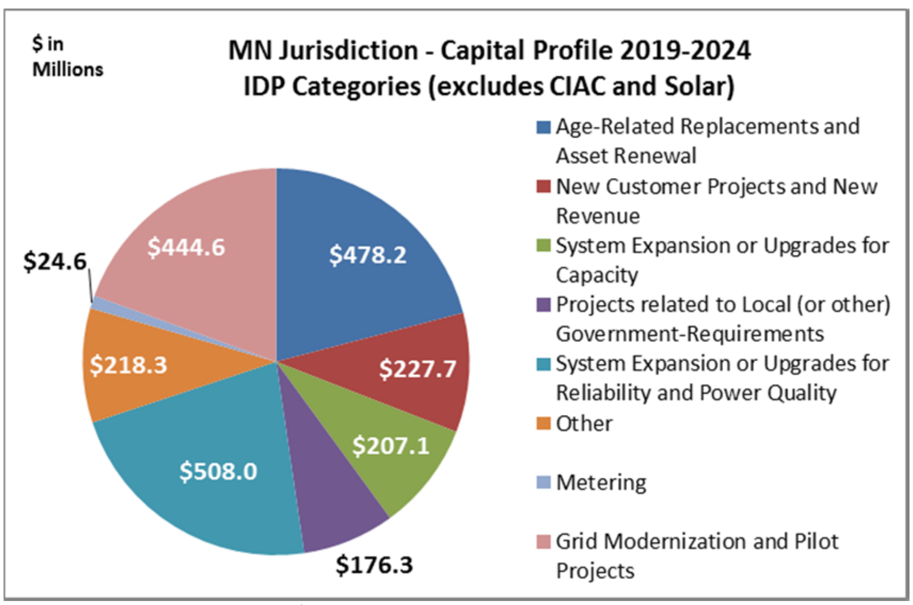
[18] This IDP Requirement also provides that the Company may include in the IDP any 2018 or earlier data in the following rate case categories: (a) Asset Health; (b) New Business; (c) Capacity; (d) Fleet, Tools, and Equipment; and (e) Grid Modernization.

Figure 6: Actual Historical Distribution Capital Profile by IDP Category State of Minnesota – Electric 2014-2018 (Millions)



Note: excludes non-investment amounts.

Figure 7: Budgeted Distribution Capital Profile by IDP Category State of Minnesota – Electric 2019-2024 (Millions)



Note: excludes non-investment/CIAC amounts.

IDP Requirement 3.A.28 requires the following:

> *Projected distribution system spending for 5-years into the future for the categories listed [in 3.A.26], itemizing any non-traditional distribution projects.*

Table 7 below provides an overview of our 5-year capital budget in the IDP categories. We provide a list of planned projects as Attachment F1 to this IDP. We understand "non-traditional distribution projects" to include projects such as a NWA in place of a traditional distribution infrastructure investment, such as a new feeder or substation. Accordingly, we clarify that do not have any specific non-traditional distribution projects in our 5-year budget.

Table 7: Distribution Capital Expenditures Budget – State of Minnesota Electric (Millions)

	Bridge Year	Budget					Budget Ave
IDP Category	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2020-2024**
Age-Related Replacements and Asset Renewal	$72.5	$87.2	$79.5	$78.3	$79.7	$81.0	$81.1
New Customer Projects and New Revenue	$34.8	$35.6	$39.3	$39.3	$39.4	$39.4	$38.6
System Expansion or Upgrades for Capacity	$19.5	$44.4	$40.1	$32.3	$32.9	$37.9	$37.5
Projects related to Local (or other) Government-Requirements	$31.3	$28.9	$29.4	$28.5	$29.0	$29.2	$29.0
System Expansion or Upgrades for Reliability and Power Quality	$19.8	$21.5	$114.7	$117.4	$117.3	$117.3	$97.6
Other	$26.7	$38.3	$39.7	$43.2	$35.4	$35.1	$38.3
Metering	$6.7	$5.5	$4.3	$3.5	$2.3	$2.3	$3.6
Grid Modernization and Pilot Projects	$4.6	$19.9	$49.3	$141.7	$152.4	$76.7	$88.0
Non-Investment	($4.9)	($3.7)	($3.7)	($3.8)	($3.8)	($3.8)	($3.8)
TOTAL	**$210.9**	**$277.5**	**$392.6**	**$480.3**	**$484.6**	**$415.2**	**$410.0**

Notes: Excludes Grid Modernization –Other includes Fleet, Tools, Communication Equipment, Locating, Transformer Purchases and the Advanced Planning Tool; Reliability includes placeholder investments for a new reliability program (Incremental System Investment); and Non-investment includes Contributions In Aid of Construction (CIAC), which partially offset total project costs and 3rd party reimbursements for system upgrades due to interconnections and Solar, which is 100% reimbursable by the developers, annual totals will vary based on payment and project timing.

We clarify that the Metering category above reflects 'business-as-usual' metering costs – not metering expenditures associated with our AMI plans.

Significant investments in the Distribution 5-year budget include our incremental system investment, or ISI initiative, which is included in the System Expansion or Upgrades for Reliability and Power Quality category. The ISI initiative focuses primarily on the heath, reliability, and resiliency of the portions of our system that are closest to our customers such as feeder and tap lines. The advanced planning tool is in the Other category, and as we have noted previously, involves approximately $4 million of initial investment for NSPM. Finally, our Distribution budget reflects our commitment to advancing EVs in Minnesota, with over $25 million in the Grid Modernization and Pilots IDP category in associated with approved and pending EV proposals.

Ordering Point No. 6 of the Commission's July 16, 2019 Order in Docket No. E002/CI-18-251 requires that we provide additional information on the Incremental Customer (now System) Initiative and the System Expansion or Upgrade for Reliability and Power Quality increases beginning in 2021. We note that we provide this discussion in Section VII.C.

Also significant are our grid modernization investments, which we present separately however, because the overall project costs involve both Distribution and Business Systems amounts. See Table 8 below.

Table 8: Grid Modernization Capital Expenditures Budget – NSPM Electric (Millions)

	MYRP Case Period			5-Year Period	10-Year Period
Component	**2020**	**2021**	**2022**	**2023-2024**	**2025-2029[19]**
ADMS[20]	$6.5	$1.0	$3.0	$7.5	-
AMI[21]	$14.0	$28.9	$144.0	$185.2	$15.0
FAN[22]	$14.7	$37.3	$36.8	$3.8	-
FLISR	$3.5	$8.6	$6.6	$18.8	$29.7
IVVO	$0.1	$6.5	$9.8	$18.6	-
Total	**$38.8**	**$82.3**	**$200.2**	**$233.9**	**$44.7**

In terms of grid modernization, ADMS represents approximately $18.0 million in the 2020-2024 timeframe. Our full AMI deployment is planned to begin in 2021 and continue through 2024, with projected capital costs for AMI and FAN of approximately $275.7 million through 2022, and approximately $204 through the 2029 IDP period, for a total of approximately $480 million.[23] FLISR implementation is planned to begin in 2021 and continue at a relatively steady rate through 2028, with projected capital costs of approximately $18.7 million through 2022, and approximately $48.5 through the 2029 IDP period, for a total of approximately $67 million. Finally, IVVO implementation is planned to begin in 2021 and continue through 2024, with projected capital costs of approximately $16.4 million through 2022, and approximately $18.6 million through the 2029 IDP period, for a total of approximately $35 million.

IDP Requirement 3.A.29 requires that we provide our planned distribution capital projects, including drivers for the project, timeline for improvement, and summary of

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[19] Period may include additional assumptions, including inflation and labor cost increases that are not part of the capital budget in periods 2020-2024.
[20] Eligible for cost recovery through the TCR Rider.
[21] Includes the TOU Pilot.
[22] Includes the TOU Pilot.
[23] Note: Table 3 includes the AGIS O&M budgets as outlined in more detail in the AGIS section.

anticipated changes in historical spending – with the driver categories aligning with the IDP distribution spending categories. We provide this information as Attachments F1 and G1 to this filing.

b. O&M – Historical Actuals and Budgeted Expenditures

The O&M budget is composed of labor costs associated with maintaining, inspecting, installing, and constructing distribution facilities such as poles, wires, transformers, and underground electric facilities. It also includes labor costs related to vegetation management and damage prevention, which is primarily provided by contractors. Finally, it includes the fleet (vehicles, trucks, trailers, etc.) and miscellaneous materials and minor tools necessary to build out, operate, and maintain our electric distribution system. We therefore generally track our Distribution O&M expenditures in the following groupings: (1) Internal Labor, (2) Contract Labor, (3) Fleet, and (4) Materials.[24]

Unlike our capital budgets, where it was possible to undertake a manual process to assign projects to the proposed investment categories, the O&M budget does not lend itself to such a manual process. The Distribution O&M budgets are a compilation of many thousands of small expenditures, most of which are associated with operating or maintaining existing facilities. While there is often a small O&M component associated with capital projects, the amount is typically small, ranging from two to seven percent of project costs, on average, for distribution. This results in voluminous small O&M charges dispersed over many projects than cannot be aggregated in the now-required categories.

We have however been able to provide a partial "functional" view of both historical actuals and 5-year budgeted amounts. Because we have budgeted for AGIS as a specific initiative, we are able to portray the associated Distribution-only O&M amounts (Table 9), and a combined Distribution and Business Systems view (Table 10).

Additionally, while both the capital and O&M information we provide in this IDP are generally for the Distribution function, the O&M information is portrayed at the NSPM operating company level and the capital costs are for the State of Minnesota, and are not fully comparable.[25] An NSPM view of historical and budgeted O&M

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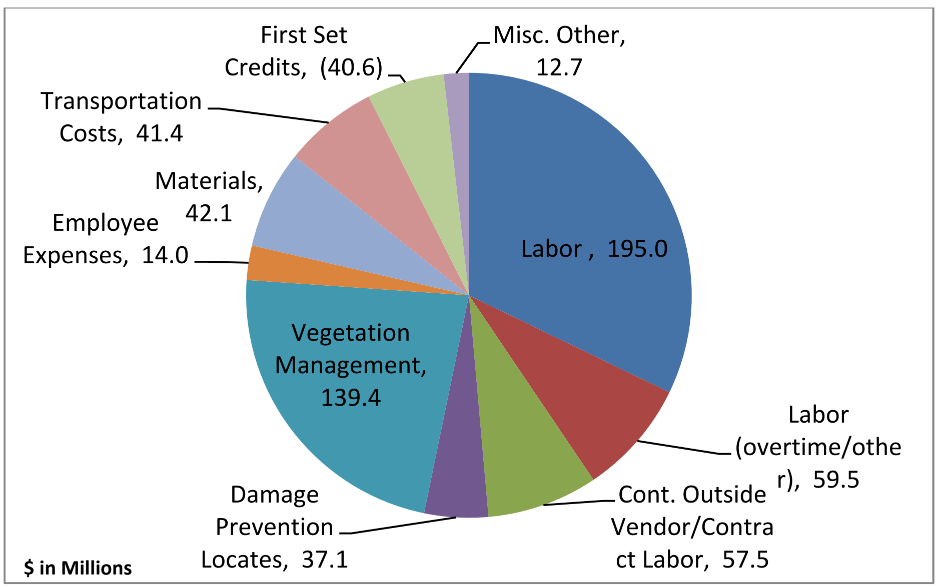
[24] As we also explained in our 2018 IDP, the IDP categories do not correspond with our internal system tracking for capital or O&M.

[25] A "functional" view of a business area, in this case Distribution, are costs directly associated with that function, so will not include allocations for items such as shared services.

provides a directionally accurate view of the O&M costs for the state of Minnesota, as Minnesota represents the overwhelming majority of the NSPM operating company. Further, an NSPM operating company view also makes it possible to portray the corresponding Business Systems-related AGIS costs.

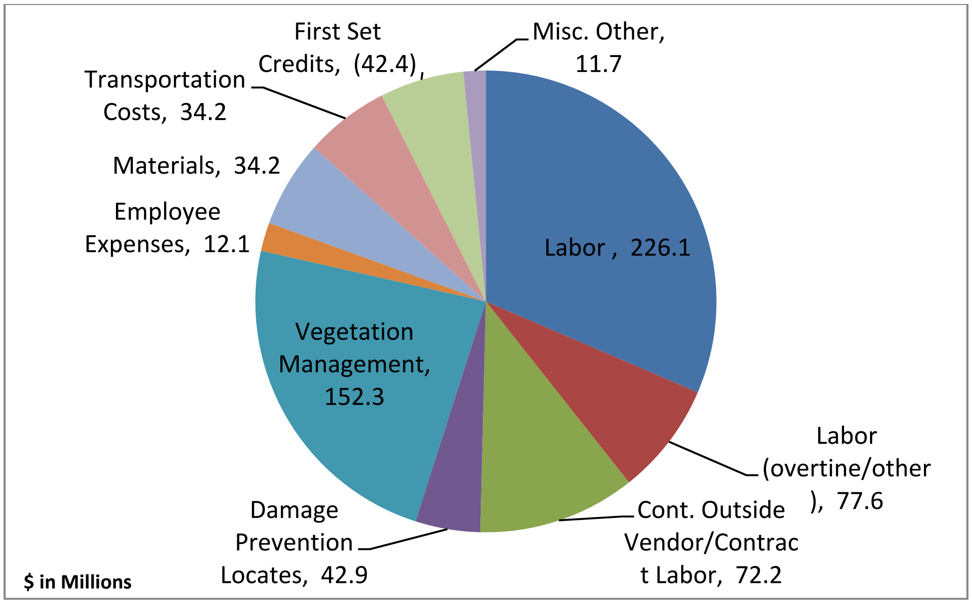
Figures 8 and 9 below provide a summary of historical actual and budgeted O&M costs in the most descriptive way that we were able to portray them given the reasons we have discussed. Following these Figures, we provide a description of the categories. Although only required for capital under IDP Requirement 3.A.29, we provide a similar view of our O&M costs over time, along with a brief narrative regarding year-over-year changes as Attachment G2 to this IDP.

Figure 8: Actual Historical Distribution O&M Costs by Cost Element NSPM Operating Company – Electric 2014-2018 (Millions)



Capital and O&M expenditures associated with the advanced grid initiative are presented separately as a holistic initiative; The average Contract Outside Vendor annual expense related to Vegetation Management and Damage Prevention are $27.9M and $7.4M, respectively; Misc. Other: Includes bad debt, use costs, office supplies, janitorial, dues, donations, permits, etc.

Figure 9: Budgeted Distribution O&M Costs by Cost Element NSPM Operating Company – Electric 2020-2024 (Millions)



Capital and O&M expenditures associated with the advanced grid initiative are presented separately as a holistic initiative; The average Contract Outside Vendor annual expense related to Vegetation Management and Damage Prevention are $30.5M and $8.6M, respectively; Misc. Other: Includes bad debt, use costs, office supplies, janitorial, dues, donations, permits, etc.

Labor and Labor (overtime/other). This category includes the labor and labor overtime associated with Xcel employee's to operation and maintain our electric distribution system. The labor pertains to the maintenance and operations of our electric distribution system. Overtime is primarily associated in response to outages, line faults, damages to our system and customer requested orders.

Contract Labor/Consulting. This category includes staff augmentation and contract outside vendors performing operations and maintenance work on our distribution systems. This also includes the delivery services for meters and transformers along with ancillary services such as barricades, flaggers, restoration, sand and gravel, etc. This is also the category where the majority of the AGIS dollars are budgeted.

Damage Prevention/Locating. This category includes costs associated with the location of underground electric facilities and performing other damage prevention activities. This includes our costs associated with the statewide "Call 811" or "Call Before You Dig" requirements, which helps excavators and customers locate underground electric infrastructure to avoid accidental damage and safety incidents.

Vegetation Management. This category includes the work required to ensure that proper line clearances are maintained, maintain distribution pole right-of-way, and address vegetation-caused outages.

Employee Expenses. This category includes the costs associated with expenditures for training, safety *meetings, travel and conferences associated with our electric distribution systems.*

Materials. This category represents costs associated with miscellaneous materials and tools necessary to build out, operate, and maintain our electric distribution system.

Transportation. This category represents costs associated with the Distribution fleet (vehicles, trucks, trailers, etc.) necessary to build out, operate, and maintain our electric distribution system, including annual fuel costs plus an allocation of fleet support.

Miscellaneous Other. This category represents the O&M expenditures that include office supplies, janitorial costs, dues, donations, permits, electric use costs, electric safety clothing for the crews, permits and other various items minor costs.

The First Set Credits. This category is the credit for the costs (labor, materials, transportation) in O&M associated with the installation of new meters and transformers.

Table 9 below provides a snapshot of our 2020-2024 O&M distribution budget.

Table 9: Distribution O&M Expenditures Budget – NSPM Electric Jurisdiction

Expenditure Category	Bridge 2019	Budget 2020	Budget 2021	Budget 2022	Budget 2023	Budget 2024	Budget Avg 2020-2024
Labor	$53.8	$58.3	$59.8	$60.5	$61.6	$63.6	$60.8
Cont. Outside Vendor/Contract Labor	$17.1	$8.9	$12.9	$9.7	$8.7	$8.6	$9.8
Damage Prevention Locates	$8.3	$8.5	$8.6	$8.6	$8.6	$8.6	$8.6
Vegetation Management	$29.0	$28.2	$28.9	$28.4	$30.2	$30.1	$29.2
Materials	$5.9	$6.9	$6.8	$6.8	$6.8	$6.8	$6.8
Transportation Costs	$7.4	$6.9	$6.8	$6.8	$6.8	$6.8	$6.8
AGIS	$0.6	$2.8	$4.5	$6.8	$8.8	$6.5	$5.9
Misc. Other	($0.2)	($3.9)	($3.6)	($3.6)	($3.4)	($3.5)	($3.6)
TOTAL	**$121.9**	**$116.6**	**$124.7**	**$124.0**	**$128.1**	**$127.5**	**$124.2**

Capital and O&M expenditures associated with the advanced grid initiative are presented separately as a holistic initiative; Misc Other includes bad debt, First Set Credits, use costs, office supplies, janitorial, dues, donations, permits, etc.

Significant O&M expenditures in the Distribution 5-year budget include the incremental programs of AGIS and ISI.

Consistent with how we present the capital budget for our grid modernization investments, we separately present the O&M to provide a complete view of both Distribution and Business Systems amounts. See Table 10 below.

Table 10: Grid Modernization O&M Expenditures Budget – NSPM Electric (Millions)

	Rate Case Period			5-Year Period	10-Year Period
AGIS Component	**2020**	**2021**	**2022**	**2023-2024**	**2025-2029**[26]
ADMS[27]	$1.9	$2.5	$2.5	$6.9	$5.2
AMI[28]	$6.6	$16.4	$14.1	$25.2	$67.2
FAN[29]	$0.1	$2.3	$1.5	$0.5	$8.6
FLISR	$0.2	$0.4	$0.3	$3.3	$2.5
IVVO	$0.0	$0.4	$0.8	$0.6	$0.8
Total	**$8.8**	**$22.0**	**$19.2**	**$36.5**	**$84.3**

In terms of grid modernization, ADMS represents approximately $19 million of O&M in through the 2029 period of this IDP. AMI and FAN comprise approximately $41 million of O&M through 2022, and approximately $101 million through the 2029 IDP period, for a total of approximately $142 million.[30] FLISR has projected O&M costs of approximately $0.9 million through 2022, and approximately $5.8 through the 2029 IDP period, for a total of approximately $6.7 million. Finally, IVVO has projected O&M costs of approximately $1.2 million through 2022, and approximately $1.4 million through the 2029 IDP period, for a total of approximately $2.6 million.

E. Distribution System Plan Summary

We summarize our near-term and long-term action plans below, and discuss them in more detail in Section XIV of this IDP.

1. 5-Year Action Plan

The first five years of our action plan will be focused on providing customers with safe, reliable electric service, advancing the distribution grid with foundational capabilities including AMI, FAN, FLISR, and IVVO – and procuring and integrating

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26 Period may include additional assumptions, including inflation and labor cost increases that are not part of the O&M budget in periods 2020-2024.
27 Eligible for cost recovery through the TCR Rider.
28 Includes the TOU Pilot.
29 Includes the TOU Pilot.
30 Includes the TOU Pilot

an enhanced system planning tool to improve our load forecasting capabilities and increase our DER and NWA analysis capabilities.

After finalizing procurement of the advanced planning tool, we will begin design, implementation, testing over the next several months. We plan to begin using the new planning tool in our distribution planning processes by late 2020 – utilizing it for our annual planning process in Fall 2020 for the 2021-2025 period. We discuss the actions specific to our proposed advanced planning tool in more detail in Attachment D1.

We summarize our proposed AGIS deployment below:

Table 11: Deployment Timeline

Program	Implementation Timeline
ADMS	In-service 2020
AMI	Meter roll-out 2021-2024
FAN	Deployment 2021-2024 (preceding AMI deployment approximately six months)
FLISR	Limited testing 2020; Implementation 2020-2028
IVVO	Limited testing 2021; Implementation 2021-2024

With respect to our ADMS initiative, we will be submitting an initial and ongoing annual reports in accordance with the Commission's September 27, 2019 Order in the Company's Transmission Cost Recovery (TCR) Rider Docket.[31] The timeline for the initial report is 120 days after the date of the Order (January 25, 2020); the timing and procedure for the annual report will be set by the Executive Secretary. Because the initial and ongoing annual reports contain most of the same elements, we propose to submit a single ADMS report by January 25, 2020 in the TCR docket and this IDP docket that contains all of the required information. We also respectfully request that the Executive Secretary establish the same January 25th due date for the ongoing annual ADMS reports beginning January 25, 2021 – and that they be filed in the same docket as future IDPs.

Finally, we will also begin implementing our ISI initiative, with projects starting in the 2021-2022 timeframe.

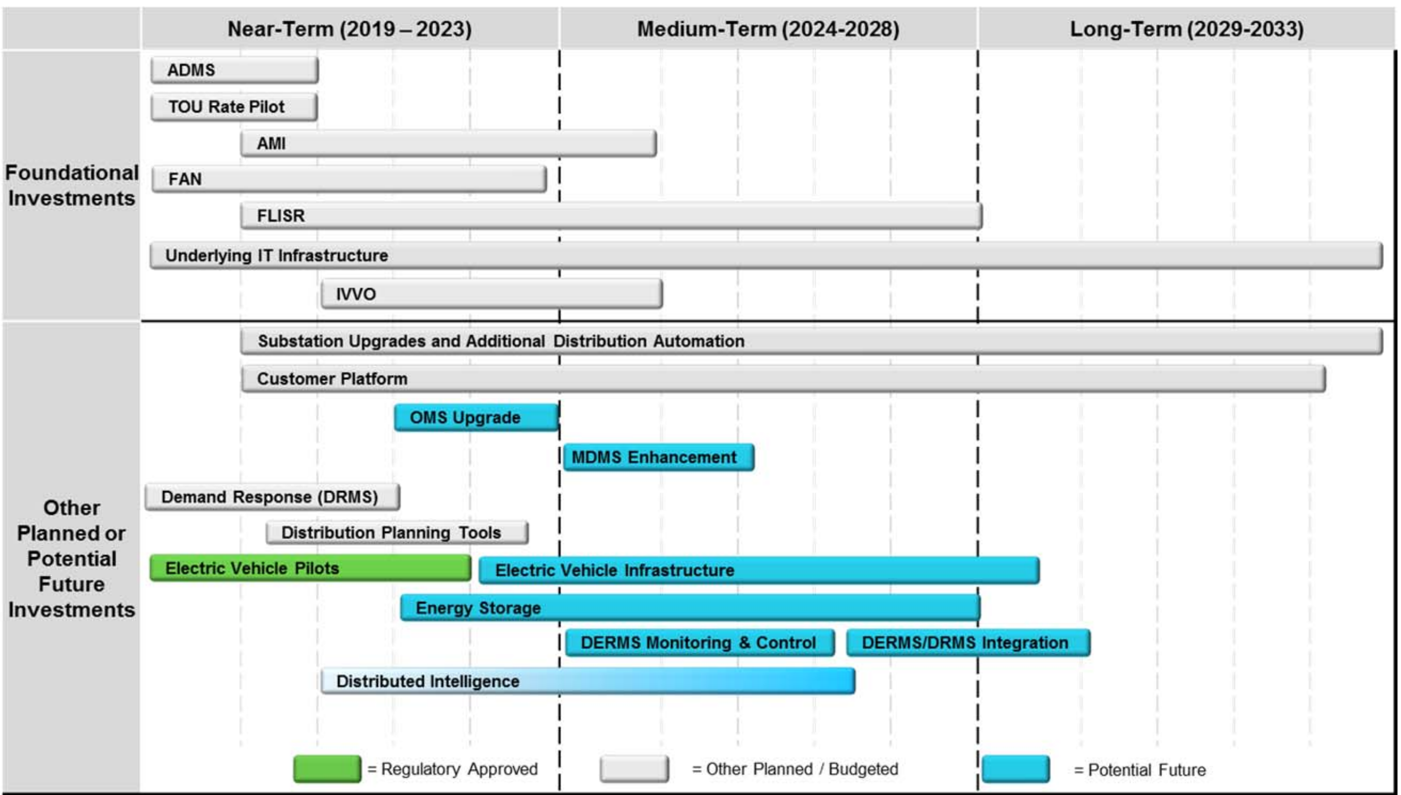
2. *Long-Term Action Plan*

Long-term, we are focused on continuing to provide our customers with reliable and

[31] Docket No. E002/M-17-797.

safe service – and advancing the grid at the speed of value for our customers. In terms of grid advancement, the below figure shows the sequencing of planned and potential advanced grid investments over time and constitutes our advanced grid roadmap.

Figure 10: Advanced Grid Initiatives – Present to 2030 View



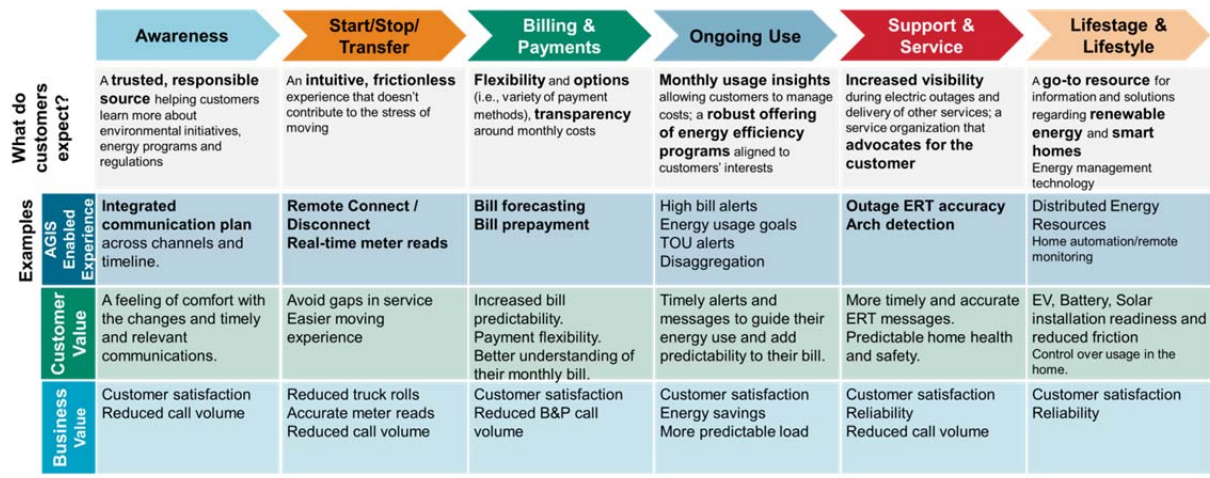
Each of these investments will provide discrete customer benefits and the combination of these investments over time will enable more sophisticated capabilities as we discuss and detail in the accompanying rate case AGIS Direct Testimony provided as Attachments M1 through M5 to this IDP.

3. *Projected Customer and System Impacts*

Our implementation of the ADMS in early 2020 is preparing the grid for increasing levels of DER. It is also paving the way for further grid advancement with AMI and our ability to leverage the underlying and necessary FAN to reduce customers' energy costs through IVVO, improve customers' reliability experience through FLISR, and more.

Customers will have access to granular energy usage data from our AMI through a customer portal, which we expect to pair with informed insights and helpful tips on how to change their behavior to save energy. Further, the AMI meters we propose include a Distributed Intelligence platform, which essentially provides a computer in each customer's meter that will be able to "connect" usage information from the customer's appliances for further insights – and be updated with new software applications, much like customers can currently update their mobile devices with applications.

Figure 11: Customer Value through Lifecycle



In terms of bill impacts from our AGIS investments, the below table illustrates the incremental cost of pursuing our AGIS investments compared to the investments that would otherwise be necessary.

Table 12: Estimated Monthly Bill Impact – Typical Residential Customer

	2020	2021	2022	2023	2024
AGIS	$0.44	$1.33	$1.84	$2.58	$2.87
Reference Case	$.01	$0.19	$0.62	$1.18	$1.51
Difference	**$0.43**	**$1.14**	**$1.22**	**$1.40**	**$1.36**

The costs of AGIS will be spread over the implementation period, which reasonably manages the cost impact for our customers. We discuss these calculations and the significant non-quantifiable impacts in Section IX and X of this IDP and in the accompanying MYRP Direct Testimonies of Company witnesses Mr. Gersack, Ms. Bloch, Mr. Harkness, Mr. Cardenas, and Dr. Duggirala.

III. BUDGET DEVELOPMENT FRAMEWORK

This section discusses Xcel Energy's overall budget development, as well as the Distribution organization's specific budget development processes.

A. Overview of Xcel Energy's Overall Budgets

Electric and gas utilities are long-term, capital intensive businesses. Every year, we prepare a five-year financial forecast that is used to anticipate the financial needs of each of the Xcel Energy operating utility companies, including NSPM. The five-year forecast provides the information necessary to make strategic and financial decisions to address these needs, and to develop supportable and attainable financial plans for each operating utility subsidiary and for Xcel Energy overall. Key components of the five-year financial forecast are the O&M and capital expenditure five-year budgets for each of Xcel Energy's operating utility subsidiaries, including the NSPM.

When a five-year budget is created and approved, the first year budget is essentially "locked in." However, budgets for the subsequent years 2-5 will be reevaluated in the next budgeting cycle, and will necessarily change in response to new developments and as business requirements change. As we get closer to when spending will occur, our forecasts become more refined, based on more relevant information for the upcoming period, and forecasted expenditures are adjusted accordingly.

To a large extent, the O&M and capital budgeting process are the same. The capital budget process however, requires additional steps and approvals for capital projects with expenditures over $10 million. Likewise, capital projects with expenditures over $50 million also require additional steps. In terms of review and oversight of expenditures after budgets are finalized, we conduct the same monthly review and variance analysis for both O&M and capital expenditures – and an additional comprehensive review on a quarterly basis.

B. Distribution Budget Framework

We begin our budgeting process in October by reviewing the recent summer peak loads to identify new or increased risks, as discussed in the System Planning section of this IDP. The state of the economy has a significant impact on the development of new and expanded business, conditions that drive new housing, large commercial load increases, and road work projects that affect distribution facilities. Consequently, our budgeting process begins with economic forecasting and analysis of historical spending trends to assess likely new business needs, required replacement of assets, and relocation of distribution facilities to accommodate road construction. We also assess the likely impacts of system growth on our capacity needs, including the risk of overloads and the system's ability to handle single contingency events.

Although economic factors drive much of our budget, we also must ensure that the existing system remains reliable. This includes proactively replacing assets near the end of their life as well as budgeting for replacement of facilities due to unanticipated failure or damage such as those facilities damaged during storms. To budget for proactive replacements, we evaluate the age and condition of facilities and determine the amount of replacement or refurbishments that are needed in a particular year. To budget for unanticipated failures, we forecast the likely costs of replacing assets that will fail or be damaged based on historical trends. This analysis results in an identification of capital projects that are needed for routine work necessary to maintain our existing system and the work required to support new customers or new construction.

The nature of the distribution system is that we must account for regular, common capital additions needed to support new business growth, system reinforcements, or rebuilds. This routine work can also include material upgrades to the distribution network, such as reconductoring a line, upgrading a distribution transformer, or replacing a substation regulator. The two largest categories of routine capital additions are cable replacements and transformer purchases.

Our budgeting process also provides flexibility to efficiently allocate funds for performing core business functions. After the preliminary forecasts estimating our new service needs have been determined, the data is reviewed with our management to determine if there will be substantial changes in the operations (e.g., crew mix, major projects, and labor issues). Depending on the outcome of these reviews, adjustments are made to the preliminary forecast and the proposed routine work order budgets are then submitted for final approval.

The budget process that we utilize has generally proven to be an accurate gauge of the routine work that will be performed each year. However, sometimes there are storms or new business fluctuations that can lead to unexpected increases in our routine work. When these circumstances arise, we seek to actively control our expenditures to stay as close to budget as reasonably practicable by prioritizing our work and allocating funds accordingly. For example, if we have a significant increase in required relocations in a given year, this may cause us to have to decrease funding in other areas. Our work on these required relocations – even when we have been given very short notice – cannot be deferred due to our contractual obligations. To maintain investment levels we must defer controllable projects which can reasonably be reduced upon short notice.

In addition to our routine work orders, the Distribution business area also budgets for and implements certain discrete projects that are identified to address a particular need that does not reoccur each year. At a high level, the identification and assessment of problems or "risks" along with their related solutions or "mitigations" is integral to identifying larger projects we must also fund. Risks are issues that can result in negative consequences to the Company's ability to provide safe and reliable service. Mitigations are solutions that address the risks. To help ensure that each risk is being addressed by the most efficient solution, we assess all mitigation alternatives and select the one that provides the best value to our customers and our Company.

All the risks and mitigations are submitted as project requests and entered into RiskRegister, a software tool developed by the Company and used to track and rank projects based on the inputs, which include information regarding their annual costs and benefits. Budgeting personnel focus on the health and age of our existing assets, standardization, and mitigation of risk, and provide coordination and consistency in evaluating individual project requests with the Distribution organization. Engineering and operations personnel then work with budgeting personnel around each risk to evaluate and score each mitigation individually before ranking the projects. The factors that are used to score the identified risks and proposed mitigations are as follows:

- *Reliability* – Identification of overloaded facilities, potential for customer outages, annual hours at risk, and age of facilities;
- *Safety* – Identification of yearly incident rate before and after the risk is mitigated;
- *Environmental* – Evaluation of compliance with environmental regulations. To the extent this factor applies to the project being evaluated, it is prioritized, however this factor is not usually applicable;
- *Legal* – Evaluation of compliance before and after the risk is mitigated; and
- *Financial* – Identification of the gross cash flow, such as incremental revenue, realized salvage value, incremental recurring costs, etc., and identification of avoided costs such as quality of service pay-outs and failure repairs.

An analysis of these factors results in a proposed project list that is ranked. The highest priority is given to projects that Distribution must complete within a given budget year to ensure that we meet regulatory and environmental compliance obligations and to connect new customers.

1. *Capital Budget Development*

Historically, the overwhelming majority of Distribution's capital budget has been dedicated to maintaining the health and reliability of our facilities through replacement of aging or damaged equipment. Our planned investments continue to demonstrate a commitment to the Company's priorities of safety, reliability, and also enhancing the customer experience. As an example of our commitment to safety and the environment, as of the end of May 2019, we completed work on an LED street light replacement program that resulted in the conversion of 85,000 cobra head style streetlights from high-pressure sodium or mercury vapor streetlights to more energy efficient LED streetlights across Minnesota. The switch to LED lights improves safety as these lights improve nighttime visibility for both drivers and pedestrians. Another example of our commitment to safety is our pole replacement program which takes a methodic approach to replacing poles that have reached their life. This program ensures that our lines and equipment are supported by quality wood poles.

Our focus on the customer experience has been demonstrated through our timely response to customer electrical needs. For instance as the economy grew over the past several years, this spurred new residential and commercial development, which required Distribution to install an increased number of service extensions. We responded to this rise in requests and met our customer's expectation for timely electrical connections. We also responded to customer demands to relocate our facilities due to an increased number of road construction projects in the metro area driven by the strong economy.

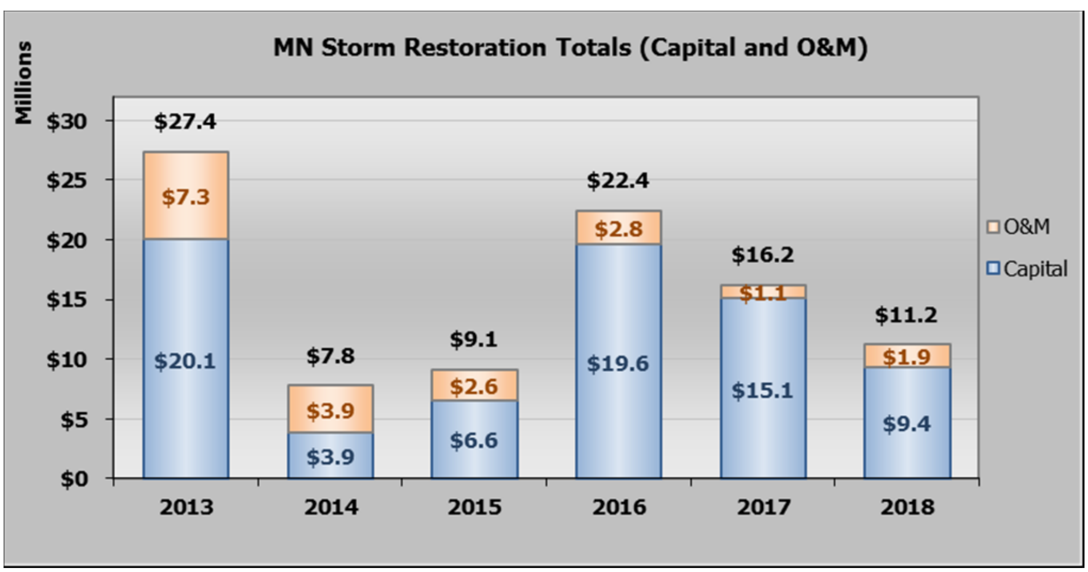
In the area of reliability, our capital budgets reflect a focus on maintaining the health of our existing facilities through established asset health and reliability programs with increasing investments in pole replacements. However, additional investment is needed and our capital budgets during this time period also include investments in our ISI initiative. The ISI initiative focuses primarily on the heath, reliability, and resiliency of the portions of our system that are closest to our customers such as feeder and tap lines.

Our capital budgets also show increasing strategic investments in the Company's AGIS initiative to advance distribution grid capabilities, increase our system visibility and control, and to enable expanded customer options. We will invest in the foundational elements of AGIS such as advanced meters, a FAN communication network, FLISR outage detection and restoration, and IVVO voltage improvement. These foundational elements, in concert with future investments, will provide cumulative benefits that will improve the operation and maintenance of the distribution system while also providing an improved customer experience. While we do not know exactly what the future will hold in terms of new technology or customer adoption rates of EVs and solar, we do know that the set of investments that we are proposing here are the right first building blocks.

We are also responding to customer expectations by expanding our EV program. This includes several pilot programs that were recently approved by the Commission, a fleet EV service pilot, a public charging pilot, and a residential subscription service pilot, as well as pilots and programs highlighted in the Company's recently filed Transportation Electrification Plan. These investments will provide the infrastructure necessary to promote greater EV use and to meet the demands of the growing EV market.

The budget process that we utilize has generally proven to be an accurate gauge of the routine work that will be performed each year. However, sometimes there are storms or new business fluctuations that can lead to unexpected increases in our routine work. When these circumstances arise, we seek to actively control our expenditures to stay as close to budget as reasonably practicable by prioritizing our work and allocating funds accordingly. We illustrate below the variability of storm restoration over the recent past.

Figure 12: Illustration – Storm Restoration Variability



In this way, the Distribution organization is unique from many other business units. While we are confident in our overall level of budgeting and our ability to manage within those annual budgets, the realities of our business require some flexibility within those budgets to respond to changing economic conditions, weather events, and evolving priorities. That being said, we are proud of our successful storm response efforts, reputation for reliable service, and our ability to manage our budget within its bounds and react and reprioritize as necessary each year to ensure our customers continue to receive safe and reliable electric service.

Our capital projects fall into eight capital budget groupings depending on the primary purpose of the project. Distribution has a well-defined process for identifying and determining our investments within these eight capital budget groupings. These groupings are:

- *Asset Health and Reliability (IDP Categories: Age-Related Replacements and Asset Renewal and System Expansion or Upgrades for Reliability and Power Quality).* Projects in this category are related to replacing infrastructure that is experiencing high failure rates and, as a result, negatively impacting the reliability of service and increasing O&M expenditures needed to repair this equipment. When poor performing assets are identified, projects that will improve asset performance are included in the budget. Projects in this category include replacement of underground cable, wood poles, overhead lines, substation equipment, transformers, and switchgear that have reached the end of their life. This category also captures replacements due to storms and public damage.

  Beginning in 2021, the Asset Health and Reliability category will include investments associated with our ISI Initiative. The ISI Initiative will expand our existing Asset Health programs, such as cable replacement, and establish new programs such as targeted undergrounding to address the health, reliability, and resiliency of the portion of the distribution system that is closest to our customers. Additionally, portions of the ISI Initiative will further customer choice and control by improving elements of the grid closest to our customers that can improve the ability to host additional DER such as solar or EVs.

- *AGIS (IDP Category*: Gird Modernization and Pilots). Traditionally, investments that advance the grid were budgeted in our Asset Health category. This is because when we sought to replace aging equipment with new equipment we also evaluated whether the functionality of a particular asset could be or should be enhanced to promote grid modernization. For instance, we replaced electro-mechanical relays with solid-state relays, which are not only communication enabled – but are also capable of providing fault data to allow us to more quickly identify faults on our system and improve our response time. Beginning in 2019 as we launched our AGIS initiative, we separated these investments into their own budget category of AGIS. The AGIS initiative will improve power reliability, reduce power outages, integrate increasingly clean energy onto the grid, and empower customers with more information to control and track their energy use.

- *New Business (IDP Category: New Customer Projects and New Revenue)*: This work includes new overhead and underground extensions and services associated with extending service to new customers. Capital projects required to provide service to new customers include the installation or expansion of feeders, primary and secondary extensions, and service laterals that bring electrical service from an existing distribution line to a new home or business.
- *Capacity (IDP Category: System Expansion or Upgrades for Capacity)*: This category includes capital investments associated with upgrading or increasing distribution system capacity to handle load growth on the system and to serve load when other elements of the distribution system are out of service. This includes installing new or upgraded substation transformers and distribution feeders. Capacity projects generally span multiple years and are necessitated by increased load from either existing or new customers.
- *Mandates (IDP Category: Projects related to Local (or other) Government-Requirements)*. This category covers projects to relocate utility infrastructure in public rights-of-way when mandated to do so to accommodate public works projects such as a road widening or realignment project. These projects generally trend with the availability of municipal and state funding for public works projects. Mandate projects typically result in updated distribution infrastructure.
- *Tools and Equipment (IDP Category: Other)*. This category includes tools, equipment, communication equipment, and locate costs associated with modifications or additions to the distribution system or supporting assets.
- *Electric Vehicle Program (IDP Category: Grid Modernization and Pilots)*. This category includes the capital costs associated with three EV pilot programs that were approved by the Commission in 2019 – the fleet EV service pilot, the public service pilot, and the residential EV subscription service pilot. The fleet EV service pilot aim to make it easier for large fleet operators like Metro Transit, the Minnesota Department of Administration, and the City of Minneapolis to integrate electric vehicles into their fleets. The goal of the public service pilot is to begin to build a fast charging network along major corridors and community mobile hubs in the Twin Cities to allow people the ability to quickly charge their EVs away from home. The residential subscription service pilot is designed to provide a simple, easy-to-understand charging experience while encouraging off-peak charging. Additionally, the Company has included budget information for other pilots and programs we have highlighted in our

Transportation Electrification Plan.

- *Solar Gardens (IDP Category: Non-Investment).* This category includes the distribution costs associated with interconnecting solar gardens to the distribution system as well as providing service extension to allow electric service for any auxiliary electric needs. The costs for these facilities are billed to the developer at several different increments throughout the development and construction of the solar garden. Once payment is received and the work is completed by Distribution, a credit is applied to this category.

2. O&M Budget Development

The Distribution O&M budget includes labor costs associated with maintaining, inspecting, installing, and constructing distribution facilities such as poles, wires, transformers, and underground electric facilities. It also includes labor costs related to vegetation management and damage prevention. Finally, it includes miscellaneous materials and minor tools necessary to build out, operate, and maintain our electric distribution system and fleet (vehicles, trucks, trailers, etc.). Specifically, the O&M component of fleet are those expenditures necessary to maintain our existing fleet. This includes annual fuel costs plus the allocation of fleet support to O&M based on the proportion of the Distribution fleet utilized for O&M activities as opposed to capital projects.

Our O&M budgeting process takes into account our most recent historical spend in all the various areas of Distribution and applies known changes to labor rates and non-labor inflationary factors that would be applicable to the upcoming budget years. We also "normalize" our historical spend for any activities and/or maintenance projects embedded in our most recent history that we would not expect to be repeated in the upcoming budget years (e.g., excessive storm activities or one-time O&M projects). We then couple that normalized historical spend information with a review of the anticipated work volumes for the various O&M programs and activities we perform, factoring in any known and measurable changes expected to take effect in the upcoming budget year. For example, for our major maintenance programs such as cable fault repairs and vegetation management, we review annual expected units/line-miles to be maintained and ensure required O&M dollars are adjusted accordingly.

We also factor in any expected efficiency gains we believe would be captured by operational improvement efforts we continuously are working on within our processes and procedures, along with productivity improvements we would expect to achieve via the implementation or wider application of new technologies. These improvements are already factored into our O&M budgets.

Given that no year ever transpires exactly as predicted or forecasted, we typically update our O&M expenditure forecasts during the year. As with our capital investments, one of our largest annual sensitivities for O&M expenditures is severe weather. The amount of O&M we spend on weather-related events, such as storm restoration and floods, can vary greatly from one year to the next. In addition, the Distribution business unit will periodically receive a request from the Company to adjust O&M costs within the financial year to account for changes in business conditions in other areas of the Company. When a greater need for expenditures in a particular area is identified, we try our best to re-prioritize and reallocate our budgeted O&M dollars while still operating within our overall O&M budget. However, there are times where circumstances dictate that, in order to maintain safe, reliable service at the levels our customers expect, we will need to spend more than our overall budget would allow to properly address certain items that come about during a given budget year.

Our annual O&M expenses are influenced by the magnitude and frequency of significant severe weather and storm restoration activities that occur throughout our service territory. The unpredictable nature of severe weather makes budgeting challenging as there is no such thing as a "typical" year for severe weather. The below table highlights the variability of O&M spending *over and above* base labor and transportation (i.e., overtime, materials, contractors) for storm restoration events from 2014 to 2018.

Table 13: 2014-2018 Annual O&M Storm Restoration Expenses (Dollars in Millions)

2014 Actual		2015 Actual		2016 Actual		2017 Actual		2018 Actual	
NSPM	MN Jur	NSPM	MN Jur	NSPM	MN Jur	NSPM	MN Jur	NSPM	MN Jur
$3.0	$2.8	$2.6	$2.3	$2.8	$2.6	$1.1	$1.1	$1.9	$1.7

As shown in this table, we experienced a moderate increase in O&M expenses related to storm restoration due to severe weather in 2014 and 2016, but nothing as significant as the $6.35 million NSPM ($6.0 million Minnesota jurisdiction) storm restoration expenses incurred by the Company due to a series of severe storms in the Twin Cities in 2013. Thus far in 2019, we are forecasting storm expenses of $5.0 million – or $2.6 million higher than the average of the previous five years. This increase is the result in a greater than average number of storms for 2019 as compared to prior years.

During the current year, we are routinely monitoring our O&M actual expenditures as compared to the budget and identifying any variances of significance as they materialize. As budget pressures are identified in certain areas or programs, we review options to mitigate those pressures as best we can. One mitigation option is to reallocate from other areas of the budget where funds for budgeted work of a lower priority and/or more discretionary nature (in the short-term) to cover the areas or programs experiencing the budget pressures. Such reallocations are considered as long as the amount of funding needed to cover the budget pressure is within a level that can be prudently covered within our overall budget allocation. If the amount of the budget pressure is too significant to accommodate via reallocation, such as in years where we have had significant storm activities driving larger deviations to O&M budgets, we then seek adjustments to year-end targeted expenditures where we would forecast an overall expenditure level exceeding our overall Distribution O&M budget. Significant deviations from existing budgets must be formally requested of and granted or denied by the Finance Council.

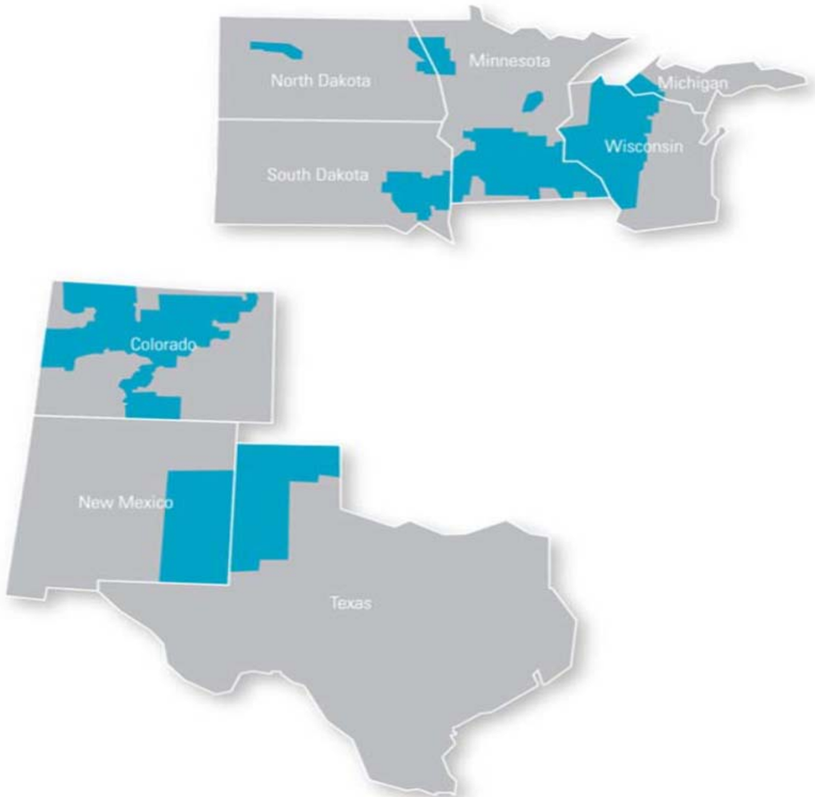
IV. SYSTEM OVERVIEW

In this Section, we provide an overview of Xcel Energy and a snapshot of distribution system statistics for the Company, as well as a financial overview of the Distribution business area and budgets.

A. Xcel Energy Overview

Xcel Energy is a major U.S. electric and natural gas company based in Minneapolis, Minnesota. We have regulated operations in eight Midwestern and Western states – Colorado, Michigan, Minnesota, New Mexico, North Dakota, South Dakota, Texas and Wisconsin – where we provide a comprehensive portfolio of energy-related products and services to approximately 3.6 million electricity customers and 2 million natural gas customers. Our Upper Midwest service area is part of an integrated system of generation and transmission made up of two operating companies –NSPM, which serves Minnesota, North Dakota and South Dakota; and Northern States Power Company –Wisconsin (NSPW), which serves Wisconsin and Michigan – collectively referred to as the NSP System. Xcel Energy serves over 1.9 million customers in its NSP service territories as shown below.

Figure 13: Xcel Energy Service Areas

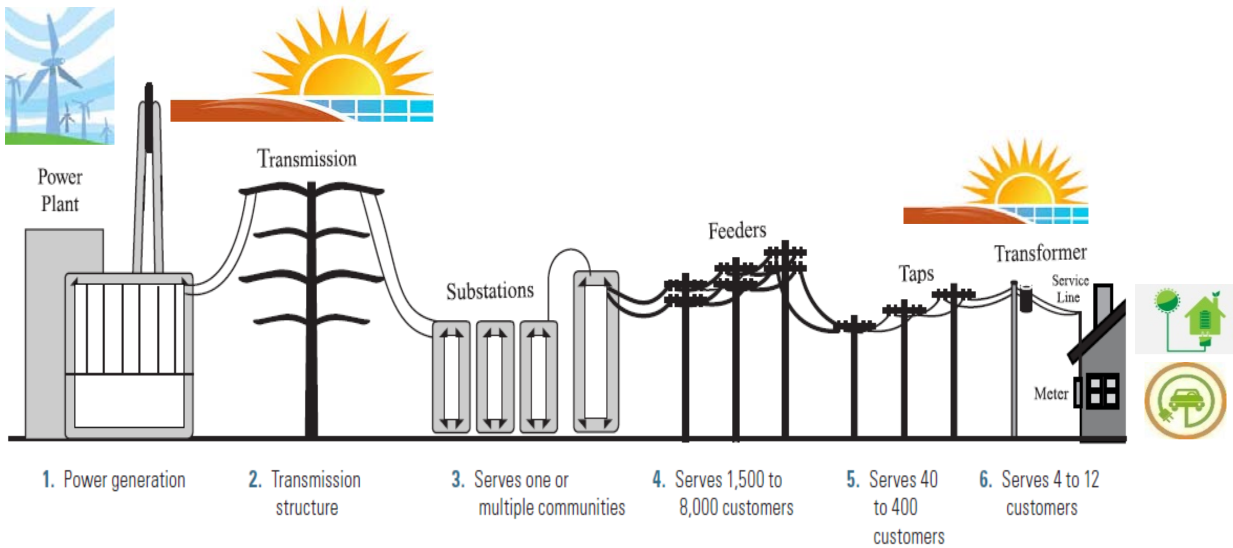


Approximately 88 percent of our NSP customers are residential, with commercial and industrial customers comprising most of the remaining 12 percent. The distribution of electricity sales by type of customer, however, is significantly different. Residential customers make up approximately 29 percent of electricity sales, with commercial and industrial customers making up most of the remaining 71 percent.

B. Distribution System Overview

The electrical grid is composed of generating resources, high voltage transmission, and the distribution system, which is the vital final link that allows the safe and reliable flow of electricity to serve our customers as shown below.

Figure 14: Illustrative Electrical Grid



As illustrated above, the poles, lines, and cables that comprise the distribution system connect individual residents and business to the larger electrical grid.

The NSPM electric distribution system serves 1.5 million customers (1.3 million in Minnesota)[32] – and is composed of 1,177 Feeders, approximately 15,000 circuit miles of overhead conductor on over 500,000 overhead poles, and over 11,000 circuit miles of underground cable. This network of feeders connects over 26,000 miles of distribution lines and 270 distribution-level substations across the NSPM system. The distribution portion of the grid, and the services that the Distribution organization provides, are generally the aspects of our electric service that are most visible to our customers. In terms of reliability, we rank nationally in the 2nd quartile.[33]

The key functions of the Distribution organization include operating the distribution system, restoring service to customers after outages, performing routine maintenance, constructing new infrastructure to serve new customers, and making upgrades necessary to improve the performance and reliability of the distribution system. There are approximately 1,300 employees assigned to provide services to the NSPM distribution system. These employees are assigned to one of the five functional areas within Distribution: Distribution Operations, Engineering, Business Operations, AGIS and Metering, and Planning and Performance. The key responsibilities of these

32 In this context, the number of customers is based on the number of electric meters.
33 Results for the NSPM operating company, as measured by SAIDI. *See IEEE Benchmark Year 2019, Results for 2018 Data* at: http://grouper.ieee.org/groups/td/dist/sd/doc/

four functional areas include:

- *Operations*. Responsible for the design, construction, and maintenance of the distribution system, as well as monitoring and operating the system from the Electric Control Center, responding to electric distribution trouble calls, and coordinating emergency response;
- *Engineering*. Provides technical support and system planning, including addressing distribution-related customer service issues;
- *Business Operations*. Responsible for several areas, including vegetation management, outdoor lighting, facility attachments, and the builders call-line.
- *AGIS and Metering*. Responsible for implementation of the AGIS initiative and metering.
- *Planning and Performance*. Provides business planning, consulting, analytical services and performance governance and management.

Distribution's 2019 key priorities are as follows:

- *Achieve operational excellence*: improve reliability performance level in 2019
- *Grid Modernization*: Targeted renewal of aging, unreliable, or obsolete components and systems (i.e. underground cable, poles, 4kV systems)
- *Distribution System Intelligence*: Installation of key equipment and systems to operate the new modern grid including, monitoring and control, DMS, and system efficiency
- *System Health*: Targeted maintenance of key assets designed to improve reliability and safety – wood poles, substation transformers & breakers, vegetation management
- *System Capacity Additions*: Installation or reinforcement of key substations and feeders to serve new load and provide backup under emergency conditions (focus on high consequence events)

C. Distribution System Statistics

The Commission's Order setting the IDP requirements includes several distribution system statistics, which we provide below.

1. Summary of existing system visibility, measurement, and control capabilities

IDP requirement 3.A.2 requires the following:

Percentage of substations and feeders with monitoring and control capabilities, planned additions.

IDP requirement 3.A.3 requires the following:

A summary of existing system visibility and measurement capabilities (feeder-level and time-interval) and planned visibility improvements; include information on percentage of system with each level of visibility (ex. max/min, daytime/nighttime, monthly/daily reads, automated/manual).

These two requirements are intertwined with each other because they both pertain to system visibility. Therefore, we have combined the information required in Items 3.A.2 and 3.A.3 into Table 14 below.

Table 14: Feeder Load Monitoring – State of Minnesota

FLM Type	% of subs[1]	Measurement	Measurement Interval	Automated /Manual	Frequency of reads	Min/ Max	Daytime/ Nighttime
Full FLM	42%	3 phase Amps, MW, MVar, MVA, kV	Hourly	Auto	Continuous[2]	Yes-*Manual effort*	Both
Partial FLM	21%	Has some or most of the above data points, varies by location	Hourly	Auto	Continuous[2]	Yes-*Manual effort*	Both
No FLM	37%	Only manual reads available (provides 3 phase Amps)	Varies	Manual	Varies	No	Neither

Note: Approximately 90% of our customers are served by substations and feeders that have Full or Partial FLM.

[1] Percentages are based on a total of 240 substations in Minnesota.

[2] While there is continuous data flow to the operation center, only hourly data is maintained in the data warehouse.

Our SCADA system provides information to control center operators regarding the state of the system and alerts when system disturbances occur, including outages. This includes control and data of our system, and we frequently refer to the data acquisition portion as Feeder Load Monitoring (FLM). A substation that has SCADA almost always contains both FLM and control. However, there may be substations where we do not have FLM, but we do have control.

Generally, our SCADA collects hourly peak load information at the feeder and substation transformer levels over an entire year as the inputs to our planning process. Ideally, this includes three phase Amps, MW, MVar, MVA, and Volts. However, not all of these data points are available for all locations. For internal tracking and reporting purposes, when all three-phase Amps, MW, MVar, and kV are included on all feeders and two of the following three for the substation transformers (MW, MVar, or MVA) then that counts as full FLM. If we are missing one or more data points at the substation, it will fall under partial FLM. If we have nothing, then it falls under no FLM. Our SCADA-enabled substations and feeders serve approximately 90 percent of our customers (*Note*: Most of our non-SCADA substations are in rural areas).

Our SCADA also collects enough information throughout the course of a year to determine daytime minimum load for all feeders equipped with this functionality, but it takes extra manual effort to derive a daytime minimum load (DML). As discussed further below, in 2019 we prioritized the tracking and updating of DML and have determined and updated historical DML for all of our feeders and substation transformers that have load monitoring.

For no FLM and some partial FLM substations, on approximately a monthly basis, field personnel collect data, including peak demands for feeders and transformers. Peak load values are recorded in the field and entered into a database that engineering accesses and uses for planning purposes. After the recordings are documented, field personnel reset the peak load register, so the following period's data can be accurately captured without influence from the previous period. Because this is a manual process, the data may have gaps or may not occur at precise monthly intervals.

We additionally note that we have control capabilities at 63 percent of our substations. Similar to customers served from substations and feeders with full- or partial-FLM, approximately 90 percent of our customers are served by substations and feeders that have control capabilities.

Given the importance of SCADA capabilities to reliability and load monitoring (for planning and due to increasing levels of DER), in 2016 we embarked on a long-term plan to install SCADA at more distribution substations – calling for installation of SCADA at 3-5 substations each year. In addition, when we add a new feeder or transformer in a new or existing substation, we equip them with SCADA.

2. Numbers of AMI Customer Meters and AMI Plans

IDP requirement 3.A.4 requires the following:

> *Number of customer meters with AMI/smart meters and those without, planned AMI investments, and overview of functionality available.*

We began installing AMI meters for Minnesota TOU pilot customers in 2019 and we expect to install a total of 17,500 AMI meters, which will be complete in early 2020. We propose to begin implementing a full rollout of AMI across our service territory in 2021, and expect our implementation to be complete in 2024.

3. Estimated System Annual Loss Percentage

IDP requirement 3.A.8 requires the following:

Estimated distribution system annual loss percentage for the prior year.

The Edison Electric Institute (EEI) defines electric losses as the general term applied to energy (kilowatt-hours) and power (kilowatts) lost in the operation of an electric system.

Losses occur when energy is converted into waste heat in conductors and apparatus. Demand loss is power loss and is the normal quantity that is conveniently calculated because of the availability of equations and data. Demand loss is coincident when occurring at the time of system peak, and non-coincident when occurring at the time of equipment or subsystem peak. Class peak demand occurs at the time when that class' total peak is reached.

There are five categories or distribution subsystems where specific losses occur. Within these categories there may be load and no-load losses, as summarized in Table 15 below.

Table 15: Categories of Load and No-Load Losses

Category	Load Losses	No-Load Losses
Distribution Primary Transformers	Yes	Yes
Primary Distribution Lines	Yes	No
Distribution Secondary Transformers	Yes	Yes
Service Lines and Drops	Yes	No
Meters	No	Yes

For example, transformers have both load and no-load losses. Load losses are function of the transformer winding resistance and the load current through the transformer; sometimes these losses are called copper losses. Transformers and electric meters have also no-load losses which are a function of voltage. Voltages in US power systems are relatively constant, so no-load losses are considered relatively constant. Sometimes no-load losses are called iron or excitation losses.

Losses are estimated using engineering calculations and load research class customer load profiles, because advanced technologies and equipment to specifically measure actual losses across the transmission and distribution systems have historically been cost-prohibitive to implement.

Advanced technologies have been implemented on the transmission system that makes actual calculations of transmission losses more of a practical reality within the next year or so. However, advancements like this at the distribution level lag transmission due to the nature of the distribution system, which requires the advanced technologies to be implemented on a much more wide scale. However, our investments in AMI, FAN, and grid sensing and controls technologies as part of our advanced grid initiative will further our capabilities to mature this analysis over time.

The engineering analysis underlying our calculated losses used Company equipment records to determine numbers and sizes of distribution system lines and transformers, and engineering models to calculate losses from average loadings based on metered sales data through various distribution system components.

The average loading method calculates losses based on the ratio loading on each of the following system components to the maximum of the components:

- Distribution substation transformers
- Primary lines
- Primary to primary voltage
- Transformers
- Distribution line transformers
- Secondary distribution lines

From this analysis, we perform calculations monthly to update the loss percentages for each system level, and then apply those percentages to sales.

The process to update the loss percentages is as follows:

1. Gather five years of monthly MWh energy and sales by state.
2. Calculate the difference of energy and sales for each of the months in the 5-year timeframe.
3. Calculate a MWh loss percentage from the original MWh energy values by month in the 5-year history.
4. Calculate a 5-year average by month, using the values derived in step 3.
5. At this point, calculate a 5-year annual average using the values from step 4.

6. The values from step 5 are then used to represent current losses in each given state.
7. The overall losses by state described in step 6 are then used to update losses at each voltage level the engineering loss study completed.

This process resulted in the 2019 loss percentages for the state of Minnesota, as provided in Table 16 below.

Table 16: 2019 System Loss Percentages – State of Minnesota

Voltage Level	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Bulk(UT)	0.9750	0.9745	0.9724	0.9727	0.9761	0.9778	0.9770	0.9770	0.9767	0.9755	0.9747	0.9745
Bulk(T)	0.9691	0.9687	0.9665	0.9671	0.9708	0.9726	0.9715	0.9716	0.9717	0.9704	0.9689	0.9687
Tran(UT)	0.9638	0.9634	0.9610	0.9620	0.9661	0.9676	0.9663	0.9666	0.9673	0.9659	0.9637	0.9633
Tran(T)	0.9621	0.9618	0.9594	0.9604	0.9647	0.9661	0.9647	0.9652	0.9659	0.9645	0.9621	0.9616
Subtran(UT)	0.9543	0.9541	0.9516	0.9529	0.9581	0.9590	0.9574	0.9583	0.9593	0.9582	0.9545	0.9537
Subtran(T)	0.9485	0.9483	0.9459	0.9472	0.9521	0.9527	0.9507	0.9519	0.9534	0.9525	0.9486	0.9478
Primary	0.9350	0.9361	0.9344	0.9354	0.9380	0.9341	0.9297	0.9331	0.9387	0.9399	0.9355	0.9344
Large secondary	0.9221	0.9227	0.9202	0.9211	0.9246	0.9209	0.9166	0.9199	0.9249	0.9254	0.9220	0.9214
Small Secondary	0.9133	0.9136	0.9110	0.9113	0.9125	0.9069	0.9016	0.9068	0.9127	0.9154	0.9127	0.9124

We discuss the amount of reduced line losses that we expect in Minnesota as a result of our proposed IVVO project in the AGIS Direct Testimony of Ms. Kelly Bloch provided as Attachment M2. Ms. Bloch also discusses the current methods for measuring distribution line losses and what it would take to measure actual distribution losses on the distribution system, which we summarize below. Company witness Mr. Ian R. Benson discusses transmission line losses.

To measure *actual* losses on the distribution system, we would need the ability to collect data from locations throughout the distribution system. Specifically, the Company would need the ability to collect energy data at both individual customer premises and from the transformers at each distribution substation. This would allow the Company to evaluate the amount of energy leaving each substation compared to the amount of energy being delivered to the customer. The difference between these two amounts would be used to determine the losses across the distribution system.

To obtain data at the customer level, AMI meters along with the FAN communication network would need to be installed throughout the system. To collect substation level data, we would need SCADA technology at each distribution substation. We discuss our SCADA capabilities in Table 14. We currently have full SCADA capabilities at 42 percent of our substations and partial capabilities at 21 percent. Even those distribution substations that currently have SCADA functionality only have it on the low side of the transformer, and similar equipment would need to be installed on the high side of the transformer to collect the data needed to quantify the losses that occur in the substation transformer.

In addition to the customer and substation level data, the Company would also need to collect secondary data regarding the transformers and service lines and lengths to perform an accurate line loss analysis. This information would need to be collected manually as it is not currently tracked by the Company in the detail needed for a line loss analysis. Once all of the customer and distribution station level data is available, the Company would need to develop or purchase software that could take the field data, integrate data from the DER on the system, and calculate the line losses.

In terms of timeframe, as we have discussed, AMI meters and FAN will be installed by the end of 2024. We expect that the installation of the necessary SCADA infrastructure to measure actual distribution losses will not be completed until much further in the future, or approximately 15 years from today.

4. SCADA Capabilities and Maximum Hourly Coincident Load (kW)

IDP Requirement 3.A.9 requires the following:

> *For the portions of the system with SCADA capabilities, the maximum hourly coincident load (kW) for the distribution system as measured at the interface between the transmission and distribution system.*

The NSP System peak in 2018 was 8,923 MW, which occurred at 5:00 p.m. on June 29, 2018. The Minnesota portion of this peak was 6,800 MW.

We have SCADA capabilities that enable the Company to measure the maximum hourly coincident load (kW) for the distribution system as measured at the interface between the transmission and distribution system at substations serving approximately 90 percent of our Minnesota customers. We have thus calculated the 2018 peak coincident load at 5,888 MW for the Minnesota portions of the distribution system with sufficient SCADA capabilities.

We clarify that in order to provide this information we must manually pull the maximum hourly load for each SCADA-enabled substation for the date and time of the NSP System. Due to the manual effort to fulfill this requirement, it would be helpful to understand how stakeholders intend to use this information – as there may be other information we could provide that would require less manual effort to meet that need.

5. *Total Distribution Substation Capacity in kVA*

IDP Requirement 3.A.10 requires the following:

Total distribution substation capacity in kVA.

NSPM distribution substation capacity = 14,837,308 kVA or 14,837 MVA

NSPM – State of Minnesota distribution substation capacity = 13,070,741 kVA or 13,071 MVA

The total distribution substation capacity is reflective of substations that are presently active, functional, and owned by the Company. We calculated this by summing each individual distribution transformer's nameplate power rating across our Minnesota service area. We note that with this 2019 IDP, we added a view of our total substation capacity in the state of Minnesota to the NSPM operating company view provided in our 2018 IDP filing.

6. *Total Distribution Transformer Capacity in kVA*

IDP Requirement 3.A.11 requires the following:

Total distribution transformer capacity in kVA.

Consistent with our 2018 IDP, we understand this requirement to be the total distribution substation transformer kVA. Given that understanding, please see our response to 3.A.10 above.

7. *Total Miles of Overhead Distribution Wire*

IDP Requirement 3.A.12 requires the following:

Total miles of overhead distribution wire.

As of June 30, 2019, we approximated our overhead conductor at 14,959 circuit miles for the NSPM operating company.

8. *Total Miles of Underground Distribution Wire*

IDP Requirement 3.A.13 requires the following:

Total miles of underground distribution wire.

As of June 30, 2019, we approximated our underground cable at 11,438 circuit miles for the NSPM operating company.

9. Total Number of Distribution Premises

IDP Requirement 3.A.14 requires the following:

> *Total number of distribution premises.*

We clarify that a premise is a unique combination of meter number and address. As of June 30, 2019, we had 1,458,922 electric premises in the NSPM operating company, with 1,272,910 of those in our Minnesota service area specifically.

V. SYSTEM PLANNING

An important aspect of distribution planning is the process of analyzing the electric distribution system's ability to serve existing and future electricity loads by evaluating the historical and forecasted load levels and utilization rates of major system components such as substations and feeders. We see this changing as our planning processes evolve, to analyze future electricity *connections*, rather than just loads. In this section we describe our present processes, and we discuss how we propose to advance our planning and forecasting capabilities with a new planning tool.

The purpose of these assessments is to proactively plan for the future and identify existing and anticipated capacity deficiencies or constraints that will potentially result in overloads during *normal* (also called "system intact" or N-0 operation) and *single contingency* (N–1) operating conditions. Normal operation is the condition under which all electric infrastructure equipment is fully-functional. Single contingency operation is the condition under which a single element (feeder circuit or distribution substation transformer) is out of service.

Corrective actions identified as part of the planning process may include a new feeder or substation, adding feeder tie connections, installing regulators, capacitors, or upsizing substation transformers. As our planning processes evolve and technologies mature, we will continue to consider non-wires alternatives. For each project, we develop cost estimates and perform cost-benefit analyses to determine the best options based on several factors including operational requirements, technical feasibility and future year system need.

Proposed projects are funded as part of an annual budgeting process, based on a risk ranking methodology that also funds other distribution investments and expenditures including asset health, grid modernization, and emergent issues such as storm response and mandated projects to relocate utility infrastructure in public rights-of-way when mandated to do so to accommodate public projects such as road widening or realignment.

In this Section, we describe the Company's distribution system planning approach, including planning processes and tools used to develop the annual plans. In compliance with Ordering Point Nos. 9 and 10 of the Commission's July 16, 2019 Order in Docket No. E002/CI-18-251, we provide the following as Attachments E and F2, respectively to this IDP:

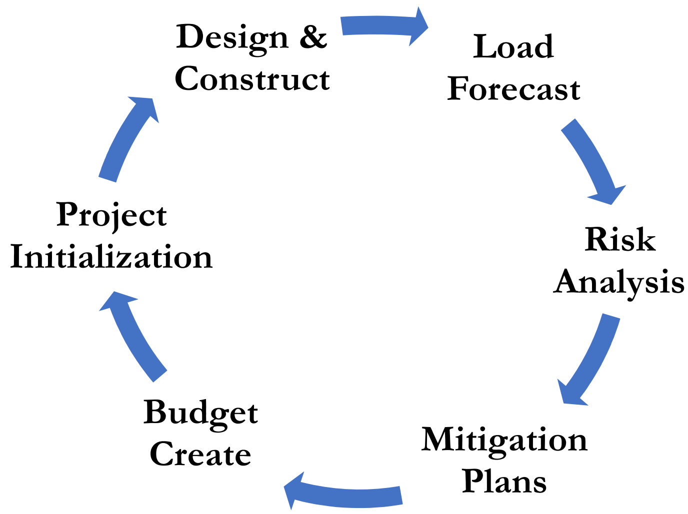
> *9. Xcel shall provide the results of its annual distribution investment risk-ranking and a description of the risk-ranking methodology, in future IDPs.*
>
> *10. Xcel shall provide information on forecasted net demand, capacity, forecasted percent load, risk score, planned investment spending, and investment summary information for feeders and substation transformers that have a risk score or planned investment in the budget cycle in future IDPs.*

We also discuss the advanced planning tool for which we propose certification, and how it will improve our load and DER forecasting capabilities.

A. Overall Approach to System Planning

We analyze our distribution system annually and conduct additional analyses during the year in response to new information, such as new customer loads, or changes in system conditions. In the fall of each year we initiate the planning process, beginning with the forecast of peak customer load and concluding with the design and construction of prioritized and funded capacity projects, as summarized in the below figure.

Figure 15: Annual Distribution Planning Process



As part of our annual distribution planning process, we thoroughly review existing and historical conditions, including:

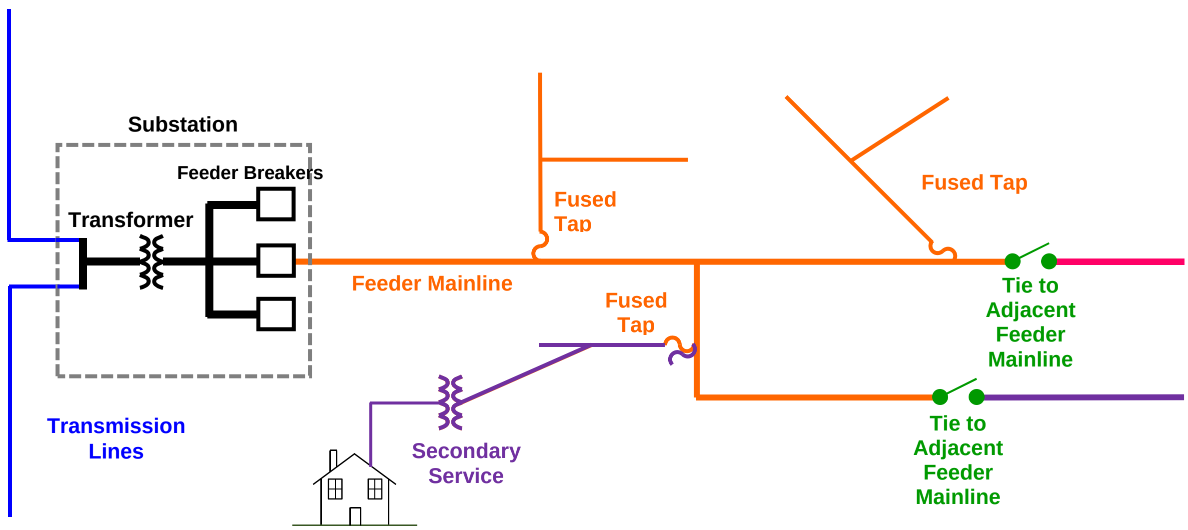
- Feeder and substation reliability performance,
- Any condition assessments of equipment,
- Current load versus previous forecasts,
- Quantity and types of DER,
- Total system load forecasts, and
- Previous planning studies.

We begin our annual plans in the fourth quarter, using measured peak load data from the current year, as well as historical peak information to forecast the loads on our distribution system over a five-year time horizon. We then perform our risk analysis based on loads near the middle of the forecast period. Tangibly the annual system planning information presented IDP is the result of the planning process initiated in Q4 2018. For this process, we used 2018 actuals and historical peak information along with any known system changes to forecast the 2019 to 2023 peaks, and perform our risk analysis based on the forecasted 2021 peak.

1. Feeder and Substation Design

Distribution feeders for standard service to customers are designed as radial circuits. Therefore, the failure of any single critical element of the feeder causes a customer outage. This is an allowed outcome for a distribution system, within established standards for reliability, which typically measure the average duration (System Average Interruption Duration Index or SAIDI) and frequency (System Average Interruption Frequency Index or SAIFI) of interruptions. The distribution system is planned to generally facilitate single-contingency switching to restore outages within approximately one hour. Foundational components in distribution system design and planning are substations and feeders.

Figure 16: Distribution System: Basic Design
Schematic of Typical Radial Circuit Design



We plan and construct distribution substations with a physical footprint sized for the ultimate substation design, which is based on anticipated load, but can occasionally be limited by factors such as geography and available land. The maximum ultimate design capacity established in our planning criteria is three transformers at the same distribution voltage. There is one exception to this criterion. In downtown Minneapolis, we have one substation that houses four transformers to serve the significant load. This maximum size balances substation and feeder costs with customer service, customer load density, and reliability considerations.

Cost considerations include the transmission and distribution capital investment in the lines, load losses (which are generally proportional to line length), land cost, and space to accommodate growth. Customer service and reliability implications include line length and route, integration with the existing system, access, and security. Over time, transformers and feeders are incrementally added within the established footprint until the substation is built to ultimate design capacity. Higher levels of DER will affect substation capacity, system protection, and voltage regulation.

Figure 17: Distribution Substation

Feeders are sized to carry existing and planned customer load. Where possible, we design-in redundancy, which has a positive impact on reliability. Feeders have a "range," like a mobile phone service tower, where they can effectively serve. For 15kV, which is common in the Twin Cities metro area, the range is approximately three miles. In rural areas where system load is less geographically dense, the range is higher – approximately one mile per kV. Thus, if customer load density remains the same, then higher voltages can serve a proportionately greater distance.

Feeders typically serve approximately 1,500 customers, though this varies based on voltage, location, customer load density, and the utilization of the feeder. The industry benchmark for feeder capacity is approximately 600 amps, which provides an efficient balance of the costs of conductors, capacity, losses, and performance. This translates to a maximum load-serving capability of about 15 MVA on 13.8 kV feeders, and 37 MVA on 34.5 kV feeders.

2. Planning Criteria and Design Guidelines

We plan, measure, and forecast distribution system load with the goal of ensuring we can serve all customer electric load under normal and first contingency conditions. Our goal is always to keep electricity flowing to as many customers on the feeder as possible. Designing our system for adequate first contingency capacity allows for restoration of all customer load by reconfiguring the system by means of electrical switching, in the event of the outage of any single element. For example, we strive to load feeders to approximately 75 percent of maximum capacity, which provides reserve capacity that can be used to carry the load of adjacent feeders during first contingency N-1 conditions.

Adequate substation transformer capacity, no normal condition feeder overloads, and adequate field tie capabilities for feeder first contingency restoration are key design and operation objectives for the distribution system. To achieve these objectives, we use distribution planning criteria to achieve uniform development of our distribution systems. Distribution Planning considers these criteria in conjunction with historical and projected peak load information in annual and ongoing assessment processes.

While the distribution guidelines vary depending on the specific distribution system attribute, there are several basic design guidelines that apply to all areas of our distribution system, as follows:

- Voltage at the customer meter is maintained within five percent of the customer's nominal service voltage, which for residential customers is typically 120 volts.
- Voltage imbalance goals on the feeder circuits are less than or equal to three percent. Feeder circuits deliver three-phase load from a distribution substation transformer to customers. Three-phase electrical motors and other equipment are designed to operate best when the voltage on all of the three phases is the same or balanced.
- The currents on each of the three phases of a feeder circuit are balanced to the greatest extent possible to minimize the total neutral current at the feeder breaker. When phase currents are balanced, more power can be delivered through the feeders.
- Under system intact, N-0 operating conditions, typical feeder circuits should be loaded to less than 75 percent of capacity.[34] We developed this standard to help ensure that service to customers can be maintained in an N-1 condition or contingency. If feeder circuits were loaded to their maximum capacity and there were an outage, the remaining system components would not be able to make up for the loss, because adding load to the remaining feeder circuits would cause them to overload.[35]

[34] 34.5 kV follows a 50 percent loading rule.
[35] By targeting a 75 percent loading level, there is generally sufficient remaining capacity on the system to cover an outage of an adjacent feeder with minimal service interruptions. A feeder circuit capable of delivering 12 MVA, for example, should be normally loaded to 9 MVA and loaded up to 12 MVA under N-1 conditions.

All distribution system equipment has capacity, or loading, limits that must factor into our planning processes. Exceeding these limits stresses the system, causes premature equipment failure, and results in customer outages. Our planning processes primarily focus at the substation and feeder levels, but also consider limitations and utilization of other system components such as cable, conductors, circuit breakers, transformers, and more.

Spatial and thermal limits restrict the number of feeder circuits that may be installed between a distribution substation transformer and customer load. Consequently, this limits substation size. Normal overhead construction is one feeder circuit on a pole line; high density overhead construction is two feeder circuits on a single pole line (double deck construction). When overhead feeder circuit routes are full, the next cost-effective installation is to bury the cable in an established utility easement. Thermal limits require certain minimum spacing between multiple feeder circuit main line cables. Thermal limits for primary distribution lines are defined in our Electric Distribution Standards. We generally discuss our Electric Distribution Standards function in Section VII below.

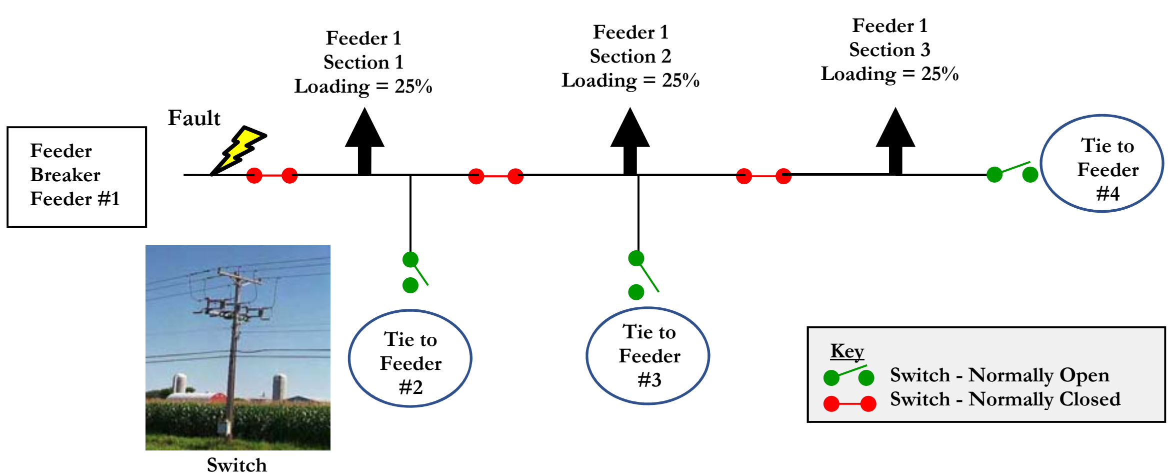
When we add new feeder circuits to a mature distribution system, we are not always able to maintain minimum spacing between feeder circuit mainline cables due to right-of-way limitations or a high concentration of feeder cables. Cable spacing limitations and/or feeder cable concentrations frequently occur where many feeder cables must be installed in the same corridor near distribution substations or when crossing natural or manmade barriers.

When feeder cables are concentrated, they are most often installed underground in groups (banks) of pipes encased in concrete that are commonly called "duct banks." When feeder circuits are concentrated in duct banks they experience mutual heating, therefore those cables encounter more severe thermal limits than multiple buried underground feeder circuits. Planning Engineers use software tools to determine maximum N-0 and N-1 feeder circuit cable capacities for circuits installed in duct banks. When underground feeders fill existing duct lines, and there is no more room in utility easement or street right-of-way routes for additional duct lines from a substation to the distribution load, feeder circuit routing options are exhausted. This would require constructing facilities from a different area to serve this load.

As we have noted, our planning criteria aims to maintain feeder utilization rates at or below 75 percent to help ensure a robust distribution system capable of providing electrical service under first contingency N-1 conditions. Therefore, to assess the robustness of the system over time, Planning Engineers analyze the historical utilization rates and projected utilization rates based on forecast demand. They generally apply the 75 percent loading guideline when assessing the system across a larger area as part of an area study. The 75 percent guideline is appropriate for these larger area studies because it is often not practical to analyze the section and tie-transfer breakdowns for each individual feeder in each of the identified solution options similar to what is done in our annual planning process. Since the section and tie-transfer breakdowns are highly detailed and specific to the geography and topology of the individual feeders, it is easier to compare and articulate the differences between solution options with a 75 percent loading guideline.

Figure 18 below illustrates this concept with a mainline feeder. The feeder shows the three sections equally loaded to 25 percent of the total feeder capacity. The green and red symbols represent switches that can be operated to isolate or connect the sections of the feeder in the case of a fault. In that circumstance, the feeder breaker in the substation will operate to isolate the feeder where the fault is detected. Then, the normally closed section switches are opened to isolate the section of the feeder in which the fault is detected. Isolating the fault allows a portion of the customers served by that feeder to remain in service while we repair the fault and return the feeder to normal operation.

Figure 18: Typical Mainline Distribution Feeder with Three Sections Capable of System Intact N-0 and First Contingency N-1 Operations Mainline Feeder No. 1



In this circumstance, Feeders 1 to 4 all have the same capacity – and are all loaded to 75 percent – so each of the feeder sections can be safely isolated and transferred to adjacent Feeders 2, 3, and 4 through the corresponding tie switches. This reconfiguration results in Feeders 2, 3, and 4 each being loaded to 100 percent (i.e., their original 75 percent, plus the transferred 25 percent from the adjacent Feeder #1 sections). This reconfiguration capability maintains electric service to customers while we repair the fault to the feeder and return the system to normal operation.

Area studies are typically initiated on a case-by-case basis, when Distribution Planning identifies a high number of individual risks or loading constraints within a localized area. These localized area studies vary in size, scope, and scale based on the issues identified, and can encompass a single substation, an entire city, or an entire geographic region. When the 75 percent guideline is applied in an area study, it provides an efficient means of approximating how much additional capacity is needed in that area. When the total feeder circuit utilization within the study area exceeds 75 percent (as calculated using Figure 19 below), it is generally no longer effective to perform more simple solutions – such as load transfers, or installing new feeder tie connections between existing feeders.

Figure 19: Total Feeder Circuit Utilization in Study Area

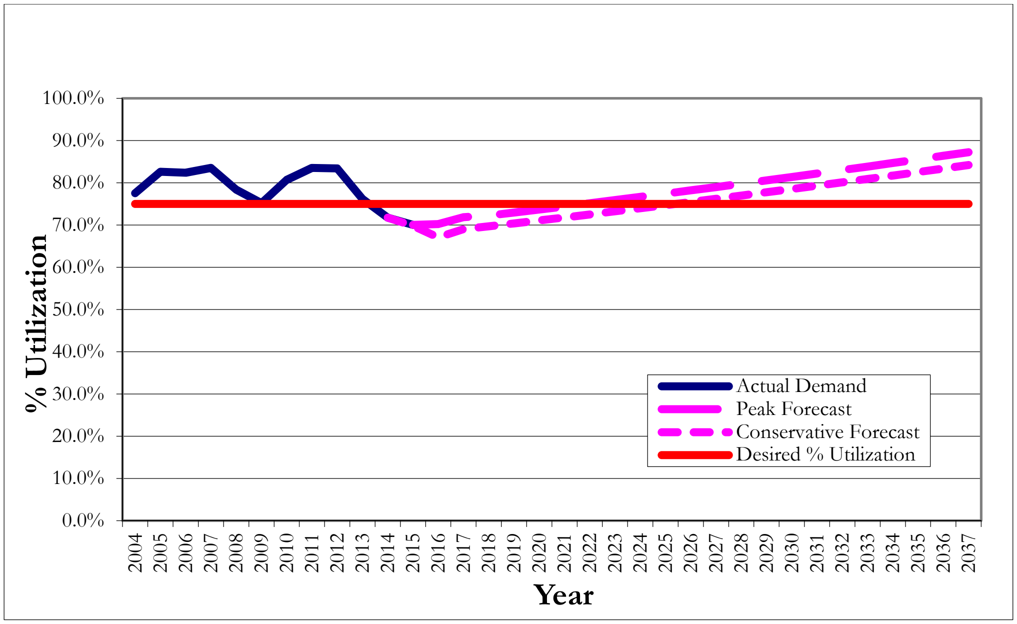
$$\text{Total Feeder Circuit Utilization} = \frac{\sum \text{Feeder Circuit Load in Area}}{\sum \text{Feeder Circuit Capacity in Area}}$$

These simple solutions merely patch a capacity-deficient portion of the system temporarily; rather than solve the issue, they often result in shifting the overloads or contingency risks from one feeder to another. However, when the total feeder circuit utilization is within a reasonable margin below 75 percent, there is generally enough capacity in the area for simple solutions to be viable for resolving any remaining risks.

While a generalized 75 percent utilization is ideal, it may not be feasible depending on system configurations. Feeder utilization in Minnesota is on average 66 percent; approximately 38 percent of the feeders are above 75 percent utilization. When we analyze feeders and transformers, we use the specific loading and configuration to determine the N-0 and N-1 overloads. Because of the wide variety of system configurations, the evaluation may show certain transformers or feeders may be loaded to higher utilization without causing an overload.

The below figure shows an example of total feeder circuit utilization for feeders in a study area over a study period timeframe.

Figure 20: Total Feeder Circuit Utilization in Study Area – Historical Peak Demand and Peak Demand Forecast



The feeder circuit load history is the actual non-coincident peak loading of all feeder circuits in the study area measured at the beginning of the feeder circuits in the substation. We compare the sum of the individual feeder circuit peak to the sum of the individual feeder circuit capacities to calculate feeder circuit utilization each year. We calculate average load growth for the time period by comparing total non-coincident feeder circuit loads from the beginning to the end of the comparison period. A peak load forecast starting from the historical peak level provides an upper forecast limit.

Isolated feeder overloads, which can be characterized by an individual feeder overload that occurs when average feeder utilization percentage is *less* than 75 percent, typically occur when there is new development or redevelopment that increases load demand within a small part of the distribution system. Widespread feeder overloads, which can be characterized by one or more individual feeder overloads that occur when average feeder utilization percentage is *more* than 75 percent, typically occur in distribution areas due to a combination of customer addition of spot loads and focused redevelopment by existing customers, developers or community initiatives.

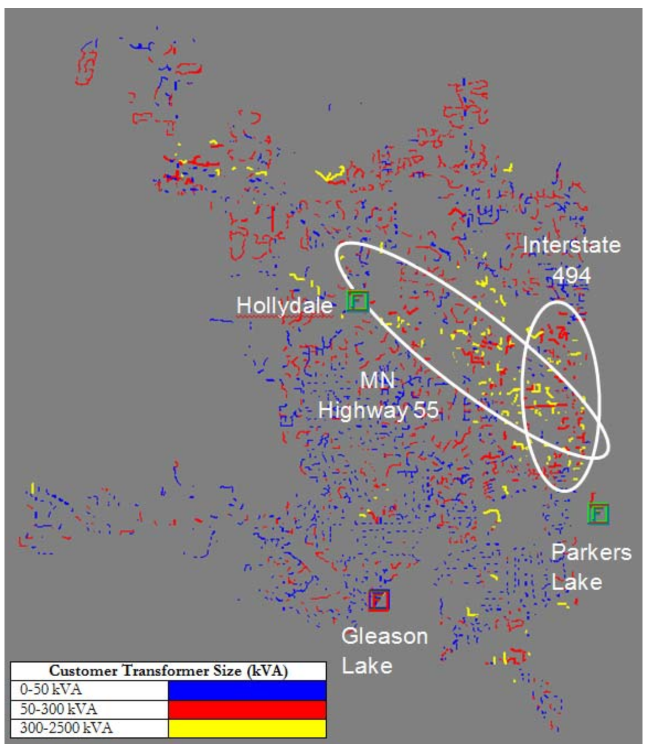
Distribution systems that start out with adequate N-1 and N-0 capacity, can quickly progress beyond isolated overloads when a large part of the distribution system is redeveloped or focused redevelopment is targeted in an area or along a corridor.

In addition to feeder peak loads, Distribution Planning examines existing feeder load density by studying the distribution transformers serving the customers. Distribution transformers are the service transformers that step the voltage down from feeder voltages to the voltage(s) that the customer receives at their point of service. As customer load grows in developed areas, we change distribution transformers to higher capacity equipment when customer demand exceeds the capacity of the original transformer.

Distribution transformers are an excellent indicator of customer electrical loading and peak electrical demand, and are used to help validate the growth that is observed and forecasted in the annual peak demand and load forecast analysis.

Figure 21 below is an example of distribution transformer installation by size from a prior analysis we completed for western Plymouth. This view is helpful to understand present customer load density.

Figure 21: Distribution Transformer Installation by Size



Developed using Synergi Electric

After examining feeder circuit peak demands, we look at the loading levels for the transformers housed at the substations.

Transformers have nameplate ratings that identify their capacity limits. Our internal Transformer Loading Guide (TLG) provides the recommended limits for loading substation transformers adjusted for altitude, average ambient temperature, winding taps-in-use, etc. The TLG is based upon the American National Standards Institute/Institute of Electrical and Electronic Engineers (ANSI/IEEE) standard for transformer loading, ANSI/IEEE C57.92. The TLG consists of a set of hottest-spot and top-oil temperatures and a generalized interpretation of the loading level equivalents of those temperatures, which are the criteria used by Substation Field Engineers to determine normal and single-cycle transformer loading limits that planning engineers use for transformer loading analysis.

A transformer's *normal* loading limit is called the transformer "loadability," which represents the maximum loading that the transformer could safely handle for any length of time. A transformer's *single-cycle* loading limit represents the maximum loading that the transformer could safely handle in an emergency for at most one load cycle (24 hours), and is what we use for our substation transformer N-1 contingency analysis. When internal transformer temperatures exceed predetermined design maximum load limits, the transformer sustains irreparable damage, which is commonly referred to as equipment "loss-of-life." Loss-of-life refers to the shortening of the equipment design life that leads to premature transformer degradation and failure.

Transformer design life is determined by the longevity of all of the transformer components. At a basic level most substation transformers have a high voltage coil of conductor and a low voltage coil electrically insulated from each other and submerged in a tank of oil. Transformer loading generates heat; the more load transformed from one voltage to the other, the more heat; too much heat damages the insulation and connections inside the transformer. Hottest-spot temperatures refer to the places inside the transformer that have the greatest heat, and top-oil temperature limits refer to the maximum design limits of the material and components inside the transformer.

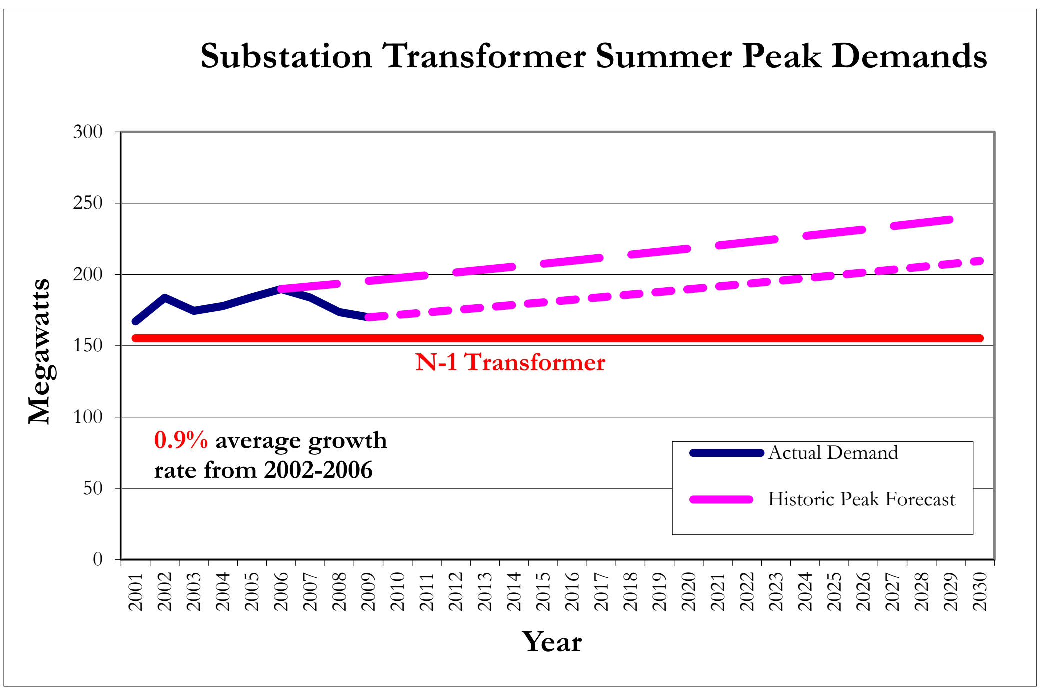
To ensure maximum life and the ability to reliably serve customers, our loading objective for transformers is 75 percent of normal rating or lower under system intact conditions. Substation transformer utilization rates below 75 percent are indicative of a robust distribution system that has multiple restoration options in the event of a substation transformer becoming unavailable because of an equipment failure or required maintenance and construction. The higher the transformer utilization rate, the higher the risk of a transformer outage that interrupts service to customers.

Each distribution substation has a demand meter that is read monthly for each substation transformer. These meters record the transformer's monthly peak. For those distribution substation transformers that have a Supervisory Control and Data Acquisition (SCADA) system connection, we are able to monitor the real-time load on the transformer. Similar to distribution feeders, the transformer data feeds into a data warehouse, which can be combined with hourly historical and forecast peak load data in our Distribution Asset Analysis (DAA) system, so we can view the substation transformer's load history.

Each transformer's peak in a multi-transformer substation is non-coincident – meaning the transformers can each individually experience peak load at different times, and potentially on different days. This is a result of the fact that each transformer serves multiple feeder circuits that each serve different loads. Substation transformer peak load is proportional to, but usually less than, the sum of the feeder circuit peak loads served from that substation transformer. The detail of substation transformer loading is a larger granularity than feeder circuit loads with a corresponding greater impact on customer service due to the larger number of customers affected for any event on a transformer than on a feeder.

Figure 22 below is an example of load growth using historical and forecasted peak loads for a set of substation transformers

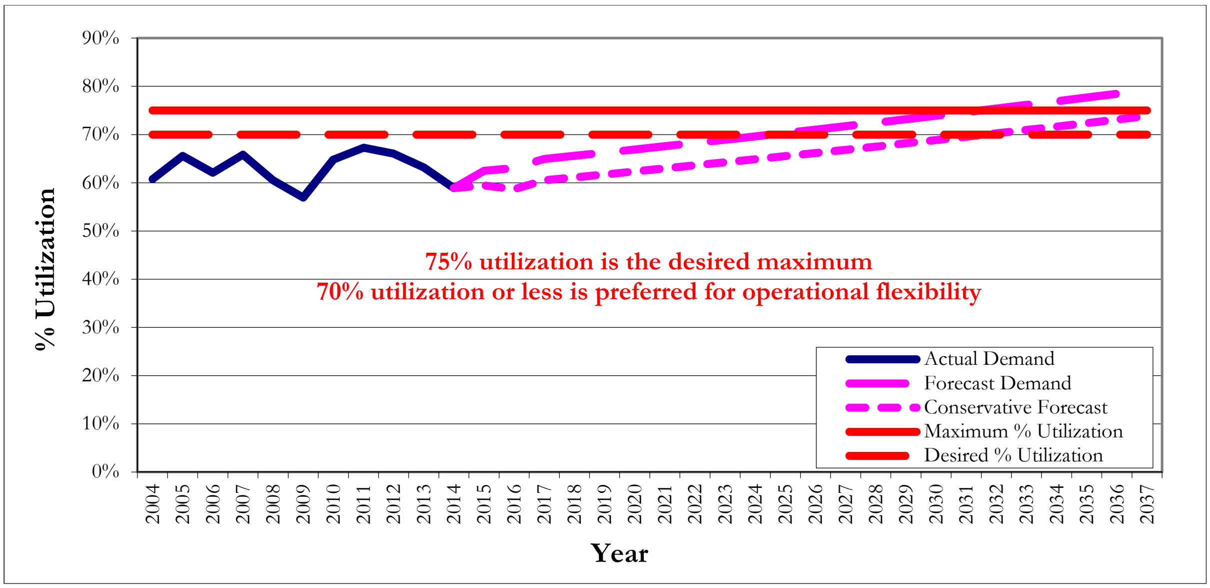
Figure 22: Greater Study Area – Historical and Forecasted Loads



The upper and lower dashed lines provide a bandwidth for growth, forecasted from the conservative peak and historical peak values, respectively.

As part of our analysis, we review the loading and utilization rates of distribution substations. We provide an example of our transformer utilization analysis in Figure 23 below, which illustrates the bandwidth of expected load growth that is forecasted to occur between the upper and lower dashed lines.

Figure 23: Total Transformer Utilization Percentage for Transformers – Focused Study Area



Even when using conservative peak load levels from the lower dashed line, in this circumstance forecasted load levels still exceed desirable loading levels for the substation transformers in the later years of the 20-year forecast in the study. The range of likely transformer utilization falls between the dashed lines of the conservative forecasted demand and the historical peak forecast load levels.

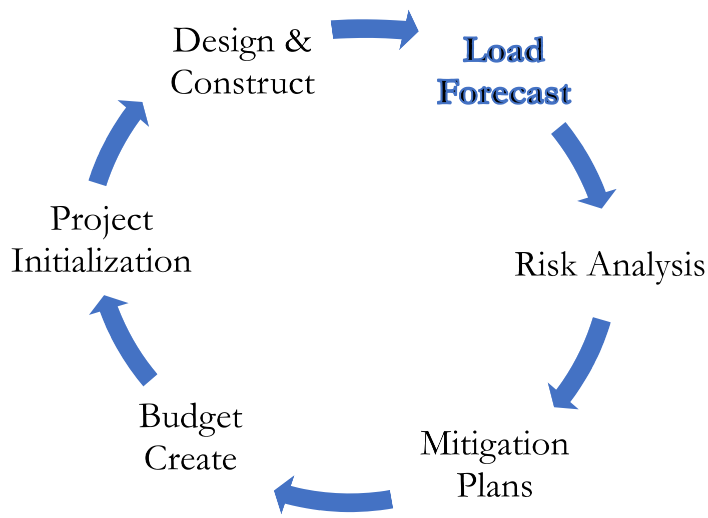
Using the planning criteria such as we have described above, Planning Engineers evaluate the distribution system, and are able to determine transformer and feeder loading and identify risks for normal and contingency operation of the system.

B. Distribution Planning Process

1. *Planning to Meet the Peak Load*

We begin our process by forecasting the load for both feeders and substations.

Figure 24: Annual Distribution Planning Process – Load Forecast



In this step, we run a variety of scenarios that account for all the various drivers of load changes. This includes consideration of historical load growth, weather history, customer planned load additions, circuit reconfigurations, new sources of demand (penetration of central air-conditioning, electric vehicles), DER applications, and any planned development or redevelopment.

Then we generate a five-year forecast, aggregate the results, and compare this analysis with system projections. See the Action Plan Section XIV for the load forecast resulting from this analysis in compliance with IDP Requirement D.2, which requires, in part, that we provide our load growth assumptions and how we plan to meet it in our 5-year action plan. We additionally provide our long-term system load projections in compliance with IDP Requirement D.3 in the Action Plan Section of this IDP.

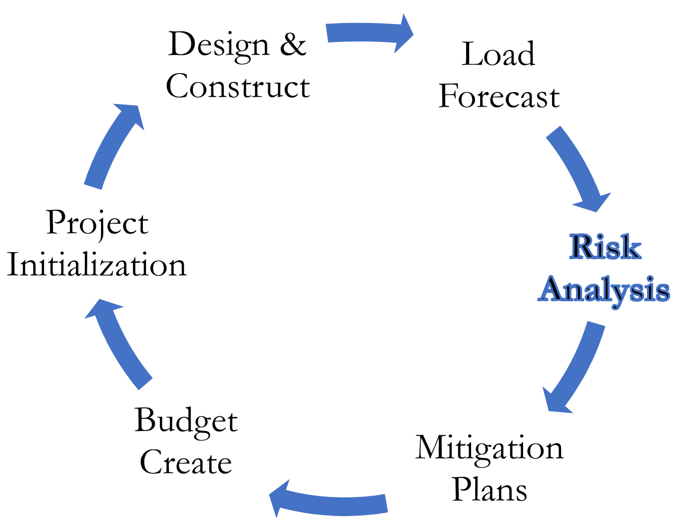
We then provide our distribution forecast to our transmission planning staff, who incorporate the load forecast into their planning efforts. In addition to this load forecast hand-off, we also communicate with transmission regularly throughout the year. Specifically, any time we become aware of larger loads or significant DER at any time of the year, we share that information with transmission. Distribution and transmission personnel also meet twice a year as a cross-functional group to further ensure we are each aware of plans and projects which may impact either system.

Our load forecast focuses on demand (kVA) not energy (kWh) to ensure we can serve loads during system peaks.[36] For planning purposes, we define "peak load" as the largest power demand at a given point during the course of one year. Measured peak loads fluctuate from year-to-year due to the impacts of duration and intensity of hot weather and customer air conditioning usage. In examining each distribution feeder and substation transformer for peak loading, we use specific knowledge of distribution equipment, local government plans, and customer loads to forecast future electrical loads. Planning Engineers consider many types of information for the best possible future load forecasts including: historical load growth, customer planned load additions, circuit and other distribution equipment additions, circuit reconfigurations, and local government-sponsored development or redevelopment.

2. *Risk Analysis*

The next step in the planning process is to conduct risk analyses.

Figure 25: Annual Distribution Planning Process



One of the main deliverables of distribution planning's annual analysis includes a detailed list of all feeders and substation transformers for which a normal overload (N-0) is a concern. A normal overload is defined as a situation in which the real time load of a system element (conductor, cable, transformer, etc.) exceeds its maximum load carrying capability. For example, a 105 percent N-0 for feeder FDR123 means that the peak load on FDR123 exceeds the limit of the feeder's limiting element by 5 percent.

[36] When three phase load data is available, we use the highest recorded phase measurement in our forecast.

Additionally, distribution planning delivers an N-1 Contingency Analysis, which is a list of all feeders and substation transformers for which the loss of that feeder or transformer results in an overload on an adjacent feeder or transformer. For example, a 1.5 MVA N-1 condition for feeder FDR123 means that for loss of FDR123, all but 1.5 MVA of FDR123's peak load can be safely transferred to adjacent feeders without causing an overload. The remaining 1.5 MVA that cannot be transferred is then referred to as "load at risk."

Our 2019 to 2023 annual planning process (initiated in Q4 2018), analyzed forecasted 2019 loads and identified the following total risks across NSPM:

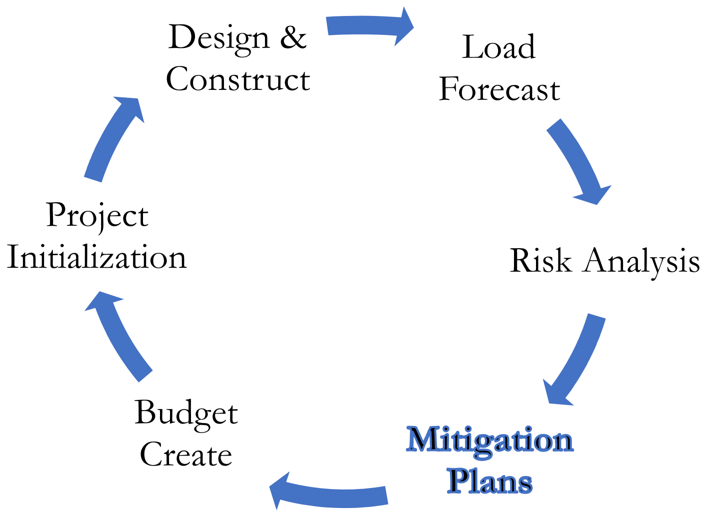
- N-0 normal overloads on 71 feeder circuits
- N-0 normal overloads on 14 substation transformers
- N-1 contingency risks on 498 feeder circuits
- N-1 contingency risks on 112 substation transformers

This process of identifying N-0 overloads and N-1 risks for feeders and substation transformers is referred to as distribution planning's annual "risk analysis." We enter all of these risks into WorkBook, an internal tool used to help rank projects based on levels of risk and estimated costs. We provide our risk scoring methodology and results from the 2019-2023 planning process as Attachment E (portions of which are not public). The total number of risks identified in the risk analysis generally exceeds the number of risks that can be mitigated with available funds. There is always a balance that we must strike in mitigating risks, planning for new customers, and addressing both the aging of our system – as well as preparing it for the future. We discuss how we strike this balance and prioritize projects below.

3. Mitigation Plans

After identifying system deficiencies, the next step in the planning process is developing mitigation plans.

Figure 26: Annual Distribution Planning Process – Mitigation Plans

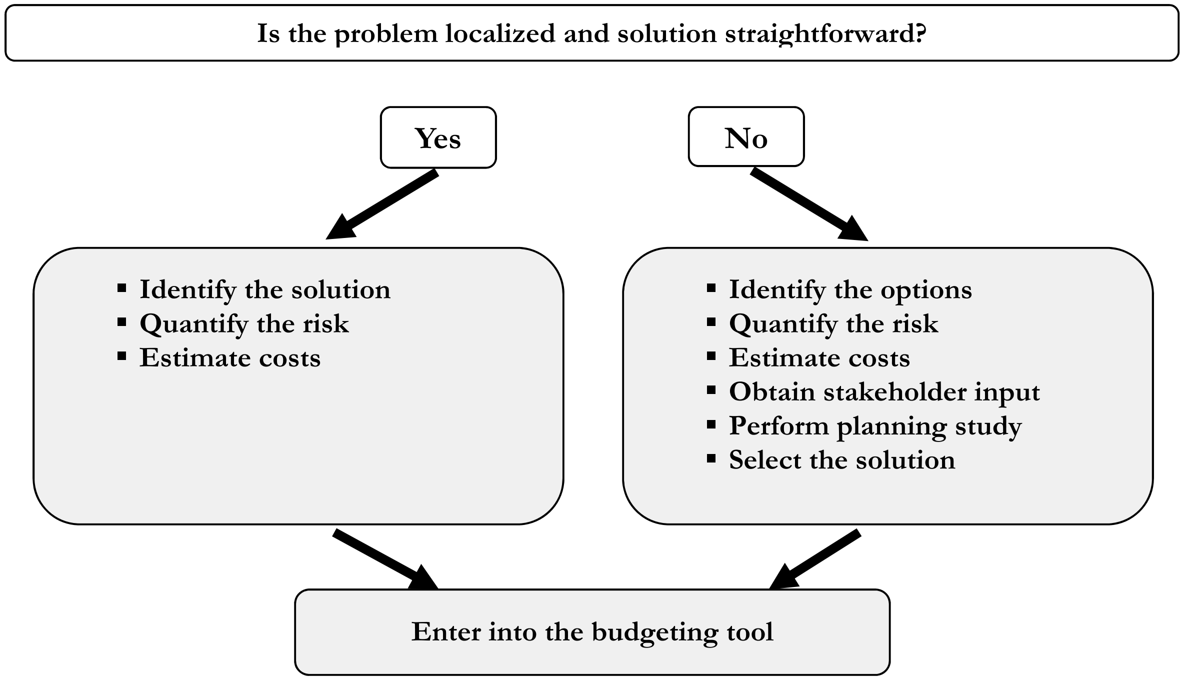


At this step, Planning Engineers identify potential solutions to provide necessary additional capacity to address the identified system deficiencies. We apply thresholds that risks must exceed before we develop a project to mitigate the risk. For N-0 conditions, the overload must exceed 106 percent; for N-1 conditions the load at risk must exceed 3 MVA before we develop a mitigation.

While many of the mitigation solutions are straightforward, others require a detailed analysis. At this point in the process the projects are high level and using indicative unit costs.

The below figure depicts the steps we take to identify potential solutions.

Figure 27: Solution Identification Process



Distribution capacity planning methods address and solve a continuum of distribution equipment overload problems, including isolated feeder overloads, widespread feeder overloads, and substation transformer contingency overloads associated with widespread feeder overloads. Alternatives include reinforcing existing feeder circuits to address isolated feeder circuit overloads, adding or extending new feeder circuits and adding substation transformer capacity up to the ultimate substation design capacity to address more widespread overloads.

Planning Engineers first consider distribution level alternatives including adding feeders, extending feeders and expanding existing substations. If these typical strategies would not meet identified needs because they had already been exhausted or would not be sufficient to address the overloads, the engineers then evaluate alternatives that would bring new distribution sources into the area. DER has not historically been considered a viable alternative for resolving distribution capacity issues due to cost, reliability, capacity, longevity, dispatchability, space constraints and dependability. However, we see these constraints lessening as the technologies mature and operational experience increases.

If we conclude that distribution level additions and improvements would not meet the identified need, we consider the addition of new distribution sources (*i.e.*, substation transformers with associated feeder circuits) to meet the electricity demands. Ideally, new distribution sources should be located as close as possible to the "center-of-mass" for the electric load that they will serve. Installing substation transformers close to the load center-of-mass minimizes line losses, reduces system intact voltage problems, and reduces exposure of longer feeder circuits and outages associated with more feeder circuit exposure.

Once we identify a mitigation solution for the associated risk(s), we enter the mitigation description, indicative estimated costs, and the risks associated into WorkBook, which uses algorithms to develop a ranking score. The result of this entire step, including any necessary planning studies, is a slate of projects for consideration and review as part of the overall Distribution budgeting process.

a. Long-Range Area Studies

If we determine a long-range plan is necessary, we conduct a location-specific study to evaluate various alternatives, which may include DER or DSM. Depending on the scope and scale of the focused study, this process can take weeks or even months, and generally involves the following:

- Identifying the study area (for instance, a single feeder, a substation, or maybe even an entire community or larger).
- Projecting future loads.
- Estimating the saturation of area (limits of development, zoning, etc. on load growth).
- Coordinating with transmission planning to advise them of our work and learn if they have area concerns or projects.
- Generating options.
- Studying and comparing the economics and reliability of the alternatives.

With respect to DSM, we are developing updated methodologies and distribution-avoided costs for energy efficiency.[37] Presently, for assessing distribution impacts, we allocate energy efficiency impacts to each distribution substation and feeder load proportionally based on percentage of system load share. We perform a subsequent summer peak analysis to determine if projects could be deferred. We calculate a deferral value, expressed as $/kW, based on the Xcel Energy corporate cost of capital and using planning level costs for the deferral period. We note that we are also

[37] *See* In the Matter of Avoided Transmission and Distribution Cost Study for Electric 2017-2019 Conservation Improvement Program Triennial Plans, Docket No. E999/CIP-16-541.

participating in the Minnesota Department of Commerce's Statewide Energy Efficiency Demand-Side and Supply-Side studies, which are examining the future potential for both customers and the Company to reduce peak and energy usage. The Supply-Side study is targeted at utility infrastructure efficiency on the generation, transmission and distribution systems.

These analyses, along with others such as focused long-term area studies, are important complements to our annual planning analysis. We previously provided examples of area studies we have completed, which included non-traditional distribution system solutions.

IDP Requirement 3.A.30 requires that we

> *Provide any available cost benefit analysis in which the company evaluated a non-traditional distribution system solution to either a capital or operating upgrade or replacement.*

We have not completed any long-term area studies since submitting our 2018 IDP. We discuss our NWA analysis that is part of this 2019 IDP in Section VI.

b. Plan comparison standards

If Distribution Planning determines a long range plan is needed, we use the following criteria to compare the potential solutions: System Performance, Operability, Future Growth, Cost, and Electrical Losses, which we describe in more detail below. All alternatives must have the ability to meet existing and forecast capacity requirements.

System performance. System performance is how the physical infrastructure addition of an alternative impacts energy delivery to distribution customers. Frequency of outages has been found to correlate to circuit length with longer feeders experiencing more outages than shorter feeders. Each unit of length of a feeder circuit generally has comparable exposure due to common outage causes, including underground circuit outages caused by public damage (*e.g.*, customer dig-ins to cable), equipment failure; and overhead circuit outages caused by acts of nature (*e.g.*, lightning). We use Synergi system models to examine loading levels and voltage impacts overall and on specific customers under normal and first contingency conditions. We evaluate performance based on the equipment and control systems required to maintain customer nominal voltage, and customer exposure to outages as differentiated by the length of the feeder circuit from the substation transformer to the customer.

Operability. Operability is how the alternative impacts the Company's distribution equipment, operating crews and construction crews operating the distribution system during normal and contingency operations. We evaluate operability based on system planning criteria that represent the robust capability of the distribution response as described by feeder circuit and substation transformer N-0 and N-1 percent utilization and ease of operation as impacted by integration with the installed distribution delivery system. Integration of non-standard equipment using new and untested technology in the first several generations of implementation are often complicated to operate, or have unanticipated difficulties that require additional engineering to solve problems, additional expenditures, additional equipment, new operating techniques and crew training. New technologies often require several generations of changes to reach simplicity of operation required to maintain present levels of customer service and reliability.

Future Growth. Future growth is how the alternative facilitates and enables future infrastructure additions required to serve future customer demand. Possibility for future growth is enhanced by an alternative that addresses future customer demand with the least cost amount of additional distribution infrastructure. For example, when considering a standard solution, an alternative that locates a substation nearest the load center and has room to add feeder circuits and substation transformers has better future growth possibilities than an alternative that requires adding another substation with an additional transmission line into the area.

Cost. For each alternative, we calculate the present value of all anticipated expenditures required for that alternative to serve the forecasted customer loads. The present value calculations are based on indicative estimates for the proposed alternatives,

Electrical Losses. Electrical losses are most often discussed in reference to the additional amount of generation required to compensate for the incremental line losses. Increased efficiency in the electrical delivery system reduces the amount of generation needed to serve load. Electrical losses also impact the amount of distribution system equipment by requiring incrementally increased amounts of electrical feeder circuits and substation transformers to make up for electrical energy lost by transporting electrical energy at distribution voltages when compared to using transmission line voltages.

c. Capacity Risk Project Prioritization

From this evaluation, projects are assigned a risk score, similar to a cost-benefit ratio. This risk score applies to the mitigation as a whole and not the individual risks that make it up. It is useful for comparing the merits of disparate projects. We then select and prioritize the actual solutions for which we intend to move forward. Attachment

F2 contains a list of our capacity risks, their details, and the projects that mitigate them.

Based on the analysis of alternatives capable of meeting area customer load requirements, we select the alternative that best satisfies the five distribution planning criteria. For example, locating a new distribution substation closest to the greatest amount of customer load and having the shortest feeder circuits would result in the least amount of customer exposure to outages and the best system performance. It might also use the smallest addition of proven reliable elements to relieve existing overloads, resulting in the highest operability of the alternatives considered – and be the least expensive to construct and has the lowest electrical losses – making it the most cost-effective and efficient option of the four alternatives.

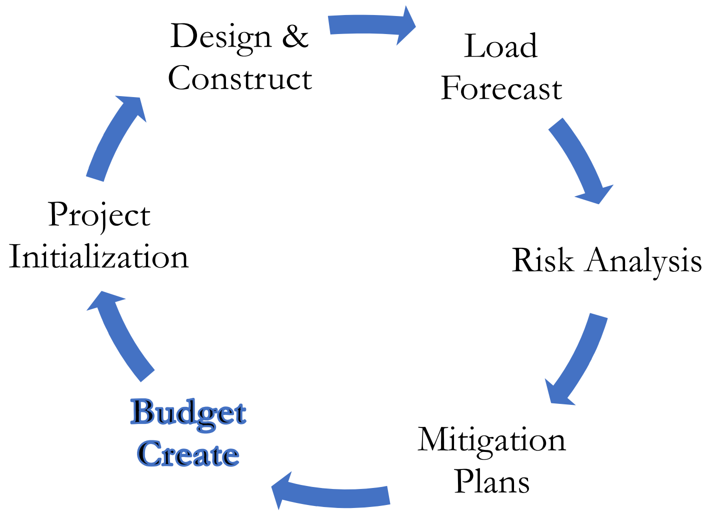
Once we have all the projects identified, we weigh each investment using a risk/reward model to determine which solutions should be selected and prioritized. While we recognize that risk cannot be eliminated and funding is always a balance, our goal is to provide our customers with smart, cost-effective solutions. Accordingly, we evaluate operational risk dependent on:

- The probability of an event occurring (fault frequency, failure history of device, etc.) causing an outage, and
- The consequence of the event (amount of load unserved, number of customers, restoration time, etc.).

4. *Budget Create*

The final step in the planning process before pursuing individual projects is prioritizing the proposed capacity projects into the distribution area's overall budget. At this step, the Company must also provide funding for asset health, new business, and meeting growing customer and policy expectations through support of new technologies and DER.

Figure 28: Annual Distribution Planning Process – Budget Create



The overall budget process recognizes that customers want reliable and uninterrupted power. To address this priority, we regularly evaluate the overall health of our system and make investments where needed to reinforce our system. This includes an asset health analysis of the overall performance of key components of the distribution system such as poles and underground cables. As we replace these key components, we do so with an eye to the future to ensure that the investments we make not only support our customers' needs for reliable service today, but also lay the groundwork for the grid of tomorrow. We must also take steps to implement new systems and technologies that improve our operations and provide customers with more choices related to their energy use. An example of this is investments in our SCADA system, as well as the ADMS we have underway. Together, these systems will provide our engineers and operational staffs significantly improved data from which to monitor and make decisions – all of which benefit our customers in both our planning and response to events occurring on the system.

Given these priorities, we must not only proactively maintain our system by making capital improvements when necessary to improve reliability and safety for our customers – we must also manage our budgets to be able to respond to outages caused by storms, mandatory work such as relocation of our facilities, and other conditions that cannot be foreseen with a high degree of accuracy. We factor-in all of these priorities as we weigh the risks associated with the various types of investments to develop our five-year budget commensurate with targeted funding levels.

As capital spending is determined and, throughout the year as new issues are identified, each operating area brings risks (problems) and mitigations (solutions) forward based on their knowledge of the assets and operations within their territory. The operating areas' focus is on building, operating, and maintaining physical assets while achieving quality improvements and cost efficiencies. All the risks and mitigations are submitted as project requests and entered into a software tool we developed and use to track and rank projects based on the inputs provided – including their annual costs and benefits.

Budgeting personnel focus on the health and age of our existing assets, standardization, and mitigation of risk, and provide coordination and consistency in evaluating individual project requests with the Distribution organization. Engineering and operations personnel then work with budgeting personnel around each risk to evaluate and score each mitigation individually before ranking the projects. The factors we use to prioritize investments are as follows:

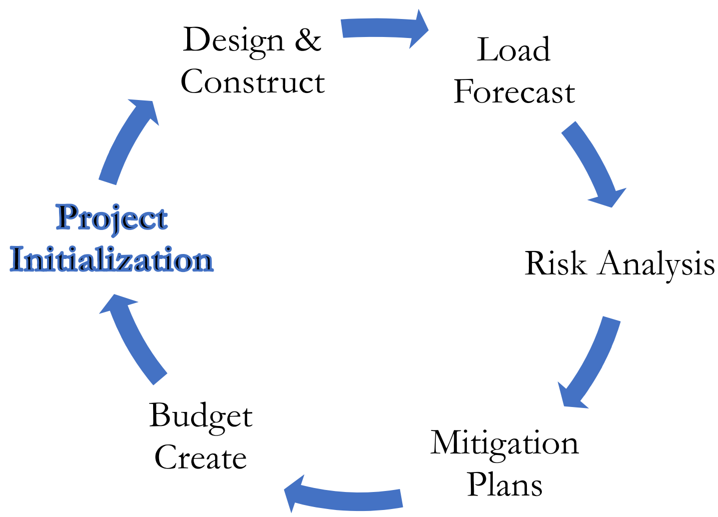
- *Reliability* – Identification of overloaded facilities, potential for customer outages, annual hours at risk, and age of facilities,
- *Safety* – Identification of yearly incident rate before and after the risk is mitigated,
- *Environmental* – Evaluation of compliance with environmental regulations. To the extent this factor applies to the project being evaluated, it is prioritized, however this factor is not usually applicable,
- *Legal* – Evaluation of compliance before and after the risk is mitigated, and
- *Financial* – Identification of the gross cash flow, such as incremental revenue, realized salvage value, incremental recurring costs, etc. – and identification of avoided costs such as quality of service pay-outs and failure repairs.

An analysis of these factors results in a proposed project list that is ranked. We accomplish this by ranking the assessment of each project against each other. The highest priority is given to projects that Distribution must complete within a given budget year to ensure that we meet regulatory and environmental compliance obligations and to connect new customers. We note that we must also apply judgment in the prioritization process. An example of this is two competing new feeder projects – one in the metro area that only involves a short distance, and the other in a rural area that involves installing infrastructure for two miles. The cost of the rural example in this circumstance is higher, and the benefits of the two projects are the same – so the metro project would score higher. However, the rural project is also needed. Our process therefore contemplates some back-and-forth with the planning engineers to validate priorities.

5. *Project Initialization*

After the capital expenditures budget is finalized, the approved project list becomes the basis for the release, or initiation, of projects during the calendar year.

Figure 29: Annual Distribution Planning Process – Project Initialization



This process must be somewhat flexible to allow for needed additions and deletions within a given year. For example, should an emergency occur during the year, priorities may change and result in an adjustment to the list of projects. Projects that were previously approved may be delayed to accommodate the emergency. Through our budget deployment process we are therefore able to meet identified needs and requirements, adjust to changing circumstances and prudently ensure the long-term health of the distribution system.

Distribution Planning takes the approved capacity projects stemming from this process and communicates them with design and construction. The Planning team continues to participate in the ongoing capital budget processes, as the Distribution business responds to changing circumstances, and interfaces with design and construction to adjust priorities as needed.

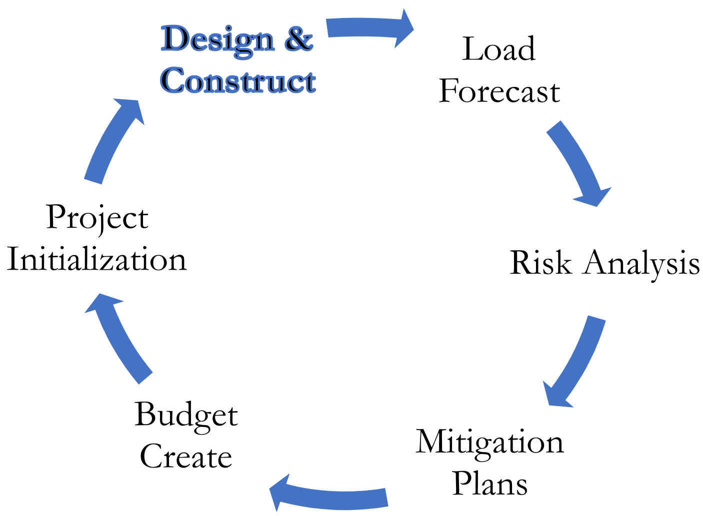
Once the five-year budget is determined, the Planning Engineers write Electric Distribution Planning (EDP) memos for the first two years of approved capacity projects. An EDP memo is a high level step-by-step description of the project that will mitigate an identified risk. The memos describe the problem, the substation design/construction steps to take (if any), and any distribution line design/

construction steps to take. The memos provide maps and text specifying where to place switches, capacitor banks, or where to cut into another feeder to transfer load to a new feeder. These memos initiate the design and construction portion of the project.

6. Design and Construct

Finally, the selected projects are communicated to substation engineering and distribution engineers and designers who bring the projects to life.

Figure 30: Annual Distribution Planning Process – Design and Construct



At this step, these engineers and designers perform detailed design work and initiate their construction. We summarize the groups generally involved and their roles below:

- *Substation Engineering.* If a project requires a new feeder bay at an existing substation or a new substation entirely, this group performs the detailed engineering, design and construction.
- *Distribution Design and Construction.* This area performs the permitting, design, and construction of new feeder circuits or modifications of existing circuits.

Ideally, projects can be implemented precisely as envisioned by Distribution Planning, but often this is an iterative process.

C. Current Planning Tools

Planning Engineers rely on a set of tools to perform the annual full system snapshot, ongoing distribution system assessments – including assessment of specific DER interconnections – and long-range area assessments. In response to the fundamental changes occurring on the distribution system, increasing customer expectations and regulatory requirements affecting how we plan the system, we are proposing certification of an advanced planning tool to increase our capabilities to develop load forecasts and plan the system.

In this section, we discuss our current planning tools in compliance with the following requirement. In Part D below, we discuss our future our proposed advanced distribution planning tool, which also complies with the following requirement.

IDP Requirement 3.A.1 requires the following:

> *Modeling software currently used and planned software deployments.*

Table 17 below summarizes the tools and how we use them in our planning process. We then discuss in more detail how we use each of the tools.

Table 17: Planning Tool Summary

Tool	Process	Description
DNV-GL Synergi Electric	Power flow	Contains a geospatially accurate model of the electric distribution Feeder system with known conductor and facility attributes such as ampacity, construction, impedance, and length to simulate the distribution system
ITRON Distribution Asset Analysis (DAA)	Medium to long-range load forecasting of major distribution system components, including feeders and transformers	System of record for historical peak feeder and substation transformer load information that we use to evaluate historical load growth and weather adjustments to match prior peaks and identified known load growth to establish a forecast for 1+ years out
Microsoft Excel Spreadsheets	Contingency planning	Analyze feeder and transformer contingency capacity by evaluating the available capacity on neighboring feeder ties and substation transformers for the forecasted years
CYMCAP	Determines normal and emergency ampacity for Feeder circuit cables	Determines the amount of amps that can flow through cables for various system configurations, soil types, and cable properties before they are thermally overloaded
Geographical Information System (GIS)	Provides the connectivity model source data to Synergi, as well as Feeder topology.	Contains location-specific information about system assets and components, allowing us to view, understand, question, interpret and visualize data in many ways that reveal relationships, patterns, and trends in the form of maps.
Distribution Supervisory Control and Data Acquisition (SCADA)	Peak load forecasting	Monitors and collects system performance information for feeders and substation transformers
WorkBook	Project Prioritization	An internal tool used to help rank projects based on levels of risk and estimated costs
PI Datalink	Load Forecast	Tool used in conjunction with Excel to help us determine our minimum loads, as well as our gross peak and minimum loads for feeders and transformers that have generation on them.

We additionally outline our hosting capacity tool that is not currently part of the planning process.

Table 18: Hosting Capacity Tool

Tool	Process	Description
Electric Power Research Institute Distribution Resource Integration and Value Estimation (DRIVE)	Hosting capacity	Using the actual Company feeder characteristics, DRIVE considers a range of DER sizes and locations in order to determine an indicative range of minimum and maximum hosting capacity by screening for voltage, thermal, and protection impacts.

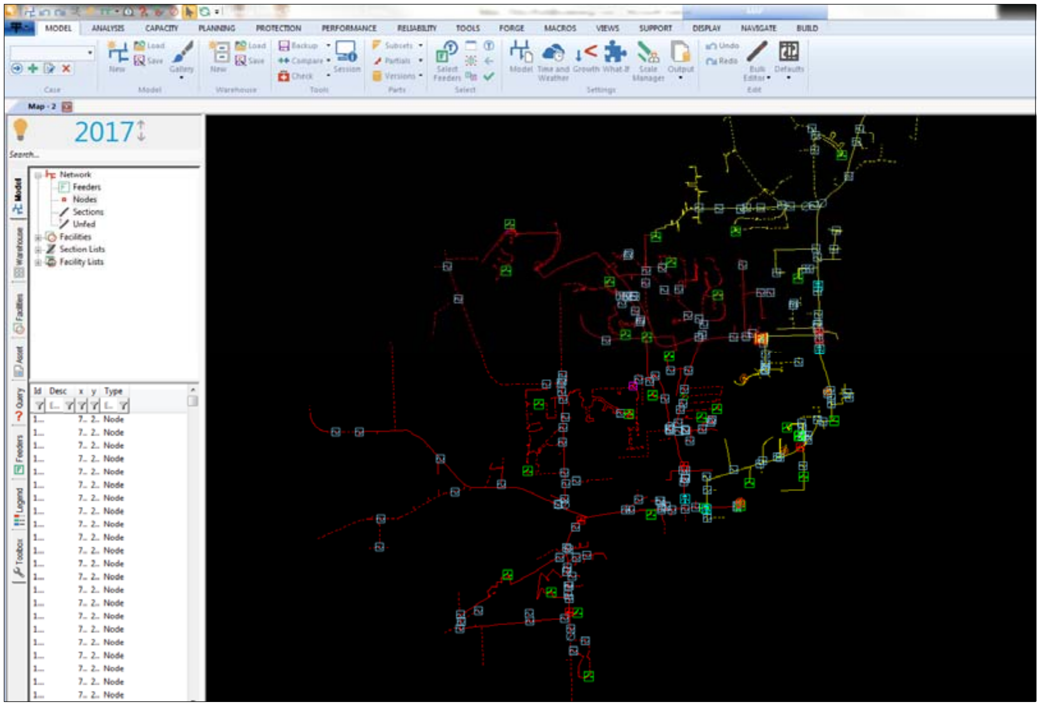
Table 19: Tool Summary by Distribution Planning Process

Tool	Forecast	Risk Analysis	Mitigation Plans	Budget Create	Initiate Construction - EDP Memo	Long-Range Plans	Hosting Capacity
	Planning Process Component						
Synergi Electric			X			X	X
DAA	X	X				X	
MS Excel		X		X		X	
CYMCAP		X					
GIS			X			X	X
SCADA	X						
WorkBook		X	X	X	X		
PI Datalink	X						
DRIVE							X

DNV-GL Synergi Electric. Synergi is the Company's distribution power flow tool, which we use to model the distribution system in order to identify capacity constraints, both thermal and voltage, that may be present or forecasted. It provides a geospatially accurate model of the electric distribution feeder system with known conductor, electrical equipment, and facility attributes such as material type, which contains ampacity and impedance values. We use it to model different scenarios that occur on the distribution system and to create feeder models that are an input to the DRIVE tool used for hosting capacity analysis; it can also be used to explore and analyze feeder circuit reconfigurations. As load is manually allocated to a feeder and we run a power flow process, exceptions such as voltage or thermal violations may occur. Areas of the feeder are then highlighted due to those exceptions to bring these issues to the engineer's attention.

Synergi can generate geographically correct pictures of tabular feeder circuit loading data, which is achieved through the implementation of a GIS extraction process. Through this process, each piece of equipment on a feeder, including conductor sections, service transformers, switches, fuses, capacitor banks, etc., is extracted from the GIS and tied to an individual record that contains information about its size, phasing, and location along the feeder. We provide a screenshot from Synergi as Figure 31 below.

Figure 31: Synergi Electric Application Example



To calibrate the model, we import peak day customer usage data into the system, and allocate it to service transformers or primary customer service points. The Customer Management Module within this software takes monthly customer energy usage data and assigns demand values based on the customer class (i.e. residential, commercial, etc.), the assigned "load curves" for that class, and the desired time period. This is done feeder-wide, so that all customers are accounted for. When historical or forecasted peak load data is added from the DAA software package, Synergi is capable of providing power flow solutions for the given condition. At that point, we can also scale the loads up or down across the entire feeder depending upon the estimated demand and scenario need.

The "load curves" that are being utilized come from our load research department and represent different customer classes on a state by state basis. They are not used to analyze different loading scenarios throughout the day, but rather to attribute more accurate peak demands at locations across a given feeder.[38]

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[38] For example, it ensures a potential residential customer receives more load at peak than a potential industrial customer with the same energy usage. This is because industrial customers typically have a flatter load profile curve. Accordingly, when industrial customers are compared to residential customers they have more consistent loading throughout the day and have less influence on the peak than the residential customer.

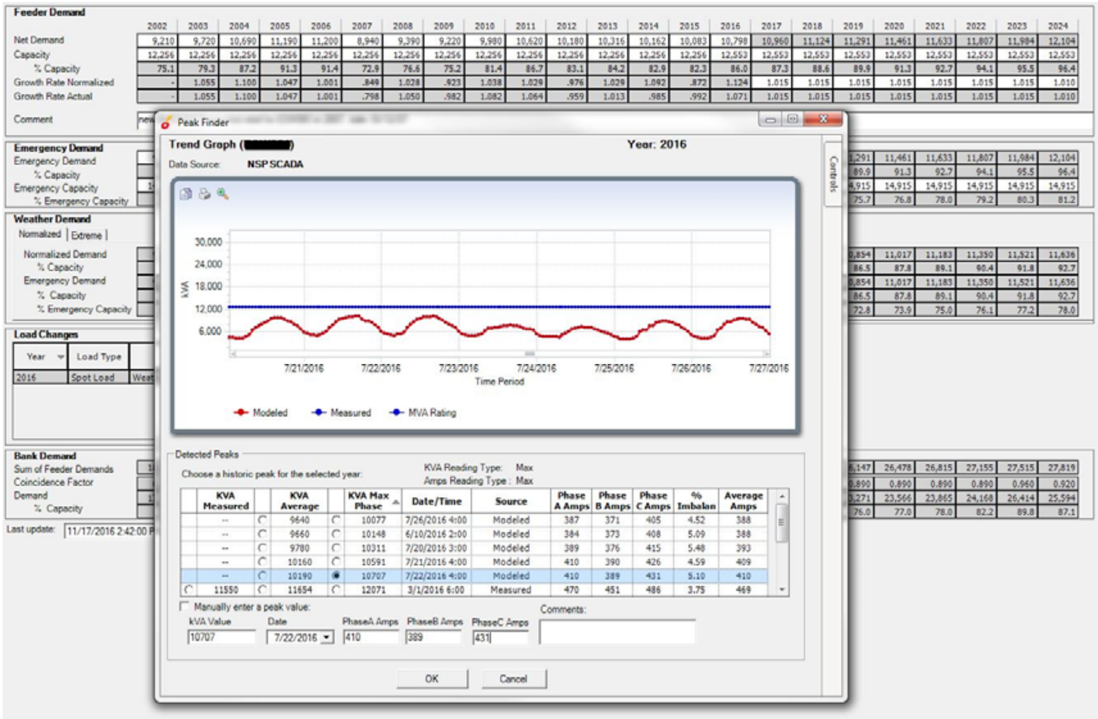
Ultimately, Synergi helps engineers plan the distribution system through modeling. It allows the ability to shift customers and load around, as well as add new infrastructure to simulate future additions to the system. It also can model distributed generation sources, such as solar or wind, so that those affects can be better accommodated.

ITRON Distribution Asset Analysis (DAA). We use DAA for medium to long-range load forecasting of distribution feeders and substation transformers. The DAA system is the historical peak system of record for those distribution elements. By having this collection of historical peaks we are better able to forecast future peaks by trending while taking into account other factors such as weather or known load growth. From this, we develop an annual load projection for future years.

Once our forecasted loads are updated every year we use DAA to create a peak substation load report for Transmission Planning and Transmission Real Time Planning. We also use these forecasts in our risk analysis evaluation, long range plans, and to populate models in Synergi for various purposes.

DAA is also a repository for feeder and substation transformer capacity limits that we use to identify areas of the system where there are capacity constraints. These limits are also passed on to Distribution Operations to ensure the correct notifications occur in the Control Center for any potential overloads.

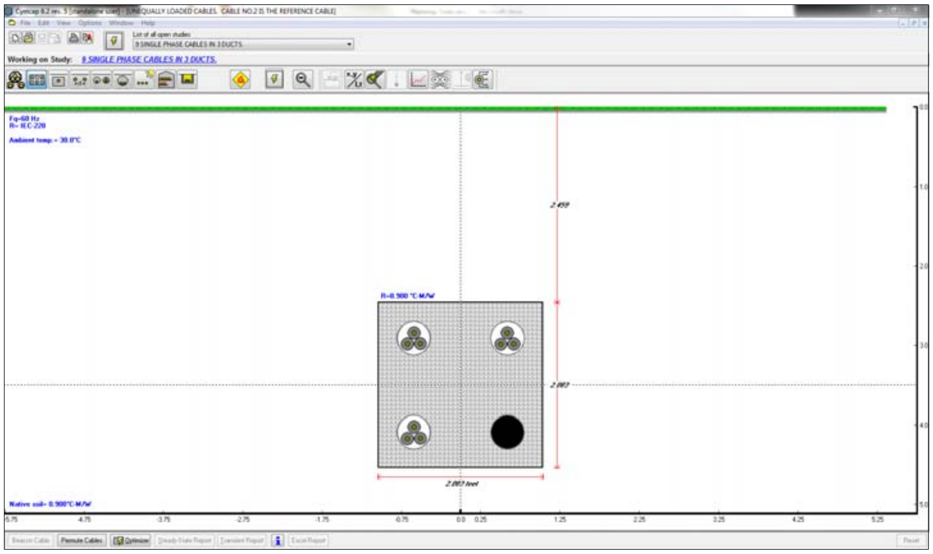
Figure 32: Distribution Asset Analysis Application Example



Microsoft Excel Spreadsheets. We use Microsoft Excel spreadsheets to perform feeder and substation transformer contingency planning. A key part of distribution planning is identifying risks, not only for normal operating situations, but also for situations where the system is in a contingency state; that is not whole. This helps in creating a system with flexibility. To do this we use a series of spreadsheets that include the tie points to other feeders and the capacity that is available at peak times through those tie points. While this is fairly simplistic tool, these spreadsheets provide valuable information about our system that we call "Load at Risk" that we use to justify projects that keep our system reliably robust.

CYME CYMCAP. Planning Engineers use CYMCAP for determining maximum normal and emergency feeder circuit cable capacities. This helps to determine the amount of amps that can flow through a given cable before it is thermally overloaded (ampacity). CYMCAP takes into account appropriate factors in determining these values, such as duct line configuration, soil conditions, and cable properties. Unlike overhead conductors that are exposed to the air and wind, underground cables have a tougher time dissipating heat. To ensure the cables are not overloaded, we model the true ampacity of them with the help of this program.

Figure 33: CYMCAP Application Example



General Electric Smallworld Geospacial Information System. Our GIS contains location-specific information about system assets and provides the connectivity model source data and feeder topology to Synergi, as well as other data to many other applications within Xcel Energy. The GIS allows us to view, understand, question, interpret and visualize data in many ways that reveal relationships, patterns, and trends in the form of maps.

GIS is also very helpful in capturing changes to the distribution system that may not always be visible to all. For example, we rely on GIS to show changes that would occur as the result of a new Community Solar Garden (CSG) installation. Any upgrades to the feeder that occurred as a result of that addition plus the details of the new CSG itself, would be added in to GIS. This would then be used to update our Synergi models for accurate modeling going forward.

Distribution Supervisory Control and Data Acquisition. Our SCADA system provides information to control center operators regarding the state of the system, provides appropriate alarms (including outage notifications), and provides for remote control of substation and certain field equipment. For operational purposes, every few seconds it provides system status information, such as operating parameters for our generation and substation facilities. It monitors and collects system performance information for feeders and substations used to ensure the system is safely and efficiently operating within its capabilities. This performance information is also used by planning engineers to perform load and operating analyses to establish system improvement programs that ensure we adequately meet load additions and continue to provide our customers with strong reliability. We have a long-term plan to install SCADA at each of our substations going forward.

For feeders where we have SCADA capabilities, we are able to monitor the real time average or three phase amps on the feeder for operational purposes. For planning purposes, the SCADA system collects enough information throughout the course of a year to determine daytime minimum load and peak demands for all feeders that have this functionality. However, it takes some manual effort beyond collecting the data to adequately decipher those values.[39] The data is maintained in a data warehouse and combined with the historical DAA hourly load data. When three phase load data is available, we use the highest recorded phase measurement to determine facility loading.

Access Database WorkBook. To help rank projects and perform cost-benefit analyses, we use an internally-developed Microsoft Access Database tool called WorkBook. This tool allows us to input our distribution system risks along with the proposed mitigations and their indicative costs that are intended to solve those risks. Algorithms in the tool result in a ranking score that helps to incorporate these projects in the budgeting process. The primary risk inputs that planning engineers develop for entry into WorkBook includes N-0 and N-1 risks for feeders and substation transformers. However, other inputs such as asset age and historical failures are also considered, which further aids prioritization of the projects as part of the budget process.

PI Datalink. A Microsoft Excel add-in that provides SCADA information from our equipment in the field. We utilize the data from this tool in our analyses for load forecasting, minimum daytime loads, and community solar gardens. By having this tool in Microsoft Excel, we are able to streamline complex and repetitive calculations. As a result, we gain better visibility of the distribution system which in turn enables us to make more informed decisions about how to mitigate risks.

D. Future Planning Tools

In this section, we discuss industry effort and the advanced planning tool we propose for Commission certification under Minn. Stat. § 216B.2425. The content in this

[39] This manual effort involves factoring out our minimum loads during non-daytime hours, adjusting for daytime minimum loads that occur under abnormal configurations, and eliminating other erroneous data possibly due to faults or other disturbances on the feeder.

section is also responsive to Order Point No. 7 of the Commission's July 16, 2019 Order in Docket No. E002/CI-18-251, which requires the Company to:

> *Make the development of enhanced load and DER forecasting capabilities, as well as, tracking and updating of actual feeder daytime minimum loads, a priority in 2019 and include a detailed description of its progress in the Company's 2019 IDP.*

As we have discussed, we need to advance our planning tools and capabilities to facilitate more targeted and granular distribution forecast analyses and more systematically evaluate NWA, as well as enable better assessment of potential customer-driven DER growth. Toward that end, we have been participating with others in the industry to examine the types of capabilities that may be needed. Enhanced planning tools have started to emerge in the industry, and we have worked to evaluate and procure a next generation distribution forecasting tool. We are currently in the advanced stages of procuring such a tool that will better suit these needs going forward, and in this IDP, we seek certification of our proposed advanced planning tool. Below, we discuss ongoing industry efforts and summarize the planning and forecasting advancements that we believe are necessary, and that we expect our new tool to provide.

1. Industry Efforts

It has been helpful to be involved with various distribution grid research efforts throughout the industry. Our membership with the Electric Power Research Institute (EPRI) has played an important role in helping us keep abreast of innovations in technology in the areas of grid modernization, reliability, integrated planning, solar integration, battery storage and DER interconnection. We participate in several research programs in these areas and are able to learn and share the latest developments with other industry members.

EPRI was key in working with the industry to develop PV hosting capacity tools and we are also excited about their interest in in developing advanced planning tools. EPRI's objective is to develop a more automated and comprehensive platform that performs more robust scenario analysis for various grid investment decisions including non-wires alternatives. EPRI's long-term vision is to develop processes and prototypes that are incorporated and adopted into commercial planning tools.

The National Renewable Energy Lab is also conducting research in similar areas and we have had the opportunity to collaborate with them on various research projects. Some of the efforts with both NREL and EPRI include:

- We are partnering with NREL and a set of Colorado customers to examine energy efficient and high renewable energy options for a new development focused on sustainable design. One aspect of the project will involve modeling the distribution system to assess the feasibility and costs of the design.

- We are participating with NREL in ARPA-E's *Network Optimized Distributed Energy Systems (NODES)* project with the vision to enable 50% renewables penetration at a feeder level through the use of innovative aggregation control methods. Both the University of Minnesota and MISO are participating in this project.
- We partnered with NREL to understand how data accuracy and sensor density influence the performance of the Advanced Distribution Management System's IVVO application. Through this research project, NREL modeled six different feeders and three substations to help assess the value and trade-offs with various levels of data and sensors to the system.
- We are partnering with EPRI on a research project designed to develop a model that helps identify where energy storage can play a role in addressing various grid issues such as system constraints, high renewable energy penetration and grid deferral. The tool helps evaluate more scenarios in a more efficient fashion and helps perform cost benefit analysis.
- Through EPRI, we are participating in an industry working group associated with DER interconnection standards and practices. A primary area of focus is discussing challenges with new options, technical requirements and responsibilities associated with adoption and application of IEEE 1547-2018.

2. Advanced Planning Capabilities and Tool

In response to the fundamental changes occurring on the distribution system, Distribution Planning has recognized a need for a new tool to aid in developing a load forecast and distribution plans. Current tools used for developing the load forecast only analyze the annual peak load for specific elements on the distribution system, such as feeders and substation transformers. As customer adoption of DER increases and our distribution system becomes more dynamic, the annual peak load view is no longer adequate. Further, we currently use a patchwork of tools to meet Commission requirements regarding scenario analysis, and even so, our capabilities to do scenario analysis are limited. Increasing penetrations of DER on the distribution system require Distribution Planning to better understand the conditions of the distribution system at a more detailed level – this could include hourly profiles in some cases for both feeders and substation transformers.

Recognizing that our current tool's capabilities would not be sufficient in a future with more customer technology adoption, we began evaluating options for a new tool several years ago. As we evaluated different options, new requirements from the Commission emerged and solidified much of what we recognized would be important tool attributes going forward. The tool's core benefits include the ability to: more efficiently and cost-effectively forecast distribution-level load, conduct more advanced scenario and NWA analyses, and better integrate our distribution planning with other Company planning processes.

We believe this tool will position us well for the future of distribution planning, where its capabilities can grow with us and help us meet current and future Commission planning requirements. We summarize the tool's capabilities below, and provide a full discussion of our proposed advanced planning tool as Attachment D1.

a. Forecast Granularity and Non-Wires Alternative Investment Analysis

As noted above, our current tool is capable of evaluating annual peak load at a feeder or substation level. A tool that provides more granular analysis options, in terms of both time intervals and proximity to the customer end point, enables us to make more accurate decisions regarding investment needs and options. For example, with the introduction of DER onto the system, the differentials between minimum and maximum load during the day become both a more valuable and harder to predict data point. With more customers adopting DER and beneficial electrification, peak loading on a specific feeder may result in different levels of load, or at a different time of day than another feeder or than the system as a whole. In order to adequately assess the impact of DER on a given part of the grid, therefore, we need a tool that can forecast hourly load at the selected analysis point. Further, the most granular analysis point we have been able to utilize in distribution planning thus far is the feeder level, but there may be value in analyzing sub-feeder data. Each feeder is generally associated with approximately 1,500 to 8,000 endpoints, depending on the area's population density. However, as DER are often localized to a specific end point, being able to analyze load and generate distribution forecasts at a sub-feeder level may provide valuable insights for both necessary grid upgrades and future potential customer offerings.

Combined, a tool that enables these more granular analyses will provide important information and efficiencies in assessing potential non-wires alternatives to identified system upgrade needs. An annual peak load analysis alone cannot communicate whether an identified upgrade is a candidate for non-wires alternative; more granular hourly data is required to determine the magnitude of overloads at specific durations. Currently this analysis is completed by extracting historical peak day load curves from feeder data, scaling them to the forecast study year, and then manually evaluating the normal and contingency load conditions. We then use these results to conduct risk analyses and develop theoretical load conditions if certain DER solutions were applied. However, a tool that can evaluate and project hourly load data on a feeder or other specific point on the grid would facilitate more efficient evaluation of potential future overloads and whether a non-wires solution – such as DER, efficiency or energy storage – is a viable alternative to traditional upgrades. In short, we anticipate a tool with these capabilities would reduce manual work and better identify opportunities for DERs to provide value on our grid.

b. Scenario Development

The Commission's Order setting out the requirements for our integrated distribution plan includes DER scenario analyses. In accordance with these requirements, we evaluate scenarios with a minimum level of assumed DER adoption, as well as medium and high adoption scenarios (corresponding to Base+10 percent and Base+25 percent, respectively). The objective of these analyses is to understand whether substantially increased levels of DER at a given point on the grid would result in different system overload conditions and upgrade needs. Currently these scenarios are developed and evaluated outside our load forecasting tool, given our current tool is incapable of generating such an analysis. A tool that can provide these scenario forecasting capabilities intrinsically would contribute to more efficient forecasting processes and better assessment regarding how these increased adoption scenarios would affect specific feeders and substation transformers. This will be particularly important going forward as DER and beneficial electrification adoption increases in our service area.

c. Aggregation and Integration with Other Resources and Planning Processes

Finally, a key aspect of a new distribution forecasting tool is its ability to integrate data source inputs, as well as communicate effectively with our other planning processes. Any new tool in which we invest will need to be able to surpass the existing tool's capabilities; preferably in its ability to handle data inputs from various sources beyond the current set of inputs such as feeder-level SCADA data and existing customer usage inputs. External data layers, such as more targeted economic and weather forecasts or projected DER adoption trends will help us more effectively forecast load changes into the future. The tool we select also needs to be able to integrate potential internal future sources of data, such as interval data from our proposed AMI investments.

Further, forecast aggregation and integration with other company planning efforts is an essential benefit we considered when evaluating replacement tools. As previously discussed, our existing tool evaluates potential load growth on a feeder or substation. However, this level of growth must be defined by the planner responsible for analyzing that specific point on the grid, and the tool cannot effectively aggregate forecasts from each point of analysis to ensure a reasonable fit with Company-wide top-line forecasts. Moreover, the forecast outputs from a future tool must be easily accessible and usable within other company planning processes. Currently, our transmission planners scale distribution forecasts to the corporate level manually, for use in transmission planning processes and tools. We also have an existing regulatory requirement to align distribution planning to integrated resource planning more closely, particularly in terms of DER forecasts. As our resource planning tools evaluate generation resources at an hourly level, a similarly granular distribution forecasting tool will facilitate this integration more effectively than the current manual translation processes.

d. Impact of the New Tool on other Distribution Planning Processes and Tools

In identifying the new planning tool as the best option for meeting these evolving requirements, we determined that it not only satisfies our forecasting requirements, but also will have a beneficial impact on other tools used by distribution planning to analyze the grid.

First, it will be able to generate, along with a load forecast, a forecast of daytime minimum loads (DML) for the various endpoints analyzed. DML are required information for DER interconnection studies, as well as hosting capacity analysis. This will greatly simplify and automate an otherwise manually-intensive process of building custom SCADA queries for each endpoint and manually parsing through the data to determine the DML.

Additionally, the APT has the ability to export forecast results directly to load flow programs, such as Synergi Electric. This will improve the efficiency of the load flow model build process, which is performed to build models for planning studies and hosting capacity analysis.

The proposed tool is able to make these improvements to the distribution planning process largely due to the fact that it ingests and outputs a significantly larger set of data as part of the forecasting process. We expect that after the tool is in use by Distribution Planning and these data sets come to fruition, we will begin to find other ways to use the new tool and its data to further benefit our processes and customers.

e. Estimated Tool Costs and Cost Benefit Summary

Given the capabilities and benefits the APT will enable for our distribution planning processes, we are confident that the investment is in the interest of both customers and the Company. As discussed previously, we have already started internal work to prepare for implementing the tool. While the contracting process and implementation planning remains in progress, we believe the costs outlined below represent an appropriate estimate for the Commission to consider as part of our certification request.

We expect the full up-front cost to procure and implement the tool at the Xcel Energy level will be approximately $9.3 million. This includes costs related to the tool's procurement – such as the license, a pre-paid five-year maintenance and support contract, internal systems integration activities, as well as the first year of ongoing O&M costs. Because the vendor portion of the cost details are market sensitive, we provide summary level costs in Table 20 below and a non-public breakdown of the estimated costs in Attachment D1, Section V.

Table 20: Xcel Energy-Wide APT Procurement and Implementation Cost Estimate ($, Nominal Millions)

Cost Category	Cost
APT License	Please refer to Att D1, Sec V for the non-public detailed cost breakdown
Company Integration – Capital Costs	
Pre-Paid Maintenance and Support for five years	
Annual Software Hosting Fee	
Company O&M Costs	
Total Up Front Costs	**$9.3**

Further, we note that our maintenance costs for the APT will be lower than the amount we currently pay for our current tool that, comparatively, has limited functionality; on an annualized basis, this savings amounts to over $100,000 Xcel Energy-wide.

The upfront acquisition costs will be apportioned to Xcel Energy operating companies based on each company's number of distribution feeders.[40] In total, we expect NSPM-specific costs to amount to approximately $4.0 million in 2020, most of which will be capital. We further note that there are some minimal O&M-related costs that will recur each year, including the hosting server cost and Company internal support; we have also accounted for annualized maintenance and service contract costs beyond year five when our initial pre-paid period ends. These costs are factored into the cost-benefit analysis (CBA), summarized in Table 21 below and provided in detail as Attachment D2 (portions of which are non-public) to this filing.

Table 21: NSPM APT Benefit-to-Cost Ratio

Net Present Value Components	Total
Benefits ($ millions)	**1.3**
O&M Benefits	0.8
Other Benefits	-
Capital Benefits	0.5
Costs ($ millions)	**3.7**
O&M Expense	0.6
Change in Revenue Requirements	3.1
Benefit/Cost Ratio	**0.35**

In this IDP, we request the Commission certify our request to procure the APT for distribution planning purposes consistent with our procedural proposal as outlined in Section XV of this IDP.

3. Daytime Minimum Loads

As discussed above, the new planning tool will more easily facilitate gathering and use of DML. We have however also otherwise prioritized the tracking and updating of DML in 2019. As we noted previously, our SCADA collects enough information throughout the course of a year to determine DML for all feeders equipped with this functionality, but it takes extra manual effort to derive a daytime minimum load.

In compliance with the Commission's requirement that we make tracking and updating actual feeder DML a priority in 2019, we determined and updated historical DML for all of our feeders and substation transformers that have load monitoring.

[40] While not an existing approved allocation methodology, we will propose this allocation method in our 2020 annual filing regarding our Service Agreement with Xcel Energy Services, Inc.

This was a large effort, and we are determining how to best include this action into the planning processes going forward. We have provided however, all of these values in our 2019 Hosting Capacity report filed concurrent with this IDP, along with other information.

We note that we will also be tracking DML and any changes to them year-to-year. Our Advanced Planning Tool will also aid in the actual forecasting of these values going forward. Minimum load forecasting is a newer concept, but our tool will allow us the ability to determine future load curves and the peak and minimum values associated with them.

VI. NON-WIRES ALTERNATIVES ANALYSIS

The discussion in this section responds to IDP Requirement 3.E.2, which requires the following:

> ***E. Non-Wires (Non-Traditional) Alternatives Analysis***
>
> *1. Xcel shall provide a detailed discussion of all distribution system projects in the filing year and the subsequent 5 years that are anticipated to have a total cost of greater than two million dollars. For any forthcoming project or project in the filing year, which cost two million dollars or more, provide an analysis on how non-wires alternatives compare in terms of viability, price, and long-term value.*
>
> *2. Xcel shall provide information on the following:*
>
> - *Project types that would lend themselves to non-traditional solutions (i.e. load relief or reliability)*
> - *A timeline that is needed to consider alternatives to any project types that would lend themselves to non-traditional solutions (allowing time for potential request for proposal, response, review, contracting and implementation)*
> - *Cost threshold of any project type that would need to be met to have a non-traditional solution reviewed*
> - *A discussion of a proposed screening process to be used internally to determine that non-traditional alternatives are considered prior to distribution system investments are made.*

Non-Wires Alternatives (NWAs) are emerging as another advanced distribution planning application. While a nascent concept only a few years ago, the United States has seen a significant rise in the number of NWA projects proposed and being implemented. States with high DER penetration and/or aggressive regulatory reform, like New York, California, Oregon, and Arizona, are leading the way. Decreasing DER costs in combination with slow or flat load growth may present opportunities for utilities to address pockets of load growth using DER over traditional build out of distribution infrastructure, like reconductoring, transformer replacement, or even new substations. Unlike traditional infrastructure projects, which typically offer fixed capacity increases at known locations, non-traditional solutions often have varying operating characteristics based on their location or the time of day they are used.

More tactically, NWA analysis processes consider several things: a set of criteria for determining which traditional projects are suitable candidates for NWA, processes to develop portfolios of solutions (including both third party resources and non-traditional utility assets), a mechanism to evaluate the costs and benefits of the NWA relative to the traditional solution, procurement processes, and standards to ensure equitable reliability and performance. For implementation and deployment, currently we are seeing NWA solutions which require a disparate set of systems to separately operate the different elements of equipment that would comprise an NWA portfolio solution (e.g. a battery- only platform or demand response- only mode).

Without integration across different systems, this makes the facilitation of NWA a custom, one-off solution that requires extensive oversight and management. Recent analysis performed by Xcel Energy has determined that the cost of incorporating DERs as the primary risk mitigation is at this time still more costly than traditional solutions. However, as technology advances and manufacturing evolves, DER have the potential to quickly become a cost competitive option. As such, Xcel Energy is working diligently with research groups, internal and external stakeholders, and other utilities that are also incorporating DER planning in order to refine the process of having NWAs solve traditional distribution system deficiencies.

One of our external efforts was to engage with stakeholders due to the high interest in NWA during the course of our 2018 IDP proceeding. We held a stakeholder workshop in April 2019 to discuss and get feedback on our screening process and approach to the NWA analysis.

In this section, we discuss the viability of NWAs by project type, the Company's timeline to consider and incorporate any NWA projects, our screening process for NWA projects, and a summary of our analysis. We provide the full results of our NWA analysis as Attachment H. Finally, we also provide an update on our involvement with Center for Energy and Environment's (CEE) in the Geotargeted

Distributed Clean Energy Initiative.[41]

A. Viability of NWAs by Project Type

IDP Requirement E.2 requires, in part, that the Company provide

> *…information on …Project types that would lend themselves to non-traditional solutions (ie. Load relief or reliability)*

In this section we discuss three project types (mandates, asset health and reliability and capacity) and discuss why capacity project best lend themselves to a non-traditional solution.

1. Mandated Projects

Mandated projects are projects where the Company is required to relocate infrastructure in public rights-of-way in order to accommodate public projects such as road widenings or realignments. For technical reasons, NWAs would not work well for mandated projects. It is a priority to keep customers connected to the grid. If we chose not to replace distribution infrastructure due to a mandated project we would leave a segment of customers electrically unserved due to having no physical connection to the Xcel Energy system. Those customers would then need to be served via some other local means, like distributed generation. However, if they were served by some other means, that would take away from the interconnectedness of the distribution system. This is necessary to continue reliable service because it allows the Company the ability to switch customers to other feeders during periods of planned maintenance or unplanned outages. Removing that interconnectedness takes away added flexibility and redundancy that has been intentionally designed into the system and makes operating it more difficult and less reliable. The grid offers many benefits, such as affordable reliability, and removing customers from it is not a viable solution for either Xcel Energy or our customers.

Beyond the technical reasoning, these projects generally follow municipal and state funding availability and consequently, are not always specifically represented in our five year budget, especially beyond one to two years. What makes these projects even more time prohibitive is the fact that they must occur prior to the actual public project taking place. A typical example would include a project that was formally funded by a municipality two years in advance of the start of construction. This

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[41] *See* https://www.mncee.org/resources/projects/geotargeted-distributed-clean-energy-initiative/

means that the municipal project design will be completed within the first year after funding was allocated, giving the Company less than one year to design its project, allocate the necessary funds, and relocate facilities in the affected areas before construction on the municipal project can begin. Implementing a detailed NWA for such a situation would be extremely difficult, if not impossible, to accomplish within such a short period of time given the complexities inherent to a totally unique and new solution that an NWA would offer.

2. *Asset Health and Reliability Projects*

Asset Health and Reliability projects are projects required to replace equipment that are reaching the end of life or have failed. This is a broad category that covers pole replacements, underground cables, storms, public damage repair, conversions, etc. To maintain the existing reliability of the distribution system we must spend money annually to replace our assets.

Keeping customers connected to the grid is the major reason Asset Health and Reliability projects are not suitable for NWAs. If we chose not to replace distribution infrastructure due to aging assets, there is a high level of risk that certain assets would fail and customers would experience an outage. To avoid or prevent the outage the customers would need to be served via some other local islanded generation. From a reliability perspective, at some point our customers need to be hooked back up to the distribution grid rather than staying in a permanent microgrid. So money is spent on infrastructure renewal regardless; it is just a matter of if it is reactive or proactive replacements.

Unlike the mandated projects, with Asset Health and Reliability projects there is more potential for ongoing costs. A mandated project requires the movement of a particular piece of the system one time. An asset health project, because it is based on condition, can occur at many points on the system. One project could first be needed to replace deteriorating poles, then another needed to address underground cable that is going bad near the customer, then another to replace breakers inside the substation. Because asset health affects every part of the distribution system and is essential to maintaining reliability, an NWA is not workable.

3. *Capacity Projects*

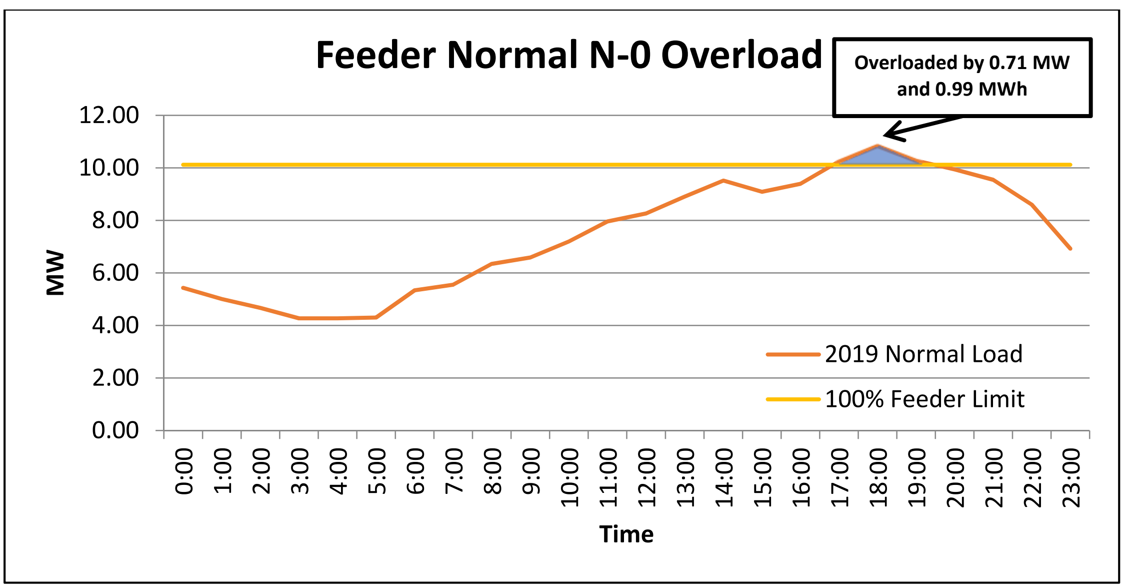
Capacity projects are better suited for NWAs as they are driven by a capacity deficiency that can be offset or otherwise deferred by strategically-sited DER. DER that can generate, discharge, or reduce the consumption of electricity downstream on a feeder can decrease the amount of load that is drawn through the substation and relieve overloads. In some cases power quality issues, such as voltage sags, could fall under the Capacity project heading. While this is not the usual case, this type of issue could also benefit from an NWA solution.

Because capacity projects do not have external requirements to build capacity, each project is scored on a cost/benefit basis, and that score is one of the key drivers for prioritizing projects for selection in the budget. Therefore, without some additional driving need, an NWA must be cost-competitive with a traditional solution to be viable in the budget create process.

Capacity risks are identified in two different categories: N-0 (system intact), and N-1 (first contingency). Existing Distribution Planning Criteria dictate that a project needs to be identified to resolve all N-0 risks greater than 106 percent loaded, and all N-1 risks with more than 3 MVA at risk. The viability of NWAs varies between N-0 and N-1 risks due to the nature of the risk types.

N-0 risks are normal overloads that occur under system intact conditions. These typically are manifested as substation transformers or distribution feeders that have just crossed their 100 percent loading capacity threshold. We provide an illustrative example of an N-0 overload below.

Figure 34: 2019 Peak Day Load Profile Reflecting an Illustrative N-0 Overload

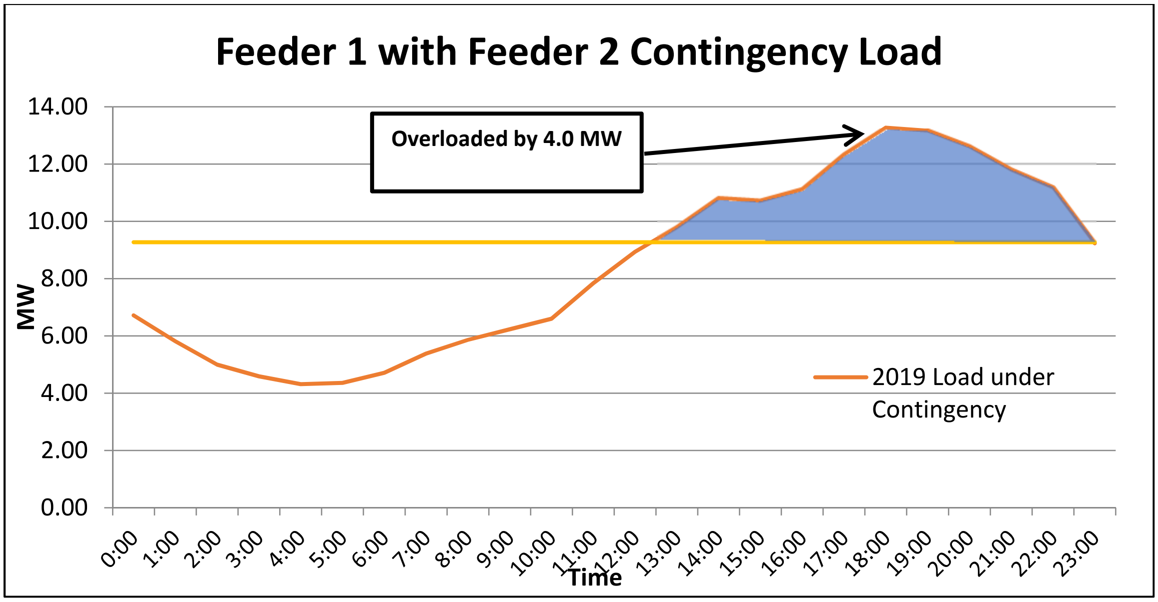


This overload is relatively small with a peak magnitude of 0.71 MW. Additionally, due to the small magnitude the total duration of the overload is brief as well, yielding a total of approximately 1 MWh overloaded. With a unit cost estimate of approximately $400,000/MWh for battery storage, this indicates that the overload could be mitigated with DER for $400,000. This cost estimate is cost-competitive with a typical traditional project to mitigate a comparable overload, which would consist of upgrading feeder cables or conductors, extending a feeder and transferring load, or installing a new feeder.

N-1 overload risks, on the other hand, are significantly less viable for NWAs. N-1 overloads occur when, for loss of a feeder, feeder load is transferred away to adjacent feeders, causing an overload. Per our planning criteria, projects are not required for N-1 risks until they exceed 3 MVA at risk – this means that total magnitude of the overload on the adjacent feeder(s) exceeds 3 MVA. At this level of overload magnitude, the duration of the overload extends by several hours. This excessive duration accumulates significant amounts of MWh overloaded, and in turn inflates the cost to mitigate the risk.

We show an illustrative example of a N-1 overload below. If an outage were to occur for the Feeder 2, the feeder's load would be broken up into sections and transferred to adjacent feeders. In the case of the Feeder 2, the load would be broken up into three sections. The first section can be transferred away to an adjacent feeder without causing any overloads. However, when the second section is transferred away to Feeder 1, it causes an approximate 4 MW overload. The resulting peak day load curve for Feeder 1 after the Feeder 2 second section load has been transferred is shown below.

Figure 35: Peak Day Load Curve for Feeder 1 After Feeder 2 Second Section Load has been Transferred



The magnitude of the N-1 overload is relatively normal for N-1 risks tied to a project at 4.0 MW at risk. However, just 4 MW of load at risks causes the duration of the overload to extend to 10 hours. Therefore, the accumulated MWh during the overload totals to 24.08 MWh. With a unit cost estimate of $400,000/MWh for battery storage, the cost to mitigate this risk rises to $9,632,000. This cost estimate is multiple orders of magnitude higher than a typical traditional project to mitigate a comparable risk. A typical traditional project could consist of upgrading feeder cables or conductors, extending a feeder for a new tie, or installing a new feeder.

The load profile shown above is of similar shape to most feeders that comprise a mix of residential and commercial customers. As such, the cost estimate for the NWA can be considered representative of a typical NWA for N-1 risks of this magnitude. However, even if a 4 MW overload were to occur for only a one hour duration (totaling to 4 MWh), it would still require $1,600,000 of battery storage to mitigate the overload. While this overload duration is unrealistically short, it indicates that the cost to mitigate a 4 MW N-1 overload for even the minimum possible duration would not be cost-competitive with a comparable traditional solution. Therefore, it is not recommended that N-1 risk-driven projects are considered viable for NWAs.

B. Timeline

IDP Requirement E.2 requires in part that the Company:

…provide information on . . A timeline that is needed to consider alternatives to any project types that would lend themselves to non-traditional solutions (allowing time for potential request for proposal, response, review, contracting and implementation).

With regard to the timeline that is needed to consider alternatives to any traditional projects, for purposes of this IDP we have assumed we need about three years to appropriately consider and incorporate a NWA solution. This timeline incorporates our internal time for analysis as well as all the steps surrounding a request for proposals (RFP) to actually procure a NWA solution. This includes issuing an RFP, obtaining response, screening the responses, technical and sourcing reviews, and then contract negotiations, and construction. It is our understanding that this timeline is consistent with the approach other utilities have used in similar analyses as well.

Perhaps as we get more experience in this process, the timeline could moderate a bit, however, these projects necessarily take a significant amount of lead time, even when we are addressing them entirely in-house.

C. Screening Process

IDP Requirement E.2. requires in part that the Company:

… provide information on the…Cost threshold of any project type that would need to be met to have a non-traditional solution reviewed. And, a discussion of a proposed screening process to be used internally to determine that non-traditional alternatives are considered prior to distribution system investments are made

NWA Analysis, from a holistic standpoint, is an emerging analysis that many utilities across the U.S. are just beginning to tackle. Not only do these alternatives use some non-traditional solutions but they also use traditional ones in new ways and may combine solutions to fully mitigate an issue. These complexities along with differing implementation and operational strategies will take time and considerable effort to build and maintain.

We note that we are just at the beginning of the future NWA process. Xcel Energy and the industry as a whole, is trying to create a comprehensive method that will focus on the projects that have the most potential and then evaluate them in an efficient manner against traditional alternatives. We believe much work needs to take place both from the Company and the industry before success can happen. At present, the effort needed to analyze one project for potential NWA is substantial and increases greatly according to the number of risks associated with it.

Recognizing the current IDP requirement to provide an analysis on how NWAs compare in terms of viability, price, and long-term value for projects with a total cost of $2 million or greater is an interim step, we believe long-term that the right approach to identify candidate projects will involve more than a financial threshold.

As we discussed with stakeholders at our NWA workshop, we applied several filters in our screening process including project type, cost, timeline and number of risks for the 2019 IDP process. However, we expect to continue to refine our process to identify projects for NWAs for future reports. The project filters were applied as follows:

- *Project types* – Project types includes mandates, asset health and reliability and capacity projects. As discussed above, mandates and asset health and reliability projects were filtered out.
- *Costs* – Per the Commission's Order, we evaluated projects with costs greater than $2 million. However, we believe there is additional work to be done to best identify the range of projects costs for this filter.
- *Timeline* – The timeline included in this screening process includes projects that fall in the 2022-2024 timeframe due to the timing considerations discussed above.
- *Risks* – The number of project risks includes both N-0 and N-1 risks. We did not use a hard cutoff for this filter, but factored it in as we determined which project would be best for a NWA analysis.

IDP Requirement E.1 requires the following:

> *Xcel shall provide a detailed discussion of all distribution system projects in the filing year and the subsequent 5 years that are anticipated to have a total cost of greater than two million dollars. For any forthcoming project or project in the filing year, which cost two million dollars or more, provide an analysis on how non-wires alternatives compare in terms of viability, price, and long-term value.*

Using the above screening process, the below table provides the list of capacity projects over $2 million that fall within the required timeline. Nine projects fit the screening criteria for further evaluation as shown below.

Table 22: Total Capacity Projects Exceeding $2 Million and Within the Timeline

Project	2020	2021	2022	2023	2024	Total
Install Hyland Lake HYL TR3 & Feeder	$0	$0	$0	$100,000	$4,600,000	$4,700,000
Install Goose Lake GLK TR3 & Feeders	$0	$0	$0	$700,000	$4,000,000	$4,700,000
Install Orono ORO TR2 & Feeder	$0	$0	$100,000	$4,000,000	$0	$4,100,000
Install East Winona EWI TR2 & Feeder	$0	$0	$0	$100,000	$3,100,000	$3,200,000
Install Zumbrota ZUM TR & Feeder	$0	$0	$100,000	$2,950,000	$0	$3,050,000
Reinforce Kasson KAN TR1 & Feeders	$0	$0	$2,850,000	$0	$0	$2,850,000
Reinforce Burnside BUR TR2	$0	$0	$100,000	$2,600,000	$0	$2,700,000
Install Viking VKG Feeder	$0	$0	$0	$2,500,000	$0	$2,500,000
Install West Coon Rapids WCR TR	$0	$0	$100,000	$1,980,000	$0	$2,080,000

Today, NWA analysis is very time consuming and manual – especially as the risks associated with a project increase. The process requires that we pull peak load curves for feeders and substation transformers from historical monitoring data and advance that to the forecasted year of interest. Those curves are then blended together, where applicable, for contingency situations that are unique for each. We then tailor and add in DR and existing generation curves and additional solar if necessary, in order to determine final energy and demand values that can be used to size an appropriate energy storage device. This is necessary for every identified risk that a traditional project is mitigating.

Most capacity projects budgeted at greater than $2 million are intended to solve larger numbers of risks – this vastly increases the complexity of the problems to solve with a NWA, and in turn increases the amount of resources required to conduct the analysis. Projects with fewer capacity risks to solve are more localized and therefore more straightforward. We also look for any opportunities to utilize resources to solve more than one risk, such as optimally placing them at key locations on the system.

We expect future tool enhancements will help make this process less burdensome. Specifically, our proposed Advanced Planning Tool, for one, will help in the beginning of the analysis by providing the forecasted load curves. While the rest of the process will still be fairly manual for the foreseeable future, we are working within the industry to help affect change and improvement. Recently, we participated with EPRI in an effort to help build a tool capable of evaluating different alternatives in a model based format. Even though a comprehensive tool solution for NWA analysis is years away, we will continue to work with EPRI and others in the industry to make advancements and improve on existing processes.

D. Non-Wires Alternatives Analysis

In this section, we outline the results of our 2019 NWA analysis, which examined the nine projects summarized above. For each of these projects we focused on the forecasted 2022 peak load curve for each feeder or transformer risk involved. We then applied focused demand response in an effort to reduce the load and followed that with energy storage and/or solar generation to make up the rest of the deficiency. In some instances, we had existing solar on particular feeders that we could utilize in the analysis as well. We provide the results of the analysis, along with the load curves and assumptions used in Attachment H.

We only considered DR for the N-0 risks. This is partially due to the complexity of the N-1 analysis (combinations of feeders resulting in multiple configurations and customer make-ups) and the difficulty in obtaining necessary data such as individual customer loads. By focusing on the N-0 risks at this time, we are looking to develop a process, observe the value, and determine next steps for all risks.

Table 23 below highlights the nine projects, their costs, and the risk deficiencies that drive those costs. Comparing these analyses to traditional projects was difficult because in some instances, the NWA is not able to fully solve all of the risks that the traditional project solved. This was in part due to contingency situations where a NWA would have to act as a microgrid for large amounts of energy. The costs for such a solution would have been substantially greater. The NWA solutions also solved the risks up to 100 percent of the capacity rating, which means that any new load growth would create the need for an expanded or new NWA solution. In comparison, our traditional capacity projects contain "spare capacity" that allows us to accommodate some new growth in the near term.

Table 23: 2019 NWA Candidate Projects – Results Summary

Project Title	# of Risks	Aggregate Project Peak Demand (MW Overload)	Aggregate Project Energy Demand (MWh Overload)	Cost of NWA ($ M)	Cost of Traditional Project ($ M)
Reinforce Kasson TR1 and Feeders	7	14.14	126.69	$49.34	$2.85
Install West Coon Rapids WCR TR	4	18.59	167	$94.64	$2.08
Reinforce Burnside BUR TR2	3	9.76	92.59	$46.86	$2.7
Install Zumbrota ZUM TR & Feeder	3	2.8	28.25	$8.84	$3.05
Install Orono ORO TR2 & Feeder	3	9.62	59.35	$31.32	$4.10
Install Hyland Lake HYL TR3 & Feeder	5	11.31	52.49	$20.99	$6.20
Install Goose Lake GLK TR3&Feeders	8	20.94	155.77	$63.31	$4.70
Install Viking VKG Feeder	4	6.99	39.10	$15.64	$2.00
Install East Winona EWI TR2 & Feeder	9	9.2	98.16	$88.90	$3.2

We discuss each of these project analyses in Attachment H.

E. Geo-Targeting

We continue to partner on a non-wires alternative pilot led by Center for Energy and Environment (CEE). This initiative started in June 2017 and is focused on energy efficiency and demand response programs within our existing CIP portfolio. The pilot officially launched in June 2019 with customer outreach and is expected to go through the end of 2019. The project implementation costs are funded by a grant from the Legislative-Citizen Commission on Minnesota Resources and existing Conservation Improvement Project program budgets.

The pilot site covers the cities of Sartell and Sauk Rapids in central Minnesota where Xcel Energy is both the electricity and natural gas provider. These locations were chosen out of a list of nine potential project areas that had forecasted capacity needs three or more years into the future. At the time the pilot site was identified, the estimated capacity need was 1.5 MVA, and the traditional distribution solution anticipated a new transformer and feeder reconfiguration. The goal of the pilot is to offset projected peak demand growth in the target location by 500 kW, deferring a traditional infrastructure upgrade by one year.

CEE's goal for annual energy efficiency participation is 340 residents and businesses, which is an increase from an average of 95 participants in previous years. Throughout the spring, the pilot team worked closely with the cities to establish community-based marketing strategies and make use of local channels. Community leaders were invited to participate in a leading-edge communication strategy developed for this project to raise local awareness. Community response to the pilot rollout thus far has been favorable. From June through September 2019, 134 residents participated, and 104 business audits were completed.

While the pilot is not yet complete, it is experiencing challenges meeting the goals. For example, the sales cycle for business customers has been a challenge, perhaps suggesting that these customers may not be able to help address a short-term wires risk. On the residential side, the cost per customer is on the higher end of the spectrum for just an energy efficiency opportunity – including the cost of an extended, targeted promotion. Including the value of the local peak demand savings will likely be needed to make residential opportunities cost effective. However, a less than normal weather pattern for the June-September timeframe may also have impacted opportunities to install smart thermostats or adjust cooling equipment when customers did not see these as necessary or immediate needs. The pilot project team is reviewing these and other pilot aspects as the pilot comes to an end in December. We will report results in our 2019 Conservation Improvement Plan Status Report (filed April 2020) and in our next IDP.

The pilot project also developed operational protocols to test existing demand response resources for distribution system purposes as a second component of the pilot. During the research stage, the team determined over 4,000 residents and businesses in the pilot area were already participating in our Saver's Switch program.[42] In addition, there has been a growing number of smart thermostat customers signed up for AC Rewards – and 56 new customers signed-up through the pilot to-date. While traditionally operated for bulk system level purposes, the pilot sought to operationalize them as a geo-targeted resource, and therefore to assist with local grid management. While CEE tested this concept in the 2019 summer, the weather conditions were not ideal to truly test peak demand, so results may be limited. The pilot evaluation will continue during the 2020 cooling season, where we hope to get more complete results. We will incorporate our learnings along the way into future IDPs and NWA analyses.

[42] Saver's Switch allows the Company to directly control air conditioners on peak electricity use days.

VII. ASSET HEALTH AND RELIABILITY MANAGEMENT

In this Section we describe several analyses and functions that support distribution system reliability and resilience.

A. Electric Distribution Standards

Utility distribution systems are complex and dynamic, in that they involve thousands of pieces of equipment, must be resilient from outside forces over vast areas of geography, and must be able to respond to changes in customer loads and operational realities. Traditionally, distribution systems have been designed for the efficient distribution of power to provide customers with safe, reliable and adequate electric service – with geography playing a significant role in the design of the system. Our Minnesota service area has diverse geography and therefore diverse planning criteria and considerations.

One of the ways we plan the system is through a set of materials and work practice standards that apply to the construction, repair and maintenance of the electric overhead distribution, underground distribution, and outdoor lighting systems. The purpose of Electric Distribution Standards at Xcel Energy is to develop and maintain a broadly-accepted set of material and construction standards that meet the needs of each of the operating companies and stakeholders, while meeting all applicable regulatory and code requirements. The Standards function acts as an expert consultant to operations and engineering, collaborates to enhance public and employee safety, drives cost-effectiveness, and improves system reliability through defining electric distribution standard materials, methods, and applications.

Standards updates may stem from a number of circumstances including regulatory or code changes, company analysis, input or an issue raised by field personnel, and industry guidance, among others.

Xcel Energy's Design standard books consist of Overhead, Underground, and Outdoor Lighting Manuals. Each of these Manuals detail equipment and designs that have been previously reviewed against industry standards and best practices to ensure installation of facilities results in safe and reliable service. Documenting approved materials and equipment configurations allows for efficient design of construction projects. The Standards Manuals simplify electrical distribution projects and optimize a Designer's work because the engineering and code compliance is built-in – and typically only requires engineering input for special circumstances. Reference material on transformer sizing and conductor lengths, which already accounts for voltage and thermal limits, is also part of the Standards Manuals.

We are providing a couple of examples of the work that Standards does, to further help put the Standards function into context:

Porcelain Cutout to Polymer Cutout Transition (2010-present day). Xcel Energy has a process to identify and analyze faulty material. In this case, material submitted from field crews and engineering identified an issue where porcelain cutouts stood out from other materials as having issues requiring further analysis. We had been using polymer cutouts in specialized applications, however not broadly, because industry standards had not yet been developed for the polymer material. We validated our observations on the porcelain cutouts and the potential viability of polymer as an alternative through peer group consultation with other utilities through Midwest Electrical Distribution Exchange and Western Underground Committee.

Electric Distribution Standards worked with local jurisdictional teams with an objective to identify and vet a polymer cutout to be used company-wide, and discontinue the use of porcelain cutouts. We additionally participated in the IEEE C37.41 and C37.42 revision to create testing requirements for polymer cutouts. Recently, we further improved this Standard by consolidating 125kV BIL to 150kV BIL cutouts –allowing a transition from three cutout types to two cutout types, and increasing the number of manufacturing sources from which we can procure polymer cutouts that meet our standards requirements. As we systematically replace remaining porcelain cutouts on our system with polymer, we are improving reliability for customers and the resilience of our system. This change also expanded material availability and resulted in cost savings.

Wood to Fiberglass Crossarm Transition (2010-present day). In 2011, the National Electrical Safety Code (NESC) changed the loading requirements for deadend crossarms. We conducted research with our industry peer groups and found that fiberglass was identified as being the best material for longevity and strength. We evaluated alternatives, and available fiberglass deadend crossarms met the NESC requirements and resulted in an approximate 17 percent cost savings. After our success implementing deadend fiberglass crossarms, we evaluated and ended-up implementing fiberglass tangent crossarms as a cost-neutral option – improving the resilience of our system in a cost-conscious way for our customers.

We have since made further improvements to the fiberglass crossarms after participating in an EPRI initiative to evaluate system materials in terms of system hardening. After conducting further internal research, to develop testing criteria based on galloping and ice loading witnessed by Xcel Energy line crews and Electric Distribution Standards, we updated Xcel Energy standards to obtain a better and longer life product – and are additionally working with the fiberglass crossarm industry to revise the national standards to better take these conditions into account.

For additional context, Table 24 below shows a list of some of the most common industry standard documents applied in distribution engineering. The list is not intended to be inclusive of all standards that may be applied to medium and low voltage systems, but rather is intended to provide insight into standards that are frequently used. Included are primarily documents from the Institute of Electrical and Electronics Engineers (IEEE) which are classified as Standards, Recommended Practice, and Guides. Standards carry more weight when compared to Recommended Practices. Guides often show a number of ways to achieve a technical objective and are the least prescriptive.

Table 24: Common Engineering Standards Summary

Condition	Standard
Safety	National Electric Safety Code (NESC)
	Xcel Energy Safety Manual
Voltage Limits	ANSI C84.1 – minimum and maximum voltage limits, voltage imbalance limits
	Xcel Energy Standard for Installation and Use – voltage limits and imbalance (same as ANSI C84.1)
Thermal limits	Xcel Energy Design Manuals (Distribution Standards Engineering)
	Substation Field Engineering (SFE) transformer loading database – based off of IEEE standards
	IEEE 738 – Overhead conductor ampacity rating IEC 287 and IEC 853 – Cable ampacity rating methodology in CYMCAP program
	IEEE C57.91 – transformer and regulator loading guide IEEE C57.92– power transformer loading guide
Distribution Interconnection	IEEE 1547 – Interconnection of Distributed Resources
Harmonics	IEEE 519 – total harmonic distortion and individual harmonic limits
Voltage Fluctuation	IEEE 1453 – rapid voltage change and flicker limits

Additionally, North American Electric Reliability Corporation (NERC) standard FAC-002-2 applies to studying the impact of interconnecting facilities to the Bulk Electric System, which comes into play with distribution substations. Specifically, Requirement R3 applies when we seek to interconnect new "end-user facilities" or materially modify existing interconnections to the transmission system. It states we shall coordinate and cooperate on studies with our Transmission Planner or Planning Coordinator as specified in Requirement R1. This includes many requirements such as reliability impact, adherence to planning criteria and interconnection requirements, conducting power flow studies, alternatives considered and coordinated recommendations.

B. Asset Health

The NSPM distribution system is composed of nearly 27,000 miles of distribution lines and 1,200 feeders that provide the path for delivering electricity from the distribution substation to the distribution customer transformer and then to customers. This vast system is key to ensuring customers receive safe, reliable and cost effective energy. We continually invest in our infrastructure through established reliability and asset health programs to ensure that we deliver the most reliable and efficient energy to our customers. While we have been able to historically deliver excellent value for customers, the utility industry is changing rapidly and customer expectations for power availability are also changing.

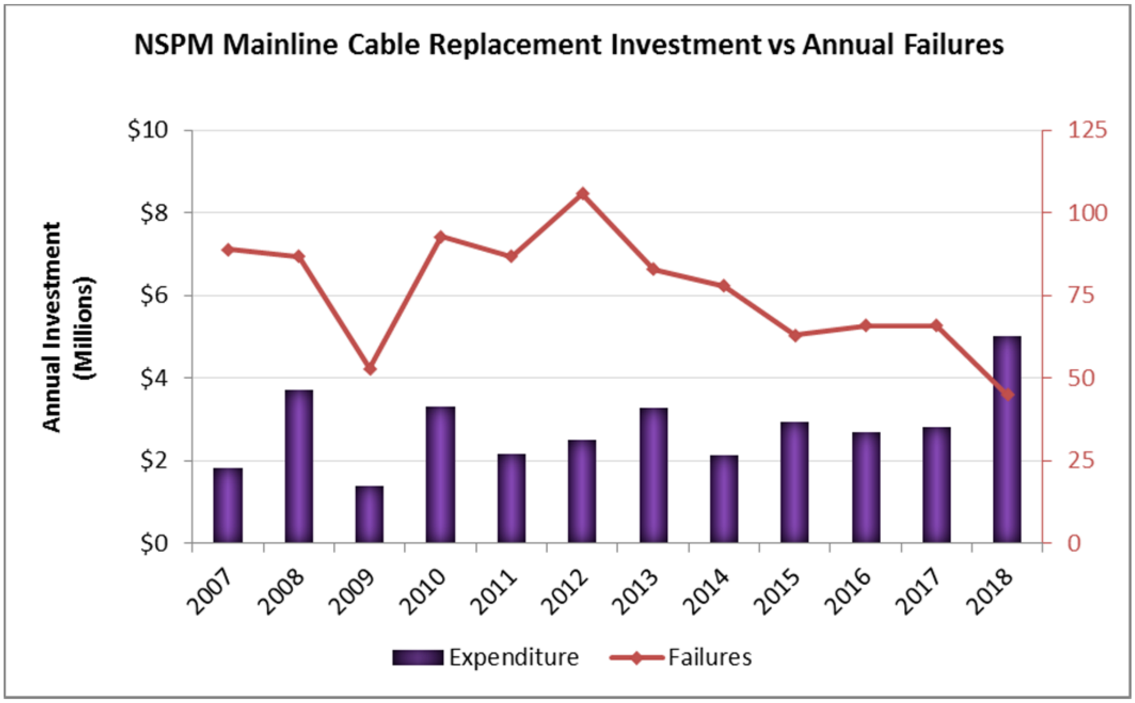
To this end, we noted in our 2018 IDP that we believe an incremental customer (now, system) investment (ISI) initiative is necessary to continue to meet the needs of our customers – and that shifting funding closer to the customer will be a foundational requirement for the grid of the future. We discuss our traditional asset health program below, and in compliance with Order Point No. 6 of the Commission's July 16, 2019 Order in Docket No. E002/CI-18-251, we provide in part C below:

> *…additional information on the Incremental Customer Investment Initiative and the System Expansion or Upgrade for Reliability and Power Quality increases beginning in 2021.*

We monitor and address the health of our distribution assets – tracking for example, the fleet age of each of our major distribution assets, and use age as a partial proxy for asset health. We also analyze reliability data and work to tie that data to asset health to create and refine programs to manage reliability. We discuss these aspects of our current efforts in terms of examples in more detail below.

To use underground distribution assets as an example, reliability performance is heavily influenced by the performance of mainline and tap cable. We analyze cable failure rates for both types of cable, and budgets to manage the reliability. Analysis has shown us that the era of the cable projects its failure rate, which allows us to focus efforts on the cable most likely to fail. Historical performance of cable has also influenced our standards for future purchases for new construction and replacement work. Figure 36 below is one of the ways that we analyze asset performance in terms of maximizing customer value.

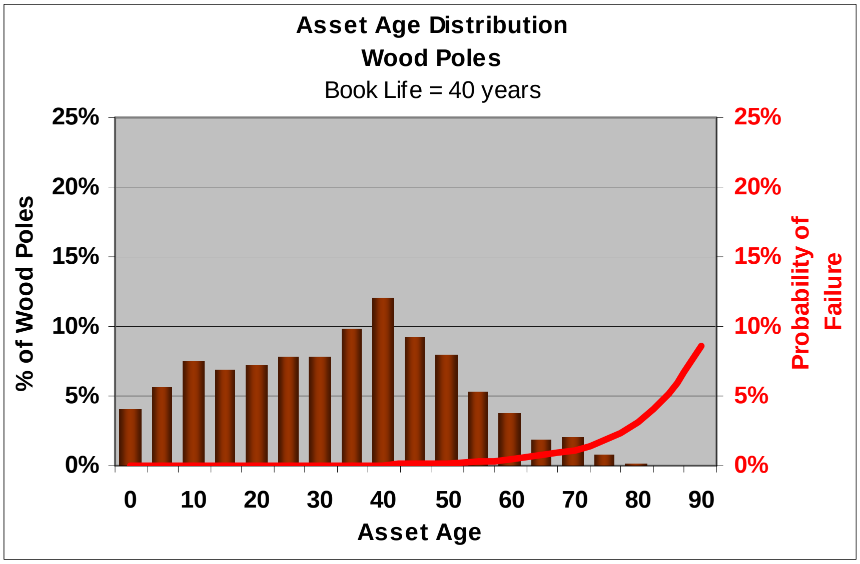
Figure 36: Example – NSPM Mainline Cable Replacement Investment Compared to Annual Failures



The overhead distribution reliability performance is dependent on many factors including vegetation, weather, and the health of the many pieces of the overhead system. The vegetation program is a key program to maintaining good reliability. The vegetation program includes quality checks by visiting outage locations associated with vegetation that impacted 100 or more customers. The check determines if the outage would have occurred if a vegetation crew had worked the line the day before. These checks are showing the value of our vegetation program in mitigating outages. Unfortunately vegetation events can cause damage to our asset health, especially to older assets, so minimizing events is a key factor in maintaining asset health.

Another key program is checking the health of our poles. Pole rot at the base of the pole can be a cause of pole failure, especially in stormy weather. We work to inspect poles on a 12-year cycle to mitigate risk of pole failures. The below figure portrays wood pole failure rates by their age.

Figure 37: Example – Wood Pole Failures by Age



We have also changed the standards for all new construction and replacement poles to larger poles as part of system hardening. Other programs include:

- Identification of the poorest performing feeders each year and doing an in-depth analysis to identify opportunities for improvement.
- Identification of a protective device that operates frequently and performing a study to identify opportunities for improvement.
- Identification of customers experiencing multiple interruptions, performing a study to identify opportunities for improvement.

Analysis of these outages commonly includes site visits that allow the engineer to see firsthand the condition of the equipment. Mitigations for these programs frequently include updating deteriorating infrastructure and may overlap with other programs.

C. Incremental System Investment

The ISI initiative is driven by the need to improve reliability on those elements of the system that are the closest to our customers as well as provide the infrastructure to support increased DER integration. While historically Distribution has made investments in our infrastructure through our established asset health and reliability programs to ensure the reliability of our system, the utility industry is changing rapidly and customers have new expectations for power availability and reliability. As a result, we believe it is necessary to shift funding closer to those portions of the system that directly connect to customers with the goal of enhancing the safety, reliability, and resiliency of the system while also enabling customer choice and the adoption of DER, such as EVs.

This initiative will both expand existing asset health programs and will create new programs to address areas of the system that have traditionally not received much focus. Specifically, this initiative will expand two of Xcel Energy's existing programs, one that replaces underground cables that are at risk of failure and another that identifies and replaces substation transformers that are nearing the end of their useful life. This initiative will create new programs that focus directly on our customers' reliability and DER adoption needs by expanding investments on the portions of our system closer to the customer. Typically these elements are the taps (radial extensions from our feeders) and secondary voltage systems.

The ISI initiative is divided into four main programs: substation, underground, overhead tap, and overhead mainline. We outline below, the capital expenditures for these ISI programs and the O&M costs in Tables 25 and 26.[43]

Table 25: ISI Capital Expenditures – Distribution State of MN Electric (Millions)

ISI Programs		2020	2021	2022	2023	2024
Overhead Tap Programs	Targeted Undergrounding		$18.2	$27.0	$27.0	$27.0
	Low Cost Reclosers		$2.7	$2.4	$2.4	$2.4
	Pole Top Reinforcements		$2.7	$2.4	$2.4	$2.4
	Transformer and Secondary Replacements		$2.5	$2.4	$2.4	$2.4
	High Customer Count Taps		$3.0	$3.0	$3.0	$3.0
	Community Resiliency		$2.0	$3.0	$3.0	$3.0
Underground Programs	Mainline Cable Replacement		$7.0	$7.8	$7.8	$7.8
	Underground Residential Distribution (URD) Cable Replacement		$5.0	$2.5	$2.5	$2.5
	Cable Assessment		$7.0	$6.0	$6.0	$6.0
	Network Monitoring		$2.0	$2.3	$2.3	$2.3
	St. Paul Tunnel Rehabilitation		$5.0	$5.0	$5.0	$5.0
	Feeder Exit Capacity		$3.8	$3.0	$3.0	$3.0
	Purchases / Tooling		$4.5	$0.2	$0.2	$0.2
Substation Programs	Substation Asset Renewal		$5.0	$5.0	$5.0	$5.0
	Transformer Replacement		$7.0	$13.0	$13.0	$13.0
Overhead Mainline Programs	Lightning Protection Replacement		$1.0	$1.0	$1.0	$1.0
	Pole Fire Mitigation		$2.5	$2.0	$2.0	$2.0
TOTAL		**$0.0**	**$81.0**	**$88.0**	**$88.0**	**$88.0**

[43] We also clarify that these O&M costs are also included in the overall Distribution O&M budget primarily in the Contract Outside Vendor category.

Table 26: ISI O&M Costs-Distribution
State of MN Electric (Millions)

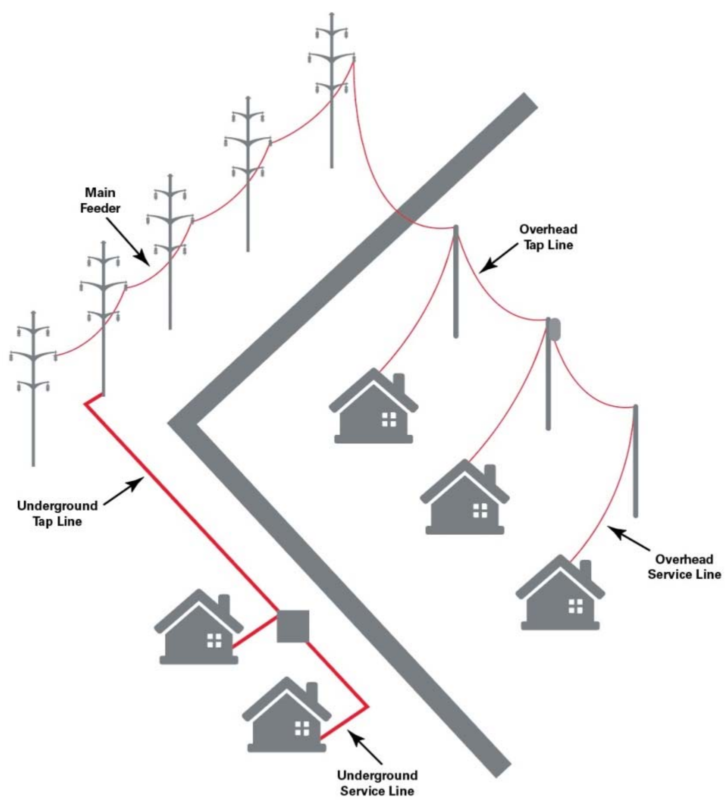
Cost Category	2020	2021	2022	2023	2024
O&M Expense	$0.0	$1.5	$1.5	$1.5	$1.5
Total	**$0.0**	**$1.5**	**$1.5**	**$1.5**	**$1.5**

1. *Overhead Tap Program*

The primary goal of the overhead tap program is to improve reliability and resiliency of the Company's electric distribution system through a series of six programs that target the overhead tap lines throughout the Minnesota service territory.

As shown below, tap lines are those that split off from the main feeder and travel through neighborhoods to connect to homes and businesses. The tap portion of the NSPM distribution system consists of nearly 22,500 circuit miles of line. Of those, approximately 58 percent, or 13,050 miles are overhead.

Figure 38: Illustration – Tap Portion of NSPM Distribution System



The six programs are: (1) targeted undergrounding; (2) low cost reclosers; (3) pole top reinforcements; (4) transformer and secondary replacement; (5) high customer count taps and (6) community resiliency program.

We outline the capital expenditures for each of these programs below.

Table 27: ISI Capital Expenditures – Distribution State of MN Electric (Millions)

ISI Programs		2020	2021	2022	2023	2024
Overhead Tap Programs	Targeted Undergrounding		$18.2	$27.0	$27.0	$27.0
	Low Cost Reclosers		$2.7	$2.4	$2.4	$2.4
	Pole Top Reinforcements		$2.7	$2.4	$2.4	$2.4
	Transformer and Secondary Replacements		$2.5	$2.4	$2.4	$2.4
	High Customer Count Taps		$3.0	$3.0	$3.0	$3.0
	Community Resiliency		$2.0	$3.0	$3.0	$3.0
TOTAL		**$0.0**	**$31.1**	**$40.2**	**$40.2**	**$40.2**

Specific to reliability, we intend this program to decrease the number of outages per year for those customers that experience frequent and long outages due to issues on the overhead tap system. As our customers live and work near the electrical system and its equipment and components, we also consider community aesthetics a factor of our customers' experience. Customer satisfaction depends on a Company's ability to meet customer expectations. Reliability is one of the foundational components for meeting customer expectations of an electric utility, and as electricity becomes increasingly entwined with every aspect of day-to-day life, the issue of reliability becomes increasingly important to customers.

Specific to distribution system resiliency, these programs aim to strengthen the electrical system to reduce weather-related impacts and outages, rather than the traditional focus on ensuring rapid response and restoration to a storm-vulnerable system. Community resiliency includes ensuring the most critical first responder services in a community are supplied by a safe, reliable, and storm-hardened grid system in the event of emergency. Additionally, we need to prepare our system for electric vehicle penetration in advance of rapid and widespread customer adoption.

a. Targeted Undergrounding

The goal of the targeted undergrounding program is to underground the outage-prone tap lines to reduce the likelihood of these outages and to enable our crews to focus restoration efforts on other areas of the system allowing for quicker response times for all customers. The primary benefit of this program is that by undergrounding the tap lines with the highest failure rate, we significantly improve the reliability of those tap lines for customers – and overall, we improve the resilience of the system because there will be fewer downed tap lines. Fewer downed tap lines means that restoration crews can focus efforts elsewhere during weather events and likely improve restoration times for other areas of the system. Also, since this targeted undergrounding will focus on areas with heavy vegetation, there will be a reduced need for vegetation management in these areas.

The Company has over 13,000 miles of overhead miles of tap lines in Minnesota. In relation to the underground tap system, failures on the overhead tap system occur 1.5 times more frequently, primarily driven by storm and weather events. Overhead power line segments with a history of high numbers of outages drive a disproportionate amount of outages that affect Xcel Energy's customers. These are typically segments of line that are aging and/or located in heavily vegetated areas. While we have systematic programs that manage vegetation to industry standard clearances, and where we replace components of our system, including conductor, that are aging or experiencing abnormal failure rates, approximately 17 percent of our overhead tap lines in Minnesota are an older vintage of conductor that generally have a higher failure rate compared to newer overhead lines.

We propose to start the targeted undergrounding program with several pilot areas – undergrounding 20 miles of overhead tap system in 2021 and 30 miles in 2022. These pilots will focus primarily on areas that have experienced outages with high quantities of tap outages due to vegetation. As the program matures, the Company expects to consider areas based on multiple criteria including but not limited to: interruption rates, interruption length, degraded infrastructure, and location of overhead line.

b. Low Cost Reclosers

A recloser is a breaker equipped with a mechanism that can automatically close the breaker after it has been opened due to a fault. Our current tap lines are predominantly equipped with fuses that, if opened, result in a sustained outage for both permanent and temporary causes. The low cost recloser program would reduce sustained outages by installing reclosers on tap lines. We plan to install up to 500 low cost reclosers in 2021 and 2022.

Low cost reclosers are single-phase devices, generally mounted in existing fuse holders. While they prevent sustained outages from temporary causes such as a tree branch falling into an overhead line, they lack the full capabilities of traditional reclosers – including the capacity and three-phase attributes of reclosers used on mainlines and with FLISR systems.

Based on industry averages and internal reliability information it is estimated that 70 percent of overhead line failures are temporary and can prevented by installing a recloser. NSPM has an estimated 61,500 fuse locations with 12,500 fuses that have opened due to a fault at least once in the past three years. By replacing these fuses with reclosers, reliability will be improved as these devices will prevent sustained outages from temporary causes. In addition, these low cost reclosers will reduce O&M expenses as crews will not need to be deployed to replace the fuse. While this will prevent a sustained outage, customers will experience a momentary outage as the fault clears.

c. Pole Top Reinforcement

This program will improve the reliability and resiliency of the system by increasing our investment in identification and replacement of pole top equipment and poles (due to pole top degradation) that have reached the end of their useful life. Pole top equipment includes cross-arms, braces and insulators. Such equipment is a major contributor to outages and storm related interruptions. We plan to reinforce the equipment on up to 900 poles in 2021 and 2022.

Every year, our pole inspection program flags approximately 2,500 potentially degraded components that can be mitigated – and where doing so will increase system resilience. Some of this mitigation is being done currently as part of our pole replacement program. This program however, will broaden and extend the reach of that program to replace other pole top equipment based on performance history, condition, vintage, and other factors.

d. Transformer and Secondary Replacement

This program will improve customer reliability and resiliency of the system through replacement of aging secondary wire that is degraded and at risk of failure, and distribution transformers throughout the system that are undersized and at risk of overloads. We plan to replace the transformer and the associated secondary wire at up to 150 locations in 2021 and 2022.

Many of the transformers and secondary systems were designed many decades ago when home electric usage mainly consisted of lighting and appliances and did not contemplate the increased adoption of air conditioners, electric vehicles, and on-site solar. The addition of these new devices changes the amount of energy consumed by customers and in many cases is higher by several multiples than the equipment was designed to handle. This increase can lead to overloads on distribution transformers and low voltage at the customer's service.

Transformers. The transformers that are at the greatest risk for overload are: (1) 25 kVA and smaller transformers, (2) transformers that are already overloaded during peak periods, (3) and transformers with more than 11 customers. We will solve the risks by either increasing the size of the transformer and secondary wires as appropriate, or adding an additional transformer and dividing the customer load between the two. Proactive replacement and upgrade of this equipment will enable DER/EV adoption by our customers.

We have approximately 31,500, 25 kVA transformers that serve 195,000 customers and over 15,900 transformers that are overloaded during peak periods and have more than 11 customers connected to them. In addition to mitigating outage risk, replacing these distribution transformers with higher capacity transformers will increase system resilience, allowing for more easily accommodating DER. As customers move to DER and EV technology, increases in the penetration of these loads may overload the current transformer serving several homes.

Secondary Wire. This program will also replace older open wire secondary – especially the small wire (#4, #6). We estimate there are nearly 3,300 miles of small open wire secondary in the NSPM operating company. The lower capacity of these smaller wires will often lead to voltage issues – and as electric vehicle penetration increases, and overloading can manifest itself as a reliability impact.

e. High Customer Count Taps

The greatest benefit of this program will be increased reliability for our customers by redesigning Taps with the greatest value potential for improvement in terms of number of customers, outage history, and implementation cost. We plan to address up to 200 different high customer count taps in both 2021 and 2022.

The industry has found one of the easiest methods to improve the customer reliability experience is to increase the number of protective devices, thus reducing the number of customers "behind" each device. This program focuses on redesigning the tap portion of the distribution system to reduce the number of customers that are located behind the protective device to an average of 40 to 50 customers. Redesigns will generally employ one of three solutions – adding phases, interjecting another source, or subdividing the tap.

Currently, there are approximately 20,000 failures per year on the Tap portion of the system that result in an outage for customers. Taps with over 100 customers are responsible for approximately 50 percent of the tap-level SAIDI impact, yet they only represent around 10 percent of the total number of Taps. By decreasing the number of customers per Tap, we expect that fewer customers will be impacted by outages.

f. Community Resiliency

This program would fund projects that would benefit our customers by providing resiliency during a prolonged or widespread outage. The program involves working with communities to identify strategic locations, such as a community center or facility that provides essential services, where we would provide additional back-up power during an extended outage. Such projects would likely consist of a microgrid that would combine DER – energy storage (most likely batteries), local generation and other DER such as demand response – and the necessary equipment and controls to safely isolate a subset of the distribution system. During normal operations, the DER can benefit the distribution system to address capacity, reliability or other needs.

Local communities will benefit from the various services that the identified facility can provide during an extended outage. Customers will also benefit from value that the DER can provide during normal grid operations, such as investment deferrals and other needs. The Company will also benefit, as lessons learned from these projects will also inform future project specifications and engineering and design requirements, as well as overall value provided to our customers. We plan to install the equipment necessary to provide back-up power at one strategic location in 2022.

2. Underground Programs

The Underground Program is comprised of seven program: (1) mainline cable replacement, (2) underground residential distribution (URD) cable replacement, (3) cable asset life extension, (4) network monitoring, (5) St. Paul tunnel work (6) feeder exit capacity work, and (7) tools and equipment.

We outline the capital expenditures for each of these programs below.

Table 28: ISI Capital Expenditures – Distribution State of MN Electric (Millions)

ISI Programs		2020	2021	2022	2023	2024
Underground Programs	Mainline Cable Replacement		$7.0	$7.8	$7.8	$7.8
	Underground Residential Distribution (URD) Cable Replacement		$5.0	$2.5	$2.5	$2.5
	Cable Assessment		$7.0	$6.0	$6.0	$6.0
	Network Monitoring		$2.0	$2.3	$2.3	$2.3
	St. Paul Tunnel Rehabilitation		$5.0	$5.0	$5.0	$5.0
	Feeder Exit Capacity		$3.8	$3.0	$3.0	$3.0
	Purchases / Tooling		$4.5	$0.2	$0.2	$0.2
TOTAL		**$0.0**	**$34.3**	**$26.8**	**$26.8**	**$26.8**

a. Mainline and URD Cable Replacements

Cable failures are a main contributor to outages for customers who are served by underground cable facilities. Proactively replacing cable allows us to avoid a potential outage caused by a cable failure and utilize a systematic approach in the replacement of this asset. As a result of our existing asset health cable replacement program, the failure rate for non-jacketed underground cables has been flat to slightly declining since 2013, averaging approximately 0.2 failures per mile each year. However, by making increased investments in cable replacements, the Company expects to reduce this failure rate even further.

Nearly 25 percent of the Company's underground cable in Minnesota is a type of cable (non-jacketed cross-linked polyethylene (XLPE) cable that was installed prior to 1985) that is more prone to failures and has a shorter useful life (approximately 35 years) than newer cable types. To address this issue, we have invested between $14 million and $26 million annually between 2014 and 2018 across Minnesota to replace non-jacketed cable that has failed or reached the end of its life with jacketed cable. Even with these investments, there is still approximately 2,700 miles of non-jacketed primary Tap cable (approximately 30 percent of total) and about 250 miles of non-jacketed mainline cable (approximately 15 percent of total) in Minnesota. This program will increase Minnesota investments for mainline cable and primary Tap cable per year starting in 2021.

Cable replacement can be time-intensive based on the complexity of the location and proximity to major thoroughfare or other utilities and geographical restrictions. When cable begins to fail, it can lead to subsequent failures that can reoccur in rapid succession based on the condition of the asset, thus impacting customers' reliability experience. Proactive replacement allows us to replace the cable before it fails – becoming unrepairable – and leading to an emergency replacement. Emergency replacements leave the system with less redundancy and switching options, which can lead to lengthy outages if additional failures occur.

The underground residential distribution (URD) system is comprised of an underground circuit in a loop arrangement, segmented by distribution transformers. With the URD cable replacement component of this program, we will replace the entire ½ loop rather than making segment replacement as sections fail. This proactive replacement of the entire ½ loop will avoid additional failures and outages for all customers located on this ½ loop.

This program will supplement our existing asset health cable replacement program. We will replace up to four additional miles of mainline cable in 2021 and up to nine additional miles of mainline cable in 2022. We will also replace 10 additional miles of URD cable in 2021 and up to 12 additional miles of URD cable in 2022.

b. Cable Asset Life Extension Program

The Company's current asset health cable replacement program focuses on replacing those underground cable systems that have had multiple failures. While this strategy has been successful at reducing cable failures, this strategy overlooks proactive assessment of the condition of the overall cable population. The program would use a cable assessment technology to assess and rehabilitate cable through use of partial discharge diagnostics to precisely assess the overall condition of the cable system and make recommendations on how to rehabilitate cables to like-new manufacturer standards. Cable systems that meet these standards perform like new and have an expected useful life of an additional 30-40 years after rehabilitation.

This assessment will allow us to determine precisely what and where defects exist within the cable system and replace only the defective portions of the cable system such as terminations, splices, or other weak points in the cable. This is opposed to a wholesale replacement, which replaces portions of the cable that still has years of useful life left. We expect that this will result in an improved reliability experience and cost savings for our customers.

With respect to reliability benefits associated with this program, cable failures are a significant contributor to the customer reliability experience. As also discussed above, cable failures can be difficult to locate and repair as they are underground and often difficult to access. Through implementation of targeted assessment and replacement of underground cable and associated termination points and splices, we will be able to reduce the failure rate of our underground cables resulting in fewer outages for our customers.

Other utilities have had success with similar cable life extension programs. For example, CenterPoint Energy (CPE) implemented a similar program in Texas in 2013 and has seen their underground failure rates reduce by 98 percent. CPE used this technology to assess over 16,000 segments of cable that were 35 or more years old. Of the underground cable loops assessed thus far, 99.6 percent have required on-site mitigation or span replacement to return the cables and terminations to manufacturer specifications, or like-new performance condition. However, the cost to assess and restore an underground loop to like-new performance has been about 65 percent less than the cost to completely replace it. Another utility with a similar underground cable failure rate assessed over 2,000 miles of cable and found 82 percent of cable did not require further action. As a result, they were able to reduce replacement costs by 76 percent and associated cable outages by 98 percent.

These two utilities had two different results based on the assessment provided by this technology. One learned that they needed to rehabilitate a large portion of their underground system, while another learned that their system was mostly intact and they could focus their efforts elsewhere. Both of these results provided value for these utilities either in terms of reduced rehabilitation costs or the ability to turn attention to other critical needs on their system. At this time, we do not have a holistic assessment of the current condition of our underground cables. As a result, we do not know which of these categories we will fall into. We plan to perform up to 60 miles of cable assessment and rehabilitation in 2021 and 2022.

c. Network Monitoring

The Network Monitoring program will enable remote monitoring of the network grids for downtown Minneapolis and St. Paul to ensure continuity of service, health of these assets, and to improve operation and maintenance. The Network Monitoring system is comprised of transceivers and VaultGard devices that monitor and communicate the status of the downtown grid facilities along fiber optic cable installed concurrently with the network conductor. Installation of the Network Monitoring equipment will provide grid visibility and control utilizing real-time data from the downtown distribution networks that will enable the Company to:

- Locate faulty equipment more quickly and accurately;
- Identify distressed equipment prior to failure;
- Identify system deficiencies and manufacturer issues on installed equipment;
- Receive instantaneous, real-time email notifications of network events;
- Monitor the system on a real-time basis;
- More accurately document system performance;

- Customize breaker parameters;
- Reduce O&M expenses related to troubleshooting and identifying faulty network equipment; and
- Provide more granular individual transformer loading and planning data.

Additional benefits we expect from this initiative include improved employee and public safety, security, reliability, planning, and control.

Safety will be improved by enabling remote operation of the network circuits and by notifying personnel of potential dangers before entering a confined space in the underground distribution system. For instance, Company personnel will be notified that equipment has failed or is failing and/or operating abnormally, and can avoid entering the enclosed vault until the equipment has been de-energized or evaluated remotely. *Reliability* will be improved by monitoring the status of and being able to remotely control the Network Protectors. Planning will be improved by having load (kW and Amps) data available for each individual network transformer, improving and optimizing the ability to serve changing or new customer loads at specific locations. *Control* will be improved because the project will enable the Company to use the additional network information to make more educated decisions regarding system design and operations. In addition, understanding that equipment is not operating as designed will enable the Company to make the necessary repairs or replacement avoiding lengthy outages to customers in our central business districts.

We are confident in expecting these benefits. Our Colorado operating company affiliate, Public Service Company of Colorado (PSCo) implemented a similar monitoring system in the Denver underground network around 2010 and has since experienced these benefits. For example, prior to the implementation of network monitoring, when PSCo's system operators were notified of a system interruption, a crew would have to be dispatched to the general area to investigate. They would begin the troubleshooting process by starting at the head end of the feeder line, and then physically enter every single vault on that feeder to inspect the equipment and determine if the cause could be found. If no immediate cause was detected, the crew would reset all equipment and attempt to energize the feeder again. If another interruption of service was detected, the crew would be forced to further begin isolation activities to narrow the root cause. This process could take hours or days and may leave the network system vulnerable to outage and other service issues.

With the implementation of network monitoring, the PSCo system operators are notified immediately of a detected interruption by the monitoring system. A crew can then be dispatched to the specific vault where the issue was detected for further testing and repair or replacement of any assets as needed. By reducing notification time for a fault and receiving data that considerably narrows down the location of the potentially faulty equipment, system faults can be identified and repaired much faster.

With respect to safety, allowing remote control of network equipment allows personnel to immediately respond to major faults from a safe location, which can help prevent catastrophic failure and system interruption. As an example, during a 2016 event in Denver, an email was sent to the PSCo system operators notifying them of a high-temperature alarm. The affected network equipment was located in an alley that had been filled with water due to a heavy rain storm. The resistors in the equipment began to boil the water inside the network protector. After receiving the alarm notification, the breaker was opened remotely by the PSCo system operator. The crew was then dispatched to dry out the equipment and prevent catastrophic failure and system interruption. The monitoring equipment kept PSCo personnel and the public safe by providing immediate notice of a serious issue and allowing the system operator to remotely open the breaker prior to sending out a crew to the scene.

We plan to have one network in service with live monitoring in 2022.

d. St. Paul Tunnel Rehabilitation

This project will improve the safety and security of our underground distribution facilities in St. Paul by eliminating the risk of system outages to downtown St. Paul if the tunnels were to collapse.

The electric distribution and network infrastructure in and around downtown St. Paul is housed underground in a sandstone tunnel system that was built in the late 1800s. There are approximately 10 miles of tunnels, and they vary in width and depth. The tunnels are made in sandstone and are eroding internally, causing a build-up of sand and debris within the tunnels; flooding can then cause complete blockage of the tunnels based on the washed-out debris. The placement of utility infrastructure in them is problematic and poses a potential hazard for our employees. Further, the tunnels are shared with other utilities, which can impact the safety and reliability of our system based on failure of the assets not owned or maintained by our Company, which may cause residual impacts to our electrical assets.

Under this program, we would build new infrastructure to retire and replace the existing tunnel system. This will include constructing new underground manhole and duct infrastructure, in accordance with current Company standards, city requirements – and in consideration of safe practices for our employees. Existing electrical facilities would be relocated from the old tunnel system and into the new duct system as it is constructed.

We additionally have concerns regarding the access and security of these tunnels. Accessing the tunnels is done in a variety of ways, including doorways built into bluffs and manhole access from street grade. As depicted in the photo in Figure 39, our employees, when entering the tunnels from a street-level manhole, use long ladders to climb down to the grade in which our electrical assets are housed, as many tunnels are 30'-50' below street grade. They are then working out of cell phone range, and may face issues with communication, particularly in an emergency situation.

Figure 39: Illustration of an Actual Tunnel Access

The length, condition, and location of the tunnels presents unique construction challenges that will require extensive city, community and customer coordination, detailed planning and engineering, and system operations considerations to ensure service is maintained to all customers currently served by these parts of our electrical system. We expect, given these challenges and the required coordination, this project may take up to 15 years to complete. We expect however, the first assets will be placed in service in 2021 and 2022. These first assets will include the first conduit vaults and duct vaults that will be required to move our electrical equipment out of the tunnels.

e. Feeder Exit Capacity

The purpose of the Feeder Exit Capacity Project is to identify areas of the distribution system in which the overall load carrying capacity feeder circuits are limited by undersized cables, conductors, or other equipment at the feeder's head end. The project will benefit customers by improving the existing distribution system's ability to accommodate new load growth. Increasing the capacity of the feeders will also reduce the overall loading on the feeder circuits, which in some cases can prevent premature equipment failure, therefore improving reliability.

The overall load carrying capacity of a feeder circuit is determined as the minimum series element's capacity rating on the feeder circuit between the feeder bay in the substation and the first customers served by the feeder – this portion of the feeder is typically referred to as the feeder's exit, or head end. This project will allocate funds toward feeders where these reduced capacity ratings can be readily increased by upgrading the feeder equipment as necessary along the feeder's exit from the substation. We will in-service up to eight feeder exits in 2021 and 2022.

f. Purchases and Tools

To support additional work volume and scope with internal resources, it is necessary and to purchase additional equipment and tools. The purchases will include Distribution fleet (vehicles, trucks, trailers, etc.) and miscellaneous materials and minor tools necessary to build out, operate, and maintain our electric distribution system. Capital investments in fleet, tools, and equipment ensure our workers have the necessary provisions and support to do their job safely and efficiently. We expect to place approximately $4.5 million of assets in-service in 2021 and up to $200,000 in 2022 with this program.

3. Substation Programs

We propose two substation programs that will improve the reliability and resiliency of the Company's 224 substations in Minnesota. These two programs are: (1) substation transformer replacement; (2) substation asset renewal.

We outline the capital expenditures for each of these programs below.

Table 29: ISI Capital Expenditures – Distribution State of MN Electric (Millions)

ISI Programs		2020	2021	2022	2023	2024
Substation Programs	Substation Asset Renewal		$5.0	$5.0	$5.0	$5.0
	Transformer Replacement		$7.0	$13.0	$13.0	$13.0
TOTAL		**$0.0**	**$12.0**	**$18.0**	**$18.0**	**$18.0**

a. Substation Transformer Replacement

Substation transformers are a fundamental to the reliability of our distribution system and are also one of the most expensive components of the substation. While the failure of transformers is not a common occurrence, when a substation transformer fails, the consequences are high and results in between 5,000 to 15,000 customers losing service.

This program will increase the rate at which the Company replaces its substation transformers from approximately three per year to approximately eight per year. Our current limited replacement of three transformers per year includes transformers that have been identified as needing replacement due to their age and condition, and transformers that have failed. The current average replacement life cycle is 60 years. Assuming we replace five additional transformers each year, we will reduce the replacement life cycle of our existing transformers to 57 years.

Under this program, we will replace up to four additional transformers in 2021 and approximately 10 additional transformers in 2022.

b. Substation Asset Renewal

Historically, we have separately replaced the individual parts within the substation as they fail or reach of the end of life. These individual parts include breakers, relays, and Remote Terminal Unit (RTUs)/Local Control Unit (LCUs). Rather than replacing individual components on a piecemeal basis, the Substation Asset Renewal program would replace the bulk of the equipment within a substation at one time. We will select and prioritize the substations using several factors, including: age and condition of equipment, amount and type of load served, system reliability and future growth and planning.

Similar to substation transformers, replacing these key components of the substation will improve the reliability of our substations. In addition, by upgrading this equipment, the new equipment will have additional functionality that will allow for improved communication and monitoring of the substation equipment. We plan to replace up to 32 breakers, 42 relays, and 5 RTU/LCUs at multiple substation locations across Minnesota during 2022.

4. Overhead Mainline Programs

This program targets overhead mainline feeders which are the larger capacity feeders found along major roadways that then branch off into smaller overhead tap lines and then to service laterals that connect to homes and businesses.

There are two components of this program: (1) pole fire mitigation; and (2) lightening arrestor replacement with capital expenditures as outlined below:

Table 30: ISI Capital Expenditures – Distribution State of MN Electric (Millions)

ISI Programs		2020	2021	2022	2023	2024
Overhead Mainline Programs	Lightning Protection Replacement		$1.0	$1.0	$1.0	$1.0
	Pole Fire Mitigation		$2.5	$2.0	$2.0	$2.0
TOTAL		**$0.0**	**$3.5**	**$3.0**	**$3.0**	**$3.0**

a. Pole Fire Mitigation Program

This program seeks to reduce the risk of pole fires by identifying poles that are risk for fire and then replacing certain components (enhanced insulation, replacing wooden cross-arms with fiberglass) – or when necessary, replacing the pole or relocating the line away from airborne contaminants.

Pole fires can be a significant cause of service interruptions. We average more than 14 mainline pole fires a year; each mainline pole fire impacts more than 1,500 customers when the outage occurs. We are typically able to restore power to most of the customers through field switching. However a smaller number of customers are usually without power until the pole can be replaced, which can be as long as 12 hours. The Company currently has 2,600 mainline poles (of the approximately 500,000 total poles, or 0.52 percent) deemed to be at risk of fire in Minnesota. By strategically addressing these at-risk poles, customers will experience fewer power interruptions.

Poles that are at risk are typically found on busy streets with high usage of chemicals used for de-icing of rights-of-way, are typically older poles, and have a higher than average number of components located on the pole. Under this program, we will spend approximately $2.5 million per year to identify at-risk poles and replace the necessary components. We plan to address up to 500 poles with this program in 2021 and 2022.

b. Lighting Arrestor Replacement Program

A lightning arrestor is a device on a distribution pole that protects the conductors and insulators from damage due to lightning. Outages due to arrester failure are one of the main causes of outages on the overhead system. It is estimated over 90 percent of the SAIDI impact from lightning arrestor failure is attributable to a few vintage models, that make up fewer than 30 percent of the arrestors. By replacing these lightning arrestors that are at risk, we anticipate that customers will experience improved reliability.

This program identifies lightning arrestors with high failure rates and replaces these arrestors to ensure this equipment operates properly in the event of a lightning strike. Under this program, we will spend approximately $200,000 per year to identify and replace lightning arrestors at risk of failure. We expect to replace up to 1,000 lighting arrestors in 2021 and 2022.

D. Reliability Management

1. Approach

Each year, Xcel Energy develops and manages programs to maintain and improve the performance of its distribution assets. We identify and implement these programs in an effort to assure reliability, enable proactive management of the system as a whole, and effectively respond when outages occur.

2. Reliability Indices

In this section, we provide a snapshot of our 2018 reliability results. We additionally outline our process for developing and implementing programs to maintain and improve our system, detail key indicators of the highest impact programs, and graphically chart current year outages by cause codes. We have also included three tables to illustrate our reliability performance trending as well as a discussion around CEMI (Customers Experiencing Multiple Interruptions) tools to better reflect the customer experience.

In 2018, we achieved a SAIDI result of 93.26 minutes, which exceeds our Quality of Service Plan tariff goal of 133.23 minutes.[44] Our 2018 SAIFI result of 0.85 outage events also exceeds the QSP tariff goal of 1.21 outage events.[45] The below graphs show overall system performance for the years 2015 through 2018, with storm days excluded, per the QSP tariff calculation method.

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[44] Minnesota Electric Rate Book MPUC. No. 2 Section 6, Sheets 7.1 through 7.11, approved by the Commission's August 12, 2013 Order in Docket Nos. E,G002/CI-02-2034 and E,G002/M-12-383
[45] In this context, "exceeding" the goals is a positive result, reflecting good system performance.

Figure 40: Minnesota SAIDI – QSP Method

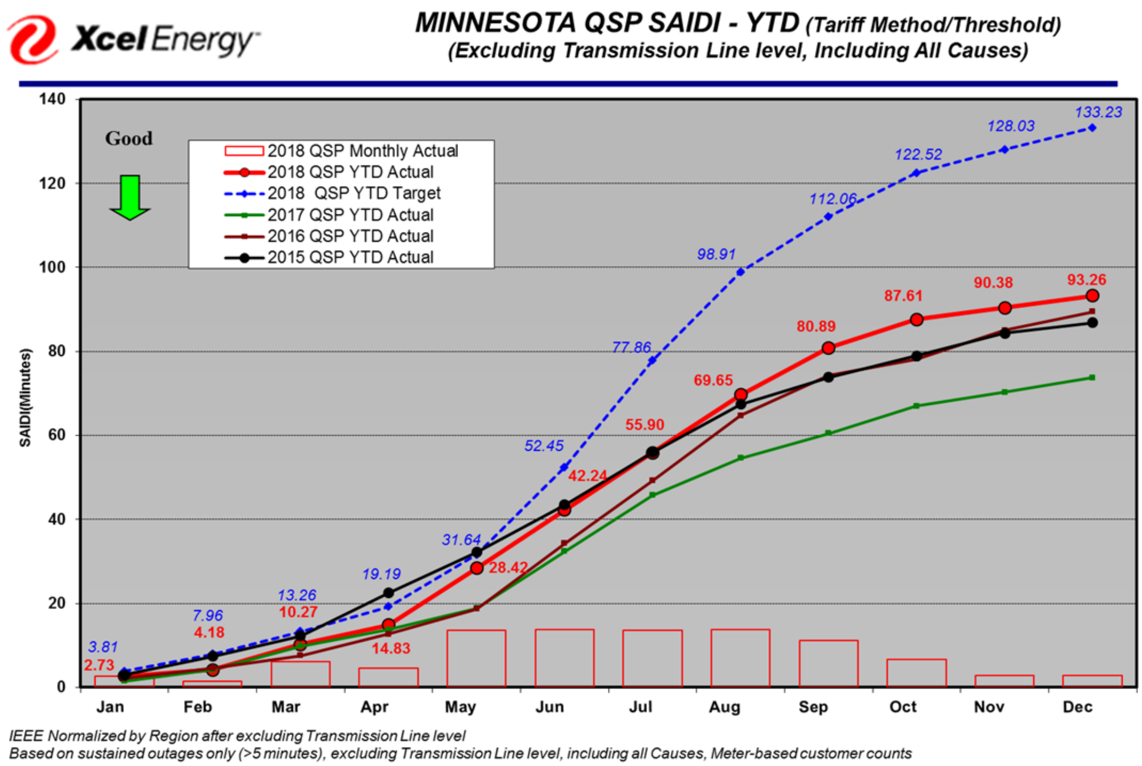
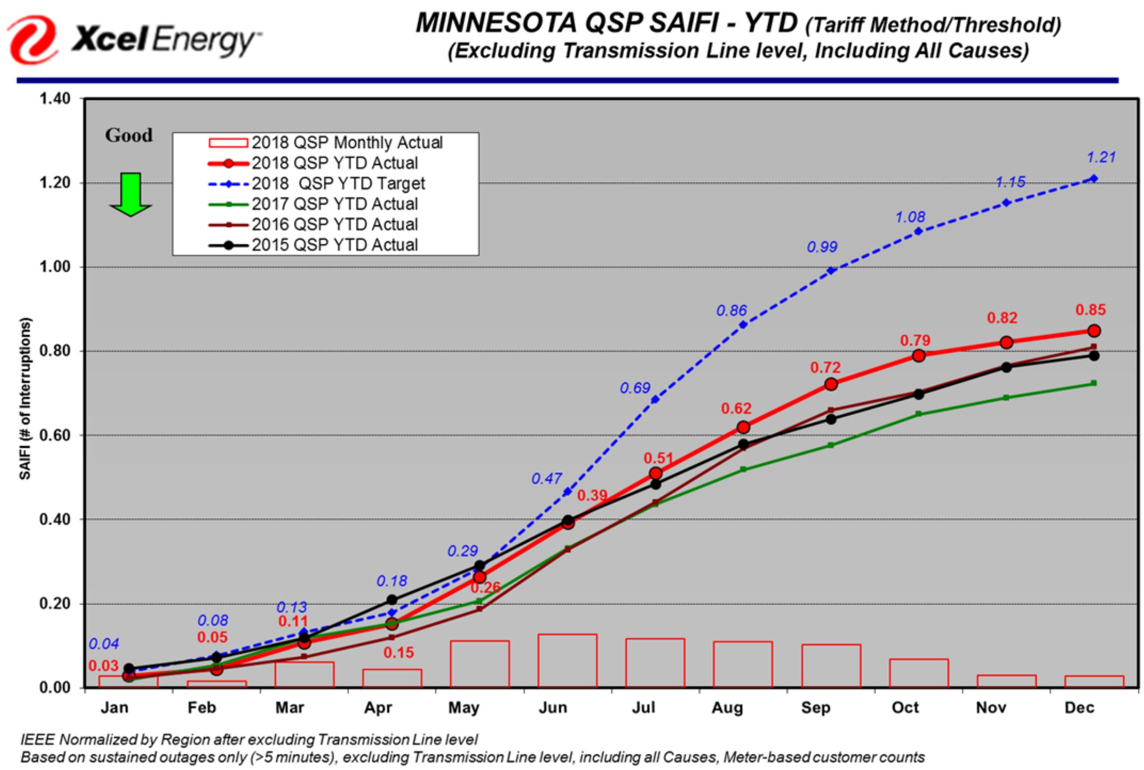


Figure 41: Minnesota SAIFI – QSP Method



In an effort to provide the Commission a better idea of our reliability performance trending, we have provided three tables showing the historical performance, storm days and the current targets under three methodologies (including storms, our QSP Tariff, and the Minnesota Rules). These three tables are presented below as Table 31.

Table 31: Historical Reliability Performance and Storm Day Exclusions – Non-Normalized and QSP Performance & Annual Rules Performance

Historical Reliability Indices & Storm Day Exclusions

With Storms[1]		2010	2011	2012	2013	2014	2015	2016	2017	2018
Minnesota	SAIDI	274.42	207.77	149.15	562.11	116.43	184.50	214.39	141.70	125.00
	SAIFI	1.50	1.11	1.07	1.39	0.92	0.96	1.05	0.90	0.95
	CAIDI	183.43	187.11	139.51	404.36	126.00	192.32	204.84	158.10	131.22
Metro East	SAIDI	270.43	113.90	190.95	352.30	123.54	177.19	223.67	136.51	112.11
	SAIFI	1.59	0.96	1.20	1.27	0.98	1.04	1.08	0.95	0.96
	CAIDI	170.23	118.95	159.23	278.46	125.93	169.86	206.85	144.37	116.71
Metro West	SAIDI	301.09	238.03	139.19	810.01	105.98	229.78	198.25	148.58	88.23
	SAIFI	1.54	1.19	1.10	1.55	0.89	1.00	1.00	0.86	0.92
	CAIDI	196.10	199.66	126.85	523.66	118.70	229.92	198.86	173.27	95.70
Northwest[4]	SAIDI	181.38	470.05	109.75	468.22	82.82	75.61	225.74	173.71	109.50
	SAIFI	1.26	1.40	0.87	1.40	0.82	0.66	1.07	0.98	0.87
	CAIDI	143.66	334.78	126.17	335.53	101.00	115.40	211.50	177.46	126.02
Southeast[5]	SAIDI	251.24	125.28	97.25	179.29	173.45	98.23	249.05	96.37	353.32
	SAIFI	1.24	0.95	0.71	1.06	0.98	0.79	1.15	0.84	1.15
	CAIDI	203.04	131.69	137.84	168.93	176.51	125.07	217.15	114.75	307.95

MN Tariff[2]		2010	2011	2012	2013	2014	2015	2016	2017	2018	'18 Target
Minnesota	SAIDI	110.83	83.87	96.20	91.12	79.85	86.83	89.49	73.80	93.26	133.23
	SAIFI	1.12	0.82	0.88	0.86	0.78	0.79	0.81	0.72	0.85	1.21
	CAIDI	99.24	102.08	109.60	106.51	102.07	109.90	110.54	102.10	109.90	NA
Metro East	SAIDI	102.03	79.34	90.70	83.56	77.58	93.71	95.49	75.70	103.28	
	SAIFI	1.20	0.83	0.88	0.83	0.82	0.90	0.87	0.75	0.92	
	CAIDI	85.09	96.00	103.35	100.72	94.81	104.58	110.07	100.79	112.40	
	MED	4	2	5	3	3	2	3	3	1	
	Days	6/25,7/17, 10/26,11/13	7/1,7/10	6/10,6/19,7/3, 8/3,11/10	6/21,6/22, 6/23	2/20,6/14,6/16	7/12, 7/18	7/5,7/6,7/21	6/11, 6/14, 7/12	5/24	
Metro West	SAIDI	123.25	88.20	103.42	101.24	81.85	88.98	82.90	69.28	81.25	
	SAIFI	1.22	0.87	0.97	0.96	0.82	0.82	0.82	0.70	0.84	
	CAIDI	101.10	101.09	106.83	105.85	100.15	108.90	101.51	98.40	96.63	
	MED	4	5	3	5	1	1	3	2	1	
	Days	6/25,7/17, 10/26,11/13	5/22,7/1,7/10, 7/18,8/1	2/29,6/19,8/3	6/21,6/22, 6/23,6/24,8/6	6/14	7/18	7/5,7/6,7/21	6/11, 6/14	7/1	
Northwest[4]	SAIDI	102.79	79.42	94.20	85.78	62.16	69.39	80.19	69.41	99.87	
	SAIFI	0.80	0.69	0.73	0.75	0.61	0.57	0.56	0.64	0.73	
	CAIDI	129.28	115.38	128.31	113.87	102.05	121.05	143.58	107.70	137.06	
	MED	2	6	0	2	0	0	4	1	0	
	Days	8/13,10/26	2/20,5/30,7/1,7 /10,8/1,8/2	None	6/21,6/22	None	None	5/19,6/19,7/5 ,11/18	6/11	None	
Southeast[5]	SAIDI	89.58	82.70	82.40	73.58	94.45	70.78	109.59	92.84	110.67	
	SAIFI	0.69	0.70	0.59	0.57	0.67	0.52	0.82	0.79	0.77	
	CAIDI	130.66	118.72	138.48	129.93	141.93	135.23	133.06	117.19	144.04	
	MED	5	2	1	4	4	1	3	0	2	
	Days	6/25,6/26,7/24 ,8/13,11/13	7/1,7/23	8/4	4/9,5/2,5/26, 6/21	2/20,6/16,8/4, 12/15	7/18	6/10,7/5,7/6	None	4/14,9/20	

Annual Rules[3]		2010	2011	2012	2013	2014	2015	2016	2017	2018	'18 Target
Minnesota	SAIDI	113.86	88.17	101.86	94.27	84.00	89.95	90.45	75.04	96.07	NA
	SAIFI	1.17	0.88	0.93	0.90	0.84	0.83	0.83	0.74	0.89	NA
	CAIDI	97.31	100.53	109.78	104.60	99.67	108.09	108.93	100.90	107.39	NA
Metro East	SAIDI	102.32	79.89	105.74	85.05	79.73	93.73	95.52	76.22	103.69	86.05
	SAIFI	1.22	0.85	0.96	0.86	0.86	0.90	0.87	0.76	0.93	0.85
	CAIDI	83.90	93.83	110.03	99.33	92.46	104.25	109.70	100.48	111.74	101.31
	Storm	4	2	3	3	3	2	3	3	1	
	Days	6/25,7/17,10/26,11/13	7/1,7/10	6/10,6/19,11/10	6/21,6/22,6/23	2/20,6/14,6/16	7/12,7/18	7/5,7/6,7/21	6/11,6/14,7/12	5/24	
Metro West	SAIDI	123.21	89.74	103.98	101.41	83.02	90.95	83.64	69.51	83.26	85.71
	SAIFI	1.22	0.90	0.98	0.96	0.84	0.84	0.82	0.71	0.87	0.84
	CAIDI	101.09	99.56	105.93	105.45	98.50	108.44	101.43	97.84	95.47	102.56
	Storm	4	5	3	5	1	1	3	2	1	
	Days	6/25,7/17,10/26,11/13	5/22,7/1,7/10,7/18,8/1	2/29,6/19,8/3	6/21,6/22,6/23,6/24,8/6	6/14	7/18	7/5,7/6,7/21	6/11,6/14	7/1	
Northwest[4]	SAIDI	110.59	94.29	95.05	97.43	82.80	75.58	85.81	75.77	109.34	83.48
	SAIFI	0.96	0.82	0.83	0.94	0.82	0.66	0.70	0.76	0.87	0.77
	CAIDI	114.86	115.31	115.16	103.70	101.02	115.39	122.38	100.28	126.05	107.83
	Storm	2	6	1	2	0	0	5	1	0	
	Days	8/13,10/26	2/20,5/30,7/1,7/10,8/1,8/2	6/17	6/21,6/22	None	None	5/19,6/19,7/5,7/16,11/18	6/11	None	
Southeast[5]	SAIDI	111.00	101.86	85.95	87.98	103.45	86.51	110.23	96.33	118.80	96.90
	SAIFI	0.98	0.90	0.67	0.73	0.80	0.75	0.85	0.84	0.92	0.79
	CAIDI	112.90	112.82	128.50	120.39	129.20	115.16	130.02	114.73	129.64	122.04
	Storm	5	1	1	4	4	1	3	0	2	
	Days	5/11,6/25,6/26,7/24,11/13	7/1	8/4	4/9,5/2,5/26,6/21	2/20,6/16,8/4,12/15	7/18	6/10,7/5,7/6	None	4/14,9/20	

1) **With Storms** - Includes All Days, Levels and Causes, Meter-based customer counts
2) **MN Tariff** - Normalized using IEEE 1366 at the Regional level after removing Transmission Line level. All Causes, Meter-based customer counts
3) **Annual Rules** - Normalized using IEEE 1366 at the Regional level, All Levels, All Causes, Meter-based customer counts
- Targets for recalculated New Annual Rules were determined for 2015-present due to the need for 5 years of prior historical actual results
4) **Northwest** - Includes customers counts and outages in the North Dakota work region that impact Minnesota customers
5) **Southeast** - Includes customers counts and outages in the South Dakota work region that impact Minnesota customers

We have developed tools that allow us to better track reliability from our customers' experience – or CEMI (Customers Experiencing Multiple Interruptions). In conjunction with a mapping tool we can look at our customers' experience as it identifies customers with multiple outages over a revolving 12 months and then provide a visual representation of those outages in our service territory. Although, the metric measures customers who have experienced at least six sustained outages during non-storm days, we can study customers' experience earlier. This customer centric tool helps highlight customers that have had outages from different causes rather than a single root cause. In other words, this tool does not look at the device that caused the outage, it examines how many times a customer was out of service regardless of the reason.

These tools compliment other programs, such as the Reliability Management System (REMs) that help us identify specific equipment issues (for instance, the same device tripping multiple times). The CEMI tools provide the link from the outage information to the specific customer information on a holistic basis. Since much of our analysis has focused on a system perspective, this new tool really rounds out our reliability planning by helping focus on the customers' experience.

Our Outage Exception Reporting Tool (OERT) combines the CEMI tool with an earlier tool that helped us identify specific equipment issues (for example, the same device tripping multiple times). The OERT tool provides the link from the outage information to the specific customer information on a holistic basis. Since much of our analysis has focused on a system perspective, this new tool really rounds out our reliability planning by helping focus on the customers' experience.

There are many reasons a customer could have an outage. These causes include downed trees, animal contact, a car hitting a pole, or even a lightning strike. Each one of these causes could show up on a different report for a different piece of equipment that all flow down to the same customer. These tools allow us to analyze customer experience *truly* from a customers' experience. These tools help our efforts in the long term to reduce repeated outages for customers.

3. Cause Analysis

Our annual reliability planning process begins with an analysis of the causes for historical outages. We use pareto graphs in our analysis, as provided below, which show outage cause codes for a multi-year time period, ranked in descending order by the number of Sustained Customer Interruptions (SCI).[46]

Pareto Analysis. The following pareto graphs show feeder, tap, substation and transmission level customer interruptions by primary cause code for the years 2014 through 2018. The "balloons" highlight areas our plans are currently focusing on.

[46] Electric service interruptions greater than five minutes in length.

Figure 42: Minnesota Customer Interruptions by Primary Cause

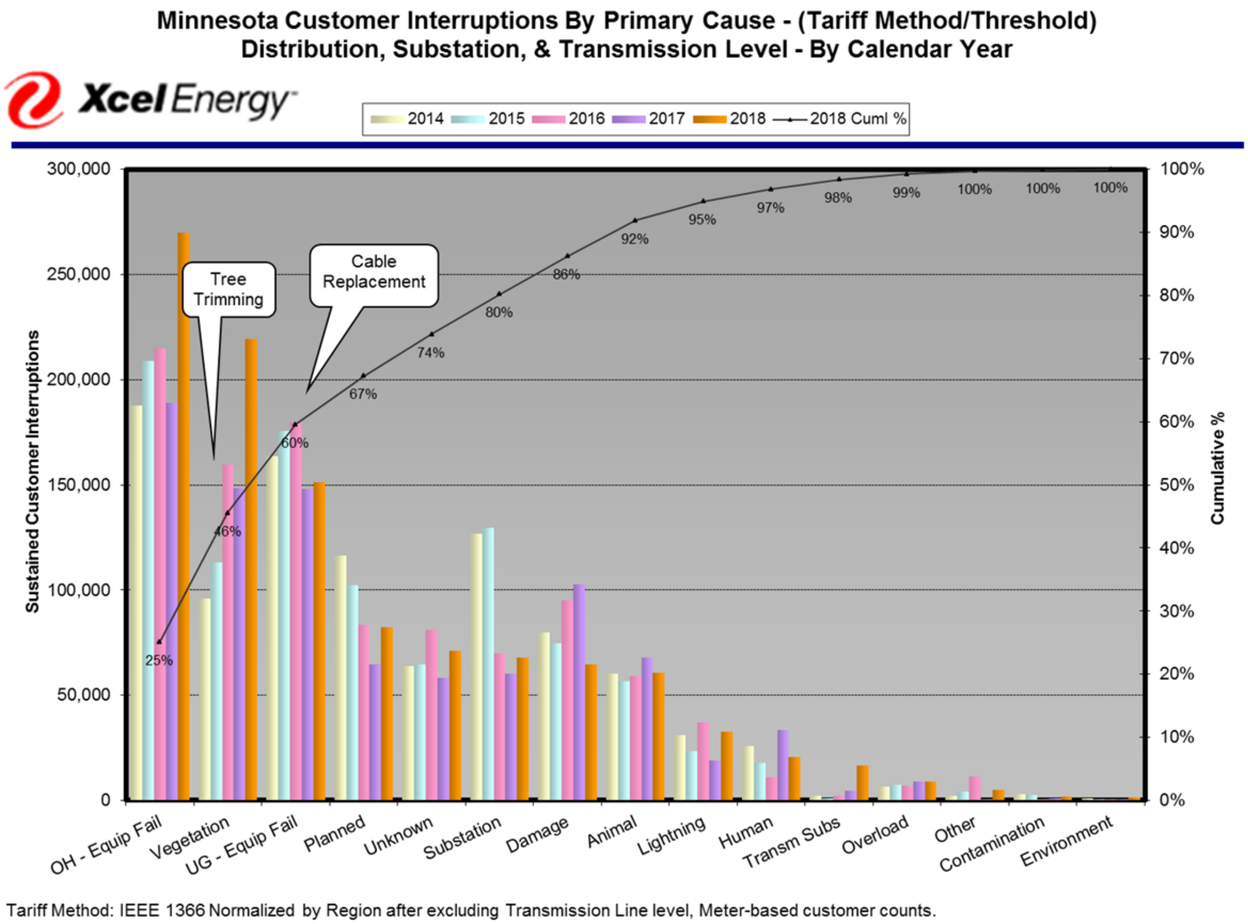
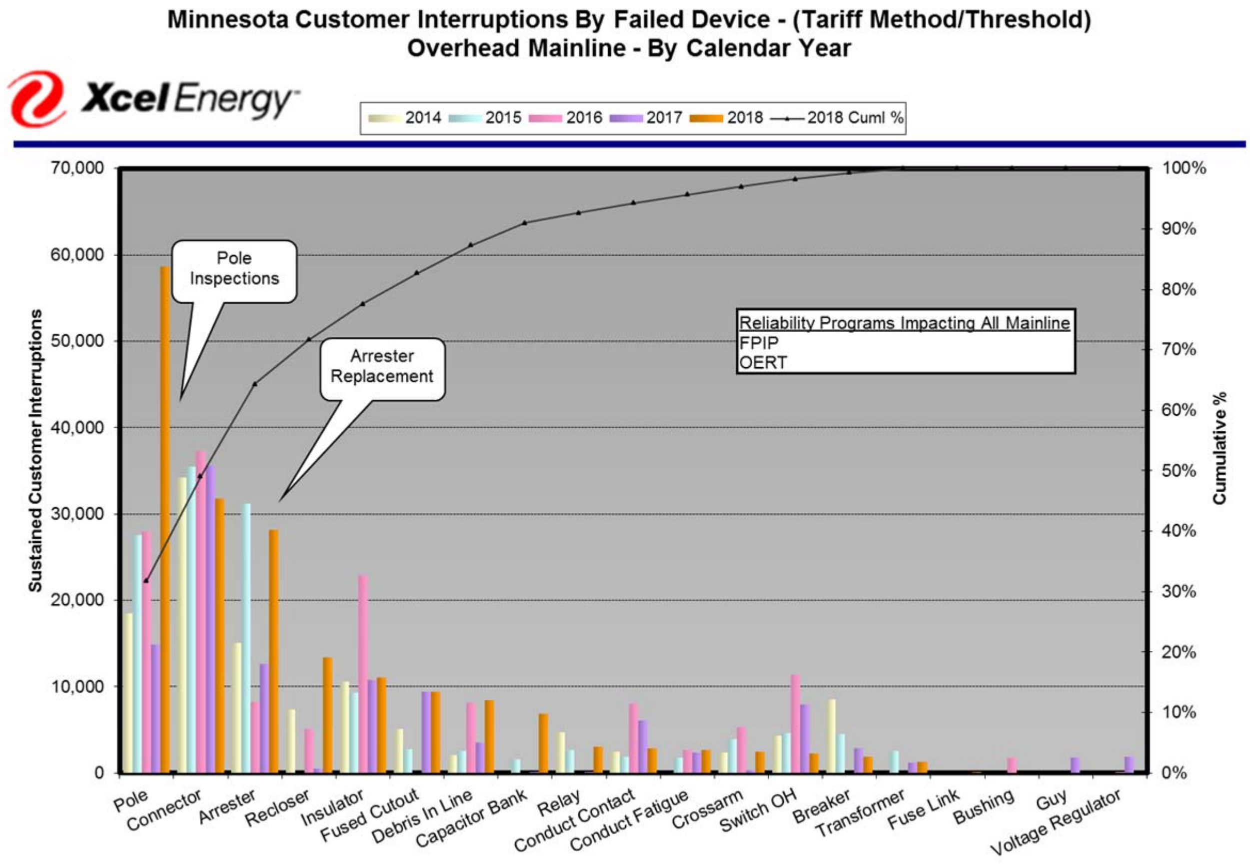


Figure 43: Minnesota Customer Interruptions by Failed Device – Overhead Mainline



Tariff Method: IEEE 1366 Normalized by Region after excluding Transmission Line level, Meter-based customer counts.

Figure 44: Minnesota Customer Interruptions by Failed Device – Overhead Tap

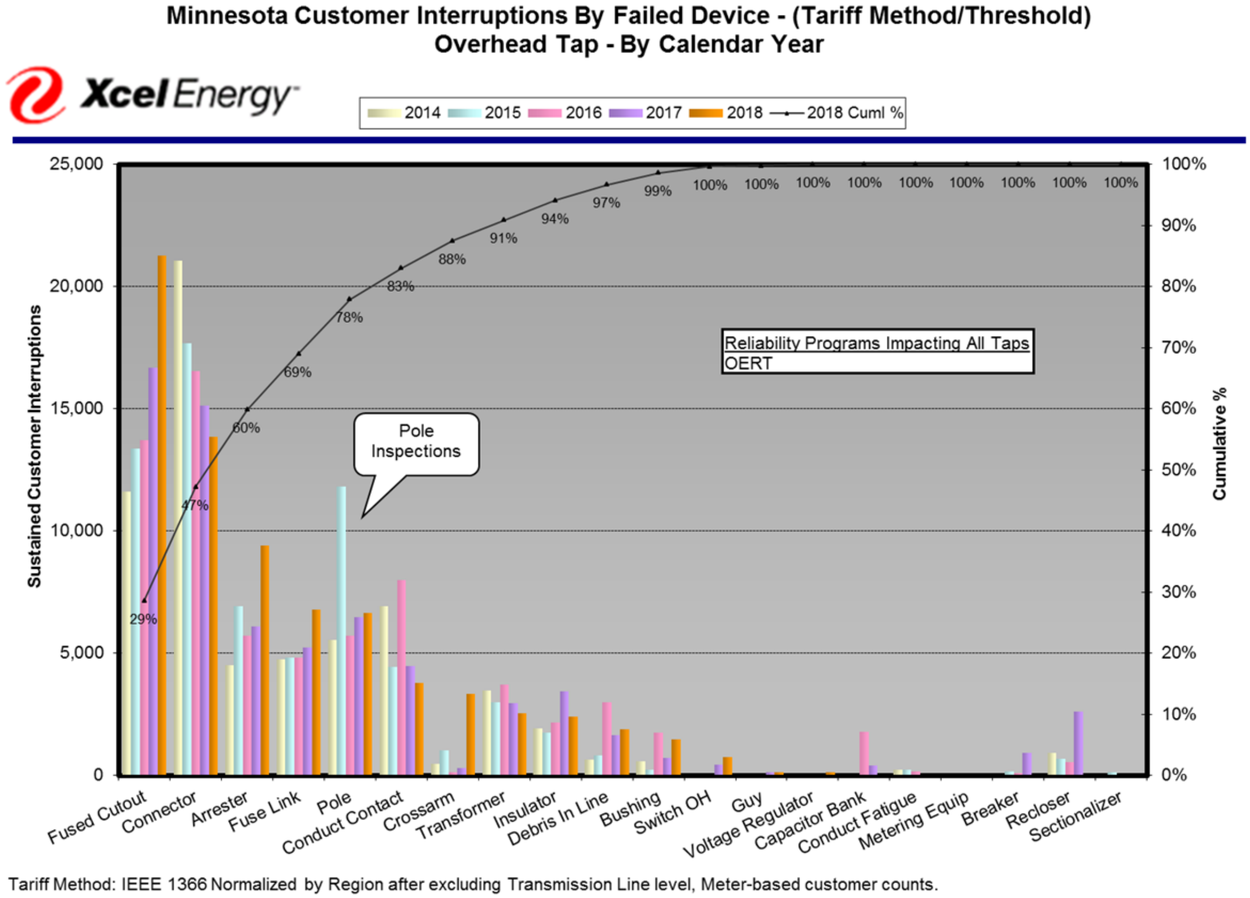


Figure 45: Minnesota Customer Interruptions by Failed Device – Underground Mainline

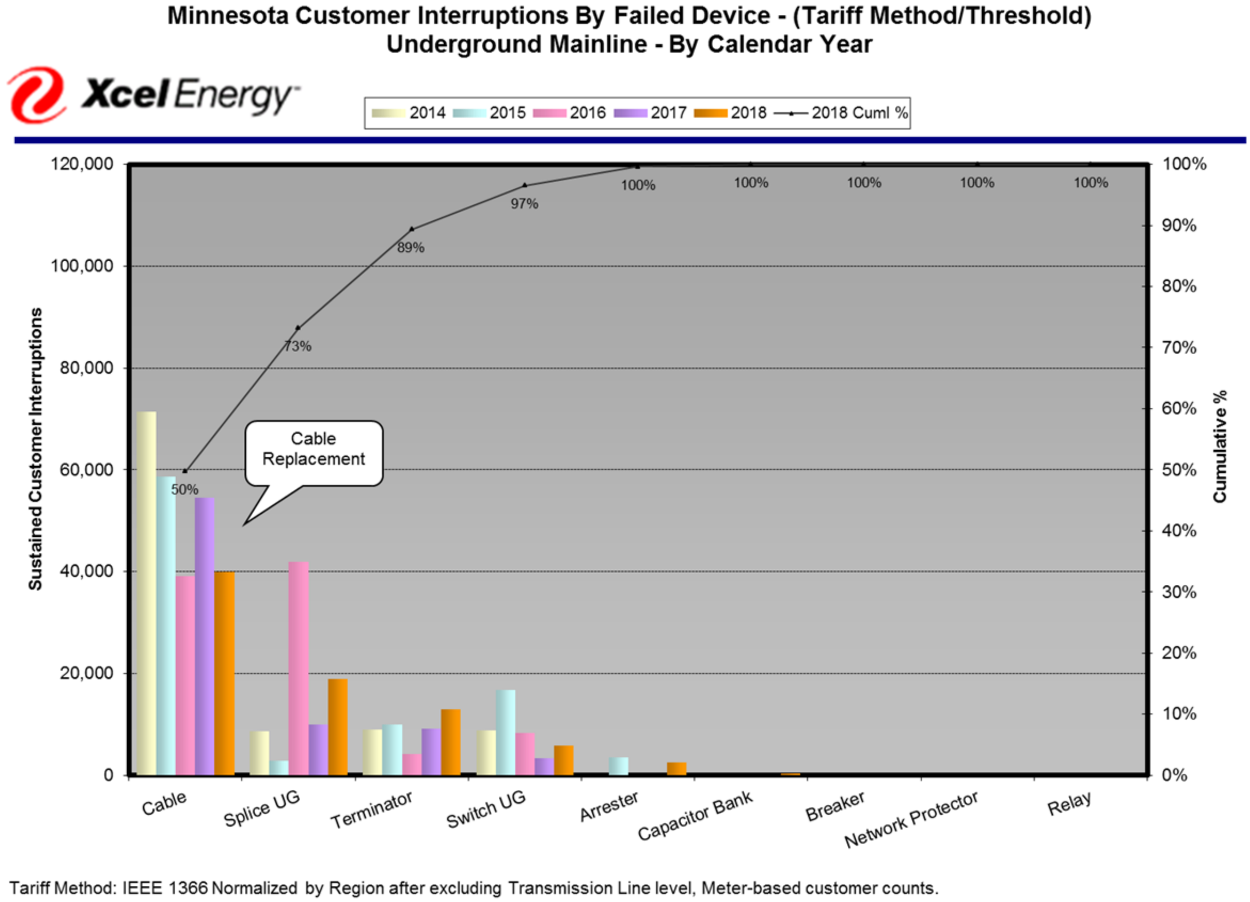
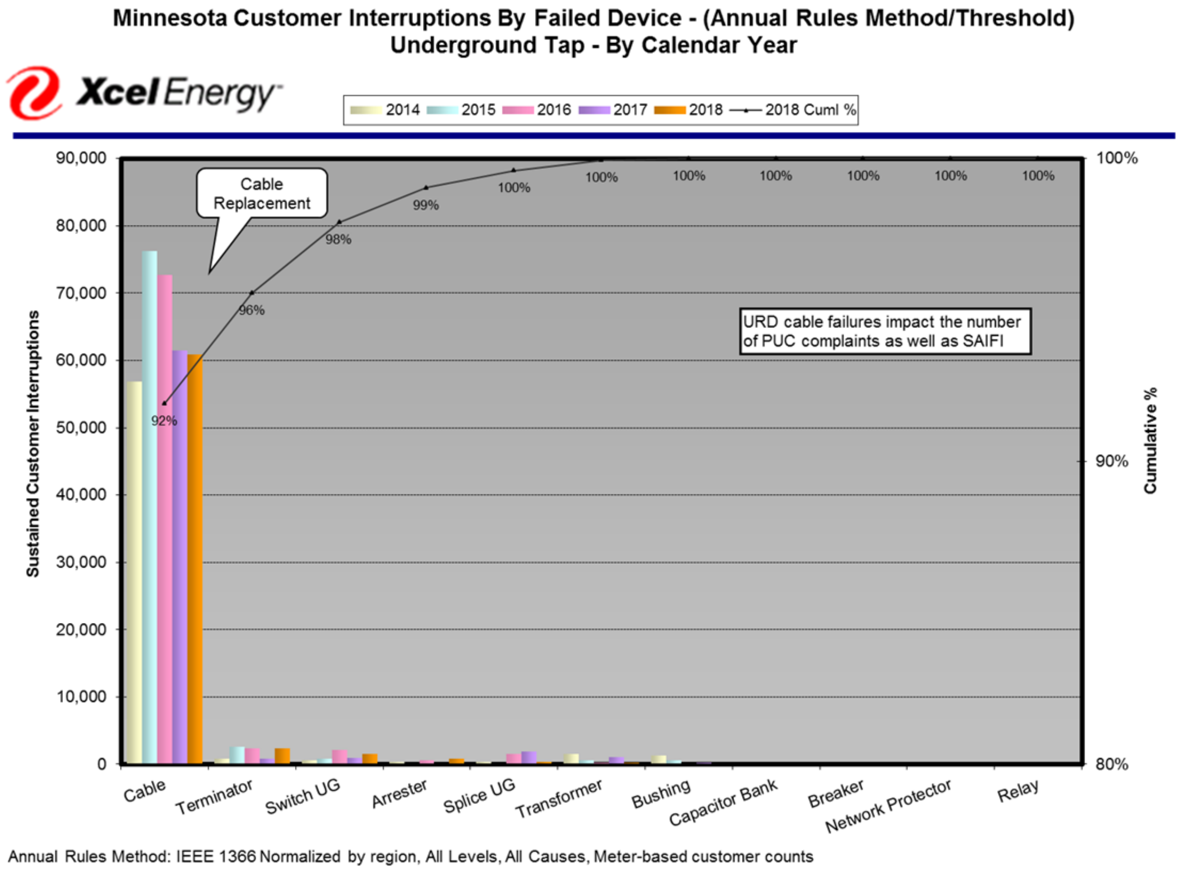


Figure 46: Minnesota Customer Interruptions by Failed Device – Underground Tap



Our current RMP investments are maintaining appropriate levels of overhead (OH) and underground (UG) system performance. We recognize that it is critical to combine our RMP process with a longer-term view of the aging distribution system in order to provide our customers with reliable electric service, and are taking actions to that end.

4. *Reliability Management Programs*

After considering the most common failures and their causes, as well as at-risk equipment, we develop work plans, or programs, to target our investments; we provide these programs in the 'Star Chart' on the following page. These programs represent those proactive investments in our transmission and distribution systems that we believe are most likely to improve overall reliability, asset health, and meet various contingency planning requirements. These investments are made in addition to other capital investments that provide for adequate capacity to meet customer requirements and to accommodate load switching during outage response to minimize customer impacts.

Table 32: Reliability Management Program Impacts (Star Chart)

NSPM Program Summary

	Funded Programs	Description	2016 Actuals (k$)	2017 Actuals (k$)	2018 Actuals (k$)	IMPACTS SAIFI	CAIDI	CEMI	Complaints
Reliability	**Feeder Perf. Improvement Program** (OH & UG)	FPIP evaluates and implements improvements for feeders experiencing an increased number of outages based on prior year information.	381	870	1,451	★		★	★
Reliability	**Outage Exception Reporting Tool** (OH & UG)	OERT process provides automatic notification to area engineers when repeating outage criteria have been met and engineering solutions are implemented to eliminate recurring problems.	637	455	490			★	★
Reliability	**Mainline Cable Replacement,** (UG)	Deteriorating non-jacketed cable is failing and causing repeat outages. Proactive and reactive replacement of this cable reduces the outages.	2,184	3,056	1,930	★			★
Reliability	**Tap (URD) Cable,** (UG)		16,980	18,329	19,593	★	★		★
Reliability	**Install Automated Switches**	These automation solutions reduce restoration times for long lines with long drive times to bring CAIDI in-line with other distribution lines.	103	0	0	★		★	★
Reliability	**Feeder Infrared Evaluation** (OH)	Many pieces of equipment show excess heating prior to failure. The FIRE program provides infrared scans of overhead mainline which reveal specific equipment that is likely to fail so it can repaired prior to causing an outage.	20	20	58	★			
Reliability	**Vegetation Management** (Transmission & Distribution)	Cost benefit prioritized circuit trimming in NSPM. Continued reactive "Hot Spot" trimming.	26,247	29,024	29,352	★		★	★
Reliability	**Program Replacements** (Transmission)	Replaces end-of-life equipment (i.e. - switches, laminated arms, specific insulators, poles) in order to reduce maintenance costs and improve reliability.	656	11	229	★			★
Integrity	**Pole Inspection & Replacement** (Distribution)	Pole Inspections include an above groundline visual inspection. Groundline inspections are based on age and environment and may include visual, sound and bore and excavation. Treatment of poles may be included. Based on results poles may be tagged for replacement.	7,197	7,707	11,035	★	★		
Integrity	**Transmission Substation**	Replaces end-of-life equipment in order to reduce maintenance costs and improve reliability.	1,472	6,984	9,228	★			
Integrity	**Line ELR Work** (Transmission)	Identifies lines that have components that have reached their end of life or where significant refurbishment work is needed to enhance system performance and reliability. Project focus may be to extend life of existing asset 20 + years or to replace and address future capacity upgrade concerns.	2,166	4,824	2,834	★			★

Footnote: The above table reflects multi-year initiatives that are part of the Reliability Management Program(RMP). Information is based on current RMP, and is subject to change.

Funding information for previous years is a combination of Capital and O&M dollars; most of the equipment replacement dollars are capital expense while the inspection and testing programs include O&M dollars; O&M dollars and capital for pole replacements and FIRE program are currently estimates since changes are included in broader programs of work(e.g., OH rebuild OH maintenance accounts).

We have indicated the primary performance impacts of these programs with a red star, where applicable; possible performance impacts include SAIFI (System Average Interruption Frequency Index), CAIDI (Customer Average Interruption Duration Index), CEMI (Customers Experiencing Multiple Interruptions), CELI (Customers Experiencing Lengthy Interruptions) and Customer Complaints.

These programs become part of the annual RMP. A Reliability Core Team (RCT), consisting of both Field and Planning functions monitors system performance and progress against the RMP on a monthly basis, taking actions as necessary to ensure the best possible system performance.

In addition to the programs shown above, in 2019 we will be initiating a pilot program in the Southeast Region. The pilot will be replacing porcelain fused cutouts with polymer cutouts. As seen in Figure 46 above, showing Interruptions by Failed Device for Overhead Tap, fused cutouts have seen an increasing failure rate and in 2019 were the device type with the highest impact to our customers on the overhead tap system. Replacement of porcelain cutouts should show a reduction in cutout failures since failures occur primarily on porcelain cutouts. If the pilot is successful, we intend to develop plans for a further roll-out.

The table below outlines primary program indicators for our key initiatives/programs. The actual amount of work completed under each program varies from year to year, and is based primarily on assessments of those areas requiring the greatest attention, as well as the results of our condition assessment (*i.e.,* the number of deficiencies requiring corrective action). For further description of the programs described in the Key Initiatives Table, please see the Star Chart above.

Table 33: Reliability Management Key Initiatives

Reliability Management Key Initiatives/Programs

	2018	2017	2016	2015	2014	2013	2012
Outage Exception Reporting Tool (OERT) (Replaced REMS in 2016)							
# of Exceptions identified	4,014	3,398	6,635	4,935	5,105	5,107	4,720
# of Service & Work Requests identified	652	297	215	408	455	698	694
Vegetation Management Program							
Total Overhead Distribution miles completed	2,307	2,417	2,086	1,856	3,737	2,780	3,084
Total Overhead Transmission miles completed	768	762	1,039	909	879	846	1,071
Normalized Tree-coded Sustained Cust Ints.(W/O Storms)	214,299	145,422	155,370	106,215	93,010	103,795	123,876
Non-normalized Tree-coded Sustained Cust Ints.(With Storms)	243,867	277,068	305,946	220,787	154,642	439,030	236,474
Underground Cable Replacement Program							
# of Segments That Have Been Replaced (est.)	1,504	1,411	1,378	861	1,165	1,256	1,024
# of Failures(Only on Primary Cable)	1,366	1,453	1,607	1,560	1,386	1,564	1,907
Feeder Infrared Evaluation(FIRE)							
# of Feeders Scanned	209	248	275	256	267	239	350
# of Hot Spots Corrected	67	71	68	99	62	52	50
Feeder Performance Improvement Plans(FPIP)							
Investigations Completed	108	113	105	96	108	98	98
Wood Pole Inspection Plan							
Total Distribution Wood Poles Inspected	33,720	17,972	18,845	10,213	9,198	31,436	20,555
Total Transmission Wood Poles Inspected	2,464	4,000	4,660	4,119	3,565	4,413	5,049

Information based on current RMP, subject to change

We note that programs typically require multiple years before their full impact is realized. At first, the programs may only halt SCI increases, but continuing investment eventually reverses adverse trends.

In addition to programs, we also implement work practices to improve reliability, which are also an important contributor to the customer reliability experience and our reliability performance. These are operational and/or procedural changes intended to either reduce the *duration* of outages should they occur, or to reduce the *frequency* of outages. These improvements to existing work practices that the RCT members and their staffs identify and implement are also an important contributor to the customer reliability experience and our reliability performance. These are operational and/or procedural changes intended to either reduce the *duration* of outages should they occur, or to reduce the *frequency* of outages.

As noted in the Reliability Management Work Practices table below, we assess and prioritize the actions based on a balance of their ability to positively impact reliability (high, medium or low), as well our ability to incorporate into standard work practices – with most occurring concurrently. Many of these actions do not require additional funding to implement, and are achieved via ongoing employee training and/or incorporation into standard work procedures. We continuously monitor all actions, and update our plan as appropriate.

Table 34: Reliability Management Program Summary

Areas of Opportunity	Key Initiative	Action/ Program	Description	Reliability impact
Resource Management	Duration	Contractor staffing	Use contractors for appointments, freeing up Xcel Energy crews to respond to outages	Medium
	Duration	Management Staffing	Schedule managers for staggered shifts in metro area to enable human response after hours: 3 managers working 5:30 a.m. to 4:00 p.m.; 1 manager 3:00 p.m. to 11:00 p.m.	Medium
Substations	Frequency	System integrity	Substation inspection done on every substation specific to identifying animal incursion risk and vegetation issues	High
	Frequency	Infra Red Substations	IR Subs after major equipment is switched out or thermal heating suspected	High
	Duration	Equipment Failure Response	Install Mobile subs and drag cables as quickly as possible when customers are out due to equipment failure	Medium
Feeders	Duration	Restore before repair	During a feeder event Control Center personal restore service to as many customers before making temporary/permanent repairs.	Medium
	Frequency	Intentional Outages	Reduce Impact of Intentional Outage to ensure all steps are being taken to keep the maximum number of customers on. Verify switching to reduce customer counts. Repair while hot instead of taking the outage.	Medium
	Frequency & Duration	VM Partnership	Partner with Vegetation Management leadership to prioritize trimming of circuits that are scheduled to be trimmed. Substations to be trimmed with associated Feeders	High
	Frequency & Duration	Feeder Patrol Program	Looking for unfused taps and animal protection. Identify 336 auto splices. Continued use of IR/thermo imaging to identify problems.	Medium
Control Center	Duration	Restore before repair	Advanced technology going into the control centers and the field	High
Control Center	CAIDI	Model 1/0 Switching	This is a pilot project to model 1/0 urd as close to real time so the OMS model will reflect the configuration of the urd circuit after it has been switched	Medium
	CAIDI	Validate Restoration Times	Tighten up existing process on actual restoration times, utilize approver process to ensure outage times are correct	High
COM	CAIDI	COM Saturday Crews	6 Metro COM Saturday Crews. 3 Metro East and 3 Metro West	Medium
	SAIFI & CAIDI	Underground cable repair	Repair and/or replace cables as directed by engineering	High
	SAIFI	REMS/CEMI work	Complete work referred by engineering in a timely manner	Low
Reliability Team/ Communications	SAIFI & CAIDI	On-going Regular Reliability meeting	Meet regularly to review reliability, and share ideas to improve reliability performance	**Low**
	CAIDI	Outage Review	Root Cause Investigation of outages greater than 90 minutes of 0.1 SAIDI	Medium

Note: The above table reflects multi-year initiatives that are part of the Reliability Management Program(RMP). Information is based on current RMP, and is subject to change.

VIII. DISTRIBUTION OPERATIONS

In this section, we discuss key aspects of our distribution operations. First, we discuss escalated operations – or how we plan for, approach, and respond to unplanned events impacting our system and customers – most frequently these are storm or weather-related. Part B of this section discusses other major components of our day-to-day work to provide our customers with reliable electric service. These activities include Vegetation Management, Damage Prevention, and Fleet and Equipment Management.

A. Reactive Trouble and Escalated Operations

We have discussed the many ways that we plan the system to ensure reliable service for our customers. However, sometimes we must quickly rally and respond to customer outages and infrastructure damage caused by outside forces, such as severe weather. In this section, we discuss our pre-event planning, outage restoration, and outline storm-related costs.

1. Escalated Operations Pre-Planning

To ensure we are prepared, we maintain a Distribution Incident Response Plan that guides our planning, execution, and communications – and we regularly assess and drill our readiness and response. Our planning and preparations start well in advance of an actual weather event with foundational elements such as agreements with contractors to supplement our field forces when needed – and mutual aid agreements with other utilities for the same purpose. One indicator of our preparedness and response is measured by the increase in storm events that do not meet Major Event Day exclusions. Due to detailed response plans, drills and pre-staging of crews we are able to complete restoration sooner for our customers, past process was to react after the storm past, this allowed for exclusions of customer minutes out and improved SAIDI, yet it's not the right thing to do for our customers. Our calculations show that in 2018 we could have reduced our SAIDI numbers by over five minutes, Xcel Energy choses to continue to prepare and respond to safely and efficiently respond to our customers.

We also maintain lists of hotel accommodations and conference facilities across our service area for when they are needed to house crews aiding in restoration activities, or serve as dispatch centers or areas to conduct tailgate or safety briefings. We also maintain lists of available transportation options such as for buses and vans, to move crews and support staff between locations. Finally, we also pre-identify staging sites across our service area so we are able to quickly implement plans that involve staging equipment or non-local crews – and ensure we have street and feeder maps readily available for them to use. Our planning also incorporates details are not top-of-mind when thinking about what might be needed for an effective storm response – such as ensuring we have ready access to catering to feed crews, adequate restroom availability, laundry facilities, garbage and debris containers, and security.

In terms of planning and preparations in the immediate timeframe before a weather event, we are continuously assessing the weather, system status and customer call volumes to recognize "early warning signs." As the storm picture becomes more clear, we inform office staff, field workforces, and strategic communications stakeholders, which includes the call centers, external communications, community relations, and regulatory affairs, among others. We begin to send regular weather and staffing updates to pre-defined internal distribution lists, and inform employees in identified storm support roles to prepare for an extended time at work. At this point, we are also informing support functions such as supply chain, fleet, safety, security operations, and workforce relations of our assessment of the impending weather. We also inform our local unions of our assessment and planning criteria. We may also begin to strategically move and stage field crews and equipment to areas expected to be significantly impacted – especially if we expect access to those areas to be limited or hampered as a result of the weather event.

At the point operations leadership believes the forecast presents risk to the distribution system, we hold an operational call where we review our assessment of conditions, staffing, and other preparations. When system impact is confirmed, we initiate "Everbridge," which alerts pre-defined lists of individuals representing key functions across the organization.[47] A regular cadence of escalated operations calls that follow a standardized agenda and checklist that both communicates key facts about the event including customer and infrastructure impacts and restoration staffing – and gathers information from support functions and external facing groups such as from the call center, community relations, and large managed accounts.

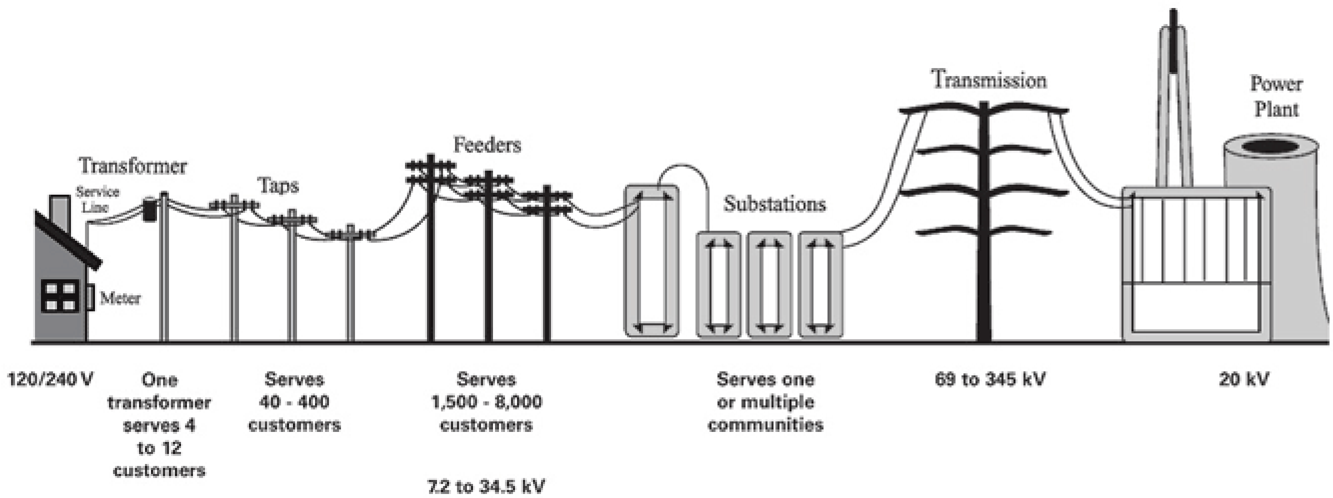
As soon as Xcel Energy knows there is an outage, a crew is dispatched to investigate. When the crew arrives on the scene, it assesses the problem and proceeds with the repair. Due to the complexity of the Xcel Energy electric system and the variety of probable causes, this process can take several minutes or, in extreme circumstances, hours. Time estimates can vary based on the extent of the outage, public safety issues that take priority, etc.

[47] Everbridge is a critical event management platform that helps organizations manage the full lifecycle of a critical event.

The Xcel Energy restoration process gives top priority to situations that threaten public safety, such as live, downed wires. Repairs are then prioritized based on what will restore power to the largest number of customers most quickly. Crews work around the clock until power is restored to all customers.

The number of customers affected by an outage will depend on where the cause of the outage occurred. Figure 47 below provides a high level view of the major electric grid components involved in restoring power to customers, whether the outages are part of an escalated operations event or a more isolated outage event.

Figure 47: Major Grid Components



2. *Outage Restoration*

Outage restoration prioritization generally follows the system components that will restore power to the greatest numbers of customers, which we describe below. We note however, that we also take into consideration critical infrastructure such as schools, hospitals, and municipal pumping operations.

Restoration of transmission lines and substations are a top priority, because they may serve one or several communities. Generally, damaged or failed transmission facilities do not cause customer outages due to the interconnected nature of the transmission grid. Regardless, they are a top priority because a failed or damaged component reduces our resilience by creating a vulnerability on the grid. Transmission lines and substations have a dedicated workforce, which allows Distribution to focus on restoring portions of the system that more directly impact customers.

Substations can be either transmission or distribution. Distribution substations distribute power to feeders. One feeder might serve between 1,500 to 8,000 customers. Feeders distribute power to power lines called taps. One tap line might serve between 40 to 400 customers. Tap lines distribute power to transformers. Transformers may serve a single building or home, or serve multiple customers (generally 4 to 12 customers). Service wires connect transformers to individual residences and businesses.

Sometimes, a tap, feeder or substation outage will be restored while a transformer or an individual customer (service) may remain without power. This type of outage may go undetected at first until the customer notices that their neighbors have power, or they receive a notification that their electricity has been restored, when in fact, it has not been. AMI will significantly improve our ability to initially "sense" and thus record individual customer outages – and track them all the way through to restoration. Similarly, with this detailed information enabled by AMI, we will have increased capabilities to avoid "okay on arrival" truck rolls, because we will have better data at an individual customer level than we do today.

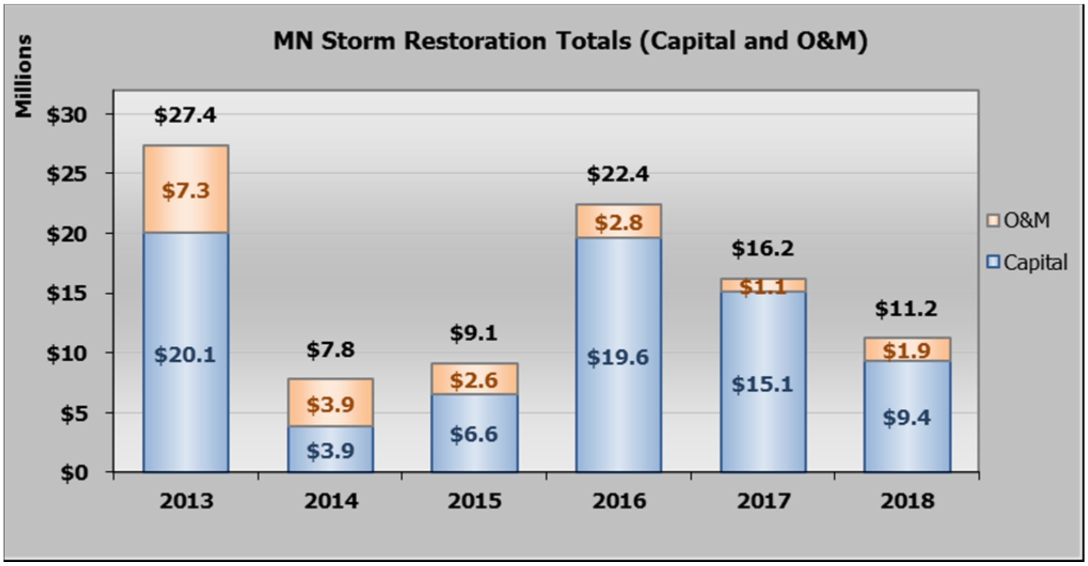
3. Costs Summary

Our annual capital and O&M expenditures are influenced by the magnitude and frequency of significant storm restoration activities that occur throughout our service territory. The unpredictable nature of severe weather makes budgeting challenging as there is no such thing as a typical year for severe weather.

Figure 48 below portrays our capital- and O&M-related Escalated Operations costs for the recent past, demonstrating how variable this aspect of our operations can be.[48]

[48] Represents escalated operations events significant enough for a workorder to be established.

Figure 48: Escalated Operations – State of Minnesota Electric Capital and O&M Expenditures 2013 to 2018 (Millions)



In terms of budgeting for storm restoration, due its significant variability from year-to-year, we budget dollars in a working capital fund that are not assigned to a specific project or program. When emergent circumstances, such as storm restoration arise, we reallocate budgeted dollars to address the circumstance while remaining in balance with our annual budget. For O&M, we do something similar – we factor-in a base level of funding within key labor accounts, such as productive labor and overtime.

B. Distribution Operations – Functional Work View

In this section, we highlight a few key aspects of the distribution function that contribute to providing customers with safe and reliable service – but that are not as prominent as storm response or constructing new feeders and substations. These include:

- Our *vegetation management* program that helps reduce preventable tree-related service interruptions and address public and employee safety,
- Our *damage prevention* program that helps the public identify and avoid underground electric infrastructure, and
- The fleet, tools, and equipment that support everything the Distribution function does every day.

1. Vegetation Management

The Vegetation Management activity includes the work required to ensure that proper line clearances are maintained, maintain distribution pole right-of-way, and address vegetation-caused outages. It includes the activity associated with the pruning, removal, mowing, and application of herbicide to trees and tall-growing brush on and adjacent to the Company's rights-of-way to limit preventable vegetation-related interruptions. An effective Vegetation Management program is essential to providing reliable service to our customers. We have established a five-year routine maintenance cycle for our distribution facilities, generally meaning that vegetation around our electric facilities will be maintained every five years.

Tree-related incidents are among the top two causes for electrical outages on the Company's distribution system. Being as close as practicable to 100 percent on a five-year cycle will better ensure that preventable tree-related interruptions are minimized, public and employee safety is addressed, and various regulatory compliance requirements are met. This category also includes the pole inspection program, because we use the same workforce to perform both of these activities.

We budget for Vegetation Management annually based primarily on the number of line-miles of transmission and distribution circuits needing to be maintained on an annual basis. To maintain on-cycle performance, varying miles of circuits come due each year that were last maintained five years previous, and need to be maintained again. Annual budgets are prepared based on the line-miles coming due in the given year. In addition to line-miles, key cost drivers are the number of line-miles due in a given year to maintain on-cycle performance, degree of difficulty (forestation) associated with scope of annual circuits due, and finally, the contract labor rates of our primary contractors.

2. Damage Prevention/Locating

The Damage Prevention category includes costs associated with the location of underground electric facilities and performing other damage prevention activities. This includes our costs associated with the statewide "Call 811" or "Call Before You Dig" requirements. This program helps excavators and customers locate underground electric infrastructure to avoid accidental damage and safety incidents. We summarize in Table 35 below the volume of requests for electric facilities locates over the recent past:

Table 35: NSPM Electric Locates Volumes (2014-2018)

	2014	2015	2016	2017	2018
Annual Total	413,469	446,838	444,773	427,791	459,499

The budget for Damage Prevention is based on several factors including our most recent historical annual locate request volume trends, regional economic growth factors including new housing starts, and the contract pricing of our Damage Prevention service providers.

3. Fleet and Equipment Management

From a functional perspective, this category represents costs associated with the Distribution fleet (vehicles, trucks, trailers, etc.) and miscellaneous materials and minor tools necessary to build out, operate, and maintain our electric distribution system. Capital investments in fleet, tools, and equipment ensure our workers have the necessary provisions and support to do their job safely and efficiently, which includes the necessary replacement of vehicles and equipment that have reached their end of life. The O&M component of fleet is those expenditures necessary to maintain our existing fleet, which includes annual fuel costs plus the allocation of fleet support to O&M based on the proportion of the Distribution fleet utilized for O&M activities as compared to capital projects.

The largest cost driver for this category is for fleet vehicles. Our fleet managers maintain accurate records on vehicles and have performed analysis to determine the optimal investments to ensure a reliable, yet cost-effective fleet. Through our rigorous tracking of vehicle maintenance expenses, we are able to select vehicles to replace in order to achieve the lowest cost of ownership. We analyze which units have met their candidate age for replacement, quantitatively prioritize which assets will return the largest reduction in maintenance and repair as a proportion to their capital investment, qualitatively review condition assessments with the mechanics, and review work priorities and gather non-replacement fleet needs with users. The annual fleet budget can then be derived based on the proposed number of fleet replacements (by type of vehicle) coupled with the latest known pricing for each type and quantity of vehicle being proposed for replacement.

IX. GRID MODERNIZATION

The Company is filing its IDP concurrently with a multi-year rate case (MYRP) filing. The IDP would typically include the Company's grid modernization report, while a rate case filing typically focuses on the test year or MYRP plan years. In this case, however, while our focus in the MYRP is on investments during the MYRP period as the elements for which are seeking cost recovery, we also introduce longer-range plans to provide context for our overall distribution system vision. For example, we discuss the core components of AGIS – AMI, the FAN, FLISR, and IVVO – and the Company's building block approach to deploying these components. We also discuss ADMS as part of our overall strategy and distribution planning, even though ADMS has been previously certified by the Commission, and the first year of costs were recently approved for recovery under our Transmission Cost Recovery (TCR) Rider.

Together, our MYRP filing and the IDP bring the overall vision for AGIS into focus, and provide extensive detail regarding AGIS and our customer and distribution strategies and planned outcomes.

A. Introduction

Xcel Energy has a 100-year track record of outstanding service to our customers and communities – delivering safe, reliable, and affordable energy. We are also looking to the future and have a vision for an advanced grid that will provide both customer and operational benefits for many years to come, by addressing changes in our system needs and in distribution technology that require further investment for the future. We are taking a measured and thoughtful approach to maximize customer value, ensure the fundamentals of our distribution business remain sound, and maintain the flexibility needed as technology and our customers' expectations continue to evolve.

We are also constantly assessing our customers' experience, and their wants and needs from their electric and gas utility. Customers want access to actionable information, more choice and greater control of their energy use – and they expect a smarter, simpler, and more seamless experience. Enhancing the customer experience is critically important, and is one of our three strategic priorities, along with leading the clean energy transition and keeping bills low. We plan to integrate modern customer experience strategies with advanced grid platforms and technologies to enable intelligent grid operations, smarter networks and meters, and optimized products and services for our customers.

The AGIS initiative is our long-term strategic plan to transform our electric distribution system to update system technology and capabilities, meet changing customer demands, enhance transparency into the distribution and to system data, to promote efficiency, and reliability, and to safely integrate more distributed resources. Overall, the AGIS initiative consists of multiple elements that work together to create a more modern and advanced distribution grid.

The core components of AGIS are the Advanced Distribution Management System (ADMS), Advanced Metering Infrastructure (AMI), and the Field Area Network (FAN). ADMS is underway, with costs being recovered in the TCR Rider. We now propose to implement AMI, FAN, and two advanced applications that we believe will provide substantial benefits to customers: Integrated Volt-VAr Optimization (IVVO) and Fault Location Isolation and Service Restoration (FLISR). More specifically:

- *Advanced Distribution Management System* is the backbone of the AGIS initiative, consisting of a real-time operating system that enables enhanced visibility into the distribution power grid and controls advanced field devices.
- *Advanced Metering Infrastructure* is the Company's proposed metering solution, consisting of an integrated system of advanced meters, communication networks, and data processing and management systems that enables secure two-way communication between Xcel Energy's business and data systems and customer meters.
- *Field Area Network* is a private, secure, flexible two-way communication network that provides wireless communications across Xcel Energy's service area – to, from, and among, field devices and our information systems.
- *Fault Location, Isolation, and Service Restoration* is an ADMS application that improves customers' reliability experience, reducing the duration of outages and number of customers affected by them. FLISR takes the form of distribution automation and involves the deployment of automated switching devices that work to detect issues on our system, isolate them, and automatically restore power.
- *Integrated Volt VAr Optimization* is an ADMS application that uses specific field devices to optimize voltage as power travels from substations to customers, reducing system losses and may result in energy savings for customers.

Of course, protective cyber security and information technology (IT) support underlie all these components, as they are essential to operating a secure, technologically-advanced grid in today's world.

B. Drivers of the AGIS Initiative

NSPM has made incremental modernization efforts on the distribution system over many years, maintaining a grid that is reliable and as efficient as it could be with the technology it currently employs. However, now is the right time to begin a more significant advancement of the grid through our AGIS initiative. Drivers of our AGIS strategy include:

- The Company's strategic priorities to lead the clean energy transition, enhance the customer experience, and keep bills affordable;
- The Company's desire to meet the growing needs and expectations of our customers;
- Current distribution system needs; and
- Commission policy and direction, and stakeholder input relative to customer offerings, performance, and technological capabilities of the grid.

Over the last several years, we have experienced a variety of converging needs and opportunities related to distribution grid modernization – some driven by internal system needs, others by industry direction, and others by customers and other stakeholder considerations. The Company's extensive assessments of these multi-faceted needs, as well as the alternatives to meet them, are described in detail in the Direct Testimony of Company witnesses Ms. Bloch, Mr. Cardenas, and Mr. Harkness. As one example, Ms. Bloch and Mr. Cardenas explain the status of the Company's current meters and the extensive planning, information gathering, RFP processes, and consideration of alternate vendors, devices, systems, and programs that we undertook prior to selecting our current AMI plan. Mr. Harkness discusses both the opportunities and challenges of integrating the IT aspects of AMI across the Company, and explains the work completed to select the appropriate IT solutions. We compared the capabilities, costs, benefits, and limitations of a variety of solutions, as well as the costs versus benefits of our preferred solutions, and ultimately propose an overall AGIS initiative that is designed to effectively address the drivers of the needs for grid advancement.

We are working every day to lead the transition to a clean energy future, enhance our customers' experience with their utility, and keep bills low. As discussed in the Direct Testimony of Mr. Gersack, our customers can be partners in a more environmentally sound future, especially if they are empowered with better information and data to manage their energy usage and make conservation-friendly choices. AMI and the associated components of the AGIS initiative are critical to these efforts. Likewise, IVVO has the potential to act as a demand side management-type tool with carbon reduction and energy savings benefits without requiring any action from customers. DER are also a key to this clean energy future, and two-way communications on the distribution grid, down to the meter level, are necessary to accommodate increased levels of DER on the system.

Further, customers are demanding more optionality and increasing levels of service from all their service providers – including their provider of electric service. The

AGIS initiative is intended to create better interfaces with customers, provide them with better information and more choices, and thus improve their overall experience. Coupled with efforts to improve the digital platforms through which we interact with customers, improved energy management, control, conservation, and bill management are all available with a more interactive, advanced distribution system. And it goes without saying that continually enhancing our customers' reliability experience is at the core of quality electric service.

Finally, our proposed AGIS initiative offers our customers opportunities to better control and manage their monthly bills by providing more timely and granular energy usage data and enabling advanced rate design. Additionally, the costs of AGIS will be spread over the implementation period, which reasonably manages the cost impact for our customers. Our grid advancement strategy is intended to support each of these strategic objectives.

Influenced by other services, customers have come to expect more from their energy providers than in the past, including greater choices and levels of service, as well as greater control over their energy sources and their energy use. Customers also expect greater functionality and interaction in how those services are delivered. Technologies that customers can use to control their energy usage, such as smart thermostats, EV chargers, smart home devices, and even smart phones and energy-related digital applications, are evolving at a fast rate.

While Xcel Energy customers today have access to numerous energy efficiency and demand management programs, renewable energy choices, and billing options, major industry technological advances provide new capabilities for utility providers to manage the electric distribution grid and service to customers. Electric meters can now more easily and flexibly gather more detailed information about customer energy usage, which utilities can leverage to help customers better understand and manage their usage. Other advanced equipment on the grid can detect, communicate, and respond in real time to circumstances that would normally result in power outages. Grid operators can also get improved data to better and more proactively plan and operate the grid. These advancements form the foundation for a flexible grid environment that helps support two-way power flows from customer-connected devices or generating resources (such as rooftop solar) and provides utilities with a greater ability to adapt to future developments.

Now is the right time for the Company to implement the AGIS initiative. Like other electric utilities, our current distribution system is based on one-way flow of information on much of our system, which means that beyond the distribution substation, the Company has little insight into the workings of the distribution system as it relates to outages, voltage levels experienced by the customer, and DER operations. Company witness Ms. Kelly Bloch describes this in further detail. Additional components that integrate with ADMS and advanced meters are necessary to better manage and shorten outages, and to maximize the voltage management on our system.

In addition, our current automated meter reading (AMR) technology in Minnesota is nearing end of life, and our meter reading services vendor, Landis+Gyr (Cellnet) has informed the Company that it will no longer manufacture replacement parts for this system after 2022. In fact, we are the last Cellnet customer still using this technology. Further, our current contract with Cellnet for meter reading services expires at the end of 2025. While we have maximized the value of this AMR system that has provided efficient meter reading services for nearly 30 years, we now have the opportunity to transition to AMI, a proven meter technology. AMI will allow us the ability to expand the use of our meter system beyond basic billing functions for the benefit of our customers.

AMI is the right direction, as AMR technology is becoming increasingly outdated – and the progressively complex needs of the distribution system require movement to technology that can accommodate these needs. As stated in the United States Department of Energy (DOE) Office of Electricity's November 2018 Smart Grid System Report to Congress,

> [f]rom 2007 to 2016, the number of advanced meters has grown ten-fold. About 70.8 million meters out of a total of 151.3 million meters were smart meters as of 2016, representing about 47 percent of U.S. electricity customers[]. Bloomberg estimates that number has risen to 51 percent by the start of 2018. This is a significant increase compared to 14 percent of customers with smart meters in 2010 and only 2 percent in 2007.[49]

Xcel Energy has always performed well with respect to system reliability, management, and customer service, but in light of the prevalence of advanced meters and smart grid technologies, we must make similar investments to ensure continuing alignment with industry direction and customer expectations.

The DOE Smart Grid System Report also recognized the broader need for attention to distribution infrastructure nationwide:

> Our [country's] electric infrastructure is aging and it is being pushed to do more than

[49] https://www.energy.gov/sites/prod/files/2019/02/f59/Smart%20Grid%20System%20Report%20November%202018_1.pdf, as of October 1, 2019 (internal citations omitted) (DOE Smart Grid System Report).

it was originally designed to do. Modernizing the grid to make it "smarter" and more resilient through the use of cutting-edge technologies, equipment, and controls that communicate and work together to deliver electricity more reliably and efficiently can greatly reduce the frequency and duration of power outages, reduce storm impacts, and restore service faster when outages occur. Consumers can better manage their own energy consumption and costs because they have easier access to their own data. Utilities also benefit from a modernized grid, including improved security, reduced peak loads, increased integration of renewables, and lower operational costs.

"Smart grid" technologies are made possible by two-way communication technologies, control systems, and computer processing. These advanced technologies include advanced sensors… that allow operators to assess grid stability, advanced digital meters that give consumers better information and automatically report outages, relays that sense and recover from faults in the substation automatically, automated feeder switches that re-route power around problems, and batteries that store excess energy and make it available later to the grid to meet customer demand.[50]

It is no coincidence that these needs are arising at the same time we have implemented ADMS and that our existing AMR meters are nearing the end of their life. And, as noted earlier, our customers are also demanding more optionality, environmentally-sound investments, more control over their energy usage, and better outage management and communications from their utility.

We have applied Commission guidance and stakeholder feedback gleaned through regulatory proceedings and Commission- and Company-sponsored stakeholder processes around grid modernization, DER hosting capacity, integrated distribution system planning, our integrated resource plan, and performance metrics for the Company's electric operations. We also considered the Commission's guidance and stakeholder feedback associated with the Company's proposed Time of Use (TOU) pilot and our EV pilot proposals, all of which were informed by extensive stakeholder input. This guidance and feedback helped shape our proposal in terms of the advanced grid capabilities, how we prioritized the advanced applications, and how we assessed and present the AGIS benefits and value for customers. As discussed further in the Direct Testimony of Mr. Gersack (Section IV), various Commission policies and specific goals of each of these efforts are supported or enabled by advanced grid technologies. We have considered these policies, goals, and the stakeholder input as we developed our overall strategy and specific project plans for AGIS implementation.

[50] https://www.energy.gov/oe/activities/technology-development/grid-modernization-and-smart-grid, as of Oct. 1, 2019.

Further, as the prevalence of DER continues to rise, the ability to manage these resources requires visibility into the grid and a more resilient and responsive grid. As the DOE Smart Grid Report stated, grid advancement is necessary to support:

> the increasing presence of renewable generation and the proliferation of customer- and merchant-owned DERs [that] are introducing significantly greater levels of variability and uncertainty in both the supply of electricity and the demand for it. Generation and load profiles, which have been predictable in the past, can now vary instantaneously and are subject to the behavior of consumers where DERs are present.[51]

Enhanced grid management through ADMS, meters with two-way communications that act as sensors, and greater voltage optimization will all support our ability to host increasing levels of DERs.

Given these circumstances and the additional customer and system benefits enabled by advanced grid technology, the Company determined now is the appropriate time to pursue a targeted AGIS initiative that will address system needs, customer needs, and our overall strategic priorities as a Company to lead the clean energy transition, enhance the customer experience, and keep bills low.

C. AGIS Implementation

With the Commission's certification and approval of our first year of costs, the ADMS is underway and scheduled to go into service in 2020. We are also in the process of implementing our TOU pilot, consistent with the Commission's Order in Docket No. E002/M-17-775, certifying it as a distribution project under Minn. Stat. §216B.2425 (*i.e.*, a grid modernization project). This pilot is intended to study time of use rates and how to maximize their value. This limited deployment of AMI meters and the FAN communications network in connection with the TOU pilot is a part of the overall AGIS initiative, and has been considered as we have developed plans for full deployment of advanced grid technologies. Likewise, we have conducted system research and testing around FLISR and IVVO, as discussed in the Direct Testimony of Ms. Bloch.

Implementation of the components of the AGIS initiative will occur over several years and be substantially complete by 2024 – with FLISR implementation expected to continue through approximately 2028. As such, a large portion of AMI, FLISR, IVVO, and FAN work will be undertaken and placed in service during the multi-year

[51] DOE Smart Grid Report at p. 5.

rate plan period (MYRP), and are included in the Company's rate request in its MYRP case filed concurrently with this IDP. We outline our implementation timeline below:

Table 36: AGIS Deployment Timeline

Program	Implementation Timeline
ADMS	In-service 2020
AMI	Meter roll-out 2021-2024
FAN	Deployment 2021-2024 (preceding AMI deployment by approximately six months)
FLISR	Limited testing 2020; Implementation 2020-2028
IVVO	Limited testing 2021; Implementation 2021-2024

That said, the grid modernization effort is ongoing by nature, and we will continue to maintain the system as well as leverage evolving technology, platforms and optionality as appropriate over time. Likewise, the Commission's IDP requirements contemplate five- and ten-year outlooks. As such, our discussion of AGIS costs and benefits in the MYRP encompasses but also extends beyond the MYRP timeframe. Our cost-benefit analysis also runs through the lifecycle of the assets based on the information currently known (as with any integrated long-range plan). This long-range view also includes discussion of potential future AGIS investments, which are not yet specifically planned for implementation nor ready for full presentation to the Commission.

D. AGIS Initiative Overall Cost Summary

The Company anticipates incurring capital expenditures totaling $582 million and O&M costs totaling $152 million for the overall AGIS initiative as summarized in Tables 37 and 38 below.[52]

[52] This AGIS view excludes ADMS, as it is certified for TCR Rider recovery.

Table 37: Total AGIS Capital Expenditures NSPM – Electric (Millions)

AGIS Program	Rate Case Period			5-Year Period	10-Year Period
	2020	2021	2022	2023-2024	2025-2029*
AMI	$14.0	$28.9	$144.0	$185.2	$15.0
FAN	$14.7	$37.3	$36.8	$3.8	$0.0
FLISR	$3.5	$8.6	$6.6	$18.8	$29.7
IVVO	$0.1	$6.5	$9.8	$18.6	$0.0
Total	**$32.3**	**$81.3**	**$197.2**	**$226.4**	**$44.7**

*Period may include additional assumptions, including inflation and labor cost increases that are not part of the capital budget in periods 2020-2024.

Table 38: Total AGIS O&M NSPM Electric (Millions)

AGIS Program	Rate Case Period			5-Year Period	10-Year Period
	2020	2021	2022	2023-2024	2025-2029*
AMI	$6.6	$16.4	$14.1	$25.2	$67.2
FAN	$0.1	$2.3	$1.5	$0.5	$8.6
FLISR	$0.2	$0.4	$0.3	$3.3	$2.5
IVVO	$0.00	$0.4	$0.8	$0.6	$0.8
Total	**$6.9**	**$19.5**	**$16.7**	**$29.4**	**$79.1**

Period may include additional assumptions, including inflation and labor cost increases that are not part of the capital budget in periods 2020-2024.

E. Proposed AGIS Cost Recovery

The Commission's requirements state that the Company is to provide detailed support for its proposed grid modernization investments, including assessment of both quantitative and qualitative benefits associated with them. As we outline and describe below, our AGIS plan extends beyond the MYRP, and the Commission has required the Company to explain its grid modernization plan through the lifecycle of the assets. We present this information in our cost-benefit analysis, and in the Direct Testimony of each of the witnesses who present operational support for the costs and benefits we have identified and modeled (where quantification is possible).

Concurrent with the IDP and the MYRP, we also filed a Petition for Approval of True-Up Mechanisms. This latter filing requests the approval of certain true-ups for 2020 which, if approved, would have the effect of the MYRP being withdrawn.

While we have included the AGIS costs in our MYRP request, we are also seeking certification for these investments for two reasons: (1) should the Commission ultimately approve the True-Up Petition and the MYRP be withdrawn, we would preserve the option to put the AGIS costs in a rider until such time as we file our next general rate case and roll the costs into base rates; and (2) regardless of approval of the True-Up Petition, the span of the AGIS costs goes beyond the timeframe for the rate case, so we would look to include the out years of the costs in a rider. Again, the Commission would have another opportunity for review and approval before any of these costs were actually included in any future rider, this approach merely preserves our options.

Given the complete information we provide on overall AGIS implementation and costs, we respectfully request certification of the AGIS initiative. The costs for which we request recovery in the MYRP are as follows:

Table 39: Capital Additions for the AGIS Components – Minnesota 2020-2022 (includes AFUDC) (Millions)

AGIS Component	2020	2021	2022
AMI	$16.0	$27.9	$119.8
FAN	$8.3	$21.3	$42.0
FLISR	$3.4	$8.4	$6.4
IVVO	-	$5.7	$8.6
Total	**$27.7**	**$63.3**	**$176.8**

Table 40: O&M for the AGIS Components – NSPM Electric 2020-2022 (Millions)

AGIS Component	2020	2021	2022
AMI	$6.6	$16.4	$14.1
FAN	$0.1	$2.3	$1.5
FLISR	$0.2	$0.4	$0.3
IVVO	-	$0.4	$0.8
Total	**$6.9**	**$19.5**	**$16.7**

The normal procedural schedule for certification under Minn. Stat. § 216B.2425 would require a determination by June 1, 2020, and under normal circumstances, we believe the process leading to certification should resemble a resource acquisition proceeding under the Commission's normal notice and comment procedures that could, in the Commission's discretion and depending on the scope of the investment, include one or more public hearings. We recognize, however, that the schedule in the

General Rate Case does not align with that timing. In addition, the AGIS initiative includes large investments and is supported by a sizeable filing that may require analysis beyond the six-month certification timeframe, even if the General Rate Case is withdrawn. Thus, we offer to work with the Commission and stakeholders to set an appropriate deadline and procedural schedule for consideration of these investments.

F. Relative AGIS Initiative Costs and Benefits – Quantifiable and Non-Quantifiable

Our proposal contains comparisons of the costs and benefits of the AGIS components as well as alternatives comparisons. We have conducted a cost-benefit analysis (CBA) for each of the AGIS components and on a consolidated basis. The CBA provides one point of reference to assess the investments in the broader context of the goals of AMI, FLISR, and IVVO implementation, the current qualitative benefits they offer, Commission policy goals, and the opportunities for future customer benefits. Company witness Dr. Duggirala presents the overall CBA model and the witnesses noted in Table 47 of this IDP provide the inputs to the CBA for each component and for the consolidated AGIS initiative.

1. Summary CBA Results

On a consolidated basis the CBA results indicate that the quantifiable costs and benefits of the AGIS initiative total 0.87 in our baseline scenario, or 1.03 under a high benefit/no contingency scenario. Thus, although the combined components do not reach 1.0 (equal quantifiable benefits and costs) under our baseline scenario, the ratio for the overall AGIS initiative approaches 1.0 even before we factor in qualitative benefits such as customer satisfaction and operational, power quality, and safety enhancements.

Table 41: AGIS Initiative Combined Cost-Benefit Ratio (Millions)

NSPM AMI, FLISR, IVVO NPV	Total
Benefits	**$571**
O&M Benefits	$53
Other Benefits	$222
Customer Benefits	$103
Capital Benefits	$193
Costs	**$(656)**
O&M Expense	$(186)
Change in Revenue Requirement	$(470)
Baseline Benefit-Cost Ratio (IVVO CVR 1.25% energy, 0.7% capacity, with contingencies)	**0.87**
High Benefit/No Contingency Sensitivity (IVVO CVR 1.5% energy/0.8% capacity, no contingency)	1.03
Lower Benefit/With Contingency Sensitivity (IVVO CVR 1.0% energy/0.6% capacity, with contingencies)	0.86

We note that while the CBA, by itself, does not show that quantifiable benefits are equal to quantifiable costs, we would not necessarily expect that result. We are proposing an initiative to both replace fundamental components of our system that are approaching end of life, and to add capabilities for our customers and for a future that includes greater DER, distributed intelligence, and greater customer engagement. We would not expect to save money (on a net basis) when investing in these kinds of technologies, but we believe the total value of the initiative significantly outpaces the cost of the investments. For these reasons, the AGIS investments are prudent based on the need for the investments to serve customers, as well as consideration of the customer-facing benefits, efficiencies, and system benefits they provide.

2. *Individual AGIS Component CBA Results Summary*

As discussed in detail in Dr. Duggirala's testimony, AMI, FLISR, and IVVO have the following approximate quantitative benefit-to-cost ratios for each component, shown here with and without contingency amounts:

Table 42: NSPM AMI Benefit-to-Cost Ratio (Millions)

NSPM-AMI-NPV	Total
Benefits	$446
O&M Benefits	$53
Other Benefits	$203
CAP Benefits	$190
Costs	$(538)
O&M Expense	$(179)
Change in Revenue Requirements	$(359)
Benefit/Cost Ratio	**0.83**
Benefit/Cost Ratio (no contingencies)	**0.99**

Table 43: NSPM FLISR Benefit-to-Cost Ratio (Millions)

NSPM FLISR- NPV	Total
Benefits	**$103**
O&M Benefits	$0
Customer Benefits	$103
Costs	**$(79)**
O&M Expense	$(5)
Change in Revenue Requirements	$(74)
Benefit/Cost Ratio	**1.31**
Benefit/Cost Ratio (no contingencies)	**1.53**

Table 44: IVVO Benefit to Cost Ratio (Millions)

NSPM IVVO- NPV	Total
Benefits	**$22**
Other Benefits	$19
CAP Benefits	$3
Costs	**$(39)**
O&M Expense	$(2)
Change in Revenue Requirement	$(37)
Benefit/Cost Ratio (CVR 1.25% energy; 0.7% capacity)	**0.57**
Benefit/Cost Ratio (no contingencies)	**0.61**
Low Benefit Sensitivity:	
Benefit/Cost Ratio (CVR 1% energy; 0.6% capacity)	0.46
Benefit/Cost Ratio (no contingencies)	0.49
High Benefit Sensitivity:	
Benefit/Cost Ratio (CVR 1.5% energy; 0.8% capacity)	0.67
Benefit/Cost Ratio (no contingencies)	0.72

We show an additional range of IVVO benefit-to-cost ratios because as Ms. Bloch and Dr. Duggirala explain, the Company is deploying IVVO to a core area, and does not have widespread data on the likely results of IVVO implementation. However, we understand that many of our stakeholders are particularly interested in IVVO deployment. Our engineers feel confident they can achieve 1.0 percent energy savings and may be able to achieve 1.5 percent through voltage optimization; in light of the uncertainty and interest, we have utilized a 1.25 percent mid-range energy savings level to show a range of potential outcomes. Our baseline benefit-to-cost ratio overall assumes 1.25 percent energy savings, 0.7 percent capacity savings, and that we will need to utilize the IVVO contingency amounts.

3. CBA MYRP Witness Support Summary

In terms of MYRP witness support for the costs and benefits of our proposed AGIS initiative, Ms. Bloch, Dr. Duggirala, and Mr. Cardenas support the benefits of AMI. Mr. Gersack discusses the purpose and limitations of the CBA, as well as the unquantifiable qualitative benefits further in his Direct Testimony. While the IT work is necessary to both implement the AGIS initiative and ensure appropriate security measures, IT by itself does not provide independent benefits; therefore, Mr. Harkness's testimony is limited to a discussion of costs. Benefits of the AGIS initiative are many and varied, but the types of benefit and supporting witnesses can be summarized as follows:

Table 45: Summary of Benefits for AGIS Components

Benefit	Supporting Witness
AMI	
Distribution System Management Efficiency	Bloch Direct, Section V(D)(4)(a)(1)
Outage Management Efficiency	Bloch Direct, Section V(D)(4)(a)(2)
Avoided Meter Purchases for Failed Meters	Bloch Direct, Section V(D)(4)(a)(3)
Avoided Capital for Alternative Meter Reading System	Bloch Direct, Section V(D)(4)(a)(4)
Avoided O&M Meter Reading Cost for Alternative Meter Reading System	Cardenas Direct, Section V(F)
Reduction in Field & Meter Services	Bloch Direct, Section V(D)(4)(b)(1)
Improved Distribution System Spend Efficiency	Bloch Direct, Section V(D)(4)(b)(2)
Outage Management Efficiency	Bloch Direct, Section V(D)(4)(b)(3)
Customer Outage Reduction	Bloch Direct, Section V(D)(4)(c)
Reduction in Energy Theft	Cardenas Direct, Section V(F)
Reduced Consumption Inactive Premise	Cardenas Direct, Section V(F)
Reduced Uncollectible/Bad Debt	Cardenas Direct, Section V(F)
Critical Peak Pricing	Duggirala Direct, Section II(B)(1)
TOU Customer Price Signals	Duggirala Direct, Section II(B)(1)
Reduced Carbon Dioxide Emissions	Duggirala Direct, Section II(B)(1)
Improved Customer Choice and Experience	Gersack Direct, Section VI and Schedule 3
Enhanced DER Integration	Bloch Direct, Section V(D)(4)(d)(1)
Environmental Benefits of Enhanced Energy Efficiency	Bloch Direct, Section V(D)(4)(d)(2)
Improved Safety to Both Customers and Company Employees	Bloch Direct, V(D)(4)(d)(3)
Improvements in Power Quality	Bloch Direct, V(D)(4)(d)(4)
FLISR	
Customer Minutes Outage –Savings	Bloch Direct, Section V(F)(5)(a)(1)
Outage Patrol Time Savings	Bloch Direct, Section V(F)(5)(a)(2)
Improved ability to plan distribution system needs	Bloch Direct, Section V(F)(5)(b)
Overall Customer Satisfaction with Utility Service	Gersack Direct, Section VII(B)

Benefit	Supporting Witness
IVVO	
Fuel savings (Energy Reduction)	Bloch Direct, Section V(G)(4)(a)(1)
Fuel Savings (Line Losses)	Bloch Direct, Section V(G)(4)(a)(2)
Avoided Capacity Costs	Bloch Direct, Section V(G)(4)(a)(3)
Reduced Carbon Dioxide Emissions	Duggirala Direct, Section II(B)(3)
Customer bill savings for customers with feeders with IVVO assets	Bloch Direct, Section V(G)(4)(b)
Greater Efficiencies from the Customer's Personal Electrical Devices	Bloch Direct, Section V(G)(4)(b)
Increased Hosting Capacity for Distributed Energy Resources.	Bloch Direct, Section V(G)(4)(b)

Additionally, Dr. Duggirala presents "Least-Cost/Best-Fit" analyses with respect to the costs/benefits of AMI and manual reading or drive-by AMR solutions; as well as for the costs of FAN versus cellular communications and dedicated AMI network alternatives.

4. *Summary*

As we have noted, while the consolidated CBA by itself does not show that quantifiable benefits are equal to quantifiable costs, we are proposing this equipment to replace a fundamental component of our system that is approaching obsolescence while also adding capabilities for our customers and for a future that includes greater DER, distributed intelligence, artificial intelligence, and greater customer engagement with all facets of their life. We would not expect to save money (on a net basis) when investing in these kinds of technologies.

G. Estimated Customer Bill Impacts

Keeping customer bills low is a core strategy of the Company and is a central consideration of our AGIS initiative. As we discuss, the combined AGIS investment will provide significant value to our customers. Of course, providing value to our customers through our AGIS investments has an impact to customer bills, resulting from the increased revenue requirement due to our investments and O&M spending necessary to implement the AGIS initiative.

To conduct this analysis, we performed a high-level revenue requirement analysis for

2020 through 2024 to illustrate the incremental revenue requirement and estimated bill impact of AGIS implementation.[53] We present the AGIS revenue requirement in the Direct Testimony of Mr. Gersack as Exhibit___(MCG-1), Schedule 9. While we did not perform an exhaustive class cost of service model for this subset of investments and O&M expenses, this analysis provides the annual cost of the AGIS initiative overall, and provides an estimate of a monthly bill impact for a typical residential customer.

We estimated the bill impact by utilizing a series of allocation assumptions applied to the AGIS costs, using allocators consistent with our 2020 proposed Class Cost of Service Study. Appropriate allocators were applied to distribution capital, distribution O&M, and the remaining costs to develop an estimated residential class revenue requirement. We then divided the estimated residential class revenue requirement by the sales forecast for each year, as provided in Company witness Ms. Janell Marks's testimony. This results in an estimated overall cost per kilowatt hour (kWh). We then calculated an estimated bill impact based the average monthly residential customer usage of 675 kWh. This assessment shows an estimated 2024 bill impact for our AGIS investments of approximately $2.87 per month for an average residential customer.

We also assessed an alternative investment and costs if the Company does not implement the AGIS initiative. As described earlier, it is not feasible for the Company to continue to use its current AMR meters because they are nearing end of life, and the Company's contract with Cellnet for meter reading service and support expires at the end of 2025. As such, the Company would, at a minimum, need to invest in new meters and provide meter reading services in order to continue to provide electric service to our customers. This means that even without AGIS implementation, there would be an incremental impact to customers' bills for an alternative metering service.

Therefore, in addition to the AGIS revenue requirement, we developed a reference case scenario to represent an alternative to our AGIS investments. The reference case reflects the necessary investments and costs if the Company were to pursue a basic AMR drive-by meter reading alternative. Ms. Bloch and Mr. Cardenas discuss AMR meters and provide details on the costs of this alternative. We calculated the bill impact by using the revenue requirements for the AMR drive-by alternative and calculated the estimated bill impact as described above. We present the reference

[53] The costs included in 2019 are related to the Company's TOU pilot. As described in Section VI, the costs of implementing AMI and FAN in connection with the TOU pilot (in 2019 and 2020) have been included in the AGIS CBA to provide a complete picture of advanced grid investments and costs. We have also included these costs in our bill impact assessment.

case revenue requirement in the Direct Testimony of Mr. Gersack as Exhibit___(MCG-1), Schedule 10. This assessment shows an estimated 2024 bill impact for the AMR drive-by alternative of approximately $1.51 per month for an average residential customer.

The key comparison and impact is the difference between the estimated bill impact of AGIS implementation versus the basic alternative, as shown below.

Table 46: Estimated Monthly Bill Impact – Typical Residential Customer

	2020	2021	2022	2023	2024
AGIS	$0.44	$1.33	$1.84	$2.58	$2.87
Reference Case	$.01	$0.19	$0.62	$1.18	$1.51
Difference	**$0.43**	**$1.14**	**$1.22**	**$1.40**	**$1.36**

Table 46 illustrates the incremental bill impact of pursuing our AGIS investments compared to the investments that would otherwise be necessary. In other words, the difference reflects the costs that will enable all the benefits of the advanced grid, both quantifiable and non-quantifiable, that AMR meters simply will not provide. Additionally, Table 46 illustrates that costs of AGIS will be spread over the implementation period, which reasonably manages the bill impact for our customers.

H. AGIS Metrics and Reporting

The AGIS initiative will be implemented over a number of years, beginning with customer outreach and education efforts, followed by deployment of the systems and technologies, and then the roll-out of new products and services enabled by the AGIS initiative. Our efforts will also include development and implementation of future products and services that will capture additional benefits of the advanced grid capabilities as customer preferences and technologies evolve over time.

Recognizing the significant investment that the advanced grid initiative requires as well as the fact that we are the first utility in Minnesota to take on this holistic effort, we propose to report on several metrics. These metrics are intended to provide progress reports to the Commission and share information and learnings with stakeholders. The proposed metrics are defined in four categories:

1. *Customer Awareness* – measuring the effectiveness of the communications on educating customers about the advanced grid and the potential benefits it entails.
2. *Customer Engagement* – measuring the adoption rates of customers in new products and services that are enabled or enhanced by the advanced grid.
3. *Customer Satisfaction* – measuring how satisfied customers are with the deployment or and services associated with the advanced grid.
4. *System Benefits* – measuring the energy savings benefits associated with products and services enabled or enhanced by the advanced grid.

Reporting of these metrics can keep stakeholders informed of the progress and value that the advanced grid is bringing to customers and also identify areas where Xcel Energy can focus additional resources to improve results. Certain metrics would have a specific baseline in a steady state. The steady state would occur within 1-2 years of the completion of mass deployment of advanced meters.

In summary, we propose to file an annual report on the AGIS initiative that will include various progress metrics that relate to different areas of our business that are involved in AGIS implementation. We propose to file the AGIS report on May 1 each year, to include reporting for the prior calendar year. Our first AGIS report would be filed May 1, 2022. We expect the content of the report and relevant metrics will change over time as we move through the phases of AGIS implementation. We provide a summary in the Direct Testimony of Mr. Gersack, Exhibit____(MCG-1), Schedule 11.

We also note that our AGIS initiative may also impact certain service quality metrics that are included in reporting that is already in place. Specifically, the Company reports service quality metrics under our established Service Quality tariff[54] as well as the Minnesota Rules governing utility service quality.[55] We propose to continue reporting the service quality metrics in those reports, and intend to address any AGIS impacts to service quality metrics or thresholds in those separate proceedings.

We clarify that we do not propose specific metrics related to future operational capabilities or products and services that will be enabled by AGIS at this time.

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[54] See the Company's Minnesota Electric Rate Book, Section 6, General Rules and Regulations, Subsection 1.9, Service Quality.
[55] *See* Minn. Rule 7826, Electric Utility Standards on safety, reliability, and service quality.

Rather, as we discuss in the MYRP Direct Testimony, we propose to report on metrics developed in those proceedings in the separate future dockets.

I. MYRP Witness Support for the Proposed AGIS Initiative

In this section, we outline the business areas involved in implementing the AGIS initiative, identify the MYRP witnesses supporting AGIS, and provide an overview of the topics covered by each. Because the large majority of information necessary to support the AGIS initiative in the MYRP and in the concurrent IDP is contained in the MYRP filing, we provide a roadmap to help navigate the extensive information and testimony we provide on our AGIS initiative and proposal.

We note additionally that while we have made every effort to provide a higher-level roadmap that identifies the location of specific topics and information to aid the reader, Exhibit___(MCG-1), Schedule 2 is the AGIS Completeness List, which identifies specific filing requirements and where the information is located. We also provide this as Attachment C, Grid Modernization Content Roadmap, to this IDP.

1. Business Areas Supporting the AGIS Initiative

The AGIS initiative is supported by and affects many operating and customer service areas of our business. In particular:

- Our Distribution Operations business area is responsible for the planning, implementation, and operations of the various advanced grid components. At a high level, this can be thought of as installing, maintaining, operating, and protecting the foundational hardware and support components of AGIS on the distribution system.
- The Business Systems area is responsible for the hardware and software systems necessary to deploy and secure the AGIS components from an IT perspective. Business Systems is also responsible for implementation of the IT platform that will enable the Company to interface with customers through various portals, and to provide customers access to additional information, products, and services that will be possible through the advanced grid initiative. Business Systems also works hand-in-hand with our security team to protect the Company's software systems from cyber attacks.
- Customer Care is responsible for meter reading, billing, credit, remittance processing, and customer contact center functions. The Customer Care team will manage customer questions and concerns as the AGIS initiative is being

deployed, as well as the new billing options and programs that will be made available.

Other customer-facing teams are also heavily involved. Customer Solutions is responsible for development and implementation of those customer-facing online and mobile applications, as well as new products and services that will be enabled by the advanced grid capabilities. Our Customer Insights group is responsible for survey and research efforts necessary to determine the needs and preferences of our customers with respect to development of new products and services, as well as to measure customer satisfaction with new products, services, or advanced grid capabilities. Corporate Communications is responsible for the customer education and communications related to implementation of new technologies and products and services related to advanced grid capabilities. In short, the AGIS initiative will touch many areas of Xcel Energy.

2. MYRP Witness Topics

The MYRP presents five witnesses who provide Direct Testimony and accompanying schedules supporting our request for approval of the capital and O&M budgets for the specific components of AGIS included in this case, as well as support for this IDP being filed concurrently with this case. These witnesses' respective topics are as follows:

- *Michael C. Gersack* presents the overview of the AGIS initiative, the background on our efforts to date, a review of governance planning, discussion of the customer experience upon implementation, explanation of our customer outreach and progress metrics proposals, and cost-benefit and bill impacts overviews.
- *Kelly A. Bloch,* Regional Vice President of Distribution Operations, addresses the AGIS initiative from the Distribution perspective, and specifically identifies those costs and benefits that derive from the Distribution portion of the business. Her testimony details the business case for AMI, FLISR, and IVVO, and provides extensive discussion of these technologies, alternatives considered, and supporting cost and benefit detail.
- *David C. Harkness,* Senior Vice President of Customer Solutions for XES, addresses the AGIS initiative from the Business Systems (IT) perspective, focusing on integration of the hardware and software necessary for the AGIS elements to function together and with existing Company systems. Mr. Harkness also details the business case for the FAN strategy and project management, as well as alternatives considered and supporting cost detail. Mr.

Harkness also discusses cyber security for the AGIS initiative, as well as the costs and benefits of the IT hardware and software systems necessary to deploy each of the AGIS components.

- *Christopher C. Cardenas,* Vice President of Customer Care for XES, explains the current status of the expiring Cellnet contract for wireless metering, meter change and billing impacts and options as AMI meters are deployed, and potential tariff changes the Company plans to pursue in the future. Mr. Cardenas also describes certain cost savings and customer benefits associated with moving away from our current meter reading system.
- *Ravikrishna Duggirala,* Director of Risk Strategy for XES, supports the Company's cost-benefit model for the both the independent core components and overall AGIS initiative. Dr. Duggirala explains the structure of the model and how inputs received from other business areas were utilized, and also explains certain benefits. Lastly, Dr. Duggirala explains the limitations of any cost-benefit modeling.

3. AGIS Policy Testimony Roadmap

The Direct Testimony of Mr. Gersack presents the AGIS policy perspective. It first provides background on grid modernization in Minnesota and discusses how our request in the MYRP relates to this IDP filed concurrently with the Commission on November 1, 2019. We believe this establishes an important backdrop for the Company's view of the future of the grid. It then identifies the Company's overall strategic goals, focusing on the environment, the customer experience, and cost of service. It also identifies customer expectations and wishes for the future of electric service based on extensive Company research, focusing on how these expectations relate to the future of the distribution system.

The Direct Testimony of Mr. Gersack then describes the Company's long-term strategic plan to use technological advances to transform our distribution system to meet changing customer demands, to enhance efficiency, reliability, resilience, and security, to safely integrate more distributed energy resources, and explain how that plan is aligned with core Company goals. It highlights the reasons now is the right time to undertake these initiatives, including our meters nearing end of life and the expiration of our meter reading contract with Cellnet, and discuss the key goals of AGIS and how they are consistent with Xcel Energy's strategic priorities.

It then addresses the scope of the core components of AGIS that are included in the MYRP, outlining the function, benefits, alternatives considered, timing of implementation, and costs of each; other Company witnesses flesh out these components, costs, and benefit assumptions in more detail. Next, it discusses in detail the current customer experience compared to what will be different when the distribution system is transformed and advanced. It also provides our customer and community outreach plan for the AGIS initiative, designed to educate and inform customers about our progress, impacts they will experience during and after implementation, and advanced grid capabilities that will provide the basis for additional opportunities and services for our customers. It also discusses progress metrics and how the Company will measure and report on progress and outcomes of the AGIS initiative.

Finally, it describes why AGIS, and thus the foundational elements included in the MYRP are in the public interest. It introduces the cost benchmarking and cost-benefit analyses we have undertaken, which are specifically supported and presented in detail in the Direct Testimony of Company witness Dr. Duggirala. It explains both the value and the inherent limitations of any cost-benefit analysis. It also summarizes the quantitative and qualitative benefits of the AGIS initiative, explaining how the benefits of certain components of AGIS are not limited to quantifiable items; they will also update aging systems, improve our customers' overall experience and satisfaction, position the Company for future grid developments, and help achieve broader energy goals.

The Direct Testimony of Mr. Gersack also provides as Exhibit___(MCG-1), Schedule 3 the Company's *Advanced Grid Customer Strategy*. This document the details the Company's AGIS strategy and plans to enhance the customer experience. The document includes, among other things, background on our customer surveys and research efforts that have informed our AGIS strategy, and details on the technologies and customer benefits of each AGIS component.

To help stakeholders further visualize our plans, the Company also prepared a brief video[56] entitled *Building the Future* to illustrate the advanced grid technologies and benefits and illustrate multiple situations where additional data and capabilities with respect to the distribution grid will facilitate a better, smoother, and more agile customer experience. While not as dynamic as the video itself, we have provided illustrations from this video as Exhibit___(MCG-1), Schedule 4.

4. *MYRP Witness Cost Support*

Because the costs of the AGIS initiative reside in our Distribution and Business

56 https://youtu.be/HoQoHFdF7kc

Systems budgets, Ms. Bloch and Mr. Harkness support the costs of the AGIS components and most aspects of our initiative's development. Specifically, Ms. Bloch supports the selection of meters and the FLISR and IVVO field devices and associated implementation; whereas Mr. Harkness describes the associated software, hardware, security, and overall IT integration.

Table 47: AGIS Components MYRP Witness Summary

AGIS Program	Component	Witness
AMI	IT Integration and head end application	Harkness Direct, Section V(E)(3)
	Meters and deployment	Bloch Direct, Section V(D)
FAN	IT Integration and deployment	Harkness Direct, Section V(E)(4)
	Installation of pole-mounted devices	Bloch Direct, Section V(E)
FLISR	System development	Harkness Direct, Section V(E)(5)
	Advanced application and field devices	Bloch Direct, Section V(F)
IVVO	System development	Harkness Direct, Section V(E)(6)
	Advanced application and field devices	Bloch Direct, Section V(G)

In addition, the Direct Testimony of Mr. Gersack supports program management for the AGIS initiative (Section V.D) and the Company's customer outreach plans (Section VI.E).

J. Our AGIS Proposal is in the Public Interest

Our distribution grid is the foundation of the service we provide our customers. We are at a point where investment in new technologies to further modernize our grid will return significant value to our customers. Our proposed AGIS initiative supports the Company's vision for an advanced grid that will provide both customer and operational benefits for many years to come and has been informed by:

- The Company's strategic priorities to lead the clean energy transition, enhance the customer experience, and keep bills low;

- The Company's desire to meet the growing needs and expectations of our customers;
- Current distribution system needs; and
- Commission policy and stakeholder input relative to customer offerings, performance, and technical capabilities of the grid.

Our AGIS initiative will enhance transparency into the distribution system and provide detailed and timely data to promote efficiency, reliability, and enable increased distributed resources on our system. AGIS will also enhance our customers' experience by providing access to actionable information, more choices, and greater control of their energy use.

Based on this, we respectfully request the Commission certify our AGIS initiative

X. CUSTOMER STRATEGY SUMMARY

The electric utility industry is in a time of significant change. Increasing customer expectations and technological advances have reshaped what customers expect from their energy service provider, and how those services are delivered. Technologies that customers can use to control their energy usage, such as smart thermostats, EV chargers, smart home devices, and even smart phones, are evolving at a fast rate. Influenced by other services, customers have come to expect more now from their energy providers than in the past, including greater choices and levels of service, as well as greater control over their energy sources and their energy use.

At the same time, major industry technological advances provide new capabilities for utility providers to manage the electric distribution grid and service to customers. Electric meters are now equipped to gather more detailed information about customer energy usage, which utilities can leverage to help customers better understand and manage their usage. Other advanced equipment on the grid can sense, communicate, and respond in real time to circumstances that would normally result in power outages. Grid operators can also get improved data to better and more proactively plan and operate the grid. These advancements form the foundation for a flexible grid environment that helps support two-way power flows from customer-connected devices or generating resources (such as rooftop solar) and provides utilities with a greater ability to adapt to future developments.

Xcel Energy has a 100-year track record of outstanding service to our customers and communities – delivering safe, reliable and affordable energy. At our core, is keeping the lights on for our customers, safely and affordably. We are also planning for the future – and have a vision for where we and our customers want the grid to go. We are taking a measured and thoughtful approach to ensure our customers receive the greatest value, and that the fundamentals of our distribution business remain sound.

Today, Xcel Energy customers have access to numerous energy efficiency and demand management programs, renewable energy choices, billing options, a mobile app, and outage notifications that include estimated restoration times. Customers also receive confirmations when our records reflect that the outages have been resolved – and they receive these via their preferred communication channel – text, email, or phone. We have made advances on our grid and with the service we offer our customers – and these and other products and services have provided our customers with significant value over many years.

However, technologies are advancing, as are customer expectations. Customers want access to actionable information, more choice and greater control of their energy use – and they expect a smarter, simpler and more seamless experience. Enhancing the customer experience is critically important, and is one of our three strategic priorities, along with leading the clean energy transition and keeping bills low. We plan to integrate modern customer experience strategies with advanced grid platforms and technologies to enable intelligent grid operations, smarter networks and meters, and optimized products and services for our customers.

While we have made incremental modernization efforts on the distribution system over many years, the time is now to begin a more significant advancement of the grid. This modernization begins with foundational advanced grid initiatives that both provide immediate benefits and new customer offerings while also enabling future systems and customer value. The foundational investments in our AGIS initiative include:

- *Advanced Distribution Management System (ADMS).* A real-time operating system that enables enhanced visibility into the distribution power grid and controls advanced field devices.
- *Field Area Network (FAN).* A private, secure two-way communication network that provides wireless communications across Xcel Energy's service area – to, from, and among, field devices and our information systems.
- *Advanced Metering Infrastructure (AMI).* AMI is an integrated system of advanced meters, communication networks, and data processing and management systems that enables secure two-way communication between Xcel Energy Energy's business and operational data systems and customer meters.

- *Fault Location, Isolation, and Service Restoration (FLISR).* A form of distribution automation that involves the deployment of automated switching devices that work to detect issues on our system, isolate them, and restore power thereby decreasing the duration of and number of customers affected an outage.
- *Integrated Volt Var Optimization (IVVO).* An application that uses selected field devices to decrease system losses and optimize voltage as power travels from substations to customers.

We are taking a measured and thoughtful approach to advancing the grid to ensure our customers receive the greatest value, the fundamentals of our distribution business remain sound, and we maintain the flexibility needed as technology and our customers' expectations continue to evolve.

A. Customer Strategy

This multi-year initiative aims to transform the customer experience by implementing capabilities, technologies, and program management strategies to enable the best-in-class customer experience that our customers now expect. Our customer strategy is focused on shifting the customer experience dynamic to one where little action is required from customers around their basic service and where we offer personalized "packages" that customers can select from to meet their needs – similar to what customers experience when purchasing cable and internet services today. These packages may include options such as demand-side management, renewable energy, rate design, and non-energy services.

Figure 49: Customer Strategy Informed by Customer Expectations

Our implementation of the Advanced Distribution Management System in early 2020 is preparing the grid for increasing levels of DER. It is also paving the way for further grid advancement with Advanced Metering Infrastructure and our ability to leverage the underlying and necessary Field Area Network to reduce customers' energy costs through Integrated Volt-Var Optimization, improve customers' reliability experience through Fault Location Isolation and Service Restoration, and more.

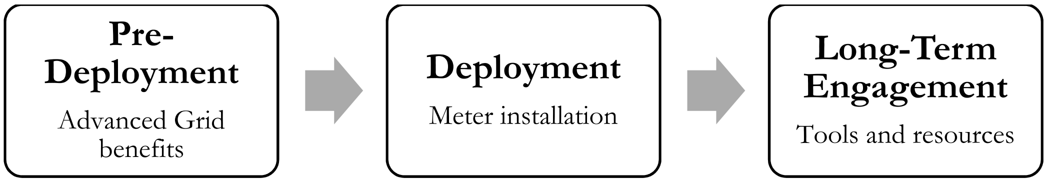
Customers will have access to granular energy usage data from our AMI through a customer portal, which we expect to pair with informed insights and helpful tips on how to change their behavior to save energy. Further, the AMI meters we propose include a Distributed Intelligence platform, which provides a computer in each customer's meter that will be able to "connect" usage information from the customer's appliances for further insights – and be updated with new software applications, much like customers can currently update their mobile devices with applications.

Figure 50: Customer Value through Lifecycle

	Awareness	Start/Stop/ Transfer	Billing & Payments	Ongoing Use	Support & Service	Lifestage & Lifestyle
What do customers expect?	A **trusted, responsible source** helping customers learn more about environmental initiatives, energy programs and regulations	An **intuitive, frictionless** experience that doesn't contribute to the stress of moving	**Flexibility** and **options** (i.e., variety of payment methods), **transparency** around monthly costs	**Monthly usage insights** allowing customers to manage costs; a **robust offering of energy efficiency programs** aligned to customers' interests	**Increased visibility** during electric outages and delivery of other services; a service organization that **advocates for the customer**	A **go-to resource** for information and solutions regarding **renewable energy** and **smart homes** Energy management technology
Examples — AGIS Enabled Experience	**Integrated communication plan** across channels and timeline.	**Remote Connect / Disconnect** **Real-time meter reads**	**Bill forecasting** **Bill prepayment**	High bill alerts Energy usage goals TOU alerts Disaggregation	**Outage ERT accuracy** **Arch detection**	Distributed Energy Resources Home automation/remote monitoring
Customer Value	A feeling of comfort with the changes and timely and relevant communications.	Avoid gaps in service Easier moving experience	Increased bill predictability. Payment flexibility. Better understanding of their monthly bill.	Timely alerts and messages to guide their energy use and add predictability to their bill.	More timely and accurate ERT messages. Predictable home health and safety.	EV, Battery, Solar installation readiness and reduced friction Control over usage in the home.
Business Value	Customer satisfaction Reduced call volume	Reduced truck rolls Accurate meter reads Reduced call volume	Customer satisfaction Reduced B&P call volume	Customer satisfaction Energy savings More predictable load	Customer satisfaction Reliability Reduced call volume	Customer satisfaction Reliability

During this transition to the advanced grid, we will take exceptional care of our customers to educate, inform, and ensure a smooth implementation. We are already developing processes that will ensure accurate, timely bills as customers change over to AMI. We are also developing dedicated, hands-on customer care processes that will provide our customers a single point of contact during implementation – and that will phase customer communications relative to our geographic deployment of AMI meter installation. Meter deployment and advanced meter capabilities will be phased in over the next several years, communications strategies, messages and tactics will be executed in three phases to match the customer journey.

Figure 51: Customer Communications Journey Phases



For example, our customer communications will begin pre-implementation to educate on the possibilities enabled by AMI, as well as customers' ability to opt-out of an AMI meter. As the AMI installation date gets closer, we will inform customers about what to expect with the AMI meter changeover at their homes or businesses. Finally, we will communicate post-AMI installation to reinforce early AMI messaging regarding possibilities and options – also providing practical steps to take advantage of the customer portal or other new or enhanced services available day one.

B. Customer Research

To develop the customer strategy, Xcel Energy committed to understanding customers' preferences, considerations, and thoughts regarding the benefits and value of an advanced grid investment. We gathered this information through primary research, such as focus groups and surveys. We also supplemented our research with information from secondary sources including the Smart Energy Consumer Collaborative, and GTM Research and other utilities' advanced grid plans.

Our key takeaways from these sources are as follows:

- *Consumers care more about technology and enabling improvements than process*. Safety and energy savings rated most highly.
- *Addressing service interruptions are important to all customer classes*. Improved reliability will allow the Company to focus more on other customer priorities.
- *Customers expect that service interruptions will be less frequent in scope and duration*.
- *Customers expect to receive detailed information from their utility*. They expect this information to be personal and frequent.
- *Customers expect more tools and information for them to make decisions about their energy usage*. Customers indicated more information allowed them to better identify opportunities and strategies to save energy and reduce their costs.
- *Business customers have more awareness and familiarity with advanced rate designs*. Residential customers expect the utility to provide them with rate comparison

tools and information about new rate designs.

- *Building trust is a key component to unlocking value.* Trust is best built by identifying solutions and showing results specific to the customers
- *Customers expect that there will be a cost associated with the advanced meter but that the meter will also provide benefits over time.*

We have incorporated customer feedback and insights into our customer transition and communication plans – and the work we are doing to develop new and enhanced products and services as enabled by the advanced grid.

C. Advanced Grid Initiative

Fundamentally, we must act to replace our current Automated Meter Reading (AMR) service to ensure we provide our customers with timely accurate bills; our current vendor is sun-setting its AMR technology in the mid-2020s. While this system has provided value to customers for many years through efficient meter reading, we have an opportunity now to seize AMI technologies that are becoming available to maximize value for our customers. As we deploy advanced grid infrastructure, platforms, and technologies we expect three outcomes: (1) a transformed customer experience, (2) improved core operations, and (3) facilitation of future capabilities, which we discuss below.

Transformed customer experience. Our planned advanced grid investments combine to provide greater visibility and insight into customer consumption and behavior. We will use this information to transform the customer experience through new programs and service offerings, engaging digital experiences, enhanced billing and rate options, and timely outage communications.

We will offer options that give customers greater convenience and control to save money, provide access to rates and billing options that suit their budgets and lifestyles, and provide more personalized and actionable communications. As our system more efficiently manages energy flows, we can save customers money by reducing line losses and conserving energy. Smarter meters will be the platform that enables smarter products and services and contributes to improved reliability for our customers. Our customers will have more information to make more effective decisions on their energy use.

We will know more about our customers and our grid – and we will use that information to make more effective recommendations and decisions and continually use new information to develop new solutions. This will serve to help keep our bills low, as customers save money through both their actions and ours. It will also help ensure that our transition to a carbon-free system occurs efficiently – and harnesses the vast potential of all energy resources, from utility-scale to local distributed generation.

Improved core operations and capabilities. Smarter networks will form the backbone of our operations, and our investments will more efficiently and effectively deliver the safe and reliable electricity that our customers expect. We will have the capability to communicate two ways with our meters and other grid devices, sending and receiving information over a secure and reliable network in near-real time.

Our current service is reliable; however, we need to continue to invest in new technologies to maintain performance in the top third of U.S. utilities, particularly as we deliver power from more diverse and distributed resources and as industry standards continue to improve. Our advanced grid investments provide the platform and capabilities to manage the complexities of a more dynamic electric grid through additional monitoring, control, analytics and automation.

Our systems will more efficiently and effectively restore power when outages do occur using automation without the need for human intervention. For those outages that cannot be restored through automation, our systems will be better at identifying where the outage is and what caused it – benefitting customers through less frequent, shorter, and less impactful outages; more effective communication from the Company when they are impacted by an outage; and reduced costs from our more efficient use and management of assets.

Facilitation of future capabilities. The backbone of our investments will also support new developments in smart products and services; in the short term by supporting the display of more frequent energy usage data through the customer portal – and over the long term, allowing for the implementation of more advanced price signals. Designing for interoperability enables a cost-effective approach to technology investments and means we can extend our communications to more grid technologies, customer devices, and third-party systems in a stepwise fashion, which unlocks new offerings and benefits that build on one another. We have planned our advanced grid investments in a building block approach, starting with the foundational systems, in alignment with industry standards and frameworks. By doing so, we sequence the investments to yield the greatest near- and long-term customer value, while preserving the flexibility to adapt to the evolving customer and technology landscape. By adhering to industry standards and designing for interoperability, we are well positioned to adapt to these changes as the needs of our customers and grid evolve.

In planning our advanced grid initiative, we have considered the long-term potential of our ability to meet our obligations to serve and our customers' expectations and needs – ensuring we extract cost-effective value from our investments and remain nimble enough to react to a dynamically changing landscape. The principles we applied to our advanced grid planning include the ability to remotely update hardware and software, security and reliability, and flexible, standards-based service components. We are planning our grid advancement with the future in mind, and to provide both immediate and increasing value for our customers over the long-term.

We are on the forefront of many of the issues and changes underway in the industry and have developed our advanced grid initiative and our customer strategy to address them and harness value for our customers. In addition to transforming the customer experience, these foundational investments will allow us to advance our technical abilities to deliver reliable, safe, and resilient energy that customers value. These foundational investments also lay the groundwork for later years. The secure, resilient communication networks and controllable field devices deployed today through these investments will become more valuable in the future as additional sensors and customer technologies are integrated and coordinated.

Now is the time to modernize the interface where we connect directly with our customers – the distribution system. Technologies have evolved and matured; our peers have successfully implemented these technologies; and, the industry landscape is evolving. We must ensure our system has the necessary capabilities to meet our customers' expectations and needs – and, the flexibility to adapt to an uncertain future.

D. Conclusion

Xcel Energy's advanced grid initiative supports our vision of a customer experience where customers' needs and preferences are met and the customer effort level is low. We understand what our customers expect and will deliver on those expectations with a seamless experience that both improves their comfort and satisfaction while reducing costs and improving the efficiency of the entire system.

XI. DISTRIBUTED ENERGY RESOURCES

In this section, we provide the DER-related information specified in the IDP Order. As a point of reference, the IDP Order defines DER as follows:

> *Supply and demand side resources that can be used throughout an electric distribution*

system to meet energy and reliability needs of customers; can be installed on either the customer or utility side of the electric meter. This definition for this filing may include, but is not limited to: distributed generation, energy storage, electric vehicles, demand side management, and energy efficiency.

Specifically, IDP Requirement Nos. 3.A.6, 3.A.17-25, and 3.A.31-33, which includes explanations regarding how DER is treated in load forecasts, present and forecasted DER levels, and DER scenario analysis.

A. DER Consideration in Load Forecasting

IDP Requirement 3.A.6 requires the following:

Discussion of how DER is considered in load forecasting and any expected changes in load forecasting methodology.

We discuss how DER is factored into both the corporate load forecast and the distribution system planning forecasts below.

1. DER Treatment in the Corporate Load Forecast

The Company's corporate sales forecast relies on econometric models and other statistical techniques that relate our historical electric sales to demographic, economic and weather variables. We also make adjustments for known and measureable changes by large customers, and to incorporate the effects of our customers' energy efficiency, distributed generation solar PV adoption, and light-duty electric vehicles in the Residential sector. The resulting sales forecasts for each major customer class in each state across the Xcel Energy footprint are summed to derive a total system sales forecast.

The sales forecast is converted into energy requirements at the generator by adding energy losses (See Section 4 for a discussion regarding loss factor percentages). The system peak demand forecast is developed using a regression model that relates historical monthly base (uninterrupted) peak demand to energy requirements and weather. The median energy requirements forecast and normal peak-producing weather are used in the model to create the median base peak demand forecast. Distribution Planning compares their summed/bottom-up feeder level forecast to the overall peak demand forecast for reasonableness, as discussed in Section V above.

a. Forecast Adjustments

After determining the base forecast, we develop net forecasts that include adjustments for future demand-side management programs, distributed solar behind-the-meter generation, and electric vehicles. We also account for the effects on the system peak demand forecast of our load management programs by subtracting expected load management amounts to derive a net peak demand forecast.

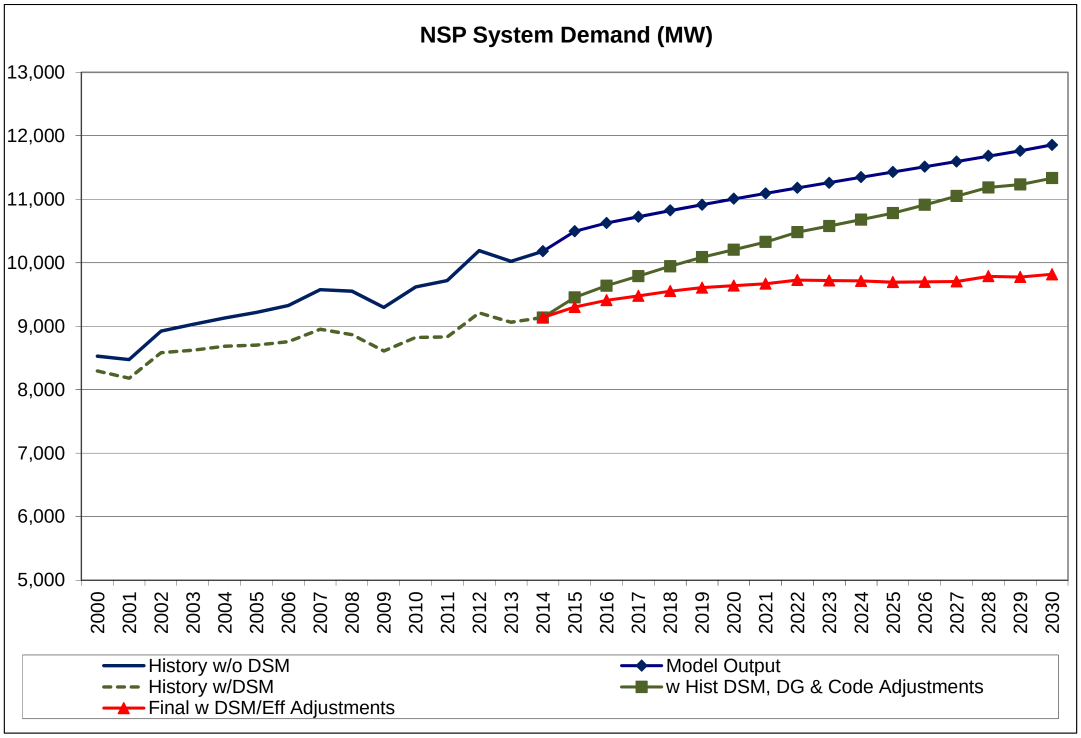
Demand-Side Management Programs. One important adjustment to the forecasts is the impact from our conservation improvement programs. The sales model implicitly accounts for some portion of changes in customer use due to conservation and other influences by basing projections of future consumption on past customer class energy consumption patterns. In addition, the regression model results for the residential and commercial and industrial classes and for system peak demand are reduced to account for the expected impacts of Company-sponsored DSM programs.

The DSM methodology for the states of Minnesota (and South Dakota) follows these distinct steps:

- Collect and calculate historical and current effects of DSM on observed sales and system peak demand.
- Project the forecast using observed data with the impact of DSM removed (i.e. increase historical sales and peak demand to show hypothetical case without DSM).
- Adjust the forecast to show the impact of all planned DSM in future years.
- Also adjust the forecast to account for codes and standards changes for lighting in the Residential and Business segment resulting in decreased sales that are in addition to company-sponsored DSM.

The Company-sponsored Minnesota DSM adjustments are based on the Company's July 1, 2019 Minnesota Resource Plan Bundles 1 and 2. Figure 52 graphically illustrates the DSM adjustment described above.

Figure 52: Illustrative DSM Adjustment



Distributed Solar PV. For distributed solar, we adjust the Minnesota class-level sales forecasts and the system peak demand forecast to account for the forecasted impacts of customer-sited behind-the-meter solar installations on the NSP System. Specifically, this adjustment is based on solar capacity targets consistent with 2017 solar-related legislative outcomes and program activity that includes but is not limited to the removal of the Made in Minnesota program after 2017, increased Solar*Rewards incentives funding for 2018-2020, and no Solar*Rewards program after 2021. Capacity targets also are included for net-metering only installations. Impacts of customer-sited behind-the-meter solar installations are extracted from this forecast to develop adjustments to reduce the class-level sales for Minnesota and the NSP System peak demand forecast. The sales and peak demand forecasts are not adjusted for community solar gardens or distribution-connected utility-scale solar because these do not affect customers' loads.

Electric Vehicles. The Residential sales and system peak demand forecasts are adjusted to account for the impact of light-duty electric vehicles. The EV forecast is developed internally based on assumptions related to both adoption (energy) and charging behavior (demand) as described in Part C of this section. Inputs to the adoption model include electricity prices, vehicle battery prices, gasoline prices, car ownership, car usage, and efficiency. The charging behavior is estimated using representative datasets from Idaho National Lab's EV Project, combined with assumptions about the share of charging done at homes and the penetration of managed charging solutions.

Large Customer Adjustments. We may also make adjustments to the forecast to account for planned changes in production levels for large customers. For example, we may add sales and demand related to a customer's new incremental additional capacity that we become aware of. We may also make adjustments to reduce our requirements due to the scheduled installation of a customer-owned Combined Heat and Power generator.

b. Data Sources

MWh Sales and MW Peak Demand. Xcel Energy uses internal and external data to create its MWh sales and MW peak demand forecast.

Historical MWh Sales and MW Peak Demand. Historical MWh sales are taken from Xcel Energy's internal company records, fed by its billing system. Historical coincident net peak demand data is obtained through company records. The load management estimate is added to the net peak demand to derive the base peak demand used in the modeling process.

Weather Data. Weather data (dry bulb temperature and dew points) were collected from National Oceanic and Atmospheric Administration weather stations for the Minneapolis/St. Paul, Fargo, Sioux Falls, and Eau Claire areas. The heating degree-days and THI degree-days are calculated internally based on this weather data. The Company uses a 20-year rolling average of weather conditions to define normal weather.

Economic and Demographic Data. Economic and demographic data is obtained from the Bureau of Labor Statistics, U.S. Department of Commerce, and the Bureau of Economic Analysis. Typically they are accessed from IHS Markit data banks, and reflect the most recent values of those series at the time of modeling.

In terms of changes to our load forecasting methodology as it relates to DER, we starting incorporating distributed solar PV beginning in 2014, and in 2018 began including EVs.

2. *DER Treatment in the Distribution Planning Load Forecast*

As we discussed in the System Planning section above, we do not currently factor DER into the feeder-level forecasts we use for system planning purposes. However, these forecasts are rooted in historical actual peak information, so are reflective of energy efficiency and load management. Additionally, we validate our rolled-up feeder level forecasts against the corporate load forecast, which as described in Part 1 above, is adjusted for several types of DER. As we have noted, we are taking action to mature our DER planning capabilities through foundational advanced grid capabilities and implementation of the APT.

The good news in terms of DER integration – from a distribution planning perspective – is that Minnesota is presently at comparatively low levels of DER penetration that can reasonably be expected to remain stable in the near-term. At this time, the level of DER on our system and the historical rate of interconnections have not had a significant impact on our forecasts. This changed somewhat in the recent past as a result of the initial response to our CSG program. Long-term, we believe integrating various forecasts will be beneficial to our planning efforts, and the implementation of the APT is expected to facilitate this integration.

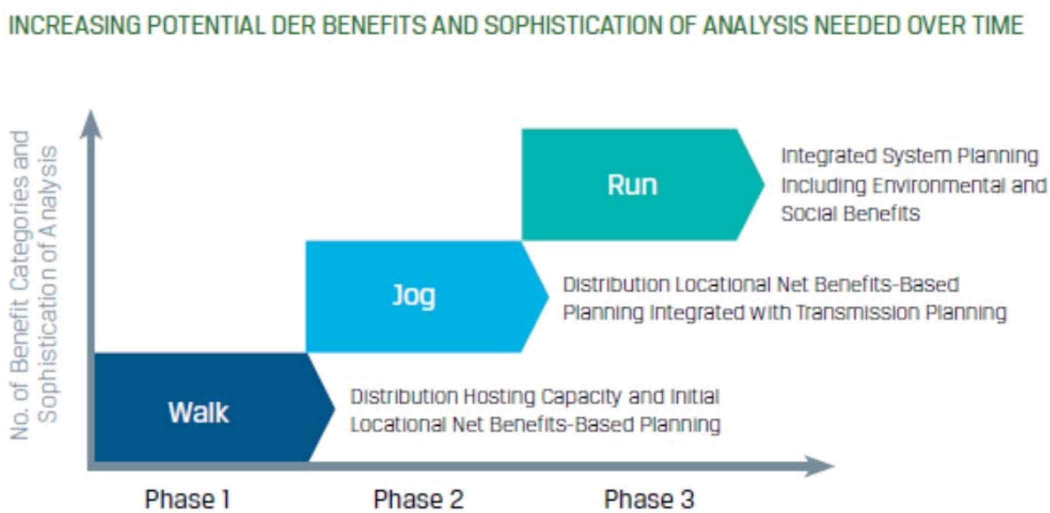
The APT will change and improve the way we incorporate DER into our load forecasts. Through forecast aggregation, the tool can apply forecasts for various DER adoption trends to the distribution load forecasting, allowing distribution planning understand the potential impact that DER adoption could have on the load forecast. These forecasts can also be disaggregated from the load forecast, to show how the native load on the distribution system is expected to change over time in the absence of DER.

The APT also provides the ability to conduct scenario analysis against the load forecast, where multiple forecasts can be developed that represent sensitivities in the forecast. For example, scenarios can be implemented in the forecast to account for different possible DER adoption trends – varying, as defined by the user, to represent higher rates of DER adoption, or lower rates of DER adoption over time.

The ability of the APT to aggregate DER forecasts into the load forecast, then run scenario analysis against those forecasts, will greatly expand distribution planning's understanding of the impact that DER has on the load forecast. Whereas today with our current tools we aren't able to factor DER impacts into our load forecast, the APT w will enable us to analyze DER impacts in a probabilistic nature that will better inform our risk analysis and project development processes.

While there are no definitive answers at this point as to how, and how fast enhanced planning for DER will occur, experts generally agree that a deliberate, staged approach to increased sophistication in planning analyses – commonly referred to as "walk, jog, run,"– is important. See Figure 53 below for one potential scenario for how the progression may occur.

Figure 53: Staged Approach to Enhanced Planning Analyses



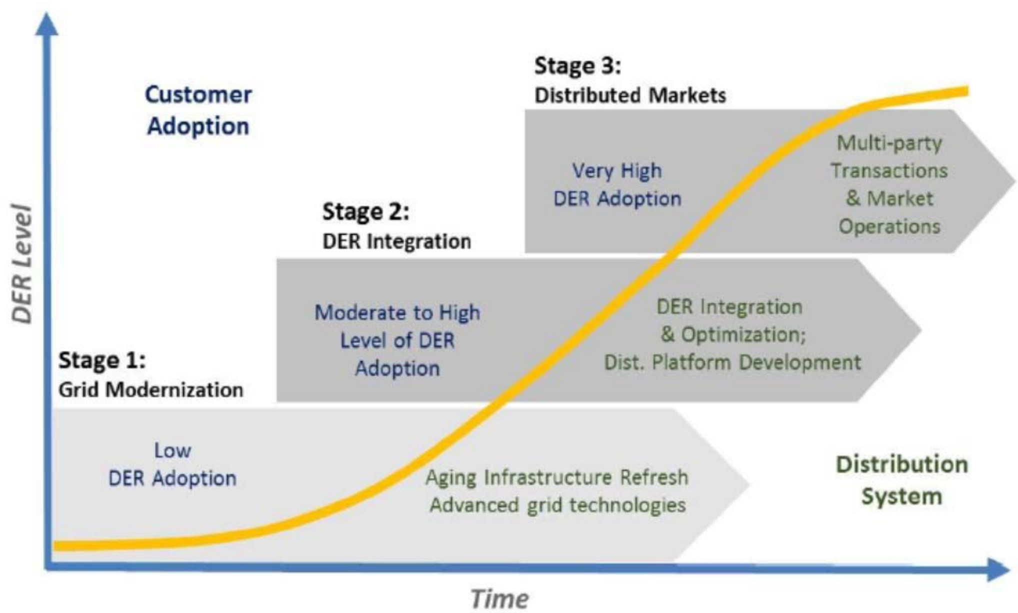
(*Source*: ICF White Paper, *The Value in Distributed Energy: It's all About Location, Location, Location* by Steve Fine, Paul De Martini, Samir Succar, and Matt Robison. *See* https://www.icf.com/resources/white-papers/2015/value-in-distributed-energy.

We agree that a staged and measured approach to enhanced planning is necessary. The ICF report where the above phased approach was portrayed explains that the answer to how best to provide needed capabilities will depend on the stage of distribution system evolution in any particular utility and state, considering both the current stage of DER adoption, level of distribution grid modernization, and the desired policy objectives.

Numerous efforts from states, the DOE, and other organizations have used the customer driven Distribution System Evolution Framework shown below in Figure 54 to describe how the growth in DER adoption and related policies correspond to the distribution modernization capabilities required. Public policy varies on a state-by-state basis, and state policy is a key driver of DER adoption. Policies like net energy metering, renewable portfolio standards, or investment tax credits may make the adoption of DER technologies more financially-attractive and drive higher levels of penetration.[57] As policy evolves and penetration levels of DER increase, it will be important for distribution system capabilities to keep pace.

Various changes in both distribution planning and operations are needed in each stage to ensure reliable distribution operations – all resting on foundational elements that enable increased utility tools and information to be in place. It is important to note that Minnesota's DER penetration is substantially lower than other states, such as California, Hawaii, Arizona, and Colorado. Much of the recent and expected DER growth in Minnesota is from CSG. In considering the staged evolution portrayed in Figure 54 below, we believe Minnesota falls squarely into Stage 1 in terms of DER penetration, which the DOE further describes as grid modernization, focusing on "enhancing reliability, resilience and operational efficiency while addressing aging infrastructure replacement."

Figure 54: Distribution System Evolution (Source: DOE)



Source: *See Modern Distribution Grid, Volume III: Decision Guide*, Page 15, U.S. Department of Energy Office of Electricity Delivery and Energy Reliability (June 2017).

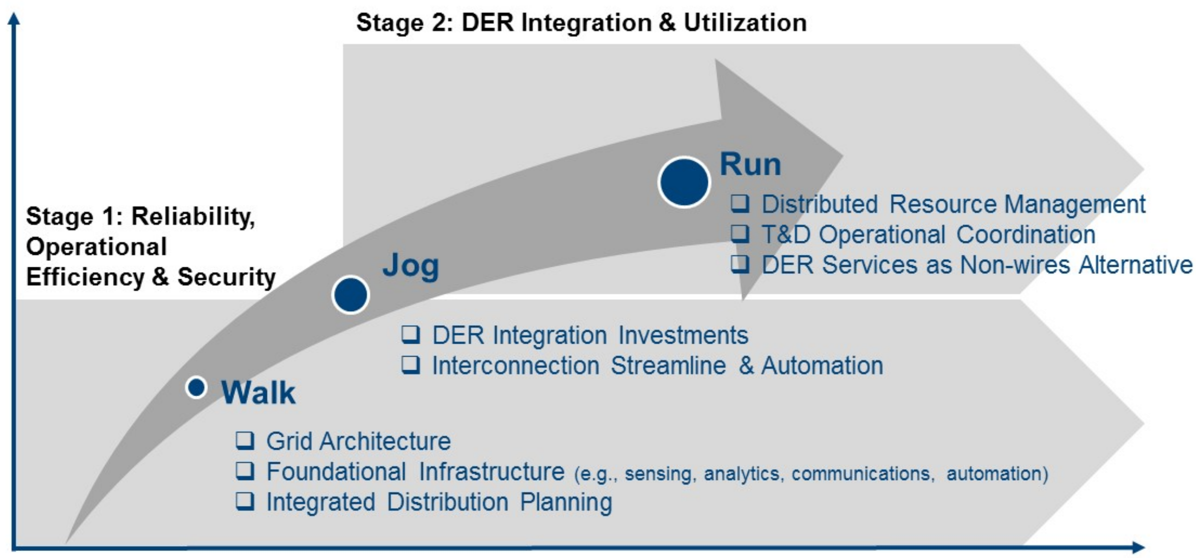
The investments that we are currently making in asset health and grid modernization, such as ADMS help to lay the foundation for continued resiliency and reliability. Near-term planned investments such as AMI, FLISR, and IVVO further cement it,

[57] These policies are described broadly as influential across the country and may apply to Minnesota in varying degrees.

and will allow the Company to gradually respond to increased DER penetration.

The DOE has also observed that U.S. utilities are in Stage 1 in terms of timing and pace toward a modern distribution grid. As shown below, DOE also incorporated evolving distribution planning processes and tools into this evolution. Stage 1 also includes improving foundational capabilities such as availability, quantity, and quality of data, which is often achieved by implementing communication systems such as the FAN that is in our near-term advanced grid plans.

Figure 55: Timing and Pace Considerations



Source: *Considerations for a Modern Distribution Grid*, Pacific Coast Inter-Staff Collaboration Summit by DOE Office of Electricity Delivery & Energy Reliability (May 24, 2017). *See* U.S. DOE DSPx presentation - More Than Smart

Stage 1 is also focused on other foundational infrastructure we are intending to implement, including additional sensing, analytics, and automation capabilities such as the FLISR initiative we are proposing to implement beginning in 2021. According to this concept, Minnesota is with the rest of the industry sitting squarely in Stage 1, with DER integration analysis and planning occurring in Stage 2 after maturing foundational advanced grid capabilities.

Using these concepts as a base, we provide a snapshot of how we contemplate evolving our planning tools and process, applying to our tools, process steps, and actions as sophistication of analysis and processes increase over time as Table 48 below. We note that this Table is an extension of Tables 17-19 in the System Planning section above, which portrays our present planning tools.

Table 48: Potential Planning Tools Evolution

	TOOLS	Forecast	Risk Analysis	Mitigation Plans	Budget Create	Design and Construct / EDP Memo	Long Range Plans	Interconnection Processing**	Scenario Planning	Integrated Resource Planning	Locational Net Benefit Analysis
		Current Process Steps					Future Planning Actions				
Current Tools	Synergi Electric		X	X			X	X			X
Current Tools	~~Distribution Asset Analysis*~~	~~X~~	~~X~~	-	-	-	-	-			
Current Tools	MS Excel		X		X		X				
Current Tools	CYMCAP		X								
Current Tools	GIS			X			X	X	X		X
Current Tools	SCADA	X									X
Current Tools	Workbook (internal)		X	X	X	X					X
Current Tools	DRIVE***		X	X				X			
Expanded Tools	Advanced Planning Tool*	X					X	X	X	X	X
Expanded Tools	ADMS	X							X		
Expanded Tools	SAP					X					

* *New Advanced Planning Tool* replaces DAA and adds more functionality
** Planning has larger role in interconnection process
*** Hosting Capacity becomes integrated into planning process

Walk Jog Run

B. Current Levels of Distributed Resources

In this section, we present current DER volumes for the DER types specified in the IDP DER definition on our Minnesota distribution system, volumes in the interconnection queue, and discuss geographic dispersion.

1. *Current and In-Queue DER Volumes*

In Tables 49 and 50 below, we present the DER volumes on our Minnesota distribution system in compliance with IDP Requirement Nos. 3.A.17, 18, 19, 20, 23, 24, and 25

Table 49: Distribution-Connected Distributed Energy Resources – State of Minnesota
(As of July 2019)

	Completed Projects		Queued Projects	
	MW/DC	# of Projects	MW/DC	# of Projects
Small Scale Solar PV				
Rooftop Solar	67	4,391	61	1,101
RDF Projects	19	25	1	2
Wind	16	61	<1	8
Storage/Batteries[58]	N/A	35	N/A	20

	Completed Projects		Queued Projects	
	MW/AC	# of Projects	MW/AC	# of Projects
Large Scale Solar PV				
Community Solar	585	208	313	286
Grid Scale (Aurora)	100	16	0	0

Table 50: Minnesota Distributed Energy Resources – Demand Side Management and Electric Vehicles

	Completed Projects		Queued Projects	
	Gen. MW	# of Projects	Gen. MW	# of Projects
Energy Efficiency	1,120	N/A	N/A	N/A
Demand Response	824	413,783	N/A	N/A
Electric Vehicles	N/A	7,081-8,500[59]	N/A	N/A

For reference, below are the IDP requirements fulfilled in Tables 49 and 50 above:

IDP Requirement 3.A.17 requires the following:

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[58] All current battery projects within our DER process are associated with other generation projects, such as solar. As such the application does not capture gen. MW as it is accounted for in other categories.
[59] We do not have information that ties our customer accounts to electric vehicle users. *See* IDP Requirement 3.A.21 below for the sources of this range.

Total nameplate kW of DER generation system which completed interconnection to the system in the prior year, broken down by DER technology type (e.g. solar, combined solar/storage, storage, etc.).

The Company provides total DER interconnection as part of our Distribution Interconnection filing on March 1 of each year. For 2018, these details were provided in Docket No. E999/PR-19-10. Additionally, the Company provides several other tracking sources for this information in other annual reports such as the Solar*Rewards Community Annual Report (Docket No. E002/M-13-867), Solar*Rewards Annual Report (Docket No. E002/M-13-1015) and Solar Energy Standard Compliance (Docket No. E002/M-18-205) to name a few.

Each of these reporting dockets have differing requirements, details and timing, therefore leading to inconsistent numbers depending upon filing. In an effort to resolve these conflicts, the Company is working as part of the Commission's Distributed Generation Advisory Group to finalize an updated and consistent reporting process for DER generation systems as part of the present Distribution Interconnection filing on March 1st of each year.

For purposes of this IDP requirement, we provide the information in Tables 49 and 50 above.

IDP Requirement 3.A.18 requires the following:

Total number of DER generation systems which completed interconnection to the system in the prior year, broken down by DER technology type (e.g. solar, combined solar/storage, storage, etc.).

The Company provides total DER interconnection as part of our Distribution Interconnection filing on March 1 of each year. For 2018, these details were provided in Docket No. E999/PR-19-10. Additionally, the Company provides several other tracking sources for this information in other annual reports such as the Solar*Rewards Community Annual Report (Docket No. E002/M-13-867), Solar*Rewards Annual Report (Docket No. E002/M-13-1015) and Solar Energy Standard Compliance (Docket No. E002/18-0205) to name a few.

Each of these reporting dockets have differing requirements, details and timing, therefore leading to inconsistent numbers depending upon filing. In an effort to resolve these conflicts, we are working as part of the Commission's Distributed Generation Advisory Group to finalize an updated and consistent reporting process for DER generation systems as part of the Distribution Interconnection filing on March 1st of each year.

For purposes of this IDP requirement, we provide the information in Tables 49 and 50 above.

IDP Requirement 3.A.19 requires the following:

> *Total number and nameplate kW of existing DER systems interconnected to the distribution grid as of time of filing, broken down by DER technology type (e.g. solar, combined solar/storage, storage, etc.).*

The Company provides information on the number of installed and pending DER generation systems as part of our Distribution Interconnection filing on March 1 of each year. In 2019, with data as of end-of-year 2018, this information was provided in Docket No. E999/PR-19-10. We clarify however, that we are not able to provide the distribution system location for current energy efficiency and DR. This is due in part to the types of DSM programs offered. For example, we do not track individual, residential customer purchases of high efficiency lighting. Also, our systems to administer DSM programs are separate from the systems that support the planning and operations of our distribution system. As we continue to evaluate enhanced distribution planning tools, we will gain a better understanding of the breadth of capabilities available and whether tracking of DSM by points on the distribution system for purposes of reporting is possible.

IDP Requirement 3.A.20 requires the following:

> *Total number and nameplate kW of queued DER systems as of time of filing, broken down by DER technology type (e.g. solar, combined solar/storage, storage, etc.).*

See Tables 49 and 50 above.

IDP Requirement 3.A.23 requires the following:

> *Number of units and MW/MWh ratings of battery storage.*

See Table 49 above. Also, we provide information on the number of installed and pending DER generation systems as part of our Distribution Interconnection filing on March 1 of each year. In 2019, with data as of end-of-year 2018, this information was provided in Docket No. E999/PR-19-10.

IDP Requirement 3.A.24 requires the following:

MWh saving and peak demand reductions from EE program spending in previous year.

See Table 50 above.

IDP Requirement 3.A.25 requires the following:

Amount of controllable demand (in both MW and as a percentage of system peak).

See Table 50 above for the MW. In terms of percent of system peak, our 824 MW of DR in the state of Minnesota is approximately 12 percent of our Minnesota system peak of 6,800 MW.

2. Electric Vehicles and Charging Stations in Service Area

IDP Requirement 3.A.21 requires the following:

Total number of electric vehicles in service territory.

Customers are not required to inform the Company when they purchase an EV, and we do not maintain this information. Therefore, we must estimate EV ownership in our service area. We provide two such estimates below, and reflect the range of these two estimates in Table 50 above:

IHS Markit (2019). This zip code-level analysis suggests there is up to 8,500 electric vehicles in our Minnesota service area. However, utility service areas do not follow zip code boundaries, so there will always be some margin of error using zip code level information.

According to an analysis completed by Minnesota Commission Staff as part of the Commission's Inquiry into Electric Vehicle Charging and Infrastructure (Docket No. E999/CI-17-879), there are 7,081 vehicles in our Minnesota service territory.[60] Based on zip-code level data we procure,[61] approximately 49 percent of vehicles are plug-in hybrids (PHEV) and 51 percent are battery EVs. This is comparable to the Minnesota Department of Transportation information on the Commission's website, with 52 percent of EVs in Minnesota attributed to battery EVs and 48 percent PHEV.[62] Most EV adoption is concentrated in the Twin Cities metro area, but there is EV adoption in most of the zip codes we serve. Over the past year, we have seen

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60 Minnesota Public Utilities. Electric Vehicles. *See* https://mn.gov/puc/energy/electric-vehicles/(as of Oct. 24, 2019)

61 We procure this zip code-level data from IHS Markit.

62 *See* http://www.dot.state.mn.us/sustainability/electric-vehicle-dashboard.html (as of Oct. 25, 2019)

the introduction of some of the first larger EVs (medium- and heavy-duty) in our service territory with Metro Transit adding eight electric buses to their fleet.

IDP Requirement 3.A.22 requires the following:

> *Total number and capacity of public electric vehicle charging stations.*

According to the Department of Energy's Alternative Fuels Data Center, there are approximately 350 public EV chargers in Minnesota, with 869 charging ports.[63] We estimate that about 200 of those charging stations are in our service territory, with 500 charging ports. The estimated total capacity of all the public chargers in our service territory could be up to 9.5 MW, if all of the charging ports were in use at once. Given the relatively low load utilization of most public charging today, it is very unlikely that all, or even most, of the EV chargers will be used at one time. Additionally, the public charger installations are geographically diverse from a distribution system perspective. System impact would vary greatly based on the charging stations in use, the capacity of the charging stations, and the design of the local distribution system.

3. Current DER Deployment – Type, Size, and Geography

IDP Requirement 3.A.31 requires the following:

> *Current DER deployment by type, size, and geographic dispersion (as useful for planning purposes; such as, by planning areas, service/work center areas, cities, etc.).*

The DER deployment in our Minnesota system by type and size is set out above in part 1. We provide associated geographic dispersion information and the number of installed and pending DER generation systems as part of our Distribution Interconnection filing on March 1 of each year. In 2019, with data as of end-of-year 2018, this information was provided in Docket No. E002/PR-19-10.

IDP Requirement 3.A.32 requires the following:

> *Information on areas of existing or forecasted high DER penetration. Include definition and rational for what the Company considers "high" DER penetration.*

We are not able to forecast DER in terms of its expected geography. As we discuss

[63] *See* public online portal at https://www.afdc.energy.gov/stations/#/find/nearest (Accessed Oct. 27, 2019). We note that in our 2018 IDP, we inadvertently attributed this number to our service territory rather than for the state.

elsewhere in this IDP, tools to perform or services available to purchase forecasts such as this are very limited at this time. Additionally, due to the Company's cost-causation regulatory construct that requires interconnecting parties to mitigate potential system issues prior to interconnecting, DER is not expected to impact system operation.

In terms of defining "high" DER penetration, we note that this is somewhat of a general term that will likely vary across utilities and the industry. We believe one way to define high DER penetration is when the connected DER output exceeds feeder load, resulting in reverse power flow. When backward flow occurs, mitigations become necessary.[64] Under this definition, the amount of DER considered to be "high penetration" would vary from feeder to feeder by, among other things, the type of DER, and how it operates, the feeder design, and the feeder voltage and other attributes.

C. DER Forecasting in the Industry

In this section, we discuss the state of the industry with respect to forecasting DER. We also address Order Point No. 7 of the Commission's July 16, 2019 Order in Docket No. E002/CI-18-251, which requires the Company to:

> *Make the development of enhanced … DER forecasting capabilities…a priority in 2019 and include a detailed description of its progress in the Company's 2019 IDP.*

In the industry, there are limited tools and experience predicting customer behavior and other key drivers of DER adoption at a system level. DER penetration analysis and forecasting at a granular *feeder* level for purposes of informing distribution planning is much more complex and likely less accurate than doing so at a system level. As we have discussed, system planning involves forecasting each feeder and each substation transformer, which for our system in Minnesota equates to approximately 1,700 individual forecasts. DER must be forecasted by type, because each type has different characteristics and impacts on the system. This exponentially complicates an already complex feeder-level planning process.

Regulators, utilities, stakeholders, service providers, and others are working to determine methodologies, processes, and tools that will meet the forecasting needs that are emerging in states such as California, New York, and Hawaii. The good news – from a distribution planning perspective – is that Minnesota is presently at

[64] Mitigations may be required for other conditions below this level, such as potential voltage issues or line capacity.

comparatively low levels of DER penetration that can reasonably be expected to remain stable in the near-term. Further, our present tariffs require interconnecting parties to mitigate adverse impacts identified in the interconnection application process. This means that we have time to take the measured approach that is necessary to properly address this issue – and develop or acquire the necessary capabilities, methodologies, and tools that will facilitate this type of complex analysis.

There are several existing models to predict DER adoption, using policy outcomes, macro-economic factors, or rooftop potential to predict DER adoption. However, a recent EPRI technical report notes several shortcomings of these models, including the challenges in making granular adoption forecasts for individual circuits, challenges verifying consumer behavior, and scarce information about the physical premises that impacts actual potential.[65]

In short, it is challenging to predict which customers will adopt which technologies, and what the impact on the circuit associated with those customers will be. This is exacerbated in Minnesota with comparatively low adoption levels for PV, EV and energy storage. Predicting accurate forecasts for new and emerging technologies at a system level is challenging, based in part on the lack of good historical, predictable data inherent with a fledging market. At a circuit or feeder level this issue becomes more exacerbated and more unpredictable, as there are accuracy issues with forecasting at smaller geographic levels. In addition, there is not a significant sample size of historical installations on a circuit to use for trend analysis and forecasting.

We note that we are engaging a third-party consultant to benchmark our EV forecast assumptions, including adoption of medium- and heavy-duty electric vehicles in our service territory – and the charging infrastructure necessary to support EV adoption. We intend to share more EV forecasting information in our next Transportation Electrification Plan filing in No. E999/ CI-17-879.

We have made it a priority to enhance our forecasting capabilities. We now include DER in our bulk system forecasts, and as otherwise discussed in this IDP, we have evaluated and propose to implement a new advanced planning tool to identify more granular inputs and impacts of DER on feeder-level load forecasts. We also expect to evolve our forecasting capabilities over time to include new approaches such as scenario analysis and probabilistic planning.

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[65] *See* Applying Discrete Choice Experiment Modeling to Photovoltaic Adoption Forecasting, Electric Power Research Institute, Palo Alto, CA, p. 13 (November 22, 2017).
See https://www.epri.com/#/pages/product/3002011011/?lang=en

We intend to use our proposed advanced planning tool to understand the locational and temporal impacts of DER. Although more sophisticated planning tools can provide more forecasting granularity, the challenge of achieving a more geographically accurate forecast in an emerging market remains. Market adoption in an early adoption stage is less predictable, there is less historical information, and the dynamic and competitive nature of the market impacts local adoption trends. By taking a measured approach, we are able to learn from early adopters in the industry and in turn reduce long run implementation and integration costs. That said, we used our present tools and methodologies to inform the forecasts we provide in this IDP.

D. DER Forecasts and Methodologies

In this section, we present our forecasts for each DER type and summarize our forecast methodologies, which respond to IDP Requirement 3.C.1 as follows:

> *In order to understand the potential impacts of faster-than-anticipated DER adoption, define and develop conceptual base-case, medium, and high scenarios regarding increased DER deployment on Xcel's system. Scenarios should reflect a reasonable mix of individual DER adoption and aggregated or bundled DER service types, dispersed geographically across the Xcel distribution system in the locations Xcel would reasonably anticipate seeing DER growth take place first.*

This section also responds to IDP Requirement 3.C.2, which requires the following:

> *Include information on methodologies used to develop the low, medium, and high scenarios, including the DER adoption rates (if different from the minimum 10% and 25% levels), geographic deployment assumptions, expected DER load profiles (for both individual and bundled installations), and any other relevant assumptions factored into the scenario discussion. Indicate whether or not these methodologies and inputs are consistent with Integrated Resource Plan inputs.*

Given the context we have portrayed, we have fulfilled these DER forecasting requirements to the best of our ability. In some cases, additional information such as studies to inform additional scenarios are outstanding at this time. We discuss each type of DER in turn below, providing our forecast, as well as the information that informed the forecast.

1. DER Forecast – Distributed Solar PV

We offer several programs to customers interested in solar as a renewable opportunity. Specifically we provide incentives under our Solar*Rewards program, and the opportunity to earn bill credits for community solar gardens in our Solar*Rewards Community program. Until its discontinuance, customers also had the opportunity to participate in the Minnesota's Made in Minnesota program. In addition, for larger systems we offer a net-metering option. We have factored all of these distributed solar PV options into our Reference Case, Medium, and High distributed solar forecast.

a. Reference Case Assumptions

In determining our Reference Case, we updated our goals to be consistent with 2017 legislative outcomes that: (1) increased 2018-2020 Solar*Rewards incentive funding, (2) eliminated new Made in Minnesota awards after 2017, with final installations completed by October 2018, and 3) eliminated new Solar*Rewards systems after 2021, with final installations completed by 2023. We assumed net-metering only system additions would continue at current annual levels through 2021 and increase in 2022 to accommodate for demand from the elimination of the Solar*Rewards program in this scenario. We based attrition and completion lag rates on historical analysis of cancelled and completed projects, and applied these to program application forecasts to derive final installation estimates.

Due to the large response to our Solar*Rewards Community program, which has no statutory budget or capacity limit, we are forecasting additions of 729 MW through 2020 in this filing. For our Reference Case assumptions through the IDP planning period, we assume Solar*Rewards Community adjusts to approximately 5 MW per year after 2024 to account for significant early adoption of CSGs and reduction in tax benefits.

Table 51 below provides our Reference Case forecast of distributed solar PV additions.

Table 51: Reference Case – Per-Year Distributed Solar Additions (MW/AC)

Year	Solar* Rewards	Made in MN	Made in MN Bonus	Net-metering	S*R Community
<=2019	22	13	5	24	698
2020	6	0	0	13	31
2021	4	0	0	12	77
2022	2	0	0	13	34
2023	1	0	0	14	11
2024	0	0	0	15	6
2025	0	0	0	15	5
2026	0	0	0	15	5
2027	0	0	0	15	5
2028	0	0	0	15	5
2029	0	0	0	15	5
Total	**35**	**13**	**5**	**165**	**884**

b. Medium and High Forecasts

The Medium and High scenarios hold the Reference Case for Solar*Rewards and Made in Minnesota constant for the reasons discussed above. For net metering and CSG, we assume that customers that participate in solar programs would consider, in the majority of cases, that these programs are substitutes for each. Therefore the incremental growth in one category is interchangeable with another category.

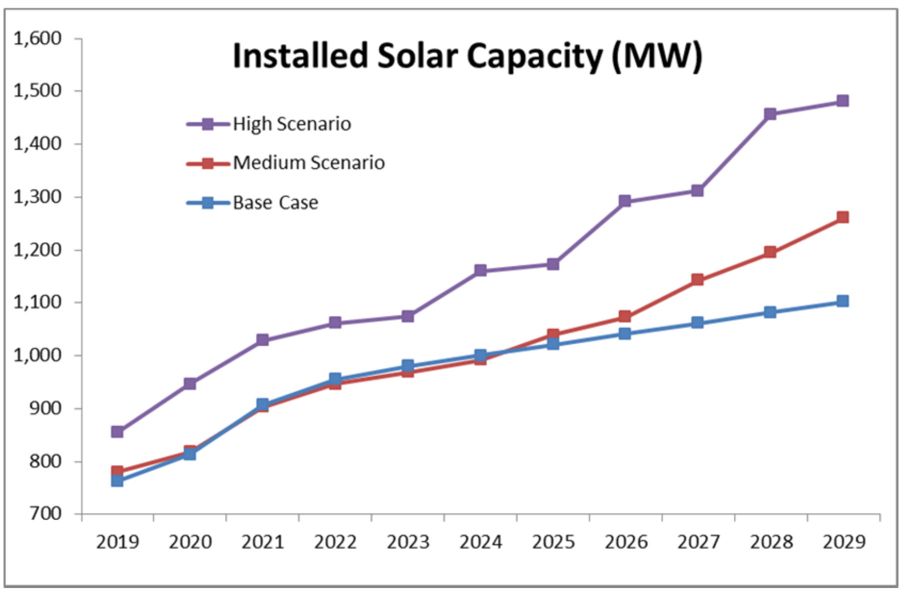
We used the average of a Bass diffusion and a Payback model estimate to derive the Medium scenario, which is around 1,261 MW for total installed distributed solar by 2029. For the High scenario, we used a Payback adoption model with lower installation costs. We applied a 10 percent reduction to the solar installation cost curve starting in 2020. Solar installation costs in the High scenario are set to be higher for the first year due to new import tariffs and contracts already in place. Hence, there is a low probability that the solar installation prices will drop significantly below the Medium scenario for 2019. The adoption of solar is flat in the early 2020s, because the decline in solar installation cost is offset by the decline in Investment Tax Credit (ITC). The Payback model results indicate around 1,481 MW for total installed distributed solar by 2029.

We provide a tabular and graphical view of the forecast in the following table and figure.

Table 52: Distributed Solar PV Forecast

	Total Base (MW)	Total Medium (MW)	Total High (MW)
2019	763	780	856
2020	813	818	946
2021	906	903	1,028
2022	955	946	1,061
2023	980	969	1,074
2024	1,001	992	1,160
2025	1,021	1,039	1,173
2026	1,041	1,073	1,291
2027	1,062	1,143	1,311
2028	1,082	1,195	1,456
2029	1,102	1,261	1,481

Figure 56: Distributed Solar PV Forecast



2. *DER Forecast – Distributed Wind Generation*

We presently have very little distributed wind our system, with a total of 61 projects that comprise 16 MW, and eight projects in the queue comprising less than 1 MW. We believe future DER growth will primarily be through solar PV and distributed storage. We believe distributed wind will continue to be a very small proportion of DER on our distribution system, largely due to the rapid development of solar and storage markets – and their relative ease of adoption compared to wind. Additionally, there is little information available in the industry regarding the adoption of distributed wind. For these reasons, we do not provide a forecast in conjunction with this IDP.

3. *DER Forecast – Distributed Energy Storage*

From January 2017 through July 2019 we received 55 interconnection applications to connect energy storage to our Minnesota electric distribution system. Of these 55 storage system applications, 35 are complete and in operation. The current total behind the meter battery storage installed on our Minnesota distribution system is approximately 0.35 MW. We provide an annual breakdown of storage applications received and completed below:

Table 53: Storage Applications – NSPM State of Minnesota

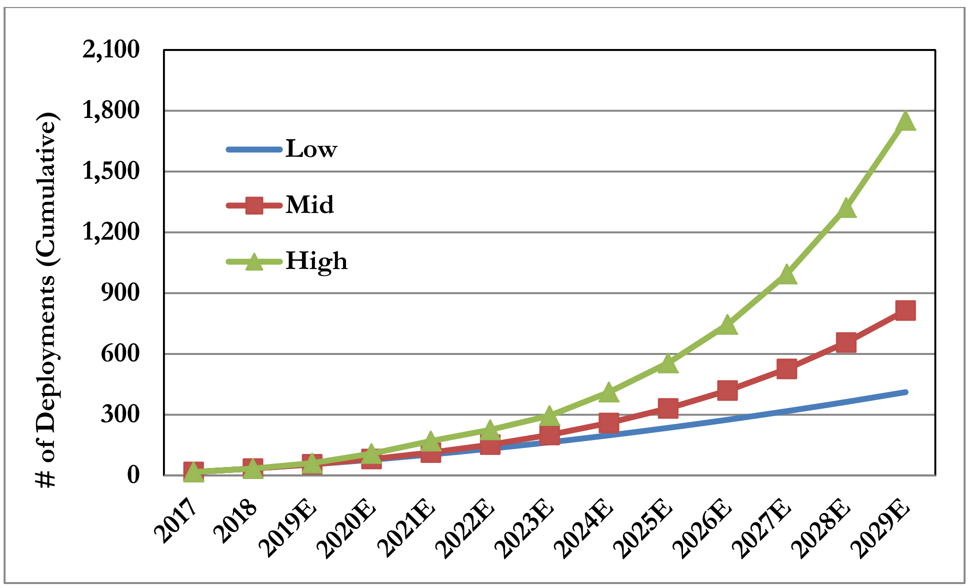
Time Period	# of Applications	# Complete
2017	18	17
2018	25	17
2019 (thru July)	12	1
Total	**55**	**35**

In order to forecast distributed storage for our system, we utilize available data from various industry consulting firms that specialize in tracking current market conditions and forecasting trends. We have found that the availability of detailed market information on distributed energy storage is limited for the state of Minnesota. Wood Mackenzie however, currently publishes a quarterly report (U.S. Energy Storage Monitor), which provides high-level trends and forecasts that can be utilized to extrapolate a possible scenario for distributed energy storage within the Company's Minnesota electric distribution system.

For **Scenario 1** entitled "High," we utilized the actual completed energy storage units for NSP Minnesota in years 2017 and 2018 and then applied the forecasted forward growth rates as provided by Wood Mackenzie's most recent forecast for behind the meter storage additions. For **Scenario 2,** entitled "Mid," we utilized a growth rate forecast from Navigant Research's Global DER Overview that estimates a growth rate of 21.9 percent for distributed energy storage systems. The model extrapolates the current number of installations on the NSP Minnesota system at the Navigant projected rate of growth. We used one additional modeling technique to develop **Scenario 3** entitled "Low," which uses a time series analysis of the historical average rate of internal applications received for energy storage systems, as tracked by NSP Minnesota. This alternate scenario models the average number of applications received per month during 2017 and 2018 and then extrapolates a continued growth rate of monthly applications received through 2029.

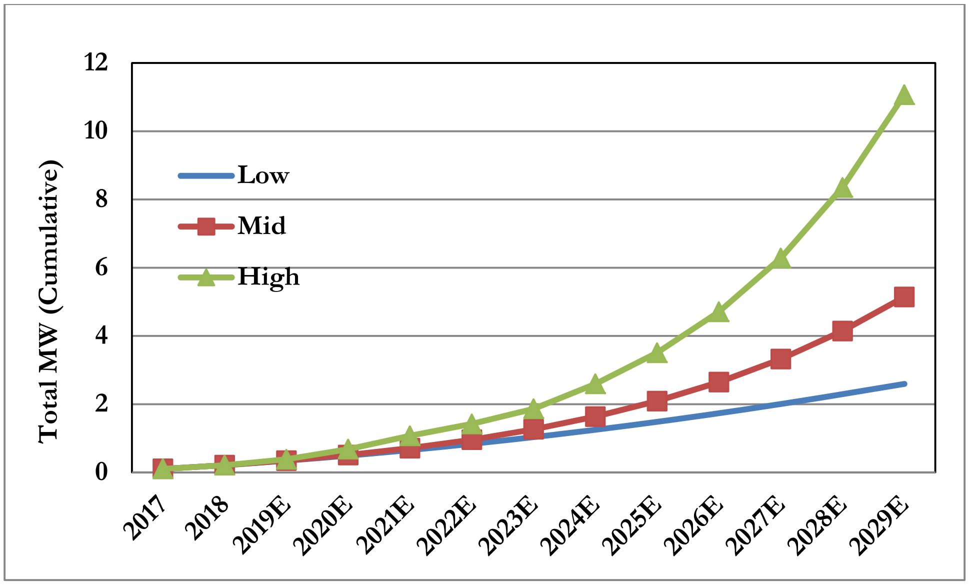
Scenario 1 results in a cumulative total of 170 energy storage units deployed within the NSP Minnesota electric distribution system by the end of 2021, while the "Low" case estimates a cumulative total of 104 units deployed. Beyond 2021, the various scenarios begin to diverge until the end of the forecast period. In 2029, the respective forecasts indicate a cumulative total of 1,752 units (High) and 411 units (Low), as shown below.

Figure 57: NSP Distributed Storage Forecast – Minnesota 2019 – 2029 (number of systems)



Utilizing all scenarios in conjunction with an estimated average MW for each respective unit deployed, the total cumulative MW of distributed energy storage is not expected to exceed 12.0 MW by 2029.

Figure 58: NSP Distributed Storage Forecast – Minnesota 2019 – 2029 (total MW)



Due to the emergent state of distributed energy storage within Minnesota, we note that the various scenarios we have developed are sensitive to externalities such as policy changes (e.g., incentive changes), technology changes (e.g., improvements in existing battery technologies and new disruptive battery technologies), and possible geopolitical risks that could negatively impact the availability of raw materials.

4. *DER Forecast – Energy Efficiency*

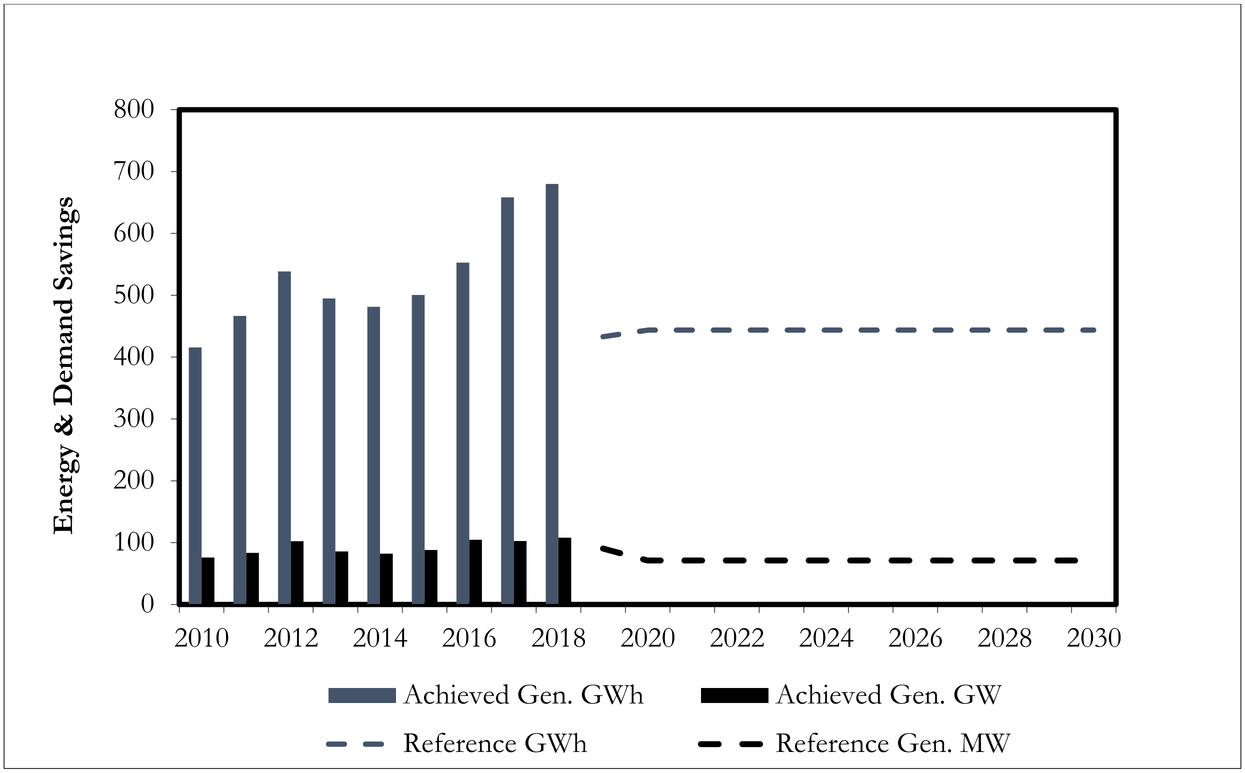
Xcel Energy has one of the longest-running and most successful Demand Side Management programs in the country. Between 1990 and 2018, the Company spent $1.5 billion (nominal) on Minnesota DSM efforts and saved over 9,700 GWh of energy and nearly 3,600 MW of demand. Our efforts to continuously grow and modify our customer offerings prove worthwhile as we continue to meet and exceed the state's 1.5 percent of retail sales energy savings target.

Energy Efficiency creates a permanently reduction at the customer meter and reduces the capacity need on the distribution system.

a. Forecast

Our Reference Case for Energy Efficiency is set at 1.5 percent of retail sales energy savings. The graph below shows historical and forecast energy efficiency annual achievements included in the forecast reference case.

Figure 59: Minnesota Energy Efficiency Forecast – Reference Case



b. Sensitivities

The Company has set forth goals in our 2020-2034 Upper Midwest Integrated Resource Plan (IRP) (Docket No. E002/19-368) to significantly increase our energy efficiency efforts. These efforts will be incremental to the 1.5 percent of retail sales energy savings. In the IRP, we began the development of additional DSM scenarios with the Minnesota Statewide Potential Study analysis conducted on behalf of the Department. The study was used as the primary input for the Company's energy efficiency potential from 2020 through 2034. This study was conducted at a state level and does not go down to individual feeder or customer area.

The Medium Scenario is an optimal view of the achievable potential identified in the Minnesota Statewide Potential Study at a cost effective level of achievement. This is the scenario we have defined as our forecast above which utilizes a 2.8 percent of retail sales energy savings (referred to the Optimal Scenario in the IRP). In addition, the Company did review a Higher Scenario (3.8 percent) or maximum achievable option. Each scenario was reviewed based on total system costs assuming achievement, expressed as both Present-Value of Revenue Requirements (PVRR) and

Present-Value of Societal Costs (PVSC). The Medium Scenario was determined to have the greatest cost savings under both metrics.[66] The graph below shows historical and forecast energy efficiency annual achievements from this Medium Scenario and compared to those included in the forecast reference case.

5. DER Forecast – Demand Response

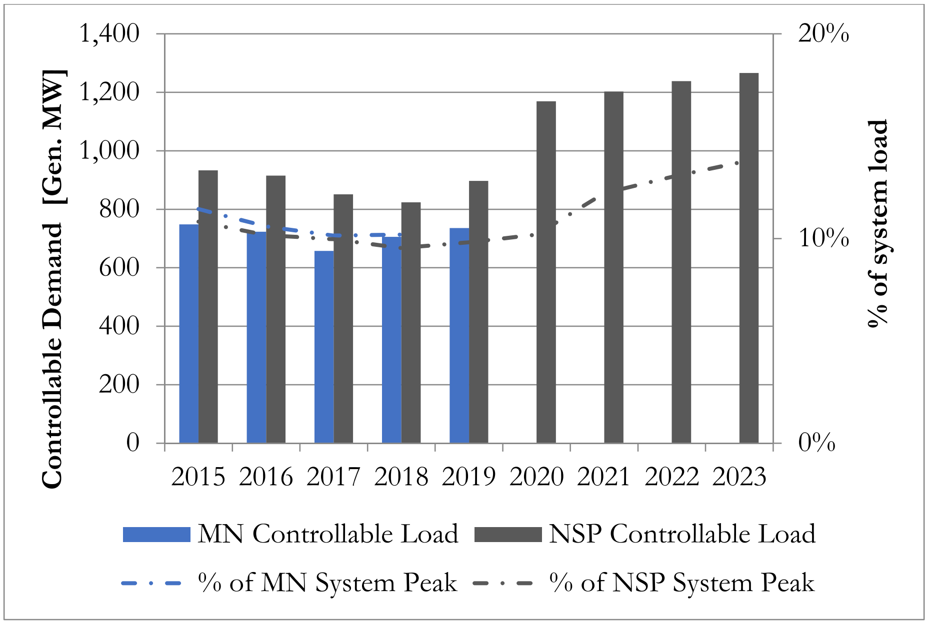
We offer several customer programs to customers for controlling load during system peak. The Residential Demand Response program provides products such as Saver's Switch and AC Rewards; both of which provides equipment and participation incentives to residential customers for controlling their heating, ventilation and air-conditioning load (HVAC). For commercial customers we offer Saver's Switch and our Electric Rate Savings program—both interruptible rates helping customers lower their load during utility initiated events.

a. Demand Response Forecast

We set forth in our 2020-2034 Upper Midwest Resource Plan (Docket No. E002/19-368) an increase of 400 MW of incremental demand response resources by 2023. This aggressive path forward is predicated on existing programs, additional interruptible programs and new technologies and non-traditional demand resources that encourage customer action and participation rather than just utility controlled resources, such as Saver's Switch. Our Reference Case for the IDP matches the IRP analysis providing an increased amount of additional demand response to the system.

[66] For further information please refer to the 2020-2034 Upper Midwest Resource Plan, Appendix G1.

Figure 60: Minnesota Demand Response Forecast – Demand Savings

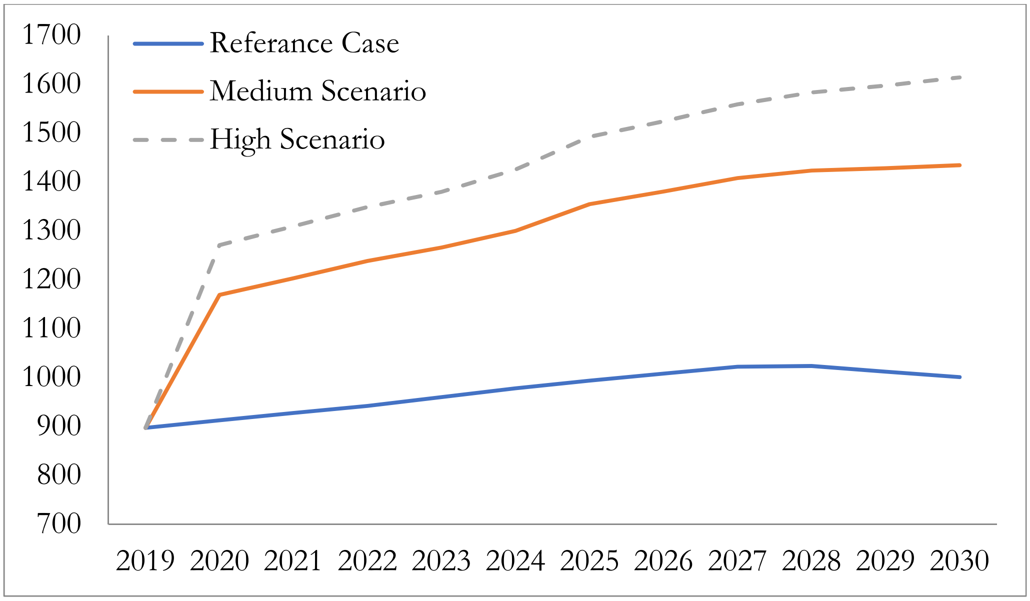


b. Sensitivities

In determining the Reference Case, we review existing programs and forecast future participation including attrition and adjusted commitments. The Medium and High scenarios assume an increase in demand response beyond current programs. These scenarios are based on the cost-effective analysis by The Brattle Group (See the 2019 Potential Study Analysis conducted by The Brattle Group found in Appendix G2 of the Company's July 1, 2019 2020-2034 Upper Midwest IRP) comparing differing levels of demand response based on customer pricing. These scenarios are explained in more detail within our IRP.[67] We provide a graphical view of these scenarios below.

[67] These scenarios are represented in the IRP as Reference Case (Demand Response Forecast), Medium Scenario (Bundle 1) and High Scenario (Bundle 2). The IRP proposes the medium scenario.

Figure 61: Scenario Analysis (Gen MW)



Ultimately, the preferred plan utilized the first bundle (additional incremental load identified as cost-effective).

c. Demand Response Considerations in Distribution

As we begin to refine our forecasting opportunities with updated forecasting tools and software as well as future AMI technology, we will begin to be able to look at the load impact of demand response at more granular level. Today, without knowing the specific load shapes and comparing them to specific capacity constrained areas it is difficult to predict the impact to distribution. As these processes are refined we hope to be able to match the needed load to active demand response programs and/or develop programs that can further meet these needs.

While these software tools are being implemented, the Company continues to test opportunities for demand response at a feeder level within our Geo-targeting pilot. In addition, we are conducting research and interest in our existing demand response offerings to determine future program frequency and customer interest as events lengthen and move from events limited to summer months to events happening in all seasons.

We further continue our exploration of new technologies and opportunities to shift load rather than shed only during system peaks. As noted in the IRP, in order to further address these opportunities, which have a significant impact to distribution, the Company will need to continue to pursue advance metering technology and identify cost recovery mechanism for program opportunities.

6. DER Forecast – Electric Vehicles

With the increase of available models EV market adoption has increased in the U.S. to approximately 1.2 million as of June. 2019. At the same point there are approximately 10,000 EVs in the state of Minnesota, and the number continues to increase.

We currently estimate EV adoption using two modeling techniques: (1) Bass Technology Diffusion, and (2) Econometric models. Bass Diffusion models are used to describe various technology adoptions that penetrate an existing market through an "S" shaped diffusion characteristic. Econometric models use simple payback to estimate potential adoption and represent the second approach in modeling EV adoption.

We have estimated a low, medium, and high simple payback scenario for EV ownership compared to traditional internal combustion engine (ICE) automobiles. An average of the two models is used as an estimate of EVs. Our cumulative medium adoption estimate for year 2029 is approximately 4.4 percent of all registered cars and light trucks in that year.

Our current approach is based on state specific and Xcel Energy service area specific data and represents an improvement from our previous methodology and vintage of data used in both our 2018 IDP and our July 2019 IRP. The Bass Diffusion model is now calibrated using state specific historical EV sales as well as data through December 2018. Additionally, we have incorporated into both the Bass diffusion and econometric models a factor for the percentage of vehicles in urban and rural areas. Presently higher adoption is occurring in urban areas with the rural areas anticipated to ramp up slowly. The IDP reflects consumption of 128 GWh in 2023 compared to 165 GWh in the IRP. Our previous approach was based on national electric vehicle adoption, which was significantly influenced by much higher adoption in the state of California.[68]

We create high and low econometric model scenarios using a combination of battery prices and gasoline prices. The high scenario assumes the battery prices are 20 percent lower than the medium scenario, and gasoline prices are higher by one standard deviation. Similarly the low scenario assumes battery prices are 20 percent

[68] Minnesota electric vehicle adoption is lagging the national trend.

higher than the medium scenario, and gasoline prices lower by one standard deviation. The high and low scenarios for the Bass Diffusion models are created using data from states that reflect high historical adoption rates for the high scenario, and low historical adoption rates for the low scenario.

We note that efficiency could be negatively impacted by road conditions as well as weather conditions; we assume gasoline cars have 27 miles per gallon. Currently, Minnesota has approximately 2.1 cars per household, which we assume to stay constant throughout the forecast period.

Analysis indicates that battery costs are the primary factor for higher EV prices. Main variables impacting adoption are available tax incentives, price differential between EV and ICE cars, and gasoline prices. Models and estimates are updated as new data becomes available and estimates can vary significantly. Since we are in the early stages of EV adoption, we expect our future estimates will be increasingly robust with additional data available every year.

Our estimates show significant volatility between various scenarios. The estimates are also sensitive to several externalities like policy changes (*e.g.*, incentive changes, cybersecurity requirements, carbon requirements), technology changes (*e.g.*, improvements in existing battery technologies and new disruptive battery technologies, autonomous vehicles, alternate technologies like fuel cell cars), geopolitical issues such as trade and tariff issues, availability of raw materials such as lithium and cobalt, and infrastructure availability.

Additionally, many of the inputs change frequently and could produce significant swings in the model outputs. As can be seen the range of high and low estimates is fairly large, reflective of the sensitivities, volatility and uncertainty associated with the estimates.

Figure 62: Cumulative EV Adoption Rate – NSP Minnesota Service Area

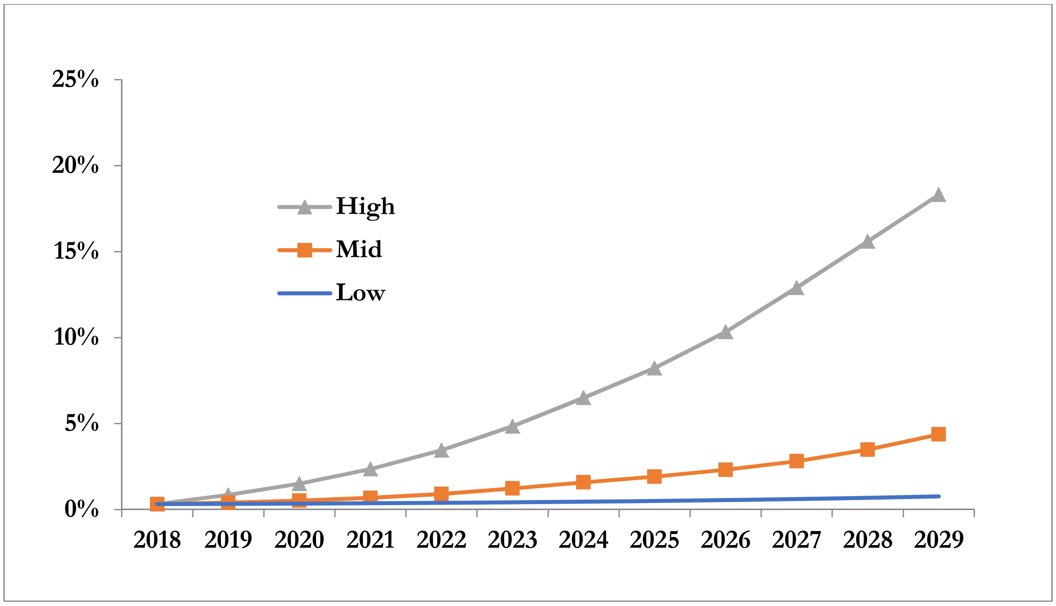


Figure 63: Cumulative Numbers of EVs – NSP Minnesota Service Area

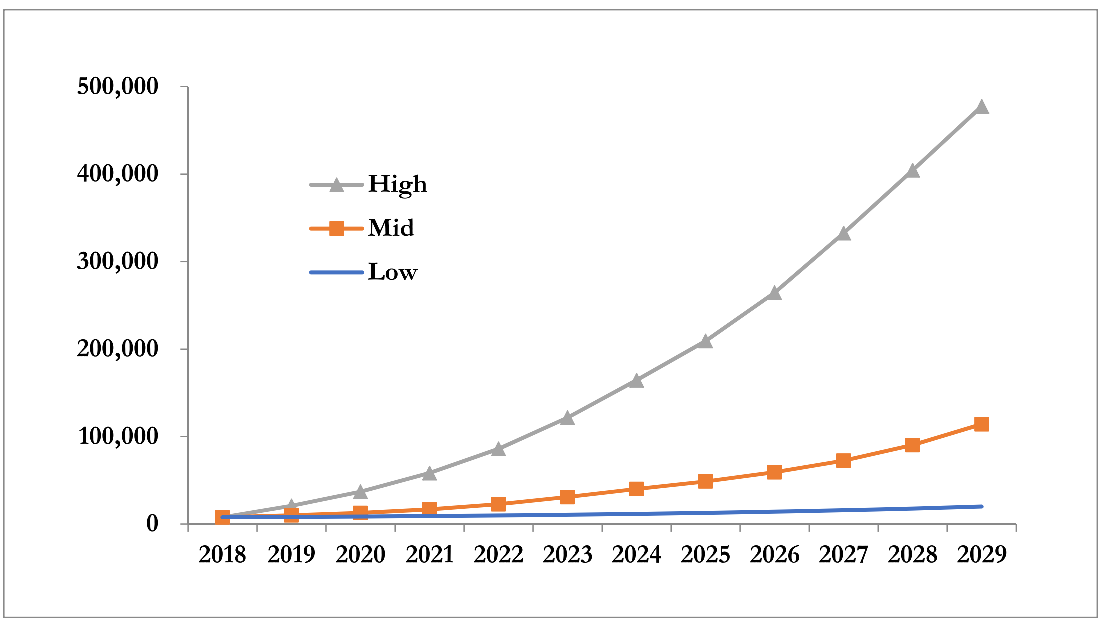
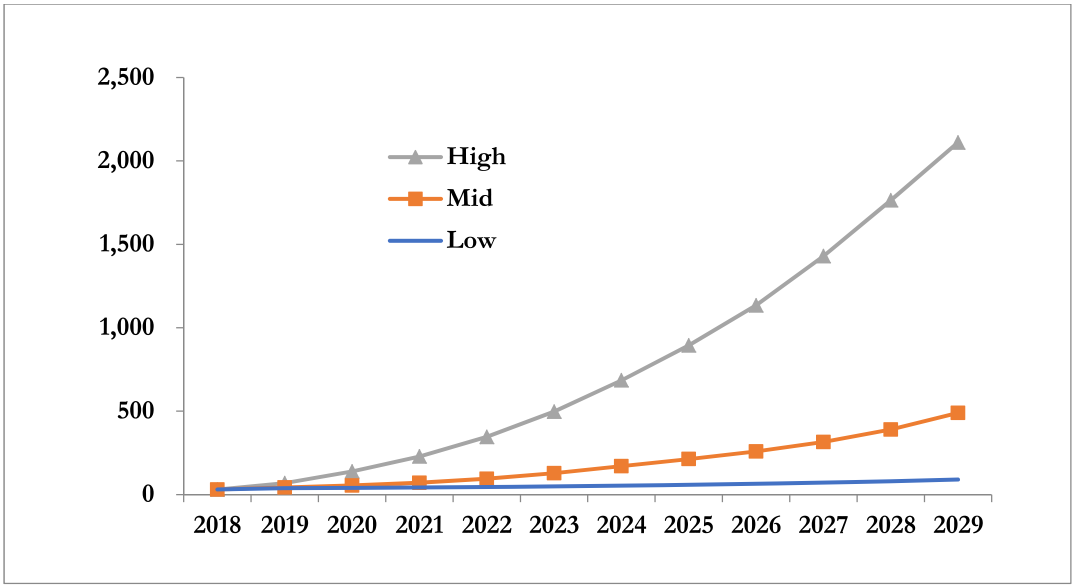


Figure 64: EV Consumption – NSP Minnesota Service Area (GWh)



As we noted earlier in this section, we have engaged a third party consultant to benchmark our EV forecast assumptions, including adoption of medium- and heavy-duty electric vehicles in our service territory and the charging infrastructure necessary to support EV adoption. We intend to share more EV forecasting information in our next Transportation Electrification Plan filing in No. E999/ CI-17-879.

E. DER Integration Considerations

IDP Requirement 3.C.3 requires the following:

> *Provide a discussion of the processes and tools that would be necessary to accommodate the specified levels of DER integration, including whether existing processes and tools would be sufficient. Provide a discussion of the system impacts and benefits that may arise from increased DER adoption, potential barriers to DER integration, and the types of system upgrades that may be necessary to accommodate the DER at the listed penetration levels.*

1. Processes and Tools

Modernization of the distribution infrastructure, new planning approaches, and investment in foundational and advanced technologies are all necessary to manage increasingly complex distribution systems and to safely enable higher penetrations of DER. To achieve these levels it will require myriad solutions and complex integrations across several information technology platforms – or more simply, it will "take a village" of solutions. Through additional monitoring and data analytics, we will have more visibility into DER and its impact on the system. Through additional control and automation, we can better manage the complexities of more dynamic grid. With these improvements we can move toward integrating higher amounts of renewable energy than today's thresholds. The industry as a whole continues to learn about technologies and best practices that can integrate more DER and these findings are often shared across the industry. Several of the tools listed below are a part of our AGIS initiative – an initiative we embarked upon with DER integration as a key driver.

Interconnection Review. Through our existing DER interconnection review process, we review each project for its impact on the grid. Each project is evaluated to determine impact on the grid during minimum load and other key periods. If system upgrades are required based on the DER impacts, the customer or developer will need to pay for the upgrades. In other cases, the customer may be required to adjust inverter settings on the DER system. As we approach higher levels, current interconnection reviews become increasingly complex and, without changes, overly burdensome and costly. We plan to continue to optimize this process and continue to examine how the situational awareness information provided by the Advanced Grid platform (specifically, more detailed information from AMI and the load flow model from ADMS) can inform our analysis and review process.

Hosting Capacity Analysis (HCA). HCA also serves as a valuable precursor to the interconnection process – helping customers or developers guide future installations. These studies that provide an indication of feeder capacity for DER will also help the Company identify trends from year-to-year. We make improvements to this analysis with each one we do and continuously strive to increase its value. For example, this year we have provided minimum daytime load information and increased the functionality of our public facing heat map. The improvements are a direct response to stakeholder feedback.

Planning Tools. As otherwise discussed in this IDP, we are planning to implement a new advanced planning tool that will allow us to perform more robust planning and scenario analyses of DER penetration at or below the feeder level. This capability is critical for our ability to accurately and efficiently perform the analysis needed to safely achieve the listed penetration levels.

The APT will provide us with the ability to aggregate DER adoption forecasts into the distribution load forecast, and conduct scenario analysis against those forecasts. Our baseline DER adoption forecasts will be integrated directly with hourly load forecasts, where the tool uses best-fit analyses to determine potential impact of DER at the feeder level. The tool will also make it easier to develop DER scenario analysis that can be applied at this more granular level, and allow us to test different adoption scenarios within the tool. All of this functionality allows us to conduct DER scenario analyses more efficiently, and will help us better assess how different levels of DER may change peak loads and load shapes on specific feeders throughout the service area.

In providing distribution planning with an hourly-level load forecast that includes the impact of forecasted DER adoption, distribution planning will have the data that is necessary to adequately perform risk analysis and inform the capital budgeting process. The data produced by the APT will help distribution planning understand the relative limits for DER penetration on feeders before potential issues crop up. The advanced planning tool's assessment of DER impacts will be probabilistic in nature and thus unable to replace the need for the interconnection review process. However, it will work in conjunction with HCA to give distribution planning a better understanding of where in the distribution system, both at present and in the future, the ability to accommodate additional DER is constrained.

Monitoring and control. The Company's existing distribution operating tools are generally adequate to integrate DER at the levels listed above. But for certain situations, and for DER levels beyond the listed projections, greater monitoring and control will become essential. The ADMS system and its advanced applications are well situated to fill much of that need. And we note that a DERMS (Distributed Energy Resource Management System) will become essential as well. Along with the monitoring and control benefits of ADMS, the side-benefit of improved system data will help with the integration of DER. We have previously discussed the necessity for system data improvements for ADMS to operate properly, and note that these data improvements fill in certain gaps in our records (size, material, etc.), which will serve to expedite our planning and hosting capacity analysis work as well. The investments we have made in the ADMS are timely (going into production in Q2 2020) and necessary, affording the capability for the required granular system knowledge and operation. Through our change management efforts, we have modified and implemented processes to secure these benefits including operator interactions with the systems, equipment installation and maintenance, communications and security controls, to design and data integrity.

We also note the necessity to continue deploying SCADA to the substations that are not so equipped, and thus our long-term plans call for the installation of SCADA at 3-5 substations each year. These additions improve our planning processes by shortening the time to collect and verify data. Dynamic voltage control will become more essential at higher DER levels as well. IVVO will provide that capability.

Investments in enabling control for IVVO on feeders with higher penetrations of DER will increase hosting capacity where voltage constraints may otherwise limit. In all cases, we note that due to the quantity and dynamic nature of DER, all control systems will need to operate in automated fashion, which is part of our design.

AMI, along with our FAN are tools that are also essential to achieving higher DER levels. AMI will provide insights into DER presence, transformer loading, and voltage levels. And using the new Distributed Intelligence platform we will attain deeper insights into both our own secondary system and the operation of DER. We will alter existing processes and develop new ones to leverage that information to the benefit of our customers. A few processes that will be impacted include hosting capacity analysis, voltage monitoring, and power quality inquiry. Communication capabilities are a core enabler. We need robust, secure communication paths for all interconnected utility and connected DER – and the Company's FAN is a key enabler, providing for AMI and our distributed monitoring and control. Of course the critical nature of such a system requires excellent monitoring and maintenance processes and tools, which we have designed into our AGIS proposal.

Additionally, we envision the integration of technologies that do not connect directly to our FAN, but through other paths. Such communication pathways must be securely integrated. One key to that effort is the development of industry standards and communication protocols, the development of which we support.

2. *System Impacts and Benefits that May Arise from Increased DER Adoption*

DER has the potential to both provide system benefits and negatively impact the system. Some of the potential benefits include:

- *Reduction of Peak Power Requirements.* Demand Response has been called upon for years to reduce peak, and will continue to be a valuable DER. Energy storage such as battery storage can be managed to discharge during peaks. And while DER such as EVs may in the future provide dispatchable storage, we note that it is imperative to manage charging so as to not increase system or distribution peaks.

- *Emergency source of power.* Standby generation generally benefits only one customer, and thus is generally considered to provide system benefits. But the technologies involved lend themselves to broader system benefits. Additional DER technologies such as battery storage provide new options to back-up power, and we are starting to see residential customers adopt this strategy. When PV is present, it can be combined with energy storage so that the combined system can provide power to some or all of the customer's load during an outage. These capabilities can be expanded – for example, a microgrid could provide community resilience for critical facilities.

- *Manage local capacity constraints.* Typically the PV does not have a perfect coincidence with demand, but offsets load in the earlier hours of the peak. Also, left unmanaged, PV can create a new capacity constraint due to high solar production during low-load periods. Energy storage can help modify this pattern by charging and discharging during certain times of the day. Each feeder is somewhat unique – and we study how DER can provide benefits as part of our non-wires alternatives analysis process, which today is on a limited number of feeders; with our proposed advanced planning tool and other enhanced capabilities, we will be able to perform this type of analysis much more broadly.
- *Reduction of system power.* Customer-sited PV offsets the overall system power requirements, which is something that is considered in the Value of Solar analysis.
- *Improvements in power quality.* PV and energy storage inverters have the potential to provide improved load factor locally.

We will continue to study these benefits as we conduct our non-wires alternative processes and other DER analysis scenarios. As DER costs come down and technology software platforms mature, we expect the opportunities in this area to continue to grow.

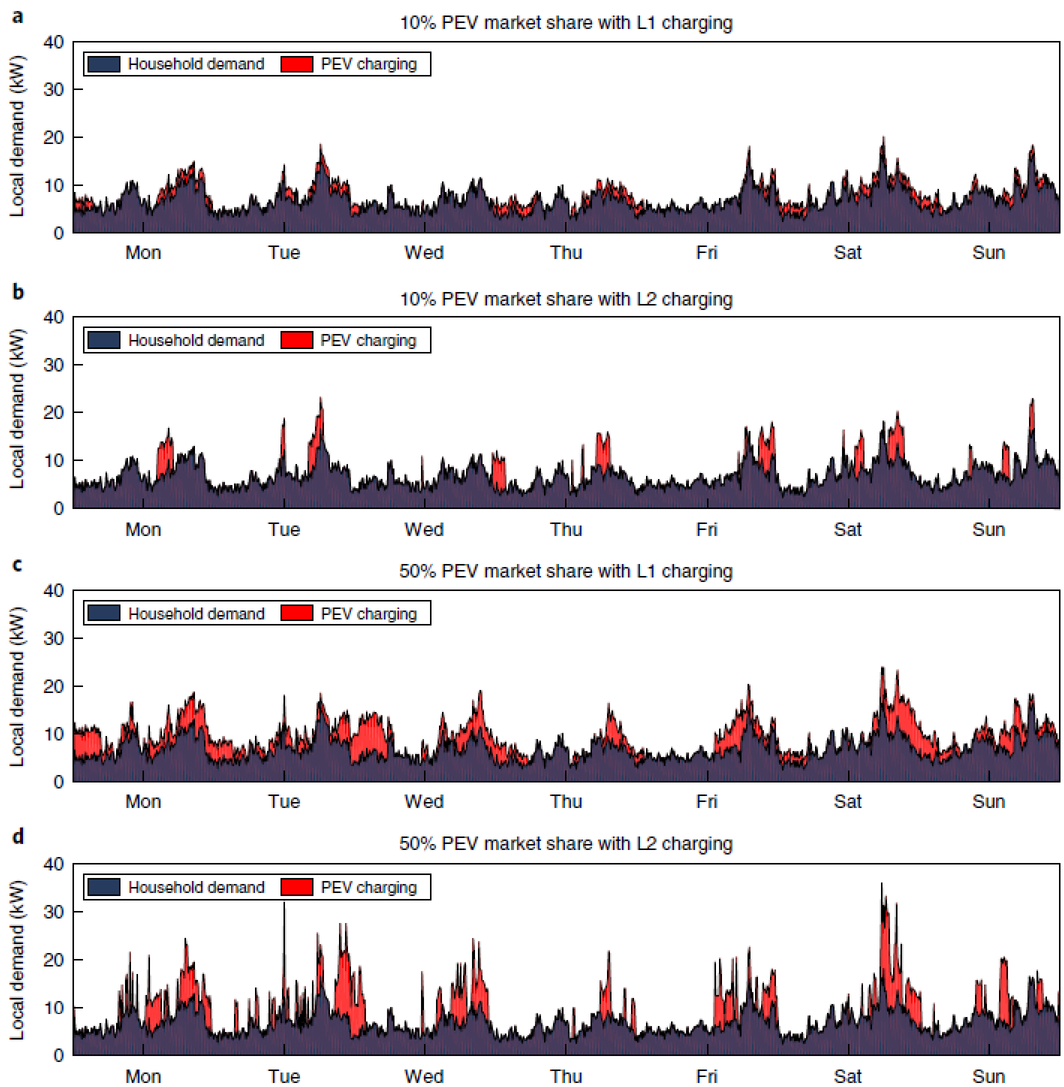
The below table summarizes the potential negative impacts of higher penetration of distributed PV.

Table 54: Potential Distribution System Impacts from Distributed Solar PV

Distribution Impact/Constraint	Constraint Description	Cause
Primary Over-Voltage	Steady-state primary side voltage exceeds nominal voltage.	Minimum daytime loading combined with maximum solar generation leads to less net load on feeder, thus leading to higher feeder voltage.
Primary Voltage Deviation	Voltage change that happens from no DER (specifically distributed PV) to full DER in aggregate.	Potentially due to cloud cover or weather related issues that caused DER to go from no output to full output and vice versa.
Regular Voltage Deviation	Change in bandwidth from no DER output to full DER output at a regulated node.	Potentially due to cloud cover or weather related issues that caused DER to go from no output to full output and vice versa.
Thermal Loading Constraints for Discharging DER	Due to specific element rating (e.g. conductors).	DER deployment at low-load feeders could lead to reverse power flow, thus violating ratings on existing elements such as conductors.
Additional Element Fault Current	Deviation in feeder fault currents.	With increased installations of Distributed PV, there will also be an increase in the fault current contribution from each PV system.
Breaker Relay Reduction of Reach	Deviation in breaker fault current	Distributed PV with voltage support functions has the potential to reduce its contribution to fault currents. This will cause inadequate breaker reach that could lead to losing visibility to remote feeder faults.
Reverse Power Flow	Element minimum loading	Minimum daytime loading combined with maximum solar generation leads to generation surpassing load at the local level, which could lead to reverse power flow back to the substation.

EV Impacts – Although EV adoption is low in the NSP service area, EV charging could potentially be "clustered" around specific feeders, e.g. downtown areas or specific residential neighborhoods. EV chargers would not only increase the load on a feeder but also would change the load shape on the feeder. The below charts are from a study performed by NREL using an aggregate of 200 sampled households for a sample week with two EV penetration levels – showing the total demand at a residential distribution transformer.[69]

Figure 65: Total Residential Power Demand for Six Households



This study assumed an unmanaged charging situation, i.e. there are no coordinated charging events such as a time-of-use (TOU) rate. With uncoordinated or unmanaged

[69] *See Impact of uncoordinated plug-in electric vehicle charging on residential power demand,* Matteo Muratori ,Nature Energy, March 2018

charging, there would be an increase in EV charging during peak times of the day which could lead to overloading issues on local distribution equipment such as transformers. There is a current EV Pilot Program in MN that monitors EV charging energy usage at participating customers home. These customers are also enrolled in the TOU rate program, where peak hours are from 3-8 p.m. and this incentivizes customers to charge at off-peak hours. As the pilot progresses we will continue to analyze customer usage and evaluate whether customers respond to price signals as anticipated.

Currently, charging times are under two hours which could lead to an opportunity to stagger the charging periods through the evening and early morning, thus preventing the second peak. This stagger charging could be performed via a rate mechanism or a price signal. There is also the option to directly control the charging behavior through the Electric Vehicle Supply Equipment (EVSE).

Aggregated and widespread solutions that are able to cut across various automotive vehicles and EVSE are still emerging. More advanced managed charging techniques involved active charging and vehicle-to-grid (V2G) technology. V2G allows bi-directional power transfer from the EV to the grid and vice versa and is still an emerging technology with utilities in California still working out the interconnection recommendations.[70]

Active charging depends on utilities or third-party aggregators dispatching the charging schedules of EVs based on local grid conditions. However, this technology requires partnerships with third-party based EV aggregators (e.g. ChargePoint, eMotorWerks, etc.) to dispatch EV charging schedules as well has the availability of a robust communication network to the EV or EV charging stations. Various utilities (mainly in California) have had different managed charging EV programs ranging from passive charging techniques such as TOU rate to a more active charging techniques such as directly controlling the charging of EVs via the car chargers or through third-party aggregators.

Xcel Energy is currently working with NREL to model and analyze the impacts of higher penetrations levels of EV on the Minnesota distribution system. This project is part of a widespread DOE research in this area.[71] The project will be modeling 15 feeders on the distribution system with varying higher adoption levels of EV's among

[70] *See Rule 21 Working Group 3 Issue 23* for the California Public Utilities Commission
[71] *See DOE Announces $80 Million invested in Advanced Vehicle Technologies Research,* https://www.energy.gov/articles/department-energy-announces-80-million-investment-advanced-vehicle-technologies-research, Sept 2018

each feeder. The NREL model will compare distribution impacts for both un-managed and managed charging scenarios. The research project is underway, but currently results aren't available. We look forward to sharing these results when they are available, likely later in 2020.

Energy Efficiency and Demand Response – There are no negative impacts foreseen with energy efficiency and demand response initiatives. It is expected that demand response programs would be able to alleviate a portion of the system peak loads.

Distribution-Sized Energy Storage Systems – Energy storage systems are a valuable asset to grid reliability and efficiency especially with increasing penetrations of DER on the distribution grid. However, the amount of installations in Minnesota is still relatively low and the cost-effectiveness of front-of-the-meter utility installations depends highly on the operational and location of the energy storage systems.

Similar to the PV interconnection review, customer-connected energy storage system would be reviewed through our interconnection process for impacts on the system. The customer chooses how to operate these systems and as such, might not be designed explicitly to provide value to the distribution grid.

Energy storage systems are well suited for many applications, especially to aid in increasing PV hosting capacity on a distribution feeder as well as relieve local congestion issues that could potentially defer an upgrade to distribution equipment.

3. Potential Barriers to DER Integration

Minnesota has a cost-causation regulatory construct for DER, which requires the "cost causer" to pay the costs – shielding other customers from the costs. As such, individuals or developers proposing to interconnect DER to the system may incur costs for necessary system changes to accommodate the DER. Based on our regulatory requirements in our Section 10 tariff, the customer or developer who installs a system pays for the cost of any necessary upgrade or modification necessary for DER integration. In some cases the developer or customer chooses not to pursue the modification and the project does not move forward. This construct limits the amount of negative impacts that DER can cause on the distribution system, enabling the Company to continue to provide safe and reliable service. It also protects the majority of customers from incurring costs generated by a few.

That being said, the Company acknowledges there are situations that may pose barriers to DER integration. For example, there may be times when a customer with a small DER system could be assessed a disproportionate amount of expenses to upgrade a neighborhood transformer because the customer installed the DER system after others in the neighborhood already had installed similar systems (and did not incur a charge to upgrade the transformer). Similarly, some customers could face disproportionate interconnection costs associated with reconductering a feeder, if they seek to install a DER system after other larger systems (e.g. community solar gardens) have done so on the same feeder. Finally, if a large customer on a feeder that also has DER systems on it were to close or move, the drop in demand could require studies and reconductering or other changes to avoid adverse reliability impacts for the customers connected to that feeder; at this time it is unclear who should pay those costs.

4. *Types of System Upgrades that Might be Necessary to Accommodate DER at the Listed Penetration Levels*

In general, with the medium and high case PV scenarios provided in the DER Forecasts Section, we believe the system impact would be low. One of the primary reasons we believe the impact would be low is because of the current levels of customer-sited PV we have with our Xcel Energy Colorado operations. At the end of 2018, Colorado had 400 MW of customer-sited PV on our system. Currently, on our Minnesota system, the amount of customer-sited PV is about 20 percent of the overall total PV on system; most of the current PV capacity is related to community solar gardens. Table 52, Distributed Solar Forecast shows our PV estimates in 2029 for the medium and high scenarios as 1,261 MW and 1,481 MW, respectively. If we project that 20 to 40 percent of the Total High (MW) will be customer-sited, then that would be about 300 to 400 MW – and we already have experience with these levels. As discussed in the Interconnection Process Section of Section XII, B.2, each DER project is reviewed individually for impact on the system.

As we have outlined in other areas of this report, we expect that AGIS upgrades will help provide additional real-time information about our system. This information will provide feedback about how PV is affecting our operations, and may influence the assumptions we make with planning processes and interconnection reviews regarding PV integration. As we note in the smart inverters discussion within this IDP, there are also some smart inverter adjustments that could be considered.

Table 55 below shows the traditional mitigation solutions we employ for common issues that occur due to DER penetration on the system. In some instances, combinations of these mitigations need to occur in order to add additional DER.

Table 55: Potential Mitigations for Common Constraints

Category	Impacts	Mitigation
Voltage	Overvoltage	Adjust DER power factor setting, reconductor
	Voltage Deviation	Adjust DER power factor setting, reconductor
	Equipment Voltage Deviation	Adjust DER power factor setting, adjust voltage regulation equipment settings (if applicable), or reconductor
Loading	Thermal Limits	Reconductor, replace equipment
Protection	Additional Element Fault Current	Adjust relay settings, replace relays, replace protective equipment
	Breaker Relay Reduction of Reach	Adjust relay settings, replace relays, move or replace protective equipment
	Sympathetic Breaker Relay Tripping	Adjust relay settings, replace relays, move or replace protective equipment
	Unintentional Islanding	Installation of Voltage Supervisory Reclosing

F. DER Scenario Analysis and Integration Considerations

In this section, we discuss the state of DER scenario analysis and integration of distribution-connected DER in wholesale and regional markets.

1. *DER Scenario Analysis*

Scenario analysis helps us understand future DER use cases. For example, we could analyze higher adoption scenarios or analyze how DER could impact or provide benefits to a feeder or certain area of the feeder. We have described how the new advanced planning tool will help us mature our capabilities and analysis. We believe probabilistic analysis will be a critical aspect of incorporating DER into the distribution planning process, and that distribution planning will evolve to include:

- Historical and forecasted weather,
- Forecasted quantities and availability of DER
- Forecasted impacts of conservation and load control,
- Electric vehicle adoption,
- More granular forecasts, and hourly data rather than solely the peak load – to the extent we have sufficient SCADA capabilities,
- Storage implications, and

- Inputs from an integrated energy supply/transmission/distribution planning process.

As we have described, the advanced planning tool will provide us with scenario analysis capabilities and will enable the use of multiple user-defined scenarios in developing the distribution load forecast. This will provide the distribution planning process with the insights needed to better understand the range of possible forecast outcomes and their impacts on the distribution system.

We believe that there could be some scenarios that apply to all utilities, like there are in IRPs. However, this issue is being addressed different ways nationally. The California Working Group on DER and Load Forecasting recommended different forecasting methodologies/scenarios be used between the utilities – but that common principles be followed:[72]

- Use statistically appropriate, data-driven methodologies for each DER, customer segment, and level of disaggregation.
- Develop approaches to manage uncertainty associated with granular allocation of DER.
- Periodically re-assess the modeling approach for each DER as increased adoption leads to better data.
- Share best practices and leverage learning process to strive for continuous improvement both in forecasting and in using the forecasts for distribution planning.
- Integrate data from DER industry partners to enhance forecasting accuracy.

As we have discussed, the distribution planning process is rooted in specific forecasts of load densities at a feeder level – and the distribution system is our direct connection point with customers, does not have the same redundancy and back-up as exists at the transmission and energy supply level, and generally requires solutions within short timeframes. Distribution planning outcomes therefore generally require more immediate action than an IRP, for example, to ensure customer reliability. So, any changes we make in our planning processes will need to ensure our focus remains on ensuring the reliability of the system for our end use customers.

[72] *See* http://drpwg.org/wp-content/uploads/2017/04/Joint-IOU-Draft-Assumption-and-Framework-Document.pdf

2. *Expected DER Output and Generation Profiles*

IDP Requirement 3.D.2 requires the Company to provide …c*osts and plans associated with obtaining system data (EE load shapes, PV output profiles with and without battery storage, capacity impacts of DR combined with EE, EV charging profiles, etc.).*

For more robust scenario analyses on a feeder, DER generation profiles are helpful. With PV systems, we can refer both to our internal generation profiles developed from load research on our customer PV systems or utilize a public tool like National Renewable Energy Laboratory's (NREL) PV Watts tool. We have also made some assumptions on EV charging usage, and hope to obtain additional information through our residential EV service pilot program. We additionally have several end-use load shapes available through our DSM program. These energy efficiency load shapes are generally used to determine the avoided marginal energy benefits of various DR and energy efficiency achievements.[73]

AMI deployment provides valuable data to develop and refine load shapes. Additionally, ADMS is able to generate load profiles using AMI interval data, a feature we will use to obtain more accurate ADMS solutions. Regardless, through AMI interval data we will be able to refine DER profiles.

3. *Changes Occurring at the Federal Level*

IDP Requirement 3.C.4 requires the following:

> *Include information on anticipated impacts from FERC Order 841 (Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators) and a discussion of potential impacts from the related FERC Docket RM-18-9-000 (Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations [RTO] and Independent System Operators [ISO]).*

In our 2018 IDP we discussed Federal Energy Regulatory Commission (FERC) Order No. 841, which addresses two different levels of participation of storage resources in wholesale markets. We outline the rule requirements and summarize the Company's comments below, and note that there has been no further action on this since our last IDP.

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[73] The Company's Conservation Improvement Program (CIP) Annual Status report shows the energy efficiency and incremental demand response achievements including load shape information.

First, the rule requires that RTOs and ISOs accommodate the various types of services that transmission-interconnected resources can provide, including transmission system support, energy, capacity and ancillary services. Xcel Energy Services Inc. (Xcel Energy) filed comments supporting these aspects of the proposed rule in the FERC rulemaking process in FERC Docket No. RM16-23 on behalf of Northern States Power Company, a Minnesota corporation (NSPM) and the other Xcel Energy Operating Companies[74] and is optimistic that expanded utilization of electric storage resources interconnected at transmission level will bring added value to customers and add security and reliability of the grid, though the pace of adoption of storage technology remains unclear.

While Xcel Energy supports FERC Order No. 841 as it relates to resources interconnected at transmission level, we have concerns about implementation of Order 841 as it relates to storage resources interconnected at distribution level.[75] Xcel Energy also has concerns about FERC's proposal in Docket No. RM18-9-000, Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators, which would expand the requirements of FERC Order No. 841 to all types of energy resources interconnected at distribution level (DERs), not just storage resources.[76]

Even at low penetration levels of DERs, FERC's expectation that storage resources and DERs be enabled to participate in wholesale RTO or ISO markets poses challenges for both utilities and their customers. The implications of these challenges become more significant at higher penetration levels. For example:

- *Metering*. Participation of distribution-interconnected storage resources raises the question about how metering will distinguish between charging for wholesale purposes as opposed to charging for retail usage in the case of dual-

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[74] XES has participated in several FERC rulemaking dockets regarding participation of storage resources and DER in wholesale markets filing comments on behalf of all of the Xcel Energy Operating Companies, namely NSPM, Northern States Power Company, a Wisconsin corporation (NSPW), Public Service Company of Colorado (PSCo), and Southwestern Public Service Company (SPS). A copy of XES's comments filed in Docket No. RM16-23-000 and AD16-20-000 is available at this link: https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14538803.

[75] XES filed a request rehearing of various aspects of FERC Order No. 841 as it relates to resources interconnected at distribution level. A copy of XES's request for rehearing is available at this link: https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14651369

[76] A copy of XES's comments in FERC Docket No. RM18-9-000 is available at this link: https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14682284. These comments largely capture input provided in XES's original comments in Docket Nos. RM16-23-000 and AD16-20-000 and XES's request for rehearing in those dockets. FERC declined to accept these comments into the record in Docket No. RM18-9-000 because FERC deemed they were duplicative.

use facilities. Charging for retail usage should be subject to state-regulated retail rates while charging for wholesale purposes would, under Order 841, be subject to FERC regulated wholesale rates. We are not aware of any metering arrangement that can distinguish between charging for wholesale purposes and charging for retail purposes in the case of a dual-use facility. It should be incumbent upon the resource owner to provide sufficient documentation to ensure that any dual-use resource can be metered in a manner that can distinguish between charging for retail use as opposed to charging for wholesale use. Otherwise, cost shifts to other retail customers will occur as a result of such a resource avoiding payment of full retail rates when it is charging a storage resource for what will ultimately be usage for a retail purpose.

- *Distribution Operations.* Distribution system operators (DSO) will need to have the capability to monitor activities of DERs in the wholesale market and potentially take action to curtail market sales if such sales will impair reliable distribution system operations. The need for such capabilities will increase as DER penetration increases. The mechanisms to manage these operations will require enhanced communications systems between the DSO, DER, and market operator; software that can monitor distribution system impacts and identify reliability issues and solutions; and additional operations personnel to effectively manage the impacts of DER participation in markets. Cost causation principles dictate that the DER owners and operators should be responsible for the costs associated with these enhancements because such costs would not be incurred "but for" the participation of DERs in wholesale markets. However, absent fairly significant DER penetration levels it is not clear how these costs can be effectively allocated and recovered. At low penetrations there will simply be an insufficient number of customers to bear the costs of these infrastructure upgrades. FERC has not proposed a mechanism to address this issue. In the meantime, distribution system operators will have to find ways to manage DER resource participation reliably, cost-effectively, and in a manner that does not shift costs to other customers.

- *Distribution system upgrades.* Existing distribution systems were not built to manage large outflows of energy that would be associated with market sales. Further, distribution systems are not as flexible as transmission systems and therefore are less able to effectively handle the types of system flows that will occur with DERs participating in markets. Distribution interconnection studies will be more complex and will identify potentially significant feeder and substation upgrades needed to enable market participation by DERs. The costs of such upgrades should be directly assigned to the DER causing such costs to be incurred.

- *Wholesale market issues*. In addition to the direct distribution-level impacts of DERs participating in markets, there are a variety of other issues that must be addressed at the wholesale market level. These issues include the ability to determine where individual DERs involved in an aggregation are located in order to ensure that resources are paid the appropriate nodal price, whether technology exists to effectively manage the state of charge of storage resources, and whether market software can effectively be deployed to manage large numbers of relatively small resources. Xcel Energy expects these issues to be addressed by FERC on rehearing of Order No. 841, through the final rule in FERC Docket No. RM18-9-000, or through appeals thereof.

The provisions of Order No. 841 regarding participation of distribution-interconnected storage resources in wholesale RTO markets have not been stayed pending rehearing. It was necessary for MISO to make a compliance filing with FERC by December 3, 2018, and MISO has a year thereafter to implement provisions of its compliance filing. MISO is actively working through its stakeholder process to develop its compliance filing.

MISO filed their compliance filing in December 2018 with the provisions regarding DERs as we laid out in our November 2018 IDP.[77] Subsequently, in their response to FERC's request for more information filed in April 2019, MISO updated their Distribution Connected Electric Storage Resource (ESR) form agreement to require an attestation from the ESR that all necessary metering and other arrangements are completed before they can participate as a DER ESR in MISO. The Company supported this revision. However, in that same filing, MISO requested a deferral of the effective date from December 3, 2019 to early 2021. MISO reasoned that their original system build and delivery plans were highly dependent upon the MISO Market System Enhancement project milestones and were altered by the lack of the Commission's acceptance of their Order 841 Compliance Filing by April 2019. MISO has suspended all work on ESR activities until a Commission Order on the deferral of

[77] Excerpt from 2018 IDP regarding key aspects of MISO's compliance filing: "One of the key aspects of MISO's compliance filing will be the relationship between MISO, the DER, and the applicable distribution system operator (DSO). After reviewing MISO's draft agreement with the DER, we have tentatively concluded that it may be appropriate to file a tariff at FERC that would address aspects of DER participation in wholesale markets. If the Company were to go forward with this concept, the tariff would address matters such as direct assignment of distribution system upgrade costs incurred due to DER participation in wholesale markets, the need for a DER to establish to the satisfaction of the utility that it has metering capability needed to ensure that it does not charge a storage resource at wholesale rates for retail usage, mechanisms to limit DER output to the extent that reliability of the distribution system is compromised by the DER's activities, and cost recovery for services provided by the distribution system operator to the DER."

the effective date is received. As of October 25, 2019, the Commission has not ruled on this request.

We plan to evaluate this issue further and take appropriate steps to move forward to ensure that DER participation in wholesale markets is not subsidized by other retail customers and that such participation is conducted in a manner that does not threaten reliability of the distribution system.

We provide additionally as Attachment I, an October 7, 2019 response to a FERC data request in FERC Docket RM-18-9-000 regarding MISO's policies and procedures that affect the interconnection of DER. Comments in response to MISO's filing are due to FERC on November 6, 2019.

Finally, we also provide a summary of relevant actions by FERC and MISO, and various entities' work on IEEE 1547-2018, which is a recently published DER interconnection and interoperability standard, as also provided in our biennial transmission projects report, filed concurrently with this IDP.

Federal Energy Regulatory Commission (FERC)
FERC Order No. 841, which was issued in February 2018, amended FERC regulations to remove barriers to the participation of electric storage resources in the capacity, energy, and ancillary service markets operates by regional transmission organizations and independent system operators by requiring RTOs and ISOs to revise its tariff to recognize the physical and operational characteristics of electric storage resources and facilitate their participation in markets. FERC has received requests to consider similar rules for DERs. In May 2018, FERC held a two day technical conference on DERs. There are two ongoing FERC dockets related to DERs. The first is Docket No. RM18-9, which relates to the Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators, and is a continuation of the rulemaking FERC originally commenced in Docket No. RM16-23. The second is Docket No. AD18-10, which relates to Distributed Energy Resources – Technical Considerations for the Bulk Power System.

MISO
According to its website, MISO has noted that "[a] high penetration of Distributed Energy Resources (DERs) could have notable implications for MISO and require a stronger transmission and distribution interface. The DER issue [in the MISO stakeholder process] is intended to explore, and advance collaboratively developed DER priorities with stakeholders." To that end, MISO has been hosting a series of workshops on DERs throughout the year. MISO is currently working with the

Organization of MISO States (OMS) and other MISO stakeholders to develop a DER participation model that accounts for the distinctive characteristics of the MISO region and promotes reliability on a least cost basis.

Institute of Electrical and Electronics Engineers (IEEE)
Another important aspect related to distributed energy resources and distribution planning is various entities' work on IEEE 1547-2018, which is a recently published distributed energy resources (DER) interconnection and interoperability standard.

The revised standard addresses three new broad types of capabilities for DER: local grid support functions; response to abnormal grid conditions; and exchange of information with the DER for operational purposes. The standard was written with a large set of required capabilities with an expectation that not all capabilities would be immediately implemented in the field. In this way, it offers options for grid operators preparing for scenarios with high penetration of DER. Some details associated with implementing the standard are part of the Commission's E002/M-16-521 docket, especially in Phase II which considers statewide technical standards, and other details are expected to be associated with Xcel Energy's business practice decisions.

In terms of specifying DER response to abnormal grid conditions, IEEE 1547 indicates that the Authority Governing Interconnection Requirements and Regional Reliability Coordinator possess a guidance role in implementing these capabilities, which, in Minnesota, are the Minnesota Commission and MISO respectively. Commission Staff requested information and guidance from MISO through a working group associated with the E002/M-16-521 docket. The response from MISO included a plan to convene a stakeholder group so that guidance on the topic could be provided on a regional basis. The Commission's interest in resolving questions associated with adopting these capabilities is helping to drive important stakeholder conversations.

Local grid support functions have generated interest in the industry in recent years based on implementation of these functions in states such as Hawaii and California in areas of high DER deployment. The IEEE 1547-2018 standard allows a utility to specify how local grid support functions are used. Xcel Energy proposed in the E002/M-16-521 docket that use of the local grid support functions should be published in utility-specific technical manuals.

The interoperability aspects of IEEE 1547-2018, which include concepts of DER monitoring and control, mark the most future-leaning required capabilities. When certified equipment is available, every DER will have a standardized communication interface for exchanging data and performing remote operations. A communication network would be necessary for making use of the interoperability interface.

XII. HOSTING CAPACITY, SYSTEM INTERCONNECTION, AND ADVANCED INVERTERS/IEEE 1547

In this Section, we summarize our hosting capacity analysis (HCA) in the context of our overall interconnection processes and how we have evolved our HCA. In part B, we generally discuss our interconnection processes and provide interconnection statistics. In Part C, we discuss advanced inverter functionality and recent changes associated with IEEE 1547.

A. Hosting Capacity

IDP Requirement 3.B.1 requires the following:

> *Provide a narrative discussion on how the hosting capacity analysis filed annually on November 1 currently advances customer-sited DER (in particular PV and electric storage systems), how the Company anticipates the hosting capacity analysis (HCA) identifying interconnection points on the distribution system and necessary distribution upgrades to support the continued development of distributed generation resources, and any other method in which Xcel anticipates customer benefit stemming from the annual HCA.*

Xcel Energy recognizes hosting capacity as a key element in the future of distribution system planning. We anticipate it has the potential to further enable DER integration by guiding future installations and identifying areas of constraint. In compliance with Minn. Stat. § 216B.2425 and by order of the Commission, we conducted and submitted annual hosting capacity studies in 2016, 2017, and 2018.[78] We will submit our latest HCA study on November 1, 2019 concurrently with this IDP. These studies provide hosting capacity results by feeder serve three purposes: (1) provide an indication of distribution feeder capacity for DER, (2) streamline interconnection studies, and (3) inform annual long-term distribution planning.[79]

On December 1, 2016 we submitted the results of our first hosting capacity study in Docket No. E002/M-15-962. We used the EPRI DRIVE tool for our analysis. EPRI defines hosting capacity as the amount of DER that can be accommodated on the

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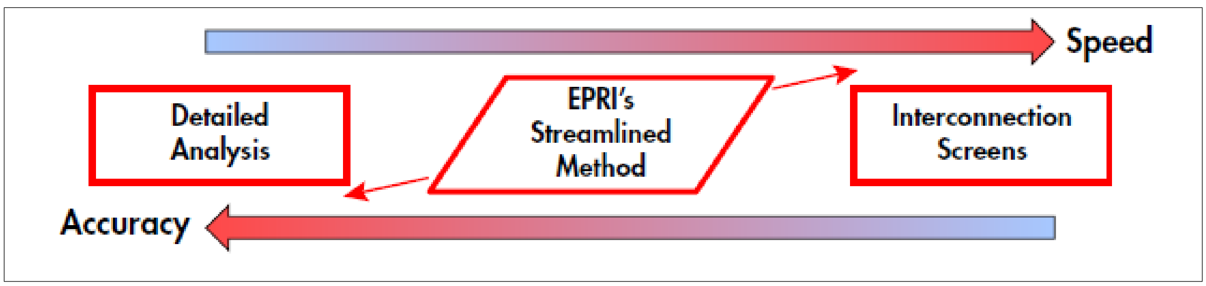
[78] *See* Distribution System Study, Docket No. E002/M-15-962 (December 1, 2016), Hosting Capacity Report, Docket No. E002/M-17-777 (November 1, 2017) and Hosting Capacity Report, Docket No. E002/M-18-684 (November 1, 2018).

[79] See Integrated Distribution Planning Report Prepared for the Minnesota Public Utilities Commission, ICF International (August 2016).

existing system without adversely impacting power quality or reliability – and introduced the DRIVE tool as a means to automate and streamline hosting capacity analysis. The analysis is based on EPRI's streamlined hosting capacity method, which incorporates years of detailed hosting capacity analysis by EPRI in order to screen for voltage, thermal, and protection impacts from DER. Using the actual Company feeder characteristics, DRIVE considers a range of DER sizes and locations in order to determine the minimum and maximum range of hosting capacity. The electric system's hosting capacity is mainly impacted by DER location and system characteristics.

Figure 66: Balancing Speed and Accuracy in Analysis



As indicated by Figure 66 above, EPRI's method is intended to strike a balance between speed and accuracy. While it does not replace a detailed analysis, it provides more value than a traditional interconnection screening, such as the criteria found in the FERC Small Generator Interconnection Procedure. The result is a more complete and efficient way to understand a feeder's ability to integrate new DER, which includes PV and energy storage, at multiple points on the distribution system

For our hosting capacity analysis, we created over 1,000 feeder models in our Synergi Electric tool. The information for these models primarily came from our GIS, but was supplemented with data from our 2018 load forecast – as well as actual customer demand and energy data. Once the models were verified, load was allocated to the feeders based on demand data and customer energy usage – and analyzed using the DRIVE tool.

Generally, it is challenging to fully predict where future DER will be located – even with an interconnection queue. For instance, a large PV interconnection may be required to make some line upgrades to accommodate the proposed generation. The line upgrades and configuration changes for that interconnection are not reflected in our GIS until the design and construction phases are complete. This means that those system modifications do not enter GIS and subsequently the feeder models in a timeframe that is well-suited for forecasting accurate hosting capacity results.

Through engaging with our customers and stakeholders, learning from other utilities around the country, and leveraging our partnership with EPRI, we have made notable improvements from our initial hosting capacity analysis in 2016. These improvements include:

- Presenting results as heat-map visual with additional data contained in pop-ups for specific locations, in addition to tabular results
- Including existing DER into the analysis
- Adopting a simplified methodology (IEEE-1453) to determine voltage fluctuation thresholds
- Application of Reverse Power Flow and Unintentional Islanding Thresholds to better align with the criteria we use in the interconnection process.
- Adjustment of Voltage Deviation Threshold to better align with how we perform interconnection studies
- Using a methodology for large centralized generators to more accurately reflect the characteristics of DER deployment most commonly seen in Minnesota – and associated with programs such as Solar*Rewards Community
- Refining our hosting capacity tool to include advanced inverter settings for fixed power factor (discussed in more detail in the IEEE-1547 section below)
- Including energy storage that is acting as a source of power
- Excluding back-up DER to improve the accuracy of hosting capacity results by analyzing of only those systems that are operating in grid-connected mode
- Modifying breaker reduction of reach thresholds to strike an appropriate balance between identifying areas where system protection impacts require closer review while not masking other limiting factors
- Use of actual Daytime Minimum Loads for approximately 25 percent of our feeders
- Use of actual feeder power factors on the vast majority of our feeders
- Developing guidance on mitigations costs, including a detailed analysis for feeders with zero hosting capacity

As EPRI continues to enhance the DRIVE tool, and we continue to refine our use of DRIVE for the Minnesota HCA, we will continue to improve our HCA results – including the report we are submitting in a separate docket November 1, 2019.

Furthermore, we anticipate the near-term advanced grid investments we outline in this IDP will provide enhanced system visibility to improve the data inputs and the analytical tools to further refine the analysis output. Additionally, in the longer term, investments like more advanced control schemes coordinating action with smart inverters and utility devices will improve the hosting capacity of circuits with voltage threshold constraints.

Hosting capacity analysis also serves as a valuable input prior to the interconnection process, helping customers or developers gather information about a location before an application is submitted. Interconnection studies are necessary to ensure the proposed generator can safely interconnect without adversely impacting electric delivery to surrounding customers and at what cost. With better data inputs and more analytical tools available to distribution engineers, we will be able to more efficiently respond to interconnection study requests and streamline the process for interconnecting customers. The interconnection process and associated studies will make use of the latest in technology and standards, such as IEEE-1547-2018, discussed in further detail in the section below and align with applicable regulatory guidance developed in the Interconnection and Operation of Distributed Generation Facilities proceeding (Docket No. E999/CI-16-521).

B. System Interconnections

In this section, we provide Company cost and customer charge information associated with interconnections on our distribution system. We also provide other information about the interconnection process as specified in the IDP requirements.

1. Company Costs and Customer Charges Associated with DER Generation Installations

The information we provide below fulfills the following IDP requirements:

IDP Requirement 3.A.15 requires the following:

> *Total costs spent on DER generation installation in the prior year. These costs should be broken down by category in which they were incurred (including application review, responding to inquiries, metering, testing, make ready, etc).*

IDP Requirement 3.A.16 requires the following:

> *Total charges to customers/member installers for DER generation installations, in the prior year. These charges should be broken down by category in which they were incurred (including application, fees, metering, make ready, etc.).*

IDP Requirement 3.A.27 requires the following:

> *All non-Xcel investments in distribution system upgrades (e.g. those required as a condition of interconnection) by subset (e.g., CSG, customer-sited, PPA, and other) and location (i.e. feeder or substation).*

We calculate our actual DER costs on a project basis and perform this calculation at the time we charge this actual cost to the DER customer. This occurs after the DER is interconnected to our network. Large projects, such as community solar gardens, may straddle more than one calendar year. This means that when we calculate the costs for a given project, the calculated costs typically include costs from prior calendar years. Similarly, if a bill for a given project under construction is not issued in a given calendar year then our tracked and reported costs will not reflect these costs until we issue a bill.

Beginning on June 17, 2019, we began following the Minnesota Distribution Interconnection Process as approved by the Minnesota Public Utilities Commission (Docket No. E002/M-16-521). This process requires the Company to track DER installation costs for substation and distribution levels for all DER customers. We began collecting this data in 2019. We do not have a full data set to provide under these conditions for historical DER projects as it would take a significant amount of time and resources to gather this information. However, we have calculated costs at a substation and distribution level for all community solar gardens (Docket No.E002/M-13-867) and can report on the DER costs for community solar garden projects as shown in bills sent in a calendar year. In 2018, the Company billed Community Solar Garden projects $12 million dollars in substation costs and $32.5 million dollars in distribution costs for an approximate total of $44.5 million dollars.

In addition to this, we separately charge an engineering study fee for all DER interconnections. In 2018, these fees totaled approximately $3,361,600. Our administrated fee for administering the analysis of DER generation applications in addition to the customer fees was approximately $565,000. For the sake of clarity, the information we provide for 3.A.15 is only Xcel Energy costs. Where a customer has provided the Company information on its costs to install the generation system, we report this in our annual DG interconnection filing each March 1 in the "xx-10"

Docket.[80]

We provide further detail for regarding our other programs and the compliance filings completed yearly below.

<u>Solar*Rewards Community – Docket No. E002/M-13-867</u>

- Annual Report filed by April 1 every year (2018 Annual Report filed on April 1, 2019).
- *Deposits*: In 2018, we received $11.4 million for new projects into our deposit accounts and refunded $35 million, including any deposit that the Company was holding that the Garden Operator moved to escrow.
- *Application Fees*: The Company collected a total of $224,400 in application fees.
- *Participation Fees*: Annual participation fees were $84,000.
- *Metering Fees*: The Company administers metering charges for single-phase projects at $5.50 per month and for three-phase projects at $8.00 per month. These monthly metering fees are specified in the Section 9 Tariff, Sheet 75 and are consistent with previously approved metering charges for the A51 tariffed rate.

<u>Solar*Rewards – Docket No. E002/M-13-1015</u>

- Annual Report filed by June 1 every year (2018 Annual Report filed on May 31, 2019).
- Engineering Fees administered in 2018: $171,250

For future DER applications that will be subject to the MN DIP, we will begin to collect additional data at a more detailed level such as the inclusion of specific engineering fees by interconnection process.

2. Interconnection Process

In this section, we generally discuss our interconnection process and respond to IDP requirement 3.B.2 regarding data sources and methodology to complete the initial

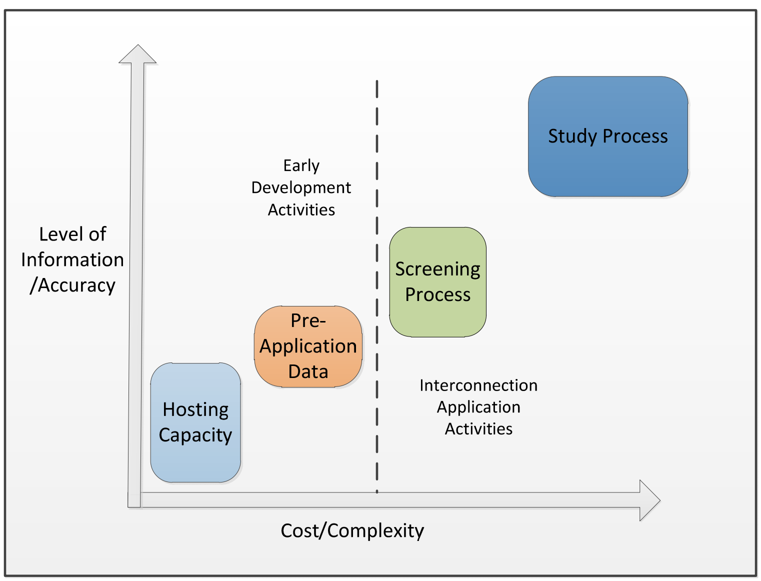
[80] *See*, for example, Docket No. E999/PR-18-10, available at this link: https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=viewDocument&documentId={C079E361-0000-C21F-8058-219C34801664}&documentTitle=20183-140701-02&userType=public

review screens in the MN DIP process.

The determination of exactly where and how much DER can be added to our system is determined through the interconnection process. Our annual HCA study has the potential to streamline the interconnection process both in the short- and longer-term. Today, the hosting capacity results are available to the public and can assist developers in choosing sites that require only screening or a less involved study. Screening is less expensive than engineering studies and typically can be completed on a shorter timeline.

Figure 67 below shows how the different components of our interconnection process currently works. The lower cost and complexity options of hosting capacity and pre-application data provide information developers information they can use to target points on the distribution system for interconnection prior to submitting an application. The screening and study processes occur after an application has been submitted and entered into engineering review.

Figure 67: Interconnection Processes



IDP Requirement 3.B.1 requires the following:

> *Describe the data sources and methodology used to complete the initial review screens outlined in the Minnesota DER Interconnection Process.*

MN DIP initial review screens use simple analysis with assumptions or readily available data to determine if a project requires further analysis due to the potential for grid impacts. The ten MN DIP initial review screens must be applied in concert to determine if a project has needs further analysis on voltage, thermal, or protection impacts. A few of the screens are related to the proposed DER being located in the Company's service territory and of a compatible wiring configuration. The specific initial review screen(s) that fail can inform more targeted analysis for the specific impact (i.e. voltage constraints). For example, one initial review screen states that the aggregate DER shall not exceed 15 percent of the peak annual loading on a given line segment. This screen approximates when reverse power flow may occur – a condition necessitating further analysis for steady state voltage rise and voltage fluctuation. For failure of any screens, the next level of analysis is performed in the MN DIP supplemental review process.

The MN DIP initial review screening methodology is relatively simple analysis that we implement in part through a spreadsheet tool. Other screens that check qualitative aspects of the interconnection are performed through review of application documentation. The initial review screens use system data and load characteristics available through a number of Company systems. We use our Geospatial Information System (GIS) to determine if the interconnection is within the Company's service area. GIS also assists in determining the aggregate amount of generation on a segment of interest. Feeder maps or GIS can be used to determine the presence of a voltage regulator, which is a relevant factor in one screen. Peak load information is retrieved from our DAA system, which we also use for system planning. Fault current can be retrieved by the OMS or a spreadsheet analysis tool.

C. Advanced Inverter and IEEE 1547 Considerations and Implications

In this section, we begin with general discussion regarding inverter advancements, then address IDP Requirements 3.A.7 and 3.A.33, as follows:

IDP Requirement 3.A.7

> *Discussion if and how IEEE Std. 1547-2018 impacts distribution system planning considerations (e.g., opportunities and constraints related to interoperability and advanced inverter functionality).*

IDP Requirement 3.A.33

> *Information on areas with existing or forecasted abnormal voltage or frequency issues that may benefit from the utilization of advanced inverter technology.*

Finally, we discuss our view of the impact of IEEE Std. 1547-2018 on interconnection standards/processes.

1. *Inverter Advancements*

Advancements in inverters can be utilized as one measure to reduce system impacts from PV and other inverter-based DER. A revision to the standard governing of the interconnection of DER with electric power systems (IEEE 1547) was published in April 2018.[81] The standard provides requirements on the performance, operation, testing of the interconnection and interoperability interfaces of DER. This revision includes several new requirements that address the technical capabilities associated with smart inverters and considerations necessary for the proliferation of DER on distribution systems, such as the ability to keep DER online – 'ride-through' – during abnormal conditions, controlling real power, and regulating reactive voltage. Furthermore, the latest revision of the standard specifies interoperability requirements, a design consideration in all of our advanced grid investments.

Currently, smart inverters that are compliant with and certified to the new standard are not available, but will be required by statewide technical requirements when available. The standard for test and conformance procedures necessary to certify inverters, IEEE 1547.1 is under development. Once available, Underwriters Laboratory will develop their testing certification standard (UL 1741). Once the inverter certification standard is available, equipment manufacturers will require time to change product lines. While the timeframe for standards development activities is fluid, we anticipate compliant and certified equipment will be available in or after the year 2020 or 2021.

An early step will be to adopt well-understood and in-use functions like fixed power factor, which are in use today and offer many of the benefits of the revised standard's functions. A recent EPRI study on a modeled radial distribution feeder with a large (almost 2 MW) solar system concludes that fixed power factor control resolves almost all voltage violations and that "modest control of reactive power can significantly reduce the voltage rise from the generator"[82] This is particularly important in Minnesota for the CSG large distributed generation systems, which are often deployed in remote areas where maintaining adequate voltage can be more challenging due to smaller conductor and a lower system strength.

Fortunately, we will have the opportunity to learn from peer utilities in states such as

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[81] See IEEE Publishes Standard Revision for Interconnection and Interoperability of Distributed Energy Resources (DER) with Associated Electric Power Systems Interfaces, Piscataway, NJ (April 2018). http://standards.ieee.org/news/2018/ieee_1547-2018_standard_revision.html

[82] *See Voltage Regulation Support from Smart Inverters,* Electric Power Research Institute, Palo Alto, CA, Page 8 (December 2017).

Hawaii and California, who have greater DER penetration levels. Since 2014, California has required smart inverters with seven autonomous functions, including both fixed power factors and dynamic Volt-VAr operation; however, even though inverters were installed with advanced capabilities, the use of these functions is being phased deliberately to confirm the various functions work as modeled.[83]

There are commercially-available inverters that meet this advanced functionality based on California rules without being certified to the IEEE 1547-2018 standard. As we learn more about the capabilities of inverters that are IEEE 1547-certified – or that meet California's standards – and we phase-in the investments of our advanced grid roadmap, we will be able to advance our related capabilities over time. Our stepped approach begins primarily with managing inverters to a fixed power factor – and as they become available, adopting the standard settings for Volt-Var and Volt-Watt operations based on industry recommendations and experience. The inverters will inherently have "ride-through" capabilities that in aggregate will prevent contributing to grid instability during a short-term transmission or generation event. Looking ahead, as we develop our modeling and simulation capabilities and phase in our investments, we will be able to evaluate more updated inverter capabilities and evaluate the benefits.

2. *Planning Considerations Associated with IEEE 1547-2018*

IDP Requirement 3.A.7 requires the following:

> *Discussion if and how IEEE Std. 1547-2018 impacts distribution system planning considerations (e.g., opportunities and constraints related to interoperability and advanced inverter functionality).*

Advanced functions offer additional capabilities from the DER side to mitigate the impacts of the interconnected DER. While modeling and simulation tools for distribution planning are evolving to include these functions, the impacts, study practices, and requirements of how to implement and use these while protecting grid integrity (i.e. safety and reliability) and generation with queue priority, still need to be developed.

The standard IEEE 1547-2018 scope is focused on the interconnection and interoperability requirements for DER. These requirements are specified through

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[83] *See* Interim Decision Adopting Revisions to Electric Tariff Rule 21 FOR Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company to Require "Smart" Inverters, Decision 14-12-035, Rulemaking 11-09-011, Page 4 (December 2014).

standard interfaces for both power and communications for the purpose of integrating DER into safe and reliable grid operations. A degree of optionality exists in the standard for advanced functions and capabilities. For example, the standard required DER be capable of a producing or consuming a range of reactive power, while it also specifies the default setting use of reactive power.

Distribution System Planning considerations including integrating DER into capacity expansion plans and grid support functions required by IEEE 1547-2018 may provide additional tools to mitigate voltage conditions caused by DER. It is important that the standard requires DER equipment be capable of providing a range of reactive power control for the lifetime of the DER as it provides necessary future proofing for mitigating voltage issues due to changes in system configuration or other anticipated changes to grid conditions. The Company currently uses a non-unity fixed power factor approach for mitigating DER caused voltage issues and reserves a power factor range of +/- 0.9 in operating agreements. While the reactive power range in use today aligns with IEEE 1547-2018, the standard offers additional control modes. The Company is evaluating the use of other real and reactive power control modes to determine benefits, drawbacks, and most suitable use of each.

In order for the advanced function to be fully integrated into distribution planning processes, the appropriate study practices and requirements must evolve to incorporate advanced functions. Because of the active response of advanced inverter function study methodologies need to move to time series analysis to fully understand their impact on the system. For example, an inverter volt-var function can interact with utility voltage regulation equipment since both have a time element to their control logic. This type of interaction could create a reliability issue due to voltage regulation equipment failing prior to end of life. We are tracking the progress of industry modeling tools that incorporate advanced inverter functions and how they are being used and studied. While we do not anticipate the advanced functions to lead to a substantial increase in hosting capacity when compared to current approach, they do offer the potential for increasing the efficiency of power delivery on the distribution system (i.e. reduced losses).

The interoperability capabilities required by IEEE 1547-2018 are related to exchanging information with the DER, including monitoring and control points. This aspect of the standard is the most future-leaning and is unlikely to be in widespread use across the United States in the near term. Using the DER interoperability interface, any DER advanced function required by the standard can be changed remotely if a communication network is established between the utility and DER system. In the more distant future, it is possible that different advanced functions are employed during different times of the day or year through a centralized control system such as DERMS. This flexibility to change between functions to better meet grid conditions at the time might offer yet another tool for mitigating DER-caused issues during distribution planning processes that involved power flow studies. As this functionality and associated products develop, it will be important to understand the costs and associated benefits to implement such a strategy.

The modeling and simulation tools needed for real time control of these systems are not in place today for the use described here. The field communication networks and backend control systems are also not in place to employ this type of use, but the Company continues to explore how the interoperability interface can best be used for integrating DER into all aspects of utility operations.

3. Advanced Inverters Response to Abnormal Grid Conditions

IDP Requirement 3.A.33 requires the following:

> *Information on areas with existing or forecasted abnormal voltage or frequency issues that may benefit from the utilization of advanced inverter technology.*

A driving factor for modifying national interconnection standard IEEE 1547-2018 is to require DER to provide support for wide area grid disturbances originating from the bulk electric system (Transmission and Generation). The standards apply to all DER, including PV inverter-based generation. Historically, DER was required to trip for minor grid disturbances. A large amount of DER tripping all at once has the potential to worsen the grid condition that caused the DER to trip in the first place. IEEE 1547-2018 requires the capability to ride-through grid voltage or frequency disturbances and allows a wide range of trip settings to provide Regional Transmission Operators, Independent System Operators, Transmission Operators, and Distribution Operators with options that balance the sometimes differing technical objectives of these stakeholders. MISO has initiated a process to collect stakeholder input and provide guidance on preferred DER settings associated with response to abnormal grid conditions.

Abnormal grid conditions such as voltage or frequency disturbances are difficult to forecast as they are typically associated with rare events such as large generators tripping or transmission line faults. Furthermore, the location of a faulted circuit greatly impacts the resulting voltage disturbance observed across the system. In contrast, any frequency disturbances observed in Minnesota are system wide phenomena across the entire Eastern Interconnect. Transmission line faults and voltage disturbances are the more common when compared to generator tripping and frequency disturbances. In general, system studies that evaluate the impact of abnormal conditions look at the worst case anticipated condition. Using a voltage disturbance to illustrate, one would look to find the most severe voltage depression caused by a transmission line fault in order to anticipate and mitigate any adverse impact to the electric system. The Company anticipates analysis along these lines will be part of the MISO stakeholder process and that appropriate guidance will be issued on the use of advanced inverter abnormal response function. The Company views Minnesota statewide DER Technical Interconnection and Interoperability Requirements being developed in Phase II of E999/CI-16-521 docket as the proper place to address DER abnormal response functions.

4. *Impact of IEEE 1547-2018 on Statewide Interconnection Standards*

As we have discussed, IEEE 1547-2018 is a recently published DER interconnection and interoperability standard. We are in the process of adopting the standard and determining implementation pathways for the numerous options it offers.

The revised standard addresses three new broad types of capabilities for DER: (1) local grid support functions; (2) response to abnormal grid conditions; and (3) exchange of information with the DER for operational purposes. The standard was written with a large set of required capabilities with an expectation that not all capabilities would be immediately implemented in the field. In this way, it offers options for grid operators preparing for scenarios with high penetration of DER. Some details associated with implementing the standard are part of the Commission's E999/CI-16-521 docket, especially in Phase II, which considers statewide technical standards, and other details are expected to be associated with Company business practice decisions.

In terms of specifying DER response to abnormal grid conditions, IEEE 1547 indicates that the Authority Governing Interconnection Requirements and Regional Reliability Coordinator possess a guidance role in implementing these capabilities, which, in Minnesota, are the Minnesota Commission and MISO respectively. Commission Staff requested information and guidance from MISO through a working group associated with the E999/CI-16-521 docket. The response from MISO included a plan to convene a stakeholder group so that guidance on the topic could be provided on a regional basis. The Commission's interest in resolving questions associated with adopting these capabilities is helping to drive important stakeholder conversations.

Local grid support functions have generated interest in the industry in recent years based on implementation of these functions in states such as Hawaii and California in areas of high DER deployment. The IEEE 1547-2018 standard allows the Company to specify how local grid support functions are used. The Company is exploring a stepped approach for implementing more advanced functions, such as volt-var, with the objective of enabling for segments of DER in a way that has the greatest benefit on hosting capacity while maintaining grid operating capabilities. The Company proposed in the E999/CI-16-521 docket that use of the local grid support functions should be published in utility-specific technical manuals.

The interoperability aspects of IEEE 1547-2018, which include concepts of DER monitoring and control, mark the most future-leaning required capabilities. When certified equipment is available, every DER will have a standardized communication interface for exchanging data and performing remote operations. A communication network would be necessary for making use of the interoperability interface. The Company is evaluating pathways for implementing the interoperability interface in the future.

XIII. EXISTING AND POTENTIAL NEW GRID MODERNIZATION PILOTS

In this section, we discuss the status of existing grid modernization pilot projects and potential new pilot programs.

IDP Requirement 3.D.2 requires the Company to provide:

> [the] …*status of any existing pilots or potential for new opportunities for grid modernization pilots.*

A. Grid Modernization Pilots

1. Time of Use Rate Pilot

As discussed in this document previously, we received Commission approval for a residential TOU rate pilot that involves two-way communication FAN infrastructure and AMI.[84] The pilot is scheduled to start in early 2020. As a part of the pilot, selected residential customers will switch to a rate design with variable pricing based on the time of day energy is used. Through the pilot, we will provide participants with new metering technology, increased energy usage information, education, and support. The pilot is designed to encourage shifting energy usage to daily periods when system load conditions are normally lower. Strategies that shift load away from

[84] *See* Docket No. E002/M-17-776.

peak times may reduce or avoid the need for system investments in fossil fuel plants that serve peak electric load.

We have begun deployment of advanced meters to approximately 17,500 residential customers. The customers are spread between two geographic locations, customers served out of the Hiawatha West/Midtown substation in Minneapolis, and the Westgate substation in Eden Prairie and surrounding communities. Deployment of meters began in Q3 2019 and will continue until early 2020. Approximately 10,000 of the customers receiving new meters will be enrolled in a new rate structure, while 7,500 will be included in a control group. The new rate structure is designed with pricing for three time periods corresponding to our system's profile at on-peak, mid-peak, and off-peak times.

The pilot was developed with the engagement of stakeholders and with the benefit of learnings from our pilot in our Colorado service territory. Through the pilot, we will study the impact of rigorously designed price signals and technology-enabled data on customer usage patterns for a subset of customers. We intend to operate the pilot for two years and will share learnings about the effectiveness of these techniques to generate peak demand savings. We will explore the performance of the selected technology, the impact of the price signals, and the effectiveness of customer engagement strategies, and will use the pilot experience to inform future consideration of a broader TOU rate deployment in Minnesota.

2. Charging Perks-Colorado Pilot

PSCo filed a Charging Perks pilot in late August with the Colorado Public Utility Commission as a pilot for inclusion in its 2019/2020 Demand Side Management Plan. The Company is seeking to work with several automobile original equipment manufacturers to manage home charging on behalf of up to 600 electric vehicle drivers. By managing when an EV charges at home, the pilot proposes to test how smart charging can shift charging outside of system peak hours and into hours that have lower production costs. In addition, the pilot will test how smart charging can support renewable integration by increasing load during hours when wind power is being curtailed due to high production and low demand. Participating customers will receive $100 for enrolling and another $50-$100 for each year they participate in the pilot. For more information, see https://www.xcelenergy.com/staticfiles/xe-responsive/Company/Rates & Regulations/Charging-Perks-Pilot-Product-Write-Up.pdf.

3. *Residential Battery Demand Response Pilot*

The Colorado Commission approved a Residential Battery Demand Response Pilot that will test how batteries can provide energy during peak hours, perform solar time shifting, and absorb energy during hours of low cost production as part of PSCo's 2019/2020 Demand Side Management Plan. The Company is currently selecting one or more vendors that will allow it to manage a battery that a residential customer installs at their home. Participating customers will receive $500 upfront and $10/month during the course of the pilot. For more information, see https://www.xcelenergy.com/staticfiles/xe-responsive/Company/Rates & Regulations/Regulatory Filings/DSM-Plan.pdf (*Note*: Pilot description starts at page 321 of the PDF).

4. *Continuing Projects*

In our 2018 IDP, we reported on two PSCo projects: (1) Pena Station/Panasonic Battery Demonstration Project, and (2) Stapleton Battery Storage Project – summarized below:

Pena Station Project. Through a public/private partnership, Xcel Energy, Panasonic, and Denver International Airport are partnering on a battery demonstration project.[85] The pilot project – located at Panasonic's Denver operations hub within the new 400-acre Peña Station NEXT development just southwest of the Denver airport – will examine how a battery storage system helps: (1) facilitate the integration of renewable energy, (2) Enhance reliability on the distribution system, (3) assist in providing voltage management and peak reduction, and (4) provide power to Panasonic in case of a grid outage by functioning as a microgrid.[86] The demonstration project is composed of four primary components: (1) a 1.3 MW ac carport solar installation (the carport is owned by the airport, but the solar system is owned by Xcel Energy (2) a 0.20 MW ac rooftop PV system at Panasonic's facility, owned by Panasonic, (3) a 1 MW/2 MWh lithium ion battery system supplied by Younicos, owned by Xcel Energy and maintained by Panasonic, and (4) the switching and control systems to operate the energy storage system and microgrid functionality, owned by Xcel Energy.

Stapleton Project: The Stapleton project is aimed at examining how battery storage can help integrate higher concentrations of PV solar energy on our system.[87] As part of

[85] See Colorado PUC Docket 15A-0847E.
[86] For additional information, *see* https://www.xcelenergy.com/staticfiles/xe-responsive/Energy%20Portfolio/CO-Panasonic-Fact-Sheet.pdf
[87] *See* CPUC Docket 15A-0847E

an energy storage demonstration project, Xcel Energy is installing six in-home batteries and six larger batteries on the distribution feeder in Denver's Stapleton neighborhood. The batteries will operate to manage solar integration and also support other areas of the grid. For the six large scale batteries, we are installing two sets of 18 kW batteries, two sets of 36 kW batteries and two sets of 54 kW batteries. The customer in-home batteries are six 6 kW batteries. Xcel Energy is particularly interested in learning about how battery storage can help: (1) increase the ability to accommodate more solar energy on our system, (2) manage grid issues such as voltage regulation and peak demand, and (3) reduce energy costs.[88]

We have been providing status reports in Docket No. E002/M-17-776 for these projects. Our most recent status report from August 16, 2019 can be accessed on eDockets at:
https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={90D19A6C-0000-C233-B680-8B1CEC95C8E3}&documentTitle=20198-155243-02

Electric vehicles are often combined into discussions related to grid modernization – and EVs are included in the Commission's definition of DER for purposes of integrated distribution planning in Minnesota. Therefore, we also summarize EV pilots we have underway and that we have recently proposed.

B. Electric Vehicle Pilots

We have received Minnesota Commission approval of four electric vehicle (EV) pilot programs: (1) a Residential EV Service Pilot, (2) a Residential EV Subscription Service Pilot, (3) a Fleet EV Service Pilot, and (4) a Public Charging Pilot. Each of the pilots was developed with significant engagement of stakeholders.

1. *Residential EV Service Pilot*

While participation in our Residential EV Charging Tariff has grown steadily, the upfront cost of installing a second meter has been a barrier to some customers enrolling. To address the issue of upfront installation costs, we developed a Residential EV Service Pilot. As a part of the pilot, the need for a second meter is eliminated and is replaced by Company-provided Electric Vehicle Service Equipment (EVSE). The EVSE provides billing-quality data through a wireless internet connection at the customer's premises, which makes off-peak charging rates available

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[88] *See* also https://www.xcelenergy.com/staticfiles/xe-responsive/Energy%20Portfolio/CO-StapletonBatteryProject-Info-sheet.pdf

without a second meter to measure usage. Interest in the pilot was high, and the limit of 100 participants was reached in a short period of time.

With continued interest in this type of service, the Company has proposed to expand the service into a conventional offering, called Electric Vehicle Home Service. The permanent service will be functionally similar to the pilot. Our proposal is currently pending Commission consideration; we hope to launch the conventional offering sometime in 2020.

2. Residential Subscription Service Pilot

We further expanded our residential offerings by developing a Residential EV Subscription Service Pilot, which is based on much of the structure of the Residential EV Service Pilot. The pilot will allow customers to charge off-peak for a preset monthly fee. This will encourage off-peak charging and offer customers certainty in monthly charging costs. Similar to the Residential EV Service Pilot, Company-provided EVSE will be used to measure charging. Enrollment in the pilot is capped at 100 participants. We expect to launch this pilot at the start of 2020.

3. Fleet EV Service Pilot

Under this three- year pilot, the Company will install, own, and maintain EV infrastructure for fleet operators in order to reduce these customers' upfront costs for EV adoption. Fleet operators participating in the pilot are required to take service under time-of-use rates for their EV charging and all chargers will need to have smart charging capabilities. Additionally, the Company will provide advisory services to fleet operators, including information relative to fleet conversion decisions. We are currently working with three fleet customers as a part of the pilot: Metro Transit, the Minnesota Department of Administration, and the City of Minneapolis. Additional participants will be considered. The Company is required that at least one must be a public entity with a primary location outside Ramsey and Hennepin Counties.

We have had discussions with Metro Transit on partnering for even larger fleet electrification efforts. Metro Transit is considering adding bus charging capabilities to a new bus garage planned for the North Loop area of Minneapolis. Our discussions with Metro Transit have included Metro Transits plans to add charging infrastructure for up to 100 buses at this new facility. The current estimate is that work on this facility will begin in the second half of 2020, with completion in 2021. Beyond charging infrastructure, the new garage project may also include work that supports advanced energy infrastructure.

4. *Public Charging Pilot*

In the Public Charging Pilot, the Company will install, own, and maintain EV infrastructure for developers of public charging stations along corridors and at community mobility hubs. Unlike the Fleet EV Service Pilot, the Company would not own or maintain any charging equipment. The goal of such investments is to increase publicly available charging options by decreasing these customers' upfront costs. Customers participating in this pilot would be required to pay time-of-use rates for their EV charging. Under this pilot, we estimate we would be able to facilitate installation of approximately 350 charging ports.

There are two main parts to this pilot. The first is the development of community mobility hubs. For this, we will be partnering with the cities of St. Paula and Minneapolis to develop the hubs, with HOURCAR serving as a car-sharing anchor tenant. These charging hubs may also be utilized by transportation network companies (*e.g.*, Uber and Lyft), and the public, including customers who do not have EV charging capabilities at home. Secondly, we will be working with applicants to leverage available public and private funding. Specifically, the pilot is available to applicants who plan to invest in deploying fast-charging stations along corridors in our service territory, specifically targeting applicants seeking funds from Minnesota's Diesel Replacement Program funded by the Volkswagen Environmental Mitigation Settlement (VW Settlement) and administered by the Minnesota Pollution Control Agency (MPCA).

Although there has been limited deployment of public charging to date, it is a critical enabler for EV market expansion. Key reasons for including the public charging component in our EV portfolio are that it can support longer distance driving, address range anxiety, and provide charging solutions for those who are not able to charge at home.

C. Potential New Pilots

With regard to new opportunities for grid modernization and electric vehicle pilots, since our 2018 IDP, we proposed an ENERGY STAR-certified Level 2 electric vehicle "smart" charger pilot with the Department of Commerce as a modification to our current Conservation Improvement Program. The pilot proposed to study how a combination of incentives or rewards encourages smart charging of EVs – enabling the management of EV charging as a demand response resource. The pilot was denied approval on June 12, 2019.[89]

We are currently evaluating the following pilot and will bring it forward to the Commission for approval as necessary in the future.

- *Vehicle-to-Grid Demonstration with School Buses:* This demonstration project would test the use of electric school bus batteries as grid resources. We believe this type of pilot can deliver learnings about the use of bus batteries as energy storage resources and also collect information related to local peak demands. We are currently in the process of identifying vendors and school districts to participate in a demonstration project. This is a relatively new area of vehicle electrification and work is needed to determine program viability.

XIV. ACTION PLANS

In this section, we provide a 5-year action plan as part of a long-term plan for the distribution system, as required by filing requirement 3.D.2. We note that in the Commission's July 16, 2019 Order in Docket No. E002/CI-18-251, the Commission merged the separate action plan required by IDP requirement 3.D.1 into 3.D.2, as indicated in redline below.[90] The Order also modified the cost-benefit analysis requirement in requirement 3.D.2 as shown in redline below.[91]

> *Xcel shall provide a 5-year Action Plan as part of a 10-year long-term plan for distribution system developments and investments in grid modernization based on internal business plans and considering the insights gained from the DER futures analysis, hosting capacity analysis, and non-wires alternatives analysis. The 5-year Action Plan should include a detailed discussion of the underlying assumptions (including load growth assumptions) and the costs of distribution system investments planned for the next 5-years (expanding on topics and categories listed above). Xcel should include specifics of the 5-year Action Plan investments. Topics that should be discussed, as appropriate, include at a minimum:*
>
> - *Overview of investment plan: scope, timing, and cost recovery mechanism*
> - *Grid Architecture: Description of steps planned to modernize the utility's grid and tools to help understand the complex interactions that exist in the present and possible future grid scenarios and what utility and customer benefits that could or will arise.*
> - *Alternatives analysis of investment proposal: objectives intended with a project, general grid modernization investments considered, alternative cost and functionality analysis (both for the utility and the customer), implementation order options, and considerations*

[89] *See* Docket No. E,G002/CIP-16-115, Department of Commerce Decision, (June 12 2019).
[90] *See* Ordering Point No. 4.
[91] See Ordering Point No. 3

made in pursuit of short-term investments. The analysis should be sufficient enough to justify and explain the investment.

- *System interoperability and communications strategy*
- *Costs and plans associated with obtaining system data (EE load shapes, PV output profiles with and without battery storage, capacity impacts of DR combined with EE, EV charging profiles, etc.)*
- *Interplay of investment with other utility programs (effects on existing utility programs such as demand response, efficiency projects, etc.)*
- *Customer anticipated benefit and cost*
- *Customer data and grid data management plan (how it is planned to be used and/or shared with customers and/or third parties)*
- *Plans to manage rate or bill impacts, if any*
- *Impacts to net present value of system costs (in NPV RR/MWh or MW)*
- *For each grid modernization project in its 5-year Action Plan, Xcel should provide a cost-benefit analysis based on the best information it has at the time and include a discussion of non-quantifiable benefits. Xcel shall provide all information used to support its analysis.*
- *Status of any existing pilots or potential for new opportunities for grid modernization pilots.*

We summarize our 5-year and long-term action plans and associated customer impacts below. However, rather than attempt to summarize our fulfillment of each of the above requirements in this section, we provide a roadmap of where we have addressed them elsewhere in the body of this IDP filing via an Action Plan Roadmap, provided as Attachment J.

A. Near-Term Action Plan

The first five years of our action plan will be focused on providing customers with safe, reliable electric service, advancing the distribution grid with foundational capabilities including AMI, FAN, FLISR, and IVVO – and procuring enhanced system planning tools to advance our localized load forecasting capabilities and our abilities to perform scenario analysis, and incorporate DER and NWA analysis into our planning.

In the balance of this section, we summarize near-term actions by subject, where we intend or expect to take specific actions. We also use this section to comply with the portions of IDP Requirement D.2 that we have not yet addressed elsewhere in this IDP.

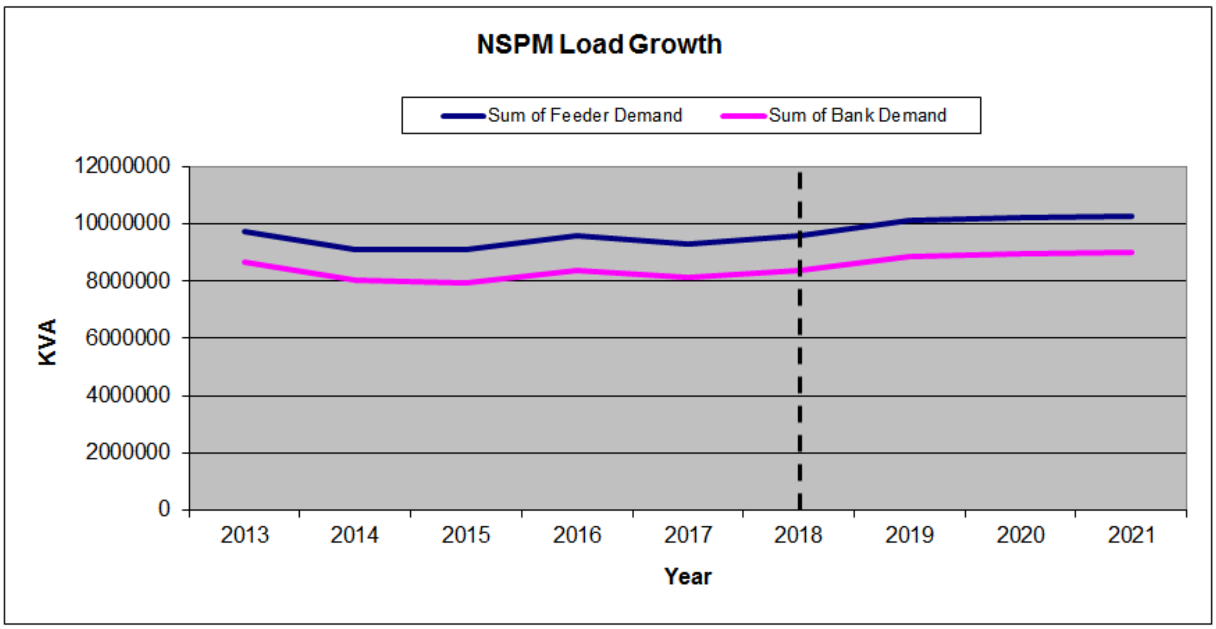
1. *Load Growth Assumptions*

IDP Requirement D.2 requires, in part:

> *The 5-year action plan should include a detailed discussion of the underlying assumptions (including load growth assumptions) and the costs of distribution system investments planned for the next 5-years…*

Figure 68 below provides the load growth assumption stemming from our Fall 2018 system planning analysis, as described in Section V.B. above.

Figure 68: Distribution System Planning Load Growth Assumptions NSPM Electric Jurisdiction



We additionally provide load growth assumptions for smaller portions of the NSPM geography in Minnesota that stemmed from this same analysis as Attachment K to this IDP. Please also see the capital projects list sorted into the IDP driver categories that we provide as Attachment F1 to this IDP. These pieces of information together with the detailed discussion in this IDP about our analyses and assumptions fulfill this IDP requirement.

2. *Grid Modernization*

While discussed in detail above and as attached to this IDP, we summarize here that our advanced grid roadmap is the continuation of efforts that have been underway for several years. The early steps of this transition are focused on building the foundational elements needed to enable more advanced applications at the "pace of value" for our customers. This means that investments are logically sequenced to build capabilities as they are needed and incrementally upon each other.

Accounting for this foundational approach and grid modernization principles and goals, our near-term plans involve the following advanced grid projects: (1) AMI, (2) FAN (3) FLISR and (4) IVVO as we have described in this IDP, and as summarized below:

Table 56: AGIS Implementation Timeline

Program	Implementation Timeline
ADMS	In-service 2020
AMI	Meter roll-out 2021-2024
FAN	Deployment 2021-2024 (preceding AMI deployment by approximately six months)
FLISR	Limited testing 2020; Implementation 2020-2028
IVVO	Limited testing 2021; Implementation 2021-2024

We also intend to submit the following associated filings during the 5-year action plan period, requesting necessary Commission approvals and eliciting stakeholder input:

- Opt-out provisions – requesting approval of the processes, cost structure, and tariffs necessary to allow customers to opt out of AMI meter installation (2020);
- AMI billing – requesting approval of a rule variance and any tariff changes necessary to enable AMI interval billing (2020);
- Future filing to enable remote connect/disconnect capabilities;
- Future filing to request approval of a pre-pay option for customers; and
- Future service quality reporting under Minnesota Rules (beginning April 1, 2022) and the Company's Quality of Service Plan (QSP) (beginning May 1, 2022) to address any impacts to service quality metrics as a result of AGIS implementation.

As discussed further in part 4 below, the TOU pilot will be underway beginning in April 2020 and is expected to conclude in 2022. The learnings from this pilot, with respect to both the rate and new products and services, will help inform our plans for advanced rates in the future, such as a full TOU rate for residential customers, or other pricing options.

Finally, with respect to our ADMS initiative, we will be submitting an initial and ongoing annual reports in accordance with the Commission's September 27, 2019 Order in the Company's Transmission Cost Recovery (TCR) Rider Docket.[92] The timeline for the initial report is 120 days after the date of the Order (January 25, 2020); the timing and procedure for the annual report will be set by the Executive Secretary. Because the initial and ongoing annual reports contain most of the same elements, we propose to submit a single ADMS report by January 25, 2020 in the TCR docket and this IDP docket that contains all of the required information. We also respectfully request that the Executive Secretary establish the same January 25th due date for the ongoing annual ADMS reports beginning January 25, 2021 – and that they be filed in the same docket as future IDPs.

3. *Investment Plan and Customer Rate Impacts*

IDP Requirement D.2 requires the following, in part:

> *Overview of investment plan: scope, timing, and cost recovery mechanism.*

As we have outlined in Section XV, Procedural Proposal, we summarize here that one of the major focuses of this IDP is our request for certification of an array of investments to modernize the Company's distribution system, pursuant to Minn. Stat. § 216B.2425. Specifically, we are seeking certification of an advanced distribution planning tool and a number of investments that are part of what is collectively referred to as the AGIS initiative: AMI, FAN, FLISR, and IVVO. Each of these investments will take years to fully implement, and we are requesting that the Commission certify the AGIS projects pursuant to Minn. Stat. § 216B.2425, subd. 3, so that the Company may request recovery of costs in concurrent or subsequent filings, as necessary.

We are also filing a General Rate Case (Docket No. E002/GR-19-564) today with a three-year plan through which we seek cost recovery for much – but not all – of these AGIS investments. Because the span of the AGIS investments goes beyond the 2020 test year and 2021-2022 plan years identified in our MYRP filing, and in light of the concurrent submission of this 2019 IDP, our AGIS rate case testimony provides support for our AGIS investments beyond the term of the rate case and addresses Commission requirements that pertain to both certification and cost recovery for grid modernization investments. In light of this support for our long-term strategy, we

[92] Docket No. E002/M-17-797.

believe certification of the full scope of the AGIS investments alongside a rate case cost recovery determination is critical, so that we may complete our AGIS investments at an appropriate pace and potentially include the out-year costs in a rider.

Additionally, IDP Requirement D.2 requires the following, in part:

> …*Plans to manage rate or bill impacts, if any.*
>
> *Impacts to net present value of system costs (in NPV RR/MWh or MW)*…

Ordering Point No. B.2 in the TCR Docket E002/M-17-797 also requires several cost and benefits information and analyses, in addition to a long-term bill impact analysis. We provide this information in detail in the attached AGIS-related Direct Testimony provided as Attachments M1 to M5, and summarize the bill impact analysis in this section.

Keeping customer bills low is a core strategy of the Company and is a central consideration of our AGIS initiative. The combined AGIS investment will provide significant value to our customers and will have an impact to customer bills from the increased revenue requirement due to our investments and O&M spend necessary to implement the AGIS initiative.

To estimate customer bill impacts, we performed a high-level revenue requirement analysis for 2020 through 2024 to illustrate the incremental revenue requirement and estimated bill impact of AGIS implementation. We summarize our approach, which results in an overall cost per kilowatt hour (kWh), in Section IX.G of this IDP – and present the AGIS revenue requirement in the Direct Testimony of Mr. Gersack as Exhibit___(MCG-1), Schedule 9. Based on average monthly residential customer usage of 675 kWh, this assessment shows an estimated 2024 bill impact for our AGIS investments of approximately $2.87 per month for an average residential customer.

We also assessed an alternative investment and costs if the Company does not implement the AGIS initiative. As we have discussed, it is not feasible for the Company to continue to use its current AMR meters because they are nearing end of life, and the Company's contract with Cellnet for meter reading service and support expires at the end of 2025. As such, the Company would, at a minimum, need to invest in new meters and provide meter reading services in order to continue to provide electric service to our customers. This means that even without AGIS implementation, there would be an incremental impact to customers' bills for an alternative metering service.

Therefore, in addition to the AGIS revenue requirement, we developed a reference case scenario to represent an alternative to our AGIS investments. The reference case reflects the necessary investments and costs if the Company were to pursue a basic AMR drive-by meter reading alternative, which is discussed in the Direct Testimonies of Ms. Bloch and Mr. Cardenas. We calculated the bill impact by using the revenue requirements for the AMR drive-by alternative and calculated the estimated bill impact as described above. We present the reference case revenue requirement in the Direct Testimony of Mr. Gersack as Exhibit___(MCG-1), Schedule 10. This assessment shows an estimated 2024 bill impact for the AMR drive-by alternative of approximately $1.51 per month for an average residential customer.

The key comparison and impact is the difference between the estimated bill impact of AGIS implementation versus the basic alternative, as shown below.

Table 57: Estimated Monthly Bill Impact – Typical Residential Customer

	2020	2021	2022	2023	2024
AGIS	$0.44	$1.33	$1.84	$2.58	$2.87
Reference Case	$.01	$0.19	$0.62	$1.18	$1.51
Difference	**$0.43**	**$1.14**	**$1.22**	**$1.40**	**$1.36**

Table 57 illustrates the incremental bill impact of pursuing our AGIS investments compared to the investments that would otherwise be necessary. In other words, the difference reflects the costs that will enable all the benefits of the advanced grid, both quantifiable and non-quantifiable, that AMR meters simply will not provide. Table 57 also illustrates that costs of AGIS will be spread over the implementation period, which reasonably manages the bill impact for our customers.

We provide a calculation of the NPV of the Distribution function as Attachment L to this IDP, in compliance with the above requirement.

4. *Grid Modernization and EV Pilot Projects*

As we have discussed previously, we have several grid modernization and EV-related pilot programs that have been approved by the Commission, and others that have been proposed.

On the Grid Modernization side as we noted above, our TOU Rate Pilot has been approved and will be launched in early 2020. The goals of the TOU pilot are to study adequate price signals to reduce peak demand, identify effective customer engagement strategies, understand customer impacts by segment, and support demand response goals. This pilot will provide us with an opportunity to better understand how customer react to a four-part rate (off peak, two shoulder peaks, and an on-peak period) as well as test tools and resources that may help customers adjust their energy usage to keep their bills low and better control their energy costs. The TOU pilot is expected to conclude in 2022.

On the EV-related side, the Company has several approved pilots that have launched, or will launch soon. Those pilots include:

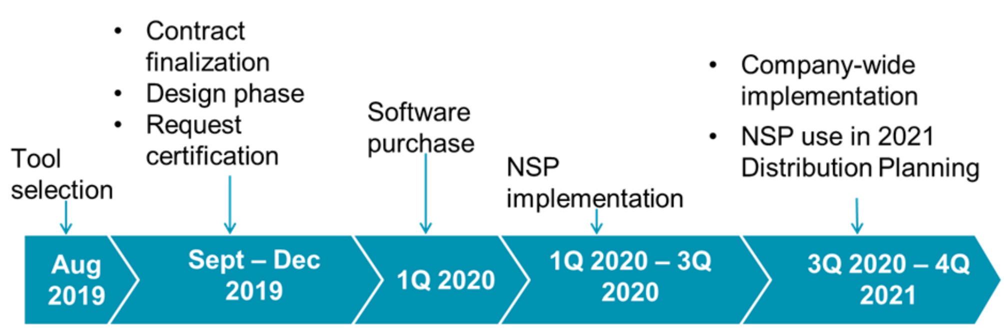
- Residential EV Home Service Pilot
- Fleet EV Service Pilot
- Public Charging Pilot
- Residential EV Subscription Service Pilot

The Company has a proposal in front of the Commission to expand our Residential EV Home Service Pilot to a broader, conventional offering called Electric Vehicle Home Service. We have also previously outlined several new opportunities for grid modernization and electric vehicle pilots that we are currently evaluating. We intend to bring them forward to the Commission for approval, as appropriate.

5. *Advanced Planning Tool*

We are currently finalizing the contract details with the vendor, which will enable us to move through the purchasing process early in the first quarter of 2020.

Figure 69: Planned APT Implementation Timeline[93]



[93] Note this implementation schedule remains fluid and subject to change.

After finalizing the procurement, design, implementation, testing, which will take place over the next several months, we anticipate the APT will be fully operational in time to use it in our 2021-2025 distribution planning cycle in late 2020.

6. Incremental System Investment Plan

The ISI initiative is driven by the need to improve reliability on those elements of the system that are the closest to our customers as well as provide the infrastructure to support increased customer choice and the adoption of DER, such as EVs. This initiative will both expand existing asset health programs and will create new programs to address areas of the system that have traditionally not received much focus. The ISI initiative is divided into four main programs: substation, underground, overhead tap, and overhead mainline, and is expected to get underway in 2021.

In the interim, we will be planning the implementation of the various programs, and taking actions as part of the programs such as:

- Start the targeted undergrounding program with several pilot areas – undergrounding 20 miles of overhead tap system in 2021 and 30 miles in 2022.
- Install up to 500 low cost reclosers in 2021 and 2022.
- Reinforce the equipment on up to 900 poles in 2021 and 2022.
- Under our Transformer and Secondary Replacement program, we plan to replace the transformer and the associated secondary wire at up to 150 locations in 2021 and 2022.
- Address up to 200 different high customer count taps in both 2021 and 2022.
- Under our Community Resiliency program, we plan to install the equipment necessary to provide back-up power at one strategic location in 2022.
- Our cable replacement program will supplement our existing program, and we plan to replace up to four additional miles of mainline cable in 2021; up to nine additional miles of mainline cable in 2022; replace 10 additional miles of URD cable in 2021; and, up to 12 additional miles of URD cable in 2022.
- We plan to perform up to 60 miles of cable assessment and rehabilitation in 2021 and 2022.
- Under our Network Monitoring program, we plan to have one network in service with live monitoring in 2022.
- We expect, given the challenges St. Paul Tunnel Rehabilitation program and the required coordination that this project may take up to 15 years to complete. We expect however, the first assets will be placed in service in 2021 and 2022. The first assets will include the first conduit vaults and duct vaults that will be required to move our electrical equipment out of the tunnels.

- We will in-service up to eight feeder exits in 2021 and 2022.
- Under the Substation Transformer Replacement program, we will replace up to four additional transformers in 2021 and approximately 10 additional transformers in 2022.
- We plan to replace up to 32 breakers, 42 relays, and 5 RTU/LCUs at multiple substation locations across Minnesota during 2022 as part of our Substation Asset Renewal program.
- We plan to address up to 500 poles with our Pole Fire Mitigation program in 2021 and 2022.
- We expect to replace up to 1,000 lighting arrestors in 2021 and 2022.

7. Demand Side Management

The five year action plan for Demand Side Management, which includes both energy efficiency and demand response, will be largely determined through our IRP and future Minnesota CIP Triennial filings.

a. Energy Efficiency

In terms of energy efficiency, our expectation is that the 2.5 percent goal proposed in the IRP will be the central focus of energy efficiency during the 10-year IDP period. In order to continue meeting and exceeding this goal, we will invest in expanding existing opportunities and bringing new opportunities to market. We will also be looking to new ways to maximize benefits for customers that may alter traditional delivery strategies and tactics that will support the integration of renewable resources and DER. We will detail our specific plans and implementation strategies for these in our upcoming 2021-2023 CIP Triennial filing, which we will submit in June of 2020.

b. Demand Response

Demand Response will be heavily influenced by our efforts to achieve the incremental 400 MW by 2023 requirement that stemmed from our 2015 IRP in Docket No. E002/RP-15-21. We expect our delivery of DR in the next 5-year period to shift in order to achieve this goal in the future, and take a broader approach to where DR opportunity can be achieved. Traditionally, DR has focused on load curtailment; however, a broader approach will likely be needed to take advantage of load shifting and behavioral actions. Modifications to existing programs or additions of new programs will require regulatory filings, at a minimum, several months in advance of implementation. Additionally, we are anticipating changes at the MISO level to influence future programs and cost-effectiveness screens, which will factor into our plans and program design. We provided a detailed 5-year plan with our IRP in 2019.

8. Daytime Minimum Loads

As discussed in conjunction with our Planning Tools, we made determination of daytime minimum loads a priority in 2019, in compliance with the Commission's July 16, 2017 Order in Docket No. E002/CI-18-251. We determined and updated historical DML for all of our feeders and substation transformers that have load monitoring. This was a large effort, and we are determining how to best include this action into the planning processes going forward. We note that we will also be tracking DML and any changes to them year-to-year. As we implement our advanced planning tool, it will also aid in the actual forecasting of these values going forward.

B. Long-Term Action Plan and Customer Impacts

In this section, we address the long-term plan IDP requirements – discussing primarily the long-term trajectory of our near-term investments.

IDP Requirement 3.D.3 requires the following:

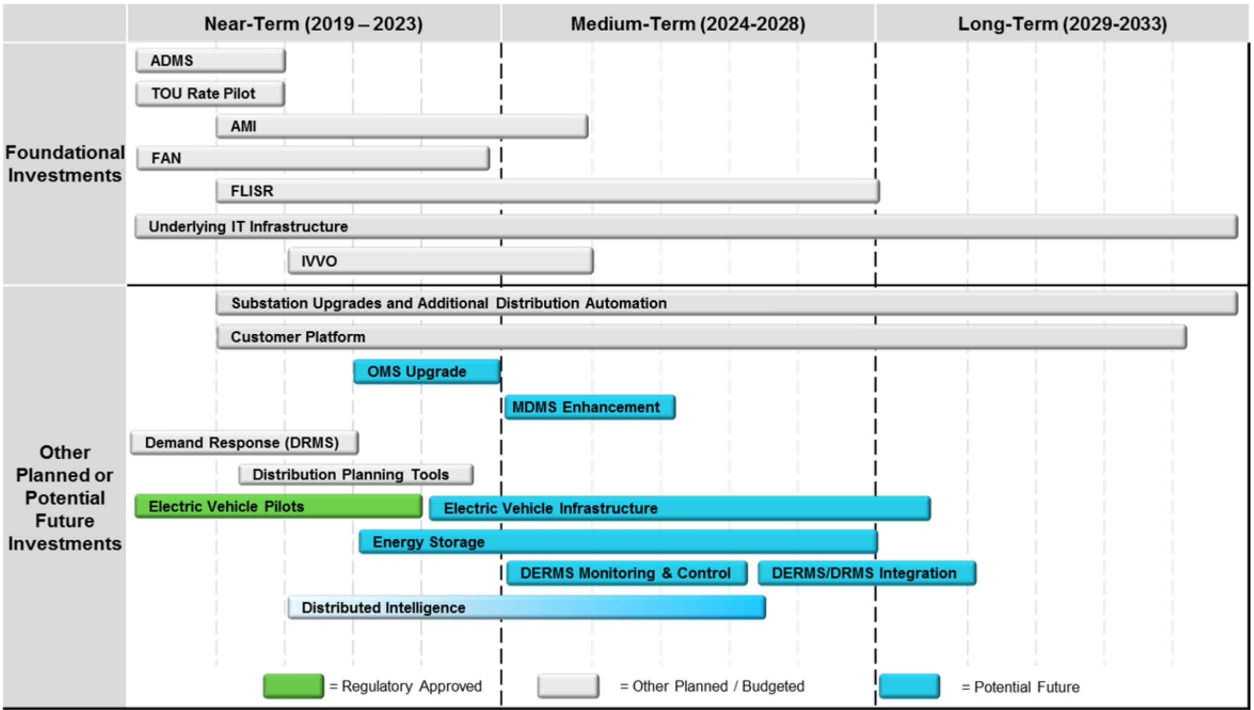
> *In addition to the 5-year Action Plan, Xcel shall provide a discussion of its vision for the planning, development, and use of the distribution system over the next 10 years. The 10-year Long-Term plan discussion should address the long-term assumptions (including load growth assumptions), the long-term impact of the 5-year Action Plan investments, what changes are necessary to incorporate DER into future planning processes based on the DER futures analysis, and any other types of changes that may need to take place in the tools and processes Xcel is currently using.*

1. Long-Term Grid, Tools, and Capabilities Focus

As we have discussed, our long-term focus for the distribution system is to advance the grid and our capabilities through first building foundational capabilities then further leveraging that foundation with advanced capabilities. This includes enhanced distribution planning tools to advance our capabilities to bring DER into our planning – and to perform DER futures analyses, as we have discussed in this IDP.

Although also provided above in this IDP, for easy reference, we again provide a 15-year view of the sequencing of planned and potential advanced grid investments in Figure 70 below.

Figure 70: Advanced Grid Initiatives – Present to 2030 View



The sequencing of initiatives aligns with the measured approach adopted by the Company that initially focuses on foundational investments, while also realizing some early capabilities and benefits for customers. This approach positions the Company to make prudent investments over time in more advanced capabilities, while maintaining flexibility to adapt to changing customer priorities, trends in DER penetration, and future policy direction. As previously discussed, the Company has received certification approval for both ADMS and the TOU Pilot. Each of these investments is underway and are important steps along the advanced grid roadmap.

In addition to discrete advanced grid investments, our corporate information technology infrastructure will require attention and investment on an ongoing basis to continue to meet increasingly demanding cybersecurity, data traffic, reliability, and compliance requirements along with the service expectations of our customers. Many of the investments discussed within this report involve additional data and communication needs, and a current information technology infrastructure is critical to supporting those efforts. As shown in Figure 70 as a single foundational investment, these advanced grid components are actually composed of a series of investments in equipment, data management hardware, systems integrations, and cybersecurity protections.

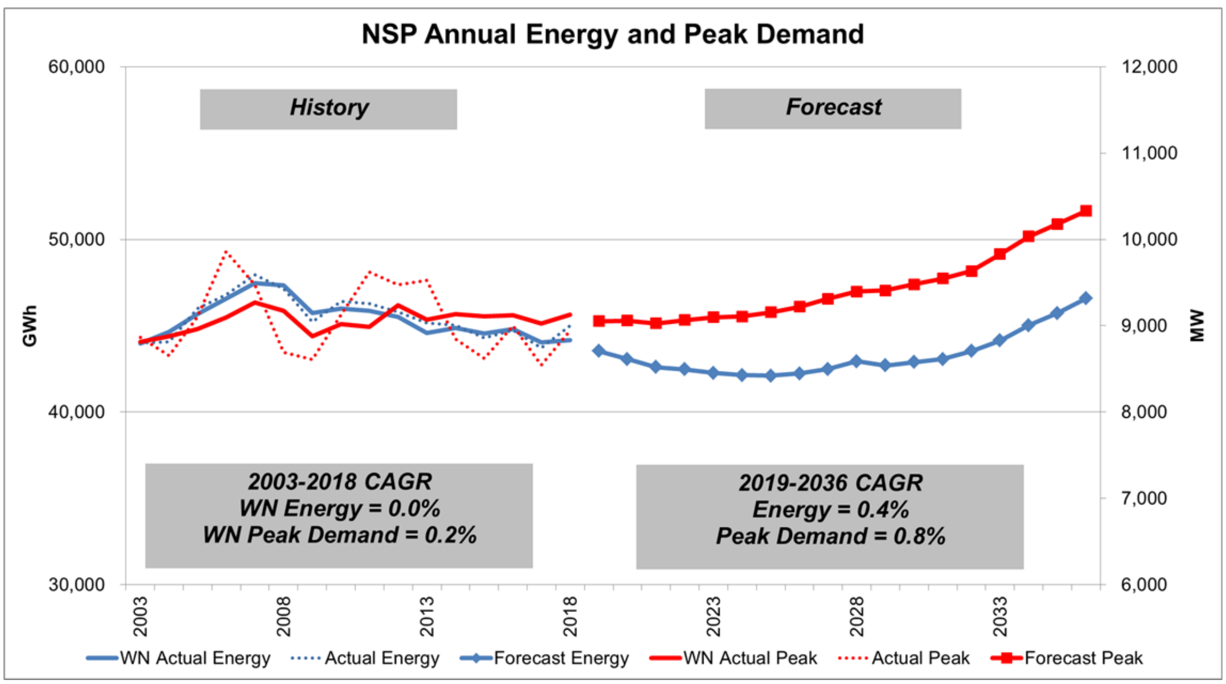
Each of these investments will provide discrete customer benefits and the combination of these investments over time will enable more sophisticated capabilities as we have discussed.

2. Long-Term Load Growth Assumptions

As we have discussed in this IDP, distribution system planning is performed for a 5-year planning horizon. In the case of this IDP, that period is 2020-2024. In part 1 above, we provided our load growth assumptions that resulted from our Fall 2018 distribution planning process.

For load growth assumptions beyond the distribution planning period, we provide our corporate load growth forecast, as follows:

Figure 71: NSP System Annual Energy and Peak Demand Forecast



XV. PROCEDURAL PROPOSAL

As we have noted, we are seeking certification for our AGIS investments to modernize the Company's distribution system, pursuant to Minn. Stat. § 216B.2425. Specifically, we are seeking certification of an advanced distribution planning tool and a number of investments that are part of what is collectively referred to as the AGIS initiative: Advanced Metering Infrastructure, a private secure Field Area Network, a form of distribution automation that decreases the duration of and number of customers affected an outage, and Integrated Volt Var Optimization, which decreases system losses and optimizes voltage as power travels from substations to customers.

These investments expand on the advanced grid investments previously approved by the Commission, namely the ADMS that will go into service in 2020. Each of these investments will take years to fully implement, and we are requesting that the Commission certify the AGIS projects pursuant to Minn. Stat. § 216B.2425, subd. 3, so that the Company may request recovery of costs in concurrent or subsequent filings, as necessary. This is consistent with other requests for certification for grid modernization investments, where certification enables the opportunity for the Company to request recovery of costs in a subsequent rider filing.

We are also filing a General Rate Case (Docket No. E002/GR-19-564) today with a three-year plan (Multi-Year Rate Plan (MYRP)) through which we seek cost recovery for much – but not all – of these AGIS investments. Because the span of the AGIS investments goes beyond the 2020 test year and 2021-2022 plan years identified in our MYRP filing, and in light of the concurrent submission of this 2019 IDP, our AGIS rate case testimony provides support for our AGIS investments beyond the term of the rate case and addresses Commission requirements that pertain to both certification and cost recovery for grid modernization investments. In light of this support for our long-term strategy, we believe certification of the full scope of the AGIS investments alongside a rate case cost recovery determination is critical, so that we may complete our AGIS investments at an appropriate pace and potentially include the out-year costs in a rider. Consideration of our certification request in tandem with our rate request will also be most efficient for all stakeholders. The Commission would, of course, have another opportunity for review and approval of specific costs if the Company were to seek rider cost recovery in the future.

Because of this dual filing approach, and in order to minimize duplication, we have provided the support for our AGIS certification request in a testimony format within the rate case, and we are including relevant portions of the testimony as attachments to this filing. We have excised unrelated portions from some witness testimony in order to provide only the relevant material. For instance, Company Witness Mr. David C. Harkness provides testimony regarding our 2020-2022 Business Systems investments for purposes of the MYRP, but not all of them are related to AGIS; we have therefore included only those sections and attachments that relate to AGIS in this IDP filing.

In addition, today we also have filed a Petition for Approval of True-Up Mechanisms. This filing requests the approval of certain true-ups for 2020 which, if approved, would result in the withdrawal of our General Rate Case. In that event, we would no longer request AGIS cost recovery through base rates until the Company's next general rate case is filed. We would, however, ask the Commission to make the more limited determination to certify the AGIS investments and Advanced Distribution Planning Tool in this IDP, so that we may plan for the implementation of our AGIS initiative, and preserve the option to put the costs of these investments in a rider between general rate case filings.

Overall, the filing requirements related to grid modernization investments, as well as for certification, are extensive, and our supporting documentation is likewise extensive and thorough. We have therefore taken several steps to facilitate review of these materials, and make them as digestible and easy to read as possible for the Commission and our stakeholders. These steps include development of executive summaries, compliance matrices, and extractions from larger pieces of testimony as noted above.

The normal procedural schedule for certification under Minn. Stat. § 216B.2425 would require a determination by June 1, 2020, and under normal circumstances, we believe the process leading to certification should resemble a resource acquisition proceeding under the Commission's normal notice and comment procedures that could, in the Commission's discretion and depending on the scope of the investment, include one or more public hearings. We recognize, however, that the schedule in the General Rate Case does not align with that timing. In addition, the AGIS initiative includes large investments and is supported by a sizeable filing that may require analysis beyond the six-month certification timeframe, even if the General Rate Case is withdrawn. Thus, we offer to work with the Commission and stakeholders to set an appropriate deadline and procedural schedule for consideration of these investments.

On a further procedural note, we respectfully request the Commission move to a biennial filing cadence for the IDP, consistent with other Minnesota utilities and the grid modernization statute filing requirements. We believe a biennial filing would better allow time to fully engage with stakeholders on the Commission's planning objectives between IDP filings, as well as to address important issues such as distributed energy resources (DER) planning, a comprehensive approach to non-wire alternatives (NWA), and our advanced grid plans. The present annual filing schedule also does not allow the Company to make significant, meaningful progress on its objectives between these extensive filings. We therefore specifically request the Commission require our next IDP be submitted on or before November 1, 2021, and biennially thereafter.

Finally, with respect to our ADMS initiative, we will be submitting an initial and ongoing annual reports in accordance with the Commission's September 27, 2019

Order in the Company's Transmission Cost Recovery (TCR) Rider Docket.[94] We propose to submit a single ADMS report by January 25, 2020 in the TCR docket and this IDP docket that contains all of the required information. We also respectfully request that the Executive Secretary establish the same January 25th due date for the ongoing annual ADMS reports beginning January 25, 2021 – and that these annual ADMS reports be filed in most recent docket of future IDPs.

XVI. STAKEHOLDER ENGAGEMENT

In this Section we discuss our stakeholder engagement in advance of this IDP.

IDP Requirement 2 requires the following:

> *Xcel should hold at least one stakeholder meeting prior to the November 1 filing of the Company's MN-IDP to obtain input from the public. The stakeholder meeting should occur in a manner timely enough to ensure input can be incorporated into the November 1 MN-IDP filing as deemed appropriate by the utility.*
>
> *At a minimum, Xcel should seek to solicit input from stakeholders on the following MN-IDP topics: (1) the load and distributed energy resources (DER) forecasts; (2) proposed 5-year distribution system investments, (3) anticipated capabilities of system investments and customer benefits derived from proposed actions in the next 5-years; including, consistency with the Commission's Planning Objectives (see above), and (4) any other relevant areas proposed in the MN-IDP.*

In an effort to educate and build a better understanding of our work and stakeholder's needs, and to comply with the Commission's August 30, 2018 Order, we held four Distribution Planning stakeholder workshops leading up to our November 1, 2019 IDP. The goal for the workshops was to have an iterative and ongoing dialogue to build a mutual understanding of our processes and the IDP- both for this instant report as well as future reports.

We summarize the stakeholder workshops we held below:

1 – December 12, 2018, to provide a recap of our 2018 IDP, seek feedback, and engage in a questions and answers session with our subject-matter-experts. The objectives for the meeting were to learn about Xcel Energy's experience in developing the first Minnesota IDP filing; clarify and better understand the information included in Xcel Energy's IDP filing to help parties develop their

[94] Docket No. E002/M-17-797.

comments in response to PUC questions; and identify specific parts of the filing or topics that would benefit from further stakeholder discussions. We also offered to engage in further meetings and discussions with stakeholders upon request.

2 – April 10, 2019, seeking general feedback on our next IDP, and also focused discussion on our non-wires alternatives analysis framework. The objectives for this session were to develop a list of criteria for what would make any future IDP filing acceptable to all stakeholders, including: what stakeholders want to see and why (the desired end state); any major steps stakeholders think are needed to meet that principle (the suggested means to achieving the desired end state); and when stakeholders think those major steps should take place and, if applicable, what information should inform that timing. We also reviewed and sought feedback on our current non-wires alternatives analysis process in advance of the November 1st deadline for the 2019 IDP filing, using the design principles as a framework for discussion.

3 – May 17, 2015, focused on the cost benefit framework for advanced grid investments. This was another key area of focus in our 2018 IDP proceeding. Objectives for this session included developing a list of stakeholders' collective expectations around Xcel Energy's grid mod investments and associated cost-benefit analysis; gain a better understand Xcel Energy's currently planned grid mod investments and cost-benefit analysis framework, using the previously discussed expectations as a framework for discussion; and, identify any next steps and discuss oral comments to the commission, if desired. We discussed the IDP requirements, discussed different ways to evaluate the value of grid modernization investments – and that a CBA is just one tool, only quantifies that which can be quantified, and implies that something is only valuable if its benefits outweigh its costs; we discussed the foundational advanced grid elements in our plan; and, we illustrated our CBA framework using our 2018 FLISR project as an example – discussing cost inputs, benefits, financial assumptions, impact on the reliability metrics and the customer reliability experience, and model outputs.

4 – September 25, 2019, to provide an overview of the forecasts and other information specified in the Commission's IDP requirements. This was a broad stakeholder workshop where we reviewed the Commission's distribution planning objectives and the functions and technologies needed to achieve those objectives; established a shared understanding of how Xcel Energy does Distribution Planning today and how distribution planning is evolving; we presented our load and DER forecasts and five year budgets; discussed our advanced grid plans and components; and, we summarized our 5-year action plans. We also summarized the feedback we received at Workshops 2 and 3.

We engaged Great Plains Institute (GPI) as a third party facilitator and for the first and last session, invited all interested parties and commenters from our 2018 IDP docket as well as our most recent IRP due to the overlap between the two efforts. The second and third sessions were more focused topics, so we invited only those parties who had submitted comments in our 2018 IDP proceeding. These sessions resulted in rich dialogue and robust feedback.

Highlights of the feedback we received at these sessions follows:

What did you like about the Company's 2018 IDP that should be repeated?

1. **Transparency:**
    - Provided a lot of helpful transparency about how Xcel Energy does distribution planning
    - Appreciate Xcel Energy saying honestly what they can provide and how much work it will take to meet the requirements.
2. **Level of detail and usefulness of information:**
    - Focus on reliability
    - Good faith effort – comprehensive, especially considering distribution planning in other states
    - The filing put more detail to the "walk, jog, run" metaphor – the direction in which Xcel Energy is heading -- than utilities in other states, which was helpful.
    - Report helps to correct information asymmetry that has existed between the company and everyone else.
    - Appreciate translating from engineering to more generally understood language.
3. **Effort given timing constraints:**
    - Strong considering timing constraints
    - NWA's – good job with the analysis given such a short turnaround
4. **Stakeholder engagement process:**
    - Stakeholders felt invited to share input
    - Provided solar businesses an opportunity to engage with the utility/developers
    - Learning from other state distribution planning processes – encourage this to continue (e.g., MI PSC website to make process accessible to stakeholders)

What changes would you like to see?

1. **Make the information more accessible and digestible**
    - Question about repeating "baseline" info that may not change year-to-year – is this needed?

- A balance between complexity and accessibility to communities/customers
- It would be helpful to Xcel Energy to know how the various required information will be used so that they can provide it in the most helpful format.
- Interest in understanding how much of an effort it is for Xcel Energy to provide certain items.
- More clarity/focus on aspects of IDP that will provide value to ratepayers – better investment, better utility planning. What is the public interest value?

2. **Use the IDP as a forward-looking tool**
    - Would like to see a "SMART" goal that says between now and the next IDP filing, Xcel Energy will do the following things, with a list of specific action steps that are time-bound.
    - Use the IDP as a platform to start putting out forward-looking ideas/proposals – have the opportunity to take a holistic look at the distribution system
        - Xcel Energy would like to develop the tools to do this more efficiently going forward

3. **Integrate other related topics, dockets, issues:**
    - Integrate storage as the technology advances
    - Integration of other like processes should be explicit and transparent – inputs should be the same or if different, explained (e.g., IRP, PBR, rates for DERs).
    - Challenging to draw a box around this, when actually this is interrelated with multiple other topics/proceedings – would like to see more intentional integration and efforts to link together where applicable.
        - Integration will require the Commission's active input – it was driven by the PUC, so hopefully they will see it through. Constant evaluation will help with this.

4. **Strengthen the stakeholder engagement process:**
    - Would help to have more general education and resource-sharing and to help raise the level of education on distribution planning.
    - Have agreement on the "anchor" of what plans should look like in 5-10 years – this can help to inform what technologies or approaches are needed to get there (and what analytical tools are needed).

- Would like more discussion between stakeholders and Xcel about what tools could help with NWA analysis – operating side and mental model side of where NWAs fit in this discussion. Hierarchy of needs, and where NWAs fit.
    - Xcel Energy still working on deploying customer-facing programs for distribution purposes
- Learning from other state distribution planning processes – encourage this to continue (e.g., MI PSC website to make process accessible to stakeholders)

Key takeaways from our grid modernization CBA framework session included:

- Clearly articulate the assumptions and the level of certainty/ uncertainty behind them.
- Articulate the dependencies (or non-) between different advanced grid investments.
- Failure is discussing whether to invest in AMI, with success being how to build on AMI.
- Consider framing in concert with performance based rates outcomes (from the Commission's investigation into performance metrics for the Company's electric utility operations in Docket No. E002/CI-17-401).
- Prioritize investments – i.e., what comes after the foundational components.
- Demonstrate innovation and creativity around the customer value proposition.
- Differentiate between easy-to-quantify and hard-to-quantify benefits for customers.

We internalized this feedback and the feedback we received on our 2018 IDP and factored it into the information we present in this IDP, including how we present the costs and benefits of our advanced grid components – and our proposal to implement IVVO in Minnesota. We discuss how stakeholder feedback and input factored into our advanced grid proposal in the Direct Testimony of Mr. Gersack, which accompanies this IDP as Attachment M1.

XVII. INTEGRATED DISTRIBUTION-TRANSMISSION-RESOURCE PLANNING

In this Section, we discuss the present state of Distribution-Transmission Resource Planning and our longer-term view of how we envision them becoming increasingly integrated.

IDP Requirement 3.A.5 requires the following:

> *Discussion of how the distribution system planning is coordinated with the integrated resource plan (including how it informs and is informed by the IRP), and planned modifications or planned changes to the existing process to improve coordination and integration between the two plans.*

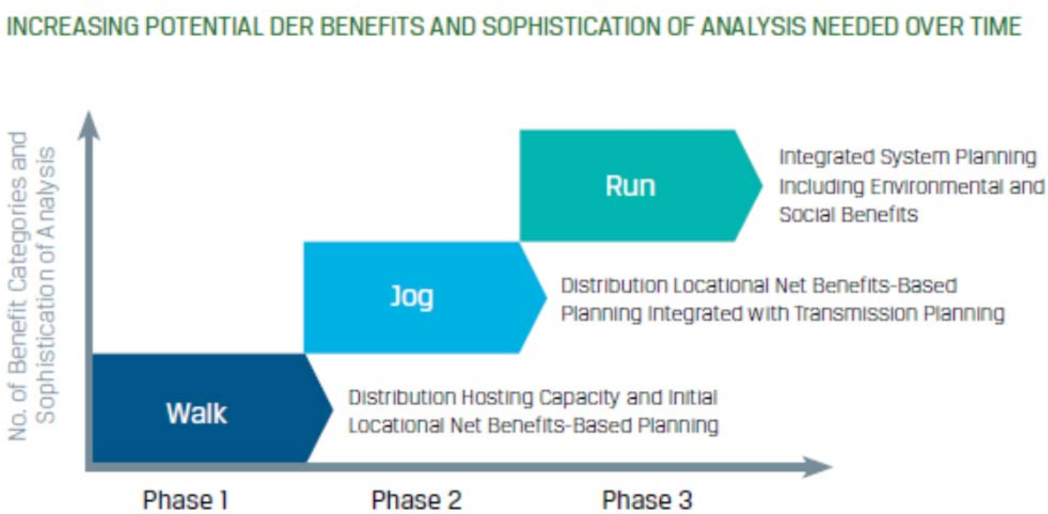
Currently, the distribution and transmission planning groups meet twice per year, and additionally work together as their respective planning processes impact or rely on one another. For example, distribution planning supplies transmission planning with substation load forecasts that are an input into the transmission planning process. These two groups also interact when distribution planning identifies the need for additional electrical supply to the distribution system – and similarly with interconnections, distribution is on point, and involves the appropriate planning resource as needed. The work that we are doing now on customer adoption-based of DER and electrification is helping to bring these planning processes closer together – and we believe will result in better informed sensitivities to ultimately inform both IRP and IDP. However, there are fundamental differences in these planning processes that will continue to challenge integration, at least in the near-term.

While increasing DER penetration levels will drive integrated resource planning and distribution planning closer together, there are fundamental differences in how these two planning activities assess and develop plans to meet customers' needs. Distribution planning, like IRPs, charts a path to meet customers' energy and capacity needs, but is more immediate and subject to emergent circumstances because distribution is the connection with customers. Unlike IRPs, five-year plans are considered long-term in a distribution context; and, IRPs are concerned with size, type, and timing, whereas the primary focus of distribution planning is location. Thus distribution loads and resources are evaluated for each major segment of the system – on a feeder and substation-transformer basis – rather than in aggregate, like occurs with an IRP.

Before a greater integration of distribution planning, transmission planning, and IRP can occur, distribution planning will need to become even more granular than it is today to address the challenges – and harness the benefits – of DER. The advanced planning tool and advanced grid investments we propose with this IDP are an important step to realizing this future.

Minnesota is among a few states, including California, New York, and Hawaii, on the forefront of advancing its distribution planning as part of its grid modernization efforts. However, each is driven by differing policies and considerations; each is taking a different approach; and, each may result in its own solution that may not fit the circumstances elsewhere. While there are no definitive answers at this point, experts generally agree that a deliberate, staged approach to increased sophistication in planning analyses – commonly referred to as "walk, jog, run" – is important. The stages are illustrated below.

Figure 72: Staged Approach to Enhanced Planning Analyses



(*Source*: ICF White Paper, *The Value in Distributed Energy: It's all About Location, Location, Location* by Steve Fine, Paul De Martini, Samir Succar, and Matt Robison. *See* White Paper.

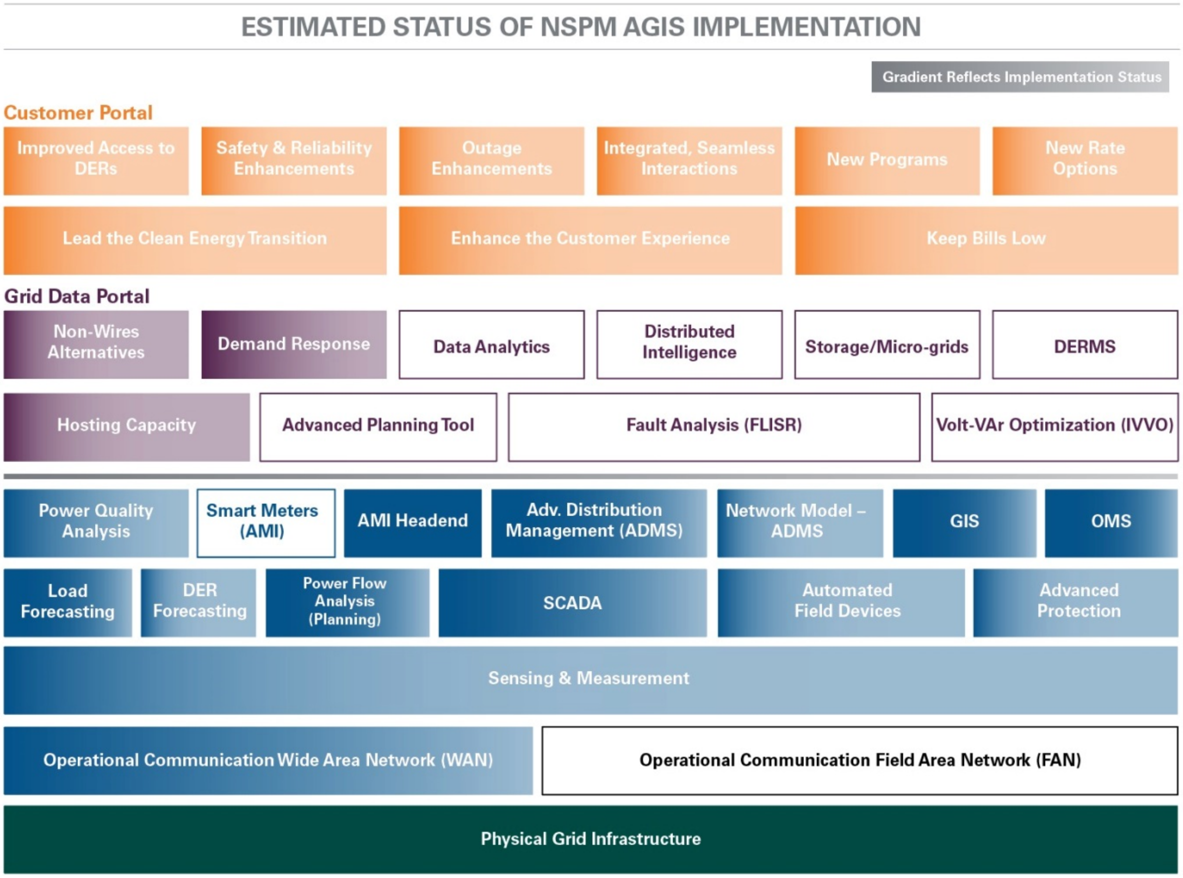
Movement from one stage to another is generally driven by growth in volume and diversity of distribution-connected, DER, the level of evolution of supporting planning practices and tools, and integration with other planning efforts, such as transmission, or resource planning.

Similarly, the Berkeley Lab report, *Distribution Systems in a High Distributed Energy Resources Future, Planning, Market Design, Operation and Oversight* proposes a three-stage evolutionary structure for characterizing current and future state DER growth, with stages defined by the volume and diversity of DER penetration – plus the regulatory, market and contractual framework in which DERs can provide products and services to the distribution utility, end-use customers and potentially each other.[95] The report emphasizes the need to ensure reliable, safe and efficient operation of the physical electric system, DERs and the bulk electric system, which correlates to Minnesota utility requirements under Minn. Stat. § 216B.04 to furnish safe, adequate, efficient, and reasonable service. The report describes Stage 1 as having low adoption of DERs, where the focus is on new planning studies when DER expansion is anticipated, which also correlates to where we are in Minnesota presently.

The U.S. Department of Energy, as part of its collaboration with state commissions and industry to define grid modernization in the context of states' policies is developing a guide for modern grid implementation that similarly recognizes foundational elements upon which increased utility tools and information and changes in infrastructure planning, grid operations, energy markets, regulatory frameworks, ratemaking, and utility business models rest, as shown in below.

[95] Future Electric Utility Regulation series (Report No. 2), by Paul De Martini and Lorenzo Kristov (October 2015). *See* https://emp.lbl.gov/publications/distribution-systems-high-distributed

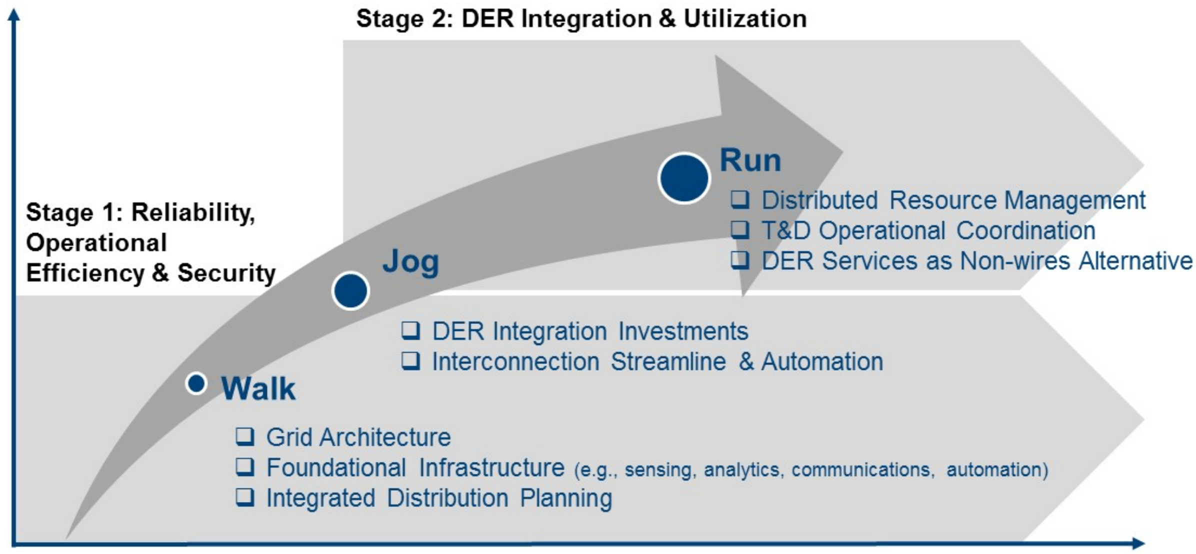
Figure 73: Platform Considerations



Source: *Considerations for a Modern Distribution Grid*, Pacific Coat Inter-Staff Collaboration Summit by DOE Office of Electricity Delivery & Energy Reliability (May 24, 2017). *See* U.S. DOE DSPx presentation - More Than Smart

The DOE's efforts also recognize timing and pace considerations, as shown in below.

Figure 74: Timing and Pace Considerations



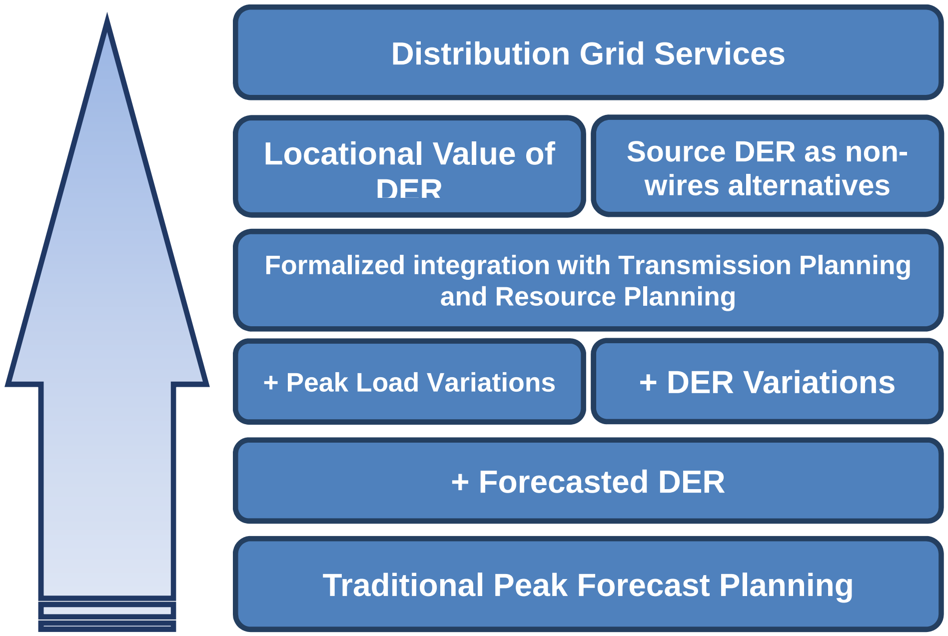
Source: *Considerations for a Modern Distribution Grid*, Pacific Coast Inter-Staff Collaboration Summit by DOE Office of Electricity Delivery & Energy Reliability (May 24, 2017). *See* U.S. DOE DSPx presentation - More Than Smart

As part of the May 24, 2017 Pacific Coast Inter-Staff Collaboration Summit, DOE observed that the U.S. distribution system is currently in Stage 1, with the issue being whether and how fast to transition to Stage 2. Underlying this question however, is the issue of identifying customer needs and state policy objectives – with a goal to implement proportionally to customer value – all of which will differ significantly across states. We would agree that Minnesota is in Stage 1. We are focused on foundational infrastructure and starting to evolve our planning tools to enable integrated distribution planning.

A potential progression in planning practices could involve the evolution shown in Figure 75 below, with the drivers of progress being:

- Customer value, such as need, public policy, and cost/benefit,
- Utility readiness, including proper foundational tools and systems, and
- Supporting regulatory frameworks that address cost recovery, and any changes in federal or state market operations, etc.

Figure 75: Potential Evolution in Planning Practices



We expect this progression will need to occur over time as tools improve, policy drivers become clear, and customer value is determined.

Evolving distribution planning to be more like integrated resource planning will need to be thoughtful and planful. Today, IRPs are grounded in Minnesota statutes and rules – and chart a long-term direction of how load can be served in a broad service area. The IRP process is grounded in Minn. R. 7843, which prescribes the purpose and scope, filing requirements and procedures, content, the Commission's review of resource plans, and plans' relationship to other Commission processes, including certificates of need and the potential for contested case proceedings.[96] These processes work for IRPs due to the long-term nature of macro resource additions and changes.

However, distribution planning is more immediate; its full planning horizon correlates

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[96] Minn. R. 7843.0500, subp. 3 prescribes the factors for the Commission to consider in reviewing IRPs. "The Commission shall consider the characteristics of the available resource options and of the proposed plan as a whole. Resource options and resource plans must be evaluated on their ability to: maintain or improve the adequacy and reliability of utility service; keep the customers' bills and the utility's rates as low as practicable, given regulatory and other constraints; minimize adverse socioeconomic effects and adverse effects upon the environment; enhance the utility's ability to respond to changes in the financial, social, and technological factors affecting its operations; and limit the risk of adverse effects on the utility and its customers from financial, social, and technological factors that the utility cannot control."

to the five-year action plan period of an IRP, which is generally a continuation of past IRPs. Distribution systems are utilities' point of connection for customers. While an unexpected loss of a macro system component, such as a power plant, can often be covered by the MISO system without interruption of power to customers, loss of a distribution system component often results in a power outage to the customers it was serving. While there is some redundancy in the system to avoid this circumstance, the types of issues addressed by distribution planning are typically much more immediate than IRPs – and do not have a back-up like MISO. Therefore, evolving distribution planning practices will need to be thoughtful – and ensure the focus remains on the immediacy of customer reliability.

While the timeline remains uncertain, it is clear that the distribution grid of the future will look and perform differently than it has over the past 100+ years. Minnesota is in the forefront on the issue of advancing its distribution planning practices with other leaders such as California, New York, and Hawaii. Lessons learned from these states that Paul De Martini, ICF International, shared as part of his presentation at the Commission's October 24, 2016 grid modernization distribution planning workshop included:

- Changes to distribution planning should proactively align with state policy objectives and pace of customer DER adoption.
- Define clear planning objectives, expected outcomes and regulatory oversight – avoid micromanaging the engineering methods.
- Define the level of transparency required for distribution planning process, assumptions and results.
- Engage utilities and stakeholders to redefine planning processes and identify needed enhancements.
- Stage implementation in a walk, jog, run manner to logically increase the complexity, scope, and scale as desired.

No one state has yet figured out the progression of distributing planning enhancements; each is taking a different approach to address the complexities inherent in implementing changes at the right pace and that is proportional to both customer and grid needs – and that realizes net value and benefits for all customers. While the national perspective and other state actions provide helpful points of reference, Minnesota has long been a leader in developing supportive regulatory frameworks to align achievement of policy objectives with business objectives. The increasing complexity of our industry requires a rethinking of the current framework to ensure it is still aligned.

We support the evolution of the grid, and are taking actions to evolve our planning tools and improve our foundational capabilities to support our customers' expanding energy needs and expectations. We support a shift toward more integrated system planning, where utilities assess opportunities to reduce peak demand using DER and to supply customers' energy needs from a mix of centralized and distributed generation resources. However, at a measured pace that correlates to Minnesota policy objectives and customer value.

We are currently evaluating our existing planning processes and tools to determine how to better align and integrate the distribution, transmission, and resource planning processes in the future. Fundamentally, they are rooted in contradictory planning paradigms – with resource planning concerned with size, type, and timing, distribution concerned with location, and transmission somewhere in between. In the near term, these groups are working together around customer adoption-based DER forecasting and electrification. This is allowing us to consider many different possible outcomes, and think about how we can design an optimal portfolio of resources that best meets our overall customer load needs under a range of potential outcomes.

CONCLUSION

This IDP presents a comprehensive view of our distribution system and how we plan the system to meet our customers' current and future needs. The backbone of our planning is keeping the lights on for our customers, safely and affordably. For over 100 years, we have delivered safe, reliable electric service to our customers, and, through our robust planning process and strong operations, we will continue to do so.

We are also planning for the future. We have a vision for where we and our customers want the grid to go, and we are implementing and installing new technologies to support our vision. We are taking a measured and thoughtful approach to ensure our customers receive the greatest value and that the fundamentals of our distribution business remain sound.

We respectfully request the Commission certify our proposed AGIS investments and advanced planning tool as outlined in Section XV, Procedural Process. On a further procedural note, we respectfully request the Commission move to a biennial filing cadence for the IDP, consistent with other Minnesota utilities and the grid modernization statute filing requirements – and specifically request the Commission require our next IDP be submitted on or around November 1, 2021, and biennially thereafter. Finally, with respect to our ADMS initiative, we propose to submit a single ADMS report by January 25, 2020 in the TCR docket and this IDP docket that contains all of the information required in the Commission's September 27, 2019 Order in the TCR Docket No. E002/M-17-797. We also respectfully request that the Executive Secretary establish the same January 25th due date for the ongoing annual ADMS reports beginning January 25, 2021 – and that these annual ADMS reports be filed in the most recent docket number of future IDPs.

Attachment	Title	Non-Public Designation
A1	IDP Attachments with Non-Public Designations	*n/a*
A2	Compliance Matrix	*n/a*
B	Correlation of IDP Content to Commission's IDP Planning Objectives	*n/a*
C	IDP Grid Modernization Content Roadmap	*n/a*
D1	Advanced Distribution Planning Tool Desciption and Certification Request	Attachment D1 has contractual cost terms for the proposed Advanced Distribution Planning Tool (APT) and current tool costs that will be negated by the APT. Xcel Energy maintains this information as a trade secret pursuant to Minn. Stat. §13.37 (1)(b) based on its economic value from not being generally known and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use. In particular, the information designated as Trade Secret derives independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain economic value from its disclosure or use.
D2	APT Cost Benefit Analysis Summary	Attachment D2 has marked and shaded contractual cost terms for the proposed APT and current tool costs that will be negated by the APT. Xcel Energy maintains this information as a trade secret pursuant to Minn. Stat. §13.37 (1)(b) based on its economic value from not being generally known and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use. In particular, the information designated as Trade Secret derives independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain economic value from its disclosure or use.

Attachment	Title	Non-Public Designation
E	Distribution Risk Scoring Methodology	Attachment E Parts II (reliability impacts) and III contain information Xcel Energy maintains as Security Information, pursuant to Minn. Stat. § 13.37, subd. 1(a). The public disclosure or use of this information creates an unacceptable risk that those who want to disrupt our system for political or other reasons may learn which facilities to target to create a disruption of our service. Part III (Examples) contains information Xcel Energy maintains as trade secret data as defined by Minn. Stat. § 13.37, subd. 1(b). This information has independent economic value from not being generally known to, and not being readily ascertainable by, other parties who could obtain economic value from its disclosure or use. Part III is marked as "Not-Public" in its entirety. Pursuant to Minn. R. 7829.0500, subp. 3, the Company provides the following description of the excised material: **1. Nature of the Material**: Calculations of expected Customer Minutes Out given electric distribution asset load and failure rate data **2. Authors**: Electric Systems Performance and the Risk Analytics Department **3. Importance**: Key values to determine the potential reliability of certain projects **4. Date the Information was Prepared**: October 29, 2019
F1	Capital Project List by IDP Category	*n/a*
F2	Risk Scored Project Details	Attachment F2 contains two shaded and marked columns that contain (1) forecasted peak demand and (2) peak capacity by feeder and/or substation that Xcel Energy maintains as Security Information, pursuant to Minn. Stat. § 13.37, subd. 1(a). The public disclosure or use of this information creates an unacceptable risk that those who want to disrupt our system for political or other reasons may learn which facilities to target to create a disruption of our service. Additionally, these fields for certain feeders contain information that if made public would be counter to our requirement to protect the anonymity of our customers' energy usage information unless we have the customers' consent to disclose it (Commission Order dated January 19, 2017 in Docket No. E,G999/CI-12-1344).
G1	Capital Profile Trend	*n/a*
G2	O&M Profile Trend	*n/a*
H	Non-Wires Alternatives Analysis	*n/a*
I	MISO Response to FERC Data Request Docket RM-18-9-000	*n/a*
J	Action Plan Roadmap	*n/a*
K	Planning Area Load Growth Assumptions	*n/a*
L	Distributed Function NPV	*n/a*

Attachment	Title	Non-Public Designation
M1	AGIS Direct Testimony – Gersack	*n/a*
M2	AGIS Direct Testimony – Bloch	Bloch Schedule 10 is an internal presentation given to provide a summary of the Company's analysis supporting the AMI meter vendor selection. Xcel Energy maintains this information as a trade secret pursuant to Minn. Stat. §13.37 (1)(b) based on its economic value from not being generally known and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use. Bloch Schedule 10 is marked as "Non-Public" in its entirety. Pursuant to Minn. R. 7829.0500, subp. 3, we provide the following description of the excised material: 1. **Nature of the Material**: An internal presentation given providing a summary of the Company's analysis supporting the AMI meter vendor selection. 2. **Authors**: Major Products & Programs Sourcing 3. **Importance**: The analysis and information contained therein has not been publicly released. 4. **Date the Information was Prepared**: The presentation was prepared in the second quarter of 2019.
M3	AGIS Direct Testimony – Harkness	Harkness Schedules 11 and 12 are internal assessment summaries that the Company has designated as Trade Secret information as defined by Minn. Stat. § 13.37, subd. 1(b). The analysis and information contained therein has not been publicly released. Harkness Schedules 11 and 12 are marked as "Non-Public" in their entirety. Pursuant to Minn. R. 7829.0500, subp. 3, the Company provides the following description of the excised material: 1. **Nature of the Material**: These Schedules contain information regarding bidder responses to requests for proposal (RFPs) issued by the Company, including sensitive pricing and other bid data; the Company's proprietary analysis of selected bids; market intelligence; and potential comparative bidder cost and negotiation planning information. 2. **Authors**: Business Systems and Sourcing employees and their representatives in conjunction with the Company's review of hardware and software needs for its Advanced Metering Infrastructure (AMI) and Field Area Network (FAN) projects, respectively. 3. **Importance**: They include sensitive pricing and other bid data. 4. **Date the Information was Prepared**: Schedule 11 was prepared in 2017 and Schedule 12 was prepared in 2015.
M4	AGIS Direct Testimony – Cardenas	*n/a*
M5	AGIS Direct Testimony – Duggirala	*n/a*
N1	RFP - APT	*n/a*
N2	RFP - AMI	*n/a*
N3	RFP - WISUN	*n/a*

Attachment	Title	Non-Public Designation
N4	RFP - IVVO	The Low Voltage VAr Compensator RFI contains a table in Section 2.0 that has a list of vendor names and contact information. Xcel Energy maintains this information as a trade secret pursuant to Minn. Stat. §13.37 (1)(b) based on its economic value from not being generally known and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use.
O1	AGIS Combined CBA Summary	*n/a*
O2	AGIS AMI CBA Summary	*n/a*
O3	AGIS FLISR CBA Summary	*n/a*
O4	AGIS IVVO CBA Summary	*n/a*
Workpapers	Workpapers - Executable CBA Model - APT	The APT CBA model represents a Company work product. Xcel Energy maintains this information as a trade secret pursuant to Minn. Stat. §13.37 (1)(b) based on its economic value from not being generally known and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use. Additionally, some data contained within the model is also maintained as trade secret based on its economic value from not being generally known and not being readily ascertainable by proper means by other persons who can obtain value from its disclosure or use, and/or contains proprietary customer and system data. This additional trade secret data includes negotiated and contractual pricing. Please note the CBA is marked as "Non-Public" in its entirety. Pursuant to Minnesota Rule 7829.0500, subp. 3, we provide the following description of the excised material: **1. Nature of the Material**: The Cost Benefit Analysis Model developed by the Company. **2. Authors**: Risk Analytics and Regulatory and Distribution **3. Importance**: The Company work product is proprietary to the Company. **4. Date the Information was Prepared**: The CBA Model was created in the third quarter of 2019.

Attachment	Title	Non-Public Designation
Workpapers	Workpapers - Executable CBA Models - AGIS	The AGIS CBA executable model represents a Company work product. Xcel Energy maintains this information as a trade secret pursuant to Minn. Stat. §13.37 (1)(b) based on its economic value from not being generally known and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use. Additionally, some data contained within the model is also maintained as trade secret based on its economic value from not being generally known and not being readily ascertainable by proper means by other persons who can obtain value from its disclosure or use, and/or contains proprietary customer and system data. This additional trade secret data includes negotiated pricing (including labor, materials, technology, and services) and contract terms; internal labor rates; number of customers per feeder; and device retirement and failure rates. Please note the CBA is marked as “Non-Public” in its entirety. Pursuant to Minn. R. 7829.0500, subp. 3, we provide the following description of the excised material: **1. Nature of the Material**: The Cost Benefit Analysis Model developed by the Company. **2. Authors**: Risk Analytics **3. Importance**: The Company work product is proprietary to the Company. **4. Date the Information was Prepared**: The CBA Model was created in the third quarter of 2019 .

Section	Heading	MPUC IDP Requirement (8/30/18 Order in Docket No. E002/CI-18-251)	Location
2	Stakeholder Meetings	Xcel should hold at least one stakeholder meeting prior to filing the November 1 MN-IDP to obtain input from the public. The stakeholder meeting should occur in a manner timely enough to ensure input can be incorporated into the November 1 filing as deemed appropriate by the utility. At a minimum, Xcel should seek to solicit input on the following MN-IDP topics: (1) the load and DER forecasts, and 5-year distribution system investments, (2) proposed 5-year distribution system investments, (3) anticipated capabilities of system investments and customer benefits derived from proposed actions in the next 5-years; including, consistency with the Commission's Planning Objectives (see above), and (4) any other relevant areas proposed in the MN-IDP. Following the November 1 filing, the Commission will issue a notice of comment period. If deemed appropriate by staff, a stakeholder meeting may be held in combination with the comment period to solicit input.	XVI
3.A.1	Baseline Distribution System and Financial Data System Data	Modeling software currently used and planned software deployments	V.C-D
3.A.2	Baseline Distribution System and Financial Data System Data	Percentage of substations and feeders with monitoring and control capabilities, planned additions	IV.C.1, Table 14
3.A.3	Baseline Distribution System and Financial Data System Data	A summary of existing system visibility and measurement (feeder-level and time interval) and planned visibility improvements; include information on percentage of system with each level of visibility (ex. max/min, daytime/nighttime, monthly/daily reads, automated/manual)	IV.C.1, Table 14
3.A.4	Baseline Distribution System and Financial Data System Data	Number of customer meters with AMI/smart meters and those without, planned AMI-investments, and overview of functionality available	IV.C.2 IX, X, Attachment C
3.A.5	Baseline Distribution System and Financial Data System Data	Discussion of how the distribution system planning is coordinated with the integrated resource plan (including how it informs and is informed by the IRP), and planned modifications or planned changes to the existing process to improve coordination and integration between the two plans	XVII
3.A.6	Baseline Distribution System and Financial Data System Data	Discussion of how DER is considered in load forecasting [and thus system planning] and any expected changes in load forecasting methodology	V.D, XI, Attachment D1
3.A.7	Baseline Distribution System and Financial Data System Data	Discussion if and how IEEE Std. 1547-2018 impacts distribution system planning considerations (e.g., opportunities & constraints related to interoperability and advanced inverter functionality). [IEEE Standard 1547-2018, published April 6, 2018).	XI.F, XII.A, XII.C
3.A.8	Baseline Distribution System and Financial Data System Data	Estimated distribution system annual loss percentage for the prior year	IV.C.3
3.A.9	Baseline Distribution System and Financial Data System Data	For the portions of the system with SCADA capabilities, the maximum hourly coincident load (kW) for the distribution system as measured at the interface between the transmission and distribution system	IV.C.1, IV.C.4
3.A.10	Baseline Distribution System and Financial Data System Data	Total distribution substation capacity in kVA	IV.C.5
3.A.11	Baseline Distribution System and Financial Data System Data	Total distribution transformer capacity in kVA	IV.C.6
3.A.12	Baseline Distribution System and Financial Data System Data	Total miles of overhead distribution wire	IV.C.7
3.A.13	Baseline Distribution System and Financial Data System Data	Total miles of underground distribution wire	IV.C.8
3.A.14	Baseline Distribution System and Financial Data System Data	Total number of distribution premises	IV.C.9

Section	Heading	MPUC IDP Requirement (8/30/18 Order in Docket No. E002/CI-18-251)	Location
3.A.15	Baseline Distribution System and Financial Data System Data	Total costs spent on DER generation installation in the prior year. These costs should be broken down by category in which they were incurred (including application review, responding to inquiries, metering, testing, make ready, etc).	XII.B.1
3.A.16	Baseline Distribution System and Financial Data System Data	Total charges to customers/member installers for DER generation installations, in the prior year. These charges should be broken down by category in which they were incurred (including application, fees, metering, make ready, etc.)	XII.B.1
3.A.17	Baseline Distribution System and Financial Data System Data	Total nameplate kW of DER generation system which completed interconnection to the system in the prior year, broken down by DER technology type (e.g. solar, combined solar/storage, storage, etc.)	XI.B.1
3.A.18	Baseline Distribution System and Financial Data System Data	Total number of DER generation systems which completed interconnection to the system in the prior year, broken down by DER technology type (e.g. solar, combined solar/storage, storage, etc.)	XI.B.1
3.A.19	Baseline Distribution System and Financial Data System Data	Total number and nameplate kW of existing DER systems interconnected to the distribution grid as of time of filing, broken down by DER technology type (e.g. solar, combined solar/storage, storage, etc.)	XI.B.1
3.A.20	Baseline Distribution System and Financial Data System Data	Total number and nameplate kW of queued DER systems as of time of filing, broken down by DER technology type (e.g. solar, combined solar/storage, storage, etc.)	XI.B.1
3.A.21	Baseline Distribution System and Financial Data System Data	Total number of electric vehicles in service territory	XI.B.2
3.A.22	Baseline Distribution System and Financial Data System Data	Total number and capacity of public electric vehicle charging stations	XI.B.2
3.A.23	Baseline Distribution System and Financial Data System Data	Number of units and MW/MWh ratings of battery storage	XI.B.1
3.A.24	Baseline Distribution System and Financial Data System Data	MWh saving and peak demand reductions from EE program spending in previous year	XI.B.1
3.A.25	Baseline Distribution System and Financial Data System Data	Amount of controllable demand (in both MW and as a percentage of system peak)	XI.B.1
3.A.26	Baseline Distribution System and Financial Data Financial Data	Historical distribution system spending for the past 5-years, in each category: a. Age-Related Replacements and Asset Renewal b. System Expansion or Upgrades for Capacity c. System Expansion or Upgrades for Reliability and Power Quality d. New Customer Projects and New Revenue e. Grid Modernization and Pilot Projects f. Projects related to local (or other) government-requirements g. Metering h. Other The Company may provide in the IDP any 2018 or earlier data in the following rate case categories: a. Asset Health b. New Business c. Capacity d. Fleet, Tools, and Equipment e. Grid Modernization For each category, provide a description of what items and investments are included.	II.D.2
3.A.27	Baseline Distribution System and Financial Data Financial Data	All non-Xcel investments in distribution system upgrades (e.g. those required as a condition of interconnection) by subset (e.g., CSG, customer-sited, PPA, and other) and location (i.e. feeder or substation.)	XII.B.1
3.A.28	Baseline Distribution System and Financial Data Financial Data	Projected distribution system spending for 5-years into the future for the categories listed above, itemizing any non-traditional distribution projects	II.D.2, Figure 7, Table 7

Section	Heading	MPUC IDP Requirement (8/30/18 Order in Docket No. E002/CI-18-251)	Location
3.A.29	Baseline Distribution System and Financial Data Financial Data	Planned distribution capital projects, including drivers for the project, timeline for improvement, summary of anticipated changes in historic spending. Driver categories should include: a. Age-Related Replacements and Asset Renewal b. System Expansion or Upgrades for Capacity c. System Expansion or Upgrades for Reliability and Power Quality d. New Customer Projects and New Revenue e. Grid Modernization and Pilot Projects f. Projects related to local (or other) government-requirements g. Metering h. Other	Attachments F1 & G1
3.A.30	Baseline Distribution System and Financial Data Financial Data	Provide any available cost benefit analysis in which the company evaluated a non-traditional distribution system solution to either a capital or operating upgrade or replacement	Attachment H
3.A.31	Baseline Distribution System and Financial Data DER Deployment	DER Deployment: Current DER deployment by type, size, and geographic dispersion (as useful for planning purposes; such as, by planning areas, service/work center areas, cities, etc.)	XI.B.3
3.A.32	Baseline Distribution System and Financial Data DER Deployment	DER Deployment: Information on areas of existing or forecasted high DER penetration. Include definition and rationale for what the Company considers "high" DER penetration.	XI.B.3
3.A.33	Baseline Distribution System and Financial Data DER Deployment	DER Deployment: Information on areas with existing or forecasted abnormal voltage or frequency issues that may benefit from the utilization of advanced inverter technology.	XII.C.3
3.B.1	Hosting Capacity and Interconnection Requirements	Provide a narrative discussion on how the hosting capacity analysis filed annually on November 1 currently advances customer-sited DER (in particular PV and electric storage systems), how the Company anticipates the hosting capacity analysis (HCA) identifying interconnection points on the distribution system and necessary distribution upgrades to support the continued development of distributed generation resources4, and any other method in which Xcel anticipates customer benefit stemming from the annual HCA.	XII.A
3.B.2	Hosting Capacity and Interconnection Requirements	Describe the data sources and methodology used to complete the initial review screens outlined in the Minnesota DER Interconnection Process.5 (Footnote: Forthcoming Order, E999/CI-16-521, MN DIP 3.2 Initial Review)	XII.B.2
3.C.1	Distributed Energy Resource Scenario Analysis	In order to understand the potential impacts of faster-than-anticipated DER adoption, define and develop conceptual base-case, medium, and high scenarios regarding increased DER deployment on Xcel's system. Scenarios should reflect a reasonable mix of individual DER adoption and aggregated or bundled DER service types, dispersed geographically across the Xcel distribution system in the locations Xcel would reasonably anticipate seeing DER growth take place first.	XI.D
3.C.2	Distributed Energy Resource Scenario Analysis	Include information on methodologies used to develop the low, medium, and high scenarios, including the DER adoption rates (if different from the minimum 10% and 25% levels), geographic deployment assumptions, expected DER load profiles (for both individual and bundled installations), and any other relevant assumptions factored into the scenario discussion. Indicate whether or not these methodologies and inputs are consistent with Integrated Resource Plan inputs.	XI.D
3.C.3	Distributed Energy Resource Scenario Analysis	Provide a discussion of the processes and tools that would be necessary to accommodate the specified levels of DER integration, including whether existing processes and tools would be sufficient. Provide a discussion of the system impacts and benefits that may arise from increased DER adoption, potential barriers to DER integration, and the types of system upgrades that may be necessary to accommodate the DER at the listed penetration levels.	XI.E
3.C.4	Distributed Energy Resource Scenario Analysis	Include information on anticipated impacts from FERC Order 841 (Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators) and a discussion of potential impacts from the related FERC Docket RM-18-9-000 (Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators)	XI.F.3

Section	Heading	MPUC IDP Requirement (8/30/18 Order in Docket No. E002/CI-18-251)	Location
3.D.1	Long-Term Distribution System Modernization and Infrastructure Investment Plan	*Merged into 3.D.2 per July 16, 2019 Order in Docket No. E002/CI-18-251.*	N/A
3.D.2	Long-Term Distribution System Modernization and Infrastructure Investment Plan	*See* 07/16/19 Order requirements below for merged wording. *See* Attachment J, which lays out the full 3.D.2 requirements and where they are addressed.	XIV Attachment J
3.D.3	Long-Term Distribution System Modernization and Infrastructure Investment Plan	In addition to the 5-year Action Plan, Xcel shall provide a discussion of its vision for the planning, development, and use of the distribution system over the next 10 years. The 10-year Long-Term Plan discussion should address long-term assumptions (including load growth assumptions), the long-term impact of the 5-year Action Plan investments, what changes are necessary to incorporate DER into future planning processes based on the DER futures analysis, and any other types of changes that may need to take place in the tools and processes Xcel is currently using.	V.D, IX, X, XI, XIV, Attachments C and D1
3.E.1	Non-Wires (Non-Traditional) Alternatives Analysis	Xcel shall provide a detailed discussion of all distribution system projects in the filing year and the subsequent 5 years that are anticipated to have a total cost of greater than $2 million. For any forthcoming project or project in the filing year, which cost $2 million or more, provide an analysis on how non-wires alternatives compare in terms of viability, price, and long-term value.	VI Attachment H
3.E.2	Non-Wires (Non-Traditional) Alternatives Analysis	Xcel shall provide information on the following: •Project types that would lend themselves to non-traditional solutions (i.e. load relief or reliability) •A timeline that is needed to consider alternatives to any project types that would lend themselves to non-traditional solutions (allowing time for potential request for proposal, response, review, contracting and implementation) •Cost threshold of any project type that would need to be met to have a non-traditional solution reviewed •A discussion of a proposed screening process to be used internally to determine that non-traditional alternatives are considered prior to distribution system investments are made.	VI

Order Pt.	Heading	MPUC IDP Requirement (7/16/19 Order in Docket No. E002/CI-18-251)	Location
3	Long-Term Distribution System Modernization and Infrastructure Investment Plan	IDP Requirement 3.D.2 shall be amended as follows: For each grid modernization project in its 5-year Action Plan, require Xcel to provide a cost-benefit analysis based on the best information it has at the time and include a discussion of non-quanitfiable benefits. Xcel shall provide all information used to support its analysis.	IX, Attachments C, M1-M5 and O1-O4
4	Long-Term Distribution System Modernization and Infrastructure Investment Plan	IDP Requirement 3.D.2 shall be amended to merge Requirement 3.D.1 into 3.D.2 as follows: Xcel shall provide a 5-year Action Plan as part of a 10-year long-term plan for distribution system developments and investments in grid modernization based on internal business plans and considering the insights gained from the DER fugtures analysis, hosting capacity analysis, and non-wire alternatives analysis. The 5-year Action Plan should include a detailed discussion of the underlying assumptions (including load growth assumptions) and the costs of distribution system investments planned for the next 5-years (expanding on topics and categories listed above). Xcel shall include specifics of the 5-year Action Plan investments. Topics that should be discussed, as appropriate, include at a minimum: [As stated in the Aug 30, 2018 IDP filing requirements at 6].	XIV Attachment J
5	N/A	Xcel shall discuss in future filings how the IDP meets the Commission's Planning Objectives, including: A. An analysis of how the information presented in the IDP related to each Planning Objective, B. The location in the IDP, C. Analysis of efforts taken by the Company to improve upon the fulfillment of the Planning Objectives, and D. Suggestions as to any refinements to the IDP filing requirements that would enhance Xcel's ability to meet the Planning Objectives.	Attachment B, Section XV
6	N/A	Xcel shall provide additional information on the Incremental Customer Investment Initiative and the System Expansion or Upgrade for Reliability and Power Quality increases beginning in 2021.	VII.C, XIV
7	N/A	Xcel shall make the development of enhanced load and DER forecasting capabilities, as well as, tracking and updating of actual feeder daytime minimum loads, a priority in 2019 and include a detailed description of its progress in the Company's 2019 IDP.	V.D.2-3, XI.F Attachment D1
8	N/A	Xcel shall provide all information, analysis, and assumptions used to support the cost/benefit ratio for AMI, FAN and FLISR; and IVVO and CVR cost-benefit analysis as part of its 2019 IDP filing or other future filings.	IX, Attachments C, M1-M5 and O1-O4
9	N/A	Xcel shall provide the results of its annual distribution investment risk-ranking and a description of the risk-ranking methodology, in future IDPs.	Attachments E and F2
10	N/A	Xcel shall provide information on forecasted net demand, capacity, forecasted percent load, risk score, planned investment spending, and investment summary information for feeders and substation transformers that have a risk score or planned investment in the budget cycle in future IDPs.	Attachments F1 & F2
11	N/A	Xcel shall file any long-range distribution studies it had conducted in the time since the last IDP.	N/A for 2019

Correlation of IDP Content to Commission's IDP Planning Objectives

The Commission's July 16, 2019 Order in Docket E002/CI-18-251 requires the Company to discuss in future filings how the IDP meets the Commission's Planning Objectives, including:

A. An analysis of how the information presented in the IDP related to each Planning Objective,
B. The location in the IDP,
C. Analysis of efforts taken by the Company to improve upon the fulfillment of the Planning Objectives, and
D. Suggestions as to any refinements to the IDP filing requirements that would enhance Xcel's ability to meet the Planning Objectives.

The Commission's August 30, 2018 Order in Docket E002/CI-18-251 provided the Commission's Planning Objectives. Specifically, it noted that Xcel Energy's distribution system planning is to be guided by the following principles and planning objectives:

- Maintain and enhance the safety, security, reliability, and resilience of the electricity grid at fair and reasonable costs, consistent with the state's energy policies;
- Enable greater customer engagement, empowerment, and options for energy services;
- Move toward the creation of efficient, cost-effective, accessible grid platforms for new products and services, with opportunities for adoption of new distributed technologies;
- Ensure optimized use of electricity grid assets and resources to minimize total system costs; and
- Provide the Commission with the information necessary to understand Xcel's short-term and long-term distribution system plans, the costs and benefits of specific investments, and a comprehensive analysis of ratepayer cost and value

We have followed the format the Department used in their February 22, 2019 Comments in Docket E002/CI-18-251 in complying with the Commission's requirement.

A. Planning Objective #1

As noted above, the first planning objective of the IDP is designed to maintain and enhance the safety, security, reliability and resilience of the electricity grid, at fair and reasonable costs, consistent with the state's energy policies. We provide a high-level analysis of the location of these topics in the IDP in Table 1 below.

Table 1: Location of Topics of the First Planning Objective in the IDP

Topic	IDP Location
Safety	Executive Summary I B II B, D III B IV B V B VIII A, C VIII A, B IX F X B XII C
Security	Executive Summary I B II C V A VII C VIII A IX A, B, F X C XI E, F XIV B
Reliability	Executive Summary I A, B, C II A, B, C, D, E III B IV B, C V A, B, C, D VI A, C, D IX A, B, H, I, J X A, B, C XI A, E, F XII A, C XIII A XIV A, B XVI XVII
Resilience	Executive Summary IB VII A, C VIII A XI A, E

Table 1: Location of Topics of the First Planning Objective in the IDP (*Cont'd*)

Fair and Reasonable Costs	Executive Summary II A, B, C IX A, B, G, I, X XIV A
Consistent with State Energy Policies	Executive Summary IIA, B, C III B IX A, B, J X

As suggested by the table above, the Company addressed each of the topics of the first planning objective in a substantive way.

B. Planning Objective #2

The second planning objective of the IDP is to enable greater customer engagement, empowerment, and options for energy services.

Our IDP Report has a robust discussion with regard to these three topics. First, our distribution system planning processes, discussed in Section II (nearly 20 pages) are in part designed to enable greater customer engagement, empowerment, and options for energy services.

The Executive Summary (over 20 pages) of the IDP provides an overview of the customer-oriented outcomes expected from deploying advanced grid infrastructure and advanced technologies.

Our IDP provides great detail and discussion of these aspects of our distribution system planning when discussing our plans for Advanced Metering Infrastructure (AMI), Field Area Network (FAN), Fault Location, Isolation, and Service Restoration (FLISR), Integrated Volt Var Optimization (IVVO), and Integrated Volt Var Optimization (IVVO), and Advanced Distribution Management System (ADMS), each of which are technological innovations that are geared toward fulfilling the second planning objective. These are discussed throughout the filing but particularly in Section IX, Grid Modernization (which is over 25 pages) and Section X, the Customer Strategy Section (which is nearly 10 pages).

Namely, the IDP says this with regard to our Advanced Grid Intelligence and Security (AGIS) initiative investments:

Our planned advanced grid investments combine to provide greater visibility and insight into customer consumption and behavior. We will use this information to transform the customer experience through new programs and service offerings, engaging digital experiences, enhanced billing and rate options, and timely outage communications.

We will offer options that give customers greater convenience and control to save money, provide access to rates and billing options that suit their budgets and lifestyles, and provide more personalized and actionable communications. As our system more efficiently manages energy flows, we can save customers money by reducing line losses and conserving energy. Smarter meters will be the platform that enables smarter products and services and contributes to improved reliability for our customers. Our customers will have more information to make more effective decisions on their energy use.

The IDP also provides an extensive discussion on Distributed Energy Resources (DER) in Section XI (nearly 50 pages), Hosting Capacity in Section XIII (over 10 pages), and Grid Modernization Pilots in Section XIII (over 6 pages) which all also support the Commission's second planning objective to enable greater customer engagement, empowerment, and options for energy services.

Specifically, when discussing the Time of Use Pilot (TOU), the IDP states:

The goals of the TOU pilot are to study adequate price signals to reduce peak demand, identify effective customer engagement strategies, understand customer impacts by segment, and support demand response goals.

We note that this list is not exhaustive of the items discussed in the IDP that relate to the second planning objective. However, this does represent that we provided extensive information and discussion of items related to the second planning objective.

C. Planning Objective #3

The third planning objective of the IDP is designed to move toward the creation of efficient, cost-effective, accessible grid platforms for new products, new services, and opportunities for adoption of new distributed technologies.

Much of the information and discussion provided in the IDP related to the second planning objective are also applicable to the third planning objective. Our description of our AGIS initiative, of which AMI, FAN, FLISR, IVVO, and ADMS were discussed, provides information and discussion relevant to the third planning objective. These are discussed throughout the filing but particularly in Section IX, Grid Modernization (which is over 25 pages) and Section X, the Customer Strategy Section (which is nearly 10 pages).

Additionally, the advanced planning tool (APT) discussed throughout the document but particularly in the Executive Summary, Section V.D (8 pages), and Attachment D1 (nearly 25 pages), also relates to the third planning objective. We note the following:

> *We will also procure and implement an APT that will enhance our ability to perform NWA analysis, and DER and load forecast scenario analysis; it will also help to facilitate a greater alignment and integration of our distribution-transmission-resource planning.*

We also provide this excerpt with respect to APT and the third planning objective:

> *Additionally, APT has the ability to export forecast results directly to load flow programs, such as Synergi Electric. This will improve the efficiency of the load flow model build process, which is performed to build models for planning studies and hosting capacity analysis.*

The IDP Customer Strategy Section X (nearly 10 pages) also discusses how our AGIS plans will help improve the existing customer portal as well as the potential for additional opportunities in the future, saying:

> *Customers will have access to granular energy usage data from our AMI through a customer portal, which we expect to pair with informed insights and helpful tips on how to change their behavior to save energy. Further, the AMI meters we propose include a Distributed Intelligence platform, which essentially provides a computer in each customer's meter that will be able to "connect" usage information from the customer's appliances for further insights – and be updated with new software applications, much like customers can currently update their mobile devices with applications.*

Finally, Section XIII Existing and Potential New Grid Modernization Pilots (over 6 pages) also relates to the third planning objective. Specifically, we provide information on our TOU Rate Pilot, four electric vehicle (EV) pilot programs as well as one additional new EV pilot, and several storage projects. Each of these pilots supports the third planning objective as they provide potential new platforms for new products, new services, and opportunities for adoption of new distributed technologies.

We note that this list is not exhaustive of the items discussed in the IDP that relate to the third planning objective. However, this does represent that we provided extensive information and discussion of items related to the third planning objective.

D. Planning Objective #4

The fourth planning objective of the IDP is designed to ensure optimized utilization of electricity grid assets and resources to minimize total system costs.

In the IDP, we provide an entire section (nearly 10 pages) discussing our efforts toward integrating Distribution, Transmission, and Resource Planning in Section XVII, which entirely supports the fourth planning objective.

We also state that we have planned our "AGIS investments in a building-block approach, starting with the foundational systems, in alignment with industry standards and frameworks." Additionally, we provide a discussion comparing our current state systems and process against the DOE DSPx framework in addition to potential progression in planning practices along with a discussion regarding the drivers of progress.

Developing "core components" as the foundation for our advanced grid roadmap first and subsequently building on that foundation to enable advanced applications is well aligned with the DSPx framework. Many of these core components are already in place, and others we plan to implement in the near future will build additional core capabilities to support grid modernization applications.

In the context of the Company's planning efforts related to distributed energy resources (DER), we also provide an entire section (nearly 50 pages) within the IDP discussing this issue, specifically Section XI Distributed Energy Resources.

The investments that we are currently making in asset health, discussed in Section VII, and grid modernization, such as ADMS, AMI, FLISR, and IVVO help to lay the foundation for continued resiliency and reliability. Near-term future planned AGIS investments such as AMI further cement it, and will allow us to gradually respond to increased DER penetration. These are discussed throughout the filing but particularly in Section IX, Grid Modernization (which is over 25 pages) and Section X, the Customer Strategy Section (which is nearly 10 pages).

The DOE has observed that U.S. utilities are in Stage 1 in terms of timing and pace toward a modern distribution grid and the DOE incorporated evolving distribution planning processes and tools into this evolution. Stage 1 also includes improving foundational capabilities such as availability, quantity, and quality of data, which is often achieved by implementing communication systems such as the FAN that is in our near-term advanced grid plans.

Again, we note that this list is not exhaustive of the items discussed in the IDP that relate to the fourth planning objective. However, this does represent that we provided extensive information and discussion of items related to the fourth planning objective.

E. Planning Objective #5

Finally, and as noted above, the fifth planning objective of the IDP is to provide the Commission with the information necessary to understand Xcel's short-term and long-term distribution system plans, the costs and benefits of specific investments, and a comprehensive analysis of ratepayer cost and value.

The IDP provides a comprehensive discussion about our short-term and long-term distribution system plans and investments within Section II.D, Distribution Financial Overview (over 12 pages), Section II.E, Distribution System Plan Summary (over 4 pages), Section IX, Grid Modernization (over 25 pages), and Section XIV, Action Plans (over 10 pages).

In addition, we provide a through description of how we plan the distribution system in Section II, Distribution System Plan Overview (nearly 20 pages) and Section V, System Planning (nearly 40 pages); as well as how we develop the budget in Section III Budget Development Framework (nearly 10 pages).

With regard to the costs and benefits of specific investments, we discuss this at length throughout the IDP. In particular, we provide Section VI Non-Wires Alternatives Analysis (10 pages in the IDP and 40 page Attachment H), which provides the cost benefit analyses we performed to evaluate non-traditional distribution system solutions to our traditional distribution solutions. We also provide cost benefit analysis for all of our AGIS investments and the Advanced Distribution Planning Tool. These can be found in Section IX Grid Modernization (over 25 pages) (as well as supporting Attachments M1-M5, totaling nearly 900 pages), Section V.D Future Planning Tools and Supporting Attachments D1 and D2 (nearly 25 pages), and Attachments O1-O4.

With regard to ratepayer value, in Section IX Grid Modernization (over 25 pages) we discuss the overall customer proposition for AGIS, including drivers of the initiative, expected customer and system benefits, and a cost benefit analysis. In this section we also provide the quantifiable impact to a customer's bill as a result of the increased revenue requirement due to our investments and O&M spending necessary to implement the AGIS initiative.

We note that this list is not exhaustive of the items discussed in the IDP that relate to the fifth planning objective. However, this does represent that we provided extensive information and discussion of items related to the fifth planning objective.

F. IDP Filing Requirement Refinements

Finally, with respect to the last discussion point requesting the Company provide suggestions as to any refinements to the IDP filing requirements that would enhance Xcel's ability to meet the Planning Objectives, we reiterate our request that the Commission move to a biennial filing cadence for the IDP, consistent with other Minnesota utilities and the grid modernization statute filing requirements.

We believe a biennial filing would better allow time to fully engage with stakeholders on the Commission's planning objectives between IDP filings, as well as to address important issues such as DER planning, a comprehensive approach to non-wire alternatives (NWA), and our advanced grid plans. The present annual filing schedule also does not allow the Company to make significant, meaningful progress on its objectives between these extensive filings.

IDP Grid Modernization Content Roadmap

Planning Objectives: The Commission is facilitating comprehensive, coordinated, transparent, integrated distribution plans to:
· Maintain and enhance the safety, security, reliability, and resilience of the electricity grid, at fair and reasonable costs, consistent with the state's energy policies;
· Enable greater customer engagement, empowerment, and options for energy services;
· Move toward the creation of efficient, cost-effective, accessible grid platforms for new products, new services, and opportunities for adoption of new distributed technologies; and,
· Ensure optimized utilization of electricity grid assets and resources to minimize total system costs.
· Provide the Commission with the information necessary to understand Xcel's short-term and long-term distribution system plans, the costs and benefits of specific investments, and a comprehensive analysis of ratepayer cost and value.

Source	Requirement/Description	IDP	Rate Case: AGIS [as presented in Gersack as Exhibit___(MCG-1), Schedule 2]
Docket No. E002/CI-18-251 Aug. 30, 2018 Order (Updated to include changes from Jul 16, 2019 Order)	**A. Baseline Distribution System and Financial Data: Financial Data**		
	26. Historical distribution system spending for the past 5-years, in each category: a. Age-Related Replacements and Asset Renewal b. System Expansion or Upgrades for Capacity c. System Expansion or Upgrades for Reliability and Power Quality d. New Customer Projects and New Revenue e. Grid Modernization and Pilot Projects f. Projects related to local (or other) government-requirements g. Metering h. Other	II.D, III.B, XIII, XIV	Addressed in IDP
	28. Projected distribution system spending for 5-years into the future for the categories listed above, itemizing any non-traditional distribution projects	II.D-E, IX, XIV, Attachments M1, M2, M3, M5	Gersack II(C) AGIS Expenditures 2020-2029 Gersack V(D)(2) AGIS PM Costs 2020-2029 Bloch V(A) AGIS - Distribtuion 2020-2029 Bloch V(D)(5) AMI - Distribution 2020-2029 Bloch V(E)(3) FAN - Distribution 2020-2029 Bloch V(F)((6) FLISR - Distribution 2020-2029 Bloch V(G)(7) IVVO - Distribution 2020-2029 Harkness V(E)(3)(c)(4) AMI - IT 2020-2029 Harkness V(E)(4)(e)(4) FAN - IT 2020-2029 Harkness V(E)(5)(c) FLISR - IT 2020-2029 Harkness V(E)(6)(c) IVVO - IT 2020-2029 Harkness V(E)(7) AGIS - IT 2020-2029 Duggirala Schedules 2, 3, 4
	29. Planned distribution capital projects, including drivers for the project, timeline for improvement, summary of anticipated changes in historic spending. Driver categories should include: a. Age-Related Replacements and Asset Renewal b. System Expansion or Upgrades for Capacity c. System Expansion or Upgrades for Reliability and Power Quality d. New Customer Projects and New Revenue **e. Grid Modernization and Pilot Projects** f. Projects related to local (or other) government-requirements g. Metering h. Other	II.D, IX, XIV, and Attachments F1, G1, M1, M2, M3	Gersack II(B) Exec Summary - Drivers Gersack IV Drivers of AGIS Strategy Gersack II(C) Exec Summary - Implementation Gersack V(A) Component Implementaion Gersack V(B) Overall Timeline/Implementation Bloch V(A) Projects and Timeline Block V(B) Drivers (Limitations of System) Bloch V(D) AMI Bloch V(E) FAN Bloch V(F) FLISR Bloch V(G) IVVO Harkness V(B)(E) AGIS Overview Harkness V(E)(3) AMI Harkness V(E)(4) FAN Harkness V(E)(5) FLISR Harkness V(E)(6) IVVO
	30. Provide any available cost benefit analysis in which the company evaluated a non-traditional distribution system solution to either a capital or operating upgrade or replacement	VI and Attachment H	Addressed in IDP

Source	Requirement/Description	IDP	Rate Case: AGIS [as presented in Gersack as Exhibit___(MCG-1), Schedule 2]
Docket No. E002/CI-18-251 Aug. 30, 2018 Order (Updated to include changes from Jul 16, 2019 Order)	**D. Long-Term Distribution System Modernization and Infrastructure Investment Plan**		
	2. Xcel shall provide a 5-year Action Plan as part of a 10-year long-term plan for distribution system developments and investments in grid modernization based on internal business plans and considering the insights gained from the DER futures analysis, hosting capacity analysis, and non-wires alternatives analysis. The 5-year Action Plan should include a detailed discussion of the underlying assumptions (including load growth assumptions) and the costs of distribution system investments planned for the next 5-years (expanding on topics and categories listed above). Xcel should include specifics of the 5-year Action Plan investments. Topics that should be discussed, as appropriate, include at a minimum:	XIV and Attachments J, M1	Gersack II Exec Summary Gersack IV Drivers of AGIS Strategy Gersack V AGIS Components and Implementation Gersack VI Customer Experience
	· Overview of investment plan: scope, timing, and cost recovery mechanism	II, IX and XIV and Attachment M1	Gersack II Exec Summary
	· Grid Architecture: Description of steps planned to modernize the utility's grid and tools to help understand the complex interactions that exist in the present and possible future grid scenarios and what utility and customer benefits that could or will arise.	IX, X, XIV, Figure 73 and Attachments M1-M4	Gersack V AGIS Components and Implementation Bloch V(D) AMI Bloch V(E) FAN Bloch V(F) FLISR Bloch V(G) IVVO Harkness V(E)(3) AMI Harkness V(E)(4) FAN Harkness V(E)(5) FLISR Harkness V(E)(6) IVVO Harkness V(D) Cyber Security Cardenas V(F) Quantifiable Benefits Gersack VI Customer Experience (Benefits)
	· Alternatives analysis of investment proposal: objectives intended with a project, general grid modernization investments considered, alternative cost and functionality analysis (both for the utility and the customer), implementation order options, and considerations made in pursuit of short-term investments. The analysis should be sufficient enough to justify and explain the investment.	IX and Attachments M1-M3	Gersack V(C) Alternatives to AGIS Bloch V(D)(6) AMI Alternatives Bloch V(F)(7) FLISR Alternatives Bloch V(G)(6) IVVO Alternatives Harkness V(E)(4)(g) FAN Alternatives
	· System interoperability and communications strategy	IX, X and Attachments M2, M3	Bloch V(D)(7) AMI Interoperability Bloch V(F)(8) FLISR Interoperability Bloch V(G)(7) IVVO Interoperability Harkness V(E)(4) FAN Overview Harkness V(E)(4)(b) FAN Interoperability Harkness V(E)(3)(b) AMI Integration
	· Costs and plans associated with obtaining system data (EE load shapes, PV output profiles with and without battery storage, capacity impacts of DR combined with EE, EV charging profiles, etc.)	IDP XI (F)	Addressed in IDP
	· Interplay of investment with other utility programs (effects on existing utility programs such as demand response, efficiency projects, etc.)	Attachment M1	Gersack VI(B)(4) Energy Savings Programs
	· Customer anticipated benefit and cost	V.D.2, IX.F-G, XVI and Attachments M1-M5, O1-O4	Gersack VII Prudence of AGIS Investments (CBA) Duggirala Overall CBA Costs, Benefits, Results Gersack VIII Bill Impacts *Costs and Benefits are also discussed throughout Bloch V (AGIS), Harkness V (AGIS), and Cardenas V (AGIS)*
	· Customer data and grid data management plan (how it is planned to be used and/or shared with customers and/or third parties)	IX, X and Attachments M1, M3	Gersack VI Customer Experience (overall) Gersack VI(B)(3) Digital Experience (web portal) Gersack Schedule 3 Customer Strategy (Appendix B: Data Access, Privacy, Governance) Harkness V(D) Cyber Security
	· Plans to manage rate or bill impacts, if any	IX.G, XIV.A and Attachment M1	Gersack VIII Bill Impacts
	· Impacts to net present value of system costs (in NPV RR/MWh or MW)	XIV and Attachment L	Addressed in IDP

Source	Requirement/Description	IDP	Rate Case: AGIS [as presented in Gersack as Exhibit___(MCG-1), Schedule 2]
Docket No. E002/CI-18-251 Aug. 30, 2018 Order (Updated to include changes from Jul 16, 2019 Order)	**· For each grid modernization project in its 5-year Action Plan, Xcel should provide a cost-benefit analysis based on the best information it has at the time and including a discussion of non-quantifiable benefits. Xcel shall include all information used to support its analysis.**	IX, X and Attachments M1-M5, O1-O4, filed Workpapers	Gersack VII(A) CBA Gesack VII(B) Qualitative Benefits Duggirala II(B) Quantitative Inputs Duggirala II(C) Results Duggirala IV Qualitative Benefits
	· Status of any existing pilots or potential for new opportunities for grid modernization pilots	IX, X, XIII and Attachment M1	Gersack III Grid Mod Background (Res TOU Pilot) Gersack IV(C)(2) Advanced Rate Design/Billing Options
	3. In addition to the 5-year Action Plan, Xcel shall provide a discussion of its vision for the planning, development, and use of the distribution system over the next 10 years. The 10-year Long-Term Plan discussion should address long-term assumptions (including load growth assumptions), the long-term impact of the 5-year Action Plan investments, what changes are necessary to incorporate DER into future planning processes based on the DER futures analysis, and any other types of changes that may need to take place in the tools and processes Xcel is currently using.	IX, X, XIV and Attachments M1, M2	Gersack II Exec Summary Gersack V AGIS Implementation Gersack VI(D) Customer Experience (Long Term) Bloch D(4)(d)(1) AMI Benefits (DER) Bloch G(4)(b) IVVO Benefits (DER)
Docket No. E002/CI-18-251 July 16, 2019 Order	**8. Provide all information, analysis and assumptions used to support the cost/benefit ratio for AMI, FAN, and FLISR; and IVVO and CVR cost-benefit analysis as part of its 2019 IDP filing or other future filings.**	IX.F and Attachments M1-M5, O1-O4, filed Workpapers	Duggirala Overall - CBA testimony points to the other witnesses who provide detailed cost and benefit forecasts.
Docket No. E002/M-17-797 Sept. 27, 2019 Order	**9. If and when Xcel requests cost recovery for Advanced Grid Intelligence and Security investments, the filing must include a business case and comprehensive assessment of qualitative and quantitative benefits to customers, considering, at a minimum, the following:** **A. Scope of Investment** **1. Investment Description** a. Detailed description of proposed investment and project life b. If multiple components, overview of costs and descriptions of each i. Include purpose and role ii. Explain known and potential future use cases for each component iii. Explain known and potential value streams and how each component fits with state policy, statues, rules and Commission orders iv. Describe beneficiaries of each investment (who, how many, over what time period) c. Articulation of principles, objectives, capability, functionalities, and technologies enabled by investment; and d. Interrelation and interdependencies with other existing or future investments, including overlapping costs: scope, amount, timing.	IX, X and Attachments M1-M5	Gersack II Exec Summary Gersack III Grid Mod Background Gersack IV(D) Commission Policy and Stakeholder Input Gersack V(A) AGIS Components Gersack V(B) Overall Implementation Gersack VII(A) CBA Quantified Benefits Gersack VII(B) Qualitative Benefits Bloch V(D) AMI Bloch V(E) FAN Bloch V(F) FLISR Bloch V(G) IVVO Harkness V(E)(3) AMI Harkness V(E)(4) FAN Harkness V(E)(5) FLISR Harkness V(E)(6) IVVO
	2. Alternatives considered a. If a Request for Proposal was used provide: i. The RFP issued, including list of all services or assets scoped in the RFP ii. Provide summary of responses iii. Provide assessment of bids and factors used for selection iv. The scope of offerings or services included in the selected bid b. If not, what was used.	Attachments M1-M3, N1-N4	Gersack V(C) Alternatives to AGIS Bloch V(D)(5) AMI Cost Development (RFP discussion) Bloch V)D)(6) AMI Alternatives Bloch V(F)(6) FLISR Cost Development Bloch V(F)(7) FLISR Alternatives Bloch V(G)(5) IVVO Cost Development Bloch V(G)(6) IVVO Alternatives Harkness V(E)(4)(e) FAN Cost Development Harkness V(E)(4)(g) FAN Alternatives AGIS Supporting files, Vol. 2B (on disc)
	3. Costs a. Provide sufficient information to determine what is included in the investment in each of the following categories: i. Direct Costs (product, service, customer, project, or activity) ii. Indirect Costs iii. Tangible Costs iv. Intangible Costs v. Real Costs	IX and Attachments M5, O1-4, filed Workpapers	Duggirala II(A) Model Structure and Requirements Duggirala Schedules 2, 3, 4, 5
	b. If needed, provide the utility's definition of each category and whether internal or external labor costs are included in the category and the instant petition. If the costs are not included in the petition, include information on where and when those costs will be sought to be recovered.	Attachment M5	Duggirala II(A) Model Structure and Requirements
	c. If there is overlap or costs included in both categories, outline the overlapping costs and explain.	Attachment M5	Duggirala II(A) Model Structure and Requirements Duggirala Schedules 2, 3, 4, 5
	d. For each of the cost categories outline whether the investment has been partially approved or included in previous or on-going docket riders, rate cases, or other cost recovery mechanisms or note all costs are included in the instant petition.	II.D-E, IX, XIV, XV	Gersack II(C) Exec Summary - AGIS Implementation Gersack III Grid Mod Background Bloch V(C) Grid Mod Efforts to Date Harkness V(E)(2) Grid Mod Efforts to Date

Source	Requirement/Description	IDP	Rate Case: AGIS [as presented in Gersack as Exhibit___(MCG-1), Schedule 2]
Docket No. E002/M-17-797 Sept. 27, 2019 Order	**4. Detailed Analysis of the type of proposed or multiple cost effectiveness analysis utilized:**	Attachment M5	Duggirala III
	a. Least-cost, best-fit (Xcel proposes in IDP Reply comments)		
	b. Utility Cost-test; and		
	c. Integrated Power System and Societal Cost test		
	B. Provide a cost benefit analysis for (1) each investment component with overlapping costs or benefits in isolation and (2) each bundled components, as appropriate	V.D, IX and Attachments D2, M1-M5, O1-O4, filed Workpapers	Duggirala II(C) CBA Results AGIS Supporting files, Vol. 2B (on disc) Gersack VII(A)(1) CBA Overview
	1. Provide Discount Rate Used and Basis; and	Attachment M5 and filed Workpapers	Duggirala II(A) Model Structure and Requirements
	2. Identify cost categories and benefit categories used (explain metrics), including an explaination of how benefits can be monitored over time and proposal for reporting to Commission:	IX and Attachments M1, M5	Duggirala II(B) Quantitative Inputs Gersack IX Metrics and Reporting
	a. Identify quantitative costs and qualitative costs: i. Use quantitative methods to address qualitative benefits to the extent possible. ii. Explain system used to assess value and priorities to qualitative benefits (points and/or weighting); and iii. Identify sensitivity ranges on estimates or value	V.D, IX and Attachments D1, D2, M5, O1-O4	Duggirala Overall CBA Costs, Benefits, Results
	b. Include a long-term bill impact analysis	IX , XIV and Attachment M1	Gersack VIII Bill Impacts
	c. Include a reference case/scenario without the project (or group of projects); and	IX, XIV and Attachments M1, M5	Duggirala II(A) Model Structure and Requirements Gersack VIII Bill Impacts
	d. Apply the following principles to ensure the investment analysis has:	Attachments M1-M5	*The Company has incorporated these priciples throughout its analyses, including:* Gersack V AGIS Components and Implementation Bloch V(D) AMI Bloch V(E) FAN Bloch V(F) FLISR Bloch V(G) IVVO Harkness V(E)(3) AMI Harkness V(E)(4) FAN Harkness V(E)(5) FLISR Harkness V(E)(6) IVVO Cardenas V(F) Quantifiable Benefits Gersack VI Customer Experience (Benefits) Duggirala Overall CBA Costs, Benefits, Results
	i. compared with traditional resources or technologies;		
	ii. clearly accounted for state regulatory and policy goals;		
	iii. accounted for all relevant costs and benefits, including those difficult to quantify;		
	iv. provided symmetry across relevant costs and benefits;		
	v. applied a full life-cycle analysis;		
	vi. provided a sufficient incremental and forward-looking view;		
	vii. is transparent;		
	viii. avoided combining or conflating different costs and benefits;		
	ix. discuss customer equity issues, as needed;		
	x. assessed bundles and portfolio where reasonable; and		
	xi. addressed locational and temporal values.		

**Advanced Distribution Planning Tool
Description and Certification Request**

INTRODUCTION

Distribution planning is a key component of the Company's efforts to modernize its grid operations. As described in Section V of the IDP, we undertake a multi-step distribution planning effort each year. This process evaluates projected peak load on each feeder and substation in our system, so that we can analyze and identify needed risk mitigation projects, and put forward a proposal for the upgrades we anticipate are necessary to accommodate customer needs. While some of this baseline distribution forecasting is performed efficiently within our current tool, there is also significant manual work and several bolt-on tools required to fulfill all of our historical distribution planning needs.

Recognizing that distribution planning needs were beginning to change and our existing tool could not accommodate all the analysis we would need or want to do going forward, we began assessing new options in 2015. Given market trends, widespread changes to our grid, and our forecasting software's lifecycle, it is now essential we implement a new, more capable, and dynamic forecasting tool. Such a tool will enable us to meet our planning and regulatory requirements and provide our customers with incremental benefits. Consistent with national trends, our customers are increasingly exercising more choice around their use of energy from our grid, choosing DER and beneficial electrification that can make load forecasting a much more complex undertaking than it was only a few years ago.

As a result of these changes, our distribution planning tools must accommodate additional data granularity to better assess how technologies interact with the grid and how they change l distribution system needs. In order to accommodate customer needs and other stakeholder requests for additional granularity and transparency, the Commission has implemented new planning analysis and reporting requirements the Company must meet. These requirements include conducting scenario forecasting and assessing non-wires alternatives (NWA) for certain upgrade needs we identify. Finally, the existing tool and its hosting server are out of date and its vendor will no longer support it in the near future. Considering these factors, it is time to implement a new solution.

After a thorough solicitation and assessment process, the Company selected a preferred advanced distribution planning tool that will enable us to meet the aforementioned customer needs and Commission requirements for distribution planning. While we are currently in the advanced stages of procuring that tool, as of November 1, 2019, we have not yet signed a contract. Thus, we refer to the tool in this certification request as the Advanced Planning Tool or APT. Beyond customer and compliance needs, the APT will enable us to deliver additional benefits via more efficient planning, enhanced load forecasting capabilities, and better integration with the Company's other planning efforts.

We have already begun to prepare our internal systems and processes to implement the APT. We expect to complete procurement in early 2020, and take the first several months of the year to integrate our data into the new tool and train employees on its use. This is an ambitious timeline, but it will allow us to begin using the APT in our distribution planning processes stating in 2020-2021. Our expected all-in upfront cost is approximately $9.3 million Xcel Energy-wide, and we estimate the proportional Northern States Power Company – Minnesota (NSPM) operating company share of these upfront costs will amount to approximately $4 million. Given the proposed contract structure, our annual costs to maintain the tool are low, and the upfront costs represent most of the total costs we expect over the tool's life.

While our benefit-to-cost assessment for the tool does not indicate direct positive returns, we believe the investment is essential to performing the more sophisticated analyses our evolving grid requires going forward. Continuing to use the existing tool is not feasible. We do expect O&M expenditures for APT will be comparatively lower than the existing tool, however; and while challenging to assess in advance, we also believe the tool may enable us to defer some distribution capital expenditures in the future. Finally, the tool will deliver additional qualitative value, beyond what is quantifiable, by improving analysis efficiency and precision.

Given these factors, the Company respectfully requests that the Commission certify our request to procure the APT for distribution planning purposes. As we discuss in more detail below, this investment meets the requirements for certification and is consistent with planning requirements and goals set forth in prior Commission Orders.

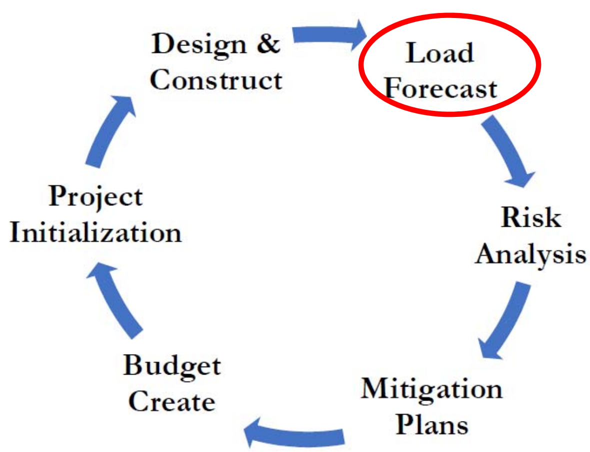
I. EXISTING DISTRIBUTION PLANNING PROCESS AND TOOLS

As discussed in detail in Section V of the IDP, our existing distribution planning process examines our distribution system's ability to serve customer peak load, identifies areas where there is a risk of overload or equipment failure, and makes plans to mitigate these potential overloads with additional or upgraded equipment. We complete this full cycle once per year, and the analysis examines projected conditions over a five-year forward-looking time horizon. As the starting point of our distribution planning process, load forecasting – and the tools we use to complete it – is an essential foundational step. Our current tool has served the Company well in the past; however, as distribution planning and needs change and software service offerings evolve, the tool has become out of date and can no longer effectively meet our system needs moving forward.

A. Load Forecasting as a Piece of the Distribution Planning Process

The process begins with load forecasting. Historically, the load forecasting step has included examining several key components of distribution system use, but remained primarily focused on expected peak load and overall utilization rates. These are two important components, because as peak load or utilization on specific feeders or substations increase and approach the equipment's capacity, there is a greater chance that deviations from expected load could result in overloads and outages.

Figure 1: Annual Distribution Planning Process



In the course of our current load forecasting process, we examine our most recent year's actual peak load and utilization data for each feeder and substation transformer, along with historical trends, and use this information to project load five years into the future. We also evaluate the potential effects of additional load growth drivers and incorporate them into our load forecast. These factors include weather, potential and planned development and new customer load, trends around DER adoption and electrification, and any circuit reconfigurations that may affect the forecast for specific locations on the grid. After completing these projections, our distribution team analyzes where forecasted peak load and utilization may exceed or approach limits for overloading in both normal and contingency conditions. Where these overloads are identified, the team evaluates potential upgrade solutions and prioritizes investments. These investment priorities then feed into our budget creation process. The team also then aggregates the forecast and coordinates with transmission planning staff, so that the Company uses consistent information across these planning processes.

B. Existing Load Forecasting Tool and Capabilities

Given the process described above, load forecasting is an essential foundational step in identifying potential pain points in the system, and balancing the need to stop potential outages before they happen with the need to manage costs to customers. The Company currently uses a tool called Distribution Asset Analysis (DAA) to facilitate its load forecasting efforts. This tool was specifically tailored to the Company's system by its vendor, Itron, and was first implemented in 2003. DAA allows us to use SCADA-based feeder and substation information, combined with customer billing data and weather data, to better examine loading conditions at each of these analysis points. Our ability to evaluate this previously disparate data within one tool helps us form the basis of our existing distribution load forecasting analysis.

There are, however, various other aspects of our distribution planning process for which DAA is not used, largely because it does not have the required functionality to perform them. For example, DAA itself cannot perform scenario analyses or aggregate feeder and substation specific forecasts. For these aspects of our distribution forecasting process, we use a combination of other tools and manual processes, as depicted in Table 1 below. In all, the combination of DAA and other tools and approaches has historically enabled us to meet our distribution planning and reporting regulatory requirements and operational needs.

Table 1: Distribution Forecasting Tools, by Planning Component

	Planning Process Component						
Tool	**Forecast**	**Risk Analysis**	**Mitigation Plans**	**Budget Create**	**Initiate Construction - EDP Memo**	**Long-Range Plans**	**Hosting Capacity**
Synergi Electric			X			X	X
DAA	X	X				X	
MS Excel		X		X		X	
CYMCAP		X					
GIS			X			X	X
SCADA	X						
WorkBook		X	X	X	X		
DRIVE							X

That said, distribution planning is changing, given customer trends, needs, and evolving regulatory requirements; DAA's usefulness as a planning tool has not kept pace with these changes. Customers now have many more options when it comes to their energy usage and are increasingly exercising those choices. These options include reducing consumption through home energy controls, increasing consumption through beneficial electrification, and feeding energy back onto the grid by installing DER. Further, the Commission has established grid planning priorities and requirements that are intended to ease the customer path to DER adoption and electrification, as well as encouraging utilities to examine options for grid upgrades beyond traditional "poles and wires" investments. DAA, as a forecasting tool, was not designed to support utility analysis in these tasks.

More specifically, the Commission has set forth several requirements for which the analysis possible within DAA falls short, and requires the Company to conduct various manual analyses. These include developing forecast scenarios that allow us to understand the grid impacts on varying levels of DER adoption, as well as evaluating non-wires alternatives for traditional poles and wires mitigation projects identified that are over $2 million in estimated cost.[1] Further, several of the Commission's objectives with regard to grid modernization are more difficult to meet given DAA's limitations. For example, one of the objectives of Grid Modernization Reports, as set forth by the Commission, is to ensure optimized utilization of electricity grid assets and resources to minimize total system costs. Given our existing tool only evaluates

[1] Per *Order Approving Integrated Distribution Planning Filing Requirements for Xcel Energy*. Docket No. E002/CI-18-251 (August 30, 3018).

annual peak load conditions, our existing forecasting tool simply does not provide the capability to meet these going forward needs.

It is also important to note that the DAA tool and its hosting server are both outdated and reaching the end of their useful life. DAA's vendor has informed us that it no longer provides ongoing updates or support for the tool beyond basic technical maintenance, and the Company is its only remaining customer for this tool.

For the foregoing reasons, DAA will no longer provide us the basic functionality we need to understand how customers are interacting with our distribution system, deliver additional value to customers by identifying potential benefits of DER in a given area, or keep pace with regulatory requirements in an efficient manner. Even if the tool were going to be available into the future, we would need a new distribution load forecasting tool that is better suited to evaluating more dynamic load conditions with more granularity, given the evolving nature of our distribution system and customer technology adoption. Further, as our advanced grid efforts continue, a more dynamic load forecasting tool will be able to grow with our capabilities, serving as an essential piece to enable new customer usage data insights, and providing additional value to customers in terms of programs and offerings.

II. NEW TOOL EVALUATION AND APT SELECTION

Recognizing that DAA's capabilities would not be sufficient in a future with more customer technology adoption and without continuing vendor support, we began evaluating options for a new tool in 2015. As we moved through this process and received bid responses to evaluate different options, new requirements from the Commission were also emerging that solidified much of what we recognized would be important tool attributes going forward. As a result of a careful evaluation process – including bid responses, initial evaluations, and vendor demonstrations – we determined that the APT is the best option for conducting the depth and breadth of analyses needed going forward. The tool's core benefits include the ability to: more efficiently and cost-effectively forecast distribution-level load; conduct more advanced scenario and NWA analyses; and better integration of our distribution planning with other Company planning processes. We believe this tool will position us well for the future of distribution planning, where its capabilities can grow with us and help us meet current and future Commission planning requirements.

A. Guiding Factors for Selecting a New Load Forecasting Tool

Overall, selecting a tool that enables us to provide customers with more value, meets our regulatory requirements, and eliminates manual data processing was of utmost importance in our evaluation process. Specifically, we see the following three key capabilities as essential to our selection process: forecast granularity and ability to support non-wires alternative investment analysis, ability to support scenario development, and integration with other resources and planning processes. We discuss each further below.

1. Forecast Granularity and Non-wires Alternative Investment Analysis

As noted above, our current tool is capable of evaluating annual peak load at a feeder or substation level. A tool that provides more granular analysis options, in terms of both time intervals and proximity to the customer end point, enables us to make more accurate decisions regarding investment needs and options. For example, with the introduction of DER onto the system, the differentials between minimum and maximum load during the day become both a more valuable and harder to predict data point. With more customers adopting DER and beneficial electrification, peak loading on a specific feeder may result in different levels of load, or at a different time of day than another feeder or than the system as a whole. In order to adequately assess the impact of DER on a given part of the grid, therefore, we need a tool that can forecast hourly load at the selected analysis point. Further, the most granular analysis point we have been able to utilize in distribution planning thus far is the feeder level, but there may be value in analyzing sub-feeder data. Each feeder is generally associated with approximately 1,500 to 8,000 endpoints, depending on the area's population density. However, as DER are often localized to a specific end point, being able to analyze load and generate distribution forecasts at a sub-feeder level may provide valuable insights for both necessary grid upgrades and future potential customer offerings.

Combined, a tool that enables these more granular analyses will provide important information and efficiencies in assessing potential non-wires alternatives to identified system upgrade needs. An annual peak load analysis alone cannot communicate whether an identified upgrade is a candidate for non-wires alternative; more granular hourly data is required to determine the magnitude of overloads at specific durations. Currently this analysis is completed by extracting historical peak day load curves from feeder data, scaling them to the forecast study year, and then manually evaluating the normal and contingency load conditions. We then use these results to conduct risk analyses and develop theoretical load conditions if certain DER solutions were applied. However, a tool that can evaluate and project hourly load data on a feeder or other specific point on the grid would facilitate more efficient evaluation of potential future overloads and whether a non-wires solution – such as DER, efficiency or energy storage – is a viable alternative to traditional upgrades. In short, we anticipate a tool with these capabilities would reduce manual work and better identify opportunities for DERs to provide value on our grid.

2. Scenario Development

The Commission's Order setting out the requirements for our integrated distribution plan includes DER scenario analyses. In accordance with these requirements, we evaluate scenarios with a minimum level of assumed DER adoption, as well as medium and high adoption scenarios (corresponding to Base+10 percent and Base+25 percent, respectively). The objective of these analyses is to understand whether substantially increased levels of DER at a given point on the grid would result in different system overload conditions and upgrade needs. Currently these scenarios are developed and evaluated outside our load forecasting tool, given our current tool is incapable of generating such an analysis. A tool that can provide these scenario forecasting capabilities intrinsically would contribute to more efficient forecasting processes and better assessment regarding how these increased adoption scenarios would affect specific feeders and substation transformers. This will be particularly important going forward as DER and beneficial electrification adoption increases in our service area.

3. Aggregation and Integration with Other Resources and Planning Processes

Finally, a key aspect of a new distribution forecasting tool is its ability to integrate data source inputs, as well as communicate effectively with our other planning processes. Any new tool in which we invest will need to be able to surpass the existing tool's capabilities; preferably in its ability to handle data inputs from various sources beyond the current set of inputs such as feeder-level SCADA data and existing customer usage inputs. External data layers, such as more targeted economic and weather forecasts or projected DER adoption trends will help us more effectively forecast load changes into the future. The tool we select also needs to be able to integrate potential internal future sources of data, such as interval data from our proposed AMI investments.

Further, forecast aggregation and integration with other company planning efforts is an essential benefit we considered when evaluating replacement tools. As previously discussed, our existing tool evaluates potential load growth on a feeder or substation. However, this level of growth must be defined by the planner responsible for analyzing that specific point on the grid, and the tool cannot effectively aggregate forecasts from each point of analysis to ensure a reasonable fit with Company-wide top-line forecasts. Moreover, the forecast outputs from a future tool must be easily accessible and usable within other company planning processes. Currently, our transmission planners scale distribution forecasts to the corporate level manually, for use in transmission planning processes and tools. We also have an existing regulatory requirement to align distribution planning to integrated resource planning more closely, particularly in terms of DER forecasts. As our resource planning tools evaluate generation resources at an hourly level, a similarly granular distribution forecasting tool will facilitate this integration more effectively than the current manual translation processes.

B. RFI Process, Evaluation, and Selection

Considering the needs outlined above, the Company took a multi-step approach to evaluating potential future tools. This includes information gathering and pre-screening, applying evaluation criteria to potential vendors subsequent bid proposals, inviting the top vendors to provide product demonstrations, and external vetting. We describe each of these steps in turn below.

1. Initial Screening and Evaluation Criteria Development

First, we independently researched available tools and their vendors, in addition to well-known technology companies that we believed may be able to develop a customized solution. This research resulted in seven distinct vendor options representing a broad range of companies; from large industrials providers to boutique solutions. After this research was complete, we issued a Request for Information from the selected vendors. This RFI included a questionnaire with over 300 questions that were designed to help us further screen the potential new tools. At the same time, we also assembled a cross functional team to use a list of scoring metrics and evaluate potential options throughout the information and bid process. This team included Company professionals from the Distribution team, as well as Enterprise Architecture, IT Security, and Sourcing. Solutions were evaluated across multiple metrics, including those in the non-exhaustive list of example scoring considerations in Table 2 below.

Table 2: Example Distribution Forecasting Tool Evaluation Metrics (Not Exhaustive)

Category	Scoring Criteria
Scope and Technical Requirements	Prior experience and customer references
	Ability of proposal to meet scope of work and timeline
	Functional requirements
	Technical requirements
	Security requirements
Cost/Pricing	Total price – base and alternate bids
	Proposal detail and cost transparency
	Implementation costs and maintenance costs
Commercial Terms	Negotiability of contract terms
Vendor Financials	Financial health of the vendor

Of the seven vendors invited to submit an informational bid, three responded. These responses were scored primarily according to the vendor's ability to demonstrate how the tool would meet the scope and technical requirements we outlined, as well as other factors. Pricing and commercial terms were evaluated in a subsequent round, after formal bids were received.

2. *Bid Evaluation and APT Selection*

Given the initial screening and bid evaluation described above, we eventually narrowed available distribution forecasting tool options to two potential products, as the third vendor failed to demonstrate their proposed solution met the project scope. At this point, we invited the vendors of each remaining product to provide a demonstration of their respective tools and discuss whether they were able to provide the core functionalities we identified. We designed the demonstration assessments to build on vendors' RFI responses, ensuring a vendor's tool could sufficiently meet the most important functional requirements we set out for our next distribution forecasting tool. The APT's vendor was able to show that the tool satisfies all of these the requirements, and it was the only vendor to do so. We describe the tool itself and its capabilities with respect to the three core guiding factors we identified further below. Further, the vendor showed that the tool would not require substantial customization for use with our other existing tools and analyses. Conversely, the other tool's vendor was unable to demonstrate most of the requirements during the course of our demonstration meeting, and would have required extensive customization to integrate. As a result, the APT was the preferred choice given its analysis capabilities and ease of integration.

In an effort to further validate this determination, we also reached out to industry experts after the demonstration phase to gauge experience with both tools. Specifically, we talked to existing APT customers in the utility industry to better understand their use cases and satisfaction with the tool and the vendor's services. We also conducted expert interviews through a third party to evaluate APT and whether there were viable alternate tools we missed the process of our evaluation. These experts confirmed that APT was one of the only solutions that could provide the functionality we need. It was based on all the aforementioned evaluations, in aggregate, that we determined APT is the appropriate tool for the next phase of the Company's distribution forecasting.

III. APT OVERVIEW AND PLANNED IMPLEMENTATION

The APT is a spatial load forecasting tool, which combines several layers of detailed electric infrastructure, weather, economic and other data layers to forecast how future load and energy demands on the grid may change and thus, where upgrades may be required. We describe the APT's capabilities relative to those benefits further below. Given our existing load forecasting tool has reached its end of life, we plan to begin procurement and implementation quickly. In fact, we are currently conducting contract discussions with the tool's vendor and have already begun our initial internal design work. We plan to finalize the contract in the near term and complete the software acquisition in early 2020. We anticipate full tool implementation for the Upper Midwest service areas will be complete in the third quarter of 2020, and Company-wide by 2021. Xcel Energy-wide we expect that procurement and implementation will cost approximately $9.3 million upfront – most of which will be capital investments. For NSPM, we expect the upfront investment will amount to approximately $4 million. As the tool will be a shared asset, other Xcel Energy operating companies will incur their proportional share of overall costs as well.

While our benefit-to-cost assessment for the tool does not indicate direct positive returns, we believe the investment is essential to performing the more sophisticated analyses our evolving grid requires going forward. Over the full seven year assumed financial life of the software, we expect a benefit-to-cost ratio of 0.35. Benefits of the tool include lower O&M costs for the APT as compared to our existing tool, even considering substantial added functionality, and some potential capital deferral benefits. However, the tool's benefits go beyond what can be shown in the CBA. The APT will provide multiple additional qualitative benefits that, while challenging to quantify in dollar terms, are tangible and substantial. We also expect to use the tool far beyond its seven year asset life – and given the low ongoing costs, customer benefits will continue to accrue into the future. In all, we believe the APT will provide substantial value in building a more robust distribution forecasting process that will better serve customer needs, and help us meet our regulatory requirements more efficiently.

A. Overview

The APT is a forecasting tool for distribution loads, which will replace – and surpass – our existing load forecasting tool in providing insight into potential future load on each of our feeders and substation transformers. The tool will do this by combining hourly historical load data with other Company and externally provided data layers, and using statistical methods to develop best-fit forecast analyses for every feeder and substation transformer on our system. The tool allows historical load data to be imported directly from SCADA systems, or at a more granular level from AMI.[2] The tool also can manage multiple data layers such as the Company's demand data and DER forecasts, as well as external geospatial and economic data such as housing starts and gross domestic product growth at a granular geographic level. The effect of each layer on the load forecast for a feeder or substation transformer can be disaggregated from the overall forecast, to provide information on the magnitude of impact resulting from any given factor.

The tool's vendor provides several combination options for licensing and deploying the software, which we carefully evaluated for fit, cost, and ease of use. Ultimately we chose to procure the tool as a hosted solution on a perpetual license. This means that the vendor will provide for our use of the tool on their servers, to which we will have access via the cloud. We determined using the APT as a hosted solution was an appropriate choice largely because it affords nearly instantaneous updates to the tool when the vendor makes improvements or adds new features. If we were to host the software on our own servers, update integration would need to be done on site, which can sometimes delay access to new or updated features up to several months. A hosted deployment option is also more cost effective for the Company in this instance, allowing us to avoid maintaining – and paying for – our servers for the software.

We chose a perpetual license primarily based on its cost-effectiveness over the duration we plan to use the tool. We believe the APT – with the vendor's continual updates – will provide the features we need far into the future, beyond the typical seven year asset life we use to assess software investments. Our internal analyses showed that a perpetual license option would be the most cost-effective if the Company uses this tool for eight years or more. To provide a point of comparison,

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[2] Note that the Company does not yet have AMI on its system, but APT could integrate the data from that infrastructure in the future, if available.

we have been using our current tool for 16 years thus far, and given the cost to acquire and integrate a new system, we do not anticipate making another change within eight years. At present, there are few to no alternatives that can provide comparable functionality, and emergent tools from other vendors remain in development phases. Especially given APT's continual updates and its "room to grow" with our advanced metering capabilities, we anticipate the upfront investment is the most prudent path forward. We further discuss the tool's total costs in Section D below

B. Capabilities and Benefits

The APT provides various functionalities and benefits that make it an appropriate choice for our future distribution system planning. As discussed previously, there are three key functions we used as guiding factors in tool evaluation and selection, to enable the range of analyses that will provide value to our customers and that meet our regulatory requirements. The APT has the demonstrated ability to provide all of these functions. We also anticipate it will facilitate additional process automation, reducing staff time dedicated to completing our forecasting and reporting requirements. We describe these capabilities in more detail below.

1. Forecast Granularity and Non-wires Alternative Investment Analysis

As noted previously, improved forecast granularity is a key enabling factor that will allow us to improve our analyses, in terms of both time intervals and proximity to the customer end point, and enable us to make more accurate decisions regarding investment needs and options. APT will be able to use historical distribution system SCADA and/or metering data, alongside in-built layers to generate statistically robust best-fit hourly load forecasts and shapes at the feeder and substation transformer level. Forecasting load shapes for each feeder and substation transformer, in particular ones that can be disaggregated from the effects of DER installed at a given point on the system, is an essential functionality for our future tool. It will enable more targeted N-0 and N-1 overload analyses, in terms of time, duration, and location. Further, where upgrade needs are identified, these hourly shapes will provide helpful insight that allows us to better analyze potential non-wires alternatives and distribution investment deferral analyses.

2. Scenario Development

As noted above, the Commission's Order setting out requirements for our distribution planning processes necessitate DER scenario analyses. We currently develop these scenarios manually outside our distribution forecasting tool, and because the tool only evaluates annual peak load conditions, it is difficult to get a full picture of how these higher DER adoption scenarios may affect a given feeder or substation across the full year. However, APT will allow us to integrate these forecasts more fully into our analyses. Our baseline DER forecasts will be integrated directly with hourly load forecasts, where the tool uses best-fit analyses to determine potential impact of DER at the feeder level. The tool will also make it easier to develop DER scenario analysis that can be applied at this more granular level, and allow us to test different adoption scenarios within the tool. All of this functionality allows us to conduct DER scenario analyses more efficiently, and will help us better assess how different levels of DER may change peak loads and load shapes on specific feeders throughout the service area.

3. Aggregation and Integration with Other Resources and Planning Processes

Finally, a key aspect of a new distribution forecasting tool is its ability to integrate data source inputs, as well as communicate effectively with our other planning processes. APT enables us to do both. The tool can be used to fit distribution system forecasts, via standard statistical modeling methods, to our corporate-level forecasts that we use in Transmission and Resource Planning, so that these forecasts can be consistent across planning functions. This is key in part because Transmission and Resource Planning already use models that conduct analyses on hourly load and generation shape data; and enabling distribution planning to analyze and forecast conditions on a similar time interval will enable all three planning processes to align better. The new tool will also provide modeling outputs that can be used in power flow modeling, which will support easier data handoffs between processes.

4. Additional Benefits

In addition to the benefits described above, the tool can also provide two additional capabilities that will support our ability to meet additional regulatory requirements: (1) inform customer energy choices and (2) perform increasingly granular analyses. First, because APT is capable of developing hourly load shapes on feeders and disaggregating the effects of DER from net load, it will help us conduct better informed Hosting Capacity Analyses (HCA) in the future. For example, daytime minimum load analyses required in the HCA are currently developed manually, by evaluating each feeder with a Community Solar Garden installation and manually removing the estimated effect of the CSG on the feeder's estimated load. With APT, the tool will provide hourly load shapes that will automatically disaggregate the effect of DERs in a particular area, so that we are able to assess daytime minimum load without additional manual work. Second, the tool can grow in its analysis capabilities in accordance with the granularity of the data we can provide, in particular with AMI and meter level interval data. When we implement AMI, APT will be able to integrate that sub-feeder level data and allow us to perform more precise forecasting and planning analyses. Overall, these added benefits support our determination that APT is the right tool to take our load forecasting capabilities into the next phase.

C. Implementation Action Plan

Now that we have determined the APT is the best tool available to suit our distribution forecasting needs for the foreseeable future, we plan to move quickly to procure and implement APT. After finalizing the procurement, design, implementation, testing, which will take place over the next several months – we plan to begin using the APT in our distribution planning processes by late 2020.

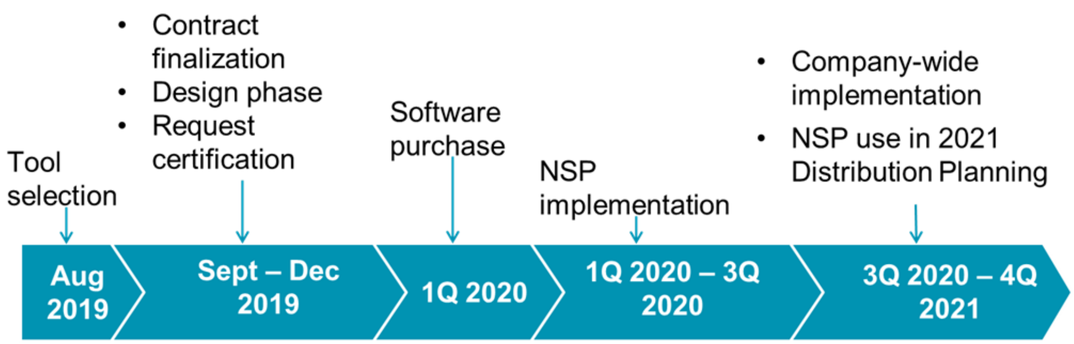
In order to prepare for tool implementation, we are currently conducting detailed design preparations. In this phase, we are undertaking activities such as developing an overall software implementation architecture, mapping functional requirements to test cases, and mapping from where each needed data stream will feed into the tool. We anticipate completing this phase by the end of the year. During this time we are also finalizing the contract details with the vendor, which will enable us to move through the purchasing process early in the first quarter of 2020.

After purchase is complete we will immediately begin partnering with the vendor on the detailed design. During this phase, we will firm up the scope of the project, including which modules/capabilities of the software we will use. We will also conduct a system architecture review, which will determine how APT and its integration will be implemented within the broader context of our IT system. This will also be followed by a data mapping effort, in which we will determine the source system and the location of the information for each level of data attribution that APT requires. Simultaneously, we will be reviewing the various requirements for the project, identifying test cases that would validate those requirements that will be conducted during the testing phase.

The project team will then begin migrating this data to the APT system to prepare for implementation for use in our Upper Midwest distribution system planning (NSPM and the Northern States Power Company-Wisconsin, or NSPW systems – collectively NSP). Given the effort and coordination required to migrate vast amounts of data into a new, more granular forecasting tool, we expect this phase will take several months. The implementation phase will include both internal work – such as necessary development to build data integration paths, prepare, migrate our data to the new system, and testing to ensure data is migrating correctly. During the testing phase, we will conduct the test cases identified in the design phase, to identify and resolve any defects. After the defects are resolved, training will begin, in which the vendor will prepare our distribution planning team (and other stakeholders as necessary) for using the system after go-live.

After the tool is tested and implemented for NSP, we plan to begin using it in our distribution planning process. In fact, we anticipate it will be fully operational in time to use it in our 2020-2021 distribution planning cycle. This timeline, while ambitious, will ensure that we can begin benefitting from its more granular analyses and draw key insights as soon as is practicable.

Figure 2: Planned APT Implementation Timeline[3]



After the tool is fully implemented in NSP, we will begin work to implement in our operating company affiliates Public Service of Colorado (PSCo) and Southwest Public Service (SPS).

D. Costs and Benefits

1. Procurement and Implementation Costs

Given the capabilities and benefits the APT will enable for our distribution planning processes, we are confident that the investment is in the interest of both customers and the Company. As discussed previously, we have already started internal work to prepare for implementing the tool. While the contracting process and implementation planning remains in progress, we believe the costs outlined below represent an appropriate estimate for the Commission to consider as part of our certification request.

We expect the full up-front cost to procure and implement the tool at the Xcel Energy level will be approximately $9.3 million. This includes costs related to the

[3] Note this implementation schedule remains fluid and subject to change.

tool's procurement – such as the license, a pre-paid five-year maintenance and support contract, internal systems integration activities, as well as the first year of ongoing O&M costs. Because the vendor portion of the cost details are market sensitive, we provide a non-public breakdown of the estimated costs in Section V and summary level costs in Table 3 below.

Table 3: Xcel Energy-Wide APT Procurement and Implementation Cost Estimate ($, Nominal Millions)

Cost Category	Cost
APT License	Please refer to Section V for the non-public detailed cost breakdown
Company Integration – Capital Costs	
Pre-Paid Maintenance and Support for five years	
Annual Software Hosting Fee	
Company O&M Costs	
Total Up Front Costs	**$9.3**

Further, we note that our maintenance costs for the APT will be lower than the amount we currently pay for our current tool that, comparatively, has limited functionality; on an annualized basis, this savings amounts to over $100,000 Xcel Energy-wide.

The upfront acquisition costs will be apportioned to Xcel Energy operating companies based on each company's number of distribution feeders.[4] In total, we expect NSPM-specific costs to amount to approximately $4.0 million in 2020, most of which will be capital. We outline the expected cost categories below, and provide the corresponding expected costs in Section V.

We further note that there are some minimal O&M-related costs that will recur each year, including the hosting server cost and Company internal support; we have also accounted for annualized maintenance and service contract costs beyond year five when our initial pre-paid period ends. These costs are factored into the cost-benefit analysis discussed below.

[4] While not an existing approved application methodology, we will propose this allocation method in our 2020 Cost Allocation Methodology filing.

Table 4: NSPM Jurisdictional Capital and O&M Budget – APT Procurement and Implementation ($2020 Millions)[5]

Cost Category	Upfront Budget	Discussion
Total Capital	Please refer to Section V	
APT Installation and License		Majority of costs incurred in 2020 for perpetual license and project/program management and contingencies.
Company IT System Integration		Costs incurred in 2019-2020, for initial business systems implementation and year 1 contingencies.
Total O&M	Please refer to Section V	
APT Software Maintenance		Pre-paid five-year maintenance service and ongoing software hosting, plus year 1 contingencies.
Company IT Maintenance and Support		Costs incurred in 2019-2020, for implementation and change management expenses, including year 1 contingencies.
Total Cost to Procure and Implement	$3.97	Total estimated capital and O&M

2. *Cost-Benefit Analysis*

The APT will become a foundational element of our increasingly robust distribution planning process, to meet the needs of an evolving grid. Considering the costs to be incurred and the directly quantified benefits, we expect this project to result in a benefit-to-cost ratio of approximately 0.35 for NSPM. We summarize the CBA below and provide the Company's full cost-benefit analysis as non-public Attachment D2 to this filing.

[5] Note that these costs include adjustments to present expected 2020 costs, based on the 2019 Company-wide cost estimates presented in Table 3.

Table 5: NSPM APT Benefit-to-Cost Ratio

Net Present Value Components	Total
Benefits ($ millions)	**1.3**
O&M Benefits	0.8
Other Benefits	-
Capital Benefits	0.5
Costs ($ millions)	**3.7**
O&M Expense	0.6
Change in Revenue Requirements	3.1
Benefit/Cost Ratio	**0.35**

We derived this ratio from our estimates of the approximately $3.7 million of present value revenue requirement the tool will represent, and $1.3 million of quantified present value benefits, on a net present value basis, over an assumed seven year asset life. The costs reflected in this calculation primarily relate to a change in capital revenue requirements associated with the software and ongoing maintenance costs described more extensively above.

The benefits relate to two key factors. First, the avoided ongoing subscription cost of our current distribution forecasting tool and a Microsoft Excel plug-in tool. Second, our estimated annual deferred capital value realized as a result of the tool's enhanced capabilities. As noted previously, the APT – with its enhanced functionality – will result in reduced maintenance costs of over $100,000 on an annualized basis. We also expect that the tool may provide some capital expenditure deferral opportunities. As the APT able to more accurately forecast the needs on the system through the incorporation of Distributed Generation, Energy Efficiency, and Corporate growth forecasts, we expect it may help us defer certain upgrades that would have otherwise been indicated with a less precise tool. We estimated this value based on the benefits of deferring one feeder upgrade for three years.

In addition to the quantifiable benefits discussed above, we believe that the qualitative benefits of an improved tool further supports our planned investment. Some of the additional benefits the APT offers as compared to our existing tools and process include:

- Hourly analysis for all measured points on the grid that examines the minimum and peak loading differentials, load shapes and more clearly shows the impact of DER;
- Improved load forecasting precision that can account for two-way power flows;

- Enables easier identification of opportunities for non-wires alternatives investments for projected overloads and contingencies;
- Processes forecasting scenarios within the tool, rather than requiring an outside, manual process;
- Enables analysis closer to the customer than the traditional feeder and substation analysis, to examine impacts of DER at a more granular level;
- Better integrates customer data, including from future AMI deployment;
- Aggregates forecasts to ensure better consistency with corporate-level forecasts, and better integration into other company planning processes

While it is difficult to quantify the benefits of the factors listed above, we believe they are substantive and should be considered when the Commission determines the prudence of our proposed investment. All these factors considered, we are confident that the APT is a valuable investment that will significantly improve our load forecasting capabilities overall, helping us to provide enhanced customer benefits in our distribution planning overall and to meet relevant regulatory requirements.

IV. REQUEST FOR CERTIFICATION

Given the above, we respectfully request that the Commission certify our request to procure APT for load forecasting purposes. In accordance with Minn. Stat. §216B.2425, we request the Commission certify the APT as a project necessary to modernize our distribution system. This statute requires utilities operating under multiyear rate plans, such as Xcel Energy, to identify in biennial reports:

> …investments that it considers necessary to modernize the transmission and distribution system by enhancing reliability, improving security against cyber and physical threats, and by increasing energy conservation opportunities by facilitating communication between the utility and its customers through the use of two-way meters, control technologies, energy storage and microgrids, technologies to enable demand response, and other innovative technologies.

The normal procedural schedule for certification under Minn. Stat. § 216B.2425 would require a determination by June 1, 2020. As also discussed in the IDP, we recognize that our request for certification of this advanced planning tool and our proposed AGIS investments in the General Rate Case does not align with that timing. In addition, the AGIS initiative includes large investments and is supported by a sizeable filing that may require analysis beyond the six-month certification timeframe, even if the General Rate Case is withdrawn. Thus, we offer to work with the

Commission and stakeholders to set an appropriate deadline and procedural schedule for consideration of these investments.

That said, we believe the APT will substantially facilitate our distribution planning process and enhance our hosting capacity analysis processes, therefore meeting the standard of an investment eligible for certification. For these reasons, we request that the Commission certify the APT; specifically because the tool will support grid modernization while enhancing reliability, and because it will facilitate increased conservation opportunities.

First, the APT is a foundational tool that will support distribution system modernization, thereby enhancing reliability. As discussed at length above, our current distribution forecasting relies on historical annual peak load data and does not enable hourly forecasts. Therefore, it does not provide sufficient visibility into, nor adequately account for, the timing of peak load throughout the day, intraday differential between minimum and peak load, or the duration of a potential feeder or substation overload. For each instance in which a potential overload or contingency condition is uncovered, we rely on historical data and manual analysis to determine the best mitigation method. As a direct improvement, the tool will significantly enhance our visibility into hourly forecasted load shapes, so that we may better identify and analyze potential issues and mitigation paths. It also enables better and more efficient DER scenario forecasting and enhanced integration with our other planning processes.

Second, the APT will better facilitate our evaluation and identification of increased conservation opportunities. One clear benefit of developing more granular load forecast capabilities, both in terms of time and spatial analysis, is that we will be able to better assess opportunities for non-wires alternatives to mitigate or eliminate identified needs. Understanding the timing and duration of an overload is essential to determining the viability of DER or energy efficiency solutions to fulfil the need. Further, because the APT enables analysis at a more granular level than feeder and substation, it could enable better us to better target those solutions. In addition to the improvements the tool will afford to our conventional distribution planning functions, we also believe the tool will better facilitate our hosting capacity analysis, because it enables analysis of daytime minimum loads and how they may change over the forecast period.

V. DETAILED COST INFORMATION

As noted above, the Company has not yet finalized the contract for the APT, and regardless whether they are being negotiated or in final form, the contractual cost terms are market sensitive and thus subject to trade secret protection. For that reason, we are providing additional detailed cost information in this separate section, with a request for trade secret designation for selected details.

As initially discussed in Table 3 above, the Company's expects that the total upfront cost to procure the APT would be approximately $9.3 million. A more detailed accounting of these costs is included in Table 6 below.

Table 6: Xcel Energy-Wide APT Procurement and Implementation Cost Estimate ($, Nominal Millions)

Cost Category	Cost
[PROTECTED DATA BEGINS	
APT License	
Company Integration – Capital Costs	
Pre-paid Maintenance and Support for Five Years	
Annual Software Hosting Fee	
Company O&M Costs	
PROTECTED DATA ENDS]	
Total Up Front Costs	**$9.27**

Further, we noted in Section III.D that APT will provide ongoing annual savings as compared to our current distribution forecasting tool. The vendor's pre-paid ongoing service agreement for APT technical support would effectively amount to approximately **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]**. This, in addition to the **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** annual hosting fee, represents over $100,000 per year in savings as compared to the **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** annual Xcel Energy-wide cost of DAA, which is the distribution forecasting tool APT replaces, and an additional **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** associated with a Microsoft Excel plug-in tool, which will be included with the APT.

For NSPM specifically, the estimated upfront investments for the APT, adjusted to 2020 values are outlined in Table 7 below.

Table 7: NSPM Jurisdictional Capital and O&M Budget – APT Procurement and Implementation ($2020 Millions)

Cost Category	Upfront Budget ($2020 millions) [6]	Discussion
[PROTECTED DATA BEGINS		
Total Capital		
APT Installation and License		Majority of costs incurred in 2020 for perpetual license and project/program management and contingencies.
Company IT System Integration		Costs incurred in 2019-2020, for initial business systems implementation and year 1 contingencies.
Total O&M		
APT Software Maintenance		Pre-paid five-year maintenance service and ongoing software hosting, plus year 1 contingencies.
Company IT Maintenance and Support		Costs incurred in 2019-2020, for implementation and change management expenses, including year 1 contingencies.
PROTECTED DATA ENDS		
Total Cost to Procure and Implement	$3.97	Total estimated capital and O&M

[6] Note that these costs include adjustments to present expected 2020 costs, based on the 2019 Company-wide cost estimates presented in Table 6.

APT Cost Analysis for NSPM

	2019	2020	2021	2022	2023	2024	2025	2026	2027	TOTAL	NPV
CAPITAL ITEMS - SUMMARY											
APT Installation-License	[PROTECTED DATA BEGINS										
License-Vendors Project Management											
Vendor Project Management - Contingency											
TOTAL - Installation and License											
Company's IT Systems and Integration											
IT Hardware-Upgrade											
Business Systems NSPM Implementation											
IT Contingency											
TOTAL - Installation and License											
Program Management											
Engineering and Supervision (E&S)-electric distribution											
TOTAL - Program Management											
											PROTECTED DATA ENDS]
TOTAL CAPITAL	**$0**	**$3,592,890**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$3,592,890**	**$3,171,724**
O&M ITEMS - SUMMARY											
APT Maintenance-License	[PROTECTED DATA BEGINS										
Hosting Software Cost											
Pre-paid M&S											
Contingency											
TOTAL - License Maintenance											
Company's IT Systems											
Business Systems Maintenance and Support											
TOTAL - BS Maintenance											
Program Management											
Program/Change Management/Training											
Contingency											
TOTAL - Program Managememt											
											PROTECTED DATA ENDS]
TOTAL O&M	**$0**	**$374,697**	**$26,357**	**$26,980**	**$27,619**	**$28,274**	**$105,814**	**$108,094**	**$110,424**	**$808,259**	**$610,383**
GRAND TOTAL CAPITAL & O&M	**$0**	**$3,967,587**	**$26,357**	**$26,980**	**$27,619**	**$28,274**	**$105,814**	**$108,094**	**$110,424**	**$4,401,149**	**$3,782,107**

Note: Input values from the "CostInputs" tab are “budget values,” which represent 2019 nominal dollars. These are not adjusted for inflation. The model on the "SumAPTCOSTS" tab adjusts the “input budget cost allocations” to real prices over time due to inflation. For instance, a 2020 budget allocation, currently in 2019 nominal dollars, will be converted to 2020 real dollars by the model.

APT Benefits Analysis for NSPM

	2019	2020	2021	2022	2023	2024	2025	2026	2027	TOTAL	NPV
O&M ITEMS - SUMMARY											
Avoided Cost From Current Systems	[PROTECTED DATA BEGINS										
DAA Annual Cost											
DSMore Annual Cost											
TOTAL - Avoided Cost Current Systems											
											PROTECTED DATA ENDS]
TOTAL O&M	**$0**	**$0**	**$155,556**	**$158,776**	**$162,063**	**$165,417**	**$168,842**	**$172,337**	**$175,904**	**$1,158,894**	**$799,381**
CAP ITEMS - SUMMARY											
Capital Deferred Projects Value											
Capital Deferred Projects Value	$0	$0	$96,328	$98,322	$100,357	$102,435	$104,555	$106,720	$108,929	$717,646	$495,017
TOTAL CAPITAL	**$0**	**$0**	**$96,328**	**$98,322**	**$100,357**	**$102,435**	**$104,555**	**$106,720**	**$108,929**	**$717,646**	**$495,017**
GRAND TOTAL QUANTIFIABLE BENEFITS	**$0**	**$0**	**$251,884**	**$257,098**	**$262,420**	**$267,852**	**$273,397**	**$279,056**	**$284,833**	**$1,876,540**	**$1,294,398**

APT Benefit to Cost Ratio

	Total ($M, net present value)
Benefits	**1.3**
Operational	1.3
Costs	**(3.7)**
O&M Expense	(0.6)
Change in Capital Revenue Requirement	(3.0)
Benefit/Cost Ratio	**0.35**

I. RISK SCORING METHODOLOGY

As part of our risk analysis and mitigation processes, discussed as part of our annual System Planning process in Section V of the IDP, Xcel Energy personnel enter projects throughout the year in the Risk Register/Workbook. Along with the description of the project, the originator must identify the primary business value driving the investment, and may also enter the benefit and any associated service quality metric impacts (i.e. customer minutes out, which impacts System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI), and Customer Average Interruption Duration Index (CAIDI), etc.). After Distribution Operations and Risk Analytics review the projects to ensure the data is accurate, Business Area Finance sets-up all appropriate accounting structures.

Projects are then run through the risk model for scoring. This process involves a number of steps:

- A project's raw financial benefit is calculated based on a project's gross cash flow (generally, incremental revenue plus realized salvage value less incremental recurring costs, non-recurring costs (e.g. taxes), and capital expenditures) and avoided costs.
- A project's raw reliability benefit is calculated based on overload customer minutes out (considering mega volt-amperes (MVA) beyond threshold, customers per MVA, and annual hours at risk), contingency customer minutes out (considering peak load less available relief MVA, customers per MVA, time to restore, peak day hours out, and yearly failure rate of equipment at risk), and the number of customer complaints to the public utilities commission.
- The raw reliability benefit is converted into the same metric as the raw financial benefit using a conversion factor (e.g., $1.25/customer minute out) based on an algorithm.
- Jurisdictional factors (including discount rates, income tax rates, property tax rates, inflation rates, historical Commission complaints, historical Quality of Service plan (QSP) SAIDI data, and historical transformer failure data) are then applied to the financial benefit and reliability benefit.
- A benefit:cost ratio (also known as a Risk Score) based on the jurisdictional financial and reliability benefits and annualized costs of each project is calculated.

From these calculations the projects get prioritized – and based on the capital budget, the projects that will be funded in the current 5-year budget are selected.

Part II reflects all Distribution projects budgeted in the latest/most current available budget (July 2019) at the time of our IDP filing. Budgets are formally updated annually, and rebalanced on an ongoing basis. Project scopes and/or timelines are subject to change at any time based on (but not limited to) engineering studies, area considerations, design estimates, permitting feasibility, capital target changes, and emergent circumstances.

IDP Capacity is the only IDP category for which Risk Scores are applicable, because it is the only category for which we have the ability to objectively quantify the annual risk. Capacity projects are driven by feeder and transformer risks that can be quantified in terms of increased reliability. We use the risk score to help prioritize capacity projects; however, as discussed in our IDP filing, the risk score is not the only factor used to determine budget priority. For other budget categories that may not be driven by reliability, and for which the risks may not be objectively quantifiable, we prioritize projects based on other factors:

- *Mandates*. Government- or customer-driven work that is covered by our tariffs or involves relocating our facilities in public rights of way when in conflict with road projects, for example. This work category is not negotiable and has established timelines/due dates – and some portion may additionally be emergent in the current year, potentially requiring us to reprioritize/rebalance our budgets.

- *New Business*. Customer-driven work under our tariffs, including customer requests for changes or applications for new service. Like Mandates, this work category is not negotiable, has established timelines/due dates, and some portion may additionally be emergent in the current budget year.

- *Asset Health*. Programs or projects driven by engineering analyses to address aging infrastructure and improve system resilience. Our budget benefit/cost model does not effectively capture the value that a programmatic approach to asset health provides.

- *Blankets*. Blankets fund high volume, low dollar, current year, reactive work and can contain hundreds of smaller projects and therefore does not lend itself to risk-ranking.

- *Programs*. Also see Asset Health above. Programs are funded based on identified needs or risks outside of the budget risk scoring model. Programmatic work for the current year is typically defined in-year based on equipment failures that are occurring, or after the previous year's reliability results are available and analyzed. For example, our cable replacement program is based on in-year cable failures and customer impacts, and is driven by engineering and reliability needs, not a budgeting risk model. As noted in Asset Health, our budget benefit/cost model does not effectively capture the value that a programmatic engineering approach to cable failures provides.

Parts II and III contain information Xcel Energy maintains as Security Information, pursuant to Minn. Stat. § 13.37, subd. 1(a). The public disclosure or use of this information creates an unacceptable risk that those who want to disrupt our system for political or other reasons may learn which facilities to target to create a disruption of our service.

Part III contains information Xcel Energy maintains as trade secret data as defined by Minn. Stat. § 13.37, subd. 1(b). This information has independent economic value from not being generally known to, and not being readily ascertainable by, other parties who could obtain economic value from its disclosure or use.

Part III is marked as "Not-Public" in its entirety. Pursuant to Minn. Rule 7829.0500, subp. 3, the Company provides the following description of the excised material:

1. **Nature of the Material:** Calculations of expected Customer Minutes Out given electric distribution asset load and failure rate data
2. **Authors:** Electric Systems Performance and the Risk Analytics Department
3. **Importance:** Key values to determine the potential reliability of certain projects
4. **Date the Information was Prepared:** October 29, 2019

PROTECTED DATA SHADED

II. CAPACITY RANKINGS

Mitigation Title	Jurisdiction	Lifespan of Project	Total Annualized Costs ($M's)	Reliability Benefit - CMO (Electric)	Financial Benefit	Reliability Benefit	Financial Benefit	Total Weighted Benefit	Project Score
				[PROTECTED DATA BEGINS					
Reinforce Medford Junction MDF TR1	NSPM - ED	40	$0.158						**114.9**
Install Switch Coon Creek CNC073	NSPM - ED	40	$0.002						**52.9**
Reinforce Fair Park FAP TR1 & Fdr	NSPM - ED	40	$0.086						**49.7**
Install Feeder Tie Wilson WIL081	NSPM - ED	40	$0.020						**34.8**
Reinforce Osseo OSS062	NSPM - ED	40	$0.013						**33.1**
Extend Red Rock RRK063	NSPM - ED	40	$0.007						**18.1**
Load Transfer ESW062 to SMT061	NSPM - ED	40	$0.007						**15.0**
Extend Main Street MST074	NSPM - ED	40	$0.020						**14.3**
Reinforce Westgate WSG Feeders	NSPM - ED	40	$0.036						**10.8**
Reinforce Medicine Lake MEL074	NSPM - ED	40	$0.033						**10.6**
Install Hiawatha West HWW Feeder	NSPM - ED	40	$0.079						**10.3**
Install Midtown MDT Feeder	NSPM - ED	40	$0.125						**9.5**
Extend Saint Louis Park SLP085	NSPM - ED	40	$0.010						**8.4**
Install Feeder Tie Osseo OSS063	NSPM - ED	40	$0.007						**8.0**
Load Transfer CGR062 to CGR071	NSPM - ED	40	$0.063						**7.7**
Install Wilson WIL TR4 & Feeders	NSPM - ED	40	$0.974						**7.5**
Reinforce Savage SAV063 & SAV067	NSPM - ED	40	$0.072						**7.1**
Install Kohlman Lake KOL Feeder	NSPM - ED	40	$0.103						**6.9**
Install Stockyards STY TR3 & Feeders	NSPM - ED	40	$0.263						**6.3**

PROTECTED DATA SHADED

Install Baytown BYT Feeders	NSPM - ED	40	$0.268						**6.2**
Install Fiesta City FIC Feeder	NSPM - ED	40	$0.066						**6.0**
Install Feeder Tie SOU083 to MDT074	NSPM - ED	40	$0.007						**5.4**
Reinforce Saint Louis Park SLP087	NSPM - ED	40	$0.010						**5.2**
Extend Saint Louis Park SLP092	NSPM - ED	40	$0.040						**4.8**
Reinforce Glenwood GLD Sub Equip	NSPM - ED	40	$0.046						**4.6**
Install Goodview GVW Feeder	NSPM - ED	40	$0.072						**4.0**
Install Chemolite CHE065 Feeder	NSPM - ED	40	$0.095						**3.9**
Install Wyoming WYO Feeder	NSPM - ED	40	$0.165						**3.9**
Install Feeder Tie EBL064	NSPM - ED	40	$0.010						**3.7**
Reinforce Basset Creek BCR062	NSPM - ED	40	$0.016						**3.7**
Reinforce Moore Lake MOL071	NSPM - ED	40	$0.036						**3.1**
Install Western WES TR3 & Feeders	NSPM - ED	40	$0.493						**2.8**
Reinforce Kasson KAN TR1 & Feeders	NSPM - ED	40	$0.188						**2.8**
Install Feeder Tie Crooked Lake CRL033	NSPM - ED	40	$0.073						**2.6**
Install Albany ALB TR	NSPM - ED	40	$0.194						**2.1**
Reinforce Terminal TER073	NSPM - ED	40	$0.072						**1.8**
Install South Washington ERU Sub	NSPM - ED	40	$0.373						**1.8**
Reinforce Veseli VES TR1 & Feeder	NSPM - ED	40	$0.171						**1.8**
Extend Terminal TER064	NSPM - ED	40	$0.010						**1.7**
Reinforce Burnside BUR TR2	NSPM - ED	40	$0.172						**1.6**
Reinforce Edina EDA062	NSPM - ED	40	$0.033						**1.3**
Reinforce Brooklyn Park BRP062	NSPM - ED	40	$0.012						**1.2**
Install Zumbrota ZUM TR & Feeder	NSPM - ED	40	$0.189						**1.2**

PROTECTED DATA SHADED

Reinforce Sibley Park SIP Sub Equip	NSPM - ED	40	$0.006						**1.1**
Install Viking VKG Feeder	NSPM - ED	40	$0.165						**1.0**
Install Rosemount RMT TR2 & Feeder	NSPM - ED	40	$0.358						**1.0**
Install Orono ORO TR2 & Feeder	NSPM - ED	40	$0.274						**0.9**
Install Goose Lake GLK TR3 & Feeders	NSPM - ED	40	$0.333						**0.8**
Install Cannon Falls Trans CTF TR2 & Fdr	NSPM - ED	40	$0.124						**0.7**
Install West Coon Rapids WCR TR	NSPM - ED	40	$0.137						**0.7**
Install Lindstrom LIN Feeder	NSPM - ED	40	$0.043						**0.7**
Install Hyland Lake HYL TR3 & Feeder	NSPM - ED	40	$0.291						**0.6**
Reinforce Tanners Lake TLK Sub Equip	NSPM - ED	40	$0.013						**0.6**
Reinforce Oakdale OAD073 & OAD075	NSPM - ED	40	$0.018						**0.5**
New MPK075-GPH061 Feeder Tie	NSPM - ED	40	$0.016						**0.5**
Install East Winona EWI TR2 & Feeder	NSPM - ED	40	$0.218						**0.4**
Install Louise LOU TR2 & Feeders	NSPM - ED	40	$0.332						**0.4**
Install Hiawatha West HWW TR2	NSPM - ED	40	$0.092						**0.1**
Reinforce St Cloud SCL TR2	NSPM - ED	40	$0.092						**0.1**
Install Midtown MDT TR2	NSPM - ED	40	$0.093						**0.1**

PROTECTED DATA ENDS]

III. Mitigation Calculation Examples

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2. **Authors:** Electric Systems Performance and the Risk Analytics Department
3. **Importance:** Key values to determine the potential reliability of certain projects
4. **Date the Information was Prepared:** October 29, 2019

IDP Requirement 3.A.29 requires the following:
Planned distribution capital projects, including drivers for the project, timeline for improvement, summary of anticipated changes in historic spending. Driver categories should include:
a. Age-Related Replacements and Asset Renewal
b. System Expansion or Upgrades for Capacity
c. System Expansion or Upgrades for Reliability and Power Quality
d. New Customer Projects and New Revenue
e. Grid Modernization and Pilot Projects
f. Projects related to local (or other) government-requirements
g. Metering
h. Other

	Mitigation	Mitigation Name	Risk Score Applied	2020	2021	2022	2023	2024	Grand Total
Age-Related Replacements and Asset Renewal				**$87,244,281**	**$79,537,631**	**$78,279,487**	**$79,652,481**	**$80,991,479**	**$405,705,358**
Accounting Correction	E114.017857	MN Elec Mixed Work Adjustment	NA	$9,099,917	$11,829,996	$11,829,996	$11,829,996	$11,829,996	$56,419,901
Blanket	E114.018176	MN - OH Rebuild Tap/Backbone/Sec Blkt	NA	$9,912,000	$10,142,000	$10,377,000	$10,618,003	$10,864,003	$51,913,006
	E114.018178	MN - OH Services Renewal Blanket	NA	$103,000	$105,003	$107,000	$109,000	$112,000	$536,003
	E114.018354	MN - OH Street Light Rebuild Blanket	NA	$822,000	$844,000	$865,000	$888,000	$888,000	$4,307,000
	E114.018274	MN - UG Conversion/Rebuild Blanket	NA	$6,758,000	$6,915,009	$7,075,009	$7,239,009	$7,407,009	$35,394,036
	E114.018275	MN - UG Services Renewal Blanket	NA	$2,903,009	$2,970,002	$3,039,009	$3,110,002	$3,182,000	$15,204,022
	E114.018355	MN - UG Street Light Rebuild Blanket	NA	$788,000	$809,002	$830,000	$852,000	$852,000	$4,131,002
	E141.017359	MPLS UG Network Vault Blanket	NA	$492,000	$504,000	$516,000	$516,000	$516,000	$2,544,000
	E151.016697	STP UG Network Vault Blanket	NA	$244,000	$250,004	$256,000	$256,000	$256,000	$1,262,004
Failure	E103.001736	MN Failed Sub Equip Replacement	NA	$2,300,000	$2,300,000	$2,300,000	$2,300,000	$2,300,000	$11,500,000
	E103.016837	MN Failed Sub TR Replacement	NA	$800,000	$1,600,000	$1,600,000	$1,600,000	$1,600,000	$7,200,000
	E103.019429	Reserve TR 115/13.8 kV 70 MVA	NA	$552,000					$552,000
	E103.013577	Reserve TR 115/34.5 kV 70 MVA	NA	$800,000					$800,000
	E103.012618	Reserve TR 69/13.8 kV 28 MVA	NA			$550,000			$550,000
Program	E103.017653	ELR MN Sub Batteries	NA	$54,000	$306,000	$180,000	$180,000	$180,000	$900,000
	E103.011890	ELR MN Sub Feeder Breakers	NA	$449,998	$2,550,000	$1,500,000	$1,500,000	$1,500,000	$7,499,998
	E103.012606	ELR MN Sub Fences	NA	$75,008	$425,008	$250,000	$250,000	$250,000	$1,250,016
	E103.012603	ELR MN Sub Regulators	NA	$60,000	$340,000	$200,000	$200,000	$200,000	$1,000,000
	E103.012586	ELR MN Sub Relays	NA	$90,000	$510,000	$300,000	$300,000	$300,000	$1,500,000
	E103.006458	ELR MN Sub Retirements	NA	$60,000	$340,000	$200,000	$200,000	$200,000	$1,000,000
	E103.013521	ELR MN Sub RTUs	NA	$31,340	$177,594	$104,467	$104,467	$104,467	$522,334
	E103.011891	ELR MN Sub Switches	NA	$30,000	$170,000	$100,000	$100,000	$100,000	$500,000
	E103.012612	ELR MN Sub TRs	NA			$2,000,004	$2,000,004	$2,000,004	$6,000,012
	E141.018795	ELR MPLS Network Protectors	NA	$250,004	$750,004	$1,000,000	$1,000,000	$1,000,000	$4,000,008
	E141.001664	ELR MPLS Vault Tops	NA		$1,000,000	$500,000	$1,000,000	$1,000,000	$3,500,000
	E151.018796	ELR STP Network Protectors	NA	$250,004	$750,004	$1,000,000	$1,000,000	$1,000,000	$4,000,008
	E151.013639	ELR STP Vault Tops	NA	$799,999	$700,006	$500,002	$1,000,000	$1,000,000	$4,000,007
	E114.018129	MN - Pole Replacement Blanket	NA	$28,900,000	$17,700,000	$17,700,000	$17,700,000	$17,700,000	$99,700,000
	E103.009150	SPCC NSPM Oil Spill Prevention	NA	$700,000					$700,000
Project	E144.013600	Convert Butterfield BTF 4kV	NA			$100,000	$2,700,000		$2,800,000
	E144.013622	Convert Lafayette LAF 4kV	NA				$100,000	$1,950,000	$2,050,000
	E144.018411	Rebuild Clara City CLC221	NA	$800,001	$599,999				$1,400,000
	E144.019617	Rebuild Sacred Heart SCH211	NA	$1,400,000					$1,400,000
	E144.017589	Rebuild Yellow Medicine YLM211 & YLM212	NA	$1,450,000	$1,450,000	$1,400,000			$4,300,000
	E141.017906	Replace Fifth Street FST Network RTU	NA	$200,000					$200,000

	Mitigation	Mitigation Name	Risk Score Applied	2020	2021	2022	2023	2024	Grand Total
Age-Related Replacements and Asset Renewal				**$87,244,281**	**$79,537,631**	**$78,279,487**	**$79,652,481**	**$80,991,479**	**$405,705,358**
	E141.012673	Replace Fifth Street FST Switchgear	NA	$2,470,001					$2,470,001
	E150.018891	Replace Linde LND TR1	NA	$1,100,000					$1,100,000
	E154.019464	T Rebuild West St Cloud to Millwood	NA	$1,500,000	$2,500,000	$900,000			$4,900,000
Working Capital	E114.018276	MN - Line Asset Health WCF Blanket	NA	$11,000,000	$11,000,000	$11,000,000	$11,000,000	$12,700,000	$56,700,000
New Customer Projects and New Revenue				**$35,598,000**	**$39,294,000**	**$39,323,000**	**$39,352,000**	**$39,352,000**	**$192,919,000**
Blanket	E114.018171	MN - OH Extension Blanket	NA	$3,290,000	$3,651,000	$3,651,000	$3,651,000	$3,651,000	$17,894,000
	E114.018172	MN - OH New Services Blanket	NA	$2,511,000	$2,788,000	$2,788,000	$2,788,000	$2,788,000	$13,663,000
	E114.018045	MN - OH New Street Light Blanket	NA	$352,000	$362,000	$371,000	$380,000	$380,000	$1,845,000
	E114.018268	MN - UG Extension Blanket	NA	$19,387,000	$21,499,000	$21,499,000	$21,499,000	$21,499,000	$105,383,000
	E114.018269	MN - UG New Services Blanket	NA	$8,330,000	$9,247,000	$9,247,000	$9,247,000	$9,247,000	$45,318,000
	E114.018046	MN - UG New Street Light Blanket	NA	$728,000	$747,000	$767,000	$787,000	$787,000	$3,816,000
Program	E114.018792	MN LED Post Top Conversion	NA	$1,000,000	$1,000,000	$1,000,000	$1,000,000	$1,000,000	$5,000,000
System Expansion or Upgrades for Capacity				**$44,375,021**	**$40,066,002**	**$32,338,001**	**$32,948,001**	**$37,908,008**	**$187,635,033**
Blanket	E114.018342	MN - New Business Network Blanket	NA	$1,282,000	$1,313,000	$1,345,001	$1,345,001	$1,345,001	$6,630,003
	E114.018181	MN - OH Reinforce Blkt Tap/Back/Sec	NA	$883,002	$883,002	$883,002	$883,002	$883,002	$4,415,010
	E114.018279	MN - UG Reinforce Blkt Tap/Back/Sec	NA	$460,000	$460,000	$460,000	$460,000	$460,000	$2,300,000
	E103.001735	MN-Sub Capacity Reinforcement	NA	$100,000	$100,000	$100,000	$100,000	$100,000	$500,000
Program	E103.018426	SUB MN Feeder Load Monitoring	NA	$880,000	$2,020,000	$2,500,000	$2,500,000	$3,750,000	$11,650,000
Project	E147.011058	Plymouth-Area Power Grid Upgrades	Non-Discretionary	$8,000,000	$7,900,000				$15,900,000
	E150.019059	T Reinforce Red Rock RRK TR2	Non-Discretionary	$670,003					$670,003
	E150.019885	Install Jamaica JAM Area Sub	Non-Discretionary	$2,800,000					$2,800,000
	E144.018970	Reinforce Medford Junction MDF TR1	114.9	$1,700,000					$1,700,000
	E147.019893	Install Switch Coon Creek CNC073	52.9	$30,000					$30,000
	E144.007793	Reinforce Fair Park FAP TR1 & Fdr	49.7	$1,300,000					$1,300,000
	E143.016730	Install Feeder Tie Wilson WIL081	34.8	$300,000					$300,000
	E147.017741	Reinforce Osseo OSS062	33.1	$200,000					$200,000
	E150.018967	Extend Red Rock RRK063	18.1	$100,000					$100,000
	E144.017637	Load Transfer ESW062 to SMT061	15.0	$100,000					$100,000
	E141.017739	Extend Main Street MST074	14.3	$300,000					$300,000
	E143.016724	Reinforce Westgate WSG Feeders	10.8	$550,000					$550,000
	E141.019911	Reinforce Medicine Lake MEL074	10.6	$500,000					$500,000
	E141.019924	Install Hiawatha West HWW Feeder	10.3	$1,200,000					$1,200,000
	E141.019929	Install Midtown MDT Feeder	9.5		$1,900,000				$1,900,000
	E141.019957	Extend Saint Louis Park SLP085	8.4	$150,000					$150,000
	E147.015637	Install Feeder Tie Osseo OSS063	8.0	$100,000					$100,000
	E150.019910	Load Transfer CGR062 to CGR071	7.7	$950,000					$950,000
	E141.010910	Install Wilson WIL TR4 & Feeders	7.6	$6,850,000	$7,950,000				$14,800,000
	E143.019055	Reinforce Savage SAV063 & SAV067	7.1	$1,100,004					$1,100,004
	E156.010177	Install Kohlman Lake KOL Feeder	6.9	$1,000,000	$600,000				$1,600,000
	E150.010914	Install Stockyards STY TR3 & Feeders	6.3		$4,000,000	$3,500,000			$7,500,000
	E156.015749	Install Baytown BYT Feeders	6.2		$2,100,000	$2,100,000			$4,200,000
	E154.016772	Install Fiesta City FIC Feeder	6.0		$1,000,000				$1,000,000
	E141.019930	Install Feeder Tie SOU083 to MDT074	5.4		$100,000				$100,000
	E141.019954	Reinforce Saint Louis Park SLP087	5.2		$150,000				$150,000

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Age-Related Replacements and Asset Renewal				**$87,244,281**	**$79,537,631**	**$78,279,487**	**$79,652,481**	**$80,991,479**	**$405,705,358**
	E141.019928	Extend Saint Louis Park SLP092	4.8		$600,000				$600,000
	E154.018960	Reinforce Glenwood GLD Sub Equip	4.6		$700,000				$700,000
	E144.002712	Install Goodview GVW Feeder	4.0		$1,100,000				$1,100,000
	E150.015662	Install Chemolite CHE065 Feeder	3.9		$1,440,000				$1,440,000
	E156.011061	Install Wyoming WYO Feeder	3.9		$2,500,000				$2,500,000
	E143.016727	Install Feeder Tie EBL064	3.7		$150,000				$150,000
	E147.019056	Reinforce Basset Creek BCR062	3.7		$250,000				$250,000
	E141.019958	Reinforce Moore Lake MOL071	3.1		$550,000				$550,000
	E151.012409	Install Western WES TR3 & Feeders	2.8		$100,000	$5,300,000			$5,400,000
	E144.013436	Reinforce Kasson KAN TR1 & Feeders	2.8			$2,850,002			$2,850,002
	E147.012463	Install Feeder Tie Crooked Lake CRL033	2.7			$1,250,000			$1,250,000
	E154.010157	Install Albany ALB TR	2.1		$100,000	$2,800,000			$2,900,000
	E141.019956	Reinforce Terminal TER073	1.8			$1,100,000			$1,100,000
	E150.012576	Install South Washington ERU Sub	1.8	$5,670,002					$5,670,002
	E144.018971	Reinforce Veseli VES TR1 & Feeder	1.8		$100,000	$2,650,004			$2,750,004
	E141.019955	Extend Terminal TER064	1.8				$150,000		$150,000
	E144.010920	Reinforce Burnside BUR TR2	1.6			$100,000	$2,600,000		$2,700,000
	E143.019054	Reinforce Edina EDA062	1.3				$500,000		$500,000
	E147.014465	Reinforce Brooklyn Park BRP062	1.2				$200,000		$200,000
	E144.000793	Install Zumbrota ZUM TR & Feeder	1.2			$100,000	$2,950,002		$3,050,002
	E144.016592	Reinforce Sibley Park SIP Sub Equip	1.1				$100,000		$100,000
	E143.017702	Install Viking VKG Feeder	1.0				$2,500,000		$2,500,000
	E150.010904	Install Rosemount RMT TR2 & Feeder	1.0	$4,400,008					$4,400,008
	E142.011721	Install Orono ORO TR2 & Feeder	0.9			$100,000	$4,000,000		$4,100,000
	E156.007927	Install Goose Lake GLK TR3 & Feeders	0.8				$700,000	$4,000,000	$4,700,000
	E144.008708	Install Cannon Falls Trans CTF TR2 & Fdr	0.7				$100,000	$1,895,003	$1,995,003
	E147.013379	Install West Coon Rapids WCR TR	0.7			$99,996	$1,979,996		$2,079,992
	E156.011752	Install Lindstrom LIN Feeder	0.7					$650,008	$650,008
	E143.019908	Install Hyland Lake HYL TR3 & Feeder	0.6				$100,000	$4,600,000	$4,700,000
	E156.011764	Reinforce Tanners Lake TLK Sub Equip	0.6					$200,000	$200,000
	E156.015811	Reinforce Oakdale OAD073 & OAD075	0.5					$275,004	$275,004
	E151.018961	New MPK075-GPH061 Feeder Tie	0.5					$250,002	$250,002
	E144.013520	Install East Winona EWI TR2 & Feeder	0.4				$100,000	$3,100,000	$3,200,000
	E153.010999	Install Louise LOU TR2 & Feeders	0.4			$100,000	$3,480,000		$3,580,000
	E141.009146	Install Hiawatha West HWW TR2	0.1	$1,400,000					$1,400,000
	E154.015728	Reinforce St Cloud SCL TR2	0.1	$1,400,002					$1,400,002
	E141.009145	Install Midtown MDT TR2	0.1				$100,000	$1,400,000	$1,500,000
Working Capital	E103.006881	Dist Subs Carryover-NSPM	NA		$1,500,000	$3,999,996	$5,100,000	$9,999,996	$20,599,992
	E114.018281	MN - Line Capacity WCF Blanket	NA		$500,000	$1,000,000	$3,000,000	$4,999,992	$9,499,992
Projects related to Local (or other) Government-Requirements				**$28,875,012**	**$29,446,025**	**$28,475,002**	**$28,958,009**	**$29,242,010**	**$144,996,058**
Blanket	E114.018173	MN - OH Reloc Tap/Backbone/Sec Blkt	NA	$8,468,000	$8,468,000	$8,468,000	$8,468,000	$8,468,000	$42,340,000
	E114.018271	MN - UG Reloc Tap/Backbone/Sec Blkt	NA	$5,408,000	$5,408,000	$5,408,000	$5,408,000	$5,408,000	$27,040,000
	E114.018273	MN - UG Service Conversion Blanket	NA	$649,009	$649,009	$649,009	$649,009	$649,009	$3,245,045
Program	E114.018479	MN - Pole Transfer 3rd Party Blanket	NA	$500,000	$500,000	$500,000	$500,000	$500,000	$2,500,000
Project	E143.019409	COMP Relocation EDINA SWLRT Road Project	NA	($457,997)	($582,993)	($462,998)			($1,503,988)
	E141.019410	COMP Relocation MPLS SWLRT Road Project	NA	($458,008)	($582,991)	($463,007)			($1,504,006)
	E141.018907	Relocation 4th Street Road Project	NA	$249,999	$300,001				$550,000
	E141.019319	Relocation 4th Street Road Project	NA	$3,577,000	$3,795,000				$7,372,000

	Mitigation	Mitigation Name	Risk Score Applied	2020	2021	2022	2023	2024	Grand Total
Age-Related Replacements and Asset Renewal				**$87,244,281**	**$79,537,631**	**$78,279,487**	**$79,652,481**	**$80,991,479**	**$405,705,358**
	E143.013574	Relocation EDINA SWLRT Road Project	NA	$908,002	$908,002	$259,998			$2,076,002
	E141.019412	Relocation Hennepin Ave Road Project (LINES)	NA	$3,033,000	$2,983,000	$1,061,000			$7,077,000
	E141.019422	Relocation Hennepin Ave Road Project (VAULTS)	NA	$615,000					$615,000
	E143.019345	Relocation Hwy 35 106th St to Cliff Rd	NA		($250,002)				($250,002)
	E141.019192	Relocation MPLS SWLRT Road Project	NA	$908,000	$908,000	$260,000			$2,076,000
Working Capital	E114.018175	MN - Mandate WCF Blanket	NA	$3,400,001	$4,345,999	$3,653,000	$3,933,000	$4,217,001	$19,549,001
	E141.017929	MPLS Mandates WCF	NA	$2,075,006	$2,597,000	$9,142,000	$10,000,000	$10,000,000	$33,814,006
System Expansion or Upgrades for Reliability and Power Quality				**$21,510,000**	**$114,689,901**	**$117,350,000**	**$117,349,933**	**$117,349,944**	**$488,249,778**
Program	E114.018471	MN - Feeder Cable Repl Blanket	NA	$5,000,000	$5,000,000	$5,000,000	$5,000,000	$5,000,000	$25,000,000
	E114.018180	MN - FPIP Blanket	NA	$600,000	$1,400,000	$1,500,000	$1,500,000	$1,500,000	$6,500,000
	E114.018179	MN - REMS Blanket	NA	$510,000	$1,190,000	$850,000	$850,000	$850,000	$4,250,000
	E114.018277	MN - URD Cable Replacement Blanket	NA	$15,400,000	$26,100,000	$22,000,000	$22,000,000	$22,000,000	$107,500,000
	E114.019275	MN Incremental System Investment	NA		$80,999,901	$88,000,000	$87,999,933	$87,999,944	$344,999,778
Other				**$38,255,280**	**$39,697,956**	**$43,162,921**	**$35,399,680**	**$35,098,111**	**$191,613,949**
Blanket	E103.002100	2002 Spec Cnstr - Sm Tool/Equipment Blanket for NSPM	NA	$789,595	$1,169,167	$1,169,167	$1,169,167	$1,169,167	$5,466,263
	E103.002265	Capitalized Locating Costs-Elec UG MN	NA	$400,000	$400,000	$400,000	$400,000	$400,000	$2,000,000
	C115.006786	Logistics-NSPM Tools Blanket	NA	$167,359	$247,850	$252,632	$252,632	$252,632	$1,173,105
	E153.011934	Logistics-NSPM Tools Blanket - SD	NA	$3,482	$4,353	$4,353	$4,353	$4,353	$20,893
	E103.001738	MN Subs tools & equip	NA	$233,309	$501,441	$501,441	$501,441	$501,441	$2,239,072
	E103.001041	MN-New Bus Transformer	NA	$21,537,000	$23,114,000	$22,104,000	$22,774,000	$23,431,000	$112,960,000
	E145.001206	ND-Electric Tools & Equip	NA	$53,105	$70,518	$70,518	$70,518	$70,518	$335,176
	E103.002099	NSPM Metering Sys-Tools & Equipment Blanket	NA	$34,822	$69,645	$69,645	$69,645	$69,645	$313,400
	E153.001257	SD-Tools & Equip	NA	$76,609	$101,855	$101,855	$101,855	$101,855	$484,029
	C103.002113	Tools & Equipment-Transportation Blanket	NA	$30,284	$90,055	$90,055	$90,055	$90,055	$390,504
	NA	Fleet Purchases	NA	$9,637,809	$12,797,349	$17,093,422	$9,095,459	$7,701,612	
Program	E103.018427	COMM MN Feeder Load Monitoring	NA	$348,223	$696,445	$870,557	$870,557	$1,305,835	$4,091,616
Project	E114.018553	AGIS - Planning and Forecasting Tool - MN	NA	$4,000,000					$4,000,000
	E150.012576	Install South Washington ERU Sub	NA	$87,056					$87,056
	E103.014467	Sub Fiber Communication Cutover	NA	$435,278	$435,278	$435,278			$1,305,835
	E144.019891	T Revenue Metering Mapleton	NA	$215,898					$215,898
	E144.019892	T Revenue Metering Minnesota Lake	NA	$205,451					$205,451
Metering				**$5,484,000**	**$4,290,000**	**$3,454,000**	**$2,338,000**	**$2,338,000**	**$17,904,000**
Blanket	E103.001040	MN-Electric Meter Blanket	NA	$5,484,000	$4,290,000	$3,454,000	$2,338,000	$2,338,000	$17,904,000
Grid Modernization and Pilot Projects				**$19,878,543**	**$49,293,082**	**$141,718,272**	**$152,381,221**	**$76,749,821**	**$440,020,938**
Program	NA	AGIS	NA	$10,350,543	$41,211,082	$131,903,272	$140,519,221	$61,990,821	$385,974,938
	E114.020058	MN Electric Vehicle Program	NA	$9,528,000	$8,082,000	$9,815,000	$11,862,000	$14,759,000	$54,046,000
Non-Investment				**($3,733,000)**	**($3,702,000)**	**($3,813,000)**	**($3,813,000)**	**($3,813,000)**	**($18,874,000)**
Blanket	E141.001140	Electric New Construction Contributions in Aid	NA	($3,733,000)	($3,702,000)	($3,813,000)	($3,813,000)	($3,813,000)	($18,874,000)
Grand Total				**$277,487,137**	**$392,612,596**	**$480,287,683**	**$484,566,325**	**$415,216,373**	**$2,050,170,114**

PROTECTED DATA SHADED

Mitigation #	Investment Summary Information	Risk Number	Risk Type N-0 or N-1	Parent Device	Risk Score	2019 Forecasted Demand kVA	2019 Forecasted Capacity kVA	2019 Forecasted Percent Loading	Planned Spending in 5 Year Budget
						[PROTECTED DATA BEGINS			
E141.009145	Install Midtown MDT TR2	2008.1458	1	MDT_TR02	0.08			54.40%	$ 1,500,000
E141.009146	Install Hiawatha West HWW TR2	2008.1457	1	HWW_TR02	0.12			73.39%	$ 1,400,000
E141.010910	Install Wilson WIL TR4 & Feeders	2016.0369	1	EDA067	7.53			93.94%	$ 14,800,000
E141.010910	Install Wilson WIL TR4 & Feeders	2016.0370	1	EDA073	7.53			93.74%	$ 14,800,000
E141.010910	Install Wilson WIL TR4 & Feeders	2020.0297	1	SLP082	7.53			75.38%	$ 14,800,000
E141.010910	Install Wilson WIL TR4 & Feeders	2012.0216	0	SOU063	7.53			103.95%	$ 14,800,000
E141.010910	Install Wilson WIL TR4 & Feeders	2020.0307	1	SOU063	7.53			103.95%	$ 14,800,000
E141.010910	Install Wilson WIL TR4 & Feeders	2008.0692	1	SOU064	7.53			89.26%	$ 14,800,000
E141.010910	Install Wilson WIL TR4 & Feeders	2020.0310	1	SOU072	7.53			103.46%	$ 14,800,000
E141.010910	Install Wilson WIL TR4 & Feeders	2008.0699	1	SOU075	7.53			106.70%	$ 14,800,000
E141.010910	Install Wilson WIL TR4 & Feeders	2016.0497	0	SOU075	7.53			106.70%	$ 14,800,000
E141.010910	Install Wilson WIL TR4 & Feeders	2011.0194	0	SOU082	7.53			110.86%	$ 14,800,000
E141.010910	Install Wilson WIL TR4 & Feeders	2012.0703	1	SOU082	7.53			110.86%	$ 14,800,000
E141.010910	Install Wilson WIL TR4 & Feeders	2016.0409	1	WIL_TR03	7.53			87.01%	$ 14,800,000
E141.010910	Install Wilson WIL TR4 & Feeders	2016.0410	1	WIL_TR04	7.53			89.20%	$ 14,800,000
E141.010910	Install Wilson WIL TR4 & Feeders	2016.0411	1	WIL_TR05	7.53			73.05%	$ 14,800,000
E141.010910	Install Wilson WIL TR4 & Feeders	2016.0390	1	WIL073	7.53			119.23%	$ 14,800,000
E141.010910	Install Wilson WIL TR4 & Feeders	2016.0391	0	WIL073	7.53			119.23%	$ 14,800,000
E141.010910	Install Wilson WIL TR4 & Feeders	2016.0394	1	WIL076	7.53			83.38%	$ 14,800,000

PROTECTED DATA SHADED

Mitigation #	Investment Summary Information	Risk Number	Risk Type N-0 or N-1	Parent Device	Risk Score	2019 Forecasted Demand kVA	2019 Forecasted Capacity kVA	2019 Forecasted Percent Loading	Planned Spending in 5 Year Budget
E141.010910	Install Wilson WIL TR4 & Feeders	2016.0396	0	WIL079	7.53			99.70%	$ 14,800,000
E141.010910	Install Wilson WIL TR4 & Feeders	2016.0400	1	WIL085	7.53			114.21%	$ 14,800,000
E141.010910	Install Wilson WIL TR4 & Feeders	2016.0401	0	WIL085	7.53			114.21%	$ 14,800,000
E141.010910	Install Wilson WIL TR4 & Feeders	2016.0402	1	WIL086	7.53			71.78%	$ 14,800,000
E141.010910	Install Wilson WIL TR4 & Feeders	2016.0403	1	WIL087	7.53			102.82%	$ 14,800,000
E141.010910	Install Wilson WIL TR4 & Feeders	2016.0404	0	WIL087	7.53			102.82%	$ 14,800,000
E141.010910	Install Wilson WIL TR4 & Feeders	2016.0406	1	WIL094	7.53			83.05%	$ 14,800,000
E141.010910	Install Wilson WIL TR4 & Feeders	2016.0407	1	WIL097	7.53			102.97%	$ 14,800,000
E141.010910	Install Wilson WIL TR4 & Feeders	2018.0936	0	WIL097	7.53			102.97%	$ 14,800,000
E141.010910	Install Wilson WIL TR4 & Feeders	2016.0408	1	WIL098	7.53			102.69%	$ 14,800,000
E141.010910	Install Wilson WIL TR4 & Feeders	2018.0937	0	WIL098	7.53			102.69%	$ 14,800,000
E141.017739	Extend Main Street MST074	2017.0160	0	MST075	14.27			104.44%	$ 300,000
E141.017739	Extend Main Street MST074	2017.0599	0	TER066	14.27			111.21%	$ 300,000
E141.019911	Reinforce Medicine Lake MEL074	2017.0168	0	MEL074	10.61			100.71%	$ 500,000
E141.019911	Reinforce Medicine Lake MEL074	2020.0267	1	MEL078	10.61			86.67%	$ 500,000
E141.019924	Install Hiawatha West HWW Feeder	2020.0233	1	ELP063	10.27			92.35%	$ 1,200,000
E141.019924	Install Hiawatha West HWW Feeder	2020.0345	1	HWW061	10.27			81.56%	$ 1,200,000
E141.019924	Install Hiawatha West HWW Feeder	2020.0248	1	HWW071	10.27			51.93%	$ 1,200,000
E141.019924	Install Hiawatha West HWW Feeder	2020.0249	1	HWW073	10.27			62.40%	$ 1,200,000
E141.019924	Install Hiawatha West HWW Feeder	2020.0251	1	HWW075	10.27			107.46%	$ 1,200,000

PROTECTED DATA SHADED

Mitigation #	Investment Summary Information	Risk Number	Risk Type N-0 or N-1	Parent Device	Risk Score	2019 Forecasted Demand kVA	2019 Forecasted Capacity kVA	2019 Forecasted Percent Loading	Planned Spending in 5 Year Budget
E141.019924	Install Hiawatha West HWW Feeder	2020.0346	1	SOU066	10.27			48.07%	$ 1,200,000
E141.019928	Extend Saint Louis Park SLP092	2017.0157	1	SLP092	4.77			88.91%	$ 600,000
E141.019929	Install Midtown MDT Feeder	2020.0347	1	ALD072	9.46			100.34%	$ 1,900,000
E141.019929	Install Midtown MDT Feeder	2020.0211	1	ALD083	9.46			68.05%	$ 1,900,000
E141.019929	Install Midtown MDT Feeder	2020.0212	1	ALD085	9.46			94.91%	$ 1,900,000
E141.019929	Install Midtown MDT Feeder	2017.0541	1	ALD092	9.46			100.82%	$ 1,900,000
E141.019929	Install Midtown MDT Feeder	2020.0331	0	ALD092	9.46			100.82%	$ 1,900,000
E141.019929	Install Midtown MDT Feeder	2020.0304	1	SLP096	9.46			85.10%	$ 1,900,000
E141.019930	Install Feeder Tie SOU083 to MDT074	2020.0314	1	SOU083	5.40			65.83%	$ 100,000
E141.019954	Reinforce Saint Louis Park SLP087	2020.0293	1	SLP074	5.17			104.33%	$ 150,000
E141.019955	Extend Terminal TER064	2020.0319	1	TER064	1.75			69.68%	$ 150,000
E141.019956	Reinforce Terminal TER073	2020.0283	1	MST075	1.84			84.16%	$ 1,100,000
E141.019956	Reinforce Terminal TER073	2020.0320	1	TER065	1.84			76.16%	$ 1,100,000
E141.019956	Reinforce Terminal TER073	2020.0343	1	TER082	1.84			80.80%	$ 1,100,000
E141.019956	Reinforce Terminal TER073	2020.0340	1	TER083	1.84			71.74%	$ 1,100,000
E141.019956	Reinforce Terminal TER073	2020.0342	1	TER085	1.84			35.79%	$ 1,100,000
E141.019957	Extend Saint Louis Park SLP085	2020.0299	1	SLP085	8.37			92.66%	$ 150,000
E141.019958	Reinforce Moore Lake MOL071	2020.0351	1	MOL061	3.13			79.46%	$ 550,000
E142.011721	Install Orono ORO TR2 & Feeder	2005.0539	1	ORO_TR01	0.87			80.24%	$ 4,100,000
E142.011721	Install Orono ORO TR2 & Feeder	2005.0766	1	ORO061	0.87			66.44%	$ 4,100,000
E142.011721	Install Orono ORO TR2 & Feeder	2005.1699	1	ORO062	0.87			81.83%	$ 4,100,000
E143.016724	Reinforce Westgate WSG Feeders	2016.0567	0	WSG061	10.78			104.81%	$ 550,000
E143.016724	Reinforce Westgate WSG Feeders	2016.0415	1	WSG066	10.78			88.49%	$ 550,000
E143.016724	Reinforce Westgate WSG Feeders	2016.0417	1	WSG071	10.78			96.97%	$ 550,000
E143.016724	Reinforce Westgate WSG Feeders	2016.0568	0	WSG074	10.78			108.59%	$ 550,000
E143.016727	Install Feeder Tie EBL064	2016.0363	1	EBL064	3.73			69.63%	$ 150,000
E143.016727	Install Feeder Tie EBL064	2016.0367	1	EBL076	3.73			35.35%	$ 150,000

PROTECTED DATA SHADED

Mitigation #	Investment Summary Information	Risk Number	Risk Type N-0 or N-1	Parent Device	Risk Score	2019 Forecasted Demand kVA	2019 Forecasted Capacity kVA	2019 Forecasted Percent Loading	Planned Spending in 5 Year Budget
E143.016730	Install Feeder Tie Wilson WIL081	2016.0397	1	WIL081	34.83			99.50%	$ 300,000
E143.017702	Install Viking VKG Feeder	2016.0376	0	EDP073	1.03			106.97%	$ 2,500,000
E143.017702	Install Viking VKG Feeder	2016.0564	1	EDP073	1.03			106.97%	$ 2,500,000
E143.017702	Install Viking VKG Feeder	2017.0451	0	HYL061	1.03			100.74%	$ 2,500,000
E143.017702	Install Viking VKG Feeder	2016.0418	1	WSG076	1.03			51.94%	$ 2,500,000
E143.019054	Reinforce Edina EDA062	2016.0385	1	NMC092	1.34			75.86%	$ 500,000
E143.019054	Reinforce Edina EDA062	2016.0386	1	NMC093	1.34			71.59%	$ 500,000
E143.019055	Reinforce Savage SAV063 & SAV067	2018.0919	0	SAV063	7.08			113.36%	$ 1,100,004
E143.019055	Reinforce Savage SAV063 & SAV067	2017.0453	0	SAV067	7.08			109.89%	$ 1,100,004
E143.019055	Reinforce Savage SAV063 & SAV067	2018.0921	1	SAV067	7.08			109.89%	$ 1,100,004
E143.019055	Reinforce Savage SAV063 & SAV067	2016.0388	1	SAV071	7.08			87.48%	$ 1,100,004
E143.019055	Reinforce Savage SAV063 & SAV067	2017.0560	1	SAV073	7.08			49.97%	$ 1,100,004
E143.019908	Install Hyland Lake HYL TR3 & Feeder	2020.0165	1	HYL_TR01	0.58			89.83%	$ 4,700,000
E143.019908	Install Hyland Lake HYL TR3 & Feeder	2020.0166	1	HYL_TR02	0.58			60.78%	$ 4,700,000
E143.019908	Install Hyland Lake HYL TR3 & Feeder	2018.0913	1	HYL062	0.58			66.84%	$ 4,700,000
E143.019908	Install Hyland Lake HYL TR3 & Feeder	2018.0917	1	HYL073	0.58			84.89%	$ 4,700,000
E143.019908	Install Hyland Lake HYL TR3 & Feeder	2018.0932	1	WIL092	0.58			84.45%	$ 4,700,000
E144.000793	Install Zumbrota ZUM TR & Feeder	2004.1114	1	ZUM_TR01	1.19			97.10%	$ 3,050,002
E144.000793	Install Zumbrota ZUM TR & Feeder	2011.0097	1	ZUM021	1.19			46.76%	$ 3,050,002
E144.000793	Install Zumbrota ZUM TR & Feeder	2011.0098	1	ZUM022	1.19			77.98%	$ 3,050,002
E144.002712	Install Goodview GVW Feeder	2009.0877	1	GVW021	4.02			89.69%	$ 1,100,000
E144.002712	Install Goodview GVW Feeder	2004.0812	1	GVW022	4.02			76.85%	$ 1,100,000
E144.002712	Install Goodview GVW Feeder	2004.0808	1	GVW023	4.02			103.67%	$ 1,100,000
E144.007793	Reinforce Fair Park FAP TR1 & Fdr	2008.0369	1	FAB_TR01	49.67			66.98%	$ 1,300,000

PROTECTED DATA SHADED

Mitigation #	Investment Summary Information	Risk Number	Risk Type N-0 or N-1	Parent Device	Risk Score	2019 Forecasted Demand kVA	2019 Forecasted Capacity kVA	2019 Forecasted Percent Loading	Planned Spending in 5 Year Budget
E144.007793	Reinforce Fair Park FAP TR1 & Fdr	2005.0479	1	FAB_TR02	49.67			90.66%	$ 1,300,000
E144.007793	Reinforce Fair Park FAP TR1 & Fdr	2007.0695	1	FAB061	49.67			55.41%	$ 1,300,000
E144.007793	Reinforce Fair Park FAP TR1 & Fdr	2007.0696	1	FAB063	49.67			71.40%	$ 1,300,000
E144.007793	Reinforce Fair Park FAP TR1 & Fdr	2007.0698	1	FAB073	49.67			49.48%	$ 1,300,000
E144.007793	Reinforce Fair Park FAP TR1 & Fdr	2011.0108	1	FAP_TR01	49.67			60.00%	$ 1,300,000
E144.007793	Reinforce Fair Park FAP TR1 & Fdr	2007.0693	0	FAP_TR02	49.67			128.69%	$ 1,300,000
E144.007793	Reinforce Fair Park FAP TR1 & Fdr	2011.0109	1	FAP_TR02	49.67			89.84%	$ 1,300,000
E144.007793	Reinforce Fair Park FAP TR1 & Fdr	2005.0741	1	FAP061	49.67			66.96%	$ 1,300,000
E144.007793	Reinforce Fair Park FAP TR1 & Fdr	2007.1920	1	FAP071	49.67			126.68%	$ 1,300,000
E144.007793	Reinforce Fair Park FAP TR1 & Fdr	2018.0090	0	FAP071	49.67			126.68%	$ 1,300,000
E144.008708	Install Cannon Falls Trans CTF TR2 & Fdr	2007.0757	1	CAF_TR01	0.71			114.23%	$ 1,995,003
E144.008708	Install Cannon Falls Trans CTF TR2 & Fdr	2013.1534	0	CAF_TR01	0.71			114.23%	$ 1,995,003
E144.008708	Install Cannon Falls Trans CTF TR2 & Fdr	2005.0386	1	CTF_TR01	0.71			94.17%	$ 1,995,003
E144.010920	Reinforce Burnside BUR TR2	2006.0285	1	BUR_TR01	1.62			33.01%	$ 2,700,000
E144.010920	Reinforce Burnside BUR TR2	2009.0884	1	REW021	1.62			80.11%	$ 2,700,000
E144.010920	Reinforce Burnside BUR TR2	2005.0433	1	REW023	1.62			85.14%	$ 2,700,000
E144.013436	Reinforce Kasson KAN TR1 & Feeders	2011.0111	1	KAN_TR02	2.77			79.47%	$ 2,850,002
E144.013436	Reinforce Kasson KAN TR1 & Feeders	2007.0707	1	KAN022	2.77			56.41%	$ 2,850,002
E144.013436	Reinforce Kasson KAN TR1 & Feeders	2007.0706	1	KAN031	2.77			111.33%	$ 2,850,002
E144.013436	Reinforce Kasson KAN TR1 & Feeders	2019.0012	0	KAN031	2.77			111.33%	$ 2,850,002
E144.013436	Reinforce Kasson KAN TR1 & Feeders	2008.0398	1	WEB_TR01	2.77			88.46%	$ 2,850,002

PROTECTED DATA SHADED

Mitigation #	Investment Summary Information	Risk Number	Risk Type N-0 or N-1	Parent Device	Risk Score	2019 Forecasted Demand kVA	2019 Forecasted Capacity kVA	2019 Forecasted Percent Loading	Planned Spending in 5 Year Budget
E144.013436	Reinforce Kasson KAN TR1 & Feeders	2005.0758	1	WEB021	2.77			104.19%	$ 2,850,002
E144.013436	Reinforce Kasson KAN TR1 & Feeders	2013.0155	0	WEB021	2.77			104.19%	$ 2,850,002
E144.013520	Install East Winona EWI TR2 & Feeder	2005.0562	1	EWI_TR01	0.42			79.53%	$ 3,200,000
E144.013520	Install East Winona EWI TR2 & Feeder	2008.1123	1	EWI022	0.42			79.65%	$ 3,200,000
E144.013520	Install East Winona EWI TR2 & Feeder	2019.0083	0	GVW023	0.42			103.67%	$ 3,200,000
E144.013520	Install East Winona EWI TR2 & Feeder	2014.0080	1	WIN_TR01	0.42			70.22%	$ 3,200,000
E144.013520	Install East Winona EWI TR2 & Feeder	2014.0081	1	WIN_TR02	0.42			92.22%	$ 3,200,000
E144.013520	Install East Winona EWI TR2 & Feeder	2014.0082	1	WIN_TR03	0.42			70.17%	$ 3,200,000
E144.013520	Install East Winona EWI TR2 & Feeder	2014.0084	1	WIN032	0.42			109.12%	$ 3,200,000
E144.013520	Install East Winona EWI TR2 & Feeder	2014.0087	0	WIN032	0.42			109.12%	$ 3,200,000
E144.013520	Install East Winona EWI TR2 & Feeder	2008.1152	1	WIN034	0.42			56.89%	$ 3,200,000
E144.016592	Reinforce Sibley Park SIP Sub Equip	2018.0091	1	SIP_TR01	1.13			80.29%	$ 100,000
E144.016592	Reinforce Sibley Park SIP Sub Equip	2018.0092	1	SIP_TR02	1.13			65.79%	$ 100,000
E144.017637	Load Transfer ESW062 to SMT061	2016.1294	0	ESW062	15.04			110.24%	$ 100,000
E144.018970	Reinforce Medford Junction MDF TR1	2019.0081	0	MDF_TR01	114.86			153.77%	$ 1,700,000
E144.018970	Reinforce Medford Junction MDF TR1	2005.0744	1	MDF021	114.86			110.88%	$ 1,700,000
E144.018971	Reinforce Veseli VES TR1 & Feeder	2008.0365	1	EKO021	1.76			110.07%	$ 2,750,004
E144.018971	Reinforce Veseli VES TR1 & Feeder	2013.1536	0	EKO021	1.76			110.07%	$ 2,750,004
E144.018971	Reinforce Veseli VES TR1 & Feeder	2013.1491	1	VES021	1.76			80.36%	$ 2,750,004

PROTECTED DATA SHADED

Mitigation #	Investment Summary Information	Risk Number	Risk Type N-0 or N-1	Parent Device	Risk Score	2019 Forecasted Demand kVA	2019 Forecasted Capacity kVA	2019 Forecasted Percent Loading	Planned Spending in 5 Year Budget
E147.011058	Plymouth-Area Power Grid Upgrades	2008.1167	1	GSL_TR04	Non-Discretionary			62.28%	$ 15,900,000
E147.011058	Plymouth-Area Power Grid Upgrades	2008.0378	1	GSL076	Non-Discretionary			61.74%	$ 15,900,000
E147.011058	Plymouth-Area Power Grid Upgrades	2007.0308	1	GSL341	Non-Discretionary			54.02%	$ 15,900,000
E147.011058	Plymouth-Area Power Grid Upgrades	2008.1166	1	GSL342	Non-Discretionary			88.17%	$ 15,900,000
E147.011058	Plymouth-Area Power Grid Upgrades	2009.0036	1	HOL_TR02	Non-Discretionary			59.28%	$ 15,900,000
E147.011058	Plymouth-Area Power Grid Upgrades	2014.0333	1	HOL061	Non-Discretionary			59.16%	$ 15,900,000
E147.011058	Plymouth-Area Power Grid Upgrades	2007.0544	1	HOL062	Non-Discretionary			89.80%	$ 15,900,000
E147.011058	Plymouth-Area Power Grid Upgrades	2013.0592	1	PKL_TR01	Non-Discretionary			80.41%	$ 15,900,000
E147.011058	Plymouth-Area Power Grid Upgrades	2013.0593	1	PKL_TR02	Non-Discretionary			79.99%	$ 15,900,000
E147.011058	Plymouth-Area Power Grid Upgrades	2013.0594	1	PKL_TR03	Non-Discretionary			71.20%	$ 15,900,000
E147.011058	Plymouth-Area Power Grid Upgrades	2014.0335	1	PKL062	Non-Discretionary			67.59%	$ 15,900,000
E147.011058	Plymouth-Area Power Grid Upgrades	2006.0128	1	PKL074	Non-Discretionary			103.71%	$ 15,900,000
E147.011058	Plymouth-Area Power Grid Upgrades	2014.0509	0	PKL074	Non-Discretionary			103.71%	$ 15,900,000

PROTECTED DATA SHADED

Mitigation #	Investment Summary Information	Risk Number	Risk Type N-0 or N-1	Parent Device	Risk Score	2019 Forecasted Demand kVA	2019 Forecasted Capacity kVA	2019 Forecasted Percent Loading	Planned Spending in 5 Year Budget
E147.011058	Plymouth-Area Power Grid Upgrades	2005.0781	1	PKL075	Non-Discretionary			104.22%	$ 15,900,000
E147.011058	Plymouth-Area Power Grid Upgrades	2012.0548	0	PKL075	Non-Discretionary			104.22%	$ 15,900,000
E147.011058	Plymouth-Area Power Grid Upgrades	2006.0129	1	PKL081	Non-Discretionary			77.26%	$ 15,900,000
E147.011058	Plymouth-Area Power Grid Upgrades	2006.0131	1	PKL083	Non-Discretionary			96.15%	$ 15,900,000
E147.011058	Plymouth-Area Power Grid Upgrades	2014.0326	0	PKL083	Non-Discretionary			100.04%	$ 15,900,000
E147.011058	Plymouth-Area Power Grid Upgrades	2006.0132	1	PKL084	Non-Discretionary			82.70%	$ 15,900,000
E147.012463	Install Feeder Tie Crooked Lake CRL033	2007.0542	1	CRL027	2.65			89.87%	$ 1,250,000
E147.012463	Install Feeder Tie Crooked Lake CRL033	2005.0773	1	CRL031	2.65			73.46%	$ 1,250,000
E147.012463	Install Feeder Tie Crooked Lake CRL033	2005.0774	1	CRL033	2.65			87.54%	$ 1,250,000
E147.012463	Install Feeder Tie Crooked Lake CRL033	2012.0527	1	CRL065	2.65			65.48%	$ 1,250,000
E147.013379	Install West Coon Rapids WCR TR	2013.0532	1	WCR_TR01	0.67			49.60%	$ 2,079,992
E147.013379	Install West Coon Rapids WCR TR	2013.0533	1	WCR_TR02	0.67			71.56%	$ 2,079,992
E147.013379	Install West Coon Rapids WCR TR	2010.0935	1	WCR_TR03	0.67			77.68%	$ 2,079,992
E147.013379	Install West Coon Rapids WCR TR	2013.0529	1	WCR311	0.67			53.48%	$ 2,079,992
E147.013379	Install West Coon Rapids WCR TR	2019.0260	1	WCR321	0.67			77.53%	$ 2,079,992
E147.013379	Install West Coon Rapids WCR TR	2020.0191	0	WCR322	0.67			101.29%	$ 2,079,992

PROTECTED DATA SHADED

Mitigation #	Investment Summary Information	Risk Number	Risk Type N-0 or N-1	Parent Device	Risk Score	2019 Forecasted Demand kVA	2019 Forecasted Capacity kVA	2019 Forecasted Percent Loading	Planned Spending in 5 Year Budget
E147.013379	Install West Coon Rapids WCR TR	2013.0531	1	WCR322	0.67			101.29%	$ 2,079,992
E147.014465	Reinforce Brooklyn Park BRP062	2012.0512	1	BRP073	1.21			77.89%	$ 200,000
E147.015637	Install Feeder Tie Osseo OSS063	2012.0532	1	OSS063	8.03			68.93%	$ 100,000
E147.017741	Reinforce Osseo OSS062	2012.0534	1	OSS065	33.06			82.88%	$ 200,000
E147.017741	Reinforce Osseo OSS062	2012.0538	1	OSS072	33.06			38.84%	$ 200,000
E147.017741	Reinforce Osseo OSS062	2017.0084	0	TWL079	33.06			102.97%	$ 200,000
E147.017741	Reinforce Osseo OSS062	2017.0086	1	TWL081	33.06			94.90%	$ 200,000
E147.019056	Reinforce Basset Creek BCR062	2018.0948	0	BCR062	3.69			100.95%	$ 250,000
E147.019056	Reinforce Basset Creek BCR062	2013.0546	1	PKL065	3.69			77.18%	$ 250,000
E147.019893	Install Switch Coon Creek CNC073	2014.0488	1	TWL089	52.92			68.37%	$ 30,000
E150.010904	Install Rosemount RMT TR2 & Feeder	2005.0576	1	RMT_TR01	1.02			36.50%	$ 4,400,008
E150.010904	Install Rosemount RMT TR2 & Feeder	2004.1089	1	RVA_TR01	1.02			82.61%	$ 4,400,008
E150.010904	Install Rosemount RMT TR2 & Feeder	2014.0188	1	RVA061	1.02			73.34%	$ 4,400,008
E150.010904	Install Rosemount RMT TR2 & Feeder	2007.0280	1	RVA062	1.02			86.46%	$ 4,400,008
E150.010914	Install Stockyards STY TR3 & Feeders	2013.1443	1	LOK062	6.33			91.62%	$ 7,500,000
E150.010914	Install Stockyards STY TR3 & Feeders	2008.0350	1	RLK066	6.33			84.64%	$ 7,500,000
E150.010914	Install Stockyards STY TR3 & Feeders	2013.1532	0	RLK071	6.33			97.38%	$ 7,500,000
E150.010914	Install Stockyards STY TR3 & Feeders	2013.1451	1	RLK071	6.33			97.38%	$ 7,500,000
E150.010914	Install Stockyards STY TR3 & Feeders	2013.1453	1	RLK073	6.33			67.90%	$ 7,500,000
E150.010914	Install Stockyards STY TR3 & Feeders	2005.1672	1	STY_TR2	6.33			63.63%	$ 7,500,000
E150.010914	Install Stockyards STY TR3 & Feeders	2008.1187	1	STY_TR1	6.33			64.76%	$ 7,500,000

PROTECTED DATA SHADED

Mitigation #	Investment Summary Information	Risk Number	Risk Type N-0 or N-1	Parent Device	Risk Score	2019 Forecasted Demand kVA	2019 Forecasted Capacity kVA	2019 Forecasted Percent Loading	Planned Spending in 5 Year Budget
E150.010914	Install Stockyards STY TR3 & Feeders	2018.0022	0	STY061	6.33			109.49%	$ 7,500,000
E150.010914	Install Stockyards STY TR3 & Feeders	2011.0091	1	STY061	6.33			109.49%	$ 7,500,000
E150.010914	Install Stockyards STY TR3 & Feeders	2005.1713	1	STY062	6.33			80.70%	$ 7,500,000
E150.010914	Install Stockyards STY TR3 & Feeders	2007.0281	1	STY063	6.33			85.69%	$ 7,500,000
E150.010914	Install Stockyards STY TR3 & Feeders	2008.0374	1	STY065	6.33			73.49%	$ 7,500,000
E150.010914	Install Stockyards STY TR3 & Feeders	2013.0131	0	STY071	6.33			107.80%	$ 7,500,000
E150.010914	Install Stockyards STY TR3 & Feeders	2005.1714	1	STY071	6.33			107.80%	$ 7,500,000
E150.010914	Install Stockyards STY TR3 & Feeders	2005.1715	1	STY072	6.33			67.98%	$ 7,500,000
E150.010914	Install Stockyards STY TR3 & Feeders	2007.0282	1	STY073	6.33			64.03%	$ 7,500,000
E150.012576	Install South Washington ERU Sub	2013.0140	1	AFT_TR01	1.80			73.82%	$ 5,670,002
E150.012576	Install South Washington ERU Sub	2013.0141	1	AFT_TR02	1.80			62.41%	$ 5,670,002
E150.012576	Install South Washington ERU Sub	2014.0077	1	AFT315	1.80			79.78%	$ 5,670,002
E150.012576	Install South Washington ERU Sub	2013.0133	0	AFT321	1.80			105.46%	$ 5,670,002
E150.012576	Install South Washington ERU Sub	2013.0143	1	AFT321	1.80			105.46%	$ 5,670,002
E150.012576	Install South Washington ERU Sub	2013.0142	1	AFT322	1.80			65.33%	$ 5,670,002
E150.012576	Install South Washington ERU Sub	2017.0107	1	RRK064	1.80			96.63%	$ 5,670,002
E150.012576	Install South Washington ERU Sub	2013.0134	1	WDY_TR01	1.80			82.25%	$ 5,670,002
E150.012576	Install South Washington ERU Sub	2013.0136	1	WDY_TR02	1.80			68.33%	$ 5,670,002
E150.012576	Install South Washington ERU Sub	2013.1468	1	WDY311	1.80			54.76%	$ 5,670,002

PROTECTED DATA SHADED

Mitigation #	Investment Summary Information	Risk Number	Risk Type N-0 or N-1	Parent Device	Risk Score	2019 Forecasted Demand kVA	2019 Forecasted Capacity kVA	2019 Forecasted Percent Loading	Planned Spending in 5 Year Budget
E150.012576	Install South Washington ERU Sub	2013.0138	1	WDY312	1.80			82.25%	$ 5,670,002
E150.012576	Install South Washington ERU Sub	2013.1469	1	WDY321	1.80			45.02%	$ 5,670,002
E150.012576	Install South Washington ERU Sub	2013.0137	1	WDY322	1.80			74.24%	$ 5,670,002
E150.015662	Install Chemolite CHE065 Feeder	2019.0214	1	CGR_TR01	3.90			82.86%	$ 1,440,000
E150.015662	Install Chemolite CHE065 Feeder	2019.0215	1	CGR_TR02	3.90			62.23%	$ 1,440,000
E150.015662	Install Chemolite CHE065 Feeder	2013.1439	1	CGR072	3.90			84.12%	$ 1,440,000
E150.015662	Install Chemolite CHE065 Feeder	2013.1441	1	CHE063	3.90			110.19%	$ 1,440,000
E150.015662	Install Chemolite CHE065 Feeder	2020.0186	0	CHE063	3.90			110.19%	$ 1,440,000
E150.018967	Extend Red Rock RRK063	2013.1436	1	CGR061	18.14			105.87%	$ 100,000
E150.018967	Extend Red Rock RRK063	2019.0082	0	CGR061	18.14			105.87%	$ 100,000
E150.019059	T Reinforce Red Rock RRK TR2	2020.0047	1	RRK_TR02	Non-Discretionary			99.16%	$ 670,003
E150.019885	Install Jamaica JAM Area Sub	2019.0532	0	JAM_TR01	Non-Discretionary			0.00%	$ 2,800,000
E150.019910	Load Transfer CGR062 to CGR071	2019.0235	0	CGR062	7.72			115.45%	$ 950,000
E151.012409	Install Western WES TR3 & Feeders	2010.0320	1	MPK078	2.82			82.38%	$ 5,400,000
E151.012409	Install Western WES TR3 & Feeders	2013.1524	1	UPP064	2.82			82.60%	$ 5,400,000
E151.012409	Install Western WES TR3 & Feeders	2013.1525	1	UPP065	2.82			83.87%	$ 5,400,000
E151.012409	Install Western WES TR3 & Feeders	2013.0167	1	WES_TR01	2.82			47.94%	$ 5,400,000
E151.012409	Install Western WES TR3 & Feeders	2013.0168	1	WES_TR02	2.82			63.40%	$ 5,400,000
E151.012409	Install Western WES TR3 & Feeders	2013.1544	0	WES064	2.82			89.13%	$ 5,400,000

PROTECTED DATA SHADED

Mitigation #	Investment Summary Information	Risk Number	Risk Type N-0 or N-1	Parent Device	Risk Score	2019 Forecasted Demand kVA	2019 Forecasted Capacity kVA	2019 Forecasted Percent Loading	Planned Spending in 5 Year Budget
E151.012409	Install Western WES TR3 & Feeders	2006.1178	1	WES064	2.82			89.13%	$ 5,400,000
E151.012409	Install Western WES TR3 & Feeders	2007.1177	1	WES065	2.82			77.93%	$ 5,400,000
E151.012409	Install Western WES TR3 & Feeders	2005.0139	1	WES072	2.82			82.35%	$ 5,400,000
E151.012409	Install Western WES TR3 & Feeders	2008.0202	1	WES073	2.82			92.30%	$ 5,400,000
E151.012409	Install Western WES TR3 & Feeders	2013.0160	0	WES073	2.82			92.30%	$ 5,400,000
E151.012409	Install Western WES TR3 & Feeders	2008.0203	1	WES074	2.82			90.54%	$ 5,400,000
E151.012409	Install Western WES TR3 & Feeders	2010.0342	1	WES075	2.82			81.89%	$ 5,400,000
E151.012409	Install Western WES TR3 & Feeders	2013.1546	1	WES076	2.82			78.87%	$ 5,400,000
E151.018961	New MPK075-GPH061 Feeder Tie	2018.0832	1	MPK075	0.48			87.84%	$ 250,002
E153.010999	Install Louise LOU TR02 and Feeders	2010.0419	1	LOU_TR01	0.38			55.82%	$ 3,580,000
E153.010999	Install Louise LOU TR02 and Feeders	2012.0595	1	LOU061	0.38			79.11%	$ 3,580,000
E153.010999	Install Louise LOU TR02 and Feeders	2018.0822	1	LOU062	0.38			93.31%	$ 3,580,000
E153.010999	Install Louise LOU TR02 and Feeders	2019.0071	1	LOU063	0.38			99.48%	$ 3,580,000
E154.010157	Install Albany ALB TR	2004.0942	1	ALB_TR02	2.05			115.49%	$ 2,900,000
E154.010157	Install Albany ALB TR	2006.0067	0	ALB_TR02	2.05			115.49%	$ 2,900,000
E154.010157	Install Albany ALB TR	2012.0102	1	ALB021	2.05			89.39%	$ 2,900,000
E154.010157	Install Albany ALB TR	2012.0103	1	ALB022	2.05			43.64%	$ 2,900,000
E154.015728	Reinforce St Cloud SCL TR2	2009.0415	1	SCL_TR01	0.12			67.67%	$ 1,400,002
E154.016772	Install Fiesta City FIC Feeder	2016.0249	0	MTV_TR02	5.95			110.34%	$ 1,000,000
E154.016772	Install Fiesta City FIC Feeder	2010.0959	0	MTV021	5.95			116.66%	$ 1,000,000
E154.016772	Install Fiesta City FIC Feeder	2016.0302	1	MTV021	5.95			116.66%	$ 1,000,000
E154.018960	Reinforce Glenwood GLD Sub Equip	2018.0825	1	GLD_TR01	4.56			66.25%	$ 700,000
E154.018960	Reinforce Glenwood GLD Sub Equip	2012.0131	1	GLD_TR02	4.56			37.52%	$ 700,000

PROTECTED DATA SHADED

Mitigation #	Investment Summary Information	Risk Number	Risk Type N-0 or N-1	Parent Device	Risk Score	2019 Forecasted Demand kVA	2019 Forecasted Capacity kVA	2019 Forecasted Percent Loading	Planned Spending in 5 Year Budget
E154.018960	Reinforce Glenwood GLD Sub Equip	2005.0076	1	GLD021	4.56			83.17%	$ 700,000
E154.018960	Reinforce Glenwood GLD Sub Equip	2009.0358	1	GLD031	4.56			78.69%	$ 700,000
E156.007927	Install Goose Lake GLK TR3 & Feeders	2005.0554	1	GLK_TR01	0.75			79.33%	$ 4,700,000
E156.007927	Install Goose Lake GLK TR3 & Feeders	2005.0555	1	GLK_TR02	0.75			80.95%	$ 4,700,000
E156.007927	Install Goose Lake GLK TR3 & Feeders	2013.0109	1	GLK061	0.75			90.40%	$ 4,700,000
E156.007927	Install Goose Lake GLK TR3 & Feeders	2013.0110	1	GLK062	0.75			74.63%	$ 4,700,000
E156.007927	Install Goose Lake GLK TR3 & Feeders	2013.0112	1	GLK064	0.75			79.95%	$ 4,700,000
E156.007927	Install Goose Lake GLK TR3 & Feeders	2013.0113	1	GLK071	0.75			81.88%	$ 4,700,000
E156.007927	Install Goose Lake GLK TR3 & Feeders	2013.0114	1	GLK072	0.75			68.00%	$ 4,700,000
E156.007927	Install Goose Lake GLK TR3 & Feeders	2013.0116	1	GLK074	0.75			87.77%	$ 4,700,000
E156.007927	Install Goose Lake GLK TR3 & Feeders	2012.0560	1	LLK071	0.75			66.91%	$ 4,700,000
E156.010177	Install Kohlman Lake KOL Feeder	2014.0455	1	LLK072	6.86			67.46%	$ 1,600,000
E156.010177	Install Kohlman Lake KOL Feeder	2007.0784	1	OAD061	6.86			90.62%	$ 1,600,000
E156.010177	Install Kohlman Lake KOL Feeder	2008.0733	1	OAD063	6.86			62.24%	$ 1,600,000
E156.010177	Install Kohlman Lake KOL Feeder	2012.0561	1	OAD064	6.86			37.81%	$ 1,600,000
E156.010177	Install Kohlman Lake KOL Feeder	2012.0562	1	OAD065	6.86			81.45%	$ 1,600,000
E156.010177	Install Kohlman Lake KOL Feeder	2012.0563	1	OAD072	6.86			92.67%	$ 1,600,000
E156.010177	Install Kohlman Lake KOL Feeder	2012.0564	1	OAD074	6.86			61.82%	$ 1,600,000
E156.010177	Install Kohlman Lake KOL Feeder	2012.0565	1	OAD075	6.86			96.36%	$ 1,600,000
E156.011061	Install Wyoming WYO Feeder	2005.0720	1	WYO021	3.87			97.15%	$ 2,500,000

PROTECTED DATA SHADED

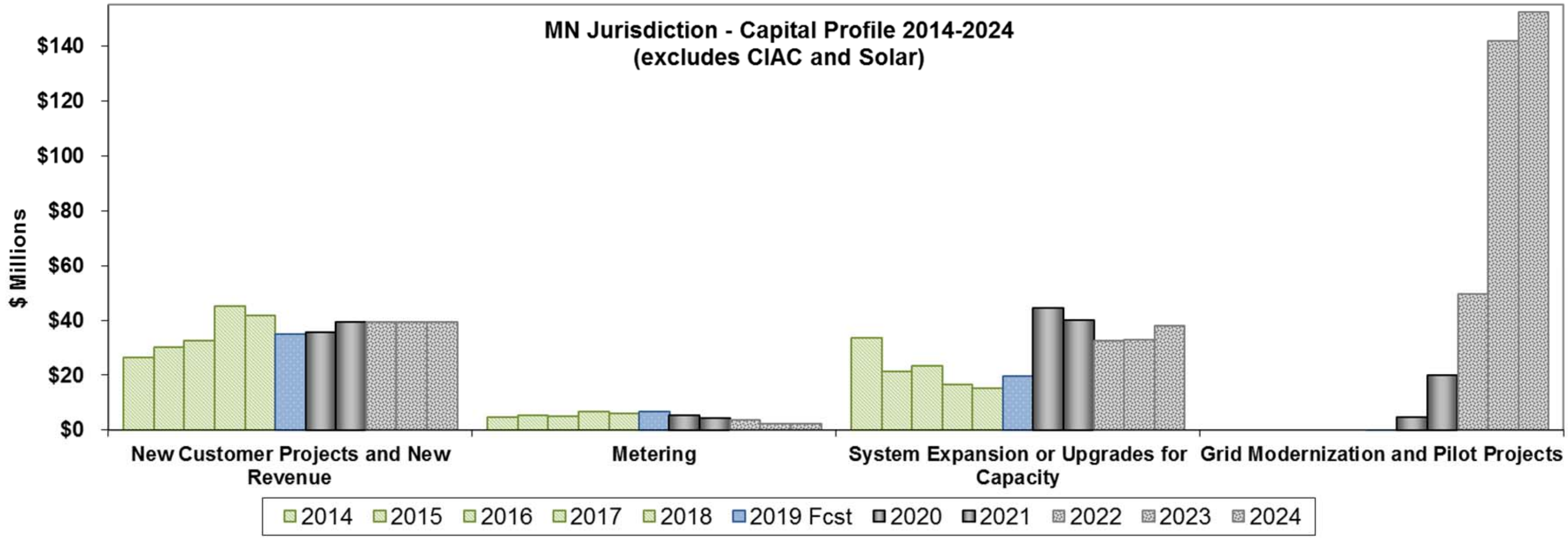
Mitigation #	Investment Summary Information	Risk Number	Risk Type N-0 or N-1	Parent Device	Risk Score	2019 Forecasted Demand kVA	2019 Forecasted Capacity kVA	2019 Forecasted Percent Loading	Planned Spending in 5 Year Budget
E156.011061	Install Wyoming WYO Feeder	2006.0229	1	WYO022	3.87			77.93%	$ 2,500,000
E156.011061	Install Wyoming WYO Feeder	2004.1268	1	WYO031	3.87			76.20%	$ 2,500,000
E156.011061	Install Wyoming WYO Feeder	2010.0166	1	WYO032	3.87			93.93%	$ 2,500,000
E156.011061	Install Wyoming WYO Feeder	2011.0158	1	WYO033	3.87			64.10%	$ 2,500,000
E156.011752	Install Lindstrom LIN Feeder	2006.0210	1	LIN022	0.66			56.55%	$ 650,008
E156.011752	Install Lindstrom LIN Feeder	2006.0211	1	LIN031	0.66			94.75%	$ 650,008
E156.011752	Install Lindstrom LIN Feeder	2005.0568	1	SCA_TR01	0.66			88.57%	$ 650,008
E156.011752	Install Lindstrom LIN Feeder	2008.0856	1	SCA021	0.66			90.71%	$ 650,008
E156.011764	Reinforce Tanners Lake TLK Sub Equip	2011.0177	1	TLK_TR01	0.57			71.03%	$ 200,000
E156.011764	Reinforce Tanners Lake TLK Sub Equip	2009.0399	1	TLK_TR02	0.57			55.03%	$ 200,000
E156.015749	Install Baytown BYT Feeders	2013.0135	1	AFT314	6.16			87.03%	$ 4,200,000
E156.015749	Install Baytown BYT Feeders	2016.0167	1	BYT072	6.16			75.40%	$ 4,200,000
E156.015749	Install Baytown BYT Feeders	2015.0574	1	HUG321	6.16			76.10%	$ 4,200,000
E156.015811	Reinforce Oakdale OAD073 & OAD075	2012.0572	1	TLK066	0.52			63.85%	$ 275,004

PROTECTED DATA ENDS]

Protected Data Justification

The shaded and marked columns in this spreadsheet contain information Xcel Energy maintains as Security Information, pursuant to Minn. Stat. § 13.37, subd. 1(a). The public disclosure or use of this information creates an unacceptable risk that those who want to disrupt our system for political or other reasons may learn which facilities to target to create a disruption of our service. Additionally, these fields for certain feeders contain information that if made public would be counter to our requirement to protect the anonymity of our customers' energy usage information unless we have the customers' consent to disclose it (Commission Order dated January 19, 2017 in Docket No. E,G999/CI-12-1344).

Figure 1: Distribution Capital Profile Trend (2014 to 2024)
State of Minnesota Electric Jurisdiction



New Business –

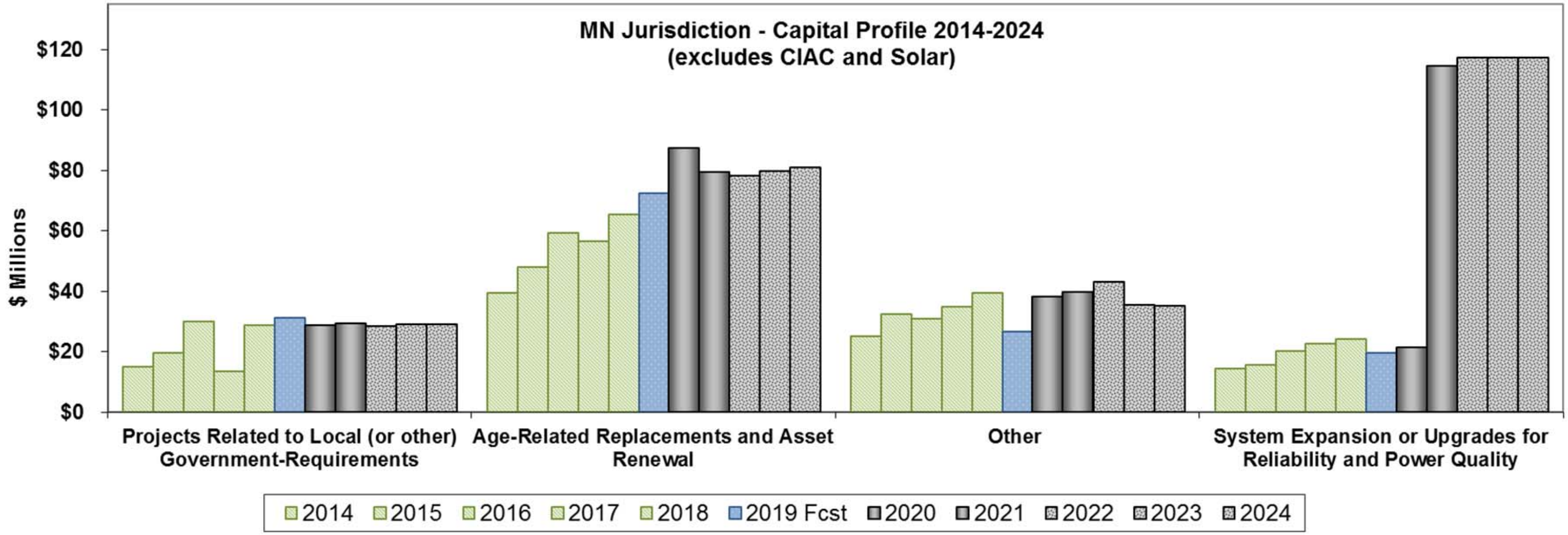
- Based on estimated cost per meter and growth assumptions. Analysis does not include 2019 results and will be refreshed in 2021-2025 budget create cycle.
- Growth assumptions based on historical results; National housing start data and known trends in service territories. National housing start data predicting growth uptick in 2020 and 2021, held growth consistent beginning in 2022 pending results in 2019 and 2020.
- 2017 and 2018 expenditures are elevated by the LED Conversion project (completed early 2019).

Metering – Includes meter purchases. No significant changes identified.

Capacity – Limited funds available for capacity projects through 2019. Uptick beginning in 2020 driven by increased funding availability and focus on overloads and contingency risk. Annual amounts will fluctuate based on needs in North and South Dakota, as well as timing of large projects.

Grid Modernization and Pilot Projects – Includes Advanced Grid Infrastructure and Security (AGIS) and Electric Vehicle (EV) Programs with AGIS starting in 2018 and EV starting in 2019.

Figure 2: Distribution Capital Profile Trend (2014 to 2024)
State of Minnesota Electric Jurisdiction



Projects Related to Local (or other) Government –

- Significant uptick in 2018 and 2019 driven by road projects in Minneapolis including 8th Street Relocation, 4th Street Relocation and Hennepin Avenue Relocation. Project schedules and final scopes greatly depend on city/government timelines, approvals and permitting.
- 2020 and beyond held consistent assuming elevated trend continues.

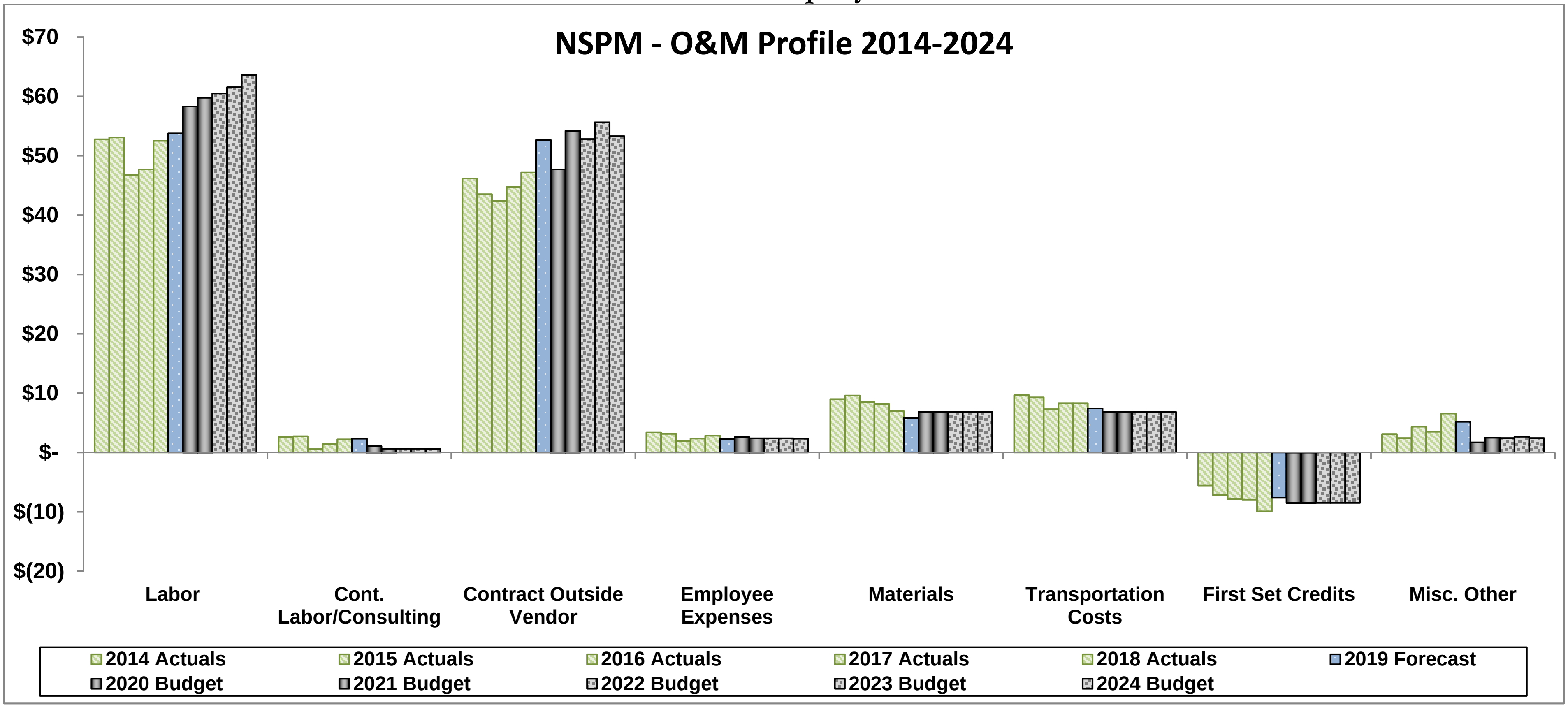
Other –

- Includes fleet, tools, communication equipment and transformer purchases. Transformer purchases and fleet purchases driving decrease in 2019.
- Uptick in 2020 includes increases to fleet, transformers and the Advanced Planning Tool. Other remains elevated in 2021 and 2022 with increased fleet needs anticipated.

System Expansion or Upgrades for Reliability and Power Quality –

- Cable replacement program is the main driver in this category. Cable replacement remains flat in 2020 due to limited funding.
- Elevated spend beginning in 2021 includes Incremental System Investment program currently starting at $81M in 2021.

Figure 1: Distribution O&M Profile Trend (2014 to 2024)
NSPM – Total Company Electric



1. Misc. Other: Includes bad debt, use costs, office supplies, janitorial, dues, donations, permits, etc.
2. The average Contract Outside Vendor annual expense related to Vegetation Management and Damage Prevention are $29.3M and $8.0M, respectively.
3. The average budgeted Contract Outside Vendor annual expense related to AGIS is $5.9M. There were no AGIS expenses from 2014-2017.

Non-Wires Alternatives Analysis

This attachment contains our non-wires alternatives analysis for the 2019 IDP. We provide an overview of our analysis and approach below. Section I provides the results for each project analyzed, Part II contains our assumptions, and Part III provides the load curves for each project.

OVERVIEW

As discussed in the IDP, we performed a non-wires alternatives analysis on the following projects. Using the screening process we described, the below table provides the list of capacity projects over $2 million that fall within the required timeline. Nine projects fit the screening criteria for further evaluation.

Table 1: Total Capacity Projects Exceeding $2 Million and Within the Timeline

Project	2020	2021	2022	2023	2024	Total
Install Hyland Lake HYL TR3 & Feeder	$0	$0	$0	$100,000	$4,600,000	$4,700,000
Install Goose Lake GLK TR3 & Feeders	$0	$0	$0	$700,000	$4,000,000	$4,700,000
Install Orono ORO TR2 & Feeder	$0	$0	$100,000	$4,000,000	$0	$4,100,000
Install East Winona EWI TR2 & Feeder	$0	$0	$0	$100,000	$3,100,000	$3,200,000
Install Zumbrota ZUM TR & Feeder	$0	$0	$100,000	$2,950,000	$0	$3,050,000
Reinforce Kasson KAN TR1 & Feeders	$0	$0	$2,850,000	$0	$0	$2,850,000
Reinforce Burnside BUR TR2	$0	$0	$100,000	$2,600,000	$0	$2,700,000
Install Viking VKG Feeder	$0	$0	$0	$2,500,000	$0	$2,500,000
Install West Coon Rapids WCR TR	$0	$0	$100,000	$1,980,000	$0	$2,080,000

For each of these projects we focused on the forecasted 2022 peak load curve for each feeder or transformer risk involved. We then applied focused demand response in an effort to reduce the load and followed that with energy storage and/or solar generation to make up the rest of the deficiency. In some instances, we had existing solar on particular feeders that we could utilize in the analysis as well.

We only considered Demand Response for the N-0 risks. This is partially due to the complexity of the N-1 analysis (combinations of feeders resulting in multiple configurations and customer make-ups) and the difficulty in obtaining necessary data such as individual customer loads. By focusing on the N-0 risks at this time, we are looking to develop a process, observe the value, and determine next steps for all risks.

Table 2 below highlights the nine projects, their costs, and the risk deficiencies that drive those costs. Comparing these analyses to traditional projects was difficult because in some instances, the NWA is not able to fully solve all of the risks that the traditional project solved. This was in part due to contingency situations where a NWA would have to act as a microgrid for large amounts of energy. The costs for such a solution would have been substantially greater. The NWA solutions also solved the risks up to 100 percent of the capacity rating, which means that any new load growth would create the need for an expanded or new NWA solution. In comparison, our traditional capacity projects contain "spare capacity" that allows us to accommodate some new growth in the near term.

Table 2: 2019 NWA Candidate Projects – Results Summary

Project Title	# of Risks	Aggregate Project Peak Demand (MW Overload)	Aggregate Project Energy Demand (MWh Overload)	Cost of NWA ($ M)	Cost of Traditional Project ($ M)
Reinforce Kasson TR1 and Feeders	7	14.14	126.69	$49.34	$2.85
Install West Coon Rapids WCR TR	4	18.59	167	$94.64	$2.08
Reinforce Burnside BUR TR2	3	9.76	92.59	$46.86	$2.7
Install Zumbrota ZUM TR & Feeder	3	2.8	28.25	$8.84	$3.05
Install Orono ORO TR2 & Feeder	3	9.62	59.35	$31.32	$4.10
Install Hyland Lake HYL TR3 & Feeder	5	11.31	52.49	$20.99	$6.20
Install Goose Lake GLK TR3&Feeders	8	20.94	155.77	$63.31	$4.70
Install Viking VKG Feeder	4	6.99	39.10	$15.64	$2.00
Install East Winona EWI TR2 & Feeder	9	9.2	98.16	$88.90	$3.2

I. PROJECT ANALYSIS RESULTS

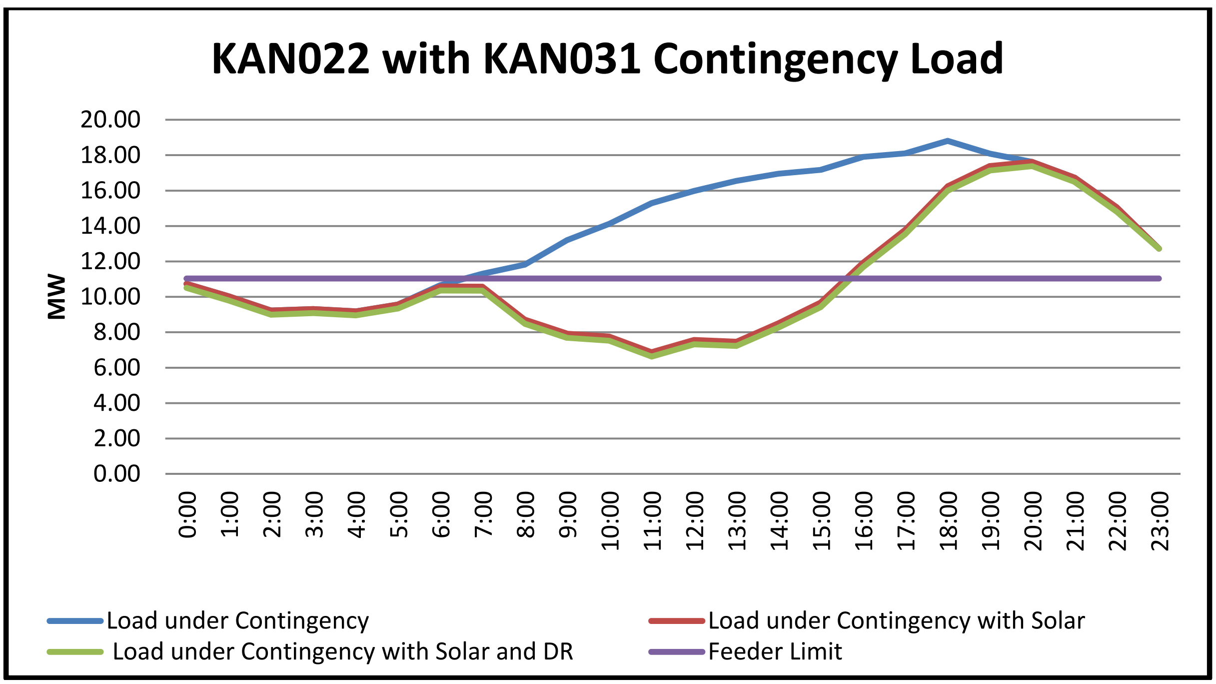
A. Reinforce Kasson TR1 and Feeders

This project has five feeder risks and two substation transformer risks. The transformer risks are both contingency risks while three of the feeder risks are due to contingencies and two are normal overloads. The traditional project that was budgeted to mitigate these issues included the upgrading of one substation transformer and the building of a new feeder.

The NWA solution for this project looked at existing solar generation on West Byron and both of the Kasson feeders (5MW on each of the three feeders) and combined it with energy storage and demand response potential. It assumed that two energy storage devices could be placed at key locations on the feeders to minimize the locations of deployment and solve all of the feeder risks. It was also assumed that the Kasson TR2 transformer risk and the West Byron TR1 risk could be mitigated by leveraging either one or both of those energy storage devices during a transformer contingency.

Figure 1 shows the amount of load at risk if feeder Kasson 31 (KAN031) were to be switched to Kasson 22 (KAN022) during contingency (this is the largest feeder risk for the project).

Figure 1: Kasson – KAN031 N-1 Contingency Load Risk



With solar contribution considered there would need to be energy storage installed that would be capable of reaching 6.6 MW at peak and discharging 31.5 MWH of energy throughout the day. This represents the largest energy storage device that would need to be deployed for this project and would also be used to mitigate the KAN031 N-0, Kasson TR2 N-1 and KAN022 N-1 risks. When observing the blue curve (total load under contingency) it's important to understand that there would not be enough available capacity under the feeder limit to charge an energy storage device for the amount of energy that is needed during discharge. Consequently, more solar needed to be added to this feeder so that the green curve (total load under contingency with solar and DR) could be realized and provide enough capacity for charging. This resulted in 15 MW of additional solar being added to the KAN031 feeder.

One other device would also be needed to mitigate two of the remaining three West Byron risks, but it would be smaller and result in less cost. Of particular interest is the fact that the combination of existing solar and demand response on WEB021 is sufficient to eliminate the WEB021 N-0 overload, which is the final risk.

Table 3: Reinforce Kasson TR1 and Feeders – Summary of DER Feeder Solutions

Capacity Risk	Overload Magnitude		Optimal DER Solution			Estimated Cost
	MW Overload	MWh Overload	Demand Response (MWh)	Solar PV (MW)	Battery Storage (MWh)	
N-1: Kasson, Loss of KAN022	Mitigated with optimal energy storage placement					
N-1: Kasson, Loss of KAN031	7.8	79.96	5.46	20	31.53	$42,611,398
N-0: KAN031	Mitigated with optimal energy storage placement					
N-1: West Byron, Loss of WEB021	5.71	45.32	15.7	5	16.82	$6,729,758
N-0: WEB021	0.6	1.41	15.7	5	0	$0
N-1: Kasson TR2	Mitigated with optimal energy storage placement					
N-1: West Byron TR1	Mitigated with optimal energy storage placement					
Total			21.16	25	48.35	$49,341,156

*Note: One of the WEB021 risks is counted in the total for DR and Solar

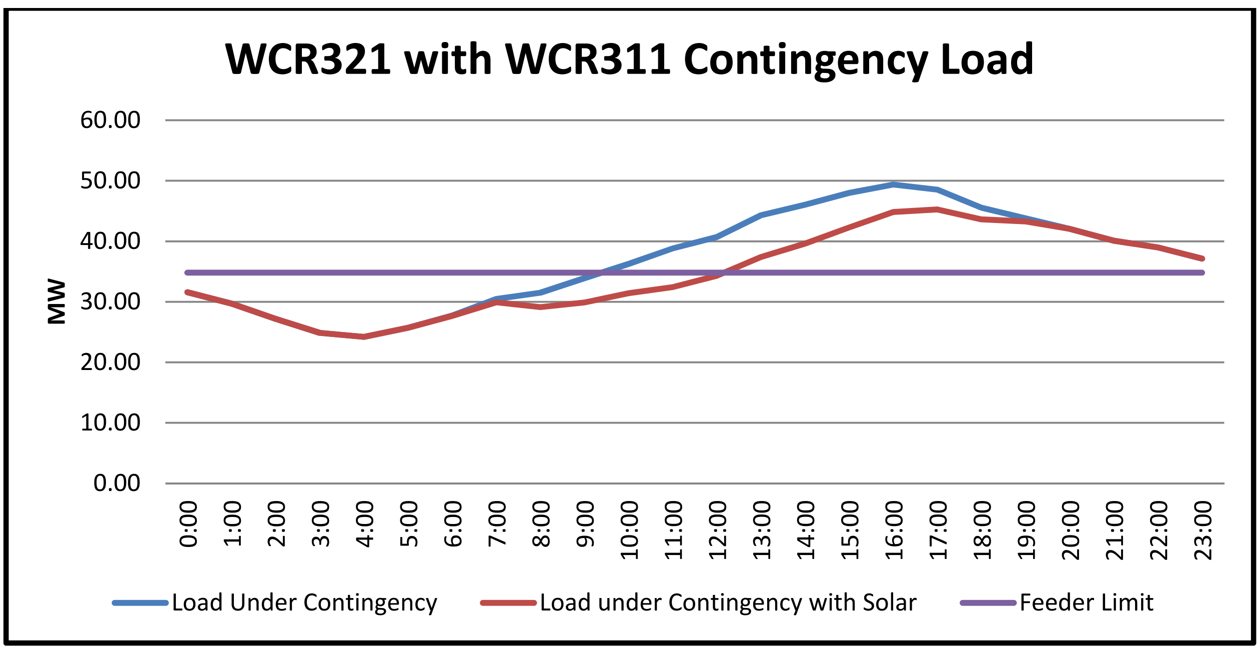
B. Install West Coon Rapids WCR TR

This project has three feeder risks and one substation transformer risk. The transformer risk is a contingency risk while two of the feeder risks are due to contingencies and the third is due to normal overloads. The traditional project that was budgeted to mitigate these issues was the installation of a new 13.8kV transformer in the substation.

The NWA solution for this project assumed that three energy storage devices could be placed at key locations on the feeders to minimize the locations of deployment and solve all of the feeder risks. Additionally, 26MW of solar PV would need to be installed on one of the feeders in order to store enough energy below the feeder capacity to discharge during a severe over-capacity case. It was also assumed that the WCR TR3 transformer risk could be mitigated by leveraging all energy storage devices during a transformer contingency.

Figure 2 shows the amount of load at risk if feeder West Coon Rapids 322 (WCR322) were to be switched to West Coon Rapids 321 (WCR321) during contingency (this is the largest feeder risk for the project).

Figure 2: West Coon Rapids WCR322 N-1 Contingency Load Risk



With the additional solar solution considered, there would need to be energy storage installed that would be capable of reaching 12 MW at peak and discharging 86.3 MWH of energy throughout the day. It should be noted that demand response is not included in this N-1 mitigation solution. This is due to WCR322's size and the requirement of its load being split apart amongst several feeders during an outage scenario, which would lead to inaccurate analysis. This represents the largest energy storage device that would need to be deployed for this project and would also be used to mitigate the WCR311 N-1, and a portion of the WCR TR3 N-1 risks. Again, more solar must be added to this feeder so that the red curve (total load under contingency plus solar) could be realized and provide enough capacity for charging. This resulted in 26 MW of additional solar being added to the WCR321 feeder. Two other devices would also be needed to mitigate the remaining West Coon rapids risks, but would be smaller and result in less cost.

Table 4: Install West Coon Rapids WCR TR – Summary of DER Feeder Solutions

Capacity Risk	Overload Magnitude		Optimal DER Solution			Estimated Cost
	MW Overload	MWh Overload	Demand Response (MWh)	Solar PV (MW)	Battery Storage (MWh)	
N-1: West Coon Rapids, Loss of WCR311	Mitigated with optimal energy storage and solar PV placement					
N-1: West Coon Rapids, Loss of WCR322	14.73	144.41	0	26	86.3	$86,501,974
N-0: WCR322	0.98	2.29	64.9	0	0	$0
N-1: West Coon Rapids TR3*	2.88	20.3	0	0	20.3	$8,135,751
Total			64.9	26	106.6	$94,637,725

*Note: Part of the WCR TR3 Optimal DER Solution relies on optimal PV and energy storage placement

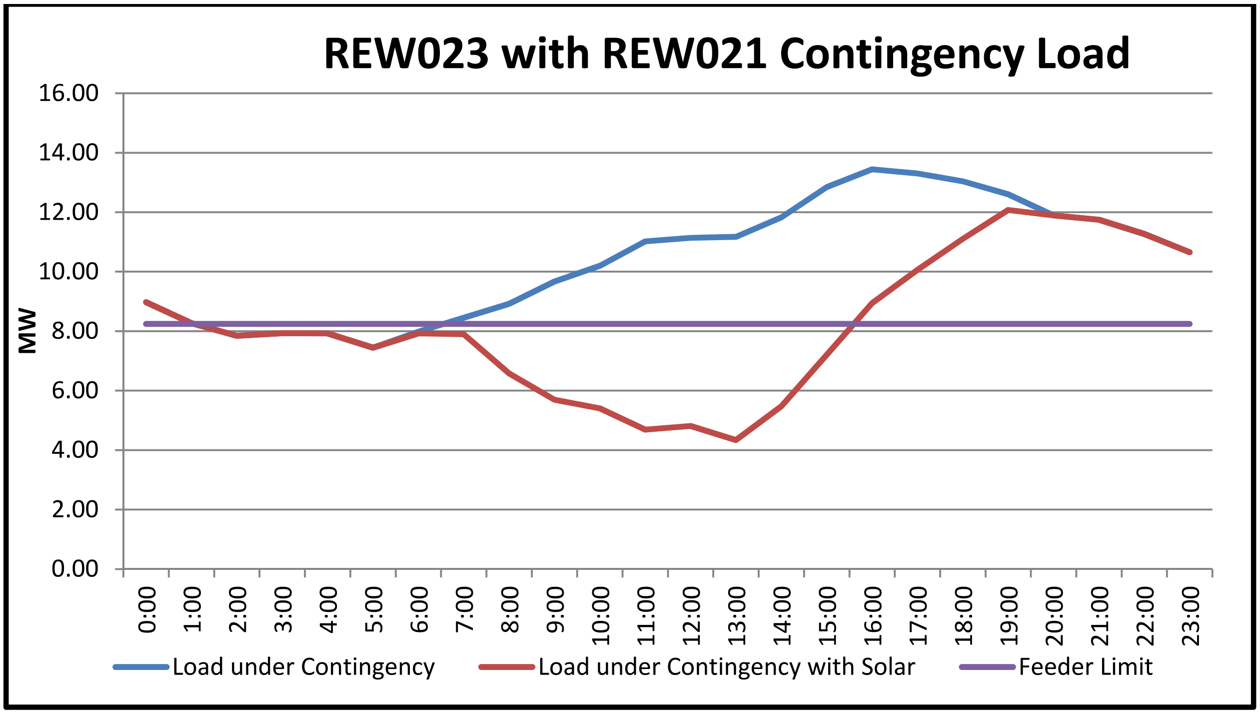
C. Reinforce Burnside BUR TR2

This project has two feeder risks and one substation transformer risk. All three of these risks are contingency risks. The traditional project that was budgeted to mitigate these issues included the upgrading of one substation transformer and the building of a new feeder.

The NWA solution for this project looked at existing solar generation on the Red Wing 23 (REW023) feeder (4.8 MW) and a feeder served by the Burnside TR1 (BURTR1) transformer (5 MW). Those amounts of existing generation were combined with energy storage potential. It assumed that two energy storage devices could be placed at key locations on the feeders to minimize the locations of deployment and solve all three of the risks.

Figure 3 shows the amount of load at risk if feeder REW021 were to be switched to REW023 during contingency (this is the largest risk for the project). Due to its geographic location and topography REW021 cannot be switched to any other feeders.

Figure 3: Red Wing – REW021 N-1 Contingency Load Risk



With solar considered there would need to be energy storage installed that would be capable of reaching 3.83 MW at peak and discharging 22.54 MWH of energy throughout the day. This represents the largest energy storage device that would need to be deployed for this project. It would also be used to mitigate the REW023 N-1 risk. When observing the blue curve (total load under contingency) it's important to understand that there would not be enough available capacity under the feeder limit to charge an energy storage device for the amount of energy that is needed during discharge. Consequently, more solar needed to be added to this feeder so that the red curve (total load under contingency plus solar) could be realized and provide enough capacity for charging. This resulted in 14 MW of additional solar being added to the REW021 feeder.

One other energy storage device would also be needed to mitigate the BURTR1 risk, but would be smaller and result in less cost.

Table 5: Reinforce Burnside BUR TR2 – Summary of DER Feeder Solutions

Capacity Risk	Overload Magnitude		Optimal DER Solution			Estimated Cost
	MW Overload	MWh Overload	Demand Response (MWh)	Solar PV (MW)	Battery Storage (MWh)	
N-1: Red Wing, Loss of REW021	5.2	53.79	0	18.8	22.54	$37,016,621
N-1: Red Wing, Loss of REW023	Mitigated with optimal energy storage and PV placement					
N-1: Burnside TR1	4.56	38.8	0	5	24.61	$9,842,961
Total			0	23.8	47.15	$46,859,581

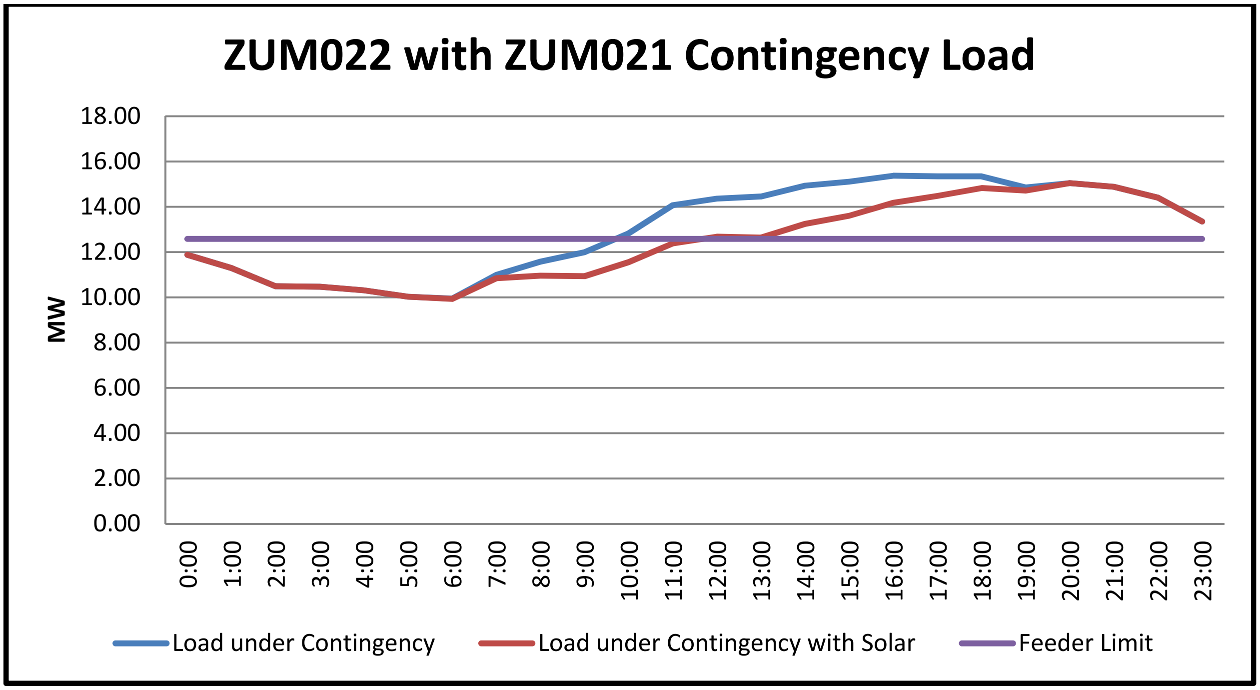
D. Install Zumbrota ZUM TR & Feeder

This project has two feeder risks and one substation transformer risk. All three of these risks are contingency risks. The traditional project that was budgeted to mitigate these issues included the addition of one substation transformer and the building of a new feeder.

The NWA solution for this project looked at existing solar generation on the Zumbrota 21 (ZUM021) feeder (2 MW) and the Zumbrota 22 (ZUM022) feeder (2 MW) and combined it with energy storage potential. It assumed that one energy storage devices could be placed at a key location so that both feeders could utilize it and minimize the locations of deployment. Also, we did not analyze the ability for the NWA to solve the transformer contingency risk. This is because Zumbrota TR1 (ZUMTR1) has no other transformers to shift any of its load to if it were to fail. It is the only transformer in the Zumbrota substation and has no other strong ties to other substation transformer via its feeders. This means that all of its peak load would have to be picked up in any NWA solution for an extended period of time. This would be extremely cost prohibitive and represent more of a large micro-grid type solution.

Figure 4 shows the amount of load at risk if feeder ZUM021 were to be switched to ZUM022 during contingency.

Figure 4: Zumbrota – ZUM021 N-1 Contingency Load Risk



With solar considered there would need to be energy storage installed that would be capable of reaching 2.47 MW at peak and discharging 17.1 MWH of energy throughout the day. It would also be used to mitigate the ZUM022 N-1 risk. When observing the blue curve (total load under contingency) it's important to understand that there would not be enough available capacity under the feeder limit to charge an energy storage device for the amount of energy that is needed during discharge. Consequently, more solar needed to be added to this feeder so that the red curve (total load under contingency plus solar) could be realized and provide enough capacity for charging. This resulted in 1 MW of additional solar being added to the ZUM021 feeder. As noted earlier, the end result would solve two of the three risks, with the third risk being too difficult and costly to accommodate.

Table 6: Install Zumbrota ZUM TR & Feeder – Summary of DER Feeder Solutions

Capacity Risk	Overload Magnitude		Optimal DER Solution			Estimated Cost
	MW Overload	MWh Overload	Demand Response (MWh)	Solar PV (MW)	Battery Storage (MWh)	
N-1: Zumbrota, Loss of ZUM022	Mitigated with optimal energy storage placement					
N-1: Zumbrota, Loss of ZUM021	2.8	28.25	0	2	17.1	$8,841,589
N-1: Zumbrota ZUMTR1	Single transformer – too costly to accommodate – risk not solved					
Total			NA	2	17.1	$8,842,000

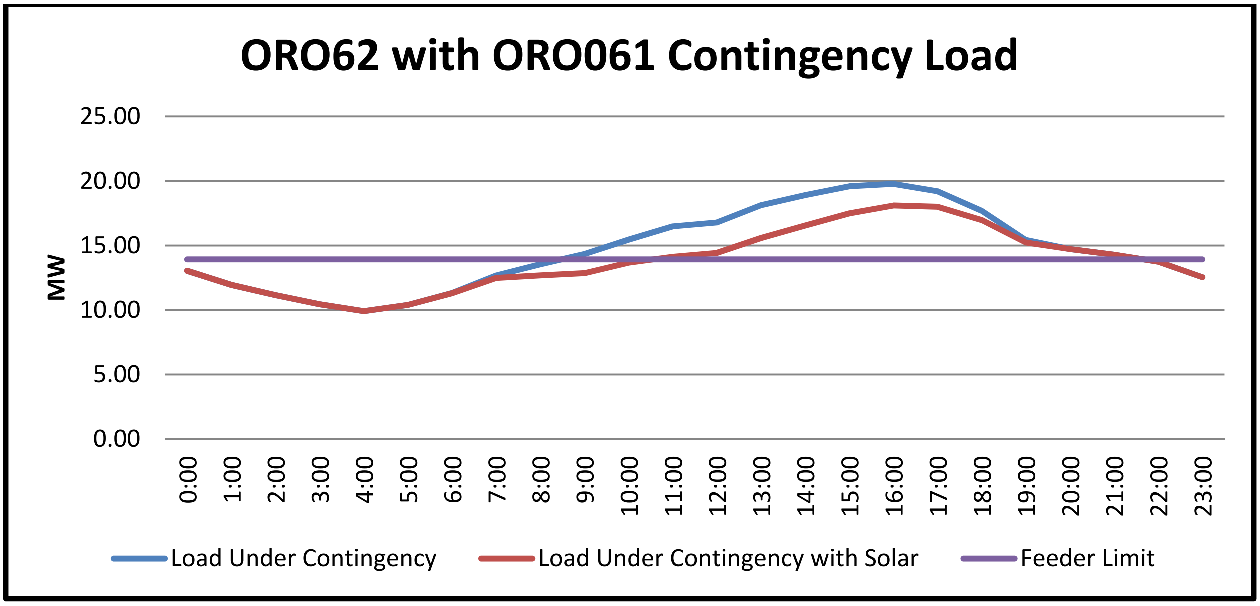
E. Install Orono ORO TR2 & Feeder

This project has two feeder risks and one substation transformer risk. All risks associated with this project are contingency risks, with no normal overloads. The traditional project that was budgeted to mitigate these issues was the installation of a new 13.8kV transformer in the substation and additional feeders.

The NWA solution for this project assumed that two energy storage devices could be placed at key locations on the feeders to minimize the locations of deployment and solve all of the feeder risks. Additionally, 5MW of solar PV would need to be installed on one of the feeders in order to store enough energy below the feeder capacity to discharge during a severe over-capacity case. Also, after analysis was completed, it was discovered that there was no ability for the NWA to solve the transformer contingency risk. This is because Orono TR1 (OROTR1) has no other transformers to shift any of its load to if it were to fail. It is the only transformer in the Orono substation and has no other strong ties to other substation transformer via its feeders. This means that all of its peak load would have to be picked up in any NWA solution for an extended period of time. This would be extremely cost prohibitive and represent more of a large micro-grid type solution.

Figure 5 shows the amount of load at risk if feeder Orono 61 (ORO061) were to be switched to Orono 62 (ORO062) during contingency (this is the largest feeder risk for the project).

Figure 5: Orono ORO061 N-1 Contingency Load Risk



With the additional solar solution considered, there would need to be energy storage installed that would be capable of reaching 4.18 MW at peak and discharging 22.32 MWh of energy throughout the day. This represents the largest energy storage device that would need to be deployed for this project. Again, more solar must be added to this feeder so that the red curve (total load under contingency plus solar) could be realized and provide enough capacity for charging. This resulted in 7 MW of additional solar being added to the ORO062 feeder. One other device would also be needed to mitigate the remaining ORO062 risks, but would be smaller and result in less cost.

Table 7: Install Orono ORO TR2 & Feeder – Summary of DER Feeder Solutions

Capacity Risk	Overload Magnitude		Optimal DER Solution			Estimated Cost
	MW Overload	MWh Overload	Demand Response (MWh)	Incremental Solar PV (MW)	Battery Storage (MWh)	
N-1: Orono, Loss of ORO061	5.85	39.79	0	7	22.32	$22,927,307
N-1: Orono, Loss of ORO062	3.77	19.56	0	0	19.56	$8,390,112
N-1: Orono TR1	Single transformer – too costly to accommodate – risk not solved					
Total			0	7	41.88	$31,317,419

F. Install Hyland Lake HYL TR3 & Feeder

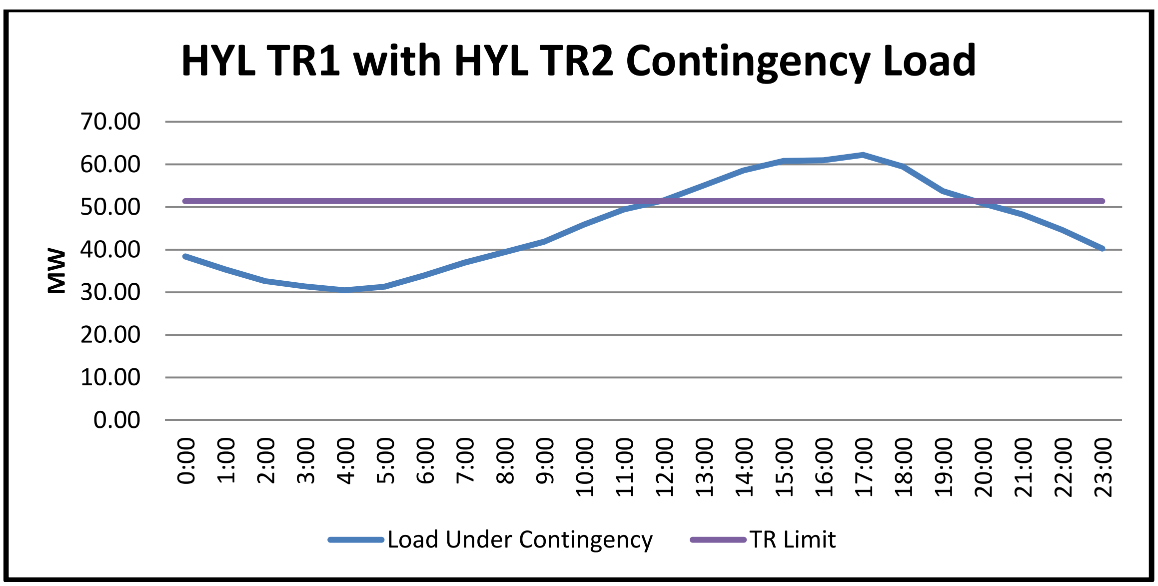
This project has three feeder risks and two substation transformer risks. The transformer risks and feeder risks are all due to contingencies. The traditional project in the budget involved installing one new substation transformer, one feeder bay, and one new feeder.

The NWA solution for this project involved placing three energy storage systems at strategic places on the feeders to mitigate risks and keep costs at a minimum.

It was assumed that two of these energy storage systems could be put at feeder ties to mitigate three of the feeder risks. The third energy storage system was assumed to be utilized at the substation transformer level to mitigate the transformer contingencies.

Figure 6 shows the amount of load at risk if the Hyland Lake substation transformer TR2 (HYL TR2) were to be switched to Hyland Lake transformer TR1 (HYL TR1) during contingency.

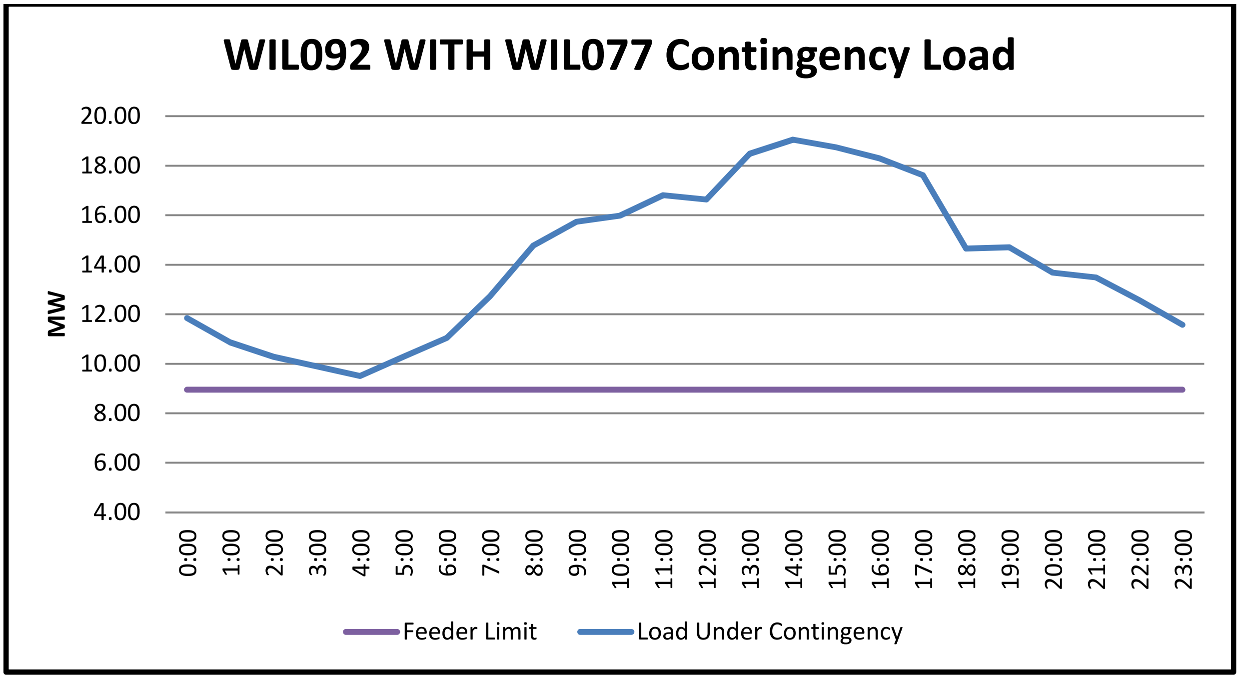
Figure 6: Install Hyland Lake HYL TR3 & Feeder – HYL TR1 N-1 Contingency Load Risk



In the current condition, there would need to be an energy storage system installed that could handle 51.39 MW at peak, discharging 10.85 MWh of energy throughout the day. This energy storage system would be the largest in magnitude (in MW) needed for the project and would mitigate both HYL TR1 and HYL TR2 N-1 risks.

Another feeder risk for this project is shown below in Figure 7. This figure shows the amount of load at risk if feeder Wilson 77 (WIL077) were to be switched to feeder Wilson 92 (WIL092) during contingency.

Figure 7: Wilson – WIL092 N-1 Contingency Load Risk



With this particular contingency, it is important to note that the load under contingency is above the feeder limit at all times. Due to the magnitude of the overload for this contingency, adding solar to mitigate the risk results in extremely high costs. Therefore, the remaining solution to this particular risk was to install an energy storage system capable of reaching 10.10 MW at peak and discharging 124.45 MWh of energy throughout the day. In order for the energy storage system to mitigate this contingency, it would have to be discharging through all hours of the day with no time to recharge. This isn't possible, so this particular contingency wasn't included in the NWA. Therefore, this NWA solution wouldn't be an equivalent to the traditional solution.

Table 8: Install Hyland Lake HYL TR3 & Feeder – Summary of DER Feeder Solutions

Capacity Risk	Overload Magnitude		Optimal DER Solution			Estimated Cost
	MW Overload	MWh Overload	Demand Response (MWh)	Incremental Solar PV (MW)	Battery Storage (MWh)	
N-1: Hyland Lake, Loss of HYL073	0.46	1.10	0.00	0.00	1.10	$441,758
N-1: Wilson, Loss of WIL077	Not able to solve risk with NWA solution					
N-1: Hyland Lake, Loss of TR2	10.85	51.39	0.00	0.00	51.39	$20,554,313
Total			0.00	0.00	52.49	$20,996,071

G. Install Goose Lake GLK TR3 & Feeders

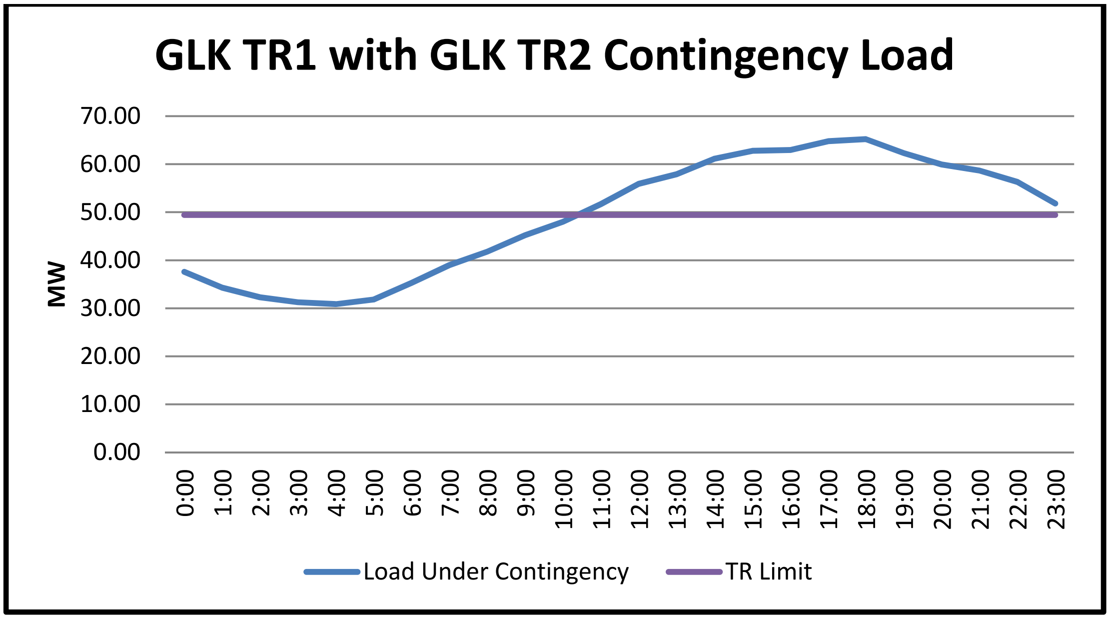
This project has six feeder risks and two substation transformer risks. The transformer risks and feeder risks are all due to contingencies. The traditional project in the budget involved installing one new substation transformer, one feeder bay, and one new feeder.

The NWA solution for this project involved placing four energy storage systems at strategic places to mitigate risks and keep costs at a minimum.

It was assumed that three of the energy storage systems could be put at feeder ties to mitigate all six of the feeder risks. The fourth energy storage system was assumed to be utilized at the substation transformer level to mitigate transformer contingencies.

Figure 8 shows the amount of load at risk if the Goose Lake substation transformer TR2 (GLK TR2) were to be switched to Goose Lake transformer TR1 (GLK TR1) during contingency.

Figure 8: Goose Lake TR2 N-1 Contingency Load Risk



In the current condition, there would need to be an energy storage system installed that could handle 15.82 MW at peak, discharging 129.27 MWh of energy throughout the day. This energy storage system would be the largest in magnitude (in MW) needed for the project and would mitigate both GLK TR1 and GLK TR2 N-1 risks.

Table 9: Install Goose Lake GLK TR3 & Feeders – Summary of DER Feeder Solutions

Capacity Risk	Overload Magnitude		Optimal DER Solution			Estimated Cost
	MW Overload	MWh Overload	Demand Response (MWh)	Incremental Solar PV (MW)	Battery Storage (MWh)	
N-1: Goose Lake, Loss of GLK065	Mitigated with optimal energy storage placement					
N-1:Goose Lake, Loss of GLK074	0.66	1.68	0.00	0.00	1.68	$1,188,477
N-1:Goose Lake, Loss of GLK063	Mitigated with optimal energy storage placement					
N-1:Goose Lake, Loss of GLK074	3.13	20.42	0.00	0.00	20.42	$8,402,552
N-1: Goose Lake GLKTR1	Mitigated with optimal energy storage placement					
N-1: Goose Lake GLKTR2	15.82	129.27	0.00	0.00	129.27	$51,706,037
N-1: Goose Lake, Loss of GLK073	Mitigated with optimal energy storage placement					
N-1: Ramsey, Loss of RAM071	1.33	4.40	0.00	0.00	4.40	$2,015,738
Total			0.00	0.00	155.77	$63,312,804

*Note: GLK074 has risks at two feeder ties and requires two mitigations

H. Install Viking VKG Feeder

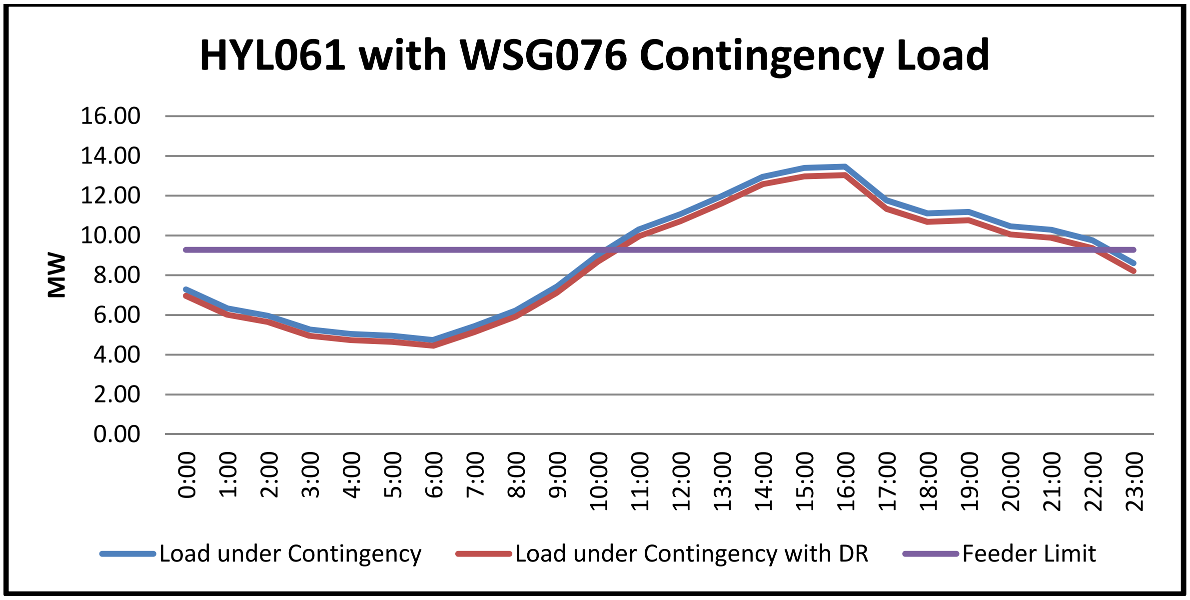
This project has four feeder risks, with two of them being due to contingencies and the other two being due to normal overloads. The traditional project in the budget involved installing one new feeder and feeder bay.

The NWA solution for this project involved placing two energy storage systems at strategic places on the feeders to mitigate risks and keep costs at a minimum.

It was assumed that both of these energy storage systems could be put at feeder ties to mitigate the contingencies and normal overload.

Figure 9 shows the amount of load at risk if the Westgate 76 feeder (WSG076) was switched to Hyland Lake 61 (HYL061) under contingency. This contingency is the highest risk in the project.

Figure 9: Hyland Lake – HYL061 N-1 Contingency Load Risk



In the current condition, there would need to be an energy storage system installed that could handle 3.76 MW at peak, discharging 21.69 MWh of energy throughout the day. This energy storage system would be the largest in magnitude (in MW) needed for the project and would mitigate both HYL061 N-0 and HYL N-1 risks.

Table 10: Install Viking VKG Feeder – Summary of DER Feeder Solutions

Capacity Risk	Overload Magnitude		Optimal DER Solution			Estimated Cost
	MW Overload	MWh Overload	Demand Response (MWh)	Incremental Solar PV (MW)	Battery Storage (MWh)	
N-1: Hyland Lake, Loss of WSG076	3.76	21.69	0.00	0.00	21.69	$8,677,622
N-1: Eden Prairie, Loss of WSG065	2.70	16.64	0.00	0.00	16.64	$6,656,069
N-0: Eden Prairie, Loss of EDP073	0.81	1.64	5.543	0.00	0.77	$309,744
N-0: Hyland Lake, Loss of HYL061	0.00	0.00	8.584	0.00	0.00	$0
Total			14.127	0.00	39.11	$15,643,435

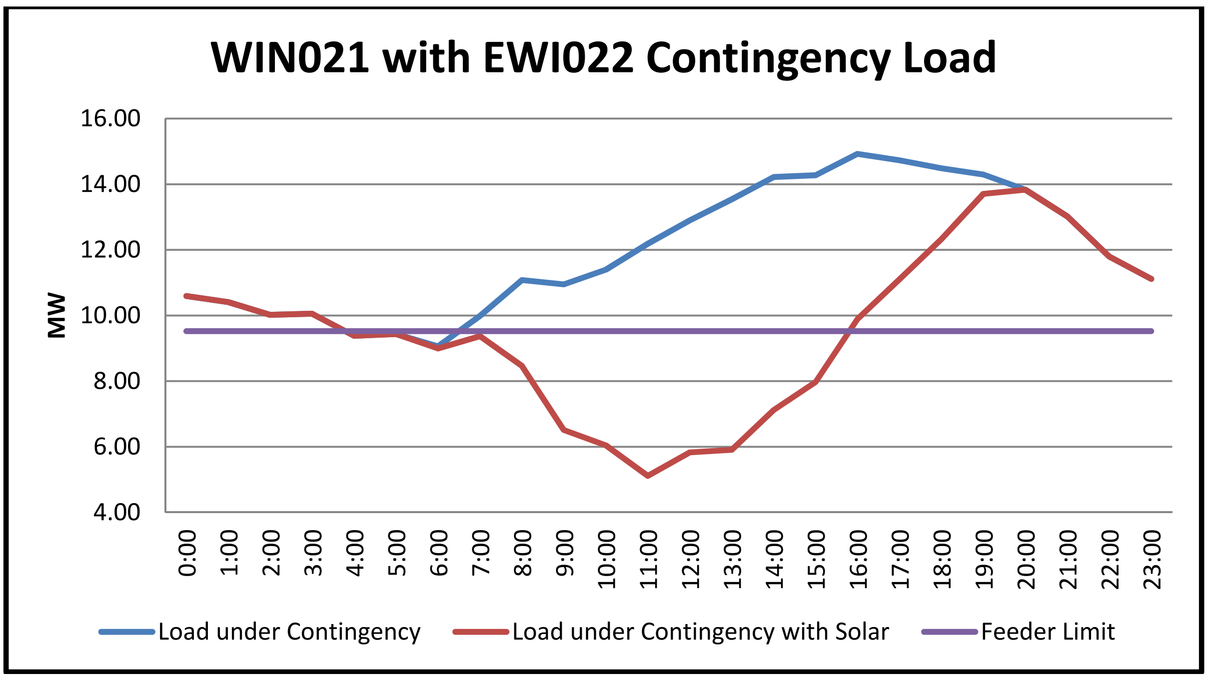
I. Install East Winona EWI TR2 & Feeder

This project has five feeder risks and four substation transformer risks. Three of the feeder risks are contingency risks and two are overloads. All four of the transformer risks are contingency risks. The traditional project that was budgeted to mitigate these issues included the addition of a second transformer and feeder at the East Winona Substation.

The NWA solution for this project considered PV and energy storage. With optimal placement of these resources only two feeder locations would be needed to solve all of the risks. The transformer risks were assumed to be solved by the feeder risks and were ignored in the analysis.

Figure 10 shows the amount of load at risk if feeder EWI022 were to be switched to WIN021 during contingency.

Figure 10: East Winona – EWI022 N-1 Contingency Load Risk



With solar considered there would need to be energy storage installed that would be capable of reaching 4.31 MW at peak and discharging 23.59 MWH of energy throughout the day. It would also be used to mitigate the WIN032 N-0 and N-1 risks. When observing the blue curve (total load under contingency) it's important to understand that there would not be enough available capacity under the feeder limit to charge an energy storage device for the amount of energy that is needed during discharge. Consequently, solar needed to be added to this feeder so that the red curve (total load under contingency plus solar) could be realized and provide enough capacity for charging. This resulted in 21 MW of additional solar being added to the EWI022 feeder. The end result would solve three of the five feeder risks, with the other two risks being mitigated with the WIN034 PV and energy storage solution indicated below.

Table 11: Install East Winona EWI TR2 & Feeder – Summary of DER Feeder Solutions

Capacity Risk	Overload Magnitude		Optimal DER Solution			Estimated Cost
	MW Overload	MWh Overload	Demand Response (MWh)	Solar PV (MW)	Battery Storage (MWh)	
N-1: Winona, Loss of WIN032	Mitigated with optimal energy storage placement					
N-1: Winona, Loss of WIN034	3.8	38.36	0	14	23.67	$37,467,286
N-1: East Winona, Loss of EWI022	5.4	59.8	0	21	23.59	$51,434,385
N-0: Winona, WIN032	Mitigated with optimal energy storage placement					
N-0: Goodview, GVW023	Mitigated with optimal energy storage placement					
Total			0	35	47.26	$88,901,671

II. ASSUMPTIONS

For all NWA studies, reasonable assumptions were made in order to streamline the process. Our goal in these studies is to reduce overloads and contingencies down to 100%. Therefore, any additional load growth in future years that could cause additional risk would require an additional risk analysis, associated mitigation, and NWA analysis. There is no “spare” capacity in these solutions.

When conducting an NWA analysis, we assumed that peak day conditions contain the highest magnitude of risk. Therefore, rather than doing analysis for potentially multiple overload events during the year, NWA studies were done utilizing available SCADA data containing peak day conditions. Historical 2018 peak days were selected and scaled to 2022 forecast peak values to accommodate the 3 year minimum that it would take to install a NWA solution in the field.

When approaching feeder and transformer risks, load that was not able to be offset by solar or demand response resulted in energy storage solutions. Unless extreme circumstances dictated otherwise, it was assumed that these energy storage systems would be available during risk hours to mitigate contingencies and overloads.

Minimum solar output curves utilized during the analyses ranged from 24-36% of peak output from 10AM to 4PM and to percentages less than that outside of that timeframe. These solar curves were obtained from the NREL PVWatts tool.

Demand response curves applied assumed peak at 6PM on associated feeders. Load curves were procured utilizing risks that had N-0 overloads. Risks containing N-1 contingencies were generally not considered for demand response due to the complexity of the N-1 analysis (combinations of feeders resulting in multiple configurations and customer make-ups) and the difficulty in obtaining necessary data, such as individual customer loads.

Battery storage systems were assumed to have no losses. In actuality during the charging and discharging of the system losses do occur, they are not 100% efficient.

It was also assumed that land would be available at key locations on feeders/transformers/substations that would enable the NWA solution.

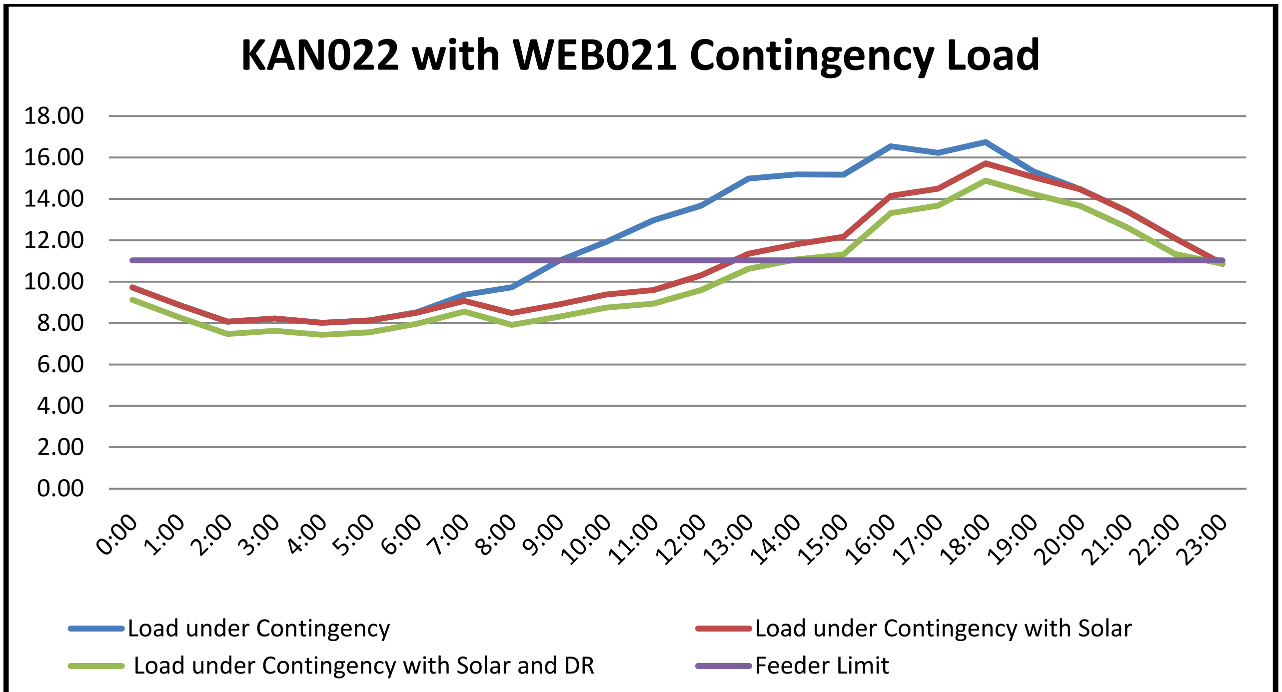
Table 12 below shows assumptions made in cost calculations during the studies.

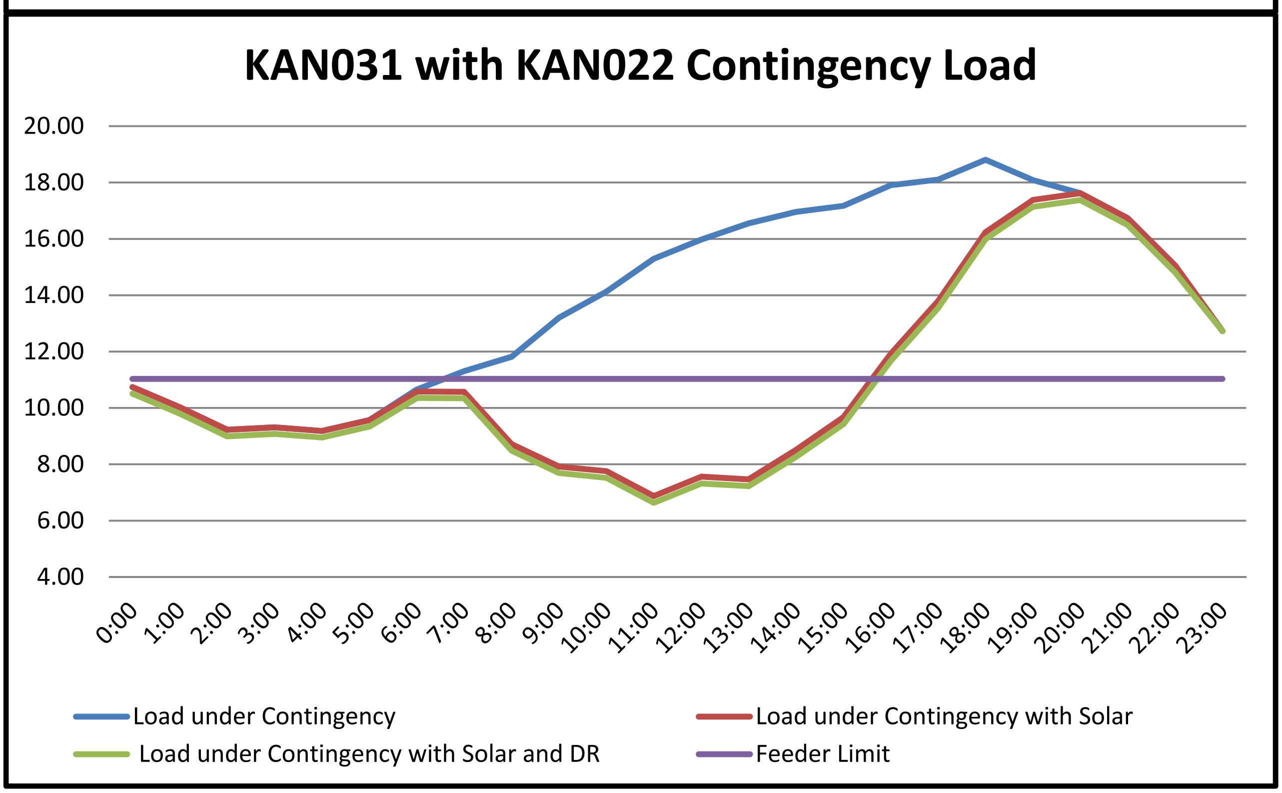
Table 12: Cost Assumptions in NWA Analysis

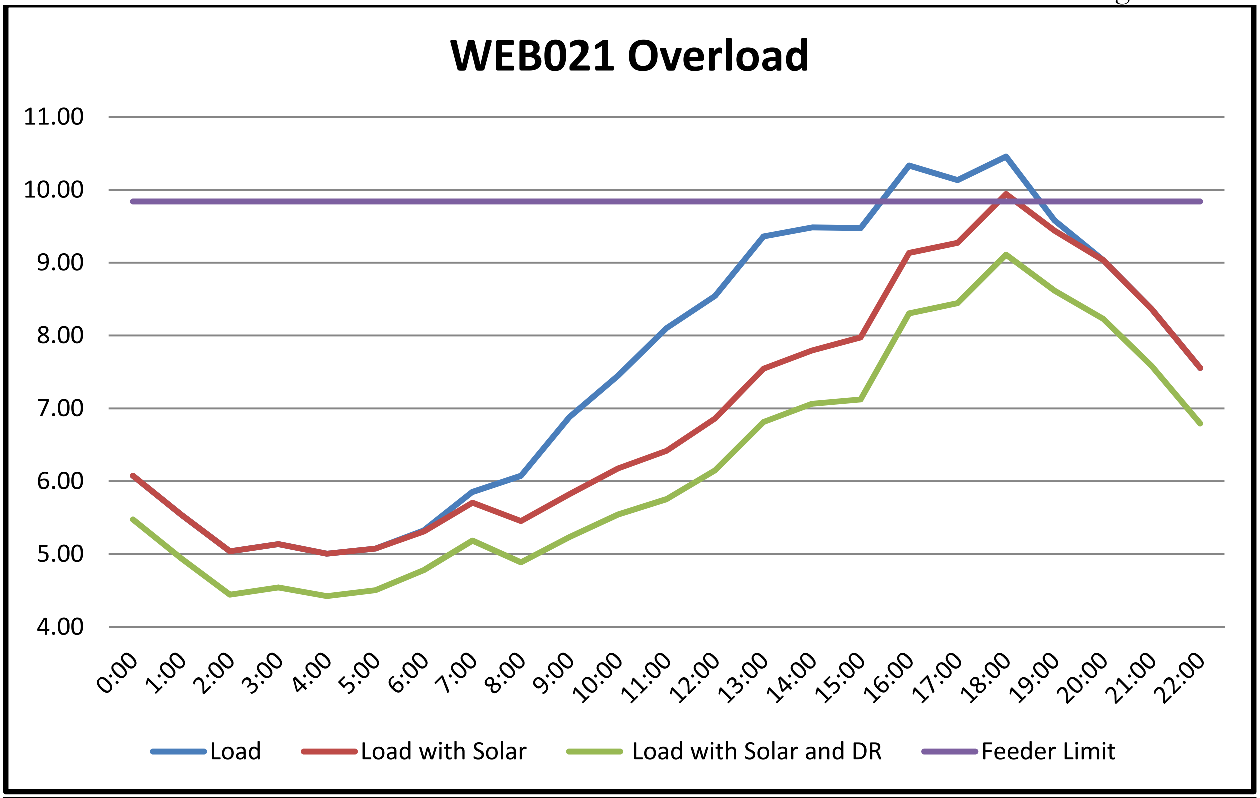
Assumption	Cost
Energy Storage Costs	$400,000/MWh
Solar PV Costs	$2,000,000/MW
O&M Costs	Not Included In Analysis
Land Costs	Not Included In Analysis
End of Life Replacement Costs	Not Included In Analysis

III. LOAD CURVES

A. Reinforce Kasson TR1 and Feeders






WEB021 Overload
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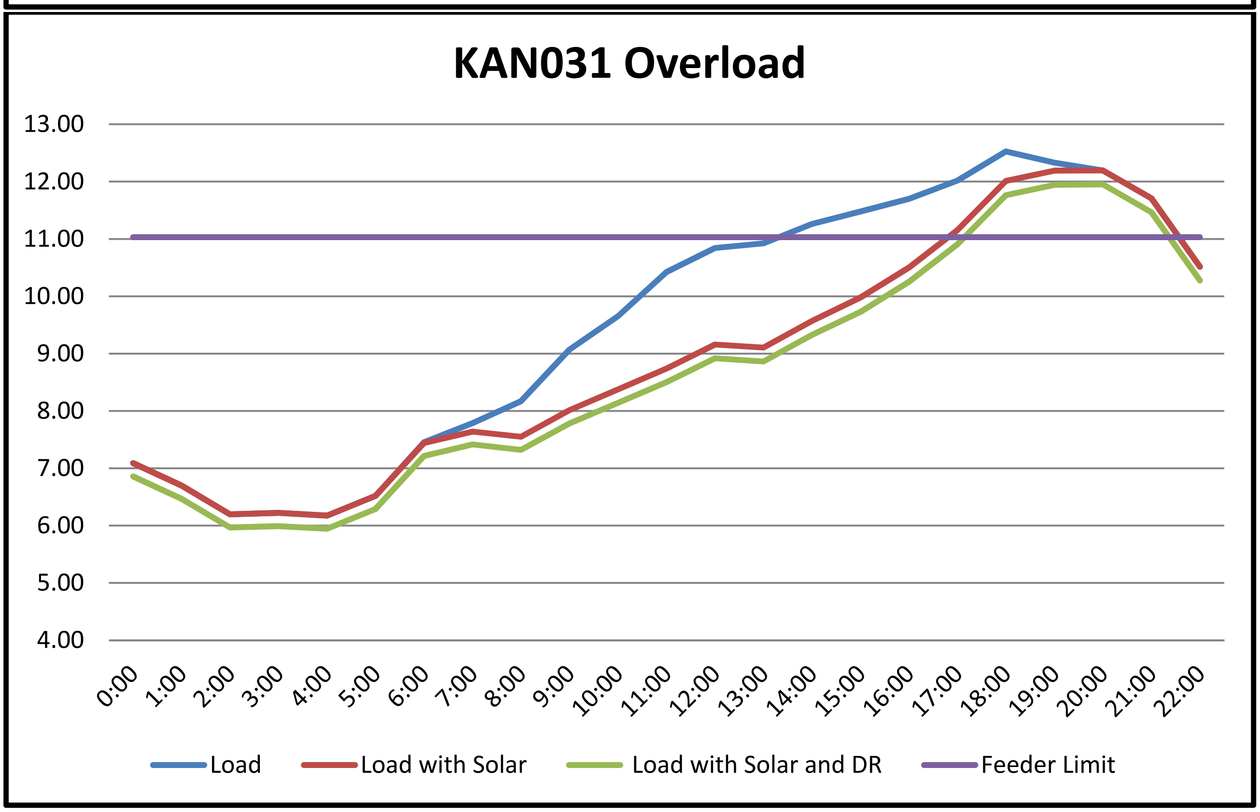
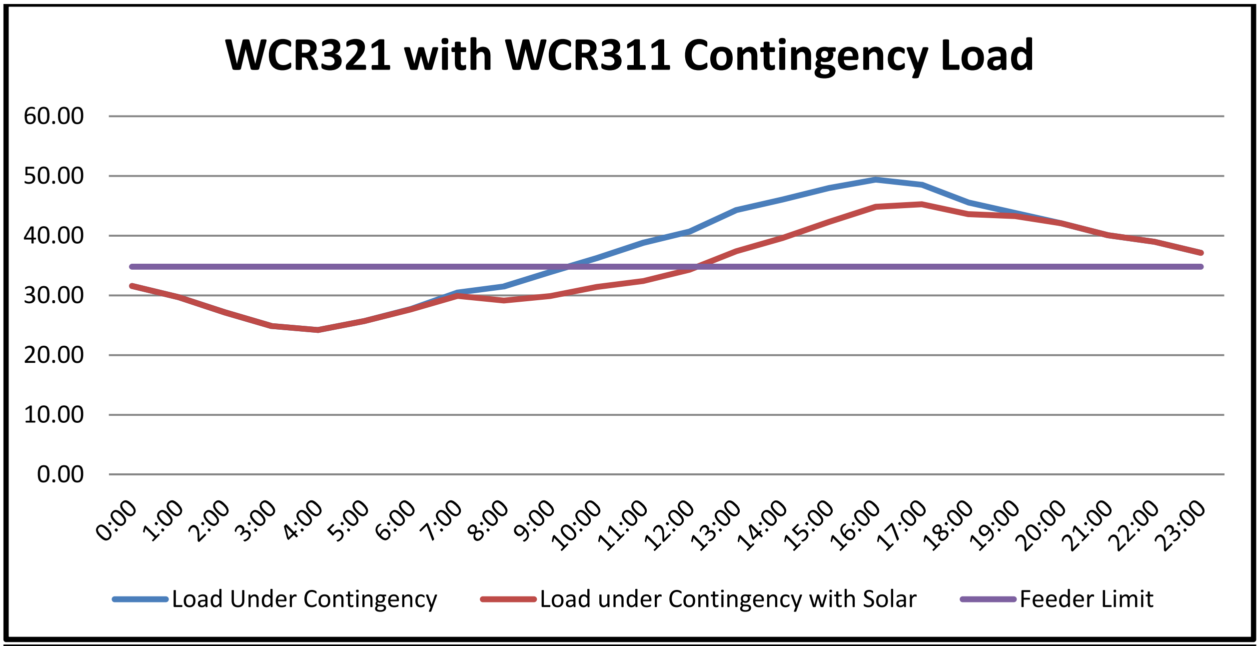
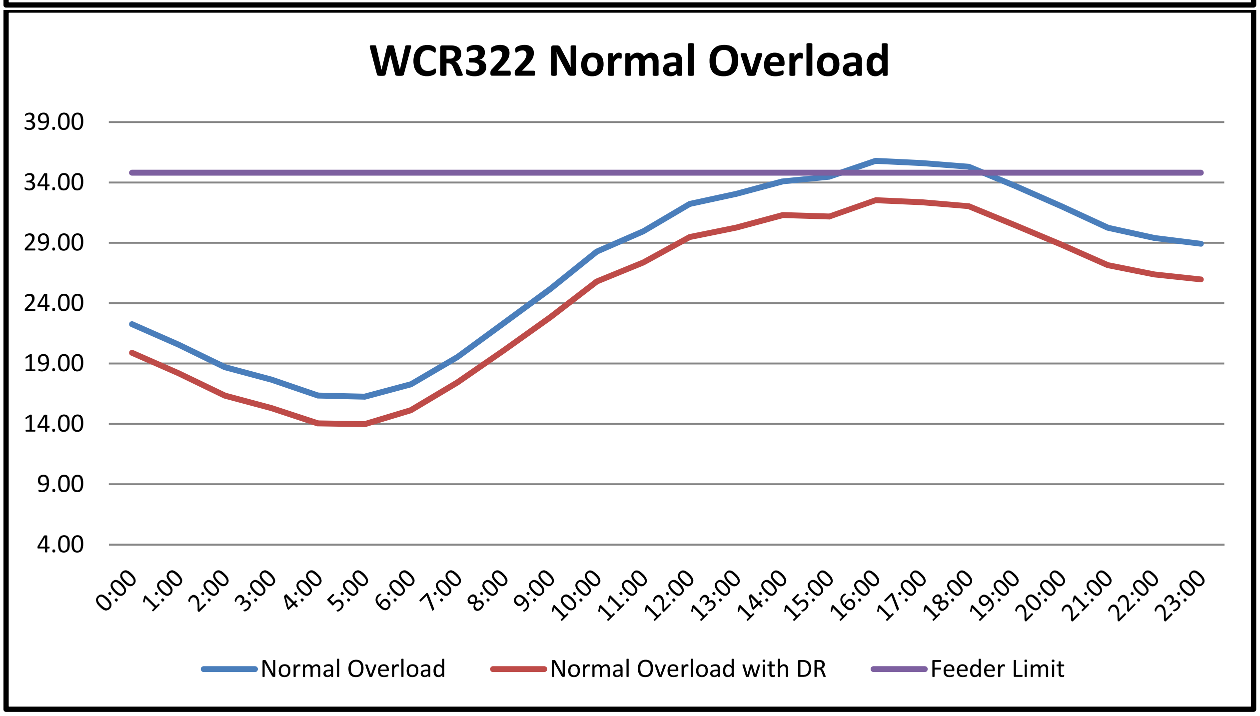
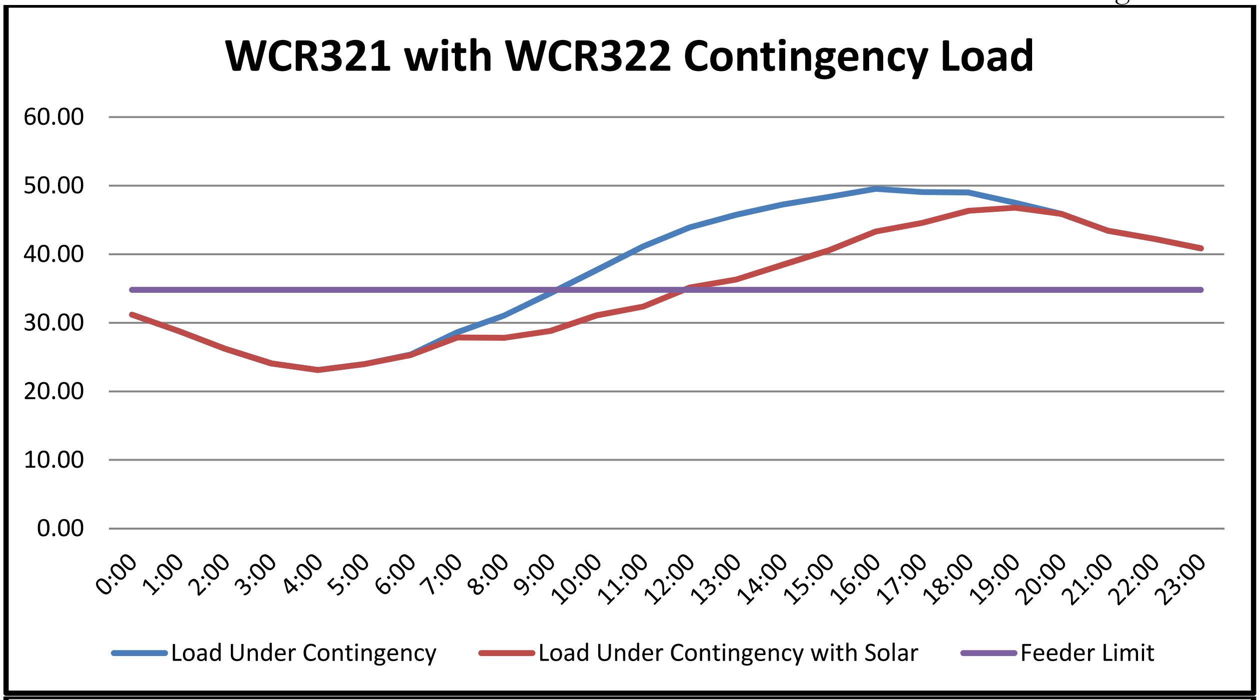
10.00
9.00
8.00
7.00
6.00
5.00
4.00
0:00
1:00
2:00
3:00
4:00
5:00
6:00
7:00
8:00
9:00
10:00
11:00
12:00
13:00
14:00
15:00
16:00
17:00
18:00
19:00
20:00
21:00
22:00
Load
Load with Solar
Load with Solar and DR
Feeder Limit

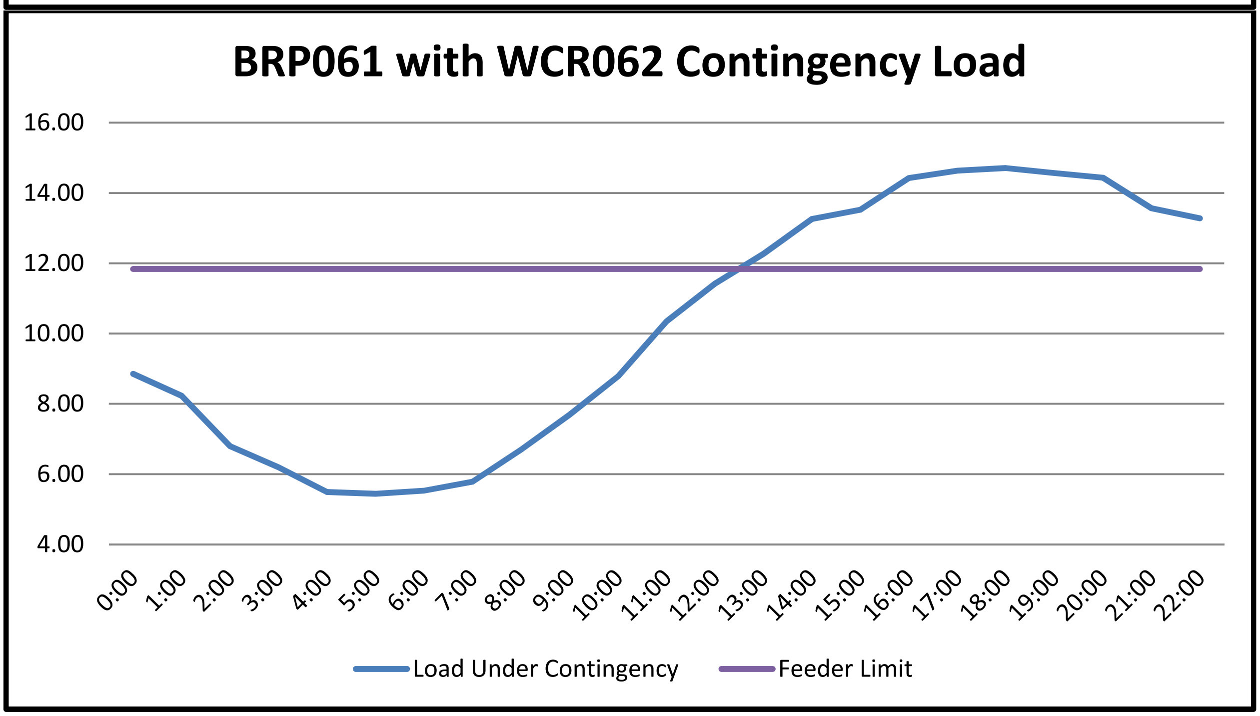

KAN031 Overload
13.00
12.00
11.00
10.00
9.00
8.00
7.00
6.00
5.00
4.00
0:00
1:00
2:00
3:00
4:00
5:00
6:00
7:00
8:00
9:00
10:00
11:00
12:00
13:00
14:00
15:00
16:00
17:00
18:00
19:00
20:00
21:00
22:00
Load
Load with Solar
Load with Solar and DR
Feeder Limit

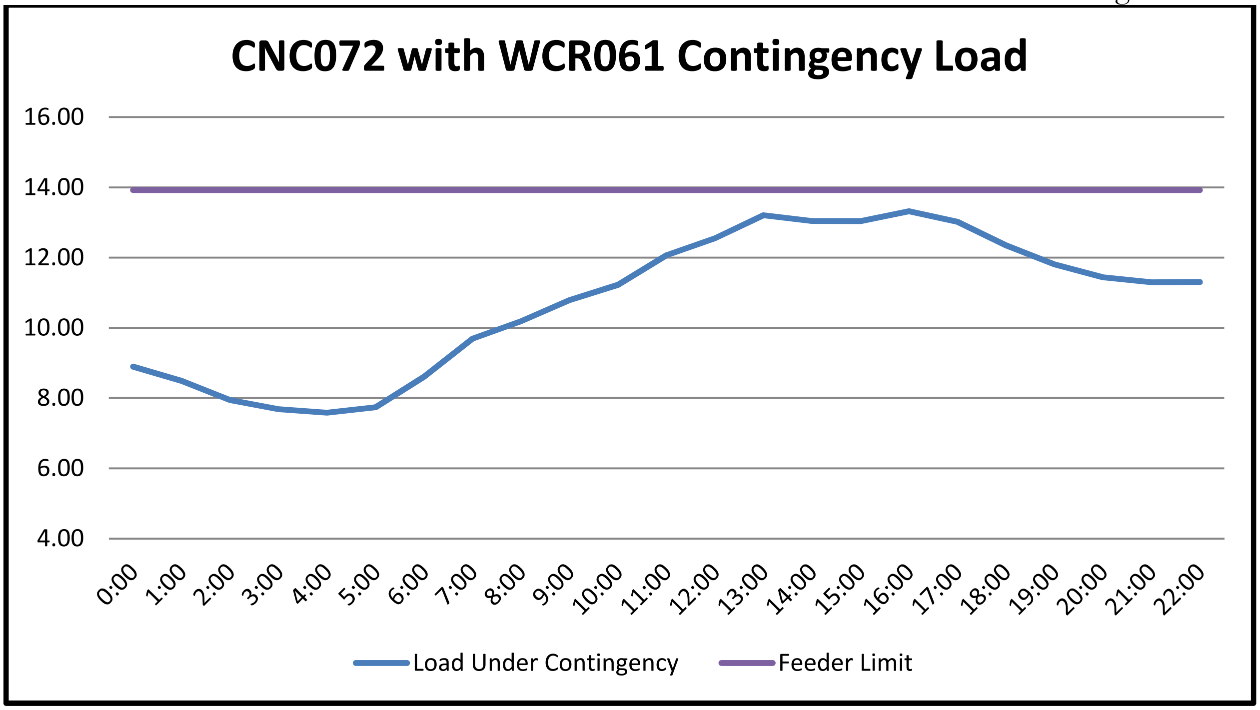
B. Install West Coon Rapids WCR TR

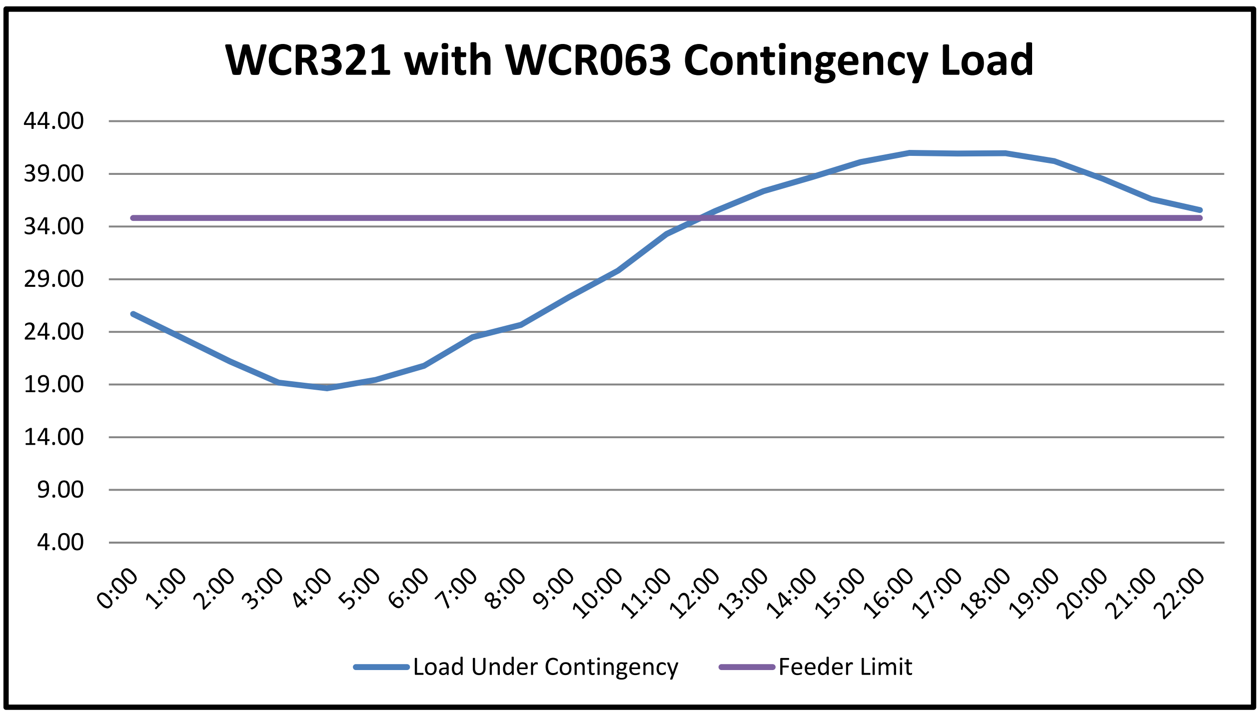




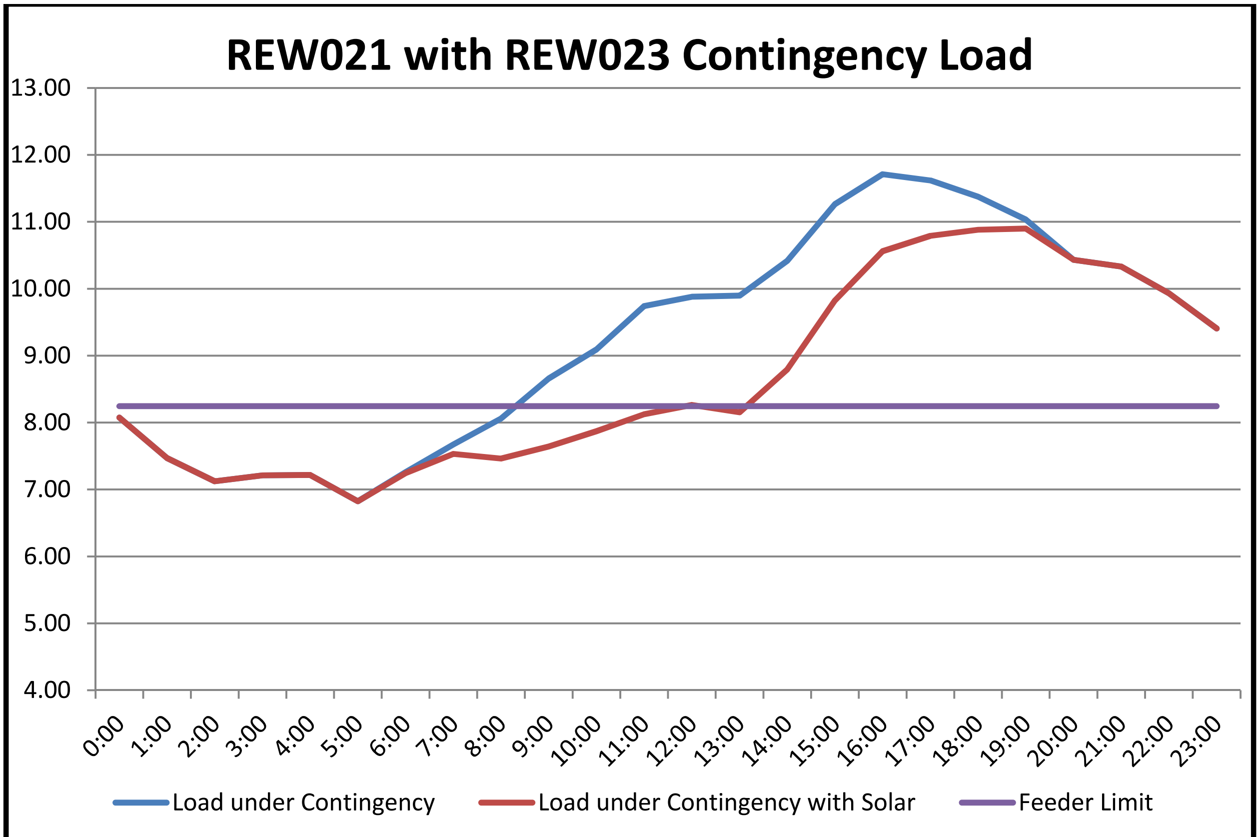

WCR321 with WCR322 Contingency Load
60.00
50.00
40.00
30.00
20.00
10.00
0.00
0:00
1:00
2:00
3:00
4:00
5:00
6:00
7:00
8:00
9:00
10:00
11:00
12:00
13:00
14:00
15:00
16:00
17:00
18:00
19:00
20:00
21:00
22:00
23:00
Load Under Contingency
Load Under Contingency with Solar
Feeder Limit

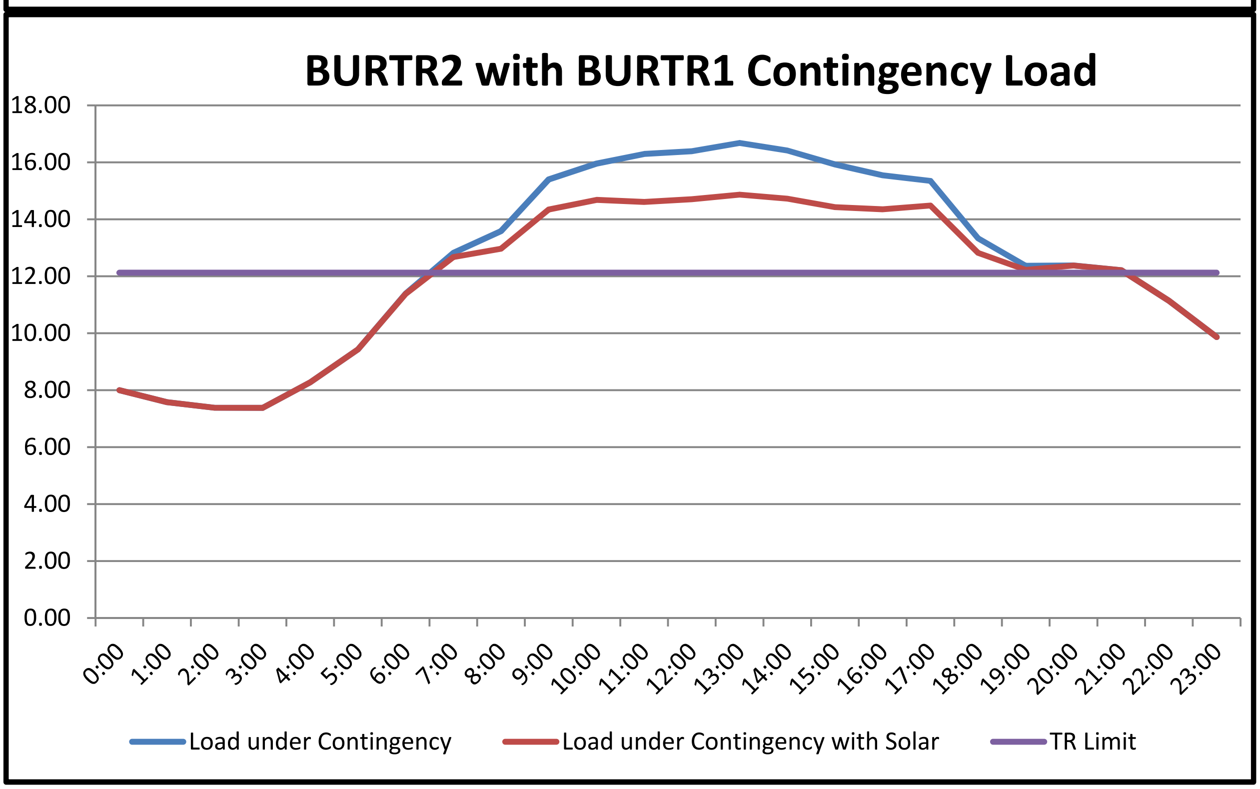

BRP061 with WCR062 Contingency Load
16.00
14.00
12.00
10.00
8.00
6.00
4.00
0:00
1:00
2:00
3:00
4:00
5:00
6:00
7:00
8:00
9:00
10:00
11:00
12:00
13:00
14:00
15:00
16:00
17:00
18:00
19:00
20:00
21:00
22:00
Load Under Contingency
Feeder Limit


CNC072 with WCR061 Contingency Load
16.00
14.00
12.00
10.00
8.00
6.00
4.00
0:00 1:00 2:00 3:00 4:00 5:00 6:00 7:00 8:00 9:00 10:00 11:00 12:00 13:00 14:00 15:00 16:00 17:00 18:00 19:00 20:00 21:00 22:00
Load Under Contingency
Feeder Limit

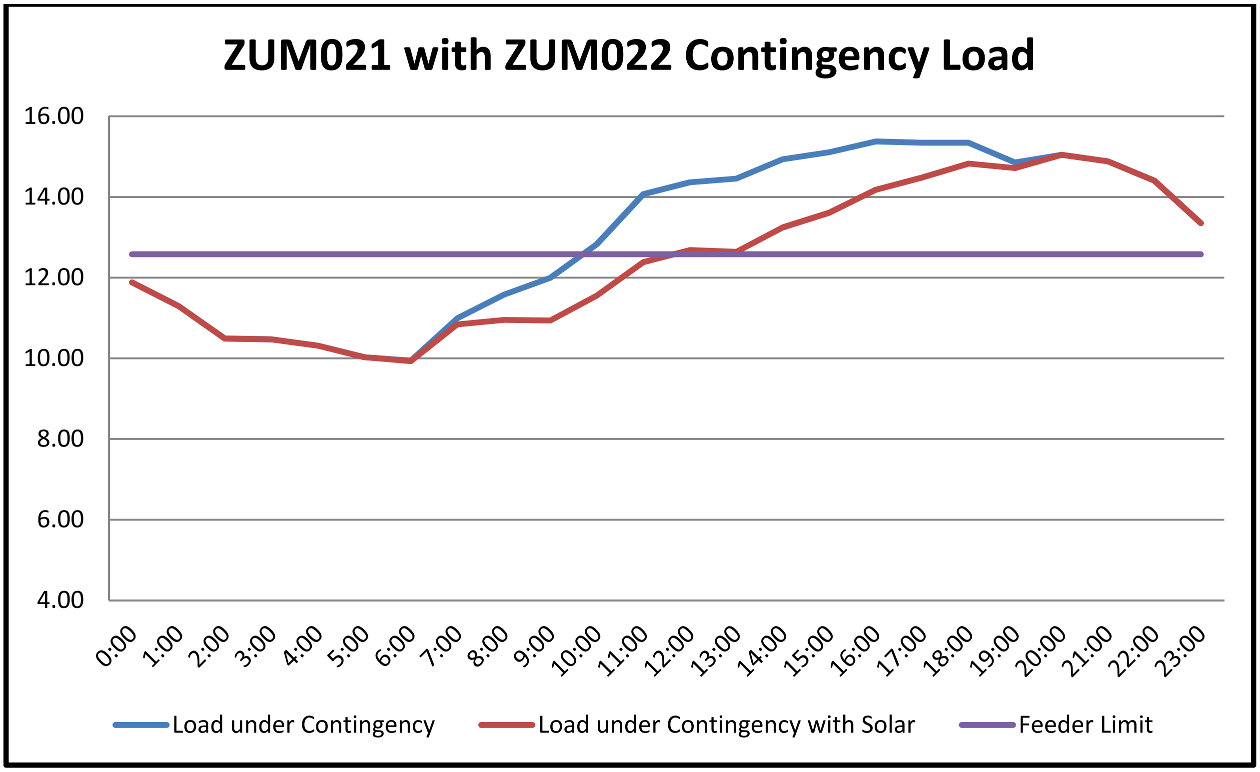

WCR321 with WCR063 Contingency Load
44.00
39.00
34.00
29.00
24.00
19.00
14.00
9.00
4.00
0:00 1:00 2:00 3:00 4:00 5:00 6:00 7:00 8:00 9:00 10:00 11:00 12:00 13:00 14:00 15:00 16:00 17:00 18:00 19:00 20:00 21:00 22:00
Load Under Contingency
Feeder Limit

C. Reinforce Burnside BUR TR2

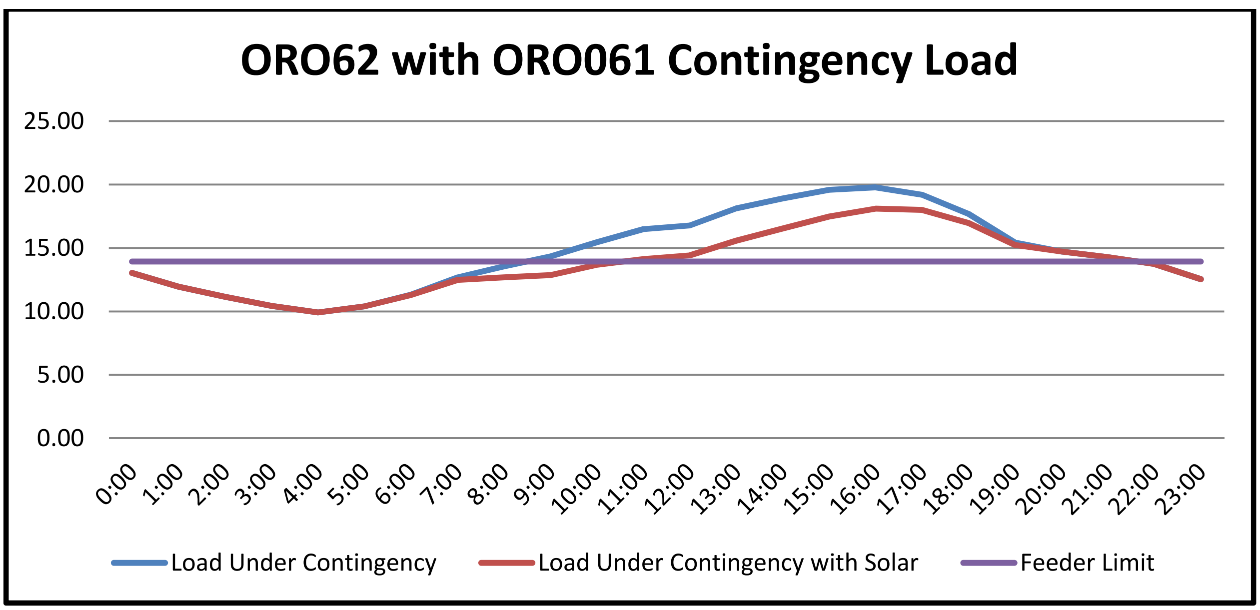


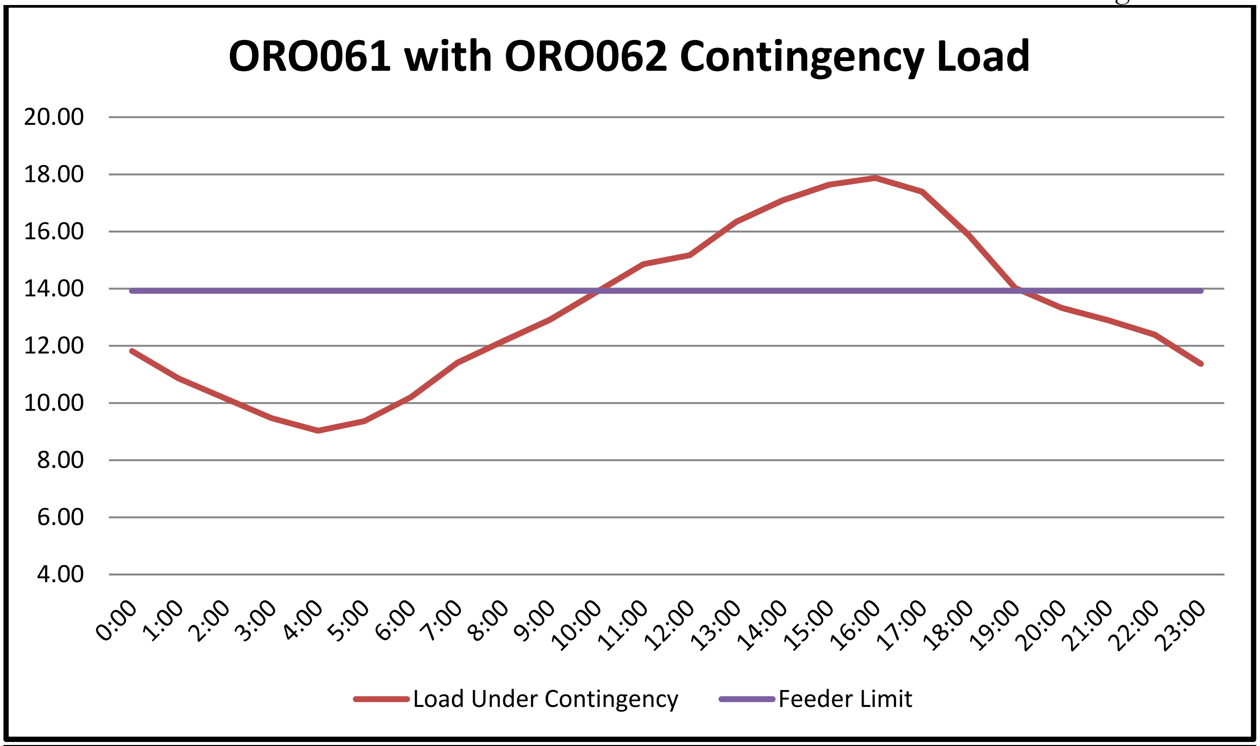


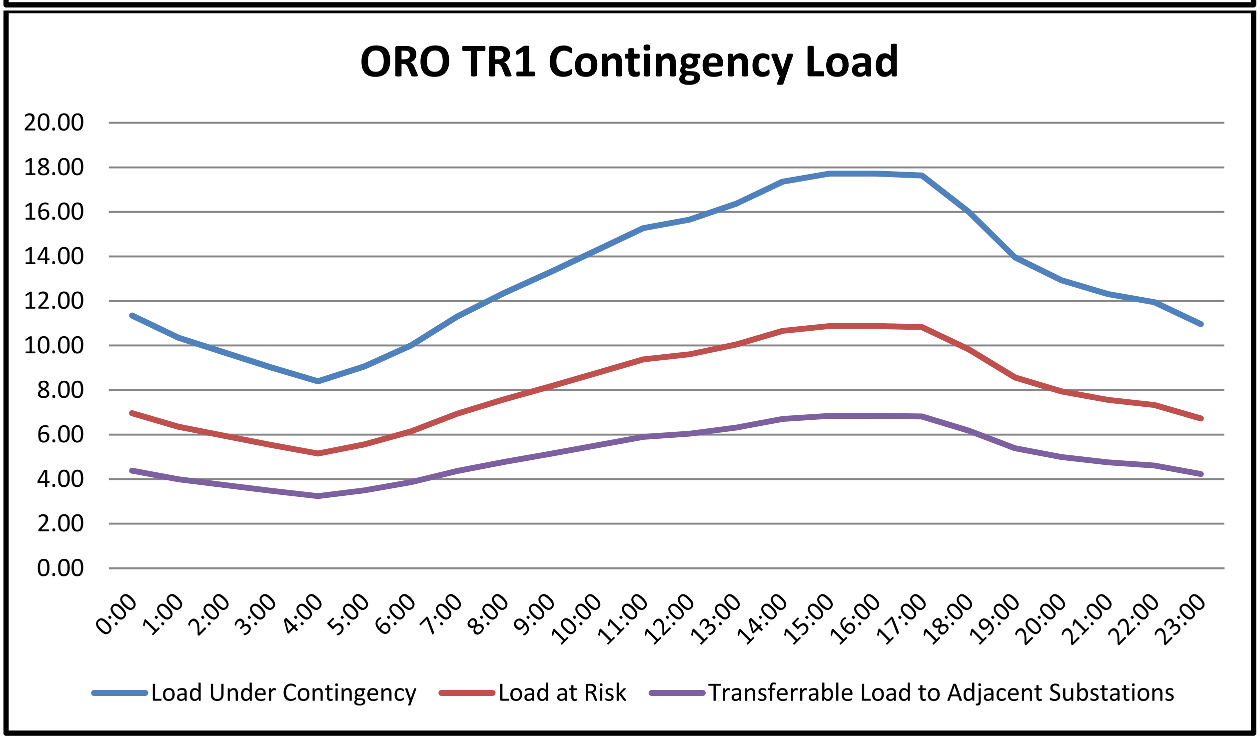
D. Install Zumbrota ZUM TR & Feeder



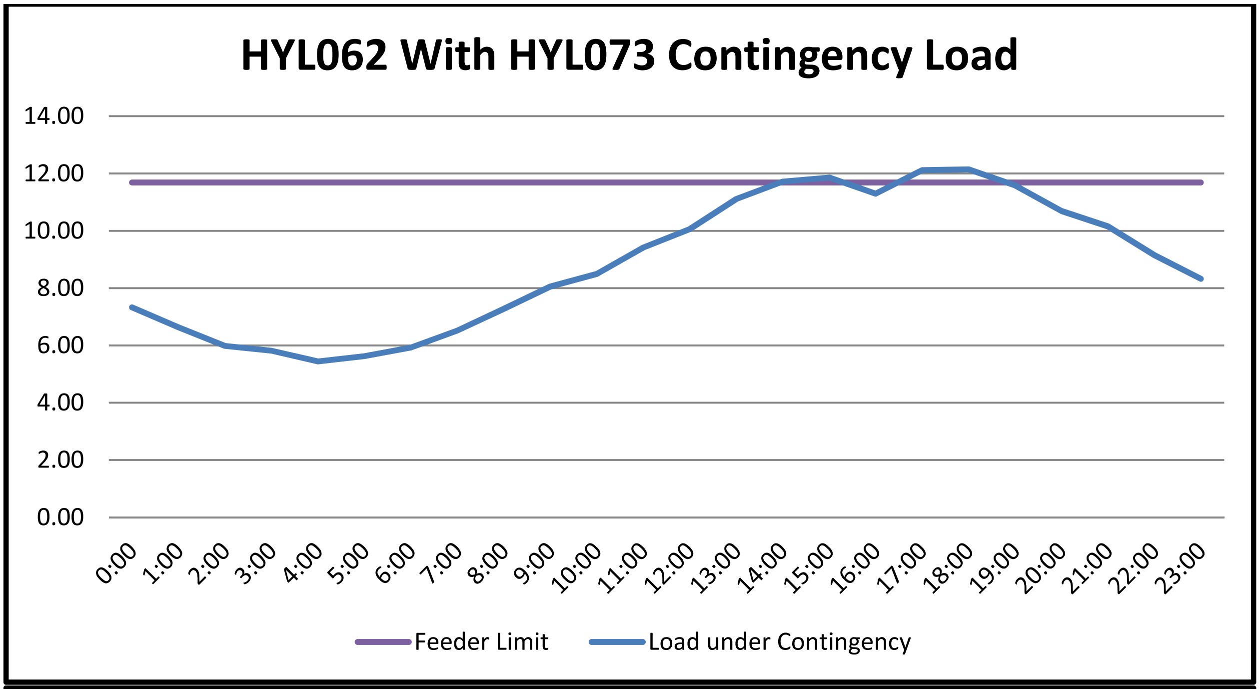
E. Install Orono ORO TR2 & Feeder

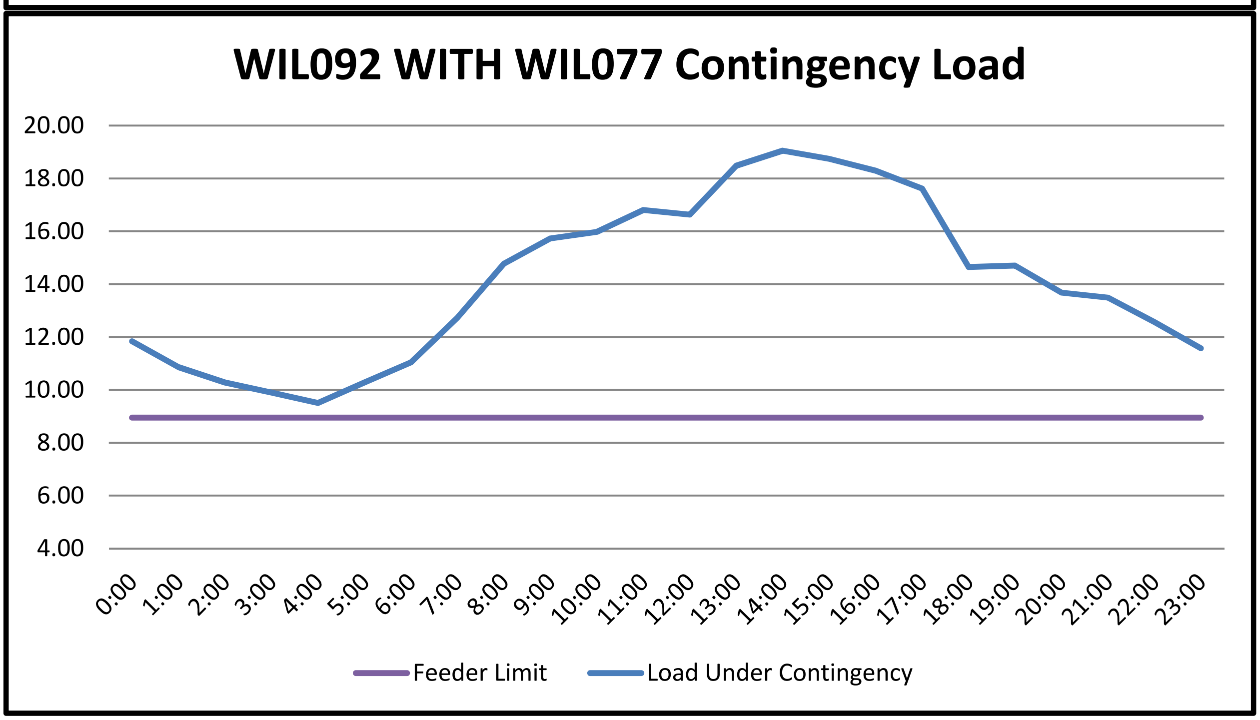


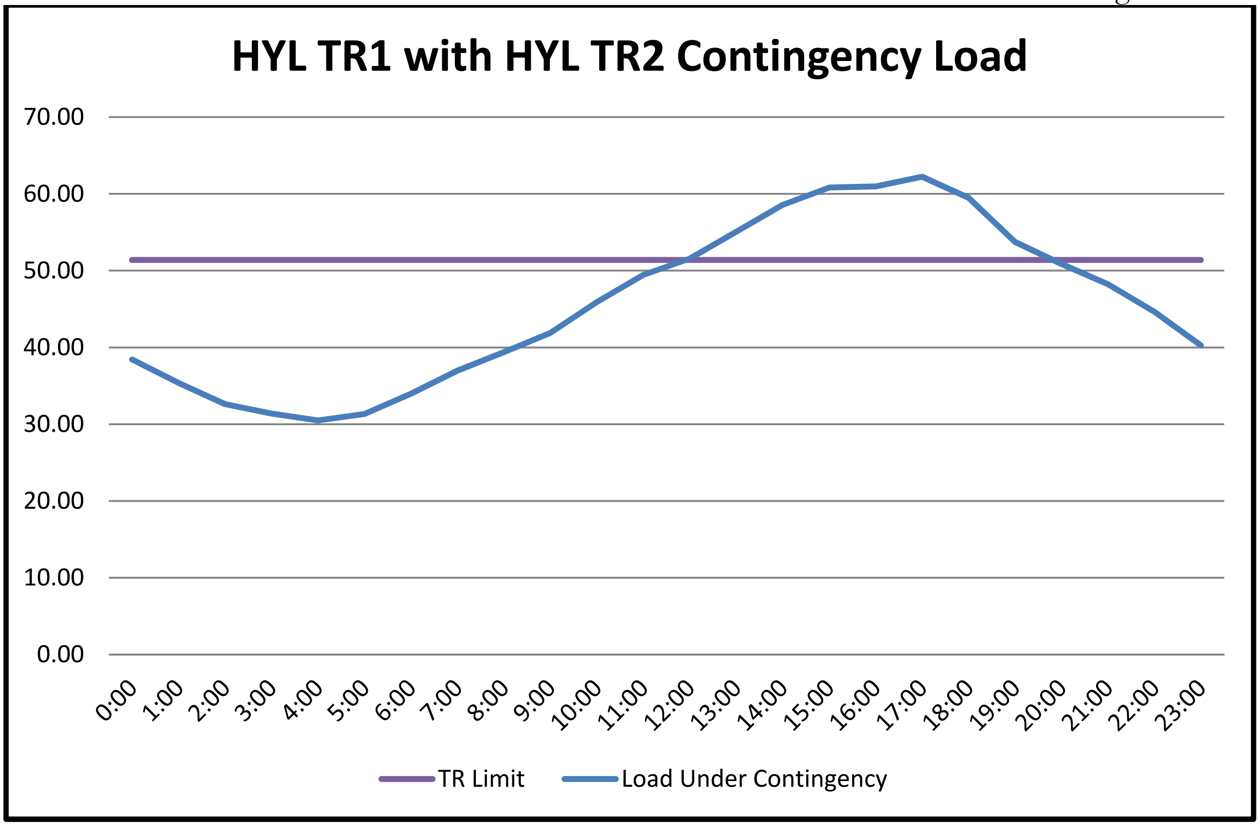

ORO061 with ORO062 Contingency Load
20.00
18.00
16.00
14.00
12.00
10.00
8.00
6.00
4.00
0:00
1:00
2:00
3:00
4:00
5:00
6:00
7:00
8:00
9:00
10:00
11:00
12:00
13:00
14:00
15:00
16:00
17:00
18:00
19:00
20:00
21:00
22:00
23:00
Load Under Contingency
Feeder Limit


ORO TR1 Contingency Load
20.00
18.00
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
0:00
1:00
2:00
3:00
4:00
5:00
6:00
7:00
8:00
9:00
10:00
11:00
12:00
13:00
14:00
15:00
16:00
17:00
18:00
19:00
20:00
21:00
22:00
23:00
Load Under Contingency
Load at Risk
Transferrable Load to Adjacent Substations

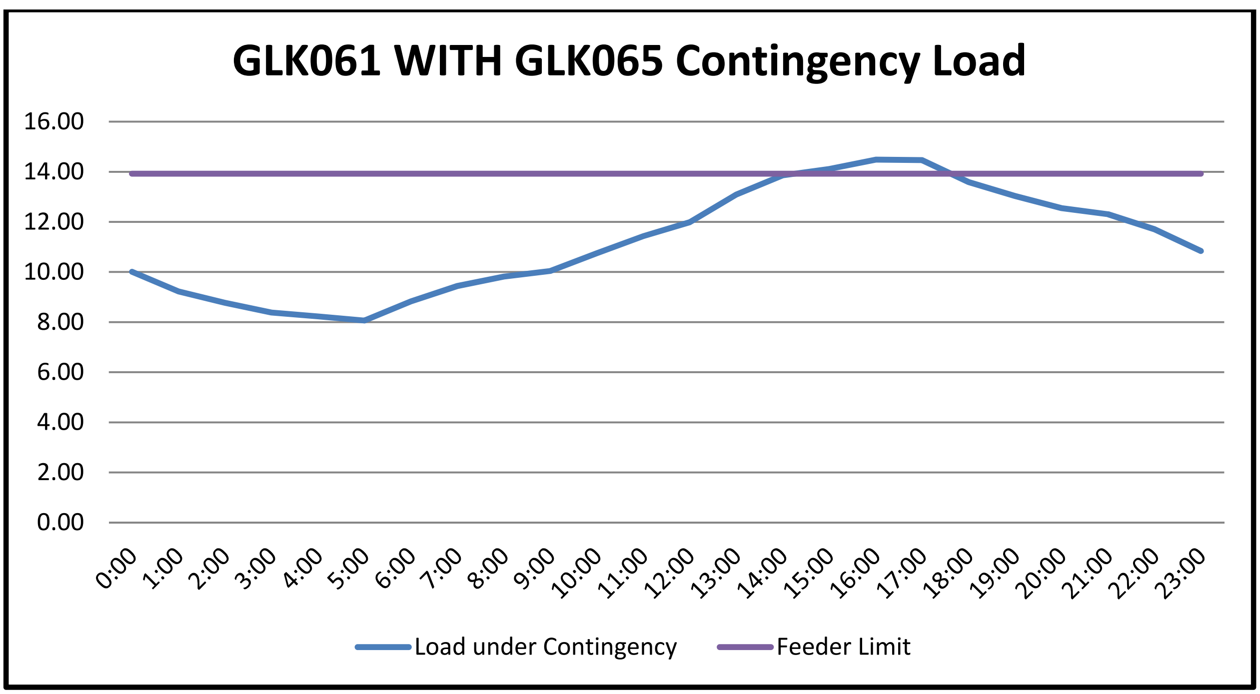
F. Install Hyland Lake HYL TR3 & Feeder

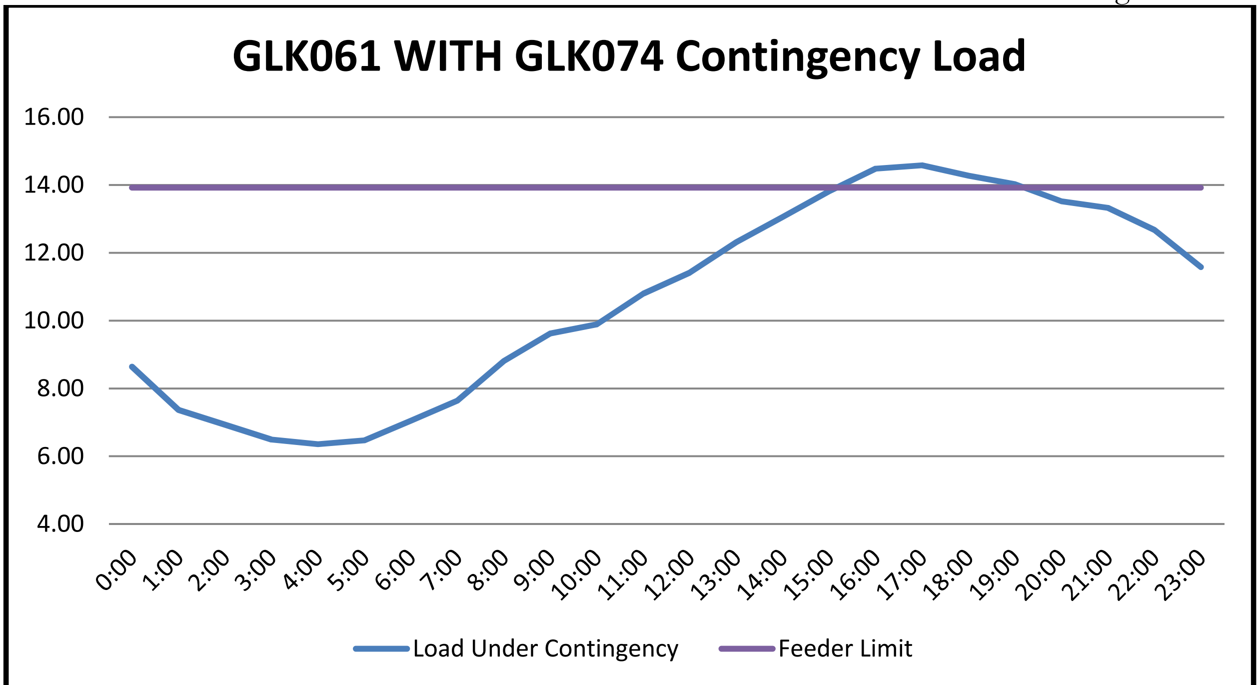


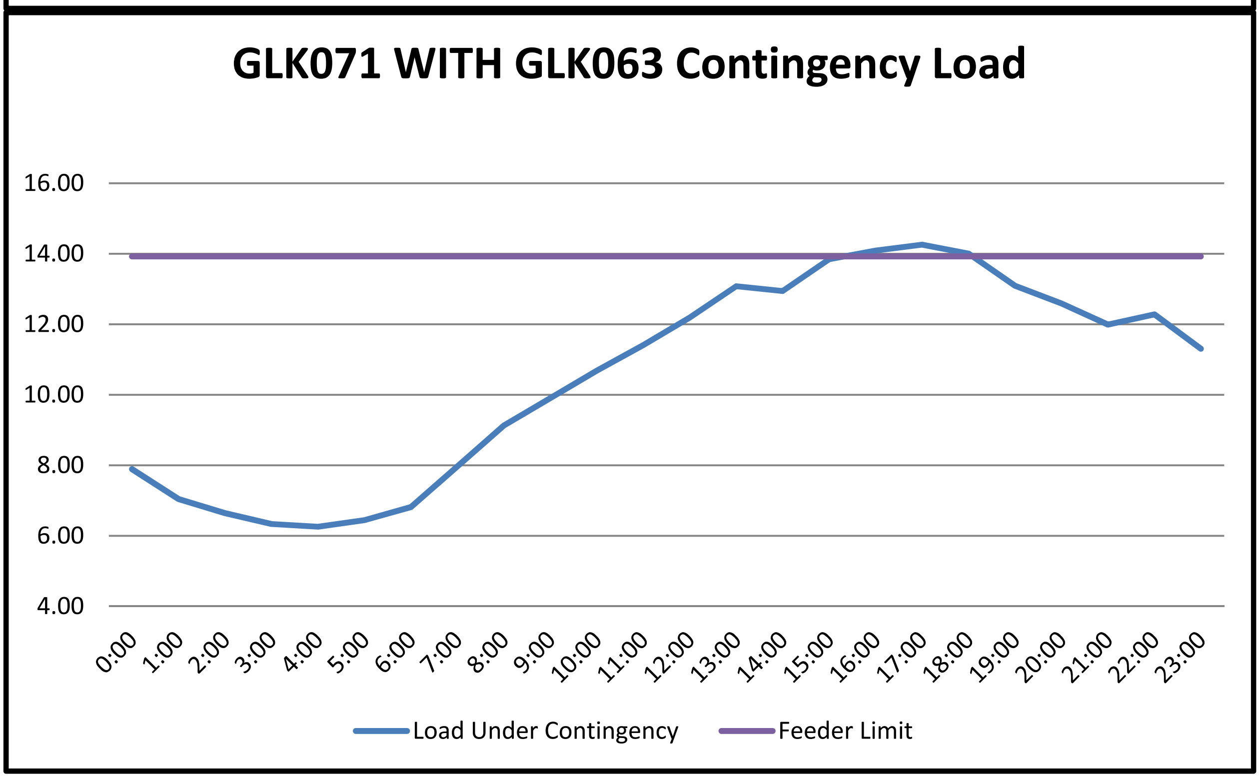


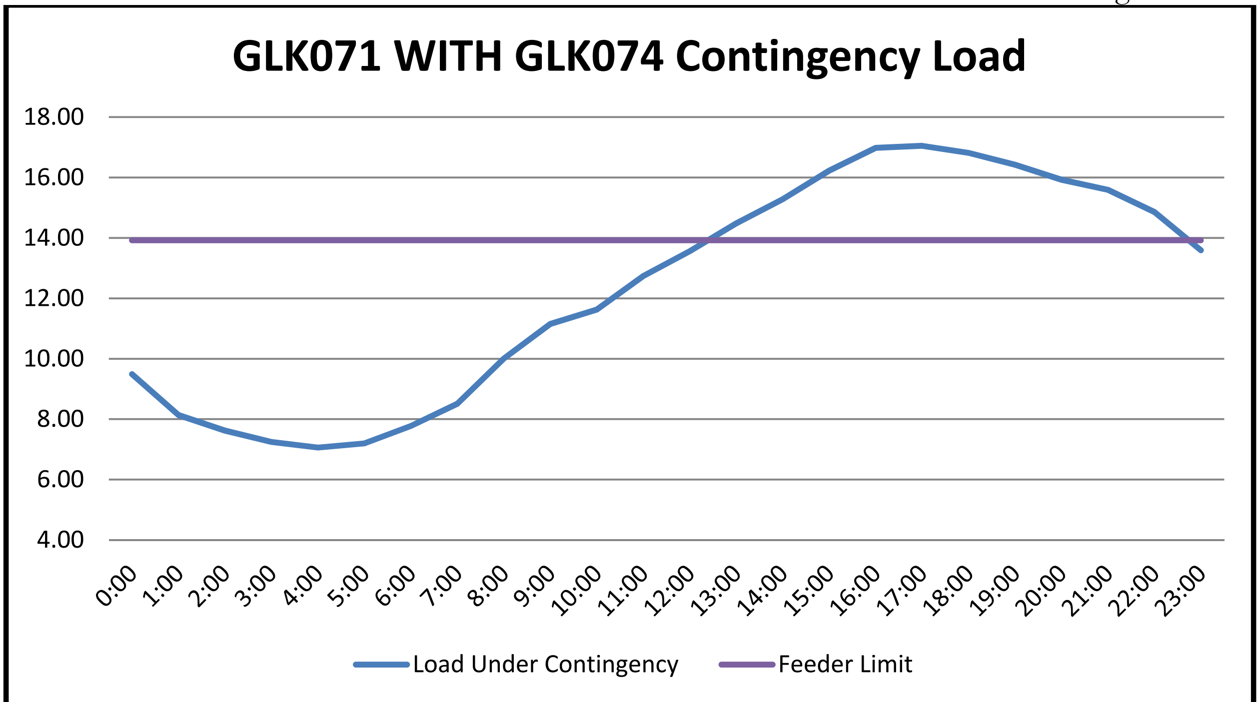


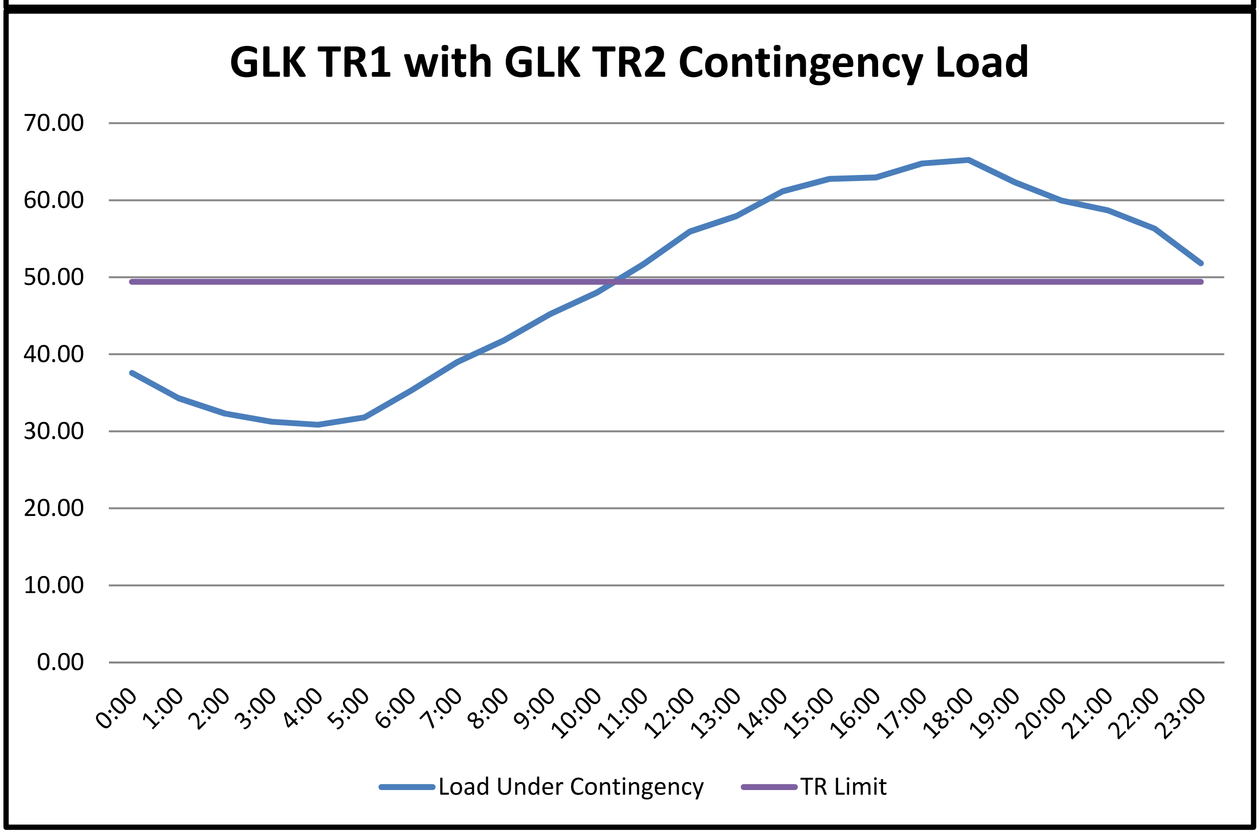
G. Install Goose Lake GLK TR3 & Feeders

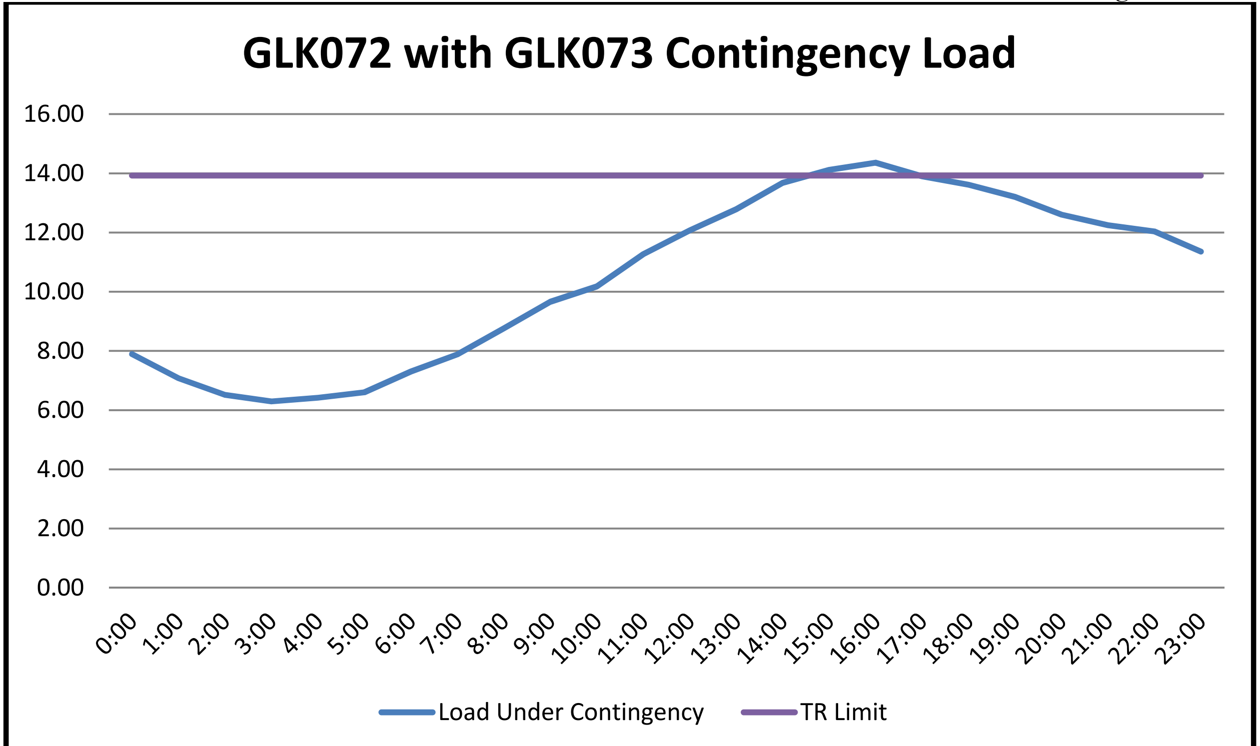


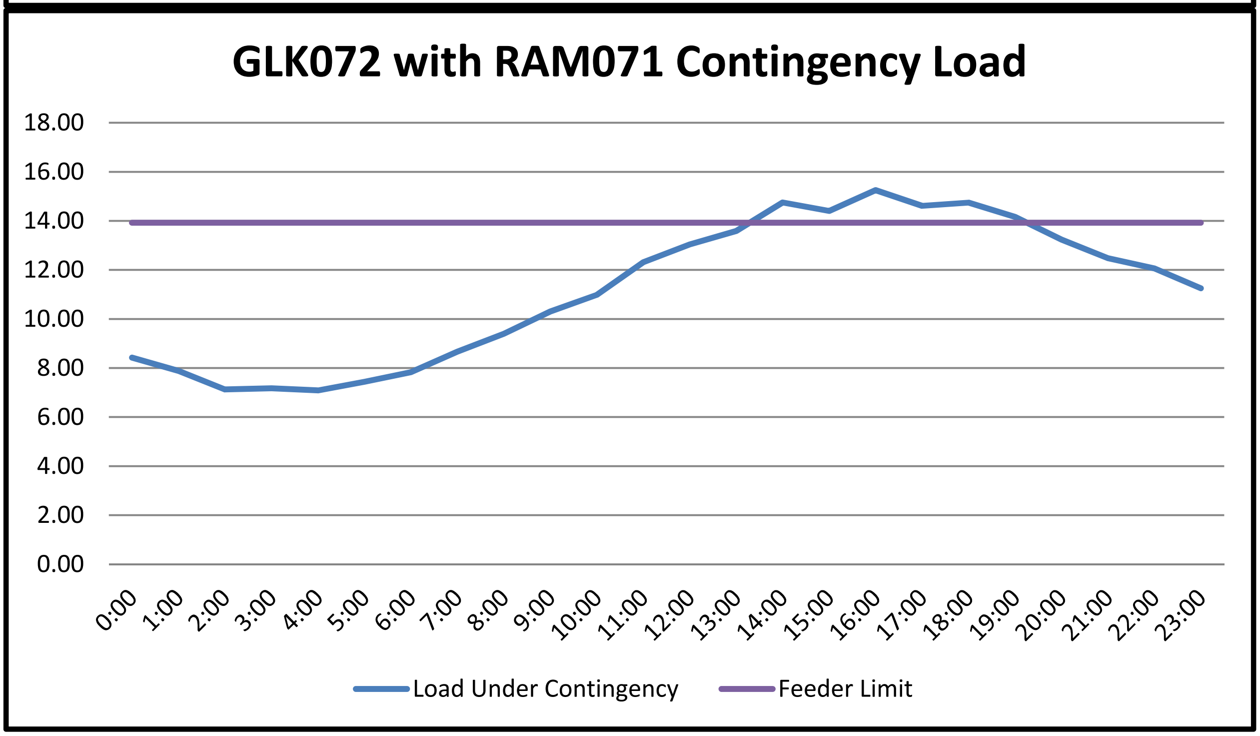

GLK061 WITH GLK074 Contingency Load
16.00
14.00
12.00
10.00
8.00
6.00
4.00
0:00
1:00
2:00
3:00
4:00
5:00
6:00
7:00
8:00
9:00
10:00
11:00
12:00
13:00
14:00
15:00
16:00
17:00
18:00
19:00
20:00
21:00
22:00
23:00
Load Under Contingency
Feeder Limit


GLK071 WITH GLK063 Contingency Load
16.00
14.00
12.00
10.00
8.00
6.00
4.00
0:00
1:00
2:00
3:00
4:00
5:00
6:00
7:00
8:00
9:00
10:00
11:00
12:00
13:00
14:00
15:00
16:00
17:00
18:00
19:00
20:00
21:00
22:00
23:00
Load Under Contingency
Feeder Limit

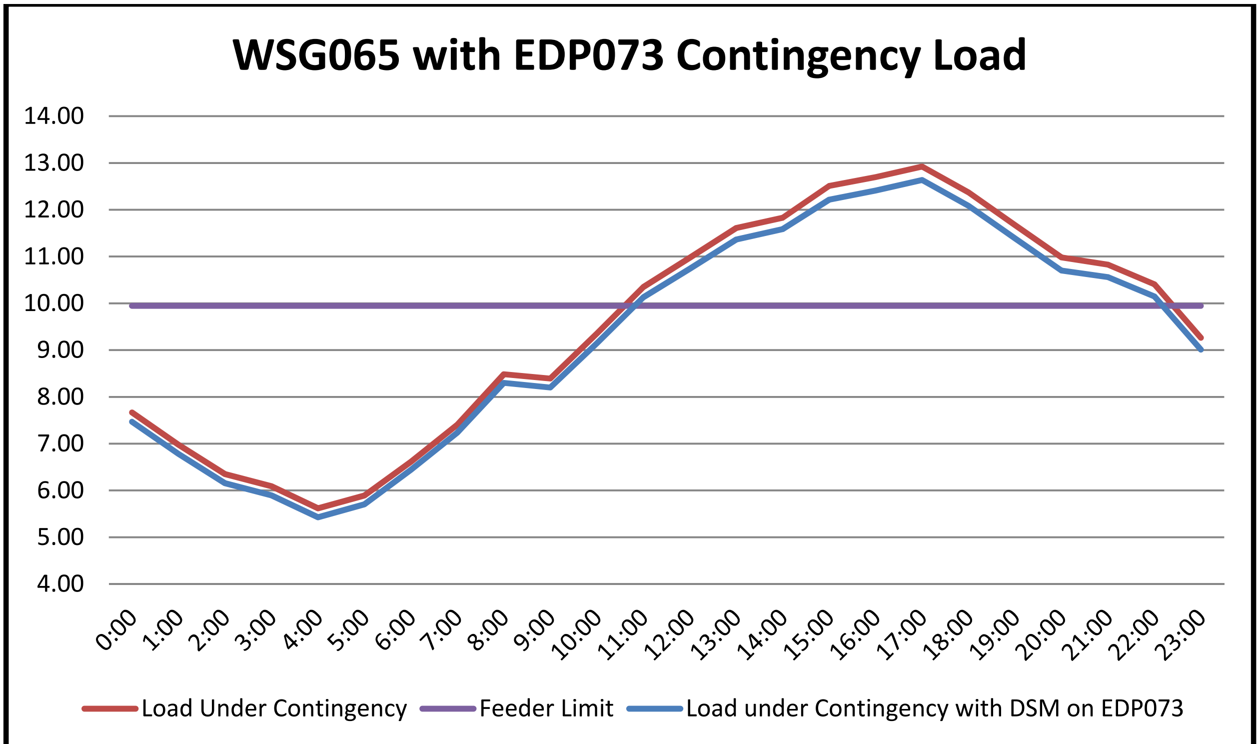

GLK071 WITH GLK074 Contingency Load
18.00
16.00
14.00
12.00
10.00
8.00
6.00
4.00
0:00 1:00 2:00 3:00 4:00 5:00 6:00 7:00 8:00 9:00 10:00 11:00 12:00 13:00 14:00 15:00 16:00 17:00 18:00 19:00 20:00 21:00 22:00 23:00
Load Under Contingency
Feeder Limit

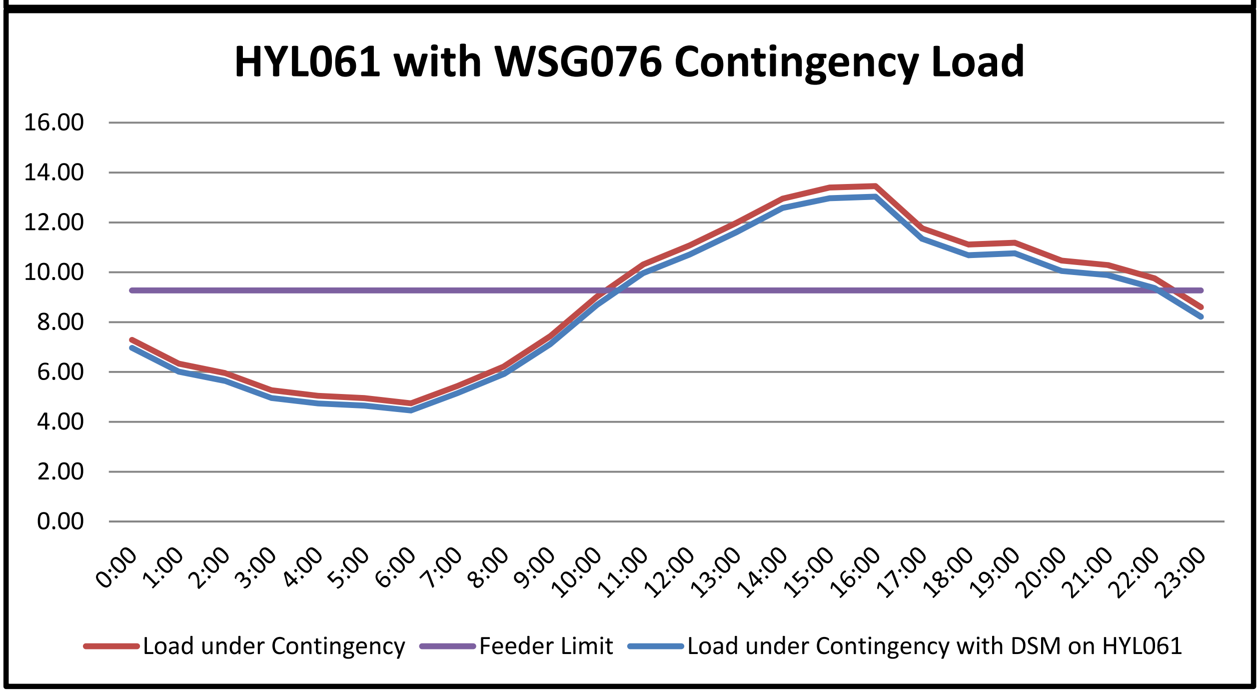

GLK TR1 with GLK TR2 Contingency Load
70.00
60.00
50.00
40.00
30.00
20.00
10.00
0.00
0:00 1:00 2:00 3:00 4:00 5:00 6:00 7:00 8:00 9:00 10:00 11:00 12:00 13:00 14:00 15:00 16:00 17:00 18:00 19:00 20:00 21:00 22:00 23:00
Load Under Contingency
TR Limit

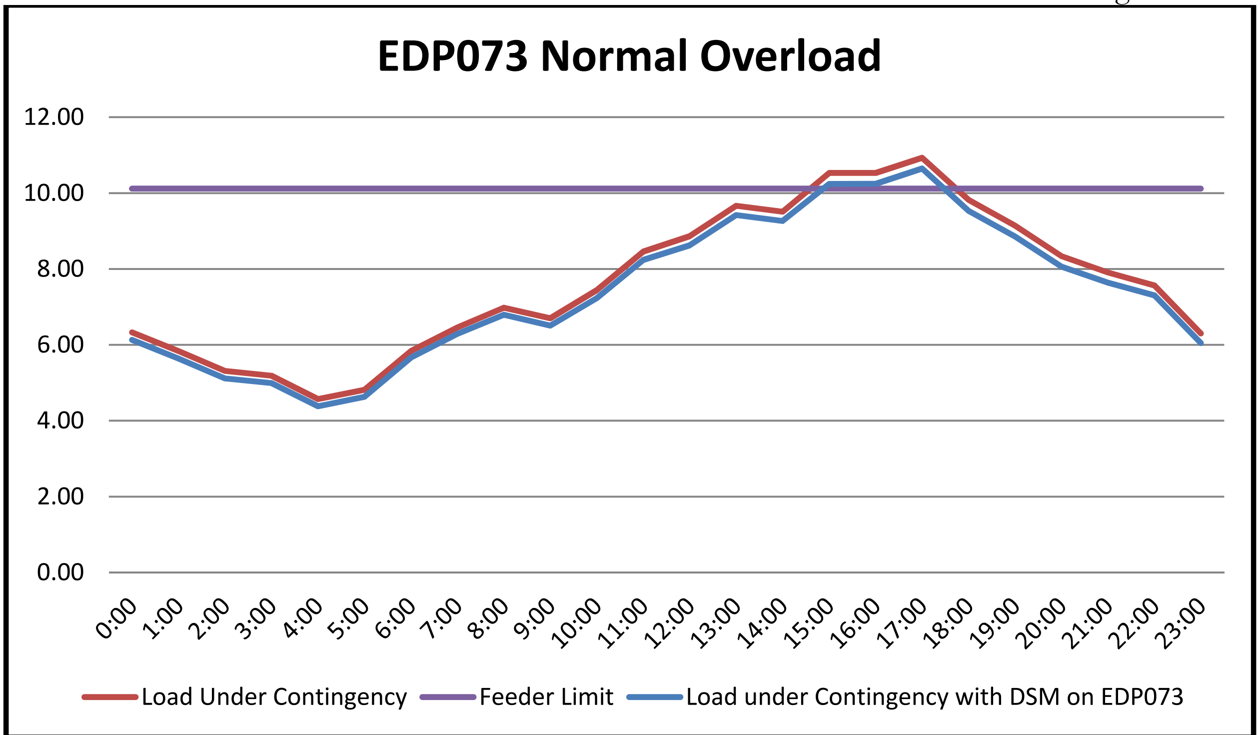

GLK072 with GLK073 Contingency Load
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
0:00 1:00 2:00 3:00 4:00 5:00 6:00 7:00 8:00 9:00 10:00 11:00 12:00 13:00 14:00 15:00 16:00 17:00 18:00 19:00 20:00 21:00 22:00 23:00
Load Under Contingency
TR Limit

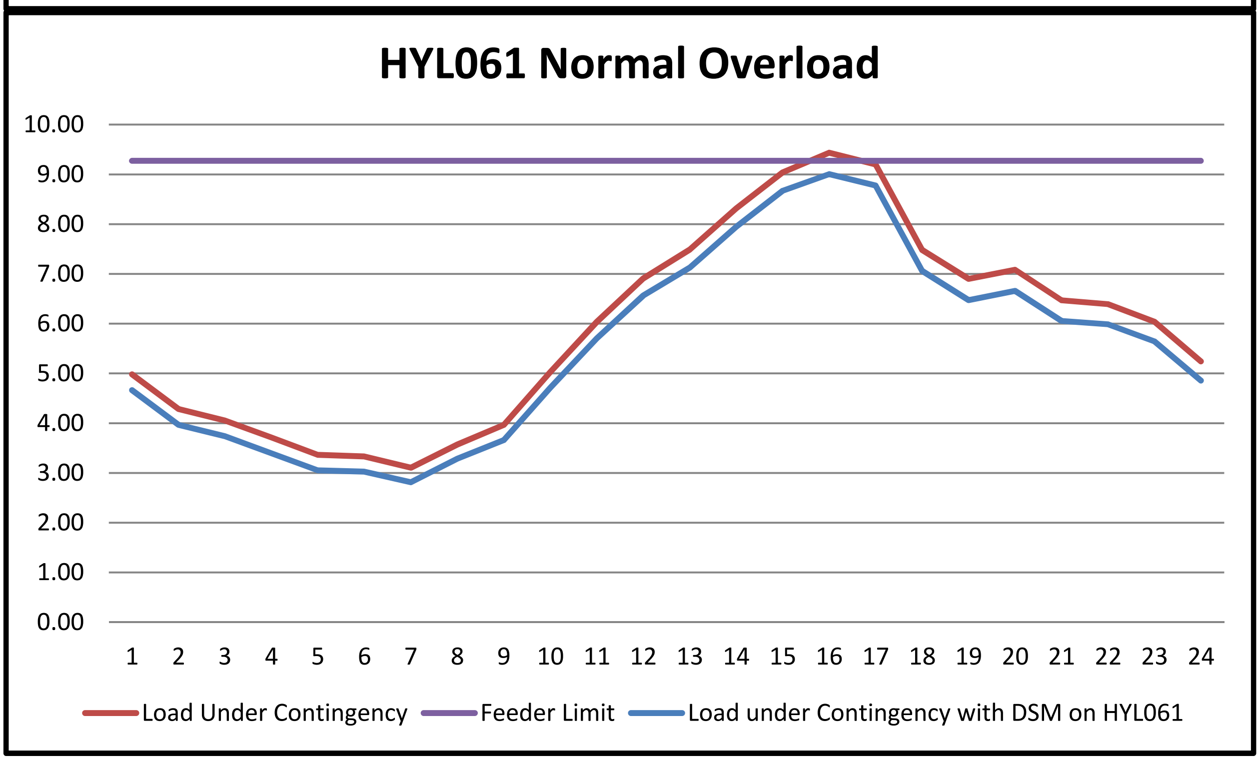

GLK072 with RAM071 Contingency Load
18.00
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
0:00 1:00 2:00 3:00 4:00 5:00 6:00 7:00 8:00 9:00 10:00 11:00 12:00 13:00 14:00 15:00 16:00 17:00 18:00 19:00 20:00 21:00 22:00 23:00
Load Under Contingency
Feeder Limit

H. Install New Viking VKG Feeder






EDP073 Normal Overload
12.00
10.00
8.00
6.00
4.00
2.00
0.00
0:00 1:00 2:00 3:00 4:00 5:00 6:00 7:00 8:00 9:00 10:00 11:00 12:00 13:00 14:00 15:00 16:00 17:00 18:00 19:00 20:00 21:00 22:00 23:00
Load Under Contingency
Feeder Limit
Load under Contingency with DSM on EDP073


HYL061 Normal Overload
10.00
9.00
8.00
7.00
6.00
5.00
4.00
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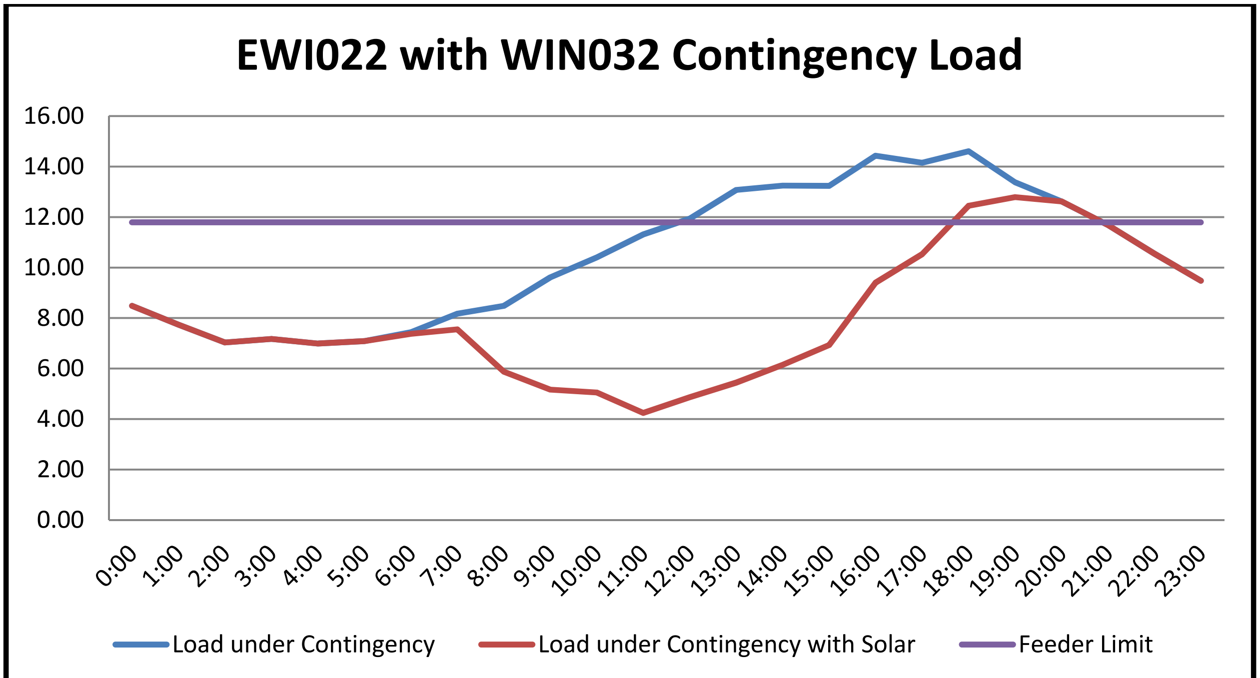
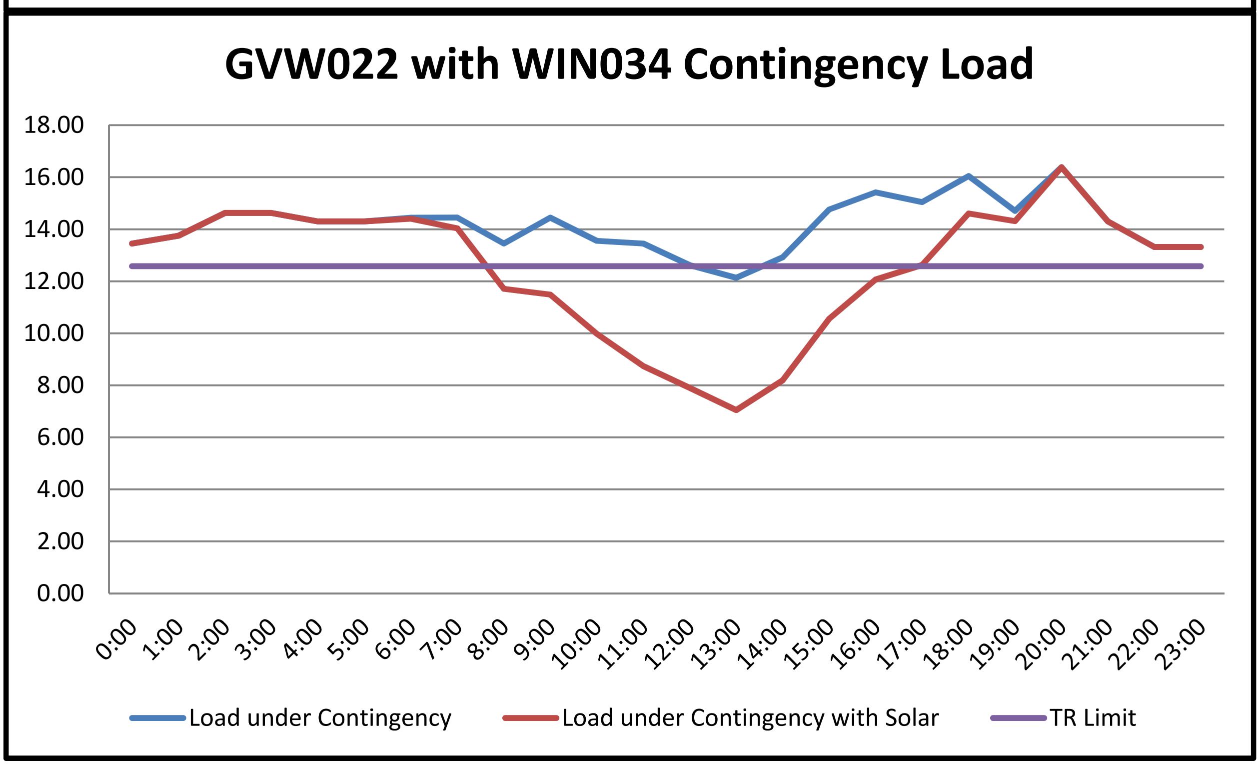
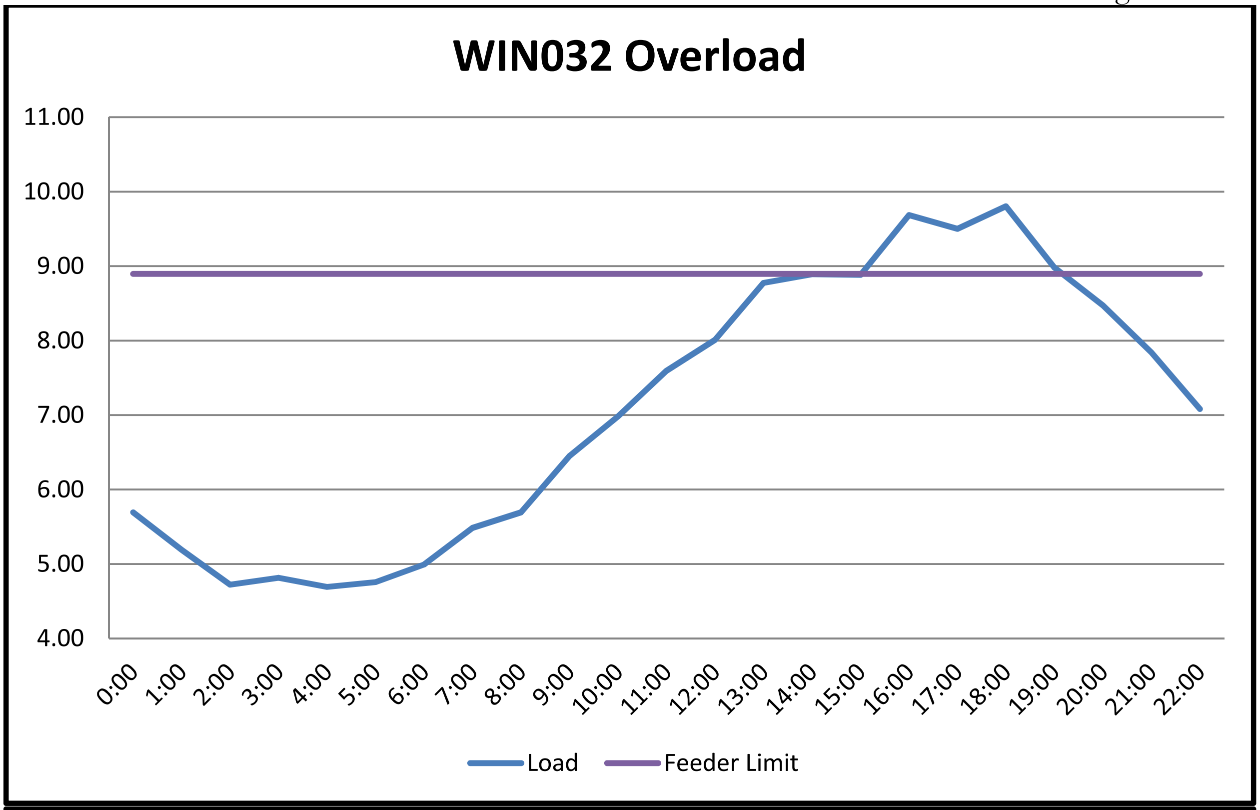
Load Under Contingency
Feeder Limit
Load under Contingency with DSM on HYL061

I. Install East Winona EWI TR2 & Feeder



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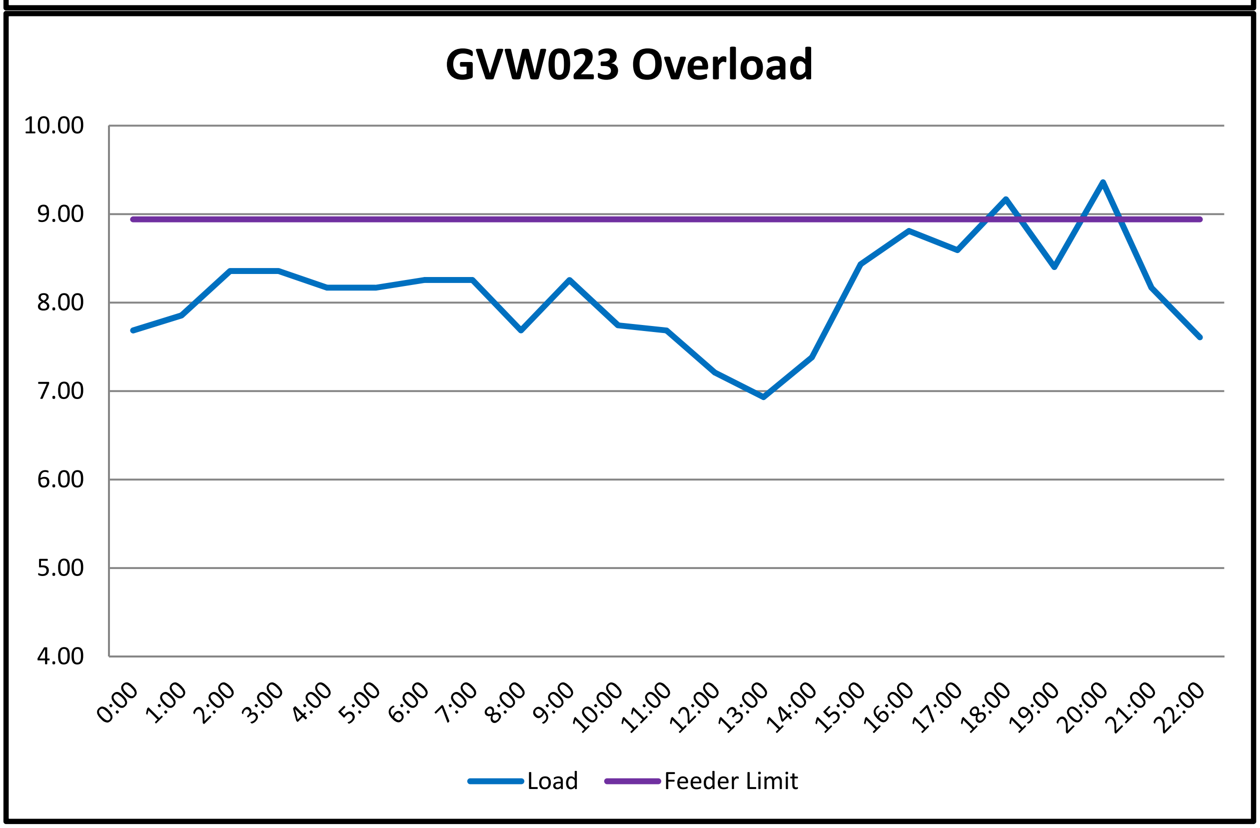
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Load
Feeder Limit

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators	))))	**Docket No. RM18-9-000**

DATA REQUEST COMMENTS OF THE
MIDCONTINENT INDEPENDENT SYSTEM OPERATOR, INC.

The Midcontinent Independent System Operator, Inc. ("MISO") submits these comments in response to the data request issued by the Federal Energy Regulatory Commission ("Commission") in the above-captioned docket on September 5, 2019 ("Data Request"). On November 17, 2016, the Commission issued a Notice of Proposed Rulemaking concerning Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators ("NOPR").[1] On February 15, 2018, the Commission announced its intention to explore the NOPR's proposed distributed energy resources ("DER") aggregation reforms. The Commission conducted a technical conference on April 10 and 11, 2018 to discuss the status of DER rules and explore potential reforms. Following the technical conference and the Commission's review of comments submitted in response to the NOPR, the Commission issued the Data Request seeking information on Regional Transmission Organizations ("RTO") and Independent System Operator ("ISO") policies and procedures that affect the interconnection of DERs.

[1] *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 157 FERC 61,121 (2016).

I. INTRODUCTION

MISO appreciates the opportunity to provide information about the rules pertaining to DER aggregators under MISO's currently-effective Tariff[2] and business practices. Generally, MISO supports efforts to remove barriers and better accommodate the participation of DER aggregations in MISO markets. However, there is much work to be done to accommodate the unique characteristics of DER units. As MISO noted in our comments filed in this docket, the MISO region currently does not have a high volume of DER installations (other than demand response resources) and MISO does not anticipate significant penetration levels in the near future.[3] DERs typically connect to distribution facilities and are subject to the rules of the directly connected local distribution provider ("Host Distribution Provider") rather than the MISO Tariff. MISO's historic involvement with distribution-level interconnections largely has been limited to coordinating with the Host Distribution Provider where MISO is identified as an affected system.

MISO's interconnection rules would apply to requests to connect directly to a facility that provides Wholesale Distribution Service ("WDS Facility") because such facilities are part of the MISO Transmission System for purposes of interconnection. To date, however, MISO has not received nor processed a request from a DER to interconnect to such a facility. Therefore, while MISO has complied with the Data Request by providing information about how MISO's existing interconnection rules would apply to DERs, the application of current rules to DERs remains untested in practice and MISO's responses consequently are to some degree hypothetical.

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[2] MISO Open Access Transmission, Energy, and Operating Reserve Markets Tariff ("Tariff").

[3] Comments of the Midcontinent Independent System Operator, Inc. (filed June 26, 2018), Docket No. RM18-9-000 ("MISO Comments") at 2.

MISO is currently working with the Organization of MISO States ("OMS") and other MISO stakeholders to develop a DER participation model that accounts for the distinctive characteristics of the MISO region and promotes reliability on a least cost basis. Such a model likely will require carefully-considered adjustments to MISO's interconnection rules in order to address the unique challenges presented by DERs, such as defining a permissible geographic scope, refining study processes to account for changes to aggregations, and enhancing coordination procedures with the diverse distribution providers in the MISO region. MISO looks forward to developing regionally appropriate rules in close coordination with the Commission and MISO stakeholders. MISO also reiterates its request that the Commission's Final Rule provide more guidance as to the desired role of the distribution provider and latitude to RTOs and ISOs, and refrain from broad implementation of prescriptive DER requirements.

II. RESPONSES TO DATA REQUESTS

MISO provides the following response to each of the Commission's data requests below.

1. Under your RTO's/ISO's existing rules for small generator interconnection, if a DER seeks to participate in wholesale markets and plans to interconnect at the distribution level, please describe the step-by-step process by which that resource would interconnect to the system.

Attachment X of the MISO Tariff contains a single Generator Interconnection Procedure ("GIP") and Generator Interconnection Agreement ("GIA") for Interconnection Requests of all sizes rather than separate procedures for interconnecting small and large projects. Therefore, the process described in this Response is the same process applicable to all Generating Facilities interconnected to the MISO Transmission System. The process that a DER connected to distribution facilities must follow to inject electricity into the Transmission System participate in MISO wholesale markets varies depending on the characteristics of the distribution facility and whether the DER seeks to participate in

MISO's Resource Adequacy construct. If the distribution facility to which the DER will connect is part of the Transmission System within the meaning of MISO's Generator Interconnection Procedures, then the DER must submit an Interconnection Request in the form of Attachment X, Appendix 1 to the Tariff. MISO processes these Interconnection Requests through the Three Phase Definitive Planning Phase of MISO's GIP. This involves grouping for study of f Interconnection Requests based on queue priority in accordance with Section 4.1 and 4.2 of the GIP, processing these groups through the three phases of MISO's definitive planning phase as described in GIP Sections 7.1 through, 7.3.3.5, and negotiating and executing a MISO GIA in accordance with Sections 11.1 through 11.3 of the GIP.

If the distribution facility is not part of the Transmission System, then MISO's GIP usually will not apply. Instead, the DER would submit an interconnection request to the applicable distribution provider (the "Host Distribution Provider") and would be subject to any applicable study requirements and interconnection procedures required by the Host Distribution Provider. If the Host Distribution Provider, applying its study procedures, determines that the DER may have impacts on the MISO Transmission System, the Host Distribution Provider would inform MISO's interconnection group of those impacts. MISO, as an affected system, would then coordinate with the Host Distribution Provider and impacted Transmission Owner to study the DER's impacts on the MISO Transmission System to determine what facilities or other mitigation are required to remedy the adverse impacts. The DER would be responsible for the costs of any upgrades needed to address adverse impacts on the MISO Transmission System under a Facilities Construction Agreement ("FCA") or Multi-Party Facilities Construction Agreement ("MPFCA") conforming to the *pro forma* FCA or MPFCA contained in Tariff Attachment X, Appendix 8 (FCA) or Appendix 9 (MPFCA), respectively.

While a DER ordinarily is not required to adhere to MISO's GIP when connecting to facilities that are not part of the Transmission System, MISO's GIP would apply if the DER seeks to participate in MISO's Resource Adequacy construct and receive capacity payments. To inject electricity and participate in the Resource Adequacy construct as a Capacity Resource, the DER must be deliverable to load through the MISO Transmission System.[4] MISO provides two services that a DER must choose between for MISO to study the DER's deliverability: (1) External Network Resource Interconnection Service ("E-NRIS"); or (2) firm Transmission Service (either Point-To-Point or Network) from the DER unit to a particular load. If the DER elects to obtain E-NRIS, they must submit an Interconnection Request specifying that the DER is seeking E-NRIS and be studied through MISO's 3-phase DPP (described above). If the DER elects to obtain firm Transmission Service to be deliverable to specific load, then the Interconnection Customer must submit a Transmission Service Reservation ("TSR") and adhere to MISO's TSR study procedures.[5] The requirement to proceed through MISO's DPP for E-NRIS or the TSR study process would not relieve a DER of its obligation to adhere to the requirements of the Host Distribution Provider's interconnection process. MISO provides a set of instructions for interconnecting to non-MISO distribution facilities on its website for the benefit of customers.[6]

4 *See* MISO Tariff, Module E-1, Section 69A.3.1.g.

5 *See* MISO Tariff, Module B.

6 *See* MISO instructions for Interconnection Requests to the Distribution System or non-MISO Transmission System within the MISO region, available at, https://cdn.misoenergy.org/Distribution_System_Interconnection_Request_Instructions108140.pdf.

a. What are the respective roles of the RTO/ISO and the distribution utility in that process?

Each of the roles of MISO and the Host Distribution Provider perform are described in response to Question 1, above.

b. How would the DER ascertain whether it must interconnect pursuant to a state-jurisdictional interconnection process or a Commission-jurisdictional process?

Interconnection customers that intend to connect generating units to transmission or distribution system elements that are a part of the Transmission System, as defined in Attachment X of the MISO Tariff, must go through MISO's interconnection process. This requirement is communicated through Sections 1 and 2 of Attachment X. Specifically, Section 2.1 provides that the MISO Generator Interconnection Procedures ("GIP") apply where the Generating Facility is proposed for interconnection to a Point of Interconnection on the Transmission System. Transmission System is defined in Section 1of Attachment X as facilities "owned by Transmission Owner and controlled or operated by Transmission Provider or Transmission Owner that are used to provide transmission service (including HVDC Service) or Wholesale Distribution Service under the Tariff."

While MISO has not yet encountered requests to connect DER resources to the Transmission System, there are two methods that DER could use to ascertain the process applicable to its interconnection request. First, the DER could contact the Host Distribution Provider to determine whether the MISO process or the Host Distribution Provider's process applies to a given facility. Second, the DER could obtain this information directly from MISO. Any DER (or other resources) registering for participation in MISO's Resource Adequacy construct would be informed of the need for study under MISO's GIP.

MISO maintains records of all facilities that comprise the Transmission System (*i.e.*, those facilities that have been transferred to MISO's functional control and those that are subject to an agency agreement).[7] In addition, MISO currently maintains a list on MISO's public website of those transmission facilities that are Transferred Transmission Facilities ("TTF") under MISO's functional control. While the TTF list does not currently include WDS facilities, the TTF list can be used by DERs and other Interconnection Customers to ascertain those transmission assets that have been transferred to MISO on MISO's public website.[8] Also, if the DER intends to connect to a distribution facility that is not included on the TTF list, the DER would need to determine whether that distribution facility has been identified as a WDS facility that is a part of the Transmission System, as defined in Attachment X of the Tariff. In this case, the DER would need to contact MISO directly and inquire whether the distribution facility is a WDS facility.

If the DER interconnection customer intends to connect the DER unit to facilities listed on MISO TTF list or a distribution facility that provides Wholesale Distribution Service, then the Interconnection Customer is required to follow the Generator Interconnection Procedures (Attachment X) of MISO Tariff. If DER is not interconnecting to such facilities, then the interconnection customer is required to follow the interconnection rules of the Host Distribution Provider.

c. How does your RTO/ISO define the physical boundaries of a distribution facility when determining whether a distribution facility to which a new DER seeks interconnection is already subject to an Open Access Transmission Tariff (OATT) for purposes of making wholesale sales?

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[7] MISO Transmission Owner's Agreement Appendices G and H.

[8] The TTF list is available at: https://www.misoenergy.org/legal/transferred-transmission-facilities/#t=10&p=0&s=FileName&sd=asc.

As discussed in response to Question 1, above, MISO's Transmission System is defined as the aggregate of individual transferred transmission facilities, non-transferred facilities including those subject to an agency agreement and distribution facilities that provide Wholesale Distribution Service. A facility that is not turned over to MISO's functional control or subject to an agency agreement does not automatically become a part of the MISO Transmission System based on its geographic location. Geography therefore does not determine the boundaries of the MISO Transmission System. If a distribution facility is part of the MISO Transmission System as defined in Attachment X of the Tariff, then MISO's Tariff and GIP apply to such facility as described above. If the distribution facility is not part of the Transmission System, then the Host Distribution Provider's procedures control.

2. Does the interconnection process described in response to Question # 1 differ based on whether or not the DER is a Qualifying Facility, and if so, how?

MISO's interconnection process does not differ based on whether or not a DER is a Qualifying Facility ("QF"). If a QF is subject to MISO's GIP, the process would be the same for a QF as it is for any other Generating Facility subject to the GIP. However, not all QFs are subject to MISO's GIP. Under Commission precedent, a QF that sells all of its output to the utility to which it is interconnected or an on-site customer pursuant to the Public Utility Regulatory Policies Act of 1978 ("PURPA") is not subject to MISO's GIP. However, if a QF plans to sell any of its output over the MISO Transmission System then it would be required to adhere to MISO's GIP and obtain a GIA for interconnection service. Likewise, if a QF that previously sold all of its output to the utility to which it is interconnected becomes able to sell its output to third parties over the MISO Transmission System, as may be the case if a power purchase agreement expires, then such QF would need to submit an Interconnection Request and proceed through MISO's queue.[9]

3. Does the interconnection process described in response to Question # 1 differ if the DER seeking to participate in wholesale markets is interconnecting behind a retail customer meter (whether on the distribution or transmission system), and if so, how?

No, the interconnection process is the same regardless of whether the DER connects behind a retail customer meter.

4. Does the interconnection process described in response to Question# 1 allow studies for bi-directional service (i.e., both from a DER to the transmission system and from the transmission system to a distribution-connected wholesale customer)?

The Host Distribution Provider will determine whether bi-directional service is allowed. If the Host Distribution Provider determines that the DER may have a material impact on MISO's Transmission System, such Host Distribution Provider would inform MISO and the impacted Transmission Owner. MISO would then coordinate with the Host Distribution Provider to conduct DER studies to ensure reliability on the Transmission System. For requests that need to go through MISO's interconnection process, the interconnection study will include bi-directional analysis (*i.e.*, injection of power into Transmission System and withdrawal of power from Transmission System) as needed. In such cases, the Interconnection Customer is still required to procure Transmission Service under the Tariff to withdraw power from the Transmission System.

5. Under the interconnection process described in response to Question# 1, and assuming all of the individual DERs in the aggregation are new resources, which of the following would apply: (1) an aggregation of DERs located at multiple points of interconnection would be studied as one aggregated resource by your RTO/ISO and require only a single Generator Interconnection Agreement (GIA); (2) each individual DER would be studied individually and require its own GIA; (3) each DER would be studied individually with the aggregation still only requiring a single

9 *Midwest Indep. Transmission Sys. Operator, Inc.*, 132 FERC ¶ 61,241, P 25 (2010), *reh'g denied*, 138 FERC ¶ 61,204 (2012).

GIA; or (4) a different approach (please describe if a different approach would be used).

As described in response #1, the interconnection of a DER often would be processed using the interconnection rules of the Host Distribution Provider. MISO has not yet received any interconnection requests from DERs. Attachment X of the Tariff defines "Generating Facility" as generating device(s) identified in the Interconnection Request. Therefore, an Interconnection Customer with multiple generating resources, such as wind turbines, has some ability to determine how many GIAs it will obtain based on how many Interconnection Requests it chooses to submit. While MISO generally discourages the splitting of projects into numerous GIAs for queue efficiency reasons, MISO is still evaluating whether this approach or another would be most appropriate for DERs.

Because DER aggregation of generation resources is new and, as a result, MISO has yet to process an Interconnection Request for a DER aggregator, MISO is still in the process of developing interconnection rules for such resources. These rules may address matters such as how wide an area can be aggregated as a single project for purposes of MISO's interconnection process.

6. **In contrast with the scenario in Question# 5, please assume that at least some of the individual DERs in a proposed aggregation are existing resources already interconnected and in service. If multiple existing and new DERs were able to aggregate at separate points of interconnection across your RTO/ISO to participate in wholesale markets as an aggregation rather than as individual resources, under what circumstances would your RTO's/lSO's existing interconnection procedures and study processes apply to the individual DERs in the aggregation? If multiple existing and new DERs were able to aggregate at separate points of interconnection across your RTO/1SO to participate in wholesale markets as an aggregation rather than as individual resources, under what circumstances would your RTO's/ISO's existing interconnection procedures and study processes apply to the aggregation? Would any revisions be needed to accommodate aggregations of DERs (existing and new) at multiple points of interconnection?**

a. Under existing tariff rules, which entity (i.e., the RTO/1SO or the distribution utility) would be responsible for processing the interconnection of the individual DERs seeking to join an aggregation?

If the individual DERs are directly connected to distribution facilities and not to the MISO Transmission System, under existing Tariff rules, the Host Distribution Provider will be responsible for processing the interconnection of the individual DERs seeking to join an aggregation. MISO has not yet received any requests to interconnect aggregations of DERs to the MISO Transmission System and has not yet developed rules that specifically address the challenges of such interconnections, including how the unit to be studied would be defined and studied.

b. For existing DERs that are currently not participating in wholesale markets and that interconnected under a state-jurisdictional process, under your current interconnection procedures would the DER's decision to participate in an aggregation trigger the RTO/ISO interconnection process? Would additional studies be necessary to ensure that participation in your RTO's/ISO's wholesale markets through an aggregation does not cause reliability problems on the transmission system? If so, what studies? If not, why not? For example, would the original state-jurisdictional interconnection process have already studied the DER in a variety of operational scenarios that eliminate the need for further studies prior to wholesale market participation in your region?

The above-described scenarios would not trigger MISO's interconnection process. As described in response #1, the Host Distribution Provider's interconnection process should have already studied the individual DER impact on the MISO Transmission System and MISO would have coordinated with the Host Distribution Provider and impacted Transmission owner to address such impacts. Aggregation without more interconnection service should not cause, and would not authorize, additional injection or impact on the Transmission System. This said, MISO notes that the study processes and assumptions used by individual Host Distribution Providers vary widely. If the Host Distribution Provider did not study the DER under a wholesale market participation scenario, and such market participation changes the characteristics and system impact of the DER from those under which it was originally studied, further studies by the Host Distribution Provider may be required.

c. If existing distribution-level DERs that are currently not participating in wholesale markets join aggregations and start making wholesale sales for the first time, how would that new wholesale use of existing DERs and their associated distribution facilities impact your assessment of whether those distribution facilities are subject to your OATT? Would Commission-jurisdictional interconnection procedures apply to subsequent requests to interconnect to those distribution facilities? Why or why not?

Under MISO's current Tariff definitions, once an existing DER begins participating in the MISO wholesale energy markets, the distribution facility to which that DER connects would be deemed as providing Wholesale Distribution Service within the meaning of MISO's Tariff. Because Attachment X of the MISO Tariff defines Transmission System as including facilities that provide Wholesale Distribution Service, any future DER interconnection to a Wholesale Distribution Service facility would be subject to the MISO Tariff and therefore required to proceed through the interconnection process established in Attachment X of the Tariff. MISO notes that these rules have not yet been applied given that MISO has thus far not received a request to interconnect a DER aggregation through MISO's interconnection process. As MISO continues developing its DER aggregator participation model, MISO may reexamine the scope and applicability of MISO's interconnection process under various scenarios.

d. For large and small generator interconnections subject to Order Nos. 2003 and 2006, the transmission provider is required to coordinate between the interconnection customer and "affected systems" (i.e., third-party transmission systems) to ensure that any needed affected system issues are resolved. With respect to new DERs seeking to interconnect to distribution facilities that are subject to a Commission-jurisdictional OATT, do the relevant small generator interconnection procedures in your region treat the transmission system to which the relevant distribution facilities are connected as an "affected system" in order to address any needed transmission upgrades at the initial interconnection stage?

MISO's Generator Interconnection Procedures (Attachment X) of the MISO Tariff covers requests for interconnection to the Transmission System as defined in Attachment X. MISO does not have two separate Generator Interconnection Procedures (GIP) for small and large interconnections. Therefore, any new DERs seeking to interconnect to distribution facilities are subject to the requirements of the Host Distribution Provider. MISO would coordinate with the Host Distribution Provider and the impacted Transmission Owner if the Host Distribution Provider determines that there is a material impact on the Transmission System caused by the new interconnection. After receiving such a notice, MISO would consult with the impacted Transmission Owner to review the assumptions used by the Host Distribution Provider. If MISO and the impacted Transmission Owner agree that adverse reliability impacts exist, the parties will engage the Interconnection Customer in a System Impact Study and, if upgrades are needed, a Facilities Study to resolve the constraint.

7. If the individual DERs in an aggregation are seeking to interconnect to a combination of distribution facilities, some of which are subject to a Commission-jurisdictional OATT and some that are not subject to an OATT, would any, all, or only a subset of the DERs in the aggregation be required to go through the interconnection process you described in response to Question # 1 and to execute GIA(s) under your tariff? Please explain.

See response to Question 6(d), above.

8. If available, please provide data on or estimates of the number of individual DERs in your region that are directly participating today in your RTO/ISO markets as compared to DERs in your region that are not participating in wholesale markets. If possible, please provide estimates by resource type and participation model (i.e., generator, demand response, etc.).

DERs Currently Participating in MISO Markets

Currently, MISO does not specifically track the DERs that are connected to the distribution system, and therefore the specific number and MW volume of such DERs that are participating in the MISO markets is not currently known. However, MISO does track the broader categories of Demand Response Resources ("DRRs"), Load Modifying Resources ("LMRs"), and Emergency Demand Response ("EDRs") that do participate in MISO's markets, whether located on the distribution or transmission system. Each of these resource types can be categorized as DERs, as defined in the Data Request,[10] but also includes other resources beyond the scope of this Data Request (*e.g.*, transmission-connected generators that are within the LMR definition). For purposes of generally estimating the DERs that may be participating in the MISO markets, MISO provides the following information about the DRRs that participate in MISO energy markets and the LMRs and EDRs that participate in MISO Resource Adequacy construct.

The inventory of DRR Type I that MISO believes are connected to distribution systems consist of 28 resources with a combined target demand reduction of 672.6 MW.[11] The largest of these DRR Type 1 resources has a target demand reduction of 195 MW, and the smallest DRR Type 1 resource has a target demand reduction of 3.1 MW.

The combined capacity of LMRs participating in MISO markets is 7326.5 MW, of which 9 resources comprising 180.8 MW are also registered as EDRs. Currently, there are 66 EDR resources totaling 2,163.3 MWs. MISO does not require Market Participants to identify the precise location of their LMR and EDR resources (*i.e.*, whether those resources are located on elements of the transmission system or distribution system). Accordingly, MISO does not track and actively monitor the precise location of LMR and EDR resources.

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10 For purposes of this data request, the Commission defines a DER as "a source or sink of power that is located on the distribution system, any subsystem thereof, or behind a customer meter. These resources may include, but are not limited to, electric storage resources, distributed generation, thermal storage, and electric vehicles and their supply equipment."

11 Demand Response Resource Type II is connected to MISO at the transmission level and is not included as a DER resource.

DERs Not Currently Participating in MISO Markets

MISO does not possess information on DER resources in the MISO region that are not participating in the MISO markets. However, the Organization of MISO States ("OMS") recently conducted a survey of utilities within the MISO footprint to estimate the quantity of DER's that are not currently participating in the MISO market. The data collected by OMS for 2019 is included in the 2019 OMS DER Survey Results.[12] A summary of the data included in that Survey is provided in the table below:

	Installations			Capacity (MW)		
DER Type	Residential	Non-Res	Total	Residential	Non-Res	Total
Solar PV	41,212	8,328	49,540	861	1,147	2,008
Wind	659	460	1,119	8	482	490
Electric Vehicle	4,101	-	4,101	0	-	0
Microturbine	-	4	4	-	9	9
Fuel Cell CHP	-	-	-	-	-	-
Fuel Cell Electric	-	-	-	-	-	-
Internal Combustion	1	385	386	0	634	634
Hydro	4	86	90	0	112	112
Gas Turbine	-	13	13	-	120	120
Battery Storage	37	9	46	246	3	250
Demand Response	137,210	1,796	139,006	118	131	249
Biodigesters	1	115	116	0	107	107
Other	14	31	45	0	718	718
Totals	183,239	11,227	194,466	1,234	3,464	4,698

9. Do you or the distribution utilities in your region have data on or estimates of how many distribution facilities, as defined in your answer to Question # l .c. above, are currently subject to an OATT compared to the total number of distribution facilities in the RTO/ISO footprint?

a. If yes, please provide this data or estimates.

[12] *See* 2019 MOS DER Survey Results, *available at* https://www.misostates.org/images/stories/Other_Projects/2019_Survey_Results_Presentation_Public_002.pdf.

MISO does not currently track the number of distribution facilities in the MISO footprint that are currently subject to the MISO Tariff. MISO does not currently track the total number of distribution facilities that exist within its footprint. However, in order to accommodate changing customer needs, MISO will expand its tracking to include WDS facilities in anticipation of DERs. MISO would adjust the prominence of this information on its website based on evolving customer needs.

b. How is this information managed and updated?

See response to Question 9(a), above.

10. Is your RTO/ISO engaged in any ongoing discussion or coordination with state or local authorities regarding the interconnection process for DERs? If so, please describe this discussion or coordination.

Yes. Currently MISO is working with local authorities including States and distribution utilities to develop a guideline for the implementation of DER interconnection standard Institute of Electrical and Electronic Engineers ("IEEE") Standard 1547-2018. This new version of this IEEE standard added voltage and frequency ride-through requirements to support the reliability of the transmission system, and requires coordination between distribution authorities and Reliability Coordinators. To help this required coordination, MISO created a stakeholder process to develop a MISO region guideline for the implementation of IEEE Standard 1547-2018.

11. If a DER needs to transmit its output over distribution facilities to make sales into the RTO/ISO markets, are there any existing tariff provisions that govern such service? If so, please list and describe such provisions and describe whether that service is bi-directional.

No, there are no provisions in the MISO Tariff that provide rules for DERs that transmit output over distribution facilities to makes sales in the MISO markets.

IV. Notice and Service

Communications and correspondence regarding this filing should be directed to:[13]

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MISO has served all parties provided in the Commission's eService list for the above-referenced docket. In addition, MISO notes that it has served a copy of this filing electronically, including attachments, upon all Tariff Customers under the Tariff, MISO Members, Member representatives of Transmission Owners and Non-Transmission Owners, as well as all state commissions within the Region. In addition, the filing has been posted electronically on MISO's website at https://www.misoenergy.org/legal/ferc-filings/ for other parties interested in this matter.

[13] To the extent necessary, the Filing Parties respectfully request a waiver of Rule 203(b)(3) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.203(b), to permit all of the persons listed to be placed on the official service list for this proceeding.

V. Conclusion

MISO appreciates the opportunity to respond to the Commission's questions in this proceeding.

Respectfully submitted,

/s/ Michael L. Kessler

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Attorneys for Midcontinent Independent System Operator, Inc.

Dated: October 7, 2019

CERTIFICATE OF SERVICE

I hereby certify that I have this day e-served a copy of this document upon all parties listed on the official service list compiled by the Secretary in the above-captioned proceeding, in accordance with the requirements of Rule 2010 of the Commission's Rules of Practice and Procedure (18 C.F.R. § 385.2010).

Dated this 7th day of October, 2019, in Carmel, Indiana.

/s/ Julie Bunn

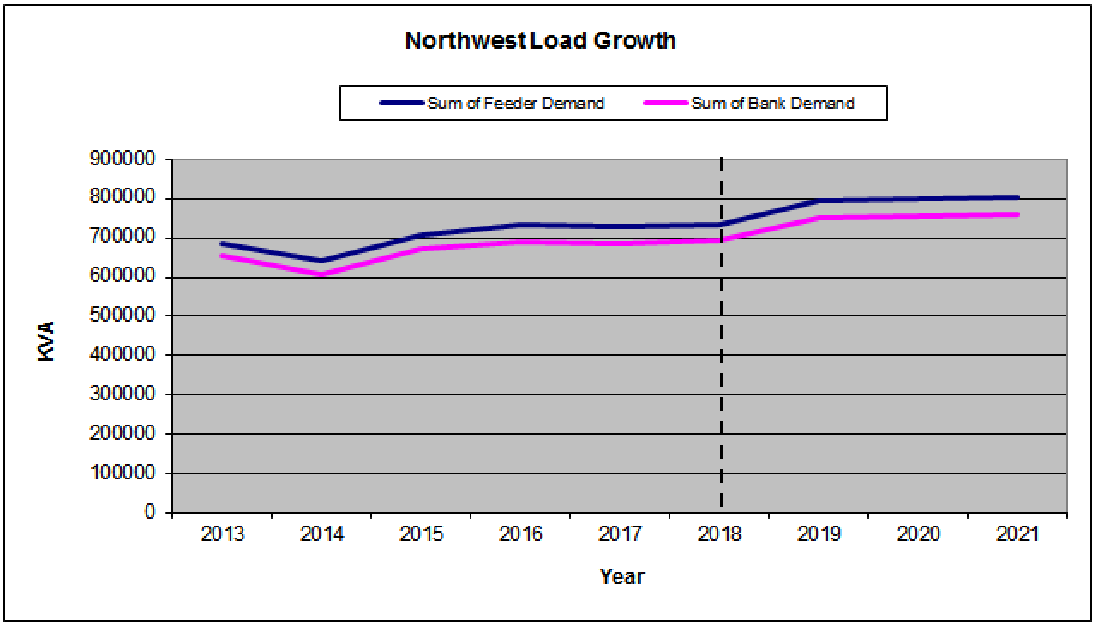
Julie Bunn
Midcontinent Independent
System Operator, Inc.
720 City Center Drive
Carmel, IN 46032

3.D.2 Action Plan Roadmap

Section	Requirement	Section or Reference
3.D.2	Xcel shall provide a 5-year Action Plan as part of a 10-year long-term plan for distribution system developments and investments in grid modernization based on internal business plans and considering the insights gained from the DER futures analysis, hosting capacity analysis, and non-wires alternatives analysis.	XIV.A.2 IX, X Attachment C
3.D.2	The 5-year Action Plan should include a detailed discussion of the underlying assumptions (including load growth assumptions)	XIV.A.1 V.B, IX, X
	and the costs of distribution system investments planned for the next 5-years (expanding on topics and categories listed above).	II.D, IX Attachment C
3.D.2	Xcel should include specifics of the 5-year Action Plan investments.	IX, X Attachment C
3.D.2	Topics that should be discussed, as appropriate, include at a minimum:	-
3.D.2 (i)	Overview of investment plan: scope, timing, and cost recovery mechanism	II, IX, XIV.A, XV Attachment C
3.D.2 (ii)	Grid Architecture: Description of steps planned to modernize the utility's grid and tools to help understand the complex interactions that exist in the present and possible future grid scenarios and what utility and customer benefits that could or will arise. (Footnote: https://gridarchitecture.pnnl.gov/)	IX, X Figure 73 Attachment C
3.D.2 (iii)	Alternatives analysis of investment proposal: objectives intended with a project, general grid modernization investments considered, alternative cost and functionality analysis (both for the utility and the customer), implementation order options, and considerations made in pursuit of short-term investments. The analysis should be sufficient enough to justify and explain the investment.	IX Attachment C
3.D.2 (iv)	System interoperability and communications strategy	IX, X Attachment C
3.D.2 (v)	Costs and plans associated with obtaining system data (EE load shapes, PV output profiles with and without battery storage, capacity impacts of DR combined with EE, EV charging profiles, etc.)	XI.F
3.D.2 (vi)	Interplay of investment with other utility programs (effects on existing utility programs such as demand response, efficiency projects, etc.)	Attachment C, Attachment M1
3.D.2 (vii)	Customer anticipated benefit and cost	V.D.2, IX.F-G, XVI Attachment C, Attachments M1-M5, Attachments O1-O4
3.D.2 (viii)	Customer data and grid data management plan (how it is planned to be used and/or shared with customers and/or third parties)	IX, X Attachment C, Attachment M1
3.D.2 (ix)	Plans to manage rate or bill impacts, if any	IX.G, XIV.A.3 Attachment C, Attachment M1
3.D.2 (x)	Impacts to net present value of system costs (in NPV RR/MWh or MW)	Attachment L

3.D.2 Action Plan Roadmap

Section	Requirement	Section or Reference
3.D.2 (xi)	For each grid mod project in its 5-year action plan, Xcel should provide a cost-benefit analysis based on the best information it has at the time and include a discussion of non-quantifiable benefits. Xcel shall provide all information used to support its analysis.	IX, X Attachment C, Attachments M1-M5, Attachments O1-O4, Workpapers (CBA)
3.D.2 (xii)	Status of any existing pilots or potential for new opportunities for grid mod pilots.	XIII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Sum of Bank Demand
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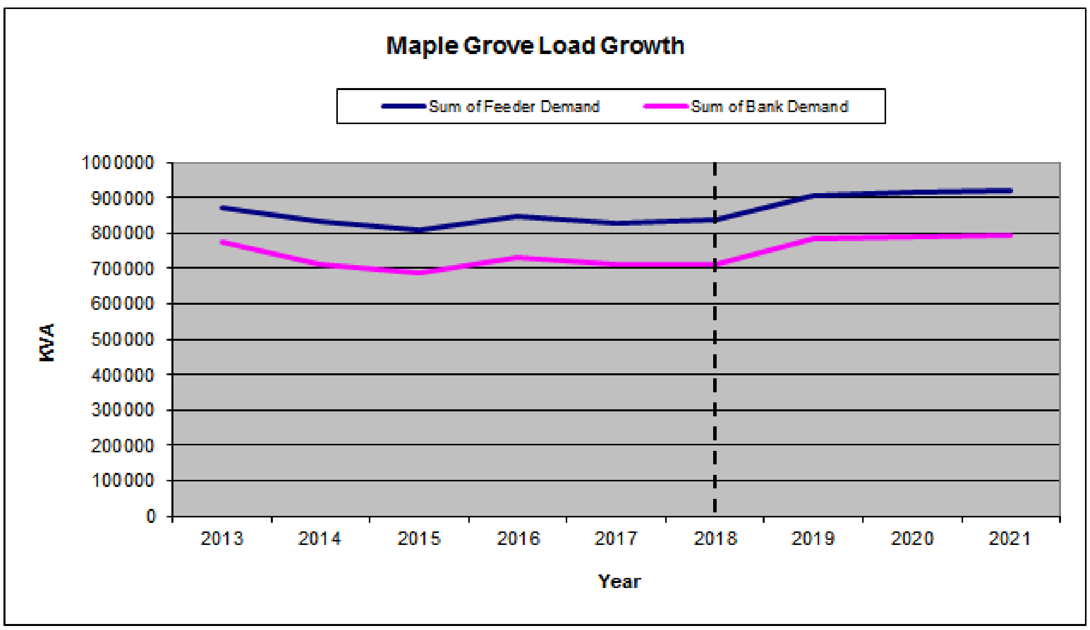
800000
700000
600000
500000
400000
300000
200000
100000
0
KVA
2013
2014
2015
2016
2017
2018
2019
2020
2021
Year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Sum of Bank Demand
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900000
800000
700000
600000
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400000
300000
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KVA
2013
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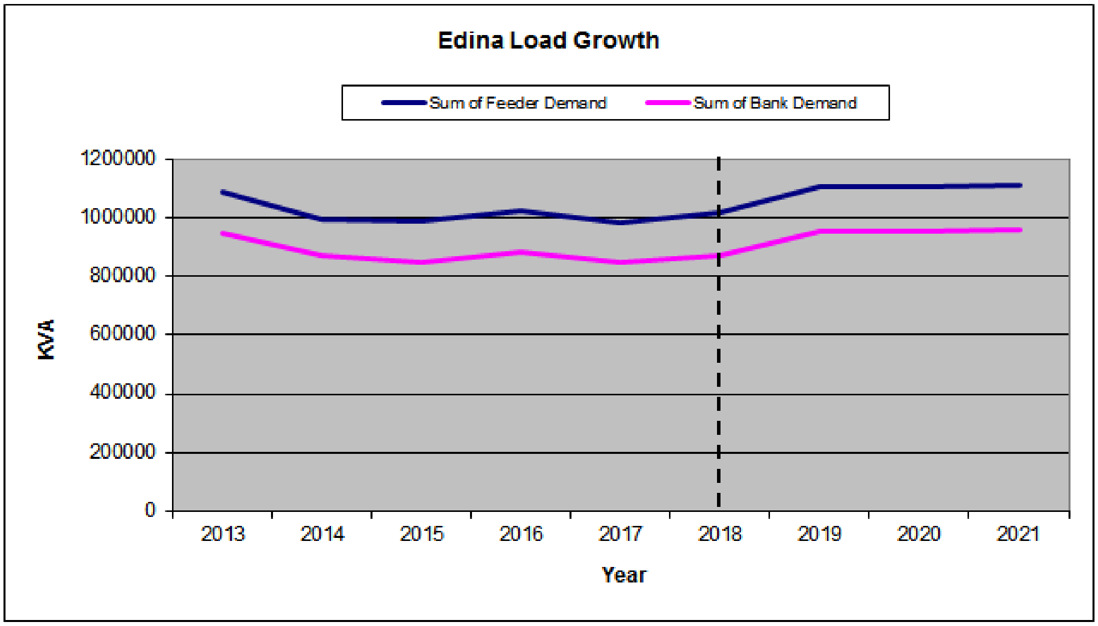
Year


Edina Load Growth
Sum of Feeder Demand
Sum of Bank Demand
KVA
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1000000
800000
600000
400000
200000
0
2013
2014
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2018
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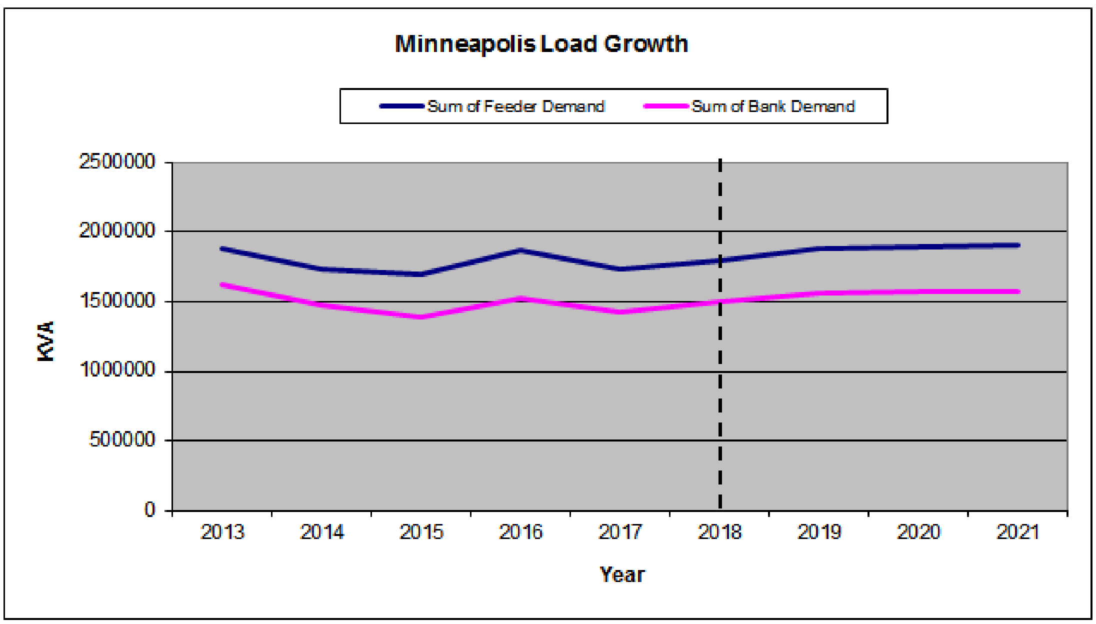
2020
2021
Year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Sum of Feeder Demand
Sum of Bank Demand
KVA
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2000000
1500000
1000000
500000
0
2013
2014
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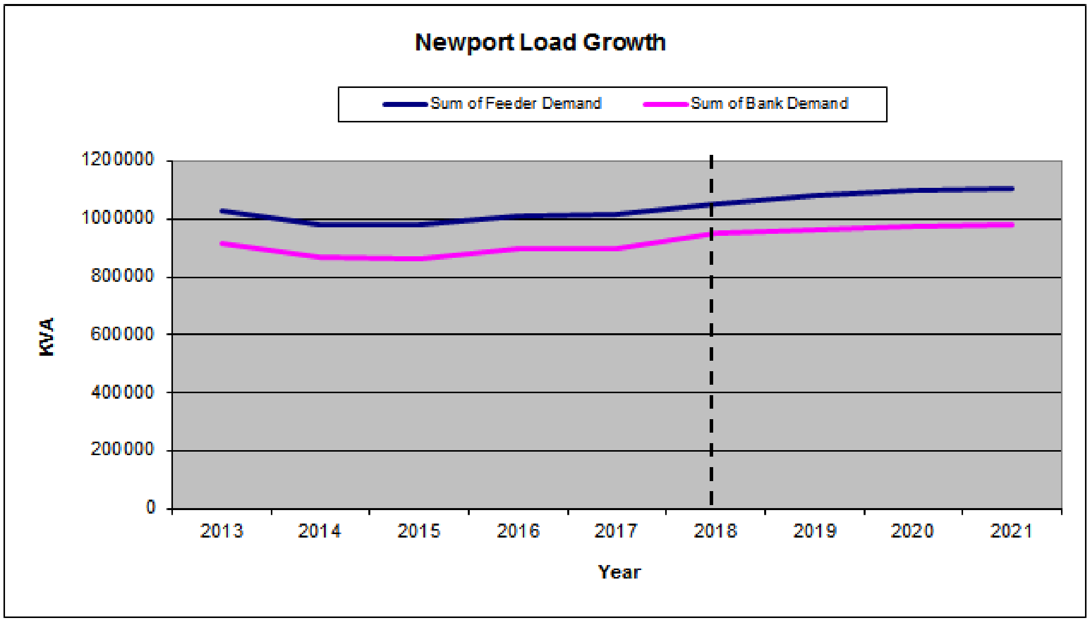
2021
Year


Newport Load Growth
Sum of Feeder Demand
Sum of Bank Demand
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1000000
800000
600000
400000
200000
0
KVA
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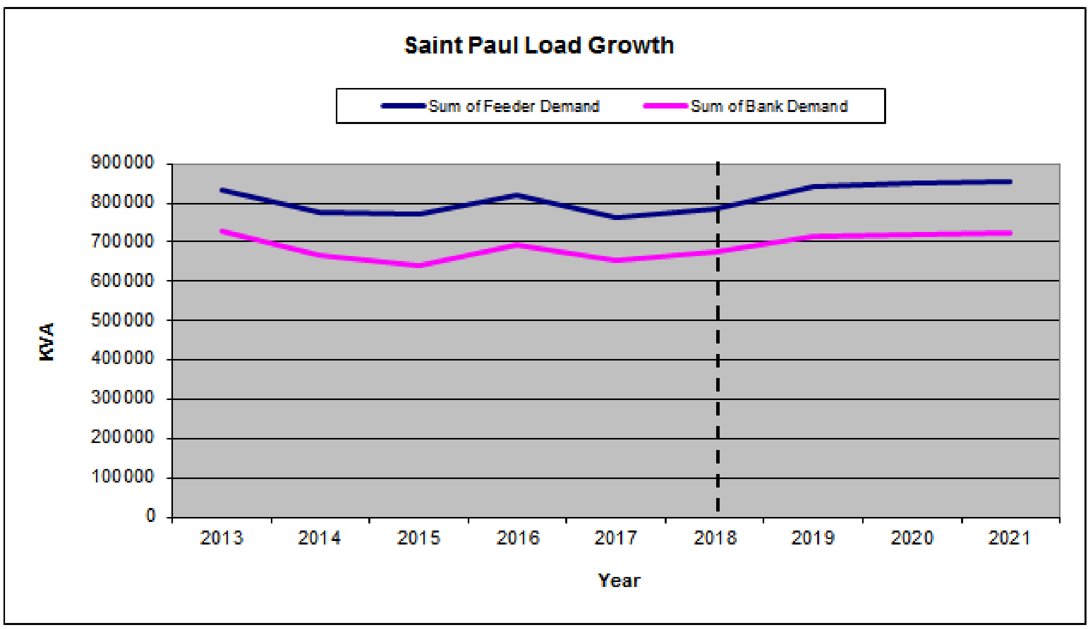
2021
Year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Sum of Feeder Demand
Sum of Bank Demand
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800000
700000
600000
500000
400000
300000
200000
100000
0
KVA
2013
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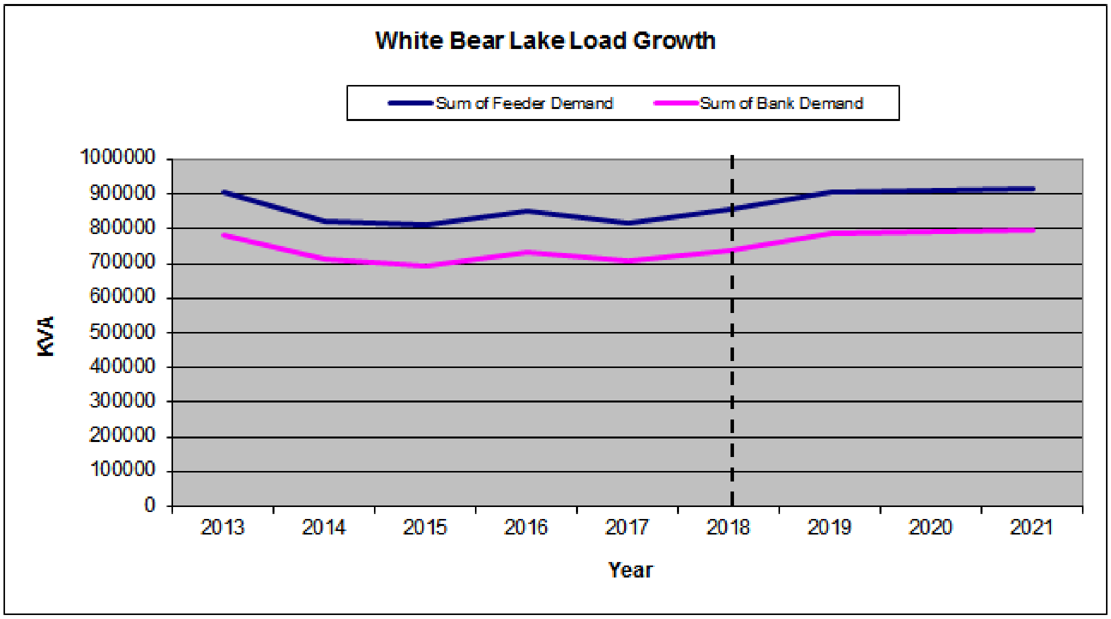
2021
Year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Sum of Bank Demand
KVA
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900000
800000
700000
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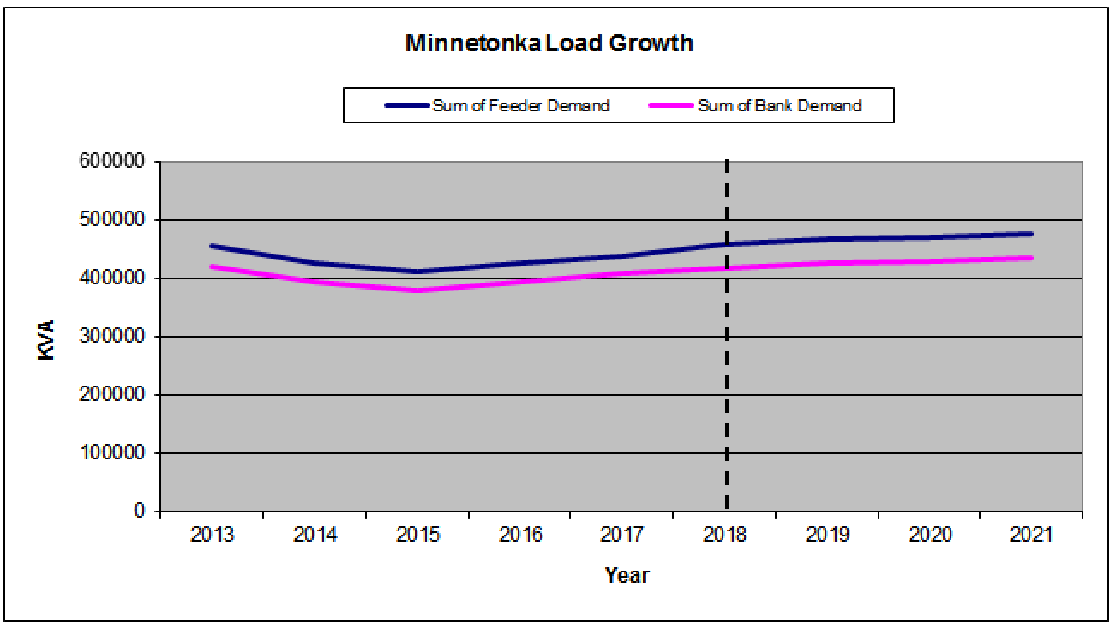
Year


Minnetonka Load Growth
Sum of Feeder Demand
Sum of Bank Demand
KVA
600000
500000
400000
300000
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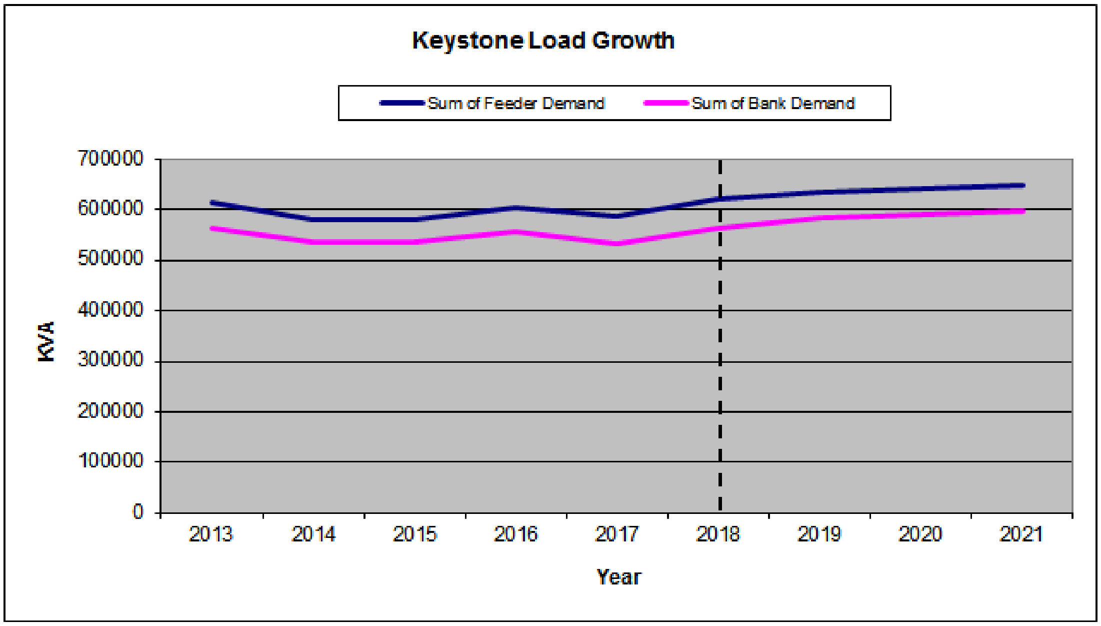
2021
Year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Sum of Bank Demand
KVA
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400000
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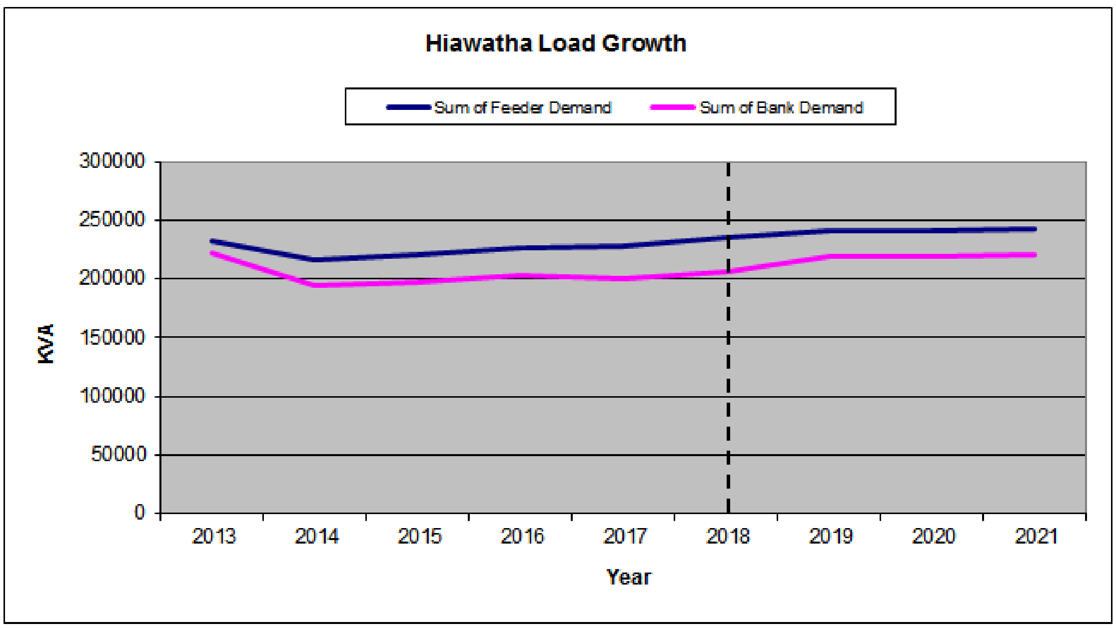
2019
2020
2021
Year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Sum of Bank Demand
KVA
300000
250000
200000
150000
100000
50000
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2013
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2019
2020
2021
Year

IDP Requirement 3.D.2 requires that we provide:

Impacts to net present value of system costs (in NPV RR/MWh or MW)

As we noted in our July 20, 2018 Reply Comments in the Docket No. E002/CI-18-251 in which our IDP requirements were established, and consistent with our fulfillment with this requirement in our November 1, 2018, we understand this requirement to be a calculation similar to that provided in conjunction with an Integrated Resource Plan. Our comments continued, saying that there are differing characteristics associated with the distribution system that may make this complex to translate – and that we would provide some sort of distribution-level calculation – but at that time were working with various business units to ascertain how best to do so.

We took the same approach in this 2019 IDP as we took in our 2018 IDP, which is an approach similar to a jurisdictional cost of service – but for just the Distribution function of the Company. In general, a jurisdictional cost of service study includes the following financial data input sections: (1) capital structure; (2) cost of capital; (3) income tax rates; (4) rate base; (5) income statement; (6) income tax calculations; and (7) cash working capital computation.

We clarify that this "rate base" view of the Distribution function will not match the budget information we provide in this IDP, because the inputs to the NPV Revenue Requirements (RR) calculation are specific to just the distribution system located in Minnesota. As such, only costs that are direct-assigned to Distribution, and distribution assets located in the state of Minnesota are included. Common and general property in support of the Distribution function are not included in this view – but are represented in the distribution budget information provided elsewhere in this IDP. Similarly, other rate base is not included, and we are not including ratemaking treatments such as net operating losses.

Rate base primarily reflects the capital expenditures made by a utility to secure plant, equipment, materials, supplies and other assets necessary for the provision of utility service, reduced by amounts recovered from depreciation and non-investor sources of capital. It is generally comprised of the following major items:

- *Net Utility Plant.* Net utility plant represents the Company's investment in plant and equipment that is used and useful in providing retail electric service to its customers, net of accumulated depreciation and amortization.
- *Construction Work in Progress (CWIP).* In Minnesota, CWIP is included as part of the revenue requirement calculation for base rates. CWIP is the accumulation of construction costs that directly relate to putting a fixed asset into use.

- *Accumulated Deferred Income Taxes (ADIT).* Inter-period differences exist between the book and taxable income treatment of certain accounting transactions. These differences typically originate in one period and reverse in one or more subsequent periods. For utilities, the largest such timing difference typically is the extent to which accelerated income tax depreciation generally exceeds book depreciation during the early years of an asset's service life. ADIT represents the cumulative net deferred tax amounts that have been allowed and recovered in rates in previous periods.

- *Pre-Funded Allowance for Funds Used During Construction (AFUDC).* In Minnesota, AFUDC is included as part of the revenue requirement calculation for base rates. Specifically, during construction, AFUDC is calculated and included in the CWIP balance and is also included in operating income as an offset to the revenue requirement. AFUDC is added to the cost of related capital projects and is reflected in rate base when the related capital project is placed into service. Once a project is placed in service, the recording of AFUDC ceases and the total capital cost of the project including accumulated AFUDC is recovered through depreciation.

- *Other Rate Base.* Other Rate Base is comprised primarily of Working Capital. It also includes certain unamortized balances that are the result of specific ratemaking amortizations. Working Capital is the average investment in excess of net utility plant provided by investors that is required to provide day-to-day utility service. In general, it includes items such as materials and supplies, fuel inventory, prepayments, and various non-plant assets and liabilities.

Rate base is generally calculated as outlined in Table 1 below.

Table 1: High Level Rate Base Calculation

	Original Average Cost of Electric Plant in Service (Plant)
Less:	Average Accumulated Depreciation Reserve
Less:	Average Accumulated Provision for Deferred Taxes
Plus:	Average Construction Work in Progress
Plus:	Average Working Capital
Equals:	Rate Base

For this Distribution Function NPV RR, we calculated the growth in revenue requirements over the 5-year budget period to derive an NPV of $164.4 million (in 2019 dollars).

	Annual Revenue Requirement						
	Electric Distribution Minnesota						
	2019-2024						
	(000's)						
				MN Jurisdiction			
	Rate Analysis	2019	2020	2021	2022	2023	2024
1	Average Balances:						
2	Plant Investment	3,698,030	3,885,363	4,138,497	4,503,003	4,919,052	5,319,332
3	Depreciation Reserve	1,380,479	1,447,122	1,520,312	1,598,759	1,685,968	1,785,101
4	CWIP	36,528	40,228	61,610	64,700	61,746	46,153
5	Accumulated Deferred Taxes	611,278	601,876	593,636	588,408	586,479	586,813
6	Average Rate Base = line 2 - line 3 + line 4 - line 5	1,742,802	1,876,594	2,086,160	2,380,537	2,708,351	2,993,572
7							
8	Revenues:						
9	Interchange Agreement offset = -line 40 x line 52 x line 53						
10							
11	Expenses:						
12	Book Depreciation	107,797	112,921	119,261	130,072	142,192	152,924
13	Annual Deferred Tax	(9,527)	(9,278)	(7,202)	(3,254)	(603)	1,271
14	ITC Flow Thru	-	-	-	-	-	-
15	Property Taxes	49,951	48,941	51,442	57,029	64,927	71,009
16	subtotal expense = lines 12 thru 15	148,221	152,585	163,501	183,847	206,516	225,203
17							
18	Tax Preference Items:						
19	Tax Depreciation & Removal Expense	92,529	99,642	112,795	136,578	158,274	177,168
20	Tax Credits (enter as negative)	-	-	-	-	-	-
21	Avoided Tax Interest	1,629	2,133	2,895	2,449	1,751	1,909
22							
23	AFUDC	2,437	3,649	4,669	4,177	2,906	3,133
24							
25	Returns:						
26	Debt Return = line 6 x (line 44 + line 45)	36,250	39,221	43,601	50,229	60,125	67,056
27	Equity Return = line 6 x (line 46 + line 47)	93,937	100,585	111,818	127,597	145,168	161,054
28							
29	Tax Calculations:						
30	Equity Return = line 27	93,937	100,585	111,818	127,597	145,168	161,054
31	Taxable Expenses = lines 12 thru 14	98,270	103,644	112,059	126,818	141,589	154,194
32	plus Tax Additions = line 21	1,629	2,133	2,895	2,449	1,751	1,909
33	less Tax Deductions = (line 19 + line 23)	(94,966)	(103,290)	(117,464)	(140,755)	(161,180)	(180,301)
34	subtotal	98,870	103,071	109,308	116,109	127,327	136,857
35	Tax gross-up factor = t / (1-t) from line 50	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351
36	Current Income Tax Requirement = line 34 x line 35	39,879	41,574	44,089	46,833	51,357	55,201
37	Tax Credit Revenue Requirement = line 20 x line 35 + line 20	-	-	-	-	-	-
38	Total Current Tax Revenue Requirement = line 36+ line 37	39,879	41,574	44,089	46,833	51,357	55,201
39							
40	Total Capital Revenue Requirements	315,850	330,316	358,340	404,329	460,260	505,382
41	= line 16 + line 26 + line 27 + line 38 - line 23 + line 9						
42	O&M Expense	110,471	114,249	132,140	127,086	128,511	128,884
43	Total Revenue Requirements	426,321	444,565	490,480	531,414	588,771	634,266
		Weighted	**Weighted**	**Weighted**	**Weighted**	**Weighted**	**Weighted**
	Capital Structure	**Cost**	**Cost**	**Cost**	**Cost**	**Cost**	**Cost**
44	**Long Term Debt**	**2.0400%**	**2.0600%**	**2.0500%**	**2.0800%**	**2.2000%**	**2.2200%**
45	**Short Term Debt**	**0.0400%**	**0.0300%**	**0.0400%**	**0.0300%**	**0.0200%**	**0.0200%**
46	**Preferred Stock**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**
47	**Common Equity**	**5.3900%**	**5.3600%**	**5.3600%**	**5.3600%**	**5.3600%**	**5.3800%**
48	**Required Rate of Return**	**7.4700%**	**7.4500%**	**7.4500%**	**7.4700%**	**7.5800%**	**7.6200%**
49	**PT Rate**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**
50	**Tax Rate (MN)**	**28.7420%**	**28.7420%**	**28.7420%**	**28.7420%**	**28.7420%**	**28.7420%**
51	**MN JUR Direct**	**100.0000%**	**100.0000%**	**100.0000%**	**100.0000%**	**100.0000%**	**100.0000%**
52	Growth in Total Revenue Requirements	0	18,244	45,915	40,934	57,357	45,495
53	Present Value of Growth in Total Revenue Requirements	164,439					

Direct Testimony and Schedules
Michael C. Gersack

Before the Minnesota Public Utilities Commission
State of Minnesota

In the Matter of the Application of Northern States Power Company
for Authority to Increase Rates for Electric Service in Minnesota

Docket No. E002/GR-19-564
Exhibit___(MCG-1)

AGIS Customer Experience and Policy

November 1, 2019

Table of Contents

Schedules

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Michael C. Gersack. I am Vice President of Innovation and Transformation for Xcel Energy Services Inc. (XES), which provides services to Northern States Power Company – Minnesota (NSPM or the Company).

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I have more than 25 years of experience in the areas of customer operations, accounting, and finance. In my current position, I am responsible for leading our Innovation & Transformation Office that governs and drives the successful implementation of critical programs or projects that focus on efficiency, operational effectiveness and innovation, and enable the Company to continuously improve and transform. Our ITO includes the following Centers of Excellence: Project Management Office; Innovation; Process Management; Data Strategy and Governance; and Change Management. I was previously Vice President of Customer Care, where I was responsible for the overall business performance of our customer operations including meter reading, billing, credit, remittance processing, and customer contact center functions. Prior to this, I held various operational, accounting and financial positions supporting Xcel Energy's distribution, marketing, transmission, and customer service functions. Before joining Xcel Energy, I held similar positions with Kinder Morgan (KN Energy). My resume is provided as Exhibit___(MCG-1), Schedule 1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to provide the overview of the Company's plans to transform the customer experience through the investments that are proposed as part of the Company's Advanced Grid Intelligence and Security (AGIS) initiative. My Executive Summary summarizes the Company's support for the AGIS initiative in my testimony and the testimony of other witnesses in this rate case. I also provide an overview of the Company's grid modernization efforts to date, outline the Company's strategic goals and identify the current state of the customer experience and the distribution system. I describe, at a high level, the work required to implement each component of the AGIS initiative for which we are requesting cost recovery in this proceeding, contemporaneous with the requests in our simultaneous Integrated Distribution Plan (IDP) filing. I outline the Company's proposed capital investments and operations and maintenance (O&M) costs for the core components of the AGIS initiative. I also summarize the timing of implementation of these components from both a system and customer perspective, and explain in detail the customer experience that will result from our work. I also discuss the Company's planned outreach efforts to help educate customers on what to expect from AGIS and how the new functionality will benefit them.

I also summarize the cost and benefits analysis that the Company has conducted with respect to the AGIS components, while also emphasizing the benefits that are qualitative and, by definition, non-quantifiable. I also provide a bill impact analysis for the components of the AGIS initiative. Lastly, I speak to the Company's plans for progress metrics and reporting with respect to the AGIS initiative.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. I present my testimony in the following sections:

- *Section II* – Executive Summary
- *Section III* – Grid Modernization Background
- *Section IV* – Drivers of the AGIS Strategy
- *Section V* – AGIS Components and Implementation Strategy
- *Section VI* – AGIS and the Customer Experience
- *Section VII* – Prudence of the AGIS Investments
- *Section VIII* – Bill Impacts
- *Section IX* – AGIS Metrics and Reporting
- *Section X* – Conclusion

II. EXECUTIVE SUMMARY

A. Introduction to the AGIS Initiative

Q. PLEASE EXPLAIN XCEL ENERGY'S APPROACH TO DISTRIBUTION SYSTEM PLANNING, IN GENERAL.

A. Xcel Energy has a 100-year track record of outstanding service to our customers and communities – delivering safe, reliable, and affordable energy. And while we remain focused on those fundamentals, we are also looking to the future and have a vision for an advanced grid that will provide both customer and operational benefits for many years to come. Our grid modernization plan is designed to maximize customer value, ensure the fundamentals of our distribution business remain sound, and maintain the flexibility needed as technology and our customers' expectations continue to evolve.

We are also constantly assessing our customers' experience, including what they want and need from their electric and gas utility. We have learned that customers want access to actionable information, more choice and greater control of their energy use – and they expect a smarter, simpler, and more seamless experience. In order to meet that need, we need a smarter grid. We therefore plan to integrate modern customer experience strategies with advanced grid platforms and technologies to enable intelligent grid operations, smarter networks and meters, and optimized products and services for our customers.

Q. WHAT IS AGIS?

A. The AGIS initiative is our long-term strategic plan to transform our electric distribution system to address aging meter technology, meet changing customer demands, enhance transparency into the distribution and to system data, to promote efficiency, and reliability, and to safely integrate more distributed resources. The AGIS initiative consists of multiple elements that work together to create a more modern and advanced distribution grid.

Q. WHAT ARE THE COMPONENTS OR ELEMENTS OF AGIS?

A. The core components of AGIS are the Advanced Distribution Management System (ADMS); Advanced Metering Infrastructure (AMI); and the Field Area Network (FAN). ADMS is underway, with costs being recovered in the TCR Rider. In this case, we propose to implement AMI, FAN, and two advanced applications that we believe will provide substantial benefits to customers: Integrated Volt-VAr Optimization (IVVO); and Fault Location Isolation and Service Restoration (FLISR). More specifically:

- *Advanced Distribution Management System (ADMS)* is the backbone of the AGIS initiative, consisting of a real-time operating system that enables enhanced visibility into the distribution power grid and controls advanced field devices.
- *Advanced Metering Infrastructure (AMI)* is the Company's proposed metering solution, consisting of an integrated system of advanced meters, communication networks, and data processing and management systems that enables secure two-way communication between Xcel Energy's business and data systems and customer meters.
- *Field Area Network (FAN)* is a private, secure, flexible two-way communication network that provides wireless communications across Xcel Energy's service area – to, from, and among, field devices and our information systems.
- *Fault Location, Isolation, and Service Restoration (FLISR)* is an ADMS application that improves customers' reliability experience, reducing the duration of outages and number of customers affected by them. FLISR takes the form of distribution automation and involves the deployment of automated switching devices that work to detect issues on our system, isolate them, and automatically restore power.
- *Integrated Volt VAr Optimization (IVVO)* is an ADMS application that uses specific field devices to optimize voltage as power travels from substations to customers, reducing system losses and may result in energy savings for customers.

Of course, protective cyber security and information technology (IT) support underlie all these components, as they are essential to operating a secure, technologically-advanced grid in today's world.

B. Drivers of the AGIS Initiative

Q. WHY IS THE COMPANY IMPLEMENTING AGIS AT THIS TIME?

A. NSPM has made incremental modernization efforts for the distribution system over many years, striving to maintain a grid that is as reliable and efficient as it could be with the technology it currently employs. However, our current one-way meters are nearing the end of their lives. With meter replacement a near-term reality, now is the right time to begin a more significant advancement of the grid through our AGIS initiative – of which AMI meters are the largest component. Other drivers impacting the timing of the AGIS transition include:

- The Company's strategic priorities to lead the clean energy transition, enhance the customer experience, and keep bills affordable;
- The Company's desire to meet the growing needs and expectations of our customers;
- Current distribution system needs; and
- Commission policy and direction, and stakeholder input relative to customer offerings, performance, and technological capabilities of the grid.

Q. BEFORE DISCUSSING EACH DRIVER IN TURN, PLEASE DESCRIBE THE COMPANY'S OVERALL APPROACH TO IDENTIFYING AND SELECTING THE COMPONENTS OF THE AGIS INITIATIVE.

A. Over the last several years, the Company has experienced a variety of converging needs and opportunities related to distribution grid modernization – some driven by internal system needs, others by industry direction, and still others by customers and other stakeholder considerations. The Company's extensive assessments of these multi-faceted needs, as well as the alternatives to meet them, are described in detail in the testimony of Company witnesses Ms. Bloch, Mr. Cardenas, and Mr. Harkness. As one example, Ms. Bloch and Mr. Cardenas explain the status of the current meters on our system, and Ms. Bloch discusses the extensive planning, information gathering, RFP processes, and consideration of alternate vendors, devices, systems, and programs that we undertook prior to landing on our current AMI plan. Mr. Harkness explains the work completed to select the appropriate IT solutions. We compared the capabilities, costs, benefits, and limitations of a variety of solutions, as well as the costs versus benefits of our preferred solutions, and ultimately propose an overall AGIS package that I believe delivers on the promise of grid advancement.

Q. PLEASE DISCUSS THE COMPANY'S STRATEGIC PRIORITIES AND HOW THEY ARE DRIVING THE AGIS INVESTMENTS.

A. We are working every day to lead the transition to a clean energy future, enhance our customers' experience with their utility, and keep bills low. The AGIS initiative advances each of these priorities. As I describe in more detail throughout my testimony, our customers can be partners in a more environmentally sound future, especially if they are empowered with better information and data to manage their energy usage and make conservation-friendly choices. AMI and the associated components of the AGIS initiative are critical to these efforts. Likewise, IVVO has the potential to act as a demand side management-type tool with carbon reduction and energy savings benefits without requiring any action from customers. Distributed energy resources (DER) are also a key to this clean energy future, and two-way communications on the distribution grid, down to the meter level, are necessary to accommodate increased levels of DER on the system. Thus, while the AGIS initiative provides direct benefits to all of our customers (beginning with implementation and over the long term), it also enables environmental benefits that will be provided for both customers and non-customers alike.

Further, customers are demanding more optionality and increasing levels of service from all their service providers – including us. The AGIS initiative is intended to create better interfaces with customers, provide them with better information and more choices, and thus improve their overall experience. Coupled with efforts to improve the digital platforms through which we interact with customers, improved energy management, control, conservation, and bill management are all available with a more interactive, advanced distribution system. And it goes without saying that continually enhancing our customers' reliability experience is at the core of quality electric service.

Finally, our proposed AGIS initiative offers our customers opportunities to better control and manage their monthly bills by providing more timely and granular energy usage data and enabling advanced rate design.

Q. WHAT ARE THE CHANGING CUSTOMER NEEDS AND EXPECTATIONS DRIVING THE COMPANY'S AGIS INVESTMENTS?

A. Influenced by other services, like Amazon, customers have come to expect more from their energy providers than in the past, including greater choices and levels of service, as well as greater control over their energy sources and their energy use. Customers also expect greater functionality and interaction in how those services are delivered. Technologies that customers can use to control their energy usage, such as smart thermostats, electric vehicle (EV) chargers, smart home devices, and even smart phones and energy-related digital applications, are evolving at a fast rate.

Q. HOW DOES AGIS ENABLE THE COMPANY TO MEET EVOLVING CUSTOMER EXPECTATIONS?

A. While Xcel Energy customers today have access to a multitude of energy efficiency and demand management programs, renewable energy choices, and billing options, there is a limit to what we can offer without taking advantage of the new technology that has emerged around grid advancement. Smart electric meters can now more easily and flexibly gather more detailed information about customer energy usage, which utilities can use to help customers better understand and manage their usage. Other advanced equipment on the grid can detect, communicate, and respond in real time to circumstances that would normally result in power outages. Grid operators can also get improved data to better and more proactively plan and operate the grid. These advancements form the foundation for a flexible grid environment that helps support two-way power flows from customer-connected devices or generating resources (such as rooftop solar) and provides utilities with a greater ability to adapt to future developments.

Q. WHAT ARE THE SYSTEM NEEDS THAT MAKE NOW THE RIGHT TIME FOR THE COMPANY TO IMPLEMENT THE AGIS INITIATIVE?

A. There are a variety of needs. Like other electric utilities, our current distribution system is based on one-way flow of information on much of our system, which means that beyond the distribution substation, the Company has little insight into the workings of the distribution system as it relates to outages, voltage levels experienced by the customer, and DER operations. Company witness Ms. Kelly Bloch describes this in further detail. Additional components that integrate with ADMS and advanced meters are necessary to better manage and shorten outages, and to maximize the voltage management on our system.

In addition, our current automated meter reading (AMR) technology in Minnesota is nearing end of life and our meter reading services vendor, Landis+Gyr (Cellnet) has informed the Company that it will no longer manufacture replacement parts for this system after 2022. In fact, we are the last Cellnet customer still using this technology. Further, our current contract with Cellnet for meter reading services expires at the end of 2025. While we have maximized the value of this AMR system that has provided efficient meter reading services for nearly 30 years, we now have the opportunity to transition to AMI, a proven meter technology. AMI will allow us the ability to expand the use of our meter system beyond basic billing functions for the benefit of our customers.

Q. TO WHAT EXTENT IS THE COMPANY'S AMI PROPOSAL ALIGNED WITH THE INDUSTRY?

A. AMR technology is becoming increasingly outdated and the progressively complex needs of the distribution system require movement to technology that can accommodate these needs. As stated in the United States Department of Energy (DOE), Office of Electricity's November 2018 Smart Grid System Report to Congress, "[f]rom 2007 to 2016, the number of advanced meters has grown ten-fold. About 70.8 million meters out of a total of 151.3 million meters were smart meters as of 2016, representing about 47 percent of U.S.

electricity customers. Bloomberg estimates that number has risen to 51 percent by the start of 2018. This is a significant increase compared to 14 percent of customers with smart meters in 2010 and only 2 percent in 2007."[1]

Xcel Energy has always performed well with respect to system reliability, management, and customer service, but in light of the prevalence of advanced meters and smart grid technologies, the Company must make similar investments to ensure continuing alignment with industry direction and customer expectations.

Q. ARE THERE BROADER INFRASTRUCTURE NEEDS THAT ARE FACTORED INTO THE COMPANY'S AGIS STRATEGY?

A. Yes. The DOE Smart Grid System Report has recognized the broader need for attention to distribution infrastructure nationwide:

> Our [country's] electric infrastructure is aging and it is being pushed to do more than it was originally designed to do. Modernizing the grid to make it "smarter" and more resilient through the use of cutting-edge technologies, equipment, and controls that communicate and work together to deliver electricity more reliably and efficiently can greatly reduce the frequency and duration of power outages, reduce storm impacts, and restore service faster when outages occur. Consumers can better manage their own energy consumption and costs because they have easier access to their own data. Utilities also benefit from a modernized grid, including improved security, reduced peak loads, increased integration of renewables, and lower operational costs.
>
> "Smart grid" technologies are made possible by two-way communication technologies, control systems, and computer processing. These advanced technologies include advanced

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[1] https://www.energy.gov/sites/prod/files/2019/02/f59/Smart%20Grid%20System%20Report%20November%202018_1.pdf, as of October 1, 2019 (internal citations omitted) (DOE Smart Grid System Report).

> sensors… that allow operators to assess grid stability, advanced digital meters that give consumers better information and automatically report outages, relays that sense and recover from faults in the substation automatically, automated feeder switches that re-route power around problems, and batteries that store excess energy and make it available later to the grid to meet customer demand.[2]

It is consistent with these broader industry needs that we are implementing ADMS at this time and that our existing AMR meters are nearing the end of their life. And, as noted earlier, our customers are also demanding more optionality, environmentally-sound investments, more control over their energy usage, and better outage management and communications.

Q. HAS THE COMPANY CONSIDERED COMMISSION AND STAKEHOLDER INPUT IN FORMING ITS GRID STRATEGY?

A. Yes. We have applied Commission guidance and stakeholder feedback gleaned through regulatory proceedings and Commission- and Company-sponsored stakeholder processes around grid modernization, DER hosting capacity, integrated distribution system planning, our integrated resource plan, and performance metrics for the Company's electric operations. We also considered the Commission's guidance and stakeholder feedback associated with the Company's proposed Time of Use (TOU) pilot and our EV pilot proposals. All of this guidance and feedback helped shape our proposal in terms of the advanced grid capabilities, how we prioritized the advanced applications, and how we evaluated the costs and benefits of the various AGIS components.

[2] https://www.energy.gov/oe/activities/technology-development/grid-modernization-and-smart-grid, as of Oct. 1, 2019.

Q. IN LIGHT OF COMMISSION POLICY DIRECTIONS, ARE THERE OTHER STRATEGIC REASONS WHY THE COMPONENTS OF THE AGIS INITIATIVE ARE IMPORTANT AT THIS TIME?

A. Yes. Various Commission policies and specific goals of each of the efforts described above are supported or enabled by advanced grid technologies. We have considered these policies, goals, and the stakeholder input as we developed our overall strategy and specific project plans for AGIS implementation. I discuss this further in Section IV, along with other drivers of our AGIS strategy.

Further, as the prevalence of DER continues to rise, the ability to manage these resources requires visibility into the grid and a more resilient and responsive grid. As the DOE Smart Grid Report stated, grid advancement is necessary to support "the increasing presence of renewable generation and the proliferation of customer- and merchant-owned DERs [that] are introducing significantly greater levels of variability and uncertainty in both the supply of electricity and the demand for it. Generation and load profiles, which have been predictable in the past, can now vary instantaneously and are subject to the behavior of consumers where DERs are present."[3] Enhanced grid management through ADMS, meters with two-way communications that act as sensors, and greater voltage optimization will all support our ability to host increasing levels of DERs.

Given these circumstances and the additional customer and system benefits enabled by advanced grid technology, the Company determined now is the appropriate time to pursue a targeted AGIS initiative that will address system

[3] DOE Smart Grid Report at p. 5.

needs, customer needs, and our overall strategic priorities as a Company to lead the clean energy transition, enhance the customer experience, and keep bills low.

C. AGIS Implementation

Q. WHAT PORTIONS OF THE AGIS INITIATIVE ARE UNDERWAY?

A. With the Commission's certification and approval of our first year of costs, the ADMS is underway and scheduled to go into service in 2020. We are also in the process of implementing our TOU pilot, consistent with the Commission's Order in Docket No. E002/M-17-775, certifying it as a distribution project under Minn. Stat. § 216B.2425 (*i.e.*, a grid modernization project). This pilot is intended to study time of use rates and how to maximize their value. This limited deployment of AMI meters and the FAN communications network in connection with the TOU pilot is a part of the overall AGIS initiative, and has been considered as we have developed plans for full deployment of advanced grid technologies. Likewise, we have conducted system research and testing around FLISR and IVVO, as discussed by Company witness Ms. Kelly Bloch.

Q. WHAT IS THE TIMING OF OVERALL AGIS IMPLEMENTATION?

A. Implementation of the components of the AGIS initiative will occur over several years and be substantially complete by 2024, with FLISR implementation expected to continue through approximately 2028. As such, a large portion of AMI, FLISR, IVVO, and FAN work will be undertaken and placed in service during the multi-year rate plan (MYRP) period, and are included in the Company's rate request. Our implementation timeline is set forth in Table 1, below:

Table 1

Program	Implementation Timeline
ADMS	In-service 2020
AMI	Meter roll-out 2021-2024
FAN	Deployment 2021-2024 (preceding AMI deployment by approximately six months)
FLISR	Limited testing 2020; Implementation 2020-2028
IVVO	Limited testing 2021; Implementation 2021-2024

That said, the grid modernization effort is ongoing by nature and we will continue to maintain the system as well as leverage evolving technology, platforms and optionality as appropriate over time. Likewise, we understand that the Commission's IDP requirements contemplate five- and ten-year outlooks. As such, our discussion of AGIS costs and benefits includes but also extends beyond the MYRP timeframe, and our cost-benefit analysis (CBA) (described in Section VI of my Direct Testimony) runs through the lifecycle of the assets based on the information currently known (as with any integrated long-range plan).

Given the longer term outlook required in the IDP filing, I also discuss potential future AGIS investments that are not planned for the MYRP. We are not seeking recovery or certification of these investments in this case and do not have an implementation schedule at this time. However, I discuss them to provide a view of potential future functionality that today's investment in the advanced grid will enable.

Q. PLEASE EXPLAIN IN MORE DETAIL HOW THE COMPANY'S RATE CASE DISCUSSION OF THE AGIS INITIATIVE AND IDP FILINGS INTERRELATE.

A. The Company is filing its IDP concurrently with this rate case filing. The IDP would typically include the Company's grid modernization report, while a rate case filing typically focuses on the test year or MYRP. In this case, however, while we focus on investments during the MYRP period as the elements for which are seeking cost recovery, we also introduce longer-range plans to provide context for our overall distribution system vision. For example, in my testimony, I discuss the core components of AGIS – AMI, the FAN, FLISR, and IVVO – and the Company's building block approach to deploying these components. I also discuss ADMS as part of our overall strategy and distribution planning, even though ADMS has been previously certified by the Commission, and the first year of costs were recently approved for recovery under our Transmission Cost Recovery (TCR) Rider.

Together, this filing and the IDP respond to the Commission's direction to bring the Company's overall vision into focus, including providing extensive detail regarding AGIS and distribution strategies as well as specifics around implementation and planned outcomes.

Q. WHAT ARE THE OVERALL ANTICIPATED COSTS OF THE AGIS INITIATIVE?

A. The Company anticipates incurring capital expenditures totaling $524 million and O&M costs totaling $152 million for the overall AGIS initiative, exclusive of ADMS.

Table 2

Total AGIS Capital Expenditures

NSPM – Total Company Electric

(Dollars in Millions)

	Rate Case Period			5-Year Period	10-Year Period
AGIS Program	**2020**	**2021**	**2022**	**2023-2024**	**2025-2029***
AMI	$14.0	$28.9	$144.0	$185.2	$15.0
FAN	$14.7	$37.3	$36.8	$3.8	$0.0
FLISR	$3.5	$8.6	$6.6	$18.8	$29.7
IVVO	$0.1	$6.5	$9.8	$18.6	$0.0
Total	**$32.3**	**$81.3**	**$197.2**	**$226.4**	**$44.7**
*Period may include additional assumptions, including inflation and labor cost increases, that are not part of the capital budget in periods 2020-2024.					

Table 3

Total AGIS O&M

NSPM – Total Company Electric

(Dollars in Millions)

	Rate Case Period			5-Year Period	10-Year Period
AGIS Program	**2020**	**2021**	**2022**	**2023-2024**	**2025-2029***
AMI	$6.6	$16.4	$14.1	$25.2	$67.2
FAN	$0.1	$2.3	$1.5	$0.5	$8.6
FLISR	$0.2	$0.4	$0.3	$3.3	$2.5
IVVO	$0.0	$0.4	$0.8	$0.6	$0.8
Total	**$6.9**	**$19.5**	**$16.7**	**$29.4**	**$79.1**
*Period may include additional assumptions, including inflation and labor cost increases, that are not part of the capital budget in periods 2020-2024.					

Q. WHAT ARE THE COMPANY'S SPECIFIC REQUESTS OF THE COMMISSION WITH RESPECT TO THE AGIS INITIATIVE?

A. We have two primary requests in this proceeding and in the IDP. First, we request approval to recover the costs of capital investments and O&M expense for the AGIS components that we propose to implement during the 2020-2022 term of the MYRP. We are proposing full AMI and FAN implementation, as well as implementation of FLISR and IVVO. The Company anticipates incurring the following capital additions and O&M costs for the AGIS initiative during the 2020-2022 period of the MYRP:

Table 4
Capital Additions for the AGIS Components (2020-2022, includes AFUDC)
$ in Millions – Minnesota

AGIS Component	2020	2021	2022
AMI	$16.0	$27.9	$119.8
FAN	$8.3	$21.3	$42.0
FLISR	$3.4	$8.4	$6.4
IVVO	-	$5.7	$8.6
Total	$27.7	$63.3	$176.8

Table 5

O&M for the AGIS Components (2020-2022)

$ in Millions – NSPM

Component	2020	2021	2022
AMI	$6.6	$16.4	$14.1
FAN	$0.1	$2.3	$1.5
FLISR	$0.2	$0.4	$0.3
IVVO	-	$0.4	$0.8
Total	$6.9	$19.5	$16.7

Second, because the AGIS implementation period extends beyond the term of our proposed MYRP, we are requesting that the Commission certify the AGIS projects overall, so that the Company would be allowed to request recovery of cost for 2023 and later in subsequent rider filings based on certification via this proceeding and/or the concurrent IDP filing. This is consistent with other requests for certification in the grid modernization and IDP filings, where certification does not guarantee cost recovery, but enables the opportunity for the Company to request recovery of costs in a subsequent rider filing. Certification of AGIS projects will provide a cost recovery option in the event the Company would not otherwise file a general rate case immediately following the conclusion of this MYRP period.

Q. DOES THE COMPANY PRESENT DETAILED SUPPORT FOR THESE COSTS, AND FOR THE QUANTITATIVE AND QUALITATIVE BENEFITS ASSOCIATED WITH THEM?

A. Yes. As I describe below, the Company presents a detailed cost-benefit analysis for each AGIS component – including both quantitative and qualitative support. Additionally, we provide detailed information to support the proposed investments for each year of the MYRP.

Q. WHY DOES THE COMPANY BELIEVE BOTH MYRP RATE RECOVERY AND CERTIFICATION FOR POTENTIAL TCR RECOVERY ARE APPROPRIATE?

A. We believe both MYRP cost recovery and certification are appropriate because of the extensive amount of support and analysis we are providing in this case – including everything required for both the MYRP and the IDP. The witnesses supporting the AGIS initiative provide support for costs during the MYRP term as well as for AGIS implementation beyond 2022. These witnesses discuss in detail the anticipated work to be done, the expected implementation timelines, and the reasonableness of underlying assumptions for planning and cost-benefit analysis purposes. Given the complete information we provide on overall AGIS implementation and costs, we believe granting cost recovery during the MYRP and certification of the AGIS projects beyond the MYRP is appropriate in this case.

D. Witness Support for the Proposed AGIS Initiative

Q. WHAT INFORMATION DO YOU PROVIDE IN THIS SECTION OF YOUR EXECUTIVE SUMMARY?

A. Below I describe the business areas involved in implementing the AGIS initiative, identify the witnesses supporting AGIS, and provide an overview of the topics covered by each. Because the large majority of information necessary to support the AGIS initiative in this rate case and in the concurrent IDP is contained in this rate case filing, this section of my Direct Testimony provides a roadmap to help navigate the extensive information and testimony we provide on the AGIS initiative.

We have made every effort here to identify the location of specific topics and information to aid the reader. Exhibit___(MCG-1), Schedule 2 is the AGIS Completeness List, which identifies specific filing requirements and where the information is located. In my testimony I provide a higher-level roadmap.

Q. WHAT AREAS OF THE COMPANY ARE INVOLVED IN IMPLEMENTING AND SUPPORTING THE AGIS INITIATIVE?

A. The AGIS initiative is supported by and affects many operating and customer service areas of our business. In particular:

- Our Distribution Operations business area is responsible for the planning, implementation, and operations of the various advanced grid components. At a high level, this can be thought of as installing, maintaining, operating, and protecting the foundational hardware and support components of AGIS on the distribution system.
- The Business Systems area is responsible for the hardware and software systems necessary to deploy and secure the AGIS components from an information technology (IT) perspective. Business Systems is also responsible for implementation of the IT platform that will enable the Company to interface with customers through various portals, and to provide customers access to additional information, products, and services that will be possible through the advanced grid initiative. Business Systems also works hand-in-hand with our security team to protect the Company's software systems from cyber attacks.
- Customer Care is responsible for meter reading, billing, credit, remittance processing, and customer contact center functions. The Customer Care team will manage customer questions and concerns as

the AGIS initiative is being deployed, as well as the new billing options and programs that will be made available.

Other customer-facing teams are also heavily involved. Customer Solutions is responsible for development and implementation of those customer-facing online and mobile applications, as well as new products and services, that will be enabled by the advanced grid capabilities. Our Customer Insights group is responsible for survey and research efforts necessary to determine the needs and preferences of our customers with respect to development of new products and services, as well as to measure customer satisfaction with new products, services, or advanced grid capabilities. Corporate Communications is responsible for the customer education and communications related to implementation of new technologies and products and services related to advanced grid capabilities. In short, the AGIS initiative will touch many areas of both NSPM and Xcel Energy as a whole.

Q. WHICH COMPANY WITNESSES ARE PROVIDING TESTIMONY IN THIS CASE TO SUPPORT THE COMPONENTS OF THE AGIS INITIATIVE?

A. As noted in the introduction to my direct testimony, the Company is presenting five witnesses who provide Direct Testimony and accompanying schedules supporting our request for approval of the capital and O&M budgets for the specific components of AGIS included in this case, as well as support for the broader Integrated Distribution Plan being filed concurrently with this case. These witnesses' respective topics are as follows:

- My testimony presents the overview of the AGIS initiative, the background on our efforts to date, an explanation of governance as it relates to the AGIS initiative, a discussion of the customer experience upon implementation, an explanation of our customer outreach and progress metrics proposals, and an overview of the cost-benefit analyses as well as customer bill impacts.

- *Kelly A. Bloch,* Regional Vice President of Distribution Operations, addresses the AGIS initiative from the Distribution perspective, and specifically identifies those costs and benefits that derive from the Distribution portion of the business. Her testimony details the business case for AMI, FLISR, and IVVO, and provides extensive discussion of these technologies, alternatives considered, and supporting cost and benefit detail.
- *David C. Harkness,* Senior Vice President of Customer Solutions for XES, addresses the AGIS initiative from the Business Systems (IT) perspective, focusing on integration of the hardware and software necessary for the AGIS elements to function together and with existing Company systems. Mr. Harkness also details the business case for the FAN strategy and project management, as well as alternatives considered and supporting cost detail. Mr. Harkness also discusses cyber security for the AGIS initiative, as well as the costs and benefits of the IT hardware and software systems necessary to deploy each of the AGIS components.
- *Christopher C. Cardenas,* Vice President of Customer Care for XES, explains the current status of the expiring Cellnet contract for wireless metering, meter change and billing impacts and options as AMI meters are deployed, and potential tariff changes the Company plans to pursue in the future. Mr. Cardenas also describes certain cost savings and customer benefits associated with moving away from our current meter reading system.

- *Ravikrishna Duggirala,* Director of Risk Strategy for XES, supports the Company's cost-benefit model for the individual core AGIS components as well as the overall AGIS initiative. Dr. Duggirala explains the structure of the model, how inputs received from other business areas were utilized, and the results of the analyses. Lastly, Dr. Duggirala explains the limitations of any cost-benefit modeling.

Q. CAN YOU IDENTIFY THE NSPM TESTIMONY SUPPORTING THE SELECTION OF AND COSTS FOR THE COMPONENTS OF THE AGIS INITIATIVE?

A. Yes. Because the costs of the AGIS initiative reside in our Distribution and Business Systems budgets, Ms. Bloch and Mr. Harkness support the costs of the AGIS components and most aspects of our initiative's development. As set forth in Table 6 below, Ms. Bloch supports the selection of meters and the FLISR and IVVO field devices and associated implementation; whereas Mr. Harkness describes the associated software, hardware, security, and overall IT integration.

Table 6

AGIS Program Witness Support

AGIS Program	Component	Witness
AMI	IT Integration and head end application	Harkness Direct, Section V(E)(3)
	Meters and deployment	Bloch Direct, Section V(D)
FAN	IT Integration and deployment	Harkness Direct, Section V(E)(4)
	Installation of pole-mounted devices	Bloch Direct, Section V(E)
FLISR	System development	Harkness Direct, Section V(E)(5)
	Advanced application and field devices	Bloch Direct, Section V(F)
IVVO	System development	Harkness Direct, Section V(E)(6)
	Advanced application and field devices	Bloch Direct, Section V(G)

In addition, I support program management for the AGIS initiative in Section V.D of my Direct Testimony, as well as the Company's customer outreach plans in Section VI.E of my Direct Testimony.

Q. PLEASE SUMMARIZE THE BENEFITS OF THE AGIS INITIATIVE AND PROVIDE THE WITNESS RESPONSIBLE FOR SUPPORTING EACH.

A. Overall, the AGIS initiative consists of multiple programs that work together to improve and update our distribution system in many ways. At a system-wide level, we will move from the predominantly one-way system that currently exists to an integrated system of centralized and decentralized energy resources that are connected and optimized through communications systems that share information from across the distribution grid. The advanced grid will leverage automation, real-time monitoring, and communication to locate and isolate disruptions in the system and improve safety, efficiency, and reliability of the system. The advanced grid will also enable greater customer choice by allowing customers to adopt new products, services, technologies, and applications, including access to timely energy usage data and more options for managing their usage. The advanced grid will be more secure, and address cyber and physical threats to the extent possible. Additionally, the advanced grid will allow the Company to manage the increasing amount of DER entering our system.

Ms. Bloch, Dr. Duggirala, and Mr. Cardenas support the benefits of AMI overall and with respect to specific individual benefits. While the IT work is necessary to both implement the AGIS initiative and ensure appropriate security measures, IT by itself does not provide independent benefits; therefore, Mr. Harkness's testimony is limited to a discussion of costs.

Benefits of the AGIS initiative are many and varied, but the types of benefit and supporting witnesses can be summarized as follows:

Table 7

Summary of Benefits for AGIS Components

Benefit	Supporting Witness
AMI	
Distribution System Management Efficiency	Bloch Direct, Section V(D)(4)(a)(1)
Outage Management Efficiency	Bloch Direct, Section V(D)(4)(a)(2)
Avoided Meter Purchases for Failed Meters	Bloch Direct, Section V(D)(4)(a)(3)
Avoided Capital for Alternative Meter Reading System	Bloch Direct, Section V(D)(4)(a)(4)
Avoided O&M Meter Reading Cost for Alternative Meter Reading System	Cardenas Direct, Section V(F)
Reduction in Field & Meter Services	Bloch Direct, Section V(D)(4)(b)(1)
Improved Distribution System Spend Efficiency	Bloch Direct, Section V(D)(4)(b)(2)
Outage Management Efficiency	Bloch Direct, Section V(D)(4)(b)(3)
Customer Outage Reduction	Bloch Direct, Section V(D)(4)(c)
Reduction in Energy Theft	Cardenas Direct, Section V(F)
Reduced Consumption Inactive Premise	Cardenas Direct, Section V(F)
Reduced Uncollectible/Bad Debt	Cardenas Direct, Section V(F)
Critical Peak Pricing	Duggirala Direct, Section II(B)(1)
TOU Customer Price Signals	Duggirala Direct, Section II(B)(1)
Reduced Carbon Dioxide Emissions	Duggirala Direct, Section II(B)(1)
Improved Customer Choice and Experience	Gersack Direct, Section VI and Schedule 3
Enhanced DER Integration	Bloch Direct, Section V(D)(4)(d)(1)
Environmental Benefits of Enhanced Energy Efficiency	Bloch Direct, Section V(D)(4)(d)(2)
Improved Safety to Both Customers and Company Employees	Bloch Direct, V(D)(4)(d)(3)
Improvements in Power Quality	Bloch Direct, V(D)(4)(d)(4)

Benefit	Supporting Witness
FLISR	
Customer Minutes Outage –Savings	Bloch Direct, Section V(F)(5)(a)(1)
Outage Patrol Time Savings	Bloch Direct, Section V(F)(5)(a)(2)
Improved ability to plan distribution system needs	Bloch Direct, Section V(F)(5)(b)
Overall Customer Satisfaction with Utility Service	Gersack Direct, Section VII(B)
IVVO	
Fuel savings (Energy Reduction)	Bloch Direct, Section V(G)(4)(a)(1)
Fuel Savings (Line Losses)	Bloch Direct, Section V(G)(4)(a)(2)
Avoided Capacity Costs	Bloch Direct, Section V(G)(4)(a)(3)
Reduced Carbon Dioxide Emissions	Duggirala Direct, Section II(B)(3)
Customer bill savings for customers with feeders with IVVO assets	Bloch Direct, Section V(G)(4)(b)
Greater Efficiencies from the Customer's Personal Electrical Devices	Bloch Direct, Section V(G)(4)(b)
Increased Hosting Capacity for Distributed Energy Resources.	Bloch Direct, Section V(G)(4)(b)

Q. DID THE COMPANY ALSO PREPARE COMPARISONS OF THE COSTS AND BENEFITS OF THESE COMPONENTS, OR ALTERNATIVES COMPARISONS?

A. Yes – we provide both. As noted above, the Company conducted a CBA for each of the AGIS components and on a consolidated basis. The CBA provides one point of reference to assess the investments in the broader context of the goals of AMI, FLISR, and IVVO implementation, the current qualitative benefits they offer, Commission policy goals, and the opportunities for future customer benefits. The witnesses noted above provide the inputs to the CBA for each component and for the consolidated AGIS initiative, and Dr. Duggirala presents the overall model.

Additionally, Dr. Duggirala presents "Least-Cost/Best-Fit" analyses with respect to the costs/benefits of AMI and manual reading or drive-by AMR solutions; as well as for the costs of FAN versus cellular communications and dedicated AMI network alternatives.

Q. WHAT DOES THE COMPANY CONCLUDE WITH RESPECT TO THE RELATIVE COSTS AND BENEFITS – BOTH QUANTITATIVE AND QUALITATIVE – FOR THE AGIS INITIATIVE?

A. The CBA results indicate that the consolidated quantifiable costs and benefits of the AGIS initiative total 0.87 in our baseline scenario, or 1.03 under a high benefit/no contingency scenario. Thus the combined components do not reach 1.0 (equal quantifiable benefits and costs) under our baseline scenario. However, the baseline benefit-to-cost ratio for the overall AGIS initiative approaches 1.0 even before we factor in qualitative benefits such as customer satisfaction and certain operational and power quality improvements, as well as safety enhancements.

We note that while the CBA, by itself, does not show that quantifiable benefits are equal to quantifiable costs, we would not necessarily expect that result. We are proposing an initiative to both replace fundamental components of our system that are approaching end of life, and to add capabilities for our customers now (and in the future) to address a future that includes greater DER, distributed intelligence, and greater customer engagement. We would not expect to save money (on a net basis) when investing in these kinds of technologies, but we believe the total value of the initiative significantly outpaces the cost of the investments. For these reasons, the AGIS investments are prudent based on the need for the investments to serve customers, as well as consideration of the customer-facing benefits, efficiencies, and system benefits they provide.

E. Roadmap to AGIS Policy Testimony

Q. WITH THAT BACKGROUND, PLEASE SUMMARIZE THE REMAINDER OF YOUR TESTIMONY.

A. In my testimony, I first provide background on grid modernization in Minnesota and discuss how our request in this case relates to our IDP filed concurrently with the Commission on November 1, 2019, in order to establish a backdrop for the Company's view of the future of the grid. I then identify the Company's overall strategic goals, focusing on the environment, the customer experience, and cost of service. I also identify customer expectations and wishes for the future of electric service based on extensive Company research, focusing on how these expectations relate to the future of the distribution system.

I then describe the Company's long-term strategic plan to use technological advances to transform our distribution system to meet changing customer demands, to enhance efficiency, and reliability, and security, to safely integrate more distributed energy resources, and explain how that plan is aligned with core Company goals. I highlight the reasons now is the right time to undertake these initiatives – including our meters nearing end of life and the expiration of our meter reading contract with Cellnet – and discuss the key goals of AGIS and how they are consistent with Xcel Energy's strategic priorities.

I then address the scope of the core components of AGIS that are included in this case, outlining the function, benefits, alternatives considered, timing of implementation, and costs of each. I defer to other Company witnesses to flesh out these components, costs, and benefit assumptions in more detail.

Next, I discuss in detail the current customer experience compared to what will be different when the distribution system is transformed and advanced. I also provide our customer and community outreach plan for the AGIS initiative, designed to educate and inform customers about our progress, impacts they will experience during and after implementation, and advanced grid capabilities that will provide the basis for additional opportunities and services for our customers. I also discuss indicators of progress and success, and how the Company will measure and report on progress and outcomes of the AGIS initiative.

Finally, I describe why AGIS, and thus the foundational elements included in this case, are in the public interest. I introduce the cost benchmarking and cost-benefit analyses we have undertaken, which are specifically supported and presented in detail in the Direct Testimony of Dr. Duggirala. I explain both the value and the inherent limitations of any cost-benefit analysis. I also summarize the quantitative and qualitative benefits of the AGIS initiative, explaining how the benefits of certain components of AGIS are not limited to quantifiable items; they will also update aging systems, improve our customers' overall experience and satisfaction, position the Company for future grid developments, and help achieve broader energy goals.

Q. DO YOU PROVIDE OTHER INFORMATION TO SUPPORT YOUR OWN DISCUSSION OF THE COMPANY'S AGIS IMPLEMENTATION STRATEGY WITH RESPECT TO THE CUSTOMER EXPERIENCE?

A. Yes. Provided as Exhibit___(MCG-1), Schedule 3 is the Company's *Advanced Grid Customer Strategy*. This document the details the Company's AGIS strategy and plans to enhance the customer experience. The document includes, among other things, background on our customer surveys and research efforts that have informed our AGIS strategy, and details on the technologies and customer benefits of each AGIS component.

To help stakeholders further visualize our plans, the Company also prepared a brief video[4] entitled *Building the Future* to illustrate the advanced grid technologies and benefits and illustrate multiple situations where additional data and capabilities with respect to the distribution grid will facilitate a better, smoother, and more agile customer experience. While not as dynamic as the video itself, I have attached illustrations from this video as Exhibit___(MCG-1), Schedule 4 to my Direct Testimony.

Q. WHAT ARE YOUR RECOMMENDATIONS WITH RESPECT TO THE AGIS INITIATIVE?

A. I recommend that the Commission approve our proposed AGIS investments for the term of the MYRP, and certify the components of the Company's long-term AGIS plan (AMI, FLISR, IVVO, and the FAN) for potential future cost recovery in the TCR rider.

[4] https://youtu.be/HoQoHFdF7kc

III. GRID MODERNIZATION BACKGROUND

Q. CAN YOU PROVIDE SOME RECENT HISTORICAL CONTEXT FOR THE COMPANY'S MODERN ERA OF GRID MODERNIZATION EFFORTS AND UNDERTAKINGS IN MINNESOTA?

A. Yes. The Company's first grid modernization report was filed in 2015[5] in compliance with Minn. Stat. § 216B.2425, subds. 2(e) and 8, which required that in addition to the biennial distribution system plan required for all utilities, a utility under a multi-year rate plan would also be required to file a separate biennial grid modernization report. At that time, the new statutory language and requirements reflected the growing interest in ensuring the distribution system would be well positioned to meet future system needs while maintaining security, reliability, and safety. The statute also allowed the Company to request Commission certification of specific projects, for which the Company would then be allowed to include requests for cost recovery in filings under the Transmission Cost Recovery Rider (TCR Rider).

Q. DID THE COMPANY REQUEST AND RECEIVE CERTIFICATION FOR ANY INITIATIVES IN ITS FIRST GRID MODERNIZATION REPORT?

A. Yes. In the 2015 grid modernization report, the Company requested and received certification for the ADMS program. In its Order, the Commission approved certification of ADMS as consistent with statutory requirements. The Commission also noted that because of ADMS' foundational role in grid modernization, the Company should be provided with reasonable incentive to move forward, specifically through the opportunity to request cost recovery through the TCR Rider. The Company has begun ADMS implementation

[5] See Docket No. E002/M-15-962.

and the first year of costs were recently approved to be recovered under the TCR Rider.[6]

Q. DID THE COMPANY REQUEST AND RECEIVE CERTIFICATION FOR ANY INITIATIVES IN ITS SUBSEQUENT GRID MODERNIZATION REPORT?

A. Yes. In its 2017 Distribution Grid Modernization report,[7] the Company sought and received certification for a TOU rate under a new pilot program.[8] The TOU pilot implements new residential TOU rates in two communities in the Twin Cities metropolitan area, and provides participants with increased energy usage information, education, and support to encourage shifting energy usage to daily periods when the system is experiencing low load conditions. To support the TOU pilot, we will deploy both AMI meters and the necessary FAN communications in the participating communities.

The goals of the pilot program are to study adequate price signals to reduce peak demand, identify effective customer engagement strategies, understand customer impacts by segment, and support demand response goals. In its Order, the Commission certified the TOU pilot as consistent with statutory requirements, noting that the pilot program will allow the Company and its customers to learn more about the TOU rate. The limited deployment of FAN and AMI through the TOU pilot will also allow the Company an opportunity to measure and verify key assumptions regarding customer behavior in advance of the planned wider rollout of both initiatives. Customer engagement and installation of both FAN and AMI in connection with the TOU pilot began in 2019.

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[6] See the Commission's Order dated September 27, 2019 in Docket No. E002/M-17-797.
[7] See Docket No. E002/M-17-776.
[8] See Docket No. E002/M-17-775.

Q. DURING THE PERIOD YOU DISCUSS ABOVE, WERE THERE OTHER PROCEEDINGS ON GRID MODERNIZATION IN MINNESOTA?

A. Yes. In 2015, after enactment of the new grid modernization statute noted above, the Commission opened an investigatory docket on grid modernization[9] and issued the *March 2016 Staff Report on Grid Modernization*. Of various potential options outlined in the Staff Report, the Commission supported examining distribution system planning as the most reasonable and actionable way to assist in the forthcoming grid evolution. The Commission also supported the staff-proposed guiding principles as its Planning Objectives, as follows:

- Maintain and enhance the safety, security, reliability, and resilience of the electricity grid at fair and reasonable costs, consistent with the state's energy policies;
- Enable greater customer engagement, empowerment, and options for energy services;
- Move toward the creation of efficient, cost-effective, accessible grid platforms for new products, new services, and opportunities for adoption of new distributed technologies; and
- Ensure optimized utilization of electricity grid assets and resources to minimize total system costs.

During this proceeding, the Commission conducted a workshop seeking stakeholder input on a Minnesota-based distribution system planning framework. The Commission also accepted comments and replies seeking to understand how utilities currently plan their systems, the status of current-year

[9] See Docket No. E999/CI-15-556.

utility plans, and recommendations for improvements to present planning practices.

The Commission then established individual utility IDP dockets,[10] where Staff and the utilities worked on proposed IDP filing requirements, with a comment and reply period for stakeholder input. The Commission determined final IDP requirements for Xcel Energy at its August 9, 2018 hearing, and issued its Order on August 30, 2018. Like development of the IDP requirements, the Order acknowledges IDP as envisioned by the planning objectives will be an iterative process – set in motion with the Company's initial IDP.

Xcel Energy's first IDP was filed November 1, 2018, and is due annually thereafter. The biennial grid modernization reports discussed above are now combined with the annual IDP filings.

Q. HOW DOES THE COMPANY'S RATE CASE REQUEST RELATE TO THE COMPANY'S MOST RECENT IDP FILED ON NOVEMBER 1, 2019?

A. The annual IDP filing addresses distribution system planning overall. Through the IDP, the Company is also allowed to request certification of specific projects that meet statutory requirement for grid modernization projects, which then allows the Company to subsequently request recovery of the costs of those projects under the TCR Rider. This year, the Company is filing its IDP and this rate case concurrently on November 1, 2019. As such, while the IDP addresses the AGIS initiative in the discussion of overall distribution system planning, the Company is requesting approval to include in base rates the costs of the AGIS components implemented during the term of

[10] Xcel Energy's IDP filing requirements were developed in Docket No. E002/CI-18-251.

the multi-year rate plan. These components include AMI, the FAN, FLISR, and IVVO.

Further, because ADMS cost recovery has been approved under the TCR Rider, and the ADMS implementation process is at an advanced stage, we propose to continue recovery of the ADMS costs under the TCR Rider. While the costs of the TOU pilot were also certified for potential recovery under the TCR Rider, we are requesting that TOU pilot costs incurred during the MYRP be included in base rates to align with the stage of the pilot and future AMI efforts. Our testimony in this case and our IDP filing provide the support for these cost recovery proposals.

Additionally, through the IDP proceedings, the Commission has issued requirements around the level and types of information that are expected to be included in any future request to proceed with AGIS initiative components. As a result, this rate case testimony provides the 2020-2022 multi-year rate plan capital and O&M expenditures for the AGIS initiative in the broader context of our longer-term AGIS strategy. The information in this case also supports our request for certification of the AGIS projects for potential future rider recovery.

Q. HOW IS THE COMPANY ILLUSTRATING ITS COMPLIANCE WITH BOTH RATE CASE AND IDP REQUIREMENTS THROUGH ITS COMPLEMENTARY NOVEMBER 1, 2019 FILINGS?

A. In our last IDP filed in November 2018, we noted that we intended to bring the costs and benefits associated with specific grid modernization projects to the Commission for approval through either a future certification request in the grid modernization/IDP filings or through a general rate case. Several additional requirements have been established in the Commission's most recent TCR Order.

Our request for rate recovery for AGIS initiatives in this case includes the information required by the Commission, as noted in my testimony and the Direct Testimony of the other witnesses supporting AGIS projects in this case. In the attached Schedule 2, I provide the AGIS Completeness List, which identifies the filing requirements for future Xcel Energy grid modernization projects in Minnesota, and specifies where we have provided this information in our direct testimony in this case. This schedule also identifies where information is provided solely in the IDP rather than this rate case, to provide a holistic view of the information provided in the two complementary dockets.

IV. DRIVERS OF THE AGIS STRATEGY

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section of my testimony, I explain why the AGIS initiative is a necessary and appropriate step for the Company, as it is aligned not only with Xcel Energy's strategic priorities to meet customers' current and forward-looking expectations and service needs but also the needs of the existing NSPM distribution system as well as the objectives that emerged from the Commission-led grid modernization planning process. Indeed, the AGIS initiative supports Commission policy and reflects our previous work with stakeholders relative to customer offerings, performance, and technological capabilities of the grid. I further describe the current customer experience with the Company's electric service delivery. In this way, I establish the reasons we have developed and propose to continue pursuing the AGIS initiative.

Q. WHAT ARE THE SPECIFIC DRIVERS BEHIND THE NEED FOR AGIS IMPLEMENTATION AT THIS TIME?

A. The need to modernize the grid is driven by

- the Company's overall strategic priorities;
- changing customer needs and preferences;
- distribution system needs; and
- Commission policy and stakeholder input.

Our goal with AGIS implementation is to use new technologies to transform the customer experience to meet the increasing customer demands for additional energy usage data as well as new products and services that will provide opportunities for customers to use that information to control usage.

In addition, there are system needs related to aging technology that make now the right time for the Company to implement the elements of the AGIS initiative. We have already begun ADMS implementation and will need to replace our current AMR infrastructure in the near term to maximize that investment in ADMS and avoid end of life issues with our current meters.

Our AGIS initiative has also been informed by Commission policy and our previous work with stakeholders in various proceedings related to distribution grid planning, advanced rate design, and performance-based metrics.
In this section of my testimony, I discuss each of these drivers.

A. The Company's Strategic Priorities

Q. WHAT ARE THE COMPANY'S OVERARCHING STRATEGIC PRIORITIES FOR ITS CUSTOMERS AND ITS BUSINESSES?

A. As described by Company witness Mr. Gregory Chamberlain, Xcel Energy presently has three overall strategic priorities, which are as follows:

- Lead the Clean Energy Transition – Decarbonize the energy sector by retiring fossil fuel resources and replacing them with cost-effective and carbon-free resources.
- Enhance the Customer Experience – Deliver personalized products and services that meet our customer's lifestyle needs and offer them a personalized and contemporary customer experience.
- Keep Bills Low – Drive costs from generation, transmission, and distribution, and continue to deliver safe, reliable, affordable, and sustainable electric and gas services.

Q. HOW DOES AGIS IMPLEMENTATION SUPPORT EACH OF THESE STRATEGIC PRIORITIES?

A. First, AGIS will improve our ability to maximize environmental and conservation goals. By implementing the advanced grid technologies that provide for two-way communications, there will be significant improvement in the Company's ability to collect system data, manage distributed energy resources, and track outages and power quality issues. This insight into the distribution grid will enhance our ability to deliver on clean energy goals and support increased DER.

With two-way communications and an integrated distribution system with ADMS, we will be able to provide the kinds of data and insights to our customers that would facilitate their own efforts around and understanding of energy efficiency, cost management, and beneficial electrification. Similarly, AGIS will improve our outage and restoration performance in two ways. Specifically, two-way communication and fault location capabilities will allow the Company to: (1) provide timely and accurate communications to customers about outages and restorations; and (2) to isolate faults and restore power to customers in an automated fashion where possible.

While the short-term solution with the least impact on bills is to maintain the distribution system status quo ("do nothing"), this is not a realistic option for any extended period. First, technology is constantly evolving and improving, and customer expectations for interactions with their service providers – both utility and non-utility – are evolving as well. Second, the Company's grid, as currently constituted, cannot be maintained at status quo because certain components are near the end of life and will not be supported in the near future. Finally, the AGIS initiative brings long-term value for customers. Accordingly, my testimony recommends taking the longer, more strategic view, in order to position the Company to continue its environmental leadership, bring the customer experience in line with customer expectations, and help manage reliability and bill impacts over time.

Q. DOESN'T IMPLEMENTATION OF ADMS ACCOMPLISH THESE GOALS?

A. No, not by itself. ADMS helps with these issues, but it is only a start – ADMS is the necessary backbone for addressing the core issues facing our system. Even with ADMS, our current system is limited because it lacks the ability to manage two-way communications and does not provide the level of insight into the distribution system that will be necessary to enhance our ability to deliver on clean energy goals and support increased DER as we move into the future. Likewise, AMI meters themselves, supported by FAN communications, are a foundational aspect of better outage and usage data, but require additional technology to enable the Company and customers to use that data and integrate it with other utility systems. As such, a more comprehensive strategy is needed to serve the Company's strategic vision – which, in the end, is all about the quality of service to our customers.

Q. IS THE AGIS INITIATIVE THE COMPANY'S ONLY PLAN TO MEET THESE XCEL ENERGY STRATEGIC PRIORITIES?

A. No. As discussed by Company witness Mr. Chamberlain, the AGIS initiative is a key part of a broader strategic vision. The AGIS initiative is specific to the distribution grid and associated information technology systems, the utility customer's experience is affected by a much broader array of services and capabilities.

For example, in conjunction with the AGIS initiative, the Company is embarking on a Customer Experience transformation, which is intended to update the Company's digital channel platforms (MyAccount and the mobile application, for example), and our customer resource management systems to ensure a better, more modern customer experience. Mr. Harkness discusses the Customer Experience efforts in more detail in his Direct Testimony. These are not specific to the AGIS initiative, but rather complement it to bring the utility's interfaces up to date and meet existing and evolving customer expectations. In other words, the Company is thinking holistically about the customer experience, with AGIS serving an important piece of that strategy.

B. Changing Customer Needs and Preferences

Q. HOW ARE CHANGING CUSTOMER NEEDS AND PREFERENCES DRIVING THE NEED FOR AGIS IMPLEMENTATION?

A. The needs and preferences of customers continue to evolve in the digital age, with increasing dependence on information and the connectivity of digital devices. While incremental modernization efforts have taken place on the distribution system over many years, and we have used these investments to provide reliable power for decades, we (along with the broader industry, as noted earlier in my testimony) believe now is the right time to begin a more significant advancement of the grid. Technological advances now make it possible to meet growing customer expectations for a more robust, reliable, and resilient system, as well as customer desire for more insight and visibility into the energy choices they are making.

Q. CAN YOU PROVIDE SOME EXAMPLES OF THESE GROWING CUSTOMER EXPECTATIONS?

A. Yes. Customers are increasingly savvy when it comes to smartphone applications and sophisticated websites. They are accustomed to engaging electronically to manage their accounts, resources, and service needs across many industries. Without advanced meters that can provide regular usage data, it is not possible to bring the energy industry along that same curve by developing sophisticated energy management and conservation tools such as TOU rates, nor the applications and web-based tools that allow the customer to observe and manage their consumption. The improved interactions with the utility, outage response, and control over their energy usage and bills that our customers want begins with foundational advanced grid initiatives that we are seeking recovery of in this case. By way of example, approximately 2/3 (66 percent) of our NSPM customers surveyed over the past 12 months through August of 2019 said they want to be able to control their energy use when not at home. Customers expect to be able to turn lights on and off remotely, for example, but have no remote insight into how much energy they are actually using at this time. Further, 44 percent of NSPM customers over the same time period said they want alerts when their monthly usage or bill amount goes over a preset amount. These services require advanced metering and more timely usage data in order to provide these services and controls to our customers.

Q. DOES THE COMPANY CURRENTLY HAVE DIGITAL CHANNELS TO PROVIDE ENERGY USAGE INFORMATION TO CUSTOMERS?

A. Yes. Currently, the Company has a web portal, called MyAccount, where customers may obtain energy usage and billing information. We provide customers with energy usage information through the MyEnergy portion of MyAccount; however, the information in this portal is primarily limited to a comparison of monthly energy usage versus weather trends and general recommendations about how to reduce energy consumption. This portal also provides Green Button Download, which enables customers to download their energy usage data. While helpful information, it is not the sort of personalized data and insight our customers are seeking, and we have largely reached the limits on the level of data and customer engagement we can provide with our current systems.

Today, the Company receives energy usage data on a monthly basis, and this customer data is limited only to energy (kWh) consumption during the read period (typically the most recent 30 days). We cannot obtain data regarding the time when customers consume energy, the demand (kW) an individual places on the grid, or what end-use technologies contribute to the energy consumption. Customers receive information only on their aggregate monthly energy usage via a monthly bill.

Q. CAN YOU EXPAND ON HOW THE FUNCTIONALITY OF THE CURRENT GRID IMPACTS THE CUSTOMER EXPERIENCE?

A. Yes. First, the most direct impact that current system functionality has on the customer experience is during an outage. Today, the Company has limited insight into an outage on certain portions of our system. Typically, we cannot anticipate an outage and, in most of our service territory and for outages below the feeder level, do not know when an outage occurs unless a customer contacts us. We also have limited insight into what caused an outage after it is identified, cannot pinpoint the location of an outage easily or quickly, and cannot definitively notify a customer when an outage has been restored. Outages and the Company's ability to restore power and provide timely and accurate communications have a large impact on our customers' day-to-day lives and the quality of service they receive. This is a fundamental aspect of our service that we seek to improve through the AGIS initiative.

In addition, the lack of data detail and timeliness of energy usage information is an impediment to empowering customers to see and respond to their own energy usage, and therefore exercise more power over both conservation efforts and their bills. The current system limits the Company's ability to provide such information to customers to better inform their decisions about their own energy usage and its impacts. Our customers increasingly want additional information and energy options that are not provided with the basic functionality of our current systems.

Q. DOESN'T THE COMPANY CURRENTLY OFFER PROGRAMS FOR CUSTOMERS TO MAKE DECISIONS ABOUT THEIR ENERGY USAGE?

A. Yes, we do offer a significant number of optional programs for customers today, between our renewable choice and CIP/Demand Management programs, but these are essentially self-service programs. While we work hard to facilitate customer engagement in these programs, a customer must make an active effort to engage in the programs and manage the process. Further, the current system does not provide the information necessary to enable the Company to provide specific and personalized advice and recommendations to customers. Rather, we provide general recommendations that tend to work for the average customer under typical conditions – but we know that is not the reality and we are missing opportunities to enhance the customer experience. Each customer is different with respect to both goals and current situations, and we need more customer-specific data and data management tools to provide the level of service customers are seeking.

Q. HOW DID THE COMPANY DEVELOP ITS STRATEGY FOR MEETING THE CHANGING CUSTOMER NEEDS AND PREFERENCES YOU MENTIONED ABOVE?

A. First we worked to understand our customers' preferences and what they think about the benefits and value of an advanced grid investment. To that end, the Company conducted primary research through customer focus groups and surveys. To supplement these research efforts, the Company also reviewed secondary sources, such as the Smart Energy Consumer Collaborative and GTM Research, as well as other utility advanced grid plans. These research efforts are also discussed in detail in Schedule 3.

Q. CAN YOU PROVIDE ADDITIONAL INFORMATION ON THE SPECIFIC RESEARCH THE COMPANY CONDUCTED REGARDING CUSTOMER PREFERENCES AND INTEREST IN THE CAPABILITIES PROVIDED BY ADVANCED GRID TECHNOLOGIES?

A. Schedule 3 identifies the Company's primary research through customer surveys and focus groups, and its secondary research sources as well as other utility advanced grid plans. Below is a summary of surveys and studies that provided key findings to support our customer strategy with respect to the AGIS initiative.

- *Grid Edge Product Survey* – This survey was conducted to gauge customers' opinions and interest toward several proposed product and service concepts that may become available after AGIS deployment, as well as willingness to engage in new services and customers' levels of price sensitivity.
- *Advanced Meter Focus Groups* –The goal of these customer focus groups was to capture customer understanding, perception, and attitudes toward advanced meters, as well as to understand customer expectations of the services enabled by advanced metering. We also sought to understand customer preferences for communications around the deployment and implementation of new meters.
- *2018 MN Smart Meter Survey* – The objective of this survey was to quantify familiarity and perceived value of smart meters, gauging the potential value of AMI-related benefits to customers, preferences for

AMI enabled data, and communications about future smart meter plans.

- *Residential Relationship Study* – This monthly survey is intended to determine the pulse of our customers' opinions and satisfaction with service. Included in the monthly survey are questions which gauge customers' interest in new products and attitudes of and practices around energy usage.

In addition to Xcel Energy's research efforts described above, the following secondary sources were used to inform our customer strategy around advance grid capabilities:

- JD Power Electric Residential Study;
- E Source, *E Design 2020 Small Medium Business Ethnographic Research*;
- Department for Business, Energy & Industrial Strategy (U.K.), *Smart Meter Customer Experience Study: Post-Installation Survey Report*;
- U.S. Department of Energy, *Advanced Metering Infrastructure and Customer Systems: Results from the Smart Grid Investment Grant (SGIG) Program*;
- Smart Grid Consumer Collaborative, *Effective Communication with Consumers on the Smart Grid Value Proposition*;
- Smart Energy Consumer Collaborative, *Understanding Your SMB Customers: A Segmentation Approach*; and
- Chartwell, *Demand Reduction Programs for TOU Customers – Madison Gas & Electric Case Study.*

Q. WHAT ARE THE KEY TAKEAWAYS IDENTIFIED THROUGH THE COMPANY'S RESEARCH EFFORTS RELATED TO ADVANCED GRID CAPABILITIES?

A. Key takeaways from the Company's research include the following:

- *Safety and energy savings* are most highly rated in order of importance to customers.[11]
- *Technology:*
  - Customers care about technology and their interactions with their utility. They want to know how the advanced grid will provide benefits related to those technologies and interactions.[12]
- *Reliability:*
  - Addressing service interruptions is important to all customer classes.[13]
  - Customers expect that service interruptions will be less frequent, smaller in scope, and shorter in duration.[14]
- *Data and Information:*
  - Customers expect to receive detailed energy usage information from their utility.[15]
  - Provision of information is expected to be personal and frequent.[16]
  - Customers expect tools that will help them use information to make decisions about their energy usage.[17]

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[11] Grid Edge Product Survey; Advanced Meter Focus Groups.
[12] Xcel Energy Residential Relationship Study; E Design 2020 Small Medium Business Ethnographic Research.
[13] 2018 MN Smart Meter Survey; JD Power Electric Residential Study; E Design 2020 Small Medium Business Ethnographic Research.
[14] Advanced Metering Infrastructure and Customer Systems: Results from the Smart Grid Investment Grant Program.
[15] Advanced Meter Focus Groups; JD Power Electric Residential Study; 2019 E Source Gap and Priority Study; Colorado Time of Use Non-Participating Customer Survey.
[16] Advanced Meter Focus Groups; 2018 MN Smart Meter Survey; JD Power Electric Residential Study.
[17] 2018 MN Smart Meter Survey; Xcel Energy Residential Relationship Study; E Design 2020 Small Medium Business Ethnographic Research; Effective Communication with Consumers on the Smart Grid Value Proposition.

  - Customers expect that more information will allow them to better identify opportunities and strategies to save energy and reduce their costs.[18]
- *Rate Design:*
  - Business customers have more awareness and familiarity with advanced rate designs.[19]
  - Residential customers expect the utility to provide them with rate comparison tools and information about new rate designs.[20]
- *Trust:*
  - Building trust is a key component to unlocking value for customers. [21]
  - Trust is best built by identifying solutions and showing results specific to the customers. [22]

Q. HOW WOULD YOU SUMMARIZE THESE TAKEAWAYS?

A. Customers want certain features of their electric service that are not possible without a more advanced grid. These include more detailed and timely information about their energy use, improved reliability and outage restoration, and the ability to remotely control their energy usage.

Q. CAN THE COMPANY'S CURRENT METERS AND SYSTEMS MEET THESE CUSTOMER EXPECTATIONS?

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[18] Advanced Meter Focus Groups; 2018 MN Smart Meter Survey; MN Time of Use Rate Study; E Design 2020 Small Medium Business Ethnographic Research.
[19] 2019 E Source Gap & Priority Study; 2018 MN Smart Meter Survey.
[20] Colorado Time of Use Non-Participating Customer Survey; MN Time of Use Rate Study; MN Time of Use Behavioral Focus Groups; 2018 MN Smart Meter Survey.
[21] MN Time of Use Behavioral Focus Groups; E Design 2020 Small Medium Business Ethnographic Research.
[22] E Design 2020 Small Medium Business Ethnographic Research; Advanced Meter Focus Groups.

A. Only to an extent. Without investments in the advanced grid through AMI, the FAN, and ADMS we will not have the tools necessary to meet these concrete customer expectations. Our system, as currently constituted, can only provide customers with the following limited information:

- Monthly, whole premise consumption data;
- General recommendations about how they use their energy – because we lack detailed customer energy usage profiles and disaggregation of their energy usage; and
- Limited information about the existence of an outage and the status of a restoration – because our systems do not report when all outages occur, cannot "self-heal," and cannot automatically identify the cause of an outage.

Q. WHAT DID YOU LEARN ABOUT CUSTOMERS' EXPECTATIONS FOR THE COSTS OF DEVELOPING THE SYSTEMS THAT WILL ACCOMPLISH THESE GOALS?

A. Generally, our research showed that customers need more information to understand the costs and benefits of our proposed investments in the advanced grid. Specifically:

- Customers believe certain safety features should be provided at no cost.[23]
- Customers need specific information about what the cost of the advanced grid is and how it will impact them. [24]
- Customer willingness to pay is tied to customer awareness of the technology and its benefits. Business customers are more familiar with the benefits and more willing to pay.[25]

[23] Grid Edge Product Survey; Advanced Meter Focus Groups.
[24] Advanced Meter Focus Groups; Colorado Time of Use Non-Participating Customer Survey; Minnesota Time of Use Rate Study Grid Edge Product Survey.

Q. CAN YOU PROVIDE ADDITIONAL INFORMATION ABOUT CUSTOMERS' EXPECTATIONS WITH RESPECT TO COSTS?

A. Yes. In our MN Smart Meter Survey, we found that awareness of "smart meters" is low among our residential customers (15 percent) and twice as high among our business customers (30 percent). This same survey found that only 13 percent of residential customers and 36 percent of business customers understood that the cost of smart meters corresponds to more value than our existing meters. This low level of awareness indicates customers are not familiar with what a smart meter is or what the benefits are likely to be. This lack of awareness was also borne out in our Advanced Meter Focus Groups which found that customers were unclear about the basic functionality of advanced meters.

As I previously discussed, while many customers are interested in the benefits of advanced meters, such as control over their energy usage, more information about their energy usage, greater reliability, and environmental benefits, customers do not fully understand the technology or how advanced meters are critical to enabling these benefits. This leads us to conclude that customer education is needed for customers to understand AMI metering and how it relates to the needed technology and associated benefits. Our communications and education plan discussed in Section VI(E) was designed to address this need.

Q. DID THE COMPANY'S RESEARCH PROVIDE ANY OTHER INSIGHT RELATED TO CUSTOMER COMMUNICATIONS AND EDUCATION?

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[25] 2018 MN Smart Meter Survey; Advanced Meter Focus Groups; Grid Edge Product Survey.

A. Yes. Through our Advanced Meter Focus Groups, we also identified that customers would prefer to learn about the meters approximately 2-3 months prior to installation. Education and awareness information is also best provided through multiple channels as not all customers will receive or digest the information the same way. We have taken these considerations and built them into our Customer and Community Outreach plans which I detail below.

Q. HOW DID CUSTOMER CONSIDERATIONS AFFECT THE COMPANY'S DEVELOPMENT OF THE AGIS INITIATIVE?

A. As I noted above, customers expect more resources to help manage their energy usage and want more information about outages. Our investments in the advanced grid are specifically designed to deliver on these expectations. Our investments in AMI, the FAN, and ADMS will reduce the number of minutes customers are out, potentially reduce the number of outages that occur, and allow us to better communicate with our customers about the status of an outage restoration. Similarly, more granular energy usage information, including the timing of when energy is used, what the specific drivers of a customer's energy usage are, and personalized advice on how to change their behavior to reduce their energy usage are only enabled because we will have advanced meters capable of providing detailed interval energy usage data that is transmitted across the FAN at hourly or faster intervals.

Q. HOW DO YOU FACTOR IN THE CONSIDERATIONS OF CUSTOMER COST?

A. Keeping bills low is a priority for Xcel Energy, and keeping bills low starts with smart investments. I discuss the prudence of the AGIS investments and the cost-benefit analyses we conducted in Section VII of my testimony, and I discuss the estimated customer bill impacts in Section VIII. We took a conservative approach in our cost-benefit analyses to ensure that costs were not understated and expected quantifiable benefits were not overstated. However, in addition to considering costs and quantifiable benefits, we also considered the non-quantifiable customer benefits as we developed our strategy for investments in advanced grid technologies. For example, customer expectations for more detailed and timely information is one factor driving our customer strategy. Similarly, although not quantifiable, improvements in overall customer satisfaction, power quality, safety are important considerations. We have also considered the benefits of our advanced grid investments over the longer term, as they will provide the flexibility that will allow the Company to respond to evolving customer expectations and technology advancements in the future.

Q. WERE YOUR RESEARCH FINDINGS USED TO DEVELOP THE COMPANY'S ADVANCED GRID STRATEGY IN ANY OTHER RESPECT?

A. Yes. Results of our research efforts were also used to inform our customer education and communications plan related to the implementation of advanced metering. Our education plan and outreach efforts are discussed further in Section V.C of my testimony.

Q. WERE CUSTOMER NEEDS THE ONLY FACTORS IN THE COMPANY'S DEVELOPMENT OF THE AGIS STRATEGY?

A. No. We also leveraged our internal expertise with respect to utility distribution systems and the Company's systems, in particular, to determine the needs of our distribution grid. We have also looked to broader industry information, which reflects the degree to which advanced grid technology has matured in recent years and demonstrates a clear trend toward its adoption.

C. System Needs

Q. ARE THERE PARTICULAR DISTRIBUTION SYSTEM NEEDS THAT FURTHER CONTRIBUTED TO THE NEED FOR AN ADVANCED GRID INITIATIVE?

A. Yes. Our NSPM distribution grid has several intersectional needs that have driven the development of the AGIS initiative. Like other electric utilities, our current distribution system is based on aging technologies. While appropriate when implemented, multiple components of the distribution system either must be replaced in the near term or they have limited capabilities that simply do not meet the needs and expectations for the system going forward. Further, additional components that integrate with ADMS and advanced meters are necessary to better manage and shorten outages, and to maximize the voltage management on our system. I provide an overview of these needs in this section of my testimony.

Q. WHAT SPECIFIC SYSTEM REQUIREMENTS PROMPTED THE NEED FOR GRID MODERNIZATION?

A. Grid modernization is an issue facing most utilities in Minnesota in varying respects, as evidenced by the Commission's specific proceeding examining the issue. NSPM is no different. The current one-way flow of information on our system means that beyond the distribution substation, the Company has little insight into the workings of the distribution system as it relates to outages or voltage levels experienced by the customer. As further outlined by Company witness Ms. Bloch, the current system is not capable of the two-way communication necessary to identify outages, gather and manage customer data more frequently, support increasing levels of DER, nor optimize voltage levels and identify faults in an automated, responsive, and proactive way.

Q. CAN YOU PROVIDE SOME ADDITIONAL EXAMPLES OF THE EXISTING LIMITATIONS YOU HAVE IDENTIFIED WITH THE COMPANY'S CURRENT METERS?

A. Yes. Without two-way communications, we have limited visibility into what is happening with a particular meter. This means we are missing the ability to provide either timely energy usage data to our customers, or recommendations about how they use their energy. We cannot always identify meter tampering, the shift of a premise to a different user, or other issues without physically visiting a meter. And, as previously noted, we have limited information about the existence of an outage and the status of a restoration – because our systems do not report when an outage occurs.

Q. HOW DOES THE CURRENT SYSTEM LIMIT THE COMPANY'S ABILITY TO IDENTIFY AND RESPOND TO OUTAGES?

A. Because the Company does not have visibility into the system beyond the substation level, the Company primarily gains outage information through customer calling about an outage at the home or business. The Company then analyzes the locations of the outage calls to determine what aspect of the distribution system lost power. It can be frustrating for a customer to have to identify an outage, rather than relying on its electric utility to do so. Ultimately to obtain information regarding outages and storm damaged facilities, the Company must send workers into the field to gather this information manually.

In addition, this lack of two-way communication and fault location capabilities limits the Company's ability to isolate faults and restore power to customers in an automated fashion where possible. These are advanced grid capabilities that FLISR will provide.

Q. DOES THE COMPANY'S CURRENT COMMUNICATIONS NETWORK LIMIT THE CAPABILITIES OF ITS EXISTING DISTRIBUTION SYSTEM?

A. Yes. The Company's current communication network is the Wide Area Network (WAN). The WAN provides high-speed, two-way communications capabilities and connectivity in a secure and reliable manner between Xcel Energy's core data centers and its service centers, generating stations, and substations. However, the WAN is not able to provide communications to support AMI meters or facilitate the operation of FLISR and IVVO. Leveraging the existing WAN, the primary function of FAN mesh network is to enable the communications between the intelligent devices deployed across the distribution system – up to and including meters at customers' homes and businesses. These advanced applications cannot be supported with the Company's current communication network.

Further, the WAN does not allow the Company to monitor and manage impacts of distributed energy resources (for example, solar resources) and other events occurring on the grid in a timely manner. The FAN, however, provides capabilities to monitor and assess impacts closer to the field devices themselves, enhancing the Company's ability to integrate more distributed resources

Q. DOES THE LIMITED AMOUNT OF INSIGHT INTO THE DISTRIBUTION SYSTEM IMPACT OTHER OPERATIONS?

A. Yes. The limited visibility and control of devices on the system also translates to a lack of ability to efficiently manage the voltage level on the system. The current system design does not inform the Company if the end-use customer is outside of an allowable voltage range; therefore, like the need for outage notifications from customers noted above, the Company can only obtain information on voltage variation if the customer calls to complain about conditions that indicate their voltage may be outside of the range. Additionally, lacking the ability to efficiently manage and optimize voltage levels diminishes our DSM options. The addition of the IVVO component of ADMS will address these limitations.

Q. ARE THERE CURRENT SYSTEM LIMITATIONS THAT AFFECT THE INTEGRATION OF DER ON THE COMPANY'S SYSTEM?

A. Yes. Currently, Xcel Energy does not have the granularity necessary to dynamically forecast the impact of distributed resources, such as private solar and batteries, on the system and our customers. Additionally, the system was designed for known system loads, and while we are able to host significant DER on most of the grid, limitations exist – especially when larger quantities of distributed generation are proposed.

Q. WILL INVESTMENTS IN AGIS IMPROVE THE INTEGRATION OF DERS ON THE COMPANY'S SYSTEM?

A. Yes. Investments in AMI, ADMS, IVVO, and the FAN will improve DER integration and enable the Company to better manage DER. The investment in these AGIS components will provide us the tools to understand the details of how and when customers use and produce energy. We can then use this information to better analyze and operate the local distribution system.

Q. HOW WILL AMI (AND ADMS) ENABLE GREATER DISTRIBUTED GENERATION INTEGRATION?

A. AMI will provide the detailed data on the flow of energy to and from customers, as well as voltage, current, and power quality data from the AMI meter to ADMS. With this information, as Ms. Bloch discusses, system operators will be able to facilitate the integration of greater amounts of distributed generation on to the system.

Additionally, with this data, we will be able to identify any voltage problems caused by solar DERs or a potential transformer overload due to DERs. Coupled with IVVO capabilities, this will allow the Company to enable distributed resources while at the same time maintaining reliability and power quality for each of our customers.

Further, AMI will enable the creation of more accurate load profiles which are used by ADMS to create better system models for planning and operational purposes.

Finally, AMI meters have bi-directional capabilities that can be utilized by our DER net metered customers, without the need for installation of a different meter, which is currently the case.

Q. HOW WILL IVVO INCREASE THE SYSTEM'S ABILITY TO HOST DER?

A. As DER penetration increases, the Company will need to manage the DER's influence on voltage through distribution system voltage control. IVVO will enable the Company to optimize voltage across a feeder where DER is present, and potentially high-voltage situations may occur as a result of DER injection. In this way, IVVO will support the ability for additional distributed resources to be hosted on the system.

Q. HOW WILL THE FAN INCREASE THE SYSTEM'S ABILITY TO HOST DER?

A. As the underlying network that supports the two-way communications of the advanced grid, the FAN supports the AMI meter and IVVO capabilities described above that enable additional DER on the system.

Q. ARE THERE ADDITIONAL CIRCUMSTANCES THAT ARE DRIVING THE NEED FOR GRID MODERNIZATION?

A. Yes. On top of the considerations above, we are facing aging systems even for their current functionality. For example, our Automated Meter Reading (AMR) contract is coming to an end in at the end of 2025, and we have a number of AMR meters that are nearing the end of their useful lives in the early 2020s. All of these considerations factor into the need for a more advanced, responsive grid.

Q. CAN YOU OUTLINE THE AMR CONTRACT EXPIRATION THAT RESULTS IN THE NEED TO REPLACE AMR IN THE NEAR TERM?

A. Yes. Our present AMR system has delivered substantial value for customers since it was implemented in the mid-1990s. Our vendor has announced that they will no longer be manufacturing replacement parts for this proprietary system past 2022. Further, our current AMR meter reading contract expires in 2025 with the possibility to extend this contract for one additional year at a substantial cost. Company witness Mr. Cardenas provides additional details on our current AMR contract in his testimony.

Q. IS THIS CONSISTENT WITH THE STATE OF AMR TECHNOLOGY ACROSS THE UNITED STATES?

A. Yes, very much so. At the same time our AMR technology is reaching the end of its life, the AMI technology and market have matured, which has driven many other vendors to also discontinue support of AMR. According to the U.S. Energy Information Administration, AMI adoption surpassed AMR in 2012, and the gap has widened as AMR rollouts have remained flat.[26] The state of the industry, combined with the state of our existing technology, requires us to make choices now about how to move forward with our metering options.

Q. WHAT DO YOU CONCLUDE WITH RESPECT TO THE CURRENT STATE OF THE COMPANY'S DISTRIBUTION GRID?

A. The technology available to operate electric grids has significantly advanced, at the same time our customers' expectations have increased substantially. It is now possible to implement equipment and systems that will provide the Company with real-time visibility into the grid that we currently lack. While the Company has implemented some of these technologies, it is time to expand the advancing technology to our entire electric grid. As I discuss in the next section of my testimony, the Company's AGIS initiative comprises the Company's strategy for meeting these needs in the years ahead.

D. Commission Policy and Stakeholder Input

Q. HOW HAVE COMMISSION POLICY AND STAKEHOLDER INPUT INFORMED DEVELOPMENT OF THE COMPANY'S GRID STRATEGY?

[26] Source: https://www.eia.gov/todayinenergy/detail.php?id=34012. Ms. Block provides additional discussion in her testimony.

A. Since 2015, the Company has provided information and engaged in extensive stakeholder processes around grid modernization, DER hosting capacity, and integrated distribution system planning. Additionally, the Company's residential TOU pilot was informed by and incorporated stakeholder input in that proceeding. Further, the docket initiated to identify performance metrics and potential incentives for the Company's electric utility operations included a robust stakeholder process. Reporting on some of the metrics identified will be enabled or enhanced through the advanced grid capabilities resulting from AGIS implementation. I discuss each of these topics below, highlighting the Commission policies, goals, and stakeholder input that the Company has considered in developing our AGIS implementation strategy.

Q. PLEASE DESCRIBE THE COMMISSION POLICIES AND GOALS AROUND GRID MODERNIZATION AND INTEGRATED DISTRIBUTION SYSTEM PLANNING.

A. The Company filed its first grid modernization report in 2015 in compliance with a new Minnesota statute.[27] In March 2016, the Commission released the *Staff Report on Grid Modernization* (Staff Report). The Staff Report outlined a phased process and potential options for the Commission to pursue in its investigation into the state's grid modernization efforts. At that time, the Commission supported distribution system planning as the most reasonable and actionable way for the Commission to assist in the forthcoming grid evolutions. The Commission agreed with the creation of a comprehensive, coordinated, transparent, and integrated distribution system planning process in Minnesota and agreed with the staff proposed principles to guide further work as follows:

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[27] Minn. Stat. § 216B.2425, subds. 2(e) and 8.

- Maintain and enhance the safety, security, reliability, and resilience of the electricity grid at fair and reasonable costs, consistent with the state's energy policies;
- Enable greater customer engagement, empowerment, and options for energy services;
- Move toward the creation of efficient, cost-effective, accessible grid platforms for new products, new services, and opportunities for adoption of new distributed technologies; and
- Ensure optimized utilization of electricity grid assets and resources to minimize total system costs.

Q. WHAT STAKEHOLDER PROCESSES INFORMED THE DEVELOPMENT OF GRID MODERNIZATION PLANS AND THE IDP PROCESS?

A. The Commission conducted a comprehensive stakeholder process that included written comments and workshops, where it solicited input and explored many topic areas and aspects of grid modernization and distribution system planning. After issuing the Staff Report, the Commission conducted a workshop and initiated a comments and replies process seeking to understand how utilities currently plan their systems, the status of current-year utility plans, and recommendations for improvements to present planning practices.

The Commission then established individual utility IDP dockets,[28] where Staff and the utilities worked on proposed IDP filing requirements, with a comment and reply period for stakeholder input. From this process, the Commission determined final IDP requirements for Xcel Energy.[29] In

[28] Xcel Energy's IDP filing requirements were developed in Docket No. E002/CI-18-251.
[29] See the Commission's August 30, 2018 Order in Docket No. E002/CI-18-251.

addition to the grid modernization principles listed above, the final IDP Planning Objectives include:

- Provide the Commission with the information necessary to understand Xcel Energy's short-term and long-term distribution system plans, the costs and benefits of specific investments, and a comprehensive analysis of ratepayer cost and value.

The Company's 2019 IDP is being filed concurrently with this rate case. As part of the annual IDP process, the Company engages with stakeholders to share at a minimum, its budgets and investment plans, DER and load forecasts, and its 5-year action plan. The Company additional held stakeholder workshops leading up to its 2019 IDP to discuss its non-wires alternatives analysis and its advanced grid cost-benefit analysis CBA framework.

Q. HOW DOES THE COMPANY'S AGIS STRATEGY INCORPORATE THE POLICIES, GOALS, OBJECTIVES, AND STAKEHOLDER INPUT DESCRIBED ABOVE?

A. Our AGIS implementation strategy and project components are closely tied to what we have heard from the Commission and stakeholders through the grid modernization and IDP efforts and as such, considers the inherent Planning Objectives, filing requirements, and stakeholder input. For example, we have added an IVVO component to our proposal, which is a direct result of the feedback we received in response to our recent grid modernization reports. Our AGIS testimony in this case addresses the Planning Objectives described above, and provides the necessary information to demonstrate the costs and operational and customer benefits of each AGIS component, as well as the long-term value of advanced grid capabilities in supporting Commission policies and objectives including those related to carbon reductions and additional DER integration.

Q. WHAT IS THE COMPANY'S UNDERSTANDING OF COMMISSION POLICIES AND GOALS AROUND HOSTING CAPACITY AND DER INTEGRATION.

A. As articulated in the IDP Planning Objectives noted above, we understand that distribution grid planning should move toward the creation of efficient, cost-effective, accessible grid platforms for new products, new services, *and opportunities for adoption of new distributed technologies*. The statute noted above also requires Xcel Energy to file hosting capacity reports in conjunction with its grid modernization reports (now submitted with the annual IDP filings). In the Company's first hosting capacity report,[30] we noted that we recognize hosting capacity as a key element in the future of distribution system planning and anticipate advanced grid capabilities will have the potential to further enable DER integration. As such, we continue to engage with stakeholders on hosting capacity and integration of increased DER.

Q. HOW DOES THE COMPANY'S AGIS STRATEGY INCORPORATE THE COMMISSION POLICY AND STAKEHOLDER INPUT AROUND OPPORTUNITIES FOR ADOPTION OF NEW DISTRIBUTED TECHNOLOGIES?

A. Our AGIS implementation strategy is designed to support further DER integration on our system, specifically through ADMS coupled with the detailed data provided by AMI meters and the IVVO voltage control capabilities (all supported through the two-way communications enabled by the FAN). As I discussed earlier in Section C, these components will provide the Company the visibility needed to understand and integrate additional DER

[30] See the Distribution System Study filed December 1, 2016, in Docket No. E002/M-15-962.

on a feeder and tools to manage any voltage issues once DER (like solar generation) is installed on a feeder. In this way AGIS supports further DER integration on our system.

Q. WHAT IS THE COMPANY'S UNDERSTANDING OF COMMISSION POLICIES AND GOALS AROUND TOU RATES?

A. We believe the Commissions policies around TOU rates are partially articulated in several of the IDP Planning Objectives, including: *Enable greater customer engagement, empowerment, and options for energy services.* In addition, TOU rates support policy objectives on carbon reduction and goals to reduce peak demand on the system. As articulated in our TOU pilot proceeding, the goals of the pilot program are to study adequate price signals to reduce peak demand, identify effective customer engagement strategies, understand customer impacts by segment, and support demand response goals.

Q. WHAT STAKEHOLDER PROCESSES INFORMED THE DEVELOPMENT OF THE COMPANY'S TOU PILOT PROGRAM?

A. The Company met with key stakeholders to gather feedback and present preliminary plans in advance of its final residential TOU pilot proposal. Xcel Energy established a framework and identified preliminary objectives as the basis of a stakeholder process through which the Company received input on the design of the pilot and made further refinements. Stakeholder input informed the features of the Company's pilot, including the criteria for participation, the design of the customer experience, the desired learnings from the study, and other important elements that shaped the Company's approach.

Q. HOW DOES THE COMPANY'S AGIS STRATEGY ADDRESS THE COMMISSION POLICIES AND STAKEHOLDER INPUT AROUND TOU RATES?

A. The pilot will implement new residential TOU rates in two geographic areas, providing participants with increased energy usage information, education, and support to encourage shifting energy usage to daily periods when the system is experiencing low load conditions. TOU rates for our residential customers are enabled through deployment of both AMI meters and the necessary FAN communications in the participating communities. The limited deployment of these AGIS components in connection with the TOU pilot began in 2019.

Q. WHAT ARE THE COMMISSION'S STATED GOALS WITH RESPECT TO PERFORMANCE METRICS AND POTENTIAL INCENTIVES?

A. In the docket initiated to identify performance metrics and potential incentives for the Company's electric utility operations, the Commission initially set forth the following regulatory policy goals in its January 8, 2019 Order,[31] to promote the public interest by ensuring:

- Environmental protection;
- Adequate, efficient, and reasonable service;
- Reasonable rates; and
- Opportunity for utilities to earn a reasonable return.

The outcomes identified in the order were: affordability; reliability, including both customer and system-wide perspectives; customer service quality, including satisfaction, engagement and empowerment; environmental performance, including carbon reductions and beneficial electrification; and cost-effective alignment of generation and load, including demand response.

[31] See Docket No. E002/CI-17-401.

Q. WHAT STAKEHOLDER PROCESSES INFORMED THE DEVELOPMENT OF THE PERFORMANCE METRICS?

A. The Commission conducted a robust stakeholder process, including two meetings, with a goal of engaging stakeholders in discussing potential metric topics. The Commission also accepted comments and replies seeking input on proposed metrics, measurement of metrics, alignment with outcomes, goals, and principles established in the January order. After determining the metrics in a September 2019 Order, the Commission also required the Company to continue to collaborate with interested parties proposals for calculating, verifying, and reporting each of the metrics.

Q. CAN YOU HIGHLIGHT SOME OF THE STAKEHOLDER INPUT ON DEVELOPMENT OF THE PERFORMANCE METRICS?

A. Yes. The Department of Commerce (Department) indicated in its June 4, 2019 Reply Comments that its policy objectives largely align with the goals and objectives set forth by the Commission.[32] Additionally, the Department expressed interests in: decarbonization and beneficial electrification; rate stability; and responding to customer desires.

Q. WHAT ARE THE STATED OUTCOMES AND METRICS RESULTING FROM THIS PROCEEDING?

A. In its Order dated September, 18, 2019, the Commission set forth metrics in the following categories:

- Environmental performance, including carbon reductions and beneficial electrification;

[32] See Department of Commerce Reply Comments, June 4, 2019, Docket No E002/CI-17-401.

- Reliability, including both customer and system-wide perspectives;
- Affordability;
- Customer service quality, including satisfaction, engagement, and empowerment; and
- Cost effective alignment of generation and load, including demand response.

Q. HOW DOES AGIS IMPLEMENTATION SUPPORT THE COMMISSION'S POLICY GOALS AND INCORPORATE STAKEHOLDER FEEDBACK DESCRIBED ABOVE?

A. Among other things, the Company's AGIS proposal provides foundational capabilities to develop and offer flexible, advanced rates and new products and services that we expect will contribute to improved environmental performance, increased customer satisfaction, engagement and empowerment, and cost-effective alignment of generation and load. It will also improve our overall reliability and the customer reliability experience – and improve the efficiency of the system, which may also result in energy savings for customers. For example, while the Commission established desired goals, outcomes, and principles for the metric design in its January 2019 Order (described above), in later determining specific metrics (September 2019 Order), the Commission recognized that additional work and technology infrastructure, particularly the installation of AMI, may be needed before certain reliability metrics could be widely implemented. The metrics identified in the Commission's Order include MAIFI, locational reliability, and power quality – all of which would enabled by our AGIS proposal in this case.

Q. WHAT OTHER COMMISSION AND STAKEHOLDER INPUT INFLUENCED THE COMPANY'S AGIS PROPOSAL?

A. In May 2019, the Company held a stakeholder workshop focused on the cost-benefit analysis framework for its advanced grid investments. We have incorporated the key aspects of the feedback we received from stakeholders, as follows:

- Clearly articulate the assumptions and the level of certainty/ uncertainty behind them;
- Articulate the dependencies (or non-) between different advanced grid investments;
- Consider framing in concert with the performance metrics proceeding outcomes;
- Prioritize investments – i.e., what comes after the foundational components;
- Demonstrate innovation and creativity around the customer value proposition; and,
- Differentiate between easy-to-quantify and hard-to-quantify benefits for customers.

In addition, the Commission's September 27, 2019 Order in our most recent TCR Rider proceeding[33] provided additional guidance for the cost-benefit analyses for any future requests for cost recovery for AGIS investments. We have addressed these requirements in our CBAs presented with this filing.

Q. CAN YOU SUMMARIZE HOW COMMISSION POLICY AND STAKEHOLDER INPUT INFORMED DEVELOPMENT OF THE COMPANY'S GRID STRATEGY?

A. Yes. These topics have been a particular focus not only for the Company but for the Commission and stakeholders in Minnesota. The Commission policies

[33] Docket No. E002/M-17-797.

and goals developed through these proceedings focus on the future of distribution systems and how advanced grid capabilities will support Commission and state policy goals, including carbon reduction and DER integration, and provide benefits for customers.

V. AGIS COMPONENTS AND IMPLEMENTATION STRATEGY

A. AGIS Component Selection

Q. IN LIGHT OF THESE DRIVERS, PLEASE SUMMARIZE THE COMPANY'S VISION FOR THE FUTURE OF THE ELECTRIC DISTRIBUTION GRID.

A. The Company envisions moving from the predominantly one-way system that currently exists to an integrated system of centralized and decentralized energy resources that are connected and optimized through communications systems that share information from across the distribution grid. The advanced grid will leverage automation, real-time monitoring, and communication to locate and isolate disruptions in the system and improve safety, efficiency, and reliability of the system. The advanced grid will enable greater customer choice by allowing customers to adopt new products, services, technologies, and applications, including access to timely energy usage data and more options for managing their usage. Additionally, the advanced grid will provide timely and accurate information that will allow the Company to manage the increasing amount of DER entering our system. This will be accomplished through the Company's AGIS initiative, which consists of multiple programs that work together to improve and update our distribution system.

Q. CAN YOU PROVIDE AN OVERVIEW OF THE COMPONENTS OF THE AGIS INITIATIVE IN MORE DETAIL?

A. Yes. The components of our AGIS plan include:

- *Advanced Distribution Management System (ADMS)* provides the foundational system for operational hardware and software applications. It acts as a centralized decision support system that assists control room personnel, field operating personnel, and engineers with the monitoring, control and optimization of the electric distribution grid. In turn, ADMS provides greater visibility into an increasingly complex electric distribution grid and operating advanced grid applications. The result is near real-time calculations of the state of the network, including factors such as voltages, currents, real and reactive power, amps, voltage drops, and losses.

  ADMS was initially certified by the Commission in 2016 as part of our 2015 Biennial Grid Modernization Report,[34] and the first year of ADMS costs have been approved for recovery under our TCR Rider.[35] Likewise, ADMS would be necessary regardless of other components of AGIS due to the need for a modern, integrated, two-way distribution system and the increasing use of distributed energy resources (DERs). ADMS also includes the Geographic Information System (GIS), which is a foundational data repository that provides location and specification information for all of the physical assets that make up the distribution system. ADMS uses this information to maintain the as-operated electrical model and advanced applications.

[34] See Docket No. E002/M-15-962.
[35] See Docket No. E002/M-17-797.

- *Advanced Meter Infrastructure (AMI)* is a system of advanced meters, communication networks, and data processing and management systems that enables secure two-way communication between Xcel Energy's business and operational data systems and customer meters. AMI provides a central source of information that is shared through the communications network with many components of an intelligent grid design. AMI enables near real-time monitoring and communication between the meter and ADMS about, among other things, energy usage and outages. The AMI meter itself functions as a sensor that, along with other intelligent field devices, will provide the Company with the necessary information to continually monitor and make the necessary adjustments to the system. AMI is a necessary first step to better customer data, enhanced customer service, and the addition of applications and services for future energy management and optionality.
- *Field Area Network (FAN)* is the communications network that will enable communications between the existing communications infrastructure at the Company's substations, ADMS, meters, and the new intelligent field devices associated with advanced grid applications. With its embedded communication module, the AMI meter itself is a part of the FAN communication network.
- *Fault Location Isolation and Service Restoration (FLISR)* is also an additional component of ADMS. FLISR is wholly different from IVVO, however, in that it involves software and automated switching devices that locate and isolate faults, thereby reducing the frequency and duration of customer outages. Specifically, these automated switching devices detect feeder mainline faults, isolate the fault by opening section switches, and

restore power to unfaulted sections by closing tie switches to adjacent feeders as necessary.

- *Integrated Volt-VAr Optimization (IVVO)* is an application that is built onto ADMS. IVVO automates and optimizes the operation of the distribution voltage regulating and VAr control devices, to in turn reduce electrical losses, electrical demand, and energy consumption. In addition to automating and improving voltage management and power quality, IVVO provides increased distribution system capacity to host DER.

Q. WHY DID THE COMPANY OBTAIN APPROVAL FOR ADMS BEFORE SETTLING ON OTHER AGIS COMPONENTS?

A. Implementation of ADMS is the foundation for all other advanced grid components. ADMS will enable the Company to implement advanced grid technologies necessary in the near term, and will allow the Company to take advantage of future capabilities that will result from rapid advances in smart grid technologies. Specifically, ADMS is a necessary upgrade to our distribution system that will utilize an enhanced distribution grid model to consolidate substations, feeders, taps, and services into a single user interface that more accurately represents the entire distribution grid. GIS is an integral part of ADMS, and ADMS will maintain the as-operated GIS electrical model and advanced applications in near real-time. This model will provide the Company with greater visibility into the distribution system and provide information about the system at a more granular level. ADMS will allow the Company to monitor and control power flow from substations to the edge of the grid. The improved capability over today's systems will enable multiple grid performance objectives to be realized over the entire grid.

Q. WHY IS THE COMPANY PROPOSING TO MOVE FROM AMR TO AMI TECHNOLOGY?

A. As previously noted, there are several reasons. First, we needed to explore options to address the expiration of the Cellnet contract and the pending obsolescence of our AMR meters. We explored multiple metering options, as described by Company witness Ms. Bloch. Operationally, AMR meters have limited functionality and are not considered modern technology. In contrast, advanced meters provide substantial near real-time data that can be used to improve the Company's ability to monitor, operate, and maintain the distribution grid. Advanced meters can be used to verify power outages and service restoration. Improved reliability monitoring can lead to improved outage response, proper protection system analysis and ultimately reduce or eliminate outages. Advanced meters can also provide improved voltage monitoring and management, support better load studies and analysis resulting in improved planning and design, and be used to support additional systems such as an ADMS with applications like IVVO that will promote energy efficiency and peak shaving and FLISR that will allow us to locate, isolate, and remedy faults much faster than our current system options. Additionally, as described in our past TOU pilot filings, advanced meters will also unlock the potential for new rate designs that cannot be supported by the Company's current AMR meters. The benefits of AMI meters are discussed in more detail in the Direct Testimony of Ms. Bloch.

Q. WHY IS THE COMPANY PROPOSING TO IMPLEMENT FLISR TECHNOLOGY?

A. The Company is implementing FLISR because it will continue to improve reliability for our customers. FLISR is a technology that, in most cases, will allow the Company to understand when a fault event occurred and allow the

Company to reconfigure the system more quickly than we are able to today. This application reduces the number of customers that experience an outage for a prolonged period of time in the event of a fault.

Q. WHY IS THE COMPANY PROPOSING TO IMPLEMENT IVVO TECHNOLOGY?

A. The current distribution system has the capability to monitor voltages at the substation but does not have the capability to allow the Company to constantly monitor voltage levels throughout its feeders to the customer premise. As a result, the Company must often operate the system at a higher voltage than what would otherwise be required to ensure the appropriate voltage at the end of a long feeder. The Company's proposed IVVO application will allow voltage to be monitored along the entire length of the feeder and at selected end points (rather than only at the substation). This insight into the voltage levels will allow the Company to utilize lower voltages across the entire feeder at most times. This will result in reduction in distribution electrical losses; reduction in electrical demand; reduction in energy consumption; and increased capacity to host DER. Fundamentally, the IVVO is a demand side management (DSM) tool that controls voltage without requiring behavioral changes from customers.

Q. WHY IS THE COMPANY PROPOSING TO IMPLEMENT THE FAN?

A. The integrated components of our AGIS initiative require an integrated, secure communication system that involves the FAN and the advanced meters. The mesh network allows the advanced meter to communicate its measurement data, power status, voltage current, usage history, and peak demand information back to the Company. Additionally, the FAN integrates with IVVO and FLISR because the advanced meters voltage information and service interruption information is communicated to the Company via the FAN.

Below I provide an overview of the individual components of the AGIS initiative.

1. AMI

Q. WHAT ARE THE UNDERLYING COMPONENTS OF AMI, AT A HIGH LEVEL?

A. The AMI infrastructure itself consists of new meters and associated hardware and software. The components of the advanced meter include: (1) the meter itself (responsible for measurements and storage of interval energy consumption and demand data); (2) an embedded two-way radio frequency communication module (responsible for transmitting measured data and event data available to backend applications); (3) embedded Distributed Intelligence capabilities; and (4) an internal service switch (to support remote connection and disconnection of service).

The AMI meters measure, store, and transmit meter data, including energy usage data from customer locations. The advanced meters can also measure values such as voltage, current, frequency. Additionally, these meters detect outage and restoration events, detect tampering and energy theft events, and perform meter diagnostics.

Q. WHAT IS THE DISTRIBUTED INTELLIGENCE COMPONENT OF THE ADVANCED METER?

A. Distributed Intelligence is an operating system that allows for the installation of a wide-range of potential applications – including grid-facing applications, or those the utility operates and with which the customer interfaces. These applications will have the potential to enhance the customer experience not only by improving the energy usage information and control that a customer has but by introducing new ways to manage the grid.

Today, the potential for applications is broad and we're working with our meter vendor to better define the long-term vision for how the Distributed Intelligence platform will be deployed. Potential use cases for these new applications include:

- Virtual Energy Audits: A remote assessment of the customer's energy usage conducted and compared to an expected baseline with recommendations on how to improve performance;
- Virtual Sub-Metering: The replacement of on-site metering equipment for end-use technologies such as electric vehicles that are on a separate electric rate;
- Smart Thermostat Support: The meter can communicate with the customer's smart thermostat to optimize the operation of the air conditioner; and
- Green Notifications: Messaging provided to the customer that notifies them of periods of high renewable energy on the system that will allow them to cycle their energy usage to align with cleaner energy.

The contract with our meter vendor includes the license costs for four applications. Working with our meter vendor we will identify the appropriate applications for mass deployment. These applications may be customer-facing, similar to those described above, or grid-facing, meaning Xcel Energy interacts with the applications. For these customer-facing applications, we envision engaging the customer through the portal currently called MyAccount. Applications may also be made available as customers participate in new products and services such as our energy efficiency offerings.

Q. HOW IS THE COMPANY PROCURING AND INSTALLING THE ADVANCED METERS?

A. Xcel Energy issued a Request for Proposal (RFP) in March 2018 to select a meter vendor that could provide an AMI meter, project management, and installation services. The Company selected Itron, and a contract was executed on September 1, 2019. Itron was selected for a number of reasons, including that they provided the lowest cost and best overall value for an offering that included distributed intelligence technology and met Xcel Energy's deployment schedule. Ms. Bloch describes the AMI RFP and selection process in her testimony. By selecting Itron, we also ensure a single vendor solution, as Itron was previously selected to provide the FAN network and AMI software, as discussed by Mr. Harkness.

The Company and Itron are committed to working together during AMI implementation to ensure our customers receive excellent service, and will provide coordinated support and address all customer inquiries and any issues that may arise. Mr. Cardenas discusses these plans, as well as customer service tracking and reporting, in his testimony.

Q. WHAT WORK IS REQUIRED TO IMPLEMENT AMI METERS?

A. We must install the AMI meter hardware, as well as software necessary to integrate the "smart meters" across the NSP system. This requires meter development and installation in coordination with our meter contractor, Itron.

Additionally, as Company witness Mr. Harkness describes, new metering technology requires integration with multiple existing Company systems, as well as security protections. This work is complex and requires multiple years of planning, design, and implementation, such that we cannot wait until our AMR technology is no longer supported to begin the process. Further, even as it stands, we are behind our industry peers in taking steps to move away from AMR and to AMI technology.

Once meters and associated software and hardware are implemented, additional work is needed to build the digital platforms for our customers.

Our work around meter installation and use of the associated capabilities also requires customer education, outreach, and support, as I describe in Section V.C. of my testimony.

Q. WHAT IS THE COMPANY'S CURRENT PLAN FOR AMI IMPLEMENTATION IN CONNECTION WITH THE TOU PILOT?

A. We have begun the limited AMI deployment for our TOU pilot. Installation of AMI in connection with the pilot began in 2019 and will be completed during the first quarter of 2020, with TOU pilot launch scheduled for April 2020.

Q. WHAT IS THE COMPANY'S PLAN FOR FULL AMI IMPLEMENTATION FOR ALL CUSTOMERS?

A. Our present AMI plan for Minnesota is to complete the installation of AMI meters in 2024, in anticipation of the end of the support for AMR meters and the end of our present service agreement. Company witnesses Ms. Bloch, Mr.

Harkness, and Mr. Cardenas describe the implementation plan in more detail. I note that our TOU pilot is not intended to validate our plan for full roll-out of AMI to all customers. Rather, the TOU pilot is intended to study the TOU rate and its impacts specifically, particularly with respect to the more timely information and advanced rate design options provided by advanced meters. In other words, it is not necessary for us to conclude the TOU pilot prior to full implementation of AMI.

2. FAN

Q. WHY IS A FAN THE RIGHT TYPE OF COMMUNICATIONS NETWORK FOR THE COMPANY AND ITS CUSTOMERS?

A. The FAN is a private, Company-owned network that will securely and reliably address the need for increased communication capacity that arises from distribution grid advancements. The advantages of the FAN over other alternatives include that a Company-owned network solution enhances security against cyber threats by reducing the use of third party networks, the use of public networks (*i.e.*, cellular), and the reliance on external entities for communications support. Further, developing the FAN as an internal private network allows us to implement our cyber security measures into the design at all levels. In addition, the private network solution allows NSPM to utilize the network's full bandwidth and all capacity is dedicated to the Company's use, which is particularly critical during emergency and outage situations. The FAN also integrates with the communication systems used for current components of our distribution system. Overall, the FAN provides for greater security and efficiency and avoids requiring the Company to incur monthly usage fees that would otherwise be paid to private vendors.

Q. IS OUR SELECTION OF THE FAN APPROACH CONSISTENT WITH WHAT OTHER UTILITIES HAVE DONE?

A. Yes. Our proposed FAN is consistent with developments within the electric utility industry, and current industry standards that have been adopted by vendors, organizations, and other electric utility companies. We actively participate with industry standards organizations and alliances – such as the Electric Power Research Institute (EPRI) and the Institute of Electrical and Electronics Engineers (IEEE) – to ensure that our requirements and assumptions are aligned with the standards and products being deployed throughout the industry. Mr. Harkness discusses this further in his testimony.

Q. WHAT ARE THE UNDERLYING COMPONENTS OF THE FAN, AT A HIGH LEVEL?

A. The FAN will consist of two separate wireless technologies: (a) a lower-speed Wireless Smart Utility Network (WiSUN) mesh network; and (b) a high-speed point-to-multipoint Worldwide Interoperability for Microwave Access (WiMAX) network.

The WiSUN component transfers information between meters and transmits data over the mesh network to an access point device that transitions the data from the mesh network to the WiMAX tier of the FAN or in some cases directly to the Company's Wide Area Network (WAN) currently in place. I also note that in addition to their metering function, the advanced meters will have embedded communication modules that will allow the devices to communicate as part of the WiSUN network.

Q. CAN YOU SUMMARIZE THE WORK AND TIMELINES FOR FAN IMPLEMENTATION?

A. Deployment of the FAN occurs slightly ahead of AMI installation to provide the necessary communications for advanced meter operations. We have already begun the limited deployment in connection with the TOU pilot, which will be completed in the first quarter of 2020. We anticipate full FAN deployment will begin in 2020 to ensure network readiness when AMI meters and other devices are deployed. Mr. Harkness and Ms. Bloch provide details related to the FAN device installation.

During the installation of FAN equipment, Business Systems will work concurrently on integration of the FAN with the Company's other systems. The IT integration work is described in the testimony of Mr. Harkness. To support the TOU pilot, Business Systems has begun to deploy WiMAX base stations in three substations, and the equipment necessary to enable the functioning of those base stations. Business Systems has also conducted field coverage studies to ensure the FAN will provide adequate coverage for both the TOU pilot as well as full deployment of meters and other devices in those areas. Work related to full FAN deployment will continue in 2020, and full FAN implementation is expected to be completed in 2024.

Q. ARE THERE OTHER BENEFITS OF IMPLEMENTING THE FAN?

A. Yes. Having a secure two-way communication network on the system provides for communications not only between ADMS and AMI, but it allows for communications between and among any other new intelligent field devices associated with advanced grid applications. Like ADMS, the FAN is a support network that enables other components of the AGIS initiative (AMI, IVVO, FLISR) to provide customer benefits. Company witness Mr. Harkness describes the strategy and costs for the FAN in more detail.

3. FLISR

Q. HOW WILL THE FLISR COMPONENT WORK WITHIN THE AGIS INITIATIVE?

A. Implementation of FLISR will enable automated capabilities to locate and isolate faults, thereby reducing the frequency and duration of customer outages. FLISR also results in cost savings by enabling the Company to more efficiently restore power with the use of fewer resources. While we currently have small-scale automation programs across our distribution system, those systems are becoming outdated and have limited ability to communicate with other components of our system. In contrast, FLISR will be fully integrated with ADMS and will be able to use the FAN network communications. Additionally, while the Company continually focuses on process improvements, these efforts around outage restoration and communications are likely to result in only limited incremental improvement in those areas. FLISR, on the other hand, will transform the process by which the Company is made aware of and responds to outages, as well as the customer experience related to outages and system reliability. Ms. Bloch discusses FLISR implementation and benefits further in her testimony.

Q. WHAT ARE THE COMPONENTS OF FLISR, AT A HIGH LEVEL?

A. There are four principal components of FLISR:

- Reclosers are pole-mounted reclosing and switching devices that have monitoring, communication, and control capabilities.
- Automated overhead switches are overhead remote switching devices that serve to isolate faults on the system.

- Automated switch cabinets are pad mounted switching devices that perform functions similar to the automated overhead switches but for underground feeders.
- Substation relays function primarily to monitor the status of the distribution system and initiate a command to open the breaker in the event of a fault on the system. These relays can also capture important fault information which will be sent to ADMS.

Q. CAN YOU SUMMARIZE THE WORK AND TIMELINES FOR FLISR IMPLEMENTATION?

A. In 2020, we plan limited installation of FLISR for testing purposes. FLISR will be deployed to a small area in conjunction with ADMS to validate capabilities. Following testing, we will begin FLISR roll-out using selected, targeted deployment to maximize benefits and reduce installation costs. The current FLISR project will cover 208 feeders benefiting approximately 350,000 customers by 2028. Ms. Bloch provides additional implementation details in her testimony.

Q. WHAT OTHER BENEFITS ARE PROVIDED THROUGH IMPLEMENTATION OF FLISR?

A. In addition to the improved system reliability and customer satisfaction and cost reductions discussed above, FLISR also provides benefits through increased visibility into the distribution systems. The ability to see system load in real-time and operate devices remotely has benefits for operating the system during our peak summer season and for construction purposes. This visibility also provides improved data for system planning purposes that, when combined with other system data, can enhance planning and design for the future. Ms. Bloch describes these benefits in more detail.

4. IVVO

Q. WHY IS THE COMPANY PROPOSING TO IMPLEMENT THE IVVO COMPONENT OF THE AGIS INITIATIVE?

A. IVVO serves to automate the optimization of distribution system voltage, providing capabilities that are not available on our current system. Managing the overall voltage profile of distribution system feeders provides benefits in reducing line losses, demand, and energy consumption, while ensuring that voltage levels are adequate for providing safe and reliable power to customers. Voltage management is becoming increasingly important because customers' energy consumption is more dynamic than ever, with on-site solar, batteries, electric vehicles, smart appliances, smart thermostats, and many more electronic devices. The voltage optimization capabilities of the advanced grid will enable not only improved power quality and cost savings attributed to the benefits noted above, but will also increase our ability to host distributed energy resources (DER).

Q. WHAT ARE THE COMPONENTS OF IVVO, AT A HIGH LEVEL?

A. There are four primary components of IVVO:

- Capacitors, a stock component used by the Company. We were able to use our existing equipment standards to support deployment.
- Secondary static VAr compensators (SVC) are a relatively new technology introduced to Xcel Energy's distribution system, and have been successfully tested implemented in our Colorado service territory.

- Voltage and current sensing devices are essentially meters that will be installed on feeders to provide monitoring of voltage and current.
- Load tap changers (LTC) are installed at the substation and function as the local controller to raise or lower the voltage, to optimize voltage levels based on the demand of the demand of the substation transformer.

The Grid Edge Management System (GEMS) is a software application that will be used to communicate between ADMS and the SVCs to improve customer voltages and achieve full value of IVVO implementation.

Q. CAN YOU SUMMARIZE THE WORK AND TIMELINES FOR IVVO IMPLEMENTATION?

A. In 2021, we plan limited installation of IVVO for testing purposes on seven distribution feeders (one transformer area). This will occur as part of the installation of ADMS in that area. Following testing, we plan to begin full implementation of IVVO on 189 feeders serving approximately 224,000 customers. This work is anticipated to be completed in 2024.

Q. WOULD THE COMPANY BE ABLE TO ACHIEVE THE BENEFITS DESCRIBED ABOVE WITHOUT IMPLEMENTATION OF IVVO?

A. To some extent, yes. While there are alternative paths to achieve certain of the benefits described above, IVVO consolidates capabilities that will result in benefits in a variety of areas. For example, energy savings could be increased through DSM programs. These are voluntary programs that require customers to take affirmative actions in order to reduce their energy usage. In contrast, IVVO enables continuous energy savings on all feeders across our system where IVVO has been installed. Further, pursuing DSM programs exclusively without IVVO implementation, we would be forgoing increased DER hosting capacity. Company witness Ms. Bloch describes IVVO alternatives, selection process, and benefits in more detail.

B. Overall AGIS Implementation

Q. WHAT IS THE CURRENT STAGE OF THE AGIS INITIATIVE IMPLEMENTATION?

A. Overall, the deployment of AGIS has already begun with the implementation of the ADMS system and deployment of the FAN and AMI meters to support the time-of-use pilot. ADMS implementation is expected to be complete in the second quarter on 2020.

Q. CAN YOU PROVIDE A SUMMARY TIMELINE VIEW OF AGIS DEPLOYMENT?

A. Yes. Table 8 below provides an overview of the deployment timeline for the various components of the AGIS initiative.

Table 8

Deployment Timeline

Program	Implementation Timeline
ADMS	In-service 2020
AMI	Meter roll-out 2021-2024
FAN	Deployment 2021-2024 (preceding AMI deployment approximately six months)
FLISR	Limited testing 2020; Implementation 2020-2028
IVVO	Limited testing 2021; Implementation 2021-2024

Q. CAN YOU ILLUSTRATE THE IMPLEMENTATION PLAN FOR AGIS IN MORE DETAIL, BOTH THROUGH THE END OF THE MYRP AND FOR THE OVERALL PLANNING AND IMPLEMENTATION HORIZONS?

A. Yes. The AGIS Implementation and Customer Experience Timeline provided as Exhibit___(MCG-1), Schedule 5 illustrates AGIS implementation for the period 2019 through 2030.

Q. HOW DOES AGIS IMPLEMENTATION IN MINNESOTA ALIGN WITH OTHER JURISDICTIONS SERVED BY THE COMPANY?

A. AGIS is an enterprise-wide initiative in several respects, as our ADMS is serving several jurisdictions and our planning for other components of the AGIS initiative is being conducted on an enterprise-wide basis. For example, we are taking into account the needs of multiple jurisdictions we serve when planning for IT needs and undertaking vendor selection and negotiations for the components of the AGIS initiative. We will therefore have shared assets between jurisdictions, as is typical for an initiative like this. However, we also must also tailor our AGIS initiative planning to the unique requirements and needs of each area we serve – both from regulatory and operational perspectives. For example, we were required to obtain a Certificate of Public Convenience and Necessity to pursue certain components of the AGIS initiative in Colorado, whereas we have different IDP and rate case requirements in Minnesota. The jurisdictions we serve will also have varying requirements for implementation of certain attributes of the system (like remote connections, as discussed by Mr. Cardenas). Our approach for this rate case is tailored to the Minnesota jurisdiction.

C. Alternatives to the AGIS Initiative

Q. DID THE COMPANY CONSIDER ALTERNATIVES TO THE AGIS INITIATIVE?

A. Yes. The Company has considered alternatives for the various components of the AGIS initiative on many levels. By that I mean that we have not only considered options as part of our overall strategic planning, but also compared options within that plan for each component and device through information gathering, vendor discussions, Requests for Information, Requests for Proposals, and vendor contract negotiations. With respect to the component-based alternatives, we have considered not only whether to move forward with AMI vs. AMR or a FAN versus a cellular network, but also different types of AMI meters and systems, different device options, and different functionalities, and different support and security considerations. While I discuss system-wide and policy options, the individual technical alternatives to each individual AGIS component – as well as the process to whittle down our options to specific systems, vendors, and devices – are discussed by Company witnesses Mr. Harkness and Ms. Bloch.[36]

Q. DID THE COMPANY CONSIDER TAKING NO ACTION AS ONE ALTERNATIVE TO PURSUING THE AGIS PROGRAMS?

A. Yes. From an overall system perspective, theoretically one alternative is to do nothing and maintain the current distribution system. However, the Company has determined that "doing nothing" is not a viable option.

Q. WHY IS TAKING NO ACTION NOT CONSIDERED A VIABLE OPTION?

A. There are several reasons. First, NSPM does not have the option to avoid investments in the distribution system because, as I describe above, the Company's existing technology is reaching the end of its life and will need to be replaced. Replacement parts will no longer be available after 2022 and our meter reading contract expires in 2025. Given that we need metering to function as a business and that vendors are choosing not to support or continue to manufacture AMR meters, there is truly no "do nothing" option. We believe this reality is understood by the Commission and our other regulators and stakeholders. Indeed, the Company has previously received Commission permission to implement ADMS as a reasonable initial approach to modernizing the distribution grid; as such, a foundational piece of grid advancement is already underway. It does not make sense to stop there.

Second, AMR meters do not provide the functionality needed for a modern utility. The communication technology currently employed is limited to

[36] The Company's RFPs related to the AGIS projects are provided on the AGIS supporting files compact disk provided with Vol. 2B.

supporting only the current infrastructure, and many of these communications networks have reached technical obsolescence. Additionally, the current system does not provide visibility into the grid or the ability to manage and optimize voltage that would enable increased DER, which is anticipated to continue to increase at a rapid rate.

Third, the "do nothing" approach ignores customers' stated expectations. For example, customers want the ability to access timely energy usage information in order to empower them to make decisions that affect their power usage. AMI metering is necessary to accomplish this objective. As a further example, few customers are likely aware of how heavily we must rely on them to identify outage locations or how manual our fault location is or how voltage is maintained at levels to avoid systemic power quality issues rather than at optimized levels. AMI, FLISR, and IVVO go a long way to addressing these issues, and will improve service to customers who care about choice, reliability, outage restoration, and energy conservation.

Q. DID THE COMPANY CONSIDER SIMPLY EXTENDING USE OF THE CURRENT METERS FOR SOME LONGER PERIOD OF TIME?

A. Yes. As Ms. Bloch describes, while the Company could conceivably continue to maintain its existing AMR meters, many of these meters were installed in the 1990s are between 20 to 30 years old. Due to their age, we expect that these meters may begin to experience mechanical issues in the coming years and we will not be able to get meter replacement parts after the end of 2022.

Further, with our Cellnet meter reading contract expiring at the end of 2025, we need to have an advance plan for either new meters or new meter reading that could be implemented by that time.

Q. DID THE COMPANY CONSIDER DSM PROGRAMS AS ALTERNATIVES TO THE RELEVANT COMPONENTS OF AGIS?

A. Yes, but AGIS and other DSM programs are not mutually exclusive, and the technology of the AGIS initiative is necessary to some forms of DSM. For example, IVVO is an efficient way to lower voltage on the electric grid because it creates benefits without customer action, and does not rely on a subset of customers to voluntarily act to lower voltage at peak periods. Further, as Ms. Bloch describes in more detail, the ability to monitor voltage across the entire grid enables lower voltage. It can be likened to a 'wholesale level' of DSM. Similarly, AMI meters are necessary to eventually facilitate providing timely, automated usage information for customers and time-of-use rates. The technology we plan to employ through AGIS is necessary to these DSM efforts but does not preclude other efforts. In fact, they complement our CIP and demand response efforts.

Q. DID THE COMPANY CONSIDER A SYSTEM-WIDE APPROACH TO UPGRADING THE DISTRIBUTION SYSTEM THAT DOES NOT REQUIRE THE IMPLEMENTATION OF INTEGRATED APPLICATIONS?

A. Yes. Ultimately each component of the AGIS initiative could have been completed through a stand-alone application. For example, the Company considered the use of independent sensors to measure voltage instead of AMI and advanced meters. However, AMI and advanced meters were selected over independent sensors because AMI is not a stand-alone system and, as Ms.

Bloch describes, the advanced meters provide a multitude of benefits in addition to being voltage sensors. While independent sensors only perform the specific function of measuring voltage, advanced meters provided the capabilities necessary for the Company to achieve visibility into an individual customer's status. AMI and advanced meters constitute the only solution that provides the Company with the visibility into the status of the electric grid at the customer level.

Similarly, the components of IVVO and FLISR were chosen based on their ability to interact with each other and provide an integrated solution to address voltage and fault regulation and correction. Because independent components could not achieve the same outcomes, stand-alone options were discarded.

Q. DID NSPM CONSIDER OTHER SYSTEM-WIDE APPROACHES?

A. Yes. We also evaluated the options of implementing only certain aspects of AGIS, and could focus on the implementation of AMI and the FAN at this time and defer FLISR and/or IVVO to a later date.

We do not recommend this approach, however. As described later in my testimony and in Ms. Bloch and Mr. Harkness's testimony, all of the components of the AGIS initiative essentially layer on top of each other with each one providing a solid foundation for the next. For example, the deployment of FAN, which will enable two-way communications with devices in the field, is a necessary foundational element that must be in place before AMI meters can be fully functional. Likewise, AMI meters must be in place to support applications like IVVO and FLISR. The ADMS provides the foundation for all of these elements. Consequently, our overall distribution advancement program consists of a strategically-developed set of components that are designed to function together.

Q. COULD IVVO AND FLISR BE DELAYED INTO THE FUTURE, TO PACE INVESTMENTS DIFFERENTLY THAN THE COMPANY HAS PROPOSED?

A. Yes, this is a possible path, although we do not recommend it. While FLISR and IVVO are additional capabilities rather than replacements for aging technology, we believe there will be some incremental cost efficiencies due to implementing them at the same time as AMI and the FAN. Perhaps just as importantly, the costs of these devices and installation are more likely to increase in the future due to inflation, so there is little to be gained from delay. We would likely be delaying the benefits of this work and at the same time creating higher costs at the time of implementation, losing the value of the work already done to investigate and plan for these components, or both.

Q. ARE THERE OTHER ALTERNATIVES THAT WOULD PROVIDE THE SAME RESULTS AS THE AGIS APPROACH?

A. No. As I describe above, the other available options are individual technologies that would not promote an integrated system. The ADMS provides a network model of the electric distribution grid that enables and indeed is essential to integrating each component of an advanced grid to work with each other. A FAN communication network keeps that model updated. To try to update the distribution grid with independent systems would create an environment in which it would be virtually impossible to manually integrate the information gathered by each system. The components selected as part of the AGIS initiative are the correct components to bring NSPM's distribution grid into the future.

Q. WHAT WOULD THE COMPANY DO IF ITS AGIS PROPOSALS ARE NOT APPROVED?

A. For metering in particular, we would have some very difficult choices to make. We would need to manage the meters we have farther into the future, potentially without access to repair parts and without vendor support. In doing so, we would risk falling behind our peers in several areas, and the experience and satisfaction of our customers will suffer as a result. We would need to make investments in our existing meters to keep them going longer, which could include hiring meter readers when the Cellnet contract expires. We considered purchasing the Cellnet technology, but determined the contract would be at market value of the system including field devices, plus costs for professional services to support the aging software. Additionally, the software is almost 20 years old and not designed to run on newer servers, and we would not be able to purchase replacement meters or modules after 2022. This solution does not address many of our concerns.

Q. ARE THERE OTHER ADVANCED GRID COMPONENTS THAT MAY BE IMPLEMENTED IN THE FUTURE?

A. Yes. While it is not possible to anticipate all possible technological innovations that may be available in the future, the Company is already looking to maximize the AGIS investments beyond what can be delivered on "Day 1". For example, we know that we will have the option to build additional customer applications and interfaces once we observe how our customers begin to use our AGIS "Day 1" capabilities. Beyond the foundational AGIS components necessary to add future capabilities, we are planning to implement the Distributed Energy Resources Management System (DERMS) in the 2024-2025 timeframe to further expand our ability to host and manage distributed energy resources.

Q. WHAT IS DERMS?

A. DERMS is a control system that will provide improved awareness of DER impacts to power-flow on the grid. DERMS allows for the integration of DER and demand response with full visibility and control, and at the same time enables the Company to maximize localized and system-wide benefits and value for our customers. DERMS will be important to support and manage DERs as they continue to grow, but is not as immediately critical to system management as replacing our meters or improving our outage response. Rather, it is a building block we expect and anticipate adding in the future.

Q. WHY IS THE COMPANY NOT BRINGING FORWARD A DERMS PROJECT RIGHT NOW?

A. While DERMS will become necessary in the near future, more time is needed for research and development activities to occur in this space. The Company will continue monitoring developments, monitoring operational and market needs, begin crafting requirements, and refine our forecasting to deploy DERMS. The penetration of DER, while increasing, has not yet reached the point where a DERMS is required. We expect that the needs of Minnesota will align with the further maturation of DERMS product offerings, such that a future investment in this functionality will ultimately prove prudent and beneficial to all.

Q. IN SUM, WHY ARE AMI, THE FAN, FLISR, AND IVVO THE RIGHT PACKAGE FOR THE COMMISSION TO APPROVE AT THIS TIME?

A. Given the need to replace our existing AMR meters that are nearing end of life, now is the right time to implement AMI and the FAN communications network. These technological advances now make it possible to meet growing customer expectations for a more robust, reliable, and resilient system, as well as customer desire for more insight and visibility into the energy choices they are making. Further, implementing FLISR and IVVO at this time will enable the reliability and energy reduction benefits at a lower cost than if the Company waits to deploy these systems in the future. The Company's targeted AGIS initiative will address system needs, customer needs, and our overall strategic priorities as a Company to lead the clean energy transition, enhance the customer experience, and keep bills low.

D. AGIS Governance

1. Governance Structure

Q. WHAT IS THE COMPANY'S GOVERNANCE STRUCTURE FOR THE AGIS INITIATIVE?

A. A robust governance structure is necessary for any project of this size and scope, especially considering the technical and integrated nature of AGIS, the various operating and customer service areas of our business that support the initiative, and the coordination necessary to deliver value for our customers as we implement AGIS in Minnesota. The Company has established a tiered governance structure for the AGIS initiative to provide the necessary controls and oversight that will enable us to achieve the desired customer and business outcomes. The program sponsors are responsible for approval of the overall strategy and funding as well as the overall program results. The program sponsors have instituted an executive level Integration Council, to ensure alignment of the enterprise vision and drive cross-workstream integration of the AGIS initiative. This council resolves execution issues and risks, and provides enterprise visibility to the design, program management, change management, and benefits realization anticipated from AGIS implementation. Any proposed changes are individually documented and brought to a change control meeting composed of program management leadership. The program management leaders can approve administrative and low impact changes to the initiative. Any significant changes to costs, benefits, scope, schedule, or resources are elevated to the Integration Council for review and approval to provide a consistent approach across the initiative.

Q. HOW WILL THIS STRUCTURE ENSURE APPROPRIATE OVERSIGHT OF AGIS IMPLEMENTATION?

A. Any significant changes to costs, benefits, scope, schedule, and resources are elevated to the Integration Council from the program management leadership team to provide a consistent approach across the initiative. Program leaders ensure that when risks and issues are identified that could affect costs, benefits, scope, schedule, or resources, they are documented and resolved. Any risks, issues or changes that meet predetermined thresholds are then elevated to the Integration Council and, if necessary, to the sponsors for appropriate resolution. This hierarchy of approvals ensures that scope, schedule and costs are documented and controlled in order to align with customer and Company check as the initiative proceeds.

2. Program Management

Q. WHAT IS PROGRAM MANAGEMENT?

A. Program management is an organizational effort designed to coordinate all projects necessary to incorporate the AGIS initiative into the current distribution system. Large, complex projects like AGIS must have established program management controls in order to ensure the effective use of resources, and thus optimal costs for the scope and benefits intended. There are various aspects of program management, some that are specific to a particular business area, and other applicable across all functional areas involved in implementation.

Coordination of projects through program management is driven through common project planning, governance, budgeting, and execution metrics methodology. Program management also provides essential corporate resources to ensure that the various individual AGIS projects are completed successfully. The program management team will coordinate the work required for the individual projects that will build the assets that make up the overall AGIS initiative. The program management team is also responsible for financial analysis and control, accounting, contract management, resource management, initiative governance, communications, and administrative assistance for each individual project and the overall AGIS initiative. The program management team will also track results, identify and determine if remedial action is necessary to keep the AGIS initiative on track, and monitor interdependencies between individual projects.

Given the size of this initiative, significant program management oversight is needed on a frequent and ongoing basis due to the highly interrelated and interdependent nature of the many components of the AGIS initiative at the individual project level. The project planning life cycle in broken into phases; Strategy, Planning, Initiation, Blueprinting, Design, Build, Test, Deploy, Warranty. Once a project has been initiated, each phase of the project's health is peer reviewed on a weekly basis. The weekly review includes, schedule, milestone, issues, risk, and budget. The Project Management office conducts a peer review of the overall AGIS budget on a monthly basis and provides the results to the Integration Council. Exhibit___(MCG-1), Schedule 6 provides the project management costs discussed in this section.

Q. PLEASE DESCRIBE THE COSTS ASSOCIATED WITH AGIS PROGRAM MANAGEMENT.

A. The AGIS budget includes program management costs for AMI and IVVO for 2019 through 2025, when advanced meter deployment and installation of IVVO devices will be substantially completed. The program management costs are discussed together below. Schedule 6 provides program management costs separately for AMI and IVVO.

We have estimated the total of AGIS program management capital costs for the MYRP period 2020-2022 will be approximately $20.3 million, or $30.0 million for 2019 through 2025. These capital expenditures are for work necessary throughout the development, deployment, and conclusion of implementing the AGIS components. We have estimated approximately $10.7 million will be attributable to operations and maintenance (O&M) expenses during the MYRP period (or $21.1for 2019-2025). These O&M costs related to strategic program oversight, as well as incremental corporate services and larger change management needs obtained in direct support of the initiative.

Q. WHAT ASPECTS OF PROGRAM MANAGEMENT ARE INCLUDED IN THE AGIS BUDGET?

A. Program management costs include:

- Change Management;
- Environment/Release Management;
- Finance;
- Project Management Organization;
- Security;
- Supply Chain;
- Talent Strategy; and
- Delivery and Execution Leadership.

Change management makes up the largest portion of the program management costs in the AGIS budget.

Q. WHAT IS CHANGE MANAGEMENT?

A. Change management is a systematic approach to effectively executing and managing fundamental organization and process changes, such as when an electric utility implements a significant change to the distribution grid. The implementation of the AGIS initiative will impact and transform the job functions for many of the Company's employees. In order to manage this transformation and properly engage employees and external stakeholders to ensure a successful transition, a comprehensive change management plan is necessary. In the context of change management, stakeholders include any person, process, or entity that is affected by the implementation of the AGIS initiative. The three main elements of change management– prepare, manage and sustain – each involve significant detailed analysis, action and documentation. The AGIS initiative has a dedicated team to ensuring that there is an appropriate overall change management plan in place, and that the plan is resourced and thoughtfully executed.

Q. WHAT ARE THE COSTS ASSOCIATED WITH AGIS CHANGE MANAGEMENT.

A. We have estimated change management costs for 2020-2022 to be approximately $10.2 million. Approximately $4.4 million of that estimate will be capitalized. These capital costs are for work throughout the development, deployment, and conclusion of on implementing the AGIS components. Specific tasks that will be capitalized are those that relate directly to design and deployment of assets, such as, but not limited to, the development of key design decisions, training development, functional alignment, integration reviews, program architecture documentation, technical change management, managing quality, and performing independent deliverable reviews. Approximately $7.5 million will be attributable to O&M expenses. These O&M costs are related to strategic program oversight, communications and customer training, as well as incremental corporate services obtained in direct support of the initiative.

Q. PLEASE DESCRIBE THE OTHER COSTS RELATED TO AGIS PROGRAM MANAGEMENT AND HOW THOSE COSTS WERE DEVELOPED.

A. The other program management costs associated with AGIS implementation are described in below. As a general note, these functions will be performed using a combination of internal employees and external consultants, and the costs forecasts related to work performed by internal employees is incremental to the general corporate budget forecasts. These costs were estimated based upon experience in deployment of the AGIS technology in Colorado, focused on the incremental requirements related to Minnesota functionality and scalability performance. I also note below where additional considerations were used in developing the specific cost forecasts.

- *Environment/Release Management:* These costs are related to performance and operating tests on the AGIS technology prior to deployment. This includes identification and remediation of issues in the software/hardware deployment and performance testing on the scalability requirements of certain AGIS technology.
- *Finance:* These costs include providing forecasting, budgeting, and reporting on the financial performance of the projects and the AGIS initiative. This includes internal reporting on monthly metrics and providing support in regulatory filings. While these costs were estimated based upon the current required financial needs in supporting AGIS implementation in Colorado, current Minnesota jurisdictional reporting requirements were also considered.
- *Project Management Organization:* These costs are related to governance activities for the projects and the overall AGIS initiative. This includes reporting on current project status, requirements for project change requests, and control of policies and guidelines designed to effectively govern the projects and AGIS initiative.
- *Security:* These costs are for work related to identifying security threats and issues on the AGIS technology prior to deployment. This includes identification and remediation of security threats in the software/hardware deployment and continuing requirements for effective cyber security programs. Security requirements for the AGIS

initiative follow the corporate strategy and process as outlined in Mr. Harkness' testimony.

- *Supply Chain:* These costs include providing centralized supply chain support, including negotiation of large strategic contracts. Costs were estimated based upon experience in providing support for the Colorado AGIS initiative, and are specific to the expectations of contracts required in Minnesota
- *Talent Strategy:* These costs include providing support in staffing and alignment of the project and initiative teams. This includes alignment with long term strategic priorities and staffing levels designed around the implementation of the AGIS technology.
- *Delivery and Execution Management:* These costs include project and initiative leadership through the design, build, and deployment phases of the AGIS initiative. Delivery and Execution Leadership will provide the oversight and alignment of the project and initiative objectives to the strategic priorities of the Company and the Commission.

Q. ARE PROGRAM MANAGEMENT COSTS REASONABLE?

A. Yes. The Company determined the costs based on the need to build a program management team that will consist of internal employees, as well as the engagement of consultants. This approach is based on the Company's experience with program management, and is consistent with its recent experience implementing the new general ledger and work and asset management systems. The costs identified in my testimony are those that were allocated to the AGIS components.

Q. DID THE COMPANY DEVELOP CONTINGENCIES FOR PROGRAM MANAGEMENT?

A. Yes. The contingency for 2019 through 2025 for both program and change management is $1.3 million in capital and $1.0 million for O&M, or approximately 5 percent of total costs. These contingencies are less than the overall contingencies estimated for design, deployment, and operations of the other components of the initiative. They reflect the uncertainty around the costs that will be necessary for program management, which may not be fully known until the AGIS program is approved and final requirements for implementation in Minnesota are known. Until design and engineering are complete, contingencies are necessary to account for the unknowns that are likely to develop during the processes and through the installation and operations phase. The contingencies for program management are consistent with the contingencies proposed for the overall AGIS initiative, as described further in Section VII.

VI. AGIS AND THE CUSTOMER EXPERIENCE

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section, I discuss the overall NSPM customer experience currently, compared to what will be different for customers upon AGIS implementation. To illustrate the impacts and customer benefits, I provide a timeline and discussion of how advanced grid capabilities will be rolled out and experienced by customers. In addition, I describe future opportunities that will be made possible by the AGIS initiative and discuss to what extent additional regulatory proceedings may be necessary to implement those opportunities.

I then discuss our customer and community outreach strategy for AMI and the associated functions, and present our Customer Education and Communication Plan related to the roll-out of AGIS initiatives over the implementation period.

Schedule 3 provides additional discussion and details related to the Company's customer strategy with respect to the advanced grid capabilities and implementation, including background on our customer surveys and research efforts that have informed our AGIS strategy, and details on the technologies and customer benefits of each AGIS component. The document also provides timeline discussions of the customer experience from pre-deployment, through the deployment and installation phase, and post-deployment when new customer products and services will be implemented. The document also discusses our customer outreach and education plan, as well as data privacy and security considerations.

A. The Customer Experience

Q. WHAT IS THE COMPANY'S VISION FOR THE FUTURE CUSTOMER EXPERIENCE?

A. The Company's vision is to further empower customers with timely and relevant information so they are more aware of their energy usage and its impacts, and can make better decisions about how and when they use energy. This will give customers greater opportunity to control their energy costs and reduce their environmental impact, two issues that rate highly with customers. In the future, the customer experience will require less direct engagement from customers yet will be a stronger partnership between customers and Xcel Energy. To meet this vision, we need to understand our customers' needs, design products and services to meet their individual needs, and seamlessly execute in ways that meet customer priorities.

Q. HOW WILL AGIS IMPLEMENTATION ENHANCE THE CUSTOMER EXPERIENCE COMPARED TO THE CAPABILITIES OF TODAY'S DISTRIBUTION SYSTEM?

A. First, the advanced grid will be able to provide data and information that is simply not available with our current system and AMR technology. This is not just an incremental step compared to the data provided by our current metering and distribution system technologies; rather, the advanced grid will provide vastly different information with a level of granularity that can impact customers' energy usage decisions, as well as increase reliability and improve the safety and security of the grid.

Q. CAN YOU SUMMARIZE HOW EACH OF THE CORE ELEMENTS OF AGIS IMPACT THE CUSTOMER EXPERIENCE?

A. Yes. Each of the core elements of AGIS (AMI, the FAN, ADMS, FLISR, and IVVO) adds to the customer experience in a specific way, but each is also interdependent upon the others to ensure that maximum benefits can be realized.

AMI provides the customer-level data that will enable an improved customer experience. AMI provides the timely and detailed energy usage data needed to better inform customers thereby empowering them to better manage their energy costs. AMI also provides additional outage information, because the Company will know when a meter stops communicating through the FAN, which is an indication that an outage has occurred. Once contact with an advanced meter in lost, we can proactively notify a customer that an outage has occurred. Additionally, we can tell when a meter is back in service, which allows us to send accurate notifications to customers about the resolution of an outage.

The FAN can be viewed as the nervous system of the AGIS system as it transmits information both to and from the advanced meter. This two-way communication is necessary to allow the meter to transmit data about energy usage or outages back to the Company's meter data management and ADMS systems.

FLISR and IVVO, which are additions to the ADMS, help us improve service reliability and quality. FLISR is a critical investment to improve the outage experience because FLISR devices can identify outages and can be used to proactively restore power through automatic switching and help isolate outages so field service crews can be more efficiently dispatched. FLISR is expected to reduce the duration of many outages thereby minimizing the impact customers experience.

Power quality, the level of voltage on the system, generally affects all customers because unnecessarily high voltage on the system or a feeder both wastes energy and can have a detrimental effect on customer's end-use technologies. ADMS and the IVVO application will allow us to better manage the voltage levels on our system thereby reducing energy usage and the associated cost and improving the voltage range on our grid, which improves the efficiency and life of customer technologies.

Q. HOW DOES THE TOU PILOT INFORM THE EVOLUTION OF THE CUSTOMER EXPERIENCE?

A. As previously noted, the TOU pilot will be underway in 2020 and is expected to conclude in 2022. The goals of the TOU pilot are to study adequate price signals to reduce peak demand, identify effective customer engagement strategies, understand customer impacts by segment, and support demand response goals. Learnings from this pilot will inform the design of future advanced rates the Company would propose, such as a full TOU rate for residential customers, or other pricing options.

While we do not yet know the pilot outcomes with respect to the pilot rate design and price signals yet, with this pilot, we are developing a digital platform to provide more granular and timely information to customers about their energy usage. We have partnered with a third-party to reimagine how we deliver this energy usage information to our customers. For TOU pilot customers, we intend to provide at least hourly interval data to customers on a prior day basis. This will allow customers to see how their energy usage tracks throughout the day as well as the cost of their energy during that time. We will offer disaggregation information that identifies the appliances or devices using energy in a home so customers can make more informed decisions about how their behavior impacts energy usage, and the best places are to start making changes. We expect to explore how to maximize advanced rate designs that benefit from more timely usage information coming from the advanced meter. We also expect to include demand response messaging that will proactively alert customers about high demand days and encourage them to take actions to change their behavior helping them save money on their bills and also reduce constraints on the grid.

These new services to be offered through the TOU pilot will be used as a template for the information to be available to customers via the web portal once an AMI meter has been installed. In other words, even though a full residential TOU rate may not be implemented to coincide with deployment of the first AMI meters in 2021, we will use the initial experience with our TOU pilot customers to better inform how we deliver new information to our customers and what channels and strategies work the best. In the future, the TOU pilot learnings will inform our rate design based on feedback we receive from TOU customers and operational results of the pilot.

Q. HOW DOES THE AGIS DEPLOYMENT TIMELINE ALIGN WITH THE ROLL-OUT OF NEW OR ENHANCED PRODUCTS AND SERVICES FOR CUSTOMERS?

A. As a general overview, impacts to the system and the customer experience will evolve as we implement AGIS components and take full advantage of the advanced grid capabilities over time. Our customer experience investments are beginning today. We are actively researching and designing new products and services that will be enabled by AGIS investments and innovating on existing products and services that can be improved by AGIS. We are also talking to our customers about what their expectations are now and in the future and how we can best meet those expectations.

Schedule 5 provides our AGIS implementation timeline, illustrating the products and services we anticipate deploying. Complimentary to this is Exhibit___(MCG-1), Schedule 7, which provides a summary of the products and services identified in the timeline. Schedule 7 also identifies how these products and services align with the Company's strategic priorities to lead the clean energy transition, enhance the customer experience, and keep bills low.

Generally, we consider implementation of new offerings in three phases:

- *Day 1*, coincident with the installation of advanced meters beginning in 2021. The Day 1 experience described below encompasses the capabilities that will be enabled and new information that will be available to customers once an advanced meter has been installed. I note, however, that the Day 1 experience for the first customer to receive an advanced meter in 2021 will be different than for a customer who receives an advanced meter later in the deployment phase. This is because the Company will be rolling out new products and services in the near term during the actual meter deployment phase. The Day 1 experience will be more robust and further enhanced with later meter deployments as we implement new products and services.
- *Near Term*, through 2025, describes the period when the Company will be developing, requesting Commission approvals (where necessary), and implementing new products and services for customers.
- *Long Term*, through 2030, describes future products and services the Company envisions implementing to realize additional capabilities that are enabled by the advanced grid. The Company will be flexible during this period, and any new products and rate design will be informed by prior experience, changing customer needs and expectations, and evolving technologies.

Q. WILL FUTURE FILINGS BE REQUIRED RELATED TO NEW PRODUCTS AND SERVICES TO ENABLE SOME ADVANCED GRID BENEFITS?

A. Yes. We recognize that many new products, services, or rate offerings – such as a full residential time of use rate – will require additional filings with the Commission and may involve a stakeholder engagement process to inform development. I discuss these additional capabilities and rate offerings below, including outlines of the development and approval processes.

B. Day 1

1. Overview

Q. PLEASE FURTHER DEFINE THE DAY 1 PERIOD.

A. As stated above, Day 1 coincides with the beginning of advanced meter deployment in 2021. Some of the services and information will be available to customers immediately upon installation of the AMI meter, while others will be implemented and available as additional meters are installed, as the Company initiates new product and service offerings, and as additional devices are deployed, building a larger base for advanced grid operations.

Q. PLEASE SUMMARIZE THE COMPANY'S VISION FOR THE DAY 1 EXPERIENCE.

A. The Day 1 experience will be heavily focused on "getting the basics right." Basics include things like accurately billing customers with the data received from the smart meter, ensuring the Company's website and customer portal are correctly displaying the interval data received from the smart meter, and ensuring there is a robust communications with customers about meter installations. These foundational elements of AGIS implementation also double as the primary touchpoints of service we have with customers.

While focusing on getting the basics right we also intend to deploy new products and services in areas where the cost-benefit is the highest or where the satisfaction value is highest for our customers. In particular, the Day 1 experience will be include an improved outage experience, an enhanced digital experience, and new energy savings programs. I discuss each of these projects below.

2. *Outages and Reliability*

Q. WHAT ARE CUSTOMER EXPECTATIONS WITH RESPECT TO OUTAGE DATA AND SYSTEM RELIABILITY?

A. As noted earlier, our customer research efforts show that:

- addressing service interruptions is important to all customer classes;
- customers expect more accurate and timely information related to outages; and
- customers expect that service interruptions will be less frequent, smaller in scope, and shorter in duration.

a. Outage Notification

Q. HOW DO CUSTOMERS RECEIVE OUTAGE NOTIFICATIONS TODAY?

A. Today, we have a mobile app, and customers can receive outage notifications that include estimated restoration times. Customers also receive confirmations when our records reflect that the outages have been resolved, and they can receive these via their preferred communication channel, wither text, email, or phone. While we have made advances on our grid and with the service we offer our customers – and these and other products and services have provided our customers with significant value over many years – we have room for improvement in our communications with customers and especially with restoration time estimates.

Q. HOW DOES AGIS IMPLEMENTATION ENABLE THE COMPANY TO PROVIDE TIMELY OUTAGE INFORMATION?

A. The AMI meters detect outage and restoration events, this real-time information is then transmitted through the meter's radio frequency communication module, through the FAN, and is received by the AMI operating software system that is used to send and receive information from an AMI-capable meter. With AMI, the Company will know when momentary or nested outages[37] occur because the advance meters will no longer communicate through the FAN back to the Company.

This improved awareness will allow for the Company to proactively notify customers of an outage, instead of relying on customers to notify the Company. In addition, with improved awareness and expected reduced restoration scopes (as discussed in the next section), the Company will be able to provide customers with more timely and accurate information about their outages. Today, customers are provided general updates and asked to confirm if their power has been restored. With the advanced grid capabilities, the Company can remotely confirm restoration of power.

Q. HOW WILL THE COMPANY COMMUNICATE OUTAGE NOTIFICATIONS TO CUSTOMERS?

A. As part of the Day 1 experience, we do not anticipate significant changes to *how* customers receive outage notifications; the significant difference will be in the Company's ability to proactively communicate with customers, provide more timely notifications, and provide more accurate restoration time estimates. By default, all customers with a valid email address in our system

[37] Storms often result in multiple failures. When we repair and reenergize a section, but a subset remains out due to a second fault, that outage is referred to as a "nested" outage.

will receive outage notifications via email. However, we will take steps to encourage customers to update their preferences in order to receive notifications in the way they prefer most. We will also begin enabling notifications through our mobile application for customers that prefer this communication channel.

b. System Reliability Improvements

Q. WHAT CAPABILITIES RELATED TO OUTAGE RESTORATION DOES THE ADVANCED GRID PROVIDE?

A. As described in the previous section, through ADMS, AMI, the FAN, and FLISR implementation, AGIS enables outage identification in real time and enhances capabilities for faster outage resolution. These improvements will begin as we begin to install FLISR devices in 2020. Customers on FLISR-enabled feeders will begin to see improvements, with improvement growing as we install FLISR on additional feeders over time.

Q. HOW DO THESE AGIS CAPABILITIES IMPROVE SYSTEM RELIABILITY EXPERIENCED BY CUSTOMERS?

A. First, as noted above, AMI can provide initial notice of an outage to the Company. This immediate notification can play a role in reduced response times. Once an outage has been noted, ADMS supports operators in determining optimal solutions faster during outage restoration through utilization of the network model, load flow calculations, and advanced analysis tools. ADMS, in conjunction with automated grid components, can improve reliability in terms of both reducing the number of outages and minimizing outage time. The FLISR application, which calculates the possible locations of the outage cause and including automated switching devices, can reduce the frequency and duration of customer outages. These automated switching devices detect feeder mainline faults, isolate the fault by opening section switches, and restore power to unfaulted sections by closing tie switches to adjacent feeders as necessary

Q. WILL THE IMPACT OF ADVANCED GRID BE REFLECTED IN THE COMPANY'S RELIABILITY METRICS?

A. Yes. Operationally, we expect improvements in the System Average Interruption Duration Index (SAIDI) when AGIS is fully implemented and the Company adapts its process to more efficiently respond to outages. However, because our current system is unable to track momentary service interruptions, there is a likelihood that the number of outages may increase as the advanced grid technology will enable the Company to track momentary outages. This may increase the System Average Interruption Frequency Index (SAIFI). I also note that because we will now be able to capture momentary outages that otherwise would go unnoticed if not observed and reported by a customer, we will be able to report MAIFI statistics, which are another measure of service quality for our customers.

Q. DOES THE COMPANY CURRENTLY REPORT ON THESE RELIABILITY METRICS?

A. Yes. We report service quality and reliability metrics under Minn. Rule 7826 and as required by our tariff governing service quality.[38] I also note that SAIFI and SAIDI have penalties attached according to established thresholds and past performance. With SAIFI and SAIDI impacts and the ability to report MAIFI as a result of AGIS implementation, new baselines for these metrics may need to be established over time through a Commission-

[38] See the Company's Minnesota Electric Rate Book, Section 6, General Rules and Regulations, Subsection 1.9, Service Quality.

approved process. I provide an overview of our service quality tariff and metrics in Section VIII, identifying how the Company expects AGIS may affect our performance and reporting under the Minn. Rule 7826 and our service quality tariff. Specific information as it relates to reliability performance is discussed in detail in the Direct Testimony of Ms. Bloch. The other service quality metrics related to billing and customer service are discussed in detail in the Direct Testimony of Mr. Cardenas.

3. *Digital Experience Improvements*

a. Customer Portal

Q. PLEASE DESCRIBE THE CURRENT CUSTOMER PORTAL EXPERIENCE?

A. Today, customer's access the customer portal through MyAccount. MyAccount provides customers with the ability to enroll in certain programs, review their usage and bill information, receive updates on outages, and personalize their communications preferences.

This experience covers many of the primary interactions a customer will have with Xcel Energy. However, the information provided in the customer portal is limited by the information that we have available today. As I have discussed above, our current system and metering technology is limited in the detail and timeliness of the data it provides. As we upgrade our system we will integrate this new information into an enhanced customer portal experience.

Q. HOW WILL THE PORTAL EXPERIENCE CHANGE?

A. The enhanced customer portal will provide customers with more detailed energy usage information. At a minimum, customers will be able to see in the portal their hourly intervals available the next day. This display of AMI-enabled energy usage data will also be supplemented with new tools such as disaggregated energy usage details and opt-in alerts and notifications that are personalized to the customer's energy usage and billing preferences. These initial enhancements to the customer portal will help empower customers with better information about their energy usage and more tools to make decisions that can help them control their energy usage. Over time, we expect to further enhance the detail and quality of this data with new products and services and more frequent updates to displayed data. Ultimately, the Company believes that on-demand meter reads through the customer portal will be added.

Q. WHAT IS THE COMPANY DOING TO PREPARE FOR THE PORTAL ENHANCEMENTS ON DAY 1?

A. We are currently conducting a full review of the look, feel, and organization of the customer portal. Generally, we are exploring ways to streamline customer use of the portal, to keep customers engaged, and present relevant information more directly. We are also working to better align the mobile and web experiences so that customers do not experience significantly different interactions between the two. Company witness Mr. Harkness addresses this in his Direct Testimony.

In summary, on Day 1, we expect to provide customers with a better portal experience that displays more detailed information that is more relevant to each customer, and keeps them more engaged and knowledgeable about their energy usage. It will also allow customers to opt-in to new types of notifications and communications.

b. Notifications and Communications

Q. WHAT ARE CUSTOMER EXPECTATIONS WITH RESPECT TO ENERGY USAGE DATA?

A. As noted earlier, key findings from research efforts show that customers expect that more energy usage data will allow them to better identify opportunities and strategies to save energy and reduce their costs. Customers also expect:

- to receive detailed information from their utility;
- that provision of information is personal and frequent; and
- that the Company will provide tools to help them use information to make decisions about their energy usage.

Q. HOW DOES THE CURRENT SYSTEM LIMIT THE TRANSFER OF ENERGY USAGE INFORMATION BETWEEN THE COMPANY AND THE CUSTOMER?

A. Our current distribution system and metering technology primarily allow for one-way communication that can generally only provide customers with usage information on a monthly basis through the Company's billing system.

Q. HOW DOES AGIS ENABLE ACCESS TO AND USE OF TIMELY ENERGY USAGE DATA?

A. The AGIS components necessary to enable timely energy usage are ADMS (as the foundational component necessary to enable advanced meter applications), AMI, and the FAN. Implementation of AMI and FAN will provide the real-time energy usage data and the foundation for new products and services that will enable customers to use that data to make decisions about their energy usage. The FAN, as the communication system for the advanced grid, will allow for transmission of data both to and from the meter.

This data can be built into digital experience channels to provide customers with more timely and accurate updates about their energy usage, thereby providing the ability for customers to better manage their energy usage and costs.

Q. WHAT ARE THE COMPANY'S PLANS WITH RESPECT TO THE CAPABILITIES OF THE ADVANCED GRID TO SUPPORT NEW INFORMATION AND DATA?

A. As part of the Day 1 experience, the Company will provide customers with more information about their energy usage. As discussed above, much of this information will be provided through the enhanced customer portal as digital experiences like the customer portal are the way customers increasingly interact with data and information. Some ways that we will share this data and information may include energy usage dashboards, energy usage alerts, and advisory tools..

Q. PLEASE SUMMARIZE THE COMPANY'S VISION FOR DASHBOARDS, ALERTS, AND ADVISORY TOOLS.

A. Dashboards will allow customers to customize the information that they see when they access their account through the web or mobile device. Customers will be able to see how devices use energy and what impact that has on their consumption, how their energy trends over time, and how their energy compares to external factors such as the weather. Dashboards can also incorporate comparisons such as to aggregated customers, like our Home Energy Reports do today, or to an individual customer's historic energy usage. These dashboards will be an enhancement to the dashboard service the Company currently offers, MyEnergy, by allowing for customization as well as incorporating more detailed data made available through AMI.

Alerts are a new function made available because of our ability to receive timely data through AMI and the FAN. Customers will be able to set thresholds for their usage or bills and the Company will proactively send alerts to customers when their energy usage is on track to exceed those thresholds. Alerts may also include helpful and personalized advice for customers to help them change their behavior before it's too late and they receive a unexpectedly high bill. Other types of alerts will focus on behavioral changes customers can make as we notify them of high peak energy usage days, such as a critical peak day. While these alerts may or may not have a financial incentive associated with them, providing customers with the information is likely to induce some type of behavioral change due to other intrinsic factors such as care for the environment.

Finally, advisory tools will analyze a customer's energy usage data and identify ways that customers can change their behavior or act to reduce their energy usage or more efficiently use energy. For example, one advisory tool may analyze a customer's energy usage relative to the costs associated with an advanced rate such as a time-of-use rate. The "advisor" may integrate with other products and services, such as disaggregation which is discussed below, to provide recommendations targeted towards specific appliances that the customer regularly uses. Alternatively, the advisor may suggest new rates or programs that help the customer manage their energy usage through price signals or direct control.

Provision of this data and enhanced communications with customers will not require additional filings for approval by the Commission. However, we will keep the Commission and stakeholders informed of customer usage and satisfaction with these new capabilities. I discuss our proposed AGIS metric and reporting in Section VII.

4. Energy Savings Programs

Q. HOW WILL AGIS INVESTMENTS ENABLE OR ENHANCE NEW DEMAND-SIDE MANAGEMENT (DSM) PROGRAMS?

A. The more detailed and timely data that our AGIS investments provide can help enable or enhance programs in a number of ways. First, as we have more information we can use that to update our program designs and marketing tactics. We will have better insight into how and when customers use their energy which will allow us to better market and segment our customers. This means our communications will be more relevant as I discussed above. Just as important will be new products and services that support our DSM goals. These may include, Home Area Networks, Green Button Connect My Data, and traditional energy efficiency, demand response, and demand management programs.

Q. WHAT ARE THE COMPANY'S PLANS WITH RESPECT TO THE GREEN BUTTON CONNECT AND HAN PRODUCTS?

A. Green Button Connect (GBC) and Home Area Network (HAN) functionality are enabled by the advanced meter and are two products that may be included in the Day 1 experience. GBC allows customers to share their energy usage data seamlessly with their approved third-parties. This is an enhancement to the existing system, Green Button Download, because it allows a customer to share their data regularly with a third-party without needing to take proactive action to share that data. For customers with third-party services that help them manage their energy usage this will allow them to work with their chosen third-party to more effectively manage their energy.

HANs vary in the benefits they provide and can be as simple as a dashboard that communicates with the meter to provide real-time energy usage or more complicated networks of devices that are receiving energy usage data from the meter and adjusting operations based on that information.

Q. WHAT ARE THE COMPANY'S PLANS WITH RESPECT TO TRADITIONAL DSM PROGRAMS?

A. We are developing multiple new programs for Day 1 deployment. These include:

- virtual energy audits;
- whole facility monitoring and continuous commissioning; and
- Enhanced Saver's Switch.

Virtual energy audits will provide customers reports of their energy usage relative to a baseline or general customer comparison. This audit is similar to the "Neighbor Comparison" that is provided with the Company's "Home Energy Reports" but because of new capabilities from AGIS – specifically AMI and the FAN, we can provide this service more frequently for customers. We can also rely on the more detailed data provided by service such as disaggregation to provide more specific details on how their energy usage compares to a baseline.

Whole facility monitoring programs will use the detailed data provided by AMI to better integrate with energy management systems. This will allow customers to get more timely and accurate feedback on how adjustments to their business processes and energy management systems impact their energy usage. For customers on certain types of advanced rates, this more timely and accurate feedback can be critical to ensuring they don't have an unexpectedly high bill or fail to meet energy curtailment requirements during demand response events.

Finally, Enhanced Saver's Switch is an upgrade to the existing Saver's Switch technology that allows for two-way communication between the Company and the Saver's Switch. This two-way communication utilizes the FAN to more reliably send signals to the switch and the switch can then send a signal back indicating it is active and receiving messages. This will result in more accurate forecasts or demand response savings and can enabled improved maintenance of the switch system to focus on disabled or broken switches first. While this program may not have a direct impact on customers like an audit or monitoring program may, the improvement in switch responsiveness will have indirect benefits because we can more accurately forecast the resources we need to require helping avoid high cost peak generation.

C. Near Term

1. Overview

Q. PLEASE SUMMARIZE THE COMPANY'S VISION FOR THE NEAR TERM CUSTOMER EXPERIENCE.

A. As defined above, the near term encompasses the period through 2025. During this time, we plan to:

- Continue innovating on existing products and services;
- Begin offering new advanced rate designs;

- Expand the capabilities of the advanced meter to utilize the Distributed Intelligence platform discussed earlier in my testimony; and
- Better integrate DERs on the system.

Continual innovation has long been a core requirement of our customer programs; however, with the rapid pace of technology advancements – including Distributed Intelligence – and the increasing amount and sophistication of data we have it will become more important. We will need to reconsider the ways our customers interact, what the most effective way to interact with them is, and how to use the data we must most cost-effectively offer products and services. I will discuss the other plans in more detail below.

2. Advanced Rate Designs and Billing Options

Q. WHAT ARE THE COMPANY'S PLANS WITH RESPECT TO THE CAPABILITIES OF THE ADVANCED GRID TO SUPPORT ADVANCED RATE DESIGNS?

A. The Company generally supports advanced rate designs, such as a TOU rates, because advanced rate designs can help customers manage their energy usage and environmental impacts. As our customer research has shown, managing costs and minimizing environmental impacts are important factors in customer satisfaction.

We have long experience with time-of-use and other advanced rate designs in Minnesota and across our other service territories. However, beginning in April 2020, we will pilot a new time-of-use rate with residential customers in two areas in the Twin Cities metropolitan area. This pilot will provide us with an opportunity to better understand how customer react to a four-part rate (off peak, two shoulder peaks, and an on-peak period) as well as test tools and resources that may help customers adjust their energy usage to keep their bills low and better control their energy costs. The learnings from this pilot, with respect to both the rate and new products and services, will help inform our plans for advanced rates in the future. In addition, the Company is proposing a new time-of-use rate for the commercial and industrial customers served under the current General Time-of-Day tariff. Implementation of this General TOU rate will require the installation of AMI meters. Company witness Mr. Lon M. Huber provides details on this proposed rate in his testimony.

Q. WHAT OTHER TYPES OF ADVANCED RATE DESIGNS OR BILLING OPTIONS MIGHT BE ENABLED BY THE AGIS INVESTMENT?

A. One billing option the Company is investigating is the option for customers to "pre-pay." A pre-pay system allows a customer to purchase a set amount of energy each month which can help customers manage within a budget. Because our investments in AMI and the FAN will provide more detailed and timely energy usage information a customer can monitor their usage towards the "pre-pay" amount regularly. Similarly, the Company can track the usage, relative to the budget, and send the customer regular notifications about their energy usage balance and ways to reduce their reduce to remain on the budget.

Other advanced rate designs may include critical peak pricing or technology specific rates. Critical peak pricing can be used to signal when energy prices are extremely high – for example, on a hot summer day. During these periods the energy price may increase significantly, and the price signal sent to customers would encourage them to shift their energy usage to a non-peak period or pay a higher price. There are a variety of peak demand rate design structures the Company may explore, such as peak time rebates. Similarly, technology specific rates may encourage customers to not use certain end-uses during periods of the day when demand is higher. For example, an EV TOU rate may encourage customers to charge electric vehicles off peak but may also include incentives or signals for customers to not charge at the same time. Investments in the FAN and AMI will allows us to send and receive the data we need in order to manage these types of rates and provide customers with detailed information about how to respond to these signals.

Q. WHAT ARE THE COMPANY'S PLANS RELATED TO THE CAPABILITIES OF THE ADVANCED GRID TO SUPPORT REMOTE CONNECTION AND DISCONNECTION SERVICES?

A. As I noted above, the advanced grid enables remote connection and disconnection capabilities. There are both customer benefits and costs savings related to these capabilities. However, any changes to our provision of these services to customers will require filings with the Commission for approval. These proceedings will allow for full review of the proposed services by the Commission and stakeholders. Mr. Cardenas addresses remote connection and disconnection and the necessary future filings in his testimony.

3. Distributed Intelligence

Q. PLEASE SUMMARIZE THE DISTRIBUTED INTELLIGENCE PLATFORM.

A. Distributed Intelligence refers to the Linux-based operating system built directly into the meter. This operating system provides the meter with the ability to conduct localized computing, analysis, and data processing. This work is done through applications that are installed by Xcel Energy on the meter. These applications may be customer-facing, meaning the customer directly interacts with them, or grid-facing – meaning, Xcel Energy interacts with the applications. Ms. Bloch discusses the technology behind the DI platform further in her Direct Testimony.

Q. WHAT ARE SOME OF THE FUNCTIONALITIES OR APPLICATIONS THAT HAVE BEEN ENVISIONED FOR THE DI PLATFORM?

A. We are actively considering a number of potential applications such as:

- Virtual Submetering – this application meters an end-use technology, such as an EV, in lieu of a physical submeter installation. This virtual metering reduces costs and can allow for submetered technologies to be billed on a different rate than the primary meter.
- Smart Feeder Restoration – when there is insufficient capacity to immediately restore all of the service to a feeder this application will sequentially restore power to critical loads (*e.g.* a hospital or fire station) first.
- Power Quality Analysis – this application can provide a regular or on-demand analysis of the quality of the power coming into a premise and on-site. If anomalies in the quality are detected it can advise the customer on next steps to address the potential anomalies.
- Green Notifications – this application may alert customers about the status of carbon free electricity on the system. This type of notification, relying on system data, would encourage customers to shift their energy usage during these periods to reduce their carbon footprint.

Because the Distributed Intelligence platform is a newer technology, we continue to research and collaborate with our vendor partner we expect to identify additional use cases and applications for use with the DI platform. We also expect to have robust engagement with other third-parties to develop additional use cases.

Q. HOW WILL APPLICATIONS FOR THE DI PLATFORM BE DEPLOYED?

A. Application deployment will be managed by Xcel energy in order to ensure that all applications meet our strict cybersecurity and technical requirements. Because these applications are installed directly on the meter there is serious risk to allowing open access to the meter. However, we are committed to offering a broad suite of applications that offer customer and grid benefits. How these applications are made available will vary as some may be offered as standalone products while others are offering as a package with participation in other programs. Grid facing applications will not be made available to customers but instead managed internally by Xcel Energy departments that need the functionality they provide for grid management.

4. DER Integration

Q. WHAT IS THE COMPANY'S CURRENT EXPERIENCE WITH THE INTEGRATION OF DERS?

A. Today, we interface with all types of DERs – DSM, EVs, solar, and batteries. In some cases, we have over 20 years of experience managing DERs on our system and have developed effective policies to ensure DERs provide customer and grid benefits without impacting safety and reliability. Without quality, granular data, we must manage the integration of DER conservatively. Access to more granular data will result in a more accurate analyses of DER impacts and a more refined approach to DER integration.

Q. HOW WILL THE AGIS INVESTMENTS IMPROVE THE COMPANY'S ABILITY TO INTEGRATE DERS?

A. AGIS investments will allow us to better understand the grid and impacts that DERs have to it. With this information we can conduct more accurate analyses of the impacts of DERs and track the impacts in near real time. This will allow us to integrate more DERs and in the future manage DERs in a collaborative way to ensure we maximize their benefit to the system. AGIS investments that are critical to this are the ADMS platform and AMI. In the future DERMS may also help integrate and manage DERs more efficiently.

Q. WHAT BENEFITS WILL DER INTEGRATION HAVE FOR CUSTOMERS?

A. In addition to better system management which will yield lower operating costs we also expect that we will be able to accommodate more DERs on the system providing customers with more access to new technologies that have environmental, energy saving, and customer satisfaction benefits. With our commitment to a 100 percent carbon free future we fully realize the value that DERs can provide to meeting this ambitious goal and we can only meet this goal by maximizing the value that all potential resources can provide. Ms. Bloch discussed DER integration, including our plans for EVs, further in her Direct Testimony.

D. Long Term

Q. PLEASE DESCRIBE THE CUSTOMER EXPERIENCE DURING THE LONGER TERM PERIOD (THROUGH 2030).

A. We cannot definitively say what will happen during this period because of the unknowns with technological advancement and how customer expectations will change. However, at this time we envision a transformation in how we do business with our customers. This will be punctuated by more sophisticated products and services that begin to integrate multiple customer systems into broader grid management. This aggregation of systems will allow for more flexibility in grid management.

We will work with our customers to become an orchestrator of the grid helping individuals and communities achieve broad energy goals. This orchestration role will relieve the customer of much of the burden of management around their energy goals. Xcel Energy will understand, in greater detail, our customers' expectations and goals and will work with third-parties to achieve those goals with minimal effort from customers.

Q. WHAT IS THE ROLE THAT THE AGIS INVESTMENTS WILL PLAY IN SUPPORTING CHANGES TO THE CUSTOMER EXPERIENCE DURING THIS PERIOD?

A. ADMS, the FAN, and AMI provide the foundational tools we need to help manage the grid and integrate increasing levels of DERs on the system. As new applications in ADMS and the DI platform are introduced we can more efficiently manage the grid because the computing power is more local thereby reducing the response time to a system need. The functional ability of our AGIS components to process information more quickly, more reliably, and more accurately will support not only support these customer experience investments but remain capable of supporting investments over the long term.

In the future, additional AGIS investments may be necessary to further the integration of more DER as customers introduce more electric end-use technologies (EVs, electrically heated homes, and other DERs) to the grid. One such investment may be in the aforementioned DERMS.

Q. WHAT DO YOU BELIEVE WILL BE THE OUTCOME IF THE COMPANY DOES NOT MAKE INVESTMENTS IN ADVANCED GRID CAPABILITIES?

A. Without advanced grid capabilities, the Company's ability to meet evolving customer expectations will be limited. Although we have and will continue to strive to provide the services and information our customers expect, our current system technology does not support two-way communications, or the granular energy usage data that will enable the Company to roll out advanced rates, and realize the energy and cost savings they can provide.

Q. OVERALL, CAN YOU SUMMARIZE WHAT WILL BE DIFFERENT FOR CUSTOMERS UPON IMPLEMENTATION OF AGIS?

A. Upon the implementation of AGIS, customers will begin to see benefits in reduced outage times and new products and services to help control their energy usage. With reduced outage times will also come the ability to better inform customers about the status of their outage. Not knowing why you're out and when you will be restored is frustrating for customers. With the investments in AGIS we'll be able to provide customers with more accurate timelines for restoration keeping them better informed about their status. We'll also be able to proactively identify and restore customers rather than wait for a customer to contact us as our current technology requires.

With new products and services, we'll be able to offer customers a range of new ways to control their energy usage. Advanced rate designs, such as time-of-use, critical peak, and technology specific rates will be possible without additional metering. We will also be able to use the more detailed data provided by the customer's meter to personalize the recommendations and information we provide them. This will help customers make more informed decisions about what steps to take rather than rely on general energy efficiency recommendations that we provide today and may not always be actionable or insightful to an individual.

Over time, we'll also be able to use our advancements in AGIS to better align programs and use the Distributed Intelligence platform to provide new, seamless interactions. Better alignment and new ways of engaging customers can keep them more involved in their energy usage and give them more control in ways – such as a mobile devices – that are increasingly prioritized.

Even with uncertainty around the long-term future customer experience, the Company remains committed to understanding customers' preferences and considerations regarding the benefits and value of advanced grid investment as technologies evolve and new technologies become available over time. Our investments in how we understand and work with our customers, combined with the foundational investments in the grid through our AGIS initiative, will provide us with the resources we need to adapt quickly to changes in technology and customer expectations.

E. Customer and Community Outreach

Q. HAS THE COMPANY DEVELOPED A DETAILED PLAN FOR CUSTOMER AND COMMUNITY OUTREACH RELATED TO AGIS IMPLEMENTATION?

A. Yes. The Company has developed a detailed Customer Education and Communication Plan (Communication Plan), which is provided as Exhibit___(MCG-1), Schedule 8. This plan details the communications strategies, messages, and tactics to be executed in three phases to match the customer's experience as we implement advanced grid capabilities.

Q. HOW WAS THE EDUCATION PLAN DEVELOPED?

A. We developed our Communication Plan based on (1) the Company's experience with advanced meter pilots and advanced grid technology initiatives for NSPM as well as other Xcel Energy operating companies; (2) examination of communication and outreach best practices among other utilities with advanced grid and advanced meter deployment experience; and (3) customer research efforts.

Q. WHAT SPECIFIC RESEARCH DID THE COMPANY CONDUCT TO DEVELOP ITS AGIS OUTREACH STRATEGY?

A. Xcel Energy has conducted qualitative customer research through focus groups in Minnesota and throughout the service territory of its other operating companies. The results of this research have informed message development and the strategic updates to this plan. Objectives of this research included exploring customers' understanding of advanced meters, perceived benefits and drawbacks of advanced meters, both positive and negative expectations about moving to advanced meters, what barriers may arise and how to address them, and customer preferences for information and communication methods.

Q. WHAT ARE THE KEY LESSONS LEARNED, BEST PRACTICES, AND TAKEAWAYS FROM THE CUSTOMER RESEARCH EFFORTS?

A. The lessons learned, best practices, and results of our customer research efforts are outlined in the Communication Plan. Key takeaways that we have considered in the development of our AGIS outreach strategy include:

- Customers want to hear from Xcel Energy about the transition to the new meters at least two or three months in advance of installation via a multi-channel approach.
- Customers believe the new meters could help them save money by providing more detailed usage information, which they perceive as empowering.
- The potential cost of the new meters is the top barrier that Xcel Energy needs to address.

I note that our research also shows that customers better understand the term "smart meter" as opposed to "advanced meter" or "AMI." We therefore used "smart meter" in our customer education planning to make the information more accessible, whereas "AMI" is used throughout our AGIS discussions because it is the more correct technical and industry term.

Q. PLEASE OUTLINE THE COMPANY'S EDUCATION PLAN.

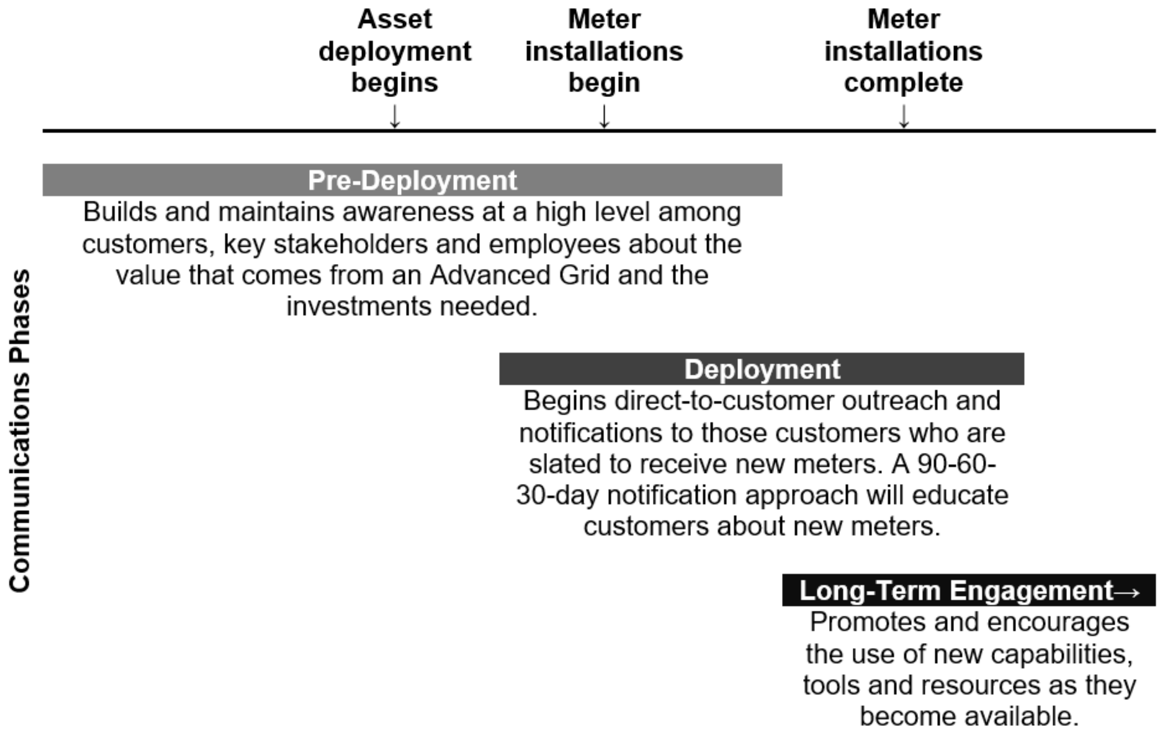
A. Our comprehensive Communication Plan provides the strategies, messaging, and tactics that will be executed in three phases to match the customer journey as we move through AMI meter installation and implementation of advanced grid capabilities. While the Communication Plan focuses primarily on the customer experience, the plan also details our efforts with respect to other key audiences that will help support customer awareness, understanding, and engagement through this transition. These audiences include: (1) community leaders and elected officials; (2) our Customer Care agents; and (3) all Company employees. Our plan also identifies how we will communicate with different customer groups, and details any communications considerations relative to specific customer segments, such as low-income or non-English speaking customers.

The overall goals of the plan are to:

- Ensure a smooth, integrated experience for all customers;
- Provide customers with relevant, up-to-date, practical information about new meters and programs through multiple channels; and
- Minimize confusion through proactive, multi-channel communications.

Our phased approach will coincide with meter deployment and advance grid capabilities as they are phased in over the next five years.

Figure 1



1. Pre-Deployment Phase

Q. PLEASE DESCRIBE THE PRE-DEPLOYMENT PHASE OF THE COMPANY'S EDUCATION PLAN.

A. The pre-deployment phase focuses on building and maintaining awareness of advanced grid capabilities at a high level among customers, key stakeholders, and employees. This will include communication and education about the value that comes from an advanced grid and the investments needed. Advanced grid will be presented as one of the Company's platforms for bringing innovative technological solutions to enhance the customer experience. The pre-deployment phase is designed to set the stage for meter installation, and will in late 2020, before AMI installations will begin, and continuing through mid-2023 in order to maintain awareness.

Q. WHAT ARE THE KEY OBJECTIVES DURING PRE-DEPLOYMENT?

A. Key objectives during this phase include:

- Create customer and stakeholder awareness about the overall benefits of the advanced grid;
- Explain why we are making this investment, focusing on tangible customer benefits;
- Educate and train employees to equip them with tools and resources necessary to engage with customers and stakeholders;
- Build customer interest in the change by explaining the benefits of advanced meters and the tools and options they enable; and
- Proactively address customer concerns and questions.

Q. WHAT ARE THE COMPANY'S SPECIFIC PLANS FOR COMMUNICATIONS AND EDUCATION EFFORTS RELATED TO ADVANCED GRID AWARENESS?

A. The Company has developed an integrated, expansive, and multi-channel approach to build awareness of advanced grid capabilities and to set the stage for AMI meter installations. We will build awareness by leveraging a variety to channels in order to reach as many customers as possible. Channels include XcelEnergy.com, social media, traditional media outreach, mass advertising, and community events. The attached Education Plan provides the details of the messages, communication channels, and materials that are being developed for each of the four key audiences.

2. Deployment Phase

Q. PLEASE DESCRIBE THE COMPANY'S EDUCATION PLAN DURING THE DEPLOYMENT PHASE.

A. The deployment phase focuses on education related to AMI meter installation. During this phase, we will begin direct-to-customer outreach and notifications to those customers who are slated to receive new meters. A 90-60-30-day notification approach will educate target audiences on the new meters, how they will be deployed and installed, and their benefits. While messaging and content will focus on meter installation, all communications will speak to the broader value and benefits of the advanced grid. This phase will also set the stage for the communications plan over the longer term by collecting customer information and preferences that can be used as new capabilities are enabled and to create deeper long-term customer relationships.

Q. WHAT ARE THE KEY OBJECTIVES OF THE DEPLOYMENT PHASE?

A. Key objectives during this phase include:

- Provide practical and timely information and notifications about the deployment, installation, and opt-out processes;
- Provide clear information on the opt-out process and associated costs, including how to take action;
- Leverage a messaging hierarchy to reiterate high-level benefits of advanced metering; and
- Further develop tools and resources for employees to use during proactive discussions with customers and stakeholders.

Q. WHAT ARE THE COMPANY'S SPECIFIC PLANS FOR COMMUNICATIONS AND EDUCATION EFFORTS RELATED TO METER INSTALLATIONS?

A. Communication efforts during this phase will provide practical, specific information to customers about meter deployment. Customers will receive notifications about their new meters 90 days, 60 days, and 30 days prior to meter installation through various channels to ensure all customers receive adequate notification. Where possible, materials will be personalized with the most relevant and up-to-date deployment information. The communications plan also provides for a phone call seven days before installation, and a follow-up communication after installation. The attached Education Plan provides the details related to timing and methods for the installation notifications, and the details of the messages, communication channels, and materials that are being developed for each of the four key audiences. The Education Plan also includes sample materials for meter installation communications.

Q. HOW WILL THE EDUCATION PLAN INCORPORATE DETAILS WITH RESPECT TO CUSTOMER INTERACTIONS WITH THE METER INSTALLATION VENDOR?

A. The Company and the meter installation vendor will work together to provide coordinated support and address all customer inquiries and any issues that may arise. The meter installation vendor will be a key point of contact for the Company's customers during the meter installation process and will have a dedicated call center phone number for Xcel Energy's customers. Mr. Cardenas provides additional detail in his testimony. We will work closely with Customer Care to ensure the communications and materials we will provide to customers prior to and during the installation will include clear directions and contact information so any questions or issues will be resolved as quickly as possible.

Q. ALTHOUGH AMI TECHNOLOGY AND ADVANCED GRID CAPABILITIES WILL ENABLE THE NEW AND ENHANCED PRODUCTS AND SERVICES FOR CUSTOMERS, WILL CUSTOMERS BE ABLE TO OPT OUT OF RECEIVING AN ADVANCED METER?

A. Yes. The Company believes that customer should have the choice to opt-out of receiving an advanced meter. However, the Company can provide the greatest benefits for our customers by deploying advanced meters consistently across our service territory. The Company will provide information on the benefits enabled by advanced metering while also providing clear information on the opportunity to decline the installation of an advanced meter or have an advanced meter removed at any time.

Q. HAS THE COMPANY DEVELOPED A FRAMEWORK FOR CUSTOMER OPT-OUTS?

A. Yes. We have developed a framework under which a customer may opt-out of advanced meter installation. In his testimony, Mr. Cardenas details the opt-out framework that the Company will propose in a separate filing submitted to the Commission. Once the opt-out provisions are finalized and approved by the Commission, we will ensure the process details, costs, tariff sheets, and any other necessary information and materials are incorporated into our customer communications plan.

Q. GIVEN THE BENEFITS OF AMI, HOW DOES THE COMPANY PROPOSE TO MINIMIZE THE POTENTIAL FOR CUSTOMER OPT-OUTS FOR ADVANCED METERS?

A. It is important to have a concentration of advanced meters to achieve the benefits of better identifying outage locations and of making time-of-use or other conservation-incentive rates widely available. It is also necessary to broadly deploy advanced meters to capture the benefits of reduced home visits and fewer meter reading costs. The Company's customer education and awareness campaign is designed to address many of the questions or concerns that customers have with advanced meters including privacy and safety. Communications will also discuss the benefits that an advanced meter provides including opportunities to reduce energy costs and improve their environmental impact. Customer care representatives will also be trained to address customer questions and concerns. The Company believes the most effective way to reduce the potential for customer opt-outs is to provide proactive, informative education to ensure customer questions and concerns are fully understood and addressed by the Company.

Q. WILL CUSTOMERS BE ABLE TO OPT OUT OF TARGETED MARKETING THAT MAY BE ENABLED BY THE ADVANCED GRID TECHNOLOGIES?

A. Yes. With advanced metering technology, the Company will be able to provide customers with enhanced energy usage data, including interval data, and will have the ability to disaggregate some end-use technologies from the customer's total energy usage. This information can be used to better market products and services that save money to customers and to improve a customer's awareness of their energy usage. However, we recognize that some customers may not want to receive targeted marketing, and the Company will provide customers the choice to opt-out of receiving this information. This option is similar to a customer's choice to opt-out of the Company's current Home Energy Report or to select how they receive notifications today. In the future, the Company expects to be able to provide customers more choice around how they receive communications to better reflect their preferences.

3. Long Term Engagement Phase

Q. PLEASE DESCRIBE THE COMPANY'S EDUCATION PLAN OVER THE LONGER TERM.

A. After AMI deployment, will promote and encourage the use of new advanced grid capabilities, tools, and resources as they become available. Communications will not only highlight the features of new tools and resources, but the broader benefits they can provide, such as:

- *Economic benefits:* With more information on energy consumption and more choices about how and when they use energy via possible future rate options, consumers may be able to save money as a result of advanced grid-enabled programs and technologies.
- *Environmental benefits*: The advanced grid enables the incorporation of greater amounts of renewable generation, gives customers more opportunities to make more environmentally conscious choices, and can also reduce the need to rely on fossil fuel generation.
- *Reliability benefits:* Grid-side intelligence offered by advanced grid technology can reduce the frequency and duration of outages while providing better information for customers when outages do occur.

This phase will also leverage customer information and preferences gathered during the deployment phase to provide a seamless experience for all customers via their preferred channels.

Q. WHAT ARE THE KEY OBJECTIVES OF POST-DEPLOYMENT CUSTOMER COMMUNICATIONS?

A. Key objectives during this phase include:

- Educate customers on new capabilities, tools, and resources as they become available.
- Develop and execute a customer campaign to follow the customer journey and encourage adoption of new capabilities, tools and resources.
- Leverage a messaging hierarchy to reiterate high-level benefits of the advanced grid and advanced metering.
- Evaluate and refine messages and tactics to continuously improve and ensure the best possible customer experience.

Q. WHAT ARE THE COMPANY'S SPECIFIC PLANS FOR COMMUNICATIONS AND EDUCATION EFFORTS RELATED CUSTOMER ENGAGEMENT IN ADVANCED GRID CAPABILITIES?

A. A multi-channel approach will reach customers via their preferred channels and include tailored messages to move them along in the engagement journey. The attached Education Plan provides the details of the messages, communication channels, and materials that are being developed for each of the four key audiences. In addition, I note that we will also develop the necessary materials and communications plans for any advanced rate design or service offerings that will be enabled by advanced grid capabilities. As discussed above, such offerings – such as a full residential time of use rate – will go through an approval process at the Commission and may involve a stakeholder engagement process to inform development.

4. Customized Communications

Q. WHAT ARE THE COMPANY'S PLANS FOR CUSTOMIZED COMMUNICATIONS FOR FIXED AND LOW-INCOME CUSTOMERS?

A. Customized communications will recognize and proactively address cost concerns among low-income households, seniors, and vulnerable customer populations. We will engage community leaders, influencers, and representatives of these communities in the development and deployment of our educational efforts. Messages will address how customers on fixed or limited budgets can take advantage of personal energy use information that may allow them to better manage their energy costs. Outreach will also focus on increasing these customers' participation rates in energy efficiency and conservation programs, and cross-marketing the state's energy assistance programs. Communication and education materials that could be customized for this segment of customers may include:

- FAQs and fact sheets to address specific concerns and needs.
- Talking points and scheduled briefings with consumer advocacy groups and nonprofit groups who serve these populations.
- Customized presentations for community relations staff to share with their community leaders.
- Outreach to organizations serving seniors, low-income, and other vulnerable customer segments, with an emphasis on providing ready-to-use materials that can be distributed via their communication channels, online resources, events, meetings, and social media platforms.

Q. WHAT ARE THE COMPANY'S PLANS FOR CUSTOMIZED COMMUNICATIONS FOR NON-ENGLISH SPEAKING CUSTOMERS?

A. According the U.S. Census Bureau's American Community Survey (ACS), in 2017, 11.3 percent of Minnesotans spoke a language other than English at home. After English, the most common language spoken at home is Spanish, with close to 200,000 speakers.[39] As such, the Company's website (xcelenergy.com) will include material related to the advanced grid in Spanish.

Q. WHAT ARE THE COMPANY'S PLANS FOR CUSTOMIZED COMMUNICATIONS FOR CUSTOMERS WITH LIFE-SUPPORTING EQUIPMENT?

A. Prior to any direct communication regarding meter installation, the Customer Contact Center will proactively reach out to customers who rely on life-supporting equipment in their homes. These customers will have the option to opt out of the new meter, or make an installation appointment and have a bridge installed to avoid a service interruption.

Q. WHAT ARE THE COMPANY'S PLANS TO ENSURE COMMUNICATIONS ARE ACCESSIBILE FOR ALL CUSTOMERS?

A. The Company has a number of options in place to assist customers and ensure accessibility for all.

- Deaf or hearing-impaired customers can dial 711 to be connected with the state transfer relay service. This service allows callers to communicate with text-telephone (TTY) users. This service is available 24/7 and is confidential.
- The company's Contact Center can make outbound calls using TTY technology.
- Any residential customer may request a large print bill statement.
- Customer emails and our website and online tools are continually reviewed, and we make improvements to ensure accessibility.

[39] U.S. Census Bureau, 2013-2017 American Community Survey 5-Year Estimates, https://factfinder.census.gov/bkmk/table/1.0/en/ACS/17_5YR/B16001/0400000US27.

Q. WHAT ARE THE COMPANY'S PLANS FOR COMMUNICATION AND EDUCATION EFFORTS FOR COMMERCIAL AND INDUSTRIAL (C&I) CUSTOMERS?

A. We expect our broad awareness communications will be applicable to small C&I customers as well, but we will also provide customized 90, 60, and 30-day meter install notifications for those customers. The content of these communications will vary depending on the customer's current tariff to ensure they receive the most relevant information. The Company has dedicated account managers for large C&I customers, who will help ensure a smooth experience before, during, and after meter installation.

Q. WHAT ARE THE COMPANY'S PLANS TO ENSURE CUSTOMERS ARE INFORMED OF THEIR CHOICES RELATIVE TO OPTING-OUT OF ADVANCED METER INSTALLATION?

A. As I discussed earlier, the Company believes customers should have the choice to opt-out of receiving an advanced meter. To that end, our communications and education materials will clearly inform customers of the opt-out process, the associated costs, and how to take action. The Company will clearly provide customers with the opportunity to decline the installation of an advanced meter or have an advanced meter removed at any time.

As also noted earlier, we have developed a framework under which a customer may opt-out of advanced meter installation; however, we are not seeking approval of specific opt-out provisions at this time. Mr. Cardenas discusses the opt-out framework in his testimony. We will work with Customer Care as these opt-out provisions and options are finalized to develop the communication channels and materials to clearly present these options to customers.

Q. HOW DOES THE COMPANY PROPOSE TO MINIMIZE THE POTENTIAL FOR CUSTOMER OPT-OUTS FOR ADVANCED METERS?

A. As discussed throughout my testimony, the Company can provide the greatest benefits for our customers by deploying advanced meters consistently across our service territory, thus it is in our customers' interests for us to minimize opt-outs for advanced meter installation. Our Education Plan is designed to address many of the questions or concerns that customers have with advanced meters, including privacy and safety. Communications will also discuss the benefits that an advanced meter provides, including opportunities to reduce energy costs and improve their environmental impact. Customer Care representatives will also be trained to address customer questions and concerns. The Company believes the most effective way to reduce the potential for customer opt-outs is to provide proactive, informative, and meaningful education to ensure customer questions and concerns are fully understood and addressed by the Company.

Q. HOW WILL THE COMPANY DETERMINE WHETHER THE CUSTOMER COMMUNICATION EFFORTS HAVE BEEN SUCCESSFUL?

A. In Section VIII below, I discuss our proposed progress metrics, which will be based on operational metrics as well as customer surveys. I also discuss how we will report the information on our customer communications and education efforts.

Q. ARE THE COSTS RELATED TO EXECUTION OF THE EDUCATION PLAN INCLUDED IN THIS CASE?

A. Yes. The costs related to the AGIS Education Plan total approximately $6.3 million over the implementation timeline discussed above. These costs are included in the overall AGIS program management budget in Distribution Operations, as presented in Ms. Bloch's testimony. I also discuss the development of program management cost forecasts in Section V.D.2.

VII. PRUDENCE OF THE AGIS INVESTMENTS

Q. WHAT INFORMATION DO YOU PROVIDE IN THIS SECTION OF YOUR TESTIMONY?

A. In this section I provide an overview and summarize the results of the Company's analyses of the quantitative and qualitative cost and benefits of the various components of the AGIS initiative, as well as of the consolidated program. I also discuss the purpose and limitations of a strictly quantitative cost-benefit analysis and present the qualitative benefits of AGIS implementation that should also be considered. Company witness Dr. Duggirala provides a detailed discussion of the Company's cost-benefit analyses in his Direct Testimony, both with respect to the Company's cost-benefit model and least-cost/best fit analyses.

A. The Company's Cost Benefit Analysis

1. Overview of AGIS Cost-Benefit Analysis

Q. DID THE COMPANY UNDERTAKE A COST-BENEFIT ANALYSIS TO ASSESS THE QUANTITATIVE COSTS AND BENEFITS OF THE AGIS INITIATIVE?

A. Yes. The Company conducted separate detailed cost-benefit analyses (CBAs) for each of the following components of the AGIS initiative: AMI, FLISR, and IVVO, with costs of the FAN (which is a supporting component that does not provide standalone measurable benefits) incorporated into each analysis of the other components. The Company provides resulting benefit-to-cost ratios for each of these components individually, as well as a total AGIS CBA, both with and without contingency amounts. While the Company expects to use some component of the contingency amounts, by definition the total amount of contingency the Company will use is not fully predictable at this time. Therefore, we show totals with and without contingency to illustrate the outer boundaries of benefit-to-cost ratio ranges.

Q. WHAT IS THE PURPOSE OF THE CBA?

A. A CBA is one tool to evaluate potential quantifiable costs and benefits of the core AGIS components, including AMI, FLISR, and IVVO, and supporting FAN costs. It can capture most costs (which are in themselves quantifiable), but only compares quantifiable projected benefits, such as O&M and capital expenditures savings and known quantifiable societal benefits.

Q. DOES THE COMPANY RELY PRIMARILY OR EXCLUSIVELY ON CBAS TO APPROVE OR REJECT PROJECTS LIKE THE AGIS INITIATIVE?

A. No. While we utilize CBAs as one tool to assess larger projects, we are always cognizant of the limits of a CBA. A cost-benefit model cannot capture other benefits that cannot be quantified, such as customer satisfaction, power quality, improved safety, and the like. As a result, the CBA is a useful tool but does not provide a complete picture of the costs and benefits of any given program.

Those modeling limitations become even more pronounced where, as here, a large portion of the costs of the AGIS initiative are unavoidable because they are associated with addressing aging metering assets that are central to core utility functioning. Given the issues with our existing meters noted earlier in my testimony and discussed in detail in the testimony of Mr. Cardenas and Ms. Bloch, the question is less whether to pursue a metering solution at all, and more whether to pursue more current technology to align with the industry and system needs, which can also offer our customers functionality they have come to expect from their service providers.

Q. WHAT IS THE COMPANY'S OVERALL APPROACH TO THE AGIS CBA?

A. Our overall approach for the CBA is to provide a customer-focused, conservative look at the AGIS investments. In other words, we have incorporated estimated customer benefits enabled by the advanced grid, but have used conservative estimates to avoid overstating these benefits. Likewise, we have include our current cost estimates, both with and without contingencies, to provide the range of results for consideration. The CBA covers the life of the proposed assets, rather than just the MYRP period, in order to examine values for the overall AGIS initiative beyond the MYRP term. Dr. Duggirala provides further discussion on the CBA design.

Q. PLEASE DESCRIBE THE OUTPUTS OF THE CBA AT A HIGH LEVEL.

A. At a high level, the CBAs present the net present value of costs and benefits on a 2019 base year net present value (NPV) basis. From a benefit-to-cost ratio perspective, a ratio greater than one (1) indicates the quantifiable benefits that can be converted to dollar values exceed the costs, and vice-versa. Of course, as previously noted, the benefit-to-cost ratio excludes qualitative benefits and other considerations such as the business's dependence on the systems being evaluated. As a result, it is not surprising that some of our benefit-to-cost ratios for AGIS components exceed 1.0, while others do not.

Q. HOW DID THE COMPANY DEVELOP THE COST INPUTS FOR THIS ANALYSIS?

A. At a high level, the Company developed the cost inputs by relying on subject matter experts in our various areas of the Company to assess the hardware, software, labor, and processes necessary to implement the various programs of the AGIS initiative. Cost development was based on such items including, but not limited to, RFPs, contracts, labor rates, company experience, and other pricing efforts.

Q. WHAT BUSINESS AREAS DEVELOPED COST INPUTS FOR THE CBA?

A. Primarily, our Distribution and Business Systems organizations developed the cost inputs for the CBA. The overall AGIS budget is split between these two business areas, as they are responsible for implementing the technologies and systems for the AGIS initiative. Information supporting the capital investments and O&M expenses related to the AGIS initiative is provided in the direct testimony of Ms. Bloch and Mr. Harkness. Their testimonies address both the specific costs included the multi-year rate plan period as well as the development of cost inputs for the CBA.

Q. ARE THERE COSTS NECESSARY FOR AGIS IMPLEMENTATION THAT ARE RELATED TO AREAS OF OPERATION OTHER THAN DISTRIBUTION AND BUSINESS SYSTEMS?

A. Yes. Like any other project of this size and scope, the AGIS initiative touches many areas of our business, and there are costs necessary for overall program management that are not developed by Distribution or Business Systems. For example, in Section D.2. above, I provided the costs for Program Management. Other program management cost inputs that are necessary for delivery of the overall AGIS project were developed for business areas such as Supply Chain, Finance, and Human Resources. These program management costs are all reflected in the Distribution or Business Systems budgets, either by direct assignment to, or allocation among, the appropriate AGIS components. I also identified the costs for execution of our Customer Education and Communications Plan as we install AMI meters and implement advanced grid capabilities. While these costs were developed by Corporate Communications, they are accounted for in the overall AGIS budget within Distribution.

Q. PLEASE FURTHER DESCRIBE THE CONTINGENCY AMOUNTS INCLUDED IN THE CBAS.

A. The costs associated with AMI, FAN, FLISR, and IVVO installation, and the necessary IT integration, include contingency amounts, which are detailed further in the Direct Testimony of Company witnesses Mr. Harkness and Ms. Bloch. These estimates appropriately reflect corresponding risk allowances and contingencies for inherent uncertainties associated with budget estimates at the current stage of project development and approval. Consistent with our conservative approach, we have reflected these contingencies in our CBAs.

Q. WHY DOES THE COMPANY BELIEVE THAT UTILIZING SUCH CONTINGENCIES IS APPROPRIATE?

A. Using contingencies is consistent with project planning practices, especially for large technology projects that implement new technologies and require major changes to enterprise IT systems. Further, the size, scope, and complexity of the AGIS initiative, as well as the multi-year implementation schedule, warrants the use of budget contingencies. While we have undertaken initial planning, benchmarking, and research, and have based our budget estimates on all known design and installation details, there remain uncertainties with respect to specific Minnesota requirements that will not be known until after Commission approval of the projects, and unknowns that may develop through the installation phases.

Further, while we believe the budgets including contingency amounts appropriately account for certain costs that may be incurred but are currently unknown, we do not look at the contingency amounts as additional budget dollars that can simply be used in any way for project implementation. Rather, use of any of the contingency amounts would only occur if cost changes are determined to be necessary, and changes have gone through the appropriate review and approval processes described in Section V.D of my Direct Testimony. As described, the Company has implemented a robust AGIS governance process to ensure the project is implemented and provides value for our customers.

Q. WHAT IS THE CONTINGENCY PERCENTAGE FOR THE AGIS INITIATIVE OVERALL?

A. The AGIS initiative capital budget forecast for the period 2020-2025 includes an overall contingency percentage of approximately 26 percent, with individual component contingencies varying depending on the complexity, size, and scope of work (as discussed by Ms. Bloch and Mr. Harkness).

Q. IS THIS CONSISTENT WITH CONTINGENCY LEVELS FOR OTHER COMPANY PROJECTS AND THOSE USED ACROSS THE INDUSTRY?

A. Yes. The Company includes contingency amounts for large projects that are appropriate to the stage of development and scope of the project. A 26 percent overall contingency AGIS at this stage of project development is very much in line with industry standards for large technical and IT projects that span multiple years, and is appropriate for the complexity, size, and integrated nature of the AGIS project.

Q. ARE THERE INDUSTRY GUIDELINES FOR ESTABLISHING CONTINGENCY AMOUNTS FOR CAPITAL PROJECT ESTIMATES?

A. Yes. The Association for the Advancement of Cost Engineering (AACE International) is the leading professional society for cost estimators, cost engineers, schedulers, project managers, and project control specialists. AACE International recommends a combination of project and process contingencies for large capital projects. Project contingency recommendations are based on the level of project definition at the time the estimate is developed, with a range of recommended contingencies between 5 and 50 percent. Process contingency recommendations are based on the programmatic or technical uniqueness and complexity of the project, with a recommended range of contingencies between 0 and 40 percent (or more).

Q. HOW DO THE CONTINGENCY BUDGETS FOR EACH OF THE AGIS COMPONENTS FACTOR INTO THE OVERALL CONTINGENCY AMOUNT?

A. As previously noted, contingency levels vary between the individual AGIS components because they are based on the current stage of project development, outstanding contract finalizations, and the specific scope of work and integrations necessary for the individual projects. The overall capital contingency levels for each of the AGIS components for the period 2020-2025 are shown in the Table 9 below.

Table 9

AGIS Project Contingencies			
AGIS Program	**Business Systems**	**Distribution**	**Combined**
AMI	37%	26%	27%
FAN	45%	0%	39%
FLISR	24%	12%	14%
IVVO	10%	10%	10%

Q. ARE THESE CONTINGENCY LEVELS FLAT WITHIN EACH AGIS COMPONENT?

A. No. Just as the overall contingency levels vary between the different AGIS components, the contingency levels also vary between the Distribution and Business Systems budgets for the same AGIS component. This is due to the differences between IT and Distribution work, and helps to ensure reasonable contingency amounts that are tailored to the individual components and work to be done. For example, IT projects generally have a higher contingency for several reasons, including the unknowns around the integrations with new and legacy systems, and necessary security controls that may evolve over the course of project implementation, to name a few. Mr. Harkness and Ms. Bloch discuss the reasons contingencies for their work on each AGIS component is needed and why these estimate are reasonable given the specific project scopes and stages of project development.

Q. DOES THE INCLUSION OF A CONTINGENCY AMOUNT IN A CBA OR INITIAL BUDGET MEAN 100 PERCENT OF THE CONTINGENCIES MUST BE CONSUMED THROUGH THE PROJECT?

A. No. In this case, the Company worked to develop a conservative budget to provide a fair view of potential costs and benefits. If the Company does not utilize all of the contingencies in order to realize the benefits of the advanced grid, the benefit-to-cost ratio of these programs will only improve.

Q. HOW WILL THE COMMISSION BE INFORMED OF PROJECT COSTS AND WHETHER CONTINGENCY AMOUNTS ARE BEING USED, AND TO WHAT EXTENT, DURING THE COURSE OF THE MULTI-YEAR RATE PLAN?

A. The Company is requesting approval in this proceeding to recover these amounts in base rates, but also for certification of these programs to provide the opportunity for the Company to request cost recovery in the TCR Rider after the end of the MYRP. Annual filings will enable the Commission to see what amounts are being spent and on what items. Likewise, the Company has proposed a capital true-up through Company witness Ms. Amy Liberkowski, and is proposing regular AGIS filings with the Commission as I describe later in my testimony. Each of these methods will provide the Commission with insight into the progress and costs around the AGIS initiative.

Q. HOW DID THE COMPANY DEVELOP THE BENEFIT INPUTS FOR THIS ANALYSIS?

A. Benefits inputs were developed by synchronizing the programs' technical capabilities, Company expectations, prior experience, alternatives, and Commission approved values where available. Where applicable, Ms. Bloch and Mr. Harkness discuss quantifiable benefits for Distribution and Business Systems, respectively. Mr. Cardenas identifies benefits related to customer care, such as reduced bad debt expense and meter reading. Dr. Duggirala discusses certain broader AMI benefits around load flexibility.

Q. WHAT TIME PERIOD DOES THE COMPANY'S CBA EXAMINE?

A. While implementation of the foundational AGIS components is expected to be completed by approximately 2025, the CBA examines the time periods that match either the expected life of the installed asset (AMI meters), or the period up to full book depreciation of the assets (IVVO and FLISR components). For AMI, the CBA covers is a 15-year project life, which is the expected life of the advanced meter equipment. The CBAs for IVVO and FLISR cover a 20-year project life, after which the equipment will be fully depreciated. Company witness Ms. Bloch describes the meter and device useful lives in her Direct Testimony.

Q. EARLIER YOU IDENTIFIED AMI, FLISR, AND IVVO AS INCLUDED IN THE CBA. HOW DO THE OTHER ASPECTS OF THE AGIS INITIATIVE – NAMELY, ADMS, THE TOU PILOT, AND THE FAN – FACTOR INTO THE CBA?

A. As I noted earlier, ADMS was separately certified for implementation via the Company's TCR Rider. In the certification proceedings, ADMS was approved as necessary regardless of any future advanced grid initiatives the Company would undertake. Further, the purpose of the CBA is primarily to provide one tool to evaluate the potential costs and quantifiable benefits of potential future grid modernization functionality. As such, ADMS costs are not part of the CBA.

However, installation of the FAN is necessary for AMI, FLISR, and IVVO implementation, respectively. The FAN does not provide benefits in its own right; therefore, all FAN costs are accounted for in the CBAs, where the associated portion of FAN is allocated into the costs for those individual components.

Finally, although the TOU pilot was previously approved, some of the work completed for the pilot will carry over to the broader AGIS initiative. Therefore, we have included TOU pilot costs in the AMI and consolidated CBA. However, the primary purpose of the TOU pilot is not to bring quantifiable benefits or cost-savings to customers, but rather to learn more about the capabilities and how to maximize the value of advanced metering technology. As such, the TOU pilot has a minor impact on the cost side of the benefit-to-cost ratio for AMI and the overall initiative (about 0.2 points), but no material quantifiable benefits.

Q. WHAT ARE THE RESULTS OF THE COMPANY'S AGIS CBA?

A. As discussed in detail in Dr. Duggirala's testimony, AMI, FLISR, and IVVO have the following approximate quantitative benefit-to-cost ratios for each component, shown here with and without contingency amounts:

Table 10

AMI Benefit-to-Cost Ratio

NSPM-AMI-NPV	**Total ($MM)**
Benefits:	446
O&M Benefits	53
Other Benefits	203
CAP Benefits	190
Costs:	(538)
O&M Expense	(179)
Change in Revenue Requirements	(359)
Benefit/Cost Ratio	**0.83**
Benefit/Cost Ratio (no contingencies)	**0.99**

Table 11

FLISR Benefit-to-Cost Ratio

NSPM FLISR- NPV	**Total ($MM)**
Benefits:	**103**
O&M Benefits	0
Customer Benefits	103
Costs:	**(79)**
O&M Expense	(5)
Change in Revenue Requirements	(74)
Benefit/Cost Ratio	**1.31**
Benefit/Cost Ratio (no contingencies)	**1.53**

Table 12

IVVO Benefit to Cost Ratio

NSPM IVVO- NPV	**Total ($MM)**
Benefits:	**22**
Other Benefits	19
CAP Benefits	3
Costs:	**(39)**
O&M Expense	(2)
Change in Revenue Requirement	(37)
Benefit/Cost Ratio (CVR 1.25% energy; 0.7% capacity)	**0.57**
Benefit/Cost Ratio (no contingencies)	**0.61**
Low Benefit Sensitivity:	
Benefit/Cost Ratio (CVR 1% energy; 0.6% capacity)	0.46
Benefit/Cost Ratio (no contingencies)	0.49
High Benefit Sensitivity:	
Benefit/Cost Ratio (CVR 1.5% energy; 0.8% capacity)	0.67
Benefit/Cost Ratio (no contingencies)	0.72

Q. WHY DO YOU SHOW AN ADDITIONAL RANGE OF IVVO BENEFIT-TO-COST RATIOS?

A. As Ms. Bloch and Dr. Duggirala explain, the Company is deploying IVVO to a core area, and does not have widespread data on the likely results of IVVO implementation. However, we understand that many of our stakeholders are particularly interested in IVVO deployment. Our engineers feel confident they can achieve 1.0 percent energy savings and may be able to achieve 1.5

percent through voltage optimization; in light of the uncertainty and interest, we have utilized a 1.25 percent mid-range energy savings level to show a range of potential outcomes. Our baseline benefit-to-cost ratio overall assumes 1.25 percent energy savings, 0.7 percent capacity savings, and that we will need to utilize the IVVO contingency amounts.

Q. WHAT ARE THE RESULTS OF THE CBA FOR THE AGIS INITIATIVE ON A CONSOLIDATED BASIS?

A. On a consolidated basis, the CBA results show a benefit-to-cost ratio for the overall AGIS initiative of between 0.86 and 1.03, with 0.87 as our baseline benefit-to-cost ratio, as set forth in Table 13 below.

Table 13

AGIS Initiative Combined Cost-Benefit Ratio

NSPM -AMI, FLISR, IVVO-NPV	**Total ($MM)**
Benefits:	**571**
O&M Benefits	53
Other Benefits	222
Customer Benefits	103
Capital Benefits	193
Costs:	**(656)**
O&M Expense	(186)
Change in Revenue Requirement	(470)
Baseline Benefit-Cost Ratio (IVVO CVR 1.25% energy, 0.7% capacity, with contingencies)	**0.87**
High Benefit/No Contingency Sensitivity (IVVO CVR 1.5% energy/0.8% capacity, no contingency)	1.03
Lower Benefit/With Contingency Sensitivity (IVVO CVR 1.0% energy/0.6% capacity, with contingencies)	0.86

Q. WHAT DOES THIS COMBINED RATIO INDICATE?

A. These ratios indicate that the quantifiable costs and benefits of the AGIS initiative do not reach 1.0 (equal benefits and costs) in their own right, but approach 1.0 even before we factor in qualitative benefits such as customer satisfaction, power quality, safety, and the like. In other words, the CBA, by itself, does not show that quantifiable benefits are equal to quantifiable costs; however, we would not necessarily expect it to when we are proposing this equipment not to avoid investments or to increase efficiency, but rather to replace a fundamental component of our system that is approaching obsolescence while adding capabilities for our customers and for a future that includes greater DER, distributed intelligence, artificial intelligence, and greater customer engagement with all facets of their life. We would not expect to save money (on a net basis) when investing in these kinds of technologies. I discuss the purpose and limitations of the CBA, as well as the unquantifiable qualitative benefits, further in the next section of my testimony.

2. Role of the CBA in AGIS Evaluation

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section of my testimony, I expand upon the purpose and limitations of a CBA from a policy perspective. While Dr. Duggirala discusses this subject from the perspective of the model itself, I provide the broader business considerations around the efficacy – and limitations – of any quantitative assessment tool.

Q. WHY IS IT IMPORTANT FOR THE COMMISSION TO EVALUATE QUALITATIVE BENEFITS AND FUTURE CUSTOMER OPTIONS THAT COULD NOT BE BUILT INTO A CBA?

A. We recognize that it is difficult to put a numeric value on future opportunity and non-monetary benefits, and that evaluating these possibilities can be a challenge. However, the trends in the utility industry and the efforts of other states to advance their distribution grids, described in this testimony and in industry-wide resources like the Department of Energy's Smart Grid effort, verify the importance of bringing utilities' distribution grids into the future. Without AGIS, the Company will soon be behind in managing to customer expectations, supporting DER, employing future technologies, maintaining reliability goals and expectations, and fully capturing DSM opportunities.

AGIS is therefore both a fundamental part of the Company's strategic plans to meet and exceed customer expectations as well as a standalone requirement for a robust and resilient distribution grid.

Q. SHOULD THE DECISION OF WHETHER TO APPROVE COST RECOVERY OF THE AGIS COMPONENTS DEPEND SOLELY ON THE OUTCOME OF THE QUANTITATIVE CBA?

A. No. That would be an overly-narrow perspective that does not take into account the broader context of AMI, IVVO, and FLISR, the place of AGIS in the Company's overall strategic plans, or future opportunities that the advanced grid can create for customers. Company witness Dr. Duggirala discusses both the purpose and limitations of a quantitative CBA in his testimony. More specifically, a CBA can only capture that which can be quantified or measured. Most costs, by definition, can be quantified. Other benefits of a project, including customer satisfaction, the secondary effects of lost productivity, business, or consumables on customers due to electric outages, and human health and safety are not fully quantifiable or quantifiable at all.

Q. IS THE OUTCOME OF A CBA THE ONLY STANDARD BY WHICH COST RECOVERY MUST BE JUDGED IN MINNESOTA?

A. No. Certainly balancing the costs and benefits of any project is an important consideration, which we do not discount. However, it is not the only consideration. In Minnesota, the Commission has approved project costs based on the need for the investments to serve customers, customer-facing benefits, efficiencies, system benefits, avoiding obsolescence, and for other reasons. The test is always whether the investment is just and reasonable – not whether dollar savings are greater than the price of the project.

Q. ULTIMATELY, WHAT DO YOU RECOMMEND IS THE PROPER PERSPECTIVE ON THE CBA?

A. I recommend that the Commission review the CBA, but do so in the broader context of the goals of AMI, FLISR, and IVVO implementation, the current qualitative benefits they offer, Commission policy goals, and the opportunities for future customer benefits.

B. Qualitative Benefits of AGIS

Q. IF THE COMMISSION SHOULD NOT RELY SOLELY ON A CBA TO ASSESS A PROJECT'S REASONABLENESS AND VALUE, WHAT SHOULD IT RELY UPON?

A. The Commission should consider a wide variety of factors, that include (but may not be limited to):

- The overall need for the proposed investments for the utility to run its business (as described above in my testimony, and in the testimony of Ms. Bloch and Mr. Cardenas);
- The value of the investments in meeting Commission policy goals (described in my testimony and Ms. Bloch's and Dr. Duggirala's testimony);
- The benefits of the investment – both qualitative and quantitative – to the utility's customers (described in each piece of the AGIS testimony);
- The cost impact of the investments on the customer (discussed later in my testimony);
- The alternatives available to and considered by the Company (discussed earlier in my testimony on a holistic level, and discussed by Ms. Bloch

and Mr. Harkness with respect to the alternatives to individual components, component types, and vendors); and

- The amount and quality of due diligence undertaken by the Company in selecting both the investments it is pursuing and the vendors and project scoping proposed (discussed throughout our AGIS testimony).

Q. CAN YOU PROVIDE AN OVERVIEW OF THE QUALITATIVE BENEFITS TO BE CONSIDERED AS PART OF THE EVALUATION OF THE AGIS COMPONENTS?

A. Yes. From a policy perspective, the unquantifiable benefits of advancing the distribution grid are difficult to overstate. Safety, reliability, and customer satisfaction are vital to our role as a public utility. Each is enhanced by the AGIS initiative, as I describe earlier in my testimony and as Ms. Bloch and Mr. Cardenas describe in more detail. A more automated, insightful, and transparent grid supports greater customer empowerment and employee safety, as discussed by Company witness Ms. Bloch. Similarly, Ms. Bloch also explains that the advanced technologies associated with the AGIS initiative support ongoing quality SAIDI and SAIFI measurements, along with improved ability to measure MAIFI. Nor can the utility keep up with greater customer demand for distributed energy resources without investing in the advanced grid technologies necessary to support these resources.

In addition, giving customers choice and control over their energy usage by providing greater insight to customers; giving customers greater input into the types of energy they use by supporting distributed energy resources; and empowering customers to make good choices about their impact on the environment are important pieces of both building customer satisfaction and managing electric demand.

Perhaps most importantly, there are simply limitations to our current system that frustrate customers and cannot be resolved without aspects of the AGIS initiative. In many cases, without AMI metering technology we have limited ability to identify outages without relying on the customer. The AGIS initiative will allow us to improve reliability by automating fault response and identifying more issues beyond the substation. Two-way communication and additional devices will allow us to enhance voltage optimization and better support distributed energy resources. It further allows us to look to the future, and to emerging capabilities like distributed intelligence, more customer application and interface technology, and additional energy sources through a modernized distribution grid. All of these benefits relate largely to customer satisfaction and future-proofing the distribution grid – benefits that are difficult or impossible to quantify.

Q. HOW DOES CUSTOMER OPTIONALITY FURTHER SUPPORT APPROVAL FOR THE AGIS INITIATIVE, INCLUDING THE PROJECT COSTS IN THIS CASE?

A. As noted earlier in my Direct Testimony, empowering customer choice is a key driver of the AGIS initiative as a whole. Digital metering and technologies enable new programs and tools for customers that give them more power over their energy usage. Some of these options, such as the opportunities to receive regular updates about their electricity usage and to tailor their electric usage to reduce their electricity costs, are discussed above. But customer choice goes beyond TOU rates or remote connect/disconnect options.

With AMI, the Company has the option to implement budgeting tools and high usage alerts that notify customers if they exceed or approach certain thresholds; to create internet portals that provide greater insight into energy consumption and peak demand; and to develop mobile apps that allow near real-time information access.

AMI will also support the two-way flow of energy via net metering, further supporting customers' abilities to invest in DER options such as rooftop solar and potential energy storage or battery options, if they should choose to do so.

Q. HAS THE COMPANY INCORPORATED ANY ASSUMPTIONS ABOUT THESE FUTURE OPTIONALITIES INTO ITS ASSESSMENT OF AMI, FLISR, AND IVVO?

A. Yes. As I discussed earlier, the Company envisions implementing a full residential time of use rate by 2024. We anticipate continuing discussion of those options in the Company's TOU pilot proceeding, as we will build on those pilot results and learnings, and engage stakeholders in developing a full residential time of use rate offering. Likewise, the implementation of the advanced meters and associated infrastructure provide an opportunity for customer web portals to access energy usage data on a near real-time basis, and we anticipate building such portals as part of the AGIS initiative. Estimated anticipated reduced consumption and benefits associated with time-of-use rates are incorporated into the Company's CBA.

Q. WHAT ARE OTHER BENEFITS ASSOCIATED WITH TOU RATES?

A. There are several key, quantifiable benefits associated with a time-of-use rate structure. TOU rates result in direct benefits for our customers, by giving customers the tools necessary to keep their bills low. Additionally, TOU rates can help to further goals shared by the Company and stakeholders, such as furthering the clean energy transition in Minnesota. With TOU rates providing customers energy price signals, customers are empowered with information necessary to shift usage to off-peak times – when energy costs are lower and system generation tends to be less carbon intensive. In addition to these direct benefits for all of our customers who have an AMI meter, the environmental benefits enabled by AGIS will be realized for both customers and the public.

In the CBA, we did not quantify reductions in carbon dioxide emissions from shifting customers away from consumption during peak periods (and therefore away from reliance on peaking units) toward more average periods, when we can rely more heavily on renewable resources. Instead, we focused on a conservative estimate of benefits we could measure, resulting in significant savings as a result of load flexibility benefits.

Q. HAS THE COMPANY SUMMARIZED THE CAPABILITIES OF CERTAIN AGIS COMPONENTS IN RELATION TO THE RELATIVE COSTS AND BENEFITS IN ANY OTHER WAY?

A. Yes. Dr. Duggirala compares the capabilities of AMI provided by Ms. Bloch to other alternatives, such as manual reading and AMR solutions, while also factoring in incremental cost and benefit information for alternatives (compared to the Company's current metering solution) where available. This "Least-Cost/Best-Fit" analysis further underscores the significant additional capabilities and higher net costs/benefits of AMI as compared to other metering solutions for which we have pricing information. It also demonstrates that while we do not have specific pricing information for all options (such as manual read meters), the capabilities of older technology are sufficiently limited and outdated as to be incomparable.

Dr. Duggirala presents a similar comparison of FAN alternatives, including a cellular or dedicated AMI communications network alternative. Mr. Harkness explains why those alternatives are not preferable solutions as compared to the FAN, and Dr. Duggirala summarizes the comparisons in his testimony. In short, a cellular alternative is expected to have approximately the same per-device costs plus additional O&M costs, with less Company control and less security than the FAN. A dedicated AMI alternative would not allow us to utilize the FAN for multiple type of devices, limiting the functionality of the solution. Overall, the capabilities of a secure, flexible, and reliable Field Area Network make this the preferable solution.

C. Summary of Prudence of AGIS Investments

Q. PLEASE SUMMARIZE THE COMPANY'S OVERALL APPROACH AND THE RESULTS OF THE AGIS CBA.

A. The AGIS CBA provides a customer-focused, conservative look at the AGIS investments. It incorporates conservative estimates of quantifiable customer benefits enabled by the advanced grid. It also incorporates our current cost estimates, both with and without contingencies, to provide a range of results for consideration. Our CBA shows individual and composite benefit-to-cost ratios that approach 1.0 (or exceed 1.0 in the case of FLISR), even before taking into account unquantifiable benefits.

Q. HOW DOES THE COMPANY'S CBA INFORM THE OVERALL ASSESSMENT OF THE PRUDENCE OF THE AGIS INVESTMENTS?

A. By evaluating the costs and quantifiable benefits of AGIS implementation, the Company's AGIS CBA is one tool that informs assessment of the overall prudence of the AGIS strategy and investments. However, a cost-benefit model is limited in that it cannot capture other benefits that cannot be quantified, such as customer satisfaction, power quality, and improved safety.

The CBA results underscore that our AGIS program is reasonable given the need to replace aging technology, bring our distribution grid into the future, meet customer needs and offer greater customer choice, and take advantage of opportunities to use technology to support demand side management, peak demand reductions, and build a more resilient, responsive grid. With those qualitative considerations and benefits, the Company believes the value of the AGIS initiative and its respective components substantially exceed the costs.

Q. ULTIMATELY, WHAT DO YOU RECOMMEND WITH RESPECT TO THE PRUDENCE OF THE AGIS INVESTMENTS?

A. I recommend that the Commission approve the Company's proposed investments in the AGIS initiative as prudent, and certify them for future cost recovery for the reasons described throughout my testimony – including in this section – and in the testimony of Ms. Bloch, Mr. Harkness, Mr. Cardenas, and Dr. Duggirala.

VIII. BILL IMPACTS

Q. PLEASE DESCRIBE HOW AGIS INVESTMENTS WILL IMPACT CUSTOMER BILLS.

A. Keeping customer bills low is a core strategy of the Company and is a central consideration of the AGIS initiative. As I previously described, the combined

AGIS investment will provide significant value to our customers – some of which we can quantify and some that we can't.

Q. WHAT TYPE OF IMPACT WILL AGIS INVESTMENT HAVE ON CUSTOMER BILLS?

A. The impact to a customer's bill will result from the increased revenue requirement due to our investments and O&M spending necessary to implement the AGIS initiative.

Q. HOW DID THE COMPANY APPROACH ITS ASSESSMENT OF THE BILL IMPACT OF AGIS?

A. The Company performed a revenue requirement analysis for 2020 through 2024 to illustrate the incremental revenue requirement and estimated bill impact of AGIS implementation. The AGIS revenue requirement calculation is provided as Exhibit___(MCG-1), Schedule 9.[40] While we did not perform an exhaustive class cost of service model for this subset of investments and O&M expenses, this analysis provides the annual cost of the AGIS initiative overall, and provides an estimate of a monthly bill impact for a typical residential customer.

Q. HOW DID THE COMPANY SPECIFICALLY CALCULATE THE ESTIMATED BILL IMPACT FOR A TYPICAL RESIDENTIAL CUSTOMER?

A. We estimated the bill impact by utilizing a series of allocation assumptions applied to the AGIS costs, using allocators consistent with our 2020 proposed Class Cost of Service Study. Appropriate allocators were applied to distribution capital, distribution O&M, and the remaining costs, to develop an

[40] The costs included in 2019 are related to the Company's TOU pilot. As described in Section VI, the costs of implementing AMI and FAN in connection with the TOU pilot (in 2019 and 2020) have been included in the AGIS CBA to provide a complete picture of advanced grid investments and costs. We have also included these costs in our bill impact assessment.

estimated residential class revenue requirement. We then divided the estimated residential class revenue requirement by the sales forecast for each year, as provided in Company witness Ms. Janell Marks' testimony. This results in an estimated overall cost per kilowatt hour (kWh). We then calculated an estimated bill impact based on the average monthly residential customer usage of 675 kWh. This assessment shows an estimated 2024 AGIS bill impact of approximately $2.87 per month for an average residential customer.

While this calculation is not a full class cost of service assessment, it does illustrate an estimated bill impact for a residential customer. We recognize that bill impacts will vary by customer class; however, we believe this approach is informative for purposes of comparing the bill impact of the AGIS initiative to the alternative investment that would be necessary to continue to provide service to our customers.

Q. WHAT ALTERNATIVE INVESTMENT AND COSTS WOULD BE NECESSARY IF THE COMPANY DOES NOT IMPLEMENT THE AGIS INITIATIVE?

A. As described earlier, it is not feasible for the Company to continue to use its current AMR meters because they are nearing end of life, and the Company's contract with Cellnet for meter reading service and support expires at the end of 2025. As such, the Company would, at a minimum, need to invest in new meters and provide meter reading services in order to continue to provide electric service to our customers. This means that even without AGIS implementation, there would be an incremental impact to customers' bills for an alternative metering service.

Q. HOW DID THE COMPANY CALCULATE THE BILL IMPACT OF THE ALTERNATIVE TO AGIS IMPLEMENTATION?

A. In addition to the AGIS revenue requirement, the Company developed a reference case scenario to represent an alternative to our AGIS investments. The reference case reflects the necessary investments and costs if the Company were to pursue a basic AMR drive-by meter reading alternative. Ms. Bloch and Mr. Cardenas discuss AMR meters and provide details on the costs of this alternative. The Company calculated the bill impact by using the revenue requirements for the AMR drive-by alternative and calculated the estimated bill impact as described above. The reference case revenue requirement calculation is provided as Exhibit___(MCG-1), Schedule 10. This assessment shows an estimated bill impact for the AMR drive-by alternative of approximately $1.51 per month for an average residential customer.

Q. COULD YOU COMPARE THE TWO CASES?

A. Yes. We provide the overall bill impact of the AGIS initiative, but the key comparison is the difference between the estimated bill impact of AGIS implementation versus the basic alternative, as shown in Table 14 below. This Table illustrates the incremental cost of pursuing our AGIS investments, compared to the investments that would otherwise be necessary but would not enable all the quantitative and qualitative benefits of the advanced grid. Table 14 also illustrates that costs of AGIS will be spread over the implementation period, which reasonably manages the cost impact for our customers.

Table 14

Estimated Residential Monthly Bill Impact

	2020	2021	2022	2023	2024
AGIS	$0.44	$1.33	$1.84	$2.58	$2.87
Reference Case	$.01	$0.19	$0.62	$1.18	$1.51
Difference	$0.43	$1.14	$1.22	$1.40	$1.36

Q. OVERALL, DO YOU BELIEVE THE AGIS INVESTMENTS ARE A GOOD VALUE FOR CUSTOMERS?

A. Yes. While there are costs associated with new technology, the combined AGIS investment will provide significant value to our customers immediately on Day 1 and over the long term.

IX. AGIS METRICS AND REPORTING

Q. WHAT INFORMATION DO YOU PROVIDE IN THIS SECTION OF YOUR TESTIMONY?

A. In this section, I discuss progress metrics and proposed reporting on the AGIS program. Our intent is to provide the Commission and stakeholders comprehensive information on deployment progress for monitoring purposes, and performance and achievement of customer and system benefits as we implement the advanced grid initiatives.

The AGIS initiative will be implemented over a number of years, beginning with customer outreach and education efforts, followed by deployment of the systems and technologies, and then the roll-out of new products and services enabled by the AGIS initiative. Our efforts will also include development and implementation of future products and services that will capture additional benefits of the advanced grid capabilities as customer preferences and technologies evolve over time. This section discusses our proposed progress metrics and reporting chronologically as we move through these phases of AGIS implementation.

Because we are the first Minnesota utility to propose implementation of these advanced grid components through a broad advanced grid initiative, we believe comprehensive reporting will contribute to and inform the ongoing discussions of distribution planning and the advanced grid among Minnesota stakeholders. Our proposed progress metrics and reporting are discussed below and are also summarized in Exhibit____(MCG-1), Schedule 11.

Q. ARE YOU PROPOSING A SEPARATE PERIODIC REPORT SPECIFICALLY RELATED TO AGIS?

A. Yes. We propose to file an annual report on the AGIS initiative that will include various progress metrics that relate to different areas of our business that are involved in AGIS implementation. We propose to file the AGIS report on May 1 each year, to include reporting for the prior calendar year. Our first AGIS report would be filed May 1, 2022. I note that the content of the report and relevant metrics will change over time as we move through the phases of AGIS implementation.

Q. WILL OTHER PERIODIC REPORTING BE IMPACTED BY THE AGIS INITIATIVE?

A. Yes. AGIS may also impact certain service quality metrics that are included in reporting that is already in place. Specifically, the Company reports service quality metrics under our established Service Quality tariff[41] as well as the Minnesota Rules governing utility service quality.[42] We propose to continue reporting the service quality metrics in those reports, and intend to address any AGIS impacts to service quality metrics or thresholds in those separate proceedings.

Q. DO YOU PROPOSE SPECIFIC METRICS RELATED TO FUTURE OPERATIONAL CAPABILITIES OR PRODUCTS AND SERVICES THAT WILL BE ENABLED BY AGIS?

A. Not at this time. I discuss below some of the types of information that the Company anticipates filing in the future. However, are currently developing operational reporting solutions, so final details concerning specific metrics and calculations are not yet available. In addition, we recognize that specific metrics or potential performance thresholds might be further developed through later Commission proceedings as the Company proposes new products or services enabled by the advanced grid. For example, the Company would seek approval for a full residential time of use rate in a future proceeding, where detailed metrics and reporting would be informed by stakeholder input and approved by the Commission. We propose to report on metrics developed in those proceedings in the separate future dockets.

A. Customer Education and Outreach Metrics

Q. WHAT INFORMATION DO YOU PROPOSE TO TRACK AND REPORT WITH RESPECT TO THE COMPANY'S CUSTOMER EDUCATION AND OUTREACH EFFORTS?

A. Because education and awareness are key to customer engagement with advanced grid offering and capabilities, we intend to measure the impact of

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[41] See the Company's Minnesota Electric Rate Book, Section 6, General Rules and Regulations, Subsection 1.9, Service Quality.

[42] See Minn. Rule 7826, Electric Utility Standards on safety, reliability, and service quality.

our communications and education efforts around installation of the advanced meters. To answer key questions and assess the overall effectiveness of our efforts, we will track and report on:

- Customer responses on the adequacy and clarity of our communications prior to installation of advanced meters.

Q. HOW WILL THE COMPANY MEASURE THIS PERFORMANCE?

A. We plan to conduct quarterly customer surveys to ensure our surveys are timely and follow soon after the distribution of meter installation communications. The surveys will continue as installation efforts proceed across our service territory.

Q. HOW DOES THE COMPANY EXPECT TO USE THESE SURVEY RESULTS?

A. We intend to closely monitor these results and modify our communication materials or education plans if these results indicate a modification may be warranted.

In addition to these survey results, we will be tracking the number of customer who elect to opt out of an advanced meter installation. To the extent the opt-out percentage may be related to the efficacy of our customer materials or education efforts, we will also take that into consideration as we continue to proceed with meter installation across our service territory.

Q. HOW AND WHEN WILL YOU REPORT ON THE PROGRESS METRICS RELATED TO CUSTOMER EDUCATION AND OUTREACH EFFORTS?

A. We intend to begin these surveys in 2021 as we begin AMI installation and will report this information in our annual AGIS report beginning in 2022.

B. Installation and Deployment Metrics

Q. WHAT INFORMATION DO YOU PROPOSE TO TRACK AND REPORT WITH RESPECT TO DEPLOYMENT AND INSTALLATION OF SYSTEMS AND TECHNOLOGIES?

A. We intend to track and report on installation for all AGIS components. This includes the timing of installation and the following statistics:

- AMI – Number of meters installed;
- FAN – Percentage of FAN deployed;
- FLISR – Number of feeders with FLISR enabled;
- IVVO – Number of feeders with IVVO enabled; and
- Number of customers electing to opt out of AMI installation.

Q. HOW DOES THE COMPANY EXPECT TO USE THIS INFORMATION RELATED TO INSTALLATION AND DEPLOYMENT OF AGIS COMPONENTS?

A. We will track these installation progress metrics to monitor our performance compared to our deployment plan for each component and our forecasted opt-out percentages. We intend to report these metrics to keep the Commission and stakeholders informed of our progress as we install and deploy AGIS equipment and systems.

Monitoring the percentage of customers opting out of advanced meter installation may provide information relative to our customer materials or education efforts. We will take that into consideration as we continue to roll-out meter installation across our service territory and develop future products and services that will utilize AMI capabilities.

Q. HOW AND WHEN WILL YOU REPORT THE INSTALLATION PROGRESS METRICS?

A. We intend to measure these installation metrics semi-annually for our internal monitoring purposes, and will report these progress metrics in our annual AGIS report beginning in 2022. This reporting would continue until deployment is completed.

Q. ARE THERE OTHER METRICS YOU INTEND TO REPORT DURING THE INSTALLATION AND DEPLOYMENT PHASE?

A. Yes. We intend to track and report:

- Number of calls to our Customer Contact Center regarding the AMI meter installations; and
- Number of complaints regarding AMI installation.

In addition to tracking our call center metrics, we have developed a robust plan with our meter installation vendor (Itron) around customer communications and service quality, as they will have direct contact with and will receive calls directly from our customers related to meter installation. Mr. Cardenas discusses our plans for the meter installation vendor service quality tracking and reporting. We would include these metrics in our reported information as well. Mr. Cardenas provides details on the tracking mechanism, categories, and methods of reporting for both the Company's and Itron's call centers, as well as any customer complaints.

Q. HOW AND WHEN WILL YOU REPORT THE COMPANY'S AND ITRON'S CALL CENTER METRICS AND ANY COMPLAINTS REGARDING AMI INSTALLATION?

A. As discussed by Mr. Cardenas, these metrics are related to and may impact metrics we report under our established Service Quality tariff and the Minnesota Rules on service quality. We intend to begin reporting this information as part of our annual service quality reporting beginning in 2022. I note, however, that for completeness and monitoring purposes, we would also include this information in our annual AGIS report.

C. Post-Implementation Metrics

Q. WHAT INFORMATION DO YOU PROPOSE TO TRACK AND REPORT ONCE AGIS IS IMPLEMENTED?

A. Post-implementation, we propose to track and report operational metrics related to AGIS components, certain service quality metrics, and customer engagement and satisfaction as it related to AGIS capabilities. In the near term, this would include metrics related to advanced grid capabilities and services that do not require future regulatory proceedings to enable.

Q. WHAT OPERATIONAL METRICS DO YOU PROPOSE TO REPORT?

A. We propose to report the following operational metrics:

- Avoided customer minutes out on FLISR-enabled feeders; and
- Energy reduction due to IVVO (that result in associated cost reduction and reduction in CO_2 emissions).

Q. HOW DOES TRACKING AND REPORTING CUSTOMER MINUTES OUT REFLECT THE IMPACT OF FLISR?

A. We are currently able to track customer minutes out (CMO) as one measure of system reliability. The automated restoration provided by FLISR will reduce customer minutes out (CMO) for customers located on FLISR-enabled feeders. As we begin to install FLISR devices, we will be able to compare CMO to past performance, indicating the extent to which FLISR has reduced CMO. Ms. Bloch provides additional information on the benefits of FLISR, including how the value of reduced CMO is quantified. I note that this reliability metric is not included in our service quality reporting. Other reliability metrics will continue to be addressed in our existing service quality reports, where calculation methodologies and performance thresholds are defined.

Q. HOW WILL THE COMPANY TRACK AND CALCULATE THE ENERGY REDUCTION DUE TO IVVO, THE ASSOCIATED COST REDUCTION, AND VALUE OF REDUCED CO_2 EMISSIONS?

A. IVVO is expected to result in energy reductions due to the voltage reductions enabled by IVVO. In other words, lowering the voltage on a feeder would result in lower energy usage, which would result in lower costs. In addition, line losses are generally a percentage of energy, so reduced energy also results in reduced line losses (and associated costs). Reduced energy usages also means reduced CO_2 emissions. As we begin to install IVVO devices, energy reductions will be calculated based on the voltage on the IVVO-enabled feeder compared to the overall system voltage. With the energy reduction will come cost savings to customers and a reduction in CO_2 emissions. Ms. Bloch provides additional information on the benefits of IVVO, including how the value of these benefits are quantified.

Q. HOW AND WHEN WILL YOU REPORT THESE OPERATIONAL METRICS?

A. We intend to report these operational metrics in our annual AGIS report. With FLISR and IVVO installation beginning in 2021, we would be able to begin this reporting for specific feeders in 2022. This reporting would continue throughout the FLISR and IVVO deployment phases as we install the devices on additional feeders.

Q. WHAT SERVICE QUALITY METRICS DO YOU PROPOSE TO REPORT?

A. As noted above, certain service quality metrics related to call center response time, meter reading, billing, and reliability may be impacted by AGIS implementation. Ms. Bloch and Mr. Cardenas discuss service quality metrics in their testimony. We propose to report those metrics and address any impacts under the already established reporting structures for our service quality tariff and the Minnesota service quality rules. However, for completeness and monitoring purposes we would include the following information in the annual AGIS report beginning in 2022:

- Percentage of customers with advanced meters that receive estimated bills; and
- Percentage of customers with advanced meters that have made a complaint about inaccurate meter readings.

Q. WHAT CUSTOMER SATISFACTION AND ENGAGEMENT METRICS DO YOU PROPOSE TO REPORT?

A. We propose to report the following metrics in our annual AGIS report beginning in 2022:

- Customer satisfaction with outage-related communications;
- Number of customers with an advanced meter with an active web portal account (MyAccount); and
- Number of unique visits to MyAccount.

Q. WHY DOES THE COMPANY BELIEVE THESE METRICS ARE IMPORTANT?

A. First, the improved visibility into the system and the ability of AMI meters to detect outage and restoration events enables the Company to provide proactive and more timely and accurate communications on outages and expected restoration times. We believe it is important to understand our customers' views on these benefits enabled by the advanced grid as well as to obtain feedback to improve our outage communications.

Second, the majority of the new information on energy usage provided by advanced metering will be available to customers via the web portal and MyAccount. Tracking our customers' use of the web portal will be useful in determining how to improve presentation of data and how to engage customers in the future as we develop new products and services enabled by the advanced grid.

D. Longer-Term Reporting

Q. WHAT TYPES OF AGIS-RELATED OPERATIONAL INFORMATION DOES THE COMPANY ANTICIPATE REPORTING IN THE FUTURE?

A. As Mr. Harkness discusses in his testimony, we are currently developing operational reporting solutions, with final details on specific reporting and metrics calculations not yet finalized. Although reporting details are not finalized, some examples of metrics we anticipate being able to report are:

- Theft / tamper detection and reduction;
- Reduction in trips due to customer equipment damage;
- Reduction in "OK on Arrival" outage field trips;
- Reduction in field trips for voltage investigations;
- Patrol time reduction; and
- Outage management efficiency.

Q. WHAT TYPES OF INFORMATION DO YOU ANTICIPATE REPORTING RELATED TO NEW PRODUCTS AND SERVICES ENABLED BY THE ADVANCED GRID?

A. For those new products and services that will require separate Commission approval for implementation, we expect the reporting details and timing will be determined in those separate proceedings, with stakeholder input and at the direction of the Commission. Future reporting will be determined in separate proceedings for any advance rates – like a full residential time-of-use rate – or for other new products such as Green Button Connect. Some examples of the types of reporting we would anticipate for new products and services are:

- TOU rate – avoided generation/peak demand;
- TOU rate – deferral of capital investments due to demand reduction;
- Remote disconnect – reduced consumption on inactive meters;
- Remote disconnect – reduced uncollectible / bad debt expense;
- Percentage of customers with AMI that have selected pre-pay billing;
- Percentage of customers with AMI that receive high bill alerts; and
- Percentage of customers with AMI that have one or more active advanced applications.

X. CONCLUSION

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. Our distribution grid is the foundation of the service we provide our customers. We are at a point where investment in new technologies to further modernize our grid will return significant value to our customers. Our proposed AGIS initiative supports the Company's vision for an advanced grid that will provide both customer and operational benefits for many years to come and has been informed by:

- The Company's strategic priorities to lead the clean energy transition, enhance the customer experience, and keep bills low;
- The Company's desire to meet the growing needs and expectations of our customers;
- Current distribution system needs; and
- Commission policy and stakeholder input relative to customer offerings, performance, and technical capabilities of the grid.

Our AGIS initiative will enhance transparency into the distribution system and provide detailed and timely data to promote efficiency, reliability, and enable increased distributed resources on our system. AGIS will also enhance our customers' experience by providing access to actionable information, more choices, and greater control of their energy use.

I recommend that the Commission approve our AGIS initiative, including recovery the costs of the capital investments and O&M expense for the AGIS components that we propose to implement during the 2020-2022 term of the MYRP. I also recommend that the Commission certify our proposed AGIS projects overall, so that the Company would have the opportunity to request cost recovery for these programs between rate cases in subsequent rider filings.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Statement of Qualifications

Michael C. Gersack
Vice President, Customer Care
Xcel Energy
1800 Larimer Street, Suite 1500, Denver, Colorado

<u>Current Responsibilities (2019 - Present)</u>

Vice President Innovation and Transformation

<u>Previous Positions</u>

Xcel Energy Inc., Minneapolis

2010 - 2018 Vice President, Customer Care
2007 - 2010 Managing Director, Revenue Cycle Operations
2006 - 2007 Managing Director, Customer Care
2004 - 2006 Managing Director, Customer Care Business Operations
2002 - 2004 Managing Director, Retail Finance, Customer and Field Operations
2000 - 2002 Director, Accounting and Financial Analysis, Retail Operations
1999 - 2000 Manager, Retail Operations Accounting

Kinder Morgan

1998 – 1999 Controller, Enable (joint venture)
1997 – 1998 Manager, Retail Accounting
1996 – 1997 Business Unit Consultant

Energy and Resource Consulting Group

1994 – 1996 Senior Analyst

<u>Education</u>

Bachelor of Science and Masters Degrees in Accounting, University of Denver

<u>Business / Industry Activities</u>

Certified Public Accountant

AGIS Grid Modernization Requirements - 2019

Planning Objectives: The Commission is facilitating comprehensive, coordinated, transparent, integrated distribution plans to:
· Maintain and enhance the safety, security, reliability, and resilience of the electricity grid, at fair and reasonable costs, consistent with the state's energy policies;
· Enable greater customer engagement, empowerment, and options for energy services;
· Move toward the creation of efficient, cost-effective, accessible grid platforms for new products, new services, and opportunities for adoption of new distributed technologies; and,
· Ensure optimized utilization of electricity grid assets and resources to minimize total system costs.
· Provide the Commission with the information necessary to understand Xcel's short-term and long-term distribution system plans, the costs and benefits of specific investments, and a comprehensive analysis of ratepayer cost and value.

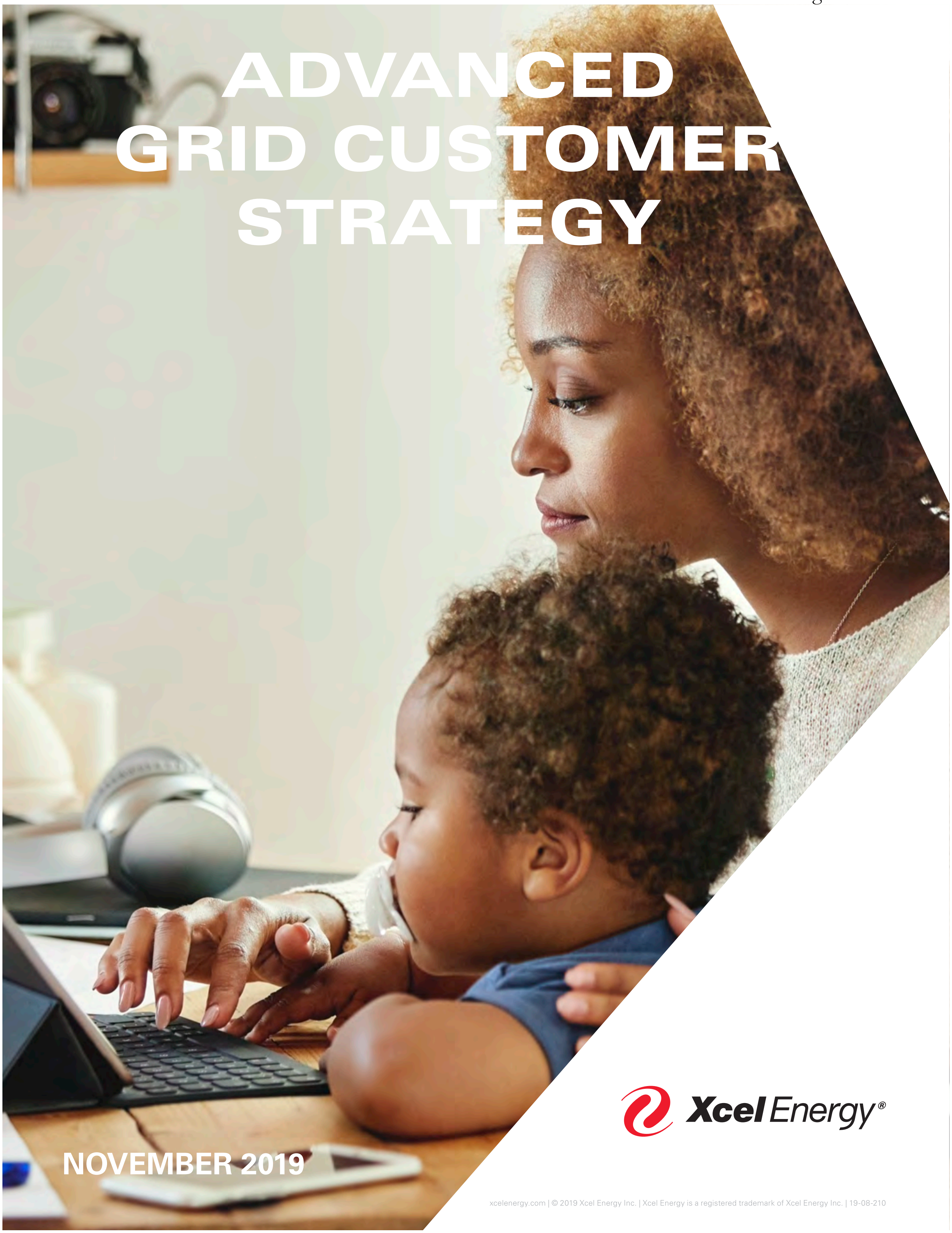
Source	Requirement/Description	IDP	Rate Case: AGIS
Docket No. E002/CI-18-251 Aug. 30, 2018 Order (Updated to include changes from Jul 16, 2019 Order)	**A. Baseline Distribution System and Financial Data: Financial Data**		
	26. Historical distribution system spending for the past 5-years, in each category: a. Age-Related Replacements and Asset Renewal b. System Expansion or Upgrades for Capacity c. System Expansion or Upgrades for Reliability and Power Quality d. New Customer Projects and New Revenue e. Grid Modernization and Pilot Projects f. Projects related to local (or other) government-requirements g. Metering h. Other	IDP II (C)	Addressed in IDP
	28. Projected distribution system spending for 5-years into the future for the categories listed above, itemizing any non-traditional distribution projects	IDP II (C)	Gersack II(C) AGIS Expenditures 2020-2029 Gersack V(D)(2) AGIS PM Costs 2020-2029 Bloch V(A) AGIS - Distribtuion 2020-2029 Bloch V(D)(5) AMI - Distribution 2020-2029 Bloch V(E)(3) FAN - Distribution 2020-2029 Bloch V(F)((6) FLISR - Distribution 2020-2029 Bloch V(G)(7) IVVO - Distribution 2020-2029 Harkness V(E)(3)(c)(4) AMI - IT 2020-2029 Harkness V(E)(4)(e)(4) FAN - IT 2020-2029 Harkness V(E)(5)(c) FLISR - IT 2020-2029 Harkness V(E)(6)(c) IVVO - IT 2020-2029 Harkness V(E)(7) AGIS - IT 2020-2029 Duggirala Schedules 2, 3, 4
	29. Planned distribution capital projects, including drivers for the project, timeline for improvement, summary of anticipated changes in historic spending. Driver categories should include: a. Age-Related Replacements and Asset Renewal b. System Expansion or Upgrades for Capacity c. System Expansion or Upgrades for Reliability and Power Quality d. New Customer Projects and New Revenue **e. Grid Modernization and Pilot Projects** f. Projects related to local (or other) government-requirements g. Metering h. Other	IDP II (C) and Attachments F1 nd G1	Gersack II(B) Exec Summary - Drivers Gersack IV Drivers of AGIS Strategy Gersack II(C) Exec Summary - Implementation Gersack V(A) Component Implementaion Gersack V(B) Overall Timeline/Implementation Bloch V(A) Projects and Timeline Block V(B) Drivers (Limitations of System) Bloch V(D) AMI Bloch V(E) FAN Bloch V(F) FLISR Bloch V(G) IVVO Harkness V(B)(E) AGIS Overview Harkness V(E)(3) AMI Harkness V(E)(4) FAN Harkness V(E)(5) FLISR Harkness V(E)(6) IVVO
	30. Provide any available cost benefit analysis in which the company evaluated a non-traditional distribution system solution to either a capital or operating upgrade or replacement	IDP VI and Attachment H	Addressed in IDP

Source	Requirement/Description	IDP	Rate Case: AGIS
Docket No. E002/CI-18-251 Aug. 30, 2018 Order (Updated to include changes from Jul 16, 2019 Order)	D. Long-Term Distribution System Modernization and Infrastructure Investment Plan		
	2. Xcel shall provide a 5-year Action Plan as part of a 10-year long-term plan for distribution system developments and investments in grid modernization based on internal business plans and considering the insights gained from the DER futures analysis, hosting capacity analysis, and non-wires alternatives analysis. The 5-year Action Plan should include a detailed discussion of the underlying assumptions (including load growth assumptions) and the costs of distribution system investments planned for the next 5-years (expanding on topics and categories listed above). Xcel should include specifics of the 5-year Action Plan investments. Topics that should be discussed, as appropriate, include at a minimum:	IDP XIV	Gersack II Exec Summary Gersack IV Drivers of AGIS Strategy Gersack V AGIS Components and Implementation Gersack VI Customer Experience
	· Overview of investment plan: scope, timing, and cost recovery mechanism	IDP II, IX and XIV and Addressed in Rate Case	Gersack II Exec Summary
	· Grid Architecture: Description of steps planned to modernize the utility's grid and tools to help understand the complex interactions that exist in the present and possible future grid scenarios and what utility and customer benefits that could or will arise.	IDP XIV and Addressed in Rate Case	Gersack V AGIS Components and Implementation Bloch V(D) AMI Bloch V(E) FAN Bloch V(F) FLISR Bloch V(G) IVVO Harkness V(E)(3) AMI Harkness V(E)(4) FAN Harkness V(E)(5) FLISR Harkness V(E)(6) IVVO Harkness V(D) Cyber Security Cardenas V(F) Quantifiable Benefits Gersack VI Customer Experience (Benefits)
	· Alternatives analysis of investment proposal: objectives intended with a project, general grid modernization investments considered, alternative cost and functionality analysis (both for the utility and the customer), implementation order options, and considerations made in pursuit of short-term investments. The analysis should be sufficient enough to justify and explain the investment.	Addressed in Rate Case	Gersack V(C) Alternatives to AGIS Bloch V(D)(6) AMI Alternatives Bloch V(F)(7) FLISR Alternatives Bloch V(G)(6) IVVO Alternatives Harkness V(E)(4)(g) FAN Alternatives
	· System interoperability and communications strategy	IDP IX, X and Addressed in Rate Case	Bloch V(D)(7) AMI Interoperability Bloch V(F)(8) FLISR Interoperability Bloch V(G)(7) IVVO Interoperability Harkness V(E)(4) FAN Overview Harkness V(E)(4)(b) FAN Interoperability Harkness V(E)(3)(b) AMI Integration
	· Costs and plans associated with obtaining system data (EE load shapes, PV output profiles with and without battery storage, capacity impacts of DR combined with EE, EV charging profiles, etc.)	IDP XI (F)	Addressed in IDP
	· Interplay of investment with other utility programs (effects on existing utility programs such as demand response, efficiency projects, etc.)	Addressed in Rate Case	Gersack VI(B)(4) Energy Savings Programs
	· Customer anticipated benefit and cost	Addressed in Rate Case	Gersack VII Prudence of AGIS Investments (CBA) Duggirala Overall CBA Costs, Benefits, Results Gersack VIII Bill Impacts *Costs and Benefits are also discussed throughout Bloch V (AGIS), Harkness V (AGIS), and Cardenas V (AGIS)*
	· Customer data and grid data management plan (how it is planned to be used and/or shared with customers and/or third parties)	Addressed in Rate Case	Gersack VI Customer Experience (overall) Gersack VI(B)(3) Digital Experience (web portal) Gersack Schedule 3 Customer Strategy (Appendix B: Data Access, Privacy, Governance) Harkness V(D) Cyber Security
	· Plans to manage rate or bill impacts, if any	IDP IX and Addressed in Rate Case	Gersack VIII Bill Impacts
	· Impacts to net present value of system costs (in NPV RR/MWh or MW)	IDP XIV and Attachment L	Addressed in IDP

Source	Requirement/Description	IDP	Rate Case: AGIS
Docket No. E002/CI-18-251 Aug. 30, 2018 Order (Updated to include changes from Jul 16, 2019 Order)	**· For each grid modernization project in its 5-year Action Plan, Xcel should provide a cost-benefit analysis <u>based on the best information it has at the time and including a discussion of non-quantifiable benefits. Xcel shall include all information used to support its analysis.</u>**	IDP IX and Addressed in Rate Case	Gersack VII(A) CBA Gesack VII(B) Qualitative Benefits Duggirala II(B) Quantitative Inputs Duggirala II(C) Results Duggirala IV Qualitative Benefits
	· Status of any existing pilots or potential for new opportunities for grid modernization pilots	IDP XIII	Gersack III Grid Mod Background (Res TOU Pilot) Gersack IV(C)(2) Advanced Rate Design/Billing Options
	3. In addition to the 5-year Action Plan, Xcel shall provide a discussion of its vision for the planning, development, and use of the distribution system over the next 10 years. The 10-year Long-Term Plan discussion should address long-term assumptions (including load growth assumptions), the long-term impact of the 5-year Action Plan investments, what changes are necessary to incorporate DER into future planning processes based on the DER futures analysis, and any other types of changes that may need to take place in the tools and processes Xcel is currently using.	IDP XIV and Addressed in Rate Case	Gersack II Exec Summary Gersack V AGIS Implementation Gersack VI(D) Customer Experience (Long Term) Bloch D(4)(d)(1) AMI Benefits (DER) Bloch G(4)(b) IVVO Benefits (DER)
Docket No. E002/CI-18-251 July 16, 2019 Order	**8. Provide all information, analysis and assumptions used to support the cost/benefit ratio for AMI, FAN, and FLISR; and IVVO and CVR cost-benefit analysis as part of its 2019 IDP filing or other future filings.**	IDP IX (F) and Addressed in Rate Case	Duggirala Overall - CBA testimony points to the other witnesses who provide detailed cost and benefit forecasts.
Docket No. E002/M-17-797 Sept. 27, 2019 Order	**9. If and when Xcel requests cost recovery for Advanced Grid Intelligence and Security investments, the filing must include a business case and comprehensive assessment of qualitative and quantitative benefits to customers, considering, at a minimum, the following:**	IDP IX and Addressed in Rate Case	Gersack II Exec Summary Gersack III Grid Mod Background Gersack IV(D) Commission Policy and Stakeholder Input Gersack V(A) AGIS Components Gersack V(B) Overall Implementation Gersack VII(A) CBA Quantified Benefits Gersack VII(B) Qualitative Benefits Bloch V(D) AMI Bloch V(E) FAN Bloch V(F) FLISR Bloch V(G) IVVO Harkness V(E)(3) AMI Harkness V(E)(4) FAN Harkness V(E)(5) FLISR Harkness V(E)(6) IVVO
	A. Scope of Investment 1. Investment Description		
	a. Detailed description of proposed investment and project life		
	b. If multiple components, overview of costs and descriptions of each		
	i. Include purpose and role		
	ii. Explain known and potential future use cases for each component		
	iii. Explain known and potential value streams and how each component fits with state policy, statues, rules and Commission orders		
	iv. Describe beneficiaries of each investment (who, how many, over what time period)		
	c. Articulation of principles, objectives, capability, functionalities, and technologies enabled by investment; and		
	d. Interrelation and interdependencies with other existing or future investments, including overlapping costs: scope, amount, timing.		
	2. Alternatives considered	Addressed in Rate Case	Gersack V(C) Alternatives to AGIS Bloch V(D)(5) AMI Cost Development (RFP discussion) Bloch V)D)(6) AMI Alternatives Bloch V(F)(6) FLISR Cost Development Bloch V(F)(7) FLISR Alternatives Bloch V(G)(5) IVVO Cost Development Bloch V(G)(6) IVVO Alternatives Harkness V(E)(4)(e) FAN Cost Development Harkness V(E)(4)(g) FAN Alternatives AGIS Supporting files, Vol. 2B (on disc)
	a. If a Request for Proposal was used provide:		
	i. The RFP issued, including list of all services or assets scoped in the RFP		
	ii. Provide summary of responses		
	iii. Provide assessment of bids and factors used for selection		
	iv. The scope of offerings or services included in the selected bid		
	b. If not, what was used.		
	3. Costs	IDP IX and Addressed in Rate Case	Duggirala II(A) Model Structure and Requirements Duggirala Schedules 2, 3, 4, 5
	a. Provide sufficient information to determine what is included in the investment in each of the following categories:		
	i. Direct Costs (product, service, customer, project, or activity)		
	ii. Indirect Costs		
	iii. Tangible Costs		
	iv. Intangible Costs		
	v. Real Costs		
	b. If needed, provide the utility's definition of each category and whether internal or external labor costs are included in the category and the instant petition. If the costs are not included in the petition, include information on where and when those costs will be sought to be recovered.	Addressed in Rate Case	Duggirala II(A) Model Structure and Requirements
	c. If there is overlap or costs included in both categories, outline the overlapping costs and explain.	Addressed in Rate Case	Duggirala II(A) Model Structure and Requirements Duggirala Schedules 2, 3, 4, 5
	d. For each of the cost categories outline whether the investment has been partially approved or included in previous or on-going docket riders, rate cases, or other cost recovery mechanisms or note all costs are included in the instant petition.	IDP II (C)	Gersack II(C) Exec Summary - AGIS Implementation Gersack III Grid Mod Background Bloch V(C) Grid Mod Efforts to Date Harkness V(E)(2) Grid Mod Efforts to Date

Source	Requirement/Description	IDP	Rate Case: AGIS
Docket No. E002/M-17-797 Sept. 27, 2019 Order	**4. Detailed Analysis of the type of proposed or multiple cost effectiveness analysis utilized:**	Addressed in Rate Case	Duggirala III
	a. Least-cost, best-fit (Xcel proposes in IDP Reply comments)		
	b. Utility Cost-test; and		
	c. Integrated Power System and Societal Cost test		
	B. Provide a cost benefit analysis for (1) each investment component with overlapping costs or benefits in isolation and (2) each bundled components, as appropriate	IDP IX and Addressed in Rate Case	Duggirala II(C) CBA Results AGIS Supporting files, Vol. 2B (on disc) Gersack VII(A)(1) CBA Overview
	1. Provide Discount Rate Used and Basis; and	Addressed in Rate Case	Duggirala II(A) Model Structure and Requirements
	2. Identify cost categories and benefit categories used (explain metrics), including an explaination of how benefits can be monitored over time and proposal for reporting to Commission:	Addressed in Rate Case	Duggirala II(B) Quantitative Inputs Gersack IX Metrics and Reporting
	a. Identify quantitative costs and qualitative costs: i. Use quantitative methods to address qualitative benefits to the extent possible. ii. Explain system used to assess value and priorities to qualitative benefits (points and/or weighting); and iii. Identify sensitivity ranges on estimates or value	Addressed in Rate Case	Duggirala Overall CBA Costs, Benefits, Results
	b. Include a long-term bill impact analysis	IDP IX and Addressed in Rate Case	Gersack VIII Bill Impacts
	c. Include a reference case/scenario without the project (or group of projects); and	IDP IX and Addressed in Rate Case	Duggirala II(A) Model Structure and Requirements Gersack VIII Bill Impacts
	d. Apply the following principles to ensure the investment analysis has:	Addressed in Rate Case	*The Company has incorporated these priciples throughout its analyses, including:* Gersack V AGIS Components and Implementation Bloch V(D) AMI Bloch V(E) FAN Bloch V(F) FLISR Bloch V(G) IVVO Harkness V(E)(3) AMI Harkness V(E)(4) FAN Harkness V(E)(5) FLISR Harkness V(E)(6) IVVO Cardenas V(F) Quantifiable Benefits Gersack VI Customer Experience (Benefits) Duggirala Overall CBA Costs, Benefits, Results
	i. compared with traditional resources or technologies;		
	ii. clearly accounted for state regulatory and policy goals;		
	iii. accounted for all relevant costs and benefits, including those difficult to quantify;		
	iv. provided symmetry across relevant costs and benefits;		
	v. applied a full life-cycle analysis;		
	vi. provided a sufficient incremental and forward-looking view;		
	vii. is transparent;		
	viii. avoided combining or conflating different costs and benefits;		
	ix. discuss customer equity issues, as needed;		
	x. assessed bundles and portfolio where reasonable; and		
	xi. addressed locational and temporal values.		

ADVANCED GRID CUSTOMER STRATEGY



Xcel Energy®

NOVEMBER 2019

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EXECUTIVE SUMMARY

The electric utility industry is in a time of significant change. Increasing customer expectations and technological advances have reshaped what customers expect from their energy service provider, and how those services are delivered. Technologies that customers can use to control their energy usage, such as smart thermostats, electric vehicle (EV) chargers, smart home devices, and even smart phones, are evolving at a fast rate. Influenced by other services, customers have come to expect more now from their energy providers than in the past, including greater choices and levels of service, as well as greater control over their energy sources and their energy use.

At the same time, major industry technological advances provide new capabilities for utility providers to manage the electric distribution grid and service to customers. Electric meters are now equipped to gather more detailed information about customer energy usage, which utilities can leverage to help customers better understand and manage their usage. Other advanced equipment on the grid can sense, communicate, and respond in real time to circumstances that would normally result in power outages. Grid operators can also get improved data to better and more proactively plan and operate the grid. These advancements form the foundation for a flexible grid environment that helps support two-way power flows from customer-connected devices or generating resources (such as rooftop solar) and provides utilities with a greater ability to adapt to future developments.

Xcel Energy has a 100-year track record of outstanding service to our customers and communities – delivering safe, reliable and affordable energy. At our core, is keeping the lights on for our customers, safely and affordably. We are also planning for the future – and have a vision for where we and our customers want the grid to go. We are taking a measured and thoughtful approach to ensure our customers receive the greatest value, and that the fundamentals of our distribution business remain sound.

Today, Xcel Energy customers have access to a multitude of energy efficiency and demand management programs, renewable energy choices, billing options, a mobile app, and outage notifications that include estimated restoration times. Customers also receive confirmations when our records reflect that the outages have been resolved – and they receive these via their preferred communication channel – text, email, or phone. We have made advances on our grid and with the service we offer our customers – and these and other products and services have provided our customers with significant value over many years.

However, technologies are advancing, as are customer expectations. Customers want access to actionable information, more choice and greater control of their energy use – and they expect a smarter, simpler and more seamless experience. Enhancing the customer experience is critically important, and is one of our three strategic priorities, along with leading the clean energy transition and keeping bills low. We plan to integrate modern customer experience strategies with advanced grid platforms and technologies to enable intelligent grid operations, smarter networks and meters, and optimized products and services for our customers.

While we have made incremental modernization efforts on the distribution system over many years, the time is now to begin a more significant advancement of the grid. This modernization begins with foundational advanced grid initiatives that both provide immediate benefits and new customer offerings while also enabling future systems and customer value. The foundational investments in our AGIS initiative include:

- *Advanced Distribution Management System (ADMS).* A real-time operating system that enables enhanced visibility into the distribution power grid and controls advanced field devices.

- *Field Area Network (FAN).* A private, secure two-way communication network that provides wireless communications across Xcel Energy's service area – to, from, and among, field devices and our information systems.
- *Advanced Metering Infrastructure (AMI).* AMI is an integrated system of advanced meters, communication networks, and data processing and management systems that enables secure two-way communication between Xcel Energy Energy's business and operational data systems and customer meters.
- *Fault Location, Isolation, and Service Restoration (FLISR).* A form of distribution automation that involves the deployment of automated switching devices that work to detect issues on our system, isolate them, and restore power thereby decreasing the duration of and number of customers affected an outage.
- *Integrated Volt VAr Optimization (IVVO).* An application that uses selected field devices to decrease system losses and optimize voltage as power travels from substations to customers.

We are taking a measured and thoughtful approach to advancing the grid to ensure our customers receive the greatest value, the fundamentals of our distribution business remain sound, and we maintain the flexibility needed as technology and our customers' expectations continue to evolve.

A. Customer Strategy

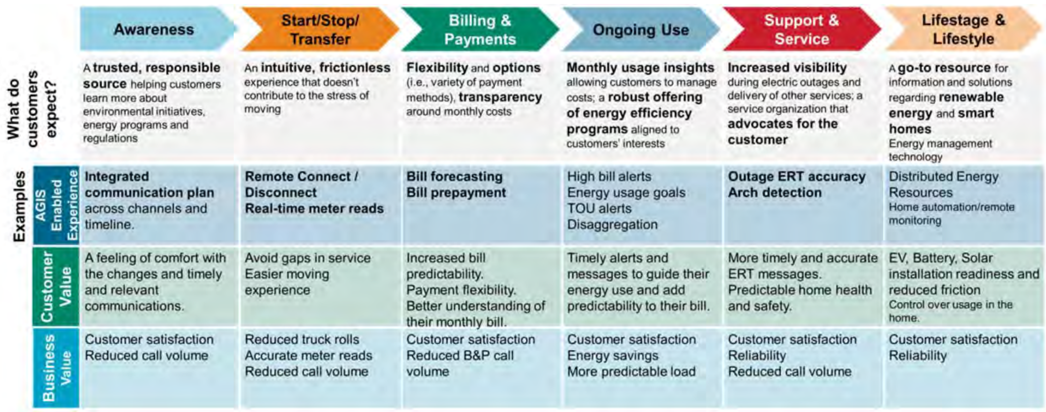
This multi-year initiative aims to transform the customer experience by implementing capabilities, technologies, and program management strategies to enable the best-in-class customer experience that our customers now expect. Our customer strategy is focused on shifting the customer experience dynamic to one where little action is required from customers around their basic service and where we offer personalized "packages" that customers can select from to meet their needs – similar to what customers experience when purchasing cable and internet services today. These packages may include options such as demand-side management, renewable energy, rate design, and non-energy services.

Figure 1. Customer Strategy Informed by Customer Expectations

Our implementation of the Advanced Distribution Management System in early 2020 is preparing the grid for increasing levels of DER. It is also paving the way for further grid advancement with Advanced Metering Infrastructure and our ability to leverage the underlying and necessary Field Area Network to reduce customers' energy costs through Integrated Volt-Var Optimization, improve customers' reliability experience through Fault Location Isolation and Service Restoration, and more.

Customers will have access to granular energy usage data from our AMI through a customer portal, which we expect to pair with informed insights and helpful tips on how to change their behavior to save energy. Further, the AMI we propose includes a Distributed Intelligence platform, which provides a computer at each customer's home that can "connect" usage information from the customer's appliances for further insights – and be updated with new software applications, much like customers can currently update their mobile devices with applications.

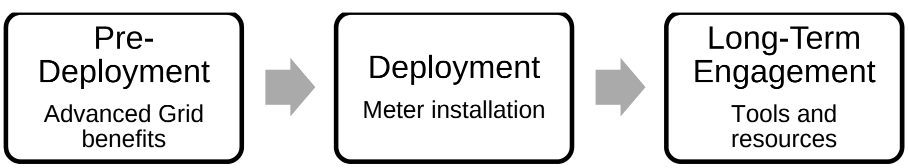
Figure 2. Customer Value through Lifecycle



	Awareness	Start/Stop/ Transfer	Billing & Payments	Ongoing Use	Support & Service	Lifestage & Lifestyle
What do customers expect?	A **trusted, responsible source** helping customers learn more about environmental initiatives, energy programs and regulations	An **intuitive, frictionless** experience that doesn't contribute to the stress of moving	**Flexibility** and **options** (i.e., variety of payment methods), **transparency** around monthly costs	**Monthly usage insights** allowing customers to manage costs; a **robust offering of energy efficiency programs** aligned to customers' interests	**Increased visibility** during electric outages and delivery of other services; a service organization that **advocates for the customer**	A **go-to resource** for information and solutions regarding **renewable energy** and **smart homes** Energy management technology
Examples: AGIS Enabled Experience	**Integrated communication plan** across channels and timeline.	**Remote Connect / Disconnect** **Real-time meter reads**	**Bill forecasting** **Bill prepayment**	High bill alerts Energy usage goals TOU alerts Disaggregation	**Outage ERT accuracy** **Arch detection**	Distributed Energy Resources Home automation/remote monitoring
Examples: Customer Value	A feeling of comfort with the changes and timely and relevant communications.	Avoid gaps in service Easier moving experience	Increased bill predictability. Payment flexibility. Better understanding of their monthly bill.	Timely alerts and messages to guide their energy use and add predictability to their bill.	More timely and accurate ERT messages. Predictable home health and safety.	EV, Battery, Solar installation readiness and reduced friction Control over usage in the home.
Examples: Business Value	Customer satisfaction Reduced call volume	Reduced truck rolls Accurate meter reads Reduced call volume	Customer satisfaction Reduced B&P call volume	Customer satisfaction Energy savings More predictable load	Customer satisfaction Reliability Reduced call volume	Customer satisfaction Reliability

During this transition to the advanced grid, we will take exceptional care of our customers to educate, inform, and ensure a smooth implementation. We are already developing processes that will ensure accurate, timely bills as customers change over to AMI. We are also developing dedicated, hands-on customer care processes that will provide our customers a single point of contact during implementation – and that will phase customer communications relative to our geographic deployment of AMI meter installation. Meter deployment and advanced meter capabilities will be phased in over the next several years, communications strategies, messages and tactics will be executed in three phases to match the customer journey.

Figure 3. Customer Communications Journey Phases



For example, our customer communications will begin pre-implementation to educate on the possibilities enabled by AMI, as well as customers' ability to opt-out of an AMI meter. As the AMI installation date gets closer, we will inform customers about what to expect with the AMI meter changeover at their homes or businesses. Finally, we will communicate post-AMI installation to reinforce early AMI messaging regarding possibilities and options – also providing practical steps to take advantage of the customer portal or other new or enhanced services available day one.

B. Customer Research

To develop the customer strategy, Xcel Energy committed to understanding customers' preferences, considerations, and thoughts regarding the benefits and value of an advanced grid investment. We gathered this information through primary research, such as focus groups and surveys. We also supplemented our research with information from secondary sources including the Smart Energy Consumer Collaborative, and GTM Research and other utilities' advanced grid plans.

Our key takeaways from these sources are as follows:

- *Consumers care more about technology and enabling improvements than process*. Safety and energy savings rated most highly.
- *Addressing service interruptions are important to all customer classes*. Improved reliability will allow the Company to focus more on other customer priorities.
- *Customers expect that service interruptions will be less frequent in scope and duration*.
- *Customers expect to receive detailed information from their utility*. They expect this information to be personal and frequent.
- *Customers expect more tools and information for them to make decisions about their energy usage*. Customers indicated more information allowed them to better identify opportunities and strategies to save energy and reduce their costs.
- *Business customers have more awareness and familiarity with advanced rate designs*. Residential customers expect the utility to provide them with rate comparison tools and information about new rate designs.
- *Building trust is a key component to unlocking value.* Trust is best built by identifying solutions and showing results specific to the customers
- *Customers expect that there will be a cost associated with the advanced meter but that the meter will also provide benefits over time.*

We have incorporated customer feedback and insights into our customer transition and communication plans – and the work we are doing to develop new and enhanced products and services as enabled by the advanced grid.

C. Advanced Grid Initiative

Fundamentally, we must act to replace our current Automated Meter Reading (AMR) service because our current vendor is sun-setting its AMR technology in the mid-2020s. While this system has provided value to customers for many years through efficient meter reading, we have an opportunity now to seize AMI technologies that are becoming available to maximize value for our customers. As we deploy advanced grid infrastructure, platforms, and technologies we expect three outcomes: (1) a transformed customer experience, (2) improved core operations, and (3) facilitation of future capabilities, which we discuss below.

Transformed customer experience. Our planned advanced grid investments combine to provide greater visibility and insight into customer consumption and behavior. We will use this information to transform the customer experience through new programs and service offerings, engaging digital experiences, enhanced billing and rate options, and timely outage communications.

We will offer options that give customers greater convenience and control to save money, provide access to rates and billing options that suit their budgets and lifestyles, and provide more personalized and actionable communications. As our system more efficiently manages energy flows, we can save customers money by reducing line losses and conserving energy. Smarter meters will be the platform that enables smarter products and services and contributes to improved reliability for our customers. Our customers will have more information to make more effective decisions on their energy use.

We will know more about our customers and our grid – and we will use that information to make more effective recommendations and decisions and continually use new information to develop new solutions. This will serve to help keep our bills low, as customers save money through both their actions and ours. It will also help ensure that our transition to a carbon-free system occurs efficiently – and harnesses the vast potential of all energy resources, from utility-scale to local distributed generation.

Improved core operations and capabilities. Smarter networks will form the backbone of our operations, and our investments will more efficiently and effectively deliver the safe and reliable electricity that our customers expect. We will have the capability to communicate two ways with our meters and other grid devices, sending and receiving information over a secure and reliable network in near-real time.

Our current service is reliable; however, we need to continue to invest in new technologies to maintain performance in the top third of U.S. utilities, particularly as we deliver power from more diverse and distributed resources and as industry standards continue to improve. Our advanced grid investments provide the platform and capabilities to manage the complexities of a more dynamic electric grid through additional monitoring, control, analytics and automation.

Our systems will more efficiently and effectively restore power when outages do occur using automation without the need for human intervention. For those outages that cannot be restored through automation, our systems will be better at identifying where the outage is and what caused it – benefitting customers through less frequent, shorter, and less impactful outages; more effective communication from the Company when they are impacted by an outage; and reduced costs from our more efficient use and management of assets.

Facilitation of future capabilities. The backbone of our investments will also support new developments in smart products and services; in the short term by supporting the display of more frequent energy usage data through the customer portal – and over the long term, allowing for the implementation of more advanced price signals. Designing for interoperability enables a cost-effective approach to technology investments and means we can extend our communications to more grid technologies, customer devices, and third-party systems in a stepwise fashion, which unlocks new offerings and benefits that build on one another. We have planned our advanced grid investments in a building block approach, starting with the foundational systems, in alignment with industry standards and frameworks. By doing so, we sequence the investments to yield the greatest near- and long-term customer value, while preserving the flexibility to adapt to the evolving customer and technology landscape. By adhering to industry standards and designing for interoperability, we are well positioned to adapt to these changes as the needs of our customers and grid evolve.

In planning our advanced grid initiative, we have considered the long-term potential of our ability to meet our obligations to serve and our customers' expectations and needs – ensuring we extract cost-effective value from our investments and remain nimble enough to react to a dynamically changing landscape. The principles we applied to our advanced grid planning include the ability to remotely update hardware and software, security and reliability, and flexible, standards-based service components. We are planning our grid advancement with the future in mind, and to provide both immediate and increasing value for our customers over the long-term.

We are on the forefront of many of the issues and changes underway in the industry and have developed our advanced grid initiative and our customer strategy to address them and harness value for our customers. In addition to transforming the customer experience, these foundational investments will allow us to advance our technical abilities to deliver reliable, safe, and resilient energy that customers value. These foundational investments also lay the groundwork for later years. The secure, resilient communication networks and controllable field devices deployed today through these investments will become more valuable in the future as additional sensors and customer technologies are integrated and coordinated.

Now is the time to modernize the interface where we connect directly with our customers – the distribution system. Technologies have evolved and matured; our peers have successfully implemented these technologies; and, the industry landscape is evolving. We must ensure our system has the necessary capabilities to meet our customers' expectations and needs – and, the flexibility to adapt to an uncertain future.

D. Reporting Metrics

Recognizing the significant investment that the advanced grid initiative requires as well as the fact that we are the first utility in Minnesota to take on this holistic effort, we propose to report on several metrics. These metrics will not only help measure the success of or areas of improvement within the advanced grid initiative, they will also provide progress reports to the Commission and share information and learnings with stakeholders. The proposed metrics are defined in four categories:

1. *Customer Awareness* – measuring the effectiveness of the communications on educating customers about the advanced grid and the potential benefits it entails.
2. *Customer Engagement* – measuring the adoption rates of customers in new products and services that are enabled or enhanced by the advanced grid.
3. *Customer Satisfaction* – measuring how satisfied customers are with the deployment or and services associated with the advanced grid.
4. *System Benefits* – measuring the energy savings benefits associated with products and services enabled or enhanced by the advanced grid.

Reporting of these metrics can keep stakeholders informed of the progress and value that the advanced grid is bringing to customers and also identify areas where Xcel Energy can focus additional resources to improve results. Each metric would have a specific baseline in a steady state. The steady state would occur within 1-2 years of the completion of mass deployment of advanced meters.

E. Conclusion

Xcel Energy's advanced grid initiative supports our vision of a customer experience where customers' needs and preferences are met and the customer effort level is low. We understand what our customers expect and will deliver on those expectations with a seamless experience that both improves their comfort and satisfaction while reducing costs and improving the efficiency of the entire system.

I. INTRODUCTION

Xcel Energy has a 100-year track record of outstanding service to our customers and communities – delivering safe, reliable and affordable energy. Currently, Xcel Energy customers have access to a state-of-the-art storm center, approximately 40 different energy efficiency and demand management programs, multiple renewable energy choices, billing options such as Average Monthly Payment, and a customer portal – MyAccount – that provides them digital access to their energy usage, energy savings recommendations, and benchmarking comparisons with similar customers. We also provide customers with outage notifications that include estimated restoration times – and confirmations when the Company's information reflects that the outages have been resolved. These have provided our customers with significant value over many years.

However, technologies are advancing, as are customer expectations. While we have done a great job meeting our customers' needs over time by maximizing the value of our existing infrastructure and technologies – customers want access to more actionable information, more choice and greater control of their energy use – and they expect a smarter, simpler and more seamless experience. Today, connected devices, such as Wi-Fi thermostats, Amazon's Alexa, and Google Home are becoming more prevalent in customer homes – influencing their perceptions about the ease of getting information conducting transactions. Distributed energy resources (DER) are becoming more cost-effective for customers – and forecasts indicate the potential for rapid growth in electric vehicles and home energy management systems. While there are no guarantees that these forecasts will be realized or that customers see promise in the potential value these technologies may unlock, we expect and want to play a role in spurring adopting of these technologies and ensuring their value is realized. We also look to these technologies to shape the way that we provide service to our customers.

Enhancing the customer experience is critically important, and is one of our three strategic priorities, along with leading the clean energy transition and keeping bills low. We plan to integrate modern customer experience strategies with advanced grid platforms and technologies to enable intelligent grid operations, smarter networks and meters, and optimized products and services for our customers. Combining enhanced experiences with smarter capabilities is a powerful and winning combination for the customers and communities we serve.

Now is the time to modernize the interface where we connect directly with our customers – the distribution system. Technologies have evolved and matured; our peers have successfully implemented these technologies; and, the industry landscape is evolving. We must ensure our system has the necessary capabilities to meet our customers' expectations and needs – and, the flexibility to adapt to an uncertain future.

II. ADVANCED GRID CUSTOMER STRATEGY

More than a century after the introduction of commercial electricity, the electricity grid and the role of the utility are being reimagined. We are on the cusp of advancing our grid with investments in the things that customers truly value. These investments will allow us to provide comprehensive and customized energy solutions that will help bring about the flexible, distributed, consumer-driven energy system of the future. While we have been incrementally advancing the grid over time, we are poised to embark and intend to complete a transformational set of investments in concert with our over 3 million Upper Midwest customers over the next five years.

Our advanced grid investments will provide the foundation for new products and services or the enhancement of existing products and services. These investments include a communications backbone that will allow us to transmit data to and from advanced meters at every customer's home or business in near real time. We will have more information about customer energy usage that will improve the quality and accuracy of our product and service recommendations. We will build this data into digital experience channels to provide customers with more timely and accurate information about their energy usage. These experiences will drive increased satisfaction and savings for customers as they have better information and as our recommendations become more relevant and actionable. Customers will feel like Xcel Energy is a partner in their energy usage – not just a provider.

The advanced meters we will implement will provide a distributed intelligence platform that is essentially a "computer" at customers' homes and businesses. This computer uses a Linux-based operating system to conduct localized, at the meter computing, analysis, and data processing that provide customers with new tools to help manage their energy usage and provide Xcel Energy with new tools to manage the grid more efficiently.

Automated sensors and controls on the grid will use the advanced grid communications backbone to smooth out the voltage and avert outages for some customers and shorten outages for others. We will delight our customers by knowing and acting without them having to call or take any other action when they lose power. The number of sensors and devices in the field will allow the Company an unprecedented level of information to continually monitor and adjust what will be a dynamic system that includes increasing amounts of distributed energy resources and electric technologies. We will have more information about our distribution grid that will improve our planning and operations – driving efficiencies, lowering costs, providing better service, and increasing customer satisfaction.

A. Customer Strategy

If we want to ensure that our customers benefit from the greater value and opportunity presented by an increasingly complex and challenging energy system, we know we must move away from the traditional one-directional customer relationship. We must instead operate in partnership with customers.

We aspire to be the preferred, trusted provider for our customers by delivering low-cost and reliable electricity and innovative, energy-efficient solutions. We understand that placing the customer at the center of everything we do is vital to the successful realization of the future electric system. Our strategy is therefore focused on shifting the customer experience dynamic to one where little action is required from customers around their basic service – and where we offer personalized "packages" that include options and opportunities in areas such as energy savings and renewable energy, lifestyle-oriented rate designs, and non-energy services – to meet individualized needs and wants.

With the impending introduction of advanced meters, greater system data availability and energy technologies, customers can increasingly decide when and how to consume electricity. Many customer experience improvements will come through foundational changes to our processes and technology – and our investment in the advanced grid will play a critical role in helping us meet our customers' expectations throughout their Xcel Energy journey.

Our advanced grid strategy is driven by our strategic priorities:

- Enhance the customer experience;
- Keep bills low; and
- Lead the clean energy transition.

These strategic priorities are driven by our customers' expectations which are informed by the routine experiences they have outside of the relationship with their energy provider. These customer expectations shape our guiding principles creating the future customer experience:

Figure 4. Customer Experience Guiding Principles

With the advanced grid, there are significant possibilities for Xcel Energy and its customers, but there are also unknowns. Our vision is that the long-term customer experience is one where customers' needs and preferences are met, and that the level of effort our customers need to take is low. We will understand what our customers expect and deliver on those expectations with a seamless experience that improves their comfort and happiness, while reducing costs and improving the efficiency of the entire system. We discuss our customer research in more detail below.

Through innovation, we will provide our customers with data-driven insights that help identify and deliver the best options, and we will work in collaboration to give them greater control to support their energy goals. We will make this easy by focusing on outcomes, responding with speed, and utilizing digital tools to improve the customer journey experience.

Our commitment to the customer experience is not just an evolution of the current experience. In all of our interactions, we are relying on our broad and in-depth customer research to better understand customer needs, preferences, and expectations and then develop the appropriate processes, products and services, and experiences needed to satisfy those expectations. The following section reviews the research we have done related to customer interest in and knowledge and awareness of advanced meters and the benefits of the advanced grid.

B. Customer Research

To develop our customer strategy, we gathered information about customers' considerations, preferences, and thoughts through primary research such as focus groups and surveys. We also supplemented this research with insights from secondary sources, such as the Smart Energy Consumer Collaborative, GTM Research, and other utilities' advanced grid plans.

Our key takeaways from these sources are as follows:

- *Consumers care more about their technology and enabling improvements from the advanced grid than process*. Safety and energy savings rated most highly. Customers have strong feelings about the cost of the advantages available through advanced meters.
- *Addressing service interruptions is important to all customer classes*. Improved reliability will allow the Company to focus more on other customer priorities.
- *Customers expect that service interruptions will be less frequent and of shorter duration*.
- *Customers expect to receive detailed information from their utility*. They expect this information to be personal and frequent.
- *Customers expect more tools and information for them to make decisions about their energy usage*. Customers indicated more information allowed them to better identify opportunities and strategies to save energy and reduce their costs.
- *Business customers have more awareness and familiarity with advanced rate designs*. Residential customers expect the utility to provide them with rate comparison tools and information about new rate designs.
- *Building trust is a key component to unlocking value.* Trust is best built by identifying solutions and showing results specific to the customers
- *Customers understand that their rates will increase in order to cover the expense of advanced meters but expect that the benefits of the meters will result in their costs being net neutral over time.*

In terms of messaging regarding implementation, customers told us our messaging should be short, specific, and positive. Messages should focus on the benefits of the project not on the process – and begin 2-3 months in advance of any implementation, which will give customers time to conduct their own research if they want. Customers want communications through multiple channels, including those that align with their preferences (email, text, phone). Finally, communications should be clear about any customer costs associated with the installation.

1. Primary Customer Research

The following studies have helped to inform our AGIS plans and deployment.

- *Grid Edge Product Survey* – This survey was conducted in March 2019 with the intent to gauge customers' opinions and interest toward several proposed product and service concepts that may become available after AGIS deployment. Beyond testing for concept interest, willingness to purchase and price sensitivity were also observed.
- *Advanced Meter Focus Groups* – Four residential customer focus groups were held in January 2019 which the goal of capturing customer understanding, perception, and attitudes toward advanced meters, as well as to understand customer expectations of the services enabled by advanced metering. Also included in these focus groups

were learning customer preferences for communications around the deployment and implementation of new meters.

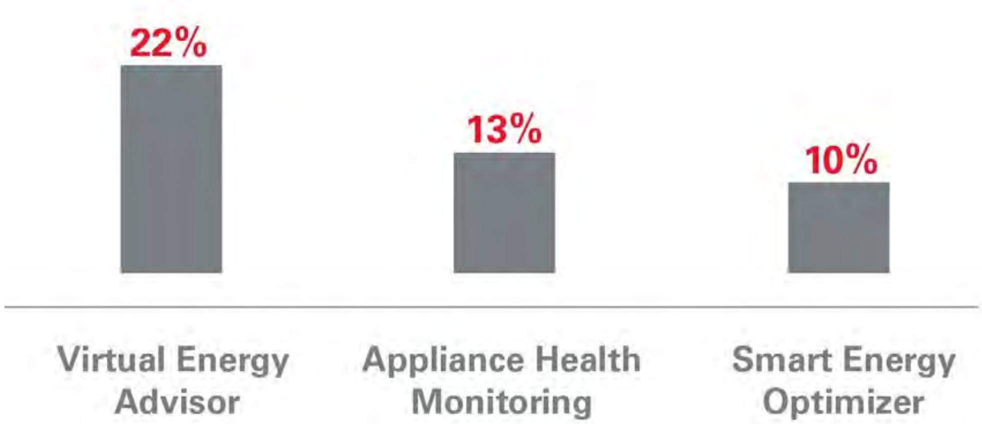
- *2018 MN Smart Meter Survey* – 500 residential and 100 business customers were surveyed in August 2017 with the objective of quantifying familiarity and perceived value of smart meters, gauging the potential value of AMI-related benefits to customers, preferences for AMI enabled data, and communications about future smart meter plans.
- *Residential Relationship Study* – The *Residential Relationship Study* has been conducted monthly since April 2018 in order to determine the pulse of Xcel Energy Energy's customers' opinions and satisfaction with service. Included in the monthly survey are questions which gauge customers' interest in new products and attitudes of and practices around energy usage.
- *Electric Residential Study* – Xcel Energy subscribes to this study, conducted by JD Power, to benchmark the company against peer utilities, to measure customer satisfaction, and to analyze data about customer electric use in their homes.

a. Grid Edge Product Survey

We conducted this survey focused on Xcel Energy residential customers in March 2019; we collected 5,119 survey completions, so consider these results robust. We tested multiple product concepts enabled by AMI. Of these concepts we have identified three, listed below, that we believe deliver significant customer value and help achieve our customer driven strategic priorities.

- *Appliance Health Monitoring*: A service that can help customers gain insight into the performance and health of their electric appliances. Xcel Energy would also provide a list of vendors that can offer expert advice and repair options to the subscriber.
- *Virtual Energy Advisor*: This product concept monitors energy consumption in the home via Amazon Echo or Google Home so that customers can control home appliances/electronics from anywhere.
- *Smart Energy Optimizer*: This product concept would connect to customers' smart home devices via Amazon Echo or Google Home and manage them based on a set budget.

Figure 5. Product/Concept Interest (Top 3 Box)



Key findings of this survey include:

- The product concepts were new at the time of the survey and do not exist in any form today, so education to build awareness and willingness to subscribe is likely necessary.
- Customers under age 45 have higher interest in AMI enabled concepts that are technology driven. 39% of customers under 45 expressed top 3 box interest in a home Virtual Energy Advisor.
- There were no significant differences seen between the larger states (Minnesota and Colorado) and smaller states (Texas, New Mexico, and Wisconsin).

b. Advanced Meter Focus Groups

These focus groups were conducted in Colorado among residential customers in January 2019. In preparation for advanced meter implementation in the coming years, our objective was to understand customer expectations, attitudes, and communications preferences around advanced meters. Key findings of these focus groups include:

- Customers believe that advanced meters will help them save money through detailed, incremental usage data.
- Customers are unclear about the basic functionality of smart or advanced meters and need to be informed before new meters are implemented.
- Customers want to be made aware of advanced meter installation 2-3 months in advance through a multi-channel approach.
- Customers under age 45 prefer to seek out information on a Frequently Asked Questions (FAQ) page or through online media tools.
- A major concern for customers is the potential for increased cost to them for new meters.

c. Minnesota Smart Meter Survey

We conducted this survey in August 2018 among residential and business customers with the intent of identifying customer familiarity with smart meters, value assigned to AMI enabled benefits, and willingness to pay for those benefits. We also sought to understand customer preferences for accessing smart meter data. Key findings include:

- Residential customers value smart meter benefits for power restoration, personalized information, monetary incentives, grid automation/monitoring, and rate comparison tools.
- Awareness is low. Only 15% of residential customers state that they are familiar with smart meters.
- Willingness to pay is tied to awareness of the benefits; 13% of residential customers would be willing to make a small monthly payment to receive advanced meter benefits.
- Digital channels are preferred among residential customers for accessing their advanced meter data.
- Business customers are much more familiar with advanced meters (30%) and are more likely to be willing to pay (36%) for advanced meter benefits.

d. Xcel Energy Residential Relationship Study

This is a proprietary study conducted by Xcel Energy on a monthly basis to determine the pulse of the customer including satisfaction, attitudes, interest in new products or services. In May 2019, we added questions on grid edge products in the survey. Key findings include:

- 43% of respondents would like to be alerted when their energy usage/dollar amount is over a preset amount.
- Energy efficient products and appliances that help reduce energy usage are a popular concept: 42% of respondents currently have or use them, and 35% of respondents are interested in such products.
- Current use of Wi-Fi connected smart thermostats and smart plugs that allow Wi-Fi control of appliances or lighting is still relatively low at 14% and 8% respectively.
- 66% of respondents want to have control of their energy use when not at home.
- 34% of respondents are interested in receiving a notification through a phone app when electricity is available from renewable sources, while 4% currently have or use this type of service.
- Customers are currently lacking the tools to know why their bill may be high; 57% of respondents have the perception that their Xcel Energy bills have increased in the past three years.

e. JD Power Electric Residential Study

Xcel Energy subscribes to this study, which analyzes survey responses from utility customers around the country. JD Power surveys customers regarding their in-home electric usage, perceptions of their utility, and satisfaction their utility. Findings from year-end 2018 include:

- Xcel Energy ranked in the 2nd quartile among its peers for efforts to help manage monthly usage.
- Xcel Energy ended 2018 near the 1st quartile for keeping customers informed about an outage.
- Xcel Energy ranks at the 51st percentile in terms of providing pricing options that meet the needs of customers, which is right at threshold for 2nd quartile.
- Customers want detailed information about their monthly bills and can benefit from advanced meter data. Diagnostics from the study indicate:
    - 91% view their monthly payment amount.
    - 39% view their kilowatt hours used.
    - 27% view price per usage level.
    - 51% review their usage compared to the prior month.
    - 40% review their usage compared to the prior year.

f. Colorado Time of Use Non-Participating Customer Survey

We conducted this survey in December 2017 among customers that were only participating in a traditional rate plan. The objective of this survey was to gain insight in to how customers learn about new pricing plans and how we can improve communications around these plans. Key findings include:

- Familiarity with advanced pricing plans is low:
    - 58% of respondents reported that they would need more specific information about rate plans, including rules and guidelines.
    - 39% said they would need additional examples of practices that would help them save while on a new rate plan.
    - 27% of respondents answered that they did not know enough about new rate plans to switch from their current rate plan.

- In order to learn more about the new rate plans, 46% of respondents answered that they were likely to visit the Xcel Energy website to obtain information.

g. Minnesota Time of Use Rate Study

Similar to the TOU customer survey in Colorado, we conducted this study during the summer of 2017 with Minnesota residential customers to learn more about the level of familiarity, customer opinions, and customer attitudes regarding new rate plans. This study also took a more detailed look at customer habits and practices with energy use willingness to switch to a Time of Use rate plan. Key findings from this study include:

- 93% of respondents had tried to save money on their bills by reducing electricity use in the past; however, 61% had never tried to save money on their bills by shifting use to a different time of day.
- 31% glance at the various costs and other information on their bill; 18% spend several minutes or more reviewing their bill to further understand their costs.
- 60% of respondents either had never heard of the term "time of use rate" or had heard it but did not know what it meant.
- 43% of respondents expressed interest (top 3 box on a 10 point scale) in using less energy during the weekday peak time.
    - The most common reasons for wanting to shift usage out of peak periods was wanting to save money (61% of respondents) and wanting to help protect the environment (43% of respondents).
- Customers largely prefer to receive information about new "Peak and Off-Peak" pilot programs through email.
- Through advanced metering, the information most valued by customers was month-to-month peak usage comparisons, and proportion of on-peak vs. off-peak energy use comparisons.

h. Minnesota Time of Use Behavioral Focus Groups

These focus groups were held in May 2019 among residential customers to gain insight into current customer behavior, and potential future behavior concerning their energy usage. Key findings include:

- Customers are most willing to shift usage of appliances that have the least impact on their quality of life, such as dishwashers and laundry washers/dryers. Customers are less likely to shift energy usage of appliances that have a large impact on their quality of life.
- Most were willing to change some behavior if electric rates went up during peak times.
- Daily schedules, convenience, and comfort are the main barriers to adapting new usage patterns.
- Economic motivators are top of mind, though customers describe environmental motivators as important.
- The younger cohort had more of a tendency to acknowledge social pressures as a motivator for change.
- Third party coverage and reporting is the most trustworthy when it comes to learning about time-of-use plans.
- Online tools and savings tips should be personalized to customers to make them more actionable.

2. *Secondary and External Customer Research*

In addition to conducting primary research, we also rely on external resources to supplement advanced grid planning, which can be seen as having a larger scope since the tendency is to study a topic industry wide rather than by a single utility. Secondary and external customer research serves to provide insight from national and international research organizations and other utilities that have or are in the process of deploying advanced grid plans. We have used the following sources and insights in our advanced grid planning.

a. E Source: *E Design 2020 Small Medium Business Ethnographic Research*

E Source conducted this research in 2018 in order to help utilities understand how to better engage with small and midsize business (SMB) customers through effective programs, services and offerings.[1] In the 2018 study, objectives included developing a better understanding of the SMB landscape, detailing SMB customer wants and needs, and determining ways that utilities can actively partner with these customers for increased satisfaction. Key findings from this research include:

- Utilities should build partnerships with business customers by building trust first.
- Improved infrastructure and availability of data will help SMB customers better monitor their energy usage and find ways to conserve on energy costs.
- Since business customers spend a significant portion of their budget each year on energy costs, bills and charges should be as transparent as possible, and utilities should be easily accessible if there is a question/concern about billing.
- Business owners define their relationship with a utility based on power reliability. Outages have a significant impact on this relationship.
- Businesses need utilities to guide them toward the tools that will allow them to be actively and passively energy efficient.

b. Department for Business, Energy & Industrial Strategy (U.K.): *Smart Meter Customer Experience Study: Post-Installation Survey Report*

The United Kingdom Department for Business, Energy & Industrial Strategy (BEIS) conducted a survey in 2017 focusing on customer experiences before, during, and immediately after smart meters were installed in residential homes. The BEIS also developed steps in the customer journey toward making changes to energy consumption. Findings from this research include:

- 80% of customers surveyed were satisfied with their smart meter; 50% were very satisfied with their smart meter (score 9 or 10 on a 10 point scale).
- Customers that proactively requested smart meter installation were among the most likely to be satisfied and highly likely to recommend smart meters to others.
- Making energy use visible was the primary motivation among respondents for having a smart meter installed.
- Respondents most commonly recalled receiving information in advance of the installation from energy suppliers.
- 67% of households that received an in-home display for their meter reported using it at least once a week to view the amount of energy being used.

[1] ESource is an industry organization focused on advancement of the efficient use of energy. They help utilities and large energy users with critical problems involving energy efficiency, utility customer satisfaction, program design, marketing, customer management, and sustainability by providing syndicated research and counsel.

c. U.S. Department of Energy: *Advanced Metering Infrastructure and Customer Systems: Results from the Smart Grid Investment Grant Program*

The Smart Grid Investment Grant (SGIG) Program, developed under the U.S. DOE is a project aimed at modernizing the electric grid, has invested heavily in deployment of AMI and customer systems technologies. This report outlines key findings from SGIG projects that have implemented AMI and customer systems technologies. This research aids the DOE in accelerating grid modernization and informing decision makers. Key findings from this report include:

- AMI deployment has resulted in reduced cost for metering and billing from fewer truck rolls, labor savings, more accurate and timely billing, fewer customer disputes, and improvements in operational efficiencies.
- New customer tools allow for more control over electricity consumption, costs, and bills.
- Customer bill savings and lower capital expenditures results in reduced peak demand and improved asset utilization.
- Outages are less frequent, restored faster, and less of an inconvenience for customers.

d. Smart Grid Consumer Collaborative: *Effective Communication with Consumers on the Smart Grid Value Proposition*

The Smart Grid Consumer Collaborative (SGCC), now known as the Smart Energy Consumer Collaborative (SECC), conducted a customer survey in 2016 with the intent of capturing feedback that will help utilities effectively communicate with customers about smart grid implementation and values. This report outlines the messaging and methods to which customers were most receptive. Findings from this report include:

- Messages should be short, specific, and positive.
- References to increasing benefits rather than reducing harmful elements are better received by customers.
- Consumers are more interested in tech enabled improvements, less interested in how a utility achieves results.
- Smart grid benefits for consumers are generally grouped in three broad categories: environmental benefits, economic benefits, and reliability benefits.

e. Smart Energy Consumer Collaborative (SECC): *Understanding Your SMB Customers: A Segmentation Approach*

The SECC conducts utility industry research on a wide variety of subjects and customer segments. The SECC conducted this research using segmentation to more clearly define utility-customer relationships and how utilities can be a more active partner for SMB customers. Key findings from this research include:

- During the course of this research, five segments emerged:
  - o *Established and Engaged* – Always on the lookout for ways to use energy more effectively and are already partnered with service providers to do so. (15% of SMB market)
  - o *Motivated Yet Inactive* – Interested in the idea of energy efficiency, although they have not yet taken the first steps. (17% of SMB market)

  - *Interested if Incented* – Energy efficiency is not top of mind. Engaging in new programs and services will require a compelling incentive. (27% of SMB market)
  - *Saving and Satisfied* – Have already taken steps to use energy more efficiently and only passively interested in doing more. (13% of SMB market)
  - *Decidedly Disengaged* – Have no interest in the idea of energy efficiency and feel there isn't much they can do. (28% of SMB market)
- Size of business matters to engaging with utility in energy efficiency. Across all segments, half of SMBs with more than 50 employees surveyed would "definitely" engage with their utility, if the utility reaches out, on energy efficiency.
- Small- and mid-sized customers vary widely within their industries in terms of size of building, number of employees, and wants and needs from their energy provider.
- 92% of the Established and Engaged have interacted with their utility on energy usage data.
- 68% of the Established and Engaged have interacted with their utility around rate adjustments.
- 86% of the Motivated Yet Inactive segment is interested in usage rates relevant to their business.

f. Chartwell: *Demand Reduction Programs for TOU Customers – Madison Gas & Electric Case Study*

Madison Gas & Electric began an On Demand Savings (ODS) pilot program for commercial & industrial (C&I) customers in 2015, originally targeting 30 customers.[2] The intent of this pilot was to allow C&I customers to monitor their energy use in real time, reduce overall energy use, and implement practical load shedding or load shifting strategies to reduce their on-peak demand and improve their operational efficiency. The pilot sought to do this by identifying a customers' unique demand profile to suggest the best load shedding and cost saving strategies through use of AMI-enabled technology to provide data to both the customer and utility. Key findings from this report include:

- Customers participating in the initial pilot from 2015-2016 averaged 9% savings in monthly demand charges.
- Between June and September 2016, the average monthly savings was 2,760 kW.
- The average monthly kWh savings for participating customers was 4.5% in the same time period.
- The initial pilot found that nearly 70% of participants changed their thinking about how they use their building automation systems after participating in the pilot program.

g. E Source: *2019 E Source Gap & Priority Study*

Xcel Energy subscribes to this annual study from E Source to better understand small, mid-sized, and large commercial and industrial customers' needs – and how we are meeting those needs. In this study, SMB and large C&I customers are asked about their participation and interest in various energy efficiency programs, utility programs or services, and demand response services that can be offered by their utility. Key findings from this study include:

[2] The pilot has since been expanded to 50 C&I customers.

- 24% of large C&I customers surveyed currently participate in energy data analytics, strategic energy management, and behavior programs; another 32% are interested in participating in these types of programs.
- 31% of large C&I respondents currently use some form of energy management system, and 25% are interested in this technology.
- 21% of large C&I respondents currently participate in an Xcel Energy power monitoring program or service and 32% are interested in participating.
- Participation in energy data analytics, strategic energy management, and behavior programs is less common among mid-sized businesses. Only 4% currently participate in these types of programs and 19% are interested in participating.

C. Research Applied to our Advanced Grid Implementation

In summary, we have taken the following insights away from this research to shape our advanced grid customer strategy and implementation.

1. Customer Value and Expectations

Customers care more about technology and enabling improvements than process. They have strong feelings about the costs and benefits of advanced meters; however, their awareness and understanding of the costs and benefits may be limited, which has an impact on their perceptions.

Addressing service interruptions is important to all customer classes. Customers expect that service interruptions will be less frequent and of shorter duration. Customers expect to receive detailed information from their utility. This information is expected to be personal and frequent. Customers believe that improved reliability will allow the Company to focus more on other customer priorities.

Customers expect more tools and information for them to make decisions about their energy usage. They indicated that more information would allow them to better identify opportunities and strategies to save energy and reduce their costs.

Business customers have more awareness and familiarity with advanced rate designs. Residential customers expect their utility to provide them with rate comparison tools and information about new rate designs.

Building trust is a key component to unlocking value. Trust is best built by identifying solutions and showing results specific to the customers.

Customers understand that their rates will increase in order to cover the expense of advanced meters but expect that the benefits of the meters will result in their costs being net neutral over time.

2. Customer Education and Outreach

Messaging should be short, specific, and positive. Messages should focus on the benefits of the project, not on the process. Messaging should begin 2-3 months in advance of any implementation. Early messaging gives customers time to conduct their own research, if they want. Messaging should be done through multiple communications channels and align with customer preferences.

Customers under the age of 45 tend to prefer digital communications whereas customers over 45 tend to prefer phone and mail communications. They expect communications to be clear about what the direct and indirect customer costs are. If customers believe there is a direct charge for the meter at the time of installation they are less likely to support deployment. Benefits can broadly be grouped as environmental, economic, and reliability.

III. ADVANCED GRID INTELLIGENCE AND SECURITY INITIATIVE

While we have made incremental modernization efforts on the distribution system over many years, we must replace our current Advanced Meter Reading (AMR) service. The current vendor of this service will stop supporting and producing the parts required to maintain the system after 2022. While this system has provided value to customers for many years through efficient meter reading, it has limited capability to improve other aspects of our operations.

The need to replace these meters provides us with an opportunity to modernize our distribution system. This modernization begins with foundational advanced grid initiatives that both provide immediate benefits and new customer offerings while also enabling future systems and customer value. The core investments in our AGIS initiative include:

- Advanced Distribution Management System (ADMS);
- Advanced Metering Infrastructure (AMI); and
- Field Area Network (FAN).

In addition, ADMS is already underway and will provide the capability to implement two advanced applications that we believe will provide substantial benefits to customers and are included in our AGIS initiative:

- Fault Location Isolation and Service Restoration (FLISR); and
- Integrated Volt-VAr Optimization (IVVO).

These core investments will provide us with the tools and information we need to improve the management of the grid, meet growing customer expectations, and develop a platform that can provide long term flexibility and value.

To ensure we have made investments that will serve our customers over the long term, we have also planned into our technology the ability to conduct remote upgrades, applied industry leading security practices, and adopted flexible, standards-based service components to ensure interoperability between systems. The following sections will detail our AGIS investment strategy, our commitment to security, and the broad benefits we will deliver for all our customers.

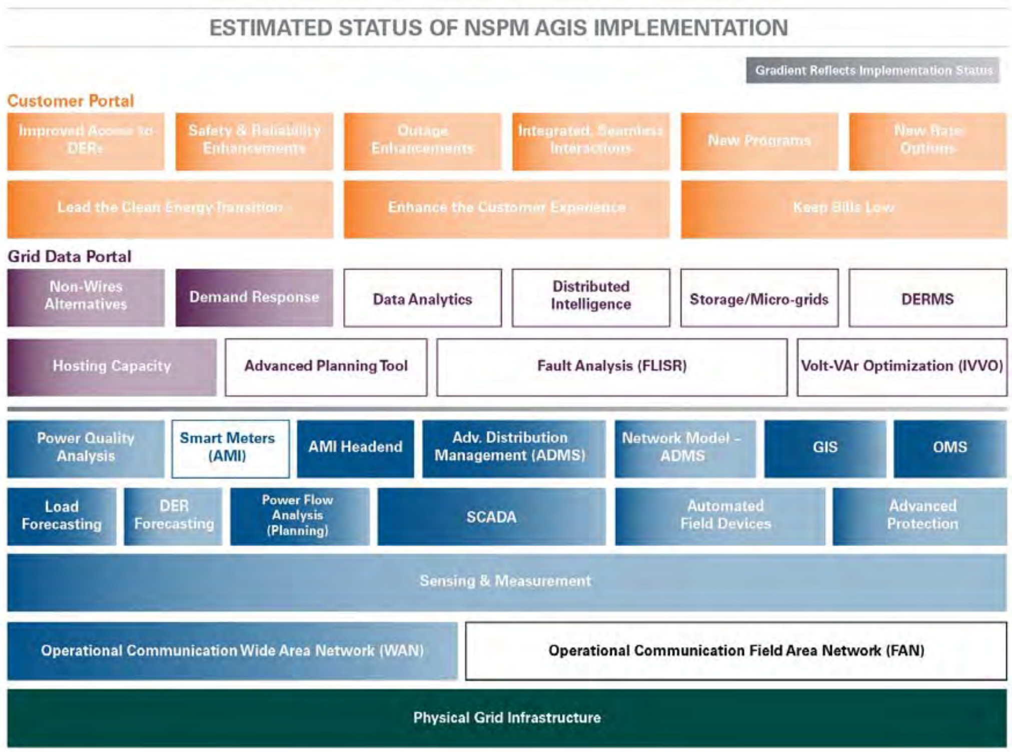
A. Technology Strategy

Unlocking the customer and operational value enabled by AGIS will evolve over time and begins with building a solid foundation. The U.S. DOE's Next Generation DSPx, Volume III provides a good reference for how to consider both the elements of a modern grid and their costs.[3]

We have taken the DOE's DSPx model and adapted it, as shown in Figure 6 below, to reflect the investments and capabilities that are part of our AGIS vision. This vision is also defined by the feedback and interactions we have had with a broad array of stakeholders and the Minnesota Commission.

[3] The DSPx report was sponsored by the U.S. DOE's Office of Electricity Delivery and Energy Reliability. *See Modern Distribution Grid, Volume III: Decision Guide*, U.S. Department of Energy Office of Electricity Delivery and Energy Reliability (June 2017).

Figure 6. Xcel Energy Advanced Grid Approach



The DSPx model begins with the "core components" as the foundation for our advanced grid roadmap. Building on that foundation enables advanced applications that will ultimately support our commitment to enhanced customer experience, keeping bills low, and leading the clean energy transition.

Our implementation of systems and hardware has already begun. As detailed below, this begins with the solid foundation and backbone in ADMS, which is expected to go into service in Minnesota in 2020 – and a limited implementation of the FAN and AMI to support the Minnesota Time of Use (TOU) pilot. This is followed by the deployment of smarter meters with more grid capabilities as we expand the FAN to support the mass deployment of advanced meters. During this timeframe of mass meter deployment, we will begin to implement other advanced grid components such as IVVO and FLISR and implement new products and services to help customers manage their energy usage and keep their bills low.

B. Step 1: Solid Foundation and Backbone

1. Advanced Distribution Management System

ADMS provides the foundational system for advanced grid operational hardware and software applications. The ADMS acts as a centralized decision support system that assists control room personnel, field operating personnel, and engineers with the monitoring, control and optimization of the electric distribution grid. This centralized platform provides greater awareness to our system and our customers. This capability is becoming critical as customer interest in solar, battery storage, electric vehicles, and other emerging technologies continues to grow – increasing the complexity of the electric distribution grid. ADMS also supports advanced applications such as IVVO and FLISR, which can provide further benefits for our customers.

A critical supporting element of the ADMS system is the Geospatial Information System (GIS). This foundational data repository is integrated with ADMS to provide location and other information for all the physical assets that comprise the distribution system. The ADMS uses this information to maintain the as-operated electrical model and operate the advanced applications.

2. *Field Area Network*

The FAN is a private, secure two-way communication network that provides wireless communications across Xcel Energy's service area – to, from, and among field devices and our information systems. It serves multiple business value streams that include, but are not limited to ADMS, IVVO, FLISR, and AMI – and will support future technologies that will unlock additional value for customers. Comprehensive geographic coverage allows Xcel Energy to grow and expand automation opportunities to the benefit of our customers. The FAN can enable future applications that may provide significant advances in situational awareness, operational efficiency, and asset lifecycle management. The FAN may allow for such applications as sensors that monitor assets, heat/temperature, pressure, flow, thermal energy, air quality, acoustic transmissions, vibration, cathodic measurements, environmental, tower lights, and security events.

We began limited implementation of the FAN in 2019 to support the TOU Pilot in Minnesota beginning in 2020. Additional build-out of the FAN to support AMI, FLISR, and IVVO will continue through 2023, which will lay the foundation for the future as we continue to innovate and improve our systems to ensure that we meet customer expectations as they evolve over the next decade or longer.

C. Step 2: Smarter Meters and Grid Capabilities

1. *Advanced Meter Infrastructure*

AMI is a foundational element of the AGIS plan because it provides a central source of information that is shared through the FAN with many components of an intelligent grid design. AMI is traditionally known as an integrated system of advanced meters, communication networks, and data processing and management systems. In the past, advanced meters were integrated with a proprietary communications network, and utilities selected a solution that would have trade-offs between meter functionality and communications capabilities. As discussed in above, the FAN we are implementing uses industry standard protocols, rather than a meter vendor's proprietary network. This not only provides important interoperability benefits to the Company and our customers, it also allowed the Company to select the best available advanced meter technology available.

The advanced meter itself is made up of several components – a metrology component (responsible for measurements and storage of interval energy consumption and demand data), an embedded two-way communication module (responsible for transmitting measured data and event data available to external applications), embedded Distributed Intelligence (DI) capabilities, and an internal service switch (to support remote connect and disconnect of single-phase service).

The core function of AMI is to measure customer energy usage so we can provide timely, accurate bills for utility service. New meters are a necessary replacement for our existing AMR, because of the impending discontinuance of our current Cellnet service in 2025. However, the new AMI meters go beyond the historic ability of our AMR meters because they facilitate two-way communications capabilities and more granular customer energy usage detail. This more detailed energy usage data will allow us to provide new rate and billing options. It will also inform many of the customer experiences that we have planned, to better inform and engage our customers.

Additionally, the advanced meters we will deploy will have the ability to conduct localized computing, analysis and data processing. This capability, called Distributed Intelligence (DI), is a Linux-based operating system that conducts localized, at the meter analysis and computing. At a high level, the DI platform allows Xcel Energy to install applications on the meter – similar to how applications are installed on a smart phone. These applications may be customer-facing, meaning the customer directly interacts with them, or grid-facing, meaning Xcel Energy interacts with the applications. Any applications available on the meter will be required to meet our strict technology and data security approvals and controls. Some of the potential use cases for these applications include:

- Improved grid and customer safety and awareness;
- Improved energy usage control and savings;
- Improved insight into power quality;
- Smarter insights about customer data and information; and
- Smarter controls to better manage and integrate customer and utility systems.

Xcel Energy is leading the nation in the deployment of the DI platform. We are working with Itron, our meter vendor to plot a vision for the design, development, and implementation of new meter applications that our customers will manage and interact with through a customer portal. Itron has already begun building a number of applications that can be enabled on the meter. We expect third parties will also develop applications that we can leverage to improve the customer experience – and we will actively partner with those that we believe offer new and innovative ways to transform our business to provide valuable services to our customers. Customers will be able to

AMI provides Xcel Energy and customers with access to timely, accurate, consistent, and granular energy usage data that is necessary to develop personalized insights and that supports informed decision making. With these insights and other data, customers are empowered to make energy usage decision based on their preferences that can reduce their bills. Additionally, the advanced meters will detect and report power outages and when power is restored, detect tampering and energy theft events, and perform meter diagnostics. Finally, the advanced meters will enhance our planning and operational capabilities by measuring values such as voltage, current, frequency, real and reactive power, and certain power quality events such as sags and swells.

In sum, the system visibility and data delivered by the advanced meters we have selected will improve reliability, enable advanced rate designs, and afford opportunities to improve the efficiency of several aspects of our business, and expand our ability to offer customer-facing products and services as a result of the DI platform. We began limited deployment of the AMI meters in 2019 to support the TOU Pilot in Minnesota beginning in 2020. We expect to begin mass deployment of AMI in 2021, with installations continuing through 2024. The following table lists the approximate number of installations per year.

Table 1. Minnesota AMI Implementation Plan

Year	Installation Estimate
2019/2020	17,500 (TOU Pilot)
2021	100,000 – 130,000
2022	550,000 – 650,000
2023	530,000 – 600,000
2024	30,000 – 60,000

In addition to the installation of meters, our AMI implementation requires certain functionalities be implemented to support the metering technology. These implementations will involve the following activities:

- *Systems integration.* This involves integrating a number of existing systems with the new advanced metering headend and meter data management system.
- *Enhanced capabilities*. This includes development of enhanced data reporting through the customer portal, operational analytics, outage management, Green Button Connect My Data, and Home Area Network functionality.
- *Meter deployment*. As we transition to actual meter deployments, we will deploy the DI platform, events processing, and enable FAN functionality.

We will also be continuing to build and refine our next steps with both advanced grid technologies and customer products and services that will leverage those investments.

2. Robust Customer portal

Our customer research tells us that customers want more information and need that information to make better decisions. Investments in AMI and the FAN will allow us to meet, and exceed, that expectation by providing us with detailed and timely data. We share that data with our customers through various digital channels including mobile and web applications. Customers will be more informed by this data by increasing their awareness about how and when they use energy. They can then apply that information to how they behave with energy – adjusting their usage to align with lower energy costs or more environmentally friendly periods of generation.

The portal will also offer other features to support customer efforts to save money and control their energy usage including access to DI applications. Applications will be made available, by Xcel Energy, through the customer portal. Applications may be part of the default meter package or customers can opt-in to certain applications. Potential applications could include (but not be limited to) energy usage dashboard with summary information about their energy usage, personalized insights about their energy usage with recommendations on how to save, and disaggregation tools that distill what end-use technologies are using energy.

The customer portal will also allow customers to share their energy usage with third-parties. We understand that our customers have relationships with third-parties and that those relationships provide energy savings and customer experience benefits. We will employ Green Button services to facilitate this exchange of information.

Currently, Xcel Energy employs Green Button Download My Data to facilitate data sharing. This tool allows only one-time data sharing with third-parties. If a customer wishes to share their data using Green Button Download My Data, they log into MyAccount, click Download My Data, and then send the file to the third-party. There is no automated connection for sharing data. Conversely, the Green Button Connect My Data (CMD) standard allows access to third parties to present the data in their application.

In the future, we will enable data sharing through both the Download function and the Green Button CMD tool. The Green Button Alliance[4] identifies awareness as one of the important factors necessary for customers to be able to change their energy use behaviors and defines CMD as "a way to download or connect to your utility-usage data (electricity, gas, water) to gain better insight of waste and inefficiencies; allowing you to make adjustments to use fewer resources and even save money."

[4] https://www.greenbuttonalliance.org/about#mission

Data sharing is conducted in a secure environment and only at the authorization of the customer. Personally Identifiable Information (PII) is required to be transmitted in a secured transmission that is separate from the secured data stream used to transmit a customer's energy-usage information (EUI). The receiving application is then required to logically connect the separate data streams. CMD's capabilities expand beyond just consumption data and include the abilities to provide payment data (generation and distribution charges, tariff name, demand charges, third-party charges, administrative adjustments, etc.), summarize billing data across multiple locations, and even to generate monthly billing statements.

3. Outage Management

Customers have come to expect a high level of service from Xcel Energy and outages are one of the critical moments in our customer's experience. With increasing dependence on mobile devices and Wi-Fi outages, even for short duration outages have a significant impact on customer's experience and this experience filters into their broader experience and expectations from Xcel Energy. Long or recurring outages reduce customers' trust in the quality service Xcel Energy and have negative repercussions when customers consider participation in other products and services.

Currently, in most of our service territory and for outages below the feeder level, customers inform the Company that they have an outage. Once aware of the outage, the Company dispatches field workers to investigate the outage and make necessary repairs. Upon completion, the Company sends a follow up communication indicating that the Company believes the customer's outage has been addressed but encouraging the customer to follow up if the outage persists. We know customers generally expect the Company to know when they are out of power and when their service has been restored.

To improve this experience, we will use the benefits of improved grid awareness, provided by ADMS, AMI, and the FAN, and additional insights into the scope of the outages (provided by FLISR, and discussed below) to provide customers with more timely and accurate information about their outage. Immediately after receiving an advanced meter, customers will receive improved communications about outages should they occur. With AMI, the Company will know when momentary or sustained outages occur because the advanced meters will communicate through the FAN back to Xcel Energy. This improved awareness will allow the Company to proactively notify customers of an outage, instead of relying on customers to make contact, which we expect will be satisfying for customers – and may additionally play a role in reduced outage response times.

We expect we will also be able to provide customers with more accurate estimates of restoration timelines and reduce the time field personnel are required to identify, diagnose, and repair an outage by utilizing the abilities of FLISR to restore power automatically thereby reducing the scope of an outage. We will also proactively notify customers of when their power has been restored by verifying the status of an advanced meter remotely. These actions will transform a customer experience currently dependent on significant communication from our customers and evaluation by our field crews to a more streamlined process where customers are informed but not actively engaged.

Operationally, improvements in reliability should be expected as the AGIS project is fully implemented and Xcel Energy updates its processes to more efficiently respond to outages.[5]

[5] While the customer experience is expected to improve, the Company's reported performance related to certain reliability indices may decline due to the Company's increased visibility into outages and events occurring on the system.

Figure 7. Residential Customer Journey – Outage Notification & Restoration

4. Improved and Actionable Billing Information

Advanced meters enable Xcel Energy to more frequently and granularly track energy usage. The FAN also allows the Company to send and receive more timely energy usage data. The combination of timely and detailed data will enable advanced rate designs, discussed further in the next section, as well as products and services that complement our existing energy efficiency and demand management programs. An example of a new service the Company expects to offer that is enabled only by investments in AMI and the FAN is High Usage Alerts, which we expect to offer upon deployment of the advanced meters.

Optional, high usage alerts will provide messaging to customers when their energy usage is expected to surpass preset limits set by the customer. Proactive messaging to customers, prior to the end of their billing cycle, will offer both a customer experience benefit and energy savings benefit. The customer experience benefit is keeping customers informed of their energy usage so they can change their behavior and avoid a surprisingly high bill. The energy savings benefit is a direct result of this behavior change as customers take actions to shift or reduce usage in order to save money.

Figure 8. Residential Customer Journey – Billing and Payment Options

5. Remote Reconnection and Disconnection

The AMI meters will be equipped with the ability to remotely disconnect or reconnect electric service, which offers potential benefits to our operations and thus customer costs, and the customer experience. We recognize using this functionality in Minnesota will require regulatory approval. We expect to engage stakeholders as a precursor to a regulatory filing where we would propose to use this functionality initially in conjunction with tenancy changes and customer requests associated with seasonal use properties to capture benefits associated with unbillable energy use.

Today, when tenancy changes occur, the meter is not automatically disconnected and any energy costs associated with the unoccupied premise are considered losses. With advanced meters capable of remote disconnection, the Company could disconnect the meter; thereby eliminating energy costs at an unoccupied premise (*e.g.* a vacant retail location) and upon new tenancy could remotely reconnect service. This eliminates the need for the Company to send field personnel to the location to disconnect and reconnect the devices, improving employee safety, reducing or eliminating the cost for the new tenant customer to reconnect, and reducing or eliminate any unbillable energy use.

Similarly, customers with seasonal homes may want to disconnect service if there are long periods where the home is unused. For example, a summer home that is not used during cold weather months beginning in the late fall through late spring. In lieu of a customer paying for a field employee to visit the customer's site and disconnect and then reconnect the meter, the customer could schedule a remote disconnection aligned with their winterization and reconnection aligned with their opening. This would save the customer the cost of the two trip charges each year, as well as any stray energy usage at an otherwise winterized premise.

In the future, use of remote capabilities associated with non-payment would offer efficiencies and thus reduced costs. For customers dealing with payment issues, the Company makes every effort to engage with them and set up a payment plan that will work with their budget and personal circumstances. When payment plans fail and disconnection for non-payment is appropriate, the Company incurs significant costs to physically disconnect and reconnect service at the customer's home or business. These costs are ultimately borne by both the affected customer, in terms of a reconnection charge, and the entire Minnesota customer base in the form of higher field collection costs and bad debt expense.

We clarify that we are *not* seeking approval of any remote connection or disconnection services at this time. Instead, we intend to engage stakeholders to develop a framework that will inform a proposal for regulatory approval, which we believe will be the best way to align stakeholder interests and ultimately reduce costs to our customers.

D. Step 3: Smart Applications

1. Fault Location Isolation and Service Restoration

Customer satisfaction depends on how well a company's products or services meet customer expectations, and reliability is one of the foundational components for meeting customer expectations. As electricity becomes more and more entwined with every aspect of day-to-day life, the issue of reliability becomes increasingly important to customers.

FLISR is a form of distribution automation that involves the deployment of automated switching devices that work to detect issues on our system, isolate them, and automatically restore power – thereby decreasing the duration and number of customers affected by an outage. Fault Location Prediction (FLP) is a subset application of FLISR that utilizes equipment information to locate a precise location for an issue on our system. The combination of FLISR and FLP will enhance our ability to detect issues on our system and restore power to customers. FLISR and FLP rely on three primary components to operate:

- ADMS, for the central control and logic
- FAN, for wireless communications to and among field devices
- Specific intelligent field devices

The common industry metrics to track reliability performance are System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI). While these metrics measure the overall performance of the system, they do not capture the reliability *experience* of each individual customer, because they typically exclude outages from major events such as storms, which can be a significant contributor to a customer's overall reliability experience. FLISR and FLP are expected to improve customers' overall reliability experience – and, in particular, outages occurring as a result of storms or other severe events.

Today, aside from the limited number of early versions of automated switches on our system, crews manually patrol distribution lines to identify the failure location and manually close and open switches to restore power to customers. FLISR and FLP will automate restoration for most customers on the feeder – preventing a sustained outage – and reduce the length of the outage for other all customers on the feeder by providing field crews a more precise location for the failure.

FLISR and FLP have the greatest impact when implemented on the worst performing feeders, where the investment will return the greatest value in terms of reliability improvement for the customers connected to those feeders. In Minnesota, we intend to implement FLISR and FLP on approximately 200 feeders between 2021 and 2028, directly improving reliability for over 250,000 customers, where we expect the number of sustained outages on these

2. *Integrated Volt VAr Optimization*

Integrated Volt-VAr Optimization, or IVVO, is an advanced application that automates and optimizes the operation of the distribution voltage regulating devices and VAr (reactive power) control devices to achieve operating objectives. These objectives can provide:

- Reduction of distribution electrical losses
- Reduction of electrical demand
- Reduction of energy consumption
- Increased ability to host Distributed Energy Resources

IVVO is an advanced application within ADMS that leverages field devices and the FAN to modify how the Company controls the voltage of the system and enables the Company to optimize the voltage of the system in ways that were not possible previously. Our implementation of IVVO will enable energy and demand savings for customers without requiring any action on their behalf.

The concept of voltage/VAr management or control is essential to electrical utilities' ability to deliver power within appropriate voltage limits so that consumers' equipment operates properly – and to deliver power at an optimal power factor to minimize system losses. These concepts are affected by a variety of technical factors throughout the distribution network, the complexity and dynamic nature of which make the task of managing electrical distribution networks challenging. While voltage regulation and VAr regulation are often referenced in combination (i.e. Volt/VAr control), they are easier to understand if described as two separate, but interrelated concepts.

Voltage Regulation. Feeder voltage regulation refers to the management of voltages on a feeder with varying load conditions. Regardless of nominal operating voltage, a utility distribution system is designed to deliver power to consumers within a predefined voltage range. Under normal conditions, the service and utilization voltages must remain within an industry standard range. When customer load is high, the source voltage at the beginning of the feeders is at the higher end of the range, and the voltages delivered to customers at the end of the feeders are at the lower end of the range.

VAr Regulation. Nearly all power system loads require a combination of real power (watts) and reactive power (VArs). Real power must be supplied by a generator while reactive power can be supplied either by a generator with VAr capabilities, or a local VAr supply, traditionally a capacitor. Delivery of reactive power from a remote VAr supply results in additional feeder voltage drop and losses due to increased current flow, so utilities prefer to deliver reactive power from a local source. Since demand for reactive power is higher during heavy load conditions than light load conditions, VAr supply on a distribution feeder is typically regulated or controlled by switching capacitors on during periods of high demand and off during periods of low demand. As with voltage control, there are both feeder design considerations and operating considerations.

The ADMS that we are in the process of implementing can run the IVVO application in several different operating modes: Voltage Control, Peak Reduction, VAr Control, and Conservation Voltage Reduction (CVR), which we explain below.

- *Voltage Control mode* functions to optimize voltage on the feeder around standard operating voltages – maintaining adequate service voltage for all customers. This mode is generally a secondary operating mode of IVVO, and only used to establish the voltage boundaries within which the other operating modes must stay within. As penetration of DER grows, Voltage Control will become more common as a primary control mode to manage the expanded range of distribution system voltage caused by DER. Traditionally, with only load on a feeder, the Voltage Control objective was to raise voltage at times of heavy load in order for voltage to remain within the acceptable range. With DER causing reverse power flow and raising voltages during times of light loading, voltage control schemes must now both raise and lower voltage.
- *Peak Reduction mode* serves to reduce load only during peak load events. It is a manually triggered mode that reduces system voltage to a targeted value to reduce load on the system for a short duration – typically one or two hours. This peak reduction tool can be used in large operating regions, such as Minnesota as a whole, or tactically by feeder, substation, or other targeted area.
- *VAr Control mode* seeks to reduce system losses and save energy by optimizing power factor on each distribution feeder.
- *CVR mode* seeks energy savings through reduced operating voltages. CVR mode first flattens the load profile along the feeder using capacitors, and then uses the Load Tap Changer (LTC) or Voltage Regulators inside the substation to lower voltage on the feeder. This lowered operating voltage results in small energy savings for most customers on a feeder.

Customer's end-use devices are designed to operate over a range of voltages. Historically, the voltage on the distribution system is toward the high end of the range, which causes devices to consume more energy. The need to have more dynamic voltage management has become more important because customers' energy consumption is more dynamic than ever. Residential customers can have on-site solar, batteries, electric vehicles, smart appliances, smart thermostats, and many more electronic devices.

Since 2010, we have been doing VAr Control through our SmartVAR program in Minnesota, which has provided benefits to the grid and our customers. SmartVAR will be transitioned to our ADMS as that is implemented. Over time, we intend to transition this to IVVO, which will allow for more dynamic voltage control that can improve end-use efficiencies while still maintaining voltage within the acceptable range. This will reduce the voltage level on our system, which we expect will result in energy savings for customers, translating directly into avoided energy costs that our customers would otherwise incur.

Implementing IVVO for our customers requires ADMS to be operational, the FAN and AMI to be deployed, and implementation of some supporting information systems including a Grid Edge Management System (GEMS). As these supporting technologies are deployed, we will implement IVVO on distribution feeders with the highest return and highest probability of success. In total, we intend to deploy IVVO between 2021 and 2024 on over 180 feeders serving over 200,000 customers.

3. Improved Power Quality

Power quality, specifically the voltage levels on the distribution system, can have a significant impact on the customer experience. Some of our customers have highly sensitive processes and technologies that perform better at lower voltage levels. Investments in AMI and ADMS with IVVO will help us improve our service quality for customers and therefore improve their customer experience. With AMI, we can monitor the voltage level at a customer's location and identify if voltage levels are too high or low. If voltage levels are determined to be out of line or adjustments can be made, the ADMS and IVVO applications will be used for these adjustments.

Other power quality improvements will include identifying potential power quality issues, such as flickering lights, before they become a negative experience for the customer. Using AMI, we can remotely identify these potential issues rather than send field personnel to conduct a diagnosis. This remote sensing capability reduces the time to address an issue and the likelihood of a customer call or formal complaint. This proactive service reduces the burden on customers to make us aware of issues in our service and helps improve customer satisfaction.

4. Distributed Intelligence

As discussed in more detail in the summary of our Advanced Metering Infrastructure investments above, we are at the leading edge of the deployment of the DI platform. With mass meter deployment rapidly approaching we are working with our meter vendor partner to develop conceptual uses for the DI platform that make grid management more efficient. This process will involve ongoing ideation, iteration, and reinvention to ensure that we continually create value from our investment. At this time, we have identified the following grid-facing use cases:

- *Real-Time Granular Voltage Optimization* – Use the edge processors / radios to intercommunicate and 'shout' who is the lowest voltage (compared to only receiving voltage from dedicated meters on the secondary).
- *Undocumented / Unregistered DER Alerts* – Detect if there is a DER behind the meter, even if it is not back feeding.
- *Grid Configuration Status* – Better, real-time grid configuration status, e.g. knowing which phase and transformer every meter is connected to. Edge computing would build on this by providing insights to loads / DERs per feeder / phase which could directly or indirectly (notification to third party or targeted message to premise owner) dispatched to improve grid balancing.
- *Distributed Transformer Load Management* – Modulating customers' devices on a secondary that are contributing to a high load situation on a distribution transformer.

- *Locate Momentary Grid Disturbances* – Uses the high granularity disaggregation capabilities across multiple meters to triangulate the location of a grid disturbance by analyzing the amplitude of the disturbance waveform. Edge meters could detect the anomaly and shout out who has the highest amplitude.
- *Meter By-Pass Detection* – Enhanced functionalities that complement the base capabilities of AMI to detect and remotely disconnect when a meter by-pass is detected.
- *Smart Feeder Restoration* – Occasionally during outage restoration utilities face the situation where capacity is insufficient to restore the next section of a feeder. Smart Feeder Restoration enables the restoration of critical loads, deferring the re-energization of other loads until full capacity is restored, for example, prioritizing restoration for a hospital or a fire station before.. This ability provides for resiliency during emergency situations.

We are also working with our vendor partner to develop customer facing applications that we will make available to customers in the future. Many of these applications are complimentary to many of our existing demand-side management and customer choice programs. They may provide customers with more information about their energy usage through services such as disaggregation, virtual energy audits, or real-time monitoring. Alternatively, they may also provide new services that our current meters and customers programs do not provide such as advanced notifications and alerts about the composition of your energy usage, internet outages, or emergency notifications. The broad categories of how we will transform the customer experience and the types of products and services will offer are detail further in Section IV of this document.

E. Broad Customer and Grid Benefits

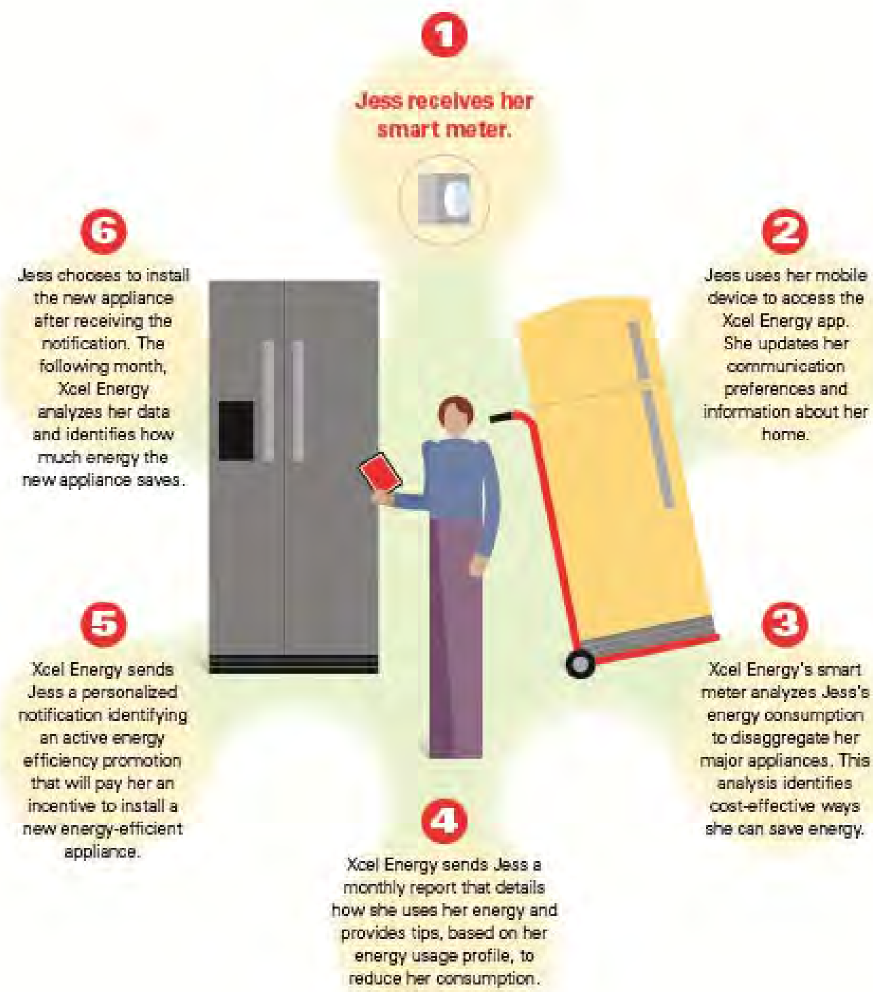
1. Improved Energy Efficiency Options

Today, to encourage customers to make informed energy saving decisions and reduce their monthly bill, we provide general recommendations and energy savings steps they can take – upgrading to a new air conditioner, turning off unused appliances, and installing high efficiency lighting. These messages and tips are general and will not be relevant to all customers. For example, customers who have already replaced an air conditioner or other major appliance – or customers interested in changing their behavior with their air conditioner to save money.

Transforming this customer experience involves targeted deployment of new products and services that build upon foundational advanced grid investments. With more granular data from advanced meters, we will be able to improve our marketing to and segmentation of our customers. This will help identify cost efficiencies in our programs and improve our communications with customers. For example, combining AMI data with disaggregation tools through Distributed Intelligence, we can better target market our customers and provide them more relevant communications about their energy usage. From a customer experience perspective, the more relevant information we share with them the more likely they will be to act upon it.

These might include improved insights and recommendations to customers regarding their energy usage, due to the availability of more granular usage information. These might also include end-use disaggregation – or programs/services that allow the customer to extract end-use and/or appliance level data from their aggregate household usage. These might also include more targeted opportunities for behavioral demand response advanced rate designs. These new products would leverage the benefit of near-real-time, interval-level usage data provided by advanced metering to help customers reduce bills and better achieve their energy goals. The following figures provide an illustrative customer journey that integrates new benefits from the advanced grid.

Figure 9. Residential/Small Business Customer Journey – Insights and Recommendations



2. *Demand Response*

As part of our Minnesota operations we are committed to delivering resources to help manage the generation, transmission, and distribution systems during both peak and non-peak periods. We define demand response as:

- *Traditional Demand Response* (DR) provides a temporary reduction to system peak. Often these products are referred to as dispatchable resources because the utility may control them directly. This peak reduction has a similar impact on our system as a combustion turbine (CT) because it can be brought on- and off-line quickly for short periods of time as an operational reserve.
- *Non-Traditional DR* provides the opportunity for our customers to plan for and manage their electric demand differently. Compared to traditional methods of peak demand reduction during the hottest days of year, these methods allow customers to shift portions of their electric loads to lower-cost periods of the day when carbon-free generation is highest.

One example of non-traditional DR that will be enabled by our advanced grid investments is Behavioral Demand Response. This is a new product we are developing where the Company provides energy savings messages to customers when energy usage is high. The Company can message customers with general or personalized opportunities, using data provided through advanced meters, to reduce their energy usage. Customers can monitor the impact these decisions have on their energy usage because of timely data communication hat is made possible by AMI and the FAN. To engage customers, incentives may be offered on top of their energy savings based upon actions the take. In this case, the Company also expects a customer satisfaction improvement because customer's not only save money but are also more informed and in control of their energy usage – two key takeaways identified through our customer research.

One example of traditional demand response that will be enabled by our advanced grid investments is a two-way communicating Saver's Switch. Two-way communication through the FAN provides a more reliable signal than our current use of the Cellnet system and allows us to monitor the status of the Saver's Switch. This proactive identification allows us to improve our maintenance cycles to ensure high levels of response when these switches are called for system needs.

3. *Advanced Rate Design*

The deployment of advanced meters will provide the information and communications capabilities necessary for the Company to provide customers with more pricing options to improve customer choice and control over their electric bills. AMI will make Time-of-Use (TOU) pricing a feasible option for all customers. By recognizing cost differences throughout the day, between weekdays and weekend days and other types of days, TOU pricing provides both customer and grid rewards for shifting energy usage away from system peaks or making better use of renewable energy resources when they are abundant on the grid. Customers may realize these benefits through reduced energy costs and perhaps a reduced carbon footprint; the Company may realize benefits in the form of avoided infrastructure investments and increased system productivity through a higher load factor.

Advanced rate designs improve the customer experience by giving customers more information and control over their energy usage. Our customer research shows that energy costs are a primary concern for all customers – but also that other factors are important, including a customer's environmental impact, their ability to control their usage and the presentation of options/choice programs. Advanced rates can create opportunities to reduce customers' bills and minimize customers' environmental impact by giving them better signaling about the cost of their energy usage. For example, higher prices during "on-peak" periods are typically correlated with more expensive and carbon intensive forms of generation whereas "off-peak" periods are typically correlated with renewable energy resources.

Advanced meters include two-way communication capabilities in contrast to the limitations of our current AMR meter infrastructure. This provides the Company the ability to communicate with the meter and any appliances or devices that a customer may choose to "connect" to their meter. With the advanced meters capable of measuring energy usage in short time intervals such as every 15 minutes, it is possible to develop dynamic pricing options that recognize cost differences between different types of days and that provide focused customer incentives for reducing energy usage during the highest system peak times of the year. Dynamic pricing can also be combined with TOU pricing for an even more robust signal to customers.

The advanced meter's ability to capture and transmit regular energy usage intervals enables us to partner advanced rates with energy usage notifications to provide a more robust customer experience and more opportunities for customers to keep their bills low. More targeted and personalized information about their energy usage empowers customers to control costs and minimize their environmental impact.

The ability to provide a seamless, timely, and detailed view of a customer's energy usage data is highly contingent upon the implementation of advanced meters and the supporting infrastructure, such as the FAN. Without investments in these new technologies we do not have the ability to effectively and efficiently meet customer expectations for increased control, new opportunities to engage with the energy usage, transparency of costs, and impacts of their energy usage.

4. DER Integration

The adoption of DER, including community solar gardens, behind the meter solar, batteries, electric vehicles, energy efficiency and DR is not likely to slow in the future as costs decline and awareness of the potential benefits of these resources becomes more widespread. As customers adopt increased levels of DER, it is incumbent upon Xcel Energy to improve its ability to accurately forecast the growth of these resources, the impacts they will have on the distribution system, and the cost to implement these resources.

Furthermore, our customer research has shown that customer's increasingly look to their utility for expert advice and are interested in engaging with the utility as an orchestrator, helping to manage their energy bills and achieve their energy goals. However, in order to achieve individual goals, collective efforts are necessary to maximize efficiency and effectiveness at the individual level.

The increasing prevalence of DER necessitates a more comprehensive integration of DER into the day-to-day operation and planning of the grid to ensure the safe and reliable management and monitoring of the distribution system. While DER can, and currently is being interconnected, this is accomplished with limited visibility and control, which prevents the Company from fully optimizing the system benefits DER can provide. For instance, energy storage could be used to regulate the amount of energy on the system during peak solar production times. In this circumstance, a battery can "absorb" the energy when demand is lower and then dispatch energy from the battery onto the system as demand increases later in the day. Alternatively, ADMS can improve our control and dispatching of demand response (DR) resources. This will help us more precisely manage the level of demand by dispatching the right amount of DR in the appropriate locations.

Investments in AMI and ADMS coupled with the FAN – and in the future, a Distributed Energy Resource Management System (DERMS) – will allow for Xcel Energy integrate DERs into the day-to-day operation and better manage DER. Currently and by necessity, Xcel Energy takes a conservative approach to the forecasted impact of resources because we do not have the granularity necessary to dynamically forecast the impact of resources such as batteries and solar. With more granular data we can better refine our estimations of the impact of new resources and better integrate more resources on the grid.

In the near term, Xcel energy is investing in an advanced planning tool which will significantly improve our distribution planning capability. The future of DER has uncertainty, and the new tool will allow for planners to explore the impacts of varying DER adoption, along with a host of other factors such as land use planning, weather, socio-economics, and more. This investment will help us identify barriers & opportunities as we and plan the grid of the future.

Figure 10. Residential Customer Journey – EV Integration with New Rate Designs

The next step in optimizing DER integration will be provided by a DERMS. Currently in the industry, interested stakeholders are identifying use cases and blueprinting how such systems may work. In the short term, we will work with the industry to define what and how a DERMS might work to provide the most benefit to our customers. By engaging in these discussions, we can help steer the future of DERMS in ways that will provide our customers with the most benefit. In the future, we plan to implement a DERMS, but only after we have successfully laid the foundational pieces of the advanced grid such as ADMS and AMI. If the technological capability continues to progress, we believe that a DERMS deployment will fit into our advanced grid plans around 2025.

Microgrids are another type of DER integration that will be improved by investments in AMI, FAN, ADMS and DERMS. Microgrids are effectively one large DER and the use of these advanced grid investments will allow the system to make more informed decisions, sometimes automatically, about what resources are needed, when they are needed, and the most efficient way to utilize those resources. As cost-effective opportunities present themselves, our distribution investments will allow for more efficient grid services, such as absorbing excess solar energy to be discharged at later periods, while also enabling backup needs power in the case of an emergency.

Figure 11. Commercial Customer Journey – DER and System Integration

F. Security

The Company has a dedicated Enterprise Security Services (ESS) business unit that encompasses both cyber and physical security, security governance and risk management, and enterprise resilience and continuity services. This combination of services is designed to cover analysis of vendor risks, alignment of the technology with security standards, secure solution design and deployment, integration with Company solutions including user access management and system monitoring and incident response, as well as threat analysis and planning for continuity of business operations in the event of a disruption. The Company's security risk management program provides Company leaders with information about threats and the level of security risks, so that mitigations and responses can be planned that are proportional to the risk.

Overall, while the implementation of the AGIS initiative solves certain existing issues, it also presents different challenges to security than a less advanced grid, and requires its own comprehensive security strategy. It starts with identification and protection of all components of the intelligent grid, both for the protection of customers and for the reliable and safe delivery of energy to customers. First, devices in the field must be protected. Unlike internal business technology, the distribution components are out in the field and at customers' residences; devices can only be hardened so much, and security must also rely on other controls. For example, detective controls at strategic locations to provide early notification of suspicious behavior or anomalous activity.

Additionally, although even legacy distribution systems and meters are vulnerable to physical tampering and disabling, adding a communications network – that provides additional capabilities and services to our customers, as well as greater insight into our system – also enhances the potential impact of a security compromise. The addition of a Company-owned FAN is a prudent approach to this concern. A private network allows Company to better control the integrity of the devices on its network and the data exchanged with those devices. The alternative – a public network – would expose the devices to increased risk because the Company would not be in control of the network.

1. *AGIS Security Approach*

As part of our AGIS initiative, we are designing security controls for each component and system implemented. These security risks can be organized into three primary areas: compromise of meters and devices; exploitation of the communications channels; and security lapses once data is within the corporate environment. There are also security risks related to the web portal, as well as future customer applications and new products and services that will be enabled by the advanced grid.

Figure 12. Key Security Components

First, advanced meters and other networked devices have an integrated network interface card (NIC) that enables them to connect to the FAN. We leverage both physical and cyber security controls to protect NICs from unauthorized access. Second, a compromise of the FAN communications protocols that carry "traffic" to and from the meters and field devices could lead to disruption or alteration of information needed for grid management. Therefore it is paramount to protect the integrity of the communication devices and channels that allow the advanced grid to perform at expected levels. It is also important to implement the correct level of monitoring and alerting, configured to identify potentially anomalous activity, so that both proactive and reactive responses are appropriate and efficient. Third, the primary risk to systems and information that reside within the Company's corporate environment is from unauthorized access – where a criminal or unqualified employee accesses sensitive data or issues commands to the grid. There are many controls in place to prevent and detect such behavior.

We have based on our controls on a security controls governance framework, which leverages industry best practices including the National Institute of Standards and Technology (NIST), Cyber Security Framework (CSF). The Company's security policies and standards incorporate regulatory compliance requirements and security controls designed to protect against CIA (Confidentiality, Integrity and Availability) breaches. This framework serves as the basis for project security requirements as well as periodic internal security technology control assessments.

2. *Cyber Security Overview*

Our cyber security program may best be described in terms of the five categories of controls outlined in the NIST CSF: identify, protect, detect, respond, recover. Combining these adds multiple layers of protection and detection including defenses at each endpoint and throughout the network. Controls within these layers include:

- *Asset management* – maintain an inventory and securely configure assets, so we know what to protect as well as what is authorized to access our networks ["Identify"];
- *Protection* – user access controls, encryption, digital certificates and other controls to ensure the confidentiality, integrity and availability of data ["Protect"];
- *Vulnerability management* – in addition to scanning equipment for known security vulnerabilities, the Company monitors emerging threats ["Detect"];
- *Monitoring and alerting* – identify potentially anomalous activity so that both proactive and reactive responses are appropriate and efficient ["Detect"];
- *Incident response* – analyze information using playbooks and escalate to the Enterprise Command Center, the Company's 24x7 watch floor operation designed to prepare for, respond to, and recover from any potential hazard that may impact customers, Company assets, operations, or its reputation ["Respond"]; and
- *Disaster recovery and business continuity planning* – to efficiently maintain and restore grid operations in the event of a cyber attack ["Recover"].

We will apply these controls to identify and protect all components of the intelligent grid and help ensure the reliable and safe delivery of energy to our customers.

Endpoint Protection is the installation and/or enablement of protective and detective cyber security controls to thwart malware and external influences from causing unexpected, unwanted or invalid behavior at an endpoint. These were specified as cyber security controls in the AMI vendor selection process, as they are essential to protect the devices and the data that are handled by AMI meters and headend servers.

Access Control is to confirm that only necessary and authorized users have access to the individual devices. This not only includes the devices that are installed on the consumer's premises, but also the devices that facilitate communication and control of the data flowing to the consumer. There are potentially many avenues of compromise with respect to unauthorized access to devices. This is a key consideration and will be addressed through strong authentication methods, which include multi-factor authentication methods.

Authentication is a method by which a user affirms their identity. In its simplest form, it involves a user ID and password. Where technically feasible, Xcel Energy requires multi-factor authentication so that a user must not only know their password, they must also possess a physical or logical token. This minimizes the ability of an unauthorized user to steal passwords and access our assets and information.

Authorization is the process of determining and configuring the minimum level of access required by a user or an automated system. Granting undue permissions to devices that comprise the intelligent electric distribution system could lead to unauthorized or inadvertent changes and instability. Complying with a least-privilege principle ensures that only necessary and authorized individuals have the ability to make administrative changes.

System and Patch Management addresses the periodic manufacturer updates to software and firmware to improve performance, add features, or address security vulnerabilities. A robust system patch management process incorporates asset inventories, secure receipt of patches from the vendor, testing and deployment to the field. The Company's threat intelligence and vulnerability management teams monitor for and inform support teams of known security vulnerabilities that require patching. Keeping current with vendor patches helps reduce the possibility that a criminal can use a known exploit to compromise our systems or data.

Data validation is a final defensive layer between the various endpoints. As data is sent from endpoints at consumer premises, data validation at the head-end must take place. If data values received from the consumer endpoint do not fall within a range of expected values, then either the data must be assumed compromised and discarded, or secondary validation must take place to measure the integrity of the data received. This validation will provide yet another level of detection and protection for the intelligent electric distribution system.

3. FAN Security

The equipment that makes up the FAN deploys the endpoint protections discussed above. Additional key controls for FAN include the use of firewalls to restrict which systems can interact and what ports and protocols they can use; encryption to minimize the opportunity to intercept and alter data traffic; monitoring and log review as well as response to suspected security events.

Firewalls are placed in multiple areas of the network between the customer meter and the company data center/head end. By default, all traffic through a firewall is blocked, and authorized only after a thorough review and change process. With a firewall, any unauthorized, unregistered devices that attempt to join the network or communicate to/from devices are blocked.

Encryption uses complex mathematical algorithms to obscure data prior to and during its travels through the communications network. It also prevents data from being altered. Only authorized parties to the transaction (sender and receiver) have the "keys" to encrypt and decrypt data.

4. AMI Data Protection

As we have described, our Company and AGIS security approach is one of "defense in depth." The advanced meters will be physically sealed and monitored to detect tampering. Meter communications will be encrypted to protect the privacy of our customers, as will the other communications that travel on the company's private FAN from and between the authorized devices that have been registered onto the network. Firewalls control the information that travels in and out of the corporate network. The AMI head-end will validate the integrity of the data received. We will actively monitor the communications path between the meters and the Company data centers to promptly detect and respond to any anomalous activity. Additional monitoring of the head-end system will trigger alerts for investigation.

5. Company Systems Security

The Company systems comprising and supporting AGIS reside in data centers with physical access protections – only authorized users are able to enter these locked facilities on company property. Data accessed from the control centers travels from the systems in the company data centers over the corporate network. At the control center, application users must follow the same rules for authentication, authorization, and least privilege.

Data from the intelligent electric distribution network passes through multiple defense-in-depth controls on its way back to the systems in the corporate data centers. Communications will pass through multiple firewalls to ensure that only authorized devices are communicating on authorized ports/protocols. Additionally, a protocol-aware Intrusion

Detection System/Intrusion Prevention System (IDS/IPS) will inspect the traffic to ensure tampering has not been performed on the data packet. Once the data has been delivered to the systems responsible for consuming this information, only authorized processes will have the ability to act upon this information.

The Company segments its networks, so that critical operational systems and information are kept separate from business data and operations including email. This segmentation adds a significant barrier should a criminal compromise a corporate user's account. In addition to using firewalls between networks, the Company requires the use of multi-factor authentication when accessing systems from outside the control center.

We take our responsibility to protect the privacy and security of our customers, grid, and information systems seriously. We have based on our controls on a security controls governance framework, which leverages industry best practices. We will take a defense-in-depth approach that will apply controls at many levels to identify and protect all components of the intelligent grid and help ensure the reliable and safe delivery of energy to our customers. See Appendix B for a summary of our data access, privacy and governance framework.

IV. TRANSFORMED CUSTOMER EXPERIENCE

Rather than simply evolving from our current state, we are revisiting our entire customer experience. Today, customers expect the we *know them* and take a personalized approach to their relationship with us; they expect that we keep them *informed* and use our expertise to *advise* them about what to do and then *enable* them to take those actions; and finally that we *deliver seamless* experiences for them reducing the burden on them to take action.

Figure 13. Customer Experience Priorities

In order to *know* our customers, *inform, advise, and enable* them, and *deliver seamlessly* we are taking time to understand the customer's journey and experience in our program design and execution. This process starts with a commitment to understanding customers' preferences, considerations, and thoughts regarding the benefits and value of an advanced grid investment from their point of view. As detailed above, we conduct robust customer research and continually update that research to ensure we are reactive to our customer's perceptions. It also requires our organization to improve the skills and competencies needed to continuously evolve and iterate our programs more quickly and leverage technology to make interactions more streamlined and enjoyable.

Our investments in the advanced grid will help us meet customer expectations. We have categorized how we expect to meet these expectations in three broad, but interconnected, categories. The categories are at the foundation of how we think about making investments in our customers every day.

- Enhance the Customer Experience

ENHANCE THE CUSTOMER EXPERIENCE

Outages

BEFORE ADVANCED GRID	AFTER ADVANCED GRID
Detecting an outage: The current Electric Management System alerts system operators only to larger system outages. Xcel Energy depends on customers to notify us about outages in their neighborhoods or individual homes.	**Detecting an outage:** System alerts operators to almost all outages. After major storm repairs are completed, we'll send signals to newer meters to verify that power has been restored.*
Identifying outage location: With no specific location pinpointed, linemen drive or walk along the line – which could be many miles – until they identify the cause of the outage.	**Identifying outage location:** New technology pinpoints where problem has occurred, allowing grid operators to dispatch linemen to specific location. The result is improved restoration times.
Restoring power: When an object or tree comes in contact with a power line, every customer served by that line – and other lines connected to it – loses power.	**Restoring power:** Smart devices on the grid can perform automated switching – or keep additional, connected power lines in service – while linemen work on the impacted power line, minimizing the number of affected customers.
	*Customers should continue to contact us to report an electric outage at 1.800.895.1999.

Setup and Billing

BEFORE ADVANCED GRID	AFTER ADVANCED GRID
Customer billing information: Customers receive their monthly energy use after the end of their monthly billing cycle.	**Customer billing information:** Through advance metering, customers may access their energy usage the next day.
Accurate Billing: Sometimes customer bills have to be estimated due to access or safety issues until their meters can physically be read.	**Accurate Billing:** New advanced meters send energy usage information directly to us so customer bills are rarely estimated.
Remote connect/disconnect capability: A technician has to physically connect or disconnect service at a customer's home or office.	**Remote connect/disconnect capability:** With advanced meters, a customer's service can be remotely connected or disconnected.

- Cleaner, more reliable energy

LEAD THE CLEAN ENERGY TRANSITION

Reliability

BEFORE ADVANCED GRID	AFTER ADVANCED GRID
System monitoring: Grid operators rely on linemen and a limited number of alarms to alert them to trouble on a power circuit.	**System monitoring:** Grid operators receive real-time information from line sensors, intelligent substations, and communication devices so they can proactively prevent and respond to grid issues.

Distributed Energy Resources

BEFORE ADVANCED GRID	AFTER ADVANCED GRID
Hosting Capacity: Customer-owned rooftop solar can shutdown at times of over voltage on feeders.	**Hosting Capacity:** Increased situational awareness and control enables both increased hosting capacity for new installations and enhanced uptime for existing systems.
Openness to New Technology: Finite utility ability to manage diverse resources limits customer ability to adopt new technology.	**Openness to New Technology:** Improved measurement, visibility and control allows customers to select advanced applications such as batteries and electric vehicles.

- Keep Bills Low

KEEP BILLS LOW

Customer Choice and Control

BEFORE ADVANCED GRID	AFTER ADVANCED GRID
Customer options: Customers have limited choices.	**Customer options:** An Advanced Grid opens the door for more energy-related products and services, including rate design choices for customers such as time-of-use rates, and more energy- and cost-savings programs.

In the following sections, we provide more details on the types of products and services we will offer in the future that fit within these categories. These products and services are currently in development and we have provided an expectation of when we expect to begin delivering on these products and services. However, it is important to reiterate that the anticipated delivery dates are not the final states of these offerings. We will continually innovate and iterate these offerings and incorporate new benefits and opportunities as they become available to us. This may include adapting offerings to incorporate DI capabilities, transitioning traditional opportunities to DI applications, or integrating new technology that is not yet in the market.

A. Enhance the Customer Experience

Outage Enhancements

Product or Service	Customers Affected	Timing
Enhanced Outage Notifications More accurate alerts informing customers about outages in a timely, relevant way. These could include proactive messaging about an outage status, automatic restoration, and restoration confirmation.	Residential Small Business Large C&I	Day 1
Smart Premise Restoration Sequentially restore power to various devices inside the home or business after an outage to reduce the likelihood of voltage or overloading issues, protecting customer system performance as power is restored.	**Residential** **Small Business** **Large C&I**	Future

Integrated, seamless interactions

Product or Service	Customers Affected	Timing
Green Button Download My Data For customers who prefer to perform their own analysis or use their granular usage information for other purposes, data in the standard Green Button protocol will be made available through the Download My Data feature in the customer web portal.	**Residential** **Small Business** **Large C&I**	Day 1
Enhanced Web and Mobile Applications Customer account information along with options to view and pay bills, visualize energy usage and trends, and manage outages will be presented to customers in an integrated and highly personalized format. This is made possible by granular information and analytics as well as a robust customer preference center.	**Residential** **Small Business** **Large C&I**	Day 1
Energy Usage Dashboard Within the new web and mobile customer portals, energy usage dashboards will informs customer about the energy usage of both the overall facility as well as individual devices in a home or business. Compares data to a comprehensive database of similar products to alert to opportunities to save energy and money. Dashboards can be customized to both residential and C&I customer needs (e.g. multi-site data).	**Residential** **Small Business** **Large C&I**	Day 1
Energy Usage Alerts and Notifications Alerts allow customers to be notified with important information in a timely, relevant way. These could include high usage alerts, TOU peak period, Peak Day notification, or goal-based alerts.	**Residential** **Small Business** **Large C&I**	Near Term
Green Button Connect My Data For customers who would like to automatically transmit their usage information to third parties, Green Button Connect My Data will also be available in the customer web portal for ongoing automated transfers.	**Residential** **Small Business** **Large C&I**	Near Term
Personalized Notifications Communication systems will be enhanced to provide timely information to customers in a form that is personalized to their lifestyle and preferences.	**Residential** **Small Business** **Large C&I**	Near Term
Artificial Intelligence Enabled Notifications As artificial intelligence technologies mature and become widely adopted in the market, meters will have the ability to leverage these capabilities to provide heightened interactions which will be customized to the unique needs of each customer.	**Residential** **Small Business** **Large C&I**	Future

Safety & Reliability Enhancements

Product or Service	Customer Affected	Timing
Power Quality Analysis With detailed information collected by the meter relating to power delivery, customers can more accurately and frequently assess their power quality. Over time, analytics of the power quality information can help flag and diagnose potential power quality related items so that customers can proactively manage any possible issues.	**Residential** **Small Business** **Large C&I**	Near Term
Emergency and Safety Notifications The meter will be able to provide customers with emergency management notifications via its analytics and communications capabilities. This can help customers identify potential risks to their energy management systems, security monitoring, and be aware of local emergency notifications that may apply to their general safety and security.	**Residential** **Small Business** **Large C&I**	Near Term
Enhanced Microgrid Integration Where the capability exists for portions of the grid to operate independently of the rest of the surrounding system, the advanced distribution management system will more seamlessly be able to manage the connection of these microgrids.	**Residential** **Small Business** **Large C&I**	Future
Smart Safety Disconnect Detects when a smart inverter has malfunctioned or was improperly installed and has not disconnected from the grid when incoming power has been lost. In this situation, the disconnect inside the meter is automatically tripped to protect the rest of the grid and the customer.	**Residential** **Small Business** **Large C&I**	Future

Product or Service	Customers Affected	Timing
Outage Notifications Alerts allow customers to be notified with important information in a timely, relevant way. These could include proactive messaging about an outage, automatic restoration, and restoration confirmation.	Residential Small Business Large C&I	Day 1
Smart Premise Restoration Sequentially restore power to various devices inside the home or business after an outage to reduce the likelihood of voltage or overloading issues, protecting customer system performance as power is restored.	**Residential** **Small Business** **Large C&I**	Future

B. Lead the Clean Energy Transition

Product or Service	Customers Affected	Timing
Enhanced Access to Battery Storage and Electric Vehicles Through the enhanced visibility and control of the distribution system, greater utilization of storage elements on the grid, including electric batteries and electric vehicles, will be possible. This capability promises to help ensure safe, reliable energy for all customers.	**Residential** **Small Business** **Large C&I**	Near Term
Green Notifications and Controls Customers would be notified when the percentage of electricity generated by renewable services in their area exceeds a certain threshold.	**Residential** **Small Business** **Large C&I**	Near Term
Enhanced DER Enablement Through the enhanced visibility and control of the distribution system, customers will be able to integrate distributed generation resources more seamlessly and potentially at higher levels within a given area.	**Residential** **Small Business** **Large C&I**	Near Term
Demand Management Optimization With more granular consumption information, new demand management programs can be created to enable customers to shift and shed load to respond to needs of the grid on an increasingly real-time basis. With new communication capabilities, the meter will be able to communicate directly with smart devices within homes and businesses. As analytics such as disaggregation and virtual submetering evolve, demand response routines can increase sophistication through optimizing sequence among various demand response resources.	**Residential** **Small Business** **Large C&I**	Near Term

C. Keep Bills Low

New Energy Saving Programs

Product or Service	Customers Affected	Timing
Virtual Energy Audits Provides an on-demand or periodic assessment of the energy usage/efficiency of a premise based on actual performance versus expected performance based on various parameters (i.e. size, year, build, occupancy, devices, etc.). With disaggregation and other analytics capabilities made possible by AMI, these audit results will improve over time to provide more accurate and relevant information. Audits may also be used to monitor the health and status of appliances to identify opportunities for customer to reduce maintenance costs and improve energy efficiency.	**Residential** **Small Business** **Large C&I**	Day 1
Whole Facility Monitoring C&I customers with long-term sustainability goals can more easily track progress at the whole facility and sub-system level through integrations between meters and customer-operated energy management systems. This information can be used to verify savings over time for the purposes of demand side management or can be used to alert customers when demand or energy usage projections are expected to exceed threshold amounts over a given period of time.	**Small Business** **Large C&I**	Near Term
Enhanced Control Options for Behind the Meter Systems From the smart home to intelligent buildings, AMI meters will be able to communicate more seamlessly with devices and systems within the customer facility. Customers can use this capability to participate in demand response programs as well as to manage facility energy consumption in a more accurate and robust way.	**Residential** **Small Business** **Large C&I**	Near Term
Enhanced Automated Demand Response As the grid evolves, distribution system management can utilize expanded automated demand response capabilities which respond to real time needs of the distribution grid.	**Residential** **Small Business** **Large C&I**	Future

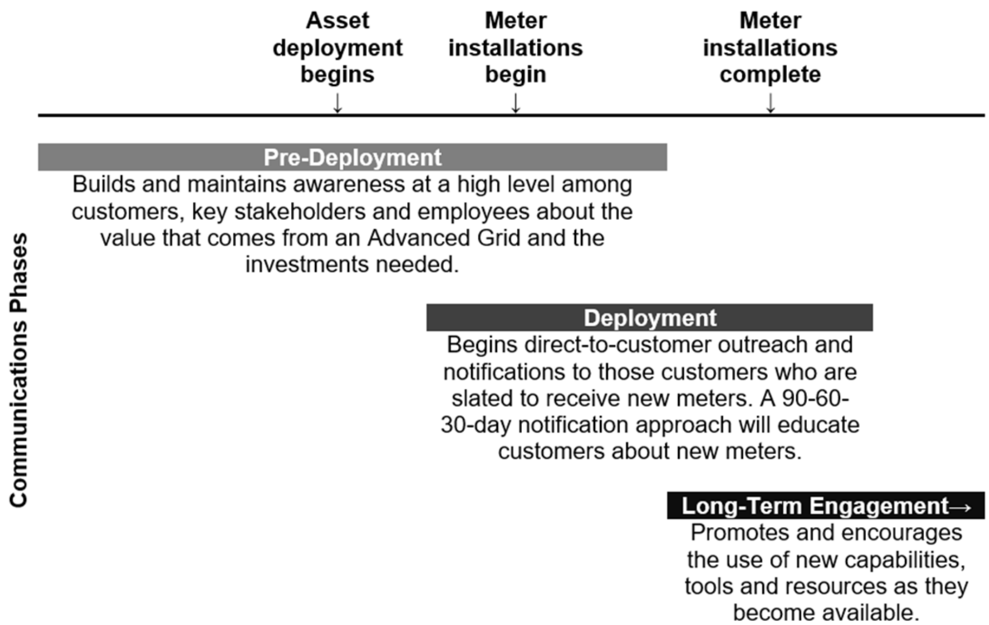
New rate options

Product or Service	Customers Affected	Timing
Rate Advisor With granular usage information and analytics capabilities made possible by AMI, the company will provide a multi-channel approach to educate customers and proactively offer ways to optimize energy usage and cost under existing and new, future rates schemes.	**Residential** **Small Business** **Large C&I**	Near Term
Time Varying Rates With more granular consumption data and more sophisticated meters, rate schedules can be created to better reflect the actual costs on the system at specific times of day. Customers can take advantage of these price signals to manage costs.	**Residential** **Small Business** **Large C&I**	Near Term
Virtual Submetering Instead of installing physical submeters, which are costly and take special wiring and their own communications channels, the main meter could act as a virtual submeter through disaggregation capabilities at the meter.	**Residential** **Small Business** **Large C&I**	Near Term
Smart Rates New rate opportunities including pre-pay and technology specific rates. Rates may rely on local management of the premise level grid or local identification of events. For example, when an EV is plugged in, this could be detected and an EV rate is automatically applied. Another example, would be a flat billing rate with use of the Premise Level Grid Management System (PLGMS) to stay within the agreed to usage levels.	**Residential** **Small Business** **Large C&I**	Future

V. CUSTOMER COMMUNICATIONS STRATEGY AND PLANNING

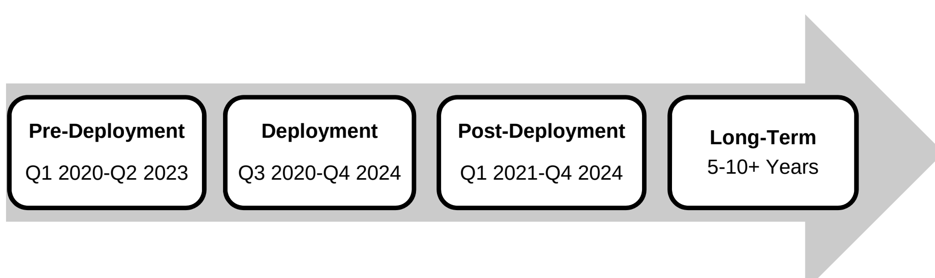
Because meter installation and advanced meter capabilities will be geographically staged over a multi-year timeframe, we will stage our customer communications to align with the value we expect customers to realize through this advanced grid journey.

Figure 14. Customer Communication Phased Implementation



We know from our research that it is important to not overwhelm customers with new products and services as part of their initial experience with advanced meters. For example, our research to-date indicates that customers are not familiar with and don't fully understand how time-of-use pricing works and how to change their behavior to account for this type of pricing. Therefore, as billing becomes ever more complex it is important that customers understand the complexities of their billing before they are introduced to new products and services that may or may not help them control their energy usage.

Figure 15. Customer Communications and Value Realization



A. Pre-Deployment

In this pre-implementation phase, we are building awareness among customers and key stakeholders about the value that comes from an advanced grid and the investments needed. We are communicating the value AGIS is expected to bring to our customers and communities and working to anticipate customers' information needs and questions and clearly outline how to take action – including how to “opt out” of receiving an advanced meter (see Appendix A for our proposed Opt-Out Framework).

We will also be setting the stage for Day One with customers – and with advanced grid infrastructure, as we will begin installing the FAN approximately six months in advanced of AMI meter deployment.

Table 2. Customer Communications Timeline and Summary

	90 days before meter install	**60 days before meter install**	**30 days before meter install**	**7 days before meter install**	**Day of install**	**Post-install**
All customers	Mailer: intro	Mailer: your meter is coming soon	Mailer: meter installation FAQs	Phone call: your meter is coming next week	Install technician door knock	Mailer: success or attempt
					Door hanger: success or attempt	
Opted-in customers (only customers who have opted into these channels will receive these notifications)	Email: what to expect during meter installation	Email: Your meter is coming soon	Email: Your meter is coming soon	Text notification		Email: success or attempt
			My Account banner: Your meter is coming this month	App push notification		My Account banner: success or attempt
Mass communication	Targeted online, print, and out of home advertising			Hyper-targeted social media advertising		
	Community outreach: meter install schedule by neighborhood, informational content about new meters					

This is a critical period where we are working to ensure the foundational customer experience is exceptional, and that customers will not only be satisfied but also active and excited for what comes next.

B. Deployment

Deployment represents the point at which customers have an advanced meter and begin to realize tangible value from our advanced grid investments. Our customer communications will become more specific – with messaging regarding the specific service improvements customer should expect to see, such as:

Improved reliability and faster outage restoration

- New digital energy grid technologies will help us prevent outages to you and your neighbors and, in some cases, enable us to automatically reroute power to shorten or prevent any service interruptions.

- Advanced grid technologies can detect outages at your home or on the larger electric system, helping reduce the time you are without service.
- You'll receive quicker notifications when service is out and more accurate information on when power will be restored.

More options to protect the environment and use new technologies

- The advanced grid will help us provide you with even more clean energy because it will allow us to maximize the use of renewable energy sources such as solar, wind, and hydro.
- Energy use data in near real-time will give you the ability to choose how and when you use technology such as batteries and electric vehicles.

Security you can trust

- Energy use data will be securely transferred electronically from the advanced meter, eliminating the need for manual meter reading or estimates, which also helps reduce costs.
- Protecting your data is extremely important to us. We use multiple layers of defense to ensure all data is secure and protected.

For customers who have received new meters, we will seek feedback to ensure satisfaction with the process. We will also continue to raise awareness about advanced meter features and engage them to take advantage of new capabilities and functions. In this phase, we will focus more on the available Home Area Network and available online tools and resources, such as the online energy usage portal. We will begin to introduce them to more products and services that help reduce energy usage and offer non-energy benefits. Finally, we will also be measuring customer awareness, understanding, interest, participation and satisfaction with the advanced meters and their associated features.

C. Long-Term Engagement

This phase will promote and encourage the use of new Advanced Grid capabilities, tools and resources as they become available. Communications will not only highlight the features of new tools and resources, but also the broader benefits they can provide. This phase will leverage customer information and preferences gathered in Phase II to provide a seamless experience for all customers via their preferred channels.

Key objectives during this phase include:

- Leverage a messaging hierarchy that reiterates high-level benefits of the project while educating customers on new capabilities, tools and resources as they become available.
- Develop and execute a customer nurturing campaign to follow the customer journey and encourage adoption of new capabilities, tools and resources.
- Evaluate and refine messages and tactics to continuously improve and ensure the best possible customer experience.

VI. CONCLUSION

Our distribution grid is the foundation of the service we provide our customers. As our current system ages and technology advances, we are at a point where modernization will return significant value to our customers. Making these investments in our system will enhance transparency into the distribution and to system data, to promote efficiency, and reliability, and to safely integrate more distributed resources. Underlying these goals are the following drivers:

- The Company's strategic priorities to lead the clean energy transition, enhance the customer experience, and keep energy prices affordable;
- The Company's desire to meet the growing needs and expectations of our customers;
- Current distribution system needs; and
- Commission policy and direction, and stakeholder input relative to customer offerings, performance, and technological capabilities of the grid.

If we delay the implementation of a smarter and more advanced grid, we will increasingly find ourselves unable to meet customer expectations and unable to benefit from the advanced in technology includes the benefits brought by DERs. As discussed above, our investments will:

- Provide customers with new products and services to manage their energy use;
- Improve our management and integration of DERs;
- Improve the outage restoration process and the accompanying customer experience; and
- Help maintain stable and reasonable costs for our customers.

APPENDIX A: CUSTOMER OPT OUT FRAMEWORK

The Company believes customers should have the choice to opt-out of receiving an advanced meter. We will therefore provide eligible customers with the opportunity to decline the installation of an advanced meter before initial installation or a request to have an advanced meter removed at any time. However, opt-out requires the Company to maintain its abilities to manually read meters, which involves maintaining supporting information systems and incremental meter reading personnel – meaning the Company will lose both its current efficiencies of reading the meters through AMR and future efficiencies of reading these meters through AMI. Therefore, we believe any opt-out framework should be based on the cost-causation principle to ensure other customers are not subsidizing customers who choose to opt-out of AMI. We outline a framework below that we intend to socialize with stakeholders to gather feedback before proposing an Opt-Out Tariff for inclusion in our Minnesota Electric Rate Book.

Because of the inefficiencies created by the opt-out option, we will work to minimize the numbers of customers choosing to opt-out – starting with our pre-AMI deployment customer education and awareness campaign, which will address many of the questions or concerns that customers typically have with advanced meters, including privacy and safety. Our communications will also discuss the benefits that an advanced meter provides, including opportunities to reduce energy costs and improve their environmental impact. As our pre-deployment communications get underway with customers, our customer service representatives will also be trained to address customer questions and concerns in a transparent and understanding manner.

To ensure no cross-subsidization and consistent with cost-causation principles, we propose that customers opting-out of AMI incur the costs to provide the services necessary to maintain billing and meter reading activities to support that choice. If an eligible customer chooses to decline installation of an AMI meter, that customer will receive a meter that will be capable of recording the customer’s interval energy usage – but the meter will not contain a communications network interface card, and therefore the usage must be retrieved manually by a Company meter reader. This will be a change from the current meter reading and billing experience for customers, because we have used an AMR system that, except for unusual circumstances, has nearly negated the need for meter reading field personnel for most customers for approximately 20 years.

We propose that customers be able to decline the installation of AMI at with no upfront charge – only incurring an ongoing cost-based charge to support the ongoing manual meter reading and related processes. If however a customer requests an AMI meter to be removed after its initial installation, we propose to charge a service fee that covers the costs of a field representative to remove the AMI meter and replace it with a non-AMI meter. The ongoing charge for these customers would be the same as for those who decline the installation at the time of initial deployment.

As noted previously, we intend to engage stakeholders with this basic framework along with proposed cost-based upfront and ongoing fees – with a goal of developing a detailed Tariff proposal to submit to the Commission for approval.

APPENDIX B: DATA ACCESS, PRIVACY, GOVERNANCE

The Customer Data and Information Strategy enables the framework for maintaining the integrity and security of our data and information assets throughout its lifecycle. This strategy encompasses the creation, storage, usage, sharing, and disposal phases of data assets. The strategy also ensures Xcel Energy data and information provides business value, minimizes risk, and complies with legal and regulatory requirements.

A. Culture

Xcel Energy's data is managed as an asset of the business. We leverage data to drive more understanding within the business about how data can be employed to improve operational performance, evaluate industry options, and help customers make better decisions. We have robust data privacy and security standards for all data that varies based on the type of data. Our customer strategy is informed by these standards, and as new products, services, and experiences are identified they will comply with these standards. At this time, the expectation is that any customer-specific data derived from AGIS will be treated similar to the way customer-specific data is treated today. The primary difference in the data AGIS will capture is expected to be the granularity of the data – i.e. today's monthly consumption compared to the 5- and 15-minute interval data from AMI.

Everyone who works for Xcel Energy understands their responsibilities for maintaining the integrity and quality of our data assets, complying with data requirements, and keeping the data safe and secure. To ensure that all employees understand the criticality and responsibility of securing data, all employees are required to complete information management training annually.

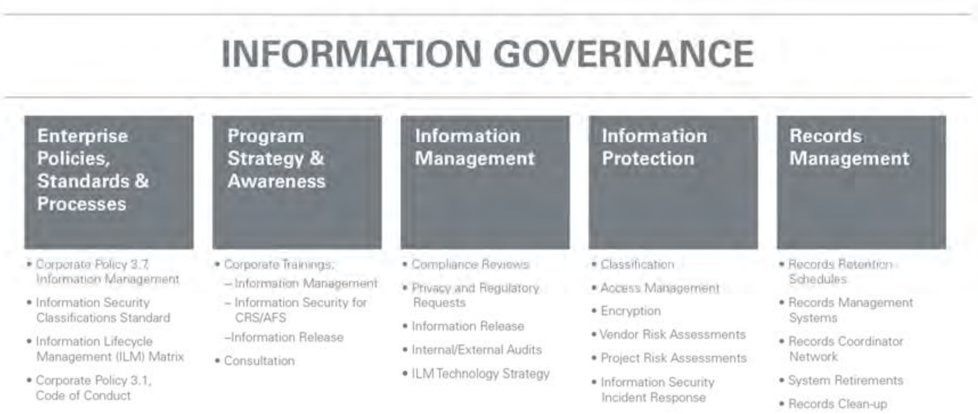
B. Information Governance Framework

Xcel Energy's Enterprise Security Services (ESS) oversees and provides leadership of the information governance policies, procedures, processes and standards. This includes strategic oversight of the creation, collection, use, protection, retention and disposal of all company information in all formats.

Compliance with is a corporate and individual responsibility, and compliance is monitored and evaluated through the corporate governance framework.

The key areas of Information Governance are as follows:

Figure 16. Xcel Energy Information Governance



C. Information Management and Protection

Customers trust that the information Xcel Energy creates, collects, and uses as part of its work to provide regulated utility service to customers is handled properly to avoid the potential for loss, misuse, or harm. Information Management is the policies and procedures that support data quality, data logistics and data integration covering the following lifecycle stages: (1) creation and collection; (2) use; (3) release; (4) disposition.

1. Creation and Collection

Company information is data, facts, and figures generated or received in connection with the transaction of business, and that is categorized as a Record or a Non-Record. Distinguishing between records and non-records is essential to the decision-making process regarding the use, release, and disposition of the information.

- Records are any documentary material, regardless of format, that have been finalized and / or identified on a records retention schedule.
- Non-Records are any documentary material, regardless of format, that has not been identified as a record; non-records include copies of records.

All Company information whether it is a record or non-record is classified into four information security categories based on its value or potential risk. We describe these categories and how we classify customer information below:

Confidential Restricted (CRI). CRI includes information where unauthorized disclosure (inside or outside the company), alteration or destruction has the potential for significant harm to the company, its employees, shareholders or its customers, including: damage to reputation; damage to Bulk Electric System (BES); legal, regulatory, or other sanctions. Data in this classification requires the strongest level of protection. Distribution of CRI must be limited to those with a business need to know and distribution of CRI to any third party must be approved through the approved data release process. Customer CRI includes Personally Identifiable Information (PII), such as Social Security Number (SSN), Driver's license or other government-issued identification numbers, financial account number, any individually identifiable information received directly from a financial institution, individually identifiable biometric data (including, fingerprints, voice print, retina or iris image), first name (or initial) and last name (whether in print or signature) in combination with any one of the following; Date of birth, Mother's maiden name, Digitized or other electronic signature, or DNA profile.

Confidential (CI). CI includes information where unauthorized disclosure (inside or outside the company), alteration or destruction has the potential for harm to the company including: damage to reputation; material productivity loss; impede the organization's operations to the BES; legal, regulatory, or other sanctions. Data in this classification requires protection and may only be distributed to those with a business need to know and distribution of CI to any third party must be approved through the approved data release process. Examples of customer CI include details regarding a customer's account or other Xcel Energy-assigned numbers, energy usage, current charges, and billing records.

Internal (I). Internal information includes information where unauthorized disclosure (inside or outside the company), alteration or destruction is unlikely to cause harm to the company, such as: damage to reputation; significant inconvenience or productivity loss; damage to BES; legal, regulatory, or other sanctions. Data in this classification may not be shared outside the company without prior approval from the information owner. Customer internal information includes aggregated customer energy usage data (CEUD) aggregated to the 15/15 threshold or whole building CEUD aggregated to the 4/50 threshold.

Unsecured (U). Information that may or must be available to the public. Unsecured information includes Xcel Energy's website, and the following documents once published and made available to the general public: SEC filings and FERC filings, brochures, advertisements, press releases, annual reports, bill board advertising, current billing rates. In terms of customer information, once aggregated CEUD is authorized, it becomes unsecured information (example: the Community Energy Reports on the xcelenergy.com website).

2. Use

Our Privacy Policy outlines the ways that we may use the information we obtain about our customers, as follows:[6]

- Assist in establishing an account with Xcel Energy
- Provide, bill, and collect for Xcel Energy products and services
- Communicate with customers, respond to their questions and comments, and provide customer support
- Provide customers access to their information via the My Account site
- Administer customers participation in events, programs, surveys, and other offers and promotions
- Operate, evaluate and improve Xcel Energy's business and the regulated products and services we offer (including developing new products and services, analyzing our products and services, optimizing customer experience on websites, managing our energy distribution system and our communications, reducing costs and improving service accuracy and reliability, and performing accounting, auditing and other internal functions)
- Create aggregated or de-identified energy usage data
- Protect against and prevent fraud, unauthorized transactions, claims and other liabilities, including past due accounts
- Manage risk exposure
- Comply with applicable legal and regulatory requirements

Internally, we base our use parameters on the information security category assigned to the type of information. Employee access to customer CRI or CI is limited to only those

[6] The Xcel Energy Privacy Policy in its entirety can be found at: https://www.Xcel Energyenergy.com/staticfiles/xe/Admin/Xcel Energy%20Online%20Privacy%20Policy.pdf

employees and contract workers with approved access to our customer system (Customer Resource System or CRS).

Employees with access to customer CRI and/or CI are prohibited from accessing viewing for a non-business reason; accessing or transferring it for personal gain, advantage or any other personal reason; giving access to or transferring it without first obtaining appropriate approvals; downloading, uploading, or saving it on a personally owned computing device; and accessing it from a public computer.

3. Release

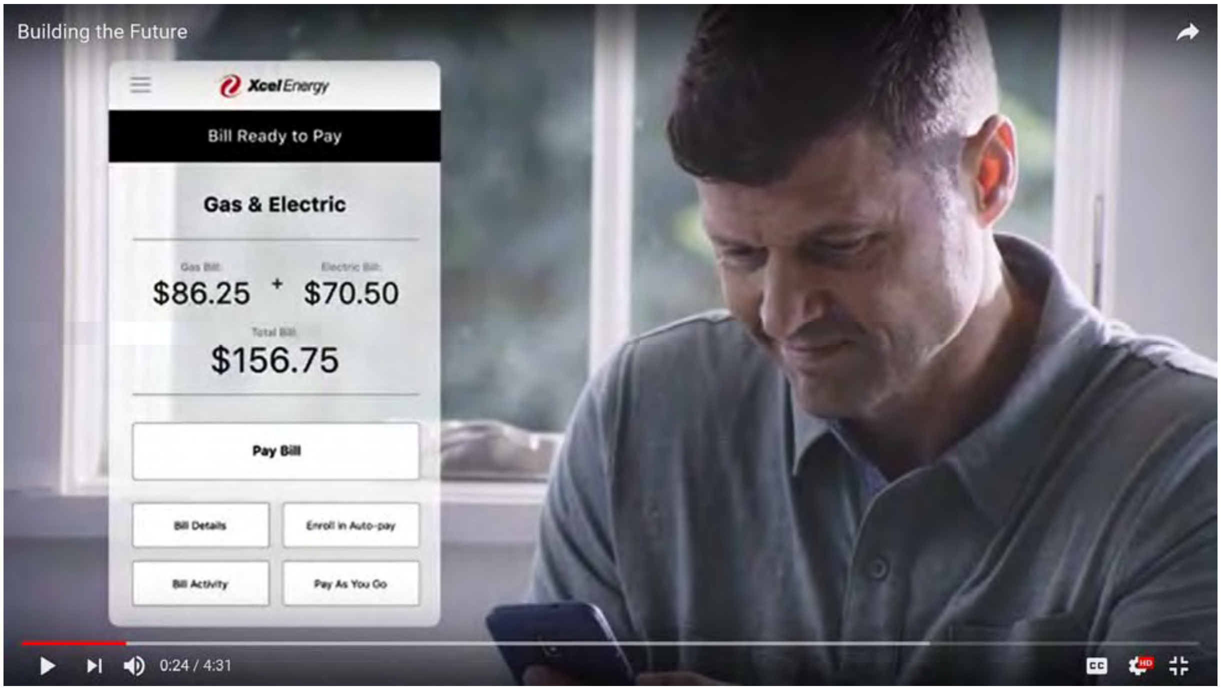
Xcel Energy will only release customer CRI pertaining to an individual to that individual once the identity of the individual has been validated. We will release customer CI to the customer of record upon validating the customer's identity, or to a third party upon receiving a documented and verified consent from the customer of record. We may also disclose customer CI as required or permitted by law or applicable regulations, including to a federal, state or local governmental agency with the power to compel such disclosure, or in response to a subpoena or court order.

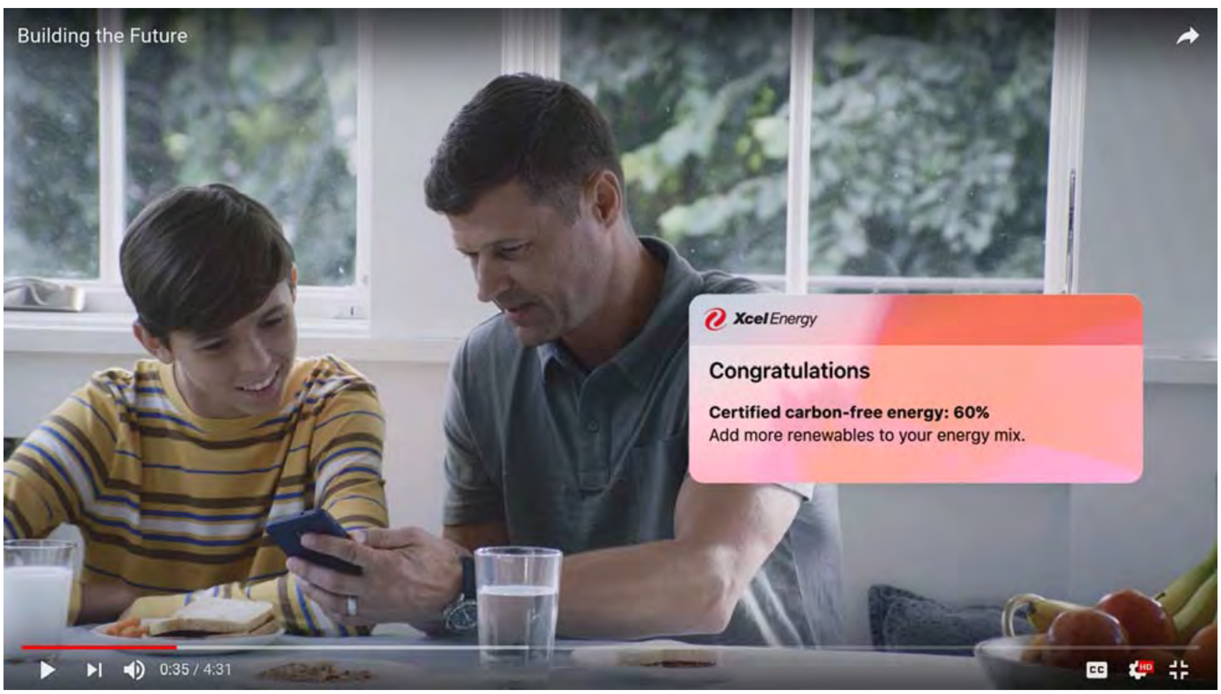
We also release customer information to our contracted agents, when it is necessary for our agent to perform the service(s) specified in an Agreement.[7] All of our contracted agents go through a security vendor risk assessment (SVRA) screening process intended to provide transparency into security-related risk(s) that could potentially be introduced to Xcel Energy as a direct result of utilizing a third-party vendor's product, service, application, etc. All newly proposed vendor arrangements are subject to the (S)VRA process before a contract is signed. Suppliers are assessed by multiple ESS teams (Security Risk Management, Physical Security, Enterprise Resilience, and Information Governance) to ensure security risk is addressed holistically. We prohibit these service providers from using or disclosing the information we provide them, except as necessary to perform specific services on our behalf or to comply with legal requirements.

4. Disposition

The disposition phase of the information management lifecycle consists of disposal requirements as defined in a records retention schedule. Customer account and billing information, and data from our meters are retained for six years.

[7] Contracted Agents are entities with whom we have a contractual relationship to support our provision of regulated utility service, or that directly provide regulated utility service to our customers on our behalf.





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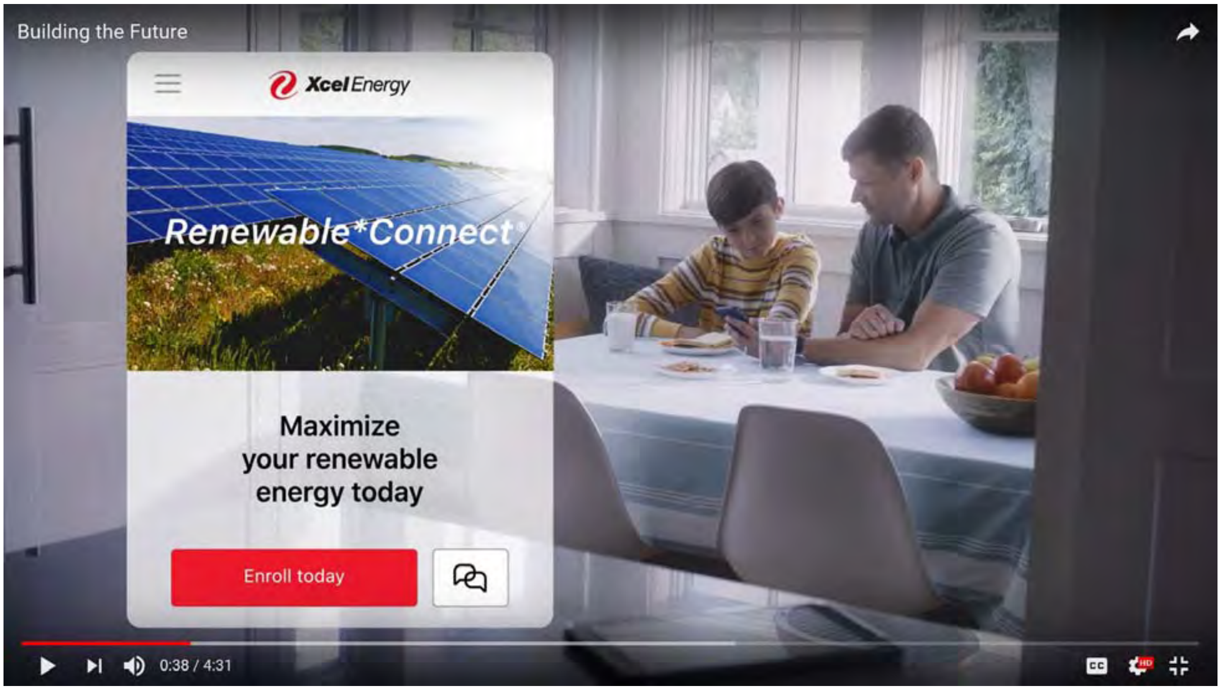

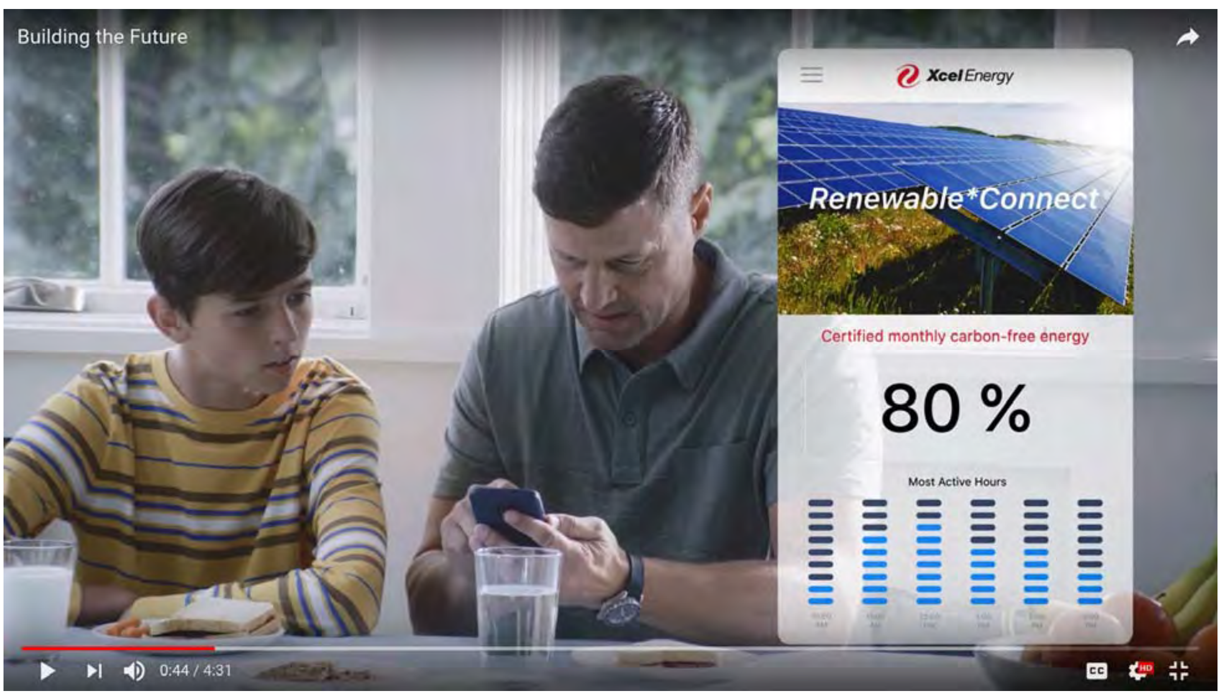

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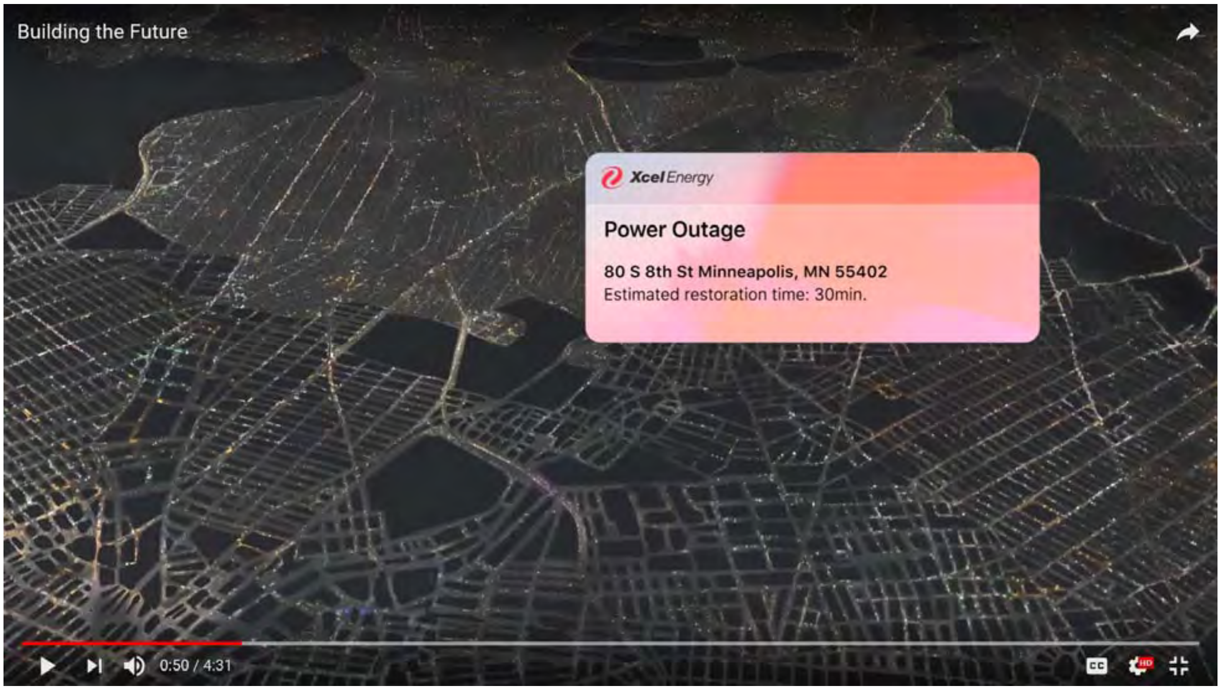

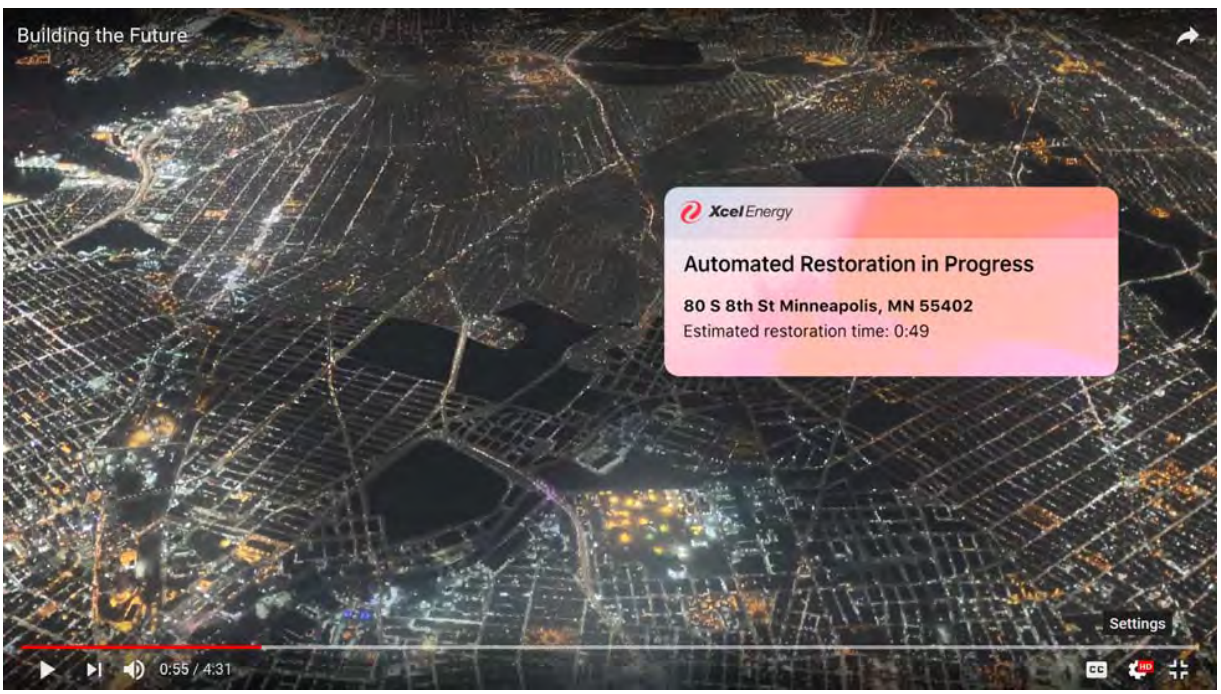

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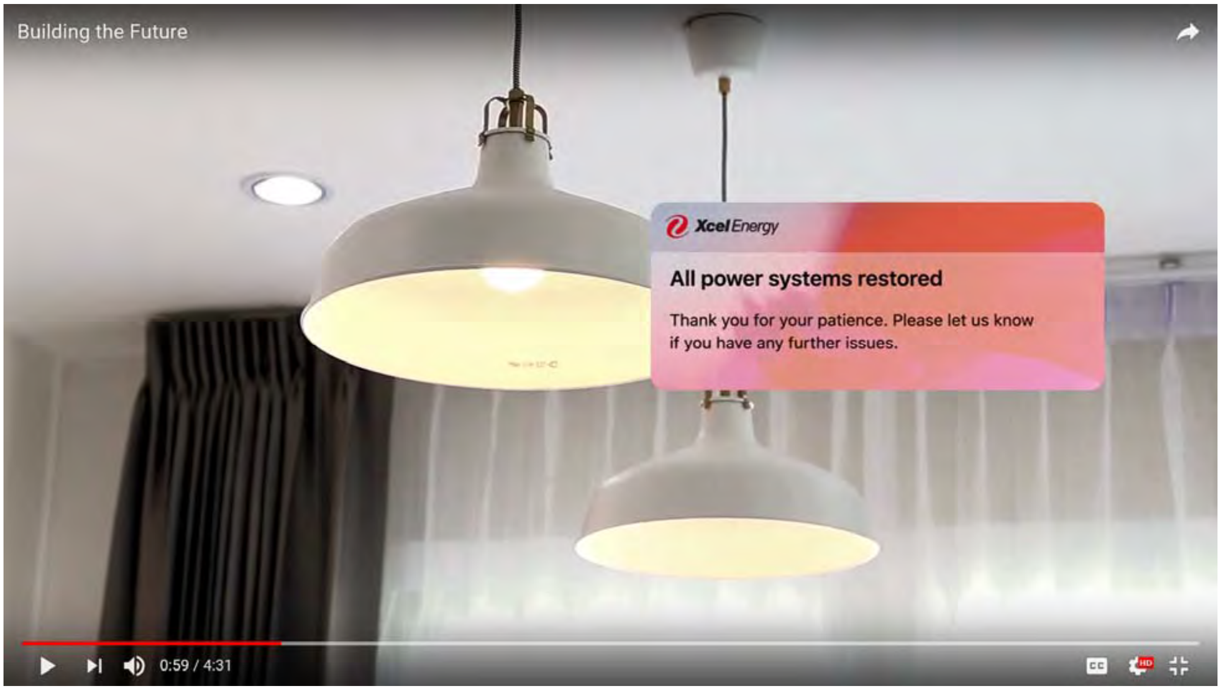

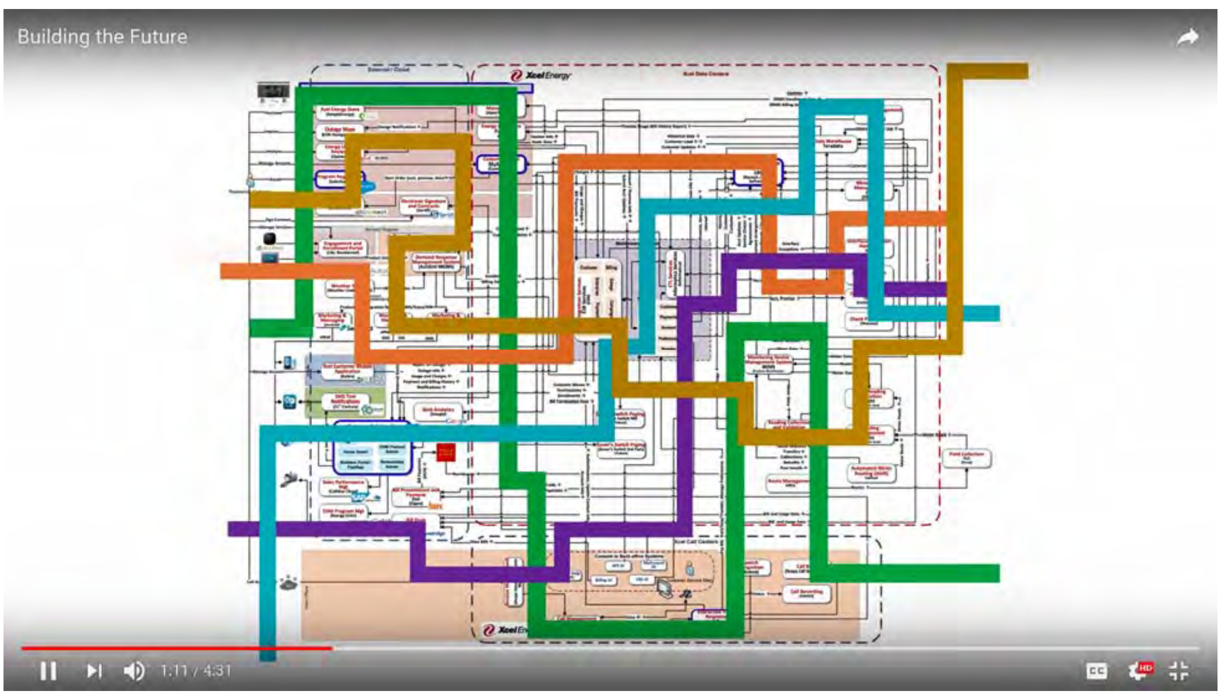

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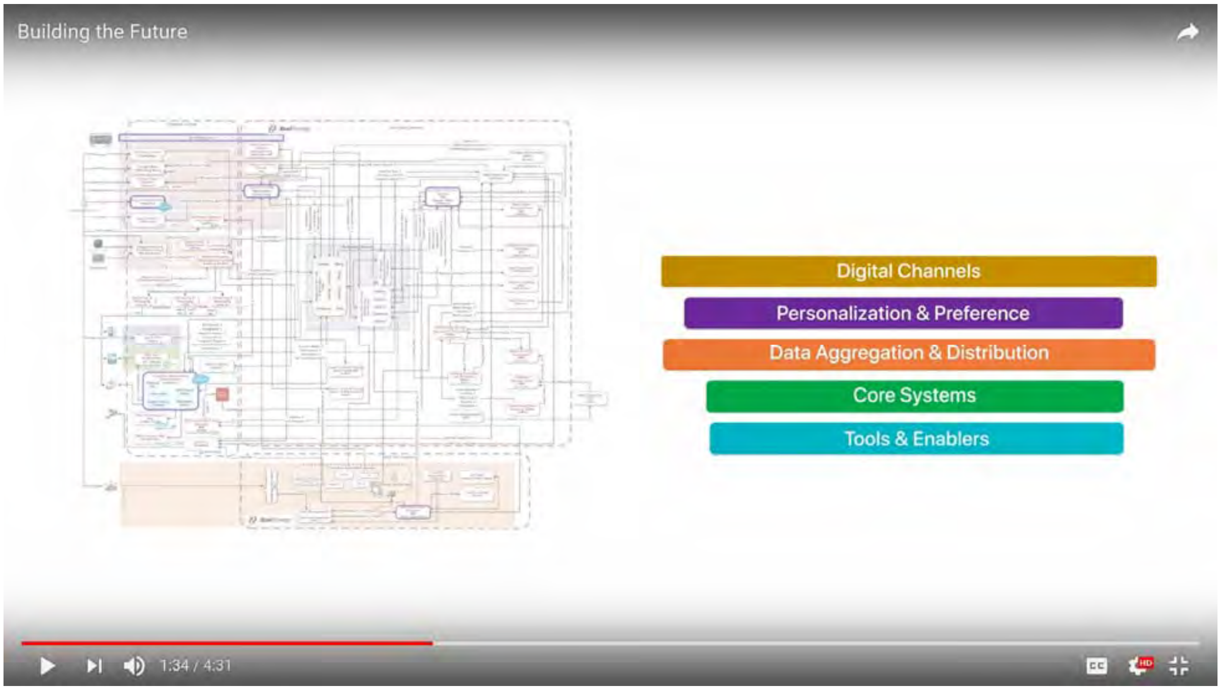

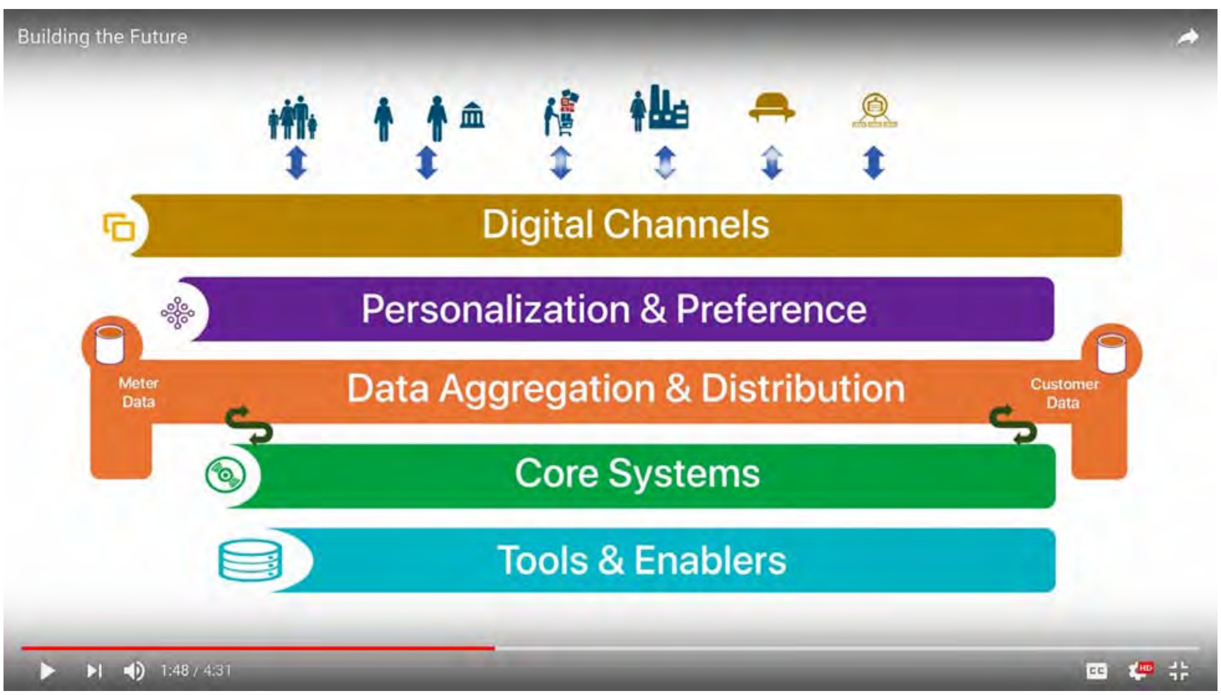

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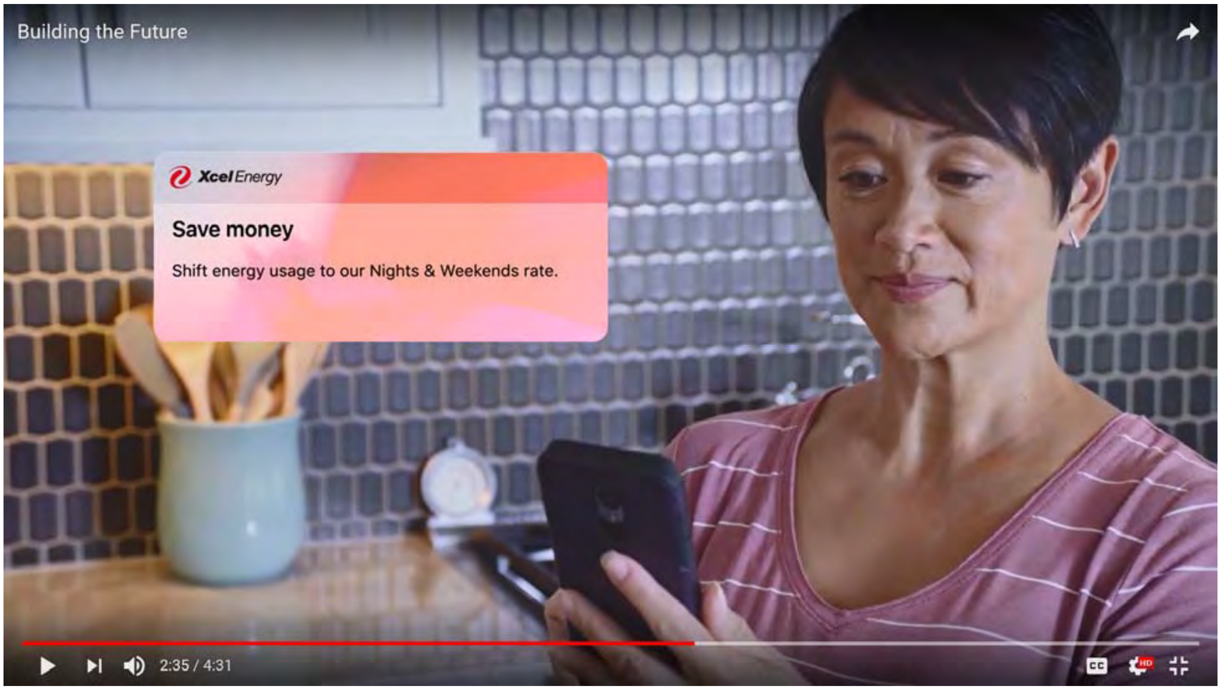

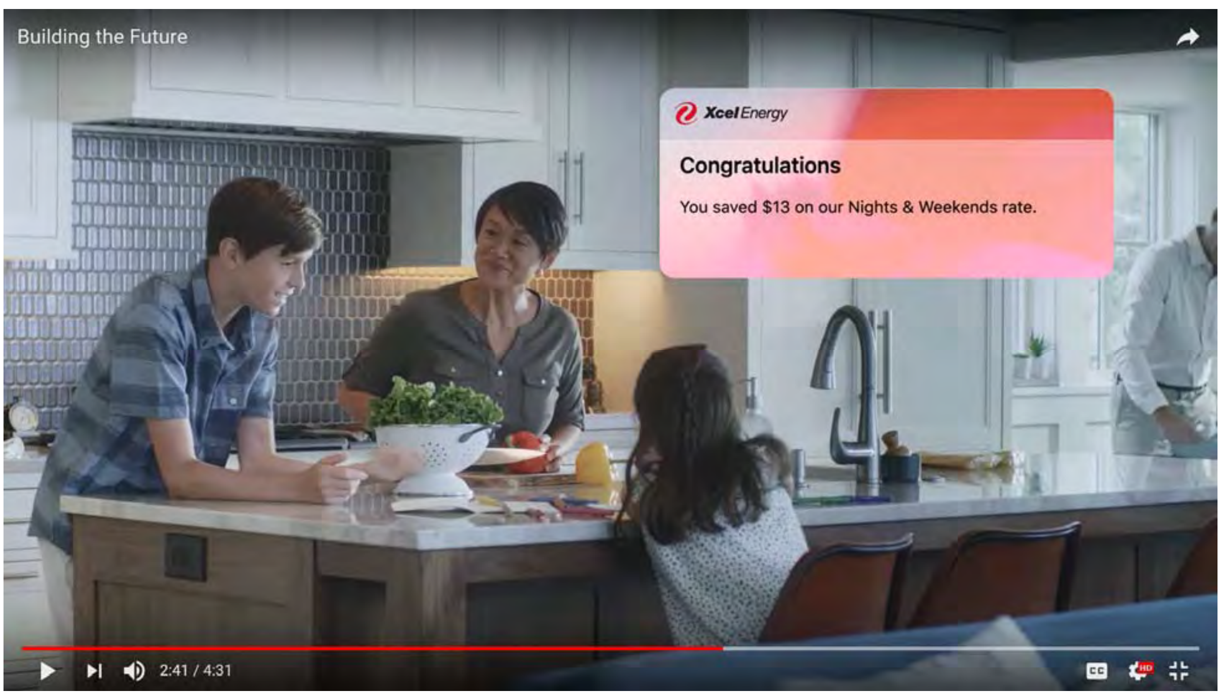

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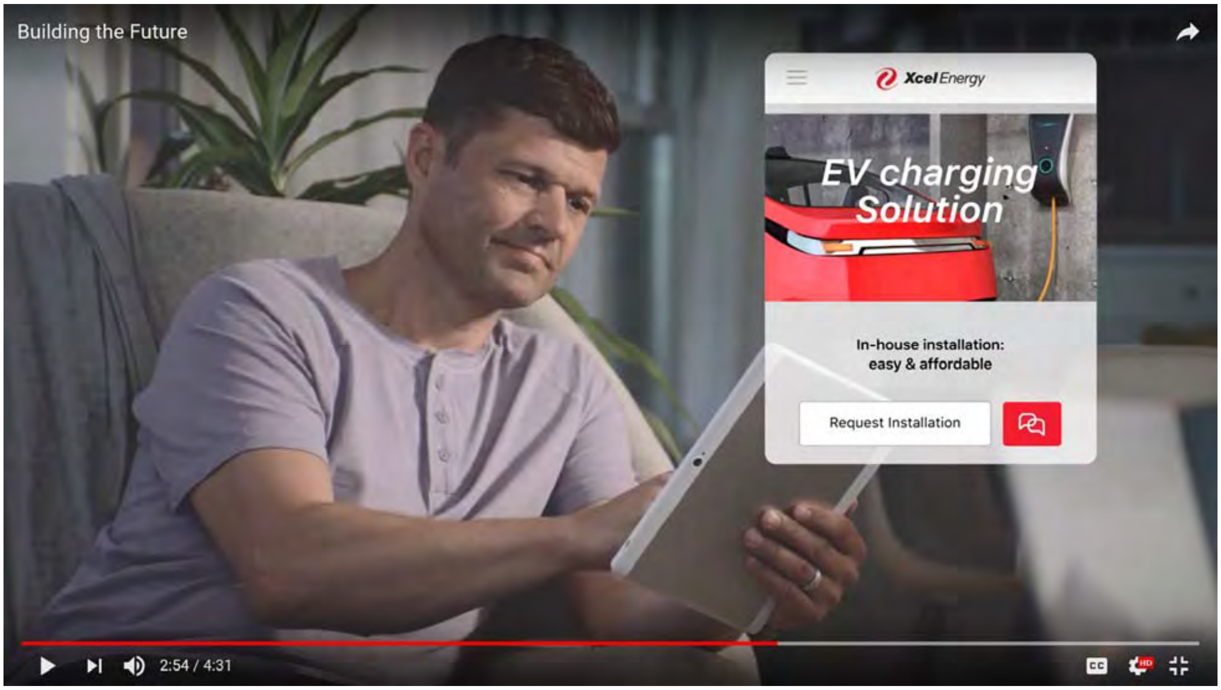

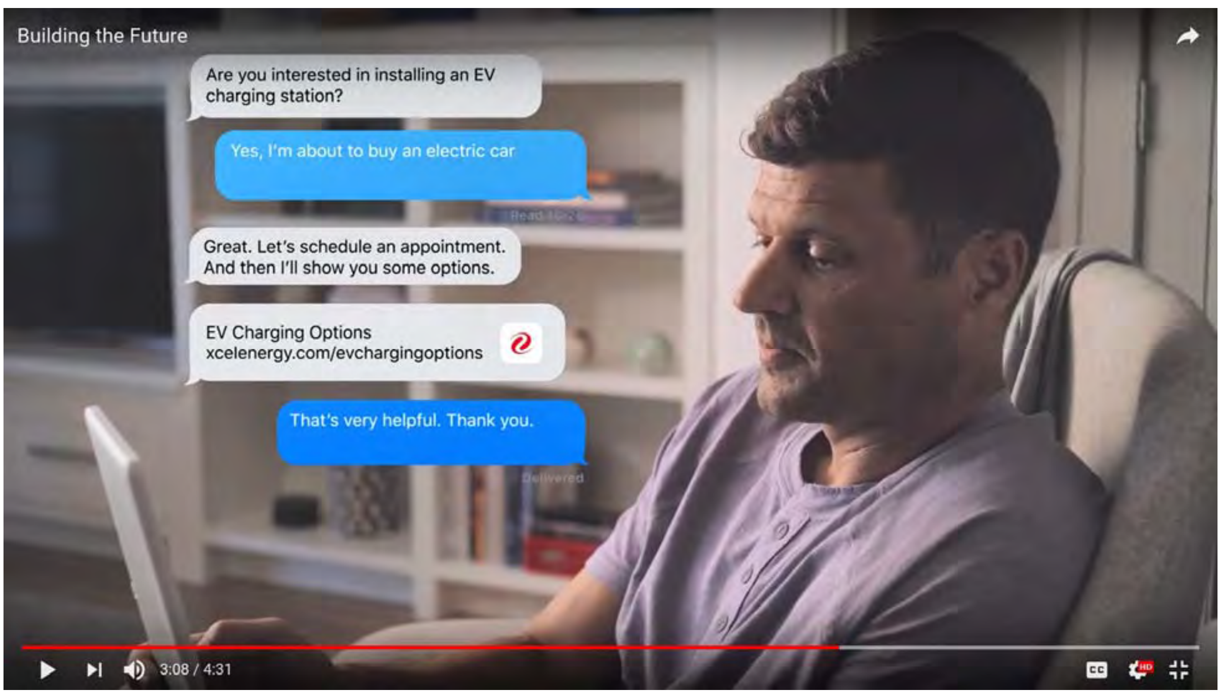

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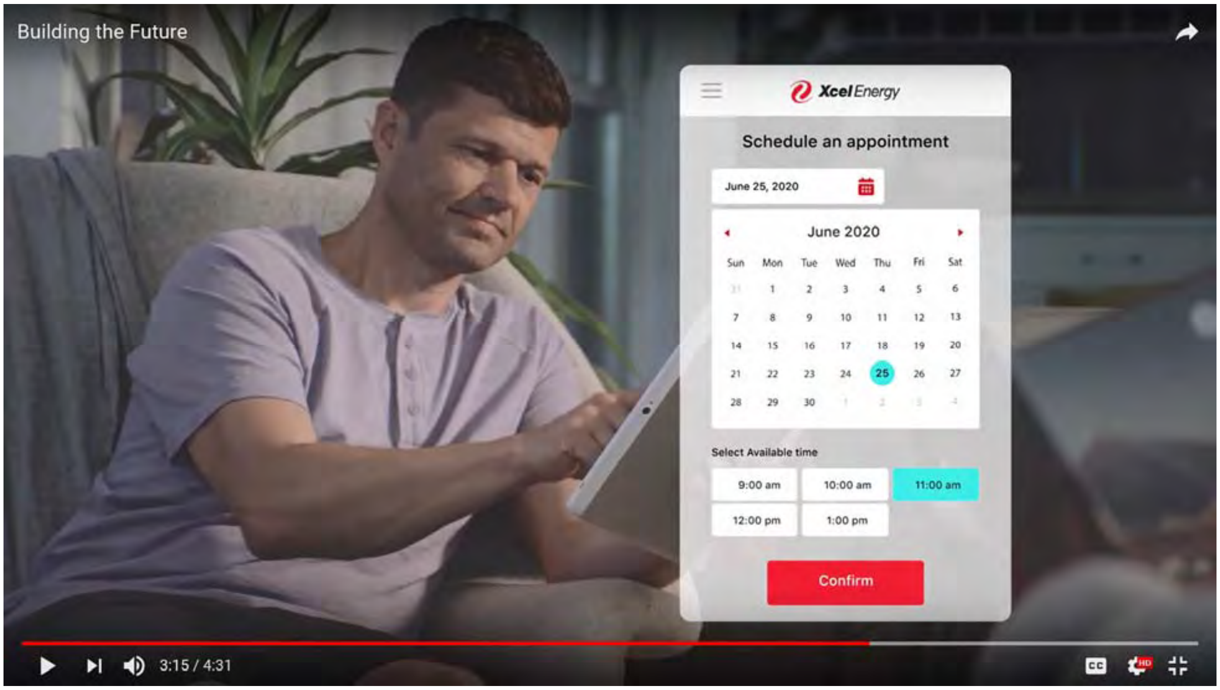

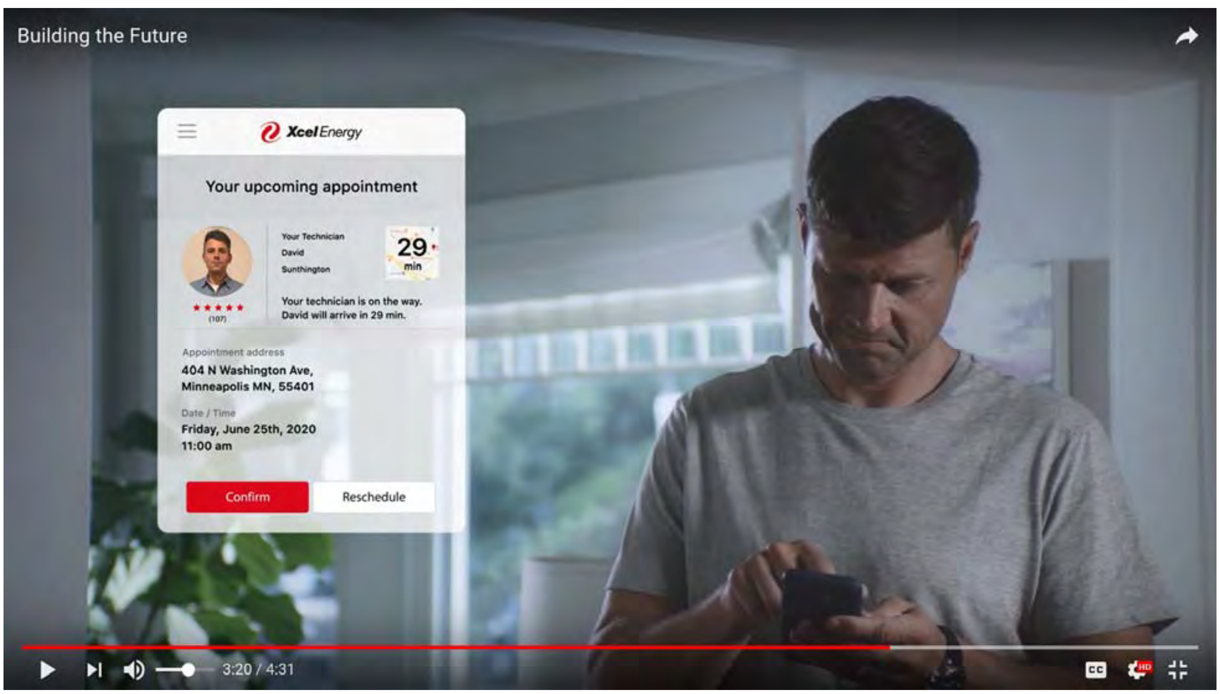

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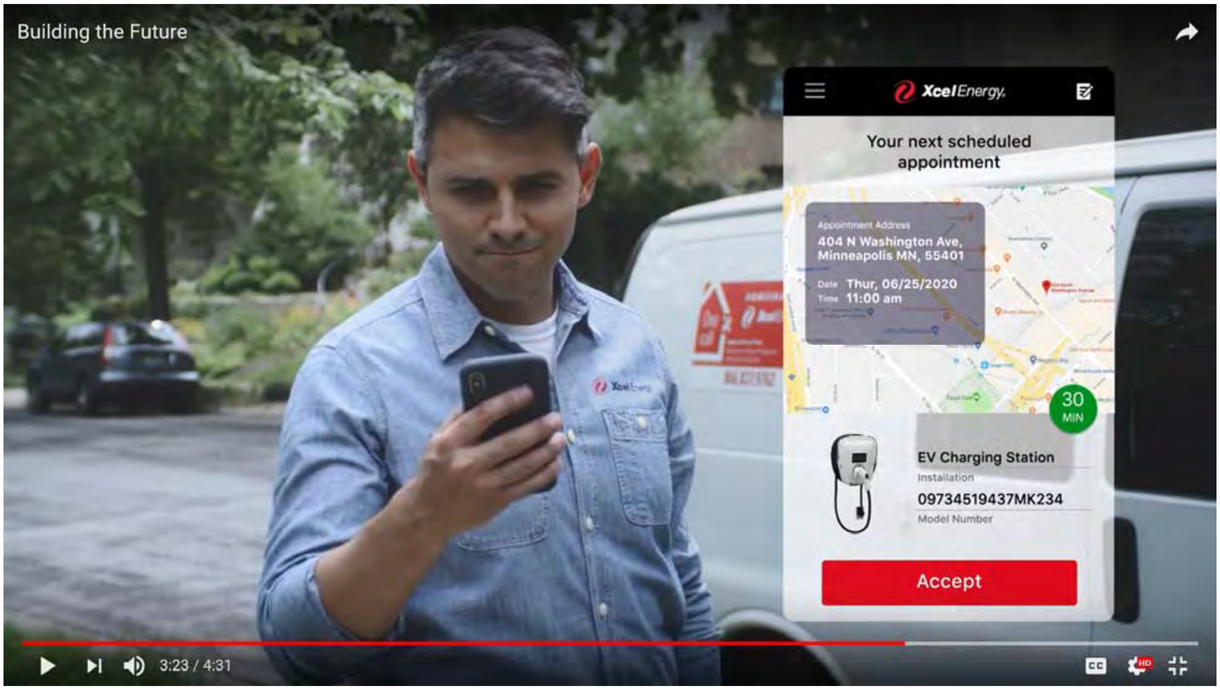

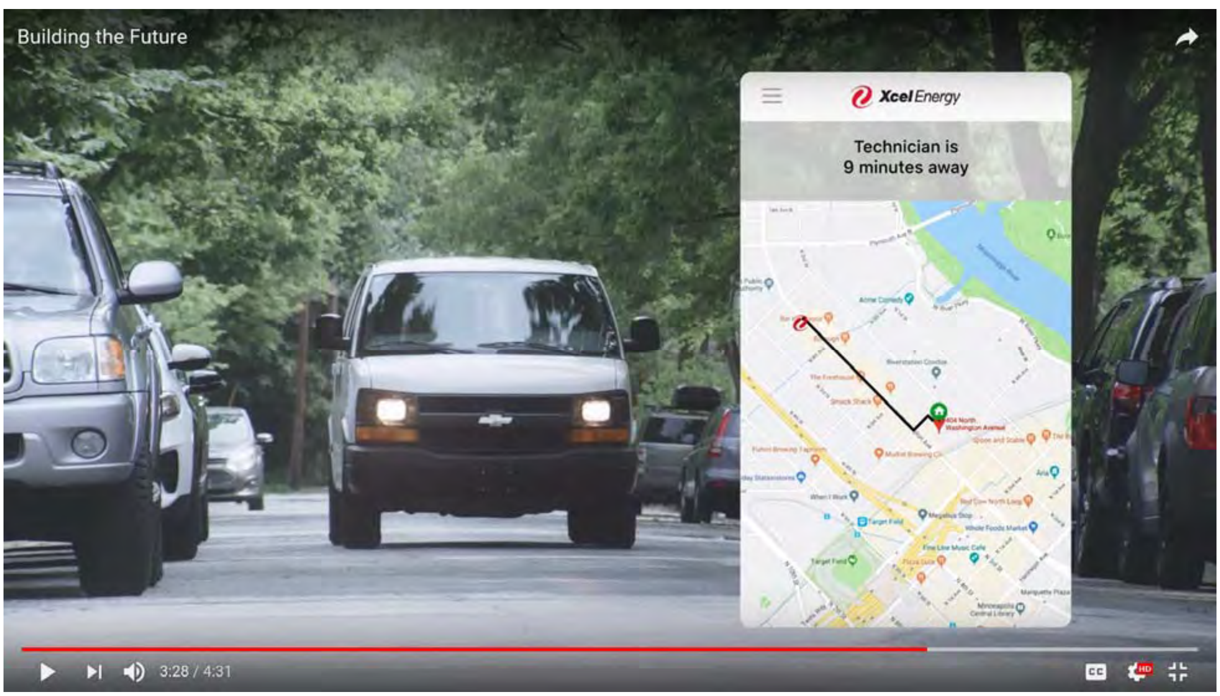

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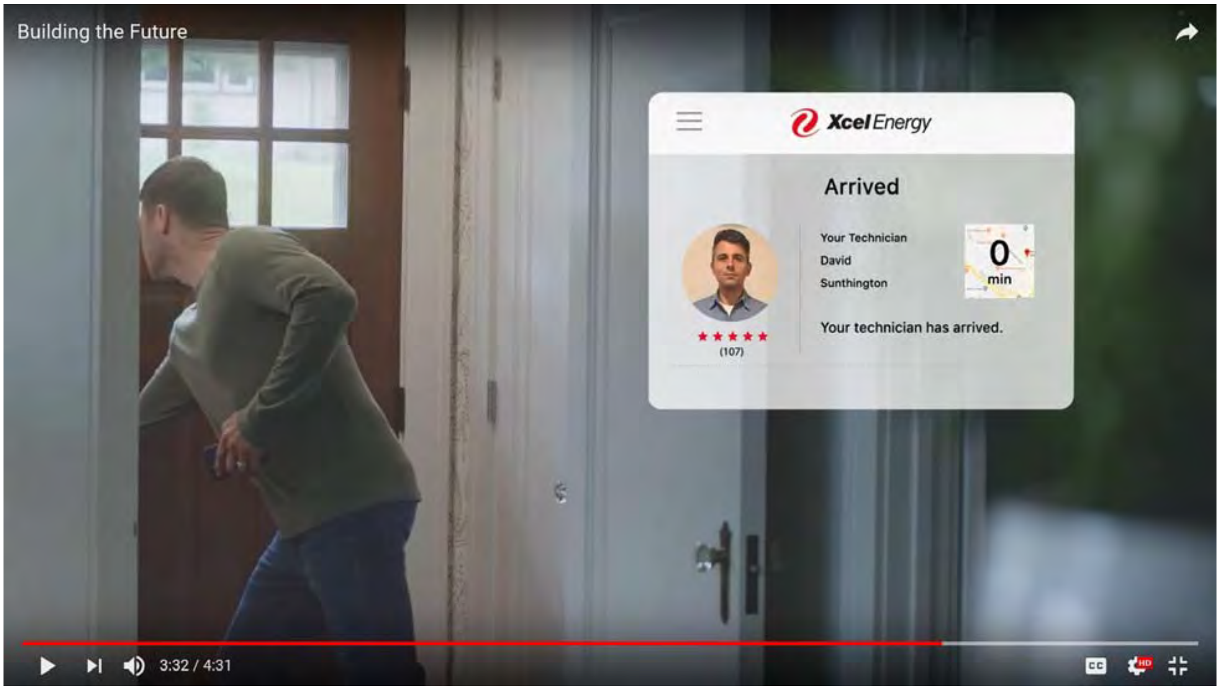

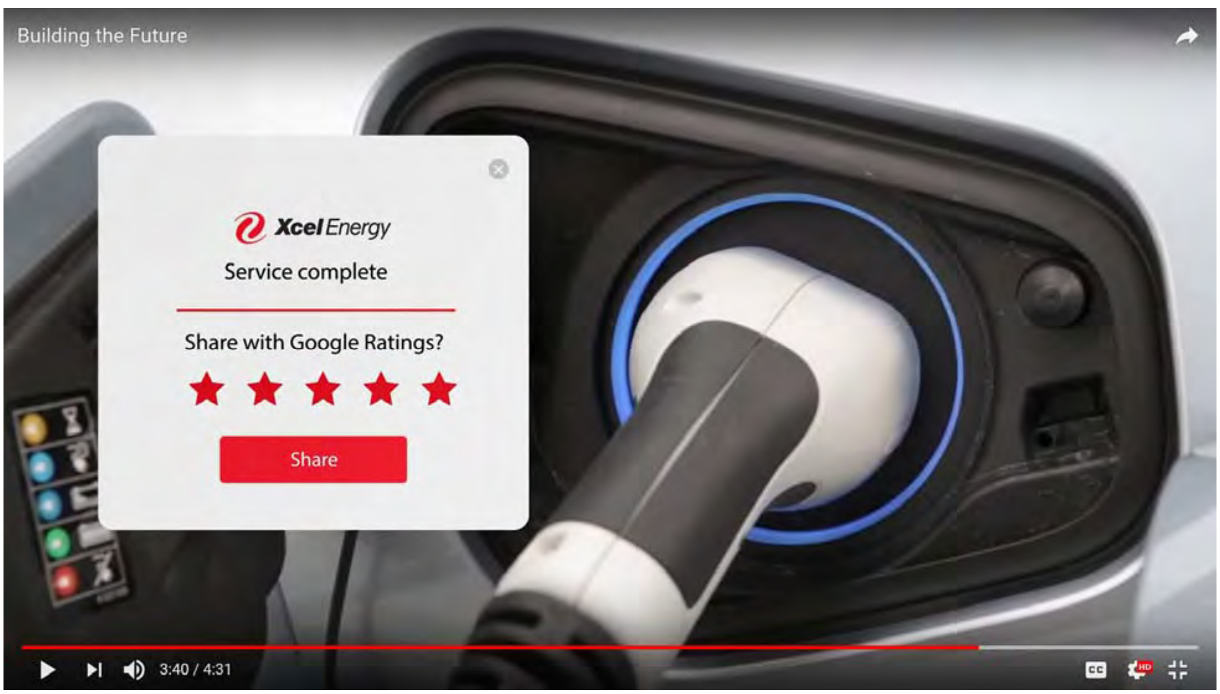

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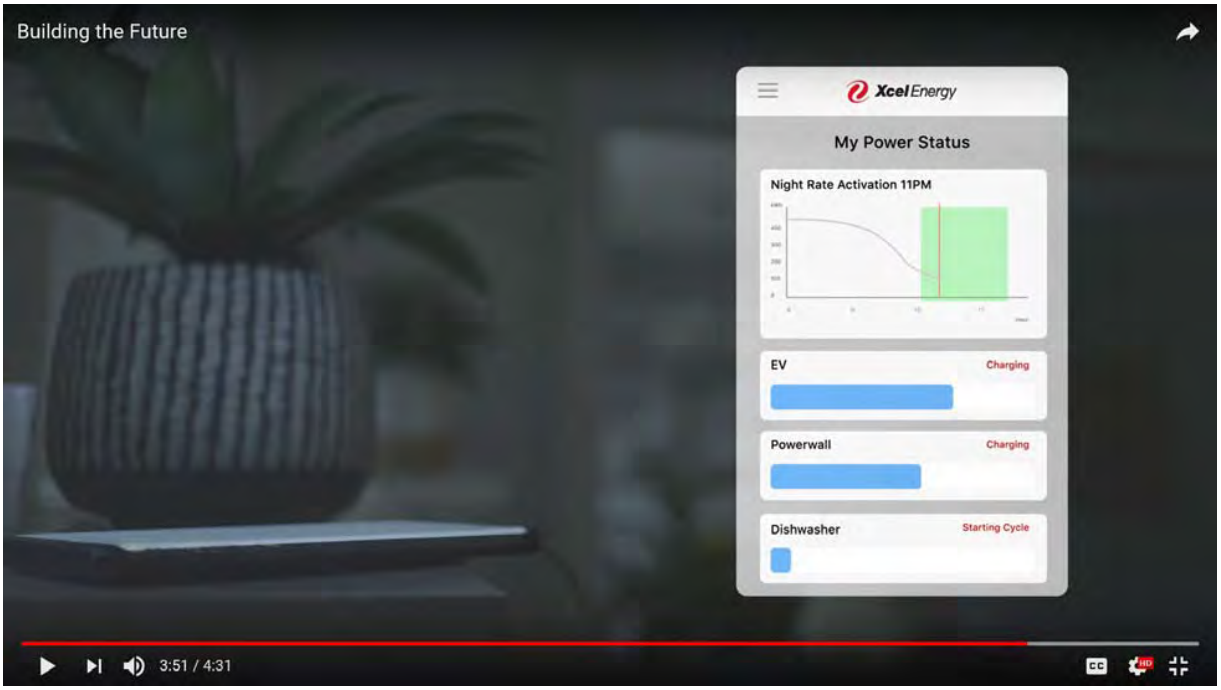

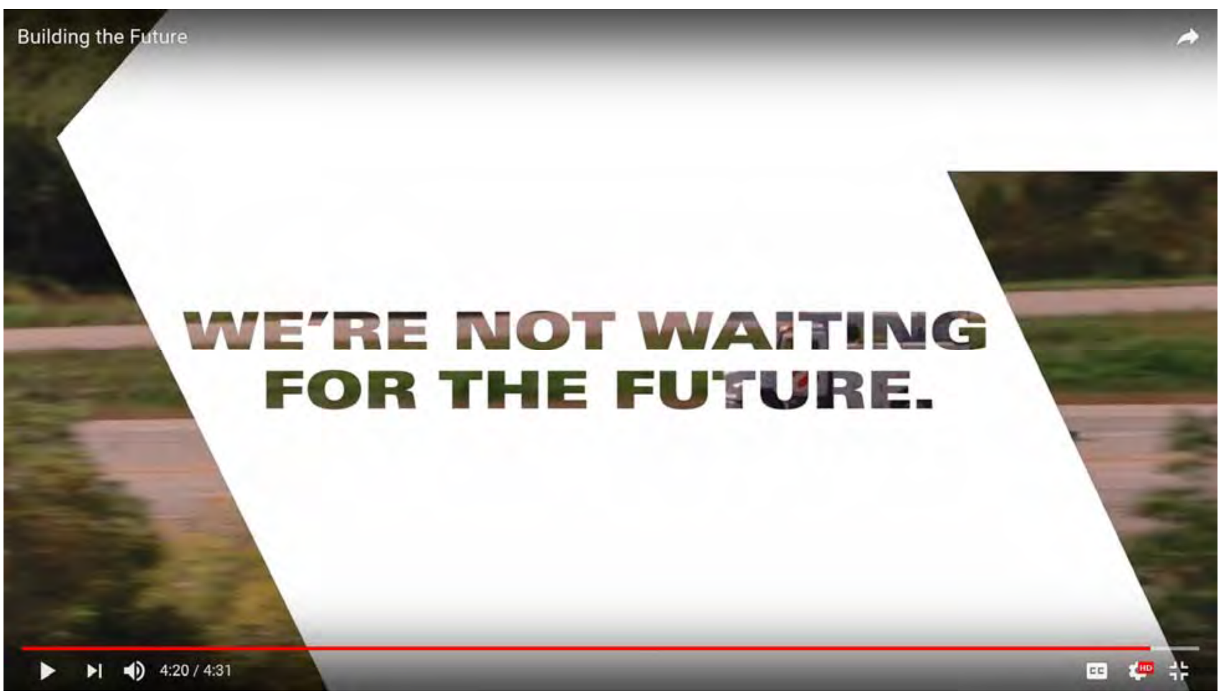

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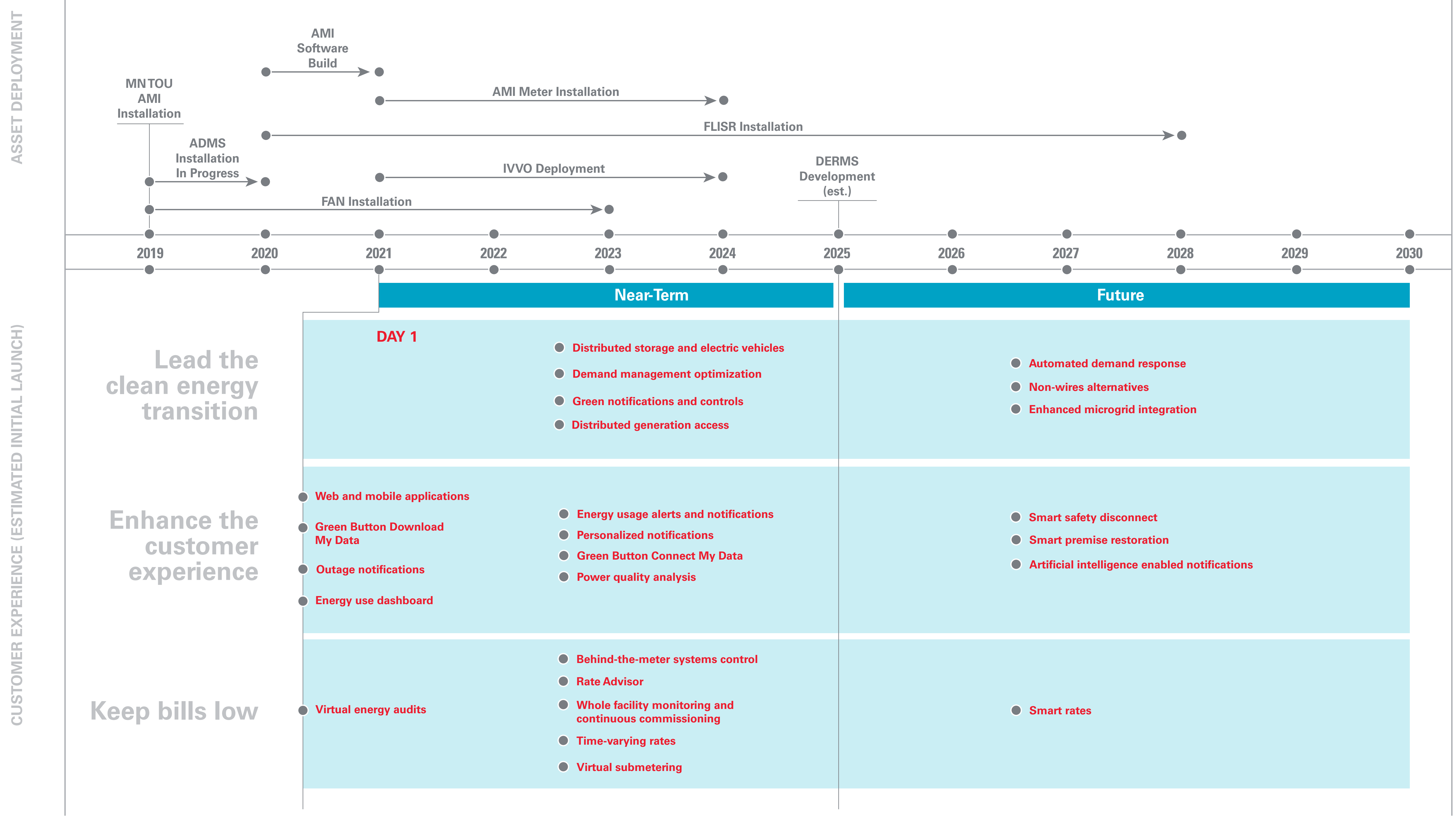
Northern States Power Company
AGIS Implementation and Customer Experience Timeline

Xcel Energy®

AGIS IMPLEMENTATION & CUSTOMER EXPERIENCE TIMELINE



Northern States Power Company
AGIS Program Management Costs

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AMI

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	TOTAL	NPV
Total Meters Deployed	*10,131*	*7,368*	*121,800*	*630,000*	*590,000*	*40,700*	*13,755*	*13,890*	*14,027*	*14,164*	*14,304*	*14,444*	*14,586*	*14,729*	*14,874*	*15,020*	*15,168*	***1,558,960***	
CAPITAL COSTS																		***TOTAL DISCOUNTED***	***NSPM-NPV***
Program Management																			
Change Management	0	1,000,000	1,035,500	1,072,260	1,110,325	1,149,742	1,190,558	0	0	0	0	0	0	0	0	0	0	**6,558,386**	**4,950,734**
Environment/Release Management	0	28,071	2,064,464	2,318,348	1,044,303	355,017	99,666	0	0	0	0	0	0	0	0	0	0	**5,909,870**	**4,617,070**
Finance	0	109,959	193,798	194,658	145,467	0	0	0	0	0	0	0	0	0	0	0	0	**643,882**	**516,017**
PMO	0	288,790	506,590	508,944	381,346	0	0	0	0	0	0	0	0	0	0	0	0	**1,685,670**	**1,350,955**
Security	0	1,105,737	1,144,991	1,185,638	1,227,728	0	0	0	0	0	0	0	0	0	0	0	0	**4,664,093**	**3,748,708**
Supply Chain	0	477,703	487,591	497,685	507,987	0	0	0	0	0	0	0	0	0	0	0	0	**1,970,966**	**1,585,917**
Talent Strategy	238,852	349,325	361,726	185,901	0	0	0	0	0	0	0	0	0	0	0	0	0	**1,135,803**	**977,689**
Delivery and Execution Leadership	0	374,158	1,294,786	1,314,010	667,319	0	0	0	0	0	0	0	0	0	0	0	0	**3,650,273**	**2,916,840**
Contingency	11,943	186,687	354,472	363,872	254,224	75,238	64,511	0	0	0	0	0	0	0	0	0	0	**1,310,947**	**1,033,197**
TOTAL - Program Management	***250,795***	***3,920,430***	***7,443,919***	***7,641,315***	***5,338,699***	***1,579,997***	***1,354,735***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***27,529,891***	***21,697,127***
TOTAL CAPITAL	**250,795**	**3,920,430**	**7,443,919**	**7,641,315**	**5,338,699**	**1,579,997**	**1,354,735**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**27,529,891**	**21,697,127**
O&M ITEMS																			
Program Management																			
Change Management	0	1,825,114	2,157,971	3,067,323	3,176,213	2,991,329	1,608,666	0	0	0	0	0	0	0	0	0	0	**14,826,616**	**11,214,681**
Environment/Release Management	0	0	22,405	23,200	24,024	24,877	11,794	0	0	0	0	0	0	0	0	0	0	**106,300**	**78,991**
Finance	0	32,456	112,027	167,045	216,218	0	0	0	0	0	0	0	0	0	0	0	0	**527,746**	**410,061**
PMO	0	79,772	275,346	410,574	531,437	0	0	0	0	0	0	0	0	0	0	0	0	**1,297,129**	**1,007,876**
Talent Strategy	37,760	58,651	60,733	0	55,000	0	0	0	0	0	0	0	0	0	0	0	0	**212,144**	**177,898**
Delivery and Execution Leadership	0	217,284	510,624	714,661	897,539	0	0	0	0	0	0	0	0	0	0	0	0	**2,340,109**	**1,829,448**
Contingency	1,888	110,664	156,955	219,140	245,022	150,810	81,023	0	0	0	0	0	0	0	0	0	0	**965,502**	**735,948**
TOTAL - Program Management	***39,648***	***2,323,940***	***3,296,060***	***4,601,944***	***5,145,453***	***3,167,016***	***1,701,483***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***20,275,545***	***15,454,901***
TOTAL O&M	**39,648**	**2,323,940**	**3,296,060**	**4,601,944**	**5,145,453**	**3,167,016**	**1,701,483**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**20,275,545**	**15,454,901**
GRAND TOTAL CAPITAL & O&M	**290,443**	**6,244,371**	**10,739,979**	**12,243,259**	**10,484,152**	**4,747,013**	**3,056,219**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**47,805,436**	**37,152,028**

Northern States Power Company
AGIS Program Management Costs

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IVVO

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	TOTAL	NPV
Feeders enabled with IVVO	0	0	26	43	61	59	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**189**	
CAPITAL COSTS																						
Program Management																						
Organizational Change Management	0	0	468,823	850,715	651,244	553,937	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**2,524,720**	**1,909,732**
TOTAL - Program Management	***0***	***0***	***468,823***	***850,715***	***651,244***	***553,937***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***				***2,524,720***	**1,909,732**
TOTAL CAPITAL	**0**	**0**	**468,823**	**850,715**	**651,244**	**553,937**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**2,524,720**	**1,909,732**
O&M ITEMS																						
Business Program Management																						
Organizational Change Management	0	0	156,274	283,572	217,081	184,646	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**841,573**	**636,577**
TOTAL - Program Management	***0***	***0***	***156,274***	***283,572***	***217,081***	***184,646***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***841,573***	**636,577**
TOTAL O&M	**0**	**0**	**156,274**	**283,572**	**217,081**	**184,646**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**841,573**	**636,577**
GRAND TOTAL CAPITAL & O&M	**0**	**0**	**625,097**	**1,134,287**	**868,325**	**738,583**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**3,366,293**	**2,546,309**

Products and Services Enabled or Enhanced by AGIS

KEEP BILLS LOW

New Energy Saving Programs

Product or Service	Customers Affected	Timing
Virtual Energy Audits Provides an on-demand or periodic assessment of the energy usage/efficiency of a premise based on actual performance versus expected performance based on various parameters (i.e. size, year, build, occupancy, devices, etc.). With disaggregation and other analytics capabilities made possible by AMI, these audit results will improve over time to provide more accurate and relevant information. Audits may also be used to monitor the health and status of appliances to identify opportunities for customer to reduce maintenance costs and improve energy efficiency.	**Residential** **Small Business** **Large C&I**	Day 1
Whole Facility Monitoring C&I customers with long-term sustainability goals can more easily track progress at the whole facility and sub-system level through integrations between meters and customer-operated energy management systems. This information can be used to verify savings over time for the purposes of demand side management, or can be used to alert customers when demand or energy usage projections are expected to exceed threshold amounts over a given period of time.	**Small Business** **Large C&I**	Near Term
Enhanced Control Options for Behind the Meter Systems From the smart home to intelligent buildings, AMI meters will be able to communicate more seamlessly with devices and systems within the customer facility. Customers can use this capability to participate in demand response programs as well as to manage facility energy consumption in a more accurate and robust way.	**Residential** **Small Business** **Large C&I**	Near Term
Enhanced Automated Demand Response As the grid evolves, distribution system management can utilize expanded automated demand response capabilities which respond to real time needs of the distribution grid.	**Residential** **Small Business** **Large C&I**	Future

New rate options

Product or Service	Customers Affected	Timing
Rate Advisor With granular usage information and analytics capabilities made possible by AMI, the company will provide a multi-channel approach to educate customers and proactively offer ways to optimize energy usage and cost under existing and new, future rates schemes.	**Residential** **Small Business** **Large C&I**	Near Term
Time Varying Rates With more granular consumption data and more sophisticated meters, rate schedules can be created to better reflect the actual costs on the system at specific times of day. Customers can take advantage of these price signals to manage costs.	**Residential** **Small Business** **Large C&I**	Near Term
Virtual Submetering Instead of installing physical submeters, which are costly and take special wiring and their own communications channels, the main meter could act as a virtual submeter through disaggregation capabilities at the meter.	**Residential** **Small Business** **Large C&I**	Near Term
Smart Rates New rate opportunities including pre-pay and technology specific rates. Rates may rely on local management of the premise level grid or local identification of events. For example, when an EV is plugged in, this could be detected and an EV rate is automatically applied. Another example, would be a flat billing rate with use of the Premise Level Grid Management System (PLGMS) to stay within the agreed to usage levels.	**Residential** **Small Business** **Large C&I**	Future

ENHANCE THE CUSTOMER EXPERIENCE

Outage Enhancements

Product or Service	Customers Affected	Timing
Enhanced Outage Notifications More accurate alerts informing customers about outages in a timely, relevant way. These could include proactive messaging about an outage status, automatic restoration, and restoration confirmation.	Residential Small Business Large C&I	Day 1
Smart Premise Restoration Sequentially restore power to various devices inside the home or business after an outage to reduce the likelihood of voltage or overloading issues, protecting customer system performance as power is restored.	**Residential** **Small Business** **Large C&I**	Future

Integrated, seamless interactions

Product or Service	Customers Affected	Timing
Green Button Download My Data For customers who prefer to perform their own analysis or use their granular usage information for other purposes, data in the standard Green Button protocol will be made available through the Download My Data feature in the customer web portal.	**Residential** **Small Business** **Large C&I**	Day 1
Enhanced Web and Mobile Applications Customer account information along with options to view and pay bills, visualize energy usage and trends, and manage outages will be presented to customers in an integrated and highly personalized format. This is made possible by granular information and analytics as well as a robust customer preference center.	**Residential** **Small Business** **Large C&I**	Day 1
Energy Usage Dashboard Within the new web and mobile customer portals, energy usage dashboards will informs customer about the energy usage of both the overall facility as well as individual devices in a home or business. Compares data to a comprehensive database of similar products to alert to opportunities to save energy and money. Dashboards can be customized to both residential and C&I customer needs (e.g. multi-site data).	**Residential** **Small Business** **Large C&I**	Day 1
Energy Usage Alerts and Notifications Alerts allow customers to be notified with important information in a timely, relevant way. These could include high usage alerts, TOU peak period, Peak Day notification, or goal-based alerts.	**Residential** **Small Business** **Large C&I**	Near Term
Green Button Connect My Data For customers who would like to automatically transmit their usage information to third parties, Green Button Connect My Data will also be available in the customer web portal for ongoing automated transfers.	**Residential** **Small Business** **Large C&I**	Near Term
Personalized Notifications Communication systems will be enhanced to provide timely information to customers in a form that is personalized to their lifestyle and preferences.	**Residential** **Small Business** **Large C&I**	Near Term
Artificial Intelligence Enabled Notifications As artificial intelligence technologies mature and become widely adopted in the market, meters will have the ability to leverage these capabilities to provide heightened interactions which will be customized to the unique needs of each customer.	**Residential** **Small Business** **Large C&I**	Future

Safety & Reliability Enhancements

Product or Service	Customer Affected	Timing
Power Quality Analysis With detailed information collected by the meter relating to power delivery, customers can more accurately and frequently assess their power quality. Over time, analytics of the power quality information can help flag and diagnose potential power quality related items so that customers can proactively manage any possible issues.	**Residential** **Small Business** **Large C&I**	Near Term
Emergency and Safety Notifications The meter will be able to provide customers with emergency management notifications via its analytics and communications capabilities. This can help customers identify potential risks to their energy management systems, security monitoring, and be aware of local emergency notifications that may apply to their general safety and security.	**Residential** **Small Business** **Large C&I**	Near Term
Enhanced Microgrid Integration Where the capability exists for portions of the grid to operate independently of the rest of the surrounding system, the advanced distribution management system will more seamlessly be able to manage the connection of these microgrids.	**Residential** **Small Business** **Large C&I**	Future
Smart Safety Disconnect Detects when a smart inverter has malfunctioned or was improperly installed and has not disconnected from the grid when incoming power has been lost. In this situation, the disconnect inside the meter is automatically tripped to protect the rest of the grid and the customer.	**Residential** **Small Business** **Large C&I**	Future

LEAD THE CLEAN ENERGY TRANSITION

Product or Service	Customers Affected	Timing
Enhanced Access to Battery Storage and Electric Vehicles Through the enhanced visibility and control of the distribution system, greater utilization of storage elements on the grid, including electric batteries and electric vehicles, will be possible. This capability promises to help ensure safe, reliable energy for all customers.	**Residential** **Small Business** **Large C&I**	Near Term
Green Notifications and Controls Customers would be notified when the percentage of electricity generated by renewable services in their area exceeds a certain threshold.	**Residential** **Small Business** **Large C&I**	Near Term
Enhanced DER Enablement Through the enhanced visibility and control of the distribution system, customers will be able to integrate distributed generation resources more seamlessly and potentially at higher levels within a given area.	**Residential** **Small Business** **Large C&I**	Near Term
Demand Management Optimization With more granular consumption information, new demand management programs can be created to enable customers to shift and shed load to respond to needs of the grid on an increasingly real-time basis. With new communication capabilities, the meter will be able to communicate directly with smart devices within homes and businesses. As analytics such as disaggregation and virtual submetering evolve, demand response routines can increase sophistication through optimizing sequence among various demand response resources.	**Residential** **Small Business** **Large C&I**	Near Term

Advanced Grid Customer Education & Communications Plan

1 Summary and Customer Vision

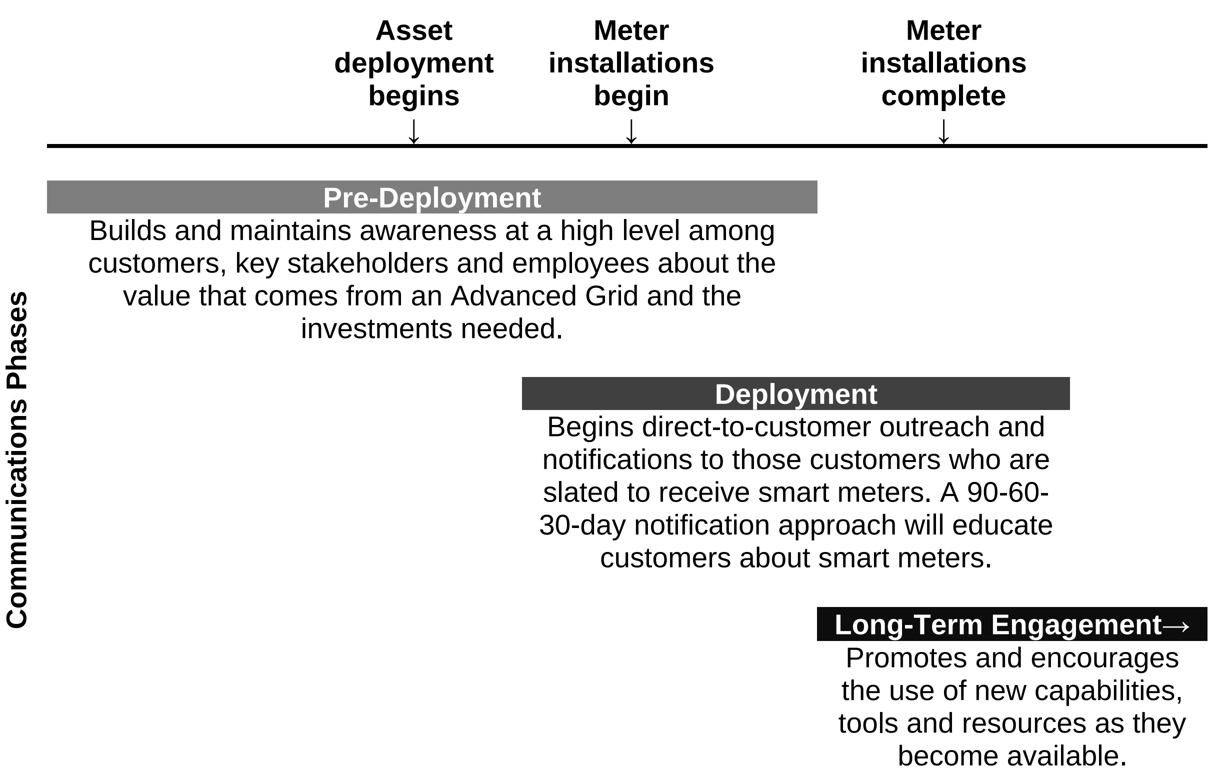
The electric utility industry is in a time of significant change. Increasing customer expectations and technological advances have reshaped what customers expect from their energy service provider, and how those services are delivered and communicated. Enhancing the customer experience is critically important, and is one of our three strategic priorities, along with leading the clean energy transition and keeping bills low. As outlined in the Advanced Grid Customer Strategy (Schedule 3), we plan to integrate modern customer experience strategies with advanced grid platforms and technologies to enable intelligent grid operations, smarter networks and meters, and optimized products and services for our customers.

This Customer Education & Communications Plan is an integral part of our customer experience transformation and Xcel Energy's Advanced Grid initiative.

2 Education and Communications Phases

Meter deployment and smart meter capabilities will be phased in over the next five-plus years. Communications strategies, messages and tactics will be executed in three phases to match the customer journey.

Figure 1. Communications phases



2.1 Pre-Deployment Phase – Advanced Grid Benefits

This phase builds and maintains awareness at a high level among customers, key stakeholders and employees about the value that comes from an Advanced Grid and the investments needed. Advanced Grid will be presented as one of the company's platforms for bringing innovative tech solutions to transforming the customer experience.

Key objectives during this phase include:

- Create customer and stakeholder awareness about the overall benefits of the advanced grid.
- Explain why we are making this investment, focusing on tangible customer benefits.
- Educate and train employees to equip them with tools and resources necessary to engage with customers and stakeholders.
- Build customer interest in the change by explaining the benefits of smart meters and the tools and options they enable.
- Proactively address customer concerns and questions.

2.1.1 Pre-Deployment Tactics

An integrated, expansive, and multi-channel awareness-building approach, as shown in Table 1, is required to set the stage for smart meter installation communication in the Deployment phase.

Table 1. Pre-deployment tactics

Audience	Messages	Channels	Materials
All customers	• Overview of Advanced Grid initiative • Intro to smart meters • Customer benefits • Privacy and security	• xcelenergy.com and blog • Email • Social media • Media outreach • Out of home advertising • Online and print advertising • Bill onserts • Community events and meetings	• Info sheets and brochures • Videos
Community leaders and elected officials	• Overview of Advanced Grid initiative • Intro to smart meters • Customer benefits • Deployment plans and processes • Privacy and security	• In-person meetings and discussions with Community Relations Managers • Community events and meetings • Email	• Presentations • Info sheets and brochures • Videos • Talking points
Customer Care agents	• Overview of Advanced Grid initiative • Intro to smart meters • Customer benefits • Deployment plans and processes • Privacy and security	• Web-based training • In-person training • Email • Customer Care Quick Reference program	• FAQs • Info sheets and brochures • Videos • Talking points
All employees	• Overview of Advanced Grid initiative • Intro to smart meters • Customer benefits • Deployment plans and processes • Privacy and security	• Intranet • Email • In-person meetings or presentations	• Internal news articles • Presentations • Info sheets and brochures • Videos • Talking points

2.1.2 Pre-Deployment Phase Success Metrics

We will measure customer awareness during this phase through existing measures of advertising/awareness campaign recall and through tracking and reporting of customer responses to the following statements:

- Communications on the advanced grid meter installation and initiative were clear and easy to understand.
- Communications encouraged me to seek additional information if needed.

2.2 Deployment Phase – Smart Meter Installation

This phase will begin direct-to-customer outreach and notifications to those customers who are slated to receive smart meters. A 90-60-30-day notification approach will educate target audiences on smart meters, how they will be deployed and installed, and on smart meter benefits. While messaging and content will focus on meter installation, all communications will speak to the broader value and benefits of the Advanced Grid.

This phase will also set the stage for the Long-Term communications phase by collecting customer information and preferences that can be used as new capabilities are enabled and to create deeper customer relationships.

Key objectives during this phase include:

- Provide practical and timely information and notifications about the deployment, installation and opt-out processes.
- Provide clear information on the opt-out process and associated costs, including how to take action.
- Leverage a messaging hierarchy to reiterate high-level benefits of advanced metering.
- Further develop tools and resources for employees to use during proactive discussions with customers and stakeholders.

2.2.1 Deployment Tactics

Most tactics in this phase will be hyper-targeted toward customers with practical information about smart meter deployment. Customers will receive notifications about their smart meters 90 days, 60 days, and 30 days prior to meter installation through various channels to ensure all customers receive adequate notification, as shown in Table 2 below. Where possible, materials will be personalized with the most relevant and up-to-date deployment information.

Table 2. 90-60-30-day communications approach

<table>
<tr><th></th><th>90 days before meter install</th><th>60 days before meter install</th><th>30 days before meter install</th><th>7 days before meter install</th><th>Day of install</th><th>Post-install</th></tr>
<tr><td rowspan="2">All customers</td><td>Mailer: intro</td><td>Mailer: your meter is coming soon</td><td>Mailer: meter installation FAQs</td><td>Phone call: your meter is coming next week</td><td>Install technician door knock</td><td>Mailer: success or attempt</td></tr>
<tr><td colspan="4"></td><td>Door hanger: success or attempt</td><td></td></tr>
<tr><td rowspan="2">Opted-in customers
(only customers who have opted into these channels will receive these notifications)</td><td>Email: what to expect during meter installation</td><td>Email: Your meter is coming soon</td><td>Email: Your meter is coming soon</td><td>Text notification</td><td></td><td>Email: success or attempt</td></tr>
<tr><td colspan="2"></td><td>My Account banner: Your meter is coming this month</td><td>App push notification</td><td></td><td>My Account banner: success or attempt</td></tr>
<tr><td rowspan="2">Mass communication</td><td colspan="2">Targeted online, print, and out of home advertising</td><td colspan="2">Hyper-targeted social media advertising</td><td colspan="2"></td></tr>
<tr><td colspan="4">Community outreach: meter install schedule by neighborhood, informational content about new meters</td><td colspan="2"></td></tr>
</table>

Table 3 describes the 90-60-30-day communications and the additional tactics used during the deployment phase to ensure a consistent and useful customer experience.

Table 3. Deployment tactics

Audience	Messages	Channels	Materials
All customers	• Smart meter benefits • Meter installation logistics • Opt-out information • New tools and how to sign up for My Account • Low income protections	• Postcard/mailer (90 days) • Direct mailers and email if available(60 days and 30 days) • Phone call (7 days) • My Account • xcelenergy.com and blog • Targeted email • Targeted social media • Media outreach • Targeted online, print, and out of home advertising • Community events and meetings	• Mailings and emails • Info sheets and brochures • Educational videos • Door hangers • FAQs
Community leaders and elected officials	• Smart meter benefits • Meter installation logistics • Opt-out information • Specific meter deployment plans and schedules • Low income protections	• In-person meetings and discussions with Community Relations Managers • Community events and meetings • Email	• Presentations • Info sheets and brochures • Educational videos • Talking points • Deployment plans
Customer Care agents and Meter Installation Vendor	• Smart meter benefits • Meter installation logistics • Opt-out information • Specific meter deployment plans and schedules • Low income protections	• Web-based training • In-person training • Email • Customer Care Quick Reference program	• FAQs • Info sheets and brochures • Educational videos • Talking points • Deployment plans
All employees	• Smart meter benefits • New tools • Meter installation logistics	• Intranet • Email • In-person meetings or presentations	• Internal news articles • Presentations • Info sheets and brochures • Educational videos • Talking points

2.2.1.1 Pilot example communications

The Minnesota time of use pilot used a 90-60-30-day communication approach to support smart meter installations:

Figure 2. Minnesota pilot 60-day postcard

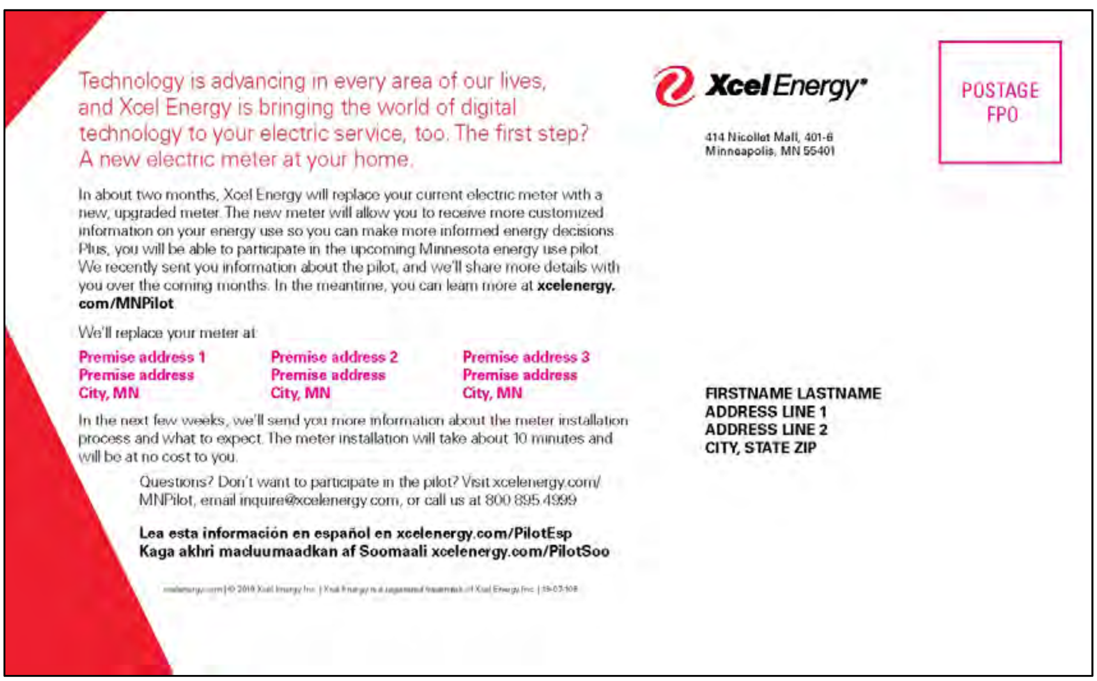


Figure 3. Minnesota pilot 30-day letter and meter FAQs

Xcel Energy

YOU'RE GETTING A
NEW ELECTRIC METER
IMPORTANT INFO INSIDE

414 Nicollet Mall
Minneapolis, MN 55401

IMPORTANT! Electric meter upgrades are coming soon to your neighborhood.

Sample A. Sample
Mailing Address 1
Mailing Address 2
City, MN ZIP-1234

In about 30 days, Xcel Energy will replace your existing electric meter with an upgraded meter. It is part of Xcel Energy's effort to build a smarter, more resilient energy grid that can better serve you for decades to come. The new meter will also allow you to participate in the upcoming Minnesota energy use pilot. We recently sent you information about the pilot, and we'll share more details with you in the coming months. In the meantime, you can learn more at **xcelenergy.com/MNPilot**.

Xcel Energy

What is different about my new meter?

Your new meter allows for two-way communication between your electric meter and Xcel Energy. The new meters will enable many benefits, including improved outage detection and response, future web tools to help you make more informed decisions about your energy use, and future programs and services to help you save energy and money.

How does the new meter work?

Compared to traditional meters, new electric meters have many benefits. Your current meter tells you and Xcel Energy how much electricity you're using, but it does not show **when** you're using electricity. The new meters measure your energy use every five minutes. This way you can see how much energy you use and when you use it. This information can help you better understand how you are using energy and help you make more informed decisions. Plus, these new meters will help us better manage the energy grid, reduce the need for added generation, and react to power outages more quickly.

What are the benefits of a new meter?

Your new meter and the larger advanced grid will enable…

2.2.2 Deployment Phase Success Metrics

To answer key questions and assess the overall effectiveness of our efforts, we will track and report customer responses to the following statements:

- Communications on the advanced grid meter installation and initiative were clear and easy to understand.
- Communications answered all of my questions about the meter installation.
- Communications encouraged me to seek additional information if needed.

2.3 Long-Term Engagement Phase – Tools and Resources

This phase will promote and encourage the use of new Advanced Grid capabilities, tools and resources as they become available. Communications will not only highlight the features of new tools and resources, but also the broader benefits they can provide. This phase will leverage customer information and preferences gathered in Phase II to provide a seamless experience for all customers via their preferred channels.

Key objectives during this phase include:

- Leverage a messaging hierarchy that reiterates high-level benefits of the project while educating customers on new capabilities, tools and resources as they become available.
- Develop and execute a customer nurturing campaign to follow the customer journey and encourage adoption of new capabilities, tools and resources.
- Evaluate and refine messages and tactics to continuously improve and ensure the best possible customer experience.

2.3.1 Long-Term Engagement Tactics

A multi-channel approach will reach customers via their preferred channels and include tailored messages to move them along in the engagement journey. Where possible, we will use available data to segment outreach about specific tools and resources. For example, a unique campaign could target only those customers who have not enrolled in My Account.

Table 4. Long-term engagement tactics

Audience	Messages	Channels	Materials
All customers	• New tools and how to use them or sign up for My Account • Savings tips and tricks • Testimonials and case studies	• xcelenergy.com and blog • Email • Direct mail • My Account • Social media • Media outreach • Bill onserts • Community events and meetings	• Mailings and emails • Info sheets and brochures • Instructional videos • Case studies • Savings tips
Community leaders and elected officials	• Customer benefits • Testimonials and case studies • Successes and results	• In-person meetings and discussions with Community Relations Managers • Community events and meetings • Email	• Presentations • Info sheets and brochures • Videos • Talking points
Customer Care agents	• New tools and how to use them or sign up for My Account • Savings tips and tricks	• Web-based training • In-person training • Email • Customer Care Quick Reference program	• FAQs • Info sheets and brochures • How-to videos • Talking points
All employees	• Customer benefits • Testimonials and case studies • Successes and results	• Intranet • Email • In-person meetings or presentations	• Internal news articles • Presentations • Info sheets and brochures • Videos • Talking points

2.3.2 Long-Term Phase Success Metrics

The success of long-term communications will largely be measured by the number of customers who enroll in optional programs and services. We will measure:

- The percentage of customers with a smart meter that have one or more active applications
- The percentage of customers with a smart meter that receive high usage alerts

- The percentage of customers with a smart meter that select pre-pay billing
- The number of customers with a smart meter that have My Account
- The number of monthly, unique visits to My Account
- The percentage of customers with a smart meter that access personalized insights

3 Best Practices and Research Results

To build on the company's experience with smart meter pilots and advanced grid technology initiatives through its service territory, Xcel Energy also has examined communication and outreach best practices among other utilities with advanced grid and smart meter deployment experience. We supplemented this research with insights from additional sources, such as the Smart Energy Consumer Collaborative and GTM Research.

Many of these best practices and lessons learned are outlined below, and they have been taken into consideration in the development of this communication plan.

- Treat advanced grid/smart meter implementation as a change management program for employees. Engage with employees throughout the lives of all activities and initiatives.
- Train employees to be ambassadors in the community and leverage employees' existing relationships and involvement in their communities to help disseminate important information. Aim for transparency and a high level of engagement between the customer and customer-facing employees.
- Educate customers before their smart meter deployment by staging communications ahead of key customer contact leading up to the actual installation.
- Use social media to approach smart meter installation as a new technology rollout across specific geographic locations and targeted customer segments.
- Focus communication directly on customers. Do not assume they understand the concept of kilowatt hours, how the utility measures electricity, on- versus off-peak usage, etc. Avoid industry terms and jargon and instead use simple language and a call to action that customers can easily understand.
- Set realistic expectations on smart meter functionality.
- Build an extensive set of FAQs to address issues and concerns. Through active employee change management and education, ensure front-line employees who work directly with customers use these messages and anticipate questions so they can clear up concerns and address issues in an accurate and timely manner.
- Collect customer success stories to make smart meter/advanced grid benefits tangible and understandable.
- Ensure full integration and coordination of field operations, communication/marketing, customer care, and billing.
- Identify customer concerns quickly, elevate to the appropriate level as needed, and resolve concerns swiftly.

3.1 Market Research Results

Xcel Energy has conducted qualitative customer research through focus groups in Minnesota and throughout its service territory.[1] The results of this research have informed message development and the strategic updates to this plan.

The objectives of research were to:

- Explore customers' current understanding of smart meters.
- Understand the perceived benefits and drawbacks of smart meters.
- Explore both positive and negative expectations consumers have about Xcel Energy moving customers to smart meters.
- Explore reactions to different ways of describing smart meters.
- Understand what barriers may arise and how to address them (pre- or post-meter installation).
- Understand how customers want to be communicated with about smart meters, including what they want to know and how they want to receive the information.
- Identify any differences between younger (under age 45) and older customers (45+) on these topics.

At a high level, the key findings of this research were:

Expectations of New Meters

- Customers believe the new meters could help them save money by providing more detailed usage information, which they perceive as empowering.
- That said, they have questions about the new meter's basic functionality that need to be addressed to convince them of the true utility in these devices.
- They are also concerned about possible out of pocket costs, with many wondering whether the new meters could either cost them money upfront or over the long-run.

Communicating the Change

- Customers want to hear from Xcel Energy about the transition to the new meters at least two or three months in advance of installation.
- They want to be contacted via a multi-channel approach, which would include paper mail, mass media, email and phone.
- Younger customers (<45) are more likely to say they would seek information on an FAQ page or watch an online video about the process.
- Overall, customers want the communications to have a high degree of transparency.

[1] Eight Minnesota focus groups were held April 16–17 and May 15–16, 2019. Four Colorado focus groups, held Jan. 22–23, 2019, also informed this plan. All focus group sessions were moderated by an independent third party consultant.

Addressing Barriers

- The potential cost of the new meters is the top barrier that Xcel Energy needs to address. Another way to address barriers is by clearly conveying the reasons why the new meters will benefit customers in the long-run, and by clearly presenting why the company is advancing this technology.

3.2 Customer Messaging and Development

Xcel Energy has developed a carefully constructed message framework using best practices and its own market research. This message framework is essential for successful completion of this plan and the overall transition to smart meters.

Xcel Energy typically develops messages using the following process:

Research

Market research lays the groundwork for message development, incorporating customer message testing, customer panels, focus groups, and utility peer research.

Understanding the Audience

While we will be raising awareness among all our Minnesota customers, smart meter messages will target specific customer market segments to ensure maximum effectiveness and tap into the benefits that customers care about the most.

Language and Tone

Messages will be developed using simple, straight-forward language and practical information that customers can easily understand and act upon. Xcel Energy has worked with its advertising agency of record – Carmichael Lynch – to explore and validate the language and terminology that resonates most with customers.

3.2.1 Overarching Messaging Themes: Customer Benefits & Value Propositions

Because of the significant investment other utilities have made in the advanced grid, consumers today are seeing the benefits. The Smart Energy Consumer Collaborative (SECC) is an independent nonprofit organization consisting of commercial, utility and advocacy organizations that collects information about customers' views and understanding of smart meters and grids. According to SECC's study titled *Effective Communication with Consumers on the Smart Grid Value Proposition*, three distinct value propositions of advanced grids have emerged:

Economic benefits: With more information on energy consumption and more choices about how and when they use energy via possible future rate options, consumers may be able to save money as a result of advanced grid-enabled programs and technologies.

> Example messaging theme: Smart meters and the smart grid provide superior energy usage information, which can help consumers save money by enabling them to better manage their electricity use.

Environmental benefits: The advanced grid enables the incorporation of greater amounts of renewable generation, gives customers more opportunities to make more environmentally conscious choices, and can also reduce the need to rely on fossil fuel generation.

> Example messaging theme: The smart grid helps reduce greenhouse gas emissions by making it easier to connect renewable energy sources to the electricity grid.

Reliability benefits: Grid-side intelligence offered by advanced grid technology can reduce the frequency and duration of outages while providing better information when outages do occur.

> Example messaging theme: A smart grid senses problems and reroutes power automatically. This prevents some outages and reduces the length of those that do occur. It strengthens the resiliency of the power network that serves you.

3.2.2 Sample Customer Messaging

Based on best practices and research results, the company has drafted sample customer messaging.

Elevator speech

Technology is advancing in every area of our lives, and Xcel Energy is bringing the world of digital technology to your electric service too. The next generation of our energy grid—the advanced grid — will help us serve you better. The advanced grid will give customers more of what they expect from Xcel Energy – clean, reliable energy, new ways to save money, and a better experience for you and all of our customers.

New technologies to help you save energy and money

- You will have more access to useful information about your household energy use, which can help you make informed energy decisions that save energy and money.

- You'll also have online tools to help understand your data and make decisions that will help save energy and money.
- In the future, the advanced grid will make it possible for you to choose pricing plans and energy savings options that work best for you.

Improved reliability and faster outage restoration

- New digital energy grid technologies will help us prevent outages to you and your neighbors and, in some cases, enable us to automatically reroute power to shorten any service interruptions.
- Advanced grid technologies can detect outages at your home or on the larger electric system, helping reduce the time you are without service.
- You'll receive quicker notifications when service is out and more accurate information on when power will be restored.

More options to protect the environment and use new technologies

- The advanced grid will help us provide you with even more clean energy because it will allow us to maximize the use of renewable energy sources such as solar, wind, and batteries.
- Energy use data in near real-time will give you the ability to choose how and when you use technology such as batteries and electric vehicles.

Security you can trust

- Energy use data will be securely transferred electronically from the smart meter, eliminating the need for manual meter reading or estimates, which also helps reduce costs.
- Protecting your data is extremely important to us. We use multiple layers of defense to ensure all data is secure and protected.

3.2.3 Addressing Concerns

Our communication materials will attempt to address key issues and possible smart meter concerns, including but not limited to:

- **Radio frequency (RF) emissions**. Smart meters emit low levels of electro- magnetic radiation through their RF communications. Xcel Energy will educate customers to alleviate unfounded concerns around health impacts and interference with other wireless devices.
- **Privacy and security**. The company will assure customers that we take their data privacy seriously by providing information about our data privacy policies. We will also clearly outline steps we take to protect customers' energy use information and personally identifiable information.
- **Accuracy**. Messages will also address the measurement accuracy of smart meters, and let customers know how to contact us if they have billing questions related to their meter readings. Call center agents will be trained to answer questions and assist customers.

- **Deployment expectations**. Communications will help make it easy for customers to properly identify our company employees and know what to expect when meter installers are working at their home or business. This includes special instructions for customers with medical conditions that may have equipment in their homes.
- **Opt-out policies**. The company will address opt-out policies for smart meter technology, and let customers know the proper channels for inquiring about available alternatives.

4 Customer Segments and Communications Considerations

Customers are interested in smart meters and functionality, but broad deployment will require the company to manage expectations and address customer concerns. Success requires the company to anticipate and respond to situations that could affect customers, stakeholders, or the community during smart meter deployment.

While individual customer issues will receive attention, Xcel Energy will also track issues on a broader scale. The company will actively monitor sources where customer issues or concerns may originate, including but not limited to:

- Customer care call centers (both residential and business inquiries)
- Inquiries to company executives, regional leaders, and front-line managers
- Inquiries to field and other employee personnel
- Xcel Energy Community Relations, Account Management, and State and Government Affairs teams
- Media relations
- Minnesota Public Utilities Commissioners and staff
- Community groups and consumer advocacy groups
- Letters, phone calls, social media posts, and emails from customers

We will use existing processes and procedures for handling issues escalated through our Customer Care team.

4.1 Commercial & Industrial Customers

We expect our broad awareness communications will be applicable to small C&I customers as well, but we will also provide customized 90, 60, and 30-day meter install notifications for those customers. The content of these communications will vary depending on the customer's current tariff to ensure they receive the most relevant information. Dedicated account managers for large C&I customers who will help ensure a smooth experience before, during, and after smart meter installation.

4.2 Fixed and Low-Income Customers

Customized communications will recognize and proactively address cost concerns among low-income households, seniors, and vulnerable customer populations. We will engage community leaders, influencers, and representatives of these communities in the development and deployment of our educational efforts. Messages will address how customers on fixed or limited budgets can take advantage of personal energy use information that may allow them to better manage their energy costs. Outreach will also focus on increasing these customers' participation rates in energy efficiency and conservation programs, and cross-marketing the state's energy assistance programs. Communication and education materials that could be customized for this segment of customers may include:

- FAQs and fact sheets to address specific concerns and needs.
- Talking points and scheduled briefings with consumer advocacy groups and nonprofit groups who serve these populations.
- Customized presentations for community relations staff to share with their community leaders.
- Outreach to organizations serving seniors, low-income, and other vulnerable customer segments, with an emphasis on providing ready-to-use materials that can be distributed via their communication channels, online resources, events, meetings, and social media platforms.

4.3 Non-English-Speaking Customers

The company's service area is expansive and includes a diverse audience spread across the state. According the U.S. Census Bureau's American Community Survey (ACS), in 2017, 11.3 percent of Minnesotans spoke a language other than English at home. Behind English, the most common language spoken at home is Spanish, with close to 200,000 speakers.[2] Spanish materials will be available on xcelenergy.com.

4.4 Customers with Life-Supporting Equipment

Prior to any direct communication regarding smart meter installation, the Contact Center will proactively reach out to customers who rely on life-supporting equipment in their homes. These customers will have the option to opt out of the smart meter, make an installation appointment or get a bridge installed to avoid a service interruption.

4.5 Communications Accessibility

The company has a number of options in place to assist customers and ensure accessibility for all.

- Deaf or hearing-impaired customers can dial 711 to be connected with the state transfer relay service. This service allows callers to communicate with text-telephone (TTY) users. This service is available 24.7 and is confidential.
- The company's Contact Center can make outbound calls using TTY technology.
- Any residential customer may request a large print bill statement.
- Customer emails and our website and online tools are constantly being improved to ensure accessibility.

[2] U.S. Census Bureau, 2013-2017 American Community Survey 5-Year Estimates, https://factfinder.census.gov/bkmk/table/1.0/en/ACS/17_5YR/B16001/0400000US27.

4.6 Customer Choice and Opting Out

The company believes customers should have the choice to opt out of receiving a smart meter. All direct customer communications will clearly overview all customer options and explain the steps required to decline initial installation of a smart meter or request to have their smart meter removed. Communications will include information about any costs associated with opting out of the smart meter.

5 Budget

The forecasted costs (**Table 5**) related to the execution of this plan total approximately $6.3 million. These estimates are based on actual expenses to date for the Minnesota time of use pilot and for meter deployment in our Colorado service territory. We also gathered additional estimates from vendors to inform the forecast of specific costs. This budget includes external resources and support for this program (i.e., goods and services), but does not include internal resources (i.e., communications personnel).

Table 5. Education & communications plan forecasted budget

Tactic	Estimated cost per piece	Estimated cost for all MN customers
90-day mailer	$0.90	$1,170,000.00
60-day postcard	$0.80	$1,040,000.00
30-day letter	$1.00	$1,300,000.00
Smart meter info sheet	$0.08	$104,000.00
Door hanger success	$0.40	$520,000.00
Door hanger sorry we missed you	$0.40	$520,000.00
Email	$0.00	$3,900.00
Targeted digital advertising		$25,000.00
Paid social		$85,000.00
Mass advertising		$350,000.00
Video production		$20,000.00
Home network/tools education mailer	$0.90	$1,170,000.00
Total	**$4.48**	**$6,307,900.00**

Northern States Power Company
AGIS Rate Impact Analysis

Docket No. E002/GR-19-564
Exhibit___(MCG-1), Schedule 9
Page 1 of 1

Annual Revenue Requirement
Summary of AGIS
2019-2024
($s)

	10364000	State of Minnesota Jurisdiction					
	Rate Analysis	2019	2020	2021	2022	2023	2024
1	Average Balances:						
2	Plant Investment	6,580,245	29,009,905	76,532,529	175,653,195	300,960,249	370,657,038
3	Depreciation Reserve	343,659	1,762,406	5,573,184	12,132,579	22,633,577	39,470,175
4	CWIP	6,077,959	4,923,865	10,920,662	11,207,715	4,295,266	1,139,888
5	Accumulated Deferred Taxes	215,274	1,186,806	3,367,552	7,591,449	13,587,298	18,886,510
6	Average Rate Base = line 2 - line 3 + line 4 - line 5	12,099,271	30,984,558	78,512,455	167,136,882	269,034,640	313,440,240
7							
8	Revenues:						
9	Interchange Agreement offset = -line 40 x line 52 x line 53	-	-	-	-	-	-
10							
11	Expenses:						
12	Book Depreciation	789,251	2,284,099	6,556,439	12,248,284	17,750,252	20,715,373
13	Annual Deferred Tax	429,201	1,513,864	2,847,628	5,600,166	6,391,532	4,206,892
14	ITC Flow Thru	-	-	-	-	-	-
15	Property Taxes	-	-	-	-	-	-
16	subtotal expense = lines 12 thru 15	1,218,453	3,797,963	9,404,067	17,848,450	24,141,784	24,922,265
17							
18	Tax Preference Items:						
19	Tax Depreciation & Removal Expense	2,312,376	7,589,079	16,657,950	32,098,686	40,379,438	35,533,814
20	Tax Credits (enter as negative)	-	-	-	-	-	-
21	Avoided Tax Interest	24,950	128,118	132,406	187,323	60,166	649
22		-	-	-	-	-	-
23	AFUDC	77,380	626,878	276,556	431,934	120,184	56,678
24							
25	Returns:						
26	Debt Return = line 6 x (line 44 + line 45)	251,665	647,577	1,640,910	3,526,588	5,972,569	7,021,061
27	Equity Return = line 6 x (line 46 + line 47)	652,151	1,660,772	4,208,268	8,958,537	14,420,257	16,863,085
28							
29	Tax Calculations:						
30	Equity Return = line 27	652,151	1,660,772	4,208,268	8,958,537	14,420,257	16,863,085
31	Taxable Expenses = lines 12 thru 14	1,218,453	3,797,963	9,404,067	17,848,450	24,141,784	24,922,265
32	plus Tax Additions = line 21	24,950	128,118	132,406	187,323	60,166	649
33	less Tax Deductions = (line 19 + line 23)	(2,389,756)	(8,215,957)	(16,934,506)	(32,530,620)	(40,499,622)	(35,590,492)
34	subtotal	(494,203)	(2,629,104)	(3,189,766)	(5,536,311)	(1,877,415)	6,195,507
35	Tax gross-up factor = t / (1-t) from line 50	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351
36	Current Income Tax Requirement = line 34 x line 35	(199,337)	(1,060,452)	(1,286,596)	(2,233,078)	(757,258)	2,498,965
37	Tax Credit Revenue Requirement = line 20 x line 35 + line 20	-	-	-	-	-	-
38	Total Current Tax Revenue Requirement = line 36+ line 37	(199,337)	(1,060,452)	(1,286,596)	(2,233,078)	(757,258)	2,498,965
39							
40	Total Capital Revenue Requirements	1,845,551	4,418,982	13,690,093	27,668,564	43,657,168	51,248,699
41	= line 16 + line 26 + line 27 + line 38 - line 23 + line 9						
42	O&M Expense	1,077,012	5,996,154	16,923,400	14,264,833	13,185,267	12,340,661
43	Total Revenue Requirements	2,922,563	10,415,136	30,613,493	41,933,397	56,842,434	63,589,359

	Capital Structure	Weighted Cost	Weighted Cost	Weighted Cost	Weighted Cost	Weighted Cost	Weighted Cost
44	**Long Term Debt**	**2.0400%**	**2.0600%**	**2.0500%**	**2.0800%**	**2.2000%**	**2.2200%**
45	**Short Term Debt**	**0.0400%**	**0.0300%**	**0.0400%**	**0.0300%**	**0.0200%**	**0.0200%**
46	**Preferred Stock**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**
47	**Common Equity**	**5.3900%**	**5.3600%**	**5.3600%**	**5.3600%**	**5.3600%**	**5.3800%**
48	**Required Rate of Return**	**7.4700%**	**7.4500%**	**7.4500%**	**7.4700%**	**7.5800%**	**7.6200%**
49	**PT Rate**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**
50	**Tax Rate (MN)**	**28.7420%**	**28.7420%**	**28.7420%**	**28.7420%**	**28.7420%**	**28.7420%**
51	**NA**	**86.6960%**	**86.6960%**	**86.6960%**	**86.6960%**	**86.6960%**	**86.6960%**
52	**MN JUR Direct**	**100.0000%**	**100.0000%**	**100.0000%**	**100.0000%**	**100.0000%**	**100.0000%**
53	**IA Demand**	**100.0000%**	**100.0000%**	**100.0000%**	**100.0000%**	**100.0000%**	**100.0000%**

Northern States Power Company
Reference Case Rate Impact Analysis

Docket No. E002/GR-19-564
Exhibit___(MCG-1), Schedule 10
Page 1 of 1

Annual Revenue Requirement
Summary of AMR
2019-2024
($s)

	10364000			State of Minnesota Jurisdiction			
	Rate Analysis	2019	2020	2021	2022	2023	2024
1	Average Balances:						
2	Plant Investment	-	-	16,069,221	63,779,109	126,994,134	172,463,867
3	Depreciation Reserve	-	-	(273,703)	358,641	4,319,457	8,264,698
4	CWIP	434,960	2,162,643	1,727,683	-	-	-
5	Accumulated Deferred Taxes	-	-	250,835	1,135,177	2,495,094	3,662,003
6	Average Rate Base = line 2 - line 3 + line 4 - line 5	434,960	2,162,643	17,819,771	62,285,292	120,179,582	160,537,166
7							
8	Revenues:						
9	Interchange Agreement offset = -line 40 x line 52 x line 53	-	-	-	-	-	-
10							
11	Expenses:						
12	Book Depreciation	-	-	964,592	3,828,093	7,621,538	10,348,936
13	Annual Deferred Tax	-	-	501,671	1,267,010	1,452,827	880,989
14	ITC Flow Thru	-	-	-	-	-	-
15	Property Taxes	-	-	-	-	-	-
16	subtotal expense = lines 12 thru 15	-	-	1,466,263	5,095,104	9,074,365	11,229,924
17							
18	Tax Preference Items:						
19	Tax Depreciation & Removal Expense	-	-	2,747,099	8,329,070	12,780,553	13,473,681
20	Tax Credits (enter as negative)	-	-	-	-	-	-
21	Avoided Tax Interest	17,140	83,696	-	-	-	-
22							
23	AFUDC	26,243	145,389	-	-	-	-
24							
25	Returns:						
26	Debt Return = line 6 x (line 44 + line 45)	9,047	45,199	372,433	1,314,220	2,667,987	3,596,033
27	Equity Return = line 6 x (line 46 + line 47)	23,444	115,918	955,140	3,338,492	6,441,626	8,636,900
28							
29	Tax Calculations:						
30	Equity Return = line 27	23,444	115,918	955,140	3,338,492	6,441,626	8,636,900
31	Taxable Expenses = lines 12 thru 14	-	-	1,466,263	5,095,104	9,074,365	11,229,924
32	plus Tax Additions = line 21	17,140	83,696	-	-	-	-
33	less Tax Deductions = (line 19 + line 23)	(26,243)	(145,389)	(2,747,099)	(8,329,070)	(12,780,553)	(13,473,681)
34	subtotal	14,341	54,225	(325,697)	104,525	2,735,438	6,393,144
35	Tax gross-up factor = t / (1-t) from line 50	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351
36	Current Income Tax Requirement = line 34 x line 35	5,784	21,872	(131,370)	42,160	1,103,342	2,578,682
37	Tax Credit Revenue Requirement = line 20 x line 35 + line 20	-	-	-	-	-	-
38	Total Current Tax Revenue Requirement = line 36+ line 37	5,784	21,872	(131,370)	42,160	1,103,342	2,578,682
39							
40	Total Capital Revenue Requirements	12,033	37,600	2,662,466	9,789,975	19,287,319	26,041,539
41	= line 16 + line 26 + line 27 + line 38 - line 23 + line 9						
42	O&M Expense	1,868	73,380	903,542	2,005,631	2,987,832	2,807,656
43	Total Revenue Requirements	13,901	110,980	3,566,008	11,795,606	22,275,151	28,849,194
	Capital Structure	**Weighted Cost**	**Weighted Cost**	**Weighted Cost**	**Weighted Cost**	**Weighted Cost**	**Weighted Cost**
44	**Long Term Debt**	**2.0400%**	**2.0600%**	**2.0500%**	**2.0800%**	**2.2000%**	**2.2200%**
45	**Short Term Debt**	**0.0400%**	**0.0300%**	**0.0400%**	**0.0300%**	**0.0200%**	**0.0200%**
46	**Preferred Stock**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**
47	**Common Equity**	**5.3900%**	**5.3600%**	**5.3600%**	**5.3600%**	**5.3600%**	**5.3800%**
48	**Required Rate of Return**	**7.4700%**	**7.4500%**	**7.4500%**	**7.4700%**	**7.5800%**	**7.6200%**
49	**PT Rate**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**
50	**Tax Rate (MN)**	**28.7420%**	**28.7420%**	**28.7420%**	**28.7420%**	**28.7420%**	**28.7420%**
51	**NA**	**86.6960%**	**86.6960%**	**86.6960%**	**86.6960%**	**86.6960%**	**86.6960%**
52	**MN JUR Direct**	**100.0000%**	**100.0000%**	**100.0000%**	**100.0000%**	**100.0000%**	**100.0000%**
53	**IA Demand**	**100.0000%**	**100.0000%**	**100.0000%**	**100.0000%**	**100.0000%**	**100.0000%**

AGIS Progress Metrics Summary

Proposed Reporting Annually May 1

First AGIS Report May 1, 2022

	Description	AGIS Report (Service Quality potential impacts and reporting noted)
Customer Outreach and Education	Survey results of customers on the adequacy and clarity of communications prior to installation of advanced meters.	AGIS
Installation and Deployment	Number of advanced meters installed.	AGIS
	Percentage of FAN deployed.	AGIS
	Number of feeders with FLISR enabled.	AGIS
	Number of feeders with IVVO enabled.	AGIS
	Number of customers electing to opt-out of AMI installation.	AGIS
	Number of calls to Customer Contact Center and meter installation vendor regarding meter installation.	AGIS / SQ
	Number of complaints regarding AMI installation.	AGIS / SQ
Post-Deployment	Avoided Customer Minutes Out due to FLISR installation.	AGIS / SQ
	Energy Reduction (MWh) due to IVVO that result in cost savings and CO_2 emissions reduction.	AGIS
	Percentage of customers with advanced meters that receive estimated bills.	AGIS / SQ
	Percentage of customers with an advanced meter that have made a complaint of inaccurate meter readings.	AGIS / SQ
	Survey of customer satisfaction with outage related communications.	AGIS
	Number of customers with an advanced meter with an active web portal account.	AGIS
	Number of monthly, unique visits to the web portal (My Account).	AGIS

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Direct Testimony and Schedules
Kelly A. Bloch

Before the Minnesota Public Utilities Commission
State of Minnesota

In the Matter of the Application of Northern States Power Company
for Authority to Increase Rates for Electric Service in Minnesota

Docket No. E002/GR-19-564
Exhibit___(KAB-1)

Distribution

November 1, 2019

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Schedules

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Kelly A. Bloch. I am the Regional Vice President, Distribution Operations for Xcel Energy Services Inc. (XES), the service company affiliate of Northern States Power Company, a Minnesota corporation (NSPM) and an operating company of Xcel Energy Inc. (Xcel Energy).

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I have over 28 years of experience in the utility industry. I joined Public Service Company of Colorado, another operating company of Xcel Energy, in 1991 and have served in various engineering roles since that time. In my current role, I am responsible for the electric and natural gas distribution design and construction activities for the Company's service areas in the states of Minnesota, North Dakota, South Dakota, Michigan, and Wisconsin. My resume is attached as Exhibit___(KAB-1), Schedule 1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I present and support the Company's capital and operations and maintenance (O&M) budgets for the Distribution business area, for purposes of determining electric revenue requirements and final rates in this proceeding. I also support the Company's Advanced Grid Intelligence and Security (AGIS) Initiative, which is a portfolio of grid modernization investments to improve reliability, shorten the duration of power outages, integrate renewables, and empower customers with more information to control and track their energy use. I further discuss the assumptions used in the Company's Minimum System Study and Zero Intercept Analysis, provide information regarding the cost savings achieved from the LED street light conversion project, and discuss methods to measure losses on the distribution system.

Q. PLEASE PROVIDE A SUMMARY OF YOUR TESTIMONY.

A. The Distribution organization is responsible for operating, maintaining, and constructing the distribution system that is the critical final link in delivering electricity to our customers to power their homes and businesses.

Traditionally, much of Distribution's investments and efforts have been focused on maintaining the reliability, resiliency, and health of our existing distribution facilities. We regularly evaluate the health of the key components of our distribution system and make the necessary investments to ensure these facilities are safe and reliable. This includes replacing aging poles, wires, underground cables, and substation transformers. Throughout the term of this multi-year rate plan, we are continuing and increasing our investments in these established asset health and reliability programs.

At the same time, we are placing greater focus on the portion of our system that is closest to our customers, including tap lines and the secondary system. To better address the needs of this portion of our system we will launch the Incremental System Investment (ISI) Initiative in 2021. The ISI Initiative will expand some of our existing programs, such as our cable replacement program, as well as adding new programs, such as a targeted undergrounding program. This initiative would provide several benefits to customers including making our system more resilient and reliable, reducing O&M, and enabling increased adoption of distributed energy resources (DER). It will also improve safety for both our workers and our customers.

While our traditional areas of investment are important to maintaining the reliability and condition of the basic elements of our system, the electric industry is also undergoing a fundamental change. As aging distribution infrastructure approaches the end of its useful life, emerging technologies promise enhanced functionalities and operational efficiencies. Technological and manufacturing advances have also driven down the costs of solar panels and electric vehicles placing them within the reach of the average customer. The pervasive nature of electronics in our society and the unlimited access to data that they provide has further elicited changes in customer expectations.

Our current investment in our distribution facilities has not kept pace with these technological advances or our customers' demands. Our current distribution system was designed to facilitate a basic one-way flow of both electricity and information, with limited monitoring points beyond the substation. As a result, we have limited insight into our customers' energy experience. This limits our ability to timely respond to outages as in many outage situations we rely on customers calling to let us know their power is out. We are also unable to provide timely energy use information to customers or to detect voltage issues absent a customer complaint. The majority of our current distribution system lacks intelligent and automated devices that would facilitate a quicker response to outages on the system. Our electric system is also not equipped to accommodate the amount of distributed generation and electric vehicle charging that is anticipated in the coming years.

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We have begun to address these limitations and transition to an advanced grid by taking a strategic building block approach. We have focused first on foundational elements that are needed to support fundamental applications. For example, we are in the process of implementing an Advanced Distribution Management System (ADMS). The ADMS is foundational to advanced grid capabilities that will provide visibility and control necessary for enhanced distribution planning and DER integration. We are also in the process of implementing a residential Time of Use (TOU) pilot (TOU pilot), as well as installing Advanced Metering Infrastructure (AMI) meters and two-way communication via a Field Area Network (FAN) in a limited area of the Twin Cities metro.

Now is the time to take the next major step towards an advanced grid. During the term of the multi-year rate plan, we propose to implement further elements of the Company's AGIS initiative including a full AMI and FAN implementation across our service territory, a targeted installation of Integrated Volt VAr Optimization (IVVO) for voltage monitoring and control, and Fault Location, Isolation, and Service Restoration (FLISR), for improved reliability.

It is an opportune time to make these investments as our current Automated Meter Reading (AMR) meters that have served our customers since the 1990s are at the end of their service contract and will no longer be supported by the vendor past the mid-2020s. In addition, AMI technology has advanced to the point where the technology has been well-tested by other utilities, and its two-way communication and command capabilities will provide multiple benefits for our customers and our operation of the grid.

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With this background, my Direct Testimony starts by describing the workings of the Distribution organization and the services that we provide to our customers. I will identify the key categories of capital investments undertaken by Distribution and describe how the Distribution business area prepares and manages its capital budget. I explain that we are proposing capital additions of approximately $235.3 million for 2020, $350.0 million for 2021, and $463.1 million for 2022 on a State of Minnesota Electric Jurisdiction basis. These capital additions are spread across investments in our traditional budget groupings of Asset Health and Reliability, New Business, Capacity, Mandates, and Tools and Equipment. I provide information about the key capital projects in each of these categories over the term of the multi-year rate plan.

I also discuss the Distribution O&M budgets for 2020 to 2022, which are driven by internal and contract labor costs, fleet, and materials. I also explain why our O&M budgets are reasonable and reflects expenditures that are needed to ensure that our distribution system is safe and reliable.

Next, I discuss Distribution's key role in implementing the AGIS initiative that includes installing the new AMI meters, FAN devices, FLISR devices, and IVVO devices that are necessary to achieving the goals of a more advanced, intelligent, and automated distribution grid. My testimony on AGIS complements that of Company witness Mr. Michael C. Gersack who provides the policy goals of AGIS and that of Mr. David C. Harkness who describes that integration of the AGIS components into the Company's existing systems.

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In addition, I address the Company's Electric Vehicle (EV) programs, and discuss the EV capital and O&M expenses included under the Distribution budget for 2020 to 2022. Further, I provide information regarding the cost and cost savings related to the Light Emitting Diode (LED) street light conversion project. I then provide information supporting the assumptions used in the Company's Minimum System Study and Zero Intercept Analysis. Finally, I discuss methods to determine electric losses on the distribution system.

Q. HOW HAVE YOU ORGANIZED YOUR TESTIMONY?

A. My testimony is organized into the following sections:

- *Section I* – Introduction
- *Section II* – Distribution Overview
- *Section III* – Capital Investments
- *Section IV* – O&M Budget
- *Section V* – AGIS Initiative
- *Section VI* – Electric Vehicle Programs
- *Section VII* – LED Street Lights
- *Section VIII* – Minimum System Study and Zero Intercept Analysis
- *Section IX* – Distribution System Losses
- *Section X* – Conclusion

Only the testimony necessary to support the Company's Advanced Grid Intelligence and Security (AGIS) Initiative have been included in the Integrated Distribution Plan (IDP) filing. Accordingly, we have excised non-AGIS pages from this attachment.

V. AGIS INITIATIVE

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. This section of my testimony is focused on describing the work that the Distribution organization will be completing as part of the Company's AGIS initiative. The AGIS initiative is a multi-year project that will transform our distribution system into an intelligent and highly automated system. Our vision for this future distribution system is one that incorporates and leverages technology throughout our system to gather and utilize data to better meet our customers' electric needs and enable increased levels of DER.

Q. HOW IS THIS SECTION OF YOUR TESTIMONY ORGANIZED?

A. First, I will provide an overview of the AGIS initiative and the different components of this initiative. I will also describe the current limitations of the distribution system and how these limitations are, in part, driving the need for the AGIS initiative. Specifically, there is a need to bring our electric distribution system in line with current technologies to improve management and operation of the distribution system, support increasing DER, and to keep pace with our peers in terms of reliability performance.

Next, I will discuss in detail the four AGIS components that the Company is seeking recovery for in this rate case: (1) AMI; (2) FAN; (3) FLISR; and (4) IVVO and describe the work that the Distribution organization is undertaking to install these components. I also provide detailed support for recovery of both the capital and O&M costs associated with this work during the term of the multi-year rate plan. As discussed by Mr. Gersack, the Company is requesting approval to recover the costs of the capital investments and O&M

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expense for the components of AGIS that we propose to implement during the term of the multi-year rate plan, and is also requesting that the Commission certify these projects so the Company may request recovery of costs for 2023 and later in subsequent rider filings (subject to all other requirements of rider recovery). Accordingly, while I focus this discussion somewhat on the term of the multi-year rate plan, I also provide support for the Distribution portions of the broader AGIS initiative, consistent with the Company's Integrated Distribution Plan (IDP) being filed concurrently with this rate case.

Finally, I provide support for the cost estimates and benefit calculations utilized in cost-benefit analysis (CBA) model presented in the Direct Testimony of Company witness Dr. Ravikrishna Duggirala. My testimony is organized by the following topic areas. I note that a detailed discussion of FAN is provided by Mr. Harkness.

- Overview of AGIS
- Limitations of Current Distribution System
- Grid Modernization Efforts to Date
    - ADMS
    - TOU pilot
- AMI
    - Overview of AMI
    - Interrelation of AMI with other AGIS components
    - AMI Implementation
    - Benefits of AMI

    - Distribution's Costs of AMI
    - Alternatives to AMI
    - Interoperability
    - Minimization of Risk of Obsolesce
- <u>FAN</u>
    - Overview of FAN
    - FAN Implementation
    - Distribution's Costs of FAN
- <u>FLISR</u>
    - Overview of FLISR
    - Prior Certification Request for FLISR
    - FLISR Implementation
    - Benefits of FLISR
    - Costs of FLISR
    - Alternatives to FLISR
    - Interoperability
    - Minimization of Risk of Obsolescence
- <u>IVVO</u>
    - Overview of IVVO
    - Interrelation of IVVO with other AGIS Components
    - IVVO Implementation
    - Benefits of IVVO
    - Costs of IVVO
    - Alternatives to IVVO
    - Interoperability

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- Minimization of Risk of Obsolescence
- <u>AGIS Distribution Overall Costs and Implementation</u>

Q. WHAT OTHER COMPANY WITNESSES ARE DISCUSSING THE AGIS INITIATIVE?

A. Mr. Gersack provides an overview of and policy support for the Company's AGIS initiative and certain Program Management costs. Specific information on the IT integration and cyber security support for AGIS is provided by Mr. Harkness. Company witness Mr. Christopher C. Cardenas provides information on how AGIS impacts Customer Care, including the Company's existing meter contract and how AGIS will impact meter reading, customer billing, and the Company's plan for customers selecting to opt-out of AMI meters. The cost-benefit analysis (CBA) model prepared by the Company is discussed by Dr. Duggirala.

A. Overview of AGIS

Q. WHAT IS THE AGIS INITIATIVE?

A. The AGIS initiative is a comprehensive plan to advance Xcel Energy's distribution system. This modernization will start with implementing foundational advanced grid initiatives that provide immediate benefits for customers while also enabling future systems and capabilities. AGIS will help to bring about an intelligent, automated, and interactive electric distribution system that will allow operators more visibility into the system, customers greater access to timely energy information, and enable future products and services for our customers.

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Q. WHAT ARE THE FOUNDATIONAL COMPONENTS OF AGIS?

A. The foundational components of AGIS are the Advanced Distribution Management System (ADMS), including the Geospatial Information System (GIS); Advanced Metering Infrastructure (AMI); the Field Area Network (FAN); Fault Location Isolation and Service Restoration (FLISR); and Integrated Volt-VAr Optimization (IVVO).

Q. PLEASE BRIEFLY DESCRIBE EACH OF THESE FOUNDATIONAL COMPONENTS.

A. A brief description of these foundational components is as follows:

- *Advanced Distribution Management System (ADMS)* provides the foundational system for operational hardware and software applications. It acts as a centralized decision support system that assists control room personnel, field operating personnel, and engineers with the monitoring, control and optimization of the electric distribution grid. The ADMS project includes investment to significantly improve the Company's existing Geospatial Information System (GIS), which is a foundational data repository, with data necessary to support the ADMS. ADMS uses this information to maintain the as-operated electrical model and advanced applications.
- *Advanced Meter Infrastructure (AMI)* is an integrated system of advanced meters, communication networks, and data processing and management systems that enables secure two-way communication between Xcel Energy's business and operational data systems and customer meters. AMI provides a central source of information that is shared through the communications network with many components of an intelligent grid design.

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- *Field Area Network (FAN)* is the communications network that will enable communications between the existing communications infrastructure at the Company's substations, ADMS, AMI, and the new intelligent field devices associated with advanced grid applications.
- *Fault Location Isolation and Service Restoration (FLISR)* involves software and automated switching devices as an additional component of the ADMS, that reduce the frequency and duration of customer outages. These automated switching devices detect feeder mainline faults, isolate the fault by opening section switches, and restore power to unfaulted sections by closing tie switches to adjacent feeders as necessary.
- *Integrated Volt-VAr Optimization (IVVO)* is an additional application within ADMS, which automates and optimizes the operation of the distribution voltage regulating and VAr control devices to reduce electrical losses, electrical demand, energy consumption, and provides increased distribution system capacity to host DER.

Q. HAS THE COMPANY SOUGHT AND RECEIVED COMMISSION APPROVAL FOR ANY OF ITS GRID MODERNIZATION INVESTMENTS?

A. Yes, two advanced grid investments have been certified in the Company's biennial grid modernization reports. In the 2015 Biennial Grid Modernization Report, the Company sought certification of its proposed ADMS investments, which was subsequently certified by the Commission on June 28, 2016 for cost recovery under the TCR Rider.[6] The implementation of ADMS is currently on track to be completed in April 2020. The Company is not seeking cost recovery for ADMS in this case as these costs will remain in the

[6] *In the Matter of the Xcel Energy's 2015 Biennial Distribution Grid Modernization Report*, Docket No. E002/M-15-962, ORDER CERTIFYING ADVANCED DISTRIBUTION MANAGEMENT SYSTEM (ADMS) PROJECT UNDER MINN. STAT. 216B.2425 AND REQUIRING DISTRIBUTION STUDY (June 28, 2016).

TCR Rider. I discuss ADMS here as it is a foundational component of the AGIS initiative and this background is helpful to understanding how other AGIS components operate in conjunction with ADMS.

In addition, the Company sought and obtained Commission certification for a proposed TOU pilot on August 7, 2018.[7] The TOU pilot requires the installation of AMI meters and associated FAN components to provide customers with pricing specific to the time of day energy is used. The Company proposes TOU Pilot costs incurred during the MYRP be included in base rates. I discuss Distribution's support for these costs below.

Q. WHAT ACTIVITIES WILL THE DISTRIBUTION BUSINESS UNIT PERFORM TO IMPLEMENT AGIS?

A. There are three primary functions that Distribution will perform to implement the AGIS initiative:

- *Installation*: At a high level, Distribution will be responsible for installing and configuring the field devices such as the AMI meters, reclosers, capacitors, sensors, and communications equipment to implement AMI, FAN, FLISR, and IVVO.
- *Operation*: Distribution will also operate the ADMS and its applications such as FLISR and IVVO. Specifically, Distribution operates the associated equipment for these applications, such as switches, reclosers, and capacitors. The Distribution Control Center will be the primary users, with the newly created Grid Management team ensuring its accuracy, availability, and effectiveness. Our Grid Management team

[7] *In the Matter of Xcel Energy's Residential Time of Use Rate Design Pilot Program*, Docket No. E002/M-17-775, ORDER APPROVING PILOT PROGRAM, SETTING REPORTING REQUIREMENTS, AND DENYING CERTIFICATION REQUEST (Aug. 7, 2018).

will monitor system performance and data integrity to ensure the improvements made to GIS data continue to provide accurate ADMS solutions.

- *Maintenance*: The Distribution Business unit will provide maintenance for the field-based equipment. When possible, maintenance activities such as firmware upgrades will be performed remotely. We note that several types of equipment reside on poles in the "power zone," and require the specialized skills of qualified line workers to access.

Q. WHICH COMPONENTS OF AGIS WILL YOU DISCUSS IN YOUR TESTIMONY?

A. The capital and O&M investments for AGIS are divided between Distribution and Business Systems. I provide primary support for the costs and implementation related to the AMI meters, procurement and installation of pole-mounted FAN devices, and the procurement and installation of the intelligent field devices required for FLISR and IVVO.

As explained by Mr. Harkness, Business Systems has primary responsibility for the IT infrastructure and IT services that will integrate the various components of the AGIS to allow these new application and field devices to communicate with and deliver data to the Company's existing applications. Mr. Harkness will also discuss the cyber security measures that the Company will implement to protect the advanced distribution network as well as the underlying data that it gathers. Table 29 below summarizes which witness support the specific components of the AGIS initiative.

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Table 29

AGIS Program Witness Support

AGIS Program	Component	Witness
AMI	IT Integration and head end application	Harkness Direct, Section V(E)(3)
	Meters and deployment	Bloch Direct, Section V(D)
FAN	IT Integration and deployment	Harkness Direct, Section V(E)(4)
	Installation of pole-mounted devices	Bloch Direct, Section V(E)
FLISR	System development	Harkness Direct, Section V(E)(5)
	Advanced application and field devices	Bloch Direct, Section V(F)
IVVO	System development	Harkness Direct, Section V(E)(6)
	Advanced application and field devices	Bloch Direct, Section V(G)

Q. CAN YOU PROVIDE AN OVERVIEW OF THE DEPLOYMENT TIMELINE FOR THE AGIS COMPONENTS?

A. Table 30 below provides an overview of the deployment timeline of the various AGIS components. I provide more detailed timelines below as part of my discussion of each individual AGIS component.

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Table 30

AGIS Foundational Program	Anticipated Deployment Timeline
AMI	AMI Meter install for TOU pilot: 2019-2020 AMI Meter install for Mass Deployment: 2021-2024
FAN	FAN installation for TOU pilot: 2019-2020 FAN installation for AMI mass deployment: 2020-2023
FLISR	Limited testing in 2020; FLISR device install: 2020-2028
IVVO	Limited testing in 2021; IVVO device install: 2021-2024

Q. HOW ARE AGIS COSTS PRESENTED IN YOUR TESTIMONY?

A. The AGIS costs presented in my testimony are provided at either the NSPM Total Company electric level or the Minnesota electric jurisdiction level. This differs from cost presentation in the non-AGIS sections of my testimony, where all Distribution costs are presented at the Minnesota electric jurisdiction level. The reason for this difference within my testimony is that we wanted to present AGIS costs consistently across the various pieces of AGIS testimony. The heading for each cost table states how costs are being presented.

Q. WHAT TYPES OF CAPITAL COSTS IS DISTRIBUTION INCURRING TO IMPLEMENT THE AGIS INITIATIVE?

A. The capital costs for Distribution to implement each of the AGIS programs (AMI, FAN, FLISR, and IVVO) generally include material and equipment, labor, and vendor services.

Q. WHAT ARE THE DISTRIBUTION CAPITAL COSTS FOR THE AGIS INITIATIVE THAT YOU ARE SUPPORTING IN THIS CASE?

A. Distribution's AGIS capital additions I am supporting in this rate case are shown in the following table.

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Table 31

AGIS Capital Additions – Distribution State of MN Electric Jurisdiction (Includes AFUDC) (Dollars in Millions)			
AGIS Program	**2020**	**2021**	**2022**
AMI	$1.8	$22.2	$110.9
FAN	$2.8	$5.4	$0.0
FLISR	$3.1	$8.0	$5.8
IVVO	$0.0	$4.1	$6.7
Total	**$7.7**	**$39.7**	**$123.4**
There may be differences between the sum of the individual AGIS program amounts and Total amounts due to rounding.			

These AGIS capital additions are also set forth in Exhibit___(KAB-1), Schedule 2 to my Direct Testimony. I provide additional details and support for Distribution's capital costs below, organized by AGIS component.

For the years beyond 2020-2022, I discuss at a higher level the anticipated work to be done and the reasonableness of underlying assumptions for Integrated Distribution Plan (IDP) and CBA model purposes. Exhibit___(KAB-1), Schedules 4, 5, and 6 to my Direct Testimony also includes currently anticipated expenditures used in our CBA beyond 2022.

Q. WHAT TYPES OF O&M COSTS WILL DISTRIBUTION INCUR TO IMPLEMENT THE AGIS INITIATIVE?

A. Distribution's AGIS related O&M costs include labor, contractor, vendor services, and materials.

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Q. WHAT ARE DISTRIBUTION'S O&M COSTS FOR AGIS IMPLEMENTATION THAT ARE INCLUDED IN THE COST OF SERVICE IN THIS CASE?

A. The forecasted AGIS O&M expenses for Distribution are shown in the table below. I provide additional details and support for the Distribution O&M costs below, organized by AGIS component.

Table 32

AGIS O&M – Distribution NSPM – Total Company Electric (Dollars in Millions)			
AGIS Program	**2020**	**2021**	**2022**
AMI	$2.3	$3.3	$5.0
FAN	$0.1	$0.2	$0.4
FLISR	$0.1	$0.3	$0.2
IVVO	$0.0	$0.4	$0.8
Total	**$2.6**	**$4.2**	**$6.5**
There may be differences between the sum of the individual AGIS program amounts and Total amounts due to rounding.			

Exhibit___(KAB-1), Schedules 4, 5, and 6 to my Direct Testimony also includes currently anticipated expenditures used in our CBA beyond 2022.

Q. TO WHAT EXTENT ARE THE DISTRIBUTION CAPITAL COSTS PRESENTED ABOVE CONSISTENT WITH THE INFORMATION PROVIDED IN THE COMPANY'S TRANSMISSION COST RECOVERY RIDER (TCR) FILINGS AND ITS 2018 IDP FILING?

A. The TCR filings presented information on only ADMS, as that is the only certified project for which the Company has sought cost recovery to date. Project costs for the TOU pilot in the Company's 2017 Grid Modernization

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report and the foundational AGIS projects in the Company's 2018 IDP filing were presented at a higher level because the Company was not yet proposing cost recovery of those initiatives at that time. Further, these filings were based on information available at that time, whereas the current rate case and 2019 IDP filings present more up-to-date information. Lastly, as I describe later, the Company's plan for FLISR has been updated since these prior filings. As a result, this rate case presents the most current information on costs as our planning and data have evolved.

Q. WHAT IS THE DIFFERENCE BETWEEN THE COST ESTIMATES IN THE MYRP AND THE LONGER TERM COST ESTIMATES?

A. While these cost assumptions in the longer term estimates are reasonable and well-supported based on the information available today, they are not intended to reflect specific budgets as in a standard rate case budget. Rather, they are subject to refinement like all costs that will be incurred several years into the future. This is consistent with Mr. Robinson's discussion of all Company projections that represent work to be completed in the longer-term. However, I believe these cost estimates are reasonable, and I explain the support for them as part of my discussion of each AGIS component.

Q. WHAT SORT OF GOVERNANCE IS IN PLACE TO MANAGE THE COSTS AND IMPLEMENTATION OF THE AGIS PROJECTS?

A. Distribution employs standard processes and procedures for selecting technologies to be deployed in the Company's environment as well as the execution of large capital projects. These include long established processes in the area of competitive vendor sourcing and pricing negotiations. In addition, the AGIS program has a dedicated Project Management Office to govern all areas within the program. Mr. Gersack discusses overall AGIS governance in his testimony.

B. Limitations of the Current Distribution System

Q. HOW WAS XCEL ENERGY'S DISTRIBUTION SYSTEM ORIGINALLY DESIGNED, AND HOW DOES THIS DESIGN LIMIT THE CAPABILITIES AND OPERATION OF THE SYSTEM?

A. Xcel Energy's distribution system was originally designed to accommodate primarily a one-way flow of electricity and information from the utility to the customer with limited monitoring points. This design limits the amount of information and visibility that the Company has regarding the workings of the system and the customer experience beyond the distribution substation level. The system was also designed to rely heavily on manual and local control schemes to operate and lacks connectivity to easily share information between different portions and components of the system. These different system limitations can be categorized as:

- Limited Visibility;
- Manual Control; and
- Limited Connectivity.

1. Limited Visibility

Q HOW DOES THE LACK OF VISIBILITY BEYOND THE SUBSTATION IMPACT OPERATION OF THE SYSTEM AND THE CUSTOMER EXPERIENCE?

A. Since the existing distribution system only measures limited data on a small number of points on the distribution system (primarily at substations), the Company has little insight into the flow of power, voltages, and the operation of equipment on the system beyond the substation. Thus, the Company has little insight into the customer experience – the voltage that the customer is receiving, whether the power is out or has been restored, or any abnormality that might be detectable. To obtain information regarding the numerous distribution system components beyond the substation, such as meter readings, current flow, or voltage levels, the Company has to send workers out into the field to gather this information.

Q. HOW DOES THIS LACK OF VISIBILITY BEYOND THE SUBSTATION LEVEL IMPACT THE COMPANY'S ABILITY TO IDENTIFY OUTAGES?

A. Since we do not have visibility into the system beyond the substation level, we rely on customers notifying us via phone or website/app of outages. Our Outage Management System (OMS) then aggregates the outage call information and determines which portion(s) of the distribution system lost power. Once we know the portion of the system that is out, we must patrol the lines to find the source of the problem. This increases the time and expenses associated with responding to outages, and leaves our customers without power for longer periods of time.

Q. HOW DOES THIS LACK OF VISIBILITY IMPACT THE COMPANY'S ABILITY TO MONITOR AND CONTROL VOLTAGE LEVELS ON THE SYSTEM?

A. Because the Company does not have visibility into the system beyond the substation level, the Company does not have insight into voltage issues on the system or the ability to efficiently manage the voltage level on the system. Similar to outage information, we rely on customers to report either high or low voltage issues. To maintain required voltage levels, the Company keeps the voltage level at the substation that is at a high end of the appropriate voltage level at all times. This helps ensure that under any conditions the last

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customer on the system will have voltage within the acceptable range. However, operating the system at higher voltage levels is more costly as it uses more energy and because many end use devices do not operate efficiently at higher voltage levels.

Q. HOW DOES THE LACK OF VISIBILITY IMPACT THE DISTRIBUTION SYSTEM'S ABILITY TO ACCOMMODATE DISTRIBUTED GENERATION?

A. We do not have the ability to accurately measure the amount of distributed generation that is flowing onto or leaving the system. Rather, we rely on conservative estimates to quantify the amount of distributed generation entering and leaving the grid. Because we must ensure adequate voltage and protection at all times, such conservative estimates, coupled with the inability to modify voltages or system configuration, can limit the accommodation of DER. This is because the output of distributed generation sources is highly variable and can lead to operational complexities such as protection or voltage regulation concerns. For example, when there are high levels of distributed generation on a feeder, protective equipment such as reclosers or substation breakers may not operate as intended because they are unable to differentiate between loads, distributed generation, and a system fault. Should this occur, there is a risk that a faulted portion of the system would remain energized and present a hazard. While Minnesota currently has low levels of distributed generation relative to some other states, it will be important for the distribution system to have the capability to accommodate increasing levels in the future.

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Q. HOW DOES THE LACK OF VISIBILITY AND INFORMATION IMPACT THE CUSTOMER EXPERIENCE?

A. The current AMR system is largely limited to providing the Company with customer usage information necessary to support customer billing. As a result, we cannot provide customers with timely power usage information to enable them to manage their electric usage more efficiently. Additionally, while the system does measure voltage to quantify energy use, it is unable to provide that data through the communication network, and thus cannot alert the Company of either high or low voltage issues.

2. Manual Control

Q. HOW DOES THE LIMITED NUMBER OF REMOTELY CONTROLLED DEVICES BEYOND THE SUBSTATION IMPACT OPERATION OF THE SYSTEM?

A. The current distribution system's operation relies on mostly manual and local control schemes that require human intervention to complete an operation. For example, field switches are manually operated switches for nearly all feeders. If there is a fault on any feeder segment, the circuit breaker will open at the substation. When this occurs, a field crew has to patrol the feeder to find the location of the fault. This process can be time consuming, especially if visibility is poor or if sections of the line are not adjacent to roads. After the crew locates the fault, they manually open immediate upstream and downstream connecting switches to isolate the faulty feeder section. Then, after the faulted section of the feeder is repaired, the switches are manually closed to restore service to the feeder. Automating this process will reduce customer outage durations, enable quicker responses to faults, and reduce crew field time.

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3. *Limited Connectivity*

Q. HOW DOES THE COMPANY CURRENTLY COMMUNICATE WITH SUBSTATIONS, FIELD DEVICES, AND METERS?

A. For many years, the Company has communicated with its substation through leased telephone circuits with widely varying capabilities, especially in rural areas, or through expensive microwave installations. Connecting field devices (switches, etc.) with communications networks has been limited due to the expense and complexity of managing these circuits. Although, we have been able to successfully operate the system for many years under these conditions, advancements in technology can now support communications between the intelligent devices deployed across the distribution system – up to and including meters at customers' homes and businesses. These advanced applications cannot be supported with the Company's current communication network. These improvements will allow the Company access to information to better manage the system and respond to outages, and to provide our customers with access to near real-time data on their energy usage. Further, the rise of small-scale DER located on the grid edge (i.e., near or behind customer meters), has created a need for improvements to accommodate these resources.

4. *Xcel Energy's Vision for the Future of the Distribution Grid*

Q. CAN YOU DESCRIBE XCEL ENERGY'S VISION FOR THE FUTURE OF THE DISTRIBUTION GRID?

A. Our vision for the future distribution grid is one that utilizes advances in technology to improve our monitoring and operation of the grid for the benefit of our customers. Our AGIS investments will provide us timely and accurate information about what is happening on all portions of the grid from

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our substations down to each individual customer's meter. These investments will also have the necessary automation and intelligence to address any problems quickly and efficiently. In some cases, these insights will alert us to situations likely to result in an outage (such as overloaded equipment) before an outage occurs. The increased number of field sensors and devices will also provide the Company with the necessary information to continually monitor and make the necessary adjustments to the system to support increasing amounts of DER and other electric technologies such as EVs.

Additionally, as discussed by Mr. Gersack, the advanced grid investments will provide the foundation for new programs and service offerings, engaging digital experiences, enhanced billing and rate options, and timely outage communications. Further, as discussed by Mr. Harkness, the advanced grid will include security protocols that will detect and remedy cyber and physical threats to our system.

Q. WHY IS IT IMPORTANT TO MAKE THE PROPOSED AGIS INVESTMENTS AT THIS TIME?

A. As discussed in the next section, while the Company has taken certain steps to modernize the grid, now is the time to build on these foundational investments and to begin a more significant advancement of the grid through our AGIS initiative. The need for these AGIS investments is the result of a number of factors including system needs, the maturity of technology, changing customer needs and expectations, and increasing amounts of DER that is anticipated in the near future. Together, these factors drive the need to make the proposed AGIS investments in modernizing our distribution system. These investments will greatly enhance our distribution system's performance and our ability to meet our customers' needs and expectations for their electric service provider now and in the future.

C. Grid Modernization Efforts to Date

Q. WHAT HAS BEEN XCEL ENERGY'S APPROACH TO GRID MODERNIZATION?

A. Our strategy for grid modernization has been a building block approach. That is, we have focused our efforts first on developing the core components that form the foundation to build upon to construct and enable more advanced components. This building-block approach, starting with the foundational systems, is in alignment with industry standards and frameworks including the Department of Energy's Next Generation Distribution Platform (DSPx) framework.[8] This approach also allows us to sequence our investments to yield the greatest near-term and long-term customer value while preserving the flexibility to adapt to the evolving customer and technology landscape.

Q. WHAT STEPS HAS THE COMPANY TAKEN TO UPDATE THE DISTRIBUTION SYSTEM IN RECENT YEARS?

A. One of the steps that we have taken is utilizing our equipment replacements as an opportunity to deploy new equipment that has the greater functionality necessary for a modern grid. An example of this strategy is replacement of electro-mechanical relays with solid-state relays that are not only communication-enabled but are also capable of providing fault data that an ADMS system can use to calculate probable fault location. This allows for faults on our system to be more quickly identified thus improving our response time. Additionally, we are replacing voltage regulators that have

[8] *See* Modern Distribution Grid, Volume III: Decision Guide, U.S. Department of Energy Office of Electricity Delivery and Energy Reliability (June 2017).

reached the end of their service life with regulators that have controls that identify reverse-power flow and react accordingly, which will facilitate integration of distributed generation onto the system. Beginning in 2015, we have deployed power line sensors on our system that aid our efforts to locate faults more quickly – improving our responsiveness to outage events, and thus the customer reliability experience.

The Company has also installed autonomous, proprietary automated switching systems on portions of its 34.5 kV system. Since these system use a proprietary, single-purpose communication network, they must be specifically designed for the portion of the grid they cover, and the system must be re-programmed when system topology changes. Where these devices have been installed, these systems have improved system reliability, proving the value of the FLISR concept. Going forward, we plan to leverage ADMS's broader FLISR capabilities, bringing reliability benefits customers served by our larger 13.8 kV systems.

Q. HAS THE COMPANY PREVIOUSLY SOUGHT AND RECEIVED COMMISSION CERTIFICATION OF GRID MODERNIZATION INVESTMENTS?

A. Yes, as mentioned above two advanced grid investments have been submitted for certification in biennial grid modernization reports and approved by the Commission. In its 2015 Biennial Grid Modernization Report, the Company outlined the ADMS initiative, which was submitted for certification and subsequently approved on June 28, 2016. In its 2017 Biennial Grid Modernization Report, the Company outlined its AMI and TOU pilot program and certification was approved in the Commission's August 7, 2018 Order.

1. ADMS

Q. WHAT IS ADMS?

A. ADMS is the foundational software platform for operational hardware and software applications used to operate the current and future distribution grid. ADMS is foundational because it provides situational awareness and automated capabilities that sustain and improve the performance of an increasingly complex grid. Specifically, ADMS acts as a centralized decision support system that assists the control room, field operating personnel, and engineers with the monitoring, control and optimization of the electric distribution grid. ADMS does this by utilizing the as-operated electrical model and maintaining advanced applications which provide the Company with greater visibility and control of an electric distribution grid that is capable of automated operations. In particular, ADMS incorporates Distribution Supervisory Control and Data Acquisition (D-SCADA) measurements and advanced application functions with an enhanced system model to provide load flow calculations everywhere on the grid, accurately adjusting the calculations with changes in grid topology and insights from sensors. This allows the Company to improve the monitoring and control of load flow from substations to the edge of the grid, which enables multiple performance objectives to be realized over the entire grid.

Q. HOW DOES ADMS ENABLE OTHER GRID MODERNIZATION COMPONENTS?

A. Implementing ADMS will enable management of the complex interaction among outage events, distribution switching operations, IVVO and FLISR in the near-term, while preparing the Company to implement advanced

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applications like Distributed Energy Resource Management System (DERMS) in the future.

The GIS data improvement needed to enable ADMS also furthers grid modernization efforts related to DER. Specifically, this effort will help DER adoption by improving the GIS model which is used for system planning and for hosting capacity analysis. The data collection and improvements will reduce the amount of time that planning engineers spend preparing each model for analysis. The verification and population of additional data attributes will also help our designers validate capacity necessary for EVs.

Q. WHAT IS THE TIMING FOR IMPLEMENTATION OF ADMS?

A. ADMS software has an expected in-service date of April 2020 when the system will be tested and go live to control a subset of the distribution system. The plan is to continue to expand the modeled system over the next several years, enabling additional benefits of ADMS including coordination with the FLISR and IVVO deployments.

Q. IS THE COMPANY SEEKING TO RECOVER ANY COSTS RELATED TO ADMS IN THIS RATE CASE?

A. No. The Company has sought recovery for the costs for ADMS in the TCR Rider and proposes to keep ADMS in the TCR Rider through the multi-year rate plan period.

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2. TOU Pilot

Q. WHAT IS THE TOU PILOT?

A. The TOU pilot implements new residential TOU rates for select customers in the Twin Cities metropolitan area, providing customers with pricing specific to the time of day energy is consumed. This pilot requires installation of AMI meters to measure and record customer usage in detailed, time-based formats and requires installation of FAN communication to transmit this data to the Company and customers.

Q. HOW MANY CUSTOMERS ARE PARTICIPATING IN THE TOU PILOT?

A. As part of this pilot, we will deploy approximately 17,500 advanced meters to residential customers in Eden Prairie and Minneapolis. We will also deploy FAN communications to these same areas.

Q. WHAT IS THE TIMING OF IMPLEMENTATION FOR THE TOU PILOT?

A. Our back-office work on AMI and FAN necessary for the TOU pilot began in 2018. In 2019, we commenced installations of both FAN devices and AMI meters and expect this work to be completed during the first quarter of 2020. The TOU pilot – with the new rate structures for participants – is expected to begin in April 2020.

Q. WHAT IS THE PURPOSE OF THIS TOU PILOT?

A. The primary aim of this TOU pilot is to study the impact of rigorously designed price signals and technology-enabled data on customer usage patterns to inform future consideration of a broader TOU rate deployment in Minnesota. The purpose of this pilot is not to study the use of AMI meters

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because, as I discuss later in my testimony, this technology is proven and widely used by other utilities.

Q. IS THE COMPANY SEEKING TO RECOVER ANY COSTS RELATED TO TOU PILOT IN THIS RATE CASE?

A. Yes. For 2020 and going forward, the Company proposes to recover the costs associated with the TOU pilot as part of this rate case. These costs for Distribution are shown in 35 below.

Table 33

AMI TOU Pilot-Distribution State of MN Electric Jurisdiction (Dollars in Millions)			
TOU Pilot-Distribution	**2020**	**2021**	**2022**
Capital Additions	$1.8	$0.0	$0.0
O&M Expenses	$0.3	$0.0	$0.0

I note that the residential TOU pilot costs are part of the Company's overall AGIS initiative (specific to AMI and the FAN). The TOU costs reflect the estimated portion of the total AMI components that are necessary to implement the residential TOU pilot. In his testimony, Mr. Harkness provides the Business Systems costs necessary to implement the TOU pilot.

Q. WHAT HAS BEEN THE IMPACT OF THESE SYSTEM UPDATES AND PILOT PROGRAMS ON THE OPERATION OF THE DISTRIBUTION SYSTEM?

A. While some of these investments (i.e., the automated devices discussed above) have had a positive impact on customer reliability, these improvements have not corrected the fundamental issues with the operation of the current system – lack of visibility and wide-spread automation. Xcel Energy's distribution system currently lacks real-time visibility into the condition of its entire distribution grid and the customer experience beyond the substation level. As a result, if a customer is experiencing an outage, the Company still primarily relies on the customer to report the outage to know that an outage occurred. In addition, the distribution system continues to lack automated controls that allow the Company to adjust and control individual pieces of equipment from a central location.

The state of technology has reached a point where it is feasible to implement equipment and systems that will provide the Company with the visibility and automation required to operate with increasing levels of DER and higher customer expectations around reliability and information about their power use. While the Company has implemented some of these technologies in a few pilot areas, it is now time to expand this technology to larger portions of our electric grid. In the next section of my testimony, I will describe the foundational components of the AGIS initiative that we plan to implement during the term of the multi-year rate plan.

D. AMI

1. Overview of AMI

Q. WHAT IS AMI?

A. AMI is an integrated system of advanced meters, communications networks, and data management systems that enables secure two-way communication between customer meters and utilities' business and operational systems that enable benefits for both the customer and the utility. AMI meters are able to measure and transmit voltage, current, and power quality data and can act as

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sensor, providing timely monitoring at the customer's point of service that has a variety of uses for customers and business operations.

AMI is a key element of the AGIS initiative because it provides a central source of information that interacts with many of the other components of the AGIS initiative. The system visibility and data delivered by AMI provides customer benefits in reliability and ability for remote connection, enables greater customer offerings for rates, programs, and services. AMI also enhances utility planning and operational capabilities. Access to timely, accurate and consistent data from the AMI system will provide insights for customers to make informed decisions about their energy sources and usage of reliable and sustainable energy.

The Company plans to deploy approximately 1.3 million AMI meters in Minnesota starting in the third quarter in 2021 and continuing through 2024. This mass deployment of AMI meters builds off the limited AMI meter installation that will be completed in late 2020 as part of the TOU pilot. Xcel Energy will own and operate the AMI meters and the FAN communication network.

Q. DESCRIBE THE ADVANCED METERS.

A. The advanced meters are the key endpoint component of an AMI system that measures, stores, and transmits meter data, including energy usage data from customer locations. The advanced meters can also measure values such as voltage, current, frequency, real and reactive power, and certain power quality events such as sags and swells. Additionally, these meters can detect outage

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events, restoration events, tampering, energy theft events, and perform meter diagnostics.

Q. HAS XCEL ENERGY SELECTED A SPECIFIC ADVANCED METER?

A. Yes. Xcel Energy has selected the Itron Riva Generation 4.2 advanced meter. This meter will be installed for mass deployment in Minnesota starting in 2021. For the TOU pilot, Xcel Energy will install a different AMI meter, a Landis+Gyr Focus meters equipped with Itron Gen 5 NICs, because the Riva Generation 4.2 advanced meter will not be ready for installation until 2021. The meters installed for the TOU pilot will be replaced by Itron with the Riva Generation 4.2 during the mass deployment at no cost to Xcel Energy. The RFP process that was used to select this meter and vendor are described in greater detail below. This specific meter is the latest model in Itron's Riva family of meters so a photo of this specific meter is not currently available. A photo of a similar model (the OpenWay® Riva CENTRON meter) from the Itron Riva family of meters is provided below in Figure 8.

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Figure 8

Q. WHAT IS THE SERVICE LIFE OF THESE ADVANCED METERS?

A. We have assumed a service life for the advanced meters of 15 years in Minnesota for purposes of depreciation and the CBA. The actual physical life of these advanced meters will likely exceed this 15 year service life.

Q. WHAT ARE THE COMPONENTS OF ADVANCED METERS?

A. The components of the advanced meter include: (1) the meter itself (responsible for measurements and storage of interval energy consumption and demand data); (2) an embedded two-way radio frequency communication module (responsible for transmitting measured data and event data available to backend applications); (3) embedded Distributed Intelligence capabilities (described below); and (4) an internal service switch (to support remote connection and disconnection).

Q. WHAT ARE THE FUNCTIONS OF THE ADVANCED METER ITSELF?

A. The primary purpose of the advanced meter is the same as our existing meters – to measure the amount of electricity used by our customers for billing purposes. However, the advanced meters have additional capabilities and can be remotely configured to measure bi-directional and/or time-of-use

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energy consumption in kilowatt hours (kWh) and demand in kilowatts (kW). An advanced meter that is configured for bi-directional energy measurement measures energy provided by the Company to the customer and also measures net energy provided from customers (i.e., customers with solar panels) to the Company. Energy consumption data for billing purposes can be recorded by advanced meters in intervals as short as five minutes, or longer intervals if desired. The advanced meters also provide granular data regarding voltage and outages as explained further below.

Q. HOW OFTEN WILL AMI METERS COLLECT AND TRANSMIT DATA TO THE COMPANY?

A. The AMI meters will collect and transmit data to the Company a minimum of six times per day or every four hours. However, there are several instances when the meters will communicate more often than every four hours. Some examples of this more frequent communication include:

- Individual meters can be read on an on-request basis. For example, a Customer Care employee may request and collect the meter data while on the phone assisting a customer.
- Through the internet portal or smartphone application, as described by Mr. Harkness, a customer could request an on-demand meter reading. This request will provide a customer with near real-time energy information.[9]
- AMI meters will transmit data when an event occurs such as a power outage, power restoration, power quality event, or a diagnostic event.

[9] The terms "near real time" refer to the fact that there is a slight delay (under ten seconds) between the time the data is pulled and when it is received by the customer.

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The length of time between the data transmission and the event depends on the type of the event.

- AMI meters selected along the distribution feeders to provide data to ADMS will be configured for five minute interval data, and will transmit data to the head-end application every five minutes to make that information available to ADMS. The interrelation between AMI and ADMS is discussed further below.

Q. WHAT ARE THE OTHER CAPABILITIES OF THE ADVANCED METERS?

A. In addition to the ability to measure, store, and transmit interval meter data, advanced meters also have the capability to:

- Measure and transmit voltage, current, and power quality data;
- Detect and transmit meter power outage and restoration events;
- Detect and report meter tampering events;
- Perform and transmit meter diagnostics pertaining to the correct functioning of the meter and communications module;
- Support electric vehicle interconnections;
- Support customer-facing energy conservation technologies (i.e., smart thermostats);
- Support Distributed Intelligence; and
- Support remote connect/disconnect functions for customers taking single-phase service (generally, residential and some small business customers).[10]

[10] The only AMI meters available in the marketplace with remote connection/disconnection switches are single-phase meters.

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Q. WHAT ARE THE CAPABILITIES OF THE ADVANCED METER'S TWO-WAY RADIO FREQUENCY COMMUNICATION MODULE?

A. The radio frequency communication module will utilize the Company's communication network (i.e., the FAN) to provide two-way communication between the meter and the AMI head-end application. The AMI head-end application is the operating system that is used to send data requests and commands to an advanced meter, and receive data from the meter. These communications include:

- Transmitting the measurements, alarms, and events performed by the meter to the head-end application;
- Receiving commands from the head-end application to send specific meter measurements, alarms, and events, configure the meter to measure specific sets of energy parameters or time-of-use intervals and data recording intervals;
- Remotely performing meter firmware upgrades;
- Receiving commands from the head-end application to open or close the internal service switch and communicate its status.

Q. WILL THE TWO-WAY RADIO MODULE WITHIN THE AMI METERS HAVE THE ABILITY TO COMMUNICATE WITH OTHER DEVICES?

A. Yes. While the primary purpose of the two-way radio is to capture and transmit customer billing data and service quality data from the AMI meter to the Company, there is also a second radio within the meter that is Wi-Fi compatible and can be configured to communicate with a customer's Home Area Network (HAN) and HAN devices.

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Q. WHAT IS A HAN?

A. The HAN is a network contained within a customer's home or business that connects a customer's HAN devices together as well as to customer's AMI meter. A HAN device can be as simple as an in-home energy display that provides real-time energy data. HAN devices can also include thermostats, home security systems, energy display devices, and smart appliances, that when connected through the HAN, these devices can communicate with each other to support energy management functions.

Q. HOW DOES THE COMPANY INTEND TO UTILIZE THE HAN FUNCTIONALITY OF THE AMI METERS?

A. As discussed by Mr. Gersack, HANs vary in the benefits they provide and can be as simple as a dashboard that communicates with the meter to provide real-time energy usage or more complicated networks of devices that are receiving energy usage data from the meter and adjusting operations based on that information. The Company will continue to build and refine our next steps with both advanced grid technologies and customer products and services that will leverage AMI capabilities.

Q. WHAT IS DISTRIBUTED INTELLIGENCE?

A. Distributed intelligence or "grid edge computing" refers to the distribution of computing power, analytics, decisions, and action away from a central control point and closer to localized devices or platforms where it is actually needed, such as advanced meters or other "smart" devices on the grid. Since data no longer has to traverse long distances over increasingly constrained networks, these technologies improve the computational speed, efficiency, and capabilities derived from these platforms. Distributed intelligence capabilities in advanced meters and other edge devices opens up a broad array of new uses that will fundamentally transform how customers will use energy in their homes and businesses, as well as how Xcel Energy will be able to optimize its AGIS investments.

Q. WHAT ARE THE EMBEDDED DISTRIBUTED INTELLIGENCE CAPABILITIES OF THE ADVANCED METER SELECTED BY THE COMPANY?

A. Our advanced meters will provide a distributed intelligence platform that is a computer at customers' homes and businesses. This computer uses a Linux-based operating system to conduct localized, at the meter computing, analysis, and data processing that provide customers with new tools to help manage their energy usage and provide Xcel Energy with new tools to manage the grid more efficiently. This capability also allows for the installation of a wide-range of potential applications. In other words, this Distributed Intelligence capability allows for the installation of applications on the meter – similar to how applications are installed on a smart phone. These applications may be customer-facing, meaning the customer directly interacts with them, or grid-facing, meaning Xcel Energy interacts with the applications.

Q. WHAT ARE THE POTENTIAL USES OF THIS DISTRIBUTED INTELLIGENCE CAPABILITY?

A. The Distributed Intelligence capabilities allow the AMI meter to run multiple applications at the same time and without the need for instructions from the Company's back-office applications or control room. This type of capability is beneficial because it allows the AMI meters to communicate directly with each other regarding issues, analyze those issues, and to solve problems directly rather than communicating these issues to a back-office system and then waiting for instructions on how to solve the problem. The potential use cases for these applications include:

- Improved and security and awareness,
- Energy usage control and savings,
- Smarter insights about customer energy data and information,
- Smarter controls to better manage and integrate different systems, and
- Identification and alarming for operational issues.

Q. CAN YOU PROVIDE AN EXAMPLE OF HOW THESE DISTRIBUTED INTELLIGENCE CAPABILITIES COULD BE USED BY THE DISTRIBUTION ORGANIZATION?

A. Xcel Energy is leading the nation in the deployment of Distributed Intelligence in the AMI meters. As a leader in this space, we are working with our meter vendor to design, develop, and implement new applications. Our meter vendor has already begun building a number of applications that can be enabled on the meter. While the specific use of these Distributed Intelligence capabilities will depend on the particular applications employed, I will provide an example of how these capabilities could be utilized to manage demand during peak times to avoid transformer overloads. During a hot summer afternoon when energy use is rising due to air conditioning use, the AMI meters at each customer location would analyze this data in real time. These meters would then share their individual data with the other meters served by a common distribution transformer, calculating and comparing the total load to the capacity of the transformer. The AMI meters would be able to discern when the transformer is approaching overload conditions and determine the most appropriate course of action, which could be reporting, alarming, modulating, or possibly shutting off controllable loads to keep the transformer below its rated capacity. The same concept would help with the integration of

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electric vehicles, as well. Finally, a transformer's capacity may be challenged by additional PV, as more of our distribution transformers begin to see their peak not from load, but from PV generation in the afternoon when solar production is strong, but loads are low.

Q. WHAT IS THE PURPOSE OF THE INTERNAL SERVICE SWITCH?

A. The internal service switch has the ability to remotely connect or disconnect power to the customer's electric service upon command from the head-end data application. I note that remote connection/disconnection of residential or small commercial customers would require revisions to our existing tariff and Xcel Energy is not currently seeking Commission approval to enable this capability.

Q. HOW IS AMI DIFFERENT THAN THE METERING SYSTEM USED TODAY?

A. The Company currently has an AMR system that has been in place since the mid-1990s. Meter readings are collected and provided to the Company via a proprietary network by Landis+Gyr (Cellnet), our current meter reading services vendor. We have served our customers for 20-30 years via this AMR system. However, AMR is now dated technology and much of the industry has or is moving to AMI meters.

Q. WHAT ARE THE LIMITATIONS OF THE CURRENT AMR SYSTEM?

A. The AMR system in general is a fixed network, one-way communication system with limited functionality that is primarily related to meter reading for billing purposes. As a result, the AMR system has a number of limitations including:

- Inability to measure and record voltage, current, or power quality;

- Lack of real-time view of a customer's metering data;
- Meter readings are transmitted via a single path communication system that precludes the ability to collect necessary data if there is an obstruction on that single communication path; and
- Cannot be reprogrammed or upgraded remotely such that on-site performance of these tasks is required.

These limitations of the current AMR system preclude us from having much visibility into our customer's energy experience, this visibility is invaluable for how we operate and plan our system. As discussed by Mr. Gersack, the AMR system also limits the customer offerings we can currently provide.

Q. WHY IS IT IMPORTANT TO MOVE FROM AMR TO AMI AT THIS TIME?

A. In addition to the limited functionality of this outdated technology, now is an opportune time to replace this legacy system as we are nearing the expiration of our current AMR meter reading service contract with Cellnet. The current Cellnet contract expires at the end of 2025, with an option to extend it through 2026 at a significantly increased cost. As we are the last remaining customer of the Cellnet system, a contract extension past 2026 is highly unlikely. In addition, Cellnet will stop manufacturing replacement components for the AMR system, including communication modules necessary for meter reading, in 2022. Given that the Cellnet system is a proprietary system, replacement parts are not commercially available from other vendors. As a result, as these meters age and require repair, we will not be able to purchase the necessary replacement components after 2022.

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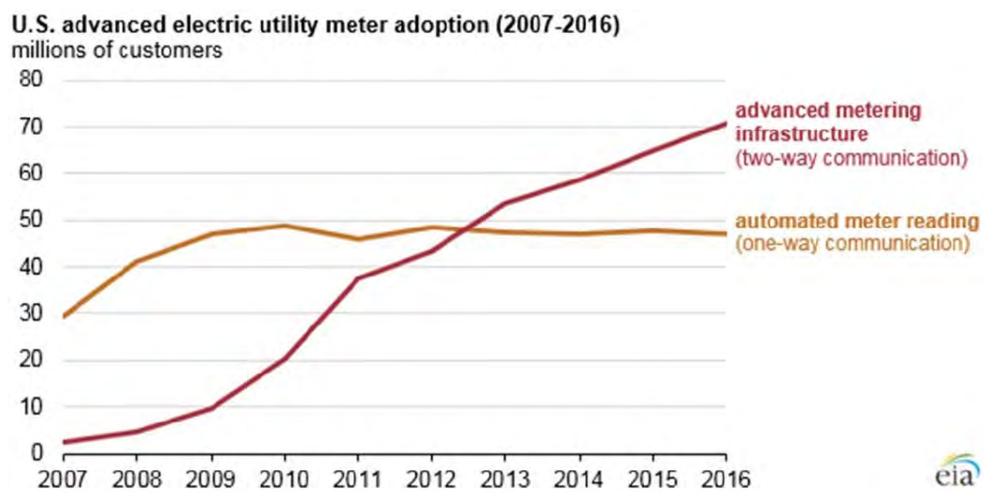
The expiration of our Cellnet contract comes at fitting time given the current state of the AMI market and its technology. AMI has advanced to the point where it is established meter technology that has widespread adoption. Installation of AMI meters has doubled since 2010 and since the end of 2016 nearly half of all U.S. electric customer accounts have AMI meters. According to the United States Energy Information Administration, and as shown in Figure 9, AMI adoption surpassed AMR in 2012, and the gap has widened as AMR deployment has remained flat.

Figure 9[11]

AMI vs. AMR Installations



In sum, it is the culmination of these several factors: (1) aging and outdated technology with limited functionality; (2) the expiration of the existing Cellnet meter reading contract; and (3) difficulty of obtaining vendor in the future for the AMR system that is driving the need to convert to AMI.

[11] https://www.eia.gov/todayinenergy/detail.php?id=34012.

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2. Interrelation of AMI with other AGIS Components

Q. CAN YOU SUMMARIZE THE ROLE OF AMI IN THE OVERALL AGIS INITIATIVE?

A. AMI is a central source of information with which virtually all components of AGIS interact and as such AMI is critical to support certain benefits of the advanced grid such as TOU rates and associated price signals, more efficient distribution management system, and greater customer control over energy usage.

Q. HOW WILL AMI INTERACT WITH ADMS?

A. AMI will also provide the ADMS with timely real and reactive power measurement data that will be used in load flow and IVVO calculations. Further, AMI meters will provide voltage measurements at various points on the distribution system to support IVVO calculations. The information collected by the AMI meters will allow the Company through IVVO to reduce the overall voltage on the system.

The AMI meters will report a power outage or "last gasp" event to the AMI head-end application and report a power-on event when the power is restored. This information will flow from the head-end application to ADMS that will improve the calculations for the fault location and restoration applications.

Q. HOW WILL AMI INTERACT WITH THE FAN?

A. The AMI meters have an integrated network interface card (NIC) that enables them to connect to the WiSUN portion of the FAN network. This enables the transmission of data and commands between the AMI meters and the Company. The meters can also act as a repeater for other mesh network devices, enabling two-way communication between the meters and the mesh

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network. This function provides increased communication reliability between the AMI meters and the head end application. For example, if the communication signal is weak between the AMI meter and the access point device, the meter may have a stronger communication path to the access point by having another meter (or several meters), act as a repeater to facilitate the communication.

Q. HOW WILL THE AMI METER INTERACT WITH FLISR?

A. The last gasp and power-on information that advanced meters will provide will be available on ADMS which will utilize this data to develop more accurate model and forecasting tools for FLISR. This transfer of data will enable the Company to more precisely locate faulted sections of feeders, which reduces patrol times, and improve FLISR switching plans, which minimizes the outage impact to customers.

Q. HOW WILL THE AMI METERS INTERACT WITH IVVO?

A. As noted above, advanced meters provide voltage information to ADMS from strategic points on the distribution system. The ADMS combines voltage information provided by the AMI meters to calculate voltage levels across the grid. This voltage data becomes more precise and accurate as the number of AMI meters providing this data increases. This voltage information is then used by the IVVO application to operate voltage control devices on the grid, optimizing the voltage levels on the grid while keeping the voltage within the desired bandwidth. Without the AMI meters acting as sensors, the Company would need to deploy stand-alone sensors to implement IVVO. I discuss this further in the alternatives section below.

3. AMI Implementation

Q. WHAT IS THE AMI DEPLOYMENT TIMELINE?

A. We plan to install approximately 1.3 million AMI meters throughout our Minnesota service territory as part of the AGIS initiative starting in the third quarter of 2021. This deployment builds off the limited installation of 17,500 AMI meters planned to be installed in late 2019 as part of the TOU pilot. By the end of 2023, we anticipate that over 90 percent of the meter installations will be complete. Table 34 below provides a summary of the number of meters we anticipate installing per year from 2021 through 2024.

Table 34

AMI Meter Installation by Year

Year	2021	2022	2023	2024
Number of AMI Meters Installed	100,000 to 130,000	550,000 to 650,000	530,000 to 600,000	30,000 to 60,000

Q. PLEASE PROVIDE ADDITIONAL DETAILS REGARDING WHERE THE AMI METERS WILL BE INSTALLED EACH YEAR?

A. Figure 10 below shows the anticipated deployment schedule for AMI. As shown below, the first meters installed as part of the mass deployment starting in third quarter 2021 are adjacent to and will build off the TOU pilot areas. From there, the deployment will continue to expand outward through 2023 with the final deployments scheduled in our Sioux Falls and Fargo service areas for 2024.

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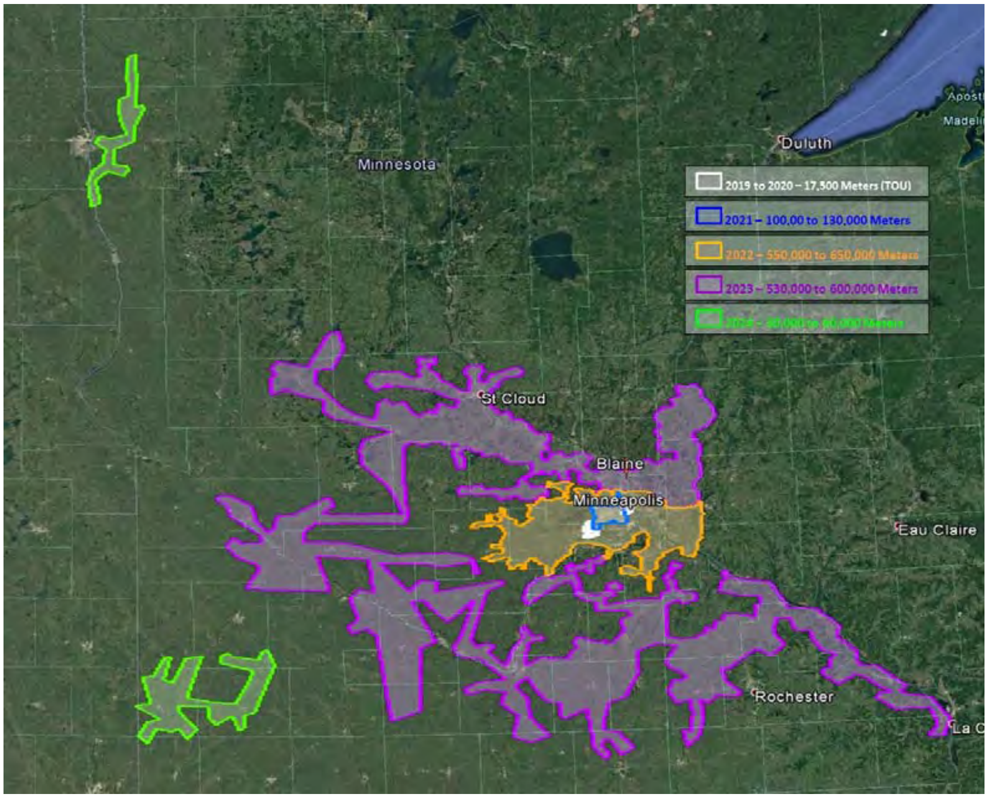
Figure 10



Q. HOW WILL THE AMI METERS BE INSTALLED?

A. The exchange of AMI meters in the field will be performed by trained and qualified contractors under the management and direction of Company employees.

Q. HOW LONG WILL IT TAKE TO INSTALL EACH INDIVIDUAL METER?

A. The time to install each meter will vary depending on the type of service and meter that each customer has but in most cases we expect that the meter exchange for a residential customer to take less than 15 minutes.

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Q. WILL INSTALLATION REQUIRE A CUSTOMER'S ELECTRICITY TO BE TURNED OFF?

A. Depending on the type of meter socket the customer has, they may experience a brief outage during installation. Customers do not need to be present during installation. We will provide customers with information about the timing of their AMI installation and what to expect during installation prior to installation. Mr. Gersack will discuss our communications and customer outreach plan in further detail.

Q. WILL THE INSTALLATION AND DEPLOYMENT OF AMI METERS BE INTEGRATED WITH THE COMPANY'S EXISTING INFORMATION TECHNOLOGY?

A. Yes. The advanced meters will be integrated with the Company's information technology system. AMI is data intensive with meter readings, energy usage interval profiles, power outage and restoration events, power quality information and other data transmitted and collected frequently. All data from the AMI meters comes into the head-end application and, depending on what the data is, it will need to be integrated and made available to the applicable business system in an accurate and timely manner. IT integration is explained in more detail by Mr. Harkness.

4. Benefits of AMI

Q. WHAT TYPES OF BENEFITS DOES XCEL ENERGY ANTICIPATE WILL BE ACHIEVED FROM AMI INSTALLATION?

A. There are four categories of benefits that we expect from implementation of AMI: (1) quantifiable capital benefits, (2) quantifiable O&M benefits, (3) other quantifiable benefits, and (4) non-quantifiable benefits. The quantifiable

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benefits of AMI were utilized by Dr. Duggirala in the CBA model prepared by the Company to calculate the benefit-to-cost ratios for each AGIS element.

Q. CAN YOU PROVIDE AN OVERVIEW OF THESE FOUR CATEGORIES OF BENEFITS?

A. With respect to quantifiable capital savings, we expect to see benefits in the areas of distribution system management efficiency, outage management efficiency, and avoided meter purchases. With respect to O&M savings, I will discuss quantitative benefits in the categories of field and meter service costs, distribution system management, outage management savings, as well as customer outage reductions. We also anticipate O&M savings in avoided meter reading costs, reduced customer calls, reduction in field and meters services, and improved distribution system spend efficiencies.

With respect to other quantifiable benefits, we anticipate reduction in energy theft, reduced consumption on inactive premises, reduced uncollectible and bad debt expense, load flexibility savings, and carbon emissions benefits. These other quantifiable benefits are discussed by Mr. Cardenas and Dr. Duggirala. Table 35 summarizes the quantifiable benefits of AMI.

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Table 35

AMI CAPITAL BENEFITS		
AMI Capital Benefits	**Description of Benefit**	**Witness**
Distribution System Management Efficiency	More efficient use of capital dollars to maintain the distribution system.	Direct Testimony of Ms. Bloch, Section V(D)(4)
Outage Management Efficiency	Improved capital spend efficiency during outage events.	
Avoided Meter Purchases	AMI meters have a lower failure rate as compared to AMR meters. By purchasing new AMI meters, the Company avoids the need to replace failing AMR meters.	
Avoided investment of an alternative meter reading system	Avoided capital cost of a drive-by meter reading system, instead of the AMI investment, since current Cellnet system requires replacement	
AMI O&M BENEFITS		
AMI O&M Benefits	**Description of Benefit**	**Witness**
Avoided O&M Meter Reading Cost	O&M cost component of a drive-by meter reading system alternative to AMI, since current Cellnet system requires replacement	Direct Testimony of Mr. Cardenas, Section V(F)
Reduction in Field and Meter Services	Reduction in O&M costs related to addressing meter and outage complaints and connections.	Direct Testimony of Ms. Bloch, Section V(D)(4)
Improved Distribution System Spend Efficiency	Increased efficiency of distribution maintenance costs.	Direct Testimony of Ms. Bloch, Section V(D)(4)
Outage Management Efficiency	Improved O&M efficiency during outage events.	Direct Testimony of Ms. Bloch, Section V(D)(4)

Table 35 (continued)

OTHER QUANTIFIABLE BENEFITS OF AMI		
Other Benefits of AMI	**Description of Benefit**	**Witness**
Reduction in Energy Theft	Easier identification of energy theft and an associated reduction in the amount of theft.	Direct Testimony of Mr. Cardenas, Section V(F)
Reduced Consumption Inactive Premise	Expedited ability to turn off power quickly when determined premise has been vacated.	Direct Testimony of Mr. Cardenas, Section V(F)
Reduced Uncollectible/Bad Debt	Decreased loss due to uncollectible/bad debt.	Direct Testimony of Mr. Cardenas, Section V(F)
Reduced Outage Duration	Direct benefit to customers associated with reduced outage duration	Direct Testimony of Ms. Bloch, Section V(D)(4)
Critical Peak Pricing	Customer demand savings in response to new rate structures.	Direct Testimony of Dr. Duggirala, Section II(B)(1)
TOU Customer Price Signals	Difference in energy prices paid by consumers in response to new rate structures.	Direct Testimony of Dr. Duggirala, Section II(B)(1)
Reduced Carbon Dioxide Emissions	Difference in emissions of generation assets due to shifted load.	Direct Testimony of Dr. Duggirala, Section II(B)(1)

A summary of the calculations for all of the quantifiable AMI benefits is provided in Exhibit___(KAB-1), Schedule 7. There are also a number of benefits that are not readily quantifiable. I address three of these non-quantifiable benefits: (1) enhanced DER integration; (2) improved safety for both customers and employees; and (3) improved power quality. Other non-quantifiable benefits are discussed by Mr. Gersack, Dr. Duggirala, and Mr. Harkness.

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Q. WHEN WILL CUSTOMERS BEGIN TO SEE THE BENEFITS OF AMI?

A. There is a relationship between when benefits will start to be realized based on when AMI meters are being installed in the field and when back office functionality is enabled via data processing and management systems and integrations with other systems. In general, most benefits will start to be fully realized after full-deployment of AMI meters in 2024. Partial benefits will begin to be realized in the 2023 timeframe.

a. Capital Benefits

Q. WHAT ARE THE CAPITAL BENEFITS FOR AMI THAT YOU PROVIDE SUPPORT FOR IN YOUR TESTIMONY?

A. I describe and provide support for calculation of the following capital benefits of AMI:

- Improved distribution system management efficiency;
- Improved outage management efficiency;
- Avoided meter purchases due to reduced failure rate of new meters; and
- Avoided capital investment of an alternative meter reading system to the existing Cellnet meter reading system.

(1) Distribution System Management Efficiency

Q. WHAT DISTRIBUTION SYSTEM MANAGEMENT EFFICIENCIES WILL BE GAINED AS A RESULT OF AMI?

A. AMI will provide a wealth of information about the workings of the distribution system. This AMI data can be aggregated at varying levels of the distribution system including tap, transformer, and service lines amongst other distribution system equipment. This data will be used by the Company to

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prioritize distribution grid improvements and more efficiently plan and design the system. Through the aggregated AMI data, we will have greater insights into the nature of the load - specifically load profiles, which will help us evaluate risk. The voltage insights will help us prioritize areas for investments in tap, transformer, and secondary wire replacement. For instance, the AMI data can be aggregated at the transformer level to identify overloaded transformers as well as determining the optimal transformer for replacement transformers. We will also have tools to better understand system losses which will help us evaluate opportunities for investment to minimize these losses. The Company estimated that AMI meters will provide a 1 percent reduction in capital expenditures for Asset Health and Reliability projects and Capacity projects.

Q. HOW WAS THIS BENEFIT CALCULATED?

A. The Company examined past projects in the Asset Health and Reliability and Capacity categories and determined that 1 percent was a reasonable estimate of the capital expenditure reduction that will result from the data provided AMI meters. In addition, the Company's 1 percent estimated benefit is consistent with the percentage utilized in the CBA performed by Ameren Illinois in 2012 when it sought approval for its AMI deployment (Ameren Business Case).

To calculate this benefit, the Company utilized an average of the actual capital expenditures in the capital budget categories of Asset Health and Reliability and Capacity over a five-year period 2014 through 2018. This average capital expenditure was then multiplied by 1 percent to calculate the reduction in capital expenditures resulting from AMI.

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(2) Outage Management Efficiency

Q. DESCRIBE THE IMPROVEMENT IN OUTAGE MANAGEMENT EFFICIENCY THAT WILL BE ACHIEVED FROM THE INSTALLATION OF AMI METERS.

A. AMI will enable increased outage management efficiencies by providing automated outage notification and restoration confirmation (power-on information) to the Company's Outage Management System (OMS). Power loss information is identified by an AMI meter's last gasp. Outage notification from the AMI meters will provide the Company with a timelier and more accurate scope of an outage. The automated outage information provided by the AMI meters will then assist the Company in restoring power more quickly. AMI will also enable more efficient outage restoration because the AMI will provide more detailed outage location information that will reduce the time and expense in locating the outage. Overall, because of these increased outage management efficiencies, AMI enables quicker response and restoration to customer outages to minimize inconveniences or economic losses that could be experienced by the customer.

Q. HOW DID XCEL ENERGY QUANTIFY THESE OUTAGE MANAGEMENT EFFICIENCY BENEFITS?

A. Xcel Energy estimates that AMI will result in a 10 percent reduction in storm-related capital costs due to the efficiencies gained from the information provided by the AMI meters. To develop this percentage, the Company examined historic storm-related capital expenditures in light of the improve outage information that AMI will provide and determined that a 10 percent reduction was a reasonable, if not conservative, estimate of expected reduction that will result from the data provided AMI meters.

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The Company utilized an average of the storm-related capital expenditures for the five-year period between 2014 and 2018. This average storm-related capital expenditure was then multiplied by 10 percent to calculate the benefit resulting from AMI deployment.

(3) Avoided Meter Purchases

Q. DESCRIBE THE AVOIDED METER PURCHASE BENEFIT THAT WILL RESULT FROM DEPLOYMENT OF THE AMI METERS?

A. AMI meters will have a lower failure rate as compared to our existing AMR meters. As a result, there is a cost savings associated with not having to replace these failed AMR meters. The benefit from avoided AMR meter purchases, however, is partially offset by the cost of ongoing replacement of AMI meters due to normal failure rates.

Q. HOW DID THE COMPANY CALCULATE THE BENEFIT ASSOCIATED WITH AVOIDED METER PURCHASES?

A. Based on historical data from 2014 to 2018, Company calculated that the average percentage failure rate of our current AMR meters is approximately 1.92 percent per year. In contrast, the AMI meter vendor provided an estimated failure rate of 0.5 percent per year for the new AMI meters based on their own experience and testing.

The total failure cost associated with replacing a failed meter has three components: meter cost, installation cost, and total number of failed meters per year. The total failure cost for replacing AMR meters was based on our current actual meter and installation costs. The total failure cost for replacing

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AMI meters was based on the meter and installation costs included in our contract with our selected meter vendor. The difference between total AMR failure costs and the total AMI failure costs was used to determine the cost savings associated with AMI.

(4) Avoided Cost of Alternative Meter Reading System

Q. DESCRIBE THE BENEFIT ASSOCIATED WITH AVOIDING AN INVESTMENT IN AN ALTERNATIVE METER READING SYSTEM?

A. As mentioned above, our current meter reading contract is set to expire in 2025 (or 2026 with a costly extension) and the Company will need to find a replacement meter reading system. One option is to replace the current AMR Cellnet meter reading system with another basic AMR meter reading alternative such as a drive-by system. Since the deployment of AMI will eliminate the need to replace the existing AMR Cellnet meter reading with an alternative drive-by meter reading system, these avoided costs are a benefit of AMI.

Q. HOW DID THE COMPANY DETERMINE THE COSTS FOR AN ALTERNATIVE DRIVE-BY SYSTEM?

A. PSCo employs an AMR drive-by system in Colorado and as a result, the Company was able to utilize actual costs of that system to estimate the upfront and projected capital and ongoing operating costs to deploy a similar system in Minnesota. To translate the costs from Colorado to Minnesota, the Company also prepared an analysis of possible routes for the drive-by meter reading system to better estimate these costs. The capital cost components include meters, meter installation, other deployment costs, vehicles, equipment and material, and project management. We also estimated reasonable O&M costs that include meter reading labor, vehicles, equipment maintenance, customer claims, and contingencies.

Q. HOW DID THE COMPANY CALCULATE THE AVOIDED COST BENEFIT ASSOCIATED WITH NOT HAVING TO DEPLOY AN ALTERNATIVE DRIVE-BY SYSTEM?

A. The total costs of this AMR drive-by system was assumed as the benefit of AMI as these costs would not be incurred if AMI is deployed.

b. O&M Benefits

Q. WHAT ARE THE O&M BENEFITS FOR AMI THAT YOU PROVIDE SUPPORT FOR IN YOUR TESTIMONY?

A. I describe and provide support for calculation of the following O&M benefits of AMI:

- Reduction in O&M for field and meter services;
- Improved efficiency in distribution maintenance; and
- Improved outage management efficiency.

The O&M benefit associated with implementing AMI as opposed to a drive-by meter reading system (i.e., avoided O&M for drive-by meter reading costs) that I mentioned in the prior section above is discussed by Mr. Cardenas.

Q. IN GENERAL, WHAT O&M BENEFITS DOES THE COMPANY ANTICIPATE AS A RESULT OF IMPLEMENTING AMI METERS?

A. AMI will enable Xcel Energy to perform several functions remotely that otherwise require a field visit to the customer premise. As a result, O&M cost savings will be realized through reductions in field personnel trips to repair damaged equipment, to confirm power has been restored after an outage, to reconnect and disconnect customers, and for voltage investigations.

(1) Reduced Field and Meter O&M Expenses

Q. WHAT ARE THE TYPES OF FIELD AND METER SERVICE EXPENSES THAT WILL BE REDUCED BY IMPLEMENTING AMI?

A. Since AMI meters will have the ability to provide billing, power, and voltage information to the Company on command, there will be a reduced need to send personnel to the field to gather this information. This will result in O&M savings in several areas:

- *Reduction in Outage Trips due to Customer Equipment Damage*: Our current AMR system requires crews to be dispatched to verify outages. Sometimes these outages are due to damaged customer equipment and not utility damaged equipment. Under the new AMI system, AMI meters will have two-way communications to the meter and the Company can verify whether there is power at the meter thus pointing to a likely customer problem. This would help reduce field trips while also assisting customers in identifying the likely cause of the outage.
- *Cost Savings from Remote Connect Capability*: AMI enables remote connection and disconnection of residential type service without the need to dispatch crews. This will result in personnel and transportation cost savings due to the reduction in field visits.
- *Reduction in "Ok on Arrival" Outage Field Visits*: AMI will allow the Company to test for loss of voltage at the service point and detect both outage conditions and to know when restoration is complete. As a result, AMI implementation will help eliminate unnecessary field trips

to customer premises that result in field personnel finding no electric service issues upon arrival.

- *Reduction in Field Visits for Voltage Investigations*: When notified of a potential voltage problem, the Company currently sends a technician to investigate. AMI enables the elimination of unnecessary trips when proper voltage can be verified remotely, and helps us prioritize and dispatch the most appropriate crews if the voltage is outside of the appropriate range.

Q. HOW DID THE COMPANY CALCULATE THE O&M SAVINGS ASSOCIATED WITH THE REDUCTION IN FIELD TRIPS DUE TO DAMAGED CUSTOMER EQUIPMENT?

A. To calculate this O&M savings, Company first determined the average number of trips per year between 2014 and 2018 for damaged customer equipment. This average was 1,796 trips per year. The Company also determined that AMI would result in a 50 percent reduction in the number of trips per year for damaged customer equipment. To determine the cost benefit from this 50 percent reduction in the number of trips, the Company utilized the average O&M costs for a trip based on historic cost estimates from 2014 to 2018. To calculate the benefit amount, the Company applied a 50 percent reduction to the average number of trips and then reduced this amount by 50 percent and multiplied this by the average O&M cost. The cost of each trip is the sum of dispatch savings (wages multiplied by time saved) plus crew savings (same as dispatch), and overhead savings. To estimate the cost savings the Company multiplied the reduced number of trips by the estimated trip costs.

Q. HOW DID THE COMPANY DETERMINE THAT AMI WOULD RESULT IN A 50 PERCENT REDUCTION IN THE NUMBER OF TRIPS DUE TO DAMAGED CUSTOMER EQUIPMENT?

A. The Company examined historic data for trips required due to damaged customer equipment and determined that 50 percent was a reasonable, if not conservative, estimate of this reduction. AMI will allow the Company to, in most cases, to determine remotely whether there is power at the meter thus pointing to a likely customer equipment issue. The only times when a field trip may still be required are when there are network communication issues, weather issues, or an issue inside the meter that will prevent us from remotely obtaining the necessary information to fix the issue. We expect that these situations will be limited and as a result the 50 percent reduction is conservative. By way of comparison, the Ameren Business Case assumed a 90 percent reduction in damaged customer equipment field trips due to AMI.

Q. HOW DID THE COMPANY CALCULATE THE COST SAVINGS FROM THE REMOTE CONNECTION CAPABILITY PROVIDED BY AMI?

A. An average of 4,416 residential disconnect and reconnect trips per year were completed by the Company between 2014 and 2018. To derive these benefits, the Company estimated that AMI will reduce the labor costs for these trips by approximately 70 percent for manual disconnections and 95 percent for manual reconnections. The Company believes that 70 percent is a reasonable reduction for disconnects as manual disconnection may still be required in approximately 30 percent of cases such as when the Company does not have accurate customer contact information or where a customer has opted out of AMI. The Company believes that 95 percent is a reasonable reduction for reconnection as manual reconnection may be required in cases where there is a poor communication connection to the AMI meter. The labor costs used to calculate these benefits were based on prevailing wage, overheads, and fleet costs. To estimate the cost savings the Company multiplied the reduced number of trips by the estimated labor costs.

Q. WILL THE COMPANY NEED COMMISSION APPROVAL TO ENABLE THE REMOTE RECONNECT AND DISCONNECT CAPABILITIES OF THE AMI METERS?

A. Yes, I understand that enabling these capabilities will require Commission approval. These regulatory filings are discussed by Mr. Cardenas. While these capabilities will require regulatory approval, the ability to remotely connect and disconnect customers is a benefit of AMI meters and as a result is included in the CBA.

Q. HOW DID THE COMPANY CALCULATE THE COST SAVINGS ASSOCIATED WITH "OK ON ARRIVAL" OUTAGE FIELD VISITS?

A. Between 2014 and 2018, there was approximately average of 7,464 trips per year where field crews found no issues with a customer's electric service upon arrival. The Company assumed that these trips would be reduced by approximately 50 percent as a result of AMI. This 50 percent reduction is reasonable, if not conservative, given that the AMI meter will allow the Company the ability to remotely determine whether or not power is on at an individual meter. There will of course be relatively rare instances where the Company will not perform this remote diagnostic test due to either network connection or weather issues. The labor costs used to calculate these benefits were based on prevailing wage, overheads, and fleet costs. To estimate the cost savings the Company multiplied the reduced number of trips by the estimated labor costs.

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Q. HOW DID THE COMPANY CALCULATE THE COST SAVINGS ASSOCIATED WITH THE REDUCTION IN FIELD VISITS FOR VOLTAGE INVESTIGATIONS?

A. There was an average of 2,858 trips per year from 2014 to 2018 for voltage investigations. The Company assumed that AMI would reduce these voltage investigation trips by 50 percent. This 50 percent reduction is reasonable given that the Company will be able to obtain detailed voltage information remotely from AMI meters. In certain cases, the Company may still need to go to a customer premise to investigate voltage information due to either a poor communication connection or in cases where the voltage information is inconclusive. The labor costs used to calculate these benefits were based on prevailing wage, overheads, and fleet costs. To estimate the cost savings the Company multiplied the reduced number of trips by the estimated labor costs.

(2) Improved Distribution Maintenance Efficiency

Q. WHAT ARE THE IMPROVED EFFICIENCIES IN DISTRIBUTION MAINTENANCE FROM AMI THAT WILL RESULT IN O&M BENEFITS?

A. AMI data can be aggregated at varying levels of the distribution system that include the tap, transformer, and service lines amongst other distribution system equipment. This data will be used by Distribution to prioritize grid improvements and more efficiently plan and design the system. This data can then be used to determine optimal timing for installation and replacement of distribution assets as well as optimizing inventory levels. As discussed in the capital benefits section above, the Company estimated that these efficiencies will provide a 1 percent reduction in capital expenditures for Asset Health and Reliability projects and Capacity projects. This benefit is the O&M portion of this benefit which the Company determined would amount to a 0.1 percent

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reduction in the O&M expenditures for Asset Health and Reliability and Capacity projects. To determine this 0.1 percent, the Company examined past O&M costs for these types of projects.

(3) Outage Management Efficiency

Q. HOW WILL AMI REDUCE O&M COSTS DURING OUTAGES?

A. AMI enables an automated outage information system that allows the Company to deploy crews more efficiently to outage areas, especially during storm outages, ensuring verification that all customers in an area have been restored before dispatching the crew to the next location.

Q. HOW DID THE COMPANY CALCULATE O&M SAVINGS FROM THE IMPROVED EFFICIENCIES IN OUTAGE MANAGEMENT AS A RESULT OF AMI?

A. The Company utilized the average yearly O&M costs for storm related activities from 2014 to 2018 ($2,100,000) and then calculated 10 percent reduction in these costs due to AMI. As discussed, AMI will enable quicker responses to outages by our field crews as they will have more detailed information as to the location of the outage thus reducing time and expense. This 10 percent reduction is reasonable based on the Company's review of historic O&M storm information. This 10 percent reduction is also in alignment with the Ameren Business Case. Ameren serves customers in a similar area of the country we expect our storm expense O&M reductions to be similar.

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c. Other Benefits of AMI

Q. OTHER THAN THE CAPITAL AND O&M BENEFITS THAT YOU DISCUSS ABOVE, ARE THERE OTHER QUANTIFIABLE BENEFITS OF AMI?

A. Yes. The other quantifiable benefits include:

- Reduced consumption on inactive meters,
- Reduced uncollectible/bad debt expense,
- Reduced theft/meter tampering,
- Load flexibility benefits associated TOU rates (peak demand reduction, customer energy price savings, and reduced emissions).
- Reduced outage duration.

The majority of these other benefits of AMI are discussed by other Company witnesses. Mr. Cardenas discusses the first three benefits and Dr. Duggirala discusses the load flexibility benefits. I will discuss the last benefit (reduced outage duration).

Q. HOW WILL AMI REDUCE THE LENGTH OF OUTAGES?

A. AMI meters send a last gasp message to the utility before the meter loses power. Not all last gasp messages make it, but usually enough messages are received to help the utility adequately determine which customers are affected. This outage data helps utility personnel respond more quickly to fix problems with the end result being that customers' power is restored more quickly. Another benefit of AMI meters is verification of power restoration. Restoration verification is accomplished when a meter reports in after being reenergized. This will provide automated and positive verification that power has been restored to all customers, there are no nested outages, and all associated trouble orders are closed before restoration crews leave the areas.

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This reduces costs, increases customer satisfaction, and further reduces outage duration.

Q. HOW DID THE COMPANY CALCULATE THE CUSTOMER BENEFIT ASSOCIATED WITH THIS REDUCTION IN OUTAGE DURATION?

A. The Company estimated that AMI meters will help reduce outage length resulting in direct benefits for customers. Three main improvement areas were evaluated for Customer Minutes Out (CMO) reduction: (1) better identification of nested outages during storm events; (2) reduction in response time for single customer events; and (3) faster response to tap level events. For each activity, the Company determined the value of these CMO based on the Interruption Cost Estimate (ICE) Calculator developed by Lawrence Berkeley National Laboratory (LBNL).[12]

Q. WHAT IS THE ICE CALCULATOR?

A. The ICE Calculator estimates the value of an interruption from a customer viewpoint. LBNL bases the value for commercial and industrial customers on their costs due to an outage, and for residential customers, the amount that they would be willing to spend to avoid an outage. It incorporates studies, analyses, and econometric models to determine these values and is widely used by utilities and government agencies across the country to estimate the costs of service interruptions and the value of reliability improvements.

[12] The ICE Calculator is available at: https://icecalculator.com/home.

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Q. HOW DID XCEL ENERGY CALCULATE THE VALUE OF THE BENEFIT RELATED TO BETTER IDENTIFICATION OF NESTED OUTAGES DURING STORM EVENTS?

A. During a large storm event, when a customer can experience multiple outage issues, it can be difficult to determine if all customers' power has been restored in an area after identifying and completing outage work at a single location. The ability to check which customers' power has been restored by automatically "pinging" their AMI meter will improve efficiencies in restoration work.

To calculate this benefit, we utilized outage data on Major Event Days (MEDs) (as this data typically captures large storms) for the years 2015-2017. CAIDI was determined to be 572 minutes for a storm day. The CAIDI value was inserted into the Customer Minute Out (CMO) value calculator. The result is a dollar savings per CMO of $0.65. The average annual number of CMO during major event days was 115,264,755 minutes. It is estimated that the ability to automatically ping AMI meters would reduce the number of CMO by 0.5 percent. This was multiplied by the $0.65 to calculate the total annual benefit of $374,610 which when divided by the number of meters for an estimated benefit of $0.30 per customer per year.

Q. HOW DID XCEL ENERGY CALCULATE THE VALUE OF THE REDUCTION IN RESPONSE TIME FOR SINGLE CUSTOMER EVENTS?

A. Today, when a single customer contacts Xcel Energy about an outage, it is frequently an outage issue on the customer's side of the meter or not an outage at all. First, Xcel Energy attempts to contact the customer and verify the outage. Frequently, this verification fails and the when the first responder arrives at the customer site the issue is then identified as a non-Xcel Energy outage event. Often while Xcel Energy is responding to the first event another single customer outage is in the queue, waiting for work on the first event to be completed. Installation of AMI will allow the Company to determine the first event is a non-Xcel Energy outage event, allowing Xcel Energy to more quickly respond to the other event.

The benefit of this reduced wait time was calculated based on single customer outage event data for 2015-2017 using only non-MEDs data. The average CAIDI for these events was 184 minutes. These outages added up to a total of 3,147,220 CMO for three years. It was estimated that half of the time the CMO could be reduced by 20 percent for an annual savings of 104,907 CMO. The CAIDI value was inserted into the CMO value calculator. The result is a savings per CMO of $0.75. This $0.75 was multiplied by the annual CMO reduction of 104,907 CMO to calculate the total annual savings of $78,680, which when divided by the number of meters equate to an estimated benefit of $0.06 per customer per year.

Q. HOW DID XCEL ENERGY CALCULATE THE VALUE RELATED TO A FASTER RESPONSE TO TAP LEVEL EVENTS?

A. Xcel Energy prioritizes outage events by the number of customers impacted by an outage. On a typical day, when an incoming outage is identified as a single customer event, work in progress continues and response to the single customer event waits until existing work is complete. Typically a multi-customer event is initially identified as a single customer event. Only when the outage event is identified as a multi-customer event, is work reprioritized. AMI will provide greater visibility into outages and will allow work to more

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quickly be reprioritized allowing for a faster response time to larger outage events.

The benefit of this faster response time was calculated using data from multi-customer events from 2015-2017 for non-MEDs. The average annual number of customers experiencing an outage or 396,883 customers was multiplied by three minutes (the estimated average time for more than one customer to report an outage) for an annual CMO savings of 1,190,649 minutes. The CAIDI value for multi-customer events, 271 minutes, was inserted into the CMO value calculator. The result is a savings for a per customer minute out of $0.70. This $0.70 was multiplied by the annual CMO reduction of 1,190,649 CMO to calculate the total annual savings of $833,454, which when divided by the number of meters equate to an estimated benefit of $0.67 per customer per year.

Q. HOW DID XCEL ENERGY CALCULATE THE TOTAL OUTAGE REDUCTION BENEFIT?

A. The total dollar value for each of these three categories of benefits was summed for a total benefit of $1.03 per customer. The Company then calculated the total outage reduction benefit by multiplying this $1.03 value by the total number of meters to be deployed.

d. Non-Quantifiable Benefits

Q. WHAT ARE THE ANTICIPATED NON-QUANTIFIABLE BENEFITS OF AMI?

A. Xcel Energy anticipates qualitative benefits in several areas, including:

- Improved customer choice and experience, leading to customer empowerment and satisfaction;

- Enhanced distributed energy resource integration;
- Environmental benefits of enhanced energy efficiency;
- Improved safety to both customers and Xcel Energy employees; and
- Improvements in power quality.

I will discuss the last four of these non-quantifiable benefits, and Mr. Gersack discusses the first benefit related to improved customer choice and experience.

(1) Distributed Energy Resource Integration

Q. HOW WILL AMI ENABLE GREATER DISTRIBUTED GENERATION INTEGRATION?

A. AMI will provide more timely and more granular data on the flow of energy to and from our customers. With this load flow information, and with voltage, current, and power quality data provided from AMI to ADMS, system operators will be able to facilitate the integration of greater amounts of distributed generation on to the system. In addition, the bi-directional capabilities of the AMI meters will allow the ability to perform net metering for our DER customers without the need to change out the existing meter.

Additionally, the AMI system will capture voltage and usage data which can be compared with nameplate or operational limits of our equipment. Using this data, we will be able to identify problems such as solar causing high secondary voltage, or transformer overload due to either a strong presence of EVs (load) or high reverse flows (such as solar generation). It is our intention to leverage AMI data for this purpose, which will allow us to enable DER while at the same time maintain reliability and power quality for each of our customers.

Further, AMI will enable the creation of more accurate load profiles which are used by ADMS to create better system models for planning and operational purposes. Initially, ADMS will be using relatively few profiles to represent typical customer loads. Once AMI has been in place for a year, we will create more refined profiles which will significantly improve our models. This data will then support planning and operational modeling, enabling us to more accurately identify problems (or the lack thereof) as more load or DER hosting is contemplated for the system.

Finally, AMI meters have bi-directional capabilities that can be utilized by our DER net metering customers. Currently, when a customer who is eligible for net-metering adds generation, we replace the meter with to enable bi-directional flow. With AMI we will be able to effect this change remotely saving the cost of a meter change.

(2) Energy Efficiency

Q. WHAT ARE THE POTENTIAL ENVIRONMENTAL BENEFITS OF AMI?

A. AMI is expected to result in greater energy efficiency by the customer and the Company. As previously stated, AMI will provide the customer more information on energy usage and will enable the Company to offer additional time-based rates or other offerings that allow more customer choice in controlling their energy usage and costs. To the extent these energy efficiency gains reduce the need for generation they will contribute to lower energy emissions.

(3) Safety Improvements

Q. HOW WILL AMI IMPROVE SAFETY FOR BOTH CUSTOMERS AND XCEL ENERGY EMPLOYEES?

A. AMI enables the meters to be read, remotely disconnected and reconnected, and enables remote diagnostics of the customer's service, thereby minimizing safety risks for Company representatives and the customer. For example, AMI will allow us to more rapidly assist emergency personnel by remotely shutting off power to a burning building as opposed to dispatching a truck to perform the disconnection. In addition, while AMR meters can do some level of automated reading, they cannot minimize meter diagnostic and connect/disconnect visits to the same extent as AMI meters. AMI provides several remote functions that eliminate or minimize the need for the Company to visit the meter, which minimizes the intrusiveness to the customer and potentially reduces safety concerns of unknown people accessing their property. Reducing these visits also reduces employee safety risks associated with customer pets and traversing unfamiliar properties.

(4) Power Quality Improvements

Q. HOW WILL AMI PROVIDE IMPROVEMENTS IN POWER QUALITY?

A. AMI will monitor and provide power measurement and voltage data at more points within the distribution system, which will be used in load flow and IVVO calculations to enable improvements in power quality. This will help ensure voltage is within acceptable limits from the substation all the way to the customer's point of service. In other words, better monitoring of power quality reduces the potential for out-of-range voltages that may interfere with electronic devices in customers' homes or businesses. Additionally, timely power outage and restoration will enable improved outage management and contribute to improved power quality to our customers overall.

5. AMI Costs

Q. PLEASE DESCRIBE THE WORK THAT DISTRIBUTION WILL UNDERTAKE IN 2020, 2021, AND 2022 TO IMPLEMENT AMI.

A. Xcel Energy plans to install 1.3 million advanced meters between 2021 and 2024. The Distribution Business Area will be primarily responsible for the purchase and installation of these meters. Distribution will support the installation of the new AMI meters as well as removal, retirement, and disposal of the existing AMR meters, but the installation and removal work will primarily be done by the meter vendor. Distribution will also test and configure all AMI hardware to ensure that it is working properly and is able to integrate with other products and applications.

Q. WHAT ARE DISTRIBUTION'S COSTS FOR THE FULL AMI DEPLOYMENT?

A. Distribution's costs for AMI are broken down by capital additions and O&M costs through the term of multi-year rate plan in Tables 36 and 37 below. I will describe these costs in further detail below.

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Table 36

AMI Capital Additions – Distribution State of MN Electric Jurisdiction (Includes AFUDC) (Dollars in Millions)			
AGIS Program	**2020**	**2021**	**2022**
AMI	$1.8	$22.2	$110.9

Table 37

AMI O&M – Distribution NSPM – Total Company Electric (Dollars in Millions)			
AGIS Program	**2020**	**2021**	**2022**
AMI	$2.3	$3.3	$5.0

a. Distribution Capital Costs for AMI

Q. WHAT ARE THE PRINCIPAL CAPITAL COSTS ASSOCIATED WITH IMPLEMENTATION OF AMI?

A. Distribution's capital costs associated with implementing AMI are: (1) the meters; (2) meter installation; (2) vendor project management; (3) AMI operations; and (4) testing equipment.

Q. WAS DISTRIBUTION PRIMARILY RESPONSIBLE FOR DEVELOPING THE COSTS FOR AMI?

A. Distribution is responsible for the costs associated with acquiring and installing the AMI meters. I describe how we developed our forecast for these costs in more detail in my Direct Testimony. Business Systems is responsible for developing the forecasts for the head-end application, other software and hardware to support AMI data processing, and integrations required by those technologies, and Mr. Harkness will address the development of those costs.

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Q. WHAT ARE THE PRIMARY COMPONENTS OF DISTRIBUTION'S AMI CAPITAL FORECAST?

A. Distribution's AMI capital forecast has five key components: (1) AMI meter purchase; (2) AMI meter installation; (3) vendor project management; (4) AMI operations (external and internal); and (5) testing equipment.

Q. HOW DID DISTRIBUTION DEVELOP THE COSTS FOR THE AMI METERS AND INSTALLATION?

A. The costs for the AMI meters and installation are based on the meter contract with our AMI meter vendor, Itron Inc. (Itron). Additional overheads such as taxes are also included in these estimates.

Q. DESCRIBE THE PROCESS USED TO SELECT THE AMI METER VENDOR.

A. Xcel Energy issued a Request for Proposal (RFP) in March 2018 to select an electric AMI meter vendor that could provide an AMI meter, project management, and installation services. As part of the RFP process, potential vendors were asked to review the Company's priorities and vision for its AMI solution including the capabilities desired by the Company for this technology. The vendors were then asked to provide precise and detailed responses to numerous technical questions regarding their AMI meter offerings related to the following:

- Technical standards of the their meter;
- Capabilities of their meter;
- Compatibility of their AMI meter with other components of the AGIS initiative;
- Data and cybersecurity safeguards;

- Plan and schedule for technology development, integration, and AMI deployment; and
- Itemized pricing information for their AMI meter and installation.

We received responses to this RFP from four different companies.

Q. HOW DID XCEL ENERGY EVALUATE THESE RFP RESPONSES?

A. Xcel Energy evaluated these responses on a number of factors including: (1) total cost; (2) schedule requirements; (3) core metrology; (4) customer benefits and capabilities; (5) integration with the selected NIC from Silver Springs (which was purchased by Itron, Inc.); (6) future proofing/new technology; (7) commercial terms and conditions; and (8) security.

Q. WERE THERE OTHER CAPABILITIES THAT THE COMPANY DESIRED FOR THE NEW AMI METERS?

A. Yes. The Company was also interested in making sure that the selected AMI meter could support distributed intelligence capabilities. As discussed above, these are computing capabilities within the AMI meter that allows the meter to run different applications. These capabilities were an important consideration as the Company understood the customer facing, operational, and future proofing benefits that these capabilities could provide.

Q. DID XCEL ENERGY SELECT AN AMI METER AND INSTALLATION VENDOR FROM THESE RFP RESPONSES?

A. Yes. Based on an assessment and comparison of the capabilities, price, and schedule commitments provided in the RFP responses from these four different meter vendors, Xcel Energy selected a meter vendor. Xcel Energy issued a Limited Notice to Proceed to that meter vendor in December 2018. However, in late March 2019, Xcel Energy learned that the meter vendor that was initially selected would not be able to integrate the selected NIC and meet the Company's meter deployment schedule set forth in the Limited Notice to Proceed. As a result, Xcel Energy requested that the initially selected vendor provide a schedule for deployment for AMI meters that incorporated the vendor's own NIC and network.

Q. WHAT RESPONSE DID THE COMPANY RECEIVE TO THIS REQUEST?

A. The initial meter vendor's response indicated that it would not be able to integrate their own NIC and network into the meters without a significant increase in cost and a risk of further schedule delays. However, the Company also received a comprehensive proposal from another meter vendor that responded to the initial RFP. This meter vendor was able to meet the Company's requested deployment schedule with the necessary NIC integration, offered the necessary meter capabilities, and offered favorable price and contractual terms. As a result, in May 2019, Xcel Energy selected Itron as its meter vendor and a contract was executed on September 1, 2019 (Meter Contract).

Q. WHY DID XCEL ENERGY SELECT ITRON AS ITS METER VENDOR?

A. The primary factors in the decision were:

- Lowest cost/best overall value for an offering that included distributed intelligence / edge technology;
- Lowest risk solution / least complexity;
- Met Xcel Energy's deployment schedule;

- Single vendor solution (Itron is already under contract for the mesh network and the head-end software);
- Met or exceeded Xcel Energy's core metrology requirements, including distributed intelligence capabilities; and
- Most favorable overall commercial terms and conditions, including for edge technology/distributed intelligence.

A summary of our analysis supporting the selection of Itron is attached is Exhibit___(KAB-1), Schedule 10.[13]

Q. HOW DID DISTRIBUTION DEVELOP ITS CAPITAL FORECAST FOR THE AMI VENDOR PROJECT MANAGEMENT COSTS?

A. The forecast for AMI vendor project management is set forth in the Meter Contract. The Company's estimates also include internal overheads.

Q. HOW DID DISTRIBUTION DEVELOP ITS CAPITAL FORECAST FOR AMI OPERATIONS RELATED TO INTERNAL AND EXTERNAL PERSONNEL?

A. Cost estimates for internal and external personnel were developed based on the role and number of required personnel required to perform necessary tasks to enable installation and deployment of the AMI meters. The necessary positions include analysts, program and project managers, engineers, and electricians. The cost estimates were determined using average pay scales for the needed positions combined with an estimate the amount of work required by each of these roles during the AMI installation and deployment. The

[13] The Company's RFPs related to the AGIS projects are provided on the AGIS supporting files compact disk provided with Vol. 2B.

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Company then determined the appropriate allocation between capital and O&M for these costs based on the type of work being performed.

Q. HOW DID DISTRIBUTION DEVELOP ITS CAPITAL FORECAST FOR TESTING EQUIPMENT?

A. These cost estimates were based on quotes obtained and purchases that were made from our existing vendors for this testing equipment. This testing equipment is standard off-the-shelf equipment and we leveraged our relationships with existing vendors to obtain the best cost for this equipment.

b. Distribution O&M Costs for AMI

Q. WHAT ARE DISTRIBUTION'S O&M COSTS ASSOCIATED WITH AMI?

A. The primary components of Distribution's AMI O&M expense relate to: (1) AMI operations (internal and external); and (2) customer claims.

Q. HOW DID THE COMPANY DEVELOP THE BUDGET FOR AMI OPERATIONS?

A. The development of these costs was discussed earlier in the capital section.

Q. HOW DID THE COMPANY DEVELOP THE BUDGET FOR CUSTOMER CLAIMS?

A. Based on input from industry experts, Company estimated approximately $100,000 for small claims from customers associated with meter installations. This total was then spread across the deployment years based on the number of meters deployed in each particular year.

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c. Distribution Contingency for AMI

Q. DOES DISTRIBUTION'S AMI FORECASTS INCLUDE CONTINGENCY AMOUNTS?

A. Yes. The use of contingencies is consistent with project planning practices, especially for large projects. We believe it is appropriate to include a contingency amount at this stage given that the project will be implemented over multiple years, as well as the complexity, size, and integrated nature of this project. Mr. Gersack discusses the overall AGIS project contingencies in his testimony.

Q. WHAT IS THE AMOUNT OF DISTRIBUTION'S CONTINGENCY FOR AMI?

A. The Distribution's AMI budget forecast for the period 2020-2025 includes capital contingency amounts of approximately 26 percent.

Q. CAN YOU PROVIDE MORE INFORMATION ABOUT THE DISTRIBUTION CONTINGENCY ASSOCIATED WITH AMI?

A. Yes. The level of contingency is based on our current risk assessment of items that may impact the final costs of the project. While the Meter Contract dictates much of Distribution's costs for AMI meters and installation, there are still certain unknowns that could impact our final costs. These include: (1) customer access issues; (2) issues with existing electrical wiring to the meter box; and (3) changes to the deployment schedule. Given that the scope of our AMI meter deployment is vast and requires that we replace all of the electric meters throughout our entire service territory, it is important that we have sufficient contingency to account for these potential risks.

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Q. PLEASE DESCRIBE THESE POTENTIAL RISKS THAT YOU IDENTIFIED?

A. Customer access issues involve difficulties associated with obtaining access to a customer's meter to remove the existing meter and install a new meter. This could involve a meter located in the basement of a home or a meter located outside that is guarded by an unfriendly dog. These types of access issues could result in increased costs due the increased labor and expense associated with multiple visits that are required perform the necessary work. Issues with existing electrical wiring to the meter box could also lead to increased costs due to the increase in labor and material costs associated with repairing such issues. Given that the existing meters at many customer locations are between 20-30 years old, it is difficult to know at this time the number of such issues that may arise with the existing electrical wiring. Finally, there may be changes to the deployment schedule that could impact final costs.

Q. HOW DID THE COMPANY DEVELOP AN APPROPRIATE CONTINGENCY AMOUNT TO ACCOUNT FOR THESE POTENTIAL RISKS?

A. Based on our assessment of these risks and their potential financial impact we set an overall contingency amount for AMI and then allocated that amount to each year of the AMI deployment based on the amount of work being completed in each year.

Q. DOES THE COMPANY BELIEVE THE CONTINGENCIES WILL BE USED?

A. Yes, to some extent. While the Company does not necessarily anticipate using all of the contingencies, we believe that some amount of contingency will be used based on experience with prior projects. Contingency amounts are included to avoid the need for tradeoffs in schedule and/or scope and functionality. In this way, we can ensure implementation of the project will

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help maximize benefits for our customers. As Mr. Gersack discusses, there are strict controls on when and how the contingency amounts may be used. The overall AGIS governance structure provides for review and approval of any project changes that will affect the scope, costs, or benefits of implementation. Any changes from budgeted amounts and any specific use of budget contingencies will need approval according to the established AGIS governance processes.

d. AMI Expenditures 2020-2029

Q. WHAT ARE DISTRIBUTION'S CAPITAL EXPENDITURE AND O&M FORECASTS FOR AMI FOR 2020 THROUGH 2029?

A. The tables below provide the Distribution's AMI capital expenditure and O&M forecasts for 2020 through 2029.

Table 38

AMI Capital Expenditures – Distribution NSPM - Total Company Electric (Dollars in Millions)					
	Rate Case Period			5-year Period	10-year Period
AGIS Program	**2020**	**2021**	**2022**	**2023-2024**	**2025-2029***
AMI	$2.6	$22.3	$133.9	$179.5	$14.1
*Period may include additional assumptions, including inflation and labor cost increases that are not part of the capital budget in periods 2020-2024.					

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Table 39

AMI O&M Expenditures – Distribution NSPM – Total Company Electric (Dollars in Millions)					
	Rate Case Period			5-Year Period	10-Year Period
AGIS Program	**2020**	**2021**	**2022**	**2023-2024**	**2025-2029***
AMI	$2.3	$3.3	$5.0	$10.0	$15.7

*Period may include additional assumptions, including inflation and labor cost increases that are not part of the capital budget in periods 2020-2024.

6. Alternatives to AMI

Q. WHAT ALTERNATIVES TO AMI DID THE COMPANY EVALUATE?

A. The Company considered several alternatives to AMI. These alternatives were to: (1) extend the life of the existing AMR meters; (2) replace existing AMR meters as they fail with AMI meters; (3) utilize a different AMR solution with limited TOU capabilities; (4) utilize an AMR drive-by solution; or (5) return to non-AMR, manually read meters. I note that none of these alternatives provide the same benefits and functionality for our customers that are provided by the full deployment of AMI proposed by the Company. AMI meters are essential to an advanced grid that provides our customers and the Company with the data and information to improve our customers' energy experience, and improve reliability, safety, and security of the grid.

a. Extend life of existing AMR meters

Q. CAN YOU DESCRIBE THE CURRENT AMR METERS THAT ARE INSTALLED IN MINNESOTA?

A. The majority of Xcel Energy's electric meters in Minnesota are part of a one-way, transmit-only Radio Frequency (RF) fixed network AMR system. This

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system mostly provides total energy and demand information once a day based on the type of meter installed. The meter is affixed with a Cellnet module that transmits meter pulse data multiple times a day to pole-mounted network components. While the current AMR system has some ability to support more complex rate designs, such as limited TOU rates, and provides non-usage data, such as a "last gasp" when the power goes out, these meters do not have two-way communication capabilities. Without two-way capabilities, we must dispatch a meter technician to reconfigure a meter's TOU intervals each time a customer wants to change their rate.

Q. WHAT DID THE COMPANY CONCLUDE AFTER EVALUATING THE POSSIBILITY OF EXTENDING THE LIFE OF THE EXISTING AMR METERS?

A. Our current AMR system has been in place since the mid-1990s and has provided substantial value for customers since its installation. However, as I mentioned above, our Cellnet meter reading and vendor support contract expires at the end of 2025. We have the ability to extend this contract for one additional year but at a significant cost increase as compared to prior years. We are the last remaining customer on the Cellnet system such that our ability to extend this meter reading and vendor support contract beyond 2026 is highly unlikely. As a result, our ability to continue to use the Cellnet system for meter reading beyond 2026 would require us to purchase the existing meter reading network, software, and meter modules from Cellnet.

Even if we purchased this system from Cellnet, it would be challenging to continue to operate and maintain this aging system in good working order because Cellnet will stop manufacturing replacement parts for this system in 2022. As this system is proprietary, there are no other vendors that we can utilize to provide replacement parts for this system. As a result, as these meters age and require repair, we will not be able to purchase the necessary replacement components. Given the inability to find replacement parts for the existing Cellnet meters, Xcel Energy determined that trying to extend the life of these meters beyond the end of the Cellnet contract was simply not a reasonable or prudent alternative.

b. Replacing AMR meters one at a time

Q. DID THE COMPANY CONSIDER REPLACING AMR METERS WITH AMI METERS ONE AT A TIME AS THEY FAIL?

A. Yes, but the Company determined that installing the 1.3 million AMI meters at the same time to all of our Minnesota customers was the best option for several reasons. First, deploying all of the AMI meters at once reduces the cost of installation of each individual meter as there are efficiencies of scale in such a large deployment. Second, the AMI mesh technology that allows the AMI meters to communicate with each other and the utility requires a certain density of meters in a particular area to sustain reliable communications. AMI meters communicate within a mesh to an access point device, and the data is then transmitted to Company. If the Company were to replace meters one at a time, we would need to replace enough meters in a particular area to comprise a sufficient AMI mesh network otherwise communications could be comprised. We would also still need to install portions of the FAN communications network at that time.

Given the complexity associated with the installation of the communication network, the Company determined that best approach was a mass deployment of AMI meters that could be synchronized with the FAN deployment. Third, AMI is an integral component to the overall AGIS initiative. For instance, AMI meters serve as sensors at the customer premise that provide vital information to FLISR and IVVO on power status and voltage level. Without AMI, the Company would need to employ independent sensors that would not be able to match the performance of AMI meters given that they could not be located at the customer's point of service like AMI meters.

c. AMR alternatives

Q. DID THE COMPANY EVALUATE INSTALLING A DIFFERENT TYPE OF AMR METER SYSTEM?

A. Yes. There are several different types of AMR metering systems: (1) two-way RF system; (2) one-way RF system (currently in use in most of Xcel Energy's Minnesota service territory); and (3) a drive-by system. Xcel Energy evaluated each of these AMR systems and a manual read meter alternative and compared their capabilities to the AMI system.

Q. WHAT DID THE COMPANY CONCLUDE AFTER EVALUATING THESE DIFFERENT METER SOLUTIONS?

A. The Company concluded none of these alternative meter systems could match the features and capabilities of the AMI system. Although both the AMI and AMR systems provide billing data, the AMI system provides additional features and information that can be used to support advanced TOU rates, improve outage information, support demand response and distributed generation, and provide timely usage information that consumers can use to save money by managing their use of electricity. A summary comparison of the different meter options to AMI is provided in Table 40 below.

Table 40

Comparison of Metering Capabilities

Feature/ Capability	AMI	AMR (One-way System)	AMR (Limited two-way system)	AMR Drive-by System	Manual Read
TOU data	● Would support more complex TOU rates and meters can be remotely programmed to capture TOU data	◐ The system supports two tier rates only and meters cannot be remotely programmed to capture TOU data	◐ Xcel Energy billing systems support only two TOU rates and meters cannot be remotely programmed to capture TOU data.	◔ Limited capability. Some meters could support one TOU bin in addition to other metering quantities.	○ Not supported
Interval data	● Capable of measuring and recording more complex interval data sets; supports more interval data lengths	◔ Can only be used for load research purposes and not for billing as data is not revenue grade quality; limited to traditional energy interval data	◐ Data can be used for billing; limited to traditional energy data; limited to 5 or 15 minute interval lengths	○ Not supported	○ Not supported
Real time notification of power outages	● Real-time availability of outage information	◐ Outage notification but not in real-time	◐ Outage notification sent up to meter head-end system	○ Not supported	○ Not supported
Fast response to customer inquires	● Real-time access to customer metering data and diagnostic information	◔ Limited access to customers metering data and meter diagnostic information	◔ Lack of real-time view of customer's metering data and no access to meter real time diagnostic information	○ Not supported	○ Not supported
Support integrated systems that offer customers options for energy conservation and cost management programs	● Technology supports customer side technologies such as smart thermostats, load control devices, etc.	◔ Limited and uncoordinated technology that can allow for such customer facing solutions.	○ Not supported	○ Not supported	○ Not supported

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Table 40 (continued)

Feature/ Capability	AMI	AMR (One-way System)	AMR (Limited two-way system)	AMR Drive-by System	Manual Read
Ability to remotely upgrade metering devices e.g. firmware upgrade, meter configuration changes	● AMI offers the platform to remotely perform such functions.	○ Not supported	○ Not supported	○ Not supported	○ Not supported
Availability of real-time data e.g. voltage, current, power, etc. that are vital for distributed energy resource monitoring	● AMI offers the foundation that makes the availability of such data possible.	○ Not supported by AMR system. Costly to extend standalone communication systems to all distributed energy resources	○ Not supported by AMR system. Costly to extend standalone communication systems to all distributed energy resources	○ Not supported	○ Not supported
Availability of power quality events e.g. momentary outages for each customer, sags, swells, etc. that are essential for system reliability improvement	● AMI offers the foundation that makes the availability of such data possible.	○ Not supported	○ Not supported	○ Not supported	○ Not supported
Remote availability of meter diagnostic data useful for remote troubleshooting	● Data available with full AMI systems.	◔ Feature supported to a limited extent.	◔ Feature supported to a limited extent.	◔ Feature supported to a limited extent.	○ Not supported
Remote reconnection/ disconnection	● System supports remote reconnect/disconnect of residential type customers and limited small commercial customers	○ Not supported	○ Not supported	○ Not supported	○ Not supported
Electric vehicle interconnects	● Allows EVs to utilize TOU pricing and provides load data to detect potential voltage issues.	○ Not supported	○ Not supported	○ Not supported	○ Not supported

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Table 40 (continued)

Feature/ Capability	AMI	AMR (One-way System)	AMR (Limited two-way system)	AMR Drive-by System	Manual Read
Detect unsafe field metering conditions	● Provides service condition information such as temperature and service quality that can be used to detect unsafe conditions such as hot sockets.	○ Current AMR systems do not provide temperature information	○ Current AMR systems do not provide temperature information	○ Current AMR systems do not provide temperature information	○ Not supported
Reliable methods for detecting energy theft	● AMI offers the platform that can be used to detect energy theft conditions.	◔ Limited capability	◔ Limited capability	○ Not supported	○ Not supported

Legend for Capabilities				
Full	**Most**	**Partial**	**Minimal**	**None**
●	◕	◐	◔	○

As shown in this table, none of the other metering options come close to matching the capabilities provided by AMI. Moreover, these meter alternatives does not provide the same quantifiable and non-quantifiable benefits that I outlined above.

Q. WHAT DID THE COMPANY CONCLUDE AFTER EVALUATING THE DIFFERENT AMR ALTERNATIVES?

A. While the AMR alternatives performing similarly to AMI in terms of basic meter reading capabilities, they cannot match the advanced TOU information, two-way capabilities, or functions provided by AMI. As the distribution system evolves with increasing amounts of DER, and customers' expectations require timely energy usage data and the ability to connect their smart devices to their meter, we must have the facilities to meet these needs. AMI is the correct technology to meet both our current and our future system and customer needs. The industry has also recognized the superiority of the AMI technology and vendors and suppliers of AMR systems and replacement parts are becoming harder to find.

Q. WHY DID THE COMPANY REJECT THE OPTION OF REVERTING TO DRIVE-BY AMR METERS?

A. Of the three types of AMR solutions, the drive-by solution is the most antiquated because such meters cannot be read remotely. Instead a drive-by AMR solution only provides meter readings when a meter reader drives by. Drive-by AMR meters would also have higher O&M costs as compared to AMI meters due to the need to perform drive-by meter readings which require additional personnel and fleet vehicles. For purposes of the CBA, the Company calculated the capital and O&M costs of a drive-by alternative. While these costs are lower than the costs for AMI, the drive-by system does not provide any of the benefits attributed to AMI as shown in Table 40 above.

d. Manual Read Meters

Q. WHY DID THE COMPANY REJECT THE OPTION OF REVERTING TO NON-AMR MANUAL READ METERS?

A. Reverting to manually read meters is not reasonable alternatives because reverting to non-AMR meters would require the replacement of well over a million meters but would not provide any of the benefits of the AMI meter such as timely energy usage data, outage information, or voltage information. In addition, manual read meters would have higher meter reading costs as

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compared to AMI meters due to the need to send personnel out into the field to perform manual monthly readings. Such manual meter reading is a less than ideal option as it would require hiring hundreds of meter readers along with the purchase of vehicles and equipment to perform these manual reads. Manual reading also has a lower read rate and an increase in the number of billing exceptions per read as compared to both AMR and AMI.

e. AMI Opt out

Q. WILL XCEL ENERGY OFFER INDIVIDUAL CUSTOMERS AN ALTERNATIVE TO AN AMI METER?

A. Yes. The Company will develop and offer customers the ability to opt out of having an AMI meter at the start of AMI deployment in 2021. This program will provide customers with the option to have a non-AMI digital meter installed and have it manually read on a monthly basis for billing purposes. This is discussed in further detail by Mr. Cardenas.

Q. WHAT DO YOU CONCLUDE ABOUT THE ALTERNATIVES TO AMI?

A. All of the variations of continuing the current outdated AMR technology provide limited benefits compared to AMI. AMI will provide customers more timely energy information and more control over how and when they use energy in their homes and businesses. It will enable the Company to provide an improved customer experience over AMR when addressing customers' concerns with their meter reading, billing, power outages, quality of service, and connections of service.

Further, AMI is much more than a meter reading technology; it is foundational component of overall AGIS initiative because it provides a

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central source of information with which many components of the advanced grid interact. For instance, AMI meters serve as important end of feeder sensors for IVVO and repeaters for the FAN communication network that increase the dependability of this network. The system visibility and data delivered by AMI provides customer benefits for reliability and enhances utility planning and operational capabilities. Although AMI offers many more customer benefits than AMR, our opt-out program plans will also provide customer choice for those who choose not to have an AMI meter installed.

7. Interoperability

Q. WHAT IS INTEROPERABILITY AND WHY IS IT AN IMPORTANT CONSIDERATION FOR THE COMPANY'S AGIS INVESTMENTS?

A. Interoperability is the ability for systems and different products from different vendors to work together seamlessly. For our AGIS investments, this means that each of the individual devices selected for this initiative will work together to perform the necessary task such as an on-demand meter reading.

Q. WHY IS INTEROPERABILITY AN IMPORTANT CHARACTERISTIC FOR THE AMI METERS?

A. Our AMI meters must be able to communicate and take direction from several different AGIS components, even if those components were manufactured by different vendors, as well as the Company's existing technology. For instance, since our AMI meters also serve as mesh network devices that transmit data from other field devices, it was important to ensure that the selected AMI meters had an interface that was capable of supporting multiple communication modules by multiple suppliers.

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Q. HOW DOES THE AMI METER SELECTED BY THE COMPANY FACILITATE INTEROPERABILITY WITH THE OTHER AGIS COMPONENTS?

A. The Company's RFP that was issued to select the AMI meter vendor required the meter to have several interoperability characteristics. These included that the meter must be built to the industry ANSI C12 standard and have an interface capable of supporting multiple communication modules. The RFP process is discussed in greater detail above.

8. Minimization of Risk of Obsolescence

Q. WHAT STEPS DID THE COMPANY TAKE TO MINIMIZE THE RISK OF OBSOLESCENCE OF THE SELECTED AMI TECHNOLOGY?

A. One of the issues with new technology is that it is ever changing and new technology can be obsolete shortly after deployment. In evaluating different AMI technology, the Company put an emphasis on "future proofing" the capabilities to minimize the risk of obsolescence. Specifically, the Company sought and selected AMI technology that had the following characteristics:

- Over the air (OTA) firmware and meter configuration upgrades without field visits or meter replacement;
- Enhanced memory size to support potential future use cases that would require certain meter configurations;
- Flexible, standard service components that are common in the industry such that any future technology would be adapted to this industry standard;
- Architecture for ease of integration with existing and future systems; and
- Reduction in technology design and development costs due to the (re)use of standard interfaces.

Q. PLEASE EXPLAIN HOW THESE CHARACTERISTICS REDUCE THE RISK THAT THE SELECTED AMI TECHNOLOGY WILL BECOME OBSOLETE IN THE NEAR FUTURE?

A. We can predict that future needs will require our technologies to have more memory and better communications throughput. Among the possible changes are currently anticipated are advances in Distributed Intelligence, cybersecurity updates, and the ability to add more logic or intelligence in the meter. Based on this, the AMI meter specifications identified above will be essential in ensuring that hardware and technology deployed can be upgraded in the field without the need for a wholesale meter replacement.

E. FAN

1. Overview of FAN

Q. WHAT IS THE FAN?

A. The FAN is a private, Company-owned wireless communications network. The primary function of FAN is to enable secure and efficient two-way communication of information and data between our existing communication infrastructure located at our substations and new or planned intelligent field devices – up to and including meters at customers' homes and businesses. Through the substation infrastructure's connectivity to the Company's existing Wide Area Network (WAN), the FAN enables back-office applications to directly communicate with field devices providing usage information for both our customers and the Company.

The implementation of FAN is a joint effort with Business Systems, and Mr. Harkness provides detailed discussion of FAN and addresses the IDP filing requirements related to FAN in his testimony.

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Q. WHAT ARE THE PRINCIPAL TECHNOLOGIES THAT WILL BE USED BY THE FAN?

A. To provide communication between the substation and field devices, the FAN will use two wireless technologies: (1) Wireless Smart Utility Network (WiSUN) mesh network; and (2) a Worldwide Interoperability for Microwave Access (WiMAX) network.

Q. WHAT IS THE PURPOSE OF THE WISUN AND WIMAX NETWORK?

A. The WiSUN mesh network will communicate directly with the AMI infrastructure (including the advanced meters) and the Distribution Automation (DA) field devices used for IVVO and FLISR.

The WiMAX network will provide redundant, reliable, and secure connectivity between the WiSUN network and the Company's WAN. The field devices and the WiSUN access points connect to the WiMAX base stations (mostly located at the Company's substations) via wireless communication modules that are integrated into these devices.

Through the substation's connectivity to the WAN, the FAN (including the WiMAX network and the downstream WiSUN mesh network (will enable the Company's advanced applications (such as ADMS and AMI, and the sub-applications including FLISR and IVVO) to communicate with the field devices that implement those applications and sub-applications. Figure 11 provides an illustration of the principal components of the FAN. The WiSUN and WiMAX technologies are discussed in more detail by Mr. Harkness.

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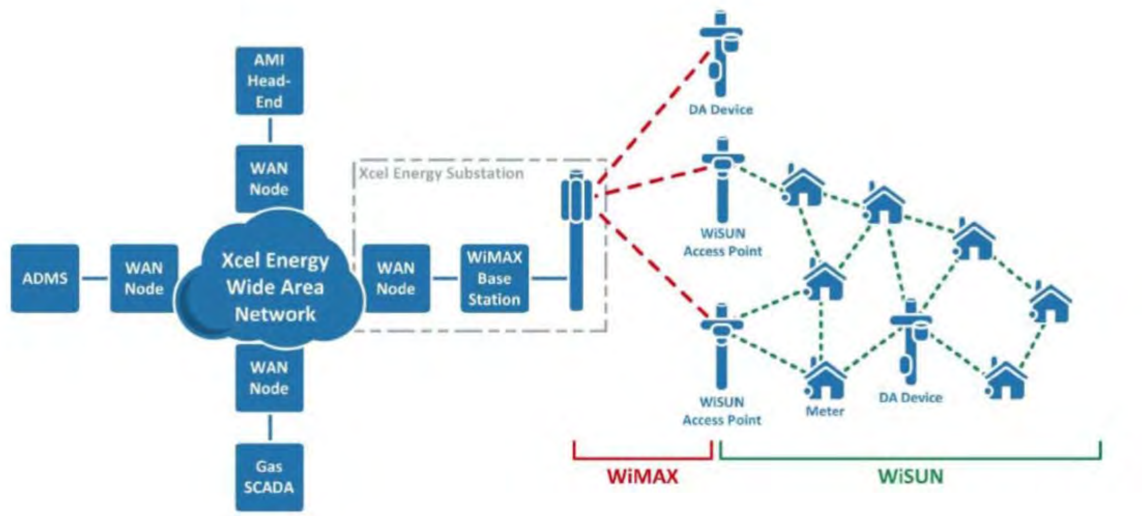
Figure 11

FAN Overview



Q. DESCRIBE THE COMPONENTS OF THE WISUN NETWORK.

A. The WiSUN mesh network is the key network structure that will communicate directly with the AMI infrastructure and most DA field devices. The core infrastructure for WiSUN will consists of three main device types:

- *Access Points*: device that will link the Company's endpoint devices that are enabled with wireless communication modules with the rest of the Company's communication network. The access points will wirelessly connect directly to backhaul (which is an intermediate link in the communications network – WiMAX, in this case) to pass data between the mesh network and the WAN. The access points will be located primarily on distribution poles and other similar structures.
- *Repeaters*: are range extenders that are used to fill in coverage gaps where devices would be otherwise unable to communicate. The mesh network design of WiSUN means that additional nodes on the network provide

devices more options to communicate with their access point. Repeaters will be located primarily on distribution poles.

- *Endpoint Devices*: include AMI meters and DA field devices, such as the intelligent FLISR and IVVO field devices, that have built-in radios. The AMI meters will be located on customer premises; the field devices will be co-located with either pole-mounted or pad-mounted distribution devices.

Q. DESCRIBE THE COMPONENTS OF THE WIMAX NETWORK.

A. The WiMAX network will consist of two main components: (1) base stations; and (2) customer premise equipment (CPE).[14]

Base stations will serve as the key communication points between the substation WAN and the WiSUN mesh network. At substations there will be a base station with up to three radios that will communicate with the WAN and multi-directionally with CPEs out in the field of operations. Where possible, the base stations at the substations will be mounted on existing poles or structures.

The CPEs will further enable the back office applications to communicate wirelessly with any device accessible to that access point's connections to the mesh network. CPEs will be mounted on distribution poles in the field of operation.

[14] CPE is an industry term that refers to specific equipment. The "customer" in CPE refers to Xcel Energy or a similarly situated entity using this equipment and does not refer to Xcel Energy's customers.

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Q. HOW WILL THE FAN DEVICES OPERATE IN THE EVENT OF A POWER OUTAGE?

A. The core infrastructure on both WiSUN and WiMAX is backed up by batteries to enable continued functionality and operations in the case of a power failure to that device – a situation where the continued functionality of those networks is critical. These battery systems also self-monitor and will automatically report any issues to ensure prompt repair. Specific devices will also have battery power, either supplied by the device itself or through a supplemental battery system, to enable continued operations during an outage. For example, the FLISR devices, that are critical during a distribution outage, will have battery power.

Q. HOW DOES THE FAN ASSIST THE OTHER AGIS COMPONENTS IN MANAGING OUTAGES?

A. As discussed above, the core infrastructure of both WiMAX and WiSUN will have battery backup as will other devices that are critical for outage operations. This means that the Distribution Control Center will still have visibility into the current status of the grid and remote control capabilities for devices like reclosers. Although AMI meters will not have battery backup, they will have energy storage adequate to send "last gasp" messages (that is, a final message transmitted by the meter upon detection of an outage) over the FAN to let the head-end system know that particular customers do not have power service. Once those customers have been reenergized, those meters will once again be able to communicate on the FAN and the head-end system will be able to remotely verify that customers have been reconnected. The additional visibility will also aid with the restoration of nested outages[15] by showing that certain customers remain without power even when the

[15] Storms often result in multiple failures. When we repair and reenergize a section, but a subset remains out due to a second fault, that outage is referred to as a "nested" outage.

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surrounding issue was resolved. This will help the control center identify those situations and reduce restoration times.

2. FAN Implementation

Q. WHAT WORK WILL DISTRIBUTION PERFORM TO SUPPORT INSTALLATION OF THE FAN?

A. The implementation of the FAN will be a joint effort between Business Systems and Distribution. Distribution will be responsible for the installation of the FAN devices (primarily access points, repeaters, and CPEs) that will be located on distribution poles. Distribution will also be responsible for installation of the WiMAX base stations. Business Systems will be responsible for installation of WiMAX base stations at the substations. Business Systems will also be responsible for the design of the network systems for WiMAX and WiSUN, the security of these networks, and configuring the software and hardware components of FAN.

Q. HOW WILL THESE FAN DEVICES BE INSTALLED BY DISTRIBUTION?

A. The access points, repeaters, and CPEs will be mounted primarily on distribution poles to provide adequate height for the radio signal to propagate. In certain instances, the distribution pole will need to be modified or replaced to support a particular device and Distribution will be responsible for completing this modification or replacement. In areas where Xcel Energy has underground service, arrangements will be made to mount the devices on street lights or other structures with appropriate height.

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Q. HAS THE COMPANY ALREADY DEPLOYED FAN DEVICES IN MINNESOTA?

A. To support the TOU pilot, the Company deployed limited FAN infrastructure in 2019 in the small geographic area overlaying the AMI meter deployment (Eden Prairie and Minneapolis). Business Systems has begun to deploy WiMAX base stations in three substations and Distribution has begun to deploy of access points (APs) and repeaters that will be connected to those base stations.

Q. WHAT IS THE FAN IMPLEMENTATION SCHEDULE TO SUPPORT THE FULL AMI DEPLOYMENT STARTING IN 2021?

A. For any given geography, FAN availability will precede AMI meter deployment by approximately 3-6 months, to ensure that meters will have a fully operational network to use when they are installed. To support this, we will need to begin FAN installation approximately 12-18 months ahead of AMI meter deployment to allow adequate time for permitting, material sourcing, and construction. Based on the current schedule for the full AMI meter deployment, we anticipate FAN deployment will begin in mid-2020 to ensure network readiness for when AMI meters

3. FAN Costs

Q. WHAT DISTRIBUTION CAPITAL AND O&M COSTS ARE NECESSARY FOR FAN IMPLEMENTATION IN 2020, 2021, AND 2022?

A. As discussed above, the work that Distribution will be performing to support the implementation of FAN is limited to the procurement and installation of pole-mounted FAN devices. Mr. Harkness discusses Business Systems' FAN costs which include the costs for the WiSUN and WiMAX components. Tables 41 and 42 below provide Distribution's capital additions and O&M

costs for FAN implementation for 2020 through 2022 and I will describe these costs in further detail below.

Table 41

FAN Capital Additions – Distribution State of MN Electric Jurisdiction (Includes AFUDC) (Dollars in Millions)			
AGIS Program	**2020**	**2021**	**2022**
FAN	$2.8	$5.4	$0.0

Table 42

FAN O&M – Distribution NSPM – Total Company Electric (Dollars in Millions)			
AGIS Program	**2020**	**2021**	**2022**
FAN	$0.1	$0.2	$0.4

a. Distribution's Capital Costs

Q. WHAT ARE THE PRIMARY COMPONENTS OF DISTRIBUTION'S FAN CAPITAL FORECAST?

A. These capital costs include FAN devices, installation, and project management, as well as preparation costs.

Q. HOW DID DISTRIBUTION DEVELOP THESE CAPITAL COST ESTIMATES FOR FAN?

A. To estimate the device costs and installation costs for FAN, Engineering performed a preliminary Radio Frequency Network Study. The purpose of this study was to determine the location and number of access points, repeaters, and CPEs that would be required to facilitate a reliable FAN

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communication network for the AMI meter and the distribution automation devices. The study concluded that approximately 550 access points, 3,000 repeaters, and 2,500 CPEs will be required for the FAN coverage area.

Q. WHAT WAS THE NEXT STEP IN DEVELOPING THE CAPITAL COST ESTIMATES?

A. After determining the number of devices, the price for each device was derived from prices included in contracts that resulted from several RFP processes. These RFPs are described by Mr. Harkness. The labor costs to install each device are based on a combination of contractor and internal labor.

Q. HOW DID DISTRIBUTION DETERMINE THE LABOR COSTS FOR THE INSTALLATION OF THE FAN DEVICES?

A. Our labor estimates are based on our prior experience with installing FAN devices for both FAN rollout in Colorado and the limited deployment of FAN in Minnesota to support the TOU pilot. This work provides a reasonable point of reference for the labor estimates for the FAN deployment in Minnesota.

b. Distribution's O&M Costs

Q. WHAT ARE THE PRIMARY COMPONENTS OF DISTRIBUTION'S O&M COSTS FOR FAN?

A. The FAN's O&M costs will include costs for infrastructure and hardware, operations (including equipment and personnel), and preparation costs. These costs include the field level support for fixing broken and damaged equipment, additional personnel to monitor and manage the FAN, other preparation work that is designated as O&M, hardware and software maintenance, and training. Personnel will include both Company employees and contractors, which will be used based on workload, location, and timing. Most incremental work will be performed by contractors.

Q. HOW DID DISTRIBUTION DETERMINE THE O&M COSTS FOR FAN?

A. The projected costs associated with project employees are based on typical Company wages, and contractor costs are costs of contractors at estimated wage scales. The costs to fix and replace broken and damaged equipment are based on expected failure and damage rates for these devices.

c. Distribution Contingency for FAN

Q. DOES DISTRIBUTION'S FAN FORECAST INCLUDE CONTINGENCY AMOUNTS?

A. No. There is no contingency amount included in Distribution's FAN costs because Distribution has limited scope of defined work related to FAN.

d. FAN Expenditures 2020 to 2029

Q. WHAT ARE THE DISTRIBUTION'S CAPITAL EXPENDITURE AND O&M FORECASTS FOR THE FAN FOR 2020 THROUGH 2029?

A. The tables below provide Distribution's capital expenditures and O&M forecasts for the FAN for 2020 through 2029.

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Table 43

FAN Capital Expenditures – Distribution NSPM – Total Company Electric (Dollars in Millions)					
	Rate Case Period			5-Year Period	10-Year Period
AGIS Program	**2020**	**2021**	**2022**	**2023-2024**	**2025-2029**
FAN	$3.2	$6.2	$0.0	$0.0	$0.0

Table 44

FAN O&M Expenditures – Distribution NSPM – Total Company Electric (Dollars in Millions)					
	Rate Case Period			5-Year Period	10-Year Period
AGIS Program	**2020**	**2021**	**2022**	**2023-2024**	**2025-2029**
FAN	$0.1	$0.2	$0.4	$0.3	$0.4

F. FLISR

1. *Overview of FLISR*

Q. WHAT IS FLISR?

A. FLISR (Fault Location, Isolation and Service Restoration) is a form of distribution automation that involves the deployment of automated switching devices that work to detect feeder mainline faults, isolate them, and restore power to unfaulted sections – decreasing the duration and number of customers affected by any individual outage. The FLISR application relies on three primary components to operate: (1) ADMS, for the central control and logic; (2) intelligent field devices to detect faults and operate field equipment; and (3) the FAN, for wireless communications to each device. Fault Location Prediction (FLP) is a subset application of FLISR that indirectly considers and leverages sensor data from the field devices to locate a faulted section of a

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feeder and reduce patrol times necessary to locate a fault. The FLISR system is expected to reduce outage durations for customers and improve overall system reliability performance metrics, such as SAIDI and SAIFI. It should be noted that while outage durations will decrease, a customer may see an increase in the number of momentary (less than 5 minutes) outages as FLISR isolates the faulted section.

Q. WHAT ARE FAULTS ON THE DISTRIBUTION SYSTEM?

A. Faults are failures of the electrical system, which result in abnormal power flows. The distribution system is designed to detect such conditions and de-energize the affected portions of the system in order to limit damage and ensure safety. Faults can be either temporary or permanent. A permanent fault is one where permanent damage is done to the system and a sustained outage (i.e., greater than five minutes) is experienced by the customer. Permanent faults may be the result of insulator failures, broken wires, equipment failure (e.g., cable failure, transformer failure), and public damage (e.g., an automobile accident impacting a utility pole). Temporary faults are those where customers experience a momentary interruption (i.e., less than five minutes). Causes of temporary faults are transient in nature. Some examples are lightning, conductors slapping in the wind, animal contact, and tree branches that fall across conductors and then fall or burn off.

Q. HOW DOES XCEL ENERGY CURRENTLY IDENTIFY AND ISOLATE FAULTS ON THE DISTRIBUTION SYSTEM?

A. The Company does have a SCADA system that informs operators of most feeder and substation-level outages. When the outage does not impact a full feeder or where SCADA capability does not yet exist (many rural systems),

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Xcel Energy must rely on calls from customers to inform the Company of an outage. As customers call to report outages, the service locations are identified in our Outage Management System (OMS). Initially, each outage is identified as affecting a single customer. But as outages for customers served by common elements accumulate, the outage "escalates", and points to the most probable location for us to initiate our repair activities. The Control Center Operator then uses aggregated information from all current outages, prioritizes, and dispatches field personnel to effect the most efficient restoration. When dispatched, crews patrol the feeder to identify the cause of the fault then proceed to manually open switches to isolate the fault. Next, they manually close other switches to restore service to as many customers as possible. Finally, they affect the repairs and restore power to the customers.

Q. WHAT IS OUTAGE TIME FOR A TYPICAL FEEDER-LEVEL FAULT?

A. The average time to restore a feeder-level fault in Minnesota has been 124.9 minutes (5-year average, not storm-normalized). NSPM feeders serve, on average, 1,219 customers. The average customer count for the feeders selected for the proposed FLISR deployment is 1,687.

Q. ARE THERE DEVICES ON THE XCEL ENERGY SYSTEM THAT CURRENTLY ASSIST WITH FAULT ISOLATION AND SERVICE RESTORATION?

A. Yes. We currently have small-scale automation programs across our distribution system. We have been installing intelligent switches for a number of years on much of our 34.5 kV system in Minnesota. Like FLISR, these devices act to isolate the faulted section of the system and restore power to unfaulted sections of the feeder when possible. These intelligent switches have improved the reliability for over 114,000 Minnesota customers. If the device is successful at isolating the fault to one portion of the line, customers upstream of the device are spared from a sustained outage.

We have also been installing faulted circuit indicators, powerline sensors, and replacing certain relays on the system to aid our ability to quickly find a fault so we can begin restoring service to interrupted customers.

Q. WHAT ARE THE LIMITATIONS OF THE THESE EXISTING DEVICES?

A. While the existing sensing devices provide important benefits, they are not as flexible as the fault location devices that are now available. For instance, faulted circuit indicators do not provide the fault magnitude, which ADMS can use to locate the probable location of the fault. Also, many of the earlier systems rely on proprietary communications systems, which means they lack the ability to communicate seamlessly with other devices on our system. While these early intelligence devices have been beneficial for our customers and our operations, we intend to implement newer FLISR technologies going forward – eventually replacing some of the current devices.

Q. CAN YOU DESCRIBE IN MORE DETAIL HOW FLISR OPERATES?

A. Yes. There are three basic steps to the operation of FLISR. First, the system identifies the faulted section and, where possible, calculates the probable location within that section. Second, the system isolates the fault by opening devices in the field. Finally, the system restores the service to as many customers as possible through additional automated field switching.

In the first step, when a fault occurs, the FLISR protective devices will open, or sectionalize the feeder to isolate the fault. Depending on the devices and

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the situation, the device may attempt to reenergize the affected area first, in case the fault was only temporary in nature. Once the fault is cleared (de-energized), data will be sent from those intelligent field devices to ADMS. ADMS will then run the FLISR application which will analyze the situation, select appropriate switching device near the fault, and generate a switching plan to restore service to other customers. In doing so, ADMS will take into account not only device and feeder loading, but surrounding substation loading as well. ADMS will then execute the proposed switching plan and notify the operator of the need to send a crew to the isolated section to manually investigate the fault event. This process is expected to take less than five minutes from the occurrence of an outage to operator notification. ADMS will also be able to run the FLP algorithm and predict which segment within a FLISR section the fault exists, which will reduce expected patrol times by crews. Figure 12 below shows how FLISR isolates that impacted feeder section to restore power to other sections of the line.

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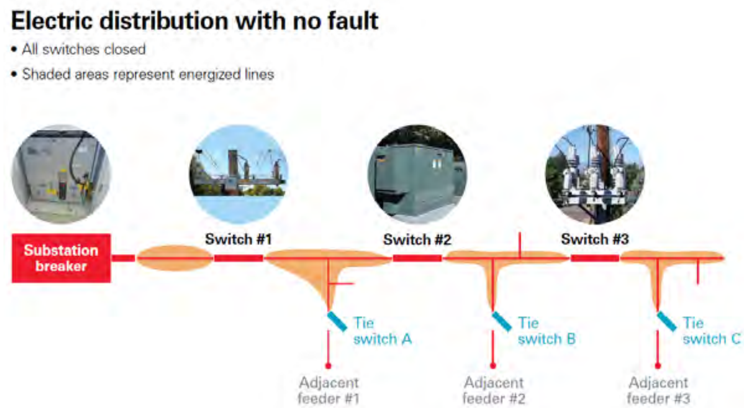
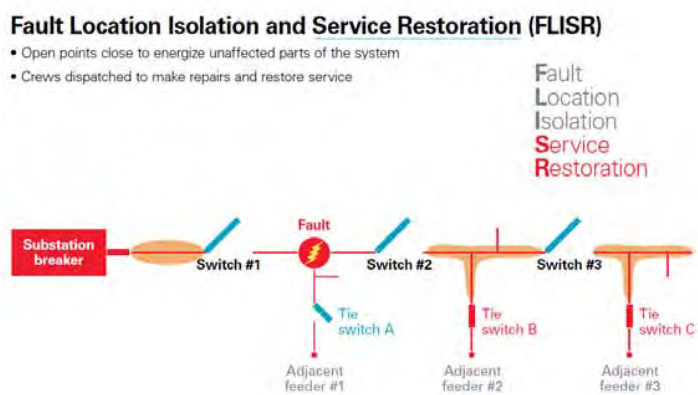
Figure 12

FLISR Feeder Configuration – Prior to Fault



FLISR Feeder Configuration – Service Restored



Q. HOW WILL FLISR IMPACT THE COMPANY'S RELIABILITY PERFORMANCE?

A. We expect that FLISR will improve our overall reliability performance and a customer's overall outage experience. However, our performance in certain reliability metrics may decline after FLISR is installed. For instance, FLISR will help some customers avoid sustained outages. Sustained outages are tracked by the SAIFI metric (annual average number of sustained service interruptions per customer served) and shorter duration outages (less than five minutes) are tracked by the Momentary Average Interruption Frequency Index (MAIFI) metric. In essence, we expect that FLISR will transform outages that would have been sustained outages into momentary outages. In addition, with AMI meters, we will be better able to track these momentary outages for all of our customers.

As a result, with FLISR, we expect that customers will experience fewer sustained outages thus improving our SAIFI performance while our MAIFI performance will decline. We also expect that FLISR will cause our Customer Average Interruption Duration Index (CAIDI) performance to decline. CAIDI is a measure of the length of time the average customer can expect to be without power during an interruption. CAIDI performance declines when the outages are more heavily concentrated on problems that take a longer time to fix. As FLISR's automatic switching will restore power quickly to customers not along the faulted section, the result will be a sustained outage that impacts fewer customers. This will negatively impact our CAIDI performance but will be a more positive outage experience for our customers because FLISR will minimize widespread extended outages on the system.

Q. PLEASE DESCRIBE HOW FLP OPERATES AND HOW IT WILL IMPROVE CUSTOMERS' OUTAGE EXPERIENCES.

A. Feeders enabled only with FLP will operate in a slightly different manner from FLISR-enabled feeders. Should a fault occur, FLP devices upstream of the fault will capture an event occurring and will communicate relevant measurements pertaining to the fault (such as current, voltage, and phase indication) to ADMS. ADMS will compare these measurements to the impedance model and will generate expected fault locations. ADMS will then notify the operator of these locations (with a level of certainty for each location), and the operator will dispatch a crew directly to the expected faulted section (as opposed to having the patrol the entire feeder line, as in the current situation) to isolate the faulted section. This reduction in patrol time will result in reduced outage durations for our customers.

Xcel Energy is proposing to install up to two sets of three-phase advanced powerline sensors along each feeder targeted for FLP deployment. At the substation where the feeder originates, we will use either an intelligent relay or install one set of sensors. Existing remote fault indicators and new intelligent device telemetry will be incorporated into the FLP deployment. If an existing device is in the correct location to employ FLP functionality, this will obviate the need for a new device. Other existing devices will enhance FLP's capabilities by providing additional data to improve FLP algorithm performance.

Q. WHAT ARE THE COMPONENTS OF FLISR?

A. There are four principal components of FLISR:

- Reclosers;
- Automated overhead switches;
- Automated switch cabinets; and
- Substation Relaying.

There are two main components to FLP:

- Powerline sensors; and
- Substation Relaying.

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Q. WHAT ARE RECLOSERS AND HOW DO THEY OPERATE?

A. Reclosers are pole-mounted reclosing and switching devices. The Company currently has reclosers on the distribution system, but only a few of these reclosers have communications to enable remote operations capabilities. The new devices employed by the Company will perform the same functions of existing reclosers but have enhanced monitoring, communications and control capabilities. The devices are able to identify and interrupt a fault event and then report the fault current to ADMS, which can then use that information to execute FLP to determine the location of the fault. The reclosers will be able to "re-close" after a fault event to determine if a fault still exists. If the fault does not persist, the recloser will reclose and restore service. If the recloser determines that there is a permanent fault after multiple attempts to reclose, the device will communicate the fault information to ADMS, which will inform the Company of the need to dispatch a crew to the fault location. In addition, the reclosers will be controlled by ADMS when there is a permanent fault to automatically restore service. Figure 13 is a picture of a recloser on a distribution pole.

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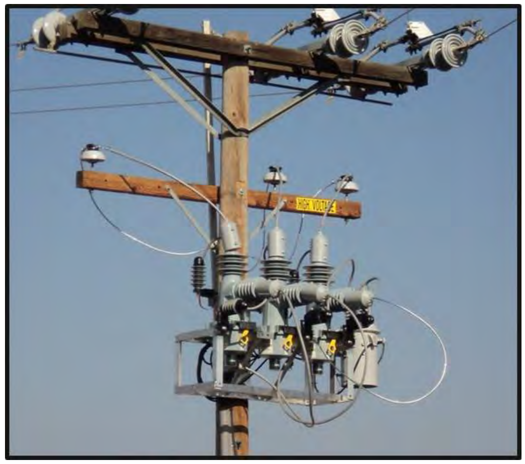
Figure 13

Recloser on Distribution Pole



Q. WHAT IS AN AUTOMATED OVERHEAD SWITCH?

A. These switches are overhead remote supervisory sectionalizing and motor operated switching devices. When a fault occurs, a feeder breaker senses the fault and opens. Although the overhead switches do not communicate directly with the feeder breaker, local controllers on switches on both sides of the fault will sense the loss of voltage and open, isolating the fault. However, unlike a recloser, the overhead switches do not have the capability of reclosing to determine whether the fault is permanent in nature. Instead, overhead switches rely on the feeder breakers for the reclosing functionality. Although automated overhead switches lack the reclosing functionality, they are more compact and less expensive than reclosers, making them the preferred choice for space-constrained locations or where localized reclosing capability is not required.

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Q. WHAT ARE AUTOMATED SWITCH CABINETS?

A. Automated switch cabinets are pad mounted sectionalizing and switching devices. Each cabinet has motor-operated, remote-controlled devices that the Company will use for switching underground feeders. They will perform functions similar to the automated overhead switches for our underground feeders. Each cabinet has two or more switches inside, providing the safe and reliable switching capabilities required for FLISR.

Q. WHAT IS THE FUNCTION OF THE POWERLINE SENSORS?

A. Powerline sensors are equipment placed on distribution lines to continuously monitor the grid and send information back to the utility for analysis and response. Sensors are available to measure such attributes as current, voltage, power factor, and faults. Specifically for FLISR, this technology will allow Xcel Energy the ability to detect disturbances on the grid and use this information to identify fault locations, isolate faults, and analyze the unique patterns of these events to predict the likelihood of future outages. Finally, we hope to leverage the equipment in the future to detect defective equipment before it fails.

Q. WHAT IS THE FUNCTION OF THE SUBSTATION RELAYS?

A. Substation-based relays, historically referred to as the feeder's overcurrent relays, provide the logic for when and why a breaker opens. The purpose of these relays is to monitor and, if warranted, to initiate commands to the feeder breaker to de-energize systems which have been compromised. This is to protect the public, utility personnel, and to minimize damage to public or private property or utility equipment. Modern relays are multi-functional and have multiple protection functions programmed into them. These relays can

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also capture important fault information which will be sent to ADMS for the fault location application.

Q. WHAT IS THE SERVICE LIFE OF THESE FLISR DEVICES?

A. The service life of each of the FLISR devices is 20 years for depreciation purposes.

2. Prior Certification Request for FLISR

Q. HAS THE COMPANY PREVIOUSLY BROUGHT FLISR FORWARD FOR COMMISSION APPROVAL?

A. Yes. The Company previously sought certification of FLISR under the Grid Modernization Statute[16] in its 2017 Biennial Grid Modernization Report.[17]

Q. WHAT ACTION DID THE COMMISSION TAKE ON THIS CERTIFICATION REQUEST?

A. The Commission denied this certification request without prejudice finding that the Company "had not fully demonstrated that FLISR is 'necessary to modernize the transmission and distribution system by enhancing reliability…" as required by the Grid Modernization Statute.[18] The Commission also found that the Company's cost calculations "emphasize the value of reliability but do not adequately assess that value and do not quantify estimated cost savings to ratepayers."[19]

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[16] Minn. Stat. § 216B.2425.

[17] *In the Matter of Xcel Energy's 2017 Biennial Distribution Grid Modernization*, Docket No. E002/M-17-775, XCEL ENERGY'S 2017 BIENNIAL DISTRIBUTION GRID MODERNIZATION REPORT (Nov. 1, 2017).

[18] *In the Matter of Xcel Energy's 2017 Biennial Distribution Grid Modernization*, Docket No. E002/M-17-775, ORDER APPROVING PILOT PROGRAM, SETTING REPORTING REQUIREMENTS, AND DENYING CERTIFICATION REQUEST at 7, (Aug. 7, 2018).

[19] *Id.*

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Q. HOW DOES THE COMPANY'S CURRENT FLISR PROPOSAL DIFFER FROM THE ONE THAT THE COMPANY SOUGHT APPROVAL FOR IN 2017?

A. Our FLISR proposal is slightly revised from that proposed in 2017 in our Grid Modernization Report. We revised our plan with the insights gained from the deployment of FLISR devices in PSCo, resulting in a slightly smaller footprint. The current FLISR proposal will cover 208 feeders, serving 267,182 customers, and require 655 devices (switches and reclosers). This is slightly smaller than the previous proposal which was slated to cover 238 feeders, 290,122 customers, and require 809 switches and reclosers. The reason for the change is that we now have a better understanding of the labor and material costs for the installations and integration of FLISR into ADMS which was gained from our PSCo deployment. Even with this slightly reduced footprint, the benefits of FLISR remain strong and FLISR is a cost-effective way to improve system reliability.

Q. DID THE COMPANY ADDRESS THE COMMISSION'S OTHER CONCERNS RELATED THE RELIABILITY BENEFITS OF FLISR AND THE QUANTIFICATION OF THE COST SAVINGS TO RATEPAYERS?

A. Yes. As described in greater detail below and by Dr. Duggirala, the Company has prepared a comprehensive CBA for each of the AGIS components, including FLISR. This CBA quantifies the reliability benefits for our customers that will result from implementation of FLISR and compares those benefits to the cost of the FLISR investment. As discussed by Dr. Duggirala, the benefits of FLISR are expected to exceed the cost of FLISR, with an expected benefit-to-cost ratio of approximately 1.31 to 1.53.

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3. Interrelation of FLISR with other AGIS Components

Q. HOW DOES FLISR INTERACT WITH THE OTHER AGIS COMPONENTS?

A. In addition to its own intelligent field devices, the FLISR application relies on two primary elements to operate: (1) ADMS, for the central control and logic; and (2) the FAN, for wireless communications to each device.

Q. HOW WILL FLISR AND THE SENSING DEVICES INTERACT WITH ADMS?

A. ADMS will maintain an impedance model of the NSP distribution system. Real-time current, voltage, and status data will be used to run load flow and state estimation applications on that model, providing awareness of system conditions for that feeder and surrounding feeders.

ADMS will provide for remote monitoring and control of FLISR and FLP devices. When a fault occurs on a FLISR or FLP-enabled feeder, any device that senses the fault will send a signal to ADMS, notifying the system of the event. Devices that are capable will also send fault current magnitude during the event. ADMS will use both sets of data, comparing fault current data against the impedance model to generate an expected fault location. If that feeder is FLISR-enabled, ADMS will generate a switching plan to isolate the faulted section based on system conditions, and will issue commands to field devices on the feeder and adjacent feeders so that non-faulted sections can be automatically restored.

Q. HOW WILL FLISR INTERACT WITH FAN?

A. FAN enables the communication that allows the FLISR field devices to communicate with ADMS and their head-end systems. Specifically, the WiMAX system of the FAN which will be used by the FLISR switches is the backbone of the same system proposed to communicate with AMI and with IVVO devices.

Q. WILL FLISR AND FLP MAKE USE OF AMI METERS?

A. Yes, indirectly. FLP considers outage prediction results from a separate outage prediction application in situations where multiple possible fault locations are indicated. The outage prediction application utilizes data from AMI meters. In this way, FLISR and FLP indirectly use AMI data when determining the location of an outage.

Q. HOW WILL FLISR INTERACT WITH IVVO?

A. Both IVVO and FLISR require ADMS to make accurate power flow calculations. ADMS will consume and use information from all the types of sensors on the system. Thus, where IVVO's capacitors provide powerline sensing, FLISR will benefit from this data. Similarly, IVVO calculations benefit from the data provided by FLISR's reclosers. Further, as more data is provided to ADMS by both FLISR and IVVO devices, this information will enhance the ADMS system model, creating greater benefits for both FLISR and IVVO as well as other applications.

4. FLISR Implementation

Q. WHAT IS THE DEPLOYMENT STRATEGY FOR FLISR?

A. The deployment strategy for FLISR is a selective, targeted deployment. In general, we plan to target areas for FLISR where the electric system is predominately overhead, has high customer density, and has a history of outages that is more frequent than the rest of the distribution system. There are two primary criteria that drove our FLISR feeder selection, both of which

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are based on historic reliability information: (1) feeder SAIDI performance; and (2) the combination of the number of feeder mainline outages and the number of customers impacted over a period of time.

Q. WERE THERE OTHER CONSIDERATIONS IN THE DEVELOPMENT OF THE DEPLOYMENT STRATEGY FOR FLISR

A. Yes, FLISR, like other advanced grid applications requires communications capabilities to each sensor and switching device. For Xcel Energy, this communications platform is the FAN. As a result, the FLISR implementation must be completed in concert with the FAN implementation.

Q. WHERE WILL FLISR FIRST BE DEPLOYED IN MINNESOTA?

A. FLISR will be deployed to a small two-feeder area in South Minneapolis in 2020 to validate the ADMS capabilities. Nearly 4,400 customers will benefit from the new capability. The location overlays the TOU pilot geographic area, providing efficiencies to both of the projects thereby leveraging the initial, underlying FAN infrastructure.

Q. WHAT IS THE COMPANY'S APPROACH TO EXTENDING FLISR BEYOND THE AREA COVERED BY THE TOU PILOT?

A. The Company's approach is a balance between addressing the poorest performing feeders in terms of reliability and deploying the technology in a concentrated enough manner to allow it to be as effective as possible. Addressing the highest priority, poorest performing feeders first provides the greatest benefit for our customers as measured by a reduction in "customer minutes out of power" or CMO. As this project progresses through its 10-year deployment, we will continue to deploy FLISR using this prioritization

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method. Since feeder performance varies from year to year, it is expected that some adjustments to the initial deployment plan may occur, while keeping with the concept of maximizing the reliability value of the investment.

However, because FLISR relies on ties to adjacent feeders, the application is most effective and can have the largest impact on reliability and operations when deployed on multiple distribution feeders in the same geographic area. This concentrated deployment allows for normally open tie switches to be shared between two automated feeders, thus reducing the cost of deployment and also increasing operational flexibility.

Therefore, the deployment plan we propose for Minnesota is focused around deploying in this concentrated geographic approach – first identifying areas where a number of feeders have experienced the lowest levels of reliability over the past several years, and building out from there.

Q. HOW DID THE COMPANY DETERMINE THE FEEDER LOCATIONS FOR THE FLISR DEPLOYMENT?

A. The Company analyzed the reliability improvement potential for 980 feeders, and, when factoring in implementation and operational costs, developed a benefit/cost curve which was utilized to determine the size of the FLISR deployment. This deployment plan calls for the automation of 208 feeders in the greater Minneapolis/St. Paul metropolitan area, which provides potential for a 21.3 minute SAIDI reduction. For perspective, 208 feeders comprise about 27 percent of our metro feeders, which serve 40 percent our metro area customers.

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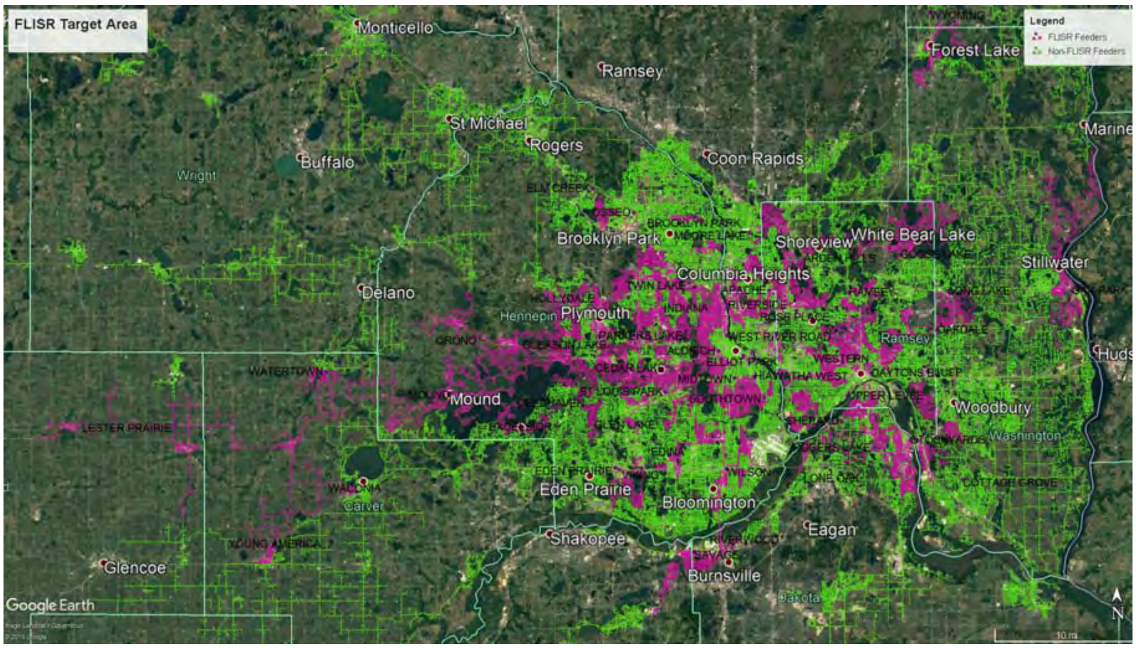
Q. WHERE ARE THESE 208 FEEDERS LOCATED?

A. These selected feeders are located throughout the greater Minneapolis/St. Paul area and are shown in magenta in Figure 14 below.

Figure 14



Q. WILL FLISR BE DEPLOYED OUTSIDE OF THE GREATER METROPOLITAN AREA?

A. Over time, we expect to bring FLP (Fault Location Prediction) and full FLISR capabilities to additional areas as we continue to evaluate reliability and cost-effective solutions.

Q WHAT IS TIMING FOR THE DEPLOYMENT OF THE FLISR DEVICES?

A. We plan to deploy FLISR devices (reclosers, switches, and substation relays) at a relatively steady rate through 2028. The device installation rate is shown in Table 45 below. By the end of 2028, FLISR devices will be installed on 208 feeders, benefiting nearly 350,000 customers.

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Table 45

FLISR Device Installation

FLISR Devices	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Total
Field Devices	6	41	108	60	88	90	67	67	67	67	661
Feeders Impacted	2	13	34	19	28	28	21	21	21	21	208

5. Benefits of FLISR

Q. WHAT ARE THE BENEFITS OF IMPLEMENTING FLISR?

A. FLISR has both quantifiable benefits and non-quantifiable benefits. The most significant quantifiable benefit of FLISR is improved reliability for our customers, which we have estimated in two parts: (1) customer savings due to a reduction in CMO; and (2) patrol time savings due to the need to patrol a smaller portion of the system to find faults. These quantifiable benefits of FLISR were utilized by Dr. Duggirala in the CBA model prepared by the Company to calculate the benefit-to-cost ratio for FLISR.

We also expect to achieve certain non-quantifiable operational efficiencies due to the increased visibility and information provided by the FLISR field devices. One of these benefits is the reduction in field trips for our employees to effect non-outage switching, enabled by the FLISR automated devices. Additionally, all remotely operable switches will necessarily have sensors which will provide operating data at strategic points along the feeders. This data will be useful in the refining planning models and hosting capacity analysis, allowing the planning engineer to more accurately distribute load along the feeders.

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Q. WHEN WILL CUSTOMERS BEGIN SEEING BENEFITS OF FLISR?

A. Customers connected to feeders modeled in ADMS will begin seeing reliability benefits in steps. First, when faults occur on feeders that are modeled within ADMS, the algorithms will develop switching plans faster, which will result in faster outage restoration. At the same time, if fault magnitude information is available, the system will calculate the fault's probable location which will reduce patrol time. Second, for feeders equipped with automated devices, the operators will use remote capabilities to open and close switches, further improving the response time. This is referred to as "advisory mode." And third, when the Company is has sufficient experience and confidence, the full automated capability of FLISR will be employed, bringing the full benefit of fast, automated switching to our customers. As such, we expect that benefits will begin in 2022 and continue to increase through 2028 as additional FLISR devices are deployed and when the fully automated capabilities are utilized.

a. Quantifiable Benefits

Q. HOW WILL FLISR PROVIDE RELIABILITY BENEFITS?

A. Overall, implementing FLISR allows the Company to more efficiently restore power to our customers with the use of fewer resources and will improve our customer's outage experience. Specifically, if there is a fault on a feeder that is automated with FLISR, we will be able reduce the number of customers who experience a sustained outage by two-thirds and will shorten the duration of certain sustained outages that affect a substantial portion of our customers.

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Q. HOW WILL FLISR REDUCE THE NUMBER OF CUSTOMERS WHO EXPERIENCE SUSTAINED OUTAGES?

A. FLISR will allow us to restore service to two-thirds of customers affected by an outage within minutes of a fault. In the event of a fault, the FLISR protective devices will reclose, or sectionalize the feeder, and send data to ADMS. ADMS will then step through the FLISR sequence. The first step is fault location, identifying the location of the fault to, at minimum, between two telemetered devices. Next, FLISR will proceed to isolation, in which ADMS will send open commands to any additional devices necessary to isolate the faulted section of feeder. Last, FLISR will execute supply restoration, which will generate a switching plan to restore load to all possible customers.

Restoration can be done manually or automatically within the system. Restoration considers not only device and feeder loading - but surrounding feeder and substation loading as well. ADMS will then execute the proposed switching plan and notify the operator of the need to send a crew to the isolated section to investigate the fault event. This process is expected to take from 15-45 seconds from start to finish and by design, restore power to approximately two-thirds of the customers on that feeder. After the service restoration step, system operators will send a crew to the isolated section to investigate the fault event, make repairs, and restore service to the remaining customers.

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Q. HOW WILL FLISR REDUCE THE OUTAGE DURATION FOR CUSTOMERS ON A FEEDER WITH A FAULT?

A. FLISR will also provide better fault location identification that will improve restoration times for those customers served by feeder experiencing a fault. Specifically, ADMS will run the FLP algorithm and predict where within a FLISR section the fault exists, which will reduce patrol times for Xcel Energy crews. As a result, crews will be able to move on to subsequent outages more quickly.

Figure 15 below illustrates how FLISR will improve restoration times for both customers on the healthy section of the feeder and those on feeder with a fault. The first timeline below shows the sequence of activities that currently take place, along with their approximate timeframes. The second timeline depicts the anticipated sequence of activities with fully-functional FLISR. The comparison is significant, a reduction in outage duration from 45-75 minutes to only 5-10 minutes for those customers not connected to the faulted section. Also, due to the fault location information, FLISR will also reduce the patrol time required for our crews to locate the fault from 15-20 minutes to 5-10 minutes. For those customers on the faulted sections, this is expected to result in quicker service restoration.

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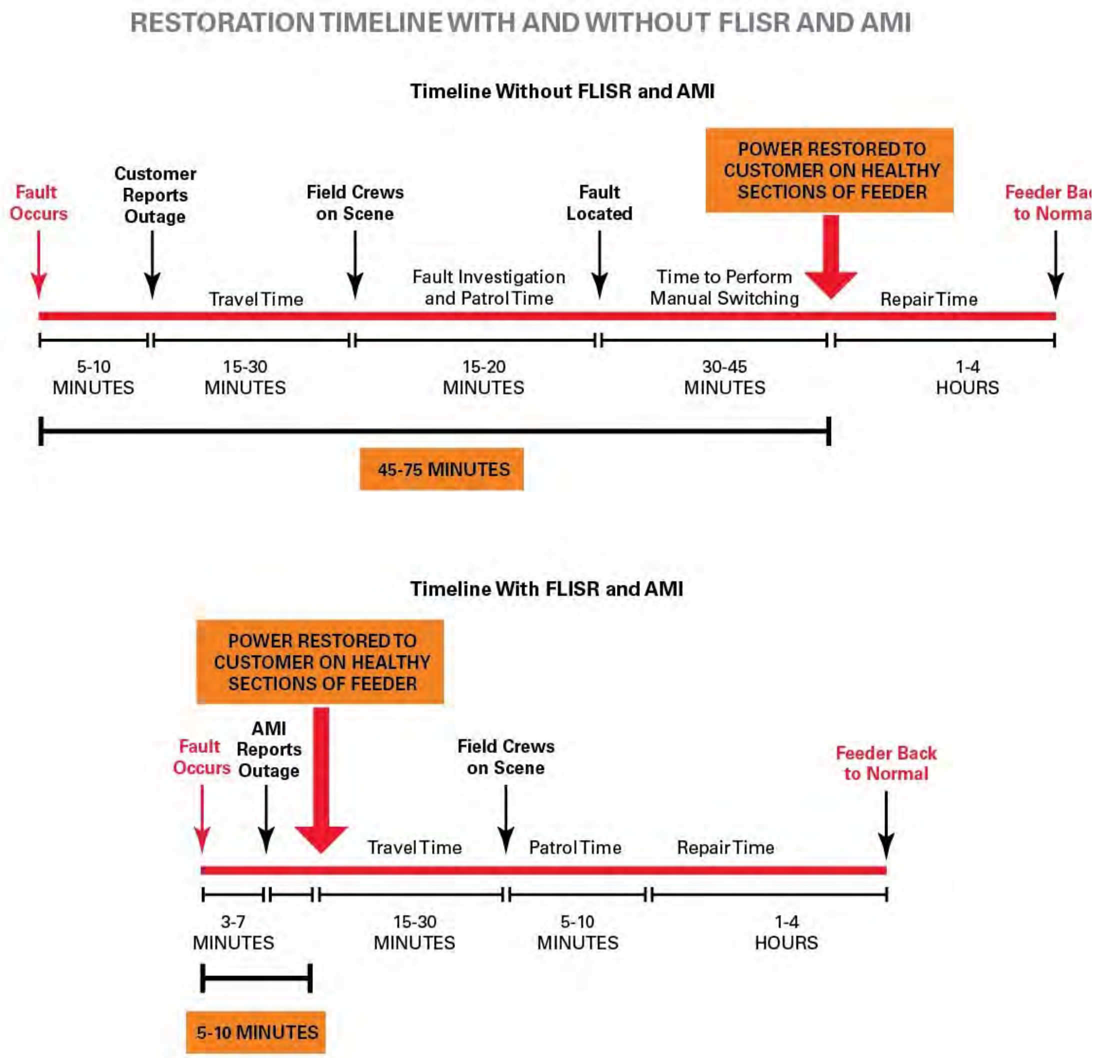
Figure 15



Q. HOW DID THE COMPANY QUANTIFY THESE RELIABILITY BENEFITS?

A. The Company quantified these reliability benefits in terms of: (1) customer benefit due to outage duration reductions and (2) reduced patrol time for crews to respond to outages. A summary of the calculations for these quantifiable FLISR benefits is provided in Exhibit___(KAB-1), Schedule 8.

(1) Customer Benefit of Reduced Outage Duration

Q. How did the Company quantify the value associated with a reduction in the duration of a customer's due to FLISR?

A. Sustained electric power outages and blackouts cost the United States approximately $44 billion annually, according to a 2018 study by Lawrence Berkeley National Laboratory (LBNL).[20] The automated restoration provided by FLISR will reduce CMOs for customers located on FLISR-enabled feeders. FLP will also reduce CMOs through more effective identification of fault events and improved dispatching of crews for restoration. To determine the value of this reduction in CMOs, Xcel Energy used the ICE Calculator developed by LBNL.

Q. How did the Company utilize the ICE Calculator to value a reduction in CMOs for its customers?

A. To calculate the value of a CMO, each FLISR feeder was divided into two classes, residential and commercial/industry, to determine the value lost during an outage. On average, the cost-per-CMO of a mainline outage for the proposed FLISR feeders is approximately $0.72. The Company then calculated anticipated benefits from FLISR using this cost-per-CMO.

Q. How did the Company perform this calculation?

A. We performed studies on the historic SAIDI performance of each feeder to establish a baseline of reliability, using a rolling five-year average. We derived a cumulative CMO for each the FLISR feeders using actual reliability data over the 2010 to 2017 period. We calculated an annual average CMO for each of the feeders to compare to after FLISR is deployed.

[20] *Improving the Estimated Cost of Sustained Power Interruptions to Electricity Customers* (June 2018), available at: http://eta-publications.lbl.gov/sites/default/files/copi_26sept2018.pdf.

To quantify FLISR benefits, we applied the value for each CMO to the number of customers impacted by mainline feeder events – again using historic data. For the comparative future state once FLISR is deployed, we assumed that in a mainline fault event:

- All but one section of the customers on the feeder will see their power restored in less than one minute, which eliminates a sustained outage for the majority of customers on the feeder,
- An improvement of at least 50 percent from historic performance,
- Efficiencies associated with sharing tie switches between two automated feeders, such that each feeder acts as the back-up for the other, and
- A 25 percent reduction in the identified benefits, to represent a conservative but realistic estimate of the percentage of time that FLISR may not be available during an outage for some reason.[21]

The formula utilized to determine the annual CMO savings for each feeder is shown in Figure 16.

Figure 16

$$CMO\ Saved = (Average\ Annual\ CMO) * \frac{(Number\ of\ Sections - 1)}{Number\ of\ Sections} * (1 - Scale\ Factor)$$

[21] The system might not be available for switching for a variety of reasons, including communication failures or devices out of service for maintenance.

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To determine the cost-per-CMO for a particular feeder, we divided the cost of the devices to automate that feeder with FLISR by the number of expected CMO saved to determine the cost-per-CMO saved.

(2) Outage Patrol Time Savings

Q. HOW DID THE COMPANY QUANTIFY THE REDUCTION IN OUTAGE RESPONSE TIME DUE TO FLISR?

A. A primary benefit of FLISR is the ability to see the real-time load across many critical points on the distribution system – and the ability to operate those devices remotely. Since FLISR and other remotely-controlled devices will allow us to identify and thus restore the root cause of an outage faster, our crews will be able to get to the next outage faster – increasing crew productivity and reducing the duration of each subsequent outage event from what it would have been without the increased system visibility. Once our system is widely automated, the cascading benefits from this will have a meaningful impact on reliability for all customers, whether they are on a FLISR feeder or not.

The Company estimates that FLISR will reduce the field time that crews spend responding to outages by an average of 10 minutes per outage. The actual time reduction will differ by situation. In some cases, damage reports will allow us to locate the problem immediately and the patrol time saving benefit from FLISR will be small. In many others, there will be substantial reduction of patrol time resulting from the ability to pin-point the fault location, which will focus our crews on either the calculated location or on a smaller portion of the feeder. This 10 minute reduction is our best estimate of the average savings due to the ability of FLISR to pinpoint the fault location.

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Q. HOW DID THE COMPANY QUANTIFY THE BENEFIT ASSOCIATED WITH THIS REDUCTION IN THE FIELD TIME REQUIRED TO RESPOND TO AN OUTAGE?

A. The Company calculated the CMO saved through this improvement in patrol time, and using the ICE calculator, assigned a value.

b. Non-Quantifiable Benefits

Q. ARE THERE OTHER BENEFITS OF FLISR THAT THE COMPANY WAS UNABLE TO QUANTIFY?

A. Yes. One of the benefits that the Company was unable to quantify is the value of the data provided by FLISR for purposes of planning the system. FLISR provides key data at critical points along the system, which is fed into historical systems and can be leveraged by engineering to make decisions about how to plan and design the future grid. System planning uses historic measured load at a single point on the feeder to allocate that load across the feeder. With multiple FLISR devices on each feeder, the granularity of these data measurements will be enhanced across the feeder. The increased system visibility will also improve our reliability management efforts by increasing the quality and amount of the information we are able to analyze. In addition, these FLISR devices can capture momentary or transient fault and disturbance information, providing the ability to proactively identify potential issues on the distribution system.

6. FLISR Costs

Q. WHAT ARE DISTRIBUTION'S COSTS TO IMPLEMENT FLISR?

A. Distribution's principal costs of implementing FLISR are related to the costs for the FLISR devices and their installation. FLISR costs are broken down by capital additions and O&M costs through the term of multi-year rate plan in Tables 46 and 47 below. I will describe each of these costs in further detail below.

Table 46

FLISR Capital Additions – Distribution State of MN Electric Jurisdiction (Includes AFUDC) (Dollars in Millions)			
AGIS Program	**2020**	**2021**	**2022**
FLISR	$3.1	$8.0	$5.8

Table 47

FLISR O&M – Distribution NSPM – Total Company Electric (Dollars in Millions)			
AGIS Program	2020	2021	2022
FLISR	$0.1	$0.3	$0.2

a. Distribution's Capital Costs

Q. WHAT ARE THE PRINCIPAL CAPITAL COSTS ASSOCIATED WITH IMPLEMENTING FLISR?

A. The capital costs associated with FLISR are: 1) asset costs; 2) asset installation; and 3) communications.

Q. WHAT IS INCLUDED IN THE ASSET COST CATEGORY?

A. This includes the capital costs for the FLISR devices (i.e., switches, reclosers, powerline sensors, and relays).

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Q. HOW DID THE COMPANY ESTIMATE THE COSTS OF THESE DEVICES?

A. The Company has experience in the use and installation of many of the devices involved in the FLISR deployment. As a result, we were able to use historical costs to develop the capital cost estimates for these devices. Our recent costs and experiences in Colorado provide confirmation that these costs estimates are reasonable.

Q. HAS THE COMPANY SELECTED THE VENDORS TO SUPPLY THE FLISR DEVICES?

A. Yes. The Company selected the vendors for the FLISR devices through our established Equipment Standards process. The process by which our materials are selected to become "standard" does involve periodic review, so as the market evolves, the Company will revisit the vendors selected to provide these devices and based on this review, these vendors may change. In addition, the Company's foresight into the needs for automation of certain devices had led to selecting devices in the past that were capable of the automation needed to implement FLISR. This is the case for reclosers, switch cabinets, and overhead switches.

Q. WHAT IS INCLUDED IN THE ASSET INSTALLATION AND LABOR COST CATEGORY?

A. The asset installation costs for FLISR include the capitalized costs for installing and commissioning FLISR devices (switches, reclosers, sensors, and relays).

Q. HOW DID THE COMPANY ESTIMATE THESE COSTS?

A. The Company has experience in the use and installation of many of the devices involved in the FLISR deployment. We were able to use historical

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installation and labor costs to develop the capital cost estimates. Our recent costs and experiences in Colorado provide confirmation that these cost estimates are reasonable.

Q. WHAT IS INCLUDED IN THE COMMUNICATION COST CATEGORY?

A. The communications installation costs for FLISR include costs to install and communications endpoints associated with the FLISR equipment to ensure reliable and secure communications.

Q. HOW DID THE COMPANY ESTIMATE THESE COSTS?

A. The Company has experience in the use and installation of many of the devices involved in the FLISR deployment. We were able to use historical costs to develop the capital cost estimates. Our recent costs and experiences in Colorado provide confirmation that these costs estimates are reasonable.

b. Distribution's O&M Costs

Q. WHAT ARE DISTRIBUTION'S O&M COSTS ASSOCIATED WITH IMPLEMENTING FLISR?

A. Distribution's O&M costs for FLISR will include costs in the following categories: (1) capital support; (2) on-going asset/device support; (3) device replacement; (4) on-going communications network; and (5) training.

Q. WHAT IS INCLUDED IN THE CAPITAL SUPPORT COST CATEGORY AND HOW WERE THESE COSTS ESTIMATED?

A. This category includes expenses related to equipment installations that are appropriately deemed O&M. One example is certain switching activities

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(operations) necessary to safely install new equipment. The Company used actual, average installation times to develop these cost estimates.

Q. WHAT IS INCLUDED IN THE ON-GOING ASSET/DEVICE SUPPORT COST CATEGORY AND HOW WERE THESE COSTS ESTIMATED?

A. This category includes labor and repairs to maintain assets in good working order. The Company estimated the annual support costs by multiplying per-unit support cost estimates by the quantity of devices in service each year.

Q. WHAT IS INCLUDED IN THE COMPONENT REPLACEMENT COST CATEGORY AND HOW WERE THESE COSTS ESTIMATED?

A. This category includes material and labor to replace batteries for certain devices on a five-year schedule. The Company estimated these costs as by multiplying per-unit replacement cost by the quantity of devices expected to be in need of battery replacement for each year.

Q. WHAT IS INCLUDED IN THE ON-GOING COMMUNICATIONS NETWORK COST CATEGORY AND HOW WERE THESE COSTS ESTIMATED?

A. This category includes costs to maintain communications to the field devices. The Company estimated these costs based on historical time to troubleshoot device communication issues and an estimate of the quantity of devices which typically have required such maintenance.

Q. WHAT IS INCLUDED IN THE TRAINING COST CATEGORY AND HOW WERE THESE COSTS ESTIMATED?

A. This category includes training costs for the FLISR program. The Company estimated these costs based on the labor costs of the employees requiring

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FLISR training (control center, engineering, line crews, etc.) and the time required to train them.

c. Distribution Contingency for FLISR

Q. PLEASE DESCRIBE THE FLISR CONTINGENCY AMOUNTS INCLUDED IN THE FORECAST.

A. Distribution's FLISR budget forecast for the period 2020-2025 includes capital contingency amounts of approximately 12 percent. This smaller contingency percentage (compared to the contingency for AMI) is considered adequate because the cost projections for devices and installation were developed based on historical costs, and we believe we have fairly accurately estimated the quantity of equipment and cost of installation of the FLISR devices.

d. FLISR Expenditures 2020-2029

Q. WHAT ARE THE CAPITAL EXPENDITURE AND O&M FORECASTS FOR FLISR FOR DISTRIBUTION FOR 2020 THROUGH 2029?

A. The tables below provide Distribution's capital expenditures and O&M related to FLISR through 2029.

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Table 48

FLISR Capital Expenditures – Distribution NSPM – Total Company Electric (Dollars in Millions)					
	Rate Case Period			5-Year Period	10-Year Period
AGIS Program	**2020**	**2021**	**2022**	**2023-2024**	**2025-2029**
FLISR	$3.1	$8.1	$5.9	$16.0	$26.3

Table 49

FLISR O&M Expenditures – Distribution NSPM – Total Company Electric (Dollars in Millions)					
	Rate Case Period			5-Year Period	10-Year Period
AGIS Program	**2020**	**2021**	**2022**	**2023-2024**	**2025-2029**
FLISR	$0.1	$0.3	$0.2	$3.2	$2.4

7. Alternatives to FLISR

Q. WHAT ALTERNATIVES TO FLISR DID THE COMPANY EVALUATE?

A. There are no real alternative technologies that provide the same reliability benefits as FLISR. As a result, the Company evaluated the following alternatives: (1) maintaining the current system; (2) implementing FLISR without the other AGIS components; and (3) delaying the deployment of FLISR.

Q. WHAT DID XCEL ENERGY CONCLUDE AFTER EVALUATING THE POSSIBILITY OF MAINTAINING THE CURRENT SYSTEM?

A. Maintaining the current system means our ability to improve system reliability would be limited to process improvements related to our outage response

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procedures, which can only provide very limited incremental improvement. This is because absent FLISR, our ability to isolate, locate, and resolve faults is limited due to: (1) a lack of intelligent field devices that interact with the FAN and ADMS to restore service to a majority of customers on the faulted circuit; and (2) a lack of visibility and information regarding where the fault may have occurred on the feeder and the type of fault occurring. Given the limitations of the current system, we determined that FLISR was necessary to improving our customers' outage experience.

Q. DID THE COMPANY CONSIDER IMPLEMENTING FLISR BY ITSELF WITHOUT THE OTHER AGIS COMPONENTS?

A. Yes. We specifically considered installing FLISR without AMI. Such an installation was proposed by the Company in our 2017 Grid Modernization Report. However, as we pointed out in that filing, the FLISR application relies on three primary components to operate: (1) ADMS, for central logic and control; (2) FAN, for wireless communications to each device; and (3) FLISR field devices. As a result, even if FLISR is implemented without AMI, some portion of the FAN infrastructure would still need to be deployed to provide the necessary communication capabilities from the Company's back-office applications to each sensor and switching device. The FAN infrastructure required for FLISR is the same infrastructure that will support AMI and IVVO. Thus, while FLISR could be implemented as a standalone project with limited FAN deployment, there are efficiencies gained by deploying FLISR at the same time as AMI and IVVO as these programs require the same FAN communication infrastructure.

Q. DID THE COMPANY EVALUATE THE POSSIBILITY OF DELAYING THE DEPLOYMENT OF FLISR?

A. Yes. However, the Company determined that such a delay would only defer the realization of the reliability benefits provided by FLISR. Further, delaying the deployment of FLISR has likely effect of increasing its costs due to inflation as well as potential increases in labor and material costs.

8. Interoperability

Q. HOW DOES THE COMPANY'S FLISR PROJECT ENSURE AND FACILITATE INTEROPERABILITY OF THIS TECHNOLOGY?

A. The Company plans to implement FLISR components that are vendor-neutral, non-proprietary, standards-based, and interoperable. This will allow the Company the ability to switch equipment vendors at any time and the new devices will be able to easily operate with the existing FLISR system and devices.

9. Minimization of Risk of Obsolescence

Q. HOW DOES THE COMPANY'S FLISR INVESTMENT PROTECT AGAINST OBSOLESCENCE?

A. Xcel Energy has always maintained an outlook that our assets must provide customer value over a long time period, a philosophy that has driven us to install quality equipment at the best price we can negotiate. That philosophy remains foundational to our goal of providing long-term value to our customers. Through our selection and sourcing procedures we select equipment from vendors which are well-established, financially viable, and show visionary leadership. While we cannot guarantee the longevity of any specific vendor, these attributes help to ensure the products will remain supported.

For electronic equipment, we specify equipment which can be remotely upgraded with new firmware as functionality or security needs dictate. Our requirement to leverage open standards is foundational to the concept that we will not become dependent on any single vendor, but that we will be free to integrate components from different vendors, should subsequent evaluations direct. In addition, we work closely with manufacturers to ensure they are building security into their equipment.

Specifically with FLISR, we have selected equipment and controls that adhere to these principles and are highly configurable. The recloser and switch controls, in particular, are sourced from industry leaders and can be used autonomously or in concert with the FLISR control system. The switches and reclosers themselves use state of the art, proven designs and technology.

G. IVVO

1. Overview of IVVO

Q. WHAT IS IVVO?

A. Integrated Volt-VAr Optimization, or IVVO, is an advanced application that automates and optimizes the voltage of the distribution system using equipment installed at the substation and along the feeder. Voltage optimization is accomplished by "flattening" a feeder line's voltage profile or, in other words, narrowing the bandwidth of the voltage from the head-end of the feeder to the tail-end via control of capacitors and other voltage regulating devices for voltage support. With IVVO, voltage can be monitored along the feeder and at select end points (rather than only at the substation), allowing the head-end voltage to be lowered to achieve a variety of operational outcomes such as:

- Reduction of distribution electrical losses;
- Reduction of electrical demand;
- Reduction of energy consumption; and
- Increased ability to host DER.

Q. CAN YOU PROVIDE ADDITIONAL DETAILS AS TO HOW IVVO WILL BE OPERATED?

A. The ADMS that we are in the process of implementing is capable of running the IVVO application in several different operating modes: Voltage Control, Peak Reduction, VAr Control, and Conservation Voltage Reduction (CVR).

- *Voltage Control mode* functions to optimize voltage on the feeder around standard operating voltages – maintaining adequate service voltage for all customers. This mode is generally a secondary operating mode of IVVO, and only used to establish the voltage boundaries within which the other operating modes must stay within. As penetration of DER grows, Voltage Control will become more common as a primary control mode to manage the expanded range of distribution system voltage caused by DER. Traditionally, with only load on a feeder, the Voltage Control objective was to raise voltage at times of heavy load in order for voltage to remain within the acceptable range. With DER causing reverse power flow and raising voltages during times of light loading, voltage control schemes must now both raise and lower voltage.

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- *Peak Reduction mode* serves to reduce load only during peak load events. It is a manually triggered mode that reduces system voltage to a targeted value to reduce load on the system for a short duration – typically one or two hours. This peak reduction tool can be used in large operating regions, such as Minnesota as a whole, or tactically by feeder, substation, or other targeted area.
- *VAr Control mode* seeks to reduce system losses and save energy by optimizing power factor on each distribution feeder.
- *Conservation Voltage Reduction (CVR) mode* seeks to save energy through reduced operating voltages. CVR mode first flattens the load profile along the feeder using capacitors, and then uses the Load Tap Changer (LTC) or Voltage Regulators inside the substation to lower voltage on the feeder. This lowered operating voltage results in small energy savings for most customers on a feeder.

Q. WHAT ARE THE PHYSICAL COMPONENTS OF IVVO?

A. There are four principal utility equipment components of IVVO:

- Capacitors;
- Secondary static VAr compensators (SVC);
- Voltage and current sensing devices; and
- Load Tap Changers (LTC).

Q. WHAT ARE CAPACITORS AND WHY ARE THE NEEDED?

A. Electric loads like motors require two types of power to operate: active and reactive power. Distribution line capacitors provide local VAr support or reactive power. By doing so, they help to limit both voltage drop and line losses across the distribution system. Capacitors are currently switched on

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and off using the SmartVAr program with a goal of improving power factor and reducing losses. With IVVO, these existing capacitor banks will continue to be used; however the control will be changed from SmartVAr to ADMS. We expect to add, on average, about half of a capacitor bank per feeder to the existing fleet to ensure proper IVVO performance. The Company plans to install 96 capacitors for this purpose.

Q. HOW DOES IVVO DIFFER FROM SMARTVAR?

A. The Company's legacy SmartVAr system currently controls 2,329 capacitor banks on 897 feeders within the NSPM footprint. This system is delivering good value by maintaining high power factor, which reduces distribution system losses. The IVVO program improves on SmartVAr by offering additional capabilities and control modes such as the CVR mode.

Q. WILL IVVO REPLACE THE SMARTVAR SYSTEM?

A. Ultimately, yes. As we enable IVVO, we will change control of 417 of these capacitors (on 189 feeders) from SmartVAr to ADMS to achieve the benefits of energy savings through reduced voltage. To consolidate control systems and enable the enhanced benefits ADMS has to offer, our plan is to move control from SmartVAr to ADMS for the remaining devices/feeders in the future.

Q. WHAT ARE SVCS AND WHY ARE THEY NEEDED?

A. The SVCs are electronic secondary capacitors that provide fast, variable voltage support to help stabilize and regulate the voltage. Each device is able to act in less than a cycle (a cycle is defined as 1/60 of a second since the United States AC frequency is 60 Hz), as opposed to a traditional utility capacitor device that operates on 60-90 second time delay. These devices provide dynamic voltage response for load, and are located closer to customers - or nearer the edge of the grid - than the Company's existing capacitors.

The devices' capabilities will enhance the system's ability to respond to the variability of renewable DERs such as solar facilities and other intermittent distributed resources. The Company will strategically place approximately 270 SVC devices along feeders that need additional voltage support. In the event that IVVO function is limited by localized low voltage, SVCs are a tool that can readily be employed to improve IVVO performance, and thus its benefits.

Q. PLEASE EXPLAIN WHY THE COMPANY IS PROPOSING BOTH PRIMARY AND SECONDARY CONNECTED (SVC) CAPACITANCE.

A. Capacitance can be added either at the primary or secondary level. While the cost-per-kVAr is substantially less when applied on the primary level, applying it on the secondary level can alleviate localized low voltage and thereby increase the depth to which CVR mode can be operated. To that end, we have found deploying SVCs on select low voltage sites to be helpful. Applying this technology is optional, but has the potential to increase energy savings. We plan to analyze the feeders where IVVO is proposed and, if warranted, install these devices selectively to mitigate potential voltage issues. Once in operation, we will deploy additional units as warranted.

Q. HOW ARE THE SVCS CONTROLLED BY THE ADMS?

A. The aggregating software Grid Edge Management System (GEMS) will be used to communicate between the ADMS and the SVCs to achieve full value.

GEMS is a software application developed by Varentec to monitor and control Varentec's "Edge of Network Grid Optimization" (ENGO) devices. These all-in-one ENGO devices are used to control and improve customer voltages in conjunction with an IVVO scheme.

The Company will install these devices with FAN NICs which will allow these devices to communicate through the GEMS system. The benefits of communicating through GEMS are:

- Ability to change devices voltage setpoints;
- Provides ADMS with VAr and voltage data from ENGOs;
- Ability to update firmware;
- Ability to query devices for operational history; and
- Enable control to help validate benefits.

Q. DID THE COMPANY CONSIDER INSTALLING SVCS WITHOUT GEMS?

A. Yes. SVCs can be installed as stand-alone devices. However, without GEMS we would not have any insight into their operational data, we would not be aware of failures, and we would not be able to quantify their effect or benefit. Further through GEMS, SVCs provide voltage data to ADMS which helps ADMS make better decisions to optimize voltage.

Q. WHAT IS THE FUNCTION OF THE LOAD SENSING DEVICES?

A. IVVO requires end-of-line voltage sensing to monitor the voltage and ensure it is compliant with ANSI Standard C84.1. The Company intends to use the newly installed AMI meters as "bellwether" sensing devices to provide near real-time voltage sensing. When located at the edge of system (i.e., at the customer premise) where voltage is predictably lowest, these sensors will

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ensure that IVVO does not lower the voltage to the degree that customers would experience voltage below the acceptable standard. The plan is to configure, on average, 10 meters per feeder to provide this data. We will be able to reassign meters as bellwether meters as necessary should load or feeder topology change.

Q. WHAT IS THE FUNCTION OF THE LOAD TAP CHANGERS (LTC)?

A. This is equipment that is installed on the substation transformer to enable voltage regulation. Substation transformers equipped with LTCs provide voltage regulation by varying the transformer ratio or tap. LTCs typically have 16 taps above and below neutral (33 taps total) and each tap adjusts the transformer turns ratio by 0.375 percent. LTCs are currently monitored and locally controlled based on the local bus voltage. LTCs raise or lower the voltage by tapping up or down based on the settings of the local controller and the demand of the substation transformer. The LTCs themselves will be used, but the controls for some of the legacy units will be upgraded to allow ADMS to control the setpoints. As part of IVVO, we will upgrade nine of the 30 LTC controls to accomplish this. The new LTCs may also require substation Remote Terminal Unit (RTU) upgrades due to the increased SCADA data demands of new LTC controls and FLISR relays. We are budgeting to replace 7 RTUs as part of IVVO.

Q. WHAT IS THE FUNCTION OF THE PRIMARY POWERLINE SENSORS?

A. Primary powerline sensors measure current, voltage, power factor, fault magnitude, and other attributes. Primary powerline sensors are also capable of providing fault current data that is useful to FLISR and FLP in detecting the location of faults on the system.

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Q. HOW WILL THE INFORMATION OBTAINED FROM THE POWERLINE SENSORS BE UTILIZED BY ADMS AND IVVO?

A. ADMS uses real-time data to fine-tune its system solutions. The primary input to this will be the feeder load and voltage information, normally delivered via SCADA from the RTU in the substation. ADMS will also use all additional data available from primary powerline sensors, meters at larger DER sites, and secondary meters at large customer locations. ADMS will use the measurements – power, reactive power, and voltage - to improve power flow calculation accuracy and display the measurements and results geospatially. Where possible, we will install new capacitors and switches with primary powerline sensors. Where existing capacitors and switches will not be replaced, we will strategically install stand-alone powerline sensors to provide the data required for ADMS.

Q. WHAT IS THE COMPANY'S INSTALLATION PLAN FOR THE POWERLINE SENSORS?

A. We plan to install 180 sets of sensors on the 189 feeders selected for IVVO to ensure that we have accurate load flow to operate IVVO. Taking into account the powerline sensors, sensors installed with new capacitor banks, and sensors at FLISR devices, there will be roughly two sensor points per feeder in addition to the feeder breaker.

2. Interrelation of IVVO with other AGIS Components

Q. HOW WILL IVVO INTERACT WITH ADMS?

A. IVVO will be an advanced application within ADMS. ADMS will operate as a centralized system that monitors inputs from devices such as substation RTUs, capacitor banks, AMI meters, LTCs, and other distribution automation

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devices. ADMS will take the inputs from these devices and compute the most efficient way for the system to operate and respond to changes. IVVO, through ADMS, will implement automated activities such as opening and closing of capacitors, and sending new settings to LTCs and SVCs. ADMS will also compute the most efficient way for the system to operate based on both manual switching and FLISR (e.g., for construction and maintenance activities and outages). The LTC control devices will take direction from ADMS, which will make decisions based on knowledge about the entire system, rather than only about voltage at the local bus. As a centralized system, ADMS will be able to control the distribution devices to work in unison and dynamically react to an increasingly complex system in a safe, efficient, and reliable manner.

Q. HOW WILL IVVO INTERACT WITH AMI?

A. AMI meters used as bellwether meters are the least cost method to provide voltage inputs to ADMS at key locations across the grid. For IVVO to be successfully and safely operated, voltage endpoints are necessary at 10 end points on each feeder; without AMI, this data would need to be gathered in other ways. Our preliminary analysis for Minnesota shows the use of voltage sensors would be approximately ten times the cost per unit of an AMI meter. Thus, the AMI initiative is a critical part of IVVO deployment to minimize the cost of providing end of line voltage data.

Q. HOW WILL IVVO INTERACT WITH THE FAN?

A. IVVO will leverage the FAN for communication with its field components, principally capacitors and static VAr compensators. The FAN will also support communications from distribution powerline sensors, necessary for

ADMS to calculate the power flows that are fundamental to IVVO operations. And as mentioned above, bellwether AMI meters will communicate via the FAN.

Q. HOW WILL IVVO INTERACT WITH FLISR?

A. First, IVVO and FLISR share the common need for accurate ADMS calculations. There is a mutual benefit when sensors installed on equipment necessary for FLISR (i.e., reclosers) and IVVO (i.e., capacitors) exist on the same feeders. The additional system inputs enhance ADMS accuracy.

Second, IVVO will react to system changes initiated by FLISR. When systems are reconfigured, the load may change significantly and the voltage controls must respond quickly. This capability exists within ADMS.

3. IVVO Implementation

Q. WHAT IS THE IMPLEMENTATION PLAN FOR IVVO?

A. The implementation plan for IVVO is a targeted, core deployment within the western Twin Cities metropolitan area which coincides with our initial ADMS deployment. This implementation will start in 2019 and continuing through 2024.

Q. WHERE AND WHEN WILL IVVO DEVICES BE DEPLOYED FIRST?

A. As part of the installation of ADMS, we plan to start by implementing IVVO on the seven-feeder system emanating from our Hiawatha West substation in Southeast Minneapolis. This system will support the testing of ADMS in the second quarter of 2020. The system's existing capacitors and LTC controls will be augmented with powerline sensors in late 2019 and early 2020 to

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enable this work. The Company will install approximately 35 SVCs, which will operate autonomously to provide localized voltage support.

Q. WHAT IS THE NEXT STEP IN THE CORE DEPLOYMENT OF IVVO?

A. Xcel Energy proposes to then implement IVVO at 13 substations (serving 224,000 customers). These 13 substations contain 30 transformers and serve 189 feeders. The Company will capture data and install and configure equipment, ensure the accuracy of the calculations, and then enable continuous IVVO functionality. IVVO will be enabled by substation transformer area (each substation contains 1-3 distribution transformers, and each transformer typically serves 4-7 feeders). This work will occur between 2021-2024, with these areas enabled roughly in a linear fashion beginning in 2022. The SVCs and controlling software (GEMS) would be deployed with IVVO. A detailed IVVO device implementation schedule is provided in the table below.

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Table 50

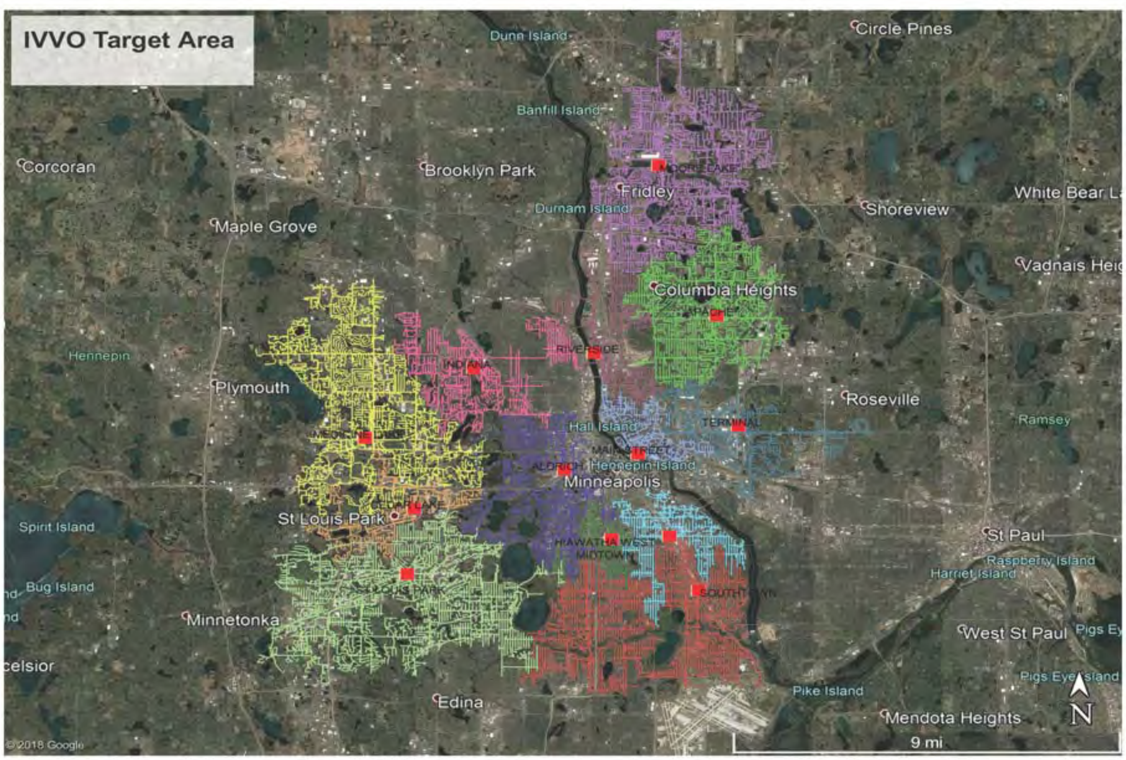
IVVO Device Implementation Schedule

VVO Devices	2019	2020	2021	2022	2023	2024	Total
Capacitors	0	0	16	32	23	25	96
ENGOS	35	0	35	82	82	71	270
Line Sensors	20	0	40	49	46	45	180
LTC Controls	0	0	1	3	3	1	8
Bellwether meters	0	0	0	945	945		1,890

Q. WHERE ARE THESE 13 SUBSTATIONS LOCATED?

A. These substations are located throughout the Minneapolis/St. Paul area and are depicted by the red circles on Figure 17 below.

Figure 17



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Q. HOW DID XCEL ENERGY DETERMINE THE SCALE AND SCOPE FOR THE CORE DEPLOYMENT OF IVVO?

A. The Company sought to optimize the value, providing maximum energy savings while minimizing investment. To select the specific substations and feeders for this core deployment, the following factors influenced this selection:

- *ADMS overlay*. The Company chose to implement in the region controlled by our Metro West control center, which is the first control center to operate ADMS in Minnesota as part of the ADMS project.
- *LTC costs*. Because one LTC controller is required per transformer, and the Company uses larger power transformers in the metro area serving many feeders, the IVVO substation investment per customer is lowest in metropolitan area. Indeed, 22 of the 30 transformers chosen already had been equipped with the appropriate LTC controller. Similarly, the chosen substations generally had newer RTUs which support the functionality.
- *Customer Density*. The selected feeders are typical for urban and suburban feeders, having a slightly greater customer density than the average feeder.
- *Load Density*. The load density for the selected feeders is slightly lower than the system average. This lower density makes them good candidates for achieving a flattened voltage profile, which gives us a greater opportunity to achieve IVVO results. The Company is interested in observing how the adoption of EVs by customers served from these feeders affects the load density and IVVO.
- *Uniformity of feeder length*. IVVO benefits are generally restricted by the longest feeder served by each transformer. This is because longer

feeders have greater voltage drop and, without additional investments, this limits the potential reduction. The feeders in the core deployment area are generally of uniform length for each transformer area.

Q. WILL XCEL ENERGY EXPAND THE DEPLOYMENT OF IVVO TO OTHER AREAS OF ITS SYSTEM AFTER 2024?

A. As I noted, Xcel Energy has determined that a core deployment of IVVO within the Twin Cities metro area is the best first step that allows us to maximize the benefits of IVVO while testing the functionality of IVVO for broader deployment. As the Company learns more about the benefits and costs of IVVO from this core deployment, we will consider implementing IVVO more broadly in the future.

Q. WHEN WILL CUSTOMERS BEGIN SEEING BENEFITS OF IVVO?

A. Customers connected to feeders with IVVO will begin seeing benefits as soon as their substation transformer area is tuned and IVVO is implemented. Thus, the customers on the initial seven feeders will see benefits starting in 2020. Customers impacted by the subsequent deployment will see benefits starting between 2022 and 2024. Of course all our customers indirectly benefit from the lowered energy requirements due to the overall energy efficiency and demand reduction. As discussed later in my testimony, this reduction provides cost savings as well as environmental benefits.

4. *Benefits of IVVO*

Q. HAS XCEL ENERGY IDENTIFIED BENEFITS THAT WILL BE GAINED FROM DEPLOYING IVVO?

A. Yes. We have identified a range of benefits, both quantifiable and non-quantifiable. In terms of quantifiable benefits, these include reduction in energy consumption, reduced electric losses, and avoided capacity costs. These quantifiable benefits of IVVO were utilized by Dr. Duggirala in the CBA model prepared by the Company to calculate the benefit-to-cost ratios for IVVO. I also describe qualitative benefits that were not quantified by the Company, but that will result from deployment of IVVO.

a. *Quantifiable Benefits of IVVO*

Q. CAN YOU PROVIDE A SUMMARY DESCRIPTION OF THE QUANTIFIABLE BENEFITS OF IMPLEMENTING THE IVVO TECHNOLOGY?

A. There are four areas of quantifiable benefits of IVVO:

- *Reduction of Energy Consumption*. Flattening the voltage profile along a feeder and operating in the lower range of 114V to 120V reduces energy consumption for certain devices, like incandescent lighting or motors such as those found in air conditioners, dryers, and refrigerators. Ensuring these types of devices are operated in the lower voltage range makes them more energy efficient. The industry term used to describe operating in the lower voltage range is CVR (Conservation Voltage Reduction). Studies have shown that the CVR benefit varies with the load type, climate zone, and feeder characteristics. The amount of energy efficiency or demand reduction that is achievable is highly dependent on a number of factors, including various attributes and the configuration of the distribution system, and customer attributes such as customer density, load characteristics, and the mix of residential and commercial customers.

- *Reduction of Distribution Electrical Losses.* IVVO models in ADMS can turn the capacitors installed along the distribution circuit on and off in an optimal manner to limit the reactive power flowing on the distribution system. This improves the efficiency of the system, reduces system losses, slightly decreases energy generation needs, and reduces carbon emissions. Because power factor improvements have largely been achieved through our existing SmartVAr program in Minnesota, we expect this incremental benefit through IVVO to be modest.
- *Avoided Capacity Costs.* A by-product of reduced energy consumption is the corollary reduction of demand. By not having to provide that capacity, the benefit can be shown as a deferral of capital investments in generation, transmission, and distribution to serve peak demand.
- *Carbon Emissions Reduction.* Another by-product of reduced energy consumption is the corollary reduction in generation which in turn results in reduced CO_2 emissions. The Company valued this reduction in CO_2 emissions using Commission approved values.

I will discuss the first three benefits (reduction in consumption, losses, and avoided capacity) and Dr. Duggirala will discuss the last benefit (carbon emissions reduction). A summary of the calculations for all of the quantifiable IVVO benefits is provided in Exhibit___(KAB-1), Schedule 9.

(1) Energy Savings

Q. CAN YOU GENERALLY DESCRIBE HOW THE IMPLEMENTATION OF IVVO WILL RESULT IN ENERGY SAVINGS?

A. Customer's end-use devices are designed to operate over a range of voltages. Historically, the voltage on the distribution system is toward the high end of the range, which causes devices to consume more energy. IVVO when operated in CVR mode will allow the Company to lower the voltage on the feeder while still keeping it within acceptable limits. This lowered operating voltage results in small energy savings for most customers on a feeder.

Q. CAN YOU PROVIDE AN EXAMPLE OF HOW IVVO WILL RESULT IN ENERGY SAVINGS?

A. One example of how IVVO will result in electricity savings is incandescent lighting, where the power consumed is directly proportional to the voltage. (For such a load, the formula $P=V^2/R$ applies, where P=power, V=voltage, and R=resistance). As shown in Figure 18, a 70W incandescent light bulb will consume around 77W at a higher voltage level of 126V and around 66W at a lower voltage level 114V. This type of load can be referred to as a constant-impedance load.

But other loads react differently, and power demand is influenced less by a reduction in voltage. For instance, the effect of a change in voltage on the demand for compact fluorescent light bulbs is shown in Figure 19 below. Analysis show the impact of voltage change on demand for CFLs is roughly half of that for the incandescent bulb (Figure 18). While the focus in on the reduction of real power, the graphics below depict the effect of change in reactive power for the benefit of understanding the impact.

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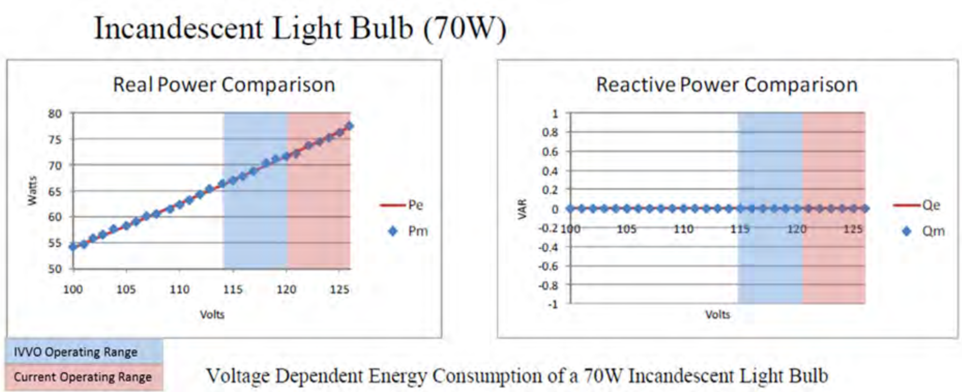
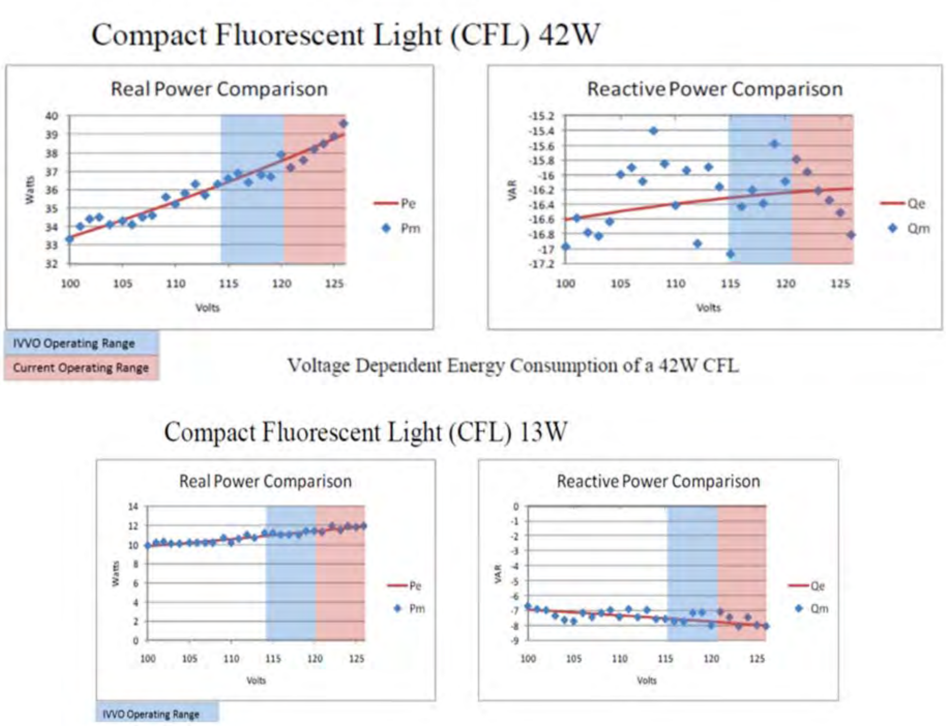
Other loads, especially electronics and most LEDs, respond even less to changes in voltage - exhibiting a constant-power behavior. Lastly, we note that energy savings is function of power over time, and that the benefit analysis does endeavor to takes this factor into account.

Figure 18



Voltage Dependent Energy Consumption of a 70W Incandescent Light Bulb

Figure 19



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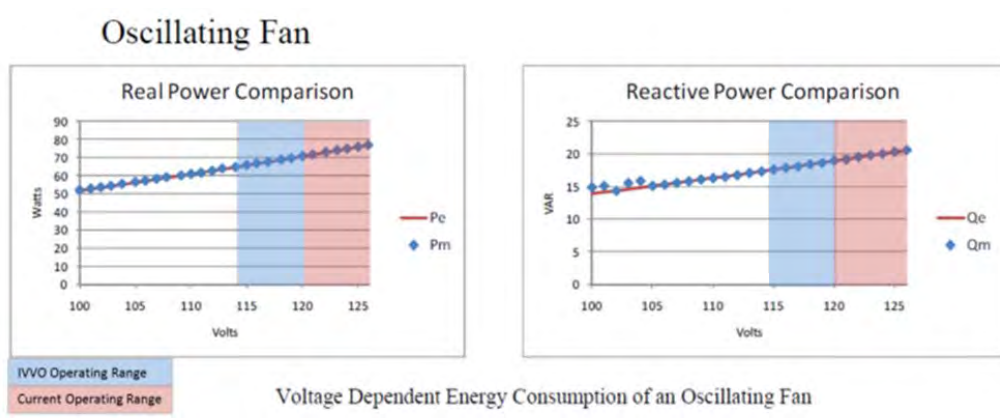
Q. ARE THERE OTHER BENEFITS ASSOCIATED WITH OPERATING ELECTRICAL DEVICES AT A LOWER VOLTAGE?

A. Yes. Some motors, such as those found in air conditioners, dryers, refrigerators, and oscillating fans operate more efficiently at a lower voltage (114V to 120V). A higher voltage (120V to 126V) generates more heat, which makes these motors less efficient. Figure 20 shows the reduced voltage level and energy consumption for an oscillating fan with IVVO.

Figure 20



Voltage Dependent Energy Consumption of an Oscillating Fan

Q. HOW DID XCEL ENERGY DETERMINE THE ENERGY SAVINGS LEVEL THAT IT ANTICIPATES ACHIEVING FROM THE CORE DEPLOYMENT OF IVVO IN MINNESOTA?

A. Xcel Energy developed the energy savings level based on information learned from pilot programs (one in Minnesota and two in Colorado) and then translating these results into a reduction that would be achievable for the Minnesota area where IVVO will be deployed based on an examination of the system characteristics core deployment area and engineering judgment.

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Q. PLEASE DESCRIBE THE IVVO PILOT PROGRAMS THAT YOU MENTIONED.

A. These pilot programs were the: 1) the Wilson Substation pilot that was conducted in 2014-2015 in Bloomington, Minnesota and 2) two pilot projects conducted by PSCo in 2011-2012 to estimate the energy savings for their IVVO deployment in Colorado.

Q. WHAT WAS THE WILSON SUBSTATION PILOT?

A. The purpose of the Wilson Substation pilot was to test and measure the impact of voltage reduction on energy use for Minnesota customers served by this substation in Bloomington. Due to equipment issues, the most substantial testing was done in October 2014 and February 2015. The pilot used the test method of alternating the Load Tap Changer set point between two settings – the normal setpoint and one 3 percent lower. As has been done nationally with many other pilot studies, testing was done day-on, day-off, and weekend-on, weekend-off to test the system's response to reduced voltage.

To determine the impacts, we compared on-days to off-days, and on-weekends to off-weekends. We also filtered out abnormalities in the data including abnormal feeder conditions and attempted to compare similar days to each other. The results of the Wilson pilot identified a CVR factor of between 0.88 and 0.91.

Q. WHAT IS A CVR FACTOR AND HOW DOES IT TRANSLATE INTO A REDUCTION IN ENERGY CONSUMPTION?

A. CVR factor is a term commonly used to refer to the ratio between voltage reduction and energy load consumption for a portion of the Distribution system. Generally, a CVR factor of 1.0 means that for a 1 percent drop in voltage, there is a 1 percent drop in energy consumption. As a result, the Wilson pilot results suggest that a 3 percent reduction in voltage would result in an over 2 percent reduction in energy consumption.

Q. WHAT ARE THE ISSUES WITH USING THE RESULTS OF THE WILSON PILOT TO THE PREDICT THE ENERGY SAVINGS FROM THE PROPOSED IVVO CORE DEPLOYMENT?

A. The biggest issue is that this pilot was conducted on only a small portion of our system (one substation), and the results may not accurately predict benefits on other areas of our system. This is because CVR factors vary widely across our system and can range from as low as 0.4 to as high as 1.5.

Q. WHY IS THERE SUCH A RANGE OF CVR FACTORS ACROSS THE MINNESOTA SYSTEM?

A. This is not an exhaustive list but some of the factors that can impact the CVR factor include: (1) length of feeders; (2) conductor sizing; (3) type, size, and location of different loads; and (4) type, size, and location of DER. The type of load on feeder has a significant impact on the CVR factor. For instance, commercial and industrial load tend to have lower CVR factors while highly resistive load such as old lighting (i.e., non-LED) tends to have higher CVR factors. With the transition to LED lighting, as well as the use of additional constant power devices, we expect that CVR factors will decline in the future across our system.

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Q. ARE THERE OTHER FACTORS THAT IMPACT THE USEFULNESS OF THE WILSON PILOT RESULTS IN PREDICTING ENERGY SAVINGS FROM THE PROPOSED CORE DEPLOYMENT OF IVVO?

A. Yes. The Wilson pilot does not account for the declining use per customer that we have seen and expect to continue to see in the future due to energy efficiency and conservation measures. This declining use per customer reduces the potential benefits of IVVO.

Q. CAN YOU PROVIDE ADDITIONAL DETAILS ABOUT THE IVVO PILOTS PERFORMED BY PSCO?

A. PSCo conducted two pilots in 2011 and 2012 to test IVVO at two substations, the Englewood Substation and the National Center for Atmospheric Research (NCAR) Substation, through its participation in the Electric Power Research (EPRI) Green Circuits program.

Q. WHAT WERE THE RESULTS OF THESE TWO COLORADO PILOTS?

A. The results of the NCAR pilot found that voltage could be lowered on average about 2.5 percent with corresponding energy savings of about 2.5 percent in 2011. The results from the Englewood Substation showed a voltage reduction of 1.5 percent and a CVR factor of 1.7 in 2011 and 2.7 in 2012, which would result in estimated energy savings of 2.55 percent and 4.05 percent. The results for both the NCAR Substation and the Englewood Substation pilots was higher than the nation-wide average for field trials with other utilities that showed an energy reduction range of 1.6 percent to 2.7 percent.

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Q. DOES THE COMPANY BELIEVE THAT THE SAME LEVEL OF ENERGY SAVINGS FROM THESE TWO COLORADO PILOTS COULD BE ACHIEVED IN MINNESOTA?

A. It is unlikely. There are key differences between the Minnesota and Colorado distribution systems that will impact the effectiveness of IVVO such that the same level of energy savings is not likely to materialize in Minnesota. These key differences include:

- *Standard substation bus voltage is lower in Minnesota:* In PSCo, the standard bus voltage is 125V, which is at the very high end of the ANSI C84.1 standard for distribution voltage. This higher starting voltage allows for the potential for greater voltage reduction to be done by IVVO which then results in greater energy savings without compromising service quality. In contrast, the standard bus voltage for the Minnesota service territory is typically 123.5V. This lower starting point reduces the potential energy savings that can be achieved in Minnesota from IVVO.
- *As compared to Minnesota, Colorado uses shorter feeders with larger conductors to support a denser load*: Large conductor size has lower impedance, which means that the voltage drop across the feeder is reduced which allows the Colorado system to achieve better results. In addition, the higher load density on each feeder means that the net impact from IVVO on a per-feeder basis will be greater than it will be in Minnesota.
- *Minnesota has a greater proportion of overhead construction as compared to Colorado*: Overhead construction inherently has greater voltage drop than underground construction. As a result, there is less opportunity for IVVO to further reduce voltage in Minnesota.

Q. HOW DID XCEL ENERGY DETERMINE THE ENERGY SAVINGS LEVEL FOR MINNESOTA BASED ON THESE PILOT PROGRAMS?

A. We examined the results of the various pilot programs discussed above and accounted for the limitations of this data. We also evaluated the characteristics of the area of the system that is planned for the core deployment for IVVO. For example, we evaluated the average feeder head-end voltage, typical loads, line design, and customer density. We also took into account that fact that IVVO may not be available at all times of the day due to abnormal configurations or maintenance.

Q. WHAT LEVEL OF ENERGY SAVINGS DOES XCEL ENERGY BELIEVE IS ACHIEVABLE HERE IN MINNESOTA?

A. Ultimately, we believe that 1.0 percent is the most readily achievable energy savings level, but we are not setting a limit on these savings at this time. After the IVVO devices are deployed, the Company will lower the voltage to the extent that the system allows and seek to achieve the maximum savings within each substation transformer area. To account for the potential for higher energy savings once the IVVO devices are deployed, we identified 1.5 percent as the higher end of the range of energy savings that may be achievable. For purposes of the CBA, we utilized the mid-point of the range between 1.0 percent and 1.5 percent energy savings or 1.25 percent as our reference case. However, we also present as sensitivities in the CBA that utilize the lower (1.0 percent) and upper (1.5 percent) ends of the identified range.

Q. WILL THE ENERGY SAVINGS FROM IVVO RESULT IN OTHER BENEFITS?

A. Yes. There will be environmental benefits associated with the increased energy efficiency. Improved energy efficiency can result in reduced demand for

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electric generation and thus a reduction in carbon emissions caused by certain types of generation. The reduction in carbon emissions, in turn, will provide environmental and societal benefits. The Company's calculation of these benefits is described by Dr. Duggirala.

(2) Electrical Loss Reductions

Q. HOW WILL IVVO REDUCE ELECTRICAL LOSSES ON THE DISTRIBUTION SYSTEM?

A. For any conductor in a distribution network, the current flowing through it can be broken down into two components – active and reactive power. Active power is measured in watts or kilowatts (one thousand watts) and is the energy required to perform actual work. Reactive power is measured in "VAr" or "kVAr" (one thousand VAr); it does not do real work but uses the current-carrying capacity of the distribution lines and equipment, and contributes to the power loss. Reactive power compensation devices (such as capacitors) are designed to reduce the unproductive component of the electric current, thereby reducing current magnitude, and thus, reducing energy losses.

For Xcel Energy's system, ADMS will turn the system's capacitors installed along the distribution circuit on and off in an optimal manner to limit the reactive power flowing on each portion of the distribution system. This improves the efficiency of the system and reduces system losses.

Q. HOW, SPECIFICALLY, IS THE ADMS CONTROL METHOD AN IMPROVEMENT ON SMARTVAR?

A. ADMS is able to calculate the reactive power needs of each section of line and optimize for the circuit. SmartVAr does optimize power factor as measured at the substation, but uses a pre-selected sequence to energize the capacitors.

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The ADMS method is superior and will result in additional loss reduction, relative to SmartVAr.

Q. WHAT ARE THE ELECTRICAL LOSSES SAVINGS THE COMPANY ANTICIPATES ACHIEVING FROM IVVO?

A. The initial deployment of IVVO at 13 substations is expected to reduce annual electrical losses by 225 MWh in 2022, rising to approximately 900 MWh in 2025. This improvement, incremental to the SmartVAr program, is due to the additional capacitance deployed as part of the IVVO program

Q. HOW DID THE COMPANY CALCULATE THE ESTIMATED ELECTRICAL LOSS SAVINGS ANTICIPATED FROM IVVO?

A. As with the calculation of energy use reduction described above, we leveraged our extensive analysis for PSCo to calculate the potential for loss reduction in NSPM. The energy loss reduction quantified for purposes of the CBA is achieved through improvement to the power factor of the feeder. Studies were completed in PSCo which found the reduced losses from improving the power factor by 4.5 percent (from 95 percent to 99.5 percent). We note that the available reduction in NSPM is less than Colorado, because our typical power factor in Minnesota – the "starting point" for these calculations - was higher (98 percent) than that in PSCo (95 percent). We calculated the portion of the reduced line losses that we expect in Minnesota to be 34 percent of what was expected in PSCo.

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(3) Avoided Capacity Costs

Q. HOW DID XCEL ENERGY ESTIMATE THE AVOIDED CAPACITY COSTS THAT WILL RESULT FROM IVVO?

A. Xcel Energy is projecting that IVVO will reduce the NSP system's peak demand by 0.7 percent, which is directly attributable to the energy reduction achievable at system peak. Since the Company will be conducting a targeted, core deployment of IVVO, this 0.7 percent reduction was applied to core IVVO deployment area's contribution to the system peak load. The value of benefit was calculated using avoided Transmission, Distribution, and Generation capacity values for each year through 2038.

b. Non-Quantifiable Benefits

Q. ARE THERE OTHER BENEFITS OF IVVO THAT ARE NOT QUANTIFIABLE?

A. Yes. For those customers whose feeders are equipped with IVVO, we anticipate fewer voltage-related complaints due to the more active voltage control throughout. This will save operating labor to investigate and resolve complaints reactively. In addition, these customers will experience higher energy efficiencies from their personal electrical devices. This improved efficiency will result in lower bills for those customers. However, since the Company is not proposing to implement IVVO for the entirety of its service territory at this time, and these voltage and efficiency benefits would not apply to all customers, the Company chose not to quantify them for the CBA. Another benefit that we did not quantify is the increase in the system's ability to host DER that will result from IVVO.

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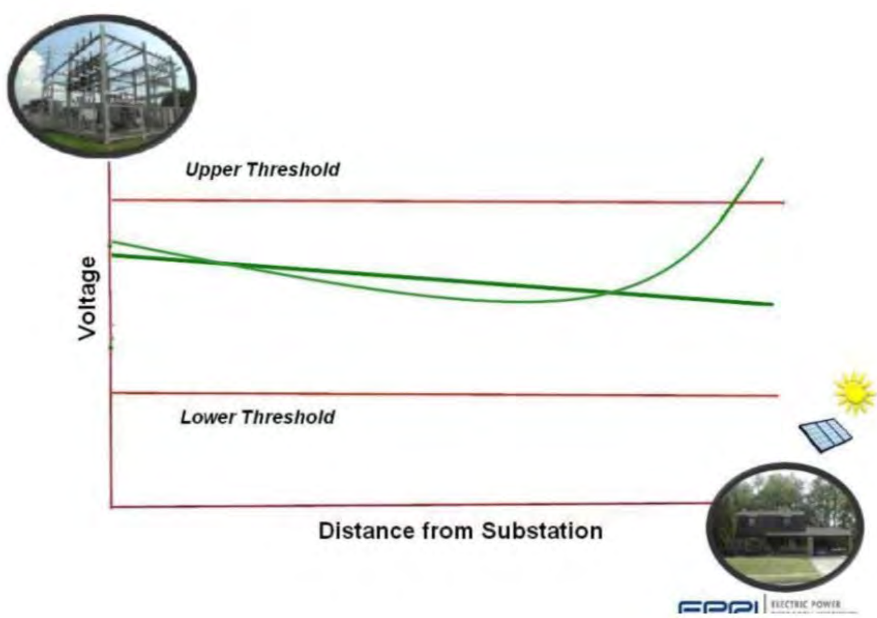
Q. HOW WILL IVVO INCREASE THE SYSTEM'S ABILITY TO HOST DER?

A. As penetration of DER grows, the Company will need to manage the DER's influence on voltage through distribution system voltage control. Traditionally, with one-way flows on a feeder, the voltage control objective was to raise voltage at times of heavy load to manage voltage within the acceptable range.

As shown in Figure 21 below, DER which injects power into the system, such as solar generation, increases the voltage on the edge of the grid, which will be most noticeable during times of lower energy use. By increasing the voltage at the end of the feeder, such DERs can cause over-voltage issues impacting both the DER and other customers. By lowering the voltage and reducing potential over-voltage impacts from solar DERs, IVVO will support the ability for additional solar to be hosted on the system.

Figure 21



Q. HAS THE COMPANY PREVIOUSLY STUDIED THE ABILITY OF IVVO TO IMPROVE HOSTING CAPACITY?

A. Yes. In our 2018 Hosting Capacity Study,[22] we studied the impact of lowering the voltage the substation bus voltage on the hosting capacity of five feeders. In that analysis we found increases in capacity between 0 and 700 kW.[23] IVVO, however, will apply its more robust control algorithms and system controls to provide greater average improvement in hosting capacity although some feeders will gain significantly, while others may remain constrained by voltage or thermal ratings.

The EPRI publication, "Value of a Distribution Management System for Increasing Hosting capacity: Centralized vs. Autonomous Control of Distributed Energy Resources" published in December 2018, provides some insight into how the ADMS can provide an increase in Hosting Capacity through voltage control.

Q. WHY IS XCEL ENERGY UNABLE TO QUANTIFY THE INCREASE IN HOSTING CAPACITY THAT WILL BE ENABLED BY IVVO?

A. Hosting capacity can be constrained by factors other than voltage, such as thermal or protection issues. Each feeder is unique in its topology and the distribution of loads along the feeder, both of which have a significant impact on the hosting capacity. And finally, the distribution of DER along the feeder has a significant impact on the hosting capacity. Consequently a robust hosting capacity analysis needs to be conducted on every feeder where IVVO is installed in order to accurately quantify the system wide impact. While it is

[22] XCEL ENERGY'S 2018 DISTRIBUTION SYSTEM HOSTING CAPACITY STUDY, Docket No. E002/18-684 (Nov. 1, 2018).
[23] *Id.* at 26.

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true that most feeders' hosting capacity may be constrained by high voltage at low load times, other constraints can appear as voltage is lowered on a given feeder, making it hard to approximate what could ultimately be gained. Due to these factors, the Company is unable to quantify and generalize the increase in hosting capacity which can be attributed to IVVO.

5. IVVO Costs

Q. WHAT ARE DISTRIBUTION'S CAPITAL AND O&M COSTS RELATED TO IMPLEMENTATION OF IVVO?

A. The table below provides the Distribution capital additions and O&M costs for IVVO implementation for 2020 through 2022.

Table 51

IVVO Capital Additions – Distribution State of MN Electric Jurisdiction (Includes AFUDC) (Dollars in Millions)			
AGIS Program	**2020**	**2021**	**2022**
IVVO	$0.0	$4.1	$6.7

Table 52

IVVO O&M – Distribution NSPM – Total Company Electric (Dollars in Millions)			
AGIS Program	2020	2021	2022
IVVO	$0.0	$0.4	$0.8

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a. Distribution's Capital Costs

Q. WHAT ARE DISTRIBUTION'S CAPITAL COSTS ASSOCIATED WITH THE IVVO IMPLEMENTATION?

A. Distribution's principal capital costs for IVVO are the costs for the IVVO devices and their installation. There are four categories of capital costs for IVVO: 1) device costs; 2) device installation; 3) labor and external contracting; and 4) communications.

Q. WHAT IS INCLUDED IN THE DEVICE DOST CATEGORY?

A. The capital device cost category includes material and equipment costs for the IVVO devices (capacitors, SVCs, voltage sensing devices, and LTC controls).

Q. HOW DID THE COMPANY ESTIMATE THE COSTS OF THE IVVO DEVICES AND THEIR INSTALLATION?

A. As many of the devices involved in the IVVO deployment are not new to the Company, we were able to use historical costs to develop the capital cost estimates to implement the IVVO. With respect to the new SVC devices, Xcel Energy used our recent costs and experiences for PSCo. For installation, the Company will use primarily contract labor. The projected labor and installation costs were developed using contractor wage scales.

Q. HOW DID THE COMPANY GO ABOUT SELECTING VARENTEC AS THE VENDOR FOR SVCS?

A. As mentioned above, the Company determined that SVCs are a cost-effective way to complement an IVVO installation and mitigate localized voltage problems. The Company completed its RFP process and selected Varentec as its supplier of SVCs in 2018 to support our Colorado IVVO activities. We

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evaluated three different vendors based on a variety of factors including cost per unit, number of devices deployed across different utilities, support capabilities, and technical capabilities, ultimately selecting Varentec's ENGO unit as the best amongst these factors. Contract negotiations were completed in the third quarter of 2018, and we received our first shipment of SVC units late in the same quarter.

Q. HOW DID THE COMPANY SELECT THE POWERLINE SENSOR EQUIPMENT AND VENDOR FOR IVVO?

A. The market for powerline sensors that integrate into capacitor controls and provide the accuracy necessary for IVVO is small. The Company researched the available products' ability to meet our criteria, field tested samples. Ultimately we selected an upgraded sensor that performed well in these field tests. Since further improvements in this technology are anticipated, the Company will continue to monitor this evolving space and modify our vendor selection if appropriate.

Q. HOW DID THE COMPANY SELECT THE VENDORS FOR THE OTHER IVVO DEVICES?

A. Primary capacitors and LTC controllers are a stock commodity within the Company, and we were able to use our existing equipment standards to support this deployment. The equipment selected for our standards undergoes periodic review, using the RFP process when appropriate.

Q. WHAT IS INCLUDED IN THE DEVICE INSTALLATION COST CATEGORY

A. The device installation capital costs for IVVO include costs for installing the IVVO devices, including any supporting internal and contract labor.

Q. WHAT IS INCLUDED IN THE LABOR AND EXTERNAL CONTRACTING COST CATEGORY?

A. This category captures costs for commissioning IVVO devices and their circuits and enabling benefits through ADMS's functionality. It includes standing up the GEMS system and enablement of AMI bellwether functionality.

Q. HOW DID THE COMPANY ESTIMATE THESE CAPITAL COSTS?

A. The projected labor and installation costs were developed using contractor wage scales.

Q. WHAT IS INCLUDED IN THE COMMUNICATION COST CATEGORY?

A. The communications installation capital costs for IVVO include costs to install and commissioning equipment to ensure reliable, secure communications.

Q. HOW DID THE COMPANY ESTIMATE THESE COSTS?

A. The Company has experience in the use and installation of many of the devices involved in the IVVO deployment. We were able to use historical costs to develop the capital cost estimates. Our recent costs and experiences in PSCo provide confirmation that the estimates in use are reasonable.

b. Distribution's O&M Costs

Q. WHAT ARE THE O&M COSTS ASSOCIATED WITH IMPLEMENTING IVVO?

A. The O&M costs include O&M costs in support of capital deployment, asset and device support, minor device replacement, and training.

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Q. WHAT IS INCLUDED IN THE O&M IN SUPPORT OF THE CAPITAL DEPLOYMENT COST CATEGORY AND HOW WERE THESE COSTS DETERMINED?

A. This category includes expenses related to equipment installations that are appropriately deemed O&M. One example is certain switching activities (operations) are necessary to safely install new equipment. The Company used actual, average installation experience to estimate these costs.

Q. WHAT IS INCLUDED IN THE ON-GOING ASSET/DEVICE SUPPORT COST CATEGORY AND HOW WERE THESE COSTS DETERMINED?

A. This category includes labor and repairs to maintain assets in good working order. The Company estimated these costs as a percentage of the number of installed IVVO assets.

Q. WHAT IS INCLUDED IN THE DEVICE REPLACEMENT COST CATEGORY AND HOW WERE THESE COSTS DETERMINED?

A. This category includes material and labor to replace assets (components which are not property units) in good working order. The Company estimated these costs as a percentage of installed IVVO assets.

Q. WHAT IS INCLUDED IN THE ON-GOING COMMUNICATIONS NETWORK COST CATEGORY AND HOW WERE THESE COSTS DETERMINED?

A. This category labor and incidental material to maintain communications link to IVVO assets. The Company estimated these costs as a percentage of the installed IVVO assets.

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Q. WHAT IS INCLUDED IN THE TRAINING COST CATEGORY AND HOW WERE THESE COSTS ESTIMATED?

A. This category includes training costs for the IVVO program. The Company estimated these costs based on number of employees, the time to train them, and wage scales.

c. Distribution Contingency for IVVO

Q. PLEASE DESCRIBE THE IVVO CONTINGENCY AMOUNTS INCLUDED IN THE FORECAST.

A. Distribution's IVVO budget forecast for the period 2020-2025 includes capital contingency amounts of approximately 10 percent. This smaller contingency (compared to AMI) is considered adequate because the cost projections for devices and installation were developed based on historical costs and we believe we have fairly accurately estimated the quantity of equipment and cost of installation of the IVVO devices.

d. IVVO Expenditures 2020-2029

Q. WHAT ARE DISTRIBUTION'S CAPITAL EXPENDITURES AND O&M FORECASTS FOR IVVO FOR 2020 THROUGH 2029?

A. The tables below provide Distribution's capital expenditures and O&M forecasts for IVVO for 2020 through 2029.

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Table 53

IVVO Capital Expenditures – Distribution NSPM – Total Company Electric (Dollars in Millions)					
	Rate Case Period			5-Year Period	10-Year Period
AGIS Program	**2020**	**2021**	**2022**	**2023-2024**	**2025-2029**
IVVO	$0.1	$4.6	$7.6	$14.3	$0.0

Table 54

IVVO O&M Expenditures – Distribution NSPM – Total Company Electric (Dollars in Millions)					
	Rate Case Period			5-Year Period	10-Year Period
AGIS Program	**2020**	**2021**	**2022**	**2023-2024**	**2025-2029**
IVVO	$0.0	$0.4	$0.8	$0.5	$0.8

6. Alternatives to IVVO

Q. WHAT ALTERNATIVES TO IVVO DID THE COMPANY EVALUATE?

A. The Company evaluated four alternatives to IVVO: (1) maintaining the status quo; (2) implementing IVVO without the other AGIS components; (3) implementing IVVO without SVC devices,; and (4) delaying the deployment of IVVO.

Q. DESCRIBE THE STATUS QUO ALTERNATIVE AND WHY THAT ALTERNATIVE WAS REJECTED.

A. One alternative to implementing IVVO is to maintain the status quo, and this relies on the SmartVAr system to maintain good power factor. There are two primary drawbacks to staying with the status quo of SmartVAr which are: 1) forgoing the benefits of reduced energy usage; and 2) forgoing increased

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DER hosting capacity. Those benefits are unavailable through SmartVAr because it is incapable of enacting CVR and enabling the system to operate at the lower levels which enable those specific benefits. Given that these two benefits are important to stakeholders, the Company, and its customers, maintaining the status quo is not a reasonable alternative.

Q. DID THE COMPANY CONSIDER IMPLEMENTING IVVO WITHOUT THE OTHER AGIS COMPONENTS?

A. Yes, however such a deployment would not be as efficient and as cost-effective as the proposed integrated deployment. This is because IVVO relies heavily on both the AMI meters and the FAN to operate. The AMI meters provide voltage sensing functions – measuring and transmitting voltage, current, and power quality data – that allow the Company access to more granular voltage data at the customer meter that makes IVVO more effective. IVVO also relies on the FAN infrastructure to communicate this data back to the Company.

Q. COULD THE COMPANY USE INDEPENDENT SENSORS RATHER THAN USING AMI METERS AS SENSORS?

A. Yes, but these sensors would not be nearly as cost-effective as the AMI meters. If independent sensors were utilized, the Company would need to install at minimum nine sensors per feeder and strategically locate these sensors to provide voltage sensing at the end of the line. Since these sensors would not be located at the customer meter, we would need to assume a conservative level of voltage drop from the sensor to the customer meter to ensure that voltages stay within required limits. This would limit our ability to optimize voltage levels as compared to using AMI meters that will provide

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precise voltage information at the service point. There would also be a significant additional cost associated with deploying independent sensors in place of AMI meters. We did estimate the additional cost for PSCo to use independent meters. Using those insights, we would anticipate a cost for the proposed NSPM deployment of over $4 million. The opportunity to leverage AMI meters provides the greater value.

Q. DESCRIBE THE ALTERNATIVE TO IMPLEMENT IVVO WITHOUT SVCS?

A. While IVVO could be implemented without any SVC devices, the SVCs will enable greater voltage reduction where deployed, thereby resulting in greater energy savings. In addition, the SVCs involved in the Company's proposed IVVO solution will increase the system's capacity to host renewables on the distribution system. SVCs will provide fast, variable voltage support that will help stabilize and regulate the voltage at the edge of the grid, near customers and DERs. Solar resources, in particular, are variable, intermittent, and non-coincident with peak demand, requiring more localized voltage support that is faster-acting than traditional utility devices. SVCs, as part of the IVVO solution, will help provide fast, variable voltage support limiting the impacts from solar and increasing the hosting capacity.

Q. DID THE COMPANY EVALUATE THE POSSIBILITY OF DELAYING THE DEPLOYMENT OF IVVO?

A. Yes. However, the Company determined that such a delay would likely result in a reduction in the energy savings benefit that will be achievable with IVVO. As a mentioned above, the transition to LED lighting and lower energy use per customer reduces the energy savings benefits of IVVO. These trends are expected to continue in the future, thus reducing IVVO's energy savings benefit. Further, delaying the deployment of IVVO has likely effect of increasing its costs due to inflation as well as potential increases in labor and material costs.

7. Interoperability

Q. HOW DOES THE COMPANY'S IVVO PROJECT ENSURE AND FACILITATE INTEROPERABILITY OF THIS TECHNOLOGY?

A. The Company plans to IVVO components that are vendor-neutral, non-proprietary, standards-based, and interoperable. This will allow the Company the ability to switch equipment vendors at any time and the new devices will be able to easily operate with the existing IVVO system and devices.

8. Minimization of Risk of Obsolescence

Q. HOW DOES THE IVVO TECHNOLOGY SELECTED BY THE COMPANY MINIMIZE THE RISK OF OBSOLESCENCE?

A. Xcel Energy has consistently sought to deploy assets that provide customer value over a long time period, a philosophy that has driven us to install quality equipment at the best price we can negotiate. That philosophy remains foundational, in our selection and sourcing procedures, where criteria include financial viability and long-term performance. The equipment itself must be robust to survive in a harsh outdoor environment and meet industry established testing standards to ensure longevity. While we cannot guarantee the longevity of any specific vendor, these attributes help to ensure the products will remain supported.

For electronic equipment, we specify equipment which can be remotely upgraded with new firmware as functionality or security needs dictate.

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Requiring interfaces to follow open protocols (e.g., DNP3, WiSUN) that are not vendor specific helps ensure interoperability between manufacturers. Standard physical interface requirements allow newer devices to connect and interface with controls that are well over 20 years old. We evaluate the equipment's physical and cybersecurity capabilities and require upgradability to help protect from unknown future cybersecurity threats. We are working with manufacturers to ensure they are building such security into their equipment.

Specifically with IVVO, we have selected equipment and controls that adhere to these principles and are highly configurable.

H. AGIS Distribution Overall Costs and Implementation

Q. OVER WHAT TIME PERIOD WILL THE FOUNDATIONAL COMPONENTS OF AGIS BE IMPLEMENTED?

A. The Company began implementation of ADMS, as well as limited deployment of AMI and the FAN in support of the Company's residential TOU pilot, in 2019. Full deployment of AMI, the FAN, and IVVO will begin in 2021 and will be substantially completed in 2024. FLISR implementation will also begin in 2021 and will be accomplished over a longer time period, through 2029.

Q. WHAT ARE THE TOTAL DISTRIBUTION COSTS FOR THE AGIS COMPONENTS?

A. The tables below show the total capital expenditure and O&M IT integration costs, by component, for 2020-2029.

PUBLIC DOCUMENT – NOT PUBLIC DATA HAS BEEN EXCISED

Table 55

AGIS Capital Expenditures – Distribution NSPM - Total Company Electric (Dollars in Millions)					
	Rate Case Period			**5-Year Period**	**10-Year Period**
AGIS Program	**2020**	**2021**	**2022**	**2023-2024**	**2025-2029***
AMI	$2.6	$22.3	$133.9	$179.5	$14.1
FAN	$3.2	$6.2	$0.0	$0.0	$0.0
FLISR	$3.1	$8.1	$5.9	$16.0	$26.3
IVVO	$0.1	$4.6	$7.6	$14.3	$0.0
Total	**$9.0**	**$41.2**	**$147.4**	**$209.8**	**$40.4**
*Period may include additional assumptions, including inflation and labor cost increases, that are not part of the capital budget in periods 2020-2024					

Table 56

AGIS O&M – Distribution NSPM – Total Company Electric (Dollars in Millions)					
	Rate Case Period			**5-Year Period**	**10-Year Period**
AGIS Program	**2020**	**2021**	**2022**	**2023-2024**	**2025-2029***
AMI	$2.3	$3.3	$5.0	$10.0	$15.7
FAN	$0.1	$0.2	$0.4	$0.3	$0.4
FLISR	$0.1	$0.3	$0.2	$3.2	$2.4
IVVO	$0.0	$0.4	$0.8	$0.5	$0.8
Total	**$2.6**	**$4.2**	**$6.5**	**$13.9**	**$19.3**
Period may include additional assumptions, including inflation and labor cost increases, that are not part of the capital budget in periods 2020-2024					

Q. WHAT IS YOUR RECOMMENDATION FOR THE COMMISSION WITH RESPECT TO THE DISTRIBUTION COMPONENTS OF THE AGIS INITIATIVE?

A. I recommend that the Commission approve our request to recover Distribution's capital investments and O&M expense for the foundational components of AGIS that we propose to implement during the 2020-2022 term of the rate case. Our proposal includes full AMI implementation, IVVO and FLISR as part of our broader grid resiliency efforts, and the FAN components necessary to support AMI and the advanced grid applications. We also recommend that the Commission certify these projects to provide the opportunity for the Company to request recovery of costs for 2023 and later in subsequent rider filings. Approval of the costs necessary to implement the AGIS initiative will advance the Company's electric distribution system, provide customers with more choices, and enhance the way the Company serves its customers.

VI. ELECTRIC VEHICLE PROGRAMS

A. Overview of the Electric Vehicle Programs

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section of my testimony I will describe the Company's EV programs and discuss the EV capital and O&M expenses included in the budget for 2020 to 2022.

Q. WHY HAS THE COMPANY INVESTED IN EV PROGRAMS?

A. EVs are becoming more prevalent as costs of ownership have decreased and consumers have become increasingly focused on utilizing greener energy. Customers have indicated that they want increased access to electricity as a transportation fuel, especially electricity generated from renewable resources.

Only the testimony necessary to support the Company's Advanced Grid Intelligence and Security (AGIS) Initiative have been included in the Integrated Distribution Plan (IDP) filing. Accordingly, we have excised non-AGIS pages from this attachment.

Statement of Qualifications

Kelly A. Bloch
Regional Vice President, Distribution Operations
825 Rice Street, St. Paul, Minnesota

Ms. Bloch has more than 28 years of experience in the utility industry where she has compiled a diverse background. She joined Public Service Company of Colorado in 1991 and served in various engineering roles in the four operating companies at Xcel Energy: Manager of Capacity Planning for Xcel Energy, Manager of Distribution Planning for Public Service, Manager of System Planning and Strategy, and Senior Director Electric Distribution Engineering, in addition to her current role.

Ms. Bloch is currently the Regional Vice President, Distribution Operations, for Northern States Power Minnesota and Northern States Power Wisconsin. She is responsible for the electric and natural gas distribution design and construction activities for the Company's service areas in the states of North Dakota, South Dakota, Minnesota, Wisconsin and Michigan.

Resume

Kelly A. Bloch
Regional Vice President, Distribution Operations
825 Rice Street, St. Paul, Minnesota

Education:

Bachelor of Science Electrical Engineering
South Dakota State University

Employment:

Xcel Energy Services

2015-Present	Vice President, Distribution Operations NSPM
2014-2015	Sr. Director, Electric Distribution Engineering
2012-2014	Manager, System Planning and Strategy
2005-2009	Manager, Distribution Capacity Planning
2002-2005	Sr. Engineer, Distribution Capacity Planning

Public Service Company of Colorado

2009-2012	Manager System Planning
1993-2002	Sr. Engineer, Distribution Reliability Assessment
1991-1993	Distribution Standards Engineer

Northern States Power Company
Capital Plant Additions: 2020-2022

Docket No. E002/GR-19-564
Exhibit___(KAB-1), Schedule 2
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Distribution Ops - Capital Additions
State of MN Electric Jurisdiction
Includes AFUDC

Capital Budget Groupings	WBS Level 2 #	Description	MN Allocated 2020	MN Allocated 2021	MN Allocated 2022
ASSET HEALTH & RELIABILITY	11662320	Tap Cable Injection	(80.45)	(0.01)	-
CAPACITY	A.0000226.009	SUB Plymouth-Area Power Grid Upgrad	-	(12,464,926.37)	-
CAPACITY	A.0000226.010	LINES Hollydale Feeder Install	-	(6,221,593.46)	-
CAPACITY	A.0000390.014	LINE Install Wilson WIL TR4 & Feede	-	(9,487,780.20)	-
CAPACITY	A.0000390.015	SUB Install Wilson WIL TR4 & Feeder	-	(8,252,961.84)	-
CAPACITY	A.0000718.003	LINE Install Stockyards STY TR3 & F	-	-	(3,953,411.66)
CAPACITY	A.0000718.004	SUB Install Stockyards STY TR3 & Fd	-	-	(3,624,386.19)
NEW BUSINESS	A.0005500.028	Edina-Oh Extension	(2.02)	(0.01)	-
NEW BUSINESS	A.0005501.001	MNUG Extension-MN	(919.14)	(1.99)	-
NEW BUSINESS	A.0005501.044	South Dakota/MN - UG Extension	1.38	-	-
CAPACITY	A.0005502.016	LINE Install Feeder Tie CRL033	-	-	(1,142,341.86)
CAPACITY	A.0005502.023	Install Kohlman Lake KOL Feeder	-	(1,614,018.35)	-
CAPACITY	A.0005502.024	LINE Install Wyoming WYO Feeder	-	(1,918,575.70)	-
CAPACITY	A.0005502.082	Mntka-Oh Reinforcements	(70.78)	(2.42)	-
CAPACITY	A.0005502.083	Edina-Oh Reinforcements	194.31	6.35	-
CAPACITY	A.0005502.090	St Paul-Oh Reinforcements	466.63	15.26	-
CAPACITY	A.0005503.021	Install Baytown BYT Feeders	-	-	(4,414,837.78)
CAPACITY	A.0005503.058	Maple Grv-Ug Reinforcements	937.02	5.36	-
CAPACITY	A.0005503.061	Newport-Ug Reinforcements	(12.78)	(0.08)	-
CAPACITY	A.0005503.063	St Paul-Ug Reinforcements	81.58	0.46	-
CAPACITY	A.0005503.156	LINE Install Chemolite CHE065 Feede	-	(901,567.26)	-
NEW BUSINESS	A.0005504.001	MNOH Services-MN	(3.83)	-	-
NEW BUSINESS	A.0005505.001	MNUG Services-MN	65.55	0.04	-
NEW BUSINESS	A.0005506.001	MNOH Street Lights-MN	(130.52)	-	-
NEW BUSINESS	A.0005507.001	MNUG Street Lights-MN	0.04	-	-
ASSET HEALTH & RELIABILITY	A.0005508.001	MNOH Rebuilds-MN	(423.23)	(0.10)	-
ASSET HEALTH & RELIABILITY	A.0005508.028	Northwest - Overhead Rebuilds	(102.96)	(0.02)	-
ASSET HEALTH & RELIABILITY	A.0005508.081	North Dakota/MN - OH Rebuilds	235.78	0.05	-
ASSET HEALTH & RELIABILITY	A.0005509.001	MNUG ConvrsnsRebuilds-MN	7,246.41	5.54	-
ASSET HEALTH & RELIABILITY	A.0005509.013	ELR STP Vault Tops	(654,689.19)	(684,776.83)	(511,851.26)
ASSET HEALTH & RELIABILITY	A.0005509.014	ELR MPLS Vault Tops	(73.57)	(737,521.21)	(584,781.20)
ASSET HEALTH & RELIABILITY	A.0005509.105	Replace 7 CM2 Network Protecto	(3,698.56)	(54.06)	(0.77)
ASSET HEALTH & RELIABILITY	A.0005512.008	MPLS UG Network Vault Blanket	(465,581.92)	(476,880.36)	(488,249.16)
ASSET HEALTH & RELIABILITY	A.0005512.012	STP UG Network Vault Blanket	(230,899.34)	(236,549.78)	(242,232.14)
FLEET, TOOLS & COMM	A.0005516.030	Scrap Sale Credits-MN	(38.31)	-	-
CAPACITY	A.0005517.023	Substation Land - MN	(110.45)	(0.07)	(0.01)
ASSET HEALTH & RELIABILITY	A.0005518.003	NSPM-Poor Perf Fdr Replace Blk	16.35	0.01	-
ASSET HEALTH & RELIABILITY	A.0005518.052	REMS-Maple Grove	(0.23)	(0.01)	-

Northern States Power Company
Capital Plant Additions: 2020-2022

Capital Budget Groupings	WBS Level 2 #	Description	MN Allocated 2020	MN Allocated 2021	MN Allocated 2022
ASSET HEALTH & RELIABILITY	A.0005521.001	MN Failed Sub Equip Replacement	(2,162,471.74)	(2,139,017.98)	(2,139,000.01)
ASSET HEALTH & RELIABILITY	A.0005521.014	SPCC NSPM Oil Spill Prevention	(672,571.32)	-	-
ASSET HEALTH & RELIABILITY	A.0005521.015	MN Infratructure Invest - Sub	(4,691.21)	(1,410.40)	(594.57)
ASSET HEALTH & RELIABILITY	A.0005521.051	ELR MN Sub Feeder Breakers	(397,252.34)	(2,211,012.49)	(1,492,777.24)
ASSET HEALTH & RELIABILITY	A.0005521.052	ELR MN Sub Switches	(34,184.85)	(143,203.00)	(101,617.44)
ASSET HEALTH & RELIABILITY	A.0005521.091	ELR MN Sub Relays	(90,245.03)	(429,599.03)	(304,852.24)
ASSET HEALTH & RELIABILITY	A.0005521.092	ELR MN Sub Regulators	(80,780.63)	(286,415.98)	(203,234.85)
ASSET HEALTH & RELIABILITY	A.0005521.093	ELR MN Sub Fences	(72,212.23)	(358,000.81)	(254,043.59)
ASSET HEALTH & RELIABILITY	A.0005521.094	ELR MN Sub TRs	-	-	(873,257.12)
ASSET HEALTH & RELIABILITY	A.0005521.095	Reserve 26/13kV 28 MVA XFMR-MN	-	-	(513,151.62)
ASSET HEALTH & RELIABILITY	A.0005521.096	SUB Replace Fifth Street FST Switch	(7,564,590.01)	-	-
ASSET HEALTH & RELIABILITY	A.0005521.103	ELR MN Sub Retirements	(55,515.13)	(286,395.61)	(203,234.84)
ASSET HEALTH & RELIABILITY	A.0005521.129	Rewind/Replace Failed Transfor	(7,994.46)	(582.08)	(42.25)
ASSET HEALTH & RELIABILITY	A.0005521.131	reserve 70 MVA 115/34.5 kV tra	(744,000.00)	-	-
ASSET HEALTH & RELIABILITY	A.0005521.212	Replace Failed Substation Transform	(659,127.21)	(1,406,772.63)	(1,498,198.90)
CAPACITY	A.0005522.001	Dist Subs Capacity WCF-NSPM	-	(685,805.90)	(2,402,293.80)
CAPACITY	A.0005522.005	Minnesota-Sub Capac Reinforcem	(87,844.46)	(99,669.29)	(99,683.05)
CAPACITY	A.0005522.033	SUB Reinforce Fair Park FAP TR1 & F	(970,304.11)	-	-
CAPACITY	A.0005522.195	SUB Install Rosemount RMT TR2 & Fee	(3,768,005.43)	-	-
CAPACITY	A.0005522.277	SUB Install Wyoming WYO Feeder	-	(503,890.13)	-
CAPACITY	A.0005522.279	SUB Install Chemolite CHE065 Feeder	-	(543,995.79)	-
CAPACITY	A.0005522.281	Reinforce SCL TR2 to 70MVA	(2,940,275.81)	-	-
FLEET, TOOLS & COMM	A.0005549.006	NSPM-Dist Sub Communication Eq	(9,140.52)	(7.35)	(0.01)
ASSET HEALTH & RELIABILITY	A.0005549.020	ELR MN Sub RTUs	(29,310.07)	(149,595.22)	(106,156.47)
ASSET HEALTH & RELIABILITY	A.0005550.002	NSPM-Accelerated URD Cable Rep	1,145.21	16.07	-
ASSET HEALTH & RELIABILITY	A.0005550.005	NSPM-Accelerated URD Cable Rep	12.07	-	-
FLEET, TOOLS & COMM	A.0005553.001	Fiber Communication Cutover -	(195,120.48)	(435,445.46)	(673,977.10)
FLEET, TOOLS & COMM	A.0005560.002	VAR Network Devices	(1,003.29)	-	-
SOLAR	A.0005566.014	Aurora Solar Sub Reinforcement	375.58	104.22	28.92
SOLAR	A.0005566.015	SE Solar Garden Extensions - E	(2,767,041.32)	(201,470.08)	(14,624.39)
SOLAR	A.0005566.017	Extend facilities to serve NW	(351,665.87)	(25,597.73)	(1,857.65)
SOLAR	A.0005566.018	Solar Garden Ext Newport - Ext	-	-	3,185,751.25
SOLAR	A.0005566.020	Solar Gardens Communications - CSG	(37,757.75)	(2,749.16)	(199.56)
SOLAR	A.0005566.021	MN-Solar Garden Sub Comm	(54,036.86)	(3,933.84)	(285.52)
SOLAR	A.0005566.022	MN-Solar Garden Sub Work	(647,806.83)	(194,386.62)	(58,180.87)
SOLAR	A.0005566.023	Solar Garden Ext - WBL	(176,360.78)	(12,840.94)	(932.09)
SOLAR	A.0005566.025	Northwest Solar Gardens Ext	-	-	2,758,785.67
SOLAR	A.0005566.026	Solar Garden Ext - Shorewood	202,559.90	13,919.81	956.57
SOLAR	A.0005566.027	Solar Garden Ext - Edina	(14,289.29)	(1,040.06)	(75.48)
SOLAR	A.0005566.028	Solar Garden Ext - MPLS	(4,616.94)	(336.17)	(24.40)
ASSET HEALTH & RELIABILITY	A.0005585.001	MINNESOTA MAJOR STORM RECOVERY	584,294.17	448.04	-
FLEET, TOOLS & COMM	A.0005585.003	NSM - MN CAPITALIZED ELECTRIC LOCA	(404,579.83)	(400,003.50)	(400,000.01)

Northern States Power Company
Capital Plant Additions: 2020-2022

Capital Budget Groupings	WBS Level 2 #	Description	MN Allocated 2020	MN Allocated 2021	MN Allocated 2022
ASSET HEALTH & RELIABILITY	A.0005585.004	MN Mixed Work Adjustment	(8,062,596.00)	(10,481,376.00)	(10,481,376.00)
FLEET, TOOLS & COMM	A.0006059.002	MN-Dist Electric Tools and Equip	(782,491.08)	(1,158,639.42)	(1,158,639.42)
FLEET, TOOLS & COMM	A.0006059.003	ND-Dist Electric Tools and Equip	(52,625.15)	(69,883.06)	(69,883.06)
FLEET, TOOLS & COMM	A.0006059.004	SD-Dist Dist Tools and Equip	(75,917.76)	(100,938.42)	(100,938.42)
FLEET, TOOLS & COMM	A.0006059.014	MN-Dist Subs Tools and Equip	(258,897.58)	(462,592.57)	(496,399.39)
FLEET, TOOLS & COMM	A.0006059.020	MN-DistLogistics	(104,263.52)	(172,765.98)	(185,678.54)
FLEET, TOOLS & COMM	A.0006059.021	SD-Dist Logistics	(3,482.23)	(4,352.78)	(4,352.78)
FLEET, TOOLS & COMM	A.0006059.024	MN-Dist Tools Common	(48,388.60)	(77,102.84)	(87,431.41)
FLEET, TOOLS & COMM	A.0006059.473	Logistics - NSPM - Tools - ND	(7,551.86)	(13,337.74)	(14,344.26)
FLEET, TOOLS & COMM	A.0006059.474	Nspm Metering Sys-Tools & Equi	(34,509.73)	(69,019.47)	(69,019.47)
FLEET, TOOLS & COMM	A.0006059.477	Logistics - Fencing - NSPM	(5,299.98)	(8,262.71)	(8,766.02)
FLEET, TOOLS & COMM	A.0006059.478	Logistics - Security Equipment	(16,362.36)	(28,269.12)	(34,058.33)
FLEET, TOOLS & COMM	A.0006059.479	Logistics Security Eqiupment N	(5,034.57)	(8,262.51)	(8,766.02)
NEW BUSINESS	A.0006062.001	Distribution CIAC MN Elec	3,733,000.00	3,702,000.00	3,813,000.00
NEW BUSINESS	A.0010003.001	MN - OH Extension Blanket	(3,205,655.32)	(3,618,136.46)	(3,650,997.74)
NEW BUSINESS	A.0010003.002	MN - UG Extension Blanket	(19,496,373.27)	(21,133,978.85)	(21,498,205.43)
NEW BUSINESS	A.0010003.003	MN - OH New Services Blanket	(2,229,455.56)	(2,746,603.91)	(2,787,909.90)
NEW BUSINESS	A.0010003.004	MN - UG New Services Blanket	(8,116,058.18)	(9,135,122.14)	(9,246,914.28)
NEW BUSINESS	A.0010003.005	MN - OH New Street Light Blanket	(360,976.13)	(361,320.38)	(370,388.18)
NEW BUSINESS	A.0010003.006	MN - UG New Street Light Blanket	(728,878.94)	(745,976.97)	(765,923.13)
CAPACITY	A.0010003.007	MN - New Business Network Blanket	(1,232,000.00)	(1,261,793.00)	(1,292,546.00)
MANDATES	A.0010011.001	MN - OH Relocation Blanket	(7,444,549.18)	(7,451,840.49)	(7,451,841.00)
MANDATES	A.0010011.002	MN - UG Relocation Blanket	(5,060,457.54)	(5,159,229.66)	(5,159,230.00)
MANDATES	A.0010011.003	MN - UG Service Conversion Blanket	(566,718.75)	(587,348.65)	(587,349.00)
MANDATES	A.0010011.004	MN - Mandate WCF Blanket	(1,932,892.37)	(3,739,880.81)	(3,739,247.15)
ASSET HEALTH & RELIABILITY	A.0010019.001	MN - OH Rebuild Blanket	(8,302,858.41)	(8,967,162.52)	(9,175,079.68)
ASSET HEALTH & RELIABILITY	A.0010019.002	MN - UG Conversion/Rebuild Blanket	(5,831,219.27)	(6,516,178.44)	(6,667,444.82)
ASSET HEALTH & RELIABILITY	A.0010019.003	MN - OH Services Renewal Blanket	(86,711.25)	(92,777.64)	(94,557.28)
ASSET HEALTH & RELIABILITY	A.0010019.004	MN - UG Services Renewal Blanket	(2,919,771.21)	(2,799,073.42)	(2,863,909.96)
ASSET HEALTH & RELIABILITY	A.0010019.005	MN - OH Street Light Rebuild Blanke	(566,596.88)	(606,602.74)	(621,772.35)
ASSET HEALTH & RELIABILITY	A.0010019.006	MN - UG Street Light Rebuild Blanke	(654,185.24)	(605,903.18)	(621,651.96)
ASSET HEALTH & RELIABILITY	A.0010019.007	MN - Network Renewal Blanket	(7,653.45)	(16.66)	(0.03)
ASSET HEALTH & RELIABILITY	A.0010019.008	MN - Pole Blanket	(25,447,453.55)	(16,584,625.12)	(15,682,420.32)
ASSET HEALTH & RELIABILITY	A.0010019.009	MN - Line Asset Health WCF Blanket	(6,173,317.44)	(9,632,830.45)	(9,742,415.20)
MANDATES	A.0010019.010	MN - Pole Transfer (3rd Party) Blan	(461,559.45)	(440,005.26)	(440,000.00)
ASSET HEALTH & RELIABILITY	A.0010027.001	MN - URD Cable Replacement Blanket	(15,092,000.00)	(25,578,000.00)	(21,560,000.00)
ASSET HEALTH & RELIABILITY	A.0010027.002	MN - Feeder Cable Replacement Blank	(4,900,000.00)	(4,900,000.00)	(4,900,000.00)
ASSET HEALTH & RELIABILITY	A.0010027.003	MN - REMS Blanket	(499,800.00)	(1,166,200.00)	(833,000.00)
ASSET HEALTH & RELIABILITY	A.0010027.004	MN - FPIP Blanket	(588,000.00)	(1,372,000.00)	(1,470,000.00)
CAPACITY	A.0010035.001	MN - OH Reinforcement Blanket	(830,905.00)	(830,905.00)	(830,905.00)
CAPACITY	A.0010035.002	MN - UG Reinforcement Blanket	(455,402.00)	(455,402.00)	(455,402.00)
CAPACITY	A.0010035.004	MN - Line Capacity WCF Blanket	-	(298,011.67)	(763,047.87)

Northern States Power Company
Capital Plant Additions: 2020-2022

Capital Budget Groupings	WBS Level 2 #	Description	MN Allocated 2020	MN Allocated 2021	MN Allocated 2022
CAPACITY	A.0010061.004	Load Transfer CGR062 to CGR071	(966,740.27)	-	-
MANDATES	A.0010069.003	MPLS Mandates WCF	(1,611,601.42)	(2,402,785.93)	(7,592,406.15)
NEW BUSINESS	A.0010069.004	MN LED Post Top Conversion	(1,000,000.00)	(1,000,000.00)	(1,000,000.00)
MANDATES	A.0010069.012	Relocation Hwy 35 106th St to Cliff	-	328,240.91	-
ASSET HEALTH & RELIABILITY	A.0010077.001	Replace Fifth Street FST Network RT	(194,920.61)	-	-
ASSET HEALTH & RELIABILITY	A.0010077.012	Rebuild Clara City CLC221	-	(2,220,077.41)	-
ASSET HEALTH & RELIABILITY	A.0010077.022	T Rebuild West St Cloud to Millwood	-	-	(5,451,608.08)
ASSET HEALTH & RELIABILITY	A.0010077.024	Rebuild Sacred Heart SCH211	(2,044,132.60)	-	-
CAPACITY	A.0010093.008	TER065, extend TER073 to provide lo	(21,883.36)	-	-
CAPACITY	A.0010093.010	Extend Main Street MST074	(300,645.01)	-	-
CAPACITY	A.0010093.015	LINE Reinforce Westgate WSG Feeders	(250,708.70)	-	-
CAPACITY	A.0010093.017	Install Feeder Tie EBL064	-	(149,485.32)	-
CAPACITY	A.0010093.019	Install Feeder Tie Wilson WIL081	(299,351.29)	-	-
CAPACITY	A.0010093.023	Add 3rd feeder to Goodview Bank #2	-	(571,979.66)	-
CAPACITY	A.0010093.024	Install new feeder tie from FAP	(386,389.02)	-	-
CAPACITY	A.0010093.028	LINE Reinforce Kasson KAN TR1 & Fee	-	-	(337,134.86)
CAPACITY	A.0010093.031	Load Transfer ESW062 to SMT061	(95,459.39)	-	-
CAPACITY	A.0010093.038	Reinforce Osseo OSS062	(199,443.89)	-	-
CAPACITY	A.0010093.044	LINE Install Albany ALB TR	-	-	(96,121.35)
CAPACITY	A.0010093.048	LINE Install Fiesta City FIC Feeder	-	(477,251.18)	-
CAPACITY	A.0010093.065	Install Feeder Tie Osseo OSS063	(99,783.76)	-	-
CAPACITY	A.0010093.070	LINE Reinforce Veseli VES TR1 & Fee	-	-	(334,767.96)
CAPACITY	A.0010093.071	Reinforce Basset Creek BCR062	-	(250,670.65)	-
CAPACITY	A.0010093.072	Extend Red Rock RRK063	(95,452.31)	-	-
CAPACITY	A.0010093.074	Reinforce Glenwood GLD Sub Equip	-	(703,119.43)	-
CAPACITY	A.0010093.076	LINE Reinforce Medford Junction MDF	(960,008.86)	-	-
CAPACITY	A.0010093.077	Extend Saint Louis Park SLP092	-	(609,059.57)	-
CAPACITY	A.0010093.078	LINE Install Midtown MDT Feeder	-	(1,421,139.05)	-
CAPACITY	A.0010093.079	Install Feeder Tie SOU083 to MDT074	-	(101,509.96)	-
CAPACITY	A.0010093.081	Reinforce Terminal TER073	-	-	(1,117,271.40)
CAPACITY	A.0010093.082	Extend Saint Louis Park SLP085	(152,643.21)	-	-
CAPACITY	A.0010093.083	Reinforce Moore Lake MOL071	-	(558,304.63)	-
CAPACITY	A.0010093.086	Reinforce Medicine Lake MEL074	(508,810.67)	-	-
CAPACITY	A.0010093.087	LINE Install Hiawatha West HWW Feed	(712,334.93)	-	-
CAPACITY	A.0010093.088	Reinforce Saint Louis Park SLP087	-	(152,264.90)	-
CAPACITY	A.0010093.089	Install Switch Coon Creek CNC073	(29,018.63)	-	-
CAPACITY	A.0010093.090	LINE Install Rosemount RMT TR2 & Fe	(822,170.18)	-	-
CAPACITY	A.0010101.001	SUB MN Feeder Load Monitoring	(850,825.38)	(1,880,579.09)	(2,436,069.03)
FLEET, TOOLS & COMM	A.0010101.002	COMM MN Feeder Load Monitoring	(356,672.79)	(669,020.94)	(857,305.75)
FLEET, TOOLS & COMM	A.0010101.006	COMM Revenue Metering to Mapleton	(220,589.23)	-	-
FLEET, TOOLS & COMM	A.0010101.007	T Revenue Metering Minnesota Lake	(209,919.07)	-	-
ASSET HEALTH & RELIABILITY	A.0010125.002	Replace End of Life Substation Batt	(52,698.36)	(257,757.27)	(182,911.32)

Northern States Power Company
Capital Plant Additions: 2020-2022

Capital Budget Groupings	WBS Level 2 #	Description	MN Allocated 2020	MN Allocated 2021	MN Allocated 2022
ASSET HEALTH & RELIABILITY	A.0010125.014	ELR MPLS Network Protectors	(268,754.76)	(680,373.93)	(934,270.67)
ASSET HEALTH & RELIABILITY	A.0010125.015	ELR STP Network Protectors	(311,178.20)	(680,384.86)	(934,270.67)
ASSET HEALTH & RELIABILITY	A.0010125.016	Replace Linde LND TR1	(2,060,335.98)	-	-
ASSET HEALTH & RELIABILITY	A.0010125.020	Reserve XFMR 115-13.8 kV at 70 MVA	(514,797.27)	-	-
CAPACITY	A.0010133.007	SUB Reinforce Westgate WSG Feeders	(301,515.93)	-	-
CAPACITY	A.0010133.011	Install Breaker for New Goodview Ba	-	(502,352.30)	-
CAPACITY	A.0010133.016	SUB Reinforce Kasson KAN TR1 & Feed	-	-	(2,523,080.47)
CAPACITY	A.0010133.033	SUB Install Albany ALB TR	-	-	(2,846,874.78)
CAPACITY	A.0010133.038	SUB Install Fiesta City FIC Feeder	-	(502,353.58)	-
CAPACITY	A.0010133.055	SUB Install Feeder Tie CRL033	-	-	(50,076.09)
CAPACITY	A.0010133.063	Reinforce Savage SAV063 & SAV067	(1,122,935.84)	-	-
CAPACITY	A.0010133.064	SUB Reinforce Medford Junction MDF	(1,685,074.28)	-	-
CAPACITY	A.0010133.065	SUB Reinforce Veseli VES TR1 & Feed	-	-	(2,437,165.04)
CAPACITY	A.0010133.066	T Reinforce Red Rock RRK TR2	(865,433.04)	-	-
CAPACITY	A.0010133.067	Install Hiawatha West HWW TR2	-	-	(1,590,036.42)
CAPACITY	A.0010133.070	SUB Install Midtown MDT Feeder	-	(507,549.67)	-
CAPACITY	A.0010133.071	SUBS New Substation for Airgas	(2,849,339.70)	-	-
CAPACITY	A.0010133.072	SUB Install Hiawatha West HWW Feede	(508,810.67)	-	-
MANDATES	A.0010143.002	Relocation EDINA SWLRT Road Project	-	-	(2,349,124.45)
MANDATES	A.0010143.005	Relocation MPLS SWLRT Road Project	-	-	(3,543,828.22)
MANDATES	A.0010143.006	COMP Relocation EDINA SWLRT Road Pr	-	-	1,389,378.98
MANDATES	A.0010143.007	COMP Relocation MPLS SWLRT Road Pro	-	-	1,382,228.91
CAPACITY	A.0010144.002	Crosstown new 13.8kv Sub(REPLACED)	-	(208,161.81)	-
ASSET HEALTH & RELIABILITY	A.0010145.002	LINE Replace Fifth Street FST Switc	(854,677.56)	-	-
CAPACITY	A.0010148.002	Install new South Washington ERU Su	(5,902,148.43)	-	-
CAPACITY	A.0010148.003	Install New Fdrs - South Washington	(503,498.02)	-	-
FLEET, TOOLS & COMM	A.0010148.004	COMM Install South Washington ERU S	(86,653.17)	-	-
CAPACITY	A.0010149.001	SUB Install Western WES TR3 & Feede	-	-	(4,081,660.82)
CAPACITY	A.0010149.002	LINE Install Western WES TR3 & Feed	-	-	(1,402,130.53)
ASSET HEALTH & RELIABILITY	A.0010151.001	YLM211 and YLM212 Rebuild OH lines	-	-	(4,131,951.98)
MANDATES	A.0010154.001	VAULT Relocation 4th Street Road Pr	-	(571,464.53)	-
MANDATES	A.0010154.002	LINE Relocation 4th Street Road Pro	-	(7,601,627.45)	-
CREMENTAL SYSTEM INVESTME	A.0010162.003	MN Incremental System Investment	-	(50,678,063.39)	(84,022,979.27)
MANDATES	A.0010167.001	LINE Relocation Hennepin Ave Rd Pro	-	-	(11,475,386.78)
MANDATES	A.0010167.002	VAULT Relocation Hennepin Ave Rd Pr	(736,199.75)	-	-
ELECTRIC VEHICLE PROGRAM	A.0010180.001	MN Electric Vehicle Program	(9,824,077.10)	(8,310,160.74)	(10,098,761.52)
AGIS	D.0001723.046	GIS Cleanup for ADMS - NSPM	(1,743,793.59)	(871,788.29)	(871,814.20)
AGIS	D.0001900.016	FAN - AGIS - NSPM	(2,834,530.53)	(5,381,531.24)	(0.21)
AGIS	D.0001901.043	AMI-DIST-NSPM-MN Full AMI	-	(22,195,456.14)	(98,698,576.32)
AGIS	D.0001901.044	AMI-DIST-NSPM-MN TOU	(1,844,215.32)	-	-
AGIS	D.0001902.009	FLISR - AGIS - NSPM	(3,062,045.76)	(7,972,873.80)	(4,390,857.96)
AGIS	D.0001904.040	IVVO-Comm-Dist Blanket-NSPM	-	(4,096,092.93)	(5,876,285.01)

Northern States Power Company
Capital Plant Additions: 2020-2022

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Capital Budget Groupings	WBS Level 2 #	Description	MN Allocated 2020	MN Allocated 2021	MN Allocated 2022
FLEET, TOOLS & COMM	D.0001907.026	AGIS-Planning & Fcst Tool-MN	(4,033,853.60)	-	-
AGIS	D.0001908.001	AGIS-Dist-Capital-Line-Contingency-	-	-	(2,002,580.52)
AGIS	D.0001908.002	AGIS-Dist-Capital-Subs-Contingency-	-	-	(838,500.84)
AGIS	D.0001908.038	AGIS-Dist-Capital-Line-AMI-Contin-N	-	-	(12,228,126.24)
AGIS	D.0001908.040	AGIS-Dist-Capital-Line-FLISR-Contin	-	-	(1,409,982.60)
NEW BUSINESS	D.0005014.004	MN Elec Distribution Transformers	(21,364,700.00)	(22,929,089.00)	(21,927,168.00)
NEW BUSINESS	D.0005014.021	MN-Electric Meter Blanket	(5,133,023.00)	(4,015,440.00)	(3,232,944.00)

Northern States Power Company
AMI & FAN Expenditures

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	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	TOTAL	NPV
Total Meters Deployed	*10,131*	*7,368*	*121,800*	*630,000*	*590,000*	*40,700*	*13,755*	*13,890*	*14,027*	*14,164*	*14,304*	*14,444*	*14,586*	*14,729*	*14,874*	*15,020*	*15,168*	***1,558,960***	
CAPITAL COSTS																		***TOTAL DISCOUNTED***	***NSPM-NPV***
AMI Meters																			
AMI Meters Purchase	1,408,513	1,024,373	13,875,456	71,769,600	67,212,800	4,636,544	1,771,935	1,826,384	1,882,506	1,940,352	1,999,976	2,061,432	2,124,776	2,190,067	2,257,364	2,326,730	2,398,226	**182,707,036**	**132,855,955**
AMI Meter Installation	620,017	450,922	5,054,700	26,145,000	24,485,000	1,689,050	645,500	665,335	685,779	706,852	728,573	750,961	774,036	797,821	822,337	847,606	873,652	**66,743,140**	**48,567,278**
RTU's (Return to Utility- Estimate 3% of installed meters)	0	0	303,282	1,568,700	1,469,100	101,343	0	0	0	0	0	0	0	0	0	0	0	**3,442,425**	**2,619,423**
Vendors deployment Project Management	0	381,182	733,817	1,198,410	1,223,217	624,270	0	0	0	0	0	0	0	0	0	0	0	**4,160,897**	**3,204,164**
AMI Operations (Internal Personnel)	843,677	983,487	1,869,203	2,046,398	2,186,980	1,903,327	0	0	0	0	0	0	0	0	0	0	0	**9,833,071**	**7,716,691**
AMI Operations (External Personnel)	0	0	658,073	1,372,663	1,365,055	637,919	0	0	0	0	0	0	0	0	0	0	0	**4,033,710**	**3,053,879**
Shop & Lab equipment (AMI Field Test, Lab equip)	0	25,888	217,401	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**243,288**	**203,171**
Distribution Contingencies	442,320	441,341	3,497,637	16,031,519	15,083,091	1,477,238	0	0	0	0	0	0	0	0	0	0	0	**36,973,146**	**28,259,602**
TOTAL - AMI Meters	3,314,527	3,307,193	26,209,569	120,132,290	113,025,244	11,069,690	2,417,435	2,491,719	2,568,285	2,647,205	2,728,549	2,812,393	2,898,813	2,987,889	3,079,701	3,174,336	3,271,878	***308,136,713***	***226,480,162***
Communications Network																			
FAN Infrastructure Distribution	100,005	650,501	1,279,994	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**2,030,499**	**1,729,867**
FAN Distribution WiMax	322,537	2,097,993	4,128,233	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**6,548,763**	**5,579,166**
TOTAL - Communications	***422,543***	***2,748,494***	***5,408,226***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***8,579,263***	***7,309,033***
TOTAL CAPITAL	**3,737,070**	**6,055,686**	**31,617,795**	**120,132,290**	**113,025,244**	**11,069,690**	**2,417,435**	**2,491,719**	**2,568,285**	**2,647,205**	**2,728,549**	**2,812,393**	**2,898,813**	**2,987,889**	**3,079,701**	**3,174,336**	**3,271,878**	**316,715,976**	**233,789,195**
O&M ITEMS																			
Communications Network																			
FAN Network Infrastructure Distribution	0	0	130,976	298,507	271,352	225,136	105,810	54,000	55,118	56,259	57,424	58,612	59,826	61,064	62,328	63,618	64,935	**1,624,966**	**1,036,835**
FAN Network Distribution Contingency	0	0	59,854	136,414	124,004	102,885	48,354	24,677	0	0	0	0	0	0	0	0	0	**496,189**	**363,768**
TOTAL - Communications	***0***	***0***	***190,831***	***434,922***	***395,356***	***328,021***	***154,164***	***78,678***	***55,118***	***56,259***	***57,424***	***58,612***	***59,826***	***61,064***	***62,328***	***63,618***	***64,935***	***2,121,155***	***1,400,602***
AMI Operations (Personnel)																			
	0	2,029	36,563	40,759	42,206	43,704	47,708	1,040,317	1,077,248	1,115,491	1,155,090	1,196,096	1,238,558	1,282,526	1,328,056	1,375,202	1,424,022	**12,445,575**	**5,756,644**
AMI Operations (External Personnel)	0	187,968	214,121	468,050	1,576,002	1,300,659	1,409,575	1,475,931	1,545,439	1,600,302	1,657,112	1,715,940	1,776,856	1,839,934	1,905,252	1,972,888	2,042,926	**22,688,954**	**11,693,307**
Customer Claims	0	663	1,719	48,916	48,843	7,423	0	0	0	0	0	0	0	0	0	0	0	**107,565**	**81,001**
Total AMI- O&M Dist Contingency	0	29,259	38,605	78,357	249,204	207,032	224,422	387,502	403,894	418,232	433,079	448,454	464,374	480,859	497,929	515,606	533,910	**5,410,717**	**2,687,292**
TOTAL - AMI Operations	0	219,920	291,008	636,082	1,916,255	1,558,818	1,681,704	2,903,750	3,026,581	3,134,024	3,245,282	3,360,490	3,479,787	3,603,319	3,731,237	3,863,696	4,000,857	***40,652,811***	***20,218,244***
TOTAL O&M	**0**	**219,920**	**481,839**	**1,071,003**	**2,311,611**	**1,886,839**	**1,835,869**	**2,982,428**	**3,081,699**	**3,190,283**	**3,302,706**	**3,419,102**	**3,539,613**	**3,664,383**	**3,793,565**	**3,927,314**	**4,065,792**	**42,773,966**	**21,618,846**
GRAND TOTAL CAPITAL & O&M	**3,737,070**	**6,275,606**	**32,099,634**	**121,203,293**	**115,336,855**	**12,956,529**	**4,253,304**	**5,474,147**	**5,649,984**	**5,837,488**	**6,031,254**	**6,231,494**	**6,438,425**	**6,652,272**	**6,873,267**	**7,101,650**	**7,337,670**	**359,489,942**	**255,408,042**

Northern States Power Company
FLISR & FAN Expenditures

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	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	TOTAL	NPV
CAPITAL ITEMS - SUMMARY																						
FLISR Assets																						
Asset Cost	0	2,456,519	6,604,776	3,745,275	5,606,776	5,852,901	4,447,353	4,539,413	4,633,379	4,729,290	0	0	0	0	0	0	0	0	0	0	**42,615,682**	**29,507,829**
Asset Installation	0	661,457	1,804,228	1,037,932	1,576,342	1,669,400	1,286,894	1,332,579	1,379,886	1,428,872	0	0	0	0	0	0	0	0	0	0	**12,177,590**	**8,386,388**
Device related Vendor Project Management + Other Labor	0	15,533	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**15,533**	**13,712**
Asset Contingency	0	0	0	1,499,386	1,866,899	919,536	604,982	617,505	630,288	643,334	0	0	0	0	0	0	0	0	0	0	**6,781,930**	**4,638,594**
TOTAL - Assets Cost	***0***	***3,133,508***	***8,409,004***	***6,282,593***	***9,050,018***	***8,441,837***	***6,339,229***	***6,489,497***	***6,643,552***	***6,801,496***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***61,590,735***	42,546,523
Communications Network																						
FAN Infrastructure Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**
FAN Distribution WiMax	60,476	393,374	774,044	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**1,227,893**	**1,046,094**
TOTAL - Communications	60,476	393,374	774,044	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	***1,227,893***	1,046,094
TOTAL CAPITAL	**60,476**	**3,526,882**	**9,183,048**	**6,282,593**	**9,050,018**	**8,441,837**	**6,339,229**	**6,489,497**	**6,643,552**	**6,801,496**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**62,818,628**	**43,592,617**
O&M ITEMS - SUMMARY																						
Deployment																						
O&M in support of capital deployment	0	85,389	229,582	130,186	194,892	203,447	154,590	157,790	161,056	164,390	0	0	0	0	0	0	0	0	0	0	**1,481,321**	**1,025,692**
TOTAL - Asset Operations	***0***	***85,389***	***229,582***	***130,186***	***194,892***	***203,447***	***154,590***	***157,790***	***161,056***	***164,390***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***1,481,321***	1,025,692
Ongoing Support																						
On-going Asset/Device support	0	9,416	34,927	50,006	72,532	96,468	115,512	135,303	155,864	177,218	180,886	184,630	188,452	192,353	196,335	200,399	204,547	208,781	213,103	217,514	**2,834,248**	**1,296,703**
Component Replacements	0	2,742	10,171	14,562	21,121	28,092	33,637	39,400	45,387	51,606	52,674	53,764	54,877	56,013	57,173	58,356	59,564	60,797	62,056	63,340	**825,333**	**377,600**
On-going Communications Network costs	0	7,324	27,166	38,894	56,414	75,031	89,843	105,236	121,227	137,836	140,689	143,601	146,574	149,608	152,705	155,866	159,092	162,386	165,747	169,178	**2,204,415**	**1,008,547**
Vendor costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**
Training	0	10,355	10,723	11,103	11,497	11,906	12,328	12,766	13,219	13,688	14,174	14,677	15,199	15,738	16,297	16,875	17,474	18,095	18,737	19,402	**274,254**	**137,195**
Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**
Asset Contingency	0	1,974	7,321	10,482	15,204	20,221	24,213	28,361	32,671	37,147	37,916	38,701	39,502	40,320	41,154	42,006	42,876	43,763	44,669	45,594	**594,092**	**271,804**
TOTAL - Assets Cost	***0***	***31,810***	***90,308***	***125,047***	***176,769***	***231,717***	***275,533***	***321,066***	***368,368***	***417,495***	***426,339***	***435,374***	***444,604***	***454,032***	***463,663***	***473,502***	***483,554***	***493,822***	***504,312***	***515,028***	***6,732,342***	3,091,849
Communications Network																						
FAN Network Infrastructure Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**
FAN Network Distribution Contingency	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**
TOTAL - Communications	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**
TOTAL O&M	**0**	**117,199**	**319,890**	**255,232**	**371,660**	**435,164**	**430,123**	**478,856**	**529,425**	**581,885**	**426,339**	**435,374**	**444,604**	**454,032**	**463,663**	**473,502**	**483,554**	**493,822**	**504,312**	**515,028**	**8,213,663**	**4,117,541**
GRAND TOTAL CAPITAL & O&M	**60,476**	**3,644,080**	**9,502,937**	**6,537,826**	**9,421,678**	**8,877,001**	**6,769,352**	**6,968,353**	**7,172,977**	**7,383,381**	**426,339**	**435,374**	**444,604**	**454,032**	**463,663**	**473,502**	**483,554**	**493,822**	**504,312**	**515,028**	**71,032,291**	**47,710,158**

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	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	TOTAL	NPV
Feeders enabled with IVVO	0	0	26	43	61	59	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**189**	
CAPITAL COSTS																						
Assets/Devices																						
Device costs	0	0	1,512,735	2,824,978	2,704,856	2,267,749	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**9,310,319**	**6,996,776**
Device Installation costs	0	0	357,063	773,839	777,449	679,695	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**2,588,046**	**1,936,047**
Xcel Personnel	0	0	132,317	272,663	277,896	283,603	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**966,479**	**720,811**
Xcel Distribution Personnel [ADMS IVVO Integration]	0	0	306,666	525,184	771,477	772,672	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**2,375,999**	**1,760,061**
External resources (Consultants, contractors etc.)	0	0	187,008	434,397	443,389	342,887	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**1,407,681**	**1,054,169**
E&S	0	103,550	750,582	777,228	804,819	833,391	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**3,269,570**	**2,482,269**
Varentec Engineering (ENGO,caps,ami)	0	0	416,731	425,358	434,163	443,150	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**1,719,402**	**1,299,884**
Continguency	0	0	107,914	269,162	256,986	175,088	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**809,149**	**607,879**
TOTAL - Business Assets/Devices	***0***	***103,550***	***3,771,016***	***6,302,808***	***6,471,034***	***5,798,235***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***22,446,644***	**16,857,896**
Communications Network																						
FAN Infrastructure Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**
FAN Distribution WiMax	20,159	131,125	258,015	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**409,298**	**348,698**
TOTAL - Communications	20,159	131,125	258,015	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	***409,298***	**348,698**
TOTAL CAPITAL	**20,159**	**234,675**	**4,029,031**	**6,302,808**	**6,471,034**	**5,798,235**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**22,855,942**	**17,206,594**
O&M ITEMS																						
O&M in support of capital deployment	0	0	17,731	37,764	33,658	34,745	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**123,898**	**92,683**
TOTAL - On-going Asset/Device support Costs	***0***	***0***	***17,731***	***37,764***	***33,658***	***34,745***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***				***123,898***	**92,683**
Assets/Devices																						
On-going Asset/Device support	0	0	0	0	7,991	25,537	40,714	57,063	59,089	61,187	63,359	65,608	67,937	70,349	72,847	75,433	78,110	80,883	83,755	86,728	**996,591**	**433,842**
Device Replacements	0	0	0	0	12,059	38,654	62,172	85,943	87,722	89,538	91,391	93,283	95,214	97,185	99,197	101,250	103,346	105,485	107,669	109,897	**1,380,003**	**609,942**
Training	0	0	0	0	195	653	1,107	1,554	1,609	1,666	1,725	1,786	1,850	1,915	1,983	2,054	2,127	2,202	2,280	2,361	**27,066**	**11,765**
Contingency	0	0	0	0	2,471	7,885	12,612	17,431	17,792	18,160	18,536	18,920	19,312	19,711	20,119	20,536	20,961	21,395	21,838	22,290	**279,968**	**123,761**
TOTAL - On-going Asset/Device support Costs	***0***	***0***	***0***	***0***	***22,715***	***72,730***	***116,604***	***161,991***	***166,212***	***170,551***	***175,011***	***179,597***	***184,312***	***189,161***	***194,146***	***199,272***	***204,544***	***209,965***	***215,541***	***221,276***	***2,683,629***	**1,179,310**
Communications Network																						
FAN Network Infrastructure Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**
FAN Network Distribution Contingency	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**
TOTAL - Communications	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	**0**
TOTAL O&M	**0**	**0**	**17,731**	**37,764**	**56,373**	**107,475**	**116,604**	**161,991**	**166,212**	**170,551**	**175,011**	**179,597**	**184,312**	**189,161**	**194,146**	**199,272**	**204,544**	**209,965**	**215,541**	**221,276**	**2,807,527**	**1,271,993**
GRAND TOTAL CAPITAL & O&M	**20,159**	**234,675**	**4,046,762**	**6,340,573**	**6,527,407**	**5,905,710**	**116,604**	**161,991**	**166,212**	**170,551**	**175,011**	**179,597**	**184,312**	**189,161**	**194,146**	**199,272**	**204,544**	**209,965**	**215,541**	**221,276**	**25,663,468**	**18,478,587**

Northern States Power Company
AMI Benefit Calculations

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	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	TOTAL	NPV
Total Meters Replaced	*10,131*	*7,368*	*121,800*	*630,000*	*590,000*	*40,700*	*13,755*	*13,890*	*14,027*	*14,164*	*14,304*	*14,444*	*14,586*	*14,729*	*14,874*	*15,020*	*15,168*	***1,558,960***	
O&M ITEMS																			
Reduction in Field and Meter Services																			
Costs savings from remote disconnect capability	0	0	0	0	386,423	1,108,454	1,592,346	1,814,095	1,878,495	2,060,451	2,133,597	2,209,340	2,287,771	2,368,987	2,453,086	2,540,171	2,630,347	**25,463,562**	**12,291,603**
Reduction in trips due to Customer equipment damage	0	0	0	0	32,617	67,549	139,894	144,860	150,003	155,328	160,842	166,552	172,465	178,587	184,927	191,492	198,290	**1,943,406**	**940,688**
Reduction in "OK on Arrival" Outage Field Trips	0	0	0	0	135,529	280,680	581,288	601,924	623,292	645,419	668,331	692,057	716,625	742,065	768,408	795,687	823,934	**8,075,238**	**3,908,746**
Reduction in Field Trips for Voltage Investigations	0	0	0	0	74,833	154,978	320,960	332,354	344,152	356,370	369,021	382,121	395,686	409,733	424,279	439,341	454,937	**4,458,764**	**2,158,225**
TOTAL - Reduction in Field & Meter Services	***0***	***0***	***0***	***0***	***629,401***	***1,611,661***	***2,634,487***	***2,893,232***	***2,995,942***	***3,217,567***	***3,331,791***	***3,450,070***	***3,572,547***	***3,699,373***	***3,830,700***	***3,966,690***	***4,107,508***	***39,940,969***	***19,299,262***
Improved Distribution System Spend Efficiency																			
Efficiency gains reliability, asset health and capacity projects- O&M	0	0	0	0	1,159	2,401	4,972	5,148	5,331	5,520	5,716	5,919	6,129	6,347	6,572	6,805	7,047	**69,067**	**33,431**
TOTAL - Improved Distribution System Spend Efficiency	***0***	***0***	***0***	***0***	***1,159***	***2,401***	***4,972***	***5,148***	***5,331***	***5,520***	***5,716***	***5,919***	***6,129***	***6,347***	***6,572***	***6,805***	***7,047***	***69,067***	***33,431***
Outage Management Efficiency																			
Outage Management Efficiency (Storm spend O&M)	0	0	0	0	604	1,250	2,589	2,681	2,776	2,875	2,977	3,082	3,192	3,305	3,422	3,544	3,670	**35,965**	**17,409**
TOTAL - Outage Management Efficiency	***0***	***0***	***0***	***0***	***604***	***1,250***	***2,589***	***2,681***	***2,776***	***2,875***	***2,977***	***3,082***	***3,192***	***3,305***	***3,422***	***3,544***	***3,670***	35,965	17,409
TOTAL O&M BENEFITS	**0**	**0**	**0**	**0**	**631,163**	**1,615,312**	**2,642,048**	**2,901,061**	**3,004,049**	**3,225,962**	**3,340,484**	**3,459,071**	**3,581,868**	**3,709,024**	**3,840,695**	**3,977,039**	**4,118,224**	**40,046,001**	**19,350,101**
OTHER BENEFITS																			
Cost reductions																			
Reduced outage duration benefit	0	0	0	0	391,289	798,777	1,630,623	1,664,377	1,698,830	1,733,996	1,769,889	1,806,526	1,843,921	1,882,090	1,921,050	1,960,815	2,001,404	**21,103,587**	**10,323,309**
TOTAL - Cost Reductions	0	0	0	0	391,289	798,777	1,630,623	1,664,377	1,698,830	1,733,996	1,769,889	1,806,526	1,843,921	1,882,090	1,921,050	1,960,815	2,001,404	***21,103,587***	***10,323,309***
TOTAL OTHER BENEFITS	**0**	**0**	**0**	**0**	**391,289**	**798,777**	**1,630,623**	**1,664,377**	**1,698,830**	**1,733,996**	**1,769,889**	**1,806,526**	**1,843,921**	**1,882,090**	**1,921,050**	**1,960,815**	**2,001,404**	**21,103,587**	**10,323,309**
CAPITAL ITEMS																			
Capital gains and other avoided purchases																			
Efficiency gains reliability, asset health and capacity projects- CAP	0	0	0	0	189,547	386,940	789,900	806,251	822,940	839,975	857,363	875,110	893,225	911,715	930,587	949,850	969,512	**10,222,915**	**5,000,776**
Outage Management Efficiency (Storm spend CAP)	0	0	0	0	313,698	649,669	1,345,465	1,393,229	1,442,688	1,493,904	1,546,937	1,601,854	1,658,719	1,717,604	1,778,579	1,841,718	1,907,099	**18,691,164**	**9,047,289**
Avoided Meter Purchases	9,788	18,152	185,992	1,086,102	2,027,125	2,203,315	2,138,852	2,218,752	2,301,754	2,387,984	2,477,572	2,570,653	2,667,369	2,767,866	2,872,297	2,980,823	3,093,609	**34,008,006**	**17,455,428**
TOTAL - Efficiency gains and other avoided CAP purchases	9,788	18,152	185,992	1,086,102	2,530,369	3,239,924	4,274,216	4,418,231	4,567,383	4,721,863	4,881,872	5,047,617	5,219,313	5,397,185	5,581,464	5,772,392	5,970,221	***62,922,085***	***31,503,493***
Avoided Meter Reading CAP investment																			
Drive-by Meter Reading Cost - CAP	20,755	412,501	3,935,923	12,881,148	23,340,750	29,130,716	29,698,551	28,887,914	28,107,557	27,361,868	26,557,430	25,715,024	24,868,419	23,999,536	23,212,398	22,384,139	21,406,031	**351,920,659**	**189,681,697**
TOTAL - Avoided Meter Reading CAP Investment	***20,755***	***412,501***	***3,935,923***	***12,881,148***	***23,340,750***	***29,130,716***	***29,698,551***	***28,887,914***	***28,107,557***	***27,361,868***	***26,557,430***	***25,715,024***	***24,868,419***	***23,999,536***	***23,212,398***	***22,384,139***	***21,406,031***	*351,920,659*	*189,681,697*
TOTAL CAPITAL BENEFITS	**30,543**	**430,653**	**4,121,915**	**13,967,250**	**25,871,119**	**32,370,640**	**33,972,767**	**33,306,145**	**32,674,940**	**32,083,731**	**31,439,303**	**30,762,641**	**30,087,732**	**29,396,720**	**28,793,861**	**28,156,530**	**27,376,252**	**414,842,744**	**221,185,190**
GRAND TOTAL BENEFITS	**30,543**	**430,653**	**4,121,915**	**13,967,250**	**26,893,572**	**34,784,729**	**38,245,438**	**37,871,584**	**37,377,819**	**37,043,689**	**36,549,676**	**36,028,238**	**35,513,521**	**34,987,835**	**34,555,606**	**34,094,385**	**33,495,880**	**475,992,333**	**250,858,601**

Northern States Power Company
FLISR Benefit Calculations

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	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	TOTAL	NPV
O&M BENEFITS																						
Operational Benefits	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**
TOTAL O&M BENEFITS	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
CUSTOMER BENEFITS																						
Customer Minutes Out- CMO Patrolling savings	0	0	0	40,757	175,083	271,514	355,725	453,382	539,313	649,433	725,847	789,440	789,440	789,440	789,440	789,440	789,440	789,440	789,440	789,440	**10,316,013**	**4,528,044**
Customer Minutes Out- CMO Customer Savings	0	0	0	2,754,556	4,809,980	6,277,181	8,295,139	10,426,430	12,214,741	14,325,875	15,433,977	16,164,602	16,164,602	16,164,602	16,164,602	16,164,602	16,164,602	16,164,602	16,164,602	16,164,602	**220,019,300**	**98,458,717**
TOTAL CUSTOMER IMPACTS	**0**	**0**	**0**	**2,795,313**	**4,985,063**	**6,548,696**	**8,650,864**	**10,879,813**	**12,754,055**	**14,975,308**	**16,159,824**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**230,335,313**	**102,986,762**
GRAND TOTAL BENEFITS	**0**	**0**	**0**	**2,795,313**	**4,985,063**	**6,548,696**	**8,650,864**	**10,879,813**	**12,754,055**	**14,975,308**	**16,159,824**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**230,335,313**	**102,986,762**

Northern States Power Company
IVVO Benefit Calculations

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Exhibit___(KAB-1), Schedule 9
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	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	TOTAL	NPV
OTHER BENEFITS																						
Energy Savings																						
Energy Reduction	0	0	165,891	423,491	910,125	1,577,997	1,904,520	1,963,148	2,014,173	2,063,569	2,041,390	1,994,758	2,019,200	2,085,180	2,025,146	2,026,282	2,185,792	2,206,891	2,172,820	2,129,363	**31,909,736**	$14,934,748
Loss Savings	0	0	3,155	8,234	18,167	32,238	39,806	41,776	43,440	44,870	45,454	45,229	46,713	49,088	48,089	48,350	52,370	53,018	52,442	52,442	**724,883**	$333,272
Total Fuel Savings	0	0	169,046	431,724	928,293	1,610,235	1,944,326	2,004,924	2,057,613	2,108,438	2,086,844	2,039,988	2,065,913	2,134,268	2,073,236	2,074,632	2,238,162	2,259,909	2,225,262	2,181,806	**32,634,620**	$15,268,020
Carbon Emissions Benefits																						
Carbon Reduction	0	0	94,698	230,703	479,367	643,180	656,339	645,988	537,529	340,791	312,713	309,097	303,111	284,879	316,482	328,421	341,160	345,262	349,364	353,466	**6,872,548**	$3,599,824
Total Carbon Emissions Savings	0	0	94,698	230,703	479,367	643,180	656,339	645,988	537,529	340,791	312,713	309,097	303,111	284,879	316,482	328,421	341,160	345,262	349,364	353,466	**6,872,548**	$3,599,824
TOTAL OTHER BENEFITS	**0**	**0**	**263,744**	**662,427**	**1,407,660**	**2,253,415**	**2,600,664**	**2,650,912**	**2,595,141**	**2,449,229**	**2,399,557**	**2,349,085**	**2,369,024**	**2,419,147**	**2,389,718**	**2,403,054**	**2,579,322**	**2,605,171**	**2,574,626**	**2,535,271**	**39,507,168**	**$18,867,844**
DEMAND BENEFITS																						
Deferral of Capital Investments As Demand Reduction	0	0	45,106	113,532	227,415	386,537	456,612	457,807	459,632	460,716	460,890	465,302	468,166	470,601	475,990	480,620	485,452	488,836	495,037	489,665	**7,387,915**	$3,481,566
TOTAL DEMAND	**0**	**0**	**45,106**	**113,532**	**227,415**	**386,537**	**456,612**	**457,807**	**459,632**	**460,716**	**460,890**	**465,302**	**468,166**	**470,601**	**475,990**	**480,620**	**485,452**	**488,836**	**495,037**	**489,665**	**7,387,915**	**$3,481,566**
GRAND TOTAL DEMAND & OTHER BENEFITS	**0**	**0**	**308,850**	**775,959**	**1,635,075**	**2,639,951**	**3,057,277**	**3,108,719**	**3,054,774**	**2,909,945**	**2,860,447**	**2,814,387**	**2,837,189**	**2,889,748**	**2,865,708**	**2,883,673**	**3,064,774**	**3,094,007**	**3,069,663**	**3,024,937**	**46,895,083**	**$22,349,410**

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Schedule 10 – Summary of Xcel Energy's Analysis
Supporting AMI Meter Vendor Selection

Trade Secret Justification

Schedule 10 is an internal assessment summary that the Company has designated as Trade Secret information in its entirety as defined by Minn. Stat. § 13.37, subd. 1(b). The analysis and information contained therein has not been publicly released. This summary was prepared by Major Products & Programs Sourcing employees and their representatives in 2019. This Schedule contains information regarding bidder responses to requests for proposal (RFPs) issued by the Company, including sensitive pricing and other bid data; the Company's proprietary analysis of selected bids; market intelligence; and potential comparative bidder cost and negotiation planning information. Because this overall analysis derives independent economic value from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain economic value from its disclosure or use, Xcel Energy maintains this information as a trade secret.

This presentation is marked as "Non-Public" in its entirety. Pursuant to Minnesota Rule 7829.0500, subp. 3, we provide the following description of the excised material:

1. **Nature of the Material**: Internal assessment of responses to RFPs.
2. **Authors**: Major Products & Programs Sourcing employees and their representatives.
3. **Importance**: The Company's proprietary analysis of RFP responses.
4. **Date the Information was Prepared**: This assessment was prepared in second quarter of 2019.

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Direct Testimony and Schedules
David C. Harkness

Before the Minnesota Public Utilities Commission
State of Minnesota

In the Matter of the Application of Northern States Power Company
for Authority to Increase Rates for Electric Service in Minnesota

Docket No. E002/GR-19-564
Exhibit___(DCH-1)

Business Systems

November 1, 2019

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Schedules

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is David C. Harkness. I am the Senior Vice President, Customer Solutions for Xcel Energy Services Inc. (XES), the service company affiliate of Northern States Power Company, a Minnesota corporation (NSPM or the Company) and an operating company of Xcel Energy Inc. (Xcel Energy). I have spent the last decade as Senior Vice President and Chief Information Officer (CIO) at Xcel Energy.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I have more than 35 years of experience in Information Technology (IT), with 30 of those years in a management role. As I transition to my new role leading Customer Solutions, I remain a subject matter expert for Xcel Energy based on the past decade serving as Senior Vice President and Chief Information Officer (CIO), where I was responsible for the XES Business Systems organization, which provides IT services to Xcel Energy's shared services and the operating companies. In this role, I was also responsible for information technology disaster recovery.

Before I joined Xcel Energy and Northern States Power Company in November 2009, I spent six years at PNM Resources in New Mexico, where I first served as Senior Director, Business Process Outsourcing, then as Senior Director of Business Transformation and, finally, as Vice President and CIO. While in New Mexico, I was also appointed by Governor Richardson to New Mexico's Information Technology Commission, where I helped establish and direct the IT Strategy for the State of New Mexico. Prior to that experience, I

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held several IT Leadership roles for McLeod USA, MCI, and Rockwell International, where I began my career in 1986.

My résumé is attached as Exhibit___(DCH-1), Schedule 1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I present and support the Company's capital and operation and maintenance (O&M) budgets during the period of the 2020-2022 multi-year rate plan (MYRP) for the Business Systems area. I also support the Company's Advanced Grid Intelligence and Security (AGIS) initiative, which consists of major grid modernization efforts to be completed in cooperation between Business Systems and the Xcel Energy business areas that will use the system.

Q. PLEASE PROVIDE AN OVERVIEW OF THE BUSINESS SYSTEMS AREA WITHIN XCEL ENERGY.

A. Business Systems provides IT services across Xcel Energy. Like all utilities, Xcel Energy must invest in computers, software, networks, mobile devices and other IT services each year in order to (among other things):

- Coordinate work in the field;
- Interact with customers;
- Operate and dispatch generation facilities;
- Run our transmission system;
- Provide information to our state and federal regulators;
- Purchase fuel;
- Bill and collect efficiently;
- Develop budgets and track expenditures;

- Manage vendors and vendor contracts; and
- Pay employees.

Each of these activities is necessary to provide reliable electricity and a positive customer experience. No relevant business, including utilities, can function without dependable and up-to-date IT capabilities for both customers and employees.

Q. CAN YOU ALSO PROVIDE AN OVERVIEW OF THE WORK BUSINESS SYSTEMS WILL BE PERFORMING OVER THE NEXT FEW YEARS?

A. Yes. Over the next three years, Business Systems will continue much of the fundamental IT work described in our last Minnesota rate case, including replacing aging technology; protecting customers and the Company against cyber security risks and attacks; and strategically enhancing our IT capabilities to improve our customer and employee experiences. We will continue to be flexible and nimble, addressing new technologies and needs as they emerge within the resources available to us.

Technology changes constantly. With a typical life of roughly three to seven years for NSPM (depending on the system), the average lifespan of IT assets is considerably shorter than it is for many business areas. Although we have been able to return great value from larger systems, on average our assets need attention frequently, especially related to unexpected technology changes.

With respect to replacing aging technology, we continue focus on making sure our employees have the basic technology tools needed for the provision of electricity to customers. While some of these tools (e.g. desk and laptop computers, mobile phones, software versions) need to be patched, updated, or replaced on a reasonably regular basis to keep up, in other areas we have been able to strategically harvest maximum value from older systems and delay investments. In the last Minnesota rate case, I described how our capital and O&M investments would increase because we had previously delayed new investments to the maximum extent. We have now begun replacements for some of these systems. For example, we waited to update to the Windows10 operating system (which was released in 2015) until 2019.

In addition to keeping technology updated, we need to maintain the security of data belonging to our customers, our employees, and our business. Knowing that we will continue to identify new cyber security risks over the next several years, we must proactively make the necessary investments to ensure data security.

Moreover, there are areas where we not only need to replace old systems, but we also have the opportunity to enhance our capabilities and become more efficient. As an example, in 2018 we implemented Blue Prism Process Automation in the financial operations area. The project leverages automation technologies, such as robotic process automation, smart workflows, and natural language processing to streamline workloads. This helps ensure a better, more efficient, and faster financial close by leveraging technology to maximize our employees' time.

Additionally, in an era where customer's expectations are higher than they have ever been, we are turning our attention to enhancing our customers' experience with their utility and electric service by leveraging data, interactive

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technology through the web and digital interfaces to improve our customers' options for energy usage, monitoring, and services. We are embarking on an enterprise-wide effort to advance and modernize the Xcel Energy customer experience, including updating existing systems such as our website and MyAccount through our Customer Experience Transformation programs, and enhancing the distribution grid and associated customer services with an eye toward the future through our Advanced Grid Intelligence and Security (AGIS) initiative.

Q. PLEASE PROVIDE A SUMMARY OF YOUR TESTIMONY.

A. In my Direct Testimony, I describe the Business System organization, as well as some of the IT and business continuity services we provide. I carry forward the discussion from our last electric rate case in Minnesota, illustrating that our capital and O&M investments have increased in light the rising importance of IT in our business. As technology continues to evolve, I explain the kinds of investments we are currently making, why they are important to meet our customers changing energy needs, and how we work to ensure reasonable costs for those investments.

I explain that we are proposing capital additions of approximately $146.3 million for 2020, $134.1 million for 2021 and $134.1 million for 2022 on a total Company basis.[1] I provide support for the key investments during the MYRP term (2020-2022).

I begin by walking through the major capital projects outside of AGIS that

[1] All costs in my testimony are stated on a NSPM total company basis unless otherwise noted.

comprise these budgets, organizing projects by our aging technology, cyber security, customer experience, enhancing capabilities, and emergent demand budget groupings.

I then discuss the Business Systems O&M budget for 2020 through 2022, which is driven by employee labor and non-labor costs, software maintenance, network communications, application development, and distributed systems such as servers, data storage, and desktop computer and printer maintenance. I explain why our O&M budget is reasonable and reflects the types of expenditures we must make to keep the technology side of our business running productively.

Next, I describe in detail why a major component of Business Systems' capital additions consist of our AGIS initiative, and how we have carefully planned for this needed investment. Building on introductory testimony by Company witness Mr. Michael Gersack and Distribution Operations testimony by Company witness Ms. Kelly Bloch, I explain Business Systems' role in developing the strategy, support, security, and implementation plans and activities for the components of AGIS, including the Advanced Data Management System (ADMS), Advanced Metering Infrastructure (AMI), the Field Area Network (FAN), Fault Location, Isolation, and Service Restoration (FLISR), and Integrated Volt-VAr Optimization (IVVO). I further explain how the Business Systems costs of the AGIS initiative were developed both for the term of this rate case multi-year rate plan (MYRP) from 2020-2022, as well as over the longer term for purposes of both the Company's concurrently-filed Integrated Distribution Plan (IDP) and the cost-benefit analysis supported by Company witness Dr. Ravikrishna Duggirala. Company witness Mr. Christopher Cardenas provides additional discussion of how the AGIS initiative benefits customers through our Customer Care area.

Q. HOW HAVE YOU ORGANIZED YOUR TESTIMONY?

A. My testimony is organized into the following sections:

- *Section II* – Business Systems Overview
- *Section III* – Capital Investments
- *Section IV* – O&M Budget
- *Section V* – The Advanced Grid Intelligence and Security Initiative
- *Section VI* – Conclusion

II. BUSINESS SYSTEMS OVERVIEW

Q. PLEASE DESCRIBE BUSINESS SYSTEMS' KEY ROLES AND RESPONSIBILITIES.

A. Business Systems is the Company's centralized IT organization, providing technology services across all operating companies, including NSP-Minnesota. These services include support for the following business operations:

- *Foundational Technology Infrastructure*. Business Systems is responsible for providing support for each employee's hardware and software needs. This includes maintaining and updating the operating system used on employee computers and providing sufficient data storage capabilities. Business Systems is also charged with protecting the security of the Company's data from cyber attacks.
- *Systems Controls*. Business Systems provides technology support to our generation, transmission, and distribution units to help manage and operate the electric and gas systems. This includes providing and supporting software applications such as Supervisory Control and Data

Only the testimony necessary to support the Company's Advanced Grid Intelligence and Security (AGIS) Initiative have been included in the Integrated Distribution Plan (IDP) filing. Accordingly, we have excised non-AGIS pages from this attachment.

V. THE ADVANCED GRID INTELLIGENCE AND SECURITY INITIATIVE

A. Introduction

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section, I discuss the IT integration and cyber security support for the Company's Advanced Grid Intelligence and Security (AGIS) initiative and provide detailed support for the recovery of associated costs incurred by the Business Systems organization, including both capital and O&M. As discussed by Mr. Gersack, the Company is requesting approval to recover the costs of the capital investments and O&M expense for the components of AGIS that we propose to implement during the MYRP, and is also requesting that the Commission certify these projects so the Company may request recovery of costs for 2023 and later in subsequent rider filings (subject to all other requirements of rider recovery). Accordingly, while I focus this discussion somewhat on the term of the multi-year rate plan, I also provide support for the IT portions of the broader AGIS initiative, consistent with the Company's Integrated Distribution Plan (IDP) being filed concurrently with this rate case.

Q. HOW IS THIS SECTION OF YOUR TESTIMONY ORGANIZED?

A. I first describe the AGIS initiative and present an overview of the Business Systems and IT services that will integrate the various components of the AGIS initiative.

I then discuss the cyber security measures that will protect the more intelligent, interactive electric distribution network as well as the underlying

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data it gathers. I describe the Company's security principles, and explain the protection that will be implemented to secure customer endpoints and the communications network that facilitates the movement of data through the advanced grid. Overall, I explain how the Company continually identifies and implements cyber security best practices to protect customers and the distribution grid. Reliable delivery of electricity is of paramount importance, protecting the integrity and security of this system is included with that responsibility.

I then discuss the IT infrastructure that will support all aspects of the AGIS initiative. I discuss each component, the implementation plan, and the associated costs for Business Systems. While the more visible components of the AGIS initiative are described by other Company witnesses, supporting IT infrastructure and integration of the components of AGIS will allow new applications and field devices to communicate with and deliver data to the Company's "back office applications." In other words, IT enables the software applications that support the Company's customer service needs, billing, payment remittance, service order management, outage management, meter reading, and asset inventory lifecycle management applications to utilize the customer data, outage data, and other information supplied by the advanced distribution grid.

This discussion includes the implementation plan for the Company's IT integration efforts, which will begin in 2020 and will continue as AGIS components are implemented during the term of the multi-year rate plan. I also describe the IT support necessary to facilitate certain customer interaction points, such as a customer internet portal that utilizes communications with advanced meters to provide timely energy usage information to customers.

Finally, I provide support for the capital and O&M costs related to the IT integration and cyber security for AGIS for which we are requesting recovery in this case. In turn, these costs flow through the Company's cost-benefit analysis presented by Dr. Duggirala and Mr. Gersack. Because hardware and software systems and integration work are critical foundations of the AGIS initiative but do not provide quantifiable benefits until they are deployed and utilized in conjunction with distribution systems, my discussion of customer cost-benefit analyses is limited to costs.

Following is an outline of the remainder of this section of my testimony. A more detailed outline including subheadings can be found in the Table of Contents.

- <u>AGIS Overview</u>
- <u>IT Support for AGIS</u>
- <u>Distribution Grid Cyber Security</u>
- <u>AGIS Components, Implementation, and IT Costs</u>
    1. Introduction and Overview
    2. Grid Modernization Efforts to Date
        - *ADMS*
        - *TOU Pilot*
    3. AMI
        - *AMI Overview*
        - *AMI Integration*
        - *AMI Costs*

4. The FAN
   - *FAN Overview*
   - *Interrelation of FAN with Other AGIS Components*
   - *FAN Benefits*
   - *FAN Implementation*
   - *FAN Costs*
   - *Minimization of Risk of Obsolescence for FAN*
   - *Alternatives to FAN*
5. FLISR
6. IVVO
7. AGIS IT Overall Costs and Implementation

Q. HOW IS THE COMPANY PRESENTING ITS OVERALL SUPPORT FOR THE AGIS INITIATIVE?

A. A discussion of the overall AGIS initiative is provided in the Direct Testimony of Company witness Mr. Michael C. Gersack. In addition to my testimony, information on the AGIS distribution system components and customer benefits and other considerations is provided in the Direct Testimonies of Company witnesses Ms. Kelly A. Bloch and Mr. Christopher C. Cardenas. The AGIS cost and benefits analyses are provided in the Direct Testimony of Company witness Dr. Ravikrishna Duggirala.

B. AGIS Overview

Q. WHAT IS AGIS?

A. The AGIS initiative is a comprehensive plan that will advance the Company's electric distribution system, provide customers with more choices, and enhance the way the Company serves its customers. AGIS provides the foundation for an interactive, intelligent, and efficient grid system that will be even more reliable and better prepared to meet the energy demands of the future.

Q. TO PROVIDE A FRAMEWORK FOR THE REMAINDER OF YOUR TESTIMONY, PLEASE IDENTIFY THE CORE COMPONENTS OF AGIS.

A. The core components of AGIS are the Advanced Distribution Management System (ADMS); Advanced Metering Infrastructure (AMI); the Field Area Network (FAN); Fault Location Isolation and Service Restoration (FLISR); and Integrated Volt-VAr Optimization (IVVO). More specifically:

- *Advanced Distribution Management System (ADMS)* is a foundational system for operational hardware and software applications. It acts as a centralized decision support system that assists control room personnel, field operating personnel, and engineers with the monitoring, control and optimization of the electric distribution grid. ADMS also includes the data enhancements for the Geospatial Information System (GIS), which is a foundational data repository that provides location and specification information for all of the physical assets that make up the distribution system. ADMS uses this information to maintain the as-operated electrical model and advanced applications.
- *Advanced Meter Infrastructure (AMI)* is an integrated system of advanced meters, communication networks, and data processing and management systems that enables secure two-way communication between Xcel Energy's business and operational data systems and customer meters. AMI provides a central source of information that is shared through the communications network with many components of an intelligent grid design.

- *Field Area Network (FAN)* is the communications network that will enable communications between the existing communications infrastructure at the Company's substations, ADMS, AMI, and the new intelligent field devices associated with advanced grid applications.
- *Fault Location Isolation and Service Restoration (FLISR)* involves software and automated switching devices, as an additional component of the ADMS, that reduce the frequency and duration of customer outages. These automated switching devices detect feeder mainline faults, isolate the fault by opening section switches, and restore power to unfaulted sections by closing tie switches to adjacent feeders as necessary.
- *Integrated Volt-VAr Optimization (IVVO)* is a significant additional component supported by ADMS, as it automates and optimizes the operation of the distribution voltage regulating and VAr control devices to reduce electrical losses, electrical demand, and energy consumption, and provides increased distribution system injection capacity to host DER.

C. IT Support for AGIS

Q. WHAT ROLE DOES INFORMATION TECHNOLOGY PLAY IN THE ADVANCED DISTRIBUTION NETWORK?

A. As discussed in the Direct Testimony of Mr. Gersack, the Company envisions an increasingly intelligent, automated, and interactive electric distribution system that utilizes advancements in sensing, controls, information, computing, communications, materials and components. This greater intelligence and automation is dependent on information technology to share and analyze information, integrate systems, and support the advanced infrastructure in a timely and efficient manner. In turn, through the AGIS initiative the more advanced distribution system will be able to better meet customers' energy needs, while also integrating new sources of energy and improving grid reliability.

Q. PLEASE INTRODUCE THE WORK THAT WILL BE REQUIRED OF BUSINESS SYSTEM TO SUPPORT THE AGIS INITIATIVE.

A. Overall, Business Systems is responsible for the IT integration of AGIS systems and data with other back office applications existing at the Company. For example, Business Systems will implement the FAN that allows intelligent field devices, ADMS, AMI, and other systems to connect. Business Systems has already implemented many foundational components of the AMI software for use in Colorado, and in Minnesota for the Residential Time of Use (TOU) pilot. This same software will provide features and data processing to support a full Minnesota rollout, and will be enhanced to support Minnesota requirements for capacity, performance, security, and functionality. From the AMI head-end, a combination of new or enhanced interfaces will be built to transfer the data to other applications, such as ADMS, the meter data management system, the billing and customer service system, and the asset inventory management system.

Implementing AGIS will require the various interfaces to transfer large volumes of data in a small amount of time. We will also be obtaining significantly more data from the field devices than we have in the past. This additional data will require additional space for storage and a data management plan to ensure we are keeping the necessary data only for as long as it is needed. The new software, additional server hardware, and increase in quantity of data stored will all need to be supported, which will require an increase in our support staffs.

Q. WHAT DO YOU MEAN BY IT INTEGRATION?

A. By IT integration, I refer to the need to integrate the technical components of the AGIS initiative (*i.e.*, the ADMS, AMI, FAN, FLISR, and IVVO systems) with other Company applications to allow the efficient, timely, and secure transfer of data between AGIS systems and other Company systems. The goal of integration is to ensure new applications and data are able to communicate with our existing applications so we are able to use the data to improve Company operations and provide a better customer experience.

As one example, AMI meter data must be communicated to the ADMS for operations and management of the grid, and to back-office applications such as billing and customer care for the data to be used consistently and as effectively as possible. As the business processes are defined or refined, the necessary data and applications requiring the new data gathered from the AGIS components will be identified. Interfaces will be designed or significantly enhanced to transfer the data between the applications. New interfaces to support the new business processes will require significant labor to design and implement. We will need to use existing tools, such as an Enterprise Service Bus (ESB),[3] to make the implementation and support of the interfaces consistent and efficient.

[3] The ESB is a type of software platform that works behind the scenes to aid application-to-application communication. The ESB can be thought of as a "bus" that picks up information from one system and delivers it to another.

Q. TO WHAT EXTENT DOES BUSINESS SYSTEMS ANTICIPATE ENHANCEMENTS TO BACK-OFFICE APPLICATIONS MAY BE NECESSARY AS A RESULT OF AGIS?

A. The new AMI field devices will provide data we have not stored in our systems before and this data will be in larger quantities than we have obtained before. As a result, effective use and communication of this data will require upgrades to many of our existing business processes. While our project plans have identified these upgrades and enhancements, there may be some additional requirements that will not be fully determined until the AGIS initiative is approved and final requirements are determined.

Q. CAN YOU DISCUSS FURTHER THE TYPES AND VOLUME OF DATA YOU WILL BE RECEIVING FROM THE FIELD AND MANAGING AS A RESULT OF AGIS IMPLEMENTATION?

A. Yes. The volume of data will increase by orders of magnitude. Related to AMI metering, we will have the capability to obtain data from meters many times a day – and will be able to provide this data to customers on a daily basis (or more frequently) via the customer data web portal or smartphone application. Not only will the advanced meters provide energy usage data, they can also measure voltage, current, frequency, and power quality. Additionally, these meters can detect outage events, restoration events, tampering, energy theft events, and perform meter diagnostics. This is in contrast to our current metering system which generally provides energy usage data once per month for billing purposes.

In addition to the meter data, the advanced grid components FLISR and IVVO will provide outage and voltage information that will be used for outage response as well as for grid management and planning purposes.

To support the new data and processes, the Company will need to enhance some software applications to accommodate new fields and increase the applications data storage capacity and processing.

Q. WHY DOES THE COMPANY NEED TO INTEGRATE THE COMPONENTS OF THE AGIS INITIATIVE WITH OTHER COMPANY SYSTEMS?

A. To realize the benefits of advanced grid capabilities and coordinate service delivery to customers as well as the work of our personnel, it is essential that we integrate our systems to coordinate timely, accurate information. Integration of systems ensures that new AGIS systems and components distribute and receive information that is synchronized across all impacted business processes. Integration is fundamental to keep large volumes of data timely, accurate, and consistent between systems of record. Integration is also key to securing the technologies we are deploying.

Conversely, compromising the integration of systems would significantly diminish the customer experience and reduce the processing and decision making that is required to manage energy services that our customers want. Lack of integration would require that customers and Company employees obtain different information from different sources or applications, creating the risk of error and making it more difficult and more time consuming to obtain and provide information, which can results in additional costs.

As the use of integrated systems matures, the Company will be able to use information from many different, integrated sources to assist in managing the electric grid and maximizing the benefits of AMI for our Minnesota electric customers.

Q. HOW WILL AMI AND BACK OFFICE APPLICATIONS BE INTEGRATED?

A. The Company will connect the AMI meter with the AMI head-end software that sends commands to meters and receives data from the meter using the FAN communication network. From the AMI head-end, data will be distributed to back office applications to enable the Company and customers to use this data in a meaningful way. ADMS data from field devices, including advanced meters, will also be distributed to various back office applications, to enable the Company to manage the distribution grid more effectively and efficiently.

Q. ARE THERE ASPECTS OF IT INTEGRATION FOR THE AGIS INITIATIVE THAT WILL HAVE TO BE DEVELOPED AS THE PROGRAM IS IMPLEMENTED?

A. Yes. While we know a great deal of the integration work that will be necessary, the full extent of the IT work to be completed in Minnesota cannot be completely anticipated ahead of time due to the need for additional filings and the need for future decisions that will depend on technology advances as time goes on. For example, as discussed by Mr. Cardenas, we will be submitting separate filings with the Commission for approval of opt-out provisions and to enable remote connection/disconnection capabilities. Once these proceedings are completed and requirements are finalized, we will be working on details to implement these processes, ensuring they comply with Minnesota requirements that may be established. As time progresses, we will also learn additional information regarding the level and type of application enhancements that will be needed. Therefore, a contingency has been added to the current cost estimates. Once those details are finalized and project plans are refined accordingly, we will be able to further refine project cost estimates. I describe our current cost estimates later in my testimony, after first describing how the Company is hardening the advanced grid against cyber threats.

D. Distribution Grid Cyber Security

Q. HOW IS CYBER SECURITY INTEGRAL TO THE AGIS PLAN?

A. Cyber security is a significant element of the AGIS plan. It starts with identification and protection of all components of the intelligent grid, both for the protection of customers and for the reliable and safe delivery of energy to customers. Also included are detective controls at strategic locations to provide early notification of suspicious behavior or anomalous activity. Further, the Company plans, refines and exercises to react appropriately to threats to the intelligent grid.

Q. DOES XCEL ENERGY HAVE A CYBER SECURITY BUSINESS AREA?

A. Yes. In addition to Business Systems, the Company has a dedicated Enterprise Security Services (ESS) business unit that encompasses both cyber and physical security, security governance and risk management, and enterprise resilience and continuity services. This combination of services is designed to cover analysis of vendor risks, alignment of the technology with security standards, secure solution design and deployment, integration with Company solutions including user access management and system monitoring and incident response, as well as threat analysis and planning for continuity of business operations in the event of a disruption.

The Company's security risk management program provides Company leaders with information about threats and the level of security risks, so that mitigations and responses can be planned that are proportional to the risk.

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The separation of ESS from Business Systems is a beneficial organizational structure in that it provides multiple layers of security oversight on an enterprise-wide basis, not just under the IT organization. ESS staff and programs, however, are tightly integrated into the AGIS program, and the ESS costs specifically related to AGIS are included in the Business Systems AGIS budget presented below.

Q. WHAT ARE SOME OF THE GENERAL TYPES OF SECURITY RISKS THAT MUST BE TAKEN INTO ACCOUNT FOR ANY UTILITY DISTRIBUTION SYSTEM AND CUSTOMER METERS?

A. First, devices in the field must be protected proportionately. Consequently, unlike internal business technology, the distribution components are out in the field and at customers' residences; devices can only be hardened so much, and security must also rely on other controls. Additionally, although even legacy distribution systems and meters are vulnerable to physical tampering and disabling, adding a communications network enhances the potential impact of a security compromise. In short, the endpoints and the communications between them all require security protections.

Q. DOES IMPLEMENTATION OF THE AGIS INITIATIVE SOLVE SOME OF THE CYBER SECURITY CHALLENGES PRESENTED BY THE COMPANY'S CURRENT DISTRIBUTION GRID?

A. Yes. For example, our current meter reading technology was implemented beginning in the 1990s; thus, it does not have state-of-the-art access controls, encryption technologies, or monitoring capabilities. Further, it is not capable of two-way communications, and the security architecture it is built upon is inadequate. The two-way communication enabled with AMI metering provides additional information to the Company about changes to the meter that can help prevent and identify meter theft and tampering, as described by Mr. Cardenas.

Further, the addition of a communication network provides additional capabilities and services to our customers, as well as greater insight into our system, but can also increase the potential impact of a cyber security compromise. The addition of a Company-owned Field Area Network is a prudent approach to this concern. A private network allows Company to better control the integrity of the devices on its network and the data exchanged with those devices. The alternative, a public network, would expose the devices to increased risk because the Company would not be in control of the network.

Overall, while the implementation of the AGIS initiative solves certain existing issues, it also presents different challenges to security than a less advanced grid, and requires its own comprehensive security strategy.

Q. CAN YOU PROVIDE MORE SPECIFIC INFORMATION REGARDING THE SECURITY RISKS THE COMPANY IS ADDRESSING AS PART OF THE AGIS INITIATIVE?

A. Yes. Security controls are designed for each component and system implemented as part of the AGIS initiative. The security risks associated with the AGIS components can be organized into three primary areas: compromise of meters and devices; exploitation of the communications channels; and security lapses once data is within the corporate environment. There are also security risks related to the web portal, as well as future customer applications and new products and services that will be enabled by the advanced grid.

First, advanced meters and other networked devices have an integrated network interface card (NIC) that enables them to connect to the WiSUN network. The Company leverages both physical and cyber security controls to protect NICs from unauthorized access.

Second, a compromise of the WiSUN and WiMAX networks that carry traffic to and from the meters and field devices could lead to disruption or alteration of information needed for grid management. Therefore, protecting the integrity of the communication devices and channels that allow the advanced grid to perform at expected levels is paramount. It is also important to implement the correct level of monitoring and alerting, configured to identify potentially anomalous activity, so that both proactive and reactive responses are appropriate and efficient.

Third, the primary risk to systems and information that reside within the Company's corporate environment is from unauthorized access – where a criminal or unqualified employee access sensitive data or issues commands to the grid. There are many controls in place to prevent and detect such behavior.

Q. DOES THE COMPANY EMPLOY BEST PRACTICES FOR CYBER SECURITY?

A. Yes. Security practices include a security controls governance framework, which leverages industry best practices including the National Institute of Standards and Technology (NIST), Cyber Security Framework (CSF). The Company's security policies and standards incorporate regulatory compliance requirements and security controls designed to protect against CIA (Confidentiality, Integrity and Availability) breaches. This framework serves as the basis for project security requirements as well as periodic internal security technology control assessments.

1. Cyber Security Principles

Q. WHAT ARE THE CYBER SECURITY BEST PRACTICES FOR XCEL ENERGY?

A. The Company's cyber security program may best be described in terms of the five categories of controls outlined in the NIST CSF: identify, protect, detect, respond, recover. Combining these for "defense in depth" adds multiple layers of protection and detection including defenses at each endpoint and throughout the network. Controls within these layers include:

- Asset management – maintain an inventory and securely configure assets, so we know what to protect as well as what is authorized to access our networks ["Identify"];
- Protection – user access controls, encryption, digital certificates and other controls to ensure the confidentiality, integrity and availability of data ["Protect"];
- Vulnerability management – in addition to scanning equipment for known security vulnerabilities, the company monitors emerging threats ["Detect"];
- Monitoring and alerting – identify potentially anomalous activity so that both proactive and reactive responses are appropriate and efficient ["Detect"];
- Incident response – analyze information using playbooks and escalate to the Enterprise Command Center, the Company's 24x7 watch floor operation designed to prepare for, respond to, and recover from any potential hazard that may impact customers, Company assets, operations, or its reputation ["Respond"]; and

- Disaster recovery and business continuity planning – to efficiently maintain and restore grid operations in the event of a cyber attack ["Recover"].

Cyber security threats are monitored and as new types of threats emerge, the Company adjusts our "defense in depth" strategy accordingly.

Q. HAS XCEL ENERGY IMPLEMENTED THE CYBER SECURITY BEST PRACTICES YOU DESCRIBED?

A. Yes. These cyber security controls will be applied to the technology to be implemented as part of the AGIS initiative to identify and protect all components of the intelligent grid and help ensure the reliable and safe delivery of energy to the Company's customers. The following discussion explains how these controls are being applied, at the endpoints, on the communications channels, and within the corporate environment.

2. Endpoint Protections

Q. FIRST, WHAT DO YOU MEAN BY ENDPOINT?

A. An endpoint in this context refers to the intelligent devices on our system. This includes the AMI meter and head-end, but also includes communication devices such as routers or switches. As a point of reference, the concept of "endpoints" is not limited to distribution system field devices; it also includes other end user devices, such as Company personal computers and network servers. However, my testimony is focused on distribution grid devices.

Q. WHAT IS ENDPOINT PROTECTION?

A. Endpoint Protection is the installation and/or enablement of protective and detective cyber security controls to thwart malware and external influences from causing unexpected, unwanted or invalid behavior at an endpoint.

Q. WHAT TYPES OF ENDPOINT PROTECTION HAS XCEL ENERGY IMPLEMENTED?

A. Xcel Energy's Endpoint Protections include: (1) Access Controls including Authentication and Authorization; (2) System Patching; and (3) Data Validation and Protection. These endpoint protections were specified as cyber security controls in the AMI vendor selection process, as they are essential to protect the devices and the data that are handled by AMI meters and headend servers. The vendor selection process is described later in my testimony and in Ms. Bloch's testimony. Authentication and Authorization is integral to Access Control for any type of endpoint so that logical access to endpoints can only be performed by duly authorized personnel.

Q. PLEASE DESCRIBE ACCESS CONTROL.

A. The first item of protection, Access Control, is to confirm that only necessary and authorized users have access to the individual devices. This not only includes the devices that are installed on the consumer's premises, but also the devices that facilitate communication and control of the data flowing to the consumer. There are potentially many avenues of compromise with respect to unauthorized access to devices. This is a key consideration and will be addressed through strong authentication methods, which include multi-factor authentication methods described below.

Q. PLEASE DESCRIBE AUTHENTICATION AND AUTHORIZATION.

A. Authentication is a method by which a user affirms their identity. In its simplest form, it involves a user ID and password. Where technically feasible, Xcel Energy requires multi-factor authentication so that a user must not only know their password, they must also possess a physical or logical token. This minimizes the ability of an unauthorized user to steal passwords and access our assets and information.

Authorization is the process of determining and configuring the minimum level of access required by a user or an automated system. Granting undue permissions to devices that comprise the intelligent electric distribution system could lead to unauthorized or inadvertent changes and instability. Complying with a least-privilege principle ensures that only necessary and authorized individuals have the ability to make administrative changes.

Sound access controls include periodic review of access levels and removing access when it is no longer needed.

Q. PLEASE DESCRIBE SYSTEM PATCH MANAGEMENT.

A. Device and system manufacturers periodically issue updates to software and firmware to improve performance, add features, or address security vulnerabilities. A robust system patch management process incorporates asset inventories, secure receipt of patches from the vendor, testing and deployment to the field. The Company's threat intelligence and vulnerability management teams monitor for and inform support teams of known security vulnerabilities that require patching. Keeping current with vendor patches helps reduce the

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possibility that a criminal can use a known exploit to compromise our systems or data.

Q. PLEASE DESCRIBE DATA VALIDATION AND PROTECTION.

A. A final defensive layer between the various endpoints is data validation. As data is sent from endpoints at consumer premises, data validation at the head-end must take place. If data values received from the consumer endpoint do not fall within a range of expected values, then either the data must be assumed compromised and discarded, or secondary validation must take place to measure the integrity of the data received. This validation will provide yet another level of detection and protection for the intelligent electric distribution system.

Each of these endpoint protections will support the overall security of the AGIS technology.

3. Communication Network Security Protections

Q. AS PART OF IMPLEMENTING CYBER SECURITY, DOES THE COMMUNICATION NETWORK ALSO NEED TO BE PROTECTED?

A. Yes. The communication network that facilitates data movement from the endpoint at the consumer premise to the utility's control center must also have a high level of security built into the architecture to ensure confidentiality, integrity, and availability of the intelligent electric distribution network.

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Q. WHAT ARE THE PROTECTIONS XCEL ENERGY APPLIES TO THE COMMUNICATIONS NETWORK?

A. The equipment that makes up the communication network deploys the endpoint protections previously discussed. Additional key controls for the communications pathways include the use of firewalls to restrict which systems can interact and what ports and protocols they can use; encryption to minimize the opportunity to intercept and alter data traffic; monitoring and log review as well as response to suspected security events.

Q. PLEASE DESCRIBE HOW FIREWALLS ARE USED TO PROTECT COMMUNICATIONS.

A. Firewalls are placed in multiple areas of the network between the customer meter and the company data center/head end. By default, all traffic through a firewall is blocked, and authorized only after a thorough review and change process. With a firewall, any unauthorized, unregistered devices that attempt to join the network or communicate to/from devices are blocked.

Q. PLEASE DESCRIBE ENCRYPTION.

A. Encryption uses complex mathematical algorithms to obscure data prior to and during its travels through the communications network. It also prevents data from being altered. Only authorized parties to the transaction (sender and receiver) have the "keys" to encrypt and decrypt data.

Q. DOES EVERY COMMUNICATION CHANNEL OR MEDIUM NEED TO HAVE THE SAME LEVEL OF PROTECTION?

A. Yes. The FAN solution described earlier in my testimony employs multiple technical protocols (WiMAX and WiSUN), as well as cellular. In order to ensure an efficient and holistic approach is taken to the intelligent electric distribution network, it must interoperate with all available communication mediums. The equipment that facilitates the specific communication medium must not impede the security controls placed on any of the equipment identified above. Therefore, all security controls should work independently of the specific communication medium.

4. Security Protections within the Corporate Environment

Q. DO ANY PROTECTIONS NEED TO BE APPLIED TO ACCESS TO INFORMATION ONCE IT RESIDES WITHIN THE COMPANY HEAD END SYSTEMS?

A. Yes. Company systems reside in data centers with physical access protections – only authorized users are able to enter these locked facilities on Company property. Data accessed from the control centers travels from the systems in the Company data centers over the corporate network. At the control center, application users must follow the same rules for authentication, authorization, and least privilege.

Data from the intelligent electric distribution network passes through multiple defense-in-depth controls on its way back to the systems in the corporate data centers. Communication will pass through multiple firewalls to ensure that only authorized devices are communicating on authorized ports/protocols. Additionally, a protocol-aware Intrusion Detection System/Intrusion Prevention System (IDS/IPS) will inspect the traffic to ensure tampering has not been performed on the data packet. Once the data has been delivered to the systems responsible for consuming this information, only authorized processes will have the ability to act upon this information.

The Company segments its networks, so that critical operational systems and information are kept separate from business data and operations including email. This segmentation adds a significant barrier should a criminal compromise a corporate user's account. In addition to using firewalls between networks, the Company requires the use of multi-factor authentication when accessing systems from outside the control center.

5. Other Security Protections

Q. DOES LOG MONITORING HAVE A ROLE IN THE DEFENSE OF THE NETWORK?

A. Yes. Devices that reside on the intelligent electric distribution network that have the ability to log various pieces of information and send those logs to an intelligent collector are sending them to the Security Incident and Event Management (SIEM) system. This system will collect, analyze, report, and alert on various security activity. All anomalous activity and known bad events, will be sent to the 24x7 Cyber Defense Center personnel responsible to investigate and take action upon those events. The SIEM will analyze events across systems and networks, correlating seemingly-unrelated activities for analysis and response. Additionally, copying logs to the SIEM frequently allows for better forensics than relying on source system logs which may be altered after-the-fact. Log data will be retained for an appropriate period of time to ensure any auditing activities will have sufficient data to perform a satisfactory review.

Q. DOES PROACTIVE CHANGE MANAGEMENT HAVE A ROLE IN THE DEFENSE OF THE SOLUTION?

A. Yes. In this context "change management" or "change control" is the process used to identify, analyze and approve changes to the technology environment,

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before those are implemented. The Company has a robust change process for computer systems, based on ITIL (formerly an acronym for Information Technology Infrastructure Library) that includes not only the steps above, but also creation of business justification, post-implementation testing (PIT) steps, and instructions for backing out a change that fails PIT. This level of rigor helps minimize unintended consequences of changes to software. Without a sufficient level of oversight and change governance, the integrity and security of individual devices, and ultimately the network, could be impacted. The absence of a sufficient level of oversight and change governance could result in the loss of information, disruption of communication, or an impact to the integrity of the data. Therefore, strict adherence to change management will be incorporated into this effort.

Q. PLEASE DESCRIBE HOW THE COMBINATION OF THESE CONTROLS IS APPLIED TO PROTECT DATA FROM THE AMI METERS

A. The Company intends to secure the smart meter by applying "defense in depth." The meter will be physically sealed and monitored to detect tampering. Meter communications will be encrypted to protect the privacy of our customers. Communications travel on the company's private FAN, hopping between authorized devices that have been registered onto the network. Firewalls control the information that travels in and out of the corporate network. The head-end validates the integrity of the data received.

The Company will actively monitor the communications path between the meters and the company data centers to promptly detect and respond to any anomalous activity. Additional monitoring of the head end system will alert the CDC to security events for investigation.

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Q. DOES LIFE-CYCLE MANAGEMENT OF DEVICES HAVE A ROLE IN THE COMPANY'S IMPLEMENTATION OF CYBER SECURITY BEST PRACTICES?

A. Yes. The overall success of cyber security within the intelligent electric distribution network will be dependent upon the life-cycle management process of the equipment that makes up this network. Safeguarding this equipment is dependent upon an accurate inventory of all devices that enable this solution. Furthermore, each device must have a known and valid configuration.

Q. HOW WOULD LIFE-CYCLE MANAGEMENT OF DEVICES BE ACCOMPLISHED?

A. Life cycle management starts with selection and acquisition of devices. Cyber security requirements are provided to vendors of meters and all new distribution field devices and compliance to those requirements factors into the selection process. Additionally, the internal security practices of each vendor that will have access to Xcel Energy data is evaluated. Gaps are communicated to the vendor and remediation is requested. Xcel Energy leaders consider these gaps, or security risks, when making their purchasing decisions.

Assets are inventoried prior to deployment. In addition to operational maintenance, security patching is done when required, and approved configuration records updated. Once an asset has reached the end of its useful life, confidential and confidential restricted information is removed and the asset is destroyed.

Q. DO MONITORING AND ANALYSIS OF COMMUNICATIONS HAVE A ROLE IN THE COMPANY'S IMPLEMENTATION OF CYBER SECURITY BEST PRACTICES?

A. Yes. Continuous monitoring of this solution is important to ensure the integrity and security of the system. As conditions change within the distribution network, Distribution Operators will closely monitor the values to ensure continuous and reliable delivery of electricity to our consumers. So too must the cyber security personnel provide continuous monitoring of the systems and the communications that support the continuous and reliable operations of the equipment responsible for the delivery of electricity.

Q. WOULD OTHER ITEMS NEED TO BE MONITORED AND EVALUATED TO ENSURE THE SECURITY OF THE INTELLIGENT ELECTRIC DISTRIBUTION SYSTEM?

A. Yes. Data integrity is also an item that must be monitored and evaluated. By confirming the returned data values fall within an expected range, the integrity of the distribution control system can be maintained. Injecting bad data is a mechanism used to compromise the integrity and availability of a system without actually taking direct control over it. This would be a potential indicator of compromise to the intelligent electric distribution network and an immediate investigation would need to commence to verify whether a real attack is occurring or has occurred.

Q. HOW HAS THE COMPANY APPLIED LEARNINGS FROM OTHER UTILITIES OR BUSINESSES THAT HAVE FACED CYBER SECURITY CHALLENGES?

A. Recognizing the increased security risk of deploying intelligent devices to facilitate customer and distribution grid operations, the Company through the ESS Threat and Vulnerability Management (TVM) group has analyzed known distribution system cyber attacks, including those in Ukraine. Through analysis including a tabletop walk through of the Ukraine attacks, the Company has evaluated existing controls that would avert such attacks. TVM continues to monitor intelligence sources and work with our partners and other utilities to understand and anticipate threats to the Company.

6. Cyber Security Costs

Q. DO YOU HAVE ANY SEPARATE COST ESTIMATES FOR THE IMPLEMENTATION OF CYBER SECURITY FOR THE AGIS INITIATIVE?

A. No, there is not a separate cost estimate for overall cyber security. Cyber security costs are part of the application development and integration efforts described above, as they permeate all aspects of this work. As such, the costs estimates provided in Section D for the IT integration of AGIS components include costs for deployment of cyber security as part of the AGIS initiative. However, the budget does include a separate line item for project management with respect to cyber security. I discuss security project management costs in Section D, and Mr. Gersack addresses overall program management costs for AGIS implementation in his testimony.

7. Cyber Security Summary

Q. WHAT ARE YOUR CONCLUSIONS REGARDING CYBER SECURITY WITH RESPECT TO AGIS?

A. AGIS will bring exciting benefits to our customers, but those benefits are achievable only with a robust interconnected network and flow of data that present cybersecurity challenges. The controls I discussed above will help protect both the consumer and the distribution network, detect attacks or attempted compromise occurrences, and respond in a timely manner to limit and/or prevent impact to the consumers or to the Company. These cyber security controls are seen as a best practice, and align with the Cyber Security Framework (CSF) to Identify, Detect, Protect, Respond and Recover to known and unknown risks.

E. AGIS Components, Implementation, and IT Costs

1. Introduction and Overview

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section, I discuss each of the AGIS components and provide detailed support for the recovery of forecasted capital additions and O&M costs for the Business Systems organization related to the AGIS initiative for the MYRP period 2020 through 2022. I also provide support for the Company's request for certification of the AGIS projects, as presented by Mr. Gersack, to allow the Company the opportunity to request recovery of costs for 2023 and beyond in a later rider filing. Mr. Gersack provides an overview of and policy support for the Company's AGIS initiative and certain Program Management costs, and Ms. Bloch provides support for the AGIS costs related to the Distribution organization.

Q. DO YOU ALSO DISCUSS BENEFITS OF AGIS FROM A BUSINESS SYSTEMS PERSPECTIVE?

A. No. IT by itself does not provide isolated benefits without the implementation of the Distribution aspects of the AGIS projects, but the benefits of AGIS could not be achieved without IT integration. Mr. Gersack, Ms. Bloch, and Mr. Cardenas are the primary witnesses describing the customer benefits driven by AGIS.

Q. CAN YOU DESCRIBE IN MORE DETAIL HOW THE COMPANY IS SUPPORTING ITS AGIS COSTS IN THIS RATE CASE FILING?

A. Yes. AGIS costs are incurred by both Distribution and the Business Systems (IT) organization for each of the AGIS programs. There are IT components for each of the AGIS components (ADMS, AMI, FAN, FLISR, and IVVO). Business Systems is responsible for all IT components of the program. This includes the ADMS and AMI software installation and interface development to all appropriate legacy applications. In addition, IT is primarily responsible for the development and installation of the FAN components (with a portion of the installation to be completed by Distribution Operations), and network connectivity from the meters to all software components. I provide the primary support for the costs and processes for these components of these AGIS programs.

ADMS was previously certified by the Commission and costs were approved for recovery under the Transmission Cost Recovery (TCR) Rider. The Company proposes to continue recovery of ADMS costs via the TCR Rider. For 2020 and going forward, the Company proposes to recover the costs associated with the Time of Use (TOU) pilot as part of this rate case. I discuss the Business Systems support for these costs below.

Ms. Bloch provides the primary support for the costs and implementation for programs and components where Distribution has primary responsibility, including the GIS data collection effort for ADMS, the AMI meters, and installation of pole-mounted FAN devices, the advanced applications utilizing intelligent field devices (*i.e.*, FLISR and IVVO), and additional elements of the AGIS implementation process.

Q. PLEASE SUMMARIZE THE AGIS COMPONENTS FOR WHICH THE COMPANY IS SEEKING RECOVERY, ALONG WITH THE RESPONSIBLE COMPANY WITNESS.

A. Ms. Bloch and I support the costs of the AGIS components as follows:

Table 24: AGIS Program Witness Support

AGIS Program	Component	Witness
AMI	IT Integration and head end application	Harkness Direct, Section V(E)(3)
	Meters and deployment	Bloch Direct, Section V(D)
FAN	IT Integration and deployment	Harkness Direct, Section V(E)(4)
	Installation of pole-mounted devices	Bloch Direct, Section V(E)
FLISR	System development	Harkness Direct, Section V(E)(5)
	Advanced application and field devices	Bloch Direct, Section V(F)
IVVO	System development	Harkness Direct, Section V(E)(6)
	Advanced application and field devices	Bloch Direct, Section V(G)

Q. HOW ARE AGIS COSTS PRESENTED IN YOUR TESTIMONY?

A. Whereas the costs in Sections I-IV of my Direct Testimony present costs at the NSPM Total Company electric level (as usual for Business Systems costs), the AGIS capital additions presented in my testimony are provided at the Minnesota electric jurisdiction level. AGIS capital expenditures and O&M costs are stated at the NSPM Total Company electric level. The reason for this difference within my testimony is that we wanted to present AGIS costs consistently across the various pieces of AGIS testimony. Additionally, the capital expenditures and O&M costs over the longer term that I present in my testimony are consistent with the AGIS cost-benefit analysis.[4] For clarity in this section, all cost tables state how the specific costs are being presented.

Q. WHAT TYPES OF IT CAPITAL COSTS IS BUSINESS SYSTEMS INCURRING TO IMPLEMENT THE AGIS PROJECTS?

A. The types of IT capital costs being incurred by Business Systems include project implementation costs related to software licensing, hardware (servers and network), and implementation labor. Labor costs include requirement specification, design, application configuration, screen display development, network security configuration, testing, and implementation.

Q. WHAT ARE THE AGIS-RELATED IT CAPITAL COSTS YOU ARE SUPPORTING IN THIS CASE?

A. The Business Systems AGIS IT capital additions I am supporting for the MYRP are shown in the following table.

Table 25

AGIS Capital Additions – Business Systems- State of MN Electric Jurisdiction (Includes AFUDC) (Dollars in Millions)			
AGIS Program	2020	2021	2022
AMI	$14.2	$5.7	$8.8
FAN	$5.4	$15.9	$42.0
FLISR	$0.3	$0.4	$0.6
IVVO	$0.0	$1.7	$1.9
Total	**$19.9**	**$23.7**	**$53.4**
There may be differences between the sum of the individual AGIS program amounts and total amounts due to rounding.			

[4] As Company witness Mr. Ravikrishna Duggirala explains, the cost-benefit analysis results are stated in 2019 dollars, on a net present value of revenue requirement basis, whereas I speak to Business Systems' underlying budgets. Mr. Duggirala notes that the CBA is consistent with these budgets, but the numbers are stated on different bases.

Total AGIS IT capital additions are also set forth at the NSPM total Company Electric level in Exhibit___(DCH-1), Schedule 2 to my Direct Testimony.[5] I provide additional details and support for the IT capital costs below, organized by AGIS component.

For the years beyond 2020-2022, I discuss at a higher level the anticipated work to be done and the reasonableness or underlying assumptions for Integrated Distribution Plan (IDP) and cost-benefit analysis (CBA) purposes. In this way, I provide support for both the rate case and IDP requirements, as they are heavily interwoven. Exhibit___(DCH-1), Schedules 8, 9, and 10 to my Direct Testimony also includes currently anticipated expenditures in our cost benefit analysis beyond 2022.

Q. WHAT TYPES OF IT O&M COSTS IS BUSINESS SYSTEMS INCURRING TO IMPLEMENT THE AGIS PROJECTS?

A. The types of O&M costs Business Systems is incurring and expects to incur for AGIS include hardware support, data storage, annual software maintenance, labor for software support, and application support, which includes ongoing testing, review of processes, application of security patches to respond to evolving threats.

[5] Schedule 2 shows all AGIS additions, including ADMS, which was previously approved with costs currently being recovered under the TCR Rider.

Q. WHAT ARE THE IT O&M BUSINESS SYSTEMS COSTS FOR AGIS IMPLEMENTATION THAT ARE INCLUDED IN THE COST OF SERVICE IN THIS CASE?

A. The forecasted AGIS O&M expenses for Business Systems are shown in the table below.

Table 26

AGIS O&M – Business Systems NSPM – Total Company Electric (Dollars in Millions)			
AGIS Program	2020	2021	2022
AMI	$4.2	$13.1	$9.1
FAN	$0.0	$2.1	$1.1
FLISR	$0.0	$0.0	$0.0
IVVO	$0.0	$0.0	$0.0
Total	**$4.3**	**$15.3**	**$10.2**
There may be differences between the sum of the individual AGIS program amounts and total amounts due to rounding.			

These O&M costs are also set forth in Exhibit___(DCH-1), Schedule 3 to my Direct Testimony,[6] along with currently anticipated costs beyond 2022 for CBA purposes. I provide additional details and support for the IT O&M costs below, organized by AGIS component.

[6] Schedule 2 shows all AGIS additions, including ADMS, which was previously approved with costs currently being recovered under the TCR Rider.

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Q. TO WHAT EXTENT ARE THE IT CAPITAL COSTS PRESENTED ABOVE CONSISTENT WITH THE INFORMATION PROVIDED IN THE COMPANY'S TCR RIDER FILINGS AND ITS PRIOR IDP?

A. Project costs in the Company's 2018 IDP Filing were presented at a higher level because the Company was not yet proposing to implement its full AGIS initiative at that time. The TCR filings presented information on only ADMS and the AMI and FAN costs related to the TOU pilot, as those projects were certified to allow the Company to request cost recovery under the TCR. Further, both the TCR filings and the IDP were based on information available at that time, whereas the current rate case and IDP filings present more up-to-date information. Lastly, the Company's plan for components like FLISR incorporated feedback from the Commission, as Ms. Bloch describes in her testimony. This rate case presents the most current information on costs as our planning and data have evolved.

Q. ARE BUSINESS SYSTEMS AGIS CAPITAL AND O&M COSTS INCLUDED IN THE CBA BEYOND THE NEXT SEVERAL YEARS MEANT TO BE "RATE CASE QUALITY" NUMBERS?

A. While these cost assumptions are reasonable and well-supported based on the information available today, they are not intended to reflect more specific budgets as in a standard rate case budget. Rather, they are subject to refinement like all costs that will be incurred several years into the future. This is consistent with my experience, and with most cost projections that represent work to be completed in the longer-term. However, I believe these cost estimates are reasonable, and I explain the support for them in this section of my testimony. I provide the overall capital expenditures and O&M

costs over the AGIS implementation period 2020 through 2029 in Section 6 below.

Q. WHAT SORT OF GOVERNANCE IS IN PLACE TO ENSURE THE AGIS PROJECTS ARE COST EFFECTIVE?

A. Business Systems employs standard processes and procedures for selecting technologies to be deployed in the Company's environment as well as the execution of large capital projects. These include long established processes in the area of competitive vendor sourcing and pricing negotiations as well as technology architectural governance processes, which are discussed earlier in Section III.B of my Direct Testimony. I also discuss sourcing considerations specific to the AGIS initiative below. In addition, the AGIS program has a dedicated Project Management Office to govern all areas within the program. Mr. Gersack discusses overall AGIS governance through the Project Management Office in his testimony. The robust governance processes for the AGIS program and Business Systems ensure fulfillment of requirements and cost effective delivery.

2. Grid Modernization Efforts to Date

Q. PLEASE PROVIDE ADDITIONAL DETAILS REGARDING THE COMMISSION'S PRIOR CERTIFICATION OF GRID MODERNIZATION INVESTMENTS FOR THE COMPANY.

A. Two advanced grid investments have been submitted for certification in biennial grid modernization reports and approved by the Commission. Specifically, in the 2015 Biennial Grid Modernization Report, the Company outlined the ADMS initiative, which was submitted for certification and subsequently approved on June 28, 2016. In the 2017 Biennial Grid Modernization Report, the Company outlined its AMI and Time of Use

(TOU) pilot program and certification was approved in the Commission's August 7, 2018 Order.

a. ADMS

Q. HAS BUSINESS SYSTEMS ALREADY PERFORMED WORK RELATED TO ADMS IMPLEMENTATION?

A. Yes. ADMS was certified by the Commission in 2016, and Distribution Operations and Business Systems have conducted their ADMS implementation activities in partnership with each other. As a utility operating in multiple jurisdictions, our enterprise-wide initiatives – like AGIS – are planned at the overall enterprise level. This allows for efficiencies and provides benefits for all our customers. Enterprise-wide planning and implementation strategies consider different timelines for project rollout in different jurisdictions. For ADMS, Business Systems completed installation of the software for Colorado, including the majority of the legacy integrations. For ADMS deployment in Minnesota, dedicated software will be implemented, design and configuration specific to Minnesota will be performed, and testing of the new NSPM environment will be executed.

Q. WHAT IS THE TIMING FOR IMPLEMENTATION OF ADMS IN MINNESOTA?

A. We expect to implement ADMS in the second quarter of 2020.

Q. IS THE COMPANY SEEKING TO RECOVER ANY COSTS RELATED TO ADMS IN THIS RATE CASE?

A. No. The Company has sought recovery for the costs for ADMS in the TCR Rider and proposes to keep ADMS in the TCR through the multi-year rate plan period.

b. TOU Pilot

Q. WHAT IS THE TOU PILOT?

A. The TOU pilot implements new residential time of use rates for select customers in two areas in the Twin Cities metropolitan area, providing customers with pricing specific to the time of day energy is consumed. This pilot requires installation of AMI meters to measure and record customer usage in detailed, time-based formats and requires installation of FAN communication to transmit this data to the Company and customers.

Q. HOW MANY CUSTOMERS ARE PARTICIPATING IN THE TOU PILOT?

A. As part of this pilot, we will deploy approximately 17,500 advanced meters to residential customers in Eden Prairie and Minneapolis. We will also deploy FAN communications to these areas.

Q. HAS BUSINESS SYSTEMS ALREADY PERFORMED WORK RELATED TO THE TOU PILOT?

A. Yes. In 2019, we began the system integration to support deployment of AMI and FAN for the TOU pilot, and the 2019 costs were certified for recovery under the TCR Rider. A description of overall AMI and FAN integration work is described in more detail in Sections 2 and 3 below.

Q. WHAT IS THE TIMING OF IMPLEMENTATION FOR THE TOU PILOT?

A. The TOU pilot is scheduled to launch, with AMI meters functioning and time of use rates available for participating customers in April 2020.

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Q. WHAT ADDITIONAL WORK WILL BE NEEDED FROM BUSINESS SYSTEMS BEFORE LAUNCH OF THE PILOT?

A. The AMI and FAN operations will require a head-end system, which was completed in early 2019. Installation and configuration of both FAN and AMI components in connection with the TOU pilot will be completed in early 2020. This provides foundational two-way communication and control for the advanced meters. Specific system interfaces require significant enhancement to properly communicate, collect, and process the new information to and from these components to support the objectives in the Commission Order approving the pilot. Business Systems will also enable enhanced data availability through the customer portal and provide for enhanced Customer Care and Distribution functionality to fully implement the TOU pilot for participating customers.

Q. IS THE COMPANY SEEKING TO RECOVER ANY COSTS RELATED TO THE TOU PILOT IN THIS RATE CASE?

A. Yes. For 2020 and going forward, the Company proposes to recover the costs associated with the TOU pilot as part of this rate case. The Business Systems costs included in the MYRP period are shown in the table below.

Table 27

Residential TOU Pilot – Business Systems State of MN Electric Jurisdiction (Dollars in Millions)			
TOU Pilot – Business Systems	2020	2021	2022
Capital Additions	$4.1	$0.0	$0.0
O&M Expense	$4.2	$0.7	$0.1

As discussed in the Company's initial petition requesting approval of the TOU pilot,[7] the AMI head end software and associated integrations to support the pilot are enterprise-wide software assets developed initially for AMI implementation in Colorado. Thus for Business Systems, the implementation costs shown above reflect the estimated carrying costs associated with the asset allocated to NSPM, reflecting implementation of the TOU pilot.

I note that the residential TOU pilot costs are part of the Company's overall AGIS initiative (specific to AMI and the FAN). The TOU costs reflect the estimated portion of the total AMI component that are necessary to implement the residential TOU pilot. In her testimony, Ms. Bloch provides the Distribution costs necessary to implement the TOU pilot.

3. AMI

a. AMI Overview

Q. WHAT IS AMI?

A. AMI is a system of advanced meters, communications networks, and data management systems that enable two-way communication between utilities' business and operational data systems and meters, enabling added benefits for customers and the utility. The current metering system uses a one-way communication technology in the collection of meter data and events for subsequent download to the Company's business and customer billing systems (with limited, manual two-way communication capability). AMI meters are able to measure and transmit voltage, current, and power quality data and can act as a "meter as a sensor," providing timely monitoring that has may use

[7] See Docket No. E002/M-17-775.

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cases for customers and business operations. AMI is a foundational element of the AGIS initiative because it provides a central source of information that interact with many of the other components of the AGIS initiative. Ms. Bloch provides detailed discussion of AMI and addresses the filing requirements related to AMI in her testimony.

Q. WHY DOES AMI REQUIRE INTEGRATION?

A. Because AMI consists of both software and hardware and works with other Company systems, information technology integration is key to the success of AMI.

Q. HOW WILL BUSINESS SYSTEMS PARTICIPATE IN THE AMI DEPLOYMENT?

A. The advanced meters will be integrated with the Company's IT systems. AMI is data intensive with meter readings, energy usage interval profiles, power outage and restoration events, power quality information and other data transmitted and collected frequently. All data to/from the advanced meters is transmitted to the AMI head-end application and, depending on what the data is, needs to be integrated and made available to the applicable business system in an accurate and timely manner.

The Company has already installed the AMI software head end for use in Colorado and for the Minnesota TOU pilot. This same software will be used and expanded upon in Minnesota for full rollout. Many of the integrations already built will be leveraged in Minnesota, and any newly required interfaces with legacy systems will be identified and developed as required to meet unique state needs.

b. AMI Integration

Q. WHAT SYSTEMS WILL BE INTEGRATED WITH AMI?

A. The major systems to be integrated with AMI are:

- ADMS;
- Customer Resource System (CRS);
- SAP;
- Field Deployment Manager;
- Meter Installation Vendor;
- Network Management System (NMS);
- Distributed Intelligence;
- Meter Asset Lifecycle Management System;
- Meter Data Management (MDM)
- Customer portal and new initiatives; and
- the FAN.

In addition, these applications will share data with other applications, such as the Company's Data Warehouse, as well as any new operational reporting solutions.

I note that the estimated work has been based upon, wherever possible, the integration work that has been completed on an enterprise-wide basis and may have been used previously to incorporate requirements in other jurisdictions. Additionally, we will need to ensure compliance with Minnesota requirements that each integration has appropriate processing capacity to additionally support Minnesota requirements.

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Q. PLEASE DESCRIBE THE INTEGRATION OF AMI WITH ADMS.

A. As previously noted, ADMS will provide an integrated operating and decision software support system to assist control room, field personnel, and engineers with the monitoring, control and optimization of the electric distribution system. ADMS will use the AMI data to deliver automated grid capabilities, such as FLISR and IVVO. AMI will provide the ADMS with timely real and reactive power measurement data that will be used in load flow and IVVO calculations. AMI meters will also provide voltage measurements at various points on the distribution system to support IVVO calculations. Additionally, advanced meters will report a power-out or "last gasp" event to the AMI head-end application and report a power-on event when power is restored. "Last gasp" is defined as the final message transmitted by the meter upon detection of an outage. This information will flow from the head-end application into ADMS, improving the calculations for the FLISR application. This is an enterprise-wide integration that will used or significantly enhanced, as necessary, to support Minnesota requirements.

Q. PLEASE DESCRIBE THE INTEGRATION OF AMI WITH CRS.

A. CRS provides capabilities for customer service, billing, service orders, and payments. CRS is currently integrated with the Meter Asset Lifecycle Management System and Meter Data Management (MDM) System. AMI head-end integration with the CRS will allow the Company to streamline multiple processes. As an example of a process improvement resulting from integrating the AMI head-end with the CRS, we will be able to obtain a meter reading to begin or end a billing cycle when a customer moves into or out of a premise without a visit to the customer's premise. As another example, when a disconnected customer pays their bill, an order generated in the CRS can be sent to the AMI head-end to automatically (and more quickly) reconnect the service. Disconnect and reconnect processes today are manual processes that require a person to physically visit the customer's site; while we would need to make a filing with the Commission to ensure permissions to utilize disconnect an reconnect (as Company witness Mr. Cardenas notes), these capabilities can be made available. This is an enterprise-wide integration that will be used or significantly enhanced, as necessary, to support Minnesota requirements.

Q. PLEASE DESCRIBE THE INTEGRATION OF AMI WITH SAP.

A. SAP manages the general ledger and work and asset management activities across the Xcel Energy enterprise, which were implemented between 2015 and 2017 as part of our Productivity Through Technology (PTT) initiative. SAP is an Xcel Energy-wide platform with financial management and asset management capabilities throughout the enterprise. As a result, two-way integration is required to support business processes for Xcel Energy personnel and customers. Through SAP, customer or field operations work orders initiated from service orders are scheduled, dispatched, and updated. These updates provide information that is synchronized back to the service order/process tracking jobs in CRS so that up-to-date information related to work orders is available to representatives and customers. Grid information will need to be integrated with SAP across the enterprise, to support Minnesota requirements.

Q. PLEASE DESCRIBE THE INTEGRATION OF AMI WITH THE FIELD DEPLOYMENT MANAGER.

A. The Field Deployment Manager is a new application that supports the field technicians work and meter communication with the advanced meters. FDM accepts meter reading requests from a customer system, converts and uses the data to load handhelds with assignments to be processed during this cycle, uploads the handhelds when the meter reader has completed the route, update the route data file, produces reports and performance tracking, and supplies meter reading information to the customer system for billing. As a new application for Xcel Energy, this integration is not currently constructed, and will go through standard software lifecycle steps to be implemented to support Minnesota.

Q. PLEASE DESCRIBE THE INTEGRATION OF THE COMPANY'S SYSTEMS WITH THE AMI METER INSTALLATION VENDOR'S SYSTEMS.

A. This is a new integration that is required to coordinate the logistics with the third-party resource provider that is performing new advanced meter installations. The vendor will be utilizing its proprietary work order management system to manage their activities, and daily synchronization of information with Xcel Energy's systems needs to occur in order to remain track and manage activities supporting Xcel Energy customers throughout the deployment. Information that needs to be synchronized between Xcel Energy and the meter installation vendor includes customer contacts and responses, installation/removal of AMI meters, cancellation/updating of orders, disposed meters, and look ahead data. This integration will keep Xcel Energy systems that support personnel and customers reflective of the work planned and in-process. As a new integration for Xcel Energy, this will require standard software lifecycle maintenance and upgrades to be implemented as needed to support our Minnesota system and customers.

Q. PLEASE DESCRIBE THE INTEGRATION OF AMI WITH THE NMS.

A. NMS is the vendor supported application for the Company's Outage Management System (OMS). OMS is the enterprise solution for the electric trouble distribution control centers outage event management. OMS is critical to outage restoration and generally critical to the Company's operations. This would be a new integration for Xcel Energy, requiring standard software lifecycle management. The Company believes that AMI meter events and functionality can be utilized to better identify and manage service outages and restoration activity, and the volume of data available from AMI systems must be pre-processed to produce timely, accurate, consumable, and actionable information for NMS. Such an integration of AMI and NMS would improve customer experiences during service outages by making the associated event details proactively available to personnel managing, communicating and making decisions during service restoration.

Q. PLEASE DESCRIBE THE INTEGRATION OF AMI WITH THE DISTRIBUTED INTELLIGENCE PLATFORM.

A. Distributed Intelligence is a processing capability within advanced meters that is controlled by a new meter application environment that is being deployed to support operational and customer application subscriptions. In other words, this Distributed Intelligence capability allows for the installation of applications on the meter – similar to how applications are installed on a smart phone. These applications may be customer-facing, meaning the customer directly interacts with them or grid-facing, meaning Xcel Energy interacts with the applications. As discussed in Mr. Gersack's testimony, the Company anticipates deploying some applications in the near term, but broader deployment will evolve over time.

On an end-to-end basis, the Distributed Intelligence environment consists of application platform, store, gateway, service bus, security manager, hub and analytics components. While the full scope of Distributed Intelligence capabilities goes beyond initial AMI deployment as described by Ms. Bloch, this environment must be at least minimally integrated in so that Xcel Energy meters can be properly and securely registered and grouped to support the deployment, administration, management and utilization of meter-based applications and services, within Company processes that are yet to be defined. The AMI program will test and validate the expected functionality of new advanced meter processing and application environment. Mr. Gersack and Ms. Bloch provide additional Distributed Intelligence details in their testimony.

Q. PLEASE DESCRIBE THE INTEGRATION OF AMI WITH THE METER ASSET LIFECYCLE MANAGEMENT SYSTEM.

A. The Meter Asset Lifecycle Management System manages the entire life cycle of serialized metering devices, including purchasing, testing, field installation location, field removal, and retirement of the asset. The Meter Asset Lifecycle Management System is currently integrated with the MDM System and CRS. The integration of the AMI head-end with the Meter Asset Lifecycle Management System will allow it to remain as the Company's primary source of location information and attributes for serialized metering devices. The AMI head-end will receive the meter location and attribute information to enable provisioning of the meter, understand its location, and obtain data from the meter.

Q. PLEASE DESCRIBE THE INTEGRATION OF AMI WITH THE METER DATA MANAGEMENT SYSTEM.

A. The Meter Data Management System provides capabilities to validate, edit, and estimate meter readings and manages events from the meter, such as power outages and tampering. The MDM will also assist in facilitating communication to, and receiving data from, the AMI head-end. The MDM is currently integrated with the Meter Asset Lifecycle Management System and CRS. The MDM will serve as the central repository for the reading data. The MDM will also validate the meter data and export it for use in billing, customer viewing, and analytics.

AMI significantly increases the number of meters and amount of data loaded to our MDM. Xcel Energy recently completed an evaluation of the current MDM system application and infrastructure and determined that an entirely new solution is needed to fulfill the requirements for AMI. The current MDM system application is approaching end of life and does not have the capacity and security elements required to support AMI, including the volume and technical capabilities needed for the Company-wide deployment of advanced meters. A new MDM solution will be utilized enterprise-wide across Xcel Energy operating companies and we are in the process of developing the full scope of work, total costs, and determining the operating company allocation. Ultimately, the MDM solution will support the security, functionality, scalability, and performance requirements of AMI meter data management.

Q. PLEASE DESCRIBE THE INTEGRATION OF AMI WITH THE CUSTOMER PORTAL AND NEW INITIATIVES.

A. The customer portal (the current version is available on the Xcel Energy website and is known by customers as MyAccount) is used by customers to obtain account information, track energy usage, view billing history, pay bills, and sign up for notifications. AMI data from field devices (i.e., the customer's meter) will move through the AMI head-end, and be integrated with other customer information, to the customer portal, where customers will have the ability to see more granular meter reading data than they see today.

After AMI deployment, we expect to begin rolling out new products and services to customers, some of which may require future filings with the Commission to determine details. These may include high bill alerts, personalized recommendations on energy usage, disaggregation of usage, and the capability to provide data to a customer's Home Area Network (HAN) and through the Company's utilization of Green Button Connect My Data (GB CMD). Ms. Bloch provides an introduction to the HAN capabilities, while Mr. Gersack provides additional information about the customer experience benefits of the advanced meter.

Q. PLEASE DESCRIBE THE INTEGRATION OF AMI WITH THE FAN.

A. The AMI meter's two-way communication module is a component of the mesh network layer of the FAN. The meter's communication module retrieves meter data that is stored within the meter as prescribed by ANSI C12.19 meter table implementation standards. The radio frequency communications modules in the meters may also act as a repeater for other mesh network devices, enabling two-way communication between the meters and the mesh network. This function has the benefit of increased reliability of communication between the AMI meters and the head-end application. In limited circumstances where deployment of the WiSUN mesh network is not practical (such as remote locations on the edge of the Company's distribution system), meter data may be transmitted over the FAN via public cellular or other wireless technologies.

Q. YOU MENTIONED THAT THE APPLICATIONS DISCUSSED ABOVE WILL SHARE DATA WITH THE COMPANY'S DATA WAREHOUSE AND OPERATIONAL REPORTING SOLUTIONS. PLEASE PROVIDE ADDITIONAL DETAILS.

A. The existing Data Warehouse is used to consolidate data from separate systems of record to facilitate efficient generation of reports and perform analysis of the data. The operational reporting solutions are expected to receive data from the AMI head-end, Meter Data Management System, and the Customer Information System. The Distribution Analytics Software is expected to use the data to perform analytics to identify trends for such items as reverse flow, tampering, load side voltage, and temperature. Once an integration solution is defined, integration details will be defined.

Q. WHAT ARE THE IMPACTS IF THE COMPANY DOES NOT MAKE THE INVESTMENTS NECESSARY TO INTEGRATE AGIS COMPONENTS WITH BACK-OFFICE APPLICATIONS?

A. Without integrating the technical components of the AGIS initiative with other Company applications, the Company and customers will not be able to utilize the benefits and capabilities of the new AGIS components. Each application provides a new capability and benefit to the Company. Without integration, existing applications would not be able to request data from new

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field devices, such as AMI meters, and the data provided from these new field devices would not be able to be communicated, stored, or analyzed by our existing applications. In addition, a lack of integration would cause many processes to be manual, and would not allow the ability to make decisions based on recent data collected, all of which will reduce the benefits of these technologies, especially AMI.

Q. OTHER THAN INTEGRATION, WHAT OTHER WORK WILL BUSINESS SYSTEMS PERFORM?

A. Beyond integrating systems, there are additional Business Systems work areas that are included in the scope. Ensuring that the system capacity and resiliency are installed and configured to scale to system levels inclusive of the Minnesota customers is one important work area. In addition, areas of functionality will include software configurations to support Minnesota requirements (*e.g.* rates), and system lifecycle work for meter data management, outage event processing, operational reporting, regional field deployment management, and Customer Care services to support Xcel Energy's Minnesota customers.

Q. WILL THE COMPANY PERFORM THE SYSTEM INTEGRATION WITH EXISTING RESOURCES?

A. Due to the large volume of work expected to occur over the integration period, the Company will need to hire third-party firms to supplement our existing IT resources. Estimates of costs for vendor IT work associated with AMI are part of our AGIS projects in this case, with IT cost estimates described in Section D below.

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Q. WHAT WORK IS BUSINESS SYSTEMS UNDERTAKING TO INTEGRATE THE AMI PROJECT?

A. The specific functions Business Systems provides for AMI include:

- Leading the design of the overall system and components.
- Procurement and installation of all hardware components that will run the software.
- Procurement of the software.
- Configuration of the software and hardware.
- Designing, procuring and installation of the necessary additional hardware and software referred to as the "head-end" application that reads the meters and other field devices in the AMI solution and monitors and manages the network and attached devices. System performance and capacity must support the expansion of processing and storage requirements to support Minnesota services. The head-end application is used by the other Xcel Energy operating companies as they deploy advanced meters.
- Enhancement, construction, configuration, and installation of any required interfaces throughout all applications involved in the AMI solution to support Minnesota requirements.
- Designing and integration of security into all aspects of the AMI solution;
- Thorough unit, system, integration, and end-to-end and regression testing of the AMI solution.
- User Acceptance Testing (UAT) with the Distribution, Customer Care and Customer Solutions business resources.

- Establishment of a full ongoing support structure including process and operational requirements.

Q. HAS BUSINESS SYSTEMS ALREADY PERFORMED WORK RELATED TO AMI IMPLEMENTATION?

A. Yes. Starting in 2015, on an enterprise-wide basis, Business Systems and Distribution Operations jointly initiated a systematic approach for selecting vendors for the AMI software and legacy system integrations. Business Systems and Distribution participated in contract awards (resulting from RFP processes) for a vendor to supply the software and network WiSUN solution for AMI. The WiSUN is the mesh network portion of the FAN that will utilize the advanced meters' communications modules.

In addition, Business Systems has already completed limited AMI implementation in connection with the TOU pilot in Minnesota, and has already completed initial work for full AMI rollout in Colorado. For example, in the summer of 2019, the first set-up of legacy interface integrations were successfully implemented to support AMI meter deployments in Colorado. Full AMI implementation in Minnesota will expand on and enhance these capabilities to meet requirements for deployment in Minnesota.

Q. PLEASE DESCRIBE THE WORK BUSINESS SYSTEMS WILL UNDERTAKE IN 2020, 2021, AND 2022 FOR AMI IMPLEMENTATION.

A. As discussed by Ms. Bloch, the Company plans to deploy approximately 1.3 million AMI meters throughout our Minnesota service territory as part of the AGIS initiative starting in the fourth quarter of 2021. This deployment builds off the AMI work already completed. By the end of 2023, we anticipate that

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over 90 percent of the meter installations will be complete. The locations and timing of AMI meter deployment will be coordinated with the network communications installations of the FAN components.

During this period, the Business Systems organization will engage in additional interface development, scaling activities, and network communications activities. This will include augmenting legacy integrations with the AMI software based on specific requirements that will be determined once full AMI implementation for our Minnesota customers is approved. This will ensure the functionality and capacity of AMI software and that the integrated legacy systems meet the scalability needs.

c. AMI Costs

Q. WHAT BUSINESS SYSTEM CAPITAL ADDITIONS AND O&M COSTS ARE NECESSARY FOR IT INTEGRATION FOR AMI DURING THE TERM OF THE MYRP IN THIS CASE?

A. The tables below provide the capital additions and O&M costs for AMI IT capacity and integration for 2020 through 2022.

Table 28

AMI Capital Additions – Business Systems State of MN Electric Jurisdiction (Includes AFUDC) (Dollars in Millions)			
AGIS Program	2020	2021	2022
AMI	$14.2	$5.7	$8.8

Table 29

AMI O&M – Business Systems NSPM – Total Company Electric (Dollars in Millions)			
AGIS Program	2020	2021	2022
AMI	$4.2	$13.1	$9.1

Q. WAS BUSINESS SYSTEMS PRIMARILY RESPONSIBLE FOR DEVELOPING THE FORECAST FOR AMI?

A. Business Systems is responsible for developing the forecasts for the head-end application, other software and hardware to support AMI data processing, and integrations required by those technologies. Therefore, I describe the forecast development process for these aspects in more detail in my Direct Testimony. Ms. Bloch addresses the forecast for the meters themselves.

Q. PLEASE PROVIDE AN OVERVIEW OF THE PROCESS FOR DEVELOPING THE AMI IT FORECAST.

A. Beginning in 2015, a series of RFPs was conducted to determine the most appropriate AMI solution for the Company on enterprise-wide basis. Business Systems began looking specifically at vendors to provide the WiSUN mesh network solution for AMI, which includes the AMI head-end software. The Company received responses from industry leaders as part of its competitive bidding process. In 2017, as a result of that process, Silver Springs Inc. (which was purchased by Itron shortly after contract signing) was selected to provide the head-end software and WiSUN mesh solution for AMI. (The WiSUN equipment and field deployment are addressed in detail in the following section on the FAN.) This selection was based on optimal pricing, strategic fit, and Silver Springs' (now Itron) industry experience. This

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effort was benchmarked and reviewed with other utilities and industry research organizations such as EPRI. I discuss this RFP process further below. Ms. Bloch discusses the Itron selection for AMI meters further in her Direct Testimony.

In addition, beginning in 2017 and as AGIS details were developed, Business Systems worked to leverage established relationships with our existing vendors to obtain optimal pricing for the legacy integration pieces for AGIS implementation.

An additional competitive bid process was completed in 2018 to select a vendor partner for all AGIS program testing on an enterprise-wide basis. Accenture was selected for this work, which is described further below. I note that while I include discussion of this competitive bid and vendor section process here, these testing costs are not all included in the AMI budget but instead are allocated across the individual AGIS component budgets.

In 2019, we conducted an RFI process to select a vendor to provide meter data management software. Cost estimates for this component in our AGIS budget forecast are based on a detailed market analysis, and costs will be finalized once contract negotiations with the vendor are concluded. Also in progress is vendor selection for an operational reporting solution for AMI.

A detailed project estimate for the AMI head-end, mesh network solution, and IT integration was created from the pricing and contract information discussed above, as well as the incremental hardware and labor necessary to support overall AMI implementation. I discuss the RFP and vendor selection processes in further detail below. For some of the cost estimates, while specific Minnesota requirements are yet to be determined, the work performed in Colorado provides a reasonable point of reference for labor estimates for most general functional and non-functional work areas supporting Minnesota. We incorporated our previous experience into the development of cost estimates for AMI implementation in Minnesota.

(1) AMI Capital Forecast

Q. WHAT ARE THE PRIMARY COMPONENTS OF THE AMI IT CAPITAL FORECAST?

A. The AMI IT forecast has three key components: (1) hardware, (2) software, and (3) labor.

Q. WHAT HARDWARE IS NEEDED FOR AMI IMPLEMENTATION FOR BUSINESS SYSTEMS?

A. The additional hardware necessary for AMI implementation consists of computing components used for data processing and storage to support AMI services, across all environments that are used in the software lifecycle of a particular service. Examples of environments that may be applicable to a service are production, disaster recovery, development, testing, and quality assurance. The functions that were analyzed within the hardware estimates are to support outage event processing, security, the head-end application, meter data management software, Customer Care support, reporting, database and operational storage, middleware, and field deployment. In other words, due to the increased volume of data and processes necessary to use that data in a meaningful way for our customers and the Company, additional servers with computing and storage capabilities will be needed.

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Q. HOW DID THE COMPANY DERIVE THE HARDWARE PORTION OF THE AMI IT FORECAST?

A. Xcel Energy has standards for all hardware that is deployed in our data centers. These standards define hardware for which the Company has industry benchmarked, negotiated pricing. Based on these standards, the hardware estimates were derived utilizing the hardware requirements of the applications(s) and applying standard pricing. Hardware estimates to support the head-end capacity, security services, outage processing, meter data management software, data storage capacity, and interfaces were all developed.

Q. HOW DID THE COMPANY DERIVE THE SOFTWARE PORTION OF THE AMI IT FORECAST?

A. Pricing for the AMI head-end software and mesh solution is provided in the contract with Itron, selected through the RFP process noted above. Software forecasts also include costs based on the other RFPs discussed above that have been completed or are in progress, as well as the vendor selections completed using our standard process. Pricing is consistent with industry benchmarks and our review with other utilities and industry research organizations such as EPRI. These benchmarks drove the negotiations with the selected vendors.

Q. DESCRIBE THE PROCESS USED TO SELECT THE VENDOR FOR THE WISUN MESH SOLUTION FOR THE AMI HEAD-END SOFTWARE.

A. Xcel Energy issued an RFP in 2015 to select a vendor to provide the WiSUN mesh solution for the AMI head-end software. Responses were received from three different companies. Xcel Energy evaluated these vendors and responses on a number of factors including:

- Technical performance;
- Operational performance;
- System long-term survivability;
- Adequacy of security capabilities;
- Warranty and support;
- Manageability with operational model;
- Ability to design mesh systems;
- Ability to implement;
- Ability to meeting scope and schedule;
- Acceptability of business terms and conditions;
- Industry experience;
- Adequacy of support systems; and
- Pricing.

In 2016, Xcel Energy selected Silver Springs (now Itron) and began contract negotiations. Contract negotiations were finalized in late 2016. The details of the contract awarded to Silver Springs (now Itron) included: detailed product (hardware and software) pricing; licensing pricing based on end device counts for many of the software specific applications; optional pricing for a number of potential software solutions; services pricing; and other related parts and services for future potential deployments.

Q. WHY DID XCEL ENERGY SELECT ITRON AS THE VENDOR FOR THE AMI HEAD-END AND MESH SOLUTION?

A. The primary factors in the decision were:

- Favorable pricing;

- Industry experience and track record with other utilities the Company benchmarked against;
- Performance in on-site testing of products against the Company requirements in the RFP;
- Breadth of solution; and
- Interoperability capabilities.

A summary of the RFP selection process and results are provided as Trade Secret Exhibit___(DCH-1), Schedule 11.[8]

Q. CAN YOU PROVIDE ADDITIONAL DETAIL ON HOW BUSINESS SYSTEMS WORKED WITH EXISTING VENDORS ON LEGACY INTEGRATION PIECES FOR AGIS IMPLEMENTATION?

A. Yes. Existing systems such as the Customer Resource System (CRS), Monitoring Device Management System (MDMS), Meter Reading and Acquisition System (MRAS) and Enterprise Service Bus (ESB) have existing support teams that consist of Xcel Energy personnel that are teams of employees and professional service vendors. In the case of the systems I listed, which are strictly representative, there are personnel from Xcel Energy, IBM, Accenture and product vendors that support the IT components of those systems. Integrations with those systems are key to coordinate the processing to/from new AMI systems to keep data and business processes timely, accurate and consistent. The existing support teams were engaged in the AMI delivery because they possess the knowledge of the operational environments to engage in system enhancement planning, design,

[8] The Company's RFPs related to the AGIS projects are provided on the AGIS supporting files compact disk provided with Vol. 2B.

construction, testing and deployment to efficiently meet the requirements of AMI system integration, and ensure that existing operational requirements for those systems remain reliable.

Q. DESCRIBE THE PROCESS USED TO SELECT THE VENDOR FOR OVERALL TESTING OF THE AGIS PROGRAM.

A. Xcel Energy issued an RFP in February 2018 to select a vendor to provide overall testing for the AGIS program on an enterprise-wide basis. The RFP sought a vendor to provide planning and execution of all AGIS testing phases including system acceptance, integration acceptance, performance acceptance, end-to-end and user acceptance testing. Responses were received from three different companies. Xcel Energy evaluated these responses on a number of factors including:

- Approach or methods recommended for testing;
- Environment and release management;
- Resource plan efficiency and effectiveness;
- Situational problem solving; and
- Pricing.

In April 2018, Xcel Energy selected Accenture and began contract negotiations, which were finalized in June 2018.

Q. WHY DID XCEL ENERGY SELECT ACCENTURE AS THE VENDOR FOR OVERALL AGIS PROGRAM TESTING?

A. The primary factors in the decision were:

- Experience delivering similar testing for other utility customers;

- Experience and strength of team members who have previously done this work;
- Strong methodology; and
- Favorable pricing.

Q. PLEASE DESCRIBE THE RFI PROCESS THAT IS CURRENTLY UNDERWAY TO SELECT A VENDOR FOR THE METER DATA MANAGEMENT SOFTWARE.

A. In 2019, we initiated an RFI process to select a vendor to provide meter data management (MDM) software. We evaluated MDM options from three vendors. We selected a vendor based on: simplicity of technical architecture; strong availability commitment; and favorable pricing. Once the vendor was selected, we evaluated three different technology options, and have made a final technology selection. This RFI process was conducted based on our standard processes. We are currently in negotiations with the vendor and expect to complete contract negotiations in 2019.

Q. HOW WERE THE MDM SOFTWARE COST FORECASTS DEVELOPED BASED ON THE RFI PROCESS?

A. Cost estimates for this component in our AGIS budget forecast are based on the vendor quotes received during the RFI process. Costs will be finalized once the vendor negotiations are concluded. While vendor negotiations and deployment methodology are still in process, vendor pricing and product deployment sizings have been provided to allow software, hardware, and labor estimates to be built to support Minnesota.

Q. PLEASE DESCRIBE THE OPERATIONAL REPORTING SOLUTION FOR AMI.

A. The AMI operational reporting solution will support several business use cases to deliver efficient, quality service to customers. Some example areas of operational reporting will include analysis of meter events, data quality, provisioning workflows, diagnostics, service quality and usage, and time-based data correlation and analysis using patterns and types of network and meter attributes. We are currently evaluating options for a reporting solution.

Q. HOW WERE THE REPORTING SOLUTION COSTS FORECASTS DEVELOPED?

A. Cost estimates for this component in AGIS budget forecast are based on vendor quotes we have previously received and will be finalized once vendor contract negotiations are concluded.

Q. HOW DID THE COMPANY DERIVE THE LABOR PORTION OF THE AMI IT FORECAST?

A. Our labor estimates are based on our experience and work that has already been completed for AMI implementation. Business Systems has leveraged spend information to date, for both AMI rollout in Colorado and the limited deployment of AMI in Minnesota to support the TOU pilot, to estimate the future costs associated with full deployment in Minnesota. In addition, we plan to leverage the same expertise and knowledgeable vendor partners to deliver additional capabilities for Minnesota, which will provide cost efficiencies. While specific Minnesota requirements are yet to be determined, the work performed in Colorado provides a reasonable point of reference for labor estimates for most general functional and non-functional work areas supporting Minnesota.

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Q. ARE THERE OTHER COSTS INCLUDED IN THE BUSINESS SYSTEMS CAPITAL FORECAST FOR AMI?

A. Yes. Like any other project of this size and scope, there are additional project management costs that are include in the AMI capital forecast. For the Business Systems portion of the AMI budget, these include labor costs for: (1) delivery and execution leadership; (2) testing environment/release management; and (3) security.

Q. HOW DID THE COMPANY DEVELOP THESE PROJECT MANAGEMENT COST FORECASTS?

A. These capital costs were developed using labor estimates for the work necessary to support AMI integration efforts. These costs were derived based on evaluation of prior work performed in Colorado, which provides a reasonable point of reference for labor estimates for most general functional areas supporting Minnesota.

(2) AMI O&M Forecast

Q. WHAT ARE THE PRIMARY COMPONENTS OF BUSINESS SYSTEMS' AMI O&M FORECAST?

A. The primary components of Business Systems AMI O&M costs include: (1) planning phase activities, including scope definition and solution selection; and (2) support activities that will occur after AMI is implemented, including contractor labor, maintenance, and warranty. In other words, these cost forecasts encompass the incremental work that will be necessary related to hardware and software maintenance, licensing, and the other work described above that will be necessary to support the increased data storage and processing related to AMI implementation.

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Q. HOW DID BUSINESS SYSTEMS DERIVE THE FORECAST FOR AMI O&M?

A. The AMI O&M forecast was developed based on vendor quotes, existing internal support team estimates of the work required, and industry benchmarking information. Each AGIS component has an internal IT team responsible for project delivery. Our forecasts for labor costs related to AMI are based on estimates from these team members, who have previous experience with similar systems implementations and support models, including AMI implementation in Colorado. I note that there could be future sourcing decisions for different AGIS components as additional requirements are identified. The Company would use its existing sourcing processes to manage additional O&M requirements in a cost-effective manner.

(3) AMI Contingency

Q. DO THE BUSINESS SYSTEMS AMI FORECASTS INCLUDE CONTINGENCY AMOUNTS?

A. Yes. Using contingencies is consistent with project planning practices, especially for large projects that implement new technologies and require major changes to enterprise IT systems. We believe it is appropriate to include a contingency amount at this stage given that the project will be implemented over multiple years (2021-2024), as well as the complexity, size, and integrated nature of the project – with integration required for both new and legacy systems. Mr. Gersack discusses the overall AGIS project contingencies in his testimony.

Q. WHAT ARE THE BUSINESS SYSTEMS CONTINGENCIES FOR AMI?

A. The Business Systems AMI budget forecast for the period 2020-2025 includes capital contingency amounts of approximately 37 percent.

Q. CAN YOU PROVIDE MORE INFORMATION ABOUT THE BUSINESS SYSTEMS CONTINGENCY ASSOCIATED WITH AMI?

A. Yes. Due to the integrated nature of deployment and implementation of AMI and the FAN, several reasons for including contingency amounts in the AMI budget are applicable to the FAN as well. While the FAN budget is discussed separately in the following section, I address the budget contingencies overall here to avoid duplication.

First, budget contingency amounts are appropriate due to the scale of the deployment and the volume of data that will be handled as a result of AMI implementation. As discussed above, the volume of data provided by AMI metering is orders of magnitude larger than our current metering system provides. While our project plans are appropriate with respect to the IT architecture, software, hardware, and integrations necessary to manage and use this data, additional work may be required as we cannot replicate in a test environment what will actually occur during full roll out.

Further, as we begin AMI deployment and throughout the installation phase, we will be running two metering systems simultaneously. We have planned for this, as AMI meters will not be installed for all customers until 2024. However, some level of contingency is needed to ensure that we can address any issues that arise as AMI implementation begins, so that our basic systems and provision of service to our customers remains the same for both AMI and non-AMI metered customers.

In addition, geography is important in the deployment and functioning of the AMI meters and FAN network devices. Similarly, weather may have an impact. Business Systems has conducted field coverage studies to ensure the FAN will provide adequate coverage for both deployment of meters and other devices, and our deployment plans are specific to the Minnesota geography and weather. However, we cannot duplicate some of the realities of field deployment in a test environment, so some level of contingency is appropriate.

The multi-year implementation schedule is also a reason using contingencies is appropriate. Part of IT planning requires that we will be able to address new security threats that may evolve over the implementation timeline. While the Company budgets for these eventualities at some level, contingency amounts are included because we must ensure that we are able implement security controls as new cyber threats arise.

Q. DOES THE COMPANY BELIEVE THE CONTINGENCY AMOUNTS WILL BE USED?

A. Yes; while the Company does not necessarily anticipate using all of the contingencies, we believe that some amount of contingency will be used based on experience with prior projects. Contingency amounts are included to avoid the need for tradeoffs in schedule and/or scope and functionality. In this way, we can ensure implementation of the project will help maximize benefits for our customers. As Mr. Gersack discusses, there are strict controls on how the contingency amounts may be used. The overall AGIS governance structure provides for review and approval of any project changes that will affect the scope, costs, or benefits of implementation. Any changes from budgeted amounts and any specific use of budget contingencies will need approval according to the established AGIS governance processes.

Q. FROM A PROJECT DETAIL PERSPECTIVE, ARE THERE OTHER SPECIFIC REASONS FOR INCLUDING CONTINGENCY AMOUNTS IN THE AMI BUDGET?

A. Yes. While we have based our budget estimates on all known design and installation details, there remain uncertainties with respect to specific Minnesota requirements that will not be known until after Commission approval of the projects, and unknowns that may develop through the installation phase. The level of contingency recognizes the following specifications that will be determined as we progress toward and during project implementation:

- Legacy interfaces – For AMI, we have a reasonable estimates of the type of interface work that will be necessary for Minnesota based on our previous experience with implementation in Colorado. However, the Minnesota-specific functionality will be dependent on final Minnesota requirements once approved.
- Capacity scaling – We have estimated the cost of scaling activities, but the full costs will be determined as all design and solution specifications finalized.
- MDM and operational reporting solution vendor selections are not yet finalized. Our budget estimates are based on market analysis and vendor quotes, but costs will not be finalized until we complete the selection processes and negotiate and execute contracts.
- Security – Security solutions will be dependent on final Minnesota requirements once approved.

(4) AMI Expenditures 2020-2029

Q. WHAT ARE THE BUSINESS SYSTEMS CAPITAL EXPENDITURE AND O&M FORECASTS FOR AMI FOR 2020 THROUGH 2029?

A. The tables below provide the Business Systems AMI capital expenditure and O&M forecasts for 2020 through 2029.

Table 30

AMI Capital Expenditures – Business Systems NSPM – Total Company Electric (Dollars in Millions)					
AGIS Program	2020	2021	2022	2023-2024	2025-2029*
AMI	$11.4	$6.5	$10.0	$5.7	$0.9
Period may include additional assumptions, including inflation and labor cost increases, that are not part of the capital budget in periods 2020-2024.					

Table 31

AMI O&M – Business Systems NSPM – Total Company Electric (Dollars in Millions)					
AGIS Program	2020	2021	2022	2023-2024	2025-2029*
AMI	$4.2	$13.1	$9.1	$15.2	$51.5
Period may include additional assumptions, including inflation and labor cost increases, that are not part of the capital budget in periods 2020-2024.					

(5) AMI Cost Summary

Q. WHY IS BUSINESS SYSTEMS' AMI FORECAST REASONABLE FOR CUSTOMERS TO SUPPORT?

A. AMI is a foundational component of AGIS, which is a long-term strategic initiative to transform our electrical distribution system to enhance security, efficiency, and reliability, to safely integrate more DERs, including those that are customer owned, and to enable improved customer products and services.

The volume and scope of data processing is several orders of magnitude greater than the legacy metering infrastructure. This allows many business processes and services supporting Xcel Energy customers to be more timely, accurate and consistent. AMI will support business operations efficiencies, and a better customer experience to empower informed energy decisions. The IT components described above are necessary to implement AMI, and the AMI IT forecast is reasonable in enabling technologies that improve customer products and services.

Further, the Company employs standard processes and procedures for selecting technologies to be deployed in the Company's environment, as well as for the execution of large capital projects. Our planning for AGIS implementation is done on an enterprise-wide basis, which allows for efficiencies and provides benefits for all our customers. Consistency across the enterprise simplifies deployment across different jurisdictions in a cost-effective manner.

The processes and procedures for selecting AMI technologies include:

- *Product Selection*:
    - Head-End. The Company used multiple RFP processes to select the optimal vendor partners for various aspects of the AMI delivery. A competitive bid was completed at the end of 2017 resulting in the selection of Itron for the AMI head-end software solution.
    - Testing. An additional competitive bid process was completed in 2018 to select a vendor partner for all program testing.
    - Meter Data Management and Operational Reporting Solution. Additional processes were implemented in 2019 to select vendors

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for the meter data management software and operational reporting solutions.

- <u>System Integration.</u> Negotiated individual statements of work were developed with existing vendors that own and support each of the interfacing applications. We leveraged our long-standing partnerships with these vendor in an effort to obtain optimal costs for the integration effort.

- *Project and Initiative Governance*: As described further by Mr. Gersack, the AGIS initiative's formal project governance processes are incorporated into the AMI project.

4. The FAN

a. FAN Overview

Q. WHAT IS THE FAN?

A. The FAN is a private, Company-owned wireless communications network that will leverage our existing Wide Area Network (WAN) and substation infrastructure to securely and reliably address the need for increased communication capacity that arise from the new advanced grid devices, including AMI, FLISR, and IVVO. The primary function of FAN is to enable secure and efficient two-way communication of information and data between our existing substation infrastructure and new or planned intelligent field devices – up to and including meters at customers' homes and businesses. The FAN will provide benefits to all AGIS programs but is designed and built according to the needs of various components, and each has different communication network requirements.

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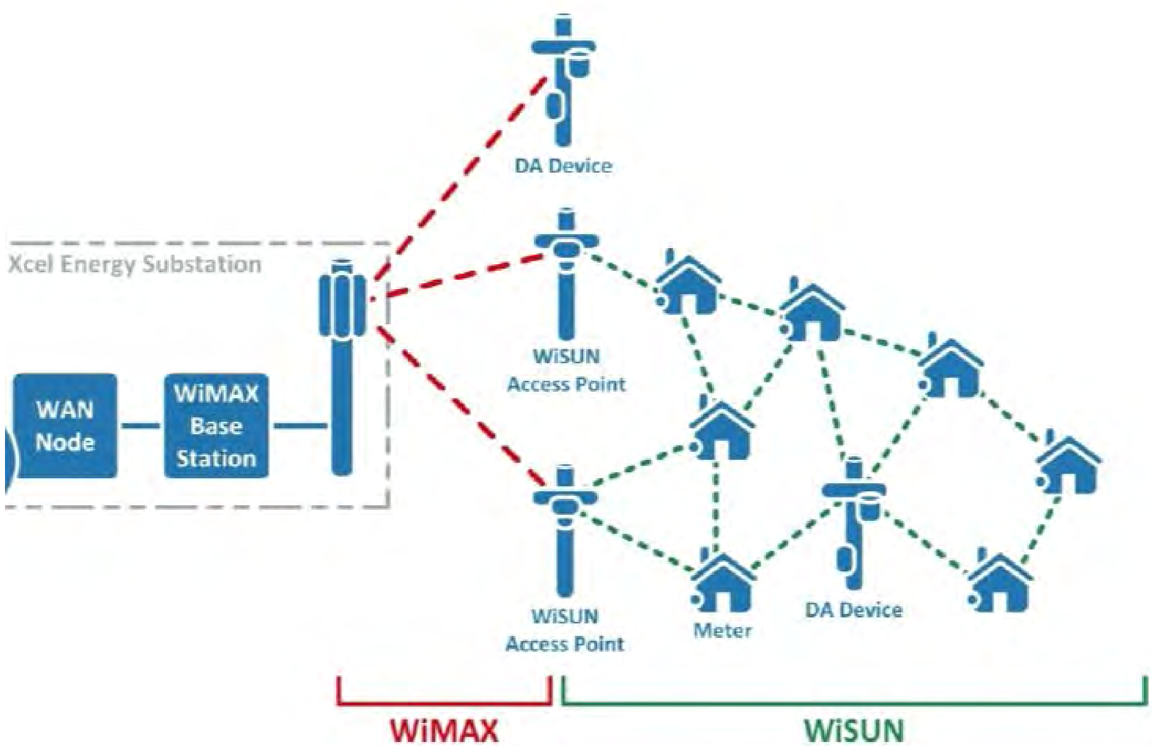
Q. WHAT ARE THE PRINCIPAL TECHNOLOGIES THAT WILL BE USED BY THE FAN?

A. To provide communication between the substation and field devices, the FAN will use two wireless technologies: (1) Wireless Smart Utility Network (WiSUN) mesh network; and (2) a Worldwide Interoperability for Microwave Access (WiMAX) network. These two networks are depicted in Figure 6 below.

Figure 6

WiSUN and WiMAX Networks



Q. DESCRIBE THE COMPANY'S CURRENT COMMUNICATION NETWORK.

A. Xcel Energy's current communication network is the WAN. The WAN provides high-speed, two-way communications capabilities and connectivity in a secure and reliable manner between Xcel Energy's core data centers and its service centers, generating stations, and substations. The Company's current WAN communications network primarily composed of private optical ground wire fiber and a collection of routers, switches, and private microwave communications that are supplemented by leased circuits from a variety of carriers as well as satellite backup facilities.

Q. HOW WILL THE FAN INTERACT WITH THE WAN?

A. The WAN, which resides upstream of the FAN, will continue to be Xcel Energy's primary means of communicating data between the Company's data centers that house data and AGIS applications, such as ADMS, and facilities such as generating plants and service centers as well as the FAN. The FAN, in turn, will provide the connectivity to intelligent devices installed across the distribution system.

Q. DESCRIBE THE COMPONENTS OF THE WISUN NETWORK.

A. The WiSUN mesh network is the key network structure that will communicate directly with the AMI infrastructure and most Distribution Automation (DA) field devices. The core infrastructure for WiSUN will consists of two main devices: (1) access points and (2) repeaters. Both of these devices will be principally located on distribution poles and other similar structures.

An access point is a device that will link the Company's endpoint devices that are enabled with wireless communication modules with the rest of the Company's communication network. The access points will wirelessly connect directly to backhaul (which is an intermediate link in the communications network – WiMAX, in this case) to pass data between the mesh network and the WAN.

Repeaters are range extenders that are used to fill in coverage gaps where devices would be otherwise unable to communicate. The mesh network design of WiSUN means that additional nodes on the network provide devices more options to communicate with their access point.

Q. DESCRIBE THE COMPONENTS OF THE WIMAX NETWORK.

A. The WiMAX network will consist of two main components: (1) base stations, and (2) customer premise equipment (CPE). I note that "customer" here refers to the Company rather than our electric utility customers. The Company is the "customer" purchasing the WiMAX equipment in this case.

Base stations will serve as the key communication points between the substation WAN and the WiSUN mesh network. At substations there will be a base station with up to three radios that will communicate with the WAN and multi-directionally with CPEs out in the field of operations. Where possible, the base stations at the substations will be mounted on existing poles or structures.

The CPEs will further enable the back office applications to communicate wirelessly with any device accessible to that access point's connections to the mesh network. CPEs will be mounted on distribution poles in the field of operation.

Q. HOW WILL THE WIMAX NETWORKS BE CONNECTED TO AND INTERFACE THE COMPANY'S EXISTING WAN NETWORK?

A. The WiMAX base stations will be connected to the pre-existing WAN connections at the substation, which, in turn, will enable connectivity back to the data center locations. This connection at the substation will be via private fiber or alternate cabling within the substation from the WiMAX base station radios to the routers at the substations which are connected to the WAN. There may be rare instances in which WiSUN devices will be connected directly to the WAN, when WiMAX is not needed.

b. Interrelation of FAN with other AGIS Components

Q. HOW WILL THE COMPONENTS OF THE FAN INTERACT WITH THE OTHER AGIS COMPONENTS?

A. The FAN is the primary communication network for many of the AGIS components to communicate with each other as well as Company's back-office systems.

Q. HOW WILL THE FAN INTERACT WITH THE AMI METERS?

A. The AMI meters will have embedded communication modules that will allow the devices to communicate with the WiSUN network. This will allow data to be transferred between the meters and the AMI head-end application, including interval reads, register reads, voltage information, and power quality data. The FAN will also allow AMI meters to send and receive of commands like power outage notifications. Once fully deployed, we estimate that the AMI meters will make up over 90 percent of the devices that will communicate as part of the mesh network.

Q. HOW WILL THE FAN INTERACT WITH FLISR?

A. The FLISR distribution equipment (*i.e.,* feeder-level devices) will have communication modules that will communicate with access points in the mesh network or directly to WiMAX CPEs.

Q. HOW WILL THE FAN INTERACT WITH THE COMPONENTS OF IVVO?

A. Most devices that control or inform IVVO (such as capacitors, SVCs and power line sensors) will have communication modules that will allow them to communicate as part of the WiSUN mesh network or directly on WiMAX. Through this network, the FAN will allow data to be transferred between the IVVO devices in the field and the ADMS. This will enable the field devices to report their current operating conditions and allow the ADMS to send commands to the devices, thereby enabling the entire system to dynamically react to changing load conditions and voltage levels.

Q. HOW WILL THE FAN INTERACT WITH ADMS?

A. The FAN enables data and information from field devices to be communicated to ADMS, and also enables commands to be transmitted to the field devices from ADMS.

Q. PLEASE DESCRIBE IN MORE DETAIL HOW THESE SYSTEMS WILL BE INTEGRATED WITH THE FAN.

A. The following applications will be integrated with the FAN:

- *AMI*: The WiSUN mesh network, including the meters' communication nodes that will communicate as part of the network, will support AMI through the meters' communication function. The FAN will provide the transport for data transfer between the meters and the AMI head-end application, including interval reads, register reads, voltage information, and power quality data. It will also provide the sending and receiving of commands like power outage notifications and remote connect/disconnect commands.

- *ADMS*: The FAN infrastructure will provide data from field devices to the WAN, which will then deliver data to ADMS. The FAN enables data and information from field devices to be communicated to ADMS, and also enables commands to be transmitted to the field devices from ADMS. The FAN infrastructure will provide data from endpoint devices, such as meters and field devices, to a common ESB via the WAN, which will then deliver data to ADMS. The ESB will also receive commands from ADMS that will be delivered to the devices connected to the FAN via the WAN. The FAN enables data and information from field devices to be communicated to ADMS, and also enables commands to be transmitted to the field devices from ADMS.

c. FAN Benefits

Q. WILL CUSTOMERS DIRECTLY BENEFIT FROM THE DEPLOYMENT OF FAN ALONE?

A. The FAN, in and of itself, does not provide direct benefits to customers or the Company. Benefits to customers and the distribution system will be realized through FAN's support of, and interaction with, other programs and technologies. The FAN strategy proposed is tightly coupled with the proposed AMI implementation and similarly enables other technologies that transform the customer experience and create customer value. The reliable, private, secure network capabilities provided by the FAN also enable the end-to-end transport of interval meter data to provide the customer and grid benefits enabled by AMI. FAN also enables the communication for FLISR and thus contributes to the outage restoration capabilities.

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Q. HOW DOES THE MESH NETWORK DESIGN OF FAN PROVIDE BENEFITS FOR THE OTHER AGIS COMPONENTS?

A. The mesh network design of FAN provides redundancy and will ensure the overall dependability of communications of the AGIS components. For example, if a device falls on the WiSUN network and can no longer communicate, the mesh configuration of the system will allow that node to be bypassed so other nodes will be unaffected and network communications will continue. Every device on the mesh network will maintain a primary and secondary access point, so that in the case of an access point failure the nodes will automatically route communications to a secondary access point. If the access point outage persists, the entire network will reconstruct itself so that every device will have a primary and secondary access point. The design also calls for access points to be served by multiple WiMAX base stations, so that in the event of a WiMAX base station goes off-line the mesh nodes will still be able to route communications through a different access point and WiMAX base station. In sum, the redundancy of the mesh network design of the FAN will enable endpoint devices to continuously communicate both with each other and with head-end systems.

Q. HOW DOES THE FAN ASSIST THE OTHER AGIS COMPONENTS IN MANAGING OUTAGES?

A. The core infrastructure of both WiMAX and WiSUN will have battery backup as will other devices that are critical for outage operations. This means that the Distribution Control Center will still have visibility into the current status of the grid and remote control capabilities for devices like reclosers. Although AMI meters will not have battery backup, they will have energy storage adequate send "last gasp" messages (that is, a final message transmitted by the meter upon detection of an outage) over the FAN to let the head-end system know that particular customers do not have power service. Once those customers have been reenergized, those meters will once again be able to communicate on the FAN and the head-end system will be able to remotely verify that customers have been reconnected. The additional visibility will also aid with the restoration of nested outages[9] by showing that certain customers remain without power even when the surrounding issue was resolved. This will help the control center identify those situations and reduce restoration times.

Q. WHY IS IT IMPORTANT TO IMPLEMENT THE FAN NOW?

A. The FAN communication network is required to support the deployment of AMI meters and will facilitate the operation of FLISR and IVVO. Deploying AMI meters without the FAN would be considerably more expensive to install and operate because the Company would need to find other ways read data from the meter such as driving by or physically reading the meter, both of which would require truck rolls and added labor costs. The primary advantage the FAN provides in terms of efficiency of meter operations is enabling the operate to send remote commands to the meter (such as connect/disconnect), as well as read data as often as required without dispatching a truck and personnel to do so.

Further, without the FAN, the Company would not be able to gain full value from the capabilities of AMI, FLISR, or IVVO. This is because FAN will support the interconnection and communication of the field device

[9] Storms often result in multiple failures. When we repair and reenergize a section, but a subset remains out due to a second fault, that outage is referred to as a "nested" outage.

components of these technologies. In addition to supporting the AGIS infrastructure, the FAN will support the ability to deploy computing capability closer to the field devices (for example, in substations) that will allow for quicker identification of potential issues and immediate resolution. This deployment will enable Xcel Energy to monitor and manage impacts of distributed energy resources (for example, solar resources) and other events occurring on the grid in a more timely manner.

d. FAN Implementation

Q. WHAT WORK IS NECESSARY TO IMPLEMENT THE FAN?

A. FAN implementation requires installation of WiMAX and WiSUN equipment in the field as well as implementation of the necessary software components and IT integration with the Company's other systems.

Q. WHAT WORK IS BUSINESS SYSTEMS UNDERTAKING TO IMPLEMENT THE FAN PROJECT?

A. The specific functions Business Systems provides for FAN implementation include:

- Leading the design of the network systems (WiMAX and WiSUN);
- Procurement and installation of all hardware components that will operate the network. This task is a joint effort between Business Systems and Distribution in the procurement and deployment of the hardware components. For WiMAX, Business Systems is primary responsible for the installation of WiMAX base stations at the substations, and Distribution Operations is responsible for the installation of the CPE devices that are located on Distribution poles. Distribution is responsible for installation of the WiSUN devices (APs

and repeaters), which will be located on Distribution poles. The Business Systems and Distribution budgets reflect this division of responsibility for hardware and installation. Company witness Ms. Bloch discusses the costs associated with the Distribution Operations' participation in the procurement and installation of pole-mounted FAN devices;

- Configuration of the software and hardware;
- Designing and integrating security into all aspects of the FAN solution;
- Thorough unit, system and end-to-end testing of the FAN solution;
- User Acceptance Testing (UAT) with the Distribution, Customer Care and Customer Solutions business resources; and
- Establishment of a full ongoing support structure including process and operational requirements.

Q. HOW WILL THE WIMAX INFRASTRUCTURE BE INSTALLED?

A. WiMAX base stations will be primarily installed at substations, with Business Systems responsible for installation using the deployment services provider selected in the RFP process described below, as well as the Company's transmission personnel as needed for work at the substations. Antennas will need to be installed at appropriate heights to provide optimal coverage of the WiMAX signal. Installation can be on existing transmission towers where possible and allowable under safety guidelines. Where there are no suitable transmission structures, a monopole will be erected on which to mount the antennas. The radio equipment will be mounted at ground level at the base of the structure and will connect to the substation's Electronic Equipment Enclosure (EEE) via trenched cabling. The equipment will connect to the WAN in the substation's EEE.

Distribution Operations is responsible for the installation of the CPEs on distribution poles. Ms. Bloch discusses this further in her testimony.

Q. How will the WiSUN infrastructure be installed?

A. WiSUN equipment consists of access points and repeaters. Distribution Operations is responsible for installation of these devices, which will be mounted primarily on distribution poles. Ms. Bloch provides additional installation details in her testimony.

Q. Has Business Systems already performed work to support the FAN implementation?

A. Yes. To support our TOU pilot, Business Systems and Distribution Operations have begun deploying a limited amount of FAN infrastructure in the same geographic area as the AMI meter deployment (Eden Prairie and Minneapolis). Business Systems has begun to deploy WiMAX base stations in three substations, and Distribution has begun to deploy of access points (APs) and repeaters that will be connected to those base stations. Business Systems has conducted field coverage studies to ensure the FAN will provide adequate coverage for both the TOU as well as full deployment of meters and other devices in those areas.

Q. What is the FAN implementation and IT integration schedule to support full AMI deployment?

A. For any given geography, FAN availability will precede AMI meter deployment by approximately three to six months, to ensure meters will have a fully operational network to use when they are installed. To support this the FAN installation will begin approximately 12-18 months ahead of AMI meter deployment to allow adequate time for permitting, material sourcing, and construction. Based on the current schedule for AMI meter deployment, we anticipate FAN deployment will begin in mid-2020 to ensure network readiness when AMI meters and other devices are deployed in mid-2021. Business Systems has already completed limited FAN implementation in connection with the TOU pilot. In addition, Business Systems has already completed initial work for full FAN rollout in Colorado. Full FAN implementation in Minnesota will expand on and enhance these capabilities to meet requirements for deployment in Minnesota.

Q. WILL THE WISUN AND WIMAX NETWORKS BE DEPLOYED THROUGHOUT THE COMPANY'S ENTIRE SERVICE TERRITORY IN MINNESOTA?

A. WiSUN will be deployed throughout the entire network where we are connecting to field devices such as AMI meters. WiMAX is the current primary means of connecting WiSUN to the main WAN backhaul systems, but it is not the only solution that will be deployed. As the Company performs field coverage studies it may deploy other solutions, such as fiber or private LTE, to provide that connectivity.

e. FAN Costs

Q. PLEASE DESCRIBE THE SPECIFIC WORK BUSINESS SYSTEMS WILL UNDERTAKE TO SUPPORT IMPLEMENTATION OF THE FAN IN 2020, 2021, AND 2022.

A. The efforts will include field studies for network coverage in areas that will require FAN implementation to ensure the number, location, and configuration of network devices will adequately cover the full deployment. This will ensure the appropriate design for the network to support all devices being deployed that will require connectivity thru the FAN. This also provide the necessary information and data to file for permitting through the FCC for frequency and location of wireless devices. The effort will also include the planning and organizing of all labor required to build out and install the network devices throughout the geography of the implementation.

Q. WHAT BUSINESS SYSTEMS CAPITAL AND O&M COSTS ARE NECESSARY FOR FAN IMPLEMENTATION DURING THE TERM OF THE MYRP IN THIS CASE?

A. The table below provides the Business Systems capital additions and O&M costs for FAN implementation for 2020 through 2022.

Table 32

FAN Capital Additions – Business Systems State of MN Electric Jurisdiction (Includes AFUDC)(Dollars in Millions)			
AGIS Program	2020	2021	2022
FAN	$5.4	$15.9	$42.0

Table 33

FAN O&M – Business Systems NSPM – Total Company Electric (Dollars in Millions)			
AGIS Program	2020	2021	2022
FAN	$0.0	$2.1	$1.1

Q. WAS BUSINESS SYSTEMS PRIMARILY RESPONSIBLE FOR DEVELOPING THE FORECAST FOR THE FAN?

A. Yes. Business Systems was responsible for developing the forecast for both the WiSUN and WiMAX components of the FAN. Therefore, I describe the forecast development process for these aspects in more detail below. Ms.

Bloch discusses the costs associated with Distribution's participation in the procurement and installation of pole-mounted FAN devices.

Q. PLEASE PROVIDE AN OVERVIEW OF THE PROCESS FOR DEVELOPING THE WISUN FORECAST.

A. As previously noted, Business Systems employs standard processes and procedures for selecting technologies to be deployed in the Company's environment, as well as the execution of large capital projects. These standard processes are being utilized for deployment of the FAN, as follows:

- *Product Selection*: The Company awarded a contract for the WiSUN mesh network in 2017 to Itron after an extensive and thorough competitive RFP process. In addition to the RFP process mentioned, the Company also provided the platform and facilities for each RFP responding company to demonstrate their claims in the RFP in a test environment. The RFP responses and the test results were primary input the RFP award.
- *Project and Initiative Governance*: The AGIS initiative's formal project governance processes are incorporated into the FAN project.

Q. PLEASE PROVIDE AN OVERVIEW OF THE PROCESS FOR DEVELOPING THE WIMAX FORECAST.

A. The Company's standard forecast development processes were followed, as set forth below:

- *Product Selection*: An RFP was issued and awarded for the WiMAX primary vendor in 2015. That portion of the project is in the deployment process. The Company awarded a contract for this part of the AGIS solution in 2017. In conjunction with the RFP for the AMI

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Software selection, Itron was also selected in 2017 for the WiSUN mesh aspects of the FAN. This process ensured the most optimal solution for the Company's needs was selected and the Company negotiated a contract with reasonable costs.

- *Project and Initiative Governance*: The AGIS initiative's formal project governance processes are incorporated into the FAN project.

(1) FAN Capital Forecast

Q. WHAT ARE THE PRIMARY COMPONENTS OF THE FAN CAPITAL FORECAST?

A. The FAN forecast has two key components: (1) labor; and (2) hardware. Ms. Bloch discusses the costs associated with Distribution's participation in the procurement and installation of pole-mounted FAN devices.

Q. HOW DID THE COMPANY DERIVE THE LABOR PORTION OF THE FAN FORECAST?

A. The labor costs were derived utilizing pricing gained from industry benchmarks and reviewed with other utilities and industry research organizations such as EPRI. In addition, our labor estimates are based on our experience and work that has already been completed for FAN implementation. Business Systems has leveraged spend information to date, for both FAN rollout in Colorado and the limited deployment of FAN in Minnesota to support the TOU pilot, to estimate the future costs associated with full deployment in Minnesota. While specific Minnesota requirements are yet to be determined, the work performed in Colorado provides a reasonable point of reference for labor estimates for most general functional and non-functional work areas supporting Minnesota. As each stage of the FAN deployment is conducted, the labor costs and estimates are reviewed on

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a per-site basis and forward-looking estimates are refined. These costs will be reviewed and refined throughout the lifecycle of the project. Labor cost types include installation labor, RF design, configuration and testing, planning engineering, program management, and network services.

Q. HOW DID THE COMPANY DERIVE THE HARDWARE PORTION OF THE FAN FORECAST?

A. The hardware portion of our FAN budget was derived from prices included in contracts resulting from RFP processes. Xcel Energy has standards for all hardware that is deployed in the field. These standards define hardware for which the Company has industry benchmarked, negotiated pricing. On an enterprise-wide basis, Xcel Energy issued four RFPs for FAN hardware and deployment services. For this project, the Company issued separate equipment and installation RFPs, so there were two RFPs for WiMAX and two for WiSUN.

Q. HOW DID THE COMPANY SELECT THE VENDORS FOR THE FAN TECHNOLOGY?

A. The Company conducted four RFPs related to the FAN technology. The following vendors were selected:

- WiMAX technology – Airspan was awarded the technology contract and Council Rock was awarded the reseller contract.
- WiMAX deployment service provider – Council Rock was awarded the deployment service contract.
- WiSUN Mesh technology – Silver Spring Networks (now Itron) was award the equipment contract which includes associated software.
- WiSUN deployment service provider – Silver Springs (now Itron) was awarded the deployment services contract.

Although these were four separate RFPs, a combined summary of the selection processes and results are provided as Trade Secret Exhibit___(DCH-1), Schedule 12.

Q. DESCRIBE THE PROCESS USED TO SELECT THE VENDOR FOR THE WIMAX TECHNOLOGY.

A. Xcel Energy issued an RFP in 2015 to select a vendor to provide the WiMAX technology and equipment. Responses were received from three different companies. Xcel Energy evaluated these vendors and responses on a number of factors including:

- Technical performance;
- Operational performance;
- System long-term survivability;
- Adequacy of security capabilities;
- Warranty and support;
- Manageability with operational model;
- Ability to design mesh systems;
- Ability to implement;
- Ability to meeting scope and schedule;
- Acceptability of business terms and conditions;
- Industry experience;
- Adequacy of support system; and
- Pricing.

In 2016 Xcel Energy selected Airspan and began contract negotiations, which were finalized in 2016. Since Airspan does not sell direct to customers, Council Rock was selected as the company that would sell Airspan technology solutions to the Company. Contract details include product pricing for base station radios, CPEs, antennas, and all associated hardware required for installation.

Q. WHY DID XCEL ENERGY SELECT AIRSPAN AS THE VENDOR FOR THE WIMAX TECHNOLOGY?

A. The primary factors in the decision were:

- Favorable pricing;
- Ability to meet technical requirements; and
- Industry experience with other utilities and similar type communication systems.

Q. DESCRIBE THE PROCESS USED TO SELECT THE VENDOR FOR THE WIMAX DEPLOYMENT SERVICES.

A. Xcel Energy issued an RFP in 2015 to select a vendor to provide implementation services for the WiMAX solution. Key requirements included ability to provide adequate resources for deployment plans, experience deploying similar technology, familiarity with solution provider and other project management related experience. Responses were received from two different companies. Xcel Energy evaluated these vendors and responses on a number of factors including those listed above, as well as references from other utilities.

In 2016 Xcel Energy selected Council Rock and began contract negotiations, which were finalized in 2016. Contract details include product pricing for installation of base station radios, CPEs, antennas, and all associated hardware.

Q. WHY DID XCEL ENERGY SELECT COUNCIL ROCK AS THE VENDOR FOR THE WIMAX DEPLOYMENT SERVICES?

A. The primary factors in the decision were:

- Council Rock's experience with implementing similar solutions for other utilities;
- Council Rock's demonstrated expertise in the technology and what the Company is deploying; and
- Council Rock's relationship with Airspan in procurement and installation.

Q. DESCRIBE THE PROCESS USED TO SELECT THE VENDOR FOR THE WISUN TECHNOLOGY.

A. Xcel Energy issued an RFP in 2015 to select a vendor to provide the WiSUN technology and equipment. Responses were received from three different companies. Xcel Energy evaluated these vendors and responses on a number of factors including those listed above. Xcel Energy also allowed each vendor to come to Xcel facilities in the summer of 2016 to deploy their technology with their own resources and demonstrate their product's performance against specific requirements in the RFP. Those tests were conducted by the vendors with Xcel Energy's assistance. Results for each vendors test were provided to them but not shared with other vendors. The results were also used for internal scoring in determining the vendor awarded the technology/product contract.

In 2016 Xcel Energy selected Silver Springs (now Itron) and began contract negotiations. Contract negotiations were finalized at the end of 2016. The contract includes detailed product pricing, licensing pricing based on end

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device counts for many of the software specific applications, optional pricing for a number of potential software solutions, services pricing and other related parts and services for future potential deployments.

Q. WHY DID XCEL ENERGY SELECT SILVER SPRINGS (NOW ITRON) AS THE VENDOR FOR THE WISUN TECHNOLOGY?

A. The primary factors in the decision were:

- Leadership in the marketplace for requirements similar to Xcel Energy's in the RFP;
- Performance in the testing against Xcel Energy requirements (met all of the testing requirements); and
- References from other utilities that implemented the same technology.

Q. DESCRIBE THE PROCESS USED TO SELECT THE VENDOR FOR THE WISUN DEPLOYMENT SERVICES.

A. Xcel Energy issued an RFP in 2016 to select a vendor to provide installation services including planning, coverage mapping, network performance planning, device installation layout, device installation planning and support service requirements. Responses were received from two different companies. Xcel Energy evaluated these responses on a number of factors including: experience, price, ability to deliver, and industry references

In 2016 Xcel Energy selected Silver Springs (now Itron) and began contract negotiations. Contract negotiations were finalized in late 2016 and included in the overall Silver Springs (now Itron) contract.

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Q. WHY DID XCEL ENERGY SELECT ITRON AS THE VENDOR FOR THE WISUN DEPLOYMENT SERVICES?

A. The primary factors in the decision were:

- Experience with the technology and requirements defined in the RFP;
- References from other utilities;
- Input from EPRI and other industry groups involved in technology deployment; and
- Favorable pricing.

(2) FAN O&M Forecast

Q. WHAT ARE THE PRIMARY COMPONENTS OF BUSINESS SYSTEMS' FAN O&M FORECAST?

A. The primary components of Business Systems' FAN O&M forecast include the work necessary for FAN implementation as well as ongoing field support for devices deployed, hardware maintenance (patches and firmware upgrades), technical support for the network, and Network Operations Center (NOC) support for monitoring the network. In other words, these cost forecasts encompass the incremental work that will be necessary to support FAN implementation and ongoing maintenance and support.

Q. HOW DID BUSINESS SYSTEMS DERIVE THE FORECAST FOR FAN O&M?

A. The FAN O&M forecast was developed based on FAN vendor contracts, existing internal support team estimates of the work required, and industry benchmarking information gathered from other utilities and industry organization such as EPRI. Each AGIS component has an internal IT team responsible for project delivery. Our forecasts for labor costs related to AMI are based on estimates from these team members, who have previous experience with similar systems implementations and support models, including FAN implementation in Colorado. I note that there could be future sourcing decisions for different AGIS components as additional requirements are identified. The Company would use its existing sourcing processes to manage additional O&M requirements in a cost-effective manner.

(3) FAN Contingency

Q. DO THE BUSINESS SYSTEMS FAN FORECASTS INCLUDE CONTINGENCY AMOUNTS?

A. Yes. The Business Systems FAN budget forecast for the period 2020-2025 includes capital contingency amounts of approximately 45 percent. Using contingencies is consistent with project planning practices, especially for large projects that implement new technologies and require major changes to enterprise IT systems. Mr. Gersack discusses the overall AGIS project contingencies in his testimony. In the AMI section above, I discuss the reasons for including contingency amounts in the AMI budget that are applicable to the FAN as well. This is due to the integrated nature of deployment and implementation of these technologies.

Q. GIVEN THE EARLIER CONTINGENCY DISCUSSION, CAN YOU HIGHLIGHT THE PRIMARY REASONS FOR INCLUDING CONTINGENCY AMOUNTS WITH RESPECT TO THE FAN?

A. Yes. While we have based our budget estimates on all known design and installation details, there remain uncertainties with respect to specific deployment of the FAN devices and unknowns that may develop through the installation phase. For the FAN, the primary for contingency is to recognize there may be situations where the primary solution being deployed may not work, for example in remote areas at edge of grid. Further, there may be a change in deployment counts of sites or devices or other situations that could not be anticipated in the initial plan. Contingencies also recognize that there may be a sudden change in viable technology or identification of a security risk or vulnerability that we would not be able to anticipate at this time.

(4) FAN Expenditures 2020-2029

Q. WHAT ARE THE BUSINESS SYSTEMS CAPITAL EXPENDITURE AND O&M FORECASTS FOR THE FAN FOR 2020 THROUGH 2029?

A. The tables below provide the Business Systems capital expenditure and O&M forecasts for the FAN for 2020 through 2029.

Table 34

FAN Capital Expenditures – Business Systems NSPM – Total Company Electric (Dollars in Millions)					
AGIS Program	2020	2021	2022	2023-2024	2025-2029*
FAN	$11.5	$31.1	$36.8	$3.8	$0.0
Period may include additional assumptions, including inflation and labor cost increases, that are not part of the capital budget in periods 2020-2024.					

Table 35

FAN O&M – Business Systems NSPM – Total Company Electric (Dollars in Millions)					
AGIS Program	2020	2021	2022	2023-2024	2025-2029*
FAN	$0.0	$2.1	$1.1	$0.2	$8.2
Period may include additional assumptions, including inflation and labor cost increases, that are not part of the capital budget in periods 2020-2024.					

(5) FAN Cost Summary

Q. WHY IS BUSINESS SYSTEMS' FAN FORECAST REASONABLE FOR CUSTOMERS TO SUPPORT?

A. The FAN is a foundational component of AGIS, which is a long-term strategic initiative to transform our electrical distribution system to enhance security, efficiency, and reliability, to safely integrate more DERs, including those that are customer owned, and to enable improved customer products and services. The FAN will provide communications between the advanced grid devices, including the AMI meters, enabling business operations efficiencies, and a better customer experience to empower informed energy decisions. The IT components described above are necessary to implement AMI, and the AMI IT forecast is reasonable in enabling technologies that improve customer products and services.

f. Minimization of Risk of Obsolescence for FAN

Q. HOW WILL THE FAN TECHNOLOGIES SELECTED BY THE COMPANY PROTECT AGAINST OBSOLESCENCE?

A. The WiSUN mesh technology is constantly being validated, refreshed, updated, and enhanced by industry organizations (WiSUN alliance and IEEE standards bodies) to ensure it is staying abreast of technology changes and requirements. The Company participates in the WiSUN alliance and ensures it technology partners are involved and leading efforts in both the Wi-SUN alliance and the IEEE standards bodies with other technology vendors and manufacturers. The Wi-SUN alliance continues to drive the incorporation of additional communications and security standards into the certification process. Currently, a number of AMI vendors have received WiSUN PHY certification. In 2019, a number of AMI vendors will receive WiSUN FAN

1.0 certification. Next will be Border Router certification and hopefully in 2022, Wi-SUN FAN 2.0 certifications are targeted. Company strategy is to continue to drive the AMI vendor community toward WiSUN certifications as they progress in the industry. Company strategy is to deploy WiSUN capable networks with continued industry standards based technological extensions which meet Company's robust security and performance objectives. In other words, as vendors update technologies, we are working with them to increase interoperability.

g. Alternatives to FAN

Q. WHAT ALTERNATIVES TO FAN DID THE COMPANY EVALUATE?

A. The FAN RFP processes and vendor selections described above were the result of an enterprise-wide effort that began in 2010 to identify an appropriate communications solution to support advanced grid capabilities. The principal alternative to the FAN for supporting AMI is the use of cellular carrier solutions. Another alternative would be to develop a dedicated AMI communications network, meaning a specific network for the singular purpose of supporting only meters and AMI. In this case devices that would make up the network would be dedicated only to AMI and be proprietary in their design and operations. However, these alternatives would not match the features and capabilities of the FAN network. Below I discuss the efforts we have undertaken since 2010 to inform our decisions on the FAN strategy, and provide the background for our assessment of the FAN compared to the alternatives.

Q. PLEASE OUTLINE THE COMPANY'S EFFORTS TO DEVELOP A COMMUNICATIONS SOLUTION FOR THE ADVANCED GRID.

A. The Company began engaging with vendors such as IBM and Accenture in 2010 to provide guidance and input on critical business applications that would or could impact the operations of the Company, and what network requirements could be defined to support those applications. Based on that work, a detailed study of potential network efforts to support operations for the Company was developed and reviewed with business units based on projected timelines and volumes for applications and associated network requirements. This was primarily focused on connectivity to devices in the field that would need to communicate with the applications identified. It also identified key requirements for reliability, security, and the need for two-way communications (*i.e.*, not just monitoring systems but also providing commands to those devices). This strategy was refined over a two-year period and involved direct input and collaboration with key engineers from all business units, including Finance, Capital Asset Accounting, and Security.

The Company then began developing initial plans for the FAN in 2012-2013 through an organized effort with external vendors comparing currently deployed network solutions and comparing that to what will be needed for communications with emerging technologies such as ADMS, AMI, FLISR, and IVVO and other grid management and customer support solutions. At that time virtually all network solutions were proprietary solutions based on the devices or applications being deployed.

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Q. HOW DID THE WORK YOU DESCRIBE ABOVE INFORM THE DEVELOPMENT OF THE COMPANY'S FAN STRATEGY?

A. In 2013, based on the preliminary work described above, the Company formalized the FAN strategy into a program. Key guidelines for the RFP/RFI processes included the following:

- Leverage Xcel Energy owned assets such as Wide Area Network connectivity to substations as well as network components in data centers and communication hubs;
- Design to capitalize equipment for full control;
- Unify equipment and services across all operating companies;
- Follow and embrace industry standards for all tiers of networks;
- Carefully integrate and coordinate network control and monitoring systems; and
- Plan and build without compromise for security controls.

The FAN team also recommended the following technical requirements:

- Point-to-Point microwave and fiber for connectivity to FAN;
- WiMAX technology for wide area broadband services;
- Mesh networking for AMI and deep access to electric, gas, and street-lighting controls;
- Rigorous attention to standards and interoperability; and
- Continued review of technology on an annual basis to ensure future proofing.

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In 2013-2015 the Company prepared and executed detailed RFIs and RFPs for the network solutions to support the business applications as discussed above.

The Company's proposed the FAN, composed of WiMAX and WiSUN components, is also consistent with developments within the electric utility industry, and current industry standards that have been adopted by vendors, organizations, and other electric utility companies. The Company actively participated with industry standards organizations and alliances – such as EPRI and IEEE – to ensure that our requirements and assumptions are aligned with the standards and products being deployed throughout the industry. In choosing FAN technology, we have relied on information from industry experts and systems integrators on actual installations of the FAN technology, public records on other utility implementations, and information through participation in industry research programs such as EPRI. The WiSUN and WiMAX networks are standards based network solutions that conform to IEEE standards.

Q. PLEASE DISCUSS THE COMPANY'S FAN PROPOSAL COMPARED TO USE OF A CELLULAR CARRIER SOLUTION FOR ADVANCED GRID COMMUNICATIONS.

A. The principal alternative to the FAN for supporting AMI is the use of cellular carrier solutions. If this was used for replacing the RF Mesh, this would require the Company to deploy a cellular modem in every meter and pay monthly fees for usage and for the private internet protocol service for every device. This alternative would cause the Company to incur substantial monthly and annual expenses.

In particular, when comparing cellular carrier solutions and the FAN, the Company determined that device costs were fairly similar but monthly and annual expenses were considerably higher with the use of public cellular network. Other key decision criteria such as security, reliability, and support costs all weighed into the decision to choose the FAN. Also factoring into our decision is consideration of latency requirements. By latency, we refer to the time it takes for data to pass from the devices through the cellular network to our applications at our data centers, and then back out to the devices. This creates an extended period of time (latency) that does not meet the Company requirements for some applications.

Cellular backhaul also would not fully support the Company's requirements for peer-to-peer requirements in all cases. Peer-to-peer requirements are associated with devices in a local setting being able to talk to each other to provide situational awareness to what is happening on the feeder or grid, and help make decisions near instantaneously without needing to communicate with applications at a data center or central office. If cellular was used to replace WiMAX (*i.e.*, Cellular backhaul from APs top data center) the same concern would apply as well as reducing the advantages of planned distributed computing at the substations to manage data traffic and provide local computing capabilities.

Q. WHAT ARE THE SECURITY ADVANTAGES ASSOCIATED WITH THE PRIVATE FAN NETWORK AS COMPARED TO A PUBLIC CELLULAR NETWORK?

A. A private network allows the Company to better control the integrity of the devices on its network and the data exchanged with those devices. Through the exchange of digital certificates, as well as other controls, Company

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determines and authorizes each device before allowing it to use the FAN. As does any utility, Company utilizes many public communications circuits for the backhaul of voice and data communications. Security threats, however, are more prevalent in networks with a higher number of points of entry. The Company's FAN network will carry communications traffic for literally millions of end-devices, span its entire service territory and experience constant device moves/adds/changes and upgrades. Company strategy to reduce cyber threat vulnerability footprint is to manage its own FAN.

Q. PLEASE DISCUSS THE COMPANY'S FAN PROPOSAL COMPARED TO AN ALTERNATIVE DEDICATED AMI NETWORK SOLUTION FOR ADVANCED GRID COMMUNICATIONS.

A. By definition, and AMI-dedicated network solution would only allow connectivity between AMI devices. When comparing this option to the FAN, the Company determined that it will be more functional and is preferable to have a FAN network that allows for connectivity of diverse devices (meters, capacitor banks, sensors, etc.). Allowing devices to connect both to each other and to back office applications not only increases the ability to conduct peer-to-peer communications on a local feeder but also reduces overhead associated with managing, supporting, and monitoring multiple networks of diverse manufacturers and network management tools.

Q. WHAT DID THE COMPANY CONCLUDE AFTER EVALUATING DIFFERENT COMMUNICATIONS NETWORK SOLUTIONS?

A. The Company concluded that virtually none of the communication network alternatives could match the features and capabilities of the FAN network. A summary comparison of the FAN capabilities to the alternative options is provided in Table 36 below.

Table 36
Comparison of Network Communications Solutions

Feature/ Requirement	FAN Mesh	Cellular	Dedicated AMI Network	Comments
Two-way Communications	●	●	●	All can do two-way communications.
Peer-to-Peer	●	◔	◕	Less clear how this would be accomplished with cellular.
Multi-purpose	●	◕	◔	Only FAN Mesh can support all potential use cases at Xcel Energy.
Latency Requirements	●	●	◕	If set up correctly each could meet requirements known today for latency.
Security	●	◑	●	Dedicated networks provide more secure traffic not travelling over public networks.
Dedicated Traffic	●	◔	◕	The network would be fully dedicated to Xcel Energy traffic.
Priority Traffic	●	◔	●	Dedicated networks allow for priority traffic routing with Xcel Energy traffic being the top priority.
O&M Costs Impact (run state)	●	◔	◑	Higher monthly costs for data traffic using cellular and higher support costs per device for dedicated AMI network.
Resiliency	●	◑	◑	Fewer unplanned outages with mesh network as it heals itself. The more devices on the mesh the more resilient.

Legend				
Full	Most	Partial	Minimal	None
●	◕	◑	◔	○

5. FLISR

a. FLISR Overview

Q. WHY IS IT INTEGRATION IMPORTANT FOR IMPLEMENTATION OF FLISR?

A. The advanced application FLISR will rely on accurate power flow calculations to determine the power flow at points on the grid where sensor information does not exist. As such, they require integration with the core ADMS systems. FLISR must be integrated with the ADMS core applications and other critical systems to provide its intended benefits to the Company's customers.

Q. WHAT WORK IS BUSINESS SYSTEMS UNDERTAKING WITH RESPECT TO FLISR?

A. The work Business Systems will undertake with respect to FLISR is as follows:

- Leading the design of the system components;
- Configuration of the required software and hardware;
- Building and installation of any required interfaces;
- Designing and integrating security into all aspects of FLISR;
- Thorough unit, system, and end-to-end testing; and|
- User Acceptance Testing (UAT) with the Distribution business resources.

Q. HAS BUSINESS SYSTEMS ALREADY PERFORMED WORK TO SUPPORT FLISR IMPLEMENTATION?

A. Yes. FLISR implementation has been planned on an enterprise-wide basis, and work to test functionality was completed for Colorado in 2019. In Minnesota, Business Systems will support testing of FLISR on the feeders selected by the Distribution organization. As discussed in Ms. Bloch's testimony, as part of the installation of ADMS, FLISR will be deployed to a

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small two-feeder area in South Minneapolis in 2020 to validate the ADMS capabilities. Business Systems has engaged in work to support this FLISR testing, which will be conducted in the second quarter of 2020. I note that this limited testing of FLISR is included in the costs for ADMS, which the Company proposes to continue recovering through the TCR Rider. FLISR implementation costs for 2020 and beyond are proposed for inclusion in base rates.

Q. PLEASE DESCRIBE THE WORK BUSINESS SYSTEMS WILL UNDERTAKE TO SUPPORT IMPLEMENTATION OF FLISR IN 2020, 2021, AND 2022.

A. As discussed in Ms. Bloch's testimony, the Company proposes to implement FLISR on 206 additional feeders between 2021 and 2028, and Distribution will install the FLISR equipment. Business Systems will support this FLISR implementation by adding and conditioning field devices to support FLISR functionality. Business Systems will also perform testing to support this implementation.

b. FLISR Costs

Q. WHAT BUSINESS SYSTEM CAPITAL ADDITIONS AND O&M COSTS ARE NECESSARY FOR IT INTEGRATION FOR FLISR DURING THE TERM OF THE MYRP IN THIS CASE?

A. Table 37 below provides the capital additions for IT integration for FLISR for 2020 through 2022. Table 38 shows that there are no IT O&M costs for FLISR integration during the term of the MYRP.

Table 37

FLISR Capital Additions – Business Systems State of MN Electric Jurisdiction (Includes AFUDC)(Dollars in Millions)			
AGIS Program	2020	2021	2022
FLISR	$0.3	$0.4	$0.6

Table 38

FLISR O&M – Business Systems NSPM – Total Company Electric (Dollars in Millions)			
AGIS Program	2020	2021	2022
FLISR	$0.0	$0.0	$0.0

Q. WAS BUSINESS SYSTEMS PRIMARILY RESPONSIBLE FOR DEVELOPING THE FORECASTS FOR FLISR?

A. No. However, Business Systems is responsible for the integration of the Sensor Management System (SMS) for Aclara sensors into ADMS, and for managing the integration of the FLISR sub-application with ADMS. Although Ms. Bloch provides a discussion of the forecast process with respect to the FLISR advanced application and its related field devices in her Direct Testimony, I discuss the Aclara SMS below.

Q. WHAT IS THE ACLARA SMS FOR FLISR?

A. The Aclara SMS is software which provides control and reporting on sensors across the Company's distribution system. It also acts as a virtual RTU, providing the ability to integrate the sensor data with the SCADA system. The sensors and SMS will be used in conjunction with each other to support FLISR. FLISR requires that the substation relay provide certain signals in order to communicate to the ADMS to begin automatic locating of the fault and subsequent restoration. The Company's current substation standard requires a specific make and model of relay which many of the Company's substations do not have, so these sensors provide a low cost alternative that can provide that telemetry. Because the Aclara SMS software is currently used for other purposes across the Company's distribution system, no new software is needed to implement FLISR.

Q. WHAT ARE THE PRIMARY COMPONENTS OF THE IT CAPITAL FORECAST TO IMPLEMENT FLISR?

A. The FLISR IT capital forecast is primarily composed of labor costs for the work described above.

Q. HOW DID THE COMPANY DEVELOP THESE COST ESTIMATES?

A. The Company developed labor estimates primarily using actual labor costs for the design and implementation of the FLISR functionality testing described above as part of ADMS implementation.

Q. PLEASE DESCRIBE THE FLISR CONTINGENCY AMOUNTS INCLUDED IN THE FORECAST.

A. The Business Systems FLISR budget forecast for the period 2020-2025 includes capital contingency amounts of approximately 24 percent. A significant portion of the FLISR IT work and cost is to develop templates which provide the computer screen interface for managing field devices used for FLISR functions. Each device requires a corresponding template. Base Templates are created as generic templates across a product family. These are used as the starting point to create Subtype Templates, which include the attribute variations needed by each device subtype in the product family. Significant work is required for each Subtype Template build.

The amount of re-use of the Base Template to create the Subtype Templates is estimated, but not precisely known until the detailed build work begins. We have included a contingency for FLISR implementation due to this unknown.

c. FLISR Expenditures 2020-2029

Q. WHAT ARE THE BUSINESS SYSTEMS CAPITAL EXPENDITURE AND O&M FORECASTS FOR FLISR FOR 2020 THROUGH 2029?

A. The tables below provide the Business Systems capital expenditure and O&M forecasts for FLISR for 2020 through 2029.

Table 39

FLISR Capital Expenditures – Business Systems NSPM – Total Company Electric (Dollars in Millions)					
AGIS Program	2020	2021	2022	2023-2024	2025-2029*
FLISR	$0.4	$0.5	$0.7	$2.9	$3.4
Period may include additional assumptions, including inflation and labor cost increases, that are not part of the capital budget in periods 2020-2024.					

Table 40

FLISR O&M – Business Systems NSPM – Total Company Electric (Dollars in Millions)					
AGIS Program	2020	2021	2022	2023-2024	2025-2029*
FLISR	$0.0	$0.0	$0.0	$0.1	$0.1
Period may include additional assumptions, including inflation and labor cost increases, that are not part of the capital budget in periods 2020-2024.					

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Q. WHY IS BUSINESS SYSTEMS' FLISR FORECAST REASONABLE FOR CUSTOMERS TO SUPPORT?

A. FLISR is an advanced grid component that will enable significant reliability improvements for our customers, and operational efficiencies for the Company. Overall, implementing FLISR allows the Company to more efficiently restore power with the use of fewer resources and will improve the customer reliability experience. The Business Systems work will provide for the implementation of FLISR and integration with the advanced grid technologies, enabling these benefits for our customers and the Company. The Business Systems FLISR forecast is reasonable based on the details provided above.

6. IVVO

a. IVVO Overview

Q. WHY IS IT INTEGRATION IMPORTANT FOR IMPLEMENTATION OF IVVO?

A. The advanced application IVVO will rely on accurate power flow calculations to determine the power flow at points on the grid where sensor information does not exist. As such, they require integration with the core ADMS systems. IVVO must be integrated with the ADMS core applications and other critical systems to provide its intended benefits to the Company's customers.

Q. WHAT WORK IS BUSINESS SYSTEMS UNDERTAKING WITH RESPECT TO THE IVVO?

A. The work Business Systems will undertake with respect to IVVO is as follows:

- Leading the design of the system components;
- Configuration of the required software and hardware;
- Building and installation of any required interfaces;

- Designing and integrating security into all aspects of IVVO;
- Thorough unit, system, and end-to-end testing;
- User Acceptance Testing (UAT) with the Distribution business resources.

Q. HAS BUSINESS SYSTEMS ALREADY PERFORMED WORK TO SUPPORT THE IVVO IMPLEMENTATION?

A. Yes. IVVO implementation has been planned on an enterprise-wide basis, and work to test functionality was completed for Colorado in 2019. In Minnesota, Business Systems will support testing and implementation of the IVVO on the feeders selected by the Distribution organization. As discussed in Ms. Bloch's testimony, as part of the installation of ADMS, the Company will implement IVVO on the seven feeders at one substation in Southeast Minneapolis. Business Systems has engaged in work to support this IVVO testing, which will be conducted in the second quarter of 2020. I note that this limited testing of IVVO is included in the costs for ADMS, which the Company' proposes to continue recovering through the TCR Rider. The implementation costs for wider IVVO deployment are proposed for inclusion in base rates.

Q. PLEASE DESCRIBE THE WORK BUSINESS SYSTEMS WILL UNDERTAKE TO SUPPORT IMPLEMENTATION OF IVVO IN 2020, 2021, AND 2022.

A. As discussed in Ms. Bloch's testimony, the Company proposes to implement IVVO at 13 substations between 2021 and 2024. Distribution will install the IVVO equipment, the Company will capture data and configure equipment, and then tune ADMS models. Business Systems will support this IVVO implementation by adding and conditioning field devices to support IVVO functionality and will perform testing to support this expansion. Business Systems will also implement the Grid Edge Management System (GEMS) software for the secondary static VAr compensator (SVC) devices that are part of the IVVO implementation, and will complete IT integration of the IVVO advanced sub-application with ADMS.

b. IVVO Costs

Q. WHAT BUSINESS SYSTEM CAPITAL ADDITIONS AND O&M COSTS ARE NECESSARY FOR IT INTEGRATION FOR IVVO DURING THE TERM OF THE MYRP IN THIS CASE?

A. Table 41 below provides the capital additions for IT integration for IVVO for 2020 through 2022. Table 42 shows that there are no IT O&M costs for IVVO integration during the term of the MYRP.

Table 41

IVVO Capital Additions – Business Systems State of MN Electric Jurisdiction (Includes AFUDC)(Dollars in Millions)			
AGIS Program	2020	2021	2022
IVVO	$0.0	$1.7	$1.9

Table 42

IVVO O&M – Business Systems NSPM – Total Company Electric (Dollars in Millions)			
AGIS Program	2020	2021	2022
IVVO	$0.0	$0.0	$0.0

Q. WAS BUSINESS SYSTEMS PRIMARILY RESPONSIBLE FOR DEVELOPING THE FORECASTS FOR IVVO?

A. No. However, Business Systems was responsible for developing the forecast for the GEMS software and for managing the integration of the IVVO advanced sub-application with ADMS. Although Ms. Bloch provides a discussion of the forecast process with respect to the IVVO advanced application and its related field devices, I discuss GEMS below.

Q. PLEASE DESCRIBE THE GEMS SOFTWARE THE COMPANY HAS SELECTED TO SUPPORT THE IVVO FIELD DEVICES.

A. The GEMS software was included in the package from the vendor supplying the SVC devices. As discussed in Ms. Bloch's testimony, the Company began an RFP process to select an SVC vendor in the second quarter of 2018. As a result of the RFP, the Company selected Varentec's Edge of Network Grid Optimization (ENGO) unit as the winning bidder for the SVC devices. The GEMS software to manage and control the SVC devices was included in the package. Business Systems will deploy the GEMS software for management and control of the ENGO SVC devices. The Company will host the server in-house for IVVO deployment.

Q. WHAT ARE THE PRIMARY COMPONENTS OF THE IVVO IT CAPITAL FORECAST TO IMPLEMENT THIS SOFTWARE?

A. The IVVO IT capital forecast has three key components: hardware, software, and labor.

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Q. WHAT HARDWARE IS NEEDED FOR IVVO IMPLEMENTATION FOR BUSINESS SYSTEMS?

A. The additional hardware necessary for AMI implementation consists of computing components used for data processing and storage to support IVVO services. Additional servers are needed due to the increased volume of data and processes necessary to implement IVVO capabilities.

Q. HOW DID THE COMPANY DERIVE THE HARDWARE PORTION OF THE AMI IT FORECAST?

A. Xcel Energy has standards for all hardware that is deployed in our data centers. These standards define hardware for which the Company has industry benchmarked, negotiated pricing. Based on these standards, the hardware estimates were derived utilizing the hardware requirements of the applications and applying standard pricing.

Q. HOW DID THE COMPANY DEVELOP THE COST FORECAST FOR IVVO SOFTWARE COSTS?

A. Pricing for the IVVO software is provided in the contract with Varentec, selected through the RFP process noted above. Pricing is consistent with industry benchmarks and our review with other utilities and industry research organizations such as EPRI. These benchmarks drove the negotiations with the selected vendor. Varentec provided budgetary quotes for their ENGO device licensing based on a cloud-based approach and an in-house server based approach. The in-house approach, described above for the AMI forecast, was used to develop cost estimates, consistent with the Company's security requirements.

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Q. HOW DID THE COMPANY DEVELOP THE FORECAST FOR THE CAPITAL LABOR COSTS?

A. Our forecast includes both internal and external labor. External labor costs are based on the contract pricing described above. The internal labor forecast is based on our experience and work that has already been completed for IVVO implementation. Business Systems has leveraged spend information to date, for both IVVO rollout in Colorado and the limited deployment in Minnesota for testing purposes, to estimate the future costs associated with full deployment in Minnesota.

Q. ARE THERE OTHER COSTS INCLUDED IN THE BUSINESS SYSTEMS CAPITAL FORECAST FOR IVVO?

A. Yes. There are additional project management costs that are include in the IVVO capital forecast. For Business Systems, these include labor costs for delivery and execution leadership and security.

Q. HOW DID THE COMPANY DEVELOP THESE PROJECT MANAGEMENT COST FORECASTS?

A. These capital costs were developed using contract pricing for the external project management work, and labor estimates for the work necessary to support IVVO integration efforts described above. These costs were derived based on evaluation of prior work performed in Colorado, which provides a reasonable point of reference for labor estimates for most general functional areas supporting Minnesota.

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Q. WHAT ARE THE PRIMARY COMPONENTS OF BUSINESS SYSTEMS IVVO O&M COSTS?

A. The primary components of Business Systems IVVO O&M costs include ongoing hardware support, data storage, annual software maintenance, application support, and labor for software support.

Q. HOW DID BUSINESS SYSTEMS DERIVE THE IVVO O&M FORECAST?

A. The IVVO O&M forecast was developed based on vendor quotes, existing internal support team estimates of the work required, and industry benchmarking information. Each AGIS component has an internal IT team responsible for project delivery. Our forecasts for labor costs related to AMI are based on estimates from these team members, who have previous experience with similar systems implementations and support models.

Q. PLEASE DESCRIBE THE IVVO CONTINGENCY AMOUNTS INCLUDED IN THE FORECAST.

A. The Business Systems IVVO budget forecast for the period 2020-2025 includes capital contingency amounts of approximately 10 percent. A significant portion of the IVVO IT work and cost is to develop templates which provide the computer screen interface for managing field devices used for IVVO functions. Each device requires a corresponding template. Base Templates are created as generic templates across a product family. These are used as the starting point to create Subtype Templates, which include the attribute variations needed by each device subtype in the product family. Significant work is required for each Subtype Template build.

The amount of re-use of the Base Template to create the Subtype Templates is estimated, but not precisely known until the detailed build work begins. We have included a contingency for IVVO implementation due to this unknown.

c. IVVO Expenditures 2020-2029

Q. WHAT ARE THE BUSINESS SYSTEMS CAPITAL EXPENDITURE AND O&M FORECASTS FOR IVVO FOR 2020 THROUGH 2029?

A. The tables below provide the Business Systems capital expenditure and O&M forecasts for IVVO for 2020 through 2029.

Table 43

IVVO Capital Expenditures – Business Systems NSPM – Total Company Electric (Dollars in Millions)					
AGIS Program	2020	2021	2022	2023-2024	2025-2029*
IVVO	$0.0	$1.9	$2.2	$4.3	$0.0
Period may include additional assumptions, including inflation and labor cost increases, that are not part of the capital budget in periods 2020-2024.					

Table 44

IVVO O&M – Business Systems NSPM – Total Company Electric (Dollars in Millions)					
AGIS Program	2020	2021	2022	2023-2024	2025-2029*
IVVO	$0.0	$0.0	$0.0	$0.1	$0.0
Period may include additional assumptions, including inflation and labor cost increases, that are not part of the capital budget in periods 2020-2024.					

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Q. WHY IS BUSINESS SYSTEMS' IVVO FORECAST REASONABLE FOR CUSTOMERS TO SUPPORT?

A. IVVO will enable automated capabilities to optimize the operation of the distribution voltage regulating and VAr control devices to reduce electrical losses, electrical demand, and energy consumption, and provides increased distribution system capacity to host DER. The Business Systems work will provide for the implementation of IVVO and integration with the advanced grid technologies, enabling these benefits for our customers and the system. The Business Systems IVVO forecast is reasonable based on the details provided above.

7. AGIS IT Overall Costs and Implementation

Q. OVER WHAT TIME PERIOD WILL THE FOUNDATIONAL COMPONENTS OF AGIS BE IMPLEMENTED?

A. The Company began implementation of the foundational components of AGIS in 2019, and implementation of AMI, the FAN and IVVO will be substantially completed in 2024. FLISR implementation will be accomplished over a longer time period, through 2028.

Q. WHAT ARE THE TOTAL IT INTEGRATION COSTS FOR THE AGIS COMPONENTS?

A. The tables below show the total capital expenditure and O&M IT integration costs, by component, for 2020-2029.

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Table 45

AGIS Capital Expenditures – Business Systems NSPM – Total Company Electric (Dollars in Millions)					
AGIS Program	2020	2021	2022	2023-2024	2025-2029*
AMI	$11.4	$6.5	$10.0	$5.7	$0.9
FAN	$11.5	$31.1	$36.8	$3.8	$0.0
FLISR	$0.4	$0.5	$0.7	$2.9	$3.4
IVVO	$0.0	$1.9	$2.2	$4.3	$0.0
Total	$23.3	$40.0	$49.7	$16.7	$4.3
Period may include additional assumptions, including inflation and labor cost increases, that are not part of the capital budget in periods 2020-2024.					

Table 46

AGIS O&M – Business Systems NSPM – Total Company Electric (Dollars in Millions)					
AGIS Program	2020	2021	2022	2023-2024	2025-2029*
AMI	$4.2	$13.1	$9.1	$15.2	$51.5
FAN	$0.0	$2.1	$1.1	$0.2	$8.2
FLISR	$0.0	$0.0	$0.0	$0.1	$0.1
IVVO	$0.0	$0.0	$0.0	$0.1	$0.0
Total	$4.3	$15.3	$10.2	$15.5	$59.8
Period may include additional assumptions, including inflation and labor cost increases, that are not part of the capital budget in periods 2020-2024.					

Q. WHAT IS YOUR RECOMMENDATION FOR THE COMMISSION WITH RESPECT TO THE BUSINESS SYSTEMS COMPONENTS OF THE AGIS INITIATIVE?

A. I recommend that the Commission approve our request to recover the Business Systems costs of the capital investments and O&M expense for the foundational components of AGIS that we propose to implement during the 2020-2022 term of the MYRP. Our proposal includes full AMI implementation, IVVO and FLISR as part of our broader grid resiliency efforts, and the FAN components necessary to support AMI and the advanced grid applications. We also recommend that the Commission certify these projects to provide the opportunity for the Company to request recovery of costs for 2023 and later in subsequent rider filings. Approval of the costs necessary to implement the AGIS initiative will advance the Company's electric distribution system, provide customers with more choices, and enhance the way the Company serves its customers.

VI. CONCLUSION

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. I recommend that the Commission approve the Business Systems capital and O&M budget presented in this rate case. Our planned capital investments are managed appropriately and established to address aging technology, cyber security, customer experience, enhanced capabilities, and emerging demand for the Company. Certain major projects, such as our investment in the AGIS initiative, will bring the distribution grid and the Company into the future. The budgets we propose are a reasonable representation of the activities we will undertake on behalf of the Company and ultimately our service to customers through 2022 and beyond.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes, it does.

DAVID C. HARKNESS

Chief Information Officer • Senior IT Executive • Chief Technology Officer • Senior Vice President IT

PROFILE

Talented and accomplished senior IT executive and corporate officer with consistent record of success in promoting corporate growth through effective management of technology operations. Special expertise in change management, turnaround leadership, digital transformation, multi-sourcing, technology development. Proven ability to lead Customer Marketing, Product Development, Sales, Brand activities. Familiar with supporting M&A activities. Adept at building relationships with business stakeholders.

IT Governance • Strategic Planning • Enterprise Business Transformation • Turnaround Operations
Service Delivery • Project/Program Management • Relationship Management • Cost/Budget Control
Technology Development • Succession Planning • Enterprise Infrastructures/Architectures
Six Sigma/Lean/ITIL • Compliance • Outsourcing • SAP/ERP Deployment • Shared Services

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PROFESSIONAL EXPERIENCE

XCEL ENERGY, Minneapolis, MN 2009 - Present

Senior Vice President Customer Solutions (2019 – Present)

Lead the Customer Solutions organization for the Commercial & Industrial, Residential and Small Business–focused customer segments. C&I portfolio currently represents 500,000 customers and 60 percent of Xcel Energy revenue, while the Residential and Small Business segment represents roughly 3.5 million customers and 40 percent of Xcel Energy revenue. This includes HomeSmart, Xcel Energy's national non-regulated home warranty business, Economic Development, Transportation and EVs, Digital Channel Management, Product Development, DSM Product Management and Regulatory & Strategy, Renewable Product Management. By combining his business and technology leadership experiences, Dave helps create and drive a transformed digital customer experience. Utilizing strategic partnerships, he leads Xcel Energy toward a product and services portfolio helping develop connected communities, advanced home and business energy solutions, and further enable the electrification of the Transportation industry.

Senior Vice President; Chief Information Officer (2009 – 2019)

Responsible for all information technology development, operations and governance, cyber security functions, and Xcel Energy's overall business continuity program. Drives innovation and transformation by leveraging technology to create business value for $11B Gas and Electric energy company operating in 8 states. Administer $500M combined budget and supervise 900 direct and indirect reports, including senior IT leadership team. Manage strategy development and ensure alignment with corporate goals. Build and maintain strategic partner relationships, primarily IBM, Accenture, Dell, Motorola, PWC. Direct infrastructure operations, including data / voice communications, service levels, and security.

- Drove $400M SAP Deployment (Productivity Through Technology program) across enterprise including all 4 subsidiaries.
- Increased deployment capacity 300% through Digital Transformation program.
- Restructured primary sourcing contract spend by $25M annually; representing a 25% reduction.
- Developed 10-yr IT strategic Roadmap including Business Unit plans, Platform Risk Assessment, Cyber Security Requirements and Enterprise Architecture principles and reference architectures.

PNM RESOURCES, Albuquerque, NM 2003 - 2009

Vice President; Chief Information Officer (2006-2009)

Oversee all technology management and development for $2.6B energy company with 4 subsidiaries in Southwest. Administer $70M combined budget and supervise 260 direct and indirect reports, including executive management team. Manage strategy development and ensure alignment with corporate goals. Identify needs and implement improvements. Evaluate new technologies and determine ROI for purchase vs. build strategies. Build and maintain partner and vendor relationships. Direct infrastructure operations, including data / voice communications, service levels, and security.

- Reduced spending 20% and headcount 40% over 18-month period.
- Increased deployment capacity 400% and internal client satisfaction 30% by implementing new portfolio management process.

Executive Director, Business Transformation (2006)

Managed organizational development, corporate training, Six Sigma Black Belt and Lean process improvement, and M&A operations. Supervised staff of 25.

- Implemented enterprise-wide competency model that included performance management, leadership development, and roundtable review. Launched online / classroom training program.

Executive Director, Business Process Outsourcing, First Choice Power (2005-06)

Directed major outsourcing project for $600M subsidiary. Project encompassed call center, field offices, bill printing, remittance processing, and various system conversions. Managed provider relationship. Created program plan and operating model. Supervised staff of 20.

- Brought call center and bill printing online in 2 months and remittance processing in 3 months.
- Facilitated >$4M in annualized savings through successful completion of initiative.

Executive Aide to CEO, President, & Chairman (2004-05)

Completed 6-month program of corporate officer mentorship. Attended board meetings, long-range strategic planning sessions, investor/regulator meetings and more. Actively involved in corporate governance and ethics review and planning sessions.

MCLEODUSA, Cedar Rapids, IA 1996 - 2003

Director, Enterprise Applications Development

Supervised application development, business analysis for $1B telecom company. Supervised staff of more than 120 developers. Administered $20M budget.

MCI COMMUNICATIONS, Cedar Rapids, IA 1991 - 1996

Manager, Business Analysis

Developed and led software projects for 800 Card marketing group and Intelligent Services Platform. Supervised 8 senior-level analysts and administered $8M+ budget.

CAREER NOTES: Previously held position of **Software Engineer** at ROCKWELL INTERNATIONAL (1985-1991). Wrote patented algorithm for robot manufacturing equipment.

ADDITIONAL EXPERIENCE

STATE OF NEW MEXICO, Santa Fe, NM 2005 - 2009

State Commissioner, Information Technology Commission

Appointed by governor to commission responsible for state information architecture and strategic information technology plan.

EDUCATION

BS in Computer Science/ BA in Applied Mathematics, The University of Iowa, Iowa City, IA

TRAINING & DEVELOPMENT

Utility Executive Course, The University of Idaho

Merger Week, Kellogg School of Business, Northwestern University

CURRENT & PAST AFFILIATIONS

Chair, Board of Directors, BestPrep, an organization driven to improve business and financial literacy of MN youth

Board of Directors, Minnesota High Tech Association, organization of Minnesota based businesses driving to improve the technology literacy and maturity in the state of Minnesota

Chair, EEI (Edison Electric Institute) Technology Advisory Council; Group of EEI and AGA (American Gas Association) CIOs designated to collaborate on key technical and business challenges facing utility Industry.

Member of EEI Executive Advisory Committee CIO group; consult on technology policy; advises Energy CEOs

Advisory Board University of Idaho Utility Executive Course – Premier Utility industry executive development program since 1952

CIO Advisory Board for IBM's Global Infrastructure

Volunteer for EarthDay; Feed my Starving Children; Holidazzle Parade; Big Brothers/Big Sisters

Chair, College Success Network Board of Directors 2006-2010
Vice Chair, PNM Resources Foundation Board of Trustees 2008-2009
PNM Resources Speakers Bureau and Community Crew 2004-2009

FOR PROFIT BOARD SERVICE

Director, PayGo Board of Directors
Director, First Choice Power Board of Directors

AWARDS / PUBLICATIONS / SPEAKING ENGAGEMENTS

Orbie Twin Cities CIO of the Year 2018
ComputerWorld Magazine's 100 Premier IT Leaders 2008
Author/Contributor - Managing Your IT Department as a Business: Leading CTOs and CIOs on Assessing Client Needs, Driving IT Costs Down, and Measuring Performance; Aspatore, September, 2009
Radio Interview – CIOTalkRadio
CIO Magazine / Martha Heller CIO Paradox
Multiple Interviews/Publications for EnergyCentral, EnergyBiz, Intelligent Utility, Five Point Partners, Utility CIO Knowledge Conference, CIO Global Forum

Capital Investment Additions
NSPM

Category	Project Name	WBS Level 2 #	Classification	Addition Amount 2020	2021	2022	Date
Enhance Capabilities	ITC- BUS SYS WIND Blazing Star2 MN	A.0001702.009	Electric General Plant	(247,338)			12/31/2020
Enhance Capabilities	ITC- BUS SYS WIND Freeborn MN	A.0001704.008	Electric General Plant	(371,540)			12/15/2020
Enhance Capabilities	ITC-BUS SYS Dakota Range WIND SD	A.0001707.008	Electric General Plant		(346,394)		12/31/2021
AGIS	ADMS SW MN	D.0001723.004	Electric General Plant	(43,165,009)			4/30/2020
Enhance Capabilities	Sub Asset Mgmt SW MN	D.0001728.004	Electric Intangible Plant			(5,583,004)	12/31/2022
Aging Technology	Emptoris SW MN-10708	D.0001732.011	Common Intangible Plant				12/31/2023
Cyber Security	NSPM C Corp Sec Furn	D.0001781.001	Common General Plant	(232)	(0)		1/1/2025
Cyber Security	NSPM E Corp Sec Ntwk	D.0001781.010	Electric General Plant	(21)			1/1/2025
Cyber Security	Security Projects - Electric -	D.0001781.035	Electric General Plant	(119,405)	(5,852)	(287)	1/1/2025
Cyber Security	Security Projects - Common - MN	D.0001781.036	Common General Plant	(282)	(14)	(1)	1/1/2025
Aging Technology	Peoplesoft Upgrade SW MN	D.0001792.040	Common Intangible Plant			(28,635,543)	12/31/2022
Aging Technology	Purch Sub Frame Relay Equip ND	D.0001797.007	Electric General Plant	3,591			12/31/2020
Emergent Demand	BS-Fcst-BD-SW-CM-M	D.0001804.085	Common Intangible Plant	(9,067,834)	(14,745,822)	(12,216,205)	12/31/2024
Cyber Security	Security Tech Refresh SW MN	D.0001807.001	Common Intangible Plant	(5,334,002)	(11,636,100)	(8,265,066)	12/31/2023
Aging Technology	2018 EMS Infra Refresh MN	D.0001821.304	Electric General Plant		(247,000)		12/31/2021
Aging Technology	2020 Planned MDT Refresh MN	D.0001821.413	Common General Plant		(2,434,870)		12/31/2021
Aging Technology	Real Property Asset Mgmt Upgra	D.0001826.005	Common Intangible Plant				12/31/2023
Enhance Capabilities	Purch Synchrophasor Net HW MN	D.0001826.370	Electric General Plant	(980,891)			4/30/2020
Aging Technology	Purch CRS Tech Stack HW MN	D.0001839.400	Common General Plant	(250,000)			12/31/2020
Aging Technology	Purch VOIP MN	D.0001840.021	Common General Plant	(399,996)			12/31/2020
AGIS	PURCH FAN HW CM COMM MN	D.0001900.049	Common General Plant	(6,813,182)	(19,966,725)	(24,796,788)	12/31/2024
AGIS	AGIS Advanced Metering SW MN	D.0001901.004	Electric Intangible Plant	(3,798,298)			12/31/2020
AGIS	AGIS Meter Data Mgmt (MDMS) SW MN	D.0001901.008	Electric Intangible Plant	(8,249,299)			12/31/2020
AGIS	AMI-BS-NSPM-MN Full AMI	D.0001901.040	Electric Intangible Plant	(3,312,399)	(6,581,018)	(4,698,678)	1/1/2025
AGIS	AMI-BS-NSPM-MN-TOU-CRS-Billing Modu	D.0001901.054	Electric Intangible Plant	(924,511)			12/31/2020
AGIS	Purch AGIS FLISR El Comm MN	D.0001902.029	Electric General Plant	(363,194)	(466,905)	(466,919)	1/1/2025
AGIS	AGIS Integrated Volt Var (IVVO) SW	D.0001904.004	Electric Intangible Plant		(1,896,843)	(1,917,915)	12/31/2024
AGIS	AGIS-BS-Capital-Comm-Contingency-NS	D.0001908.018	Common General Plant			(27,925,189)	12/31/2022
AGIS	AGIS-BS-Capital-E-Comm-Contingency-	D.0001908.025	Electric General Plant			(274,223)	12/31/2024
AGIS	AGIS-BS-Cap-SW-Cont-AMI-NSPM	D.0001908.053	Electric Intangible Plant			(5,460,955)	1/1/2025
AGIS	AGIS-BS-Cap-SCom-Cont-IVVO-NSPM	D.0001908.061	Electric General Plant			(255,715)	1/1/2025
Aging Technology	2020 Oracle SW MN	D.0002003.015	Common Intangible Plant		(1,656,526)		12/31/2020
Aging Technology	2021 Oracle SW MN	D.0002003.019	Common Intangible Plant		(1,656,526)		12/31/2021
Aging Technology	2022 Oracle SW MN	D.0002003.023	Common Intangible Plant			(1,170,900)	12/31/2022
Cyber Security	Ent DataBase Security Ph4 SW MN-107	D.0002008.015	Common Intangible Plant	(375,927)			3/20/2020
Aging Technology	Purch WAN HW MN-BSPRJ0001167	D.0002011.001	Common General Plant	(8,251,371)	(15,823,270)	(10,792,247)	12/31/2023
Aging Technology	Purch Facility IT Investments HW MN	D.0002021.001	Common General Plant		(2,771,384)		12/31/2021
Aging Technology	TAMS Replacement SW MN	D.0002025.001	Electric Intangible Plant			(1,576,550)	12/31/2022
Customer	Customer Identity Access SW MN-1068	D.0002028.004	Common Intangible Plant	(1,509,750)			4/20/2020
Enhance Capabilities	BUD-Application Virtualization HW M	D.0002029.005	Common General Plant			(2,500,002)	12/31/2022
Aging Technology	Cash Management System SW MN	D.0002032.001	Common Intangible Plant		(599,666)		12/31/2021
Enhance Capabilities	Customer Engagement Platform SW MN	D.0002036.001	Common Intangible Plant			(353,400)	12/31/2022
Customer	CEC-Cust Service Console SW MN-1070	D.0002037.001	Common Intangible Plant		(9,524,378)		12/20/2021
Customer	CEC-Homesmart Ph2 SW MN-10722	D.0002037.011	Common Intangible Plant	(372,984)			12/18/2020
Customer	CEC-Builders Call SW MN-10723	D.0002037.016	Common Intangible Plant	(633,950)			12/31/2020
Aging Technology	DEMS Ph4 HW MN-10756	D.0002038.004	Electric General Plant	(12,380,272)			12/31/2020
Aging Technology	ITC-Purch DEMS HW MN	D.0002038.010	Electric General Plant	(3,391,272)			12/31/2020
Aging Technology	eGRC Phase IV SOx Corp Com SW MN-10	D.0002041.001	Common Intangible Plant	(594,172)			12/20/2020
Aging Technology	eGRC FERC Compliance SW MN	D.0002041.005	Common Intangible Plant			(371,208)	12/31/2022
Aging Technology	eGRC Ph IV SOX SW MN-10764	D.0002041.013	Common Intangible Plant	(227,201)			12/20/2020
Enhance Capabilities	BUD-Enterprise Operational HW MN	D.0002045.005	Common General Plant		(1,333,332)		12/31/2021
Emergent Demand	BUD-IT Blanket Core Tech HW MN	D.0002060.001	Common General Plant		(254,000)	(558,764)	12/31/2024
Aging Technology	Meridium Upgrade SW MN	D.0002063.001	Common Intangible Plant	(1,913,002)			12/31/2020
Enhance Capabilities	Remote Branch Office SW MN	D.0002071.001	Common Intangible Plant	(827,642)			12/31/2020
Enhance Capabilities	Safety Observation SW MN	D.0002073.001	Electric Intangible Plant		(286,026)		12/31/2021
Enhance Capabilities	BUD-BSPRJ1134 SAP Data Gov SW MN	D.0002074.001	Common Intangible Plant				12/31/2023
Aging Technology	TWR SW MN-10713	D.0002078.004	Electric Intangible Plant	(1,583,980)			4/30/2020
Enhance Capabilities	Video Conf SW MN	D.0002082.001	Common Intangible Plant			(2,619,555)	12/31/2022
Aging Technology	BUD-Windows OS Upgrade SW MN	D.0002083.001	Common Intangible Plant			(2,163,726)	12/31/2022
Enhance Capabilities	Software Asset Mgmt SW MN-10729	D.0002084.008	Common Intangible Plant	(1,017,437)			12/31/2020
Enhance Capabilities	Tririga Mobile SW MN-10730	D.0002084.017	Common Intangible Plant	(504,448)			12/31/2020
Aging Technology	2022 Remittance SW MN	D.0002086.001	Common Intangible Plant			(200,608)	12/31/2022
Enhance Capabilities	Data Analytics SW MN	D.0002091.001	Common Intangible Plant			(4,428,288)	12/31/2024
Aging Technology	Product Office Enable SW MN	D.0002103.001	Common Intangible Plant				12/31/2023
Aging Technology	ITSM Modernization SW MN	D.0002104.001	Common Intangible Plant			(3,113,151)	12/31/2022
Enhance Capabilities	ITAM Mod SW MN	D.0002105.001	Common Intangible Plant				12/31/2023
Aging Technology	Purch VOIP Refresh HW MN	D.0002106.001	Common General Plant	(223,105)	(452,885)	(376,078)	12/31/2023
Aging Technology	NMS 2x SW MN	D.0002107.001	Electric Intangible Plant			(6,364,439)	12/31/2022
Aging Technology	Purch Rugged Tablet HW MN	D.0002109.001	Common General Plant	(357,508)	(642,492)		12/31/2021
Aging Technology	Commodity Mgmt Sys SW MN	D.0002110.001	Common Intangible Plant			(1,463,026)	12/31/2022
Aging Technology	SubTran Portal SW MN	D.0002111.001	Electric Intangible Plant		(639,916)		12/31/2021
Enhance Capabilities	Purchase Power SW MN	D.0002113.001	Electric Intangible Plant	(1,306,773)			12/31/2020
Aging Technology	Trans Change Asset SW MN	D.0002119.001	Electric Intangible Plant			(1,036,460)	12/31/2022
Aging Technology	Site Scope SW MN	D.0002126.001	Common Intangible Plant	(240,648)			12/31/2020
Aging Technology	2022 Planned Printer HW MN	D.0002127.001	Common General Plant			(250,000)	12/31/2022
Aging Technology	Bus Obj SW MN	D.0002133.001	Common Intangible Plant		(455,045)		6/30/2021
Enhance Capabilities	Mobile App Mod SW MN	D.0002136.001	Common Intangible Plant	(363,624)			12/31/2020
Aging Technology	Workforce One 2020 Lic MN	D.0002138.005	Common Intangible Plant	(88,510)			12/31/2020
Aging Technology	2023 Planned Printer HW MN	D.0002144.001	Common General Plant				12/31/2023
Aging Technology	2021 Planned Printer HW MN	D.0002145.001	Common General Plant		(125,000)		12/31/2021
Cyber Security	Purch SPAM Filter HW MN	D.0002146.005	Common General Plant		(200,000)		12/31/2021
Enhance Capabilities	Micro Monitor SW MN	D.0002147.001	Common Intangible Plant	(84,030)			12/31/2020
Aging Technology	DRMS PH 2 SW MN	D.0002149.001	Common Intangible Plant		(2,339,677)		12/31/2021
Aging Technology	Tech Lic 2020 SW- MN	D.0002150.001	Common Intangible Plant	(509,232)			12/31/2020
Aging Technology	Tec Lic 2021 SW-MN	D.0002151.001	Common Intangible Plant		(503,072)		12/31/2021
Aging Technology	Tec Lic 2022 SW-MN	D.0002152.001	Common Intangible Plant			(503,345)	12/31/2022
Aging Technology	Tec Lic 2023 SW-MN	D.0002153.001	Common Intangible Plant				12/31/2023
Cyber Security	Purch 2020 Sec Cam HW MN	D.0002154.001	Common General Plant	(175,000)			12/31/2020
Cyber Security	Purch 2022 Sec Cam HW MN	D.0002156.001	Common General Plant			(575,000)	12/31/2022
Aging Technology	Purch 2021 Net Ref HW MN	D.0002157.001	Common General Plant		(1,000,000)		12/31/2021

Aging Technology	Purch 2022 Net Ref HW MN	D.0002158.001	Common General Plant			(1,625,000)	12/31/2022
Aging Technology	Purch 2023 Net Ref HW MN	D.0002159.001	Common General Plant				12/31/2023
Aging Technology	2023 Oracle SW MN	D.0002160.001	Common Intangible Plant				5/1/2023
Aging Technology	OSI Soft PI Ent Agree SW MN	D.0002161.001	Common Intangible Plant				8/31/2023
Enhance Capabilities	Diagnostic Center 5 SW MN-10725	D.0002163.003	Electric Intangible Plant			(603,508)	12/31/2022
Aging Technology	Sharepoint Nuclear EL SW MN only	D.0002164.002	Electric Intangible Plant	(1,236,689)			12/31/2020
Aging Technology	Purch Teradata Hadoop HW MN	D.0002169.001	Common General Plant		(785,228)		12/31/2021
Cyber Security	Security Svc 2022 SW MN	D.0002171.001	Common Intangible Plant			(124,213)	12/31/2022
Aging Technology	2021 EMS Refresh HW MN	D.0002172.001	Electric General Plant		(202,313)		12/31/2021
Aging Technology	2022 EMS Refresh HW MN	D.0002173.001	Electric General Plant			(250,000)	12/31/2022
Aging Technology	BUD-Purch MT Security Servers Nuc M	D.0002174.001	Electric General Plant		(3,286,580)		12/31/2021
Aging Technology	SAP Purge Archive SW MN	D.0002176.001	Common Intangible Plant		(1,346,202)		12/31/2021
Aging Technology	IIB Lic ESB SW MN-10742	D.0002184.002	Electric Intangible Plant	(1,511,097)			12/31/2020
Aging Technology	ITC-Purch IIB ESB EL HW MN	D.0002184.006	Electric General Plant	(36,896)			12/31/2020
Enhance Capabilities	CRS Voice Agent SW MN-10753	D.0002199.003	Common Intangible Plant	(351,006)			12/31/2020
Aging Technology	BUD-ITC-Purch 2020 EMS Infra HW MN	D.0002208.001	Electric General Plant		(127,328)		12/31/2021
Aging Technology	BUD-ITC-Purch 2020 Handheld Mobile	D.0002209.001	Common General Plant		(62,140)		6/30/2021
Aging Technology	BUD-ITC-Purch 2020 IT INFS Ref HW M	D.0002210.001	Common General Plant	(1,893,750)			12/31/2020
Aging Technology	BUD-ITC-Purch 2020 Planned PC HW MN	D.0002211.001	Common General Plant	(2,069,650)			12/31/2020
Aging Technology	BUD-ITC-Purch 2020 Plan Server HW M	D.0002212.001	Common General Plant	(750,000)			12/31/2020
Aging Technology	BUD-ITC-Purch 2020 Storage HW MN	D.0002213.001	Common General Plant	(1,700,000)			12/31/2020
Aging Technology	BUD-ITC-Purch 2020 UnPlan PC HW MN	D.0002215.001	Common General Plant	(600,000)			12/31/2020
Aging Technology	BUD-ITC-Purch 2020 Unplan Server HW	D.0002216.001	Common General Plant	(250,000)			12/31/2020
Aging Technology	BUD-ITC-Purch 2021 Unplan PC HW MN	D.0002217.001	Common General Plant		(600,000)		12/31/2021
Aging Technology	BUD-ITC-Purch 2022 Unplan PC HW MN	D.0002218.001	Common General Plant			(750,000)	12/31/2022
Aging Technology	BUD-ITC-Purch 2023 Plan PC HW MN	D.0002219.001	Common General Plant				12/31/2023
Aging Technology	BUD-ITC-Purch 2023 Unplan PC HW MN	D.0002220.001	Common General Plant				12/31/2023
Aging Technology	BUD-ITC Active Directory 2020 SW MN	D.0002221.001	Common Intangible Plant	(396,684)			12/31/2020
Aging Technology	BUD-ITC-Cust Care IVR SW MN	D.0002223.002	Common Intangible Plant		(1,913,772)		12/31/2021
Enhance Capabilities	BUD-ITC Cust Care Stop Start SW MN	D.0002224.002	Common Intangible Plant			(748,196)	12/31/2022
Aging Technology	BUD-ITC-Purch Data Center HW MN	D.0002225.005	Common General Plant				3/31/2023
Aging Technology	BUD-ITC-DMZ SW MN	D.0002226.002	Common Intangible Plant			(1,748,318)	12/31/2022
Aging Technology	BUD-ITC-GIS SW MN	D.0002227.002	Common Intangible Plant				12/31/2023
Aging Technology	BUD-ITC Integrated Energy Mgmt SW M	D.0002228.002	Electric Intangible Plant				12/31/2023
Aging Technology	BUD-ITC-Internet Explorer SW MN	D.0002229.002	Common Intangible Plant			(1,692,602)	12/31/2022
Aging Technology	BUD-ITC-Purch 2021 Plan Converged H	D.0002230.001	Common General Plant		(2,462,500)		12/31/2021
Aging Technology	BUD-ITC-Purch 2022 Plan Converged H	D.0002231.001	Common General Plant			(2,337,500)	12/31/2022
Aging Technology	BUD-ITC-Purch 2023 Plan Converged H	D.0002232.001	Common General Plant				12/31/2023
Aging Technology	BUD-ITC-Purch 2021 Plan PC HW MN	D.0002233.001	Common General Plant		(2,187,494)		12/31/2021
Aging Technology	BUD-ITC-Purch 2022 Plan PC HW MN	D.0002234.001	Common General Plant			(2,450,007)	12/31/2022
Aging Technology	BUD-ITC-SCCM 2021 SW MN	D.0002235.001	Common Intangible Plant		(522,287)		12/31/2021
Aging Technology	BUD-ITC-Software Defined Data SW MN	D.0002236.002	Common Intangible Plant		(8,439,181)		12/31/2021
Enhance Capabilities	BUD-ITC-TRIRIGA Construction SW MN	D.0002238.002	Common Intangible Plant			(682,376)	12/31/2022
Aging Technology	BUD-ITC-VDI 2020 SW MN	D.0002239.001	Common Intangible Plant	(1,307,332)			12/31/2020
Enhance Capabilities	BUD-ITC-Integrated Financial SW MN	D.0002242.002	Common Intangible Plant				12/31/2023
Customer	BUD-CXT NSPMN	D.0002246.001	Common Intangible Plant	(13,064,636)	(13,588,109)	(12,096,288)	12/31/2022
Enhance Capabilities	BUS SYS Purch Net Equip Crown Wind	A.0001705.006	Electric General Plant	(326,893.46)			7/1/2020
Enhance Capabilities	ITC Purch BUS SYS Net Eq Jeffers WI	A.0001721.002	Electric General Plant	(255,846.65)			11/30/2020
Enhance Capabilities	ITC-Purch BUS SYS Net Eq Comm WIND	A.0001722.002	Electric General Plant	(254,442.97)			11/30/2020

Northern States Power Company
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O&M Costs by Cost Element Account
NSPM Electric

Posting Accou	Description	2016 Actuals	2017 Actuals	2018 Actuals	2019 July Forecast	2020 Forecast	2021 Forecast	2022 Forecast
5540001	Productive Labor	9,445,867.32	11,489,995.52	14,392,160.77	20,013,380.25	26,618,582.03	27,438,069.42	28,245,647.27
5540180	Premium Time Labor	3,664.02	4,407.80	3,534.97	2,321.89			
5540185	Other Compensation Accruals	101,105.02	1,077.65					
5540220	Labor Overtime	156,096.03	180,120.97	231,961.35	82,998.61			
5540260	Other Compensation	16,479.69	13,086.27	28,707.15	16,721.42			
5540270	Welfare Fund				1,150.63			
5600001	Contract Labor	5,702,636.57	7,369,602.20	6,604,799.37	7,647,724.41	7,779,023.98	17,405,908.89	12,932,487.81
5600006	Consulting Professional Services Other	3,812,047.49	1,879,969.09	2,160,301.27	1,563,284.01	1,414,567.55	1,396,813.96	1,403,070.47
5600016	Consulting Professional Eng and Design			3,699.90				
5600021	Consulting Professional Services Legal	2,348.69	11,138.18	96,418.71	80,059.43			
5600031	Consulting Legal Regulatory	(6.45)						
5600041	Outside Vendor Contract	33,000.79	109,172.39	216,815.85	215,683.14	84,985.51	84,985.52	84,985.47
5600051	Outside Services Customer Care	924.77	236.89	1,729.25	198.20			
5600066	Materials	225,406.40	175,940.20	153,838.55	102,931.94	66,971.51	67,119.25	67,268.09
5600069	Service Consumption			2,298.41	2,889.04			
5600070	Material - Direct Purchase			21.61				
5600073	Material Small Cap Purchases	15.90						
5600091	Print and Copy Cost - Other	4,358.66	7,065.35	10,794.62	5,520.10	4,294.61	4,294.61	4,294.61
5600106	Equipment Maintenance	898,701.26	858,020.06	466,173.02	649,508.39	1,109,648.23	1,138,725.21	1,168,610.64
5600116	IT Hardware Maintenance	1,327,486.65	1,367,195.26	2,449,287.07	3,207,812.24	4,415,084.19	6,014,404.92	5,540,848.42
5600121	IT Hardware Purchases	283,075.98	255,842.36	388,866.39	219,516.48	229,586.25	237,827.35	246,269.20
5600126	Software License Purchase - Perpetual	395,562.71	388,398.81	766,721.33	402,055.31	515,519.51	535,916.07	557,128.41
5600131	Software License Purchase - Term	1,838,213.72	2,697,602.55	3,103,080.36	3,832,168.82	4,418,479.60	4,941,501.30	5,382,050.63
5600136	Software Maintenance	16,742,281.24	18,319,353.96	19,912,536.46	20,808,379.47	27,047,680.10	28,289,357.96	28,878,350.24
5600141	Network Services	424,470.01	305,101.08	710,233.46	270,114.88	406,460.31	406,456.33	406,288.96
5600146	Network Voice	3,455,268.09	3,710,632.45	3,501,184.26	3,157,451.10	2,416,631.87	2,426,543.25	2,389,662.89
5600151	Network Data	4,973,833.21	4,486,014.98	5,996,223.92	11,108,871.60	12,356,769.47	12,355,940.41	12,315,150.01
5600156	Network Telecommunication	8,507,920.09	8,623,754.37	6,232,358.54	1,175,169.01	181,761.22	181,991.50	180,531.24
5600161	Network Radio	1,593,947.30	814,638.80	1,680,717.57	1,698,628.97	539,918.98	539,918.85	539,918.97
5600166	Mainframe Services	753,878.57	760,457.86	1,071,116.24	1,262,353.05	1,614,724.91	1,477,614.80	1,477,614.80
5600171	Distributed Systems Services	9,377,993.58	3,718,164.42	2,943,690.32	2,318,769.18	2,107,676.24	2,180,520.86	2,254,847.55
5600176	Application Development and Maintenance	9,740,307.36	8,560,964.78	7,751,183.49	9,806,799.24	9,252,251.15	9,279,977.26	8,990,494.18
5600186	Software - ASP	1,404,737.15	1,101,757.07	733,196.26	1,195,689.89	1,716,581.41	1,757,717.85	1,815,822.59
5600191	Employee Expenses Airfare	107,549.38	110,909.06	156,094.23	191,583.06	180,136.03	183,308.00	186,710.63
5600196	Employee Expenses Car Rental	11,128.32	10,012.97	12,080.71	13,394.85	18,969.96	19,333.29	19,712.81
5600201	Employee Expenses Taxi and Bus	9,845.45	11,867.22	15,570.00	16,413.71	18,204.17	18,510.44	18,819.54
5600206	Employee Expenses Mileage	26,536.61	24,175.29	19,246.46	19,361.76	16,302.29	16,642.41	16,987.00
5600211	Employee Expenses Conf Seminar Trng	85,239.68	136,435.39	75,503.50	85,748.55	110,574.35	113,705.09	115,745.30
5600216	Employee Expenses Hotel	131,614.53	160,492.84	197,294.94	169,974.81	159,597.04	162,233.88	164,975.40
5600221	Employee Expenses Meals	70,528.41	54,983.52	77,853.59	56,239.38	61,651.10	62,586.78	63,546.39
5600226	Employee Expenses Meals Non-Employee	13,209.46	18,986.68	17,492.32	10,540.43	1,992.90	2,021.37	2,049.60

Northern States Power Company
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5600231	Employee Expenses Parking	34,515.04	23,213.79	44,353.20	55,468.73	73,027.39	73,237.04	73,454.51
5600236	Employee Expenses Per Diem	645.33	6,405.12	(113.40)	18.00			
5600241	Employee Expenses Safety Equipment	18,740.05	9,900.05	3,390.25	2,986.35	8,844.08	8,851.56	8,851.56
5600246	Employee Expenses Other	(276,570.85)	72,057.96	58,502.73	61,313.38	42,881.83	42,992.50	43,828.86
5600251	Employee Expense Personal Communication	482,044.55	559,814.79	640,067.13	201,994.58	372,445.66	373,482.95	374,748.26
5600256	Office Supplies	47,921.19	24,466.16	37,807.19	54,440.03	71,887.37	71,969.31	72,052.03
5600261	Workforce Administration Expense	49.69	278.14	35.99				
5600271	Safety Recognition	33,895.88						
5600276	Life Events	2,743.48	2,315.96	3,758.57	2,256.04	942.47	942.47	948.18
5600291	Transportation Fleet Cost	77,020.77	39,452.41	485.00	77,613.19	170,972.06	170,972.06	170,972.06
5600296	Janitorial - Routine				2,951.81	5,903.63	5,903.63	5,903.63
5600306	Fire Life Safety Maintenance		1,467.80	4,218.62	792.92			
5600311	General Interior Exterior Maintenance	50.00	290.33	2,035.83	3,991.68			
5600316	Use Costs	5.37		1,828.06	855.29			
5600336	Trash Removal Costs		50.00					
5600341	Water Use Costs			358.08	204.92			
5600351	Moves Adds Changes	12,112.08	13,929.48	91.17	34,382.58	6,411.88	6,488.33	6,564.78
5600381	Rent - Space	786.50	192.83	169.46	3,541.06	7,082.13	7,082.14	7,082.13
5600382	Rent - Equipment	4,041.48	255.71	1,868.22	1,118.97	1,888.57	1,888.57	1,888.57
5600436	Postage	32,677.84	35,926.93	32,882.30	30,222.07	32,001.75	32,619.19	33,253.76
5600516	Advertising - General			55.48				
5600546	Customer Program - Advertising		58.86					
5600566	Customer Program - Non-Recoverable		99.00					
5600591	Dues - Professional Association	130,296.10	19,037.47	34,348.43	50,129.84	54,320.93	54,575.77	54,830.83
5600596	Dues - Utility Association Other	(1,096.99)	1,500.00	1,000.00	3,000.00			
5600601	Dues - Utility Association		11,650.16		6,556.49			
5600721	Environmental Permits and Fees			198.86				
5600726	License Fees and Permits	4,731.54	56,567.77	12,385.72	5,819.45			
5600778	Removal Salvage	(2,337.25)		(2,079.93)				
5600781	O and M Credits - Other	(5,687.62)						
5600861	Shared Asset Costs	19,965,797.23	24,528,479.80	23,814,823.56	29,537,058.80	38,418,314.92	37,610,104.49	45,733,295.76
5600866	Shared Assets - Owning Co Credit	(27,026,164.78)	(33,166,416.75)	(25,379,661.93)	(27,799,858.36)	(33,870,939.56)	(33,671,599.04)	(34,453,235.86)
5600871	Other	182,335.74	3,539.58	90,363.58	(5,190,565.89)			
5600896	Online Information Services	602,382.50	525,656.25	784,942.39	1,242,211.92	1,045,419.90	1,082,030.27	1,126,956.64
5600951	Purchasing Overhead Expense		(88.48)					
5610000	External Settlement Labor	(89.90)	1,315.47	25,125.59	6,066.44			
5610003	External Settlement Contract Labor	(901.52)	13,296.17	114,072.13	3,425.57			
5610004	External Settlement Consulting	(447.59)	18,629.74	15,116.62	2,897.13			
5610005	External Settlement Contract Outside Ven		303.36	(120.31)	94.04			
5610006	External Settlement Materials	(0.46)	(2.53)	1,370.43	0.77			
5610007	External Settlement Employee Expense	(0.01)	66.70	58.89	1,141.37			
5610008	External Settlement Transportation		(3,852.02)					
5610009	External Settlement Miscellaneous	1,798.10	1,771.50	19,190.96	704.57			
5610011	External Settlement Overhead	37,044.97	191,440.32	5,296.24	(2,160.92)			
8000000	Prod Labor Bargaining Benefit Group 1	(30,410.83)	131,312.69	7,842.24	1,421.76			
8000005	Prod Labor Bargaining Benefit Group 6		(7,966.15)		7.98			
8000020	Prod Labor Non-Bargaining Benefit Grp 1	166,680.99	535,547.20	54,773.61	(61,054.94)			

Northern States Power Company
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8000022	Prod Labor Non-Bargaining Benefit Grp 3	25.75						
8000023	Prod Labor Non-Bargaining Benefit Grp 4	2,071.44	4,798.93	13,175.62	(122.62)			
8000025	Prod Labor Non-Bargaining Benefit Grp 6	(258.84)						
8000037	Productive Labor Non-Barg No Load	(7,126.07)	(1,803.92)	(43.26)	60.58			
8000100	Premium		(9.10)					
8000105	Overtime	1,585.43	21,751.87	488.80	563.39			
8000110	Other Compensation		3,454.18					
8000115	Other Compensation Craft Welfare Fund		(4,331.86)		5.83			
8100000	Non-Prod Labor Bargaining Benefit Grp 1	185,797.37	256,895.24	256,040.07	111,249.95			
8100020	Non-Prod Labor Non-Bargaining Ben Grp 1	1,495,538.35	1,873,789.34	2,213,205.59	1,229,449.62			
8100022	Non-Prod Labor Non-Bargaining Ben Grp 3	1,345.59						
8100023	Non-Prod Labor Non-Bargaining Ben Grp 4	4,984.56	13,068.50	16,920.25	10,439.69			
8100205	AG Overhead	0.59						
8100260	Purchasing - Overhead	140,326.78		213,145.45	153,896.17			
8100315	Warehouse - Overhead	0.03						
8100500	NonProd Bargaining Labor G1_OH Alloc	3,696.27	4,867.22	943.32				
8100502	NonProd NonBarg Labor G1_OH Alloc	31,105.09	4,074.66	21,998.53				
8100530	Purchasing_OH Allocation	(45,631.62)		262,424.10	81,958.48			
8100532	Fleet_OH Allocation	(7,458.89)						
8100533	Warehouse Energy Supply_OH Allocation	199.72						
8100534	Purchasing Nuclear_OH Allocation	(0.08)						
8100540	NonProd NonBarg Labor G3_OH Alloc	(409.32)						
8100541	NonProd NonBarg Labor G4_OH Alloc	676.63	(372.78)	(41.25)				
8100550	Fleet-Base Rates		39,359.37	76,148.08	38,513.55			
	Total	77,978,351.02	73,605,079.47	85,690,032.49	91,378,469.54	111,306,031.47	124,611,488.08	128,731,284.83

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Northern States Power Company
AGIS: AMI and FAN Expenditures

XCEL ENERGY

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	TOTAL	NPV
Total Meters Deployed	*10,131*	*7,368*	*121,800*	*630,000*	*590,000*	*40,700*	*13,755*	*13,890*	*14,027*	*14,164*	*14,304*	*14,444*	*14,586*	*14,729*	*14,874*	*15,020*	*15,168*	***1,558,960***	
CAPITAL COSTS																		***TOTAL DISCOUNTED***	***NSPM-NPV***
Communications Network																			
FAN Bus Sys Costs	1,709	51,120	88,387	59,329	56,142	15,200	0	0	0	0	0	0	0	0	0	0	0	**271,887**	**217,842**
FAN Bus Sys WiMAX Cost	334,633	10,011,076	17,309,267	11,618,600	10,994,506	2,976,466	0	0	0	0	0	0	0	0	0	0	0	**53,244,549**	**42,660,847**
FAN Bus Sys Contingency	73,854	1,267,037	2,253,221	1,166,606	1,103,942	298,863	0	0	0	0	0	0	0	0	0	0	0	**6,163,522**	**4,979,818**
TOTAL - Communications	***410,196***	***11,329,233***	***19,650,875***	***12,844,535***	***12,154,590***	***3,290,528***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***59,679,958***	***47,858,507***
IT Systems and Integration																			
IT Hardware	1,504,080	2,537,978	2,141,049	545,521	556,814	568,340	580,104	0	0	0	0	0	0	0	0	0	0	**8,433,885**	**7,028,256**
IT Software	1,064,115	1,552,117	5,536,877	4,669,670	323,141	0	0	0	0	0	0	0	0	0	0	0	0	**13,145,919**	**10,838,063**
IT Labor + Project Management	1,725,374	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**1,725,374**	**1,621,097**
IT Contingency	0	0	0	11,176,589	605,252	548,564	174,031	0	0	0	0	0	0	0	0	0	0	**12,504,436**	**9,642,915**
TOTAL - IT Systems and Integration	***4,293,568***	***4,090,095***	***7,677,926***	***16,391,780***	***1,485,207***	***1,116,904***	***754,136***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***35,809,615***	***29,130,330***
TOTAL CAPITAL	**4,703,764**	**15,419,328**	**27,328,801**	**29,236,315**	**13,639,797**	**4,407,432**	**754,136**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**95,489,573**	**76,988,837**
O&M ITEMS																			
Communications Network																			
FAN Network Business Systems	0	0	335,766	3,171,422	2,673,589	1,491,278	499,575	671,918	685,827	700,023	714,514	729,304	744,401	759,810	775,538	791,592	807,978	**15,552,536**	**9,460,970**
FAN WiMAX Cost	233,600	357,245	427,150	434,290	562,241	1,048,049	653,607	0	0	0	0	0	0	0	0	0	0	**3,716,182**	**2,782,723**
NOC Opco Allocation	200,000	408,280	625,097	638,037	651,244	664,725	678,485	692,529	706,864	721,497	736,432	751,676	767,235	783,117	799,328	815,874	832,762	**11,473,181**	**6,445,717**
FAN Network Bus Sys Contingency	0	0	301,130	686,305	623,871	517,616	243,271	124,153	0	0	0	0	0	0	0	0	0	**2,496,348**	**1,830,131**
TOTAL - Communications	***433,600***	***765,525***	***1,689,144***	***4,930,054***	***4,510,945***	***3,721,669***	***2,074,937***	***1,488,601***	***1,392,691***	***1,421,520***	***1,450,946***	***1,480,980***	***1,511,636***	***1,542,927***	***1,574,866***	***1,607,466***	***1,640,740***	***33,238,246***	***20,519,541***
IT Systems and Integration																			
IT Hardware	42,114	1,654,282	1,678,585	1,705,324	1,740,624	1,776,655	1,813,432	1,850,970	1,889,285	1,928,393	1,968,311	2,009,055	2,050,642	2,093,091	2,136,418	2,180,642	2,225,781	**30,743,604**	**17,268,781**
IT Software	27,285	85,988	983,487	1,845,314	2,011,390	2,053,026	2,095,523	2,138,900	2,183,176	2,228,367	2,274,495	2,321,577	2,369,633	2,418,685	2,468,752	2,519,855	2,572,016	**32,597,467**	**17,432,600**
IT Labor	0	2,056,405	1,553,273	1,750,246	1,680,090	1,717,226	1,721,011	1,789,073	1,859,799	1,933,290	2,009,656	2,089,007	2,171,461	2,257,136	2,346,156	2,438,653	2,534,759	**31,907,241**	**17,784,018**
Common Corporate Business System development-Allocation	646,904	4,270,861	5,304,505	11,866,886	12,378,199	10,847,247	10,347,121	0	0	0	0	0	0	0	0	0	0	**55,661,724**	**41,239,207**
IT Contingency	0	997,287	9,826,939	4,112,864	2,099,639	2,145,629	2,192,624	2,240,646	2,289,716	2,339,857	2,391,093	2,443,448	2,496,946	2,551,611	2,607,470	2,664,547	2,722,871	**46,123,186**	**28,075,602**
TOTAL - IT Systems and Integration	***716,303***	***9,064,823***	***19,346,789***	***21,280,633***	***19,909,942***	***18,539,783***	***18,169,711***	***8,019,589***	***8,221,975***	***8,429,907***	***8,643,555***	***8,863,087***	***9,088,683***	***9,320,523***	***9,558,795***	***9,803,697***	***10,055,427***	***197,033,221***	***121,800,207***
TOTAL O&M	**1,149,903**	**9,830,348**	**21,035,932**	**26,210,687**	**24,420,887**	**22,261,452**	**20,244,648**	**9,508,190**	**9,614,666**	**9,851,427**	**10,094,500**	**10,344,068**	**10,600,319**	**10,863,450**	**11,133,661**	**11,411,162**	**11,696,167**	**230,271,467**	**142,319,748**
GRAND TOTAL CAPITAL & O&M	**5,853,667**	**25,249,675**	**48,364,733**	**55,447,002**	**38,060,684**	**26,668,884**	**20,998,783**	**9,508,190**	**9,614,666**	**9,851,427**	**10,094,500**	**10,344,068**	**10,600,319**	**10,863,450**	**11,133,661**	**11,411,162**	**11,696,167**	**325,761,039**	**219,308,585**

Northern States Power Company
AGIS: FLISR and FAN Expenditures

XCEL ENERGY

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	TOTAL	NPV	Cost Category
CAPITAL ITEMS - SUMMARY																							
Communications Network																							
FAN Bus Sys Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**	**Direct and Tangible**
FAN Bus Sys WiMAX Cost	62,744	1,877,077	3,245,488	2,178,488	2,061,470	558,087	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**9,983,353**	**7,998,909**	**Direct and Tangible**
FAN Bus Sys Contingency	48,467	831,493	1,478,676	765,585	724,462	196,129	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**4,044,811**	**3,268,006**	**Direct and Tangible**
TOTAL - Communications	**111,210**	**2,708,569**	**4,724,164**	**2,944,073**	**2,785,932**	**754,216**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**14,028,164**	**11,266,914**	
IT Systems and Integration																							
ADMS FLISR Integration	0	372,780	503,962	521,853	1,023,270	1,059,597	807,499	836,165	865,849	896,587	0	0	0	0	0	0	0	0	0	0	**6,887,562**	**4,636,414**	**Direct and Tangible**
IT Contingency	0	0	0	299,788	632,358	654,807	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**1,586,953**	**1,147,107**	**Direct and Tangible**
TOTAL - IT Systems and Integration	***0***	***372,780***	***503,962***	***821,641***	***1,655,629***	***1,714,403***	***807,499***	***836,165***	***865,849***	***896,587***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***8,474,515***	***5,783,521***	
TOTAL CAPITAL	**111,210**	**6,214,857**	**13,637,130**	**10,048,307**	**13,491,578**	**10,910,457**	**7,146,728**	**7,325,662**	**7,509,401**	**7,698,082**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**84,093,414**	**59,596,959**	
O&M ITEMS - SUMMARY																							
Communications Network																							
FAN Network Business Systems	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**	**Direct and Tangible**
FAN WiMAX Cost	43,800	66,983	80,091	81,429	105,420	196,509	122,551	0	0	0	0	0	0	0	0	0	0	0	0	0	**696,784**	**521,761**	**Direct and Tangible**
NOC Opco Allocation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**	**Indirect and Tangible**
FAN Network Bus Sys Contingency	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**	**Direct and Tangible**
TOTAL - Communications	43,800	66,983	80,091	81,429	105,420	196,509	122,551	0	0	0	0	0	0	0	0	0	0	0	0	0	**696,784**	**521,761**	
TOTAL O&M	**43,800**	**66,983**	**80,091**	**81,429**	**105,420**	**196,509**	**122,551**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**696,784**	**521,761**	
GRAND TOTAL CAPITAL & O&M	**155,010**	**6,281,841**	**13,717,220**	**10,129,736**	**13,596,999**	**11,106,966**	**7,269,279**	**7,325,662**	**7,509,401**	**7,698,082**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**84,790,198**	**60,118,719**	

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Exhibit___(DCH-1), Schedule 10
Page 1 of 1

Northern States Power Company
AGIS: IVVO and FAN Expenditures

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	TOTAL	NPV	Cost Categories
Feeders enabled with IVVO	0	0	26	43	61	59	0	0	0	0	0	0	0	0	0	0	0	0	0	0	189		
CAPITAL COSTS																							
Communications Network																							
Communications Operations-IVVO Budget	0	0	61,332	115,547	110,814	104,193	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**391,886**	**293,733**	**Direct and Tangible**
FAN Bus Sys Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**	**Direct and Tangible**
FAN Bus Sys WiMAX Cost	20,915	625,692	1,081,829	726,163	687,157	186,029	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**3,327,784**	**2,666,303**	**Direct and Tangible**
FAN Bus Sys Contingency	16,156	277,164	492,892	255,195	241,487	65,376	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**1,348,270**	**1,089,335**	**Direct and Tangible**
TOTAL - Communications	37,070	902,856	1,636,054	1,096,905	1,039,458	355,598	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**5,067,941**	**4,049,371**	
IT Systems and Integration																						**0**	
Xcel Personnel [ADMS IVVO Integration]	0	0	803,466	1,375,982	2,021,270	2,024,401	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**6,225,118**	**4,611,361**	**Direct and Tangible**
External resources (Consultants, contractors etc.) [GEMS]	0	0	520,914	265,849	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**786,763**	**639,234**	**Direct and Tangible**
GEMS hardware	0	0	104,183	53,170	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**157,353**	**127,847**	**Direct and Tangible**
Varentec PM & Services	0	0	52,091	26,585	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**78,676**	**63,923**	**Direct and Tangible**
IT Project Management	0	0	52,091	26,585	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**78,676**	**63,923**	**Direct and Tangible**
IT Travel Expenses	0	0	10,418	5,317	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**15,735**	**12,785**	**Direct and Tangible**
Security	0	0	104,183	53,170	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**157,353**	**127,847**	**Direct and Tangible**
Continguency	0	0	130,158	158,367	190,817	188,381	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**667,722**	**500,682**	**Direct and Tangible**
Program Management	0	0	104,183	319,018	325,622	332,362	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**1,081,185**	**802,089**	**Direct and Tangible**
TOTAL - IT Systems and Integration	***0***	***0***	***1,881,688***	***2,284,042***	***2,537,708***	***2,545,144***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***9,248,582***	***6,949,692***	
TOTAL CAPITAL	**37,070**	**902,856**	**3,517,741**	**3,380,947**	**3,577,166**	**2,900,742**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**14,316,523**	**10,999,063**	
O&M ITEMS																							
Communications Network																							
On-going Communications Network costs	0	0	0	0	4,920	15,829	25,585	35,371	36,103	36,850	37,613	38,392	39,187	39,998	40,826	41,671	42,533	43,414	44,312	45,230	**567,832**	**250,941**	**Direct and Tangible**
FAN Network Business Systems	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**	**Direct and Tangible**
FAN WiMAX Cost	14,600	22,328	26,697	27,143	35,140	65,503	40,850	0	0	0	0	0	0	0	0	0	0	0	0	0	**232,261**	**173,920**	**Direct and Tangible**
NOC Opco Allocation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**	**Indirect and Tangible**
FAN Network Bus Sys Contingency	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**	**Direct and Tangible**
TOTAL - Communications	***14,600***	***22,328***	***26,697***	***27,143***	***40,060***	***81,332***	***66,435***	***35,371***	***36,103***	***36,850***	***37,613***	***38,392***	***39,187***	***39,998***	***40,826***	***41,671***	***42,533***	***43,414***	***44,312***	***45,230***	***800,094***	***424,861***	
IT Systems and Integration																							
Program Management	0	0	22,576	35,446	36,180	36,929	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**131,132**	**98,245**	**Direct and Tangible**
TOTAL - IT Systems and Integration	***0***	***0***	***22,576***	***35,446***	***36,180***	***36,929***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***131,132***	***98,245***	
TOTAL O&M	**14,600**	**22,328**	**49,273**	**62,590**	**76,240**	**118,261**	**66,435**	**35,371**	**36,103**	**36,850**	**37,613**	**38,392**	**39,187**	**39,998**	**40,826**	**41,671**	**42,533**	**43,414**	**44,312**	**45,230**	**931,225**	**523,106**	
GRAND TOTAL CAPITAL & O&M	**51,670**	**925,184**	**3,567,014**	**3,443,536**	**3,653,406**	**3,019,003**	**66,435**	**35,371**	**36,103**	**36,850**	**37,613**	**38,392**	**39,187**	**39,998**	**40,826**	**41,671**	**42,533**	**43,414**	**44,312**	**45,230**	**15,247,748**	**11,522,169**	

PUBLIC DOCUMENT – NOT PUBLIC DATA HAS BEEN EXCISED
Schedule 11 – Business Systems AMI RFP Results
Schedule 12 – Business Systems FAN RFP Results

Trade Secret Justification

Schedules 11 and 12 are internal assessment summaries that the Company has designated as Trade Secret information in their entirety as defined by Minn. Stat. § 13.37, subd. 1(b). The analysis and information contained therein has not been publicly released. These summaries were prepared by Business Systems and Sourcing employees and their representatives in 2017 (Schedule 11) and 2015 (Schedule 12), in conjunction with the Company's review of hardware and software needs for its Advanced Metering Infrastructure (AMI) and Field Area Network (FAN) projects, respectively. These Schedules contain information regarding bidder responses to requests for proposal (RFPs) issued by the Company, including sensitive pricing and other bid data; the Company's proprietary analysis of selected bids; market intelligence; and potential comparative bidder cost and negotiation planning information. Because these overall analyses derive independent economic value from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain economic value from its disclosure or use, Xcel Energy maintains this information as a trade secret pursuant to Minn. Rule 7829.0500, subp 3.

Direct Testimony and Schedules
Christopher C. Cardenas

Before the Minnesota Public Utilities Commission
State of Minnesota

In the Matter of the Application of Northern States Power Company
for Authority to Increase Rates for Electric Service in Minnesota

Docket No. E002/GR-19-564
Exhibit___(CCC-1)

Customer Care and Bad Debt Expense

November 1, 2019

Table of Contents

Schedules

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Christopher C. Cardenas. I am Vice President of Customer Care for Xcel Energy Services Inc. (XES), which provides services to Northern States Power Company (NSPM or the Company).

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I have more than 20 years of experience in the areas of customer service and finance for energy utilities, cable and telecommunication companies. I joined XES in January 2019, previously serving as Vice President of Customer Services for PPL Electric Utilities in Pennsylvania. In my current position, I am responsible for the overall business performance of the Customer Care organization. Prior to this, I held various customer service and financial leadership roles with Time Warner Cable, Comcast Cable, U.S. Cellular and Sprint Nextel. I have also held various positions in corporate strategy, customer service operations and business development. My resume is provided as Exhibit___(CCC-1), Schedule 1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. My testimony provides an overview of the Customer Care organization and its 2020-2022 Operation and Maintenance (O&M) expense levels. I share ways we measure customer satisfaction for work Customer Care performs. I also present and discuss the Company's commodity and non-commodity bad debt expense, and the actions we have taken to minimize and manage it to the benefit of customers. Finally, I discuss impacts that Advanced Grid Infrastructure and Security (AGIS), and specifically Advanced Metering

Infrastructure (AMI), will have on Customer Care costs, functions, and processes, as well as changes that are needed to facilitate the transition to AMI for customers.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. The Customer Care organization has achieved strong customer satisfaction results, controlled its O&M expenses, and outperformed other utilities in managing bad debt expense. The 2020 test year O&M expense I propose for the Customer Care organization is $33.2 million for the State of Minnesota Electric Jurisdiction. This level of O&M expense continues Customer Care's trend of relatively flat levels of O&M expense since 2016, while continuing to achieve strong results in the Company's service quality measures and high levels of satisfaction with the service we provide our customers.

The 2020 test year bad debt ratio we propose is 0.35 percent, which results in a 2020 test year commodity bad debt expense of $11.3 million, and approximately $80,000 for non-commodity bad debt expense for the State of Minnesota Electric Jurisdiction. In addition to bad debt performance comparing favorably to other utilities, this bad debt ratio is consistent with performance since 2016.

The AGIS initiative is a comprehensive plan that will advance the Company's electric distribution system, provide customers with more choices, and enhance the way the Company serves its customers. Implementation of advanced metering technology and the communications network will enable the availability of detailed and timely data, system automation, and communications enhancements that will impact and provide benefits for our customers and the Customer Care organization. As I will describe below, the process changes enabled by advanced grid implementation will help reduce Customer Care O&M expenses in meter reading, and potentially other areas.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. I present the remainder of my testimony in the following sections:

- *Customer Care Organization.* I discuss my organization in terms of the business functions it provides to the Company and its customers. I also discuss the improvements we have made to various aspects of our service and the research we have done to understand our customers and to measure their satisfaction with the service we provide. In addition, I summarize the Company's service quality results. In this section, I also present the overall Customer Care O&M budget and the budgets by business function.
- *Commodity Bad Debt Expense.* This is the bad debt expense associated with the provision of energy services. I discuss the test year expense and proposed bad debt ratios, as well as how we determine our bad debt ratios and manage our bad debt expense.
- *Non-Commodity Bad Debt Expense.* This is bad debt expense associated with all types of retail customer billing, other than the provision of energy services. I discuss the Company's test year levels of expense, the various components of non-commodity bad debt expense, and what the various business functions do to manage non-commodity bad debt expense.
- *The AGIS Initiative.* I discuss Customer Care's responsibilities with respect to implementation of the Company's proposed AGIS initiative, including meter reading and billing, as well as direct customer contacts

that will support and facilitate AGIS implementation. I also discuss the impacts and benefits of AGIS from the Customer Care perspective, the framework for customer opt-out provisions, and how advanced grid capabilities will enable new products and services for our customers. I also discuss potential impacts to Customer Care operational and customer service metrics, and how the Company plans to track and report progress metrics as AGIS is implemented.

II. CUSTOMER CARE ORGANIZATION

A. Overview

Q. PLEASE SUMMARIZE THIS SECTION OF YOUR TESTIMONY.

A. In this section, I discuss the structure of the Customer Care organization and describe the various functions involved in providing service to the Xcel Energy organization, including NSPM and the other Operating Companies and their customers. I also present the Company's test year O&M expense, and discuss how we have managed to keep O&M expenses relatively flat since 2012 while introducing new customer programs and options and maintaining high levels of customer satisfaction relative to the work Customer Care performs.

Q. PLEASE DISCUSS THE FUNCTIONS OF THE CUSTOMER CARE ORGANIZATION AND HOW THEY RELATE TO THE COMPANY'S OVERALL BUSINESS GOALS.

A. The Customer Care organization performs essential functions that help the Company effectively provide its customers energy products and services and high levels of customer service. We ensure energy use is measured and billed accurately, collect and process customer payments, and assist our customers

Only the testimony necessary to support the Company's Advanced Grid Intelligence and Security (AGIS) Initiative have been included in the Integrated Distribution Plan (IDP) filing. Accordingly, we have excised non-AGIS pages from this attachment.

Table 11
Non-Commodity Bad Debt Expense by Business Area
State of Minnesota Electric Jurisdiction
($ millions)

	Actual Expense			July Forecast	Test Year	Plan Years	
	2016	2017	2018	2019	2020	2021	2022
Customer Care	$0.09	$0.08	$0.08	$0.07	$0.08	$0.08	$0.08
Distribution Operations	$0.60	$0.68	$0.44	$0.19	$0.15	$0.15	$0.15
Total	*$0.69*	*$0.76*	*$0.51*	*$0.27*	*$0.23*	*$0.23*	*$0.23*

Q. HOW DID THE COMPANY DEVELOP THE 2020 THROUGH 2022 NON-COMMODITY BAD DEBT EXPENSE LEVELS?

A. Each of the functions identified above assesses its current reserve in light of expected test year activities, such as expected billing amounts and Company credit policies, and then budgets accordingly.

V. THE ADVANCED GRID INFRASTRUCTURE AND SECURITY INITIATIVE

Q. WHAT INFORMATION DO YOU PROVIDE IN THIS SECTION OF YOUR TESTIMONY?

A. In this section, I discuss Customer Care's responsibilities with respect to implementation of the Company's proposed Advanced Grid Infrastructure and Security (AGIS) initiative. Specifically, Customer Care is responsible for meter reading and billing, as well as direct customer contacts that will support and facilitate AGIS implementation. I discuss the impacts and benefits of

AGIS from the Customer Care perspective. I provide details on how the Customer Care team will manage customer questions and concerns as the AGIS initiative is being deployed, the framework of a customer opt-out option, and how advanced grid capabilities will enable new products and services for our customers. I also discuss impacts to Customer Care operational and customer service metrics, and how the Company plans to track and report progress metrics as AGIS is implemented.

Q. HOW IS THE COMPANY PRESENTING ITS OVERALL SUPPORT FOR THE AGIS INITIATIVE?

A. In addition to my testimony, a discussion of the overall AGIS initiative and customer experience is provided in the Direct Testimony of Mr. Gersack. The budget for AGIS implementation is primarily split between the Distribution Operations and Business Systems areas of the Company, as those areas are responsible for implementing the technologies and systems for the AGIS initiative. Company witnesses Ms. Kelly A. Bloch and Mr. David C. Harkness provide testimony for those business areas, respectively. Mr. Gersack provides support for program management costs and the overall AGIS customer experience. A summary of AGIS cost and benefits analyses are addressed in the Direct Testimony of Company witness Dr. Ravikrishna Duggirala.

Q. HOW IS THIS SECTION OF YOUR TESTIMONY ORGANIZED?

A. I first describe the AGIS initiative and Customer Care's role with respect to implementation. This includes an overview of the impacts, benefits and opportunities associated with AGIS from the Customer Care perspective.

I then discuss our current meter reading technology, what will change with installation of advanced meters, and how that affects meter reading operations.

Next, I discuss how Customer Care will provide support for AGIS during the advanced meter installation phase. While Mr. Gersack describes our overall customer education plan, I discuss how Customer Care will work in conjunction with Customer Communications to ensure customers are informed about the new meters and capabilities, and that we answer all questions as they arise. This includes plans for the Company's contact center as well as the meter installation vendor as it relates to direct contact with our customers. I also discuss the opt-out framework we have developed for customers who choose to decline advanced meter installation.

I then discuss impacts to billing operations and the minimal changes necessary to enable AMI billing. I also discuss how AGIS implementation will enable new capabilities, products and services, and the benefits related to Customer Care and certain other business areas that intersect. I detail which capabilities will be available to customers upon installation of the advanced meters, and which will be enabled through new products or services that will require separate Commission approval. For example, these future filings may address a pre-pay option for customers, use of remote reconnection and disconnection capabilities, or full residential time of use rates. We recognize that these new products and services will require additional filings with the Commission and may involve a stakeholder engagement processes to inform development, but they are important to understand in assessing the potential benefits of AGIS.

I also provide details related to the quantifiable benefits of AGIS implementation that are related to Customer Care. I describe these benefits here to support their inclusion in the Cost Benefit Analysis (CBA) as discussed by Dr. Duggirala.

Finally, I discuss tracking and reporting of Customer Care's operational and quality of service metrics. For those metrics that we expect will be impacted by AGIS implementation, I discuss how the Company plans to track and report these metrics as AGIS is implemented. I also discuss future filings with the Commission and separate proceedings that may be necessary to ensure stakeholder review and input relative to the Company's service quality reporting.

A. AGIS Overview

Q. WHAT IS AGIS?

A. The AGIS initiative is a comprehensive plan that will advance the Company's electric distribution system, provide customers with more choices, and enhance the way the Company serves its customers. AGIS provides the foundation for an interactive, intelligent, and efficient grid system that will be even more reliable and better prepared to meet the energy demands of the future.

Q. TO PROVIDE A FRAMEWORK FOR THE REMAINDER OF YOUR TESTIMONY, PLEASE IDENTIFY THE CORE COMPONENTS OF AGIS THAT WILL IMPACT THE CUSTOMER CARE ORGANIZATION.

A. As outlined in Mr. Gersack's testimony, and discussed in detail in the testimonies of Ms. Bloch and Mr. Harkness, the core components of AGIS that will impact Customer Care are the Advanced Metering Infrastructure (AMI) and the Field Area Network (FAN).

- *AMI* is an integrated system of advanced meters, communication networks, and data processing and management systems that enables secure two-way communication between the Company's business and operational data systems and customer meters. AMI enables timely monitoring and communication between the meter and Advanced Distribution Management System (ADMS) about, among other things, energy usage and outages, and is a necessary first step to better customer data, enhanced customer service, and the addition of applications and options for future energy management and optionality.

- *The FAN* is the communications network that will enable communications between the existing communications infrastructure for the distribution system and the new advanced grid components.

These two components work in conjunction with the foundational ADMS that the Company is currently implementing.

Q. WHAT IS THE OVERALL IMPLEMENTATION SCHEDULE FOR AGIS?

A. As outlined by Mr. Gersack, the Company already has begun limited deployment of AMI and the FAN to support the Company's residential Time of Use (TOU) pilot scheduled to launch in April 2020. To ensure communications are in place for AMI functionality, the FAN deployment precedes AMI by approximately three to six months. Beyond the TOU pilot phase, our present AMI plan for Minnesota is to begin full AMI deployment in 2021 and to conclude in 2024, in anticipation of the end of the support for AMR meters and the end of our present service agreement. Ms. Bloch and Mr. Harkness describe the implementation plan in more detail.

Q. HOW WILL THESE COMPONENTS IMPACT THE CUSTOMER CARE ORGANIZATION?

A. The availability of detailed and timely data, system automation, and communications enhancements, will impact and provide benefits for our customers and the Customer Care organization. As discussed in detail in Mr. Harkness' testimony, work of the Business Systems organization will include integration of AMI with "back office applications," meaning the software applications that support the Company's customer service needs, billing, payment remittance, service order management, outage management, meter reading, and asset inventory lifecycle management applications to utilize the customer data, outage data, and other information supplied by the advanced distribution grid. This will enable changes to current business practices, and positively transform the nature of interactions with our customers.

Further, as I will describe below, the process changes enabled by advanced grid implementation will help reduce Customer Care O&M expenses in meter reading, and potentially other areas.

Q. ARE THERE SPECIFIC COSTS FOR AGIS IMPLEMENTATION IN THE CUSTOMER CARE BUDGET IN THIS CASE?

A. No. The overall budget to implement AGIS is split between the Distribution Operations and Business Systems budgets, which are presented and supported in the testimonies of Ms. Bloch and Mr. Harkness. However, O&M cost reductions attributed to reduced meter reading costs as a result of AGIS implementation are reflected in Customer Care's MYRP O&M budget in this case. I discuss this O&M cost reduction further in the next section.

Q. ARE THERE OTHER QUANTIFIABLE BENEFITS OF AGIS IMPLEMENTATION RELATED TO THE CUSTOMER CARE ORGANIZATION?

A. Yes. As it relates to the Customer Care organization, AMI technology enables cost reductions primarily due to remote connection and disconnection capabilities and improved data and analytics. Specifically, the Company anticipates benefits related to reductions in energy theft, consumption at inactive premises, and uncollectible/bad debt. I address these quantifiable benefits in Section F below, and Dr. Duggirala discusses how these benefits are reflected in the CBA.

Q. ARE THESE COST REDUCTIONS INCLUDED IN CUSTOMER CARE'S MYRP BUDGETS IN THIS CASE?

A. No. Unlike the meter reading O&M expense reduction, these benefits are not anticipated during the term of the multi-year rate plan. In addition, realization of these benefits may require future filings and Commission approvals.

B. Meters and Meter Reading

1. Current Meter Technology and Service Agreement

Q. PLEASE DESCRIBE THE COMPANY'S CURRENT METER TECHNOLOGY AND METER READING SERVICE AGREEMENT.

A. As discussed above, the Company currently uses AMR technology. Meter readings are collected and provided to the Company via a proprietary network by Cellnet. In addition to providing the meter readings, Cellnet owns and maintains the communication network and software used to transmit the readings. Cellnet also owns and maintains meter communication modules which refers to the radio interface that is installed as part of the electric meter. The Company's payments to Cellnet for these services are reflected as O&M expense in our budgets.

The Cellnet AMR system in service in Minnesota is nearing end of life. Cellnet has informed the Company that it will stop manufacturing the AMR meter reading modules and components compatible with the current system in 2022, so there will be no support for ongoing maintenance after that time. Further, our current contract with Cellnet for meter reading services ends at the end of 2025, with an option to extend it through 2026 at increased cost.

Given these circumstances, the Company must plan an electric metering solution for the years 2022 and beyond. Ms. Bloch and Mr. Harkness discuss the Company's approach to this process, our consideration of alternatives, and the additional customer and system benefits enabled by advanced metering technology. Below I describe how the AMI and FAN solutions affect customers through our Customer Care organization.

2. *AMI and Meter Reading Cost Reductions*

Q. PLEASE DESCRIBE, AT A HIGH LEVEL, THE AMI TECHNOLOGY THE COMPANY IS PROPOSING TO IMPLEMENT.

A. AMI is a system of advanced meters, communication networks, and data processing and management systems that enables secure two-way communication between Xcel Energy's business and operational data systems and customer meters. AMI enables timely monitoring and communication about, among other things, energy usage and outages, and is a necessary first step to better customer data, enhanced customer service, and the addition of applications and options for future energy management and optionality.

Q. PLEASE DISCUSS THE CURRENT CELLNET CONTRACT IN LIGHT OF THE PLANNED TRANSITION TO AMI.

A. The current Cellnet contract requires the Company to pay for meter reading services for a minimum of two million (total electric and gas) meters through December 31, 2021. The Company currently has 2.4 million Cellnet meters in service. Beginning in 2022, the Company can reduce meter reading costs when it transitions below two million Cellnet meters as a result of our anticipated AMI deployment schedule. Customer Care's meter reading O&M expenses would decline over time as AMI electric meters are deployed in Minnesota. These reductions are incorporated into our O&M budget in this case.

Q. HOW WILL METER READING CHANGE AFTER AMI DEPLOYMENT?

A. AMI technology will provide for automated meter reading via the Company-owned FAN communications network. There may be instances when a meter is not read by the AMI system, primarily due to network communication issues or meter issues. In these cases, the meter will be manually read, which is the same as we do today when the Cellnet system is unable to communicate with a specific meter. In addition, there may be customers who opt-out of AMI meter installation, which will require that the Company manually read meters for these customers. In the following section, I discuss the Company's plans for allowing customers to opt out of an AMI meter if they choose.

Q. WHAT ARE THE FORECASTED METER READING O&M COST REDUCTIONS ASSOCIATED WITH AMI DEPLOYMENT?

A. The forecasted O&M cost reductions associated with AMI deployment that are reflected in Customer Care's 2020 through 2022 budgets are represented in a separate line item "reduction" based on our forecasted deployment timeline. O&M budget reductions would generally grow over time as meters are deployed, reaching almost $8.9 million in annual savings by 2024. These cost savings are shown in Table 12 below.

Table 12
Anticipated Customer Care O&M Savings in Meter Reading Costs
From AMI Electric Meter Deployment
State of Minnesota Electric

Year	Customer Care O&M Savings	Annual AMI Meter Deployment	Cumulative AMI Meter Deployment
2019	$4,000	8,916	8,916
2020	$95,000	8,584	17,500
2021	$786,000	121,800	139,300
2022	$3,097,000	630,000	769,300
2023	$8,231,000	590,000	1,359,300
2024	$8,875,000	40,000	1,399,300

These reductions are reflected in Customer Care's O&M budget forecasts for 2020-2022 in this case. In Section F, I discuss how the Cost-Benefit analysis presented by Dr. Duggirala incorporates this reduction over the term addressed by the CBA.

C. AMI Installation

1. Customer Care Support for AMI Installation

Q. WHAT ARE CUSTOMER CARE'S PLANS TO SUPPORT AMI INSTALLATION BEGINNING IN 2021?

A. Customer Care is working closely with Customer Communications to support all phases of the Customer Communications and Education Plan (Communications Plan) discussed in Mr. Gersack's direct testimony. This Communications Plan is designed to inform customers before, during, and after AMI deployment regarding what they can expect and how they can use and benefit from AMI.

Q. HOW WILL YOU PREPARE CUSTOMER CARE EMPLOYEES TO PROVIDE SUPPORT TO CUSTOMERS REGARDING THE AMI DEPLOYMENT?

A. Training for Customer Care employees is an important step to enhance customer understanding and satisfaction, as well as reduce customer complaints. In anticipation of AMI deployment in Colorado, we have already developed and started to deliver training to Customer Care employees regarding AMI technology, the benefits for customers, and how it will impact their work. This training will help prepare our employees for Minnesota AMI meter deployment, as well as for deployments in other states, such as Colorado.

Training has been and will continue to be developed and delivered based on an employee's role in the organization, what they need to know to do their job, and when they need to know it. The Company has utilized training experts from inside and outside the organization to create the training developed so far. Training development and delivery is an existing function and competency within the Company today. Customer Care employees receive training throughout the year to perform their jobs well and learn about changes impacting their work to best serve customers. AMI-related training development and delivery will continue as new knowledge needs to be shared over time.

All Customer Care employees will take general AMI program overview training to become familiar with the technology, benefits and general program plan. After that, training will be tailored to an employee's role. For example, a contact center agent would take training regarding the Minnesota TOU pilot, how a customer can opt out of the TOU pilot, and how to handle an AMI-related customer inquiry. Some of the training is universal and applies to AMI implementation in any state. Other training will be targeted to a particular state's deployment and offerings. The training is delivered and assigned through an online Learning Management System (LMS) for efficient delivery and tracking to insure completion within appropriate timeframes.

Q. WHAT EFFORTS WILL THE COMPANY UNDERTAKE TO HELP MITIGATE ANY INCONVENIENCE TO CUSTOMERS DURING AMI DEPLOYMENT?

A. The Communications Plan noted earlier uses an integrated, expansive, and multi-channel approach to reach as many customers a possible. The plan is designed to build awareness of advanced grid capabilities, proactively educate customers about the AMI installation process, and keep customers informed at every stage leading up to installation and during installation. Customer Care is working closely with Customer Communications to provide the necessary information and answer questions when customers contact our call centers. In addition, as I discuss in the next section, we are developing plans with respect to our meter installation vendor as they will also have direct contact with our customers.

Q. WHAT ARE CUSTOMER CARE'S PLANS TO TRACK CUSTOMER FEEDBACK RELATED TO AMI INSTALLATION?

A. I discuss our plans for tracking customer feedback in our service quality reporting in Section G below, along with our plans for tracking call center activity related to AMI installation.

2. *Meter Installation Vendor Support*

Q. HOW DOES CUSTOMER CARE PLAN TO WORK WITH THE METER INSTALLATION VENDOR DURING AMI DEPLOYMENT?

A. The Company is committed to working with our meter installation vendor during AMI implementation to ensure our customers receive excellent service. We recognize that due to the volume of meter installations and the number of customers affected during the AMI deployment phases, the impact goes well beyond that of any other projects we would engage in during the normal course of providing service to our customers. As such, the Company and the meter installation vendor will work together to provide coordinated support and address all customer inquiries and any issues that may arise.

Q. PLEASE DISCUSS AT A HIGH LEVEL THE METER INSTALLATION VENDOR SELECTED BY THE COMPANY.

A. The Company selected Itron as the AMI meter vendor to provide the meters, installation, and project management. Ms. Bloch discusses the Itron selection for AMI meters in her testimony. Itron has extensive experience providing direct customer support during AMI meter deployments. They have worked on projects for several utilities, including Consumers Energy (1.8 million electric and 600,000 gas meter AMI deployment) and British Columbia Hydro (1.8 million electric meter AMI deployment currently in progress). They will also begin work for Nova Scotia Power (500,000 electric meter AMI deployment) in October 2019.

Q. PLEASE DISCUSS HOW THE COMPANY AND METER VENDOR WILL COORDINATE CUSTOMER SERVICE EFFORTS.

A. Itron is committed to working with the Company to address and resolve all customer inquiries related to the new meters throughout deployment. This will involve any communications received via telephone, email, letter, social media, PUC complaint, or other communication channel.

The meter installation vendor will be a key point of contact for the Company's customers during the meter installation process and will have a dedicated call center phone number for Xcel Energy's customers. The various communications and materials we plan to provide to customers prior to and during the installation will include specific directions to ensure our customers have the right contact information so any questions or issues will be resolved as quickly as possible. Our plan is to direct customers to call the vendor with any questions related to installation. However, if the vendor receives calls that should instead be directed to the Company, the vendor will also have the ability to warm transfer calls to the Company. (Warm transfer means the vendor representative would remain on the line to ensure the call is answered and the customer is successfully connected with a live Company agent.) Similarly, the Company will have the ability to warm transfer calls to the meter installation vendor as needed.

3. Opt-Out Provisions

Q. PLEASE DESCRIBE THE OPT-OUT PROVISIONS FOR CUSTOMERS ELECTING TO DECLINE INSTALLATION OF ADVANCED METER TECHNOLOGY.

A. The Company can provide the greatest benefits for all our customers by deploying advanced meters throughout our entire service territory. We also recognize the importance of providing our customers with the opportunity to decline the installation of an advanced meter, or have an advanced meter removed at any time, and discuss how we intend to provide clear information regarding this option.

We intend to provide the option for eligible customers to decline installation of an AMI meter. However, we believe these customers should also pay the cost of doing so in light of standard cost-causation principles. For a customer choosing a non-transmitting meter, the Company would need to manually probe the meter to obtain data for billing and energy use analysis, instead of having an AMI meter transmit meter readings electronically. The full set of data, including interval readings, would still be available to customers and could be used to bill advanced rates, such as time of use. This data would be available on a monthly basis after the readings were manually obtained, but it would not be transmitted at the time the interval readings occurred. This results in incrementally higher metering costs for the customer who opts out of an advanced meter.

Q. HOW DOES OPTING OUT OF AN AMI METER RESULT IN INCREMENTAL COSTS?

A. Primarily, the incremental costs associated with opting out of an AMI meter are due to the need for manual meter readings. This includes the cost to obtain manual meter readings in the field to bill consumption. There would also be incremental cost for field visits to remove a meter that does not communicate meter readings electronically and install an AMI meter for the next customer at that premise, or install a meter that does not communicate meter readings electronically after the initial meter deployment has occurred. We do not believe an additional charge associated with initial meter installation would be required if a customer made this choice prior to or at the time of initial meter deployment.

Q. PLEASE OUTLINE THE PROCESS FOR REQUESTING COMMISSION APPROVAL OF OPT-OUT PROVISIONS.

A. We plan to submit a separate filing with the Commission with our detailed opt-out proposal in 2020. Initial deployment of advanced meters is anticipated to begin in 2021. The timing of our filing will allow enough time for the proceeding to include stakeholder input and final Commission approval so that we can incorporate the necessary information when we begin pre-deployment communications with our customers. Our proposal will include the necessary tariff sheets reflecting the incremental costs and service provisions for customers who decline installation of AMI meters or choose to have the AMI meter removed at any time, as well as any associated rule variances.

D. Billing

Q. HOW WILL AMI IMPLEMENTATION AFFECT CUSTOMER BILLS?

A. AMI billing itself will result in one minor change to the customer bill, which will require a variance from Minn. R 7820.3500 on billing content. Minn. R 7820.3500 (A) requires that a customer's bill include "the present and last preceding meter readings." Customer bills currently include this information, with usage for the billing period determined as the difference between these two meter readings. In contrast, interval billing using AMI technology does not use this method of subtraction to calculate usage; instead, it individually measures consumption at predictable intervals (for example, every 15 minutes) and calculates the total amount to be billed for a given period without reference to the prior billing period. As such, with no other billing format changes, AMI bills will show 0 for the "previous reading," and the "current reading" will show the total energy usage for the billing period.

I note that the Company already bills many larger commercial customers using interval meter readings today, so our billing employees are familiar with this type of billing.

Although the necessary bill format change is limited as described above, with AMI, customers will be provided additional granular information and energy usage data on the MyAccount web portal. For customers opting into potential new services enabled by AMI technology, information may also be provided via other digital channels, which is discussed further in Mr. Gersack's testimony

Q. IS THE COMPANY REQUESTING THIS RULE VARIANCE AS PART OF THIS RATE CASE FILING?

A. No. We plan to submit a separate filing with the Commission requesting approval of the necessary rule variance in 2020. Initial deployment of advanced meters is anticipated to begin in late 2021. The timing of our filing will allow enough time for Commission review and approval prior to commencement of AMI installation.

Q. IS THE COMPANY ALSO CONSIDERING BILL FORMAT CHANGES?

A. Yes. As part of the coordinated customer experience efforts planned in 2020, a team will be re-evaluating the bill format in light of AMI deployment and considering other best practices. As a result, the Company may wish to propose additional bill format changes prior to AMI installation. We may submit a filing encompassing all proposed changes, not only the limited format change that may be required to implement AMI billing itself.

Q. HOW WILL AMI IMPLEMENTATION AFFECT CUSTOMER CARE'S BILLING OPERATIONS?

A. Billing Operations will perform the same work it does today, which is to address exceptions identified by the customer meter data and billing systems because they fall outside of established parameters and require intervention. The volume of meter data and billing exceptions that need to be handled by Billing Operations is expected to increase given the large number of meter exchanges that will occur during meter deployment.

Q. PLEASE DESCRIBE THE ADDITIONAL WORK ANTICIPATED WITH THE METER EXCHANGES.

A. Although the change to the actual customer bill is limited as described above, a typical meter exchange bill can be complex due to the meter being exchanged in the middle of a billing cycle and the manual entry of information. A sample bill showing a typical meter exchange bill is provided as Exhibit___(CCC)-1), Schedule 9.

Q. WHY DO METER EXCHANGE EXCEPTIONS GENERALLY OCCUR?

A. Meter exchange exceptions occur for several reasons, including a final reading that is incorrectly entered from a removed meter, an error in the date noted for the meter exchange, or a meter exchange that occurs during the normal billing window for a premise. An exception requiring intervention is typically flagged using pre-determined system parameters. Once flagged, it is routed to a work queue for review by Billing Operations. This typically happens before a bill is issued to a customer. Rarely, a bill may be issued containing an error. When the Company is notified by a customer of an error, a bill may need to be cancelled and re-issued.

Q. WILL AMI HAVE ANY IMPACT ON CUSTOMER CARE'S METER READING OR BILLING METRICS THAT ARE REPORTED UNDER THE SERVICE QUALITY RULES?

A. As with any comprehensive deployment of meter equipment and systems, the Company expects there may be an impact to meter reading or billing statistics initially during the installation phase, but not over the longer term. As I discuss further in Section G below, we will track and report these statistics using the established service quality reporting process. Any impacts specifically related to AGIS will be addressed in our separate service quality proceedings.

E. Customer Care Benefits

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF AMI IMPLEMENTATION FROM A CUSTOMER CARE PERSPECTIVE AND THE IMPACTS AND BENEFITS TO THE CUSTOMER CARE ORGANIZATION.

A. Initial deployment of advanced meters is anticipated to begin in late 2021. This initial deployment will be heavily focused on "getting the basics right."

For Customer Care, the basics include things like accurate, on-time customer billing, and ensuring we provide meaningful information and resolve any issues for customers about the installation process for new AMI meters.

Building on the basics, Mr. Gersack discusses in more detail how we intend to deploy new products and services, or improve existing services for our customers. We will take a judicious approach to deploying new products and services, focusing on areas where the cost-benefit is the highest, or where the satisfaction value is highest for our customers. Some of these new services impacting Customer Care may include a pre-pay billing option and remote connection and disconnection.

To enable the customer benefits or cost-savings these services would provide, we will need to make separate filings for Commission approval. In the following section I provide information on the quantifiable benefits that these services or AMI implementation, in general, are expected to provide.

Q. HOW WILL THE COMPANY PURSUE THE ADDITIONAL REGULATORY AND TARIFF CHANGES THAT WILL BE NEEDED TO ENABLE THE TRANSITION TO AMI METER TECHNOLOGY?

A. The Company plans to make a separate filing in 2020 to request approval of the rule variance that will be needed to transition to AMI meters.

In addition, to leverage the operational functionality the technology enables, we would also make separate filings for approval of any new products or services that may follow in the future. We recognize there are stakeholders who will have interest in these matters and how any changes affect customers.

We believe it is important to engage in a process to solicit stakeholder perspectives, discuss options, consider implications, and seek consensus; and intend to do so as we contemplate future services.

Q. WHAT ARE THE BENEFITS ASSOCIATED WITH REMOTE CONNECTION AND DISCONNECTION CAPABILITIES ENABLED BY AMI TECHNOLOGY?

A. The ability to remotely connect or disconnect service, when paired with customer protections, provides both cost and convenience benefits. When a customer wants to start service at a single-phase premise today, a field visit is necessary. This involves a fee for the customer and requires someone to be present at the location to meet a Company representative. With remote connection capability, a customer would not need to be present and a lower fee could be possible.

Another scenario where remote capabilities could be beneficial for a customer involves seasonal disconnections, where a customer may want electric service disconnected for a lengthy period of time because a home is unused. Instead of incurring the cost for two field visits to disconnect and reconnect service, a customer could schedule a remote disconnection and reconnection aligned with their occupancy needs. This would save customers money through reduced fees and energy usage and would be more convenient for them.

There would also be benefits when changes in tenants occur. AMI remote disconnection will enable the Company to disconnect electric service between tenants if there was no landlord agreement in place. Today, it is typically cost prohibitive to disconnect the account given the expense to send employees into the field. This is considered part of the line loss factor and can result in electricity being consumed with no responsible party to bill. While this benefit does not reside in Customer Care's O&M budget, Customer Care could positively reduce this loss by changing current business practices through AMI remote disconnection functionality. Remote disconnection and reconnection can also help reduce the cost of an unoccupied retail location for a building owner who has a vacant property that is between tenants as well.

Q. WHAT REGULATORY APPROVALS WOULD BE NEEDED TO IMPLEMENT REMOTE DISCONNECTION AND RECONNECTION OF SERVICE?

A. Use of remote connection/disconnection capabilities of AMI would require a variance from Minn. R 7820.2500, which requires a field visit prior to disconnection of service. This would be to enable the benefits described above related to start, stop, and transfer of service, shut-off between tenants, and seasonal disconnect/reconnect.

Q. DOES THE COMPANY PLAN TO MAKE A FILING TO ENABLE THE BENEFITS OF REMOTE CONNECTION/DISCONNECTION CAPABILITIES?

A. Yes. The Company anticipates submitting this filing in the future, and will include in such a filing a discussion of customer protections and benefits at that time. As I discuss further below, the AMI CBA assumes a level of cost reduction for remote connect/disconnect capabilities beginning in 2023. The Company would make a filing requesting Commission approvals necessary to enable these capabilities, allowing for stakeholder input into proposed changes and service provisions.

Q. ARE THERE OVERALL ADDITIONAL BENEFITS ASSOCIATED WITH REMOTE CONNECTION AND DISCONNECTION CAPABILITIES USED IN CONNECTION WITH NON-PAYMENT?

A. Yes. I note that for customers experiencing payment issues, the Company works to engage with them through proactive contacts, encourages them to seek energy assistance, and tries to establish a payment plan that works with their budget and personal situation. However, in cases where disconnection for non-payment is appropriate, the Company incurs significant costs to disconnect service. These costs are ultimately borne by a combination of the affected customers and the customer base as a whole. In addition, remote reconnection of service would reduce the cost of reconnecting service and enable faster service restoration for disconnected customers. Customer and employee safety would be enhanced as well.

While the Company believes it will be important to consider the use of remote disconnection and reconnection for customer non-payment, we recognize that any proposed changes would need to be addressed in a separate proceeding before the Commission. Implementing remote disconnection through AMI for non-paying accounts would require approval of a variance to Minn. R 7820.2500, as described above, as well as changes to our collection practices. The Company would engage with stakeholders during the development of any processes and procedures the Company would ultimately propose for Commission approval that would leverage these capabilities of the advanced grid.

Q. ARE THERE OTHER CAPABILITIES ENABLED BY AMI THAT PROVIDE ADDITIONAL CUSTOMER CARE BENEFITS?

A. Yes. Improved data and analytics enabled by AMI technology will also help reduce energy theft through better detection and prevention capability, which can provide an overall cost benefit for all of our customers. Today, customers who have been disconnected and try to reconnect their service illegally typically do so by removing the meter, removing the "boots" placed on the meter contacts, and then replacing the meter. This is an extremely unsafe and illegal practice. When AMI technology is in place, remotely disconnecting service will involve opening a disconnection switch on the meter to disconnect power to the customer. However, the meter still has power and can communicate over the network. If a customer removes the meter from the socket to bypass it, the Company would receive a notification flag over the network to indicate meter tampering. This will improve detection of instances where customers illegally bypass our meter to receive electricity without paying for it. These situations require time-intensive identification to detect today, but they can be detected automatically through AMI technology. For safety reasons, however, these situations will still require a physical visit to remedy.

Q. HOW DO ADVANCED GRID CAPABILITIES ENABLE THE PRE-PAYMENT OPTION YOU MENTIONED EARLIER IN YOUR TESTIMONY?

A. The advanced grid enables the Company to offer a pre-payment option due to the frequent energy usage measurements provided by AMI metering, and the ability to remotely disconnect and reconnect service.

Q. WHAT ARE THE BENEFITS OF OFFERING CUSTOMERS A PRE-PAY OPTION?

A. The main direct benefits for customers are fewer missed payments and no late payment fees, helping customers save money on their energy bills, and giving them greater control. Utility companies benefit from fewer missed payments, reduced costs for disconnections due to non-payment, and generally reduced costs and financial risk, which ultimately also benefit our customers. Several other utilities offer this option to customers, including Salt River Project, Alabama Power, APS, and Consumers Energy.

Q. DOES THE COMPANY ANTICIPATE OFFERING THIS PAYMENT OPTION TO CUSTOMERS?

A. Yes. The Company would like to offer a pre-payment option in the future enabled by our proposed investments in advanced grid technology and plans to include a detailed proposal in a future regulatory filing.

F. Quantifiable Benefits

Q. WHAT INFORMATION DO YOU PROVIDE IN THIS SECTION?

A. In this section, I discuss the quantifiable benefits of AGIS implementation that are related to Customer Care. I describe these benefits here to support their inclusion in the CBA as discussed by Dr. Duggirala. These benefits include:

- Reduction in meter reading costs;
- Reduction in the amount of energy theft;
- Reduced consumption at inactive premises; and
- Reduced uncollectible/bad debt.

Although the reduction in energy theft and reduced consumption at inactive premises would not impact Customer Care's O&M budget, these benefits are related to Customer Care operations and processes so are discussed in my testimony. The bad debt O&M expense reduction would impact Customer Care's O&M budget, but is not included in our budget in this case because these benefits are assumed to begin after the multi-year rate plan period. Additionally, to enable the necessary capabilities to realize the reduction in the amount of energy theft and bad debt expense, the Company would need to submit separate filings with the Commission.

Q. HOW DID THE COMPANY QUANTIFY THE REDUCTION IN METER READING EXPENSES?

A. First, I note that the reduction in meter reading O&M expense is reflected in the Customer Care O&M rate case budget forecast. This is due to AMI implementation that will begin during the multi-year rate plan.

Q. ARE THESE O&M REDUCTIONS REFLECTED IN THE AMI CBA?

A. Yes, but not as a separate line item. The CBA presented by Dr. Duggirala essentially looks at AMI costs and benefits compared to a reference case scenario, which is an AMR drive-by basic alternative. In other words, by implementing AMI, the Company will avoid costs associated with the alternative of replacing the current AMR Cellnet meter reading services with another service or potential drive-by meter reading option. This is a fixed benefit value calculated at the time the CBA analysis was done. The amount represents an avoided cost of a potential AMR basic alternative, besides AMI investment, since the current Cellnet system requires replacement in any case, as I discussed earlier. In this way, the meter reading O&M cost reduction is reflected in the CBA, not as cost reduction or "benefit" of AMI itself, but rather, as it is incorporated into the cost of the AMR alternative.

The avoided O&M meter reading expense was calculated by comparing the projected costs to replace the Cellnet system with a drive-by AMR solution. These reductions are included in the AMI cost benefit analysis as shown in Exhibit___(CCC-1), Schedule 10.

Q. HOW DID THE COMPANY QUANTIFY THE REDUCTION IN ENERGY THEFT?

A. As described above, the improved data and analytics enabled by AMI technology will help reduce meter tampering and energy theft through better detection and prevention capability, which can provide an overall benefit for all of our customers. To differentiate these instances more quickly from dead and malfunctioning meters, the Company will use an analytics software that enables frequent recording of energy consumption and detect anomalous patterns of energy resulting from theft and tampering. The Company will proceed to change the meter or make field adjustments and bring the situation to a normal condition, and will then bill and charge to customers the appropriate unbilled estimates.

To quantify these benefits, the Company estimated the reduction in the amount unbilled energy. We based this estimate on average sales for the five-year period 2014-2018. Industry organizations, such as EEI, estimate between 1 percent and 2 percent of revenue is lost to tampering and theft. Because there is no way to actually track this amount, the Company used 1 percent to provide a conservative estimate of lost revenue due to tampering and theft. Using the estimated amount of lost revenue, the Company's benefit calculation provides a conservative estimate of 0.1 percent (residential) and 0.15 percent (small C&I) reduction in unbilled energy. In other words, the Company anticipates the estimated lost revenue amount will decrease by these percentages. As a comparison, the Company also looked at Ameren Illinois' business case for AMI implementation. Our estimate is consistent with Ameren's energy theft reduction estimate.

As noted above, this benefit does not result in a reduction to the Customer Care budget, but rather an overall reduction to costs for energy that would not be offset by revenue. These reductions are included in the AMI cost benefit analysis as shown in Schedule 10.

Q. HOW DID THE COMPANY QUANTIFY THE REDUCTION IN CONSUMPTION ON INACTIVE METERS?

A. This benefit is related to electric consumption during a gap between two separate user accounts and the process to disconnect and connect service between tenants or owners. With the remote connect/disconnect capability; the Company will reduce usage on inactive meters.

To quantify these benefits, the Company calculated the average cost of consumption on inactive meters between the years 2014 through 2018, and estimates a 20 percent benefit. We believe this is a conservative benefit estimate.

As a comparison, the Company also looked at Ameren's business case for AMI implementation, which included a 56 percent reduction in consumption on inactive meters. Xcel Energy took a conservative approach for this benefit estimate due to Minnesota's Cold Weather Rule and the assumption that the Company will continue with its current practice, choosing not to disconnect residential heat-affected premises in the winter. With Minnesota's cold weather disconnection rules in effect between October 15 and April 15 (six months of the year), we believe a conservative benefit estimate would be half of Ameren's estimated benefit. This assumption is based, in part, on the difference between Illinois and Minnesota winter disconnection rules. The Illinois winter disconnection rule applies only if a customer is an electric heat customer and electricity is the customer's primary heat source. Additionally, the period it is in effect is shorter in duration than Minnesota's and does not apply to premises that do not have a responsible party. Even though not entirely comparable, our comparison with Ameren's estimate is informative. Further, our benefit estimate also assumes the Company would not use remote disconnection when there is a gap between tenants of less than three days. For these reasons, we believe our 20 percent benefit estimate is conservative.

As noted above, this benefit does not result in a reduction to the Customer Care budget, but rather an overall reduction to costs for energy that would not be offset by revenue. These reductions are included in the AMI cost benefit analysis as shown in Schedule 10.

Q. HOW DID THE COMPANY QUANTIFY THE POTENTIAL REDUCTION IN COMMODITY BAD DEBT EXPENSE?

A. Due to the manual nature of the existing disconnect for non-payment process, the Company is not able to complete all the physical disconnections for non-payment orders issued in a given year. As described above, the Company plans to propose the use of the AMI remote disconnect capabilities in the future as approved by the Commission, with input from stakeholders. This would result in a reduction in commodity bad debt expense.

To quantify these benefits, the Company calculated the average commodity bad debt expense between the years 2014 through 2018, and estimates that an 8 percent reduction in residential customer commodity bad-debt expense could be realized. This estimate is consistent with data provided to the Federal Energy Regulatory Commission in other utilities' pre- and post-AMI deployment reporting. We looked at eight utilities comparable to Xcel Energy and calculated the average commodity bad debt expense reduction, comparing their post-AMI deployment reports to pre-AMI deployment reports. Our estimate is consistent with the average. I also note that the remote disconnect capability may also reduce non-commodity bad debt expense, but non-commodity bad debt makes up only a small portion of Customer Care's bad debt expense. Regardless, we have not assumed any benefit associated with non-commodity bad debt expense in the CBA.

As described above, with the necessary regulatory approvals, these benefits would be reflected in Customer Care's O&M budgets in the future as a reduction in bad debt expense. These reductions are included in the AMI cost benefit analysis as shown in Schedule 10.

G. Metrics and Reporting

Q. WHAT INFORMATION DO YOU PROVIDE IN THIS SECTION?

A. In this section I discuss the tracking and reporting of Customer Care's operational and quality of service metrics. For those metrics that we expect will be impacted by AGIS implementation, I discuss how the Company plans to track and report these metrics as AGIS is implemented. I also discuss our future service quality filings with the Commission, as we believe those proceedings provide the appropriate venue to ensure stakeholder input relative to the Company's service quality reporting.

Q. HOW DOES THE COMPANY CURRENTLY REPORT SERVICE QUALITY METRICS?

A. Like other utilities, the Company reports service quality metrics under Minn. R 7826, Electric Utility Standards, on safety, reliability, and service quality. The Company also has a Quality of Service Plan (QSP)[7] that includes additional metrics, specifies thresholds, and includes penalties for performance not meeting the thresholds. Our service quality tariff was established and has evolved over many years in proceedings before the Commission, and is the result of extensive stakeholder input and agreements. Given the process to establish those metrics and baseline performance thresholds, we propose to address any changes in a separate proceeding to allow for full stakeholder review and input on any changes that may be necessary.

Q. HOW DOES THE COMPANY EXPECT AMI DEPLOYMENT AND AMI FUNCTIONALITY WILL IMPACT THE CUSTOMER CARE SERVICE QUALITY METRICS?

A. We believe several metrics related to Customer Care in the Company's QSP may be impacted and should be reviewed and re-evaluated in light of an AMI deployment. The QSP metrics that could be impacted both during and after AMI rollout include: customer complaints; billing accuracy and timeliness; and telephone response time. Ms. Bloch discusses potential impacts to QSP metrics related to Distribution Operations in her testimony.

[7] See the Company's Minnesota Electric Rate Book, Section 6, General Rules and Regulations, Subsection 1.9, Service Quality.

Q. HOW COULD THE LEVEL OF CUSTOMER COMPLAINTS, AS MEASURED BY THE CUSTOMER COMPLAINT QSP METRIC, BE IMPACTED BY AMI DEPLOYMENT AND ENABLING AMI FUNCTIONALITY?

A. The Company will carefully plan and seeks to deliver a seamless and easy experience for customers as they receive their new electric meter and understand and use the information and insights it will provide. However, we recognize that some customer dissatisfaction, resulting in increased customer complaints, could occur as we visit 1.4 million customer premises to exchange electric meters. This meter deployment is not business as usual.

Q. DESCRIBE HOW THE CUSTOMER COMPLAINT QSP METRIC IS CALCULATED AND HOW IT WORKS TODAY.

A. Currently, the Company has a limit on the number of complaints per customer that can be filed with the Commission in a year. Exceeding the complaint limit of 0.2059 complaints per 1,000 customers carries a $1 million fine annually. The number of customers in this metric is measured by the total number of natural gas and electric meters reported annually to the Commission.

The complaint limit is based on historical performance, reflects past business practices, and does not consider fault. Every complaint filed by a customer counts against the Company's annual limit, regardless of whether the Company adhered to rules, tariffs, and reasonable business practices, or whether the complaint otherwise has any merit.

Q. HOW DOES THE COMPANY EXPECT AMI IMPLEMENTATION MAY IMPACT THE NUMBER OF CUSTOMER COMPLAINTS?

A. While the Company has not exceeded the complaint limit since the QSP has been in place, we believe this significant initiative to convert to AMI meters warrants consideration of how complaints will be counted against a QSP limit both during and after deployment. The Company has created complaint-type codes related to AMI that could be used for tracking AMI-related complaints during deployment. This could be used to monitor and exclude these complaints from the QSP limit during meter deployment. In addition, complaint levels could be impacted beyond meter deployment, especially concerning potential changes to collections practices if such changes are approved by the Commission through a later filing.

Q. HOW COULD BILLING ACCURACY AND TIMELINESS METRICS, AS MEASURED BY THE INVOICE ACCURACY AND INVOICE ADJUSTMENT TIMELINESS QSP METRICS, BE IMPACTED BY AMI DEPLOYMENT?

A. The large volume of meter exchanges that will occur during a mass meter deployment will generate billing exception work requiring manual intervention as described earlier. Exception work is normal and occurs during the course of business today. However, the volume of meter exchanges that will occur during AMI deployment and the time required to process the resulting exceptions could impact both the invoice accuracy and invoice adjustment timeliness metrics.

The Company believes that invoice accuracy and invoice adjustment timeliness could be impacted during deployment, but should not be impacted following that timeframe. The Company believes an exclusion to the QSP penalty for these two metrics may be appropriate during the deployment window. The Company could still report performance during the deployment for trending and transparency. The Company will closely monitor Billing Operations work during meter deployment and will determine whether staffing increases may be warranted.

Q. HOW COULD TELEPHONE RESPONSE TIME, AS MEASURED BY THE TELEPHONE RESPONSE TIME QSP METRIC, BE IMPACTED BY AMI DEPLOYMENT?

A. The telephone response time QSP metric measures the percent of calls into the Company's contact centers or business office that are answered within 20 seconds during a year.

While customers will be advised to contact the meter deployment vendor regarding meter deployment issues, we recognize that some customers will contact the Company's customer service number instead. This could increase call volume and impact telephone response time during meter deployment, which could adversely impact the telephone response time metric. It is also reasonable to assume that customers may have questions regarding their new meter, its functionality and how to use it, as well as any new rates that may impact them.

While there may be impacts to telephone response time during and after deployment, the level of that impact is not known at this time. Customer education is being carefully planned to inform customers about their new meter and its benefits to help answer questions at the time they are most likely to have them. A digital experience, including a customer portal, will be deployed for customers to use and interact with their enhanced usage data and insights as well. Mr. Gersack discusses the customer education plan and customer portal functionality.

The Company will monitor call center volume and performance and will make every effort to maintain the prompt telephone response time our customers receive from us today, which may require staffing increases not included in O&M budgets today. The Company proposes to address call center response time in our service quality report, to the extent this QSP metric may be impacted as we move through the AMI deployment process and actual deployment impacts become better known.

H. AGIS Customer Care Summary

Q. PLEASE SUMMARIZE YOUR TESTIMONY AS IT RELATES TO CUSTOMER CARE'S RESPONSIBILITIES WITH RESPECT TO IMPLEMENTATION OF THE AGIS INITIATIVE.

A. Implementation of the AGIS initiative, and specifically advanced metering technology and the communications network, will enable the availability of detailed and timely data, system automation, and communications enhancements that will impact and provide benefits for our customers and the Customer Care organization. The process changes enabled by advanced grid implementation will help reduce Customer Care O&M expenses in meter reading, and potentially other areas. Customer Care has plans in place with respect to customer service, meter reading, and billing during AMI deployment and beyond as future advanced grid capabilities are enabled.

Q. PLEASE SUMMARIZE THE COMPANY'S PLANS WITH RESPECT TO FUTURE FILINGS NECESSARY FOR AMI IMPLEMENTATION, AS WELL AS THOSE TO ADDRESS FUTURE CAPABILITIES AND IMPACTS OF AGIS.

A. The Company intends to submit the following future filings requesting necessary Commission approvals and eliciting stakeholder input:

- Opt-out provisions – requesting approval of the processes, cost structure, and tariffs necessary to allow customers to opt out of AMI meter installation (2020);
- AMI billing – requesting approval of a rule variance and any tariff changes necessary to enable AMI interval billing (2020);
- Future filing to enable remote connect/disconnect capabilities;
- Future filing to request approval of a pre-pay option for customers; and
- Future service quality reporting under Minnesota Rules (beginning April 1, 2022) and the Company's QSP (beginning May 1, 2022) to address any impacts to service quality metrics as a result of AGIS implementation.

VI. CONCLUSION

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. The Customer Care organization continues to achieve strong customer satisfaction results and effectively manage its O&M expense levels. It continues to perform favorably to other electric utilities in managing bad debt expense and the cost to perform overall Customer Care functions. Therefore, the Customer Care organization's overall O&M expenses, including commodity and non-commodity bad debt expense, are reasonable and should be approved. Finally, Customer Care is preparing to realize the benefits of

AMI deployment through reduced O&M costs for meter reading and improved service offerings to customers.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Résumé

Christopher C. Cardenas
Vice President, Customer Care
Xcel Energy
1800 Larimer Street, Suite 1500, Denver, Colorado

Current Responsibilities (2019 - Present)

Provides leadership and direction for the Company's customer care functions, including meter reading, field collection, billing, credit and collection, customer contact centers, and related business support functions.

Previous Positions

PPL Electric Utilities
2014 - 2018 Vice President, Customer Services

Time Warner Cable
2012 – 2014 Vice President, Customer Service Operations

Comcast Cable
2011 – 2012 Director, Customer Service

U.S. Cellular
2007 – 2010 Director, Customer Service Operations

Sprint
2001 – 2007 Senior Manager, Business Customer Support

Education

Bachelor's Degree, Business Administration in Finance, Texas Lutheran University; Master's Degree, Business Administration (Finance emphasis), Webster University

Business / Industry Activities

Chair, Customer Service Committee for Association of Edison Illuminating Companies (AEIC); Advisory Board, J.D. Power (Electric Utility Industry); Advisory Board, CS Week; Advisory Board, Utility Analytics Institute

Xcel Energy®
RESPONSIBLE BY NATURE®

NORTHERN STATES POWER COMPANY

SERVICE ADDRESS	ACCOUNT NUMBER		DUE DATE
CUSTOMER NAME STREET ADDRESS CITY ST ZIP CODE	51-1234567-8		08/06/2019
	STATEMENT NUMBER	STATEMENT DATE	AMOUNT DUE
	666666666	07/10/2019	$57.81

YOUR MONTHLY ELECTRICITY USAGE

DAILY AVERAGES	Last Year	This Year
Temperature	76° F	73° F
Electricity kWh	0.0	16.8
Electricity Cost	$0.39	$2.57

QUESTIONS ABOUT YOUR BILL?

See our website: xcelenergy.com
Email us at: Customerservice@xcelenergy.com

Call Mon - Fri 7 a.m.-7 p.m. or Sat 9 a.m.-5 p.m.

Please Call: 1-800-895-4999
Hearing Impaired: 1-800-895-4949
Español: 1-800-687-8778

Or write us at: XCEL ENERGY
PO BOX 8
EAU CLAIRE WI 54702-0008

Like us on Facebook Follow us on Twitter YouTube

SUMMARY OF CURRENT CHARGES (detailed charges begin on page 2)

Electricity Service	06/14/19 - 07/09/19	421 kWh	$64.36
Current Charges			**$64.36**

ACCOUNT BALANCE *(Balance de su cuenta)*

Previous Balance	As of 06/14	$563.95
Payment Received	Check 06/26	-$563.95 **CR**
	Check 06/18	-$6.55 **CR**
Balance Forward		**-$6.55 CR**
Current Charges		$64.36
Amount Due *(Cantidad a pagar)*		**$57.81**

028400 1/2

INFORMATION ABOUT YOUR BILL

Thank you for your payment.

Call *before* you move

If you're moving, remember to contact us in advance so we can stop your natural gas and electricity billing at your current address and start service, if needed, at your new one. Save yourself money and ensure a smooth transition to your new place. Please call or submit your changes at xcelenergy.com up to 45 days in advance.

RETURN BOTTOM PORTION WITH YOUR PAYMENT • **PLEASE DO NOT USE STAPLES, TAPE OR PAPER CLIPS**

Xcel Energy®

ACCOUNT NUMBER	DUE DATE	AMOUNT DUE	AMOUNT ENCLOSED
51-1234567-8	08/06/2019	$57.81	

Please see the back of this bill for more information regarding the late payment charge. Pay on or before the date due to avoid assessment of a late payment charge.
Make your check payable to XCEL ENERGY

AUGUST

S	M	T	W	T	F	S
				1	2	3
4	5	6	7	8	9	10
11	12	13	14	15	16	17
18	19	20	21	22	23	24
25	26	27	28	29	30	31

11

------ manifest line ---------

CUSTOMER NAME
STREET ADDRESS
CITY ST ZIP CODE

XCEL ENERGY
P.O. BOX 9477
MPLS MN 55484-9477

31 0000000643600000005781

Xcel Energy®

SERVICE ADDRESS	ACCOUNT NUMBER		DUE DATE
CUSTOMER NAME STREET ADDRESS CITY ST ZIP CODE	51-1234567-8		08/06/2019
	STATEMENT NUMBER	STATEMENT DATE	AMOUNT DUE
	666666666	07/10/2019	$57.81

SERVICE ADDRESS: STREET ADDRESS CITY ST ZIP CODE
NEXT READ DATE: 08/09/19

ELECTRICITY SERVICE DETAILS

PREMISES NUMBER: 300000000
INVOICE NUMBER: 0777777777

METER READING INFORMATION			
METER 66666666	Read Dates: 06/14/19 - 06/14/19 (0 Days)		
DESCRIPTION	CURRENT READING	PREVIOUS READING	USAGE
Total Energy	26175 Actual	26175 Estimate	0 kWh

METER READING INFORMATION			
METER 999999999	Read Dates: 06/14/19 - 07/09/19 (25 Days)		
DESCRIPTION	CURRENT READING	PREVIOUS READING	USAGE
Total Energy	421 Actual	0 Actual	421 kWh

ELECTRICITY CHARGES — RATE: Residential Service

DESCRIPTION	USAGE UNITS	RATE	CHARGE
Basic Service Chg			$6.67
Energy Charge Summer	421 kWh	$0.103010	$43.37
Fuel Cost Charge	421 kWh	$0.026318	$11.08
Decoupling Adj	421 kWh	- $0.001625	- $0.68 **CR**
Res Savers Switch AC			- $8.18 **CR**
Affordability Chrg			$0.81
Resource Adjustment			$3.02
Subtotal			**$56.09**
City Fees			$3.75
Transit Improvement Tax		0.50%	$0.30
County Tax		0.15%	$0.10
State Tax		6.875%	$4.12
Total			**$64.36**

INFORMATION ABOUT YOUR BILL

For an average residential customer, 51% of your bill refers to power plant costs, 11% to high voltage line costs and 38% to the cost of local wires connected to your home.

THANKS, MINNESOTA.

Our Minnesota customers have electric bills that are 22 percent lower than the national average. Thank you for supporting our investments in clean energy and participating in our energy efficiency programs.

Learn more at **xcelenergy.com/KeepingCostsLow**.

Northern States Power Company

XCEL ENERGY

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	TOTAL	NPV
Total Meters Replaced	*10,131*	*7,368*	*121,800*	*630,000*	*590,000*	*40,700*	*13,755*	*13,890*	*14,027*	*14,164*	*14,304*	*14,444*	*14,586*	*14,729*	*14,874*	*15,020*	*15,168*	***1,558,960***	
O&M ITEMS																			
Avoided O&M Meter Reading Costs																			
Drive-by Meter Reading Cost - O&M	2,155	86,393	1,085,789	2,460,063	3,740,671	3,587,859	4,153,792	4,287,938	4,426,475	4,562,493	4,702,691	4,847,197	4,996,143	5,149,667	5,307,907	5,471,011	5,639,126	**64,507,370**	**33,455,306**
TOTAL - Reduction in Meter Reading Costs	***2,155***	***86,393***	***1,085,789***	***2,460,063***	***3,740,671***	***3,587,859***	***4,153,792***	***4,287,938***	***4,426,475***	***4,562,493***	***4,702,691***	***4,847,197***	***4,996,143***	***5,149,667***	***5,307,907***	***5,471,011***	***5,639,126***	***64,507,370***	***33,455,306***
TOTAL O&M BENEFITS	**2,155**	**86,393**	**1,085,789**	**2,460,063**	**3,740,671**	**3,587,859**	**4,153,792**	**4,287,938**	**4,426,475**	**4,562,493**	**4,702,691**	**4,847,197**	**4,996,143**	**5,149,667**	**5,307,907**	**5,471,011**	**5,639,126**	**64,507,370**	**33,455,306**
OTHER BENEFITS																			
Cost reductions																			
Reduced Consumption on Inactive Meters	0	0	0	0	350,052	714,596	1,458,776	1,488,973	1,519,795	1,551,255	1,583,366	1,616,141	1,649,595	1,683,742	1,718,595	1,754,170	1,790,482	**18,879,538**	**9,235,364**
Reduced Uncollectible / Bad Debt Expense	0	0	0	0	259,816	538,078	1,114,360	1,153,920	1,194,884	1,237,303	1,281,227	1,326,711	1,373,809	1,422,579	1,473,081	1,525,375	1,579,526	**15,480,670**	**7,493,278**
Theft / Tamper Detection & Reduction	0	0	0	0	847,310	1,729,700	3,531,009	3,604,101	3,678,706	3,754,855	3,832,580	3,911,915	3,992,891	4,075,544	4,159,908	4,246,018	4,333,911	**45,698,446**	**22,354,455**
TOTAL - Cost Reductions	0	0	0	0	1,457,178	2,982,374	6,104,146	6,246,994	6,393,385	6,543,412	6,697,173	6,854,766	7,016,295	7,181,865	7,351,584	7,525,563	7,703,918	***80,058,654***	***39,083,097***
TOTAL OTHER BENEFITS	**0**	**0**	**0**	**0**	**1,457,178**	**2,982,374**	**6,104,146**	**6,246,994**	**6,393,385**	**6,543,412**	**6,697,173**	**6,854,766**	**7,016,295**	**7,181,865**	**7,351,584**	**7,525,563**	**7,703,918**	**80,058,654**	**39,083,097**
GRAND TOTAL BENEFITS	**2,155**	**86,393**	**1,085,789**	**2,460,063**	**5,197,849**	**6,570,233**	**10,257,938**	**10,534,932**	**10,819,860**	**11,105,905**	**11,399,864**	**11,701,963**	**12,012,439**	**12,331,532**	**12,659,491**	**12,996,574**	**13,343,044**	**144,566,024**	**72,538,404**

Direct Testimony and Schedules
Ravikrishna Duggirala

Before the Minnesota Public Utilities Commission
State of Minnesota

In the Matter of the Application of Northern States Power Company
for Authority to Increase Rates for Electric Service in Minnesota

Docket No. E002/GR-19-564
Exhibit___(RD-1)

Advanced Grid Cost Benefit Analysis

November 1, 2019

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Schedules

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Ravikrishna Duggirala. I am the Director of Risk Strategy for Xcel Energy Services Inc. (XES), the service company affiliate of Northern States Power Company, a Minnesota corporation (NSPM or the Company) and an operating company of Xcel Energy Inc. (Xcel Energy).

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I joined Xcel Energy in 2002, and have held my current position, in which I am responsible for Enterprise Risk Management, Asset Risk Management, risk analytics, and modeling, since 2008. Previously, I was the Manager of Energy Sales Risk for XES, where I was responsible for retail sales risk analysis, key risk analysis, sensitivity analysis, and risk analytics. I was also a Risk Consultant at Xcel Energy between 2002 and 2005. I received my Ph.D in Engineering from Purdue University in 1996, and my Master's Degree in Business Administration from Washington University in St. Louis in 2000. My Statement of Qualifications is provided as Exhibit___(RD-1), Schedule 1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my Direct Testimony is to present the Company's overall assessment of the costs and quantifiable benefits of the future components of its Advanced Grid Intelligence and Security (AGIS) initiative. I present the structure of the Company's overall cost benefit model, which is provided with the Company's AGIS supporting files compact disc in Volume 2B of this filing. I identify its purpose as one tool to utilize in assessing the quantifiable costs and benefits of the Company's overall plans for the AGIS initiative. I also support specific types of benefits in the model, which include avoided peak capacity and customer savings resulting from the implementation of time-of-use rates with our Advanced Metering Instructure (AMI) component of AGIS. Additionally, I summarize some of the qualitative benefits that are difficult to capture in a quantitative model.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. My testimony supports the Company's cost benefit model for the AGIS initiative, which was required by the Minnesota Public Utilities Commission (Commission) for our advanced grid planning. Overall, I explain why the model is appropriate and presents a reasonable comparison of the costs and quantifiable benefits of the future components of the AGIS initiative from the customer perspective. I note that the model has some limitations, in that it only presents costs and benefits that the Company has converted to dollars – whereas some benefits (like customer satisfaction) cannot be quantified, and the Company is not comfortable attaching a cost basis to other benefits (like human safety). As such, the cost benefit analysis (CBA) is simply one useful tool to assess certain aspects of the Company's proposed AGIS initiative.

In my Direct Testimony, I begin by introducing the structure of, and our approach to the model. I explain that the model is intended to present a conservative comparison of the net present value (NPV) of the costs of the components of the AGIS initiative with the NPV of benefits of those components, on a revenue requirements basis. The model also presents a composite NPV comparison between costs and benefits of the overall AGIS initiative. I identify the cost and benefit inputs, stated in terms of capital, operations and maintenance (O&M), or other benefits. While I present these inputs within the cost benefit model itself, the costs and benefits are largely supported by our business area witnesses, namely Mr. David C. Harkness on Information Technology (IT) components, Ms. Kelly Bloch on Distribution Operations, Mr. Michael Gersack on Program Management, and Mr. Christopher Cardenas on Customer Care. These witnesses support costs and benefits for each component of the AGIS initiative (AMI, Fault Location Isolation and Service Restoration (FLISR), Integrated Volt-VAr Optimization (IVVO), and associated components of the Field Area Network (FAN)). In my testimony, I identify where information about the costs and benefits can be found. I also support the aspects of our modeling assumptions related to avoided peak capacity and peak pricing avoidance as a result of AMI, and reduced carbon emissions as a result of AMI and IVVO, illustrating why those assumptions are reasonable.

Next, I provide the ranges of results of the Company's CBA for each of the components of the AGIS initiative, as well as the overall AGIS CBA. Our model results in a ratio of estimated benefits to costs for each component, as well as the composite ratio of estimated benefits to costs for the overall initiative. A ratio of 1.0 or higher indicates quantifiable benefits are expected to equal to or exceed the costs, whereas a ratio of less than 1.0 indicates costs are expected to exceed quantifiable benefits:

Table 1
Range of AGIS Benefit-to-Cost Ratios[1]
(Includes allocated components of FAN)

	<u>LOW SENSITIVITY</u> *IVVO 1.0% Energy Savings, With Contingency*	<u>BASELINE</u> *IVVO 1.25% Energy Savings, With Contingency*	<u>HIGH SENSITIVITY</u> *IVVO 1.5% Energy Savings, No Contingency*
AMI	0.83	0.83	0.99
FLISR	1.31	1.31	1.53
IVVO	0.46	0.57	0.72
Overall AGIS	**0.86**	**<u>0.87</u>**	**1.03**

I also provide discussion regarding the limitations of a cost benefit model, both with respect to unquantifiable qualitative benefits and in relation to the need to update aging distribution infrastructure that is a central requirement of an electric service delivery business. While Company witnesses Mr. Gersack and Ms. Bloch describe those benefits in their testimony, I provide context for these unquantifiable benefits and explain how they support the Company's overall advanced grid strategy.

Finally, I provide "Least-Cost/Best-Fit" summaries of the relative functions, limitations, costs, and benefits (to the extent applicable) for metering and communications network alternatives. These comparisons underscore why we have selected our AMI and FAN solutions, as described in extensive detail in the testimony of Ms. Bloch and Mr. Harkness.

Overall, I conclude that the Company's cost benefit model is one reasonable means of assessing quantifiable costs and benefits of the overall AGIS

[1] The Overall AGIS ratio is not intended to be a sum or simple average of other ratios, but rather is a consolidated ratio as I discuss in Section II.C of my Direct Testimony.

initiative, but a comprehensive assessment requires consideration of additional factors that are discussed by the Company's other AGIS witnesses.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. I present the remainder of my testimony in the following sections:

- Section II: AGIS Quantitative Cost Benefit Model
- Section III: Least-Cost/Best-Fit Alternatives
- Section IV: Qualitative Benefits of AGIS
- Section V: Conclusion

II. AGIS QUANTITATIVE COST BENEFIT MODEL

A. Model Structure and Requirements

Q. WHAT IS THE PURPOSE OF THE AGIS CBA, FROM THE COMPANY'S PERSPECTIVE?

A. The Company is presenting its CBA to illustrate its assessments of the quantitative value of the requirements for and benefits of the AGIS initiative. This model is intended to aid the Commission and other stakeholders in evaluating the overall prudence of the AGIS proposals, and was likewise required by the Commission's Order Point 9.B in its Order Authorizing Rider Recovery, Setting Return on Equity, and Setting Filing Requirements, dated September 27, 2019 in our 2017 Transmission Cost Recovery (TCR) rider (Docket No. E002/M-17-797) (TCR Rider Order).

Q. PLEASE INTRODUCE THE COMPANY'S COST BENEFIT MODEL IN THIS MATTER.

A. The CBA model compares the costs with the quantifiable benefits of each component of the Company's AGIS initiative, as well as the overall costs and quantifiable benefits of the initiative. More specifically, the model calculates the benefit-to-cost ratios for the proposed components of the AGIS initiative that the Company is planning to pursue at this time – namely, AMI, FLISR, and IVVO. The cost components of the FAN are also incorporated into the CBA because the FAN benefits are realized through its support of the other components of the AGIS initiative. The CBA utilizes specific cost and quantifiable benefit estimates and assumptions provided by Company witnesses Mr. Gersack, Ms. Bloch, Mr. Harkness, and Mr. Cardenas. I also support certain benefits, as discussed later in my Direct Testimony.

The Company's CBA model utilizes the Discounted Cash Flow (DCF) procedure and the 2019 Net Present Value (NPV) for quantifiable costs and benefits, to determine the value of the AGIS investments. Specifically, the benefit-to-cost ratio evaluates the standalone costs and benefits of each of AMI, IVVO, and FLISR respectively, including the FAN costs allocated to each of these components. Finally, the model evaluates the NPV benefit-to-cost ratio for AMI, IVVO, and FLISR on a combined basis.

Q. HOW WAS THE COST BENEFIT MODEL DEVELOPED?

A. The structure and form of the CBA are consistent with the Company's general approach to CBAs, including the CBA provided to the Colorado Public Utilities Commission in our Public Service Company of Colorado AGIS Certificate of Public Convenience and Necessity (CPCN) proceeding. (That matter, Proceeding No. 16A-0588E, resulted in an unopposed settlement approving the Company's need for the components of AGIS for which it needed a CPCN.) In structuring the CBA for grid modernization investments specifically, we also looked at similar analyses conducted by others for similar types of assets. For example, our framework is similar to that used by Ameren Illinois in their grid modernization efforts. We also considered the Electric Power Research Institute (EPRI's) technical report on Estimating the Costs and Benefits of the Smart Grid.[2]

Q. WHY DID THE COMPANY SELECT THIS FORM OF QUANTITATIVE MODEL?

A. This CBA is just one phase of a much more extensive assessment performed by the Company prior to seeking Commission approval for the four AGIS components presented in this case. This assessment included evaluation of the needs and goals of our distribution system, customers, the Commission, and other stakeholders, and then assessments of the alternatives to meet those needs and goals. These processes are described in detail in the testimony of Company witnesses Mr. Gersack, Ms. Bloch, Mr. Cardenas, and Mr. Harkness. (For example, Ms. Bloch and Mr. Cardenas explain the status of the current meters on our system and the extensive planning, information gathering, RFP processes, and consideration of alternate vendors, devices, systems, and programs that we undertook prior to selecting our current AMI plan.[3]) Now, as we are at the point of proposing our overall strategy and plan to the Commission, we provide this cost benefit model to identify and discuss the cost-effectiveness of the components of that plan (including the avoided costs of necessary alternative solutions) and of the total AGIS initiative.

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[2] https://www.smartgrid.gov/files/Estimating_Costs_Benefits_Smart_Grid_Preliminary_Estimate_In_201103.pdf.

[3] To the extent it makes sense, I have summarized these considerations in the least-cost/best-fit segment later in my testimony, which illustrates our conclusions with respect to alternatives to AMI and the FAN.

Q. HOW DID THE COMPANY STRUCTURE THE CBA PRESENTED IN YOUR TESTIMONY?

A. The model compares the upfront and ongoing project implementation costs (including planning and installation), as well as avoided costs, against the quantifiable benefits of the Company's proposed project over the analysis period. The model incorporates the Distribution costs and Customer Care costs of the systems, as well as the Business Systems costs required for the implementation of the projects, including integration, software-hardware, project management, and other costs in order to provide a complete picture of AGIS initiative costs.

Further, the model views costs and benefits from the customer perspective, meaning that it quantifies the estimated net impact of costs and savings to customers, including Commission-approved measures of societal benefits.[4] In this respect, all quantifiable utility costs and benefits were estimated in the model as they would be effectuated through utility electric rates. For example, the Company estimated the total cost of meter installation and operation in terms of revenue requirements.

We also estimated reasonably quantifiable direct customer benefits of improvements in the Company's electric service. These benefits can take many different forms, such as cost savings in system management or reduced energy and generation needs that benefit the customer through rates; pricing opportunities for customers through time-of-use rates; reduced outage impacts to customers' own activities; and avoidance of lost revenue through

[4] For example, carbon dioxide emission reductions can be measured and quantified via the Commission-ordered externality values.

meter tampering. In measuring such benefits, we took into account past Commission determinations of value (as with the social cost of carbon, as described in my testimony) and feedback on previous submissions (as with the CMO values, as described in Ms. Bloch's testimony).

Q. ONCE THE QUANTIFIABLE COSTS AND BENEFITS FROM THE OTHER WITNESSES ARE IN THE MODEL, WHAT CALCULATIONS DOES THE MODEL MAKE TO ESTIMATE THE CUSTOMER IMPACT?

A. First, it is necessary to take the projected capital costs and benefits and estimate a net capital revenue requirement. The net capital revenue requirement is the aggregate impact of both the capital costs and the capital savings over the analysis period. Therefore, the net capital revenue requirement estimates how the capital related costs and benefits would impact the customer through electric rates.

The model takes the annual capital costs and capital benefits and makes assumptions regarding how those costs and benefits may be reflected in rate base, and estimates a net capital revenue requirement as a function of depreciable book and tax lives for the assets, as well as the Company's weighted average costs of capital (WACC) and tax rates. The estimated net revenue requirement associated with the capital costs and benefits represents the annual impact of the capital spend, which is how the Company would calculate electric rate recovery on the underlying investment.

Second, for O&M costs and savings, fuel savings, and other benefits, the model assumes that those costs and benefits would be expensed or earned in the year they were incurred, and are embedded in the Company's electric rates. Any such changes will flow through to the customers.

Q. HOW DOES THE MODEL CONVERT THE ESTIMATES OF NET CAPITAL REVENUE REQUIREMENT, O&M COSTS, AND BENEFITS TO A BENEFIT-TO-COST RATIO?

A. Once the stream of the net capital revenue requirements, O&M costs and benefits are calculated, the streams are compared on an NPV basis. Each stream of costs or benefits is present-valued back to 2019 dollars utilizing the Company's WACC as a discount rate. Then, by dividing the net present value of benefits by the net present value of costs, a benefit-to-cost ratio is calculated. A benefit-to-cost ratio of 1.0 indicates benefits of that component of the AGIS initiative – or of the overall initiative – equal costs; a ratio of less than 1.0 means costs exceed benefits; and a ratio of greater than 1.0 means benefits exceed costs.

Q. PLEASE DESCRIBE THE PERIOD OF TIME THE MODEL EXAMINES.

A. The model for AMI (including the TOU Pilot) examines the period beginning in 2019 and ending 2035. The period for IVVO and FLISR is longer (2019 through 2038), due to the longer useful life of the underlying assets.

Q. WHY DOES THE MODEL EXAMINE THESE PERIODS OF TIME?

A. For AMI, the model reflects the current phase of work beginning in 2019, and future installation phases beginning in 2021, as described by Ms. Bloch. This includes the assumption that AMI meters and associated software and hardware, as well as the necessary components of the FAN will begin depreciation upon installation. It also includes the meters we are installing for 2019 and 2020 for the TOU pilot evaluation period, which will subsequently be replaced with meters with Distributed Intelligence capabilities at no cost to the Company or customers.

While additional meters will be installed after 2021, the IT components will need to be in place by the time of the initial meter installations in order for the system to function. Thus by 2035 (after the fifteen-year period from 2021-2035), the network will be fully depreciated. Additionally, while the potential service life of AMI meters is between 15 and 20 years in the industry, we have utilized a fifteen-year period for AMI examination. This is consistent with the 15-year depreciation terms presently approved by the Commission for our existing automated meter reading (AMR) meters and reflects the challenging climate in Minnesota.

As Ms. Bloch further describes, the FLISR and IVVO assets are expected to have a 20-year life. The twenty-year life for IVVO and FLISR follows the industry standard for the life cycle evaluation of similar projects. While FLISR and IVVO devices will be installed beginning in 2020 and 2021 respectively, as with AMI the underlying IT systems must be in place before device installation. As a result, the 2019-2038 IVVO and FLISR CBA timelines capture the estimated costs and benefits from installation for the projected life of the system.

While some of the distribution assets installed may be useful beyond this timeframe, overall, our timeframes are intended to be conservative and therefore support a conservative assessment of total benefits and costs.

Q. CAN YOU PROVIDE MORE INFORMATION ON HOW THE COMPANY DEVELOPED THE COST AND BENEFIT INPUTS INTO THE MODEL?

A. Yes. The capital and O&M costs and benefits of AMI (including the TOU pilot), FLISR, and IVVO, including the associated FAN components, were determined by our Customer Care, Business Systems, and Distribution areas (including business area financial teams), with additional support from the AGIS Program Management Office, as discussed in more detail below. Our Program Management Office, Risk Management, and the Regulatory Department coordinated and developed modeling assumptions consistent with these cost and benefit estimates. The testimonies of Mr. Gersack, Ms. Bloch, Mr. Harkness, and Mr. Cardenas provide detail regarding the cost and benefit assumptions for each component of the AGIS projects, while I summarize those model inputs and provide explanations on the overall results of our CBAs.

Q. WHY DO YOU REFER TO AMI, FLISR, AND IVVO COSTS AND BENEFITS AS "INCLUDING THE ASSOCIATED FAN COMPONENTS"?

A. As Company witnesses Ms. Bloch and Mr. Harkness discuss in their Direct Testimony, the FAN will be a single, general-purpose, field area wireless networking resource that enables two-way communication of information and data to and from infrastructure at the Company's substations and the field devices. The FAN will provide the necessary communication capacity for the AGIS initiative, while also ensuring that the data being transmitted is secure. However, the FAN is not a standalone program and does not provide benefits on its own; rather, it is the communications network to enable AMI, IVVO, and FLISR functionality and provide their respective benefits to customers.

As such, we have incorporated FAN costs into the models for AMI, FLISR, and IVVO.

Q. HOW WERE THE FAN COMPONENTS THEN INCORPORATED INTO THE MODEL?

A. The model allocated FAN costs across the analyses for the individual AGIS components the FAN serves. Specifically, as explained by Mr. Harkness in his Direct Testimony, the FAN structure is primarily made up of two technological modules: WiMAX and WiSUN. WiMAX (Worldwide Interoperability for Microwave Access) is used to transfer data over different transmission modes such as point to point and multipoint modes. WiSUN (Smart Utility Network) is a low rate wireless system that must be in place to enable AMI device-to-device and device-to-headend communication. Because AMI is the predominant beneficiary of the WiSUN system, WiSUN costs have been completely allocated to AMI.

The meters and repeaters that constitute the AMI, the IVVO capacitors and voltage monitors, and the FLISR reclosers will each have embedded communication modules that will allow them to communicate directly with the FAN's access points on the WiMAX core infrastructure. But while the WiMAX system will provide coverage for all of NSPM's service territory, including 1050 feeders that all will contain AMI meters, Ms. Bloch explains that only a subset of the feeder population will have FLISR and IVVO equipment installed. Specifically, FLISR equipment will be initially installed on 208 feeders, while IVVO will be installed on 189 feeders. Likewise, each program will benefit from the communication system based proportionally on the amount of data needed and transferred. WiMAX costs are therefore distributed between AMI, FLISR, and IVVO according to the number of devices in proportion to the number of feeders.

Based on the total number of devices installed by feeder for each program, and given that additional devices affecting the WiMAX component may be installed in the future for both IVVO and FLISR, the business has estimated an allocation to capture that growth of AMI at 80 percent, IVVO at 5 percent, and FLISR at 15 percent. These percentages are also consistent with the total initial capital investment required by each program.

Consequently, the AMI, IVVO, FLISR, and consolidated models assume implementation of the FAN from 2019 through 2024, consistent with the timeline to subsequently implement the AMI meters, IVVO, and FLISR assets.

Q. CAN YOU ALSO PROVIDE MORE DETAIL AS TO HOW THE IT COMPONENTS ARE INCORPORATED INTO THE MODEL?

A. Yes. As described by Company witness Mr. Harkness, IT efforts include the costs of integrating the components of the AGIS initiative with existing Company back-end applications that will utilize the data. Similarly, IT efforts are necessary to ensure the security of the data collected and transmitted from advanced metering. As with the FAN, IT work is not a standalone program that provides benefits on its own; rather, it is a necessary component of the AGIS programs. Therefore, the costs of IT efforts for AMI, FLISR, and IVVO are included in the cost benefit model for these components.

Q. WHY IS THE CBA FOCUSED ON AMI (INCLUDING THE TOU PILOT), FLISR, AND IVVO, WITH ASSOCIATED COMPONENTS OF THE FAN?

A. These are the components of the AGIS initiative that are forward-looking, and which the Company plans to undertake as an integrated plan for the advancement of our distribution system. While they build on the Advanced Distribution Management System (ADMS), the ADMS was previously approved by the Commission through Docket No. E002/M-15-962 under Minn. Stat. § 216B.2425, before other components of the AGIS initiative were submitted or approved, and is necessary regardless of other selected advanced grid efforts. Consequently, the CBA is structured to aid the Commission's decision-making for the future, both from rate recovery and Integrated Distribution Planning (IDP) perspectives.

Q. HOW WERE THE MODEL'S COST AND BENEFITS INPUTS DETERMINED FOR THE FIRST FIVE-YEAR PERIOD, FROM 2019 THROUGH 2023?

A. Each subject matter expert provided estimated capital and O&M costs and benefits in 2019 dollars, by year, for the period 2019 through 2023. The dollars for 2020-2022 align with the Company's multi-year rate plan (MYRP) in this proceeding (plus one year).

These costs and benefits, except for fixed price items, were then converted into nominal dollars within the model using assumptions for labor and non-labor inflation over the analysis period.

Q. HOW WERE THE MODEL'S COST AND BENEFITS INPUTS DETERMINED FOR 2024 THROUGH 2038?

A. The additional capital and O&M costs beyond 2023 were estimated for each respective part of the project through 2035 for AMI and 2038 for IVVO and FLISR, in order to capture the costs and benefits of each of the programs beyond the initial implementation period. These O&M and capital costs were provided in 2019 dollars by or at the direction of Company witnesses Mr. Gersack, Ms. Bloch, and Mr. Harkness, and were escalated to nominal dollars for either the full twenty-year (FLISR, IVVO) or fifteen-year (AMI) analysis period.

Benefits were also estimated for this period based on when we expect customers to experience these benefits, including continued escalation of benefits beginning in 2023 or earlier to the appropriate future year.

Q. HAVE THE COSTS LISTED IN THE MODEL BEEN CORRELATED TO THE COMPANY'S RATE CASE BUDGET?

A. Yes. My group worked closely with the Financial Planning area to ensure that the two are consistent. However, it is important to be clear that there are some differences in how the numbers are presented. In particular, the analysis is based on net present value of revenue requirements, with capital investment costs captured in the year the investment is in service and costs stated in 2019 dollars. The MYRP budgets presented by other AGIS witnesses are stated in annual capital expenditure and capital addition dollars. As a result, the numbers in the CBA correspond to the rate case budgets but will not look exactly the same.

Q. HOW ARE THE COSTS IN THE MODEL CATEGORIZED?

A. It is possible to review the costs in the model from several perspectives. The costs, which are set forth in Exhibit___(RD-1), Schedules 2, 3, 4 and 5 of my Direct Testimony, are identified as:

- Rate case budgets to the extent they are for the years of the Company's MYRP, or longer-range planning costs for the years after 2022;
- Either capital or O&M;
- Either Business Systems or Distribution costs; and
- Direct, Indirect, Tangible, or Intangible costs, consistent with Order Point A.3 in the Commission's September 27, 2019 TCR Rider Order.

Q. PLEASE PROVIDE THE COMPANY'S DEFINITIONS OF DIRECT, INDIRECT, TANGIBLE, INTANGIBLE, AND "REAL" COSTS FOR PURPOSES OF ITS AGIS INITIATIVE.

A. The Company defines these categories of costs as follows:

- *Direct costs* – the cost of the materials and the workers that are involved when a company makes a particular product or provides a particular service that can be easily traced to that product, department, or project – similar to costs that are assigned rather than allocated.
- *Indirect costs* – a cost that cannot be directly traced to a particular product, department, activity, project, or providing a particular service – similar to overhead, or costs that are allocated rather than assigned.
- *Tangible costs* – Like direct costs, a tangible cost (or benefit) is a quantifiable cost related to an identifiable source or asset. It can be directly connected to a material item used to conduct operations or run a business. Tangible costs represent expenses arising from such things

as purchasing materials, paying employees or renting equipment. The costs in the CBA are tangible.

- *Intangible costs* – an unquantifiable cost (or benefit) relating to an identifiable source. Intangible costs represent a variety of expenses such as losses in productivity, customer goodwill, drops in employee morale, or damage to corporate reputation. Most qualitative costs and benefits are intangible, although the Company has chosen not to assign a dollar value to some potentially tangible costs (like human safety).
- *Real costs* – total costs the utility incurs to produce a good or service or to implement a program, including the cost of all resources used and the cost of not employing those resources in alternative uses. Real costs analysis gives a greater picture of a product and the spending associated with it. The CBA model is intended to identify Real Costs throughout.

These categories do at times overlap, as most tangible costs are also assigned or allocated and are therefore either an Indirect or Direct cost. Where overlap occurs in the Company's AGIS modeling, both categories are identified.

Q. ARE INTERNAL AND EXTERNAL LABOR COSTS INCLUDED IN THE COSTS OF EACH COMPONENT OF THE AGIS INITIATIVE INCLUDED IN THE MODEL?

A. Yes. As Mr. Gersack discusses, both the model and our overall support for the AGIS initiative in this proceeding are intended to capture the "all-in" costs of the project. Further, the Company is seeking base rate recovery for project costs being incurred or placed-in service during the MYRP; therefore, it is appropriate to include both internal and external labor costs. The support for these costs is provided by Ms. Bloch and Mr. Harkness.

Q. DO THE COST INPUTS FOR AMI, FLISR, AND IVVO INCLUDE CONTINGENCY ASSUMPTIONS?

A. Yes. In addition to the cost estimates, the Distribution and Business Systems areas developed contingency estimates for each aspect of the project that warranted a contingency. These contingency estimates are depicted on Exhibit___(RD-1), Schedule 2 (AMI CBA Summary), Schedule 3 (FLISR CBA Summary), and Schedule 4 (IVVO CBA Summary) as cost line items. Since by definition the amount and type of contingency dollars that will actually be spent cannot be wholly defined up front, the Company prepared CBAs summaries for each component both with and without contingency dollars, to provide insight into how the range of potential contingency amounts could affect the overall benefit-cost ratio. The testimonies of Ms. Bloch, Mr. Harkness, and Mr. Gersack provide additional support for the contingency amounts included in the CBA.

Q. HOW WERE THE ESTIMATES OF CONTINGENCY FOR EACH WORK STREAM INTEGRATED INTO THE MODEL?

A. The estimates of contingency were added to the estimated costs of the project and input into the model as a cost. In essence, the model evaluates the cost of the project as if the Company needed to spend up to the full contingency amounts or none of the contingency. This allows both the most conservative view of potential benefit-to-cost ratios (all contingency used), as well as the greatest calculated benefit-to-cost ratio, providing a view of range of potential outcomes.

Q. WHAT STEPS DID THE COMPANY UNDERTAKE TO VERIFY THAT THE MODEL IS STRUCTURALLY SOUND?

A. The model structure was based on models and similar analyses undertaken by the Company and other utilities in support of similar AMI and grid advancement programs. A number of business areas within the Company, including Regulatory Administration, Risk, Corporate Development, Capital Asset Accounting, Revenue Requirements, Demand Side Management, Business Systems and Distribution, subsequently collaborated to develop and ensure the model incorporated requirements necessary to properly estimate the known and quantifiable life cycle value proposition.

Q. OVERALL, IS THIS CBA AN APPROPRIATE TOOL FOR EVALUATING THE QUANTIFIABLE ASPECTS OF THE AGIS INITIATIVE?

A. Yes. By developing the model from the customer's perspective, the Company is providing clear and comprehensive information about the overall quantifiable impact of implementing these programs to customers. By this we mean that the CBA includes benefits that can be both quantified generally and stated in terms of a reasonably calculable dollar value.

The cost benefit model also provides a high-level look at the costs versus the quantifiable benefits of the overall AGIS initiative for customers, as well as a more detailed breakdown of individual costs and benefits assumptions for each program. However, the cost benefit model does not address all reasons for undertaking the AGIS program or the benefits of the program because many such reasons and benefits cannot be quantified or reduced to a dollar value. Therefore, the cost benefit model provides an appropriate perspective on the quantifiable costs and benefits of the program but not on all relevant considerations.

Q. WHY DO YOU SAY THE MODEL PROVIDES AN APPROPRIATE PERSPECTIVE ON QUANTIFIABLE CONSIDERATIONS?

A. Because a CBA is, by definition, intended to quantify costs and benefit, it can only capture the quantifiable. As discussed later in my testimony, examples of benefits that were not quantified include customer satisfaction, customer choice, planning and control of the grid, greater hosting capacity, job creation, improved quality of service delivered, and safety, among others described by Ms. Bloch, Mr. Cardenas, Mr. Gersack, and myself. This is why the CBA is one tool, but it should not be regarded as a definitive analysis on the merits of AGIS, because it cannot consider factors that are qualitative or on which the Company has not put a price (like human safety).

In addition, a model based on measureable considerations does not take into account any fundamental need for the infrastructure in question. For example, the Company must have meters in order to provide and bill for electric service. We therefore must plan for the pending expiration of the Cellnet AMR service contract while also taking into account that Xcel Energy is the last company using the Cellnet technology embedded in the Company's current meters. However, a cost versus benefit model cannot fully reflect that the primary function of updated meters is not necessarily to reduce the net cost of meters compared to aged technology, but rather to enable the utility to provide services to meet the needs and expectations of the customer.

Finally, while the model can and does reflect the costs of AMI versus AMR technology as an avoided cost alternative, it cannot fully assess whether it would be short-sighted or impracticable for the Company to replace aging technology with other aging technology, nor the effect of using older technology on unquantifiable customer expectations (like better outage and service restoration communications, and more timely energy consumption data) that is more dependent on advanced metering technology. All told, the model is a helpful assessment tool within the scope of its intended purpose. And because the Company has taken a conservative approach to modeling the benefits and costs of the AGIS strategy, we believe it is a reliable and helpful tool.

B. Quantitative Inputs

1. AMI Inputs

Q. WHAT ARE THE KEY COSTS AND BENEFITS OF AMI?

A. Company witness Ms. Bloch discusses the costs and benefits of AMI in detail in her testimony. At a high level, the benefits of AMI include: (i) providing more granular customer energy usage information that supports greater customer energy usage choice, pricing flexibility, and carbon reduction; (ii) reducing field and meter service and meter reading costs; (iii) reducing unaccounted for energy; (iv) assisting with identification of service outages and foster restoration; (v) providing voltage measurement information to assist in load flow and voltage calculations performed in the ADMS; (vi) serving as signal repeaters for other AMI meters and FAN network components; and (vii) improving infrastructure investment efficiencies. The purchase of AMI meters also enables the Company to retire the end-of-life Cellnet technology that will no longer be supported in the future (as described by Company witness Mr. Cardenas) and avoid the purchase of other, less functional advanced meter reading (AMR) meters in the near future. As discussed below, not all of the benefits of AMI are quantifiable or able to be reduced to a dollar value. In the cost benefit model, however, we have identified and captured the costs and quantifiable benefits associated with the technology.

The key costs of AMI include the meters themselves, including the labor cost of installation and testing, supporting FAN and IT resources, AMI program and management, and other supporting labor for operations.

Q. HOW WERE AMI CAPITAL COST AND BENEFIT INPUTS DERIVED FOR PURPOSES OF THE COST BENEFIT MODEL?

A. Capital and O&M cost and benefit estimates for the AMI program were developed by the Company's subject matter experts and are detailed in the Direct Testimonies of Ms. Bloch, Mr. Harkness, Mr. Gersack, and Mr. Cardenas, as set forth in Tables 2 through 6 below. My Exhibit ___ (RD-1), Schedule 2 provides a summary of each component of the quantifiable AMI costs and benefits, as they appear in the CBA.

Table 2

AMI Capital Costs

Capital Cost	**Description**	**Supporting Witness (including Section of Testimony)**
Meters and Installation	Capital costs portion of AMI meter purchase and installation. Capital costs of both internal and external support personnel.	Direct Testimony of Ms. Bloch, Section V(D)(5)
Field Area Network (AMI)	Capital costs associated with implementation of the WiSUN network and associated assets.	Direct Testimony of Mr. Harkness, Section V(E)(4)(e)
	Capital costs associated with installation of pole-mounted devices.	Direct Testimony of Ms. Bloch, Section V(E)(3)
IT Systems and Integration	Capital costs associated with the various IT infrastructure and integration in support of AMI.	Direct Testimony of Mr. Harkness, Section V(E)(3)(c)
Program and Change Management	Capital costs associated with internal management of AMI.	Direct Testimony of Mr. Gersack, Section V(D)(2)

Table 3

AMI Capital Benefits

Capital Benefit	**Description**	**Supporting Witness (including Section of Testimony)**
Distribution System Management Efficiency	More efficient use of capital dollars to maintain the distribution system.	Direct Testimony of Ms. Bloch, Section V(D)(4)
Outage Management Efficiency	Improved capital spend efficiency during outage events.	Direct Testimony of Ms. Bloch, Section V(D)(4)
Avoided Meter Purchases for Failed Meters	AMI meters have a lower failure rate as compared to AMR meters. By purchasing new AMI meters, the Company avoids the need to replace failing AMR meters.	Direct Testimony of Ms. Bloch, Section V(D)(4)
Avoided investment of an alternative meter reading system	Avoided capital cost of a drive-by meter reading system, instead of the AMI investment, since current Cellnet system requires replacement	Direct Testimony of Ms. Bloch, Section V(D)(4)

Q. HOW WERE AMI O&M COST AND BENEFIT INPUTS DERIVED FOR PURPOSES OF THE COST BENEFIT MODEL?

A. O&M estimates for the AMI program were likewise developed by the Company's other AGIS witnesses, as set forth in Tables 3,4, and 5 below.

Table 4

AMI O&M Costs

O&M Cost	**Description**	**Supporting Witness (including Section of Testimony)**
Field Area Network (AMI) allocated portion	O&M costs associated with implementation of the WiSUN network and associated assets.	Direct Testimony of Mr. Harkness, Section V(E)(4)(e)
IT Systems and Integration	O&M costs associated with the various IT infrastructure and integration in support of AMI.	Direct Testimony of Mr. Harkness, Section V(E)(3)(c)
AMI Operations (Personnel)	O&M costs of both internal and external support personnel.	Direct Testimony of Ms. Bloch, Section V(D)(5)
Program Management	O&M costs associated with internal change management and oversight for AMI.	Direct Testimony of Mr. Gersack, Section V(D)(2)

Table 5

AMI O&M Benefits

O&M Benefit	**Description**	**Supporting Witness (including Section of Testimony)**
Avoided O&M Meter Reading Cost	O&M cost component of a drive-by meter reading system alternative to AMI, since current Cellnet system requires replacement	Direct Testimony of Mr. Cardenas, Section V(F)
Reduction in Field and Meter Services	Reduction in O&M costs related to addressing meter and outage complaints and connections.	Direct Testimony of Ms. Bloch, Section V(D)(4)
Improved Distribution System Spend Efficiency	Increased efficiency of distribution maintenance costs.	Direct Testimony of Ms. Bloch, Section V(D)(4)
Outage Management Efficiency	Improved O&M efficiency during outage events.	Direct Testimony of Ms. Bloch, Section V(D)(4)

Table 6

Other Quantifiable AMI Benefits

Benefit	**Description**	**Supporting Witness (including Section of Testimony)**
Reduction in Energy Theft	Easier identification of energy theft and an associated reduction in the amount of theft.	Direct Testimony of Mr. Cardenas, Section V(F)
Reduced Consumption Inactive Premise	Expedited ability to turn off power quickly when determined premise has been vacated.	Direct Testimony of Mr. Cardenas, Section V(F)
Reduced Uncollectible/Bad Debt	Decreased loss due to uncollectible/bad debt.	Direct Testimony of Mr. Cardenas, Section V(F)
Reduced Outage Duration	Direct benefit to customers associated with reduced outage duration.	Direct Testimony of Ms. Bloch, Section V(D)(4)
Critical Peak Pricing	Customer demand savings in response to new rate structures.	Brattle Group Report, Exhibit ___ (RD-1), Schedule 6 and additional detail in this Section of my Direct Testimony
TOU Customer Price Signals	Difference in energy prices paid by consumers in response to new rate structures.	Integrated Resource Plan – RP-19-368 Appendix F2 and additional detail in this Section of my Direct Testimony
Reduced Carbon Dioxide Emissions	Difference in emissions of generation assets due to shifted load.	Additional detail in this Section of my Direct Testimony

Q. CAN YOU SUMMARIZE THE BENEFITS YOU DESCRIBE IN YOUR TESTIMONY?

A. Yes. As noted in Table 6 above, I discuss how the Company calculated AMI benefits associated with critical peak pricing and TOU customer price signals (combined, "load flexibility" benefits), as well as reduced CO_2 emissions. Exhibit ___ (RD-1), Schedule 5 identifies the quantification of these benefits for purposes of the CBA.

Q. CAN YOU PROVIDE MORE INFORMATION REGARDING THE COMPANY'S LOAD FLEXIBILITY ASSUMPTIONS?

A. Yes. The Company engaged The Brattle Group (Brattle) to model likely customer response to Time of Use (TOU) and Critical Peak Pricing (CPP) rates. The Brattle Group produced a study entitled "The Potential for Load Flexibility in Xcel Energy's Northern States Power Service Territory" (the Brattle Study), which is attached to my Direct Testimony as Exhibit___ (RD-1), Schedule 6. The Brattle Study developed quantification of the benefits of potential TOU and CPP rates, which were in turn incorporated into our CBA.[5] Further, the Company utilized information about shifting demand from on-peak to off-peak periods, resulting in energy price savings for customers and carbon reduction benefits.

Q. WHY DID THE COMPANY RELY ON THE BRATTLE STUDY?

A. Brattle is a well-respected economic consulting and analytics firm, and conducted a similar study for Public Service Company of Colorado (Xcel Energy's Colorado utility operating company), in relation to its portion of the AGIS initiative. As a result, we have experience with this group and have found their studies to be robust and reasonable.

Q. PLEASE DESCRIBE THE TOU ASSESSMENT IN THE BRATTLE STUDY.

A. The Brattle Study assumes a static price signal with higher prices during the five-hour period around system peak on non-holiday weekdays, and models both opt-in and opt-out approaches to time of use rates.[6] Demand reduction

[5] I note that while Brattle modeled CPP rates and we have used this information in our CBA in this case, there are a variety of peak demand rate design structures the Company may explore, such as peak time rebates.
[6] Brattle Study at p.6.

grows modestly as TOU adoption and utilization expands. Based on these assumptions and the base case in the Brattle analysis, this rate has the potential to shift demand approximating 161 Megawatts (MW) for residential customers and 52 MW for medium commercial and industrial customers from on-peak to off-peak.[7] The overall result is cost savings to customers.

Q. WHAT ARE THE BENEFITS ASSOCIATED WITH CRITICAL PEAK PRICING?

A. The potential CPP rate "provides customers with a much higher rate during peak hours on 10 to 15 days per year."[8] CPP rates were modeled by Brattle as being offered on both an opt-in and an opt-out (default) basis, with demand reduction growing modestly as the system and system usage mature. This rate has the potential to reduce peak demand at the generator level by 164 MW for residential customers and 90 MW for medium commercial and industrial customers under the base case scenario.[9]

Q. HOW WERE THESE CHANGES IN THE COMPANY'S CUSTOMER PRICE SIGNALS TRANSLATED TO BENEFITS IN THE AGIS AMI CBA?

A. The Company utilized the peak demand reduction assumptions from the Brattle Study to generate an estimated energy shift from peak to off-peak hours. This shift from peak to off-peak was then multiplied by the difference in the Minnesota Hub on and off-peak price forecasts filed with our Integrated Resource Plan (Docket No. E002/RP-19-368) on page 13 of Appendix F2. This estimates the savings in energy prices customers will experience in shifting their demand from on to off-peak.

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[7] Brattle Study at Appendix D, p.68.
[8] Brattle Study at p.6.
[9] Brattle Study at Appendix D, p. 68.

Q. HOW DID THE COMPANY QUANTIFY THE BENEFIT DUE TO REDUCTIONS IN CARBON DIOXIDE EMISSIONS FOR AMI?

A. The Company utilized load shifting estimates in MWh for TOU rates from The Brattle Study. The Company estimated on-peak and off-peak average CO_2 emissions by year using internal tools. The difference in those two estimates represents the emissions improvement. This amount is multiplied by the MWh shifted due to TOU rates. The avoided carbon emission is valued by multiplying the avoided emissions by the Commission-ordered externality values from Docket No. E999/CI-14-643.

Q. HOW DOES THE BRATTLE GROUP'S FRAMEWORK COMPARE TO OTHERS FOR MEASURING LOAD FLEXIBILITY?

A. As noted by Brattle on page ii of the Study, its modelling framework "builds upon the standard approach to quantifying [demand response] potential that has been used in prior studies around the U.S. and internationally, but incorporates a number of differentiating features which allow for a more robust evaluation of load flexibility programs." The Brattle Group then goes on to identify those differentiating features, each of which is intended to enhance the reliability and sophistication of the analysis. The Company therefore relied upon the Brattle Study to assume that a consistent reduction in peak demand would be reasonable and achievable as a function of the demand rates AMI will enable as part of the Company's proposal. This reduction is then incorporated into the CBA as a benefit of AMI.

Q. WHAT ASSUMPTIONS ARE MADE WITH RESPECT TO CUSTOMER ADOPTION OF THESE NEW TECHNOLOGIES?

A. As discussed in more detail by Company witness Mr. Cardenas, we propose an opt-out approach to AMI metering, meaning that customers will be automatically integrated into the new system unless they actively opt out. In addition, the opt-out deployment approach tends to result in overall higher enrollment rates than when utilities adopt an opt-in approach to AMI, and therefore enables larger aggregate demand impacts via the more advanced rate structures AMI enables. Overall, the Brattle Study notes that an opt-out approach – with the default being the customer receives AMI functionality – "maximizes the overall economic benefit of the program."[10] The Brattle Group modeled this opt-out approach as the default rate offering.

Q. WHAT IS THE IMPACT OF THESE OPT-OUT ASSUMPTIONS ON THE CBA?

A. There is no direct net cost impact because, as Mr. Cardenas explains, we propose to have those customers who opt out pay for the cost of a new meter capable of storing data needed for future rate designs. In addition, customers who opt out would incur a monthly charge to cover the cost of meter reading. Because these charges would be established in an amount that directly offsets the costs of opting out, there is no direct material net cost impact to the CBA. However, the opt-out approach does improve the benefit as described above.

2. FLISR Inputs

Q. WHAT IS THE FLISR PROGRAM?

A. The Fault Location Isolation and Service Restoration (FLISR) component of the AGIS initiative is a synchronized system of devices that can reduce the

[10] Brattle Study at p. 31.

number of customers impacted by a fault via automatically isolating the trouble area and restoring service to remaining customers by transferring them to adjacent circuits. The fault isolation feature of the technology can help crews locate the trouble spots more quickly, resulting in shorter outage durations for the customers impacted by the faulted section. In short, the purpose of FLISR is to reduce the duration and impact of outages on our customers. Company witness Ms. Bloch discusses the purpose of FLISR in more detail.

Q. WHAT ARE THE COSTS OF FLISR?

A. The majority of the FLISR costs are the asset/device costs, as well as the labor cost of installation. Other costs include the supporting FAN components and IT resources. As previously noted, FLISR costs also include contingency amounts.

Q. HOW WERE FLISR COST AND BENEFIT INPUTS DERIVED FOR PURPOSES OF THE COST BENEFIT MODEL?

A. Capital and O&M cost and benefit estimates for the FLISR program (including contingencies) are detailed in the Direct Testimony of Company witnesses Ms. Bloch and Mr. Harkness, as set forth in Tables 6 through 8 below. FLISR's quantifiable benefits relate primarily to Customer Minutes Out (CMO) measures of reduced customers' outage duration; therefore, the benefits of FLISR are not directly O&M or capital-related. My Exhibit___(RD-1), Schedule 3 provides a summary of each component of the quantifiable FLISR costs and benefits, as they appear in the CBA.

Q. WHAT ARE THE CAPITAL COSTS AND BENEFITS OF FLISR?

A. A summary of capital costs is set forth in Table 7, below.

Table 7

Capital Costs of FLISR

Capital Cost	**Description**	**Supporting Witness (including Section of Testimony)**
Assets and Installation	Capital costs of the FLISR devices and installation, including both internal and external support	Direct Testimony of Ms. Bloch, Section V(F)(6)
Field Area Network (FLISR)	Capital costs associated with implementation of the WiSUN network and associated assets.	Direct Testimony of Mr. Harkness, Section V(E)(4)(e)
IT Systems and Integration	Capital costs associated with the various IT infrastructure and integration in support of FLISR.	Direct Testimony of Mr. Harkness, Section V(E)(5)(b)

Q. HOW WERE FLISR O&M INPUTS DERIVED FOR PURPOSES OF THE COST BENEFIT MODEL?

A. FLISR O&M costs and benefits were developed by Ms. Bloch and Mr. Harkness as set forth below:

Table 8

FLISR O&M Costs

O&M Cost	**Description**	**Supporting Witness (including Section of Testimony)**
Assets and Installation	O&M costs of the FLISR devices and installation.	Direct Testimony of Ms. Bloch, Section V(F)(6)
Field Area Network (FLISR)	O&M costs associated with implementation of the WiSUN network and associated assets.	Direct Testimony of Mr. Harkness, Section V(E)(4)(e)
IT Systems and Integration	O&M costs associated with the various IT infrastructure and integration in support of FLISR.	Direct Testimony of Mr. Harkness, Section V(E)(5)(b)

Table 9

Other Quantifiable FLISR Benefits

Benefits	**Description**	**Supporting Witness (including Section of Testimony)**
Customer Minutes Outage – Savings	Benefits to customers associated with reduced outage duration	Direct Testimony of Ms. Bloch, Section V(F)(5)
Outage Patrol Time Savings	Benefit associated with reduction in time spent by field crews responding to outages	Direct Testimony of Ms. Bloch, Section V(F)(5)

3. IVVO Inputs

Q. WHAT IS INTEGRATED VOLT-VAR OPTIMIZATION?

A. Generally speaking, IVVO is a leading technology that automates and optimizes the operation of distribution voltage regulating devices and VAr control devices to maximize system efficiency. As described in more detail in the Direct Testimony of Ms. Bloch, through the implementation of IVVO the Company will be able to control the voltage on a distribution feeder to a tighter tolerance, permitting the Company to lower the voltage on that controlled feeder while still maintaining a high level of service quality. This lower voltage will effectuate energy and demand savings for the system and for the customer.

Q. WHAT ARE THE PRIMARY COSTS AND BENEFITS OF IVVO?

A. The primary costs of implementing IVVO relate to installation of application assets as well as the labor cost of installation. Other costs include FAN communications, IT systems and integration, and program management. The benefits of IVVO that were quantified in the CBA are the fuel and energy savings and capacity savings associated with the program, which are described by Ms. Bloch, and the associated carbon reduction that I describe. The costs of IVVO also include contingency amounts, which are supported by Company witnesses Ms. Bloch, Mr. Harkness, and Mr. Gersack.

Q. HOW WERE IVVO CAPITAL INPUTS DERIVED FOR PURPOSES OF THE COST BENEFIT MODEL?

A. Capital and O&M cost estimates for the IVVO program (including contingencies) are detailed in the Direct Testimony of Company witnesses Ms. Bloch, Mr. Harkness, and Mr. Gersack, as set forth in Tables 10 through 13 below. My Exhibit___(RD-1), Schedule 4 provides a summary of each component of the quantifiable IVVO costs and benefits, as they appear in the CBA.

Q. WHAT ARE THE CAPITAL COSTS AND BENEFITS OF IVVO?

A. A summary of capital costs and benefits is set forth in Table 10 and 11, below.

Table 10

IVVO Capital Costs

Capital Cost	**Description**	**Supporting Witness (including Section of Testimony)**
Assets and Installation	Capital costs of the IVVO devices and installation. Capital costs of both internal and external support personnel.	Direct Testimony of Ms. Bloch, Section V(G)(5)
Field Area Network (IVVO)	Capital costs associated with implementation of the WiSUN network and associated assets.	Direct Testimony of Mr. Harkness, Section V(E)(4)(e)
IT Systems and Integration	Capital costs associated with the various IT infrastructure and integration in support of IVVO.	Direct Testimony of Mr. Harkness, Section V(E)(6)(b)
Program Management	Capital costs associated with internal management of IVVO.	Direct Testimony of Mr. Gersack, Section V(D)(2)

Table 11

IVVO Capital Benefits

Capital Benefits	**Description**	**Supporting Witness (including Section of Testimony)**
Avoided Capacity Costs	Avoided generation, transmission and distribution capacity achieved through demand reduction	Direct Testimony Ms. Bloch, Section V(G)(4)

Q. HOW WERE IVVO O&M AND OTHER INPUTS DERIVED FOR PURPOSES OF THE COST BENEFIT MODEL?

A. IVVO O&M costs and Other benefits were developed as set forth below:

Table 12

IVVO O&M Costs

O&M Cost	Description	Supporting Witness (including Section of Testimony)
Assets and Installation	O&M costs of the IVVO devices and installation.	Direct Testimony of Ms. Bloch, Section V(G)(5)
Field Area Network (IVVO)	O&M costs associated with implementation of the WiSUN network and associated assets.	Direct Testimony of Mr. Harkness, Section V(E)(4)(e)
IT Systems and Integration	O&M costs associated with the various IT infrastructure and integration in support of IVVO.	Direct Testimony of Mr. Harkness, Section V(E)(6)(b)
Program Management	O&M costs associated with internal management of IVVO.	Direct Testimony of Mr. Gersack, Section V(D)(2)

Table 13

Other Quantifiable IVVO Benefits

Other Benefits	Description	Supporting Witness (including Section of Testimony)
Fuel Savings (Energy Reduction)	Fuel cost savings associated with avoided energy usage	Direct Testimony of Ms. Bloch, Section V(G)(4)
Fuel Savings (Energy Reduction)	Fuel cost savings associated with reduction in line losses	Direct Testimony of Ms. Bloch, Section V(G)(4)
Reduced Carbon Dioxide Emissions	Difference in emissions of generation assets due to load reduction.	My Direct Testimony, below

Q. HOW DID THE COMPANY QUANTIFY THE BENEFIT DUE TO REDUCTIONS IN CARBON DIOXIDE EMISSIONS FOR IVVO?

A. As described by Company witness Ms. Bloch, the Company estimated the energy savings associated with the IVVO program. This reduction in energy usage was converted to avoided CO_2 emissions based on projected CO_2 intensity per MWh. We then calculated the societal benefit of these avoided CO_2 emissions using the Commission-ordered externality values from its

January 3, 2018, Order Updating Environmental Cost Values in Docket No. E999/CI-14-643.

Q. ARE THERE ANY UNIQUE ASPECTS OF IVVO FOR CBA PURPOSES, AS COMPARED TO THE OTHER COMPONENTS OF AGIS?

A. Yes. As Ms. Bloch describes in more detail, IVVO benefits depend on assumptions about the level of energy and demand savings that can be achieved on NSPM's specific system. She explains that while the Company feels confident that 1 percent average energy savings and 0.6 percent capacity savings are the most readily achievable levels, the Company also identified 1.5 percent energy savings and 0.8 percent capacity savings as the higher end of the achievable range. For purposes of the CBA, we utilized the mid-point of the range (1.25 percent energy savings and 0.7 percent capacity savings), and also present as sensitivities that utilize the lower (1.0 percent energy/0.6 percent capacity savings) and upper (1.5 energy/0.8 percent capacity savings) ends of the identified range. Below I provide the resulting benefit-to-cost ratios with and without contingency.

Q. OVERALL, HOW WOULD YOU CHARACTERIZE THE COST AND BENEFIT BUDGETING ASSUMPTIONS IN THIS MODEL FOR EACH OF THE COMPONENTS OF THE AGIS INITIATIVE?

A. Particularly for the modeling results that include 100 percent of the Company's planned contingencies, I would characterize this model as a conservative representation of estimated costs and benefits. Because AMI, FLISR, and IVVO are still in their early phases, the contingencies represent early estimates of potential additional costs. Likewise, the Company has estimated customer adoption and response on the basis of the Brattle Study;

as technologies continue to improve, the benefits associated with these technologies may also increase. Our goal is to represent a conservative but realistic analysis to support the Commission's review of our cost benefit model for the AGIS initiative.

C. CBA Results

Q. PLEASE SUMMARIZE THE QUANTITATIVE COST AND BENEFIT COMPARISON FOR THE AMI PROGRAM.

A. Table 14 summarizes the results of the Company's evaluation of AMI, both with and without contingency.

Table 14
AMI Benefit-to-Cost Ratio

NSPM-AMI-NPV	**Total ($MM)**
Benefits	446
O&M Benefits	53
Other Benefits	203
CAP Benefits	190
Costs	(538)
O&M Expense	(179)
Change in Revenue Requirements	(359)
Benefit/Cost Ratio	**0.83**
Benefit/Cost Ratio (no contingencies)	**0.99**

Exhibit___(RD-1), Schedule 3 to my Direct Testimony provides more detail regarding the results of the Company's analysis of the costs and benefits of AMI, including FAN components.

Q. WHAT DO YOU CONCLUDE REGARDING THE OVERALL COSTS AND BENEFITS OF AMI?

A. On a total resource benefit-to-cost ratio basis, AMI is expected to have a benefit-to-cost ratio of approximately 0.83-0.99, which indicates that the costs somewhat exceed quantitative benefits over the analysis period.

Q. PLEASE SUMMARIZE THE QUANTITATIVE COST AND BENEFIT COMPARISON FOR THE FLISR PROGRAM.

A. Table 15 summarizes the results of the Company's evaluation of FLISR:

Table 15

FLISR Benefit-to-Cost Ratio

NSPM FLISR- NPV	**Total ($MM)**
Benefits	**103**
O&M Benefits	0
Customer Benefits	103
Costs	**(79)**
O&M Expense	(5)
Change in Revenue Requirements	(74)
Benefit/Cost Ratio	**1.31**
Benefit/Cost Ratio (no contingencies)	**1.53**

Exhibit___(RD-1), Schedule 3 to my Direct Testimony provides more detail regarding the results of the Company's analysis of the costs and benefits of FLISR, including FAN components.

Q. WHAT DO YOU CONCLUDE REGARDING THE OVERALL COSTS AND BENEFITS OF THE FLISR PROGRAM, INCLUDING THE FAN COMPONENT?

A. On a total resource benefit-to-cost ratio basis, FLISR benefits are expected to exceed FLISR cost, with an expected benefit-to-cost ratio of approximately 1.31 to 1.53.

Q. PLEASE SUMMARIZE THE QUANTITATIVE COST AND BENEFIT COMPARISON FOR THE IVVO PROGRAM.

A. Table 16 summarizes the results of the Company's evaluation of IVVO, showing sensitivities for contingency ranges and levels of capital/O&M savings assumptions.

Table 16

IVVO Benefit to Cost Ratio

NSPM IVVO- NPV	Total ($MM)
Benefits	**22**
Other Benefits	19
CAP Benefits	3
Costs	**(39)**
O&M Expense	(2)
Change in Revenue Requirement	(37)
Benefit/Cost Ratio (CVR 1.25% energy; 0.7% capacity)	**0.57**
Benefit/Cost Ratio (no contingencies)	**0.61**
Low Benefit Sensitivity:	
Benefit/Cost Ratio (CVR 1% energy; 0.6% capacity)	0.46
Benefit/Cost Ratio (no contingencies)	0.49
High Benefit Sensitivity:	
Benefit/Cost Ratio (CVR 1.5% energy; 0.8% capacity)	0.67
Benefit/Cost Ratio (no contingencies)	0.72

Exhibit___(RD-1), Schedule 4 to my Direct Testimony provides more detail regarding the results of the Company's analysis of the costs and benefits of IVVO, including FAN components.

Q. WHAT DO YOU CONCLUDE REGARDING THE OVERALL COSTS AND BENEFITS OF THE IVVO PROGRAM, INCLUDING THE FAN COMPONENT?

A. On a total resource benefit-to-cost ratio basis, IVVO costs are expected to exceed quantifiable IVVO benefits, with an expected benefit-to-cost ratio of 0.57 to 0.61, within a range of sensitivities between 0.46 to 0.72.

Q. DO YOU ALSO PROVIDE A COMBINED SUMMARY OF THE COSTS AND QUANTITATIVE BENEFITS OF THE PROGRAMS?

A. Yes. To determine the combined cost benefit ratio for the AGIS initiative, we identified and aggregated the benefits of each project into four different categories: O&M, Capital, Customer, and Other benefits. At the same time, we aggregated the two types of costs of each project: O&M and Capital/ Change in Revenue Requirements. The final combined ratio is the result of dividing the aggregated benefits by the aggregated costs. Table 17 summarizes the results of the Company's evaluation of the combined AMI/FLISR/IVVO program:

Table 17

AGIS Initiative Combined Cost Benefit Ratio

NSPM -AMI, FLISR, IVVO-NPV	Total ($MM)
Benefits	**571**
O&M Benefits	53
Other Benefits	222
Customer Benefits	103
Capital Benefits	193
Costs	**(656)**
O&M Expense	(186)
Change in Revenue Requirement	(470)
Baseline Benefit-Cost Ratio (IVVO 1.25% energy, 0.7% capacity, with contingencies)	**0.87**
High Benefit/No Contingency Sensitivity (IVVO 1.5% energy/0.8% capacity, no contingency)	1.03
Lower Benefit/With Contingency Sensitivity (IVVO 1.0% energy/0.6% capacity, with contingencies)	0.86

Exhibit___(RD-1), Schedule 7 to my Direct Testimony provides the overall relative costs and benefits of the AGIS initiative.

Q. WHAT DO YOU CONCLUDE REGARDING THE OVERALL QUANTITATIVE OUTCOMES OF THE AGIS CBA?

A. On a combined basis, the quantifiable benefits of AMI, FLISR, and IVVO are expected to be lower than or in line with program costs, with an expected benefit-to-cost ratio of approximately 0.86 under our low scenario and up to 1.03 with our high sensitivity IVVO benefits and no contingencies. These totals represent a simple combination of AMI, FLISR, and IVVO respective costs and benefits, inclusive of the costs attributable to that portion of the FAN needed to enable AMI, FLISR, and IVVO, presented on a NPV basis.

In the next section of my Direct Testimony, I address other cost/benefit considerations that factor into the overall prudence of the Company's proposed AGIS initiative.

III. LEAST-COST/BEST-FIT ALTERNATIVES

Q. DID THE COMPANY ALSO DEVELOP ANY LEAST-COST/BEST-FIT ANALYSES TO COMPARE METERING ALTERNATIVES?

A. Yes. While Company witness Ms. Bloch also provides extensive discussion regarding the relative costs and benefits of various meter-reading alternatives, my Table 18 summarizes the results of the Company's evaluation. The aggregated benefits and capabilities provided by the AMI system related to its costs definitely surpasses other options, considering the increasing needs and choices demanded by the customers and the upcoming operational distribution-grid challenges. This assessment essentially summarizes the bases for our selection of the AMI solution we are presenting in this case.

Table 18

Meter Reading Least-Cost Best-Fit Alternative

Item	Description	Alternative: Manual	Alternative: AMR 1 way/ Limited 2 way	Alternative: AMR Drive-By	Alternative: AMI
Meter Capabilities	Time of use data	◔	◑	◔	●
	Real time notification of power outages	○	◑	○	●
	Fast response to customers inquires	○	◔	○	●
	Support integrated systems that offer customers	○	◔	○	●
	Vehicle to grid interconnects	○	○	○	●
	Remote reconfiguration/ firmware updates	○	○	○	●
	Availability of real time data	○	○	○	●
	Availability of power quality events	○	○	○	●
	Remove availability of meter diagnostic data	◔	◔	◔	●
	Remote disconnect/ connect	○	○	○	●
	Detect unsafe field metering conditions	○	○	○	●
	Energy Theft	◔	◔	◔	●
	Support for advanced rates	○	○	○	●
	Support for ADMS	○	○	○	●
Operational Features	Time consuming activity	A	NA	NA	NA
	Labor intensive - Safety Concerns	A	NA	PA	NA
	Cost of paying someone to read the meters.	A	NA	PA	NA
	Need access to meters to read them.	A	NA	NA	NA
	Accuracy of the meter read, human error.	A	NA	NA	NA
	Usually carried out infrequently (monthly).	A	PA	PA	NA
	Doesn't usually match invoice billing period.	A	PA	PA	NA
	Cost of system maintenance	NA	A	A	A
	Relying on technology	NA	A	A	A
NPV (2019)	Calculated COSTS - CAP Change in RR and O&M			$223M	$539M
	BENEFITS-Incremental to current reading/ billing			$0M	$442M
	NET COST-OUTCOME			**$223M**	**$97M**
	Least-Cost, Best-Fit Alternative Selected				**AMI System**

Legend for Capabilities

Full	Most	Partial	Minimal	None
●	◕	◑	◔	○

Legend for Operational Features

Applicable	Partially Applicable	Non-Applicable
A	PA	NA

Q. HOW DID YOU CALCULATE THE COSTS AND BENEFITS OF THE AMR AND AMI SOLUTIONS FOR PURPOSES OF THIS LEAST-COST/BEST-FIT ANALYSIS?

A. The AMR Drive-by cost and benefit assessments were provided by Company witness Ms. Bloch, and are discussed in her Direct Testimony. The total cost of this system results from the incremental capital and O&M necessary to implement an AMR drive-by solution as a replacement for our current meters. However, this system does not provide any incremental benefit to the current Cellnet meter/billing structure. The costs and benefits of the AMI system were provided by Ms. Bloch, Mr. Harkness, and Mr. Cardenas, as described earlier in my testimony. In contrast, we did not calculate the cost of manual or AMR limited two-way alternatives because we did not consider these realistic solutions given the state of the industry and the needs of our system, customers, and other stakeholders. Table 18 above underscores why we are proposing an AMI solution.

Q. DID YOU COMPLETE A SIMILAR ASSESSMENT WITH RESPECT TO THE COMMUNICATIONS NETWORK NECESSARY TO SUPPORT THE AGIS INITIATIVE?

A. Yes. Company witness Mr. Harkness provides an extensive discussion relative to the costs and benefits of the three communication network alternatives the Company considered. My Table 19 summarizes the results of the Company's evaluation of the aggregated capabilities and protections provided by the FAN with a mesh network, compared to other alternatives.

Table 19

Communications Least-Cost Best-Fit Alternative

		Alternative		
Item	**Feature/ Requirement**	**Cellular**	**Dedicated AMI**	**FAN Mesh**
Network Capabilities	Two way communications	●	●	●
	Peer-to-Peer	◔	◕	●
	Multipurpose	◕	◔	●
	Latency Requirements	●	◕	●
	Security	◑	●	●
	Dedicated traffic	◔	◕	●
	Priority traffic	◔	●	●
	O&M Costs Impact (run state)	◔	◑	●
	Resiliency	◑	◑	●
Operational Features	Cost of paying a third party for service	A	NA	NA
	Unable to fully control the system "end-start"	A	NA	NA
	Unable to implement to some AGIS processes	NA	PA	NA
	Relying on technology	A	A	A
NPV (2019)	Calculated COSTS - CAP Change in RR and O&M			$102M
	BENEFITS-Incremental to current reading/ billing			$0M
	NET COST-OUTCOME			**$102M**
Least-Cost, Best-Fit Alternative Selected				**FAN Mesh**

Legend for Capabilities

Full	Most	Partial	Minimal	None
●	⍰	⍰	⍰	○

Legend for Operational Features

Applicable	Partially Applicable	Non-Applicable
A	PA	NA

Q. HOW DID YOU CALCULATE THE COSTS OF THE COMMUNICATION NETWORK ALTERNATIVES IN THE LEAST-COST/BEST-FIT ANALYSIS?

A. The cost of the FAN components and deployment were provided by Company witness Mr. Harkness, and are described in his testimony. Additionally, Mr. Harkness explains that in comparing alternatives to the FAN, the Company determined that a cellular option would likely have a similar device cost with additional O&M costs; therefore, the cost is expected to be at best equal to and more likely higher than FAN costs. Furthermore, Mr. Harkness explains that a dedicated AMI network was ruled out because it would not allow non-AMI devices to connect to each other or to back office applications, affecting overall system functionality. As such, Table 19 does not show specific cost vs. benefit estimates for alternatives to the FAN, but rather focuses on the relative capabilities of all three alternatives.

Q. DID THE COMPANY COMPLETE A LEAST-COST/BEST-FIT ANALYSIS FOR IVVO OR FLISR?

A. No; it would not have made sense for these components of the AGIS initiative. IVVO and FLISR are, more simply, additional ADMS capabilities. In contrast, there are different fundamental types of meter solutions and communication networks. While there are forms of IVVO and FLISR devices that have different individual capabilities, such comparisons were conducted in the RFP processes, as discussed by Ms. Bloch.

Q. WHAT DO THESE LEAST-COST/BEST-FIT ANALYSES SHOW?

A. They provide another means (in addition to the CBA and the extensive narrative testimony) of comparing the AGIS solutions with alternatives. They largely summarize the analyses Ms. Bloch, and Mr. Harkness provide in much greater detail, and underscore why it was prudent to select AMI and the FAN.

IV. QUALITATIVE BENEFITS OF AGIS

Q. ARE THERE SPECIFICALLY IDENTIFIABLE BENEFITS THE AMI PROGRAM WILL PROVIDE TO CUSTOMERS OR THE DISTRIBUTION SYSTEM THAT WERE NOT MODELED IN YOUR ANALYSIS?

A. Yes. There are a number of benefits of AMI that cannot be quantified either in whole or in part. For example, it is difficult to quantify customers' need and broad expectation to have more choice in and control over their energy usage, or their frustration with older technologies that cannot be updated without better data access. Our analysis captures estimates of customer adoption of technologies to support customer choice and the impacts on energy usage, but cannot fully quantify customer satisfaction associated with having better energy usage and pricing information. Nor can it fully quantify the convenience to customers of better outage management.

The unquantifiable benefits, or benefit the Company did not model in the CBA, are largely discussed by Company witnesses Ms. Bloch, Mr. Harkness, and Mr. Gersack. These include but are not limited to:

- Improved customer choice and experience, leading to customer empowerment and satisfaction;
- Enhanced distributed energy resource integration;
- Environmental benefits of enhanced energy efficiency;
- Improved safety to both customers and Company employees;
- Improvements in power quality; and
- Cyber and data security.

Q. ARE THERE ANY BENEFITS THAT THE FLISR PROGRAM PROVIDES TO CUSTOMERS OR THE DISTRIBUTION SYSTEM THAT WERE NOT MODELED IN YOUR ANALYSIS?

A. Yes. As with AMI, there are benefits of FLISR that the Company did not attempt to quantify. It is important to note that FLISR does not avoid outages altogether, but works to minimize their impacts on customers when they do occur, improving the customer's experience and leading to customer satisfaction. Thus the qualitative benefits include but are not limited to:

- Improved public and employee safety,
- Value of the data provided by FLISR for system planning purposes, and
- Overall customer satisfaction with utility service.

Q. ARE THERE ANY BENEFITS THAT THE IVVO PROGRAM PROVIDES TO CUSTOMERS OR THE DISTRIBUTION SYSTEM THAT WERE NOT MODELED IN YOUR ANALYSIS?

A. Yes. As with AMI and FLISR, there are benefits of IVVO that the Company did not attempt to quantify. They include but are not limited to:

- Customer bill savings specific to customers whose feeders are equipped with IVVO assets;
- Enhanced automatic access of low income customers to energy efficiency savings;
- Greater efficiencies from the customers' personal electrical devices; and
- Increased hosting capacity of distributed energy resources.

Q. CAN YOU PROVIDE MORE DETAIL REGARDING THESE QUALITATIVE BENEFITS OF IVVO?

A. Yes. With respect to low income customers' access to energy efficiency savings, I note that Ms. Bloch explains how IVVO can reduce voltage, and therefore save customers money without requiring any change in energy usage or activities on the customers' part. Additionally, IVVO is not tied to any particular energy efficiency program, so it has the added benefit of saving money for customers – including low income customers – who are sometimes unable to take advantage of such programs.

Q. WHY DIDN'T THE COMPANY ATTEMPT TO QUANTIFY THESE BENEFITS?

A. Although the Company feels strongly that these benefits are meaningful to our customers, it is difficult and often highly subjective to attempt to place a dollar value on them. For example, customer satisfaction and empowerment are important to the Company's business model and role as a public utility, but do not easily lend themselves to monetization.

The Company therefore concluded that it was best to provide a cost and benefit analysis to the Commission that fairly represents the cost and benefits of quantifiable projects components, and which we were able to value with reasonable confidence, and then ask the Commission to weigh the other impacts to our customers as it sees fit. In this way, the Commission may rely on the CBA as a baseline of our business case for our projects, and then evaluate and discuss the merits of the additional beneficial impacts to our customers.

Q. WHY SHOULD THE COMMISSION CONSIDER APPROVING COST RECOVERY FOR AMI, FLISR, AND IVVO IF COMBINED PROGRAM COSTS EXCEED THE OVERALL QUANTITATIVE BENEFITS?

A. There are several reasons why AMI, FLISR, and IVVO are overall valuable resources, even if costs slightly exceed estimated quantifiable benefits.

First, the Company AMI, FLISR, and IVVO implementation will allow the Company to achieve greater visibility into its distribution system, greater opportunities for demand side management, and improved reliability. Conversely, we cannot make the same progress in these areas without enhancing the distribution grid. As Mr. Gersack discusses, these are also necessary components of any new rate structures or other initiatives the Commission may wish to implement; right now, the Company simply does not have the technical capability or insight into customer usage to implement such technologies or customer support without AMI, FLISR, and IVVO.

Second, I would not necessarily expect quantifiable benefits to exceed costs, particularly for AMI, because it is necessary to replace aging technology. On the one hand, the Company's current meters will no longer be considered current technology nor supported as the Cellnet contract comes to an end, but on the other hand a CBA does not take into account that we cannot function without metering. Further, the model cannot fully reflect that AMR meters are an outdated option that will not provide the functionality customers, stakeholders, and the Commission have come to expect, nor the system support necessary in the age of DER.

Third, this model is not the only manner in which we measure the value of the grid advancement options available to us. Much of the Company's comparison of alternative options is completed in the Request for Information (RFI) and Request for Proposal (RFP) proceedings, rather than in a CBA based on our final selections. As described by Ms. Bloch, we have made careful and prudent AMI selections and negotiated a strong contract with our new AMI vendor. Ms. Bloch also discusses alternative considerations and vendor options for other system devices. Likewise, the FAN communications network is the product of robust RFP processes discussed by Mr. Harkness.

Given this prudent approach to selection of infrastructure, the ultimate question is whether overall costs are reasonable.

Fourth, this model can only quantify that which is quantifiable. Its expression of benefits does not include such qualitative benefits as customer choice and convenience, human safety, and potential support for future distributed energy resources. We recognize that choice, convenience, and greater control over energy costs and usage are of increasing importance to our customers. Customer satisfaction and customer empowerment with respect to their energy choices are of central importance to the public utility model.

Fifth and finally, the Company's AGIS witnesses describe at length why it is important to advance the NSPM grid to continue providing safe, increasingly reliable electric service to our customers not just in the present but also into the future. While we cannot predict every new technology that will arrive, we know that our current system is not future-proofed. Conversely, the AGIS program will support a fundamental utility function while improving existing infrastructure that is no longer maximizing service to our customers. It makes future applications, optionality, and distributed energy resources available in a way it is not possible to fully measure because it is not possible to fully predict the future. But as Mr. Gersack describes, utilities nationwide are making these important grid investments because "doing nothing" is not a realistic option. Therefore, the Company feels that this is both the right time and an important time to modernize critical components of its distribution grid.

V. CONCLUSION

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. The Company's AGIS CBA is a tool that is helpful, but not sufficient, to assess the overall prudence of the AGIS strategy and investments. We believe it is realistic and appropriate that our CBA shows individual and composite benefit-to-cost ratios that approach 1.0 (or exceed 1.0 in the case of FLISR), even before taking into account unquantifiable benefits. With those qualitative considerations and benefits, the Company believes the value of the AGIS initiative and its respective components substantially exceed the costs. Finally, both the CBA itself and our least cost/best fit summative analyses underscore that our AGIS program is reasonable given the need to replace aging technology, bring our distribution grid into the future, meet customer needs and offer greater customer choice, and take advantage of opportunities to use technology to support demand side management, peak demand reductions, and build a more resilient and responsive grid.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Statement of Qualifications

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Director, Risk Strategy
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Ravikrishna Duggirala has more than 25 years of diverse experience in various industries in the areas of Engineering, Operations, Business Development, and Risk Management. Dr. Duggirala joined Xcel Energy in 2002 and is currently Director of Risk Strategy, where he is responsible for Enterprise Risk Management, Asset Risk Management, risk analytics, and modeling. He has held this position since 2008. Previously, Dr. Duggirala was the Manager of Energy Sales Risk for Xcel Energy from 2005 through 2008, where he was responsible for retail sales risk analysis, key risk analysis, sensitivity analysis, and risk analytics. Dr. Duggirala was also a Risk Consultant with the Company between 2002 and 2005, where he was responsible for monitoring and reporting of trading risks, managing risk policies and procedures and supporting Corporate Risk Management Oversight Committee. Prior to working for Xcel Energy, Dr. Duggirala worked at other companies including Enron, Monsanto, and Purdue University in various capacities.

Dr. Duggirala received his Masters Degree in Business Administration from Washington University in St. Louis in 2000, and his Ph.D in Engineering from Purdue University in 1996.

Northern States Power Company
AMI Cost Benefit Analysis

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	TOTAL	NPV
Total Meters Deployed	*10,131*	*7,368*	*121,800*	*630,000*	*590,000*	*40,700*	*13,755*	*13,890*	*14,027*	*14,164*	*14,304*	*14,444*	*14,586*	*14,729*	*14,874*	*15,020*	*15,168*	*1,558,960*	
CAPITAL COSTS																		***TOTAL DISCOUNTED***	***NSPM-NPV***
AMI Meters																			
AMI Meters Purchase	1,408,513	1,024,373	13,875,456	71,769,600	67,212,800	4,636,544	1,771,935	1,826,384	1,882,506	1,940,352	1,999,976	2,061,432	2,124,776	2,190,067	2,257,364	2,326,730	2,398,226	**182,707,036**	**132,855,955**
AMI Meter Installation	620,017	450,922	5,054,700	26,145,000	24,485,000	1,689,050	645,500	665,335	685,779	706,852	728,573	750,961	774,036	797,821	822,337	847,606	873,652	**66,743,140**	**48,567,278**
RTU's (Return to Utility- Estimate 3% of installed meters)	0	0	303,282	1,568,700	1,469,100	101,343	0	0	0	0	0	0	0	0	0	0	0	**3,442,425**	**2,619,423**
Vendors deployment Project Management	0	381,182	733,817	1,198,410	1,223,217	624,270	0	0	0	0	0	0	0	0	0	0	0	**4,160,897**	**3,204,164**
AMI Operations (Internal Personnel)	843,677	983,487	1,869,203	2,046,398	2,186,980	1,903,327	0	0	0	0	0	0	0	0	0	0	0	**9,833,071**	**7,716,691**
AMI Operations (External Personnel)	0	0	658,073	1,372,663	1,365,055	637,919	0	0	0	0	0	0	0	0	0	0	0	**4,033,710**	**3,053,879**
Shop & Lab equipment (AMI Field Test, Lab equip)	0	25,888	217,401	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**243,288**	**203,171**
Distribution Contingencies	442,320	441,341	3,497,637	16,031,519	15,083,091	1,477,238	0	0	0	0	0	0	0	0	0	0	0	**36,973,146**	**28,259,602**
TOTAL - AMI Meters	3,314,527	3,307,193	26,209,569	120,132,290	113,025,244	11,069,690	2,417,435	2,491,719	2,568,285	2,647,205	2,728,549	2,812,393	2,898,813	2,987,889	3,079,701	3,174,336	3,271,878	***308,136,713***	***226,480,162***
Communications Network																			
FAN Infrastructure Distribution	100,005	650,501	1,279,994	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**2,030,499**	**1,729,867**
FAN Distribution WiMax	322,537	2,097,993	4,128,233	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**6,548,763**	**5,579,166**
FAN Bus Sys Costs	1,709	51,120	88,387	59,329	56,142	15,200	0	0	0	0	0	0	0	0	0	0	0	**271,887**	**217,842**
FAN Bus Sys WiMAX Cost	334,633	10,011,076	17,309,267	11,618,600	10,994,506	2,976,466	0	0	0	0	0	0	0	0	0	0	0	**53,244,549**	**42,660,847**
FAN Bus Sys Contingency	73,854	1,267,037	2,253,221	1,166,606	1,103,942	298,863	0	0	0	0	0	0	0	0	0	0	0	**6,163,522**	**4,979,818**
TOTAL - Communications	*832,739*	*14,077,726*	*25,059,102*	*12,844,535*	*12,154,590*	*3,290,528*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	***68,259,221***	***55,167,540***
IT Systems and Integration																			
IT Hardware	1,504,080	2,537,978	2,141,049	545,521	556,814	568,340	580,104	0	0	0	0	0	0	0	0	0	0	**8,433,885**	**7,028,256**
IT Software	1,064,115	1,552,117	5,536,877	4,669,670	323,141	0	0	0	0	0	0	0	0	0	0	0	0	**13,145,919**	**10,838,063**
IT Labor + Project Management	1,725,374	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**1,725,374**	**1,621,097**
IT Contingency	0	0	0	11,176,589	605,252	548,564	174,031	0	0	0	0	0	0	0	0	0	0	**12,504,436**	**9,642,915**
TOTAL - IT Systems and Integration	*4,293,568*	*4,090,095*	*7,677,926*	*16,391,780*	*1,485,207*	*1,116,904*	*754,136*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	***35,809,615***	***29,130,330***
Program Management																			
Change Management	0	1,000,000	1,035,500	1,072,260	1,110,325	1,149,742	1,190,558	0	0	0	0	0	0	0	0	0	0	**6,558,386**	**4,950,734**
Environment/Release Management	0	28,071	2,064,464	2,318,348	1,044,303	355,017	99,666	0	0	0	0	0	0	0	0	0	0	**5,909,870**	**4,617,070**
Finance	0	109,959	193,798	194,658	145,467	0	0	0	0	0	0	0	0	0	0	0	0	**643,882**	**516,017**
PMO	0	288,790	506,590	508,944	381,346	0	0	0	0	0	0	0	0	0	0	0	0	**1,685,670**	**1,350,955**
Security	0	1,105,737	1,144,991	1,185,638	1,227,728	0	0	0	0	0	0	0	0	0	0	0	0	**4,664,093**	**3,748,708**
Supply Chain	0	477,703	487,591	497,685	507,987	0	0	0	0	0	0	0	0	0	0	0	0	**1,970,966**	**1,585,917**
Talent Strategy	238,852	349,325	361,726	185,901	0	0	0	0	0	0	0	0	0	0	0	0	0	**1,135,803**	**977,689**
Delivery and Execution Leadership	0	374,158	1,294,786	1,314,010	667,319	0	0	0	0	0	0	0	0	0	0	0	0	**3,650,273**	**2,916,840**
Contingency	11,943	186,687	354,472	363,872	254,224	75,238	64,511	0	0	0	0	0	0	0	0	0	0	**1,310,947**	**1,033,197**
TOTAL - Program Management	*250,795*	*3,920,430*	*7,443,919*	*7,641,315*	*5,338,699*	*1,579,997*	*1,354,735*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	***27,529,891***	***21,697,127***
TOTAL CAPITAL	8,691,629	25,395,444	66,390,515	157,009,920	132,003,740	17,057,120	4,526,306	2,491,719	2,568,285	2,647,205	2,728,549	2,812,393	2,898,813	2,987,889	3,079,701	3,174,336	3,271,878	*439,735,439*	*332,475,159*
O&M ITEMS																			
Communications Network																			
FAN Network Infrastructure Distribution	0	0	130,976	298,507	271,352	225,136	105,810	54,000	55,118	56,259	57,424	58,612	59,826	61,064	62,328	63,618	64,935	**1,624,966**	**1,036,835**
FAN Network Business Systems	0	0	335,766	3,171,422	2,673,589	1,491,278	499,575	671,918	685,827	700,023	714,514	729,304	744,401	759,810	775,538	791,592	807,978	**15,552,536**	**9,460,970**
FAN WiMAX Cost	233,600	357,245	427,150	434,290	562,241	1,048,049	653,607	0	0	0	0	0	0	0	0	0	0	**3,716,182**	**2,782,723**
NOC Opco Allocation	200,000	408,280	625,097	638,037	651,244	664,725	678,485	692,529	706,864	721,497	736,432	751,676	767,235	783,117	799,328	815,874	832,762	**11,473,181**	**6,445,717**
FAN Network Distribution Contingency	0	0	59,854	136,414	124,004	102,885	48,354	24,677	0	0	0	0	0	0	0	0	0	**496,189**	**363,768**
FAN Network Bus Sys Contingency	0	0	301,130	686,305	623,871	517,616	243,271	124,153	0	0	0	0	0	0	0	0	0	**2,496,348**	**1,830,131**
TOTAL - Communications	*433,600*	*765,525*	*1,879,974*	*5,364,975*	*4,906,301*	*4,049,690*	*2,229,101*	*1,567,278*	*1,447,809*	*1,477,779*	*1,508,369*	*1,539,592*	*1,571,462*	*1,603,991*	*1,637,194*	*1,671,084*	*1,705,675*	***35,359,401***	***21,920,143***
IT Systems and Integration																			
IT Hardware	42,114	1,654,282	1,678,585	1,705,324	1,740,624	1,776,655	1,813,432	1,850,970	1,889,285	1,928,393	1,968,311	2,009,055	2,050,642	2,093,091	2,136,418	2,180,642	2,225,781	**30,743,604**	**17,268,781**
IT Software	27,285	85,988	983,487	1,845,314	2,011,390	2,053,026	2,095,523	2,138,900	2,183,176	2,228,367	2,274,495	2,321,577	2,369,633	2,418,685	2,468,752	2,519,855	2,572,016	**32,597,467**	**17,432,600**
IT Labor	0	2,056,405	1,553,273	1,750,246	1,680,090	1,717,226	1,721,011	1,789,073	1,859,799	1,933,290	2,009,656	2,089,007	2,171,461	2,257,136	2,346,156	2,438,653	2,534,759	**31,907,241**	**17,784,018**
Common Corporate Business System development-Allocation	646,904	4,270,861	5,304,505	11,866,886	12,378,199	10,847,247	10,347,121	0	0	0	0	0	0	0	0	0	0	**55,661,724**	**41,239,207**
IT Contingency	0	997,287	9,826,939	4,112,864	2,099,639	2,145,629	2,192,624	2,240,646	2,289,716	2,339,857	2,391,093	2,443,448	2,496,946	2,551,611	2,607,470	2,664,547	2,722,871	**46,123,186**	**28,075,602**
TOTAL - IT Systems and Integration	*716,303*	*9,064,823*	*19,346,789*	*21,280,633*	*19,909,942*	*18,539,783*	*18,169,711*	*8,019,589*	*8,221,975*	*8,429,907*	*8,643,555*	*8,863,087*	*9,088,683*	*9,320,523*	*9,558,795*	*9,803,697*	*10,055,427*	***197,033,221***	***121,800,207***
Program Management																			
Change Management	0	1,825,114	2,157,971	3,067,323	3,176,213	2,991,329	1,608,666	0	0	0	0	0	0	0	0	0	0	**14,826,616**	**11,214,681**
Environment/Release Management	0	0	22,405	23,200	24,024	24,877	11,794	0	0	0	0	0	0	0	0	0	0	**106,300**	**78,991**
Finance	0	32,456	112,027	167,045	216,218	0	0	0	0	0	0	0	0	0	0	0	0	**527,746**	**410,061**
PMO	0	79,772	275,346	410,574	531,437	0	0	0	0	0	0	0	0	0	0	0	0	**1,297,129**	**1,007,876**
Talent Strategy	37,760	58,651	60,733	0	55,000	0	0	0	0	0	0	0	0	0	0	0	0	**212,144**	**177,898**
Delivery and Execution Leadership	0	217,284	510,624	714,661	897,539	0	0	0	0	0	0	0	0	0	0	0	0	**2,340,109**	**1,829,448**
Contingency	1,888	110,664	156,955	219,140	245,022	150,810	81,023	0	0	0	0	0	0	0	0	0	0	**965,502**	**735,948**
TOTAL - Program Management	*39,648*	*2,323,940*	*3,296,060*	*4,601,944*	*5,145,453*	*3,167,016*	*1,701,483*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	***20,275,545***	***15,454,901***
AMI Operations (Personnel)																			
AMI Operations (Internal Personnel)	0	2,029	36,563	40,759	42,206	43,704	47,708	1,040,317	1,077,248	1,115,491	1,155,090	1,196,096	1,238,558	1,282,526	1,328,056	1,375,202	1,424,022	**12,445,575**	**5,756,644**
AMI Operations (External Personnel)	0	187,968	214,121	468,050	1,576,002	1,300,659	1,409,575	1,475,931	1,545,439	1,600,302	1,657,112	1,715,940	1,776,856	1,839,934	1,905,252	1,972,888	2,042,926	**22,688,954**	**11,693,307**
Customer Claims	0	663	1,719	48,916	48,843	7,423	0	0	0	0	0	0	0	0	0	0	0	**107,565**	**81,001**
Total AMI- O&M Dist Contingency	0	29,259	38,605	78,357	249,204	207,032	224,422	387,502	403,894	418,232	433,079	448,454	464,374	480,859	497,929	515,606	533,910	**5,410,717**	**2,687,292**
TOTAL - AMI Operations	*0*	*219,920*	*291,008*	*636,082*	*1,916,255*	*1,558,818*	*1,681,704*	*2,903,750*	*3,026,581*	*3,134,024*	*3,245,282*	*3,360,490*	*3,479,787*	*3,603,319*	*3,731,237*	*3,863,696*	*4,000,857*	***40,652,811***	***20,218,244***
TOTAL O&M	1,189,551	12,374,208	24,813,831	31,883,634	31,877,951	27,315,307	23,782,000	12,490,618	12,696,365	13,041,711	13,397,206	13,763,169	14,139,931	14,527,833	14,927,226	15,338,477	15,761,959	293,320,977	179,393,496
GRAND TOTAL CAPITAL & O&M	9,881,180	37,769,652	91,204,347	188,893,554	163,881,691	44,372,427	28,308,306	14,982,337	15,264,650	15,688,915	16,125,755	16,575,562	17,038,744	17,515,722	18,006,927	18,512,812	19,033,837	733,056,417	511,868,655

Northern States Power Company
AMI Cost Benefit Analysis

XCEL ENERGY

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	TOTAL	NPV
Total Meters Replaced	*10,131*	*7,368*	*121,800*	*630,000*	*590,000*	*40,700*	*13,755*	*13,890*	*14,027*	*14,164*	*14,304*	*14,444*	*14,586*	*14,729*	*14,874*	*15,020*	*15,168*	***1,558,960***	
O&M ITEMS																			
Avoided O&M Meter Reading Costs																			
Drive-by Meter Reading Cost - O&M	2,155	86,393	1,085,789	2,460,063	3,740,671	3,587,859	4,153,792	4,287,938	4,426,475	4,562,493	4,702,691	4,847,197	4,996,143	5,149,667	5,307,907	5,471,011	5,639,126	**64,507,370**	**33,455,306**
TOTAL - Reduction in Meter Reading Costs	***2,155***	***86,393***	***1,085,789***	***2,460,063***	***3,740,671***	***3,587,859***	***4,153,792***	***4,287,938***	***4,426,475***	***4,562,493***	***4,702,691***	***4,847,197***	***4,996,143***	***5,149,667***	***5,307,907***	***5,471,011***	***5,639,126***	***64,507,370***	***33,455,306***
Reduction in Field and Meter Services																			
Costs savings from remote disconnect capability	0	0	0	0	386,423	1,108,454	1,592,346	1,814,095	1,878,495	2,060,451	2,133,597	2,209,340	2,287,771	2,368,987	2,453,086	2,540,171	2,630,347	**25,463,562**	**12,291,603**
Reduction in trips due to Customer equipment damage	0	0	0	0	32,617	67,549	139,894	144,860	150,003	155,328	160,842	166,552	172,465	178,587	184,927	191,492	198,290	**1,943,406**	**940,688**
Reduction in "OK on Arrival" Outage Field Trips	0	0	0	0	135,529	280,680	581,288	601,924	623,292	645,419	668,331	692,057	716,625	742,065	768,408	795,687	823,934	**8,075,238**	**3,908,746**
Reduction in Field Trips for Voltage Investigations	0	0	0	0	74,833	154,978	320,960	332,354	344,152	356,370	369,021	382,121	395,686	409,733	424,279	439,341	454,937	**4,458,764**	**2,158,225**
TOTAL - Reduction in Field & Meter Services	***0***	***0***	***0***	***0***	***629,401***	***1,611,661***	***2,634,487***	***2,893,232***	***2,995,942***	***3,217,567***	***3,331,791***	***3,450,070***	***3,572,547***	***3,699,373***	***3,830,700***	***3,966,690***	***4,107,508***	***39,940,969***	***19,299,262***
Improved Distribution System Spend Efficiency																			
Efficiency gains reliability, asset health and capacity projects- O&M	0	0	0	0	1,159	2,401	4,972	5,148	5,331	5,520	5,716	5,919	6,129	6,347	6,572	6,805	7,047	**69,067**	**33,431**
TOTAL - Improved Distribution System Spend Efficiency	***0***	***0***	***0***	***0***	***1,159***	***2,401***	***4,972***	***5,148***	***5,331***	***5,520***	***5,716***	***5,919***	***6,129***	***6,347***	***6,572***	***6,805***	***7,047***	***69,067***	***33,431***
Outage Management Efficiency																			
Outage Management Efficiency (Storm spend O&M)	0	0	0	0	604	1,250	2,589	2,681	2,776	2,875	2,977	3,082	3,192	3,305	3,422	3,544	3,670	**35,965**	**17,409**
TOTAL - Outage Management Efficiency	***0***	***0***	***0***	***0***	***604***	***1,250***	***2,589***	***2,681***	***2,776***	***2,875***	***2,977***	***3,082***	***3,192***	***3,305***	***3,422***	***3,544***	***3,670***	**35,965**	**17,409**
TOTAL O&M BENEFITS	**2,155**	**86,393**	**1,085,789**	**2,460,063**	**4,371,835**	**5,203,171**	**6,795,840**	**7,189,000**	**7,430,524**	**7,788,455**	**8,043,175**	**8,306,268**	**8,578,011**	**8,858,691**	**9,148,602**	**9,448,050**	**9,757,350**	**104,553,371**	**52,805,408**
OTHER BENEFITS																			
Cost reductions																			
Reduced Consumption on Inactive Meters	0	0	0	0	350,052	714,596	1,458,776	1,488,973	1,519,795	1,551,255	1,583,366	1,616,141	1,649,595	1,683,742	1,718,595	1,754,170	1,790,482	**18,879,538**	**9,235,364**
Reduced Uncollectible / Bad Debt Expense	0	0	0	0	259,816	538,078	1,114,360	1,153,920	1,194,884	1,237,303	1,281,227	1,326,711	1,373,809	1,422,579	1,473,081	1,525,375	1,579,526	**15,480,670**	**7,493,278**
Reduced outage duration benefit	0	0	0	0	391,289	798,777	1,630,623	1,664,377	1,698,830	1,733,996	1,769,889	1,806,526	1,843,921	1,882,090	1,921,050	1,960,815	2,001,404	**21,103,587**	**10,323,309**
Theft / Tamper Detection & Reduction	0	0	0	0	847,310	1,729,700	3,531,009	3,604,101	3,678,706	3,754,855	3,832,580	3,911,915	3,992,891	4,075,544	4,159,908	4,246,018	4,333,911	**45,698,446**	**22,354,455**
TOTAL - Cost Reductions	0	0	0	0	1,848,467	3,781,151	7,734,769	7,911,371	8,092,215	8,277,408	8,467,062	8,661,292	8,860,217	9,063,955	9,272,633	9,486,379	9,705,322	***101,162,241***	***49,406,407***
Load Flexibility Benefits																			
Critical Peak Pricing -CPP-DSM Peak	0	0	0	0	0	19,965,050	20,415,850	21,129,600	21,780,000	22,361,590	23,136,860	23,755,800	24,531,638	25,336,224	26,164,958	27,023,654	27,910,308	**283,511,530**	**138,479,332**
Time Of Usage-TOU-Customer energy price shift	0	0	0	0	0	1,819,116	1,975,194	2,019,888	2,037,750	2,133,144	2,262,273	2,392,520	2,517,599	2,573,992	2,725,849	2,753,107	2,780,638	**27,991,070**	**13,576,886**
Time Of Usage-TOU-Avoided CO2 Emissions	0	0	0	0	0	226,876	352,119	485,400	361,972	230,903	344,421	271,720	330,772	309,477	297,166	310,767	413,652	**3,935,245**	**1,961,868**
TOTAL - Load Flexibility Benefits	0	0	0	0	0	22,011,042	22,743,163	23,634,888	24,179,722	24,725,637	25,743,554	26,420,040	27,380,008	28,219,692	29,187,972	30,087,528	31,104,598	***315,437,845***	***154,018,085***
TOTAL OTHER BENEFITS	**0**	**0**	**0**	**0**	**1,848,467**	**25,792,193**	**30,477,932**	**31,546,259**	**32,271,937**	**33,003,045**	**34,210,616**	**35,081,332**	**36,240,224**	**37,283,648**	**38,460,605**	**39,573,907**	**40,809,920**	**416,600,086**	**203,424,492**
CAPITAL ITEMS																			
Capital gains and other avoided purchases																			
Efficiency gains reliability, asset health and capacity projects- CAP	0	0	0	0	189,547	386,940	789,900	806,251	822,940	839,975	857,363	875,110	893,225	911,715	930,587	949,850	969,512	**10,222,915**	**5,000,776**
Outage Management Efficiency (Storm spend CAP)	0	0	0	0	313,698	649,669	1,345,465	1,393,229	1,442,688	1,493,904	1,546,937	1,601,854	1,658,719	1,717,604	1,778,579	1,841,718	1,907,099	**18,691,164**	**9,047,289**
Avoided Meter Purchases	9,788	18,152	185,992	1,086,102	2,027,125	2,203,315	2,138,852	2,218,752	2,301,754	2,387,984	2,477,572	2,570,653	2,667,369	2,767,866	2,872,297	2,980,823	3,093,609	**34,008,006**	**17,455,428**
TOTAL - Efficiency gains and other avoided CAP purchases	9,788	18,152	185,992	1,086,102	2,530,369	3,239,924	4,274,216	4,418,231	4,567,383	4,721,863	4,881,872	5,047,617	5,219,313	5,397,185	5,581,464	5,772,392	5,970,221	***62,922,085***	***31,503,493***
Avoided Meter Reading CAP investment																			
Drive-by Meter Reading Cost - CAP	20,755	412,501	3,935,923	12,881,148	23,340,750	29,130,716	29,698,551	28,887,914	28,107,557	27,361,868	26,557,430	25,715,024	24,868,419	23,999,536	23,212,398	22,384,139	21,406,031	**351,920,659**	**189,681,697**
TOTAL - Avoided Meter Reading CAP Investment	***20,755***	***412,501***	***3,935,923***	***12,881,148***	***23,340,750***	***29,130,716***	***29,698,551***	***28,887,914***	***28,107,557***	***27,361,868***	***26,557,430***	***25,715,024***	***24,868,419***	***23,999,536***	***23,212,398***	***22,384,139***	***21,406,031***	***351,920,659***	***189,681,697***
TOTAL CAPITAL BENEFITS	**30,543**	**430,653**	**4,121,915**	**13,967,250**	**25,871,119**	**32,370,640**	**33,972,767**	**33,306,145**	**32,674,940**	**32,083,731**	**31,439,303**	**30,762,641**	**30,087,732**	**29,396,720**	**28,793,861**	**28,156,530**	**27,376,252**	**414,842,744**	**221,185,190**
GRAND TOTAL BENEFITS	**32,698**	**517,046**	**5,207,705**	**16,427,313**	**32,091,421**	**63,366,004**	**71,246,539**	**72,041,404**	**72,377,400**	**72,875,232**	**73,693,094**	**74,150,241**	**74,905,968**	**75,539,059**	**76,403,069**	**77,178,487**	**77,943,522**	**935,996,201**	**477,415,090**

NSPM -AMI- NPV

	Total ($MM)
Benefits	**446**
O&M Benefits	53
Other Benefits	203
CAP Benefits	190
Costs	**(539)**
O&M Expense	(179)
Change in Revenue Requirements	(359)
Benefit/Cost Ratio	**0.83**

RATIO SENSITIVITY	VALUE
FAN(80% WiMAx)+ Contingencies	0.83
FAN(80% WiMAx) NO Contingencies	0.99

Northern States Power Company
FLISR Cost Benefit Analysis

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	TOTAL	NPV	Cost Category
CAPITAL ITEMS - SUMMARY																							
FLISR Assets																							
Asset Cost	0	2,456,519	6,604,776	3,745,275	5,606,776	5,852,901	4,447,353	4,539,413	4,633,379	4,729,290	0	0	0	0	0	0	0	0	0	0	**42,615,682**	**29,507,829**	**Direct and Tangible**
Asset Installation	0	661,457	1,804,228	1,037,932	1,576,342	1,669,400	1,286,894	1,332,579	1,379,886	1,428,872	0	0	0	0	0	0	0	0	0	0	**12,177,590**	**8,386,388**	**Direct and Tangible**
Device related Vendor Project Management + Other Labor	0	15,533	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**15,533**	**13,712**	**Direct and Tangible**
Asset Contingency	0	0	0	1,499,386	1,866,899	919,536	604,982	617,505	630,288	643,334	0	0	0	0	0	0	0	0	0	0	**6,781,930**	**4,638,594**	**Direct and Tangible**
TOTAL - Assets Cost	***0***	***3,133,508***	***8,409,004***	***6,282,593***	***9,050,018***	***8,441,837***	***6,339,229***	***6,489,497***	***6,643,552***	***6,801,496***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***61,590,735***	**42,546,523**	
Communications Network																							
FAN Infrastructure Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**	**Direct and Tangible**
FAN Distribution WiMax	60,476	393,374	774,044	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**1,227,893**	**1,046,094**	**Direct and Tangible**
FAN Bus Sys Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**	**Direct and Tangible**
FAN Bus Sys WiMAX Cost	62,744	1,877,077	3,245,488	2,178,488	2,061,470	558,087	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**9,983,353**	**7,998,909**	**Direct and Tangible**
FAN Bus Sys Contingency	48,467	831,493	1,478,676	765,585	724,462	196,129	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**4,044,811**	**3,268,006**	**Direct and Tangible**
TOTAL - Communications	171,686	3,101,943	5,498,207	2,944,073	2,785,932	754,216	0	0	0	0	0	0	0	0	0	0	0	0	0	0	***15,256,057***	**12,313,008**	
IT Systems and Integration																							
ADMS FLISR Integration	0	372,780	503,962	521,853	1,023,270	1,059,597	807,499	836,165	865,849	896,587	0	0	0	0	0	0	0	0	0	0	**6,887,562**	**4,636,414**	**Direct and Tangible**
IT Contingency	0	0	0	299,788	632,358	654,807	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**1,586,953**	**1,147,107**	**Direct and Tangible**
TOTAL - IT Systems and Integration	***0***	***372,780***	***503,962***	***821,641***	***1,655,629***	***1,714,403***	***807,499***	***836,165***	***865,849***	***896,587***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***8,474,515***	**5,783,521**	
TOTAL CAPITAL	**171,686**	**6,608,231**	**14,411,173**	**10,048,307**	**13,491,578**	**10,910,457**	**7,146,728**	**7,325,662**	**7,509,401**	**7,698,082**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**85,321,307**	**60,643,052**	
O&M ITEMS - SUMMARY																							
Deployment																							
O&M in support of capital deployment	0	85,389	229,582	130,186	194,892	203,447	154,590	157,790	161,056	164,390	0	0	0	0	0	0	0	0	0	0	**1,481,321**	**1,025,692**	**Direct and Tangible**
TOTAL - Asset Operations	***0***	***85,389***	***229,582***	***130,186***	***194,892***	***203,447***	***154,590***	***157,790***	***161,056***	***164,390***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***1,481,321***	**1,025,692**	
Ongoing Support																							
On-going Asset/Device support	0	9,416	34,927	50,006	72,532	96,468	115,512	135,303	155,864	177,218	180,886	184,630	188,452	192,353	196,335	200,399	204,547	208,781	213,103	217,514	**2,834,248**	**1,296,703**	**Direct and Tangible**
Component Replacements	0	2,742	10,171	14,562	21,121	28,092	33,637	39,400	45,387	51,606	52,674	53,764	54,877	56,013	57,173	58,356	59,564	60,797	62,056	63,340	**825,333**	**377,600**	**Direct and Tangible**
On-going Communications Network costs	0	7,324	27,166	38,894	56,414	75,031	89,843	105,236	121,227	137,836	140,689	143,601	146,574	149,608	152,705	155,866	159,092	162,386	165,747	169,178	**2,204,415**	**1,008,547**	**Direct and Tangible**
Vendor costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**	**Direct and Tangible**
Training	0	10,355	10,723	11,103	11,497	11,906	12,328	12,766	13,219	13,688	14,174	14,677	15,199	15,738	16,297	16,875	17,474	18,095	18,737	19,402	**274,254**	**137,195**	**Direct and Tangible**
Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**	**Direct and Tangible**
Asset Contingency	0	1,974	7,321	10,482	15,204	20,221	24,213	28,361	32,671	37,147	37,916	38,701	39,502	40,320	41,154	42,006	42,876	43,763	44,669	45,594	**594,092**	**271,804**	**Direct and Tangible**
TOTAL - Assets Cost	***0***	***31,810***	***90,308***	***125,047***	***176,769***	***231,717***	***275,533***	***321,066***	***368,368***	***417,495***	***426,339***	***435,374***	***444,604***	***454,032***	***463,663***	***473,502***	***483,554***	***493,822***	***504,312***	***515,028***	***6,732,342***	**3,091,849**	
Communications Network																							
FAN Network Infrastructure Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**	**Direct and Tangible**
FAN Network Business Systems	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**	**Direct and Tangible**
FAN WiMAX Cost	43,800	66,983	80,091	81,429	105,420	196,509	122,551	0	0	0	0	0	0	0	0	0	0	0	0	0	**696,784**	**521,761**	**Direct and Tangible**
NOC Opco Allocation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**	**Indirect and Tangible**
FAN Network Distribution Contingency	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**	**Direct and Tangible**
FAN Network Bus Sys Contingency	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**	**Direct and Tangible**
TOTAL - Communications	43,800	66,983	80,091	81,429	105,420	196,509	122,551	0	0	0	0	0	0	0	0	0	0	0	0	0	**696,784**	**521,761**	
TOTAL O&M	**43,800**	**184,182**	**399,980**	**336,662**	**477,080**	**631,673**	**552,674**	**478,856**	**529,425**	**581,885**	**426,339**	**435,374**	**444,604**	**454,032**	**463,663**	**473,502**	**483,554**	**493,822**	**504,312**	**515,028**	**8,910,447**	**4,639,301**	
GRAND TOTAL CAPITAL & O&M	**215,486**	**6,792,413**	**14,811,154**	**10,384,969**	**13,968,659**	**11,542,130**	**7,699,402**	**7,804,518**	**8,038,826**	**8,279,967**	**426,339**	**435,374**	**444,604**	**454,032**	**463,663**	**473,502**	**483,554**	**493,822**	**504,312**	**515,028**	**94,231,754**	**65,282,354**	

Northern States Power Company
FLISR Cost Benefit Analysis

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	TOTAL	NPV
O&M BENEFITS																						
Operational Benefits	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**
TOTAL O&M BENEFITS	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
CUSTOMER BENEFITS																						
Customer Minutes Out- CMO Patrolling savings	0	0	0	40,757	175,083	271,514	355,725	453,382	539,313	649,433	725,847	789,440	789,440	789,440	789,440	789,440	789,440	789,440	789,440	789,440	**10,316,013**	**4,528,044**
Customer Minutes Out- CMO Customer Savings	0	0	0	2,754,556	4,809,980	6,277,181	8,295,139	10,426,430	12,214,741	14,325,875	15,433,977	16,164,602	16,164,602	16,164,602	16,164,602	16,164,602	16,164,602	16,164,602	16,164,602	16,164,602	**220,019,300**	**98,458,717**
TOTAL CUSTOMER IMPACTS	**0**	**0**	**0**	**2,795,313**	**4,985,063**	**6,548,696**	**8,650,864**	**10,879,813**	**12,754,055**	**14,975,308**	**16,159,824**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**230,335,313**	**102,986,762**
GRAND TOTAL BENEFITS	**0**	**0**	**0**	**2,795,313**	**4,985,063**	**6,548,696**	**8,650,864**	**10,879,813**	**12,754,055**	**14,975,308**	**16,159,824**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**230,335,313**	**102,986,762**

NSPM FLISR- NPV

	Total ($MM)
Benefits	**103**
O&M Benefits	0
Customer Benefits	103
Costs	**(78)**
O&M Expense	(5)
Change in Revenue Requirements	(74)
Benefit/Cost Ratio	**1.31**

RATIO SENSITIVITY	VALUE
FAN(15% WiMax)+ Contingencies	**1.31**
FAN(15% WiMax) NO Contingencies	**1.53**

Northern States Power Company
IVVO Cost Benefit Analysis

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	TOTAL	NPV
Feeders enabled with IVVO	0	0	26	43	61	59	0	0	0	0	0	0	0	0	0	0	0	0	0	0	189	
CAPITAL COSTS																						
Assets/Devices																						
Device costs	0	0	1,512,735	2,824,978	2,704,856	2,267,749	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**9,310,319**	**6,996,776**
Device Installation costs	0	0	357,063	773,839	777,449	679,695	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**2,588,046**	**1,936,047**
Xcel Personnel	0	0	132,317	272,663	277,896	283,603	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**966,479**	**720,811**
Xcel Distribution Personnel [ADMS IVVO Integration]	0	0	306,666	525,184	771,477	772,672	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**2,375,999**	**1,760,061**
External resources (Consultants, contractors etc.)	0	0	187,008	434,397	443,389	342,887	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**1,407,681**	**1,054,169**
E&S	0	103,550	750,582	777,228	804,819	833,391	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**3,269,570**	**2,482,269**
Varentec Engineering (ENGO,caps,ami)	0	0	416,731	425,358	434,163	443,150	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**1,719,402**	**1,299,884**
Contingency	0	0	107,914	269,162	256,986	175,088	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**809,149**	**607,879**
TOTAL - Business Assets/Devices	***0***	***103,550***	***3,771,016***	***6,302,808***	***6,471,034***	***5,798,235***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***22,446,644***	***16,857,896***
Communications Network																						
Communications Operations-IVVO Budget	0	0	61,332	115,547	110,814	104,193	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**391,886**	**293,733**
FAN Infrastructure Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**
FAN Distribution WiMax	20,159	131,125	258,015	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**409,298**	**348,698**
FAN Bus Sys Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**
FAN Bus Sys WiMAX Cost	20,915	625,692	1,081,829	726,163	687,157	186,029	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**3,327,784**	**2,666,303**
FAN Bus Sys Contingency	0	0	0	1,482,861	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**1,482,861**	**1,155,589**
TOTAL - Communications	41,073	756,817	1,401,176	2,324,571	797,971	290,222	0	0	0	0	0	0	0	0	0	0	0	0	0	0	***5,611,829***	**4,464,323**
IT Systems and Integration																						**0**
Xcel Personnel [ADMS IVVO Integration]	0	0	803,466	1,375,982	2,021,270	2,024,401	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**6,225,118**	**4,611,361**
External resources (Consultants, contractors etc.) [GEMS]	0	0	520,914	265,849	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**786,763**	**639,234**
GEMS hardware	0	0	104,183	53,170	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**157,353**	**127,847**
Varentec PM & Services	0	0	52,091	26,585	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**78,676**	**63,923**
IT Project Management	0	0	52,091	26,585	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**78,676**	**63,923**
IT Travel Expenses	0	0	10,418	5,317	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**15,735**	**12,785**
Security	0	0	104,183	53,170	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**157,353**	**127,847**
Contingency	0	0	130,158	158,367	190,817	188,381	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**667,722**	**500,682**
Program Management	0	0	104,183	319,018	325,622	332,362	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**1,081,185**	**802,089**
TOTAL - IT Systems and Integration	***0***	***0***	***1,881,688***	***2,284,042***	***2,537,708***	***2,545,144***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***9,248,582***	**6,949,692**
Program Management																						
Organizational Change Management	0	0	468,823	850,715	651,244	553,937	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**2,524,720**	**1,909,732**
TOTAL - Program Management	***0***	***0***	***468,823***	***850,715***	***651,244***	***553,937***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***				***2,524,720***	**1,909,732**
TOTAL CAPITAL	**41,073**	**860,367**	**7,522,703**	**11,762,136**	**10,457,957**	**9,187,538**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**39,831,775**	**30,181,642**
O&M ITEMS																						
O&M in support of capital deployment	0	0	17,731	37,764	33,658	34,745	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**123,898**	**92,683**
TOTAL - On-going Asset/Device support Costs	***0***	***0***	***17,731***	***37,764***	***33,658***	***34,745***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***				***123,898***	**92,683**
Assets/Devices																						
On-going Asset/Device support	0	0	0	0	7,991	25,537	40,714	57,063	59,089	61,187	63,359	65,608	67,937	70,349	72,847	75,433	78,110	80,883	83,755	86,728	**996,591**	**433,842**
Device Replacements	0	0	0	0	12,059	38,654	62,172	85,943	87,722	89,538	91,391	93,283	95,214	97,185	99,197	101,250	103,346	105,485	107,669	109,897	**1,380,003**	**609,942**
Training	0	0	0	0	195	653	1,107	1,554	1,609	1,666	1,725	1,786	1,850	1,915	1,983	2,054	2,127	2,202	2,280	2,361	**27,066**	**11,765**
Contingency	0	0	0	0	2,471	7,885	12,612	17,431	17,792	18,160	18,536	18,920	19,312	19,711	20,119	20,536	20,961	21,395	21,838	22,290	**279,968**	**123,761**
TOTAL - On-going Asset/Device support Costs	***0***	***0***	***0***	***0***	***22,715***	***72,730***	***116,604***	***161,991***	***166,212***	***170,551***	***175,011***	***179,597***	***184,312***	***189,161***	***194,146***	***199,272***	***204,544***	***209,965***	***215,541***	***221,276***	***2,683,629***	**1,179,310**
Communications Network																						
On-going Communications Network costs	0	0	0	0	4,920	15,829	25,585	35,371	36,103	36,850	37,613	38,392	39,187	39,998	40,826	41,671	42,533	43,414	44,312	45,230	**567,832**	**250,941**
FAN Network Infrastructure Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**
FAN Network Business Systems	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**
FAN WiMAX Cost	14,600	22,328	26,697	27,143	35,140	65,503	40,850	0	0	0	0	0	0	0	0	0	0	0	0	0	**232,261**	**173,920**
NOC Opco Allocation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**
FAN Network Distribution Contingency	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**
FAN Network Bus Sys Contingency	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**
TOTAL - Communications	***14,600***	***22,328***	***26,697***	***27,143***	***40,060***	***81,332***	***66,435***	***35,371***	***36,103***	***36,850***	***37,613***	***38,392***	***39,187***	***39,998***	***40,826***	***41,671***	***42,533***	***43,414***	***44,312***	***45,230***	***800,094***	**424,861**
IT Systems and Integration																						
Program Management	0	0	22,576	35,446	36,180	36,929	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**131,132**	**98,245**
TOTAL - IT Systems and Integration	***0***	***0***	***22,576***	***35,446***	***36,180***	***36,929***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***131,132***	**98,245**
Business Program Management																						
Organizational Change Management	0	0	156,274	283,572	217,081	184,646	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**841,573**	**636,577**
TOTAL - Program Management	***0***	***0***	***156,274***	***283,572***	***217,081***	***184,646***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***841,573***	**636,577**
TOTAL O&M	**14,600**	**22,328**	**223,278**	**383,926**	**349,694**	**410,382**	**183,039**	**197,362**	**202,315**	**207,401**	**212,625**	**217,989**	**223,499**	**229,158**	**234,971**	**240,943**	**247,077**	**253,379**	**259,854**	**266,506**	**4,580,325**	**2,431,676**
GRAND TOTAL CAPITAL & O&M	**55,673**	**882,695**	**7,745,981**	**12,146,062**	**10,807,651**	**9,597,920**	**183,039**	**197,362**	**202,315**	**207,401**	**212,625**	**217,989**	**223,499**	**229,158**	**234,971**	**240,943**	**247,077**	**253,379**	**259,854**	**266,506**	**44,412,100**	**32,613,318**

Northern States Power Company
IVVO Cost Benefit Analysis

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	TOTAL	NPV
OTHER BENEFITS																						
Energy Savings																						
Energy Reduction	0	0	165,891	423,491	910,125	1,577,997	1,904,520	1,963,148	2,014,173	2,063,569	2,041,390	1,994,758	2,019,200	2,085,180	2,025,146	2,026,282	2,185,792	2,206,891	2,172,820	2,129,363	**31,909,736**	$14,934,748
Loss Savings	0	0	3,155	8,234	18,167	32,238	39,806	41,776	43,440	44,870	45,454	45,229	46,713	49,088	48,089	48,350	52,370	53,018	52,442	52,442	**724,883**	$333,272
Total Fuel Savings	0	0	169,046	431,724	928,293	1,610,235	1,944,326	2,004,924	2,057,613	2,108,438	2,086,844	2,039,988	2,065,913	2,134,268	2,073,236	2,074,632	2,238,162	2,259,909	2,225,262	2,181,806	**32,634,620**	$15,268,020
Carbon Emissions Benefits																						
Carbon Reduction	0	0	94,698	230,703	479,367	643,180	656,339	645,988	537,529	340,791	312,713	309,097	303,111	284,879	316,482	328,421	341,160	345,262	349,364	353,466	**6,872,548**	$3,599,824
Total Carbon Emissions Savings	0	0	94,698	230,703	479,367	643,180	656,339	645,988	537,529	340,791	312,713	309,097	303,111	284,879	316,482	328,421	341,160	345,262	349,364	353,466	**6,872,548**	$3,599,824
TOTAL OTHER BENEFITS	**0**	**0**	**263,744**	**662,427**	**1,407,660**	**2,253,415**	**2,600,664**	**2,650,912**	**2,595,141**	**2,449,229**	**2,399,557**	**2,349,085**	**2,369,024**	**2,419,147**	**2,389,718**	**2,403,054**	**2,579,322**	**2,605,171**	**2,574,626**	**2,535,271**	**39,507,168**	**$18,867,844**
DEMAND BENEFITS																						
Deferral of Capital Investments As Demand Reduction	0	0	45,106	113,532	227,415	386,537	456,612	457,807	459,632	460,716	460,890	465,302	468,166	470,601	475,990	480,620	485,452	488,836	495,037	489,665	**7,387,915**	$3,481,566
TOTAL DEMAND	**0**	**0**	**45,106**	**113,532**	**227,415**	**386,537**	**456,612**	**457,807**	**459,632**	**460,716**	**460,890**	**465,302**	**468,166**	**470,601**	**475,990**	**480,620**	**485,452**	**488,836**	**495,037**	**489,665**	7,387,915	**$3,481,566**
GRAND TOTAL DEMAND & OTHER BENEFITS	**0**	**0**	**308,850**	**775,959**	**1,635,075**	**2,639,951**	**3,057,277**	**3,108,719**	**3,054,774**	**2,909,945**	**2,860,447**	**2,814,387**	**2,837,189**	**2,889,748**	**2,865,708**	**2,883,673**	**3,064,774**	**3,094,007**	**3,069,663**	**3,024,937**	46,895,083	**$22,349,410**

NSPM IVVO- ***NPV***

	Total ($MM)
Benefits	**22**
Other Benefits	19
CAP Benefits	3
Costs	**(39)**
O&M Expense	(2)
Change in Revenue Requirement	(37)
Benefit/Cost Ratio (DVO 1.25% O&M; 0.7% capital)	**0.57**

RATIO BASE (DVO Savings 1.25% O&M, 0.7% CAP)	VALUE
FAN(5% WiMax)+ Contingencies	**0.57**
FAN(5% WiMax) NO Contingencies	**0.61**

RATIO LOW SENSITIVITY (DVO Savings 1% O&M, 0.6% CAP)	VALUE
FAN(5% WiMax)+ Contingencies	**0.46**
FAN(5% WiMax) NO Contingencies	**0.49**

RATIO HIGH SENSITIVITY (DVO Savings 1.5% O&M, 0.8% CAP)	VALUE
FAN(5% WiMax)+ Contingencies	**0.67**
FAN(5% WiMax) NO Contingencies	**0.72**

Northern States Power Company
AMI Pricing and CO2 Benefits Summary

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	TOTAL	NPV
Total Meters Replaced	*10,131*	*7,368*	*121,800*	*630,000*	*590,000*	*40,700*	*13,755*	*13,890*	*14,027*	*14,164*	*14,304*	*14,444*	*14,586*	*14,729*	*14,874*	*15,020*	*15,168*	***1,558,960***	
OTHER BENEFITS																			
Load Flexibility Benefits																			
Critical Peak Pricing -CPP-DSM Peak	0	0	0	0	0	19,965,050	20,415,850	21,129,600	21,780,000	22,361,590	23,136,860	23,755,800	24,531,638	25,336,224	26,164,958	27,023,654	27,910,308	**283,511,530**	**138,479,332**
Time Of Usage-TOU-Customer energy price shift	0	0	0	0	0	1,819,116	1,975,194	2,019,888	2,037,750	2,133,144	2,262,273	2,392,520	2,517,599	2,573,992	2,725,849	2,753,107	2,780,638	**27,991,070**	**13,576,886**
Time Of Usage-TOU-Avoided CO2 Emissions	0	0	0	0	0	226,876	352,119	485,400	361,972	230,903	344,421	271,720	330,772	309,477	297,166	310,767	413,652	**3,935,245**	**1,961,868**
TOTAL - Load Flexibility Benefits	0	0	0	0	0	22,011,042	22,743,163	23,634,888	24,179,722	24,725,637	25,743,554	26,420,040	27,380,008	28,219,692	29,187,972	30,087,528	31,104,598	***315,437,845***	***154,018,085***
TOTAL OTHER BENEFITS	**0**	**0**	**0**	**0**	**1,848,467**	**25,792,193**	**30,477,932**	**31,546,259**	**32,271,937**	**33,003,045**	**34,210,616**	**35,081,332**	**36,240,224**	**37,283,648**	**38,460,605**	**39,573,907**	**40,809,920**	**416,600,086**	**203,424,492**

The Potential for Load Flexibility in Xcel Energy's Northern States Power Service Territory

PREPARED FOR

Xcel Energy

PREPARED BY

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THE Brattle GROUP

Notice

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Executive Summary

Highlights:

- This study estimates the amount of cost-effective demand response available in Xcel Energy's Northern States Power (NSP) service territory, including an assessment of emerging "load flexibility" programs that can capture advanced sources of value such as geo-targeted distribution investment deferral and grid balancing services.
- Through 2023, NSP's cost-effective DR opportunities are constrained by limitations of its existing metering technology, access to low-cost peaking capacity, a limited need for distribution capacity deferral and grid balancing services, and relatively high costs of emerging DR technologies.
- In later years of the study horizon, and under conditions that are more favorable to the economics of DR, cost-effective DR potential increases significantly, exceeding the PUC's 400 MW DR procurement requirement.
- New, emerging load flexibility programs account for around 30% of the 2030 incremental DR potential estimates in this study.

Background

The purpose of this study is to estimate the potential capability of all cost-effective demand response (DR) that could be deployed in Xcel Energy's Northern States Power (NSP) service territory through 2030.[1] The study addresses the Minnesota PUC's requirement that NSP "acquire no less than 400 MW of additional demand response by 2023" and "provide a full and thorough cost-effectiveness study that takes into account the technical and economic achievability of 1,000 MW of additional demand response, or approximately 20% of Xcel's system peak in total by 2025."

The scope of this study extends significantly beyond those of prior studies. Specifically, we account for opportunities enabled by the rapid emergence of consumer-oriented energy technologies. Advanced metering infrastructure (AMI), smart appliances, electric vehicles, behavioral tools, and automated load control for large buildings are just a few of the technologies

[1] Throughout this study, we simply refer to Xcel Energy as "NSP" when describing matters relevant to its NSP service territory.

driving a resurgence of interest in the value that can be created through new DR programs. These technologies enable DR to evolve from providing conventional peak shaving services to providing around-the-clock "load flexibility" in which electricity consumption is managed in real-to address economic and system reliability conditions.

This study also takes a detailed approach to assessing the cost-effectiveness of each DR option. While emerging DR programs introduce the potential to capture new value streams, they are also dependent on technologies that in some cases have not yet experienced meaningful cost declines. Further, opportunities to create value through DR vary significantly from one system to the next. A detailed assessment of the costs and benefits of each available DR option is necessary to identify the DR portfolio that is the right "fit" for a given utility system.

The Brattle Group's Load*Flex* model is used to assess NSP's emerging DR opportunities. The Load*Flex* modeling framework builds upon the standard approach to quantifying DR potential that has been used in prior studies around the U.S. and internationally, but incorporates a number of differentiating features which allow for a more robust evaluation of load flexibility programs:

- **Economically optimized enrollment:** Assumed participation in DR programs is tailored to the incentive payment levels that are cost-effective for the DR program, thus providing a more complete estimate of total cost-effective potential than prior methodologies.
- **Utility-calibrated load impacts:** Load impacts are calibrated to the characteristics of NSP's customer base. This includes accounting for the market saturation of various end-use appliances, customer segmentation based on size, and NSP's estimates of the capability of its existing DR programs.
- **Sophisticated DR program dispatch:** DR program dispatch is optimized subject to detailed accounting for the operational constraints of the program, including tariff-related program limitations and an hourly representation of load control capability for each program.
- **Realistic accounting for "value stacking":** DR program operations are simulated to maximize total benefits across multiple value streams, while recognizing the operational constraints of the program and accounting for necessary tradeoffs when pursuing multiple value streams.
- **Industry-validated program costs:** DR program costs are based on a detailed review of NSP's current DR offerings, a review of experience and studies in other jurisdictions, and conversations with vendors.

Findings

Base Case

NSP currently has one of the largest DR portfolios in the country, with 850 MW of load curtailment capability (equivalent to roughly 10% of NSP's system peak). The portfolio primarily consists of an interruptible tariff program for medium and large C&I customers, and a residential air-conditioning direct load control (DLC) program. The DLC program is transitioning from utilizing a conventional compressor switch technology to instead leveraging newer smart thermostats.

There is an opportunity to tap into latent interest in the current NSP programs and grow participation in those existing programs through new marketing efforts. According to our analysis, doing so could provide 293 MW of incremental cost-effective potential by 2023. The majority of this growth could come from increased enrollment in the interruptible tariff program for the medium and large C&I segments, and from the transition to a residential air-conditioning DLC program that more heavily utilizes smart thermostat technology.

NSP's DR portfolio could also be expanded to include new programs that are not currently offered by the company. Our analysis considered eight new programs, including time-of-use (TOU) rates, critical peak pricing (CPP), home and workplace EV charging load control, timer-based water heating load control and a more advanced "smart" water heating program, behavioral DR, ice-based thermal storage, and automated DR for lighting and HVAC of commercial and industrial customers. Some of these programs could provide ancillary services and geo-targeted distribution deferral benefits, in addition to the conventional DR value streams.

Based on current expectations about the future characteristics of the NSP market, smart water heating is the only new program that we find to be cost-effective in 2023 among the emerging options described above, providing an additional 13 MW of incremental cost-effective potential. Through 2023, NSP's cost-effective DR opportunities are constrained by limitations of its existing metering technology, access to low-cost peaking capacity, a limited need for distribution capacity deferral and frequency regulation, and relatively high costs of emerging DR technologies.

This expanded portfolio, which reflects all cost-effective DR options available to NSP across a broad range of potential use cases, would fall short of the PUC's 2023 procurement requirement. In 2023, the current portfolio plus the incremental cost-effective DR identified in this study would equate to 1,156 MW of total peak reduction capability, 154 MW short of the procurement requirement.[2]

In 2025, the potential in the expanded portfolio increases. This increase is driven primarily by the ability to begin offering time-varying rates once smart meters are fully deployed in 2024. However, it is likely that several years will be needed for smart metering-based programs to ramp up to full participation, so the incremental potential associated with these programs is still somewhat constrained in 2025. The current portfolio plus the incremental DR in the expanded portfolio equate to 1,243 MW of cost-effective DR potential in 2025.

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[2] NSP has interpreted the PUC's Order to require 400 MW of capacity-equivalent DR, which equates to 391 MW of generator-level load reduction when accounting for the reserve requirement, and 362 MW of meter-level load reduction when additionally accounting for line losses.

By 2030, NSP's cost-effective DR potential will increase further. This increase is driven primarily by the maturation of smart metering-based DR programs. Other factors contributing to the increase in cost-effective potential include a continued transition to air-conditioning load control through smart thermostats, an expansion of the smart water heating program through ongoing voluntary replacements of expiring conventional electric water heaters, and overall growth in NSP's customer base. By 2030, we estimate that NSP's current portfolio plus the incremental cost-effective DR would amount to 468 MW. New, emerging DR programs account for 33% of the incremental potential. Achieving this potential would require not only growth in existing programs, but the design and implementation of several new DR program as well.

High Sensitivity Case

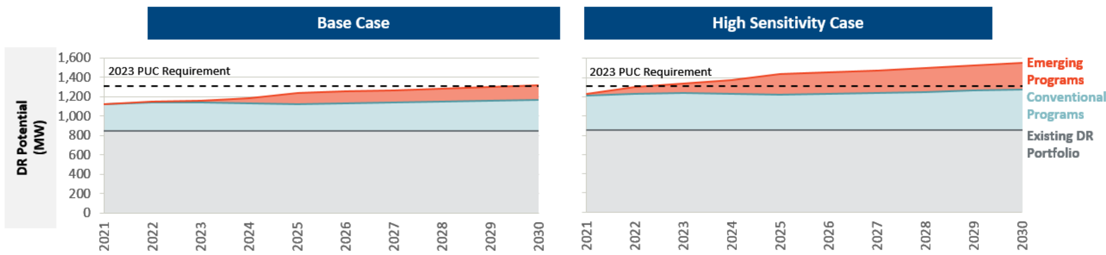
NSP's market may evolve to create more economically favorable conditions for DR than currently expected. For instance, growth in market adoption of intermittent renewable generation could contribute to energy price volatility and an increased need for high-value grid balancing services. Further, the costs of emerging DR technologies may decline significantly, or the cost of competing resources (e.g., peaking capacity) may be higher than expected. To understand how these alternative conditions would impact DR potential, we analyzed a sensitivity case. The High Sensitivity Case illustrates the potential for DR under an alternative set of market conditions that are more favorable to DR program economics. The case is <u>not</u> a forecast of what is likely to happen in the future in NSP's service territory, particularly in the near-term years of the study horizon.

Under the illustrative assumptions of the High Sensitivity Case there is significantly more cost-effective incremental potential. In 2023 there is a total of 484 MW of incremental cost effective potential, which would satisfy the PUC's procurement requirement. By 2030, the total portfolio of DR programs, including the existing programs, could reach 705 MW.

The mix of cost-effective programs in the High Sensitivity case is essentially the same as in the Base Case. However, larger program benefits justify higher incentive payments, which leads to higher participation and overall potential in these programs. Auto-DR for C&I customers also presents an opportunity to increase load flexibility in the High Sensitivity Case, though the potential in this program is subject to uncertainty in technology cost and customer adoption.

Under both the Base Case and the High Sensitivity Case assumptions, avoided generation capacity costs are the primary benefit of the DR portfolio. In the High Sensitivity Case, additional price volatility due a greater assumed mix of renewable generation in the regional supply portfolio leads to an increase in the share of total that is attributable to avoided energy costs. The total value of frequency regulation provided by DR also increases modestly relative to the Base Case, as a greater need for this service is assumed for renewable generation integration purposes. Figure ES-1 summarizes the DR potential estimates and benefits of the DR portfolio under Base Case and High Sensitivity Case assumptions.

Figure ES-1: NSP's DR Potential and Annual Portfolio Benefits



2030 Avoided Cost ($M/yr)

Base Case

	Energy	Generation Capacity	System Average T&D Deferral	Geotargeted Distribution Deferral	Frequency Regulation	Total
Conventional Programs	$5.0	$43.6	$2.8	$0.0	$0.0	$51.4
Emerging Programs	$5.7	$7.4	$0.4	$0.0	$1.2	$14.7
Total	$10.7	$50.9	$3.2	$0.0	$1.2	$66.1

High Sensitivity Case

	Energy	Generation Capacity	System Average T&D Deferral	Geotargeted Distribution Deferral	Frequency Regulation	Total
Conventional Programs	$8.6	$69.7	$3.3	$0.0	$0.0	$81.5
Emerging Programs	$19.6	$19.5	$0.8	$0.7	$4.6	$45.2
Total	$28.2	$89.2	$4.0	$0.7	$4.6	$126.8

An expanded portfolio of DR programs will have operational flexibility beyond the capabilities of conventional existing programs. For instance, load flexibility programs could be dispatched to reduce the system peak, but also to address local peaks on the distribution system which may occur during later hours of the day. Off-peak load building through electric water heating could help to mitigate wind curtailments and take advantage of negative energy prices. The provision of frequency regulation from electric water heaters could further contribute to renewables integration value.

Specific recommendations for acting on the findings of this study including the following:

- Aggressively pursue the transition to smart thermostats as well as recruitment of medium C&I customers into the Interruptible program.
- Pilot and deploy a smart water heating program. As a complementary activity, evaluate the impacts of switching from gas to electric heating, accounting for the grid reliability benefits associated with this flexible source of load.
- Prior to the smart metering rollout, build the foundation for a robust offering of time-varying rates, including identifying rate options that could be offered on an opt-out basis.
- Develop measurement & verification (M&V) 2.0 protocols to ensure that program impacts are dependable and can be integrated meaningfully into resource planning efforts.
- Design programs with peak period flexibility, to be able to respond to changes such as a shifts in the net peak due to solar PV adoption, or a shift in the planning emphasis from a focus on the MISO peak to a focus on more local peaks, for instance.

I. Introduction

Purpose

The purpose of this study is to estimate the potential capability of all cost-effective demand response (DR) that could be deployed in Xcel Energy's Northern States Power (NSP) service territory.[3] Xcel Energy commissioned this study to satisfy the requirements of the Minnesota Public Utilities Commission (PUC) Order in Docket No. E-002/RP-15-21. That Order, established in January 2017, required NSP to "acquire no less than 400 MW of additional demand response by 2023" and to "provide a full and thorough cost-effectiveness study that takes into account the technical and economic achievability of 1,000 MW of additional demand response, or approximately 20% of Xcel's system peak in total by 2025."

Background

The Brattle Group conducted an assessment of NSP's DR potential in 2014.[4] That study specifically addressed opportunities to reduce NSP's system peak demand. As such, the assessment had a primary focus on "conventional" DR programs that are utilized infrequently to mitigate system reliability concerns. The study also included price-based DR options that would be enabled by the eventual deployment of smart meters.

The scope of this 2018 study extends significantly beyond that of the 2014 study. Specifically, we account for opportunities enabled by the rapid emergence of consumer-oriented energy technologies. Advanced metering infrastructure (AMI), smart appliances, electric vehicles, behavioral tools, and automated load control for large buildings are just a few of the technologies driving a resurgence of interest in the value that can be created through new DR programs. These technologies enable DR to evolve from providing conventional peak shaving services to providing around-the-clock "load flexibility" in which electricity consumption is managed in real-to address economic and system reliability conditions. The Brattle Group's Load*Flex* model is used to assess these emerging opportunities.

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[3] Throughout this study, we simply refer to Xcel Energy as "NSP" when describing matters relevant to its NSP service territory.

[4] Ryan Hledik, Ahmad Faruqui, and David Lineweber, "Demand Response Market Potential in Xcel Energy's Northern States Power Service Territory," prepared for Xcel Energy, April 2014.

This 2018 study also extends beyond the scope of the 2014 study by evaluating the cost-effectiveness of each DR option.[5] While emerging DR programs introduce the potential to capture new value streams, they are also dependent on technologies that in some cases have not yet experienced meaningful cost declines. Further, opportunities to create value through DR vary significantly from one system to the next. A utility with significant market penetration of solar PV may find the most value in advanced load shifting capabilities that address evening generation ramping issues on a daily basis, whereas a system with a near-term need for peaking capacity may find more value in the types of conventional DR programs that reduce the system peak during only a limited number of hours per year. A detailed assessment of the costs and benefits of each available DR option is necessary to identify the DR portfolio that is the right "fit" for a given utility system.

This report summarizes the key findings of The Brattle Group's assessment of NSP's DR market potential. Additional detail on methodology and results is provided in the appendices.

NSP's Existing DR Portfolio

The capability of NSP's existing DR portfolio is substantial. It is the eighth largest portfolio among all US investor-owned utilities when DR capability is expressed as a percentage of peak demand. The portfolio is the largest in MISO in terms of total megawatt capability, and second when expressed as a percentage of peak demand.

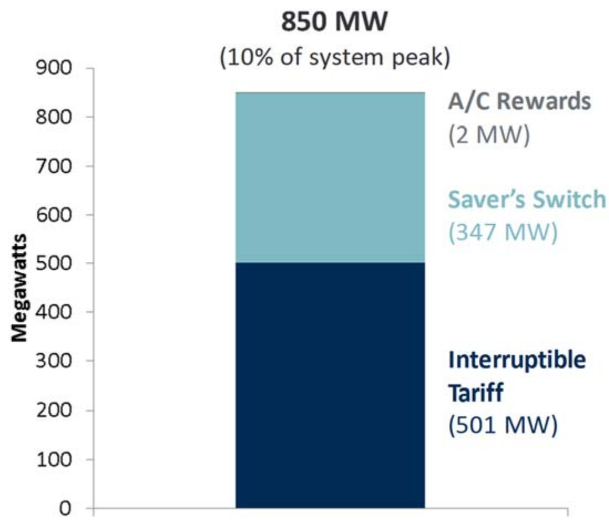
As of 2017, Xcel Energy had 850 MW of DR capability across its NSP service territory, accounting for roughly 10 percent of system peak demand. This capability comes primarily from two programs. The largest is an "interruptible tariff" program, which provides commercial and industrial (C&I) customers with energy bill savings in return for a commitment to curtail electricity demand to pre-established levels when called upon by the utility. Roughly 11 percent of the peak-coincident demand of medium and large C&I customers is enrolled in this program.

The second program is NSP's Saver's Switch program. Saver's Switch is a conventional residential load control program, in which the compressor of a central air-conditioning unit or the heating element of an electric resistance water heater is temporarily cycled off to reduce electricity demand during DR events. Saver's Switch is one of the largest such programs in the country. Roughly 52 percent of all eligible residential customers (i.e., those with central air-conditioning) are enrolled in the program, accounting for around 29% of all of NSP's residential customers. Saver's Switch is gradually being transitioned to a program based on newer smart thermostat technology, called "A/C Rewards." A/C Rewards contributes an additional 2 MW to

[5] The 2014 study developed a "supply curve" of DR options available to NSP as inputs to its integrated resource plan (IRP), but did not explicitly evaluate the extent to which those options would be less costly than serving electricity demand through the development of new generation resources.

NSP's existing DR capability, though this is expected to grow significantly in coming years. A summary of NSP's DR portfolio is provided in Figure 1.

Figure 1: NSP 2017 DR Capability



Sources: NSP 2017 DR program data and 2017 NSP system peak demand (8,546 MW)

Important Considerations

The focus of this study is on quantifying the amount of cost-effective DR capability that can be achieved above and beyond NSP's current 850 MW DR portfolio. We estimate the incremental DR potential that can be achieved through an expansion of existing program offerings, the introduction of new programs, and consideration of a broad range of potential system benefits that are available through DR. Specifically, this study is structured to quantify all DR potential that satisfies the following three conditions:

1. **Incremental:** All quantified DR potential is incremental to NSP's existing 850 MW DR portfolio.[6]

2. **Cost-effective:** The present value of avoided resource costs (i.e., benefits) must outweigh program costs, equipment costs, and incentives.

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6 For the purposes of this analysis, all incremental potential estimates assume NSP's portfolio of existing programs continues to be offered as currently designed in future years, and that the 850 MW impact persists throughout the forecast horizon.

3. **Achievable:** Program enrollment rates are based on primary market research in NSP's service territory and supplemented with information about utility experience in other jurisdictions.

The findings of this study should be interpreted as a quantitative screen of the DR opportunities available to NSP. Further development of individual programs, and testing of the programs through pilots, will provide additional insight regarding the potential benefits and costs that such programs may offer to NSP and its customers when deployed on a full scale basis.

II. Methodology

This study analyzes three ways to increase the capability of NSP's existing DR portfolio. First, we assess the potential to increase enrollment in existing programs. Increased enrollment could be achieved through targeted program marketing efforts, for example. Second, the menu of DR programs offered to customers could be expanded to include new, non-conventional options. These non-conventional options include emerging "load flexibility" programs which go beyond peak shaving to provide around-the-clock decreases and increases in system load. Third, consistent with the introduction of more flexible DR programs, we consider a broadened list of potential benefits in the cost-effectiveness screening process, such as ancillary services and geographically-targeted deferral of distribution capacity upgrades.

Conventional DR Programs

Our analysis considers conventional DR programs that have been offered by utilities for many years, including in some cases by NSP.

- **Direct load control (DLC):** Participant's central air-conditioner is remotely cycled using a switch on the compressor. The modeled program is based on NSP's Savers Switch program.

- **Smart thermostats:** An alternative to conventional DLC, smart thermostats allow the temperature setpoint to be remotely controlled to reduce A/C usage during peak times. The modeled program is based on NSP's A/C Rewards program, which provides customers with options to use their own thermostat, self-install a thermostat purchased from NSP's online store, or use a NSP-installed thermostat. Smart thermostat programs are based on newer technology than the other "conventional" DR programs in this list, but included here as the program is already offered by NSP.

- **Interruptible rates:** Participants agree to reduce demand to a pre-specified level and receive an incentive payment in the form of a discounted rate.

- **Demand bidding:** Participants submit hourly curtailment schedules on a daily basis and, if the bids are accepted, must curtail the bid load amount to receive the bid incentive payment or may be subject to a non-compliance penalty. While a conventional option, demand bidding is not currently offered by NSP.

Non-conventional DR Programs

Pricing programs are one type of non-conventional DR option. We consider two specific time-varying rate options which generally span the range of impacts that can be achieved through pricing programs: A static time-of-use rate and a dynamic critical peak pricing rate.

- **Time-of-use (TOU) rate:** Currently being piloted by NSP for residential customers and offered on a full-scale basis to C&I customers. Static price signal with higher price during peak hours (assumed 5-hour period aligned with system peak) on non-holiday weekdays. Modeled as being offered on an opt-in and an opt-out (default) basis. The study also includes an optional TOU rate for EV charging.

- **Critical peak pricing (CPP) rate:** Provides customers with a discounted rate during most hours of the year, and a much higher rate (typically between 50 cents/kWh and $1/kWh) during peak hours on 10 to 15 days per year. CPP rates are modeled as being offered on both an opt-in and an opt-out (default) basis.

The second category of non-conventional DR programs relies on a variety of advanced behavioral and technological tools for managing customer electricity demand.

- **Behavioral DR:** Customers are informed of the need for load reductions during peak times without being provided an accompanying financial incentive. Customers are typically informed of the need for load reductions on a day-ahead basis and events are called somewhat sparingly throughout the year. Behavioral DR programs have been piloted by several utilities, including Consumers Energy, Green Mountain Power, the City of Glendale, Baltimore Gas & Electric, and four Minnesota cooperatives.

- **EV managed charging:** Using communications-enabled smart chargers allows the utility to shift charging load of individual EVs plugged-in from on-peak to off-peak hours. Customers who do not opt-out of an event receive a financial incentive. The managed EV charging program was modeled on three recent pilots: PG&E (with BMW), United Energy (Australia), and SMUD. Allows curtailment of charging load for up to three hours per day, fifteen days per year. Impacts were modeled for both home charging and workplace charging programs.

- **Timed water heating:** The heating element of electric resistance water heaters can be set to heat water during off-peak hours of the day. The thermal storage capabilities of the water tank provide sufficient hot water during peak hours without needing to activate the heating element.

- **Smart water heating:** Offers improved flexibility and functionality in the control of the heating element in the water heater. The thermostat can be modulated across a range of temperatures. Multiple load control strategies are possible, such as peak shaving, energy price arbitrage through day/night thermal storage, or the provision of ancillary services such as frequency regulation. Modeled for electric resistance water heaters, as these represent the vast majority of electric water heaters and are currently the most attractive candidates for a range of advanced load control strategies.

- **Ice-based thermal storage:** Commercial customers shift peak cooling demand to off-peak hours using ice-based storage systems. The thermal storage unit acts as a battery for the customer's A/C unit, charging at night (freezing water) and discharging (allowing ice to thaw to provide cooling) during the day.

- **C&I Auto-DR:** Auto-DR technology automates the control of various C&I end-uses. Features of the technology allow for deep curtailment during peak events, moderate load shifting on a daily basis, and load increases and decreases to provide ancillary services. Modeled end-uses include HVAC and lighting (both luminaire and zonal lighting options).

DR Benefits

This study accounts for value streams that are commonly included in assessments of DR potential:

- **Avoided generation capacity costs:** The need for new peaking capacity can be reduced by lowering system peak demand. Important considerations when estimating the equivalence of DR and a peaking generation unit are discussed later in this section of the report.

- **Reduced peak energy costs:** Reducing load during high priced hours leads to a reduction in energy costs. Our analysis estimates net avoided energy costs, accounting for costs associated with the increase in energy consumption during lower cost hours due to "load building." The energy benefit accounts for avoided average line losses. Our analysis likely includes a conservative estimate of this value, as peak line losses are greater than off-peak line losses. Our analysis does not include the effect of any potential change in energy market prices that may result from changes in load patterns (sometimes referred to as the "demand response induced price effect," or DRIPE). It is simply a calculation of reduced resource costs.

- **System-wide deferral of transmission and distribution (T&D) capacity costs.** System-wide reductions in peak demand can, on average, contribute to the reduced need for peak-driven upgrades in T&D capacity. We account for this potential value using methods that were established in a recent Minnesota PUC proceeding.[7]

This study also accounts for value streams that can be captured through more advanced DR programs:

- **Geo-targeted distribution capacity investment deferral:** DR participants may be recruited in locations on the distribution system where load reductions would defer the need for capacity upgrades. NSP's 5-year distribution plan was used to identify candidate deferral projects, and qualifying DR programs were evaluated based on their ability to contribute to the deferral.[8]

- **Ancillary services:** The load of some end-uses can be increased or decreased in real time to mitigate system imbalances. The ability of qualifying DR programs to provide frequency regulation was modeled, as this is the highest-value ancillary service (albeit with limited system need).

- **Load building / valley filling:** Load can be shifted to off-peak hours to reduce wind curtailments or take advantage of low or negatively priced hours. DR was dispatched against hourly energy price series to capture the economic incentive that energy prices provide for this service.

Figure 2 summarizes the ways in which this assessment of DR potential extends the scope of prior studies in Minnesota and other jurisdictions. In the figure, "X" indicates the value streams that each DR program is assumed to provide.

7 Minnesota PUC Docket No. E999/CIP-16-541.

8 The distribution plan was in-development at the time of our analysis. Distribution data was provided to Brattle in March 2018.

Figure 2: Options for Expanding the Existing DR Portfolio

1 Increase enrollment in the conventional portfolio

2 Extend DR value streams

3 Include non-traditional DR options

	Generation capacity avoidance	Reduced peak energy costs	System peak related T&D deferral	Targeted distribution capacity deferral	Valley filling/ Load building	Ancillary services
Direct load control (DLC)	X	X	X			
Interruptible tariff	X	X	X			
Demand bidding	X	X	X		X	
Smart thermostat	X	X	X			
Time-of-use (TOU) rates	X	X	X			
Dynamic pricing	X	X	X			
Behavioral DR	X	X	X			
EV managed charging	X	X	X	X	X	
Smart water heating	X	X	X		X	X
Timed water heating	X	X	X		X	
Ice-based thermal storage	X	X	X	X	X	
C&I Auto-DR	X	X	X	X	X	X

Notes: "X" indicates the value streams that each DR option is assumed to be able to provide.

Defining DR Potential

We use the Utility Cost Test (UCT), also known as the Program Administrator Cost Test (PACT), to determine the cost-effectiveness of the incremental DR portfolio. The UCT determines whether a given DR program will increase or decrease the utility's revenue requirement. This is the same perspective that utilities take when deciding whether or not to invest in a supply-side resource (e.g., a combustion turbine) through the IRP process.[9] Since the purpose of this DR potential study is to determine the amount of DR that should be included in the IRP, the UCT was determined to be the appropriate perspective. Major categories of benefits and costs included in the UCT are summarized Table 1.

[9] According to the National Action Plan for Energy Efficiency: "The UCT is the appropriate cost test from a utility resource planning perspective, which typically aims to minimize a utility's lifecycle revenue requirements."

Table 1: Categories of Benefits and Costs included in the Utility Cost Test

Benefits	Costs
Avoided generation capacity	Incentive payments
Avoided peak energy costs	Utility equipment & installation
Avoided transmission capacity	Administration/overhead
Avoided distribution capacity	Marketing/promotion
Ancillary services	

Throughout this study, we quantify DR potential in two different ways:

Technical Potential: Represents achievable potential without consideration for cost-effectiveness. In other words, this is a measure of DR capability that could be achieved from anticipated enrollment associated with a moderate participation incentive payment, regardless of whether or not the incentive payment and other program costs exceed the program benefits. As it is used here, the term "technical potential" differs from its use in energy efficiency studies. Technical potential in energy efficiency studies assumes 100% participation, whereas we assume an achievable level of participation in this assessment of DR potential.

Cost-effective Potential: Represents the portion of technical potential that can be obtained at cost-effective incentive payment levels. For each program, the assumed participation incentive payment level is set such that the benefit-cost ratio is equal to 1.0. Participation rates are estimated to align with this incentive payment level. When non-incentive costs (e.g., equipment and installation costs) are found to outweigh the benefits alone, the benefit-cost ratio is less than 1.0 and there is no opportunity to offer a cost-effective participation incentive payment. In that case, the program is considered to have no cost-effective potential.

The Load*Flex* Model

The Brattle Group's Load*Flex* model was used to estimate DR potential in this study. The Load*Flex* modeling framework builds upon the standard approach to quantifying DR potential that has been used in prior studies around the U.S. and internationally, but incorporates a number of differentiating features which allow for a more robust evaluation of DR programs:

- **Economically optimized enrollment:** Assumed participation in DR programs is tailored to the incentive payment levels that are cost-effective for the DR program. If only a modest incentive payment can be justified in order to maintain a benefit-cost ratio of 1.0, then the participation rate is calibrated to be lower than if a more lucrative incentive payment were offered. Prior approaches to quantifying DR potential ignore this relationship between incentive payment level and participation, which tends to under-state the potential (and, in some cases, incorrectly concludes that a DR program would not pass the cost-effectiveness screen).

- **Utility-calibrated load impacts:** Load impacts are calibrated to the characteristics of NSP's customer base. In the residential sector, this includes accounting for the market saturation of various end-use appliances (e.g., central air-conditioning, electric water heating). In the commercial and industrial (C&I) sector, this includes accounting for customer segmentation based on size (i.e., the customer's maximum demand) and industry (e.g., hospital, university). Load curtailment capability is further calibrated to NSP's experience with DR programs where available (e.g., impacts from existing DLC programs or dynamic pricing pilots).

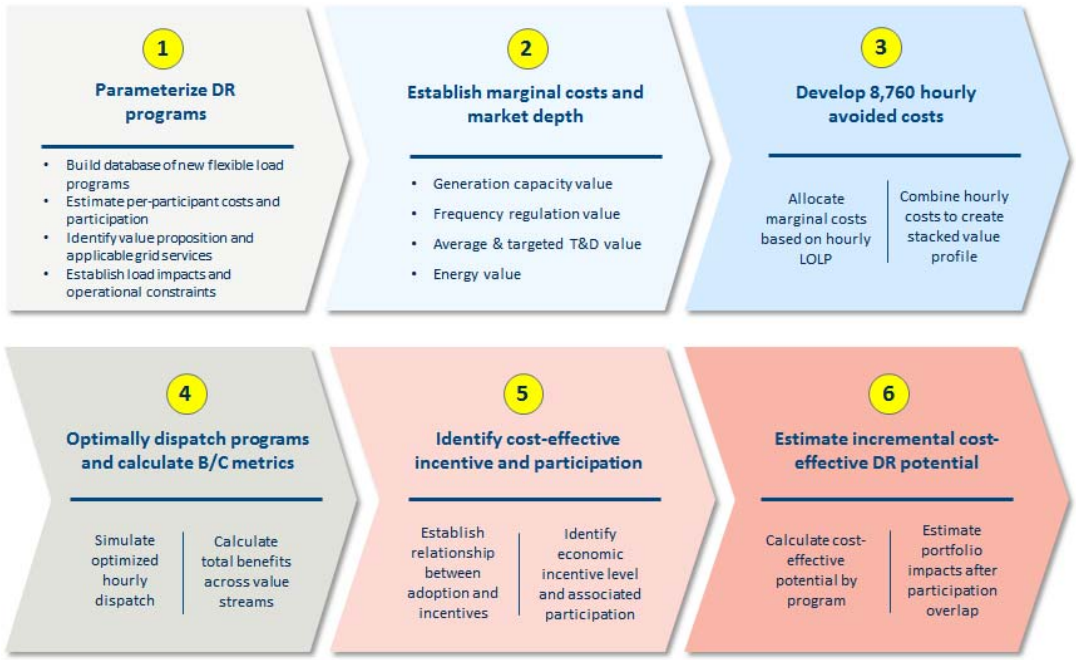
- **Sophisticated DR program dispatch:** DR program dispatch is optimized subject to detailed accounting for the operational constraints of the program. In addition to tariff-related program limitations (e.g., how often the program can be called, hours of the day when it can be called), Load*Flex* includes an hourly profile of load interruption capability for each program. For instance, for an EV home charging load control program, the model accounts for home charging patterns, which would provide greater average load reduction opportunities during evening hours (when EV owners have returned home from work) than in the middle of the day.

- **Realistic accounting for "value stacking":** DR programs have the potential to simultaneously provide multiple benefits. For instance, a DR program that is dispatched to reduce the system peak and therefore avoid generation capacity costs could also be dispatched to address local transmission or distribution system constraints. However, tradeoffs must be made in pursuing these value streams – curtailing load during certain hours of the day may prohibit that same load from being curtailed again later in the day for a different purpose. Load*Flex* accounts for these tradeoffs in its DR dispatch algorithm. DR program operations are simulated to maximize total benefits across multiple value streams, while recognizing the operational constraints of the program. Prior studies of load flexibility value have often assigned multiple benefits to DR programs without accounting for these tradeoffs, thus double-counting benefits.

- **Industry-validated program costs:** DR program costs are based on a detailed review of NSP's current DR offerings. For new programs, costs are based on a review of experience and studies in other jurisdictions and conversations with vendors. Program costs are differentiated by type (e.g., equipment/installation, administrative) and structure (e.g., one-time investment, ongoing annual fee, per-kilowatt fee) to facilitate integration into utility resource planning models.

The Load*Flex* modeling framework is organized around six steps, as summarized in Figure 3. Appendix A provides detail on the methodology behind each of these steps.

Figure 3: The Load*Flex* Modeling Framework



Modeling Scenarios

The value that DR will provide depends on the underlying conditions of the utility system in which it is deployed. Generation capacity costs, the anticipated need for new transmission and distribution (T&D) assets, and energy price volatility are a few of the factors that will determine DR value and potential. To account for uncertainty in NSP's future system conditions, we considered two modeling scenarios: A "Base Case" and a "High Sensitivity Case."

The **Base Case** most closely aligns with NSP's expectations for future conditions on its system, as defined in its IRP. The Base Case represents a continuation of recent market trends, combined with information about known or planned developments during the planning horizon.

The **High Sensitivity Case** was developed to illustrate how the value of DR can change under alternative future market conditions. The High Sensitivity Case is defined by assumptions about the future state of the NSP system and MISO market that are more favorable to DR program economics. The High Sensitivity Case is not intended to be the most likely future state of the NSP system. Relative to the Base Case, the High Sensitivity Case consists of a higher assumed generation capacity cost, more volatile energy prices due to greater market penetration of renewable generation, a significant reduction in emerging DR technology costs, and an increase in the need for frequency regulation.

Defining features of the two cases are summarized in Table 2. Appendix A includes more detail on assumptions and data sources behind the two cases.

Table 2: Defining Features of Base Case and High Sensitivity Case

	Base Case	High Sensitivity Case
Generation capacity (Net CONE)	\$64/kW-yr (2018 NSP IRP)	\$93/kW-yr (2018 EIA Annual Energy Outlook)
Hourly energy price	Based on MISO MTEP "Continued Fleet Change" case (15% wind+solar by 2032)	Based on MISO MTEP "Accelerated Fleet Change" case (30% wind+solar by 2032)
Frequency regulation	Price varies, 25 MW average need by 2030	Price same as Base Case, 50 MW average need by 2030
System average T&D deferral	Transmission: \$3.6/kW-yr, Distribution: \$9.5/kW-yr (2017 NSP Avoided T&D Study)	Same as Base Case
Geo-targeted T&D deferral	Value varies by distribution project, 90 MW eligible for deferral by 2030	Same as Base Case
DR technology cost	10% reduction from current levels by 2030 (in real terms)	30% reduction from current levels by 2030 (in real terms)

Notes: Unless otherwise specified, values shown are for year 2030 and in nominal dollars.

Modeling results are summarized for the years 2023 and 2030. 2023 is the year by which NSP must procure additional DR capability according to the Minnesota PUC's Order in Docket No. E-002/RP-15-21. The 2030 snapshot captures the potential for significant future changes in system conditions and their implications for DR value, and is consistent with the longer-term perspective of NSP's IRP study horizon. A summary of annual results, including intermediate years, is provided in Appendix D.

Data

To develop participation, cost, and load impact assumptions for this study, we relied on a broad range of resources. Where applicable, we relied directly upon information from NSP's experience with DR programs in its service territory. We also utilized the results of primary market research that was conducted directly with customers in NSP's service territory in order to better understand their preferences for various DR program options. Where NSP-specific information was unavailable, we reviewed national data on DR programs, DR potential studies from other jurisdictions, and DR program impact evaluations. A complete list of resources is provided in the References section and described further in Appendix A.

In an assessment of emerging DR opportunities, it is important to recognize that data availability varies significantly by DR program type. Conventional DR programs, such as air-conditioning load control, have decades of experience as full-scale deployments around the US and internationally. By contrast, emerging DR programs like EV charging load control have only recently begun to be explored, largely through pilot projects. Figure 4 summarizes data availability for each of the DR program types analyzed in this study.

Figure 4: Data Availability by DR Program Type

	Participation	Costs	Peak Impacts	Advanced Impacts
Residential				
Air-conditioning DLC	●	●	●	N/A
Smart thermostat	●	●	●	N/A
TOU rate	●	●	◑	N/A
CPP rate	●	●	◑	N/A
Behavioral DR	◑	◑	◑	N/A
Smart water heating	◔	◔	◑	◔
Timed water heating	◔	◔	◑	◔
EV managed charging (home)	○	○	◔	N/A
EV charging TOU (home)	○	○	◔	N/A
C&I				
Interruptible tariff	●	●	●	N/A
Demand bidding	●	●	●	N/A
TOU rate	●	●	◑	N/A
CPP rate	●	●	◑	N/A
Ice-based thermal storage	◔	◔	◔	◔
EV workplace charging	○	○	◔	N/A
Automated DR	○	◔	◔	○

Notes:

● NSP-specific data, including market research, pilot programs, and full-scale deployments

◑ Signficant program experience in other jurisdictions

◔ Some pilot or demonstration project experience in other jurisdictions

○ Speculative, estimated from theoretical studies and calibrated to NSP conditions

"Advanced impacts" refers to load flexibilty capability beyond conventional peak period reductions (e.g., frequency regulation)

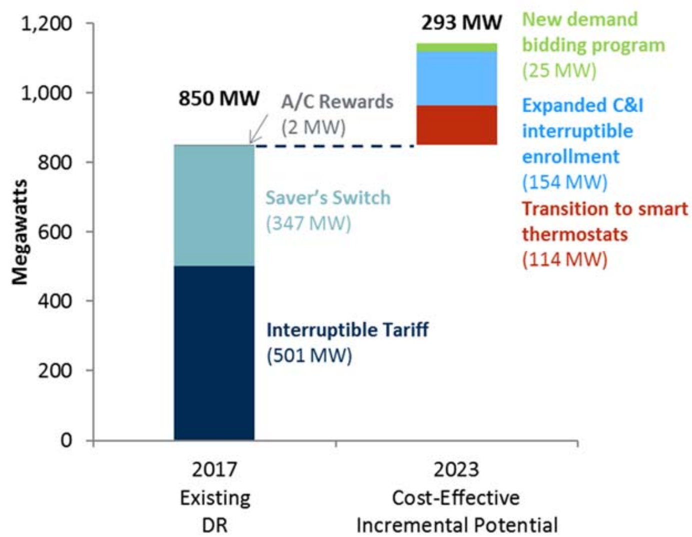
III. Conventional DR Potential in 2023

As an initial step in the assessment of NSP's cost-effective DR potential, we analyzed the potential if NSP were to deploy a portfolio of conventional DR programs. As defined for this study, conventional programs include interruptible tariffs, air-conditioning DLC, smart thermostats, and demand bidding. These program types are currently offered by NSP, with the exception of demand bidding. Therefore, the assessment of conventional programs is largely an assessment of the potential to grow the current DR portfolio through options such as new marketing initiatives or targeted marketing toward specific customer segments. We initially focus on the year 2023, as that is the year by which the Minnesota PUC has required NSP to procure additional DR capability.[10]

Figure 5 summarizes the cost-effective potential in a conventional DR portfolio in 2023. There is 293 MW of cost-effective incremental potential. Drivers of this potential include the expanded enrollment in NSP's interruptible tariff program, greater per-participant impacts that will be achieved as NSP continues to transition from a switch-based air-conditioning DLC program to a smart thermostat-based program, overall growth in NSP's customer base between 2017 and 2023, and a modest amount of potential in a new demand bidding program.

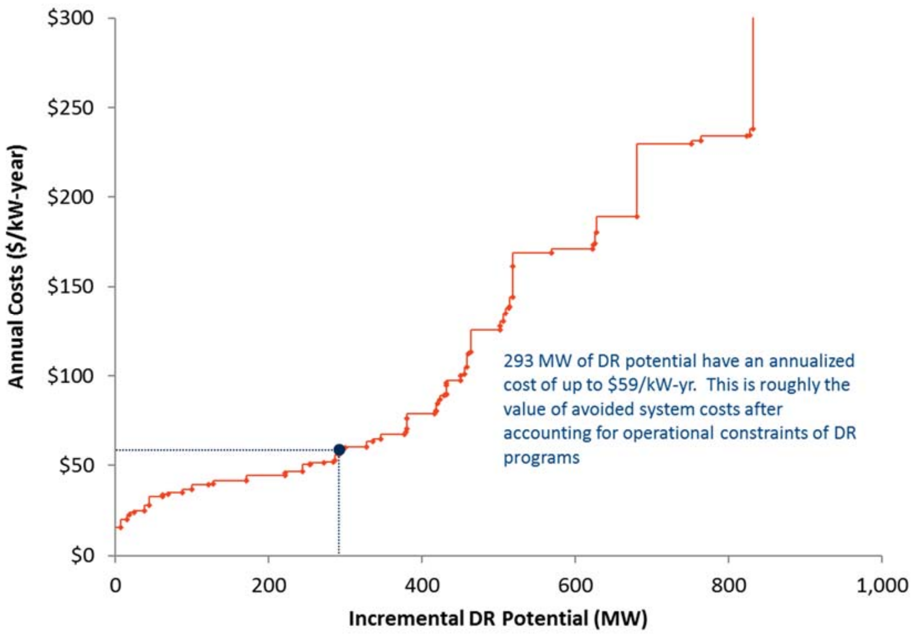
[10] NSP has interpreted the PUC's Order to require 400 MW of capacity-equivalent DR, which equates to 391 MW of generator-level load reduction when accounting for the reserve requirement, and 362 MW of meter-level load reduction when also accounting for line losses.

Figure 5: Total DR Potential in 2023 (Conventional Portfolio)



The incremental potential in conventional DR programs can be expressed as a "supply curve." Figure 6 illustrates the costs associated with achieving increasing levels of DR capability. The upward slope of the curve illustrates how DR capability (i.e., enrollment) increases as incentive payments increase. The curve also captures the different costs and potential associated with each conventional DR program and applicable customer segment. Cost-effective DR capability is identified with the blue dotted line. There is roughly 293 MW of incremental DR potential available at a cost of less than $59/kW-year. That cost equates to the value of avoided system costs after accounting for the operational constraints of DR programs.

Figure 6: NSP's Incremental DR Supply Curve in 2023 (Conventional Portfolio)



Note: Supply curve shows conventional DR potential without accounting for cost-effectiveness. Potential estimates if the DR options were offered simultaneously as part of a portfolio at each price point (i.e. accounts for overlap). Program costs presented in nominal terms.

As discussed previously in this report, the Minnesota PUC has established a DR procurement requirement of 400 MW by 2023. It is important to clarify whether this 400 MW is a capacity-equivalent value, a generator-level value, or a meter-level value. Specifically, 1 MW of load reduction at the meter (or customer premise) avoids more than 1 MW at the generator level due to line losses between the generator and the customer. Further, 1 MW of load reduction at the generator level provides more than 1 MW of full capacity-equivalent value, as the load reduction would also avoid the additional capacity associated with NSP's obligation to meet the planning reserve requirement. Based on NSP's calculations, which account for line losses and the reserve requirement, 1 MW of load reduction at the meter level equates to 1.08 MW of load reduction at the generator level and 1.11 MW of capacity-equivalent value.

NSP has interpreted the PUC's Order to require 400 MW of capacity-equivalent DR. This equates to 391 MW of generator-level load reduction when accounting for the reserve requirement, and 362 MW of meter-level load reduction when also accounting for line losses. These values are summarized in Table 3. Throughout this report, DR values are reported at the generator level. Thus, for consistency, we refer to the procurement requirement as a 391 MW generator-level value unless otherwise specified.

Table 3: NSP's 2023 DR Procurement Requirement

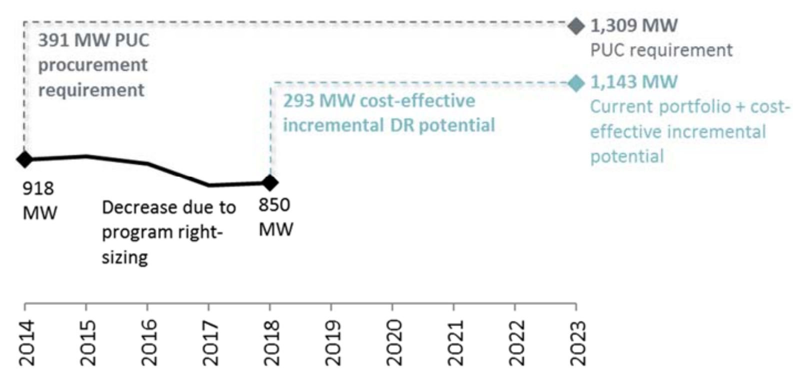
	Requirement (MW)	Notes
Meter level	361.7	Premise-level
Generator level	390.7	Grossed up for 8% line losses
Capacity equivalent	400.0	Grossed up for line losses and reserve requirement

Source: Calculations provided by NSP.

Our interpretation of the PUC's Order is that the required DR procurement is incremental to NSP's DR capability as it existed in 2014.[11] NSP had 918 MW of DR capability in 2014, leading to a total DR capability requirement of 1,309 MW in 2023. NSP's DR capability decreased between 2014 and 2017 largely due to an effort to ensure that enrolled load would be available for curtailment when called upon, thus leading to an incremental DR requirement that is larger than 391 MW (at the generator level).[12]

Combined with current capability of 850 MW, the incremental cost-effective DR potential in 2023 would result in a total portfolio of 1,143 MW. This estimate of cost-effective potential is 166 MW short of the PUC's DR procurement requirement. Figure 7 illustrates the gap between NSP's conventional DR potential and the DR procurement requirement.

Figure 7: NSP DR Capability (Conventional Portfolio)



Note: Chart is scaled such that vertical axis does not start at zero. 391 MW procurement requirement is expressed at the generator level and is equivalent to 400 MW of DR capacity.

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[11] 2014 is the year of NSP's prior DR potential study, which was used to inform the Minnesota PUC's establishment of the DR procurement requirement.

[12] For instance, some customers did not realize that they were participating in the program and dropped out when notified, or otherwise elected to reduce their enrolled load level.

IV. Expanded DR Potential in 2023

Given the shortfall of the conventional DR portfolio relative to the 2023 procurement target, it is relevant to consider if an expanded portfolio of DR options could mitigate the shortfall. We analyzed eight additional emerging DR programs that could be offered to up to four different customer segments (if applicable). As described in Section II, these emerging DR options include both price based programs (e.g., TOU and CPP rate designs) and technology-based programs (e.g., Auto-DR and smart water heating).

Base Case

Among the individual measures with the most *technical potential* in 2023 are HVAC Auto-DR for Medium C&I customers and thermal storage for commercial customers. Each of these programs has technical potential in excess of 100 MW.

Pricing programs and lighting Auto-DR for C&I customers, timed water heating programs, and behavioral DR compose the next tier of opportunities, with technical potential in each ranging between 50 and 100 MW. These programs generally have the potential to reach significant levels of enrollment or, alternatively, to provide deep load reductions among a smaller share of customers.

The Small C&I segment accounts for many of the DR programs with the lowest technical potential, as there is a relatively small share of load in this segment and these customers have historically demonstrated a lower willingness to participate in DR programs.

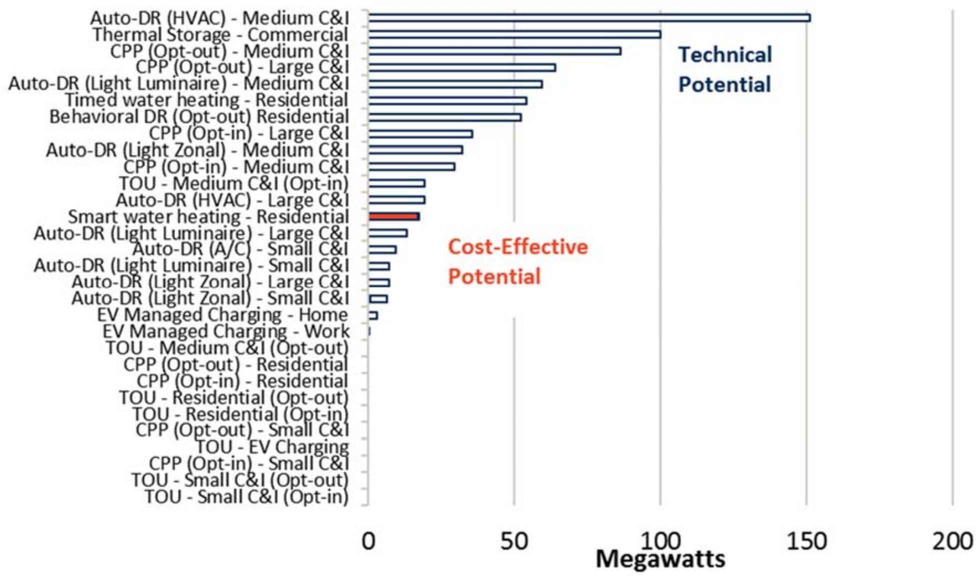
EV charging load control programs also have very modest technical potential in 2023. This is driven in part by a limited projection of EV adoption over the next five years. It is also driven by a lack of coincidence between peak charging load and the timing of the system peak.

Pricing programs (i.e., TOU, CPP) cannot be offered on a full scale basis in 2023 to residential and small C&I customers, as AMI will not yet be fully deployed. Therefore, pricing programs have not been included in the potential estimates for 2023. Rollout of the programs is assumed to begin in 2024, upon NSP's projected completion of the AMI rollout.

Programs with significant *technical potential* do not necessarily have significant *cost-effective potential*. After accounting for cost-effectiveness under Base Case market conditions as well as technical constraints, the potential in DR programs is limited in 2023. Individually, only smart water heating and a modest amount of automated load control for C&I customers pass the cost-effectiveness screen. These programs pass the cost-effectiveness screen largely because they are capable of providing an expanded array of value streams, such as frequency regulation and geo-targeted T&D deferral.

Figure 8 summarizes the technical and cost-effective potential in each of the new DR program options. Potential is first shown for DR programs as if they were each offered in isolation.

Figure 8: New DR Program Potential in 2023 (Base Case)

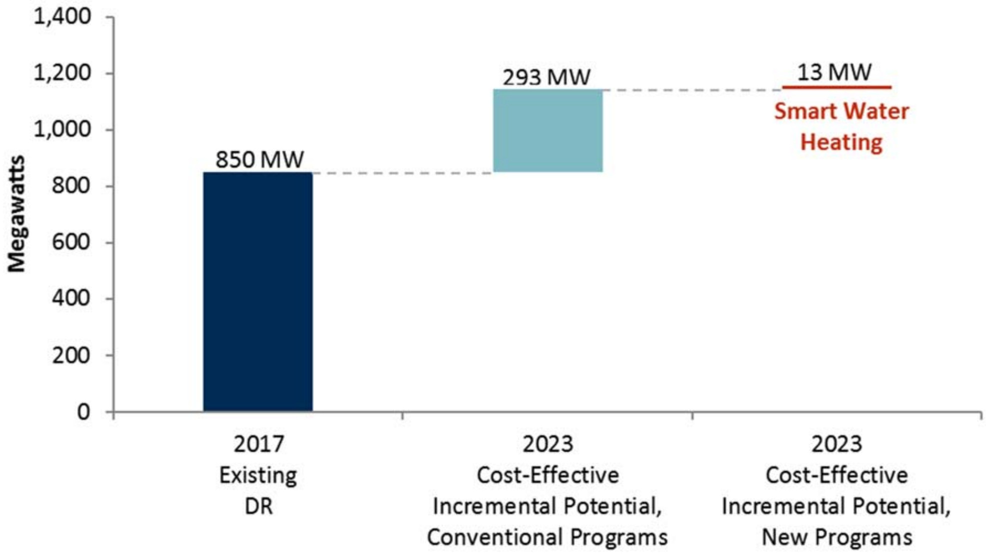


Note: Results reflect NSP system-wide DR potential. Impacts assume each program is offered in isolation; they are not additive. All potential is incremental to NSP's existing portfolio.

The program-level DR impacts shown above cannot be added together to arrive at the potential capability of a DR portfolio. Adjustments must be made to account for double-counting of impacts when customers are enrolled in more than one program, and for limits on the need for certain value streams such as frequency regulation. Thus, combining the cost-effective programs into a portfolio can result in lower total potential DR capability than if the individual impacts shown above were simply summed.

In the 2023 scenario described above, the smart water heating program alone could satisfy NSP's need for frequency regulation. With that value stream no longer available to the Auto-DR program, the Auto-DR program fails the cost-effectiveness screen. **With the addition of the smart water heating program, NSP's cost-effective DR portfolio would increase by 13 MW. Achievement of all cost-effective DR potential would amount to total system-wide DR capability of 1,156 MW, but would still fall short of the PUC's procurement target by 154 MW.** The expanded capability in 2023 is illustrated in Figure 9.

Figure 9: Total DR Potential in 2023 (Expanded Portfolio)



Near-term Limitations on DR Value

The value of DR is very dependent on the characteristics of the system in which it is deployed. Several factors limit NSP's cost-effective DR in 2023, relative to other jurisdictions.

- **Low capacity prices:** NSP has access to low-cost peaking capacity, primarily due to the presence of brownfield sites that significantly reduce development costs. For instance, the all-in cost of a new combustion turbine in NSP's IRP is $63/kW-year, which is 23 percent lower than the cost of a CT assumed by the U.S. Energy Information Administration (EIA) in its Annual Energy Outlook (AEO). Similarly, a recent study approved by the Minnesota PUC determined that the average value of T&D capacity deferral achieved through reductions in customer consumption is approximately $11/kW-year in NSP's service territory.[13] This value, which was determined through a detailed bottom-up engineering assessment, is significantly lower than that of T&D deferral benefits observed in other studies, which can commonly reach values of $30/kW-year.[14] The value of T&D deferral is dependent on characteristics of the utility system and drivers of the investment need, and therefore varies significantly across utilities.

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[13] Xcel Energy, "Minnesota Transmission and Distribution Avoided Cost Study," submitted to the Minnesota Department of Commerce, Division of Energy Resources (Department), July 31, 2017

[14] Ryan Hledik and Ahmad Faruqui, "Valuing Demand Response: International Best Practices, Case Studies, and Applications," prepared for EnerNOC, January 2015.

- **Metering technology limitations:** NSP has not yet deployed AMI, with an estimated forecast that system-wide AMI installation will be completed in 2024. AMI-based DR programs, such as time-varying rates and behavioral DR, cannot be offered to customers until deployment is complete. This effectively excludes the possibility of introducing any AMI-based programs in the year 2023.

- **High DR technology costs:** Some emerging DR programs depend on new technologies that have not yet experienced the cost declines that could be achieved at scale. While these technology costs could decrease over time, those reductions are not achieved in the early years of the study horizon.

- **Limited need for additional DR value streams:** While certain DR value streams potentially can be very valuable, these value streams can also be limited in need. For instance, our analysis of NSP's five-year distribution plan identified only 38 MW of projects that were potential candidates for geo-targeted capacity investment deferral. Those projects accounted for roughly 10 percent of the total value of NSP's plan. To qualify, projects need to satisfy criteria such as being driven by growth in demand and being of a certain size.[15] Similarly, while frequency regulation is often a highly-valued ancillary service and can be provided by certain types of DR, the need for frequency regulation across most markets is significantly less than one percent of system peak demand. This limits the amount of that value stream that can be provided by DR.

High Sensitivity Case

The High Sensitivity Case illustrates the potential for DR under an alternative set of market conditions that are more favorable to DR program economics. As discussed earlier in this report, assumptions behind the High Sensitivity Case are not a forecast of what is likely to happen in the future in NSP's service territory, particularly in the near-term years of the study horizon.

Under the illustrative High Sensitivity Case assumptions, cost-effective DR potential increases significantly. Several programs that were not previously passing the cost-effectiveness screen, such as medium C&I HVAC-based Auto DR, residential timed water heating, and a small amount of lighting-based Auto-DR do pass the screen under the more favorable assumptions in this case. Figure 10 summarizes the increase in cost-effective potential at the individual program level.

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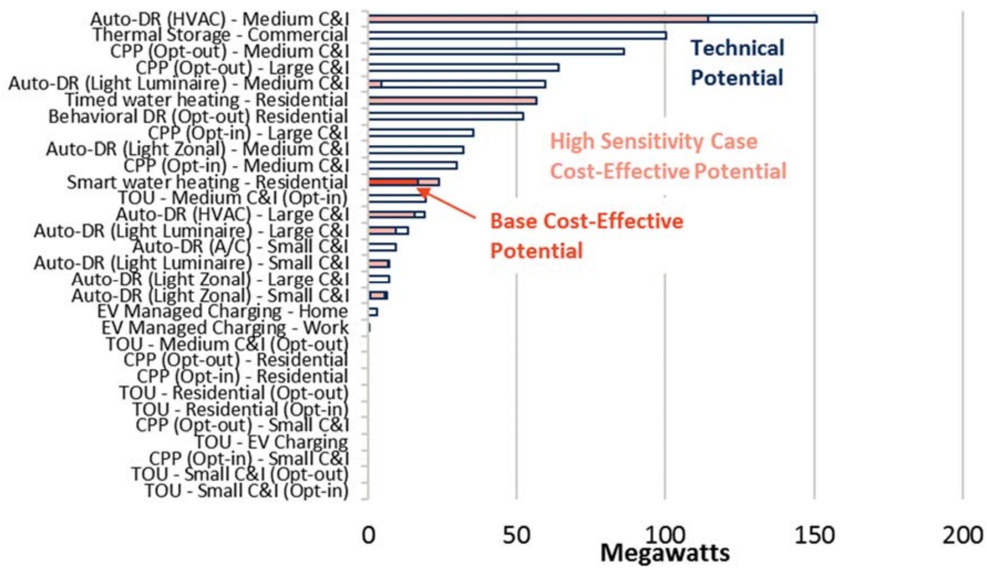
[15] Details of the geo-targeted T&D deferral analysis are included in Appendix A.

Figure 10: New DR Program Potential in 2023 (High Sensitivity Case)



Note: Results reflect NSP system-wide DR potential. Impacts assume each program is offered in isolation; they are not additive. All potential is incremental to NSP's existing portfolio.

A DR portfolio constructed from cost-effective programs in the High Sensitivity Case would produce total incremental DR potential of 484 MW in 2023. Under the illustrative assumptions in this case, the cost-effective incremental portfolio would consist of 393 MW of conventional DR programs, and 91 MW of new DR programs. The portfolio of new DR programs includes residential smart water heating[16] (24 MW) and C&I HVAC-based Auto-DR (67 MW). Achievement of all cost-effective DR potential under the High Sensitivity Case would amount to total system-wide DR capability of 1,334 MW.

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[16] Smart water heating has lower cost-effective potential in 2023 than timed water heating. However, the smart water heating program provides more value and more significant per-participant impacts as participation ramps up in the later years of the study horizon, so it is the water heating program that was included in the portfolio.

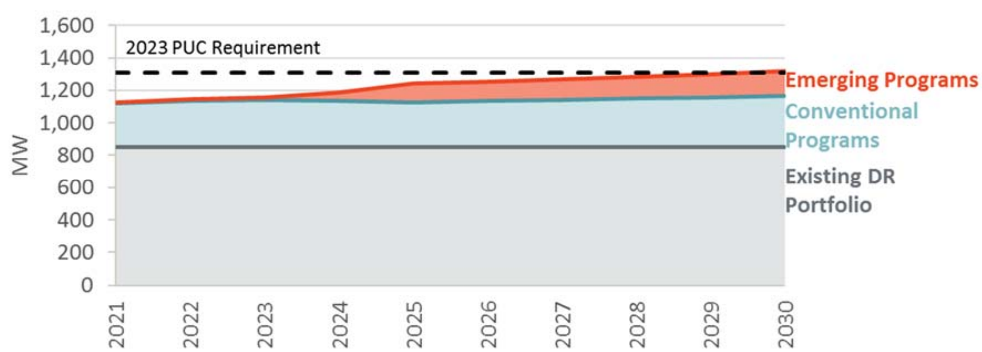
V. Expanded DR Potential in 2030

Base Case

Opportunities to expand cost-effective DR portfolio will grow beyond 2023. Most significantly, time-varying rates (such as TOU and CPP rates) can be offered to customers following completion of the AMI rollout in 2024. Additionally, the customer base is projected to grow over the study horizon, expanding the population of customers eligible to participation in DR programs. Growth in the market penetration of renewable generation will likely lead to more volatility in energy costs, further creating opportunities for DR to provide value. Additionally, current participants in the Savers Switch program are expected to transition to the smart thermostat-based A/C Reward program over time. Smart thermostats provide a greater per-participant demand reduction than the technology in the Savers Switch program, therefore further increasing DR potential.

Figure 11 summarizes growth in DR potential under Base Case assumptions for the portfolio of cost-effective DR programs. The majority of the post-2023 growth comes from the introduction of time-varying pricing programs.

Figure 11: Cost-Effective DR Potential, Base Case



Under Base Case conditions, benefits of the DR program are primarily driven by avoided generation capacity costs. Avoided generation capacity costs account for $51 million of the $66 million (77 percent) in total annual benefits from the DR programs in the year 2030. This is because the relatively low avoided costs in the Base Case scenario tend to favor conventional DR programs which are primarily constrained to reducing the system peak, but have lower costs as a result of this somewhat limited functionality. Table 4 summarizes the annual benefits, by category, of the incremental cost-effective DR portfolio in 2030 for the Base Case.

Table 4: Annual Avoided Costs from 2030 DR Portfolio, Base Case ($ million/year)

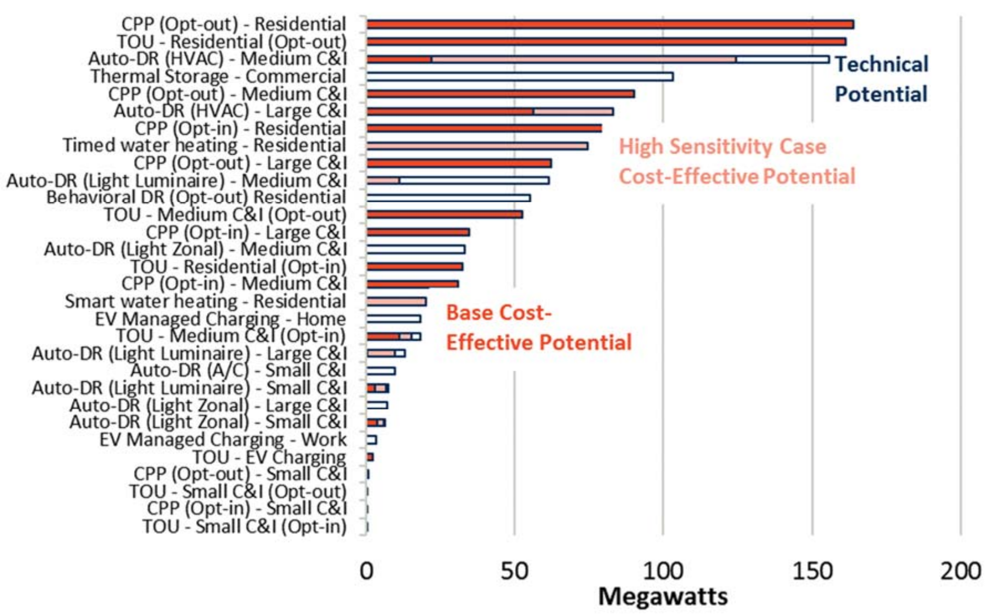
	Energy	Generation Capacity	System Average T&D Deferral	Geotargeted Distribution Deferral	Frequency Regulation	Total
Conventional Programs	$5.0	$43.6	$2.8	$0.0	$0.0	$51.4
Emerging Programs	$5.7	$7.4	$0.4	$0.0	$1.2	$14.7
Total	$10.7	$50.9	$3.2	$0.0	$1.2	$66.1

Notes: Benefits shown in 2023 dollars.

High Sensitivity Case

Drivers of growth over time under the illustrative High Sensitivity Case conditions are similar to growth drivers under Base Case conditions, with AMI-enabled time-varying rates accounting for the majority of new opportunities after 2023. Figure 12 summarizes the 2030 incremental measure-level potential for both the Base Case and the High Sensitivity Case.

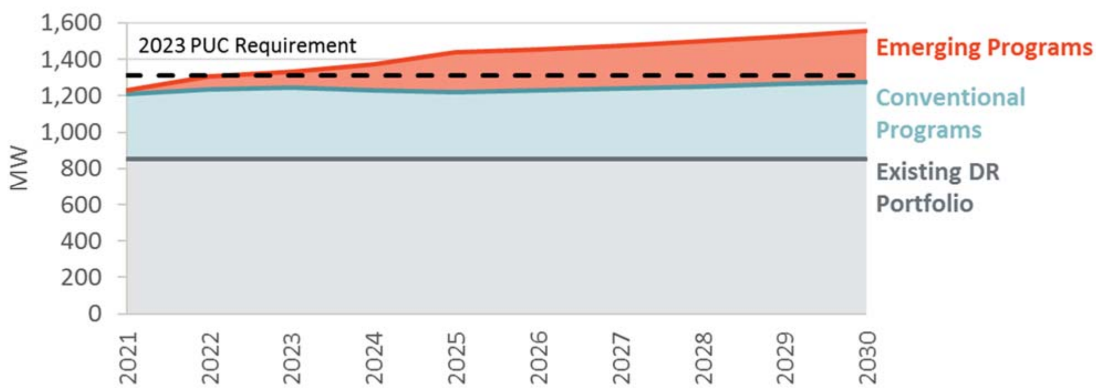
Figure 12: New DR Program Potential in 2030



Note: Results reflect NSP system-wide DR potential. Impacts assume each program is offered in isolation; they are not additive. All potential is incremental to NSP's existing portfolio.

The capability of the cost-effective DR portfolio for the High Sensitivity Case is summarized in Figure 13.

Figure 13: Cost-Effective DR Potential, High Sensitivity Case



Over the longer-term, new policies could potentially drive down DR costs and therefore increase cost-effective potential. One initiative that has garnered some attention is the development of a technology standard known as "CTA-2045." CTA-2045 is a communications interface which would allow various control technologies to connect to appliances through a standard port or socket. While widespread adoption of this standard is not considered to be imminent, it could potentially have positive implications for DR adoption in the longer term. See the Sidebar at the end of this section for further discussion of the outlook for CTA-2045.

The benefits of DR under the High Sensitivity Case assumptions continue to be driven primarily by avoided generation capacity costs. However, additional price volatility due a greater assumed mix of renewable generation in the regional supply portfolio leads to an increase in the share of total that is attributable to avoided energy costs. The total value of frequency regulation provided by DR also increases modestly relative to the Base Case, as a greater need for this service is assumed for renewable generation integration purposes. Table 5 summarizes the annual benefits, by category, of the incremental cost-effective DR portfolio in 2030 for the High Sensitivity Case.

Table 5: Annual Avoided Costs from 2030 DR Portfolio, High Sensitivity Case ($ million/year)

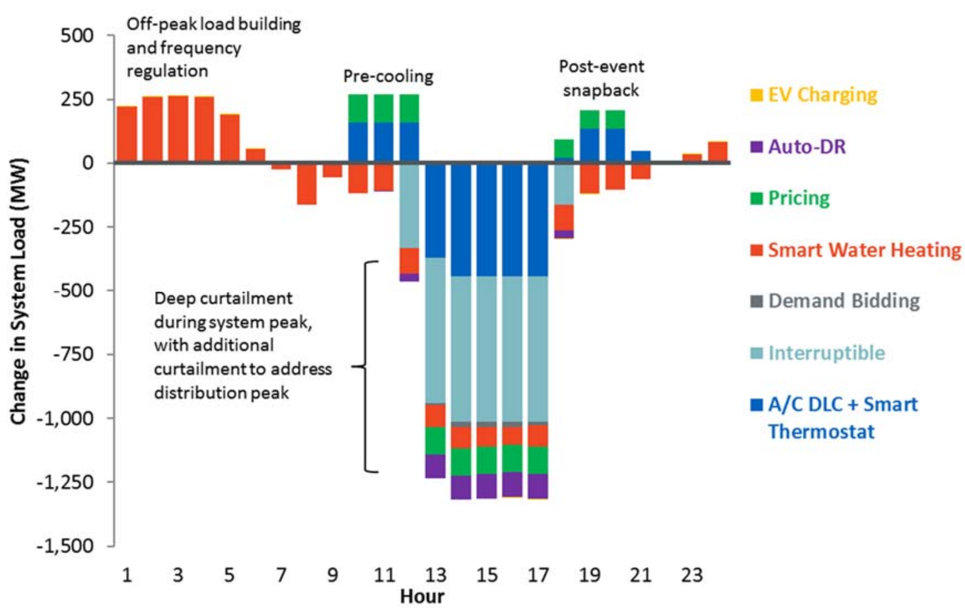
	Energy	Generation Capacity	System Average T&D Deferral	Geotargeted Distribution Deferral	Frequency Regulation	Total
Conventional Programs	$8.6	$69.7	$3.3	$0.0	$0.0	$81.5
Emerging Programs	$19.6	$19.5	$0.8	$0.7	$4.6	$45.2
Total	$28.2	$89.2	$4.0	$0.7	$4.6	$126.8

Notes: Benefits shown in 2023 dollars.

DR Portfolio Operation

The addition of emerging programs to NSP's DR portfolio will improve operational flexibility across NSP's system. Figure 14 illustrates how the cost-effective DR portfolio from the High Sensitivity Case could operate on an hourly basis during the days of the year with the highest system peak demand. The profile shown maximizes avoided costs relative to the system cost assumptions used in this study.

Figure 14: Average Load Impacts of the 2030 Cost-Effective DR Portfolio on Top 10 Load Days (High Sensitivity Case)



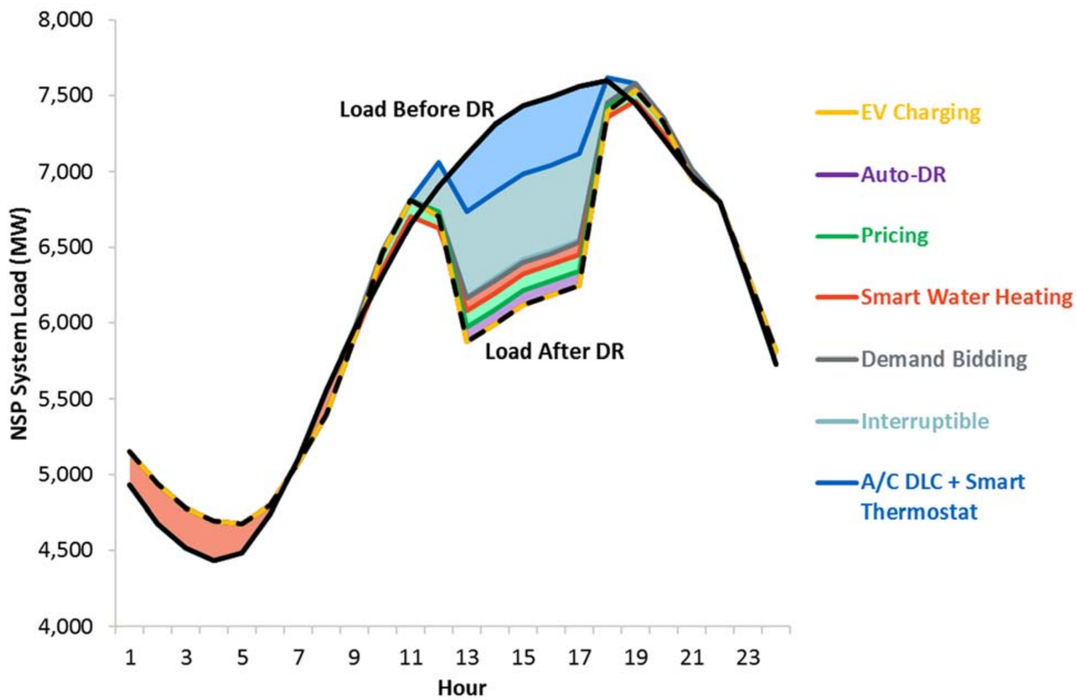
Note: Shown for cost-effective programs identified in 2030, accounting for portfolio overlap.

A deep curtailment of load during system peak hours is utilized to capture significant generation and T&D capacity deferral benefits. These also tend to be hours when energy costs are highest, leading to additional energy value. The duration of the peak load curtailment spans a fairly broad period of time – seven hours – in order to account for the lack of coincidence of the system and local peak demand that drive capacity needs. Load curtailment can be staggered across DR programs – and across participants in a given DR program – in order to achieve this duration of demand reduction.

Load increases are observed immediately before and after the peak load reduction. This is driven mostly by the need to maintain and restore building temperatures to desired levels around DR events. The smart water heating program builds load during nighttime hours, shifting heating load to the lowest cost hours and potentially reducing the curtailment of renewable generation.

Figure 15 illustrates how NSP's system load shape changes as a result of the impacts shown in Figure 14 above. The figure shows a steep reduction in load during hours of the MISO system peak, while NSP's later peak is only modestly reduced. This is primarily due to NSP's planning needs being driven by MISO coincident peak demand. If the MISO peak shifts later in the day due to solar PV adoption, or if NSP transitions to an increased focus on its own peak demand in planning activities, then the dispatch of the DR programs would need to be modified accordingly. In particular, it may become necessary to stagger the utilization of DR programs across a broader window of hours in order to "flatten" peak demand across the hours of the day.

Figure 15: Average Impacts of the 2030 Cost-Effective DR Portfolio on NSP System Load (High Sensitivity Case)



Note: Shown for cost-effective programs identified in 2030, accounting for portfolio overlap.

Sidebar: The Outlook for CTA-2045

CTA-2045 is a standard which specifies a low-cost communications “socket” that would be embedded in electric appliances and other consumer products. If consumers wished to make an appliance capable of participating in a demand response program, they could simply plug a communications receiver into the socket, thus allowing the appliance to be controlled by themselves or a third party. CTA-2045 has the potential to establish a low-cost option for two-way communications capability in appliances, thus reducing the cost and hassle of consumer enrollment in DR programs that would otherwise require on-site installation of more costly equipment.

Development of CTA-2045 began in 2011, through work by the Consumer Technology Association (CTA) and the Electric Power Research Institute (EPRI). Refinements to the standard are ongoing. To assess the outlook for CTA-2045 and its potential implications for future DR efforts, we conducted phone and email interviews with subject matter experts from utilities, appliance manufacturers, and DR software platforms.

There is a shared view that CTA-2045 is facing a chicken-and-egg problem. Manufacturers have been hesitant to incorporate the standard into their products, because there is a cost associated with doing so and they have not yet observed demand in the market for the communications functionality. At the same time, a barrier preventing increased adoption of DR technologies could be some of the costs and installation challenges that CTA-2045 would ultimately address.

Products with CTA-2045 functionality have not yet been deployed at scale, and where available are sold at a price premium that is significantly higher than the unit costs that could ultimately be achieved at scale. The relative lack of enthusiasm among manufacturers for rolling out CTA-2045 compliant products has led to a slow pace of development of the standard itself. Progress is being made incrementally, though technical issues still remain to be resolved.

Looking forward, some in the industry feel that the mandating CTA-2045 through a new state appliance standard could be the catalyst that is needed for adoption to become broadly widespread. Aggressive support for CTA-2045 by large utilities is also considered to be the type of activity that would facilitate adoption.

If compliance with CTA-2045 ultimately were to accelerate through activities like those described above, electric water heaters are poised to become the first such commercial application, as they have been the most common test case for proving the technical concept and are an attractive source of load flexibility. Particularly in the context of water heaters, CTA-2045 would help to overcome the challenge of enrolling customers in a DR program during the very narrow window of time during which their existing water heater expires and must be replaced. Other controllable end-uses, such as thermostats or even electric vehicle chargers could be candidates for the standard, though these technologies sometimes already come pre-equipped with communications capabilities.

VI. Conclusions and Recommendations

NSP's sizeable existing DR portfolio has the potential to be expanded by tapping into latent demand for existing programs and also by rolling out a new portfolio of emerging DR programs. Specific recommendations for acting on the findings of this study including the following:

Aggressively pursue the transition to smart thermostats as well as recruitment of medium C&I customers into the Interruptible program. NSP's relatively low avoided costs mean that lower cost, established DR programs are the most economically attractive options in the near term. Smart thermostats and a Medium C&I interruptible program present the largest incremental opportunity and the least amount of uncertainty/risk.

Pilot and deploy a smart water heating program. There is significant experience with advanced water heating load control in the Upper Midwest, and the technology is rapidly advancing. The thermal storage capabilities of water heaters provide a high degree of load flexibility that can be adapted to a range of system needs.

As a complementary activity to the development of a smart water heating program, also evaluate the economics and environmental impacts of switching from gas to electric heating, factoring in the grid reliability benefits associated with this flexible source of load. Doing so would require revisiting existing state policies that prohibit utility-incentivized fuel switching.

Build the foundation for a robust offering of time-varying rates. As a first step, prepare a strategy for rolling out innovative rates soon after AMI is deployed. This should include exploring rate offerings that could be deployed to customers on a default (opt-out) basis, as default rate offerings maximize the overall economic benefit for the program.

Develop measurement & verification (M&V) 2.0 protocols to ensure that the impacts of the program are dependable and can be integrated meaningfully into resource planning efforts. Included in this initiative could be the development of a data collection plan to enhance the quality of future market potential studies. Further, detailed customer segmentation and geographically granular load data at the distribution system level will provide an improved base from which to develop a cost-effective DR strategy.

Design programs with peak period flexibility. From a planning standpoint, the timing of the peak period could change for a variety of reasons (e.g., DR flattens the peak, solar PV shifts the net peak, or the planning emphasis shifts from a focus on the MISO peak to a focus on more local peaks). DR programs will need to be designed with the flexibility to adjust the timing of curtailments in response to these changes.

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Appendix A: Load*Flex* Modeling Methodology and Assumptions

The Load*Flex* Model

The Brattle Group's Load*Flex* model was developed to quantify the potential impacts, costs, and benefits of demand response (DR) programs. The Load*Flex* modeling approach offers the flexibility to accurately estimate the broader range of benefits that are being offered by emerging "DR 2.0" programs which not only reduce system peak demand, but also provide around-the-clock load management opportunities.

The Load*Flex* modeling framework builds upon the standard approach to quantifying DR potential that has been used in prior studies around the U.S. and internationally, but incorporates a number of differentiating features which allow for a more robust evaluation of DR programs:

- **Economically optimized enrollment:** Assumed participation in DR programs is tailored to the incentive payment levels that are cost-effective for the DR program. If only a modest incentive payment can be justified in order to maintain a benefit-cost ratio of 1.0, then the participation rate is calibrated to be lower than if a more lucrative incentive payment were offered. Prior approaches to quantifying DR potential ignore this relationship between incentive payment level and participation, which tends to under-state the potential (and, in some cases, incorrectly concludes that a DR program would not pass the cost-effectiveness screen).

- **Utility-calibrated load impacts:** Load impacts are calibrated to the characteristics of the utility's customer base. In the residential sector, this includes accounting for the market saturation of various end-use appliances (e.g., central air-conditioning, electric water heating). In the commercial and industrial (C&I) sector, this includes accounting for customer segmentation based on size (i.e., the customer's maximum demand) and industry (e.g., hospital, university). Load curtailment capability is further calibrated to the utility's experience with DR programs (e.g., impacts from existing DLC programs or dynamic pricing pilots).

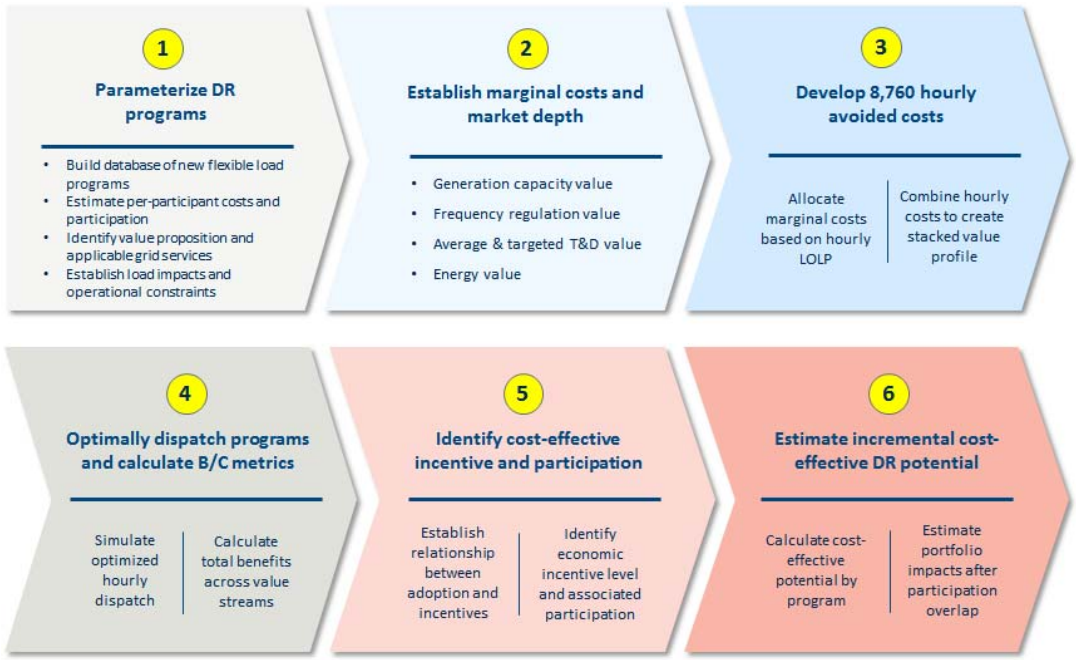
- **Sophisticated DR program dispatch:** DR program dispatch is optimized subject to detailed accounting for the operational constraints of the program. In addition to tariff-related program limitations (e.g., how often the program can be called, hours of the day when it can be called), Load*Flex* includes an hourly profile of load interruption capability for each program. For instance, for an EV home charging load control program, the model accounts for home charging patterns, which would provide greater average load reduction opportunities during evening hours (when EV owners have returned home from work) than in the middle of the day.

- **Realistic accounting for "value stacking":** DR programs have the potential to simultaneously provide multiple benefits. For instance, a DR program that is dispatched to reduce the system peak and therefore avoid generation capacity costs could also be dispatched to address local distribution system constraints. However, tradeoffs must be made in pursuing these value streams – curtailing load during certain hours of the day may prohibit that same load from being curtailed again later in the day for a different purpose. Load*Flex* accounts for these tradeoffs in its DR dispatch algorithm. DR program operations are simulated to maximize total benefits across multiple value streams, while recognizing the operational constraints of the program. Prior studies have often assigned multiple benefits to DR programs without accounting for these tradeoffs, thus double-counting benefits.

- **Industry-validated program costs:** DR program costs are based on a detailed review of the utility's current DR offerings. For new programs, costs are based on a review of experience and studies in other jurisdictions and conversations with vendors. Program costs are differentiated by type (e.g., equipment/installation, administrative) and structure (e.g., one-time investment, ongoing annual fee, per-kilowatt fee) to facilitate integration into utility resource planning models.

The Load*Flex* methodology is organized around six steps, as summarized in Figure 16. The remainder of this appendix describes each of the six steps in further detail, documenting methodology, assumptions, and data sources.

Figure 16: The Load*Flex* Modeling Framework



Step 1: Parameterize the DR programs

Each DR program is represented according to two broad categories of characteristics: Performance characteristics and cost characteristics.

Program Performance Characteristics

The performance characteristics of each DR program are represented in detail in Load*Flex* to accurately estimate the ability of the DR programs to provide system value. The following are key aspects of each program's performance capability.

Load impact profiles

Each DR program is represented with 24-hour average daily profiles of load reduction and load increase capability. These 24-hour impact profiles are differentiated by season (summer, winter, shoulder) and day type (weekday, weekend). For instance, air-conditioning load curtailment capability is highest during daytime hours in the summer, lower during nighttime summer hours, and non-existent during all hours in the winter.

Whenever possible, load impacts are derived directly from NSP's experience with its existing DR programs and pilots. NSP's experience directly informed the impact estimates for direct load control, smart thermostat, and interruptible rates programs. For emerging non-pricing DR programs, impacts are based on a review of experience and studies in other jurisdictions and tailored to NSP's customer mix and climate. Methods used to develop impact profile estimates for emerging non-pricing DR programs include the following:

- *C&I Auto-DR:* The potential for C&I customers to provide around-the-clock load flexibility was primarily derived from data supporting a 2017 statewide assessment of DR potential in California[17], a 2013 LBNL study of DR capability[18], and electricity load patterns representative of C&I buildings in Minneapolis developed by the Department of Energy.[19] Customer segment-specific estimates from these studies were combined to produce a composite load impact profile for the NSP service territory based on assumptions about NSP's mix of C&I customers. Impacts were scaled as necessary for consistency with NSP's prior experience with C&I DR programs.

- *Water heating load control:* Assumptions for the water heating load control programs – both grid interactive water heating and static timed water heating - are derived from a 2016 study on the value of various water heating load control strategies.[20] The program definition assumes that only customers with existing electric resistance water heaters will be eligible for participating in the water heating programs.

- *Behavioral DR:* Impacts are derived from a review of the findings of behavioral DR pilot studies conducted around the US, including for Baltimore Gas & Electric, Consumers Energy, Green Mountain Power, Glendale Water and Power, Portland Gas Electric, and Pacific Gas and Electric. Most behavioral DR pilot studies have been conducted by Oracle (OPower) and have generally found that programs with a limited number of short curtailment events (4-10 events for 3-5 afternoon/evening hours) can achieve 2% to 3% load reduction across enrolled customers.[21] Based on these findings, we assumed that a

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17 Peter Alstone et al., Lawrence Berkeley National Laboratory, "Final Report on Phase 2 Results: 2025 California Demand Response Potential Study." March 2017.

18 Daniel J. Olsen, Nance Matson, Michael D. Sohn, Cody Rose, Junqiao Dudley, Sasank Goli, and Sila Kiliccote (Lawrence Berkeley National Oaboratory), Marissa Hummon, David Palchak, Paul Denholm, and Jennie Jorgenson (National Renewable Energy Laboratory), and Ookie Ma (U.S. Department of Energy), "Grid Integration of Aggregated Demand Response, Part 1: Load Availability Profiles and Constraints for the Western Interconnection," LBNL-6417E, 2013.

19 See U.S. Department of Energy Commercial Reference Buildings at: https://www.energy.gov/eere/buildings/commercial-reference-buildings

20 Ryan Hledik, Judy Chang, and Roger Lueken. "The Hidden Battery: Opportunities in Electric Water Heating." January 2016. Posted at: http://www.electric.coop/wp-content/uploads/2016/07/The-Hidden-Battery-01-25-2016.pdf

21 For example, see Jonathan Cook et al., "Behavioral Demand Response Study – Load Impact Evaluation Report", January 11, 2016, prepared for Pacific Gas & Electric Company, available at: http://www.oracle.com/us/industries/utilities/behavioral-demand-response-3628982.pdf, and OPower,

Continued on next page

behavioral DR program called 10 times per year between 3 pm and 6 pm would achieve a 2.5% load reduction.

- *EV managed charging:* Estimates of load curtailment capability are based on projections of aggregate EV charging load shapes provided by Xcel Energy. The ability to curtail this charging load is based on a review of recent utility EV charging DR pilots, including managed charging programs at several California utilities (PG&E, SDG&E, SCE, and SMUD) and United Energy in Australia.[22]

- *Ice-based thermal energy storage:* Estimates of load curtailment capability are estimated based on charging and discharging (freezing and cooling) information from Ice Bear[23] and adapted to mirror building use patterns in Minnesota based on load profiles from the U.S. Department of Energy.[24]

For impacts from pricing programs, we relied on Brattle's database of time-varying pricing offerings. The database includes the results of more than 300 experimental and non-experimental pricing treatments across over 60 pilot programs.[25] It includes published results from Xcel Energy's various pricing pilots during this time period. The results of the pilots in the database are used to establish a relationship between the peak-to-off-peak price ratio of the rates and the average load reduction per participant, in order to simulate price response associated with any given rate design. This relationship between load reduction and price ratio is illustrated in Figure 17.

Continued from previous page

"Transform Every Customer into a Demand Response Resource: How Utilities Can Unlock the Full Potential of Residential Demand Response", 2014, available at: https://go.oracle.com/LP=42838?elqCampaignId=74613.

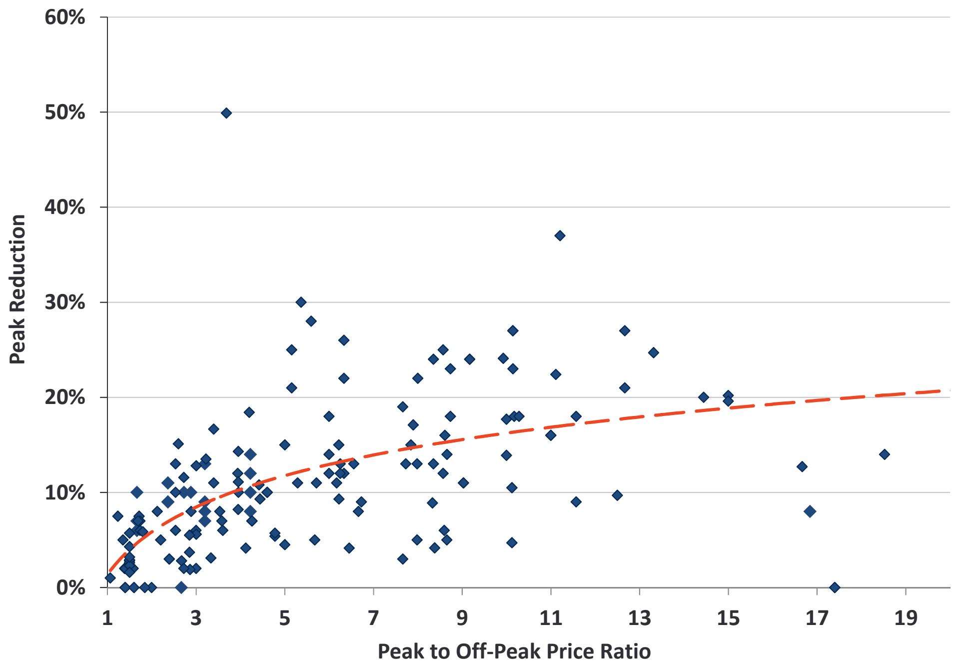
22 Pilot programs reviewed include BMW and PG&E's i Charge Forward Pilot, SCE's Workplace Charging Pilot, SMUD's EV Innovators Pilot, SDG&E's Power Your Drive Pilot, and United Energy's EV smart grid demonstration project.

23 Ice Energy, "Ice Bear 20 Case Study," November 2016. Available: https://www.ice-energy.com/wp-content/uploads/2016/12/SantaYnez_CaseStudy_Nov2016.pdf

24 See U.S. Department of Energy Commercial Reference Buildings at: https://www.energy.gov/eere/buildings/commercial-reference-buildings

25 Ahmad Faruqui, Sanem Sergici, and Cody Warner, "Arcturus 2.0: A Meta-Analysis of Time-Varying Rates for Electricity," *The Electricity Journal*, 2017.

Figure 17: Relationship between Price Ratio and Price Response in Residential Pricing Pilots



Results shown only for price ratios less than 20-to-1 and for treatments that did not include automating technology such as smart thermostats.

Daily relationship between load reduction and load increase

Some DR programs will require a load increase to offset or partially offset the load that is reduced during a curtailment event. In Load*Flex*, each program definition includes a parameter that represents the percent of curtailed load that must be offset by increased load on the same day, including the timing of when the load increase must occur. For instance, in a water heating load control program, any reduction in water heating load is assumed to be offset by an equal increase in water heating load on the same day in order to meet the customer's water heating needs. Alternatively, a reduction in air-conditioning load may only be offset partially by an increase in consumption, but it would immediately follow the curtailment.

Where data is available, these load building assumptions are based on the same data sources described above. Otherwise, these impacts are derived from assumptions that were developed for FERC's 2009 *A National Assessment of Demand Response Potential*.

Tariff-related operational constraints

Most DR programs will have administrator-defined limits on the operation of the program. This includes the maximum number of hours per day that the program can be curtailed, whether or not those curtailment hours must be contiguous, and the maximum number of days per year with allowed curtailment. Assumed operational constraints are based on Xcel Energy's program definitions and a review of common limitations from programs offered in other jurisdictions.

Ancillary services availability

If a DR program has the advanced control and communications technology necessary to provide ancillary services, Load*Flex* accounts for the capacity that is available to provide fast-response load increases or decreases in response to real-time fluctuations in supply and demand. In this study, smart water heating and Auto-DR are assumed to be able to offer ancillary services. Specifically, we model frequency regulation as it is the most valuable ancillary services product. Capability is based on the same data sources described above.

Table 6 summarizes the performance characteristics for each DR program in this study. In the table, "load shifting capability" identifies whether or not a program is capable of shifting energy usage from peak periods to off-peak periods on a daily basis.

Table 6: DR Program Performance Characteristics

Segment	Program	Peak-coincident curtailment capability (kW/participant)	Hours of Curtailment (hours)	Average regulation up provided (kW/participant)	Average regulation down provided (kW/participant)	Load shifting capability?
Residential	A/C DLC - SFH	0.62	75	0.00	0.00	No
Residential	Behavioral DR (Opt-out)	0.06	40	0.00	0.00	No
Residential	CPP (Opt-in)	0.34	75	0.00	0.00	No
Residential	CPP (Opt-out)	0.17	75	0.00	0.00	No
Residential	EV Managed Charging - Home	0.46	45	0.00	0.00	Yes
Residential	EV Managed Charging - Work	0.09	45	0.00	0.00	Yes
Residential	Smart thermostat - MDU	0.86	75	0.00	0.00	No
Residential	Smart thermostat - SFH	1.15	75	0.00	0.00	No
Residential	Smart water heating	0.46	4,745	0.37	0.38	Yes
Residential	Timed water heating	0.43	1,825	0.00	0.00	Yes
Residential	TOU - EV Charging (Opt-in)	0.05	1,460	0.00	0.00	Yes
Residential	TOU (Opt-in)	0.17	1,284	0.00	0.00	No
Residential	TOU (Opt-out)	0.08	1,284	0.00	0.00	No
Small C&I	A/C DLC	1.93	75	0.00	0.00	No
Small C&I	Auto-DR (A/C)	1.37	200	0.37	0.49	Yes
Small C&I	Auto-DR (Light Luminaire)	1.07	300	0.52	0.57	Yes
Small C&I	Auto-DR (Light Zonal)	0.92	300	0.44	0.49	Yes
Small C&I	CPP (Opt-in)	0.02	75	0.00	0.00	No
Small C&I	CPP (Opt-out)	0.01	75	0.00	0.00	No
Small C&I	Demand Bidding	0.02	200	0.00	0.00	No
Small C&I	Interruptible	1.98	90	0.00	0.00	No
Small C&I	TOU (Opt-in)	0.01	1,281	0.00	0.00	No
Small C&I	TOU (Opt-out)	0.00	1,281	0.00	0.00	No
Medium C&I	A/C DLC	3.92	75	0.00	0.00	No
Medium C&I	Auto-DR (HVAC)	46.17	430	14.61	14.09	Yes
Medium C&I	Auto-DR (Light Luminaire)	18.22	300	8.62	8.83	Yes
Medium C&I	Auto-DR (Light Zonal)	9.81	300	5.47	5.78	Yes
Medium C&I	CPP (Opt-in)	4.83	75	0.00	0.00	No
Medium C&I	CPP (Opt-out)	2.42	75	0.00	0.00	No
Medium C&I	Demand Bidding	4.43	200	0.00	0.00	No
Medium C&I	Interruptible	27.45	90	0.00	0.00	No
Medium C&I	Thermal Storage	50.97	644	0.00	0.00	Yes
Medium C&I	TOU (Opt-in)	2.31	1,281	0.00	0.00	No
Medium C&I	TOU (Opt-out)	1.39	1,281	0.00	0.00	No
Large C&I	Auto-DR (HVAC)	592.09	430	151.57	207.60	Yes
Large C&I	Auto-DR (Light Luminaire)	416.95	120	191.67	200.74	Yes
Large C&I	Auto-DR (Light Zonal)	224.51	120	103.21	108.09	Yes
Large C&I	CPP (Opt-in)	283.92	75	0.00	0.00	No
Large C&I	CPP (Opt-out)	141.67	75	0.00	0.00	No
Large C&I	Demand Bidding	260.28	200	0.00	0.00	No
Large C&I	Interruptible	483.62	90	0.00	0.00	No

Notes:
Program impacts shown reflect impacts for new participants. Impacts shown assume each program is offered independently.

Program Cost Characteristics

The costs of each program include startup costs, marketing and customer recruitment, the utility's share of equipment and installation costs, program administration and overhead, churn costs (i.e., the annual cost of replacing participants that leave the program), and participation incentives.[26]

[26] The Utility Cost Test (UCT) is the cost-effectiveness screen used in this study, which calls for including incentive payments as a cost.

Cost assumptions are based on NSP's current program costs, where applicable. Otherwise, costs are based on a review of experience and studies in other jurisdictions and conversations with vendors, and are tailored for consistency with NSP's current program costs. Notable assumptions in developing the cost estimates include the following:

- Water heating technology costs include the cost of the load control and communications equipment and the *incremental* cost of replacing the existing water heater (50-gallon average) with a larger water heater (80-gallon) when the existing water heater expires. The full cost of a new water heater is not assigned to the program.

- Similarly, EV charging load control equipment costs include the incremental cost of load control and communications technology, but not the full cost of a charging unit.

- The cost of AMI is not counted against any of the DR programs, as it is treated as a sunk cost that is likely to be justified by a broad range of benefits that the new digital infrastructure will provides to customers and to NSP. However, a rough estimate of the cost of IT and billing system upgrades specifically associated with offering time-varying pricing programs are included in the costs for those programs.

- The cost of advanced lighting control systems is not counted against DR programs as these control systems are typically installed for non-energy benefits.

Table 7 summarizes Base Case cost assumptions for 2023 and Table 8 summarizes High Sensitivity Case cost assumptions for 2030. The 2030 assumptions reflect an assumed 25% reduction in the cost (in real terms) of emerging technologies. Costs in both tables are shown in nominal dollars. As discussed later in this appendix, the "base" incentive levels are derived from commonly observed payments both by NSP and in other jurisdictions. They do not reflect the cost-effective incentive payment levels that are ultimately established through the modeling.

Table 7: 2023 Base Case Program Cost Assumptions

		One-Time Costs			Recurring Costs			
Segment	Program	Fixed Cost ($)	Variable Equipment Cost ($/participant)	Other Initial Costs ($/participant)	Fixed Admin & Other ($/year)	Variable Admin & Other ($/participant-year)	Base Annual Incentive Level ($/participant-year)	Economic Life (years)
Residential	A/C DLC - SFH	$0	$172	$92	$0	$13	$59	15
Residential	Behavioral DR (Opt-out)	$0	$0	$0	$0	$4	$0	15
Residential	CPP (Opt-in)	$223,208	$0	$80	$83,703	$2	$0	15
Residential	CPP (Opt-out)	$223,208	$0	$40	$83,703	$2	$0	15
Residential	EV Managed Charging - Home	$0	$229	$0	$0	$17	$45	15
Residential	EV Managed Charging - Work	$0	$229	$0	$0	$17	$45	15
Residential	Smart thermostat - MDU	$0	$126	$92	$0	$11	$28	10
Residential	Smart thermostat - SFH	$0	$126	$92	$0	$11	$28	10
Residential	Smart water heating	$0	$686	$34	$0	$0	$28	10
Residential	Timed water heating	$0	$458	$34	$0	$0	$11	10
Residential	TOU - EV Charging (Opt-in)	$0	$0	$0	$83,703	$0	$0	15
Residential	TOU (Opt-in)	$223,208	$0	$57	$83,703	$1	$0	15
Residential	TOU (Opt-out)	$223,208	$0	$29	$83,703	$0	$0	15
Small C&I	A/C DLC	$0	$172	$92	$0	$13	$237	15
Small C&I	Auto-DR (A/C)	$0	$0	$2,218	$0	$22	$112	15
Small C&I	Auto-DR (Light Luminaire)	$0	$0	$1,328	$0	$22	$112	15
Small C&I	Auto-DR (Light Zonal)	$0	$0	$1,001	$0	$22	$112	15
Small C&I	CPP (Opt-in)	$74,403	$0	$80	$27,901	$0	$0	15
Small C&I	CPP (Opt-out)	$74,403	$0	$40	$27,901	$0	$0	15
Small C&I	Demand Bidding	$0	$0	$0	$691,944	$0	$1	15
Small C&I	Interruptible	$0	$0	$0	$280,126	$0	$259	15
Small C&I	TOU (Opt-in)	$74,403	$0	$57	$20,926	$0	$0	15
Small C&I	TOU (Opt-out)	$74,403	$0	$29	$20,926	$0	$0	15
Medium C&I	A/C DLC	$0	$343	$92	$0	$13	$481	15
Medium C&I	Auto-DR (HVAC)	$0	$0	$26,820	$0	$22	$9,444	12
Medium C&I	Auto-DR (Light Luminaire)	$0	$0	$33,220	$0	$22	$4,351	15
Medium C&I	Auto-DR (Light Zonal)	$0	$0	$24,719	$0	$22	$4,351	15
Medium C&I	CPP (Opt-in)	$74,403	$0	$1,144	$27,901	$22	$0	15
Medium C&I	CPP (Opt-out)	$74,403	$0	$572	$27,901	$22	$0	15
Medium C&I	Demand Bidding	$0	$0	$0	$280,126	$0	$249	15
Medium C&I	Interruptible	$0	$0	$0	$280,126	$0	$5,627	15
Medium C&I	Thermal Storage	$0	$120,114	$34	$0	$382	$0	20
Medium C&I	TOU (Opt-in)	$74,403	$0	$1,144	$20,926	$22	$0	15
Medium C&I	TOU (Opt-out)	$74,403	$0	$572	$20,926	$22	$0	15
Large C&I	Auto-DR (HVAC)	$0	$0	$306,980	$0	$22	$108,307	12
Large C&I	Auto-DR (Light Luminaire)	$0	$0	$495,047	$0	$22	$86,691	15
Large C&I	Auto-DR (Light Zonal)	$0	$0	$367,510	$0	$22	$86,691	15
Large C&I	CPP (Opt-in)	$74,403	$0	$1,144	$27,901	$22	$0	15
Large C&I	CPP (Opt-out)	$74,403	$0	$572	$27,901	$22	$0	15
Large C&I	Demand Bidding	$0	$0	$0	$315,839	$0	$14,651	15
Large C&I	Interruptible	$0	$0	$0	$315,839	$0	$90,997	15

Notes:

All costs shown in nominal dollars. Variable equipment cost and other initial costs include 2.5% churn cost adder. Analysis assumes a 6.44% discount rate for annualizing one-time costs.

Table 8: 2030 High Sensitivity Case Program Cost Assumptions

		One-Time Costs			Recurring Costs			
Segment	Program	Fixed Cost ($)	Variable Equipment Cost ($/participant)	Other Initial Costs ($/participant)	Fixed Admin & Other ($/year)	Variable Admin & Other ($/participant-year)	Base Annual Incentive Level ($/part.-yr)	Economic Life (years)
Residential	A/C DLC - SFH	$0	$140	$75	$0	$16	$69	15
Residential	Behavioral DR (Opt-out)	$0	$0	$0	$0	$5	$0	15
Residential	CPP (Opt-in)	$182,204	$0	$65	$97,609	$2	$0	15
Residential	CPP (Opt-out)	$182,204	$0	$33	$97,609	$2	$0	15
Residential	EV Managed Charging - Home	$0	$187	$0	$0	$20	$52	15
Residential	EV Managed Charging - Work	$0	$187	$0	$0	$20	$52	15
Residential	Smart thermostat - MDU	$0	$103	$75	$0	$13	$33	10
Residential	Smart thermostat - SFH	$0	$103	$75	$0	$13	$33	10
Residential	Smart water heating	$0	$560	$28	$0	$0	$33	10
Residential	Timed water heating	$0	$374	$28	$0	$0	$13	10
Residential	TOU - EV Charging (Opt-in)	$0	$0	$0	$97,609	$0	$0	15
Residential	TOU (Opt-in)	$182,204	$0	$47	$97,609	$1	$0	15
Residential	TOU (Opt-out)	$182,204	$0	$23	$97,609	$1	$0	15
Small C&I	A/C DLC	$0	$140	$75	$0	$16	$277	15
Small C&I	Auto-DR (A/C)	$0	$0	$1,810	$0	$26	$130	15
Small C&I	Auto-DR (Light Luminaire)	$0	$0	$1,084	$0	$26	$130	15
Small C&I	Auto-DR (Light Zonal)	$0	$0	$817	$0	$26	$130	15
Small C&I	CPP (Opt-in)	$60,735	$0	$65	$32,536	$0	$0	15
Small C&I	CPP (Opt-out)	$60,735	$0	$33	$32,536	$0	$0	15
Small C&I	Demand Bidding	$0	$0	$0	$806,905	$0	$1	15
Small C&I	Interruptible	$0	$0	$0	$326,666	$0	$302	15
Small C&I	TOU (Opt-in)	$60,735	$0	$47	$24,402	$0	$0	15
Small C&I	TOU (Opt-out)	$60,735	$0	$23	$24,402	$0	$0	15
Medium C&I	A/C DLC	$0	$280	$75	$0	$16	$561	15
Medium C&I	Auto-DR (HVAC)	$0	$0	$21,893	$0	$26	$11,013	12
Medium C&I	Auto-DR (Light Luminaire)	$0	$0	$27,117	$0	$26	$5,074	15
Medium C&I	Auto-DR (Light Zonal)	$0	$0	$20,178	$0	$26	$5,074	15
Medium C&I	CPP (Opt-in)	$60,735	$0	$934	$32,536	$26	$0	15
Medium C&I	CPP (Opt-out)	$60,735	$0	$467	$32,536	$26	$0	15
Medium C&I	Demand Bidding	$0	$0	$0	$326,666	$0	$291	15
Medium C&I	Interruptible	$0	$0	$0	$326,666	$0	$6,562	15
Medium C&I	Thermal Storage	$0	$98,049	$28	$0	$445	$0	20
Medium C&I	TOU (Opt-in)	$60,735	$0	$934	$24,402	$26	$0	15
Medium C&I	TOU (Opt-out)	$60,735	$0	$467	$24,402	$26	$0	15
Large C&I	Auto-DR (HVAC)	$0	$0	$250,588	$0	$26	$126,301	12
Large C&I	Auto-DR (Light Luminaire)	$0	$0	$404,107	$0	$26	$101,093	15
Large C&I	Auto-DR (Light Zonal)	$0	$0	$299,998	$0	$26	$101,093	15
Large C&I	CPP (Opt-in)	$60,735	$0	$934	$32,536	$26	$0	15
Large C&I	CPP (Opt-out)	$60,735	$0	$467	$32,536	$26	$0	15
Large C&I	Demand Bidding	$0	$0	$0	$368,313	$0	$17,085	15
Large C&I	Interruptible	$0	$0	$0	$368,313	$0	$106,116	15

Notes:
2030 one-time costs assumed to be 30% lower than 2023 one-time costs (in real terms), reflecting assumed declines in technology costs. All costs shown in nominal dollars. Variable equipment cost and other initial costs include 2.5% churn cost adder. Analysis assumes a 6.44% discount rate for annualizing one-time costs.

Step 2: Establish system marginal costs and quantity of system need

Load*Flex* was used to quantify a broad range of value streams that could be provided by DR. These include avoided generation capacity costs, avoided system-wide T&D costs, additional avoided distribution costs from geo-targeted deployment of the DR programs, frequency regulation, and net avoided marginal energy costs.

The system costs that could be avoided through DR deployment are estimated based on market data that is specific to NSP's service territory. Assumptions used in developing each marginal (i.e., avoidable) cost estimate are described in more detail below, for both the Base Case and the High Sensitivity Case.

Avoided generation capacity costs

DR programs are most appropriately recognized as substitutes for new combustion turbine (CT) capacity. CTs are "peaking" units with relatively low up-front installation costs and high variable costs. As a result, they typically only run up to a few hundred hours of the year, when electricity demand is very high and/or there are system reliability concerns. Similarly, use of DR programs in the U.S. is typically limited to less than 100 hours per year. This constraint is either written into the DR program tariff or is otherwise a practical consideration to avoid customer fatigue and program drop-outs.

In contrast, new intermediate or baseload capacity (e.g., gas-fired combined cycle) has a higher capital cost and lower variable cost than a CT, and therefore could run for thousands of hours per year. The DR programs considered in this study cannot feasibly avoid the need for new intermediate or baseload capacity, because they cannot be called during a sufficient number of hours of the year. Energy efficiency is a more comparable demand-side alternative to these resource types since it is a permanent load reduction that applies to a much broader range of hours.

In the Base Case, the installed cost of new CT capacity is based on data provided directly by NSP and consistent with the assumptions in NSP's 2019 IRP for a brownfield CT. The total cost amounts to $60.60/kW-year; this is sometimes referred to the gross cost of new entry (CONE). The gross CONE value is adjusted downward to account for the energy and ancillary services value that would otherwise be provided by that unit. Based on simulated unit profit data provided by NSP, we have estimated the annual energy and ancillary services value to be roughly $5.50/kW-year. The resulting net CONE value is $55.20/kW-year. This calculation is described further in Table 9 below.

This same approach is used to establish the capacity cost for the High Sensitivity Case. Rather than using the CT cost from NSP's IRP, we relied on the U.S. Energy Information Administration's (EIA's) estimate of the installed cost of an Advanced CT from the 2018 Annual Energy Outlook. For the Midwest Reliability Organization West region, this amounts to a gross CONE of $76.80/kW-year. Reducing this value by the same energy and ancillary services value described above leads to a net CONE of $71.40/kW-year.

Table 9: Combustion Turbine Cost of New Entry Calculation

Variable		NSP 2019 IRP Brownfield CT	NSP 2019 IRP Greenfield CT	AEO 2018 Advanced CT
Overnight Capital Cost ($/kW)	[1]	$467	$617	$698
Effective Charge Rate (%)	[2]	10%	10%	10%
Levelized Capital Cost ($/kW-yr)	[3]=[1]x[2]	$46.7	$61.7	$69.8
Annual Fixed Costs ($/kW-yr)	[4]	$13.9	$13.9	$7.0
Gross Cost of New Entry ($/kW-yr)	[5]=[3]+[4]	$60.6	$75.6	$76.8
E&AS Margins ($/kW-yr)	[6]	$5.5	$5.5	$5.5
Net Cost of New Entry ($/kW-yr)	[7]=[5]-[6]	$55.2	$70.2	$71.4

Notes: All costs shown in 2018 dollars. Assumes that overnight capital costs are recovered at 10% effective charge rate. AEO 2018 advanced CT costs shown for the Midwest Reliability Organization West region. Capacity costs are held constant in real terms throughout the period of study.

DR produces a reduction in consumption at the customer's premise (i.e. at the meter). Due energy losses on transmission and distribution lines as electricity is delivered from power plants to customer premises, a reduction in one kilowatt of demand at the meter avoids more than one kilowatt of generation capacity. In other words, assuming line losses of 8% percent, a power plant must generate 1.08 kW in order to deliver 1 kW to an individual premise.[27] When estimating the avoided capacity cost of DR, the avoided cost is grossed up to account for this factor. For this study, Xcel Energy provided load data at the generator level, thus already accounting for line loss gross-up.

Similarly, NSP incorporates a planning reserve margin of 2.4% percent into its capacity investment decisions.[28] This effectively means NSP will plan to have enough capacity available to meet its projected peak demand plus 2.4% percent of that value. In this sense, a reduction of one kilowatt at the meter level reduces the need for 1.024 kW of capacity. Including the 2.4% reserve margin adjustment increases the net CONE value described above from $55.2 and $71.4/kW-year to $56.5 and $73.1/kW-year, for the Base and High Sensitivity Cases respectively. This is the generation capacity value that could be provided by DR if it were to operate exactly like a CT.

Avoided transmission capacity costs

Reductions in system peak demand may also reduce the need for transmission upgrades. A portion of transmission investment is driven by the need to have enough capacity available to

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27 8% represents an average line loss across NSP territories and customer segments. Actual line losses range from 2 to 10%.

28 NSP's planning reserve margin target is 7.8% of load during the MISO peak, which translates into a margin of 2.4% during its own system peak.

move electricity to where it is needed during peak times while maintaining a sufficient level of reliability. Other transmission investments will not be peak related, but rather are intended to extend the grid to remotely located sources of generation, or to address constraints during mid- or off-peak periods. Based on the findings of NSP's 2017 T&D Avoided Cost Study for energy efficiency programs, we have assumed an avoidable transmission cost of $3.10/kW-year in 2023, rising to $3.60/kW-year in 2030.[29]

Avoided system-wide distribution capacity costs

Similar to transmission value, there may be long-term distribution capacity investment avoidance value associated with reductions in peak demand across the NSP system. For programs that do not provide the higher-value distribution benefits from geo-targeted deployment, as described below, we have assumed that peak demand reductions can produce avoided distribution costs of $8.10/kW-year in 2023, rising to $9.50/kW-year in 2030, based on NSP's 2017 T&D Avoided Cost Study.

Geo-targeted distribution capacity costs

DR participants may be recruited in locations on the distribution system where load reductions would defer the need for local capacity upgrades. This local deployment of the DR program can be targeted at specifically locations where distribution upgrades are expected to be costly.

DR cannot serve as a substitute for distribution upgrades in all cases, such as adding new circuit breakers, telemetry upgrades, or adding distribution lines to connect new customers. However, in many cases, system upgrades are needed to meet anticipated gradual load growth in a local area. At times, system planners must over-size distribution investments relative to the immediate needs to meet local load to allow for future load growth or utilize equipment (such as transformers) that only comes in certain standard sizes. To the extent that DR can be used to reduce local peak loads, the loading on the distribution system is reduced, which means otherwise necessary distribution upgrades may be deferred. Such deferrals are especially valuable if load growth is relatively slow and predictable such that the upgraded system would not be fully utilized for many years.

To quantify geo-targeted distribution capacity deferral value in Load*Flex*, we began with a list of all distribution capacity projects in NSP's five-year plan. Brattle worked with NSP staff to reduce this list to a subset of projects that are likely candidates for deferral through DR. Four criteria were applied to identify the list of candidate deferral projects:

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[29] Xcel Energy, Minnesota Power, Otter Tail Power Company, Mendota Group & Environmental Economics, "Minnesota Transmission and Distribution Avoided Cost Study," July 31, 2017.

1. The need for the distribution project must be driven by load growth. DR could not be used to avoid the need to simply replace aging equipment, for example.

2. The project must have a meaningful overall cost on a per-kilowatt basis. In our analysis, we required that the cost of the project equate to a value of at least $100,000 per megawatt of reduced demand in order to be considered.[30] This is the equivalent of roughly $7/kW-year on an annualized basis. Projects below this cost threshold were excluded from the geo-targeted deferral analysis.

3. There must be sufficient local customer load in order for the upgrade to be deferrable through the use of DR. For instance, if a 20 MW load reduction would be needed to avoid a specific distribution upgrade, and there was only 25 MW of total load at that location in the system, then DR would not be a useful candidate because it is unlikely that DR could consistently and reliably produce an 80% load reduction. In establishing this criterion, projects with more than 6 MVA of "load at risk"[31] were excluded, as 6 MVA represents about half of the load on a typical feeder.

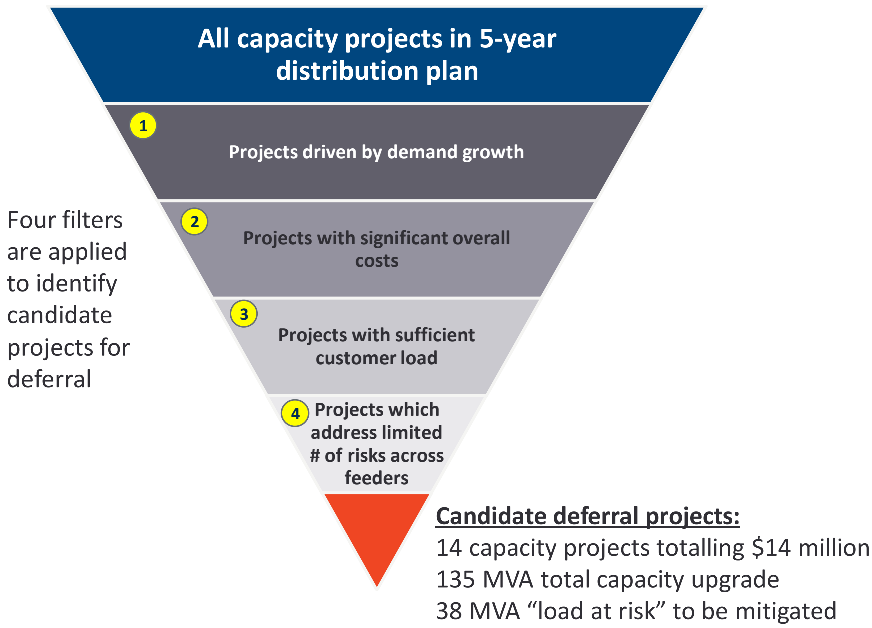
4. The project should not be needed to simultaneously address many risks across feeders. In some cases, distribution upgrades are needed to mitigate a number of different contingencies. There are significant operational challenges associated with using DR in a similar manner. Projects were screened out based on the number and severity of risks that they were intended to address.

After applying the above criteria, up to roughly 10% of the cost of NSP's 5-year plan remained as potentially deferrable through the use of DR. We have assumed linear growth in NSP's distribution capacity needs, meaning the geo-targeted distribution deferral opportunity increases by this amount every five years over the forecast horizon. Figure 17 summarizes the process for identifying geo-targeted distribution deferral opportunities.

[30] For simplicity, we assumed 1 MVA = 1 MW.

[31] "Load at risk" effectively represents the load reduction that would need to be achieved to defer the capacity upgrade.

Figure 18: Identification of Candidates for Geo-targeted Distribution Investment Deferral



Avoided energy costs

Load can be shifted from hours with higher energy costs to hours with lower energy costs, thus producing net energy cost savings across the system.[32] Hourly energy costs in this study are based on the 2018 MISO Transmission Expansion Plan (MTEP18) modeled day-ahead prices for the NSP hub. These modeled prices were used to capture evolving future system conditions that would not be reflected in historical prices. MTEP18 presents four "futures" that represent broadly different long-term views of MISO energy system, enabling the evaluation of the avoided energy value of DR under different market conditions.

For the Base Case, we relied on prices from MTEP18's Continued Fleet Change (CFC) future. This future assumes a continuation of trends in the MISO market from the past decade: persistent low gas prices, limited demand growth, continued economic coal retirements, and gradual growth in renewables above state requirements.[33] Figure 19 below shows that 2022 energy prices

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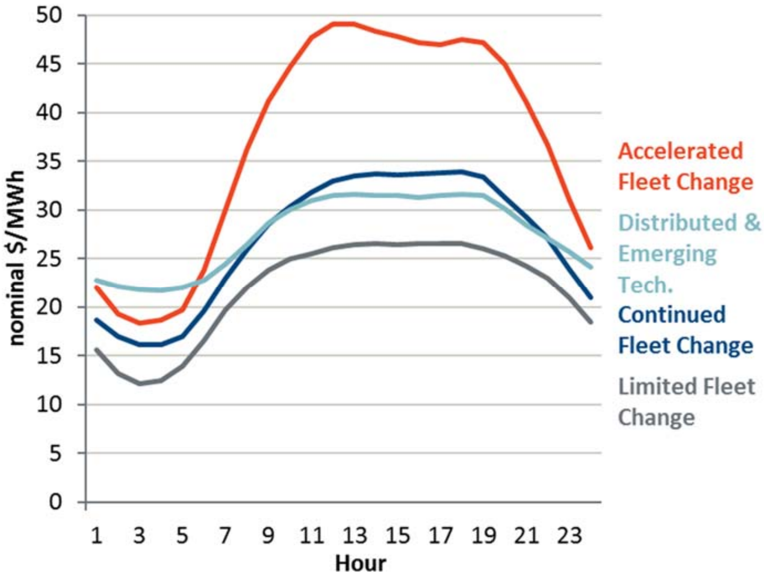
32 Energy savings refer to reduced fuel and O&M costs. In this study, we do not model the impact that DR would have on MISO wholesale energy prices. This is sometimes referred to as the demand response induced price effect (DRIPE). It represents a benefit to consumers and an offsetting cost to producers, with no net change in costs across the system as a whole.

33 See MISO, "MTEP 18 Futures – Summary of definitions, uncertainty variables, resource forecasts, siting process and siting results." for additional details on MTEP18 scenarios.

under the CFC future lie somewhere in the middle of the four MTEP scenarios (energy prices in other years follow the same relative pattern across scenarios).

Figure 19: Average Energy Price by Hour of Day in 2022 MTEP Scenarios for NSP Hub



For the High Sensitivity Case, we relied on prices from the Accelerated Fleet Change (AFC) future. The AFC case has twice the amount of renewable generation capacity additions as the CFC future. However, increased load growth, accelerated coal retirements, and higher gas prices lead to overall higher energy prices, particularly in daytime hours. For our analysis years (2023, 2025 and 2030), we relied on prices from the nearest MTEP modeling year (2022, 2027, and 2032, respectively) and adjusted them accordingly for inflation (assumed to be 2.2% per year).

Ancillary services

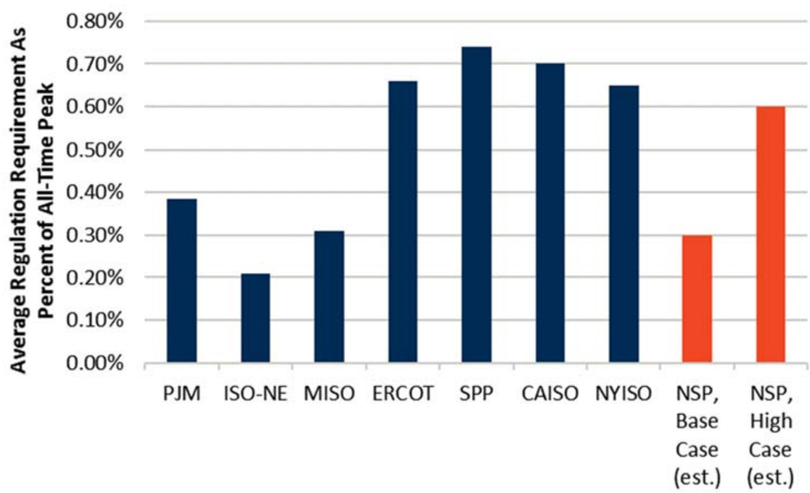
The load of some end-uses can be increased or decreased in real time to mitigate system imbalances. The ability of qualifying DR programs to provide frequency regulation was modeled, as this is the highest-value ancillary service.

Frequency regulation is a high value resource with a very limited need. Across most markets, the need for frequency regulation capacity is less than 1% of the system peak. We assume that the frequency regulation needs in the NSP system across all analysis years are 25 MW (0.3% of annual peak) in the Base Case, and 50 MW in the High Sensitivity Case (0.6% of annual peak).[34] Figure 20 summarizes frequency regulation needs across various U.S. markets, demonstrating

[34] Calculated assuming an annual peak of 8,335 MW after line losses.

that the quantities of frequency regulation assumed in this study are consistent with experience elsewhere.

Figure 20: Frequency Regulation Requirements Across Wholesale Markets



Sources and Notes: Values for wholesale markets extracted from PJM, "RTO/ISO Regulation Market Comparison", April 13, 2016. Orange bars for NSP assume that NSP's all-time peak is 8,335 MW at the customer level, based on three years of provided peak load data and assumed 8% line losses. Frequency regulation values for all markets are average levels as of 2016.

Because regulation prices were not available from the 2018 MTEP, we utilized 2017 hourly generation regulation prices for the MISO system adjusted for inflation.

Table 10 summarizes the potential value of each DR benefit. Values shown are the maximum achievable value. Operational constraints of the DR resources (e.g., limits on number of load curtailments per year) often result in realized benefits estimates that are lower than the values shown.

Table 10: Summary of Avoided Costs/Value Streams in 2023

Value Stream	Quantity of Need		Avoided Cost		Description
	Base Case	High Case	Base Case	High Case	
Avoided Generation Capacity	Unconstrained	Unconstrained	$63.0/kW-year	$81.5/kW-year	Base: Xcel's Brownfield CT costs minus estimated CT energy revenues from 2018 IRP, plus 2.4% reserve margin gross-up.
Avoided Transmission Capacity	Unconstrained	Unconstrained	$3.1/kW-year	$3.1/kW-year	72% of avoided transmission & distribution costs estimated under the discrete valuation approach in Xcel's 2017 T&D Avoided Cost Study.
Avoided Distribution Capacity	Unconstrained	Unconstrained	$8.0/kW-year	$8.0/kW-year	28% of avoided transmission & distribution costs estimated under the discrete valuation approach in Xcel's 2017 T&D Avoided Cost Study.
Geo-targeted Distribution Capacity	38 MW	38 MW	$25.8/kW-year	$25.8/kW-year	Total value of 14 projects identified as eligible for distribution capacity deferral by demand response.
Frequency Regulation	25 MW	50 MW	Avg: $12.4/MWh	Avg: $12.4/MWh	2017 MISO regulation prices. Assumes that NSP's share of regulation need is 25 MW in 2023 and 50 MW in 2030.
Avoided Energy	Unconstrained	Unconstrained	Avg: $27.5/MWh	Avg: $27.5/MWh	Hourly MISO MTEP18 modeled energy prices for NSP HUB. 2023 used prices from the CFC 2022 scenario, and 2030 used prices from the AFC 2032 scenario.
Top 10% Average			$50.5/MWh	$71.3/MWh	
Bottom 10% Average			$8.1/MWh	$8.6/MWh	

Notes:
All values shown in nominal dollars. 2030 avoided costs are similar, rising at inflation.

Step 3: Develop 8,760 hourly profile of marginal costs

Each of the annual avoided cost estimates established in Step 2 is converted into a chronological profile of hourly costs for all 8,760 hours of the year. In each hour, these estimates are added together across all value streams to establish the total "stacked" value that is obtainable through a reduction in load in that hour (or, conversely, the total cost associated with an increase in load in that hour).

Capacity costs are allocated to hours of the year proportional to the likelihood that those hours will drive the need for new capacity. In other words, the greater the risk of a capacity shortage in a given hour, the larger the share the marginal capacity cost that is allocated to that hour.

Capacity costs are allocated across the top 100 load hours of the year. The allocation is roughly proportional to each hour's share of total load in the hours. This means more capacity value is allocated to the top load hour than the 100th load hour.

Different allocators are used to allocate generation, transmission, and distribution capacity costs. Generation and transmission capacity costs are allocated based on 2017 hourly MISO system gross load.[35] Distribution capacity costs are allocated based on hourly feeder load data provided by NSP. Both generic distribution capacity deferral and geo-targeted distribution capacity deferral value are allocated over a larger number of peak hours (roughly 330 hours, rather than 100 hours), representing that a single distribution project will address multiple feeders with load profiles that are only partially coincident.

A conceptually similar approach to quantifying capacity value is used in the California Energy Commission's time-dependent valuation (TDV) methodology for quantifying the value of energy efficiency, and also in the CPUC's demand response cost-effectiveness evaluation protocols. This hourly allocation-based approach effectively derates the value of distributed resources relative to the avoided cost of new peaking capacity by accounting for constraints that may exist on the operator's ability to predict and respond to resource adequacy needs. These constraints could result in DR utilization patterns that reflect a willingness to bypass some generation capacity value in order to provide distribution deferral value, for instance. The approach is effectively a theoretical construct intended to quantify long-term capacity value, rather than reflecting the way resource adequacy payments would be monetized by a DR operator in a wholesale market.

Figure 21 illustrates the "stacked" marginal costs associated with each value stream for a single week in the study period. The figure shows that certain hours present a significantly larger opportunity to reduce costs through load reduction – namely, those hours to which capacity costs are allocated.

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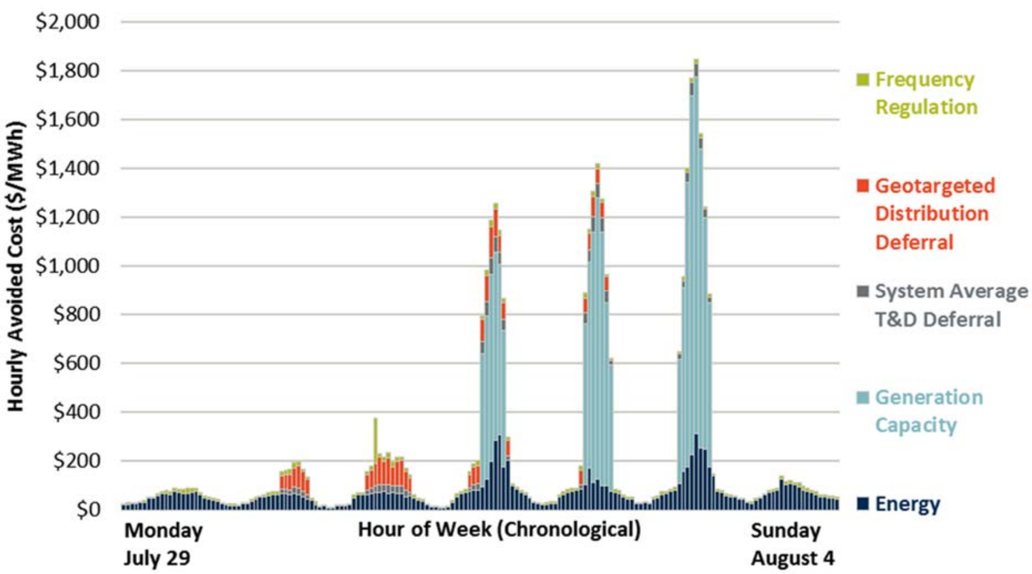
[35] Capacity value was allocated proportional to MISO gross load because NSP is required to use its MISO-coincident peak for resource adequacy planning decisions.

Figure 21: Chronological Allocation of Marginal Costs (Illustration for Week of July 29)



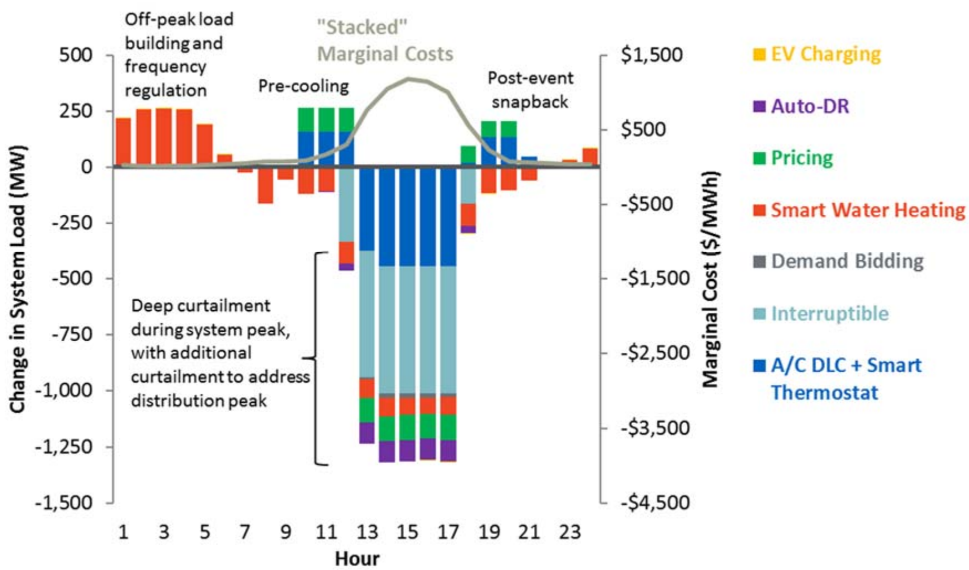
Notes: Marginal costs reflect avoided costs from the 2030 High Sensitivity Case.

Step 4: Optimally dispatch programs and calculate benefit-cost metrics

As discussed above, using DR to pursue one value stream may require forgoing opportunities to pursue other "competing" sources of value. While the value streams quantified in this study can be estimated individually, those estimates are not purely additive. A DR operator must choose how to operate the program in order to maximize its value. Accurately estimating the total value of DR programs requires accounting for tradeoffs across the value streams.

Load*Flex* employs an algorithm that "co-optimizes" the dispatch of a DR program across the hourly marginal cost series from Step 3, subject to the operational constraints defined in Step 1, such that overall system value produced by the program is maximized. In other words, the programs are operated to reduce load during hours when the total cost is highest and build load during hours when the total cost is lowest, without violating any of the established conditions around their use. Figure 22 illustrates how the dispatch of the High Sensitivity Case portfolio in this study compares to the hourly cost profile on those same days.

Figure 22: Illustrative Program Operations Relative to "Stacked" Marginal Costs



Through an iterative process, Load*Flex* determines when the need for a given value stream has been fully satisfied by DR in each hour, and excludes that value stream from that hour for incremental additions of DR. This ensures that DR is not over-supplying certain resources and being incorrectly credited for services that do not provide additional value to the system.

Step 5: Identify cost-effective incentive and participation levels

A unique feature of Load*Flex* is the ability to identify participation levels that are consistent with the incentive payments that are economically justified for each DR program. This ensures that each program's economic potential estimate is based on an incentive payment level that produces a benefit-cost ratio of 1.0. Without this functionality, the analysis would under-represent the potential for a given DR program, or could even exclude it from the analysis entirely based on inaccurate assumptions about uneconomic incentive payments levels.

As a starting point, participation estimates for each DR program are established to represent the maximum enrollment that is likely to be achieved when offered in NSP's service territory at a "typical" incentive payment level. The estimates are tailored to NSP's customer base using data on current program enrollment, as well as survey-based market research conducted directly with

NSP's customers.[36] For DR programs not included in the market research study, we developed participation assumptions based on experience with similar programs in other jurisdictions and applied judgement to make the participation rates consistent with available evidence that is specific to NSP's customer base.

Table 11 summarizes these "base" participation rates for conventional DR programs. In all cases, participation is expressed as a percent of the eligible customer base. For instance, the population of customers eligible for the smart thermostat program is limited to those customers with central air-conditioning.

The 2017 values represent current participation levels. Values in future years reflect participation rates if the programs were offered as part of an expanded DR portfolio. This accounts for the fact that a single customer could not simultaneously participate in two different programs.

Residential air-conditioning load control participation assumptions reflect a transition from compressor switch-based direct load control program to a smart thermostat-based program. These programs are currently marketed by NSP as "Savers Switch" and "AC Rewards", respectively. Based on the aforementioned primary market research conducted in NSP's service territory, we estimate that a 66% participation rate among eligible customers is achievable at the medium incentive level for these programs collectively. In 2017, participation in air-conditioning load control programs reached 52% of eligible residential customers, mostly through the Savers Switch program. In the future, NSP will increase its marketing emphasis on the AC Rewards program as its primary air-conditioning load control program. Therefore, we assume that achievable incremental participation in residential air-conditioning load control transitions from an equal split between AC Rewards and Savers Switch in 2018 to a 75/25 split in favor of AC Rewards by 2023. Additionally, NSP will focus on transitioning customers from Savers Switch to AC Rewards as compressor switches reach the end of their useful life. Based on information about the age of deployed switches and conversations with NSP, we assume that the number of switches replaced by smart thermostats grows from around 6,600/year in 2018 to 10,000/year in 2023 and onwards.

It is important to note that the participation rates shown are consistent with a participation incentive payment level that is representative of common offerings across the U.S. Participation rates are shown for all programs at these incentive levels, regardless of whether or not the programs are cost-effective at those incentive levels.[37] Later in this section of the appendix, we describe adjustments that are made to these "base" incentive levels to reflect enrollment that could be achieved at cost-effective incentive levels.

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[36] Ahmad Faruqui, Ryan Hledik, and David Lineweber, "Demand Response Market Potential in Xcel Energy's Northern States Power Service Territory," April 2014.

[37] This is the basis for our estimate of "technical potential".

Table 11: Participation Assumptions for Conventional DR Programs

Participation as a percentage of eligible customers

Segment	Program	2017	2023	2030
Residential	A/C DLC - SFH	52%	50%	39%
Residential	Smart thermostat - SFH	0%	16%	24%
Residential	Smart thermostat - MDU	0%	35%	32%
Small C&I	A/C DLC	0%	30%	30%
Small C&I	Interruptible	0%	14%	12%
Small C&I	Demand Bidding	0%	2%	1%
Medium C&I	A/C DLC	73%	64%	64%
Medium C&I	Interruptible	3%	13%	11%
Medium C&I	Demand Bidding	0%	6%	5%
Large C&I	Interruptible	12%	44%	43%
Large C&I	Demand Bidding	0%	5%	4%

Notes:
Participation rates shown for programs at the portfolio level (i.e. accounts for program overlap). Lower participation rates for some programs in 2030 relative to 2023 result from customers switching to an opt-in CPP rate (for which participation estimates are shown separately). High Medium C&I participation in A/C DLC is relative to a small portion of the customer segment that is eligible for enrollment.

Table 12 illustrates the potential participation rates for each new DR program analyzed in the study. As noted above, these enrollment rates are consistent with "base" incentive payment levels and do not reflect enrollment associated with cost-effective payment levels. **Here, participation in each program is shown as if the program were offered in isolation.** In other words, it is the achievable participation level in the absence of other programs being offered. In our assessment of expanded DR portfolios that include multiple new DR programs, restrictions on participation in multiple programs are accounted for and the participation rates are derated accordingly.

Table 12: Participation Assumptions for New DR Programs

Participation as a percentage of eligible customers

Segment	Program	2017	2023	2030
Residential	Behavioral DR (Opt-out)	0%	80%	80%
Residential	CPP (Opt-in)	0%	0%	20%
Residential	CPP (Opt-out)	0%	0%	80%
Residential	EV Managed Charging - Home	0%	20%	20%
Residential	EV Managed Charging - Work	0%	20%	20%
Residential	Smart water heating	0%	15%	50%
Residential	Timed water heating	0%	50%	50%
Residential	TOU - EV Charging (Opt-in)	0%	0%	20%
Residential	TOU (Opt-in)	1%	0%	16%
Residential	TOU (Opt-out)	0%	0%	80%
Small C&I	Auto-DR (A/C)	0%	5%	5%
Small C&I	Auto-DR (Light Luminaire)	0%	5%	5%
Small C&I	Auto-DR (Light Zonal)	0%	5%	5%
Small C&I	CPP (Opt-in)	0%	0%	20%
Small C&I	CPP (Opt-out)	0%	0%	80%
Small C&I	TOU (Opt-in)	3%	0%	10%
Small C&I	TOU (Opt-out)	0%	0%	80%
Medium C&I	Auto-DR (HVAC)	0%	5%	5%
Medium C&I	Auto-DR (Light Luminaire)	0%	5%	5%
Medium C&I	Auto-DR (Light Zonal)	0%	5%	5%
Medium C&I	CPP (Opt-in)	0%	14%	14%
Medium C&I	CPP (Opt-out)	0%	79%	79%
Medium C&I	Thermal Storage	0%	3%	3%
Medium C&I	TOU (Opt-in)	21%	19%	19%
Medium C&I	TOU (Opt-out)	0%	0%	80%
Large C&I	Auto-DR (HVAC)	0%	5%	5%
Large C&I	Auto-DR (Light Luminaire)	0%	5%	5%
Large C&I	Auto-DR (Light Zonal)	0%	5%	5%
Large C&I	CPP (Opt-in)	0%	22%	22%
Large C&I	CPP (Opt-out)	0%	81%	81%
Large C&I	TOU (Opt-in)	100%	100%	100%

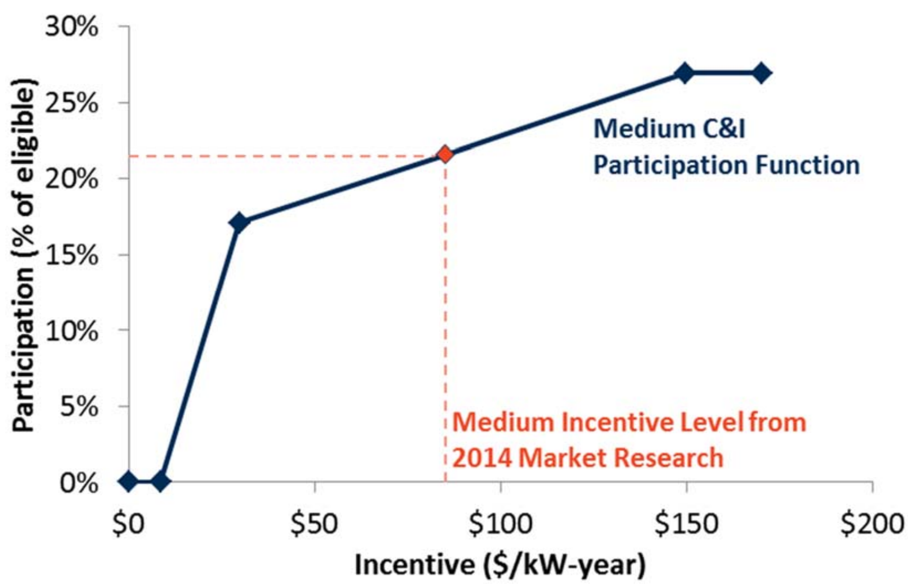
Notes:
Participation rates shown for programs when offered independently (i.e. rates do not account for program overlap).

As discussed above, the cost-effectiveness screening process in many DR potential studies often treats programs as an all-or-nothing proposition. In other words, the studies commonly assume a base incentive level and then simply evaluate the cost-effectiveness of the programs relative to that incentive level. However, in reality, the incentives can be decreased or increased to accommodate lower or higher thresholds for cost effectiveness. For instance, in a region with lower avoided cost, a lower incentive payment could be offered, and vice versa. Program participation will vary according to these changes in the incentive payment level.

In Load*Flex* model, participation is expressed as a function of the assumed incentive level. The incentive level that produces a benefit-cost ratio of 1.0 is quantified, thus defining the maximum potential cost-effective participation for the program.[38] The DR adoption function for each program is derived from the results of the aforementioned 2014 market research study, which tested customer willingness to participate in DR programs at various incentive levels.

An illustration of the participation function for the Medium C&I Interruptible program is provided in Figure 23. The figure expresses participation in the program (vertical axis) as a function of the customer incentive payment level (horizontal axis). At an incentive level of around $85/kW-yr, slightly more than 20% of eligible customers would participate in the program. If the economics of the program could only justify an incentive payment less than this (e.g., due to low avoided capacity costs), participation would decrease according to the blue line in the chart, and vice versa. Below an incentive payment level of around $25/kW-yr, customer willingness to enroll in the program quickly drops off.

Figure 23: Medium C&I Interruptible Tariff Adoption Function



Step 6: Estimate cost-effective DR potential

After the cost-effective potential of each individual DR program is estimated, the programs are combined into a portfolio. Constructing the portfolio is not as simple as adding up the potential estimates of each individual program. In some cases, two programs may be targeting the same end-use (e.g., timed water heating and smart water heating), so their impacts are not additive.

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38 In some cases, the non-incentive costs (e.g., equipment costs) outweigh the benefits, in which case the program does not pass the cost-effectiveness screen.

In instances where two cost-effective programs target the exact same end-use, we have assumed that the portfolio would only include the program that produces the larger impact by the end of the study horizon. In the water heating example, this means that the smart water heating program was included and the timed water heating program was not.

In other cases, two "competing" programs would likely be offered simultaneously to customers as mutually exclusive options. For instance, it is possible that C&I customers would only be allowed to enroll in either an interruptible tariff program or a CPP rate. Simultaneous enrollment in both could result in customer being compensated twice for the same load reduction – once through the incentive payment in the interruptible tariff, and a second time through avoiding the higher peak price of the CPP rate. In these cases, we relied on the results of the aforementioned 2014 market research study, which used surveys to determine relative customer preferences for these options when offered simultaneously. Participation rates were reduced in the portfolio to account for this overlap.

In cases where two programs would be offered simultaneously to the same customer segment, but would target entirely different end-uses (e.g., a smart thermostat program and an EV charging load control program), no adjustments to the participation rates were deemed necessary.

Appendix B: NSP's Proposed Portfolio

At a stakeholder meeting on August 8, 2018, NSP presented a draft portfolio of proposed DR programs. The DR portfolio that NSP is considering consists of the programs and deployment years summarized in Table 13.

Table 13: NSP's Draft Portfolio of DR Programs

Program	First Year of Rollout
Saver's Switch	Existing
A/C Rewards	Existing
EV home charging control	2020
Med/large C&I Auto-DR	2021
Med/large C&I interruptible tariff (program expansion)	2021
Med/large C&I Opt-in CPP	2022
Residential smart water heating	2023
Residential behavioral DR	2023
Residential opt-out TOU	2024

The potential for this portfolio was quantified under the Base and High Sensitivity cases for years 2023 and 2030. Results are summarized in Table 14. In the table, the values in the row labeled "All Proposed Programs" indicate the incremental technical potential in each of the programs that have been proposed by NSP. The values in the row "Cost-Effective Proposed programs" indicate the amount of incremental DR in the proposed programs that can be achieved at cost-effective incentive payment levels. In both cases, DR potential is shown at the portfolio level, accounting for overlap in participation when multiple programs are offered simultaneously.

Table 14: Incremental Potential in NSP's Draft Portfolio of DR Programs (MW)

	Base Case		High Sensitivity Case	
	2023	**2030**	**2023**	**2030**
All Proposed Programs	642	907	658	927
Cost-Effective Proposed Programs	262	461	411	677

Note: Values shown are incremental to the existing 850 MW portfolio.

Appendix C: Base Case with Alternative Capacity Costs

For its 2019 IRP, NSP has developed cost assumptions for new CT capacity at brownfield and greenfield sites. Our Base Case assumptions rely on brownfield CT costs as the avoided generation cost estimate, as this is the lowest cost option available to NSP for future peaking generation development. To test the sensitivity of our findings to that assumption, we modeled an alternative case in which the avoided capacity cost in the Base Case is based on a greenfield CT rather than a brownfield CT.[39] Other Base Case assumptions remained unchanged.

The greenfield CT capacity cost is higher than the brownfield CT cost, which increases the benefits of DR programs due to higher avoided generation costs. Relative to the Base Case, the cost-effective incremental potential in the DR portfolio increases by 73 MW in 2023 and by 119 MW in 2030. Nearly all of this increase in potential is attributable to a further expansion of participation in programs that were already cost-effective in the Base Case. The additional potential is mostly in the smart thermostat program, increases from 112 MW to 148 MW in 2023 and from 169 MW to 220 MW in 2030. Other programs that were economic in the Base Case (residential smart water heating, additional C&I interruptible, and demand bidding) also have small increases in cost-effective potential.

The only program that was initially uneconomic under Base assumptions but becomes economic under the greenfield CT capacity cost assumption is HVAC-based Auto-DR: 3 MW of Large C&I Auto-DR becomes cost-effective in 2023, growing to 6 MW in 2030 (in addition to 32 MW of Medium C&I Auto-DR). Together, these programs account for 4% of additional potential in 2023, but over 30% of additional potential in 2030.

Table 15 compares the portfolio-level incremental DR potential for the Base Case with brownfield CT costs to the alternative case with greenfield CT costs. Annual program-level potential estimates are provided in Appendix D.

[39] Table 9 of this report summarizes the greenfield, brownfield and AEO 2018 CT costs used in this analysis.

Table 15: Incremental Cost-Effective Potential in Portfolio of DR Programs with Alternative CT Costs (MW)

	2023	2030
Base Case (Brownfield CT Cost)	306	468
Alternative Case (Greenfield CT Cost)	378	587
Difference (Alternative - Base)	73	119

Note: Values shown are incremental to the existing 850 MW portfolio.

Appendix D: Annual Results Summary

Base Case, All Programs

Technical Potential (MW, at generator-level)

Segment	Program	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Residential	A/C DLC - SFH	0	0	0	0	0	0	0	0	0	0
Residential	Behavioral DR (Opt-out)	52	52	52	53	53	54	54	54	55	55
Residential	CPP (Opt-in)	0	0	0	15	62	65	69	73	76	80
Residential	CPP (Opt-out)	0	0	0	157	157	159	160	161	163	164
Residential	EV Managed Charging - Home	1	2	3	5	7	9	12	14	16	18
Residential	EV Managed Charging - Work	0	0	1	1	1	2	2	3	3	3
Residential	Smart thermostat - MDU	3	13	16	16	16	16	16	16	17	17
Residential	Smart thermostat - SFH	161	161	161	175	190	204	219	233	248	262
Residential	Smart water heating	6	11	17	23	29	30	34	40	49	60
Residential	Timed water heating	11	43	54	55	55	55	55	56	56	56
Residential	TOU (Opt-in)	0	0	0	6	23	25	26	28	29	31
Residential	TOU (Opt-out)	0	0	0	155	155	156	157	159	160	161
Residential	TOU - EV Charging (Opt-in)	0	0	0	0	1	1	1	2	2	2
Small C&I	A/C DLC	44	44	44	44	44	44	45	45	45	45
Small C&I	Auto-DR (A/C)	2	8	9	9	9	10	10	10	10	10
Small C&I	Auto-DR (Light Luminaire)	1	6	7	7	7	7	7	7	8	8
Small C&I	Auto-DR (Light Zonal)	1	5	6	6	6	6	6	6	6	6
Small C&I	CPP (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-out)	0	0	0	1	1	1	1	1	1	1
Small C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Small C&I	Interruptible	65	65	65	65	66	66	66	67	67	67
Small C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	TOU (Opt-out)	0	0	0	0	0	1	1	1	1	1
Medium C&I	A/C DLC	3	3	3	4	4	4	5	5	5	6
Medium C&I	Auto-DR (HVAC)	30	121	151	152	152	153	154	154	155	156
Medium C&I	Auto-DR (Light Luminaire)	12	48	60	60	60	60	61	61	61	62
Medium C&I	Auto-DR (Light Zonal)	6	26	32	32	32	33	33	33	33	33
Medium C&I	CPP (Opt-in)	6	24	30	30	30	30	30	31	31	31
Medium C&I	CPP (Opt-out)	86	86	86	87	87	88	89	89	90	90
Medium C&I	Demand Bidding	4	16	20	20	20	20	20	20	20	20
Medium C&I	Interruptible	310	310	310	313	316	318	321	324	326	329
Medium C&I	Thermal Storage	20	80	100	101	101	101	102	102	103	103
Medium C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-out)	0	0	0	51	51	51	51	52	52	52
Large C&I	Auto-DR (HVAC)	4	15	19	19	19	19	19	19	19	18
Large C&I	Auto-DR (Light Luminaire)	3	11	13	13	13	13	13	13	13	13
Large C&I	Auto-DR (Light Zonal)	1	6	7	7	7	7	7	7	7	7
Large C&I	CPP (Opt-in)	7	28	36	35	35	35	35	35	35	35
Large C&I	CPP (Opt-out)	64	64	64	64	64	63	63	63	63	62
Large C&I	Demand Bidding	2	6	8	8	8	8	8	8	8	8
Large C&I	Interruptible	85	85	85	84	83	82	81	80	79	78

Notes:
Figure shows incremental load reduction available when DR programs are offered in isolation.
Measure-level results do not account for cost-effectiveness or overlap when offered simultaneously as part of a portfolio.
No incremental potential is shown for residential air-conditioning load control, because NSP is transitioning it to the smart thermostat program.

Base Case, All Programs

Cost-Effective Potential (MW, at generator-level)

Segment	Program	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Residential	A/C DLC - SFH	0	0	0	0	0	0	0	0	0	0
Residential	Behavioral DR (Opt-out)	0	0	0	0	0	0	0	0	0	0
Residential	CPP (Opt-in)	0	0	0	11	44	46	49	52	54	57
Residential	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Residential	EV Managed Charging - Home	0	0	0	0	0	0	0	0	0	0
Residential	EV Managed Charging - Work	0	0	0	0	0	0	0	0	0	0
Residential	Smart thermostat - MDU	0	1	1	4	6	6	6	6	7	7
Residential	Smart thermostat - SFH	112	112	112	122	131	139	146	154	162	169
Residential	Smart water heating	4	9	13	17	22	23	25	29	35	42
Residential	Timed water heating	0	0	0	0	0	0	0	0	0	0
Residential	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Residential	TOU (Opt-out)	0	0	0	0	0	0	0	0	0	0
Residential	TOU - EV Charging (Opt-in)	0	0	0	0	0	0	1	1	2	2
Small C&I	A/C DLC	19	19	19	21	22	22	22	22	22	22
Small C&I	Auto-DR (A/C)	0	0	0	0	0	0	0	0	0	0
Small C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Small C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Small C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Small C&I	Interruptible	32	32	32	31	30	30	30	30	30	30
Small C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	TOU (Opt-out)	0	0	0	0	0	0	0	0	0	0
Medium C&I	A/C DLC	0	0	0	0	0	0	0	0	0	0
Medium C&I	Auto-DR (HVAC)	0	0	0	0	0	0	0	0	0	0
Medium C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Medium C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Medium C&I	CPP (Opt-in)	0	0	0	10	19	19	19	20	20	20
Medium C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Medium C&I	Demand Bidding	4	14	18	16	15	15	15	15	15	15
Medium C&I	Interruptible	45	45	45	31	16	17	18	19	20	22
Medium C&I	Thermal Storage	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-out)	0	0	0	0	0	0	0	0	0	0
Large C&I	Auto-DR (HVAC)	0	0	0	0	0	0	0	0	0	0
Large C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Large C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Large C&I	CPP (Opt-in)	0	0	0	16	32	32	32	32	32	31
Large C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Large C&I	Demand Bidding	1	6	7	6	5	5	5	5	5	5
Large C&I	Interruptible	58	58	58	55	51	51	50	49	48	47
Portfolio-Level Total		**276**	**296**	**306**	**338**	**393**	**405**	**418**	**433**	**450**	**468**

Notes:

Incremental load reduction available when DR programs are offered simultaneously as part of portfolio, accounting for overlap between programs.

No incremental potential is shown for residential air-conditioning load control, because NSP is transitioning it to the smart thermostat program.

Alternative Base Case with Greenfield CT Costs, All Programs

Technical Potential (MW, at generator-level)

Segment	Program	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Residential	A/C DLC - SFH	0	0	0	0	0	0	0	0	0	0
Residential	Behavioral DR (Opt-out)	52	52	52	53	53	54	54	54	55	55
Residential	CPP (Opt-in)	0	0	0	15	62	65	69	73	76	80
Residential	CPP (Opt-out)	0	0	0	157	157	159	160	161	163	164
Residential	EV Managed Charging - Home	1	2	3	5	7	9	12	14	16	18
Residential	EV Managed Charging - Work	0	0	1	1	1	2	2	3	3	3
Residential	Smart thermostat - MDU	3	13	16	16	16	16	16	16	17	17
Residential	Smart thermostat - SFH	180	180	180	204	227	245	262	280	298	315
Residential	Smart water heating	6	13	19	26	33	34	38	44	53	65
Residential	Timed water heating	11	43	54	55	55	55	55	56	56	56
Residential	TOU (Opt-in)	0	0	0	6	23	25	26	28	29	31
Residential	TOU (Opt-out)	0	0	0	155	155	156	157	159	160	161
Residential	TOU - EV Charging (Opt-in)	0	0	0	0	1	1	1	2	2	2
Small C&I	A/C DLC	44	44	44	44	44	44	45	45	45	45
Small C&I	Auto-DR (A/C)	2	8	9	9	9	10	10	10	10	10
Small C&I	Auto-DR (Light Luminaire)	1	6	7	7	7	7	7	7	8	8
Small C&I	Auto-DR (Light Zonal)	1	5	6	6	6	6	6	6	6	6
Small C&I	CPP (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-out)	0	0	0	1	1	1	1	1	1	1
Small C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Small C&I	Interruptible	65	65	65	65	66	66	66	67	67	67
Small C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	TOU (Opt-out)	0	0	0	0	0	1	1	1	1	1
Medium C&I	A/C DLC	3	3	3	4	4	4	5	5	5	6
Medium C&I	Auto-DR (HVAC)	30	121	151	152	152	153	154	154	155	156
Medium C&I	Auto-DR (Light Luminaire)	12	48	60	60	60	60	61	61	61	62
Medium C&I	Auto-DR (Light Zonal)	6	26	32	32	32	33	33	33	33	33
Medium C&I	CPP (Opt-in)	6	24	30	30	30	30	30	31	31	31
Medium C&I	CPP (Opt-out)	86	86	86	87	87	88	89	89	90	90
Medium C&I	Demand Bidding	4	16	20	21	21	21	21	22	22	22
Medium C&I	Interruptible	310	310	310	313	316	318	321	324	326	329
Medium C&I	Thermal Storage	20	80	100	101	101	101	102	102	103	103
Medium C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-out)	0	0	0	51	51	51	51	52	52	52
Large C&I	Auto-DR (HVAC)	4	15	19	19	19	19	19	19	19	19
Large C&I	Auto-DR (Light Luminaire)	3	11	13	13	13	13	13	13	13	13
Large C&I	Auto-DR (Light Zonal)	1	6	7	7	7	7	7	7	7	7
Large C&I	CPP (Opt-in)	7	28	36	35	35	35	35	35	35	35
Large C&I	CPP (Opt-out)	64	64	64	64	64	63	63	63	63	62
Large C&I	Demand Bidding	2	6	8	8	8	8	8	8	8	8
Large C&I	Interruptible	85	85	85	84	83	82	81	80	79	78

Notes:
Figure shows incremental load reduction available when DR programs are offered in isolation.
Measure-level results do not account for cost-effectiveness or overlap when offered simultaneously as part of a portfolio.
No incremental potential is shown for residential air-conditioning load control, because NSP is transitioning it to the smart thermostat program.

Alternative Base Case with Greenfield CT Costs, All Programs

Cost-Effective Potential (MW, at generator-level)

Segment	Program	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Residential	A/C DLC - SFH	0	0	0	0	0	0	0	0	0	0
Residential	Behavioral DR (Opt-out)	0	0	0	0	0	0	0	0	0	0
Residential	CPP (Opt-in)	0	0	0	11	44	46	49	52	54	57
Residential	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Residential	EV Managed Charging - Home	0	0	0	0	0	0	0	0	0	0
Residential	EV Managed Charging - Work	0	0	0	0	0	0	0	0	0	0
Residential	Smart thermostat - MDU	2	10	12	12	12	12	12	12	13	13
Residential	Smart thermostat - SFH	148	148	148	159	170	180	190	200	210	220
Residential	Smart water heating	5	10	15	21	26	27	30	35	42	51
Residential	Timed water heating	0	0	0	0	0	0	0	0	0	0
Residential	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Residential	TOU (Opt-out)	0	0	0	0	0	0	0	0	0	0
Residential	TOU - EV Charging (Opt-in)	0	0	0	0	0	0	1	1	2	2
Small C&I	A/C DLC	31	31	31	31	32	32	32	32	32	32
Small C&I	Auto-DR (A/C)	0	0	0	0	0	0	0	0	0	0
Small C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Small C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Small C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Small C&I	Interruptible	34	34	34	32	31	31	31	31	31	31
Small C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	TOU (Opt-out)	0	0	0	0	0	0	0	0	0	0
Medium C&I	A/C DLC	0	0	0	0	0	0	0	0	0	0
Medium C&I	Auto-DR (HVAC)	0	0	0	9	18	20	23	26	29	32
Medium C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Medium C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Medium C&I	CPP (Opt-in)	0	0	0	10	19	19	19	20	20	20
Medium C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Medium C&I	Demand Bidding	4	16	19	18	16	16	16	16	16	16
Medium C&I	Interruptible	47	47	47	32	17	18	19	20	21	23
Medium C&I	Thermal Storage	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-out)	0	0	0	0	0	0	0	0	0	0
Large C&I	Auto-DR (HVAC)	1	2	3	4	5	5	5	5	6	6
Large C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Large C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Large C&I	CPP (Opt-in)	0	0	0	16	32	32	32	32	32	31
Large C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Large C&I	Demand Bidding	2	6	8	6	5	5	5	5	5	5
Large C&I	Interruptible	61	61	61	58	54	53	52	51	50	49
Portfolio-Level Total		**335**	**365**	**378**	**418**	**480**	**498**	**517**	**538**	**562**	**587**

Notes:

Incremental load reduction available when DR programs are offered simultaneously as part of portfolio, accounting for overlap between programs.

No incremental potential is shown for residential air-conditioning load control, because NSP is transitioning it to the smart thermostat program.

High Sensitivity Case, All Programs

Technical Potential (MW, at generator-level)

Segment	Program	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Residential	A/C DLC - SFH	0	0	0	0	0	0	0	0	0	0
Residential	Behavioral DR (Opt-out)	52	52	52	53	53	54	54	54	55	55
Residential	CPP (Opt-in)	0	0	0	15	62	65	69	73	76	80
Residential	CPP (Opt-out)	0	0	0	157	157	159	160	161	163	164
Residential	EV Managed Charging - Home	1	2	3	5	7	9	12	14	16	18
Residential	EV Managed Charging - Work	0	0	1	1	1	2	2	3	3	3
Residential	Smart thermostat - MDU	3	13	16	17	17	17	17	17	17	17
Residential	Smart thermostat - SFH	213	213	213	238	263	283	302	321	341	360
Residential	Smart water heating	8	16	24	32	40	42	47	56	68	83
Residential	Timed water heating	11	45	57	66	76	76	75	75	75	74
Residential	TOU (Opt-in)	0	0	0	6	23	25	26	28	29	31
Residential	TOU (Opt-out)	0	0	0	155	155	156	157	159	160	161
Residential	TOU - EV Charging (Opt-in)	0	0	0	0	1	1	1	2	2	2
Small C&I	A/C DLC	44	44	44	44	44	44	45	45	45	45
Small C&I	Auto-DR (A/C)	2	8	9	9	9	10	10	10	10	10
Small C&I	Auto-DR (Light Luminaire)	1	6	7	7	7	7	7	7	8	8
Small C&I	Auto-DR (Light Zonal)	1	5	6	6	6	6	6	6	6	6
Small C&I	CPP (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-out)	0	0	0	1	1	1	1	1	1	1
Small C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Small C&I	Interruptible	65	65	65	65	66	66	66	67	67	67
Small C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	TOU (Opt-out)	0	0	0	0	0	1	1	1	1	1
Medium C&I	A/C DLC	3	3	3	4	4	4	5	5	5	6
Medium C&I	Auto-DR (HVAC)	30	121	151	152	152	153	154	154	155	156
Medium C&I	Auto-DR (Light Luminaire)	12	48	60	60	60	60	61	61	61	62
Medium C&I	Auto-DR (Light Zonal)	6	26	32	32	32	33	33	33	33	33
Medium C&I	CPP (Opt-in)	6	24	30	30	30	30	30	31	31	31
Medium C&I	CPP (Opt-out)	86	86	86	87	87	88	89	89	90	90
Medium C&I	Demand Bidding	4	17	21	21	22	22	22	22	22	22
Medium C&I	Interruptible	310	310	310	313	316	318	321	324	326	329
Medium C&I	Thermal Storage	20	80	100	101	101	101	102	102	103	103
Medium C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-out)	0	0	0	51	51	51	51	52	52	52
Large C&I	Auto-DR (HVAC)	4	15	19	19	19	19	19	19	19	18
Large C&I	Auto-DR (Light Luminaire)	3	11	13	13	13	13	13	13	13	13
Large C&I	Auto-DR (Light Zonal)	1	6	7	7	7	7	7	7	7	7
Large C&I	CPP (Opt-in)	7	28	36	35	35	35	35	35	35	35
Large C&I	CPP (Opt-out)	64	64	64	64	64	63	63	63	63	62
Large C&I	Demand Bidding	2	6	8	8	8	8	8	8	8	8
Large C&I	Interruptible	85	85	85	84	83	82	81	80	79	78

Notes:
Figure shows incremental load reduction available when DR programs are offered in isolation.
Measure-level results do not account for cost-effectiveness or overlap when offered simultaneously as part of a portfolio.
No incremental potential is shown for residential air-conditioning load control, because NSP is transitioning it to the smart thermostat program.

High Sensitivity Case, All Programs

Cost-Effective Potential (MW, at generator-level)

Segment	Program	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Residential	A/C DLC - SFH	0	0	0	0	0	0	0	0	0	0
Residential	Behavioral DR (Opt-out)	0	0	0	0	0	0	0	0	0	0
Residential	CPP (Opt-in)	0	0	0	11	44	46	49	52	54	57
Residential	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Residential	EV Managed Charging - Home	0	0	0	0	0	0	0	0	0	0
Residential	EV Managed Charging - Work	0	0	0	0	0	0	0	0	0	0
Residential	Smart thermostat - MDU	3	12	15	15	15	15	15	15	15	15
Residential	Smart thermostat - SFH	176	176	176	186	197	208	219	230	241	252
Residential	Smart water heating	8	16	24	32	40	42	47	56	68	83
Residential	Timed water heating	0	0	0	0	0	0	0	0	0	0
Residential	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Residential	TOU (Opt-out)	0	0	0	0	0	0	0	0	0	0
Residential	TOU - EV Charging (Opt-in)	0	0	0	0	0	0	1	1	2	2
Small C&I	A/C DLC	32	32	32	32	32	32	32	33	33	33
Small C&I	Auto-DR (A/C)	0	0	0	0	0	0	0	0	0	0
Small C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Small C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Small C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Small C&I	Interruptible	34	34	34	32	31	31	31	31	31	31
Small C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	TOU (Opt-out)	0	0	0	0	0	0	0	0	0	0
Medium C&I	A/C DLC	0	0	0	0	0	0	0	0	0	0
Medium C&I	Auto-DR (HVAC)	11	45	56	64	72	72	73	74	75	76
Medium C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Medium C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Medium C&I	CPP (Opt-in)	0	0	0	10	19	19	19	20	20	20
Medium C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Medium C&I	Demand Bidding	4	16	20	18	16	16	16	16	16	16
Medium C&I	Interruptible	47	47	47	32	17	18	19	20	22	23
Medium C&I	Thermal Storage	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-out)	0	0	0	0	0	0	0	0	0	0
Large C&I	Auto-DR (HVAC)	2	8	10	11	12	12	11	11	11	11
Large C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Large C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Large C&I	CPP (Opt-in)	0	0	0	16	32	32	32	32	32	31
Large C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Large C&I	Demand Bidding	2	6	8	7	5	5	5	5	5	5
Large C&I	Interruptible	62	62	62	58	55	54	53	52	51	50
Portfolio-Level Total		**380**	**454**	**484**	**524**	**586**	**603**	**623**	**647**	**674**	**705**

Notes:

Incremental load reduction available when DR programs are offered simultaneously as part of portfolio, accounting for overlap between programs.

No incremental potential is shown for residential air-conditioning load control, because NSP is transitioning it to the smart thermostat program.

Base Case, NSP Proposed Portfolio

Technical Potential (MW, at generator-level)

Segment	Program	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Residential	A/C DLC - SFH	0	0	0	0	0	0	0	0	0	0
Residential	Behavioral DR (Opt-out)	0	0	52	53	53	54	54	54	55	55
Residential	CPP (Opt-in)	0	0	0	0	0	0	0	0	0	0
Residential	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Residential	EV Managed Charging - Home	2	3	3	5	7	9	12	14	16	18
Residential	EV Managed Charging - Work	0	0	0	0	0	0	0	0	0	0
Residential	Smart thermostat - MDU	0	0	0	0	0	0	0	0	0	0
Residential	Smart thermostat - SFH	161	161	161	175	190	204	219	233	248	262
Residential	Smart water heating	0	0	8	15	22	23	26	31	39	48
Residential	Timed water heating	0	0	0	0	0	0	0	0	0	0
Residential	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Residential	TOU (Opt-out)	0	0	0	155	155	156	157	159	160	161
Residential	TOU - EV Charging (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	A/C DLC	44	44	44	44	44	44	45	45	45	45
Small C&I	Auto-DR (A/C)	0	0	0	0	0	0	0	0	0	0
Small C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Small C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Small C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Small C&I	Interruptible	53	53	53	53	54	54	54	54	54	55
Small C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	TOU (Opt-out)	0	0	0	0	0	1	1	1	1	1
Medium C&I	A/C DLC	3	3	3	4	4	4	5	5	5	6
Medium C&I	Auto-DR (HVAC)	30	121	151	152	152	153	154	154	155	156
Medium C&I	Auto-DR (Light Luminaire)	12	48	60	60	60	60	61	61	61	62
Medium C&I	Auto-DR (Light Zonal)	6	26	32	32	32	33	33	33	33	33
Medium C&I	CPP (Opt-in)	0	6	24	30	30	30	30	31	31	31
Medium C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Medium C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Medium C&I	Interruptible	310	310	310	313	316	318	321	324	326	329
Medium C&I	Thermal Storage	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-out)	0	0	0	0	0	0	0	0	0	0
Large C&I	Auto-DR (HVAC)	4	15	19	19	19	19	19	19	19	18
Large C&I	Auto-DR (Light Luminaire)	3	11	13	13	13	13	13	13	13	13
Large C&I	Auto-DR (Light Zonal)	1	6	7	7	7	7	7	7	7	7
Large C&I	CPP (Opt-in)	0	7	28	35	35	35	35	35	35	35
Large C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Large C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Large C&I	Interruptible	85	85	85	84	83	82	81	80	79	78

Notes:
Figure shows incremental load reduction available when DR programs are offered in isolation.
Measure-level results do not account for cost-effectiveness or overlap when offered simultaneously as part of a portfolio.
No incremental potential is shown for residential air-conditioning load control, because NSP is transitioning it to the smart thermostat program.

Base Case, NSP Proposed Portfolio

Cost-Effective Potential (MW, at generator-level)

Segment	Program	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Residential	A/C DLC - SFH	0	0	0	0	0	0	0	0	0	0
Residential	Behavioral DR (Opt-out)	0	0	0	0	0	0	0	0	0	0
Residential	CPP (Opt-in)	0	0	0	0	0	0	0	0	0	0
Residential	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Residential	EV Managed Charging - Home	0	0	0	0	0	0	0	0	0	0
Residential	EV Managed Charging - Work	0	0	0	0	0	0	0	0	0	0
Residential	Smart thermostat - MDU	0	0	0	0	0	0	0	0	0	0
Residential	Smart thermostat - SFH	112	112	112	122	131	139	146	154	162	169
Residential	Smart water heating	0	0	8	13	18	19	21	25	30	36
Residential	Timed water heating	0	0	0	0	0	0	0	0	0	0
Residential	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Residential	TOU (Opt-out)	0	0	0	95	95	96	96	97	98	99
Residential	TOU - EV Charging (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	A/C DLC	21	21	21	22	23	23	23	23	22	22
Small C&I	Auto-DR (A/C)	0	0	0	0	0	0	0	0	0	0
Small C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Small C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Small C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Small C&I	Interruptible	14	14	14	14	15	15	15	15	15	15
Small C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	TOU (Opt-out)	0	0	0	0	0	0	0	0	0	0
Medium C&I	A/C DLC	0	0	0	0	0	0	0	0	0	0
Medium C&I	Auto-DR (HVAC)	0	0	0	0	0	0	0	0	0	0
Medium C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Medium C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Medium C&I	CPP (Opt-in)	0	4	15	19	19	19	19	20	20	20
Medium C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Medium C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Medium C&I	Interruptible	13	13	13	15	16	17	18	19	20	22
Medium C&I	Thermal Storage	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-out)	0	0	0	0	0	0	0	0	0	0
Large C&I	Auto-DR (HVAC)	0	0	0	0	0	0	0	0	0	0
Large C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Large C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Large C&I	CPP (Opt-in)	0	6	26	32	32	32	32	32	32	31
Large C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Large C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Large C&I	Interruptible	52	52	52	52	51	51	50	49	48	47
Portfolio-Level Total		**213**	**223**	**262**	**384**	**400**	**410**	**420**	**433**	**446**	**461**

Notes:
Incremental load reduction available when DR programs are offered simultaneously as part of portfolio, accounting for overlap between programs.
No incremental potential is shown for residential air-conditioning load control, because NSP is transitioning it to the smart thermostat program.

High Sensitivity Case, NSP Proposed Portfolio

Technical Potential (MW, at generator-level)

Segment	Program	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Residential	A/C DLC - SFH	0	0	0	0	0	0	0	0	0	0
Residential	Behavioral DR (Opt-out)	0	0	52	53	53	54	54	54	55	55
Residential	CPP (Opt-in)	0	0	0	0	0	0	0	0	0	0
Residential	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Residential	EV Managed Charging - Home	2	3	3	5	7	9	12	14	16	18
Residential	EV Managed Charging - Work	0	0	0	0	0	0	0	0	0	0
Residential	Smart thermostat - MDU	0	0	0	0	0	0	0	0	0	0
Residential	Smart thermostat - SFH	213	213	213	238	263	283	302	321	341	360
Residential	Smart water heating	0	0	8	16	24	26	31	39	51	66
Residential	Timed water heating	0	0	0	0	0	0	0	0	0	0
Residential	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Residential	TOU (Opt-out)	0	0	0	155	155	156	157	159	160	161
Residential	TOU - EV Charging (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	A/C DLC	44	44	44	44	44	44	45	45	45	45
Small C&I	Auto-DR (A/C)	0	0	0	0	0	0	0	0	0	0
Small C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Small C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Small C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Small C&I	Interruptible	53	53	53	53	54	54	54	54	54	55
Small C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	TOU (Opt-out)	0	0	0	0	0	1	1	1	1	1
Medium C&I	A/C DLC	3	3	3	4	4	4	5	5	5	6
Medium C&I	Auto-DR (HVAC)	30	121	151	152	152	153	154	154	155	156
Medium C&I	Auto-DR (Light Luminaire)	12	48	60	60	60	60	61	61	61	62
Medium C&I	Auto-DR (Light Zonal)	6	26	32	32	32	33	33	33	33	33
Medium C&I	CPP (Opt-in)	0	6	24	30	30	30	30	31	31	31
Medium C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Medium C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Medium C&I	Interruptible	310	310	310	313	316	318	321	324	326	329
Medium C&I	Thermal Storage	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-out)	0	0	0	0	0	0	0	0	0	0
Large C&I	Auto-DR (HVAC)	4	15	19	19	19	19	19	19	19	18
Large C&I	Auto-DR (Light Luminaire)	3	11	13	13	13	13	13	13	13	13
Large C&I	Auto-DR (Light Zonal)	1	6	7	7	7	7	7	7	7	7
Large C&I	CPP (Opt-in)	0	7	28	35	35	35	35	35	35	35
Large C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Large C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Large C&I	Interruptible	85	85	85	84	83	82	81	80	79	78

Notes:
Figure shows incremental load reduction available when DR programs are offered in isolation.
Measure-level results do not account for cost-effectiveness or overlap when offered simultaneously as part of a portfolio.
No incremental potential is shown for residential air-conditioning load control, because NSP is transitioning it to the smart thermostat program.

High Sensitivity Case, NSP Proposed Portfolio

Cost-Effective Potential (MW, at generator-level)

Segment	Program	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Residential	A/C DLC - SFH	0	0	0	0	0	0	0	0	0	0
Residential	Behavioral DR (Opt-out)	0	0	0	0	0	0	0	0	0	0
Residential	CPP (Opt-in)	0	0	0	0	0	0	0	0	0	0
Residential	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Residential	EV Managed Charging - Home	0	0	0	0	0	0	0	0	0	0
Residential	EV Managed Charging - Work	0	0	0	0	0	0	0	0	0	0
Residential	Smart thermostat - MDU	0	0	0	0	0	0	0	0	0	0
Residential	Smart thermostat - SFH	176	176	176	186	197	208	219	230	241	252
Residential	Smart water heating	0	0	8	16	24	26	31	39	51	66
Residential	Timed water heating	0	0	0	0	0	0	0	0	0	0
Residential	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Residential	TOU (Opt-out)	0	0	0	95	95	96	96	97	98	99
Residential	TOU - EV Charging (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	A/C DLC	36	36	36	34	33	33	34	34	34	34
Small C&I	Auto-DR (A/C)	0	0	0	0	0	0	0	0	0	0
Small C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Small C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Small C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Small C&I	Interruptible	15	15	15	15	15	15	15	15	15	15
Small C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	TOU (Opt-out)	0	0	0	0	0	0	0	0	0	0
Medium C&I	A/C DLC	0	0	0	0	0	0	0	0	0	0
Medium C&I	Auto-DR (HVAC)	11	45	56	64	72	72	73	74	75	76
Medium C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Medium C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Medium C&I	CPP (Opt-in)	0	4	15	19	19	19	19	20	20	20
Medium C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Medium C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Medium C&I	Interruptible	14	14	14	15	17	18	19	20	22	23
Medium C&I	Thermal Storage	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-out)	0	0	0	0	0	0	0	0	0	0
Large C&I	Auto-DR (HVAC)	2	8	10	11	12	12	11	11	11	11
Large C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Large C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Large C&I	CPP (Opt-in)	0	6	26	32	32	32	32	32	32	31
Large C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Large C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Large C&I	Interruptible	56	56	56	55	55	54	53	52	51	50
Portfolio-Level Total		**309**	**359**	**411**	**543**	**570**	**585**	**603**	**624**	**649**	**677**

Notes:
Incremental load reduction available when DR programs are offered simultaneously as part of portfolio, accounting for overlap between programs.
No incremental potential is shown for residential air-conditioning load control, because NSP is transitioning it to the smart thermostat program.

Northern States Power Company
Summary of Cost Benefit Analysis Results
IVVO 1.25%

NSPM -AMI- NPV

	Total ($MM)
Benefits	**446**
O&M Benefits	53
Other Benefits	203
CAP Benefits	190
Costs	**(539)**
O&M Expense	(179)
Change in Revenue Requirements	(359)
Benefit/Cost Ratio	**0.83**

FLISR

Benefits	**103**
O&M Benefits	0
Customer Benefits	103
Costs	**(79)**
O&M Expense	(5)
Change in Revenue Requirements	(74)
Benefit/Cost Ratio	**1.31**

IVVO

Benefits	22
Other Benefits	19
CAP Benefits	3
Costs	(39)
O&M Expense	(2)
Change in Capital Revenue Requirement	(37)
Benefit/Cost Ratio	**0.57**

NSPM -AMI,FLISR, IVVOS- NPV

	Total ($MM)
Benefits	**571**
O&M Benefits	53
Other Benefits	222
Customer Benefits	103
CAP Benefits	193
Costs	**(657)**
O&M Expense	(186)
Change in Revenue Requirement	(470)
Benefit/Cost Ratio	**0.87**

Northern States Power Company
Summary of Cost Benefit Analysis Results

IVVO 1.25% - No Contingency

NSPM -AMI- NPV

	Total ($MM)
Benefits	**446**
O&M Benefits	53
Other Benefits	203
CAP Benefits	190
Costs	**(452)**
O&M Expense	(146)
Change in Revenue Requirements	(306)
Benefit/Cost Ratio	**0.99**

FLISR

Benefits	**103**
O&M Benefits	0
Customer Benefits	103
Costs	**(67)**
O&M Expense	(4)
Change in Revenue Requirements	(63)
Benefit/Cost Ratio	**1.53**

IVVO

Benefits	22
Other Benefits	19
CAP Benefits	3
Costs	(37)
O&M Expense	(2)
Change in Capital Revenue Requirement	(34)
Benefit/Cost Ratio	**0.61**

NSPM -AMI,FLISR, IVVOS- NPV

	Total ($MM)
Benefits	**571**
O&M Benefits	53
Other Benefits	222
Customer Benefits	103
CAP Benefits	193
Costs	**(556)**
O&M Expense	(152)
Change in Revenue Requirement	(404)
Benefit/Cost Ratio	**1.03**

Northern States Power Company
Summary of Cost Benefit Analysis Results
IVVO 1%

NSPM -AMI- NPV

	Total ($MM)
Benefits	**446**
O&M Benefits	53
Other Benefits	203
CAP Benefits	190
Costs	**(539)**
O&M Expense	(179)
Change in Revenue Requirements	(359)
Benefit/Cost Ratio	**0.83**

FLISR

Benefits	**103**
O&M Benefits	0
Customer Benefits	103
Costs	**(79)**
O&M Expense	(5)
Change in Revenue Requirements	(74)
Benefit/Cost Ratio	**1.31**

IVVO

Benefits	18
Other Benefits	15
CAP Benefits	3
Costs	(39)
O&M Expense	(2)
Change in Capital Revenue Requirement	(37)
Benefit/Cost Ratio	**0.46**

NSPM -AMI,FLISR, IVVOS- NPV

	Total ($MM)
Benefits	**567**
O&M Benefits	53
Other Benefits	219
Customer Benefits	103
CAP Benefits	193
Costs	**(657)**
O&M Expense	(186)
Change in Revenue Requirement	(470)
Benefit/Cost Ratio	**0.86**

Northern States Power Company
Summary of Cost Benefit Analysis Results

IVVO 1% - No Contingency

NSPM -AMI- ***NPV***

	Total ($MM)
Benefits	**446**
O&M Benefits	53
Other Benefits	203
CAP Benefits	190
Costs	**(452)**
O&M Expense	(146)
Change in Revenue Requirements	(306)
Benefit/Cost Ratio	**0.99**

FLISR

Benefits	**103**
O&M Benefits	0
Customer Benefits	103
Costs	**(67)**
O&M Expense	(4)
Change in Revenue Requirements	(63)
Benefit/Cost Ratio	**1.53**

IVVO

Benefits	18
Other Benefits	15
CAP Benefits	3
Costs	(37)
O&M Expense	(2)
Change in Capital Revenue Requirement	(34)
Benefit/Cost Ratio	**0.49**

NSPM -AMI,FLISR, IVVOS- ***NPV***

	Total ($MM)
Benefits	**567**
O&M Benefits	53
Other Benefits	219
Customer Benefits	103
CAP Benefits	193
Costs	**(556)**
O&M Expense	(152)
Change in Revenue Requirement	(404)
Benefit/Cost Ratio	**1.02**

Northern States Power Company
Summary of Cost Benefit Analysis Results
IVVO 1.5%

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NSPM -AMI- *NPV*

	Total ($MM)
Benefits	**446**
O&M Benefits	53
Other Benefits	203
CAP Benefits	190
Costs	**(539)**
O&M Expense	(179)
Change in Revenue Requirements	(359)
Benefit/Cost Ratio	**0.83**

FLISR

Benefits	**103**
O&M Benefits	0
Customer Benefits	103
Costs	**(79)**
O&M Expense	(5)
Change in Revenue Requirements	(74)
Benefit/Cost Ratio	**1.31**

IVVO

Benefits	27
Other Benefits	23
CAP Benefits	4
Costs	(39)
O&M Expense	(2)
Change in Capital Revenue Requirement	(37)
Benefit/Cost Ratio	**0.67**

NSPM -AMI,FLISR, IVVOS- *NPV*

	Total ($MM)
Benefits	**575**
O&M Benefits	53
Other Benefits	226
Customer Benefits	103
CAP Benefits	194
Costs	**(657)**
O&M Expense	(186)
Change in Revenue Requirement	(470)
Benefit/Cost Ratio	**0.88**

Northern States Power Company
Summary of Cost Benefit Analysis Results
IVVO 1.5% - No Contingency

NSPM -AMI- *NPV*

	Total ($MM)
Benefits	**446**
O&M Benefits	53
Other Benefits	203
CAP Benefits	190
Costs	**(452)**
O&M Expense	(146)
Change in Revenue Requirements	(306)
Benefit/Cost Ratio	**0.99**

FLISR

Benefits	**103**
O&M Benefits	0
Customer Benefits	103
Costs	**(67)**
O&M Expense	(4)
Change in Revenue Requirements	(63)
Benefit/Cost Ratio	**1.53**

IVVO

Benefits	27
Other Benefits	23
CAP Benefits	4
Costs	(37)
O&M Expense	(2)
Change in Capital Revenue Requirement	(34)
Benefit/Cost Ratio	**0.72**

NSPM -AMI,FLISR, IVVOS- *NPV*

	Total ($MM)
Benefits	**575**
O&M Benefits	53
Other Benefits	226
Customer Benefits	103
CAP Benefits	194
Costs	**(556)**
O&M Expense	(152)
Change in Revenue Requirement	(404)
Benefit/Cost Ratio	**1.03**

QUESTIONS ASKED TO VENDORS THROUGH XCEL ENERGY'S eSOURCING SYSTEM FOR THE RFI FOR THE ADVANCED PLANNING TOOL

1.0 Overview and Introduction

1.1 Instructions to Bidders - Indicate whether or not you agree with the instructions to bidders

1.2 What is your company's legal name?

1.3 Indicate your company's entity type.

1.4 List any applicable trade names or d/b/a names associated with your company (if applicable).

1.5 Who is your single point of contact and their title for communications concerning this Proposal?

1.6 Provide the following contact information for the single point of contact:

Address (street, city, state &zip)
Email
Phone
Fax

1.7 What is your internal proposal number for this event?

1.8 If successful in being awarded this contract, who is your duly authorized representative and their position who would be responsible for signing the contract?

1.9 What is the following contact information of your duly authorized representative?

Address (street, city, state & zip)
Email
Phone number
Fax

1.10

1.10.1 List all states that your company is authorized to work in.

1.10.2 What % of work do you typically self-perform? If answer is 100%, a letter of explanation is required and must be submitted with your bid submission. A sample letter has been attached here for your reference.

1.10.3 If you do not self-perform all work, please fill out attached Subcontracting Utilization Report.

Have you attached a completed Subcontracting Utilization Report?

1.11 This proposal shall remain valid for a period of 120 days following the closing of the event. Select Yes if you agree and No if you disagree.

2.0 <u>Scope of Work and Qualifications</u>

2.1 Qualifications

2.1.1 Provide a list of three industry references that can provide input as to the data provided in this RFP. Provide company name, project description, project start date, contact name, contact phone # and completion date.

2.1.2 As an attachment, provide a list of the key personnel you propose to work on this project and include a brief summary of their experience, including any specialized qualifications and certifications.

Select yes to indicate that you have attached a summary of their qualifications or Resume.

2.1.3 Please provide a list of the available resources and their level of expertise.

2.1.4 Please describe your ideal project process.

2.2 Scope of Work and Technical Requirements

2.2.1 Scope of work and/or Technical specifications and description are found attached to this RFx. Bidders should submit their responses based on the requirements listed in the RFx and addendums.

Select Yes if you have submitted your bids based on these requirements.
Select no to indicate you do not comply with the specifications attached. Enter exceptions as an attachment labeled "table of SOW exceptions".

Each Bidder shall be solely responsible for examining the project-specific specifications and make all necessary investigations to be fully informed of all conditions that will affect the completion of the work to be performed.

2.2.2 Bidders shall take no advantage of any apparent errors or omissions in any related documents.

If a Bidder believes there are errors or omissions in supplied documentation or if the Bidder is in doubt as to the meaning of any part of the documentation, Bidder is to contact Event Owner via Emptoris messaging functionality before the close of the bidding event. If Xcel Energy agrees that a change is required or if any explanation or interpretation is required, Xcel Energy will issue an Addendum.

Select yes to indicate that you comply with these terms.

Select no to indicate you do not comply with the terms stated above, and provide an attachment of exceptions

2.3 Quality Assurance and Process Control

2.3.1 Please describe your Quality Assurance Program. Attach additional information as needed.

2.3.2 If you are providing material for this project, please describe in detail where they are manufactured and distributed.

2.3.3 What are your auditing process to ensure your goods are in compliance with Xcel's requirements?

3.0 <u>Pricing Requirements</u>

3.1 Have you completed all questions and attachments of the RFP?

3.2 The Bidder is encouraged to offer options (enhancements to components, materials, or parts; regarding performance, reliability, wear ability, and longevity) in addition to, but not as alternates to, the requirements of the Scope of work and Technical Specification. The offering of such options must include a discussion of the advantages and disadvantages of each option.

Have you attached additional options?

4.0 Commercial Terms

4.1 Attached are the Xcel Energy General Conditions for Consulting Services Agreement.

Please select from the responses below.

If you take exceptions, please fill out the attached table of exceptions document.

4.2 Xcel Energy reserves the right to disqualify any and all responses submitted in a format which is either incomplete or does not comply with the rules for the event. Do you agree to comply with these terms?

4.3 This Proposal is genuine and not made in the interest of or on behalf of any undisclosed person, firm, or corporation and is not submitted in conformity with any agreement or rules of any group, association, organization, or corporation; Bidder has not directly or indirectly induced or solicited any other Bidder to submit a false or sham Proposal; Bidder has not solicited or induced any person, firm, or a corporation to refrain from bidding; and Bidder has not sought by collusion to obtain for itself any advantage over any other Bidder or over Company.

4.4 Have you verified that your current insurance form has been attached to your Supplier Profile?

4.5 Standard payment terms are net 30 days after receipt of invoice (unless Bidder submits a cash discount for early payment). Do you agree to the standard payment term? Select yes to indicate that you agree with these terms. Select no to indicate you do not comply with the terms stated above, but offer the terms entered into the "Comments" section.

4.6 Xcel Energy is interested in early payment discount terms for all work covered under this proposal. What early payment terms discount does your company offer?

5.0 <u>Financials</u>

5.1 Have you attached your most recently audited Balance Sheet and Income Statement?

5.2 Annual Sales Volume (Each of Last Three Years).

5.3 Provide your Dunn & Bradstreet No.

6.0 <u>Diversity</u>

6.1 Is your company Certified as a diverse supplier?

6.2 If you answered yes to Question 6.1 above, indicate your company's diversity status. If you answered no, please indicate "N/A" as your status.

6.3 Xcel Energy has a commitment to involve diversity business (e.g., minority, women-owned, etc...) in all phases of its procurement processes. How would your organization support Xcel Energy in achieving this objective through the use of Tier II subcontracting plans?

6.4 Currently, what percentage of your purchases are through diverse tier II suppliers?

(in decimal format - i.e.: 99% = .99)

6.5 Are you planning on using diverse Subcontractors for this project?

If Yes please verify that you have thoroughly completed the Subcontracting Utilization Report in Question 1.10.3

6.6 Are you currently barred from doing business with the U.S. Federal Government?

7.0 <u>Functional Requirements</u>

7.1 Is your solution cloud based?

7.2 How is your cloud based solution configurable?

7.3 The Solution will interface with SAP.

7.4 Does your solution integrate Distributed Generation (DG) into Distribution planning load forecasts? If so, how does it properly plan for the effects of DGsystem load?

7.5 What other Distributed Energy Resources (DER) options can your tool incorporate? If "Other", please describe.

7.6 Which socio-economic factors can be incorporated into planning forecasts in your tool? If "Other", please describe.

7.7 Does your solution provide sensitivity analysis capabilities? If so, please describe your methodology.

7.8 Does your solution provide the capability to adjust adoption rates for technologies? If so, please describe your methodology.

7.9 How does your solution provide the capability to adjust forecasts by adjusting policy and subsidization factors?

7.10 Does your solution provide the capability to adjust parameters by political entity? If so, please describe your methodology.

7.11 Currently, when we review load and generation SCADA data for use in our forecasts, we manually decipher what the maximums or minimums are and exclude switching or abnormal periods. What features does your tool have to improve efficiency in this regard?

7.12 Our current forecasting process relies on historical loads, known growth and manual adjustments. What features does your tool have to improve efficiency in forecasting loads?

7.13 Describe any additional efficiency features incorporated into your tool to reduce the planning forecast process (e.g., Automation, data cleansing, etc.).

7.14 Does your solution show historical and forecasted maximums and minimums on the same screen, for both load and generation, at the feeder and substation transformer levels?

7.15 Does your solution have the ability to aggregate load on a regional level?

7.16 Does your solution aggregate load on a state level?

7.17 Does your solution adjust feeder load forecasts by applying factors at the regional levels?

7.18 Does your solution adjust feeder load forecasts by applying factors at the state levels?

7.19 Where have you added the most value to your customers so far?

7.20 Provide examples how your tool supports accurate forecasts which can be used for PUC and regulatory agency reporting, as well as intra-company reporting. Any white papers to support this capability would be of interest.

7.21 Does your solution perform Distribution scenario planning? If yes, describe your methodology.

7.22 Does your solution utilize hosting capacity information? If yes, describe your methodology.

7.23 Can your solution be integrated with EPRI's DRIVE hosting tool without custom code?

7.24 Which other hosting tool(s) does your solution integrate with?

7.25 How many years of feeder and transformer load history can your solution accommodate and account for?

7.26 Can your solution be integrated with Synergi Electric, version 6.0 without custom code?

7.27 Which other major distribution planning tool(s) does your solution integrate with?

7.28 Does your solution utilize Advanced Metering Infrastructure (AMI) data? If so, what devices?

7.29 Does your solution have the ability to incorporate multiple SCADA points on a distribution feeder?

7.30 Can your solution take into account real and reactive power by phase?

7.31 Does your solution record daytime minimum load?

7.32 Does your solution integrate with Hansen Technologies Peace software version 7.1 Customer Resource System without custom code?

7.33 Which other major customer resource system(s) does your solution integrate with?

7.34 Please describe your solution's reporting capabilities.

7.35 Does your solution integrate with Business Objects? If so, please describe how?

7.36 What exporting capabilities does your solution have? If "Other", please describe.

7.37 Does your solution forecast medium term (1-5 years) feeder and substation load growth? If so, describe the forecasting methodology.

7.38 Does your solution forecast long term (+10 years) feeder and substation load growth? If so, describe the forecasting methodology.

7.39 Does your solution integrate with GE's EMS/SCADA system, PowerOn Reliance (XA/21) version 17.1.2 without custom code?

7.40 Which other major SCADA system(s) does your solution integrate with?

7.41 Is your solution able to incorporate GIS Smallworld data? If yes, how?

7.42 Which other major geographic information systems does your solution integrate with?

7.43 Does your solution provide any equivalent planning and forecasting functionality for the following:

7.43.1 Gas Distribution? If so, please describe.

7.43.2 Transmission? If so, please describe.

7.43.3 Generation? If so, please describe.

7.44 Does your solution integrate with any third party products that provide equivalent planning and forecasting functionality for the following:

7.44.1 Gas Distribution? If so, please describe.

7.44.2 Transmission? If so, please describe.

7.44.3 Generation? If so, please describe.

8.0 <u>Security – General, System, Data Integrity</u>

8.1 Security – General

8.1.1 Should you have access to any Company or client confidential information, please describe how confidentiality is maintained, including how information is retained and/or disposed of at designated times.

8.1.2 Describe your employee background check as part of the onboarding process.

8.1.2.1. Do you run background checks on every employee? Please describe your process.

8.1.2.2. Do you run background checks on contractors? Please describe your process.

8.1.2.3. What types of checks are included? Please describe your process.

8.1.2.4. Are criminal background checks performed? Please describe your process.

8.1.3 Does your company have agreements which both employees and contractors sign pertaining to non-disclosure, acceptable use, and code of conduct? If yes, please describe and attach a sample.

8.1.4 Do you have a dedicated internal audit and compliance team in place who govern policies, procedures, approvals, and review processes?

8.1.5 Do you outsource any security management functionality? If yes, please describe what is outsourced, the scope of the outsourced arrangement, and to whom.

8.1.6 Do you have a Computer Security Incident Response Team (CSIRT) in place? If so, please describe your procedures for responding to and reporting security incidents.

8.1.7 Are there any issues with allowing Company to review your information security documents and risk management procedures, including vulnerability assessment results and remediation activities?

8.1.8 Does your company have a process implemented to ensure all violations, unauthorized access (including data protection) and anomalous activities are logged, monitored, reviewed and addressed in a timely manner?

8.1.9 What tools, if any, are used for DLP? Provide a description overview of your DLP program.

8.1.10 Is there a procedure to track announcements of vulnerability patches for your networking devices? If yes, describe the procedure.

8.1.11 Do you have formally written and documented policies and procedures for the following and how often are they reviewed. (For each one, please respond with Yes or No and how often they are reviewed.)

8.1.11.1. Data Classification

8.1.11.2. Acceptable Use

8.1.11.3. Data Handling, Destruction, Retention & Return

8.1.11.4. Remote and Third Party Access

8.1.11.5. Change Management

8.1.11.6. Privacy

8.1.11.7. Incident, Problem & Emergency Management

8.1.11.8. Business Continuity

8.1.11.9. Disaster Recovery

8.1.11.10. Password Management Policies

8.1.11.11. Encryption Policy and Standards

8.1.12 Provide a descriptive overview of your Business Continuity program/plan.

8.1.12.1. Do you test your Business Continuity program/plan capabilities?

8.1.12.2. Based on testing results, what is your operational Recovery Time Objective [RTO]?

8.1.13 Provide a descriptive overview of your Disaster Recovery program/plan.

8.1.13.1. Based on testing results, what is your Recovery Time Objective [RTO] / Recovery Point Objective [RPO] for the technology service that is the subject of this RFI?

8.1.13.2. How often are your Disaster Recover plans tested?

8.2 Security System

8.2.1 Do you have a standard patching process in your environment? If yes, describe automated product/manual process.

8.2.2 Do you have a formal patch/hotfix testing and deployment process?

8.2.3 Do you perform security assessments, web application assessments, or penetration tests against the infrastructure and application (include source code) to identify security vulnerabilities at least twice a year?

8.2.4 What type, and at what frequency, are vulnerability scans performed?

8.2.5 How does your solution handle data validation? Does the solution have a flagging capability for missing data, tolerances for data, or manual data input errors?

8.2.6 Would you be able to configure field based data integrity checks and validation rules?

8.2.7 Describe the cyber security testing of your software/hardware product(s).

8.2.8 Do you deploy secure application development methodologies, such as OWASP, in all or any aspects of software development?

8.2.9 Please indicate how data is transmitted securely between your service locations and the recipients.

8.2.10 Do you use encryption on all of the communication protocols? Please list protocol and encryption method. If encryption isn't used, please explain why.

8.2.11 Please describe your process for performing application security Quality Assurance testing. For example, testing of authentication, authorization, and accounting functions, as well as any other activity designed to validate the security architecture.

8.2.12 Have you completed web code reviews, including CGI, Java, etc., for the explicit purposes of finding and remediating security vulnerabilities?

8.2.13 Describe your software maintenance process, as well as access methods with regard to security / vulnerability patch management.

8.2.14 Do you utilize open source code or operating systems? Please specify.

8.2.15 Does your solution have the ability to lock data entry fields after field users submit data, or workflow is moved to a "completed" status?

8.2.16 Does your solution have audit trail capabilities built into standard reports?

8.2.17 Will each transaction be accounted for on a real-time basis, including:

8.2.17.1. Workstation identification

8.2.17.2. Window name

8.2.17.3. Mobile device

8.2.17.4. Application name

8.2.17.5. OS user name

8.2.17.6. Application execution name

8.2.17.7. User name

8.2.17.8. Timestamp

8.2.18 Describe the configuration abilities for security, data integrity and version control in the document repository.

8.2.19 Please indicate the ability to exchange data with SFTP services.

8.2.20 What TCP/IP services are invoked by your software?

8.2.21 Can a new individual contact or group be established as "private" or "public"?

8.2.22 Describe the process for updating custom data fields if they persist in multiple areas of the solutions.

8.2.23 Will your solution allow, store, and create encrypted Zip / compressed files?

8.2.24 Does your solution have the ability to apply security at different levels within an organizational or cost center hierarchy?

8.2.25 Will your solution support secure messaging? Please explain.

8.2.26 Does the system maintain an audit trail on both customized and standard data fields (name of data field, who made the change, when it was changed)? Please attach a sample screen shot. Is this information reportable?

8.2.27 Does your solution use service accounts and if so, do they require password expiration?

8.2.28 What version of program languages is your product based on, and what version of languages are used?

8.2.29 Encryption algorithms must be of sufficient strength to equate to AES-256. What type(s) of encryption algorithms are used?

8.3 Security – Data Integrity

8.3.1 Company reserves the right to periodically audit the environment in which its data will be stored to ensure compliance with Company security standards. This includes physical and non-intrusive network audits performed randomly and without notice. More intrusive on-site network and physical audits may be conducted with advance notification of 1 - 3 weeks. Please indicate if this is acceptable, if not, why?

8.3.2 What policies and controls are in place to prevent Company's data from being "co-mingled" with data from other entities?

8.3.3 Will you use Company data for benchmarking?

8.3.4 Is any part of your solution cloud hosted? If yes, will Company's data be potentially or actually stored outside of the United States?

8.3.5 How is data used in test, development and other non-production environments protected? Is client data scrubbed/de-personalized in these environments? Please explain.

8.3.6 What are the real and actual data retention periods?

8.3.6.1. How long do you keep backups that can be restored?

8.3.6.2. How long is data actually kept prior to being overwritten and/or purged from the data stores?

8.3.6.3. Does it vary by customer, by solution, by module?

8.3.7 Does your solution have purge/archive capabilities?

8.3.8 Can archived data be queried using a standard query tool?

8.3.9 Does your solution have the ability to make certain records / data private?

8.3.10 How does your solution handle legal hold data? Please provide details.

8.3.11 The equipment hosting your solution and Company data must be located in a physically secure facility, which requires badge access at a minimum. Please describe the environment.

8.3.12 Do all data storage locations have 24-hour security guard coverage 7 days a week?

8.3.13 Is sensitive data of any type (credit card number, account login, passwords, PII, PHI) stored in encrypted form? How is the data encrypted?

8.3.14 If you are audited by another customer, will Company's proprietary data be exposed?

8.3.15 Please describe your IPS / IDS environment and how Company data is protected from attack.

9.0 <u>Security – Logging, Authorization, Authentication, Mobile Devices</u>

9.1 Security-Logging

9.1.1 Does your solution create detailed log files? If so, how are the log files accessed?

9.1.2 Do log files show clear text data transactions and credentials?

9.1.3 What type of information is collected in system logs? (Web, database, application, firewall and other network equipment.) Please explain.

9.1.3.1. How long is this information retained? Please explain.

9.1.3.2. How is this information reviewed and at what interval? Please explain.

9.1.4 What security events does the software log and how is it logged?

9.1.5 Please describe the transactional logging that occurs in the system.

9.1.5.1. Would Company have the ability to see the logs?

9.1.5.2. Would Company have the ability to report from the logs all transactional access, usage, information from third party tool integration?

9.1.5.3. Would Company have vendor based administration access?

9.1.6 Describe your source code protections.

9.1.7 Can or do logs normalize multiple time zones?

9.1.7.1. Are there any limitations when accessed from mobile devices?

9.1.8 Is sensitive information ever "in the clear" or unencrypted in logs or any other transient storage?

9.2 Security-Authorization and Authentication

9.2.1 How are security, access levels (read/write), permissions, and other administrative features handled?

9.2.2 Do you support multi-factor authentication?

9.2.3 Does your solution have the ability to create role based security access?

9.2.4 Will all permission levels allow for specific modifications at the granular level to specific modules, screens, custom codes, fields, etc.? Please explain.

9.2.5 How will your solution provide security levels at the individual role and any group levels? Within a project, or department?

9.2.6 Are credentials stored in a relational database?

9.2.7 Is the system compatible with single sign on, or a federated trust relationship?

9.2.8 Does your solution have the ability to apply security at different levels within an organizational or cost center hierarchy? If yes, please explain.

9.2.9 Does your solution enforce secure access based upon Active Directory user or group permissions?

9.2.10 Does your solution support SAML 2.0?

9.2.11 If your product is based on web services, what authentication do you offer?

9.2.12 Is cloud-hosted data encrypted at rest?

9.3 Security-Mobile Devices

9.3.1 Does your solution provide support for mobile technologies? If so, please specify.

9.3.2 Does your solution have security alerts for detected anomalies with mobile platforms?

9.3.3 Are there any constraints when the client uses an MDM solution?

10.0 <u>Architecture, Integration, Infrastructure, Organization, Reliability</u>

10.1 Architecture

10.1.1 What architecture model best describes your application(s)?

10.1.2 What database systems does your application support (and versions)?

10.1.3 What programming languages were used to build the application?

10.1.4 Which server platforms does your application support (and versions)?

10.1.5 Which desktop platforms does your application support (and versions)?

10.1.6 Which web browsers are certified for your application (and versions)?

10.1.7 What local (client side) objects does your application include?

10.1.8 What middleware does your application support?

10.1.9 If Java is required at the desktop, what version is necessary?

10.1.10 What third party software is required by the application or can be launched?

10.2 Application Integration

10.2.1 Do you have experience integrating with SAP? If so, please provide details.

10.2.2 Provide the names of applications your solution integrates with.

10.2.3 What application integration model best describes your system's integration capabilities? (For example, Web Services, Proprietary Published API)

10.2.4 What integration products are supported by the application?

10.2.5 Does this application utilize any integration technology standards? (For example, Web Services, JMS)

10.2.6 Does the application integrate with enterprise applications? If so, how?

10.2.7 What are the Service-Oriented Architecture capabilities of your application? (For example, How does your application expose its core functionality to other collaborating applications?)

10.2.8 Describe how your application depends on or interacts with an enterprise service bus.

10.2.9 Describe your applications' use of open source technology. Please provide a list of all open source technology used.

10.3 Application Support & Shared Services

10.3.1 Is your application configurable? If yes, what customization capabilities does your application support? (For example, allowing Users to customize screens & make online changes to configuration data on field devices)

10.3.2 How scalable is your application? (For example, what's the maximum number of proven clients)

10.3.3 What are the reporting capabilities of your application?

10.3.4 Does your application integrate with Knowledge Management/collaboration tools? If so, how?

10.3.5 Does your application integrate with Data Warehouse products? If so, how?

10.3.6 Do you integrate with Document and Records Management products?

10.3.7 Describe the application user Interface.

10.3.8 Describe the amount of time estimated to implement the application (vanilla), including interfaces to other applications.

10.3.9 Describe the application administration effort.

10.3.10 What reporting tools do you recommend for your solution?

10.4 Infrastructure

10.4.1 Describe the application security design.

10.4.2 Does your application integrate with any services for authentication and group membership? If yes, which authentication products does your application integrate with. (For example, Active directory)

10.4.3 Does the application integrate with third party Web Single Sign-On products? If yes, what third party Web Single Sign-On products does it integrate with? In particular, is your Application supported on PING Platform?

10.4.4 Describe the e-mail requirements of the application.

10.4.5 Describe the service and support features of the application.

10.4.6 Describe the upgrade and release information of the application.

10.4.7 Describe the supporting documentation/resources for the application.

10.4.8 Describe the training for the application (User and Support).

10.4.9 Describe the availability and Disaster Recovery features of the application.

10.4.10 Describe the operational monitoring capabilities of the application.

10.4.11 Does your application run on Windows Server 2012 R2 or Windows Server 2016?

10.4.12 Does your application interface has to be a heavy client? If so, does it run on Windows 7 or Windows 10?

10.4.13 Does your application run on following Database versions? SQL SERVER 2012, SQL SERVER 2016, Oracle 11G, and Oracle 12.x

10.4.14 Does your application have the ability to exchange data using Web Services (through XML, and or REST APIs) in a Websphere 8.x environment? If not, please specify the Web Services Infrastructure that supports your

10.5 Application Service Provider (ASP) Considerations

10.5.1 Do you provide an ASP service for your products, or is the application offered in an ASP format? Please describe.

10.5.2 Describe the system availability for the application (For example, how is availability measured? How is a test/development environment managed?)

10.5.3 Describe the backup and recovery procedure for the application.

10.5.4 Is your product secure? If so, please describe the security of the product.

10.5.5 Describe the encryption capabilities of the application (at rest and in transit)

10.5.6 Describe the anti-virus solution in place, if applicable.

10.5.7 Describe the support for the hosted information for the application. (For example, End User and Application Support capabilities of the ASP)

10.5.8 Describe the physical hosting information for the application. (For example, where is the service located, do you rely on other partners?)

10.5.9 Describe the scalability of the application.

10.5.10 Describe the release strategy for your product.

10.5.11 Describe the vertical application integration barriers of the application. (For example, are there any key barriers to integration and customization?)

10.5.12 Do you have previous experience in migrating data from legacy systems (other than your own) to your application(s).

10.5.13 Do you have native integration to SAP or is a custom integration using SAP PI required? Please describe.

10.6 Organization

10.6.1 Have you supplied the proposed solution to other utilities sectors, either directly or through a partnership with a System Integrator?

10.6.2 Do you have a "road map" for this product over the next five (5) years? Please provide details.

10.6.3 Please provide details of previous successful implementations with other clients.

10.7 Change Management and Change Controls

10.7.1 Are any principles of the systems development lifecycle (SDLC) methodology followed with respect to application systems?

10.7.2 How are changes to configurations or patch management handled within your system?

10.7.3 Do you support the validation of changes in non-production environments prior to applying changes to the production environment?

10.7.4 How can the impact to the system from changes to the application be validated?

10.7.5 Do you manage multiple instances prior to changes in systems?

10.7.6 Is your solution cloud based?

10.7.7 How is your cloud based solution configurable?

10.8 Security Change Management

10.8.1 How are security patch notifications and evaluations performed prior to applying any changes?

10.8.2 What is the procedure for testing and evaluating the impact of applying security patches on devices prior to apply in the production environment?

10.9 Bandwidth Requirements

10.9.1 What is the proposed bandwidth for your solution? Please justify.

10.10 Reliability

10.10.1 Describe how high availability is achieved by the solution as a whole, as well as by key critical components. Diagrams are welcome.

10.10.2 Describe how disaster recovery across multiple data centers is achieved by your solution.

10.10.3 Describe how data archival and records retention is supported and managed by your solution.

10.10.4 Describe how database replication is supported by your solution.

10.10.5 Explain in detail how scalability is achieved across your solution.

10.10.6 Describe the backup architecture for your system.

10.10.7 Describe how performance optimization is achieved across your solution

10.10.8 Describe how your solution should be monitored, and the monitoring technologies that are supported.

10.10.9 Describe how load balancing is supported, and for what solution components you recommend.

10.10.10 Describe how downtime is minimized for configuration changes and upgrades.

10.10.11 Describe how automative failover and recovery are supported.

10.10.12 Describe how your solution supports multi-side deployments.

10.10.13 Can your application records be archived?

10.10.14 Do you have native archiving, or have a relationship with an archive vendor?

10.10.15 Do you have version control for configurations and customizations?

Overview and Bidder Instructions

Dear Bidder,

You have been invited by Xcel Energy Services Inc. (hereinafter referred to as “Xcel Energy”) to submit information in response to a request proposal (“RFX”). This document contains important information about Xcel Energy and the RFX and we suggest you take the time to read it carefully. We look forward to your proposal submission using our electronic sourcing system (the “eSourcing System”).

Thank you.

About Xcel Energy at www.xcelenergy.com

Our name reflects our core value — excellence in energy products and services. We are dedicated to providing you the best in service, value and information to enhance your professional and personal life. We are committed to customer satisfaction by continuously improving our operations to be a low-cost, reliable, environmentally sound energy provider. We have been successfully proving this to our customers for more than 130 years and will work hard to continue with this commitment in the future.

As a leading combination electricity and natural gas energy company, we offer a comprehensive portfolio of energy-related products and services to 3.4 million electricity customers and 1.9 million natural gas customers.

We have regulated operations in 8 Western and Midwestern states, and revenue of more than $9 billion annually; and own more than 35,000 miles of natural gas pipelines. We are proud of our community involvement. Through the Xcel Energy Foundation, our economic development activities, and employee volunteer efforts, we are committed to using our considerable resources and skills to benefit the communities we serve.

Our environmental policy states that Xcel Energy will be valued as a leader in the energy industry by demonstrating excellence in environmental performance. The most recent National Renewable Energy Lab's ranking of green pricing programs ranked our Windsource® and Renewable Energy Trust first in number of customers and fifth in energy sales out of over 500 U.S. utilities. Our key environmental commitment includes improving air quality, conserving resources, harnessing renewable energy, and protecting wildlife and habitats.

Proposal Evaluation Criteria

Xcel Energy’s objective in sourcing via the eSourcing System, Emptoris, is to obtain goods and services that best meet technical and functional requirements at the best price. Proposals will be evaluated by Xcel Energy on the basis of the information provided by you through the eSourcing System. The lowest price proposal may not indicate the best overall evaluated proposal. The following criteria may be used by Xcel Energy in its consideration (not necessarily listed in order of importance):

- Bidder’s understanding of and responsiveness to the scope of work, technical specifications and other requirements
- General feasibility of the bidder’s plan to meet the requirements of the scope of work and/or technical specifications
- Bidder’s ability to meet the stated work schedule
- Bidder's acceptance of the general terms and conditions
- Bidder’s experience with similar work and safety record
- The evaluated total cost of the services and/or goods
- The quality of services offered by the bidder

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- Comprehensiveness of the bidder's proposal, including options
- Bidder's diversity classification or utilization of diverse suppliers as subcontractors; and demonstration that bidder has made good faith efforts to provide maximum practicable subcontracting opportunities to diverse suppliers

Bidding Instructions

Failure to comply with these bidding instructions may disqualify a bidder from further consideration.

- Xcel Energy requires that all bidders (and their subcontractors, alliances, or partners) provide a single point of contact during the RFX process.
- In the eSourcing System, click on the green **"Accept"** button to indicate your intention to respond or click the red **"Decline"** button to indicate your intention not to respond. During the course of your review and response you can indicate that you wish to not proceed further.
- Correspondence or questions concerning the RFX content and attachments **must be sent using the eSourcing System's messaging functionality** to the Xcel Energy Sourcing & Purchasing Contact / ("Event Owner"). The name of the "Event Owner" is listed in the upper left hand corner of the RFX, labeled as "Contact Information". Instructions on how to send messages are provided in the computer based training module titled *Using System Messaging*. All responses to technical questions will be answered via the eSourcing System's messaging functionality to the RFX and issued to all bidders. Contacting anyone besides the Event Owner about this RFX may be grounds for disqualification.
- All bidding, both qualitative and quantitative, will be submitted through the eSourcing System. You will be asked to answer a number of questions, including pricing on items.
- All submissions must be submitted on time per the schedule indentified in the RFX. Late submittals will not be accepted.
- All submissions must be complete in order to be evaluated. **Incomplete submissions will not be accepted.** The bidder's proposal must be all-inclusive to provide complete and reliable services and/or goods to meet the requirements and technical specifications documented in the RFX.
- The bidder shall not alter any part of the RFX in any way except by stating all exceptions in a response to the appropriate question or as an attachment to the appropriate question with a detailed explanation for each exception.
- Any modification made to the RFX by Xcel Energy will be made through the eSourcing System.
- The bidder shall separately state in its proposal all taxes (including sales, use, and other excise taxes) it believes to be imposed by law upon the transfer of equipment or other materials to Xcel Energy or upon the provision of services. Please contact the Event Owner for applicable tax rates.
- If you have difficulties with the eSourcing System, you may contact the Xcel Energy Supply Chain Hotline at 303-628-2644 from 8:00 a.m. to 5:00 p.m. (MST) Monday through Friday.

RFX Terms and Conditions

In addition to the terms and conditions you accepted on the eSourcing System login screen, the following terms and conditions apply to the RFX:

- **Bidder's submission of proposal information in response to this RFX shall constitute bidder's agreement to these terms and conditions.**
- All costs associated with bid preparation and the provision of related documents are to be borne by the bidder.

- Xcel Energy reserves the right to open proposals privately and unannounced, and to be the sole and final judge of all proposals.
- Bidder's proposal is genuine and not made in the interest of or on behalf of any undisclosed person, firm, or corporation and is not submitted in conformity with any agreement or rules of any group, association, organization, or corporation; bidder has not directly or indirectly induced or solicited any other bidder to submit a false or sham proposal; bidder has not solicited or induced any person, firm, or a corporation to refrain from bidding; and bidder has not sought by collusion to obtain for itself any advantage over any other bidder or over Xcel Energy.
- Bidders shall take no advantage of any apparent errors or omissions in any related documents. If a bidder believes there are errors or omissions in supplied documentation or if the bidder is in doubt as to the meaning of any part of the documentation, bidder is to contact the Event Owner via the eSourcing System's messaging functionality before the close of the RFX. If Xcel Energy agrees that a change is required or if any explanation or interpretation is required, Xcel Energy will modify the RFX and notify bidders via the eSourcing System messaging functionality.
- The bidder agrees that, if its proposal is accepted, it will remove taxes from any charges to Xcel Energy upon receipt of a properly completed exemption certificate or direct pay tax license number. Except with respect to taxes imposed by law upon the transfer of equipment or other materials to Xcel Energy, the bidder shall pay all other taxes, tariffs, import duties, entry fees, permit fees, license fees, and other charges of any kind incurred in performing the activities contemplated by its proposal; and all such expenses shall be included in the price. If the bidder is in doubt about whether it may incur any such expense, and it would reduce its charges to Xcel Energy by the amount of such expense in the event such expense is not incurred, then the bidder shall explain the nature and amount (if known) of any such expense in its proposal.
- Xcel Energy reserves the right to reject any or all proposals, including without limitation the rights to reject any or all nonconforming, non-responsive, irregular or conditional proposals and to reject the proposal of any bidder if Xcel Energy believes that it would not be in the its best interest to make an award to that bidder. Bidder agrees that any such rejection shall be without liability on the part of Xcel Energy nor shall bidder seek any recourse of any kind against Xcel Energy because of such rejection.
- Xcel Energy may enter into discussions with the bidder proposing the best overall evaluated offer on the terms of the attached general conditions, scope of work and/or technical specifications, and other attachments.
- All proposals shall become the property of Xcel Energy.

Additional Information

For additional eSourcing System information, visit https://www.xcelenergy.com/working_with_us/suppliers

Electric AMI Meters and Installation
Request for Proposal v12
February 21, 2018

Table of Contents

1 Introduction and Background

Xcel Energy Services Inc. and its operations affiliates (collectively, for purposes of this Request for Proposal (RFP), "Company") are proceeding with establishing Advanced Metering Infrastructure (AMI) as a fundamental and essential component to an implementation of Company's Advanced Grid Intelligence and Security (AGIS) initiative.

In this RFP, Company solicits Proposals from vendors (hereafter referred to as "Suppliers"), for the supply of electric Meters and electric Meter exchanges (installation). Such Meters shall be required to be technically and operationally compatible with a Head-end and Network acquired from Itron Networked Solutions (INS) (previously Silver Springs Networks (SSN), under a separate contract.

Currently, Company only intends to enter into a firm commitment for the supply of electric Meters for Company territories served by the PSCo (Colorado) Operating Company. As such, Company seeks firm bids for the supply of electric Meters and the installation of electric Meters in the PSCo region. Company also seeks information and indicative pricing for an enterprise-wide deployment of electric AMI Meters.

Suppliers who are adequately qualified are invited to respond to this RFP following the instructions that are provided in this document set.

1.1 Abbreviations, Short Forms, and Acronyms Used in this Document

Refer to Appendix 1 for a detailed list of abbreviations, definitions, short forms, and acronyms.

1.1.1 Nomenclature Concerning "Meters" with Capitalized "M"

For clarity, in this document the word "Meter" with a capital "M" means an electric meter that is suitably equipped with a Network Interface Card (NIC) also known as an electric AMI Meter. A "Meter" consists of a carefully calibrated measurement instrument that is normally connected to a wireless network by way of a NIC, for residential or commercial and/or industrial applications.

1.2 AMI Meter Vision and Priorities

Company AMI Meter strategy is to coordinate integration of a multitude of business needs and applications into a common platform that can be leveraged enterprise wide by Company's business units. Company has selected Itron Networked Solutions as its AMI network solution provider.

AMI data will provide Company a return on investment and make a positive impact on moments-that-matter in the customer lifecycle. AMI provides enhanced functionalities such as:

1. Voltage metrics for Integrated Volt/VAR Optimization (IVVO) application.
2. Premise-specific information to corroborate Momentary Average Interruption Frequency Index (MAIFI) events.
3. Premise-specific outage management and storm restoration capabilities, including near real-time views of restorations.
4. Power quality event capture, to enhance response time and proactively resolve distribution problems.
5. Tamper and energy theft detection in collaboration with data analytics.
6. Distributed Energy Resource (DER) monitoring.
7. Remote electric service connect/disconnect capabilities, reducing truck rolls.
8. Scheduled and on-demand Meter reading, enhancing billing and customer management.
9. Provide customers with data enabling more efficient energy use.
10. Ability to offer variable rate structures such as CPP, PTR, TOU, etc.
11. Provide enhanced demand response programs.

12. Enable use of downstream monitoring devices for special rates, e.g. DER and Electric Vehicle (EV) charging.
13. Maximizing life of existing or new infrastructure.

Company's wireless mesh network will adhere to the Neighborhood Area Network (NAN) Field Area Network (FAN) profiles that are founded on the IEEE 802.15.4g and IEEE 802.15.4e standards. This results in a cohesive, standards-based, wireless mesh network intended to provide reliable network services across a wide geographic area, all owned and managed by Company.

When fully deployed, the network will be fault tolerant in design and topology and be multi-tenant in nature, meaning multiple applications will share the same communication infrastructure. The multi-tenant nature of the network has mandated the necessity to implement the network with proven, reliable, and efficient end-to-end message priority forwarding protocols.

Company has a companion WiMAX (Worldwide Interoperability for Microwave Access) project underway, for the primary purpose of establishing a wireless backhaul backbone for much of the service territory. WiMAX is a point-to-multipoint technology providing broadband data services and an extensive Quality of Service (QoS) feature set. In the context of this AMI project, WiMAX will be the data backhaul technology of choice for mesh networks. WiMAX will be used at transition points from the mesh network to provide transport services along a path toward Company's core network.

Company places priority emphasis on its cyber and physical security programs. Company seeks to continuously and proactively plan, refine, and exercise appropriate levels of attention, action, and response to security issues and threats to the intelligent grid. This project will help to ensure all AMI and FAN components are identified and protected, both for the protection of customers and for the reliable and safe delivery of energy to customers. Additionally, Company will apply its cyber security program to validate sufficiency of security controls that are integrated with the AMI Meters. These activities, and others, help to protect, proactively and reactively provide customer privacy, detect suspicious behavior, events and/or anomalous activity, and provide the information necessary to respond to and mitigate security threats.

Company strives to adhere to world and industry standards in ways that promote multi-supplier interoperability, industry innovation, and operational flexibility, and that are exampled in such domains as Wi-Fi, Ethernet, and 3GPP. Company is a Wi-SUN Alliance member and supporter, and stands behind the basic principles of the organization. This will enable Company to realize value when installing successively new generations of Meters. This is a goal toward which Company expects that its Supplier will adhere.

1.3 Project Scope of Supply

1. The Scope of Supply is inclusive of the following items:

    a. Electric Meters, meeting the requirements, as outlined herein.
    b. Optional Electric Meter Installation as outlined herein, in Section 8.
    c. Warranty provisions covering supplied goods in Section 9.

2. Subsequent to a successful RFP process, Company may award a bid to a single Supplier, or multiple Suppliers, for various items in the Scope of Supply.

3. The table below indicates electric Meters that are presently acceptable for supply to Company. Company will qualify and acceptance test future meter types that may become commercially available to maintain up-to-date technologies and applications.

Table 1: Electric Meter Models/Series

Elster	Residential RX4

Elster	Commercial A4
Itron	Residential Centron II
Itron	Commercial Centron Poly-phase
Aclara	Residential I-210+
Aclara	Commercial KV2c
Landis+Gyr	Residential Axe-SD
Landis+Gyr	Commercial S4x

4. Goods shall be supplied to Company in quantities and with options that are specified in the Electric AMI Master Pricing Template v1.0.xlsx. Company expects Supplier to provide pricing for both bundled and unbundled services and goods. Bundled pricing is for Suppliers that offer discounted pricing for some of the components if goods and services are bundled together. Unbundled pricing assumes various components could be awarded to multiple Suppliers.

5. During AMI Meter deployment, in August of each year, Company will provide Supplier with anticipated Meter purchases by month for the following year. Refer to Appendix 4 for the anticipated electric Meter purchase timelines for purchase and delivery of Meters to support the PSCo deployment.

6. All supplied Electric Meters shall be equipped with the INS Generation 5 NIC as specified herein, including but not limited to:

   a. 32MB of RAM for residential and commercial NICs.
   b. 600 kbps speed for residential and commercial NICs or other options Company might select in the future as offered by INS.
   c. HAN Radio.
   d. 5-year all-inclusive warranty on residential and commercial NICs. Base Meter price shall reflect 5-year all-inclusive warranty.
   e. All future options as selected by Company and offered by INS.

7. Electric AMI deployment schedule. (Note: PSCo deployment dates are firm. Deployment in other Operating Companies is conceptual and subject to change based on Company planning development and regulatory alignment.)

   a. PSCo (CO)
      i. Electric Meters
         1. 1% in 2019 – 15,876 Meters: Begin Q2 2019
         2. 10% in 2020 – 158,760 Meters: Begin Q1 2020
         3. 25% in 2021 – 396,901 Meters: Begin Q1 2021
         4. 30% in 2022 – 476,281 Meters: Begin Q1 2022
         5. 29% in 2023 – 460,405 Meters: Begin Q1 2023
         6. 5% in 2024 – 79,380 Meters: Q1 2021 – Finish Q2 2024

   b. NSPM (MN)
      i. Electric Meters
         1. 1% in 2019 – 17,500 Meters: Begin Q3 2019
         2. 7% in 2020 – 98, 000 Meters: Begin Q1 2020
         3. 10% in 2021 – 140,000 Meters: Begin Q1 2021
         4. 45% in 2022 – 630, 000 Meters: Begin Q1 2022
         5. 37% in 2023 – 477,000 Meters: Begin Q1 2023
         6. 7% in 2024 – 36,000 Meters: Begin Q1 2024 – Finish Q2 2024

   c. NSPM (ND)
      i. Electric Meters
         1. 50% in 2020 – 50,000 Meters : Begin Q1 2020
         2. 50% in 2021 – 50,000 Meters: Begin Q1 2021 – Finish Q4 2021

   d. NSPM (SD)

i. Electric Meters
    1. 50% in 2020 – 50,000 Meters : Begin Q1 2021 - Finish Q4 2022
    2. 50% in 2021 – 50,000 Meters: Begin Q1 2022 – Finish Q4 2022

e. NSPW (WI and MI)

i. Electric Meters
    1. 30% in 2023 – 84,000 Meters: Begin Q1 2023
    2. 40% in 2024 – 112,000 Meters: Begin Q1 2024
    3. 30% in 2025 – 84, 000 Meters: Begin Q1 2025- Finish Q4 2025

f. SPS (TX and NM)

i. Electric Meters
    1. 50% in 2023 – 205, 000 Meters: Begin Q1 2023
    2. 50% in 2024 – 205, 000 Meters: Begin Q1 2024 – Finish Q4 2024

1.4 Essential Requirements for Detailed RFP Assessment

Per Section 2.1 of this RFP, Supplier responses will be assessed by Company in detail on the condition that Supplier is able to satisfy Company that they are capable of meeting and/or exceeding the essential requirements set out here.

Responses to this RFP that fail to satisfy Company that Supplier has the ability to meet these essential requirements, might result in Company not conducting a detailed assessment of Supplier RFP responses.

The essential requirements are:

1. Supplier demonstrates the capacity, or offers assurances for factory output capacity, that meets Meter delivery requirements.
2. Supplier demonstrates compliance to requirements outlined in section 3.4 and Supplier is qualified, capable, and equipped to offer and deliver all or some of the items identified in the scope of supply in Section 1.3, suitably equipped with communications interfaces and with all of the necessary features and functionality that are necessary to interface to Company's network and Head-end systems.
3. Supplier satisfies Company that:
    a. Supplier has executed a legally binding reseller agreement with the third party NIC Supplier (Itron Networked Solutions) that meets or exceeds the legal and contractual conditions set out herein) and evidences its legally binding reseller agreement with the third party NIC Supplier as an attachment to the response to this RFP.
    b. Supplier has, or will have, fiscally sound, business amicable, and legally binding Joint Development business arrangement with Itron Networked Solutions that guarantees that:
        i. Includes, in its third party legally binding reseller agreement, full scope partnering relationships that guarantee Company ongoing product supply, and that include the unified benefits of electric metrology and NIC enhancements beyond the current generation of products for a period of twenty (20) years.
        ii. Grants adequate influencer rights to any any Joint Technology Development arrangement with Company.
4. Per Sections 6 and 7, Supplier offers full feature support for the following classes and forms of electric Meter models listed in Section 1.3:
    a. Class 20 forms 3S, 5S, 6S, 9S, 36S and 45S
    b. Class 200 forms 1S, 2S, 12S and 16S

   c. Class 320 forms 2S, 12S and 16S

5. Per Sections 6 and 7, concerning essential operational features:
   a. All residential type electric Meters are capable of measuring voltage, current, temperature, power, reactive power, apparent power, power factor, and harmonics.
   b. Reactive energy is made available as a load profile interval channel recording alongside other energy quantities, e.g. kWh.
   c. All electric Meter types are offered and equipped with optical ports with metal rings for magnetic connection.
   d. All electric Meters are equipped to sense and measure internal Meter temperature, and the parameter is made available as a load profile interval channel recording, along-side other energy measurement quantities. Additionally, electric Meter is equipped to provide an alert on internal user-defined Meter temperature threshold.
6. Supplier Meter offerings are inclusive of the Itron Networked Solutions Gen 5 NIC and Supplier demonstrates long-term, progressive, three-way business/technology relationships.
7. Supplier adheres to and adequately demonstrates that it adheres to Company's main cyber security principles, that is:
   a. Utilize cyber security best practices based on standards established by various government organizations such NIST, IEEE, IEC, SEPA, etc.
   b. Defense-in-Depth: Ensures there are multiple layers of protection and detection defined.
   c. Zero Trust: Creates isolation points within the information network so only specific hosts are able to communicate with other specific hosts.
   d. Tightly-Controlled Access: Ensures only necessary people and systems are able to access devices or software.
   e. Least Privilege: Only necessary individuals and services are allowed to interact with devices.
   f. Hardened Equipment with Hardened Operating System (Meter Operating System): Only necessary ports and services are open and running on the systems and devices.
8. Suppliers wishing to participate in the AMI Meter Supply RFP process shall participate in testing of the proposed Meters. The testing program will be carried out by Company with Supplier support.
9. Company prefers electric meters that do not require batteries for operation. If Supplier requires batteries for meter operation, Supplier is required to provide details on batteries that include, but are not limited to: battery manufacturer and specifications, performance under various conditions, expected life, etc.
10. Section 6.3.19 (Residential section) and 7.3.19 (Commercial section) of this RFP shall apply to AMI meters deployed in the PSCo territory.

2 General Provisions

2.1 Invitation to Bid

1. This RFP invites Suppliers to submit proposals setting forth all terms, including pricing, for provision to Company, of the equipment and services listed herein, at all of the required locations set out herein.
2. Suppliers are required to provide insurance documentation, security questionnaire, and complete a subcontracting diversity form.

3. Suppliers who are participating in this RFP are required to confirm that they are able to supply equipment and services that are functionally in-line with Company's vision, and in substantial conformance to the Essential Requirements set out herein.

4. Prior to carrying out a thorough assessment of Supplier responses, Company will evaluate Supplier responses to the Essential Requirements (Section 1.4), and where Suppliers are able to demonstrate that their solutions are sufficiently in compliance with Company's vision and requirements, the balance of the RFP response will be comparatively assessed against functional and technical requirements of the RFP.

5. In order to propose the provision of the Equipment and/or Services as specified in this RFP, Supplier, in addition to any other requirements in this RFP, shall:

   a. Have signed the pre-requisite Confidentiality and Non-Disclosure Agreement with Company.

   b. Have significant, demonstrable experience providing the same or similar AMI Equipment and Services as those identified herein.

   c. Be able to provide the Services and/or Equipment at all of the required locations set out herein, either by itself or through a subsidiary, affiliate, parent company or its partner, all of whom are otherwise qualified as defined in this RFP.

   d. Demonstrate that its financial situation is sound (refer to Section 3.4–Corporate Profile).

6. In order to propose the provision of any components of this RFP, Suppliers must comply with the applicable requirements of this RFP.

2.2 Critical Dates in the RFP Process

Table 2: Critical Dates for RFP Processing

No	Scheduled Item	Required Schedule
1	RFP Released to Suppliers	March 8, 2018
2	Multi-Round Vendor Clarifications	March 9, 2018 - March 22, 2018
3	Meter Qualification Testing	Begin October 25, 2017; end May 16, 2018
4	RFP Responses Delivered to Company	March 29, 2018
5	Supplier Onsite Presentation	April 2 – 5, 2018

2.3 Instructions to Suppliers

The following instructions are additional to those provided in the attached document titled: Instruction to Bidders. Instruction to Bidders can be downloaded from Company Emptoris website.

2.3.1 Company Emptoris Response Procedures

1. Suppliers are required to respond to this RFP using Company Emptoris Secure Internet Sourcing System. Follow the instructions set out herein:

   a. Logon to Xcelenergy.esourcing.emptoris.com.
   b. Enter Supplier Username in the Name field.
   c. Enter Supplier Password in the Password field.
   d. Click the Login button.
   e. From the Main Menu, select RFx(s) > Manage RFx(s).
   f. Locate the RFx Name in the list of RFx(s).
   g. Click on the RFx Name link to view the RFx.
   h. Click the green "Accept" button in order to enable response function.

2. Note: Once you have reviewed the RFP material, please click the Green "Accept" button as your intention to bid or the Red "Decline" button as an indication that you will not be participating.
3. Be sure to answer all questionnaires and questions.
4. Pricing shall be submitted via the "Single Bid" tab or "Multibid" Tab. Please adhere to the format, no other formats will be accepted unless otherwise approved by Company.
5. Suppliers are required to address the following documents which are attached to the event. Please download these, and upon review, upload your return documents with your "Supplier name + original document name" included in the file name so submissions may be deciphered. Documents include:
    a. This RFP.
    b. Instructions to Bidders.
    c. Sample No Opportunity for SUB Letter.
    d. Sub-Contracting Plan.
    e. Sample Insurance Certificate.
    f. General Conditions Major Supply Agreement – Any redlines should be documented on the original document and returned as an attachment. Note that any exceptions will be weighted and may preclude Supplier from further engagement in the sourcing process.
    g. Company Electric AMI Master Pricing Template v1.0.xlsx.
    h. Safety Program Requirements.

2.3.2 Response Requirements

1. Suppliers are required to respond to this RFP with a wholly compliant response. That is, a response that is intended to directly, and without modification to the terms and requirements, meet and/or exceed the terms and requirements set out herein, and be inclusive of full and complete pricing.
2. Where Suppliers are responding with a whole and complete compliant response to this RFP, Suppliers are invited to offer separately prepared, and separately attached, RFP response Amendments that present Company with alternatives. Under such conditions, Suppliers must:
    a. Have first prepared and completed a wholly, and fully priced response to this RFP.
    b. Not alter Company's methodology for Network and Head-end design and buildout.
    c. Document the proposed amendment(s) in the form of one or more fully priced options that Company may or may not avail itself.
    d. Include, in its proposed amendment(s), full and complete descriptions, and demonstrate the technical, operational, and economic benefits of the amendment.
    e. Include, in its amendment(s), clear statements that define any business, operational, or technical implications if Company chooses any of the proposed amendment(s). Such include, but are not limited to: long term support implications, any remedial work that may be required, implications to other Suppliers with whom Company is conducting business.
    f. Include, in its amendment(s), full and complete pricing, including components of pricing where prices may increase or decrease so as to achieve the benefits of the proposed amendment.

2.3.3 Pricing Methodology

1. Pricing is structured and tendered into various components:
    a. Electric Meters
    b. Optional Electric Meter Installation
    c. Warranty Provisions

2. Supplier pricing shall include volume breaks/volume discounts.
3. Suppliers are required to tender pricing through completion of the pricing template attached here as: Electric AMI Master Pricing Template v1.0.xlsx.
4. Following a period of assessment and negotiation, Company expects to:
    a. Form a Major Supply Agreement (MSA) and companion Statement of Work (SoW) for all, or a portion, of the supply components.
    b. Optionally, select and award one or more Meter Installation offer(s).
    c. Optionally, select and award one or more of the components outlined in Section 1.3 on scope.
5. Supplier shall offer pricing that is valid for at least nine (9) months from receipt of RFP responses.
6. Supplier to also include pricing for facility rental or warehousing space required to support deployment activities.

2.3.4 Pricing Modules

1. Pricing is required to be tendered in the form of itemized tables in the Xcel Energy Electric AMI Master Pricing Template v1.0.xlsx.

2.3.5 2018 Tax Reform

1. It is understood that most US corporate entities will benefit from the corporate tax reform aspects of the 2018 Tax Cuts and Jobs Act. Supplier shall engage in open book discussion with Company about the impact of the tax reform, primarily but not limited to that benefit derived from the reduction in the corporate income tax rate, and share transparently how this is taken into account in the development of pricing provided in response to this RFx?

2.3.6 Managing Questions and Inter-Company Communications

1. Prior to submitting questions, Suppliers are requested to review the full RFP, formulate Supplier's questions, and submit them via the Emptoris portal in compliance to the schedule. Company will then respond to Supplier's questions in compliance to the schedule.
2. Questions are required to be submitted in batched written format. Please batch Supplier's questions using two (2) segments: 1) Electric Meters and 2) Electric Meter Installation.
3. All questions and answers will be distributed equally to all participating Suppliers for transparency purposes.
4. Suppliers are directed to communicate all questions via Company Sourcing: contact Edem Umoh (612-342-8945) or Dan Pendar (612-330-6521).

2.3.7 Evaluation Procedures for Proposals

1. Where Supplier Responses meet evaluation conditions set out in Essential Requirements–Section 1.4 herein, Supplier's response will be evaluated considering the following:
    a. Testing evaluations
    b. RFP Proposal Responses, including ability to meet industry acceptable standards
    c. RFP Pricing
    d. Acceptability toward synchronization with Company goals and vision
    e. Ability to meet execution timing
    f. Ability to meet Company's current and future needs

2.3.8 Contact Information

Suppliers are required to include in their response a table indicating the parties with whom Company may communicate in regard to the content of individual Sections. The following Table is a reference template:

Table 3: Contact Information – Example Supplier's Fill-in Table

RFP Section	Business Area	Team Member	Lead or Subject Matter Expert	Email Address	Telephone No.
	Business Terms and Conditions				
	AMI Electric Meters				
	Electric Meter Installation Services				
	Third Party Contractual Arrangements				
	Warranties				
	MSA				
	Installation Services				

2.3.9 Required Submittals

Suppliers responding to this RFP are required to submit the following documentation, attached in the form of Annexes.

1. Meter and NIC Supplier's detailed product description:
    a. Description including part number, circuit board revision number, firmware revision number
    b. Circuit design block diagram
    c. Photograph of a completed Meter and NIC
    d. Performance Specifications of Meter
    e. Detailed list of Meter and NIC events to include fatal, diagnostic, informational, or any other event type
2. For each electric Meter type, form, and class submitted, a report, authored and signed by the NIC and Meter Supplier that presents the nature and results of the regression tests, and that confirms all of the necessary tests have been completed, and that the NIC and Meter Supplier are satisfied that the NIC together with Supplier's electric Meter will perform in compliance with Supplier's specifications and the requirements stated herein.
3. For each electric Meter, evidence of compliance to FCC, IEEE, OSHA, and ICNIRP RF safety standards while operating in a dual band NAN/HAN mode.
4. Electric Meter, measured azimuth and elevation antenna radiation patterns for horizontal and vertical polarization taken at ~915 MHz. Measurements must be taken under the condition of co-operation of the HAN radio, and when mounted on a metallic electrical enclosure in a manner that is typical for home or industrial installations, as the case may be.
5. Electric Meter, measured azimuth and elevation antenna radiation patterns for horizontal and vertical polarization taken in the 2.4 GHz ZigBee band, or subsequent frequency used for HAN. Measurements must be taken under the condition of co-operation of the Wi-SUN radio, and when mounted on a metallic electrical enclosure in a manner that is typical for home or industrial installations, as the case may be.

6. Documents that outline detailed description, including sensor types used, of the mathematical algorithms and theoretical accuracy and precision that are used to calculate power factor.
7. Detailed test results for internal service switch for Class 200 and Class 320 Meters.
8. Electric Meter Supplier's product description sheet for each Meter type, form, and class that is proposed to be supplied, including no less than:
    a. List of supported functional features
    b. List of data elements available
    c. Technical specifications
    d. Performance specifications: speed, accuracy and precision
    e. ANSI C12 compliance data
    f. Physical dimensions
    g. Security compliance
    h. NEC compliance reports
9. Provide documentation related to item 1.4.9 above on use of batteries.
10. Provide AMI Meter technology roadmap.
11. Provide documentation related to various power factor calculation methodologies as it relates to items in Section 6.3.11.8 and 7.3.11.8.

3 Business Terms and Conditions

3.1 Additional Business Terms and Conditions/Pricing

In addition to any Business related Terms and Conditions and other legal/business matters outlined in attachments to this RFP, the following conditions are appended:

1. Suppliers are requested to outline the value-added services (above and beyond those outlined within this RFP), that Supplier's organization will bring to Company for this project at no additional cost to Company.
2. Suppliers must outline the cost take-out guarantee which Supplier's company will provide to Company over the life of this Agreement. Please provide examples and formula for tracking.
3. Suppliers are required to review and accept the General Conditions for Major Supply Agreement document. Supplier may provide exceptions on the document and submit, as an attachment, back to Company for review. Note that exceptions will be weighted and may preclude Supplier's company from further engagement in the sourcing process.
4. Suppliers will provide a high-level overview of what the market is currently tracking as success metrics utilized to gauge the success of deployment projects of this scope (please include economic and technical considerations). Supplier will be expected to provide success tracking dashboards for reporting purposes if awarded this business.
5. Suppliers are required to inform Company in writing of any foreign nationals, including subcontractors, who will work-on or provide advice concerning the contents of this RFP/project and its outcomes.
6. Company shall require advanced engineering change notification for all hardware and firmware changes. Changes should include risk/impact assessment.

7. Supplier shall notify Company of any reliability/failure causes known by Supplier and attributed to their product.
8. Company shall on an annual basis review Supplier roadmap to ensure alignment with Company goals and expectations.
9. Meter handling and installation personnel in NSPM and NSPW shall be International Brotherhood of Electrical Workers (IBEW)or other Union represented.

3.2 Supplier Support Options for AMR to AMI Transition

1. During deployment of Company's AMI, NSP Minnesota and NSP Wisconsin Operating Companies will transition from an AMR technology utilizing a managed services business model to a Company-owned and operated AMI environment. What would you, as the Meter Supplier and/or Meter exchange provider, offer or provide to enable Company to realize customer satisfaction, meter reading and billing continuity, and efficiencies and reductions in transitional operating costs? Please attach Supplier's plan as a standalone exhibit.

3.3 Executive Level Support

1. Suppliers are required to provide a statement indicating the level of corporate commitment to which Supplier is undertaking. Indicate no less than:
    a. Statement of commitment to Company articulating the key elements where executive commitment brings value to Company's Projects.
    b. Names and positions of executives who represent the commitment.
    c. Manner in which executive level support is applied to Supplier's customers, specifically to Company and to Supplier's internal resources.
    d. Manner in which Executive Level Support is executed where it relates to Supplier's own hierarchy of internal resources.

3.4 Required Corporate Information/Supplier Profile

1. Suppliers are required to submit corporate profile related information as follows:
    a. Supplier legal name
    b. Supplier contact information: phone, fax, email, websites
    c. Postal mail address of business headquarters and field offices
    d. Supplier names, including international, of organizations that sell and/or resell Supplier equipment and services
    e. Dunn and Bradstreet #, ABA#
    f. W9 detail, invoice remittance, and banking information
    g. Diversity certification
    h. Corporate history since inception
    i. Corporate mandate including:
        i. Mission
        ii. Business sectors in which Supplier is operating (water, gas, electric, smart cities, etc.)
        iii. Percentage of revenue generated by electric/gas utility markets in past three (3) years
        iv. Description of projects taken on in last ten (10) years that are similar, including:
            a. Exact system installation and generation as proposed for this RFP
            b. US dollar value of the project
            c. Nature of the project (Metering, DA, Smart Cities, etc.)
            d. Customer reference: names, email address, and phone number

e. Project scope and scale compared to Company's

3.5 Obligations of Company

3.5.1 General Obligations

Company will:

1. Be reasonably available for questions and meetings in a timely manner during normal business hours.
2. Provide contact list, including a Project/Program Manager single-point-of-contact for Company's Meter organization, of Company managed project resources and stakeholders.
3. Coordinate and provide required security clearances and/or escorts to access the site and facilities for completion of the services described in this RFP within Company's standard security response times. Unescorted Access security clearance times may average between 2-4 weeks, and Supplier shall plan accordingly.
4. Execute according to the agreed-upon plans at hand-off/interface points, including the completion of material responsibilities assigned to Company in any SoW that results from this RFP.
5. Assist Supplier in discussions with any third party that Company requires Supplier to manage within the scope of the project, and authorize Supplier to manage and direct such third parties on Company's behalf, if necessary.
6. Reserve the right to witness and inspect the project work at any time.

3.5.2 Obligations Regarding Project Management

Company will:

1. Provide the high-level project schedule.
2. Designate a Project Manager.
3. Provide site documentation, drawings, and master records (if available).
4. Assist Supplier in the creation, distribution, and adherence of an overall project schedule.
5. Take reasonable steps to execute and deliver on required tasks in a timely manner.

3.5.3 Obligations Concerning Electric Meter Deployment

Company will:

1. Use an electronic work order system, or functional equivalent, that collects barcode data and GPS coordinates for each location where Meters and mesh network transition equipment is installed. Supplier can offer alternative use of own work order management system. If alternative Supplier work order management system is proposed, Supplier shall provide detailed operational description and integration to Company business systems requirements.
2. Following training by Supplier, perform all field investigations and remediation of AMI Meters as applicable.
3. Complete all tasks necessary to inventory and warehouse Meters where applicable.

3.5.4 Obligations Concerning Back Office Setup

1. Where it is determined to be necessary for support and maintenance requirements, establish a business-to-business (B2B) and/or virtual private network (VPN) connection from Company back office to Supplier back office systems environment. Each Party shall pay for its cost to set up its end of B2B/VPN connection(s).

3.6 Obligations of Supplier

1. Notwithstanding the details of Supplier and Company obligations stated herein, Supplier shall state the obligations that are necessary for Company to accept for Supplier to fulfil its obligations under this RFP. The statement of Company obligations shall:

    a. Be in the form of a list of resources required by role and responsibilities.
    b. Indicate the timeline that is required for the requirement to be completed by Company.
    c. Include any equipment to be supplied by Company or by any third party.
    d. Include any services to be supplied by Company or by any third party.
    e. Include any additional commitments required from Company to deliver.

2. All documentation supplied or submitted to Company shall be in the form of MS Office 2010 formats, unless otherwise approved by Company.

3. Supplier shall assign and provide a secure de-militarized zone (DMZ) where the product upgrades/patches, etc. are downloaded and applied.

3.7 Obligations of Supplier Project Manager for Optional Electric Meter Installation Services

Where Supplier is authorized to carry out the optional AMI Meter installations, as specified in Section 8, Supplier's Project Manager shall at least perform the following functions:

1. Coordinate with Company Network, Head-end, and Meter Deployment Managers, and third-party Integration Project Managers, to identify and manage project dependencies.
2. Participate with Supplier Delivery Manager and with other AGIS teams on cross-program activities, including dependencies, risk mitigation and issue management, problem solving, optimizing schedules to meet milestone dates, and testing and defect resolution.
3. Be responsible for leading Company, Supplier, Meter Supplier, and third-party Contractor activities diligently toward project success against Meter deployment scope, performance, and schedule and budget metrics.
4. Be responsible in securing cross-docking facilities to support Meter deployment.
5. Ensure project resources comply with Company's onboarding process.
6. Lead a project kickoff meeting in Denver, Colorado. Supplier shall use the session as an opportunity to gather detailed project requirements, and to gain a full and detailed understanding of the project scope. Company's Network Project Manager, Head-end Project Manager, Supplier Delivery Manager, and installation Contractor representatives shall attend the kickoff meeting. At, and associated with, the kickoff meeting:
    a. Ensure all Company onboarding, Company training, and security screening processes are followed.
    b. Ensure Company safety performance standards are followed or exceeded.
    c. Develop details of the project scope, WBS, and schedule.
    d. Document assumptions, constraints, and dependencies.
    e. Commence details of gathering Meter deployment requirements.
    f. Finalize the Meter installation plan.
7. Develop an initial formulation of installation requirements that are in conformance to Meter Installation details contained herein.
8. Act in the role of single point of Meter deployment contact (SPOC) on behalf of Supplier project team.
9. Coordinate project activities from the initial kick-off meeting through delivery of all Agreement elements, as well as any tasks mutually agreed to through a documented change order process, until final acceptance.
10. Under oversight of Company's Business/Meter Project Manager, direct the project activities by way of assigning tasks and responsibilities and monitoring project progress and performance against task completion status, acceptability of performance, and project milestones.

11. Prepare and issue weekly progress status reports, which are first approved by Company Project Manager, and lead project status meetings by telephone or in person following Company AGIS reporting mechanism.
12. Maintain and distribute all documentation by way of email, or by electronic means determined by Supplier and Company to be most efficient and in the interest of both parties.
13. Proactively identify, document, communicate, and mitigate risks and issues. Report deficiencies and concerns proactively on an ongoing basis.
14. Coordinate with Company Meter Deployment Project Manager on Meter first article testing (FAT) process, associated training, and acceptance testing of new Meter shipments.
15. Coordinate with Company Meter Deployment Manager on the delivery of production Meters between Meter manufacturer and Company Meter Deployment Project Manager.
16. Where Supplier's Project Manager is directing or participating in the direction of work for which there are components of work attributable to Company, they shall be carried out through a process in which the work assignment is initiated, carried out, and monitored through Company's Project Manager.
17. Review the Contractor responsibilities with Supplier and Agreement with Company Meter Deployment Project Manager.
18. Lead planning and execution of Supplier project activities from the initial kick-off meeting through delivery of all contract elements, as well as any tasks mutually agreed to through a documented change order process, until final acceptance. This includes project status, change control, scope, risk, communication, schedule, issue, budget, and deliverable management for activities as defined in the Installation plan.
19. Prepare and maintain the project plan which lists the activities, tasks, assignments, effort, dependencies, and milestones for performance of the Installation scope.
20. Lead weekly project status meetings. Schedule additional meetings as needed.
21. Prepare and submit weekly status reports, in format provided by Company, to Company Distribution Business Operations/Meter Project Manager.
22. Coordinate and manage the activities and facilities of Supplier and Contractor project personnel.
23. Direct the project activities by way of assigning tasks and responsibilities and monitoring project progress and performance against task completion status, acceptability of performance, and project milestones.
24. Initiate and lead engagement with Company Distribution Business Operations/Meter Project Manager to address and resolve deviations from the project plan.
25. Maintain project communications with Company Distribution Business Operations/Meter Project Manager.
26. Participate with Client Delivery Manager and with other AGIS teams on cross-program activities, including dependencies, risk mitigation and issue management, problem solving, optimizing schedules to meet milestone dates, and testing and defect resolution.
27. Coordinate the cross-docking, installation, and disposal of meters as specified herein.
28. Lead development of training materials.
29. Lead all testing phases and take accountability for defect resolution within the terms outlined herein.
30. Supplier will participate in and support end-to-end testing as defined by Company in the AGIS initiative, including writing and running of test scripts in conjuction with Itron Networked Solutions, as appropriate, and defect fixing as needed.

4 General Security Requirements

4.1 Overview

1. As Company adds intelligence to the electric grid, each part of the grid must be evaluated for security risk. Risks must be mitigated to ensure the reliable delivery of electricity to our

customers. Company has developed principles, strategies, and requirements to assist in identifying and mitigating risks.

2. Suppliers are required to comply with all of the principles, strategies, and requirements outlined herein.
3. Suppliers are required to meet the security requirements for Meters set out in Sections 6 and 7 herein.

4.2 Company Security Strategies

1. Conforms to industry standards and best practices as pertains to Meter technology.
2. Support and utilize secure network communication protocols (e.g. HTTPS, SFTP, SSH, SSL, TLS, etc).
3. Leverages strong authentication and authorization model (role-based access and role-based activity to individual Meters).
4. Support a deny-by-default approach to AMI component configuration.
5. No reliance on non-secure protocols/ports (e.g., telnet).
6. Disable all unnecessary and unused protocols/ports.
7. Support and integrate with centralized system configuration, change management, and monitoring systems.
8. System must be capable of security event logging capabilities that can be utilized and regularly reviewed.
9. Unauthorized access attempts shall be logged with alerts presented to the appropriate parties.

4.3 Company General Security Requirements

If Supplier has access to any Company or client confidential information, please describe how confidentiality is going to be maintained, including how information is retained and/or disposed of at designated times.

1. The corporate software maintenance process shall be followed for upgrades and patches.
2. Vulnerability scans are to be performed for equipment or product before it is put into both test and production.
3. Product shall not use unsupported open source code or operating systems.
4. Product shall have application security testing performed by Supplier and the results shall be shared with Company.
5. Supplier shall follow best practices in their coding by utilizing secure application development methodologies such as those recommended by the Open Web Application Security Project (OWASP).
6. All product testing shall be performed in non-production environments.
7. All security logs shall be captured by a centralized logging device, such as Security Information and Event Management (SIEM).
8. Data encryption shall be utilized for both data-at-rest and data-in-motion.
9. Encryption algorithms shall be of sufficient strength with equivalency of AES-256.
10. Multi-factor authentication shall be utilized.

11. AMI Head-end user access shall utilize role-based security, enabling access to be assigned by, for example, functionality, geographic area(s), asset grouping, and business areas.
12. Active Directory shall be used for user and service authentication.
13. Credentials are required to be stored in encrypted form.
14. Secure messaging shall be utilized whenever technically feasible such as SFTP.
15. If mobile technology is available, the application shall be compatible with Mobile Device Management Systems.
16. Appropriate firewall rules shall be used.
17. Intrusion prevention technology shall be utilized.
18. Only secure TCP/IP protocols shall be utilized.
19. Least functionality principles shall be practiced.
20. Least Privilege principles shall be practiced.
21. Defense-in-depth posture shall be practiced.
22. Zero-Trust Networking shall be practiced.
23. Tightly-controlled access shall be practiced across all network layers.
24. AMI Head-end shall support 8-character password with complexity (upper and lower case alpha, numeric, special characters).
25. AMI Head-end application shall not need to store Personal Identifiable Information (PII), but if it does, the application shall ensure the security and privacy of such information.
26. Supplier shall notify Company immediately in writing and electronically when security vulnerability is identified.
27. A patch shall be released to resolve firmware or security vulnerabilities within a Company-specified timeframe depending on the criticality of the security risk.

4.4 General Security Questions

Supplier will need to provide answers for each of the questions listed below. These questions will also be included in Company's Vendor Risk Assessments (VRA).

1. Does the vendor have a formal/documented Information Security program that includes the following elements?
   - Information security policies and standards
   - Information security governance function
   - Training and/or awareness program
2. Does the vendor have the following processes in place?
   - Information security incident management
   - Change management
   - Computing system patch management
3. Does the vendor have the following controls in place in its Information Technology, firmware development, and manufacturing environments?
   - Network IPS/IDS
   - Firewalls
   - Malware protection
4. Has the vendor experienced any Information Security incident/data breach during the past twelve (12) months? If Yes, please provide a summary report.

5. Is the vendor aware of any critical vulnerability(ies) in its computing environment/product?
6. If **Yes**, will the vulnerability(ies) be fully remediated prior to the start of the proposed engagement with Xcel Energy?
7. Does the vendor perform periodic reviews of access rights to systems, applications, databases, and network devices?
8. Does the vendor limit access to its systems and information technology assets to those with a business need for access?
9. Does the vendor anticipate the need to have unescorted physical access to any Xcel Energy critical assets (e.g., data centers, substations)?
10. Does the vendor conduct pre-employment background checks for all of its workers, including the topics of prior employment, criminal history, credit history, academic history, and drug screening (unless prohibited by law)?
11. Does the vendor have a formal/documented Business Continuity Program that includes the following elements?
    - Business Continuity and/or Disaster Recovery policies, standards, and plans.

5 General Requirements for All Electric AMI Meters

5.1 Technology Compatibility

1. Meters
    a. Meter must maintain seamless communication between Meters and NICs (Network Interface Cards).
    b. Meter Supplier must maintain a written agreement concerning the adoption, deployment, and use of standards with the NIC Supplier.
2. Application
    a. Supplier's Application that allows Meter access must be deployed on an operating system that is the CORE Standard established by Company (please review Appendix 2 for list of Enterprise Technology Standards).
    b. Application must access Meter through a USB port (e.g. from a user's laptop) through an optical cable physically plugged to Meter (Wi-Fi and Bluetooth are also options for local connectivity, per Section 5.11.6).

5.2 Managing the Lifecycle of Standards (Changes, Updates, Depreciation, etc.)

1. Supplier shall not implement any product changes unless:
    a. Company and Supplier consult concerning any financial, technical, and/or operational impacts, in the form of meetings of qualified individuals.
    b. The amended product capabilities, performance, and security features are provided by Supplier in writing to Company well-in-advance and accepted in writing by Company.
    c. An acceptable implementation work plan is established and agreed upon by Company.
    d. Supplier completes any testing required to confirm continued stability at a location that is not service impacting.
2. Where Supplier requires adoption of any new Standard and/or upgrade of a Standard, even if such an upgrade is offered at no cost, and such action implies any new consequential costs to Company, Supplier shall:
    a. Pay such costs unless agreed to otherwise by Company.
    b. Guarantee that such changes are not service-impacting in any negative way.

5.3 Evolutionary Equipment Upgrades

1. Regardless of any product evolutionary improvements, Supplier shall maintain the capacity to supply products of equal function to those supplied to Company, and interchangeable without any modification, for a period of twenty (20) years, commencing on the date of execution of the Major Supply Agreement. This includes maintaining capability for the Meter products to seamlessly interface to the most current generation NIC in use by Company.
2. Throughout the project term, where Supplier upgrades hardware and/or firmware and/or software, for the purpose of improvement, feature enhancement, etc., and ceases to manufacture and/or develop the existing product, Supplier shall:
   a. Notify the change expectation to Company no less than twelve (12) months prior to cessation of Supplier's delivery of existing product or product set.
   b. Identify revision numbers.
   c. Provide a written description of the change, and a statement of impact of the change, on Company operation.
   d. Not increase the price of the product.
   e. Continue to supply products of like function without supply interruption.
   f. Revise, at Supplier cost, any processes or documentation that changes as a result of the upgrade.
3. Where Supplier offers a new feature offered as an enhancement, Company may elect to take-up the incremental feature under the following conditions:
   a. The feature is fully characterized and explained to Company.
   b. Company, following a period of testing and assessment determines whether the enhancement is acceptable for production.
   c. The offered or negotiated incremental price is acceptable to Company.
4. Throughout the project term, where Supplier upgrades hardware and/or firmware and or/software, for the purpose of improvement, feature enhancement, Supplier shall:
   a. Notify Company within sixty (60) days.
   b. Provide Company copies of software and hardware firmware upgrades.
   c. Identify revision numbers.
   d. Provide a written description of the change, and a statement of impact of the change, on Company operations.

5.4 General Meter Qualification Testing Requirements

1. Company will designate a meter engineering test coordinator.
2. Supplier is required to supply to Company a quantity of twenty (20) electric Meters of each type and form to be FAT tested at a date to be coordinated with the Meter Test Coordinator.
3. Supplier is required to appoint one or more Subject Matter Expert(s) (SME) who will interface with Company's engineering test coordinator and Company SMEs for purposes of designing and carrying out the testing program.
4. Supplier's SME shall work with Company to provide/assist Company with opportunities to explore system features and capabilities in Company's AMI lab and in hands-on settings.
5. The actual testing events are expected to consist of, but not be limited to:
   a. Metrology testing at Company Material Distribution Center (MDC) location for each Meter type.

  b. AMI-specific functionality and performance testing at locations determined by Company.
  c. Performance testing with respect to access to mesh networking.
  d. Outdoor Meter testing.

6. Company evaluators will, independently, carry out AMI Meter testing as a means to quantify, qualify, validate, and confirm Supplier's detailed point-by-point response to the RFP and any purported features and/or specifications that Supplier offers or has offered.
7. Company will document the testing undertaken and provide a detailed report of tests and results. Supplier will be provided with opportunity to inspect and review testing results from their individual Meters. Where Supplier disagrees with any result, Supplier may propose changes or adjustments to the testing methodology in consultation with Company. Where it is determined that a testing method requires adjustment or change, Company may, at its election, carry out a repeat measurement on competing products.
8. Where Supplier develops and/or requests any form of testing that is in addition to that necessary to validate and/or test any specifications or features stated herein, Company reserves the right to carry out the developed and/or requested test on any competing Meter, at its election.
9. All communications will be subject to a Non-Disclosure Agreement (NDA). Company will not conduct any form of validation testing without agreed upon NDAs in place.
10. Company will be testing all Meter Suppliers' products sequentially.
11. Demonstrations are expected to take place at Company's location in Denver, Colorado, in an assigned controlled environment. Suppliers will be provided with secured access to the setup space at one of the following locations :
    a. MDC – 9500 Brighton, Henderson, CO 80640.
    b. HomeSmart – 6981 South Quentin Street, Suite A, Centennial, CO 80112-3939.

5.5 First Article Testing (FAT) Requirements

1. For all AMI Meters supplied to Company, Company will conduct FAT (First Article Testing) testing. The following conditions apply:
    a. For Meters that fail FAT, Company shall communicate to Supplier reasons for the failure. Supplier shall immediately correct deficiencies, and within one (1) week send corrected production type FAT Meters to Company for FAT.
    b. On any new Meter model or form, Supplier shall provide Company with at least four (4) production samples for each model type and Form for FAT testing. FAT Meters must be provided to Company within two (2) weeks of placing the order for the Meters. Manufacturing of production samples will not begin until Company has completed FAT testing and issued approvals to Supplier.
    c. FAT will, at a minimum, encompass the following items:
        i. Physical construction
        ii. Accuracy and dielectric testing
        iii. Nameplate label
        iv. Metrology
        v. Display
        vi. Communication Module (NIC)
        vii. Programming
        viii. Other (KYZ operation, service switch operation, LP verification)

2. Supplier shall maintain a real-time secure database, with an exportable format for Company's inventory management system from which Company may access information on Meter inventory components, holding no less than the following information:

    a. Meter model type and model number
    b. Catalog number
    c. Hardware version number(s)
    d. Meter serial number
    e. Firmware load rev number
    f. Date of manufacture
    g. Date tested
    h. Name of testing person
    i. FAT test document reference
    j. Date shipped
    k. Ship-to addressing
    l. Security keys via appropriate certificate management methods

3. Supplier shall not ship any Meters that have not complied with Company FAT test regimen.
4. Meter supply chain security requirement to include, but not limited to:

    a. Meters are to be properly security tested and hardened to Company's security standard (to be established in a Meter security workshop) prior to shipment.
    b. From manufacturing to shipment of Meter, a secure and documented chain of custody process shall be established to ensure the security and operational integrity of the Meter once deployed on Company's FAN.
    c. Meter shall be shipped with a tamper detection seal to ensure the device has not been tampered with prior to delivery to Company.

5. All shipments greater than three (3) Meters will be sample tested for accuracy and Meter functionality. Meters not meeting Company accuracy requirements and/or functionality requirements will be shipped back to Supplier, for correction, at cost to Supplier. A root cause analysis report shall be provided by Supplier for each Meter returned to Supplier and tested within thirty (30) business days from the date the returned Meter is received at Supplier.
6. Company will use an AQL of 0.40% for full load (FL) light load (LL) and power factor (PF) and an accuracy requirement of +/- 0.5% for FL, LL, and PF in analyzing the samples. Company will follow the requirements in ANSI/ASQC Z1.9-2003, inspection level II, Table A-2 and Table B-3 in analyzing the samples for accuracy. In addition a sample Meter functionality test will be conducted using ANSI/ASQC Standard Z1.4-2003, reduced inspection, inspection level II, Table I and Table II-C using an AQL of 1.0. For each sample tested any one of the following is counted as one non-conformance: service disconnect not fully functional when operated (open/close) via the network, AMI communications not working properly, display not visible, incorrect programming and significant error message.
7. Supplier shall support Company in setting up Meter hardware in Company lab environment for AMI testing.

5.6 Meter Technical Requirements

1. All Meters, with the exception of 2S and 12S network Meters, must be multi-ranging voltage Meters from 120 – 480V.
2. All Meters to have a polycarbonate cover with magnetized cable-free Opticom Port with a ¼ turn Reset Mechanism for resetting demand.

3. KYZ wiring should exit the rear of the Meter. No pigtails are required for KYZ wiring for Form 9S single KYZ Meters. Internal Meter KYZ wiring should be connected to output terminals on the back of the Meter for this Form only.

5.7 Meter Shipment Requirements

1. All Meters to be accurately tested prior to shipment. Test results (FL, LL, and PF) to be formatted and delivered to Company as specified below in Test Results.
2. All Meters to be programmed at the factory with a Company-supplied program.
3. All Meters to be shipped with two (2) replacement labels attached to the Meter cover. The replacement labels should have the AEP bar code and lettering on each label.
4. Meters in each shipment shall have serial numbers consecutively numbered with no more than nine (9) numeric characters.
5. Nameplates and box labels must be approved by Company for any new model or Meter types.
6. For all Meters with Network Interface Cards (NIC), the cost for installing the NIC should be included in the Meter price. Supplier to be responsible for scheduling shipment of the NIC to meet Meter manufacturing schedule.

5.8 Electric Meter Nameplate Requirements

1. All nameplates shall have an AEP bar code approved by Company.
2. Two nameplate barcode stickers must be affixed to the back of each Meter.
3. All nameplates shall be inclusive of Company name and logo, and shall be approved by Company prior to manufacture.

5.9 Box Label Requirements

1. All boxes are to be arranged on a pallet so that the box labels are visible in a way that allows the box labels to be read and scanned.
2. All containers, including shipping boxes and packaging, shall include the following information on labels:

    a. Name of Company in bold lettering
    b. Meter serial number and AEP bar code for each Meter in box
    c. Beginning and ending barcodes of pallet contents
    d. Quantity of Meters in box
    e. Manufacturer name, address, and assigned Meter catalog/model number
    f. Purchase order (PO) number
    g. Sales order number
    h. Date of shipment
    i. Meter model number
    j. Company material
    k. Line item number and release number
    l. Quantity in shipment
    m. Number of units in each pallet
    n. Pallet number box is located in
    o. Meter type/model
    p. Meter Form
    q. Meter number of wires
    r. Meter Test Amperes (TA)

s. Meter class
t. Meter frequency in Hertz
u. Item number

5.10 Supplier Test Results

1. FL, LL, and PF test results to be emailed to Company within five (5) days prior to Meter shipment. Test results to be emailed to: dlMeterdata@xcelenergy.com.
2. Format for test results per Appendix 5 (Meter Calibration File Format).
3. Meter and NIC marriage or integration information.

5.11 Optional AMI Meter Functional Features

5.11.1 Requirements for Voltage Phase Identification

1. AMI Meters shall enable, internally and/or by way of third party software systems operating at the AMI Head-end, a means to identify and communicate information that identifies Meters, within a specified community, that share a common power systems phase connection.

5.11.2 Requirements for Open Neutral Detection

1. AMI Meters shall enable, internally and/or by way of third party software systems operating at the AMI Head-end, a means to detect, identify, and communicate information that indicates an open neutral fault condition for the individual Meter or group of Meters under study.

5.11.3 Meter Support for Electric Pre-pay

1. All Meters shall be certified to support Electric Pre-pay as specified in ZigBee® Alliance Smart Energy Profile (SEP 2.x) Specification (ZigBee® Document: Smart Energy Profile 2, 13-0200-00, April 2013 and revisions).

5.11.4 Meter Support for Total Voltage Harmonic Distortion

1. Meters shall be equipped to measure and report on Total Voltage Harmonic Distortion (TVHD) in compliance to IEEE 519-2014.
2. Supplier shall provide a functional block diagram that illustrates the quantity and type of sensors that are provided in the Meter for the purpose of sensing voltage and current parameters, the salient circuitry that is used to sense and calculate TVHD.
3. Supplier shall indicate the mathematical algorithm and manner in which TVHD is calculated and state the specified accuracy and precision.
4. Supplier shall confirm that TVHD reporting is wholly immune to the effects of radio frequency emissions arising from the use of the third party NIC in both the 900MHz and 2.4 GHz bands including any related spurious components.
5. TVHD shall be carried out on a continuous basis and be sampled at a rate that:
    a. Is capable of reporting computed results at a rate of 60 Hz.
    b. Guarantees a 3dB bandwidth of 20,000 Hz for any sampled line/node.

5.11.5 Expanded Meter Functionality

1. Four Quadrant Meter Measurements

5.11.6 Wi-Fi and Bluetooth Meter Connectivity

1. Meters shall have the option of local connectivity via Wi-Fi and/or Bluetooth. This would enable local Meter access for troubleshooting and other activities.

5.11.7 Load Signature Analysis

1. AMI Meters shall enable, internally or by way of third party, a means to identify loads by signature and communicate this information via the NIC.

6 AMI Electric Residential Meter Requirements

6.1 Non Functional Requirements

1. Supplier's final assembled products shall have wholly integrated third party Gen 5 series NIC devices.
2. Supplier's products shall perform up to the:
   a. Specifications stated by Company
   b. Requirements drafted by Company

6.2 Detailed Security Requirements for Every AMI Electric Residential Meter Supplied

1. Security requirements shall apply to all AMI Meter types that are deployed on Company AMI network.
2. Encryption of data stored in Meter memory, and in the transfer from CPU to memory, shall be required.
3. Meter shall lock/disable chip diagnostic and programming ports (JTAG).
4. Provisions for secure local access shall be made available through the network or secure direct connection to the Meter (i.e. optical port).
5. Meter (and Field Tool) shall include cryptographic secured authorization/authentication for local Meter data download attempts.
6. NIC shall be integrated with Meter under the cover.
7. Meter shall log all login attempts to its indelible log and support a lockout for a configurable amount of time upon repeated invalid attempts. Supplier shall provide list of other security events that the system is capable of logging. Additionally, Meters must send log alerts to Company for further analysis and response.
8. Meter shall support, at minimum, symmetric key lengths of 128 bits.
9. Supplier shall provide a detailed cryptographic key management description explaining how cryptographic material is provisioned, used, stored, and deleted within the system.
10. NIC shall explicitly deny any information flow based on illegal message structure. NIC shall have provisions to detect and thwart a message replay attack e.g. as per ANSI C12.22.
11. Meter shall employ mechanisms that ensure device integrity from external tamper and compromise.
12. Meter shall comply with cyber security programs based on good industry standards according to NIST SP800-53,SP800-82 and NISTIR 7628.
13. Meter shall supply a Meter-to-Head-end cryptographic solution which assures the confidentiality of Meter's data while in transit.
14. Meter shall supply mechanisms which allow for secure device authentication, registration, and revocation.
15. Meter shall supply cryptographic mechanisms or materials which allow for unique device identification, authentication, and communications.

16. Meter shall supply cryptographic mechanisms or materials which allow for group access.
17. Meter shall supply mechanisms which audit, store, and transfer to SIEM all security related events, including all access and modifications events within the system.
18. Meter shall supply a security audit store, which includes date and time of event, type of event, user identity, and the outcome (success or failure) of event, and transfer the event to Company's SIEM.

6.3 Meter Functional and Performance Related Requirements

6.3.1 Compliance to Company Specifications

1. All Meters shall:
   a. Meet or exceed Supplier's technical and functional specifications over the twenty (20) year lifetime of the product.
   b. Meet or exceed the electric Meter requirements herein.
   c. Include Itron NIC device in final assembly of Meter.

6.3.2 Interoperability and Standards

1. Meters shall be built to ANSI C12 standards.
2. Meters shall have an interface capable of supporting multiple communication modules furnished by multiple potential Suppliers. The communications modules will reside under the Meter cover and collectively support the functional and non-functional requirements as specified herein. This includes making accessible all metering data to the communication interface for remote access.
3. The NIC furnished by potential Suppliers shall have an interface capability for the life of the Meter.
4. There shall be transparent IP routing to the Meters. Meters and control devices shall be configurable to support either or both IPv-4 and IPv-6 communication.
5. All electric Meters shall have a 0.5% or better accuracy performance.

Please refer to Appendix 2 at the end of this document for Enterprise Technology Standards.

6.3.3 Meter Feature Requirements

1. Meters shall be equipped with temperature sensors capable of measuring and logging Meter temperature for detection of hot sockets.
2. Meter shall be capable of reporting internal temperature as an interval channel or a temperature alarm as specified below:
   a. Meter shall be capable of reporting internal temperature for purposes of hot socket detection. When equipped with an internal service switch, Meters shall be capable of remote disconnect initiated by back office function.
   b. Meter shall be capable of generating an alarm when a configured internal temperature is exceeded. When equipped with a service disconnect switch, Meters shall be capable of remote disconnect initiated by back office function.
3. Meters shall be equipped with tilt/motion sensors.
4. Tilt/motion shall be captured/processed at power down by motion sensors to differentiate removal from normal outage.
5. Meter internal timekeeping clocks shall be governed by a disciplined clock analogous to that used by the Network Time Protocol (NTP) in which the clock speed, rather than the clock setting, is adjusted to effect time error corrections. In this case the Meter clock should be disciplined against the clock which governs the anticipated mesh network. With a disciplined clock there will never be discontinuities in the time record of, for example, load profile records which would

produce short and long intervals except in the possible case of power-up operations when the clock is initially set. Reference the RFC 1129 NTP algorithms described in a 1989 paper at URL: https://www.ietf.org/rfc/rfc1129.pdf. The case of a GPS disciplined clock is described in a Wiki article at URL: https://en.wikipedia.org/wiki/GPS_disciplined_oscillator.

6. Transformer rated Meters shall optionally allow Company to include potential and current ratios in transmitted Metered data.
7. Meter shall be able to self-register on the AMI network and communicate to the field network setup tool whether or not all aspects of the Meter and its communication with the AMI system are operating properly.
8. Load profile data shall be recorded and date/time stamped at the end of each interval. The date and time stamping of load profile data shall be consistent with ANSI C12.19.
9. Meter shall be configurable to support delivered, received, net, and absolute power at the Meter.
10. Meter shall support a configurable flag on detected reverse power flow. This flag would send an alarm when reverse power flow is detected. Parameters would include recognizing reverse flow at a configurable level (watts to kilowatts) over a configurable interval (five seconds to one hour) to prevent false triggering.
11. Meter shall support a network time synchronization of one (1) second or better and be able to time stamp its voltage peak to an accuracy of one (1) second. If an optional Phase Detection feature is deployed which requires greater time accuracy and resolution, Meter shall support such increased time resolution.
12. Meter load profile interval shall be configurable from one (1) minute to twenty four (24) hours. (Options to include one (1) minute, two (2) minutes, five (5) minutes, ten (10) minutes, fifteen (15) minutes, thirty (30) minutes, sixty (60) minutes, one (1) day).
13. Both Meters and communication devices must be capable of hard resets to factory default conditions by local means without shipping back to Supplier.
14. To facilitate Meter processing and installation, Meters and NICs shall be uniquely identifiable by both bar coding and electronic communication. Meter label shall conform to Company standard template which will be provided prior to manufacture date and confirmed during First Article testing.
15. Both Meter and communication infrastructure shall support remote desktop access to Meter using Supplier's native configuration software (e.g., Metercat, PCPro, etc.) over an IPv4 and/or IPv6 connection. This remote access shall be possible in equivalent terms through the Meter's optical port if so equipped, through the field area mesh network, and through the enterprise network from, for example, a Meter technician's desktop.
16. Each Meter shall have the capability to backup and restore.
17. Meters shall support independent demand register times so that meters can simultenously support multiple demand intervals e.g. 5, 15, 30 and 60 minutes.

6.3.4 Upgradeability and Configurability

1. Each Meter subsystem (e.g. metrology, register, Meter configuration [Program], HAN (if equipped), and Network Interface [NIC]) shall be upgradeable by secure remote download.
2. Each Meter subsystem shall have sufficient memory to support, at minimum, an anticipated 2x increase in memory requirements due to future enhancements and/or bug fixes.
3. Each Meter subsystem shall have sufficient memory to maintain operating, previous, and in-transit images of their respective firmware and shall support rollback to the previous successful image in the event of an error in either transmission or configuration that might require such rollback.

4. Residential Meters, if equipped with a service switch, shall have the ability to limit load/service. The load limit shall be configurable such that multiple configurable steps (e.g. ninety percent (90%) of rated capacity, seventy five percent (75%) of rated capacity, etc.) can be configured in the AMI Meter.
5. If bi-directional energy measurement functionality is required to be activated in the Meter, Meter shall be able to be re-programmed remotely over the air. This reprogramming event will be logged in the Meter and sent back to the Head-end immediately.
6. Data sent from Meters shall be configurable as to whether interval data, register data, event data or all data shall be sent during routine or on-demand Meter read requests.
7. Meter shall permit TOU, CPP, and PTR time period to be remotely configurable.
8. Meter shall permit its firmware and programs to be remotely downloadable without loss of register data.
9. Meter shall report failures, e.g. communication failure after reboot, program lock-up, etc., following a software/firmware upgrade within fifteen (15) minutes after start-up of a new program. Reportable failures shall include billing information loss or loss of electric service. Meter failures to report shall be configurable in Meter program.
10. Register Meter functions shall be programmable both remotely and locally.
11. Handling of received energy shall be configurable in the Meter, e.g. sum of delivered and received energy, ignored, net, etc.
12. Meter feature set shall include an indelible logging facility that records all administrative actions, e.g. reconfigurations performed on Meters, and report to the AMI Head-end. Indelible logs shall survive Meter reprogramming and firmware upgrades.

6.3.5 Availability

1. Meter shall continue to record all required data during a communication failure.

6.3.6 Connect, Disconnect, or Limit Service

1. All self-contained residential Meters class 200 (Forms 1S 2S and 12S) and class 320 (Forms 2S and 12S) shall be able to remotely connect/disconnect/limit electric service to customer premises.
2. The service switch shall be rated for at-least 10,000 service disconnect/reconnect operations.
3. Meter shall be able to limit demand served to a customer by a remote utility on-demand request or through utility pre-configured rules (e.g. 90% of rated capacity, 75% of rated capacity, etc.)
4. Meter's disconnect switch shall be capable of inhibiting the close operation when there is voltage on the load side to prevent equipment damage or personal injury.
5. Remote disconnect shall be integrated with Meter rather than a collared solution for Meter types that have been identified as requiring a disconnect switch.
6. Meter shall permit remote changes to the threshold for load limiting from MDM or Head-end. Thresholds shall be configurable.
7. Internal service switch shall have a rating consistent with Meter class rating at 60% lagging power factor.
8. Internal service switch shall close a configurable number of times automatically after a configurable delay if Internal Service Switch trips open because the demand/energy limit is exceeded.
9. Meter shall acknowledge load limit command successful to Head-end.

10. Meter shall acknowledge and communicate open/close status of the internal service switch after operating command is issued and shall be confirmed by Head-end.
11. Internal service switch shall be operable through the optical port and/or through the Field Tool used for Meter installation and maintenance.
12. Meter disconnect event (remote or local) shall not generate a last gasp message.
13. Meter shall record a disconnect event if the switch operates without a command.

6.3.7 Visible Access to Data

1. Meters equipped with an internal service switch shall provide for an external indication of the switch status discernable to a customer or Company employee on site.
2. Meter display shall provide date and time as specified by the utility. The display shall also display and label measured quantities in engineering units.
3. Displayed data shall match stored and transmitted data.
4. Meters shall be capable of displaying registers of all possible Metered data. Displayed data must show associated metrics/unit of measure.
5. Meter display shall include status of FAN communication link.
6. If equipped with Home Area Network (HAN) or Internet of Things (IoT) interface, Meter shall display status of HAN/IoT communication.
7. A visual disk emulator shall be provided on all Meters.
8. Meter shall be able to operate in alternate and test modes and display separately configurable alternate and test mode display sets.
9. Meter shall be placed into alternate and test modes locally. Test mode to have configurable time-out period (reverting to normal mode) and ability to be set to normal mode remotely.
10. Normal and alternate displays to include error and warning conditions.

6.3.8 Demand Response

1. The Meter will not inhibit Company practice that all control and reconfiguration commands sent through the field area network must be confirmed by field devices to the back office within fifteen (15) seconds.

6.3.9 Distributed Generation

1. The Meter shall collect delivered, received, and net cumulative values, as well as interval data as signed (positive or negative) values. Delivered cumulative shall be equal to the sum of delivered intervals, received cumulative shall be equal to the sum of received intervals. Both time duration and energy threshold shall be configurable in seconds.
2. Meter display shall be configurable to display any or all of the measured quantities identified in item 1 above.

6.3.10 Installation and Maintenance

1. NIC in the Meter shall have unique identification for LAN and FAN.
2. Meter shall have an indelible unique serial number over the life of the AMI system.
3. If equipped with HAN/IoT, Meter shall have a unique ID for HAN/IoT communication.
4. Upon installation, Meter shall optionally recognize, as configured by Company, the service type and issue alarm messages for unrecognized services (or abnormal service conditions). Meter shall have functionality that enables it to individually disable service level alarms.

5. Meter shall be able to identify itself to a field network setup tool and provide access to its data and configuration settings at installation time, and later in support of ongoing operations and maintenance activities subject to security authorization.
6. Meter shall perform self-checks and report results to installer field tool, local display, and to the AMI network. Self-checks to include integrity of the HAN/IoT communications card (if present) and AMI network communication card, and ability to communicate with local collector (AMI communication network architecture dependent).
7. Meter shall be capable of communicating with Supplier-supplied Field Tool over the NAN network via the Meter's NIC.
8. Field Communication Tool shall be capable of operating internal service switch and resetting demand.
9. Field tool shall be capable of communicating to Meter using wireless mesh network with at least the same functionality as is offered using shop or desktop tools.

6.3.11 Meter Measurement Capabilities

1. Meter shall provide time-stamped peak demand and energy for all configured time of use periods.
2. On the occurrence of an on-demand interval data read, the Meter shall be capable of sending time stamped any selected or all stored data and other associated register and diagnostic information.
3. Based on company requirements the Meter shall complete a self-read and store the value for each channel register of data.
4. On the occurrence of a scheduled read, the Meter shall be capable of sending time stamped any selected or all stored data and other associated register and diagnostic information.
5. Voltage resolution reported to Head-end shall be 0.1V or better.
6. Power Factor calculations shall include at least the following: average, max, min, coincident, etc.
7. Power Factor calculations shall be have both options for using either the total power factor (real power/apparent power) or by the displacement power factor (cos(θ)) methods.
8. Supplier shall provide detailed description of each of the options available for power factor calculation.
9. Meter shall accommodate a minimum of sixty (60) days of load profile data with five (5) minute intervals for at least four (4) channels of data.
10. Meters shall support TOU and critical peak pricing capabilities: (a) 4 TOU rates, (b) critical peak pricing rate, (c) ability to switch between time zones, (d) ability to switch between Standard Time and Daylight Saving Time, (e) support for four (4) seasons, (f) support advance calendar for at least twenty (20) years, including holidays.
11. Residential Meters shall be configurable to measure both integrated and instantaneous values (linear average over one (1) second) for the following:
    a. kW
    b. kVAr
    c. Voltage
    d. Current
    e. kVA
12. Residential type Meters shall be configurable to provide at least the following register and interval data:

a. kVArh delivered
b. kWh delivered and received
c. Internal Meter temperature and temperature alarm
d. Voltage magnitude and angle
e. Current magnitude and angle
f. kVAh Delivered

13. Residential meters shall have capability for selecting either vectorial or arithmetic methods for calculating KVA delivered and received.

6.3.12 Outage Management

1. Meter shall be capable of sending a message if load side voltage is detected on a disconnected Meter.
2. Meter shall maintain sufficient function for a sufficient amount of time to differentiate between an interruption and a power quality (PQ) event.
3. Meter shall alarm if voltage less than a configurable threshold is detected for a configurable period of time.
4. Meter shall alarm if voltage greater than a configurable threshold is detected for a configurable period of time.
5. Meter shall detect and send a last gasp/tamper alarm to the Head-end. Detection shall be possible after the Meter is removed and before it stops communicating.
6. Meter shall be able to send a last gasp message over the communications network during an interruption or removal.
7. At the system level, Meters shall remain operational after an interruption for a period of time that is sufficient to achieve:
   a. 100% reporting on single meter outage.
   b. 90% of meters reporting on outages of up to 1000 Meters.
   c. 80% of meters reporting on outages of 11 to 100 Meters.
   d. 60% of meters reporting on outages of 101 to 1,000 Meters.
   e. 50% of meters reporting on outages of up to 10,000 Meters.
   f. 30% of meters reporting on outages of 1,001 to 10,000 Meters.
8. Measurements of momentary interruptions, momentary interruption events and sustained interruptions shall be consistent with IEEE Std 1366-2012. In the case where IEE 1366 standard changes, the new definition shall supersede the old.
9. A single momentary interruption event includes all momentary interruptions experienced by Meter within a configurable period (e.g. five (5) minutes, etc.). Service must be restored within a configurable time period (e.g. five (5) minutes) to be classified as a single momentary event.
10. An interruption of less than a configurable time period (e.g. five (5) minutes) shall be considered a momentary interruption and shall be logged by the Meter as a momentary interruption.
11. An interruption of more than a configurable time period (e.g. five (5) minutes) shall be considered a sustained interruption and shall be logged by Meter as a sustained interruption. The sustained interruption includes all the switching events from the initial interruption to full restoration of the sustained interruption event.

12. Data recorded by the AMI Meters will be used to calculate Momentary Average Interruption Frequency Index (MAIFI) and Momentary Average Interruption Frequency Event (MAIFE). MAIFI and MAIFE include all momentary interruptions that are not part of a sustained interruption.
13. A single interruption shall trigger Meter logging.
14. Momentary interruptions shall be reported up to the Head-end with the next scheduled Meter read.
15. The above notwithstanding, power quality event selection shall be possible based on a pick-list of industry accepted power quality events in Meter setup tool in addition to ad-hoc definitions entered at Meter configuration definition.
16. Meters shall log outages and restorations and make data available to Head-end AMI system. This shall include time stamp.

6.3.13 Reliability

1. Supplier shall provide accelerated life testing results for all the system components that substantiate the system's life and that identify top failure causes.
2. Meter must survive and function properly without losing data or programs through repetitive short-term power outage cycles as might be experienced by recloser operations.
3. Meter time clock shall be configurable through the network and shall be accurate with a drift rate of no worse than one (1) minute per year. Meter clock shall be governed by a disciplined clock controlled by the system time using techniques similar to the Internet Network Time Protocol (NTP). Maximum allowable deviation from absolute time is no greater than one (1) second.
4. Meter shall be provisioned with an indelible log to receive event entries.
5. Type of events logged by Meter shall be configurable. Event messages for transmission and priority shall be determined by Company.
6. Meter shall send acknowledgement of a successfully completed or failed electric service connect/disconnect/limit event to the Head-end with latency not to exceed twenty (20) seconds.
7. Meter shall log the date and time stamped establishment of load limit set points.
8. When Meter's rated and configured load limits are exceeded, support for solicited and unsolicited reporting shall be available.
9. Meter shall log all local (and remote) Meter access attempts (configuration, data download, time adjustments, etc.), whether successful or not, and the requester ID. System shall support solicited and unsolicited reporting.
10. Meter shall be able to detect loss of load (greater than a configurable period of time) on the customer side of the Meter that is not related to a remote disconnect, log the event, and send an event message to Head-end. When load is restored, Meter shall log the event.
11. Meter reinstallation events shall be sent to Head-end immediately upon reinstallation along with any unsent tamper events.
12. An event generated when Meter is reinstalled is different from an event generated if Meter is initially installed (provisioned) or re-energized (e.g. after an outage). This is to avoid transmission of useless and confusing information to the enterprise systems because of non-tamper related events.
13. Meter's internal clock shall be synchronized in such a manner that Meter data that includes register and interval data shall not be affected and shall log the event. This requires the use of a disciplined clock governing the Meter as discussed above.

14. Meter shall be able to detect and log communications link failures upon failed communications initiated from Meter.
15. Meter shall be able to send an alarm/event to the Head-end (in the format in which Head-end can receive) when a configurable number of consecutive communications link failures are detected (e.g. three consecutive link failures).
16. Meter NIC shall be able to periodically record the communication signal strength and report it back to the Head-end as part of all communication transactions.
17. Each Meter shall be capable of capturing and recording a time stamped instantaneous voltage at configurable intervals ranging from one (1) minute to one (1) hour.
18. Each Meter shall be capable of sensing and capturing high/low voltage variations with reference to user definable set points and, upon exceeding the predefined limits, send notifications. Note the requirement above to include industry-standard Power Quality definitions in a setup picklist.
19. Meter shall support an indelible event log sufficient to contain entries for at least sixty (60) days after which oldest entries are over-written first.
20. Meters equipped with an internal service switch shall log all disconnections and connections within its indelible event log.
21. Meter shall communicate to both its event log and the Head-end any service reconnection and disconnection events.
22. Meter shall log to its indelible event log messages (informational and functional) received from the Head-end with Meter date/time and message code.
23. Meter shall detect and store as an event that an electrical parameter (voltage, current, load) has differed from a specified threshold for a configurable period of time.
24. Meter shall be able to discern authorized access to internal tables and information. Meter shall immediately transmit any events that indicate a breach of Meter's data by an unauthorized user or other security threat. The transmission of the data must continue until the AMI Head-end responds with a validation confirming that the data was received.

6.3.14 Tamper/Theft Detection

1. Meter shall detect physical tampering, such as Meter removal, case/cover removal, etc. and generate a tamper event.
2. All tamper related events shall be stored in the Meter's event log. Events shall be stored for at least sixty (60) days.
3. Meter shall be capable of detecting and alarming on an inverted Meter condition.
4. Meter shall be capable of sending a removal tamper event before communications are interrupted.
5. For each tamper event, Meter shall transmit to the Head-end and locally log the following information about the event: timestamp, tamper status (event type), Meter ID. This tamper information should be in a format that supports SIEM security logging services.

6.3.15 Power Quality

1. Meter shall have report by exception capabilities for selected parameters e.g. voltage, demand, etc. for operational purposes.
2. Meter shall be capable of recording both instantaneous and average voltage, current, power factor, kWh, kVArh, and kW values during each interval.

3. Meter shall monitor voltage and current in order to detect power quality variations as defined by CAN/CSA 61000-4-30, IEEE 1159, CBEMA/ITIC and IEC 61000-4-30 standards. These industry standards shall be selectable in a configuration tool pick list at Meter program time.
4. Meter shall allow authorized Company employees to retrieve any recorded device information including logs both locally and remotely (on-demand). Local communication has priority over remote. Such communication shall be supported using Supplier tools connected using the optical port (if so equipped), the mesh network (using a wireless field tool), or from a remote desktop through the corporate network to Meter. All such communication shall conform to corporate security practices as defined elsewhere.
5. Meters with power quality capabilities shall store the power quality data for a period of up to sixty (60) days.
6. Each Meter shall be capable of sensing and capturing high/low voltage variations with reference to Company configurable set points and, upon exceeding the predefined limits, send notifications.
7. Power quality setup shall include an option to use industry standard definitions.

6.3.16 Instrumentation Profiling Data

1. Meter must be capable of transmitting instrumentation data at least every five (5) minutes (configurable for five (5), fifteen (15), thirty (30) and sixty (60) minutes) or on demand.
2. When equipped with instrumentation profiling data, Meters shall be required to capture date, time, and measurement value for minimum, maximum, instantaneous and average values per phase and total for the following:
    a. Voltage
    b. Current
    c. Temperature
    d. Power (kW)
    e. Reactive power (kVAr)
    f. Apparent power (kVA)
    g. Power factor
    h. Harmonics
    i. Average values to be configurable for instantaneous, five (5), fifteen (15), thirty (30), and sixty (60) minutes

6.3.17 Functionality Requirements for Meters

1. All Class 320 Meters shall have a green background nameplate.
2. All Meters shall have a separately configurable alternate display and test display that can display all Meter measured quantities. Additionally, Meters shall be separately configurable to display instantaneous individual phase current, voltage and associated phase angles in normal, alternate, and test modes.

6.3.18 Bellwether Meter Functionality

1. Bellwether Meters shall be equipped to measure, record, and transmit no less than the following parameters:
    a. kWh delivered and received
    b. kVArh delivered
    c. kVAh

d. Voltage
e. Current
f. Temperature

2. Load profile interval data from all bellwether Meters shall be made available to the Head-end no more than twenty (20) seconds after the close of every Meter load profile interval.

6.3.19 Meter Support for Home Area Network (HAN)

1. All Meters shall be certified to operate as an Energy Service Portal (ESP) as detailed in the ZigBee® Alliance Smart Energy Profile (SEP 1.x) specification (ZigBee® Document Numbers 07-5356-19 and revisions).
2. All Meters shall be certified to operate as ESP as detailed in the ZigBee® Alliance Smart Energy Profile (SEP 2.x) specification (ZigBee® Document: Smart Energy Profile 2, 13-0200-00, April 2013 and revisions).
3. All direct connected AMI Meters shall be certified to operate as ESP as detailed in the ZigBee® Alliance Smart Energy Profile (SEP) specification (ZigBee® Document Numbers 075356r14 and 084914r03).
4. ESP shall operate in the 2.400 to 2.4835 GHz ISM band and comply with FCC regulations. ESP shall be capable to operate with an effective radiated power of up to 36 dBm.
5. ESP shall be configured to operate in a Utility Private HAN and shall support all ESP mandatory and optional clusters.
6. Communications to all HAN devices shall first require that those devices join the Utility Private HAN using a secure method that is approved by Company.
7. ESP shall be capable of interacting with a minimum of sixteen (16) Smart Energy Profile certified devices that have joined the Utility Private HAN. AMI system shall support an average of three (3) HAN devices per ESP.
8. AMI system shall enable the interactions between the Head-end and ESP as detailed SEP.
9. AMI system shall provide to ESP, and ESP shall store, tariff information required to allow ESP to populate the fields in the SEP publish price command for implementation of a TOU tariff (with at least one (1) set of seven (7) TOU periods for weekdays, one (1) set of seven (7) TOU periods per Saturday and one (1) set of seven (7) TOU periods per Sunday) and critical peak price notification.
10. Meter shall record as an event when tariff information is updated or changed in the ESP.
11. Home Area Network: All Meters shall be certified to operate IEEE 802.11 (Wi-Fi).
12. Meter shall record as an event any confirmation or status response (arising from a command from the AMI system) that ESP receives from HAN devices, triggered by:

    a. A message confirmation (as detailed in the SEP) from a HAN device.
    b. A load control report event status (as detailed in the SEP) from a HAN device.
    c. A notification that a HAN device has joined or failed to join the Utility Private HAN.

7 AMI Electric Commercial Meter Requirements

7.1 Non Functional Requirements

1. Supplier's final assembled products shall have wholly integrated Itron Gen 5 NIC devices.
2. Supplier's products shall perform up to the:

    a. Specifications stated by Company

b. Requirements drafted by Company

7.2 Detailed Security Requirements for Every AMI Electric Commercial Meter Supplied

1. Security requirements shall apply to all AMI Meter types that are deployed on Company AMI network.
2. Encryption of data stored in Meter memory and in the transfer from CPU to memory shall be required.
3. Meter shall lock/disable chip diagnostic and programming ports (JTAG).
4. Provisions for secure local access shall be made available through the network or secure direct connection to Meter (i.e. optical port).
5. Meter (and Field Tool) shall include cryptographic secured authorization/authentication for local Meter data download attempts.
6. NIC shall be integrated with Meter under the cover.
7. Meter shall log all login attempts to its indelible log and support a lockout for a configurable amount of time upon repeated invalid attempts. Supplier shall provide list of other security events that the system is capable of logging. Additionally, Meters must send log alerts to Company for further analysis and response.
8. Meter shall support, at minimum, symmetric key lengths of 128 bits.
9. Supplier shall provide detailed cryptographic key management description explaining how cryptographic material is provisioned, used, stored, and deleted within the system.
10. NIC shall explicitly deny an information flow based on illegal message structure. NIC shall have provisions to detect and thwart a message replay attack e.g. as per ANSI C12.22.
11. Meter shall employ mechanisms that ensure device integrity from external tamper and compromise.
12. Meters shall comply with cyber security programs based on good industry standards based on NIST SP800-53, SP800-82 and NISTIR 7628.
13. Meter shall supply a Meter-to-Head-end, cryptographic solution which assures the confidentiality of Meter's data while in transit.
14. Meter shall supply mechanisms which allow for secure device authentication, registration, and revocation.
15. Meter shall supply cryptographic mechanisms or materials which allows for unique device identification, authentication and communications.
16. Meter shall supply cryptographic mechanisms or materials which allows for group access.
17. Meter shall supply mechanisms which audit, store and transfer to SIEM of all security related events including all access and modifications events within the system.
18. Meter shall supply a security audit store which includes the date and time of the event, type of event, user identity, and the outcome (success or failure) of the event and transfer this event to Company's SIEM.

7.3 Meter Functional and Performance Related Requirements

7.3.1 Compliance to Company Specifications

1. All Meters shall:

a. Meet, or exceed, Supplier's technical and functional specifications over the twenty (20) year lifetime of the product.
b. Meet, or exceed, the Electric Meter Requirements herein.
c. Be inclusive of the third party NIC device.

7.3.2 Interoperability and Standards

1. Meters shall be built to ANSI C12 standards.
2. Meters shall have an interface capable of supporting multiple communication modules furnished by multiple potential Suppliers. Communications modules will reside under Meter cover and collectively support the functional and non-functional requirements as specified in this Request for Proposal.
3. NIC furnished by potential Suppliers shall have an interface capability for the life of Meter.
4. There shall be transparent IP routing to Meters. Meters and control devices shall be configurable to support either or both of IPv-4 and IPv-6 communication.
5. All electric Meters shall have a 0.5% or better accuracy class.

Please refer to Appendix 2 at the end of this document for Enterprise Technology Standards.

7.3.3 Meter Feature Requirements

1. Meters shall be equipped with temperature sensors capable of measuring and logging Meter temperature for detection of hot sockets.
2. Meter shall be capable of reporting internal temperature as an interval channel or a temperature alarm as specified below:
   a. Meter shall be capable of reporting internal temperature for purposes of hot socket detection. When equipped with an internal service switch, Meters shall be capable of remote disconnect initiated by back office function.
   b. Meter shall be capable of generating an alarm when a configured internal temperature is exceeded. When equipped with a service disconnect switch, Meters shall be capable of remote disconnect initiated by back office function.
3. Meters shall be equipped with tilt/motion sensors.
4. Tilt/motion shall be captured/processed at power down by motion sensors to differentiate removal from normal outage.
5. Meter internal timekeeping clocks shall be governed by a disciplined clock analogous to that used by the Network Time Protocol (NTP) in which the clock speed, rather than the clock setting, is adjusted to effect time error corrections. In this case, Meter clock should be disciplined against the clock which governs the anticipated mesh network. With a disciplined clock there will never be discontinuities in the time record of, for example, load profile records which would produce short and long intervals except in the possible case of power-up operations when the clock is initially set. Reference the RFC 1129 NTP algorithms are described in a 1989 paper at URL: https://www.ietf.org/rfc/rfc1129.pdf. The case of a GPS disciplined clock is described in a Wiki article at URL: https://en.wikipedia.org/wiki/GPS_disciplined_oscillator.
6. Transformer rated Meters shall optionally allow Company to include potential and current ratios in the transmitted Metered data.
7. Meter shall be able to self-register on the AMI network and communicate to the field network setup tool whether or not all aspects of the Meter and its communication with the AMI system are operating properly.

8. Load profile data shall be recorded and date/time stamped at the end of each interval. The date and time stamping of load profile data shall be consistent with ANSI C12.19
9. Meter shall be configurable to support delivered, received, net and absolute power at the Meter.
10. Meter shall support a configurable flag on detected reverse power flow. This flag would send an alarm when reverse power flow is detected. Parameters would include recognizing reverse flow at a configurable level (watts to kilowatts) over a configurable interval (five (5) seconds to one (1) hour) to prevent false triggering.
11. Meter shall support a network time synchronization of one (1) second or better and be able to time stamp its voltage peak to an accuracy of one (1) second. If an optional Phase Detection feature is deployed which requires greater time accuracy and resolution, Meter shall support such increased time resolution.
12. Load profile interval shall be configurable from one (1) minute to twenty four (24) hours (one (1) minute, two (2) minutes, five (5) minutes, ten (10) minutes, fifteen (15) minutes, thirty (30) minutes, sixty (60) minutes, one (1) day).
13. Both Meters and communication devices must be capable of hard resets to factory default conditions by local means without shipping back to Supplier.
14. To facilitate Meter processing and installation, Meters and NICs shall be uniquely identifiable by both bar coding and electronic communication. Meter label shall conform to Company standard template which will be provided prior to manufacture date and confirmed during First Article Testing.
15. Both Meter and communication infrastructure shall support remote desktop access to Meter using Supplier's native configuration software (e.g., Metercat, PCPro, etc.) over an IPv4 and/or IPv6 connection. This remote access shall be possible in equivalent terms through Meter's optical port if so equipped, through the field area mesh network, and through the enterprise network from, for example, a Meter technician's desktop.
16. Each Meter shall have the capability to Backup and Restore.
17. Meters shall support independent demand register times so that meters can simultenously support multiple demand intervals e.g. 5, 15, 30 and 60 minutes.

7.3.4 Upgradeability and Configurability

1. Each of Meter subsystems (e.g. metrology, register, Meter configuration [Program], HAN (If equipped) and Network Interface [NIC]) shall be upgradeable by secure remote download.
2. Each of Meter subsystems shall have sufficient memory to support, at minimum, an anticipated 2x increase in memory requirements due to future enhancements and/or bug fixes.
3. Each of Meter subsystems shall have sufficient memory to maintain operating, previous and in-transit images of their respective firmware and shall support rollback to the previous successful image in the event of an error in either transmission or configuration that might require such rollback.
4. Residential Meters, if equipped with a service switch, shall have the ability to limit load/service. The load limit shall be configurable such that multiple configurable steps (e.g. ninety percent (90%) of rated capacity, seventy five percent (75%) of rated capacity, etc.) can be configured in the AMI Meter.
5. If bi-directional energy measurement functionality is required to be activated in Meter, Meter shall be able to be re-programmed remotely over the air. This reprogramming event will be logged in Meter and sent back to the Head-end immediately.

6. Data sent from Meters shall be configurable as to whether interval data, register data, event data or all shall be sent during routine or on-demand Meter read requests.
7. Meter shall permit TOU, CPP, and PTR time period to be remotely configurable.
8. Meter shall permit its firmware and programs to be remotely downloadable without loss of register data.
9. Meter shall report failures, e.g. communication failure after reboot, program lock-up, etc., following a software/firmware upgrade within fifteen (15) minutes after start-up of new program. Reportable failures shall include billing information loss or loss of electric service. Meter failures to report shall be configurable in Meter program.
10. Register Meter functions shall be programmable both remotely and locally.
11. Handling of received energy shall be configurable in Meter, e.g. sum of delivered and received energy, ignored, net, etc.
12. Meter feature set shall include an indelible logging facility that records all administrative actions, for example reconfiguration, performed on Meter and report it to the AMI Head-end. Indelible log shall survive Meter reprogramming and firmware upgrades.

7.3.5 Availability

1. Meter shall continue to record all required data during a communication failure.

7.3.6 Connect, Disconnect, or Limit Service

1. Class 320 (Forms 2S and 12S) shall be able to remotely connect/disconnect/limit electric service to customer premises.
2. Service switch shall be rated for at-least 10,000 service disconnect/reconnect operations.
3. Meter shall be able to limit demand served to the customer by a remote utility on-demand request or through utility pre-configured rules (e.g. 90% of rated capacity, 75% of rated capacity, etc).
4. Meter's disconnect switch shall be capable of inhibiting the close operation when there is voltage on the load side to prevent equipment damage or personal injury.
5. Remote disconnect shall be integrated with Meter rather than a collared solution for Meter types that have been identified as requiring a disconnect switch.
6. Meter shall permit remote changes to the threshold for load limiting from MDM or Head-end. Thresholds shall be configurable.
7. Internal service switch shall have a rating consistent with Meter class rating at 60% lagging power factor.
8. Internal service switch shall close a configurable number of times automatically after a configurable delay if internal service switch trips open because the demand/energy limit is exceeded.
9. Meter shall acknowledge load limit command successful to Head-end.
10. Meter shall acknowledge and communicate open/close status of the internal service switch after operating command is issued and shall be confirmed by Head-end.
11. Internal service switch shall be operable through the optical port and/or through the Field Tool used for Meter installation and maintenance.
12. Meter disconnect event (remote or local) shall not generate a last gasp message.
13. Meter shall record a disconnect event if the switch operates without a command.

7.3.7 Visible Access to Data

1. Meters equipped with an internal service switch shall provide for an external indication of the switch status discernable to a customer or Company employee on site.
2. Meter display shall provide date and time as specified by the utility. The display shall also display and label measured quantities in engineering units.
3. Displayed data shall match stored and transmitted data.
4. Meters shall be capable of displaying registers of all possible Metered data. Displayed data must show associated metrics/unit of measure.
5. Meter display shall include status of FAN communication link.
6. If equipped with home area network (HAN) or internet of Things (IoT) interface, Meter shall display status of HAN/IoT communication.
7. A visual disk emulator shall be provided on all Meters.
8. Meter shall be able to operate in alternate and test modes and display separately configurable alternate and test mode display sets.
9. Meter shall be placed into alternate and test modes locally. Test mode to have configurable time out period (reverting to normal mode) and ability to be set to normal mode remotely.
10. Normal and alternate displays to include error and warning conditions.

7.3.8 Demand Response

1. Meter will not inhibit Company practice that all control and reconfiguration commands sent through the field area network must be confirmed by field devices to the back office within fifteen (15) seconds.

7.3.9 Distributed Generation

1. Meter shall collect delivered, received, and net cumulative values, as well as interval data as signed (positive or negative) values. Delivered cumulative shall be equal to the sum of delivered intervals, received cumulative shall be equal to the sum of received intervals. Both time duration and energy threshold shall be configurable in seconds.
2. Meter display shall be configurable to display any or all of the measured quantities identified in item 1 above.

7.3.10 Installation and Maintenance

1. NIC in Meter shall have Unique Identification for: LAN, FAN.
2. Meter shall have an indelible unique serial number over the life of the AMI system.
3. If equipped with HAN/IoT, Meter shall have a unique ID for HAN/IoT communication.
4. Upon installation, Meter shall optionally recognize, as configured by Company, the service type and issue alarm messages for unrecognized services (or abnormal service conditions). Meter shall have functionality that enables it to individually disable service level alarms.
5. Meter shall be able to identify itself to field network setup tool and provide access to its data and configuration settings at installation time, and later in support of ongoing operations and maintenance activities subject to security authorization.
6. Meter performs self-check and reports results to installer field tool, local display, and to the AMI network. Self-checks to include integrity of the HAN/IoT communications card (if present) and AMI network communication card and ability to communicate with local collector (AMI communication network architecture dependent).

7. Meter shall be capable of communicating with Supplier-supplied Field Tool over the NAN network via the Meter's NIC.
8. Field Tool shall be capable of operating internal service switch and resetting demand.
9. Field tool shall be capable of communicating to Meter using wireless mesh network with at least the same functionality as is offered using shop or desktop tools.

7.3.11 Meter Measurement Capabilities

1. Meter shall provide time-stamped peak demand and energy for all configured time-of-use periods.
2. On the occurrence of an on-demand interval data read, Meter shall be capable of sending time stamped any selected or all stored data and other associated register and diagnostic information.
3. Based on Company requirements, Meter shall complete a self-read and store the value for each channel register of data.
4. On the occurrence of a scheduled read, Meter shall be capable of sending time stamped any selected or all stored data and other associated register and diagnostic information.
5. Voltage resolution reported to Head-end shall be 0.1V or better.
6. Power Factor calculations shall include at least the following: average, max, min, coincident, etc.
7. Power Factor calculations shall have both options for using either the total power factor (real power/apparent power) or the displacement power factor (cos(θ)) methods.
8. Supplier shall provide detailed description of each of the options available for power factor calculation.
9. Meter shall accommodate a minimum of sixty (60) days of load profile data with five (5) minute intervals for at least four (4) channels of data.
10. Meters shall support TOU and critical peak pricing capabilities including: (a) four (4) TOU rates (b) Critical peak pricing rate (c) Ability to switch between Time Zones (d) Ability to switch between Standard Time and Daylight Saving Time (e) Support for four (4) Seasons (f) Support advance calendar for at least twenty (20) years including Holidays.
11. Commercial Meters shall be configurable to measure both integrated and instantaneous values (linear average over one (1) second) for the following:
    a. kW
    b. kVAr
    c. Voltage
    d. Current
    e. kVA
12. Commercial type Meters shall be configurable to provide at least the following register and interval data:
    a. kVArh delivered and received.
    b. kWh delivered and received.
    c. Internal Meter temperature and temperature alarm.
    d. Voltage magnitude and angle.
    e. Current magnitude and angle.
    f. kVAh delivered and received.

13. Commercial meters shall have capability for selecting either vectorial or arithmetic methods for calculating KVA delivered and received.

7.3.12 Outage Management

1. Meter shall be capable of sending a message if load side voltage is detected on a disconnected Meter.
2. Meter shall maintain sufficient function for a sufficient amount of time to differentiate between an interruption and a power quality (PQ) event.
3. Meter shall alarm if voltage less than a configurable threshold is detected for a configurable period of time.
4. Meter shall alarm if voltage greater than a configurable threshold is detected for a configurable period of time.
5. Meter shall detect and send a last gasp/tamper alarm to the Head-end. Detection shall be possible after Meter is removed and before it stops communicating.
6. Meter shall be able to send a last gasp message over the communications network during an interruption or removal.
7. At the system level, Meters shall remain operational after an interruption for a period of time that is sufficient to achieve:
   a. 100% reporting on single meter outage.
   b. 90% of meters reporting on outages of up to 1000 Meters.
   c. 80% of meters reporting on outages of 11 to 100 Meters.
   d. 60% of meters reporting on outages of 101 to 1,000 Meters.
   e. 50% of meters reporting on outages of up to 10,000 Meters.
   f. 30% of meters reporting on outages of 1,001 to 10,000 Meters.
8. Measurements of momentary interruptions, momentary interruption events, and sustained interruptions shall be consistent with IEEE Std 1366-2012. In the case where IEE 1366 standard changes, the new definition shall supersede the old.
9. A single momentary interruption event includes all momentary interruptions experienced by Meter within a configurable period (e.g. five (5) minutes, etc.). Service must be restored within a configurable time period (e.g. five (5) minutes) to be classified as a single momentary event.
10. An interruption of less than a configurable time period (e.g. five (5) minutes) shall be considered a momentary interruption and shall be logged by Meter as a momentary interruption.
11. An interruption of more than a configurable time period (e.g. five (5) minutes) shall be considered a sustained interruption and shall be logged by Meter as a sustained interruption. The sustained interruption includes all the switching events from the initial interruption to full restoration of the sustained interruption event.
12. Data recorded by AMI Meters will be used to calculate Momentary Average Interruption Frequency Index (MAIFI) and Momentary Average Interruption Frequency Event (MAIFIE). MAIFI and MAIFIE include all momentary interruptions that are not part of a sustained interruption.
13. A single interruption shall trigger Meter logging.
14. Momentary interruptions shall be reported up to the Head-end with the next scheduled Meter read.

15. The above notwithstanding, power quality event selection shall be possible based on a pick-list of industry accepted power quality events in Meter setup tool in addition to ad-hoc definitions entered at Meter configuration definition.

7.3.13 Reliability

1. Supplier shall provide accelerated life testing results for all the system components that substantiate the system's life and that identify top failure causes.
2. Meter must survive and function properly without losing data or programs through repetitive short-term power outage cycles as might be experienced by recloser operations.
3. Meter time clock shall be configurable through the network and shall be accurate with a drift rate of no worse than one (1) minute per year. Meter clock shall be governed by a disciplined clock controlled by the system time using techniques similar to the Internet Network Time Protocol (NTP). Maximum allowable deviation from absolute time is no greater than one (1) second. Reference discussion Disciplined Clock above.
4. Meter shall be provisioned with an indelible log to receive event entries.
5. Type of events logged by Meter shall be configurable. Event messages for transmission and priority shall be determined by Company.
6. Meter shall send acknowledgement of a successfully completed or failed electric service connect/disconnect/limit event to the Head-end with latency not to exceed twenty (20) seconds.
7. Meter shall log the date and time stamped establishment of load limit set points.
8. When Meter's rated and configured load limits are exceeded, support for solicited and unsolicited reporting shall be available.
9. Meter shall log all local (and remote) Meter access attempts (configuration, data download, time adjustments, etc.), whether successful or not, and the requester ID. The system shall support solicited and unsolicited reporting.
10. Meter shall be able to detect loss of load (greater than a configurable period of time) on the customer side of the Meter that is not related to a remote disconnect, log the event, and send an event message to Head-end. When load is restored, Meter shall log the event.
11. Meter reinstallation events shall be sent to Head-end immediately upon reinstallation along with any unsent tamper events.
12. An event generated when Meter is reinstalled is different from an event generated if Meter is initially installed (provisioned) or re-energized (e.g. after an outage). This is to avoid transmission of useless and confusing information to the enterprise systems because of non-tamper related events.
13. Meter's internal clock shall be synchronized in such a manner that Meter data that includes register and interval data shall not be affected and shall log the event. This requires the use of a disciplined clock governing the Meter as discussed above.
14. Meter shall be able to detect and log communications link failures upon failed communications initiated from Meter.
15. Meter shall be able to send an alarm/event to the Head-end (in the format in which Head-end can receive) when a configurable number of consecutive communications link failures are detected (e.g. three (3) consecutive link failures).
16. Meter NIC shall be able to periodically record the communication signal strength and report it back to the Head-end as part of all communication transactions.

17. Each Meter shall be capable of capturing and recording a time stamped instantaneous voltage at configurable intervals ranging from one (1) minute to one (1) hour.
18. Each Meter shall be capable of sensing and capturing high/low voltage variations with reference to user definable set points and, upon exceeding the predefined limits, send notifications. Note the requirement above to include industry-standard Power Quality definitions in a setup picklist.
19. Meter shall support an indelible event log sufficient to contain entries for at least sixty (60) days after which oldest entries are over-written first.
20. Meters equipped with an internal service switch shall log all disconnections and connections within its indelible event log.
21. Meter shall communicate to both its event log and the Head-end any service reconnection and disconnection events.
22. Meter shall log to its indelible event log messages (informational and functional) received from the Head-end with Meter date/time and message code.
23. Meter shall detect and store as an event that an electrical parameter (voltage, current, load) has differed from a specified threshold for a configurable period of time.
24. Meter shall immediately transmit any events that indicate a security threat. The transmission of the data must continue until the AMI Head-end responds with a validation confirming that the data was received.

7.3.14 Tamper/Theft Detection

1. Meter shall detect physical tampering, such as Meter removal, case/cover removal, etc. and generate a tamper event.
2. All tamper related events shall be stored in Meter's event log. Events shall be stored for at least sixty (60) days.
3. Meter shall be capable of detecting and alarming on an inverted Meter condition.
4. Meter shall be capable of sending a removal tamper event before communications are interrupted.
5. For each tamper event, Meter shall transmit to the Head-end and locally log the following information about the event: timestamp, tamper status (event type), Meter ID. This tamper information should be in a format that supports SIEM security logging services.

7.3.15 Power Quality

1. Meter shall have report by exception capabilities for selected parameters e.g. voltage, demand, etc., for operational purposes.
2. Meter shall be capable of recording both instantaneous and average voltage, current, power factor, kWh, kVArh, and kW values during each interval.
3. Meter shall monitor voltage and current in order to detect power quality variations as defined by CAN/CSA 61000-4-30, IEEE 1159, CBEMA/ITIC and IEC 61000-4-30 standards. These industry standards shall be selectable in a configuration tool pick list at Meter program time.
4. Meter shall allow authorized Company employees to retrieve any recorded device information including logs both locally and remotely (on-demand). Local communication has priority over remote. Such communication shall be supported using Supplier tools connected using the optical port (if so equipped), the mesh network (using a wireless field tool), or from a remote desktop through the corporate network to the Meter. All such communication shall conform to corporate security practices as defined elsewhere.

5. Meters with power quality capabilities shall store the power quality data for a period of up to sixty (60) days.
6. Each Meter shall be capable of sensing and capturing high/low voltage variations with reference to Company configurable set points and, upon exceeding the predefined limits, send notifications.
7. Power quality setup shall include an option to use industry standard definitions.

7.3.16 Instrumentation Profiling Data

1. Meter must be capable of transmitting instrumentation data at least every five (5) minutes (configurable for five (5), fifteen (15), thirty (30) and sixty (60) minutes) or on demand.
2. When equipped with instrumentation profiling data, Meters shall be required to capture date, time, and measurement value for minimum, maximum, instantaneous, and average values per phase and total for the following:
    a. Voltage
    b. Current
    c. Temperature
    d. Power (kW)
    e. Reactive power (kVAr)
    f. Apparent power (kVA)
    g. Power factor
    h. Harmonics
    i. Average values to be configurable for instantaneous, five (5), fifteen (15), thirty (30), and sixty (60) minutes

7.3.17 Functionality Requirements for Meters

1. All Class 320 Meters shall have a green background nameplate.
2. All Meters shall have a separately configurable alternate display and test display that can display all Meter measured quantities. Additionally, Meters shall be separately configurable to display instantaneous individual phase current, voltage, and associated phase angles in normal, alternate, and test modes.

7.3.18 Meter Support for Bellwether Services

1. Bellwether Meters shall be equipped to measure, record, and transmit no less than the following parameters:
    a. kWh (delivered and received)
    b. KVArh (delivered and received)
    c. KVAh
    d. Voltage
    e. Current
    f. Temperature

2. Load profile interval data from all bellwether Meters shall be made available to the Head-end no more than twenty (20) seconds after the close of every Meter load profile interval.

7.3.19 Meter Support for Home Area Network (HAN)

1. All Meters shall operate as an Energy Service Portal (ESP) as detailed in the ZigBee® Alliance Smart Energy Profile (SEP 1.x) Specification (ZigBee® Document Numbers 07-5356-19 and revisions).
2. All Meters shall operate as ESP as detailed in the ZigBee® Alliance Smart Energy Profile (SEP 2.x) Specification (ZigBee® Document: Smart Energy Profile 2, 13-0200-00, April 2013 and revisions).
3. All direct connected AMI Meters shall be certified to operate as ESP as detailed in the ZigBee® Alliance Smart Energy Profile (SEP) Specification (ZigBee® Document Numbers 075356r14 and 084914r03).
4. ESP shall operate in the 2.400 to 2.4835 GHz ISM band and comply with FCC regulations. ESP shall be capable to operate with an effective radiated power of up to thirty-six (36) dBm.
5. ESP shall be configured to operate in a Utility Private HAN and shall support all ESP mandatory and optional clusters.
6. Communications to all HAN devices shall first require that those devices join the Utility Private HAN using a secure method that is approved by Company.
7. ESP shall be capable of interacting with a minimum of sixteen (16) Smart Energy Profile certified devices that have joined the Utility Private HAN. The AMI system shall support an average of three (3) HAN devices per ESP.
8. AMI system shall enable the interactions between the Head-end and the ESP as detailed SEP.
9. AMI system shall provide to ESP, and ESP shall store, tariff information required to allow ESP to populate the fields in the SEP publish price command for implementation of a TOU tariff (with at least one (1) set of seven (7) TOU periods for weekdays, one (1) set of seven (7) TOU periods per Saturday and one (1) set of seven (7) TOU periods per Sunday) and critical peak price notification.
10. Meter shall record as an event when tariff information is updated or changed in the ESP.
11. Home Area Network: All Meters shall be certified to operate IEEE 802.11 (Wi-Fi).
12. Meter shall record as an event any confirmation or status response (arising from a command from the AMI system) that the ESP receives from HAN devices, triggered by:
    a. A message confirmation (as detailed in the SEP) from a HAN device.
    b. A load control report event status (as detailed in the SEP) from a HAN device.
    c. A notification that a HAN device has joined or failed to join the Utility Private HAN.

8 General Requirements for Electric Installation Services

8.1 Scope of Supply

1. Supplier shall fulfill the requirement to install the inventory of electric Meters in accordance with the Project Schedule.
2. In the event Supplier hires sub-contractors to perform work, the same requirements, processes and expectations shall hold true for sub-contractors as Supplier's. Supplier will be held responsible for all work, damages or any other issues caused by sub-contractors. Company reserves its right to review Supplier's sub-contractors' past safety and quality performance as well as their relevant experience for the tasks being sub-contracted.
3. Throughout the electric Meter deployment period, Supplier will adhere to completing device exchanges according to the provided reading/billing schedule. As installed Meters move into bill window dates, Supplier will refrain from exchanging Meters in any reading/billing cycles that are in the bill window.

4. Company expects field installations shall be completed during normal business hours Monday-Friday between the hours of 8:00am and 5:00pm local time. Company shall review, and potentially approve, any Supplier proposed exceptions.
5. Working on Saturday's may be acceptable but field installations shall not commence before 9:00am local time, unless a scheduled appointment was previously setup by customer request. Supplier shall be required to notify and receive approval from Company when field installations will be done on Saturdays. Supplier will not be additionally compensated for Saturday installations, unless the work is specifically requested in writing by Company.
6. Installation requirements include, but are not limited to:
   a. Supplier shall install electric Meters in accordance with guidelines regarding installation procedures provided herein.
   b. Supplier shall safely install/exchange electric Meters of all types in accordance with AMI Project Schedule (schedule to be refined and fully developed after contract award) utilizing qualified personnel.
   c. Supplier shall complete electric Meter exchange orders and ensure those orders are successfully transferred to Company provided work order management tool on a daily basis.
   d. Supplier shall provide staging/cross-docking facilities for incoming and disposal of electric Meters.
   e. Company shall supply six (6) weeks of inventory of new electric Meters including all electric Meter forms and classes. Non-AMI electric meters will be held for six (6) weeks. After this time, meters will be processed for retirement and disposal.
   f. Supplier shall provide inventory control of new and used electric Meters.
   g. Supplier shall provide asset management of electric Meters.
   h. Supplier shall provide disposal of replaced electric meters in accordance with Section 8.13 and Section 8.14.
   i. Supplier shall recycle sufficient number of AMR electric meters removed from the field to support existing non-AMI meter business requirements in areas that have not been deployed with AMI. Company will coordinate with Supplier on desired inventory levels.
   j. Supplier shall capture GPS Latitude and Longitude of Meter locations as part of the Meter exchange process. Coordinates must not be truncated to fewer than five (5) places after the decimal point; for example 37.46668 rather than 37.466.
7. Anticipated installation rate is outlined in Section 1.3.7 but subject to agreement between Supplier and Company in writing. Refer to Appendix 3 (PSCo Electric Meter Deployment) for anticipated rollout by quarter and block..

8.2 Obligations Concerning Meter Deployments

Supplier shall:

1. Perform Meter exchanges as outlined herein.
2. Use Company electronic work order system or functional equivalent that collects barcode data and GPS coordinates for each location where Meters and mesh network transition equipment is installed. Supplier can offer alternate proposal for using Supplier's work order management solution. Additional discussions will be required with Company, if Supplier offers an alternate proposal.
3. Ensure that cyber security key material is handled according to Company's security requirements during all lifecycles of Meter (i.e., manufacturing, installation, exchange, removal and destruction).
4. Ensure the confidentiality of Meter and FAN network configuration specifications.
5. Be responsible for ensuring company safety procedures and policies are complied.

8.3 Items Supplied by Company

1. Company will provide Supplier with necessary work asset management/work completion business software application tool during deployment for all field personnel performing electric Meter exchanges. Such tools will be loaded with Company's software allowing for real time order completion. Some work requirements may not apply should Supplier propose, and Company accept, an alternate work tool.
2. Company will provide Supplier with bar code scanners for each of the field asset tools issued during deployment. Requirements will not apply should Supplier propose an alternate work tool.
3. Company provided work asset tool will have access to software Application used for inventory tracking and instruct Supplier on its operation. Inventory tracking requirements shall still apply should Supplier propose an alternate work tool.
4. Company will provide Supplier keys for all Company owned locks, lock boxes and barrel locks for accessing meters and/or locked meter rooms.

8.4 Required Tools and Instrumentation

1. Supplier shall provide all tools necessary for the safe installation or exchange of electric Meters.
2. Supplier shall be responsible for acquisition and installation of truck mounts for work order management tools and any associated costs for installation of pedestal materials for all field vehicles. Company will provide Supplier with work order management tool cradles. Pedestals are a customized item depending on type of vehicle and will need to be secured to the vehicle.
3. If Supplier proposes, and Company accepts, Supplier's own work order management tool, Supplier shall provide all tools and work order management system including handhelds/tablets equipped with cameras required to perform and validate proper electric Meter exchanges.
4. For Company to accept a Supplier-proposed Meter installation work management software application tool, Supplier shall provide Company with full description of tools, apps, and procedures.

8.5 Required Customer Notification Process

1. Company will inform customers of the expected timeframe and procedures for the electric Meter exchange prior to carrying out the exchange through customer mailings or other Forms of communications.
2. Company will notify law enforcement and city officials of the working areas.
3. Supplier shall attempt to contact all customers upon arrival before accessing electric meter to perform exchanges.
4. Supplier shall leave a Company-supplied door hangar at the customer's permises after the electric Meter exchange. Door hanger will include information that the electric Meter was exchanged, reason for the exchange, and information regarding Advanced Metering Infrastructure (AMI). Company will also supply information to Supplier for its employees training program detailing customer communication regarding the electric Meter exchange and benefits of Company's AMI program.
5. If unable to contact customer on arrival, Supplier shall safely attempt to gain access and exchange electric Meter. A customer oriented notification of the completed or pending action shall be left at the customer premise in the form of a door hanger supplied by Company upon completion of electric Meter exchanges.
6. If unable to exchange the Meter due to access issues, Supplier shall follow procedure in Section 8.6.

7. Supplier will coordinate with Company to produce list of customers (daily, weekly, etc.) that are going to be exchanged so that Company can add PTJ's (work orders) to Customer Information System.
8. If Supplier is not able to contact customers that have 3-phase self-contained electric meters, Supplier shall follow procedure in Section 8.6.

8.6 Return to Utility Process / No Access Expectations

1. Supplier shall attempt to make multiple attempts before returning order to Company consisting of:
    a. Two (2) Field attempts.
    b. Two (2) Phone/message attempts to set appointments.
    c. One (1) No access letter sent to the Customer.
2. If Supplier cannot exchange electric Meter after multiple attempts, using the processes outlined above, Supplier shall refer electric Meter exchange to Company for completion. Company will assess no access expectations through a close evaluation of Supplier percentage of RTU's
3. If Supplier cannot exchange electric Meter after following the steps defined above, the work order will be returned to Company and Supplier will bill Company for unsuccessful attempts at the applicable unit rate. An unsuccessful attempt shall be considered to be a single field attempt and not an attempt from the back office.
4. Items 1 and 2 above shall flow through Supplier provided tools or Company work order system.

8.7 Immediate Return to Utility (RTU)

1. Supplier will mark accounts as immediate RTU for scenarios such as suspected tampering, customer refusal, and hazardous conditions. Supplier to outline conditions that qualify for suspected tampering.
2. Such conditions will be billed to Company at the applicable rate.
3. All instances of RTU's shall be documented and tracked.

8.8 Required Procedure for Handling Equipment Damage

1. In the event an unexpected customer outage condition should occur while attempting to complete a Meter exchange, Supplier's field technician shall:
    a. Notify customer (if home) about the unexpected outage.
    b. Report outage to Supplier Supervisor or office personnel, and depending upon the nature of the problem either initiate an order for repair or request a proper order be generated by Company for resolution.
2. If unsafe condition(s) exist, Supplier shall remain on site until relieved by another duly appointed and qualified representative of Supplier's company or until Company representative arrives on site.
3. When Supplier personnel are required to standby onsite, standby time will be billed at the hourly rate listed in the fee schedule if the outage is determined to not be the fault of Supplier's personnel.

8.9 Required Procedures for Property Damage (non-outage related)

1. If damage is caused by Supplier as a result of an improper or accidental action during the electric Meter exchange process, Supplier is responsible for all necessary repairs and associated costs including any Supplier associated Supplier costs above.
2. If damage is unavoidable (due to pre-existing stressed wires or broken block, etc.), Company shall be responsible for needed repairs and all associated costs and will resolve with Customer as appropriate.

8.10 Site Clean-up

1. Any unused, old, or discarded electric meter related materials (demand seals, meter seals, used disconnect boots, index screws, etc.) shall be picked up by Supplier and properly disposed.
2. Disposal shall follow processes outlined in Section 8.13 and Section 8.14.

8.11 Cross Docking Inventory Management

1. Equipment to be provided by Supplier shall include, but is not limited to, tools, work order management tools if provided by Supplier, warehouse equipment (such as fork lift, pallet jacks), computers and associated connections, etc. Any computers requiring Company software (such as MDMS, CRS and Advantex) will be provided by Company.
2. To avoid any potential slowdown for lack of electric Meter inventory, a four (4) week supply of Meters shall be on hand at all times. Below is the average expected weekly peak installation quantities:
   a. PSCo (CO)
      i. Electric Meters – 10,000
   b. NSPM (MN)
      i. Electric Meters – 10,000
   c. NSPM (ND)
      i. Electric Meters – 13,000
   d. NSPM (SD)
      i. Electric – 1,100
   e. NSPW (WI and MI)
      i. Electric Meters – 2,100
   f. SPS (TX and NM)
      i. Electric –3,100
3. Supplier shall coordinate with Company on recycling electric meters that support on-going Meter installation and replacement work in areas that are designated for future AMI deployment.
4. Supplier must participate in regularly scheduled electric Meter inventory planning sessions with Company.
5. Supplier shall secure and equip cross docking facilities for receiving, storing, and dispatching of new electric Meters, as well as storage of returned meters, and preparing them for disposal. Locations of cross docks will vary depending on geographic deployment.

8.12 Inventory Tracking/Reporting Requirements

1. All new electric Meters shall be electronically transferred to appropriate Supplier storerooms at cross docking facilities once they have passed bar-X and network communication testing by Company and have been purchased into Company's Monitor Device Management System (MDMS).
2. Unless otherwise agreed in writing, all electric Meters shall be shipped directly to Supplier's facility. Sample electric Meters will be drawn for acceptance testing to be performed at Company's Meter Shop, or off-site location designated for deployment.
3. Company personnel will initiate transfer process of new electric Meter shipments to a designated Supplier storeroom after each electric Meter shipment has been receipted into MDMS and acceptance testing has been completed.
4. In order to complete transfer process to Supplier's storeroom, Supplier shall verify electric Meters included in pending transfer are correct. Once verified, electric Meters will be receipted in MDMS to complete transfer process to Supplier's storeroom. New electric Meter shipments will be quarantined until the transfer process is fully completed. Company will provide necessary training and access to MDMS to Supplier's office personnel.

5. On a daily basis, individual electric Meters shall be electronically scanned and transferred/assigned to each field technician for daily Meter exchanges in an effort to help reduce the risk of lost electric Meters. Scanners will be provided by Company if Supplier opts to use Company Work Order system.
6. Company will provide necessary training for individual assignment of electric Meters.
7. Individual electric Meter inventory shall be conducted on a daily basis by all field technicians using company supplied inventory software that will be available on Company provided work order management tool. Company will provide training for required inventory procedure. If Supplier proposes a different work order tool, Supplier shall outline how Supplier tool will reconcile inventory with Company systems.
8. Supplier will conduct a complete inventory (at least once a year) that may coincide with Company's own electric Meter inventory or when deemed necessary. An electronic file of all electric Meters both new and used electric Meters not yet retired will be provided by Supplier. Additional information will be given to Supplier prior to scheduled inventory date.
9. At the end of each day, Supplier field personnel shall return a number of old electric meters that match the number of exchange orders completed during the day.
10. At the end of each day, Supplier field personnel shall return electric Meters that are equal to electric Meters taken out minus electric Meters installed.

8.13 Disposal of Equipment Requirement

1. Supplier shall take pictures of each electric Meter clearly showing the electric Meter's ID and Meter index before exchanges. At a minimum, expect to have pictures of total consumption.
2. Supplier shall be responsible for the disposal of all hazardous materials in a safe and environmentally appropriate manner. Supplier warrants that all regulatory and legal requirements are adhered to on the disposal process.
3. Before and after pictures showing Meter service and/or any pre-existing conditions worth noting may also be required to assist in any potential claims or disputes from customers. All pictures will be stored by Supplier and readily available to Company.
4. Supplier shall manage, transport, and recycle or dispose of waste and hazardous materials in accordance with applicable law and Company's Environmental Directives for Contractors.
5. Supplier and any subcontractors that are responsible for recycling of retired meters and modules and recycling or disposal of any associated waste and hazardous materials must be approved pursuant to Company's Procedure ENV 8.811 Waste Vendor Approval and Maintenance Procedure.
6. Supplier shall provide advance written notice to Company disclosing the identity of facilities to be utilized for waste and hazardous material processing, recycling, or disposal. Company shall have two (2) weeks to determine whether proposed facilities shall be rejected.
7. Supplier shall provide advance notice to Company identifying list of transporters that may be used to transport wastes and hazardous material for processing, recycling, or disposal. Company shall have one (1) week to determine whether proposed transporter shall be rejected.
8. Supplier shall provide Company with an annual inventory of hazardous materials disposed of or recycled. The annual reports must identify the total pounds of each waste type (i.e., mercury contaminated waste, batteries and circuit boards) recycled or disposed of in the calendar year

8.14 Meter Disposal/Retirement Process

1. Supplier shall be responsible for providing information to Company for recycling of retired meters and modules in Company's meter inventory management system.
2. Meter sorting will be required for meters that will be retired, and re-usable meters, based on Company-defined lots and Customer needs.

3. Supplier will separate and segregate all environmentally hazardous materials and recycle or dispose of in accordance with Section 8.13 prior to recycling the retired meters or modules.
4. The remaining meter or module components will be recycled by Supplier.
5. Prior to recycling, Supplier shall be required to provide a nightly file containing meters and modules that have been removed from the field and are being retired. Supplier and Company will mutually agree upon the required file format and layout for this process. The file shall contain pertinent information to revoke the retired meter's participation in Company's FAN (i.e., Certificate revocation).
6. Supplier will bear the responsibility for the quantity of meters and modules recycled as compared to the required nightly file containing meters and modules that have been removed from the field for retirement and recycling.
7. Supplier shall provide a list of all Third Parties that are utilized for recycling of meters and modules.
8. Supplier shall provide cost and time to remove and recycle or dispose of any and all lithium batteries, lead seals, mercury switches, and glass/polycarbonate covers.
9. Supplier shall separate meters and module covers (glass or polycarbonate) and recycle or dispose of covers prior to recycling meters.
10. Supplier shall remove and dispose of any ERT's and batteries in accordance with Company waste disposal policies prior to recycling retired meters and modules.
11. Company, at its option, may consider shipping meters and modules containing mercury switches or batteries off-site for processing. If sent off-site, Supplier shall be required to sort meters and modules and palletize for shipment to off-site facility.
12. Supplier shall remove nameplates where applicable and or permanently mask the nameplate, as appropriate.

8.15 Salvage of Retired Meters or Modules

1. Company requires that the residual value of retired meters or modules be returned to Company through one of the following two options:
    a. Contractor Salvage:
        i. Supplier will recycle retired meters and modules and return proceeds as credit to Company.
        ii. Supplier will separate and segregate all environmentally hazardous materials and recycle or dispose of in accordance with Section 8.13 and 8.14.
        iii. The remaining meter and module components will be recycled by Supplier and Supplier will return the value to Company by providing credits on progress payment invoices. Supplier shall detail such credits as a separate line item in invoices to Company, and shall provide documentation supporting such credits upon reasonable request by Company.
        iv. Supplier shall provide a list of all third parties that are utilized for recycling of meters and modules.
        v. Supplier shall provide a copy of all documentation exchanged between Supplier and third party (or buying party) of such equipment or materials.
        vi. Supplier will bear the responsibility for the quantity of meters and modules recycled as compared to the required nightly file containing meters and modules that have been removed from the field for retirement and recycling. Company will bear the risk of price fluctuations in an agreed-upon scrap market index. The recycling revenue less the Contractor's mark-up for handling/expenses/profit shall be credited against the progress payment.

vii. As part of this RFP, Supplier must state current price per pound that would be paid back to Company for meters and modules.

b. Company Salvage:
   i. Company will provide recycling containers to Supplier worksites for recycling of retired meters and modules through a third party.
   ii. Supplier will separate and segregate all environmentally hazardous materials and recycle or dispose of in accordance with Section 8.13 and 8.14.
   iii. The remaining meter and modules components will be placed in a Company-provided recycling container for recycling by a third party.

8.16 Requirement to Supply Miscellaneous Materials

1. Company shall provide the required installation materials including but not limited to: seals, rings, locks, and a-base socket adapters.
2. Supplier shall notify Company of its installation material inventory requirements no less than thirty (30) days prior to the scheduled requirement to for field installation.
3. Supplier must participate in inventory planning meetings.

8.17 Lock/Key Management

1. Company will provide Supplier keys for all Company owned locks, lock boxes, and barrel locks for accessing meters and/or locked meter rooms. All keys provided will be tracked and Supplier will be responsible for lost keys.
2. Additional keys that customers have provided to Company for Meter access may also be available from Company Meter Reading Department. Use of keys from the Meter Reading Department shall be coordinated and tracked by Supplier, and all keys shall be returned to Company within forty eight (48) hours.
3. Suppliers may not copy keys.

8.18 Required Skill Sets of Electric Meter Exchangers

1. Company will review Supplier's training program for electric Meter exchangers. Once the training program has been reviewed, Company will approve, ask to amend, or reject.

8.19 Supplier's Management Obligations

1. Supplier shall provide project management of the installation activities in accordance with methods outlined in PMP. Supplier shall:
   a. Establish work scope, schedule, and costs in consultation with Company
   b. Monitor work progress against the agreed-upon plans with Company
   c. Report on progress to Company weekly indicating the assignments issues, completions with respect to assignments and project schedule, ongoing concerns and resolution progress and any new concerns.
2. Supplier to provide staffing for daily dispatching, scheduling of appointments (as needed), electric Meter management/inventory, electric meter and module disposal, and other administrative duties as determined by Supplier.
3. Supplier shall continuously assess and monitor its employee's performance in day-to-day work and customer contact activities and where necessary, remove or retrain/requalify technicians.
4. Supplier shall ensure all relevant safety training sessions are held for field personnel.

8.20 Minimum PPE Requirements

1. All Supplier field personnel shall carry out their work meeting Company PPE requirements. Included, but not limited to, items are:

   a. Clothing – 8 cal/cm2 long-sleeve shirt (w/Supplier logo), natural fiber/self-extinguishing clothing elsewhere, including under garments.
   b. Appropriate fire rated pants.
   c. Gloves – Class 0 gloves for voltages under 600v, leather gloves or equivalent for non-electrical tasks based on Supplier's hazard assessment.
   d. Safety glasses - appropriate safety glasses/goggles are required.
   e. Safety shoes – steel-toe or equivalent.
   f. Hard hats – hard hat with E rating.
   g. Face shields – arc-rated face shield or hood appropriate for fault current. (277-480v, 3 phase, etc.).
2. All PPE equipment shall be provided by Supplier.

8.21 Vehicle Signage

1. Supplier shall provide vehicle stickers/magnetic signs approved by Company, identifying Supplier as an authorized contractor of Company and such signage shall be prominently displayed by Supplier at all times during the course of carrying out the work.
2. Supplier vehicles shall be well maintained and in good repair.
3. If vehicles are not Supplier owned, signage shall be removed from exterior of vehicles when not in use on behalf of Company.

8.22 Requirements for Integrating with Supplier Work Order Management Systems if Proposed

1. Company and Supplier will mutually define processes and integrations for the following:
   a. System integration of data transfer from Company systems to Supplier systems to support electric Meter installations as outlined in the requirements herein.
   b. System integration of data transfer from Supplier to Company systems to support completion of electric Meter installations in accordance with the requirements contained herein.
   c. Name of software Supplier will use to manage work orders for which Company will need to create or modify integrations.
   d. Resource titles, tasks, duration, and cost for completing process and integration work.

8.23 Required Security Screening/On-Boarding Procedures

1. Notwithstanding Supplier requirements for security screening and onboarding procedures that are outlined in the Major Supply Agreement, Supplier shall meet the following requirements:
   a. Supplier employees shall not perform any work on behalf of Company or have access to Company's or its customers' property until the employee has successfully passed Company screening processes, required training, and been issued a badge.
   b. Every Supplier employee will be required to follow a screening process that includes completion of request/supply of personal information. Samples of the required documentation are available from Company Sourcing.
   c. Once drug testing results and background screening has been completed and approved, Supplier will provide individual photos for each employee and ID badge requests will be submitted.
   d. Employee ID badges shall be worn at all times and shall be visible at all times and used as a form of identification upon customer request.
   e. All newly hired Supplier employees or its contractors shall be required to complete Company's required compliance training courses within first thirty (30) days of employment.

f. Supplier employees or its contractors shall be required, after employment, to complete any new Company required compliance training courses within thirty (30) days of training being made available.

g. Yearly and on-going compliance training courses are required by Company. If Supplier's employee(s) do not comply with all training courses and due dates, Supplier employee will be immediately off boarded and denied access to Company property and data. This applies to all Supplier personnel on the project regardless of whether or not they are working on Meter sets, networks, software, on site or off site.

8.24 Cyber and Physical Security Requirements

1. Cryptographic key material shall be properly handled, accounted for, and destroyed when appropriate to prevent unauthorized access to Company's network.

8.25 Requirements for All Training Programs

1. Supplier shall provide a copy of its training program outlining the process that will be used to train field technicians to ensure assigned work shall be properly completed in a safe and efficient manner.
2. Supplier training program shall be reviewed by Company to ensure it meet's Company's standards and, if needed, Company will have the right to request changes to the program.

9 Products and Services Warranties

9.1 Definitions

For purposes of this section, the following definitions shall apply. All other capitalized terms not defined in this section shall have the meaning ascribed to them in Appendix 1 (Essential Definitions and Acronyms) of this RFP. In the event of a conflict between the capitalized terms defined and set forth in this section and the defined terms in Appendix 1, the definitions set forth in this section shall control.

1.1 "**Annual Failure Rate**" means (i) the total number of a particular type of Goods having a Defect in any rolling twelve (12) month period divided by the total number of the same type of Goods delivered by Supplier in the rolling twelve (12) month period, or (ii) the total number of a particular type of Goods having a Defect in any Lot divided by the total number of Goods in the Lot.

1.2 "**Defect**" means any material defect in design, manufacturing, materials, workmanship or damage (where the damage is caused by Supplier or by any defect for which Supplier is responsible) in or to, as applicable, the Work, the Goods, or any part thereof.

1.3 "**Epidemic Failure**" means (i) with respect to Integrated Electric Meters, an Annual Failure Rate greater than 0.5%, and (ii) with respect to all other Goods, an Annual Failure Rate greater than 5%.

1.4 "**Goods**" shall include all Goods as defined in Appendix 1 (Essential Definitions and Acronyms) of the RFP.

1.5 "**Extended Goods Warranty Period**" means the period beginning on the date the Standard Goods Warranty expires and ending at the end of any additional warranty period for which Company has paid all applicable fees.

1.6 "**Integrated Electric Meter**" means an electric Meter provided by Supplier into which a NIC compatible with Company's systems has been integrated in accordance with applicable Specifications.

1.8 "**Lot**" means a set of any Goods of the same type with the same manufacturing location and critical components, such as application-specific integrated circuits (ASICs), processors, radios, printed circuit boards (PCB), initial Firmware loaded at time of manufacture, etc.

1.9 "**NIC**" has the meaning set forth in Appendix 1 (Essential Definitions and Acronyms) to this RFP.

1.10 "**Recall Failure**" means (i) an Annual Failure Rate greater than 5% in any particular Goods , (ii) a voluntary recall of any particular Goods (for example, due to safety issues), or (iii) an involuntary recall of any particular Goods (for example, due to a mandate of a Governmental Body).

1.11 "**Services Warranty Period**" means the period commencing on Final Acceptance and ending on the anniversary date one year thereafter.

1.12 "**Standard Goods Warranty**" has the meaning set forth in Section 9.3 (Standard Goods Warranty).

1.13 "**Software**" has the meaning set forth in Appendix 1 (Essential Definitions and Acronyms) to this RFP.

1.15 "**Standard Goods Warranty Period**" means the period commencing on acceptance of the Goods and ending:

(a) for Integrated Electric Meters, thirty six (36) months thereafter; or

(b) for all Goods other than Integrated Electric Meters, twelve (12) months thereafter.

9.2 Services Warranty

9.2.1 Warranty

During the term of the Services Warranty Period, Supplier shall warrant to Company that the Services are performed in accordance with standards of care, skill and diligence consistent with (i) recognized and sound industry practices, procedures and techniques; (ii) all applicable laws and regulations at the time the Services are performed; (iii) the Specifications, documents and procedures applicable to the Services; and (iv) the degree of knowledge, skill and judgment customarily exercised by professional firms with respect to services of a similar nature ("Services Warranty").

9.2.2 Remedy

Supplier shall, at its expense, promptly correct or correctly re-perform any non-conforming Services during the Services Warranty Period. Any corrected or re-performed Services will be warranted with the same scope as the Services Warranty for a period of ninety (90) days after delivery of the corrected or re-performed Services or until the end of the Services Warranty Period, whichever period is longer.

9.3 Software Warranty

9.3.1 Software Warranty

For a period of ninety (90) days from the date a piece of Software is installed and accepted by Company, Supplier shall warrant that the Software will substantially conform in all material respects to its Specifications and Documentation.

9.3.2 Remedy for Breach of Software Warranty

Supplier shall, at its option, during the warranty period described in this Section, repair or replace any non-conforming Software to substantially conform to the foregoing warranty.

9.3.3 Exceptions to Software Warranty

The Software warranty shall not apply to non-conformities in Software due to: (a) misuse or abuse, including the failure to use or install the Software in accordance with the Specifications; or (b) third party software, hardware or firmware not provided or authorized by Supplier in writing.

9.4 Standard Goods Warranty

9.4.1 Warranty

During the Standard Goods Warranty Period, and subject to Company's payment of all Standard Goods Warranty fees, Supplier shall warrant that all Goods (i) will perform in all material respects in accordance with applicable Specifications set out in this Agreement; (ii) will be free from Defects; (iii) on delivery, will be free and clear of any liens, security interests or encumbrances of any nature whatsoever, and (iv) will be produced, processed, delivered and sold or licensed in conformity with all applicable federal, state and local laws, administrative regulations and orders ("Standard Goods Warranty").

9.4.2 Remedy

For any breach of the Standard Goods Warranty, Supplier will, at its option and expense, and during the Standard Goods Warranty Period, promptly repair or replace any non-conforming Goods within fourty five (45) Business Days of Supplier's receipt of the non-conforming Goods and reimburse Company for its reasonable out-of-pocket costs incurred in shipping the Goods to Supplier.

9.5 Extended Warranty for Integrated Electric Meters

9.5.1 Extended Warranty Duration

Supplier shall offer Extended Warranties for Integrated Electric Meters for the following durations:

Standard Warranty Period	Extended Warranty Period	Total Warranty Period
3 years	2 years	5 years
3 years	7 years	10 years
3 years	12 years	15 years
3 years	17 years	20 years

9.5.2 Extended Warranty Scope

Subject to Company's payment of all Extended Goods Warranty fees, Supplier shall provide the same scope of warranty as the Standard Goods Warranty for the duration of the Extended Warranty Period (the "**Extended Warranty**"). Company's remedies for any breach of the Extended Goods Warranty shall be the same as the remedies provided for the Standard Warranty Period.

9.6 Epidemic Failures; Recalls

9.6.1 Warranty

Supplier shall warrant all Integrated Electric Meters against Epidemic Failures and Recall Failures for a period of twenty (20) years after acceptance.

9.6.2 Investigation of Failures

Supplier will, with Company's reasonable assistance, use commercially reasonable efforts to investigate and determine the cause of any Epidemic Failure or Recall Failure. Supplier's investigation shall begin within seven (7) days of receipt of notice from Company of an Epidemic Failure or Recall Failure, or Supplier's discovery of the Epidemic Failure or Recall Failure, whichever occurs earlier. Supplier shall provide a preliminary report of its investigation within (30) days of beginning the investigation.

9.6.3 Corrective Action Plan

The Parties shall work together to promptly establish and implement, at Supplier's expense, a corrective action plan to cure any Epidemic Failures or Recall Failures. If Supplier is unable to remotely repair Goods affected by an Epidemic Failure or a Recall Failure, the corrective action plan shall require, at a minimum, Supplier, at its expense, to:

(a) Repair and/or replace the affected Goods;

(b) Deliver such repaired and/or replaced Goods to Company;

(c) Pay prevailing union labor rates, if union labor is required, or non-union labor rates, if union labor is not required, in the applicable area for labor costs to repair and/or remove and replace such Goods; and

(d) For replacement Integrated Electric Meters, extend the Standard Warranty Period for the remaining life of the Standard Warranty Period to 51 months from shipment of the replaced Integrated Electric Meters.

9.6.4 Suspension

Until an Epidemic Failure or Recall Failure is cured to Company's reasonable satisfaction, Company may suspend all outstanding Purchase Orders, Work Orders, and Releases for any Goods of the same catalog number as the Goods subject to Epidemic Failure.

9.6.5 Monitoring Customer Data

Supplier will monitor data regarding the operation of (i) Supplier's other customers' products similar to Goods, and (ii) Goods ("Customer Data"). Supplier will notify Company if Supplier determines, based on Customer Data, that an Epidemic Failure or a Recall Failure has or is statistically likely to occur.

9.7 Additional Terms

9.7.1 Changes in Good Lots

During the goods installation period, Supplier will notify Company about any new Goods Lots.

9.8 Manufacturer Warranties

9.8.1 Terms

Supplier shall transfer and assign to Company any and all manufacturer warranties regarding any Goods supplied pursuant to this Agreement.

9.9 Exceptions to Warranties

Supplier shall have no liability to Company under this section or any other warranty to the extent such liability was caused by:

a. improper repairs or alterations, misuse, abuse, neglect, negligence, accident, or intentional acts by Company or a third party;
b. modifications made to Goods, Services, and Software without Supplier's prior written approval;
c. operation, maintenance or use of the System, Work, Goods, Software or any component thereof in a manner not in compliance with a material requirement of operation or maintenance manuals delivered by Supplier to Company at the time of delivery of the non-compliant System, Work, Good, Software or any component thereof;
d. normal wear and tear;
e. incorrect data entry or output by Company or a third party not under Supplier's control; or

f. Force Majeure conditions.

9.10 Requirements for Return Material Analysis (RMA)

1. Supplier will perform returned material analysis (RMA) on all returned goods within sixty (60) days of Company's shipment of the returned goods, and, by the fifteenth (15^{th}) day of each month, provide Company an RMA Report that analyzes at aggregate by good type:
    a. Performance and operational issues discovered.
    b. Incremental and cumulative to-date (since model's introduction to Company) quantity of Meters affected.
    c. Initial prognosis, to include specific malfunctioning component to assembled Meter.
    d. Anticipated steps for resolution by Supplier,
    e. On a quarterly basis, beginning on the one (1) year anniversary of the Effective Date, Company and Supplier shall meet to review the results of the equipment failure analyses and develop strategies for addressing recurring Meter performance and operational issues.
2. The same monthly RMA report will have a separate section with specific analysis of each good returned, with none dating further than sixty (60) days prior, and that includes no less than the following for each returned good:
    a. Meter ID
    b. NIC ID
    c. Reason for removal (specific event error code or unsolicited exchange) originally provided by Company
    d. Date that event was generated originally provided by Company
    e. Date removed from field originally provided by Company
    f. Confirmation of agreement to Company's index reading of Meter
    g. Date inspected
    h. Inspector name, ID or test machine ID where appropriate
    i. Problem found
    j. Supplier resolution
3. Any Meter that will be reused by Supplier and be procured by Company will be certified through testing in accordance with Company standards.
4. Supplier will provide As Found metrology and communication test results on electric Meters removed from the field that will be retrofitted for reuse. The results will be provided to Company for further analysis.
5. Supplier will perform an As Left metrology and communication test and calibration of Meters. Meter calibration tests and performance standards will be within Supplier's standards for such Meters. All updated test results shall be sent to Company for updates.
6. Supplier shall identify, diagnose, and determine remedy for all operational and performance issues affected by the Meter and NIC and provide Company with a comprehensive report on all identified issues with.
7. Supplier shall make all reasonable efforts to determine all issues including intermittent ones and not use no trouble found as an appropriate diagnosis. Reasonable efforts shall include but not limited to tests under varying temperature conditions and load over an extended period of time.
8. Supplier shall establish a resolution matrix that identifies responsibilities for how defects associated with Meters versus NIC components shall be addressed. Such a matrix shall be shared with Company before contract execution.

10 Maintenance Support Provisions

10.1 General Requirements

1. Suppliers shall offer support for the life of the product:

   a. Help desk/technical advice.
   b. Service/repair capabilities and,
   c. Equipment replacement supply capabilities.

10.2 Requirements of Supplier

1. Provide staffed help desk offering technical support by telephone with 1-800#, email, and Internet chat advice service during normal business hours 8:00am to 5:00pm local time (Central and Mountain Time).
2. Guarantee of access to a knowledgeable individual by telephone within four (4) hours of a service support request.
3. Maintain a secure web-based bug or issue reporting and tracking system.
4. The primary path to report and manage issues shall be through the customer support group. Supplier support engineers shall help troubleshoot issues, open and track tickets, process requests and route issues to the correct Supplier teams for resolution.
5. On-call and possibly on-site assistance in troubleshooting end-point communication issues.

10.3 Equipment Replacement Supply Capabilities

1. Where replacement equipment is necessary to affect repair, it shall be supplied under the terms of the relevant equipment warranty (Section 9-Supplier’s Comprehensive Integrated Meter Warranty).
2. For any field Meter maintenance service requested by Company, not otherwise covered under Warranty terms (Section 9), Supplier shall be in a position to provide maintenance service. Supplier shall deliver services based on Supplier’s Exhibit X-Maintenance Program, in accordance with the labor rates in Supplier’s Rate Card.

10.4 Ongoing Maintenance

1. For any field Meter maintenance service requested by Company, not otherwise covered under Warranty terms (Section 9 – Supplier’s Comprehensive Integrated Meter Warranty), Supplier shall be in a potision to provide maintenance service in the field. Supplier shall provide a separate exhibit describing Supplier’s field maintenance program. (Exhibit x-Maintenance Program). Supplier shall provide a rate card including, at a minimum: trades, hourly rates, and travel expenses.

10.5 Training Requirements

10.5.1 On-site Training

1. Supplier shall provide an on-site training program that shall include, but not be limited to: training material, schedule, and topics which shall be offered in a classroom/or web-based as appropriate. Training topics can include operations, diagnostics, maintenance, and installation.
2. Training program shall include classroom or field time as appropriate with an on-site qualified instructor or subject matter expert.

3. Training program shall be for Engineers and Meter Technicians and shall be comprehensive and interactive. Program shall be intended to demonstrate and instruct on the subject of Supplier's hardware, software, and tools.
4. Training shall include field installation, maintenance, and diagnostic demonstrations and an installation manual to grant participants a working knowledge of Supplier's AMI Meters without continuous support by Supplier.
5. Supplier shall work with Company to provide additional time in training courses for training material required for Meter Technicians and Engineers on external communication.
6. Company does not require skills testing and certification for training program.
7. Training shall be set up in modules that will be relevant to different groups within Company.
8. The classroom training shall be supplemented with a set of web training sessions given at flexible times throughout the deployment or in a single or multiple-day live training session.
9. Company may record any training provided by Supplier for use and distribution by Company for internal training purposes.
10. All training material will be provided in a format that is acceptable to Company and stored in a repository for future training purposes.
11. Supplier shall provide train-the-trainer session(s) to transfer knowledge to Company on training material and requirements.
12. On-site training and web training, where applicable, shall cover no less than the following topics:
    a. Theory and design of the supplied Meters.
    b. Operation techniques and features of the Meter.
    c. Hardware design configurations.
    d. Meter firmware update – local and remote.
    e. Meter programming – local and remote.
    f. Diagnostics interpretation for troubleshooting on a daily basis.
    g. Techniques for firmware upgrading including but not limited to Meter metrology and NICs.
    h. Safety issues concerning physical installation and RF.
    i. Cyber and physical security.
    j. Understanding the mounting configuration and operation.
    k. Physical installation techniques.
    l. Electrical connections.
    m. Grounding and lightning protection.
    n. Initial set-up and testing.
    o. Problem-solving and troubleshooting techniques.
    p. Compliance with ECC regulations in the installation and operation.
    q. Field Tool operation and use.
    r. Trouble shooting for the wireless connection.
    s. Diagnostics for meter theft and voltage detection at the socket.

10.5.2 Factory Training

1. Supplier shall offer an optional factory training program. Factory training shall mean training provided at Supplier's site on the use of systems.
2. Factory training shall include additional topics as defined by Company.

10.5.3 Optional Training Modules

1. Supplier shall offer additional or repeat training courses as needed.

11 Appendix 1 – Essential Definitions and Acronyms

Contracting Related, Short Forms, and Acronyms

1. AMI – Advanced Metering Infrastructure (AMI) is architecture for automated, two-way communication between an advanced utility Meter with an IP address and a utility Company.
2. AMI System – The collection of interworking components parts including hardware, software, integration, installation and intellectual content forming the complete functional AMI environment.
3. AGIS – Advanced Grid Intelligence and Security.
4. ATP – Acceptance Test Plan. A document that defines certain technical and operational tests that are required to be completed by Supplier, and witnessed by Company for the purpose of defining a set of technical and operational conditions that must be satisfied. The ATP includes both identification of the required tests and the procedures that are expected to be followed so as to carry out the tests.
5. AQL- Acceptable Quality limit is the worst tolerable process average (mean) in percentage or ratio that is still considered acceptable.
6. Bill Window – Three (3) business days from the date Meter reading routes are available to be read by cycle. Each route has a specific date it becomes available to be read. For example, Cycle 1 for May 2017 was first available to be read on 04/28/2017 and therefore the three business day window would run from 4/28/2017 to 05/02/2017. Meter can be read anytime during the three business day window. Company has 22 read cycles.
7. Blocks – Geographically defined areas of land delineating territory for electric service that is offered by Company.
8. BOM – Bill of Materials.
9. Company – As defined in the Agreement.
10. Company Security Standards – The standards defined in Appendix 2.
11. Contractor – Company or personnel hired by Supplier as contractors.
12. Cost Take Out – Any trackable effort to reduce soft or hard cost associated with this multiyear project resulting in the benefit of optimized service, hardware, support, maintenance and/or warranty for Company or both parties.
13. DA – Distribution Automation. In this document, DA refers to the control aspects of electric field automation, often referred to in the context of SCADA systems.
14. DA System – The collection of interworking components parts including hardware, software, integration, installation and intellectual content forming the complete functional control and monitoring environment for various forms of electric distribution system automation.
15. Design – The plan and assembly of equipment for implementation/construction of the system components including engineering drawings, parts, circuit diagrams, etc.
16. Document – A solicitation made through a bidding process by Company in procurement of a commodity, service, or valuable asset, to potential Suppliers to submit business proposals.
17. Engagement Manager – The fully qualified and experienced Supplier individual having the responsibility for the business and financial aspects of the project.
18. Failure, as related to AMI Loss of Communication – Where any devices are intended to communicate and they cannot communicate or any reason, it has failed.
19. Failure, as related to AMI Meter Accuracy – If it is not within specified parameters set out herein, it has failed.
20. Field Work – The performance of maintenance on Meters performed by Supplier on behalf of Company.
21. Field Work Orders – Company-generated order requiring Supplier to perform Field Work.
22. Functional Requirements – What the system does. This would include general descriptions of features, capabilities, information, etc.
23. Gantt Chart– A project management oriented graphical presentation that is prepared to illustrate predicted and (later) actual start and finish dates of the elements of the project. A Gantt chart visually presents project elements, timelines for start and completion and the critical components, all of which are

useful to identify, monitor and manage, so as to gain successful project completion against a well-defined) scope, schedule, and cost.

24. Goods - Supplier hardware and related accessories and other personal property (except Documents)
25. Head-end – A system of hardware and software that receives streams of data brought back to utility through the AMI system.
26. INS - Itron Networked Solutions.
27. ISOW – Independent Statement of Work.
28. Meters – Electric AMI Meters.
29. MSOW – Master Statement of Work.
30. Mobile Computing Environment – Company's Mobile Computing Environment, the wireless network environment utilized to collect, manage, and communicate information in performing Field Work and which is capable of interfacing with Company's software and applications, including, without limitation, MDMS and CRS.
31. MOU – Memorandum of Understanding.
32. MPS – Master Pricing Schedule.
33. MTS – Master Test Strategy.
34. MFC – Most Favored Customer.
35. NOC – Network Operations Center.
36. Non-Functional Requirements – Description of the system, such as constraints, usability, reliability, performance, capacity, and supportability.
37. NSPM – Northern States Power Minnesota.
38. NSPW – Northern States Power Wisconsin.
39. OEM – Original Manufactured Equipment.
40. OPCo – Operating Company.
41. Pert Chart – A project management oriented graphical presentation that is prepared to illustrate the relationship of tasks or project elements as they relate to project flow from commencement to completion over the project lifecycle.
42. PMP – Project Management Professional, as recognized by the Project Management Institute (see PMI.org).
43. Project Manager – Fully qualified and experienced individual both from Supplier and Company having the responsibility for the planning, execution and closing of the project.
44. PSCo – Public Service Company of Colorado.
45. RFP – Request For Proposal.
46. Services – Includes Meter installation or exchange services.
47. Single Phase Underground Installation – Termination at the pedestal and installation of Meter at the customer facility in accordance with Company standards.
48. Special Meter Reading – Retrieval by Supplier and delivery to Company of data from Meters designated by Company. Special Readings are typically generated because of End User billing disputes or generated Meter events.
49. SPS – Southwest Public Service.
50. SOW – Statement of Work. The document that defines the necessary work activities and obligations by Supplier and that forms part of binding contractual conditions of Supplier.
51. Supplier – A Corporate entity that is proposing to supply equipment and Services in response to this Request for Proposal.
52. Survey Meters – Meters specifically configured to collect load profile data for load research purposes.
53. SSA – Support Services Agreement.
54. SSN – Silver Spring Networks, now known as Itron Networked Solutions.

Technical Related, Short Forms, and Acronyms

1. 6LowPAN – IPv6 over Low power Wireless Personal Area Networks.

2. ADA – Advanced Distribution Automation. Systems that apply modern computational and communications techniques to intelligently control electrical power grid functions to the distribution level and beyond.
3. ADMS – Advanced Distribution System Management System. A unified DMS, SCADA, OMS AND EMS solution that provides utilities with a modular and flexible platform within a common user experience, data model, integration framework, and secure infrastructure.
4. Advanced Grid – (From the Office of Electricity Delivery and Energy Reliability) a class of technology people are using to bring utility electricity delivery systems into the 21st century, using computer-based remote control and automation.
5. AES-256 – Advanced Encryption Standard. Standard to protect classified information; implemented in software and hardware to encrypt sensitive data.
6. Aggregator – System that collects AMI data.
7. Automated Sectionalizing – Systems used by utility electric distribution and transmission operators to perform circuit sectionalizing by means of remote control of a variety of different protective devices installed across the electric grid for the purpose of protecting the system from damaging fault currents and minimizing the time and number of consumers experiencing an outage.
8. AMI Meter – Combination of Meter metrology, register, and communication.
9. AMI Meter Failure – Any failure of Meter/Network Interface Card to perform its function within specifications.
10. Back Office – A suite of applications, supplied by Supplier that are deployed on a standards-based Critical Infrastructure Networking Platform. The applications enable utilities to support multiple advanced grid applications on common infrastructure. The Back Office Systems application suite includes utility applications for advanced grid initiatives as well as network administration software for configuring, upgrading, and managing the advanced utility network.
11. B.E. – Best effort.
12. BER – Bit Error Rate.
13. Border Router – A NAN defined WMN routing deployment-ready platform for interconnecting IP and 6LoWPAN networks. It assumes an Ethernet interface on the IP side and an 802.15.4g interface on the 6LoWPAN side.
14. CDF – Cumulative Distribution Function; a useful means to quantify statistical network performance metrics. In probability theory and statistics, CDF of a real-valued random variable X, or just distribution function of X, evaluated at X, is the probability that X will take a value less than or equal to X.
15. CPI – Consumer Price Index
16. CRS – Company's computer system designed to generate End User bills, collect information regarding End Users, monitor End User complaints, and disseminate information to End Users.
17. CSS – Customer Service System.
18. CVR – Conservation Voltage Regulation. Systems that facilitate controlled reduction in the voltages received by an energy consumer to reduce energy use, power demand, and reactive power demand.
19. CPE – Customer Premise Equipment, used in the context of WiMAX, formally defined as Subscriber Station component of a WiMAX system.
20. CPP – Critical Peak Pricing rate offering.
21. CT – Instrument Current Transformer.
22. Customer Outage – Customer interruption of service.
23. C&I – Commercial and Industrial Customers.
24. DER – Distributed Energy Resources. Decentralized energy that is generated or stored by a variety of small, grid-connected devices such as solar, wind, or battery.
25. DA – Distribution Automation. In this document, DA refers to the control aspects of electric field automation, often referred to in the context of SCADA systems.
26. DG – Distributed Generation.
27. DMS – Distribution Management Systems. A collection of applications designed to monitor and control the entire distribution network efficiently and reliably.
28. DSCP – Differentiated Services Code Point.

29. DR – Demand Response. (From the Federal Energy Regulatory Commission) is defined as “Changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized”.
30. ERT – Encoder Reciever and Transmitter.
31. ESP – Energy Service Portal.
32. EV Charging – Electric Vehicle battery charging systems. Systems that are used to charge the batteries of electric vehicles, sourcing energy over the grid.
33. FAN – Field Area Network. A collection of (usually) wireless networks, operating over a large geographic area for the purpose of providing data services.
34. FAST AMI – Meter read rates for all Meters, excluding bellwether Meters, shall record interval, register and events data every fifteen (15) minutes and complete transmission of this recorded data to the Head-end, at an interval that does not exceed every fifteen (15) minutes.
35. FAT – First Article Testing.
36. FLISR – Fault Location Isolation and System Restoration. Combines hardware, software, telecommunications, and grid engineering to decrease the duration and number of customers affected by any specific outage.
37. Field Communication Tool – The devices and instruments that are used by AMI field personnel to communicate wirelessly, over the air to electric Meters and network.
38. HAN – Home Area Network.
39. HTTPS – Secure version of Hypertext Transfer Protocol (HTTP), using SSL.
40. IEEE – Institute of Electrical and Electronics Engineers. A professional association dedicated to advancing technological innovation and excellence for the benefit of humanity. In Company context, IEEE defines standards for wired and wireless communications.
41. IETF – Stands for Internet Engineering Task Force, a large open international community of network designers, operators, vendors and researchers concerned with the evolution of the Internet architecture
42. IHD – In Home Display.
43. IoT- Internet of Things
44. IP – Internet Protocol address is a numerical label assigned to each device such as computer and printer participating in a network that uses internet protocol communication.
45. IPv6 – Internet Protocol version 6 is the most recent version of the Internet Protocol (IP), the communication protocol that provides and identification and location system for computers on networks and routes traffic across the Internet.
46. ISOW – Individual Statement of Work.
47. ISP – Internet Service Provider.
48. IT – Information Technology, the use of systems (especially computers and telecommunications) for storing, retrieving, and sending information.
49. IVVO – Integrated Volt/VAR Optimization, Voltage/Voltage-Ampere Reactive Optimization. A suite of modern control technologies that use extensive sensor data, wireless communication links, and computational control systems to increase grid visibility and efficiency. Generally, IVVO technology operates by gathering extensive performance metrics on power lines and equipment through a wireless network, then adjusts and optimizes system performance through data analysis and control actions.
50. JTAG – Joint Test Action Group. An electronics industry association for developing a method of verifying designs and testing printed circuit boards after Supplier.
51. KYZ – Electronic pulses used to represent amount of energy consumed.
52. LAN – Local Area Network.
53. Logging – Recording and storage of data.
54. LOT – A group of homogeneous devices where the selection of the devices in the LOT is based upon one or more specific criteria such as operating company (i.e., PSCo), Supplier, Meter model, Meter form, Meter class, age, or any other attribute as required for analysis purposes.
55. LP – Load Profile Data.
56. MAIFE – Momentary Average Interruption Frequency Index Event.

57. MAIFI – Momentary Average Interruption Frequency Index.
58. MDM – Meter Device Management.
59. MDMS – Monitoring Device Management System; Company lifecycle asset system.
60. Momentary Interruption – The brief loss of power delivery to one or more customers caused by the opening and closing operation of an interrupting device. NOTE: Two circuit breaker or recloser operations (each operation being an open followed by a close) that briefly interrupt service to one or more customers are defined as two momentary interruptions.
61. Momentary Interruption Event – An interruption of duration limited to the period required to restore service by an interrupting device. NOTE 1: Such switching operations must be completed within a specified time of five minutes or less. This definition includes all reclosing operations that occur within five minutes of the first interruption. NOTE 2: If a recloser or circuit breaker operates two, three, or four times and then holds (within five minutes of the first operation), those momentary interruptions shall be considered one momentary interruption event.
62. MCE – Mobile Computing Environment.
63. MDT –Mobile Data Terminal. Could be a notebook/laptop or field tool used by field personnel for completion of assigned work.
64. Module – Itron ERT or Landis+Gyr AMR interface units.
65. MSOW – Master Statement of Work.
66. MTTR – Mean Time to Repair.
67. NAN – Neighborhood Area Network.
68. NIC – Network Interface Card.
69. NMS – Network Management Systems. Electronic systems consisting of hardware and software used in the setup, configuration, dimensioning, management, and monitoring of data networks.
70. NTP – Network Time Protocol. Internet protocol used to synchronize computer clocks to a time reference.
71. OEM – Original Equipment Manufacturer.
72. OMS – Outage Management System. A computer system used by operators of electric distribution systems to assist in restoration of power.
73. OSI – Open Systems Interconnection model (OSI model) is a conceptual model that characterizes and standardizes the communication functions of a telecommunication or computing system without regard to their underlying internal structure and technology.
74. OWASP – Open Web Application Security Project. Organization focused on improving security of software.
75. Outage – Per IEEE definition of outage, is the loss of ability of a component to deliver power.
76. P2MP – Point to Multipoint Radio Systems. A wireless radio system that generally consists of a single base station that communicates virtually with multiple endpoints.
77. P2P – Point to Point Radio Systems. Wireless radio systems that enable wireless communications circuit between two distinct endpoints.
78. PEN – Penetration testing is the practice of testing computer and network systems to find vulnerabilities that could be exploited.
79. PHY – In networking terms, a short form for the component that operates at the physical layer of the OSI layer of the OSI network model.
80. PII – Personally Identifiable Information. Information that can be used on its own or with other information to identify, contact, or locate a single person, or to identify an individual in context.
81. PKI – Public Key Infrastructure. A set of roles, policies, and procedures needed to create, manage, distribute, use, store, and revoke digital certificates and manage public key encryption.
82. PPE – Personal protective equipment.
83. PTR – Peak Time Rebate rate offering.
84. PQ – Power Quality.
85. PTJ – Process Tracking Job.
86. QoS – Quality of Service.
87. RAM – Random Access Memory.
88. RF – Radio Frequency.
89. RMA – Return Material Analysis.
90. RSSI – Received Signal Strength Indicator.

91. RTT – Round Trip Time. The length of time it takes for a signal to be sent plus the length of time it takes for an acknowledgment of that signal to be received.
92. RTU – Return To Utility.
93. SAP – Systems, Applications, and Products in Data Processing is a German multinational software corporation that makes enterprise software to manage business operations and customer relations.
94. SC – Self Contained Meters.
95. SCADA – Supervisory Control and Data Acquisition; Systems used for remote monitoring and control that operate with data signals over communication channels.
96. SEP – Smart Energy Profile.
97. SFTP – Protocol for file transfer over SSH (secure shell)
98. SIEM – Security Information and Event Management. Software products and services that provide real-time analysis of security alerts generated by applications and network hardware.
99. SMA – Sub Miniature version A type connector. A semi-precision coaxial RF connector having a 50 Ω impedance.
100. SNMP – Simple Network Management Protocol is an Internet-standard protocol for collecting and organizing information about managed devices on IP networks and for modifying that information to change device behavior. Devices that typically support SNMP include cable modems, routers, switches, servers, workstations, printers, and more.
101. SNR – Signal to Noise Ratio.
102. Soft Key – Mechanisms by which built-in factory features/hardware can selectively be enabled using separately purchased authorizations.
103. Software - Supplier's proprietary software.
104. Solicited Field Work – Field work requested by Company and performed by Supplier or Supplier Contractor.
105. SSH – Secure Shell
106. SSL – Secure Sockets Layer
107. SUN – Smart Utility Network. Networks that are compliant to IEEE 802.15 Smart Utility Networks (SUN) Task Group 4g, consisting of a PHY amendment to 802.15.4, and providing a global standard that facilitates very large scale process control applications such as the utility smart-grid network capable of supporting large, geographically diverse networks with minimal infrastructure, with potentially millions of fixed endpoints.
108. TCP/IP – Transmission Control Protocol/Internet Protocol. Suite of communication protocols used to interconnect network devices on the Internet.
109. TLS – Transport Layer Security
110. TOU – Time of Use rate offering.
111. T-Min – Minimum time.
112. T-Max – Maximum time.
113. TVHD – Total Voltage Harmonic Distortion.
114. UI – User Interface.
115. Un-solicited – Work peformed by Supplier or Contractor without request from Company.
116. TR – Transformer rated Meters.
117. VT – Instrument Voltage Transformer.
118. FAN – Field Area Network
119. WMN – Wireless Mesh Network. Refers to any wireless network that operates in a topology in which endpoint mesh nodes cooperate in the distribution of data, relaying information between neighbors. NAN is an example of a WMN. In the context of Company, WMN shall mean equipment and services that are necessary to implement a SUN compliant network.
120. WiMAX CPE or CPE – Customer Premise Equipment, referring to the wireless endpoint equipment on a WiMAX system (although the term may be generalized to other wired or wireless systems). It generally consists of an antenna and transmission line feed system as well as the electronics unit which may be placed inside or exterior to a building (dwelling) or enclosure.
121. WIMAX – Interoperable implementations of the IEEE 802.16 family of wireless-networks standards ratified by the WiMAX Forum.

122. Zigbee - IEEE 802.15.4 based specification Wireless communications protocols used to create personal areas networks.

12 Appendix 2 – IT Standards

IT Standards

Hardware/Device/ Application/Tool/Software	Xcel Standard	Notes
CISCO Flexpod	Series B, Series C	Current version is "CORE" stage of the Standards Lifecycle.
CISCO NetApp Filer (Storage)		Current version is "CORE" stage of the Standards Lifecycle.
Redhat Linux Enterprise Edition Server	7.2	Current version is "CORE" stage of the Standards Lifecycle.
Microsoft Windows Server 2016	2016	Version is "Strategic" stage of the Standards Lifecycle.
Microsoft SCCM	7	Version is "Declining" stage of the Standards Lifecycle
Microsoft Windows 10 *(IE 11/Chrome 24+)*	7	Version is "Strategic" stage of the Standards Lifecycle.
Microsoft SQL Server 2016	2016	Current version is "CORE" stage of the Standards Lifecycle.
Backup (Symantec NetBackup)	7.7.2	Version is in "CORE" stage of the Standards Lifecycle.
McAfee Anti-Virus	8.8	Version is in "CORE" stage of the Standards Lifecycle.
CheckPoint Firewall	R80.10, R80.00, R77.30, R77.20	Version is in "CORE" stage of the Standards Lifecycle.
AD/AD LDS	69/31	Version is "Strategic" stage of the Standards Lifecycle.
Terminal Services	2016	Version is "Strategic" stage of the Standards Lifecycle.
ESXi	6.x	Version is "Strategic" stage of the Standards Lifecycle.

SCCM	2016	Version is in “Strategic” stage of the Standards Lifecycle.
CyberArk Password Vault	8.2	Current Standard is CORE for this version.
IBM Integration Bus	IIB 10	Version is in “Strategic” stage of the Standards Lifecycle.
Oracle Database EE on Exadata version X6-2	12.c	Version is in “CORE” stage of the Standards Lifecycle.
Information Model Exchange	CIM	
PING Fed	7.3	Version is in “CORE” stage of the Standards Lifecycle.
Web Traffic	https	Version is in “CORE” stage of the Standards Lifecycle.

13 Appendix 3 – PSCo Electric Meter Deployment (Preliminary)

PSCo Electric Meter Deployment

Block	Quarter	Branches	Meter Count	General Location
Block 1	2019 Q4	DM, NM, SE, SW	15,881	Bellwether meter deployment, mainly in metro Denver (Denver)
Block 2	2020 Q1	DM, SW	39,227	South and Southwest of Downtown Denver (Denver)
Block 3	2020 Q2	DM, SW	40,373	SW of DT Denver, along Sixth Avenue (Lakewood)
Block 4	2020 Q3	SW, NO	38,723	Along Sixth Avenue, intersection of I-70 and US 6 (Lakewood and Golden)
Block 5	2020 Q4		40,492	Along I-70, West of DT Denver (Wheat Ridge, Edgewater, and Arvada)
Block 6	2021 Q1	SW, NO, DM, SE	100,840	West, South, and East of DT Denver (Denver and Edgewater)
Block 7	2021 Q2	SE, SW, DM	99,944	SE of DT Denver along Parker Road (Denver, Glendale, and Aurora)
Block 8	2021 Q3	SW, SE	105,057	S of Colfax along 225, along Hampden and Belleview to Wadsworth. (Aurora, Cherry Hills Village, Greenwood Village, Sheridan, Littleton, Bow Mar)
Block 9	2021 Q4	SW	98,766	SW, S of Evans along 470 to University (Morrison, Littleton)
Block 10	2022 Q1	SW, SE	116,647	S of 470, S of 225 out to Parker Road (Highlands Ranch, Centennial, Lone Tree)
Block 11	2022 Q2	SE	115,904	E of Parker Road, E of 225, E of Peoria, up to DIA (Aurora, Watkins, Parker, Denver)
Block 12	2022 Q3	DM, NO	127,449	N of Colfax, along I-70, East, North, and Northeast of DT Denver (Denver, Commerce City, Arvada, Thornton, Dupont)
Block 13	2022 Q4	NO	121,023	N of I-70, from foothills to I-76, S of 104th. (Northglenn, Thornton, Westminster, Commerce City)
Block 14	2023 Q1	NO, DM, BD	115,090	DT Denver, N of 104th (Henderson, Brighton, Broomfield, NorthGlenn), Boulder Division around Broomfield
Block 15	2023 Q2	BD, HL	120,324	Boulder county, Greeley
Block 16	2023 Q3	100% of Evergreen, Silverthorne, Vail, Leadville, Salida, and Alamosa. 48% of Fort Collins.	110,246	I-70 to Evergreen to Silverthorne to Vail. US-24 to Leadville to Salida and then to SLV/Alamosa. Start Fort Collins
Block 17	2023 Q4	52% of Fort Collins. 100% Brush, Sterling, and Grand Junction	96,880	Fort Collins, then along I-76 to Brush and then Sterling. Grand Junction
Block 18	2024 Q1	100% Rifle	17,172	Rifle

Block 19	**2024 Q2**			**Empty**
Subtotal			**1,520,038**	**Excludes electric meters inside Boulder**
City of Boulder	**?**	**BD**	**67,574**	**All electric meters inside city of Boulder**
Total			**1,587,612**	**All electric meters in PSCO**

14 Appendix 4 – PSCo Electric Meter Purchasing Schedule (Preliminary)

PSCo Electric Meter Purchasing Schedule

					Arrival comparison to planned deployment							
		Orange= Commulative Installment goal					Green = Commulative meter arrival					
	Jan	Feb	Mar	Apl	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2018												
2019			0	0	0	0	1200	7200	13200	21200	29200	37200
												15881
2020	57200	77200	97200	115200	133200	151200	169200	179200	189200	201200	213200	223200
			54521			94857			132459			171611
2021	238200	250200	286200	322200	358200	414200	470200	526200	582200	600200	618200	636200
			272421			372211			472755			570490
2022	660200	684200	708200	744200	780200	816200	852200	908200	964200	1019200	1063200	1107200
			697691			809159			930182			1048106
2023	1149200	1173200	1237200	1281200	1325200	1353200	1397200	1425200	1469200	1497200	1519200	1529200
			1161217			1276251			1391104			1506794
2024	1551200	1559200	1567200	1575200	1583200	1588000						
			1546979			1587607						

15 Appendix 5 – Meter Calibration File Format

Overview and Bidder Instructions

Dear Bidder,

You have been invited by Xcel Energy Services Inc. (hereinafter referred to as “Xcel Energy”) to submit information in response to a request proposal (“RFX”). This document contains important information about Xcel Energy and the RFX and we suggest you take the time to read it carefully. We look forward to your proposal submission using our electronic sourcing system (the “eSourcing System”).

Thank you.

About Xcel Energy at www.xcelenergy.com

Our name reflects our core value — excellence in energy products and services. We are dedicated to providing you the best in service, value and information to enhance your professional and personal life. We are committed to customer satisfaction by continuously improving our operations to be a low-cost, reliable, environmentally sound energy provider. We have been successfully proving this to our customers for more than 130 years and will work hard to continue with this commitment in the future.

As a leading combination electricity and natural gas energy company, we offer a comprehensive portfolio of energy-related products and services to 3.4 million electricity customers and 1.9 million natural gas customers.

We have regulated operations in 8 Western and Midwestern states, and revenue of more than $9 billion annually; and own more than 35,000 miles of natural gas pipelines. We are proud of our community involvement. Through the Xcel Energy Foundation, our economic development activities, and employee volunteer efforts, we are committed to using our considerable resources and skills to benefit the communities we serve.

Our environmental policy states that Xcel Energy will be valued as a leader in the energy industry by demonstrating excellence in environmental performance. The most recent National Renewable Energy Lab's ranking of green pricing programs ranked our Windsource® and Renewable Energy Trust first in number of customers and fifth in energy sales out of over 500 U.S. utilities. Our key environmental commitment includes improving air quality, conserving resources, harnessing renewable energy, and protecting wildlife and habitats.

Proposal Evaluation Criteria

Xcel Energy’s objective in sourcing via the eSourcing System, Emptoris, is to obtain goods and services that best meet technical and functional requirements at the best price. Proposals will be evaluated by Xcel Energy on the basis of the information provided by you through the eSourcing System. The lowest price proposal may not indicate the best overall evaluated proposal. The following criteria may be used by Xcel Energy in its consideration (not necessarily listed in order of importance):

- Bidder’s understanding of and responsiveness to the scope of work, technical specifications and other requirements
- General feasibility of the bidder’s plan to meet the requirements of the scope of work and/or technical specifications
- Bidder’s ability to meet the stated work schedule
- Bidder's acceptance of the general terms and conditions
- Bidder’s experience with similar work and safety record
- The evaluated total cost of the services and/or goods
- The quality of services offered by the bidder

- Comprehensiveness of the bidder's proposal, including options
- Bidder's diversity classification or utilization of diverse suppliers as subcontractors; and demonstration that bidder has made good faith efforts to provide maximum practicable subcontracting opportunities to diverse suppliers

Bidding Instructions

Failure to comply with these bidding instructions may disqualify a bidder from further consideration.

- Xcel Energy requires that all bidders (and their subcontractors, alliances, or partners) provide a single point of contact during the RFX process.
- In the eSourcing System, click on the green **"Accept"** button to indicate your intention to respond or click the red **"Decline"** button to indicate your intention not to respond. During the course of your review and response you can indicate that you wish to not proceed further.
- Correspondence or questions concerning the RFX content and attachments **must be sent using the eSourcing System's messaging functionality** to the Xcel Energy Sourcing & Purchasing Contact / ("Event Owner"). The name of the "Event Owner" is listed in the upper left hand corner of the RFX, labeled as "Contact Information". Instructions on how to send messages are provided in the computer based training module titled *Using System Messaging*. All responses to technical questions will be answered via the eSourcing System's messaging functionality to the RFX and issued to all bidders. Contacting anyone besides the Event Owner about this RFX may be grounds for disqualification.
- All bidding, both qualitative and quantitative, will be submitted through the eSourcing System. You will be asked to answer a number of questions, including pricing on items.
- All submissions must be submitted on time per the schedule indentified in the RFX. Late submittals will not be accepted.
- All submissions must be complete in order to be evaluated. **Incomplete submissions will not be accepted.** The bidder's proposal must be all-inclusive to provide complete and reliable services and/or goods to meet the requirements and technical specifications documented in the RFX.
- The bidder shall not alter any part of the RFX in any way except by stating all exceptions in a response to the appropriate question or as an attachment to the appropriate question with a detailed explanation for each exception.
- Any modification made to the RFX by Xcel Energy will be made through the eSourcing System.
- The bidder shall separately state in its proposal all taxes (including sales, use, and other excise taxes) it believes to be imposed by law upon the transfer of equipment or other materials to Xcel Energy or upon the provision of services. Please contact the Event Owner for applicable tax rates.
- If you have difficulties with the eSourcing System, you may contact the Xcel Energy Supply Chain Hotline at 303-628-2644 from 8:00 a.m. to 5:00 p.m. (MST) Monday through Friday.

RFX Terms and Conditions

In addition to the terms and conditions you accepted on the eSourcing System login screen, the following terms and conditions apply to the RFX:

- **Bidder's submission of proposal information in response to this RFX shall constitute bidder's agreement to these terms and conditions.**
- All costs associated with bid preparation and the provision of related documents are to be borne by the bidder.

Xcel Energy RESPONSIBLE BY NATURE™

- Xcel Energy reserves the right to open proposals privately and unannounced, and to be the sole and final judge of all proposals.
- Bidder's proposal is genuine and not made in the interest of or on behalf of any undisclosed person, firm, or corporation and is not submitted in conformity with any agreement or rules of any group, association, organization, or corporation; bidder has not directly or indirectly induced or solicited any other bidder to submit a false or sham proposal; bidder has not solicited or induced any person, firm, or a corporation to refrain from bidding; and bidder has not sought by collusion to obtain for itself any advantage over any other bidder or over Xcel Energy.
- Bidders shall take no advantage of any apparent errors or omissions in any related documents. If a bidder believes there are errors or omissions in supplied documentation or if the bidder is in doubt as to the meaning of any part of the documentation, bidder is to contact the Event Owner via the eSourcing System's messaging functionality before the close of the RFX. If Xcel Energy agrees that a change is required or if any explanation or interpretation is required, Xcel Energy will modify the RFX and notify bidders via the eSourcing System messaging functionality.
- **Bidders must clearly document exceptions or clarifications to the general conditions in its response to the RFX.**
- The bidder agrees that, if its proposal is accepted, it will remove taxes from any charges to Xcel Energy upon receipt of a properly completed exemption certificate or direct pay tax license number. Except with respect to taxes imposed by law upon the transfer of equipment or other materials to Xcel Energy, the bidder shall pay all other taxes, tariffs, import duties, entry fees, permit fees, license fees, and other charges of any kind incurred in performing the activities contemplated by its proposal; and all such expenses shall be included in the price. If the bidder is in doubt about whether it may incur any such expense, and it would reduce its charges to Xcel Energy by the amount of such expense in the event such expense is not incurred, then the bidder shall explain the nature and amount (if known) of any such expense in its proposal.
- Xcel Energy reserves the right to reject any or all proposals, including without limitation the rights to reject any or all nonconforming, non-responsive, irregular or conditional proposals and to reject the proposal of any bidder if Xcel Energy believes that it would not be in the its best interest to make an award to that bidder. Bidder agrees that any such rejection shall be without liability on the part of Xcel Energy nor shall bidder seek any recourse of any kind against Xcel Energy because of such rejection.
- Xcel Energy may enter into discussions with the bidder proposing the best overall evaluated offer on the terms of the attached general conditions, scope of work and/or technical specifications, and other attachments.
- All proposals shall become the property of Xcel Energy.

Additional Information

For additional eSourcing System information, visit
http://www.xcelenergy.com/Energy_Partners/Sourcing_and_Purchasing_Process

Advanced Metering Infrastructure

Request for Proposal v10

July 18th, 2016

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1 Essential Definitions used in this RFP

1.1 Contracting Related, Short Forms and Acronyms

1. AMI –Advanced Metering Infrastructure (AMI) is architecture for automated, two-way communication between an advanced utility meter with an IP address and a utility Company.
2. AMI System –The collection of interworking components parts including hardware, software, integration, installation and intellectual content forming the complete functional AMI environment.
3. AGIS- Advanced Grid Intelligence and Security
4. ATP – Acceptance Test Plan; A document that defines certain technical and operational tests that are required to be completed by the Supplier, and witnessed by Company for the purpose of defining a set of technical and operational conditions that must be satisfied. The ATP includes both identification of the required tests and the procedures that are expected to be followed so as to carry out the tests.
5. Company – The legal corporate entity of Xcel Energy Inc.
6. Cost take out - any track able effort to reduce soft or hard cost associated with this multiyear project resulting in the benefit of optimized service, hardware, support, maintenance and/or warranty for Company or both parties.
7. Coverage Blocks–Geographically defined areas of land delineating territory for electric and gas service that is offered by Company.
8. DA – Distribution Automation – in this RFP, DA refers to the control aspects of electric and gas field automation, often referred to in the context of SCADA systems.
9. DA system –The collection of interworking components parts including hardware, software, integration, installation and intellectual content forming the complete functional control and monitoring environment for various forms of electric or gas distribution system automation.
10. Design –The plan and assembly of equipment for implementation/ construction of the system components including engineering drawings, parts, circuit diagrams, etc.
11. Engagement Manager – shall mean: the– The fully qualified and experienced Supplier individual having the responsibility for the business and financial aspects of the project.
12. Functional Requirements – What the system does. This would include general descriptions of features, capabilities, information, etc.
13. Gantt Chart– A project management oriented graphical presentation that is prepared to illustrate predicted and (later) actual start and finish dates of the elements of the project. A Gantt chart visually presents project elements, timelines for start and completion and the critical components, all of which are useful to identify, monitor and manage, so as to gain successful project completion against a well-defined scope, schedule and cost.
14. Headend – A system of hardware and software that receives stream of data brought back to utility through the AMI system.
15. Non-Functional Requirements – Shall mean: description of the system, such as constraints, usability, reliability, performance, capacity, and supportability.
16. Project Manager – the fully qualified and experienced individual both from Supplier and Company having the responsibility for the planning, execution and closing of the project.
17. PMP – shall mean Project Management Professional, as recognized by the Project Management Institute; see PMI.org
18. Pert Chart – A project management oriented graphical presentation that is prepared to illustrate the relationship of tasks or project elements as they relate to project flow from commencement to completion over the project lifecycle.
19. RFP – Is a solicitation made through a bidding process by the company in procurement of a commodity, service or valuable asset, to potential Suppliers to submit business proposals.
20. SoW – Statement of Work; the document that defines the necessary work activities and obligations by the Supplier and that forms part of binding contractual conditions of the Supplier.
21. Supplier –A Corporate entity that is proposing to supply equipment and Services in response to this Request For Proposal

22. SSA – Support Services Agreement
23. WBS – Work Breakdown Structure; WBS consists of a hierarchically organized list of tasks or "items to be completed" or delivered, prior to completing a project. It is a useful framework for defining overall activities and tasks that are necessary to estimate a project scope, schedule and cost.
24. WRT – With Respect To

1.2 Technical Related, Short Forms and Acronyms

1. 6LowPAN - IPv6 over Low power Wireless Personal Area Networks.
2. ADA – Advanced Distribution Automation; Systems that apply modern computational and communications techniques to intelligently control electrical power grid functions to the distribution level and beyond.
3. Advanced Grid – (From the Office of Electricity Delivery and Energy Reliability) a class of technology people are using to bring utility electricity delivery systems into the 21st century, using computer-based remote control and automation.
4. ADMS – Advanced Distribution System Management System is a unified DMS, SCADA, OMS AND EMS solution that provides utilities with a modular and flexible platform within a common user experience, data model, integration framework and secure infrastructure.
5. Aggregators – System that collects AMI data
6. Automated Sectionalization – Systems used by utility electric distribution and transmission operators to perform circuit Sectionalizing by means of remote control of a variety of different protective devices installed across the electric grid for the purpose of protecting the system from damaging fault currents and minimizing the time and number of consumers experiencing an outage.
7. Back Office – A suite of applications, supplied by Supplier that are deployed on a standards-based Critical Infrastructure Networking Platform. The applications enable utilities to support multiple advanced grid applications on common infrastructure. The Back Office Systems application suite includes utility applications for advanced grid initiatives as well as network administration software for configuring, upgrading, and managing the advanced utility network.
8. B.E – Best effort
9. BER – Bit Error Rate
10. Border Router – shall mean: A Wi-SUN defined WMN routing deployment-ready platform for interconnecting IP and 6LoWPAN networks. It assumes an Ethernet interface on the IP side and an 802.15.4g interface on the 6LoWPAN side.
11. CCF – is a measurement of space or volume. It represents amount of gas contained in space equal to one hundred cubic feet.
12. CDF – Cumulative Distribution Function; a useful means to quantify statistical network performance metrics. In probability theory and statistics, CDF of a real-valued random variable X, or just distribution function of X, evaluated at x, is the probability that X will take a value less than or equal to x.
13. CSS – Customer Service System
14. CVR - Conservation Voltage Regulation; Systems that facilitate controlled reduction in the voltages received by an energy consumer to reduce energy use, power demand and reactive power demand.
15. CPE – Customer Premise Equipment, used in the context of WiMAX, formally defined as Subscriber Station component of a WiMAX system.
16. CPP – Critical Peak Pricing rate offering
17. CT – instrument Current Transformer
18. DER – Distributed Energy Resources; decentralized energy that is generated or stored by a variety of small, grid-connected devices such as solar, wind or battery.

19. DA – Distribution Automation; in this RFP, DA refers to the control aspects of electric and gas field automation, often referred to in the context of SCADA systems.
20. DG – Distributed Generation
21. DMS – Distribution Management Systems; a collection of applications designed to monitor & control the entire distribution network efficiently and reliably
22. DR - Demand Response; (From the Federal Energy Regulatory Commission) is defined as: “Changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized”.
23. EV charging – Electric Vehicle battery charging systems; Systems that are used to charge the batteries of electric vehicles, sourcing energy over the grid.
24. ESB – Enterprise Service Bus
25. FAN – Field Area Network; A collection of (usually) wireless networks, operating over a large geographic area for the purpose of providing data services.
26. FAST AMI – Meter read rates for all meters, excluding the bellwether meters, shall record interval, register and events data every 15 minutes and complete transmission of this recorded data to the Headend, at an interval that does not exceed every 15 minutes.
27. FLISR – Fault Location Isolation and System Restoration combines hardware, software, telecommunications, and grid engineering to decrease the duration and number of customers affected by any specific outage.
28. Field Communication Tool – shall mean: The devices and instruments that are used by AMI field personnel to communicate wirelessly, over the air to gas and electric meters.
29. IEEE – Institute of Electrical and Electronics Engineers; A professional association dedicated to advancing technological innovation and excellence for the benefit of humanity. In Company context, IEEE defines standards for wired and wireless communications.
30. IETF – Stands for Internet Engineering Task Force, a large open international community of network designers, operators, vendors and researchers concerned with the evolution of the internet architecture
31. IHD – In Home Display
32. IP – Internet Protocol address is a numerical label assigned to each device such as computer and printer participating in a network that uses internet protocol communication
33. IPv6 – Internet Protocol version 6 is the most recent version of the internet Protocol (IP), the communication protocol that provides and identification and location system for computers on networks and routes traffic across the internet.
34. IT – Information Technology, the use of systems (especially computers and telecommunications) for storing, retrieving, and sending information.
35. IVVO - Integrated Volt/Var Optimization – Voltage/Voltage-Ampere Reactive Optimization; a suite of modern control technologies that use extensive sensor data, wireless communication links and computational control systems to increase grid visibility and efficiency. Generally, IVVO technology operates by gathering extensive performance metrics on the power lines and equipment through a wireless network then adjusting and optimizing system performance through data analysis and control actions.
36. JTAG – Joint Test Action Group is an electronics industry association for developing a method of verifying designs and testing printed circuit boards after manufacturer.
37. LP – Load Profile Data
38. Momentary interruption - The brief loss of power delivery to one or more customers caused by the opening and closing operation of an interrupting device. NOTE: Two circuit breaker or recloser operations (each operation being an open followed by a close) that briefly interrupt service to one or more customers are defined as two momentary interruptions.
39. Momentary interruption event - An interruption of duration limited to the period required to restore service by an interrupting device. NOTE 1: Such switching operations must be completed within a

specified time of five minutes or less. This definition includes all reclosing operations that occur within five minutes of the first interruption. NOTE 2: If a recloser or circuit breaker operates two, three, or four times and then holds (within five minutes of the first operation), those momentary interruptions shall be considered one momentary interruption event.

40. MCF – Is an abbreviation denoting a thousand cubic feet of natural gas
41. MDT –Mobile Data Terminal that could be a notebook/laptop or field tool used by field personnel for completion of assigned work.
42. MTTR – Mean Time to Repair
43. NMS – Network Management Systems; Electronic systems consisting of hardware and software used in the setup, configuration, dimensioning, management and monitoring of data networks.
44. OMS – Outage Management System is a computer system used by operators of electric distribution systems to assist in restoration of power
45. OSI - Open Systems Interconnection model (OSI model) is a conceptual model that characterizes and standardizes the communication functions of a telecommunication or computing system without regard to their underlying internal structure and technology.
46. P2MP – Point to Multipoint Radio Systems; a wireless radio system that generally consists of a single base station that communicates virtually with multiple endpoints.
47. P2P – Point to Point Radio Systems; wireless radio systems that enable wireless communications circuit between two distinct endpoints.
48. PEN – Penetration testing is the practice of testing computer and network systems to find vulnerabilities that could be exploited
49. PHY – in, networking terms, a short form for the component that operates at the physical layer of the OSI layer of the OSI network model.
50. PKI – Public Key Infrastructure is a set of roles, policies, and procedures needed to create manage, distribute, use, store, and revoke digital certificates and manage public key encryption.
51. PPE – Personal protective equipment
52. PTR – Peak Time Rebate rate offering
53. RAM – Random Access Memory
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62. T-min – minimum time
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64. TR – Shall mean: Transformer rated meters
65. VT – Instrument Voltage Transformer
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Essential Definitions

67. WiMAX CPE or CPE – Customer Premise Equipment, referring to the wireless endpoint equipment on a WiMAX system (although the term may be generalized to other wired or wireless systems). It generally consists of an antenna and transmission line feed system as well as the electronics unit which may be placed inside or exterior to a building (dwelling) or enclosure.
68. Wi-SUN – A WMN Smart Utility Network (SUN) that is compliant to the FAN interoperability profiles set out by the Wi-SUN Alliance. See: https://www.wi-sun.org/
69. WIMAX – Interoperable implementations of the IEEE 802.16 family of wireless-networks standards ratified by the WiMAX Forum.

2 Introduction and Background

The Company has recognized the necessity to establish Advanced Metering Infrastructure (AMI) as a fundamental and essential component to an implementation of Company's Advanced Grid Intelligence and Security (AGIS) initiative.

Company's vision for AMI in the form of a solicitation for proposals from Suppliers for product supply and implementation is contained in this request for proposal (RFP). Suppliers who are adequately qualified are invited to respond to this RFP following the instructions that are provided in this document set.

2.1 Vision and Priorities

The Company AMI strategy provides a coordinated effort for integrating a multitude of business needs and applications into a common platform that can be leveraged enterprise wide by the Company's business units.

AMI data will provide the Company a return on investment and make a positive impact on moments that matter in the customer life cycle. AMI offers enhanced functionalities such as:

- Daily meter reading, enhancing billing and customer management.
- Provides customers with data for enhanced operation of smart appliances and load control.
- Offers the ability to offer variable rate structures. (CPP, PTR, TOU, etc.)
- Offers a cost effective method of providing voltage metrics for IVVO application.
- AMI provides effective premise-specific information to corroborate Momentary Average Interruption Frequency Index (MAIFI)- Regulatory and customer satisfaction driving the need for MAIFI
- Enables premise specific outage management and storm restoration capabilities, even near real-time views of restorations.
- Enables improved power quality event capture. This would enhance response time, proactively resolving distribution problems before they magnify.
- Provides tamper and energy theft detection.
- Enhances demand response programs.
- Enables distributed energy resource (DER) monitoring.
- Enable use of downstream sub-meters for special rates, e.g. - DER and EV charging.
- Enables remote electric service connect/disconnect capabilities, reducing truck rolls.

The Company envisions that its wireless AMI network will consist of clusters of Wi-SUN FAN Profile compliant wireless networks that are founded on the IEEE 802.15.4g and IEEE 802.15.4e standards, providing for wide geographic area network services; all of which are owned and managed by Company internally.

When fully deployed, the network will be fault tolerant in design and topology and be multi-tenant in nature, meaning that multiple applications are expected to share the same communication infrastructure. The multi-tenant nature of the network drives the necessity to implement the network with proven, reliable and efficient end-to-end message priority forwarding protocols.

The Company seeks an AMI solution that is flexible, scalable and backward compatible. Toward this expectation, Company has established internal priorities to implement this AMI RFP focused on the metering components with full expectation of following-on with layered gas and electric SCADA oriented applications.

The Company has a companion WiMAX project underway. In the context of this RFP, WiMAX will be the data backhaul technology of choice for mesh networks. WiMAX will be used at transition points from the mesh network to provide transport services along a path toward Company's core network. WiMAX is a point to multipoint technology providing broadband data services and exceptional quality of service.

Provisioning of WiMAX equipment, implementation services and support services are not in scope for this RFP. Suppliers should carry out designs on the contemplation that WiMAX service will be available in the required coverage areas.

Of significance, the Company places priority emphasis on its cyber and physical security programs. Company seeks to continuously and proactively plan, refine and exercise appropriate levels of attention, action and response to security issues and treats to the intelligent grid. This project will ensure that all AMI components are identified and protected, both for the protection of customers and for the reliable and safe delivery of energy to customers. Additionally, the Company will apply its cyber security program to validate sufficiency of detective controls that are integrated with the Suppliers AMI solution. These activities, and others, help to proactively provide notification of suspicious behavior or anomalous activity.

Finalists to the RFP selection process shall be given access to Company Technology Standards, and Reference Architecture documents. Supplier must confirm that the delivery of the system/product configuration shall conform to these Standards and Reference Architectures. Any exception must be approved by AGIS Lead Enterprise Architect or the Chief Architect.

The Company seeks to adhere to world and industry standards in ways that promote multi-supplier interoperability, industry innovation and operational flexibility and that are exampled in such domains as; Wi-Fi, Ethernet and 3GPP. In this regard the Company is a Wi-SUN Alliance member and supporter and stands behind the basic principles of the organization. This will enable the Company to realize value when installing successively new generation products.

2.2 Project Scope

2.2.1 Understanding the Project Scope Components and Plans

This RFP relates to the supply, design and implementation of AMI for Company, consisting of WMN facilities and meters.

The fundamental operational requirement, detailed herein, will provide the Company with devices and systems that will systematically and programmatically collect electric metering data (consumption, power quality, outages, diagnostic, etc.) and perform advanced functions such remote meter and communication module firmware upgrades, meter programming, and remote electric service connect /disconnect functionality, etc. AMI will provide data that will be used by the advanced distribution management system (ADMS) for applications such as State Estimation, IVVO and FLISR. Mesh network will also enable two-way communication to distribution automation field devices such as cap-bank controls, reclosers, fault locators, etc. These are all essential components of Grid Modernization.

Table 1 – Electric Meter

Alamosa/Salida	25331	1.80%
Boulder	127676	9.06%
Brush/Sterling	12207	0.87%
Denver	223761	15.88%
Evergreen	19031	1.35%
Ft. Collins	31996	2.27%
Greeeley	62426	4.43%
Grand Junction/Rifle	72436	5.14%
Arvada/Brighton	279789	19.85%
Southeast	249491	17.70%
Southwest	266548	18.92%
Silverthorne/Leadville/Vail	38487	2.73%
Pueblo	6	0.00%
totals	**1409185**	**100.00%**

Schedule prioritization is given to the Colorado PSCo service territory with Suppliers expected to provide costs for deploying in other Company service territories as well as provide anticipated volume discount pricing for all hardware and software. The equipment required consists of a collection of WMN control nodes, routing nodes, endpoints and meters, as well as the back office applications that are required to operate and manage the network.

The Scope of Work is AMI centric as is described in Section 3.3.2 “Pricing Methodology” and it includes provisions for implementing network and system related components for electric and gas distribution automation related services.

This RFP is structured as having three distinct components:

1. Equipment Supply,
2. Implementation Services and,
3. Support Services, including Software Licenses and Maintenance

Included in this document is an implementation plan, which sets out the geographic boundaries for the required coverage regions and the estimated endpoint device counts as well as establishing a proposed delivery schedule for implementation.

2.2.2 Implementation Plan and Completion Schedule

As of 2016, there are some 1.4 million electric meters over the PSCo service territory. The full scope of meter counts and percentages is shown in table 2 (below). This table indicates "Blocks" within Company's PSCo service area.

The sequence of installation work relating to the network and meter installation is defined by the Implementation Plan. The implementation plan defines installation and completion dates for network and meters in "Blocks" within the Company service areas. Blocks have been derived from PSCo service center locations and meter "routes" that are historically based on efficient automated meter reading (AMR) drive-by and manual meter reading methods. These methods are now being proposed for replacement.

The implementation plan is based on a business requirement to complete 7%, 57% and 36% meter deployment in 2018, 2019 and 2020 respectively. Nine coverage blocks have been defined. The scheduling requirements for each region are shown in the table [3] below.

Table 2 – Table of Coverage Blocks and Required Completion Dates

Block	Quarter	Divisions	Meter Count	General Location
Block 1	2018 Q4	45% of Denver	100,490	Southwest to southeast of downtown Denver (Southern portion of Denver Metro Branch)
Block 2	2019 Q1	53% of Denver, 28% of North Metro	200,025	Downtown Denver; East, North, and West of Downtown Denver out to DIA (Northern and Eastern portion of Denver Branch, Southern portion of North Metro Branch)
Block 3	2019 Q2	1% of Denver, 27% North Metro, 100% Boulder	204,486	North West of Downtown Denver along 36 up into Boulder, all of Boulder including the canyons (Western portion of North branch, all of Boulder)
Block 4	2019 Q3	45% North Metro, 1% Denver, 30% Southeast	200,133	North and Northeast of downtown Denver, North of Arsenal, South of DIA, along I-225 (North and Eastern portion of North metro branch, eastern portion of Southeast branch, starts south of DIA)
Block 5	2019 Q4	70% of Southeast, 10% of Southwest	199,692	South of Denver Metro, along I-25 (Western portion of Southeast branch and into portion of Southwest branch along I-25)
Block 6	2020 Q1	74% Southwest	198,985	South of Northern Branch, West of I-25 (Western portion of Southwest branch)
Block	2020	16% Southwest, 100% Fort	136,303	North portion of Southwest branch; Fort

7	Q2	Collins, 100% Greeley		Collins and Greeley (Northern most portion of Southwest branch near 6th Avenue, north into Fort Collins branch, and then into Greeley Branch)
Block 8	2020 Q3	100% Sterling, 100% Brush, 100%Evergreen, 100%Leadville, 100% Silverthorne, 100% Vail, 100% Salida, 100% Alamosa, 100% Rifle	109,840	Northeast, Mountains, SLV, Rifle (From Greeley move along I-76 into Brush and then to Sterling. Then go to Evergreen along I-70, on Silverthorne, and then to Vail. Go south to Leadville, Salida, and then Alamosa. Move northwest to Rifle)
Block 9	2020 Q4	100% Grand Junction	57,004	Grand Junction (From Rifle move along I-70 to Grand Junction)
		Total	**1,406,958**	

For purposes of contracting expediency, the proposed dates for network installation and meter exchange completion over the entire Company service territory are shown in Table 3. **Dates shown for operating companies other than PSCo are high level estimates only and subject to revision.**

Table 3 Proposed Completion Dates for AMI Installations

Xcel Energy Operating Company	Estimated Implementation and Completion Dates	Quantity of Electric Meters	Quantity of Gas Meters
Public Service of Colorado (PSCo) Electric	Q4 2018- 2020*	1.4 M	
Public Service of Colorado (PSCo) Gas	TBD		1.4 M
Northern States Power Co – Minnesota (NSPM)	2021 - 2023	1.5 M	550 K
Southwest Public Service (SPS)	2024 - 2025	400 K	0
Northern States Power (NSPW)	2026 - 2027	300 K	150 K

*****Suppliers should base designs and pricing on these dates.

2.2.3 AMI Geographic Coverage Requirements

Coverage requirements are linked to the AMI Completion dates. For PSCo, the schedule relationship between coverage blocks and schedules is delineated in Table 2.

For PSCo, AMI coverage requirements are defined in nine geographic “Blocks”. The boundaries of the geographic blocks are defined in the PSCo coverage map Figure [1] and included attachments “AMI Block Deployment with Gas - Only.kmz” and “AMI Deployment Blocks with Gas Areas.pdf”

AMI coverage requirements are provided to Suppliers in the form of spreadsheets. The spreadsheets indicate the location of meter devices provided by geographic coordinates and include specific information concerning the meter device model/type and vintage that is in place as is best known at the time of release of this RFP.

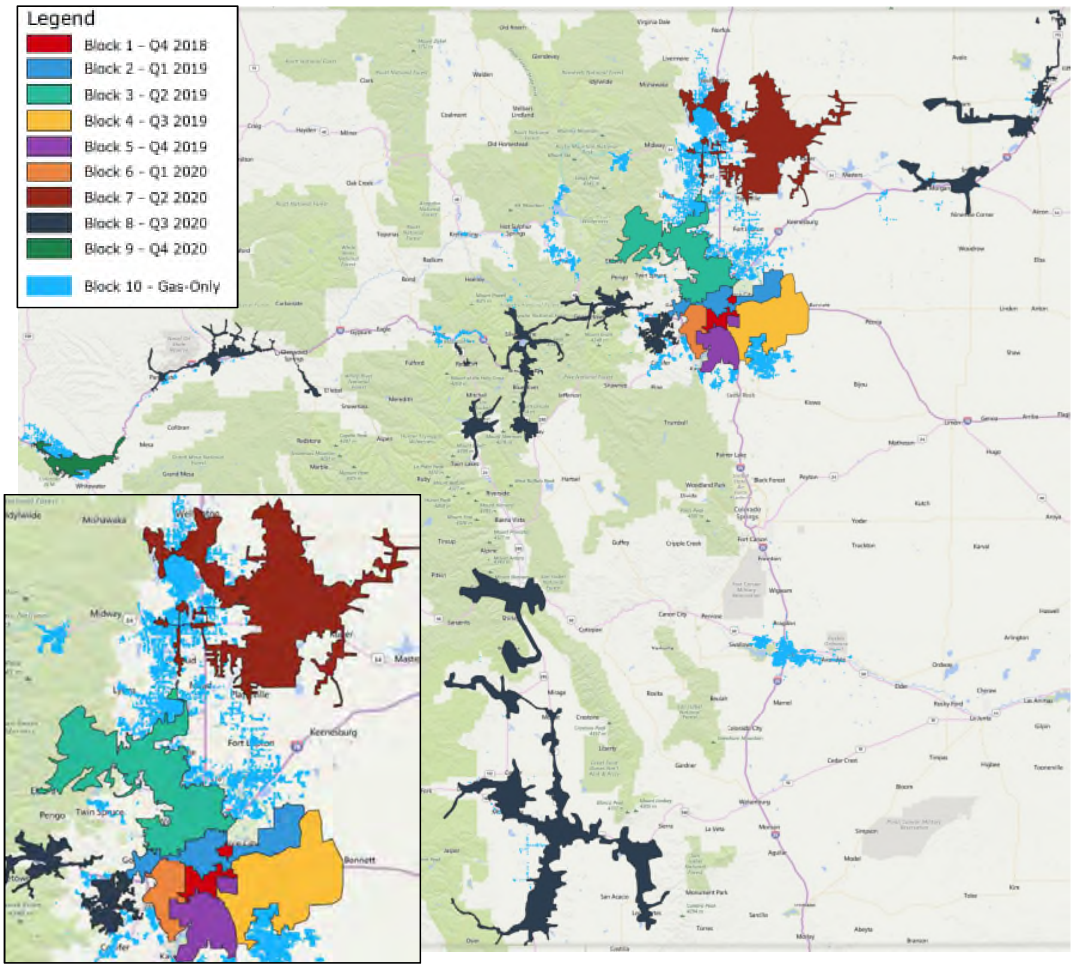
2.2.4 DA Related Geographic Coverage Requirements

Coverage requirements for DA related functions are synchronized to the AMI Completion dates. For PSCo, the schedule relationship between coverage blocks and schedules is delineated in Table 2.

For PSCo, DA coverage requirements are synchronized to the nine geographic “Blocks”. The boundaries of the geographic blocks are defined in the PSCo coverage map Figure [1].

DA endpoint coverage requirements are provided to Suppliers in the form of multi-tab spreadsheets. The spreadsheets indicate the location of meter devices provided by geographic coordinates and include specific information concerning the meter device model/type and vintage that is in place as is best known at the time of release of this RFP.

Figure 1 - PSCo Service Blocks and Required Completion Dates



2.2.5 Equipment Supply, Scope

The Scope of Supply covers the following items;

1. Wireless mesh network equipment
2. Electric residential meters
3. Electric commercial and industrial (C&I) meters
4. Network Management Systems

5. Headend application software equipment for electric and Gas metering, including installation
6. Electric DA infrastructure
7. FAN Lab equipment
8. Meter Shop equipment
9. Field testing equipment
10. Pre-Pay Options
11. Home area network software and hardware
    a. Assume 10% of electric meter customer participation (140,000)
12. Future needs to be priced:
    a. Gas Meter Reading
    b. Electric SCADA endpoint nodes
    c. Gas SCADA endpoint nodes

2.2.6 Supply of Implementation Services – Scope of Supply

Implementation services (per coverage region) include:

1. Project Management
2. AMI Electric and Gas Meter Network Design Services
3. Installation of network equipment and network optimization
4. Inventory, staging, installation, and disposal of electric meters
5. Support installation and configuration of AMI Headend Software
6. Optionally, Installation of Back Office Home Area Network management software components
7. FUTURE
    a. Design and installation of gas metering related infrastructure
    b. Design and installation of electric SCADA infrastructure
    c. Design and installation of gas SCADA endpoint infrastructure

2.2.7 Required Support Services – Scope of Supply

The following support services are required:

1. Training
    a. Meter firmware update – local and remote
    b. Meter programming - local and remote
    c. Headend host application software training – administrative and client and web-based as required
    d. Diagnostics interpretation for troubleshooting on a daily basis
    e. Module programming – Local and remote
2. Product warranties
    a. Meter manufacturers must warranty everything under the meter cover (Metrology, communication module, etc.).
    b. Network warranty
3. Software maintenance support – with detail as to product technical and functional change pricing
4. Hardware and software application maintenance support services.
5. Security Warranties
    a. Security Modules installation, maintenance, and upgrades as required.
    b. Penetration Testing
    c. Scope should include the certificate and key management installation, deployment, management, and retirement
6. Monitoring
    a. Exception handling
    b. Integration of event-based monitoring and escalation process to an Enterprise based monitoring tool

2.3 Essential Requirements

Suppliers participating in this RFP are required to confirm that they are able to supply a system that is functionally in line with Company's vision and in substantial conformance to the essential requirements set out herein. Prior to carrying out a thorough assessment of Supplier responses, Company will evaluate Supplier responses to the Essential Requirements (this Section), and, where Suppliers are able to demonstrate that their solutions are sufficiently in compliance to our vision and requirements, the balance of the RFP response will be comparatively assessed against functional and non-functional requirements; otherwise, it will not be considered.

The Essential Requirements are:

1. The proposed system is capable of gathering and processing AMI related data from an inventory of no less than ten million endpoint devices located in urban, suburban and rural settings of the Company Service territory and meeting the Key Performance Metrics, that is:

    a. At the end of each load profile interval, the system shall be capable of reading residential and C&I electric load profile data and corresponding register data configured for 15 minutes load profile interval recording from all meters except ones configured to support ADMS. Data transmission to the Headend shall be randomized over the next 15 minutes before the next interval close and shall have a reliability of no less than 99.9% on read performance and delivery.

    b. The system shall support the use of no less than 20,000 "bellwether" meters (mix of residential and commercial meters) as distribution sensors for advanced distribution management system (ADMS) in support of applications such as IVVO. 10,000 of these meters shall be assumed to be deployed in the PSCo territory and the rest in the other Company jurisdictions. These meters will be evenly distributed proportionately to electric feeders and shall be configured to record electrical parameters e.g. voltage and power, consumption interval data and register data at a rate of no more than 5 minutes and transmit that data to the Headend at a rate of no more than 5 minutes after close of the interval. The success rate of meter data collection and delivery shall be no less than 99.9%. Refer to attachment "Electric Distribution Points.xlsx" for meter sensor locations.

2. The WMN is Wi-SUN Alliance compliant per Field Area Network Working Group Technical Profile Specification V1.0 (or subsequent revision)). New revisions shall be required to be compatible with the old.

3. The WMN is multi-tenant and fault tolerant in nature, that is: it will consist of clusters of single, shared access, shared media, networks capable of carrying multiple forms of IPv4 and IPv6 traffic for a wide range of applications including but not limited to AMI and SCADA.

4. AMI Suppliers shall provide proof of support for three (3) out of four (4) major meter manufacturers with whom Company has business relationships; these meter manufacturers include Elster, Itron, Landis+Gyr and Aclara. If AMI Supplier also manufacturers meters, then their brand of meters shall constitute one (1) of the three (3) meter Suppliers required. If all proposed three meter manufactures are not presently supported, AMI Suppliers shall provide dates that meter support will be commercially available. Meter support of all meter forms from three (3) meter manufacturers shall be required within 10 months following contract signing and all meter forms from the three suppliers shall be provided to Company for first article testing (FAT).

    Full feature support for the following meters shall be required for all three (3) Suppliers:

    a. Class 20 forms 3S, 4S, 5S, 6S, 9S, 35S , 36S and 45S
    b. Class 200 Forms 1S, 2S, 12S and 16S

   c. Class 320 Forms 2S, 12S and 16S

5. The AMI system includes full-meter programming, metrology firmware update and communication module firmware update for (3) of the following meters supported by the Suppliers as stated in requirement 4 above.

   a. Itron(Centron II, Centron II Poly-phase)
   b. Landis+Gyr (Focus AXD, Focus WR AXD, S4e)
   c. Elster (A3T, A3RAL, A3RALNQ,etc)
   d. Aclara (I-210, KV2c)

6. Suppliers are required to provide AMI gas modules that retrofit to all of Company's meter population. Xcel's meter population list is attached (Final – PSCo Meters.zip, Final – NSPM Meters.zip, Final – NSPW Meters.zip)

7. The WMN shall include and operate under IETF and Wi-SUN standards for routing and multi-level priority marking, classifying, queuing and forwarding of data packets.

8. The manufacturer will be capable of delivering complete systems, conforming to the essential requirements following the timelines set out herein.

9. Suppliers are required to adhere to the Companies main cyber security principles, that is:

   a. Utilize Cyber Security Best Practices (e.g. NIST SP800-53, NISTIR 7628, NIST CSF)
   b. Defense-in-depth: Ensures there are multiple layers of protection and detection defined.
   c. Zero Trust: Creates isolation points within the information network so only specific hosts are able to communicate with other specific hosts.
   d. Tightly-Controlled Access: Ensures only necessary people and systems are able to access devices or software.
   e. Least Privilege: Only necessary individuals and services are allowed to interact with devices.
   f. Least Functionality: Only necessary ports and services are open and running on the systems and devices.

2.4 Security Requirements

2.4.1 Overview

1. As the Company adds intelligence to the electric grid, each part of the grid must be evaluated for cyber security risk. The risks must be mitigated to ensure the reliable delivery of electricity to our customers. The Company has developed principles, strategies, and requirements to assist in identifying and mitigating the risks.

2. Suppliers are required to comply with all of the Principles, Strategies and Requirements outlined in Sections 2.4.2, 2.4.3 and 2.4.4.

2.4.2 Principles

1. Utilize Cyber Security Best Practices (e.g. NIST SP800-53, NISTIR 7628, and NIST CSF).
2. Defense-in-Depth Posture: Ensures there are multiple layers of protection and detection defined.
3. Zero-Trust Networking: Creates isolation points within the information network so only specific hosts are able to communicate with other specific hosts.
4. Tightly-Controlled Access: Ensures only necessary people and systems are able to access devices or software.
5. Least Privilege: Only necessary individuals and services are allowed to interact with devices.

6. Least Functionality: Only necessary ports and services are open and running on the systems and devices.

2.4.3 Strategies

1. Conforms to industry standards and best practices as pertains to meter technology.
2. Support and utilize secure network communication protocols where practical (e.g. HTTPS, SFTP, SSH, SSL, TLS, etc.)
3. Leverages strong authentication and authorization model (role-based access to individual meters).
4. Support a “deny-by-default” approach to AMI component configuration
5. No reliance on non-secure protocols/ports when possible (e.g., telnet).
6. Disable all unnecessary and unused protocols/ports.
7. Support and integrate with centralized system configuration, change management and monitoring systems
8. Security event logging capabilities should be utilized and regularly reviewed.
9. Unauthorized access attempts shall be logged with alerts presented to the appropriate parties.

2.4.4 Requirements

1. The AMI Headend application integration interfaces shall allow the security administrator to generate security reports based on the integration interface’s logs.
2. If Supplier has access to any Company or client confidential information, please describe how confidentiality is going to be maintained, including how information is retained and/or disposed of at designated times.
3. The corporate software maintenance process shall be followed for upgrades and patches.
4. Vulnerability scans are to be performed for equipment or product before it is put into both test and production.
5. Product shall not use unsupported open source code or operating systems.
6. Product shall have application security testing performed by Supplier and the results shall be shared with Company.
7. AMI Supplier shall follow best practices in their coding by utilizing secure application development methodologies such as OWASP.
8. All product testing shall be performed in non-production environments.
9. All security logs shall be captured by a centralized logging device, such as Security Incident and Event Management (SIEM).
10. Data encryption shall be utilized for both data-at-rest and data-in-motion.
11. Encryption algorithms shall be of sufficient strength with equivalency of AES-128.
12. Multi-factor authentication shall be utilized.
13. AMI Headend user access shall utilize role-based security, enabling access to be assigned by , for example, functionality, geographic area(s), asset grouping, and business areas.
14. Active Directory shall be used for user and service authentication.
15. Credentials are required to be stored in encrypted form.
16. Secure messaging shall be utilized whenever technically feasible such as SFTP.
17. If mobile technology is available, the application shall be compatible with Mobile Device Management Systems.
18. Appropriate firewall rules shall be used.
19. Intrusion prevention technology shall be utilized.
20. Only secure TCP/IP protocols shall be utilized.
21. Least functionality principles shall be practiced.
22. Least Privilege principles shall be practiced.
23. Defense-in-depth posture shall be practiced.
24. Zero-Trust Networking shall be practiced.
25. Tightly-controlled access shall be practiced across all network layers.

26. The AMI Headend shall support 8-character password with complexity (upper and lower case alpha, numeric, special characters).
27. The AMI Headend application shall not need to store Personal Identifiable Information (PII), but if it does, the application shall ensure the security and privacy of such information.
28. A Supplier shall notify Company immediately in writing and electronically when a security vulnerability is identified.
29. A patch shall be released to resolve a firmware or security issue within 30 days of identification of an issue.

3 General Provisions

3.1 Invitation to Bid

This RFP invites Suppliers to submit Proposals setting forth all terms, including pricing, for the provision to Company of the equipment and services listed herein at all of the required locations set out herein.

Consults will also be asked to redline a base agreement, provide insurance documentation, Security questionnaire as well as complete a subcontracting diversity form.

Suppliers who are participating in this RFP are required to confirm that they are able to supply a system that is functionally in-line with Company's vision and in substantial conformance to the essential requirements set out herein. Prior to carrying out a thorough assessment of Supplier responses, Company will evaluate Supplier responses to the Essential Requirements (Section 2.3) , and where Suppliers are able to demonstrate that Supplier solutions are sufficiently in compliance to Company vision and requirements, the balance of the RFP response will be comparatively assessed against functional and technical requirements of the RFP.

In order to propose the provision of the Equipment and/or Services as specified in this RFP, the Supplier, in addition to any other requirements in this RFP, shall:

1. have signed the pre-requisite Confidentiality and Non-disclosure Agreement with Company;
2. have significant, demonstrable experience providing the same or similar AMI/DA and Networking Equipment and Services as those identified herein;
3. be able to provide the Services and/or Equipment at all of the required locations set out herein, either by itself or through a subsidiary, affiliate, parent company or its partner, all of whom are otherwise qualified as defined in this RFP;
4. Demonstrate that its financial situation is sound (refer to Section 4.2 – Corporate Profile).
5. Connect the company with other customers that have deployed similar systems being proposed.

In order to propose the provision of any components of this RFP, the Suppliers must comply with the requirements of this RFP including all sections.

3.2 Critical Dates in the RFP Process

Table 4 - Critical dates for RFP processing

No	Scheduled Item	Required Schedule
1	Supplier Presentations	23-27 May 2016
2	RFP Released to Suppliers (RFP OPEN)	25 July 2016
3	Questions from Suppliers Closing Date	22 August 2016
4	Supplier Demonstrations	18 July to 14 October 2016
5	RFP Responses Delivered to Company (RFP CLOSE)	29 Aug 2016
6	Recommended Supplier of choice Identified	4 November 2016

3.3 Instructions to Suppliers

The following instructions are additional to those provided in the attached document titled: Instruction to Bidders. Instruction to Bidders can be downloaded from the Company Emptoris website.

3.3.1 Company Emptoris Response Procedures

1. Suppliers are required to respond to this RFP using the Company Emptoris Secure Internet Sourcing System. Follow the instructions set out herein:
   a. Logon to Xcelenergy.esourcing.emptoris.com

b. Enter your user name in the Name field.
c. Enter your password in the Password field.
d. Click the Login button.
e. From the main menu select RFx(s) > Manage RFx(s).
f. Locate the RFx Name in the list of RFx(s).
g. Click on the RFx Name link to view the RFx.

2. Note: Once you have reviewed the RFP material, please click the Green "Accept" button as your intention to bid or the Red "Decline" button as an indication that you will not be participating.

3. Be sure to answer all questionnaires and questions.

4. Pricing shall be submitted via the "Single Bid" tab or "Multibid" Tab. Please adhere to the format, no other formats will be accepted unless otherwise approved by Company.

5. Suppliers are required to address the following documents which are attached to the event. Please download these, and upon review, upload your return documents with ***Original document name-Supplier name*** included in the file name so submissions may be deciphered. Documents include:

    a. This RFP [Advanced Metering Infrastructure Request for Proposal for Company]
    b. Instructions to Bidders
    c. Sample No Opportunity for SUB Letter
    d. Sub-Contracting Plan
    e. Sample Insurance Certificate
    f. General Conditions Major Supply Agreement – Any redlines should be documented on the original document and returned as an attachment. Note that any exceptions will be weighted and may preclude Supplier from further engagement in the sourcing process.*
    g. Xcel Energy AMI RFP Pricing Template v4
    h. Safety Program Requirements

6. Suppliers are required to provide a comprehensive written response to this RFP providing specifications, confirmations and descriptions in response to the RFP specifications and queries.

7. Suppliers shall submit responses in a form that linked to the RFP numbering and therefore appropriately accessible to the response reviewers. Suppliers are required to respond to each and every numbered point in this RFP by providing a short form summary of their offering on a line by line basis:
    a. Supplier's responses to this RFP shall be clearly titled and numbered.
    b. Suppliers shall indicate whether they "comply" or "do not comply" with each numbered section and point. In the case of "non-compliance", append a clear description of how the supplier's solution meets Company's requirements.
    c. Requirements or statements are numbered as simple list items such as 1,2,3, Suppliers should interpret numbers to be an extension of the higher level numbering scheme. Example: in item number 5a of this section (3.3.1) should be identified as "3.3.1.5.a" in Supplier responses.
    d. Supporting documentation shall be cross-referenced, clearly marked and attached as appendices.
    e. Once complete, Suppliers are required to submit their responses through Company Emptoris Secure Internet Sourcing System only. The attachment will use the following naming convention: Xcel Energy AMI RFP Responses-supplier name.

3.3.2 Pricing Methodology

1. Pricing is structured into two tiers, namely: AMI and DA.

a. AMI (Advanced Metering Infrastructure) refers to hardware, software and services that are associated with electric and gas metering.
b. DA (Distribution Automation) refers to systems that are used for monitoring and control of gas and electric systems; generally, this includes all forms of SCADA.

2. Pricing is required to be tendered by Suppliers in two ways; namely;
   a. Firm Fixed pricing for AMI and DA functionality that is specified over a defined Coverage block(s). Suppliers are required to tender a price for each block for each of AMI and DA requirements.
   b. Variable pricing for equipment and services to the extent of all Company service territory.

3. Suppliers are required to tender pricing in itemized form through completion of the pricing template attached here as: Xcel Energy AMI RFP pricing Template v4.0.xlsx. Supplier must respond to all sections of the pricing Template including the grouped items under the (+) columns.

4. Following a period of assessment and negotiation, Company expects to:
   a. Form a Master Services Agreement (MSA) and companion Statement of Work (SoW) for one or more of the Initial Service Blocks
   b. Consider purchases beyond the Initial Coverage Blocks based on the pricing and pricing formulas provided in the response to this RFP or as subsequently negotiated.

3.3.3 Pricing Modules

The following pricing is required to be tendered, in the form of itemized tables on the attached spreadsheet name: Xcel Energy AMI RFP pricing Template v4.0.xlsx.

Refer to the “Xcel Energy AMI RFP pricing Template v4.0.xlsx” where Suppliers are required to enter their pricing information.

Table 5 -- Pricing Modules

No/ Tab	Name	Item	Resources
1	Baseline AMI PSCo Coverage Block 1-9 and Block 10	Fixed pricing for all AMI meter and network equipment, network design and installation, based on a 2 year deployment (Q42018 - 2020). Pricing must be itemized per block and per design, supply, installation and services components. Costs of gas meter reading modules, network design and supply must be separately identified for both service territories where Company offers electric and gas service and for areas that offer gas service exclusively. Gas components include module installation.	Per requirements set out herein: • Coverage area “blocks” defined in Figure 1. • AMI requirements in Section: 5. • Network requirement in Section 6. • Baseline read/transmission rates are defined in Section 5.3.1 • Services requirements in Section 7. • Electric AMI Meter locations and types in attachments: <Final – PSCo Meters.zip> and, < Xcel Energy AMI RFP pricing Template v4.xlsx> • Gas Meter locations and types in attachments: <Final – PSCo Meters.zip> and <Xcel Energy AMI RFP pricing Template v4.xlsx >
2	Fast Transmission AMI PSCo Coverage Block 1-9 and Block 10	Fixed pricing for all AMI meter and network equipment, network design and installation, based on a 2 year deployment (Q42018 - 2020). Pricing must be itemized per block and per design, supply, installation and services components.	Per requirements set out herein: • Coverage area “blocks” defined in Figure 1. AMI requirements in Section: 5. • Network requirement in Section 6. • Fast read/transmission rates are defined in Section 5.3.2 • Services requirements in Section 7. • Electric AMI Meter locations and types in attachments:

		Costs of gas meter reading modules, network design and supply must be separately identified for both service territories where Company offers electric and gas service and for areas that offer gas service exclusively. Costs of gas meter reading modules, design and supply must be separately identified. Gas components include installation of modules.	<Final – PSCo Meters.zip> and, < Xcel Energy AMI RFP pricing Template v4.xlsx > • Gas Meter locations and types in attachments: <Final – PSCo Meters.zip> and <Xcel Energy AMI RFP pricing Template v4.xlsx >
3	Five Minute Read rate Intervals PSCo Coverage Block 1-9 and Block 10	Fixed pricing for all AMI meter and network equipment, network design and installation, based on a 2 year deployment (Q42018 - 2020). Pricing must be itemized per block and per design, supply, installation and services components. Costs of gas meter reading modules, network design and supply must be separately identified for both service territories where Company offers electric and gas service and for areas that offer gas service exclusively. Costs of gas meter reading modules, design and supply must be separately identified. Gas components include installation of modules.	Per requirements set out herein: • Coverage area "blocks" defined in Figure 1. • AMI requirements in Section: 5. • Network requirement in Section 6. • Five Minute Interval Read Rates are defined in Section 5.3.3 • Services requirements in Section 7. • Electric AMI Meter locations and types in attachments: <Final – PSCo Meters.zip> and, < Xcel Energy AMI RFP pricing Template v4.xlsx> • Gas Meter locations and types in attachments: <Final – PSCo Meters.zip> and <Xcel Energy AMI RFP pricing Template v4.xlsx >
4	AMI for SPS	Fixed pricing for all AMI electric meter and network equipment, network design and installation, based on a 2 year deployment (2024-2025). Pricing must be itemized per design, supply, installation and services components.	Per requirements set out herein: • AMI requirements in Section: 5. • Network requirement in Section 6. • Baseline read/transmission rates are defined in Section 5.3.1 • Services requirements in Section 7. • Meter locations and types in attachment <Final – SPS Meters.zip> and <Xcel Energy AMI RFP pricing Template v4.xlsx >
5	AMI for NSPM	Fixed pricing for all AMI meter and network equipment, network design and installation, based on a 3 year deployment (2021-2023). Pricing must be itemized per network design, supply, installation and services components. Costs of gas meter reading modules, network design and supply must be separately identified for both service territories where Company offers electric and gas service and for areas that offer gas service exclusively. Gas components include installation of modules.	Per requirements set out herein: • AMI requirements in Section: 5. • Network requirement in Section 6. • Baseline read/transmission rates are defined in Section 5.3.1 • Services requirements in Section 7. • Meter locations and types in attachment <Final – NSPM Meters.zip> and <Xcel Energy AMI RFP pricing Template v4.xlsx > • Gas Meter locations and types in attachment: <Final – NSPM Meters.zip> and <Xcel Energy AMI RFP pricing Template v4.xlsx >
6	AMI for NSPW	Fixed pricing for all AMI meter and network equipment, network design and installation, based on a 2 year deployment (2026-2027). Pricing must be itemized per design, supply, installation and services components. Costs of gas meter reading modules, network design and supply must be separately identified for both service territories where	Per requirements set out herein: • AMI requirements in Section: 5. • Network requirement in Section 6. • Baseline read/transmission rates are defined in Section 5.3.1 • Services requirements in Section 7. • Meter locations and types in attachment <Final – NSPW Meters.zip> and <Xcel Energy AMI RFP pricing Template v4.xlsx Tab> • Gas Meter locations and types in attachment: <Final – NSPW Meters.zip> and

		Company offers electric and gas service and for areas that offer gas service exclusively. Gas components include installation of modules.	<Xcel Energy AMI RFP pricing Template v4.xlsx >
7	DA for PSCo Blocks 1-9	Fixed pricing for all AMI meter and network equipment, network design and installation, based on a 2 year deployment (Q42018 - 2020). Pricing must be itemized per block and per design, supply, installation and services components.	Per requirements set out herein: • Coverage area “blocks” defined in Figure 1. • Technical requirements in Section 6. • Services requirements in Section 7. • DA locations in attachment <Electric Distribution Points.xlsx> and <Gas Distribution Points>
8	DA for SPS	Fixed pricing for all equipment, network design and installation pricing for DA services based on 2 year deployment (2024-2025). Pricing must be itemized per design, supply, installation and services components.	Per requirements set out herein: • Technical requirements in Section: 6 • Services requirements in Section: 7 • DA locations in attachment Electric Distribution Points.xlsx
9	DA for NSPM	Fixed pricing for all equipment, network design and installation pricing for DA services based on a 3 year deployment (2021-2023). Pricing must be itemized per design, supply, installation and services components.	Per requirements set out herein: • Technical requirements in Section: 6 • Services requirements in Section: 7 • DA locations in attachment <Electric Distribution Points.xlsx> and <Gas Distribution Points>
10	DA for NSPW	Fixed pricing for all equipment, network design and installation pricing for DA services based on a 2 year deployment (2026-2027). Pricing must be itemized per design, supply, installation and services components.	Per requirements set out herein: • Technical requirements in Section: 6 • Services requirements in Section: 7 • DA locations in attachment <Electric Distribution Points.xlsx> and <Gas Distribution Points>
11	Replace form 2s meters with form 12s meters	Carry out pricing in the exact same manner as Table 5 item 1 but replace all form 2s meters with form 12s meters.	All Requirement are the same as Table 5 Item No. 1 with exception of noted meter form change
12	Meter Shop	Price proposal to design, set-up and configure a meter shop in Denver, Co	Per requirements set out in Section 6.6 herein.
13	Phase Identification	Price proposal for additional components that are required to implement systems capable of identifying phase	Per requirements set out in Section 5.7 herein.
14	Headend Application	Fixed price for redundant server Headend Application for AMI Control	Per requirements set out herein: • Technical and operational requirements in Section 5.5 and 5.6
15	Network Management Systems	Redundant Network Management System	Per requirements set out herein: • Technical and operational requirements in Section 6.1.1
16	Incremental Headend	Incremental license costs to AMI Headend components (priced per 1000, meters)	Per requirements set out herein: • Technical and operational requirements in Section 5.5 and 5.6
17	Incremental NMS	Incremental license costs to NMS components (priced per 100 network nodes)	Per requirements set out herein: • Technical and operational requirements in Section 6.1.1
18	Itron 100g support	Meter Reading and Network support for up to 500,000 Itron 100G ERT modules	Per requirements set out herein: • Technical and operational requirements in Section 5.10 herein • Location of 100G ERT modules: <Final- PSCo ERT Modules.zip>
19	T&M	Roles and Responsibility rate card indicating hourly rate as well as discount provided to Company	Volume Tier Rates
20	HAN	Optional Pricing for all required equipment and services required to establish a HAN offering	Per requirements set out herein in Section 5.8
21	All Goods	Price for warranty covering all goods and	Per requirements set out herein in Section 8.1

	Warranty	services. Covers equipment and services as defined in "blocks and/or regions and handles meters separately.	
22	Blank	Intentionally left blank	• Intentionally left blank
23	Support Services	Support Services, includes field maintenance, online support services, software support agreements, etc.	Per requirements set out herein in Section 8.2
24	Software Support Agreements	Price for renewable Software Support Agreement	Per requirements set out herein in Section 8.1.2
25	Field Service Equipment	Pricing for equipment used by Company field personnel	Per requirements set out herein in Section 6.7
26	WiMAX Gateway Requirements	Pricing for interface enclosures – between Wi-SUN border router and WiMAX CPE	Per requirements set out herein in Section 6.2
27	FAN Lab Equipment	Itemized pricing for all equipment necessary to equip FAN lab in Denver, Co	Per requirements set out in Section 6.5.

1. AMI systems are considered to be baseline. This means:

    a. In areas where the Company services both electric and gas the network shall be designed to support both services.
    b. AMI pricing includes all back office and field equipment, systems, network design installation, testing, performance verification, warranty, training, etc.
    c. For purposes of pricing all AMI systems are assumed to be interconnected to the Xcel Core network by way of WiMAX networking.
    d. All AMI systems shall be designed and included in implementations, without compromise, on the expectation and principle that the DA tier will be added. The DA tier will be added either concurrently or incrementally at a later date.
    e. Where equipment and or services are required at AMI system installation time to meet longer term DA requirements but is superfluous to immediate AMI needs, it shall be included in the AMI design and so priced. Suppliers are required to identify and separately price any and all equipment fitting this DA requirement.
    f. Where equipment and or services are required for DA functionality and are not necessary to purchase, design, integrate or install at AMI installation time, such items shall not be included in AMI pricing but rather included in the DA system pricing.

2. DA systems are considered to be supplemental to AMI systems. This means:

    a. DA pricing includes all back office and field equipment, systems, installation, testing, performance verification, warranty, training, etc., that is required so as to meet the DA functional requirements and that are supplemental to AMI.
    b. For purposes of pricing all DA systems are assumed to be interconnected to the Xcel Core network by way of WiMAX networking and using AMI related interface equipment such as but not limited to border routers.
    c. Unless specifically called out in this RFP, all DA systems shall be designed on the principle that the AMI tier will be in place prior to implementing DA services.

3. There are 10 coverage blocks defined by Company for the PSCo region. Each coverage block defines an area to be served and a delivery schedule. Block 10 represents service territory in which Company offers only gas services.

4. For coverage blocks 1-10 PSCo, Company has provided:

a. A table showing the specific location of every known electric meter and a description of the existing installed meter device.
b. A table showing the specific location of every known gas meter and a description of the existing installed meter device.
c. A table indicating the specific location of every known metering points and control endpoints for electric applications. In some cases, the tables contain randomized data designed to be representative of the required installed locations.
d. A table showing the specific location of every known control endpoints for gas applications

5. For all other operating companies in Company Service territory, Company has provided:

    a. A table indicating the location of electric meter deployments and a description of the existing installed meter devices
    b. A table indicating the density of gas meter deployments and a description of the existing installed meter devices.
    c. A table indicating the density of control endpoints for electric applications over the coverage areas
    d. A table indicating the density of control endpoints for gas applications over the coverage areas

3.3.4 Security Related Responses

Security responses are considered to be highly confidential in nature and will be handled on a "need to know" basis during the RFP evaluation process. Suppliers shall:

1. Address all questions associated with AMI Security in a manner that respects the requirements for confidentiality. Questions related to Security shall be isolated from other non-security related questions and submitted to Company by way of Emptoris (See Item 3.3.4d for addressing methodology)
2. In preparing a response to this RFP, isolate and separate all RFP items that are associated with Security and respond in a single, separately labeled package and submit way of Emptoris (See Item 3.3.4d for addressing methodology)
3. In all cases, Supplier responses shall reference the RFP question and number, followed by Supplier query or response.
4. Suppliers are required to submit their Security related responses through Company Emptoris Secure Internet Sourcing System only. The attachment will use the following naming convention: Xcel Energy AMI Security Responses-Supplier name.

3.3.5 Managing Questions and Inter-Company Communications

1. Prior to submitting questions, Suppliers are requested to review the full RFP, formulate your questions and submit them via the Emptoris portal in compliance to the schedule. Company will then respond to your questions in compliance to the schedule.
2. Questions are required to be submitted in batched written format. Please batch your questions using five segments (1) AMI, (2) Meters ,(3) Mesh networking,(4) DA, (5) HAN
3. All questions and answers will be distributed equally to all participating Suppliers for transparency purposes.
4. Suppliers are directed to communicate all questions via Company Sourcing: Contact Dan Pendar (612-330-6521) or Barry Brooks (612-321-3154).

3.3.6 Evaluation Procedures for the Proposals

Where Supplier Responses meet evaluation conditions that are set out in in the "Essential Requirements - Section 2.3", herein, the Supplier's response will be evaluated critically for its merits, and considering the following:

1. Demonstration Performance Evaluations
2. RFP Proposal Responses including ability to meet industry acceptable standards
3. RFP Pricing
4. Acceptability toward synchronization to Company goals and vision
5. Ability to meet execution timing
6. Ability to meet Company current and future needs

3.3.7 Contact Information

Suppliers are required to include in their response, a table indicating the parties with whom Company may communicate with regard to the content of individual Sections. The following table is a reference template:

Table 6 - Contact Information – Example Supplier's Fill-in Table

RFP Section	Business Area	Team Member	Lead or SME	Email	Telephone
	Business terms and Conditions				
	AMI Systems				
	Networking and DA Systems				
	Mesh networking				
	Warranties				
	Support Services				
	Installation Services				

4 Business Terms and Conditions

4.1 Additional Business Terms and Conditions/Pricing

In addition to any Business related Terms and Conditions and other legal/business matters outlined in attachments to this RFP, the following conditions are appended:

1. Where Suppliers offer 3rd party electric meter components as part of any whole meter related offering, such offerings shall be put forward in a form that includes a pass-through agreement with the source manufacturer which is inclusive of no less than the wholly integrated and functional equipment, long term support services and warranties.
2. Suppliers are requested to outline the value added services (above and beyond those outlined within this RFP), that your organization will bring to Company for this project at no additional cost to Xcel.
3. Suppliers are requested to outline the cost take out guarantee which your company will provide to Company over the life of this Agreement. Please provide examples and formula for tracking.
4. Suppliers are required to review and accept the General Conditions for Major Supply Agreement document. Supplier may provide exceptions (redlines) on the document and submit, as an attachment, back to Company for review. Note that exceptions will be weighted and may preclude your company from further engagement in the sourcing process.
5. Please provide a high-level overview of what the market is currently tracking as success metrics utilized to gauge the success of deployment projects of this scope (please include economic and technical considerations). You will be expected to provide “success tracking” dashboards for reporting purposes if awarded this business.
6. Suppliers are required to inform Company in writing of any foreign nationals including subcontractors who will work-on or provide advice concerning the contents of this RFP/project and its outcomes.
7. Company shall require advanced engineering change notification for all hardware and firmware changes. Changes should include risk/impact assessment.
8. Company shall require advanced notification of all reliability/failure causes and effects that have become known to the manufacturer.

4.2 Executive Level Support

Suppliers are required to provide a Statement indicating the level of Corporate Commitment to which Supplier is undertaking. Indicate no less than:

1. The Statement of Commitment to Company articulating the key elements where executive commitment brings value to Company’s Projects.
2. Names and positions of executives who represent the Commitment.
3. The manner in which Executive Level Support is applied to the Supplier’s customers, specifically to Company and to the Supplier’s internal resources.
4. The manner in which Executive Level Support is executed where it relates to the Supplier’s own hierarchy internal resources.

4.3 Required Corporate Information / Supplier Profile

Suppliers are required to submit Corporate Profile related information as follows:

a. Supplier legal name.
b. Supplier Contacts, Phone, Fax, Email, Web Sites
c. Postal mail address of business headquarters and field offices
d. Supplier names, including international, of organizations that sell and or resell the Supplier equipment and services.

e. Dunn and Bradstreet#, ABA#
f. W9 detail, Invoice Remittance and Banking Information
g. Diversity Certification
h. Corporate history since inception.
i. Corporate Mandate; including:
    i. Mission,
    ii. Business sectors in which the Corporation is operating in; (water, gas, electric, smart cities, etc.)
    iii. Percentage of revenue generated by electric/gas utility markets in past 3 years
j. Description of Projects taken on in last 10 years that are similar, including
    I. Exact system installation and generation as proposed for this RFP
    II. US Dollar value of the project
    III. Nature of the project (metering, DA, smart Cities, etc.)
    IV. Customer reference; names, email address and phone number
    V. How the project scope and scale compare to Company's

4.4 Obligations of Company

4.4.1 General Obligations:

Company will:

1. Be reasonably available for questions and meetings in a timely manner during normal business hours.
2. Provide contact list, including a Project Manager Single Point of Contact, of the Company managed project resources and stakeholders.
3. Coordinate and provide required security clearances and/or escorts to access the site and facilities for completion of the services described in this RFP within Company's standard security response times. Unescorted Access security clearance times may average between 2-4 weeks and Supplier shall plan accordingly.
4. Execute according to the agreed upon plans at hand-off/interface points, including the completion of material responsibilities assigned to Company in any SoW that results from this RFP.
5. Assist the Supplier in discussions with any Third Party that Company requires Supplier to manage within the scope of the project, and authorize the Supplier to manage and direct such Third Parties on Company's behalf, if necessary.
6. Use reasonable efforts to secure the cooperation of all and any necessary license rights from Company's Third Party Suppliers as required for Supplier's performance of the services, except for any Third Party cooperation or licenses for which the Supplier is responsible or is required to obtain under Applicable Law.
7. Reserve the right to witness and inspect the project work at any time.

4.4.2 Obligations Regarding Project Management:

Company will:

a. Designate a Project Manager
b. Provide the high level project schedule.
c. Provide site documentation, drawings, and master records (if available).
d. Assist the Supplier in the creation, distribution, and adherence of an overall project schedule
e. Take reasonable steps to execute and deliver on required tasks in a timely manner.

4.4.3 Obligations Regarding Field Area Network design

Company will:

1. Provide the specific placement criteria and installation techniques acceptable to Company for the installation of mesh network equipment on Company facilities.
2. Conduct site surveys to validate the initial field network design. Review the site survey and recommended installation locations and propose changes to these locations if necessary.
3. Secure and pay for all internal and external approvals, improvements, modifications, for attachment of network equipment, including local construction permits, licenses, or other fees. This step must be completed prior to AMI deployment.
4. Determine the method of power connection (direct line connect or photo cell adaptor on a streetlight arm) for network equipment at any given location.
5. If necessary, and upon mutual agreement of the Parties, install additional poles, or provide alternate installation methods, to satisfy the Network Design requirements.
6. Upon Company's acceptance of Supplier's Design, Company will provide backhaul capabilities consistent with the Network Design. Company intends to provide a private WiMAX network as the primary backhaul communication technology. The Supplier will be carrying out designs based on interconnecting Wi-SUN border routers to WiMAX CPE and directly to layer 3 switches that are located at network access points on the Xcel fiber network, typically at substation locations.
7. Company may elect, in certain circumstances, to use a Third Party WAN provider(s) (e.g., cellular operators) to provide backhaul capabilities. If Company elects to do so, Company shall obtain the services of the Third Party WAN provider, provide coverage maps to Supplier for use during the design of the field network, and facilitate communications between Supplier and the Third Party WAN provider regarding operational issues.
8. In gas only areas, Company shall handle third party agreements for required attachment facilities.

4.4.4 Obligations Concerning AMI Meters and Network Deployment

Company will:

1. Use an electronic work order system, or functional equivalent that collects barcode data and GPS coordinates for each location where the meters and mesh network transition equipment is installed.
2. Following training by Supplier, install and perform all field investigations and remediation of network field equipment. Supplier shall take responsibility for failures beyond the Supplier's stated acceptable limits as stipulated in the subsequent contract.
3. Following training by Supplier, perform all field investigations and remediation of AMI meters.
4. Complete all tasks necessary to inventory, warehouse, and stage for installation all network equipment (excluding AMI meters and associated tools and materials covered under Section 7.5 of this RFP), provided that Supplier adheres to all shipping requirements specified by Company, including but not limited to, shipping to a designated recipient.
5. Compile as-built data for network equipment that includes pertinent information about the location of each device, including but not limited to GPS coordinates, AC power source, device height, inventory control information for the object to which the access point or relay will be attached (e.g., inventory control tag on a utility pole, transformer tag on a pad-mount transformer, asset tag for a street light or pole belonging to an entity other than Company, etc.), and any other relevant site-specific information. GPS Latitude and Longitude coordinates must not be truncated to fewer than 5 places after the decimal point; for example 37.46668 rather than 37.466.
6. Perform troubleshooting of installed network equipment and correct any installation errors caused by Company prior to completion of formal acceptance testing.
7. If a Third Party installer is utilized, Company shall provide specifications for attaching network equipment prior to the scheduled date for installation.
8. Provide any 'make-ready' components and consumable commodity supplies needed for completion of the mutually approved installation (e.g., transformers, arms, miscellaneous wire and raceways, wiring connectors for secondary voltage connections on utility poles, and through

bolts, lag screws, and/or stainless steel banding to mount RF pole-top devices to wood or metal poles)

9. Complete all tasks necessary to order, inventory and warehouse Equipment needed to install the network equipment (excluding AMI meters).

4.4.5 Obligations Concerning Back Office setup

Where it is determined to be necessary for support and maintenance requirements, establish a B2B VPN connection from the Company back office to the Supplier Back Office Systems Environment. Each Party shall pay for its cost to set up its end of the B2B VPN connection. The recommended approach typically is for the Supplier to assign and provide a secure DMZ where the product upgrades/patches etc. are downloaded and applied

4.5 Supplier Obligations

1. Notwithstanding the details of Supplier obligations stated herein and the foretasted obligations of Company, Supplier shall state the obligations that are necessary for Company to accept, that are necessary for Supplier to fulfil its obligations under this RFP. The Statement of Company Obligations shall:

   a. Be in the form of list of resources required by role and responsibilities
   b. Indicate the timeline that is required for the requirement to be completed by Company
   c. Include any equipment to be supplied by Company or by any 3rd party .
   d. Include any services to be supplied by Company or by any 3rd party .
   e. Include any additional commitments required from Company to deliver

2. All documentation supplied or submitted to Company shall be in the form of MS Office 2010 formats unless otherwise approved by Company.

4.6 Demonstrations Required for Company AMI RFP

4.6.1 Demonstration Conditions

Company requires that all Suppliers wishing to participate in the AMI RFP process- carry out a hosted demonstration of the proposed system. Refer to <Advanced Metering Infrastructure Demonstration Test Plans and Assessments v4.0.doc> for additional updated details.

The following conditions apply:

1. The proposed system for demonstration shall be commercially available and shall be of the exact generation proposed in response to this RFP
2. Each Supplier is given approximately 3 weeks of time on Xcel Property to set-up and prepare for the demonstration. The Company team of AMI RFP evaluators will attend and witness demonstrations and, where necessary, conduct the testing with assistance from the Supplier.
   a. Suppliers are required to perform or outline demonstration results in an executive level presentation/demonstrations completed in 1 business day's duration and,
   b. Suppliers are required to work with Company to provide Company with opportunities to explore system features and capabilities in hands on manner.

3. The actual "demonstration" event is expected to consist of:
   a. Introductions
   b. Description of the system setup and configuration
   c. Discussion toward understanding system architecture
   d. Presentation of operational features and functionality
   e. Performance testing per requirements set out here
   f. Any additional testing or demonstrations that may be offered by the Supplier
   g. Summary

4. The Xcel evaluators' will witness the demonstrations and assess the results against a common criteria, considering no less than feature availability, functionality, compliance to essential requirements and overall performance based on the test criteria identified herein . The assessment results will be used as a component of RFP response assessment.

5. The demonstrations will take place at Company's location in Denver Co. in an assigned lab space. Suppliers will be provided with security access to the setup space.

   HomeSmart
   6981 South Quentin Street,
   Suite A,
   Centennial, Colorado
   80112-3939

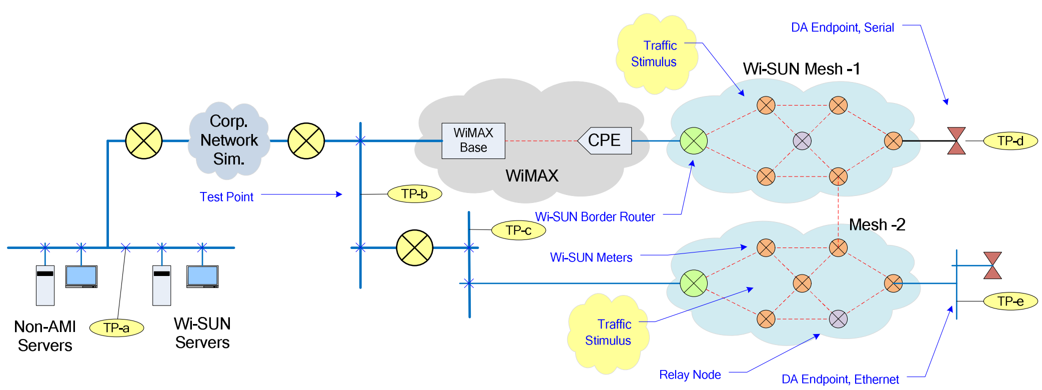
6. Suppliers are required to document the testing undertaken and to provide a detailed report of tests and results within 2 weeks following the completion of the testing.

7. Demonstrations will begin on or about July 18 and be conducted in a sequential manner. Schedules and locations will be coordinated between Company and the Suppliers.

8. All communications will be subject to a Non-Disclosure Agreement (NDA). Company will not conduct demonstration testing without agreed upon NDA's in place.

4.6.2 Demonstration Setup

Suppliers shall supply a profile of the communication environment sufficient to operate the entire system in a stand-alone manner. Below is a sample configuration:



AMI RFP - Demonstration Test Setup

Note the following points:

1. Company shall furnish the following:
   a. Facilities to energize and load up to 30 electric meters (meters provided by Suppliers)
   b. Gas meters (AMI modules to be provided by Supplier)
   c. High speed communication circuit between HomeSmart and Supplier Headend
   d. Electrical power for all network equipment and electric meters

2. Except for equipment and support provided by Company, Suppliers are responsible to supply, install and operate whatever equipment is necessary to complete the required testing. This includes test equipment.

3. No less than two Wi-SUN mesh clusters are required. Mesh clusters must be arranged so as to achieve intermeshing between clusters.

4. At least one Wi-SUN cluster must be configured so as to achieve traffic carriage and testing over no less than 5 radio hops.

5. Suppliers are required to provide-for and simulate real world traffic in the mesh network so as to simulate "contention" and real world AMI traffic scenarios. Traffic simulation stimulus must be of IPv6 AMI type and be no less than that expected to be carried for operational conditions having 5 minute meter read rates and 15 minute transfer cycles in typical residential conditions.

6. Minimum of two Border Routers

7. Company will provide and configure the routing and switching infrastructure to simulate or actuate its internal networking facilities.

8. The demonstration testing includes a requirement to interface to IEEE802.16e, WiMAX compliant AirSpan WiMAX backhaul equipment. Company will supply this component of equipment and assist in any necessary configuration. The equipment is presently set-up and operating at Company FAN Lab in Denver Co. The equipment includes AirSynergy 3.65 GHz base station sectors and WiMAX Pro CPE, operating under NetSpan NMS.

9. Mesh clusters shown in the sketch "AMI RFP – Demonstration Test Setup" should be considered to be figurative. Suppliers should configure mesh clusters to adequately demonstrate their equipment.

10. At the conclusion of demonstrations and within 24 hours, Suppliers must remove all of their supplied equipment.

11. Company will conduct DA performance testing using its own test equipment.

4.6.3 Required Demonstrations

Company expects Suppliers to complete the following demonstrations:

1. AMI Meter Management functionality; no less than:
    a. Accurate handling of LP Data
    b. Service Disconnect/Reconnect Operation
    c. Electric Meter Over the Air Reprogramming (with meters from multiple manufacturers))
    d. Electric Meter Over the Air Meter and Communication Firmware Upgrades (with meters from multiple manufacturers)
    e. Ability to obtain gas ERT reads over the AMI network and performance
    f. Electric bridge meter conversion from ERT mode to AMI mode
    g. User Programmable Space Tests and Functionality (Send customer real time demand, communicate to pole top transformer)
    h. Electric Meter Demand Reset performance.
    i. Verification of ability to retrieve voltage, current, phase angle on demand
    j. Verify ability to bring back fatal alarms from meter/module (Gas and Electric)

k. Verification of Meter Program (Is correct program in meter, alarm if not)
l. Gas Meter Cum Data Transmittal Verification
m. Gas Correcting Device Information Retrieval
n. Testing of field devices used to trouble shoot/test modules in the field and shop

2. AMI Meter Data Collection Performance [Graph]

   a. AMI meter read rates, capacity and reliability
   b. Duration (ms) of successful C12.18 session [Avg, 25%, median, 75% and 99%]
   c. Failure sessions for C12.18 per round. [Rel. frequency vs Failures per round %]

3. Non-AMI (DA oriented) performance, 64 bytes, in the presence of AMI traffic [graph]

   a. Average RTT for 1,2,3,4 and 5 hops [Avg. RTT over 24 hours]
   b. Average Ping Loss Ratio for 1,2,3,4 and 5 hops [Avg. loss% over 24 hours]
   c. Cumulative Distribution Function (CDF) of RTT (5 hops min)[CDF vs RTT ms.]
   d. CDF of Ping Lost Ratio over 5 hops min [CDF vs Failed Ping Requests 5]
   e. Throughput capacity for 1,2,3,4 and 5 hops
   f. SCADA performance over 1,2,3,4 and 5 hops; messaging speed, latency and reliability. This test to be undertaken with Xcel owned and operated test equipment with support and consultation with Suppliers.

4. Interoperability Performance:

   a. Interface to WiMAX strategy (L2, L3, etc.) efficacy of QoS mapping, and preservation of flow prioritization as data traverses Wi-SUN-WiMAX boundaries.
   b. Between Wi-SUN compliant meters running ANSI C12.18 on application layer
   c. Between Wi-SUN compliant meters running DLMS/COSEM on application layer
   d. Between Wi-SUN compliant network nodes, (border, relay and endpoint nodes)
   e. Carriage of IPv4 traffic over IPv6 in 6LowPAN

5. Security Features:

   a. Scope of security features
   b. PKI
   c. End to end encryption

6. Fault tolerance and rerouting; In the event of full or partial failure of:

   a. Meters
   b. Relay nodes
   c. Endpoint nodes
   d. Border Routers
   e. Concentrator server

7. Quality of Service Capabilities including:

   a. Methods of marking traffic types for priority carriage at egress and ingress points
   b. Methods of prioritizing traffic flows based on traffic marking
   c. Methods for managing traffic congestion and performance
   d. Demonstration of prioritization of critical traffic flows in a network that is congested with non-critical AMI related traffic.
   e. Availability of IPv4/6 routing functionality at wired side of border routers
   f. Methods of transporting IPv4 flows over IPv6 Wi-SUN.

8. Application Support Approach and Methodology
    a. Method by which 3rd party applications can be implemented
    b. Applications that are available
9. Availability and thoroughness of support for the following residential and commercial meter models from Elster, Itron, Aclara/GE and Landis+Gyr:
    a. Class 20 forms 9S
    b. Class 200 Forms 2S, 12S and 16S
10. Full-meter programming, metrology firmware update and communication module firmware update for the following meter suppliers
    a. Itron(Centron II, Centron II Poly-phase)
    b. Landis+Gyr (Focus AXD, Focus WR AXD, S4e)
    c. Elster (A3T, A3RAL, A3RALNQ,etc)
    d. Aclara/GE(I-210, KV2c)
11. RF performance:
    a. Demonstrate available modulation modes and dynamic fallback modes
    b. Demonstrate transmit power capability per mode and noise figure
    c. Demonstrate that theoretical link budgets tracks with practice
12. Packaging and Powering
    a. Demonstrate the manner in which the WMN border routers will be physically integrated to WiMAX CPE and provide 8 hours of uninterrupted service in event of power failure and support battery charging/maintenance and monitoring for all components.
    b. Show all system components including but not limited to: typical border routers, relay nodes, endpoint nodes, meters, etc.
13. Testing for AMI modules for gas meters (devices listed in Table 7 below)
    a. Visual inspection and proof testing:
        i. Demonstrate compliance to ANSI B109 series standards including but not limited to integrity of gaskets, venting and housing for weather protection.
        ii. Demonstrate alignment of module shaft to meter wriggler and the alignment of the module shaft to the index.
        iii. For wriggler operated modules, demonstrate that the module does not alter the measurement accuracy of the meter.
    b. Fit test: Demonstrate meter module alignment, drive geometry, and backlash/lost motion for “spotting the dial” tests, ease of installation, ability to follow module manufacturers’ installation instructions on meter vintages.
    c. Programming: demonstrate that all modules can be programmed per module manufacturers’ installation instructions.
    d. Count accuracy: Through actual operation of modules; demonstrate that the transmitted system read is at all times accurate within 1 count of the least significant visual index read.

e. Data handling and auditing: Demonstrate that all documentation is available in English language and that the meter functions in accordance with documentation including but not limited to:

   i. drive rate,
   ii. start read,
   iii. cumulative meter read that matches the visual index read,
   iv. number of dials information and methods used to determine cumulative reading,
   v. time stamping of reads;
   vi. which data is retained in the module,
   vii. which data is transmitted to the network,
   viii. how frequently the data is transmitted,
   ix. how an index change in the field is processed and the module re-programmed for the replacement index,
   x. process for reusing the module on a different meter,
   xi. battery change process,
   xii. alarms originating from within the module and alarms that are generated by the network or back office,
   xiii. interval usage data, how the module recovers when the network is unavailable for 2 days, 1 week, 1 month,
   xiv. how the module programming and current read is determined when auditing at the meter site,
   xv. installation of the modules in a gas only service area,

xvi. capability of the system to read the existing installed population of 100G ERTs

Table 7 - Gas meters that will be used for evaluating and/or testing AMI modules

Meter Manufacturer	Model(s)	Visual number of	Index type	Visual read	Billing units	Number of billing	Wriggler Drive	Meter pulse output	Visual and fit evaluat	Install and operate
Elster, American Mete	AL175, AM225, AL250, AC250	4	pointer, front mount	CCF	CCF	4	1'	N/A	Yes	1 module
Elster, American Mete	AL175, AM225, AL250, AC250, AL425, AC630	4	pointer, front mount	CCF	CCF	4	2'	N/A	Yes	1 module
Elster, American Mete	AL800, AL1000	5	pointer, top mount	CCF	CCF	5	5', 10'	N/A	Yes	1 module
Elster, American Mete	AL1400, AL2300,	5	pointer, top mount	CCF	CCF	5	5', 10'	N/A	Yes	1 module
Metric	80B, 250B, 500B	5	pointer, top mount	CCF	CCF	5	5', 10'	N/A	Yes	No
Rockwell, Sensus	175, 250, 275, 31	4	pointer, front mount	CCF	CCF	4	2'	N/A	Yes	1 module
Sprague, Schlumberger, Itron	175, 240, 250	4	pointer, slanted front mount	CCF	CCF	4	2'	N/A	Yes	1 module
Dresser, Roots, GE	LMMA Counter drive, 8C, 15C, 3M, 5M, 7M, 11M	5	MFG odometer or vertical index on ID	CCF	CCF	5	10'	N/A	Yes	1 module
Dresser, Roots, GE	LMMA Counter drive, 16M	6	MFG odometer or vertical index on ID	CCF	CCF	6	100'	N/A	Yes	1 module
Dresser, Roots, GE	B3 Counter drive, 8C, 15C, 3M, 5M, 7M, 11M	5	MFG odometer or vertical index on ID	CCF	CCF	5	10'	N/A	Yes	No
Dresser, Roots, GE	B3 Counter drive, 16M, 38M, 56M	6	MFG odometer or vertical index on ID	CCF	CCF	6	100'	N/A	Yes	No
Dresser, Roots, GE	B3TC with instrument drive, 8C, 15C, 3M, 5M, 7M,	6	MFG odometer or vertical index on ID	CCF	CCF	6	100'	N/A	Yes	No
Dresser, Roots, GE	B3TC with instrument drive, 16M	6	MFG odometer or vertical index on ID	CCF	CCF	6	1000'	N/A	Yes	1 module
Dresser, Roots, GE	B3TC with Mfg Form A pulse out, 3M, 5M,	5	MFG odometer	CCF	CCF	5	N/A	10', circular connector	Yes	1 module
Romet	TC with Mfg Form A pulse out, 3000,	5	MFG odometer	CCF	CCF	5	N/A	10', circular connector	Yes	1 module
Mercury/Honeywell	TCI	5	MFG digital	CCF	CCF	5	N/A	100' solid flying lead	Yes	1 module
Mercury/Honeywell	Mini AT	6	MFG digital	MCF	MCF	6	N/A	1000' screw terminal	Yes	1 module
Mercury/Honeywell	Mini Max	5	MFG digital	CCF	CCF	5	N/A	100' screw terminal block	Yes	1 module

5 AMI Meter Requirements

5.1 Electric Meter Requirements

5.1.1 Interoperability and Standards

1. Meters shall be built to ANSI C12 standards
2. Meters shall have an interface capability to operate with communication modules furnished by multiple potential Suppliers; the communications modules will reside under the meter cover and collectively support the functional and non-functional requirements as specified in this RFP.
3. The communication module furnished by potential Suppliers shall have an interface capability for the life of the meter.
4. There shall be transparent IP routing to the meters. Meters and control devices shall be both IPv-4 and IPv-6 addressable
5. All electric meters shall have a 0.5% or better accuracy class

5.1.2 Meter Feature Requirements

1. Both residential and commercial type meters shall be equipped with temperature sensors capable of measuring meter temperature for detection of “hot sockets”
2. Hot socket algorithm shall open the service switch at extreme temperatures. Temperature thresholds shall be configurable. Control algorithm shall include reporting of at least 8 hours of load and temperature information prior to interruption. Optionally automated or manual interruption based on system alert.
3. Both residential and commercial type meters shall be equipped with tilt/motion sensors.
4. Tilt/motion sensors shall be captured/processed at power down to differentiate removal from normal outage
5. The meter will be required to support at-least 2 independent clocks, and both shall be required to independently and optionally support DST. The two clocks shall function from the same time-base (basic clock “tick”) but shall have independent clock values so that the company can support, for example, different time-bases for load profile data (reported to the master back office applications as Universal Time) and for local representation (for example, governing local registration for TOU and for customer display). That can best be accomplished by allowing all time-based meter functions to be tagged to either of the requested independent clocks. Various meter functions shall be assignable to either meter clocks. This would support local time offsets as well as load profile recording without time discontinuities due to DST shifts. See also Section 6.4 “Timing and clock References”
6. Residential meters shall have no batteries (no real-time clock) and operate based on network time that is distributed upon system power up.
7. Transformer rated meters shall have the option to include potential and current ratios in the transmitted metered data.
8. The meter shall be able to self-register on the AMI network and communicate to the field network setup tool whether or not all aspects of the meter and its communication with the AMI system are operating properly.
9. Load profile data shall be recorded and date/time stamped at the end of each interval. The date and time stamping of load profile data shall be consistent with ANSI C12.19
10. The meter shall be configurable to support delivered, received, net and absolute power at the meter.
11. The meter shall support a configurable “disconnect on detected DG” flag. Setting this flag would trip the service disconnect when DG is detected. Parameters for DG detection would include recognizing reverse flow at a configurable level (watts to kilowatts) over a configurable interval (five seconds to one hour) to prevent false triggering.
12. The meter shall support a network time synchronization of 1 second or better and be able to time stamp its voltage peak to an accuracy of 1 second.

13. Load profile interval shall be configurable from 1 minute to 24 hours. (1 min, 2 min, 5 min, 10 min, 15 min, 30 min, 60 min, 1 day)
14. Both meters and communication devices must be capable of hard resets to factory default conditions by local means without shipping back to manufacturer
15. To facilitate meter processing and installation, customer meters shall be uniquely identifiable by both bar coding and electronic communication

5.1.3 Upgradeability and Configurability

1. The meters shall be equipped with 4x the level of memory storage than required by the initial meter specification.
2. The system shall have firmware/code image size that is 2x the size at initial deployment for code changes associated with metering and power supply
3. The system shall have 2x the peak quantity of used RAM at the time of initial deployment for code changes associated with metering and power supply
4. The system shall have firmware/code image size that is 4x the size at initial deployment for code changes associated with communications
5. The system shall have 4x the peak quantity of used RAM at the time of initial deployment for code changes associated with communications.
6. Meters shall support a disciplined clock in order to minimize clock adjustments that result in discontinuities in time. The clock shall be synchronized to NIST master clock with a maximum error of 1 Second. This will provide more graceful time management, will eliminate both “short” and “long” intervals from interval data recordings, and will provide more accurate demand intervals without having to invalidate intervals due to time adjustment.
7. Residential meters, equipped with a service switch, shall have the ability to limit load/service. The load limit shall be configurable such that multiple configurable steps (e.g. 90% of rated capacity, 75% of rated capacity, etc.) can be configured in the AMI Meter.
8. If bi-directional functionality is required to be activated in the meter, the meter shall be able to be re-programmed remotely over the air. This reprogramming event will be logged in the meter and sent back to the Headend immediately.
9. Data sent from meters shall be configurable as to whether interval data, register data, event data or all shall be sent during routine or on-demand meter read requests.
10. The meter shall permit TOU, CPP and PTR time period to be remotely configurable.
11. The meter shall permit its firmware and programs to be remotely downloadable without loss of register data.
12. Meter shall report failures e.g. communication failure after reboot, program lock-up, etc. following a software/firmware upgrade within 15 minutes after start-up of new program. Reportable failures shall include billing information loss or loss of electric service. Meter failures to report shall be configurable in the meter program.
13. Firmware and programs shall revert back to old functioning versions if the new one fails or upon utility command and meter will report that action and status. There shall be room to store previous image, current image and downloading image.
14. Register meter functions shall be programmable both remotely and locally.
15. Handling of received energy shall be configurable in the meter. e.g. sum of delivered and received energy, ignored, net, etc.

5.1.4 Availability

1. The meter shall continue to record data during a communication failure.
2. The meter shall be recognized by the network and registered within 4 hours of installation.

5.1.5 Connect, Disconnect or Limit Service

1. All self-contained residential meters class 200 (Forms 1S 2S and 12S) and class 320 (Forms 2S and 12S) shall be able to remotely connect/disconnect/limit electric service to customer premises.
2. The service switch shall be rated for at-least 10,000 service disconnect operations
3. The meter shall be able to limit demand served to the customer by a remote utility on-demand request or through utility pre-configured rules (e.g. 90% of rated capacity, 75% of rated capacity, etc.)
4. The meter's disconnect switch shall be capable of inhibiting the close operation when there is voltage on the load side to prevent equipment damage or personal injury.
5. The remote disconnect shall be integrated with the meter rather than a collared solution for meter types that have been identified as requiring a disconnect switch.
6. The meter shall permit remote changes to the threshold for load limiting from MDM or Headend. Thresholds shall be configurable.
7. The Remote disconnect shall have a rating consistent with meter class rating at 60% lagging power factor
8. The meter shall re-energize a configurable number of times automatically after a configurable delay if meter trips off because the demand/energy limit is exceeded.
9. The meter shall acknowledge load limit command successful to Headend
10. Meter shall acknowledge and communicate open/close status after operating command is issued and shall be confirmed by Headend.
11. The remote connect/disconnect switch shall be operable through the optical port.
12. The meter disconnect event (remote or local) shall not generate a last gasp message.
13. The meter shall be optionally able to disconnect upon power outage and delay reconnecting upon power restoration with a configurable randomized delay between a T-min and T-max for:
    a. Soft system recovery after outages
    b. Installer safety

5.1.6 Visible Access to Data

1. Meters equipped with a service switch shall provide for an external indication of the switch status discernable to a customer or Company employee on site.
2. Meter display shall provide date and time as specified by the utility. The display shall also display measured quantities in engineering units.
3. Displayed data shall exactly match stored and transmitted data
4. Meters shall be capable of displaying registers of all possible metered data. Displayed data must show associated metrics/unit of measure.
5. Meter display shall include status of FAN communication link
6. If equipped with HAN, meter shall display status of HAN communication.
7. A visual disk emulator shall be provided on all meters.
8. Meter shall be able to operate in alternate and test modes and display configurable alternate and test mode display sets
9. Meter shall be placed into alternate and test modes locally. Test mode to have configurable time out period (reverting to normal mode) and ability to be set to normal mode remotely.
10. Normal and alternate displays to include error and warning conditions

5.1.7 Demand Response

All control and reconfigurations commands must be confirmed by field devices within 15 seconds.

5.1.8 Distributed Generation

1. The meter shall collect delivered, received and net cumulative values as well as interval data that are signed. Delivered cumulative shall be equal to the sum of delivered intervals, received

cumulative shall be equal to the sum of received intervals. Both time duration and energy threshold shall be configurable in seconds.

2. Meter display shall be configurable to display all or any of the measured quantities identified in item 1 above.

5.1.9 Installation and Maintenance

1. The communication module in the meter shall have Unique ID's for: LAN, WAN.
2. The meter shall have an indelible unique serial number over the life of the AMI system.
3. The meter shall have a unique ID for HAN communication.
4. Upon installation, the meter shall optionally recognize the service type and issue alarm messages for unrecognized services. The meters shall have functionality that enables to individually disable service level alarms.
5. Meter shall be able to identify itself to field network setup tool and provide access to its data and configuration settings at installation time, and later in support of ongoing operations & maintenance activities subject to security authorization.
6. The meter performs self-check and reports results to installer field tool, local display and to the AMI network. Self-checks to include integrity of the HAN communications card (if present) and AMI network communication card and ability to communicate with local collector (AMI communication network architecture dependent).

5.1.10 Meter Reading - On Demand

1. The meter shall be able to provide peak demand during a defined demand window and on-peak/off-peak usage
2. On the occurrence of an on-demand interval data read, the meter shall send data since the last successful read and other associated register and diagnostic information.

5.1.11 Meter Reading – Scheduled

1. The meter shall complete a self-read and store the value for each channel register of data.
2. Residential type meters shall be configurable to provide at least the following register and interval data:
    a. kwh (delivered and received)- Individual phase and total
    b. Kvarh(delivered and received) – Individual phase and total
    c. Internal meter temperature
    d. Voltage (magnitude and angle) - Individual phase and total
    e. Current (magnitude and angle)- Individual phase and total
3. Commercial type meters shall be configurable to provide at least the following register and interval data:
    a. kwh (delivered and received) - Individual phase and total
    b. Kvarh (delivered or received)- Individual phase and total
    c. Internal meter temperature
    d. Voltage (magnitude and angle) - Individual phase and total
    e. Current (Magnitude and angle)- Individual phase and total
    f. Kvah- Individual phase and total
4. Voltage resolution reported to Headend shall be 0.1V or better
5. Power Factor calculations shall include at least the following: Average, max, min, coincident, etc.
6. Supplier shall provide detailed description of each of the options available for power factor calculation
7. Residential meters shall be configurable to measure both integrated and instantaneous values (Per phase and total) for the following: In this context, “instantaneous” means a linear average over 1 second:
    a. KW

   b. Kvar
   c. Voltage
   d. Current
   e. Kva
8. Commercial meters shall be configurable to measure both integrated and instantaneous values (Per phase and total) for the following: In this context, "instantaneous" means a linear average over 1 second:
   f. KW
   g. Kvar
   h. Voltage
   i. Current
   j. Kva
9. The meter shall accommodate a minimum of 60 days of load profile data with 5 minute intervals for at least 4 channel data
10. Meters shall support TOU and critical peak pricing capabilities:
    a. 4 TOU rates
    b. 1 Critical peak pricing rate
    c. Ability to switch between time zones
    d. Ability to switch between standard time and daylight savings time
    e. Support for 4 seasons.
    f. Support advance calendar for at least 20 years including holidays

5.1.12 Meter Reading - Real time

Any metered quantify shall be available for a push or pull to the Headend in real-time with latency not to exceed 20 seconds

5.1.13 Outage Management

1. The meter shall be capable of sending a message if load side voltage is detected on a disconnected meter. Latency not to exceed 20 seconds.
2. The meter shall maintain sufficient function for a sufficient amount of time to differentiate between an outage and a PQ event.
3. The service switch shall operate if voltage less than a configurable threshold is detected for a configurable period of time.
4. The service switch of the meter shall operate if voltage greater than a configurable threshold is detected for a configurable period of time. If the service switch is operated, Company shall receive notification of the event.
5. Reconnection of the service switch of the meter shall occur automatically once the voltage has returned within the acceptable limits for more than a configurable amount of time. If the service switch is operated, Company shall receive notification of the event.
6. The meter shall detect and send a last gasp/tamper alarm to the Headend. Detection shall be possible after the meter is removed and before it stops communicating.
7. The meter shall be able to send a last gasp message over the communications network during an outage or removal.
8. At the system-level, meters shall remain operational after an outage for a period of time that is sufficient to achieve:
   a. 100% reporting on single outage
   b. 90% reporting on outages of up to 1000 meters
   c. 50% reporting on outages of up to 10,000 meters
   d. 30% reporting on outages that are system wide

9. Measurements of momentary interruptions, momentary interruption events and sustained interruptions shall be consistent with IEEE Std 1366-2012. In the case where IEE 1366 standard changes, the new definition shall supersede the old.
10. A single momentary interruption event includes all momentary interruptions experienced by the meter within a configurable period (e.g. 5 minutes, etc.). Service must be restored within a separately configurable time period (e.g. 5 minutes) to be classified as a single momentary event.
11. The system must be capable to report service restoration from 100% of meters within 10 minutes of restoration. System must support outage confirmation (head-end to meter and back) to determine online status to support field crews.
12. An interruption of less than a configurable time period (e.g. 5 minutes) shall be considered a momentary interruption and shall be logged by the meter as a momentary interruption.
13. An interruption of more than a configurable time period (e.g. 5 minutes) shall be considered a sustained interruption and shall be logged by the meter as a sustained interruption. The sustained interruption includes all the switching events from the initial interruption to full restoration of the sustained interruption event.
14. Data recorded by the AMI meters will be used to calculate Momentary Average Interruption Frequency Index (MAIFI) and Momentary Average Interruption Event Frequency Index ($MAIFI_E$). MAIFI includes all momentary interruptions that are not part of a sustained interruption. $MAIFI_E$ includes all momentary interruption events that are not part of a sustained interruption.
15. A single interruption shall trigger meter logging.
16. Momentaries shall be reported up to the Headend with the next scheduled meter read.

5.1.14 Security

1. Encryption of data stored in meter memory and in the transfer from CPU to memory shall be required.
2. The meter shall lock/disable chip diagnostic and programming ports (JTAG)
3. Provisions for secure local access shall be made available through the network or direct connection to the meter (via optical port).
4. The meter (and Field Tool) shall include authorization/authentication for local meter data download attempts.
5. The communication module shall be integrated with the meter under the cover.
6. The meter shall log all login attempts and support a lockout for a configurable amount of time upon repeated invalid attempts. Supplier shall provide list of other security events that the system is capable of logging.
7. Meter shall support, at minimum, symmetric key lengths of 128 bits.
8. Supplier shall provide detailed cryptographic key management description explaining how cryptographic material is provisioned, used, stored, and deleted within the system.
9. The communication module shall explicitly deny an information flow based on illegal message structure. The communication module shall have provisions to detect and thwart a message replay attack e.g. as per ANSI C12.22
10. Meter shall employ mechanisms that ensure device integrity from external tamper and compromise.
11. Meters shall comply with cyber security programs based on good industry standards such as NIST SP800-53 and SP800-82.
12. Meter shall supply a meter-to-Headend, cryptographic solution which assures the confidentiality of the meter's data while in transit.
13. Meter shall supply mechanisms which allow for secure device authentication, registration, and revocation.
14. Meter shall supply cryptographic mechanisms or materials which allows for unique device identification, authentication and communications.

15. Meter shall supply cryptographic mechanisms or materials which allows for group access
16. Meter shall supply mechanisms which audit and store all security related events including all access and modifications events within the system.
17. Meter shall supply a security audit store which includes the date and time of the event, type of event, user identity, and the outcome (success or failure) of the event.

5.1.15 Reliability

1. Suppliers shall submit accelerated life testing results for all the system components, substantiating the system's life and identifying top failure causes.
2. Meter must survive and function properly without losing data or programs through repetitive short-term power outage cycles as might be experienced by recloser operations
3. Meter time must be settable through the communication medium and the meter shall keep accurate time with a drift rate of no worse than 1 minute per year and in accordance with Section 7.4 "Timing and Clock References"
4. Some meters identified to support near real-time operations will require a low latency network to support Company's ADMS or SCADA needs.
5. Meter failure rate must be less than 0.5%/yr. for the first two-years and less than 0.3% for the remainder of the 20 year system service life.

5.1.16 Storing, Logging and Reporting Events

1. The meter shall be configurable as to what events are logged by the meter. Event messages for transmission and priority shall be determined by Company.
2. Meter shall send acknowledgement of a successfully completed or failed electric service connect/disconnect/limit event to the Headend latency not to exceed 20 seconds.
3. The meter shall log the date and time stamped establishment of load limit set-points, when load limits are exceeded, support for solicited and unsolicited reporting shall be available.
4. The meter shall log all local (and remote) meter data download attempts and the requester ID. The system shall support solicited and unsolicited reporting
5. The meter shall be able to detect loss of load (greater than a configurable period of time) on the customer side of the meter that is not related to a remote disconnect, log the event, and send an event message to Headend. When load is restored, the meter shall log the event.
6. The meter reinstallation events shall be sent to Headend immediately upon reinstallation along with any unsent tamper events.
7. An event generated when the meter is reinstalled is different from the event generated if the meter is initially installed (provisioned) or re-energized (e.g. after an outage). This is to avoid transmission of useless information to the enterprise systems because of non-tamper related events.
8. Meter's internal clock shall be synchronized in such a manner that the meter data that includes register and interval data shall not be affected and shall log the event
9. Meter shall be able to detect and log communications link failures upon failed communications initiated from the meter.
10. Meter shall be able to send an alarm/event to the Headend when a configurable number of consecutive communications link failures are detected (e.g. three consecutive link failures).
11. Meter communication module shall be able to periodically record the communication signal strength and report it back to the Head-end as part of all communication transactions.
12. Each meter shall be capable of capturing and recording a time stamped instantaneous voltage at configurable intervals ranging from 1 minute to 1 hour.
13. Each meter shall be capable of sensing and capturing high/low voltage variations with reference to user definable set points and, upon exceeding the predefined limits, send notifications.
14. The meter shall support an indelible event log sufficient to contain entries for at-least 60 days after which oldest entries are over-written first.

15. Meters with internal service switch shall log all disconnections and connections within its indelible event log.
16. The meter shall communicate to both its event log and the Headend any reactivation (reconnect) and disconnection events.
17. The meter shall log to its indelible event log messages (informational and functional) received from the Headend with the meter date/time and message code.
18. The meter shall detect and store as an event that an electrical parameter (voltage, current, load) has differed from a specified threshold for a certain period of time.
19. The meter shall immediately transmit any events that indicate a security threat. The transmission of the data must continue until the AMI Headend responds with a validation the data was received.

5.1.17 Tamper/Theft Detection

1. The meter shall detect physical tampering, such as, meter removal, case/cover removal, removal from socket, etc. and generate a tamper event.
2. All tamper related events shall be stored in the meter's event log. Events shall be stored for at least 60 days.
3. The meter shall be capable of detecting and alarming on an inverted meter condition.
4. The meter shall be capable of sending a removal tamper event before communications are interrupted.
5. Meter tamper events shall be sent with a higher priority than normal status messages.
6. For each tamper event, the meter shall transmit to the Headend and locally log the following information about the event: timestamp, tamper status (event type), meter ID.
7. In real-time the AMI-head and data analytical applications shall be able to determine which meters with an open disconnect switch have secondary voltage.

5.1.18 Power Quality

1. The meter shall have report by exception capabilities for selected parameters e.g. voltage, demand, etc. for operational purposes.
2. The meter shall be capable of recording both instantaneous and average configurable voltage, current, power factor, kWh, kvarh, and kW values during each interval
3. Meter shall monitor voltage and current in order to detect power quality variations according to CAN/CSA 61000-4-30, IEEE 1159, CBEMA / ITIC and IEC 61000-4-30 standards.
4. Meter shall allow authorized Company employees to retrieve any recorded device information including logs both locally and remotely (on-demand). Local communication has priority over remote.
5. Both meter and communication infrastructure shall support remote desktop access to the meter using meter manufacturer's native configuration software (e.g., Metercat, PCPro, etc.) over an IPv4 and/or IPv6 connection.
6. Meters with power quality capabilities shall store the power quality data for a period of up to 60 days.

5.1.19 Instrumentation Profiling Data

When equipped with instrumentation profiling data, meters shall be required to capture date and time for minimum, maximum, instantaneous and average values per phase and total for the following values:

a. Voltage
b. Current
c. Temperature
d. power (KW)
e. reactive power (KVAR)

f. Apparent power (KVA)
g. Power factor
h. Harmonics

5.2 Meter Requirements for HAN Support

5.2.1 HAN Interface – Hardware and Communications

AMI meters and system must have the ability to support IEE 2030.5 standard for interface with 3rd party HAN providers. Xcel requires the AMI solution to support communication with HAN, though anticipates it will be selectively deployed (see Section 5.8). The Supplier may propose solutions with technology embedded in all, or only select meters.

5.2.2 HAN Interface- Data Requirements

Using the HAN interface hardware and communications protocol, the meters demand data must be made available to 3rd party HAN providers at a granularity of 1 minute or less.

5.3 Meter Read Performance Metrics

5.3.1 Baseline Read Rates

All meters, excluding the bellwether meters, shall record interval, register and events data every 15 minutes and complete transmission of this recorded data to the Headend, at an interval that does not exceed every 4 hours and meeting or exceeding data transmission completion reliability criteria of 99.9% on first attempt.

5.3.2 Fast Transmission Read Rates

Where meter read rate performance is considered to be “Fast”; all meters, excluding the bellwether meters, shall record interval, register and events data every 15 minutes and complete transmission of this recorded data transmit to the Headend, at an interval that does not exceed every 15 minutes and meeting or exceeding data transmission completion reliability criteria of 99.9% on first attempt.

5.3.3 Five Minute Interval Read Rates

All meters, excluding the bellwether meters, shall record interval, register and events data every 5 minutes and complete transmission of this recorded data to the Headend, at an interval that does not exceed every 4 hours and meeting or exceeding data transmission completion reliability criteria of 99.9% on first attempt.

5.3.4 Register readings - Auto scheduling

The AMI Head-End Application shall initiate scheduled meter read requests and collect at least 99.9% billing quality meter register reads on first attempt.

5.3.5 Register / Interval readings – Auto scheduling

The AMI Head-End Application shall initiate scheduled meter interval data read requests and collect 100.0% billing quality interval meter reads for at least 99.9% of the scheduled meters on first attempt.

5.3.6 Register / Interval readings – On Demand readings from other sources

The AMI Head-End Application shall successfully process on-demand meter read requests initiated thru the MDM and CSS (and other designated systems such as web interface).

Data retrieval directly from meter - response time shall be < 20 seconds 99.9% of the time on first attempt.

Meter data retrieval from AMI Head-End Application database - response time shall be <10 seconds 99.9% of the time on first attempt.

5.3.7 Register / Interval readings – On Demand readings from Headend

The metering system shall successfully process on-demand meter read requests initiated within AMI Head-End Application (user menu). If not successful, AMI Head-End Application shall produce a specific error message at a configurable duration as set by Company.

Data retrieval from meter - response time shall be < 20 seconds 99.9% of the time on first attempt.

Data retrieval from AMI Head-End Application database - response time shall be <10 seconds 99.9% of the time on first attempt.

5.3.8 Register / Interval readings User initiated data output request

Data collected from on-demand meter read requests may include: register reads, interval data for a configurable period, service switch status, service voltage, or any meter logs that may include events, warnings or alarms.

Data processing extraction time frames must not exceed 15 minutes per 250,000 register or interval records retrieved and successfully written to an output file.

5.3.9 Interval readings Gap retrieval

The AMI Head-End Application shall successfully re-request interval data from the meter when data collection has encountered gaps in the data. The gap retrieval process shall be automated and configurable in the duration (length of time to try to recover data) and number of retry attempts (every XX minutes/hours).

Suppliers shall indicate the manner in which these options can be configured.

The gap retrieval process should successfully retrieve 100% of the missing interval data when the interval data is available in the meter tables. There shall be no discontinuities to energy registration for DST and meter clock resets. The total pulse counts or energy registration from the intervals shall equal exactly the total register readings.

5.3.10 Register readings recovery

The AMI Head-End Application shall successfully re-request register data from the meter when data collection encounters missing register reads. The retrieval process shall be automated and configurable in the duration (length of time to try to recover data) and number of retry attempts (every XX minutes/hours).

Suppliers shall indicate the manner in which these options can be configured.

The retrieval process shall successfully retrieve 100% of the missing register data when the register data is available in the meter tables on first attempt.

5.3.11 Demand Reset Performance

The AMI Head-End Application shall successfully perform automated and on request demand reset functions 100% of the time on applicable demand meters. The demand reset process shall be able to be initiated upon request and shall be automated and configurable through an auto schedule such as a schedule established for billing cycle meter reading collection. In the event a demand reset is unsuccessful the AMI Head-End Application shall initiate a configurable number of retry attempts (every XX minutes/hours).

Suppliers shall indicate the manner in which these options can be configured.

5.3.12 Accuracy of Delivered Meter Reads

Data collected from field devices and processed thorough the Headend Database, shall accurately reflect customer consumption taking into account such things as meter multipliers, pulse multipliers, or data adjustments of any nature.

5.3.13 Precision of delivered data

Precision of delivered data shall no less than precision of the original source data precision.

5.4 Bellwether Meters Performance Requirements

5.4.1 Support for Advanced Distribution Management System (ADMS)

1. The AMI system shall support the use of no less than 20,000 meters, referred to as "bellwether meters", for use as distribution parameter sensors for ADMS in support of applications such as IVVO. 10,000 shall be located in PSCo and the rest in the other company jurisdictions.
2. Bellwether meters are evenly distributed proportionately to electric feeders throughout Company service territory. Refer to the "Electric Distribution Points.xlsx" attachment for details on location.
3. Approximately 50% of the devices are of residential type. The balance is of a commercial type.
4. Residential bellwether meters shall measure, record and transmit no less than the following parameters:
    a. kwh (delivered and received),
    b. Kvarh (delivered and received)
    c. Voltage,
    d. Current
    e. Temperature
5. Commercial bellwether meters shall measure, record and transmit no less than the following parameters:
    a. Kwh (delivered and received),
    b. Voltage (per phase),
    c. Current (per phase),
    d. Kvarh (delivered and received),
    e. Kvah,
    f. Power Factor,
    g. Temperature
6. Data accuracy shall be no less than 1 incorrect parameter received in 1 million parameters sent from meters to the Headend.
7. Load profile interval data from all bellwether meters shall be made available to the Headend no more than 20 seconds after the close of every meter load profile interval.
8. Load profile data from bellwether meters shall be processed by the Headend and made available to other applications e.g. MDM no more than 30 seconds from the close of every meter load profile interval.
9. AMI Headend shall process meter raw interval data, usually in pulse counts, and make it available in engineering units to other systems such as ADMS. As an example, volt-hours interval data in pulses from the meters shall be processed by the Headend and made available to other systems as average voltage values through integration interfaces.

5.4.2 Bellwether Read and Transmission Rates – Residential Meters

Interval and register data from bellwether residential meters shall be collected and transmitted to ADMS via the Headend at intervals that do not exceed 5 minutes. The AMI system shall make this data available 99.9% of the time to ADMS.

5.4.3 Bellwether Read and Transmission Rates – Commercial Meters

Data from bellwether commercial meters shall be collected and transmitted to ADMS via the Headend at intervals that do not exceed 5 minutes. AMI system shall make this data available 99.9% of the time to ADMS.

5.4.4 Option - Total Voltage Harmonic Distortion

As an optional response including pricing on Xcel Energy AMI RFP pricing Template v4.xlsx repeat section 5.4.1 Support for Advanced Distribution Management System (ADMS) with the addition of:

a. In line 5.4.1 – line 4 add f.% Total voltage harmonic distortion
b. In line 5.4.1 – line 5 add h.% Total voltage harmonic distortion

Use Xcel Energy AMI RFP pricing Template v4.xlsx, “Baseline AMI Meters” TAB and expand on the block of options that can be offered by Suppliers.

5.5 Requirements for Headend Application

5.5.1 Availability

1. Headend shall log information (i.e. retrieval pathway) associated with both successful and unsuccessful retrieval of missing/incomplete meter data to aid in troubleshooting. The Headend shall provide specific details on success and failures
2. Headend shall monitor and measure both communication and device availability metrics for metering endpoints and network equipment.
3. Headend shall enable customer notification of communication status with HAN devices within 30 minutes of enrolling them. Expected value is 2 minutes 90% of the time.
4. Headend shall be able to remotely detect network communications problems including loss of redundant communications pathways, diminishing signal strength, repeated delays in reporting etc.
5. The Headend shall support configuration of Quality of Service parameters in the underlying communication network.

5.5.2 Connect, Disconnect or Limit Service

1. If a command to disconnect or reconnect a meter fails, Headend shall be capable of automatically retrying the command. The number and frequency of automated retries shall be configurable with grouping capabilities with strategies behind them. (Meter type, rate class, geography, individual meter, etc.)
2. Headend shall transmit to the meter a load limiting request initiated by either the MDM or user logged into the AMI GUI
3. Headend shall have the ability to schedule; reschedule and cancel remote connect, disconnect and demand limiting commands for future dates/times.
4. The Headend shall support both human and machine initiated connect/disconnects

5.5.3 Customer Access to Data (If HAN is enabled at the meter)

1. Headend shall send rate change event schedule information to the meter with a future effective date and time. Expect a minimum of 12-24 hours.
2. Provide usage by billing period up to last interval on-demand
3. Headend shall provide notification when system defined or user defined "peak" kW is exceeded.

5.5.4 Data Analysis - Reporting

1. The Headend shall produce system report for each meter indicating the average RSSI and SNR levels for system analytics and optimization.

2. The Headend shall produce system load profile data for gas and electric that would be suitable for use by aggregators for studies to facilitate growth planning.
3. Headend shall have the capability to localize the source of the communication failure and produce diagnostic and trend reports to support operations and maintenance efforts.
4. The Headend shall support the definition, creation, management, and delivery of predefined reports, which can be customized based on all database fields in the system. The Headend shall also provide a mechanism to save these reports in different formats e.g. CSV, xml, etc. from within its environment.
5. The Headend shall provide reports for performance metric evaluation based on Company's Requirements (e.g. response times, message delivery reliability, Headend system availability, communications network availability).
6. The Headend shall provide facilities to automate routine report generation.
7. The Headend shall generate a status report daily that includes information regarding anomalies and issues affecting the integrity of the metering system or any component of the metering system including information related to any foreseeable impact that such anomalies or issues might have on the metering system's ability to collect and transmit meter reads. This would include confirming the successful collection and transmission of meter reads or logging all unsuccessful attempts to collect and transmit meter reads, identifying the cause, and indicating the status of the unsuccessful attempt(s).
8. At the completion of every read schedule, the Headend shall generate a status report that confirms the accuracy of the meter reads. e.g. The report shall be able to identify any meter related errors that might affect the accuracy of the data.
9. At the completion of every read schedule, the Headend shall generate a status report that monitors time and reports any deviations.
10. At the completion of every daily read period and following a transmission of meter reads, the Headend shall generate a status report that confirms whether time synchronization within the metering system or any components of the metering system has been reset within the daily read period.
11. The Headend shall have the ability to export AMI-specific, meter, and network events list.
12. The Headend shall have the ability to configure AMI-Headend specific, meter, and network events that can be transmitted and the frequency.
13. AMI system shall detect and report hot-socket conditions to the Headend.

5.5.5 Data Collection

1. Headend shall support CCF and MCF measurements for gas
2. Headend shall support measurement of temperature and pressure for gas

5.5.6 Data Reporting

1. Headend shall provide load profile data reports at a frequency configured by the Company, e.g. several times daily, weekly, monthly, etc. Report shall contain all of the data from Load profile configured meters.
2. Headend shall provide an energy consumption report at a frequency configured by the Company, e.g. daily, weekly, etc. The report shall contain the meter serial number, current consumption data, demand reset success, etc.
3. Headend shall provide a zero usage report at a frequency configured by the Company. e.g. daily, weekly, etc. The report shall contain the meter serial number, current consumption data, status, and diagnostic data.
4. Headend shall provide a report on meters not communicating at a frequency configured by the Company, e.g. daily, weekly, etc. The report shall contain the meter serial number, current consumption data.

5. Headend shall provide roll-up network and reading performance reports, daily, weekly, monthly, yearly etc. The report shall contain performance categories as specified by the utility. I.e., by route, by area, by zip by grouping.
6. AMI Headend application will generate internal AMI application synchronization report listing synchronization errors with company MDM.

5.5.7 Distributed Generation

Headend shall collect the following metering data and export the data. in a user defined format:

a. Delivered values
b. Received values
c. Net cumulative values
d. Interval data that is assigned.
e. Delivered cumulative values (sum of all delivered intervals)
f. Received cumulative values (sum of received intervals)

5.5.8 Interoperability and Standards

1. The Headend shall be responsible for collecting, storing and presenting all data collected.
2. The Headend shall be the raw data processor for all data to and from the meters.
3. Headend shall be able to support common information model (CIM) structures, multi-speak, and/or service oriented integration patterns for IT systems integration with Meter Data Management System (MDM) and other enterprise IT systems.
4. Headend shall support both electric and gas endpoints
5. Headend shall manage read operations (read, transmit, etc.) of gas meters to enable maximum battery life.
6. The Headend shall provide an open interface that supports multiple MDM systems.
7. Headend shall support standards based integration interfaces: IEE XML, Configurable XML, Configurable CSV, CMEP, LODESTAR, HHF, MDEF, IEE_ ASCII, CIM, Multi-speak, Web services

5.5.9 Manageability

1. Headend software for collecting and processing metering data from field devices shall be separate from software application required to manage network devices. Network management software shall be hosted at the Network Operations Center while software application for managing metering data may be hosted at a different location. Separate network management from data management.
2. All data requests, control commands, configuration commands, and upgrade commands shall be able to be made through the MDM or Headend.
3. Headend shall be capable of collecting, storing, and transmitting all data collected by the meter. This will include register reads and interval reads
4. The Headend shall support time management of meters with multiple clocks. See Section 6.4 “Timing and Clock References”
5. The Headend shall be able to process requests for missing data for both scheduled and on-demand reads.
6. In the event a meter is replaced due to a communication failure, Headend shall be able to remotely restore the proper meter configuration into the new meter.
7. AMI Headend shall have the ability to place meters into groups (regional, rate, schedule, etc.).
8. Headend shall have the ability to place meters into ad-hoc groups for operator analysis.
9. The Headend shall gather and store configurations from network equipment and track changes made to the devices, and to configure, to restore configurations, and to support automated provisioning of new equipment.

10. Headend shall have system administration tools to perform maintenance, monitor system performance, and handle exceptions.
11. The Headend shall provide administrative management and optimization functionality with both user and machine interfaces to support the NOC and network management.
12. The Headend shall provide authorized users with a mechanism to perform queries against the data repository and save the resulting queries for additional analysis. Direct access to tables shall be made available via other systems such as MS Access, SQL, etc.
13. Relevant Xcel personnel shall have direct table access using alternative systems such as, but not limited to MS Access, SQL, etc. to underlying database table structures and all schemas shall be provided.
14. Headend application GUI shall be intuitive and user friendly
15. Headend shall support both scheduled and ad hoc data extract reports for any or all metered values (The report shall be configurable by Company) e.g. kWh, voltage, current, temperature, customer information, etc.
16. AMI Headend shall support managing and administering all aspects of security for various network devices e.g. meters, gas modules, network devices, etc.
17. Headend shall accurately track and manage various network installation stages of endpoints
18. Headend extract reports shall be configurable (e.g. time and date, meter id, etc.)
19. Headend shall support collection, storage and transmission of multiple interval lengths for electric meters (1, 5,15,30,60 minutes)
20. Headend shall support collection, storage and transmission of multiple interval lengths for gas meters (Configurable length for example gas day, max hour, etc.)
21. Headend shall support exception handling and reporting of data during meter time adjustment
22. Headend shall support exception handling and reporting of data during communication failures
23. Headend shall support exception handling and reporting of data during meters errors
24. Headend shall report all statuses associated with Load Profile data
25. Headend shall report all statuses associated with Load Profile data during exception conditions, e.g. loss of network communication
26. Headend shall accurately track and report meter and module program changes. If meter is reprogrammed over the air (OTA), system shall acknowledge with a latency of no more than 20 seconds. Data delivery must be suspended pending user or system action
27. Headend shall support index change for gas modules
28. Headend shall support reuse of gas modules on a different meter
29. Headend shall support process to retain the install index read, pulse value and retain the data in the module itself.
30. Headend shall support tracking of lost module ID's
31. Headend shall have a mechanism for marrying meters to gas modules that is internally tied for inventory tracking and audits
32. Headend shall track network performance of each end-point
33. Headend shall provide general network performance health reports at a frequency desired by company, hourly, weekly, and daily, etc.
34. Headend shall provide demand reset reports (both success and failure) at a frequency desired by Company e.g. daily, weekly, monthly, etc. Report shall show at a minimum meters that reset (or failed to reset), date and time of reset, date of peak demand, present demand counter, previous demand counter
35. Headend shall provide a menu driven user interface to request all data directly from the meter tables. The data shall be presented in a usable format
36. Headend shall provide menu functionality to manage time zones within the AMI application. This feature would allow time management settings by areas all the way down to the device level.
37. Headend shall support geo coding, and robust visual mapping capability

38. Headend shall offer a meter status management feature, if meters are off line or cannot be reached or system status changes based on user specified parameter. This could more accurately direct auto retries and other reporting/maintenance
39. Headend shall have a real-time dash board display of network device events e.g. failed communication, unreachable devices, network devices, etc. Alert thresholds shall be configurable
40. Identify meters by status i.e. no reading for 2 months. Assign action capability. Auto forward service order
41. Headend users shall have a GUI interface and the capability to manage, change, add, or delete meter records within the AMI application. System users shall have the capability to manage, change, add, and delete meter centric /hardware centric records within the AMI application. (Shall have full AMI on line update capabilities).
42. The demand reset function shall have the capability to be automated by referencing a predetermined billing schedule and initiating auto retry functions if reset attempts fail. User shall also be able to set number of retry parameters. The demand reset function shall also be available via an on demand request. The Headend shall receive confirmation of successful or failed demand reset from the meter(s).
43. Headend shall provide menu functionality to manage historical data (purge) records within the AMI application. This shall include internal tables/log file files / event logs
44. Headend shall provide the functionality to recognize records that are out of synchronization with Company's MDM.
45. Headend shall provide the functionality to manage meters installed but not communicating on the network. Additionally the Headend shall provide functionality to manage meters whose installation is not recorded but are communicating on the network.
46. Headend shall provide the functionality to capture the actual meter program (programmed ID in the meter), and populate this information within the AMI application (so user can reference this information when working with customer/meter information)
47. Headend shall provide the functionality for real-time system reporting and monitoring.
48. Headend shall provide the functionality to identify meter programs within the meter, real time access to this information
49. Headend shall provide the functionality for hardware/device history from both AMI and MDM.

5.5.10 Meter Reading - On Demand

1. On demand meter reads (both human and machine requested) shall be supported. Both successful and failed attempts shall be logged.
2. Headend shall provide specific ANSI table information for data retrieved. For example table 23 for current register reads, table 25 for previous demand, etc.
3. Headend shall provide direct access to meter ANSI tables
4. Headend shall be capable of sending commands directly to the meter in absence of an installed meter status within the Headend while the Meter is in a discovered status.
5. Meter data information retrieved when performing an on request read shall be configurable to include e.g. kwh, kw, date of peak demand, etc.
6. On demand reads shall have the option to be retrieved from either the Headend database or directly from ANSI meter tables.

5.5.11 Meter Reading – Scheduled

1. Headend shall have the capability to manage meter read schedules e.g. flexible parameters based on meter reading requirements (rates, geography, etc.)
2. The Headend shall publish all data collected from meters and made available to the MDM based on user configurable parameters.
3. Headend shall be able to remotely set/update/cancel a meter's read schedule for a specified duration.

4. Headend shall schedule default read times for all unscheduled meters by placing them in a default read group, maintaining balance among the currently scheduled read groups (ensuring system optimization).
5. Headend shall be able to identify those read groups and/or individual meters that consistently fail to meet targeted schedule read times.
6. Headend shall be able to schedule default read times for various groups of meters as initiated by the AMI NOC or user initiated - Menu driven
7. The Headend shall collect load profile data from all meters.
8. Headend shall be able to import Xcel billing schedule. This schedule shall drive meter reading data collections, and automated demand resets
9. Meter reading outputs written to MDM files shall be selectable at the register level/interval channel level. This includes all meter reading registers and interval channels programmed into the meter.
10. User shall have the capability to select menu driven functions when generating ad hoc or scheduled meter reading output files.
11. User shall be able to designate, reads extraction time, billing file create date-time, billing file delivery date-time.
12. AMI Head-End Application shall have an Auto-scheduling feature. Auto scheduling may occur multiple times daily, the time and frequency of the schedule executi0n shall be user configurable.

5.5.12 Outage management

1. Items from section 5.1.13 above shall be supported by Headend.
2. The Headend shall have an auto-retry process after an outage to determine status of electric service.
3. The Headend shall have the ability to process and send power-up messages from all meters to the Headend.
4. Last gasp messages shall be sent by the Headend to the outage management system for processing.
5. Last gasp messages shall be date/time stamped by endpoints. Headend shall include locations to assist in determining the outage area.

5.5.13 Performance - Steady State

The Headend shall gather device usage statistics from network equipment and to track link and system utilization and response times.

5.5.14 Power Quality

Headend shall publish power quality information be subscribed to by other applications.

5.5.15 Reliability

1. Headend shall attempt to recover any information which would have been sent to it from the meter in the absence of a communication failure. This shall include robust interval data gap recovery and events and register data information.
2. Headend shall identify when meters no longer have redundant communication paths available.
3. Headend shall identify exact failure point in the mesh network
4. Headend shall be able to remotely check meters for communications status, energized status, load side voltage and switch status on-demand.
5. Headend shall be able to remotely detect network communications problems including repeated delays in reporting.
6. Headend shall send notice to MDM of failures that would make meters unreachable.
7. Headend shall be able to remotely detect network communications problems including at least diminishing signal strength, loss of redundant communications pathways, etc.

8. Headend shall be able to remotely test communications with customer devices attached to HAN.
9. Headend shall be able to conduct diagnostics for troubleshooting communication problems. This would include network packet tracking, where does the packet fall out, not just hop counter
10. Headend shall have configurable alert levels and notifications based on the severity of a problem detected and the number of endpoints affected.
11. Headend shall be able to classify specific testing/diagnostic results to either require or not require human intervention, test/diagnostic criteria to be configurable.
12. The AMI system shall have redundancies to ensure aggregated system availability of at least 99.999%.
13. Headend shall provide meter diagnostic reports at a frequency desired by Company e.g. real-time, hourly, and daily, etc. The report shall contain the serial number of the meter, all associated time stamped diagnostic events.
14. Headend shall provide a load profile gap report that identifies meters with missing load profile data at a frequency desired by Company, e.g. daily, weekly, etc. The report shall contain the meter serial number, start and stop time of missing data, etc.

5.5.16 Scalability

1. Each Headend instance shall support scalable meter population from 1 million to 10 million.
2. The Headend shall have a distributed architecture that can support redundancy, load balancing and network optimization.

5.5.17 Security

1. Headend shall supply mechanisms which allow for secure device authentication, registration, and revocation.
2. Headend shall supply mechanisms which audit and store all security related events including all access and modifications events within the system.
3. Headend shall supply access control mechanisms (i.e., Identification & Authentication mechanisms) which prevent unauthorized access of information and resource. Example is limiting number of disconnects that can be issued by a single user.
4. The Headend shall be a secure system with strong user authentication processes.
5. Headend shall log all login attempts and support a lockout for a configurable amount of time upon repeated invalid attempts. The login attempt must be reported to the Administrator.
6. The AMI Head-End system should have the ability to integrate with LDAP for authentication (such as Active Directory). The authorization will be managed within the Head-End system.

5.5.18 Storing, Logging and Reporting Events

1. The Headend shall publish all meter events to the MDM
2. Headend shall log successful and failed meter procedures (e.g. Clock reset, demand reset, and reconfiguration, connect/disconnect, etc.). Date and time shall be logged as well.
3. Headend shall have the ability to prioritize messages (functional and non-functional) that are transmitted to the meter (e.g. connect/disconnect, load control, etc.). The priority shall be configurable by Company.
4. Headend shall be able to publish configurable exception events (sag, swell, interruption, fault level, outages, security events, other meter diagnostic events, etc.)
5. The meter logs shall be retrieved regularly as determined by Company.
6. The Headend shall have a configurable alarming system to notify of failure or maintenance requirements. Thresholds shall be configurable
7. Headend shall export a list of failures that would make meters unreachable.
8. Headend shall produce reports that identify system health such that incipient failures can be corrected before they become permanent

9. The Headend shall provide a time stamped event progress log for all commands initiated by the Headend.
10. The Headend shall provide automated email and or text reports configurable by Company.
11. All Headend security logs shall be exported for use by a centralized logging device, such as Security Incident and Event Management (SIEM).

5.5.19 Upgradeability and Configurability

1. Headend shall support a HAN gateway internal or external to the meter.
2. Raw interval data from meters shall be retained for at least 90 days in the Headend. This data can be used for "re-loading" data into batch processes if data is lost or corrupted.
3. Headend shall provide support for disciplined clock in field devices.
4. Headend shall support full meter reprogramming of meters identified from section 2.3 item #5. of the
5. Headend will support use of manufacturer specific software to reprogram meters over the MESH network
6. Headend shall support upgrade of communication module firmware. The application shall report all successes or failures of module firmware upgrades
7. Headend shall support upgrade of meter metrology firmware. The application shall report all successes or failures of metrology firmware upgrades
8. Headend shall support upgrade of meter register firmware. The application shall report all successes or failures of register firmware upgrades

5.5.20 User Interface

1. Headend shall have a real-time dash board display of meter events e.g. sags, swells, harmonics, meter specific events, etc.
2. Headend shall have a real-time dash board display of gas module events
3. Headend shall have a real-time dash board display of network device events e.g. failed communication, unreachable devices, network devices, etc.
4. Headend shall have a real-time dash board display of meter register information
5. Headend shall have a real-time dash board display of demand reset performance
6. Headend shall have a real-time dash board display of ad-hoc reports of meter data, including both registers and profile recordings, individually and aggregated. Such reports must be printable or electronically transmittable for external use (.csv, .xls, html, xml, etc.)
7. Headend shall have a real-time dash board display AMI system performance - overall read performance, failed meters, demand reset statuses, etc. - drill down from system to individual meters
8. Headend shall support role-based security in which access rights can be granted on an incremental basis.

5.6 AMI Headend Non-Functional Requirements

5.6.1 Logging

1. Logging for the AMI Head-End system should be enabled.
2. Any Application, Network, Database, Messaging, User Access, etc. must be managed within the Application and the error must be escalated appropriately. If these errors can be integrated with a Monitoring system (such as HP Operations Manager or similar tool).

5.6.2 Communication

1. The AMI Headend application must support integrations using industry standards similar to CIM and Multi-speak.

5.6.3 Database

The AMI Headend application database must run on Supplier supported versions of SQL Server or Oracle.

5.6.4 Environments

1. The AMI Headend application must have Disaster Recovery capability.
2. The AMI Headend shall be licensed to allow Company to have at least one production environment and two concurrent test environments.

5.6.5 Interface

The AMI Headend application shall provide interfaces to allow for the import, export, and update (synchronization) of information (including meter, premise, and customer information) from the Company's other systems, such as Asset Management, GIS, Meter Data Management, Demand Response, and Customer Information Systems.

5.6.6 Headend Landscape

The Headend application shall support high availability configurations using industry standard tools. Note: Company uses load balancing pairs of servers, and database clusters for the DB. The AMI Headend application should be able to work across server pairs and database clusters.

5.6.7 Logging

1. AMI Headend shall log user activities and include date/time, user id, activity, and success or failure of the activity. The logs shall be searchable by each field and be exportable in a common format, such as xls, csv, or pdf.
2. AMI Headend shall log system activities and include date/time, process id, activity, and success or failure of the activity. The logs shall be searchable by each field and be exportable in a common format, such as xls, csv, or pdf.

5.6.8 Mobile Devices

The system shall enable mobile and/or tablet access to meters for troubleshooting, field access, pinging, etc.

5.6.9 Operating System

1. The AMI Head-End application must operate on all supported releases of Microsoft's desktop operating system.
2. AMI Head-End Application Database must be running on SQL Server 2012 R-2 and or Oracle 11g (Minimum).
3. AMI Head-End Application should be hosted on Microsoft Windows Server 2012 R-2, and/or RHEL version 6.x or greater.

5.6.10 Security

1. The AMI Headend application integration interfaces shall allow the security administrator to generate security reports based on the integration interface's logs.
2. If Supplier has access to any Company or client confidential information, please describe how confidentiality is going to be maintained, including how information is retained and/or disposed of at designated times.
3. The corporate software maintenance process shall be followed for upgrades and patches.
4. Vulnerability scans are to be performed for equipment or product before it is put into both test and production.
5. Product shall not use unsupported open source code or operating systems.

6. Product shall have application security testing performed by Supplier and the results shall be shared with Company.
7. AMI Supplier shall follow best practices in their coding by utilizing secure application development methodologies such as OWASP.
8. All product testing shall be performed in non-production environments.
9. All security logs shall be captured by a centralized logging device, such as Security Incident and Event Management (SIEM).
10. Data encryption shall be utilized for both data-at-rest and data-in-motion.
11. Encryption algorithms shall be of sufficient strength with equivalency of AES-128.
12. Multi-factor authentication shall be utilized.
13. AMI Headend user access shall utilize role-based security, enabling access to be assigned by, for example, functionality, geographic area(s), asset grouping, business areas, etc.
14. Active Directory shall be used for user and service authentication.
15. Credentials are required to be stored in encrypted form.
16. Secure messaging shall be utilized whenever technically feasible such as SFTP.
17. If mobile technology is available, the application shall be compatible with Mobile Device Management Systems.
18. Appropriate firewall rules shall be used.
19. Intrusion prevention technology shall be utilized.
20. Only secure TCP/IP protocols shall be utilized.
21. Least functionality principles shall be practiced.
22. Least Privilege principles shall be practiced.
23. Defense-in-depth posture shall be practiced.
24. Zero-Trust Networking shall be practiced.
25. Tightly-controlled access shall be practiced across all network layers.
26. The AMI Headend shall support 8-character password with complexity (upper and lower case alpha, numeric, special characters).
27. The AMI Headend application shall not need to store Personal Identifiable Information (PII), but if it does, the application shall ensure the security and privacy of such information.
28. A Supplier shall notify Company immediately in writing and electronically when a security vulnerability is identified.
29. A patch shall be released to resolve a firmware or security issue within 30 days of identification of an issue.

5.6.11 Time

1. The AMI Headend application shall be capable of storing and displaying data from multiple time zones.
2. The AMI Headend application shall process Daylight Saving Time switchovers automatically and assure that all functions and programs are updated appropriately. The system shall handle switching to and from daylight saving time without an outage to the system or loss of data. Capability to enable/disable or change the scheduled date and time of automatic switchover of the daylight saving time shall also be provided via graphical user interface.
3. The AMI Headend application shall accommodate daylight saving time switchover such that the missing or extra hour is processed appropriately without manual intervention, including logs, reports, displays, trend graphs, etc.

5.6.12 Reliability

1. The AMI Headend application must support automated data backup, archiving, purging, and restoration. This includes Disaster Recovery.
2. Describe the development languages and architectures the system supports. Include both proprietary and standard languages and architectures: e.g. JEE, SPRING, .NET.

5.6.13 Timed Lockout

The AMI Headend application shall automatically logout a user after a configurable number of minutes of inactivity.

5.6.14 Usability

1. The AMI Headend shall provide functionality to schedule processes to execute.
2. When specifying a periodic execution, it shall be possible to define if the period is based on the start or end of the previous execution.
3. All time-based schedules shall be definable based on absolute or relative time using either standard or application system time scales.
4. The scheduling services shall monitor all schedules to ensure execution at the correct times and notify the users via the Alarm/Events subsystem for any failures or missed schedules, as well as the successful start of a scheduled activity with the reason for activation. The system shall also support the ability to log these events to the Central Logging system as well as notify IT Support personnel about these application scheduling failures via e-mail or text message.
5. All AMI Headend parameters for configuration, performance tuning, and variants shall be defined without having to modify any source code.
6. The AMI Headend shall incorporate displays/forms to manage the configuration parameters. These displays/forms shall be easy to understand and navigate. The system configuration parameters shall be clearly and concisely documented.
7. The AMI Headend shall provide report services that are available for use from any application and server. The AMI Headend shall support routing reports to a report repository, Email or printer. A report repository may be configured for easy user access to reports as well as time based report deletion.

5.6.15 User Lockout

The AMI Headend application shall lock out a User account after a configurable number of consecutive failed login attempts, and provide an administrator function to unlock accounts.

5.6.16 Users

The system shall support up to 1000 users, with up to 500 concurrent users with direct access to meters ; e.g., field, meter shop, meter analyst, call center, billing.

5.7 Requirements for Voltage Phase Identification

5.7.1 Description

Company wishes to consider applying a form of Distribution Automation "Intelligence" using its network of connected meters. Company invites Suppliers to submit an optional technical and price proposal for a system that may be attached or included in the WMN that provides a means to identify phase information, hereafter referred to as the Voltage Phase Identification System.

5.7.2 Requirements

The Voltage Phase Identification system shall consist of a hardware/software and any applications that uses any form of computational and/or WMN networking technologies that have the means to detect and identify phase information for any metered attachment and to transmit the information to a Headend attached application server for subsequent use in DA control and monitoring applications.

5.7.3 Response Methodology

1. Suppliers shall submit a proposal responding to the Description and considering the Requirements listed (above). The response shall include the following components:

a. Description of the offering including narrative and equipment block diagram identifying hardware and software components and their interconnection.
b. Description of the proposed scientific principles by which the phase information will be obtained.
c. The guaranteed accuracy of the information that is presented to the Headend and downstream application.
d. Description of any special features and or requirements that are necessary to be included or provisioned in the meters that are participating in the Voltage Phase Identification System.
e. List of meters types (manufacturer, make and model) including NIC types supported.
f. Description of the methods and procedures that are required to physically and electrically attach any devices to customer or Company owned property or equipment
g. Description of the Back Office IT equipment that is necessary to implement to support the Voltage Phase Identification system.
h. Tabulation of the industry standard(s) applied and used.
i. Speed at which the application reports data to the end user application.
j. The method by which Company will set-up and monitor the performance of the application.
k. The method and protocols by which Company will interact with the resulting data.
l. A definition and description of the communication protocols used between the Headend and the application server, if used.
m. The software language protocols used between the meters and application for inter-device communications.
n. Description of other requirements that Company must fulfil so as to achieve a wholly working system that is integrated into a fully operational IT environment.
o. A description of the security protocols applied and the manner in which security protocols can be upgraded or added to.
p. Description of the methods by which any firmware or software can be upgraded.
q. Description of the impact of adding Phase Identification to the AMI network proposed herein in terms of offered traffic and prioritization requirements in forward and reverse directions
r. Per unit costs for equipment to be located on all consumer premises (~1.4 M). Price for valid meter types per item (e) above.
s. Cost for Back Office equipment as required to operate the system.
t. Cost for annual support agreement for deploying to all consumer premises in a two-year period.

5.8 Requirements for Home Area Networking

5.8.1 Description

Company anticipates that either through its own or third party offered programs and services, customers may require access to their individual meter data in greater granularity and frequency (near real-time) than may be practical to backhaul over the AMI network and store at the Xcel owned/operated Headend on a routine basis. One mechanism for obtaining this type of granular data is for the customer meter to interface directly with the customer's HAN or similar enabling technology. This Section seeks responses and proposals from Suppliers to demonstrate how their AMI solution can meet these anticipated use cases.

5.8.2 Response Methodology

Suppliers shall submit a proposal responding to the general description (above) and considering the "Requirements for HAN" listed below. The response shall include the following components:

1. Description of the offering including narrative and equipment block diagram.
2. Description of the proposed customer facing interface and the methods by which customers interact with the information.
3. Description of the methods and procedures that are required to physically and electrically attach any devices to customer or Company owned property or equipment
4. Description of the Back Office IT equipment that is necessary to implement
5. Tabulation of the energy related information that is expected to be available to the customer.
6. Tabulation of the industry standard(s) applied and used.
7. Expected accuracy, precision and currency (or timeliness) of the information that is presented to the customer.
8. Description of the methods by which information that is available to the customer is synchronized to the information that is transferred and available to Company.
9. Response to the Requirements set out here (below).
    a. Description of the installation methodology required.
    b. Description of the proposed method by which the customers will gain/access customer care support.
    c. Description by which any firmware or software can be upgraded.
    d. Description of the impact of adding HAN to the AMI network proposed herein in terms of offered traffic and prioritization requirements in forward and reverse directions.
    e. Per unit costs for equipment to be located on consumer premises in quantity of 10,000, 60,000 and 70,000 for the first, second and third year respectively.
    f. Cost for Back Office equipment as required for system operation.
    g. Cost for annual support agreement to accompany item "e" above.
10. Supplier shall be expected to participate with the Company in industry research or demonstration projects that seek to enhance understanding or capabilities of the AMI system to meet Company goals.

5.8.3 HAN Interface Requirements

1. The Supplier shall document types of interfaces and data types supported to be consistent with the proposed solution. .
2. Supplier shall describe how their system shall meet the HAN Requirements specified above.

5.8.4 HAN Data requirements

1. Through the HAN interface, the customer facing HAN device must be provided with metering data such present energy consumption (current kwh consumption rate), present demand(present KW), peak demand (peak KW), real-time voltage ,etc.) at a highly granular rate. Retrieved or pushed data, shall be updated at a highly granular rate, for example, for meters configured to measure demand over a block 15 minutes interval, retrieved demand data shall be in real-time even in instances where the demand interval has not elapsed. Similar requirements shall apply to load profile data, voltage, etc.
2. Through Company back office IT and web-portal, provide customers with metering data such present energy consumption (current kwh consumption rate), present demand (present kW), peak demand (peak kw), real-time voltage, etc.) at a highly granular rate. Retrieved or pushed data, shall be updated at highly granular rate, for example, for a meter configured to measure demand over a block 15 minutes interval, retrieved demand data shall be in real-time even in instances where the demand interval has not elapsed. Similar requirements shall apply to load profile data, voltage, etc.

5.8.5 Availability

The HAN interface shall be available as an optional feature on meter hardware provided for the AMI solution. Company estimates ~10% of customers (~140,000) will desire this functionality and therefore the HAN interface should be available as an option for these customers.

5.8.6 HAN Interface Security

1. The Supplier must demonstrate that the HAN interface can withstand security testing requirements (ex. PEN testing) to insure the HAN interface does not create an unprotected entry point to the AMI network.
2. Supplier's HAN interface must maintain customer's data privacy by preventing unauthorized access to the meter data.
3. Supplier must demonstrate how their solution allows customer's HAN access to the data through a registration process or other means. This process should account for what happens when the customer moves in/out of a premise. Supplier should also address how data is encrypted.

5.9 Requirements for Gas Modules

5.9.1 Meter reading-Schedule

1. AMI Gas Modules shall be configurable to provide hourly interval data.
2. System shall report gas usage daily

5.9.2 Data availability

1. AMI modules shall be capable of storing at a minimum 60 days' worth of 1hr intervals in non-volatile memory.
2. AMI modules for meters attached to correcting instruments shall report all available data from the instruments e.g. usage, time, pressure, temperature, etc. Adapt to legacy communicating devices (metscans, Metretek, Mercury correcting instruments, Reynolds, etc.)
3. AMI modules and associated AMI system shall report customer peak usage, date and time each billing period based on tariff.
4. Where aggregate billing is required, associated AMI modules shall be time synchronized to 15 minutes to support aggregate billing.
5. AMI modules shall capture start and stop time and volume of gas consumed during curtailment period.
6. AMI modules shall provide battery end-of-life alarms no less than 6 months before end of life.
7. AMI system shall provide report on remaining useful life of batteries

5.9.3 Meter Configurability

1. AMI modules that shall provide temperature compensated and uncorrected index reads (dials) for meters without correcting instruments.
2. Interval data from gas meters (such as transport or interruptible class customer) shall be time stamped.

5.9.4 Storing, logging, and reporting events or Outage Management

AMI modules shall provide notification and acknowledgement of curtailment events

5.9.5 Meter reading-real time

Gas module time related measurements shall be within 60 seconds of actual time.

5.9.6 Installation and Maintenance

AMI modules shall be compatible to all the existing Company gas meter population

1. If modules have a mechanical interface to the meter, then AMI device shall not place more than 1 inch ounce of mechanical torque on meter drive else if an electronic interface, then modules shall be compatible with pulse outputs of existing meters and instruments.
2. AMI modules shall be suitable for both outdoor and indoor installations.
3. Modules must be capable of communicating from meter rooms, basements, etc.
4. AMI modules shall be field replaceable.
5. AMI modules shall preserve the integrity of device configuration and data during battery exchanges
6. AMI module and field tools must have mechanisms that preserve data and configuration from one module to another during a module exchange
7. AMI module shall not exert torque in excess of 1 inch oz or meter manufacturer specifications whichever is less and shall not cause gas leakage.

5.9.7 Tamper/Theft detection

The AMI module shall report any logged errors within the module.

5.9.8 Upgradeability and Configurability

1. AMI modules shall support 4, 5, 6 and 7 dial indexes.
2. AMI modules shall be field configurable to accommodate meters with different drive rates including; 1, 2, 5, 10, 50, 100, 500 and 1000 foot drive rates.
3. AMI modules attached to electronic instruments, indexes or meters shall collect and transmit any errors logged locally by the instrument
4. AMI modules shall maintain an audit trail of changes to configuration and information shall be made available to back-end systems

5.9.9 Tamper/Theft detection

AMI modules shall be equipped with tamper detect mechanisms e.g. module removal, module dis-assembly, magnetic interference, etc.

5.9.10 Storing, logging, and reporting events

AMI modules and associated Headend system shall have mechanisms for detecting usage anomalies (e.g. Excessive or zero usage)

5.9.11 Reliability

Meter manufacturer's index read shall remain functional through any AMI module failure

5.9.12 Interoperability and standards

1. AMI modules shall be in compliance with ANSI B 109.
2. AMI modules shall be in compliance with class I division 2 group D of the National Electrical Code (NEC)

5.9.13 Meter reading- on demand

AMI modules shall be field readable via a field device without requirement for a direct connection. The field device shall have provisions for waking up the module for immediate communication to the field device.

5.9.14 Power quality

1. Batteries must perform in a predictable and environmentally acceptable manner. Expected battery life of no less than 20 years.

2. AMI module battery gas Leakage shall be self-contained - no out gassing of toxic/corrosive materials and no exothermic reactions
3. AMI modules shall furnish own power requirements

5.9.15 Reliability

Gas modules must be capable of bi-directional communication directly to network without intermediate devices. Communicate to AMI network in absence of electric meters - gas only deployment

5.9.16 Security

AMI modules shall preserve data and customer privacy per NIST SGIP security requirements

5.9.17 Upgradeability and Configurability

1. AMI module must be capable of supporting pulse and / or mechanical interfaces. Support all available gas meter products in marketplace
2. AMI modules and associated systems shall support local and remote configuration of modules and / or configuration of correcting instruments
3. AMI modules shall provide details of its current configuration e.g. Meter dials, drive rate, value of right most digit, tamper detect, etc.

5.10 Requirements for Gas ERT modules

5.10.1 Description

Company has in service a quantity of Itron 100G ERT gas modules. The modules are diversely located within the PSCo service territories and, notably, are also in use in service territory that serves gas only – i.e. no electric AMI services.

A database of endpoint devices is attached to this RFP indicating the location of the 100G ERT modules under the name of Final – PSCo 100G ERT Modules. Zip

5.10.2 Requirements for Reading Itron 100G ERT Modules

Suppliers are required to submit innovative technical/price proposals to address the general problem of finding an economically viable and practical solution to reading the modules (meters) in a modern AMI environment: Proposals of the following nature are invited:

1. A technical/business solution that reads the Itron 100G ert meter modules in all service territories without changing the ERT module.

5.10.3 Response Methodology

Suppliers shall submit a proposal responding to the general description (above) and considering the “Requirements for Reading Itron 100G ert Modules” listed above. The response shall include the following components:

1. Descriptive response to the Requirements set out here (above) including any required narrative and equipment block diagrams.
2. Description of the methods and procedures that are required to physical and electrically attach any devices Description of the Back Office IT equipment that is necessary to implement
3. to customer or Company owned property or equipment
4. Description of the proposed customer facing interface and the methods by which customers interact with the information.
5. Tabulation of the energy related information that is expected to be available to the customer.
6. Tabulation of the industry standard(s) applied and used.

7. Expected accuracy and precision of the information that is presented to the customer.
8. Description of the methods by which information that is available to the customer is synchronized to the information that is transferred and available to Company.
9. Description of the installation methodology required
10. Description of the proposed method by which the customers will gain/access customer care support
11. Description by which any firmware or software can be upgraded.
12. Description of the impact, if any, of adding this gas related data traffic to the AMI network proposed herein in terms of offered traffic and prioritization requirements in forward and reverse directions
13. Per unit costs for equipment to be located on consumer premises in quantity of 103,400 annually for a period of 5 years totaling 517,223 ERT modules.
14. Cost for resilient Back Office equipment as required for system operation.
15. Cost for annual support agreement to accompany items # 13 above.

5.11 Requirements for Electric Pre-pay Services

5.11.1 Description

The Company anticipates that either through its own or third party offered programs and services, customers may desire to use Pre-pay services in the form of network connected AMI meters. The Company considers Pre-pay services as a technology option arising from the use of AMI. Company will consider its application as a customer option.

This section seeks responses and proposals from Suppliers to demonstrate how their AMI solution can meet these anticipated use cases.

5.11.2 Response Methodology

Suppliers shall submit a proposal responding to the general description (above) and considering the requirements and queries itemized below. The response shall include the following components:

1. Item by item written response to the Requirements set out here in Section 5.11.3
2. Item by item written response to the Queries set out here in Section 5.11.4
3. Pricing for Pre-pay Meter option per “meter options” on Xcel Energy AMI RFP pricing Template v4.xlsx
4. Pricing for Pre-pay Back Office software and any other costs attributable to Pre-pay option to be provided on Xcel Energy AMI RFP pricing Template v4.xlsx

5.11.3 Electric Pre-pay Requirements

1. The Supplier’s Pre-pay solution shall consist of a network integrated solution that operates by way of AMI meters and one or more applications operating within the Headend and through its interfaces to external components.
2. All measurements, including but not limited to, voltage, current, tamper, outage, etc. as defined in Sections 5.1, 5.3 and 5.4 shall apply.
3. Pre-pay shall be offered in a form that it is configured as a firmware or software option to the base meter.
4. The meter service switch shall be operable with or without Pre-pay credit.
5. The Pre-pay solution shall be end-to-end compliant to Company Security principles, strategy and Requirements per Section 2.4.
6. Any interface used to enable Pre-pay option shall maintain customer’s data privacy by preventing unauthorized access to the meter data.

5.11.4 Queries Concerning Electric Pre-pay Option

Suppliers are required to respond to the following information requests, provide:

AMI Meter Requirements

1. General

    a. A general description of the offering including narrative and any figurative descriptions that are necessary to describe the hardware and software components that are necessary and the manner in which Electric Pre-pay services are enabled/configured and may be offered to customers.
    b. A description of the Supplier's Pre-pay option defining the offered feature set, and product performance specifications.
    c. Information concerning deployment at other utilities utilizing Pre-pay system described in item 1 above; including customer contact name and address, scope of the project and the year of deployment.
    d. A description of the methods and procedures that are required to physically and electrically attach any devices to customer or Company owned property or equipment.

2. Security

    a. A description of the technologies applied and the means by which physical and cyber security is enabled.
    b. A statement indicating areas where security defenses differ and/or are unique from the Baseline Electric Metering Systems as defined in this RFP.
    c. A statement indicating any known security related vulnerabilities or concerns.
    d. A description of the means by which the Pre-pay system can withstand security testing requirements (ex. PEN testing) to insure the interface does not create an unprotected entry point to the AMI network.

3. Impact on Existing Systems and Network

    a. A description of the impact of Pre-pay services on the network in terms of traffic flow volumes, network performance requirements and the required network availability specifications.
    b. A statement indicating the industry standards and protocols applied to the solution including, but not limited to:
    c. Transport and application layer protocols used between meters and the Headend
    d. Transport and application layer protocols used between the Headend and any other platforms
    e. Protocols applied for enablement of secure services
    f. Operating systems and languages
    g. Customer Facing Functionality
    h. A description of procedures, methods, requirements for establishing and terminating the service or migrating in the event of Company or customer initiated changes. This process should account for what happens when the customer moves in/out of a premise.
    i. A description of options available to customers for purchases for prepayment such as; vending kiosks, cell phone applications, telephone, and internet.
    j. If vending kiosks are part of the system, provide descriptions to include specifications, operations and maintenance details
    k. Description of any proposed cards or tokens, etc. that are required or desired to be used in conjunction to the service offering.
    l. A description of the customer options for viewing/monitoring status of their Pre-pay account including, but not limited to:
        i. display or on-line, for example
        ii. rate of usage
        iii. balance remaining
        iv. Estimated time remaining
        v. Status / error codes

vi. Time/date
vii. Tariff
viii. Other information available (describe).

m. A description of the customer configuration and settings options that are available to customers for self-management of their account.
n. A statement indicating the expected accuracy, timeliness and precision of the information that is presented to the customer.

4. Application Functionality

a. A description of the locally or remotely configurable parameters, including:
   I. Time based rates
   II. Credit forgiveness, on non-disconnecting periods. For example, service switch is configurable to not operate if meter goes into arears during Company defined holidays, defined overnight hours, defined season, etc.
   III. Enabling the meter to continue service into a defined credit amount
   IV. Energy pricing, taxes, other tariff cost adders, etc.
b. Descriptions of software configuration features including but not limited to:
   I. the means by which Company can establish and make adjustments to prepayment plans.
   II. the means by which pricing is updated and customers are informed of the pricing status.
   III. The means by which any firmware or software can be upgraded.
   IV. the means and speed by which a tariff is applied and the manner in which Company and the customer are informed that the tariff is in effect. Description of the proposed method by which the customers will gain/access customer care support.
   V. Any other configuration features available from Supplier to Company when applying the Pre-pay option
c. A description of the Back Office IT equipment that is necessary to implement the service.
d. A description of the methods by which information that is available to the customer is synchronized to the information that is transferred and available to Company.

6 Network Requirements

6.1 General Networking Requirements

6.1.1 Management Network & Device Configuration

1. The Supplier must clearly state the Networking Strategy for implementing 1.4 Million Devices on the field with an IPv6 Addressing spacing, able to successfully transmit the data while many other legacy devices (in substations, and corporate areas) are on IPv4.
2. Supplier shall provide a network management system (NMS) that is capable of managing and monitoring all aspects of the communications devices on the systems. This includes, but is not limited to; IP addressing, software/firmware updates, current operational status, historical operational status, performance, RF characteristics/link budget.
3. Supplier's network management system (NMS) shall be provided for installation inside of Company's private IT environment, to be managed and operated by Company.
4. Supplier's network management system (NMS) shall operate in a virtualized server environment.
5. Supplier's network management system (NMS) shall be wholly redundant with installations in separate physical locations with the ability to automatically failover operation from one installation to the other.
6. Supplier's solution shall provide real-time reporting of events and alarms.
7. Supplier's solution shall support reporting and alarming based on configurable thresholds set for specific criteria. For example, alarming for a node whose link performance falls below threshold.
8. Supplier's solution shall utilize a standardized method for reporting events and alarms, including support for SNMP up to and including version 3.
9. Supplier's network management system (NMS) shall provide an API and/or north bound interface in order to integrate with Company's network operations center (HP OpenView and Network Node Manager).
10. Supplier's solution shall provide Over-The-Air firmware and software upgrades to communications devices utilizing the communications network.
11. Supplier's solution shall maintain two working copies of the operating software on board the device and a mechanism to enable rapid fallback to the redundant OS.
12. Supplier's solution shall support automatic provisioning.
13. Access to the network management system (NMS) shall be secured through configurable user roles and permissions and accessible via secure protocols such as SSH or HTTPS.
14. Supplier’s network management system (NMS) shall support the use of external and centralized Access, authorization, and accounting (AAA) through an integration with Active Directory or similar technology.

6.1.2 Network Design

1. In areas where the Company serves both electric and gas, the network shall be designated to support both electric and gas metering.
2. In areas where the Company serves gas exclusively, the network shall be designated to support gas metering.
3. Every node in the Wi-SUN system shall be able to communicate to multiple border router nodes with diverse WAN connections (e.g., connection to different WiMAX base stations).
4. Purposed network design shall provide sufficient battery backed Wi-SUN nodes such that any device on the network can be reached in the case of power failure.
5. The network must be designed to support communications to all devices in the attachments “Electric Distribution Points” and “Gas Distribution Points”.
6. The network must be designed to support the performance criteria listed in Table 8 below.
7. The maximum number of hops from border router node to any Distribution Automation (DA) node shall not exceed 3.

8. The maximum number of hops from border router node to any meter node shall not exceed 5.
9. In the event of access point loss, the system shall be capable of automatically re-routing all affected meters through alternate access points such that they are reachable from the head-end within one hour.
10. Supplier shall quote sufficient spare infrastructure to support the solution in an operation (non-deployment) environment.

Table 8 – Performance Requirement by Traffic Type

		Round-Trip			
Traffic Type	**Minimum Bandwidth**	**Maximum Total Network Latency**	**Maximum Wi-SUN Network Latency**	**Total Jitter**	**Packet Loss**
Fast DA	300 kbps	300ms	100ms	20ms	< 1%
Normal DA	300 kbps	500ms	300ms	20ms	< 2%
Sensors	10 kbps	1000ms	800ms	100ms	< 3%
AMI	10 kbps	2000ms	1800ms	100ms	< 4%
Management	B.E.	B.E.	B.E.	100ms	< 5%

6.1.3 Physical & Environmental

1. All communications devices shall have sufficient solid state, non-volatile storage to accommodate ten (10) full copies of the operating firmware and software.
2. Supplier shall indicate the quantity of volatile memory available on the network interface card (NIC).
3. Supplier's solution shall utilize an ARM7 or equivalent at a minimum.
4. Supplier's network interface card (NIC) shall utilize an industry supported operating system. Supplier to indicate the operating system and version.
5. All non-meter communications devices in the Wi-SUN mesh shall provide sufficient battery backup to remain operational for no less than 8 hours in all environmental conditions (Item 10).
6. All battery devices in the network shall employ an automatic battery load self-test to operate on a set interval and provide alarms in the event a battery is performing outside of specification and be connected to the network management system for presentation/coordination of the alarm(s).
7. All Wi-SUN infrastructure (border router nodes and relay nodes) shall operate from mains AC voltage between 100 and 240VAC.
8. Any Wi-SUN end-point node used for Distribution Automation shall operate from 12VDC and/or 24VDC.
9. Supplier shall provide datasheets for each piece of equipment in the solution that provides the following, at a minimum:
    a. Physical Dimensions & Weight
    b. Operating Temperature/Conditions
    c. Physical Interfaces (power, I/O, etc.) and how they are physically secured.

    d. Picture(s)
    e. RF Characteristics
    f. Power Supply
    g. Necessary cables and connectors
    h. Communications Interfaces and protocols
    i. Methods of powering form AC mains
    j. Methods of providing grounding for human safety
    k. Methods of providing grounding for equipment protection
    l. Methods of providing electrical protection for electrical transients
    m. Methods of providing protection for lightning
10. Devices intended for outdoor mounting should operate in temperatures between -30F and 120F at altitudes up to 11,000 ft. AMSL.
11. Supplier's solution shall include a small form-factor Wi-SUN (endpoint) node for general interface and control applications. The small form factor node shall:
    a. be compliant to Wi-SUN protocols
    b. be capable of participation in the wireless mesh as a non-repeating endpoint or as a repeating device with endpoint functionality.
    c. be fitted with no less than one Ethernet IEEE802.1Q interface on RJ-45 port to connect to an IPv4 or IPv6 device.
    d. Include routing and QoS functionality that is required to enable Requirements set out in Section 6.1.5
    e. be physically smaller than 6in x 6in x 4in.
    f. include an RS-232 capable DB-9 port.
    g. Include a management interface using the Wi-SUN NMS infrastructure
    h. be designed using no-corrosive components for use in outdoor unheated cabinets
    i. be inclusive of AC and DC powering options having surge and lightning protection
    j. be offered in an configuration that facilitates standardized mounting in outdoor NEMA rated cabinets.

6.1.4 Standards & Interoperability

1. Supplier shall participate in the Wi-SUN Alliance as a Promoter or Member Company.
2. Supplier's solution shall be certified for Wi-SUN interoperability to all layers currently published by the Wi-SUN alliance at the time of response submission of this Request for Proposal.
3. Supplier shall provide documentation showing Wi-SUN certification for any devices submitted as part of the Wireless Mesh Networking solution.
4. Suppliers shall also fill-out “FAN-Profile-Implementation-Poll-Template 0v02 Xcel Energy.xlsx”
5. Supplier's solution shall be Over-The-Air Upgradable to a fully-compliant Wi-SUN protocol stack.
6. Supplier will provide a fully-compliant Wi-SUN firmware and/or software package for Over-The-Air deployment to all devices within twelve (12) months of the ratification of the full Wi-SUN protocol stack by the Wi-SUN Alliance.
7. Supplier shall allow Company to test their solution against other Wi-SUN equipment (including other Suppliers or test kits, such as EPRI's Wi-SUN tool) in order for Company to satisfy itself of the solution's interoperability.
8. All supplied equipment shall be FCC regulatory compliant in all aspects as related to no less than in and out-of-band RF emissions, power level, interference mitigation technologies, band filtering and health and safety.

6.1.5 Technology

1. Security is core and critical to the success of AMI and the mesh network. Provide an overview and detailed description of how the solution is secured, what components are needed to create the necessary security, and how the entire security solution is managed.

2. The solution must be an IPv6 network based on IEEE 802.15.4g using IEEE 802.15.4e
3. For each radio type supplied, Supplier shall state the radio RF performance parameters in the form of a table that is ordered by frequency band, modulation type and error correction scheme and that tabulates no less than the following guaranteed values:
    a. Maximum Transmitter output power
    b. Transmitter Error Vector Magnitude (EVM) for 100% FCC rated power, taken as the average power of the constellation error vector as a ratio of the constellation average power.
    c. Occupied bandwidth, quantified as bandwidth in Hertz, while under full modulated operating conditions where the emission relative magnitudes levels are 3db, 20db and 40 dB less than occupied necessary power magnitude.
    d. Receiver sensitivity as signal level, given in decibels above a mill watt, that is required at the 50 Ohm antenna connector, that is required to achieve a bit error rate of 1 error in 100,000 bits sent.
    e. Receiver Selectivity, measured as a ratio of the interfering power outside of the desired channel but within the authorized operating band, to that of the desired signal, for the condition in that causes a 10% reduction in received BER relative to the non-interfering case.
    f. Receiver blocking, measured as a ratio of the interfering power outside of the desired channel and outside of the authorized operating band, to that of the desired signal, for the condition in that causes a 10% reduction in received BER relative to the non-interfering case.
4. For each radio type offered, Suppliers shall provide a block diagram of the transmission/reception chain design and radio the front end filter characteristics indicating no less than the 3 dB bandwidth of the radio front end and the availability of any dynamic selectivity options.
5. For each radio type offered, Suppliers shall provide the following information:
    a. The manufacturer and part number of the semiconductors used to implement the radio
    b. The manufacturer and part number of the semiconductors used to implement the device controller
    c. The operating systems used including version deployed
6. The system shall allow for users to statically determine primary and secondary routes for certain nodes.
7. All Wi-SUN Border Router Nodes shall be able to transport all forms of traffic, including AMI and Distribution Automation.
8. Supplier's solution shall support carrying IPv4 traffic over the Wi-SUN network.
9. The network shall support DiffServ/DSCP as a standardized method for managing and Quality of Service and marking, queueing, and priority forwarding. DSCP marking is a requirement at Wi-SUN nodes where the node is used for control applications.
10. The network shall support adding 802.1Q VLAN tags at the point traffic enters the network.
11. The Wi-SUN border router, at its Ethernet wired side, shall support:
    a. IEEE 802.1Q
    b. Dual Stack
    c. Mapping of QoS and COS tags between IETF layers 2 and 3
    d. Routing protocols including but not limited to OSPFv2, RIP2 and BGP4
12. Devices in the network shall not re-mark any QoS information for any traffic without being explicitly told to do so.
13. Supplier's solution shall provide no less than 6 levels of prioritization for Quality of Service Management.
14. Any Wi-SUN nodes that participate in the network in a repeating mode shall only repeat data traffic that belongs to the Company and is a member of its assigned cluster.
15. Wi-SUN nodes shall be configurable to participate in the Wi-SUN mesh as Router Nodes or Leaf Nodes.

16. Any node in the network shall be capable of running applications or scripts locally on the device, utilizing the network interface card for wireless communication
17. Supplier shall provide a Software Development Kit (SDK) for their network interface card to support the development of applications and scripts to operate on the device.
18. Applications or scripts deployed to the device may be written by any party, including Company, the Supplier, or a third party.
19. The Wi-SUN network management system shall support over-the-air deployment of applications or scripts to the network interface card in any device on the network.
20. Network traffic shall not be required to route through the Headend or any other application. For example, the SCADA system shall be able to directly communicate with a distribution automation device on the Wi-SUN mesh without routing through or utilizing an intermediary application.
21. Node-to-Node one-way latency shall not exceed 50ms.
22. The hop-by-hop performance must meet the requirements detailed in Table 9 below.
23. Supplier's solution shall support all Wi-SUN defined data rates, including 50kbps, 100kbps, 150kbps, and 300kbps.
24. Supplier's solution shall support data rates in excess of 1 Mbps.
25. Supplier's solution shall support Forward Error Correction (FEC)
26. Supplier's solution shall support Orthogonal Frequency-Division Multiplexing (OFDM).
27. Supplier's solution shall support North and South America frequency band (902-928 MHz) in conformance with [FCC-Part-15.247]
28. Supplier's solution shall support TCP.
29. Software and Firmware updates to any single node in the network shall complete within 10 minutes.
30. Supplier shall participate in 3rd party security and network penetration testing through public security events or engagement with security Suppliers. Supplier shall elaborate on their engagement in this category.
31. Supplier's solution shall include a network interface card (NIC) that is embeddable in other Supplier's products. This includes integrating the embedded NIC with device including, but not limited to Street Light photo controls, Capacitor Banks, Reclosers, Voltage Regulators, and Fault Location Devices. Suppliers shall provide a list of products for which their NIC is already embedded.
32. Every node-to-node connection shall be encrypted.
33. Any IPv4 traffic coming off of the Wi-SUN Border Router Node shall be routable on the WAN at the physical interface.
34. Wi-SUN nodes shall support the following security features;
    a. Embedded Firewall
    b. MAC Locking
    c. IPSec
    d. Port Rules
    e. IP Rules
35. Supplier's solution shall support direct device-to-device communication over the Wi-SUN mesh without needing to traverse a border router node; including both IPv4 and IPv6 devices.
36. System shall include a user-friendly field configuration tool (e.g., web-based) that can interact with field devices through the mesh network itself.
37. Supplier's solution shall be able to transport jumbo frames.
38. Any IPv4 traffic generated by a node on the Wi-SUN network shall be routable as native IPv4 traffic at the WAN interface of the border router. Supplier shall detail how this is accomplished (tunnels, translation, dual-stack, etc.).
39. Access to any devices on the network shall be managed through defined users and configurable roles with varying levels of permissions.
40. Access, authorization, and accounting (AAA) for any device on the network shall support integration with Active Directory or similar technology.

Table 9 – Performance Requirement by Hop Count

Hop Count	Total One-Way Latency	Total Round Trip Latency	Total Jitter	Packet Loss
1	50ms	100ms	10ms	< 1%
2	100ms	200ms	20ms	< 2%
3	150ms	300ms	30ms	< 3%
4	200ms	400ms	40ms	< 4%
5	250ms	500ms	50ms	< 5%

6.2 WiMAX Gateway Requirements

6.2.1 Description

Company requires the Supplier to provide a quantity of environmentally sound enclosures to house communications electronics equipment and battery(s) for vertical or horizontal pole mounting in a power utility application. The arrangement is configured in a single enclosure however it may require two enclosures to accommodate suitable batteries and mounting standards. The required enclosure forms the basis for interconnecting and powering the required equipment.

The enclosures are necessary to conveniently package and integrate the Wi-SUN border router with the WiMAX self-contained CPE unit. The CPE unit contains a directional antenna and integrated electronics unit. It requires powering by way of battery backed-up PoE.

Company preference is to secure a solution that is tightly integrated to the Supplier's equipment from a packaging perspective. Size is important (~ 6" x 8" x 10") or smaller. The requirement develops product that is easy to install without aid of large equipment or extensive field crews.

6.2.2 Requirements for the Enclosure

1. Company Preferences:
    a. a single battery/charging arrangement for both radios.
    b. Size; (~ 6 x 8 x 10) inches
2. The arrangement shall accommodate no less than two radios:
    - One radio (for wireless mesh applications) is expected to be contained in the enclosure and having an antenna connector on the outside of the enclosure.
    - The other radio is for microwave applications (WiMAX); it is a self-contained unit about 10" square and 3" thick and will be mounted some distance from the enclosure. This radio unit will be interconnected with the "inside" radio by way of PoE Ethernet.
    - The inside Wi-SUN radio consists of the Supplier's provided device.
    - The outside radio is manufactured by AirSpan Inc. It is usually called: WiMAX CPE. The radio/antenna are integrated and operated through an Ethernet PoE interface.
3. Batteries shall be manufactured using a technology that has long service life and high energy density. Suppliers shall state the technology used, manufacturer and part number(s) proposed.

4. Battery backup protection shall be provided for 8 hours of service in the event of power failure. The WiMAX radio is expected to use 24W peak power and 13 Watts of power continuously however, Suppliers are required to confirm the power requirements by their own means.
5. An integrated system of battery performance, maintenance and management is a requirement for all included components including the WiMAX CPE.
6. The system shall be fitted up with 115v AC powering that is suitable for outdoor interconnection to pole or underground connection arrangements and shall include a positive disconnect arrangement for field service safety.
7. The enclosures shall be fitted up in such a way as to be secure against tampering and include a system of intrusion alarms that are integrated to the Suppliers network management environment.
8. All units shall be fitted up with high quality environmentally appropriate weatherproofing, lightning, grounding, surge and security protection.
9. The enclosures shall be labelled with weather resistant bar-codes that are compliant to the Suppliers Inventory management system as applied to Company
10. Mounting arrangements shall accommodate vertical mounting on utility poles and horizontal arms.
11. Company requires that the completed WiMAX gateway be designed for long term outdoor utility service and that it be mocked-up and extensively tested, trialed, prior to be placed into service.

6.2.3 Response Methodology

Response Proposals shall take the following form:

a. Itemized price proposal for 100, 1000, 5000 and 10000 units.
b. Description of the product development cycle including development of prototypes, testing program, and delivery schedules.
c. Description of the offering including narrative and equipment block diagram.
d. Wiring diagram showing interconnection of components.
e. Description of lightning and grounding protection
f. Dimensioned sketch of the equipment.
g. Environmental specifications.
h. Description of the methods used to weatherproof the equipment.
i. Physical specifications and mounting configuration.
j. Description by which any firmware or software can be upgraded.
k. Battery performance specification including: lifetime, technology, temperature specifications
l. Battery monitoring technology methodology (SNMP, etc.)
m. Performance guarantees and warranty commitment
n. Description of security methods applied to the physical and electrical/communications components
o. Description of the methods by which Company can manage inventory control
p. Description of the methods by which Company interacts with the user interface

6.3 Use of IP-VPN's

Where any IP-VPN used over the public Internet for service, support and or maintenance, it shall be:

a. equipped and configured to interface to Xcel's existing standard based IPSEC infrastructure, presently Xcel uses Cisco IPSEC based IP VPNs;
b. approved for use by Company;
c. Operated in a manner that is compliant with the Company security policy; and subject to periodic security assessment audits by Company.

6.4 Timing and Clock References

1. Clocks shall function from the same reference time-base and shall be capable of operating under independent clock values.

2. The Suppliers timing solution shall provide for application support for, no less than; tagging and reporting load profile data based on differing time-bases. For example: (reported to the master back office applications as Universal Time) and for local representation (for example, governing local registration for TOU and for customer display).
3. The clock timing reference shall be UTC is defined by International Telecommunications Union Recommendation ITU-R TF.460-6

6.5 Equipment Required for the Company FAN Laboratory

6.5.1 Description of the Company FAN Lab

Presently Company owns and operates a FAN laboratory that is used to test and evaluate communications equipment and applications. The lab is located at the Company Material Distribution Center (MDC) in Denver Co. The lab is equipped with two sectors of WiMAX base station equipment and is fully functional with network management and CPE devices. The lab also includes Ruggedcom 1500 series switch/routing equipment, Checkpoint firewalls and test equipment.

The FAN laboratory is isolated from a security perspective from any operating networks that are used by Company. Broadband connectivity is available by way of a 3rd party attachment.

This laboratory will be used on an ongoing basis for continued performance evaluation of communications systems and attached applications.

The test environment shall capable of operating in two modes, they are:

1. A stand-alone system (Headend and RF) without interacting with a co-located production environment (logical RF isolation)
2. A mode in which it can interact with production devices for test and troubleshooting purposes (not isolated at the RF level)

6.5.2 Requirements for the FAN Laboratory

1. Suppliers shall submit itemized priced proposals for the following equipment:
   a. Wi-SUN border router, Quantity 4
   b. Wi-SUN node capable of relaying wireless traffic, Qty 4
   c. Wi-SUN node, capable of acting as a routing DA endpoint , Qty 4
   d. Wi-SUN leaf nodes, Qty 6
   e. System Controller used for Network Management
   f. Standalone, non-redundant Headend including all hardware and software
   g. System manuals and instruction books
   h. 902-928 MHz USB programmable frequency source, 1w output, low noise, Qty. 2
   i. 4', SMA/SMA cables, double shield, Qty 20.
   j. Configuration tools as necessary to set-up and operate the WMN equipment, Qty 2
   k. Meter programming tools – both over-the-air and direct connect.
   l. AMI meters to mirror those used in deployment, Qty 4 sets of each device
   m. AMI meters and DA Field configuration tools, Qty 2
   n. Equipment and/or tools sufficient to RF isolate AMI devices (meters, etc.) for mesh testing purposes.

2. Suppliers shall propose and provide pricing for a method to achieve RF isolation between participating mesh devices having sufficient isolation specification to facilitate controlled performance testing under known data contention conditions and without interference from outside sources.

3. All equipment shall be use connectors of the SMA type having female connectors on equipment components and using male connectors on cables. Where SMA is not native, adaptors are required to be supplied.

4. Where Suppliers foresee other requirements, they are requested to describe the requirement and to provide pricing on the pricing template.

6.6 Equipment Required for Meter Shop Testing Facility

6.6.1 Functional Requirements of the Company Meter Shop

Presently Company owns and operates a meter shop in Denver Co. that is used to evaluate, re-service, test and assess meters and associated equipment.

The meter shop is used to:

a. Carry out full configuration programming of both meters and communication modules
b. Troubleshoot meter and communication problems
c. Test communication functionality and performance
d. Test, calibrate, and re-service meters
e. Perform acceptance testing for newly purchased meters
f. Reset both meter and communication modules

6.6.2 Equipment Requirements for the Meter Shop

1. Suppliers shall submit proposals that fulfil the functional requirements of the meter shop. Proposals shall include all of the necessary hardware, software, interconnecting cables, mounting boards, furnishings, test equipment, design services, integration services and set-up services, etc. that are necessary to equip the meter shop.
2. All proposals shall include any equipment that is necessary to ensure human safety against the effects of non-ionizing radiation in the frequency bands of interest in compliance to FCC and OSHA requirements.

6.6.3 Response Methodology

Response Proposals shall take the following form:

a. Description of the offering including narrative and equipment block diagram.
b. Itemized pricing on the Company Pricing template.
c. Description of the manner in which Back Office IT can interface with the equipment.
    I. Description of the installation methodology proposed
    II. Description by which any firmware or software can be upgraded.

6.7 Equipment Required By Field Technicians

6.7.1 Functional Requirement

In addition to any field installation or service that is required by the Supplier, Company requires field equipment for its own use, so as to carry out the following activities:

a. Carry out full configuration programming of both meters and communication modules
b. Troubleshoot meter and network communication problems
c. Test communication functionality and performance
d. Test, calibrate, and re-service meters

e. Reset both meter and communication modules

6.7.2 Equipment Requirements for Field Technicians

Suppliers shall submit itemized proposals that fulfil the functional requirements of the field technicians. Proposals shall include all of the necessary hardware, software, interconnecting cables, mounting boards, furnishings, test equipment, design services, integration services and set-up services, etc. that are necessary to equip the field personnel.

6.7.3 Response Methodology

Response Proposals shall take the following form:

a. Description of the offering including narrative and equipment block diagram.
b. A description; indicating the operational means by which the functional requirements are carried out
c. Tabulation of itemized pricing on the Company Pricing template indicating per unit costs and the estimated quantity of units required. Submit pricing on Xcel Energy AMI RFP pricing Template v4.xlsx
d. Description of the manner in which Back Office IT can interface with the equipment.
    i. Description of the installation methodology proposed
    ii. Description by which any firmware or software can be upgraded.

7 Services Requirements

7.1 Project Management Services

7.1.1 Requirements of the Engagement Manager

1. The Supplier shall provide an Engagement Manager for the duration of the project.
2. The Engagement Manager shall be responsible for managing the relationship with the Company and monitoring services delivery throughout the project. The Engagement Manager shall carry out the following duties:
3. Attend the project kickoff meeting;
4. Manage the contractual relationship between the Supplier and Company for the project duration (not the management of the project itself);
5. Act as the main point of contact between Company and Supplier organization;
6. Ensure the services delivered by Supplier conform to the contractual agreements;
7. Monitor the delivery of the contracted services against schedule, quality, scope and budget;
8. Manage Supplier resource planning and address resource performance issues;
9. Manage the financial aspects of the contract (billing for services, following-up on payments, etc.);
10. Act as the escalation point in the event of issues regarding Supplier resources/services;
11. Manage any dispute or conflict for purpose of resolution to the benefit of Company;
12. Report internally within Supplier organization on project performance (services delivery, progress, economics, etc.); and
13. Report to Company concerning the business aspects of services delivery, progress, economics, etc. on a monthly basis.
14. The Engagement Manager is not required on a full time basis. The Engagement Manager is required to:
15. Proactively fulfill the required duties, and
16. Be available for response to issues in no less than 48 hours following a request for involvement by Company.

7.1.2 Requirements of the Project Manager

1. The Supplier shall provide project management for all phases of the project by assigning a PMP (Project Management Professional Certified) Project Manager to the project.
2. The Project Manager in conjunction with designated Company Project Manager shall be responsible for coordinating all Company, Supplier, and Third-Party contractor (if any) activities diligently toward project success against system performance, schedule and budget metrics.
3. The Project Manager shall carry out the following duties:
    a. Establish, attend and participate in a project kickoff meeting in Denver CO. The Supplier shall use the session as an opportunity to gather detailed project requirements and to gain a full and detailed understanding of the work. Ensure that the Supplier's engineers and the Engagement Manager attend the kickoff meeting.
    b. At, and associated with, the kickoff meeting:
        a. Develop details of the project scope, WBS, and schedule to the team,
        b. Commence research into requirements,
        c. Establish a design criteria,
    c. Develop an initial formulation of design concepts in the form of draft sketches and tables
    d. Act in the role of single point of contact (SPOC) for Company project team.
    e. Coordinate project activities from the initial kick-off meeting through delivery of all contracted elements as well as any tasks mutually agreed to through a documented change order process, until final acceptance.
    f. Direct the project activities by way of assigning tasks and responsibilities and monitoring project progress and performance against task completion status, acceptability of performance, and project milestones.
    g. Prepare and issue weekly progress status reports and lead project status meetings by telephone or in person following company AGIS reporting mechanism.
    h. Maintain and distribute all documentation by way of email.

i. Report deficiencies and concerns proactively on an ongoing basis.
j. Coordinate the installation of the Back Office Systems system and associated training and acceptance testing.

4. Where the Suppliers Project Manager is directing or participating in the direction of work for which there are components of work attributable to Company, they shall be carried out through a process in which the work assignment is initiated, carried out and monitored through Company's Project Manager.

7.2 AMI and/or DA Oriented Design Service Requirements.

7.2.1 Understanding the Pricing Methodology

1. Company requires that Suppliers carry out designs in sufficient depth that pricing can be developed and submitted by Suppliers. The formal detailed design requirements are outlined in this RFP.
2. Suppliers are referred to "RFP Instruction to Suppliers, RFP Section 3.3" for description of the priority and methodological approach to design and pricing in respect of AMI and DA components.
3. Designs shall be "service oriented"; that is; they shall take into account the endpoint locations and performance requirements as inputs and develop realizable plans consisting of equipment and its' placement and configuration, that offer services that meet the requirements and objectives set out herein.

7.2.2 Scope

The Supplier shall lead and carry out the system designs. The scope of designs includes both AMI and DA related components as defined herein:

1. The design of WMN shall include selection of locations and equipment for nodes in the relevant deployment coverage area.
2. The design shall include any and all equipment configuration that is necessary for operation in compliance to the objectives and requirements set out in this RFP.
3. In all cases, designs shall accommodate the implementation of a network that serves both AMI and DA components without compromise.
4. The design package shall form a complete package having sufficient details and instructions and drawings to hand-off to an independent 3rd party integration team for construction.
5. Following the completion of the design packages, the Supplier shall include follow-up design services including, but not limited to:
   a. Integration support in the form of answering questions and supplying missing details, etc.
   b. Post construction inspection in accordance with the acceptance test plans.
   c. Post construction instructions to installation personnel for the purpose of rectification of deficiencies.
   d. Issuance of compliance to standards and design certifications.
   e. Issuance of Statements of Completion for each of the engineering designs.

7.2.3 Requirements for Design Services

1. The Supplier shall provide a complete network design for each of the Coverage Areas. The network design shall result in:
   a. A written detailed technical performance specification defining the design criteria applied.
   b. Determination of the location of field located equipment, taking into consideration, radio frequency signal propagation, technical performance specifications, physical topography, and network device site restrictions.
   c. A network design carried out in consultation with Company including consideration for and not limited to:
      i. Electric and gas meter read rates and reliability
      ii. RF availability for individual and cascaded wireless links
      iii. Packet throughput, latency and loss ratios

iv. packet prioritization and queuing,
v. routing protocols,
vi. Physical wiring, and IPv4/6 addressing.

2. A key tenant of the WMN design shall be to embody the basic networking principle of bulk carriage of mixed use traffic types for real-time flows for DA, gas, street lighting and AMI oriented applications and managing the flows to common interface points in a manner that prioritizes critical, time sensitive communications for DA devices over other less critical devices such as gas metering, AMI, and street lighting.

3. The design shall provide communications coverage for both AMI and DA oriented services based on the Network Performance Requirements set out herein

4. The design shall:

   a. Consider all required equipment and systems that are required to build a working WMN including network operational tools for network management and monitoring.
   b. Consider the issues of physical placement and mounting of all components
   c. Consider and take into account the requirements for networking for the ultimate applications that will run on the communications network.

7.2.4 Security Considerations for Design Services

4. The Supplier shall ensure that all of the security features as specified below, including any updates, are installed, applied, tested and operable to the full extent of the specification including those required for equipment Network Management. The required security feature specification sets are no less than:

   a. Security features specified in this RFP
   b. Security features specified in Suppliers Response to the RFP
   c. Security features that form part of IEEE 802.15.4g 2012 and IEEE 802.15.4e 2012
   d. Security features that form part of the Wi-SUN Alliance Technical Profile Specification v1 and proposed version 2, for IEEE 802.15.4g Standard-Based Field Area Networks.

5. The Supplier shall notify Company's Project Manager of any potential security threats and risks in circumstances where WMN data privacy and security are potentially compromised and in such circumstances shall act diligently and expediently to remedy the breach(s).
6. The Supplier is required to contribute to coordinating and carrying out the configuration of security protocols for the implementation in co-operation with other interfacing systems.
7. The Supplier shall communicate and dialogue with representatives of Company for the purpose of providing detailed explanations of the security features offered, their efficacy and their configuration.
8. The Supplier shall provide and install any and all security updates that are required during the warranty period and any extended warranty period.
9. The Supplier shall keep Company fully apprised of such security updates and seek Company approval prior to installation.

7.2.5 Required System Performance Technical Specification

The Supplier shall prepare a system performance specification. The performance specification shall specify and document, no less than:

   a. A design criteria; defining the expected traffic types and performance requirements.
   b. Guaranteed performance specifications as specified in this RFP. .
   c. The design rules, relating to physical placement, number of allowable hops, operating power, environmental conditions, obstruction losses, etc. that shall be adhered to so as to achieve the afore-stated specifications.

d. Details of networking requirements for interconnection of any NMS components to the WMN network components.
e. Statistical percentage of time in which the communications channel is able to deliver service performance to a quantifiable standard (as, for example, BER = 1e4 for 99.99% of time), or an alternative standard, as approved by Company.

7.2.6 Required Design Documentation / Deliverables

1. The design process shall be carried out in a manner that includes representatives of Company in the process for the purposes of information exchange and learning.
2. In the course of the design, the Supplier shall host meetings and Company shall be entitled to participate in design strategy sessions, midstream reviews and final design reviews.
3. The design shall be complete in written/graphical form, suitable to hand off to a qualified installation crew including no less than:

   a. Title, defining the site location and document identifiers, including list of authors and qualifications.
   b. Summary page including Company approval signature.
   c. Table of contents.
   d. List of figures and drawings.
   e. Design criteria
   f. Design principles followed,
   g. Statement of requirements.
   h. Design standards and metrics applied,
   i. Statement of required installation practices and standards.
   j. Wiring diagrams,
   k. The WMN design, all layers, Physical/IP/QoS/segmentation/queuing/protocols
   l. Mapping and geographic information delineating placement of nodes
   m. Integration instructions.
   n. Acceptance test plans.
   o. Supporting drawings.
   p. Network performance expectations,
   q. Anything else that is required so as to complete a design for a working system.

4. The design reference documentation shall be of sufficient substance that Company can, and without further instruction, use the prepared documentation to:

   a. place equipment in the field at known locations,
   b. mount equipment on the expected vertical assets,
   c. expect on-site service performance that is synchronized with the developed specifications

7.3 Requirements for Integration and Installation of the Outdoor Network Infrastructure Equipment

7.3.1 Required Outdoor Installation Activities for Network Components

1. This component of work does not include the installation of electric and gas meters.
2. Regardless of the installation methodology used to deploy the Network, the Supplier is responsible to make the system operate in accordance with the design and the specifications, including indoor and outdoor components.
3. For each Service Block and/or Company service territory considered, the Supplier shall undertake and carry out the installation integration leadership role. This role includes:
   a. Leadership in the form of a qualified Project Manager.
   b. Supplier establishment of a work schedule and plan, together, and in consultation with Company Project Manager and Company stakeholders.
   c. Carrying out whatever training is required for Company Field installation personnel.
   d. Act as a lead resource to guide the installation process.

   e. Be available to the installation forces for problem solving.
   f. Provide regular progress reports to the Company Project Manager.
   g. Setting up and commission the equipment to performance in accordance with the ATP
   h. Testing per ATP
4. Where the Supplier prepares a pricing proposal for installation of network components, the Supplier shall Itemize its' pricing proposal as follows:
   a. Identify "types" of structures on which network infrastructure components (border routers, relay nodes, etc.) will be located
   b. Develop an installation strategy and methodology for each type of installation structure
   c. Identify the quantity of installation events for each of the type of installation structures
   d. Compute installation costs by aggregating installation types with per unit prices
   e. Adjust installation pricing with any other costs and quantity discounts
   f. Document the infrastructure installation methodology in the format of an itemized tabulation of costs, summarized in accordance with the Coverage Blocks and Xcel service territories defined herein.
   g. Provide Company with a statement indicating the areas of responsibilities under which Company shall operate in regard to Installation obligations.
5. The Supplier is not responsible for:
   a. Structural engineering for tower/pole related services. These services will be carried out by a Third Party under direct contract with Company.
   b. Installation of endpoint communications equipment that is forming a component of the mesh network.
6. The Supplier is responsible for powering-on the Equipment and achieving fully configured operable conditions for the WMN including, but not limited to, all mesh nodes, network management systems and controllers.
7. The Supplier shall act as a team participant, together with Company and 3rd party participants, as authorized by Company, in a cooperative and supportive manner in matters involving the configuration of any related and required IT switches, router, RTU's and security equipment, etc., so as to ensure interface of all contributing systems that are required to make up the working WMN.

7.3.2 Development of an Acceptance Test Plan

1. The Supplier shall:

   a. Take a lead role in the development of the Acceptance Test Plan (ATP). The ATP shall include rigorous testing of the supplied Equipment using the manufacturer's specifications, the design criteria, the developed design, Wi-Sun Forum certification and IEEE802.15.4g/e as benchmarks.
   b. Ensure that the ATP provides thorough procedures and methodologies and a requirement to confirm the WMN compliance to the performance specifications that are required to be developed in the course of the design process. Such testing shall, at a minimum, test AMI and DA oriented metrics for each of the application service types identified (DA, AMI, etc.) and compare the results to the developed specifications.
   c. Tests shall be conducted in the on-site data traffic congested environment.
   d. Ensure that tests are developed that exercise any and all packet priority forwarding schemes where they relate to expedited forwarding for more critical applications such as distribution automation over less critical AMI traffic.
   e. Support Company testing protocols that are compliant to IETF RFC2544
   f. Consult with Company in development of the ATP.
   g. In the development of the ATP, include end-to-end performance evaluation of all system components that are required for operation of the WMN system including controllers, relay nodes, endpoints and network management systems.

h. Prepare the ATP on a schedule that ensures its completion and approval by Company no less than 4 weeks prior to the date when acceptance testing will commence.
i. Secure approval of the ATP form and content by Company prior to carrying out the tests.

7.3.3 Network Optimization

The Supplier shall carry out network optimization; no less than:

a. Complete an assessment of the preliminary as-built system performance with purpose to identify areas of design, installation and integration deficiency. Carry out assessments for no less than: meter collection metrics, routing, throughput, latency, bandwidth; resiliency and service availability;
b. Undertake design and identify installation revisions to be completed by Company
c. Manage the implementation of the network/system changes
d. Reassess the system performance and iteratively repeat the process until the network performance is optimized.
e. Upon completion, issue a notification certifying that the network Block has been optimized and indicate results of the measured performance.

7.3.4 Carrying out Testing per ATP

1. The Supplier shall lead Company's full acceptance testing of the completed systems. Acceptance involves:

    a. The development of an ATP,
    b. Testing against the ATP,
    c. Remedial actions where faults are discovered, and
    d. Final system inspection and acceptance by Company.

2. The Supplier shall complete all of the tests that are identified in the ATP.

3. The Supplier shall prepare and issue a formal report of the outcomes of the testing indicating no less than:

    a. The detailed outcomes of the testing.
    b. A summary table of the results showing a management level table of expected results and actual results.
    c. A narrative indication of the formal compliance to (1) manufacturer's specifications and (2) of the system specifications that are developed as part of the design process.

4. Individual endpoint or node device testing is not required per se, however; where function or performance problems are identified the Supplier is responsible to remedy the problem through repair/replacement processes in accordance with the applicable warranty provisions of the Major Supply Agreement. In any case of fault, Company shall be informed of its nature and the corrective action taken for its remedy including the expected repair schedule, by way of email to the Company Project Manager. If the problem is determined to be the result of an installation issue, then the resolution of the installation issue will be provided by Company.

7.3.5 Remedy of Deficiencies.

1. Following the completion of acceptance testing, the Supplier shall finalize the system set-up and configuration, and:
2. Configure the system in a finished state for hand-off to Company
3. Review the inventory of materials and services to be supplied to Company and remedy any shortages. Such materials include but are not limited to, handbooks, web links, maintenance manuals, configuration guides, hardware, firmware, training documents, etc.
4. Ensure and test that support procedures and protocols are in place.

7.3.6 Final System Inspection

1. The Supplier is required to inspect the completed installations and to deliver a statement of completion to Company no later than 5 days after completion.
2. Where deficiencies are identified, they shall be documented and subsequently remedied in accordance with the applicable warranty provisions of the Major Supply Agreement. Where remedial work is required by Company, the Supplier shall provide clear instructions of the work in the form of a written work order.
3. At project completion the documents shall demonstrate full completion of the work. The final Statement of Completion report shall include no less than:
   a. a summary narrative of the WMN project segment
   b. corrected drawings,
   c. configuration settings,
   d. statements concerning problems, issues and concerns,
   e. statement of compliance to the ATP,
   f. statement of compliance to manufacturer's specifications,
   g. photographs of the completed work

7.4 Requirements for Integration and Installation of the Indoor Network Infrastructure Equipment

7.4.1 Conditions for Installation

a. Company will own and operate all application, control and support servers
b. All servers will be on the premises of Company
c. Company will supply all necessary computational hardware and operating systems.
d. Company will perform software installations and updates.

7.4.2 Supplier Requirements

All software components are subject to the SSA.

7.5 Requirements for Installation/Meter Exchange of Electric Meters

7.5.1 General Requirements

The Supplier shall:

1. Install AMI meters in accordance with meter provider guidelines regarding installation procedures
2. Safely install/exchange meters of all form types in accordance with AMI Project Schedule (Schedule to be refined and fully developed after contract award) utilizing qualified employees
3. Complete meter exchange orders and ensure those orders are successfully transferred from Mobile Data Terminals (MDT's) to Company
4. Provide staging / cross-docking facilities for incoming of new AMI meters and replaced meters to be disposed.
5. Provide inventory control of new and used meters
6. Provide disposal of replaced meters
7. Capture GPS Latitude and Longitude. Coordinates must not be truncated to fewer than 5 places after the decimal point; for example 37.46668 rather than 37.466.
8. Provide any 'make-ready' components and consumable commodity supplies needed for completion of the mutually approved installation (e.g., transformers, arms, miscellaneous wire and raceways, wiring connectors for secondary voltage connections on utility poles, and

through bolts, lag screws, and/or stainless steel banding to mount RF pole-top devices to wood or metal poles)

9. Where installation is applied and priced for NSPM, NSPW and SPS coverage territories it shall be carried out using union labor.

7.5.2 Installation Rate

1. The installation rate shall be:

    a. 7% in 2018 – 98,643 meters
    b. 57% in 2019 – 803,235 meters
    c. 36% in 2020 – 507,307 meters

2. Throughout the meter deployment, Supplier will adhere to completing meter exchanges according to the provided reading/billing schedule. As billing cycles move into bill window dates, contractor will refrain from working in any billing cycles that are in the window.

7.5.3 Installation Procedure/Expectations for Single Phase Meters

1. Installation of Single Phase meters shall include devices of types FM1, 2 and12. This includes approximately 1,327,060 meters. Majority of the meters are socket type meters but there are a number of A-base meters that will require the installation of a socket adapter before the meter exchange can be completed. A-base meter quantities will be provided by form type at a later date.
2. The Supplier shall:

    a. Notify customer of your presence and intent
    b. Read and record meter number and index of meter being removed
    c. Verify new meter is the correct form type, class rating, voltage rating
    d. Open meter housing and check for safety hazards (stressed wires, broken blocks, previous signs of arcing, signs of extreme heat or melted materials etc.)
    e. Check for full voltage on line side of meter
    f. Install bypass jumpers where appropriate or engage meter bypass lever. If unable to by-pass make attempt to notify customer that service will be shut off momentarily to complete exchange.
    g. Remove meter.
    h. Tighten all connections in meter socket
    i. Verify 5th terminal is grounded
    j. Install meter
    k. Remove by-pass jumpers (if used) or disengage bypass lever.
    l. Complete voltage check on line a load side
    m. Close meter housing, seal with meter seal.
    n. Clean up work area
    o. Complete meter exchange in MDT
    p. If meters are installed in multi-unit applications the meter installer shall perform above steps for each meter before proceeding to the next meter exchanges at that location

7.5.4 Installation Procedure/Expectations for Three Phase Self-Contained Meters

1. Installation of Three Phase SC meters shall include devices of types FM16, This includes approximately 47,846 meters.
2. The Supplier shall:
    a. Notify customer of your presence and intent
    b. Read and record meter number and index of meter being removed
    c. Verify new meter is the correct form type, class rating, voltage rating

d. Open meter housing and check for safety hazards (stressed wires, broken blocks, previous signs of arcing, signs of extreme heat or melted materials etc.)
e. Verify voltage on line side of meter
f. Safely engage bypass lever
g. Remove meter.
h. Verify 7th terminal is grounded
i. Install meter
j. Disengage bypass
k. Perform service check
l. Close meter housing, seal with meter seal.
m. Clean up work area
n. Complete meter exchange in MDT

7.5.5 Installation Procedure/Expectations for Three Phase Transformer Rated Meters

1. Installation of Transformer rated meters shall include devices of types FM5, 6, 9, 35 & 36. This includes approximately 34,279 TR meters.
2. The Supplier shall:

    a. Notify customer of your presence and intent
    b. Read and record meter number and index of meter being removed
    c. Verify new meter is the correct form type, class rating, voltage rating
    d. Open meter housing and check for safety hazards (stressed wires, broken blocks, previous signs of arcing, signs of extreme heat or melted materials etc.)
    e. Verify voltages at test block or potential stabs if meter has lever by-pass
    f. If meter has test block, shunt current switches to ground to divert current from meter
    g. Pull all voltage switches to de-energize meter socket
    h. Pull meter from socket
    i. Verify new meter is the correct form type, install meter, if meter has lever by-pass, dis-engag3e lever by-pass and proceed to step l.
    j. Engage potential switches returning voltage to meter
    k. Dis-engage current shunts returning current to meter
    l. Verify voltages at test block or potential stabs if meter has lever by-pass
    m. If CT cabinet is accessible, safely open CT cabinet
    n. Based on information provided on meter exchange order, verify CT serial numbers, CT ratios, VT serial numbers (if applicable), VT ratio (if applicable), and meter multipliers are correct.
    o. Replace meter cover and seal
    p. Complete meter order in MDT

7.5.6 Required Tools and Instrumentation

1. The Company will provide the Supplier with necessary MDT's/tablet's for all field personnel performing meter exchanges. MDTs will be loaded with Xcel's software allowing for real time order completion.
2. Supplier shall be responsible to install MDT truck mounts for all field vehicles including all associated costs for installation and pedestal materials. Company will provide the MDT cradles but pedestals are a customized item depending on type of vehicle and will need to be secured to vehicle.
3. With exception of MDT/tablet the Supplier shall provide all tools required to perform and validate proper meter exchanges.
4. Company will provide the Suppliers with bar code scanners for each of the MDT's/Tablets issued.

7.5.7 Customer Notifications:

1. Company will send customer a mailings informing customers of the expected timeframe dates and procedures for the meter exchange prior to carrying out the meter exchange.

2. The Supplier shall attempt to contact customer upon arrival before accessing meter to perform exchange.
3. If unable to contact customer on arrival, Supplier shall safely attempt to gain access and exchange meter. A customer oriented notification of the completed or pending action shall be left at the customer premise in the form of a door hanger upon completion of meter exchange.
4. If unable to exchange the meter due to access issues, the Supplier shall follow procedure of 8.5.8

7.5.8 No Access Expectations:

1. The Supplier shall to make multiple attempts before returning order to Company consisting of:
   a. **2** field attempts
   b. **2** Phone/message attempts
   c. **1** no access letter
2. If the Supplier cannot exchange the meter after the multiple attempts, Supplier shall refer the meter exchange to Company for completion

7.5.9 Equipment Damage

In the event a customer outage should occur while attempting to complete a meter exchange, the Supplier's field technician shall:

a. notify customer (if home) about the unexpected outage
b. report outage to Supplier Supervisor or office personnel about outage and request a proper order be generated to Xcel for resolution
c. If unsafe condition exists, Supplier shall remain on site until relieved by another duly appointed and qualified company representative of the Suppliers company or until Company representative arrives on site

7.5.10 Property Damage (non-outage related)

1. If damage is caused by Supplier as a result of an improper or accidental action during the meter exchange process, the Supplier is responsible for all necessary repairs and associated costs.

2. If damage is unavoidable (due to pre-existing stressed wires or broken block) Company or the customer will be responsible for needed repairs and all associated costs.

7.5.11 Site Clean-up

All old or discarded meter related materials (demand seals, meter seals, used disconnect boots etc.) shall be picked up by Supplier and properly disposed of.

7.5.12 Cross Docking Inventory Management

1. The Supplier shall provide and equip cross docking facilities for receiving, storing and dispatching of new meters as well as storing meters being returned until disposal. Locations will vary dependent on geographic deployment.

2. Equipment to be provided by Supplier shall include but is not limited to tools, warehouse equipment (such as fork lift, pallet jacks), computers and associated connections, etc. Any computers requiring Company software (such as MDMS, CRS and Advantex) will be provided by Company.

3. During peak installation period, an average of 15,500 meter per week will need to be readily available for installation. To avoid any potential slowdown for lack of meter inventory, a 4 week supply of meters should be on hand at all times.

7.5.13 Inventory tracking/reporting expectations

1. All new meters will be electronically transferred to appropriate Supplier storerooms at cross docking facilities once they have passed acceptance (bar-X) testing by Company and have been purchased into Company's Monitor Device Management System (MDMS). It is anticipated that all meters will be shipped directly to Supplier's facility, and sample meters will be drawn for acceptance testing to be performed at the Company meter shop.

2. Company personnel will initiate meter transfer process of new meter shipments to a designated Supplier storeroom after each meter shipment has been purchased into MDMS and bar-X testing has been completed by Xcel.
3. In order to complete transfer process to Supplier's storeroom, Supplier will verify meters included in pending transfer are correct. Once verified, meters will be receipted for in MDMS to complete transfer process to Supplier's storeroom. New meter shipments will be quarantined until the transfer process is fully completed. Company will provide necessary training and access to MDMS to Supplier's office personnel.
4. On a daily basis, individual meters will be electronically scanned and transferred/assigned to each field technician for daily meter exchanges in an effort to help reduce the risk of lost meters. Scanners will be provided by Company. Company will provide necessary training for individual assignment of meters.
5. Individual meter inventory shall be conducted on a weekly basis by all field technicians using inventory software that will be available on MDT or tablet provided. Company will provide training for required weekly inventory.
6. Supplier will conduct a complete inventory (at least once a year) that may coincide with Company's own meter inventory or when deemed necessary. An electronic file of all meters, both new and used meters not yet retired will be provided by Supplier. Additional information will be given to Supplier prior to scheduled inventory date.

7.5.14 Disposal of Equipment Requirements

1. If field MDT/tablet is equipped with a camera, pictures of each meter will be required clearly showing the meter number and meter index before meter is de-energized.
2. Before and after pictures showing meter service and/or any pre-existing conditions worth noting may also be required to assist in any potential claims or disputes from customers. If MDTs are not equipped with cameras, Supplier shall be required to provide cameras. All pictures shall be stored by Supplier and readily available upon request. Company may request pictures to be uploaded to a site yet to be determined.
3. Sorting expectations:
    a. If all random and periodic testing is suspended during the project, meter sorting will not be required.
    b. If testing is not suspended, all meters selected each year for random/periodic testing will be saved and sent to Xcel's MDC facility for testing. Supplier will be required to initiate transfer in MDMS for each pallet of meters being sent back to the MDC facility.
4. Meter disposal/retirement process
    a. Prior to disposal, Supplier shall be required to provide a nightly file containing meters that have been removed from the field and are being retired and disposed. The required file format and layout for this process will be provided by Company.
    b. The Supplier shall separate meters and meter covers
    c. The Supplier shall remove and dispose of Itron ERT's and batteries in accordance with Company waste disposal policies and dispose of all retired meters.
    d. Company, at its option, may consider shipping meters containing mercury switches or batteries off-site for disposal. If sent off-site, Supplier shall be required to sort meters and palletize for shipment to off-site facility.

7.5.15 Inventory tracking/reporting expectations

1. All new meters will be transferred to appropriate Supplier storerooms once they have been purchased into Xcel's Monitor Device Management System (MDMS) and provided meters are being shipped directly to Supplier's facility.
2. Supplier will verify and receipt for all meter transfers to complete transfer process to Supplier storeroom
3. Individual meters will be transferred to individual field technicians for daily meter exchanges to help reduce the risk of lost meters
4. Individual meter inventory shall be conducted on a weekly basis by all field technicians

7.5.16 Miscellaneous materials

1. Company shall provide the required installation materials including but not limited to: seals, rings, locks, a-base socket adapters.
2. The Supplier shall notify Company of its installation material inventory requirements no less than 30 days prior to the scheduled requirement to for field installation.

7.5.17 Lock/key management

1. Company will provide the Supplier keys for all Company owned locks, lock boxes and barrel locks for accessing meters and/or locked meter rooms. All keys provided will be tracked and Supplier will be responsible for lost keys.
2. Additional keys that customers have provided to Company for meter access may also be available from the Company Meter Reading Department. Use of keys from the Meter Reading Department shall be coordinated and tracked by Supplier, and all keys will be returned promptly.

7.5.18 Required skill sets of meter exchangers

1. The Supplier shall prepare and deliver a field installation training program for all field installation personnel. The training program shall include no less than the following components:
    a. Instruction concerning matters of human safety to the general public, home/business owner and themselves.
    b. Instruction concerning the physical, electrical and mechanical characteristics of the installation sites
    c. Problem solving techniques
    d. Protocols for handling out-of-normal situations
    e. Methods to test and certify that installations are
    f. Methods to communicate with customers and public
    g. A testing program that validates each trainees knowledge and ability

2. The Supplier shall continuously assess and adjust the training program so as to meet evolving and changing installation requirements.
3. Where changes are made to installation/meter change-out processes, field installation personnel shall be informed and retrained if necessary.
4. No field installation activities shall be conducted by any person unless the individual has completed the training program and achieved certification to be a qualified field installation technician as granted under the training program.

7.5.19 Management Obligations

1. The Supplier shall provide for project management of the installation activities in accordance to methods outlined in PMP. The Supplier shall:
    a. Establish work scope, schedule and costs in consultation with Company
    b. Monitor work progress against the agreed-upon plans with Company
    c. Report on progress to Company weekly indicating no less than: (a) the assignments issues, (b) completions wrt assignments and project schedule, ongoing concerns and resolution progress and any new concerns.

2. Supplier to provide staffing for daily dispatching, scheduling of appointments (as needed), meter management/inventory, meter disposal and other administrative duties as determined by Supplier
3. The Supplier shall continuously assess and monitor its employee's performance in day-to-day work activities and where necessary, remove or retrain/requalify technicians.

7.5.20 Security screening/On-boarding procedures

1. Supplier employees shall not perform any work on behalf of Company or have access to Company's or its customers' property until the employee has successfully passed Company screening processes and been issued a badge.
2. Every Supplier employee will be required to begin screening process by filling out initial request at enterprise.fadv.com/pub/l/prospects/Company/Supplier

3. Once drug testing results and background screening has been completed and approved, Supplier will provide individual photos for each employee and ID badge requests will be submitted.
4. Employee ID badges shall be worn at all times and shall be visible at all times and used as a form of identification upon customer request
5. All newly hired Supplier employees or its contractors shall be required to complete Xcel's required compliance training courses within first 30 days of employment.
6. Yearly and on-going compliance training courses are required by Company. If the supplier's employee(s) do not comply with all training courses and due dates, the supplier employee will be immediately off boarded and denied access to Company property and data. This applies to all supplier personnel on the project regardless of whether or not they are working on meter sets, networks, software, on site or off site.

7.5.21 Minimum PPE Requirements

1. All Supplier field technicians shall be carry out their work meeting the Company PPE requirements. Included, but not limited to, items are:

    a. Clothing – 8 cal/cm2 long-sleeve shirt (w/Supplier logo), natural fiber/self-extinguishing clothing elsewhere, including under garments.
    b. Appropriate to function, fire rated pants
    c. Gloves – Class 0 gloves for voltages under 600v, leather gloves or equivalent for non-electrical tasks based on Supplier's hazard assessment
    d. Safety glasses - appropriate safety glasses/googles are required
    e. Safety shoes – steel-toe or equivalent
    f. Hard hats – hard hat with E rating
    g. Face shields – arc-rated face shield or hood appropriate for fault current (277-480v, 3 phase, etc.)

2. All PPE equipment shall be provided by the Supplier

7.5.22 Vehicle signage

1. Supplier shall provide vehicle stickers/magnetic signs approved by the Company, identifying the Supplier as an authorized contractor of Company
2. Supplier vehicles shall be well maintained and in good repair.

8 Support Services Requirements

8.1 Warranties

8.1.1 Warranty Methodology

1. For the first year, following successful completion of Acceptance Testing, all supplied equipment and services are covered under an inclusive blanket "repair or replace warranty". See "Section 8.1.3 1st Year all-Inclusive Warranty"
2. Meter components are covered under the conditions of a "Meter Goods Warranty". See "Section 8.1.4
3. Non-meter components are covered under the conditions of a "Goods other than Meter Goods Warranty". See "Section 8.1.5
4. All firmware and software is covered under a long term Software Support Agreement See "Section 8.1.2

8.1.2 Software Support Agreement

1. Supplier shall provide support for the AMI Headend software. Details of the support plan shall be delivered to Company and include, but not limited to, resolution times of issues based on severity level.
2. Supplier shall provide Software Upgrades at no additional charge to Company. Such Upgrade Releases will include notes describing the fixes contained in each release.
3. Supplier offers to the RFP shall be inclusive of a full five (5) year warranty for all equipment and services supplied. Suppliers shall:
    a. Comply with the warranty conditions as agreed to between the Supplier and Company.
    b. Include provisions for system wide hardware, firmware and software repair or replacement under the condition that design and/or manufacturing defects preclude the reliable operation of the WMN system.
    c. Include the provision for field repair and/or replacement of equipment by the Supplier's personnel for conditions where the equipment, functionality or its design is found to be defective or unreliable for its intended use.
    d. Include repair and replacement provisions having a MTTR of no more than forty-eight (48) hours for critical functionality/operation/components and seven (7) days non-service/non-critical functionality/operations/components.
    e. Any costs associated with the work (parts, labor, travel, etc.) required to remedy the defect, shall be the responsibility of Supplier.
4. Notwithstanding the warranty conditions between Company and the Supplier, the Supplier shall pass-through all warranties for 3rd party equipment, purchased by the Supplier and resold to Company.
5. Supplier shall include, in their proposals, an extended warranty covering repair and/or replacement of all supplied WMN components. Suppliers shall:
    a. Comply with the warranty conditions as stated herein or as agreed to, between the Supplier and Company.
    b. Offer annual pricing over a five (5) year period in the attached Pricing spreadsheet.

8.1.3 1st Year all-Inclusive Warranty

Supplier offers to the RFP shall be inclusive of a full first year all-inclusive warranty for all equipment, software and services supplied. Suppliers shall:

a. Comply with the warranty conditions as stated herein or as agreed to between Supplier and Company.

b. Include provisions for system wide hardware, firmware and software repair or replacement under the condition that design and/or manufacturing defects preclude the reliable operation of the WMN system.
c. Include the provision for field repair and/or replacement of equipment by the Suppliers personnel for conditions where the equipment or its design is found to be defective or unreliable for its intended use.
d. Include repair and replacement provisions having an MTTR of no more than 48 hours for critical components and 7 days for components that are not service impacting.

8.1.4 Warranty for Meter Goods

1. In addition to the all-inclusive warranty set out in Section 8.1.3, all Goods comprising of meters and NICs items (collectively, “Meters”) shall be subject to the warranties set out in this Section 8.1.3 for a period of twenty years from the date of inspection and the earlier of (i) acceptance of the Meters or (ii) fourteen days from the date of shipping (the “Meter Warranty Period”).
2. Supplier warrants that the Meters will conform to the kind, quality and capability designated or described by this Agreement and any applicable Specifications, SOW, Purchase Order or Work Order. Supplier warrants that the Meters furnished under the Agreement meet all Specifications and are free from defects in material, workmanship, and title for the Meter Warranty Period. The Supplier warrants that the Meters perform in a manner set forth in or required by the Agreement, and have been produced, processed, delivered and sold or licensed in conformity with all applicable federal, state and local laws, administrative regulations and orders. The Supplier shall execute, certify and deliver to Company any documents as may be required to effect or evidence compliance with such federal, state and local laws.
3. If within the first five (5) years of the Warranty Period (the “Initial Warranty Period”), the Meters furnished hereunder do not conform to these warranties and upon receipt of notice from Company of any failure to comply with the terms of the warranty, the Supplier, at Supplier’s cost, shall thereupon promptly correct any defect in the Meters, or at its option, replace the Meters after returned properly packaged to Supplier's authorized repair facility. Supplier shall pay Company a ‘first-set’ (labor) cost of thirty dollars ($30) per defective unit.
4. If Supplier chooses to replace the Meters, Supplier shall deliver the replacement Meters to Company and Company shall return defective Meters to Supplier. Supplier shall have no obligation to install the replacement Meters. If Supplier chooses to repair the defective Meters, Supplier shall pay to ship the Meters to Supplier's repair facility, and Supplier shall pay to ship the corrected Meters back to Company. Supplier shall promptly pay Company a ‘first-set’ (labor) cost of thirty dollars ($30) per defective unit.
5. If Supplier is unable to repair or replace any defective Meters, Company will return the Meters to Supplier and Supplier will refund to Company the monies paid by the Company for such Meters, including shipping costs. If such return occurs within the Initial Warranty Period, Supplier shall also pay Company ‘first-set’ (labor) costs of thirty dollars ($30) per unit.
6. If, in the period after the first five (5) years of the Warranty (the “Extended Warranty Period”), the Meters supplied hereunder experience failure rates in excess of zero point three (0.3%) percent annually, and Company notifies the Supplier, the Supplier shall make available like kind replacement Meters for such failed Meters exceeding the zero point three (0.3%) percent annual threshold in accordance with the following table. Annual failure rates shall be determined by dividing (a) the failed number of Meters in a one (1) year period (i.e. this is not a cumulative calculation) which shipped in a specific calendar year by (b) the total number of Meters shipped in that same specific calendar year. If it is determined that the failure rates are due to a defect in the product, then one hundred (100%) of the defective Meters will be replaced by like kind replacement Meters by the Supplier at the reduced rate.
7. Failures in years beyond the initial 5 year Warranty period will result in a discount off of current price of Meters as reflected in the negotiated Price list, as follows:

Failure Years	Discount
6-8	75% off current Company list price
9-15	50% off current Company list price
16-20	25% off current Company list price

8.1.5 Warranty for Goods other than Meter Goods.

1. In addition to the all-inclusive warranty set out in Section 8.1.3, all Goods other than Meters shall be subject to the warranties set out in this Section for a period of five (5)years from the date of inspection and the earlier of (i) acceptance of the Goods or (ii) fourteen days from the date of shipping (the "Goods Warranty Period").
2. Supplier warrants that the Goods will conform to the kind, quality and capability designated or described by this Agreement and any applicable Specifications, SOW, Purchase Order or Work Order. Supplier warrants that the Goods, furnished under the Agreement meet all Specifications and are free from defects in material, workmanship, and title for the Meter Warranty Period. Supplier warrants that the Goods perform in a manner set forth in or required by the Agreement, and have been produced, processed, delivered and sold or licensed in conformity with all applicable federal, state and local laws, administrative regulations and orders. The Supplier shall execute, certify and deliver to Company any documents as may be required to effect or evidence compliance with such federal, state and local laws.
3. Supplier shall provide warranty support for all other supplied Goods. Details of the support plan shall be delivered to Company and include, but not limited to, resolution times of issues based on severity level.
4. Supplier offers to the RFP shall be inclusive of a full five (5) year warranty for all non-meter Goods supplied. Suppliers shall:
    a. Comply with the warranty conditions as agreed to between the Supplier and Company.
    b. Include the provision for field repair and/or replacement of equipment by the Supplier's personnel for conditions where the equipment, functionality or its design is found to be defective or unreliable for its intended use.
    c. Include repair and replacement provisions having a MTTR of no more than forty-eight (48) hours for critical functionality/operation/components and seven (7) days non-service/non-critical functionality/operations/components.
    d. Any costs associated with the work (parts, labor, travel, etc.) required to remedy the defect, shall be the responsibility of Supplier.
5. Notwithstanding the warranty conditions between Company and the Supplier, the Supplier shall pass-through all warranties for 3rd party equipment, purchased by the Supplier and resold to Company.
6. Supplier shall include, in their proposals, an extended warranty covering repair and/or replacement of all supplied WMN components. Suppliers shall:
    a. Comply with the warranty conditions as stated herein or as agreed to, between the Supplier and Company.
    b. Offer annual pricing over a five (5) year period in the attached pricing table.

8.1.6 Warranty for Epidemic Failure

1. Supplier warrants that for the expected life of provided Goods, as set forth in the Specifications, Goods will not experience Epidemic Failure in the first ten (10) years of service.
2. "Epidemic Failure" means that the Goods have experienced any nonconformance to the Specifications due to the same type of defect at a cumulative failure rate of more than 10%, within (a) Company's total installed base ("Installed Base") or specific installation "Blocks" or (b) a particular release/version, manufacturing lot, or group of Goods, using particular subcomponents ("Subpopulation").
3. If (i) an Epidemic Failure occurs, (ii) Supplier becomes aware of the likelihood of an Epidemic Failure occurring in a Good, or (iii) it can be statistically proven by Company that an Epidemic Failure will occur, Supplier and Company will use their best efforts to understand the cause of the Epidemic Failure condition and, upon notice from Company, Supplier will, use its best efforts to correct and eliminate the Epidemic Failure as soon as possible by, at its expense, taking the following actions:
    a. Removing all units or providing a field upgradeable solution of the Goods for the Installed Base or the identified Subpopulation, as applicable, or;
    b. At Supplier's option, (1) replacing all the identified Products with replacement Goods which contain the correction and conform to the Specifications or (2) refunding payments made by Company for all the identified Goods and canceling all invoices for the identified Goods; (3) Providing seed stock units of Goods in order for a retrofit of the identified Goods within 180 days from the date the Epidemic Failure was declared. The number of seed stock units required will be calculated as follows:

        A = B*C = Seed Stock Units
        B = Material Cycle Time (Weeks)
        C = D/E = Retrofit Rate
        D = Number of units to be retrofitted
        E = Change Completion Date – Implementation Date (in weeks), or;

    c. Reimbursing Company for out-of-pocket expenses directly related to management of Goods replacement.

    Regardless of the above remedy options, Supplier shall provide a workaround until a replacement Goods are available and Epidemic Failure is resolved to the satisfaction of Company, at the sole expense of Supplier.

4. In addition, Company may cancel all outstanding purchase orders, work orders, and releases for the Goods subject to Epidemic Failure without further obligation.

8.1.7 Support Services, Extended Warranties.

Company may request Supplier to provide software support, extended warranties, maintenance support and similar technical support. The parties shall mutually agree upon the terms of any such extended warranties and/or support services in a SOW, Purchase Order, Work Order, or separate agreement.

8.1.8 Additional Warranty Terms

1. Notwithstanding any other provision of this agreement, and any warranties provided by Supplier to Company, Company hereby transfers and assigns to Company any and all manufacturer warranties regarding any Goods supplied pursuant to this Agreement.
2. Supplier represents, warrants and covenants that (i) Supplier is the owner of and has clear title to all Supplier Intellectual Property Rights related to the Deliverables that are being assigned or licensed, respectively, to Company in accordance with this Agreement, and is the owner of and has clear title to all Intellectual Property Rights related to the Work; (ii) Supplier has the right to assign and license the Supplier Intellectual Property Rights in the Deliverables, respectively, to

Company, and to provide the Work, in accordance with this Agreement without violating any Applicable Law or infringing upon or violating any Intellectual Property Rights of any Third Party, or breaching any agreement with any Third Party; (iii) the use by Company and its Affiliates of the Deliverables in their intended manner does not and will not violate any Applicable Law or infringe upon or violate any Intellectual Property Rights of any Third Party, or breach or be an unauthorized use relating to any agreement with a Third Party; (iv) Supplier has not entered into an agreement by which it assigned, transferred, licensed or otherwise affected any right, title or interest to any Deliverables that would conflict with its obligations under this Agreement and Supplier will not do so during the Term of this Agreement; and (v) all software used in or constituting Work or Deliverables is free from (a) any virus or other routine designed to permit access or use of such software or any other software by Persons not authorized by Company, or (b) Malicious Code; or except as provided otherwise in detail in a SOW accepted by Company, the Deliverables do not contain any Open Source Materials, and no Open Source Materials have been used in, incorporated into, integrated or bundled with, or used in the development or compilation of the Deliverables.

3. If Supplier proposes to make any material change to the process, formula, ingredients, components, source or other material aspect of Goods to be supplied, or is informed that any manufacturer of the Goods proposes to do so, Supplier will promptly provide written notification of the proposed change to Company. Such notification shall be accompanied by confirmation acceptable to Company that the Goods will continue to conform to the kind, quality and capability designated or described by the Agreement notwithstanding the proposed change.
4. Upon receipt of notice from Company of any failure to comply with the terms of the Agreement and/or these General Conditions including, without limitation, any defect with respect to the Work, either prior to or after Final Acceptance, Supplier shall, without additional compensation, correct any such defects within a time acceptable to Company and reimburse Company for any resulting costs, expenses or damages suffered by Company, including but not limited to costs of removal, reinstallation, re-procurement and any other Third Party costs, damages and losses incurred by Company. If Supplier fails to timely replace any such defective Deliverables or Goods or re-perform the applicable Work, Company may cause such defective Deliverables and/or Work to be provided or replaced by a Third Party and the direct and indirect expense thereof shall be the responsibility of Supplier. Company shall be entitled to deduct this expense and the resulting damages from amounts otherwise due to Supplier.

8.2 Maintenance Support Provisions

8.2.1 General Requirements

1. Suppliers shall offer a Support Services Agreement (SSA) for the initial 2 year period after which the Supplier shall offer a 5 year renewable service support agreement fulfilling the following requirements:
    a. Help desk/technical advice,
    b. Service/repair capabilities and,
    c. Equipment replacement supply capabilities
2. Suppliers shall prepare the SSA in the form of an itemized price proposal
3. Suppliers shall bind their Support Service Agreement conditions to the Service Level Agreement (SLA) as documented in Section 8.2.6 below.

8.2.2 Obligations of Company and the Supplier

1. Company will carry out first line performance, service monitoring and repair dispatch services for the meters, network systems and hardware. This means that Company will use the Network Management Services capabilities as contemplated as part of purchase in this RFP, together with its own internal resources, operating its Network Operating Center, to identify faults and performance issues and to dispatch work orders internally and to the Supplier in the form of “tickets”.
2. It shall be the responsibility of the Supplier to address the service related matter of the “ticket” and to expeditiously participate in resolution of the service related issue in accordance with the SSA.

8.2.3 Requirements of the Help Desk / Technical Advice

1. Provide a 365/24/7 staffed, help desk offering technical support by telephone with 1-800#, email and internet chat advice service.
2. Guarantee of access to a knowledgeable individual by telephone within 4 hours of a service support request.
3. Maintain and operate a tiered secure IT based fault reporting system, having the operational function of logging faults, assigning repair duties, tracking their remedy, and reporting status on a web interface.
4. The primary path to report and manage issues shall be through the customer support group. The Supplier support engineers shall help troubleshoot issues, open and track tickets, process requests and route issues to the correct Supplier teams for resolution.

8.2.4 Required Service Repair Capabilities

1. The Supplier shall provide and offer "on-call" repair technician support services to the Company.
2. On-Call Service technicians shall be qualified and trained concerning the technical and operational aspects of the supplied equipment as sold and used by the Supplier to Company.
3. The Supplier shall equip the on-call technician with all of the necessary spare parts, test, service equipment, tools, safety apparatus, etc., that is necessary to facilitate in-situ repairs.
4. Service response metrics shall be compliant to the SLA (Section 8.2.6)

8.2.5 Equipment Replacement Supply Capabilities

Where replacement equipment is necessary to effect repair, it shall be supplied under the terms of the relevant equipment warranty (Section 8.1.4).

8.2.6 Support Service Level Agreement

Table 8 / Customer Support Operational Metrics

Priority Level	Response Time	Resolution Process	Escalation Timeline	Customer Notification
1 resolution in 4 hours	Acknowledge by a personal phone call within 15 min (24x7)	24 x 7 x 365	Every 60 minutes: Support Manager After 1 hour: Dir., Customer Support After 4 hours: VP, Solution Services	Every 30 min
2 resolution 8 hours	Acknowledge by a personal phone call within 60 min of receiving alert (24x7)	24 x 7 x 365	Every 2 hours: Support Manager After 4 hours: Dir. Customer Support After 8 hours: VP Solution Services	Every 2 hours

3 resolution 24 hours or next business day	Acknowledge within 4 hours or next business day receiving alert or request M-F, 6 am-6 pm PT	M-F, 6 am – 6 pm (PT)	-	daily on business days
4 resolution 72 hours or next business day	Acknowledge within 20 hours of receiving alert or request M-F, 6 am-6 pm PT	M-F, 6 am – 6 pm (PT)	-	Weekly As needed

8.3 Spare Parts

1. Supplier shall maintain an inventory of spare parts in the USA and keep in force a priority order/dispatch process.

2. Supplier shall identify a list of recommended spare parts and consumables, if any, that Company should keep in Company inventory during the Warranty and Extended Warranty periods.

3. Supplier shall identify the spare parts and consumables, if any, that Supplier will keep in inventory for the duration of the Warranty and Extended Warranty periods.

4. Supplier shall provide a documented list of both Supplier and Company parts list with description, part number, pricing and recommended quantities.

5. Once agreed upon by both Company and Supplier:
   a. the volumes shall remain in force through the duration of the Extended Warranty. Inventory levels can only be down adjusted with an agreement of Supplier and Company, and
   b. firm pricing shall remain in force for the first two years of the agreement. Each consecutive year (one time per year) through the Extended Warranty term, a price review will occur between both Supplier and Company. Annual price adjustments will be capped at 1.5% of previous year's price.

8.4 Training Requirements

8.4.1 On-site training

1. The Supplier shall provide an on-site training program, which shall consist of a classroom program and instruction manual for operations, maintenance and installation personnel.

2. The on-site training program shall no less than cover the following topics:

   a. Theory and design of the supplied WMN.
   b. Operation techniques and features of the WMN.
   c. Hardware design configurations
   d. Meter firmware update – local and remote
   e. Meter programming - local and remote
   f. Headend training – Design, implementation, testing, maintenance, administrative and use
   g. Diagnostics interpretation for troubleshooting on a daily basis
   h. Radio communications in mesh networking
   i. Techniques for firmware upgrading including but not limited to meter metrology, meter modules, network components, DA endpoints

j. Safety issues concerning physical installation and RF
k. Understanding the mounting configuration and operation of the outdoor nodes
l. Physical installation techniques
m. Electrical connections
n. Grounding and lightning protection
o. Initial setup and testing
p. Problem solving and troubleshooting techniques
q. Compliance with FCC regulations in the installation and operation of the supplied WMN
r. Operations oriented training that is required for a Licensed back office solution and includes training to assist Company's IT staff in deploying AMI within Company's data center on Company hardware and software.

3. The training program shall include classroom time or field time with an on-site qualified instructor or subject matter expert.
4. The training program shall be comprehensive and interactive training program to system users, and system administrators and shall be intended to demonstrate and instruct on the subject of the Supplier's software and tools.
5. The training shall include field installation demonstrations and a takeaway installation manual to the extent necessary to grant participants a working knowledge of the Supplier's WMN and AMI meters without continuous support by the Supplier.
6. The training program shall facilitate involvement by no more than 15 individuals consisting of engineers, technicians, operations, information technology and management personnel.
7. The training program does not require a skills testing and certification program.
8. The training shall be set up in modules that will be relevant to different groups within Company.
9. The classroom training shall be supplemented with a set of web training Sections given at flexible times throughout the deployment or in a single or multiple-day live training session.
10. The training modules will include AMI system software training
11. Company may record any training provided by Supplier for use and distribution by Company for internal training purposes.

8.5 Factory Training

1. The Supplier shall offer an optional factory training program. Factory training shall mean training provided at Supplier's site on the use of systems.
2. Factory training shall be carried out on a per diem basis.
3. Factory training shall include topics to be defined by Company.

8.6 Optional Training Modules

1. The Supplier shall offer additional or repeat training courses which can be purchased as needed.
2. The Supplier will work with Company to ensure the correct level of training is provided.

9 Attachments

9.1 Computer Files with Meter Counts and Locations

1. Final – PSCo Meters.zip
2. Final – SPS Meters.zip
3. Final – NSPM Meters.zip
4. Final – NSPW Meters.zip
5. Final – PSCo 100G ERT Modules.zip
6. AMI Deployment Blocks with Gas Areas.pdf
7. AMI Block Deployment with gas only.kmz

9.2 Computer Files with DA Device Locations

1. Electric Distribution Points.xlsx
2. Gas Distribution Points.xlsx

9.3 Business Related Attachments

1. Xcel Energy AMI RFP Pricing Template v4.xlsx
2. Sample No Opportunity for SUB Letter
3. Creating Digital Signature
4. General Conditions for Major Supply Agreement
5. Safety Program Requirements
6. Sub-Contracting Plan
7. Sample Insurance Certificate
8. Essential Security Compliance Forms
9. FAN-Profile-Implementation-Poll-Template 0v02 Xcel Energy.xlsx
10. Advanced Metering Infrastructure - Request for Proposal v10 July 18^{th}, 2016
11. Demonstration Test Plans and Assessments v4.0.docx
12. Xcel Energy table of Conformance Compliance.

Low Voltage VAr Compensator RFI

1.0 Purpose

Xcel Energy is herein soliciting information from vendors about Low Voltage VAr Compensator devices (LV VCs). This RFI describes the application for the devices. There is also a section in the RFI with general questions that Xcel Energy requests Vendors respond to, in order to better assist Xcel Energy in understanding each Vendor's product and its market adoption.

- Vendors responses will be reviewed to aid Xcel Energy's market and product knowledge and will be used to aid in Xcel Energy's determination of a vendor to provide LV VCs for at least its Colorado service territory.
- Xcel Energy will execute background checks on each vendor (installed base, relevant clients, financial health, etc)
- Follow up questions to vendors may be issued.

2.0 Distribution list

This RFI is being provided to:

[PROTECTED DATA BEGINS

PROTECTED DATA ENDS]

3.0 Contingency Language

Xcel Energy's down selected AMI and FAN mesh vendor is being determined currently. AMI and FAN mesh final selection is expected between July and August of 2017. Once that decision is finalized, it will be communicated to LV VC vendors.

4.0 Background

Xcel Energy is embarking on an effort to modernize the electric distribution grid across its service territories, defined as the Advanced Grid Intelligence and Security initiative (AGIS). This program encompasses many parallel projects, including a dynamic voltage and power factor optimization project, defined as the Integrated Volt VAr Optimization project (IVVO).

This project will involve installation of new load tap changer controls at substations (LTCs), advanced primary capacitor bank controls (Capacitors), and possibly LV VCs. These devices will work in tandem under the control of a Schneider Electric Advanced Distribution Management System (ADMS) to dynamically adjust voltage and power factor, with the intent of reducing system demand and energy. It is envisioned that LTCs and Capacitor banks will provide the majority of voltage support on each feeder, with the option of LV VCs providing ancillary support to the system.

Currently, it is thought that these LV VC devices will primarily be used on overhead distribution systems; however applications may extend to underground systems as well.

If applied, the LV VC devices would be primarily used in metropolitan areas, within range of Xcel Energy's Field Area Network (FAN). The devices would have use of the AMI 900 MHz mesh component of that FAN. Optional applications outside of that FAN could leverage 4G cellular technologies. Overhead LV VCs are primarily desired, though Xcel Energy may find applications for pad mounted units as well, both for new construction as well as infill in existing areas.

5.0 Desired Applications

5.1 CVR Steady State Support

This is the primary application for Xcel Energy. Feeders chosen for IVVO could have units deployed to provide ancillary feeder voltage support in conjunction with other voltage support devices. Devices are desired to have local operational settings and regularly provide telemetry to the ADMS. Based on system conditions, the ADMS may provide new settings to override the local device settings, with the intent of realizing Conservation Voltage Reduction or Volt VAr Optimization goals.

5.2 Mitigation of existing DER (Distributed Energy Resources)

LV VC devices may also be connected to distribution transformers with high DER penetration. The LV VC could be used to reduce or eliminate any voltage excursions caused by the intermittent nature of the DER, with the goal of improving customer and feeder power quality.

5.3 New Construction Incorporation

New subdevelopments (particularly residential) within Xcel Energy's service territory generally have a high DER component. As part of standard metropolitan area construction, Xcel Energy may elect to place LV VCs within new subdevelopments as other construction is underway.

5.4 Specific Local Voltage Issues

There may be cases where a specific issue is identified by Engineering in a small area, or a particular customer has a more sensitive voltage tolerance than the majority of the feeder. In these cases, LV VC devices may be deployed to address the voltage quality.

6.0 RFI Schedule

Below is an approximate schedule for the RFI. Any changes to this schedule will be communicated to Vendor by Xcel Energy representative.

Event	Timeframe	Description
RFI Issue (Day 1)		Xcel issues all RFI questions to Vendors
RFI Responses due (Day 28)	4 weeks	Vendors provide responses to RFI to Xcel
Xcel Energy reviews vendor responses (Day 35)	1 week	Follow up questions determined
Xcel Energy follow up questions issued (Day 56)	3 weeks	Xcel Energy issues any follow up questions to vendors (1 week per Vendor, order to be determined)
RFI follow up responses due (Day 63)	1 week	Vendors provide responses to RFI follow up questions back to Xcel (1 week per Vendor, order based on when follow up questions received)
Xcel Energy reviews follow up responses (Day 77)	2 weeks	RFI responses reviewed, course of action determined and communicated to Vendors

7.0 Vendor Questionnaire

Please see attached document “XCEL Energy LV VC RFI Questions.docx”. This document lists the RFI questions requiring response from the vendors.

Mechanism – Ratings and Design

1A Longevity
What is the average lifespan of one of these devices?

1B Wear Monitoring
Please provide your method of tracking the health of each Low Voltage VAr Compensator (LV VC), including number of operations vs expected total operations count, time installed, etc.

1C AC Switch
Can an integrated, lockable AC disconnect switch be provided within the enclosure to Xcel Energy?

1D Planning
Please provide product roadmaps for the next 24 months for your LV VC device and management software (if applicable).

1E Mounting Bracket
Are mounting brackets available for multi-phase installations of the LV VC on poles? Please provide details about the available mounting brackets, including type of material, applications, installation methods, etc.

1F Voltage Compatibility
Does your product support a voltage range between 208-277 V utilizing either line to line connection or a line to neutral connection?

1G Sensor Accuracy
If applicable, what is the accuracy of the voltage and current sensors in both frequency and magnitude?

1H Safety
How much time is required to safely discharge the device? How does your design accomplish this?

1I Overcurrent Protection
Are there integrated interrupt capabilities in the device? How is overcurrent protection achieved in the device? Is this component serviceable by Xcel Energy?

1J Capacity and Increments
What is the available VAr (Leading) capacity and associated increments? What is the available VAr (Lagging) capacity and associated increments? Are the increments adjustable through the software?

1K Control

Please describe the available control scheme and any mode options.

1L Power Quality

What is the Total Harmonic Distortion (THD) of the device? Please describe any active or passive mitigation features.

Communications

2A Deployments

Please describe any deployments done specifically using AMI 900 MHz mesh radio communications hardware. Include communications vendor and model information, deployment locations and dates, number of devices, count of units RMA'd, and a customer reference that can be contacted.

2B GPS

Has GPS been integrated into your device? If not, is it on your roadmap and when is that integration planned?

2C Software

Please provide a network diagram describing your management software, its connection to the LV VC units in the field, and its interaction with a SCADA or ADMS.

2D Data Usage

Please provide the average data usage of your devices over a month and year (including firmware updates).

2E FAN Network Compatibility

Can the device be integrated within an AMI mesh radio systems?

2F Management Server Capabilities

Do you have a method (through a management server or otherwise) of reporting information about your devices and controlling them at a fleet level (device status, firmware version, etc.)? Please describe your solution and whether it can be fully contained and integrated in the Xcel Energy IT environment or if it relies on public infrastructure (i.e. "cloud").

Commercial

3A Total Units

Please provide a count of total units installed in the field.

3B Deployments – Current

Please provide Xcel Energy your 5 largest customers by deployment size. Include deployment locations and dates, number of devices, customer use cases, count of units RMA'd to date, and a customer reference that can be contacted. Please also include what communication mediums are being used by your 5 largest customers?

3C Deployments – Future

Please provide information on any deployments actively planned for the next 6 months. Information should include customer name, deployment location and dates, number of devices, and a customer reference that can be contacted. Please also include what communication mediums will be used by your 5 largest customers?

3D Pricing – LV VC

Please provide an itemized quote for each valid LV VC configuration (overhead, pad mount, pedestal mount, cellular option, AMI 900 MHz mesh radio, associated brackets, AC disconnect switch, etc.).

3E Pricing – Installation

Please provide estimates from previous customer installs on the amount of time required by a construction crew to install your device, for both overhead and pad mount applications.

3F Pricing – Ongoing Costs

Please provide any expected ongoing costs (software licensing, technical support, cellular service, etc.).

3G Market Sustainability

How many years of experience does your company have with low voltage VAr compensators?

3H Supply and Origin

Where are the components for the LV VCs manufactured? Where are these components assembled?

3I Lead Times

Please provide estimated lead times for your LV VC units.

Application Support

4A Integration

Please provide any information on integrating your LV VC device in centrally managed IVVO schemes. Include customer name, location, dates, ADMS vendor name, and results of the integration.

4B Construction

Have customers installed your devices on poles with secondary but away from transformers? (For instance, several poles away from a transformer but on the same secondary connection). What has their experience been with these? How did they go about notifying trouble or construction crews that your device is located on that secondary?

4C Connection

Please provide any research done on the effect of connecting your LV VC device on a single or 2 phases of three phase transformers. Specifically, include any research done on impact to customer loads with 1 or more unsupported phases (specifically three phase motor loads).

4D DER

Please provide any research done on mitigating the effects of DER using your LV VC device.

4E Modeling

Please describe your experience modeling your device on real world utility systems. Include approximate number of utility feeders modeled and which customers those feeders were on at a minimum.

4F Maintenance

Please provide any recommended maintenance schedules for your device, by component as applicable. Are there any components that the customer can repair without the manufacturer?

4G Voltage Rise

Please provide typical customer voltage rise margins that are seen at installations. For example, small single-phase loads vs larger three-phase loads.

Testing

5A Test Reports
Please provide certified test reports for the device.

5B Enclosure Protection
Please provide test reports for corrosion control of the enclosure, environmental test reports, intrusion protection, as well as any tests for cyber protection.

5C Mean Time Between Failure
Please provide any information available on experienced Mean Time Between Failure (MTBF) of your LV VC device. Information should be broken out between data from customer installs and data from Vendor lab testing, and should also be broken out between communications module and control modules (if applicable).

5D Failure
Please provide the experienced infancy failure rate of your devices (defined as the rate of device failure within 30 days of customer installation). Please depict failure rates for components separately (communications module, voltage regulation device, VAr injecting device, controller, etc.).

IVVO 1.25%

NSPM -AMI- ***NPV***

	Total ($MM)
Benefits	**446**
O&M Benefits	53
Other Benefits	203
CAP Benefits	190
Costs	**(539)**
O&M Expense	(179)
Change in Revenue Requirements	(359)
Benefit/Cost Ratio	**0.83**

FLISR

Benefits	**103**
O&M Benefits	0
Customer Benefits	103
Costs	**(79)**
O&M Expense	(5)
Change in Revenue Requirements	(74)
Benefit/Cost Ratio	**1.31**

IVVO

Benefits	22
Other Benefits	19
CAP Benefits	3
Costs	(39)
O&M Expense	(2)
Change in Capital Revenue Requirement	(37)
Benefit/Cost Ratio	**0.57**

NSPM -AMI,FLISR, IVVOS- ***NPV***

	Total ($MM)
Benefits	**571**
O&M Benefits	53
Other Benefits	222
Customer Benefits	103
CAP Benefits	193
Costs	**(657)**
O&M Expense	(186)
Change in Revenue Requirement	(470)
Benefit/Cost Ratio	**0.87**

IVVO 1.25% - No Contingency

NSPM -AMI- ***NPV***

	Total ($MM)
Benefits	**446**
O&M Benefits	53
Other Benefits	203
CAP Benefits	190
Costs	**(452)**
O&M Expense	(146)
Change in Revenue Requirements	(306)
Benefit/Cost Ratio	**0.99**

FLISR

Benefits	**103**
O&M Benefits	0
Customer Benefits	103
Costs	**(67)**
O&M Expense	(4)
Change in Revenue Requirements	(63)
Benefit/Cost Ratio	**1.53**

IVVO

Benefits	22
Other Benefits	19
CAP Benefits	3
Costs	(37)
O&M Expense	(2)
Change in Capital Revenue Requirement	(34)
Benefit/Cost Ratio	**0.61**

NSPM -AMI,FLISR, IVVOS- ***NPV***

	Total ($MM)
Benefits	**571**
O&M Benefits	53
Other Benefits	222
Customer Benefits	103
CAP Benefits	193
Costs	**(556)**
O&M Expense	(152)
Change in Revenue Requirement	(404)
Benefit/Cost Ratio	**1.03**

IVVO 1%

NSPM -AMI- *NPV*

	Total ($MM)
Benefits	**446**
O&M Benefits	53
Other Benefits	203
CAP Benefits	190
Costs	**(539)**
O&M Expense	(179)
Change in Revenue Requirements	(359)
Benefit/Cost Ratio	**0.83**

FLISR

Benefits	**103**
O&M Benefits	0
Customer Benefits	103
Costs	**(79)**
O&M Expense	(5)
Change in Revenue Requirements	(74)
Benefit/Cost Ratio	**1.31**

IVVO

Benefits	18
Other Benefits	15
CAP Benefits	3
Costs	(39)
O&M Expense	(2)
Change in Capital Revenue Requirement	(37)
Benefit/Cost Ratio	**0.46**

NSPM -AMI,FLISR, IVVOS- *NPV*

	Total ($MM)
Benefits	**567**
O&M Benefits	53
Other Benefits	219
Customer Benefits	103
CAP Benefits	193
Costs	**(657)**
O&M Expense	(186)
Change in Revenue Requirement	(470)
Benefit/Cost Ratio	**0.86**

IVVO 1% - No Contingency

NSPM -AMI- NPV

	Total ($MM)
Benefits	**446**
O&M Benefits	53
Other Benefits	203
CAP Benefits	190
Costs	**(452)**
O&M Expense	(146)
Change in Revenue Requirements	(306)
Benefit/Cost Ratio	**0.99**

FLISR

Benefits	**103**
O&M Benefits	0
Customer Benefits	103
Costs	**(67)**
O&M Expense	(4)
Change in Revenue Requirements	(63)
Benefit/Cost Ratio	**1.53**

IVVO

Benefits	18
Other Benefits	15
CAP Benefits	3
Costs	(37)
O&M Expense	(2)
Change in Capital Revenue Requirement	(34)
Benefit/Cost Ratio	**0.49**

NSPM -AMI,FLISR, IVVOS- NPV

	Total ($MM)
Benefits	**567**
O&M Benefits	53
Other Benefits	219
Customer Benefits	103
CAP Benefits	193
Costs	**(556)**
O&M Expense	(152)
Change in Revenue Requirement	(404)
Benefit/Cost Ratio	**1.02**

IVVO 1.5%

NSPM -AMI- *NPV*

	Total ($MM)
Benefits	**446**
O&M Benefits	53
Other Benefits	203
CAP Benefits	190
Costs	**(539)**
O&M Expense	(179)
Change in Revenue Requirements	(359)
Benefit/Cost Ratio	**0.83**

FLISR

Benefits	**103**
O&M Benefits	0
Customer Benefits	103
Costs	**(79)**
O&M Expense	(5)
Change in Revenue Requirements	(74)
Benefit/Cost Ratio	**1.31**

IVVO

Benefits	27
Other Benefits	23
CAP Benefits	4
Costs	(39)
O&M Expense	(2)
Change in Capital Revenue Requirement	(37)
Benefit/Cost Ratio	**0.67**

NSPM -AMI,FLISR, IVVOS- *NPV*

	Total ($MM)
Benefits	**575**
O&M Benefits	53
Other Benefits	226
Customer Benefits	103
CAP Benefits	194
Costs	**(657)**
O&M Expense	(186)
Change in Revenue Requirement	(470)
Benefit/Cost Ratio	**0.88**

IVVO 1.5% - No Contingency

NSPM -AMI- NPV

	Total ($MM)
Benefits	**446**
O&M Benefits	53
Other Benefits	203
CAP Benefits	190
Costs	**(452)**
O&M Expense	(146)
Change in Revenue Requirements	(306)
Benefit/Cost Ratio	**0.99**

FLISR

Benefits	**103**
O&M Benefits	0
Customer Benefits	103
Costs	**(67)**
O&M Expense	(4)
Change in Revenue Requirements	(63)
Benefit/Cost Ratio	**1.53**

IVVO

Benefits	27
Other Benefits	23
CAP Benefits	4
Costs	(37)
O&M Expense	(2)
Change in Capital Revenue Requirement	(34)
Benefit/Cost Ratio	**0.72**

NSPM -AMI,FLISR, IVVOS- NPV

	Total ($MM)
Benefits	**575**
O&M Benefits	53
Other Benefits	226
Customer Benefits	103
CAP Benefits	194
Costs	**(556)**
O&M Expense	(152)
Change in Revenue Requirement	(404)
Benefit/Cost Ratio	**1.03**

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	TOTAL	NPV
Total Meters Deployed	*10,131*	*7,368*	*121,800*	*630,000*	*590,000*	*40,700*	*13,755*	*13,890*	*14,027*	*14,164*	*14,304*	*14,444*	*14,586*	*14,729*	*14,874*	*15,020*	*15,168*	***1,558,960***	
CAPITAL COSTS																		***TOTAL DISCOUNTED***	***NSPM-NPV***
AMI Meters																			
AMI Meters Purchase	1,408,513	1,024,373	13,875,456	71,769,600	67,212,800	4,636,544	1,771,935	1,826,384	1,882,506	1,940,352	1,999,976	2,061,432	2,124,776	2,190,067	2,257,364	2,326,730	2,398,226	**182,707,036**	**132,855,955**
AMI Meter Installation	620,017	450,922	5,054,700	26,145,000	24,485,000	1,689,050	645,500	665,335	685,779	706,852	728,573	750,961	774,036	797,821	822,337	847,606	873,652	**66,743,140**	**48,567,278**
RTU's (Return to Utility- Estimate 3% of installed meters)	0	0	303,282	1,568,700	1,469,100	101,343	0	0	0	0	0	0	0	0	0	0	0	**3,442,425**	**2,619,423**
Vendors deployment Project Management	0	381,182	733,817	1,198,410	1,223,217	624,270	0	0	0	0	0	0	0	0	0	0	0	**4,160,897**	**3,204,164**
AMI Operations (Internal Personnel)	843,677	983,487	1,869,203	2,046,398	2,186,980	1,903,327	0	0	0	0	0	0	0	0	0	0	0	**9,833,071**	**7,716,691**
AMI Operations (External Personnel)	0	0	658,073	1,372,663	1,365,055	637,919	0	0	0	0	0	0	0	0	0	0	0	**4,033,710**	**3,053,879**
Shop & Lab equipment (AMI Field Test, Lab equip)	0	25,888	217,401	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**243,288**	**203,171**
Distribution Contingencies	442,320	441,341	3,497,637	16,031,519	15,083,091	1,477,238	0	0	0	0	0	0	0	0	0	0	0	**36,973,146**	**28,259,602**
TOTAL - AMI Meters	3,314,527	3,307,193	26,209,569	120,132,290	113,025,244	11,069,690	2,417,435	2,491,719	2,568,285	2,647,205	2,728,549	2,812,393	2,898,813	2,987,889	3,079,701	3,174,336	3,271,878	***308,136,713***	***226,480,162***
Communications Network																			
FAN Infrastructure Distribution	100,005	650,501	1,279,994	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**2,030,499**	**1,729,867**
FAN Distribution WiMax	322,537	2,097,993	4,128,233	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**6,548,763**	**5,579,166**
FAN Bus Sys Costs	1,709	51,120	88,387	59,329	56,142	15,200	0	0	0	0	0	0	0	0	0	0	0	**271,887**	**217,842**
FAN Bus Sys WiMAX Cost	334,633	10,011,076	17,309,267	11,618,600	10,994,506	2,976,466	0	0	0	0	0	0	0	0	0	0	0	**53,244,549**	**42,660,847**
FAN Bus Sys Contingency	73,854	1,267,037	2,253,221	1,166,606	1,103,942	298,863	0	0	0	0	0	0	0	0	0	0	0	**6,163,522**	**4,979,818**
TOTAL - Communications	*832,739*	*14,077,726*	*25,059,102*	*12,844,535*	*12,154,590*	*3,290,528*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	***68,259,221***	***55,167,540***
IT Systems and Integration																			
IT Hardware	1,504,080	2,537,978	2,141,049	545,521	556,814	568,340	580,104	0	0	0	0	0	0	0	0	0	0	**8,433,885**	**7,028,256**
IT Software	1,064,115	1,552,117	5,536,877	4,669,670	323,141	0	0	0	0	0	0	0	0	0	0	0	0	**13,145,919**	**10,838,063**
IT Labor + Project Management	1,725,374	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**1,725,374**	**1,621,097**
IT Contingency	0	0	0	11,176,589	605,252	548,564	174,031	0	0	0	0	0	0	0	0	0	0	**12,504,436**	**9,642,915**
TOTAL - IT Systems and Integration	*4,293,568*	*4,090,095*	*7,677,926*	*16,391,780*	*1,485,207*	*1,116,904*	*754,136*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	***35,809,615***	***29,130,330***
Program Management																			
Change Management	0	1,000,000	1,035,500	1,072,260	1,110,325	1,149,742	1,190,558	0	0	0	0	0	0	0	0	0	0	**6,558,386**	**4,950,734**
Environment/Release Management	0	28,071	2,064,464	2,318,348	1,044,303	355,017	99,666	0	0	0	0	0	0	0	0	0	0	**5,909,870**	**4,617,070**
Finance	0	109,959	193,798	194,658	145,467	0	0	0	0	0	0	0	0	0	0	0	0	**643,882**	**516,017**
PMO	0	288,790	506,590	508,944	381,346	0	0	0	0	0	0	0	0	0	0	0	0	**1,685,670**	**1,350,955**
Security	0	1,105,737	1,144,991	1,185,638	1,227,728	0	0	0	0	0	0	0	0	0	0	0	0	**4,664,093**	**3,748,708**
Supply Chain	0	477,703	487,591	497,685	507,987	0	0	0	0	0	0	0	0	0	0	0	0	**1,970,966**	**1,585,917**
Talent Strategy	238,852	349,325	361,726	185,901	0	0	0	0	0	0	0	0	0	0	0	0	0	**1,135,803**	**977,689**
Delivery and Execution Leadership	0	374,158	1,294,786	1,314,010	667,319	0	0	0	0	0	0	0	0	0	0	0	0	**3,650,273**	**2,916,840**
Contingency	11,943	186,687	354,472	363,872	254,224	75,238	64,511	0	0	0	0	0	0	0	0	0	0	**1,310,947**	**1,033,197**
TOTAL - Program Management	*250,795*	*3,920,430*	*7,443,919*	*7,641,315*	*5,338,699*	*1,579,997*	*1,354,735*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	***27,529,891***	***21,697,127***
TOTAL CAPITAL	8,691,629	25,395,444	66,390,515	157,009,920	132,003,740	17,057,120	4,526,306	2,491,719	2,568,285	2,647,205	2,728,549	2,812,393	2,898,813	2,987,889	3,079,701	3,174,336	3,271,878	***439,735,439***	***332,475,159***
O&M ITEMS																			
Communications Network																			
FAN Network Infrastructure Distribution	0	0	130,976	298,507	271,352	225,136	105,810	54,000	55,118	56,259	57,424	58,612	59,826	61,064	62,328	63,618	64,935	**1,624,966**	**1,036,835**
FAN Network Business Systems	0	0	335,766	3,171,422	2,673,589	1,491,278	499,575	671,918	685,827	700,023	714,514	729,304	744,401	759,810	775,538	791,592	807,978	**15,552,536**	**9,460,970**
FAN WiMAX Cost	233,600	357,245	427,150	434,290	562,241	1,048,049	653,607	0	0	0	0	0	0	0	0	0	0	**3,716,182**	**2,782,723**
NOC Opco Allocation	200,000	408,280	625,097	638,037	651,244	664,725	678,485	692,529	706,864	721,497	736,432	751,676	767,235	783,117	799,328	815,874	832,762	**11,473,181**	**6,445,717**
FAN Network Distribution Contingency	0	0	59,854	136,414	124,004	102,885	48,354	24,677	0	0	0	0	0	0	0	0	0	**496,189**	**363,768**
FAN Network Bus Sys Contingency	0	0	301,130	686,305	623,871	517,616	243,271	124,153	0	0	0	0	0	0	0	0	0	**2,496,348**	**1,830,131**
TOTAL - Communications	*433,600*	*765,525*	*1,879,974*	*5,364,975*	*4,906,301*	*4,049,690*	*2,229,101*	*1,567,278*	*1,447,809*	*1,477,779*	*1,508,369*	*1,539,592*	*1,571,462*	*1,603,991*	*1,637,194*	*1,671,084*	*1,705,675*	***35,359,401***	***21,920,143***
IT Systems and Integration																			
IT Hardware	42,114	1,654,282	1,678,585	1,705,324	1,740,624	1,776,655	1,813,432	1,850,970	1,889,285	1,928,393	1,968,311	2,009,055	2,050,642	2,093,091	2,136,418	2,180,642	2,225,781	**30,743,604**	**17,268,781**
IT Software	27,285	85,988	983,487	1,845,314	2,011,390	2,053,026	2,095,523	2,138,900	2,183,176	2,228,367	2,274,495	2,321,577	2,369,633	2,418,685	2,468,752	2,519,855	2,572,016	**32,597,467**	**17,432,600**
IT Labor	0	2,056,405	1,553,273	1,750,246	1,680,090	1,717,226	1,721,011	1,789,073	1,859,799	1,933,290	2,009,656	2,089,007	2,171,461	2,257,136	2,346,156	2,438,653	2,534,759	**31,907,241**	**17,784,018**
Common Corporate Business System development-Allocation	646,904	4,270,861	5,304,505	11,866,886	12,378,199	10,847,247	10,347,121	0	0	0	0	0	0	0	0	0	0	**55,661,724**	**41,239,207**
IT Contingency	0	997,287	9,826,939	4,112,864	2,099,639	2,145,629	2,192,624	2,240,646	2,289,716	2,339,857	2,391,093	2,443,448	2,496,946	2,551,611	2,607,470	2,664,547	2,722,871	**46,123,186**	**28,075,602**
TOTAL - IT Systems and Integration	*716,303*	*9,064,823*	*19,346,789*	*21,280,633*	*19,909,942*	*18,539,783*	*18,169,711*	*8,019,589*	*8,221,975*	*8,429,907*	*8,643,555*	*8,863,087*	*9,088,683*	*9,320,523*	*9,558,795*	*9,803,697*	*10,055,427*	***197,033,221***	***121,800,207***
Program Management																			
Change Management	0	1,825,114	2,157,971	3,067,323	3,176,213	2,991,329	1,608,666	0	0	0	0	0	0	0	0	0	0	**14,826,616**	**11,214,681**
Environment/Release Management	0	0	22,405	23,200	24,024	24,877	11,794	0	0	0	0	0	0	0	0	0	0	**106,300**	**78,991**
Finance	0	32,456	112,027	167,045	216,218	0	0	0	0	0	0	0	0	0	0	0	0	**527,746**	**410,061**
PMO	0	79,772	275,346	410,574	531,437	0	0	0	0	0	0	0	0	0	0	0	0	**1,297,129**	**1,007,876**
Talent Strategy	37,760	58,651	60,733	0	55,000	0	0	0	0	0	0	0	0	0	0	0	0	**212,144**	**177,898**
Delivery and Execution Leadership	0	217,284	510,624	714,661	897,539	0	0	0	0	0	0	0	0	0	0	0	0	**2,340,109**	**1,829,448**
Contingency	1,888	110,664	156,955	219,140	245,022	150,810	81,023	0	0	0	0	0	0	0	0	0	0	**965,502**	**735,948**
TOTAL - Program Management	*39,648*	*2,323,940*	*3,296,060*	*4,601,944*	*5,145,453*	*3,167,016*	*1,701,483*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	***20,275,545***	***15,454,901***
AMI Operations (Personnel)																			
AMI Operations (Internal Personnel)	0	2,029	36,563	40,759	42,206	43,704	47,708	1,040,317	1,077,248	1,115,491	1,155,090	1,196,096	1,238,558	1,282,526	1,328,056	1,375,202	1,424,022	**12,445,575**	**5,756,644**
AMI Operations (External Personnel)	0	187,968	214,121	468,050	1,576,002	1,300,659	1,409,575	1,475,931	1,545,439	1,600,302	1,657,112	1,715,940	1,776,856	1,839,934	1,905,252	1,972,888	2,042,926	**22,688,954**	**11,693,307**
Customer Claims	0	663	1,719	48,916	48,843	7,423	0	0	0	0	0	0	0	0	0	0	0	**107,565**	**81,001**
Total AMI- O&M Dist Contingency	0	29,259	38,605	78,357	249,204	207,032	224,422	387,502	403,894	418,232	433,079	448,454	464,374	480,859	497,929	515,606	533,910	**5,410,717**	**2,687,292**
TOTAL - AMI Operations	*0*	*219,920*	*291,008*	*636,082*	*1,916,255*	*1,558,818*	*1,681,704*	*2,903,750*	*3,026,581*	*3,134,024*	*3,245,282*	*3,360,490*	*3,479,787*	*3,603,319*	*3,731,237*	*3,863,696*	*4,000,857*	***40,652,811***	***20,218,244***
TOTAL O&M	1,189,551	12,374,208	24,813,831	31,883,634	31,877,951	27,315,307	23,782,000	12,490,618	12,696,365	13,041,711	13,397,206	13,763,169	14,139,931	14,527,833	14,927,226	15,338,477	15,761,959	293,320,977	179,393,496
GRAND TOTAL CAPITAL & O&M	9,881,180	37,769,652	91,204,347	188,893,554	163,881,691	44,372,427	28,308,306	14,982,337	15,264,650	15,688,915	16,125,755	16,575,562	17,038,744	17,515,722	18,006,927	18,512,812	19,033,837	733,056,417	511,868,655

XCEL ENERGY

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	TOTAL	NPV
Total Meters Replaced	*10,131*	*7,368*	*121,800*	*630,000*	*590,000*	*40,700*	*13,755*	*13,890*	*14,027*	*14,164*	*14,304*	*14,444*	*14,586*	*14,729*	*14,874*	*15,020*	*15,168*	*1,558,960*	
O&M ITEMS																			
Avoided O&M Meter Reading Costs																			
Drive-by Meter Reading Cost - O&M	2,155	86,393	1,085,789	2,460,063	3,740,671	3,587,859	4,153,792	4,287,938	4,426,475	4,562,493	4,702,691	4,847,197	4,996,143	5,149,667	5,307,907	5,471,011	5,639,126	**64,507,370**	**33,455,306**
TOTAL - Reduction in Meter Reading Costs	*2,155*	*86,393*	*1,085,789*	*2,460,063*	*3,740,671*	*3,587,859*	*4,153,792*	*4,287,938*	*4,426,475*	*4,562,493*	*4,702,691*	*4,847,197*	*4,996,143*	*5,149,667*	*5,307,907*	*5,471,011*	*5,639,126*	*64,507,370*	*33,455,306*
Reduction in Field and Meter Services																			
Costs savings from remote disconnect capability	0	0	0	0	386,423	1,108,454	1,592,346	1,814,095	1,878,495	2,060,451	2,133,597	2,209,340	2,287,771	2,368,987	2,453,086	2,540,171	2,630,347	**25,463,562**	**12,291,603**
Reduction in trips due to Customer equipment damage	0	0	0	0	32,617	67,549	139,894	144,860	150,003	155,328	160,842	166,552	172,465	178,587	184,927	191,492	198,290	**1,943,406**	**940,688**
Reduction in "OK on Arrival" Outage Field Trips	0	0	0	0	135,529	280,680	581,288	601,924	623,292	645,419	668,331	692,057	716,625	742,065	768,408	795,687	823,934	**8,075,238**	**3,908,746**
Reduction in Field Trips for Voltage Investigations	0	0	0	0	74,833	154,978	320,960	332,354	344,152	356,370	369,021	382,121	395,686	409,733	424,279	439,341	454,937	**4,458,764**	**2,158,225**
TOTAL - Reduction in Field & Meter Services	*0*	*0*	*0*	*0*	*629,401*	*1,611,661*	*2,634,487*	*2,893,232*	*2,995,942*	*3,217,567*	*3,331,791*	*3,450,070*	*3,572,547*	*3,699,373*	*3,830,700*	*3,966,690*	*4,107,508*	*39,940,969*	*19,299,262*
Improved Distribution System Spend Efficiency																			
Efficiency gains reliability, asset health and capacity projects- O&M	0	0	0	0	1,159	2,401	4,972	5,148	5,331	5,520	5,716	5,919	6,129	6,347	6,572	6,805	7,047	**69,067**	**33,431**
TOTAL - Improved Distribution System Spend Efficiency	*0*	*0*	*0*	*0*	*1,159*	*2,401*	*4,972*	*5,148*	*5,331*	*5,520*	*5,716*	*5,919*	*6,129*	*6,347*	*6,572*	*6,805*	*7,047*	*69,067*	*33,431*
Outage Management Efficiency																			
Outage Management Efficiency (Storm spend O&M)	0	0	0	0	604	1,250	2,589	2,681	2,776	2,875	2,977	3,082	3,192	3,305	3,422	3,544	3,670	**35,965**	**17,409**
TOTAL - Outage Management Efficiency	*0*	*0*	*0*	*0*	*604*	*1,250*	*2,589*	*2,681*	*2,776*	*2,875*	*2,977*	*3,082*	*3,192*	*3,305*	*3,422*	*3,544*	*3,670*	35,965	17,409
TOTAL O&M BENEFITS	**2,155**	**86,393**	**1,085,789**	**2,460,063**	**4,371,835**	**5,203,171**	**6,795,840**	**7,189,000**	**7,430,524**	**7,788,455**	**8,043,175**	**8,306,268**	**8,578,011**	**8,858,691**	**9,148,602**	**9,448,050**	**9,757,350**	**104,553,371**	**52,805,408**
OTHER BENEFITS																			
Cost reductions																			
Reduced Consumption on Inactive Meters	0	0	0	0	350,052	714,596	1,458,776	1,488,973	1,519,795	1,551,255	1,583,366	1,616,141	1,649,595	1,683,742	1,718,595	1,754,170	1,790,482	**18,879,538**	**9,235,364**
Reduced Uncollectible / Bad Debt Expense	0	0	0	0	259,816	538,078	1,114,360	1,153,920	1,194,884	1,237,303	1,281,227	1,326,711	1,373,809	1,422,579	1,473,081	1,525,375	1,579,526	**15,480,670**	**7,493,278**
Reduced outage duration benefit	0	0	0	0	391,289	798,777	1,630,623	1,664,377	1,698,830	1,733,996	1,769,889	1,806,526	1,843,921	1,882,090	1,921,050	1,960,815	2,001,404	**21,103,587**	**10,323,309**
Theft / Tamper Detection & Reduction	0	0	0	0	847,310	1,729,700	3,531,009	3,604,101	3,678,706	3,754,855	3,832,580	3,911,915	3,992,891	4,075,544	4,159,908	4,246,018	4,333,911	**45,698,446**	**22,354,455**
TOTAL - Cost Reductions	0	0	0	0	1,848,467	3,781,151	7,734,769	7,911,371	8,092,215	8,277,408	8,467,062	8,661,292	8,860,217	9,063,955	9,272,633	9,486,379	9,705,322	*101,162,241*	*49,406,407*
Load Flexibility Benefits																			
Critical Peak Pricing -CPP-DSM Peak	0	0	0	0	0	19,965,050	20,415,850	21,129,600	21,780,000	22,361,590	23,136,860	23,755,800	24,531,638	25,336,224	26,164,958	27,023,654	27,910,308	**283,511,530**	**138,479,332**
Time Of Usage-TOU-Customer energy price shift	0	0	0	0	0	1,819,116	1,975,194	2,019,888	2,037,750	2,133,144	2,262,273	2,392,520	2,517,599	2,573,992	2,725,849	2,753,107	2,780,638	**27,991,070**	**13,576,886**
Time Of Usage-TOU-Avoided CO2 Emissions	0	0	0	0	0	226,876	352,119	485,400	361,972	230,903	344,421	271,720	330,772	309,477	297,166	310,767	413,652	**3,935,245**	**1,961,868**
TOTAL - Load Flexibility Benefits	0	0	0	0	0	22,011,042	22,743,163	23,634,888	24,179,722	24,725,637	25,743,554	26,420,040	27,380,008	28,219,692	29,187,972	30,087,528	31,104,598	*315,437,845*	*154,018,085*
TOTAL OTHER BENEFITS	**0**	**0**	**0**	**0**	**1,848,467**	**25,792,193**	**30,477,932**	**31,546,259**	**32,271,937**	**33,003,045**	**34,210,616**	**35,081,332**	**36,240,224**	**37,283,648**	**38,460,605**	**39,573,907**	**40,809,920**	**416,600,086**	**203,424,492**
CAPITAL ITEMS																			
Capital gains and other avoided purchases																			
Efficiency gains reliability, asset health and capacity projects- CAP	0	0	0	0	189,547	386,940	789,900	806,251	822,940	839,975	857,363	875,110	893,225	911,715	930,587	949,850	969,512	**10,222,915**	**5,000,776**
Outage Management Efficiency (Storm spend CAP)	0	0	0	0	313,698	649,669	1,345,465	1,393,229	1,442,688	1,493,904	1,546,937	1,601,854	1,658,719	1,717,604	1,778,579	1,841,718	1,907,099	**18,691,164**	**9,047,289**
Avoided Meter Purchases	9,788	18,152	185,992	1,086,102	2,027,125	2,203,315	2,138,852	2,218,752	2,301,754	2,387,984	2,477,572	2,570,653	2,667,369	2,767,866	2,872,297	2,980,823	3,093,609	**34,008,006**	**17,455,428**
TOTAL - Efficiency gains and other avoided CAP purchases	9,788	18,152	185,992	1,086,102	2,530,369	3,239,924	4,274,216	4,418,231	4,567,383	4,721,863	4,881,872	5,047,617	5,219,313	5,397,185	5,581,464	5,772,392	5,970,221	*62,922,085*	*31,503,493*
Avoided Meter Reading CAP investment																			
Drive-by Meter Reading Cost - CAP	20,755	412,501	3,935,923	12,881,148	23,340,750	29,130,716	29,698,551	28,887,914	28,107,557	27,361,868	26,557,430	25,715,024	24,868,419	23,999,536	23,212,398	22,384,139	21,406,031	**351,920,659**	**189,681,697**
TOTAL - Avoided Meter Reading CAP Investment	*20,755*	*412,501*	*3,935,923*	*12,881,148*	*23,340,750*	*29,130,716*	*29,698,551*	*28,887,914*	*28,107,557*	*27,361,868*	*26,557,430*	*25,715,024*	*24,868,419*	*23,999,536*	*23,212,398*	*22,384,139*	*21,406,031*	*351,920,659*	*189,681,697*
TOTAL CAPITAL BENEFITS	**30,543**	**430,653**	**4,121,915**	**13,967,250**	**25,871,119**	**32,370,640**	**33,972,767**	**33,306,145**	**32,674,940**	**32,083,731**	**31,439,303**	**30,762,641**	**30,087,732**	**29,396,720**	**28,793,861**	**28,156,530**	**27,376,252**	**414,842,744**	**221,185,190**
GRAND TOTAL BENEFITS	**32,698**	**517,046**	**5,207,705**	**16,427,313**	**32,091,421**	**63,366,004**	**71,246,539**	**72,041,404**	**72,377,400**	**72,875,232**	**73,693,094**	**74,150,241**	**74,905,968**	**75,539,059**	**76,403,069**	**77,178,487**	**77,943,522**	**935,996,201**	**477,415,090**

NSPM -AMI- NPV

	Total ($MM)
Benefits	**446**
O&M Benefits	53
Other Benefits	203
CAP Benefits	190
Costs	**(539)**
O&M Expense	(179)
Change in Revenue Requirements	(359)
Benefit/Cost Ratio	**0.83**

RATIO SENSITIVITY	VALUE
FAN(80% WiMAx)+ Contingencies	0.83
FAN(80% WiMAx) NO Contingencies	0.99

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	TOTAL	NPV	Cost Category
CAPITAL ITEMS - SUMMARY																							
FLISR Assets																							
Asset Cost	0	2,456,519	6,604,776	3,745,275	5,606,776	5,852,901	4,447,353	4,539,413	4,633,379	4,729,290	0	0	0	0	0	0	0	0	0	0	**42,615,682**	**29,507,829**	**Direct and Tangible**
Asset Installation	0	661,457	1,804,228	1,037,932	1,576,342	1,669,400	1,286,894	1,332,579	1,379,886	1,428,872	0	0	0	0	0	0	0	0	0	0	**12,177,590**	**8,386,388**	**Direct and Tangible**
Device related Vendor Project Management + Other Labor	0	15,533	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**15,533**	**13,712**	**Direct and Tangible**
Asset Contingency	0	0	0	1,499,386	1,866,899	919,536	604,982	617,505	630,288	643,334	0	0	0	0	0	0	0	0	0	0	**6,781,930**	**4,638,594**	**Direct and Tangible**
TOTAL - Assets Cost	***0***	***3,133,508***	***8,409,004***	***6,282,593***	***9,050,018***	***8,441,837***	***6,339,229***	***6,489,497***	***6,643,552***	***6,801,496***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***61,590,735***	**42,546,523**	
Communications Network																							
FAN Infrastructure Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**	**Direct and Tangible**
FAN Distribution WiMax	60,476	393,374	774,044	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**1,227,893**	**1,046,094**	**Direct and Tangible**
FAN Bus Sys Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**	**Direct and Tangible**
FAN Bus Sys WiMAX Cost	62,744	1,877,077	3,245,488	2,178,488	2,061,470	558,087	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**9,983,353**	**7,998,909**	**Direct and Tangible**
FAN Bus Sys Contingency	48,467	831,493	1,478,676	765,585	724,462	196,129	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**4,044,811**	**3,268,006**	**Direct and Tangible**
TOTAL - Communications	171,686	3,101,943	5,498,207	2,944,073	2,785,932	754,216	0	0	0	0	0	0	0	0	0	0	0	0	0	0	***15,256,057***	**12,313,008**	
IT Systems and Integration																							
ADMS FLISR Integration	0	372,780	503,962	521,853	1,023,270	1,059,597	807,499	836,165	865,849	896,587	0	0	0	0	0	0	0	0	0	0	**6,887,562**	**4,636,414**	**Direct and Tangible**
IT Contingency	0	0	0	299,788	632,358	654,807	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**1,586,953**	**1,147,107**	**Direct and Tangible**
TOTAL - IT Systems and Integration	***0***	***372,780***	***503,962***	***821,641***	***1,655,629***	***1,714,403***	***807,499***	***836,165***	***865,849***	***896,587***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***8,474,515***	**5,783,521**	
TOTAL CAPITAL	**171,686**	**6,608,231**	**14,411,173**	**10,048,307**	**13,491,578**	**10,910,457**	**7,146,728**	**7,325,662**	**7,509,401**	**7,698,082**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**85,321,307**	**60,643,052**	
O&M ITEMS - SUMMARY																							
Deployment																							
O&M in support of capital deployment	0	85,389	229,582	130,186	194,892	203,447	154,590	157,790	161,056	164,390	0	0	0	0	0	0	0	0	0	0	**1,481,321**	**1,025,692**	**Direct and Tangible**
TOTAL - Asset Operations	***0***	***85,389***	***229,582***	***130,186***	***194,892***	***203,447***	***154,590***	***157,790***	***161,056***	***164,390***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***1,481,321***	**1,025,692**	
Ongoing Support																							
On-going Asset/Device support	0	9,416	34,927	50,006	72,532	96,468	115,512	135,303	155,864	177,218	180,886	184,630	188,452	192,353	196,335	200,399	204,547	208,781	213,103	217,514	**2,834,248**	**1,296,703**	**Direct and Tangible**
Component Replacements	0	2,742	10,171	14,562	21,121	28,092	33,637	39,400	45,387	51,606	52,674	53,764	54,877	56,013	57,173	58,356	59,564	60,797	62,056	63,340	**825,333**	**377,600**	**Direct and Tangible**
On-going Communications Network costs	0	7,324	27,166	38,894	56,414	75,031	89,843	105,236	121,227	137,836	140,689	143,601	146,574	149,608	152,705	155,866	159,092	162,386	165,747	169,178	**2,204,415**	**1,008,547**	**Direct and Tangible**
Vendor costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**	**Direct and Tangible**
Training	0	10,355	10,723	11,103	11,497	11,906	12,328	12,766	13,219	13,688	14,174	14,677	15,199	15,738	16,297	16,875	17,474	18,095	18,737	19,402	**274,254**	**137,195**	**Direct and Tangible**
Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**	**Direct and Tangible**
Asset Contingency	0	1,974	7,321	10,482	15,204	20,221	24,213	28,361	32,671	37,147	37,916	38,701	39,502	40,320	41,154	42,006	42,876	43,763	44,669	45,594	**594,092**	**271,804**	**Direct and Tangible**
TOTAL - Assets Cost	***0***	***31,810***	***90,308***	***125,047***	***176,769***	***231,717***	***275,533***	***321,066***	***368,368***	***417,495***	***426,339***	***435,374***	***444,604***	***454,032***	***463,663***	***473,502***	***483,554***	***493,822***	***504,312***	***515,028***	***6,732,342***	**3,091,849**	
Communications Network																							
FAN Network Infrastructure Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**	**Direct and Tangible**
FAN Network Business Systems	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**	**Direct and Tangible**
FAN WiMAX Cost	43,800	66,983	80,091	81,429	105,420	196,509	122,551	0	0	0	0	0	0	0	0	0	0	0	0	0	**696,784**	**521,761**	**Direct and Tangible**
NOC Opco Allocation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**	**Indirect and Tangible**
FAN Network Distribution Contingency	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**	**Direct and Tangible**
FAN Network Bus Sys Contingency	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**	**Direct and Tangible**
TOTAL - Communications	43,800	66,983	80,091	81,429	105,420	196,509	122,551	0	0	0	0	0	0	0	0	0	0	0	0	0	**696,784**	**521,761**	
TOTAL O&M	**43,800**	**184,182**	**399,980**	**336,662**	**477,080**	**631,673**	**552,674**	**478,856**	**529,425**	**581,885**	**426,339**	**435,374**	**444,604**	**454,032**	**463,663**	**473,502**	**483,554**	**493,822**	**504,312**	**515,028**	**8,910,447**	**4,639,301**	
GRAND TOTAL CAPITAL & O&M	**215,486**	**6,792,413**	**14,811,154**	**10,384,969**	**13,968,659**	**11,542,130**	**7,699,402**	**7,804,518**	**8,038,826**	**8,279,967**	**426,339**	**435,374**	**444,604**	**454,032**	**463,663**	**473,502**	**483,554**	**493,822**	**504,312**	**515,028**	**94,231,754**	**65,282,354**	

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	TOTAL	NPV
O&M BENEFITS																						
Operational Benefits	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**
TOTAL O&M BENEFITS	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
CUSTOMER BENEFITS																						
Customer Minutes Out- CMO Patrolling savings	0	0	0	40,757	175,083	271,514	355,725	453,382	539,313	649,433	725,847	789,440	789,440	789,440	789,440	789,440	789,440	789,440	789,440	789,440	**10,316,013**	**4,528,044**
Customer Minutes Out- CMO Customer Savings	0	0	0	2,754,556	4,809,980	6,277,181	8,295,139	10,426,430	12,214,741	14,325,875	15,433,977	16,164,602	16,164,602	16,164,602	16,164,602	16,164,602	16,164,602	16,164,602	16,164,602	16,164,602	**220,019,300**	**98,458,717**
TOTAL CUSTOMER IMPACTS	**0**	**0**	**0**	**2,795,313**	**4,985,063**	**6,548,696**	**8,650,864**	**10,879,813**	**12,754,055**	**14,975,308**	**16,159,824**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**230,335,313**	**102,986,762**
GRAND TOTAL BENEFITS	**0**	**0**	**0**	**2,795,313**	**4,985,063**	**6,548,696**	**8,650,864**	**10,879,813**	**12,754,055**	**14,975,308**	**16,159,824**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**230,335,313**	**102,986,762**

NSPM FLISR- ***NPV***

	Total ($MM)
Benefits	**103**
O&M Benefits	0
Customer Benefits	103
Costs	**(78)**
O&M Expense	(5)
Change in Revenue Requirements	(74)
Benefit/Cost Ratio	**1.31**

RATIO SENSITIVITY	VALUE
FAN(15% WiMax)+ Contingencies	**1.31**
FAN(15% WiMax) NO Contingencies	**1.53**

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	TOTAL	NPV
Feeders enabled with IVVO	0	0	26	43	61	59	0	0	0	0	0	0	0	0	0	0	0	0	0	0	189	
CAPITAL COSTS																						
Assets/Devices																						
Device costs	0	0	1,512,735	2,824,978	2,704,856	2,267,749	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**9,310,319**	**6,996,776**
Device Installation costs	0	0	357,063	773,839	777,449	679,695	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**2,588,046**	**1,936,047**
Xcel Personnel	0	0	132,317	272,663	277,896	283,603	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**966,479**	**720,811**
Xcel Distribution Personnel [ADMS IVVO Integration]	0	0	306,666	525,184	771,477	772,672	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**2,375,999**	**1,760,061**
External resources (Consultants, contractors etc.)	0	0	187,008	434,397	443,389	342,887	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**1,407,681**	**1,054,169**
E&S	0	103,550	750,582	777,228	804,819	833,391	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**3,269,570**	**2,482,269**
Varentec Engineering (ENGO,caps,ami)	0	0	416,731	425,358	434,163	443,150	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**1,719,402**	**1,299,884**
Contingency	0	0	107,914	269,162	256,986	175,088	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**809,149**	**607,879**
TOTAL - Business Assets/Devices	***0***	***103,550***	***3,771,016***	***6,302,808***	***6,471,034***	***5,798,235***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***22,446,644***	***16,857,896***
Communications Network																						
Communications Operations-IVVO Budget	0	0	61,332	115,547	110,814	104,193	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**391,886**	**293,733**
FAN Infrastructure Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**
FAN Distribution WiMax	20,159	131,125	258,015	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**409,298**	**348,698**
FAN Bus Sys Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**
FAN Bus Sys WiMAX Cost	20,915	625,692	1,081,829	726,163	687,157	186,029	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**3,327,784**	**2,666,303**
FAN Bus Sys Contingency	0	0	0	1,482,861	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**1,482,861**	**1,155,589**
TOTAL - Communications	41,073	756,817	1,401,176	2,324,571	797,971	290,222	0	0	0	0	0	0	0	0	0	0	0	0	0	0	***5,611,829***	**4,464,323**
IT Systems and Integration																						**0**
Xcel Personnel [ADMS IVVO Integration]	0	0	803,466	1,375,982	2,021,270	2,024,401	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**6,225,118**	**4,611,361**
External resources (Consultants, contractors etc.) [GEMS]	0	0	520,914	265,849	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**786,763**	**639,234**
GEMS hardware	0	0	104,183	53,170	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**157,353**	**127,847**
Varentec PM & Services	0	0	52,091	26,585	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**78,676**	**63,923**
IT Project Management	0	0	52,091	26,585	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**78,676**	**63,923**
IT Travel Expenses	0	0	10,418	5,317	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**15,735**	**12,785**
Security	0	0	104,183	53,170	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**157,353**	**127,847**
Contingency	0	0	130,158	158,367	190,817	188,381	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**667,722**	**500,682**
Program Management	0	0	104,183	319,018	325,622	332,362	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**1,081,185**	**802,089**
TOTAL - IT Systems and Integration	***0***	***0***	***1,881,688***	***2,284,042***	***2,537,708***	***2,545,144***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***9,248,582***	**6,949,692**
Program Management																						
Organizational Change Management	0	0	468,823	850,715	651,244	553,937	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**2,524,720**	**1,909,732**
TOTAL - Program Management	***0***	***0***	***468,823***	***850,715***	***651,244***	***553,937***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***				***2,524,720***	**1,909,732**
TOTAL CAPITAL	**41,073**	**860,367**	**7,522,703**	**11,762,136**	**10,457,957**	**9,187,538**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**39,831,775**	**30,181,642**
O&M ITEMS																						
O&M in support of capital deployment	0	0	17,731	37,764	33,658	34,745	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**123,898**	**92,683**
TOTAL - On-going Asset/Device support Costs	***0***	***0***	***17,731***	***37,764***	***33,658***	***34,745***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***				***123,898***	**92,683**
Assets/Devices																						
On-going Asset/Device support	0	0	0	0	7,991	25,537	40,714	57,063	59,089	61,187	63,359	65,608	67,937	70,349	72,847	75,433	78,110	80,883	83,755	86,728	**996,591**	**433,842**
Device Replacements	0	0	0	0	12,059	38,654	62,172	85,943	87,722	89,538	91,391	93,283	95,214	97,185	99,197	101,250	103,346	105,485	107,669	109,897	**1,380,003**	**609,942**
Training	0	0	0	0	195	653	1,107	1,554	1,609	1,666	1,725	1,786	1,850	1,915	1,983	2,054	2,127	2,202	2,280	2,361	**27,066**	**11,765**
Contingency	0	0	0	0	2,471	7,885	12,612	17,431	17,792	18,160	18,536	18,920	19,312	19,711	20,119	20,536	20,961	21,395	21,838	22,290	**279,968**	**123,761**
TOTAL - On-going Asset/Device support Costs	***0***	***0***	***0***	***0***	***22,715***	***72,730***	***116,604***	***161,991***	***166,212***	***170,551***	***175,011***	***179,597***	***184,312***	***189,161***	***194,146***	***199,272***	***204,544***	***209,965***	***215,541***	***221,276***	***2,683,629***	**1,179,310**
Communications Network																						
On-going Communications Network costs	0	0	0	0	4,920	15,829	25,585	35,371	36,103	36,850	37,613	38,392	39,187	39,998	40,826	41,671	42,533	43,414	44,312	45,230	**567,832**	**250,941**
FAN Network Infrastructure Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**
FAN Network Business Systems	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**
FAN WiMAX Cost	14,600	22,328	26,697	27,143	35,140	65,503	40,850	0	0	0	0	0	0	0	0	0	0	0	0	0	**232,261**	**173,920**
NOC Opco Allocation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**
FAN Network Distribution Contingency	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**
FAN Network Bus Sys Contingency	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**
TOTAL - Communications	***14,600***	***22,328***	***26,697***	***27,143***	***40,060***	***81,332***	***66,435***	***35,371***	***36,103***	***36,850***	***37,613***	***38,392***	***39,187***	***39,998***	***40,826***	***41,671***	***42,533***	***43,414***	***44,312***	***45,230***	***800,094***	**424,861**
IT Systems and Integration																						
Program Management	0	0	22,576	35,446	36,180	36,929	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**131,132**	**98,245**
TOTAL - IT Systems and Integration	***0***	***0***	***22,576***	***35,446***	***36,180***	***36,929***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***131,132***	**98,245**
Business Program Management																						
Organizational Change Management	0	0	156,274	283,572	217,081	184,646	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**841,573**	**636,577**
TOTAL - Program Management	***0***	***0***	***156,274***	***283,572***	***217,081***	***184,646***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***841,573***	**636,577**
TOTAL O&M	**14,600**	**22,328**	**223,278**	**383,926**	**349,694**	**410,382**	**183,039**	**197,362**	**202,315**	**207,401**	**212,625**	**217,989**	**223,499**	**229,158**	**234,971**	**240,943**	**247,077**	**253,379**	**259,854**	**266,506**	**4,580,325**	**2,431,676**
GRAND TOTAL CAPITAL & O&M	**55,673**	**882,695**	**7,745,981**	**12,146,062**	**10,807,651**	**9,597,920**	**183,039**	**197,362**	**202,315**	**207,401**	**212,625**	**217,989**	**223,499**	**229,158**	**234,971**	**240,943**	**247,077**	**253,379**	**259,854**	**266,506**	**44,412,100**	**32,613,318**

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	TOTAL	NPV
OTHER BENEFITS																						
Energy Savings																						
Energy Reduction	0	0	165,891	423,491	910,125	1,577,997	1,904,520	1,963,148	2,014,173	2,063,569	2,041,390	1,994,758	2,019,200	2,085,180	2,025,146	2,026,282	2,185,792	2,206,891	2,172,820	2,129,363	**31,909,736**	$14,934,748
Loss Savings	0	0	3,155	8,234	18,167	32,238	39,806	41,776	43,440	44,870	45,454	45,229	46,713	49,088	48,089	48,350	52,370	53,018	52,442	52,442	**724,883**	$333,272
Total Fuel Savings	0	0	169,046	431,724	928,293	1,610,235	1,944,326	2,004,924	2,057,613	2,108,438	2,086,844	2,039,988	2,065,913	2,134,268	2,073,236	2,074,632	2,238,162	2,259,909	2,225,262	2,181,806	**32,634,620**	$15,268,020
Carbon Emissions Benefits																						
Carbon Reduction	0	0	94,698	230,703	479,367	643,180	656,339	645,988	537,529	340,791	312,713	309,097	303,111	284,879	316,482	328,421	341,160	345,262	349,364	353,466	**6,872,548**	$3,599,824
Total Carbon Emissions Savings	0	0	94,698	230,703	479,367	643,180	656,339	645,988	537,529	340,791	312,713	309,097	303,111	284,879	316,482	328,421	341,160	345,262	349,364	353,466	**6,872,548**	$3,599,824
TOTAL OTHER BENEFITS	**0**	**0**	**263,744**	**662,427**	**1,407,660**	**2,253,415**	**2,600,664**	**2,650,912**	**2,595,141**	**2,449,229**	**2,399,557**	**2,349,085**	**2,369,024**	**2,419,147**	**2,389,718**	**2,403,054**	**2,579,322**	**2,605,171**	**2,574,626**	**2,535,271**	**39,507,168**	**$18,867,844**
DEMAND BENEFITS																						
Deferral of Capital Investments As Demand Reduction	0	0	45,106	113,532	227,415	386,537	456,612	457,807	459,632	460,716	460,890	465,302	468,166	470,601	475,990	480,620	485,452	488,836	495,037	489,665	**7,387,915**	$3,481,566
TOTAL DEMAND	**0**	**0**	**45,106**	**113,532**	**227,415**	**386,537**	**456,612**	**457,807**	**459,632**	**460,716**	**460,890**	**465,302**	**468,166**	**470,601**	**475,990**	**480,620**	**485,452**	**488,836**	**495,037**	**489,665**	**7,387,915**	**$3,481,566**
GRAND TOTAL DEMAND & OTHER BENEFITS	**0**	**0**	**308,850**	**775,959**	**1,635,075**	**2,639,951**	**3,057,277**	**3,108,719**	**3,054,774**	**2,909,945**	**2,860,447**	**2,814,387**	**2,837,189**	**2,889,748**	**2,865,708**	**2,883,673**	**3,064,774**	**3,094,007**	**3,069,663**	**3,024,937**	**46,895,083**	**$22,349,410**

NSPM IVVO- NPV

	Total ($MM)
Benefits	**22**
Other Benefits	19
CAP Benefits	3
Costs	**(39)**
O&M Expense	(2)
Change in Revenue Requirement	(37)
Benefit/Cost Ratio (DVO 1.25% O&M; 0.7% capital)	**0.57**

RATIO BASE (DVO Savings 1.25% O&M, 0.7% CAP)	VALUE
FAN(5% WiMax)+ Contingencies	**0.57**
FAN(5% WiMax) NO Contingencies	**0.61**

RATIO LOW SENSITIVITY (DVO Savings 1% O&M, 0.6% CAP)	VALUE
FAN(5% WiMax)+ Contingencies	**0.46**
FAN(5% WiMax) NO Contingencies	**0.49**

RATIO HIGH SENSITIVITY (DVO Savings 1.5% O&M, 0.8% CAP)	VALUE
FAN(5% WiMax)+ Contingencies	**0.67**
FAN(5% WiMax) NO Contingencies	**0.72**

**PUBLIC DOCUMENT –
NOT PUBLIC DATA HAS BEEN EXCISED**

The APT CBA model represents a Company work product. Xcel Energy maintains this information as a trade secret pursuant to Minn. Stat. §13.37 (1)(b) based on its economic value from not being generally known and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use.

Additionally, some data contained within the model is also maintained as trade secret based on its economic value from not being generally known and not being readily ascertainable by proper means by other persons who can obtain value from its disclosure or use, and/or contains proprietary customer and system data. This additional trade secret data includes negotiated and contractual pricing.

Please note the CBA is marked as "Non-Public" in its entirety. Pursuant to Minnesota Rule 7829.0500, subp. 3, we provide the following description of the excised material:

1. **Nature of the Material**: The Cost Benefit Analysis Model developed by the Company.
2. **Authors**: Risk Analytics and Regulatory and Distribution
3. **Importance**: The Company work product is proprietary to the Company.
4. **Date the Information was Prepared**: The CBA Model was created in the third quarter of 2019.2019.

The AGIS CBA executable model represents a Company work product. Xcel Energy maintains this information as a trade secret pursuant to Minn. Stat. §13.37 (1)(b) based on its economic value from not being generally known and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use. Additionally, some data contained within the model is also maintained as trade secret based on its economic value from not being generally known and not being readily ascertainable by proper means by other persons who can obtain value from its disclosure or use, and/or contains proprietary customer and system data. This additional trade secret data includes negotiated pricing (including labor, materials, technology, and services) and contract terms; internal labor rates; number of customers per feeder; and device retirement and failure rates.

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1. **Nature of the Material**: The Cost Benefit Analysis Model developed by the Company.
2. **Authors**: Risk Analytics
3. **Importance**: The Company work product is proprietary to the Company.
4. **Date the Information was Prepared**: The CBA Model was created in the third quarter of 2019.

[PROTECTED DATA BEGINS

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PROTECTED DATA ENDS]