2013 Economic Study

System Planning | Resource Adequacy

October 30, 2014

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Nomenclature

Nomenclature used in this report.[1]

ACP	alternative compliance payments associated with Renewable Portfolio Standards
BAA	balancing authority area
BHE	Bangor Hydro Energy (i.e., northern Maine)
BIT	anthracite coal and bituminous coal
BLQ	black liquor (Biomass)
BIO	fuel type for wood and other organic biomass used as a combustion fuel
BOS	RSP Area—Greater Boston, including the North Shore
CF	capacity factor
CMA/NEMA	RSP area—Central Massachusetts/Northeastern Massachusetts
CMP	Central Maine Power
CSC	Cross-Sound Cable
CT	combustion turbine
CT	RSP area—northern and eastern Connecticut
CTFC	contributions to fixed costs
DARD	dispatchable asset-related demand
DFO	distillate fuel oil
DG	distributed generation
DR	demand resources
EE	energy efficiency
EFOR	equivalent forced-outage rate
EGBH	location for real-time emergency generation concentrated in the BHE RSP area
EGCT	location for real-time emergency generation concentrated in the CT, SWCT, and NOR RSP areas
EGMA	location for real-time emergency generation concentrated in the BOS, CMA, and WMA RSP areas
EGME	location for real-time emergency generation concentrated in the ME RSP area
EGSM	location for real-time emergency generation concentrated in the SME RSP area
EMS	Energy Management System network model
FCA	Forward Capacity Auction
FO2	fuel oil (number 2)

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

FO6	fuel oil (number 6)
GADS	Generating Availability Data System
GSU	generator step-up unit
GV	GridView
GWh	gigawatt-hours
HVDC	high-voltage direct current
ICR	Installed Capacity Requirement
IROL	Interconnection Reliability Operating Limit
JF	jet fuel
KER	kerosene
LFG	landfill gas
LMP	locational marginal price
LOS	loss of source
LSE	load-serving entity
LSP	Local System Plan
MBtu	million British thermal units (frequently referred as MMBtu with 'M' representing thousands)
MOD	Model on Demand database
MPRP	Maine Power Reliability Project
MSW	municipal solid waste
MW	megawatt(s)
MWh	megawatt-hour
NESCOE	New England States Committee on Electricity
NEWIS	New England Wind-Integration Study
NGCC	natural gas combined cycle
NH	RSP area—northern, eastern, and central New Hampshire/eastern Vermont and southwestern Maine
NOR	RSP area—Norwalk/Stamford, Connecticut
NUC	nuclear
NNC	Norwalk–Northport
OATT	*Open Access Transmission Tariff*
OBG	other biomass gas—includes digester gas, methane, and other biomass gasses
PAC	Planning Advisory Committee
PSSE	Transmission Planning Network Model
REC	Renewable Energy Certificates
RENEW	Renewable Energy New England

RFO	residual fuel oil
RI	RSP area—Rhode Island/bordering MA
RSP	Regional System Plan
RTEG	real-time emergency generation
RUMF	Rumford
SCC	seasonal claimed capability
SEMA	RSP area—Southeastern Massachusetts/Newport, Rhode Island
SEMA/RI	Southeast Massachusetts/Rhode Island
SUB	subbituminous coal
SWCT	RSP area—Southwestern Connecticut
TDF	tire-derived fuels
VOM	variable operation and maintenance
WBIG	Wyman/Bigelow
WDA	Wind Development Area
WDS	wood/wood waste solids—including paper pellets, railroad ties, utility poles, wood chips, bark, and wood waste solids
VT	RSP area—Vermont/southwestern New Hampshire
WMA	RSP area—Western Massachusetts

Section 1
Executive Summary

The ISO New England *2013 Economic Study* investigated the economic and environmental metrics that could result from an increase in the largest *loss-of-source* (LOS) *contingency* allowed in New England, that is, the failure of the largest single source of power to the region. The study assumed that Hydro-Québec Phase II (HQ PII) was the largest LOS contingency in the region and that external systems could accommodate an LOS contingency of 2,000 MW. This report presents the study methodologies, assumptions, simulation results, and observations.

Studies have concluded that the loss of large resources, such as the HQ PII facilities when operating at high levels of imports, could have an adverse effect on the New York Independent System Operator (NYISO) and PJM transmission systems.[2] Under interpool agreements, NYISO and PJM must operate their bulk power systems to support a New England loss-of-source contingency no more severe than the largest internal contingency that these individual systems normally protect against. This requires them to operate, and possibly redispatch generation, to permit the largest LOS to be at least 1,200 MW. When favorable system conditions exist in NYISO and PJM, additional HQ PII import capacity may be granted to ISO New England on an hourly basis.

HQ PII interconnects with New England at a nameplate capacity of 2,000 MW but frequently operates at a lower level due to economic and system conditions. HQ PII often is the largest single source of power in New England, and ISO New England (ISO) system operators must consider its possible failure—or what could be the region's largest single-source contingency. ISO operators manage the system, accounting for the possible instantaneous failure of HQ PII as well as other large resources.

Analyzing a potential LOS contingency is important because this type of contingency could disrupt the balance between electric power generation and demand. The sudden loss of input energy from one source must instantly be provided from other sources of energy. This energy would be provided by all the on-line generators in the Eastern-Interconnection through the extraction of energy from their rotational inertia.[3] The impacts of a New England LOS is more constraining to NYISO and PJM than a New England transmission contingency because a transmission contingency would redistribute existing flows within New England, whereas an LOS would create sudden, additional flows across the NYISO and PJM transmission networks.

Additionally, an LOS contingency does not allow time for automatic generation control (AGC) response for regulating unit response or to change dispatch set points. Thus, the system must be dispatched in preparation of the occurrence of a LOS contingency and the post-contingency flows on each critical element. These preparations must ensure that thermal limits are respected, voltages remain within acceptable limits, and the changes in flows do not violate stability limits.

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[2] PJM Interconnection LLC is the RTO for all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia.

[3] The *Eastern Interconnection* consists of the interconnected transmission and distribution infrastructure that synchronously operates east of the Rocky Mountains, excluding the portion of the system located in the Electric Reliability Council of Texas and Québec.

In addition to operating the system to survive a loss-of-source contingency, the ISO must have sufficient operating reserves to return the system to a state where the system can contain the next-largest contingency within 30 minutes. The focus of this study was to investigate the economic and environmental impacts associated with providing the additional operating reserve that must be on line for recovering from an LOS contingency.

While this study nominally focuses on HQ PII, other large resources could benefit from an increase in the maximum allowable LOS. The emphasis of this report is not on determining the economics of any contractual arrangements associated with HQ PII or other resources but the system planning and operational issues associated with increasing LOS. This study also is not a comprehensive economic evaluation of other subsequent effects that a change in LOS could bring about, such as an increase in the valuation of qualified capacity that could lead to the deactivation or retirement of existing resources or defer the entry of new resources. Omitting these subsequent changes in the planning environment most likely produces are more optimistic results than if these other planning responses were considered.

Five scenarios were hypothesized under the assumption that the energy was delivered using one of several self-scheduled profiles. These self-scheduled profiles were assumed to be $0/megawatt-hour (MWh), price-taking transactions. A sixth scenario, Scenario E, assumed four different dispatch prices ranging from a high of 80% of an expensive peaking unit to a low of $10/MWh.

These six scenarios covered the range from near zero to 100% capacity factor. Each of these profiles considered five maximum transfer levels (1,200, 1,400, 1,600, 1,800, and 2,000 MW).

- Scenario A—24/7 at Transfer Limit
- Scenario B—On-Peak Hours (Every Day) at Transfer Limit
- Scenario C—Peak Hour (1 Hour per Day) at Transfer Limit
- Scenario D—Historical Import Pattern
- Scenario D2—Adjusted Historical Import Pattern
- Scenario E—Dispatchable Based on Energy Price

The benefits of importing energy from Québec may be partially offset by the cost of additional unit commitment to ensure that enough resources are on line and available to provide the required spinning (i.e., on line and electrically synchronized to the system) reserve. If the increased energy were imported in all hours, this additional cost of providing reserves may be difficult to discern. However, if the energy were taken in only one hour per day, the cost of providing the reserves may exceed the energy benefits and could be more easily observed. Two different representations for reserve requirements were assumed:

- **Daily reserve**—A reserve requirement was enforced for all hours in a day based on the maximum amount of the HQ PII import during that day. This reserve requirement was decreased during maintenance days when HQ PII was assumed unavailable.
- **Dynamic reserve**—This reserve requirement was enforced in each hour to satisfy the requirement for 125% of largest committed resource.

Both representations provide similar results because they require the system to have enough operating reserve in the constraining hour of the day.

Figure 1-1 shows a decrease in the average locational marginal price (LMP) of the Dynamic Reserve cases as imported energy increased. When the electric energy was priced at 80% of an expensive peaking unit

(Scenario E—$289/MWh), small amounts of energy flowed and the LMP metric was mostly unaffected by the increase in transfer levels.

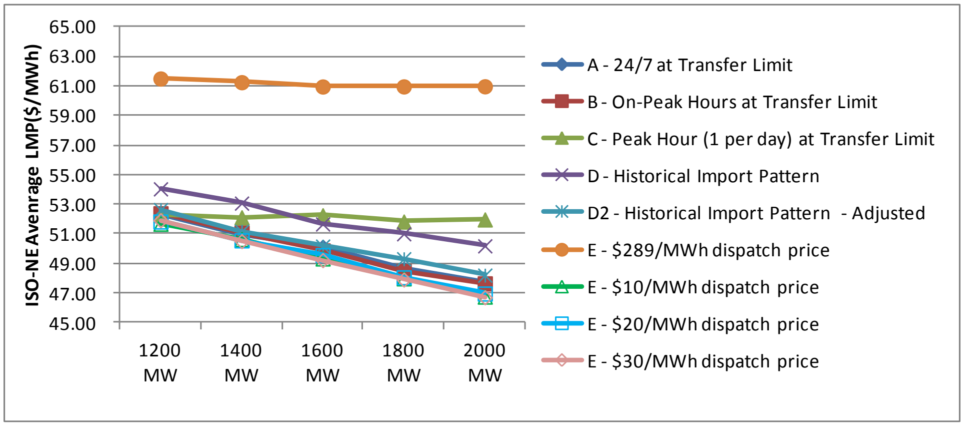

Figure 1-1: Average LMP as HQ PII import capacity increased from 1,200 to 2,000 MW ($/MWh).

Figure 1-2 and Table 1-1 show that the production cost metric of the Dynamic Reserve cases tends to follow the same pattern as the LMP metric. Scenario C, where the import amount was increased in only one hour per day, showed very little change because the cost of additional resources committed to satisfy the required 10-minute spinning and nonspinning reserve requirement was approximately equal to the benefits of the increased self-scheduled, $0/MWh energy from Québec.[4] The production cost metrics for Scenario E include the stated energy cost.

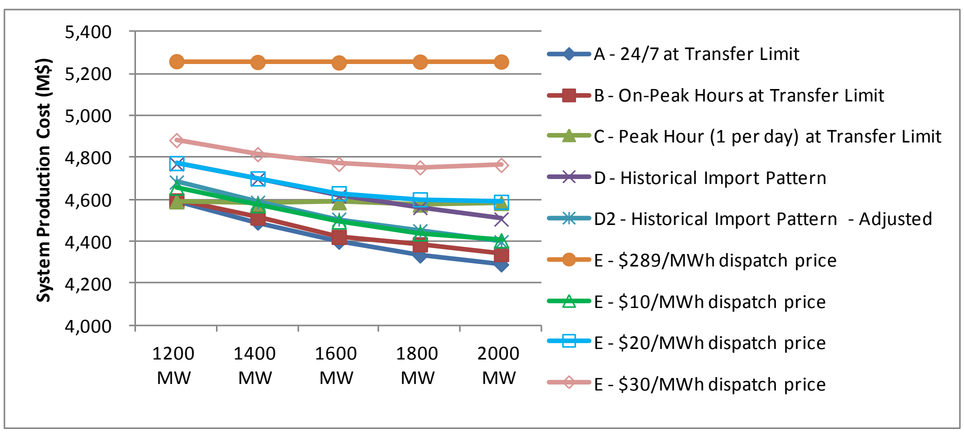

Figure 1-2: Production cost as HQ PII import capacity increased from 1,200 to 2,000 MW, assuming imports were valued at zero cost, except as noted ($ million).

[4] *Nonspinning reserve* is off-line generation not synchronized to the system.

HQ PII Import Level (MW)	Production Cost (M$)								
	A - 24/7 at Transfer Limit	B - On-Peak Hours at Transfer	C - Peak Hour (1 per day) at	D - Historical Import Pattern	D2 - Historical Import Pattern -	E - $289/MWh dispatch price	E - $10/MWh dispatch price	E - $20/MWh dispatch price	E - $30/MWh dispatch price
1200 MW	4,591	4,596	4,591	4,770	4,683	5,260	4,656	4,774	4,883
1400 MW	4,490	4,514	4,582	4,697	4,587	5,256	4,573	4,701	4,816
1600 MW	4,399	4,422	4,587	4,616	4,506	5,254	4,495	4,630	4,770
1800 MW	4,333	4,387	4,576	4,562	4,451	5,258	4,439	4,601	4,753
2000 MW	4,291	4,340	4,584	4,507	4,399	5,258	4,406	4,589	4,765
Reduction	301	255	8	263	285	2	251	185	118
Reduction%	7%	6%	0%	6%	6%	0%	5%	4%	2%

Table 1-1: Comparison of annual production costs among various scenarios under the Dynamic Reserve requirements ($ million).

Note: The Scenario E production cost values are the same as in Table 1-2 because they use the stated dispatch cost when calculating this metric.

Figure 1-3 and Table 1-2 shows the study results of the New England-wide production cost with the HQ PII energy valued at the LMP of the delivery point instead of $0/MWh. Valuing the energy at the LMP of the delivery point reduced the observed benefits of the increased import capabilities. These results suggest that this production cost framework with increased import levels could provide some economic benefits to New England if the energy were taken every day according to a fixed profile. Because the benefits of increased imports are less on some days relative to other days, operating at higher levels on only the days when it is profitable may improve the economic metrics. The production cost metrics shown in Table 1-2 for Scenario E include the stated energy cost and was not valued at the LMP.

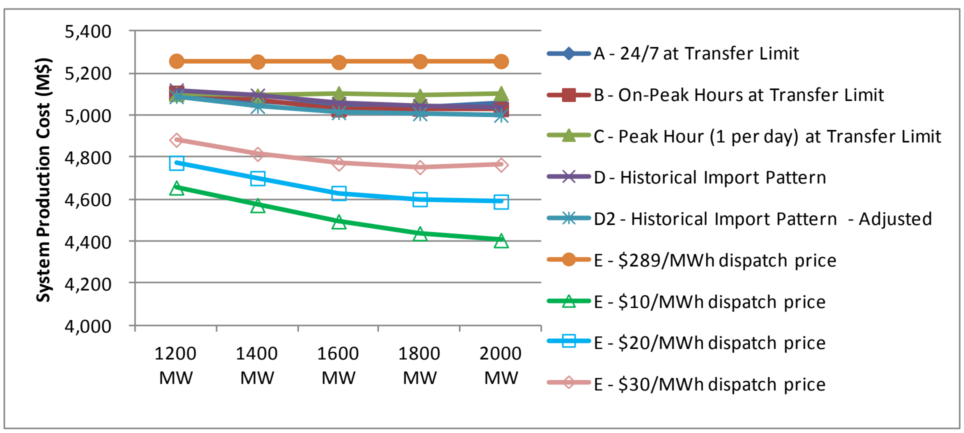

Figure 1-3: Production cost as HQ PII import capacity increased from 1,200 to 2,000 MW, assuming the electric energy was valued at the LMP ($ million).

HQ PII Import Level (MW)	Production Cost (M$)								
	A - 24/7 at Transfer Limit	B - On-Peak Hours at Transfer	C - Peak Hour (1 per day) at	D - Historical Import Pattern	D2 - Historical Import Pattern -	E - $289/MWh dispatch price	E - $10/MWh dispatch price	E - $20/MWh dispatch price	E - $30/MWh dispatch price
1200 MW	5,102	5,107	5,102	5,120	5,090	5,260	4,656	4,774	4,883
1400 MW	5,068	5,075	5,094	5,095	5,043	5,256	4,573	4,701	4,816
1600 MW	5,046	5,029	5,105	5,055	5,013	5,254	4,495	4,630	4,770
1800 MW	5,038	5,032	5,093	5,046	5,008	5,258	4,439	4,601	4,753
2000 MW	5,057	5,030	5,106	5,033	5,001	5,258	4,406	4,589	4,765
Reduction	45	77	(4)	87	89	2	251	185	118
Reduction%	1%	2%	0%	2%	2%	0%	5%	4%	2%

Table 1-2: Comparison of annual production costs among various scenarios under the Dynamic Reserve requirements, with HQ PII energy valued at the LMP, except as noted ($ million).

Note: The Scenario E production cost values are the same as in Table 1-1 because they use the stated dispatch cost when calculating this metric.

Figure 1-4, Figure 1-5 and Figure 1-6 show the effects on total New England carbon dioxide (CO_2), sulfur dioxide (SO_2), and nitrogen oxides (NO_X) emissions of additional imports under the various scenarios.

Because the study assumed that energy imported from HQ PII does not have any emissions, only thermal units within New England contributed to the emission metrics.

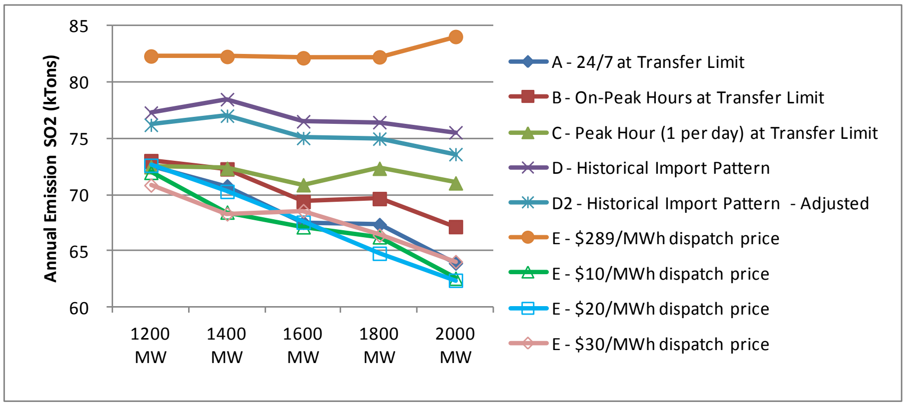

Figure 1-4: CO_2 emissions as HQ PII import capacity increased from 1,200 to 2,000 MW (million tons).

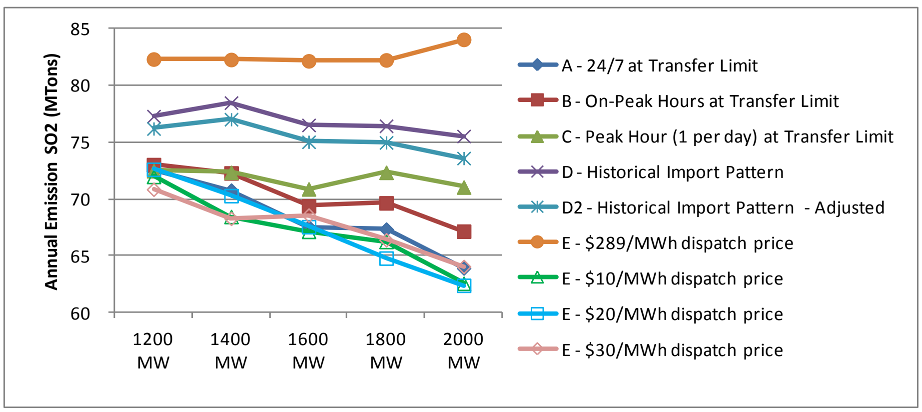

Figure 1-5: SO_2 emissions as HQ PII import capacity increased from 1,200 to 2,000 MW (thousand tons).

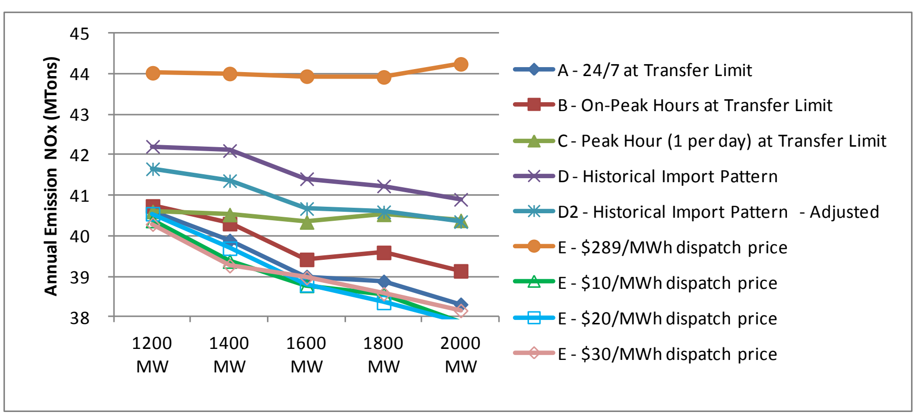

Figure 1-6: NO_X emissions as HQ PII import capacity increased from 1,200 to 2,000 MW (thousand tons).

Section 2
Introduction

Attachment K of the ISO New England (ISO) *Open Access Transmission Tariff* (OATT) states that the ISO must conduct economic studies arising from one or more stakeholder requests submitted by April 1 of each year through the Planning Advisory Committee (PAC).[5] These may be requests to study the 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.

The role of the PAC in the economic study process (Attachment K, Section 4.1b) is to discuss, identify, and prioritize proposed studies. The criteria for study selection are situations that could result in a net reduction in total production cost, reduced congestion, or the integration of new resources.

National Grid's 2013 proposed study may show, absent any consequential changes to the capacity and energy resources available to New England, that total production costs for the ISO New England region potentially could be reduced by allowing an increase in the Hydro-Québec Phase II (HQ PII) loss-of-single-source operating limit.

In fulfillment of this obligation, ISO staff presented the study scope of work, assumptions, draft results, and final results to the PAC in several meetings.[6]

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[5] *ISO New England Inc. Transmission, Markets, and Services Tariff* (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.

[6] *2013 Economic Study: The Economic Impact of Different Levels of Imports on HQ Phase II; Scope of Work,* PAC presentation (May 22, 2013), http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2013/may222013/a2_draft_scope_of_work_2013_economic_studies_052213.pdf.

2013 Economic Study Analysis of HQ Phase II Imports Scope of Work and Assumptions Update, PAC presentation (July 9, 2013), http://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2013/jul92013/a7_hq_phase2_imports_2013_economic_study.pdf.

2013_Economic_Study_Unit_Commitment_Prologue, PAC presentation (January 23, 2014), http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2014/jan232014/a8_2013_economic_study_update.zip.

2.1 Submitted 2013 Economic Study Requests

In 2013, the ISO received a single economic study request, which was presented to the PAC on April 24, 2013.[7]

2.1.1 National Grid Proposed Economic Study

Because the transmission systems of the three northeastern regions have changed since the commissioning of HQ PII in 1990, New England's ability to reliably and consistently operate the HQ Interconnection above the 1,200 megawatts (MW) level has been restudied periodically. The possible economic benefit to New England customers of an increase in imports of hydroelectric-based energy, resulting from a significant increase in the HQ PII loss-of-single-source limit, has not been studied recently in detail.

National Grid requested, pursuant to Attachment K of the OATT, that ISO New England evaluate the economic impacts of different megawatt levels of imports across the HQ PII interface on regional production costs; consumer costs, including energy market locational marginal prices (LMPs), Forward Capacity Market (FCM) prices, and reserve costs; and other metrics.

The scope of the *2013 Economic Study*, based on discussion with the PAC, considered the effects of increasing the acceptable loss-of-source (LOS) limits in New England. Because the primary focus of this study is on the economic impacts on New England, the study assumed that the Interconnection Reliability Operating Limit (IROL) constraints in the New York Independent System Operator (NYISO) and PJM Interconnection (PJM) could accommodate this increase.[8] The analysis modeled the New England generation and transmission system with a simplified representation of the neighboring systems. Depending on the results, follow-up analyses may be conducted with more detailed models of the NYISO and PJM systems.

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. Assumptions about the future are uncertain, and the modeling results indicate relative values and trends. These results should not be characterized as accurate projections of future transmission congestion, ultimate project economics, and resultant environmental impacts. Given these caveats, this high level approach was adequate to evaluate the economic impacts of additional imports.

2013 Economic Study—The Economic Impact of Different Levels of Imports on HQ Phase II, PAC presentation (April 29, 2014), http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2014/apr292014/a9_2013_economic_study_update_rev1.pdf.

[7] National Grid, *Proposed Economic Study to Assess Potential Regional Benefits for Increased Operating Limit on New England/Québec Interconnector,* PAC presentation (April 24, 2013), http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2013/apr242013/a6_1_ngrid_economic_study_request_presentation.pdf.

National Grid, *National Grid Request for an Economic Study*, (March 27, 2013), http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2013/apr242013/a6_1_ngrid_2013_economic_study_request.pdf.

[8] PJM Interconnection LLC is the RTO for all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia.

2.1.2 Background: New England/Québec HVDC Interconnector

The New England/Québec HVDC Interconnector, shown in Figure 2-1, was built during the late 1980s and placed into full commercial operation in 1990. The predecessor to National Grid, the New England Electric System (NEES), led the project's development. The project was initially a short segment that started at Des Canton, Québec, just north of the Vermont (VT) border, with the southern terminal in northern New Hampshire (NH) at Comerford near the VT/NH border. This was referred to as Phase I. Later, the transmission line was extended in both directions, first by 700 miles north to Québec's hydroelectricity project at James Bay, and then 133 miles south to Ayer, MA, where it was interconnected with the New England system at the Sandy Pond substation. This expanded transmission project was known as HQ PII.

Figure 2-1: Geographic overview of Hydro-Québec Phase II.

An HQ affiliate (TransÉnergie) owns and operates the Canadian side of the transmission line. The US portion of the line is jointly owned by a large number of utilities and municipalities within New England that have capacity rights to the line. The New England side is operated by National Grid at the direction of ISO New England. The Ayers, MA, terminal facility has a total nameplate capacity of 2,000 MW, but it often is operated at a lower level due to economic and system operational considerations.

2.1.3 Explanation of Loss-of-Source Constraints

A loss-of-source contingency on an electric power system is critical because the system's electric energy must be in balance on an instantaneous basis. Therefore, when input energy is suddenly lost, other sources must instantly provide the electric energy. After an LOS contingency in New England, the instantaneous additional flows come from all on-line generators in the Eastern Interconnection.[9] These

[9] The *Eastern Interconnection* consists of the interconnected transmission and distribution infrastructure that synchronously operates east of the Rocky Mountains, excluding the portion of the system located in the Electric Reliability Council of Texas and Québec.

resources contribute immediately to the shortfall because energy is withdrawn from their rotational inertia. This results in incremental power flows within NYISO and PJM, which affect their line loadings and voltage levels. To prevent uncontrollable cascading outages, ISO New England operators limit the maximum output of a New England resource to respect these post-contingency consequences. An LOS contingency does not allow time for automatic generation control (AGC) response for regulating unit response, and it does not allow time to change generator dispatch set-points.[10] The system must be dispatched so that if a contingency occurs, the post-contingency flows on each critical element remains within thermal and voltage limits, and the change in energy output does not violate stability limits.

In New England, the concerns about an LOS contingency affects not only HQ PII but also any large generating resource or multiple resources with a common-failure mode that could reasonably result in a large instantaneous loss. A New England contingency cannot be more severe than the worst internal contingency that NYISO and PJM normally protect against. Frequently, system conditions in these areas provide a sufficient margin so that ISO New England's LOS contingency can be greater than 1,200 MW. When this occurs, NYISO and PJM communicate the allowable LOS to New England. When HQ PII or other resources exceed the maximum allowable LOS, ISO New England is obligated to respond by reducing its output.

Other large facilities have the potential for being the largest single contingency on the New England system from time to time. Table 2-1 shows the possible largest single-source contingencies above 1,200 MW in New England.

Asset ID	Generator Name	Summer Seasonal Claimed Capability (SCC) (MW)	Winter SCC (MW)
485	Millstone Point 3	1,225	1,235
555	Seabrook	1,247	1,247
1478	Mystic 8	703	842
1616	Mystic 9	714	858
1478 and 1616	Mystic 8 and 9 contingency	1,417	1,700
–	Hydro-Québec Phase II	2,000	2,000

Table 2-1: Possible largest single-source contingencies

Source: The *2014–2022 Forecast Report of Capacity, Energy, Loads, and Transmission* (CELT 2014) (May 2014), http://www.iso-ne.com/trans/celt/report/.

2.1.4 Reserve Requirements

ISO New England has four classifications of operating reserve:

- **Regulation and automatic generation control**: While this is an important part of maintaining the reliable operation of the system, it is not affected by the size of the largest contingency.

- **Total 10-minute reserve**: This equals 125% of the largest committed resource, assumed to be HQ PII in most cases, although other resources can sometimes be the largest.

[10] *Automatic generation control* is the automatic adjustment of a balancing authority area's (BAA) generation to match its interchange schedule plus frequency bias. (A BAA is an area comprising a collection of generation, transmission, and loads within metered boundaries for which a responsible entity [defined by the North American Electric Reliability Corporation to be a balancing authority] integrates resource plans for that area, maintains the area's load-resource balance, and supports the area's interconnection frequency in real time.)

- **10-minute spinning reserve requirement (TMSR):** At least 50% of the total 10-minute reserve requirement must be provided by on-line generation resources committed to providing these reserves. [11]

- **10-minute nonspinning reserve (TMNSR):** The remainder of the total 10-minute reserve requirement could be satisfied by conventional hydro, pumped storage, and fast-start resources plus any surplus spinning reserve.[12]

- **30-minute operating reserve (TMOR):** This requirement can be satisfied by conventional hydro, pumped storage and fast-start resources, which are assumed to be available in all hours. This assumption of adequacy is reasonable, except, possibly, at times of peak loads. Therefore, this study did not model this aspect of reserves.

- **Replacement reserves:** These are supplemental reserves needed to ensure that regional reserves can be satisfied in the event of a contingency. New England is responsible for 180 MW in the winter and 160 MW in the summer. Typically, conventional hydro, pumped storage, and off-line gas turbines satisfy this requirement in a manner similar to TMNSR.

Table 2-2 summarizes the TMSR, TMNSR, and TMOR requirements and specifications in ISO New England.

On-Line 10-Minute Spinning Reserve (TMSR)	Off-Line 10-Minute Nonspinning Reserve (TMNSR)	On-Line or Off-Line 30-Minute Operating Reserve (TMOR)
• Capability of on-line unit to provide increased energy within 10 minutes • Partially loaded on-line generator • Limited ramp rate and economic maximum[a]	• Capability of off-line resources to provide energy within 10 minutes • Off-line generation turbine, diesel, or hydro generators • Load interruption by dispatchable asset-related demand (DARD) resources[b]	• Capability of resources to provide energy within 30 minutes • On-line or off-line resources • Generally, the larger generation turbines • Load interruption; DARD resources can also qualify

Table 2-2: ISO New England reserve requirements.

(a) *Economic maximum* is the highest unrestricted level of electric energy (in megawatts) a generating resource is able to produce, representing the highest megawatt output available from the resource for economic dispatch.

(b) *Dispatchable asset-related demand* is demand that can be modified on the basis of the physical load's ability to respond to remote dispatch instructions from the ISO.

Neither TMOR, nor replacement reserves were modeled explicitly because the quantities of hydro, pumped storage, and other fast-start resources were assumed to be adequate under all circumstances to provide them. This is a reasonable assumption except, possibly, at times of peak loads.

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[11] *Spinning reserve* is on line generation electrically synchronized to the system.

[12] *Nonspinning reserve* is off-line generation not synchronized to the system. *Fast-start resources* can be electrically synchronized to the system quickly and reach maximum production or output within 10 to 30 minutes to respond to a contingency and serve demand.

Additionally, the value of a resource's willingness to provide off-line reserves cannot be clearly determined. Market parameters reflecting a resources willingness to provide these reserves are part of the ISO's process to co-optimize the energy and reserve markets. Because these costs would be incurred only after a contingency occurred, these parameters would not be applicable—this study is based on simulations that assume "all resources are in" and that the system must be operated recognizing that contingencies might occur. Consequently, valuing nonspinning reserve was outside the scope of this study.

2.1.5 Operational Limitations of the New England–Québec HVDC Interconnection

A HQ PII limit of 1,400 MW or higher has been common in recent years. Figure 2-2 shows the level of imports for the highest 15% of the hours for three years (2010 to 2012). The observed trend is that the maximum import has increased. In 2010, the imports exceeded 1,575 MW about 1% of the time. In 2012, this one-percentile point showed an import level of nearly 1,800 MW. For 2012, the maximum import level was approximately 1,850 MW. Currently, the ISO has no mechanism for compensating PJM or NYISO for out-of-market actions needed to allow higher LOS limits. This suggests that "favorable" system conditions must have allowed these higher import levels to occur.

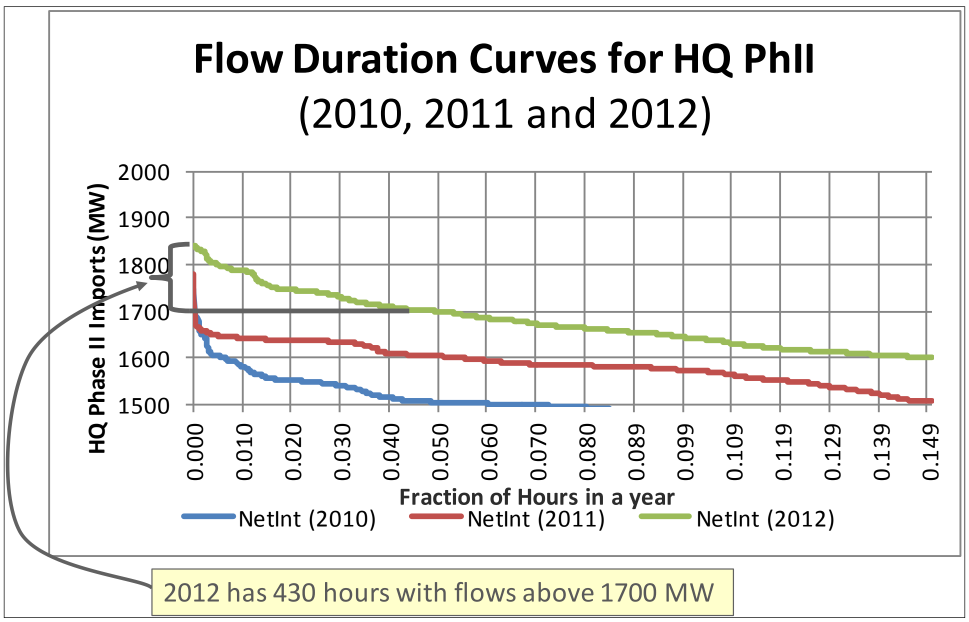

Figure 2-2: Historical flow duration curves for HQ PII (MW).

2.2 ISO New England Response Framework

The ISO developed a scope of work to evaluate the effects of increasing the acceptable LOS by showing the economic benefit to New England customers of greater hydro imports resulting from a significant increase in the HQ PII import limit. The economic metrics are regional production costs ($) and consumer costs including load-serving entity energy expenses ($), and average locational marginal prices ($/megawatt-hours; MWh). Changes in environmental emissions (tons) and other metrics, as appropriate, were also analyzed.

2.3 Scope of Work

The study was a New England-only analysis that assumed the constraints in NYISO and PJM have been resolved. This study tested five different profiles at five different import levels where the largest source was increased from 1,200 MW to 2,000 MW in 200 MW increments. Each case respected two different representations of the reserve requirements. The results quantified the change in economic metrics, accounting for the electric energy and the cost of incremental reserves. Additionally, to examine whether dispatch cost assumptions would affect the result, a scenario consisting of several additional cases assumed four price levels for dispatchable energy from HQ PII. In these cases, the model determined the reserve requirements dynamically on the basis of economic merits. The other cases used static reserve requirements based on the maximum peak load exposure in each day.

Changes to the quantities procured in the Forward Reserve Market and subsequent economic impact were not included in this analysis.

2.4 Evaluation Framework

Increasing the maximum import from Québec would increase the amount of capacity needed to be on-line in New England to provide the required amount of spinning reserves. The relative magnitude of the energy imported compared with the dispatch of resources needed to provide the spinning reserve would determine the associated increase or decrease in the economic and environmental metrics.

The production cost metric may increase or decrease as the HQ PII import level increases. The direction of change depends on the amount of energy associated with the HQ PII import. While the cost of the imports typically is assumed to be $0/MWh, this is a modeling convenience acceptable when imports are effectively constant among cases. The assumed $0/MWh may not be appropriate when the quantity of imports changes. The assumption about the cost of the imported energy is important because the metrics produced within the simulation are unlikely to accurately reflect the relative economics when the quantity of imports increases or decreases.

In most multiarea production simulation models, the interchange between areas is valued at the LMP of the energy at the point of interchange where the seller receives revenue per megawatt-hour and the buyer pays that same amount per megawatt-hour. While other assumptions about pricing are possible, they are beyond the control of, and concern of, ISO New England. For example, if the energy were priced below the LMP, the benefit would accrue to the parties involved in the transaction and not to New England customers as a whole. Consequently, for the final metrics, the most appropriate value for the energy is likely the nondiscriminatory market value price (i.e., the LMP at the point of delivery). The study shows the production cost metric under two assumptions: first, at a zero production cost and, second, with the energy valued at the LMP.

2.5 Profiles

In addition to one scenario where HQ PII was dispatched based on specific prices, five scenarios were investigated based on input profiles. These evaluated the range from a near-zero to a 100% capacity factor. Each of these profiles were investigated at different HQ PII import levels (1,200 to 2,000 MW in 200 MW steps). Figure 2-3 shows four of the input patterns used.

- Scenario A—24/7 at Transfer Limit
- Scenario B—On-Peak Hours (Every Day) at Transfer Limit
- Scenario C—Peak Hour (1 Hour per Day) at Transfer Limit
- Scenario D—Historical Import Pattern
- Scenario D2—Adjusted Historical Import Pattern
- Scenario E—Dispatchable Based on Energy Price

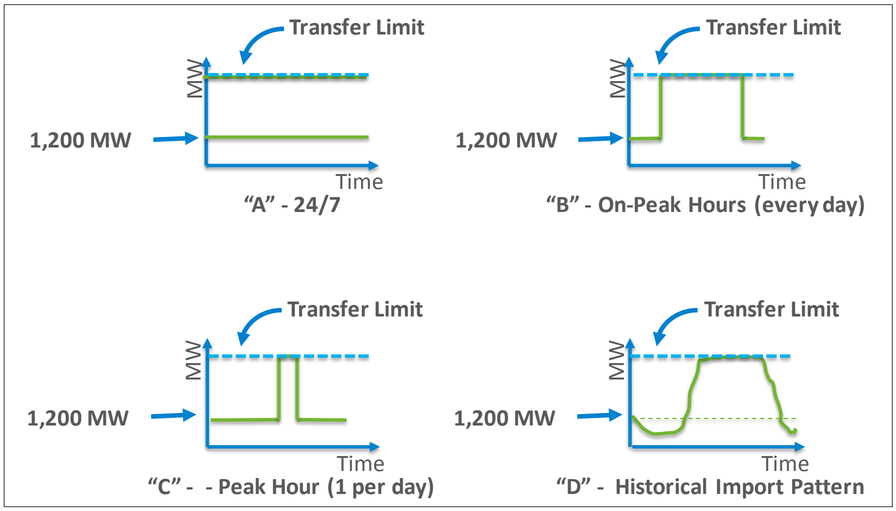

Figure 2-3: HQ PII import profile patterns investigated.

2.5.1 Scenario A—24/7 at Transfer Limit

In this scenario, the hourly import power was assumed constant year round and equal to the transfer limit every hour that HQ PII was not on maintenance. This results in nearly 100% capacity factor.

2.5.2 Scenario B—On-Peak Hours (Every Day) at Transfer Limit

The import power for this scenario was assumed equal to the transfer limit during the on-peak hours every day that HQ PII was not on maintenance. During the off-peak hours, 1,200 MW was imported. The on-peak hours were assumed to be 7:00 a.m. to 11:00 p.m., seven days per week.

2.5.3 Scenario C—Peak Hour (1 Hour per Day) at Transfer Limit

The import power was assumed to equal the transfer limit during the peak hour of the day (1 hour per day); during other hours, the import power was 1,200 MW.

Figure 2-4 shows the averaged system daily load profiles within each season used to identify the hour in which the import would create the largest reserve requirement.

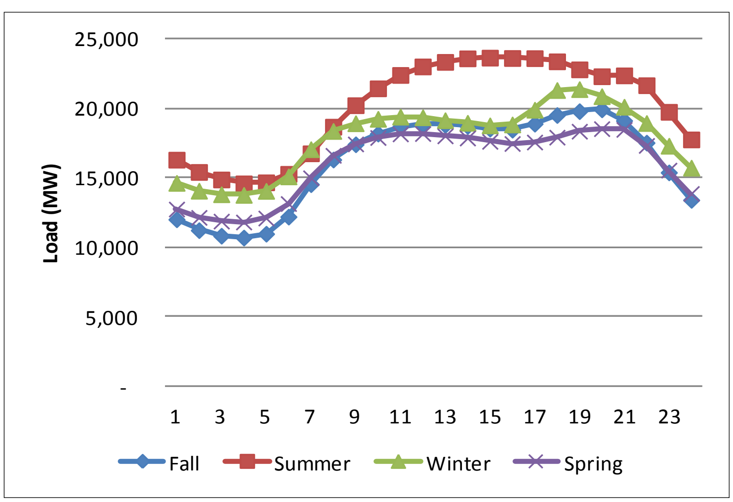

Figure 2-4: Averaged system daily load within each season (MW).

The hour selected for import within each season was as follows:

- Spring: March to May (hour ending 20)[13]
- Summer: June to August (hour ending 15)
- Fall: September to November (hour ending 20)
- Winter: December to February (hour ending 19)

The purpose of this unrealistic (one hour per day) case was to be able to isolate the impacts on the metrics of providing reserves from the impacts of additional energy imports. Because the small amount of energy creates minimal distortion, the impacts of providing the reserves can be observed clearly.

2.5.4 Scenario D—Historical Import Pattern

The historical pattern was an average diurnal profile used to represent an import that varied from hour to hour and month to month. The study evaluated two broad and valid approaches to using such a profile. The first approach scaled up the shape on an annual basis so that the maximum value reached the target import limit in only one month and was lower in the other 11 months. The second approach scaled the loads so that the maximum reached the target import limit in every day of each month.

2.5.4.1 D— Historical Import Pattern

Based on the annual historical import reaching the maximum level in only one month, the average diurnal profile in all months was scaled up by a single annual scaling factor. Figure 2-5 shows the resulting family of import profiles. These curves can be interpreted as representing a profile that made more energy available when New England "needed" it and less energy available when it was less desirable. Figure 2-6 shows these imports as a family of annual flow duration curves.

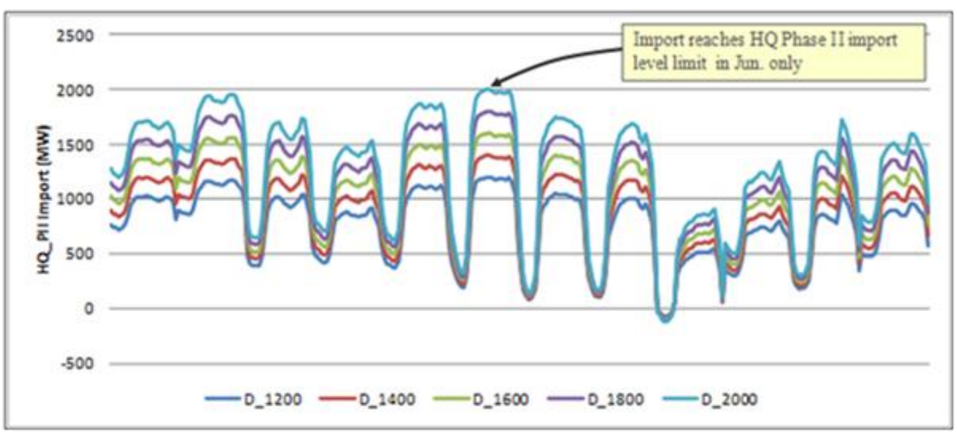

Figure 2-5: Scenario D—Historical Import Pattern—average diurnal profile (MW).

[13] *Hour ending* denotes the preceding hourly period. For example, 12:01 a.m. to 1:00 a.m. is hour ending 1. Hour ending 6:00 p.m. is the time period from 5:01 p.m. to 6:00 p.m.

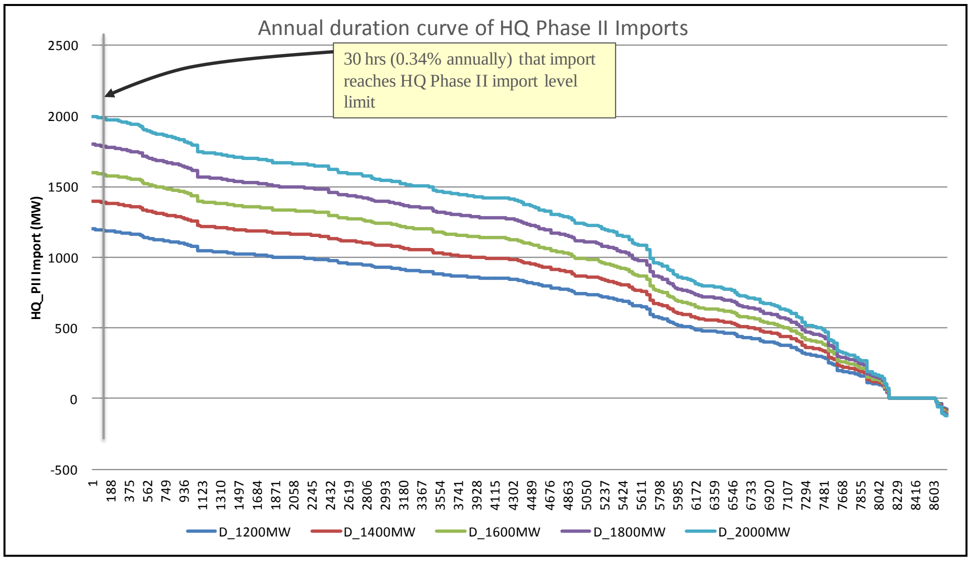

Figure 2-6: Scenario D—Historical Import Pattern—annual flow duration curve (MW).

2.5.4.2 D2—Adjusted Historical Import Pattern

The second way to shape the historical profile was to assume that the maximum amount of imports equaled the import limit in each month. Because these are diurnal profiles, the maximum amount equaled the import limit each day in every month, as shown in Figure 2-7. This would tend to resemble Scenario B, which represents the import of the higher amount of energy during the "on-peak" hours. Figure 2-8 shows these imports as a family of flow duration curves.

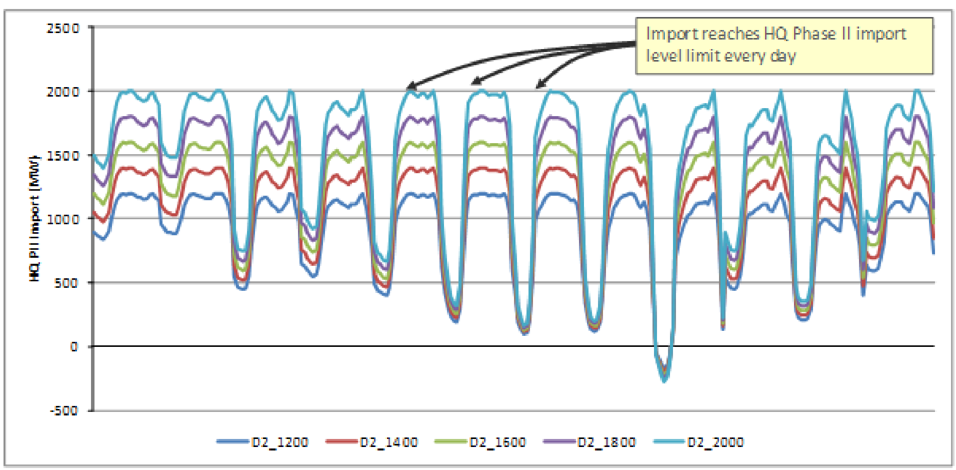

Figure 2-7: Average diurnal profile for Scenario D2—Adjusted Historical Import Pattern—so that the import limit was reached each day (MW).

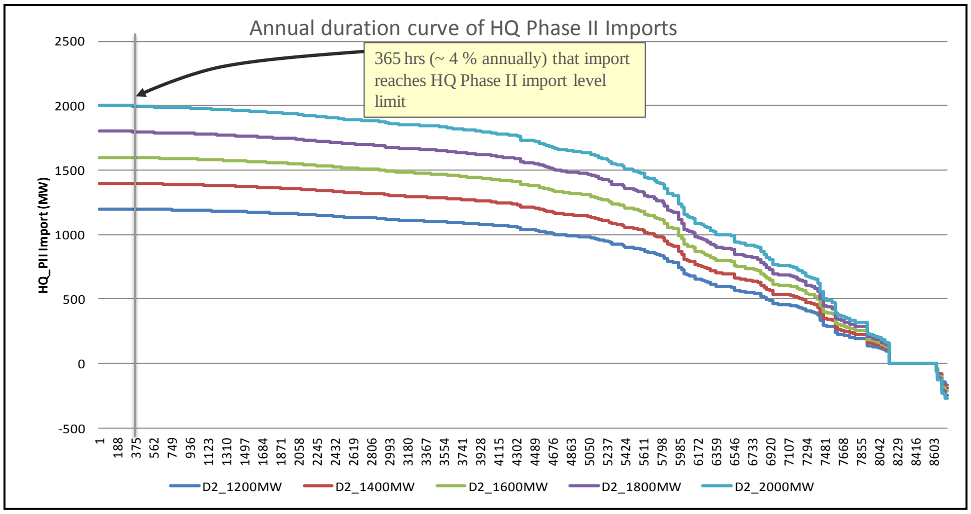

Figure 2-8: Annual duration curve of HQ PII imports for Scenario D2—Adjusted Historical Import Pattern—so that the import limit was reached each day (MW).

2.5.5 Scenario E—Dispatchable Based on Energy Price

In addition to the five import profiles assumed for Scenarios A through D2, a sixth scenario was developed that investigated the effects of dispatching the HQ PII facilities as if it were a large dispatchable facility requiring the ISO to provide spinning reserve only when HQ PII was dispatched. This resource was modeled as a fast-start unit dispatched on the basis of an assumed energy price. When dispatched, the minimum import level was 105 MW, and the maximum import level was limited by the transfer limit being tested. The start-up time, minimum up time, and minimum down time were each assumed to be one hour. Additionally, the start-up cost was assumed to be zero, and no emissions were assumed associated with the operation of this resource.

Four dispatch price levels were assumed for Scenario E:

- $289/MWh, based on an assumed energy cost of 80% of the distillate oil price, which was assumed to be $16.96/MBtu) (based on the US Department of Energy [DOE] Energy Information Administration [EIA] 2013 forecast), with heat rate of 17.1 MBtu/MWh (i.e., the heat rate of an inefficient oil fast-start unit).[14]
- $30/MWh
- $20/MWh
- $10/MWh

The lower dispatch price levels were intended to test whether, by changing the unit commitment, the simulation model would "work harder" to get $10/MWh energy than it would to get $30/MWh energy.

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[14] EIA, *Annual Energy Outlook 2013* (AEO2013) (US DOE, April 2013), http://www.eia.gov/forecasts/archive/aeo13/. *Heat rate* is a measure of a thermal power plant's efficiency of converting fuel (British thermal units) to electricity (kilowatt-hours); the lower the heat rate, the more efficient the facility.

2.6 Assumed Reserve Requirements

The benefits of importing energy from Québec may be partially offset by the cost of additional unit commitment to ensure that enough resources are on line and available to provide the spinning reserve. If the increased energy were imported in all hours, this additional cost of providing reserves may be difficult to discern. However, if the energy were taken in only one hour per day, the cost of providing the reserves may exceed the energy benefits and would be more easily observed. Two different representations for reserve requirements were assumed.

- **Daily reserve**—A reserve requirement was enforced for all hours in a day on the basis of the maximum amount of the HQ PII import during that day. This reserve requirement is decreased during maintenance days when HQ PII was assumed unavailable.
- **Dynamic reserve**—This reserve requirement was enforced in each hour to satisfy the requirement for 125% of largest committed resource. Depending on maintenance periods and the scenario investigated, as well as the maximum transfer associated with the HQ PII import profile, the largest committed resource would have been either HQ PII, Mystic 8 and 9, Seabrook, Millstone 2, or Millstone 3.

To illustrate the representation for the Daily Reserve requirement, Scenario C and Scenario D were compared assuming 2,000 MW of import, as shown in Figure 2-9 through Figure 2-13. For Scenario C at the 2,000 MW import level, Figure 2-9 shows the annual system reserve requirement. HQ PII was assumed to be undergoing maintenance for 20 different days (10 days in spring and 10 days in fall). In these 20 days, the reserve requirement was based on a nuclear unit being the largest contingency and assumed to be 1,500 MW. Figure 2-10 shows the reserve requirement as an annual "reserve duration" curve.

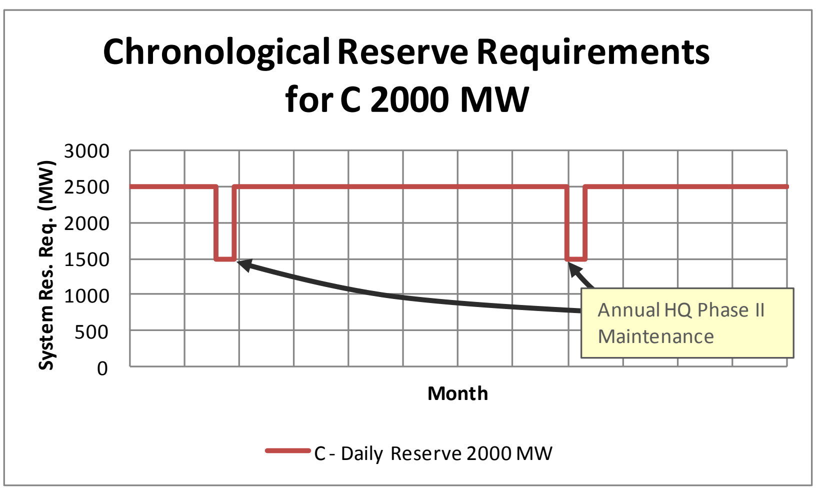

Figure 2-9: Annual chronological reserve requirement for Scenario C—the Peak Hour (1 Hour per Day) at Transfer Limit—at 2,000 MW.

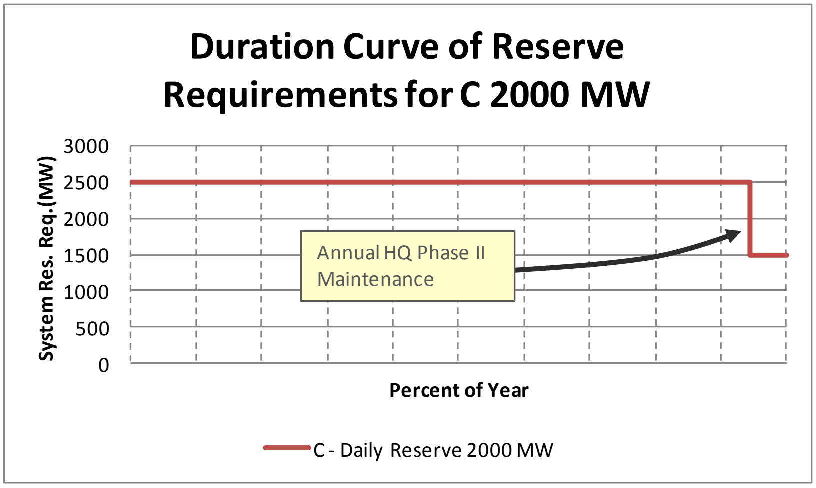

Figure 2-10: Annual duration curve of reserve requirement for Scenario C—the Peak Hour (1 Hour per Day) at the Transfer Limit—at 2,000 MW.

Figure 2-11 shows a comparison of the Daily Reserve requirement for the 1,200 MW, 1,400 MW, 1,600 MW, 1,800 MW, and 2,000 MW cases for Scenario D.

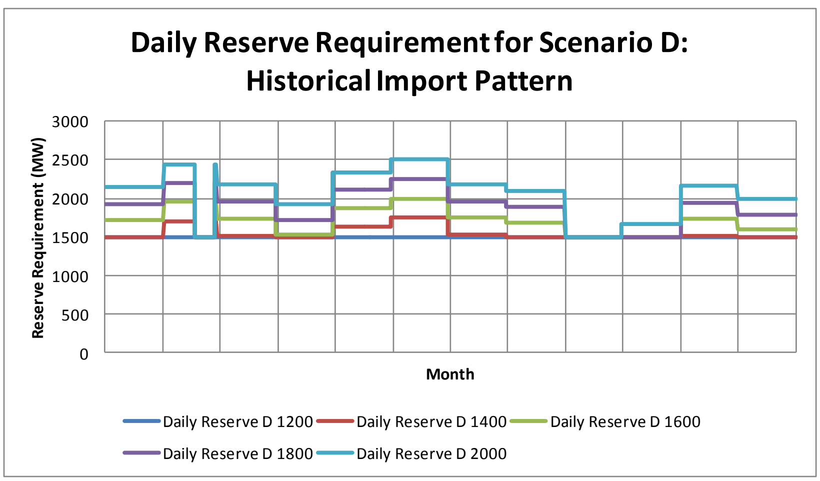

Figure 2-11: Annual chronological curve of reserve requirement for Scenario D—Historical Import Pattern cases (MW).

Figure 2-12 shows the Daily Reserve requirement at the 2,000 MW import level. While the two assumed 10-day maintenance outages result in lower reserve margins in the spring and the fall, similar to Scenario C in Figure 2-9, the Scenario D profile has lower operating reserve in many months. Figure 2-13, shows the reserve requirement as an annual “reserve duration” curve.

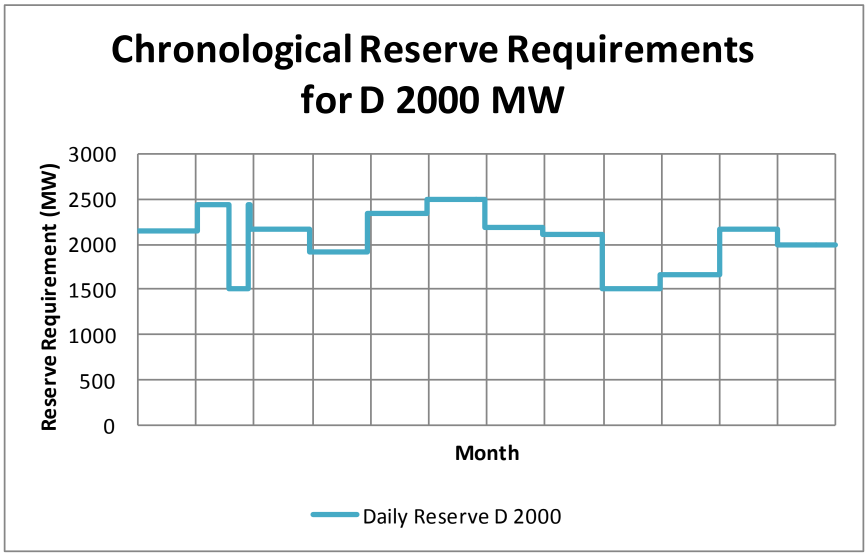

Figure 2-12: Annual chronological curve of the reserve requirements for Scenario D—the Historical Import Pattern—at 2,000 MW.

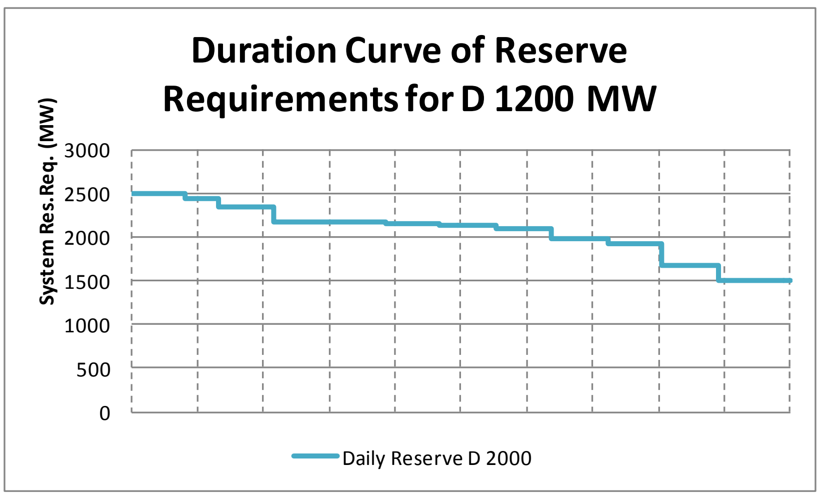

Figure 2-13: Annual duration curve of reserve requirement for Scenario D—the Historical Import Pattern—at 2,000 MW.

2.6.1 Daily Reserve Requirements Compared with Dynamic Reserve Requirements

The Daily Reserve representation was based on the assumption that HQ PII was the largest committed unit. For the 1,200 MW, 1,400 MW, and 1,600 MW import levels, Mystic 8 and 9 combined may be the largest single contingency. Therefore, these higher reserve requirements may result in HQ PII operating at 1,200 MW, 1,400 MW, and 1,600 MW without any need for increased unit commitment to provide additional reserves.

2.6.2 Static Reserve Requirements

To understand the Dynamic Reserve requirement compared with the Daily Reserve requirement, Figure 2-14 and Figure 2-15 show the hourly reserve requirement under both reserve representations at 1,200 MW and 2,000 MW, respectively. At the 1,200 MW HQ PII import level, the Daily Reserve requirement was set by the assumed largest committed resource, while the Dynamic Reserve requirement was set by the actual largest LOS contingency, as shown by the green line. Figure 2-15 shows that in the 2,000 MW

HQ PII case, HQ PII established the reserve requirement, except when it was on maintenance. For these days, the reserve dropped to 1,500 MW because the largest resource was a nuclear unit.

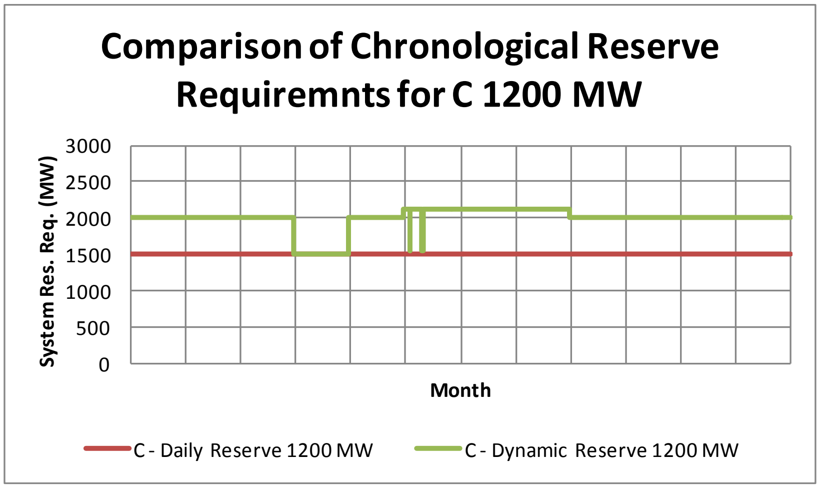

Figure 2-14: Annual chronological curve of the reserve requirement for Scenario C—Peak Hour (1 Hour per Day) at Transfer Limit—at the 1,200 MW import level.

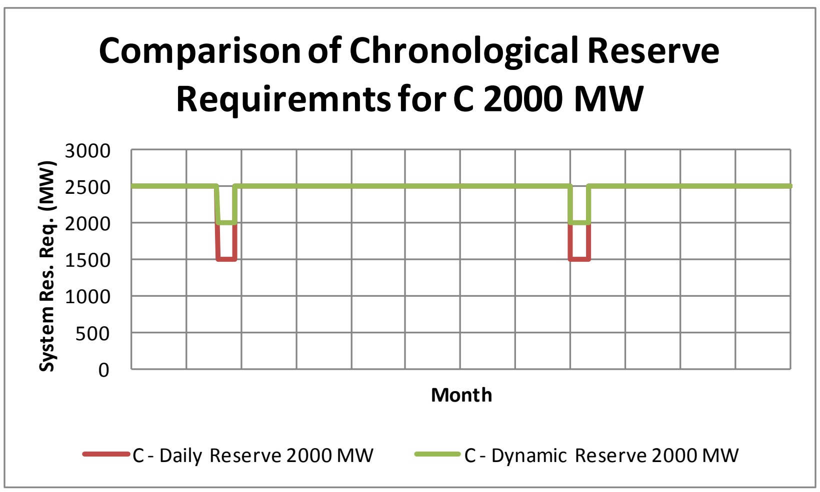

Figure 2-15: Annual chronological curve of the reserve requirement for Scenario C—Peak Hour (1 Hour per Day) at Transfer Limit—at the 2,000 MW import level.

2.6.3 Dynamic Reserve Requirements

To understand the Dynamic Reserve requirement compared with the Daily Reserve requirement for Scenario D, Figure 2-16 through Figure 2-19 compare the hourly reserve requirement under the Daily Reserve and Dynamic Reserve requirements, at 1,200 MW and 2,000 MW.

Figure 2-16 shows that at 1,200 MW, the Dynamic Reserve requirements are higher, except when Mystic 8 and 9 were on maintenance. In all other hours, the combined commitment of both units creates a larger LOS contingency.

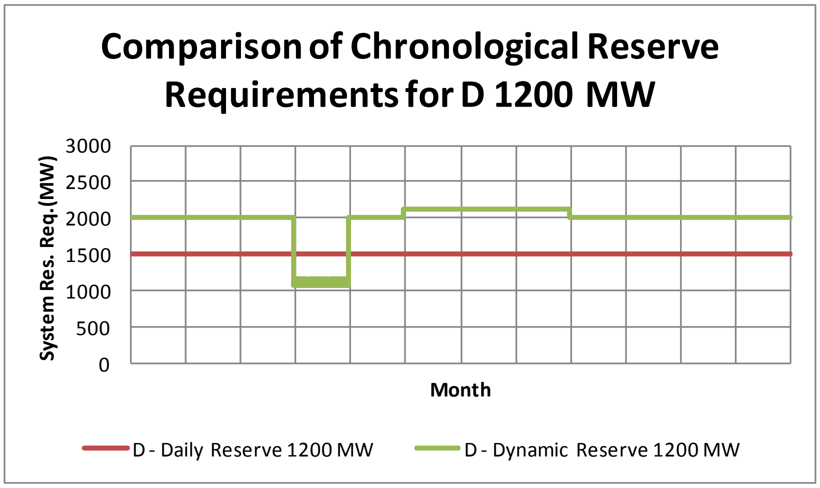

Figure 2-16: Annual chronological curve of the reserve requirement for Scenario D—Historical Import Pattern—at 1,200 MW.

Figure 2-17 shows that, at 1,200 MW, more operating reserves were required to cover Mystic 8 and 9 in many more hours when these units were dispatched dynamically, compared with the Daily Reserve.

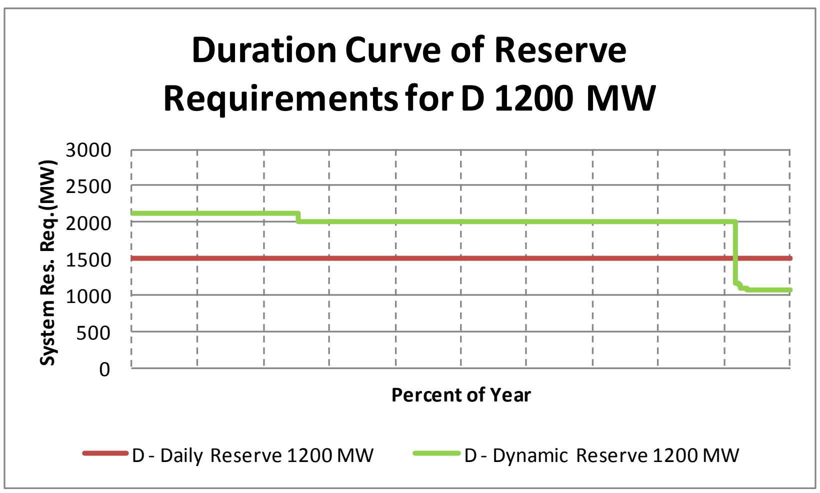

Figure 2-17: Annual duration curve of the reserve requirement for Scenario D—Historical Import Pattern—at 1,200 MW.

Figure 2-18 and Figure 2-19 show that, at 2,000 MW, less operating reserves were required when dispatched dynamically compared with the Daily Reserve alternative. Figure 2-18 shows this as a chronological profile, while Figure 2-19 shows this as a reserve duration profile.

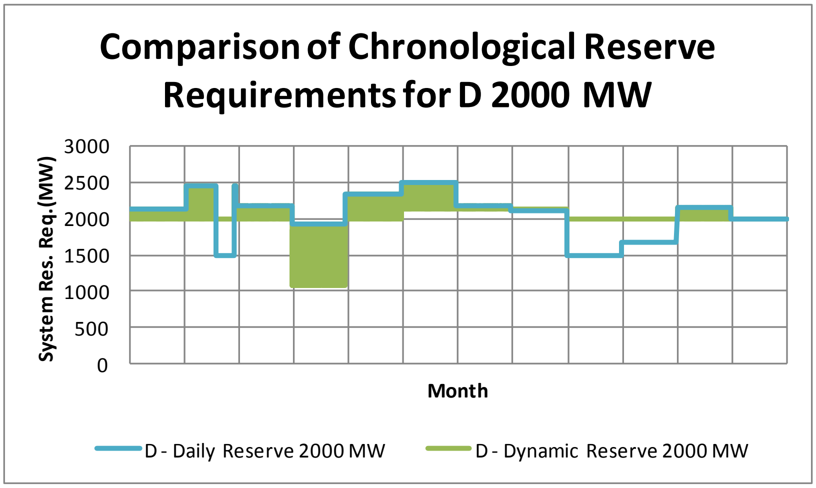

Figure 2-18: Annual chronological curve of the reserve requirement for Scenario D—Historical Import Pattern—at 2,000 MW.

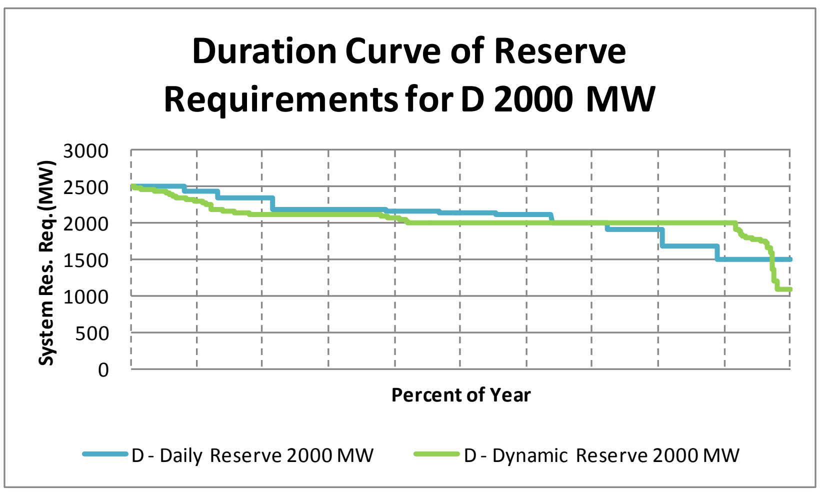

Figure 2-19: Annual duration curve of the reserve requirement for Scenario D—Historical Import Pattern—at 2,000 MW.

2.6.4 Case Matrix

Table 2-3 provides a matrix that defines the cases evaluated.

Scenario and Reserve Requirement	Maximum Import Level (MW)				
	1,200 MW	1,400 MW	1,600 MW	1,800 MW	2,000 MW
A—daily reserve	√	√	√	√	√
A—dynamic reserve	√	√	√	√	√
B—daily reserve	√	√	√	√	√
B—dynamic reserve	√	√	√	√	√
C—daily reserve	√	√	√	√	√
C—dynamic reserve	√	√	√	√	√
D—daily reserve	√	√	√	√	√
D—dynamic reserve	√	√	√	√	√
D2—daily reserve	√	√	√	√	√
D2—dynamic reserve	√	√	√	√	√
E—dynamic reserve ($289/MWh)	√	√	√	√	√
E—dynamic reserve ($10/MWh)	√	√	√	√	√
E—dynamic reserve ($20/MWh)	√	√	√	√	√
E—dynamic reserve ($30/MWh)	√	√	√	√	√

Table 2-3: Matrix of cases investigated.

Section 3
Data and Assumptions

The data, assumptions, and modeling inputs are described in this section. This study used detailed resource modeling that represented thermal unit heat-rate curves, transmission constraints and unit commitment.

3.1 System Generation

The supply-side resources are based on the 2018 summer case of the ISO's 2013 FERC 715 filing, with a total capacity of 33,415 MW. The major capacity additions and retirements include two 204 MW gas turbine units added in Boston, a 670 MW combined-cycle unit added in southwestern Connecticut, and the retirement of Vermont Yankee with a capacity of 650 MW. Figure 3-1 presents an overview of generation capacity by fuel type.

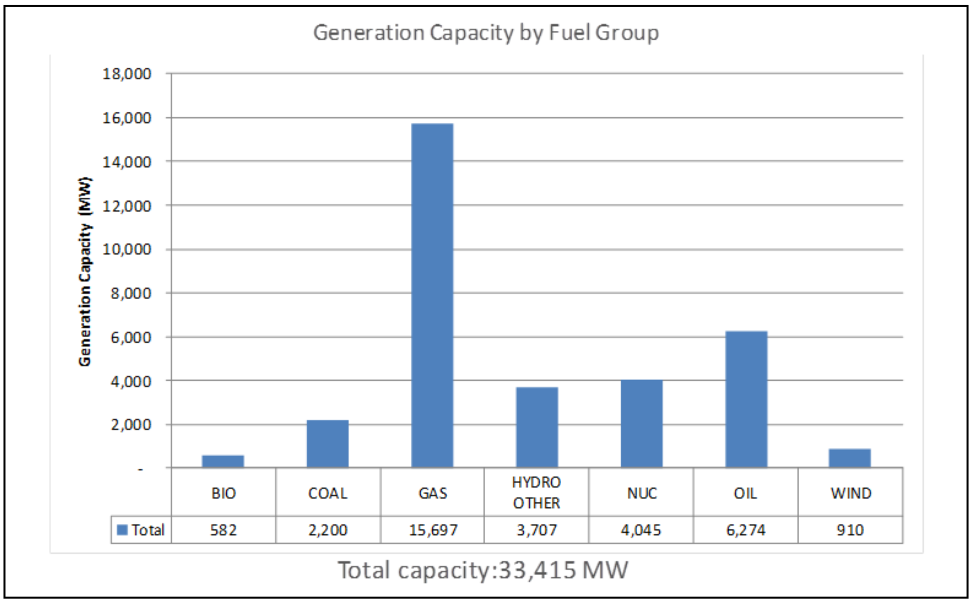

Figure 3-1: Generating capacity by fuel group in ISO New England, 2018 summer case of the ISO's FERC 715 filing (MW).

Note: "BIO" refers to the fuel type for wood and other organic biomass used as a combustion fuel. "HYDRO OTHER" includes hydro run of river, hydro pond, pumped storage, thermal units that burn landfill gas (LFG), municipal solid waste (MSW), tire-derived fuels (TDFs), and photovoltaic (PV) resources.

3.1.1 Detailed Modeling of Thermal Unit Heat-Rate Curves

The resource model included generating unit operational constraints, such as start-up costs, no-load costs, and incremental heat-rate curves, along with operating limits, including minimum up time, minimum down time, and start-up time. This detailed modeling allowed for the more accurate determination of the marginal costs of supplying energy.

3.1.2 Resource Availability

The equivalent availability factors, used to quantify a resource's reliability, were based on the assumptions used in establishing New England's Installed Capability Requirements (ICRs). Generating resources were assumed completely unavailable when on maintenance. The representation for unplanned and forced outages was to derate the capacity by the amount of the Equivalent Forced Outage Rate.[15] Derating to represent random, forced outages was a simplification to the more rigorous approach that would have required the development of a schedule of full-unit forced outages. Developing a forced-outage schedule would not have a significant impact on the analysis because the simulation optimization would adjust for this predetermined constraint when performing the unit commitment and dispatch. Any additional impact on reserves from such a granular analysis would be minimal because the model would accommodate foreknowledge of these events during the model optimization.

3.1.3 Fuel Prices

The forecast of fuel prices was based on DOE's *2013 Annual Energy Outlook*.[16] Figure 3-2 presents the monthly fuel prices assumed in the *2013 Economic Study*.

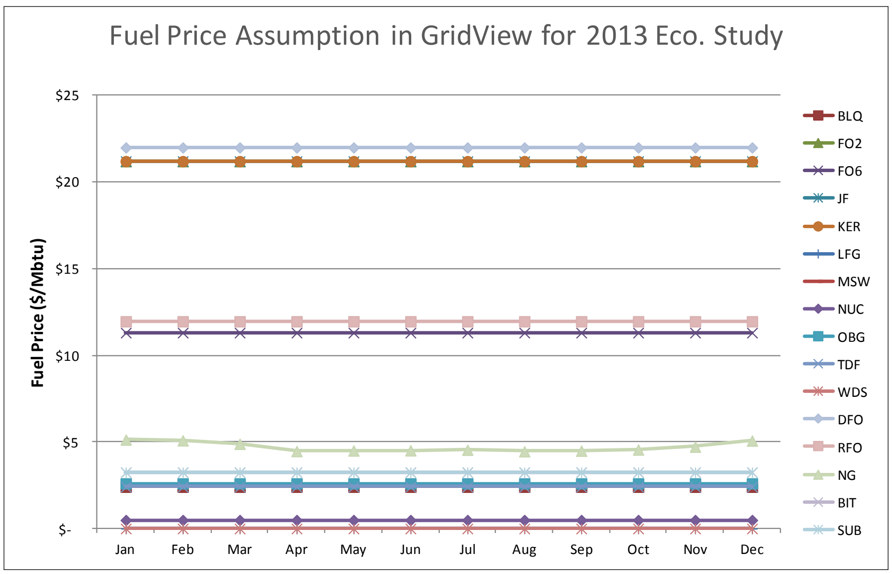

Figure 3-2: Fuel price assumptions ($/MWh).

Fuel prices were assumed constant across all months in a year with the exception of natural gas. Natural gas prices were assumed to vary monthly to reflect the seasonal trends resulting from shifts in supply and demand. Historical trends have shown that prices are higher for natural gas during the high heating, winter months and lower during the nonheating months. Figure 3-3 details the assumed monthly natural gas price multiplier.

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[15] *Equivalent demand forced-outage rate* (EFORd) is the portion of time a unit is in demand but unavailable because of forced (i.e., unplanned) outages.

[16] *Annual Energy Outlook 2013*, http://www.eia.gov/forecasts/archive/aeo13/.

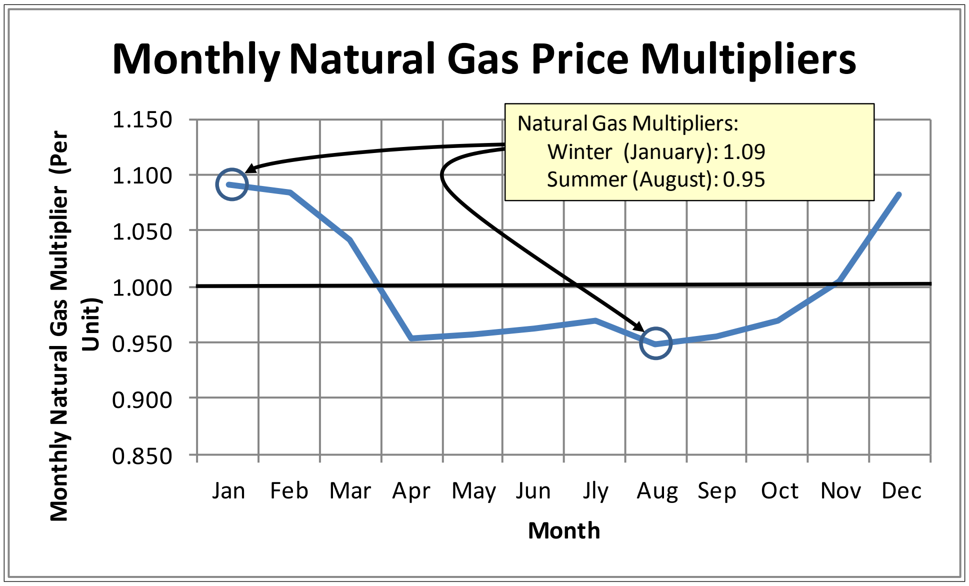

Figure 3-3: Assumed monthly multipliers for natural gas prices.

3.1.4 Environmental Emissions

The emissions from thermal units were calculated from unit generation and the associated emission rates. Emission rates were determined by aggregating unit-based emission rates for each technology and primary fuel type defined in the *2011 ISO New England Electric Generator Air Emissions Report*.[17] The energy imported from HQ PII was assumed to have no associated emissions.

3.1.5 Wind Generators

The wind capacity modeled in this study was based on the capacity supply obligations in the ISO's fifth Forward Capacity Auction (FCA #5), plus an additional 18 MW that was installed before the queue process was initiated. Therefore, the total wind capacity was 910 MW.

Figure 3-4 presents a wind profile developed for northern Maine (BHE) using estimated 2006 synthetic wind estimates to create a chronological profile. The graph on the right side of the figure shows a rolling average 24-hour profile, which provides a clearer view of the trends.

[17] *2011 ISO New England Electric Generator Air Emissions Report* (February 2013), http://www.iso-ne.com/genrtion_resrcs/reports/emission/2011_emissions_report.pdf.

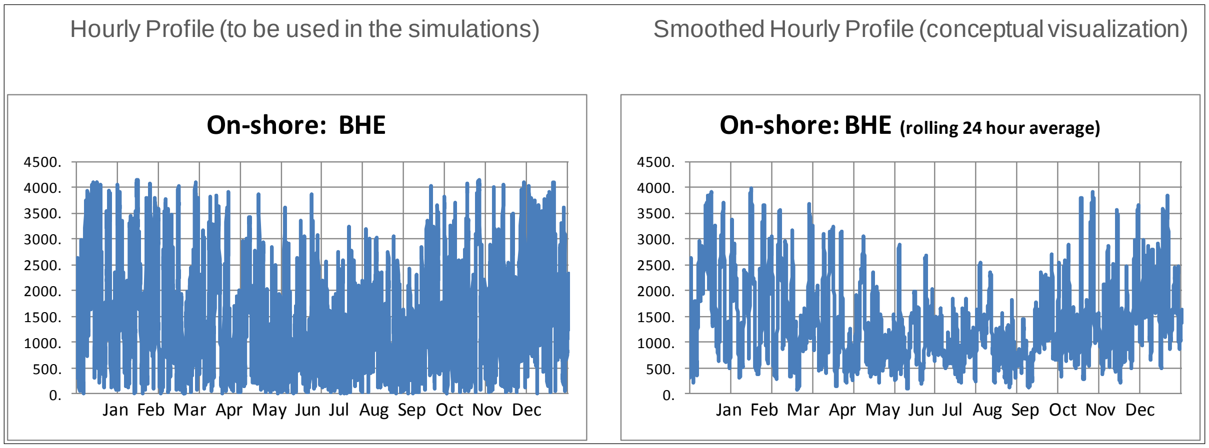

Figure 3-4: BHE onshore wind profiles assumed (MW).

3.2 Load forecast

The New England load forecasts were based on the demand data for 2014 to 2023, as presented in the 2013 CELT Report.[18] The hourly profile for the 2018 load was based on the historical 2006 hourly load profile, which reflected a 2006 weather pattern. The hourly profile for 2006 was used as the basis for representing the New England loads because of the availability of estimated correlated, time-stamped profiles for wind and photovoltaic resources.

To allocate loads to the busses across the New England network, historical distribution factors were used. These distribution factors resulted in a slight shift in the location of the peak loads compared with the CELT Report allocation, which was based on a different historical year load shape. Figure 3-5 presents the monthly peak load modeled in *2013 Economic Study*, with an annual peak of 30,062 MW.

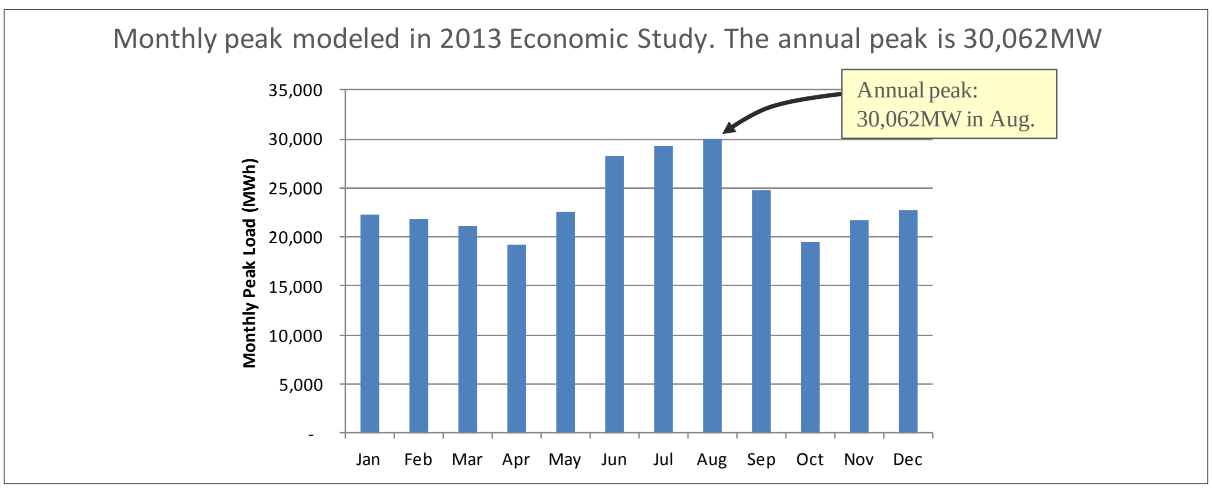

Figure 3-5: Modeled monthly New England peak loads (MW).

Similarly, Figure 3-6 shows the monthly electric energy modeled in the *2013 Economic Study*. The annual total energy was 145,501 GWh.

[18] "2013 Forecast Data File" (2013), http://www.iso-ne.com/trans/celt/fsct_detail/2013/isone_fcst_data_2013.xls.

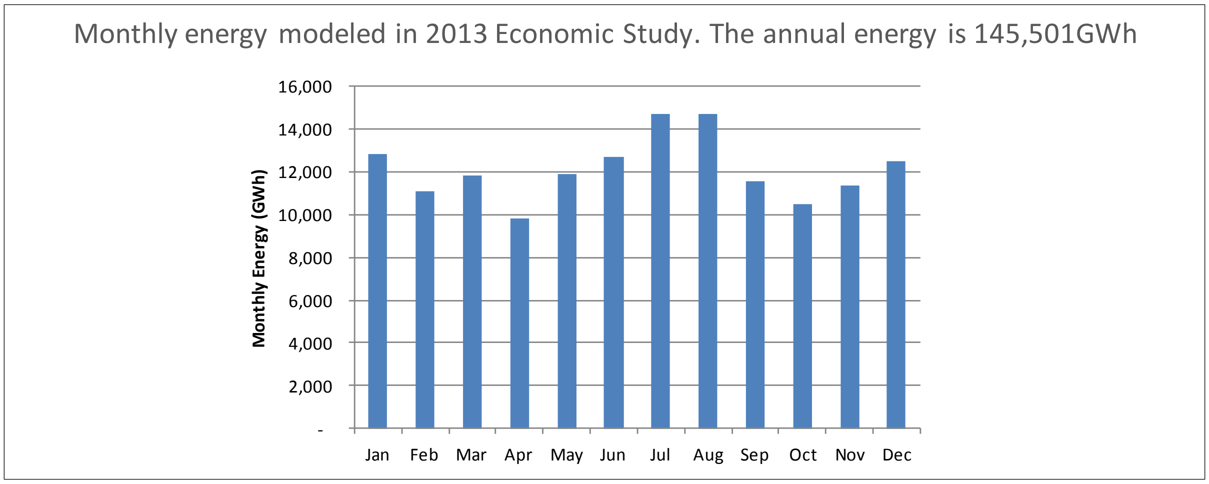

Figure 3-6: Modeled monthly New England electric energy (GWh).

3.2.1 Effects of Active Demand Resources, Energy Efficiency, and Real-Time Emergency Generation on Load

The ISO explicitly modeled the energy efficiency (EE), demand response (active DR) and real-time emergency generation (RTEG) by developing a profile for each of the three components.[19] These profiles underscore the ISO's expectation that active demand response and real-time emergency generators will be called and must be ready to respond.

The demand resources modeled in New England were based on the 2013/2014 capacity supply obligations (including proration) and *2013 Energy Efficiency Forecast for 2016–2022*, as shown in Table 3-1.[20]

[19] *Energy efficiency* is a type of demand resource that reduces the total amount of electrical energy and capacity at an end-use customer's facility that otherwise would have been needed to deliver an equivalent or improved level of end-use service. Such measures or systems include the use of more efficient lighting, motors, refrigeration, HVAC equipment, control systems, and industrial process equipment. *Demand response* is when market participants reduce their consumption of electric energy from the network when instructed in exchange for compensation based on wholesale market prices. *Active demand response* is when a demand resource reduces load quickly or continuously in response to a request from the ISO for system reliability reasons or in response to a price signal. *Real-time emergency generation* is distributed (i.e., on-site) generation the ISO calls on to operate during certain voltage-reduction or more severe actions; limited to 600 MW per the ISO market rules.

[20] A *capacity supply obligation* is a requirement for a resource to provide capacity, or a portion of capacity, to satisfy a portion of the ISO's Installed Capacity Requirement acquired through a Forward Capacity Auction, an FCM reconfiguration auction, or a CSO bilateral contract through which a market participant may transfer all of part of its CSO to another entity. *Final 2013 Energy-Efficiency Forecast 2016-2022* (February 22, 2013), http://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/othr/enrgy_effncy_frcst/2013frcst/iso_ne_final_ee_forecast_2016_2022.pdf.

Resource Type	Megawatts with Obligations
Real-time demand-response	1,172
Energy efficiency (seasonal and on peak)	1,178
Real-time emergency generation (activated in OP #4, Action 6)[(a)]	683

Table 3-1: Amount and type of demand resources in New England (MW, 2018).

(a) Operating Procedure No. 4 (OP 4) actions include allowing the depletion of the 30-minute reserves and the partial depletion of 10-minute reserves (1,000 MW), scheduling market participants' submitted emergency transactions and arranging emergency purchases between balancing authority areas (1,600 to 2,000 MW), and implementing 5% voltage reductions (400 to 450 MW). Operating Procedure No. 4, *Action during a Capacity Deficiency* (August 12, 2014), http://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op4/op4_rto_final.pdf.

Figure 3-7, Figure 3-8, and Figure 3-9 present the EE, active DR, and RTEG capacity based on location.

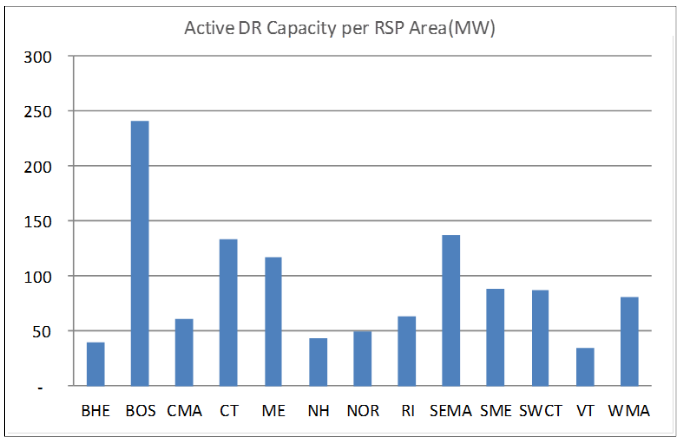

Figure 3-7: Active demand-resource capacity by Regional System Plan (RSP) area (MW).

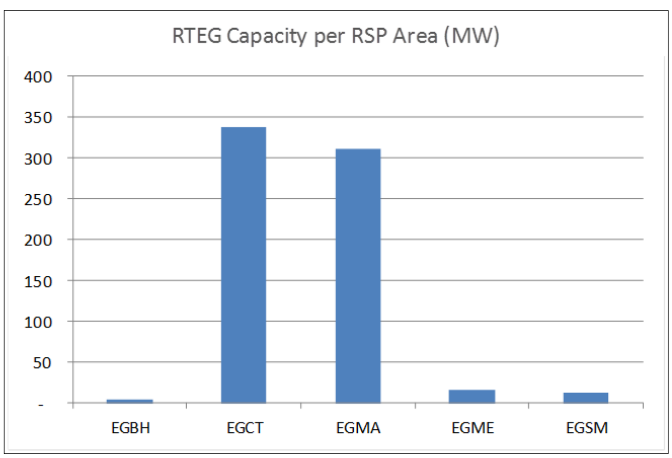

Figure 3-8: Real-time emergency generation capacity by RSP area (MW).

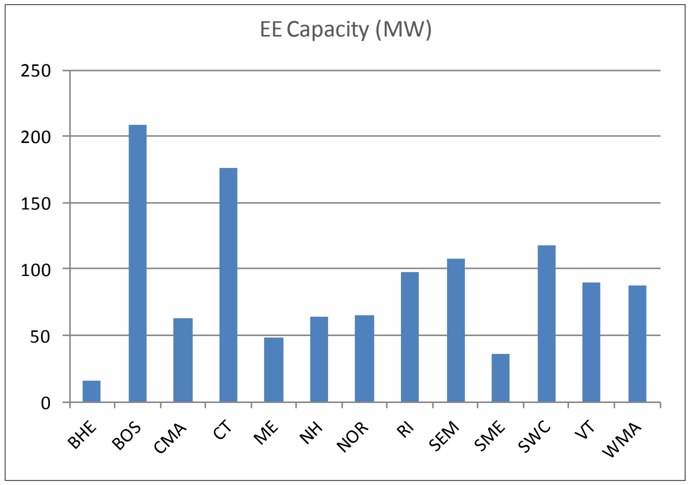

Figure 3-9: Energy efficiency by RSP area (MW).

Figure 3-10 presents the combined hourly values of EE, active DR, and RTEG used to modify the hourly load the generating resources need to serve.

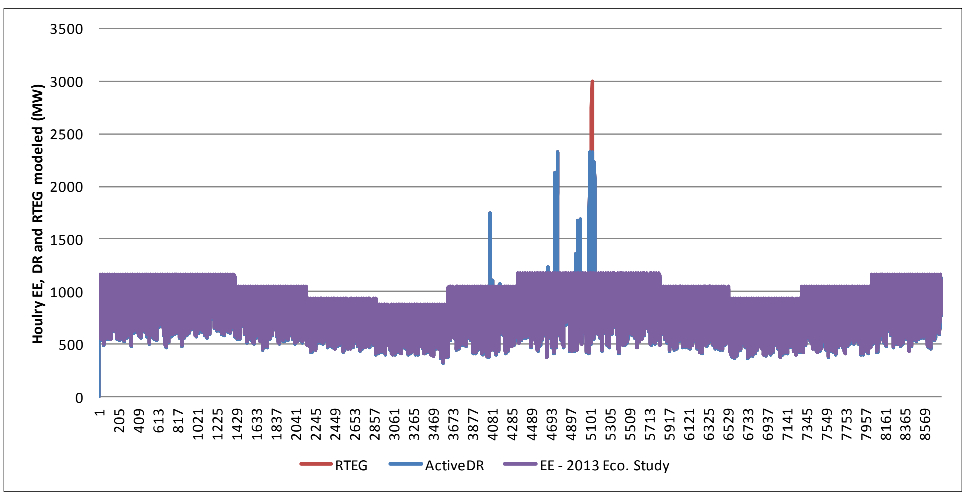

Figure 3-10: Profile representing energy efficiency, active demand response, and real-time emergency generation (MW).

3.3 Imports and Exports

One of the key assumptions was New England's import/export interchange flows with New York, Québec, and New Brunswick (Maritimes).

Figure 3-11 shows the external areas along the periphery of the New England footprint identified with dark arrows. To represent these external areas, historical flows were used to develop typical diurnal profiles. This approach captured the characteristics observed within the historical data and summarized the flows by month throughout the year. An alternative was to use a single 8,760-hour profile from a specific year as representative of future flows. However, this was not the preferred approach because the study did not attempt to duplicate fuel prices, weather patterns, load levels, and associated resource availability that would have been the driving factors behind the actual real-time interface flows for a specific historical year.

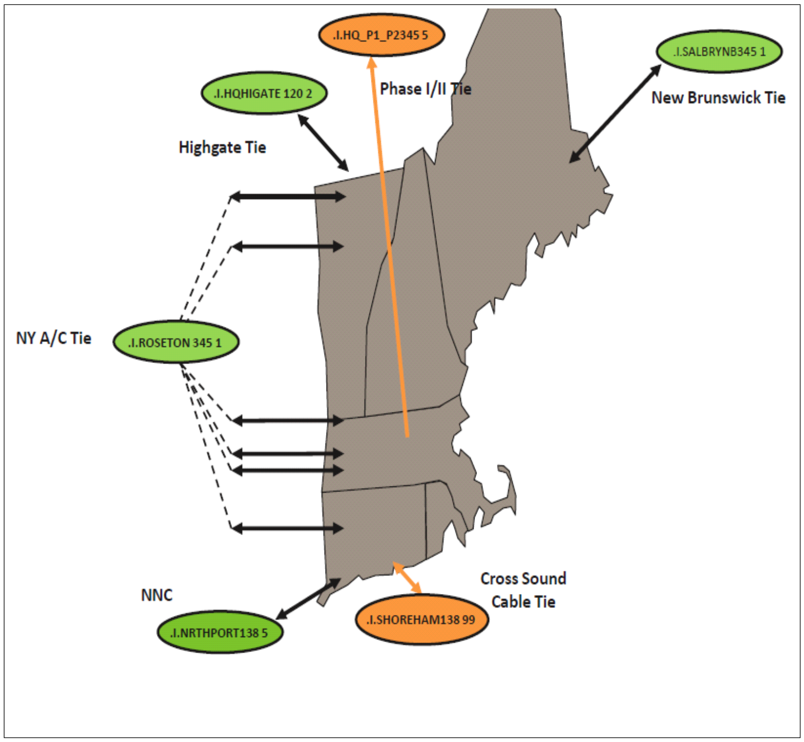

Figure 3-11: New England's external interfaces.

Three years' worth of data for 2007, 2008, and 2009 were used to develop the average diurnal interchange profiles. The typical diurnal profiles were developed by averaging the historical hourly loads to get 12 typical profiles, one for each month. For each month, all the hourly values, 12:01 a.m. to 1:00 a.m., 1:01 a.m. to 2:00 a.m., etc., were averaged together to develop a 24-hour profile. Because each month has about 30 days, and the study covers three sampled years, each hour represents an average of 90 values.

The diurnal flows across these external interfaces are presented in Figure 3-12 to Figure 3-16. These graphs show the profiles for each of the three years with the three-year average shown as a thick blue line.

3.3.1 Québec

Flows across HQ PII into Sandy Pond are shown in Figure 3-12. From this graph, variations in the trends can be seen in the summer and fall months. This profile will be used as the basis for the import profile used in Scenarios D and D2.

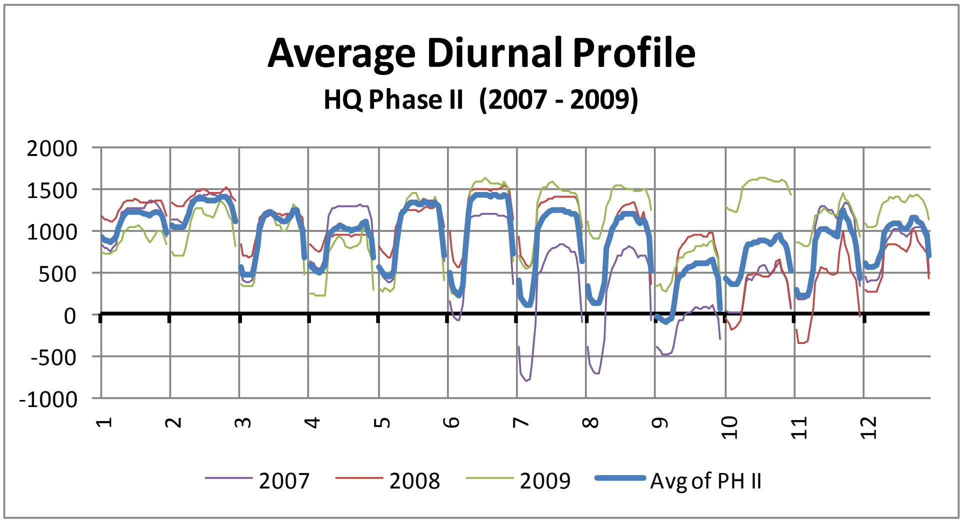

Figure 3-12: Average diurnal flows by month, representing net energy injections into New England at HQ PII (MW).

Figure 3-13 shows the diurnal profiles for imports from Québec at Highgate, which were relatively constant during the summer and fall months.

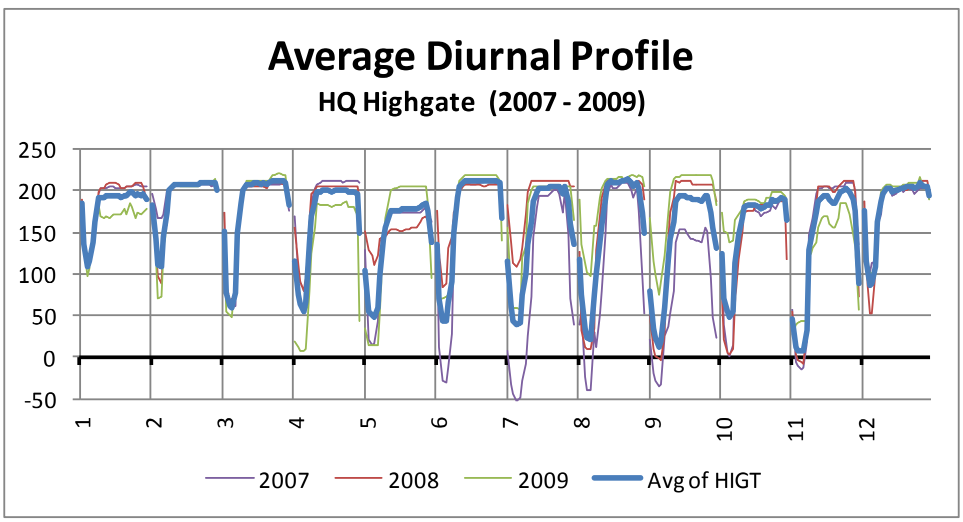

Figure 3-13: Average diurnal flows by month, representing net energy injections into New England at Highgate (MW).

3.3.2 Maritimes

Figure 3-14 shows the profiles for imports from the Maritimes for each of the years and an average for all three years.

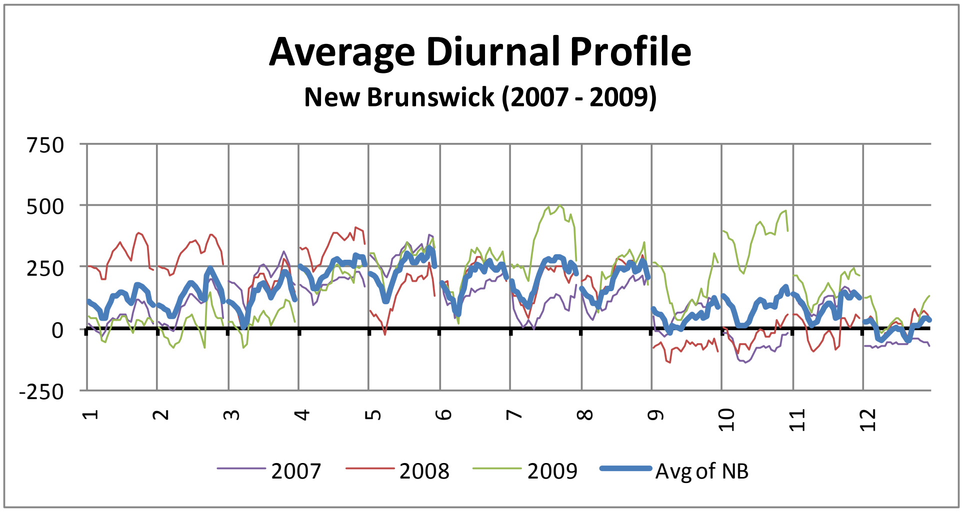

Figure 3-14: Average diurnal flows by month, representing net energy injections into New England at New Brunswick (MW).

3.3.3 New York

Figure 3-15 and Figure 3-16 show the interchange profiles between New England and New York for each of the years and an average for all three years. These show a pattern of New England exports to New York during the on-peak hours and imports during the off-peak hours.

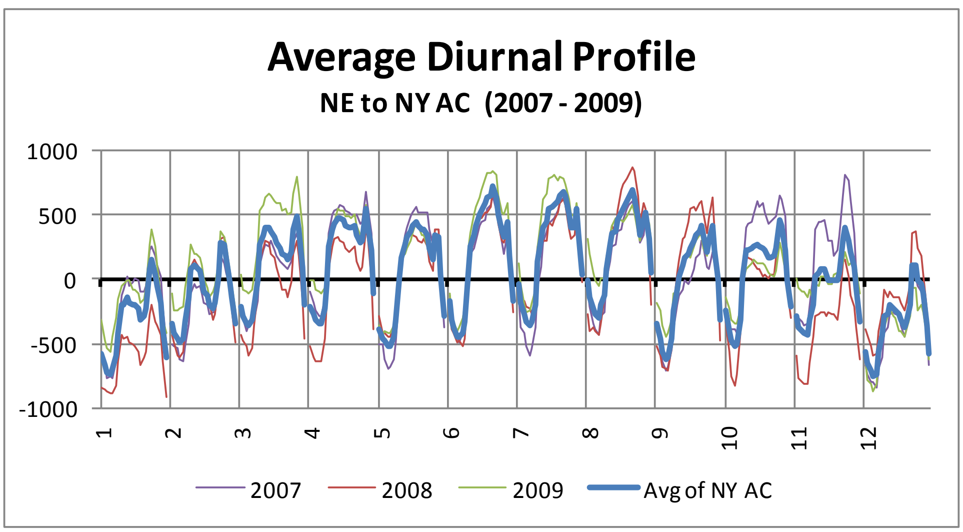

Figure 3-15: Average diurnal flows by month, representing net energy injections into New England at the NY AC tie (MW).

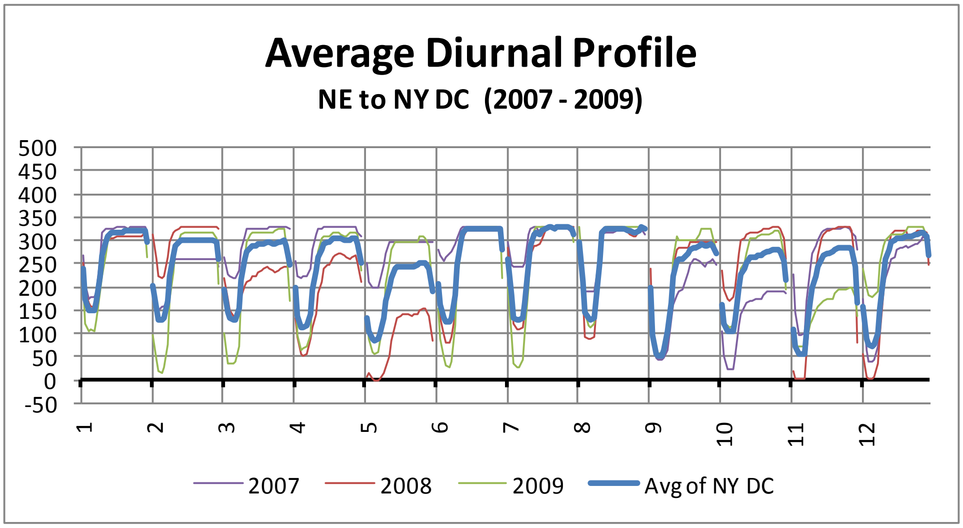

Figure 3-16: Average diurnal flows by month, representing net energy injections into New England at Cross-Sound Cable (MW).

3.4 Transmission System Network

The detailed ISO New England transmission network was based on the ISO's 2013 FERC 715 filing using the 2018 summer case. Transmission lines operated at 230 kV and above were monitored. Generator step-up (GSU) transformers were not monitored to prevent a GSU transformer from artificially limiting a combined-cycle plant.

3.4.1 Contingency Modeling

The list of contingencies used was derived from an archive of events that occurred within a three-year period. A total of 160 contingencies meet the criteria. Approximately 100 of these contingencies were converted from the ISO Operations' network model (EMS) to the simulation network model. The contingencies were based on an historical network and did not include future transmission infrastructure that would be expected to be in service by the study year.

3.4.2 Phase-Shifter Modeling

The simulation monitored two aspects of phase shifters:

- Angle and megawatt limits
- Enforcement of the parallel phase-shifter operation at Baker Street and Waltham substations in the Boston area

3.4.3 Transmission interfaces

Transmission interface limits consistent with planning criteria were used for major interfaces between load and generation areas.[21] These interfaces restricted flows on a limited number of paths to the levels

[21] *Transmission Transfer Limits for Transportation Models: 2012 Regional System Plan Assumptions*, Planning Supply Power 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.

shown in Table 3-2. These interface limits provided the only mechanism for including voltage and stability limits in the simulations.

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 (HQ PII)	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

Table 3-2: Interface limits for 2018 (MW).

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

Section 4
Simulation Results

This section presents the simulation results for each of the scenarios investigated. The key aspect of this study was to investigate how varying the amount of HQ PII import capability affects various metrics. The metrics included the ISO's regionwide energy production cost, LSE energy expense, "make-whole" (i.e., "uplift") payments, congestion costs, and emissions under various reserve-requirement representations. For convenience, the results are presented for each Scenario A through E, showing the effects of the maximum import level for each reserve-requirement representation. The simulation metrics are presented at the end of each section for each HQ PII profile by reserve-requirement representation.

The metrics discussed assume that the underlying resources did not change as the maximum amount of HQ PII imports increased. An increase in available imports that decreases the other installed resources, through retirements or the deferral of new additions, could create an offsetting effect on the metric.

4.1 Energy Metrics—HQ PII Annual Generation

The amount of energy associated with each scenario and import level had an impact on the economic metrics presented in this section. Figure 4-1 and Table 4-1 present the annual energy imports from HQ PII for Scenarios A through D2. Because these scenarios are the result of explicit import profiles, the amount of energy imported from HQ PII was the same for both the reserve representations.

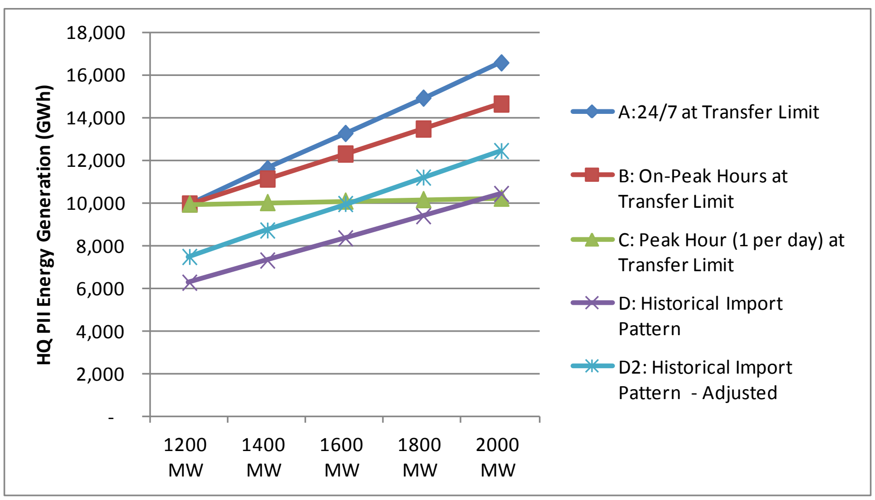

Figure 4-1: Comparison of HQ PII annual generation for Scenarios A to D2 (GWh).

HQ PII Import Level	HQ PII Energy Generation (GWh)				
	A:24/7 at Transfer Limit	B: On-Peak Hours at Transfer Limit	C: Peak Hour (1 per day) at Transfer Limit	D: Historical Import Pattern	D2: Historical Import Pattern - Adjusted
1200 MW	9,936	9,936	9,936	6,244	7,452
1400 MW	11,592	11,109	10,005	7,285	8,694
1600 MW	13,248	12,282	10,074	8,325	9,936
1800 MW	14,904	13,455	10,143	9,366	11,178
2000 MW	16,560	14,628	10,212	10,407	12,420

Table 4-1: Comparison of HQ PII annual generation for Scenarios A to D2 (GWh).

Figure 4-2 and Table 4-2 show that, in Scenario E, when the HQ PII annual imports were modeled using a dispatch price of $289/MWh based on 80% of an inefficient combustion turbine and distillate fuel price, the amount of energy imported was quite small. Part of the reason for this low amount of energy was because Scenario E did not have the 1,200 MW minimum import level assumed in Scenarios A through C or the off-peak energy assumed in Scenarios D and D2. Because the cost of HQ PII was high, energy was only taken when it was needed to satisfy the requirements for energy plus reserve. For the Scenario E cases with the lower dispatch prices of $10, $20, and $30/MWh, the HQ PII energy imports were slightly greater than the "base load" Scenario A because no maintenance outages were assumed.

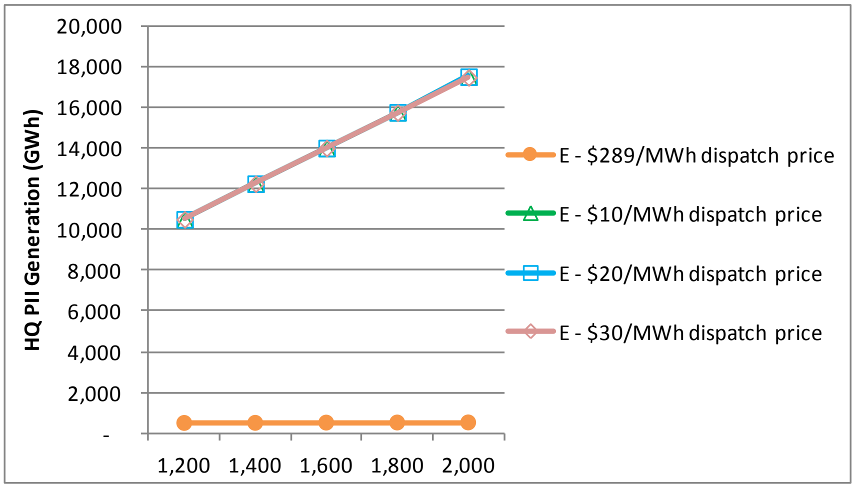

Figure 4-2: Comparison of HQ PII annual generation for Scenarios E—Dispatchable Based on Energy Price (GWh).

HQ PII Import Level (MW)	HQ PII Energy Generation (GWh)			
	E - $289/MWh dispatch price	E - $10/MWh dispatch price	E - $20/MWh dispatch price	E - $30/MWh dispatch price
1,200	491	10,512	10,512	10,510
1,400	495	12,264	12,264	12,259
1,600	507	14,016	14,016	14,012
1,800	511	15,768	15,768	15,755
2,000	516	17,520	17,520	17,484

Table 4-2: Comparison of HQ PII annual generation for Scenarios E—Dispatchable Based on Energy Price (GWh).

4.2 Reserve Requirements: Daily Reserves Compared With Dynamic Reserves

The results presented in this section include economic and environmental metrics for both the Daily Reserve and the Dynamic Reserve cases. Within the simulations, both the Daily and Dynamic representations have comparable constraints. Figure 4-3 shows the available spinning reserve by hour for the peak week of the simulation for Scenario B. This available reserve was developed by summing each committed resource's maximum change in output within 10 minutes, limited by the difference between each resource's hourly dispatch point and maximum rating. Pumped-storage resources are included even when they are off line or in pumping mode. The large amounts of reserves between midnight and early morning reflect the assumption that the pumped-storage resources could transition from pumping to generating within the required period. The simulation constraints, only binding during the peak load hours of the day, resulted in ample reserves during the nonpeak hours.

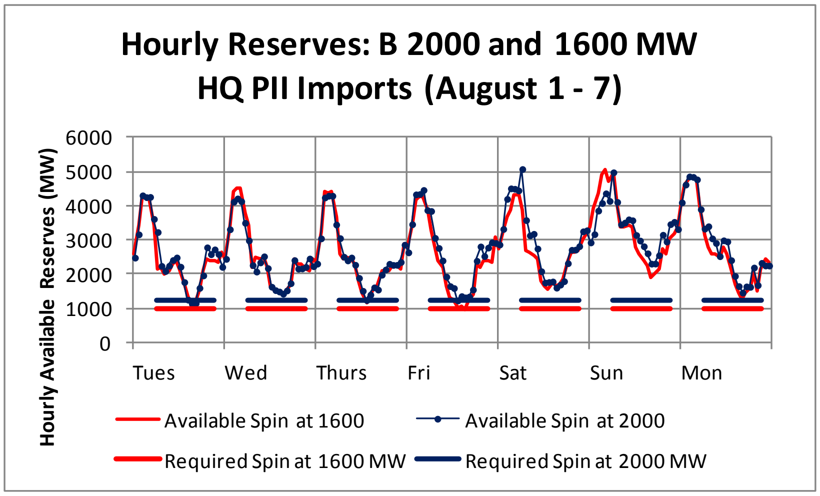

Figure 4-3: Comparison of available spinning reserve for the Daily Reserve and Dynamic Reserve Requirements.

While this illustration was based on Scenario B, the characteristic trend in the supply of available 10-minute reserves would be similar for other scenarios.

Both the Daily Reserve and Dynamic Reserve representations are reasonable, and neither can be viewed as inherently better than the other. Because the ISO New England markets co-optimize energy and reserves, these Daily Reserve and the Dynamic Reserves representations do not capture all the factors that could influence the procurement of reserves. The level of granularity needed for co-optimization was outside the scope of this investigation

4.3 Economic Metrics—Production Cost

The key economic metrics used to compare the cases are production cost and LSE energy expense. The production cost metric was based on the summation of hourly dispatch costs for each unit multiplied by the hourly amount of energy produced. This calculation aggregates all New England resources used to serve customer demands. Production costs for resources located in external areas were not included in this metric. The absolute values of these metrics are not the focus of this analysis because the aim was to quantify relative changes. This section presents the production cost metrics for all the simulation cases.

4.3.1 Scenario A—24/7 at the Transfer Limit

Scenario A assumed that when HQ PII was not on maintenance, the import levels were increased and held at a constant level for 24 hours per day, every day (24/7). Figure 4-4 and Table 4-3 present the results as the HQ PII transfer limit increased from 1,200 MW to 2,000 MW for the two different reserve-requirement representations. Figure 4-4 shows the production cost results of the Daily Reserve with a green line and the results of Dynamic Reserve assumptions shown with a purple line.

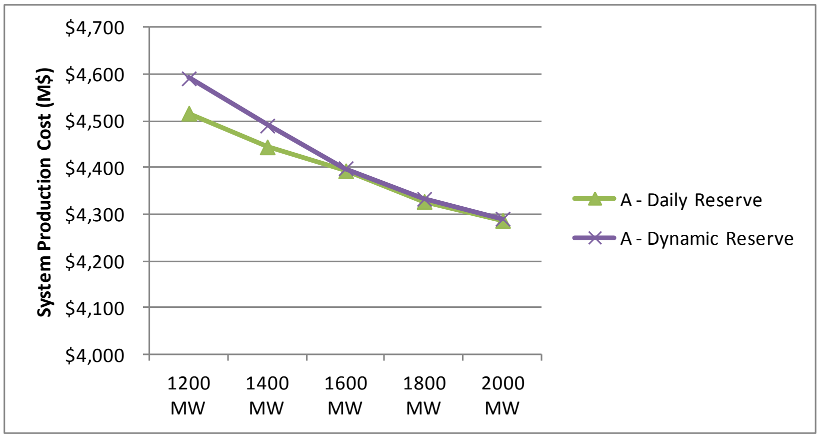

Figure 4-4: Comparison of annual production cost for Scenario A—24/7 at Transfer Limit, assuming the cost of HQ PII energy is zero ($ million).

HQ PII Import Level (MW)	Production Cost (M$) - Assume cost of HQ PII are zero	
	A - Daily Reserve	A - Dynamic Reserve
1200 MW	$ 4,517	$ 4,591
1400 MW	$ 4,445	$ 4,490
1600 MW	$ 4,393	$ 4,399
1800 MW	$ 4,328	$ 4,333
2000 MW	$ 4,287	$ 4,291

Table 4-3: Annual production cost for Scenario A—24/7 at Transfer Limit ($ million).

These results show that the production costs decreased as more energy was imported from Hydro-Québec. When the HQ PII import level increased from 1,200 MW to 2,000 MW, the system production cost decreased between 5 and 7%. This was largely the result of the modeling assumption, which assumed the production cost of this imported energy was zero.

The cost of additional unit commitment that might have been necessary to satisfy the reserve requirements cannot be separated from the value of the energy in this scenario. Other scenarios assume less imported energy and can be used to investigate the cost of additional unit commitment.

The Dynamic Reserve cases show that the production costs at 1,200 and 1,400 MW are higher than the Daily Reserve cases because the simulation must provide higher reserves for the Mystic 8 and 9 contingency, as well as the loss of the larger nuclear units. At 1,800 MW and 2,000 MW, the reserve requirement was driven by HQ PII.

Figure 4-5 presents production costs compared with the annual imported energy from HQ PII. The Dynamic Reserve cases are associated with higher production costs for the 1,200 and 1,400 MW scenarios because higher reserve requirements are needed to support the combined Mystic 8 and 9 resources, as well as the larger nuclear units.

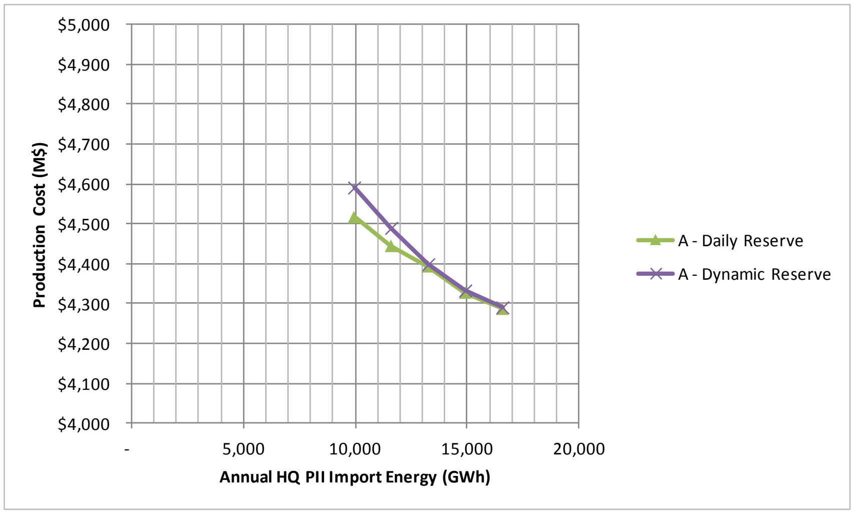

Figure 4-5: Effect of imported energy from HQ PII on the production cost metric for Scenario A—24/7 at Transfer Limit ($ million).

4.3.2 Scenario B—On-Peak Hours at Transfer Limit

For Scenario B, which only simulates HQ PII reaching the limit during the on-peak hours of each day, the production cost metric shows characteristics similar to Scenario A but with smaller decreases, commensurate with the reduction in energy from HQ PII. Figure 4-6 and Table 4-4 show that the production cost metric decreased $170 million under the Daily Reserve cases. The Dynamic Reserve cases show that the production costs are higher than the Daily Reserve cases at 1,200 MW and 1,400 MW because more reserves are required to support the combined Mystic 8 and 9 resources, as well as the larger nuclear units.

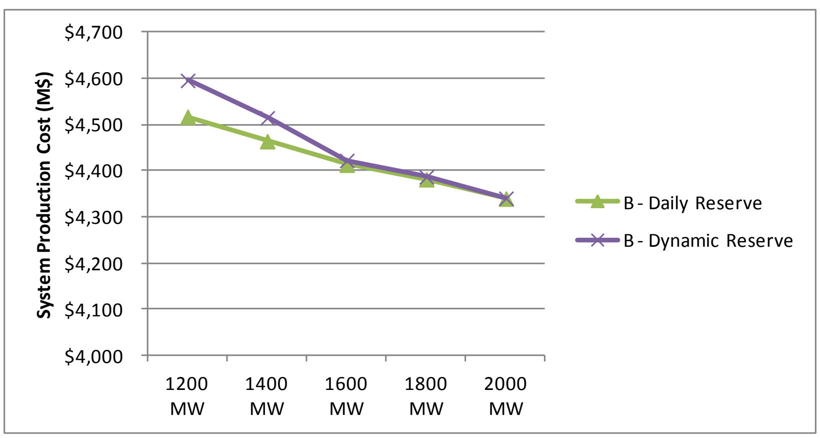

Figure 4-6: Comparison of annual production costs for Scenario B—On-Peak Hours at Transfer Limit, assuming the cost of HQ PII energy is zero ($ million).

HQ PII Import Level (MW)	Production Cost (M$) - Assume cost of HQ PII are zero	
	B - Daily Reserve	B - Dynamic Reserve
1200 MW	$ 4,517	$ 4,596
1400 MW	$ 4,464	$ 4,514
1600 MW	$ 4,413	$ 4,422
1800 MW	$ 4,381	$ 4,387
2000 MW	$ 4,339	$ 4,340

Table 4-4: Annual production cost for Scenario B—On-Peak Hours at Transfer Limit ($ million).

Figure 4-7 compares production costs with the annual imported energy from HQ PII. At 1,200 MW and 1,400 MW, the higher production costs were associated with the Dynamic Reserve cases because the possible loss of the combined Mystic 8 and 9 resource, as well as the larger nuclear units, are larger contingencies with subsequently higher reserve requirements.

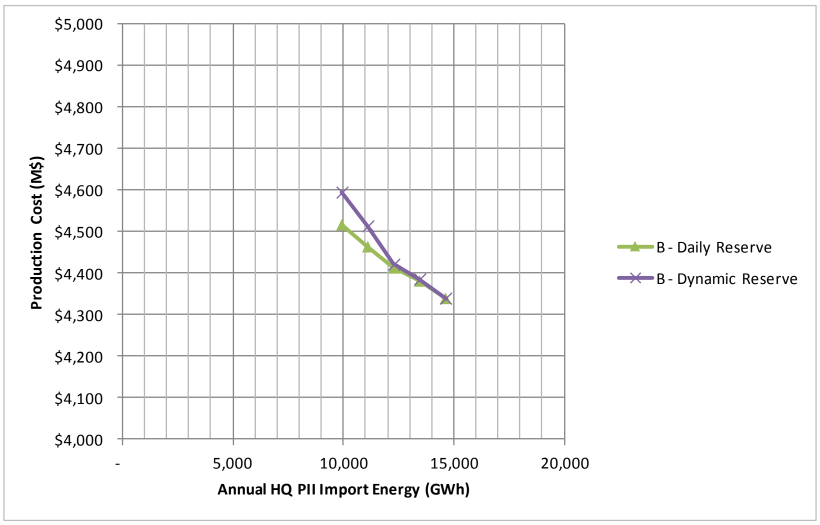

Figure 4-7: Effect of imported energy from HQ PII on the production cost metric for Scenario B—On-Peak Hours at Transfer Limit ($ million).

4.3.3 Scenario C—Peak Hour (1 Hour per Day) at Transfer Limit

The production cost metric for Scenario C, which only simulates HQ PII reaching the import limit during a single on-peak hour each day while all other hours are at 1,200 MW, has a different trend from Scenarios A and B. This change was because the amount of imported energy associated with this profile was much smaller, and the impact on the metric was driven by the need to commit additional resources to provide the reserves. Figure 4-8 and Table 4-5 show that the production cost metric increased $150 million under the Daily Reserve cases as the import level increased from 1,200 to 2,000 MW.

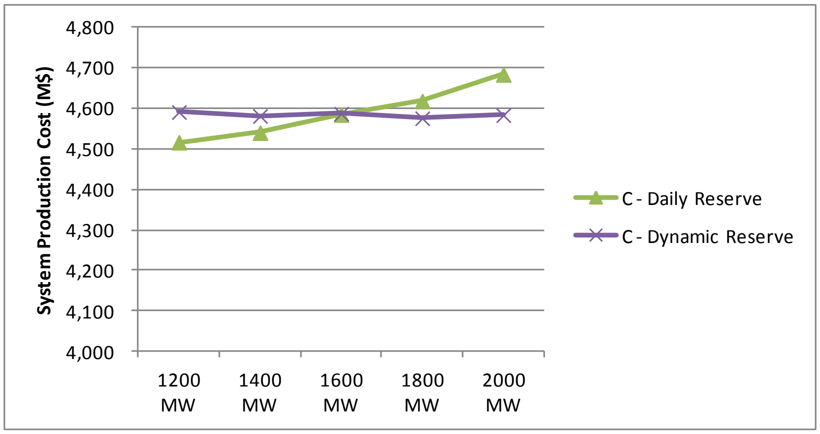

Figure 4-8: Comparison of annual production costs for Scenario C—Peak Hour (1 Hour per Day) at Transfer Limit, assuming the cost of HQ PII energy Is zero ($ million).

HQ PII Import Level (MW)	Production Cost (M$) - Assume cost of HQ PII are zero	
	C - Daily Reserve	C - Dynamic Reserve
1200 MW	$ 4,517	$ 4,591
1400 MW	$ 4,540	$ 4,582
1600 MW	$ 4,585	$ 4,587
1800 MW	$ 4,619	$ 4,576
2000 MW	$ 4,684	$ 4,584

Table 4-5: Annual production cost for Scenario C—Peak Hour (1 hour per day) at Transfer Limit ($ million).

The production costs for the Dynamic Reserve cases were higher than the costs in the Daily Reserve cases for the 1,200 and 1,400 MW import levels because reserves were required for the largest single source. However, the production cost metric for this case did not increase as the maximum import level from HQ PII increased. This suggests that the cost of these additional committed resources may be nearly offset by the assumed zero-cost energy from Québec.

Figure 4-9 presents the production costs compared with the annual imported energy. At the lower import levels of 1,200 MW (9,936 GWh) and 1,400 MW (10,005 GWh), the Dynamic Reserve cases were associated with higher production costs because the possible loss of the combined Mystic 8 and 9 resource, as well as the larger nuclear units, are larger contingencies. At the higher import level of 1,800 MW (10,143 GWh) and 2,000 MW (10,212 GWh) under the Dynamic Reserve cases, the production costs are less than the Daily Reserve cases. This was partly because more economic energy was available to serve load instead of being held to serve the higher reserve requirements needed in the Daily Reserve cases. The horizontal scale for this graph is much smaller because of the small range of gigawatt-hours imported.

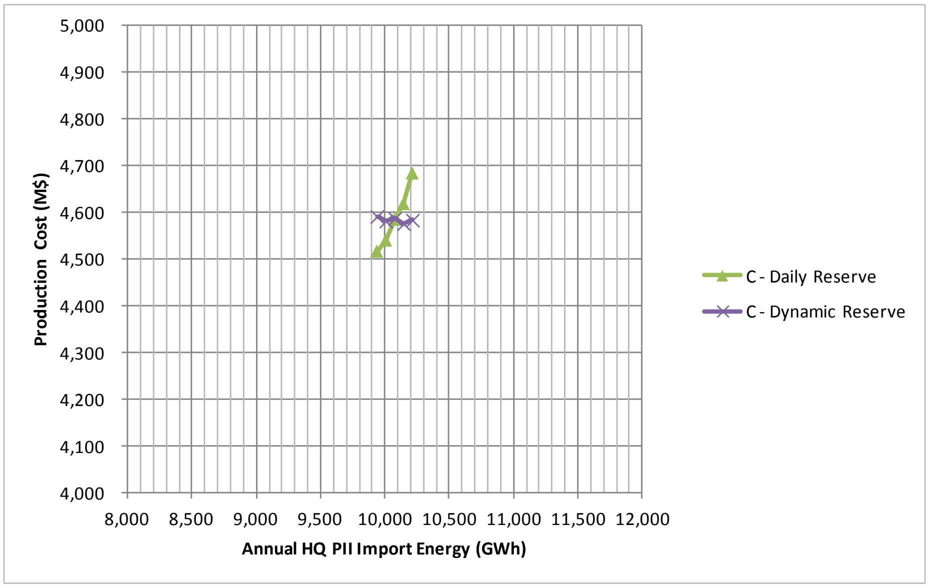

Figure 4-9: Effect of imported energy from HQ PII on the production cost metric for Scenario C—Peak Hour (1 Hour per Day) at Transfer Limit ($ million).

4.3.4 Scenario D—Historical Import Pattern

Figure 4-10 and Table 4-6 compare the production costs for each of the reserve-requirement representations of Scenario D, which used an assumed historical profile for HQ PII that reached the assumed import limit only in June. These results show that the production cost metric decreased about $100 million, with most of the reduction coming from the change in HQ PII imports from 1,200 to 1,600 MW. At the higher transfer levels of 1,800 and 2,000 MW, the assumed zero cost of energy under the Daily Reserve cases appears to approximately offset the cost implications of providing reserves.

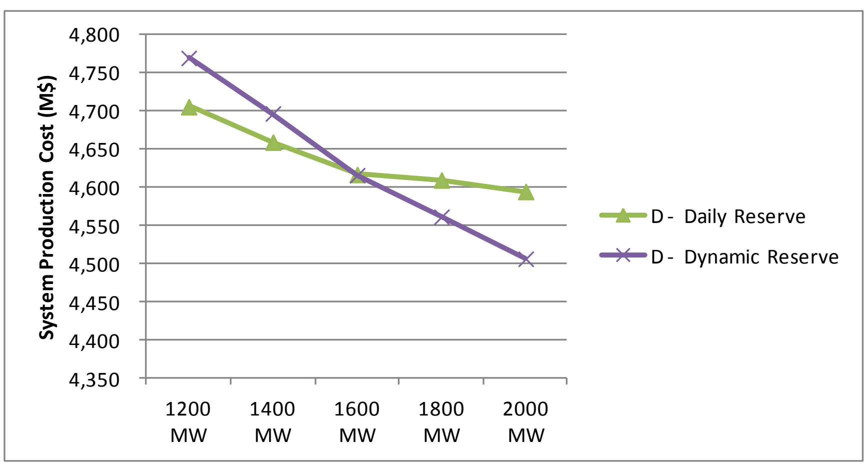

Figure 4-10: Comparison of annual production costs for Scenario D—Historical Import Pattern, assuming the cost of HQ PII energy is zero ($ million).

HQ PII Import Level (MW)	Production Cost (M$) - Assume cost of HQ PII are zero	
	D - Daily Reserve	D - Dynamic Reserve
1200 MW	$ 4,706	$ 4,770
1400 MW	$ 4,660	$ 4,697
1600 MW	$ 4,617	$ 4,616
1800 MW	$ 4,610	$ 4,562
2000 MW	$ 4,595	$ 4,507

Table 4-6: Annual production costs for Scenario D—Historical Import Pattern ($ million).

The results show that the Dynamic Reserve cases have production costs that begin higher than the Daily Reserve cases because reserves are needed to cover the resources larger than the assumed HQ PII. As the assumed import levels increase, the production costs decrease nearly uniformly up to 2,000 MW. The production cost savings attributable to increasing the import level from 1,200 to 2,000 MW was approximately $270 million.

Figure 4-11 presents the production costs compared with the annual imported energy. At the lower import levels of 1,200 MW and 1,400 MW, the Dynamic Reserve cases were associated with higher production costs because the possible loss of the combined Mystic 8 and 9 resource, as well as the larger nuclear units, are larger contingencies. At the higher import level of 1,800 MW and 2,000 MW under the Dynamic Reserve cases, the production costs are less than the Daily Reserve cases.

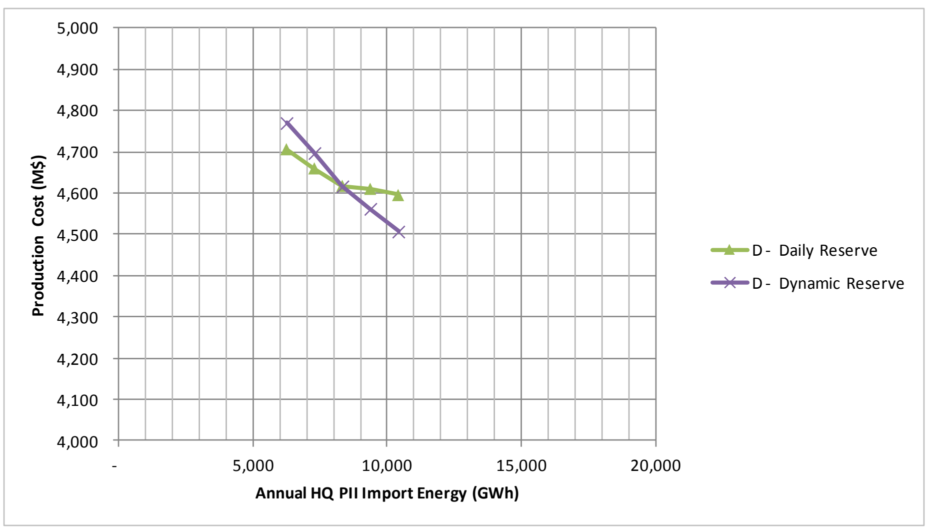

Figure 4-11: Effect of imported energy from HQ PII on the production cost metric for Scenario D—Historical Import Pattern ($ million).

4.3.5 Scenario D2—Historical Import Pattern-Adjusted

Scenario D2 used an assumed historical profile for HQ PII, adjusted to reach the assumed import limit on each day of the year. For this profile, HQ PII provided more energy than Scenario D, which only reached the assumed import limit in a single month of the year. Figure 4-12 and Table 4-7 compare the production cost for each of the reserve-requirement representations. These results show that production costs decreased about $150 million (3%), with most of the reduction coming from the first 400 MW (from 1,200 to 1,600 MW) of increased transfer capability.

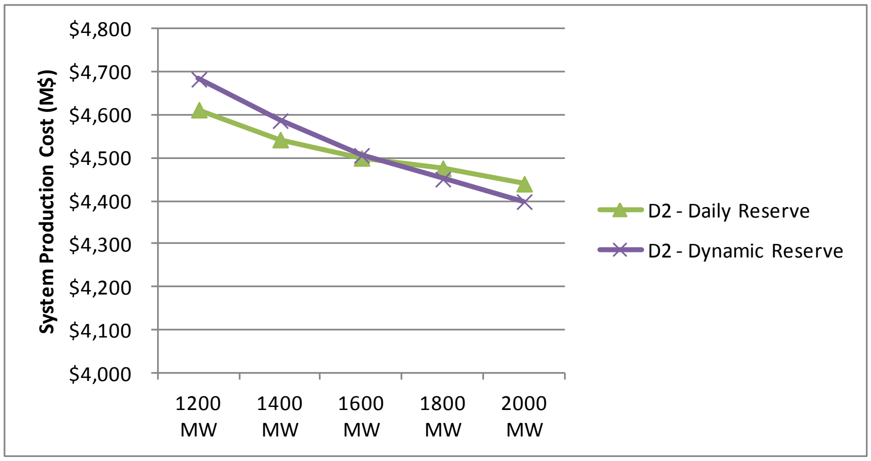

Figure 4-12: Comparison of annual production costs for Scenario D2—Adjusted Historical Import Pattern, assuming the cost of HQ PII energy is zero ($ million).

HQ PII Import Level (MW)	Production Cost (M$) - Assume cost of HQ PII are zero	
	D2 - Daily Reserve	D2 - Dynamic Reserve
1200 MW	$ 4,612	$ 4,683
1400 MW	$ 4,543	$ 4,587
1600 MW	$ 4,500	$ 4,506
1800 MW	$ 4,476	$ 4,451
2000 MW	$ 4,440	$ 4,399

Table 4-7: Annual production cost for Scenario D2—Adjusted Historical Import Pattern ($ million).

The Dynamic Reserve cases show that the production costs begin higher, reflecting the cost of providing the reserves needed to cover the loss of the larger resources. As the assumed import levels increased, the production cost decreased nearly uniformly up to the 2,000 MW import level. The range of production-cost savings from 1,200 to 2,000 MW was about $300 million (6%).

Figure 4-13 compares the production costs with the annual imported energy from HQ PII. At the lower import levels of 1,200 MW and 1,400 MW, the Dynamic Reserve cases were associated with higher production costs because the possible loss of the combined Mystic 8 and 9 resource, as well as the larger nuclear units, are larger contingencies. At the higher import level of 1,800 and 2,000 MW under the Dynamic Reserve cases, the production costs are less than in the Daily Reserve cases.

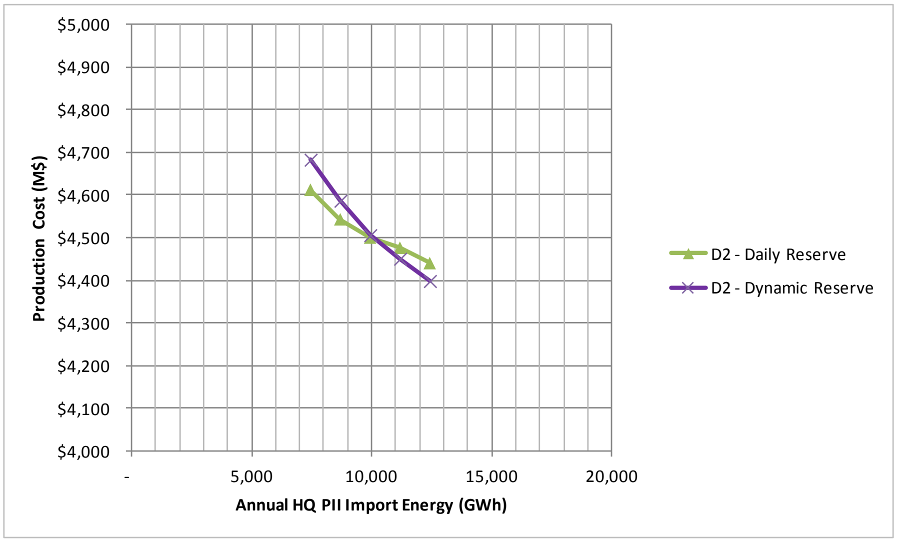

Figure 4-13: Effect of imported energy from HQ PII on the production cost metric for Scenario D2—Adjusted Historical Import Pattern ($ million).

4.3.6 Scenario E—Dispatchable Based on Energy Price

Scenario E allows HQ PII energy to be dispatched in accordance with the economic benefits that the resource provides to New England. Figure 4-14 and Table 4-8 compare the production costs for four assumed dispatch price levels. To test how often the HQ PII resource should be dispatched to preserve adequate reserve margins, a dispatch price based on 80% of an inefficient combustion turbine using distillate fuel was assumed. In addition, three cases with low dispatch prices of $10, $20, and $30/MWh were assessed to show any significant changes in the metrics. For Scenario E, all the cases assumed the Dynamic Reserve representation.

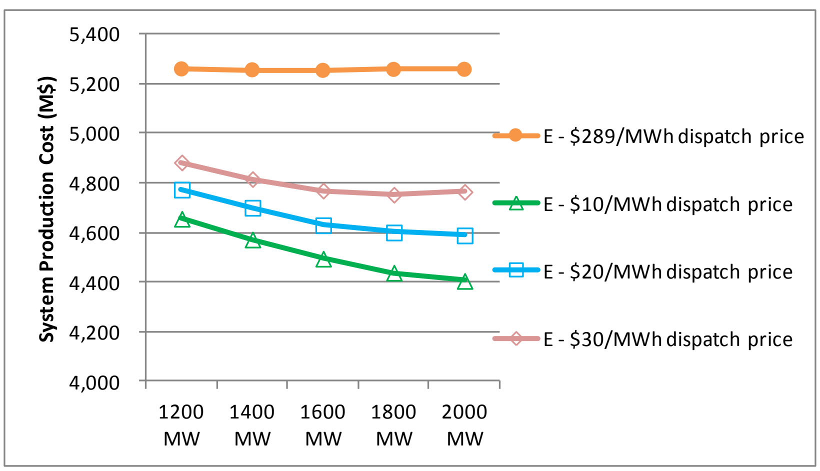

Figure 4-14: Comparison of annual production costs for Scenario E—Dispatchable Based on Energy Price, assuming the cost of HQ PII energy is as indicated ($ million).

HQ PII Import Level (MW)	Production Cost (M$)			
	E - $289/MWh dispatch price	E - $10/MWh dispatch price	E - $20/MWh dispatch price	E - $30/MWh dispatch price
1200 MW	5,260	4,656	4,774	4,883
1400 MW	5,256	4,573	4,701	4,816
1600 MW	5,254	4,495	4,630	4,770
1800 MW	5,258	4,439	4,601	4,753
2000 MW	5,258	4,406	4,589	4,765

Table 4-8: Annual production cost for Scenario E—Dispatchable Based on Energy Price ($ million).

These results show that the production costs decreased a negligible amount for the high-priced distillate-oil-based case, which imported very few megawatt-hours. The cases with the lower dispatch costs imported at the maximum rate every hour HQ PII was available. Because this was the production cost metric, the rate of decrease was a function of the assumed dispatch cost of the resource. Consequently, production costs decreased $250, $185, and $67 million at the dispatch prices of $10, $20, and $30, respectively.

Figure 4-15 compares the production costs with the annual imported energy for Scenario E. The figure shows that at $289/MWh, very few gigawatt-hours were imported and the production cost was the highest. At dispatch prices of $10, $20, and $30/MWh, the production costs decreased as a function of both the quantity and the assumed price paid for the energy.

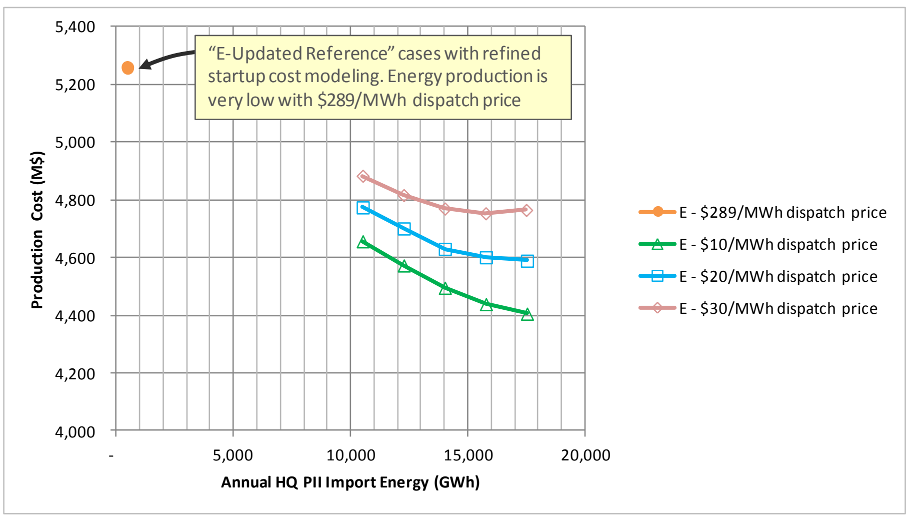

Figure 4-15: Effect of imported energy from HQ PII on the production cost metric for Scenario E—Dispatchable based on Energy Price ($ million).

4.3.7 Comparison of Production Costs across Scenarios

In addition to the previous comparisons where the reserve-requirement representations were compared by scenario, this section compares the reserve-requirement representation across the scenarios.

Figure 4-16 and Table 4-9 present the results for the Daily Reserve requirement cases for each of the scenarios. The trend for all the cases showed that production costs decreased when HQ PII increased, with the exception of Scenario C. Only Scenario C shows an increase in production costs as the maximum imports and the associated reserve requirements increased. The relatively small amount of imported zero-cost energy in Scenario C cannot mask the additional cost of unit commitment, which was clearly identifiable in these results.

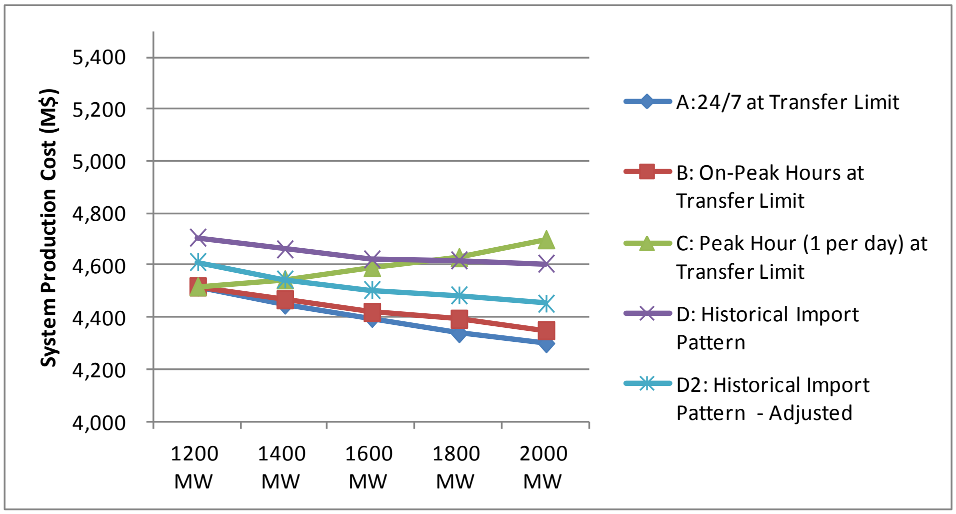

Figure 4-16: Comparison of annual production costs among various scenarios under the Daily Reserve requirements ($ million).

HQ PII Import Level (MW)	Production Cost (M$)				
	A - Daily Reserve	B - Daily Reserve	C - Daily Reserve	D - Daily Reserve	D2 - Daily Reserve
1200 MW	4,517	4,517	4,517	4,706	4,612
1400 MW	4,445	4,464	4,540	4,660	4,543
1600 MW	4,393	4,413	4,585	4,617	4,500
1800 MW	4,328	4,381	4,619	4,610	4,476
2000 MW	4,287	4,339	4,684	4,595	4,440
Reduction	230	177	(167)	111	172
Reduction%	5%	4%	-4%	2%	4%

Table 4-9: Comparison of annual production costs among various scenarios under the Daily Reserve requirements ($ million).

The results for the Dynamic Reserve requirement cases are shown in Figure 4-17 and Table 4-10. As before, the trend shows that the greater the HQ PII import, the greater the reduction in production costs. However, this was not observed in two cases. Scenario E, where HQ PII energy was priced equivalent to 80% of an inefficient combustion turbine using distillate fuel, was relatively constant because of the negligible amount of energy imported. The production cost for Scenario C also was relatively constant because the cost of providing reserves for only one hour was approximately offset by the assumed zero value of the imported energy.

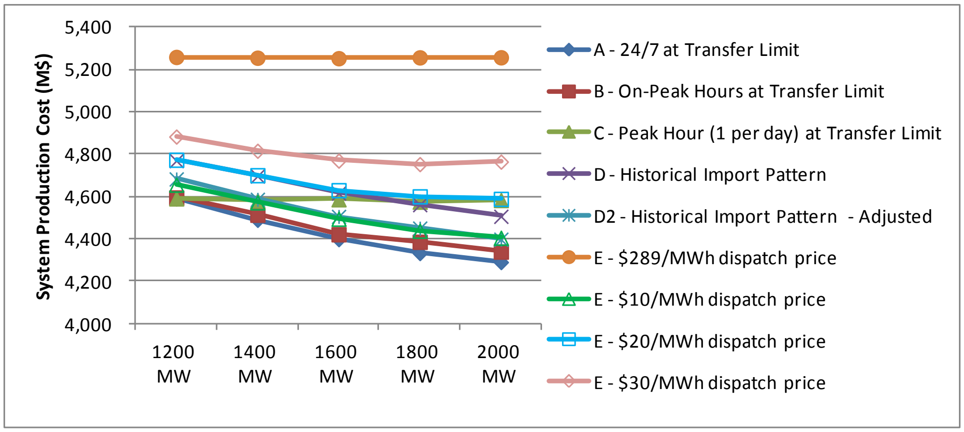

Figure 4-17: Comparison of annual production costs among various scenarios under the Dynamic Reserve requirements ($ million).

HQ PII Import Level (MW)	Production Cost (M$)				
	A - Dynamic Reserve	B - Dynamic Reserve	C - Dynamic Reserve	D - Dynamic Reserve	D2 - Dynamic Reserve
1200 MW	4,591	4,596	4,591	4,770	4,683
1400 MW	4,490	4,514	4,582	4,697	4,587
1600 MW	4,399	4,422	4,587	4,616	4,506
1800 MW	4,333	4,387	4,576	4,562	4,451
2000 MW	4,291	4,340	4,584	4,507	4,399
Reduction	301	255	8	263	285
Reduction%	7%	6%	0%	6%	6%

Table 4-10: Comparison of annual production costs among various scenarios under the Dynamic Reserve requirements ($ million).

4.3.8 Comparison of Production Costs across Scenarios when Electric Energy was Valued at the LMP

Because the import of HQ PII energy into New England at zero cost was a modeling convenience, adjusting the cost of the energy to represent a competitive price level is a reasonable sensitivity. While, the competitive price level is not known, PAC members suggested that the energy might be valued at the LMP of the bus where the energy was delivered.

Figure 4-18 and Table 4-11 show that when the imported energy was valued at the LMP, the production cost trend generally increased instead of declining, as shown in the earlier sections when the energy was valued at zero. Scenario C shows the most significant increase in production cost. The additional cost of unit commitment was clearly identifiable in these results.

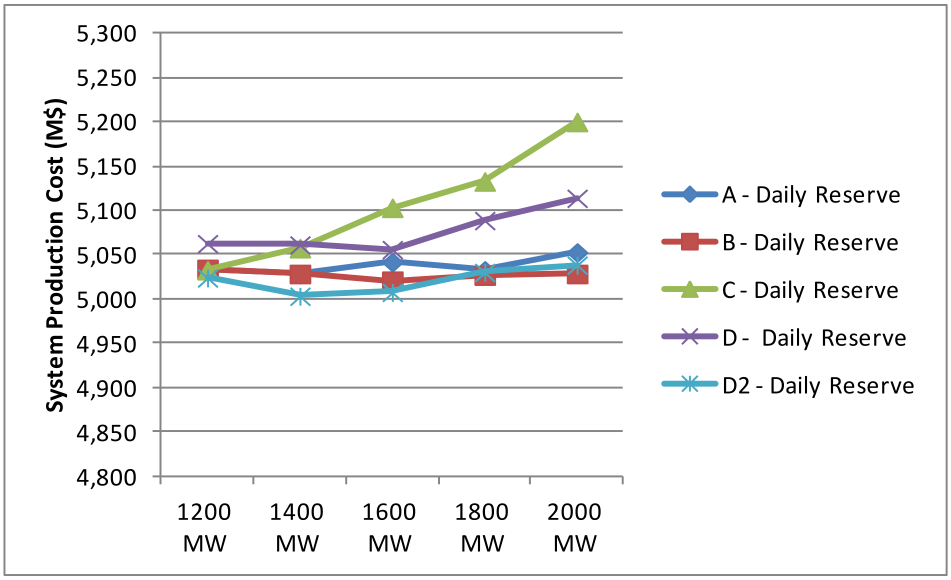

Figure 4-18: Comparison of annual production costs among various scenarios under the Daily Reserve requirements, with HQ PII energy valued at the LMP ($ million).

HQ PII Import Level (MW)	Production Cost (M$)				
	A - Daily Reserve	B - Daily Reserve	C - Daily Reserve	D - Daily Reserve	D2 - Daily Reserve
1200 MW	5,033	5,034	5,033	5,063	5,024
1400 MW	5,028	5,028	5,058	5,061	5,003
1600 MW	5,042	5,021	5,103	5,056	5,008
1800 MW	5,033	5,027	5,133	5,089	5,030
2000 MW	5,053	5,028	5,200	5,114	5,038
Reduction	(20)	6	(167)	(51)	(15)
Reduction%	0%	0%	-3%	-1%	0%

Table 4-11: Comparison of annual production costs among various scenarios under the Daily Reserve requirements, with HQ PII energy valued at the LMP ($ million).

The results for the Dynamic Reserve requirement cases are shown in Figure 4-19 and Table 4-12. These cases show a slight decrease in production costs compared with the Daily Reserve cases because the unit commitment costs decreased as the level of the imports increased from 1,200 MW to 2,000 MW. Scenario C was effectively constant while the other scenarios showed a 1 to 2% decrease in production cost.

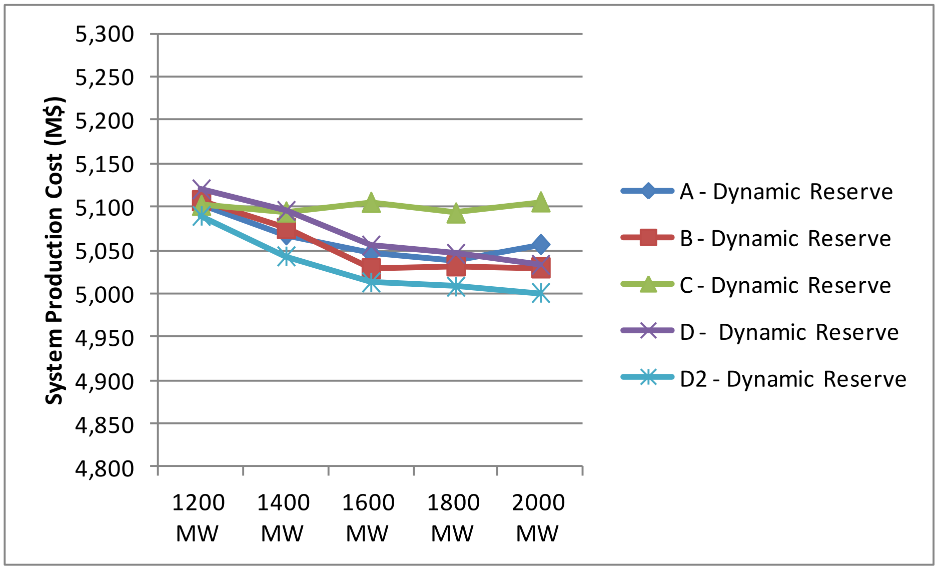

Figure 4-19: Comparison of annual production costs among various scenarios under the Dynamic Reserve requirements, with HQ PII energy valued at the LMP ($ million).

HQ PII Import Level (MW)	Production Cost (M$)				
	A - Dynamic Reserve	B - Dynamic Reserve	C - Dynamic Reserve	D - Dynamic Reserve	D2 - Dynamic Reserve
1200 MW	5,102	5,107	5,102	5,120	5,090
1400 MW	5,068	5,075	5,094	5,095	5,043
1600 MW	5,046	5,029	5,105	5,055	5,013
1800 MW	5,038	5,032	5,093	5,046	5,008
2000 MW	5,057	5,030	5,106	5,033	5,001
Reduction	45	77	(4)	87	89
Reduction%	1%	2%	0%	2%	2%

Table 4-12: Comparison of annual production costs among various scenarios under the Dynamic Reserve requirements, with HQ PII energy valued at the LMP ($ million).

4.4 Economic Metrics—LSE Energy Expense and Average LMP

LSE energy expense was calculated by taking the hourly marginal energy cost (e.g., the LMP) at a specific location and multiplying it by the hourly load. Total LSE energy expense includes the effects of congestion.

4.4.1 Scenario A—24/7 at the Transfer Limit

Scenario A assumed that when HQ PII was not on maintenance, the import levels were increased and held constant for 24 hours per day, every day (24/7). Figure 4-20 and Table 4-13 present the results as the HQ PII transfer limit increased from 1,200 MW to 2,000 MW (Figure 4-21 and Table 4-14 convert LSE energy expense to LMP). The results for the different reserve-requirement cases are presented for comparison. These results show that the LSE energy expense decreased as more energy was imported from HQ PII. This was because the marginal unit that sets the LMP would be less expensive (further down the dispatch stack) as the HQ PII import level increased.

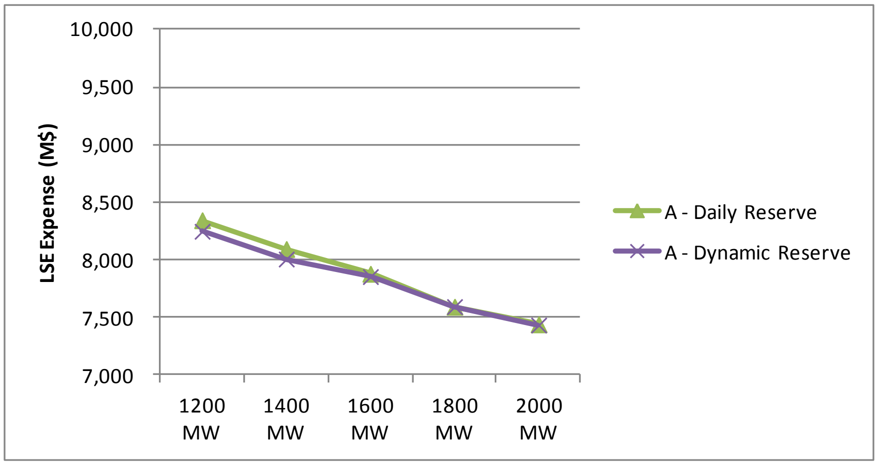

Figure 4-20: Comparison of LSE energy expense for Scenario A—24/7 at the Transfer Limit cases ($ million).

HQ PII Import Level (MW)	LSE Expense (M$)	
	A - Daily Reserve	A - Dynamic Reserve
1200 MW	$ 8,345	$ 8,249
1400 MW	$ 8,095	$ 8,008
1600 MW	$ 7,880	$ 7,856
1800 MW	$ 7,594	$ 7,596
2000 MW	$ 7,442	$ 7,436

Table 4-13: LSE energy expense for Scenario A—24/7 at Transfer Limit ($ million).

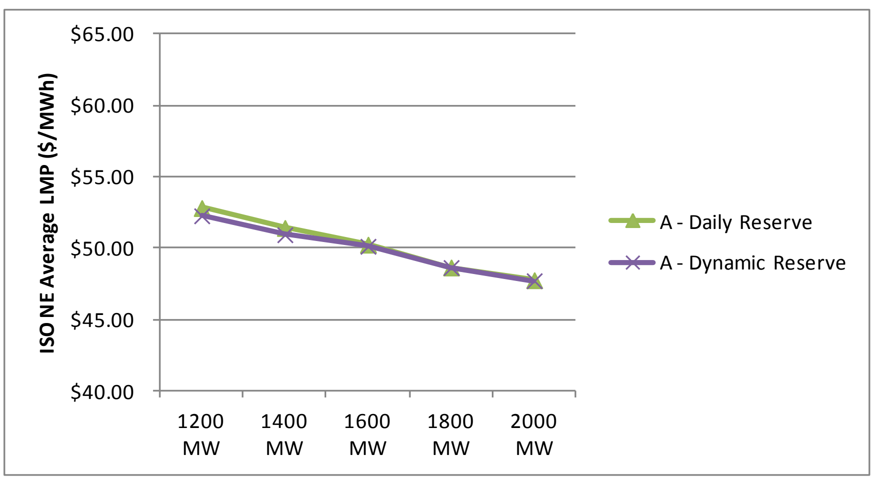

Figure 4-21: Comparison of the ISO-NE average LMP for Scenario A—24/7 at the Transfer Limit ($ million).

HQ PII Import Level (MW)	LMP ($/MWh)	
	A - Daily Reserve	A - Dynamic Reserve
1200 MW	$52.81	$52.27
1400 MW	$51.41	$50.94
1600 MW	$50.24	$50.13
1800 MW	$48.64	$48.64
2000 MW	$47.75	$47.71

Table 4-14: ISO-NE average LMPs for Scenario A—24/7 at Transfer Limit ($ million).

These graphs show that, effectively, the LSE energy expenses did not differ for the different reserve-requirement cases. They all fall within a tight band and show that the most significant effect was the trend of decreasing LSE energy expense as imported energy increased. Increasing the maximum import level from 1,200 to 2,000 MW decreased the LSE energy expense by about $800 to $900 million (10 to 11%).

The LSE energy expense metrics for the Dynamic Reserve cases tend to be lower at the 1,200 MW to 1,400 MW level. This was because a higher level of committed resources were needed to provide reserves for covering the Mystic 8 and 9 or larger nuclear unit contingencies. This commitment of more resources provided additional flexibility that allowed for the dispatch of lower-cost energy for serving load.

4.4.2 Scenario B—On-Peak Hours at the Transfer Limit

For Scenario B, which simulates HQ PII importing at the limit during the on-peak hours, the LSE energy expense metric exhibits characteristics similar to Scenario A but with a smaller rate of decrease in LSE energy expenses. Figure 4-22 and Table 4-15 present the results as the HQ PII transfer limit increased from 1,200 MW to 2,000 MW (Figure 4-23 and Table 4-16 convert LSE energy expense to LMP). The results for the different reserve-requirement cases are similar to Scenario A, which showed that LSE energy expenses decreased as more energy was imported.

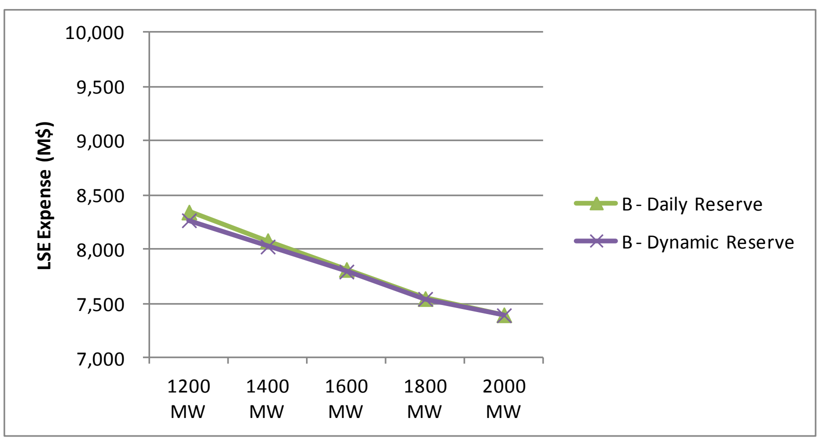

Figure 4-22: Comparison of LSE energy expense for Scenario B—On-Peak Hours at the Transfer Limit ($ million).

HQ PII Import Level (MW)	LSE Expense (M$)	
	B - Daily Reserve	B - Dynamic Reserve
1200 MW	$ 8,345	$ 8,269
1400 MW	$ 8,082	$ 8,027
1600 MW	$ 7,816	$ 7,796
1800 MW	$ 7,547	$ 7,545
2000 MW	$ 7,398	$ 7,393

Table 4-15: LSE energy expense for Scenario B—On-Peak Hours at Transfer Limit ($ million).

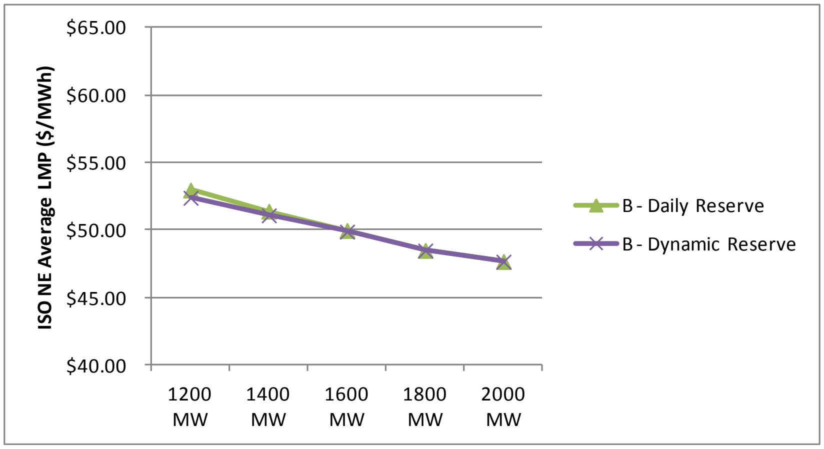

Figure 4-23: Comparison of the ISO-NE average LMP for Scenario B—On-Peak Hours at the Transfer Limit ($ million).

HQ PII Import Level (MW)	LMP ($/MWh)	
	B - Daily Reserve	B - Dynamic Reserve
1200 MW	$52.96	$52.39
1400 MW	$51.40	$51.09
1600 MW	$49.97	$49.88
1800 MW	$48.49	$48.48
2000 MW	$47.67	$47.66

Table 4-16: ISO-NE average LMP for Scenario B—On-Peak Hours at Transfer Limit ($ million).

The LSE energy expense metrics for the different reserve-requirement cases were effectively the same. The minor differences all fall within a tight band and show that the most significant characteristic was a trend of decreasing LSE energy expense as a function of an increase in imported energy. Increasing the maximum import level from 1,200 to 2,000 MW decreased the LSE energy expense between $900 and $1,000 million (10 to 11%). As shown in Scenario A, the Dynamic Reserve representation has a slightly lower LSE energy expense at 1,200 MW and 1,400 MW.

4.4.3 Scenario C—Peak Hour (1 Hour per Day) at Transfer Limit

For Scenario C, which simulates HQ PII importing at the maximum limit during only one on-peak hour of each day, the LSE energy expense metric characteristic was similar to Scenarios A and B for all the reserve representations, but the magnitude of the reductions was smaller because of the lower amount of energy imported. Figure 4-24 and Table 4-17 present the results as the HQ PII transfer limit increased from 1,200 MW to 2,000 MW (Figure 4-25 and Table 4-18 convert LSE energy expense to LMP). The results for both reserve-requirement cases are similar to the previous scenarios and show that the LSE energy expense metric decreased as more energy was imported.

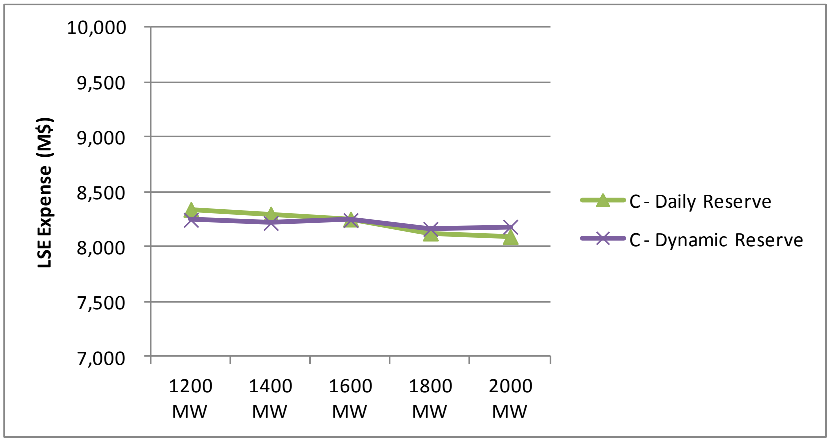

Figure 4-24: Comparison of the LSE energy expense for Scenario C—Peak Hour (1 Hour per Day) ($ million).

HQ PII Import Level (MW)	LSE Expense (M$)	
	C - Daily Reserve	C - Dynamic Reserve
1200 MW	$ 8,345	$ 8,249
1400 MW	$ 8,302	$ 8,221
1600 MW	$ 8,256	$ 8,246
1800 MW	$ 8,128	$ 8,166
2000 MW	$ 8,098	$ 8,186

Table 4-17: LSE energy expense for Scenario C—Peak Hour (1 Hour per Day) at Transfer Limit ($ million).

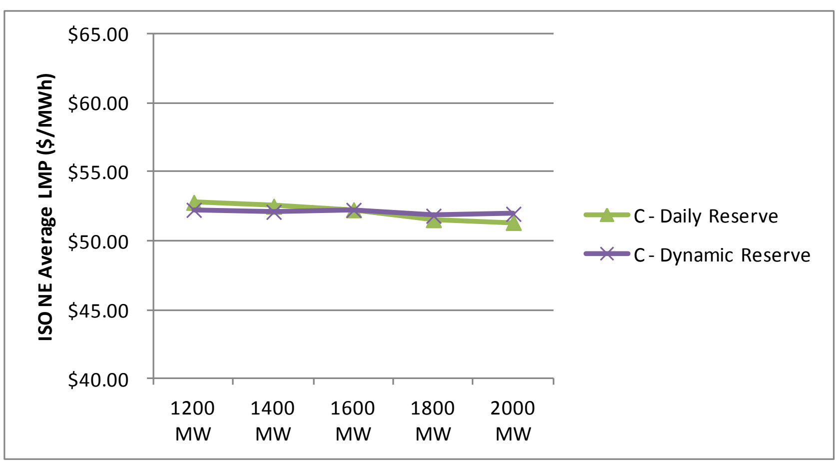

Figure 4-25: Comparison of the ISO-NE average LMP for Scenario C—Peak Hour (1 Hour per Day) at Transfer Limit ($ million).

HQ PII Import Level (MW)	LMP ($/MWh)	
	C - Daily Reserve	C - Dynamic Reserve
1200 MW	$52.81	$52.27
1400 MW	$52.53	$52.12
1600 MW	$52.27	$52.26
1800 MW	$51.55	$51.84
2000 MW	$51.35	$51.98

Table 4-18: ISO-NE average LMP for Scenario C—Peak Hour (1 Hour per Day) at Transfer Limit ($ million).

The LSE energy expenses for both scenarios effectively were the same; increasing the maximum import level from 1,200 to 2,000 MW decreased the LSE energy expense by about $50 and $250 million (1 to 3%).

As shown in Scenarios A and B, LSE energy expenses were lower for the Dynamic Reserve cases at 1,200 MW and 1,400 MW. The metric for the Dynamic Reserve case was higher than the Daily Reserve cases when the transfer limit was 1,800 MW or 2,000 MW, suggesting that the higher-cost resources that were dispatched set the LMP. These resources would have been eligible to set the LMP when the HQ PII was importing because reserves were being held for the one peak hour on a less expensive resource that could provide more 10-minute reserve.

4.4.4 Scenario D—Historical Import Pattern

Scenario D used an assumed historical profile for HQ PII imports that reaches the assumed import limit in only one month (June). In the other eleven months, the peak import amount was less than the June import level. Figure 4-26 and Table 4-19 compare the LSE energy expense for each of the reserve-requirement cases (Figure 4-27 and Table 4-20 convert LSE energy expense to LMP). These results show that LSE energy expenses decreased between $650 and $950 million (7 to 11%).

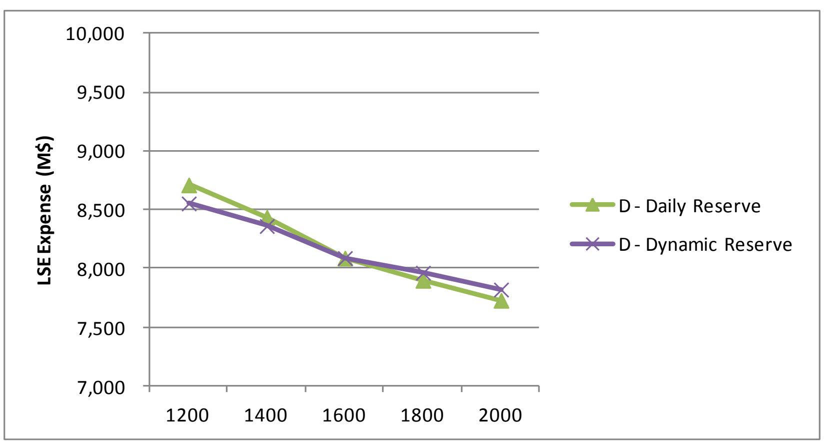

Figure 4-26: Comparison of LSE energy expense for Scenario D—Historical Import Pattern ($ million).

HQ PII Import Level (MW)	LSE Expense (M$)	
	D - Daily Reserve	D - Dynamic Reserve
1200 MW	$ 8,712	$ 8,555
1400 MW	$ 8,437	$ 8,363
1600 MW	$ 8,089	$ 8,090
1800 MW	$ 7,900	$ 7,965
2000 MW	$ 7,730	$ 7,822

Table 4-19: LSE energy expense for Scenario D—Historical Import Pattern ($ million).

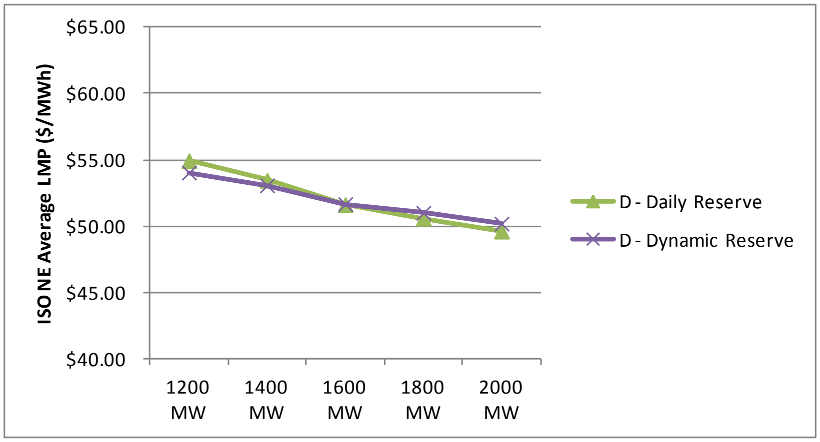

Figure 4-27: Comparison of the ISO-NE average LMP for Scenario D—Historical Import Pattern ($ million).

HQ PII Import Level (MW)	LMP ($/MWh)	
	D - Daily Reserve	D - Dynamic Reserve
1200 MW	$54.94	$54.05
1400 MW	$53.46	$53.08
1600 MW	$51.63	$51.67
1800 MW	$50.61	$51.01
2000 MW	$49.63	$50.19

Table 4-20: ISO-NE average LMP for Scenario D—Historical Import Pattern ($ million).

The Dynamic Reserve cases show that at the 1,200 and 1,400 MW import limits, the LSE energy expenses were lower because the reserves needed to cover the larger contingencies depressed the prevailing LMPs. These additional committed resources allowed lower-cost units to be the marginal units, which lowered the resulting LMPs. As the assumed import levels increased to 1,800 MW and 2,000 MW, the LSE energy expenses became higher than for the Daily Reserve cases. This suggests that some higher-cost, dispatched resources set the LMP when HQ PII was importing.

4.4.5 Scenario D2—Adjusted Historical Import Pattern

Scenario D2 used an assumed historical profile for HQ PII adjusted to reach the assumed import limit every day. More imported energy was associated with this profile than Scenario D (which only reached the assumed import limit in a single month). Figure 4-28 and Table 4-21 compare the LSE energy expense for each of the reserve-requirement cases (Figure 4-29 and Table 4-22 convert LSE energy expense to

LMP). These results show that LSE energy expenses decreased between $800 and $950 million (9 to 11%).

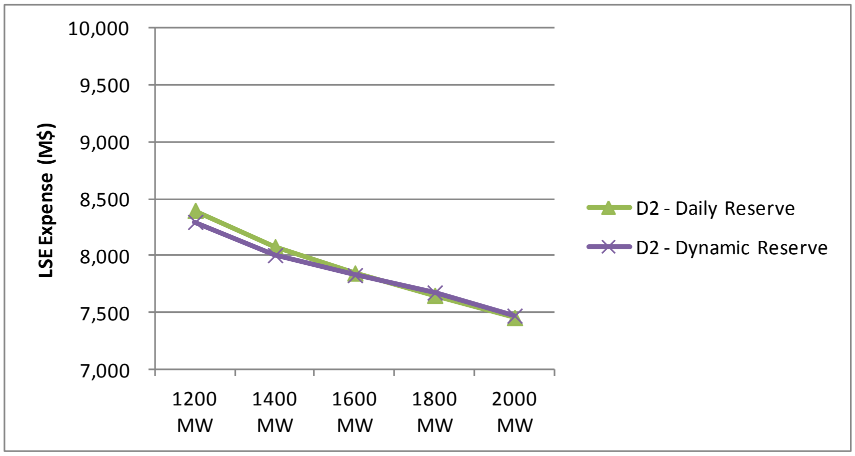

Figure 4-28: Comparison of LSE energy expenses for Scenario D2—Adjusted Historical Import Pattern ($ million).

HQ PII Import Level (MW)	LSE Expense (M$)	
	D2 - Daily Reserve	D2 - Dynamic Reserve
1200 MW	$ 8,400	$ 8,298
1400 MW	$ 8,079	$ 8,005
1600 MW	$ 7,848	$ 7,829
1800 MW	$ 7,652	$ 7,677
2000 MW	$ 7,457	$ 7,473

Table 4-21: LSE energy expense for Scenario D2—Adjusted Historical Import Pattern ($ million).

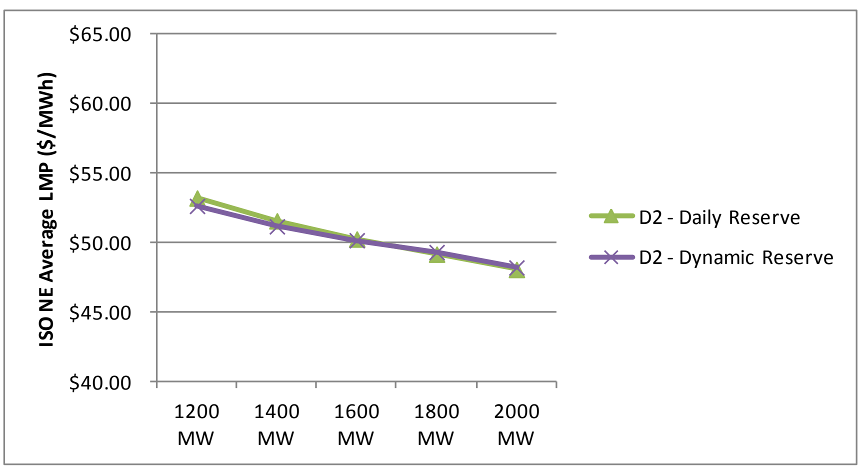

Figure 4-29: Comparison of the ISO's average LMP for Scenario D2—Adjusted Historical Import Pattern ($ million).

HQ PII Import Level (MW)	LMP ($/MWh)	
	D2 - Daily Reserve	D2 - Dynamic Reserve
1200 MW	$53.21	$52.65
1400 MW	$51.57	$51.18
1600 MW	$50.26	$50.17
1800 MW	$49.17	$49.32
2000 MW	$48.07	$48.21

Table 4-22: The ISO-NE average LMP for Scenario D2—Adjusted Historical Import Pattern ($ million).

The Dynamic Reserve cases show that at the 1,200 and 1,400 MW levels, the LSE energy expense was lower because reserves were needed to cover the larger contingencies. These additional committed resources decreased the marginal unit, which allowed lower cost units to be the marginal units and thus depressed the resulting, prevailing LMPs. As the assumed import levels increased, the LSE energy expense for the Dynamic Reserve case decreased at the same rate as the Daily Reserve cases. To a significant extent, the larger amount of energy imported, compared with Scenario D, lowered the prevailing LMPs in many hours, which then offset an increase in the LMP during other hours when a more expensive resource was eligible to set the LMP.

4.4.6 Scenario E—Dispatchable Based on Energy Price

Scenario E assumed that the HQ PII energy was imported only when it provided economic benefits to New England. Figure 4-30 and Table 4-23 compare the LSE energy expense for four assumed dispatch price levels (Figure 4-31 and Table 4-24 convert LSE energy expense to LMP).

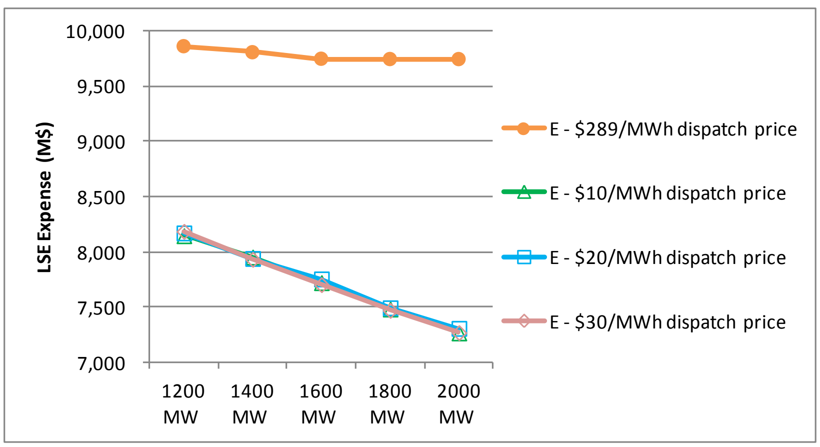

Figure 4-30: Comparison of LSE energy expenses for Scenario E—Dispatchable Based On Energy Price ($ million).

HQ PII Import Level (MW)	LSE Expense (M$)			
	E - $289/MWh dispatch price	E - $10/MWh dispatch price	E - $20/MWh dispatch price	E - $30/MWh dispatch price
1200 MW	9,864	8,148	8,173	8,187
1400 MW	9,809	7,954	7,942	7,934
1600 MW	9,750	7,722	7,756	7,704
1800 MW	9,747	7,483	7,494	7,471
2000 MW	9,747	7,267	7,308	7,269

Table 4-23: LSE energy expense for Scenario E—Dispatchable Based on Energy Price ($ million).

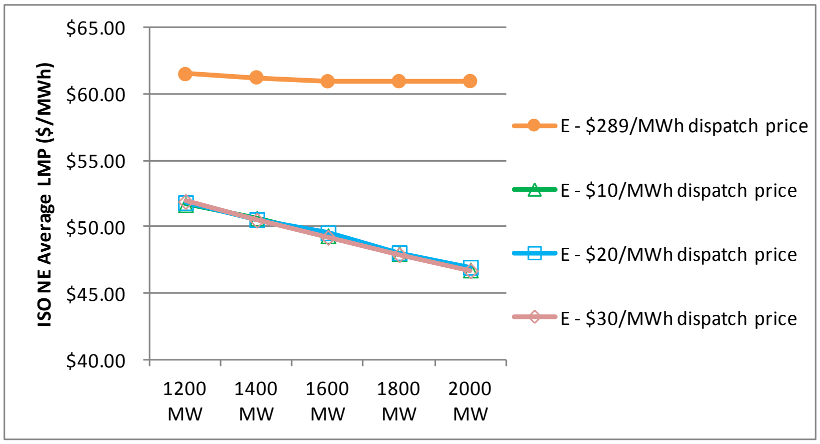

Figure 4-31: Comparison of ISO-NE average LMP for Scenario E—Dispatchable Based on Energy Price ($ million).

HQ PII Import Level (MW)	LMP ($/MWh)			
	E - $289/MWh dispatch price	E - $10/MWh dispatch price	E - $20/MWh dispatch price	E - $30/MWh dispatch price
1200 MW	$ 61.50	$ 51.69	$ 51.84	$ 51.92
1400 MW	$ 61.26	$ 50.65	$ 50.56	$ 50.52
1600 MW	$ 60.96	$ 49.34	$ 49.57	$ 49.23
1800 MW	$ 60.97	$ 48.00	$ 48.07	$ 47.92
2000 MW	$ 60.98	$ 46.77	$ 46.97	$ 46.72

Table 4-24: ISO-NE average LMP Scenario E—Dispatchable Based on Energy Price ($ million).

These results show that LSE energy expenses decreased a negligible amount for the high-cost distillate-oil-based case, which imported very few megawatt-hours. The amount of imported energy at the three lower dispatch price thresholds of $10, $20, and $30/MWh were substantial as well as identical. The cases with the lower dispatch costs imported the maximum amount of energy every hour. Consequently, LSE energy expenses decreased about $900 million at these three lower dispatch price levels (about 11%).

4.4.7 Comparison of LSE Energy Expenses across Scenarios

In addition to the previous comparisons where both reserve-requirement representations were compared by scenario, this section compares the reserve-requirement representation across the scenarios.

Figure 4-32 presents the LSE energy expense for the Daily Reserve requirement cases for each of the scenarios. This figure shows that LSE energy expenses decreased for all cases when HQ PII imports increased. Scenario C shows the lowest rate of decrease in LSE energy expenses because of this scenario's relatively small amounts of imported energy. Scenario D shows that the reduced amount of energy in the months where the import was below the annual maximum (January to May and July to December) resulted in higher on-peak LMPs in these months; therefore, the magnitude of the annual metric was higher, although the slope of the curve was nearly the same as Scenarios A, B, C, and D2.

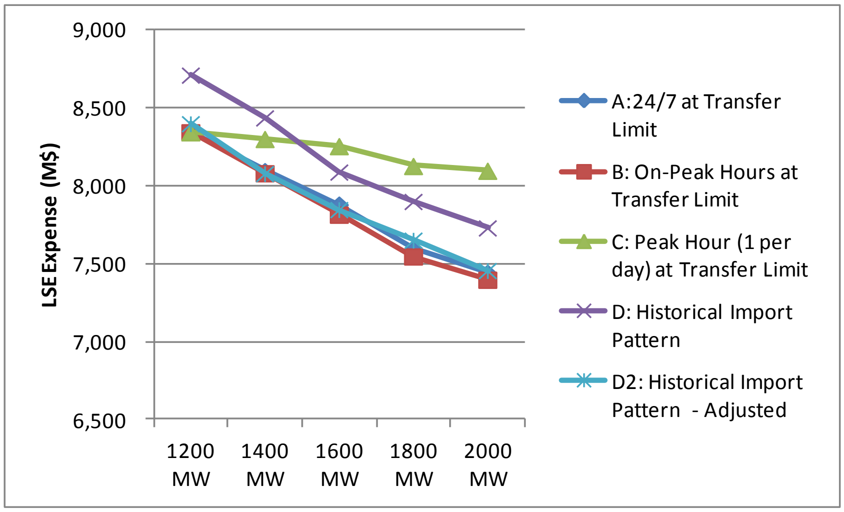

Figure 4-32: Comparison of LSE energy expenses among various scenarios under the Daily Reserve requirements ($ million).

The results for the Dynamic Reserve requirement cases are shown in Figure 4-33 and Table 4-25. As before, the trend shows that the greater the HQ PII import, the greater the reduction in LSE energy expenses. However, two cases behave differently. The LSE energy expense for Scenario E was relatively constant because of the negligible amount of energy imported when the energy was priced equivalent to 80% of an inefficient combustion turbine using distillate fuel. However, importing the energy into New England caused a significant reduction in LMPs in a few hours, which was enough to reduce annual LSE energy expenses. The LSE energy expenses for Scenario C also were relatively constant because the net reduction in LMPs was minor during the hours when energy was imported. This appears to be the result of higher LMPs in some hours and lower LMPs in other hours. The higher LMPs were the result of the Dynamic Reserve requirement dispatching higher-marginal-cost, fast-start resources rather than dispatching a unit with a lower marginal cost but higher start-up cost and, possibly, a longer minimum run time.

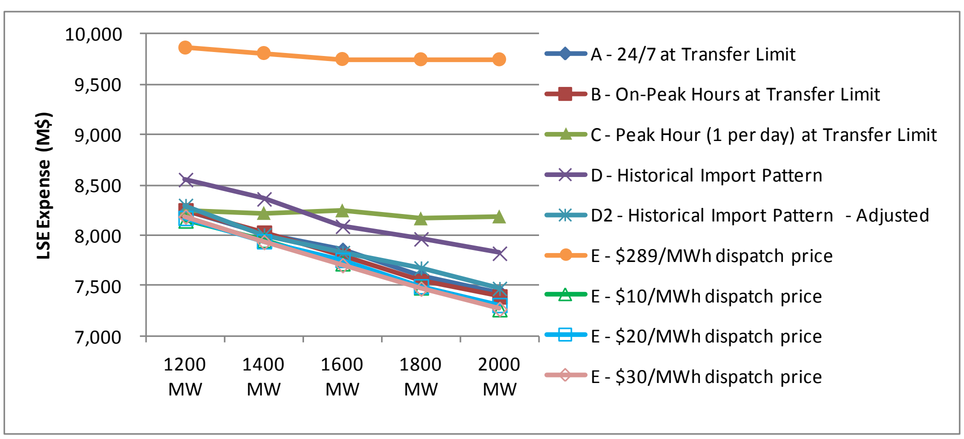

Figure 4-33: Comparison of LSE energy expenses among various scenarios under the Dynamic Reserve requirements ($ million).

HQ PII Import Level (MW)	LSE Expense (M$) - Dynamic Reserve								
	A - 24/7 at Transfer Limit	B - On-Peak Hours at Transfer Limit	C - Peak Hour (1 per day) at Transfer Limit	D - Historical Import Pattern	D2 - Historical Import Pattern - Adjusted	E - $289/MWh dispatch price	E - $10/MWh dispatch price	E - $20/MWh dispatch price	E - $30/MWh dispatch price
1200 MW	8,249	8,249	8,249	8,555	8,298	9,864	8,148	8,173	8,187
1400 MW	8,008	8,027	8,221	8,363	8,005	9,809	7,954	7,942	7,934
1600 MW	7,856	7,796	8,246	8,090	7,829	9,750	7,722	7,756	7,704
1800 MW	7,596	7,545	8,166	7,965	7,677	9,747	7,483	7,494	7,471
2000 MW	7,436	7,393	8,186	7,822	7,473	9,747	7,267	7,308	7,269
Reduction	813	856	63	732	825	117	881	865	918
Reduction%	10%	10%	1%	9%	10%	1%	11%	11%	11%

Table 4-25: Comparison of annual production costs among various scenarios under the Dynamic Reserve requirements ($ million).

4.5 Economic Metrics—Make-Whole "Uplift"/NCPC Expense

In these simulations, the resources did not need to recover all their production costs including startup and no-load costs through the energy revenues they received based on the LMP at their delivery point to the transmission system. Because generators are allowed to recover all their short-run marginal costs, any revenue shortfall from their production cost, not recovered from the value of the energy during a 24-hour period, was summed. Any resource that has a 24-hour net revenue shortfall was assumed to be paid a "make-whole," "uplift" payment to eliminate the shortfall. This was intended to approximate ISO New England's Net Commitment-Period Compensation (NCPC) reimbursement process.

Some of this shortfall resulted from constraints within the transmission network that depressed the LMP at a resource's delivery point. The remainder was caused by a fuel-only-based marginal resource setting the LMP without any provision for including no-load and start-up cost components into the marginal bid. The magnitude of the make-whole, uplift metric was affected by the cost of both starting and operating the generators compared with the LMPs at the point of delivery.

The LMP used to compensate resources for their operation would increase or decrease as the cost of the marginal resource changed. In the simulations where more units are committed to provide higher levels of spinning reserve, the LMPs typically are depressed. Depressed LMPs would tend to increase the total cost of make-whole payments because fewer units can recover all their costs, including startup and no-load costs.

4.5.1 Scenario A—24/7 at Transfer Limit

Figure 4-34 and Table 4-26 present the uplift as the HQ PII transfer limit increased from 1,200 MW to 2,000 MW for the different reserve-requirement cases. These results show the uplift increased as more energy was imported from Hydro-Québec. This was caused by both the additional imported energy and the additional unit commitment necessary to provide the operating reserves, reducing the cost of the marginal unit. Both these effects lowered the LMPs, which then decreased the resource's revenues, thus increasing uplift.

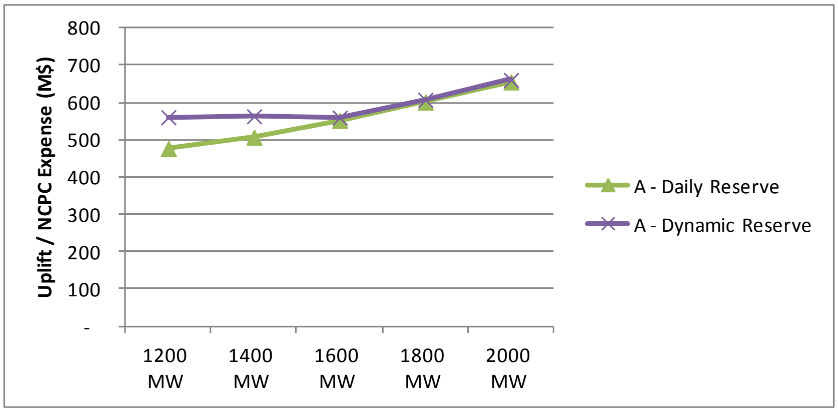

Figure 4-34: Comparison of annual uplift/NCPC expenses for Scenario A—24/7 at Transfer Limit ($ million).

HQ PII	Uplift (M$)	
Import Level	A - Daily Reserve	A - Dynamic Reserve
1200 MW	$ 477	$ 561
1400 MW	$ 507	$ 564
1600 MW	$ 552	$ 560
1800 MW	$ 602	$ 608
2000 MW	$ 656	$ 661

Table 4-26: Annual uplift/NCPC expense for Scenario A—24/7 at Transfer Limit ($ million).

The results of the Dynamic Reserve case show that, at the lower import levels of 1,200 MW and 1,400 MW, the uplift was higher than for the Daily Reserve cases and was approximately constant at these two import levels. This was because the production cost for the Dynamic Reserve case was higher than in the Daily Reserve cases, as shown in Figure 4-4, while the LMPs, as shown in Figure 4-21 were about the same. The production cost decreased faster until about 1,600 MW, which tended to offset potential increases in uplift. As the rate of decrease in production cost slowed (i.e., production costs remained "higher"), uplift increased because the LMPs continued declining at a constant rate, leaving more resources with operating costs greater than their energy revenues.

4.5.2 Scenario B—On-Peak Hours at Transfer Limit

Figure 4-35 and Table 4-27 present the uplift as the HQ PII transfer limit increased from 1,200 MW to 2,000 MW for the different reserve-requirement representations. These results show a similar trend to that observed for Scenario A.

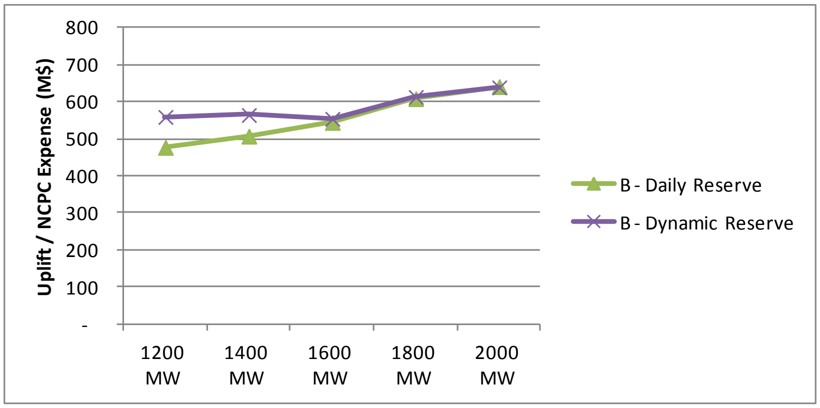

Figure 4-35: Comparison of annual uplift/NCPC expenses for Scenario B—On-Peak Hours at Transfer Limit ($ million).

HQ PII Import Level	Uplift (M$)	
	B - Daily Reserve	B - Dynamic Reserve
1200 MW	$ 477	$ 559
1400 MW	$ 507	$ 564
1600 MW	$ 544	$ 554
1800 MW	$ 608	$ 613
2000 MW	$ 641	$ 639

Table 4-27: Annual uplift/NCPC expense for Scenario B—On-Peak Hours at Transfer Limit ($ million).

4.5.3 Scenario C—Peak Hour (1 Hour per Day) at Transfer Limit

Figure 4-36 and Table 4-28 present the uplift as the HQ PII transfer limit increased from 1,200 MW to 2,000 MW for the different reserve-requirement cases. For the Daily Reserves, the LMPs remained relatively constant, but the production costs increased as more units were committed to provide reserves. This resulted in uplift costs that had the potential to increase at a relatively stable rate.

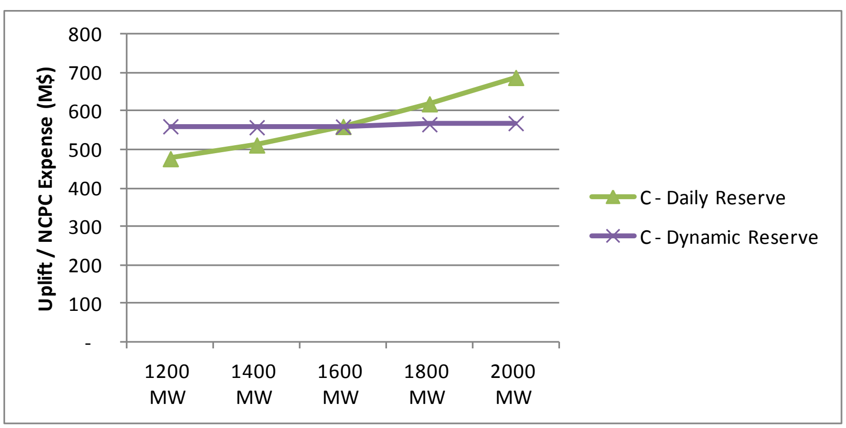

Figure 4-36: Comparison of annual uplift/NCPC expense for Scenarios C—Peak Hour (1 Hour per Day) at Transfer Limit ($ million).

HQ PII Import Level	Uplift (M$)	
	C - Daily Reserve	C - Dynamic Reserve
1200 MW	$ 477	$ 561
1400 MW	$ 512	$ 559
1600 MW	$ 561	$ 560
1800 MW	$ 620	$ 566
2000 MW	$ 688	$ 569

Table 4-28: Annual uplift/NCPC expense for Scenarios C—Peak Hour (1 Hour per Day) at Transfer Limit ($ million).

The results of the Dynamic Reserve case show that the uplift cost was approximately constant at all import levels. This was because the production cost was approximately constant, as shown in Figure 4-8, and the LMPs, as shown in Figure 4-25, also were approximately constant.

4.5.4 Scenario D—Historical Import Pattern

Figure 4-37 and Table 4-29 present the uplift as the HQ PII transfer limit increased from 1,200 MW to 2,000 MW for the different reserve-requirement cases. The uplift costs increased for the Daily Reserve cases because the LMPs, shown in Figure 4-27, declined at a constant rate for all cases, while the production costs declined gradually. This could lead to uplift costs that increase at a constant rate.

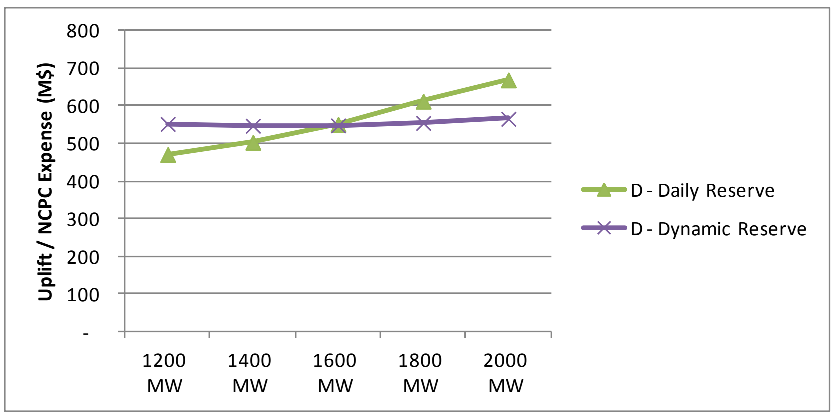

Figure 4-37: Comparison of annual uplift/NCPC expenses for Scenarios D—Historical Import Pattern ($ million).

HQ PII Import Level	Uplift (M$)	
	D - Daily Reserve	D - Dynamic Reserve
1200 MW	$ 471	$ 552
1400 MW	$ 503	$ 547
1600 MW	$ 551	$ 548
1800 MW	$ 613	$ 555
2000 MW	$ 669	$ 566

Table 4-29: Annual uplift/NCPC expense for Scenarios D—Historical Import Pattern ($ million).

The results of the Dynamic Reserve case showed that the uplift was approximately constant at all import levels. This was because the production cost (shown in Figure 4-10) and the LSE energy expense (shown in Figure 4-27) both declined at a constant rate, and the reduction in the production cost was faster than for the Daily Reserve cases. This resulted in an uplift metric that had a lower slope than the Daily Reserve cases.

4.5.5 Scenario D2—Adjusted Historical Import Pattern

Figure 4-38 and Table 4-30 present the uplift as the HQ PII transfer limit increased from 1,200 MW to 2,000 MW for the different reserve-requirement cases. The uplift costs for the Daily Reserve cases increased because the LMPs, shown in Figure 4-29, declined at a constant rate for all cases, while the production costs, shown in Figure 4-12, declined gradually. This could lead to uplift costs that increase at a constant rate.

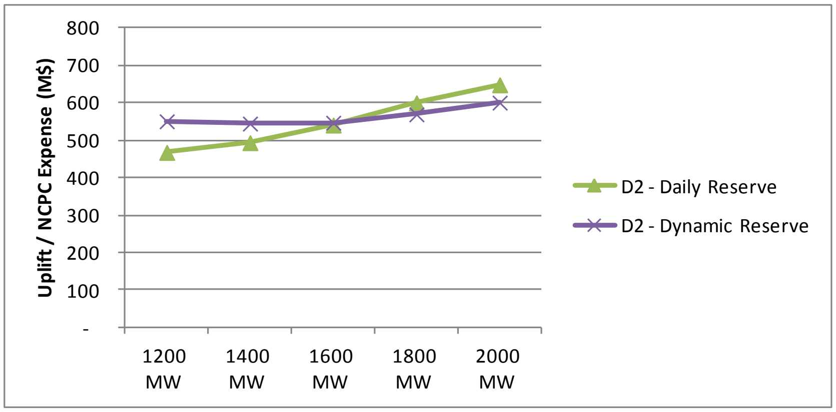

Figure 4-38: Comparison of annual uplift/NCPC expense for Scenario D2—Adjusted Historical Import Pattern ($ million).

HQ PII	Uplift (M$)	
Import Level	D2 - Daily Reserve	D2 - Dynamic Reserve
1200 MW	$ 468	$ 551
1400 MW	$ 494	$ 545
1600 MW	$ 541	$ 547
1800 MW	$ 600	$ 569
2000 MW	$ 648	$ 601

Table 4-30: Annual uplift/NCPC expense for Scenarios D2—Adjusted Historical Import Pattern ($ million).

The results of the Dynamic Reserve case showed that the uplift costs were approximately constant at all import levels. This was because the production cost (shown in Figure 4-12) and the LSE energy expense (shown in Figure 4-29) both declined at a constant rate and the reduction in production cost was faster than for the Daily Reserve cases. The lowering of production costs as the imports increased resulted in uplift costs that would be more stable compared with the Daily Reserve cases.

4.5.6 Scenario E—Dispatchable Based on Energy Price

Figure 4-39 and Table 4-31 show the uplift as the HQ PII transfer limit increased from 1,200 MW to 2,000 MW. Dynamic Reserve was the only reserve-requirement representation used with Scenario E. The uplift costs for the scenario where HQ PII energy was priced equivalent to 80% of an inefficient combustion turbine using distillate fuel was relatively constant because of the negligible amount of energy imported. This scenario had the lowest uplift costs because the LMPs were the highest and more resources could cover their operating costs with their available energy market revenues.

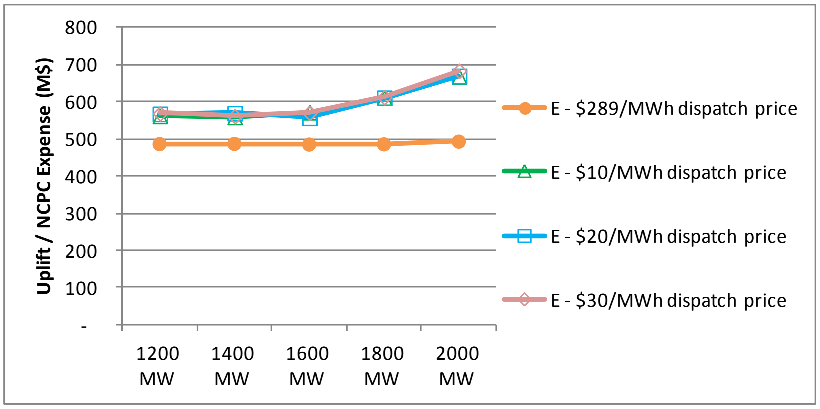

Figure 4-39: Comparison of annual uplift/NCPC expenses for Scenario E—Dispatchable Based on Energy Price ($ million).

HQ PII Import Level (MW)	Uplift (M$)			
	E - $289/MWh dispatch price	E - $10/MWh dispatch price	E - $20/MWh dispatch price	E - $30/MWh dispatch price
1200 MW	$ 485	$ 562	$ 568	$ 569
1400 MW	$ 486	$ 559	$ 569	$ 561
1600 MW	$ 484	$ 572	$ 557	$ 571
1800 MW	$ 485	$ 611	$ 611	$ 613
2000 MW	$ 492	$ 669	$ 670	$ 683

Table 4-31: Annual uplift/NCPC expense for Scenario E—Dispatchable Based on Energy Price ($ million).

For the three cases where the dispatch prices were $10, $20, and $30/MWh, respectively, the uplift costs were relatively constant for the 1,200 MW to 1,600 MW cases. The uplift costs began to increase for the 1,800 and 2,000 MW import levels. This was because the production cost, as shown in Figure 4-14, declined at a faster rate in the range of 1,200 to 1,600 MW than in the range of 1,800 to 2,000 MW, while the LMPs, as shown in Figure 4-31, declined at an approximately constant rate.

4.5.7 Comparison of Uplift across Scenarios

In addition to the previous comparisons where the reserve-requirement cases were compared by scenario, this section compares the reserve-requirement representation across the scenarios. For example, Figure 4-40 presents the uplift costs for Scenarios A through D2 for the Daily Reserve requirement cases. The trend for uplift costs in all the cases was a monotonic increase as HQ PII imports increased.

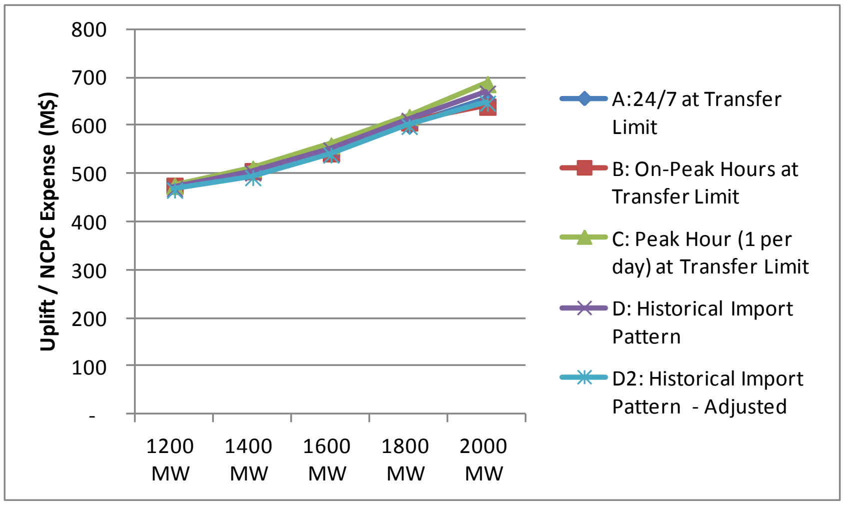

Figure 4-40: Comparison of uplift/NCPC expenses among various scenarios under the Daily Reserve requirement cases ($ million).

Figure 4-41 shows the results of the Dynamic Reserve requirement cases. At a high level, the trend shows that the greater the HQ PII import, the greater the uplift costs. Additionally, for import levels of 1,200 MW to 1,600 MW, the uplift costs were approximately constant because the largest contingency determined the unit commitment independent of HQ PII import levels. For the 1,800 MW and 2,000 MW scenarios, uplift increased because the additional unit commitment needed to satisfy the operating reserve requirements resulted in lower LMPs, while production costs remained approximately constant, or at least declined slowly.

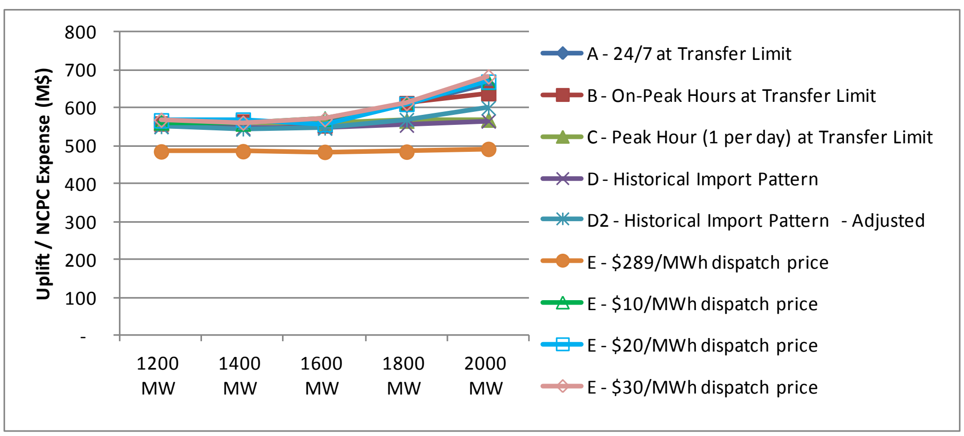

Figure 4-41: Comparison of uplift/NCPC expenses among various scenarios under the Dynamic Reserve requirements ($ million).

The uplift costs for Scenario E were the lowest for the case when HQ PII energy was priced equivalent to 80% of an inefficient combustion turbine using distillate fuel. This was because with the higher LMPs, resources experienced fewer days with revenue deficiencies and thus needed additional compensation through an NCPC framework less often. The negligible amount of energy associated with all the import levels for these cases did not affect this metric appreciably.

4.6 Economic Metrics—Congestion

One of the contributing factors to the uplift metric was congestion where the LMP at a generator's delivery point was driven down to the generator's own marginal cost. This has the potential to isolate a resource from the prevailing New England LMP and consequently disadvantage a resource from earning sufficient revenues from its energy sales.

For example, a resource with an assumed low dispatch price behind an export constraint will contribute to congestion because the energy flowing across the constraint typically would be set at the low dispatch price on the transmitting side while the LMP would be higher on the receiving side. The combination of price difference and the megawatts flowing across the constrained interface contribute to this metric.

Additionally, congestion could occur when a thermal unit is constrained down because of a transmission limitation or a transmission contingency that precludes the full output of a resource that would have been economic. This issue was exacerbated by modeling the physical incremental heat-rate curves for thermal resources, which did not allow for a bidding behavior that could have anticipated these export constraints. Resources have the opportunity to include higher amounts of operations and maintenance costs as they are dispatched at higher output levels. This tends to reduce the amount of congestion as resources manage their output across export constraints.

Figure 4-42 and Figure 4-43 show that the total simulated New England congestion was within a tight range and declined as the imports from HQ PII increased. This is characteristic of resources constrained down because of export limits that isolated the resource from the prevailing New England LMP. The downward slope shown in the figures was caused by lower LMPs resulting from higher energy imports from HQ PII combined with a higher level of unit commitment needed to support the higher reserves. Scenario C exhibited the least amount of change in congestion as imports were assumed to increase from 1,200 MW to 2,000 MW because the prevailing LMP in New England declined the least, as shown in Figure 4-32.

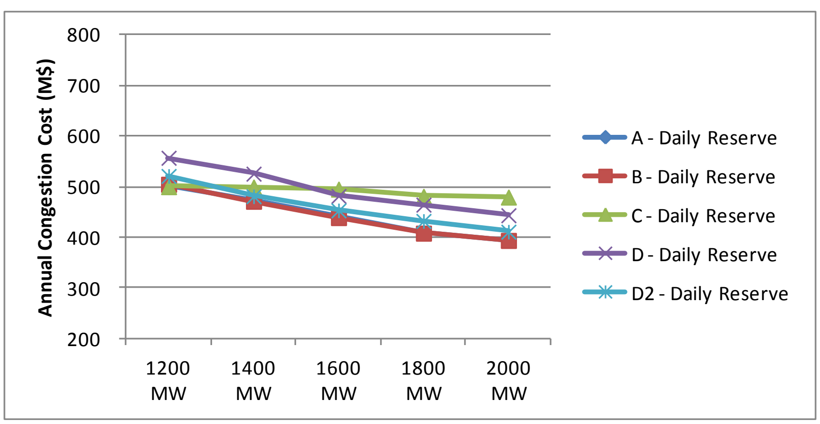

Figure 4-42: Congestion for Daily Reserve cases ($ million).

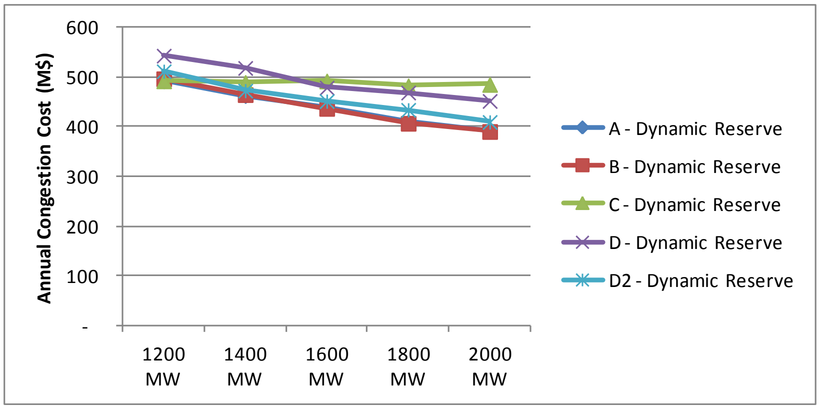

Figure 4-43: Congestion for Dynamic Reserve cases ($ million).

Figure 4-44 shows the congestion for Scenario E. The annual congestion for the $10, $20, and $30/MWh dispatch price cases was slightly lower than the other Dynamic Reserve requirements cases because the higher level of imported energy resulted in lower LMPs. These lower prevailing LMPs created smaller LMP differences across constrained elements. Similarly, the high dispatch cost case resulted in higher congestion because of the greater LMP differences across the constrained elements.

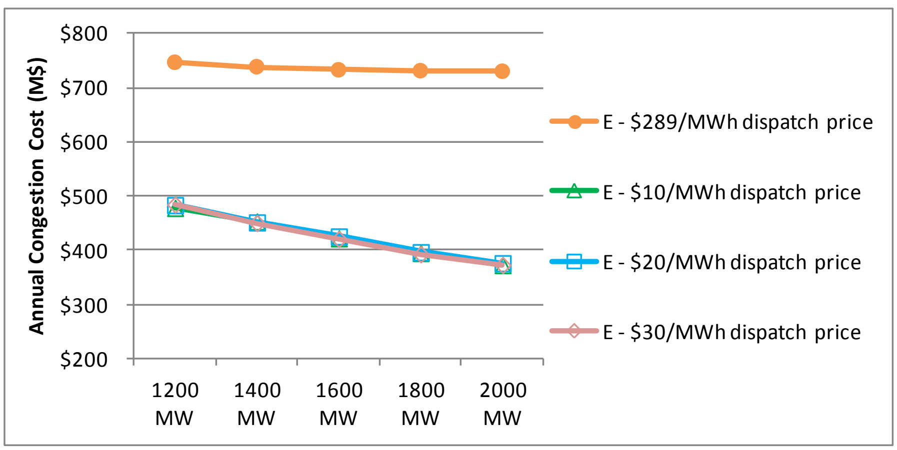

Figure 4-44: Comparison of congestion expenses for Scenario E—Dispatchable Based on Energy Price ($ million).

4.7 Metrics for System Emissions

The environmental emissions are another important metric associated with increased imports of energy from HQ PII. This section summarizes the total New England CO_2, NO_X, and SO_2 emissions under the various scenarios and reserve-requirement representations. Only the thermal units within New England contributed to the emission metrics. Energy imported from HQ PII was assumed to not have any emissions.

4.7.1 Emissions—CO_2

Figure 4-45 to Figure 4-50 present the CO_2 emissions for all scenarios. All the scenarios show that the emissions decreased when the HQ PII import level increased. Additionally, the magnitude of these CO_2 emissions decreased in proportion to the amount of energy imported; the higher the amount of imported energy, the lower the magnitude of the CO_2 emissions. This was because the HQ PII generation replaced thermal generation, which in turn reduced the CO_2 emissions. Some specific results are as follows:

- Figure 4-45 shows a reduction of approximately 4 million tons of CO_2 for Scenario A, and Figure 4-46 shows a reduction of approximately 3 million tons for Scenario B.
- As shown in Figure 4-47 for Scenario C, the reduction in emissions was almost negligible because very little energy was associated with HQ PII.
- Figure 4-48 shows that Scenario D has a reduction of 2 million tons of CO_2, and Figure 4-49 shows that Scenario D2 has a reduction of 2.5 million tons.
- As shown in Figure 4-50 for Scenario E, the New England CO_2 emissions did not change significantly when the HQ PII import level increased and the energy was economically dispatched at 80% of a inefficient combustion turbine using distillate fuel oil (at $289/MWh). At the lower dispatch prices of $10, $20, and $30/MWh, the energy was imported in all hours at the maximum rate, which reduced the CO_2 emissions by approximately 4 million tons.
- The reserve-requirement representations did not have an obvious impact on the simulated CO_2 emission metric.

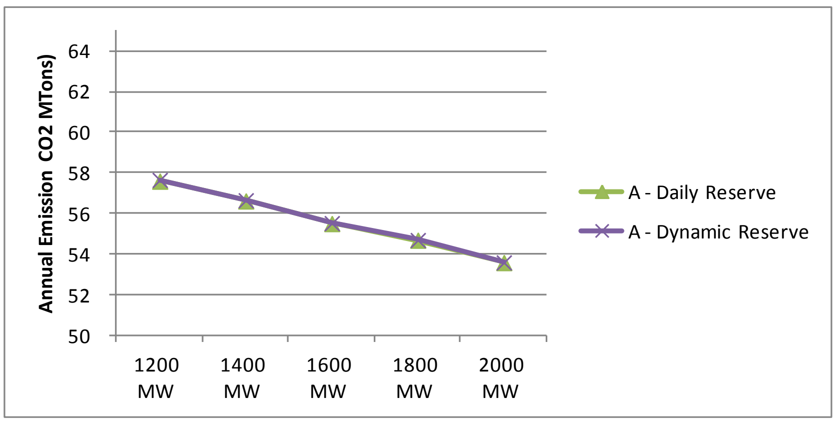

Figure 4-45: CO_2 emissions for Scenario A—24/7 at Transfer Limit (million tons).

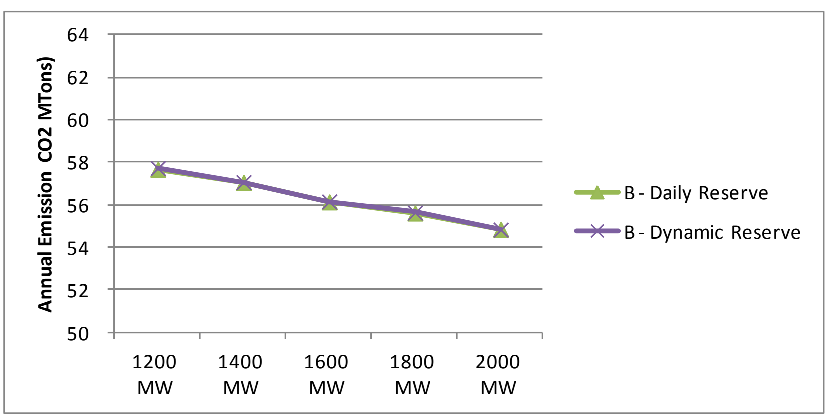

Figure 4-46: CO_2 emissions for Scenario B—On-Peak Hours at Transfer Limit (million tons).

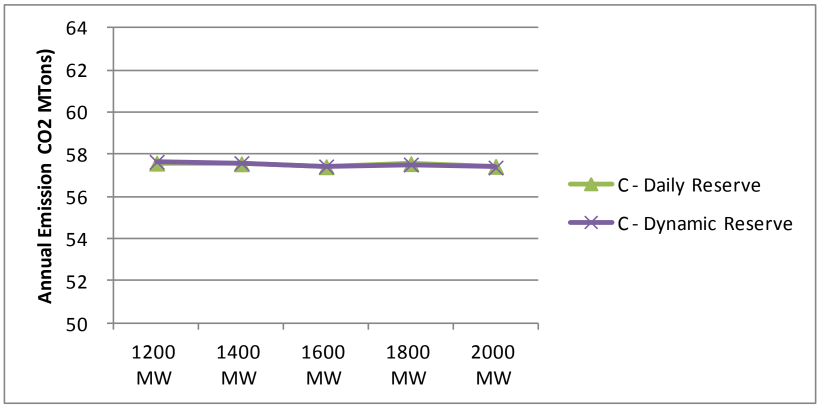

Figure 4-47: CO_2 emissions for Scenario C—Peak Hour (1 Hour per Day) at Transfer Limit (million tons).

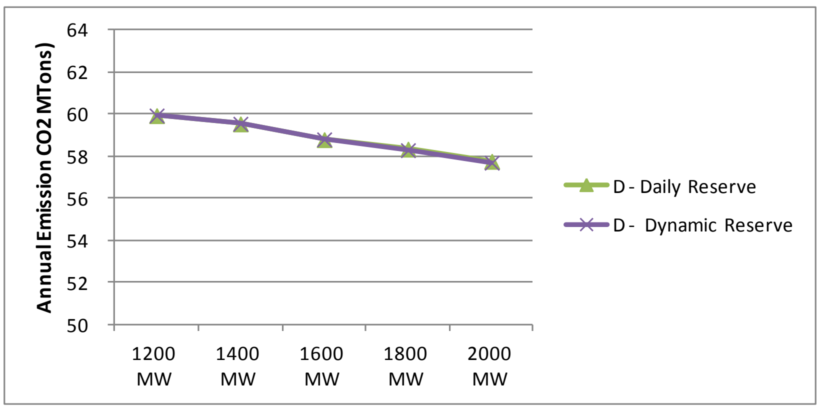

Figure 4-48: CO_2 emissions for Scenario D—Historical Import Pattern (million tons).

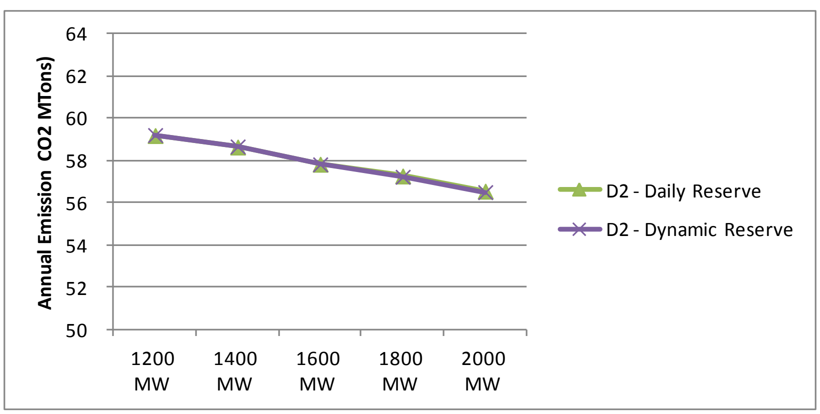

Figure 4-49: CO_2 emissions for Scenario D2—Adjusted Historical Import Pattern (million tons).

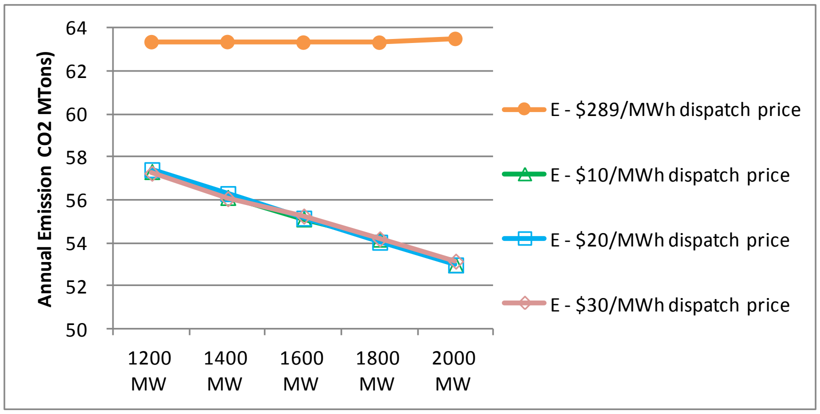

Figure 4-50: CO_2 emissions for Scenario E—Dispatchable Based on Energy Price (million tons).

4.7.2 Emissions—SO_2

Figure 4-51 to Figure 4-56 present the SO_2 emissions for all scenarios. Similar to the CO_2 emissions, the magnitude of these SO_2 emissions decreased in proportion to the amount of energy imported from HQ PII. For Scenarios A, B, D, and D2, the SO_2 emission decreased about 6% when the HQ PII import level increased from 1,200 MW to 2,000 MW. Other results are as follows:

- Figure 4-51 shows a reduction of approximately 11% for Scenario A, and Figure 4-52 shows a reduction of approximately 8% for Scenario B.
- Figure 4-53 for Scenario C shows that the reduction was almost negligible because very little energy was associated HQ PII.
- Figure 4-54 shows that Scenario D has a reduction of 2%, and Figure 4-55 shows that Scenario D2 has a reduction of 2.5%.
- As shown in Figure 4-56 for Scenario E, the New England SO_2 emission did not change significantly when the HQ PII import level increased and the energy was economically dispatched at 80% of a inefficient combustion turbine using distillate fuel oil (at $289/MWh). At the lower dispatch prices of $10, $20, and $30/MWh, the energy was imported in all hours at the maximum rate, which reduced the SO_2 emissions approximately 12%.
- The reserve-requirement representations did not have an obvious impact toward the simulated emission results.

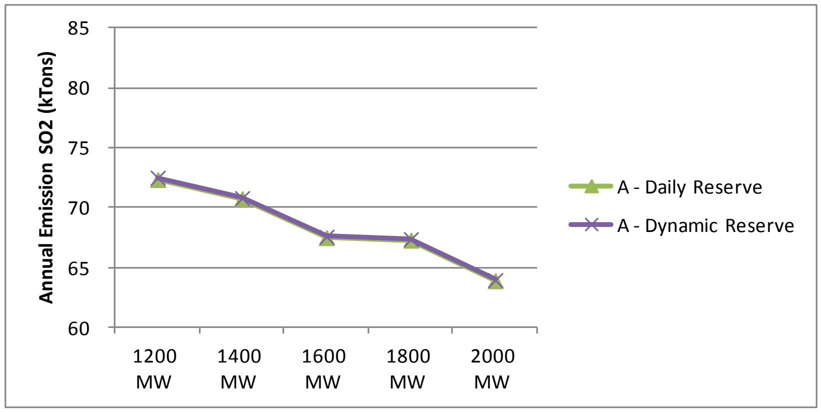

Figure 4-51: SO_2 emissions for Scenario A—24/7 at Transfer Limit (thousand tons).

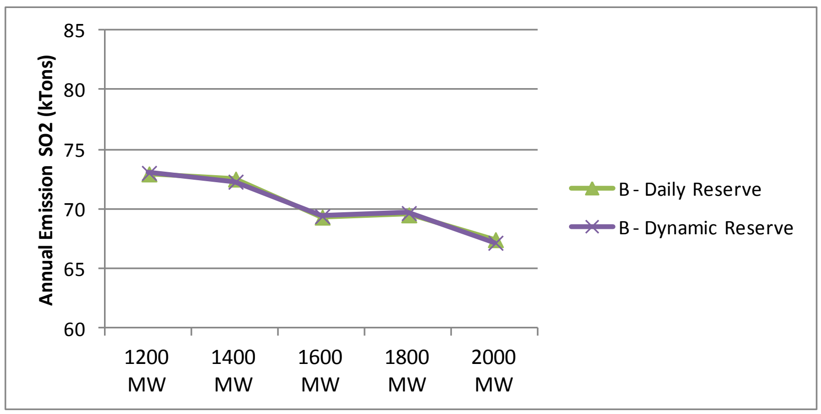

Figure 4-52: SO_2 emissions for Scenario B—On-Peak Hours at Transfer Limit (thousand tons).

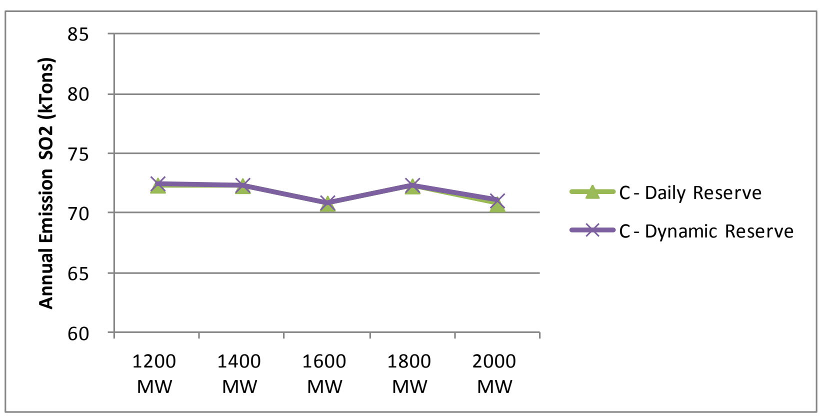

Figure 4-53: SO_2 emissions for Scenario C—Peak Hour (1 Hour per Day) at Transfer Limit (thousand tons).

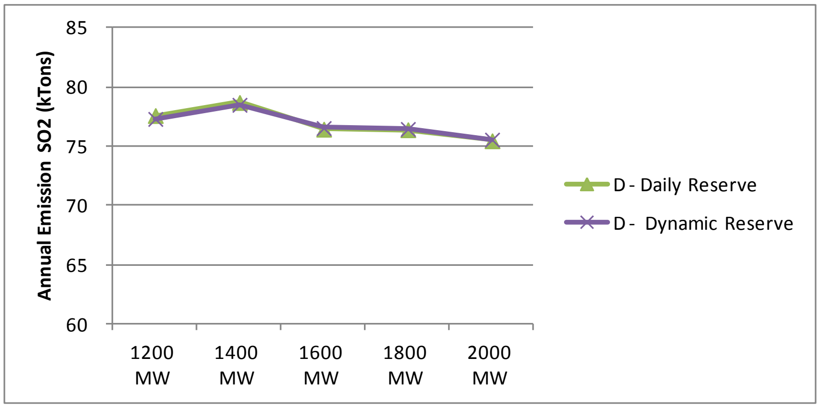

Figure 4-54: SO_2 emissions for Scenario D—Historical Import Pattern (thousand tons).

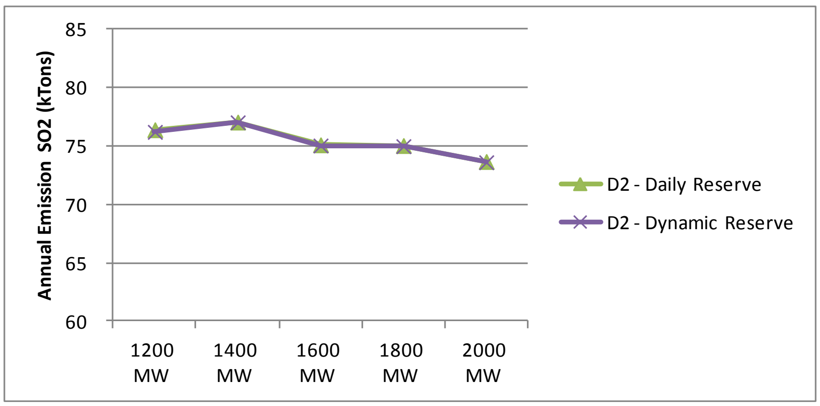

Figure 4-55: SO_2 emissions for Scenario D2—Adjusted Historical Import Pattern (thousand tons).

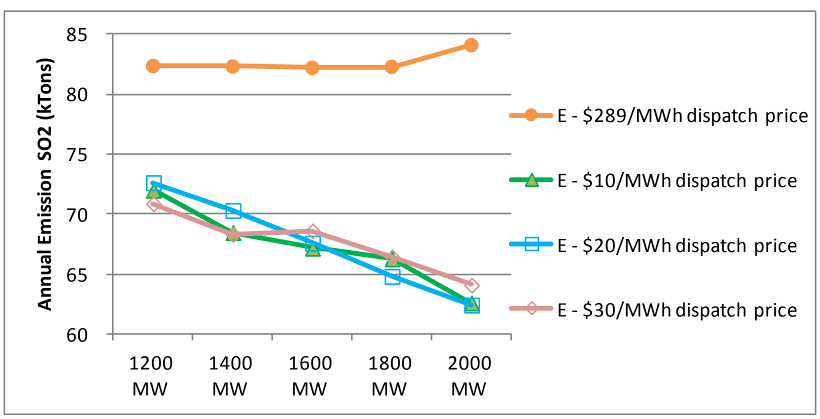

Figure 4-56: SO_2 emissions for Scenario E—Dispatchable Based on Energy Price (thousand tons).

4.7.3 Emissions—NO_X

Figure 4-57 to Figure 4-62 present the NO_X emissions for all scenarios. Similar to the CO_2 and SO_2 emissions, the magnitude of the NO_X emissions decreased in proportion to the amount of energy imported from HQ PII. For Scenarios A, B, D, and D2, the NO_X emissions decreased from 0 to 6% when the HQ PII import level increase from 1,200 MW to 2,000 MW. Other results were as follows:

- Figure 4-57 shows a reduction of approximately 7% for Scenario A, and Figure 4-58 shows a reduction of approximately 5% for Scenario B.
- Figure 4-59 shows that for Scenario C net emissions increased 1 to 3%, resulting from additional unit commitments covering the increased reserve requirement not offset by the emission-free imports.
- Figure 4-60 and Figure 4-61 shows that Scenarios D and D2 have a reduction of about 5%.
- As shown in Figure 4-62 for Scenario E, the New England NO_X emissions did not change significantly when the HQ PII import level increased and the energy was economically dispatched at 80% of a inefficient combustion turbine using distillate fuel oil (at $289/MWh). At the lower dispatch prices of $10, $20, and $30/MWh, the energy was imported in all hours at the maximum rate, which reduced the NO_X emissions approximately 6%.

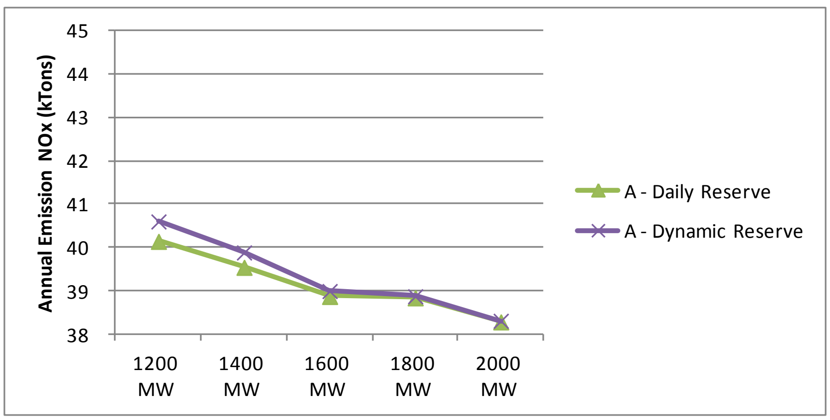

Figure 4-57: NO_X emissions for Scenario A—24/7 at Transfer Limit (thousand tons).

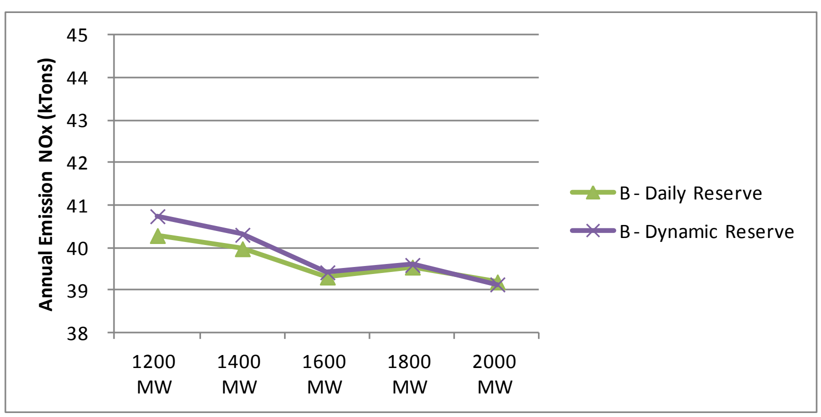

Figure 4-58: NO_X emissions for Scenario B—On-Peak Hours at Transfer Limit (thousand tons).

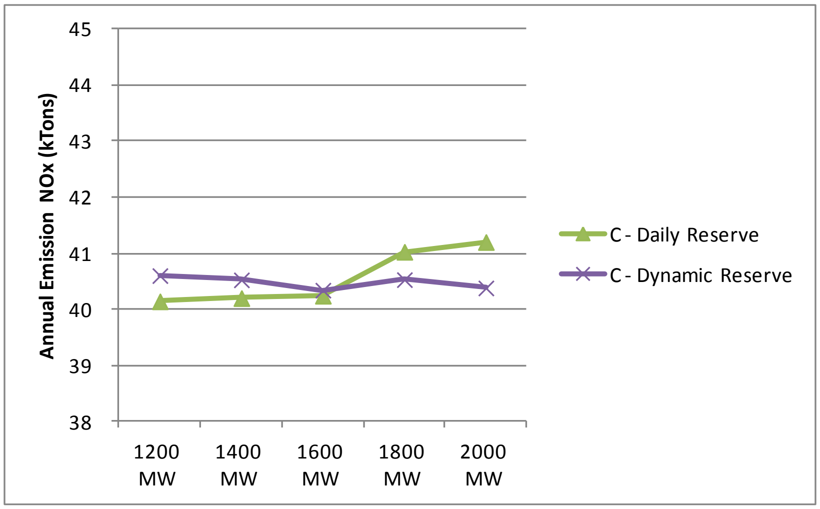

Figure 4-59: NO_X emissions for Scenario C—Peak Hour (1 Hour per Day) at Transfer Limit (thousand tons).

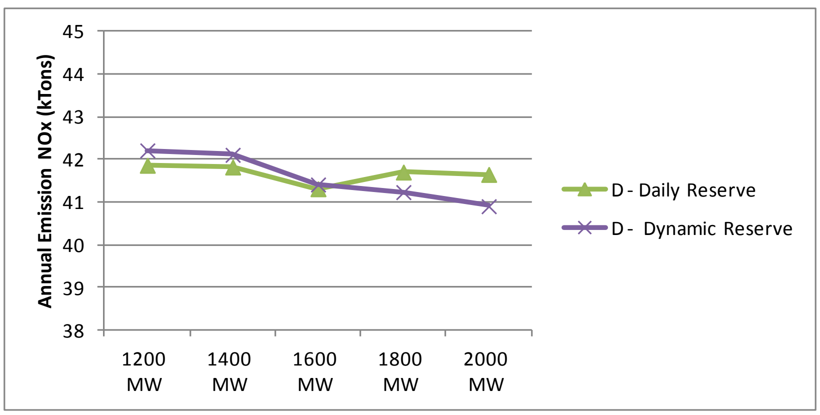

Figure 4-60: NO_X emissions for Scenario D—Historical Import Pattern (thousand tons).

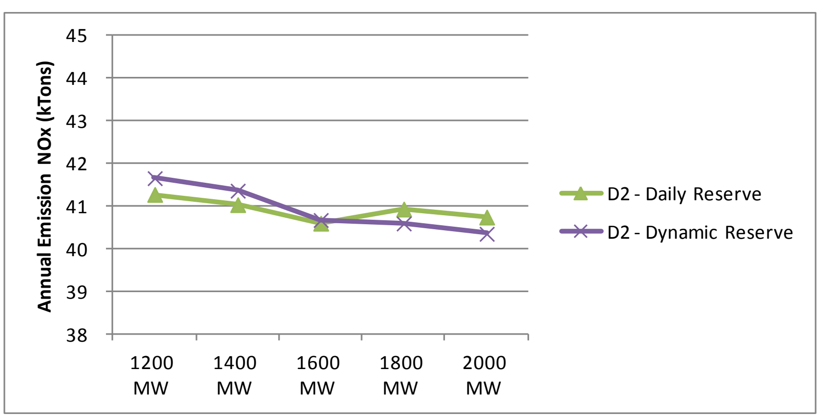

Figure 4-61: NO_X emissions for Scenario D2—Adjusted Historical Import Pattern (thousand tons).

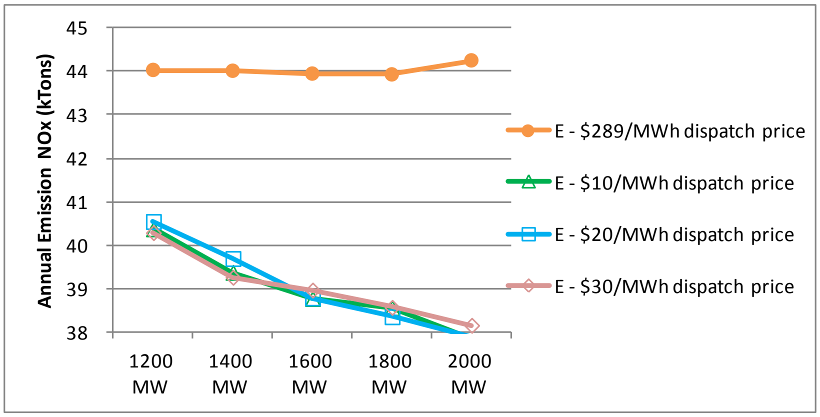

Figure 4-62: NO_X emissions for Scenario E—Dispatchable Based on Energy Price (thousand tons).

Section 5
Observations

This analysis evaluated the benefits of increasing the maximum loss-of-source contingency allowed from Québec on the Hydro-Québec Phase II facilities. For most scenarios, the various economic and environmental metrics showed lower costs and lower emissions as the import level increased and the energy was imported at an assumed $0/MWh cost.

The reserve requirements were represented in two distinct ways, static and dynamic, which affected the character of the results. The static reserve requirements assumed that HQ PII was the largest contingency when HQ PII was not on scheduled maintenance. The Dynamic Reserve requirements representation was affected by other potential large LOS contingencies caused by the potential simultaneous loss of both Mystic 8 and 9 at full output. Because both of these new and efficient units were assumed to operate at high output levels, their combined capacities frequently created the largest LOS contingency that needed to be protected against. The various metrics showed that HQ PII could operate at up to 1,400 MW in the summer and 1,700 MW in other months, using a Dynamic Reserve representation, without incurring a significant additional cost of reserves.

An analysis of the available reserves showed that both the Daily and the Dynamic Reserve representations are reasonable representations of the operational constraints, and neither can be viewed as inherently better than the other. The results of both representations provide a consistent range of metrics. Under the assumptions used, New England appears to have adequate resources to provide operating reserves to operate HQ PII at up to 2,000 MW, if the external systems could accommodate an LOS of this magnitude.

For most scenarios, the production cost decreased when the HQ PII import level increased and the cost of HQ PII was assumed to be $0/MWh. For all scenarios, the LSE energy expense and system LMPs decreased as the maximum amount of HQ PII import levels increased. Make-whole, uplift payments, which approximates ISO New England's Net commitment-Period Compensation, grew as the LMPs decreased because fewer resources were able to cover their start-up, no-load, and operating expenses based only on their associated energy revenues. When the HQ PII import level increased, the imported energy displaced generation from gas, oil, and coal units. For most scenarios, system emission decreased as a result.

The only exceptions to these generalizations were when the amount of imported energy was small. For example, in Scenario C, the capacity factors of HQ PII imports was under 5%, and the effect on the metrics tended to result in higher production costs, higher uplift, and higher emissions. This scenario increased the imports in only one peak hour per day, and the benefit of the increased energy imports at $0/MWh, in some cases, was less than the increased production costs to provide the reserves. Additionally, the LSE energy expense and system LMP deceased when the HQ PII import level increased.

In Scenario E, when HQ PII was based on an assumed high energy price ($289/MWh), the economic and environmental metrics did not change significantly because energy imports from HQ PII were very limited. When the energy price was $10, 20, or $30/MWh, the energy was imported at a 100% capacity factor, and the associated economic and environmental metrics showed reductions.

If the cost of HQ PII was assumed to be $0/MWh, the additional imports could reduce production costs by up to $300 million, depending on the amount of energy imported. If the energy were valued at the LMP at the delivery point instead of $0/MWh, the reductions in production costs were much smaller and, in some cases, actually increased the production cost metric.

Further investigations into the Dynamic Reserve representation and the make-whole, uplift metric should be considered in future economic studies.

