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MCLANE MIDDLETON

March 28, 2016

Via Electronic Mail & Hand Delivery

Pamela Monroe, Administrator
New Hampshire Site Evaluation Committee
21 South Fruit Street, Suite 10
Concord, NH 03301-2429

**Re: New Hampshire Site Evaluation Committee Docket No. 2015-06
Joint Application of Northern Pass Transmission LLC and Public Service Company of New Hampshire d/b/a Eversource Energy for a Certificate of Site and Facility for Construction of a New High Voltage Transmission Line in New Hampshire
Filing of Proposed Redacted Versions**

Dear Ms. Monroe:

The Applicants enclose for filing in the above-captioned matter, an original and one copy of redacted versions of Appendix 43, the Cost – Benefit and Local Economic Impact Analysis of the Proposed Northern Pass Transmission Project ("Report") and the Pre-Filed Testimony of Julia Frayer ("Testimony") of London Economics International LLC ("LEI"). Unredacted versions of both documents were previously provided to the Site Evaluation Committee ("SEC" or "Committee") and Counsel for the Public. Unredacted versions will be made available to parties to the proceeding as and when directed by the Committee.

The Applicants filed an Unassented to Motion for Protective Order and Confidential Treatment (the "Motion") on October 19, 2015. In Paragraph 19 of the Motion, the Applicants indicated that redacted versions of Ms. Frayer's Report and corresponding Testimony would be filed upon leave of the Committee. Consistent with discussions at the Pre Hearing Conference held on March 22, 2016, the Applicants submit the accompanying proposed redacted versions of both documents. Pursuant to the Order issued by Chairman Honigberg on March 25, 2016, the Applicants understand that objections to confidential treatment are due by April 7, 2016.

The Applicants reiterate their underlying request for a protective order for confidential and proprietary business information in the Report and Testimony but do not repeat the entire analysis here. Based on further review, and the passage of time since the Motion as discussed below, the Applicants note that they have narrowed their request for protection to information that if publicly disclosed would place NPT at a business disadvantage relative to its competitors in the wholesale electricity marketplace.

The Applicants have focused on the protection of business confidential information contained in the Report at Appendix C: Detailed Assumptions for wholesale power market simulations, as well as corresponding references to such information contained in Section 5 of the Report and the Testimony, and related information contained in discussions of "stress tests" conducted by Ms. Frayer. The Applicants have identified a privacy interest in such information in the Motion and they assert that if the information were to be publicly disclosed its competitors would gain unwarranted insight into the Applicants' business strategy. The Applicants further note that protection is sought for the full scope of the detailed assumptions, rather than on what might be argued to be the most sensitive parts of the whole, because it is the whole approach that is confidential; to the extent one or more parts of the whole are revealed, the easier it becomes for a competitor to recreate the overall business strategy.

The Applicants acknowledge that as a general matter there is a public interest in the disclosure of materials to the SEC. In these circumstances, however, the Applicants believe that the balancing of the Applicants' privacy interests in non-disclosure of the redacted sections of the Report and Testimony outweigh a generalized interest in disclosure for the following reasons.

First, the Applicants have made appropriate efforts to limit the amount of material redacted, and the remaining unredacted material reasonably informs the general public as to "the potential economic benefits of NPT in terms of the wholesale electricity market impacts and environmental effects, as well as the impact on the local economy in New Hampshire and other states in New England." See, Report, p. 12.

Second, the Committee and Counsel for the Public have unredacted versions of the Report and Testimony to permit them to perform their statutory obligations, and the Committee will determine the conditions under which parties to the proceeding may be afforded access to the unredacted versions. In this regard, the Applicants request the opportunity to weigh in at the proper time on such conditions. As a consequence, the adjudication of the Application will be conducted in a manner consistent with due process.

Third, the Applicants' request for protective treatment is time-limited. As explained in the Motion, the Applicants were specifically concerned about the Clean Energy RFP process being conducted by Massachusetts, Connecticut, and Rhode Island. Bids have since been submitted in that process, but it is not yet complete. The Applicants believe that public disclosure of the redacted portions of the Report and Testimony will be appropriate within the next several months.

Finally, while the original Motion references LEI's proprietary business models, the Report and Testimony themselves do not contain sensitive information of that nature. However, to the extent a party seeks such information through discovery, the Applicants will seek a protective order for this competitively sensitive information at that time.

Please feel free to contact me with any questions regarding the enclosed information.

Very truly yours,

Thomas B. Getz

TBG:rs3

Enclosures

cc: Distribution List

PROPOSED REDACTED VERSION

Cost-Benefit and Local Economic Impact Analysis of the Proposed Northern Pass Transmission Project

October 16, 2015

Prepared for

Northern Pass Transmission, LLC

by

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Disclaimer

London Economics International LLC ("LEI") was retained by Northern Pass Transmission, LLC ("NPT") to develop an economic impact analysis of the proposed Northern Pass Transmission Project. LEI has made the qualifications noted below with respect to the information contained in this report and the circumstances under which the report was prepared:

While LEI has taken all reasonable care to ensure that its analysis is complete, wholesale electricity markets are highly dynamic, and thus certain recent developments may or may not be included in LEI's analysis. Interested parties should note that:

- LEI's analysis is not intended to be a complete and exhaustive analysis of NPT. All possible factors of importance to all interested parties have not necessarily been considered. The provision of an analysis by LEI does not obviate the need for interested parties to make further appropriate inquiries as to the accuracy of the information included therein, and to undertake their own analysis and due diligence.

- No results provided or opinions given in LEI's analysis should be taken as a promise or guarantee as to the occurrence of any future events.

- There can be substantial variation between assumptions and market outcomes analyzed by various consulting organizations specializing in electricity markets and economic analysis. Neither LEI nor its employees make any representation or warranty as to the consistency of LEI's analysis with that of other parties.

The contents of LEI's analysis do not constitute investment advice. LEI, its officers, employees and affiliates make no representations or recommendations to any party. LEI expressly disclaims any liability for any loss or damage arising or suffered by any third party as a result of that party's, or any other party's, direct or indirect reliance upon LEI's analysis and this report.

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1 List of Acronyms

AC	Alternating Current
ACP	Alternative Compliance Payment
AEO	Annual Energy Outlook
AIM	Algonquin Incremental Market
A/S	Ancillary Services
BHE	Bangor Hydro Electric
CAA	Clean Air Act
CAGR	Compound Annual Growth Rate
CAIR	Clean Air Interstate Rule
CCGT	Combined Cycle Gas Turbine
CELT	Capacity, Energy, Loads, and Transmission
CEMS	Continuous Emissions Monitoring System
CDD	Cooling Degree Days
CGE	Committee for a Green Economy
CHPE	Champlain Hudson Power Express
CMA	Central Massachusetts
CONE	Cost of New Entry
CPP	Clean Power Plan
CSAPR	Cross-State Air Pollution Rule
CSC	Cross Sound Cable
CT	Connecticut
DR	Demand Resource
ECRC	Energy Cost Reduction Contract
EIA	Energy Information Administration
EPA	Environmental Protection Agency
EPAct	Energy Policy Act
FCA	Forward Capacity Auction
FCM	Forward Capacity Market
FERC	Federal Energy Regulatory Commission
FT	firm transmission
FTE	Full-Time Equivalent

FTR	Financial Transmission Rights
GDP	Gross Domestic Product
GHG	Greenhouse Gases
HDD	Heating Degree Days
HH	Henry Hub
HR	Heat Rate
HQ Hydro	HQ Hydro Renewable Energy, Inc.
HVDC	High Voltage Direct Current
ICAP	Installed Capacity
ICR	Installed Capacity Requirements
I/O	Input-Output
IRM	Internal Reserve Margin
IRP	Interstate Reliability Project
ISO-NE	Independent System Operator-New England
LCOE	Levelized Cost of Energy
LCOP	Levelized Cost of Pipeline
LEI	London Economics International LLC
LMP	Locational-based Marginal Pricing
LOLE	Loss of Load Expectation
LSR	Local Sourcing Requirement
MA	Massachusetts
MATS	Mercury and Air Toxic Standards
MCL	Maximum Capacity Limit
MECRA	Maine Energy Cost Reduction Act
MEx	Maine Power Express
ME	Maine
MW	Megawatt
MWh	Megawatt-hour
NCPC	Net Commitment Payment Compensation
NECPL	New England Clean Power Link
NEEWS	New England East-West Solution

NEL	Northeast Energy Link
NEPOOL	New England Power Pool
NERC	North American Electric Reliability Council
NESCOE	New England States Committee on Electricity
NETP	New Entry Trigger Price
NEMA	Northeast Massachusetts
NH	New Hampshire
NOATT	NEPOOL Open Access Transmission Tariff
NO_x	Nitrogen Oxides
NPCC	Northeast Power Coordinating Council
NPT	Northern Pass Transmission, LLC or the Northern Pass Transmission Project
NTA	Non-Transmission Alternative
NYCA	New York Control Area
NYISO	New York Independent System Operator
O&M	Operations and maintenance
OTAG	Ozone Transport Assessment Group
OTC	Ozone Transport Commission
PER	Peak Energy Rent
PI	Performance Incentive
PPA	Power Purchase Agreement
PSNH	Public Service New Hampshire
PTC	Production Tax Credit
PTF	Pool Transmission Facility
QUA	Qualified Upgrade Awards
REMI	Regional Economic Models, Inc.
RFP	Request For Proposals
RGGI	Regional Greenhouse Gas Initiative
RI	Rhode Island
ROS	Rest of System
RPS	Renewable Portfolio Standard
RSP	Regional System Plan

RTO	Regional transmission Organization
SCC	Seasonal Claimed Capability
SMP	System Marginal Price
SO_2	Sulfur Dioxide
SOEP	Sable Offshore Energy Project
SRMC	Short Run Marginal Cost
TDI	Transmission Developers Inc.
TSA	Transmission Service Agreement
TTC	Total transfer capability
VT	Vermont
WCI	Western Climate Initiative
WMA-VT	Western Massachusetts - Vermont

2 Executive Summary

The proposed Northern Pass Transmission Project ("NPT") is a high voltage direct current ("HVDC") transmission infrastructure project that will be able to bring approximately 1,090 megawatts ("MW")[1] of energy from Hydro-Québec's fleet of hydroelectric generation into New Hampshire and the rest of New England. London Economics International LLC ("LEI") analyzed the potential economic benefits of NPT in terms of the wholesale electricity market impacts and environmental effects, as well as the impact on the local economy in New Hampshire and other states in New England.[2]

2.1 LEI's "Base Case" outlook

For the modeling process, we first began by forecasting a "Base Case," spanning an 11-year forecast period of 2019 through 2029.[3] The Base Case outlook for New England's wholesale electricity market combines the most likely set of market assumptions for key market drivers along with normal system operations and average load conditions, based on ISO-NE's "50/50" load forecasts from its 2015 ISO-NE Capacity, Energy, Loads, and Transmission ("CELT") Report. The Base Case also builds on conservative market-oriented expectations for marginal costs of generation, including fuel prices, variable operations and maintenance costs, and carbon allowance prices. Fuel price and carbon allowance prices are key drivers for setting energy price levels in the New England market. In terms of fuel prices, the primary factor is delivered natural gas prices. We have conservatively assumed that new natural gas pipelines will be built during the forecast timeframe, which would keep delivered natural gas prices in check in the region. We further assumed that there will be no changes in the current Regional Greenhouse Gas Initiative ("RGGI") regime or the national carbon reduction goals under Environmental Protection Agency's ("EPA") proposed Clean Power Plan ("CPP") such that future carbon allowance prices would not rise significantly from current levels. Similarly, we assumed current market rules would prevail over the forecast timeframe.

In the Base Case we assume that generic investments are developed to meet the Installed Capacity Requirement ("ICR") and are timed appropriately based on economic decision-making by new entrants. Once the Base Case is set, we then consider how market outcomes would change if NPT is developed. This case (with NPT) is referred to as the "Project Case". It is important to note that this study does not simply evaluate the same world with and without NPT. Such a static assumption would not be justified given the dynamics we have observed in power markets over the years and will result in a bias that overstates the longevity of market

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[1] The capacity supply obligation in the capacity market is assumed to be 1,000 MW.

[2] LEI used its proprietary modeling suite of wholesale electricity markets for the analysis of energy and capacity market impacts and in order to estimate the reduction in major pollutants emitting from electric generation in New England. The local economic benefits of NPT are modeled using the PI+ model, developed by Regional Economic Models, Inc. ("REMI"). See Appendix E for complete details of REMI modeling.

[3] NPT is expected to begin commercial operations in May 2019; therefore, the economic benefits in 2019 throughout the analysis only reflect partial year benefits.

price reduction-related benefits from the project. A more realistic approach is to model a Project Case (with NPT), where investment by other parties reacts to the new supply stemming from the Project. LEI has therefore modified the new entry profile (and also evaluated the need for generation retirements) under the Project Case. This approach results in modeling two different worlds, and both are internally consistent with the projected market dynamics. Such an analysis also ensures that we are not over-stating the market price-related benefits that NPT can offer to New England consumers.

2.2 NPT creates a variety of quantifiable benefits for the New England electricity market

The market benefits of NPT are measured as a function of the difference in market prices between the Base Case and the Project Case. In terms of the wholesale electric market impacts, we focused on the wholesale energy market and capacity market impacts, as those would then flow through to customers as a reduction in the commodity component of their retail tariffs for electricity.

We also measured the production cost savings created as a result of NPT for the wholesale electricity market in New England, due to the addition of low cost supply resulting from NPT's operations and more efficient generation dispatch. The more efficient dispatch and flow of hydroelectric based imports from Québec on NPT also leads to reduction in greenhouse gases (as measured by CO_2 emissions), and other pollutants such as SO_2 and NO_X. The local economic benefits include increased employment and improvements in the state's economic activity as measured by Gross Domestic Product ("GDP").[4]

2.3 Timeframe of analysis

In the Project Case, we have projected energy market sales that are transmitted via NPT starting in May 2019 onward (in accordance with NPT's expected in-service date). Therefore, we have quantified NPT's wholesale energy market benefits over 11 years, covering 2019 to 2029. We have also assumed that shippers will make capacity sales into ISO-NE's Forward Capacity Market ("FCM") using NPT's 1,000 MW of capacity commencing in June 2020 (June 2020 is the start of the delivery period associated with Forward Capacity Auction ("FCA") #11). As such, we have conservatively quantified only the wholesale capacity market benefits for ten years, covering the calendar years of 2020 to 2029.

2.4 Implications of gas market price uncertainty

Gas creates some uncertainty in future energy market benefits – LEI has captured that uncertainty with two different scenarios.

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[4] GDP is commonly defined as the monetary value of all the finished goods and services produced within a country (or within a region/state) over a specific time period. It includes all private and public consumption, government expenditures, investments and net exports that occur within the country (or region/state).

The first gas scenario assumes that New England will continue to source its gas supplies from Henry Hub. This scenario utilizes LEI's Levelized Cost of Pipeline ("LCOP") forecasting approach (and is referred to throughout this report as "LCOP/HH"). LEI relied on the EIA's 2015 Annual Energy Outlook ("AEO 2015") and current forwards for gas prices at the Algonquin Citygate to develop this gas price outlook for New England.

The second gas scenario explores the possibility that the Marcellus Shale region will overtake Henry Hub as New England's gas supply point, which is enabled through the development of the gas pipeline infrastructure. This gas scenario utilizes a detailed gas infrastructure model, Gas Pipeline Competition Model ("GPCM"), produced by RBAC. This scenario and the associated results are referred to throughout this report with the "GPCM/MS" label.

2.5 Summary of electricity market, environmental, and economic benefits of NPT

Wholesale market benefits make up the highest share of total benefits created by NPT. Over the modeling horizon, wholesale market benefits average between $851 and $866 million per annum ("p.a.") for New England and between $81 and $83 million p.a. for New Hampshire in nominal dollars. While we also analyze production cost savings and the economic benefits from emissions reduction, these are not considered direct customer benefits and are treated separately. The benefits are shown in Figure 1 below.

Figure 1. Average annual NPT benefits summary

Benefit Categories	New England	New Hampshire
Wholesale Market	($millions, nominal)	($millions, nominal)
Wholesale Market Benefits (11-yr avg)	$851 - $866	$81.0 - $82.5
Energy Market (11-yr avg)	$80 - $100	$8.2 - $10.2
Capacity Market (10-yr avg)	$843 - $848	$79.6 - $80.1
Production Costs	($millions, nominal)	
Production Cost Savings (11-yr avg)	$330 - $425	
Environmental Benefits	Metric Tons	
CO_2 Reduction (11-yr avg)	3.3 - 3.4 millon	
NO_x Reduction (11-yr avg)	537 - 624	
SO_2 Reduction (11-yr avg)	261 - 460	
Gross Domestic Product	($millions, nominal)	($millions, nominal)
During Construction Peak (2017)	$489	$214
During Operation (11-yr avg)	$1,156	$162
Jobs	Jobs	Jobs
During Construction Peak (2017)	5,574	2,677
During Operation (11-yr avg)	6,820	1,148

Note:

1) Wholesale market benefits represent an 11-year average of energy and capacity market benefits, whereby the capacity market benefits in 2019 are $0.
2) LEI also calculated the incremental social benefits from carbon emissions reduction assuming the social cost of carbon of approximately $70.6/ metric ton (in 2019 dollars). The modeled carbon reduction benefits range from $207-$208 million/ year as explained in Section 6.3.
3) Local economic benefits analysis was based on the LCOP/HH gas scenario result.

The following sections will discuss the key findings across these categories of benefits in more detail. New Hampshire's customers will not bear the costs of building NPT. If NPT is selected as part of the Clean Energy and Transmission Request for Proposal, as discussed further in Section 4 of this Report, Connecticut, Massachusetts, and Rhode Island customers will pay for transmission charges associated with NPT.

2.6 Wholesale energy market benefits

LEI projects that NPT is expected to decrease wholesale energy prices by an annual load-weighted average price of $0.6/MWh in the GPCM/MS gas scenario and $0.8/MWh in the LCOP/HH gas scenario over the first eleven years of operation in the ISO-NE energy market (2019 through 2029). Under normal operation conditions, the New England power system is generally uncongested and therefore the wholesale energy price reductions are equally distributed to wholesale load across New England.

The key drivers for wholesale energy market benefits include: fuel prices (specifically, delivered natural gas prices (see Figure 16 in Section 5.5), carbon allowance prices, and the state of supply-demand conditions (including quantity of new entry, as well as technology choice of new entry). [redacted]

Furthermore, we assumed just-in-time entry to meet demand growth subject to the forecast capacity prices. In both the Base Case and Project Case, the New England power system is able to maintain a balance in supply-demand conditions over time. In fact, new entry reduces the overall market price in the long run because of the improved technology and overall efficiency of newer generic CCGTs in converting the fuel to electricity.

[redacted]

If delivered natural gas prices or carbon allowance price were projected to be higher in the forecast time horizon, or if New England experiences higher demand without additional supply coming to market, we would have much higher wholesale energy market benefits (see Section 5.10).

Under the conservative Base Case assumptions, over the forecast timeframe, the wholesale energy market savings are estimated to be approximately $80 million p.a. to $100 million p.a. New Hampshire's share of these direct wholesale energy market benefits ranges from $8.2 million to $10.2 million p.a. More detailed discussion of wholesale energy market benefits can be found in Section 5.7.

In terms of production cost savings, NPT will result in an average of $330 million to $425 million p.a. in savings from lower production costs for the ISO-NE system.[5] These savings are essentially the change in the total marginal costs of production for the entire ISO-NE system. As will be explained later, unlike energy market savings, production savings do not dissipate in the long run as these benefits accrue as a result of changes to the merit order below the marginal, price setting unit. A more detailed discussion of production cost savings can be found in Section 5.8.

2.7 Wholesale capacity market benefits

LEI assumed that NPT would create an opportunity for shippers to qualify and sell 1,000 MW of new capacity into the FCM, based on the line's nominal rating. LEI further assumed that this new capacity created by NPT will first bid into ISO-NE's FCA#11, for which capacity obligations would then begin in June 2020.

[redacted] kW [redacted] These capacity market price impacts equate to a 10-year average wholesale capacity market benefit ranging from $843 million p.a. to $848 million p.a. for the ISO-NE region as a whole.

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[5] The level of estimated production cost savings depends on the marginal costs of production for the hydroelectric-based imports on NPT (as hydroelectric resources have essentially negligible physical marginal cost of production, we have assumed a $0 per MWh offset in the above calculations). But even under alternative assumptions, where there is an additional opportunity cost assigned to the imported energy that is transmitted on NPT (we assumed for example, $25/MWh), the production cost savings for ISO-NE's power system are still substantial, at over $232 million p.a. under the LCOP/HH gas scenario and $137 million under the GPCM/MS gas scenario.

[redacted]

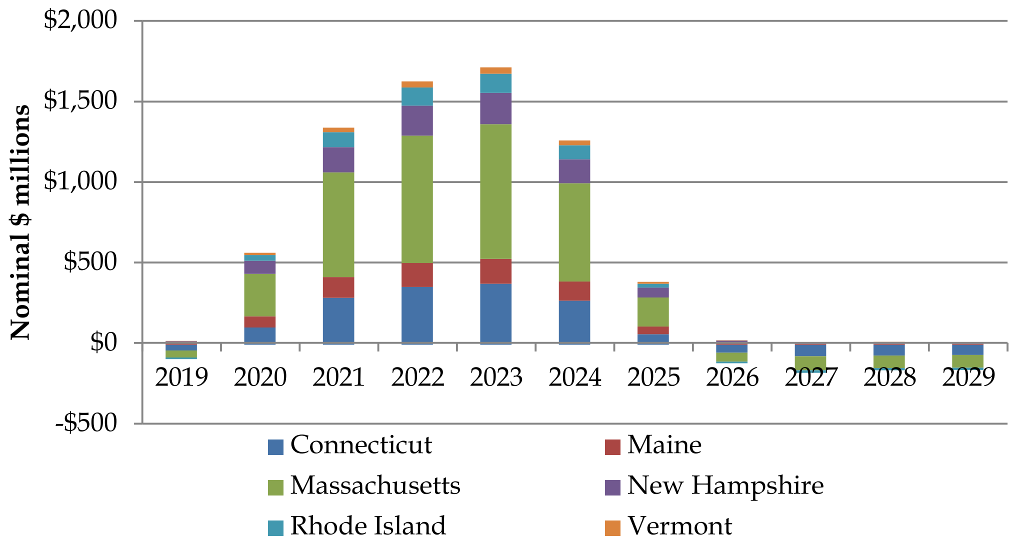
New Hampshire accounts for roughly 9.5% of New England's system peak demand. On average, LEI expects New Hampshire wholesale load to benefit by approximately $79.6 million p.a. over the ten year forecast horizon from these wholesale capacity market impacts under the LCOP/HH gas scenario and $80.1 million p.a. under the GPCM/MS gas scenario. A more detailed discussion of wholesale capacity market benefits can be found in Section 5.6.4.

2.8 Retail electricity cost savings

To properly evaluate the impact of NPT on New England's retail consumers, LEI converted the wholesale energy price impacts into a retail rate impact figure. To estimate the effect of the wholesale market changes on retail rates, LEI took into account limitations on retail load's exposure to wholesale market conditions, including self-supply and long term contracts for energy and/or capacity (collectively referred to as "retail hedges"). New England utilities generally have very limited self-supply and long term contracts currently in place, and as such the presence of retail hedges does not significantly reduce the electricity market benefits.

With these adjustments for retail hedges and potential contributions to the costs of the project, on a regional basis, New England retail consumers are projected to enjoy $577.7 million p.a. of retail electricity cost savings as a result of NPT's effects on the wholesale energy and capacity markets. As highlighted in the figure below, the retail electricity savings peak in 2023 and decline with time, following trends established in the wholesale market analysis. More detailed discussion of retail electricity cost savings can be found in Section 5.9 and Section 11.

Figure 4. New England retail electricity costs savings by state (nominal $ millions)



Although New Hampshire's retail load is somewhat insulated from wholesale market impacts with certain long term contracts and cost-of-service generation that will remain with Public Service of New Hampshire (even after the planned divestiture), New Hampshire retail consumers are nevertheless able to enjoy $79.9 million p.a. in retail electricity cost savings. Approximately half of these retail savings will go to residential customers, based on the current composition of retail load in the state.

2.9 NPT can provide insurance to consumers against the impact of real world uncertainties

In periods of system stress, for example, when load peaks during New England's summertime or when the gas infrastructure is highly constrained and gas supply is limited (and expensive), the energy flows on NPT can be extremely valuable to New England's consumers. NPT can serve as a form of physical insurance against the impact of such events, protecting consumers from at least a portion of the higher market cost that are consequence of such events.

Through back-cast simulation modeling, LEI recreated past market conditions that had exhibited very high energy prices under summer and winter stress events. LEI then added energy flows on NPT into the back-cast supply mix and thereby evaluated the wholesale market cost savings produced by NPT under such system stress conditions.

For example, between July 15 and July 19 2013, New England experienced a prolonged heat wave that resulted in prices as high as $218/MWh in the day-ahead energy market because of unusually high load and a supply shortfall (that actually caused an OP4[6] event on July 19).

[6] Known as the ISO Operating Procedure No. 4, Action during a Capacity Deficiency, OP4 is implemented when available resources are insufficient to meet anticipated electricity demand plus required operating reserves. The

Although the weather was a big contributor to these events and the fact that peak load breached the ISO-NE's 90/10 demand forecast from the prior year, similar peak demand occurrences have occurred in other years – indeed, ISO-NE has recorded actual demand exceeding 90/10 expectations six times in the last 23 years. [redacted]

The winter of 2013-14 was a record breaking winter in terms of natural gas prices in New England. Constrained natural gas pipelines led to exceptionally high delivered natural gas prices and therefore also very high wholesale energy prices. Some gas-fired plants were not able to get fuel and the cold weather compounded the problem of unavailability of resources with other generation outages. LEI simulated the conditions in New England over the five day period of January 24-28, 2014. This was a period of high gas prices (peaking at $78/MMBtu), high energy prices (max of $529/MWh recorded in the day-ahead energy market), and significant resource unavailability. In addition, pricing in some hours were driven by oil-fired units, rather than natural gas-fired generation, therefore, increasing New England's emissions footprint. [redacted]

2.10 Environmental benefits

The hydroelectric based energy flows that will be imported from Québec and transmitted on NPT will lead to a reduction in carbon emissions within New England. Based on LEI's simulation modeling of the Base Case and Project Case, the 7,958 GWh of energy flowing on NPT will result in approximately 3.3 – 3.4 million metric tons of avoided CO_2 emissions per year in New England.[7] This level of reduction is equivalent to removing roughly 690,000 passenger vehicles off the road annually.

In order to measure the economic value of this environmental benefit to society, LEI also estimated the incremental social benefit of the avoided CO_2 emissions. The social cost of carbon has been established by the Environmental Protection Agency ("EPA") at approximately $70.6/metric ton (in 2019 dollars) and rising. This figure was then reduced by the marginal value of carbon already accounted for in the electricity market modeling, namely the forecast RGGI carbon allowance price (which is paid for by generators in New England and raises the wholesale energy prices, which retail consumers ultimately pay as part of their retail tariff). The resulting net social cost of CO_2 reductions was then multiplied by the avoided tons of CO_2 per

procedure includes 11 steps that the operators can take to either increase the available supply of electricity for the region or reduce the actual real-time demand for electricity.

[7] This is a net figure that already accounts for the greenhouse gases emitted in Québec in the production of these 7,958 GWh of energy (based on the estimated average life-cycle CO_2 emissions from large hydroelectric systems). See Section 6 for further discussion of the accounting for emissions of greenhouse gas in Québec in LEI's analysis. Both the LCOP/HH and GPCM/MS gas scenarios show similar results

year. LEI estimates that NPT will create roughly $207-$208 million p.a. in incremental social benefits from CO_2 reductions in New England. Similar to production costs savings, these benefits remain stable over time, as clean energy flowing through NPT is permanently shifting dirtier units out of the supply curve relative to the Base Case.

Nitrous oxide ("NOx") emissions also decline as a result of NPT by approximately 624 tons annually under the LCOP/HH gas scenario. In addition, New England would also see approximately 460 tons less of SO_2 per year. Even under the GPCM/MS gas scenario, the reductions in NO_X and SO_2 would be 537 tons and 261 tons respectively.

2.11 Local economic benefits

The local economic benefits of an infrastructure project such as NPT arise in both the construction phase and operations phase of the project.[8] During construction phase, the local economic benefits are derived from (a) increased employment (such as the direct benefits of the construction jobs needed to build the project), (b) incremental employment generated from the regional supply chain effects of various other goods and services being supplied to the construction project and (c) the multiplier effects (for example, the induced increase in local economic activity from the local spending of the construction workers – at restaurants, hotels, and for other services).

During the operations phase, there will be economic benefits created as a result of NPT's commitment to economic development in New Hampshire, as well as the direct employment of workers to support the operations and maintenance ("O&M") activities of NPT. However, the largest economic benefits stem from the reduced retail costs of electricity. For example, as a result of lower electricity utility bills, households will be able to spend their higher disposable income on other goods or services, stimulating the economy. Similarly, firms that benefit from lower costs of electricity will be able to expand production, further benefiting the local economy. NPT will also pay property taxes which may be used by the state and local governments to increase government spending on programs that benefits the economy (however, LEI has conservatively not included this in its economic modeling).

At the peak of construction (in 2017), NPT is projected to be directly employing over 2,089 persons and spending $68.1 million on materials and other non-labor services, within New Hampshire and other New England states. As a consequence of this local spending NPT would create a total of nearly 2,676 total jobs in New Hampshire (this number includes direct, indirect, and induced jobs) and 5,574 total jobs across the New England region (in 2017). In terms of GDP, NPT will increase New England states' annual GDPs by $489 million (at the peak of construction in 2017) and about 44% of that additional economic growth ($214 million) will be situated in New Hampshire.[9]

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[8] While the bulk of construction would occur in 2017 and 2018, we have referred to a construction period that covers 2016 to early 2019 in our calculations. Therefore, we include pre-construction spending from 2016 in our analysis.

[9] Local economic benefits analysis was based on the LCOP/HH gas scenario result.

During the commercial operations phase (2019-2029), NPT will create on average over 6,820 total jobs p.a. across New England. New Hampshire will see an increase of 1,148 total jobs on average. These local economic impacts are primarily being driven by the retail electricity savings; however, NPT is also providing additional support to New Hampshire through approximately $13.5 million per year of direct spending (through O&M of NPT's infrastructure in the state and also community funding initiatives). In addition to the increased employment, NPT will generate over $1,156 million dollars annually in new economic activity for the New England region (distributed across all six states in New England). More specifically, New Hampshire's annual GDP would increase by over $162 million on average over the forecast timeframe. More detailed discussion of local economic benefits can be found in Section 7.

3 Overview of the wholesale Electricity Market in New England

Created in 1997, the New England Independent System Operator ("ISO-NE") oversees and administers the competitive wholesale electricity markets in New England. ISO-NE is the independent system operator for the six-state New England region that includes Maine "(ME"), Vermont ("VT"), New Hampshire ("NH"), Massachusetts ("MA"), Rhode Island ("RI"), and Connecticut ("CT"), as represented in Figure 6 on page 24. New England's power system includes 350 generating facilities connected by over 8,600 miles of transmission lines serving more than 6.5 million customers.[10]

On November 9, 1965, the entire Northeastern portion of the US experienced a blackout due to a trip of a heavily loaded 230-kv transmission line near Ontario which also led to the failure of several other overloaded lines. To ensure that this incident would not be repeated and to meet the need for centralized coordination, the North American Electric Reliability Council ("NERC") was established. Initiatives promulgated by NERC also led to the creation of the New England Power Pool ("NEPOOL") in 1971 as a voluntary association of electric utilities in New England. NEPOOL was in some ways the predecessor organization to the ISO-NE.[11] Some experts also view the so-called Great Northeast Blackout as the seminal event that set in motion the development of the current regional power markets in North America. Prior to this event, the electric transmission and distribution networks of utilities in New England (similar to utilities in the rest of the US) were operated and dispatched independently.

Currently, the centrally coordinated dispatch of generation to meet load is performed on a regional basis, integrating all six New England states. ISO-NE's market rules and the overall operation of the wholesale electricity market come under Federal jurisdiction, subject to the regulatory oversight of the Federal Energy Regulatory Commission ("FERC"). Certain other issues (such as those related retail rates, how supply is procured for retail customers, renewable portfolio standards, regulation of distribution rates and approval for siting of new infrastructure) are within the purview of states.

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[10] ISO-NE. Draft 2015 Regional System Plan ("RSP"), Figure 2-1 on page 26

[11] The Energy Policy Act ("EPAct") of 1992 created a new category of electricity producer, the exempt wholesale generator, and empowered FERC to open the national electricity transmission system to wholesale (or third-party) suppliers to bring more efficient, lower-cost electricity to customers across the country. FERC Orders 888 and 889, issued in 1996, opened the nation's bulk transmission systems to fair and non-discriminatory access. NEPOOL submitted to FERC a reorganization plan in response to open access requirements by the end of 1996. Following the approval of this plan by FERC, ISO-NE was established as a not-for-profit corporation on July 1, 1997. At that time the "assets" of NEPOOL – essentially the control center located in Holyoke, Massachusetts, which managed the real-time operations of the New England bulk power system – were transferred to ISO-NE. That same day, under a service contract with NEPOOL, ISO–NE assumed operational responsibility for the New England bulk power market, commenced administration of the NEPOOL Open Access Transmission Tariff ("NOATT"), and began the design and development of a restructured wholesale electricity marketplace. Operations of New England wholesale electricity market commenced on May 1, 1999.

Following its inception, the ISO-NE wholesale electricity market has been subject to an evolution that involved both significant changes in market design and some material adjustments in market rules. The current wholesale energy market design was implemented in 2003, when ISO-NE began to use nodal day-ahead and real-time markets. In terms of wholesale capacity market, the current market design stems from FERC intervention more than a decade ago. In 2002, the FERC requested that ISO-NE revise its Installed Capacity ("ICAP") market to better address resource adequacy and local reliability issues in New England. This directive culminated in a Settlement Agreement that was negotiated in 2006 before a FERC-assigned administrative law judge and was acquiesced to by numerous stakeholders, including state officials, utility companies, generating companies, consumer representatives, regulators, and other market participants. On June 16, 2006, FERC approved the Settlement Agreement, which created the Forward Capacity Market ("FCM"). FERC approved the FCM rules on April 16, 2007 and the first FCA auction took place in February 2008. A more detailed discussion of capacity market evolvements can be found in Section 9.2 (which is part of Appendix B: Introduction to POOLMod and FCA Simulator).

As noted above, currently, ISO-NE operates day-ahead and real-time energy markets, as well as the auctions for the FCM. In addition, ISO-NE has several centrally-procured ancillary services markets, and an auction-based market for financial transmission rights ("FTRs"). In the analysis presented in this report, LEI has focused on the wholesale energy markets and the FCM, as those are the primary components of wholesale electricity market costs in New England.

Figure 5. Summary of ISO-NE Wholesale Market Cost

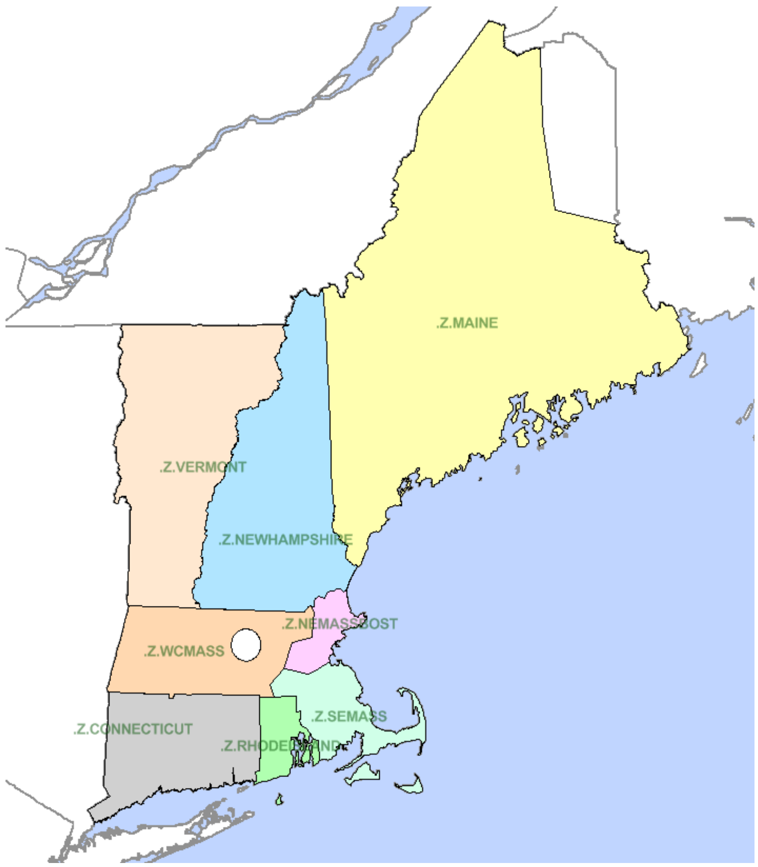
Markets	Frequency of trading or auction	2014 annual costs ($ Billions)	2014 annual costs share (%)	2013 annual costs ($ Billions)	2013 annual costs share (%)
Energy	hourly trading	$8.42	85%	$7.49	85%
Capacity	annual auction	$1.06	11%	$1.06	12%
Ancillary services	various	$0.41	4%	$0.27	3%
Total		$9.89		$8.82	

Source: ISO-NE, 2014 Annual Markets Report, Page 3, table 1-2

In 2014, wholesale energy costs amounted to $8.42 billion for the region, while FCM costs totaled $1.06 billion, as shown in Figure 5 below. Total wholesale market costs and energy costs increased by about 12% from the prior year. The increase in energy costs was the result of an increase in delivered natural gas prices to New England. Higher ancillary service costs resulted from the increased operating reserve requirements and additional "make-whole" payments to suppliers for costs that could not be recovered through energy market payments, also known as Net Commitment-Period Compensation ("NCPC"). The increase in NCPC charges was the result of the operation of expensive generation during extreme cold weather in the first quarter of 2014.[12]

ISO-NE's energy market uses a nodal or locational marginal price ("LMP") framework, where generators are paid based on their location, taking into account the marginal cost of energy, marginal cost of transmission congestion, and the value of marginal transmission losses. There are currently 1,000 nodes in the ISO-NE energy market, related to over 838 operating power plant units. Wholesale energy prices are also reported on the basis of eight separate load zones (see Figure 6 above), which are used to settle wholesale load costs. ISO-NE also publishes an "Internal Hub" price, which was created to support bilateral trading and represents an average of 32 node-specific LMPs.

Figure 6. Geographic coverage of ISO-NE and eight load zones



Note: The white dot in Massachusetts refers to the approximate visualized location of Internal Hub

For long-term regional system planning purposes, ISO-NE models its control area on the basis of thirteen sub-regions (Northeastern ME, Western and Central ME, Southeastern ME, NH/Eastern Vermont/Southwestern ME, Vermont/Southwestern NH, Boston,

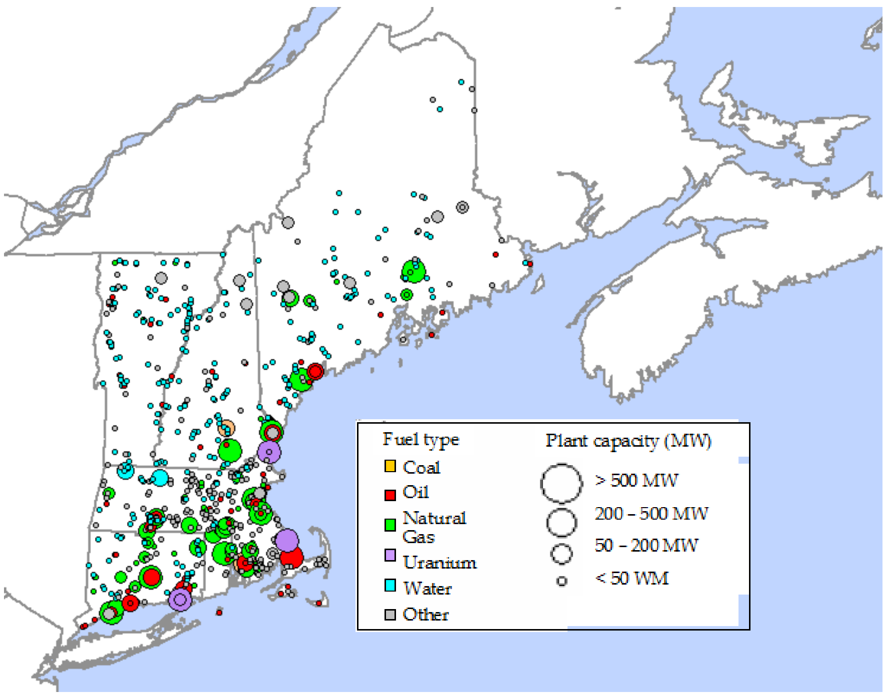
[12] ISO-NE, 2014 Annual Markets Report, page 2.

Central/Northeastern MA, Western MA, Southeastern MA, RI, Northern/Eastern CT, Southwestern CT, and Norwalk/Stamford CT), defined by the presence of binding transmission constraints. LEI's modeled topology is consistent with the market topology used by ISO-NE in their long-term planning models and the location of the most binding transmission constraints. Details of LEI's ISO-NE modeling topology are presented in Section 10.1 (which is part of Appendix C: Detailed assumptions for wholesale power market simulations).

3.1 Delivered natural gas prices are a major driver of energy prices in ISO-NE

Figure 7 shows the existing generation resources within New England. The dominant fuel is natural gas, which is represented by a light green symbol. Larger plants are mostly located in eastern part of region. There are three operating nuclear plants in the region currently: one in southern New Hampshire, one in Massachusetts and another plant in Connecticut. Renewables are spread-out across the region, although the majority of wind is in northern New England. Note that this is the current mix of resources. The map of operating generators will evolve with the near term retirements, as discussed in Section 3.2, and new entry.

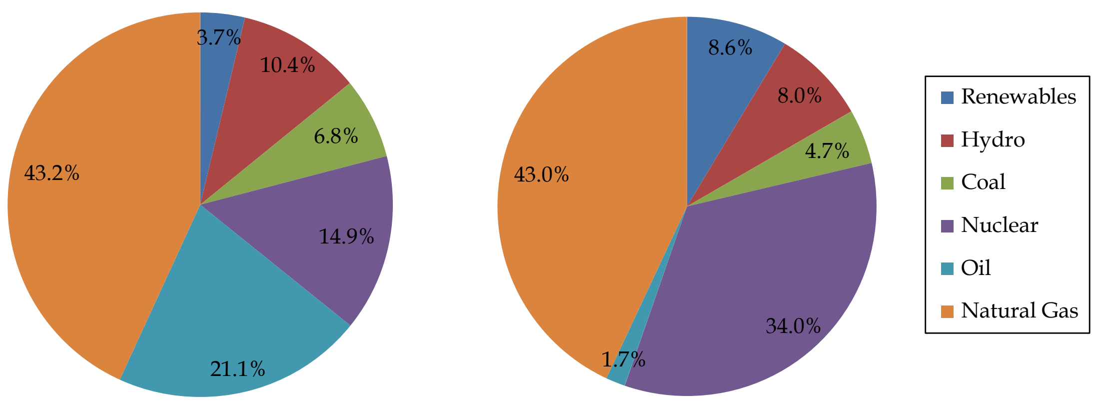
Figure 7. Power plants in New England region, by fuel type and capacity (size)



Source: Third party data provider

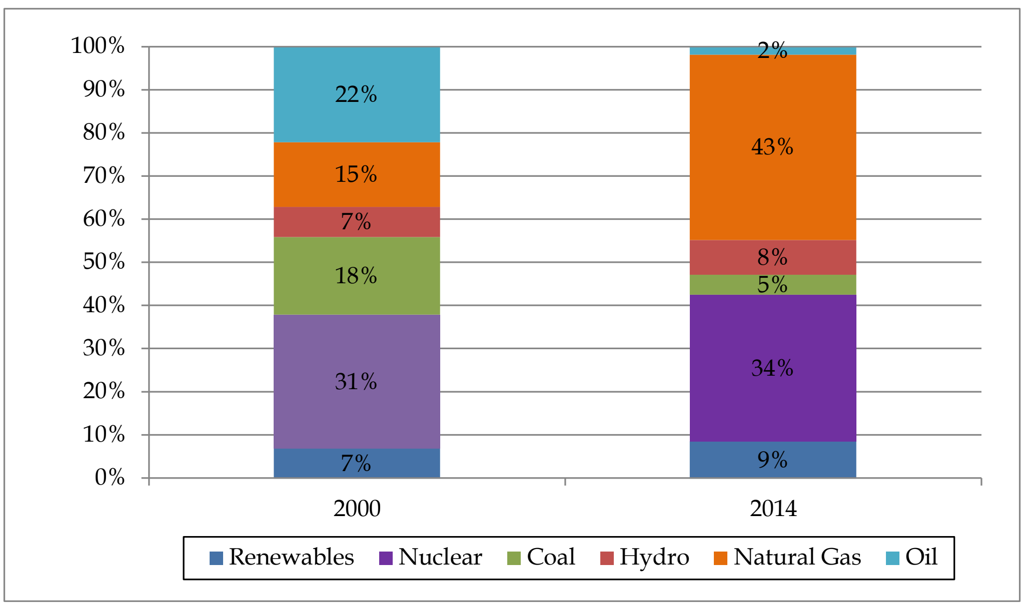
As can be seen in Figure 8, approximately 43% of the capacity is currently natural gas-fired generation. The gas fleet in total is almost twice the size of the oil-fired fleet (which accounts for about 22% of the total operable capacity in the region). Once we look at the energy production (generation) mix, we see the importance of natural gas fired capacity even more clearly: while natural-gas fired generation accounts for about 45% of region's generation, oil-fired capacity only accounts for less than 1% of total energy produced in the region. Nuclear is the third largest fuel supply in terms of capacity, about 15%, and it supplies over 30% of the region's energy production – but nuclear output is rarely price setting. Coal, hydro and renewables each account for less than 10% of the region's capacity and generation.

Figure 8. New England's summer seasonal claimed capability (left) and generation (right) by fuel type for 2014



Source: ISO-NE, Draft 2015 Regional System Plan ("RSP"), Figure 8-1 on page 127.

Figure 9. Energy production by fuel type in 2000 and 2014



Sources: ISO-NE, 2001 Regional System Plan and Draft 2015 Regional System Plan

New England is moving toward a fuel mix that is ever more reliant on natural gas-fired capacity. While natural gas-fired generation accounted for 15% of fuel mix in 2000, it has since increased to 43% (in 2014) as shown in Figure 9. More importantly, natural gas-fired generation is the most frequent fuel on the margin - setting energy market prices. Per ISO-NE's 2014

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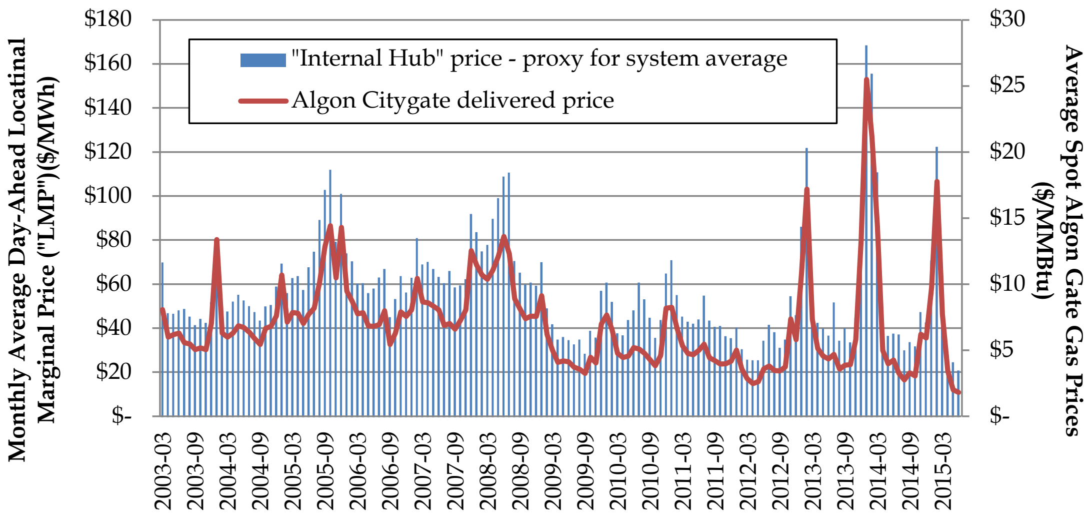
Annual Markets Report, it *"…natural gas was the marginal fuel during 70% of all pricing intervals, followed by coal and pumped-storage generation, which were marginal in 8% and 7% of all pricing intervals, respectively. . ."*[13] The big influence of natural gas-fired generation in energy price setting is due to the shape of supply curve relative to demand. Demand levels generally land in the part of the supply curve where gas is located – even the low periods of demand.

LMPs closely follow gas price trends (see Figure 10). The correlation between delivered natural gas prices and LMPs is in the range of 98% (as measured by monthly average prices between March 2003 and June 2015).

Figure 10. Historical New England electricity prices and delivered natural gas prices in New England since start of current LMP-based energy market



Source: ISO-NE (for LMPs) and SNL (for delivered natural gas prices)

3.2 Historical investment trends

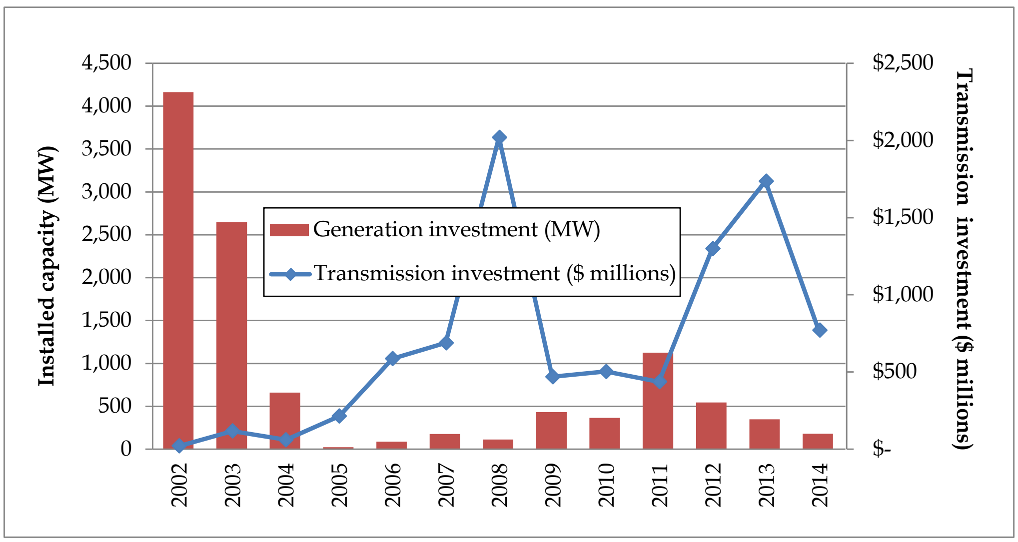
The investment in the generation fleet was strong in the first half of last decade, after market restructuring first opened the wholesale electricity market. There were many new gas-fired generators built between 2001 and 2004 (see Figure 11). In the past 6 years, the market has attracted a fair amount of renewable investment, mostly wind capacity. The market has generally been over-supplied since 2002, as evident in relative low capacity prices on average (though the supply-demand balance is changing going forward, as indicated by the outcomes from the most recent two FCAs, see discussion in Section 3.3). However, between 2005 and 2014, there was only one major new combined cycle gas-fired plant ("CCGT") that came into

[13] ISO-NE. 2014 Annual Markets Report, page 39.

service (and that plant was built as a consequence of a state-led competitive procurement for new capacity).[14]

The transmission system has been expanded significantly since the early 2000s. The new transmission infrastructure, along with generation build out in 2000s, has reduced congestion in the energy market.[15] For example, the congestion component of LMPs on average has been below $1/MWh since 2009 across all the load zones. In 2014, the congestion cost in LMPs across the entire New England region totaled $34.2 million[16] – which was about 0.4% of the total wholesale energy market costs that year. Congestion costs are also captured in the NCPC - these payments were above $200 million per annum between 2005 and 2008, but have subsequently dropped (reaching a low of $33 million in 2009) and then risen more recently due to local areas of congestion and the cold weather in the first quarter of 2014 (NCPC charges totaled $174 million in 2014). In summary, congestion has moderated as a result of infrastructure investments in both transmission and generation.

Figure 11. Generation and transmission additions since 2002



Note: Transmission additions in dollar terms were calculated based on year on year changes in the net book value of the transmission facilities owned by New England Transmission companies. The high transmission investment in 2008 is due to SWCT expansion while the higher reported transmission investment in 2012 and 2013 is due to construction of NEEWS and MPRP projects.

Source: ISO-NE and utilities' financial reports

Due to a period of low capacity prices, low energy prices, more stringent environmental regulations and the capital expenditure needs of aging infrastructure, the region has seen an

[14] Namely the Kleen Energy power plant in Connecticut started commercial operations in 2011.

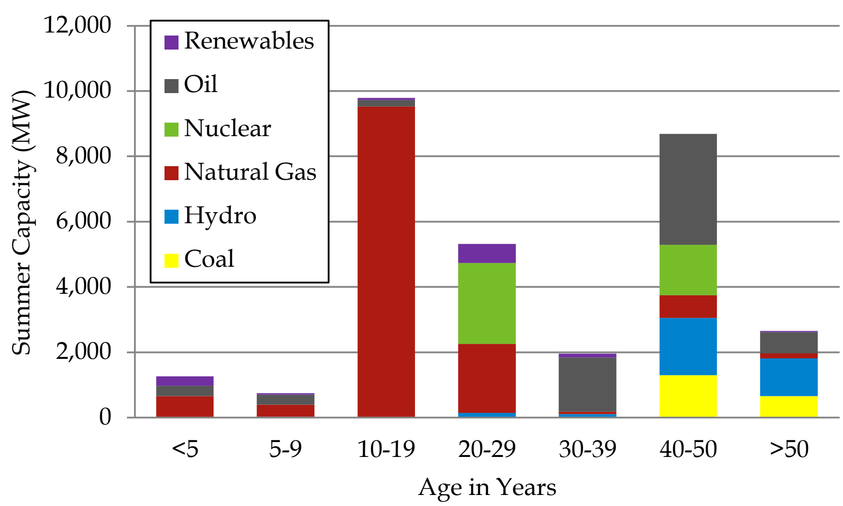
[15] For example, Southwest Connecticut Reliability Projects (Phase 1 and Phase 2), Boston 345 kV Transmission Reliability Projects (Phase 1 and Phase 2), Greater Springfield and Rhode Island components of New England East-West Solutions ("NEEWS") and Maine Power Reliability Program ("MPRP").

[16] ISO-NE. 2014 Annual Markets Report, page 65.

increased rate of retirements in recent years. Norwalk Harbor (342 MW), Salem Harbor (749 MW) and Vermont Yankee (604 MW) were retired between 2013 and 2014. In 2015 and 2016, we expect further retirements that have been announced to date, such as the coal-fired 143 MW Mt Tom and the coal and oil-fired 1,535 MW Brayton Point plants. These retirements consists of permanent delists from prior FCAs (i.e., Mt Tom) and non-price retirement requests (i.e., Brayton Point).

The potential shortage in generation in the future is further magnified by the aging fleet and the prospect of additional retirements – especially in light of capacity market design changes which would penalize resources who could not provide energy in the real time market commensurate with their capacity supply obligation. Though most of the natural gas-fired generation in the region is less than 20 years old, many of other types of generating resources are much older, as seen in the age profile in Figure 12. In total, over 13,300 MW – or nearly 44% of the total supply - is over 30 years old. And these older, less efficient oil units (over 6,500 MW) on average run infrequently - recording only 3.1% load factor in 2014. Such units may be retired under the sustained low capacity price market (especially if they cannot meet the performance requirements of ISO-NE's new Performance Incentive regime). A project such as NPT can provide "insurance" to New England against the negative reliability consequences (and higher capacity prices) from such retirements.

Figure 12. Age profile of fossil plants in New England as of 2015



Sources: ISO-NE, 2015 CELT Report, summer seasonal claimed capability ("SCC")

3.3 The prospect for new investment

Through the combination of announced and approved retirements as well as forecasts for load growth, it is widely recognized that New England needs more energy resources and possibly other infrastructure investments in the coming years. In the ISO-NE Draft 2015 Regional System Plan ("RSP"), the operable capacity analysis suggested that *"if the loads associated with the 50/50 forecast occurred, the ISO could expect New England to experience a negative operable capacity margin ranging from 6 MW to 160 MW for four of the 10 years of the study period …... New England could* *experience large negative operable capacity margins of approximately 1,680 MW as early as summer 2015 if the 90/10 peak loads occurred…"*[17]

Earlier this year, the President and CEO of ISO New England also projected potential supply shortages for the region and discussed the necessity of new infrastructure investment.[18] Mr. van Welie explicitly stated that "*More resources are needed to replace retiring resources, particularly in Greater Boston and Southeastern Massachusetts and Rhode Island*."

The results of the most recent two FCAs also provide evidence of the need for new investment. The FCA#8 for the 2017-2018 delivery period cleared at an administrated price for the system as a whole because there was an insufficient level of resources in the auction to ensure a competitive outcome, which triggered administrative pricing rules.[19] FCA #8 concluded with a slight shortfall of 143 MW below the required ICR of 33,855 MW. In the most recent FCA#9, which concluded on February 5, 2015, the "Rest of Pool" capacity price cleared at $9.55/kW-month while the SEMARI zone cleared at administered pricing levels ($17.73/kW-month for new resources and $11.08/kw-month for existing resources), because of insufficiency of supply. The ICR for 2018-2019 was set at 34,189 MW. The total capacity that cleared in the auction was 34,695 MW, which included 1,427 MW of new resources in New England, including a new 725 MW dual-fuel unit and two 45 MW units in CT, a new 190 MW peaking power plant in SEMARI, and 367 MW of new demand-side resources. Administrative pricing rules were triggered because of SEMARI's inadequate supply.

There are multi-state initiatives led by the New England States Committee on Electricity ("NESCOE") that have also called for new investment in various infrastructure. In December 2013, the six New England state governors agreed to work together, in coordination with ISO-New England and through NESCOE, to advance a regional energy infrastructure initiative that diversifies our energy supply portfolio while ensuring that the benefits and costs of transmission and pipeline investments are shared appropriately among the New England States.[20] In January 2014, in its Request for ISO-NE technical support and assistance with tariff filings related to electric and natural gas infrastructure in New England, the governors of the New England states agreed that in the future, they would issue one or more requests for proposals for the development of transmission infrastructure that would enable delivery of at least 1,200 MW and as much as 3,600 MW of clean energy into the New England electric system from no and/or low carbon emissions resources. NESCOE was also proposing to solicit ways to increase in the amount of firm pipeline capacity into New England of 1,000 MMCf/day above

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[17] ISO-NE. Draft 2015 Regional System Plan. Pages 66 and 68.

[18] Gordon van Welie, *State of the Grid: Managing a System in Transition* (January 21, 2015)

[19] Administrative pricing rules were triggered in FCA #8. Most existing resources received $7.02/kW-month and all new resources received $15/kW-month in all zones except NEMA/Boston. In NEMA/Boston, the administrative pricing rules require all resources to receive $15/kW-month except one resource, which in the previous auction (FCA #7) opted for a five-year price commitment of $14.99/kW-month.

[20] http://www.nescoe.com/uploads/New_England_Governors_Statement-Energy_12-5-13_final.pdf

2013 levels or, 600 MMCf/day beyond what has already been announced for the Algonquin Incremental Market ("AIM") and CT expansion projects.[21]

NESCOE's efforts were superseded by a joint solicitation for clean energy and transmission to accommodate such clean energy from three states. The Connecticut Department of Energy and Environmental Protection, the Massachusetts Department of Energy Resources, Eversource, National Grid and Unitil have developed a Request for Proposals ("RFP") to advance the statutory and policy goals of Connecticut, Massachusetts and Rhode Island.[22] The draft Clean Energy RFP was issued on February 25th, 2015 and the Clean Energy RFP was filed with Massachusetts DPU and Rhode Island PUC on June 25th and 26th, respectively. It is expected that the RFP will be released to bidders in the early third quarter of 2015. NPT will be offered into this RFP.

3.4 Evolution of market design

Several initiatives have taken place in recent years in ISO-NE to maintain and improve system operations and overall reliability of service and attract investment. The most notable changes include the downward sloping demand curve and introduction of a performance incentives scheme in the FCM. To spur investment in the generation sector, ISO-NE developed and proposed a downward sloping demand curve for the FCM over the course of 2013 and 2014.[23] ISO-NE, with wide stakeholder support, submitted its system-wide demand curve proposal to FERC on April 1st, 2014 (FERC accepted the market revision on May 30, 2014).[24] ISO-NE started implementing the demand curve in FCA #9, which was held in February 2015. A graphic illustrating the downward sloping demand curve can be found in Figure 58 of Section 9.2 (which is part of Appendix B: Introduction to POOLMod and FCA Simulator) on page 97. LEI has used the demand curve in its modeling of the FCM and future FCAs, as discussed further in Section 9.2 on page 95 (which is part of Appendix B: Introduction to POOLMod and FCA Simulator).

Furthermore, ISO-NE had also created a new performance and penalty scheme for the FCM, which was also accepted by FERC in an Order on May 30, 2014.[25] Going forward and starting in

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[21] Berwick, Ann G. (President, New England States Committee on Electricity). Letter to Gordon van Welie, President and CEO, ISO New England, Inc. January 21st, 2014. <http://www.nescoe.com/uploads/ISO_assistance_Trans___Gas_1_21_14_final.pdf>

[22] http://cleanenergyrfp.com/

[23] In its application to FERC, ISO-NE noted that one of the primary goals of moving from vertical demand curve to downward sloping demand curve is to provide stable and reasonable capacity revenue streams for continued generation investment, which is much needed for the aging New England generation fleet. See ISO New England Inc. and New England Power Pool, Docket No. ER14-1639-000, Demand Curve Changes.

[24] FERC. Order Accepting Tariff Revisions. Issued May 30, 2014. Docket No. ER14-1639-000. <http://www.ferc.gov/CalendarFiles/20140530161324-ER14-1639-000.pdf>

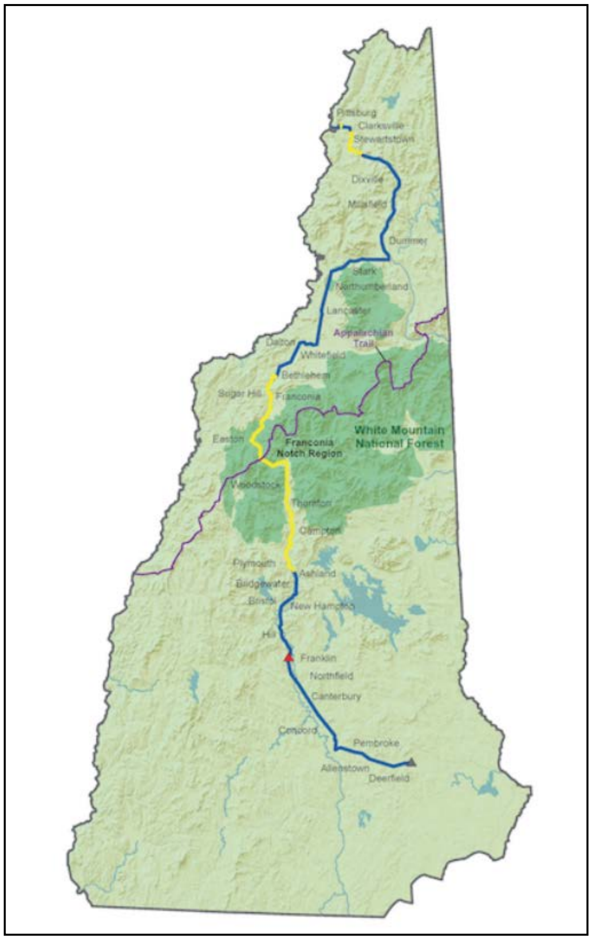
[25] FERC. Order on Tariff Filing and Instituting Section 206 Proceeding. Issued May 30, 2014. Docket Nos. ER14-1050-000, ER14-1050-001, and EL14-52-000. <http://www.ferc.gov/CalendarFiles/20140530160247-ER14-1050-000.pdf>

FCA#9, capacity market remuneration for resources will be based on a two-settlement process, comprised of a Base Payment and a Performance Payment. While the Base Payment is the FCA clearing price, the Performance Payment will be based on real time energy market operations (i.e., performance penalties or credits will be paid by capacity suppliers based on real time energy market operations during periods of scarcity and a pre-set rate mechanism). LEI has intentionally not modeled Performance Incentive, as its direct (financial) impact on generators will arise from market events that are outside the range of "normal" operations. More importantly, in this study, we are interested in market price differences. To the extent that Performance Incentive ("PI") penalties are prolific, it will mean that all capacity suppliers will adjust upward their offers with time to account for the risk of penalties. Therefore, in this case, PI is likely to raise FCA prices in both the Base Case and Project Case by equal amounts. Since we are measuring the difference in capacity prices between the Base Case and Project Case, the PI would not affect that difference.[26] Therefore, from a static "market impacts" perspective, PI is neutral on the wholesale capacity market benefits we are estimating. However, if PI creates risks that are not deemed reasonable for existing resources, it may trigger a wave of retirements. In this instance, NPT's presence can provide a very material level of "insurance" value to New England consumers. We have not quantified this "insurance" value, but it is nevertheless a real benefit embedded in NPT.

[26] See more detailed explanation in footnote 33.

4 Introduction to the Northern Pass Transmission project

The proposed NPT project is an approximately $1.6 billion transmission infrastructure project that will bring 1,090 MW of additional transmission capacity between Québec and ISO-NE.[27] NPT will allow for the import of energy and capacity from Hydro-Québec's hydroelectric fleet into New Hampshire. The imported energy would be transmitted on NPT and then injected into ISO-NE via a substation in New Hampshire. This imported energy is expected to affect overall wholesale electricity market dynamics across all of New England because of the uncongested nature of the ISO-NE wholesale electricity market under normal system operations.



As illustrated in the adjoining figure, NPT will involve construction of HVDC transmission line from the Canadian border to Franklin, New Hampshire, where a converter terminal will be built to convert the electricity from direct current to alternating current ("AC"). From there, a new AC transmission line will carry the energy to an existing substation in Deerfield, New Hampshire and into New England's transmission system.

4.1 Who pays for NPT?

The project was first proposed in 2008.[28] NPT will be offered into the Clean Energy RFP. If the Project is selected in the Clean Energy RFP, some project costs (including both capital costs and O&M costs) may be passed through and paid for by consumers of the electric distribution utilities in the states sponsoring the Clean Energy RFP for some period of time. In the local economic impact analysis we presented below, we have conservatively factored in the allocation of the transmissions project costs to the three states of Connecticut, Massachusetts, and Rhode Island for the duration of the 11-year modeling period.

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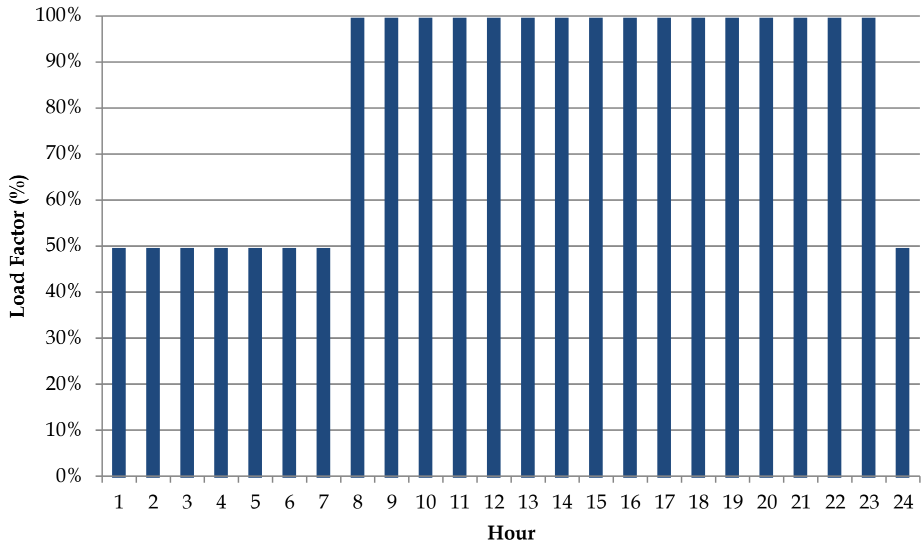
[27] The "fully loaded" total cost estimate is $1.6 billion, which includes contingency, property taxes and allowance for funds used during construction ("AFUDC"), in addition to the "unloaded" total costs. The direct project cost is an "unloaded" total cost estimate, and is approximately $1.3 billion for NPT.

[28] Source: SNL, "*Northeast Utilities, NSTAR pursue transmission interconnection with Québec*", December 15, 2008.

4.2 How is NPT modeled in LEI's analysis of the wholesale electricity market?

NPT is expected to start commercial operations and provide for the transmission of imported energy into New England market in May 2019 in the wholesale energy market. In our simulation modeling of the Project Case, we conservatively assume that the energy flows on NPT will have an annual load factor of 83%, with an hourly profile that is weighted towards the peak hours, as illustrated in the figure below.

Figure 13. Projected hourly energy flow for NPT



LEI believes an annual load factor (covering both on-peak and off-peak hours) of 83% is a reasonable assumption, and in fact may be conservative relative to recent dynamics on existing interties between Québec and New England. In 2013 and 2014, flows on the Phase II intertie with Québec averaged a capacity factor of 91%.[29] From the shipper's perspective, this is also a rational assumption to impose on NPT and associated energy flows as any shipper utilizing the line would be economically motivated to maximize the flows, to the extent possible. [30]

For the capacity market, we have conservatively assumed that NPT's infrastructure would be in service starting in June 2020, based on the expected timing of qualifications for new resources for FCA#11. Furthermore, it was assumed that shippers on NPT would seek to provide and get qualified to sell 1,000 MW, which is slightly below its nominal rating of 1,090 MW.

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[29] The load factor was calculated using total transfer capability ("TTC") as reported by ISO. TTC limit is a dynamic limit and is calculated in advance of each hour and is used for scheduling purposes. < http://www.iso-ne.com/isoexpress/web/reports/operations/-/tree/ttc-tables>

[30] The entity supplying the energy that flows on NPT is referred to as the "shipper" in our report.

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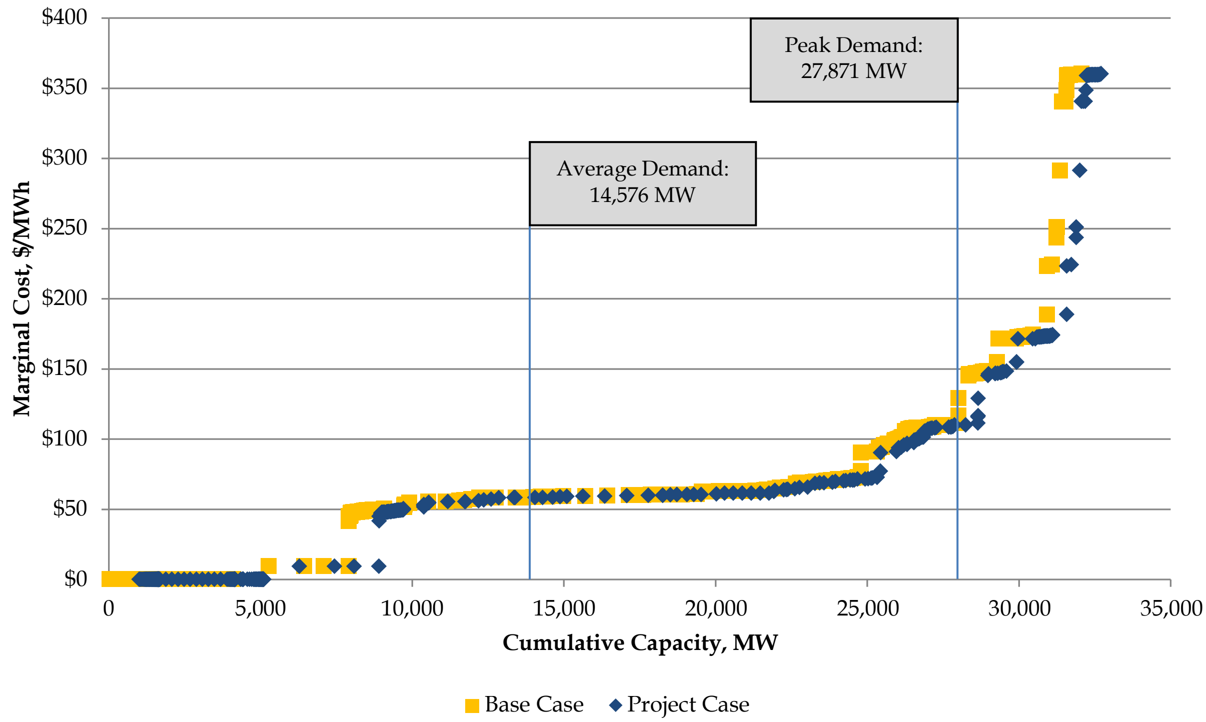
5 Analysis of Wholesale Electricity Market Benefits associated with NPT

Beginning in May 2019, NPT is expected to provide for the transmission of incremental energy into the New England system. As mentioned above, LEI has assumed an annual average capacity factor of 83% (as discussed in Section 4). The shippers are assumed to be price takers in the ISO-NE wholesale electricity market, in order to ensure that the value of the energy and capacity is optimized. By virtue of these energy sales, other more expensive generation will not be needed and consequently the market clearing price of energy (i.e., LMPs) will decline, as suggested in the illustrative supply curve diagram below.

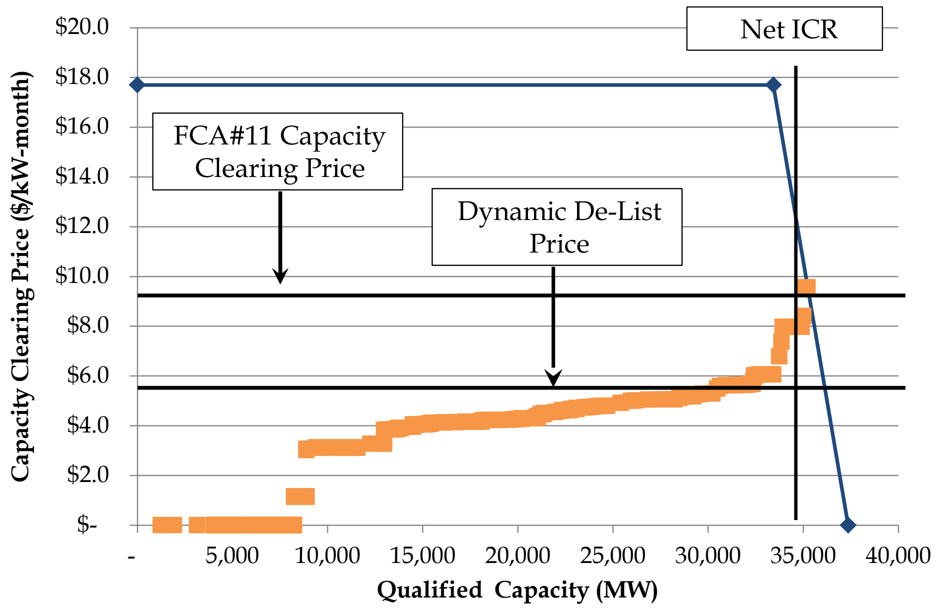
Figure 14. Indicative internal supply curve for New England under Project Case, 2024



The energy imports accommodated by NPT will reduce energy prices as additional lower cost energy will extend the supply curve to the right with lower marginal cost unit setting system price. The energy price reductions will vary from hour to hour, depending on the mix of available resources, fuel prices, and demand levels. As a consequence of the change in the supply stack, NPT also produces production cost savings for the system and emissions reductions, explained in later sections.

On the capacity side, we expect a similar dynamic when the additional 1,000 MW of new capacity associated with NPT enters the FCM. Capacity clearing prices in the FCA will move down as NPT increases the total volume of supply and the New England system's reserve margin (making the ISO-NE wholesale electricity market more reliable).

Figure 15. Illustrative capacity market supply curve for Base Case (FCA#11)



Note: The capacity market supply curve for Base Case is based on LEI's estimation of the indicative minimal going forward fixed costs for existing units and all-in fixed cost for new units

In principle, under the downward sloping demand curve, increased supply in the market will translate into lower capacity prices (unless retirements are triggered). Under the Project Case, however, we do not anticipate retirements of existing generation as the overall capacity prices are still sufficient to remunerate existing generation for their minimum going forward fixed costs, as we discuss further in Section 10.

5.1 Summary of Wholesale Electricity Market Benefits

Under the modeled Base Case and Project Case, over the forecast timeframe, the wholesale energy market savings are estimated to be approximately $80 million to $100 million on average per year for New England as a whole. New Hampshire's share of these wholesale energy market benefits is $8.2 million to $10.2 million on average per year. The variation in the wholesale energy market benefits stems from different assumptions for future natural gas prices. Wholesale energy market benefits will be higher under higher gas price conditions. Therefore, the higher energy market benefits are driven by the LCOP/HH scenario, and the lower energy market benefits are driven by the GPCM/MS scenario.

As we discuss further below, the wholesale energy market benefits are larger in the earlier years of the forecast timeframe and decline with time, as the ISO-NE power market recalibrates to the long run equilibrium.

In terms of production cost savings, the project will result in an average of $330 million to $425 million in annual production cost savings. Production cost savings represent the avoided marginal costs of generation that would have run but for NPT. In these calculations we are using the physical marginal costs of production, which are essentially $0/MWh for the hydroelectric-based imports on NPT.

In terms of wholesale capacity market benefits, NPT will result between $843 million p.a. to $848 million p.a. in wholesale capacity market benefits for the New England region, with approximately $80 million p.a. allocated to New Hampshire wholesale load on average over the 10-year (2020-2029) timeframe. Wholesale capacity market benefits also decline with time, as surplus supply conditions in the system under the Project Case are absorbed with growing demand and the capacity market prices find their long run equilibrium point at or near net CONE.

Lastly, NPT will result in approximately 3.3 – 3.4 million metric tons of avoided CO_2 emissions per year in New England, net of the CO_2 emissions associated with the production of this imported energy in Québec. The incremental social value of these avoided CO_2 emissions is projected to be approximately between $207 million p.a. to $208 million p.a.

Beyond the first eleven years of energy market operations for NPT, it is not likely that wholesale energy and capacity market benefits will continue, which we determine through testing the statistical significance of price impacts over 20 seeds. However, production cost savings and emissions benefits will continue for much longer, as explained later in this section.

5.2 Introduction to LEI's methodology and models

In order to quantify the impact of NPT on wholesale energy and capacity markets, we need to be able to measure how the project and associated energy flows and capacity sales would impact the wholesale electricity market. The best methodological approach for examining and estimating these impacts involves simulation modeling.

LEI explicitly studied the first eleven years of the project's operations.[31] An 11-year simulation analysis provides a long enough timeframe to establish year over year market trends. A simulation-based forecast beyond this time period is likely to need more assumptions and therefore involve an increasing forecast error. It is also likely that market design and government policy could change in unexpected ways once we look out beyond the next fifteen years. Furthermore, given LEI's experience with such modeling exercises and based on the observations in the first eleven years of the modeling in the case of NPT, the market price impacts will dissipate with time as the market recalibrates to a balanced supply-demand condition. Therefore, the benefits would dissipate and it is not as meaningful to continue the simulation modeling beyond 2030.

For the wholesale energy price outlook, LEI employed its proprietary simulation model, POOLMod, to forecast wholesale energy prices in ISO-NE with and without NPT. POOLMod

[31] While LEI studied the first eleven years of the project's operation for energy market, we only quantified the first ten years of the project's capacity market benefits.

simulates the dispatch of generating resources in the market subject to least cost dispatch principles to meet projected hourly load and technical assumptions on generation operating capacity and availability of transmission. For this modeling exercise, we conservatively assumed perfect competition[32] and therefore the energy offers of generators and external suppliers were based on marginal costs of production or competitive opportunity costs.

POOLMod consists of a number of key algorithms, such as maintenance scheduling, assignment of stochastic forced outages, hydro shadow-pricing, commitment of resources and dispatch, as described further in Section 9.1 (Appendix B: Introduction to POOLMod and FCA Simulator). As set out in Figure 56 in Appendix B, POOLMod first evaluates the available generation, then determines the marginal costs of generation by resource, and finally dispatches the resources needed to meet hourly demand across the system in a least cost manner, while taking into account operational constraints on generation and congestion on the transmission system. In this way, POOLMod's algorithms, in the aggregate, simulate the LMP-setting process that ISO-NE performs as part of its day-ahead and real-time energy markets.

In addition, to the wholesale energy market, we also simulated the FCM. The capacity market simulations provide a projection of the annual FCA clearing prices, and, importantly, a determination of new entry and retirements that then affects the energy market simulations in POOLMod. LEI has developed a proprietary FCA model that represents the key market design features of the FCM and competitive bidding behavior in the FCA. Furthermore, LEI's modeling of the New England wholesale electricity market properly represents the linkages between energy and capacity market designs. Capacity market outcomes from the proprietary model of the FCM determine the new entry profile and schedule of economic retirements, which are then reflected in the energy modeling using POOLMod. There is also a feedback effect from the energy modeling, whereby the energy price trends from POOLMod are used to adjust the Net CONE calculation which is the critical input in the FCA simulation model. A more detailed discussion of POOLMod and LEI's FCA simulation model can be found in Appendix B (Section 9).

5.3 Developing the Base Case and Project Case

The analysis starts with a forecast of a "Base Case", spanning an 11-year period of 2019 through 2029. The Base Case outlook combines the most likely set of market assumptions for key market drivers along with normal system operations and average load conditions, based on ISO-NE's "50/50" load forecasts. The Base Case also builds on conservative market-oriented expectations for marginal costs of generation, including fuel prices, variable O&M costs, and carbon allowance prices. We assume that the New England wholesale electricity market converges and

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[32] Although policymakers have widely recognized (and we have quantified through the use of other complementary models in conjunction with POOLMod) that transmission can also create economic benefits associated with reduction in potential market power, we have conservatively excluded such benefits from this study. This is practically reasonable in a market such as New England, where competition is intense and market prices tend to closely approximate competitive market outcomes.

maintains a balanced supply-demand profile over the longer term (i.e., that reserve margin requirements are generally met in each year and new investment is made when it is economic). Therefore, the Base Case represents a future evolution from the current status quo, based on economically rational investor response to the projected market dynamics and system needs.

Once the Base Case is set, we then need to consider how market outcomes would change if the project – in this case, NPT – is developed. This is referred to as the "Project Case". NPT is represented as a 1,090 MW HVDC transmission project, with a termination point in New Hampshire zone of the ISO-NE wholesale power market. We further assume that imported energy totaling approximately 7,958 GWh per year flows annually on NPT into the New England region. NPT lowers LMPs and also lowers capacity prices in the FCM. As a result of NPT's operations and the impact it has on wholesale market prices, other investment decisions may be impacted. Therefore, the Project Case requires a re-calibration of the retirement and new entry profile to the specific market outcomes projected under the Project Case. In other respects – such as demand forecast, fuel prices – the Project Case and the Base Case are the same.

The market benefits of NPT are then measured as a function of the difference in market prices between the Base Case and the Project Case.

5.4 Key Modeling Inputs & Assumptions

To simulate the ISO-NE power market and project future energy and capacity prices, we have relied on various assumptions reflecting current and expected market dynamics obtained from market forwards, industry news, the ISO-NE, and our own industry intelligence. Key modeling inputs include: fuel prices, carbon allowance prices, expected load growth, regional trade, transmission constraints, capability and operating characteristics of installed generating capacity and demand-side resources, known decisions on new supply and retirements of supply. Furthermore, LEI's Base Case outlook is based on current market rules and does not consider future market rules changes as that would be speculative and could introduce bias into the results.[redacted] In summary, the Base Case outlook combines the most likely set of market

[redacted]

assumptions for key market drivers along with normal system operations and average load conditions, based on ISO-NE's "50/50" load forecasts (see Section 10.2).

It is important to note that LEI's Base Case builds on conservative market-oriented set of expectations for marginal costs of generation, such as fuel prices and carbon allowance prices, and conservative assumptions around system dynamics.

[redacted]

[redacted]

[redacted] However, it is important to note that this treatment will result in conservative energy market benefits. Should new generation get built around the same time as NPT because it had already committed to market, it will extend the longevity of the market benefits.

Lastly, we model energy flows on NPT at a conservative 83% annual average capacity factor, which tends to reduce the energy market benefits, production cost savings, and emissions reductions, as well. Other transmission projects proposed for the Northeast power markets that originate in Québec have suggested much higher utilization rates in their public statements.[34]

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[34] This includes the public filing documents for Champlain Hudson Power Express and New England Clean Energy Power Link.

In conclusion, our assumptions as a whole create a considerable level of conservativeness in the estimated wholesale energy market impacts of NPT in LEI's analysis.

5.5 Fuel prices

As forwards are usually not liquid beyond 18 to 24 months out, LEI largely relied on the forecast set by the EIA in their AEO 2015, and specifically the fuel forecast under the AEO's Reference Case. The figure below contains an annual summary of the various fuel price levels used in the modeling.

Figure 16. Projected fuel prices for New England market simulations (nominal dollar terms)

[redacted]

Source: EIA AEO 2015, LEI analysis. Henry Hub prices shown refer to those used in the LCOP/HH gas modeling

<u>**Natural Gas**</u>

As described in Section 3.1, the primary wholesale energy price setting fuel in New England is natural gas. [redacted] More detailed natural gas price assumption can be found in Section 10.6 of Appendix C.

[redacted]

[redacted]

[redacted]

How do delivered natural gas prices affect the estimated wholesale energy market benefits?

If new natural gas pipelines do not develop as forecast in LEI's conservative Base Case, then delivered natural gas prices could be substantially higher. As a consequence, wholesale energy prices would be higher in both the Base Case and Project Case. The price difference between the two cases would expand and result in higher estimated wholesale energy market benefits and also higher production cost savings in the Project Case. As an illustrative example, let's take an hour where the price setting unit is a gas-fired steam plant with a marginal cost of $86.6/MWh based on a heat rate of 10,000 Btu/kWh and gas price of $7.5/MMBtu. Let's then move to the Project Case where the energy flows on NPT displace the steam plant and the new marginal price setting unit is a CCGT plant with a marginal cost of $66.2/MWh based on a heat rate of 7,800 Btu/kWh. The energy market benefit created by NPT is therefore equal to $20.4/MWh (the difference between $86.6/MWh and $66.2/MWh). Now let us assume that delivered gas prices rise by 10%. Now the marginal cost of the steam plant is $94.1/MWh while the marginal cost of the CCGT is now $72.05/MWh. Therefore, the energy market benefit created by NPT would now be $22.1/MWh, or approximately 8.1% higher than that calculated under 10% lower natural gas price scenario.

Oil

The distillate oil prices is based on the heating oil forwards for the first two years, and escalated at the same rate as the EIA crude oil forecast in the long term from AEO 2015 Reference Case. The residual oil price was developed based on a multi-year average of the ratio of residual and distillate oil prices. Note that oil units are rarely used fuels under normal operating conditions in ISO-NE. More detailed oil price assumption can be found in Section 10.6 in Appendix C.

Coal

Given the diversity in coal sourcing, quality, and price, we developed plant specific coal price outlooks for the Merrimack, and Bridgeport Harbor coal plants that are operating in ISO-NE over the forecast timeframe. We began with the 2014 reported delivered fuel costs, taking into account the type of coal used at each plant (since each coal plant has different sulfur content levels) and plant-specific transportation costs. We then escalated the 2014 reported delivered

[36] RBAC Inc. develops and licenses economic forecasting tools for management decision support systems for the energy industry, as well as State and Federal government agencies involved with Energy, Transportation and the Environment. www.rbac.com.

costs with the longer term trends for the commodity (the coal price forecast) and inflation rate (for the transportation added) from EIA's AEO 2015 Reference Case.

5.5.1 Carbon allowance prices

Carbon allowance prices are the second most important element in the offer price of generators. [redacted]

[redacted]

5.5.2 Energy market offers

As mentioned above, generators are expected to offer into the energy market based on perfectly competitive market dynamics, which presumes short-run marginal cost ("SRMC") bidding in the energy market. Therefore, the most important driver of thermal generators' offers in the energy market will be fuel prices as demonstrated in the figure below, which that captures the key components of SRMC for a sample of different generation technologies.

Figure 17. Hypothetical SRMCs by components for each technology

	Gas (LCOP/HH) - Steam Turbine	Gas (LCOP/HH) - CCGTs	Gas (LCOP/HH) - Peakers	Gas (GPCM/MS) - Steam Turbine	Gas (GPCM/MS) - CCGTs	Gas (GPCM/MS) - Peakers	Coal	Oil - Steam Turbine	Oil - Jet Engines
2020 fuel price, $/MMBtu	$6.3	$6.3	$6.3	$4.5	$4.5	$4.5	$5.1	$16.2	$16.2
Heat rate, MMBtu/MWh	10.50	7.50	9.00	10.50	7.50	9.00	10.00	10.50	15.00
Fuel Costs, $/MWh	$66.2	$47.3	$56.7	$47.3	$33.8	$40.5	$51.0	$170.1	$243.0
Carbon prices, $/ton	$10.8	$10.8	$10.8	$10.8	$10.8	$10.8	$10.8	$10.8	$10.8
CO_2 content, lb/MMBtu	117	117	117	117	117	117	205	174	174
Carbon costs, $/MWh	$6.6	$4.7	$5.7	$6.6	$4.7	$5.7	$11.0	$9.8	$14.0
Variable O&M costs, $/MWh	$1.9	$1.7	$1.2	$1.9	$1.7	$1.2	$2.4	$1.9	$0.7
SRMC, $/MWh	**$74.7**	**$53.7**	**$63.6**	**$55.8**	**$40.2**	**$47.4**	**$64.4**	**$181.8**	**$257.7**
Fuel Costs as % of SRMC	89%	88%	89%	85%	84%	86%	79%	94%	94%

5.5.3 Supply-side assumptions

The construction of the supply mix begins with taking stock of all existing resources, announced retirements, and known and certain new entry. We relied heavily on ISO-NE data, such as that contained in the CELT and the ISO-NE's Informational Filings with FERC. New entry is added based on the projections in the FCM. Over the modeling timeframe, and consistent with rational investment assumptions, resources are assumed to make "just-in-time" capacity investment decisions timed to load growth and forecast FCM outcomes. [redacted]

New entry will enter the market when the market price is sufficient to recover its investment cost, i.e., all-in fixed cost. All these rules are based on economic rational behavior. [redacted]

[redacted]

Retirements, as well, are driven by the modeled economics of the FCM coupled with energy market profits. [redacted]

5.5.4 Demand-side assumptions

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

5.5.5 Other energy market modeling inputs & assumptions

Other key assumptions include transmission assumptions, imports/exports, hydrology, and operating parameters for generators.

[redacted]

[redacted]

Hydroelectric production is seasonal. In general, hydroelectric production increases during the spring and early summer months, but then contracts in the late summer and fall before rebounding again in late winter. This pattern is primarily driven by climatological patterns in the region: the spring is characterized by high precipitation and melting of frozen water resources, while the late summer and fall tends to be a drier period. LEI developed the long term average hydrology and reflected the seasonality in the model, based on long run historical monthly production data by plant.

A number of other inputs are needed to model the dispatch of generation in the wholesale energy markets, such as the heat rates (thermal efficiency), forced outage rates, maintenance and ramp rates of power plants; variable costs include variable operations and maintenance costs (VO&M) and emissions factors (i.e., how much CO_2, SO_2, or NO_X is emitted per MWh of production for each plant).

For operating parameters, we used a standard set of assumptions to model plant dynamic constraints. Our assumptions for these types of parameters were driven by "normalized" or average industry benchmarks. For example, reflecting industry standards, peaking units in the system are assumed to be the most flexible units, while long-lead time thermal baseload units (e.g., nuclear plants and coal plants) were assumed to be the least flexible. Our maintenance data and forced outage rates are based on historical trends observed across the US by NERC and compiled in their *GADS database*. A detailed description of other modeling assumptions can be found in Appendix C (Section 10).

5.6 Capacity market parameters

Beginning in FCA #9 (capability year 2018-19), ISO-NE utilized the downward sloping demand curve, which replaced the vertical demand curve used in previous FCAs. The downward sloping demand curve design is similar to those used in NYISO and PJM, where the demand curve uses administratively pre-set parameters to arrive at a capacity clearing price based on the amount of capacity participating in the market. Figure 20 shows how the key parameters

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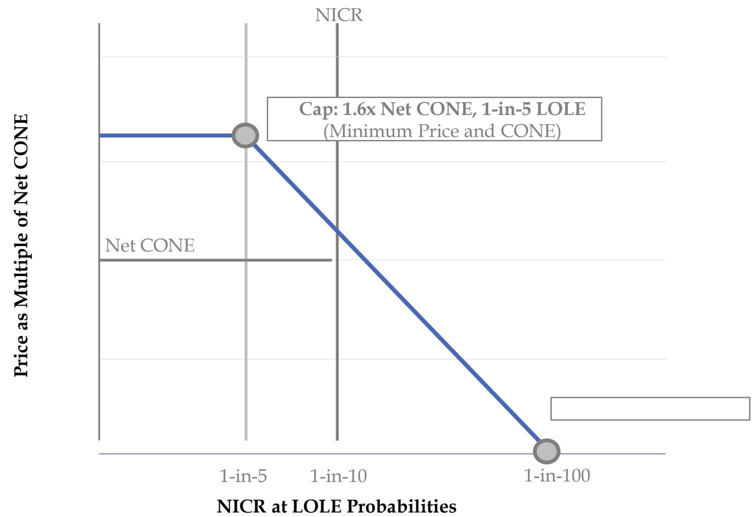
[41] The transfer limits for Boston Import and North-South were developed in consultation with Eversource, prior to the certification of the Greater Boston solution.

would be used to form ISO-NE's capacity demand curve according to ISO-NE's FERC filing from April 1, 2014.[42]

Figure 20. Design of ISO-NE's capacity market demand curve



Source: ISO New England Inc. and New England Power Pool, Docket No. ER14-1639-000, Demand Curve Changes

ISO-NE's demand curve design aims to link the level of reliability in terms of Loss of Load Expectation ("LOLE") with the amount of money the system is willing to pay. For the same amount of expected reserve margin that the vertical demand curve would procure (14.1% for a 0.1 LOLE), the downward sloping demand curve is be benchmarked at approximately 1.2x Net Cost of New Entry ("CONE") of a new CCGT unit. Based on ISO-NE's published parameters for FCA #10, this value is estimated to be $12.97/kW-month, significantly higher than the clearing price of the first eight FCAs, including the administratively set price of $7.025/kW-month for existing generation located outside NEMA/Boston zone for FCA #8. FCA #9 also saw capacity prices clear at $9.55/kW-month for the Rest-of-Pool, despite over 1 GW of new entry in the system.

5.6.1 Target procurement of capacity

In New England's FCM, capacity is characterized as a system resource available to meet the system's ICR, which is an ISO-NE estimate of the resources needed to supply the system's peak load within an acceptable probability of not meeting demand or having a loss of load event. In this case, the ICR is the estimate of the amount of capacity that will result in a LOLE no higher than one day in 10 years (0.100 days per year).[43] The ICR can be satisfied by the summer (peak) production capability from a variety of different resources: electrical generating capacity with

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[42] ISO New England Inc. and New England Power Pool, Docket No. ER14-1639-000, Demand Curve Changes

[43] LEI used the latest ICR values presented at the time of modeling, which was the April 28, 2015 PAC Meeting presentation titled, "RSP15 Resource Adequacy and Related Studies," by Peter Wong. <http://www.iso-ne.com/static-assets/documents/2015/04/a2_rsp15_resource_adequacy_and_related_studies.pdf>

various characteristics, imports into the system over transmission ties, demand response (curtailments by consumers during times of system need), or even reductions in demand (e.g., passive demand response, which is also referred to as energy efficiency). All these resources qualify as eligible capacity supply in the FCM, subject to certain restrictions which we account for in our modeling.[44]

The starting point of supply stack was based on the cleared capacity from FCA#9. LEI also looked for market dynamic between ISO-NE and the surrounding markets. [redacted]

5.6.2 Downward-sloping demand curve

LEI assumed the downward sloping demand curve in its simulation of the future FCAs. The key parameter of the demand curve, as illustrated in Figure 20 on page 48, is the Net CONE (which is set by ISO-NE is in line with the estimated all-in fixed costs of a new CCGT minus its profits from the energy and ancillary service markets).

Conceptually, the downward sloping demand curve leads to new investment when a generic CCGT can expect to recover its all-in costs of investment given the resulting capacity clearing price (after including itself in the capacity supply) and expected energy market profits. Otherwise, the unit would not be making sufficient revenue to break even and recover its return on investment. This implies that in an efficient, balanced market, capacity clearing price would converge around Net CONE, which is higher than the expected capacity prices under a vertical demand curve design that we have observed in the past FCAs. In addition, the downward sloping demand curve design is also expected to create less volatility in capacity prices from year to year, as there is pre-set levels of elasticity of demand, based on the slope of the demand curve. Existing resources would have less of a financial incentive to retire so long as capacity prices remain above their minimum going forward fixed costs, and new resources would enter the market only when demand grows sufficiently to absorb their capacity without putting too much downward pressure on the auction clearing price.

Compared to the FCM design in place in FCA#1 through FCA#8, the downward sloping demand curve is expected to retain more of the older and thermally inefficient units that do not get dispatched often in the energy market. These existing units are expected to forego retirement, as the higher and more stable capacity price should provide them with the financial incentive to delay their retirement. [redacted]

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[44] For information on how LEI obtained the ratings and model various resources such as wind, EE, and DG, see Section 10.4 in Appendix C.

[redacted]

The construct of the downward sloping demand (based on parameters explained above, as well as the details described in Section 9.2 of Appendix B), institutionalizes the concept of a capacity price suppression effect from any new resource, such as NPT. [redacted]

5.6.3 Wholesale capacity market outlook and price impacts of NPT

In LEI's modeling, capacity market prices will converge around Net CONE, when the system is balanced. In both the Base Case and the Project Case, new entry is assumed to occur when it is economically rational. Figure 21 shows an example of the forecast of Net CONE by year, LEI's Base Case capacity prices, as well as capacity prices from previous auctions. As illustrated, capacity clearing prices closely follow forecasted Net CONE values.

[redacted]

The forecasted Net CONE values are based off the cost of new CCGTs, adjusted for inflation trends in Gross CONE based on the AEO 2015 Wholesale Price Index for fuel and power, and the peak price trends modeled (for the Energy and Ancillary Services revenue offset). In our analysis, a CCGT unit is the most rational new investment from an economic perspective.

Peaker units are not as likely to be built given current forecasts of their net costs as compared to the downward sloping demand curve parameters. While peaker units have a slightly lower capital cost and thus a slightly lower gross CONE, they earn much less from the energy market compared with CCGTs. As a result, a peaker unit's Net CONE is higher than CCGT's Net CONE.

System peak demand grows annually by approximately 300 MW per annum on average over the modeling timeframe net of EE pursuant to ISO-NE's 50/50 demand forecast. Given the minimum scale of new CCGTs (in the range at least 400 MW),[45] new entry is not needed every year of the forecast timeframe. Therefore, new CCGTs are introduced when they can clear the market at or above Net CONE.[46]

In theory, generators will build where there is sufficient fuel and transmission infrastructure. LEI added CCGTs in the southern regions of New England (Central Massachusetts, Western Massachusetts, Connecticut and SEMARI), as these load zones are close to New England's load centers. This assumption is consistent with the evidence from New England's interconnection queue, in which nearly all proposed CCGT projects are located in Massachusetts, Connecticut, or Rhode Island.

5.6.4 Wholesale capacity market price impact of NPT

[redacted]

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[45] Based on SNL Financial data, 394 MW was found to be the average of natural gas power projects announced or in development within the NPCC region as of December 2014.

[46] Under current market rules, a new entrant can choose to "lock-in" their capacity price. This is intended to ensure that the overall market design provides sufficient certainty to attract new investment when needed.

[redacted]

The introduction of capacity from NPT pushes down the clearing price in the FCA for several years, as discussed above in Section 5.6.2. The chart in Figure 22 shows the level of procured capacity under the Base Case and Project Case. [redacted]

NPT is expected to start producing energy in May 2019. However, the sale of energy does not require any specific pre-qualification period (other than testing of the equipment during a brief pre-commercialization stage). On the other hand, as a new capacity resource, the capacity on NPT would need to be qualified by ISO-NE. LEI is not aware whether any shipper associated with NPT sought to qualify as new capacity in the Show of Interest period for FCA#10 (which occurred in March 2015 for the 2019/20 capacity delivery period); therefore, LEI has assumed that capacity sales would start with the 2019/20 deliverability period (FCA#11).

As a result of capacity price reduction, from 2020-2029, LEI expects roughly $843 million p.a. in capacity market benefits for ISO-NE as a whole under the LCOP/HH gas scenario, or $848 million p.a. under the GPCM/MS gas scenario. Using a 7% discount rate,[47] the net present value of these savings over the 11-year period is $6.2 billion and $6.3 billion, respectively, for New England wholesale load (in 2019 dollar terms).

[redacted]

In order to isolate the wholesale capacity market benefits for New Hampshire, LEI allocated a portion of the total wholesale capacity market benefits for New England to each state by using each state's coincident peak load share, which ISO-NE makes available in its annual load forecasts.[48] On average, LEI expects New Hampshire wholesale load to benefit by approximately $79.6 million p.a. under the LCOP/HH gas scenario and $80.1 million p.a. under the GPCM/MS scenario. Using a 7% discount rate, the net present value of these savings over the 11-year period is $586 million and $591 million, respectively, in 2019 dollar terms.

5.7 Wholesale energy price outlook and energy price impacts of NPT

[redacted]

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[47] LEI is using a 7% discount rate for illustrative purposes. For reference, the Clean Energy RFP issued by the states of Connecticut, Massachusetts, and Rhode Island require an evaluation of project benefits using a 7% discount rate.

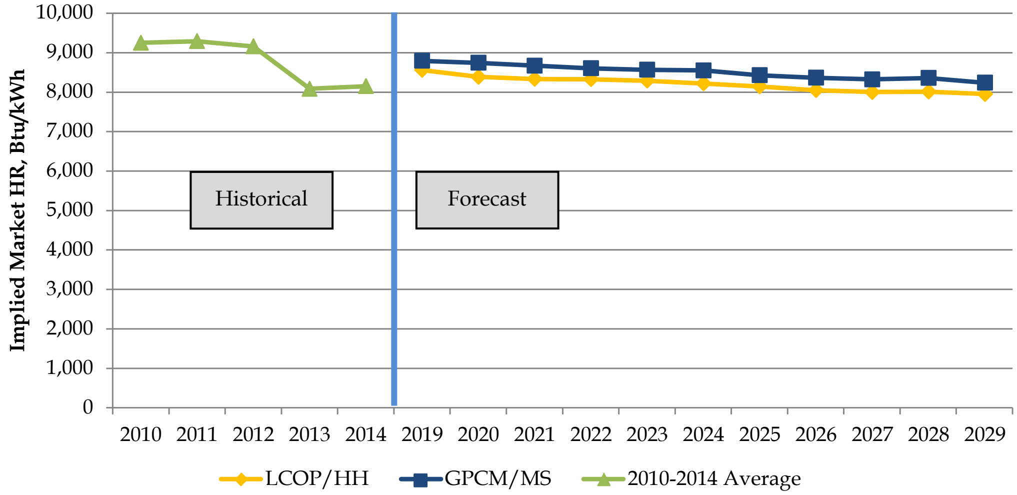
[48] This is consistent with Section III.13.7.3.1. of ISO-NE's market rules, which states that the capacity requirement for each capacity zone shall equal the product of the Capacity Supply Obligation and the ratio of the sum of all load serving entities' annual coincident contributions to the system-wide annual peak load in that capacity zone.

[redacted] This results in a relatively stable implied market heat rate, which is shown in Figure 26. It should be noted that the system remains uncongested in LEI's modeling, and therefore only the Internal Hub LMP is shown below in Figure 25.

[redacted]

LMPs increase moderately over time based on changes in delivered natural gas price increases in nominal terms. However, in some years, the year over year change in LMPs is relatively flat when new generic CCGTs are assumed to start operations (in 2024, 2025, 2026, 2027, and 2029 under the Base Case). As can be seen in the implied market heat rate, there is an overall "real" decline in wholesale energy prices as the ISO-NE system is getting more efficient with generic new CCGT entry. The implied market heat rate goes from 8,554 Btu/kWh (in 2019) to 7,948 Btu/kWh (by 2029), which is an annual average decrease of 0.7% under the LCOP/HH gas scenario. Under the GPCM/MS gas scenario, a similar decline in the implied market heat rate is seen from 8,787 Btu/kWh to 8,234 Btu/kWh. The starting market heat rate in 2019 is consistent with recent historical trends in implied market heat rates, which were roughly 8,100 Btu/KWh in 2013 and 2014, as shown in Figure 26.

Figure 26. Historical implied market heat rates and forecasted Base Case implied market heat rate, 2019-2029



Source: Historical implied market heat rates calculated based on actual delivered gas prices (SNL Financial) and Internal Hub LMPs for the Day-Ahead Energy Market (ISO-NE) as of December 2014

5.7.1 Wholesale energy market price impact of NPT

[redacted]

The relative magnitude of the LMP impacts between the Project Case and the Base Case is the result of the new entry profile in each case. [redacted] When the surplus energy created by NPT is absorbed by demand growth, the same generation unit eventually becomes price setting and therefore the wholesale energy market benefits of NPT "dissipate" over time. Figure 27 below shows that the decrease in NPT benefits begins and accelerates with each incremental generic new entrant under both the Base Case and Project Case.[50]

[redacted]

50 Demand weighted LMPs are hourly energy price weighed by hourly demand. As such, peak prices will have more weight because the demand is highest during peak hours.

[redacted]

In addition to calculating the wholesale energy market benefits for New England as a whole, LEI also estimated the benefits for wholesale load in New Hampshire. LEI isolated the load for New Hampshire in its model and multiplied that load by the wholesale energy price changes relevant to the New Hampshire zone.[51] On average, LEI expects New Hampshire wholesale load to benefit from the reduced LMPs by approximately $8.2 million p.a. under the GPCM/MS gas scenario and $10.2 million p.a. under the LCOP/HH gas scenario. Using a 7% discount rate, the net present value sum of these wholesale energy market benefits for New Hampshire ranges from $66.3 million to $84.0 million (in 2019 dollar terms). The year-by-year wholesale energy market benefits for New Hampshire are shown below in Figure 28.

[51] New Hampshire's share of energy consumption is available from ISO-NE's CELT 2015 load forecast.

Figure 28. Annual load and wholesale energy market benefits for New Hampshire, 2019-2029

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Average	NPV
Wholesale Energy Market Benefits, $millions, nominal												11-yr	11-yr NPV
LCOP/HH, $m	$12.3	$16.2	$16.3	$16.9	$17.7	$12.2	$4.9	$3.6	$3.8	$4.9	$3.5	$10.2	$84.0
GPCM/MS, $m	$8.8	$11.3	$11.8	$13.2	$14.4	$10.5	$4.8	$3.7	$3.9	$4.9	$3.1	$8.2	$66.3

Note: Average energy market benefits and NPV covers 2019-2029. NPV uses a 7% discount rate.

These estimates of wholesale energy market benefits are conservative because they are based on conservative assumptions, such as relatively low delivered natural gas prices, flat (in real terms) carbon allowance price trends, weather normalized demand under a 50/50 scenario, additional new CCGT build (which improves the overall efficiency of the system) and moderate assumptions on energy flows on NPT.

Testing for the Statistical Significance of projected LMP reductions from NPT

When running POOLMod, the generation plants are modeled to take maintenance outages and forced outages. The scheduling of the forced outages is subject to a stochastic algorithm. The timing of forced outages (and maintenance) can affect LMPs – even annual average LMPs. As such, LEI ran 20 iterations of the energy model for 2019-2029 for the Project Case and the Base Case where the timing of these generation outages were varied within each year (although the same amount of outages were maintained between iteration for each plant). The observed wholesale energy prices from these iterations (including the average across all 20 iterations for each year and the standard deviation) were then used to assess whether the observed average of the annual price differences in a given year between the Project Case and the Base Case are statistically significant relative to the variance in LMPs created by stochastic variation in generation outages. In other words, we can test whether the price impact caused by NPT is statistically robust relative to "modeling noise" caused by the randomness of forced outage and maintenance schedules of generation.

Based on observed average price impacts from the 20 iterations and the variance in price impacts across the iterations, LEI concludes that the observed energy price differences in all years are statistically significant.

As shown in Section 5.10 of this Report, NPT may provide substantial insurance benefits against periods with higher demand and/or higher natural gas prices and, more generally, during more stressed system conditions. Under such conditions, when the price setting unit is located on the steeper part of the supply curve, the addition of NPT could move energy prices sharply down, and produce a larger LMP difference.

5.8 Production cost savings

In evaluating wholesale energy market impacts of NPT, LEI also measured the change in the total marginal costs of production for the entire ISO-NE system. Production costs decline as a result of NPT, because the energy flows on NPT displace other, more expensive generation resources in the wholesale energy market. As such, production costs measure not just the change in the marginal unit's operation, but the cost savings across the infra-marginal part of the supply curve, below the price setting unit.

[redacted]

Unlike energy market savings, production costs savings do not dissipate in the long run. Production cost savings are a function of energy flow volume on the NPT line and the marginal cost of the resources that are displaced. The energy flows on the NPT line remain constant over the modeling timeframe, while the marginal costs of the resources that are being displaced increase moderately over time given rising fuel prices and carbon allowance prices, in nominal dollar terms. As a result, we observed a moderate increase in the production cost savings over time. Using a 7% discount rate, the eleven year sum of production cost savings is approximately $2.4 billion under the GPCM/MS gas scenario and $3.1 billion for the New England wholesale energy market) under the LCOP/HH gas scenario (both are in 2019 dollar terms).

It is also useful to consider the production cost savings assuming a positive (non-zero) opportunity cost for the hydroelectric imports from Québec. [redacted]

[redacted]

5.9 Retail rate impacts for NH customers under Base Case

In order to properly evaluate the impact of NPT on New England's retail consumers, LEI converted the wholesale energy price impacts and changes in wholesale capacity prices into a retail rate impact figure. To estimate effect of the wholesale market changes on retail rates, LEI took into account limitations on retail load's exposure to wholesale market conditions. For example, in some states, utilities still own generation and that generation is under regulated cost-of-service regime; therefore, through the continued operation of such regulated generation (which we also refer to as "self-supply"), the utilities' customers are shielded from wholesale market changes. Similarly, if a utility or retail load serving entity has signed a long term contract with fixed pricing terms (that are not indexed to the trends in the wholesale electricity market), the energy and capacity terms of that contract would also limit retail customers' exposure to wholesale market prices. Based on extensive research conducted by LEI on the presence of long term contracts in New England and regulated self-supply arrangements, LEI concluded that retail customers across the region are exposed to 92% of wholesale energy price changes and 94% of capacity market price changes, on average, over the forecast timeframe.

New Hampshire has a slightly lower level of exposure to changes in wholesale market conditions because of the contracts and residual generation that PSNH will retain after the planned divestiture of its generation. New Hampshire's combined average annual wholesale energy market benefits and capacity market benefit of $82.2 million[52] per year would translate to a retail cost savings of $79.9 million, as shown in Figure 30. A more detailed discussion of the retail electricity cost savings for each New England state can be found in Appendix D (Section 11).

[redacted]

5.10 Insurance Value of NPT

The projected wholesale electricity market benefits and retail cost savings discussed in the previous sections of this report have assumed normalized weather and normal system conditions. However, recent history has shown that "weather normal" or a "P50" load forecast is not guaranteed in the real world. For example in the winter 2013-14, severe cold snaps occurred in January, when nine days that month were the coldest 5% of days over the past 20

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[52] The $82.2 million is based on the sum of the 11-year average wholesale energy market benefit of $10.2 million and wholesale capacity market benefit of $72.1 million.

years.[53] Moreover, the actual load has been near or has exceeded the 90/10 forecast six times over the last 22 years, because of hot and humid weather conditions.[54]

New England's system is susceptible to system stress as a result of extreme weather conditions, volatile natural gas markets, and unplanned generation outages. During such events, market prices rise quickly, affecting wholesale costs of electricity and ultimately retail costs of electricity. A project such as NPT can provide valuable "insurance" to consumers by mitigating some of the market price impacts of such events. To evaluate the "insurance" value of NPT, LEI conducted two simulations for demonstrative purposes on how NPT could have mitigated market price escalations under actual, system stress conditions in recent years.

In the modeling, LEI gathered real market data for the most significant price drivers in the New England energy market for two separate events: a summer heat wave with high demand and a winter period with constrained natural gas pipelines. These two scenarios were chosen so that LEI could evaluate price drivers that have very different effects on supply in the system. During the summer, the higher load means that very expensive units that are typically out of merit will have to come online and set the clearing price. In the winter, high gas prices cause gas units to shift along the supply curve, causing more expensive oil units to displace gas units in the merit order.

LEI employed actual hourly metered demand that takes into account interchange levels. Also, daily spot fuel prices (for delivered natural gas, oil, and coal) were obtained and employed in the determination of generators' offers and therefore resulting LMPs.

5.10.1 Summer Stress Case

The first system stress case recreates high summer load. In mid-July 2013, New England experienced higher than normal temperatures (≥89° F) for six consecutive days beginning on Monday, July 15, 2013 and ending on Saturday, July 20, 2013. During this period, more expensive peaking units were required to come online to serve the higher electricity loads in the region. Day-Ahead and Real-Time wholesale electricity prices rose markedly in comparison to the normal range of energy prices for this time of the year. For example, Real-Time LMPs exceeding $400/MWh for seven hours on July 19th, while the normal range of LMPs during this month is in the range of only $40/MWh since 2010. In addition to high LMPs on this day, ISO-NE had a capacity deficiency, which resulted in the ISO-NE declaring an OP4 event. There were 4,724 MW of generator outages and reductions over the peak hour of the day that contributed to system stress and ultimately an OP4 declaration.[55]

LEI replicated the market conditions and outcomes for five consecutive days (July 15- 19), using actual market data on supply, demand, and fuel prices. After replicating actual market outcomes, LEI then added NPT into the supply mix and documented the energy price impact

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53 Babula, Mark. Post Winter 2013/14 Review. ISO-NE. March 6, 2014. Speaker.

54 Weather conditions were slightly above the expected 90/10 weather during the 2006, 2011, and 2014 peaks. <http://www.isone.com/markets/hstdata/rpts/ann_seasonal_pks/seasonal_peak_data_summary.xls>

55 ISO-NE. 2014 Third Quarter – Quarterly Markets Report.

under these actual market conditions.[56] [redacted]

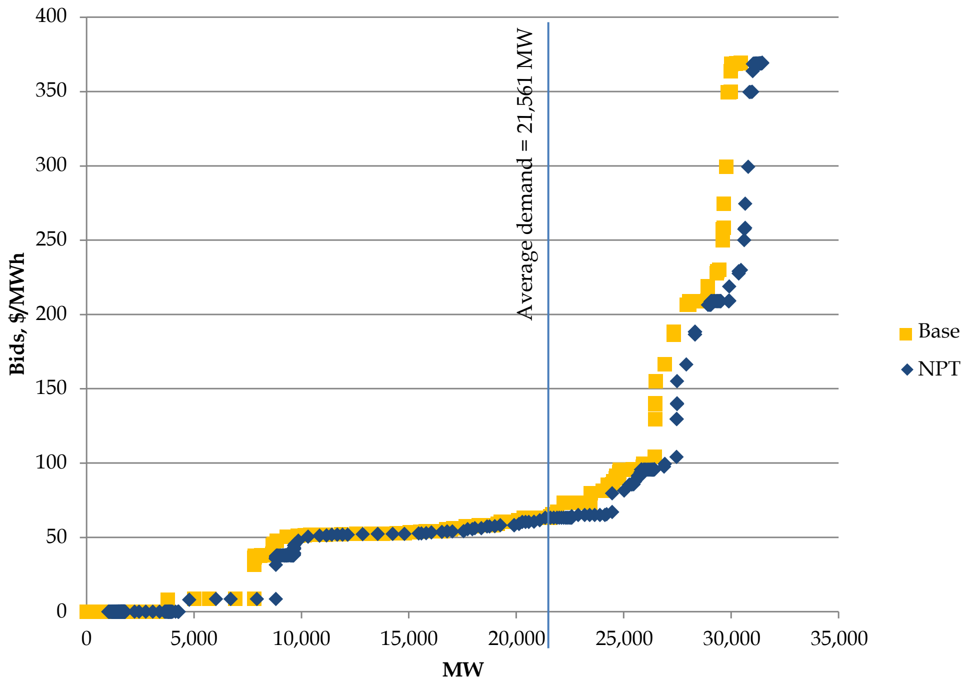
[redacted]

During the summer, delivered natural gas prices rise slightly due demands from higher loads, but still remain at modest levels, as compared to the winter months. The short-run marginal costs for CCGTs typically range from $40-$60/MWh. Therefore, on the supply curve, gas units will remain fairly flat. Figure 33 shows the effect of introducing NPT. The results show that when demand is low, NPT has a lower price suppressing effect. However, based on LEI's

[56] An 83% load factor was used, which is the same level conducted in LEI's other simulation models for NPT.

backcast simulations, when hourly demand approaches and exceeds 20,000 MW, energy flows on NPT has the potential to offset very expensive units in the steeper parts of the supply curve.

Figure 33. Illustrative supply curve on July 19



5.10.2 Winter Stress Case

The second system stress case recreates the conditions of one of the "polar vortex" events that occurred during the winter of 2013-14, when a confluence of fundamentals led to the extremely high delivered natural gas prices and resulting high LMPs. Periods of severe cold weather resulted in increased gas demand from LDCs (who were sourcing natural gas on behalf of their retail customers for heating load), and as a consequence, physical limits on the region's natural gas pipeline network emerged, causing delivered natural gas prices to soar. Some gas-fired generators had problems securing fuel supply. In addition, as a consequence of the ISO-NE's Winter Reliability Program ("WRP"), during some periods, natural gas-based generation was displaced by oil-fired generation, leading to narrowing of spark spreads.

Delivered gas prices at the Algonquin Citygate during December 2013 to January 2014 averaged $19.96/MMBtu — almost double what they were in that same period during winter 2012-13 when the average price for delivered natural gas was $11.16/MMBtu. The $24.49/MMBtu price for natural gas in January 2014 was the highest average monthly price in more than 10 years, with a daily price of over $73/MMBtu on one day (occurring on January 28). As a result of high delivered gas prices, oil-fired generation became cheaper than gas-fired generation on some days, and given the availability of oil on-site for those plants that signed up for the WRP, some oil-fired units were able to be dispatched. Such oil-fired unites contribute to system security during the cold snap events, particularly in January 2014.[57]

The total value of the wholesale energy market in New England for the months of December 2013 through February 2014 amounted to $5.05 billion, or roughly the same value of the entire 12 months of 2012.[58] Therefore, this was a significant cost increase for consumers. Although very extreme conditions led to such wholesale electricity market costs, it is not improbably that natural gas pipelines may see further constraints in the future, resulting in similar magnitudes of costs for consumers, if not otherwise mitigated. NPT can provide some mitigation as the energy flows on NPT are not directly linked to natural gas prices.

[redacted]

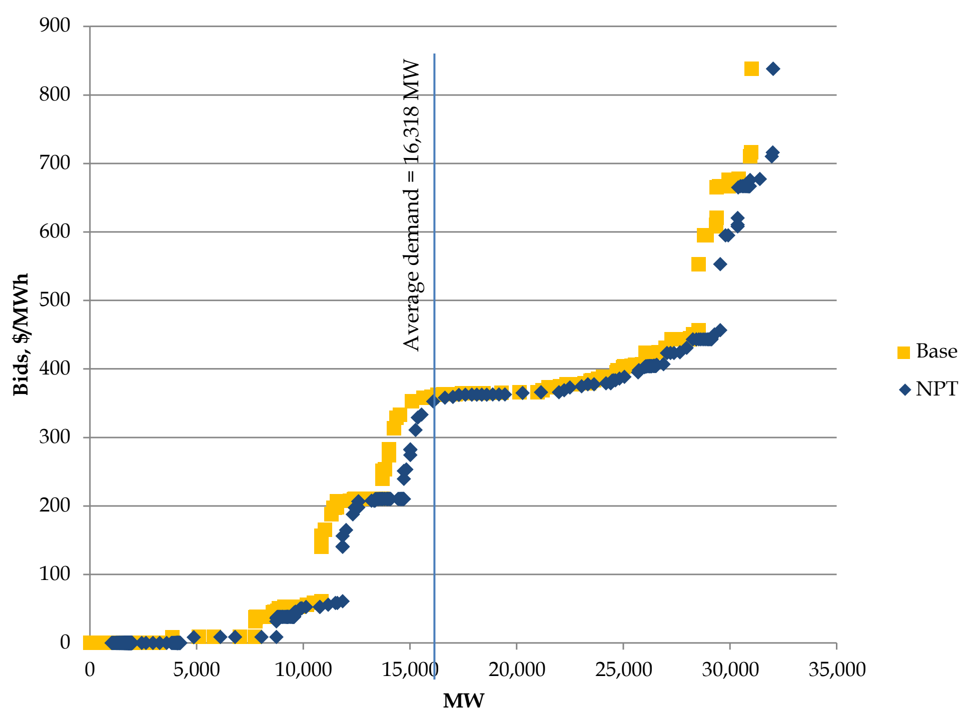
[57] It is important to also keep in mind that the oil fleet was largely enabled last winter by the Winter Reliability Program.

[58] Babula, Mark. Post Winter 2013/14 Review. ISO-New England. March 6, 2014. Speaker.

In recreating the polar vortex conditions of winter 2013-14, LEI studied five consecutive days in January 2014 (January 24th through January 28th), when oil-fired generation often replaced natural gas generation in the merit order. Again, two cases were run – a backcast simulation of actual market conditions without NPT and then a case where NPT was inserted into the simulated actual conditions, in order to demonstrate the possible price impacts that a 1,090 MW transmission line could have made, had it been in service in January 2014. [redacted]

During events such as a polar vortex, delivered natural gas prices can rise significantly due to heating demand from retail consumers served by local distribution utilities. This impacts the supply curve through higher fuel costs and outages at select plants due to unavailability of fuel supply. Figure 36 illustrates the supply curve with high fuel costs for natural gas units, which cause gas-fired units to shift right along the supply curve and results in much higher LMPs. Based on LEI's market simulations, when actual hourly demand was approximately between 13,000 MW and 16,000 MW, NPT had the potential to significantly reduce LMPs and offset the impact of very high delivered natural gas prices.

Figure 36. Illustrative supply curve on January 28, 2014



6 Environmental Project Benefits

In addition to the tangible market price reductions that will affect the ISO-NE wholesale electricity markets and ultimately flow through to retail customers as retail electricity cost savings, there are other electricity market-related benefits associated with the operations of NPT. As a result of the energy flows from Québec (sourced from clean hydroelectric generation), New England will see a reduction in CO_2, SO_2, and NOx emissions from fossil fuel-fired generators.[59]

6.1 Overview of historical emissions trends for SO_2, NO_X, and CO_2

Pollutants are important to consider as significant amounts can impair human health and the environment. CO_2, SO_2, and NO_X are the result of the combustion of sulfur- or nitrogen-containing fossil fuels in the production of energy. Emission levels of SO_2 and NO_X are regulated by the EPA under various environmental regulations, such as Ozone Transport Assessment Group ("OTAG"), Ozone Transport Commission ("OTC"), and more recently Clean Air Interstate Rule ("CAIR").

To date, CO_2 has not been regulated by the federal EPA, but such emissions are monitored through the EPA's Continuous Emissions Monitoring System ("CEMS") program. On June 2, 2014, the EPA released its proposed Carbon Pollution Standards for Existing Power Plants (known as the Clean Power Plan or "CPP"), per its authority under Section 111(d) of the Clean Air Act ("CAA"). The CPP would establish different target emission rates (lbs of CO_2 per megawatt-hour) for each state due to regional variations in generation mix and electricity consumption, but overall is projected to achieve a 30% cut from 2005 emissions by 2030, with an interim target of 25% on average between 2020 and 2029. While the RGGI program in New England is already aiming to curb CO_2 emissions and is in a good position to meet the CPP requirements, a project such as NPT could be complimentary to these efforts.

In New England, emissions from these three pollutants has declined dramatically since the 1980s through the installation of pollution abatement systems and moderation of the fuel and changes in the system's fuel mix (i.e., entry of more efficient, gas-fired resources), as seen in the figure below. In particular, over the last decade the increased use of natural gas power plants with combined cycle technology has significantly decreased the atmospheric emissions of CO_2, SO_2, and NO_X.

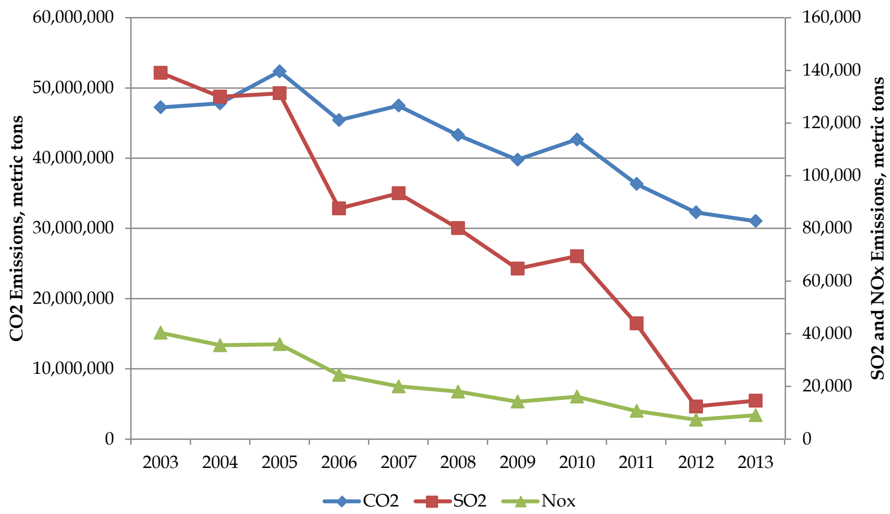
Further reductions in ambient concentrations may occur due to revision of performance standards and new regulatory requirements for emissions reductions that contribute to regional haze, mercury, and ozone, but these are not expected to lead to significant declines in New

[59] More detailed assumptions behind the estimate of these emissions reductions can be found in Appendix C.

England's emissions footprint, given the achieved conversion away from coal and oil-fired generation.[60]

Further material reductions in overall emissions levels may be difficult to achieve without significant reduction in the use of fossil fuel-fired resources. NPT, however, can provide an opportunity to do just that without requiring retirement of existing generation.

Figure 37. Emissions reduction in ISO-NE



Note: This chart presents data for those plants required to report hourly CEMS data to the EPA.

6.2 SO_2 and NO_X reductions as a result of NPT

LEI estimated the reduction in SO_2 and NOx emissions for the ISO-NE system by comparing the emissions profiles of each generator under the Base Case and Project Case. The region-wide reductions are summarized by year in the figure below. These emissions reductions generally decrease over time as the ISO-NE system becomes more efficient due to additional CCGT entry. Under the Project Case assumptions, as a result of the energy flows on NPT, the New England system would benefit from approximately 624 tons of lower NOx emissions annually under the LCOP/HH gas scenario. In addition, New England would also see approximately 460 tons less of SO_2 per year. Even under the GPCM/MS gas scenario, there are reductions in NO_X and SO_2 (537 tons and 261 tons, respectively, for each pollutant). These SO_2 and NO_X reductions typically come from a mix of approximately fifty gas, coal and oil-fired units in the ISO-NE system, as no single power plant's production is being completely and exclusively displaced by NPT.

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[60] Efforts from programs such as CSAPR and MATS were designed to alleviate the problems of air pollution and other toxics.

Figure 38. SO_2 and NOx reductions due to NPT (short tons)

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	11-Yr Average
NOx reduction, short tons												
LCOP/HH	417	602	612	604	613	643	682	684	658	675	670	624
GPCM/MS	365	530	541	542	549	553	598	575	547	546	555	537
SO2 reduction, short tons												
LCOP/HH	337	473	509	479	508	490	502	480	427	442	409	460
GPCM/MS	176	244	283	287	312	293	327	283	206	219	243	261

6.3 CO_2 reductions as a result of NPT

The results of LEI's simulation modeling show that NPT could result in approximately 3.3 – 3.4 million metric tons of avoided annual CO_2 emissions in New England, after adjusting for emissions of CO_2 associated with large hydroelectric generation.[61] Based on the EPA's comparative analysis, this level of CO_2 reduction is approximately equivalent to removing over 690,000 passenger vehicles off the road annually.[62] Over the modeling horizon, the emissions reduction are fairly constant because of the constant year-on-year energy flows assumed on NPT and the similarity in the emissions footprint of (primarily natural gas-fired) resources that are being displaced by the energy flows on NPT.

[redacted]

In the estimate of the avoided CO_2 emissions in ISO-NE's control area summarized in the figure above, LEI included a deduction for the assumed CO_2 emitted by the large hydroelectric plants in Québec, which are the source of the energy flows on NPT. There is substantial scientific and policy debate on how to estimate possible CO_2 emissions from large hydroelectric resources. LEI applied a pragmatic method, where we acknowledged that large hydroelectric resources may emit carbon due to the decomposition of fauna in the newly formed reservoir. Based on studies conducted by Hydro Québec scientists, it has been forecast that a large hydroelectric complex such as Eastmain 1/1A had a lifecycle emissions profile of greenhouse gases of 136

[61] If no emissions are expected from resources that produce energy on the NPT line, emissions reductions would increase to approximately 2.7 million metric tons.

[62] Environment Protection Agency. "Calculations and References." <http://www.epa.gov/cleanenergy/energy-resources/refs.html#vehicles>. Accessed on December 23, 2014.

lbs/MWh.[63] This figure is higher than the actual historical system-wide profile of CO_2 emissions reported by Hydro Québec of 239 metric tonnes/TWh (approximately 0.5 lbs/MWh).[64] Although the emissions profile of a new large hydroelectric plants are likely to be higher in the initial years than this lifecycle figure, it is difficult and intractable to pinpoint the exact, time-specific emissions profile of the energy flows on NPT, as they will not be associated with any single generation development. Therefore LEI chose to apply the lifecycle rate of 136 lbs/MWh. This results in approximately 491,000 metric tons of carbon for the 7,958 GWh of energy imported on NPT under the Base Case assumptions. This value however, still contrasts significantly with the emissions associated with output from a natural gas-fired combined cycle, which can typically emit between 700-1,000 lbs/MWh (depending on heat rate).

LEI also estimated the incremental value to society of the avoided CO_2 emissions. The social value of these emissions reductions (in nominal $ millions terms) is projected to increase with time due to the estimated social cost of carbon value established by the EPA. The EPA (specifically, the Interagency Working Group on Social Cost of Carbon of the US Government)[65] forecasts that social cost of CO_2 emissions would be as high as $65/ton by 2020, based on 2007 dollar values.[66] LEI converted these real social costs of carbon to nominal figures, which are shown above in Figure 39 on the previous page. The incremental social benefits of carbon emissions reductions were valued based on these dollar values.[67]

[redacted]

[63] Teodoru, C. R., et al. (2012), The net carbon footprint of a newly created boreal hydroelectric reservoir, Global Biogeochem. Cycles, 26, GB2016.

[64] Hydro Québec Production's Electricity Facts. 2013.

[65] Interagency Working Group on Social Cost of Carbon, United States Government. "Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis - Under Executive Order 12866." Pg. 3. < http://www.whitehouse.gov/sites/default/files/omb/inforeg/social_cost_of_carbon_for_ria_2013_update.pdf >

[66] The aforementioned report lists the following values in 2007 values: $58 (2015), $65 (2020), $70 (2025), and $76 (2030).

[67] In calculating the incremental social emissions reduction benefit, LEI subtracted the market value of carbon allowances (RGGI prices) from this social cost.

7 Local Economic Benefits for New Hampshire and New England

LEI analyzed the potential local economic benefits of NPT in terms of the employment and GDP impacts to New Hampshire and other states in New England, using the PI+ model developed by Regional Economic Models, Inc. ("REMI").

NPT, the developer of the proposed Project, is planning to make direct investments in the State of New Hampshire during the construction and operations phases of the project. [68] For example, the construction and installation of NPT will require construction workers, logging workers engineering project managers, environmental specialists, legal professionals and other local labor services. NPT will also employ personnel (and services) based in New Hampshire once the project begins operations in order to operate and maintain the transmission infrastructure. NPT's expenditures in the state – for O&M and also community development - will result in the creation of new jobs and increased economic activity in New Hampshire and across the New England region.

In addition, NPT is expected to lower the wholesale market price of electricity as a result of the energy flows and capacity sales associated with the transmission line. This will lead to a reduction in retail electricity costs for New England (see Appendix D: Calculation for retail cost impact and in turn, benefit the state economies in the New England region.

At the peak of construction (in 2017), NPT is expected to create a total of nearly 2,676 direct, indirect, and induced jobs in New Hampshire. Other states in New England also see an increase in total jobs during the construction of NPT, due to the linkages in states' economies and also as a result of the construction-related jobs that will be sourced from Massachusetts, Maine and Vermont. For example, in 2017, the other five states in New England would experience an increase of almost 2,898 total jobs. At the peak of construction (in 2017), NPT is expected to create a GDP increase of $214 million in New Hampshire, which is a 0.3% increase from the 2014 nominal GDP in New Hampshire.[69] The other five states in New England are expected to have a GDP increase of $276 million, which is 0.03% increase from the 2014 nominal GDP of the five states.[70]

NPT will also create an average of 6,820 jobs p.a. across all of New England in the first 11 years of commercial operations (2019-2029). From this total, New Hampshire will see on average 1,148

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[68] NPT expects the pre-construction and construction periods for the transmission line will be completed over a 40 month period, starting in January 2016 and concluding in April 2019. There is also certain pre-construction spending, which is associated with development of the Project in 2015, which we have included in our modeling of the local economic benefits (this is identified as the "planning" period in the charts and tables herein).

[69] New Hampshire 2014 GDP was over $71 billion in nominal terms, according to US Department of Commerce, Bureau of Economic Analysis.

[70] According to US Department of Commerce, Bureau of Economic Analysis; Massachusetts 2014 GDP was $460 billion (nominal), Connecticut 2014 GDP was $253 billion (nominal), Rhode Island 2014 GDP was $55 billion (nominal), Maine 2014 GDP was $56 billion (2014) and Vermont 2014 GDP was $30 billion (nominal).

new jobs per year. In addition, NPT will generate over $1.16 billion dollars on average annually in new economic activity for the New England region during this period, which is 0.12% increase from New England's 2014 nominal GDP.[71] NPT will also generate over $159 million average increase in New Hampshire's annual GDP, which is 0.23% increase from the state's 2014 nominal GDP.

7.1 Methodology and Key Assumptions

NPT expects that the line will be constructed over a 40-month period, starting in 2016 and concluding in April 2019. There is also some pre-construction spending, which is associated with planning and development of NPT, which has been accruing since 2009.[72] The operations phase of NPT is expected to commence in May 2019 for the purposes of this analysis, and is expected to go out 40 years (or even longer). For the macroeconomic study of the NPT operations phase, we only model an 11-year period from 2019 to 2029. In this report we do not quantify any macroeconomic benefits for the remainder of the 40-year period beyond 2029.

NPT provided a number of inputs necessary to estimate the local economic effects of the Project, including the estimates of labor and material spending in New Hampshire, other states of New England, and outside New England. NPT also provided wage rates by job type, annual O&M spending, and funds allocated to community development programs. There will also be other local benefits associated with NPT. For example, NPT is also setting aside funds for a local jobs initiatives and training (apprenticeship) program, which we have not included in the quantitative assessment of local economic benefits. The PI+ model requires the labor data presented in the form of number of employees.[73] Therefore, LEI has used the estimated labor

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[71] The 2014 GDP in New England was over $924 billion in nominal terms, according to US Department of Commerce, Bureau of Economic Analysis

[72] The local project spending inputs from 2015 (the planning year) and onwards was used for modeling purposes. This is the conservative assumption, as the inclusion of prior expenditures would have increased the total local spending figures.

[73] The PI+ model uses jobs inputs as per the US Bureau of Economic Analysis ("BEA") and US Bureau of Labor Statistics ("BLS"). The BEA employment series for states and local areas comprises estimates of the number of jobs, full-time plus part-time, by place of work. Full-time and part-time jobs are counted at equal weight. Employees, sole proprietors, and active partners are included, but unpaid family workers and volunteers are not included. The BLS data pertains to workers covered by State unemployment insurance (UI) laws and Federal civilian workers covered by the Unemployment Compensation for Federal Employees (UCFE) program. The BLS employment count includes all corporation officials, executives, supervisory personnel, clerical workers, wage earners, pieceworkers, and part-time workers. Workers are reported in the State and county of the physical location of their job. Persons on paid sick leave, paid holiday, paid vacation, and so forth are included, but those on leave without pay for the entire payroll period are excluded. The BLS employment count excludes employees who earned no wages during the entire applicable period because of work stoppages, temporary layoffs, illness, or unpaid vacations, and employees who earned wages during the month but not during the applicable pay period.

spending divided by fully loaded wage rates,[74] as provided by NPT, to estimate the number of employees needed for construction and for operations phases of the Project.

During the 2016 to 2019 construction phase, NPT is estimated to hire 582 employees (direct jobs) in New Hampshire on average per year to construct the line, and 213 employees from Massachusetts per year.[75] Other New England states account for a small amount of direct jobs, as seen in the figure below.[76]

Figure 40. Direct jobs created by NPT during the planning and construction phase in New England

State	Planning	Construction Phase				Construction Average
	2015	2016	2017	2018	2019	(2016 to 2019)
New Hampshire	52	38	1249	976	132	582
Massachusetts	7	9	439	349	53	213
Connecticut	9	5	14	12	4	9
Rhode Island	0	0	0	0	0	0
Maine	1	4	295	233	34	142
Vermont	4	3	92	73	11	45
Total	73	60	2089	1642	234	1006

Note: results are presented as yearly totals, not incrementally
Source: Results of PI+ model

Including labor and materials spending, total project spending to construct the transmission line is estimated to be almost $1.123 billion in New England and outside New England from 2015 to 2019.[77] For the project, total labor and materials spending in New England is $658 million from 2015 to 2019. Total labor and materials spending (2015 to 2019) outside of New England is $465 million. Of the total $1.123 billion project pending (2015 to 2019), approximately $616.1 million will be spent on labor, including the hiring of environmental experts, lawyers, and other experts, as well as construction workers, project engineers, and personnel for site preparation. Spending on materials is projected to equal almost $506.7 million, of which almost 27% would

[74] Note this is fully loaded wage rate, which is intended to include all health, pension and other benefits. For the purposes of evaluating the NPT project, including fully loaded wages for all hiring/compensation related spending on NPT will provide a more accurate (and more conservative) estimate of the local economic effects of the Project. LEI cross checked the base salaries provided by NPT with other sources and found that the base salary NPT provided was comparable.

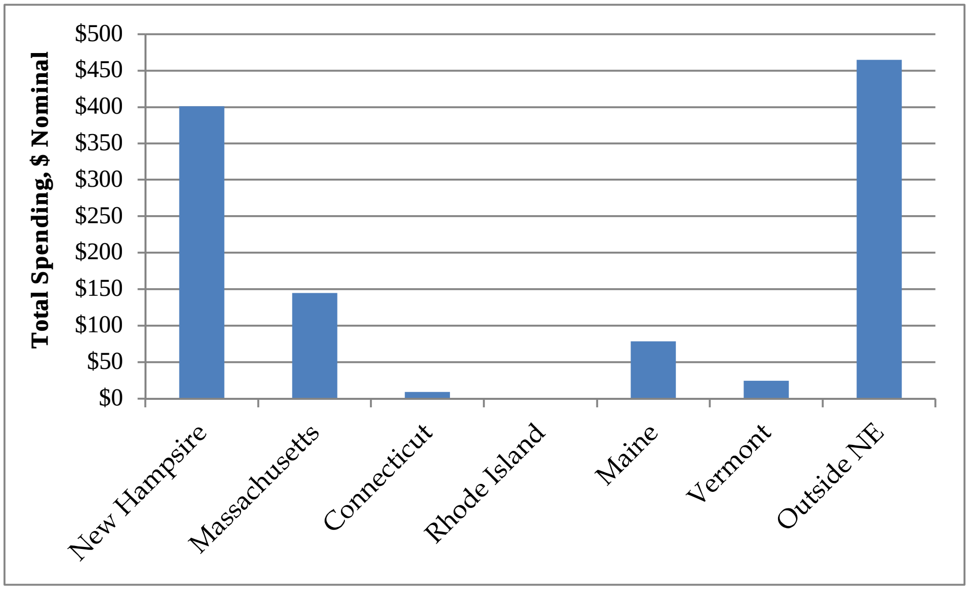
[75] Approximately 21% of all New England direct NPT hires are expected to come from Massachusetts. This is because Massachusetts has the largest population from which to source workers and as a result of NPT labor agreements. While the bulk of construction would occur in 2017 and 2018, we have referred to a construction period covering 2016 to early 2019 in our calculations, which includes pre-construction spending from 2016.

[76] During construction, NPT estimated that over 50% of direct hires will be residents of New Hampshire, while 25% will come from other states in New England and the remainder (another 25%) from outside New England.

[77] NPT also estimated another $336 million for contingency, escalation, property tax, and carrying charges.

be spent in New Hampshire. The project will incur additional spending as well, but the remainder is outside of New England.[78] Total labor and materials spending from 2015 to 2019 in New Hampshire is projected to be approximately $401.2 million, with an additional $144.7 million over this same period in Massachusetts. There will also be some relatively small expenditures in other New England states (totaling $112 million among the remaining four states), as summarized in figure below.

Figure 41. Labor and materials spending by location during the planning (2015) and construction (2016 to 2019) phases in New England, nominal $ millions



$ Millions	NH	MA	CT	RI	ME	VT	Outside NE
Total Spending	$401.2	$144.7	$9.1	$0.0	$78.5	$24.7	$464.6

Source: NPT

Note: For the purpose of economic impact modeling, spending by the Project for construction outside New England is not modeled. It is being shown above to provide a complete understanding of the overall project costs. Furthermore, for the purposes of the PI+ modeling, these real dollar figures are converted within the PI+ model inputs (which are in nominal terms), assuming a 2% annual average inflation rate.

Input data provided by NPT for the operations phase includes projected annual O&M expenses and funding for community development programs.[79] Community development spending is

[78] Outside New England spending is not modeled or included as a driver of local economic benefits. This information is presented above solely to demonstrate where spending is directed.

[79] Although NPT also provided an estimate of annual property tax payments, LEI has conservatively not included these payments as a source of local economic benefit. Local property tax revenues collected from NPT could be used to pay off existing debt and are therefore not likely to generate additional economic activity. However, it is also plausible that such local tax revenues are deployed to expand government spending, which would

considered charitable spending (for example, an environmental research fund or customer rebates) and is modeled as additional funding for the local government.[80] Finally, O&M spending is notionally divided into labor (70%) and material spending (30%). These payments (not including property tax payments) over the first 11 years of operations average $13.5 million per year (totaling $148.7 million), as presented in the figure below.

Figure 42. Direct spending by NPT during the operations phase (nominal $ millions)

Operation Period Inputs	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Average
Economic Development Programs	$ 10.5	$ 10.5	$ 10.5	$ 10.5	$ 10.5	$ 10.5	$ 10.5	$ 10.5	$ 10.5	$ 10.5	$ 10.3	$ 10.5
O&M and AGE	$ 2.7	$ 2.7	$ 3.3	$ 2.5	$ 2.6	$ 3.3	$ 2.7	$ 3.1	$ 3.9	$ 3.8	$ 2.9	$ 3.0

Source: NPT

Once commercial operations begin, NPT is expected to reduce the wholesale market price of electricity (energy and capacity) in the ISO-NE markets, which will ultimately benefit retail electricity consumers. Based on LEI's analysis, the reduction in retail electricity costs to electricity consumers in the region is estimated to be approximately $577.7 million per year on average for the first 11 years of commercial operations. The calculation of retail electricity cost savings are described further in Section 11.

7.2 Construction Period Benefits

During the construction period, NPT is projected to require on average more than 582 direct jobs per year in the state of New Hampshire. In addition, NPT is expected to spend $134.3 million and $372.3 million between 2015 to 2019 for the purchase of services and materials in New Hampshire and outside of New England, respectively. Both the labor and non-labor spending will stimulate the local economy and create even more jobs and expand states' GDPs.

Planning (2015) and Construction period (2016-2019) Impacts

During the construction phase (2016 to 2019), based on the fully loaded wage data provided by NPT, it is estimated that an average of approximately 582 direct jobs and a total of labor and non-labor spending of $401.2 million in New Hampshire will be made.[81] As a result, on average

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positively impact the state economy. In other words, the macroeconomic benefits would be higher if tax revenues were included in the model.

[80] Community development spending was set as the "local government spending" policy variable in the PI+ model. This variable was selected since more specific information was not provided on exactly how this spending would be allocated. It is expected that this would create a larger impact because it is localized, labor-intensive, and mirrors the economic activities normally handled by local governments. Putting money into the local government spending variable means adding to the budget which is used for standard local government spending initiatives which local governments including education, transportation, public safety, etc.

[81] We do not focus on the planning period in the discussion given the more limited scale of spending during that stage, but the impacts associated with this period were modeled and the results are reported in the detailed tables.

approximately 1,369 total jobs (direct, indirect and induced) will be created per year in New Hampshire during the construction phase. The construction phase will also expand state economic activity (as measured by GDP) in New Hampshire by $111 million p.a. on average from 2016 to 2019, or approximately 0.16% of New Hampshire's GDP based on 2014 GDP levels.[82]

A crucial component of the expected employment benefits is the indirect and induced jobs. Indirect jobs arise as a result of the need to satisfy demand for the goods and services required by the project's direct suppliers. By contrast, induced jobs are created by increased spending by the workers hired to construct NPT. The chart below is a simple illustration of how spending associated with the construction of NPT creates benefits to New Hampshire and other states in New England.

Figure 43. Simple illustration of how construction of NPT leads to local economic benefits to New Hampshire and other states in New England

The pie charts in Figure 44 and Figure 45 below summarize the composition of indirect jobs during the construction phase in New Hampshire and New England as a whole. For example, in New Hampshire during the construction phase, twenty-four percent (24%) in the administrative services sector, seventeen percent (17%) of indirect jobs are created for professional, technical services sector, ten percent (10%) in agriculture and forestry support services, three percent (3%) in the food services sector and another three percent (3%) in the

[82] New Hampshire 2014 GDP was over $71 billion in nominal terms, according to US Department of Commerce, Bureau of Economic Analysis.

wholesale trade sector. In New England as a whole, twenty percent (20%) of indirect jobs are created for professional, technical services sector, twenty percent (20%) in the administrative services sector and five percent (5%) in the agriculture and forestry sector.

Figure 44. Indirect jobs created by NPT during the construction phase by sector in New Hampshire

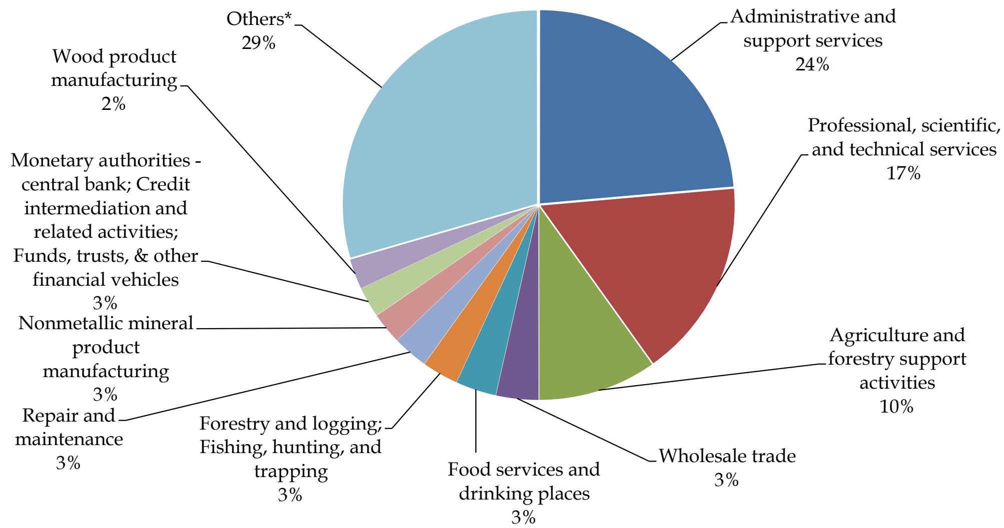
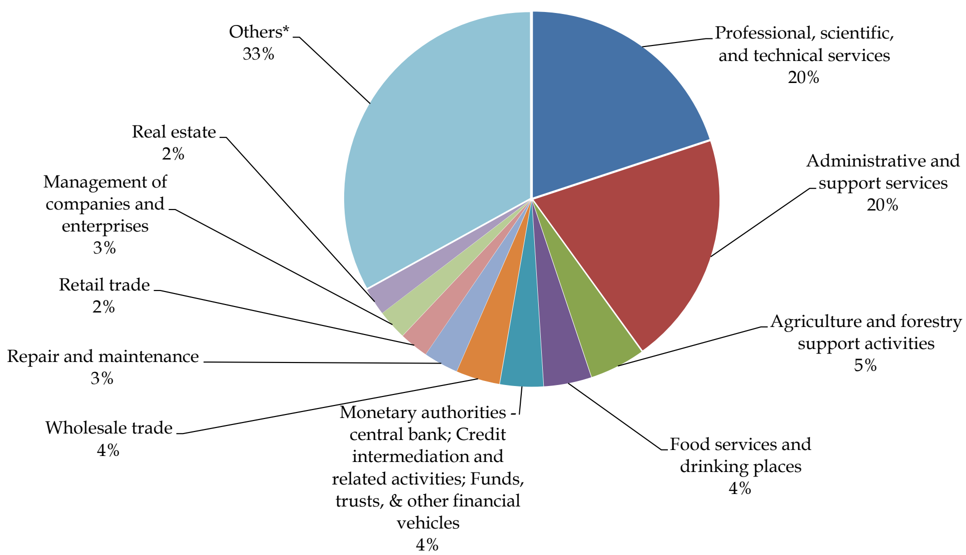
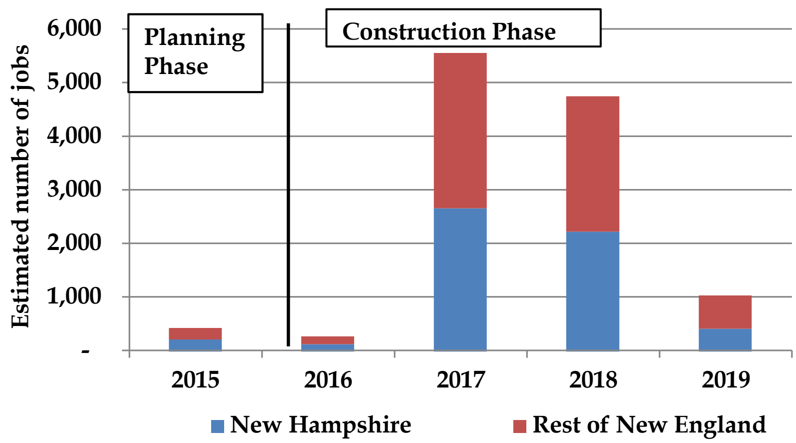


Figure 45. Indirect jobs created by NPT during the construction phase by sector in New England



Due to the close economic ties between New Hampshire and other New England states, there will also be spill-over effects in the form of additional indirect and induced jobs and expanding economic activity (as measured by GDP) throughout New England. For example, retail and administrative services demanded by NPT would further induce manufacturing activities and financial services provided by firms located in other New England states, such as Massachusetts and Connecticut. REMI's PI+ model incorporates these interregional linkages and calculates the impact of NPT on other New England states' economies. Across New England and excluding New Hampshire, NPT's construction phase will generate on average more than 1,548 direct, indirect and induced jobs between 2016 and 2019[83] (of which more than 25% is direct, construction related jobs). At the peak year of construction (in 2017), NPT is expected to generate 2,898 direct, indirect and induced jobs.

Figure 46. Estimated number of new jobs in New England as a result of local spending on NPT during the planning and construction phase

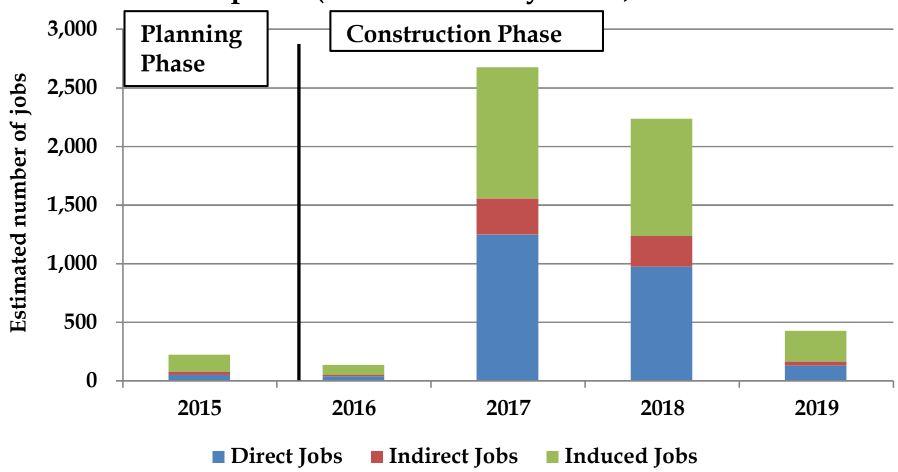


Region	Planning	Construction Phase				Construction Average
	2015	2016	2017	2018	2019	
New Hampshire	225	136	2,676	2,238	427	1,369
Rest of New England	216	147	2,898	2,527	622	1,548
Total	440	283	5,574	4,765	1,049	2,918

Note: Jobs in the figure above includes direct, indirect and induced. While the bulk of construction would occur in 2017 and 2018, we have included in our analysis pre-construction spending from 2016. Therefore the construction phase reported above covers part or all of the years 2016 through 2019.

[83] Total jobs are the sum of direct jobs, indirect jobs, and induced jobs. The direct jobs include the jobs that are needed for the construction or commercial operations of the project, indirect jobs are jobs created by the businesses which provide goods and services essential to the construction or operations of the project, and induced jobs are jobs that are created in other sectors of the economy as a result of spending of the wages and salaries of the direct and indirect employees. It is also important to note that "Jobs" in the REMI PI+ model include full-time, part-time, and seasonal employment, consistent with the definition used by BLS. The BLS data pertains to workers covered by State unemployment insurance (UI) laws and Federal civilian workers covered by the Unemployment Compensation for Federal Employees (UCFE) program. The BLS employment count includes all corporation officials, executives, supervisory personnel, clerical workers, wage earners, pieceworkers, and part-time workers.

Figure 47. Estimated number of new jobs in New Hampshire from the proposed Project during the planning and construction phase (broken down by direct, indirect and induced jobs)

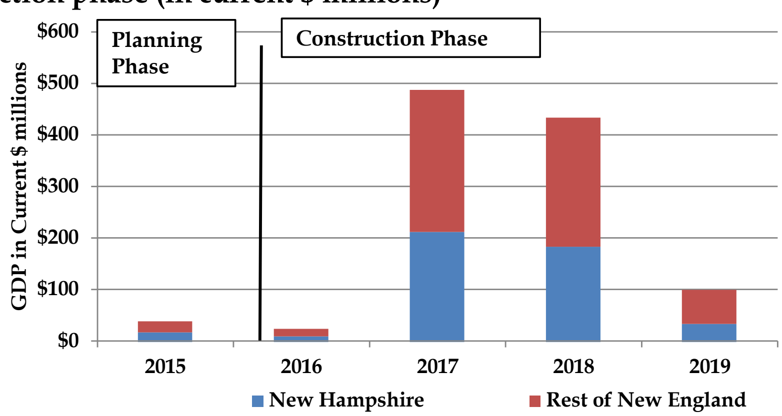


Jobs	Planning	Construction Phase				Construction Average
	2015	2016	2017	2018	2019	
Direct Jobs	52	38	1249	976	132	599
Indirect Jobs	27	15	308	261	34	154
Induced Jobs	146	83	1120	1001	261	616
Total jobs	225	136	2676	2238	427	1,369

Note: Jobs in the figure above includes direct, indirect and induced.

In addition, there will be an increase in rest of New England states' GDPs by approximately $152 million per year, as summarized in the figure below.

Figure 48. Estimated increase in state GDPs in New Hampshire and rest of New England during the construction phase (in current $ millions)



Region	Planning	Construction Phase				Construction Average	Total
	2015	2016	2017	2018	2019		
New Hampshire	$19	$11	$214	$185	$35	$111	$445
Rest of New England	$21	$15	$276	$251	$66	$152	$607
Total	$40	$25	$489	$436	$101	$263	$1,052

7.3 Operations Period Benefits

Commercial operations of NPT will begin in May 2019. As already described in Section 5.9 of this report, energy flows on NPT will reduce the commodity component of retail costs of electricity across New England, by as much as $577.7 million a year.[84] Households (residential consumers) would be able to spend the money they save from lower retail costs of electricity on other goods and services, which will stimulate the economy and lead to an expansion of GDP and employment.

Commercial and industrial customers, especially those that rely heavily on electricity use, may also experience a positive income effect as a result of reduced costs of electricity. Electricity costs are generally treated as a variable cost in business (or a component of costs of goods sold). Assuming the same production level in the short term, decreases in electricity costs will increase profitability. In the medium term, businesses facing decreasing electricity costs may choose to increase production, and that may mean expansion of their capital, which then induces demand in other industries. For example, this will indirectly create opportunities for additional employment as production expansions typically require additional labor. Businesses will also require incremental inputs to their production process which will, therefore, indirectly increase demand in other industries. There will also be a substitution effect, where possible technically and economically sensible (as a result of relative price changes) electricity use will displace other fuel use in the economy. In the long run, businesses that have production cost savings from lower electricity costs may choose to expand their capacity through capital expenditures, which in turn will also increase production levels and create additional employment opportunities and result in tertiary economic impacts.[85]

As a result of the lower retail costs of electricity, as well the O&M spending and community development funding, LEI estimates that New Hampshire's GDP would increase by an average of $162 million p.a. during the first 11 years of commercial operations and there will be an increase of 1,148 total jobs per year on average. Across all of New England, NPT will serve as the catalyst for new jobs as well: 6,820 direct, indirect and induced jobs per year on average. New England states will see an increase in states' GDPs by an average of approximately $1,156 million p.a.[86] Figure 49 and Figure 50 below show the annual results in terms of total jobs for

84 See

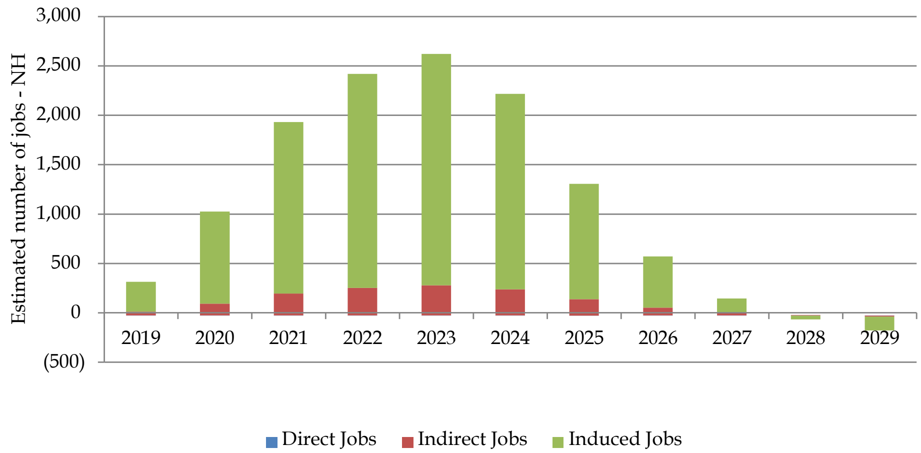
Appendix D: Calculation for retail cost impact for a further description of the conversion of the wholesale electricity market benefits into retail cost savings for consumers.

85 Long-term capacity expansion of businesses is included in REMI PI+ model through a capital stock adjustment process. The stock adjustment process assumes that investment occurs in order to fill the gap between the optimal and actual level of capital. New investment provides a strong feedback mechanism for further growth, since it represents immediate demand for building and equipment that are to be used over a long period of time.

86 The retail electricity cost savings and the increase in GDP are conceptually both economic benefits. However, these two benefits are not mathematically additive. Retail electricity cost savings are estimated using simulation of the wholesale energy and capacity markets. The GDP impact is estimated using REMI PI+ model. In fact, the retail

both NH and New England, respectively; while, Figure 51 presents the annual GDP improvements for NH and New England, respectively.

Figure 49. Estimated number of new jobs in New Hampshire created by NPT during its first 11 years of commercial operation



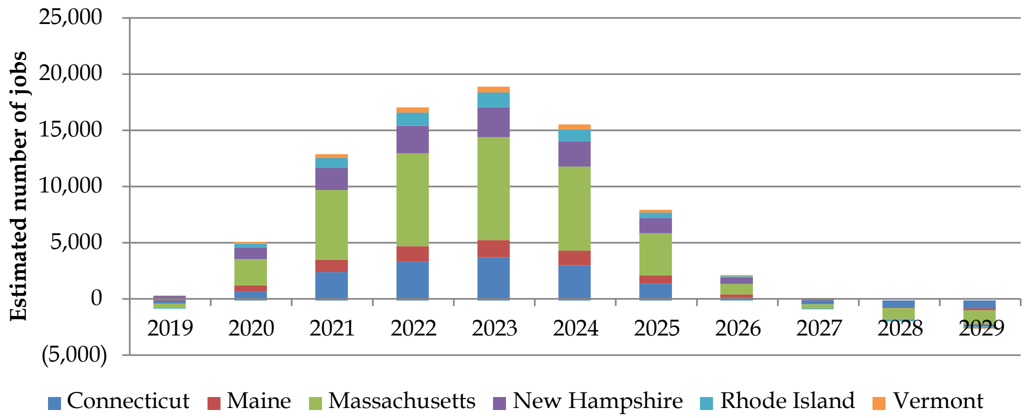
Jobs	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Average
Direct Jobs	2	2	2	2	2	2	1	2	2	2	1	2
Indirect Jobs	39	119	222	279	306	266	165	80	31	6	(9)	137
Induced Jobs	301	934	1,735	2,167	2,341	1,979	1,168	519	142	(38)	(142)	1,010
Total jobs	342	1,054	1,959	2,448	2,649	2,246	1,334	601	175	(30)	(149)	1,148

As seen in Figure 49 and Figure 50, local employment benefits decline during the operations phase from 2024 and onwards. This is mainly due to the induced economic effects during the operations phase. Between 2019 and 2025, the induced jobs account for approximately 88% of total jobs created per year. In 2026, the retail cost savings decrease significantly, however, the employment effects are still positive due to the population increase and investment from prior years. The negative employment effects from 2027 to 2029 are due to a decline in disposable income which is a result of the change in electricity costs (the electricity market benefits have dissipated by then). However the employment loss is not a reduction in direct jobs, rather it is a reduction in induced labor effects and caused by the fact the households are scaling back and spending less on consumer expenditures. Such changes in spending habits are to be expected and are a natural byproduct of a market that is re-balancing itself from a "booming" period. The industries with the highest reduction in induced employment in those later years include

electricity cost savings are a key input to the increased economic activity that is represented by the GDP impact. The electricity cost savings that New England households and businesses receive as a result of NPT increase economic activity. The effect is achieved through increased consumption (households have more disposable income to spend on other goods and services) and increased business output (because firms are able to lower their production cost and thus become more competitive and increase production).

construction, retail trade, ambulatory healthcare services, professional, scientific and technical services, and administrative and support services.

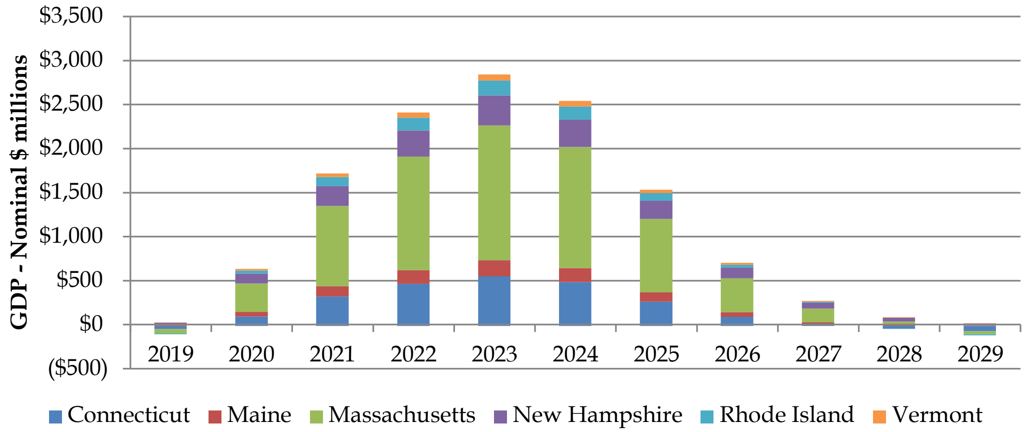
Figure 50. Estimated number of total new jobs created in New England during its first 11 years of the commercial operations by state



Yearly total jobs	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Average
Connecticut	(279)	835	2,524	3,428	3,843	3,142	1,494	265	(340)	(605)	(725)	1,235
Maine	61	507	1,084	1,402	1,533	1,284	724	262	20	(100)	(162)	601
Massachusetts	(386)	2,326	6,215	8,259	9,171	7,497	3,763	927	(368)	(952)	(1,245)	3,201
New Hampshire	342	1,055	1,959	2,448	2,649	2,246	1,334	601	175	(30)	(149)	1,148
Rhode Island	(80)	313	886	1,182	1,307	1,049	494	91	(91)	(171)	(211)	434
Vermont	17	147	341	464	522	444	254	97	13	(29)	(53)	201
Total	(324)	5,182	13,008	17,182	19,025	15,662	8,062	2,242	(590)	(1,886)	(2,543)	6,820

Note: Jobs in the figure above includes direct, indirect and induced.

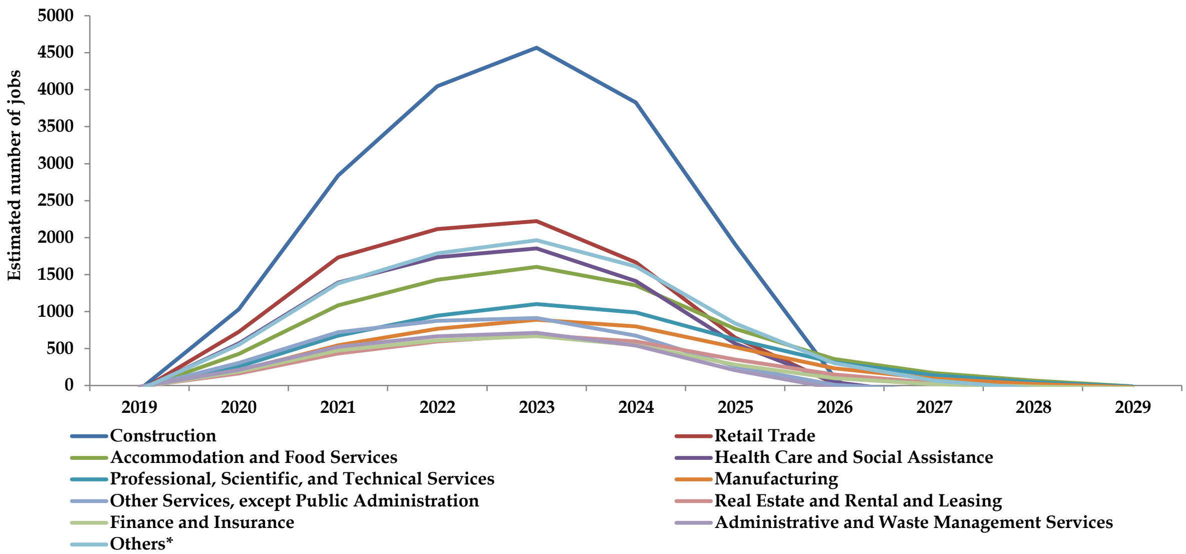
Figure 51. Estimated increase in states' annual GDP during the first 11 years of commercial operations



GDP-Current $ millions	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Average
Connecticut	($34)	$108	$337	$479	$566	$498	$278	$103	$13	($31)	($58)	$205
Maine	$6	$51	$114	$155	$179	$161	$104	$55	$28	$13	$4	$79
Massachusetts	($51)	$324	$914	$1,292	$1,534	$1,374	$835	$384	$157	$38	($36)	$615
New Hampshire	$31	$113	$225	$297	$341	$311	$208	$120	$69	$43	$25	$162
Rhode Island	($8)	$35	$103	$146	$172	$150	$85	$34	$9	($4)	($12)	$65
Vermont	$2	$17	$42	$59	$69	$63	$40	$21	$11	$6	$2	$30
Total	($54)	$648	$1,734	$2,426	$2,860	$2,557	$1,550	$717	$287	$65	($75)	$1,156

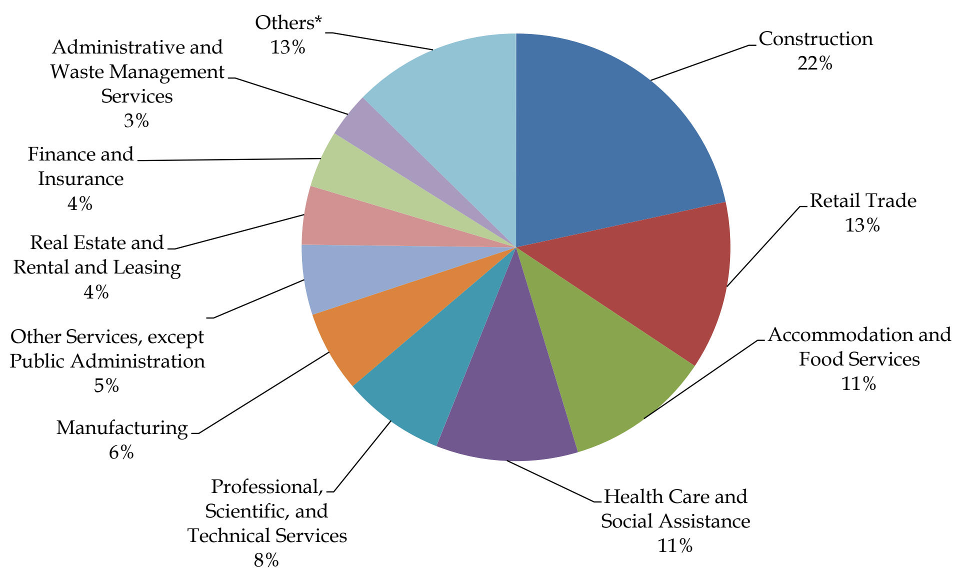
During the modeled years of commercial operations of the NPT, there will be a significant increase in the number of jobs in the construction and service sectors. The service sectors mainly include retail trade, health care and social assistance, professional, scientific and technical services, and accommodation and food services. The figures below illustrate the distribution of new jobs by sector (in terms of total jobs and percentage terms, respectively).

Figure 52. Estimated number of new total jobs in New England from NPT commercial operations (by year and sector)



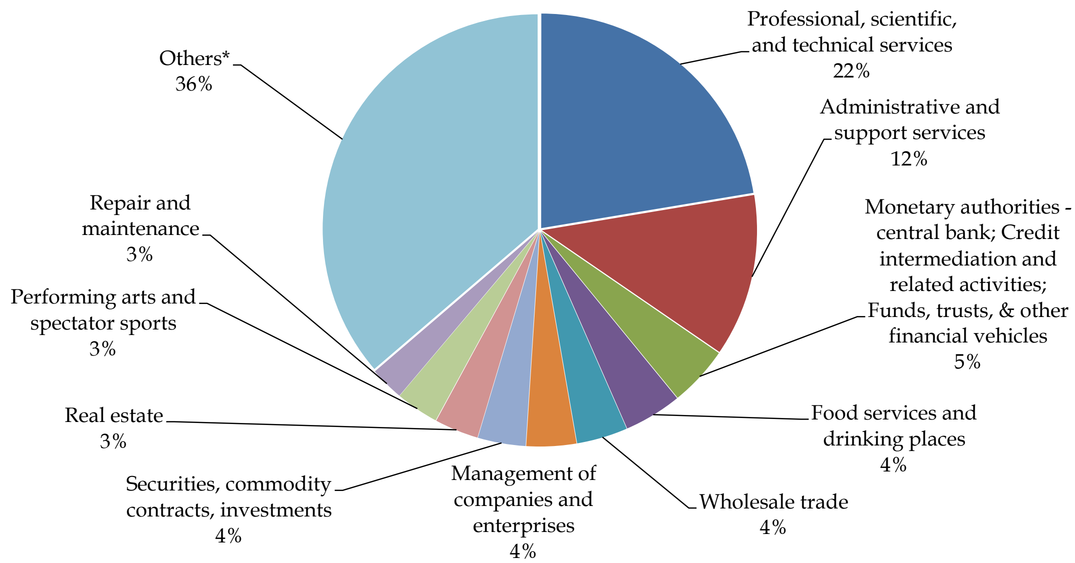
*Note: *Others include the following sectors: Wholesale Trade; Utilities; Arts, entertainment, and recreation; Transportation and warehousing; Educational services; Information services; Management of companies; Mining and Forestry.*

Figure 53. Breakdown of jobs in New England by sector arising as a result of NPT operations, average 2019-2029



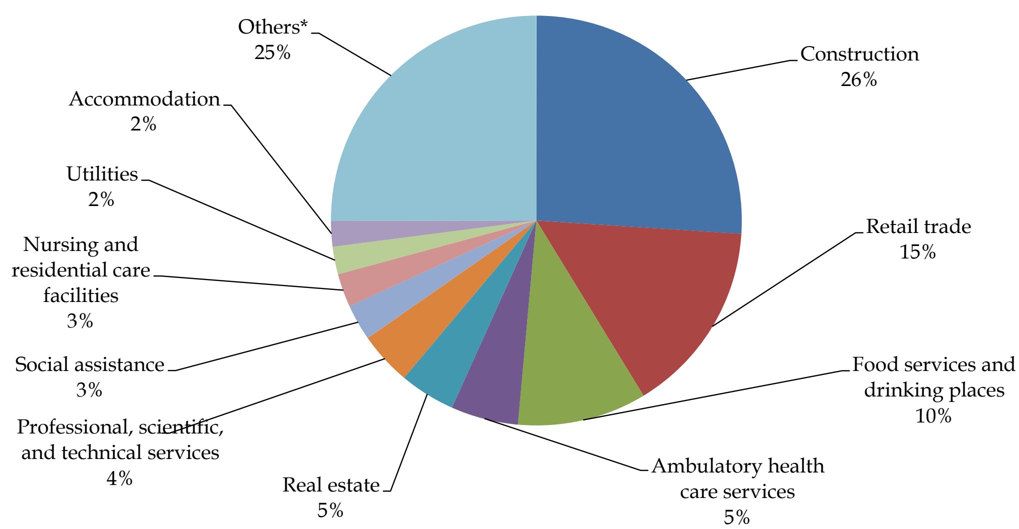
*Note: *Others include the following sectors: Wholesale Trade; Utilities; Arts, entertainment, and recreation; Transportation and warehousing; Educational services; Information services; Management of companies; Mining and Forestry.*

Figure 54. Indirect Jobs by sector during the operating phase in New England



**Others includes approximately 57 employment categories which include but are not limited to retail trade; insurance carriers and related activities; membership associations and organizations; fabricated metal product manufacturing; ambulatory health care services; warehousing and storage; accommodation; personal and laundry services; computer and electronic product manufacturing; truck transportation; wood product manufacturing and nonmetallic mineral product manufacturing.*

Figure 55. Induced jobs by sector during the operating phase in New England



Others includes approximately 57 employment categories which include but are not limited to wholesale trade; hospitals; personal and laundry services; securities, commodity contracts, investments; educational services; membership associations and organizations; administrative and support services; private households; amusement, gambling, and recreation; computer and electronic product manufacturing; and performing arts and spectator sports.*

Within New Hampshire, during the operating phase, there are estimated to be 137 indirect jobs on average created per year and 1,010 induced jobs on average created per year. NPT creates jobs indirectly via its O&M spending which feeds into other intermediary industries. As such, O&M spending on NPT creates indirect jobs in professional technical and scientific services, as well as administrative jobs, food service jobs, financial jobs and many others.

By contrast, induced jobs are created as a result of increased consumer spending which is driven by retail electricity cost savings and economic development funding. Therefore, induced jobs are created across the many sectors in which consumers spend their money and in the industries impacted by the government sector (such as construction, retail trade, food services, etc.).

8 Appendix A: LEI Qualifications

8.1 Introduction to the firm

LEI is a global economic, financial, and strategic advisory professional services firm specializing in energy, water, and infrastructure. The firm combines detailed understanding of specific network and commodity industries, such as electricity generation and distribution, with sophisticated analysis and a suite of proprietary quantitative models to produce reliable and comprehensible results.

The firm also has in-depth expertise in many economic and financial issues related to the electricity, gas, and water sectors, such as asset valuation, procurement, regulatory economics, and market design and analysis. LEI has worked extensively in North America, Europe, Asia, Latin America, Africa, and the Middle East, and has a comprehensive understanding of the issues faced by the utilities and regulators alike.

Specifically, LEI has worked on projects with many stakeholders and market participants in the New England energy market since late 1990s. LEI is extremely knowledgeable about New England market. LEI worked with NEPOOL to prepare testimony on behalf of NEPOOL for filing at FERC (the subject matter related to the proposed performance incentive changes to the capacity market design). LEI recently perform a simulation analysis to estimate the market impacts resulting from a new transmission interconnection and project the impact on Maine customers (including Northern Maine customers). On behalf of Public Service of New Hampshire, the LEI team testified on issue of eminent domain generally and more specifically, on the power market context and near term outlook for the New England power market and reasons for the development of a new proposed transmission project known as Northern Pass.

8.2 Relevant experience

A sample of LEI's experience pertaining to transmission and New England can be found below. Note that this list is intended to be indicative of LEI's project experience and is not a comprehensive record of all pertinent experience.

8.2.1 New England transmission related experience

- ***Non-Transmission Alternatives Study:*** LEI was hired to conduct a Non-Transmission Alternatives ("NTA") analysis for two transmission projects, which are a component of larger transmission solution being proposed for the Greater Hartford and Central Connecticut ("GHCC") area. The objective of the NTA analysis was to determine the feasibility and viability of other non-transmission resources – such as new generation and new demand-side resources – to be developed in lieu of transmission projects to relieve transmission reliability concerns.

- ***Price forecasting on a proposed transmission project in New England:*** LEI prepared a 10-year energy market price outlook for the New England wholesale power market and forecast the impact of a proposed project on New England market prices. The project proposes to build a 1,000 MW DC-based transmission line that between Québec and Vermont and import energy into Vermont. LEI modeled the long-term price forecast for Vermont and the rest of ISO-NE over the 2019-2028 period, and examined the price differentials. Two cases were modeled: a Base Case (without the HVDC project), and the Project Case (with the HVDC project). Analysis was done under the assumption that the transmission capacity on the project will accommodate low-cost hydro imports from Québec. LEI also determined the benefits of the proposed transmission project on employment, economic activity, and tax revenues in New England. LEI utilized the dynamic input-output ("I/O") economic model developed by Regional Economic Models, Inc. ("REMI") to measure the economic benefits to various New England states from the project on employment, economic activity, and tax revenues. LEI separated the economic impact caused by the construction of the project, and the impact caused by the reduction in energy prices due to the commercial operation of the project, taking into account issues such as usage of electricity in residential, commercial, and industrial sectors in the region, and also existing long-term energy contracts that would limit the impact of the project.

- ***Assessed non-transmission alternatives as replacements to transmission solutions:*** LEI was engaged by National Grid and Northeast Utilities ("the Utilities") to determine the economic viability of non-transmission alternatives ("NTAs") to replace a combination of three transmission solutions designed to address reliability and performance issues raised by North American Electric Reliability Corporation ("NERC"), Northeast Power Coordinating Council ("NPCC"), and/or ISO-NE for the Greater Boston Area for the period 2018 through 2023. In order to accomplish this objective, the project was divided into four phases. In the first Phase, LEI analyzed the costs associated with congestion caused due to the construction of the proposed transmission solutions. In addition, the first phase also included a forecast of expected wholesale energy and capacity market impacts of the transmission solutions. In the second and third phases of the project, LEI assessed the technical and operational characteristics of available NTA technologies in New England and conducted a comparative cost analysis to estimate the levelized cost per kW-month over the economic life of the NTA asset. This eliminated feasible NTAs that are materially more expensive than other comparable options at the same location. Finally, in phase 4, the project team conducted a complete benefit-cost analysis to compare the list of feasible NTAs against the transmission solution. The benefit metrics that were reported included changes in energy market costs and capacity market costs, as well as changes in fuel costs and congestion costs for the system. Additional metrics were considered as well, such as emissions reductions and the potential savings from reduced system losses. Once the benefit analysis was completed, LEI combined the estimated benefits of the AC Solution and the studied NTAs with the estimated costs in Phase III to complete a cost-benefit analysis. The net benefit (benefits less costs) were presented on a NPV basis and normalized for the size of the NTAs relative to the AC Solution.

- ***Testimony on New England's power market and new transmission project:*** On behalf of Public Service of New Hampshire, LEI staff testified in front of the New Hampshire

Senate Committee on issue of eminent domain generally and more specifically, on the power market context and near term outlook for the New England power market and reasons for the development of a new proposed transmission project known as Northern Pass.

- ***Cost-benefit analysis for a proposed transmission line in northeastern US:*** For a utility in the northeastern US, LEI prepared a cost-benefit analysis of a proposed transmission line with the potential to change existing market arrangements. In the analysis, LEI developed a base case and multiple project cases based on different configurations of the transmission project. Using its proprietary modeling tool, POOLMod, LEI simulated energy and capacity prices in each configuration over a 15-year timeframe, and compared the price differences against various cost allocation scenarios for the transmission line's construction. LEI also tested the statistical significance of the project case results against the base case results, and conducted further analysis on the economic effects of additional renewable generation projects that construction of the transmission line would make possible.

- ***Prepared presentation material on New England transmission project:*** LEI prepared presentation material on the electricity market impacts and the benefits of Northern Pass Transmission project for New Hampshire and New England consumers. In addition, LEI staff assisted the client in preparation of an op-ed piece for dissemination to New Hampshire press outlets. LEI staff also attended an internal company meeting and testified on behalf of the client. Lastly, LEI staff assisted in the preparation for and attended the live New Hampshire Public Radio program "The Exchange" to discuss the benefits of the Northern Pass Transmission over the hour-long live show.

- ***Advised on NYC/Connecticut transmission line:*** LEI advised a major transmission company on financial implications of proposed new 400kV transmission line to New York City and Connecticut. LEI analyzed the impact of new transmission, assuming it delivered 100% carbon-free energy, on electricity prices and emissions levels in New York and New England.

- ***Analyzed New England transmission project:*** LEI was retained by a Canadian power consortium to analyze a 660-MW transmission project that would directly interconnect Maine and NEMASS/Boston zones within New England ISO. LEI developed a base case and a project case. Using its proprietary modeling tool, POOLMod, LEI simulated energy and capacity prices in each configuration over a 15-year timeframe, and compared the price differences against various cost allocation scenarios for the transmission line's construction.

- ***Assessed economic benefits of transmission project for Northeast Utilities:*** LEI was commissioned by Northeast Utilities to determine the potential economic benefits of the proposed NEEWS transmission project. Using detailed hourly simulation modeling of future power market conditions, LEI studied the potential market implications of NEEWS for ten years from a notional expected date of commercial operation of 2014. LEI reached the following conclusions: New England customers could expect cumulative energy cost savings attributable to NEEWS over ten years under normal operating conditions; NEEWS would create regional energy market impacts; each phase of NEEWS would create energy market benefits over the ten-year modeling horizon; NEEWS would reduce LFRM costs each year; NEEWS would provide an insurance hedge against stressed system events; and NEEWS would offer market access to renewable resources in Northern New England/Canada.

- ***Evaluated New England congestion concerns:*** LEI assisted a New England incumbent utility in evaluating the economic benefits of two solutions aiming to relief the long-time congestion in the metropolitan area. There were two solutions considered: AC-only and AC/DC hybrid solutions. The objective of the economic analysis from the energy market perspective was to examine whether there are any production cost savings or market price ("LMP") impacts from either proposal, and to describe under what conditions (assumptions) these benefits are realize.

- ***Prepared market outlook for New England power market:*** LEI prepared a 10-year energy market price outlook for the New England wholesale power market and forecast the impact of the proposed Maine Power Express HVDC (MEx) project on New England market prices. The MEx HVDC project proposes to build a 1,000 MW DC-based transmission line that traverses New England and takes energy from Maine into Boston. LEI modeled the long-term price forecast for Maine and Boston over the 2015-2024 period, and examined the price differentials. Two cases were modeled: a Base Case (without the MEx project), and the MEx Case (with the MEx project). Analysis was done under the assumption that the transmission capacity on the MEx project will accommodate low-cost imports from Maine and hydro imports from Canada (New Brunswick and Québec). The MEx project allows these resources to access the Boston power market and earn higher energy revenues.

- ***Reviewed proposed transmission upgrades in New England:*** For the National Grid, LEI analyzed the economic impact of constructing the Greater Springfield Reliability Project ("GSRP"), a substantial transmission upgrade in ISO-NE. Using its proprietary modeling tool, POOLMod, LEI compared the forecasted energy price between a base case (where the IRP will be built) and project case (where the GSRP will not be built). Furthermore, LEI conducted sensitivity tests to demonstrate the importance of the IRP under system stress conditions, such as a high demand or outage of a significant generation unit.

- ***Long term transmission planning***: LEI advised MPUC on methodologies for transmission cost allocation by comparing and contrasting alternative planning approaches and pricing models employed within the US and one international jurisdiction, the United Kingdom. The final report provided a 'strawman' recommendation for an effective cost allocation methodology

8.2.2 Other relevant project experience in New England

- ***Due diligence and monitoring of a cogeneration gas-plant***: LEI worked with private equity investor on an M&A due diligence review of a cogeneration unit in New England. LEI provided market analysis, price forecasting services, and supported the investor in its valuation of the asset. LEI's services were also acquired to monitor the performance and profit sharing mechanism for the plant.

- ***Cost-benefit analysis of Energy Cost Reduction Contract ("ECRC") Proposals***: The Maine Energy Cost Reduction Act ("MECRA") authorizes the Commission to execute an ECRC, a contract executed to the specification of MECRA to procure firm transmission ("FT") capacity on a natural gas transmission pipeline. LEI was hired by the Maine Public Utilities Commission to perform an independent cost benefit analysis of each ECRC proposal, to inform the Commission's determination as to whether sufficient benefits will result to Maine consumers of natural gas and electricity to warrant entering an ECRC. This involved gas modeling using GPCM and power market modeling of ISO-NE to determine the proposals' net benefits.

- ***Reviewed performance incentives in New England:*** LEI was retained by the New England Power Pool ("NEPOOL") to provide expert insight in the Federal Energy Regulatory Commission ("FERC") proceeding related to Performance Incentives in ISO New England's Forward Capacity Market. LEI submitted a written affidavit to FERC discussing the relative benefits of keeping the capacity product primarily as a standalone planning tool rather than moving the capacity market design closer to that of a real-time energy market.

- ***Due diligent support for the New England hydro-electric generation asset:*** LEI was hired by a private equity company to provide support on the acquisition of a portfolio of hydropower plants in New England. More specifically LEI developed forecast of energy and capacity prices in the New England market over a 20 year horizon. In addition, LEI provided an overview of the Long term Reserve Market in New England, as well as our view on the market outlook.

- ***Renewable Portfolio Study for New England market***: Pursuant to An Act To Reduce Energy Prices for Maine Consumers, P.L 2011, ch.413, sec. 6 (Act) , the Maine Public Utilities Commission ("MPUC" or the "Commission") was directed by the Legislature to study Maine's renewable portfolio requirement established in 35-A M.R.S.A. § 3210 (3-A). LEI was engaged by MPUC to conduct an in-depth analysis of the renewable portfolio standards ("RPS") required by the Act which would support the Commission's study and report to the Legislature. LEI team prepared the report, which was submitted to the Commission in January 2012 and later testified at the state legislature on the key findings of that report.

- ***Assessed investment needs for State of Connecticut for a capacity procurement solicitation***: For the Connecticut Department of Public Utility Control ("DPUC"), designed a procurement process to encourage the development of new and incremental capacity in the state of Connecticut geared at reducing the impact of Federally Mandated Congestion Charges on customers in line with the Connecticut Energy Independent Act and within the framework of legislative limits on utility behavior. Eva has developed an assessment of the economic new capacity entry that is needed in the state through modeling New England's Forward Capacity market, Locational Forward Reserves market, and spot energy market for the Connecticut Department of Utility Control. This analysis was used to guide the capacity procurement solicitation as directed by the Connecticut Legislature to reduce Federally Mandated Congestion Charges.

- ***Section 203 support***: LEI supported the client in preparation of a merger application to the Federal Energy Regulatory Commission ("FERC") under Section 203 of the Federal Power Act, in conjunction with the client's acquisition of a Maine-based hydroelectric generation portfolio. LEI performed a full Delivered Price test analysis for the ISO New England control area. LEI's analysis was filed with FERC and the Merger Application was approved in February 2013.

- ***Section 203 support:*** LEI assessed the wholesale power market impacts of the merger of NRG, Inc. and GenOn. LEI staff performed Delivered Price Tests analysis for the Federal Energy Regulatory Commission ("FERC") under Section 203 of the Federal Power Act and submitted extensive analysis to FERC in the summer of 2012. The Merger Application was successfully approved by FERC in December 2012. Subsequently, LEI assisted the client in preparation of the 205 market-based rate authority analysis.

- ***PURA related support:*** LEI provided written testimony and oral testimony at the Connecticut Public Utility Regulatory Authority ("PURA") related to the market power consequences of proposed merger of NU-NSTAR.

8.2.3 Transmission related experience in other jurisdictions

- ***Analyzed proposed transmission project in New York:*** LEI was retained by an electricity transmission technology developer to perform an analysis of the macroeconomic impacts of the proposed Champlain Hudson Power Express ("CHPE") project in New York State. The proposed CHPE project would involve substantial investment and spending in-state during the course of construction of the transmission line and converter station. Once operational, the CHPE would also create macroeconomic benefits through direct employment, local spending for operations and maintenance, and also as a result of the electricity cost reductions for customers in the state. LEI utilized the dynamic input-output ("I/O") economic model developed by Regional Economic Models, Inc. ("REMI") to measure the economic benefits to New York from the project, specifically analyzing the impact on employment and GDP.

- ***Testifying potential economic benefits of a transmission investment:*** LEI team testified in front of the New Mexico Finance Authority Oversight Committee regarding the potential economic benefits of new investment in transmission in the state of New Mexico; LEI considered the impacts of local spending during construction of the proposed HVDC project on the state economy, using BEA RIMS multipliers to estimate the boost to economic activity. LEI also employed the DOE's JEDI model to estimate the potential for new jobs and GDP growth as a result of new renewables development in state (wind and solar) as a result of the transmission access that would be provided by the HVDC project.

- ***White paper on market resources alternatives:*** LEI was engaged by WIRES to prepare a White Paper on Market Resource Alternatives ("MRAs") which provides external parties with a clear understanding of MRAs and a concise description of how MRAs can work effectively alongside transmission investment in US power markets to support market development, reliability, and cost-effective supply. LEI considered in its review both supply-side and demand-side resources, including demand response, energy efficiency, energy storage devices, conventional generation and distributed generation (mainly solar PV).

- ***Congestion Study:*** LEI assessed the need for new transmission in New York, outlining key issues from relevant materials; a market study of the congestion costs based on LEI's current base case outlook for the New York wholesale electricity market; and the public presentation of findings.

- ***New York Transmission Study:*** For a private transmission developer, LEI analyzed the impact of a new transmission project between upstate and downstate New York. LEI used its proprietary energy and capacity models to assess the impact of the proposed transmission line on New York energy and capacity markets over a 20-year horizon. LEI further prepared a forecast of revenues for potential shippers from the results of the simulations.

- ***Investment assessment in California***: LEI was retained by a large US utility to provide a paper on California ISO's transmission economic planning process ("TEPP") and transmission economic assessment methodology ("TEAM"). Len was part of the team that reviewed the CAISO's regulations related to transmission planning and economic studies to evaluate transmission projects, and co-wrote the paper describing CAISO's TEPP and TEAM with illustrative and quantitative examples. LEI later analyzed the viability of potential investment of a client in a proposed electricity transmission line in California connecting the South California Edison and San Diego Gas & Electric utility service areas in light of the state's electric transmission approval process, the relative feasibility of the project compared to proposed alternatives, and the increased need for electricity reliability in the LA Basin and San Diego region in the aftermath of the shutdown of the San Onofre Nuclear Generating Station.

- ***Transmission rate case assessment***: In the context of a transmission rate case at the Regie (Québec) and consideration of alternative transmission rate designs, LEI investigated the impact on trade from increased transmission costs, involving multi-factor regression analysis of nodal electricity prices, price spreads across markets, and interchange flows (imports and exports) across borders. LEI team also considered the impact of the elasticity of demand for transmission services between Canadian provinces and US markets in the Northeast for maximizing revenues in rate setting. LEI team provided testimony at the Regie.

- ***Transmission investment in PJM/ MISO market area***: LEI conducted an independent rigorous modeling exercise to determine the potential revenues for the proposed transmission project wheeling power from western MISO to East MISO (and eventually PJM). LEI evaluated both the revenue opportunities to the investors (e.g., private benefits of the line based on market price differences and the market value of the transmission) as well as social benefits to the MISO system (i.e., wholesale price reductions and capacity market price differences); and evaluated the incremental value of the business strategy of selling the energy (and capacity) out of East MISO to third parties who will serve customers ultimately in PJM. LEI's modeling exercise entailed evaluating intrinsic revenues (originating from power markets), extrinsic revenue (originating from price volatility), along with the green value of the Project (originating from the purchase of low cost renewable energy). LEI's overall analysis was comprehensive and included a series of sensitivity scenarios testing key value drivers.

- ***Developing a framework for analyzing social benefits of transmission investment***: LEI was retained by the California ISO to create a comprehensive framework for analyzing the full social benefits of transmission investment for the ISO's market. Issues addressed included the impact on wholesale power prices, implications for market power, environmental issues, congestion management, and siting. Real options valuation techniques, as well as strategic bidding modeling, will also be employed.

- ***Midwest Transmission Alternative Study:*** LEI was hired by to independently determine the potential revenues for the proposed transmission project wheeling power from western MISO to East MISO (and eventually PJM). LEI evaluated both the revenue opportunities to the investors (e.g., private benefits of the line based on market price differences and the market value of the transmission) as well as social benefits to the MISO system (i.e., wholesale price reductions and capacity market price differences); and evaluated the incremental value of the business strategy of selling the energy (and capacity) out of East MISO to third parties who will serve customers ultimately in PJM.

- ***Macroeconomic analysis of a transmission investment in WECC***: LEI performed a macroeconomic analysis to estimate the local economic benefits accruing to taxpayers, residents, and businesses along the 800+mile route during construction of the Zephyr HVDC project, which runs from Wyoming to Colorado, Utah, and Nevada. LEI performed the analysis using the REMI P1+ model.

- ***Economic assessment of Lake Erie HVDC transmission project***: LEI assessed the economics of the proposed Lake Erie HVDC transmission project and determining the additional revenue streams or value adders of the Lake Erie HVDC transmission project ("LEP") from the perspective of third-party shippers. The LEP is a 100-km long 1,000 MW bi-directional HVDC transmission line that will connect the Ontario energy market with the PJM market. LEI prepared a comprehensive report that includes a review of the

Ontario and PJM markets, a 20-year (2017 to 2036) market outlook and prices for electricity, capacity and renewable energy credits in Ontario and the relevant zone/s in PJM; the total gross arbitrage value for the energy congestion rents, the capacity revenue potentials for PJM, and the renewable energy credits revenue potential in PJM.

9 Appendix B: Introduction to POOLMod and FCA Simulator

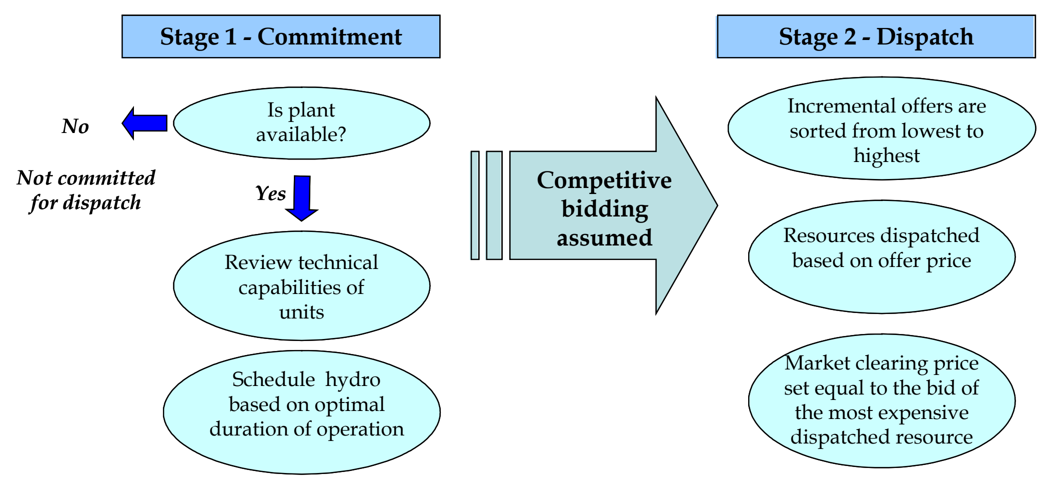
To evaluate the wholesale power market impact of NPT, we employed our proprietary simulation model, POOLMod, as the foundation for the 8,760 hourly electricity price forecast for 11 year horizon, covering 2019 to 2029. The FCA Simulator, also developed by LEI, was used to forecast capacity market impacts. In addition, in order to be able to replicate economically rational entry and retirement decisions, we simulated the energy and capacity markets on an integrated basis. In this section, we described these two modeling tools in more detail.

9.1 Overview of the wholesale energy market forecasting model – POOLMod

For the wholesale energy prices outlook, we employed our proprietary simulation model, POOLMod, as the foundation for our electricity price forecast. POOLMod simulates the dispatch of generating resources in the market subject to least cost dispatch principles to meet projected hourly load and technical assumptions on generation operating capacity and availability of transmission.

POOLMod consists of a number of key algorithms, such as maintenance scheduling, assignment of stochastic forced outages, hydro shadow pricing, commitment, and dispatch. The initial stage of analysis requires the development of an availability schedule for system resources. First, POOLMod determines a 'near optimal' maintenance schedule on an annual basis, accounting for the need to preserve regional reserve margins across the year and a reasonable baseload, mid-merit, and peaking capacity mix. Then, POOLMod allocates forced (unplanned) outages randomly across the year based on the forced outage rate specified for each resource.

Figure 19. POOLMod's two-stage process



POOLMod next commits and dispatches plants on a daily basis. Commitment is based on the schedule of available plants net of maintenance, and takes into consideration the technical requirements of the units (such as start/stop capabilities, start costs (if any), and minimum on and off times). During the commitment procedure, hydro resources are scheduled according to the optimal duration of operation in the scheduled day. They are then given a shadow price just below the commitment price of the resource that would otherwise operate at that same schedule (i.e., the resource they are displacing). Shadow-pricing allows the resulting modeled clearing prices (LMPs) to reflect the opportunity costs of hydroelectric resources that have the capacity to store water or shift their water release profile within the day and between days and seasons.

In addition, POOLMod is a transportation-based model, giving it the ability to take into account thermal limits on the transmission network. We have modeled ISO-NE control areas on a zonal basis, as described in Appendix C (Section 10.1). POOLMod also uses a heuristic, serial-limited transportation algorithm to determine LMPs subject to identified transmission limits. It is very similar to other production-cost based transportation models available commercially.[87] The other commercially available models typically approach the dispatch decisions through linear programming-based optimization. In our experience, the heuristic approach and optimization approaches produce very similar results, assuming similar sets of input data. However, POOLMod has quicker run times given its heuristic algorithms, especially as modeled markets increase in terms of complexity.

9.2 Overview of the capacity market forecasting model

The Forward Capacity Market is a long-term wholesale market designed to promote adequate and economic investment in supply and demand resources. Capacity resources may include supply from new power plants, the decreased use of electricity through demand resources, and import capacity. In the FCM, generators receive compensation for their generating capacity. Load-serving entities, the market participants with load obligations, are responsible for paying for the capacity.

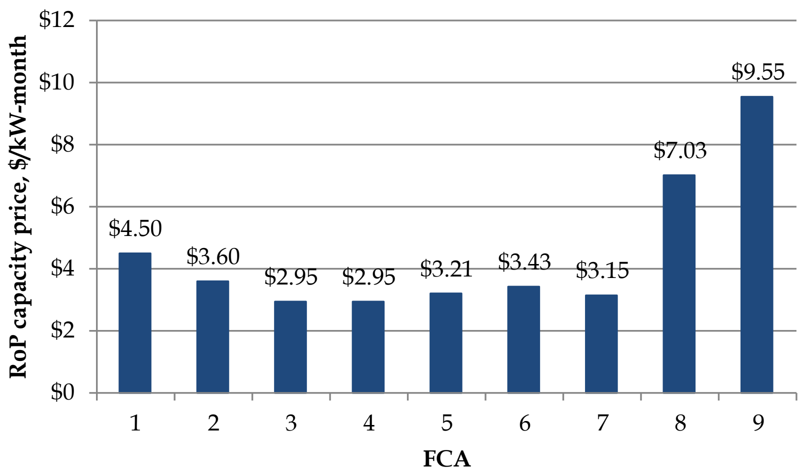
New England's capacity market has gone through a long way of development and redesign. In 2002, the FERC charged the ISO-NE with revising the Installed Capacity ("ICAP") Market to better address resource adequacy and local reliability issues in New England. This directive culminated in a Settlement Agreement that was negotiated before a FERC settlement judge and was approved by numerous stakeholders, including state officials, utility companies, generating companies, consumer representatives, regulators, and other market participants. On June 16, 2006, FERC approved the agreement, which provided a framework for drafting the Forward Capacity Market rules. FERC approved the FCM rules on April 16, 2007. The period between the December 2006 (when the FCM Settlement Agreement terminated the Installed Capacity Market) and June 1, 2010 (when the winners of the first FCA must deliver capacity) is referred to as the FCM transition period, and prices were asset based on an administrative schedule

[87] In addition to transportation algorithm models, there is another class of system models, referred to as AC-based or DC-based or load flow models. Such models stem from engineering tools used to model detailed transmission elements of the system. It takes substantial time to run these models given that most power systems are composed of thousands of transmission elements; thus, these models are typically less suited for long term economic analysis and extensive sensitivity testing. Load flow models are typically run for a sample set of intervals (i.e., typical day or peak hour of the year) rather than chronologically for every hour of each day in a multi-year timeframe.

rather than auction process. Specifically, the FCM Settlement Agreement prescribed a schedule of fixed payments to resource owners during this time to compensate them for maintaining their availability and developing new capacity.

The first auction took place on February 2008. Prices have tended to be around the price floor, which was extended on one occasion beyond the original dates in the FCM Settlement Agreement. However, once the price floor expired, other administrative pricing rules kicked in due to insufficiency of supply. The uncertainty in the pricing rules led to retirements and lack of investment, which then prompted a capacity shortage and the administrative pricing rules were triggered in FCA#8, as seen in the figure below.

Figure 57. Historical FCA auction result



ISO-NE and other stakeholders believed that the FCM, as implemented in 2010, was unable to provide correct price signals to attract new capacity.

In the prior Forward Capacity Auctions, ISO-NE has always procured a fixed quantity of capacity regardless of the auction clearing price, referring as vertical demand curve market design. On April 1st, 2014, the ISO-NE, joined by the NEPOOL Participants Committee, filed tariff changes to incorporate a system wide downward sloping demand curve and associated parameters for use in New England's FCM, which was ultimately approved by FERC. [88] It was first used in FCA#9, February 2015.[89] By introducing a downward-sloping demand curve into New England's FCA, price volatility is expected to be reduced (and capacity prices have risen

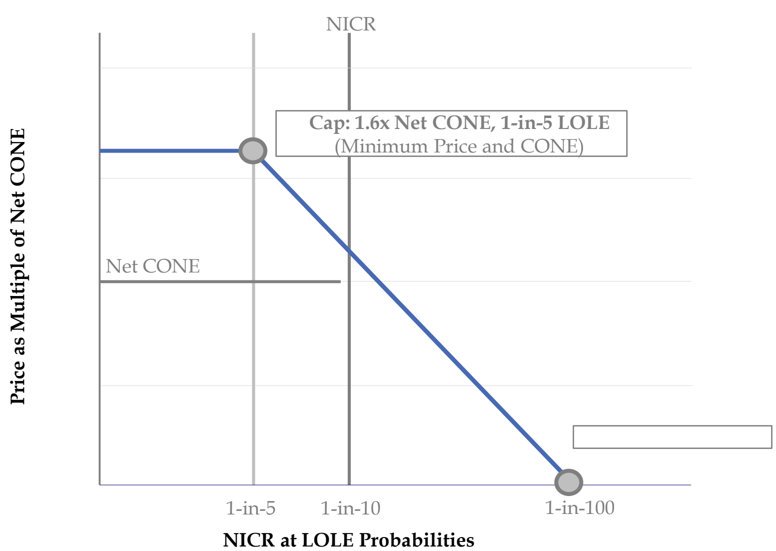
[88] Note that Performance Incentive ("PI") was also proposed and is likely to be implemented in the near future. However, LEI chose not to model it explicitly as it won't significantly affect the estimation of the NPT benefits. See more discussion on Footnote 33.

[89] ISO-NE was not able to develop and implement sloped demand curves at the zonal level for FCA#9 (or for FCA#10). However, the ISO intends to pursue working with stakeholders to develop the necessary rules and implement sloped demand curves at the zonal level for future FCAs.

above levels historically observed under the vertical demand curve in the FCM). The capacity market outcomes are also easier to predict for suppliers given the demand curve as it provides a schedule of expected prices for every level of total supply in the market.

There are several key parameters in a demand curve design: regional wide Installed Capacity Requirement ("ICR"), and the local sourcing requirements ("LSRs") and maximum capacity limits ("MCLs") for capacity zone. The ICR is determined using specific prescribed methods and is filed with FERC before each auction. Other key FCM auction inputs that provide information on locational capacity needs are local sourcing requirements ("LSRs") and maximum capacity limits ("MCLs"). These limits and requirements are based on network models using assumptions on existing generation and transmission. Some new transmission, so long as it is certified to be in service no later than the first day of the relevant capacity commitment period, is also included in ISO-NE's determination. In the November 4th, 2014 Information Filing, ISO-NE states that *"…ISO will model four Capacity Zones in the ninth FCA: Southeastern Massachusetts/Rhode Island ("SEMA/RI"), Connecticut, Northeastern Massachusetts/Boston ("NEMA/Boston") and Rest of Pool. The Rest of Pool Capacity Zone includes Maine, Western/Central Massachusetts ("WCMA"), New Hampshire and Vermont*."[90] [91]

Figure 58. Design of ISO-NE's capacity market demand curve



Source: ISO New England Inc. and New England Power Pool, Docket No. ER14-1639-000, Demand Curve Changes

[90] ISO-NE, *Information Filing for Qualification in the Forward Capacity Market Comment due date of November 19, 2014 pursuant to the tariff*, November 4th, 2014.

[91] Import-constrained areas that have insufficient local capacity are assigned an LSR, and export-constrained areas that have a surplus of capacity are assigned an MCL. Areas with either an LSR or MCL are designated as capacity zones. Defining capacity zones helps ensure that the capacity resources procured to satisfy the ICR can effectively contribute to total system reliability.

The demand curve is illustrated in the chart above. This curve aims to achieve 1 (day)-in-10 (years) loss of load expectation ("LOLE") on average, which is aligned with the amount of supply needed to achieve that standard (on the X axis) and the net costs of new generation (i.e., the Net CONE) (on the Y axis). The curve has a price cap at a price of 1.6x Net CONE, that is reached when supply at the cap provides a 1-in-5 LOLE and a foot, i.e., X-axis intercept, when it reaches the quantity that provides a 1-in-87 LOLE.

The other key parameter in the downward sloping demand curve is Cost of New Entry ("CONE"). The capacity market demand curve is designed to procure sufficient capacity to maintain resource adequacy. Premised on the assumption that new entrants will set prices at the level necessary to full remunerate their investment, the Net CONE is based on the all-in costs of new investment in a long-term equilibrium state, net of expected energy and ancillary services profits. The reference technology used to develop the CONE for FCA #10 is a 2x1 combined cycle gas turbine ("CCGT"). The high penetration of CCGT technology in the region also provides ISO-NE an opportunity to prepare a better estimation of the capital costs and revenues (from energy, reserve and other ancillary markets). Lastly, there is a lower risk that basing Net CONE on the CCGT technology will result in capacity market under-procurement or will over-compensate generation.

To calculate CONE and Net CONE values, the estimated total costs must be converted into a value that represents the capital and fixed cost recovery needed in the first year, given a reasonable long-term view of future net revenues, cost of capital and economic life (illustrated in the formula below). The cost of entry values that LEI relied upon are based on published parameters by ISO-NE for FCA#10, namely a gross CONE value of $14.29/kW-month and $10.81/kW-month for Net CONE.

Net CONE = Gross CONE – Energy and A/S Revenues

Net CONE is calculated as gross CONE less expected Energy & Ancillary Service ("E&AS") revenues. Over the modeling timeframe, gross CONE is inflated at the wholesale price index forecast for fuel and power from EIA's AEO 2015, which approximates the index that ISO-NE relies upon in the Market Rules. LEI's analysis suggests that this provides a fairly consistent growth rate with the Bureau of Labor Statistics data that is used by ISO-NE. The E&AS revenues are also inflated in LEI's modeling based on the modeled energy prices from POOLMod under each case and gas-price scenario, as an approximation of the updates that ISO-NE performs using published forward on-peak prices.

Note that not less than once every three years, CONE and Net CONE will be recalculated by ISO-NE using updated data used in their ORTP calculations. In anticipation of this re-set, we conservatively assume a 2% technology efficiency gain over time to CONE every 3 years, to represent improvements in manufacturing and technological advances in turbine design and efficiency.[92]

[92] LEI reviewed the thermal efficiency data from EIA's AEO. It is consistent with LEI's assumption of 2% gain in efficiency every four years

9.3 Integration of energy and capacity market models

In order to be able to replicate economically rational entry and retirement decisions, we simulated the wholesale energy and capacity markets on an integrated basis. This allowed us to then track the profits that existing and new entry capacity were projected to earn across these markets. Our modeling for the New England power market represents the linkages between energy and capacity market designs and the institution's specific capacity market structure. For example, we simulated the FCA by having inputs into and outputs from POOLMod linked with a suite of Excel-based models created specifically to project market clearing prices in the FCM. In addition, the results of the energy forecast from POOLMod impact the Net CONE values in the FCA Simulator, as discussed above.

The steps below highlight the process and sequencing we use in the modeling and the inter-relationships between the energy and capacity models, and the entry and retirement decisions of resources. (i) The modeling process starts with the capacity model. We first use the existing qualified capacity and determine the surplus or shortfall in supply vis-à-vis the downward sloping demand curve; (ii) next, we add the generic new entry and tests whether it is economic (which would be the case if the capacity clearing price is equal to or slightly above Net CONE. This is consistent with a new CCGT's decision making for testing its return on investment prospects; (iii) then, we add the revised entry into POOLMod and produce an energy price forecast; (iv) we check whether the new entry is economic based on its energy profits and the capacity clearing prices and we fine tune the Net CONE based on the modeled on-peak energy price trends (and if necessary, we refine the new entry amount and repeat the cycle of steps).

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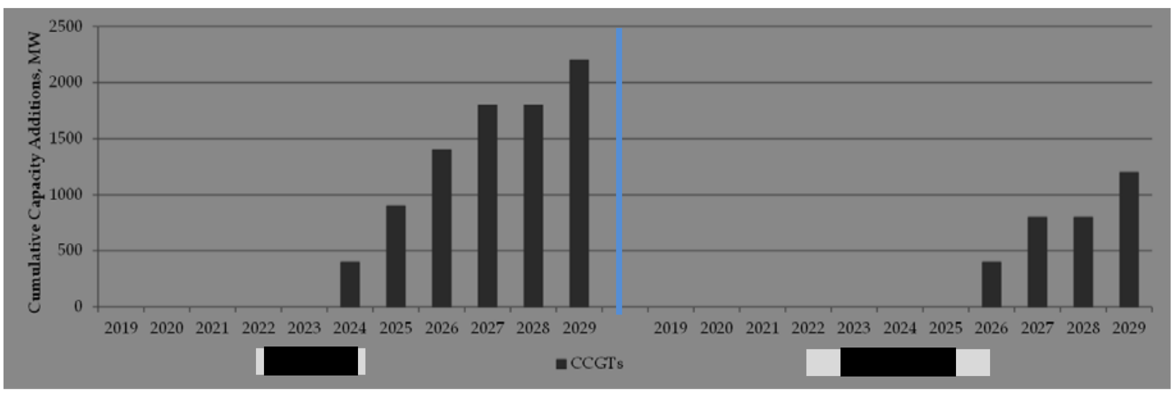

Generic New Entry Summary	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total
MW Added												
Base Case												
CCGT						400	500	500	400		400	2200
NPT @ 1,000 MW Capacity												
CCGT								400	400		400	1200

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11 Appendix D: Calculation for retail cost impact

As stated in Section 5.9, LEI converted the wholesale energy and wholesale capacity market benefits into a retail electricity cost savings figure in order to properly evaluate the impact of NPT on New England's retail consumers. The conversion process required derivation of hedge rates, which show the percentage of load (and peak demand) that may be exposed to the wholesale market price changes. This percentage is based on published data on long term contracts and utility-owned generation – which otherwise insulate or "hedge" retail customers from wholesale market price changes.

Figure 69. Estimated percentage of total annual consumption under long-term contract or self-supply (energy)

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	average
Vermont	49%	51%	50%	50%	49%	49%	49%	49%	49%	48%	48%	49%
Connecticut	16%	16%	16%	16%	16%	16%	16%	16%	1%	1%	0%	12%
New Hampshire	5%	5%	5%	5%	4%	3%	3%	3%	3%	3%	3%	4%
Maine	4%	4%	4%	4%	4%	4%	4%	4%	4%	3%	3%	4%
Rhode Island	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%
Massachusetts	4%	4%	4%	4%	4%	4%	4%	4%	3%	3%	3%	4%
New England	**9%**	**9%**	**9%**	**9%**	**9%**	**9%**	**9%**	**9%**	**5%**	**5%**	**4%**	**8%**

Note: Above numbers were estimated by LEI based on research of long-term energy contracts and modeled energy generated by utility-owned generation. This data on energy self-supplied or contracted is compared with total annual consumption figures from CELT 2015. Data on energy under long-term contract is based on reports filed with state public utility commissions and FERC or other public records.

Source: FERC, Vermont Department of Public Service, Massachusetts Department of Energy Resources, Maine Public Utilities Council, and Connecticut Department of Energy & Environmental Protection

Figure 69 presents the estimated energy that is under long term contract or self-supply (regulated generation) in each state in New England. Vermont, with its vertically integrated utility regime, has the largest share of total load that is shielded from wholesale energy market impacts (49% on average over the forecast timeframe). Connecticut has the next biggest share of total load that is not exposed to wholesale energy market price impacts (12% on average over the forecast timeframe), as a result of long term contracts.

Figure 70. Estimated percentage of peak load under long-term contract or self-supply (capacity)

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	average
Vermont		62%	55%	50%	48%	48%	48%	47%	47%	46%	46%	50%
Connecticut		15%	14%	14%	14%	13%	13%	13%	5%	5%	5%	11%
New Hampshire		3%	3%	3%	3%	2%	2%	2%	2%	2%	2%	2%
Maine		1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
Rhode Island		1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
Massachusetts		2%	2%	2%	1%	1%	1%	1%	1%	1%	1%	1%
New England		**7%**	**7%**	**7%**	**6%**	**6%**	**6%**	**6%**	**4%**	**4%**	**4%**	**6%**

Note: Above numbers were estimated by LEI based on research of long-term contracts and capacity ratings of utility-owned generation. Peak load data is compared with capacity under long-term contracts, based on reports filed with state public utility commissions and FERC or other public records, and utility-owned capacity (based on CELT 2015 capacity ratings or FCA#9 capacity ratings).

Source: FERC, Vermont Department of Public Service, Massachusetts Department of Energy Resources, Maine Public Utilities Council, and Connecticut Department of Energy & Environmental Protection

Figure 70 presents the estimated share of each state's peak demand that is under long term contract or self-supply (regulated generation) for capacity. Similarly, Vermont has the largest share of peak load that is shielded from wholesale capacity market prices (about 50% of peak load on average is hedged from 2020 to 2029, according to LEI's research). The next state with the largest amount of capacity hedges is Connecticut where on average 11% of its peak load hedged.

Changes in retail cost savings state by state need to also be allocated to the three customer classes (residential, commercial and industrial) before they are inputted into REMI PI+. Retail cost savings by customer class are based on retail volumes reported for 2014 to the EIA; the shares are documented in Figure 71.

Since retail electricity cost savings are driven by lower wholesale energy and capacity prices, jurisdictions like Massachusetts and Connecticut with the greatest load and the highest exposure to wholesale market outcome will benefit the most (in million dollar terms) from wholesale energy and capacity price reductions. By contrast, Vermont has the smallest retail cost savings. Although some portion of retail load is not going to benefit from wholesale market impacts in New Hampshire, the retail cost savings are still substantial – at $79.9 million per year on average over the forecast timeframe of 2019 - 2029.

Figure 71. Estimated breakdown of retail electricity sales by customer type

State	Residential	Commercial	Industrial
Connecticut	44%	44%	12%
Maine	38%	48%	14%
Massachusetts	39%	33%	28%
New Hampshire	41%	41%	18%
Rhode Island	41%	48%	12%
Vermont	38%	37%	25%

Source: US Energy Information Administration ("EIA")

Figure 30. New England retail electricity costs savings by state and customer class (nominal $ millions)

New England	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Average
Connecticut	**$ (33.9)**	**$ 108.5**	**$ 293.1**	**$ 359.5**	**$ 379.5**	**$ 274.3**	**$ 65.4**	**$ (48.5)**	**$ (70.0)**	**$ (65.6)**	**$ (63.4)**	**$ 109.0**
Residential	$ (15.0)	$ 48.1	$ 130.0	$ 159.4	$ 168.3	$ 121.6	$ 29.0	$ (21.5)	$ (31.0)	$ (29.1)	$ (28.1)	$ 48.3
Commercial	$ (14.9)	$ 47.8	$ 129.2	$ 158.5	$ 167.3	$ 120.9	$ 28.8	$ (21.4)	$ (30.8)	$ (28.9)	$ (28.0)	$ 48.0
Industrial	$ (3.9)	$ 12.6	$ 33.9	$ 41.6	$ 43.9	$ 31.7	$ 7.6	$ (5.6)	$ (8.1)	$ (7.6)	$ (7.3)	$ 12.6
Maine	**$ 10.6**	**$ 68.1**	**$ 128.4**	**$ 149.4**	**$ 155.3**	**$ 118.2**	**$ 49.1**	**$ 11.8**	**$ 6.4**	**$ 7.6**	**$ 6.6**	**$ 64.7**
Residential	$ 4.1	$ 26.4	$ 49.9	$ 58.0	$ 60.3	$ 45.9	$ 19.1	$ 4.6	$ 2.5	$ 2.9	$ 2.6	$ 25.1
Commercial	$ 3.5	$ 22.6	$ 42.7	$ 49.7	$ 51.6	$ 39.3	$ 16.3	$ 3.9	$ 2.1	$ 2.5	$ 2.2	$ 21.5
Industrial	$ 3.0	$ 19.0	$ 35.9	$ 41.7	$ 43.4	$ 33.0	$ 13.7	$ 3.3	$ 1.8	$ 2.1	$ 1.8	$ 18.1
Massachusetts	**$ (45.5)**	**$ 263.7**	**$ 649.1**	**$ 790.9**	**$ 835.9**	**$ 611.2**	**$ 179.1**	**$ (55.2)**	**$ (88.4)**	**$ (78.9)**	**$ (79.3)**	**$ 271.1**
Residential	$ (17.4)	$ 100.5	$ 247.5	$ 301.5	$ 318.7	$ 233.0	$ 68.3	$ (21.0)	$ (33.7)	$ (30.1)	$ (30.2)	$ 103.4
Commercial	$ (21.9)	$ 126.9	$ 312.3	$ 380.6	$ 402.2	$ 294.1	$ 86.2	$ (26.6)	$ (42.5)	$ (38.0)	$ (38.2)	$ 130.5
Industrial	$ (6.3)	$ 36.3	$ 89.3	$ 108.8	$ 115.0	$ 84.1	$ 24.6	$ (7.6)	$ (12.2)	$ (10.9)	$ (10.9)	$ 37.3
New Hampshire	**$ 11.8**	**$ 82.1**	**$ 157.2**	**$ 184.8**	**$ 193.7**	**$ 148.8**	**$ 61.9**	**$ 14.6**	**$ 7.7**	**$ 8.9**	**$ 7.8**	**$ 79.9**
Residential	$ 4.8	$ 33.8	$ 64.8	$ 76.1	$ 79.8	$ 61.3	$ 25.5	$ 6.0	$ 3.2	$ 3.7	$ 3.2	$ 32.9
Commercial	$ 4.8	$ 33.6	$ 64.3	$ 75.6	$ 79.2	$ 60.9	$ 25.3	$ 6.0	$ 3.1	$ 3.7	$ 3.2	$ 32.7
Industrial	$ 2.1	$ 14.7	$ 28.1	$ 33.1	$ 34.7	$ 26.6	$ 11.1	$ 2.6	$ 1.4	$ 1.6	$ 1.4	$ 14.3
Rhode Island	**$ (9.5)**	**$ 35.7**	**$ 93.0**	**$ 114.0**	**$ 120.2**	**$ 87.2**	**$ 23.8**	**$ (10.7)**	**$ (15.2)**	**$ (13.8)**	**$ (13.8)**	**$ 37.4**
Residential	$ (3.8)	$ 14.5	$ 37.7	$ 46.2	$ 48.7	$ 35.3	$ 9.6	$ (4.3)	$ (6.2)	$ (5.6)	$ (5.6)	$ 15.1
Commercial	$ (4.5)	$ 17.1	$ 44.5	$ 54.5	$ 57.5	$ 41.7	$ 11.4	$ (5.1)	$ (7.3)	$ (6.6)	$ (6.6)	$ 17.9
Industrial	$ (1.1)	$ 4.1	$ 10.8	$ 13.2	$ 14.0	$ 10.1	$ 2.8	$ (1.2)	$ (1.8)	$ (1.6)	$ (1.6)	$ 4.3
Vermont	**$ 3.0**	**$ 13.6**	**$ 28.8**	**$ 36.7**	**$ 39.3**	**$ 30.1**	**$ 12.5**	**$ 3.0**	**$ 1.6**	**$ 1.9**	**$ 1.7**	**$ 15.6**
Residential	$ 1.1	$ 5.2	$ 11.0	$ 14.0	$ 15.0	$ 11.5	$ 4.8	$ 1.2	$ 0.6	$ 0.7	$ 0.6	$ 6.0
Commercial	$ 1.1	$ 5.0	$ 10.6	$ 13.5	$ 14.4	$ 11.0	$ 4.6	$ 1.1	$ 0.6	$ 0.7	$ 0.6	$ 5.8
Industrial	$ 0.7	$ 3.4	$ 7.2	$ 9.2	$ 9.9	$ 7.6	$ 3.1	$ 0.8	$ 0.4	$ 0.5	$ 0.4	$ 3.9

12 Appendix E: Introduction to REMI PI$^+$

LEI utilized the dynamic forecasting and policy analysis PI$^+$ model developed by REMI to measure the local economic benefits of NPT to New Hampshire and other states in New England. . The PI$^+$ model incorporates several modeling approaches, including input-output ("I/O"), computable general equilibrium theory, econometric equations, and new economic geography theory to create a comprehensive model that understands detailed interrelated changes in a regional (or state) economy.[106] PI+ generates year-by-year estimates of the total regional effects of any specific policy initiative or large investment. The REMI model used for this analysis was a 70 sector, state-level model that covers the entire New England region.[107]

REMI's PI$^+$ model is widely used in both the public and private sectors to simulate the dynamic and interactive effects over time and across industries that result from large investments, policy changes, and infrastructure projects, such as NPT. In New England, the REMI PI$^+$ model was recently used by the Committee for a Green Economy ("CGE") to measure whether or not a carbon tax in Massachusetts can improve the state economy.[108] Furthermore, REMI's model has also been used to assess the local economic benefits of a variety of projects and policy by public institutions including Vermont's Department of Public Service, Vermont Legislative Joint Fiscal Office, Rhode Island Department of Revenue, New Hampshire Employment Security Department, Maine Governor's Office of Policy and Management, and Connecticut Department of Economic and Community Development.

The key inputs that LEI used in PI$^+$ are shown in Figure 73. As an output, LEI focused on change in employment and expansion of state GDP.

106 An Input/Output ("I/O") analysis is a type of applied economic analysis that tracks the interdependence among various producing and consuming sectors of an economy, by capturing inter-industry transactions and accounting for how businesses react to additional demand for goods and services and how consumers are likely to spend their money. An I/O model measures the relationship between a given set of demand for final goods and services and the inputs required to satisfy this demand. It was first introduced by Wassily Leontief, which won him the Nobel Memorial Prize in Economic Sciences in 1973.

107 The full list of economic sectors in the REMI PI+ model is included later on in this Appendix.

108 REMI. "Modeling the economic, demographic, and climate impact of a carbon tax in Massachusetts". July 11, 2013.

Figure 73. Key inputs that LEI used in REMI

Construction Period		
Type of Spending	**Parameters Varied in PI+**	**Industries Affected**
Labor	Industry Employment	Construction; Utilities; Professional, scientific, and technical services; Real Estate; Administrative and support services
Labor	Detailed Industry Sales (*Note: this variable was used as the equivalent of Industry Employment for Forestry, fishing and related activities with Logging as a more specific sector*)	Logging
Materials	Industry Sales	Nonmetallic mineral product manufacturing

Operations Period		
Type of Spending	**Parameters Varied in PI+**	**Industries Affected**
Labor	Industry Employment	Utilities
Materials	Industry Sales	Utilities
Electricity Savings	Consumer Price (amount); Electricity (Commercial Sectors) Fuel Cost (amount); Electricity (Industral Sectors) Fuel Cost (amount); Compensation (amount)	Residential, commercial and industrial
Community Development	Local Government Spending	Government sector
O&M	Industry Sales	Utilities

Note: Industries affected such as "Fishing, hunting and trapping" are considered due to indirect secondary economic impacts.

There are three main sources that REMI relies on to create the PI+ model: Bureau of Economic Analysis ("BEA"), Bureau of Labor Statistics ("BLS") and County Business Patterns ("CBP").

The primary national, state, and county data for REMI PI+ comes from the BEA. The BEA prepares annual and quarterly estimates of state personal income and annual estimates of state disposable personal income and employment. The state personal income accounts are detailed, timely, and comprehensive economic time series that provide comparisons among states and among industries within a state. Estimates of compensation (wages and salaries plus supplements to wages) and earnings (compensation plus proprietors' income) by place of work indicate economic activity of establishments within the state. Estimates of personal income by place of residence provide a measure of fiscal capacity. State disposable personal income provides a measure of income available for consumption and saving. Annual estimates of per capita personal income are an indicator of economic well-being of the residents of a state. State personal income is the income that is received by, or on behalf of, the residents of that state.

The BEA also prepares annual estimates of personal income for local areas (counties, metropolitan areas, and the Bureau's BEA economic areas). Local area personal income is the only detailed, broadly inclusive economic time series for local areas that is available annually. For both the national and regional accounts, personal income is defined as the sum of wages and salaries, supplements to wages and salaries, proprietors' income with inventory and capital consumption adjustments, rental income of persons with capital consumption adjustments, personal dividend income, personal interest income, and personal current transfer receipts, less contributions for government social insurance. Disposable personal income is defined as personal income less personal current taxes.

The second major source of historical data used by REMI is the BLS, whose pertains to workers covered by State Unemployment Insurance ("UI") laws and Federal civilian workers covered by the Unemployment Compensation for Federal Employees ("UCFE") program. The data for both private sector and public sector workers are reported to the BLS by the employment security agencies of the 50 States, the District of Columbia, Puerto Rico, and the Virgin Islands as part of the Quarterly Census of Employment and Wages ("QCEW") program. The QCEW, also called ES-202, was formerly known as the Covered Employment and Wages ("CEW"). REMI uses their annual average employment and total annual wages at the summary level for all counties and states.

The QCEW program derives its data from quarterly tax reports submitted to State Employment Security Agencies by over eight million employers subject to State unemployment insurance laws and from Federal agencies subject to the Unemployment Compensation for Federal Employees program. This includes 99.7% of all wage and salary civilian employment. These reports provide information on the number of people employed and the wages paid to the employees each quarter. The program obtains information on the location and industrial activity of each reported establishment, and assigns location and standard industrial classification codes accordingly. This establishment level information is aggregated, by industry code, to the county level, and to higher aggregate levels (such as state).

The final source of employment and wage data relied on by REMI is the CBP, which is an annual data series that provides subnational economic data by industry and covers most of the country's economic activity. The series excludes data on self-employed individuals, employees of private households, railroad employees, agricultural production employees, and most government employees. This data is available at a very detailed level, and while it has many suppressions due to confidentiality requirements, its advantage is that when the data is suppressed, ranges for the establishments are supplied. This provides some basis from which to make a rough estimate of employees in that industry in the absence of any other information.

Lastly, the list below provides the 70 sectors used in the PI^{+} model version which LEI relied upon for its analysis:

1. Forestry and logging; Fishing, hunting, and trapping
2. Agriculture and forestry support activities
3. Oil and gas extraction
4. Mining (except oil and gas)
5. Support activities for mining

6. Utilities
7. Construction
8. Wood product manufacturing
9. Nonmetallic mineral product manufacturing
10. Primary metal manufacturing
11. Fabricated metal product manufacturing
12. Machinery manufacturing
13. Computer and electronic product manufacturing
14. Electrical equipment and appliance manufacturing
15. Motor vehicles, bodies and trailers, and parts manufacturing
16. Other transportation equipment manufacturing
17. Furniture and related product manufacturing
18. Miscellaneous manufacturing
19. Food manufacturing
20. Beverage and tobacco product manufacturing
21. Textile mills; Textile products mill
22. Apparel manufacturing; Leather and allied product manufacturing
23. Paper manufacturing
24. Printing and related support activities
25. Petroleum and coal product manufacturing
26. Chemical manufacturing
27. Plastics and rubber products manufacturing
28. Wholesale trade
29. Retail trade
30. Air transportation
31. Rail transportation
32. Water transportation
33. Truck transportation
34. Couriers and messengers
35. Transit and group passenger transportation
36. Pipeline transportation
37. Scenic and sightseeing transportation; Support activities for transportation
38. Warehousing and storage
39. Publishing industries, except Internet
40. Motion picture and sound recording industries
41. Internet publishing and broadcasting, ISPs search portals and data processing
42. Broadcasting, except Internet
43. Telecommunications

44. Monetary authorities – central bank; Credit intermediation and related activities; Funds, trusts, & other financial vehicles
45. Securities, commodity contracts, investments
46. Insurance carriers and related activities
47. Real estate
48. Rental and leasing services; Lessors of nonfinancial intangible assets
49. Processional, scientific, and technical services
50. Management of companies and enterprises
51. Administrative and support services
52. Waste management and remediation services
53. Educational services
54. Ambulatory health care services
55. Hospitals
56. Nursing and residential care facilities
57. Social assistance
58. Performing arts and spectator sports
59. Museums, historical sites, zoos, and parks
60. Amusement, gambling, and recreation
61. Accommodation
62. Food services and drinking places
63. Repair and maintenance
64. Personal and laundry services
65. Membership associations and organizations
66. Private households
67. State and local government
68. Federal civilian
69. Federal military
70. Farm (crop and animal production)