STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS
PUBLIC UTILITIES COMMISSION

IN RE: Application of
Invenergy Thermal Development LLC's
Proposal for Clear River Energy Center

Docket No. 4609

PRE-FILED DIRECT TESTIMONY

OF

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Direct Testimony of Robert Fagan

Introduction

Q. Please state your name and occupation.

A. My name is Robert M. Fagan and I am a Principal Associate at Synapse Energy Economics.

Q. Please describe Synapse Energy Economics.

A. Synapse Energy Economics is a research and consulting firm specializing in electricity industry regulation, planning and analysis. Synapse works for a variety of clients, with an emphasis on consumer advocates, regulatory commissions, and environmental advocates.

Q. Please summarize your qualifications.

A. I am a mechanical engineer and energy economics analyst, and I've analyzed energy industry issues for more than 25 years. My activities focus on many aspects of the electric power industry, in particular: production cost modeling of electric power systems, general economic and technical analysis of electric supply and delivery systems, wholesale and retail electricity provision, energy and capacity market structures, renewable resource alternatives, including wind and solar PV, and assessment and implementation of energy efficiency and demand response alternatives. I hold an MA from Boston University in energy and environmental studies and a BS from Clarkson University in mechanical engineering. My resume is included as Attachment A hereto.

Q. Please summarize your specific experience and familiarity with electric power sector issues in Rhode Island.

A. My professional career began in Rhode Island, working for Narragansett Electric Company as a field engineer and eventually as supervisor of electrical operations and maintenance (early 1980s). I also worked as a senior energy specialist at Rhode Islanders Saving Energy (RISE), conducting commercial and industrial facility energy assessments (late 1980s/early 1990s) and supporting the implementation of burgeoning electric utility energy efficiency programs for commercial and industrial customers. After graduate school, my consulting work over the past 20+ years has focused on myriad electric power sector issues in regulatory jurisdictions throughout the US and Canada, and included detailed engagement on specific Rhode Island energy efficiency issues as part of Synapse's work on behalf of the Rhode Island Division of Public Utilities and Carriers (during the period 2007-2011).

Q. On whose behalf are you testifying in this case?

A. I am testifying on behalf of the Conservation Law Foundation ("CLF").

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address and critique aspects of Invenergy's Clear River Energy Center application (Invenergy plant, or Invenergy project, or Invenergy application)[1] and supporting documents, in particular assertions of reliability need for the proposed power plant.

Q. What documents do you rely upon in your analysis, and for your findings and observations?

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[1] Rhode Island Energy Facility Siting Board Application, Clear River Energy Center, Burrillville, Rhode Island. Prepared by ESS Group, Inc. October 28, 2015.

A. I rely upon the following documents:

1. ESS Group Inc., Application to the Rhode Island Energy Facility Siting Board, Clear River Energy Center (CREC), Burrillville, Rhode Island, October 28, 2015.
2. Independent System Operator of New England (ISO NE, or ISO) Capacity, Energy, Loads, and Transmission (CELT) forecast data from current (2016) and earlier CELT reports.
3. ISO NE Final 2016 PV Forecast (April 2016) and ISO NE Final 2015 Solar PV Forecast Details (April 2015).
4. ISO NE 2015 Regional System Plan (December 2015).
5. ISO NE Installed Capacity Requirements, Local Sourcing Requirements and Capacity Requirement Values for the System-Wide Capacity Demand Curve for the 2019/20 Capacity Commitment Period (January 2016), and earlier versions of similar filings to the Federal Energy Regulatory Commission (FERC).
6. Forward Capacity Auction #10 (FCA #10)[2] – 2019/2020 Capacity Commitment Period, Results Summary & Trends, March 23, 2016 (ISO NE Presentation).
7. ISO NE Internal Market Monitor 2015 Annual Markets Report, May 25, 2016.
8. ISO NE FERC Filing on Results of the Tenth Forward Capacity Market Auction (February 29, 2016).
9. Discovery request responses in this PUC docket and in the parallel RI EFSB Docket.

Summary Observations

Q. Please summarize your findings/observations.

A. I have three summary observations.

1) There is no near-to-medium term reliability need for the proposed Invenergy plant;

2) Existing and projected energy efficiency and behind-the-meter solar PV resources in New England more than supplant the energy output of the proposed plant and support a reliable electric sector in Rhode Island and New England without the proposed plant; and

3) There is no longer-term reliability need for the proposed plant.

1. **There is no near-to-medium term reliability need for the proposed plant**. The

[2] The ISO NE forward capacity market auction is a market-based three-year forward capacity procurement mechanism used by the ISO NE as part of the overall capacity market construct to ensure sufficient capacity is available to meet reliability needs.

proposed power plant is not needed for near-term New England or Rhode Island electric power sector reliability. Rhode Island and New England net loads (both peak load and annual energy, concepts I explain further below) exhibit declining trends, contrary to the applicant's assertions. The applicant offers no evidence of a near-to-medium term (within the next three to eight years)[3] reliability need for this specific proposed power plant. The ISO NE forward capacity market (FCM) auction framework put forth by the applicant in support of a reliability need is not indicative of reliability need, or even economic need, for the plant. Notably, only half of the proposed plant even cleared the tenth forward capacity market auction, in contrast to the applicant's estimation.[4] Indeed, the ISO's most recent forward capacity auction results cleared (or, established a financial supply obligation for) 1,416 MW *more* than the reliability requirement for New England for the 2019/2020 planning period, which was forecast in January 2016 by the ISO NE to be 34,151 MW (net installed capacity requirement).[5] This result directly indicates *surplus* capacity in excess of reliability requirements. The auction sets price in a spot capacity market, and supports resource procurement, but proposed new resources that clear in such an auction can sell the forward "capacity supply obligation"

[3] The most recent ISO NE Regional System Plan (November, 2015) lists "Future System Needs (MW)" through the summer of 2024. I use this end date and the proposed operation date of the Invenergy plant in 2019 as a definition of "near-to-medium term."
[4] Results of the ISO NE tenth forward capacity market auction (February, 2016) indicate that 485 MW of the Burrillville Energy Center cleared the auction. See, e.g., slide 6 of the ISO NE "Forward Capacity Auction #10 (FCA #10) – 2019/2020 Capacity Commitment Period, Results Summary & Trends," March 23, 2016, available at http://www.iso-ne.com/static-assets/documents/2016/03/a6_fca_10_results_summary.pptx. The Invenergy application indicated "PA's analysis suggests that the facility will clear the auction." Page 120.
[5] See ISO NE "Installed Capacity Requirements, Local Sourcing Requirements and Capacity Requirement Values for the System-Wide Capacity Demand Curve for the 2019/20 Capacity Commitment Period", January 2016, p. 10.

that is obtained, and other resources – either existing or new – can provide any eventual physical capacity need required to support regional reliability. Subsequent secondary market capacity auctions[6] held by the ISO NE update the actual closer-in-time reliability need and allow those who obtain a capacity supply obligation in a three-year forward capacity market auction to sell that obligation.

2. **Energy efficiency and behind-the-meter solar PV dramatically lower ISO NE net load forecasts and support reliability without the proposed plant.** ISO NE energy efficiency and behind-the-meter solar PV resource projections for New England as a whole more than supplant the energy output of the proposed plant, and contribute to ensuring the reliability of the electric power system without the presence of this proposed plant by directly contributing to reduced net peak loads[7] in New England and Rhode Island. ISO NE projections of energy efficiency and behind-the-meter solar PV output *from Rhode Island alone* approach estimated energy output levels for the portion of this proposed plant that actually cleared the ISO NE's tenth FCA, which as noted was only half of the applicant's dual-unit plant proposal. The applicant ignores or minimizes the effect that these resources, and other renewable resource supplies, can have on reliability needs in

[6] See for example a description of the annual reconfiguration auctions and how secondary forward capacity auctions work, in the 2015 Annual Market Report by the ISO NE Internal Market Monitor. Available at http://www.iso-ne.com/static-assets/documents/2016/05/2015_imm_amr_final_5_25_2016.pdf.

[7] "Net peak load" as used throughout this testimony is in reference to the summer peak loads seen on the transmission grid and used by ISO NE when assessing reliability. They are net of the peak-load reducing effects of energy efficiency and behind-the-meter solar PV. Net annual energy is a reference to the *annual* energy (in kilowatt hours (kWh), or Gigawatt-hours (GWh = 1 million kWh) consumed, and is also net of the effects of energy efficiency and behind-the-meter solar PV. I note that net annual energy is *not* net of the contributions that transmission-grid-connected renewable resources (utility-scale wind, solar, and hydro) can make to further reducing the need for fossil-fueled energy generation.

both the near-to-medium term and the long term.

3. **No long-term need for the proposed plant**. The proponent offers no evidence of any longer-term reliability or other need for the proposed plant. They incorrectly inflate the energy forecast need for Rhode Island and New England. Their narrative on alternative energy resources, including energy efficiency and renewable energy resources, is completely absent of any quantitative analysis of the effect of a portfolio of energy efficiency and renewable resource supply as an alternative to the proposed plant. When considering energy efficiency and alternative new resources including behind-the-meter solar PV, other solar PV (utility scale), onshore wind, offshore wind, Canadian hydro, demand response, and storage alternatives - in addition to existing capacity resources and a recently strengthened New England transmission system - near-term and long-term reliability of Rhode Island and New England electric power sectors can be assured without reliance on the proposed power plant.

Q. How is your testimony structured?

A. I first explain the fundamental underpinnings of potential reliability needs for supply or demand side resources in New England and Rhode Island. I address the role that the ISO NE forward capacity market, including the forward capacity auction (FCA) and its follow-on "reconfiguration auctions"[8] plays in addressing – but not defining - these needs. I next discuss

[8] Reconfiguration auctions are described in a number of places in the ISO NE market rules and related tariff documents. The ISO NE internal market monitor report provides a summary: "Reconfiguration auctions enable the exchange of capacity supply obligations [CSO]. Each clearing price and quantity in the reconfiguration auctions depends on the amount of CSO MW market participants are willing to acquire and transfer. Market participants may submit an offer to increase or a bid to decrease a resource's total obligation. Reconfiguration auctions are also used to adjust the total capacity supply obligation amount based on updated requirements (ICR, LSR). The ISO can purchase to make up shortfalls in any annual reconfiguration auction, or buy back excess in the last annual

the critical and timely effects of energy efficiency and behind-the-meter solar PV resources in lowering net demand (both summer peak, and annual energy) in the New England region and in Rhode Island, and what that implies for reliability and the need for the proposed plant. Lastly, I address longer-term issues by discussing the ISO NE regional planning information and how it might be applied to considerations of reliability need for this proposed plant. I comment on the lag that exists in the ISO NE forecasting process, and how future needs are likely even lower than data from the most recent ISO NE Regional System Plan, and the ISO NE 2016 CELT (Capacity, Energy, Loads, Transmission) indicate. Throughout, I provide specific critiques of certain assertions in Invenergy's application.

Reliability Needs and the ISO NE Forward Capacity Market Auction

Q. The Invenergy application implies that the proposed plant is needed to meet reliability needs of Rhode Island and the New England region.[9] Is it?

A. No, the proposed Invenergy plant is not needed to support electric power sector reliability in Rhode Island or in the New England region. A reliable power system requires sufficient resources and a secure transmission system, both of which currently exist in Rhode Island and New England without the Invenergy plant, and both of which will be in place in Rhode Island and New England if the proposed plant is not built.

reconfiguration auction. Three annual auctions are conducted between the FCA and the commitment period, for the entire commitment period. There are also monthly reconfigurations auctions for each month of the commitment period." ISO NE, Internal Market Monitor Report, May 25, 2016, page 130.

[9] Rhode Island Energy Facility Siting Board Application, Clear River Energy Center, Burrillville, Rhode Island. Prepared by ESS Group, Inc. October 28, 2015. Section 7.2.2, "Analysis of Need – Reliability," and more generally, Section 7.0, "Assessment of Need."

Q. What is system reliability?

A. System reliability[10] consists of having sufficient resources to meet load at all times (which is generically referred to as "resource adequacy" in the electric power industry),[11] and a secure transmission system that can withstand contingencies (such as the loss of a transmission line, or successive losses of multiple transmission lines, or the loss of a major generation plant, during a time of high system load). North American Electric Reliability Corporation (NERC) standards[12] provide the high level guidance that Regional Transmission Organizations (RTOs) such as ISO NE follow to ensure both resource adequacy and transmission security.

Q. On what basis does the Invenergy application claim that its plant is needed for reliability purposes?

A. Invenergy erroneously claims that the ISO NE forward capacity market and its attendant forward capacity auctions (FCAs) "determine both system-wide and localized needs for both existing and new generation capacity through a competitive auction process…"[13] This is not correct; the FCM mechanisms do not determine need. Need is determined in the ISO NE annual filings to FERC[14] defining the parameters to use in the subsequent FCA, and is updated on an

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[10] System reliability as used here does not refer to distribution system outages or interruptions due to, for example, localized equipment failure or weather-related events.
[11] More specifically, reliability standards for resource adequacy in the U.S. electric power industry generally require no more than a one-in-ten years' frequency of "loss of load" events arising from a resource shortage. Based on this determination, regions can determine planning reserve margins to ensure adequate installed capacity resources.
[12] The complete set of NERC reliability standards are available here: http://www.nerc.com/pa/Stand/Reliability%20Standards%20Complete%20Set/RSCompleteSet.pdf.
[13] Invenergy application, page 115.
[14] For 2019/2020, this need was determined to be 34,151 MW of net installed capacity. See "ISO NE Installed Capacity Requirements, Local Sourcing Requirements and Capacity Requirement Values for the System-Wide Capacity Demand Curve for the 2019/20 Capacity Commitment Period (January, 2016)," available at http://www.iso-ne.com/static-assets/documents/2016/01/icr_values_2019_2020_report_final.pdf.

annual basis.

Q. What is the forward capacity market and the attendant forward capacity auctions?

A. The forward capacity market (FCM) is the construct put in place by the ISO NE (and approved by FERC) for obtaining and selling capacity resources. The time horizon of the FCM starts with a three-year forward auction process, but continues with closer-in-time annual reconfiguration auctions, and bilateral trading opportunities in even monthly increments. In short, it is a spot market for capacity. The FCM construct, through its FCAs and bilateral contracting arrangements,[15] represent procurement arrangements but they do not determine need. The FCA for any given year – they are held each year for a single-year planning period beginning three years later – is not determining need for that year, but is rather clearing an administratively complex capacity market based on a projected forecast of resource need three years out. It is also not determinative of need for any future year or years beyond the planning period to which it applies. The most recent FCM auction in New England (known as FCA 10 or the tenth forward capacity auction held since the inception of the forward capacity market construct) was held in February of 2016.

Q. What were the relevant results of the FCA 10?

A. Two salient points can be taken from the results of the tenth FCA.

First, based on revised zonal boundary assumptions, the SEMA/RI zone no longer exists in New England,[16] replaced with a larger "Southeast New England" (SENE) zone that

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[15] Parties with "capacity supply obligations" can generally trade those obligations to other parties at market rates.

[16] The SEMA/RI zone was a defined region composed of Rhode Island and southeastern Massachusetts. In the ninth FCA, the SEMA/RI zone cleared at a relatively high price, indicating an estimated near-term shortage of capacity

encompasses Rhode Island and much of eastern Massachusetts. The SENE zone was modeled as an import-constrained zone in advance of FCA 10. However, transmission constraints between the SENE zone and the rest of New England did not bind in the tenth forward capacity auction (the cleared spot capacity prices were the same on either side of the interface). The interface between SENE and the rest of New England is relatively strong, and includes recently-completed upgrades and new 345 kV facilities in and around the Rhode Island, Connecticut and Massachusetts borders.[17] No price premium was given to any resource because of its location in a considered import-constrained zone. This illustrates that resources throughout the rest of New England can compete to serve load in all locations in New England, and renders less important any particular proposed plant, or the need to locate in a particular zone in New England to support reliability. To the extent that net peak load trajectories continue to decline in New England, it would continue to be less likely that such constraints would bind in future auctions.

Second, the clearing price in FCA 10 was relatively low ($7.03/kW-month) compared to the clearing price for the SEMA/RI zone in the previous, ninth FCA (more than $17/kW-month). This indicates that in the span of just one year, market and transmission arrangements had changed so much that supply/demand pressures in the Rhode Island/Southeast Massachusetts region were greatly relieved – indeed, the low clearing price in FCA 10 was directly an artifact of

for the region. With completed transmission improvements and an updated load and resource forecast for FCA 10, the zone was eliminated in favor of a larger regional zone.

[17] See, for example, the southern portion of the New England transmission map (Attachment D) which shows the recently completed reinforcements as part of the interconnected grid.

the 1,431 MW surplus capacity cleared in the auction.[18] This is due in part to the ISO's direct use, for the first time in FCA 10, of an explicit forecast of peak load that accounts for the presence of behind-the-meter solar PV in addition to energy efficiency impacts in New England.[19]

Q. What was the result of the FCA 10 in regards to the Invenergy plant?

A. The Invenergy plant is a proposed two-unit, 850-1000 MW combined cycle plant.[20] Only one of those two units cleared the FCA 10 auction. If one were to use Invenergy's own (flawed) definition of reliability need, only one of the 2 units would be needed based on the result of the auction.

Q. Does the Invenergy application present any evidence for a near-term reliability need for the proposed plant?

A. No. The applicant relies on the prospective results of the ISO NE capacity market auction to indicate a reliability need for the plant. They state "In other words, if the facility clears FCA 10, then ISO-NE will have determined CREC to be a needed resource that maximizes social surplus to meet the overall system-wide and local reliability needs of ISO-NE."[21]

Q. Is it true that clearing the FCA 10 means that ISO-NE has determined a reliability need for this plant?

A. No, not at all. Physical reliability needs are defined, in the near-term (for the three-year

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[18] See Attachment F.
[19] See ISO NE "Installed Capacity Requirements, Local Sourcing Requirements and Capacity Requirement Values for the System-Wide Capacity Demand Curve for the 2019/20 Capacity Commitment Period" (January, 2016), pages 27-28.
[20] Invenergy project application, page 1.
[21] Invenergy project application, page 116.

ahead, 1-year period covered by any given FCA) by the installed capacity requirement for the New England system as a whole, and by the local sourcing requirements. A proposed resource such as the Invenergy plant clearing the FCA means that the resource obtains a capacity supply obligation – a financial obligation - but it doesn't mean that the resource is physically needed for reliability. In subsequent "reconfiguration" auctions, the capacity supply obligations can be sold, or traded, to other parties; and/or, the resource need for the given FCA period may be updated with the most recent forecast information available.

Energy Efficiency and Behind-the-Meter Solar PV Supplant the Output of the Proposed Plant and Contribute to Reliability

Q. In this section you use two related, but distinct terms: net peak load, and annual net energy. Please define and explain these terms.

A. Net peak load (in megawatts, or MW) is the summer peak load (or maximum rate of power consumption seen all year, in MW, occurring in the summer) net of the load-reducing effects of energy efficiency, and net of the peak output of solar PV that is installed behind customer meters ("behind-the-meter solar PV" or BTM solar PV). ISO NE, in its annual CELT reports, provides forecasts for both gross peak load and net peak load. Annual net energy is the annual energy consumed net of the effects of both energy efficiency and the output of BTM solar PV. As with peak load reporting, ISO NE reports both gross and net energy usage on an annual basis. In this testimony, I refer to New England, and to Rhode Island, when using these terms. ISO NE provides (in its CELT reports) historical and forecast data for these metrics for the entirety of New England, and for each state. Lastly, in general I use ISO NE's "50/50" net peak load forecast. ISO NE provides two peak load forecasts: its 50/50 forecast, and its 90/10 forecast. The 50/50 forecast is the forecast of peak load for which there is a 50% probability it will be higher, and a 50% probability it will be lower.[22] This 50/50 peak load value is the forecast value ISO NE uses in assessing resource adequacy for reliability purposes.[23] The 90/10 peak load forecast is a forecast peak load for which there is a 10% chance that the peak load will be higher, and a 90% chance that it will be lower. I do not use the 90/10 metrics in this testimony.

Q. Please summarize this section.

A. Energy efficiency and behind-the-meter solar PV result in declining net peak load and declining annual net energy needs in New England and Rhode Island. Net peak load and net energy are the peak load seen by, and the energy needed from, the transmission grid; net peak load is equal to gross load minus the effect of energy efficiency and behind-the-meter solar PV. The existence of these resources alone – energy efficiency and behind-the-meter solar PV – lowers forecast net demand. When coupled with existing capacity resources, additional utility-scale solar PV, and a much-enhanced transmission grid across New England, near-term reliability for Rhode Island and the New England region is ensured without the proposed Invenergy plant.

Q. What is the historical pattern of electric peak load and electric energy consumption in Rhode Island and New England as a whole?

A. Figures 1 and 2 show the pattern of net peak load and annual energy consumption in

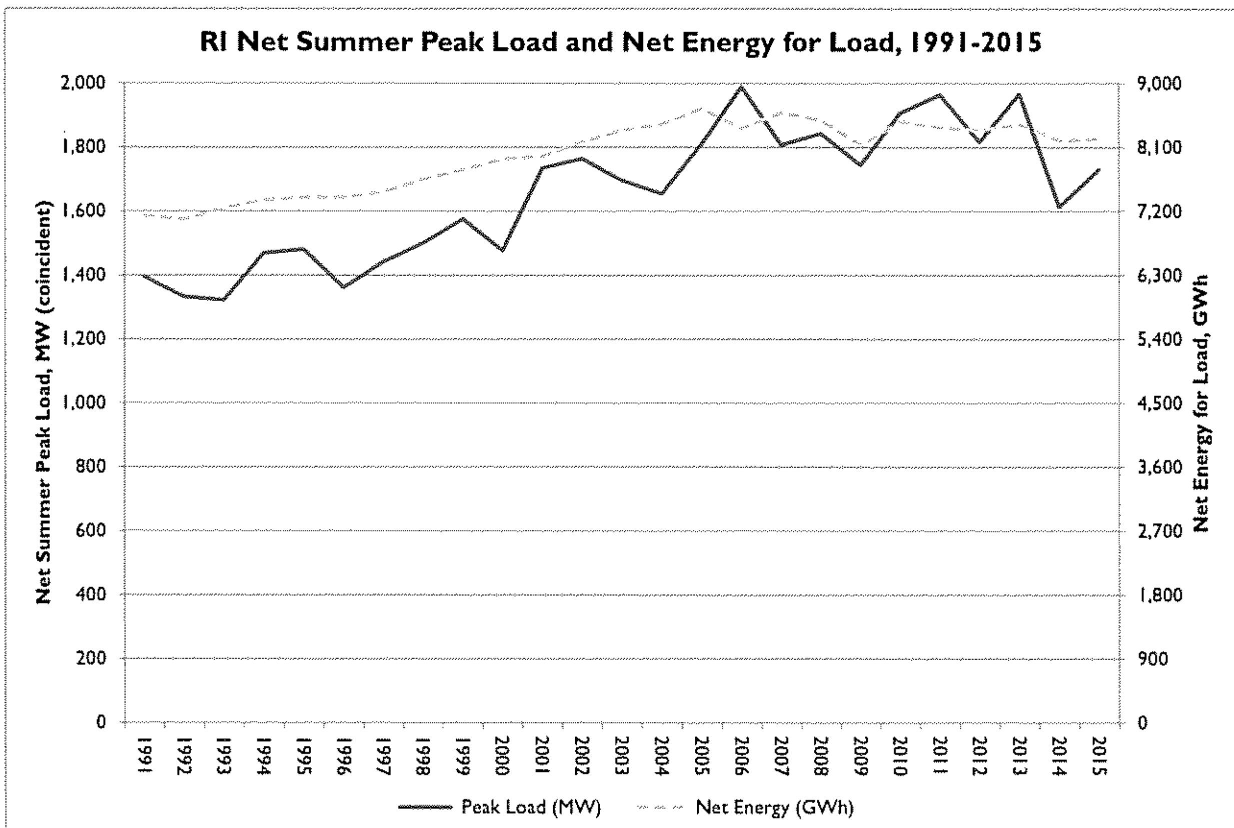
[22] See the ISO NE 2016 CELT, Tab "1.6 Frcst Distributions".
[23] See for example, ISO NE 2015 Regional System Plan, Table 4-7, Future Systemwide Needs (MW), using 50/50 Peak Load when determining representative net ICR (installed capacity requirement) need.

Rhode Island and New England. The values shown are from actual ISO NE 2016 CELT data.

Q. What do these figures illustrate?

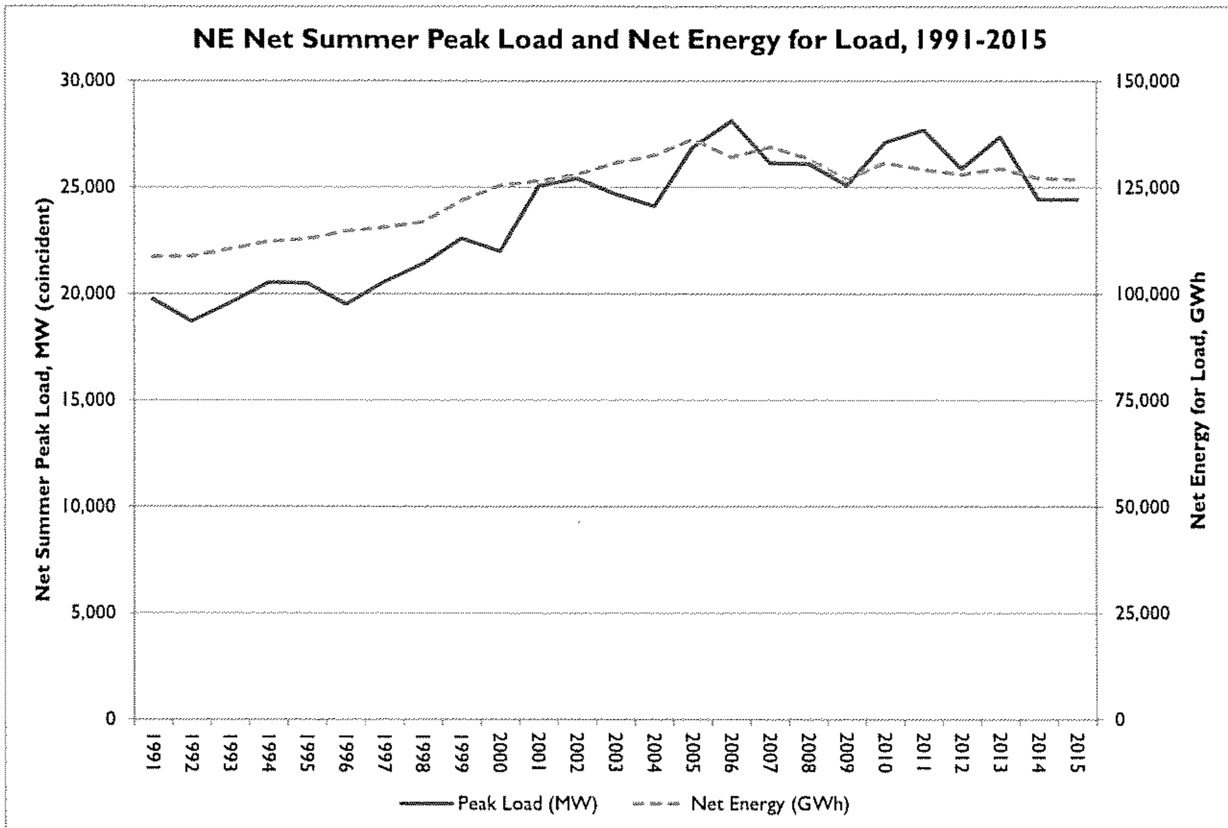
A. The figures show that for both Rhode Island, and New England as a whole, net electricity load has flattened (both summer net peak load, and annual net energy), and has begun to trend downward over the past decade, contrary to the assertion made by Invenergy.[24]

Figure 1. Rhode Island Summer Peak Load and Annual Net Energy for Load, 1991-2015



[24] Invenergy Application, page 121, "The State of Rhode Island's electric generation portfolio has scarcely changed over the past decade while energy use and specifically the use of electricity has significantly increased over the same period."

Figure 2. New England Summer Peak Load and Annual Net Energy for Load, 1991-2015



Note: Net energy for load is energy net of energy efficiency and behind-the-meter (BTM) solar PV resources. Net summer peak load is summer coincident peak load, net of the effects of energy efficiency and BTM solar PV. Source: ISO NE, 2016 CELT.

Q. What is the cause of the change to the often-heard conventional wisdom that electric load is growing?

A. There are multiple factors, but two dominating factors are Rhode Island's increasing investment in energy efficiency resources,[25] and its investment in behind-the-meter solar PV resources. Rhode Island also has significant levels of utility-scale solar PV resources, in addition to its behind-the-meter solar PV resources.

[25] See, for example, Rhode Island PUC approval of the most recent three-year energy efficiency plan, which projects annual electric efficiency achievements of 2.5% (2015), 2.55% (2016), and 2.6% (2017). RI PUC, Docket 4443.

Q. What level of solar PV exists in Rhode Island, and what levels are forecast for Rhode Island?

A. As of the end of 2015, 23.6 MW exists, of which 6.4 MW is behind-the-meter. Through 2020, 158.2 MW of additional solar PV is projected to be added, for a cumulative amount of 181.8 MW. 52.6 MW of this cumulative amount is behind-the-meter solar, impacting the net peak demand and energy forecast for Rhode Island. Through 2025, ISO NE projects a total of 217.2 MW of solar PV in Rhode Island. Of this amount, 63 MW is behind-the-meter solar PV.[26]

Q. How do solar PV resources – either behind-the-meter, or utility scale – support reliability needs in New England, and Rhode Island?

A. Behind-the-meter solar PV resources reduce peak load and the attendant distribution and transmission losses that occur on peak; they are accorded a peak-load-reducing credit proportional to their output during times of peak demand. Peak demand occurs after the time of peak solar PV output, but still reduces peak by a value currently equal to roughly 40% of their nameplate AC rating.[27] Solar PV contributes to reducing peak load because total nameplate capacity is producing (albeit at lower than maximum levels) during the peak hours, which occur in the mid to later afternoon in New England. Behind-the meter solar PV also reduces peak period losses on the transmission and distribution system.

Q. How do energy efficiency resources help ensure reliability in New England?

[26] See ISO NE Final 2016 PV Forecast, Distributed Generation Forecast Working Group, April 15, 2016. Pages 9 and 31.
[27] See 2016 ISO NE CELT, Tab 3.1.2 PV Forecast - BTM MW, which indicates a 40% peak load reduction credit for 2015, decreasing to 34.1% by 2025. The value reduces over time because the time of net system peak is moving towards later in the day, when solar output is lower (than earlier in the day).

A. Energy efficiency resources reduce peak load by reducing end use load during times of system peak, including reduced lighting, air conditioning, and other loads.

Q. How do energy efficiency and behind-the-meter solar PV resources together help ensure reliability in New England?

A. Energy efficiency and behind-the-meter solar PV resources exert continuous downward pressure on net peak load and net annual energy trajectories in New England, and in Rhode Island. Over the past decade or so, the effect of the presence of energy efficiency resources (and more recently, in combination with behind-the-meter solar PV resources) has been to flatten out or turn negative the projected annual load growth in New England and Rhode Island. The forecast for net load has only very recently turned negative, as seen by comparing the 2016 CELT forecast for net energy needs with earlier CELT forecasts. Figures 3 through 6 below demonstrate the trends, by showing: (i) successive vintage CELT forecasts of New England net energy for load (Figure 3); (ii) the impact of energy efficiency and behind-the-meter solar PV, by showing gross and net energy for load projections for New England (Figure 4); (iii) successive vintage CELT forecasts of Rhode Island net energy for load (Figure 5); and (iv) the impact of energy efficiency and behind-the-meter solar PV, by showing gross and net annual energy load projections for Rhode Island (Figure 6).

Figure 3. Net Energy for Load - Forecast Trends in New England by Forecast Vintage

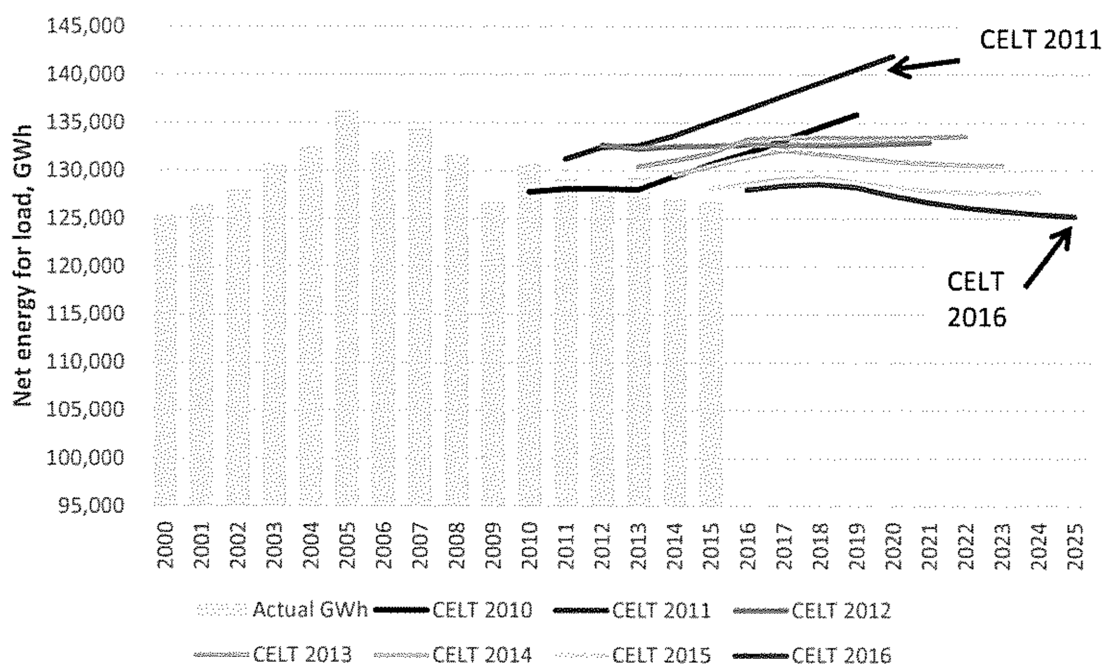


Figure 4. Gross and Net Energy for Load – EE, Solar PV Forecast Effects in New England

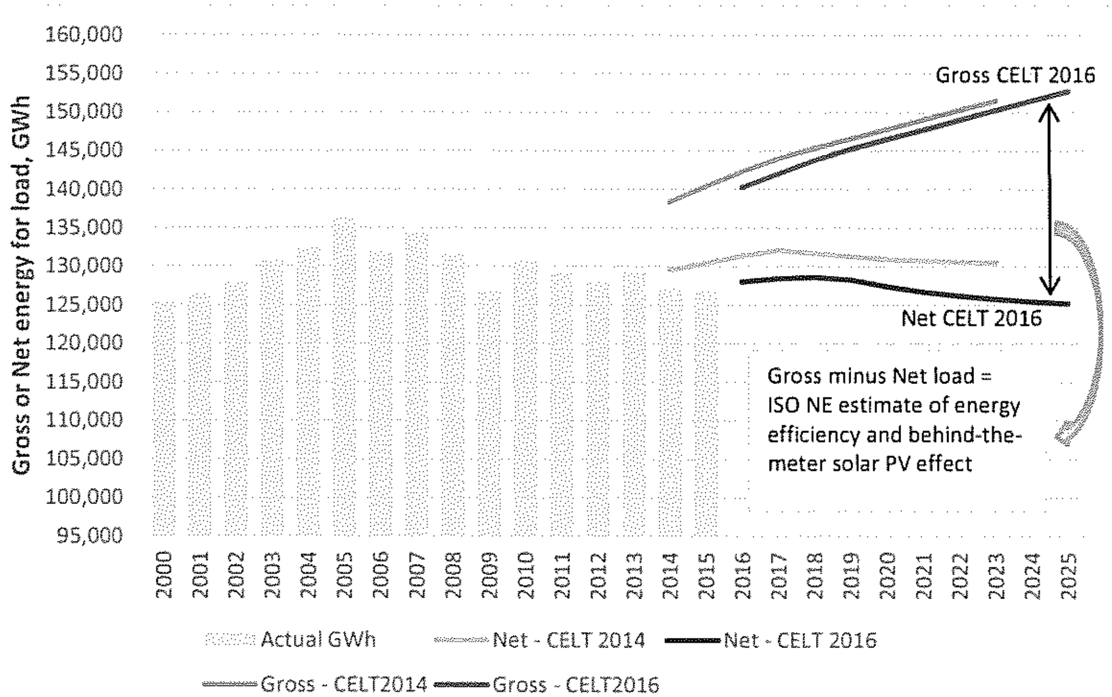


Figure 5. Net Energy for Load - Forecast Trends in Rhode Island by Forecast Vintage

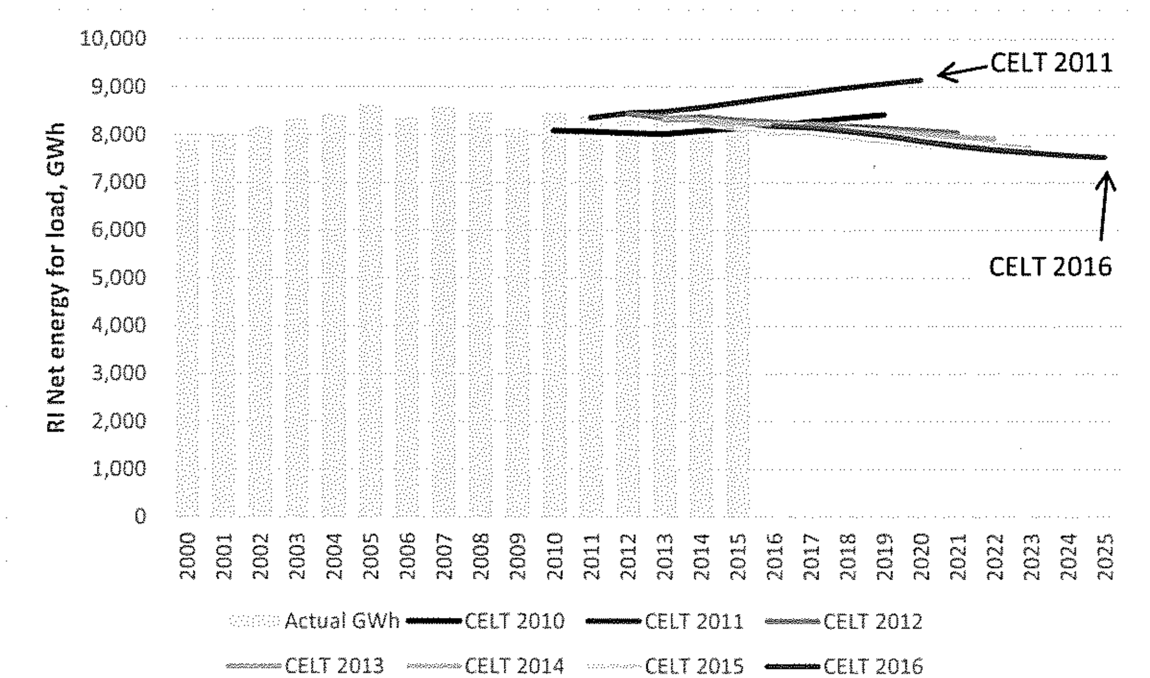
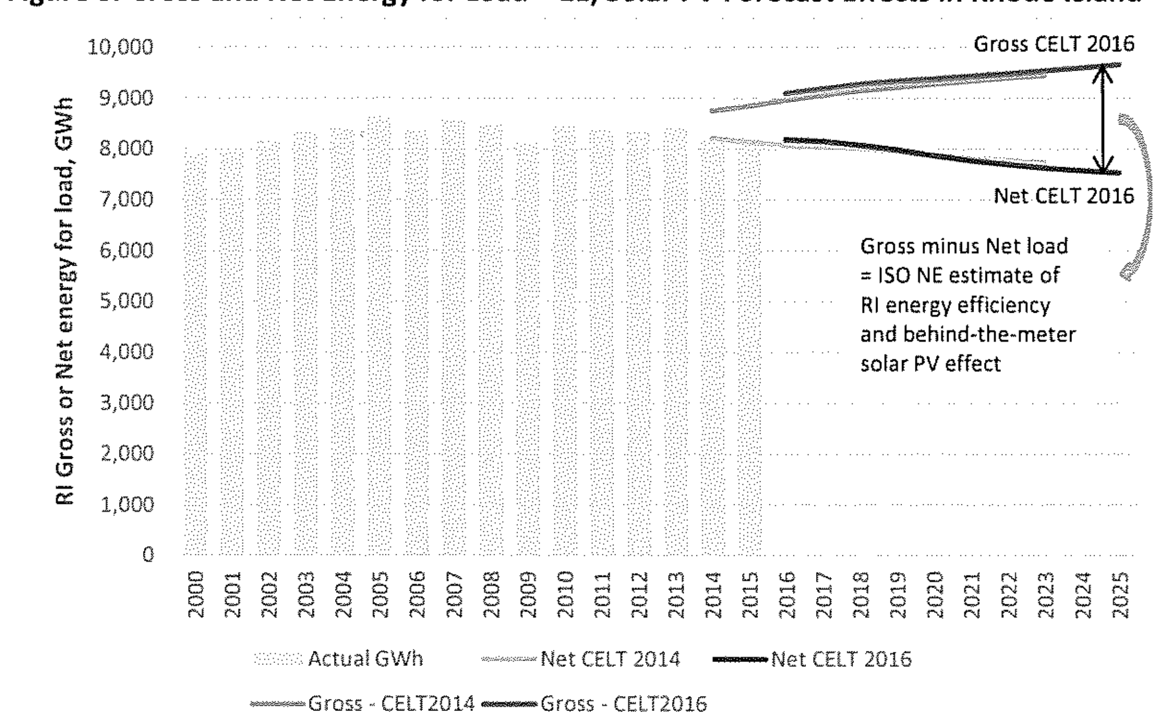


Figure 6. Gross and Net Energy for Load – EE, Solar PV Forecast Effects in Rhode Island



Source, Figures 3 through 6 - ISO NE, CELT Reports Data, 2010-2016, compilation by Synapse

Q. Please summarize your observations of what Figures 3 through 6 illustrate.

A. The data in Figures 3 through 6 illustrate that net energy needs are declining – and these data do not account for the impact that future new renewable resources other than behind-the meter solar PV may have on energy needs for the New England system. Thus the graphs illustrate that the net energy that needs to be provided from the grid – from utility scale renewables, hydro, nuclear, and conventional fossil fuel resources – is declining. To the extent that new grid-scale renewables resources are built, the net energy needs from conventional natural gas-fired resources decline even more than these graphs indicate.

Q. Can these resources – energy efficiency, and behind-the-meter solar PV in New England, or in Rhode Island - displace the energy that might otherwise be produced by the proposed Invenergy plant?

A. Yes, certainly if one considers New England-wide energy efficiency and solar PV; and even if one considers the ISO NE's current (likely underestimated)[28] trajectory of energy efficiency and solar PV resources in Rhode Island alone, they could provide much of the output of a 500 MW combined cycle plant, depending on the assumed or modeled level of output for the plant. Figure 4 above and Table 1 below show New England-wide energy efficiency and behind-the-meter solar PV resource output in even the first year of possible operation of the proposed Invenergy plant (i.e., 2019) as far exceeding the estimated output of the plant (4,104 GWh/year, see Table 1). Table 1 below contains the estimates for annual energy output from

[28] I address this point later in my testimony. The ISO NE forecast of solar PV resources in 2015 for future years was significantly lower than the ISO NE 2016 forecast for solar PV resources in those same future years.

energy efficiency and behind-the-meter solar PV from New England and from Rhode Island, and includes Invenergy's estimate of the annual energy output of the proposed plant. For additional comparison, it shows the energy output of a 500 MW combined cycle plant operating at a 50% annual capacity factor.

Table 1. Comparison of Annual Energy Provision by 500 MW Invenergy Plant, and New England and Rhode Island Behind-the-Meter Solar PV and Energy Efficiency Resources As Projected by ISO NE in the 2016 CELT

<table>
<tr><th>Annual Output, GWh</th><th>2020</th><th>2025</th></tr>
<tr><td>NE EE and BTM solar PV</td><td>19,078</td><td>27,518</td></tr>
<tr><td>RI EE and BTM solar PV</td><td>1,522</td><td>2,139</td></tr>
<tr><td></td><td></td><td></td></tr>
<tr><td>Invenergy plant average first three Years of operation – response to CLF-2-5. Equal to ~500 MW plant at 94% annual capacity factor (CF).</td><td colspan="2">4,104</td></tr>
<tr><td>500 MW plant at 50% annual CF</td><td colspan="2">2,190</td></tr>
</table>

Source: Gross and net load data from ISO NE, 2016 CELT. Specific Invenergy plant value from response to CLF-2-5. Output of 500 MW plant at 50% CF computed by Synapse.

Q. What will be the annual energy output of the proposed Invenergy plant?

A. Invenergy's response to CLF-2-5 indicated that the plant would produce roughly 4,104 GWh per year, on average over its first three years of operation. Depending on the output capacity considered for the plant, that level of output represents an annual capacity factor of roughly 47% (for a 1000 MW plant) or 94% (for a 500 MW plant).

Q. What do the ISO's net peak load forecasts reveal for New England and Rhode Island?

A. The net peak load forecast patterns are similar to that seen with energy, though the current CELT forecast indicates slightly increasing net peak load in New England, and slightly decreasing net peak load growth in Rhode Island, over the 2016-2025 period. Figures 7 and 8 show these data. For New England, the compound annual growth rate (CAGR), 2016-2025, is 0.17%. For Rhode Island, the CAGR is -0.07% (negative).

Q. Do you have an opinion on whether the net peak load growth in New England will actually reach zero, or begin to be negative, any time soon?

A. Yes. In my opinion, given the trends seen in subsequent net peak load forecasting in recent CELT reports, and looking at the overall historical trends seen in New England (1991-2015, Figure 2, and the pattern of lower forecast net peak growth with later forecast vintages seen in Figure 7, below), it is reasonable to project that the net peak load growth will continue to flatten towards zero or be negative as soon as over the next few years.

Q. What effect will a negative net peak load forecast have on reliability?

A. It would lead to reliability needs being secured with generally lower total capacity resources than would be needed if the peak load increased.

Q. And what effect will a net negative peak load forecast have on the putative need to build the Invenergy facility?

A. It would make any assumed need for the Invenergy plant less important, because a relatively greater surplus of capacity to meet reliability needs would exist if the future net peak load forecast was lower.

Figure 7 – New England Net Peak Load Forecast

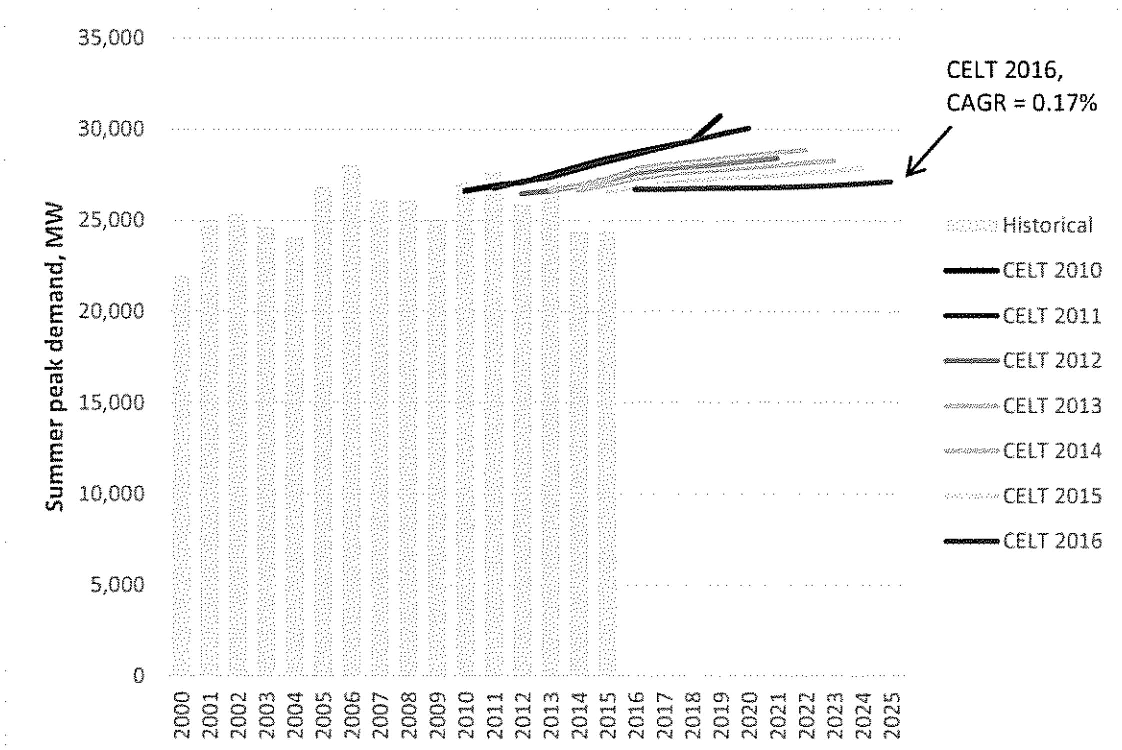
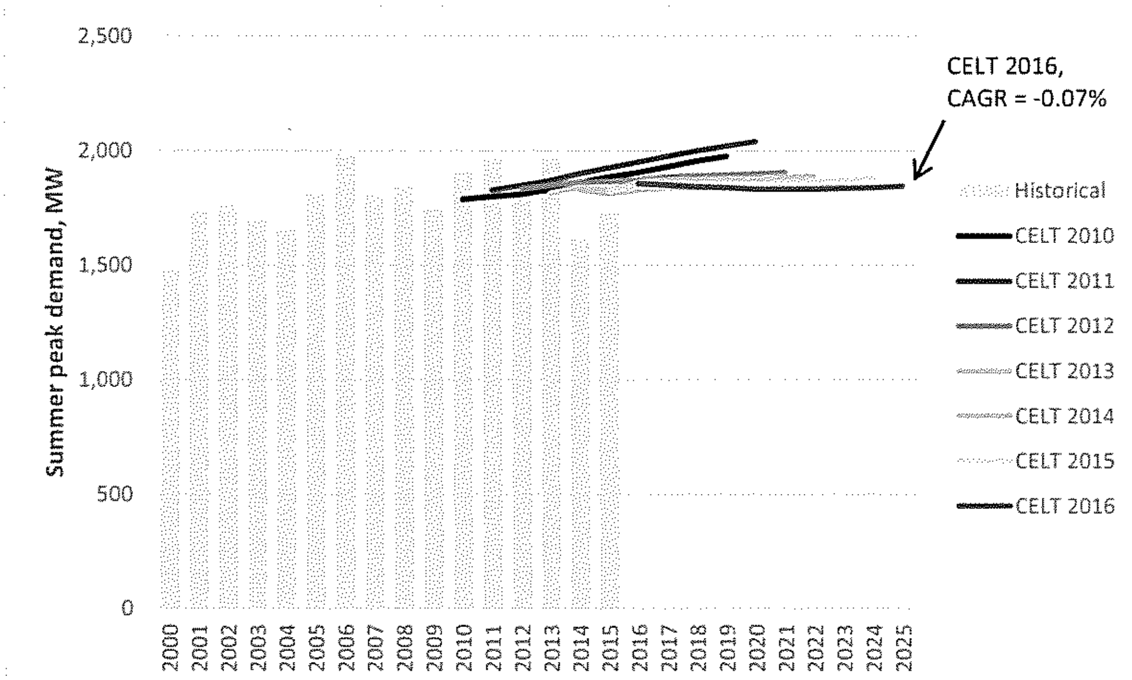


Figure 8 Rhode Island Net Peak Load Forecast



Source: ISO NE CELT data, 2016, 2015, 2014, 2013, 2012, 2011, 2010.

Q. Are there other renewable resources, besides behind-the-meter solar PV, that could displace the energy otherwise provided by the proposed Invenergy plant?

A. Yes, certainly. Utility-scale solar PV, onshore wind, offshore wind, and hydro resources from Canada could all displace the energy, and capacity, that might otherwise be provided by the Invenergy facility, or other new natural gas plants for that matter. The above Table 1 and Figures 1-8 illustrate the relative scale of the output of the proposed facility and the scale of the demand-side energy efficiency and behind-the-meter resources that could displace Invenergy plant output.

Q. Are there specific reasons to think that the solar PV forecast contained in the current CELT report is conservative – i.e., is lower than what will actually occur?

A. Yes. The ISO NE 2016 solar PV forecast resulted in a significantly higher level of solar PV projected for New England than the previous ISO NE forecast. Figures 9 and 10 below show, respectively, the current forecast levels (in a table taken directly from the ISO NE presentation document) and last year's 2015 solar PV forecast. Figure 11 is a comparison between last year's forecast, the earlier 2014 forecast, and this year's forecast in graphical form, from ISO NE. As seen, there was a dramatic increase in projected solar PV resources in 2016 compared to the 2015 forecast, which itself exhibited a significant increase above 2014 projections.

Q. What reasons might exist for next year's forecast for solar PV resources in a given year being greater than this year's forecast?

A. The underlying economics of solar PV drive the increasing penetration of the resource. Solar PV costs have dropped dramatically over the past few years, and are expected to continue to decline in cost.[29] The ISO also assumes that "historical PV growth trends across the region are indicative of future intra-annual growth rates[,]"[30] but declining solar PV costs could reasonably result in increases to the future growth rates, relative to historical patterns.

Figure 9. ISO NE Solar PV Final Forecast, 2016

Final 2016 PV Forecast

Nameplate, MW_{ac}

Note: Values in red boldface have changed relative to the draft forecast

States	Annual Total MW (AC nameplate rating)											Totals
	Thru 2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	
CT	188.0	85.5	104.5	81.0	81.0	81.0	55.8	54.3	45.0	45.0	45.0	866.1
MA	947.1	294.4	122.7	69.7	38.7	38.7	38.7	38.7	38.7	38.7	38.7	1,705.0
ME	15.3	4.7	4.7	4.4	4.4	4.4	4.2	3.9	3.9	3.9	3.9	57.9
NH	26.4	13.3	7.6	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	79.3
RI	23.6	21.6	38.7	36.0	36.0	25.9	9.1	6.6	6.6	6.6	6.6	217.2
VT	124.6	30.2	23.8	22.5	22.5	22.5	21.3	20.0	20.0	20.0	20.0	347.3
Regional - Annual (MW)	1325.0	449.6	301.9	217.7	186.7	176.5	133.2	127.5	118.2	118.2	118.2	3,272.8
Regional - Cumulative (MW)	1325.0	1774.7	2076.5	2294.2	2480.9	2657.4	2790.6	2918.1	3036.3	3154.6	3272.8	3,272.8

Notes:

(1) Forecast values include FCM Resources, non-FCM Energy Only Generators, and behind-the-meter PV resources

(2) The forecast reflects discount factors to account for uncertainty in meeting state policy goals

(3) All values represent end-of-year installed capacities

[29] Solar PV costs have declined dramatically over the past five years, and are projected to continue to decline. See, for example, Attachment G of this testimony, from the US DOE, Solar Energy Technologies Office, "On the Path to Sunshot: Executive Summary," Figure 1. Solar PV LCOE – historical, current, and 2020 targets (page 4).

[30] ISO NE Final 2016 PV Forecast, slide 12.

Figure 10. ISO NE Solar PV Final Forecast, 2015

Final 2015 PV Forecast

Annual Nameplate (MW_{ac})

States	Annual Total MW (AC nameplate rating)											Totals
	Thru 2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	
CT	118.8	70.9	89.9	45.8	43.1	40.4	40.4	26.9	26.9	26.9	26.9	556.8
MA	666.8	197.0	229.8	51.4	48.4	45.4	45.4	30.2	30.2	30.2	30.2	1,405.1
ME	10.4	2.2	2.2	2.0	1.8	1.7	1.7	1.7	1.7	1.7	1.7	28.9
NH	12.7	4.3	4.3	3.8	3.6	3.4	3.4	2.3	2.3	2.3	2.3	44.4
RI	18.2	9.7	20.4	27.2	31.0	29.0	20.6	7.1	5.4	5.4	5.4	179.3
VT	81.9	40.4	40.4	22.3	13.9	6.3	6.3	6.3	6.3	6.3	4.2	234.7
Regional - Annual (MW)	908.8	324.3	386.9	152.4	141.7	126.2	117.8	74.6	72.9	72.9	70.8	2,449.1
Regional - Cumulative (MW)	908.8	1233.1	1620.0	1772.4	1914.1	2040.3	2158.1	2232.6	2305.5	2378.4	2449.1	2,449.1

Notes:

(1) Forecast values include FCM Resources, non-FCM Energy Only Generators, and behind-the-meter PV resources

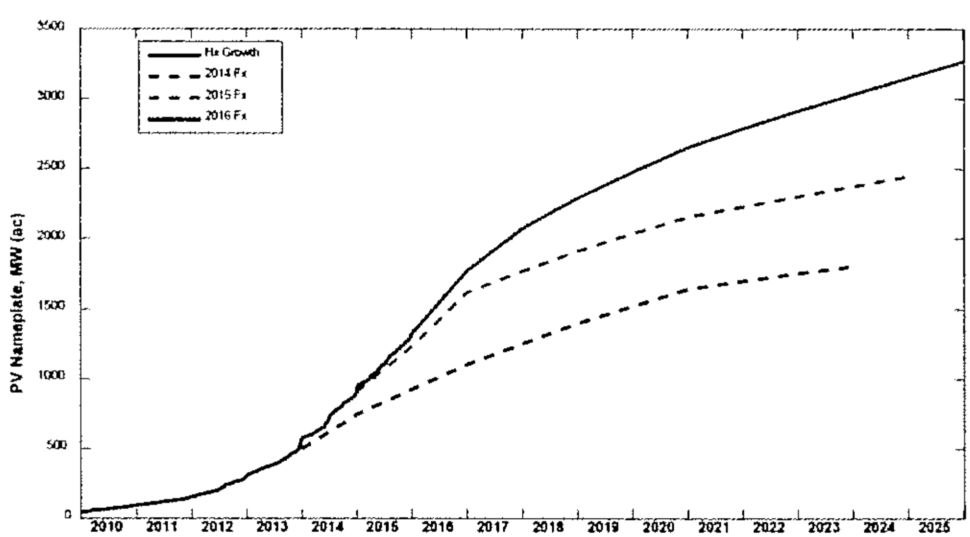
(2) The forecast reflects discount factors described on slides 4

(3) All values represent end-of-year installed capacities

(4) ISO is working with stakeholders to determine the appropriate use of the forecast

Figure 11. ISO NE Graph Comparing 2015 and 2016 Solar PV Forecast

PV Growth: Reported Historical vs. Forecast



Sources, Figures 9 and 11: ISO NE, Final 2016 PV Forecast, http://www.iso-ne.com/static-assets/documents/2016/04/2016_pvforecast_20160415.pdf, slides 9-10. Figure 10: ISO NE Final 2015 Solar PV Forecast Details.

Q. Please explain how the solar PV forecast trends seen in the above figure affects the assessment of reliability needs in Rhode Island and New England, and how they impact the need for the proposed Invenergy plant.

A. The figures illustrate the potential for increasing levels of solar PV in future forecasts, for any given year relative to earlier forecasts. As solar PV increases, the net peak load forecast will decrease. Decreasing net peak load forecasts places downward pressure on the need for new capacity resources.

Q. Are there specific reasons to think that the effect of energy efficiency installation efforts in Rhode Island could contribute to even lower net load forecasts in future years?

A. Yes. The most recently approved three-year energy efficiency plan for National Grid in Rhode Island indicates an *increasing* annual target for energy efficiency installations – from 2.5% of annual energy sales in 2015, to 2.6% by 2017.[31]

Q. Invenergy says "the use of electricity has significantly increased"[32] over the past decade. Has it?

A. No, that is incorrect. Figure 1 above, from historical CELT data on Rhode Island electric energy use, shows that net annual energy use has actually declined.

The Applicant Does Not Address Long-Term Reliability Needs in Rhode Island or New England

Q. Does the Invenergy application present any evidence for a long-term reliability need

[31] See, for example, Rhode Island PUC approval of the most recent three-year energy efficiency plan, which projects annual electric efficiency achievements of 2.5% (2015), 2.55% (2016), and 2.6% (2017). RI PUC, Docket 4443.
[32] Invenergy Application, page 121.

for the proposed plant?

A. No. The applicant relies only on the prospective results of the ISO NE capacity market auction to indicate a reliability need for the plant. The applicant's failure to present any evidence of a long-term reliability need for the plant is significant, because absent such a need, I don't see how this proposed plant fits with Rhode Island state energy policy that, according to the applicant,[33] emphasizes increasing energy efficiency, integration of renewable energy into the system, and achieving reductions in greenhouse gases.

Q. How are long-term resource needs determined, or forecast, for the Rhode Island or the New England region?

A. ISO NE sets out its current and anticipated future reliability needs in its annually-updated Regional System Plan, and documents its near-term requirements in its annual Installed Capacity Requirement filing to the Federal Energy Regulatory Commission (FERC). The annual Regional System Plan uses the most recent CELT forecast data, and each year's plan is effectively an update to the prior year's plan. ISO NE regional planning forecasts of capacity requirements do not indicate any specific need for the Invenergy plant. For example, the table below from ISO NE (Figure 12) shows the latest Regional System Plan forecast of resource needs, prior to the tenth FCA.

[33] Invenergy application, page 122.

Figure 12. ISO NE Representative System Wide Resource Needs From 2015 Regional System Plan

Year	50/50 Peak Load[a]	Representative Net ICR (Need)	FCA #9 (Known Resources)[b]	EE Forecast (New Resource)[c]	Resource Surplus/Shortage[d]
2020/2021	30,182	34,500	34,695	477	672
2021/2022	30,487	34,800	34,695	695	590
2022/2023	30,804	35,200	34,695	900	395
2023/2024	31,131	35,600	34,695	1,093	188
2024/2025	31,455	36,000	34,695	1,274	-31

(a) The 50/50 peak loads reflect the behind-the-meter PV resources.
(b) FCA #9 resource numbers are based on FCA #9 auction results, assuming no retirements and the same level of imports (i.e., most imports need to requalify for every auction). Details are available at the ISO's FERC filing, *ISO New England Inc., Docket No. ER15-Informational Filing for Qualification in the Forward Capacity Market* (November 4, 2014), http://www.iso-ne.com/static-assets/documents/2014/11/er15-___-000_11-3_14_fca_9_info_filing_public_version.pdf.
(c) EE forecast values are based on the 2015 EE forecast. Details are available at http://www.iso-ne.com/static-assets/documents/2015/04/iso_ne_final_2015_ee_forecast_2019_2024.pdf.
(d) Additional resources would be required if additional resources retired or less capacity imports obtain CSOs.

Source: Table 4-7, Future Systemwide Needs (MW), from 2015 ISO NE Regional System Plan (November 2015).

Q. Does this table indicate a future need for the Invenergy plant?

A. No. It indicates a relative resource surplus beginning 2020, and into the middle of the next decade. It includes the results from FCA 9, indicating that it assumes those resources would be built.

Q. Does it include the most recent updates to the projections for solar PV forecasts in New England, or net peak load projections from the 2016 CELT?

A. Critically, no. The plan is from December 2015, and uses net peak load forecasts from the 2015 CELT and solar PV forecasts that were developed in 2015 and which are now seen to significantly underestimate the amount of installed solar PV. The 2015 forecasts underestimated solar PV for 2019 by 441 MW (nameplate AC), and underestimated solar PV for 2024 by 705 MW (nameplate AC).[34]

[34] See Figures 9 and 10 above, comparing 2015 and 2016 ISO NE solar PV forecasts for 2019 and 2024.

Q. Can you illustrate an updated "50/50 Peak Load" forecast based on the 2016 CELT data, for comparison to what is reflected in the above table?

A. Yes. The table above (Figure 12) contains a 2024/2025 forecast of peak load (net of solar PV behind-the-meter resources, but exclusive of energy efficiency effects on peak load) of 31,455 MW. The 2016 CELT forecast of net peak load inclusive of behind-the-meter solar PV but excluding energy efficiency effects is 30,691 MW for 2024/2025. In other words, a one-year forward update to the data contained in this table (i.e., Figure 12) illustrates that the net peak load for which resource requirements are based for 2024 *is 763 MW lower than the prior year's estimate*.

Q. How will that affect future capacity market reconfiguration auctions?

A. ISO NE will update the parameters for installed capacity need to account for these types of adjustments, effectively allowing a re-balancing of capacity supply obligations by the marketplace.

Q. How has the future ISO NE 50/50 peak load forecast, on which resource requirements for future year reliability are based, changed over the past five years?

A. Table 2 below shows how this critical metric has changed. As noted above in Figures 7 and 8 and the discussion around changing net peak load forecast trends in New England, the effect of aggressive energy efficiency resource deployment and exponentially increasing behind-the-meter solar PV installations has dramatically altered future peak load conditions on which resource needs are based. As seen below, the ISO NE Regional System Plan forecast for resource requirements and the CELT forecast (which is the source for those resource requirement projections) have been significantly overestimating peak load, and thus resource needs, for each of the past five years. Even in the most recent Regional System Plan (based on 2015 CELT data), the overestimation of peak load (in comparison to ISO NE's own 2016 CELT forecast) is 518 MW for 2019, the year of operation for the proposed plant.

Table 2. Pattern of 50/50 Peak Load Forecast Overestimation by ISO NE

ISO NE 50/50 Peak	MW Peak Load Forecast Overestimate - Years Before Current CELT				
For Peak Load in:	5 Years Out (2011 CELT)	4 Years Out (2012 CELT)	3 Years Out (2013 CELT)	2 Years Out (2014 CELT)	1 Year Out (2015 CELT)
2016	1,232	857	807	587	130
2017	1,368	1,108	1,003	823	279
2018	1,455	1,205	1,085	935	413
2019	1,532	1,262	1,182	992	518
2020	1,615	1,330	1,260	1,075	582
2021		1,391	1,341	1,126	623
2022			1,383	1,178	667
2023				1,205	716
2024					763
2025					

Source: CELT Forecast Data, 2016, 2015, 2014, 2013, 2012, 2011 versions.
Note: 50/50 Peak load excludes the effect of energy efficiency impacts on peak load.

Q. In general, please comment on ISO NE forecasts and planning, and what that means for any potential reliability need for this plant.

A. As seen in the above table, ISO NE forecasts for future resource needs have been conservative over at least the past five years. As a specific example, in 2011 ISO NE overestimated by 1,232 MW the peak load that would occur in 2016. That same year its longer-term forecast, for 2020 (nine years later) overestimated peak load by 1,615 MW (relative to the 2016 CELT). The implication of these overestimations is that future needs are likely to be lower than current projections; fortunately, the structure of the capacity market allows for closer-in-time adjustments, or rebalances, to installed capacity requirements and the market procurements that meet those requirements. Thus, when assessing the longer-term reliability need for any particular proposed power plant, it is critical to keep in mind that ISO NE planning forecasts have tended to overestimate the actual needs.

Q. Did Invenergy examine long-term resource issues including the availability of indigenous Rhode Island and regional renewable resources, or potential electric storage alternatives, and how they could affect future need for the Invenergy plant, or in general for fossil-fueled power plants?

A. No, not to any level of detail.[35] Rhode Island's indigenous resources include considerable energy efficiency, as noted, as well as solar and offshore wind resources. New England is also considering the importation of significantly increased levels of renewable Canadian hydropower.[36] Invenergy did not explicitly consider a portfolio of these resources as providing energy that could supplant the output from the proposed Invenergy project, and that could contribute to regional capacity supply.[37] ISO NE projects an incremental 184 MW of peak load reduction (across New England) from energy efficiency installed between 2016 and 2025.[38]

[35] Invenergy's characterization included a statement that said "Rhode Island has few indigenous energy resources and must import most of the fuels from which its electricity is generated." Page 121.
[36] Two merchant transmission projects are in progress for the potential delivery of up to roughly 2,000 MW of incremental Canadian hydro resources to the ISO NE transmission grid.
[37] Invenergy appears to have examined solar, wind, hydro, and energy efficiency alternatives individually, not as a possible portfolio, for example stating: "solar energy technologies are considered as infeasible for the Project's objectives" (page 127), and "wind energy generation is not a feasible alternative to the Project" (page 126), and "it is highly unlikely, or feasible, to rely exclusively on additional end user improvements to energy efficiency as an alternative to the need for new generation…" (page 128), and "hydropower energy generation is not a feasible alternative to the Project" (page 128).
[38] Computation by Synapse. ISO NE 2016 CELT, forecast energy efficiency impact on peak load (MW) in 2025 (337 MW) less the forecast energy efficiency impact on peak load (MW) in 2016 (153 MW).

ISO NE projects 155.9 MW of solar PV in Rhode Island by the end of 2019, and over 200 MW by 2023. This year, Rhode Island will complete installation of its first offshore wind farm, the 30 MW Block Island wind farm; and a larger southeastern Massachusetts installation (1,000 MW)[39] with a possible Rhode Island interconnection site[40] is under consideration for the future. While RI may not have indigenous fossil resources, it is rich in renewable resources and energy efficiency resources which have already contributed significantly to meeting local electric energy and capacity needs.

Q. Does that complete your testimony?

A. Yes.

Attachments to Testimony

A. Robert M. Fagan Resume
B. ISO NE 2016 CELT Table – Summer Peak Load
C. ISO NE 2016 Final PV Forecast
D. ISO NE 2016 Geographical Transmission Map – Southern New England portion
E. Discovery Response to CLF-2-5.
F. Selected page from results of FCA 10.
G. Selected page from US Department of Energy, Solar Energy Technologies Office, "On the Path to Sunshot: Executive Summary".

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[39] DONG Energy, Bay State Wind, "Bay State Wind is a utility scale offshore wind farm, located 15 miles off the coast of Martha's Vineyard, with water depths of between 130 - 165 feet. The site area was awarded by the Department of Interior's BOEM in 2015 and additional feasibility assessment and stakeholder engagement, at both a local and state level will now be undertaken. If given approval, we plan to build an offshore wind farm which could have an installed capacity of up to 1,000MW." http://www.dongenergy.com/en/business-activities_/Pages/U-S--Project.aspx.

[40] See ESS Group Inc., "Offshore Wind Transmission Study Final Report", prepared for the Massachusetts Clean Energy Center, Sept. 2014, at p. 23-25. http://files.masscec.com/research/MassCECOSWTransmissionStudy.pdf.

TAB A

Robert M. Fagan, Principal Associate

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rfagan@synapse-energy.com

SUMMARY

Mechanical engineer and energy economics analyst with over 25 years of experience in the energy industry. Activities focused primarily on electric power industry issues, especially economic and technical analysis of transmission, wholesale electricity markets, renewable resource alternatives and assessment and implementation of demand-side alternatives.

In-depth understanding of the complexities of, and the interrelationships between, the technical and economic dimensions of the electric power industry in the US and Canada, including the following areas of expertise:

- Wholesale energy and capacity provision under market-based and regulated structures; the extent of competitiveness of such structures.
- Potential for and operational effects of wind and solar power integration into utility systems; modeling of such effects.
- Transmission use pricing, encompassing congestion management, losses, LMP and alternatives; transmission rights; and transmission asset pricing (embedded cost recovery tariffs).
- Physical transmission network characteristics; related generation dispatch/system operation functions; and technical and economic attributes of generation resources.
- RTO and ISO tariff and market rules structures and operation, and related FERC regulatory policies and initiatives, including those pertaining to RTO and ISO development and evolution.
- Demand-side management, including program implementation and evaluation; and load response presence in wholesale markets.
- Building energy end-use characteristics, and energy-efficient technology options.
- Fundamentals of electric distribution systems and substation layout and operation.
- Energy modeling (spreadsheet-based tools, industry standard tools for production cost and resource expansion, building energy analysis, understanding of power flow simulation fundamentals).
- State and provincial level regulatory policies and practices, including retail service and standard offer pricing structures.
- Gas industry fundamentals including regulatory and market structures, and physical infrastructure.

PROFESSIONAL EXPERIENCE

Synapse Energy Economics, Inc., Cambridge, MA. *Principal Associate*, 2004 – Present.

Responsibilities include consulting on issues of energy economics, analysis of electricity utility planning, operation, and regulation, including issues of transmission, generation, and demand-side management. Provide expert witness testimony on various wholesale and retail electricity industry issues. Specific project experience includes the following:

- Analysis of California renewable energy integration issues, local and system capacity requirements and purchases, and related long-term procurement policies.
- Analysis of air emissions and reliability impacts of Indian Point Energy Center retirement.
- Analysis of PJM and MISO wind integration and related transmission planning and resource adequacy issues.
- Analysis of Nova Scotia integrated resource planning policies including effects of potential new hydroelectric supplies from Newfoundland and demand side management impact; analysis of new transmission supplies of Maritimes area energy into the New England region.
- Analysis of Eastern Interconnection Planning Collaborative processes, including modeling structure and inputs assumptions for demand, supply and transmission resources. Expanded analyses of the results of the EIPC Phase II Report on transmission and resource expansion.
- Analysis of need for transmission facilities in Maine, Ontario, Pennsylvania, Virginia, Minnesota.
- Ongoing analysis of wholesale and retail energy and capacity market issues in New Jersey, including assessment of BGS supply alternatives and demand response options.
- Analysis of PJM transmission-related issues, including cost allocation, need for new facilities and PJM's economic modeling of new transmission effects on PJM energy market.
- Ongoing analysis of utility-sponsored energy efficiency programs in Rhode Island as part of the Rhode Island DSM Collaborative; and ongoing analysis of the energy efficiency programs of New Jersey Clean Energy Program (CEP) and various utility-sponsored efficiency programs (RGGI programs).
- Analysis of California renewable integration issues for achieving 33% renewable energy penetration by 2020, especially modeling constructs and input assumptions.
- Analysis of proposals in Maine for utility companies to withdraw from the ISO-NE RTO.
- Analysis of utility planning and demand-side management issues in Delaware.
- Analysis of effect of increasing the system benefits charge (SBC) in Maine to increase procurement of energy efficiency and DSM resources; analysis of impact of DSM on transmission and distribution reinforcement need.

- Evaluation of wind energy potential and economics, related transmission issues, and resource planning in Minnesota, Iowa, Indiana, and Missouri; in particular in relation to alternatives to newly proposed coal-fired power plants in MN, IA and IN.
- Analysis of need for newly proposed transmission in Pennsylvania and Ontario.
- Evaluation of wind energy "firming" premium in BC Hydro Energy Call in British Columbia.
- Evaluation of pollutant emission reduction plans and the introduction of an open access transmission tariff in Nova Scotia.
- Evaluation of the merger of Duke and Cinergy with respect to Indiana ratepayer impacts.
- Review of the termination of a Joint Generation Dispatch Agreement between sister companies of Cinergy.
- Assessment of the potential for an interstate transfer of a DSM resource between the desert southwest and California, and the transmission system impacts associated with the resource.
- Analysis of various transmission system and market power issues associated with the proposed Exelon-PSEG merger.
- Assessment of market power and transmission issues associated with the proposed use of an auction mechanism to supply standard offer power to ComEd native load customers.
- Review and analysis of the impacts of a proposed second 345 kV tie to New Brunswick from Maine on northern Maine customers.

Tabors Caramanis & Associates, Cambridge, MA. *Senior Associate*, 1996 – 2004.

- Provided expert witness testimony on transmission issues in Ontario and Alberta.
- Supported FERC-filed testimony of Dr. Tabors in numerous dockets, addressing various electric transmission and wholesale market issues.
- Analyzed transmission pricing and access policies, and electric industry restructuring proposals in US and Canadian jurisdictions including Ontario, Alberta, PJM, New York, New England, California, ERCOT, and the Midwest. Evaluated and offered alternatives for congestion management methods and wholesale electric market design.
- Attended RTO/ISO meetings, and monitored and reported on continuing developments in the New England and PJM electricity markets. Consulted on New England FTR auction and ARR allocation schemes.
- Evaluated all facets of Ontario and Alberta wholesale market development and evolution since 1997. Offered congestion management, transmission, cross-border interchange, and energy and capacity market design options. Directly participated in the Ontario Market Design Committee process. Served on the Ontario Wholesale Market Design technical panel.

- Member of TCA GE MAPS modeling team in LMP price forecasting projects.
- Assessed different aspects of the broad competitive market development themes presented in the US FERC's SMD NOPR and the application of FERC's Order 2000 on RTO development.
- Reviewed utility merger savings benchmarks, evaluated status of utility generation market power, and provided technical support underlying the analysis of competitive wholesale electricity markets in major US regions.
- Conducted life-cycle utility cost analyses for proposed new and renovated residential housing at US military bases. Compared life-cycle utility cost options for large educational and medical campuses.
- Evaluated innovative DSM competitive procurement program utilizing performance-based contracting.

Charles River Associates, Boston, MA. *Associate*, 1992 – 1996.

Developed DSM competitive procurement RFPs and evaluation plans, and performed DSM process and impact evaluations. Conducted quantitative studies examining electric utility mergers; and examined generation capacity concentration and transmission interconnections throughout the US. Analyzed natural gas and petroleum industry economic issues; and provided regulatory testimony support to CRA staff in proceedings before the US FERC and various state utility regulatory commissions.

Rhode Islanders Saving Energy, Providence, RI. *Senior Commercial/Industrial Energy Specialist*, 1987 – 1992.

Performed site visits, analyzed end-use energy consumption and calculated energy-efficiency improvement potential in approximately 1,000 commercial, industrial, and institutional buildings throughout Rhode Island, including assessment of lighting, HVAC, hot water, building shell, refrigeration and industrial process systems. Recommended and assisted in implementation of energy efficiency measures, and coordinated customer participation in utility DSM program efforts.

Fairchild Weston Systems, Inc., Syosset, NY. *Facilities Engineer*, 1985 – 1986.

Designed space renovations; managed capital improvement projects; and supervised contractors in implementation of facility upgrades.

Narragansett Electric Company, Providence RI. *Supervisor of Operations and Maintenance*, 1981 – 1984.

Directed electricians in operation, maintenance, and repair of high-voltage transmission and distribution substation equipment.

EDUCATION

Boston University, Boston, MA

Master of Arts in Energy and Environmental Studies – Resource Economics, Ecological Economics, Econometric Modeling, 1992

Clarkson University, Potsdam, NY
Bachelor of Science in Mechanical Engineering – Thermal Sciences, 1981

ADDITIONAL EDUCATION

- **Utility Wind Integration Group**: Short Course on Integration and Interconnection of Wind Power Plants into Electric Power Systems, 2006
- **University of Texas at Austin**: Short course in Regulatory and Legal Aspects of Electric Power Systems, 1998
- **Illuminating Engineering Society**: courses in lighting design, 1989
- **Worcester Polytechnic Institute and Northeastern University**: Coursework in Solar Engineering; Building System Controls; and Cogeneration, 1984, 1988 – 1989
- **Polytechnic Institute of New York**: Graduate coursework in Mechanical and Aerospace Engineering, 1985 – 1986

REPORTS AND PAPERS

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TESTIMONY

Massachusetts Electric Facilities Siting Board (Docket 15-1): Testimony regarding the impact of Exelon's proposed Medway power plant on compliance with the Global Warming Solutions Act. On behalf of Conservation Law Foundation. November 13, 2015.

California Public Utilities Commission (Docket No. A.14-06-014): Testimony examining Southern California Edison (SCE) proposals for Marginal Energy and Capacity Costs in Phase 2 of its 2015 General Rate Case (GRC). On behalf of the California Office of Ratepayer Advocate. Jointly, with Patrick Luckow. February 13, 2015.

California Public Utilities Commission (Docket No. A.14-11-014): Testimony examining Pacific Gas and Electric's Marginal Energy Costs and LOLE Allocation among TOU Periods. Jointly, with Patrick Luckow. On behalf of the California Office of Ratepayer Advocate. May 1, 2015.

California Public Utilities Commission (Docket No. A.14-11-012): Testimony reviewing Southern California Edison 2013 local capacity requirements request for offers for the western Los Angeles Basin, specifically related to storage. On behalf of Sierra Club. March 25, 2015.

California Public Utilities Commission (Docket No. A.14-01-027): Testimony examining San Diego Gas & Electric's proposal to change time-of-use periods in its application for authority to update its electric rate design. Jointly, with Patrick Luckow. On behalf of the California Office of Ratepayer Advocate. November 14, 2014.

California Public Utilities Commission (Docket No. R.12-06-013): Rebuttal testimony regarding the relationship between California investor-owned utilities hourly load profiles under a time-of-use pricing and GHG emissions in the WECC regions in the Order Instituting Rulemaking on the Commission's Own Motion to Conduct a Comprehensive Examination of Investor Owned Electric Utilities' Residential Rate Structures, the Transition to Time Varying and Dynamic Rates, and Other Statutory Obligations. On behalf of the California Office of Ratepayer Advocate. October 17, 2014.

California Public Utilities Commission (Docket No. R.13-12-010): Direct and reply testimony on Phase 1a modeling scenarios in the Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans. On behalf of the California Office of Ratepayer Advocate. August 13, 2014, October 22, 2014, and December 18, 2014.

New York State Department of Environmental Conservation (DEC #3-5522-00011/000004; SPDES #NY-0004472; DEC #3-5522-00011/00030; DEC #3-5522-00011/00031): Direct, rebuttal, and surrebuttal testimonies regarding air emissions, electric system reliability, and cost impacts of closed-cycle cooling as the "best technology available" (BTA), and alternative "Fish Protective Outages" (FPO), for the Indian Point nuclear power plant. On behalf of Riverkeeper. February 28, 2014, March 28, 2014, July 11, 2014, June 26, 2015, and August 10, 2015.

California Public Utilities Commission (Docket No. RM.12-03-014): Reply and rebuttal testimony on the topic of local reliability impacts of a potential long-term outage at the San Onofre Nuclear Power Station (SONGS) in Track 4 of the Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans. On behalf of the California Office of Ratepayer Advocate. September 30, 2013 and October 14, 2013.

Nova Scotia Utility and Review Board (Matter No. 05522): *Filing to the Nova Scotia Utility and Review Board on Nova Scotia Power's October 15, 2014 Integrated Resource Plan, Key Planning Observations and Action Plan Elements.* On behalf of Board Counsel to the Nova Scotia Utility and Review Board, October 20, 2014. With Rachel Wilson, David White and Tim Woolf.

Nova Scotia Utility and Review Board (Matter No. M05419): Direct examination regarding the report *Economic Analysis of Maritime Link and Alternatives: Complying with Nova Scotia's Greenhouse Gas Regulations, Renewable Energy Standard, and Other Regulations in a Least-Cost Manner for Nova Scotia Power Ratepayers* jointly authored with Rachel Wilson, Nehal Divekar, David White, Kenji Takahashi, and Tommy Vitolo. In the Matter of The Maritime Link Act and In the Matter of An Application by NSP MARITIME LINK INCORPORATED for the approval of the Maritime Link Project. On behalf of Board Counsel to the Nova Scotia Utility and Review Board. June 5, 2013.

Prince Edward Island Regulatory and Appeals Commission (Docket UE30402): Jointly filed expert report with Nehal Divekar analyzing the Proposed Ottawa Street – Bedeque 138 kV Transmission Line Project in the matter of Summerside Electric's Application for the Approval of Transmission Services connecting Summerside Electric's Ottawa Street substation to Maritime Electric Company Limited's Bedeque substation. Oh behalf of the City of Summerside. November 5, 2012.

New Jersey Board of Public Utilities (Docket No. GO12070640): Direct testimony regarding New Jersey Natural Gas Company's petition for approval of the extension of the SAVEGREEN energy efficiency programs. On behalf of the New Jersey Division of the Ratepayer Advocate. October 26, 2012.

California Public Utilities Commission (Docket No. RM.12-03-014): Direct and reply testimony regarding the long-term local capacity procurement requirements for the three California investor-owned utilities in Track 1 of the Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans. On behalf of the California Office of Ratepayer Advocate. June 25, 2012 and July 23, 2012.

California Public Utilities Commission (Docket No. A.11-05-023): Supplemental testimony regarding the long-term resource adequacy and resource procurement requirements for the San Diego region in the Application of San Diego Gas & Electric Company (U 902 3) for Authority to Enter into Purchase Power Tolling Agreements with Escondido Energy Center, Pio Pico Energy Center, and Quail Brush Power. On behalf of the California Office of Ratepayer Advocate. May 18, 2012.

New Jersey Board of Public Utilities (Docket No. GO11070399): Direct testimony in the matter of the petition of Pivotal Utility Holdings, Inc. D/B/A Elizabethtown Gas for authority to extend the term of energy efficiency programs with certain modifications and approval of associated cost recovery. On behalf of New Jersey Division of Rate Counsel. December 16, 2011.

New Jersey Board of Public Utilities (Docket No. EO11050309): Direct testimony regarding aspects of the Board's inquiry into capacity and transmission interconnection issues. October 14, 2011.

Federal Energy Regulatory Commission (Docket Nos. EL11-20-000 and ER11-2875-000): Affidavit regarding reliability, status of electric power generation capacity, and current electric power procurement policies in New Jersey. On behalf of New Jersey Division of Rate Counsel. March 4, 2011.

New Jersey Board of Public Utilities (Docket Nos. GR10100761 and ER10100762): Certification before the Board regarding system benefits charge (SBC) rates associated with gas generation in the matter of a generic stakeholder proceeding to consider prospective standards for gas distribution utility rate discounts and associated contract terms. On behalf of New Jersey Division of Rate Counsel. January 28, 2011.

New Jersey Board of Public Utilities (Docket No. ER10040287): Direct testimony regarding Basic Generation Service (BGS) procurement plan for service beginning June 1, 2011. On behalf of New Jersey Division of Rate Advocate. September 2010.

State of Maine Public Utilities Commission (Docket 2008-255): Direct and surrebuttal testimony regarding the non-transmission alternatives analysis conducted on behalf of Central Maine Power in the Application of Central Maine Power Company and Public Service of New Hampshire for a Certificate of Public Convenience and Necessity for the Maine Power Reliability Program Consisting of the Construction of Approximately 350 Miles of 345 and 115 kV Transmission Lines, a $1.55 billion transmission enhancement project. On behalf of the Maine Office of the Public Advocate. January 12, 2009 and February 2, 2010.

Virginia State Corporation Commission (CASE NO. PUE-2009-00043): Direct testimony regarding the need for modeling DSM resources as part of the PJM RTEP planning processes in the Application of Potomac-Appalachian Transmission Highline (PATH) Allegheny Transmission Corporation for CPCN to construct facilities: 765 kV proposed transmission line through Loudoun, Frederick, and Clarke Counties. On behalf of Sierra Club. October 23, 2009.

Pennsylvania Public Utility Commission (Docket number A-2009-2082652): Direct and surrebuttal testimony regarding the need for additional modeling for the proposed Susquehanna-Roseland 500 kv transmission line in portions of Luckawanna, Luzerne, Monroe, Pike, and Wayne counties to include load forecasts, energy efficiency resources, and demand response resources. On behalf of the Pennsylvania Office of Consumer Advocate. June 30, 2009 and August 24, 2009.

Delaware Public Service Commission (Docket No. 07-20): Filed the expert report *Review of Delmarva Power & Light Company's Integrated Resource Plan* jointly authored with Alice Napoleon, William Steinhurst, David White, and Kenji Takahashi In the Matter of Integrated Resource Planning for the Provision of Standard Offer Service by Delmarva Power & Light Company Under 26 DEL. C. §1007 (c) & (d). On behalf of the Staff of Delaware Public Service Commission. April 2, 2009.

New Jersey Board of Public Utilities (Docket No. ER08050310): Direct testimony filed jointly with Bruce Biewald on aspects of the Basic Generation Service (BGS) procurement plan for service beginning June 1, 2009. On behalf of the New Jersey Division of the Ratepayer Advocate. September 29, 2008.

Wisconsin Public Service Commission (Docket 6680-CE-170): Direct and surrebuttal testimony in the matter of the alternative energy options available with wind power, and the effect of the MISO RTO in helping provide capacity and energy to the Wisconsin area reliably without needed the proposed coal plant in the CPCN application by Wisconsin Power and Light for construction of a 300 MW coal plant. On behalf of Clean Wisconsin. August 11, 2008 and September 15, 2008.

Ontario Energy Board (Docket EB-2007-0707): Direct testimony regarding issues associated with the planned levels of procurement of demand response, combined heat and power, and NUG resources as part of Ontario Power Authority's long-term integrated planning process in the Examination and Critique of Demand Response and Combined Heat and Power Aspects of the Ontario Power Authority's Integrated Power System Plan and Procurement Process. On behalf of Pollution Probe. August 1, 2008.

Ontario Energy Board (Docket EB-2007-0050): Direct and supplemental testimony filed jointly with Peter Lanzalotta regarding issues of congestion (locked-in energy) modeling, need, and series compensation and generation rejection alternatives to the proposed line of in the matter of Hydro One Networks Inc.'s application to construct a new 500 kV transmission line between the Bruce Power complex and the town of Milton, Ontario. On behalf of Pollution Probe. April 18, 2008 and May 15, 2008.

Federal Energy Regulatory Commission (Dockets ER06-456, ER06-954, ER06-1271, ER07-424, EL07-57, ER06-880, et al.): Direct and rebuttal testimony addressing merchant transmission cost allocation issues on PJM Regional Transmission Expansion Plan (RTEP) Cost Allocation issues. On behalf of the New Jersey Division of the Ratepayer Advocate. January 23, 2008 and April 16, 2008.

State of Maine Public Utilities Commission (Docket No. 2006-487): Pre-file and surrebuttal testimony on the ability of DSM and distributed generation potential to reduce local supply area reinforcement needs in the matter of the Analysis of Central Maine Power Company Petition for a Certificate of Public Convenience and Necessity to Build a 115 kV Transmission Line between Saco and Old Orchard Beach. On behalf of Maine Office of the Public Advocate. February 27, 2007 and January 10, 2008.

Minnesota Public Utilities Commission (OAH No. 12-2500-17037-2 and OAH No. 12-2500-17038-2; and MPUC Dkt. Nos. CN-05-619 and TR-05-1275): Supplemental testimony and supplemental rebuttal testimony on applicants' estimates of DSM savings in the Certificate of Need proceeding for the Big Stone II coal-fired power plant proposal In the Matter of the Application by Otter Tail Power Company and Others for Certification of Transmission Facilities in Western Minnesota and In the Matter of the Application to the Minnesota Public Utilities Commission for a Route Permit for the Big Stone Transmission Project in Western Minnesota. On behalf of Fresh Energy, Izaak Walton League of America – Midwest Office, Wind on the Wires, Union of Concerned Scientists, Minnesota Center for Environmental Advocacy. December 8, 2006 and December 21, 2007.

Pennsylvania Public Utility Commission (Docket Nos. A-110172 *et al.*): Direct testimony on the effect of demand-side management on the need for a transmission line and the level of consideration of potential carbon regulation on PJM's analysis of need for the TrAIL transmission line. On behalf of the Pennsylvania Office of Consumer Advocate. October 31, 2007.

Iowa Public Utilities Board (Docket No. GCU-07-01): Direct testimony regarding wind energy assessment in Interstate Power and Light's resource plans and its relationship to a proposed coal plant in Iowa. On behalf of Iowa Office of the Consumer Advocate. October 21, 2007.

New Jersey Board of Public Utilities (Docket No. EO07040278): Direct testimony on certain aspects of PSE&G's proposal to use ratepayer funding to finance a solar photovoltaic panel initiative in support of the State's solar RPS. September 21, 2007.

Indiana Utility Regulatory Commission (Cause No. 43114): Direct testimony on the topic of a proposed Duke – Vectren IGCC coal plant and wind power potential in Indiana. On behalf of Citizens Action Coalition of Indiana. May 14, 2007.

British Columbia Utilities Commission: Pre-filed evidence regarding the "firming premium" associated with 2006 Call energy, liquidated damages provisions, and wind integration studies In the Matter of BC Hydro 2006 Integrated Electricity Plan and Long Term Acquisition Plan. On behalf of the Sierra Club (BC Chapter), Sustainable Energy Association of BC, and Peace Valley Environment Association. October 10, 2006.

Maine Joint Legislative Committee on Utilities, Energy and Transportation (LD 1931): Testimony regarding the costs and benefits of increasing the system benefits charge to increase the level of energy efficiency installations by Efficiency Maine before in support of an Act to Encourage Energy Efficiency. On behalf of the Maine Natural Resources Council and Environmental Defense. February 9, 2006.

Nova Scotia Utility and Review Board: Direct testimony and supplemental evidence regarding the approval of the installation of a flue gas desulphurization system at Nova Scotia Power Inc.'s Lingan station and a review of alternatives to comply with provincial emission regulations In The Matter of an Application by Nova Scotia Power Inc. for Approval of Air Emissions Strategy Capital Projects and The Public Utilities Act, R.S.N.S., 1989, c. 380, as amended. On behalf of Nova Scotia Utility and Review Board Staff. January 30, 2006.

New Jersey Board of Public Utilities (BPU Docket EM05020106): Joint direct and surrebuttal testimony with Bruce Biewald and David Schlissel regarding the Joint Petition Of Public Service Electric and Gas Company And Exelon Corporation For Approval of a Change in Control Of Public Service Electric and Gas Company And Related Authorizations. On behalf of New Jersey Division of the Ratepayer Advocate. November 14, 2005 and December 27, 2005.

Indiana Utility Regulatory Commission (Cause No. 42873): Direct testimony addressing the proposed Duke – Cinergy merger. On behalf of Citizens Action Coalition of Indiana. November 8, 2005.

Indiana Utility Regulatory Commission (Causes No. 38707 FAC 61S1, 41954, and 42359-S1): Responsive testimony addressing a proposed Settlement Agreement between PSI and other parties in respect of issues surrounding the Joint Generation Dispatch Agreement in place between PSI and CG&E. On behalf of Citizens Action Coalition of Indiana. August 31, 2005.

Illinois Commerce Commission (Dockets 05-0160, 05-0161, 05-0162): Direct and rebuttal testimony addressing wholesale market aspects of Ameren's proposed competitive procurement auction (CPA). On behalf of Illinois Citizens Utility Board. June 15, 2005 and August 10, 2005.

Illinois Commerce Commission (Docket 05-0159): Direct and rebuttal testimony addressing wholesale market aspects of Commonwealth Edison's proposed BUS (Basic Utility Service) competitive auction procurement. On behalf of Illinois Citizens Utility Board and Cook County State's Attorney's Office. June 8, 2005 and August 3, 2005.

State of Maine Public Utilities Commission (Docket No. 2005-17): Joint testimony with David Schlissel and Peter Lanzalotta regarding an Analysis of Eastern Maine Electric Cooperative, Inc.'s Petition for a Finding of Public Convenience and Necessity to Purchase 15 MW of Transmission Capacity from New Brunswick Power and for Related Approvals. On behalf of Maine Office of the Public Advocate. July 19, 2005.

Indiana Utility Regulatory Commission (Cause No. 38707 FAC 61S1): Direct testimony in a Fuel Adjustment Clause (FAC) proceeding concerning the pricing aspects and merits of continuation of the Joint Generation Dispatch Agreement in place between PSI and CG&E, and related issues of PSI lost revenues from inter-company energy pricing policies. On behalf of Citizens Action Coalition of Indiana. May 23, 2005.

Indiana Utility Regulatory Commission (Cause No. 41954): Direct testimony concerning the pricing aspects and merits of continuation of the Joint Generation Dispatch Agreement in place between PSI and CG&E. On behalf of Citizens Action Coalition of Indiana. April 21, 2005.

State of Maine Public Utilities Commission (Docket No. 2004-538): Joint testimony with David Schlissel and Peter Lanzalotta regarding an Analysis of Maine Public Service Company Request for a Certificate of Public Convenience and Necessity to Purchase 35 MW of Transmission Capacity from New Brunswick Power. On behalf of Maine Office of the Public Advocate. April 14, 2005.

Nova Scotia Utility and Review Board (Order 888 OATT): Testimony regarding various aspects of OATTs and FERC's *pro forma* In The Matter of an Application by Nova Scotia Power Inc. for Approval of an Open Access Transmission Tariff (OATT). On behalf of the Nova Scotia Utility Review Board Staff. April 5, 2005.

Texas Public Utilities Commission (Docket No. 30485): Testimony regarding excess mitigation credits associated with CenterPoint's stranded cost recovery in the Application of CenterPoint Energy Houston Electric, LLC. for a Financing Order. On behalf of the Gulf Coast Coalition of Cities. January 7, 2005.

Ontario Energy Board (RP-2002-0120): Filed testimony and reply comments reviewing the Transmission System Code (TSC) and Related Matters, Detailed Submission to the Ontario Energy Board in Response To Phase I Questions Concerning the Transmission System Code and Related Matters. On behalf of TransAlta Corporation. October 31, 2002 and November 21, 2002.

Alberta Energy and Utilities Board (Application No. 2000135): Filed joint testimony with Dr. Richard D. Tabors in the matter of the Transmission Administrator's 2001 Phase I and Phase II General Rate Application pertaining to Supply Transmission Service charge proposals. On behalf of Alberta Buyers Coalition. March 28, 2001.

Ontario Energy Board (RP-1999-0044): Testimony critiquing Ontario Hydro Networks Company's Transmission Tariff Proposal and Proposal for Alternative Rate Design. On behalf of the Independent Power Producer's Society of Ontario. January 17, 2000.

Massachusetts Department of Public Utilities (Docket # DPU 95-2/3-CC-I): Filed a report (Fagan R., G. Watkins. 1995. *Sampling Issues in Estimating DSM Savings: An Issue Paper for Commonwealth Electric*. Charles River Associates). On behalf of COM/Electric System. April 1995.

Massachusetts Department of Public Utilities (Docket # DPU 95-2/3-CC-I): Filed initial and updated reports (Fagan R., P. Spinney, G. Watkins. 1994. *Impact Evaluation of Commonwealth Electric's Customized Rebate Program*. Charles River Associates. Updated April 1996). April 1994 and April 1995.

Resume dated December 2015

TAB B

1.1 Summer Peak Capabilities and Load Forecast (MW)

ISO-NE RELIABILITY COORDINATOR AREA	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
1. LOAD (1, 2, 3)											
1.1 REFERENCE - Without reductions	28660	28966	29307	29652	29975	30276	30578	30883	31190	31493	31794
1.1.1 Behind-the-Meter (BTM) PV (4)	314	423	520	582	632	676	714	746	775	802	828
1.2 REFERENCE - With reduction for BTM PV	28346	28543	28788	29070	29344	29601	29863	30137	30415	30691	30966
1.2.1 Passive DR (PDR) used in System Planning (5)	1685	1839	2089	2306	2561	2812	3047	3267	3473	3665	3844
1.3 REFERENCE - With reduction for BTM PV and PDR	26661	26704	26698	26765	26783	26789	26816	26870	26942	27026	27122
2. CAPACITY BASED ON FCM OBLIGATIONS											
2.1 GENERATING RESOURCES (6)	29726	29888	29547	30393	31341	31441	31441	31441	31441	31441	31441
2.2 DEMAND RESOURCES (6, 7)	2326	2441	2798	2751	2746	2746	2746	2746	2746	2746	2746
2.2.1 ACTIVE DR	638	556	841	597	378	378	378	378	378	378	378
2.2.2 PASSIVE DR	1687	1885	1957	2154	2369	2369	2369	2369	2369	2369	2369
2.3 IMPORTS (8)	1337	1162	1406	1479	1480	96	90	90	90	90	90
2.4 TOTAL (9)	**33389**	**33492**	**33750**	**34623**	**35567**	**34283**	**34277**	**34277**	**34277**	**34277**	**34277**
3. CAPACITY BASED ON SEASONAL CLAIMED CAPABILITY (SCC) (10) (11)											
3.1 GENERATION CLAIMED FOR CAPABILITY	30580	30581	29908	30968	32118	32111	32121	32127	32133	32138	32144
4. RESERVES - Based on Reference Load with reduction for Passive DR											
4.1 INSTALLED RESERVES - Based on CSOs of Generating Resources (line 2.1), Active DR (line 2.2.1), and Imports (line 2.3)											
4.1.1 MW	5040	4903	5096	5704	6415	5125	5092	5038	4966	4882	4786
4.1.2 % OF LOAD	19	18	19	21	24	19	19	19	18	18	18
4.2 INSTALLED RESERVES - Based on Generation SCC (line 3.1), Active DR (line 2.2.1), Imports (line 2.3), and Exports (see footnote 12)											
4.2.1 MW	5794	5496	5357	6179	7093	5796	5773	5725	5659	5580	5490
4.2.2 % OF LOAD	22	21	20	23	26	22	22	21	21	21	20

KEY

4.1.1 = 2.1 + 2.2.1 + 2.3 − 1.3
4.1.2 = (4.1.1 / 1.3) x 100
4.2.1 = (3.1 + 2.2.1 + 2.3) − 1.3
4.2.2 = (4.2.1 / 1.3) x 100
2.4 = 2.1 + 2.2 + 2.3

FOOTNOTES

See Section 1.1 Footnotes on following sheet

1.1 Footnotes

(1) Represents MW load level associated with a reference forecast having a 50% chance of being exceeded. More information on the April 2016 CELT forecast, including the high and low bandwidths, is available on the ISO-NE Website located at http://www.iso-ne.com/system-planning/system-plans-studies/celt.

(2) Three versions of the seasonal peak load forecast are shown. The first forecast does not reflect the peak and energy savings of Passive Demand Resources (PDR) or Behind-the-Meter (BTM) PV. The second forecast shown reflects a reduction for BTM PV. The third forecast shown reflects the reductions of BTM PV and PDR. Detailed forecast documentation on the ISO-NE website includes all three versions of the forecast.

(3) The 2015 summer peak load shown reflects weather normalization. Prior to weather normalization, the actual metered 2015 summer peak of 24,437 MW occurred on July 20, 2015 at hour ending 17:00. See Section 1.5 for actual and estimated peaks and energies. The reconstituted (for the load reducing action of FCM Passive Demand Resources) peak of 26,472 MW occurred on July 20, 2015 at hour ending 17:00.

(4) Line 1.1.1 consists of Behind-the-Meter PV estimated summer peak load reductions as of July 1 of that year, including an 8% transmission and distribution loss gross up. Refer to Section 3.1 for more details on these values.

(5) The passive DR shown on line 1.2.1 consists of the Qualified Capacity (QC) of existing resources and primary auction (FCA) results for new resources. These values are used by ISO-NE System Planning in their long-term Needs Assessments and Solutions Studies (see Sec. 5.2 of this report for a breakdown by Load Zone and DR type), and are different from the Capacity Supply Obligations shown on line 2.2.2. Beginning in 2020-2021, passive DR includes an ISO-NE forecast of incremental EE beyond the FCM.

(6) The 2016 through 2019 capacity for generating and demand resources consists of the current Forward Capacity Market CSOs as of March 18, 2016, and the 2015 CSOs are based on the 2015-2016 ARA 3 results. The 2019 FCM CSO is assumed to remain in place through the end of the CELT reporting period. It is assumed that the 211 MW of Static De-List Bids that were cleared to leave the 2019-2020 Forward Capacity Auction will remain de-listed through the reporting period. The Citizens Block Load CSO is treated as an import rather than a generating resource.

(7) The demand resource values are based on DR with FCM CSOs, including an 8% transmission and distribution loss gross-up. A passive DR forecast is included with the QC-based DR values on line 1.2.1, beginning in 2020.

(8) The 2015 through 2019 imports are based on FCM import CSOs. An Administrative Export De-List of 100 MW, which expires on May 31, 2020, is taken into account in the generation capability values from 2015 through 2019. The purchases beyond the 2019-2020 Capacity Commitment Period reflect only known, long-term contracts. Note that one of those long-term contracts is a 6 MW contract that ends October 2020. The FCA #11 qualification process will take this into account in determining its qualified capacity for the upcoming auction.

(9) May not equal sum due to rounding.

(10) The generating capability based on SCC values includes all existing ISO New England generating assets as well as projected additions and retirements. Future generating assets consist of non-FCM resources that are expected to go commercial in 2016 or 2017, and all new resources with FCM CSOs. The capabilities of the FCM resources are based on their Qualified Capacity. Also included is a forecast of non-FCM PV capacity, which is based on the nameplate PV forecast shown in Section 3.1.1, together with the assumed percentage of annual growth (37% in service by July 1), and estimated summer seasonal peak load reduction (in % of nameplate) for each year, as shown in Section 3.2.2.

(11) The 2016 SCC value of 30,581 MW is consistent with the total capacity projected for August 1 in the Section 2.1 Generator List.

(12) Exports consist of a 100 MW Administrative Export De-List through 2019.

TAB C

APRIL 15, 2016 | HOLYOKE, MASSACHUSETTS

ISO new england

Final 2016 PV Forecast

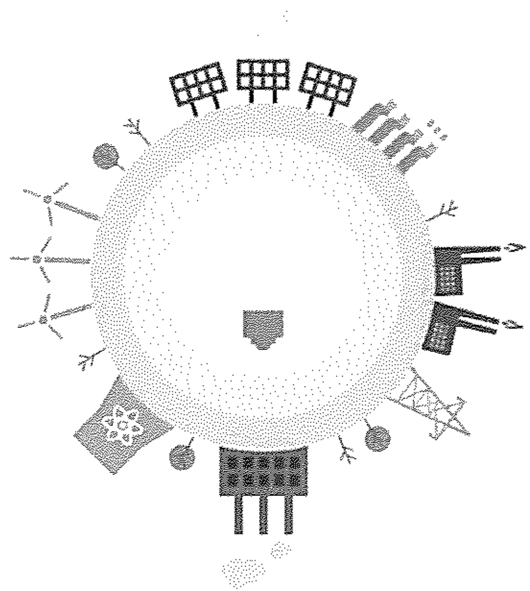
Distributed Generation Forecast Working Group

Jon Black

MANAGER, LOAD FORECASTING

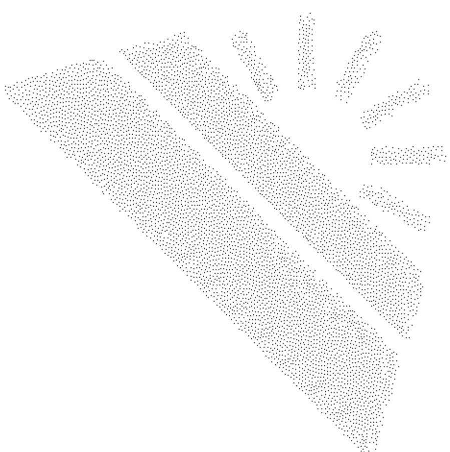
Presentation Outline

- Background and Forecast Process
- Changes to February 2016 Draft PV Forecast and Final 2016 PV Forecast
- 2016 PV Energy Forecast
- Behind-the-meter PV: Estimated Energy and Summer Peak Load Reductions
- Geographic Distribution of PV Forecast
- Summary and Next steps



BACKGROUND AND FORECAST PROCESS

Background and Forecast Review Process



- The ISO discussed the draft PV forecast with the DGFWG at the February 24, 2016 meeting
  - See: http://www.iso-ne.com/static-assets/documents/2016/03/2016_draftpvforecast_20160224revised.pdf
- Stakeholders provided many helpful comments on the draft forecast
  - See: http://www.iso-ne.com/committees/planning/distributed-generation/?eventId=129509
- The final PV forecast will be published in the 2016 CELT

CHANGES TO FEBRUARY 2016 DRAFT PV FORECAST AND FINAL 2016 PV FORECAST

Changes to the February 2016 Draft PV Forecast

State	Changes/Comments
Massachusetts	Made the MA forecast more "front-loaded" to reflect that the SREC program is close to fully subscribed and the recent faster-than-expected PV growth in MA. This change to the forecast resulted in the achievement of the SREC policy goal in 2018 rather than 2020.
Vermont	Adjusted VT's 2017 forecast value downward to reflect the implementation of the Renewable Energy Standard goals.

FINAL 2016 PV NAMEPLATE FORECAST

Draft 2016 PV Forecast – February 24, 2016

Nameplate Capacity, MW_{ac}

States	Annual Total MW (AC nameplate rating)											Totals
	Thru 2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	
CT	188.0	85.5	104.5	81.0	81.0	81.0	55.8	54.3	45.0	45.0	45.0	**866.1**
MA	947.1	122.7	122.7	77.5	77.5	77.5	43.0	43.0	43.0	43.0	43.0	**1,640.0**
ME	15.3	4.7	4.7	4.4	4.4	4.4	4.2	3.9	3.9	3.9	3.9	**57.9**
NH	26.4	13.3	7.6	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	**79.3**
RI	23.6	21.6	38.7	36.0	36.0	25.9	9.1	6.6	6.6	6.6	6.6	**217.2**
VT	124.6	30.2	30.2	22.5	22.5	22.5	21.3	20.0	20.0	20.0	20.0	**353.7**
Regional - Annual (MW)	**1325.0**	**277.9**	**308.3**	**225.4**	**225.4**	**215.3**	**137.5**	**131.8**	**122.5**	**122.5**	**122.5**	**3,214.3**
Regional - Cumulative (MW)	**1325.0**	**1602.9**	**1911.2**	**2136.6**	**2362.0**	**2577.3**	**2714.8**	**2846.6**	**2969.2**	**3091.7**	**3214.3**	**3,214.3**

Notes:

(1) Forecast values include FCM Resources, non-FCM Energy Only Generators, and behind-the-meter PV resources

(2) The forecast reflects discount factors to account for uncertainty in meeting state policy goals

(3) All values represent end-of-year installed capacities

Final 2016 PV Forecast

Nameplate, MW_{ac}

Note: Values in red boldface have changed relative to the draft forecast

States	Annual Total MW (AC nameplate rating)											Totals
	Thru 2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	
CT	188.0	85.5	104.5	81.0	81.0	81.0	55.8	54.3	45.0	45.0	45.0	**866.1**
MA	947.1	**294.4**	122.7	**69.7**	**38.7**	**38.7**	**38.7**	**38.7**	**38.7**	**38.7**	**38.7**	**1,705.0**
ME	15.3	4.7	4.7	4.4	4.4	4.4	4.2	3.9	3.9	3.9	3.9	**57.9**
NH	26.4	13.3	7.6	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	**79.3**
RI	23.6	21.6	38.7	36.0	36.0	25.9	9.1	6.6	6.6	6.6	6.6	**217.2**
VT	124.6	30.2	**23.8**	22.5	22.5	22.5	21.3	20.0	20.0	20.0	20.0	**347.3**
Regional - Annual (MW)	**1325.0**	**449.6**	**301.9**	**217.7**	**186.7**	**176.5**	**133.2**	**127.5**	**118.2**	**118.2**	**118.2**	**3,272.8**
Regional - Cumulative (MW)	**1325.0**	**1774.7**	**2076.5**	**2294.2**	**2480.9**	**2657.4**	**2790.6**	**2918.1**	**3036.3**	**3154.6**	**3272.8**	**3,272.8**

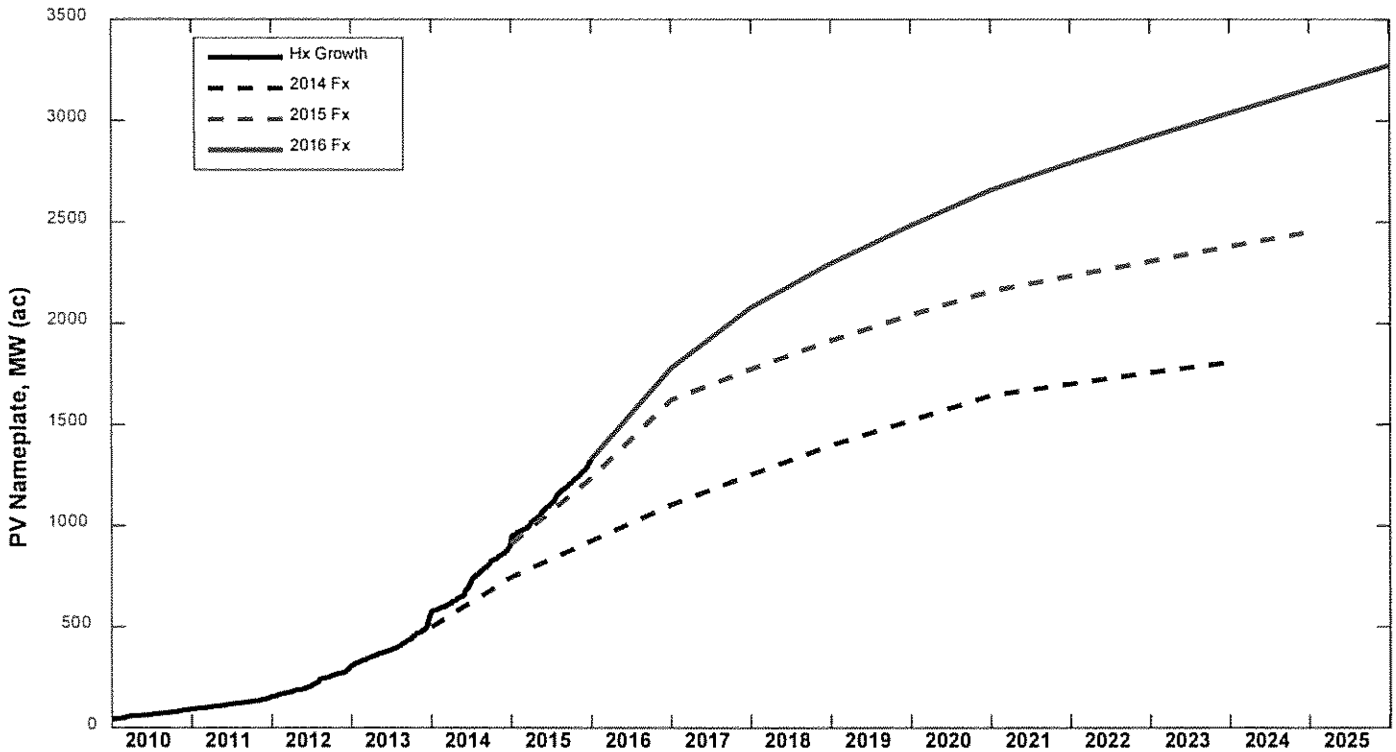
Notes:

(1) Forecast values include FCM Resources, non-FCM Energy Only Generators, and behind-the-meter PV resources

(2) The forecast reflects discount factors to account for uncertainty in meeting state policy goals

(3) All values represent end-of-year installed capacities

PV Growth: Reported Historical vs. Forecast

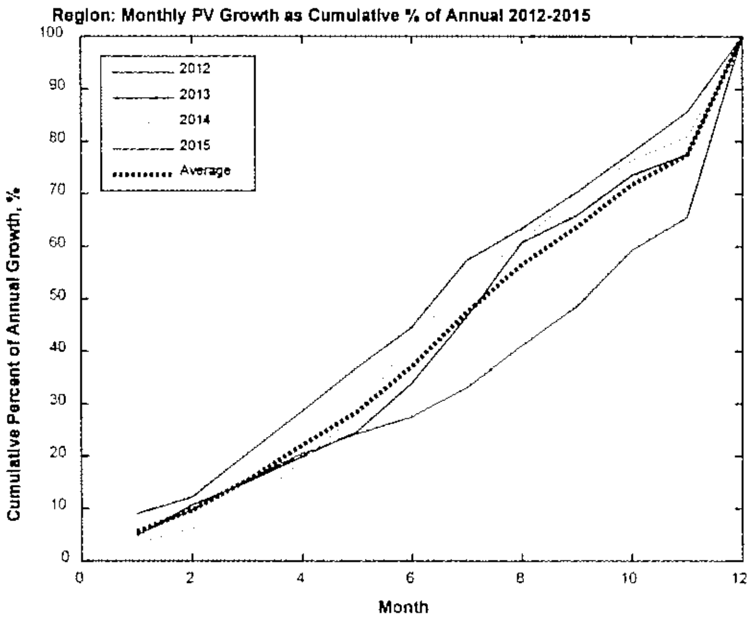


2016 PV ENERGY FORECAST

Development of PV Energy Forecast

- The 2016 PV nameplate forecast reflects end-of-year values
- Energy estimates in the PV forecast are inclusive of incremental growth during a given year
- ISO assumed that historical PV growth trends across the region are indicative of future intra-annual growth rates
  - Growth trends between 2012 and 2015 were used to estimate intra-annual incremental growth over the forecast horizon (*see next slide*)
- The PV energy forecast was developed using a monthly nameplate forecast along with average monthly capacity factors from Yaskawa-Solectria data (*see slide 14*)
  - Annual capacity factor = 14.1%
  - Yaskawa-Solectria data is described further (*see slide 23*)

Historical Monthly PV Growth Trends, 2012-2015



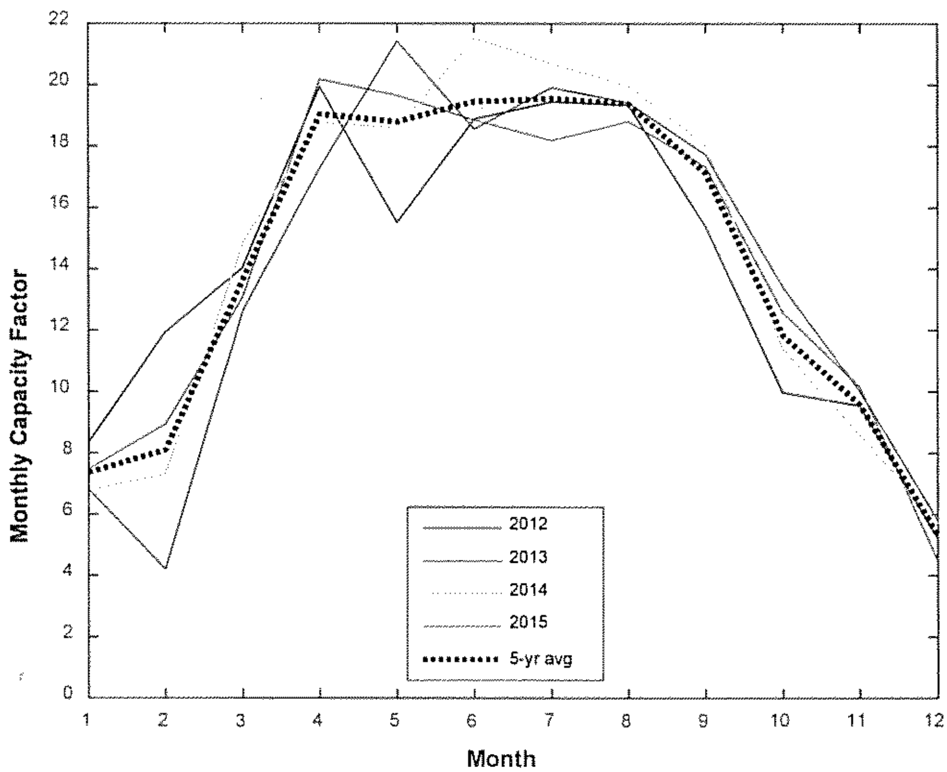
Average Monthly Growth Rates, % of Annual

Month	Monthly PV Growth (% of Annual)	Monthly PV Growth (Cumulative % of Annual)
1	6%	6%
2	4%	10%
3	6%	15%
4	7%	22%
5	6%	28%
6	9%	37%
7	10%	47%
8	9%	56%
9	7%	64%
10	8%	72%
11	6%	77%
12	23%	100%

Note:
Monthly percentages represent end-of-month values, and may not sum to total due to rounding

Monthly PV Capacity Factors

Yaskawa-Solectria PV Site Data, 2012-2015



Source: http://www.solrenview.com/

Final 2016 PV Energy Forecast

All Resource Types, GWh

States	Total Estimated Annual Energy (GWh)									
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
CT	287	409	535	642	749	844	917	984	1,043	1,103
MA	1383	1,692	1,829	1,907	1,958	2,009	2,060	2,111	2,162	2,213
ME	22	28	35	40	46	52	57	62	68	73
NH	41	56	64	69	75	80	85	91	96	101
RI	41	77	127	175	217	244	255	263	272	281
VT	178	215	246	275	305	334	361	388	414	440
Regional - Annual Energy (GWh)	**1953**	**2,477**	**2,836**	**3,109**	**3,350**	**3,563**	**3,735**	**3,899**	**4,055**	**4,211**

Notes:

(1) Forecast values include energy from FCM Resources, non-FCM Energy Only Generators, and behind-the-meter PV resources
(2) Monthly in service dates of PV assumed based on historical development
(3) All values are grossed up by 6.5% to reflect avoided transmission and distribution losses

BREAKDOWN OF PV NAMEPLATE FORECAST INTO RESOURCE TYPES

Forecast Includes Classification by Resource Type

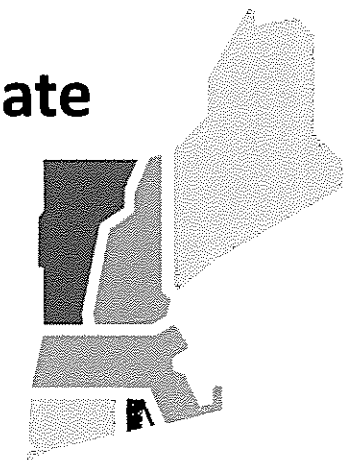
- In order to properly account for existing and future PV in planning studies and avoid double counting, ISO classified PV into three distinct types related to the resources assumed market participation/non-participation
- These market distinctions are important for the ISO's use of the PV forecast in a wide range of planning studies
- The classification process requires the estimation of hourly PV production that is behind-the-meter (BTM), i.e., PV that does not participate in ISO markets
  - This requires historical hourly BTM PV production data to reconstitute PV into the historical load data used to develop the long-term load forecast

Three Mutually Exclusive PV Resource Types

1. **PV as a resource in the Forward Capacity Market (FCM)**
   - Qualified for the FCM and have acquired a capacity supply obligations
   - Size and location identified and visible to the ISO
   - May be supply or demand-side resources
2. **Non-FCM Settlement Only Resources (SOR) and Generators**
   - ISO collects energy output
   - Participate only in the energy market
3. **Behind-the-Meter (BTM) PV**
   - Not in ISO Market
   - Reduces system load
   - ISO has an incomplete set of information on generator characteristics
   - ISO does not collect energy meter data, but can estimate it using other available data

Notes:
For 2015 CELT, BTM was further subdivided into two categories, behind-the-Meter PV embedded in load (BTMEL) and behind-the-meter PV not embedded in load (BTMNEL); Full PV reconstitution allowed ISO to combine these two categories into one (BTM)

Determining PV Resource Type By State



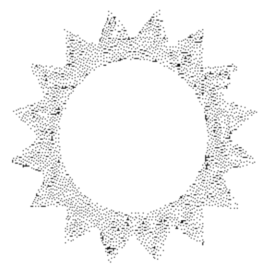
- Resource types vary by state
  - Can be influenced by state regulations and policies (*e.g.*, net metering requirements)
- The following steps were used to determine PV resource types for each state over the forecast horizon:
  1. **FCM**
     - Identify all Generation and Demand Response FCM PV resources for each Capacity Commitment Period (CCP) through FCA 10
  2. **Non-FCM SOR/Gen**
     - Determine the % share of non-FCM PV participating in energy market at the end of 2015 and assume this share remains constant throughout the forecast period
  3. **BTM**
     - Subtract the values from steps 1 and 2 from the annual state PV forecast, the remainder is the BTM PV

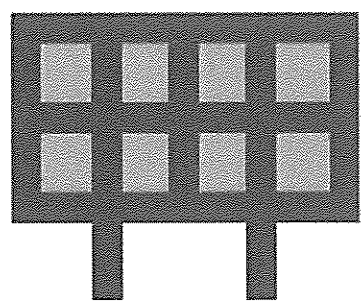
PV in ISO New England Markets

- **FCM**
  - ISO identified all PV generators or demand resources (DR) that have Capacity Supply Obligations (CSO) in FCM up through FCA 10
  - Assume aggregate total PV in FCM as of FCA 10 remains constant from 2019-2025
- **Non-FCM Gen/SOR (Energy Only Resources (EOR))**
  - ISO identified total nameplate capacity of PV in each state registered in the energy market as of 12/31/15
  - Assume % share of nameplate PV in energy market as of 12/31/15 remains constant throughout the forecast horizon
- Other assumptions:
  - Supply-side FCM PV resources operate as SOR/Gen prior to their first FCM commitment period (this has been observed in Massachusetts)
  - Planned PV projects known to be > 5 MW_{ac} nameplate are assumed to trigger OP-14 requirement to register in ISO energy market as a Generator

Estimation of Hourly BTM PV

- In order to estimate hourly BTM PV production, ISO developed hourly state PV profiles for the period 1/1/2012 –1/31/2015 using publicly-available historical production (*see slide 23*)
  - Data aggregated into normalized PV profiles for each state, which represent a per-MW-of-nameplate production profile for PV





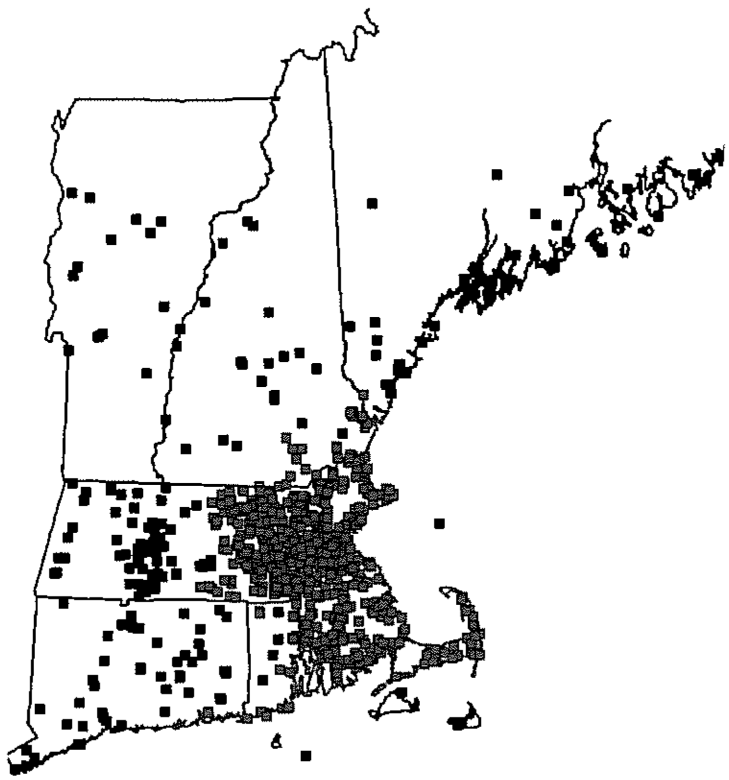
Estimation of Hourly BTM PV (*continued*)

- Using the normalized PV profiles, total state PV production was then estimated by scaling the profiles up to the total PV installed over the period according to recently-submitted distribution utility data
  - (Normalized Hrly Profile) x (Total installed PV Capacity) = Hourly PV production
- Subtracting the hourly PV settlements energy (where applicable) yields the total BTM PV energy for each state
  - BTM profiles were used for PV reconstitution in the development of the gross load forecast

Historical PV Profile Development and Analysis

- Hourly state PV profiles developed for four years (2012-2015) using production data using Yaskawa-Solectria Solar's web-based monitoring system, SolrenView*
  - Represents PV generation at the inverter or at the revenue-grade meter
- A total of more than 1,200 individual sites representing more than 125 MW_{ac} in nameplate capacity were used
  - Total nameplate capacity represents approximately 10% of installed PV capacity in the region as of 12/31/15
  - The site distribution throughout the region is sufficient for estimating profiles of all PV installations in New England
  - Site locations depicted on adjacent map

Yaskawa-Solectria Sites



***Source:** http://www.solrenview.com/

FINAL 2016 PV NAMEPLATE FORECAST BY RESOURCE TYPE

Final 2016 PV Forecast

Cumulative Nameplate, MW_{ac}

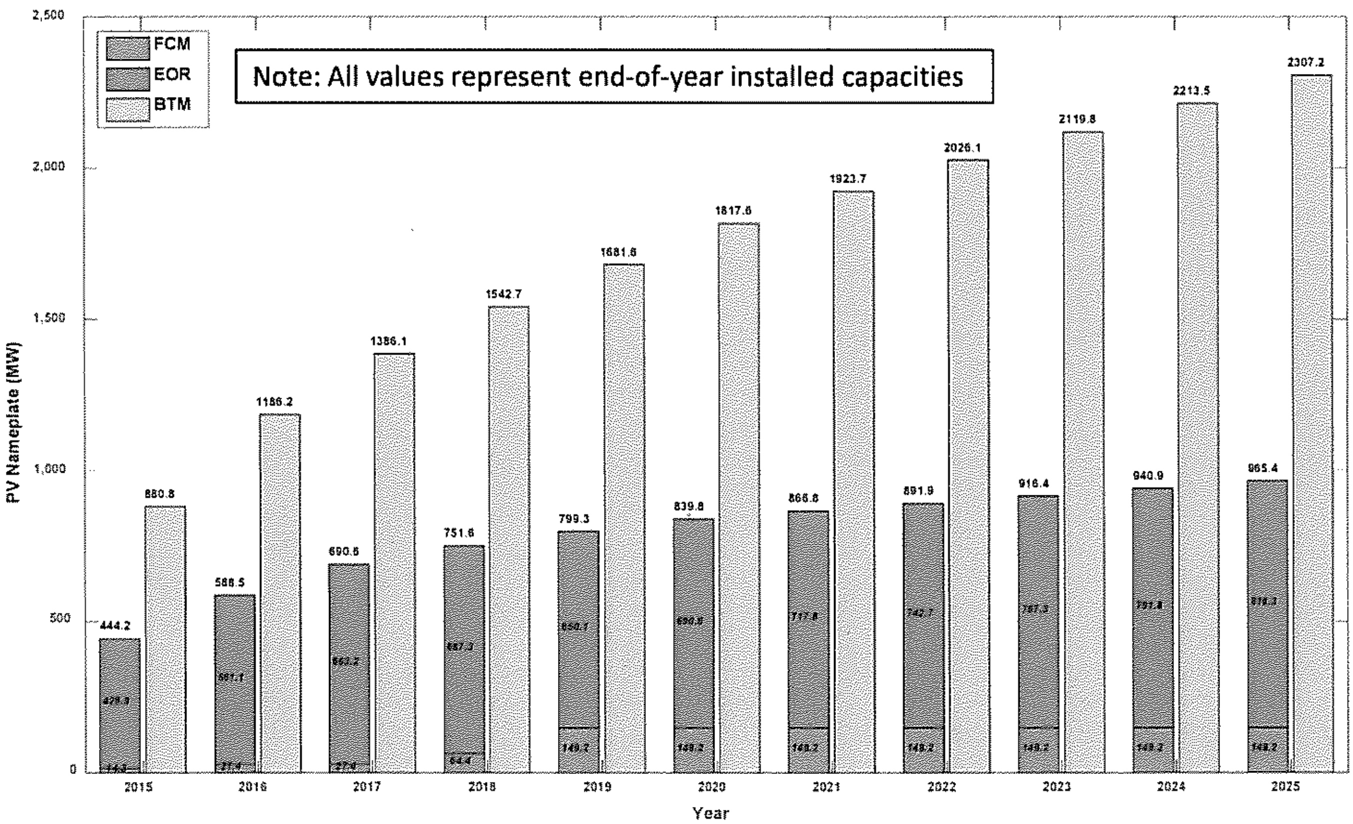
States	Cumulative Total MW (AC nameplate rating)										
	Thru 2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
CT	188.0	273.5	378.0	459.0	540.0	621.0	676.9	731.2	776.2	821.1	866.1
MA	947.1	1241.5	1364.2	1433.9	1472.6	1511.3	1550.1	1588.8	1627.6	1666.3	1705.0
ME	15.3	20.0	24.6	29.1	33.5	37.9	42.1	46.1	50.0	53.9	57.9
NH	26.4	39.7	47.3	51.3	55.3	59.3	63.3	67.3	71.3	75.3	79.3
RI	23.6	45.2	83.9	119.9	155.9	181.8	190.9	197.5	204.1	210.7	217.2
VT	124.6	154.8	178.5	201.0	223.5	246.0	267.3	287.3	307.3	327.3	347.3
Regional - Cumulative (MW)	**1325.0**	**1774.7**	**2076.5**	**2294.2**	**2480.9**	**2657.4**	**2790.6**	**2918.1**	**3036.3**	**3154.6**	**3272.8**

***Notes*:**

(1) Forecast values include FCM Resources, non-FCM Energy Only Generators, and behind-the-meter PV resources
(2) The forecast reflects discount factors to account for uncertainty in meeting state policy goals
(3) All values represent end-of-year installed capacities

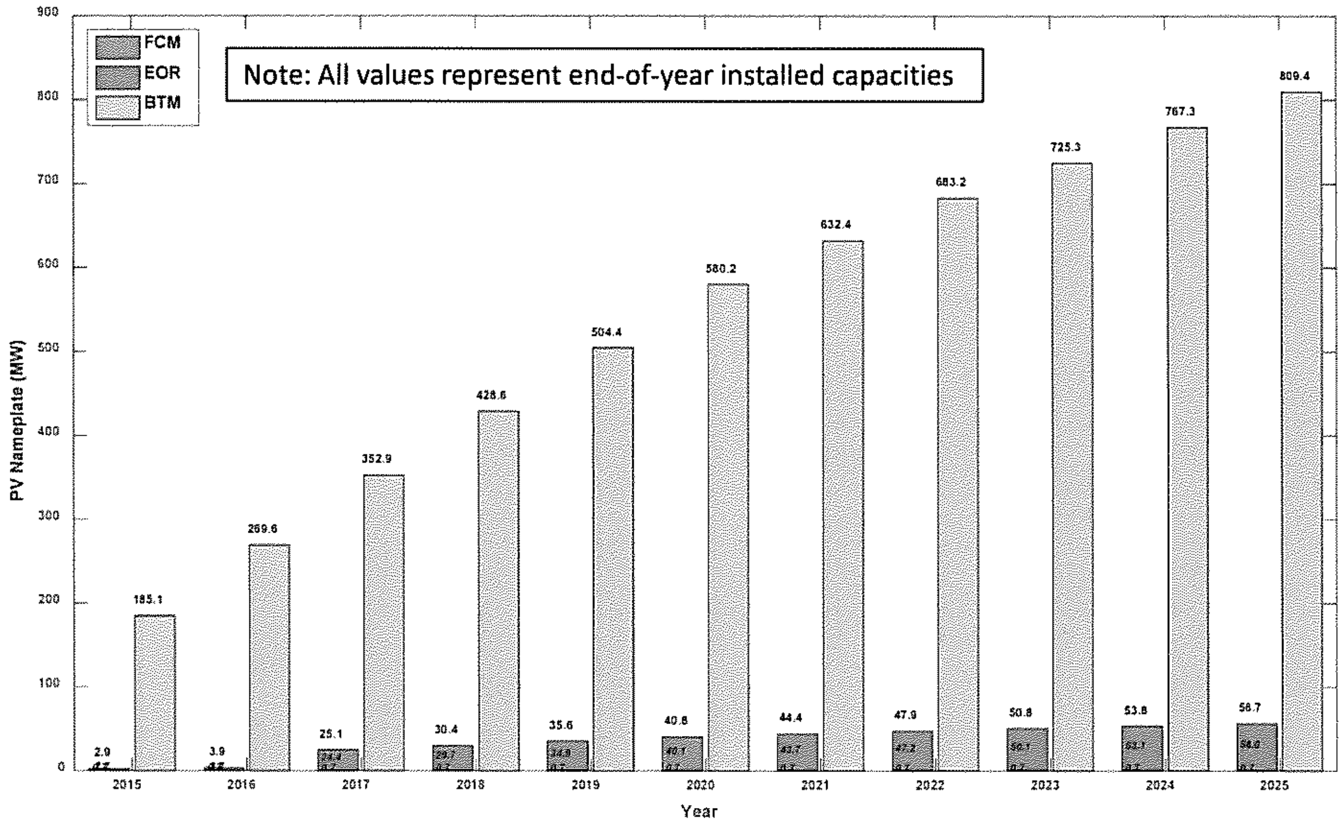
Final 2016 PV Forecast

Cumulative Nameplate, MW_{ac}



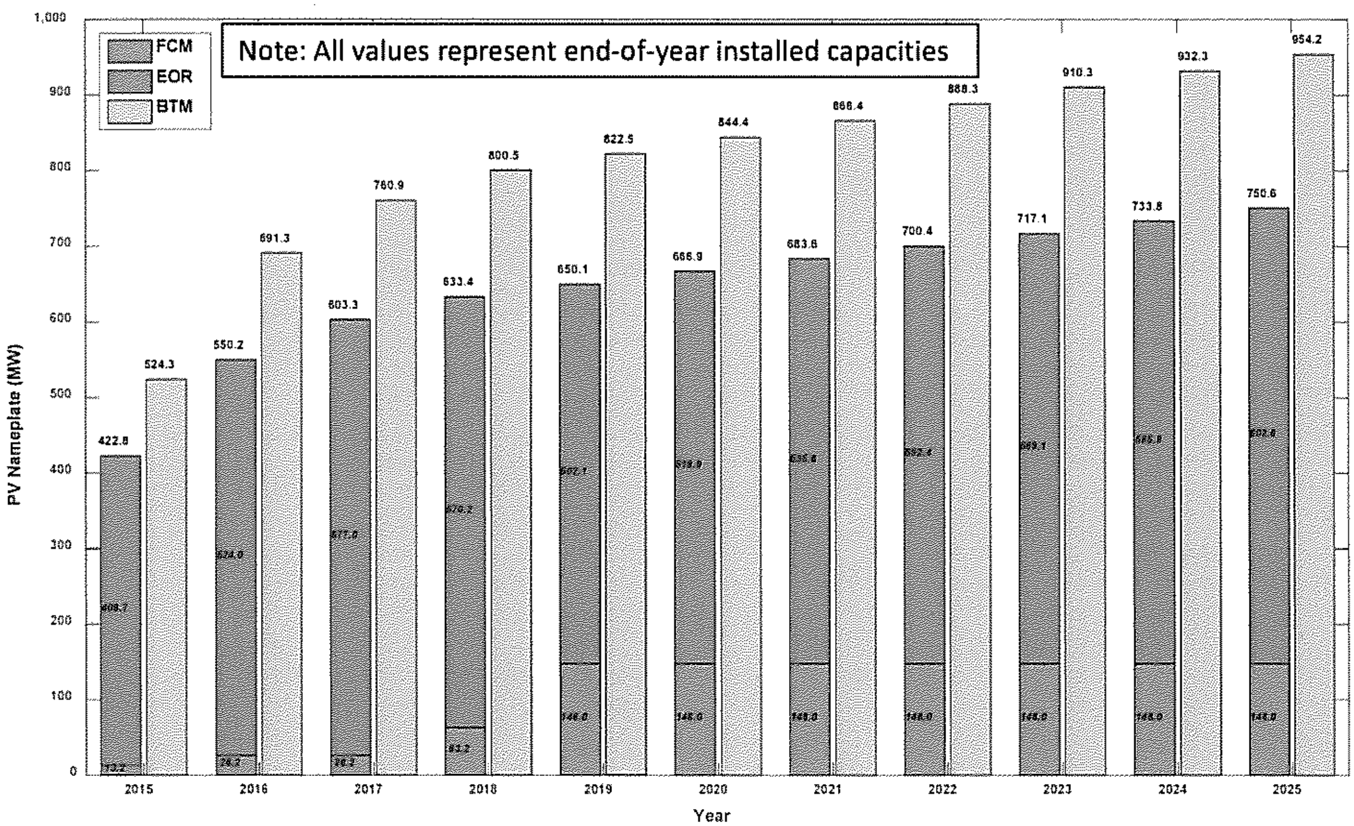
Cumulative Nameplate by Resource Type, MW_{ac}

Connecticut



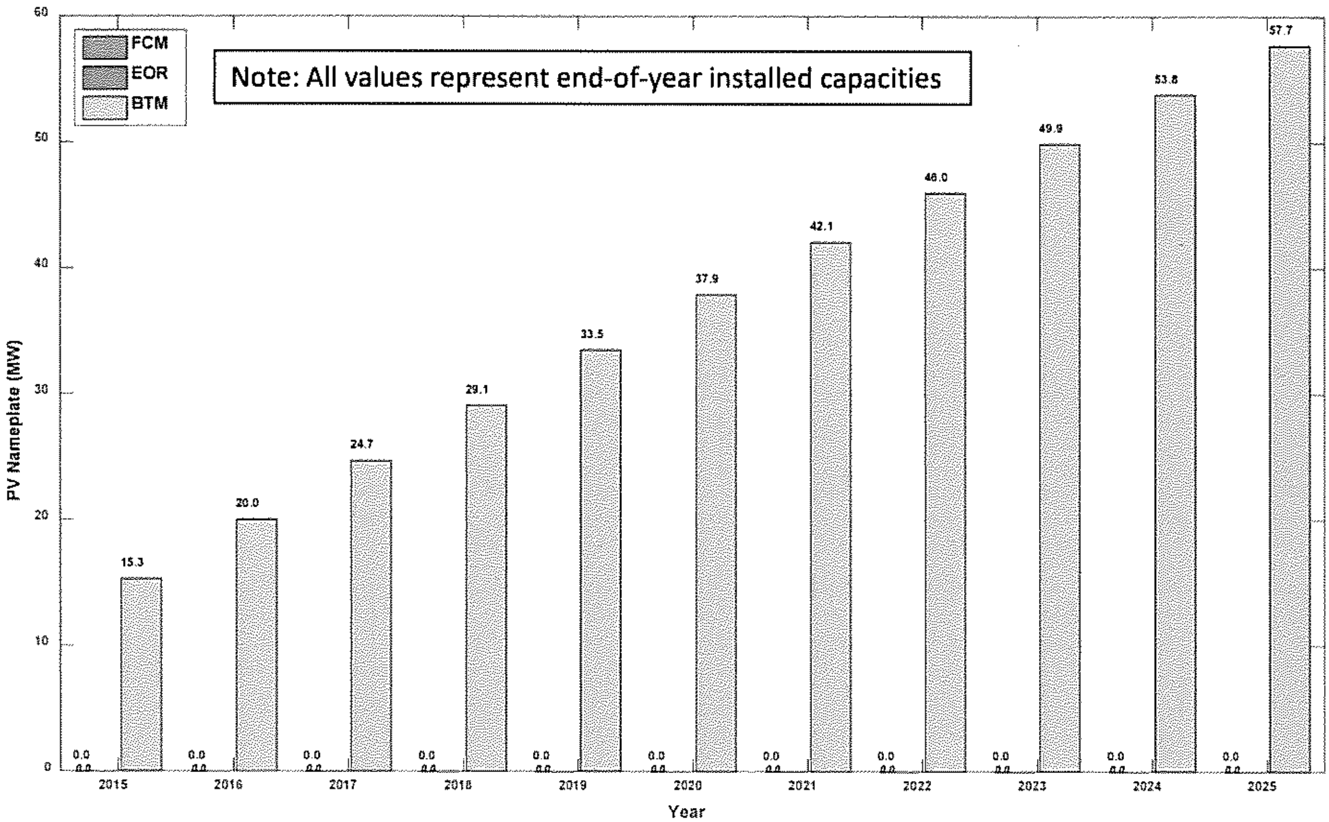
Cumulative Nameplate by Resource Type, MW_{ac}

Massachusetts



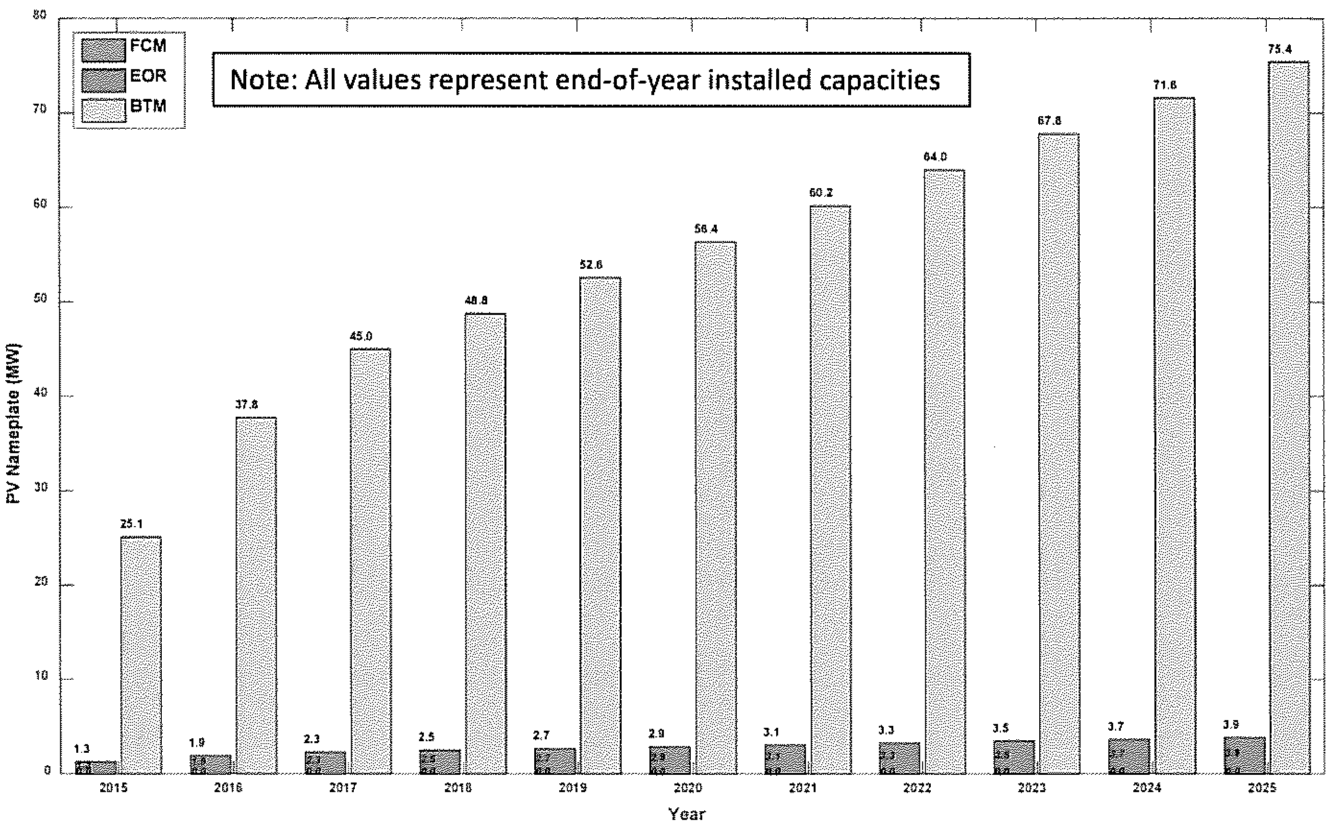
Cumulative Nameplate by Resource Type, MW_{ac}

Maine



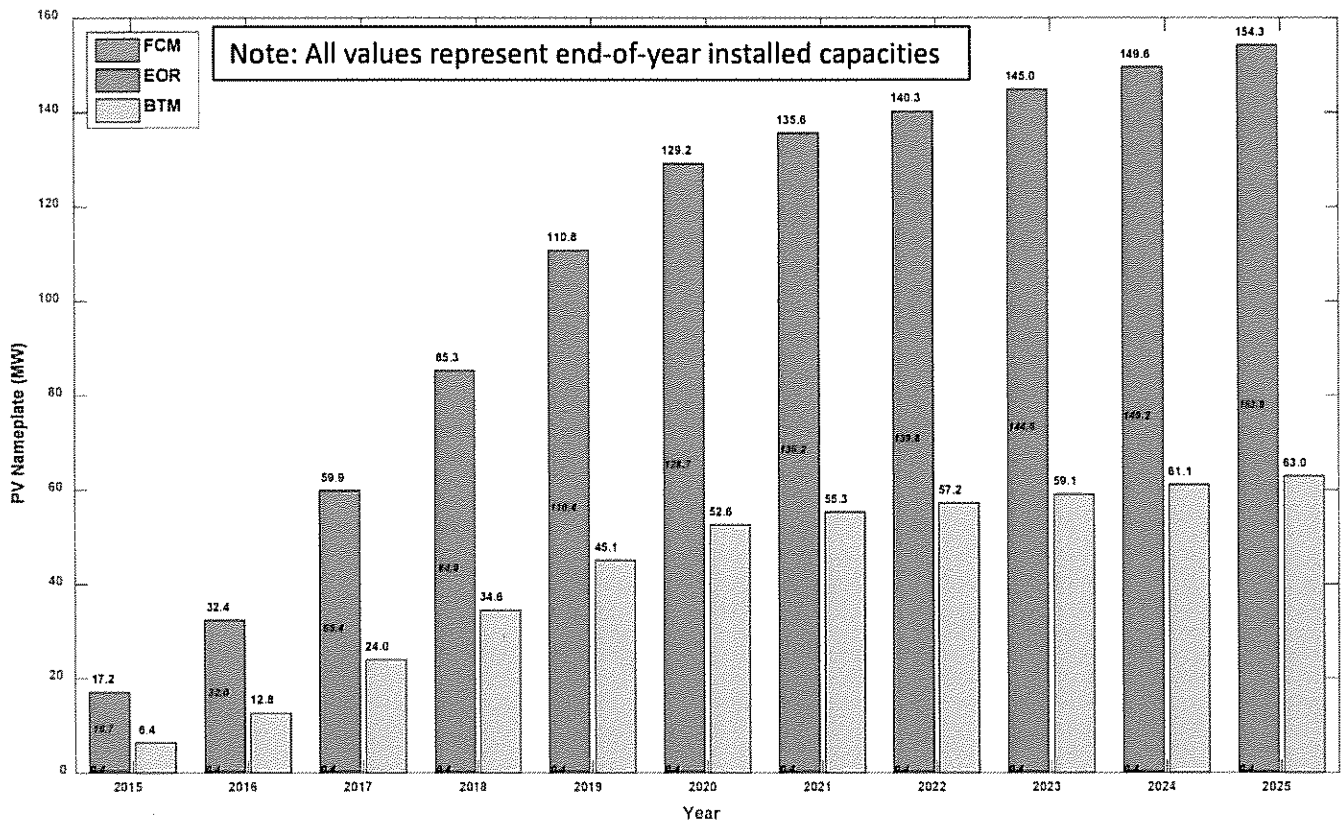
Cumulative Nameplate by Resource Type, MW_{ac}

New Hampshire



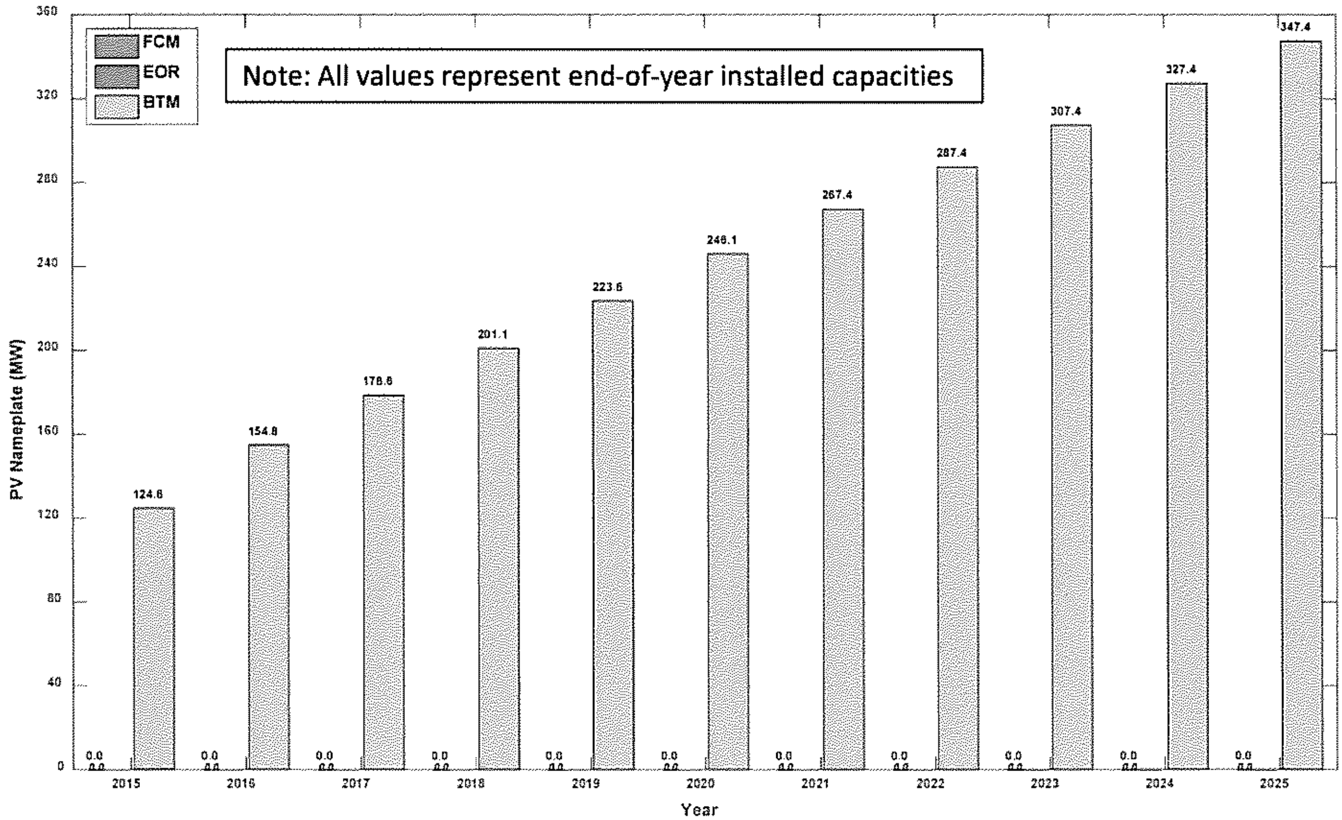
Cumulative Nameplate by Resource Type, MW_{ac}

Rhode Island



Cumulative Nameplate by Resource Type, MW_{ac}

Vermont



BTM PV: ESTIMATED ENERGY & SUMMER PEAK LOAD REDUCTIONS

BTM PV Forecast Used in CELT Net Load Forecast

- The 2016 CELT net load forecast will reflect deductions associated with the BTM PV portion of the PV forecast
- The following slides show values for annual energy and summer peak load reductions anticipated from BTM PV that will be reflected in the 2016 CELT net load forecast
  - PV does not reduce winter peak loads
- Values for expected summer peak load reductions from BTM PV incorporates the results of ISO's analysis discussed at the 2/24/16 DGFWG meeting
  - This analysis is described on slides 33-59 here: http://www.iso-ne.com/static-assets/documents/2016/03/2016_draftpvforecast_20160224revised.pdf

Final 2016 PV Energy Forecast

BTM PV, GWh

States	Total Estimated Annual Energy (GWh)									
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
CT	283	394	500	600	699	788	857	919	975	1,030
MA	768	943	1,021	1,065	1,094	1,123	1,152	1,181	1,209	1,238
ME	22	29	35	40	46	52	57	62	68	73
NH	39	53	61	66	71	76	81	86	91	96
RI	11	22	37	50	63	71	74	76	79	81
VT	178	215	246	275	305	334	362	388	414	441
Regional - Annual Energy (GWh)	**1301**	**1,655**	**1,898**	**2,097**	**2,278**	**2,444**	**2,582**	**2,713**	**2,836**	**2,959**

***Notes*:**

(1) Forecast values include energy from FCM Resources, non-FCM Energy Only Generators, and behind-the-meter PV resources
(2) Monthly in service dates of PV assumed based on historical development
(3) All values are grossed up by 6.5% to reflect avoided transmission and distribution losses

Final 2016 Forecast

BTM PV: July 1st Estimated Summer Peak Load Reductions

States	Estimated Summer Peak Load Reduction - BTM PV (MW)									
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
CT	92.1	123.9	153.6	181.0	207.7	230.6	247.6	262.8	275.7	288.2
MA	249.4	295.6	312.6	320.4	324.0	327.9	332.5	337.1	341.8	346.2
ME	7.3	9.0	10.6	12.2	13.7	15.2	16.6	17.8	19.1	20.3
NH	12.7	16.7	18.7	19.9	21.1	22.2	23.4	24.6	25.8	26.9
RI	3.7	7.0	11.3	15.2	18.7	20.6	21.3	21.8	22.3	22.7
VT	57.8	67.4	75.4	83.0	90.5	97.7	104.5	110.9	117.1	123.3
Regional - Cumulative Peak Load Reduction (MW)	422.9	519.5	582.2	631.6	675.6	714.3	745.9	775.0	801.7	827.6

Notes:

(1) Forecast values are for behind-the-meter PV resources only
(2) Values include the effect of diminishing PV production as increasing PV penetrations shift the timing of peaks later in the day
(3) All values represent anticipated July 1st installed PV, and are grossed up by 8% to reflect avoided transmission and distribution losses
(4) Different planning studies may use values different that these estimated peak load reductions based on the intent of the study

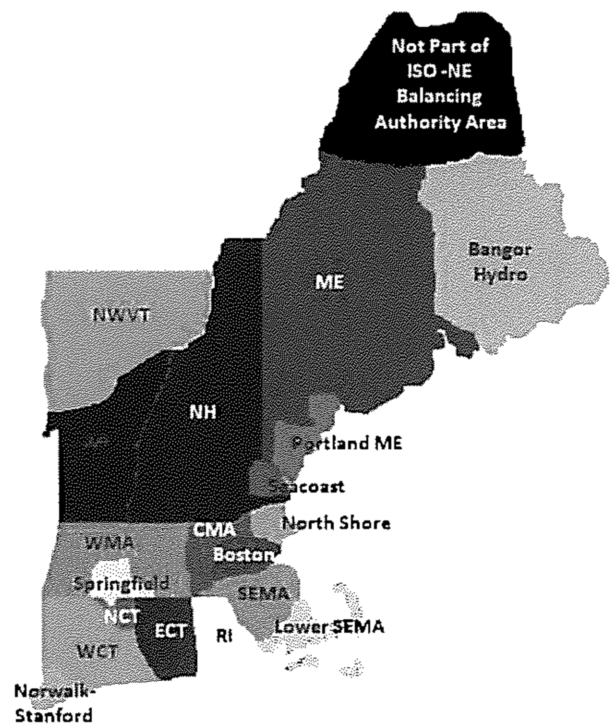
GEOGRAPHIC DISTRIBUTION OF PV FORECAST

Background

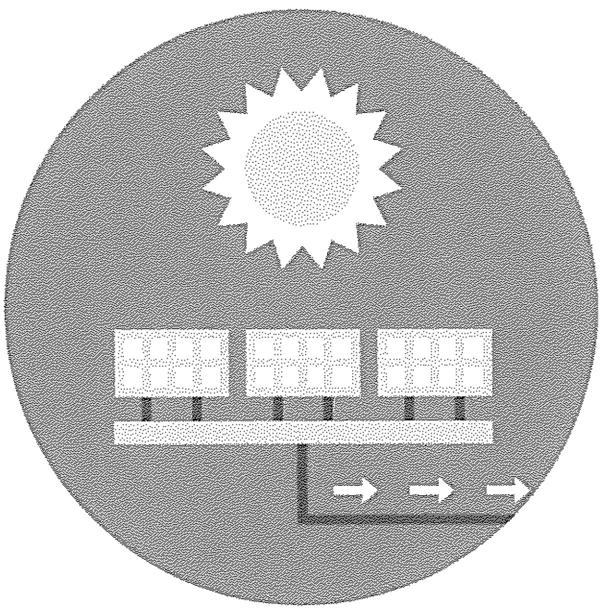
- A reasonable representation of the locations of existing and future PV resources is required for appropriate modeling
- The locations of most future PV resources are ultimately unknown
- Mitigation of some of this uncertainty (especially for near-term development) is possible via analysis of available data

Forecasting Solar By DR Dispatch Zone

- Demand Response (DR) Dispatch Zones were created as part of the DR Integration project
- These zones were created in consideration of electrical interfaces
- Quantifying existing and forecasted PV resources by Dispatch Zone (with nodal placement of some) will aid in the modeling of PV resources for planning and operations purposes



Geographic Distribution of PV Forecast



- Existing MWs:
  - Apply I.3.9 project MWs nodally
  - For remaining existing MWs, determine Dispatch Zone locations of projects already interconnected based on utility distribution queue data (town/zip), and apply MWs equally to all nodes in Zone
- Future MWs:
  - Apply I.3.9 project MWs nodally
  - For longer-term forecast, assume the same distribution as existing MWs

Dispatch Zone Distribution of PV

Based on December 31, 2015 Utility Data

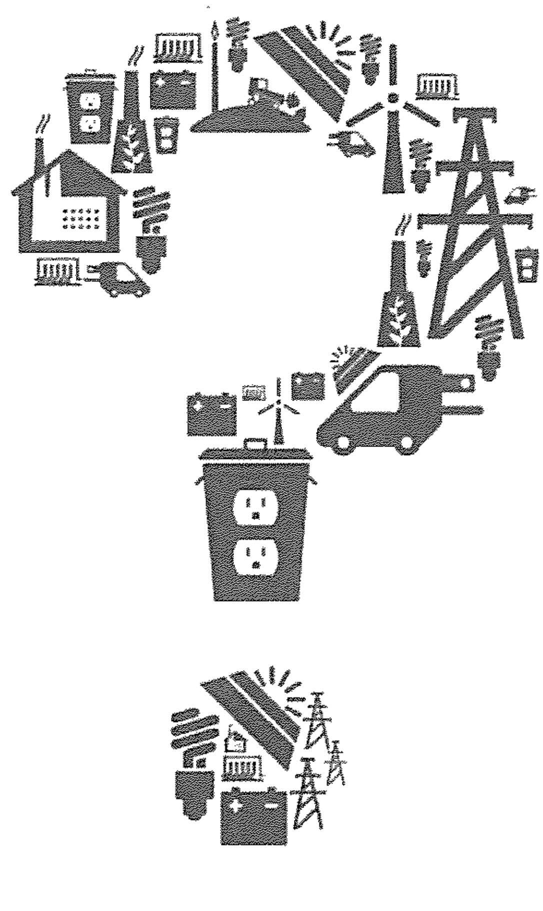
State	Dispatch Zone	% Share
MA	SEMA	21.5%
	Boston	10.9%
	Lower SEMA	18.7%
	Central MA	15.3%
	Spfld	6.0%
	North Shore	4.9%
	Western MA	22.7%
CT	Eastern CT	18.8%
	Western CT	53.7%
	Northern CT	20.1%
	Norwalk-Stamford	7.5%
NH	New Hampshire	88.3%
	Seacoast	11.7%
VT	Northwest VT	62.9%
	Vermont	37.1%
RI	Rhode Island	100.0%
ME	Bangor Hydro	15.6%
	Maine	51.2%
	Portland	33.3%

SUMMARY AND NEXT STEPS

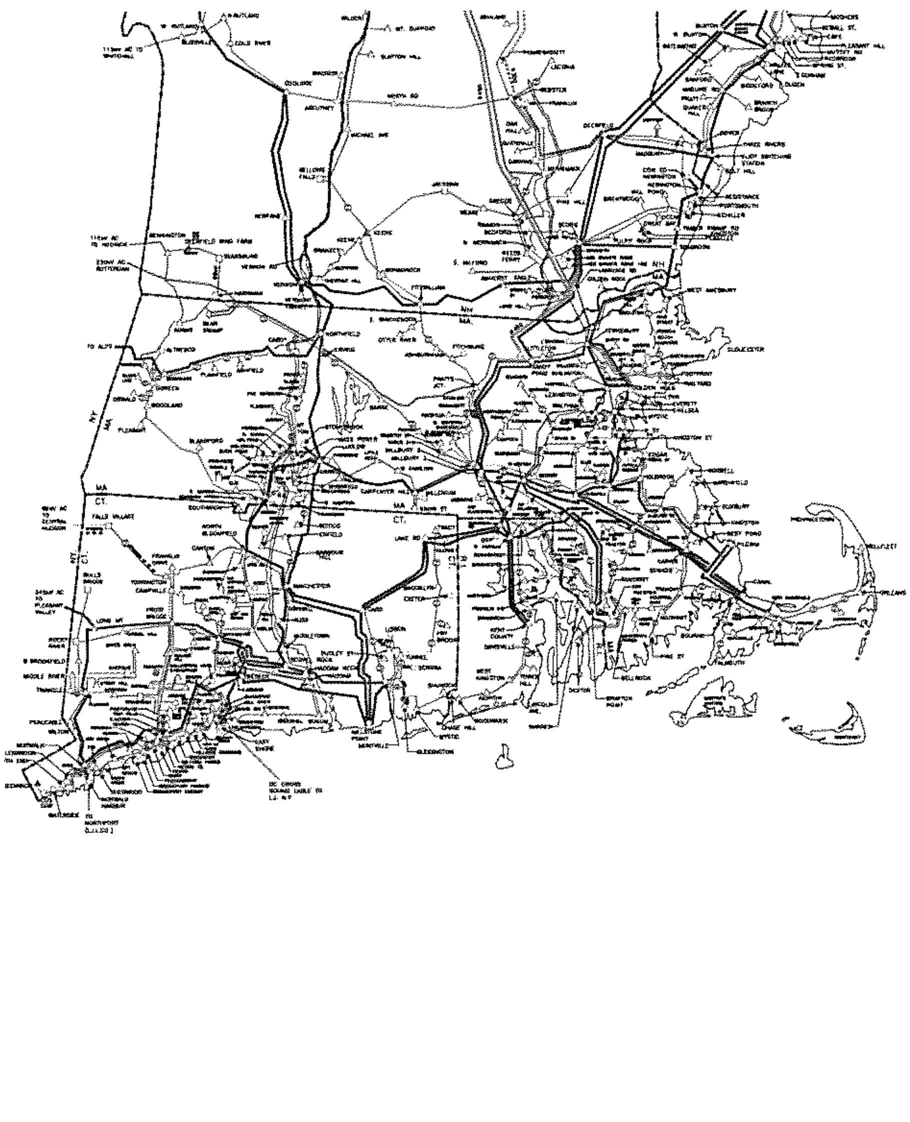
Stakeholder and State Regulator Input Has Resulted in Improved Forecast

- The 2016 PV nameplate and energy forecasts have been finalized
- ISO has classified the 2016 state and regional PV forecasts according to the three PV resource categories
- The ISO has updated its geographic distribution assumptions based on recent data
- The final PV forecast will appear in the 2016 CELT, which will be published by May 1st

Questions



TAB D



EXISTING INSTALLATIONS	LEGEND	AUTHORIZED OR PLANNED INSTALLATIONS
	WIND FARM	
	FOSSIL FUEL STATION	
	NUCLEAR STATION	
	HYDRO STATION	
	SUBSTATION	
	PUMPED STORAGE	
	SUBSTATION WITH INTERNAL COMBUSTION GENERATION	
	HVDC	
	BIOMASS	
	345 kV TRANSMISSION	
	230kV TRANSMISSION	
	138kV, 115kV, & 69kV	
2	DENOTES NUMBER OF CIRCUITS WHEN MORE THAN ONE	2
+ −	HVDC	

0 5 10 15 20 25 30 35 40 45 50

SCALE MILES
(APPROX.)

NEW ENGLAND GEOGRAPHIC TRANSMISSION MAP THROUGH 2026

ISO NEW ENGLAND, Inc.

3-23-16
Hard Copy Uncontrolled

TAB E

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS

PUBLIC UTILITIES COMMISSION

IN RE: INVENERGY THERMAL DEVELOPMENT LLC	)	
APPLICATION TO CONSTRUCT AND OPERATE THE	)	**Dkt. 4609**
CLEAR RIVER ENERGY CENTER, BURRILLVILLE,	)	
RHODE ISLAND	)	

INVENERGY THERMAL DEVELOPMENT LLC'S REPONSES TO CONSERVATION LAW FOUNDATION'S SECOND DATA REQUEST

2-5. In Invenergy's January 12, 2016 PowerPoint presentation to the EFSB, Slide 24, Invenergy projects $46 million in "energy cost savings" (not capacity costs) during the first three years of operation.

(a) For each of the first three years of operation, what assumption was made as to the number of hours during the operating year the plant would be operating at full load equivalent?
(b) For each of the first three years of operation, what assumption was made as to the number of hours during the operating year the plant would be burning ULSD?
(c) For each of the first three years, what assumption was made as to the number of megawatt-hours of energy the plant would sell into the ISO-NE market?

RESPONSE 2-5: The dispatch model determined the number of operating hours as an output based on the forecasted market power prices. No assumption was made relating to the number of hours operating or the number of hours on oil. The facility's ability to use oil is merely a backup, provided for electric reliability purposes in the event natural gas is not available. Natural Gas ("NG") was assumed to be available in every hour and NG was assumed to be the most economic fuel for the plant throughout the commitment period. All of the facility's production was assumed to be sold into the ISO-NE market and the dispatch model results for the 1x1 configuration from January 2016 are shown in the table below.

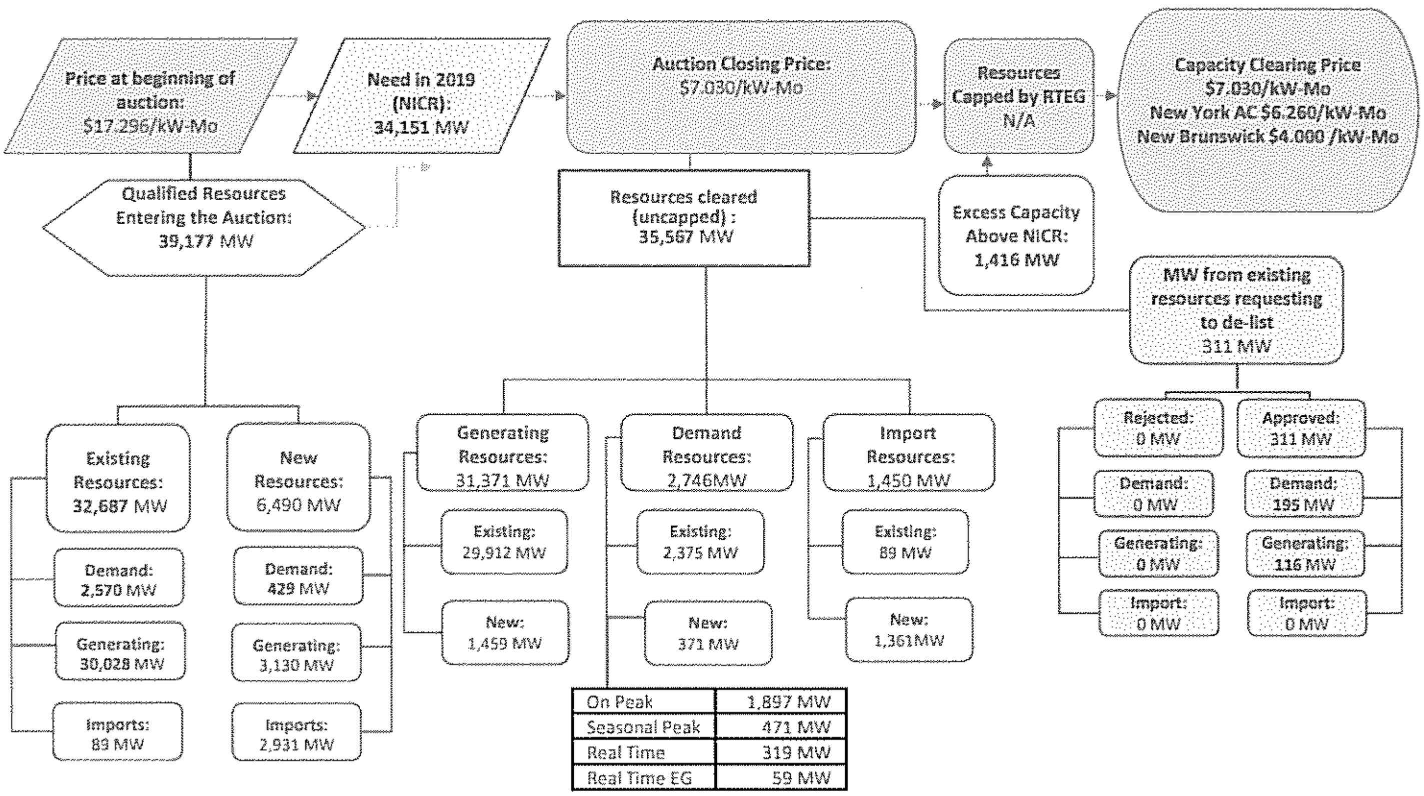
Year	6/19-5/20	6/20-5/21	6/21-5/22
GWh	4,207	4,130	3,975
hours operating	7,822	7,686	7,403
hours operating at full load	7,642	7,504	7,211

RESPONDENT: John Niland, Director Business Development, Invenergy
Mark Repsher, PA Consulting
Ryan Hardy, PA Consulting

DATE: April 14, 2016

TAB F

Results of New England's FCA #10



TAB G

Calculated LCOE for Photovoltaics Systems in the United States

30% Federal ITC in 2010 and 2015 and 26% Federal ITC in SunShot 2020 Scenarios. 1120 to 2380 kWh/kW systems.

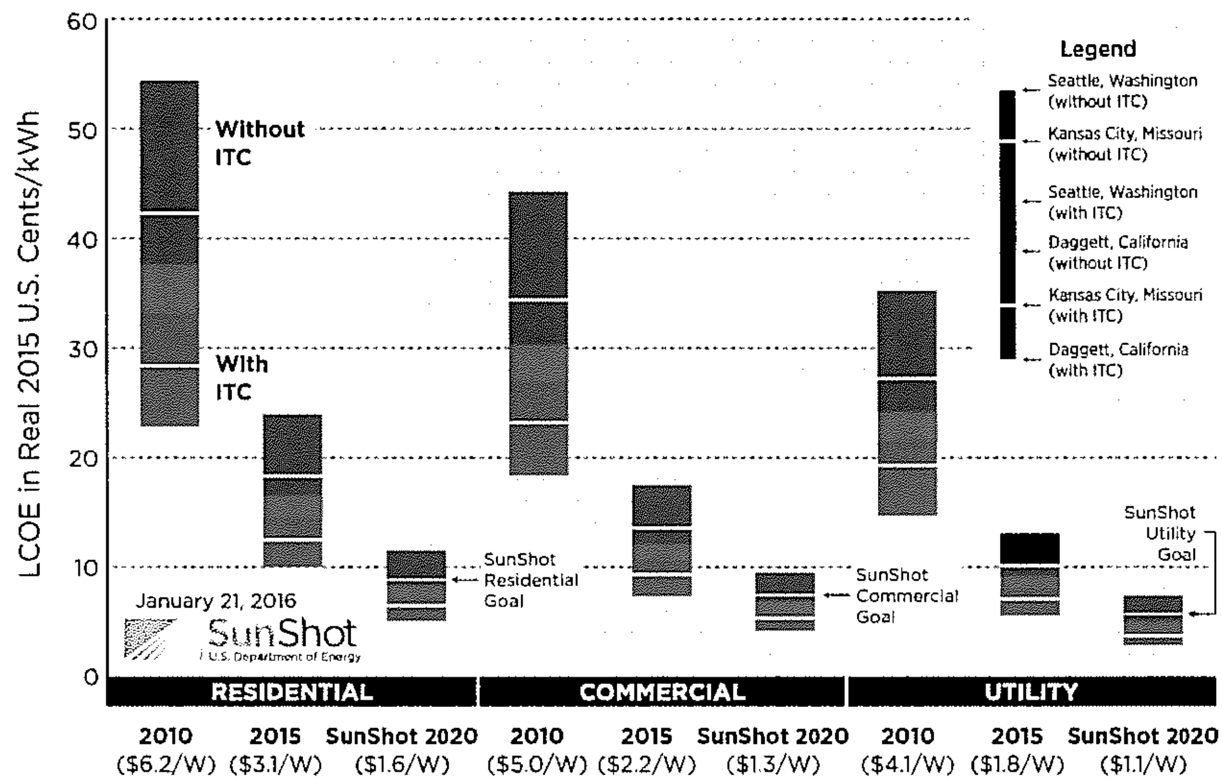


Figure 1. Solar PV LCOE – historical, current, and 2020 targets

In Section 2, below, we provide a brief synthesis of key insights and findings from across all of the On the Path to SunShot reports. For additional context, detailed findings, and important discussions about methods, limitations, and future research needs, readers can download the full reports at the On the Path to SunShot webpage . In Section 3, we conclude with a brief discussion of future SunShot Initiative work.