INTEGRATING LOCATIONALLY-CONSTRAINED RESOURCES INTO TRANSMISSION SYSTEMS: A SURVEY OF U.S. PRACTICES

WIRES

(Working group for Investment in Reliable & Economic electric Systems)

In conjunction with

CRA International

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PREFACE AND COMMENT ON THIS REPORT

The WIRES Committee on Wind and Remote Resources Integration, in conjunction with CRA International, has surveyed transmission-related practices in the United States that will prove critical for the efficient development and integration of clean energy resources such as wind and solar energy or clean coal generation with carbon capture and sequestration. These forms of electrical generation will assume greater importance as the Nation implements renewable portfolio standards and climate change legislation. However, attractive "clean energy" resources are frequently and necessarily located a great distance from large numbers of electricity consumers. In other words, they are locationally-constrained. Moreover, the operational characteristics and up-front costs of these new technologies pose significant challenges to industry participants and policymakers that seek to integrate location-constrained resources into the energy mix.

This Report surveys how regulators, industry, and investors currently are meeting those challenges. It focuses on five specific areas:

- ***Investment Priorities*** – selecting from and prioritizing competing transmission investment opportunities

- ***Planning Processes*** – planning transmission efficiently and regionally, taking account of stakeholder interests as well as reliability, economics, and efficiency

- ***Operational and Regulatory Accommodations*** -- new measures and rules that help aggregate and integrate locationally-constrained resources

- ***Rate Recovery*** -- the use of state and federal rate regulation, pricing, and cost allocation to address the uncertainties of cost recovery

- ***Tax Incentives*** – using state and federal tax policy to facilitate investments that help create market access for clean energy resources

I. WIRES' OBJECTIVE IN CREATING THIS REPORT

WIRES is pleased to issue this comprehensive Report on effective U.S. practices in integrating locationally-constrained electric generation outputs into the electric transmission system. This Report was commissioned by WIRES in light of two of the most critical public policy challenges we face: first, the pressing need to utilize more fully the enormous potential of renewable resources and clean forms of central generation power; and, second, the equally important challenge of connecting markets to these resources, which are typically located far from most customers, by strengthening and expanding the transmission infrastructure. Whether developed for renewable energy or economic and reliable service of all kinds, transmission delivers the life's blood of the Twenty-first Century digitalized economy.

The Report we issue today is not a policy paper, strictly speaking. It is instead a thorough exposition of the methods currently employed by various states, industry, and investors to integrate these locationally-constrained resources into the electric grid. This Report is a first-of-its-kind survey of these practices for the benefit of policy makers, stakeholders, and the power industry itself. This Report is also important for several additional reasons:

First, it forcefully points out that there exist several extraordinary financial, technical, and regulatory obstacles to achievement of the popular objective of greater U. S. reliance on clean energy resources. This is a transformative moment in the power sector and one measure of our success in meeting the challenges of climate change and clean energy will be how effectively these new resources are integrated into the delivery system.

Second, successful advancement of transmission upgrades and expansions will be based on widely-employed solutions to problems. Because the transmission system is open, regionally coordinated, and highly integrated across large portions of the country, planning and managing its expansion may benefit from uniform, previously-tested, and proven approaches.

WIRES acknowledges that one size does not fit all situations with respect to financing, siting, constructing, or operating transmission facilities. So, third, WIRES believes that this Report will enable policymakers to evaluate the effectiveness of solutions that have been developed within different regional electrical systems, under diverse regulatory circumstances and standards, and in different technical environments.

And, finally, this Report infuses the current national conversation about how to address climate change and enhance our portfolio of renewable energy with a dose of realism about why additional infrastructure is required to deliver clean energy to market. WIRES contends that our rising national expectations for a cleaner-energy economy will require supporting transmission investment in dramatic new proportions, which will in turn require innovation and a devotion to economic efficiency. It will therefore necessitate identification and implementation of the "best practices" insofar as we can make that judgment based on today's state of the art.

II. WIRES' VIEW OF THE MOST EFFECTIVE PRACTICES

WIRES applauds those jurisdictions and industry innovators that are working to integrate remote clean energy resources into the transmission grid, which will ultimately result in their widespread development of such resources. The Report concludes that "great strides" are being made in addressing the challenges to the integration of location-constrained clean energy resources. WIRES nevertheless emphasizes that best practices and innovation are greatly needed. Indeed, they will be critical if the drive to achieve a low-carbon, renewable energy economy is to continue gathering momentum. Without innovation and continued investment in the transmission system, the current state of the grid -- or the absence of investment in major transmission additions -- will force the U.S. to scale down or abandon its ambitions for "green power," for an electrified transportation sector, for energy independence, or for large targeted reductions in carbon emissions.

WIRES therefore highlights four areas where we perceive that current practices are or can be made "best" or most effective: **A)** regional transmission planning, **B)** aggregating energy resources with characteristically variable outputs over broad balancing areas, **C)** using optimal methods of allocating and recovering costs, and **D)** reforming the "queues" of proposed projects to accelerate development. However, we acknowledge that, because the industry is in transition, any estimate of what it "best" today should be reassessed in light of performance and what technology permits us to achieve in the future.

A. Regional transmission planning is crucial. High voltage transmission expansions and upgrades, even if physically located in a single state, will have regional and diverse economic benefits and effects. Moreover, the facilities that move electricity to major loads from locationally-constrained clean resources will often cross state boundaries. In that environment, multiple determinations of need, concurrent or successive state and regional planning exercises, and conflicting rate and cost allocation rules constitute an inefficient and outmoded response to proposals that would improve or expand the transmission system. Stakeholders such as regulators, generation developers, load-serving entities, customer and environmental groups, and others must be given a forum within which to work collaboratively to advance multi-state resource development and to create markets based on long-term plans for the economic, reliability, and environmental policies of the region. If the planning principles in FERC Order No. 890 are rigorously followed and enforced on a regional basis, they clearly would constitute best practices. In that eventuality, additional planning processes would be duplicative and inefficient and should be eliminated.

B. The variability of wind and other resources can be diversified through regional operations and planning. Consolidating or aggregating resources over larger balancing areas and feeding diverse resources into the transmission system reduces variability on the system and levelizes peak loads. The cost of variable (sometimes referred to as intermittent) outputs goes down in proportion to the breadth of the resource base, making the connection of remote resources to distant load centers more economically justifiable. Together with advanced wind forecasting tools that can predict levels of variability, methods of resource aggregation positively improve system operations. We believe these are effective practices.

C. **Appropriate cost allocation and cost recovery will contribute significantly to promoting investment in needed transmission.** The recent report of the National Renewable Energy Laboratory ("NREL"), 20% Wind By 2030, identifies these as among the principal challenges to the development of transmission for large-scale integration of wind. Today's WIRES Report identifies ways in which state and federal regulators are seeking to reassure investors by providing favorable pricing, cost recovery incentives, and cost allocation models designed to encourage particular kinds of investment in the context of normal cost-of-service ratemaking. Similarly, certain tax policymakers have supplied various credits for transmission construction to serve in-state renewable resources. While these may be considered best practices under today's circumstances, WIRES points out that they are insufficient to eliminate other key obstacles that jeopardize continuing and future investment in much-needed transmission expansions.

For example, considerable uncertainty surrounding the allocation of the costs of new transmission arises from the lack of "clear, consistent and principled policy and oversight" of the kind advocated by the independent Blue Ribbon Panel on Cost Allocation in its 2007 report entitled A National Perspective on Allocating the Cost of New Transmission Investment (commissioned by WIRES).

WIRES recognizes that cost allocation cannot always be one-size fits-all. It believes that any cost allocation must nevertheless be held up to a set of principles to be adjudged just and reasonable. The Panel proposed such principles, one of which is that the larger the size of a proposed new transmission facility, the broader its potential to serve interstate commerce and the larger the region that should support it. It also recognized that state rate proceedings can compromise the ability of utilities to realize the benefits of federal incentives. Moreover, state "need" and siting determinations often undermine the ability to optimize the regional benefits of transmission through cost allocation decisions. Policymakers should therefore take seriously the Panel's proposal that state and federal regulators establish clear guiding principles and "find an effective, non-disruptive way in which to move transmission out of retail rate base and into FERC tariffs."

D. **The queue processes now employed by RTO's constitute a critical "gating" issue that must be addressed before issues associated with transmission access or dispatch can rise to an equivalent level of importance.** If renewable energy development and related transmission expansions are to garner the level of investment that will be required to meet ambitious goals like that announced by NREL, decisions about which projects merit quick action and must be built should be made expeditiously and efficiently. However, queue processes have themselves become congested and burdened with multiple proposals that necessitate system impact studies for projects whose financial and operational viability is not demonstrable. The Report relates current efforts to reform and streamline the queues in various regional markets. While it may be too early to deem one approach "best," we see a number of creative ways to cluster interconnection requests, accelerate system studies, conduct open seasons, and develop institutional forms that improve the interconnection process.

CONCLUSION

WIRES' members contend that the country needs major additional transmission investment. Such transmission investment faces significant barriers, whether new transmission facilities are needed for reliability, to relieve congestion, to ensure energy security or the efficient use of generation assets, or to accommodate expansion of nuclear and other central station power. This Report, however, highlights a major new challenge: how to efficiently interconnect and integrate into the grid the location-constrained and often-variable clean energy resources that have become the focus of so much domestic energy policy. This is particularly important at a time when the Nation is poised to increase its use of renewable and other location-constrained forms of electric generation and to target significant reductions in greenhouse gas emissions. WIRES believes this Report will be a significant contribution to meeting the need for clean energy through infrastructure enhancement.

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Our special thanks to Jim Drzemiecki and Tanya Bodell of CRA International for their hard work and insight. WIRES takes full responsibility for the views expressed in this Preface, however.

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REPORT

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Integrating Locationally-constrained Resources into Transmission Systems: A Survey of US Practices

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CRAI DISCLAIMER

The information contained herein is based on sources believed to be reliable and is written in good faith. Given the ongoing evolution of the issues addressed in this report, this report should not be considered a complete and definitive identification of the initiatives underway to integrate locationally-constrained generation into the transmission system, but a survey of examples of the activities currently under consideration and being implemented in the US electricity industry.

A Survey of US Practices

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1. EXECUTIVE SUMMARY

This paper reviews effective practices that have been adopted throughout the United States by utilities, regulators, politicians, and markets to encourage the network to integrate locationally-constrained generation into the existing transmission network. Locationally-constrained generation refers to power production that faces limitations on geographical placement due to i) inputs, ii) technology, or iii) outputs. Most generation faces siting limitations for one or more of these reasons.

The issue of integrating such generation into the transmission systems across the US is still evolving. As such, this research effort attempts to identify those practices that are seen to be working in the current environment. Unlike an evaluation of business processes accomplished under a static environment, this effort emphasizes what appears to be working under current conditions as opposed to what might be seen as most effective under optimal conditions.

Renewable resources that have the most significant location constraints include wind, solar, and geothermal resources that are most efficient in areas far away from load centers. Most of these renewable resources are variable, creating operational challenges for the transmission networks to which they connect. Carbon capture and storage (CCS) technologies also are locationally-constrained because they require specific geological formations for carbon outputs. As investments in these new technologies increase due to the prospect of a carbon-constrained world, transmission systems must adapt. This report focuses on commercial, regulatory, and technical implications of locationally-constrained generation on transmission decisions. It addresses specific activities occurring in the more general areas of investment priorities, planning process, operational and regulatory accommodations, rate recovery, and incentives.

1.1. INVESTMENT PRIORITIES

Players in the electricity industry have developed new ways of thinking about transmission policy. Whereas transmission providers have addressed technological issues surrounding expansions of backbone facilities and network build-outs, they now also must address regulatory and commercial implications of locationally-constrained generation. Queuing processes, which traditionally have subscribed to a “first-come-first-served” philosophy, are being overwhelmed by a large number of small renewable projects, and certain jurisdictions are adjusting their queuing rules to rationalize the backlog. FERC, recognizing the difficulties created by interconnection queues held a technical conference at the end of 2007 and subsequently issued an Order that requires RTOs and ISOs to proceed with evaluating their queue management more quickly.[1] Each RTO and ISO was required to file a report within 30 days of the Order on the status of their queue and identify any target dates for filing the necessary tariff amendments or waivers. Transmission regions are thus evaluating transmission in concert with wind and adjusting the term length commitments for recovery of transmission investment.

The following strategies constitute the basis for effective practices:

- **Reservation priority** moving from “first-come-first-served” to a “first-ready, first-served” approach. In other words, a transmission connection request must continue to earn its ordinal position in the transmission queue or risk moving to the back of the line.

- **Up-front payments** of a magnitude sufficient to let economics dictate which projects should drop out of the queue.

- **Open season** that invites all projects to submit requests for transmission thereby eliminating the first-come-first-served construct and imposing contingencies as part of the acceptance.

- **Suspension rule revisions** that allow RTOs and ISOs to clear the queue in a timelier basis compared to the three-year grace period under FERC Order No. 2003.

- **Integration** of static queuing rules with competitive rationalization mechanisms such as forward capacity markets.

It is important to note, however, that these approaches are still under development and subject to the results of actual implementation.

1.2. PLANNING PROCESSES

Regional and cross-utility collaboration are encouraging new planning processes for transmission, including transmission infrastructure authorities and renewable enterprise zones. Whereas generation projects used to be assessed individually, the cluster approach addresses multiple projects in the planning process simultaneously, applying system impact studies and facilities studies to a collection of connection requests. In general, the US continues to adopt an approach to planning where transmission drives the best siting of generation although certain accommodations have been made to integrate optimal locations for locationally-constrained generation into the network.

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1 122 FERC ¶ 61,252, Docket No. AD08-2-000 Order on Technical Conference, March 20, 2008, http://www.ferc.gov/whats-new/comm-meet/2008/032008/E-27.pdf

In a number of regions, considerable debate is underway over the issue of building transmission trunklines to resource-rich areas with little initial entry. As these lines are meant to facilitate future generation investment, some hold the view that these types of transmission facilities are more appropriately handled within the interconnection process. Others have pointed out that any efficiently-sized line would have capacity that is far greater than what is needed by initial entrants, that it is unrealistic to expect a few initial entrants to subsidize competitors that may come later. To overcome this barrier, the development of renewable energy trunklines is occurring during the planning process.

Effective planning practices that have been put into action include the following:

- **Regional planning** through RTOs, ISOs, or voluntary organizations that address barriers to entry by location-constrained resources in resource-rich, yet undeveloped, areas.
- **Wind penetration studies** that estimate in advance the potential impact of different levels of wind generation on transmission systems.
- **Clustering** different projects into a single set of feasibility and impact studies, decreasing the time spent in the queue due to more efficient implementation of required milestones.
- **Regional joint planning organizations** and transmission infrastructure authorities to support transmission projects that connect locationally-constrained generation to load centers.
- **Renewable energy zones** that focus on regional planning, regional transmission plans, and interstate cooperation to identify potential transmission investment to connect locationally-constrained areas and address associated permitting and cost-allocation issues. States that are active in developing such zones include Texas and an association of the western states including California.

1.3. Operational and Regulatory Accommodations

Regulatory rules of the marketplace increasingly are being designed to address the technical challenges of connecting locationally-constrained resources, including relaxation of otherwise prohibitively costly scheduling and imbalance charges for variable generation resources. Consolidation, either through physical or virtual balancing across wide geographic areas, addresses many of the technical challenges with most renewable resources. Similarly, adaptation of the natural gas gathering model to aggregate interconnected generating units behind the meter and combining various generation resources such as solar with wind has the same effect. In anticipation of significant wind facilities, many markets are building wind forecasting services into their scheduling and dispatch just as they do weather and load forecasts.

A number of initiatives have been implemented to accommodate variable resources and other locationally-constrained generation with operational constraints. Effective practices include:

- **Addressing variability** through offsetting consolidation/aggregation
  - over larger balancing areas
  - through windfarms that aggregate behind the transmission meter (i.e., following the natural gas gathering model)
  - by combining uncorrelated renewable resources (e.g., wind and solar)
- **Creating markets for flexibility** through mechanisms to compensate dynamic load following and frequency responses, adaptable for incorporation of new demand-side technologies.
- **Market Rules** that adjust for the operational realities of renewable resources, including scheduling concessions and waiving imbalance penalties. However, economic dispatch rules have not yet been modified to prioritize renewable resources over thermal generation.
- **Wind forecasting services** that provide projected wind conditions to transmission operators for purposes of incorporating expected conditions into scheduling, similar to weather conditions and load forecasts.

1.4. RATE RECOVERY

Transmission pricing and cost recovery is a critical part of a transmission investment decision. In addition to standard transmission tariffs which are approved by FERC, certain jurisdictions have passed legislation providing legal guarantees for recovery of investment in transmission built to connect to renewable resources. Some jurisdictions socialize the recovery of these costs from larger numbers of ratepayers. A "conditional firm" transmission service also has been developed to make better use of the transmission system which previously had been locked into the limited constructs of firm or interruptible service. In examining transmission tariffs, valuation metrics for capacity and energy also are being addressed in light of the realities of variable resources. Whether these conditions extend to standard performance metrics under FERC Order 890 remains to be seen.

Within this structure, there has been significant discussion with limited implementation. Effective practices that actually have been passed and put into place include:

- **Implementing legislation and regulations** to provide legal mandates and regulatory incentives to build transmission for purposes of connecting to locationally-constrained generation, such as giving priority to transmission projects necessary to support RPS requirements and granting public utility commissions authority to approve transmission cost adjustments on a timely basis.

- **Assurance on cost recovery** of investment in transmission projects to connect resources required to meet RPS requirements.

- **Socialization of costs** across all ratepayers in support of building transmission to identified renewable energy zones.

- **Pro-rata connection charges** to reflect the incremental contribution of a single facility to transmission line expansions instead of a but-for analysis that assigns the entire cost of a line expansion to one unit.

- **"Conditional Firm" transmission service** which modifies the historic transmission products of firm versus interruptible to recognize available capacity on the transmission system that can be accessed with minimal cost by wind and other renewable resources.

- **Defining capacity of variable resource generation** to reflect the incremental contribution to the transmission system during peak periods as opposed to an annual average that reflects only wind patterns.

1.5. INCENTIVES

Federal and state governments are passing incentives to accommodate integration of locationally-constrained resources, extending tax breaks for investment in renewable resources to the transmission investment required to connect those resources.

Examples of effective practices that have been implemented on the state and federal levels include:

- **Accelerated depreciation** for investment in transmission connection costs.

- **State income tax credits** for investment in transmission connection costs.

- **Property tax reduction/rebates** for investment in transmission equipment and land required to connect a facility to the transmission system, including rebates for up to 50 percent of the cost of transmission lines and collector systems for the integration of the wind farm and reduced property tax value assessments at 20 percent of depreciated cost.

- **Research and development (R&D) grants** that identify the importance of R&D for new transmission and distribution to connect utility-scale renewable generation to the grid, including methods for siting new transmission lines and reducing energy losses.

1.6. CONCLUSION

Great strides are being made to accommodate locationally-constrained resources. Transmission investment decisions of expansion and upgrades are being evaluated in conjunction with locationally-constrained resources. The transmission planning process and organizations, structures, and practices driving the process are considering regional needs and addressing regulatory structures such as renewable energy zones. Markets and transmission operators are adopting regulatory accommodations for new technologies that operate in ways very different from traditional generation. Rate recovery practices are being modified to provide requisite returns in transmission investment to ensure build-outs to locationally-constrained generation is recovered. Even federal and state tax incentives, normally focused on promoting investment in renewable technologies, are extending to the transmission investment required to connect those technologies to the network. In the same way the existing transmission system grew to accommodate the location constraints of fossil fuel technology, new transmission investment and operations are evolving to accommodate the location constraints of sustainable technologies.

This paper provides a summary of effective practices being undertaken to integrate locationally-constrained generation resources on the existing transmission network. It examines such practices from relevant technical, regulatory and commercial lenses to produce a more complete vision of the integration process. The report is organized as follows:

- Section 1 provides the executive summary.
- Section 2 provides background information on the geography of locationally-constrained resources and the potential impact of these resources on transmission systems.
- Section 3 addresses investment priorities and queuing protocols, and how these priorities are changing to incorporate locationally-constrained generation technologies.
- Section 4 examines the transmission planning process and the organizations, structures, and practices driving the process.
- Section 5 summarizes regulatory accommodations that are being made to adapt to new technologies that operate in ways very different from traditional fossil-fuel and nuclear generation.
- Section 6 looks at rate recovery practices to determine how investment and the required return on transmission investment to connect locationally-constrained generation are recovered.
- Section 7 reviews federal and state tax incentives for transmission investment that integrates renewable resources into the network.

2. BACKGROUND

Centralized resource planning by regulated utilities over the past century built out a transmission network to accommodate fossil fuel power generation and recovered this investment through regulated rates. The existing network is less able to accommodate generation technologies that face different location constraints. Renewable resources such as hydropower and biomass already are interconnected to the transmission system. Others may be less likely to impact transmission on a national level because of the limited geographical footprint of the economically viable locations.[2] Renewable resources that have the most significant location constraints include solar and wind, resources that are most efficient in areas far away from load centers, and carbon capture and storage (CCS) technologies that require specific geological formations for its outputs. As investment in these new technologies increases due to the prospect of a carbon-constrained world, transmission systems must adapt. Yet, the need to adapt comes precisely when an aging transmission infrastructure and deregulated electricity markets impose their own investment requirements. Despite these challenges, practices that support locationally-constrained generation have developed.

This report provides a summary of effective practices currently being undertaken to integrate locationally-constrained generation resources on the existing transmission network. It looks at such practices from the relevant technical, regulatory, and commercial lenses to produce a more complete vision of integration. This section describes the context in which locationally-constrained generation is relevant, addressing each type of generation resource and how its expansion impacts transmission. With the foundation laid in this section of the report, subsequent sections describe the practices already in place or being considered to address the integration of locationally-constrained resources to the transmission network.

2.1. TRADITIONAL GENERATION RESOURCES

Fossil fuel power generation faces many constraints, most of which have been addressed by the evolution of the US energy system. The current network thus extends to gas-fueled generation units located on gas pipelines, coal-fired power plants located either near coal mines or rail or water transportation, and nuclear reactors and hydroelectric facilities located by water due to the cooling and fueling requirements of the technology. With transmission systems already established to support traditional power generation facilities, most new investment in these power sources is likely to occur at existing sites or to be situated near the existing network, imposing only incremental impacts on transmission investment decisions.

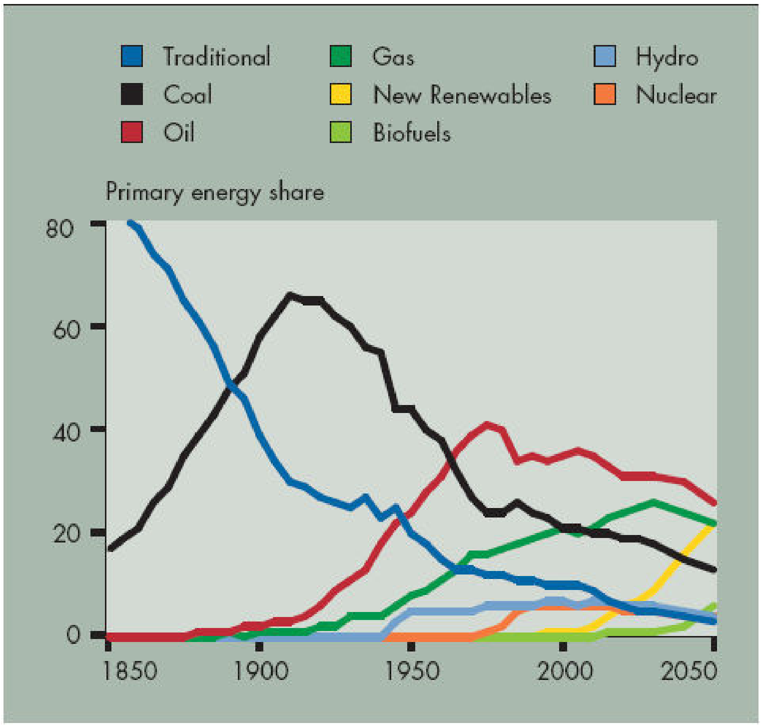
2 Most geothermal sites are located in Nevada and Eastern California. Biomass tends to be situated near the fuel source close to the existing system. Tidal power is limited to coastal areas with sufficiently high tidal changes.

The current system in the US interconnects various transmission networks, generation facilities that deliver power over those wires, and the fossil fuel transportation systems in the form of rail and pipelines that deliver fuel to those power generation facilities. These networks form an integrated system that requires new generation to be sited in locations where the resources for inputs, outputs, and technological requirements can be satisfied.

Without any substantial means of storing electricity, operation of the transmission network must maintain a real-time balance between supply and demand for electricity. This requires a diverse portfolio of generating technologies, including plants with baseload capability as well as peaker units with quick ramp-rates and units that can provide ancillary services such as load following and voltage support. The system is well established for purposes of connecting and operating fossil-fuel and nuclear units as well as a combination of baseload and peaker plants. It is less prepared for the recent changes that promote locationally-constrained resources, many of which have different operational characteristics and variable output.

The introduction of competition and open access has introduced challenges to the system of networks that were developed under a different regime. Figure 1 illustrates the trends over the past century in which energy usage shifts from one source to another. As each source reaches a peak, it is replaced by another primary energy source, first wood then coal, followed by oil and gas.

Figure 1: Trends in Historic and Projected Energy Sources[3]



Source: Shell (2001)

Shell global scenarios of electricity fuel sources under a carbon reduction regime estimates that over 60 percent of electricity would be generated by non-fossil sources.[4] Other projections indicate solar photovoltaic installations increasing tenfold and a tripling of installed wind capacity and biofuels over the next ten years (see Table 1). Possibly optimistic, the message is still clear: the transmission system must adapt to new sources of electricity generation.

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3 Shell, "Exploring the Future: Energy Needs, Choices and Possibilities, Scenarios to 2050," Global Business Environment, 2001. http://www.cleanenergystates.org/CaseStudies/Shell_2050.pdf

4 Shell, "Energy Scenarios through 2050," 2008. http://www-static.shell.com/static/aboutshell/downloads/our_strategy/shell_global_scenarios/shell_energy_scenarios_2050_2008.pdf

Table 1: Projected Growth in Installed Capacity over the Next Ten Years[5]

Global Installation/Production Growth: Solar, Wind, Biofuels

	2003	2007	2017 (est.)
Solar PV Installations	620 MW	2,821 MW	22,760 MW
Wind Power Installed	8000 MW	20,060 MW	75,781 MW
Biofuels Produced	7 Billion Gallons	15.6 Billion Gallons	45.9 Billion Gallons

Source: Clean Edge, Inc. (2008)

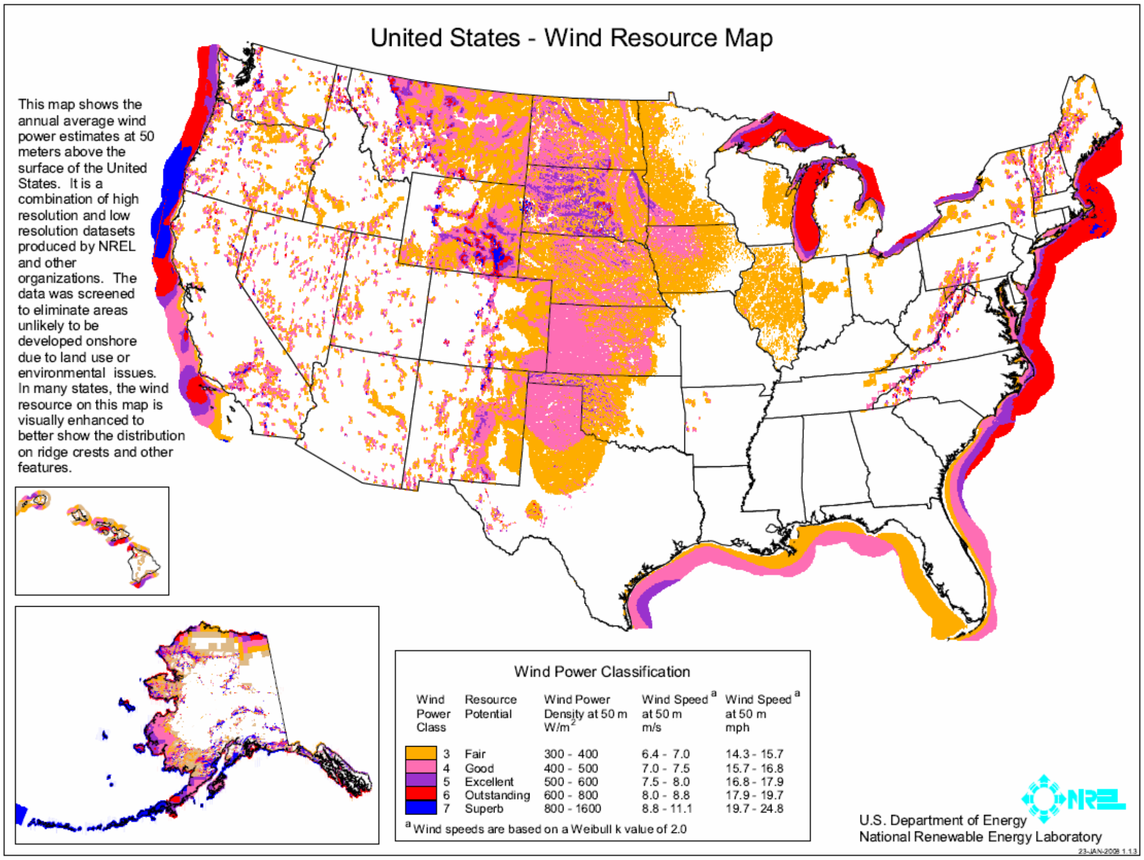
This adjustment is happening now. Regulated requirements for generation mix, in the form of renewable portfolio standards (RPS) and commercial decisions due to environmental restrictions, are changing the system mix and supply curve merit order. Location constraints are generating challenges for network expansions while the variable nature of these resources is testing operations. Although the network is able to incorporate traditional generation sources into its system, a significant amount of renewable resources creates the need for a new regime to address each source of renewable power.

2.2. WIND RESOURCES

Areas in the US that are potentially suitable for wind energy applications (wind power class 3 and above) are dispersed throughout much of the United States. As reported by the US Department of Energy (DOE), the best areas for wind energy production include the Midwest from northwestern Texas to the Dakotas, coastal areas, and exposed ridge crests and mountain summits. Figure 2 illustrates how the best wind resources are located far from most load centers and the transmission networks required to deliver wind energy to load.

5 Joel Makower, Ron Pernick, and Clint Wilder, Clean Edge, Inc., "Clean Energy Trends 2008," March 2008. http://www.cleanedge.com/reports/pdf/Trends2008.pdf

Figure 2: US Wind Resource Map[6]



Source: US DOE, National Renewable Energy Laboratory (2008)

Reaching wind resources will require significant transmission investment. A 2008 NREL study analyzes the scenario where wind composes 20 percent of US power generation. A total of 293 GW of new wind capacity would have to be developed, including 241 GW of land-based wind power and 54 GW of shallow offshore wind resources to optimize delivered costs.[7] Such generation would require expanding the US transmission network in a manner that would allow wind generation to connect to the system and investing in upgrades to offset congestion delivered by these connections.

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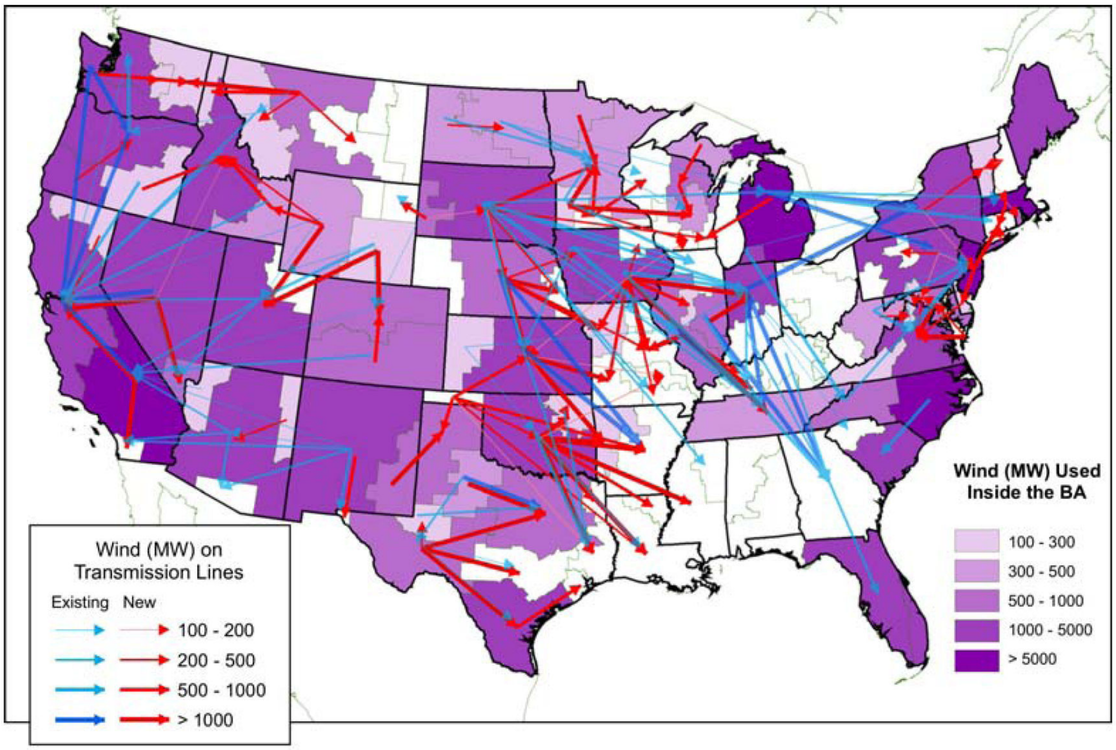
6 US Department of Energy, National Renewable Energy Laboratory, January 23, 2008. http://www.eere.energy.gov/windandhydro/windpoweringamerica/pdfs/wind_maps/us_windmap.pdf

7 US Department of Energy, "20% Wind Energy by 2030: Increasing Wind Energy's Contribution to US Electricity Supply," Prepublication Version, May 2008. http://www1.eere.energy.gov/windandhydro/pdfs/41869.pdf

DOE's WinDS model projects transmission development to meet future load, wind generation, and associated constraints, summarized in Figure 3.

Figure 3: Expansion of US Transmission System by 2030[8]



Total Between Balancing Areas Transfer >= 100 MW (all power classes, land-based and offshore) in 2030.
Wind power can be used locally within a Balancing Area (BA), represented by purple shading, or transferred out of the area on new or existing transmission lines, represented by red or blue arrows. Arrows originate and terminate at the centroid of the BA for visualization purposes; they do not represent physical locations of transmission lines.

In addition to location constraints, wind power is very variable, often strongest during evening hours, yet subject to directional shifts and speed changes. The inability to store power creates technical challenges for managing a transmission system with high penetration of wind.

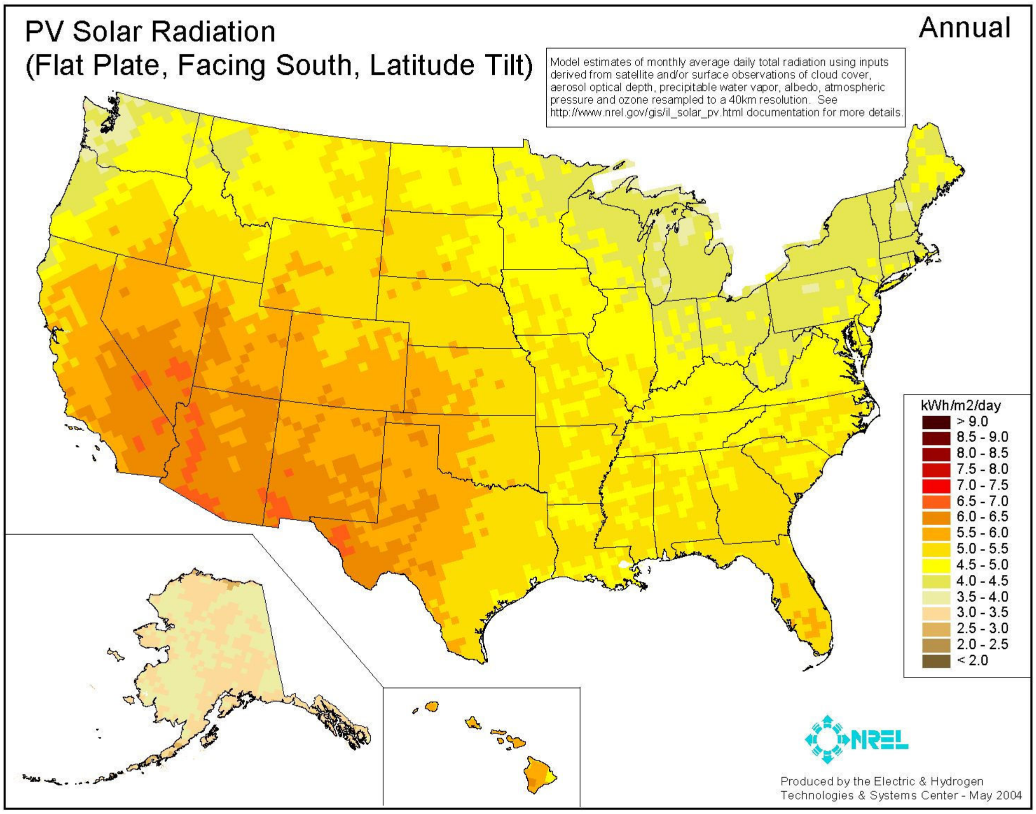
2.3. Solar Resources

Solar resources require consistently sunny days as well as large expanses of land to permit photovoltaic panels to produce large-scale power generation. Both are found in the southwest,

8 Ibid., Figure 1-8, p. 11.

generally far away from large load pockets and the transmission needed to deliver to that load. Figure 4 illustrates where solar resources are best for a flat-plate photo-voltaic panel facing south.

Figure 4: US Solar Resources[9]



Source: NREL (2004)

Solar power also has variable operational characteristics based on the intensity of the sun.

2.4. GEOTHERMAL RESOURCES

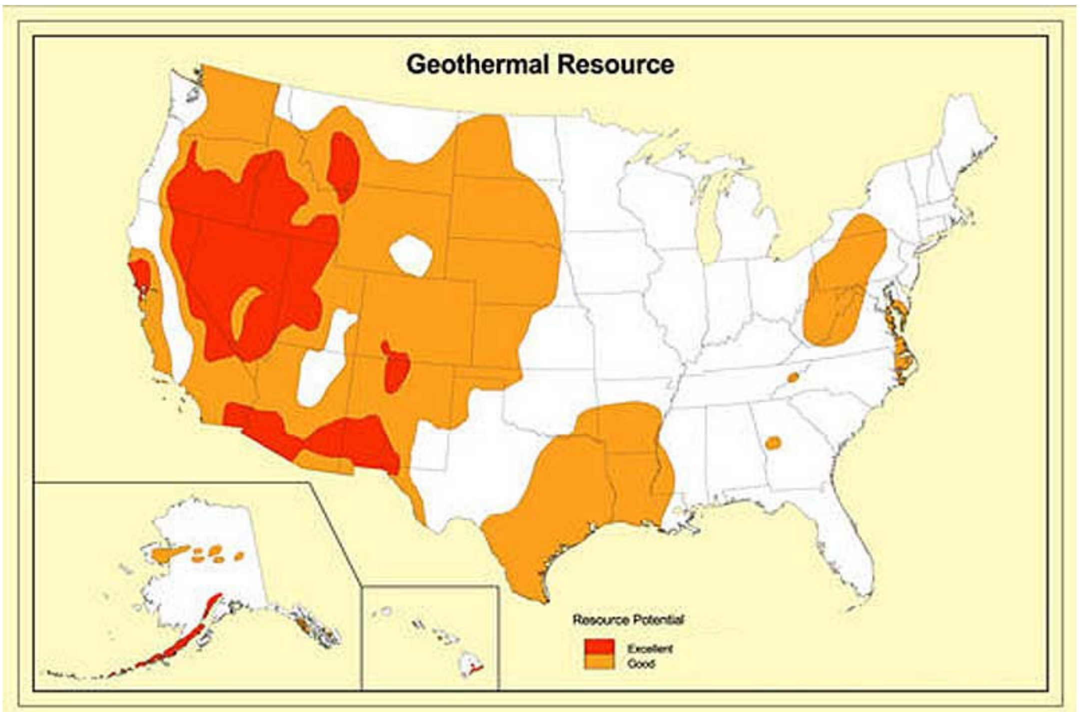
Geothermal resources are locationally-constrained due to the inputs required to generate electricity from the heat from the earth. In the western states of the US, geothermal energy produces electricity in large power plants. Approximately five percent of California's electricity is produced by geothermal

9 US DOE, NREL. http://www.nrel.gov/gis/images/us_pv_annual_may2004.jpg

energy. Figure 5 illustrates the geographical location of good and excellent geothermal resources in the US.

As a long-standing renewable resource, the transmission system has adapted to geothermal's baseload characteristics. Extending transmission service to geothermal sites traditionally has been done on a project by project basis, according to standard transmission connection rules. Many of the locationally-convenient resources already have been tapped. As a defined renewable resource for purposes of RPS standards, however, expansion to reach additional geothermal sites is being reviewed.

Figure 5: US Geothermal Resources[10]



Source: NREL

10 Presented by Union of Concerned Scientists on their website: http://www.ucsusa.org/clean_energy/technology_and_impacts/energy_technologies/how-geothermal-energy-works.html

2.5. Hydroelectric Facilities

Hydroelectric power has been accessed in the US since before electricity was invented. Originally used to turn mills, it was a simple stretch to use the same forces to produce electricity. A significant amount of large hydroelectric plants with reservoirs was developed with federal government support as part of President Roosevelt's "New Deal." Pumped storage provides one of the few effective means of storing electricity and supply-shifting from off-peak to peak hours. Run-of-river hydro has generated growing support from those who consider this technology more sustainable than large hydroelectric systems that disrupt ecosystems and communities.

The current system network already connects the most efficient hydroelectric resources to the transmission system. Thus, location constraints are not a significant issue as the potential for new hydro on a large scale is limited. There are some impacts associated with run-of-river hydro, but these already have been addressed through experience. In fact, the ability to control hydroelectric power is considered a means of offsetting the variable impacts of wind and other renewable resources. Therefore, most hydroelectric power does not create a significant set of new challenges for the existing transmission system, and it actually may serve as a tool in addressing some of the challenges created by other generation sources.

2.6. Carbon Capture & Storage

CCS requires certain geological formations for storage of captured carbon emissions. Options include:

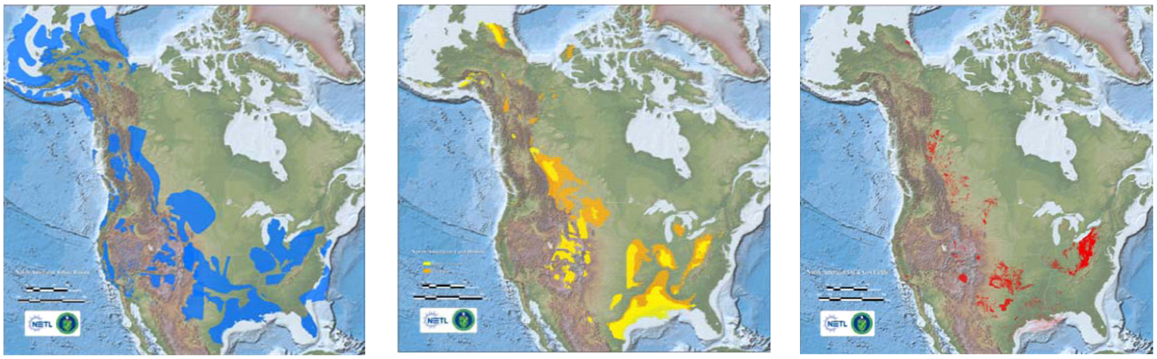
- Saline formations
- Basalt formations
- Unmineable coal seams
- Depleted oil and gas fields.

Figure 6 illustrates the potential areas for CCS in the US. Site selection is likely to be driven by effectiveness and economics.

In order for CCS to be viable, new generation must be located i) close to coal resources or delivery of such resources, ii) on or near coal seams or oil and gas fields where the carbon can be used or near pipelines that can deliver carbon output to the appropriate storage, and iii) where the requirements of clean coal technology can be satisfied. Given the many other location constraints facing CCS, electricity transmission is likely to be only one of many key constraints facing the siting of clean coal generation facilities.

Figure 6: Summary of Potential Carbon Capture and Storage Areas[11]

Saline Formations **Coal Seams** **Oil & Gas Fields**



Source: US DOE (2008)

2.7. CONCLUSION

Although most power generation sources are subject to some form of location constraint, renewable resources are the most likely to create significant integration issues with the existing transmission system. Integration of fossil fuel generation technologies already have been addressed with more than a century of systems and networks designed to optimize the location of new generation give the input constraints of fuel, technological constraints requiring cooling water, and output requirements related to transmission to load. Nuclear units have baseload operating constraints, system protection requirements, and regulatory obligations pertaining to safety that are issues for which the power system already has adapted.

Wind, solar, and most forms of hydroelectric power are variable, imposing new technical challenges on transmission operations to account for system requirements. These resources also are geographically-constrained, with inputs typically located far away from load centers and the existing transmission networks. Geothermal resources have location constraints with baseload characteristics or variability. Biomass has fewer constraints, and can be incorporated into existing facilities and transmission connections.

Although CCS faces location constraints for its outputs and requires very specific geological formations that can store carbon, these are the least of its restrictions. Clean coal facilities face many other location limitations because they need to be close to coal mines and coal transportation. These

11 US Department of Energy. Interactive maps available at: http://www.mapcruzin.com/climate-change-maps/carbon-sequestration-atlas.htm

input constraints already have been addressed by the existing network and are likely to continue to be addressed in a similar fashion. Therefore, CCS creates incremental issues with respect to connection to the transmission system.

In light of the location constraints created by renewable resources, this report focuses on the transmission integration issues associated with wind, solar, geothermal, and hydroelectric generation. Location constraints related to CCS and fossil fuels, which already have been addressed by the existing set of rules, regulations and operations, are discussed more generally. Similarly, this paper describes new means of addressing the impacts of renewable resources; baseload generation and system protection associated with large facilities are outside the purview of the research.

In this context, the following sections survey US practices that answer the challenges of integrating locationally-constrained resources and generation with variable output into the transmission network.

3. INVESTMENT PRIORITIES

Locationally-constrained generation often requires new investment in transmission, either extension of backbone facilities or "build-out" of the existing network to accommodate new generation. The technical considerations are the same as with any connection request; the regulatory and commercial implications are evolving in light of greater demand for interconnections of renewable resources to transmission systems.

Any interconnection request to a US transmission provider generally enters into the transmission queue according to FERC Order 2003, with provisions clarified and issued in 2004 and 2005 (FERC Order 2003).[12] Once in the queue, a generation project is subject to three interconnection studies where the impacts of the request on the transmission system are evaluated.[13] With open access and low barriers to entering the queue, a significant backlog has developed on various transmission systems. This backlog has been identified as an impediment to meeting RPS requirement deadlines. As a result, stakeholders have raised concerns about the effectiveness of the queuing process and transmission investment priorities.

Various proposals have been suggested as a means to alleviate these backlogs and facilitate timely achievement of RPS requirements. Proponents of queue reform have suggested that the smaller size of most renewable resource generation facilities warrant an expedited queuing process. Others have suggested that multiple projects be clustered and analyzed together in light of the single transmission tie-line that would be required to connect the group of projects. Although discussion has been lengthy, actual progress has been limited.

This section summarizes the status of transmission investment priorities. It first examines queuing rules and how these processes are being changed to facilitate investment in locationally-constrained resources. It then looks at how term commitments for transmission investments are being incorporated into interconnection analyses to determine investment priorities.

3.1. QUEUING PROCESS

3.1.1. FERC Rules for Interconnection Requests and Queuing

FERC Order 2003 outlines required procedures for integration of new generation into the grid. The final rule was intended to establish a set of procedures to minimize opportunities for discrimination in

[12] 104 FERC ¶ 61,103, Standardization of Generator Interconnection Agreements and Procedures, Docket No. RM02-1-000; Order No. 2003, Issued July 24, 2003 (FERC Order 2003)

[13] FERC Order 2003.

transmission provision and expedite development of new generation. In order to initiate an integration request, an interconnection customer must submit to the transmission provider a $10,000 refundable deposit, a completed Interconnection Request, and either a "demonstration of site control" (e.g., securing land rights, air permit) or an additional $10,000 deposit. Deposits are applied to the cost of the integration feasibility study that each interconnection request must undergo and are meant to ensure that interconnection customers are serious about their interconnection requests. The interconnection customer and the transmission provider also must hold a "scoping meeting" wherein alternatives for interconnection points can be discussed and narrowed down.[14]

Once an interconnection request and deposit are completed, the interconnection customer is assigned a queue position in the geographic region. The queue position determines the order in which feasibility studies are conducted, which in turn determines the cost responsibility for the facilities necessary to accommodate the interconnection request. The queue position traditionally is assigned based on the date and time of the completed interconnection request on a first-come-first-served basis. There tends to be a single queue for each geographic location.

The transmission provider may conduct feasibility studies serially in order of the queue, or under a more recent FERC option, it may "cluster" requests in order to simultaneously study all the requests received during a 180-day period. Clustering is intended to allow the transmission provider to better coordinate interconnection requests with its overall transmission planning process. FERC now strongly encourages clustering in the interconnection study process for all transmission providers.[15] The following section addresses changes to queuing rules in more detail.

3.1.2. Queuing Rules to Address Locationally-constrained Resources

FERC 2003 was developed for fair and non-discriminatory treatment for traditional fossil-fueled plants and transmission owners were quickly overwhelmed with multiple requests for relatively small connections by wind generators. In 2007, FERC held a technical conference of RTOs and ISOs to address concerns of queue backlog under the current rules.[16] There was agreement from all regions and sectors that the Commission should not undertake a rule-making proceeding to address this issue. Rather, the Commission should encourage faster improvement of these processes by clearly signaling its willingness to allow a degree of flexibility in the ways transmission providers meet the

14 Ibid., section 3.

15 Ibid.

16 In the Matter of Technical Conference on Interconnection Queuing Practices, FERC Docket No. AD08-2-000, December 11, 2007. http://www.ferc.gov/eventcalendar/Files/20071221074227-AD08-2-12-11-07.pdf

multiple goals of FERC Order 2003.[17] Although FERC addressed queuing rules generally, its focus has direct consequences for the interconnection of locationally-constrained resources.

Following the technical conference, on March 20, 2008, FERC issued an Order that requires RTOs and ISOs to proceed with evaluating their queue management more quickly.[18] Specifically, each RTO and ISO was required to file a status report within 30 days of the Order on the status of their queue, including "the status of stakeholder discussions on queue reform" and a "schedule for selecting and implementing any necessary reforms, including a target date for filing any necessary tariff amendments or waivers."[19] FERC thus is accepting queue reform proposals on a state-by-state basis.

CAISO and Midwest ISO have taken the lead in pursuing queuing reforms, and FERC has conditionally accepted both CAISO's petition for waiver and Midwest ISO's proposal. The Midwest ISO's reforms, effective August 25, 2008, with a 60 day transition period, illustrate the following key changes that are being adopted in other jurisdictions:[20]

- Creation of a "fast-lane" for generation projects that are in areas with relatively unconstrained transmission.
- Transition from a "first-come-first-served" to a "first-ready, first-served" approach as demonstrated through the achievement of specific milestones.
- Increased deposit amounts based on the size of the project and changes in the timing of those deposits to front-load most payments.
- Elimination of the ability to suspend projects for economic reasons.
- Introduction of a temporary interconnection agreement.

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17 Organization of Midwest ISO States, Inc. Board of Directors Meeting Conference Call Minutes, January 10, 2008. http://www.misostates.org/MinutesOMSBoDmtg10Jan2008withattachmentsFINAL.pdf

18 122 FERC ¶ 61,252, Docket No. AD08-2-000 Order on Technical Conference, March 20, 2008. http://www.ferc.gov/whats-new/comm-meet/2008/032008/E-27.pdf

19 Ibid., P 9. FERC also recognized that there may be a distinction between two sources of required tariff modifications: i) procedural changes that apply to early-stage and future interconnection requests; and ii) modifications to the queuing rules that impact existing requests that are at a later stage in the process (P 10).

20 124 FERC ¶ 61,183, Midwest Independent Transmission System Operator, Inc.,Docket No. ER08-1169-000, Order Conditionally Accepting Tariff Revisions and Addressing Queue Reform, August 25, 2008, P 47.

The Midwest ISO's proposal illustrates how different jurisdictions are addressing backlogs, extraneous projects, and system complications created by the first-come-first-served rules and developing procedural changes to their queuing process to facilitate progression of viable projects and remove non-viable projects. Solutions include higher up-front payment requirements to enter into the queue, open-season, clustering, and more timely suspension as supported by FERC Order No. 890, which provides regulatory backing for these regional initiatives. Each of these initiatives is addressed below.

Reservation Priority

In FERC Order 890, the Commission changed the reservation priority rules to give "priority to pre-confirmed transmission service requests (for non-firm service and short-term firm service) submitted in the same time period as non-confirmed requests."[21] This effectively moves more serious projects to the front of the queue.

The Midwest ISO queue reform proposal illustrates this change in philosophy from "first-come-first-served" to the exercise of qualitative judgment in a philosophy referred to as "first-ready, first-served." The Midwest ISO proposed "to change the nature of the Feasibility Study from an informational screen of the affected facilities to a qualitative screen of the affected facilities, which then is used to direct interconnection requests to the appropriate phase of the interconnection process."[22] Performed at regular stages, different studies effectively will determine whether the interconnection request can be "fast tracked" to a later stage. FERC accepted the Midwest ISO's proposal to use studies as a "qualitative tool" rather than its prior function as simply an informational screen.[23]

The "first-ready, first-served" approach also has been referred to as the "not-ready, not-served" approach, although the former requires more qualitative judgment than the latter. In other words, a transmission connection request must continue to earn its ordinal position in the transmission queue or risk moving to the back of the line.

Higher Deposits

Some regions have made policy recommendations that address concerns regarding "phantom projects" that enter into the queue, require valuable resources, and result in delayed implementation

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21 FERC, Fact Sheet, FERC Docket Nos. RM05-25-000 AND RM05-17-000, Order No. 890, Final Rule: Preventing Undue Discrimination and Preference in Transmission Service http://www.ferc.gov/industries/electric/indus-act/oatt-reform/order-890/fact-sheet.pdf

22 124 FERC ¶ 61,183, Midwest Independent Transmission System Operator, Inc., Docket No. ER08-1169-000, Order Conditionally Accepting Tariff Revisions and Addressing Queue Reform, August 25, 2008, P 38.

23 Ibid., P 44.

for viable projects. These transmission providers argue that the FERC queue deposit of $10,000 is not enough to exclude less viable projects from undergoing evaluation, delaying progression of more promising ones.

California ISO suggests stricter requirements to maintain a queue position, increased deposits to eliminate non-viable projects, and fast-tracking renewable generator requests selected to meet the RPS requirements.[24] A "core component" of CAISO's proposed queue management program is increasing the Interconnection Study Deposit to $250,000.[25] This figure is based on the total deposits required for a project that completes the entire interconnection process, but simply requires the full amount up front in order to "deter speculative projects from entering and remaining in the queue."[26]

The Midwest ISO proposed to increase its interconnection deposits using a sliding scale based on project size and point in the queue. For example, study deposits range from $10,000 for generators of less than 6 MW up to $120,000 for the "application review phase" and from $40,000 for projects less than 6 MW in the "definitive planning phase" up to $520,000 for projects of 1,000 MW or more.[27] Again, the justification was that the current single-price tariff was too low to rationalize the interconnection requests. FERC conditionally approved Midwest ISO's Queue Reform Tariff filing on August 25, 2008.[28]

Bonneville also has implemented higher queue deposits in which developers must support their requests for transmission with $1.56 million for every 100 MW to be added to the network, encouraging less serious projects to drop out of the queue.[29]

Economics suggests that higher up-front cost to enter the queue will discourage less economic projects from submitting an application for interconnection. Some argue, however, that the price changes that have been implemented are still insufficient for complete rationalization of requests from well-financed developers for whom a change in cash flow timing of the stated magnitude remains

24 The Center for Resource Solutions Team (2005). "Achieving a 33% Renewable Energy Target," p. 76. http://docs.cpuc.ca.gov/word_pdf/misc/051102_FinalDraftReport_RenewableEnergy.pdf

25 Motion for Leave to Answer and Answer of the California Independent System Operator Corporation to Comments on and Protests to its Generator Interconnection Process Reform Filing, Docket No. ER08-1317-000, September 2, 2008, p. 20. http://www.caiso.com/2036/2036c7322d6c0.pdf

26 Ibid., p. 21.

27 124 FERC ¶ 61,183, Midwest Independent Transmission System Operator, Inc., Docket No. ER08-1169-000, Order Conditionally Accepting Tariff Revisions and Addressing Queue Reform, August 25, 2008, P 47.

28 Ibid., P 56.

29 Gail Kinsey Hill, "Rush of Wind Power to Hit the Northwest," The Oregonian, July 20, 2008. http://www.oregonlive.com/environment/index.ssf/2008/07/rush_of_wind_power_to_hit_the.html

inconsequential. A market-based open-season approach, such as the approach adopted by the Wyoming-Colorado-Intertie Transmission Project (WCI) may offer a glimpse of a future where market-based mechanisms are used more fully to rationalize entry into the interconnection queue.

Open Season

Instead of using the first-come-first-served transmission priority rule, some jurisdictions have moved to an "open season" system for transmission requests to address speculative requests that cause significant delays in the queue.

BPA has taken the lead in this area. As of March 2008, over 60 percent of BPA's point-to-point service requests were from wind generators, many of which are for projects that are "unlikely to come to fruition."[30] BPA established the "Network Open Season" to differentiate between these speculative projects and commercially viable ones.

CAISO also is moving forward with an open season approach under its "Queue Cluster Window," which commenced on June 2, 2008.[31] Under this approach, California utilities can receive interconnection requests in a specified window of time, allowing the ISO to group requests for purposes of study. Southern California Edison issued a notice to establish an initial queue cluster window on July 11, 2008.[32]

The Midwest ISO also has taken steps to remedy queue management delays. As part of the Midwest Transmission Expansion Plan of 2007, Midwest ISO has also suggested an open season for interconnection where the size of transmission expansions are consistent with the ISO's long range transmission plan, which had been developed in consideration of likely future generation interconnections. This continuous feedback loop results in consistency and certainty for investors with respect to planning. Furthermore, under the Midwest ISO plan, transmission costs are

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30 Bonneville Power Administration, "Transmission to offer Network Open Seasons: Meeting our obligations to the next generation," March 2008. http://www.bpa.gov/corporate/pubs/fact_sheets/08fs/Factsheet-Network_Open_Season_March_2008.pdf

31 Motion for Leave to Answer and Answer of the California Independent System Operator Corporation to Comments on and Protests to its Generator Interconnection Process Reform Filing, Docket No. ER08-1317-000, September 2, 2008. http://www.caiso.com/2036/2036c7322d6c0.pdf

32 Southern California Edison, Notice of Establishment of Initial Queue Cluster Window under SCE's Wholesale Distribution Access Tariff Large Generator Interconnection Procedures, July 11, 2008. http://www.sce.com/NR/rdonlyres/FD7FD677-939A-4E60-A935-FBFF5B6D49B2/0/08Jul_WDATInitialQueueCluster_071108.pdf

apportioned between the generation and the load as interconnections materialize, rather than being imposed on the first unit connecting to the system, again resulting in more certainty for investors.[33]

Open season enables transmission providers to group interconnection requests for purposes of analysis, resulting in a cluster analysis of multiple projects. Thus, the clustering approach is a direct consequence of queue reform. As clustering effectively provides an alternative means of planning transmission investment, we address this approach in more detail in section 4.1.2.

Suspension

In order to "clear" the queue, some RTOs and ISOs have proposed stricter suspension requirements than FERC otherwise required. Whereas FERC Order No. 2003 allows a generator to suspend its project for up to three years, FERC now is reviewing and approving proposals to shorten the suspension period, thereby releasing inactive projects from the queue in a timelier manner.[34]

For example, the Midwest ISO proposed that a project should be allowed to suspend only under Force Majeure conditions and that suspension for economic reasons should not be allowed. By setting pre-specified milestones, however, the ISO does provide leeway for interconnection customers to market its capacity before executing their interconnection agreements. In addition, the Midwest ISO proposed that a suspending interconnection customer be required to provide for the cost of network upgrades associated with its request so that projects queued behind the suspending project is not harmed by the suspension.[35] FERC approved this stricter set of suspension provisions.[36]

3.2. INTEGRATION OF QUEUING RULES INTO NEW CAPACITY MARKETS

Implementation of new markets for electricity products, specifically the forward capacity markets being implemented in New England and PJM, also create pressure for RTOs and ISOs to re-examine their queuing rules. New England and PJM have implemented competitive forward markets to rationalize who gets paid how much to build new capacity. Based on economics, the rationalization of new capacity creates a tension with the traditional "first-come-first-served" philosophy of FERC

33 Smith, Sandy, "An Overview of Current Initiatives to Expand Transmission Infrastructure to Accommodate Utility Interconnection and Integration of Wind Power," presented at DistribuTech/TransTech 2008. http://www.uwig.org/transtech08/Smith_paper.pdf

34 Order No. 2003, FERC Stats. & Regs. ¶ 31,146 at P 177. The stated intent of this order was to encourage new generation by allowing generators maximum flexibility to respond and adjust to market uncertainties.

35 124 FERC ¶ 61,183, Midwest Independent Transmission System Operator, Inc.,Docket No. ER08-1169-000, Order Conditionally Accepting Tariff Revisions and Addressing Queue Reform, August 25, 2008, P 91.

36 Ibid., P 106.

access rules. Although any new generation that bids into the forward capacity markets is required to be in the queue, they may be processed faster according to their bids. Yet, the cost allocation of their transmission connection still will be based on their original position in the queue.

In recognition of this tension, ISO-NE has engaged in discussions regarding how the queue process should be treated to better integrate with forward capacity markets.[37] A July 2008 draft term sheet proposes potential changes to adjust the large generator interconnection process, including the following:

- **Milestones and deposits**: Modifying milestones and financial requirements to reflect the operational and economic aspects of the interconnection process.
- **Bifurcation**: Dividing the queue into two types of connections: i) an energy-only interconnection and ii) capacity connections.
- **Study Timing**: Changing the timing of the optional study so that it may be requested earlier in order to allow the developer to specify which queued generation to model in the subsequent studies.

As markets continue to evolve, queuing rules that conflict with competitive generation investment rationalization mechanisms are likely to come under increased scrutiny and modification.

3.3. Term of Commitments for Transmission Investment

FERC does not require the use of a specific time horizon for the purpose of conducting system impact or facilities studies required under Order 2003. Yet certain jurisdictions have argued that standards are required in their interconnection process.

Policy makers in California have suggested that long-term planning horizons of at least 20 years would be needed to meet the state's renewable portfolio target due to the time lag between plan conception and operation, as well as the need to develop transmission operations strategies for renewable resources with variable output. A long-term view of transmission planning can help to

[37] DRAFT Forward Capacity Market Generator Interconnection Process Stakeholder Group Conditional Qualified Capacity Resources & Interconnection Process Issues, Term Sheet - Version 3.4, July 2008, http://www.iso-ne.com/committees/comm_wkgrps/relblty_comm/relblty/mtrls/2008/jul292008/fcmq_term_sheet_clean.doc

avoid error of focusing on short-term costs as the long term benefits of the new transmission may take up to 30 years to come to fruition.[38]

The Midwest ISO echoes this opinion of long-term transmission planning. As part of its MTEP plan to address transmission needs outside of the interconnection request queue, the system operator argues that extended planning horizons make it easier to have transmission available when generation comes online.[39]

3.4. CONCLUSION

The "first-come-first-served" approach of FERC requirements on transmission interconnection requests has resulted in backlogs that threaten the attainability of RPS requirements in several states. Some transmission providers have suggested raising the interconnection request deposit required by FERC to eliminate non-viable projects from entering and sitting in the queue. Other transmission providers such as BPA and the Midwest ISO have implemented "open season" and clustering practices where all requests for interconnection filed within a specified time frame are evaluated simultaneously. FERC also has approved the Midwest ISO revisions to suspension rules, removing inactive projects from the queue on a timelier basis. Queuing rules also are being examined as wholesale markets implement market-based mechanisms for attracting generation capacity. These approaches rationalize the queue in a more effective way, contributing to more accurate transmission infrastructure planning and cost estimation.

The following strategies constitute a set of effective practices:

- **Reservation priority** for confirmed interconnection requests over non-confirmed requests. A transmission connection request must continue to earn its ordinal position in the transmission queue or risk moving to the back of the line.
- **Up-front payments** of a magnitude sufficient to let economics dictate which projects should drop out of the queue or not enter in the first place.
- **Open season** that invites all projects to submit requests for transmission, thereby eliminating the first-come-first-served construct and imposing contingencies as part of the acceptance.

38 The Center for Resource Solutions Team. "Achieving a 33% Renewable Energy Target," 2005 http://docs.cpuc.ca.gov/word_pdf/misc/051102_FinalDraftReport_RenewableEnergy.pdf

39 National Wind Coordinating Committee, "Transmission Planning and Wind Energy in the Midwest," June 22, 2005, meeting summary. http://www.nationalwind.org/events/transmission/midwest/2005/summary.pdf

- **Suspension rule revisions** that allow RTOs and ISOs to clear the queue in a timelier basis than the three-year grace period under FERC Order 2003.

- **Integration** of queuing rules into new competitive market mechanisms such as forward capacity markets.

It is important to note, however, that these approaches continue to be under development and their true effectiveness will be subject to actual implementation.

4. PLANNING PROCESSES

Traditionally, the transmission system remained relatively fixed and new generation located itself near the network based on the economics of interconnection. Although additional build-out might be required to connect a large generation unit, such investment was limited to the constraints of the current system. Similarly, industrial load tended to situate itself close to the transmission system, minimizing the cost of connection.

The realities of locationally-constrained resources turn the traditional model upside-down. Whereas generation used to locate next to the network, locationally-constrained resources must balance optimum sites against the economic costs of interconnection to those sites. As this decision may differ according to who pays, society could suffer a net loss as optimal sites for renewable resources are bypassed for connection convenience. Realizing this dilemma, federal, regional, and local regulators, as well as transmission providers and renewable resource developers, have developed new models for transmission planning.

This section describes planning processes that are being implemented in support of locationally-constrained resources. It starts with joint planning that considers both transmission and wind, including regional planning, the cluster approach, and incorporation of multiple facilities into system impact and feasibility studies. This section then extends planning to the formation of transmission planning authorities that have been established by at least seven states and renewable energy zones such as those that have been established by Texas and the western US.

4.1. JOINT PLANNING FOR TRANSMISSION AND LOCATIONALLY-CONSTRAINED RESOURCES

As demand for renewable and other locationally-constrained generation grows, transmission planners are adopting new approaches to incorporate green-field generation into the grid. Increasingly, utilities, RTOs, and state governments are planning transmission systems in conjunction with locationally-constrained resources. This move toward regional transmission planning allows for inclusion of locationally-constrained resources that may lie outside a utility's existing service territory.

To ensure transparent and non-discriminatory access, FERC Order 890 explicitly addresses transmission planning. It forces transmission providers to adopt planning processes on both local and regional levels that meet the following nine planning principles:[40]

- Coordination

[40] FERC, Fact Sheet, FERC Docket Nos. RM05-25-000 AND RM05-17-000, Order No. 890, Final Rule: Preventing Undue Discrimination and Preference in Transmission Service http://www.ferc.gov/industries/electric/indus-act/oatt-reform/order-890/fact-sheet.pdf

- Openness
- Transparency
- Information exchange
- Comparability
- Dispute resolution
- Regional coordination
- Economic planning studies
- Cost allocation

These factors do not explicitly differentiate between locationally-constrained resources and traditional connection requests. However, FERC Order 890 does note that it is meant to address "opportunities for undue discrimination in the application of the pro forma OATT" and there is explicit reference to wind resources that may not have been accommodated on an equal basis under prior rules.[41]

4.1.1. Regional Planning

Historically, transmission planning was performed by an individual utility for that utility's service area. As utilities joined independent power pools, regional planning started to take place. The rise of RTOs and ISOs has furthered regional planning and ad-hoc associations are developing to address adding locationally-constrained resources to the transmission system.

Regional planning is especially important for interconnection of wind resources. The variable and oftentimes uncorrelated output of wind units located in different geographic areas decreases the net volatility of output. The impact of wind on the entire system also is mitigated by balancing geographically dispersed wind resources.[42] Given the realities of operational impacts, it makes sense that planning should address regional impacts instead of locationally-isolated effects. This section describes efforts on the national, regional, and utility level to engage in regional transmission planning.

National

Transmission planning increasingly is being viewed as a national issue. Under the Energy Policy Act of 2005, FERC has authority to permit new transmission facilities within a National Corridor

41 Ibid.

42 Holttinen, Hannele et al. "Design and operation of power systems with larger amounts of wind power," VTT Working Paper 82, 2007. http://www.vtt.fi/inf/pdf/workingpapers/2007/W82.pdf

designated by DOE. In May 2007, DOE proposed two National Interest Electric Transmission Corridors (NIETC) - the Mid-Atlantic Critical Congestion Area and the Southern California Critical Congestion Area. As part of its NIETC study, DOE identified potential wind, geothermal, and solar resources that might be used to meet generation requirements throughout the critical congestion areas.[43]

RTOs/ISOs

Open access and development of RTOs allowed for regional planning across multiple utility areas. Indeed, one of the main functions of RTOs is regional planning. By studying a large region versus a smaller service territory, RTOs may be able to connect locationally-constrained generation in one territory to load centers in another, crossing utility boundaries to the benefit of the region.

The challenge that faces players in the market is to how best reflect the value to existing owners and customers of the existing transmission system. At the RTO/ISO level, this involves providing the proper balance between actions designed to accommodate integration of locationally-challenged generation without compromising the reliability of the networks. RTOs and ISOs are attempting to address this issue through enhancements to their respective regional planning processes.

An example of regional planning to address locationally-constrained areas is Midwest ISO's plans to institute a new category of transmission upgrades called "regionally planned generation interconnection projects," defined as upgrades[44]

> . . . consisting of one or more transmission facilities that are needed to interconnect large concentrations of location-constrained resources, and that are sized to accommodate anticipated interconnections that will be using the upgrades based on current queued requests, long- term portfolio standard requirements and assessment of other drivers of future capacity needs.

All generators in the area would share costs on pro rata basis that will be proposed as a revision to the ISO tariff.[45]

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43 US DOE. "Draft National Interest Electric Transmission Corridor Designations; Notice," May 2007. http://nietc.anl.gov/documents/docs/FR_Notice_NIETC_7_May_07.pdf

44 Smith, Sandy, "An Overview of Current Initiatives to Expand Transmission Infrastructure to Accommodate Utility Interconnection and Integration of Wind Power," presented at DistribuTECH/TransTECH 2008, January 22, 2008. http://www.uwig.org/transtech08/Smith_paper.pdf; see also Midwest ISO, "Expansion Planning," http://www.midwestiso.org/page/Expansion+Planning

45 Ibid.

Various RTOs and ISOs have examined the potential impact of renewable resources on their system. The IEA reports at least 98 studies on the integration of renewable resources into the transmission system for the US as well as the potential impacts of increased connections to such generation.[46] These analyses include the impacts of wind and hydro on a variety of areas, including WAPA, NYSERDA, California, and other regional areas.

Provisional Associations

RTOs are not the only way regional planning can occur. For example, the Rocky Mountain Area Transmission Study (RMATS), created in 2003, identified various transmission projects that should be phased in to provide greater reliability as well as access to locationally-constrained resources.[47] The RMATS process provided an opportunity for wind developers, transmission providers, and regulators to engage jointly in the process of regional planning.

Figure 7: States included in the RMATS process[48]

Source: NREL (2004)

[46] Studies collected as of May 27, 2008. http://www.ieawind.org/AnnexXXV/Publications/IEA_List_of_all_reports%205-27-08.xls

[47] NREL, "Integrating Wind into Transmission Planning: The Rocky Mountain Area Transmission Study (RMATS)," March 2004, NREL/CP-500-35969. http://www.nrel.gov/docs/fy04osti/35969.pdf

[48] Ibid.

Utilities

Utilities themselves also may have incentive to invest in transmission outside of their service region. For example, PG&E is participating in regional planning efforts to access renewable resources from the Pacific Northwest, is contributing to the feasibility study of a line that will deliver renewable power across western states, and is studying the feasibility of developing transmission access to renewable resources in British Columbia.[49]

4.1.2. Cluster Approach

FERC Order 2003, which describes the interconnection request and queuing process, allows for transmission companies to "cluster" interconnection requests that have been filed within 180-days of each other.[50] This clustering approach not only relieves the interconnection request backlog, but it also allows for more effective transmission planning, as each new generation project or upgrade will have network effects throughout the transmission system. Conducting transmission studies on potential new interconnections that may be related simultaneously allows for a more accurate representation of the system for long-term planning.

Transmission providers have noted that the clustering provision in FERC Order 2003 is ineffective as the 180-day period for including interconnection requests is too short to be able to coordinate and cluster multiple requests for transmission service to the same geographical area. Various ISOs have addressed this issue by proposing modifications to its OATT that would allow for retroactive clustering of queued generation projects and establish a clustering approach for future interconnection requests.

Subsequent to its open-season process, BPA applies a clustering approach rather than conducting separate feasibility, system impact, and facilities studies for each of these interconnection requests. BPA analyzed the interconnection requests in a group to determine how much available transfer capability can be offered and which new facilities will be required to accommodate the requests. By taking a clustered approach, BPA was able to predict aggregate net impacts of all interconnection requests, their network interactions, which flowgates would be affected, what infrastructure would be needed, and how the costs of that infrastructure would be recovered.[51]

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49 California Energy Commission. "2007 Integrated Energy Policy Report," 2007. http://dnr.wi.gov/environmentprotect/gtfgw/documents/CEC-100-2007-008-CTD.pdf

50 104 FERC ¶ 61,103, Standardization of Generator Interconnection Agreements and Procedures, Docket No. RM02-1-000; Order No. 2003, Issued July 24, 2003.

51 Bonneville Power Association, "Transmission to offer Network Open Seasons- Meeting our obligations to the next generation," March 2008. http://www.bpa.gov/corporate/pubs/fact_sheets/08fs/Factsheet-Network_Open_Season_March_2008.pdf

CAISO also has adopted a clustering approach under its Waiver Petition in Docket No. ER08-960 by separating pending and anticipated interconnection requests into the following groups:[52]

1. "Serial Study Group" – The petition separates pending "late stage" requests and proposes to analyze them according to their order in the queue, thereby distinguishing this "grandfathered" group of requests from those that will be reviewed under the newly proposed approach.

2. "Transition Cluster" – All other pending interconnection requests as of June 2, 2008, that are not assigned to the Serial Study Group are included in "Transition Cluster."

3. "Initial GIPR Cluster" – All interconnection requests contained in the "Queue Cluster Window" commencing on June 2, 2008.

The Midwest ISO also proposed to perform system impact studies and facilities studies in a group format. If a project exits from the queue during the group study, the Midwest ISO proposes to identify the next highest-queued project and integrate it into the study.[53]

The clustering approach more effectively addresses the backlog of interconnection requests being generated by the multitude of locationally-constrained resources that require connection to the network.

4.1.3. System Impact Studies and Facilities Studies

FERC Order 2003 requires that all interconnection requests undergo an interconnection feasibility study, an interconnection system impact study, and an interconnection facilities study. The transmission provider may conduct these studies in any manner that is standard for the region.[54] The system impact study evaluates the impact of the proposed interconnection on the reliability of the transmission system, and it consists of a short circuit analysis, a stability analysis, and a power flow analysis.[55] The facilities study is done simultaneously with the system impact study and determines the estimated cost of implementing the conclusions of the system impact study.

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52 Motion for Leave to Answer and Answer of the California Independent System Operator Corporation to Comments on and Protests to its Generator Interconnection Process Reform Filing, Docket No. ER08-1317-000, September 2, 2008, http://www.caiso.com/2036/2036c7322d6c0.pdf

53 124 FERC ¶ 61,183, Midwest Independent Transmission System Operator, Inc.,Docket No. ER08-1169-000, Order Conditionally Accepting Tariff Revisions and Addressing Queue Reform, August 25, 2008, P 112.

54 FERC Order No. 2003, section 6.

55 Ibid., section 7.

The cluster approach and open season has implications for system impact/facility studies. When multiple locationally-constrained generation resources request access to the transmission during an open season, multiple parties can be incorporated into system impact/facility studies. This approach facilitates system impact studies that examine the simultaneous impacts of integrating multiple new sources of generation with diversified system load growth. Customers must commit to binding terms and conditions under a Precedent Agreement so that studies can be based upon known commitments. This may clear the queue and may be a potentially superior plan-of-service when compared to sequential studies of potential generation additions. Clustering also is more consistent with the way planning used to be done by vertically integrated utilities. The drawback to it is that in the event of unanticipated withdrawals by one or more projects, a re-determination of the required amount of transmission upgrades may occur, lengthening the time to expand the transmission network.

While FERC Order 2003 was in development, wind power developers expressed a concern that power specifications of proposed project are needed to complete an initial interconnection request. With respect to wind generation, however, these specifications are often the result of the feasibility study. To address this issue, AWEA proposed to FERC that wind plants be allowed to enter the queue and receive base-case data from the transmission planner in order to self-study the feasibility of its proposed project without having to first submit a formal interconnection request. FERC denied this request. However, in the Final Rule, FERC did allow for wind plants to provide a preliminary set of specifications that depict the entire wind plant as a single equivalent generator in terms of its megawatt output and reactive power range in order to enter the queue.[56]

4.2. FORMATION OF TRANSMISSION PLANNING ORGANIZATIONS

Seven states have created transmission planning organizations to research, fund, and implement transmission projects that connect locationally-constrained generation to load centers.

Transmission planning organizations are designed to facilitate transmission infrastructure development in their respective states. The first authority was created in Wyoming in 2004 as a means to move new generation sources to market. South Dakota, North Dakota, Idaho, Kansas, New Mexico, and Colorado followed over the next three years.

Most of the authorities are governed by a board of five to eight directors appointed by the governor of the state and are responsible for issuing revenue bonds for the financing of new projects. In Wyoming and South Dakota, this financing is capped at $1 billion, but in Idaho, Kansas, and New

56 Blakeway, Darrell and Carol Brotman White, "Tapping the Power of Wind: FERC Incentives to Facilitate Transmission of Wind Power," Energy Law Journal 26:397-428. http://www.acore.org/renewableenergyinfo/includes/resource-files/energy_law_journal.pdf

Mexico, there is no maximum bond amount. Most of the infrastructure authorities are involved in transmission development, ownership, and operations, with the exception of Kansas, which has to contract out operations. In New Mexico, each transmission project financed by the infrastructure authority must source at least 30 percent of the energy from renewable resources. In Colorado, the infrastructure authority was created specifically to facilitate the production and consumption of "clean energy" and has a broad focus including transmission, transportation, equipment manufacturing, and storage of clean energy.[57]

Minnesota has adopted a slightly different approach, relying upon a consortium of utilities that are analyzing and promoting a series of transmission investments, known as CapX 2020. CapX 2020 is a joint transmission planning effort among 11 utilities (including investor-owned utilities, electric cooperatives, and municipal utilities) that own transmission lines and serve the majority of customers in Minnesota and the surrounding region. The region expects significant electricity growth in the coming decade while meeting the recently implemented Minnesota Renewable Energy Standards statute that requires most utilities in the state to source 25 percent of their retail energy usage from renewable energy sources by the year 2025. Planning studies conducted by the CapX2020 organization identified four transmission lines that are needed in the region for local reliability, regional system reliability, and generation outlet. These lines are currently in the Certificate of Need review process before by the Minnesota Public Utilities Commission and include:[58]

- CapX 2020 Fargo, N.D.–St Cloud-Monticello 345-kV project
- CapX 2020 Southeast Twin Cities–Rochester–La Crosse 345-kV project
- CapX 2020 Brookings, S.D.–Southeast Twin Cities 345-kV project
- CapX 2020 Bemidji-Grand Rapids 230-kV Project

4.3. RENEWABLE ENERGY ZONES

A current trend in regional planning with respect to locationally-constrained resources is the establishment of renewable energy zones. Rather than individual wind generators requesting interconnection from transmission companies, transmission planners first identify areas that are best suited for wind generation and plan the transmission processes and infrastructure that will be needed to connect these areas to high load areas before new generation is developed. Renewable energy zone planning is underway in Texas, and US DOE has agreed invest up to $2.3 million to help identify

57 See National Wind Coordinating Collaborative, Transmission Update, October 2007. http://www.nationalwind.org/pdf/NWCCtransmissionupdateOct07FINAL.pdf

58 CapX2020 website: http://www.capx2020.com/Projects/index.html

zones throughout the western United States.[59] Federal legislators also have shown an interest, proposing legislation to identify nationwide renewable energy zones and lauded this approach as a way to eliminate the chicken-egg dilemma where generation will not be built without transmission lines to connect to load and transmission will not build to a location without facilities that require connection.[60]

4.3.1. Texas Competitive Renewable Energy Zones

Texas Senate Bill 20, which was introduced to raise the state's RPS targets, instructs the PUC to designate competitive renewable energy zones (CREZ) that are sufficient to develop the new wind generation capacity required under the RPS and to develop a plan to construct transmission capacity to deliver to customers the electric energy from these zones.[61] In December, 2006 ERCOT published a report that identifies the geographic areas best suited for wind development.[62] In July 2007, PUCT designated eight areas as CREZs, which were then combined into five zones in Uptown County, Abilene, Sweetwater, and the Panhandle.[63] ERCOT was then ordered to study certain tiers of transfer capability ranging from 12,000 MW to 24,000 MW. In April 2008, ERCOT released the final study. The Final Order designating the CREZs was issued in October 2007 by the PUCT. The CREZ system could result in up to 18,000 MW of wind capacity in Texas.[64]

The PUC has designated four scenarios for levels of wind power generation in each of the CREZs (ranging from 18,000 to 24,000 MW), and ERCOT was ordered to develop optimal transmission plans for each scenario. ERCOT sought transmission plans that would meet three overarching criteria: system reliability, sufficient transfer capacity, and cost-effectiveness, but it notes that other criteria such as plan flexibility, the potential for expansion, transmission-siting considerations, equitable distribution of wind generation curtailment, and the potential for the plan to meet a distribution of wind generation different from that specified in the PUCT Order. The ERCOT report was issued in April 2008.[65]

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59 US DOE, "DOE to Invest up to $2.3 million to Identify Renewable Energy Zones in Western United States," May 28, 2008. http://www.doe.gov/news/6284.htm

60 Ibid.

61 Texas Senate Bill No. 20, effective September 1, 2005. http://www.capitol.state.tx.us/BillLookup/Text.aspx?LegSess=791&Bill=SB20)

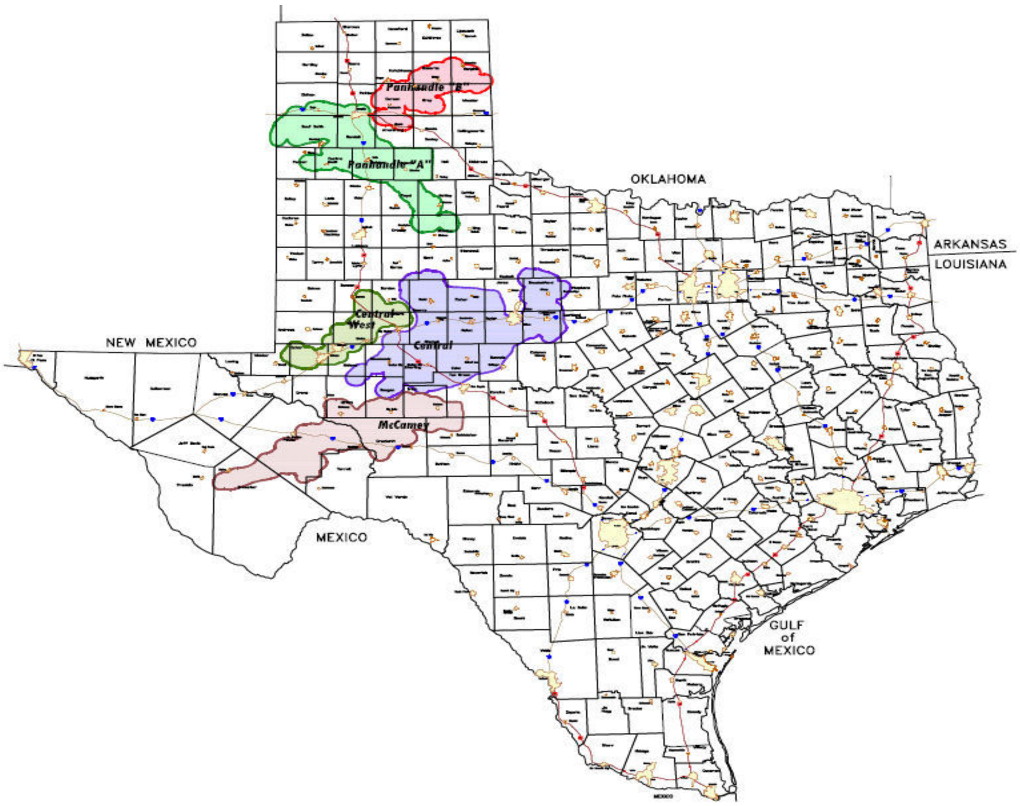
62 ERCOT, "Analysis of Transmission Alternatives for Competitive Renewable Energy Zones in Texas," 2008. http://www.ercot.com/news/presentations/2006/ATTCH_A_CREZ_Analysis_Report.pdf

63 Texas State Energy Conservation Office, "Wind Energy Transmission," July 22, 2008. http://www.seco.cpa.state.tx.us/re_wind-transmission.htm

64 ERCOT, Competitive Renewable Energy Zones Optimization Study, 2006.

65 Ibid.

Figure 8: Texas Renewable Energy Zones[66]



Source: ERCOT

In July 20, 2008, the PUC issued their Final Order selecting the transmission plan scenario that will accommodate approximately 18,000 MW of additional wind capacity. The cost of the transmission lines will be socialized across all consumers on the Texas system. Current activities in Texas are focused on selecting the transmission service providers (TSP) to build the designated transmission plan. Additional details continue to develop.[67]

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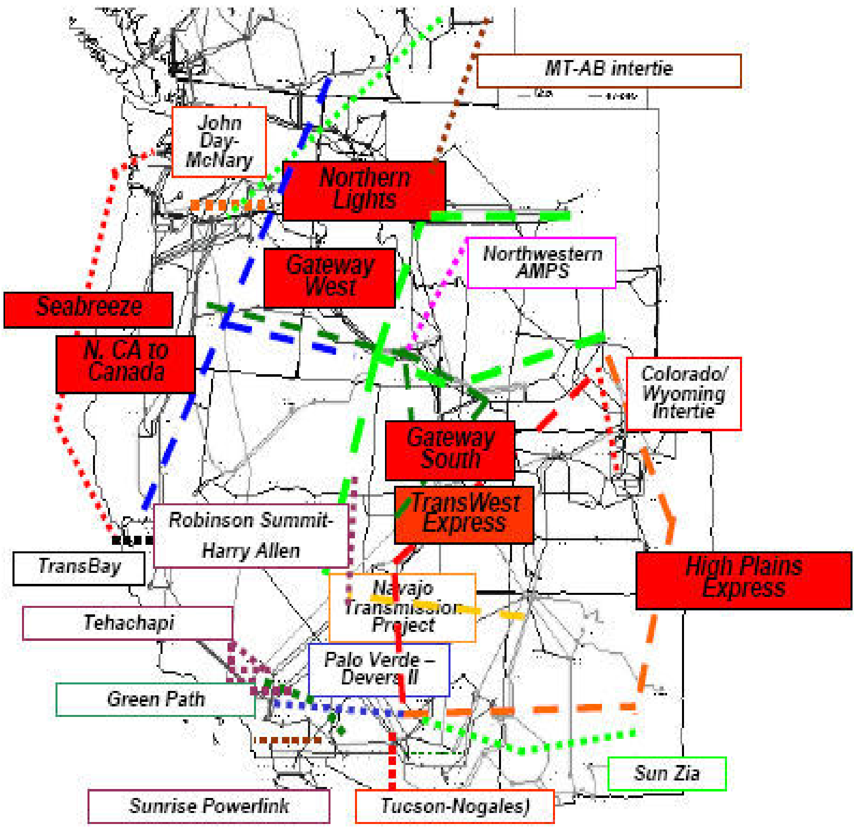
66 ERCOT, Planning Section on CREZ , http://www.ercot.com/news/presentations/2007/CREZ-11-02-07_public.pdf

67 Docket No. 35665, Commission Staff's Petition For Selection Of Entities Responsible For Transmission Improvements Necessary To Deliver Renewable Energy From Competitive Renewable Energy Zones, Public Utility Commission of Texas, Order No. 19, Establishing Procedural Schedule, July 22, 2008.

4.3.2. Western Renewable Energy Zones

Another renewable energy zone involves 11 major states in Western US, the area of Mexico, and the two Canadian provinces that comprise Western Interconnection. In May 2008, DOE joined with the Western Governors' Association to identify areas in the western United States with widespread renewable energy resources. The development of these areas, known as Western Renewable Energy Zones (WREZ), will focus on regional planning and will involve regional transmission plans and interstate cooperation to address permitting and cost-allocation issues.

Figure 9: Proposed Transmission Projects under Western Renewable Energy Zones[68]



Source: Larson (2008)

68 Larson, Doug "From Concept to Reality: How the Western States and Industry Address the Need for a Balanced Resource Mix and the Transmission to Get the Power to Load," 2008. http://www.psc.state.mt.us/WCPSC2008/pdf/Powerpoint/pdf/panel22Larson.pdf

Arizona, California, Colorado, Nevada, New Mexico, Utah, and Wyoming each are working to identify renewable energy zones in their states. Although restricting generation and transmission development to in-state resources could lead to less efficient use of the renewable resources that are available across the Western Interconnection, benefits of the multi-state approach taken in the WREZ initiative include economies of scale, optimal line loadings, more liquid markets, a more robust regional transmission system, lower costs, and attention to environmental considerations.[69]

For example, California has established the Renewable Energy Transmission Initiative (RETI), a statewide initiative to help identify the transmission projects needed to accommodate California's renewable energy goals. RETI is assessing potential competitive renewable energy zones in California and surrounding areas that have a high potential for renewable resource generation. As part of this process, RETI is preparing detailed transmission plans for those zones identified for development. RETI is supervised by a committee representing the California Public Utilities Commission (CPUC), California Energy Commission (Energy Commission), California Independent System Operator (California ISO), and Publicly-Owned Utilities (SCPPA, SMUD, and NCPA).[70]

Other states also have moved forward with identifying renewable energy zones within their borders.

4.3.3. Federal Proposals

Senate Majority Leader Harry Reid, a Nevada Democrat, crafted federal legislation (S. 2076) that would enable the president to designate national renewable energy zones. The legislation would direct the President to identify geographical areas rich enough in renewable resources to be able to generate at least 1,000 MW of electricity. Federal power marketing administrations such as the Western Area Power Administration, Bonneville, Southeastern, Southwestern, and TVA would identify the best transmission route to those areas. If no private entities stepped forward to construct the transmission lines, the power marketing administrations would receive $10 billion each to finance construction of those lines for which at least 75 percent of the capacity is dedicated to renewable electricity.[71]

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69 Western Governors' Association Workplan to Identify Renewable Energy Zones and Associated Transmission in the Western Interconnection, April 21, 2008 http://www.westgov.org/wga/initiatives/wrez/wrez-workplan.pdf

70 The California Energy Commission, http://www.energy.ca.gov/reti/index.html

71 Press Release, "Reid Introduces Bill To Spur Nevada's Renewable Energy Industry," September 20, 2007. http://relbid.senate.gov/newsroom/pr_092007_energy.cfm

4.4. CONCLUSION

A common approach to the integration of locationally-constrained resources is regional planning. Examining large geographical areas for renewable resource potential allows for greater opportunities to connect optimal generation sources to the load centers where energy is most needed. Identifying concentrated areas of locationally-constrained sources can increase the efficiency of the transmission system while meeting demand for renewable resources. Regional planning is not limited to RTOs. Individual states such as California and Texas have embarked on planning, and the Western Governors' Association has identified Western Renewable Energy Zones. In addition, federal legislators are supporting these efforts and promoting similar programs on a national level.

In regional planning, various stakeholders such as regulators, generation developers, and load serving entities must work together to define multi-state resource development and markets to facilitate planning and select the appropriate plan. This multi-state or regional need contrasts with the needs and approaches utilized in single states such as Texas and California. Indeed, as locationally-constrained resources are benefiting from a general move towards regional planning through RTOs and ISOs and in recognition of the need to meet RPS requirements, individual states also are implementing planning approaches that incorporate locationally-constrained generation resources. Effective practices that have been put into action include the following:

- **Regional planning** through RTOs, ISOs, states, or voluntary organizations.
- **Wind penetration studies** that estimate in advance the potential impact of different levels of wind generation on transmission systems.
- **Clustering** different projects into a single set of feasibility and impact studies, decreasing the time spent in the queue due to more efficient implementation of required milestones.
- **Regional joint planning organizations** to support transmission projects that connect location-constrained generation to load centers.
- **Renewable energy zones** that focus on regional planning, regional transmission plans, and interstate cooperation to identify potential transmission investment to connect locationally-constrained areas and address associated permitting and cost-allocation issues.

5. OPERATIONAL AND REGULATORY ACCOMMODATIONS

Most regulations have been developed for a system dominated by fossil-fuel generation. In response to the increase in locationally-constrained generation and the variable characteristics of many renewable resources, various regulatory accommodations have been made on both the federal and local levels. This section summarizes effective practices for such regulatory accommodations.

When renewable resources compose a negligible portion of the system, transmission providers essentially can ignore their varying output, which hits the system similar to natural load fluctuations.[72] Indeed, while those areas with limited wind resources and generation such as New England and PJM may have very few explicit concessions built into their operations or rules, states with significant wind resources and proposed renewable generation have been willing to allow favorable treatment for the varying nature of renewable resource output. At the same time, technology and different configurations have minimized the potential impact of renewable resources on the system.

The ability to mitigate the impacts of variable output on the transmission system has made some view the concept of "intermittency" as an archaic term. A guest editorial on the IEEE Power Engineering Society website describes how far technology has come:[73]

> The other term we need to examine is intermittent. I often hear wind referred to as an intermittent resource. This is another term out of the distant past. To most people, the term intermittent means a random sort of unpredictable on-off behavior. This term is usually used in a negative sense. The understanding conveyed is that the output of the plant cannot be predicted and that it rapidly goes from no-load to full-load conditions, or vice versa. While this view was prevalent after looking at the output of a single wind turbine, before we had sufficient data to understand the behavior of large, modern wind plants, it is no longer the case . . . As a result of this improved understanding of the behavior of wind plants, we are making a transition away from the term intermittent to *variable output*, which describes much more accurately the nature of the quantity with which we are dealing.

In keeping with this observation, this report does not use the term intermittent or intermittency to refer to the varying output of renewable resources unless referencing a quote or discussing specific programs that target "intermittent" generation. Instead, the operational characteristics of locationally-constrained are referred to as "variable." This section describes the manner in which different jurisdictions are accommodating the variable operational characteristics of renewable resources in their regulations, markets, and technical requirements.

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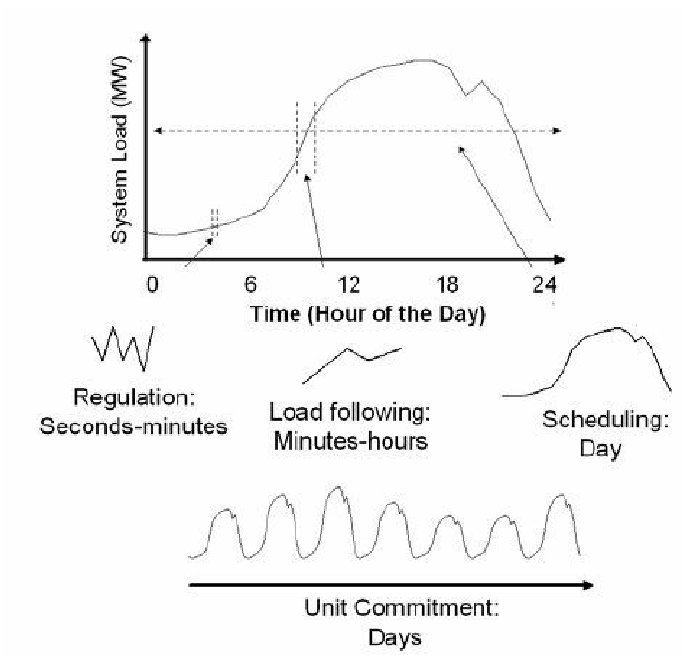
[72] Exceptions occur when wind generation is located on the periphery of power systems and wind generation levels are significant in relation to local network capabilities, leading to network constraints.

[73] IEEE Power Engineering Society Guest Editorial, J. Charles Smith and Brian Parsons, http://www.ieee.org/organizations/pes/public/2007/nov/pesguesteditorials.html

5.1. ADDRESSING VARIABILITY

Significant development of renewable resources has forced transmission providers and system operators to consider effective ways to address the impacts of variable output in theory. The need to address variable generation in practice occurs when significant declines in renewable generation occur simultaneously with rising load.[74] Although solar, run-of-river hydro, and wind all have variability, technological advances in wind turbines versus solar or hydro, as well as the more sporadic and directional nature of wind as a resource, has focused industry discussion on wind.

Figure 10: Time Frames for Dispatch and Variable Resource Impacts[75]



Source: NREL (2006)

74 For instance, this happened in ERCOT during the afternoon of February 26, 2008 when, over the course of three hours, wind production fell from more than 1,700 MW to 300 MW, coinciding with rising electricity demand. Electric Reliability Council of Texas and Public Utility Commission of Texas, ERCOT's Operations Report on EECP Event of February 26, 2008, Project No. 27706. http://interchange.puc.state.tx.us/WebApp/Interchange/Documents/27706_114_577769.PDF

75 NREL, "Grid Impacts of Wind Power Variability: Recent Assessments from a Variety of Utilities in the United States," Conference Paper, NREL/CP-500-39955, July 2006, p. 2. http://www.nrel.gov/wind/systemsintegration/pdfs/2006/parsons_wind_grid_impacts.pdf

As reproduced by Smith, Parsons, et. al. (2007). http://www.uwig.org/EWEC07paper.pdf

Figure 10 illustrates the timeframes traditionally of interest in dispatch. In addressing system impacts, studies generally address regulating the key timeframes that correspond to traditional transmission operations: system dynamic stability studies (milliseconds to seconds), regulation (several seconds to minutes), load following (10 minutes to a few hours), and scheduling (few hours to day ahead).

Various studies have estimated the impact of significant penetration of wind on transmission systems in each of the areas of operations. In general, the incremental impact on transmission costs over the next five to ten years are expected to be low, as existing capabilities are sufficient or nearly sufficient to handle proposed levels of wind integration, but costs increase exponentially with the level of penetration.

The highest impacts appear to be associated with the unit commitment and scheduling time domain -- in the range of $2 to $5 per MWh of wind output. This comes about because thermal units tend to have start times that require they be scheduled a day ahead as well as impacts due to scheduling/dispatch of the gas transportation system. Uncertainty due to the output of wind generation may require that more uneconomic resources be committed. The associated cost impact, while estimated in some studies, is not readily visible under the current market structures -- it may show up as higher uplift costs, but it is not calculated explicitly. As described in section 5.4.2 on scheduling and section 5.4.3 on imbalances, market penalties associated with discrepancies usually are relaxed for renewable resource generation.

Impacts for load following and regulation are estimated at negligible levels. In restructured markets, there generally are sufficient market signals and compensation to provide regulation (often called automatic generation control or AGC) and operating reserve. Modest increases in requirements due to high levels of wind penetration could result in explicit compensation for dynamic load following (i.e., ramping capability) that have been adopted in certain jurisdictions. Table 2 summarizes estimated impacts on transmission system operations.

Table 2: Wind Impacts on Transmission System Operating Costs[76]

Date	Study	Wind Capacity Penetration (%)	Regulation Cost ($/MWh)	Load Following Cost ($/MWh)	Unit Commit-ment Cost ($/MWh)	Gas Supply Cost ($/MWh)	Total Operating Cost Impact ($/MWh)
May 03	Xcel-UWIG	3.5	0	0.41	1.44	na	1.85
Sep 04	Xcel-MNDOC	15	0.23	na	4.37	na	4.60
July 04	CA RPS Phase III	4	0.46 (1)	na	Na	na	na
June 03	We Energies	4	1.12	0.09	0.69	na	1.90
June 03	We Energies	29	1.02	0.15	1.75	na	2.92
2005	PacifiCorp	20	0	1.6	3.0	na	4.6
April 06	Xcel-PSCo	10	0.20	na	2.26	1.26	3.72
April 06	Xcel-PSCo	15	0.20	na	3.32	1.45	4.97

Source: NREL (2006)

5.1.1. System Balancing

A general approach to addressing the impacts of variable output from renewable resources is to consolidate balancing areas into larger entities or access a larger resource base through dynamic scheduling. Just as load diversity aggregated over large areas reduces the magnitude of peak load, wind diversity reduces the magnitude and frequency of the tails on the variability distributions, reducing the number of hours during which the most expensive units on the supply curve will be dispatched.[77] To this end, RTOs and ISOs have an advantage by virtue of how their systems are organized. Individual utilities are addressing the benefits of consolidating service areas on a case-by-case basis.

Balancing systems can be combined physically or virtually. Physically combining balancing areas is straightforward but may not always be desirable. Two or more balancing areas can retain their

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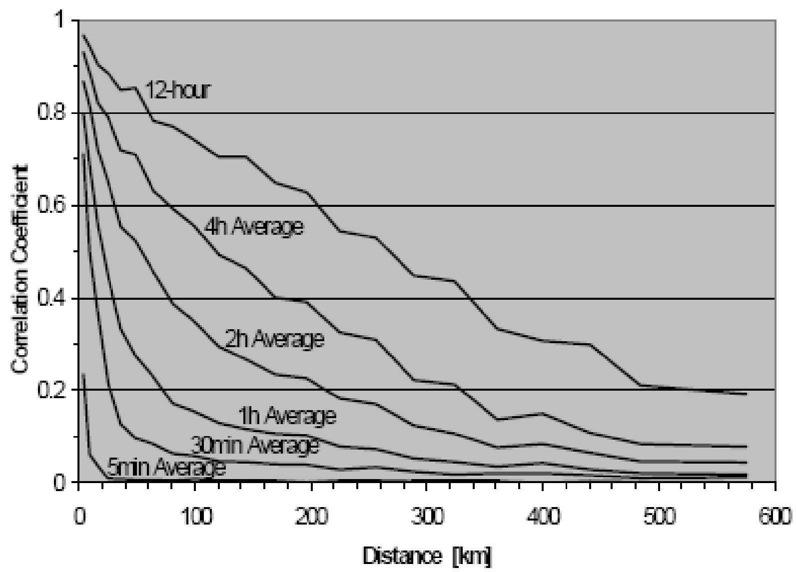
76 NREL, "Grid Impacts of Wind Power Variability: Recent Assessments from a Variety of Utilities in the United States," Conference Paper, NREL/CP-500-39955, July 2006, p. 9. http://www.nrel.gov/wind/systemsintegration/pdfs/2006/parsons_wind_grid_impacts.pdf

77 Smith, J. Charles et al. (2007), "Best Practices in Grid Integration of Variable Wind Power: Summary of Recent US Case Study Results and Mitigation Measures." http://www.uwig.org/EWEC07paper.pdf

autonomy and still capture much of the aggregation benefit by electronically combining their Area Control Errors (ACE), and allocating a portion of the combined ACE so that reliability is met at lower cost. If operations could be coordinated, much of the ramping and associated costs could be eliminated.

Figure 11: Smoothing Effects of Geographical Dispersion on Output Variations[78]



Source: Ernst, Wan and Kirby (1999)

Figure 11 illustrates how balancing over a large geographical area counteracts the variability of renewable resources. Natural offsetting patterns between wind output located in different geographical areas decreases the number of zero output hours and the impact of wind on the transmission system.[79]

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78 Ernst, Wan and Kirby (1999), Figure 7. http://www.ornl.gov/sci/btc/apps/Restructuring/STpowerfluct_windturb.pdf

79 Short-term Power Fluctuation of Wind Turbines: Looking at Data from the German 250 Mw Measurement Program from the Ancillary Services Viewpoint, B. Ernst, Y. Wan and B. Kirby 1999, American Wind Energy Association Windpower '99 Conference, Washington, DC, June. http://www.ornl.gov/sci/btc/apps/Restructuring/STpowerfluct_windturb.pdf

IEA, "Variability of Wind Power and Other Renewables Management Options and Strategies," 2005. http://www.iea.org/Textbase/Papers/2005/variability.pdf

The benefits of large electricity markets apply to systems around the world. Balancing large geographic areas with dispersed load and wind resources reduces the cost of integration and the cost of serving load. These results are corroborated by the New York State wind integration study that found combined operation of the eleven zones in the New York State power system reduces hourly and five-minute variations in both wind and wind combined with load. Their findings concluded:[80]

- **Hourly load** variability was reduced by 5 percent
- **Five-minute load** variability was reduced by 55 percent
- **Hourly wind** variability was reduced by 33 percent
- **Five-minute wind** variability was reduced by 53 percent

Considering load and wind together,

- **Hourly system** variability is further reduced by 10 percent
- **Five-minute system** variability is further reduced by 15 percent

Given the technical realities of managing an electric transmission system, operational impacts of wind resources must be balanced in conjunction with the entire system.

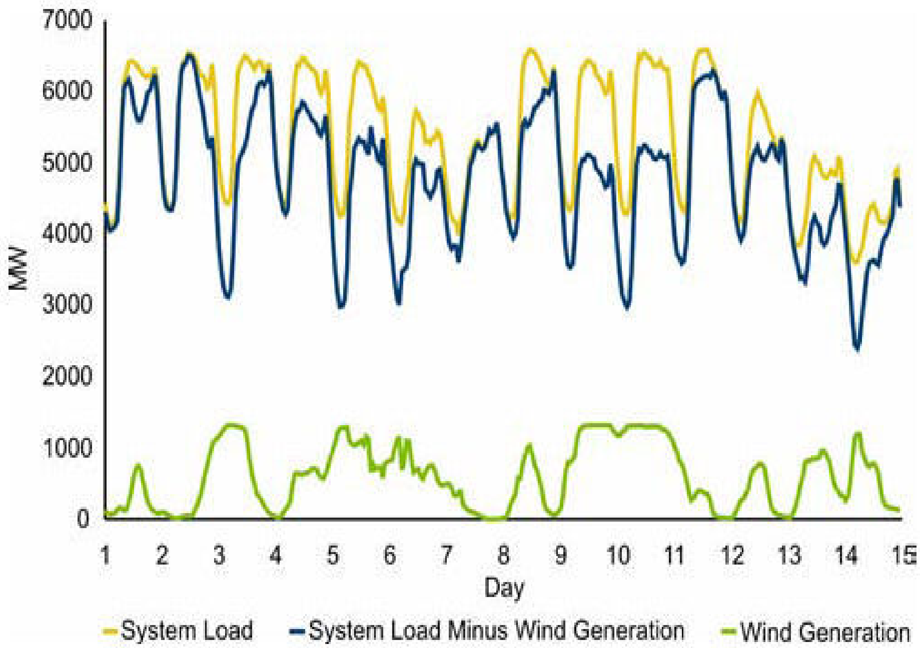
5.1.2. Dynamic Load Following

Just as variations in load requires dynamic load following, variations in renewable resource output require similar treatment, albeit at a reduced level if addressed over a larger geographical area. Whereas load following used to be a standard part of system operations, however, some transmission providers are suggesting that there be a new market for these services.

Figure 12 illustrates how wind can offset system load while at the same time changing its shape. As already mentioned, combining load variability with uncorrelated wind variability can decrease overall variability in the hourly and even five-minute timeframes. However, combining the two can result in significant changes to the load shape, impacting load following requirements.

80 NREL, "Facilitating Wind Development: The Importance of Electric Industry Structure," Technical Report NREL/TP-500-43251, B. Kirby and M. Milligan, May 2008, referencing the 2005 GE study. http://www.nrel.gov/wind/systemsintegration/pdfs/2008/milligan_facilitating_wind_development.pdf

Figure 12: Hourly Load Shapes with and without Wind[81]



Source: US DOE (2008)

The impact may be even more significant in those regions with other system constraints. For example, the Pacific Northwest is rich in hydroelectric resources, but operationally-constrained by fish protection, recreation and other uses. As a result, Bonneville's system may have difficulties integrating proposed wind projects unless it can develop more flexible resources. As part of its implementation of 16 recommendations to address wind impacts, Bonneville is developing a separate product for dynamic load following that "will enable Northwest utilities to buy and sell system flexibility services."[82] As smart meters, smart grids, and other automated load control systems are put in place, new suppliers may enter the market to provide flexibility services in ways that currently are not possible. Combining technological advances with market-based incentives may produce a new line of load following resources to allow Bonneville and other jurisdictions to integrate wind into their systems.

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81 US DOE, "20% Wind Energy by 2030: Increasing Wind's Contribution to US Electric Supply," May 2008. http://www1.eere.energy.gov/windandhydro/pdfs/41869.pdf

82 "Meeting Summary," Increasing Renewable Energy in the Western Grid Summit, September 27-28, 2007, Ft. Collins, CO. http://www.nationalwind.org/pdf/IncreasingRenewableEnergyintheWesternGridsummaryFINAL.pdf

5.1.3. Voltage and Reactive Power

With low wind energy penetration levels, there historically has been little need in most jurisdictions for wind farms to contribute to support voltage or participate in meeting reactive power demands. This was opportune because traditional technology underlying wind turbines were not able to control their voltage. This has changed with new technological advances.

FERC Order 661-A, referred to as the "limited grid code for wind plants," addressed concerns of wind turbine manufacturers and wind power developers who sought standardized interconnection requirements. Lack of standardization across the country may increase manufacturing costs and be a barrier to the development of this renewable resource. Yet, transmission providers required wind generation to install those technologies that would protect the system from the impacts of variable generation output. FERC Order 661-A allows transmission providers to impose the following requirements on large wind plants as required:[83]

1. **Operations:** Maintaining operations during system voltage disturbances.

2. **Technical:** Meeting the same technical criteria for providing reactive power to the grid as required of conventional large generating facilities.

3. **Communications:** Communicating supervisory control and data acquisition (SCADA) to ensure appropriate real-time communications and data exchanges between the wind power producer and the grid operator.

Wind generators generally cannot provide reactive power and are in fact consumers of reactive power. After these requirements took effect in December 2005, large wind power plants were required to meet the low voltage ride-through and reactive power standards but only if the transmission system operator could demonstrate they were needed to safely and reliably connect each wind facility to its system. These requirements often are met and mitigated by the installation of appropriate dynamic compensation systems at the points of connection.

5.1.4. System Frequency

The variability and the unpredictability of wind means that a wind farm with unconstrained operations will not meet the basic requirement of delivering the stated output within a specified voltage range under steady state conditions. Generators contribute to power system frequency regulation by controlling the primary energy supply rates to generator prime movers, an option not available to wind farms where wind cannot be controlled. What is possible is to control energy extraction rates, limiting

83 FERC Order 661-A. http://www.ferc.gov/EventCalendar/Files/20051212171744-RM05-4-001.pdf

the turbine power output to levels lower than what existing wind flow levels allow to the detriment of the wind operator who already faces relatively low capacity factors.

5.2. AGGREGATION BEHIND THE METER (I.E., "NATURAL GAS GATHERING MODEL")

As already discussed, broadening the geographic area and resources offsets the variability inherent in most renewable resources. A similar effect can be accomplished by combining multiple wind resources behind the meter. Whereas balancing can be consolidated either physically or virtually, aggregation behind the meter requires physical combination.

Although the power measurement from a single wind turbine has a large fluctuation of output power, the power fluctuation from one turbine may cancel that of another, which mitigates power fluctuations from the connection to a wind farm. A comparison of output indicates the smoothing effect that aggregation of multiple wind generators behind the transmission meter creates. Table 3 indicates that both the average generation and standard deviation of the group of generators tends to decrease within the same time interval as more generating units are added.

Table 3: Wind Generation Variability as a Function of Number of Generators[84]

		14 Turbines (%)	61 Turbines (%)	138 Turbines (%)	250+Turbines (%)
1-Second Interval					
	Average	0.4	0.2	0.1	0.1
	Std. Dev.	0.5	0.3	0.2	0.1
1-Minute Interval					
	Average	1.2	0.8	0.5	0.3
	Std. Dev.	2.1	1.3	0.8	0.6
10-Minute Interval					
	Average	3.1	2.1	2.2	1.5
	Std. Dev.	5.2	3.5	3.7	2.7
1-Hour Interval					
	Average	7.0	4.7	6.4	5.3
	Std. Dev.	10.7	7.5	9.7	7.9

Source: US DOE. Std. Dev. is the abbreviation for standard deviation.

84 US Department of Energy, "20% Wind Energy by 2030: Increasing Wind Energy's Contribution to US Electricity Supply," Prepublication Version, May 2008, Figure 1-8, p. 11. http://www1.eere.energy.gov/windandhydro/pdfs/41869.pdf

Interconnecting multiple wind generating units behind the meter is a simple way to reduce volatility and frequency disturbances on the network caused by sporadic wind resources. Interconnecting different sites in an array decreases the correlation of wind speed among the sites and acts more like a single farm with steady wind speed and constant wind power.[85] This smoothing effect can reduce volatility within the hour and over multiple hours, reducing the reserve requirement needed for any subset of wind generation.[86]

As illustrated in Table 3, the smoothing effect on output can be substantial. Power/voltage fluctuations on the transmission system also are reduced by combining multiple units. An NREL study by Jan T. Bialasiewicz and Eduard Muljadi concluded that wind farms with turbines spanning larger areas have a more diverse wind profile that drives each turbine, but wind farms with more small turbines create fewer power/voltage fluctuations on the power grid.[87]

There does not appear to be any specific initiatives underway to require aggregation of multiple generators or windfarms behind the meter. However, windfarms as a general rule perform this function. Renewable energy zones and clustering lay the foundation for co-locating multiple renewable resources in a similar geographical area that can be arrayed together behind the transmission interconnection meter and compensated at market rates (or under bilateral contracts) according to their metered unit generation.

5.3. COMBINING VARIABLE RENEWABLE RESOURCES

The same way balancing territories and aggregation behind the meter can smooth variability, combining wind with other renewable resources, such as solar, creates a symbiotic relationship that smooths the volatility normally associated with a single resource. In the US, wind power generally is generated during the evening, and slows down significantly as the day begins. As wind ramps down, however, solar power ramps up. Alone, each contributes wide variations in load, frequency, and voltage to the transmission system. Together, however, their variability offsets each other, delivering a smooth and constant power stream to the system.

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85 Archer, Christine and Jacobson, Mark (2006). "Supplying Baseload Power and Reducing transmission requirements by interconnecting wind farms." Journal of Applied Meteorology and Climatology, 46, pp. 1701-1717.

86 "Utility Wind Integration and Operating Impact State of the Art" J. Charles Smith, Senior Member, IEEE, Michael R. Milligan, Member, IEEE, Edgar A. DeMeo, Member, IEEE, and Brian Parsons, IEEE TRANSACTIONS ON POWER SYSTEMS, VOL. 22, NO. 3, August 2007. http://www.nrel.gov/docs/fy07osti/41329.pdf

87 J.T. Bialasiewicz and E. Muljadi, "The Wind Farm Aggregation Impact on Power Quality," **Preprint,** National Renewable Energy Laboratory, To be presented at the 32nd Annual Conference of the IEEE Industrial Electronics Society (IECON '06), Paris, France, November 7–10, 2006 , **Conference Paper, NREL/CP-500-39870,** http://www.nrel.gov/wind/pdfs/39870.pdf

While solar energy production is more predictable than wind energy production, it does have distinctly variable components. It is non-existent during night-time and is reduced by cloud cover, dust storms, or even high winds that can affect the focus of the solar beam into thermal troughs. Because of its variable nature, solar energy production is included in the California RPS and the PIRP. Indeed, CAISO has even developed forecasting methodologies for solar that would be incorporated into its scheduling.

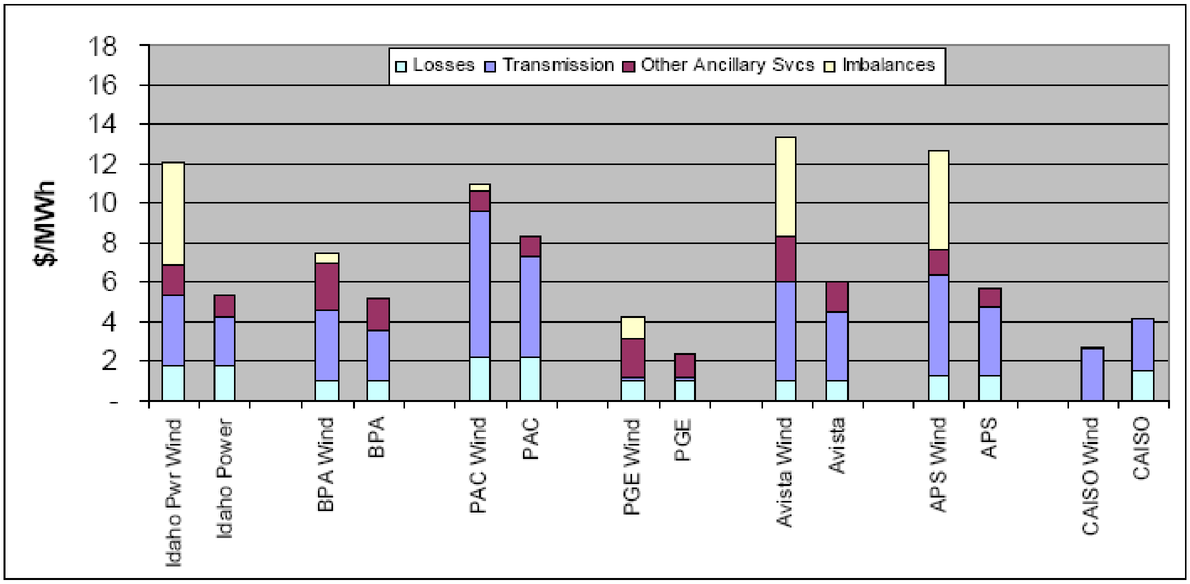
An operations analysis report for CAISO provides a very extensive analysis of the operational challenges from large amounts of renewable resources.[88] They have shown the combined effects of load variability, wind variability, and solar variability can reduce the variability of the entire fleet. This combination, however, is likely to be useful only in those regions that have favorable solar conditions (i.e., California and southwestern US). Furthermore, it is not clear that combining with solar creates a naturally more optimal combination than combining with any other flexibly-dispatched generator such as gas, hydro, or even demand-side response.

5.4. Clemency Granted to Variable Generation Resources

Early in market design, jurisdictions considered treating renewable resources differently in light of their operational realities and political impact. Operating under FERC Order 888, which did not grant special privileges to wind resources, many transmission providers petitioned the Commission to approve certain exemptions. The basis for their petitions was that FERC regulations were discriminatory against variable resources such as wind facilities. As part of the technical conference to examine this issue, FERC staff prepared the following analysis, estimating transmission costs for wind versus combined cycle gas turbine (CCGT) units.

[88] CAISO Integration of Renewable Resources Report, November 2007. http://www.caiso.com/1ca5/1ca5a7a026270.pdf

Figure 13: Cost Comparison of Transmission for Wind versus CCGT Plants[89]



Source: FERC analysis, derived from data in OATT Tariffs, NREL, CAISO, PacifiCorp, FERC OMTR, FERC OMOI

Following the technical conference, FERC issued various orders explicitly addressing how wind should be treated in transmission tariffs. This section addresses the operational and tariff exemptions offered to variable resources in the areas of ancillary services, scheduling, imbalances, line losses, transmission pricing, and other dispatch rules.

5.4.1. Ancillary Services

Ancillary services include those activities required to keep the transmission system operational, including regulation of variations in system supply and demand less than ten minutes, load-following for variations of ten minutes to a few hours, and scheduling of real-time and day-ahead generating commitments. Originally expected to be a discriminatory aspect of market design for renewable

89 United States of America Federal Energy Regulatory Commission, Assessing the State of Wind Energy In Wholesale Electricity Markets, Docket No. AD04-13-000, Notice, Agenda and Staff Paper for the December 1, 2004 Technical Conference on Wind Energy (November 22, 2004), p.25. http://www.ferc.gov/EventCalendar/Files/20041122142848-ad04-13.pdf

Note: Calculations based on OATT tariff schedules; 55% capacity factor for CCGT and 38% capacity factor for wind; scheduling imbalance error of 1% for CCGT and 20% for wind; $50/MWh average system price for power; CAISO rate based on SCE TAC rate.

resources, ancillary services have not created a burden. Most markets impose the charge for ancillary services on load, not generators, and the calculation of the costs for ancillary services tends to be for the entire system as opposed to allocations to individual generators. Therefore, even though most renewable resources generally do not provide ancillary services and may impose greater costs on the system, those costs are passed through to end-users. Renewable resources obtain their revenues primarily through markets for energy and renewable energy credits.

Table 4: Market Rules for Ancillary Services[90]

RTO/ISO	Ancillary Services Rules
CAISO	Wind does not participate in ancillary services market.
ERCOT	All costs associated with ancillary services are borne by loads, not generation.
Midwest ISO	Midwest ISO is about to start its ancillary services market and is currently performing testing. Services and requirements are specific to each regional reliability organization in Midwest ISO (MAPP, ECAR, MAIN).
ISO-NE	ISO-NE has well-developed markets for regulation and various kinds of reserve.
NYISO	Wind does not participate in ancillary services markets, but is not precluded from doing so.
PJM	Wind does not participate in ancillary services markets. No near-term impact expected on the level of ancillary-services requirements in the market due to wind based on limited resources.
SPP	SPP does not offer ancillary services directly, since SPP is not a control area operator. As under Order 888, SPP can act as the transmission customer's agent to procure ancillary services.

5.4.2. Scheduling

Wholesale power markets typically require that power from generators be scheduled in advance to allow transmission providers to meet real-time demand more reliably. In most cases, scheduling is done on a day-ahead basis, but in some instances schedules can be revised up to 20 minutes in

90 Utility Wind Interest Group, "Wind Power and Electricity Markets: A living summary of markets and market rules for wind energy and capacity in North America," Market Operation and Transmission Policy Best Practices Users Group, Information compiled through December 1, 2004. Updated through 2008. http://www.ferc.gov/EventCalendar/Files/20041213162331-UWIG%20Handout.pdf

advance. Once scheduled, generators or their scheduling agents are obligated to provide power to the network in accordance with the amounts scheduled.

Because renewable resources (e.g., wind, solar and run-of-river) are naturally variable, they may have difficulty scheduling their output on a day-ahead basis. When the amount of such generation on a transmission system is relatively small, it may be better to simply accept the output of these generating units in real-time. New England and PJM have relatively small shares of renewable resources and settle them at real-time nodal pricing. Similarly, in NYISO day-ahead scheduling is available but not required, and up to 500 MW is settled at real-time prices beyond day-ahead amounts. In contrast, those regions in the west and southwest with significant renewable resources are incorporating long-term and short-term wind forecasts into their dispatch algorithms (see Section 5.6 on Wind Forecasting Services). The following table summarizes the market rules for scheduling as they apply to renewable resources.

Table 5: Market Rules for Scheduling[91]

RTO/ISO	**Scheduling Rules**
CAISO	Wind Energy is sold to Load Serving Entities via QF or Bilateral contracts. The Scheduling Coordinator (SC) for the wind energy can either i) make its best forecast of energy production and schedule it in the Day-Ahead or Hour-Ahead Market, or ii) participate in the CAISO Participating Intermittent Resource Program (PIRP) Program. In the PIRP the wind generation forecast is used as the energy schedule in the Hour-Ahead Market.
ERCOT	Wind scheduled as all other resources, as part of a Qualified Scheduling Entity's (QSE) portfolio. No centralized energy market; transactions done on bilateral basis. Approval to adopt nodal pricing is scheduled to begin in 2009.
Midwest ISO	If renewable resource is designated as a "capacity resource," then it has a must offer obligation for the amount of certified capacity (20 percent of nameplate for wind) in the day-ahead market and the reliability assessment commitment (RAC) process. Otherwise, the resource can—but has no obligation to—offer into the markets. Wind resources are price takers.
ISO-NE	Day-ahead bid option; or self schedule day before. Settle at real-time nodal price for energy not scheduled day-ahead.

91 Ibid.

RTO/ISO	Scheduling Rules
NYISO	Day-ahead scheduling available but not required. Resources take real-time price for all energy produced beyond day-ahead amounts. NYISO administers a centralized wind energy forecast with forecasts provided for all wind plants by a third party contractor and paid for by fees to wind generators. Forecasts are incorporated in day-ahead and real-time market evaluations.
PJM	Day-ahead scheduling; wind usually submits zero. Takes real-time LMP for energy provided.
SPP	No centralized energy market; transactions done on bilateral basis.

5.4.3. Imbalances

Traditionally, generators have been subject to two types of imbalance penalties:

1. **Energy Imbalances:** Differences between the scheduled and the actual delivery of energy to a load

2. **Generator Imbalances:** Differences between the energy scheduled for delivery from a generator and the amount of energy actually generated in an hour

Transmission providers monitor and correct these imbalances in order to keep the system safe and reliable.

Historic policies on both the Federal and local levels allowed for wide variances in the development of these charges. Although FERC Order 888 defined the penalties for such imbalances, most RTOs asked for and received waivers in favor of their own, more lenient, policies for purposes of renewable generation resources. This section describes the evolution of imbalance policies and practices as they currently exist.

FERC

Under the 1996 Order No. 888, FERC adopted two different types of imbalance penalty provisions: energy imbalances and generator imbalances. However, the Commission approved energy imbalance service pricing provisions on a case-by-case basis, and most of the major RTOs and ISOs already had granted relief from imbalance fees to renewable generation.

In April 2005, FERC issued a notice of proposed rule-making that exempted certain resources from charges for generation imbalance provisions under the OATTs that contained them. The Commission found the existing imbalance policy as unduly discriminatory against wind and other resources with variable output. Under FERC Order 890, the Commission revised the existing *pro forma* OATT Schedule 4 for energy imbalances and adopted a new Schedule 9 for generator imbalances to require imbalances to be based on a tiered structure similar to the imbalance provision used by Bonneville in that imbalance charges escalate as the imbalance increases and are based on incremental cost. Variable resources are exempt from the highest deviation band.[92] The Commission allows for deviation subject to the following conditions:[93]

> Any deviations from these provisions must be consistent with or superior to the *pro forma* OATT as modified by this Final Rule and must meet the following criteria: the charges must (1) be related to the cost of correcting the imbalance, (2) be tailored to encourage accurate scheduling behavior, such as by increasing the percentage of the adder as the deviations become larger, and (3) account for the special circumstances presented by intermittent generators.

Bonneville Power Administration

FERC Order 890 adopts a structure similar to that of Bonneville's imbalance policy, which features a three-tiered deviation band structure that exempts wind from the most stringent penalties. PacifiCorp modified its OATT Schedule 4 with an energy imbalance service that features a +/- 5% bandwidth for deviations from scheduled energy and penalties based on market prices rather than incremental/ decremental costs of the transmission provider. PacifiCorp also advocates linking imbalance provisions to requirements that generators use state-of-the-art forecasting technologies.[94]

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92 FERC, Fact Sheet, FERC Docket Nos. RM05-25-000 AND RM05-17-000, Order No. 890, Final Rule: Preventing Undue Discrimination and Preference in Transmission Service http://www.ferc.gov/industries/electric/indus-act/oatt-reform/order-890/fact-sheet.pdf

93 Ibid.

94 Ibid.

Table 6: Bonneville's Imbalance Penalties[95]

Category	Range	Penalty
Deviation Band 1	Less than or equal to 1.5% of the scheduled energy or 2 MW, whichever is larger	Assessed monthly with a financial settlement based on average incremental costs for high and low load hours
Deviation Band 2	Deviations between 1.5% to 7.5%, or 2MW to 10 MW, whichever is larger	+/- 10% penalty of Bonneville's incremental costs for actual generation less/greater than scheduled energy
Deviation Band 3	Deviations greater than 7.5% or 10 MW, whichever is larger	Wind is exempted from the +/- 25% penalty of Bonneville's incremental costs for actual generation less/greater than scheduled energy

RTO/ISO Provisions

As already mentioned, most RTOs requested waivers to FERC's imbalance penalty provisions well in advance of the 2005 NOPR. The following table summarizes the current practices of selected RTOs.

Table 7: Imbalance Provisions for Variable Resources[96]

ISO/RTO	Provisions for Imbalance Penalties for Variable Resources
CAISO	Under its FERC-approved PIRP, positive and negative scheduling deviations from intermittent renewable energy generators are netted on a monthly basis. Penalties associated with energy imbalances are waived. To receive these concessions, generators must participate in CA ISO's centralized wind forecasting program and coordinate hourly scheduling.
ERCOT ISO	Wind generation is allowed a 50% deviation from schedules (50% under schedule or 50% over schedule). Load serving entities absorb any energy imbalance costs as they are required to buy wind energy to meet the renewable energy requirement.

95 Western Governor's Association, "Clean and Diversified Energy Initiative," Wind Task Force Report, March 2006, http://www.westgov.org/wga/initiatives/cdeac/Wind-full.pdf

96 Unless referenced otherwise, based on Table 1 presented in NREL, "Regional Transmission Organizations and Wind Energy: A Happy Marriage or Divorce Proceedings?" NREL/CP-500-32467, Parsons and Porter, May 2002, Table 1, p. 3. (Referenced source: Milligan 2002 and RTO West 2002a). Updated to include recent events and changes to policy. http://www.nrel.gov/docs/fy02osti/32467.pdf

ISO/RTO	Provisions for Imbalance Penalties for Variable Resources
Midwest ISO[97]	If a source is designated by the market participant as 'intermittent,' then the resource is a price taker in the real-time market with no uninstructed deviation penalties. Wind generators are subject to imbalance charges if participating in the day-head market, which is only required for that portion of capacity claimed as a Network Resource.
ISO-NE[98]	If deviations, generators must notify the ISO. There are no imbalance charges.
New York ISO (NYISO)	Currently operating intermittent renewable energy generators, and up to 500 MW more of such generating capacity, are exempt from penalties. If bidding into the day-ahead market, then any deviations in energy deliveries are settled at the real-time prices without penalties, with wind generators being paid the real-time price for energy deliveries over schedule, and conversely, paying the real-time price if energy deliveries are below schedule. These provisions are available to all generators. For the hour-ahead market (advisory in New York), the NYISO resets the wind schedule to actual metered delivery before real-time settlement.
SPP[99]	Real-time balancing market launched as an offer-based market, and nodal prices will be based on the resource offers submitted to SPP.
WAPA Rocky Mountain Region[100]	The Western Area Power Administration's Rocky Mountain Region has adopted an imbalance rate for intermittent renewable energy sources with no bandwidth. Western purchases, on a pass-through cost basis, the resource necessary to mitigate the shortfalls inherent in renewable resources. When generation exceeds the forecast, Western pays for the over-delivery. Intermittent resource providers pay only for the energy imbalance service they take and are not penalized for any out-of-bandwidth activity.

97 Utility Wind Interest Group, "Wind Power and Electricity Markets: A living summary of markets and market rules for wind energy and capacity in North America," Market Operation and Transmission Policy Best Practices Users Group, Information compiled through December 1, 2004. http://www.ferc.gov/EventCalendar/Files/20041213162331-UWIG%20Handout.pdf

98 Ibid.

99 Ibid.

100 Western Governor's Association, "Clean and Diversified Energy Initiative," Wind Task Force Report, March 2006. http://www.westgov.org/wga/initiatives/cdeac/Wind-full.pdf

5.4.4. Line Losses

Transmitting electricity long distances for locationally-constrained resources on long radial lines since the resources are usually located great distances from the existing network. This generally results in larger line-losses and therefore may impact locationally-constrained generation more than standard generation that is connected closer to the backbone of the network. That said, line losses are impacted by a variety of technical factors, making it very difficult to estimate the losses associated with any particular plant.

As part of Standard Market Design (SMD), the Commission has stated a preference for charging for transmission usage based on locational marginal costs in order to promote economic efficiency. When prices at each location reflect the full cost of delivery (energy, congestion, and losses), system operators can make efficient dispatch decisions. To the extent this policy disadvantages remote resources, FERC has allowed each jurisdiction to offer proposals to counteract any negative impact.[101]

To date, it does not appear that any states have petitioned for something different for purposes of accommodating locationally-constrained resources.

5.4.5. Dispatch Rules

Once locationally-constrained resources are built and connected to the network, they expect to produce electricity. In the case of variable generation (i.e., wind, solar, and run-of-river hydro), energy production occurs when the wind blows, the sun shines, or the water flows. Given zero marginal cost pricing of the resource, most dispatch rules would allow those resources to produce electricity whenever they can subject to system constraints.

Both the timing of power production and locationally-constrained characteristics of renewable resource generation may challenge traditional dispatch rules. Although system constraints always have held priority over marginal cost economics, support for renewable resources over fossil fuel may create its own priorities. For example, if wind generates excessive power during off-peak hours, which units will be backed-down? Will the system operator shut down the wind unit or back down a different baseload unit that should not be cycled due to technological constraints? Various academic articles have addressed the issue internationally for purposes of isolated systems.[102]

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[101] FERC, “Assessing the State of Wind in Wholesale Electricity Markets,” Docket No. AD04-13-000. http://www.ferc.gov/legal/maj-ord-reg/land-docs/11-04-wind-report.pdf

[102] See for example, Warsono, D. J. King, C. S. Özveren and D.A. Bradley, “Economic Load Dispatch Optimization of Renewable Energy in Power System Using Genetic Algorithm,” 2007. http://www.labplan.ufsc.br/congressos/powertech07/papers/531.pdf

In the US, there have not yet been explicit priorities placed on renewable resources over other units for purposes of dispatch. Under FERC 890, transmission providers are obligated to evaluate the provision of redispatch from their own resources and provide customers with information on the capabilities of other generators to provide redispatch. Transmission providers must post information associated with the actual cost of redispatch services each month.[103] This information is posted for the benefit of all market participants and does not differentiate for locationally-constrained resources.

5.5. Satisfying RPS with Out-of-State Resources

More than two dozen states have implemented RPS requirements. The regulatory pressure on load-serving entities to abide by these requirements has created political pressure to fix many of the issues that are limiting development of locationally-constrained resources. A temporary solution may be to import renewable energy from out-of-state resources. This also could be a more economic solution for those areas that do not have significant renewable resources.

Satisfying an RPS standard with imports has both a physical and financial aspect to it. Physically, one can develop a transmission line to locationally-constrained resources outside of the jurisdiction and physically import the power back to load centers. This approach is being considered as part of the WCI tie-line from Wyoming to Colorado.

Financially, most of the states that have implemented RPS also have created a separate property right associated with the renewable aspects of generation and allowed that property right to be traded. For example, ERCOT developed RECs and New England developed its generation information system (GIS) certificates. New York originally started tracking renewable power through bilateral trades and has started to delink the renewable aspect of power from the electrons. In these systems, the ability to import a renewable MW depends on the rules surrounding the creation and trading of renewable certificates. Whether or not physical transmission has to occur for a financial property right to be traded into a different jurisdiction is simply a matter of the rules surrounding the markets for those property rights. Although the original approach was to tie physical transmission to a renewable certificate from a generating unit outside the transmission system, thinking is evolving to decouple completely the financial property right to a renewable credit from the physical flow of such power.

CHEN Chun-Lung, LEE Tsung-Ying, JAN Rong-Mow, "Optimal wind-thermal coordination dispatch in isolated power systems with large integration of wind capacity," *Energy conversion and management,* 2006, vol. 47, n°18-19, pp. 3456-3472 http://cat.inist.fr/?aModele=afficheN&cpsidt=17982698

[103] FERC, Fact Sheet, FERC Docket Nos. RM05-25-000 AND RM05-17-000, Order No. 890, Final Rule: Preventing Undue Discrimination and Preference in Transmission Service http://www.ferc.gov/industries/electric/indus-act/oatt-reform/order-890/fact-sheet.pdf

5.6. WIND FORECASTING SERVICES

Wind forecasting is a proposed way to better incorporate wind variability into transmission operations. Just as weather is incorporated into load forecasts, wind forecasts can be incorporated into supply dispatch. Although RTOs are beginning to ask for wind information directly from wind generators, many of the forecasts tend to be centralized to cover a wider geographical range in order to improve accuracy by pooling variability.

Prior to 1982, the DOE forecasted wind but stopped its efforts due to limited funding and a belief that techniques had gone as far as possible.[104] Wind forecasting technology has changed since then, including real-time forecasts by the National Weather Service, and even as early as 1995, advocates were noting that wind forecasting would assist transmission providers in their planning and scheduling.[105]

CAISO was the first ISO/RTO that started relying on wind forecasting to incorporate wind energy into energy and transmission scheduling protocols.[106] CAISO conducts day-ahead, hourly, and near real-time forecasts of potential wind generation. Wind generators schedule based on the Cal ISO forecasts and pay a forecast fee of up to $0.10/MWh.[107] Today, CAISO's PIRP allows those producers who use the ISO's wind forecasts to schedule their energy deliveries to net out deviations from that schedule over a monthly period.[108]

In March/April 2008, NYISO and ERCOT both announced plans to incorporate wind forecasts into their dispatch systems by the summer.[109] These announcements reflect the significant increase in announced and installed wind capacity on the system. ERCOT currently has 5,173 MW of wind

104 Brendan Kirby, Eric Hirst, Brian Parsons, Kevin Porter, John B. Cadogan, Electric Industry Restructuring, Ancillary Services, and the Potential Impact on Wind, 1997 20585 http://www.ornl.gov/sci/btc/apps/Restructuring/WindPower1997.pdf

105 Milligan, M., A. Miller, and F. Chapman (1995). "Estimating the Economic Value of Wind Forecasting to Utilities." *Windpower '95* Proceedings, March 21-31, 1995, Washington, D.C.

106 NREL, "Regional Transmission Organizations and Wind Energy: Happy Marriage or Divorce Proceedings?" NREL/CP-500-32467. Preprint. B. Parsons and K. Porter (Exeter Associates, Inc.) May 2002 http://www.nrel.gov/docs/fy02osti/32467.pdf

107 Ibid., p. 3.

108 Karl Stahlkopf, "Taking Wind Mainstream," First Published June 2006, http://www.spectrum.ieee.org/print/3544

109 Peter Fairley, "Scheduling Wind Power: Better wind forecasts could prevent blackouts and reduce pollution," April 17, 2008. http://www.technologyreview.com/Energy/20646/page1/

generation (7 percent of installed capacity), an increase from nearly nothing eight years ago with another 45,000 MW of wind resources are up for review.[110]

NYISO currently has 425 MW of nameplate capacity, which is less than 1 percent of its system. However, New York Governor Paterson has a stated goal of increasing renewable energy to 25 percent of New York's power by 2013, a goal that will require another 3,000 MW of wind over the next five years.[111] Under the new tariff approved by FERC, wind plant operators of plants larger than 12 MW would be responsible for the cost of installing and maintaining equipment necessary to collect meteorological data to be transmitted to NYISO every 15 minutes. This will be enforced with daily penalties on wind resources that fail to provide the required information. Additionally, NYISO is required to report the progress of this program and information regarding costs, revenues collected, and disposition of those revenues to FERC in 2 years.[112]

Several studies have shown that the cost of balancing the system is lower when control area operators are informed by state-of-the-art wind energy forecasts.[113] The forecasting service can be performed by individual wind operators or by a centralized agent such as a transmission owner or control area operator. The argument for wind forecasting by the transmission provider is that larger geographic and electrical size also makes forecasting easier. When aggregated over a broad geographic region, wind forecast errors can be reduced by as much as 30 percent to 50 percent.[114] Thus, power system operators can more accurately predict and plan for changes in wind output when their systems are larger. On the other hand, individual wind operators may have better data that can be provided to transmission providers.

[110] Bob Kahn, ERCOT, "Planning for Texas' Energy Future," April 15, 2008. http://www.ercot.com/news/presentations/2008/BKahnSenB&CandNatlRes041508.pdf

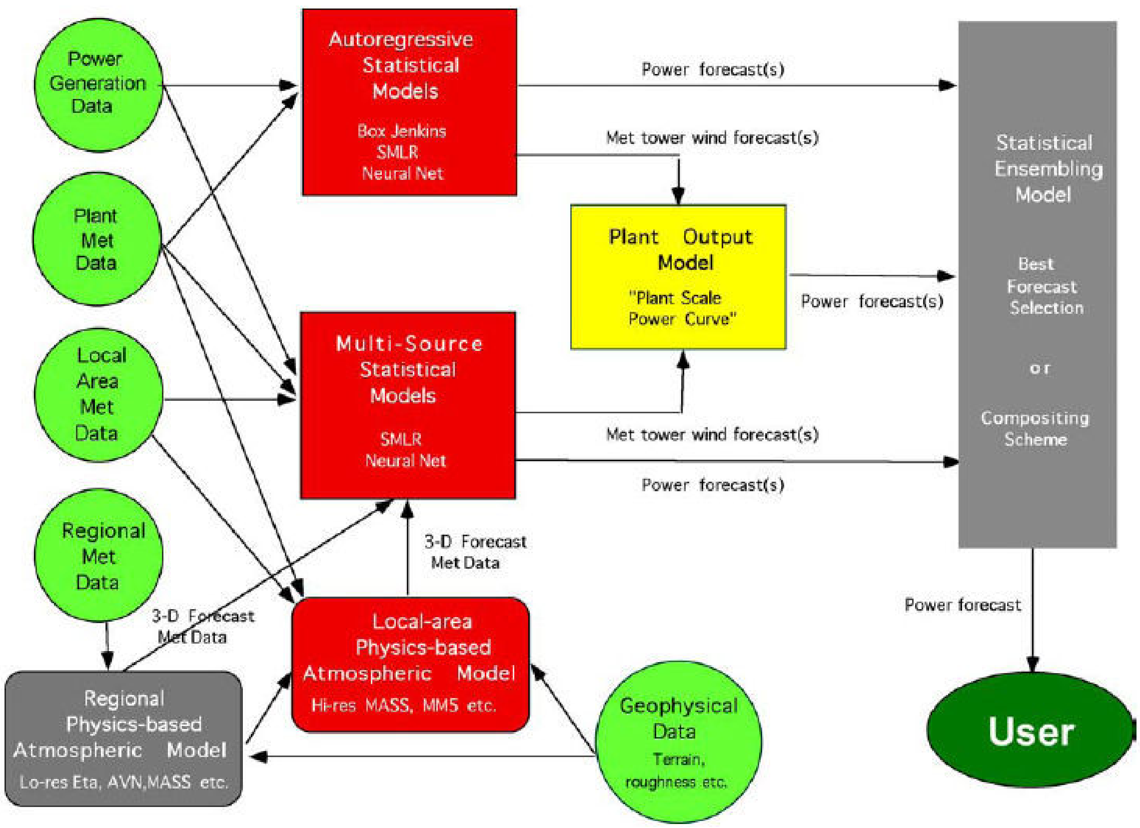
[111] Jason Subik, "Companies poised to profit from state wind-power push," Gazette, Sunday, June 1, 2008. http://www.dailygazette.com/news/2008/jun/01/0601_Wind/

[112] Bracewell & Guiliani, "NYISO's Plan to Integrate Wind wins FERC Approval," posted on Wednesday, July 09, 2008 12:10 PM by Maria Urbina http://energylegalblog.com/archive/2008/07/09/439.aspx

[113] Western Governor's Association, "Clean and Diversified Energy Initiative," Wind Task Force Report, March 2006, http://www.westgov.org/wga/initiatives/cdeac/Wind-full.pdf

[114] NREL, "Facilitating Wind Development: The Importance of Electric Industry Structure," Technical Report NREL/TP-500-43251, B. Kirby and M. Milligan, May 2008 http://www.nrel.gov/wind/systemsintegration/pdfs/2008/milligan_facilitating_wind_development.pdf

Figure 14: Schematic Diagram of the Components of a Very Short-term Forecast System[115]



Source: TrueWind Solutions, LLC and AWS Scientific, Inc. (2003)

A wide variety of methods have been employed to integrate wind generation forecasts in the very short-term (i.e., the next hour). Figure 14 illustrates an example of the interaction between local and system data on wind and generation availability in order to develop short-term wind power production forecasts.

In 2006, Brian Parsons of NREL presented best practices that are emerging on wind forecasting. They include the following:[116]

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115 TrueWind Solutions, LLC (Principal Author: Dr. John Zack) and AWS Scientific, Inc., "Overview of Wind Energy Generation Forecasting," (Draft Report), Submitted To: New York State Energy Research and Development Authority and the New York State Independent System Operator, December 17, 2003, p. 10. http://www.uwig.org/forecst_overview_report_dec_2003.pdf

- Use models and simulations of the system to capture response to wind patterns
- Synchronize weather simulation to create wind generation scenarios across diverse geographic areas
- Assess modeling results against actual historic load and forecasts
- Incorporate actual wind farm power statistics for short-term regulation and ramping
- Examine wind variation in combination with load variations
- Adopt wind forecasting best practices
- Combine wind forecast errors with load forecast errors
- Examine actual costs independent of tariff design structure

5.7. CONCLUSION

The unique characteristics of locationally-constrained generation and the political motivation to support them have resulted in various operational and regulatory accommodations. Consolidation over large geographic areas, primarily through RTOs, ISOs and voluntary organizations of multiple utilities, helps to mitigate some of the system-wide impacts. Aggregation behind the meter (i.e., the natural gas gathering model) performs a similar purpose, allowing the natural diversification effects to offset each other before reaching the system. Combining different types of variable resources such as wind and solar also serves to mitigate system impacts.

Market rules that may be discriminatory to locationally-constrained resources or variable generation have been revised to address ongoing concerns, especially in the area of scheduling and imbalance penalties. Many system operators are incorporating the realities of variable generation resources into their planning and scheduling programs.

A number of initiatives have been implemented to accommodate operationally variable generation resources and other locationally-constrained resources. Effective practices include:

- **Addressing variability** through offsetting consolidation/aggregation
  - over larger balancing areas
  - through windfarms that aggregate behind the transmission meter (i.e., natural gas gathering model)
  - by combining renewable resources (e.g., wind and solar)

[116] Brian Parsons, NREL, “Grid Impacts of Wind Power Variability: Recent Assessments from a Variety of Utilities in the United States,” Presented at the European Wind Energy Conference, Athens, Greece, February 27 – March 2, 2006. http://www.uwig.org/ewec06gridpresentation.pdf

- **Creating markets for flexibility** through mechanisms to compensate dynamic load following and frequency responses, adaptable for incorporation of new technologies.
- **Market rules** that adjust for the realities of variable resources, including scheduling concessions and waiving imbalance penalties. However, economic dispatch rules have not yet been modified to prioritize renewable resources over thermal generation sources.
- **Wind forecasting services** that provide wind conditions to transmission operators for purposes of incorporating expected conditions into scheduling similar to weather conditions and load forecasts.

6. RATE RECOVERY

Transmission in the US remains a cost-of-service based regulated service with a few exceptions of merchant transcos that allow for market-based rate determinations. As such, the US has a long history of establishing rules and regulations for transmission operations and investment recovery. With a long history of overseeing vertically-integrated regulated monopolies, most state public utility commissions (PUCs) set rates for bundled retail services while FERC regulates wholesale interstate transmission.

As US electricity markets started to open in the 1990s, FERC established new rules that aimed to ensure open access and non-discriminatory transmission service, including FERC Order No. 888 and 889. The past few years have seen even more modification of the open access transmission rules with FERC Order 890, 890-A and 890-B. In the meantime, state PUCs have been refining their tariff structures and connection rules to address the increasing realities of locationally-constrained generation. They are pushing the bounds on FERC rules concerning investment recovery in transmission tariffs with feed-in tariffs, REC pricing and property rights, conditional firm transmission services, and valuation of capacity and energy.

This section summarizes the effective practices, and where there are no practices but serious proposals, with respect to rate recovery of transmission to locationally-constrained resources. It starts with a summary of US cost-recovery principles on the federal and state levels, and describes in more detail specific rate recovery practices being implemented in various jurisdictions in support of locationally-constrained generation.

6.1. COST RECOVERY

The United States has a bifurcated system of transmission investment recovery through regulated rates with federal and state governments regulating different areas of the electric industry. FERC regulates interstate electric wholesale transactions and sets wholesale transmission tariffs whereas state regulatory commissions (often referred to as public utility commissions or PUCs) have jurisdiction over bundled retail rates within their respective states through which transmission costs are recovered from end-users.

Electric power industry players may be subject to both regulatory institutions, one of them, or neither. Jurisdictional entities are generally investor owned utilities (IOUs) subject to both state and FERC regulation. Merchant power and transmission entities are subject to FERC jurisdiction. Power marketing entities created by the federal government (e.g., Bonneville Power Administration (BPA), Western Area Power Administration (Western), or local governments (municipals, public utility districts "PUDs," rural cooperatives, generation, and transmission cooperatives)) are non-jurisdictional entities that are not subject to FERC or state jurisdiction for most purposes. However, many non-jurisdictional entities follow FERC rules by voluntary choice or under reciprocity provisions.[117]

This section discusses the general approaches to cost recovery adopted by regulatory bodies for the transmission companies over which they have jurisdiction.

6.1.1. Transmission Pricing

Locationally-constrained resources may be subject to pancaked transmission rates, to the extent they cross multiple utility borders for delivery. This can make locationally-constrained resources even more expensive because 1) the remote nature of such resources may require pancaking of multiple rates before delivery to the ultimate load center, and 2) duplicative charges may push resources to sub-optimal locations. RTOs and regional ISOs overcome this pancaking issue by charging postage-stamp tariffs or only by charging a single transmission owner an exit point rate. However, those jurisdictions without regional system operations continue to have jurisdictional transmission rates that can unduly discriminate against remote resources under a point-to-point transmission tariff.

Recognizing this barrier to locationally-constrained resources, eight WestConnect utilities[118] petitioned FERC on June 10, 2008, for guidance on a proposed two-year experimental transmission pricing initiative that would eliminate rate pancaking in the southwest. The proposed experiment will offer customers the option to purchase hourly non-firm, point-to-point transmission service at a single regional transmission rate instead of having to pay pancaked rates under each provider's open-access tariff. WestConnect proposes to charge the transmission customer a single, flat rate that would be equal to the highest non-firm ceiling rate charged by a participating transmission owner. In addition to an administrative charge for the experiment, the transmission customer would pay for scheduling and dispatch along with reactive and voltage control. Under the experiment, regional service would result in a lower rate than is currently available. Revenues will be distributed on a pro rata basis to each participating transmission provider. Assuming FERC approval, the proposed pricing is expected to begin February 1, 2009, and last for two years, at which point WestConnect would evaluate the experiment.[119]

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[117] Western Governors' Association, Clean and Diversified Energy Initiative, Wind Task Force Report, March 1996. http://www.westgov.org/wga/initiatives/cdeac/Wind-full.pdf

[118] Including Arizona Public Service Company, El Paso Electric, Nevada Power, Public Service Company of Colorado, Public Service Company of New Mexico, Southwest Transmission Cooperative, Tri-State, Tucson Electric Power, and WAPA.

[119] Bracewell & Giuliani, "WestConnect Utilities Experiment to Eliminate Rate Pancaking in Southwest," posted on Monday, June 30, 2008 2:31 PM by Kristin McKeown. http://energylegalblog.com/archive/2008/06/30/438.aspx

6.1.2. FERC Rate Recovery Incentives

In 2006, FERC passed The Final Rule: Promoting Transmission Investment through Pricing Reform to establish various incentive-based rate treatments for interstate transmission.[120] Although the Commission noted that promotion of renewable energy projects supports certain policy objectives, the Final Rule does not extend to adoption of separate rate-based incentives for renewable energy projects. The Final Rule does, however, describe eight incentive-based rate treatments that will be considered for any transmission project for all jurisdictional public utilities, including Transcos. For completeness, we list these rate recovery principles here because they would be considered (but not guaranteed) in any FERC-regulated transmission investment to locationally-constrained generation.

In allowing for recovery through rates, the Commission intends to consider:[121]

- **Incentive-based Return on Equity (ROE)** for building new transmission facilities that ensure reliability and reduce the cost of delivered power.
- **Accelerated depreciation** for new transmission facilities that ensure reliability and reduce the cost of delivered power.
- **Overall rates of return** based on hypothetical capital structures presented to the Commission as part of the approval process.
- **Deferred recovery** of new transmission investment costs by public utilities under retail freezes.
- **Construction Work in Progress (CWIP)** through the inclusion of 100 percent of CWIP in the calculation of transmission rates.
- **Abandoned investment** through the inclusion of 100 percent of costs of abandoned transmission facilities in transmission rates if such abandonment is outside the control of management.
- **Single-issue** ratemaking.

All rates approved under the Final Rule are subject to Federal Power Act rate filing standards. The rule allows utilities on a case-by-case basis to select and justify the package of incentives needed to support new investment. These rate recovery incentives are being used in the development of

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120 116 FERC ¶61,057, Final Rule, "Promoting Transmission Investment through Pricing Reform," July 20, 2006.

121 Ibid.

transmission for locationally-constrained generation. For example, PG&E filed a petition for declaratory order on December 21, 2007. Their petition sought incentive rate treatment under Order No. 679 for a proposed transmission project from Canada to northern California with capacity of up to 3,000 MW. PG&E claimed that this transmission investment would enable integration of renewable energy resources and help various parties in the west to meet state RPS and greenhouse gas reduction goals, along with reliability and development goals. FERC granted the petition, and with its Order on April 21, 2008, allowed PG&E to recover prudently incurred pre-commercial costs related to the Project and prudently incurred abandonment costs if PG&E cancels the project for reasons beyond PG&E's control.[122]

Additional incentives granted specifically to Transcos include return on equity incentives, accumulated deferred income taxes, acquisition premiums for Transco formation, and merchant transmission incentives.

6.1.3. PUC Rate Recovery Incentives

For vertically integrated utilities, cost recovery is established by the FERC and the PUCs that have jurisdiction over the transmission company. Transmission owners recover the portion of prudent transmission investment used to provide retail service through end-user prices set by the PUC; the balance of cost recovery occurs through FERC tariffs. Thus, state PUCs generally continue to have decision-making responsibility about cost recovery for projects in their respective states.

In recent cases, however, state policy makers have passed legislation concerning transmission cost recovery to create incentives for purposes of meeting renewable policy objectives:

- **California** is pursuing a generic transmission cost recovery policy for those areas endowed with renewable resources that currently are not able to connect to the network. The PUC already allows for state cost recovery backstops for transmission investment made to connect renewable resources, and FERC is contemplating a proposal to allow investors in California to recovery costs through a wholesale transmission tariff.

- **Colorado**, similar to California and Texas, has passed laws that identify renewable energy zones and enable utility cost recovery through retail rates.

- **Minnesota** recently passed a law requiring that 25 percent of its power come from renewable resources by 2025. The legislation recognizes that insufficient transmission is a potential barrier to achieving these goals and addresses this potential. If utilities claim transmission is

[122] FERC Order on Petition for Declaratory Order, Docket No. EL08-24-000, Issued April 21, 2008. http://www.ferc.gov/whats-new/comm-meet/2008/041708/E-3.pdf

a reason they will not make the RPS, they still can be required to move forward in the regulatory and construction process for the needed new lines or upgrades.

- **Missouri** passed legislation that requires the Missouri Public Service Commission to adopt rules that integrate the renewable energy and energy efficiency objective into its resource planning, including the costs of transmission investments necessary to access renewable energy sources.[123]

- **New Mexico** adopted a transmission policy in conjunction with its 20 percent RPS requirement by 2020.

- **Texas** passed an amendment to its RPS legislation that instructs the Public Utility Commission of Texas (PUCT) to require utilities to add to their transmission systems as necessary to meet the renewable energy goal of 5,880 MW by 2015, and allows these utilities to recover the cost of the additions through electric rates.[124] Texas legislation effectively socializes the cost of building transmission to renewable resources as part of its initiative on renewable energy zones.

6.2. TRANSMISSION TARIFFS

Transmission tariffs include charges for capacity and delivery, as well as for costs incurred to connect to the network. Capacity and delivery generally is covered by end-user rates where as costs to connect and other system charges are incurred by generators with some included in a general uplift charge that is passed along as part of a delivery charge. How these charges are shared between transmission owners, generators, and end-users varies by utility and jurisdiction, and it may be determined by FERC, the PUC, or a combination. The need to build locationally-constrained resources outside of a jurisdiction that requires them for policy purposes creates another factor that needs to be addressed in the cost sharing decision.

6.2.1. Generation Tie Lines

Generation tie-lines connect a generator to the nearest point of interconnection with the system. FERC generation interconnection rules require that the interconnecting generator bears the full cost

[123] Missouri Revised Statutes, Chapter 393 Gas, Electric, Water, Heating, and Sewer Companies, Section 393.1025. http://www.moga.state.mo.us/statutes/C300-399/3930001025.htm

[124] PUCT, Order Adopting Amendment to §25.173 as Approved at the July 20, 2007 Open Meeting. http://www.puc.state.tx.us/rules/subrules/electric/25.173/33492adt.pdf

of the line.[125] Similarly, many states have adopted a highway/driveway model where generators are responsible for facility costs from the generator to the interconnection (driveway) and transmission owners are responsible for all other costs for upgrades necessary to accommodate the requested transmission service (highway).[126]

This approach creates a "chicken-egg" dilemma, however, for locationally-constrained resources. For those areas that could support multiple generation facilities, the first unit may be charged a disproportionate share of the costs required to build a tie line from the transmission system to the site. Transmission capacity expansions necessary to access renewable energy resources often are more economic if the expansion accommodates a full build-out of the locational resource even if that build-out exceeds the capacity required for a given generation project.[127]

To address this dilemma, certain regional initiatives have been organized to promote regional transmission investment and cost sharing. For example, Minnesota, Iowa, Wisconsin, North Dakota, and South Dakota recently created The Upper Midwest Transmission Development Initiative to identify areas for wind generation along with the transmission projects and other infrastructure required to support those wind resources. Participants intend to allocate costs for the region and propose tariffs consistent with those cost allocations to Midwest ISO.[128]

Other initiatives are being implemented on the state level to build surplus capacity from the outset that offers economies of scale to future renewable generation projects. For example, California has adopted an approach to ensure that utilities assessing locationally-constrained generation to meet their RPS requirement assess the costs of connecting those units using a pro-rata share of the incremental transmission costs for which they are responsible; the costs of any unsubscribed portion of these facilities are charged to system customers.[129] This approach is being used to connect to the

[125] Standardization of Generator Interconnection Agreements and Procedures, 104 FERC ¶ 61,103 (2003) ("Order 2003").

[126] See Texas Public Utility Regulation Act, §35.004 (Texas statute on the socialization of transmission costs in ERCOT) www.puc.state.tx.us/rules/statutes/Para03.pdf and Texas PUC Substantive Rule 25.195(c) www.puc.state.tx.us/rules/subrules/electric/25.195/25.195.pdf

[127] Piwko, Richard, et al., "What comes first?" 2007. http://ieeexplore.ieee.org/iel5/8014/4382976/04383125.pdf?isnumber=4382976&arnumber=4383125&htry=8

[128] Minnesota North Star, Office of the Governor, Tim Pawlenty, "Governor Pawlenty Announces Regional Electric Transmission Planning to Support Wind Energy," September 18, 2008, http://www.governor.state.mn.us/mediacenter/pressreleases/PROD009122.htm

[129] Docket 05-07-040. The CPUC directed utilities to assign the costs of large transmission upgrades that would be used by more than one RPS project on a pro-rata basis for purposes of bid evaluation in the 2005 procurement process. See also "California ISO Proposal for Location Constrained Resource Interconnection," October 1, 2007. http://www.caiso.com/1c73/1c73b2f471ec2.pdf

Tehachapi area located at the southern end of the San Joaquin Valley which is expected to add 3,540 MW of wind generation to Southern California Edison's system.[130]

Figure 15: Planned Transmission Line to Tehachapi[131]

Online	Seg	Description	Cumulative Capability*
2008	1	Antelope-Pardee 500 kV T/L and Antelope Expansion	300
2009	2	Antelope-Vincent No.1 500 kV T/L	700
2009	3	Antelope-WindHub 500 kV & WindHub-HighWind 220 kV	
2011	5	Antelope-Vincent No.2 500 kV T/L	2,200
2011	4	Antelope-Whirlwind 500 kV and Whirlwind-Cottonwind 220 kV T/L Facilities	
2011	9	Increase Operation to 500 kV/Transformer Banks/Substation Equipment/ Static VAR Compensators	
2011	10	New Whirlwind-Windhub 500 kV T/L	
2011	6	New Replacement Vincent-Rio Hondo No.2 500 kV T/L	
2012	7	New Vincent-Mira Loma 500 kV T/L (portion between Vincent-Mesa Area)	
2012	8	New Vincent-Mira Loma 500 kV T/L (portion between Mesa Area-Mira Loma)	
2013	11	New Vincent-Mesa (via Gould) 500/220 kV T/L	4,500

Source: SCE (2008)

6.2.2. Network Upgrades

Network upgrades are defined as the additions, modifications, and upgrades to the transmission system at or beyond the point of connection to the grid to accommodate the generator to the system.

130 California Independent System Operator, "Proposed Transmission Plan for Integration of Renewables." http://www.caiso.com/1c64/1c64e4fc2b20.pdf

131 Southern California Edison, "Tehachapi Renewable Transmission Project," 2008. http://www.sce.com/NR/rdonlyres/D92D6387-CF9A-4B60-868C-35EF45CE35E3/0/Greening_The_Grid_FINAL_0311.pdf

Generally, the full cost of the network upgrade for a generator interconnection is rolled into the transmission rates of the transmission owner. In some cases, however, the transmission provider may require the interconnecting generator to provide upfront funding for a portion of the network upgrade (usually 50 percent) and then credit the funds, with interest, back to the generator over time following commercial operation of the generator.

Traditionally focused on system safety and reliability, interconnection policy does not draw a distinction between new transmission required for those reasons versus transmission developed for economic or policy reasons.

6.2.3. Investment to Support Locationally-constrained Resources

In addition to working around FERC requirements to encourage renewable resources, various states are enacting legislation to provide legal and regulatory incentives to build transmission for purposes of connecting to locationally-constrained generation.

For example, Texas has passed legislation that authorizes the Public Utility Commission to require electric utilities to construct or enlarge transmission facilities to meet Texas RPS goals.[132] Texas legislation SB 20 also provides cost recovery incentives for transmission projects that support RPS goals. Such projects automatically are deemed used and useful, and prudent and includable in the rate base, regardless of the utility's actual use of the facilities.

In Minnesota, SF 1368 contains transmission provisions to support renewable energy development and to meet the Minnesota RPS goal.[133] SF 1368 requires utilities to identify necessary transmission upgrades that support development of renewable energy to meet RPS requirements. Transmission projects determined to be necessary to support a utility's plan to meet RPS requirements would be deemed a priority electric transmission project and satisfy a certificate of need, which then gives the public utility commission authority to approve transmission cost adjustments on a timely basis. This politically-authorized rate recovery allows utilities to recover costs on a timely basis with a return on investment at a level most recently approved or another rate consistent with the public interest. A return on construction work in progress also is allowed to be incorporated into the rates.

Other states also have considered or passed new laws that provide similar support to locationally-constrained resources.

[132] Texas Legislature SB 20, Legislative Session 79(1), signed by Governor Rick Perry on August 2, 2005, and effective on Sept. 1, 2005. http://www.capitol.state.tx.us/

[133] Minnesota State Legislature, SF 1388, Legislative Session 84, signed by Governor Tim Pawlently on May 25, 2005. http://www.leg.state.mn.us/leg/legis.asp

6.3. Conditional Firm Transmission Service

Traditionally, transmission service has been offered as either firm or interruptible. Firm service has priority over interruptible, with the interruptible rate generally being less on a volumetric unit of usage. More recently, conditional firm service has been introduced. Similar to firm service that is reserved and has priority over interruptible service, it can have restrictions in that it can be curtailed before firm service that has priority over interruptible, but can be interrupted. Conditional firm service may be especially attractive to renewable resources that, by their variable nature, may not value transmission during those times when interruption is most likely to occur.

FERC Order No. 890, issued in February 2007, expands the obligations of transmission providers to ensure that transmission service is provided on a non-discriminatory basis, reduce the potential for exercise of market power, strengthen the reliability of the transmission system and support competitive wholesale power markets.[134] Order No. 890 directed transmission providers to develop a transmission planning process that follows nine planning principles, including cost allocation for new projects. A major reform of the Final Rule over prior open access orders includes adoption of a "conditional firm" component to long-term point-to-point service and reform of existing requirements for redispatch service.[135]

In Order No 890, the Commission adopted a "conditional firm" component to long-term firm point-to-point service that requires the transmission provider to identify either defined system conditions or an annual number of hours during which service will be conditional, and allows the customer to select one of them. The duration of both service options is limited to a time period over which service can be reasonably provided without impairing reliability.

To date, conditional firm service has gained traction primarily in the western states. The service is discussed in the Western Governor's Association Clean and Diversified Energy Committee reports (WGA CDEAC report) and the Rocky Mountain Area Transmission Study.[136]

The Western Area Power Administration offers "priority non-firm" transmission service. Bonneville Power Administration, the originator of the conditional firm service proposal that was incorporated into the FERC Order, notes in its 2008 transmission rate schedule:[137]

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[134] FERC Order No. 890.

[135] FERC Order 890 Final Rule Preventing Undue Discrimination and Preference in Transmission Service, Fact Sheet FERC Docket Nos. RM05-25-000 and RM05-17-000, http://www.ferc.gov/industries/electric/indus-act/oatt-reform/order-890/fact-sheet.pdf

[136] Western Governors' Association, Clean and Diversified Energy Initiative, Wind Task Force Report, March 1996. http://www.westgov.org/wga/initiatives/cdeac/Wind-full.pdf

> This schedule supersedes Schedule PTP-06. It is available to Transmission Customers taking Point-to-Point (PTP) Transmission Service over Federal Columbia River Transmission System (FCRTS) Network and Delivery facilities, for hourly non-firm service over such FCRTS facilities for customers with Integration of Resources agreements, *and to customers taking Conditional Firm (CF) Transmission Service, if BPA adopts CF Transmission Service*.
>
> (emphasis added)

6.4. Valuation Metrics for Capacity and Energy

Electric generation facilities provide both energy value and capacity value. The system ultimately delivers energy to consumers, but without sufficient capacity, the transmission system can become unstable. Capacity is thus critical to assure the reliability of the electric system and a generator's ability to deliver power when needed provides value that is separate and distinct from the energy it delivers.

For purposes of connecting a new generator, transmission providers usually allow for the name-plate capacity of the unit even though one expects the unit to generate less on average due to forced outages and maintenance outages. Similarly, the name-plate capacity of locationally-constrained resources determines the minimum amount of transmission capacity required to connect the facility. In some RTOs, capacity-based transmission fees thus require wind generators to pay for 100 percent of the transmission capacity even though the unit has a much lower capacity factor.

The costs can be offset by a capacity credit that measures the value a generator provides to system reliability. Due to the variable nature of certain renewable resources, utilities historically have been reluctant to assign a value for capacity from renewable generators. Renewable resources such as wind, solar, or run-of-river hydro, were thought to have no capacity value because they are not dispatchable — they cannot be turned on and off by a system operator to meet peak demand. Yet even variable resources have capacity value and contribute to the reliability of the transmission network. Today, there are various proposals for calculating the value of reliability provided by such generation facilities, as described in the following table.[138]

137 Bonneville Power Administration Transmission Services 2008, Transmission and Ancillary Service Rate Schedules, Effective October 1, 2007, p. 17. http://www.transmission.bpa.gov/Business/Rates_and_Tariff/ratesdocs/2008_Rate_Schedules_10_01_07.pdf

138 See also the report prepared by California Wind Energy Collaborative for PIER, California Energy Commission, "California Renewables Portfolio Standard Renewable Generation Integration Cost Analysis. Phase III: Recommendations for Implementations," P500-04-054, July 2004. http://www.energy.ca.gov/reports/500-04-054.PDF

Table 8: Capacity Value by Region/Utility[139]

Region/Utility	Method	Note
CA/CEC	Effective Load Carrying Capacity (ELCC)	Rank bid evaluations for RPS (20%-25%)
PJM	Peak Period	June-Aug HE 3pm – 7pm, capacity factor using 3-year rolling average (20%, fold in actual data when available)
ERCOT	10%	May change to capacity factor, 4:00 – 6:00 pm in July (2.8%)
MN/DOC/Xcel	ELCC	Sequential Monte Carlo (26% - 34%)
GE/NYSERDA	ELCC	Offshore/onshore (40%/10%)
CO PUC/Xcel	ELCC	PUC decision (10%), Full ELCC study using 10-year data gave average value of 12.5%
RMATS	Rule of Thumb	20% of all sites in RMATS
PacifiCorp	ELCC	Sequential Monte Carlo (20%). New Z-method 2006
MAPP	Peak Period	Monthly 4-hour window, median
PGE	(method not stated)	33%
Idaho Power	Peak Period	4pm – 8pm capacity factor during July (5%)
PSE and Avista	Peak Period	Lesser of 20% or 2/3 of January Capacity Factor
SPP	Peak Period	Top 10% loads/month; 85th percentile

Other models tend to assign a capacity value of approximately the capacity factor to a new plan. Thus, adding a 100-MW wind plant with an average capacity factor of 35 percent to the system is approximately the same as adding 35 MW of conventional fueled generating capacity.[140] As seen in the variety of methods used by transmission providers, however, the exact answer depends on, among other factors, the correlation between the time that the wind blows and the time that the utility sees peak demand.

139 Western Governor's Association, "Clean and Diversified Energy Initiative," Wind Task Force Report, March 2006, Table 6, p. 34. http://www.westgov.org/wga/initiatives/cdeac/Wind-full.pdf

As updated in US DOE, Office of Energy Efficiency and Renewable Energy, "20% Wind Energy by 2030: Increasing Wind's Contribution to the Energy Supply," May 2008. http://www1.eere.energy.gov/windandhydro/pdfs/41869.pdf

140 AWEA, "Wind Energy Potential," http://www.awea.org/faq/wwt_potential.html

6.5. REC PRICING AND TRANSMISSION COST RECOVERY

As a means of promoting renewable energy, state policy has adopted RPS and green power marketing. In support of these policies given the physical realities of electricity production and transmission, certain markets have developed a separate property right associated with power generation. These property rights assume the form of either renewable energy credits (RECs) or generation information system (GIS) certificates. RECs pre-assign a generation unit the status of renewable or non-renewable, and generate REC certificates for every MWh produced. In contrast to the binary title assignment, GIS certificates simply describe the attributes of the generation unit that produces the power, including fuel type, air emissions, union/non-union labor, and whether it meets the definition of renewable resource by state. Texas operates a market for RECs whereas eastern markets operate a GIS system.

In general, those markets that have defined environmental attributes as a separate property right allow them to be traded and transacted separately from the electrons. The price of these environmental attributes, therefore, is determined according to supply and demand forces. Supply is a function of the amount of energy produced by renewable generation units as well as regulations concerning the ability of imports to trade into the environmental attribute market and exports to be traded in other markets. Demand is a function of market-based demand for green power as well as regulatory-based demand created by RPS.

In almost all cases, RECs are generated with the production of energy. If a renewable resource produces a MWh of energy, it receives a certificate for a MWh of renewable energy credit. If requirements of the operation of the transmission system require a renewable resource to back-down production, neither generation nor renewable energy credit is produced.[141] As supply is related to the production of power, any transmission operation decision that reduces production of renewable energy impacts the price of RECs.

Normally, transmission owners and operators do not carry title to the power they transmit. Similarly, they would not carry title to the RECs or GIS certificates generated by renewable resources connected to their systems. However, the concept of connection cost recovery establishes a new paradigm in which REC pricing may be considered as part of the incentives for connection of resource-constrained generation facilities to the network.

To date, however, RECs have been considered only in conjunction with power purchase agreements. As part of the incentives to encourage connection of renewable resources, policy makers are considering the role that the environmental attributes of generation resources may play. For

[141] The section on regulatory accommodations addresses policy discussions about accommodating those instances where RECs still may be produced even when the unit does not produce electricity.

example, California SB 451 (2007) proposed a feed-in tariff that transferred RECs to the utilities; it was vetoed because of this provision. Vermont S 209 which was passed and signed does transfer GIS certificates to the utility as part of the feed-in tariff. In Wisconsin, utilities have established "buy-back rates" for certain renewables that contract for system electricity and the RECs.[142] On the Federal level, recently proposed legislation would then require all electric utilities in the US to enter into fixed-rate, 20-year power purchase agreements at the request of any new renewable energy facility owner. Utilities would earn any associated RECs in order to help meet RPS requirements.[143] These policies, however, relate to contracts for energy and whether the associated RECs would be part of the transaction. They do not directly relate to recovery of transmission connection and operation.

6.6. CONCLUSION

Rate recovery is one of the most important issues for transmission providers and has been implemented in the US through regulated rates since the first wire was strung. Transmission service thus has a rich set of precedents concerning rules and regulations for investment recovery. These precedents expanded with the opening of the markets in the 1990s and during the 2000s with expansion of locationally-constrained generation.

Within this structure, there has been significant discussion with limited implementation. Effective practices that actually have been passed and put into place include:

- **Implementing legislation and regulations** to provide legal mandates and regulatory incentives to build transmission for purposes of connecting to locationally-constrained generation, such as giving priority to transmission projects necessary to support RPS requirements and granting public utility commissions authority to approve transmission cost adjustments on a timely basis.

- **Assurance on cost recovery** of investment in transmission projects to connect resources required to meet RPS requirements.

- **Socialization of costs** across all ratepayers in support of building transmission to identified renewable energy zones.

- **Pro-Rata connection charges** to reflect the incremental contribution of a single facility to transmission line expansions instead of a but-for analysis that assigns the entire cost of a line expansion to one unit.

[142] Rickerson, et. al. (May 2008)

[143] Ibid.

- **"Conditional Firm" transmission service** that modifies the historic transmission products of firm versus interruptible to recognize available capacity on the transmission system that can be accessed with minimal cost by certain renewable resources.

- **Defining capacity of variable resources** to reflect the incremental contribution to the transmission system during peak periods as opposed to an annual average that reflects only wind patterns.

7. TAX INCENTIVES

This section reviews federal and state tax incentives for the integration of locationally-constrained and other renewable resources into the transmission grid. Federal tax policy allows for accelerated depreciation of electrical transmission property in general, regardless of whether integration of renewable resources is involved. At least eight states have adopted their own rules for tax incentives to resolve the transmission needs for meeting renewable energy standards and tapping into their wind resources. In 2006, FERC issued a rule providing for "incentives" for transmission investment, most of which are based on cost recovery for public utilities and pricing reform. Although not specific to renewable resources, they would be considered in FERC-regulated transmission investment to locationally-constrained areas. The sections below briefly describe current federal and state policies that provide incentives for transmission investment.

7.1. FEDERAL INCENTIVES

Federal tax incentives focus primarily on capital depreciation for renewable generation and transmission investment. There currently is no specific accounting treatment for transmission investment dedicated to connecting renewable resources. For completeness, however, we provide a summary of federal tax incentives for transmission systems.

The Federal Modified Accelerated Cost Recovery System (MACRS) allows businesses to recover investments in certain property through depreciation deductions over an abbreviated asset lifetime.[144] There are two depreciation systems under MACRS: the General Depreciation System (GDS) and the Alternate Depreciation System (ADS). GDS is used except when ADS is required by law or elected. The recovery periods under ADS generally are longer than recovery periods under GDS.[145]

The Energy Policy Act of 2005 allows for a five-year accelerated depreciation of some renewable energy property, including micro-turbines.[146]

144 US DOE, Office of Energy Efficiency and Renewable Energy, "20% Wind Energy by 2030: Increasing Wind's Contribution to the Energy Supply," May 2008. http://www1.eere.energy.gov/windandhydro/pdfs/41869.pdf

145 ADS must be used if listed property is used 50 percent or less in a qualified business use, if tangible property is used predominately outside the United States, if the property is tax-exempt, if it is tax-exempt bond-financed property, if it is property predominately used in the farming industry, if the property is imported from a foreign country for which an Executive Order is in effect because the country maintains trade restrictions or engages in other discriminatory acts. (IRS, Publication 946 (2007), *How to Depreciate Property*, Section 4: Figuring depreciation under MACRS. http://www.irs.gov/publications/p946/ch04.html)

146 US DOE, "20% Wind Energy by 2030: Increasing Wind's Contribution to the Energy Supply," May 2008. http://www1.eere.energy.gov/windandhydro/pdfs/41869.pdf

However, this five-year depreciation deduction does not include electric transmission property. Electric transmission property placed in service after April 12, 2005, and used for the transmission of 69 kilovolts of electricity or more qualify for a 15-year depreciation under MACRS versus the 30 year depreciation under ADS.[147] To qualify for 15-year depreciation, the transmission property must not be “self-constructed property” (i.e., property manufactured, constructed, or produced for one’s own use for use by another person under a binding contract entered into before the construction of the property). The electrical transmission property must be “section 1245 property”—“tangible” or “real” property under the definition in the tax code.[148]

7.2. State Incentives

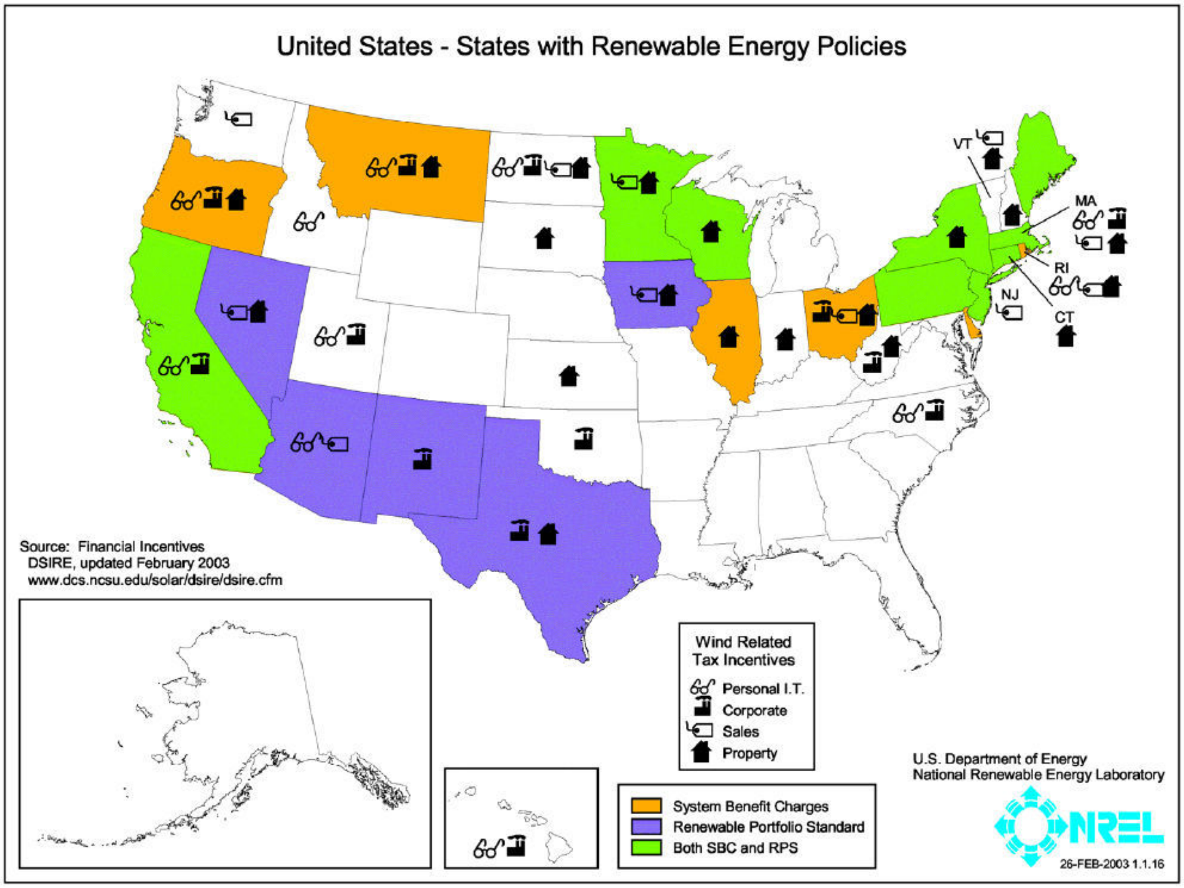
Several states have passed legislation to create incentives for companies to install or improve transmission equipment within their states. Most of these state programs are designed to create incentives for the integration of renewable resources into the transmission grid. In certain states, incentives are earned through development and use of renewable resources, but they may be applied to improving the overall transmission system.

Figure 16 summarizes which incentives different states have implemented to support renewable energy, of which a subset extends incentives to transmission. As can be seen from this map, states promote renewable resources using a combination of regulatory and financial incentives that include tax deductions as well as regulatory requirements.

147 IRS, Publication 946, *How to Depreciate Property*, Section 4: Figuring depreciation under MACRS, 2007. http://www.irs.gov/publications/p946/ch04.html

148 See Cornell University Law School, “US CODE: Title 26, 1245. Gain from dispositions of certain depreciable property,” http://www4.law.cornell.edu/uscode/uscode26/usc_sec_26_00001245----000-.html

Figure 16: Renewable Energy Policies by State[149]



Source: NREL (2003)

The matrix below provides an overview of the states that offer incentives for transmission investments related to renewable resources and the type of incentives they offer. Comparing Figure 16 to Table 9, it is clear that the states offering incentives for transmission to connect to locationally-constrained resources are the same states that have passed legislation to promote renewable resources. That said, the number of states extending financial incentives to transmission is a fraction of those that have created incentives in support of renewable resources.

149 State incentives developed by NREL and provided on Nevada's energy website: http://energy.state.nv.us/st_en_pol.ppt

Table 9: State Incentives for Transmission Investment

	Income Tax Credits	Property Tax Reduction/Rebates	R&D Grants	RPS Credits
Arizona		X		
California			X	
Missouri				X
Nevada		X		
North Dakota	X			
South Dakota		X		

Each type of incentive is described in more detail below.

7.2.1. Income Tax Credits

There are a variety of tax credits available for investment in renewable generation, and far less for the transmission investment required to connect those resources. In most cases, income tax incentives do not extend to transmission connection costs, even for the renewable resource. North Dakota is an exception, allowing any part of the unused income tax credit for installation of renewable resources to be sold or otherwise transferred to any North Dakota taxpayer who constructs or expands electric transmission lines in the state after August 1, 2007.[150]

7.2.2. Property Tax Reduction/Rebates

Although various states offer property tax reductions or rebates for renewable investment, only a few states extend the definition of such investment to transmission. For example, South Dakota enacted legislation for a two-part "alternate tax" to promote wind energy generation and related transmission. Each wind farm developer receives a rebate for up to 50 percent of the cost of transmission lines and collector systems for the integration of the wind farm.[151] In Arizona, "renewable energy equipment" is assessed at 20 percent of its depreciated cost for determining property tax, and includes electric transmission and distribution.[152] Nevada enacted a ten-year statute that allows certain businesses a

150 North Dakota Office of State Tax Commissioner, "Tax Incentives for Solar, Wind, and Geothermal Devices," 2005. http://www.nd.gov/tax//genpubs/energy.pdf

151 South Dakota State Legislature House Bill 1320ENR. http://legis.state.sd.us/sessions/2008/Bills/HB1320ENR.pdf

152 DSIRE, "Incentives by State: Incentives in Arizona," http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive_Code=AZ30F&state=AZ&CurrentPageID=1&RE=1&EE=1

50 precent property tax exemption for real and personal property used to generate electricity from renewable energy with a generating capacity over 10 MW.

7.2.3. Research & Development Grants

Research and development (R&D) grants tend to be available for developing renewable technologies. In some cases, such grants extend to transmission projects. For example, California's PIER Program awards $62.5 million annually to support electricity research, development, and demonstration projects. The governing statute, California Senate Bill 1250, specifically identifies the importance of R&D for new transmission and distribution to connect utility-scale renewable generation to the grid.[153] In 2007, the Commission awarded $6.1 million in contracts for transmission and distribution research to improve methods for siting new transmission lines and to research emerging technologies that help increase the amount of renewable resources used while reducing energy losses.[154]

7.2.4. RPS Credits

RPS policies require utilities and other load-serving entities to generate or procure a certain portion of their electricity from renewable resources. Generally silent on transmission, these policies generally focus on energy procurement. An exception is Missouri, where credits may be achieved through infrastructure improvements.[155]

7.3. CONCLUSION

State and Federal incentives for transmission infrastructure improvements related to the transmission and integration of locationally-constrained sources are not as abundant as those for development and operation of renewable generation. Federal property tax code allows for accelerated depreciation of certain electrical transmission equipment and further accelerated depreciation for renewable energy generation property. Cost recovery for transmission infrastructure investment is available to public utilities with the 2006 adoption of 116 FERC 61,057.

Some incentives do exist in states with RPS requirements (i.e., Arizona, California, Idaho, and Texas) and potential for high wind energy capacity (i.e., the Dakotas, Missouri, and Alaska). These states offer tax incentives and financing for expansion and improvements to their transmission systems,

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153 California Energy Commission, *Public Interest Energy Research (PIER) Program 2007 Annual Report*, April 2008. http://www.energy.ca.gov/2008publications/CEC-500-2008-026/CEC-500-2008-026-CMF.PDF

154 Ibid.

155 Missouri Revised Statutes, Chapter 393 Gas, Electric, Water, Heating, and Sewer Companies, Section 393.1025. http://www.moga.state.mo.us/statutes/C300-399/3930001025.htm

particularly with respect to renewable energy sources. Effective practices that have been put into place on the state level include:

- **Accelerated depreciation** for investment in transmission connection costs.
- **State income tax credits** for investment in transmission connection costs.
- **Property tax reduction/rebates** for investment in transmission equipment and land required to connect a facility to the transmission system, including rebates for up to 50 percent of the cost of transmission lines and collector systems for the integration of the wind farm and reduced property tax value assessments at 20 percent of depreciated cost.
- **Research and development grants** that identify the importance of R&D for new transmission and distribution to connect utility-scale renewable generation to the grid, including methods for siting new transmission lines and reducing energy losses from locationally-constrained areas.

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