2012 Economic Study

System Planning | Resource Adequacy
April 2014

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Nomenclature

Nomenclature used in this report.[1]

ACP	alternative compliance payments associated with Renewable Portfolio Standards
BHE	Bangor Hydro Energy (i.e., northern Maine)
CF	capacity factor
CMP	Central Maine Power
CSC	Cross-Sound Cable
CT	combustion turbine
CTFC	contribution to fixed costs
DG	distributed generation
DR	demand resource
EE	energy efficiency
EFOR	equivalent forced-outage rate
EMS	Energy Management System network model
FCA	Forward Capacity Auction
GADS	Generating Availability Data System
GSU	generator step-up unit
GV	GridView
GWh	gigawatt-hour(s)
HVDC	high-voltage direct current
ICR	Installed Capacity Requirement
IREMM	Inter Regional Electric Market Model
LMP	locational marginal price
LSE	load-serving entity
LSP	Local System Plan
MOD	Model on Demand database
MPRP	Maine Power Reliability Project
MW	megawatt(s)
NESCOE	New England States Committee on Electricity
NEWIS	New England Wind Integration Study

[1] Additional nomenclature used comes from the ISO New England Glossary and Acronyms available at http://www.iso-ne.com/support/training/glossary/.

NGCC	natural gas combined cycle
NNC	Norwalk–Northport
OATT	*Open-Access Transmission Tariff*
PAC	Planning Advisory Committee
PSSE	Transmission Planning Network Model
REC	Renewable Energy Certificate
RENEW	Renewable Energy New England
RSP	Regional System Plan
RTEG	real-time emergency generation
RUMF	Rumford
SCC	seasonal claimed capability
SEMA/RI	Southeast Massachusetts/Rhode Island
VOM	variable operation and maintenance
WBIG	Wyman/Bigelow
WDA	wind development area

Section 1
Executive Summary

This *ISO New England 2012 Economic Study Report* (2012 Economic Study) presents the methodologies, data and assumptions, simulation results, and observations of the following three-part study:

1) Investigation of the most suitable locations for developing different types of resources without causing congestion
2) High-level overview of the economic viability of various technologies
3) Comparison of four hypothetical expansion scenarios that illustrate various low-carbon resource futures

The first part of the study showed the most suitable locations for developing various types of resources without causing congestion. The study considered resources such as baseload, wind, photovoltaic solar (PV), energy efficiency (EE), and smart grid, as well as others:

- BASE—Baseload generating units (i.e., units that operate at a constant level for 24 hours/day, seven days/week)
- INTR—Intermediate generating units (i.e., units that ramp up and down to follow the system load as it transitions between off-peak and on-peak load levels. This generation profile operates at a 20% capacity factor)
- DR—Active demand response/peaking resources
- EE—Energy efficiency
- PV—Photovoltaics
- WNDN—Wind onshore
- WNDF—Wind offshore
- SGRD—Smart grid
- CHPG—Combined heat and power/geothermal (CHP/G)

From these results, the most-suitable locations for unit retirements or resource removals were tested, summarized, and presented in diagrams that distinguished locations where changes in supply and demand balances were significant from areas where changes in supply and demand balance were not significant. For example, Table 1-1 illustrates the areas where the change in supply and demand balance can result in congestion. The diagram is arranged as a progression from northern Maine at the top to southwestern Connecticut on the bottom. The values in the cells represent the increased production costs due to the transmission constraints. The cells colored red/orange show when congestion becomes significant and can be interpreted as follows:

- The relative production costs in northern New England are most affected by the congestion created by resource additions (or load removals). The greatest impacts are in northern Maine.
- The relative production costs in southern New England show congestion created by resource removals (or load additions). The greatest impacts are in Norwalk, Southwestern Connecticut, and Boston.

- The addition or removal of resources in these areas could create or exacerbate transmission-constraints that would result in significant inefficiencies.
- The quantification of these more or less suitable locations for resource additions or removals communicates the desirability of adding or removing resources in one area compared with a different area.

Table 1-1
Effectiveness of Load/Resource Additions or Removals Based on Production Cost

Change in Annual Congestion From an Unconstrained Case for a Change in “BASE” MW ($Million per year)

		<= Resource Removals <= Load Increases							Resource Additions=> Load Decreases =>						
Sub Area	Most Constraining Interface	-2700	-2100	-1500	-1200	-900	-600	-300	300	600	900	1200	1500	2100	2700
BHE	Orrington South	2	1	1	1	1	1	1	2	4	15	43	143	372	595
ME	Surowiec South	2	1	1	1	2	1	1	2	3	9	24	73	276	499
SME	Maine-New Hampshire	2	1	1	1	2	1	1	2	3	3	7	14	65	229
NH	North/South	2	2	1	1	2	1	1	1	2	2	3	6	18	52
VT	North/South	2	2	1	1	2	1	1	1	1	2	3	5	14	39
WMA	N/A	3	2	2	1	2	1	1	1	1	1	1	1	1	1
CMAN	N/A	3	2	2	1	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	1	1	1	1
BOST	Boston Import	143	24	3	1	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	1	1	1	1
SEMA	SEMA/RI	3	2	2	1	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	1	1	4	9
RI	SEMA/RI	3	2	2	1	2	1	1	1	1	1	1	1	4	9
CT	N/A	2	2	2	1	2	1	1	1	1	1	1	1	1	1
SWCT	SWCT Import	104	4	2	1	2	1	1	1	1	1	1	1	1	1
NOR	Norwalk Import	7828	4675	1549	441	71	5	1	1	1	1	1	1	1	1

Range of “better” places for resource / load addition / removal

Significant Import-Limited Energy
More Significant Import-Limited Energy
Significant Bottled-in Energy
More Significant Bottled-in Energy
Unconstrained

Because some types of resources have relatively low capacity factors, their additions or removals create smaller changes in supply and demand balances and therefore smaller impacts on the magnitude of congestion. A graphic similar to Table 1-1 but showing the sensitivity of supply and demand balance to the LSE energy expense metric can also be developed; however, unlike the relative production cost metric, the relative LSE energy-expense metric may not increase monotonically, and therefore, the LSE energy-expense metric is less robust than the production cost metric.

The second part of the study evaluated the economic viability of various technologies. This analysis compared the annual fixed costs of a resource technology with the net energy market revenues it would earn from operations. A resource’s annual fixed cost is the amount the resource needs to pay for capital investment, financing expenses, and certain operations and maintenance costs. The ISO calculated these annual fixed costs from the resource’s capital cost and an estimate of annual carrying charge rates of 15%

to 25% of the capital costs. This range is considered representative of the upper and lower bounds for this study.[2]

This analysis considered only net energy market revenues, which are based on the simulated energy market clearing prices minus a resource's cost of production. As shown in Figure 1-1, as resources were added, downward pressure was exerted on energy market clearing prices, which reduced energy market revenues. For this figure showing gross energy market revenues, a resource's cost of production was not considered.

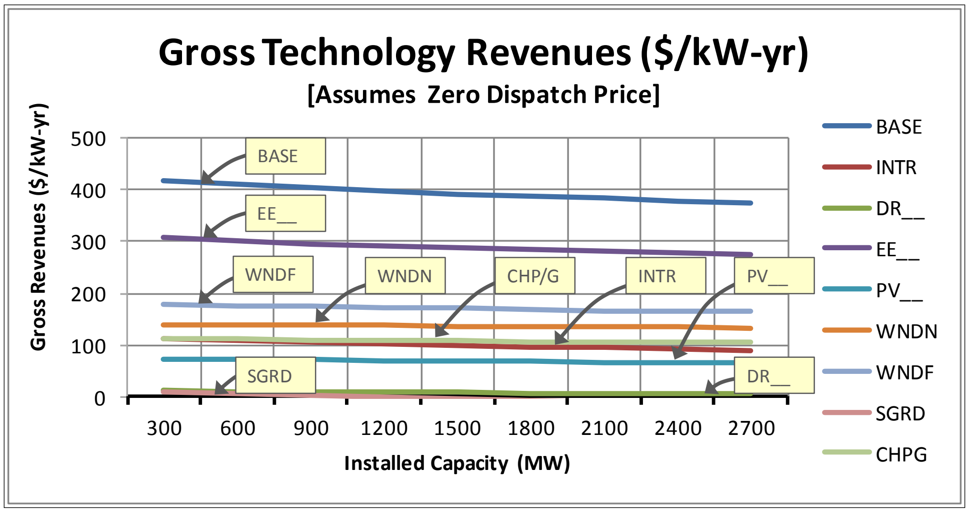

Figure 1-1: Annual gross revenues for each load shape ($/kW-yr).

The results of this part of the study developed a comparison of the net energy revenues (gross energy revenues minus the assumed cost of fuel consumed) with the annual carrying cost of the resource. Figure 1-2 shows the net energy revenues (e.g. annual contributions to fixed costs) compared with the upper and lower ranges of the annual carrying costs.

[2] This range of estimated of annual carrying charge rates, 15% to 25% of the capital costs, was used in the ISO's 2007 *New England Electricity Scenario Analysis* (August 2, 2007), http://www.iso-ne.com/committees/comm_wkgrps/othr/sas/mtrls/elec_report/scenario_analysis_final.pdf.

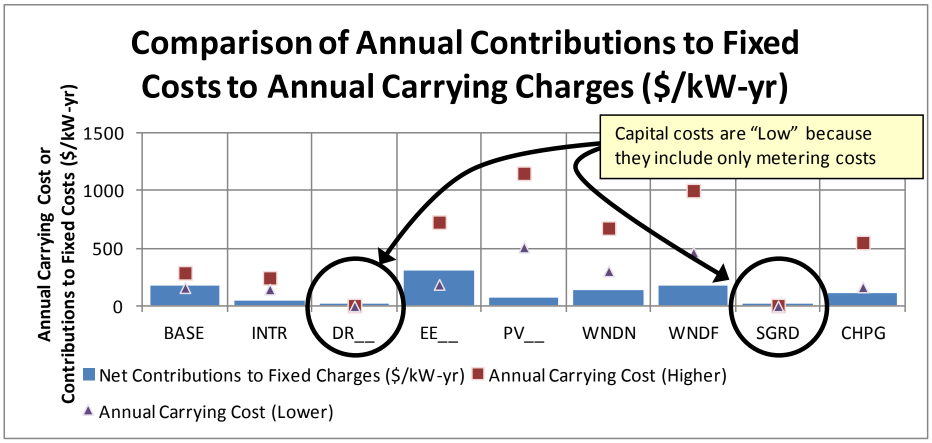

Figure 1-2: Comparison of annual contributions to fixed costs with annual carrying charges ($/kW-yr).

Some observations from these results are as follows:

- An advanced combined-cycle unit with low financing and capital costs would be nearly able to support itself on energy market revenues.
- A conventional simple-cycle combustion turbine operating at a capacity factor of approximately 20% would not be able to recover its capital investment costs from energy market revenues alone. This suggests that these resources would need additional revenues streams from markets such as the Forward Reserve Market and Forward Capacity Market.
- Energy-efficiency resources with typical energy-efficiency program costs can recover their capital investment costs from energy market revenues. The wide range of technology costs suggests that the energy savings alone makes some technologies economic, while other technologies may require revenues from other market streams.
- If only the metering costs were considered, demand-response resources would be able to recover their capital investment costs from energy market revenues. The viability of the end-user technologies necessary to manage the customer-side loads is not known and was not evaluated as part of this study.
- Photovoltaics, which are assumed to operate at a capacity factor of approximately 15%, would not be able to recover its capital investment costs from energy market revenues. This suggests that these resources would need additional revenues streams, such as those from the Forward Capacity Market and from Renewable Energy Credits.
- Onshore and offshore wind resources would not be able to recover their capital investment costs from energy market revenues alone. This suggests that these resources would need additional revenues streams, such as the Forward Capacity Market and Renewable Energy Credits.
- The results for smart grid, which has a profile with characteristics similar to pumped storage (an energy-storage technology), show that increased penetration leads to a sharp decline in the net energy revenue savings because the cost of procuring the off-peak energy (including losses) begins to outweigh the on-peak revenues.
- Combined heat and power/geothermal systems can recover a significant contribution to fixed costs. The technology that would be used to create any specific CHP/G load shape is uncertain.

The third part of the study compared four hypothetical expansion scenarios for low-carbon resource futures. The study focused on compliance with the states' Renewable Portfolio Standards (RPSs) as the system evolved over a 10-year period, 2012 to 2021. Key assumptions in the sensitivities were a doubling of the energy-efficiency growth rate after 2015 and the inclusion of the effects of photovoltaics and combined heat and power/geothermal resources. If there were scenarios where the RPS requirements were not met, sufficient amounts of wind resources would be added to satisfy the shortages.

Four scenarios were developed, which included the specific renewable technologies to be evaluated. The initial resource mix included the currently obligated and envisioned FCM resources. However, the coal, heavy oil, and natural gas steam resources older than 40 years in 2021 (e.g., older than 30 years in 2011) were assumed to be retired. These retired resources were then postulated to be replaced with a variety of low, or nonemitting, resources.

A high-level definition of the four hypothetical scenarios is as follows:

- Case 1: Base energy efficiency with retirements replaced by new natural gas resources
- Case 2: Same as Case 1, except retirements were replaced by:
    - 3,000 MW of photovoltaics
    - 340 MW of combined heat and power/geothermal
    - New natural gas resources to satisfy the remainder
- Case 3: Same as Case 1, with double energy-efficiency growth rates after 2015
- Case 4: Same as Case 3, except retirements were replaced by:
    - 3,000 MW of photovoltaics
    - 340 MW of CHP/G
    - New natural gas resources to satisfy the remainder

Observations from the third part of the study include the following:

- Adding resources that produce energy at costs lower than the prevailing market clearing price puts downward pressure on energy market clearing prices.
- Changes in resource expansion produced changes in economic metrics in 2021, which had a range of about 16% for production costs, while the range in LSE energy expense was 2%.
- With the assumptions in these cases, the amount of renewable energy produced is adequate to meet the required new growth in RPS and related goals.
- The Financial Transmission Rights/Auction Revenue Rights (FTR/ARR) congestion was not significant if the postulated resources were distributed consistent with the results of the first part of this economic study.
- Emissions were much lower because of the retirement of residual oil, coal, and natural gas steam units and their replacement with significantly more efficient natural gas units.
- The sulfur dioxide (SO_2) emissions in all cases were virtually eliminated as a result of the retirement of residual oil and coal steam units and their replacement with natural gas units.

This 2012 Economic Study used assumptions for variable factors, such as fuel prices, unit availability, and load growth, all of which could affect system performance metrics. Because all the assumptions are uncertain, the modeling results indicate relative values and trends. These results are not characterized as accurate projections of future transmission congestion, ultimate project economics, or resultant environmental impacts.

Section 2
Introduction

According to Attachment K of its *Open Access Transmission Tariff* (OATT), ISO New England (ISO) is required to conduct economic studies arising from one or more stakeholder requests submitted by April 1 of each year through the Planning Advisory Committee (PAC).[3] These requests may be to study scenarios of general locations for the expansion of various types of resources, resource retirements, and possible changes to transmission interface limits. By May 1 of each year, the proponents of these studies are provided an opportunity to present the PAC with the reasons for the suggested studies. The ISO discusses the draft scope(s) of work with the PAC by June 1 and reviews the study assumptions with the PAC at later meetings. The ISO then performs up to three economic studies and subsequently reviews all results and findings with the PAC.

The economic studies provide information on system performance, such as estimated production costs, load-serving-entity (LSE) energy expenses, estimates of transmission congestion, and environmental emissions metrics. This information can assist market participants and other stakeholders in evaluating various resource and transmission options that can affect New England's wholesale electricity markets and operations. The studies may also assist policymakers who formulate strategic visions of the future New England power system.

In fulfillment of this obligation, ISO staff presented the simulation scope of work, assumptions, draft results, and final results to the PAC in several meetings.[4]

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[3] ISO tariff Section II, *Open Access Transmission Tariff,* Attachment K, "Regional System Planning Process" (January 1, 2013), http://www.iso-ne.com/regulatory/tariff/sect_2/oatt/sect_ii.pdf.

[4] *2012 Economic Study: Scope of Work*, PAC presentation (June 19, 2012), http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2012/jun192012/2012_eco_study_sow.pdf.

2012 Economic Study: Incremental/Decremental Phase, and Appendix, PAC presentations (October 18, 2012), http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2012/oct182012/eco_study_first_phase.pdf and http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2012/oct182012/eco_study_appendix.pdf.

2012 Economic Study: Next Steps, PAC presentation (October 18, 2012), http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2012/oct182012/eco_study_next_steps.pdf.

2012 Economic Study results, Excel spreadsheet (October 18, 2012), http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2012/oct182012/eco_results.xlsx.

Executive Summary Preliminary Results for 2012 Economic Study Request Specific Scenario Phase, PAC presentation (January 17, 2013), http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2013/jan172013/a2_iremm_2012_economic_study_update_011713.pdf.

Preliminary Results for 2012 Economic Study Request Specific Scenario Phase, PAC presentation (January 17, 2013), http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2013/jan172013/eco_study_results.pdf.

2.1 Submitted 2012 Economic Study Requests

In 2012, the ISO received three economic study requests, which were presented to the PAC on April 18, 2012.[5]

2.1.1 End User Alliance—Assessing the Impacts of Retiring New England's Nuclear Plants

The End User Alliance requested an Attachment K study to analyze the impacts of the loss of one or more (including all) of New England's nuclear power plants. They requested an investigation of the following factors:

- The amount that New England nuclear plants lower the energy clearing price
- The cost impacts on wholesale and retail power prices if one or more plants were retired
- The replacement fuel mix needed to maintain existing grid services
- The impacts of existing nuclear resources on the levels of regional emissions, including sulfur dioxide (SO_2), nitrous oxides (NO_X), and carbon dioxide (CO_2)
- The impacts of removing nuclear generation in New England on the Regional Greenhouse Gas Initiative (RGGI)

The End User Alliance requested that the following metrics be used in this evaluation:

- Effect on energy pricing
- Congestion
- Tie-line usage
- Changes in fuel use
- Environmental emissions

2.1.2 Synapse Energy Economics

Synapse Energy Economics submitted a study request on behalf of Conservation Services Group, Vermont Energy Investment Corporation, PowerOptions, Connecticut Office of Consumer Counsel, and Conservation Law Foundation. The request was to analyze the impact of several trends in New England that were hypothesized to affect regional reliability needs over the next 20 years. These trends include the impact of state-sponsored demand-side management programs and the inclusion of the 2012 energy-efficiency forecast in the Base Case. [6]

The request included assumptions about the potential impact of state net-metering programs; distributed generation to satisfy state Renewable Portfolio Standard (RPS) goals, specific PV goals, or other state and

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[5] End User Alliance, *Attachment K Request: Assessing the Impact of Retiring New England's Nuclear Fleet*; Synapse Energy Economics Inc*, Forecasting Public Policy Impacts,* PAC presentation (April 18, 2012), http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2012/apr182012/index.html (Also see economic study request letters from Central Maine Power, End User Alliance, and Synapse, at the same link.)

[6] "2012 Forecast Data File," Excel worksheets (2012), http://www.iso-ne.com/trans/celt/fsct_detail/2012/isone_fcst_data_2012.xls (Tab 2).

federal targets; and the likely impacts of federal regulations to protect public health. Synapse's aim for the study was for regional stakeholders to better understand possible system conditions in 2032, which would help guide the development of the most needed improvements to the New England transmission and distribution systems while avoiding investments in system facilities unlikely to be needed.

The study was envisioned to include the following elements and associated assumptions whose development could rely on previous ISO economic studies:

- Renewable Portfolio Standards quantified the "renewable resource" goals of the New England states.
- The demand-side management programs of the New England states that would be derived from the Forward Capacity Market (FCM) auctions and the 2012 energy-efficiency forecast.[7]
- The potential retirement of fossil fuel resources due to competitive pressures and emission mandates to protect public health. Synapse noted that the ISO is already investigating assumptions about regional retirements as part of its Strategic Planning Initiative and suggested that this could be used, or adapted for, this element of the economic study.
- The net-metering programs of the New England states, with assumptions developed by analyzing the state program goals and achievements to date for estimating future impacts.
- Doubling the growth rate of the energy-efficiency forecast after the 2014/2015 capacity commitment period established by the Forward Capacity Auction (FCA #5).
- State programs that promote specific resource technologies. The study could model a variety of specific state goals for resources, all of which will have an impact on peak loads and energy consumption. Some of these categories may include the following types of resources being developed with or without a public-policy mandate:
    - Combined heat and power (CHP)
    - Photovoltaic
    - Ground water heat pumps (geothermal)
    - Biomass

2.1.3 Central Maine Power Request

Central Maine Power submitted a request for a study of the economics of constrained-in wind energy in western Maine. This request was withdrawn in advance of its presentation to the PAC meeting because the ISO had already addressed the topic of the request.

[7] "FCM Auction Results," web page (2013), http://www.iso-ne.com/markets/othrmkts_data/fcm/cal_results/index.html. "Energy-Efficiency Forecast Working Group," web page (2013), http://www.iso-ne.com/committees/comm_wkgrps/othr/enrgy_effncy_frcst/index.html.

Section 3
Methodology and Assumptions

The ISO's review of the two study requests presented to the PAC identified similarities and synergies between the studies, so the ISO combined the two requests into a multipart analysis. Although the request by Synapse lacked specificity of resource expansions that other economic requestors commonly provide, the ISO worked with the PAC to develop a draft set of assumptions through an open and transparent process.

To implement this in an expedited manner, this analysis was based on the 2011 Economic Study database.[8]

Economic studies generally use assumptions for variable factors, such as fuel prices, unit availability, and load growth, all of which could affect system performance metrics. Because all the assumptions are uncertain, the modeling results indicate relative values and trends and should not be characterized as accurate projections of future transmission congestion, ultimate project economics, and resultant environmental impacts. Given these caveats, this approach was adequate to address many of the issues associated with the retirement of specific types of resources and the addition of other resources in each area around New England.

3.1 ISO New England Response Framework

The ISO envisioned the 2012 Economic Study as quantifying metrics that identified the most suitable locations for developing various types of resources without causing significant congestion. Additionally, this approach would also identify the least suitable locations for unit retirements. The types of resources analyzed included baseload, wind, photovoltaic solar, and energy efficiency, among other types. The first two parts of the study were performed for a single year, 2021, while the last part of the study used a 10-year period covering 2012 to 2021.[9]

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[8] *2011 Economic Studies: Draft Results*, PAC presentation (May 17, 2012), http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2012/may172012/2011_eco_study.pdf. 2011.

Economic Studies Supporting Documentation (June 28, 2012), http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2012/may172012/index.html.

2011 Economic Studies: GridView Simulation Results, PAC presentation (January 17, 2013), http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2013/jan172013/a3_gridview_economic_study_011713.pdf.

2011 Economic Studies—Supplemental: GridView Simulation Results—Effect of Relieving a Binding Constraint in SMEA, Supplemental Study (January 17, 2013), http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2013/jan172013/gridview_2011_eco_supplemental.pdf.

2011 Economic Studies: An Update of Gridview Simulation Results, PAC presentation (March 21, 2013), http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2013/mar212013/a6_2011_gridview_economic_study.pdf.

[9] ISO New England 2012 Economic Study: Incremental/Decremental Phase, PAC presentation (October 12, 2012), http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2012/oct182012/eco_study_first_phase.pdf.

This study was structured to analyze the addition and removal of capacity by adding or subtracting loads and resources represented by specific load shapes. For example, an analysis of the retirement of a baseload nuclear plant on the west side of the East–West constraint would be nearly equivalent to an analysis that included an increase in loads equal in size to the retired nuclear unit. In both cases, the supply/demand balances would change by a similar megawatt (MW) amount in a similar location. The effects of increasing loads by a fixed amount on the west side of the East–West interface would appear like a larger perturbation in the supply/demand balance, which would be similar to retiring one or more nuclear units, and the resulting flows would be seen on specific interfaces. Similarly, the addition of active demand response, which reduces loads at peak times, has approximately the same effect on the supply/demand balance as adding a peaking generator at the same location.

This is a high-level study that only represents the effect of major interfaces and does not involve a level of detail that a "transmission needs assessment" would require.[10] Figure 3-1 provides the representation of the New England system showing the interfaces that separate the different areas in New England. The Regional System Plan (RSP) areas are shown as yellow bubbles, and many additional subareas are shown for wind, photovoltaic, and demand response.

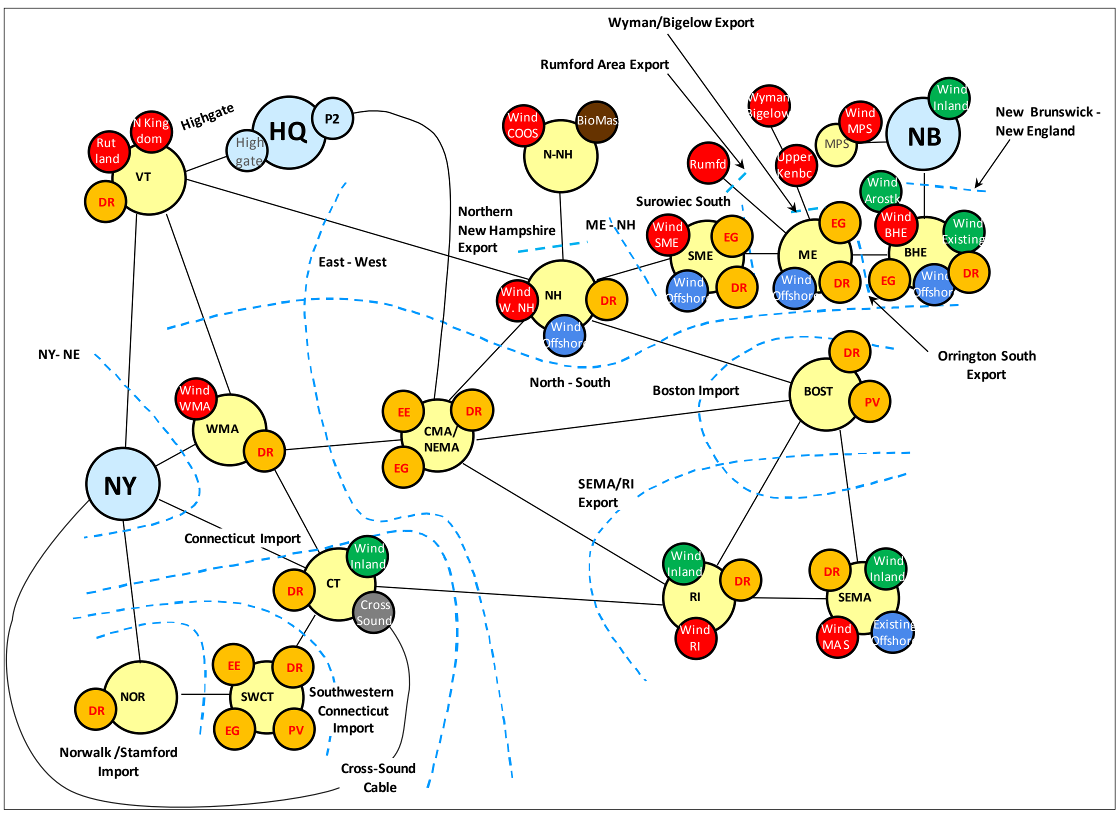

Figure 3-1: Modeling of ISO New England areas and transmission limits.

[10] A transmission needs assessment is a planning study of the adequacy of the regional or interregional transmission system.

The first part of the study quantified metrics for the locations in various areas around New England for developing or retiring various amounts of resources that would result in minimal congestion. Because the amount of congestion is based on the magnitude of the change in loads and the frequency of the change, capacity factor is important.

A baseload resource that affects the load the same amount in every hour would have the greatest impact on congestion. Other types of resource additions (or retirements) would have a smaller effect on annual congestion throughout New England because of fewer hours at maximum output. The congestion in locations that had baseload resource development (or baseload resource removals) would be more than in locations where other resource types with lower capacity factors were added or removed. The addition of load in some areas, which represents resource retirements without replacement, may result in congestion, as well.

The second part of the study compared the estimated capital costs in terms of an annual carrying cost ($/kilowatt-year; $/kW-year), with the electric energy revenues accruing to the postulated resources from the production cost simulations (also expressed as $/kW-year). The technologies that could support most or all of the annual carrying charges from simulated energy revenues were reasonably assumed to be economically self-sufficient. A resource that could not support itself from the simulated energy revenues would suggest the need for other sources of revenue. Possible additional sources of revenues could be other wholesale electricity markets, such as the Forward Capacity Market and Forward Reserve Market (FRM), as well as other incentives, such as production tax credits.

In the third part of the study, four low-carbon cases were evaluated that assumed various resource scenarios to meet expected Renewable Portfolio Standards and two assumed growth rates for energy efficiency. The addition of resources with low fuel costs—such as combinations of efficient natural-gas-fired generators or zero-dispatch cost wind, photovoltaic, energy efficiency, and demand response—would show reductions in the systemwide production costs and total load-serving entity (LSE) energy expenses. Metrics were developed for assessing the following low-carbon cases over a 10-year horizon:

Case 1—Base energy efficiency with no additional renewables

Case 2—Base energy efficiency with:

- 3,000 MW of photovoltaics
- 340 MW of combined heat and power/geothermal (CHP/G)

Case 3—Double energy-efficiency growth with no additional renewables

Case 4—Double energy-efficiency growth with

- 3,000 MW of photovoltaics
- 340 MW of combined heat and power/geothermal

3.2 Assumptions

The data, assumptions, and modeling inputs, as listed below, were largely based on the 2011 Economic Study. However, the third part of the study required the use of the 2012 load forecast because it was the first year that an energy-efficiency forecast was available for the years following the Forward Capacity Market commitment period.

- System generation—The supply-side resources for the New England system were based on the *2011–2020 Forecast Report of Capacity, Energy, Loads, and Transmission* (2011 CELT Report) plus the new supply-side resources that cleared in FCA #5 for 2014/2015.[11] Under these assumptions, supply resources were adequate to meet the Installed Capacity Requirement (ICR) through the period:[12]

- Generator heat rates were based on publicly available databases supplemented by ISO information and technology-appropriate defaults, as needed.
- Resource expansion, retirements, and replacements reflect ISO capacity markets and other scenario-specific plans for generation expansion.
- Dispatch costs are consistent with assumptions, such as for fuel prices, heat rates, and emissions-allowance dispatch adders.
- Wind energy resources were assumed to have a composite FCM-qualified capacity equal to 27.6% of the nameplate capacity.
- Photovoltaic energy resources were assumed to have a composite FCM-qualified capacity equal to 39.4% of the nameplate capacity.

- Load forecast—The New England load and electric energy forecasts were based on the demand data for 2012 to 2021, as presented in the 2011 CELT.[13] The third part of the study used the load forecast presented in the 2012 CELT.
- The hourly load profile for 2006 was used as the basis for representing the New England loads because of the availability of correlated, time-stamped profiles for wind and photovoltaic resources.
- Demand resources—The three broad types of demand resources were modeled (i.e., "passive" energy efficiency, "active" demand response, and real-time emergency generation). These demand resources were based on profiles developed as inputs. The 2012 energy-efficiency forecast was used in the third part of the study to reflect the magnitude of energy efficiency in the years after 2015. This required the use of the corresponding load forecast from the 2012 CELT Report.
- Transmission interfaces—Transmission-interface limits consistent with planning criteria were used for major interfaces that limit flows between load and generation areas.[14] These interfaces restricted flows to the levels shown in Table 3-1 for a limited number of paths. The flows in most "reverse" directions, such as Boston Export, or New Hampshire to Maine, were not included in this study.

[11] "CELT Report, 2011," web page (2013), http://www.iso-ne.com/trans/celt/report/2011/index.html.

[12] The ICR is the minimum amount of capacity the region needs to meet resource adequacy requirements.

[13] ISO New England, "2012 Forecast Data File," http://www.iso-ne.com/trans/celt/fsct_detail/2012/isone_fcst_data_2012.xls.

[14] *Transmission Transfer Limits for Transportation Models: 2012 Regional System Plan Assumptions*, Power Supply Planning Committee Meeting (June 14, 2012), http://www.iso-ne.com/committees/comm_wkgrps/relblty_comm/pwrsuppln_comm/mtrls/2012/jun142012/2012_transmission_interface_limit_assumptions.pdf.

Table 3-1: Interface Limits for 2016 (MW)

Interface Name	Interface Limit (MW)
New Brunswick–New England	700
Orrington South Export	1,200
Surowiec South	1,150
Maine–New Hampshire	1,550
North–South	2,700
Boston Import (N-1)[(a)]	4,900
SEMA Export	No limit
SEMA/RI Export	3,300
Connecticut Import (N-1)[(a)]	3,400
SW Connecticut Import (N-1)[(a)]	3,200
Norwalk/Stamford	1,650
HQ–NE (Highgate)	200
HQ–NE (Phase II)	1,400
Cross-Sound Cable (CSC) (In)	0
CSC (Out)	346
East–West	3,500
Wyman / Bigelow Export	350
Rumford Export	519
Northern New Hampshire Export	140

(a) N-1 refers to a system's first contingency—when the power element (facility) with the largest impact on system reliability is lost.

- Fuel price forecast— Figure 3-2 shows the 10-year forecast of fuel prices. This forecast was based on the US Department of Energy's (DOE's) *2011 Annual Energy Outlook* (AEO).[15]

[15] US DOE, *Annual Energy Outlook, 2011*, EIA-0383 (April 2011), http://www.eia.gov/forecasts/archive/aeo11/.

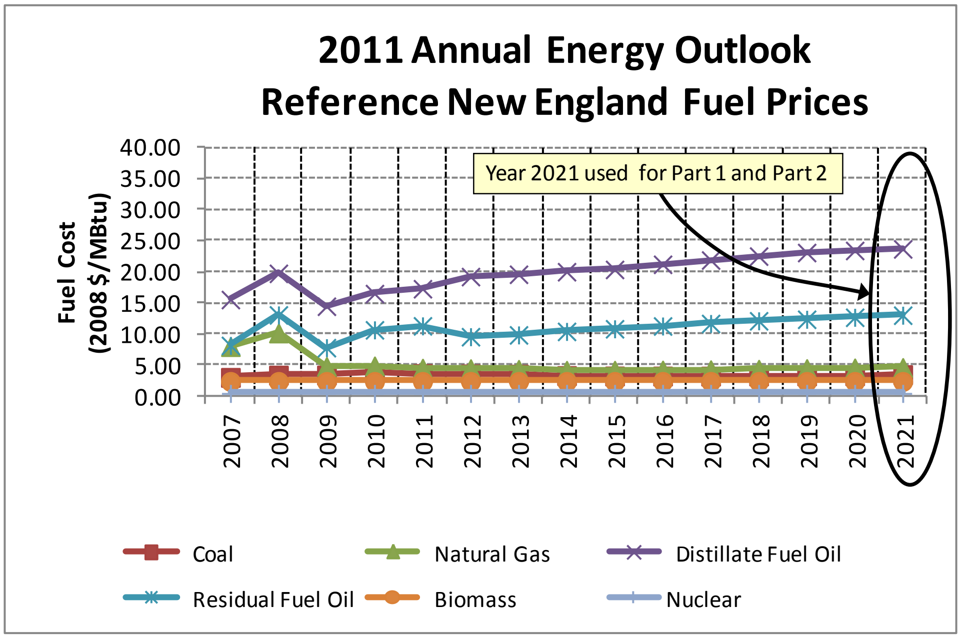

Figure 3-2: Annual 10-year fuel price forecast from DOE's *2011 Annual Energy Outlook*.

- Emission rates—Emission rates were based on the (primary) fuel type and generic Environmental Protection Agency (EPA) conversion rates supplemented by ISO information.
- Allowance prices—The most significant air emissions modeled within the dispatch cost was CO_2. The CO_2 emissions allowance price for all cases was assumed to be $10/ton.

Section 4
Evaluation Metrics

The simulation metrics provide a basis for summarizing the economic, fuel-usage, and environmental performance of the system. Most of the metrics are New England-wide indicators, and the Financial Transmission Rights/Auction Revenue Rights (FTR/ARR) metric (defined in Section 4.2) is an additional economic metric that provides a locational dimension to the congestion.

4.1 Economic Metrics from Production Simulation

The key economic metrics used to compare the cases are production cost, load-serving entity (LSE) energy expense, and the profitability of representative technologies quantified by contributions to fixed costs (CTFCs). The absolute values of these metrics are not the focus of this analysis because the aim was to quantify relative changes.

4.1.1 Production Cost and LSE Energy-Expense

The production cost metric is based on the summation of dispatch costs for each unit multiplied by the amount of energy produced. This calculation aggregates all New England resources used to serve customer demands. Production costs for resources located in external areas would be constant in all cases and therefore would not affect the relative difference between cases. Therefore, external resources were not included.[16]

$$\text{Production Cost} = \sum_{i=1}^{nUnit} \sum_{h=1}^{8,760} DispatchCost_i * MWh_{i,h}$$

Where:

i is a resource identifier (index)

h is the hour (index)

nUnit is the number of generating units in the simulation (count)

$DispatchCost_i$ is the cost of producing energy from resource 'i' ($/MWh)

$MWh_{i,h}$ is the generation of unit 'i' in hour 'h' (MWh)

LSE electric energy expense is calculated by taking the hourly marginal energy cost (e.g., the locational marginal price; LMP) in an area and multiplying it by the hourly load within that same area. Total LSE energy-expense is the summation of each area's LSE energy-expense, which includes the effects of congestion.

$$\text{LSE Energy Expense} = \sum_{r=1}^{nRSP} \sum_{h=1}^{8,760} LMP_{r,h} * MWh_{r,h}$$

[16] Interchange with neighboring areas is represented by a fixed interchange schedule with a zero cost for imports and zero revenues for exports.

Where:

r is an "area" (typically an RSP area) (index)

h is the hour (index)

nRSP is the number of areas (count)

$LMP_{r,h}$ is the energy price for area 'r' in hour 'h' ($/MWh)

$MWh_{r,h}$ is the load of area 'r' in hour 'h' (MWh)

4.1.2 Contribution to Fixed Costs from the Energy Market

The viability of a generating unit, or a generating technology, can be implied by its ability to earn sufficient revenues from the energy market alone to support its investment cost. The contribution to fixed costs for a specific generating unit provides a metric that can be used across cases to illustrate the economic viability of the resource. As shown in the calculation below, the contribution to fixed costs equals the sum of the difference between the simulated market-clearing price and the simulated dispatch cost of a specific resource multiplied by the number of associated megawatt-hours (MWh) in each hour. This is then summed across an annual period and normalized on a $/kW-year basis.

$$\text{Contribution to Fixed Cost}_i = \sum_{h=1}^{8,760} \left(LMP_{r,h} - DispatchCost_i \right) * MWh_{i,h}$$

Where:

i is the resource for which the contribution to fixed cost is being calculated (index)

r is an "area" (typically an RSP area) (index)

h is the hour (index)

$DispatchCost_i$ is the cost of producing energy from resource 'i' ($/MWh)

$LMP_{r,h}$ is the energy price for area 'r' in hour 'h' ($/MWh)

$MWh_{i,h}$ is the load of area 'i' in hour 'h' (MWh)

A comparable CTFC can be calculated on a $/kW-year basis for a load reduction because both the economic metric and the change in capacity would be negative.

4.2 FTR/ARR-Based Congestion

The economics of energy brought into an import-constrained area, or delivered from an export-constrained area, can be accounted for using a mechanism that, effectively, allows the imported energy to be valued at the producing area's LMP. This mechanism is based on the concept of Financial Transmission Rights, where load has a right to a portion of any lower-cost energy produced in other areas.[17] The value of these FTRs is monetized in an FTR auction and flows back to the LSEs as their share of the Auction

[17] An FTR is a financial instrument—equal to the amount of electric energy flowing in one direction between two specific locations on the regional power system—that a market participant can buy to help hedge against the economic impacts associated with transmission congestion and to arbitrage differences between expected and actual day-ahead congestion caused by constraints on the transmission system. The FTR holder buys a contract to obtain the right to receive price differences between two locations for each megawatt of FTR obtained.

Revenue Rights.[18] Thus, a fourth economic metric is "FTR/ARR" congestion. FTR/ARR congestion values are equal to the product of the constrained interface flow and the price differential across the constrained interface:

$$\text{FTR/ARR Congestion Cost}_k = \sum_{h=1}^{8,760} \left(LMP_{rt,h} - LMP_{rf,h} \right) * MWh_k$$

Where:

k is the interface identifier (index)

rt is the RSP "area" into which energy is flowing (index)

rf is the RSP "area" from which energy is flowing (index)

h is the hour (index)

$LMP_{rt,h}$ is the energy price for area 'r' in hour 'h' into which energy is flowing ($/MWh)

$LMP_{rf,h}$ is the energy price for area 'r' in hour 'h' from which energy is flowing ($/MWh)

This valuation was used to indicate the relative economic penalty of adding or removing load in one area compared with a different, unconstrained area.

4.3 Generation by Fuel Types

Another metric used to highlight the differences between cases shows the generation by fuel type and how different strategies affected the fuel needed in New England. This metric could not be produced for the first two parts of the study because load increases or decreases were used to represent decreases or increases, respectively, driven by unknown fuel types. For example, a load decrease could be used to represent the addition of a nuclear unit; a coal unit; a high-efficiency, gas-fired combined-cycle unit; or an energy-efficiency technology. The total fuel consumption associated with the sensitivity case could not be specified, and such a fuel-consumption metric would not be informative.

This metric was used in the third part of the study because specific resources using specific fuels are modeled.

4.4 Environmental Metrics

Environmental metrics were only calculated during the third part of the study. The first two parts of the study used load shapes with emission characteristics that could not be defined and were therefore not suitable for developing emissions metrics.

4.5 Metrics Not Considered

The analysis did not include other costs that wholesale electricity customers would pay, such as payments to resources operated out of economic merit order, FCM payments, ancillary service costs,

[18] An ARR is a mechanism for distributing auction revenue to congestion-paying LSEs and transmission customers that have supported the transmission system.

Renewable Energy Certificates (RECs), and alternative compliance payments (ACPs) associated with Renewable Portfolio Standards, transmission costs, and other costs.[19]

[19] A REC is a tradable, nontangible commodity representing the eligible renewable generation attributes of 1 MWh of actual generation from a grid-connected renewable resource. If the development of renewable resources falls short of providing sufficient RECs to meet the RPSs, load-serving entities can make state-established alternative compliance payments. ACPs also can serve as a price cap on the cost of Renewable Energy Certificates.

Section 5
Part 1: Development of a Framework for Identifying Areas Resilient to the Addition or Removal of Resources

The purpose of the first part of this study was to provide a framework for identifying the most resilient areas for the addition or removal of resources or loads. This incremental/decremental evaluation was performed using load increments and decrements to avoid the need to specify specific resources. This analysis was developed using the ISO's *2004 Regional Transmission Expansion Plan* (RTEP04) framework, which used a single, 100% capacity factor, load-shape adjustment.[20] To perform this analysis, the ISO developed load shapes to represent different types of resources as well as the operation of nonbaseload resource types. The load-shape profile is constant regardless of the amount of resources the shape is intended to represent.

5.1 Load Shapes for Increments/Decrements

Each load shape represents a resource profile, which served as a proxy for different generation or load technologies. The ISO developed the following load shapes for this incremental/decremental analysis:

- BASE—Baseload generating units (i.e., units that operate at a constant level for 24 hours/day, seven days/week)
- INTR—Intermediate generating units (i.e., units that ramp up and down to follow the system load as it transitions between off-peak and on-peak load levels. This generation profile operates at a 20% capacity factor)
- DR — Active demand response/peaking resources
- EE—Energy efficiency
- PV—Photovoltaics
- WNDN—Wind onshore
- WNDF—Wind offshore
- SGRD—Smart grid
- CHPG—Combined heat and power/geothermal (CHP/G)

The amount of energy in each of these profiles affected the magnitude of the associated metrics. For example, a 1 MW baseload increment (BASE) is associated with 8,760 MWh over the course of a year, while a 1 MW active demand-response profile (DR) is associated with only 52 MWh/yr. However, the energy clearing price when the active demand-response adjustment is activated (or removed) potentially has a disproportionately greater impact on the economic metric because the energy is used at a time when small changes in supply and demand may result in very different marginal costs (i.e., where small changes may result in large cost/price differences). Decreased loads (as a result of the addition of DR megawatts) should reduce the energy clearing price in the hours when activated. Removing the active

[20] "Regional System Plan 2004," web page (2013), http://www.iso-ne.com/trans/rsp/2004/index.html.

demand-response resource (i.e., the same as adding load) , could dramatically increase the clearing price of electricity. This analysis captured the effect of capacity factors and the potential nonlinearities of the LMPs. Table 5-1 provides the capacity factor assumptions associated with each load shape used.

Table 5-1
Annual Capacity Factor of Load Shapes

Load Shape	Annual Capacity Factor (%)
BASE	100.0
INTR	21.0
DR	0.6
EE	70.8
PV	15.5
WNDN	33.9
WNDF	41.9
SGRD	−5.2
CHPG	25.9

The resource profiles were time synchronized with the 2006 systemwide load shape used in the simulations. For example, the DR profile had its maximum activation during the annual peak load hours of the 2006-based load shape.

5.1.1 BASE—Baseload Generating Units

This load shape, as shown in Figure 5-1, was envisioned to have a 100% capacity factor (i.e., a constant, 24 x 7 shape) to represent the maximum change to the supply and demand balance in an area assuming the addition or removal of a resource that operates all the time. Consequently, using this approach, an increase in load can represent the higher net loads that would occcur if one or more nuclear units were removed from service for the year being analyzed. Alternatively, reduced loads could represent the addition of a nuclear unit in the year being analyzed.

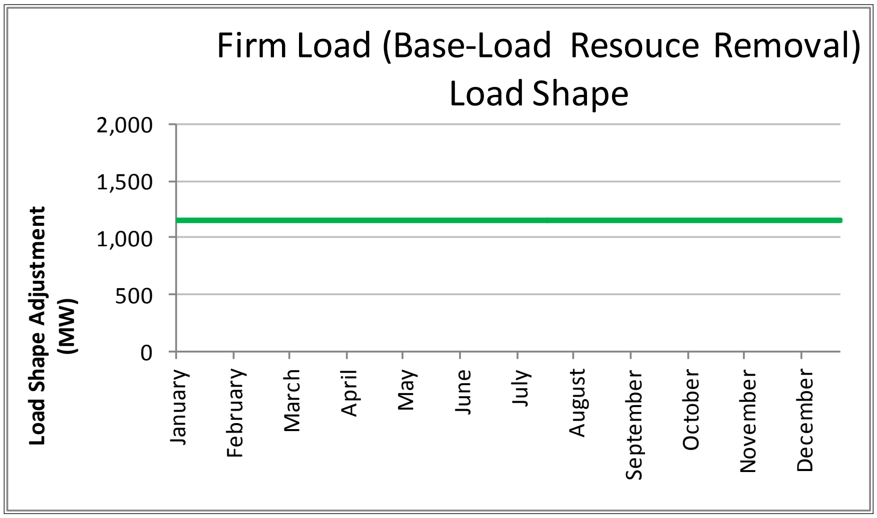

Figure 5-1: Load shape used to analyze the effect of adding or removing a baseload resource.

5.1.2 INTR—Intermediate Generating Units

This load shape, as shown in Figure 5-2, represents a generating unit that operates about 20% of the time, developed from an initial simulation run using the 2006 load shape. Consequently, adding this profile as an increase to the load would resemble the retirement of an intermediate generating unit. Conversely, the resulting change in the supply/demand balance from reducing the loads by this amount would resemble the addition of an intermediate generating unit.

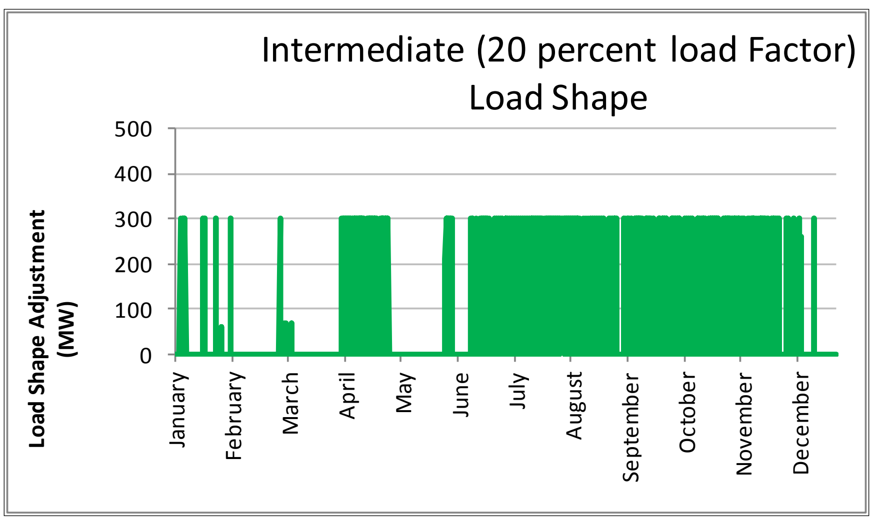

Figure 5-2: Load shape used to analyze the effect of adding or removing an intermediate resource operating at a 20% capacity factor.

5.1.3 DR—Active Demand Response/Peaking Resource

Most of the ISO's economic studies explicitly represent active demand response as a specific profile, time synchronized with New England's historical hourly load profile. This profile represents a resource assumed to be dispatched in the same manner as active demand response. Using this profile, the ISO simulated the DR being activated in specific hours.[21] The analysis of loads reduced using this DR profile would mimic the activation of a peaking unit or demand response because these are the hours when such a resource would most likely be dispatched. The analysis of loads increased by this amount would represent the retirement of DR or a peaking resource. Figure 5-3 shows the DR load shape.

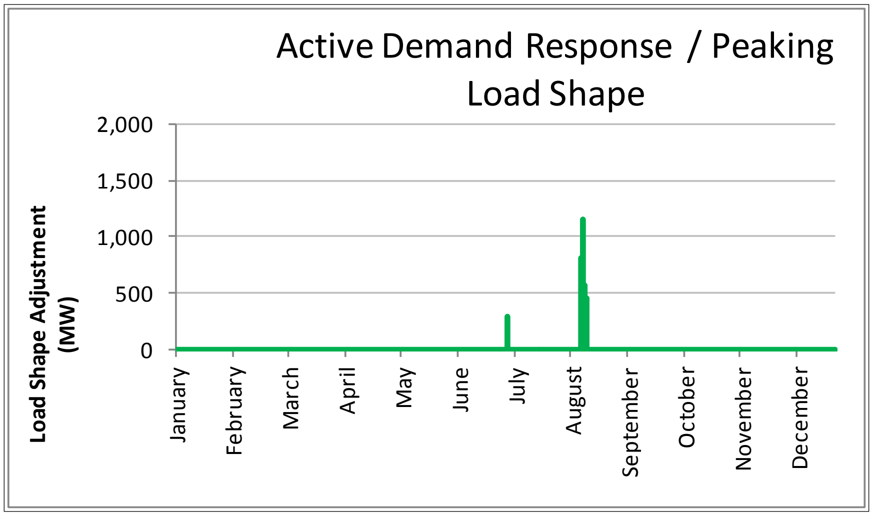

Figure 5-3: Load shape used to analyze active demand response (DR) increases and decreases.

5.1.4 EE—Energy Efficiency

A profile was developed to explicitly model the installation of energy-efficiency technologies, which was time synchronized with the 2006 hourly load profile. As shown in Figure 5-4, the EE load shape is modeled with a pattern that changes seasonally to reflect lower load levels in the spring and fall. An analysis of the loads reduced using this EE profile would resemble the addition of passive load-reduction technologies. Loads increased by this amount would resemble the retirement of, or loss of, some energy-efficiency resources.

[21] It is well known that modeling active DR as a "pseudo-generator" with a high, fixed dispatch price will result in a resource that is rarely "dispatched" in production simulation models. This is because production cost models are mostly "expected-value" models with perfect foresight and that typically underestimate the times when active demand response (and peaking units) will be called. A DR profile developed from a production costing simulation using a high, fixed dispatch price typically suggests infrequent demand-resource activation in response to such a price trigger. This is thought to provide an erroneous market signal, which would lead to active demand-response participants expecting not to be called.

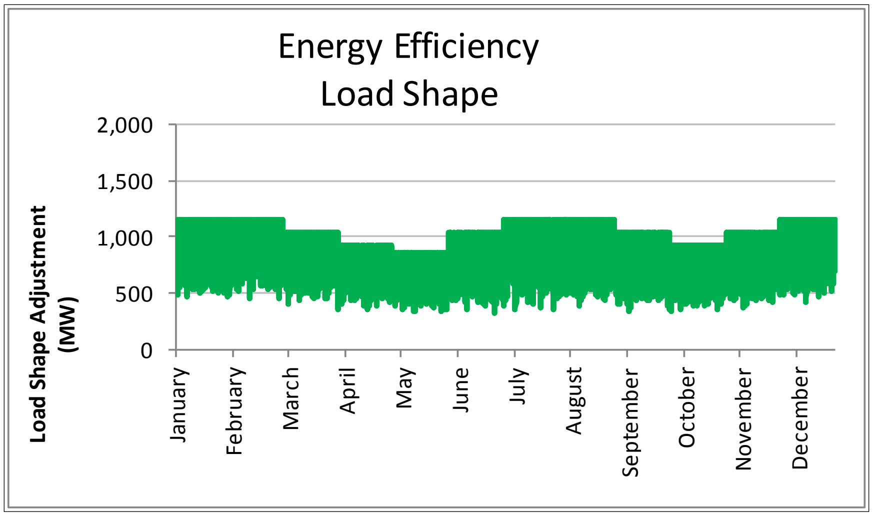

Figure 5-4: Load shape for analyzing EE increases or decreases in energy efficiency.

5.1.5 PV—Photovoltaics

In developing the solar PV load shape for this analysis, the ISO assumed that it was necessary to capture the volatility of PV while maintaining a pattern consistent with the historical loads. Because the data sources for 2006 were limited, the ISO used the solar incidence data associated with a single pyrometer site located on Thompson Island near Boston.

The drawback for using the performance from a single site is a lack of geographical diversity. However, the use of an historical, time-synchronized profile is consistent with the approach used for other resources, despite being developed from a single location. Because the Thompson Island solar data were based on a pyrometer, not a photovoltaic facility, a conversion and temperature correction was needed. Figure 5-5 shows the resulting photovoltaic profile.

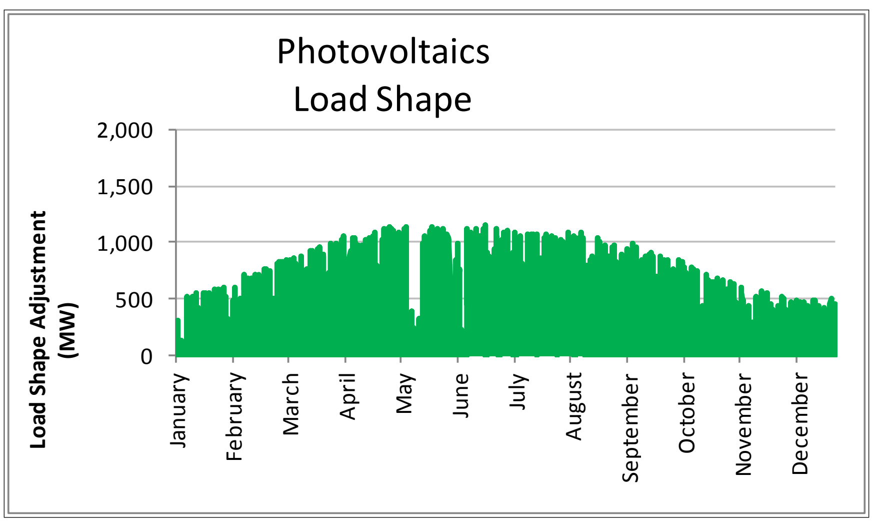

Figure 5-5: Load shape for analyzing photovoltaic increases and decreases.

An analysis of the loads reduced using this PV profile would resemble the energy production of a PV system, which hypothesizes solar energy production during the appropriate hours. The analysis of the loads that were increased by this amount would resemble the retirement of, or loss of, some PV resources.

5.1.6 WNDN—Wind Onshore

The wind load shape used for onshore wind was developed as part of the *New England Wind Integration Study* (NEWIS).[22] The wind profiles were developed from the aggregation of specific resources at specific locations to represent all the wind in a certain zone. For example, the data used in these simulations were obtained from a distribution of resources representing a widespread build out across New England.[23] Even though each RSP area has its own unique wind characteristics, a single profile was selected to represent onshore wind across New England. Because the shape of this profile was held constant in all of the areas, the effect of wind penetration was comparible among areas.

An analysis of the loads reduced using the onshore wind profile, as shown in Figure 5-6, would resemble the energy production of a wind farm associated with the hours when the wind energy would be serving loads. An analysis of the loads that were increased by this amount would resemble the retirement of onshore wind resources.

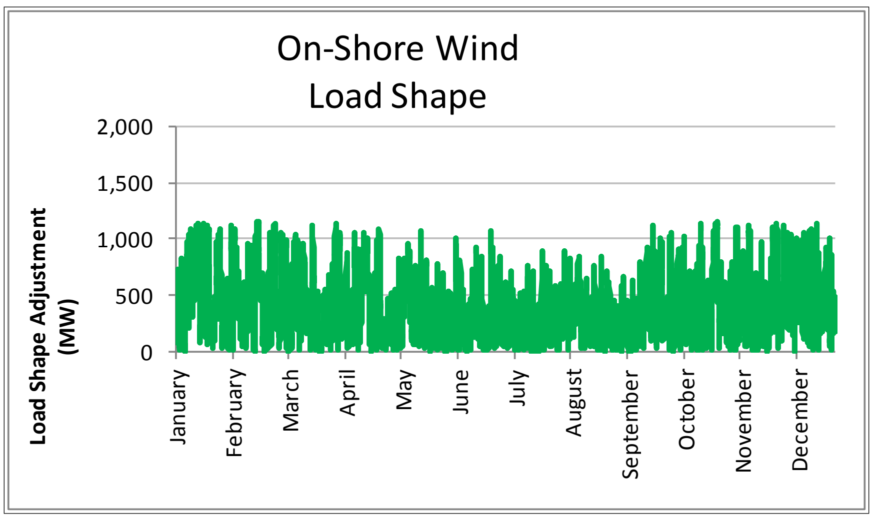

Figure 5-6: Load shape for analyzing onshore wind (WNDN) increases and decreases.

5.1.7 WNDF—Wind Offshore

As with the onshore wind load shape, the offshore wind load shape was developed from the aggregaton of specific resources at specific locations to represent all the wind in a certain area. This profile was obtained from a distribution of resources representing the NEWIS assumptions.[24] Even though not all the

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[22] GE Applications and Systems Engineering. *New England Wind Integration Study* (December 5, 2010), http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/reports/2010/newis_report.pdf. PAC archives of NEWIS materials are available at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/reports/2010/index.html.

[23] The 2006 wind shapes were derived from the NEWIS "20% Best Onshore Wind Case."

[24] The 2006 wind shapes were derived from the NEWIS "20% Best Onshore Wind Case."

areas have an offshore capability, the same offshore profile was applied in each each of the areas to quantify the effect of increased or decreased load shapes. The shape of this profile was held constant regardless of location or the amount of wind penetration.

An analysis of loads reduced using this offshore wind profile, as shown in Figure 5-7, would resemble the energy production of an offshore wind farm associated with the hours when the wind energy would be reducing loads. An analysis of the loads that were increased by this amount would resemble the retirement of, or loss of, some offshore wind resources.

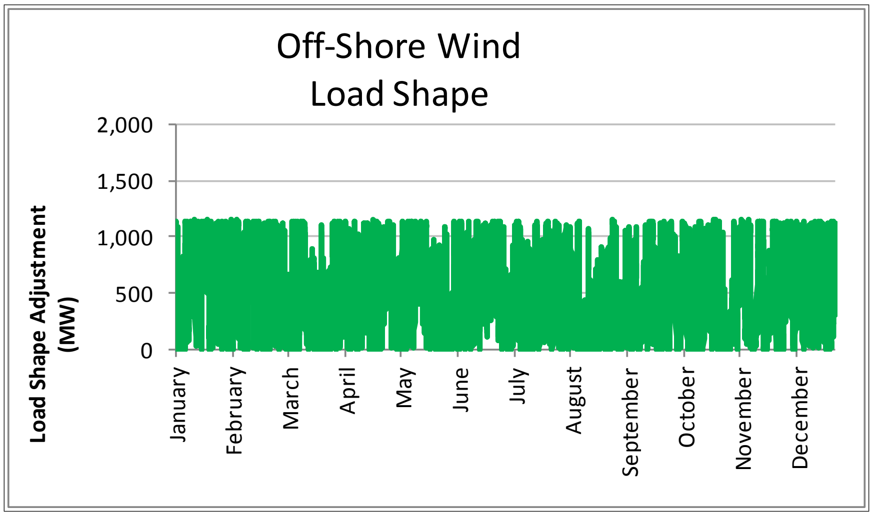

Figure 5-7: Load shape for analyzing offshore wind (WNDF) increases and decreases.

5.1.8 SGRD—Smart Grid and Net Metering

In its study request submission, Synapse Energy Economics requested that this analysis assess the impacts associated with both smart grid and net metering, but there was a lack of specificity in operating characteristics or costs that were to be used.

In discussions at the PAC, it was agreed that net metering was intended to promote specific "behind-the-meter" resources, such as photovoltaics, wind, and possibly cogeneration as one prong of a public policy initiative. Consequently, net metering by itself is not a resource technology, rather a mechanism for subsidizing small customer co-located generation that facilitates the deployment of smart grid technologies.

Smart grid has the goal to reduce on-peak energy consumption and increase off-peak energy consumption to levelize energy requirements across the day. The smart grid load-shape profile is not associated with any specific underlying resource technology. Rather, this smart grid load-shape profile is intended to represent the residual impact that the underlying technologies this study analyzed separately as DR, EE, PV, wind, and combined heat and power did not capture.

The SGRD profile representing smart grid technologies was assumed to be the residual load shape adjustment that is not part of other profiles. This piece of smart grid not represented by the other customer co-located technologies was represented by the ability to time-shift energy consumption from on-peak loads to lower off-peak loads. This residual load shape was assumed to resemble energy storage with a one-day storage capacity. Variable, real-time pricing is expected to underlie SGRD because it provides consumer incentives to install their own “smart” devices and adjust their own behaviors by expanding demand response to smaller, more numerous applications.

Specifically, the SGRD profile used here reduces “higher” loads during the day by using energy stored from “lower” load periods. The SGRD operation is assumed to resemble battery charging and discharging plus losses. These “losses” represent the less-efficient use of energy because it is used to provide a service at a different time than when “needed” (e.g., preprogramming a dishwasher to operate partly full every day off-peak instead of running a full load after a meal every second day).

In developing the SGRD load shape, it was assumed that the inefficiencies due to time shifting would require 20% more energy than if the energy were consumed directly when it was needed. Additionally, for each 1 MW of on-peak load reduction, the off-peak load increased approximately 1.5 MW due to the shorter time window for storing the energy. The energy that was shifted using smart grid was assumed to be balanced within each 24-hour period so that the deferred use of on-peak energy equaled the off-peak energy stored plus losses. (This was done to prevent all the dirty dishes from being washed in the off-peak hours of the spring and fall months rather than washed each night.)

Figure 5-8 shows a customer load profile before and after smart grid was used to better manage loads. The blue line represents the original load shape, and the resulting red line represents the effect after the implementation of the smart grid adjustments.

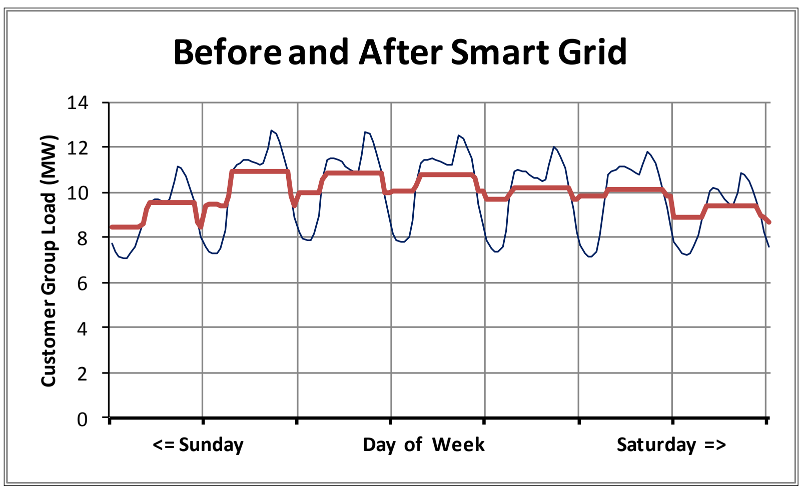

Figure 5-8: Development of smart grid load shape showing the load shape before and after.

Figure 5-9 shows the changes to the injection of energy during the on-peak hours and withdrawal (storage) of energy during the off-peak period. The net effect of these injections and withdrawals is to change the blue profile into the red profile in Figure 5-8.

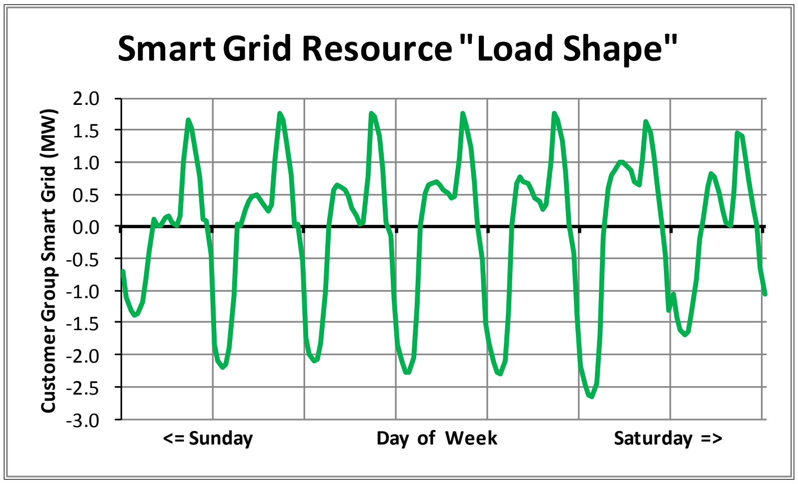

Figure 5-9: Smart grid load shape showing when loads are increased or decreased.

Figure 5-10 shows an annual profile of a load adjustment associated with a smart grid profile, viewed as a resource addition. An analysis of loads increased by this amount resembles the retirement of, or loss of, smart grid technologies.

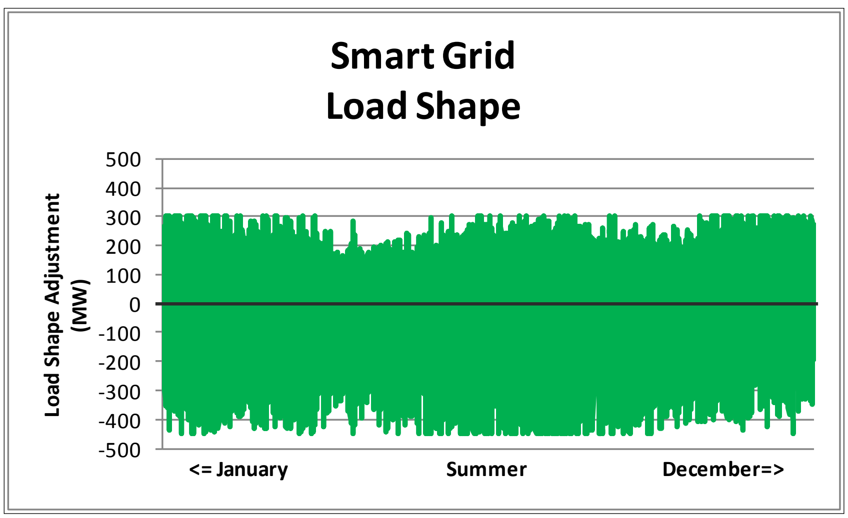

Figure 5-10: Smart grid load shape reflecting residual energy-storage component.

5.1.9 CHPG—Combined Heat and Power/Geothermal

To better understand the effects of two, somewhat related, technologies associated with the more efficient use of energy for space heating and cooling, a load profile was created by integrating combined heat and power with geothermal heat pumps. The performance of these technologies are interrelated and assumed to be driven by space heating and cooling needs.

The CHP component was viewed as follows:

- CHP is primarily a cogeneration facility.
- Cogeneration can be viewed as one of the components of an energy-efficiency load profile.

- The residual effect that the energy-efficiency load profile does not capture is the additional contribution by waste heat that can be used for space heating and cooling.

The geothermal component was viewed as an alternative, or supplement, to CHP for space heating in the winter periods. The geothermal technology can reduce electric energy used for winter space heating, and to some extent, the heat energy may provide some space heating. However, in the summer, the effect on space cooling has a direct impact on electricity consumption because there is no significant substitution for electricity to provide space cooling.

Because both these technologies could produce a combination of heating and cooling services associated with weather conditions, the hypothesized operation of a CHP/G system was driven by the 2006 historical weather. The ISO used this concept to develop a profile based on heating degree days and cooling degree days.[25] The assumption was that an "averaged" spring/fall load day was "weather neutral." The colder the temperatures in the winter, the greater the winter heating contributions from both CHP and the geothermal heat pump. The decrease in summer electrical consumption is due to the much greater efficiency from the geothermal heat pump. Figure 5-11 shows this effect for a typical week in the winter, spring (April), and summer, and Figure 5-12 shows a profile for this technology across the year. The largest effect occurs in the heating and cooling seasons; a much smaller impact occurs during the moderate weather in the spring and the fall.

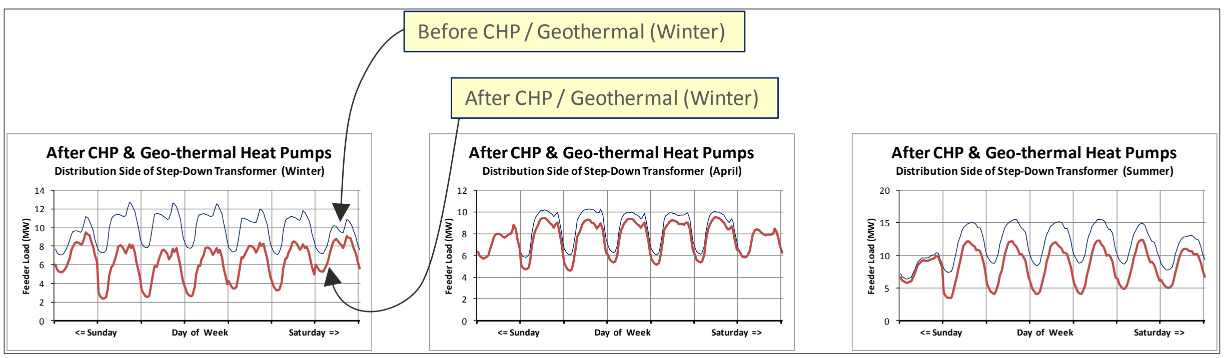

Figure 5-11: Combined heat and power/geothermal load adjustment.

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[25] A heating degree day is an indication of a building's demand for energy (fuel consumption) based on each degree the daily mean temperature is below 65°F. A cooling degree day is a unit that relates a day's temperature to the demand for electricity due to air conditioning or refrigeration. It is an estimate of electric energy requirements and indicates fuel consumption for the air conditioning or refrigeration. Cooling-degree days are provided for each degree the daily mean temperature and humidity index are above the baseline of 65°F.

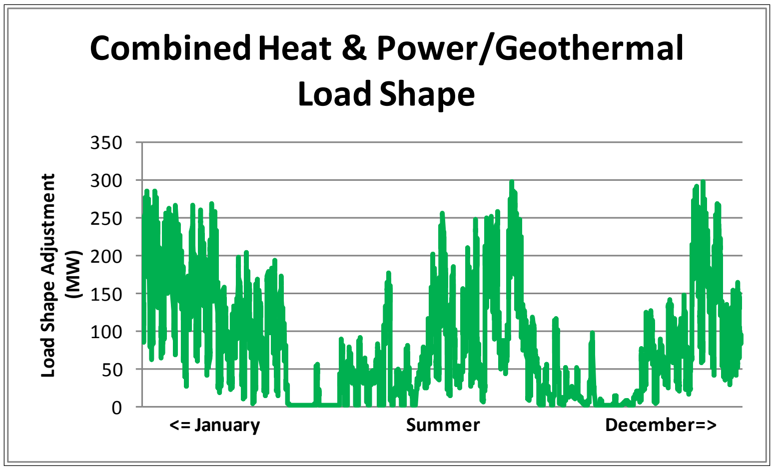


Figure 5-12: Load shape for the Combined Heat and Power and Geothermal (CHPG) profile.

5.2 Results

Using the defined load shapes, the ISO developed economic metrics for increases or decreases of each load shape. The metrics were developed for changes in an unconstrained system as well as for changes in each of the 13 RSP areas with the effects of transmission constraints included. The ISO has posted a spreadsheet that contains the detailed numerical results underlying this analysis.[26]

5.2.1 Understanding Incremental/Decremental Graphs

Using an unconstrained system as the basis for comparison eliminated the effect of transmission constraints because a load or resource change in any area would provide the same impact on the metric as if it were added in any other area. Viewing the addition of a resource as the same as the removal of a load with the same fixed load shape allows the relative changes in supply and demand balances to be quantified. Because the load shape for the unconstrained system has no fuel cost associated with it, the production cost and LSE energy-expense metrics decline as more load is replaced by a resource with a zero production cost.

5.2.1.1 Production Cost

Figure 5-13 and Figure 5-14 summarize the effect of adding or removing nine technology-based load shapes at 15 different megawatt levels representing both increases and decreases. The right side of the figure shows that as more zero cost resources were added (or alternatively, as more load was removed), production costs decreased. This is because less energy was produced by fuel-consuming resources. Conversely, as more resources were removed (alternatively, as more load was added), production costs increased (as shown in the left side of the chart) because more fuel-consuming resources need to produce energy.

[26] The results for this analysis are available in the PAC materials for October 18, 2012, http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2012/oct182012/index.html. The spreadsheet is available at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2012/oct182012/eco_results.xlsx.

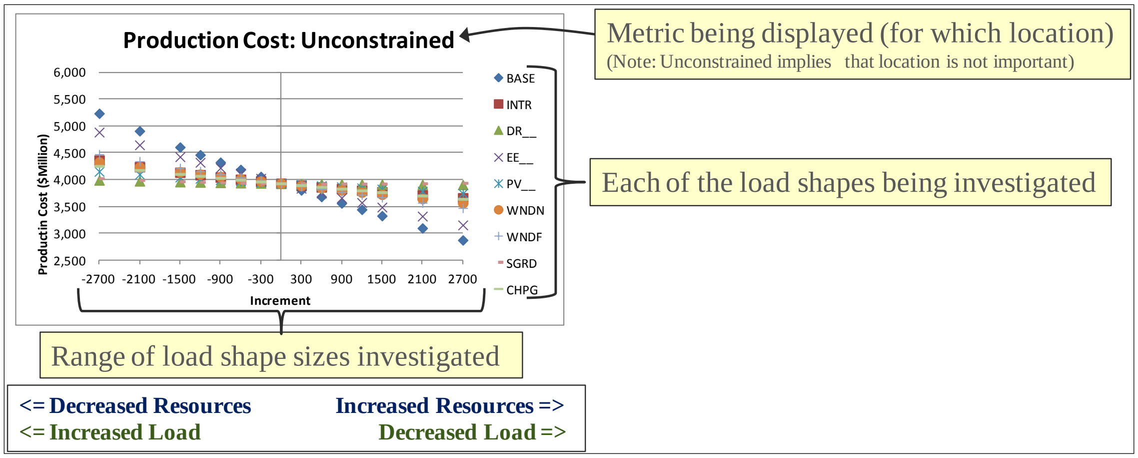
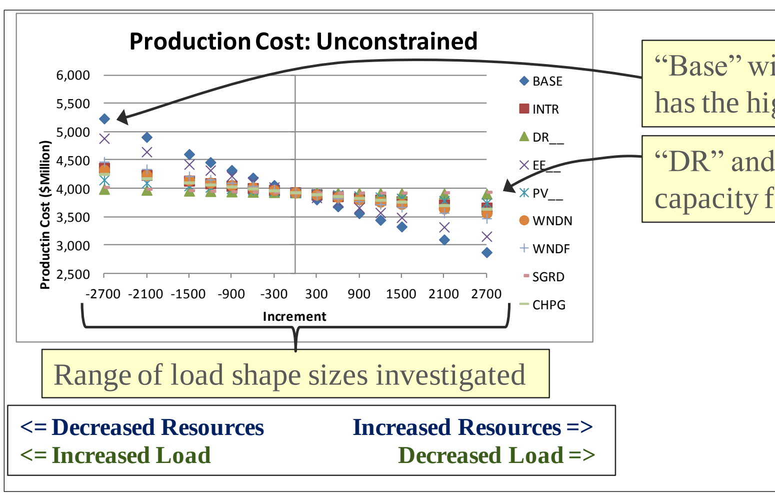


Figure 5-13: Change in the production cost metric as resources were added to an unconstrained system.

While the trends in production cost for all load shapes monotonically decreased as resources were increased (loads were decreased), the sensitivity of the metrics for each technology (slope) differed. Most of the change in the metric can be attributed to the amount of energy associated with a load shape. For example, the slope of the line associated with baseload increments/decrements (BASE), which provided the greatest amount of energy (24 x 7), has the greatest slope. To the contrary, the demand-response profile (DR), which provided the least amount of energy, has one of the smallest slopes.

While load shapes associated with the largest amounts of energy tended to have the biggest impact on the economic metrics, the timing of the energy dispatch was also important. As shown in Figure 5-14 demand-response activations had the smallest number of megawatt-hours (as characterized by capacity factor). However, this energy was provided when the load was the highest; therefore, the impact per-megawatt-hour was the greatest.



Load Shape	Annual Capacity Factor (Percent)
BASE	100.0
EE	70.8
WNDF	41.9
WNDN	33.9
CHPG	25.9
INTR	21.0
PV	15.5
DR	0.6
SGRD	-5.2

Figure 5-14: Change in the production cost metric as resources were added to an unconstrained system.

5.2.1.2 LSE Energy Expense

The character of the LSE energy-expense metric is similar to the production cost curves described previously. Figure 5-15 shows that for both production cost and LSE energy-expense metrics, as the amount of resources increased (alternatively, as load decreased), the metric decreased monotonically. Conversely, as the amount of resources decreased (alternatively, as load increased), the metric increased.

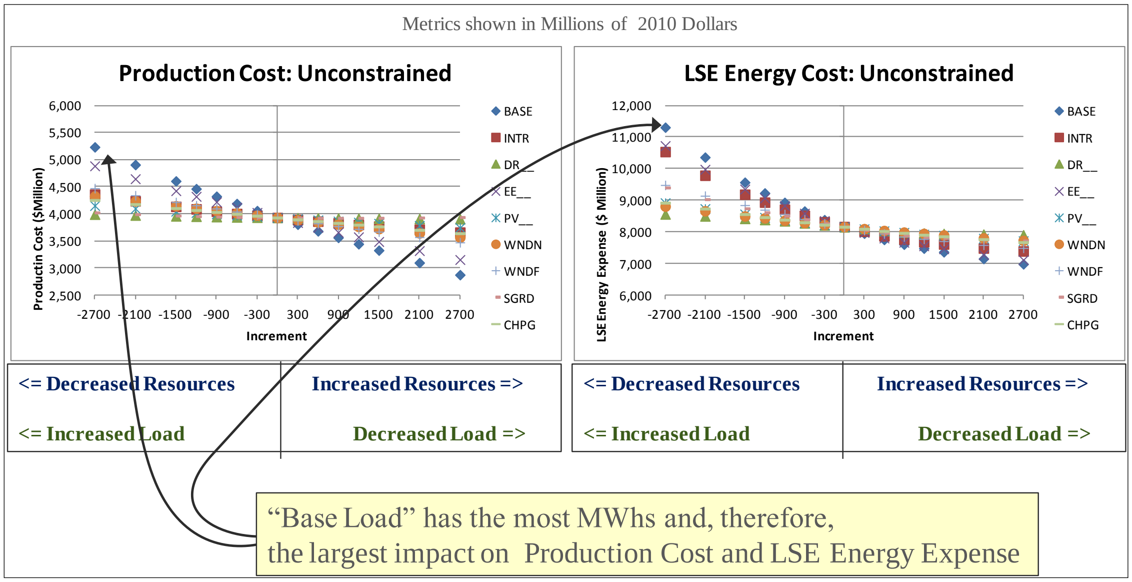


Figure 5-15: New England metrics for load-shape adjustments without constraints.

5.2.2 Effect of Constraints in Export-Constrained Areas

The effect of transmission constraints in the system was that lower-cost energy was prevented from flowing to displace higher-cost energy elsewhere in New England. For example, as more resources were added in the BHE area (or load was removed), the production cost and LSE energy-expense metrics declined initially for a small number of megawatts. As the amounts were increased, the change in production cost flattened out as the export constraint created limitations on how much energy could be exported. In other words, the addition of more resources in BHE would not benefit the rest of New England as much as the Unconstrained Case because the added energy could not be exported from BHE to displace more expensive resources in the rest of New England.

This effect is seen clearly in the LSE energy expense shown in the right side of Figure 5-16. Adding more resources (same as decreasing loads) had little effect on either production cost or the LSE energy-expense metrics when more than a 300 MW increment was tested in BHE. This resulted in congestion that can be quantified by comparing the results for the constrained areas with the results for the unconstrained areas.

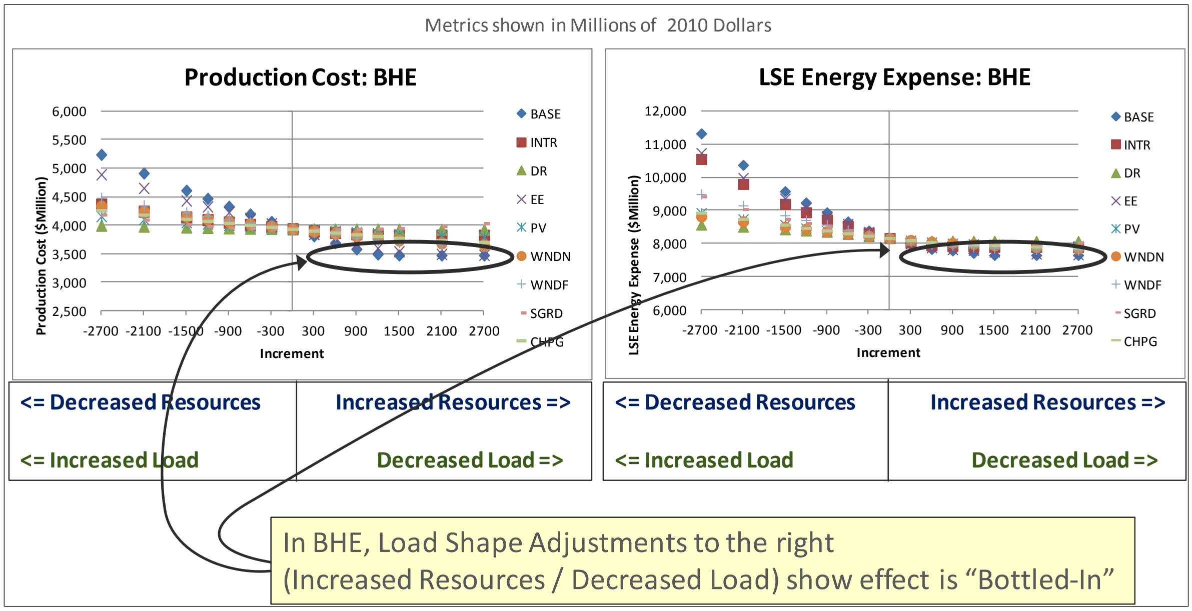


Figure 5-16: Change in the economic metrics as resources were added in the BHE area.

If fewer resources were added in an export-constrained area, such as the BHE area (or loads were increased), the export constraints would be alleviated and the production cost and LSE energy-expense metrics would be similar to, or identical to, the Unconstrained Case. This occurs because the reduction in resources (or increased loads) relieved the existing constraints.

The effect on the central Maine (ME) area was less pronounced than for the BHE area, as shown in Figure 5-17 because the additional resources (or reduced load) affected a larger, combined pair of areas that diluted the effect. Because no transmission constraint was defined for flows in the direction of ME to BHE, the only export constraint was south into the SME area. This effectively made the ME and BHE areas a larger internally unconstrained area.

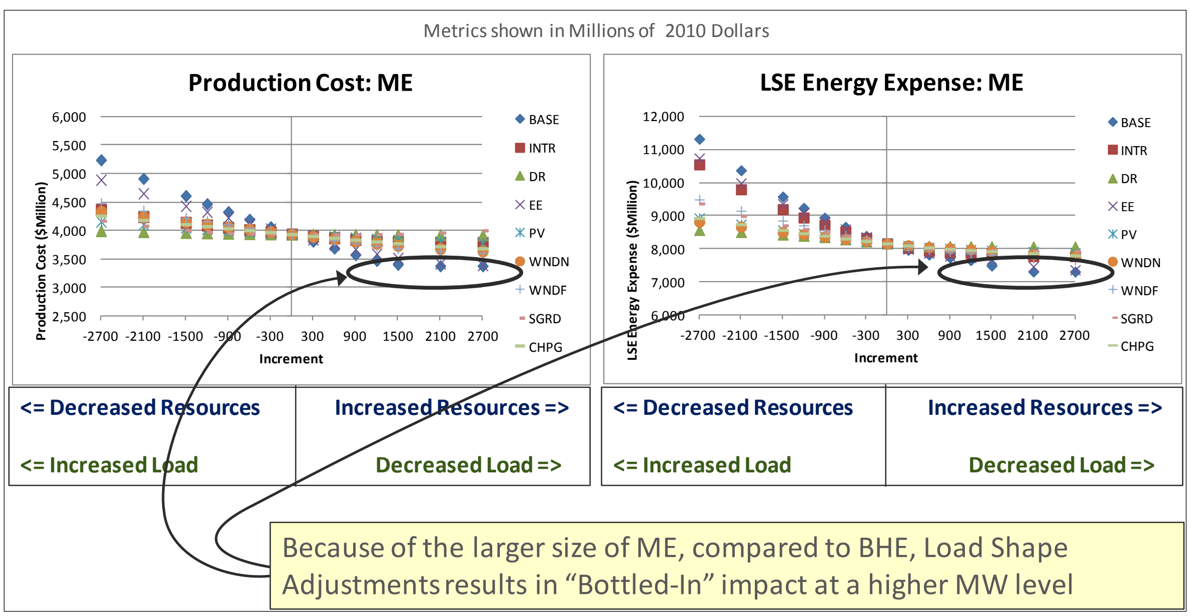


Figure 5-17: Change in the economic metrics as resources were added in the ME area.

Continuing this trend, an expansion of the region being evaluated to include the SME area diluted the effect even more, as shown in Figure 5-18. This happened because the only modeled export constraint was south into the New Hampshire area, and this effectively made the SME plus ME plus BHE areas into a larger, internally unconstrained area.

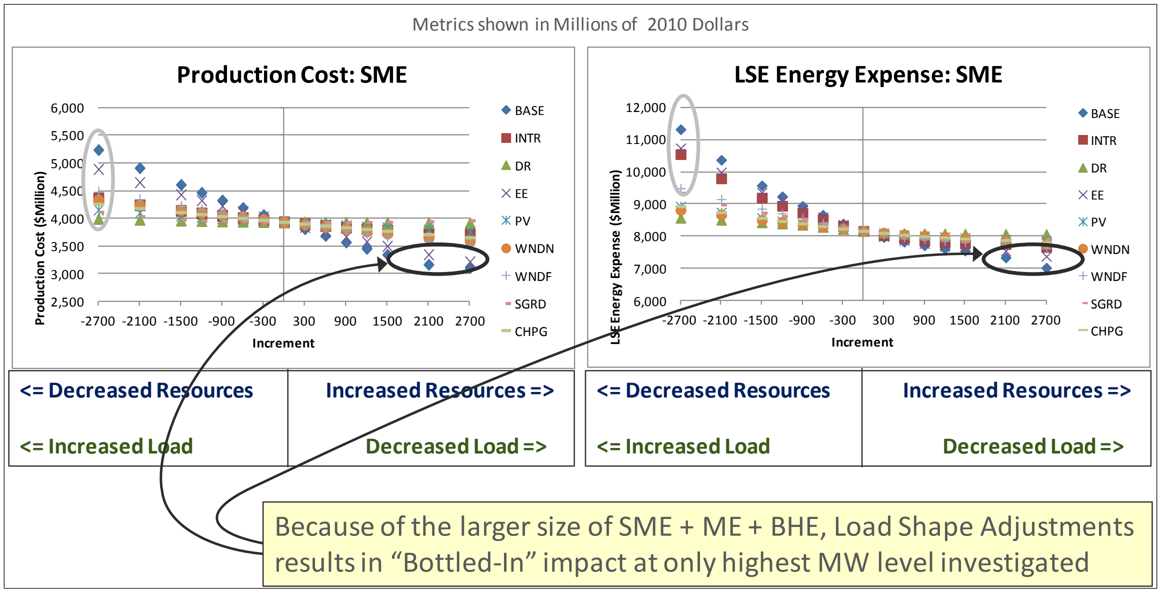


Figure 5-18: Change in the economic metrics as resources were added in the SME area.

5.2.3 Effect of Constraints in Import-Constrained Areas

The reduction of resources (or increased loads) in the areas with known import limits exacerbated the constraints. An examination of an import-constrained area, such as the SWCT area, showed that the effect of transmission constraints was to impede lower-cost energy from flowing into the import-constrained area. The economic impacts of the constraint could then be quantified.

In areas with import transmission constraints, increased resources (same as decreased loads) relieved the constraints, resulting in production cost and LSE energy-expense metrics indistinguishable from the Unconstrained Case.

Reducing available resources (same as increased loads) in the SWCT area increased the production cost and LSE energy-expense metrics when a small number of resource megawatts were removed (or loads were increased). The metrics rose sharply as more and more hours experienced the maximum-modeled $500/MWh shortage price, the highest price allowed in the model. Although the biggest affect on the economic metrics was in SWCT, the increase in energy imported into SWCT increased the production cost and LMP throughout the rest of New England. This effect is most easily seen in the graph of the LSE energy expense, Figure 5-19. This shows increased congestion as resources were decreased (or load increased) in SWCT.

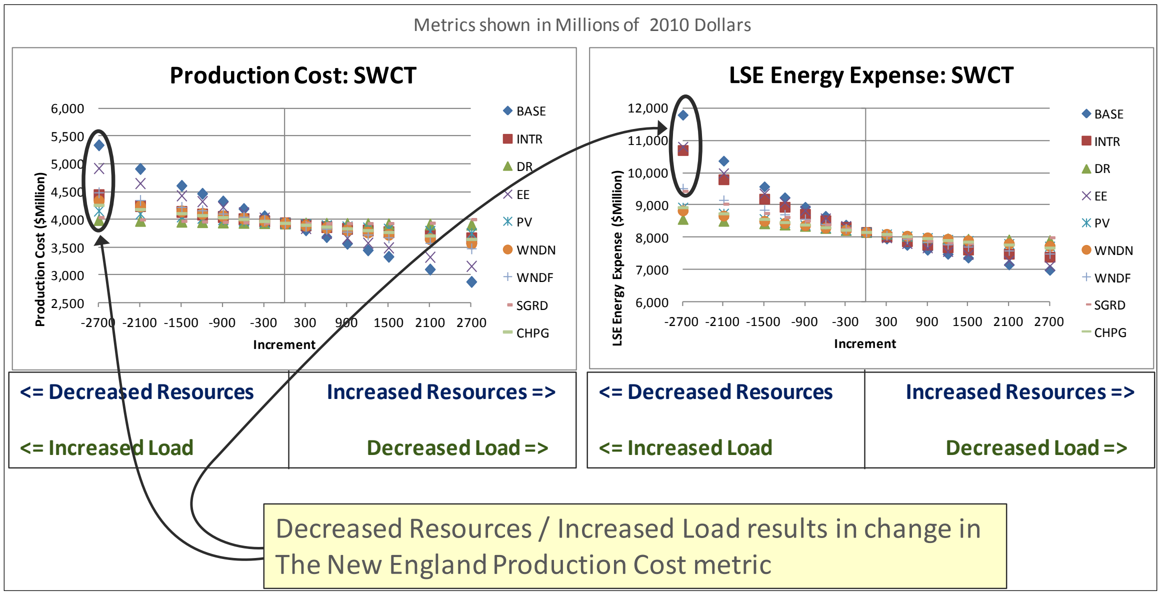


Figure 5-19: Change in the economic metrics as resources were added in the SWCT area.

Furthermore, the resource profile added or removed affected the magnitude of the change in the metric, which can be seen by comparing the highlighted portion of Figure 5-19 with a similar data points (see gray ovals) on Figure 5-18 for the comparable total New England metrics.

The demonstrated effect accelerates as the load in the import-constrained areas becomes larger and the constraint is reached. For example, Figure 5-20 shows that the effect of adding load in the BOST area was larger than for the SWCT area shown in Figure 5-19. The difference is relatively small for the production cost metric and much larger for the LSE energy-expense metric.

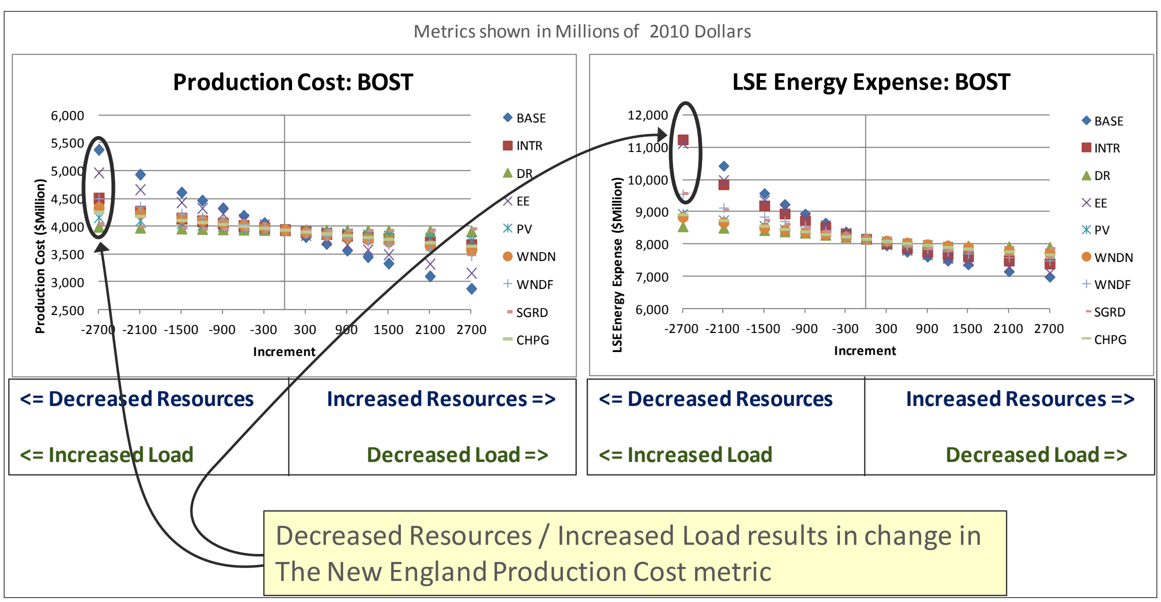


Figure 5-20: Change in the economic metrics as resources were added in the BOST area.

5.3 Effect of Constraints—Differences

While the previous illustrations are helpful as an introduction to the trends, quantifying how much the constraints shift the results away from the Unconstrained Case is difficult to discern. To facilitate comparisons between cases and to reveal the congestion directly, the difference between each constrained case and the Unconstrained Case is presented. The comparison is calculated as the "Constrained Case" minus the Unconstrained Case:

$$\text{Production Cost "Difference" Metric}_{i,m} = \text{Constrained Case Production Cost}_{i,m} - \text{Unconstrained Case Production Cost}_{i,m}$$

$$\text{LSE Energy-Expense "Difference" Metric}_{i,m} = \text{Constrained Case LSE Energy-Expense}_{i,m} - \text{Unconstrained Case LSE Energy-Expense}_{i,m}$$

Where:

i = Profile type

m = MW amount of the change

5.3.1 Effect of Constraints—Difference Metrics for Export-Constrained Areas

In an Unconstrained Case, a resource addition (or a load reduction) displaced the most expensive resources anywhere on the system. This caused LMPs to decline across New England and reduced the LSE energy-expense metric for all New England.

If transmission constraints were considered and if this resource addition (or load reduction) were located in an-export constrained area, it would only be able to displace the most expensive resources in the immediate area. Consequently, LMPs would be reduced only in the immediate area. The LMPs across the rest of New England would then remain largely unchanged because the energy could not flow through the constraint to displace other, next-more-expensive resources. Therefore, compared with the Unconstrained Case, the production cost "difference" metric must be higher (i.e., positive).

Figure 5-21 shows that for an increase in baseload resources (the 'positive,' right side of both graphs in the figure), the area with the greatest difference is the BHE area, where the economic "difference" metrics monotonically increased for both production cost and LSE energy expense. This was caused by the inability of the increased resource to displace costlier resources in other areas of New England when located in the export-constrained area of BHE compared with a case where it was located anywhere in an unconstrained area.

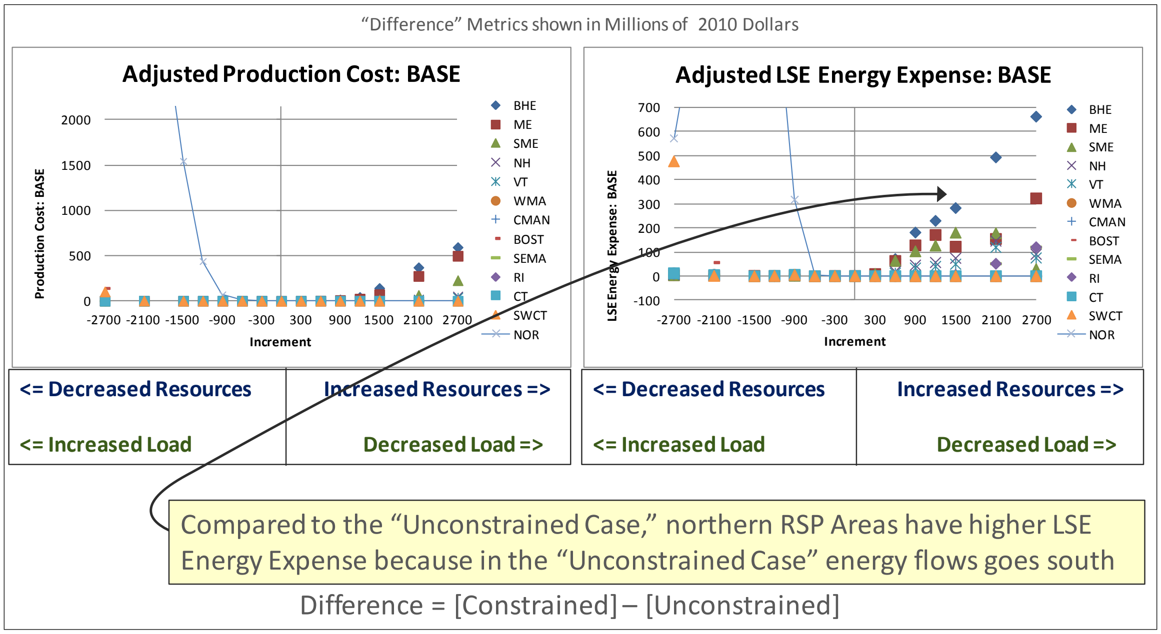


Figure 5-21: Economic "difference" metric for baseload energy changes in export-constrained areas.

While the production cost "difference" metric was monotonically increasing for both positive increments (to the right) or negative increments (to the left) as constraints began to create congestion, the behavior of the LSE energy-expense "difference" metric was more complex.

The addition of energy at a low dispatch price will tend to decrease the LSE energy-expense. However, the inability of this energy to be exported and reduce LMPs across the rest of New England typically results in a higher total New England LSE energy expense for the constrained case compared with the Unconstrained Case.

The LSE energy-expense "difference" metric for BHE (blue diamond) in Figure 5-21 was monotonically increasing as resources were added. As resources were added to the ME area (red square), the "difference" metric began rising and then dropped before resuming an upward trend. This drop was caused by different rates of change in the LSE energy expense in various locations, such as the ME plus BHE area and the loads associated with the geographic area of those changes compared with all of New England in the Unconstrained Case.

In the Unconstrained Case, the decrease in LSE energy expense was gradual as resources were added, as shown in Figure 5-15. However, the addition of a baseload resource in the ME area caused the LSE energy expense to decline in both the ME and BHE areas during some hours, which affected the LSE energy expense disproportionately in the ME and BHE areas, compared with the LSE energy-expense metric for the rest of New England. As more baseload energy was added to the ME and BHE areas, the LMPs dropped to zero in many hours. This resulted in the LMPs for approximately 15% of the load in New England being valued at zero during constrained hours. As more baseload resources were added to the combined area, ME plus BHE, the local LMPs could not drop lower, and the energy could not be exported. Consequently, the total New England LSE energy-expense "difference" metric diverged from the Unconstrained Case and resumed its monotonic increase. This resumption of the monotonic increase began at a lower level that was associated with fewer resources in the Unconstrained Case.

The SME (green triangle) area also showed this effect, although the minimum point shifted to the right because the combined SME plus ME plus BHE area is a larger load share of New England.

5.3.2 Effect of Constraints—Difference Metrics for Import-Constrained Areas

The left side of each graph of Figure 5-21 shows the effect of decreased resources (same as increased loads) in an import-constrained area, such as the NOR area. The "difference" metrics for both production cost and LSE energy expense rose after only a small decrease in resource megawatts in the NOR area. Both the production cost and LSE energy-expense "difference" metrics rose dramatically as more hours in the NOR area experienced the $500/MWh shortage price (assumed cost of the most expensive resource allowed in the simulations).

The production cost "difference" metric rose monotonically once the constraint began to bind, so that removing more resources accelerated the effect on the production cost "difference" metric.

The higher prices in the import-constrained area affected only a small portion of the system, and this resulted in another characteristic of the LSE energy-expense "difference" metric. In the case of NOR, as shown in Figure 5-21, the LSE energy-expense "difference" metric rose sharply compared with the Unconstrained Case when more than 600 MW of resources were removed. However, the import constraint compartmentalized the higher LMPs, and the rest of New England did not experience the same gradual rise in LMPs that characterized the Unconstrained Case.

As more resources continued to be removed in NOR, the higher LMPs in the import-constrained area remained compartmentalized. Compared with the Unconstrained Case with the same amount of resource megawatts removed, the difference from the unconstrained LSE energy expense was small. Eventually, as even more resources were removed, the LSE energy expense in the compartmentalized constrained NOR area became a smaller portion of the increase in LSE energy expense experienced in the Unconstrained Case. This was because the decreased resources in the Unconstrained Case affected the LMPs for all New England's load, and the LSE energy-expense "difference" metric turned negative.

5.3.3 Visualization of Congestion Due to Changes in Supply and Demand Balance

While the graphs shown above illustrate changes in supply and demand balances, these data can also be presented as a "map." Table 5-2 illustrates the areas where the supply and demand balance can change without creating significant congestion. The map is arranged as a progression from northern Maine at the top to southwestern Connecticut on the bottom. The value in the cells represents the increased production costs due to the transmission constraints compared with the Unconstrained Case. The cells in light yellow (or light blue) are areas where the difference in production costs compared with the Unconstrained Case is negligible. The cells colored red/orange show when the production costs increase more than $10 million per year due to congestion compared with the Unconstrained Case. This congestion can be characterized as follows:

- The relative production costs affected by congestion are predominantly due to transmission constraints in northern New England for resource increases (or load decreases). The greatest impacts are due to transmission constraints in northern Maine.
- The relative production costs show congestion in southern New England for resource decreases (or load increases). The greatest impacts are in Norwalk, Southwestern Connecticut, and Boston.

Table 5-2
Load/Resource Additions or Removals Effectiveness Based on Production Cost

Change in Annual Congestion From an Unconstrained Case for a Change in “BASE” MW ($Million per year)

		<= Resource Removals <= Load Increases							Resource Additions=> Load Decreases =>						
Sub Area	Most Constraining Interface	-2700	-2100	-1500	-1200	-900	-600	-300	300	600	900	1200	1500	2100	2700
BHE	Orrington South	2	1	1	1	1	1	1	2	4	15	43	143	372	595
ME	Surowiec South	2	1	1	1	2	1	1	2	3	9	24	73	276	499
SME	Maine-New Hampshire	2	1	1	1	2	1	1	2	3	3	7	14	65	229
NH	North/South	2	2	1	1	2	1	1	1	2	2	3	6	18	52
VT	North/South	2	2	1	1	2	1	1	1	1	2	3	5	14	39
WMA	N/A	3	2	2	1	2	1	1	1	1	1	1	1	1	1
CMAN	N/A	3	2	2	1							1	1	1	1
BOST	Boston Import	143	24	3	1							1	1	1	1
SEMA	SEMA/RI	3	2	2	1							1	1	4	9
RI	SEMA/RI	3	2	2	1	2	1	1	1	1	1	1	1	4	9
CT	N/A	2	2	2	1	2	1	1	1	1	1	1	1	1	1
SWCT	SWCT Import	104	4	2	1	2	1	1	1	1	1	1	1	1	1
NOR	Norwalk Import	7828	4675	1549	441	71	5	1	1	1	1	1	1	1	1

Range of “better” places for resource / load addition / removal

Significant Import-Limited Energy
More Significant Import-Limited Energy
Significant Bottled-in Energy
More Significant Bottled-in Energy
Unconstrained

Because of lower capacity factors, increases or decreases of other types of resources had smaller impacts on the magnitude of the “difference” metric.

Increasing or decreasing loads or resources with profiles that affect fewer hours at their maximum change (i.e., compared to BASE) will produce a lower amount of congestion. The trends in Table 5-2 will repeat with other lower-capacity-factor resources, but the congestion values will be smaller. This map can be used to suggest areas where retirements and the permanent loss of resources would be problematic.

Table 5-3 illustrates the areas where changes in the supply and demand balance can be made without congestion causing a significant impact on LSE energy expense. Similar to Table 5-2, the map is arranged as a progression from northern Maine at the top to southwestern Connecticut on the bottom. The value in the cells represents the increase in LSE energy expense due to the transmission constraints. The cells in light yellow (or light blue) are areas where the change in LSE energy expense compared with the Unconstrained Case is negligible. The colored cells show when the LSE energy expense metric increase, due to congestion, is greater than $10 million per year and can be characterized as follows:

- The relative LSE energy expense shows that for resource increases (or load decreases) congestion will increase in northern New England. The greatest impacts are in northern Maine.
- The relative LSE energy expense shows congestion in southern New England for resource decreases (or load increases). The greatest impacts are in Norwalk, Southwestern Connecticut, and Boston, which are load pockets in the ISO New England region.

Table 5-3
Effectiveness of Load and Resource Additions or Removals Based on LSE Energy-Expense

Change in Annual Congestion From an Unconstrained Case for a Change in "BASE" MW ($Million per year)

		<= Resource Removals <= Load Increases							Resource Additions=> Load Decreases =>						
Sub Area	Most Constraining Interface	-2700	-2100	-1500	-1200	-900	-600	-300	300	600	900	1200	1500	2100	2700
BHE	Orrington South	4	1	1	0	2	0	0	8	70	181	229	282	493	662
ME	Surowiec South	4	1	1	0	2	0	0	8	63	127	171	122	154	323
SME	Maine-New Hampshire	4	1	1	0	2	0	0	9	63	103	127	180	178	29
NH	North/South	6	1	-1	-1	4	-1	0	1	19	45	56	74	146	91
VT	North/South	6	1	-1	-1	4	-1	0	1	12	33	40	49	119	75
WMA	North/South	12	5	-1	0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	-1	-1	-1	-1
CMAN	North/South	13	7	1	1	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	-1	-1	-1	-1
BOST	Boston Import	828	56	0	2	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	-1	-1	-1	-1
SEMA	SEMA/RI	12	6	-1	2	5	-1	0	0	0	-1	0	5	51	120
RI	SEMA/RI	9	5	-1	0	5	-1	0	0	0	-1	0	5	51	120
CT	N/A	12	4	-1	1	5	-1	0	0	0	-1	-1	-1	-1	-1
SWCT	SWCT Import	477	1	-1	1	5	-1	0	0	0	-1	-1	-1	-1	-1
NOR	Norwalk Import	572	1518	2149	1265	317	6	0	0	0	-1	-1	-1	-1	-1

Range of "better" places for resource / load addition / removal

Significant Import-Limited Energy
More Significant Import-Limited Energy
Significant Bottled-in Energy
More Significant Bottled-in Energy
Unconstrained

Unlike the relative production cost metric, the relative LSE energy-expense metric may not be monotonically increasing. The shape of the curve depends on the relative load and amount of resources in the import-constrained area compared with the balance of the New England areas and the relative effect on prices in those unconstrained areas. It is also affected by the range of allowable prices in these areas, including the maximum $500/MWh LMP in an import-constrained area and the minimum price of $0/MWh in an export-constrained area.

Section 6
Part 2: Analysis of Capital Investment Supported by Energy Market Revenues by Resource Type

The second part of the 2012 study analyzed the economics of specific resource technologies. The objective was to estimate the amount of capital costs ($/kW-year) that revenues from the energy market alone could support. These electric energy market revenues may, or may not, be sufficient to support the annual carrying costs of these resources. Insufficient revenues suggest that other sources of revenue would be required to support the resource additions. Possible sources of supplemental revenues could be other wholesale electricity markets, such as the Forward Capacity Market or Forward Reserve Market, or a combination of other policy incentives, such as production tax credits or renewable energy credits.

6.1 Generic Capital Costs of New Supply-Side Resources

An update of generic capital costs for new resources was developed with a focus on the resource technologies in the ISO Generator Interconnection Queue and those participating in the Forward Capacity Market. The updated resource costs are from DOE's Energy Information Administration (EIA) and the Electric Power Research Institute (EPRI) for technologies that likely will dominate the future generation mix in the United States. Table 6-1 shows these updated generic capital costs.

Table 6-1
Generic Capital Costs of New Supply-Side Resources

Generation Type	Nominal Plant Capacity (MW)	Plant Costs ($/kW)[(a)]
Natural gas combined cycle (NGCC)	550	1,060–1,150
Conventional combustion turbine (CT)	85	975
Advanced CT[(b)]	210	665
Wind onshore	100	2,025–2,700
Wind offshore	200	3,100–4,000
Biomass	100	3,500–4,400
Solar PV	10	3,400–4,600
Reciprocating engine for CHP	NA	1,100-1,200
Smart grid metering[(c)]	NA	3-15
Demand-response metering[(c)]	NA	3-15
Energy efficiency[(d)]	NA	1,248-2,907

(a) Unless otherwise noted, costs are from EPRI's *Program on Technology Innovation: Integrated Generation Technology Options* (June 2011).

(b) Advanced CT costs are from EIA's *Updated Capital Costs Estimates for Electricity Generating Plants* (November 2010).

(c) These costs are metering costs only.

(d) ISO New England, *Energy-Efficiency Forecast 2016-2021 March Update* (March 15, 2012), Slide 12 (Min and Max), http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2012/mar152012/ee_forecast.pdf.

The capital cost of each resource technology was converted to an approximate annual fixed cost that a resource would need to recover to pay for capital investment, financing expenses, and certain operations and maintenance costs typically associated with the amount of capital investment (e.g., property taxes, insurance, return on and return of capital, among other costs). These annual fixed costs were calculated from the resource's capital cost and an estimate of annual carrying charge rates. These annual carrying charge rates typically are expressed as a percentage of the capital investment. The range of 15% to 25% of the capital costs was used in the ISO New England 2007 Scenario Analysis and is considered representative of the upper and lower bounds for this study.[27]

The actual capital costs of new resources may be different from these generic estimates due to various factors, such as the follwing:

- State of technology development
- Changes in material, labor, and overhead costs
- Supply-chain backlogs or oversupply
- Specific site requirements
- Regional cost differences
- Difficulties in obtaining site and technology approvals

In addition, experience suggests that many construction projects encounter unforeseen design and construction problems that tend to increase costs.

6.2 Load Shapes and Associated Technologies

The incremental and decremental load shapes (or resource profiles) discussed in Section 5 were conceptually associated with a type of resource. However, the simulated load shapes (or resource profiles) could be produced by one or more technologies. Therefore, the capital costs required to procure a resource to operate in a manner that would create one of the production profiles is unknown. Because of large uncertainties in the cost of the resource needed to create the load shapes, this analysis should only be used for guidance and comparative discussions. The various types of simulated load shapes (or resource profiles) and associated types of resources are as follows:

- **BASE:** This load shape could represent a nuclear unit or a highly efficient natural gas combined-cycle unit that would operate, effectively, all the time. For quantifying the capital cost, an efficient combined-cycle resource was assumed as the basis of this load shape.
- **INTR:** The technology that would operate in the range of a 20% capacity factor was uncertain. In this dispatch cost range, a small change in dispatch price could result in large changes in capacity factor. This load shape could have represented an existing generating unit that operated infrequently, and therefore the difference between the unit's production cost and the energy market revenues would factor into the decision about the continued operation or retirement. For quantifying the capital cost, a new conventional simple-cycle gas turbine was assumed to underlie this load shape (or resource profiles).

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[27] *New England Electricity Scenario Analysis* (August 2, 2007), http://www.iso-ne.com/committees/comm_wkgrps/othr/sas/mtrls/elec_report/scenario_analysis_final.pdf.

- **DR:** The customer technologies controlled “behind-the-meter” to enable the DR are unknown and were assumed to be economically self-supportive. Therefore, only the costs of advanced metering were used to underlie the load shape.
- **EE:** The technologies employed for using electric energy more efficiently are varied, and no single technology was used as the proxy for cost purposes. Investment costs for programs that would provide the overall amounts of energy efficiency were assumed.
- **PV:** The mode of deployment of photovoltaics is significant in developing cost estimates for this technology. Installed residential-scale systems are more expensive than larger commercial and industrial-scale deployments on a $/kW basis.
- **WNDN:** Representative capital costs for onshore wind resources were assumed.
- **WNDF:** Representative capital costs for offshore wind resources were assumed.
- **SGRD:** The customer cost of the technology investment necessary for managing demand more intelligently is unknown and not included. The customer technologies controlled “behind-the-meter” to enable the operation of the smart grid are unknown and assumed to be economically self-supportive. Capital costs were assumed to be for the installation of advanced meters only.
- **CHP/G:** All (100%) of the gross revenues were applied toward the contribution to fixed costs. Any fuel consumed by CHP was assumed to be allocated to the CHP heat byproduct. Capital costs were based on reciprocating engines used for CHP. No adjustment was made to represent the capital cost of geothermal.

6.3 Annual Cost of Installed Technologies

The range of annual carrying costs for a technology was based on a resource’s investment costs and the carrying charge rates. An estimate of the range of annualized carrying costs was calculated by assessing the range of capital costs and the range of rates for fixed charges:

- The upper limit used the “higher capital cost” and the higher annual carrying charge rate of 25% of the capital cost.
- The lower bound used the “lower capital cost” and the lower annual carrying charge rate of 15%.

Table 6-2 shows the higher and lower range of annual carrying costs.

Table 6-2
Range of Annual Fixed Charges ($/kW-yr)

Technology assumed	BASE Advanced Gas-Fired Combined Cycle (6,000 Btu/KWh)	INTR Combustion Turbine (8,600 BTHu/kWh)	DR Active Demand Resources (Metering Only)	EE Energy Efficiency	PV Photovoltaic	WNDN Wind Onshore	WNDF Wind Offshore	SGRD Smart Grid (Metering Only)	CHPG Reciprocating Engine
High capital cost ($/kW)	1,150	975	15	2,907	4,600	2,700	4,000	15	2,200
Low capital cost ($/kW)	1,060	975	3	1,248	3,400	2,025	3,100	3	1,100
High carrying charge rate (%)	25%	25%	25%	25%	25%	25%	25%	25%	25%
Low carrying charge rate (%)	15%	15%	15%	15%	15%	15%	15%	15%	15%
Annual carrying cost (higher) ($/kW-yr)	288	244	4	727	1,150	675	1,000	4	550
Annual carrying cost (lower) ($/kW-yr)	159	146	0	187	510	304	465	0	165

6.4 Contribution to Fixed-Costs Metric

The economic viability of a new resource was assessed on the basis of the net revenues the resource can earn from energy market revenues only. Figure 6-1 shows an illustrative price-duration curve for the central Massachusetts region of New England. This curve shows, in a single view, the range of simulated LMPs across the entire year, sorted from highest to lowest.

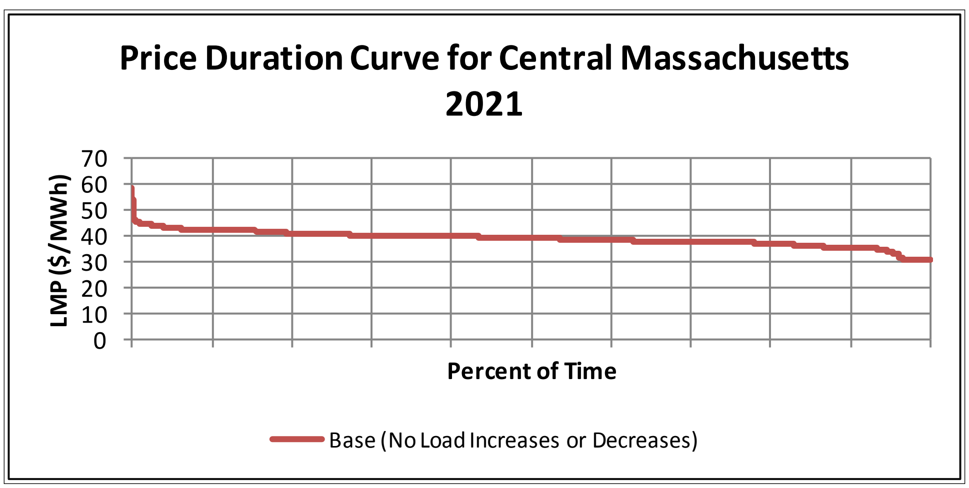

Figure 6-1: Price-duration curve for Base Case (no resource increases or decreases), central Massachusetts, 2021.

In general, generating units that can produce energy for a lower cost than the LMP have an incentive to produce the energy. Likewise, a generating unit whose cost of production is higher than the LMP has no incentive from the energy market to produce energy because it would lose money. Figure 6-2 shows an example where the LMP is above a resource's assumed dispatch cost about 60% of the time in 2021. It is reasonable to assume that the resource will operate in these hours. The other 40% of the time, the LMP is below the resource's production cost, and it can be assumed that the resource will not be dispatched in these hours.

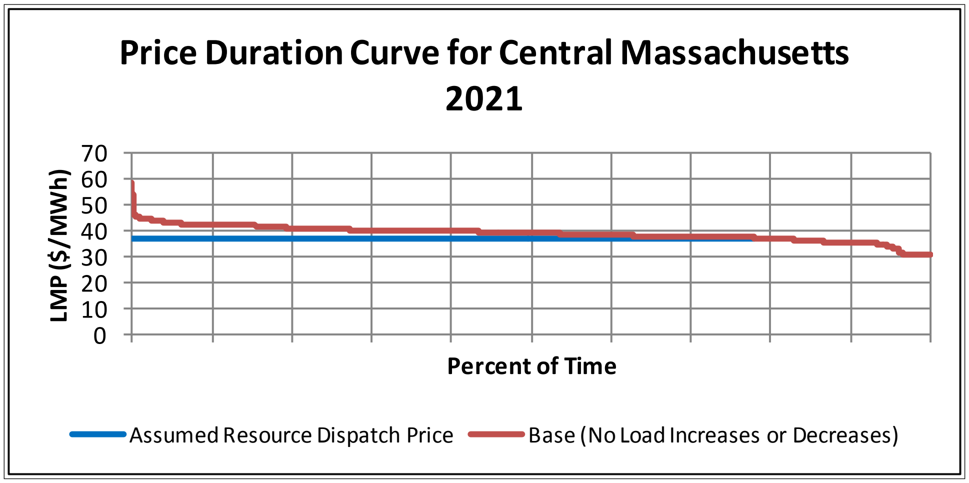

Figure 6-2: Price-duration curve for Base Case in central Massachusetts, 2021, shown with assumed resource dispatch price.

The total net energy revenues for a generating unit can be estimated by summing the earnings across the year. This "contribution to fixed costs" is a high-level metric for summarizing the net energy revenues for a specific resource technology in a specific location. Figure 6-3 shows the hours in yellow where the LMP exceeds the assumed dispatch price.

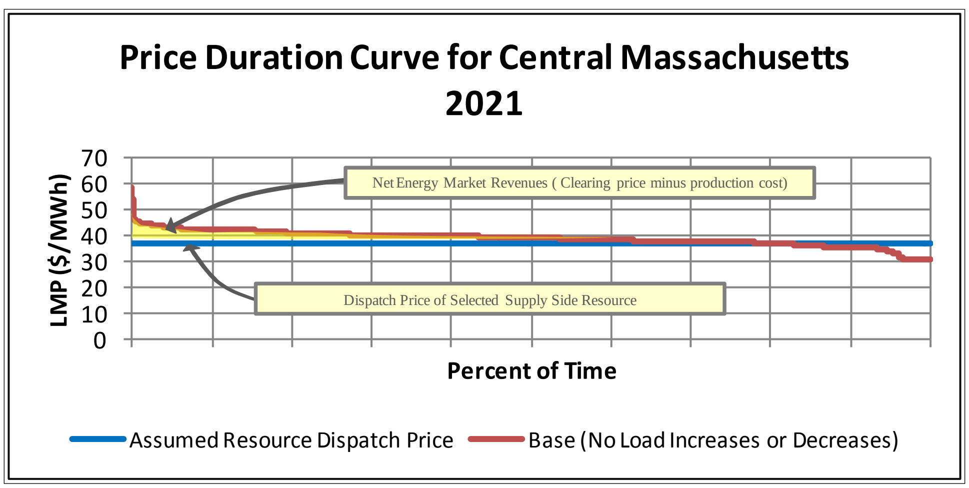

Figure 6-3: Price-duration curve for Base Case for central Massachusetts, 2021, shown with assumed resource dispatch price highlighting net energy revenues.

6.5 Economic Viability of Resources based on Net Energy Market Revenues

This analysis considers only net energy revenues, which are based on the simulated LMPs minus a resource's cost of production. As shown in Figure 6-4, as resources were added to the mix (or loads were reduced) downward pressure was exerted on energy market clearing prices, which reduced energy revenues. For this figure, a resource's cost of production was assumed to be zero for the assumed load profile.

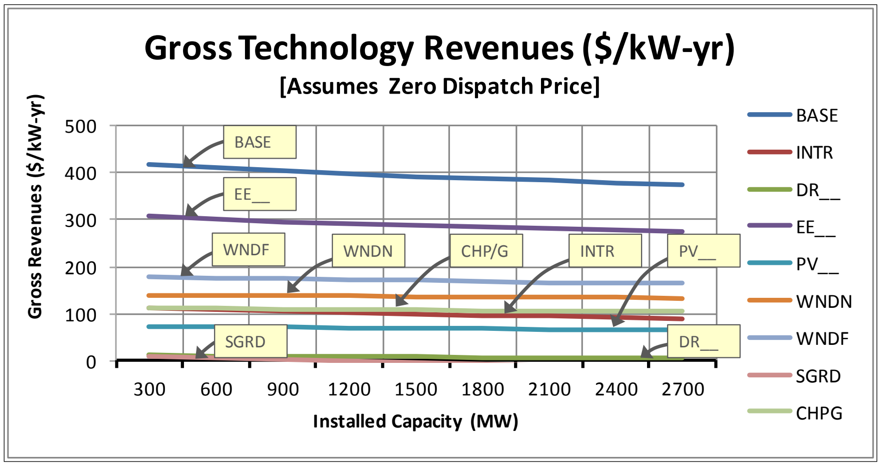

Figure 6-4: Annual gross revenues for each load shape ($/kW-yr).

For some existing resources, insufficient energy market revenues could result in their inability to cover ongoing costs, which could lead to their retirement.

Figure 6-5 through Figure 6-13 each show two horizontal lines. The lower (green) line reflects the annual costs associated with the low capital cost estimates and the low estimate of carrying costs (15% per year) for a specific technology. The higher (red) line reflects the higher end of the range of investment costs and a high estimate of carrying costs in a given year, at 25%. A comparison of the contributions to fixed costs to the range of annual carrying costs of a technology provides an indication of the need for other revenue sources.

6.5.1 Advanced Combined-Cycle Resources

Figure 6-5 shows that under the assumptions used in this analysis, an advanced combined-cycle unit would have earned nearly enough to support itself on energy market revenues, given low financing and low capital costs. The contributions to fixed costs were assumed to be the gross energy market revenues calculated for the "BASE" resource in Figure 6-4, minus the cost of the natural gas fuel, assuming a 6,000 Btu/kWh heat rate. Figure 6-5 also shows that the economic viability began to erode as more of these resources were added. For example, if only 300 MW of combined-cycle resources were added, they could have potentially earned $180 kW-year. However, if 2,700 MW of these resources were added, the amount of contribution to fixed costs would have declined to $130 kW-year.

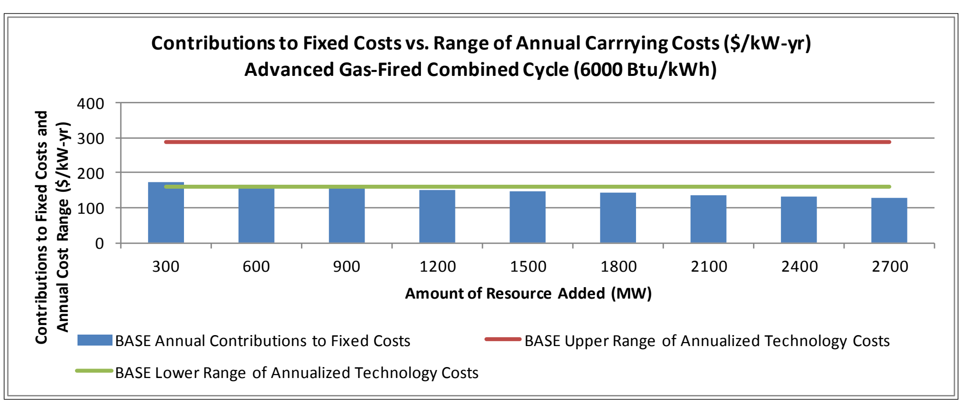

Figure 6-5: Contributions to fixed costs compared with expected annual requirements for advanced combined-cycle units.

6.5.2 Conventional Simple-Cycle Combustion Turbine Resources

Figure 6-6 shows that a conventional simple-cycle combustion turbine operating at up to a 20% capacity factor would not be able to recover its capital investment costs from energy market revenues alone. The contributions to fixed costs were assumed to be the gross energy market revenues calculated for the "INTR" resource in Figure 6-4, minus the cost of the natural gas fuel, assuming an 8,600 Btu/kWh heat rate. This suggests that additional revenues streams would be needed from markets such as the FRM and FCM.

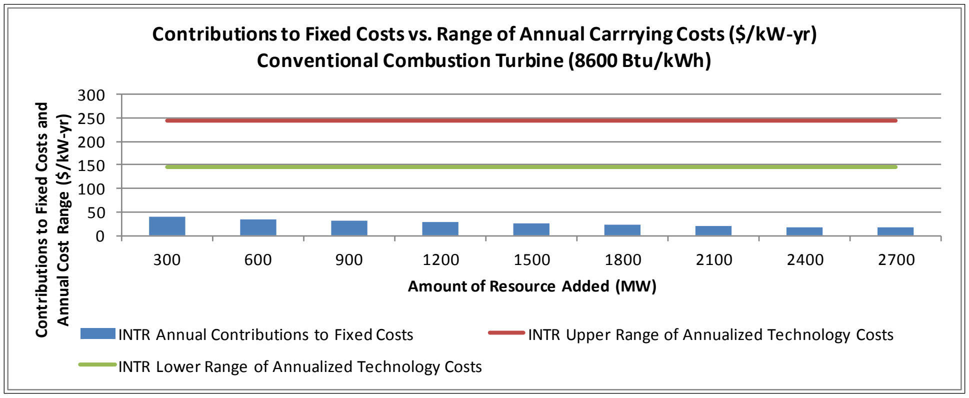

Figure 6-6: Contributions to fixed costs compared with expected annual requirements for conventional simple-cycle combustion turbines (assumed 20% capacity factor).

6.5.3 Active Demand-Response Resources

Figure 6-7 shows that considering only the metering costs, demand-response resources would be able to recover their assumed metering costs from energy market revenues. What is not known from this analysis is the cost of the technologies on the end-user side that would be necessary to manage the customer-side loads. These costs may be substantial and could be much greater than the cost of the advanced meters, thus requiring additional revenues from other sources, such as the FCM. These behind the meter technologies are assumed to be economically self-supportive.

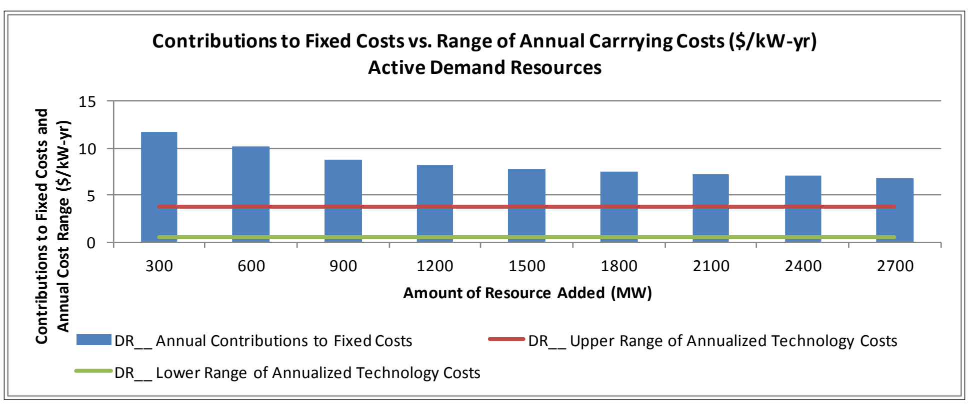

Figure 6-7: Contributions to fixed costs compared with expected annual requirements for active demand-response resources.

6.5.4 Energy-Efficiency Resources

Figure 6-8 shows that, energy-efficiency technologies with typical program costs can recover their capital investment costs from energy market revenues. The wide range of technology costs suggests that some technologies are economic based only on energy savings, while others may not be economic without revenues from other market streams.

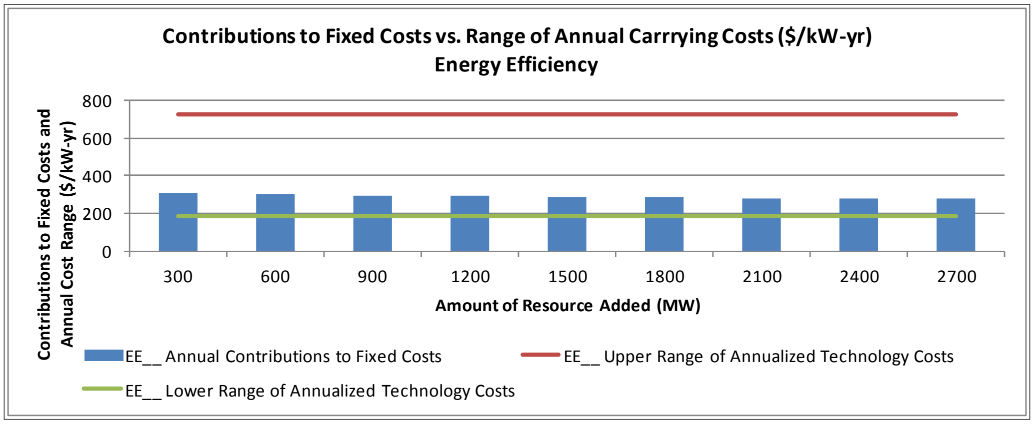

Figure 6-8: Contributions to fixed costs compared with expected annual requirements for energy-efficiency resources.

6.5.5 Photovoltaic Resources

Figure 6-9 shows that photovoltaics, which are assumed to operate at a capacity factor of approximately 15%, would not be able to recover their capital investment costs from energy market revenues. This suggests that additional revenues streams would be needed from markets such as the FCM and renewable energy credits (RECs).

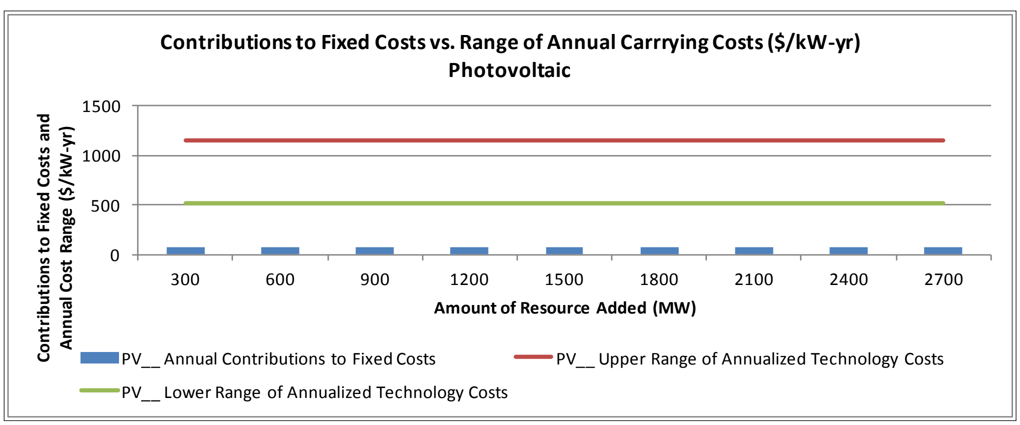

Figure 6-9: Contributions to fixed costs compared with expected annual requirements for photovoltaic resources.

6.5.6 Wind Resources

Figure 6-10 and Figure 6-11 show that onshore and offshore wind resources, respectively, would not be able to recover their capital investment costs from energy market revenues alone. This suggests that additional revenues streams would be needed from markets such as the FCM and RECs.

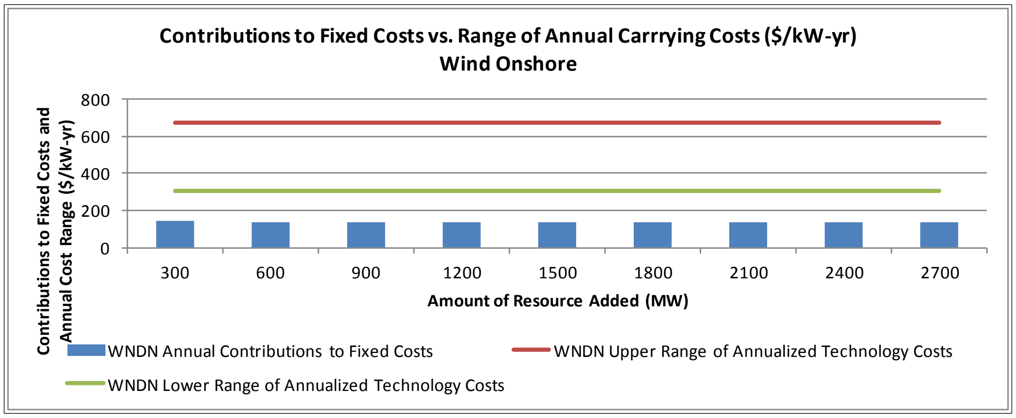

Figure 6-10: Contributions to fixed costs compared with expected annual requirements for onshore wind resources.

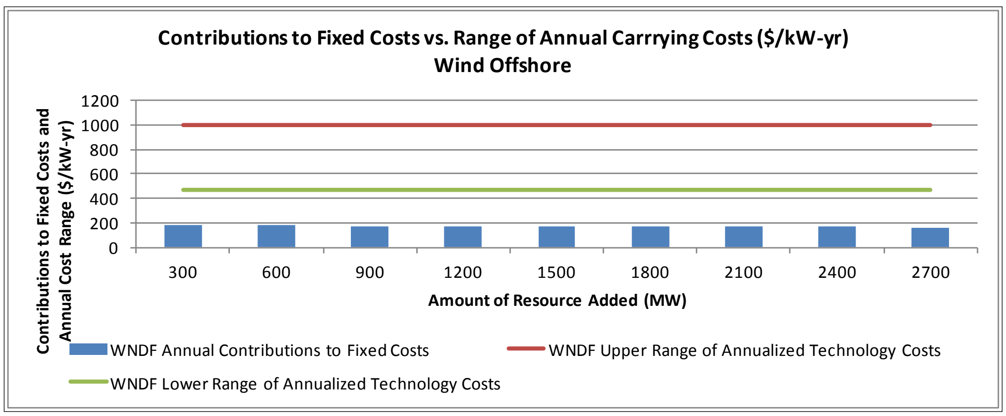

Figure 6-11: Contributions to fixed costs compared with expected annual requirements for offshore wind resources.

6.5.7 Smart Grid Resources

Figure 6-12 shows the results for smart grid, which was based on analyzing a profile that had characteristics similar to pumped storage (an energy-storage technology). When viewed as a resource, on-peak energy was injected into the system (or load was reduced), while off-peak energy was withdrawn from the system (or load was increased) to represent the storage of energy. As discussed previously, the premise is that, through time shifting, smart grid enables the management of load to economically benefit the consumer. The more on-peak demand supplanted by this technology, the more off-peak energy that must be stored. These results show a sharp decline in the net energy revenue savings for a fixed profile of energy storage as the cost of the off-peak energy, including losses begins to outweigh the on-peak revenues. At 1,200 MW, or more, the cost of off-peak energy, including losses, exceeded the value of the on-peak energy. The cost of the technology shown is only for the metering that would enable this load management; the cost of the technologies that end-use customers could or would use is so varied that it was not quantified in this analysis and was assumed to be economically self supportive.

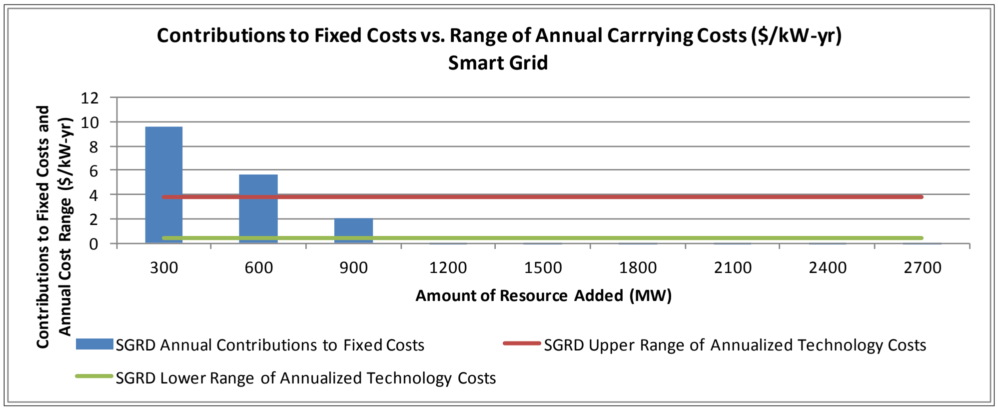

Figure 6-12: Contributions to fixed costs compared with expected annual requirements for smart grid infrastructure.

6.5.8 Combined Heat and Power/Geothermal Resources

Figure 6-13 shows the results for a combined heat and power/geothermal system. This technology profile has a 26% capacity factor and can provide a significant contribution to fixed costs. However, the technology that would be used to create this CHP/G load shape is not unique. The CHP/G technology was assumed to be a reciprocating engine, while the geothermal component was assumed to be based on a groundwater-assisted heat pump. Gross revenues from the energy market were assumed to be allocated to cover the annual carrying charges, while the cost of the fuel was assumed to be recovered from sales of the process heat.

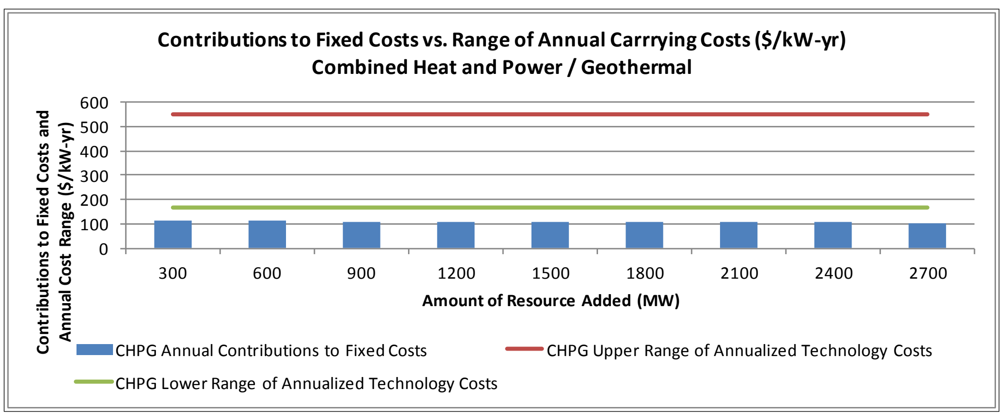

Figure 6-13: Contributions to fixed costs compared with expected annual requirements for combined heat and power/geothermal units.

Section 7
Part 3: Development of Expansion Scenarios for Low-Carbon Resources

The third part of the study compared four hypothetical expansion scenarios for low-carbon resource futures. The study focused on compliance with the states' Renewable Portfolio Standards (RPSs) as the system evolved over a 10-year period, 2012 to 2021.

Four scenarios were developed, which included the specific renewable technologies to be evaluated. The initial resource mix included the currently obligated and envisioned FCM resources. However, the coal, heavy oil, and natural gas steam resources older than 40 years in 2021 (e.g., older than 30 years in 2011) were assumed to be retired. These retired resources were then postulated to be replaced with a variety of low, or nonemitting, resources:

- Energy efficiency and active demand resources
- Wind generation
- Photovoltaics
- Combined heat and power/geothermal
- New efficient, simple-cycle combustion turbine resources (maximum of 1,000 MW)
- New efficient, advanced combined-cycle resources

Key assumptions in the sensitivities were a doubling of the energy-efficiency growth rate after 2015 and the inclusion of the effects of photovoltaics and combined heat and power/geothermal resources. To satisfy the shortages in the scenarios where the RPS requirements were not met, sufficient amounts of wind resources would be added.

7.1 Scenarios Analyzed

A high-level definition of the four hypothetical scenarios is as follows:

- Case 1: Base energy efficiency with retirements replaced by new natural gas resources
- Case 2: Same as Case 1, except retirements were replaced by:
    - 3,000 MW of photovoltaics
    - 340 MW of combined heat and power/geothermal
    - New natural gas resources to satisfy the remainder
- Case 3: Same as Case 1 with double energy-efficiency growth rates after 2015
- Case 4: Same as Case 3 except retirements were replaced by:
    - 3,000 MW of photovoltaics
    - 340 MW of CHP/G
    - New natural gas resources to satisfy the remainder

7.2 Scenario Development

To avoid the potential for transmission bottlenecks affecting the economics of a scenario, the results of the first part of the study were used as the basis for identifying the locations to add resources to replace those that are retired.

7.2.1 Retirement of Residual Oil, Coal, and Natural Gas Steam

Residual oil, coal, and natural gas steam units were assumed to be retired at the age of 40 years old by 2021. Table 7-1 shows the units that were assumed to be retired for these scenarios. Some of the resources have already signaled their willingness to retire by initiating the delisting process through the Forward Capacity Market (FCA #5).[28]

Table 7-1
Coal, Heavy Oil/Natural Gas Steam Units Assumed to be Delisted by 2021

ASSET ID	Year	Age in 2021	Generator Name	Summer (MW)	Coal-or-Not	Primary Fuel Category	Alternate Fuel Category	Sub-Total	Cumulative Total
551	1952	Delisted	SALEM HARBOR 1	82.0	Coal	BIT	FO6		
552	1952	Delisted	SALEM HARBOR 2	80.0	Coal	BIT	FO6		
553	1958	Delisted	SALEM HARBOR 3	149.8	Coal	BIT	FO6		
577	1959	Delisted	SOMERSET 6	109.1	Coal	BIT			
594	1989	Delisted	AES THAMES	185.0	Coal	BIT			
1694	1957	Delisted	WEST SPRINGFIELD 3	94.3	Not-Coal	NG	FO2		
554	1972	Delisted	SALEM HARBOR 4	436.8	Not-Coal	FO6		1137.0	
556	1952	70	SCHILLER 4	47.5	Coal	BIT	FO6		
558	1957	65	SCHILLER 6	47.9	Coal	BIT	FO6		
498	1960	62	MT TOM	143.6	Coal	BIT			
489	1961	61	MERRIMACK 1	112.5	Coal	BIT			
350	1963	59	BRAYTON PT 1	228.2	Coal	BIT	NG		
351	1964	58	BRAYTON PT 2	225.8	Coal	BIT	NG		
340	1968	54	BRIDGEPORT HARBOR 3	380.0	Coal	BIT	FO6		
490	1968	54	MERRIMACK 2	320.0	Coal	BIT			
352	1969	53	BRAYTON PT 3	591.5	Coal	BIT	NG	2097.1	3234.0
493	1954	68	MONTVILLE 5	81.0	Not-Coal	FO6	NG		
639	1957	65	YARMOUTH 1	51.8	Not-Coal	FO6			
480	1958	64	MIDDLETOWN 2	117.0	Not-Coal	FO6	NG		
640	1958	64	YARMOUTH 2	51.1	Not-Coal	FO6			
519	1960	62	NORWALK HARBOR 1	162.0	Not-Coal	FO6			
339	1961	61	BRIDGEPORT HARBOR 2	130.5	Not-Coal	FO6			
520	1963	59	NORWALK HARBOR 2	168.0	Not-Coal	FO6			
481	1964	58	MIDDLETOWN 3	236.0	Not-Coal	FO6	NG		
641	1965	57	YARMOUTH 3	115.5	Not-Coal	FO6			
365	1968	54	CANAL 1	550.4	Not-Coal	FO6			
494	1971	51	MONTVILLE 6	407.4	Not-Coal	FO6			
482	1973	49	MIDDLETOWN 4	400.0	Not-Coal	FO6			
353	1974	48	BRAYTON PT 4	422.0	Not-Coal	FO6	NG		
508	1974	48	NEWINGTON 1	400.2	Not-Coal	FO6	NG		
502	1975	47	MYSTIC 7	577.6	Not-Coal	NG	FO6		
513	1975	47	NEW HAVEN HARBOR	447.9	Not-Coal	FO6	NG		
366	1976	46	CANAL 2	553.0	Not-Coal	FO6	NG		
642	1978	44	YARMOUTH 4	603.5	Not-Coal	FO6		5474.9	8708.9

Delist Accepted

Assumed to Delist Based on Age

7.2.2 Existing and Future RPS Resources

Central to this part of the study was the assumption that the states' RPS goals would be satisfied. Because a comprehensive inventory of existing RPS resources is not available, the amount of existing RPS-qualified energy is not known. For this study, it was assumed that the 2011 RPS resources were adequate to meet the 2011 RPS requirements. To accommodate the study request, the growth in new RPS resources was assumed to keep pace with the growth in the state RPS goals. Consequently, this study focused on the growth in RPS resources after 2011, assuming that the growth in state-level requirements

[28] For more information on delist bids, refer to the ISO's *Overview of New England's Wholesale Electricity Markets; Market Oversight* (May 15, 2013), http://www.iso-ne.com/pubs/spcl_rpts/index.html.

could be summed together to develop an estimate of the aggregate New England requirement for new RPS energy.

To ensure that sufficient resources were available to reliably serve the loads, resources that were retired were partially replaced by wind, solar photovoltaic, and combined heat and power/geothermal resources while maintaining a reserve margin of 15%. When additional resources were needed to attain the target reserve margin, up to 1,000 MW of simple-cycle conventional gas turbines with a heat rate of 8,600 Btu/kWh were added. Remaining shortfalls were satisfied by the addition of advanced gas-fired combined-cycle resources with a heat rate of 6,000 Btu/kWh.

Because some of the resources do not provide a capacity contribution equal to their nameplate ratings, a capacity value of these intermittent resources was defined. Full nameplate capacity values were assumed for new combined-cycle, new simple-cycle combustion turbines, CHP/G units, and active and passive demand-response resources. Solar photovoltaic was counted at 39.4% of nameplate capacity, and composite onshore and offshore wind was counted at 27.6% of nameplate capacity. These capacity values for intermittent resources were based on an evaluation using the "reliability-hour" calculation approach.

7.2.3 Forecasts of Energy Efficiency

The Forward Capacity Market secures the resources intended to provide capacity up to three years in advance. This includes resources that provide a reduction in energy use attributable to energy-efficiency technologies. The ISO also has been analyzing energy-efficiency programs and studying how to forecast incremental, future long-term equivalent supply stemming from EE in the five- to 10-year planning horizon. The driver for this reduction is the historical and assumed annual spending rate across the six New England states, which forms the basis of significant reductions in annual energy use. The regional energy-efficiency forecast, as summarized in this section, is part of the ongoing efforts to analyze the long-term impacts of state-sponsored energy-efficiency programs on future energy use and demand.

Figure 7-1 shows the base forecast for New England's annual energy use. This figure shows the New England load with and without energy efficiency. Table 7-2 shows the numerical values for New England's energy-efficiency programs as well as their impact by RSP area. The New England totals show that the energy-efficiency programs, which reduced energy use by 5,525 GWh in 2012, is expected to provide a reduction of 17,409 GWh by 2021. A doubling of the rate of growth of energy efficiency beginning in 2015 would reduce energy use by a total of 26,807 GWh by 2021.

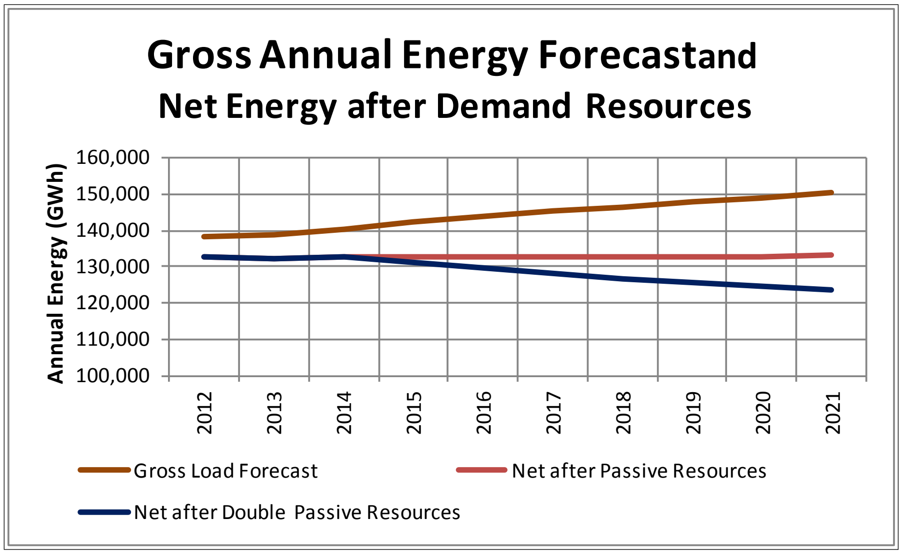

Figure 7-1: Gross annual energy-use forecast and net energy after accounting for passive demand resources.

Table 7-2
Annual Energy Adjustments for Passive Resources (GWh)

Passive Resources: Base Forecast (GWh)

Year	BHE Energy GWh	ME Energy GWh	SME Energy GWh	NH Energy GWh	VT Energy GWh	BOST Energy GWh	CMAN Energy GWh	WMA Energy GWh	SEMA Energy GWh	RI Energy GWh	CT Energy GWh	SWCT Energy GWh	NOR Energy GWh	NE Energy GWh
2012	53	159	123	318	418	964	307	413	483	456	894	605	331	5524
2013	94	282	216	382	530	1233	355	477	549	531	972	659	360	6640
2014	128	387	296	428	630	1619	439	589	655	622	1084	734	400	8011
2015	142	429	326	492	734	2074	562	745	841	829	1201	814	444	9633
2016	155	468	354	552	829	2501	676	891	1014	1022	1312	889	484	11147
2017	167	504	380	610	919	2900	784	1028	1175	1204	1416	960	522	12569
2018	177	538	403	664	1002	3274	885	1157	1327	1376	1515	1027	559	13904
2019	187	569	425	716	1080	3625	979	1278	1467	1537	1606	1089	592	15150
2020	197	599	444	764	1153	3954	1068	1390	1598	1687	1693	1148	624	16319
2021	205	626	462	809	1221	4261	1150	1495	1719	1829	1775	1204	653	17409

Passive Resources: Double Growth (GWh)

Year	BHE Energy GWh	ME Energy GWh	SME Energy GWh	NH Energy GWh	VT Energy GWh	BOST Energy GWh	CMAN Energy GWh	WMA Energy GWh	SEMA Energy GWh	RI Energy GWh	CT Energy GWh	SWCT Energy GWh	NOR Energy GWh	NE Energy GWh
2012	53	159	123	318	418	964	307	413	483	456	894	605	331	5524
2013	94	282	216	382	530	1233	355	477	549	531	972	659	360	6640
2014	128	387	296	428	630	1619	439	589	655	622	1084	734	400	8011
2015	156	471	356	556	838	2529	685	901	1027	1036	1318	894	488	11255
2016	182	549	412	676	1028	3383	913	1193	1373	1422	1540	1044	568	14283
2017	206	621	464	792	1208	4181	1129	1467	1695	1786	1748	1186	644	17127
2018	226	689	510	900	1374	4929	1331	1725	1999	2130	1946	1320	718	19797
2019	246	751	554	1004	1530	5631	1519	1967	2279	2452	2128	1444	784	22289
2020	266	811	592	1100	1676	6289	1697	2191	2541	2752	2302	1562	848	24627
2021	282	865	628	1190	1812	6903	1861	2401	2783	3036	2466	1674	906	26807

Table 7-3 shows the development of Case 1. For each of the years from 2012 to 2021, an estimated value for the ISO's Installed Capacity Requirement (ICR) was developed. From this value, the amount of assumed active and passive demand response was removed. The existing wind capacity, adjusted to its capacity value, was then removed. As shown in the table, the amount of installed capacity was assumed to be 31,545 MW before the assumed retirement of 7,616 MW of older oil, coal, and gas steam generators. This amount of assumed retired generators over this time horizon was removed, leaving a net shortage (or surplus) of capacity. When a shortage existed, new resources were needed to eliminate the deficiency.

The last two columns of the table show the amounts of simple-cycle combustion turbines and advanced combined-cycle capacity needed to be installed to satisfy the assumed ICR value. Up to 1,000 MW of simple-cycle combustion turbines were added.

Table 7-3
Case 1: Base Energy-Efficiency Expansion Capacity Analysis

	Reserve Margin					Wind Capacity Value				Heat Rate	Heat Rate
	0.150		2016 / 2017 (MW)	2016 / 2017 (MW)	Active Queue	0.276				8600 Btu/kWh	6000 Btu/kWh
Year	ICR	EE	Active DR	RTEG	Wind	Wind QC	Existing IC MW	40 year Retire	Surplus/Shortage	New CT	Advanced CC
2012	31,556	976	1,444	534	1,988	549	31,545	-5,460	-1,968	1,000	968
2013	31,930	1,137	1,444	534	3,224	890	31,545	-5,460	-1,840	1,000	840
2014	32,516	1,397	1,444	534	3,381	933	31,545	-5,460	-2,123	1,000	1,123
2015	33,166	1,646	1,444	534	3,927	1,084	31,545	-6,462	-3,376	1,000	2,376
2016	33,810	1,881	1,444	534	3,927	1,084	31,545	-7,015	-4,338	1,000	3,338
2017	34,379	2,097	1,444	534	3,927	1,084	31,545	-7,015	-4,691	1,000	3,691
2018	34,816	2,300	1,444	534	3,927	1,084	31,545	-7,616	-5,525	1,000	4,525
2019	35,196	2,496	1,444	534	3,927	1,084	31,545	-7,616	-5,709	1,000	4,709
2020	35,570	2,673	1,444	534	3,927	1,084	31,545	-7,616	-5,905	1,000	4,905
2021	35,943	2,841	1,444	534	3,927	1,084	31,545	-7,616	-6,111	1,000	5,111

Table 7-4 provides the same capacity analysis with the assumption that the energy-efficiency growth rate would double beginning in 2015. By 2021, the energy-efficiency growth rate increased the capacity equivalent for energy efficiency from 2,841 MW to 4,285 MW. The associated energy increased from 17,409 GWh to 26,807 GWh by 2021.

Table 7-4
Case 3: Double Energy-Efficiency Growth Rate Expansion Capacity Analysis

	Reserve Margin					Wind Capacity Value				Heat Rate	Heat Rate
	0.150		2016 / 2017 (MW)	2016 / 2017 (MW)	Active Queue	0.276				8600 Btu/kWh	6000 Btu/kWh
Year	ICR	EE	Active DR	RTEG	Wind	Wind QC	Existing IC MW	40 year Retire	Surplus/Shortage	New CT	Advanced CC
2012	31,556	976	1,444	534	1,988	549	31,545	-5,460	-1,968	1,000	968
2013	31,930	1,137	1,444	534	3,224	890	31,545	-5,460	-1,840	1,000	840
2014	32,516	1,397	1,444	534	3,381	933	31,545	-5,460	-2,123	1,000	1,123
2015	33,166	1,895	1,444	534	3,927	1,084	31,545	-6,462	-3,127	1,000	2,127
2016	33,810	2,365	1,444	534	3,927	1,084	31,545	-7,015	-3,854	1,000	2,854
2017	34,379	2,797	1,444	534	3,927	1,084	31,545	-7,015	-3,991	1,000	2,991
2018	34,816	3,203	1,444	534	3,927	1,084	31,545	-7,616	-4,622	1,000	3,622
2019	35,196	3,595	1,444	534	3,927	1,084	31,545	-7,616	-4,610	1,000	3,610
2020	35,570	3,949	1,444	534	3,927	1,084	31,545	-7,616	-4,629	1,000	3,629
2021	35,943	4,285	1,444	534	3,927	1,084	31,545	-7,616	-4,667	1,000	3,667

Because the economic study request specified that the New England RPS be satisfied, an accounting of expected RPS energy was needed to determine whether supplemental wind resources would be needed to meet these goals. Cases 2 and 4 included 3,000 MW of photovoltaics and 340 MW of CHP/G, plus enough additional wind to satisfy the RPS targets. Table 7-5 shows the RPS energy accounting and the development of the requirements (if any) for new wind to make up for any shortfall from renewable energy goals. The new, post-2011 RPS energy from new wind was added to the assumed photovoltaic energy and the combined heat and power energy to determine how much RPS energy was available. This was then compared to the goals. The difference determined the amount of additional wind needed to attain the RPS requirement. A negative “need” meant a surplus of RPS energy was available and no adjustment of the capacity assumptions would be needed.

Table 7-5
Case 1 and Case 2: Analysis of RPS GWh Target Compared with GWh of RPS-Eligible Resources—Base Energy Efficiency

Year	Post 2011 Queue Wind (GWh)	Post 2011 PV (GWh)	Post 2011 CHP (GWh)	Post 2011 Total RPS (GWh)	Regional Increase in New RPS relative to 2011	Total VT Renewables	Total Regional Renewable & EE Targets and Goals Relative to 2011 (GWh)	Surplus / Shortage (GWh)	Equivalent Wind Needed for Shortage (MW)
2012	4,136	407	45	4,589	1,345	355	1,701	2,888	N/A
2013	7,806	815	91	8,711	2,494	523	3,017	5,694	-1,917
2014	8,273	1,222	136	9,632	3,685	690	4,374	5,257	-1,770
2015	9,893	1,629	227	11,750	5,069	853	5,922	5,828	-1,962
2016	9,893	2,037	318	12,248	6,446	1,012	7,458	4,790	-1,613
2017	9,893	2,444	408	12,746	7,817	1,169	8,986	3,760	-1,266
2018	9,893	2,851	499	13,244	9,070	1,160	10,230	3,014	-1,015
2019	9,893	3,259	590	13,742	10,643	1,152	11,794	1,948	-656
2020	9,893	3,666	681	14,240	11,469	1,145	12,614	1,626	-548
2021	9,893	4,073	771	14,738	12,147	1,140	13,287	1,451	-489
	0.339	0.155	0.259						
		Capacity Factors							

Because assumed growth in PV, Wind and CHP/G exceeds increase in RPS relative to 2011
No additional wind resource needed

Table 7-6 shows the RPS energy accounting for the case with the double energy-efficiency growth rate. These two tables show that, with the assumptions for these cases, RPS energy would be adequate to meet the required new growth; therefore, no additional wind energy was needed to make up a shortfall.

Table 7-6
Case 3 and Case 4: Analysis of RPS GWh Target Compared with GWh of RPS-Eligible Resources—Base Energy Efficiency

Year	Post 2011 Queue Wind (GWh)	Post 2011 PV (GWh)	Post 2011 CHP (GWh)	Post 2011 Total RPS (GWh)	Regional Increase in New RPS relative to 2011	Total VT Renewables	Total Regional Renewable & EE Targets and Goals Relative to 2011 (GWh)	Surplus / Shortage (GWh)	Equivalent Wind Needed for Shortage (MW)
2012	4,136	407	45	4,589	1,345	355	1,701	2,888	-973
2013	7,806	815	91	8,711	2,494	523	3,017	5,694	-1,917
2014	8,273	1,222	136	9,632	3,685	690	4,374	5,257	-1,770
2015	9,893	1,629	227	11,750	4,934	837	5,772	5,978	-2,013
2016	9,893	2,037	318	12,248	6,155	976	7,130	5,117	-1,723
2017	9,893	2,444	408	12,746	7,349	1,107	8,457	4,289	-1,444
2018	9,893	2,851	499	13,244	8,412	1,081	9,493	3,751	-1,263
2019	9,893	3,259	590	13,742	9,770	1,056	10,826	2,916	-982
2020	9,893	3,666	681	14,240	10,401	1,035	11,436	2,804	-944
2021	9,893	4,073	771	14,738	10,888	1,015	11,903	2,835	-955
	0.339	0.155	0.259						
		Capacity Factors							

Because assumed growth in PV, Wind and CHP/G exceeds increase in RPS relative to 2011
No additional wind resource needed

Table 7-7 shows the development of Case 2, which has a modified capacity expansion with an enhanced RPS assumption that includes 3,000 MW of photovoltaics and 340 MW of CHP/G. Table 7-8 shows a similar development for the case with double energy-efficiency growth.

Table 7-7
Case 2: Enhanced RPS Energy-Efficiency Expansion Capacity Analysis—with Retirements

			PV Capacity Value	CHP Capacity Value		Wind Capacity Value		Heat Rate	Heat Rate
			0.394	1.000		0.276		8600 Btu/kWh	6000 Btu/kWh
Year	Surplus/Shortage	PV MW	PV QC	CHP	Make-up Wind	Wind QC	Surplus/Shortage	New CT (MW)	Advanced CC (MW)
2012	-1,968	300	118	20	0	0	-1,830	1,000	830
2013	-1,840	600	236	40	0	0	-1,563	1,000	563
2014	-2,123	900	355	60	0	0	-1,708	1,000	708
2015	-3,376	1,200	473	100	0	0	-2,803	1,000	1,803
2016	-4,338	1,500	591	140	0	0	-3,607	1,000	2,607
2017	-4,691	1,800	709	180	0	0	-3,802	1,000	2,802
2018	-5,525	2,100	827	220	0	0	-4,478	1,000	3,478
2019	-5,709	2,400	946	260	0	0	-4,503	1,000	3,503
2020	-5,905	2,700	1,064	300	0	0	-4,542	1,000	3,542
2021	-6,111	3,000	1,182	340	0	0	-4,589	1,000	3,589

Table 7-8
Case 4: Enhanced RPS with Double Energy-Efficiency Expansion Rate Capacity Analysis—with Retirements

			PV Capacity Value	CHP Capacity Value		Wind Capacity Value		Heat Rate	Heat Rate
			0.394	1.000		0.276		8600 Btu/kWh	6000 Btu/kWh
Year	Surplus/Shortage	PV MW	PV QC	CHP	Make-up Wind	Wind QC	Surplus/Shortage	New CT (MW)	Advanced CC (MW)
2012	-1,968	300	118	20	0	0	-1,830	1,000	830
2013	-1,840	600	236	40	0	0	-1,563	1,000	563
2014	-2,123	900	355	60	0	0	-1,708	1,000	708
2015	-3,127	1,200	473	100	0	0	-2,554	1,000	1,554
2016	-3,854	1,500	591	140	0	0	-3,123	1,000	2,123
2017	-3,991	1,800	709	180	0	0	-3,102	1,000	2,102
2018	-4,622	2,100	827	220	0	0	-3,575	1,000	2,575
2019	-4,610	2,400	946	260	0	0	-3,404	1,000	2,404
2020	-4,629	2,700	1,064	300	0	0	-3,266	1,000	2,266
2021	-4,667	3,000	1,182	340	0	0	-3,145	1,000	2,145

7.3 Location of Resources to Minimize Congestion

The results of the first part of the study can be used to map the location of the resources where congestion was minimized. These areas were shown in Table 5-2 for production costs and Table 5-3 for LSE energy-expense. Additions of resources within low-congestion areas are not expected to create significant congestion.

7.3.1 Case 1: Base Energy-Efficiency Expansion Capacity Analysis—With Retirements

Table 7-9 and Table 7-10 show the load/resource addition and removals for Case 1 superimposed on the map of the location effectiveness developed during the first part of the study. The green boxes on these maps indicate the number of megawatts removed, and the blue boxes indicate the number of megawatts added. The red diamonds indicate the resulting net change. This net change is the sum of additions and retirements. The location of the red diamond in each of the areas suggests that the amount of congestion would not be a problem.

Table 7-9
Net Capacity Additions on Production Cost Map—Case 1: Reference EE Growth with No PV and CHP/G

		"BASE" MW Added and Impacts Production Cost Compared to Unconstrained ($Million)													
		<= Resource Removals <= Load Increases							Resource Additions=> Load Decreases =>						
Sub Area	Most Constraining Interface	-2700	-2100	-1500	-1200	-900	-600	-300	300	600	900	1200	1500	2100	2700
BHE	Orrington South	2	1	1	1	1	1	1	2	4	15	43	143	372	595
ME	Surowiec South	2	1	1	1	2	1	1	2	3	9	24	73	276	499
SME	Maine-New Hampshire	2	1	1	1				2	3	3	7	14	65	229
NH	North/South	2	2	1					1	2	2	3	6	18	52
VT	North/South	2	2	1	1	2	1	1	1	1	2	3	5	14	39
WMA	N/A	3	2	2	1	2	1		1	1	1	1	1	1	1
CMAN	N/A	3	2	2	1	2	1	1						1	1
BOST	Boston Import	143	24	3											1
SEMA	SEMA/RI	3	2						1	1	1	1	1	4	9
RI	SEMA/RI	3	2						1	1	1	1	1	4	9
CT	N/A	2	2								1	1	1	1	1
SWCT	SWCT Import	104	4	2	1	2									1
NOR	Norwalk Import	7828	4675	1549	441	71			1	1	1	1	1	1	1

Import Limited > $100 Million | Import Limited > $10 Million | Unconstrained < 10 $Milllion | Bottled-in > $10 Million | Bottled-in > $100 Million

Retirement of resources | Addition of resources | Net change in resources

Table 7-10
Net Capacity Additions on LSE Expense Map—Case 1: Reference EE Growth with No PV and CHP/G

		"BASE" MW Added and Impacts LSE Enery Expense Compared to Unconstrained ($Million)													
		<= Resource Removals <= Load Increases							Resource Additions=> Load Decreases =>						
Sub Area	Most Constraining Interface	-2700	-2100	-1500	-1200	-900	-600	-300	300	600	900	1200	1500	2100	2700
BHE	Orrington South	4	1	1	0	2	0	0	8	70	181	229	282	493	662
ME	Surowiec South	4	1	1	0	2	0	0	8	63	127	171	122	154	323
SME	Maine-New Hampshire	4	1	1	0				9	63	103	127	180	178	29
NH	North/South	6	1	-1					1	19	45	56	74	146	91
VT	North/South	6	1	-1	-1	4	-1	0	1	12	33	40	49	119	75
WMA	North/South	12	5	-1	0	5	-1		0	0	-1	-1	-1	-1	-1
CMAN	North/South	13	7	1	1	5	-1	0						1	-1
BOST	Boston Import	828	56	0											-1
SEMA	SEMA/RI	12	6						0	0	-1	0	5	51	120
RI	SEMA/RI	9	5						0	0	-1	0	5	51	120
CT	N/A	12	4								-1	-1	-1	-1	-1
SWCT	SWCT Import	477	1	-1	1	5									-1
NOR	Norwalk Import	572	1518	2149	1265	317			0	0	-1	-1	-1	-1	-1

Import Limited > $100 Million | Import Limited > $10 Million | Unconstrained < 10 $Milllion | Bottled-in > $10 Million | Bottled-in > $100 Million

Retirement of resources | Addition of resources | Net change in resources

7.3.2 Case 2: Double Energy-Efficiency Growth Expansion Capacity Analysis—with Retirements

Table 7-11 and Table 7-12 show the load/resource addition and removals for Case 2 superimposed on the mapping of the location effectiveness developed during the first part of the study.

Table 7-11
Net Capacity Additions on Production Cost Map—Case 2: Reference EE Growth with PV and CHP/G

"BASE" MW Added and Impacts Production Cost Compared to Unconstrained ($Million)

		<= Resource Removals <= Load Increases							Resource Additions=> Load Decreases =>						
Sub Area	Most Constraining Interface	-2700	-2100	-1500	-1200	-900	-600	-300	300	600	900	1200	1500	2100	2700
BHE	Orrington South	2	1	1	1	1	1	1	2	4	15	43	143	372	595
ME	Surowiec South	2	1	1	1	2	1	1	2	3	9	24	73	276	499
SME	Maine-New Hampshire	2	1	1	1				2	3	3	7	14	65	229
NH	North/South	2	2	1					1	2	2	3	6	18	52
VT	North/South	2	2	1	1	2	1	1	1	1	2	3	5	14	39
WMA	N/A	3	2	2	1	2	1		1	1	1	1	1	1	1
CMAN	N/A	3	2	2	1	2	1	1				1	1	1	1
BOST	Boston Import	143	24	3											1
SEMA	SEMA/RI	3	2						1	1	1	1	1	4	9
RI	SEMA/RI	3	2						1	1	1	1	1	4	9
CT	N/A	2	2								1	1	1	1	1
SWCT	SWCT Import	104	4	2	1	2							1	1	1
NOR	Norwalk Import	7828	4675	1549	441	71			1	1	1	1	1	1	1

Import Limited > $100 Million | Import Limited > $10 Million | Unconstrained < 10 $Milllion | Bottled-in > $10 Million | Bottled-in > $100 Million

Retirement of resources | Addition of resources | Net change in resources

Table 7-12
Net Capacity Additions on LSE Expense Map—Case 2: Reference EE Growth with PV and CHP/G

"BASE" MW Added and Impacts LSE Enery Expense Compared to Unconstrained ($Million)

		<= Resource Removals <= Load Increases							Resource Additions=> Load Decreases =>						
Sub Area	Most Constraining Interface	-2700	-2100	-1500	-1200	-900	-600	-300	300	600	900	1200	1500	2100	2700
BHE	Orrington South	4	1	1	0	2	0	0	8	70	181	229	282	493	662
ME	Surowiec South	4	1	1	0	2	0	0	8	63	127	171	122	154	323
SME	Maine-New Hampshire	4	1	1	0				9	63	103	127	180	178	29
NH	North/South	6	1	-1					1	19	45	56	74	146	91
VT	North/South	6	1	-1	-1	4	-1	0	1	12	33	40	49	119	75
WMA	North/South	12	5	-1	0	5	-1		0	0	-1	-1	-1	-1	-1
CMAN	North/South	13	7	1	1	5	-1	0				1	-1	-1	-1
BOST	Boston Import	828	56	0											-1
SEMA	SEMA/RI	12	6						0	0	-1	0	5	51	120
RI	SEMA/RI	9	5						0	0	-1	0	5	51	120
CT	N/A	12	4								-1	-1	-1	-1	-1
SWCT	SWCT Import	477	1	-1	1	5							-1	-1	-1
NOR	Norwalk Import	572	1518	2149	1265	317			0	0	-1	-1	-1	-1	-1

Import Limited > $100 Million | Import Limited > $10 Million | Unconstrained < 10 $Milllion | Bottled-in > $10 Million | Bottled-in > $100 Million

Retirement of resources | Addition of resources | Net change in resources

7.3.3 Case 3: Enhanced RPS Energy-Efficiency Expansion Capacity Analysis—with Retirements

Table 7-13 and Table 7-14 show the load/resource addition and removals for Case 3 superimposed on the mapping of the location effectiveness developed during Part 1.

Table 7-13
Net Capacity Additions on Production Cost Map—Case 3: Double EE Growth with No PV or CHP/G

		"BASE" MW Added and Impacts Production Cost Compared to Unconstrained ($Million)													
		<= Resource Removals <= Load Increases							Resource Additions=> Load Decreases =>						
Sub Area	Most Constraining Interface	-2700	-2100	-1500	-1200	-900	-600	-300	300	600	900	1200	1500	2100	2700
BHE	Orrington South	2	1	1	1	1	1	1	2	4	15	43	143	372	595
ME	Surowiec South	2	1	1	1	2	1	1	2	3	9	24	73	276	499
SME	Maine-New Hampshire	2	1	1	1				2	3	3	7	14	65	229
NH	North/South	2	2	1					1	2	2	3	6	18	52
VT	North/South	2	2	1	1	2	1	1	1	1	2	3	5	14	39
WMA	N/A	3	2	2	1	2	1		1	1	1	1	1	1	1
CMAN	N/A	3	2	2	1	2	1	1						1	1
BOST	Boston Import	143	24	3										1	1
SEMA	SEMA/RI	3	2						1	1	1	1	1	4	9
RI	SEMA/RI	3	2						1	1	1	1	1	4	9
CT	N/A	2	2								1	1	1	1	1
SWCT	SWCT Import	104	4	2	1	2						1	1	1	1
NOR	Norwalk Import	7828	4675	1549	441	71			1	1	1	1	1	1	1

Import Limited > $100 Million | Import Limited > $10 Million | Unconstrained < 10 $Milllion | Bottled-in > $10 Million | Bottled-in > $100 Million

Retirement of resources | Addition of resources | Net change in resources

Table 7-14
Net Capacity Additions on LSE Expense Map—Case 3: Double EE Growth with No PV or CHP/G

		"BASE" MW Added and Impacts LSE Enery Expense Compared to Unconstrained ($Million)													
		<= Resource Removals <= Load Increases							Resource Additions=> Load Decreases =>						
Sub Area	Most Constraining Interface	-2700	-2100	-1500	-1200	-900	-600	-300	300	600	900	1200	1500	2100	2700
BHE	Orrington South	4	1	1	0	2	0	0	8	70	181	229	282	493	662
ME	Surowiec South	4	1	1	0	2	0	0	8	63	127	171	122	154	323
SME	Maine-New Hampshire	4	1	1	0				9	63	103	127	180	178	29
NH	North/South	6	1	-1					1	19	45	56	74	146	91
VT	North/South	6	1	-1	-1	4	-1	0	1	12	33	40	49	119	75
WMA	North/South	12	5	-1	0	5	-1		0	0	-1	-1	-1	-1	-1
CMAN	North/South	13	7	1	1	5	-1	0						-1	-1
BOST	Boston Import	828	56	0										-1	-1
SEMA	SEMA/RI	12	6						0	0	-1	0	5	51	120
RI	SEMA/RI	9	5						0	0	-1	0	5	51	120
CT	N/A	12	4								-1	-1	-1	-1	-1
SWCT	SWCT Import	477	1	-1	1	5						-1	-1	-1	-1
NOR	Norwalk Import	572	1518	2149	1265	317			0	0	-1	-1	-1	-1	-1

Import Limited > $100 Million | Import Limited > $10 Million | Unconstrained < 10 $Milllion | Bottled-in > $10 Million | Bottled-in > $100 Million

Retirement of resources | Addition of resources | Net change in resources

7.3.4 Case 4: Enhanced RPS with Double Energy-Efficiency Expansion Capacity Analysis—with Retirements

Table 7-15 and Table 7-16 show the load/resource addition and removals for Case 4 superimposed on the mapping of the location effectiveness developed during the first part.

Table 7-15
Net Capacity Additions on Production Cost Map—Case 4: Double EE Growth with PV and CHP/G

		"BASE" MW Added and Impacts Production Cost Compared to Unconstrained ($Million)													
		<= Resource Removals <= Load Increases							Resource Additions=> Load Decreases =>						
Sub Area	Most Constraining Interface	-2700	-2100	-1500	-1200	-900	-600	-300	300	600	900	1200	1500	2100	2700
BHE	Orrington South	2	1	1	1	1	1	1	2	4	15	43	143	372	595
ME	Surowiec South	2	1	1	1	2	1	1	2	3	9	24	73	276	499
SME	Maine-New Hampshire	2	1	1	1				2	3	3	7	14	65	229
NH	North/South	2	2	1					1	2	2	3	6	18	52
VT	North/South	2	2	1	1	2	1	1	1	1	2	3	5	14	39
WMA	N/A	3	2	2	1	2	1		1	1	1	1	1	1	1
CMAN	N/A	3	2	2	1	2	1	1			1	1	1	1	1
BOST	Boston Import	143	24	3									1	1	1
SEMA	SEMA/RI	3	2						1	1	1	1	1	4	9
RI	SEMA/RI	3	2						1	1	1	1	1	4	9
CT	N/A	2	2								1	1	1	1	1
SWCT	SWCT Import	104	4	2	1	2					1	1	1	1	1
NOR	Norwalk Import	7828	4675	1549	441	71			1	1	1	1	1	1	1

Import Limited > $100 Million; Import Limited > $10 Million; Unconstrained < 10 $Milllion; Bottled-in > $10 Million; Bottled-in > $100 Million
Retirement of resources; Addition of resources; Net change in resources

Table 7-16
Net Capacity Additions on LSE Expense Map—Case 4: Double EE Growth with PV and CHP/G

		"BASE" MW Added and Impacts LSE Enery Expense Compared to Unconstrained ($Million)													
		<= Resource Removals <= Load Increases							Resource Additions=> Load Decreases =>						
Sub Area	Most Constraining Interface	-2700	-2100	-1500	-1200	-900	-600	-300	300	600	900	1200	1500	2100	2700
BHE	Orrington South	4	1	1	0	2	0	0	8	70	181	229	282	493	662
ME	Surowiec South	4	1	1	0	2	0	0	8	63	127	171	122	154	323
SME	Maine-New Hampshire	4	1	1	0				9	63	103	127	180	178	29
NH	North/South	6	1	-1					1	19	45	56	74	146	91
VT	North/South	6	1	-1	-1	4	-1	0	1	12	33	40	49	119	75
WMA	North/South	12	5	-1	0	5	-1		0	0	-1	-1	-1	-1	-1
CMAN	North/South	13	7	1	1	5	-1	0			-1	-1	-1	-1	-1
BOST	Boston Import	828	56	0									-1	-1	-1
SEMA	SEMA/RI	12	6						0	0	-1	0	5	51	120
RI	SEMA/RI	9	5						0	0	-1	0	5	51	120
CT	N/A	12	4								-1	-1	-1	-1	-1
SWCT	SWCT Import	477	1	-1	1	5					-1	-1	-1	-1	-1
NOR	Norwalk Import	572	1518	2149	1265	317			0	0	-1	-1	-1	-1	-1

Import Limited > $100 Million; Import Limited > $10 Million; Unconstrained < 10 $Milllion; Bottled-in > $10 Million; Bottled-in > $100 Million
Retirement of resources; Addition of resources; Net change in resources

7.4 Economic Metrics

Figure 7-2 and Figure 7-3 show the trend in the economic metrics for these cases. Figure 7-2 shows that the production costs are tending to decline, which reflects both the trend of the natural gas price as well as the impact of an increase in the assumed amount of energy efficiency, wind energy, and other renewables. Figure 7-1 showed that with the base energy-efficiency forecast, the number of gigawatt-hours of energy across the study period was nearly constant. After accounting for wind energy, the energy production, from fuel-consuming resources decreased slightly.

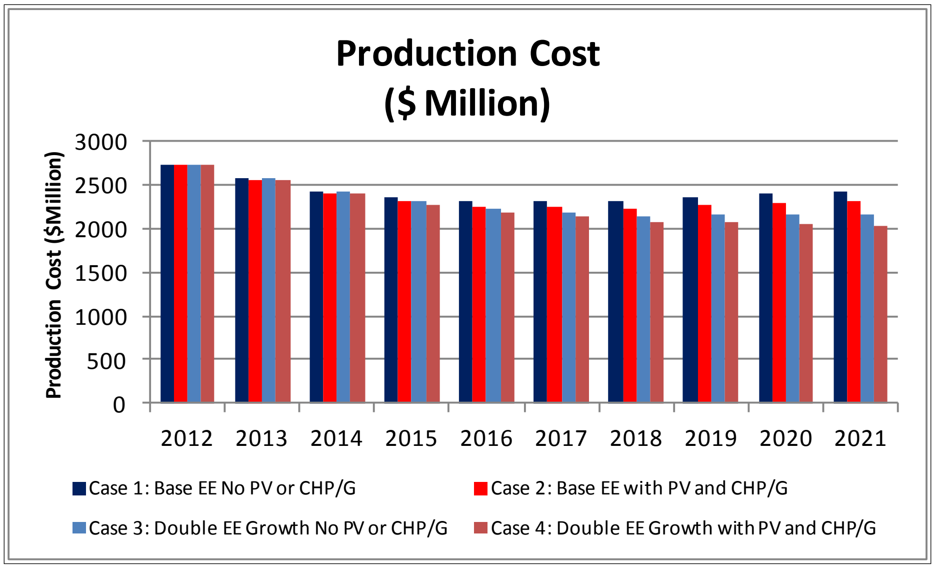

Figure 7-2: Production costs for the four cases (million 2008 $).

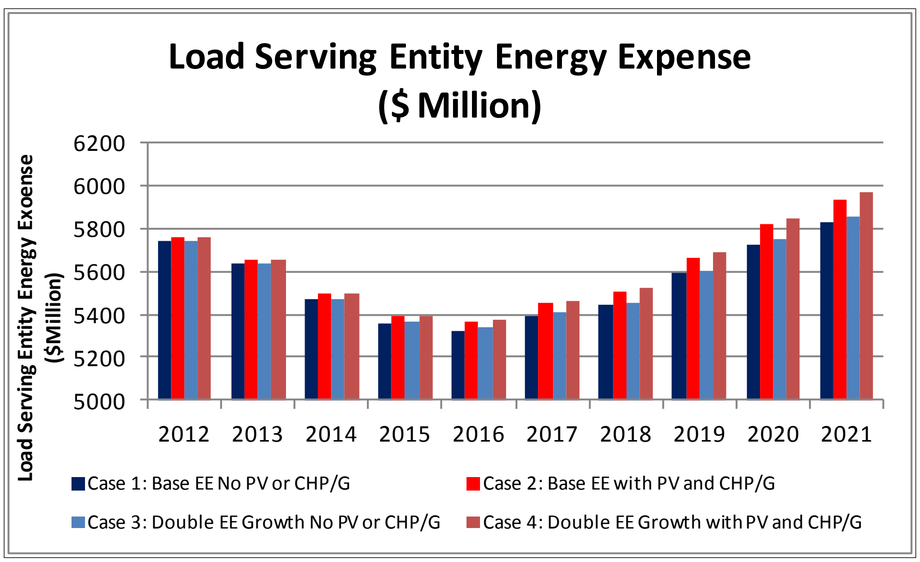

Figure 7-3: Load-serving entity energy expenses for the four cases (million 2008 $).

In aggregate, the total production cost of these fuel-consuming resources continued to decline in light of increased wind energy production. In the cases with the double energy-efficiency growth rate (Cases 3 and 4), the amount of energy also declined before the effect of the wind energy was included. By 2021, the range of the production cost metric among these four cases is about $400 million dollars.

The effect of doubling the growth rate of energy efficiency (Cases 3 and 4 compared with Cases 1 and 2, respectively) was to reduce the production cost metric by about $300 million per year. The effect of the photovoltaics and CHP/G (Cases 2 and 4 compared with Cases 1 and 3, respectively) was to reduce the production cost metric by approximately $150 million dollars per year.

Figure 7-3 shows that the LSE energy-expense tended to decline through 2016 before rising again in the latter half of the study period. The scale is magnified so that these changes appear large when, in fact, they are relatively small.

The effect of the photovoltaics and CHP/G was to increase the LMPs slightly and thereby increase the LSE energy expense. This can be seen by comparing Case 1 versus Case 2 and Case 3 versus Case 4. This occurred because the photovoltaics and CHP/G precluded the installation of the newer, combined-cycle capacity. These combined-cycle units had lower dispatch costs, which resulted in more gigawatt-hours of energy production that would tend to depress the LMP.

Doubling the growth rate of energy efficiency resulted in increases in the LSE energy-expense because of less energy from advanced combined-cycle units.

7.5 Contribution to Fixed-Cost Metric

The net revenues a resource earns from energy revenues can indicate the relative economic viability of a new or existing resource. In general, if a generating unit can produce energy for a lower cost than the locational energy price, it will have an incentive to produce the energy and earn income. Likewise, if the generating unit's cost of production is higher than the locational energy price, it has an incentive not to produce. A generating unit's earnings from producing energy (i.e., the difference between its cost of production and the prevailing energy price) can be summed across the year to develop a metric referred to as the "contribution to fixed costs."

Figure 7-4 shows the contribution to fixed costs that a typical 7,300 Btu/kWh natural gas combined-cycle generator could earn in the energy market for each of the four cases. The declining amount of contribution to fixed costs over the study horizon is due to a narrowing of the prevailing market clearing prices and the cost of natural gas. In each of the four cases, additional advanced combined-cycle units were being added throughout the study period. The cases with double energy-efficiency growth rates (Case 3 and Case 4) show that the contribution to fixed costs was mostly constant in the last half of the study years.

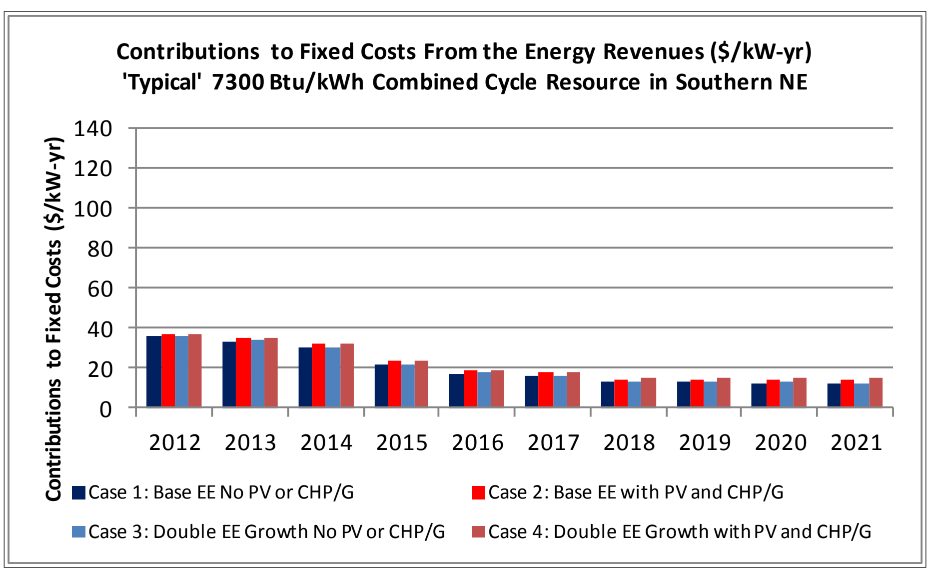

Figure 7-4: Contribution to fixed costs (million 2008 $); combined-cycle unit in southern New England.

The results show that adding resources to produce energy at costs lower than the prevailing energy market price puts downward pressure on the clearing prices. Typical wind resources and typical natural gas, combined-cycle resources would realize slightly lower revenues in the mid-years of this study and rise slightly in the later years. Even the most efficient new resources (e.g., an advanced combined-cycle, natural-gas-fired generator) would be challenged to continue operating based on the economic results of this study. For some resources, the reduction in energy revenues could be the driver behind a generator's decision to retire. As with all resources, this contribution to fixed costs from energy market revenues provides insight about the extent to which the available revenue streams would be sufficient to support resources.

As the LSE energy-expense metric showed, the cases with more photovoltaic and CHP/G (Case 2 and Case 4) had slightly higher LMPs, and the contribution to fixed costs in these cases were slightly higher.

Figure 7-5 and Figure 7-6 show the contribution to fixed costs that an inland wind resource could earn in the energy market in the four cases. With transmission constraints, the value would be lower in areas of New England where transmission impedes the export flow of energy. Figure 7-5 shows the contribution to fixed costs for wind in northern New Hampshire. The 2012 values are higher than the subsequent years. The values for 2013 to 2021 are lower because a new wood-fueled resource was assumed to be installed in this area in early 2013, and this created export congestion and frequently low prices in the exporting area.

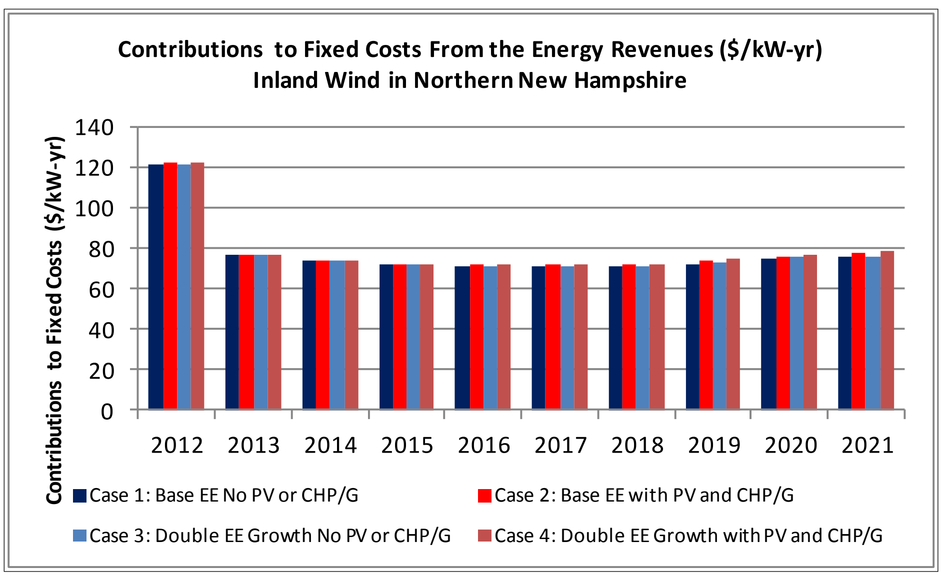

Figure 7-5: Contribution to fixed costs (million 2008 $); inland wind in northern New Hampshire.

Figure 7-6 shows the contributions to fixed costs for wind in northern Maine, which are relatively constant across the study period compared with the wind in northern New Hampshire. While energy prices were substantially lower in the occasional instances of congestion, in northern Maine, the number of the congested hours was approximately constant across the study period.

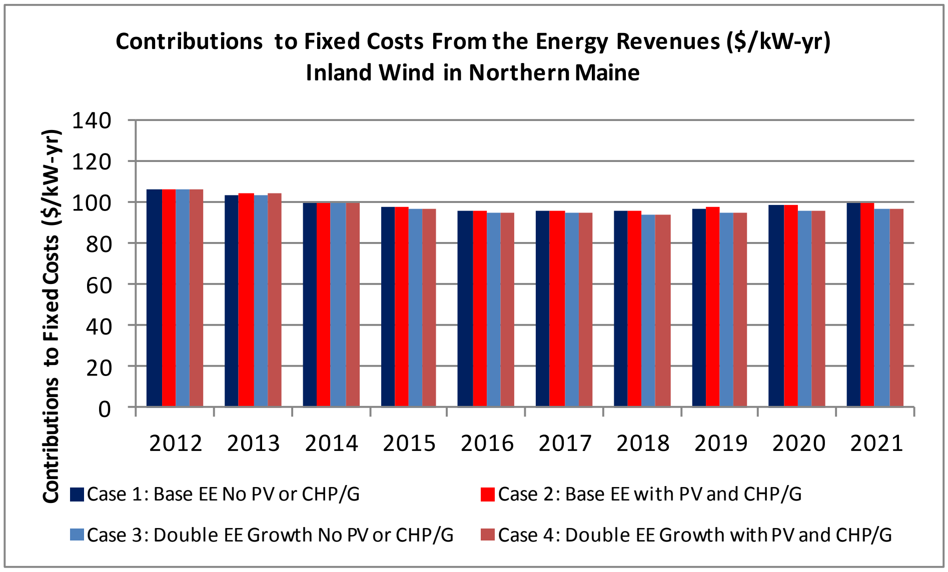

Figure 7-6: Contribution to fixed costs (million 2008 $); inland wind in Northern Maine.

Figure 7-7 shows the contribution to fixed costs for energy efficiency in southern New England. These contributions are in the range of $225 to $250/kW-year, which is substantially higher than for wind because of the much higher amount of energy attributable to EE, as indicated by the capacity factor. For example, the capacity factor of the wind in Figure 7-5 and Figure 7-6 is only about 34% compared with an approximate 70% capacity factor for energy efficiency.

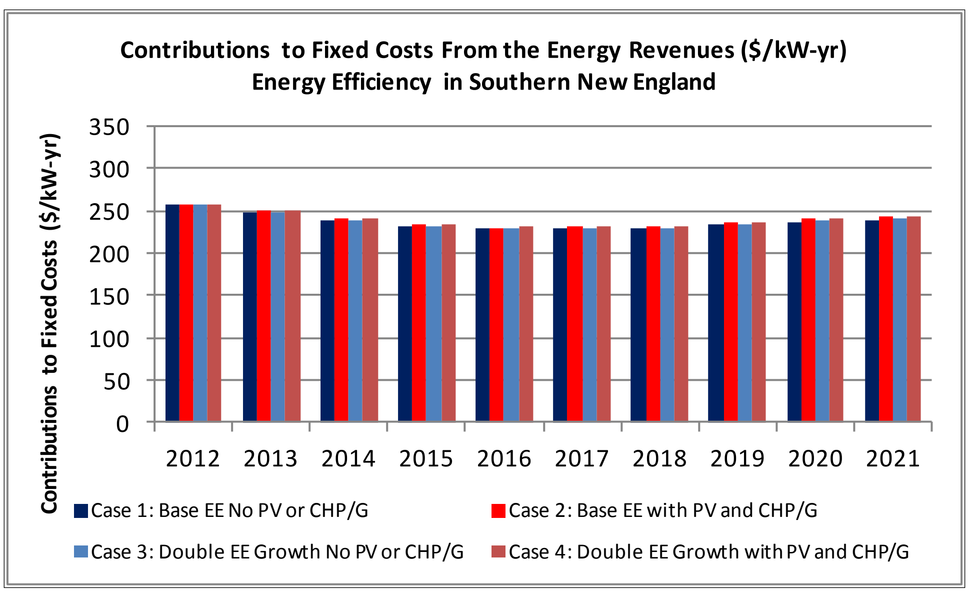

Figure 7-7: Contribution to fixed costs (million 2008 $); energy efficiency in southern New England.

7.6 Congestion Metric Based on FTR/ARR Methodology

The approach used in this study allowed the congestion associated with adding resources in various areas of New England to be quantified. The following figures show that the amount of congestion was relatively small and arose primarially from wind development areas of New England that were not central to of this analysis. These wind development areas had constant amounts of installed wind capacity resulting in congestion that was effectively constant among the cases.

As shown in Figure 7-8 through Figure 7-11 only three interfaces showed nonzero congestion. The interface with the greatest amount of congestion is associated with the Wyman/Bigelow export interface, which had 597 MW of wind capacity installed behind a 350 MW export interface. This interface exhibits congestion because the amount of wind in the active queue case frequently exceeded the export capability of this interface in many hours. No additional resources were added behind this interface for this part of the study.

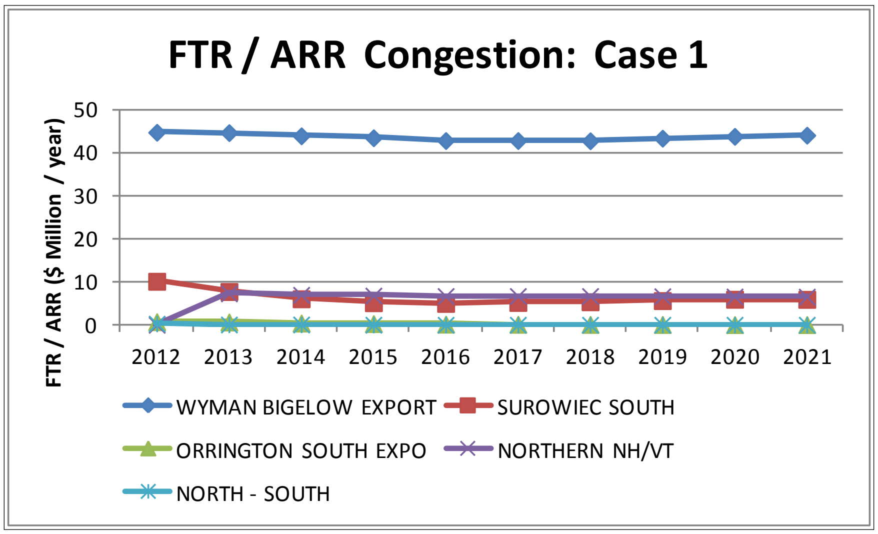

Figure 7-8: FTR/ARR congestion metric—Case 1: base EE, no PV or CHP/G.

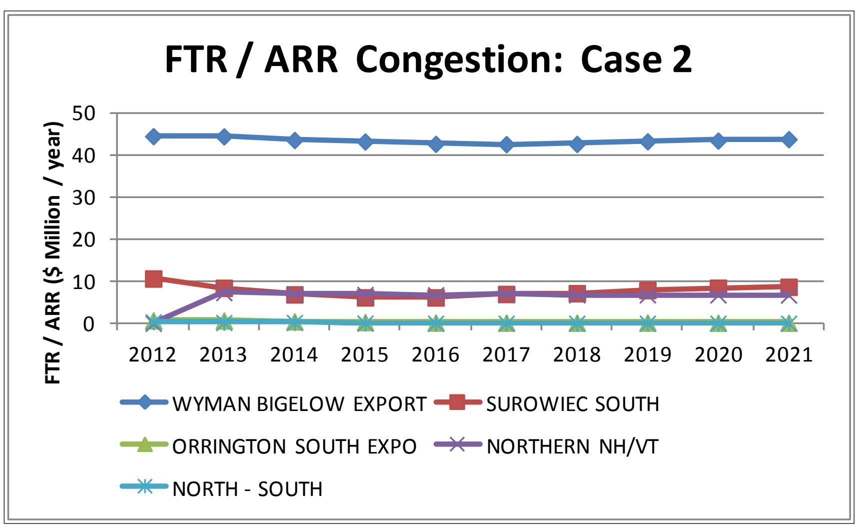

Figure 7-9: FTR/ARR congestion metric—Case 2: base EE with PV and CHP/G.

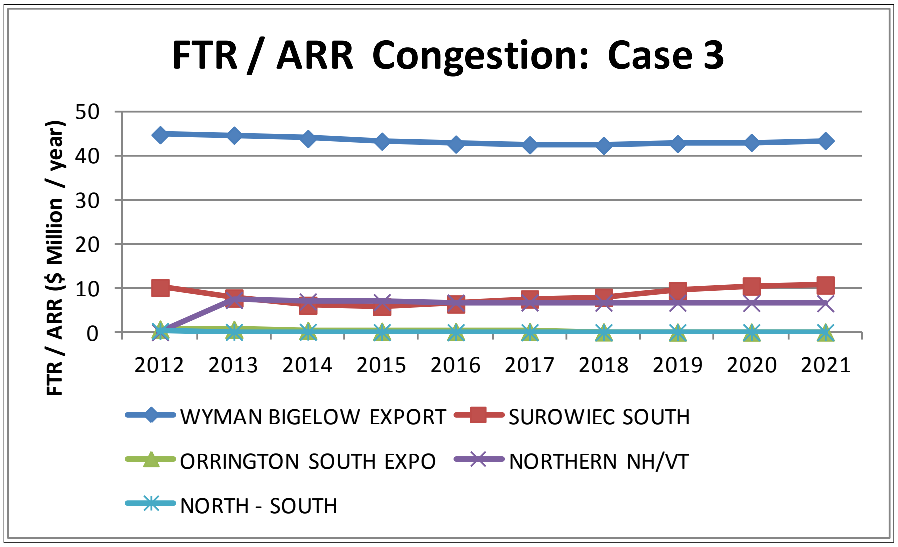

Figure 7-10: FTR/ARR congestion metric—Case 3: double EE with no PV or CHP/G.

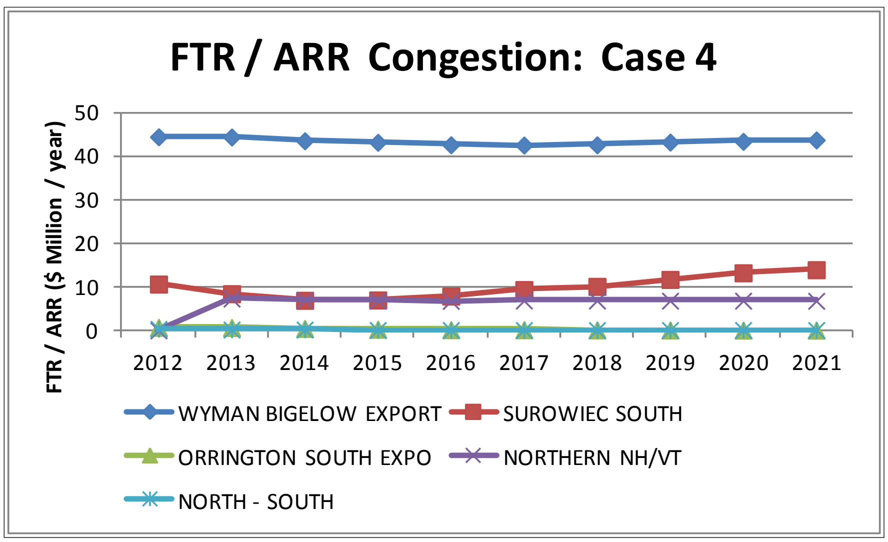

Figure 7-11: FTR/ARR congestion metric—Case 4: Double EE with PV and CHP/G.

The interface with the second-greatest amount of congestion was associated with the Surowiec South interface. This interface exhibited congestion because the amount of wind in the Active Queue Case (597 MW behind Wyman Bigelow export interface, 191 MW behind the Rumford export interface and 1257 MW in Northern Maine) caused the interface to be binding in many hours. No additional resources were added behind this interface.

The interface with the third-largest amount of congestion was associated with the Northern New Hampshire/Vermont Export interface (also known as Coos County export). This interface exhibited congestion because the amount of wind in the Active Queue Case (134 MW behind the Northern New Hampshire 140 MW export interface) caused the interface to be binding in many hours after a new wood-fueled resource was installed within this area in early 2013. No additional resources were added behind this interface as part of this study.

7.7 Fuel Consumption Metric

A broad metric that characterizes these four cases is the amount of energy generated by fuel type. The cases were assumed to retire most of the oil, coal, and less-efficient natural-gas-fueled steam resources. Figure 7-12 to Figure 7-15 compare the fuel categories, listed below, across the study horizon:

- Other
- CHP/G
- PV
- Wind
- Oil
- Natural gas
- Energy efficiency and active demand resources
- Coal
- Nuclear
- Biomass and municipal solid waste

Biomass and nuclear energy are shown at the bottom of each stacked bar graph (they are constant across the study period). The next-higher resource in the graphs is coal, which is nonexistent after 2012 when the last of the coal units was assumed to retire based on age. Energy efficiency is shown next, and its value reflects the changes in scenario assumptions across the years and between cases. The next fuel category is natural gas, which shows a significant amount of energy in each of the years. The next-higher category in the figures is wind, which increases over time as more wind capacity is assumed to become operational. Energy from photovoltaic and CHP/G are small and become noticeable in Case 2 and Case 4.

Figure 7-12 shows the results for Case 1, which is characterized by slowly growing energy efficiency and wind. Natural gas energy is roughly constant across the study horizon. Figure 7-13 shows the results for Case 2, which also is characterized by slowly growing energy efficiency and wind. Like in Case 1, natural gas energy is roughly constant across the study horizon of Case 2. Figure 7-14 shows the results for Case 3, and Figure 7-15 shows the results for Case 4. These last two figures illustrate the reduction in natural gas consumption that results from doubling the energy-efficiency growth rate beginning in 2015.

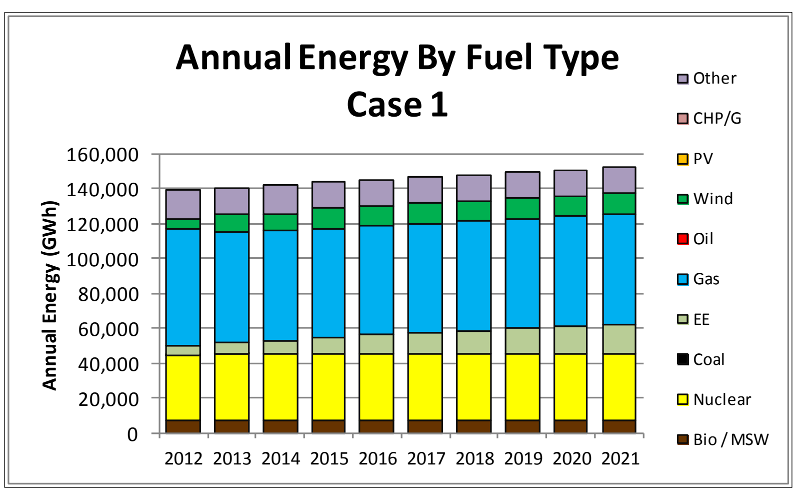

Figure 7-12: Fuel consumption by fuel type for the energy-efficiency case—with retirements (GWh).

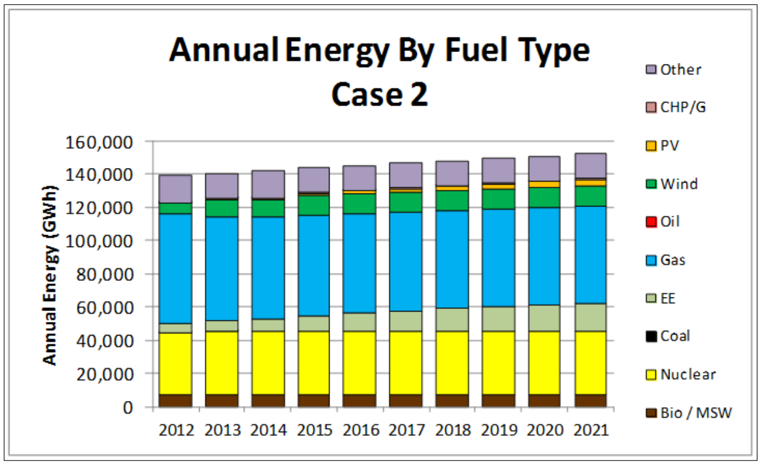

Figure 7-13: Fuel consumption by fuel type for the energy-efficiency case—with retirements and with PV and CHP/G (GWh).

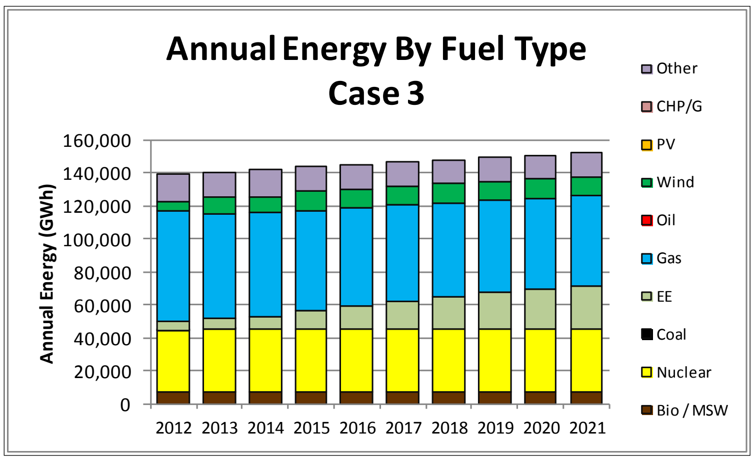

Figure 7-14: Fuel consumption by fuel type for the case with the double energy-efficiency growth rate (GWh).

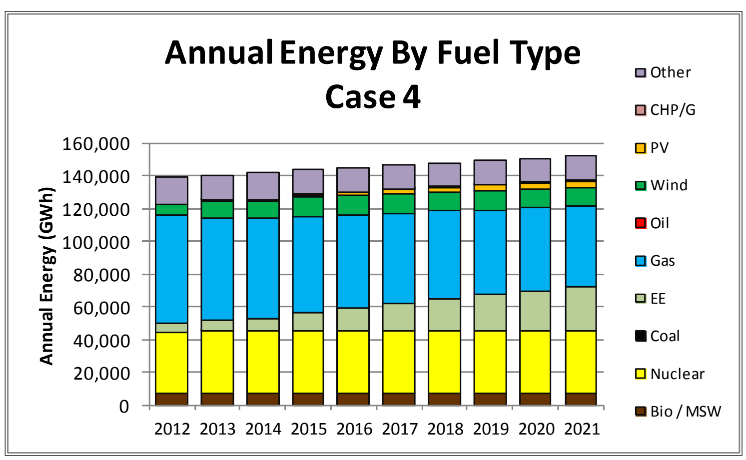

Figure 7-15: Fuel consumption by fuel type for the double energy-efficiency growth rates—with retirements and With PV and CHP/G (GWh).

7.8 Environmental Metrics

One of the key reasons for developing these four cases was to demonstrate the impacts these alternative expansion plans would have on carbon and other emissions. The 2011 economic study presented results for the annual emissions from several levels of assumed wind penetration. The most comparable of the 2011 Economic Study cases to these four cases is the Active Queue Case that assumed 3,927 MW of installed wind.[29] The results for that case showed the following for the Unconstrained Case for 2016:

- 41.8 million tons of CO_2
- 17.0 thousand tons of NO_X
- 16.5 thousand tons of SO_2

The results for this 2012 analysis show much lower emissions with the retirement of residual oil, coal, and natural gas steam units and their replacement with significantly more efficient natural gas units.

Figure 7-16 shows a downward trend for CO_2 emissions in all cases as a result of the increased amount of energy efficiency over the study period. By 2021, the range of CO_2 emissions is 27 to 31 million tons, which is significantly less than the 41.8 million tons of CO_2 emissions for the 2011 Economic Study case for 2016. The effect of doubling the growth rate of energy efficiency (in Cases 3 and 4 compared with Cases 1 and 2, respectively) is to reduce emissions by about 3 million additional tons per year (tons/yr). The effect of the photovoltaics and CHP/G (Cases 2 and 4 compared with Cases 1 and 3, respectively) is to reduce CO_2 emissions by approximately 1 million additional tons/yr.

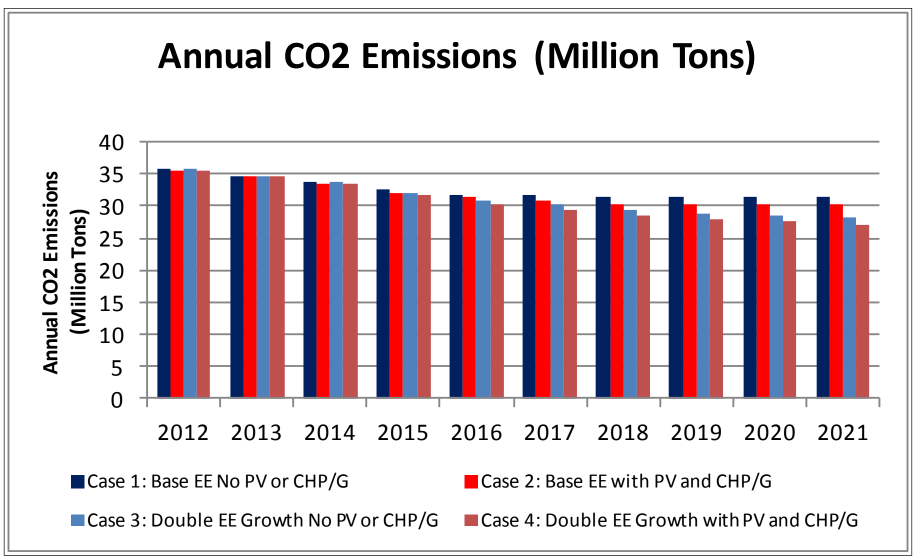

Figure 7-16: Annual CO_2 emissions for the four cases (million tons).

[29] *Economic Studies Update Preliminary Results*, PAC presentation (February 15, 2012), page 71, results for the "All Active Wind Unconstrained Case," http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2012/feb152012/eco_studies_update.pdf.

Figure 7-17 shows that the trend for NO_X emissions is downward in all cases as a result of the increasing amount of energy efficiency over the study period and the addition of efficient and low-NO_X-emitting combined-cycle units. By 2021, the range of NO_X emissions is 11 to 12 thousand tons, which is significantly less than the 17.0 thousand tons of NO_X for the 2011 Economic Study case for 2016. The effect of doubling the growth rate of energy efficiency in (Cases 3 and 4 compared with Cases 1 and 2, respectively) is to reduce NO_X emissions by about 500 additional tons/yr. The effect of the photovoltaics and CHP/G (Cases 2 and 4 compared with Cases 1 and 3, respectively) is to reduce NO_X emissions by approximately 100 additional tons/yr.

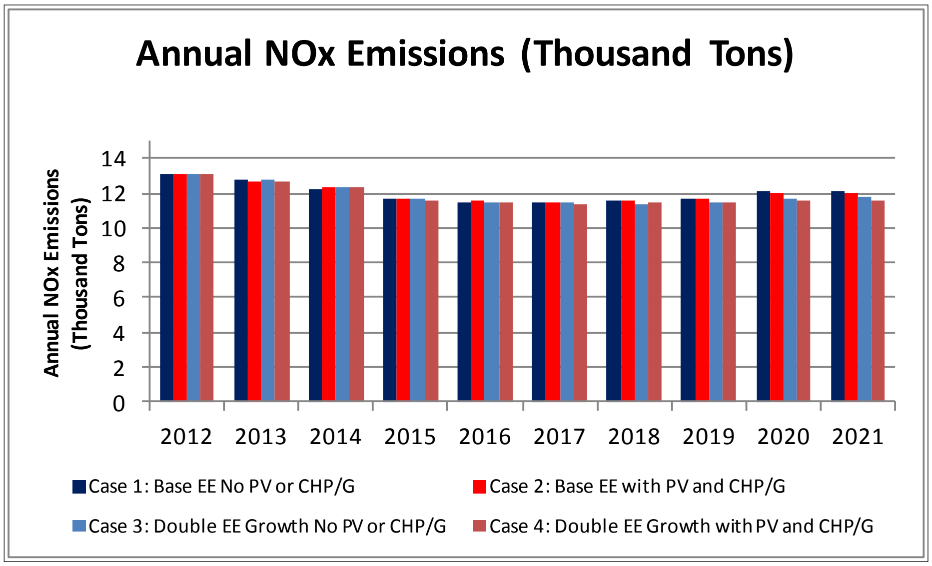

Figure 7-17: Annual NO_X emissions for the four cases (thousand tons).

Figure 7-18 shows that the SO_2 emissions in all cases are eliminated as a result of the retirement of residual oil and coal steam units and their replacement with significantly more efficient natural gas units, which effectively do not emit significant amounts of sulfur.

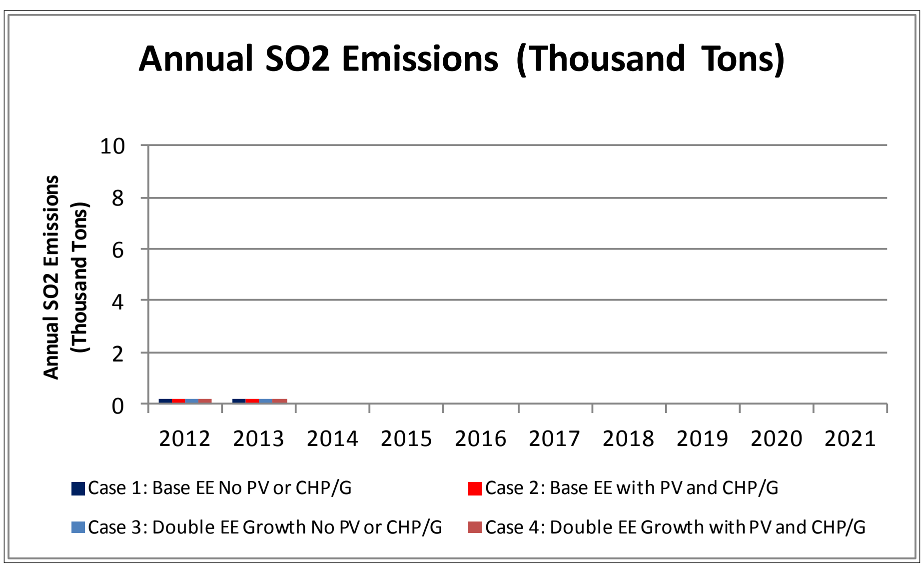

Figure 7-18: Annual SO_2 emissions for the four cases (thousand tons).

Section 8
Observations

The ISO made a number of observations from the three parts of this study:

From the first part of the study:

- Adding resources (or decreasing loads) in export-constrained areas creates bottled-in resources and congestion.
- Removing resources (or increasing loads) in import-constrained areas created congestion.
- Because of different capacity factors, the type of resource added or removed affected the magnitude of the changes in production costs and LSE energy expenses.
- "Better" and "worse" places for resource additions and removals can be quantified based on congestion.
- As a regionwide economic metric, LSE energy expense is less stable than the production cost metric.

From the second part of the study:

- An advanced combined-cycle unit with low financing and capital costs would be nearly able to support itself on energy market revenues.
- A conventional simple-cycle combustion turbine operating at a capacity factor of up to 20% would not be able to recover its capital investment costs from energy market revenues alone. This suggests that these resources would need additional revenues streams from markets such as the Forward Reserve and Forward Capacity Markets.
- Energy-efficiency resources with typical energy-efficiency program costs can recover their capital investment costs from energy market revenues. The wide range of technology costs suggests that the energy savings alone makes some technologies economic, while other technologies may require revenues derived from other market streams.
- If only the metering costs were considered, demand-response resources would be able to recover their capital investment costs from energy market revenues. The viability of the end-user technologies necessary to manage the customer-side loads is not known and was not evaluated as part of this study.
- Photovoltaics, which are assumed to operate at a capacity factor of approximately 15%, would not be able to recover its capital investment costs from energy market revenues. This suggests that these resources would need additional revenues streams, such as from the Forward Capacity Market and from Renewable Energy Credits.
- Onshore and offshore wind resources would not be able to recover their capital investment costs from energy market revenues alone. This suggests that these resources would need additional revenues streams, such as the Forward Capacity Market and Renewable Energy Credits.
- The results for smart grid, which has a profile with characteristics similar to pumped storage (an energy-storage technology) show that increased penetration leads to a sharp decline in the net energy revenues because the cost of the off-peak energy (including losses) begins to outweigh the on-peak revenues.

- Combined heat and power/geothermal systems can provide a significant contribution to fixed costs. However, the technology that would be used to produce this CHP/G load shape is uncertain, and therefore the investment cost thresholds are not definitive.

From the third part of the study:

- Adding resources to produce energy at costs lower than the prevailing market clearing price puts downward pressure on energy market clearing prices.
- In a framework where there is a constant reserve margin, significant changes in resources did not result in significant changes in economic metrics.
- With the assumptions in these cases, the growth in RPS energy is adequate to meet the mandated new RPS requirements.
- The FTR/ARR congestion metric showed little variation among the cases.
- Emissions were much lower with the retirement of residual oil, coal, and natural gas steam units and their replacement with significantly more efficient, low-emitting, natural gas units:.
    - By 2021, the range of CO_2 emissions is 27 to 31 million tons, which is significantly less than the 41.8 million tons of CO_2 resulting from the 2011 Economic Study case for 2016.
    - The effect of doubling the growth rate of energy efficiency reduces emissions by about 3 million tons/yr. The effect of the photovoltaics and CHP/G reduces CO_2 emissions by approximately 1 million tons/yr.
    - By 2021, the range of NO_X emissions is 11 to 12 thousand tons, which is significantly less than the 17 thousand tons of NO_X resulting from the 2011 Economic Study case for 2016.
    - The trend for NO_X emissions in all cases is downward as a result of the increasing amount of energy efficiency over the study period and the addition of efficient and low-NO_X-emitting combined-cycle units.
    - The effect of doubling the growth rate of energy efficiency is to reduce emissions by about 500 tons/yr. The effect of the photovoltaics and CHP/G is to reduce NO_X emissions by approximately 100 tons/yr.
    - The SO_2 emissions in all cases are eliminated as a result of the retirement of residual oil and coal steam units and their replacement with significantly more efficient natural gas units.

