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Independent Analysis of Electricity Market and Macroeconomic Benefits of the New England Clean Energy Connect Project

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Prepared for

Maine Public Utilities Commission

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LONDON ECONOMICS

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Disclaimer

London Economics International LLC ("LEI") was retained by the Maine Public Utilities Commission to develop an independent electricity market and macroeconomic impact analysis of the New England Clean Energy Connect Project and to conduct an independent review of the benefits that were included as part of Central Maine Power's ("CMP") Request for Approval of a Certificate of Public Convenience and Necessity ("CPCN") application. LEI has made the qualifications noted below with respect to the information contained in this report and the circumstances under which the analysis 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. 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.

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1 Executive Summary

On September 27, 2017, Central Maine Power Company ("CMP") filed a Request for Approval of a Certificate of Public Convenience and Necessity ("CPCN") with the Maine Public Utilities Commission ("PUC" or "Commission") for the New England Clean Energy Connect ("NECEC" or the "project"). This project consists of the construction of a 1,200 MW high-voltage direct current ("HVDC") transmission line from the Quebec-Maine border to Lewiston, and related network upgrades. Pursuant to Maine Statute, the Commission shall take in to account the costs and benefits of the project to determine the public need for the CPCN.

As part of the process for evaluating whether a CPCN should be awarded, the Commission retained London Economics International LLC ("LEI") to prepare an independent analysis of the wholesale electricity market and macroeconomic impacts of the NECEC, and a review of the project benefits developed by CMP's consultants, including Daymark Energy Advisors ("Daymark") for the wholesale electricity market benefits and University of Southern Maine ("USM") for the macroeconomic benefits.[1] Specifically, the Commission asked LEI to analyze the impact of NECEC on the ISO New England wholesale energy and capacity market costs to Maine electric ratepayers as well as the economic benefits to the state from direct spending and economic activity, job creation, and municipal tax revenues.[2] LEI also analyzed the level of CO_2 emissions reduction, as well as the "insurance value" of the NECEC against high energy market costs for New England (including Maine) electric ratepayers as consequence of extreme summer and winter weather conditions. However, LEI's analysis did not include estimation of all possible market impacts, such as the project's impacts on ancillary services markets, Renewable Energy Credit ("REC") markets, fuel diversification benefits, gas market savings for non-power sector customers, long-term reliability and resiliency benefits, and socio-economic impacts of decarbonization. These benefits were also not quantitatively analyzed by CMP's consultants.

1.1 Overview of the NECEC Transmission Project

The NECEC transmission project is a $1 billion HVDC transmission infrastructure project that can bring up to 1,200 MW of additional transmission capacity between Hydro Québec's system and the New England Control Area ("NECA"). Energy and capacity sales on the project will be sourced from Hydro Quebec's hydroelectric fleet and will flow into NECA through the interconnection point in Maine, starting in 2023. CMP is the developer of the Maine portion of the project, which runs from Beattie Township in the northwest corner of Maine to Lewiston, Maine. The Québec portion will be constructed by Hydro Québec TransEnergie, Inc. ("HQT").

NECEC's bid (specifically, the 100% hydroelectric power-based bid) was selected by Massachusetts as the winner of the Request for Proposal ("RFP") pursuant to Section 83D of the

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[1] CMP's CPCN application includes Exhibit 5 (Peaco, Daniel E, Douglas A Smith, and Jeffrey D Bower. *NECEC Transmission Project: Benefits to Maine Ratepayers Quantitative and Qualitative Benefits*. September 27, 2017.) by Daymark Energy Advisors ("Daymark"), and Exhibit 7 (Wallace, Ryan D, and Charles S Cogan. *The Economic and Employment Contributions of the New England Clean Energy Connect in Maine*. September 2017) by The Maine Center for Business and Economic Research, University of Southern Maine ("USM").

[2] LEI did not estimate the impact on Maine consumers in Northern Maine, given that region is not part of the ISO New England market. Northern Maine is part of the New Brunswick System Operator's control area.

Green Communities Act ("83D RFP") March 2018. According to CMP, construction is set to begin in 2019 and the project life is approximately 40 years based on the RFP application form submitted by NECEC.[3]

1.2 LEI's approach

LEI began by reviewing Exhibit 5 ("Daymark Report") and Exhibit 7 ("USM Report") of the CPCN application, past data responses,[4] oral data requests[5] from other intervenors, and the transcript from Daymark's December 11, 2017 technical conference. LEI also participated in a technical session hosted by the Commission on April 5, 2018, where CMP, Daymark, and USM sponsored witnesses that answered questions from LEI, Commission staff, and other parties. In parallel to LEI's review of the CPCN application and discovery materials, LEI undertook its own simulation-based modeling analysis to determine the potential wholesale energy and capacity market cost impacts, as well as a macroeconomic impacts analysis on jobs and GDP. In addition, LEI re-estimated the municipal taxes that would be payable by the project across the affected towns in Maine.[6]

LEI developed its own estimate of the electricity market and macroeconomic impacts from NECEC using its own proprietary suite of wholesale energy and capacity models and the REMI PI+ models, respectively. To derive the wholesale electricity market and CO_2 emissions impacts, LEI began by developing a "Base Case" in which LEI projected operations of the New England market from 2023 through 2037 without the project. Importantly, the project is assumed to not be built, and no other similar HVDC transmission project is built either (so that the benefits attributable to NECEC could be isolated). Next, LEI modeled a "Project Case" in which NECEC is developed and put into service by 2023. The existence of NECEC also changes the course of other supply decisions - triggering some changes in capacity supply, such as 750 MW of permanent retirements and the deferment of 350 MW of generic new investment. The wholesale electricity market benefits of NECEC are measured as a function of the difference in wholesale energy and capacity market costs between the Base Case and the Project Case.

The Base Case is built upon conservative and reliable market-oriented expectations, which are detailed in Section 7. This includes ISO-NE's 50/50 weather-normal load forecast from its capacity, energy, loads, and transmission ("CELT") 2017 report[7] and a delivered natural gas price forecast based on forwards as well as market trends in the near term and growth trends from the

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[3] Section 83D RFP Application form, pg. 185. Provided by CMP in ICEG-001-034, Attachment 3.

[4] In addition to the data requests issued by LEI on March 9, 2018, LEI also reviewed CMP data responses EXM, CLF, IECG, OPA, and KELLY.

[5] LEI reviewed the oral data requests issued to Daymark following its December 11, 2017 technical conference. LEI also issued its own oral data requests following the April 5, 2018 technical conference.

[6] LEI adopted several key assumptions from CMP, including the commercial operation date ("COD") of 2023 the assumed pattern of energy flows ([redacted] TWh distributed evenly across all hours), the internal New England interface transfer limit upgrades, as well as the updated project costs and local spending information, which was provided in the form or data requests and oral data requests by LEI and other parties.

[7] CELT 2018 was released in early May 2018; however, LEI had already begun modeling the project and estimating the wholesale electricity market impacts. Total demand in CELT 2018 is approximately 3% lower than CELT 2017, and peak demand is approximately 1% lower.

Energy Information Agency's ("EIA") Annual Energy Outlook ("AEO") 2018.[8] In addition, LEI adopted ISO-NE's most recent estimate of the Net Cost of New Entry ("Net CONE"), which has been vetted by stakeholders through the ISO-NE Markets Committee. Furthermore, LEI also adapted its capacity market model to account for ISO-NE's Competitive Auctions for Sponsored Policy Resources ("CASPR") beginning in Forward Capacity Auction ("FCA") #13 (see Section 2 for discussion of CASPR).

The Base Case forecast began with an annual average energy price of [redacted]/MWh in 2023, escalating over time to [redacted]/MWh in 2037 (in nominal dollars). The wholesale capacity price under the Base Case started at [redacted]/kW-month for FCA #14 and converges towards Net CONE in the $11/kw-month range by 2037. While not specifically relevant to the analysis of NECEC, LEI's Base Case outlook in the short term (2018-2020) is consistent with current forward prices and congruent with historical market price trends, normalized against future supply, demand and fuel price assumptions.

LEI engages in extensive benchmarking to ensure the robustness of its forecasts. In addition to considering the congruency of the forecast with recent trends and also market forwards, LEI staff perform backcasts of the New England model using actual historical data every 12-24 months. For more details, of LEI's modeling tools see Section 6.

LEI routinely forecasts future market conditions in New England as part of its various consulting engagements in the region. New England market price outlooks are also included in the company's semi-annual multi-client studies of electricity market trends across deregulated markets in North America. The Base Case and Project Case prepared for this report are customized and extended versions of LEI's multi-client outlooks. LEI's POOLMod simulation model has been used to support millions of dollars in merger and acquisition ("M&A") deals, market design support, and contract evaluations.[9]

1.3 Summary of LEI's independent analysis of the wholesale electricity market impacts and environmental benefits of NECEC

LEI estimates that the 1,090 MW NECEC project (with energy flows of [redacted] TWh per year) would provide $346 million in wholesale electricity market benefits to Maine during the first fifteen years of operation (2023-2037) on a Net Present Value ("NPV") basis in 2023 dollars.[10] Of this, $122 million comes from wholesale energy market benefits and $223 million comes from wholesale capacity market benefits from the sale of 1,090 MW of capacity. This presumed NECEC would clear the primary auction or FCA (its unit-specific Minimum Offer Price Rule ("MOPR")

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[8] These assumptions do not assume sudden spikes in demand or natural gas prices because of heat waves and cold spells which occasionally occur in New England and could increase the value of the wholesale energy market benefits of the project.

[9] In addition to bespoke consulting engagements, LEI performs semi-annual forecasts using POOLMod for 12 wholesale power markets. These forecasts, known as LEI's Continuous Modeling Initiative ("CMI"), examine recent market developments, draw on the latest information and data available, and apply LEI's proprietary modeling tools to provide a 10-year energy, and where applicable, capacity market price outlooks.

[10] Unless otherwise stated, LEI used a 7% discount rate for all the NPV estimates in this report.

would be sufficiently low as to permit it to clear).[11] If NECEC is unable to clear the FCA and then clears the substitution auction (as a Sponsored Policy Resource), then there would be no wholesale capacity market benefits from the project. Therefore, the wholesale electricity market benefits would fall to $122 million in NPV terms for Maine load.

To put the size of these benefits into context, the annual average wholesale electricity market benefits of $346 million constitute approximately 4.4% of the total expected electricity market costs (energy and capacity) between 2023-2037. For Maine retail customers specifically, the annual average retail electricity market benefits constitute approximately 4.2% of the total expected retail market costs over the same timeframe. Figure 1 below shows a summary of the wholesale and retail electricity market and environmental benefits for Maine and for the entire New England region (all six states) under the assumption the NECEC would be able to clear the FCA and create wholesale capacity market benefits.

Figure 1. LEI's analysis of wholesale and retail electricity market benefits and regional CO_2 impacts of NECEC (assuming NECEC clears the FCA)

	Wholesale Impacts		Retail Impacts	
	Maine	New England	Maine	New England
15-yr NPV, $2023 million				
Energy market benefits	$122	$1,197	$119	$1,046
Capacity market benefits	$223	$2,962	$221	$2,734
Total electricity market benefits	$346	$4,160	$341	$3,780
15-yr annual average, $nominal million				
Energy market benefits	$14	$134	$13	$117
Capacity market benefits	$19	$255	$19	$2,734
Total electricity market benefits	$33	$388	$32	$2,851
Potential insurance value against extreme weather (five-day average)				
Summer 2013 heat wave	$6	$52	Not modeled	Not modeled
Winter 2013/14 polar vortex	$4	$72	Not modeled	Not modeled
Annual average CO_2 emissions reduction, million metric tons				
CO_2 reduction	Not modeled	3.58	Not modeled	Not modeled

Note: The energy market results are based on the average of 20 iterations (see Section 6.1) and were found to be statistically significant in all years of the modeling horizon. The retail electricity market benefits are slightly lower than wholesale electricity market benefits for New England as LEI took into account limitations on retail load's exposure to wholesale market conditions, including the generation units that self-supply or are under a long-term contract with fixed prices.

1.3.1 Extreme weather cases

In addition to ISO-NE's 50/50 weather-normal load forecast, LEI considered the impact of more extreme weather conditions on wholesale energy prices and then estimated the energy market cost savings that NECEC could create for electric ratepayers in the face of such extreme conditions. New England on occasion experiences extreme swings in weather, which can cause spikes in natural gas prices during the winter months, or high electricity demand during the

[11] LEI did not attempt to estimate the MOPR of NECEC to determine whether NECEC would clear the primary as auction. CMP did not provide sufficient cost data for LEI to perform such an estimation.

summer months, both of which can drive up wholesale energy prices. To analyze the market impact that NECEC could provide during these events, LEI estimated the impact NECEC would have had on ISO New England's wholesale energy market costs in two past weather-related events over a five-day period – the summer heatwave of July 2013 and the polar vortex of winter 2013/14. LEI's analysis found that NECEC (with [redacted] MW of energy flows per hour) could have resulted in \$6.0 million in wholesale energy market savings for Maine between the five-day period from January 24-28, 2014, and \$4.3 million in wholesale energy market savings between July 15-19, 2013. These savings represent a 12% and 21% reduction, in wholesale energy market costs during the January 24-28, 2014 and July 15-19, 2013 timeframes, respectively. These savings are a form of "insurance" that the project can provide electric ratepayers in the region and would be incremental to the annual wholesale energy market benefits identified in LEI's analysis under weather-normal conditions. These benefits are discussed in Section 2.4.

1.3.2 Environmental impacts

In terms of environmental benefits, LEI estimates that [redacted] TWh of hydroelectric-based energy flows on NECEC could reduce CO_2 emissions in New England by approximately 3.6 million metric tons per year. For this analysis, LEI did not monetize the social benefits of the CO_2 emissions reduction, nor did it analyze the emissions changes in other jurisdictions as a result of NECEC. These results are in line with Daymark's estimate of carbon emission reduction by 3.4 million metric tons.[12] The results of the CO_2 reduction are discussed in Section 2.5. Other greenhouse gas ("GHG") emissions include NO_X and SO_2 (which largely come from oil and coal generation). While LEI was not specifically asked to analyze the reductions in these pollutants, LEI expects the reductions to be small, as oil-fired electric production is minimal under normal weather conditions and coal-fired generation is expected to be phased out in LEI's Base Case forecast in the first few years.

1.4 Summary of LEI's independent analysis of the macroeconomic impacts to Maine

During the development and construction period of 2017 to 2022, the installation of the new transmission line and associated equipment is expected to generate 1,631 total new jobs per year and \$98.2 million increase in GDP in Maine, as presented in Figure 2, LEI's analysis for the development and construction period's macroeconomic impacts is based on \$567.8 million total local spending, and the year-by-year construction cost schedule was provided by CMP in response to ODR-003-011.[13]

For the first 15 years of the project's commercial operations (assumed to be 2023 to 2037), 291 new jobs will be created in Maine, according to LEI's analysis. Across all of New England, LEI's modeling suggests 1,826 new jobs on average per year. In addition, the Maine economy will also enjoy an increase in GDP of \$29.1 million per year. In New England, LEI's results show an increase in the six states' GDP of \$205.3 million per year on average. These benefits to the region accrue

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[12] Although Daymark's analysis noted 3.1 million metric tons were attributable to NECEC in its report, 3.4 million metric tons was the approximate value for the 1086 Case based on Daymark's response to IECG-004-001, attachment 4.

[13] LEI did not adjust the project cost estimates provided by CMP. However, LEI is concerned about the local spending might have been over-estimated. Please see Section 5.2.1.

primarily due to lower wholesale electricity market costs. The project's wholesale electricity market savings are enjoyed by electric ratepayers across the region, roughly proportionally to their electric consumption due to the generally uncongested nature of the transmission system (except that Massachusetts retail consumers will see a smaller share of these benefits as compared to its overall load share of the New England regional load, because its electric ratepayers are responsible for the contract costs associated with the project, pursuant to the award made under the 83D RFP).

Figure 2. LEI's independent analysis of macroeconomic benefits (annual average)

Benefit categories	LEI Analysis	
	Maine	New England
Jobs - development and construction period (Annual average for 2017-2022)		
Direct	856	N/A
Indirect and Induced	775	N/A
Total	1,631	N/A
Jobs - operations period (Annual average for 2023-2037)		
Total	291	1,826
GDP - development and construction period (Annual average for 2017-2022), fixed 2009$ million		
	$98.2	N/A
GDP - operations period (Annual average for 2023-2037), fixed 2009$ million		
	$29.1	$205.3

Note: "N/A" signifies "not applicable." LEI did not estimate any macroeconomic benefits to other states in New England during the development and construction period. Economic impacts - new jobs and GDP increases - presented in the table are reported in annual average terms over the relevant modeling period (2017-2022 for the construction period and 2023-2037 for the operations period). The incremental new jobs and GDP impacts in New England during the operations period do not include those created by O&M activities related to the operations of the NECEC. Those pare modeled using the REMI PI+ model for Maine, rather than the REMI PI+ model for New England, to be in consistent with the USM analysis.

1.5 Comparison of LEI's analysis and Daymark's analysis

LEI's estimate of total wholesale electricity market benefits is approximately 58% lower than Daymark's analysis, and the estimate for total wholesale capacity market benefits is approximately 24% lower as shown in the figure below (in NPV terms).[14] The biggest difference lies in relation to Daymark's forecast of energy market benefits, specifically as it relates to the assumed natural gas price levels and generation availability during the summer months.[15] Capacity market differences between LEI and Daymark relate primarily to the FCA parameters for new entry, the slope of the demand curve, and the assumed quantity of cleared capacity in the FCM. In both LEI's and Daymark's analysis of NECEC, capacity market benefits dissipate over time as the capacity market supply-demand balance equilibrates over time, and capacity prices in the Project Case catch up to the capacity price levels forecast under the Base Case.

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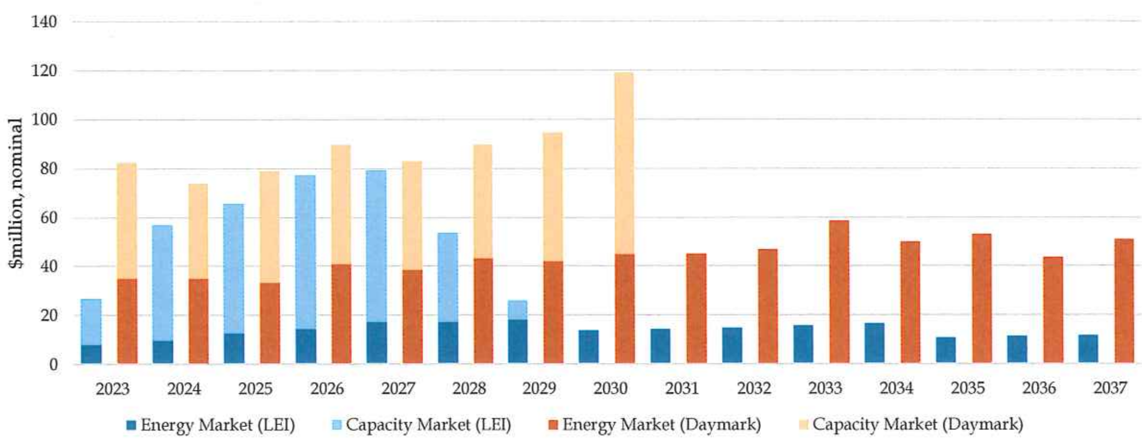
[14] LEI compared its analysis to Daymark's "1086 NECEC Case", as this case is the most similar in terms of total annual energy output.

[15] As noted in Section 7.6.2 of this report, new generation resources in LEI's analysis are in the form of combustion turbines (peakers). If baseload new entry, such as combined cycle gas turbines, were built in lieu of peakers in the long run, energy market benefits would dissipate over time and tend to zero as well.

Figure 3. LEI's and Daymark's estimate of wholesale electricity market benefits associated with NECEC



LEI identified four key drivers (see Section 4.1) that account for most of the differences in the wholesale energy market benefits projected by LEI versus Daymark:

1. Daymark's simplified modeling approach to account for maintenance and forced outages in AURORA resulted in artificially low supply availability when demand conditions peaked in the summer months and therefore overstated energy prices in those periods;

2. Daymark's delivered natural gas price outlook for generators was an average \$1.3/MMBtu higher than LEI's outlook because Daymark's was based on an outdated projection for wellhead gas prices;

3. Daymark's energy prices - and therefore energy market benefits - were also affected by the unnecessary addition of "regional" and plant-specific ("peaker") adders to gas prices, which increased delivered gas prices for some units by \$2-4/MMBtu above New England delivered gas prices;

4. Daymark used an outdated demand forecast from ISO-NE, which was 4-5% higher than the 2017 demand forecast that LEI relied on.[16]

As for capacity market benefits, LEI identified three key drivers (see Section 4.2) that account for the differences between LEI's and Daymark's capacity market price levels:

1. Daymark assumed a static slope of the demand curve by not adjusting the penalty factor over time. This resulted in slowly rising capacity prices, which prolonged the duration of the capacity market benefits. In addition, the penalty factor was calibrated for an outdated

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[16] LEI recognizes that the use of 2016 CELT forecast was required by the MA RFP for purposes of bid submission. However, there is no basis to suggest that this MA RFP requirement should bind the MPUC in its decision-making in this case.

Net CONE of $10.95/kW-month (in January 2017, FERC approved the current Net CONE of $8.04/kW-month for FCA #12. LEI began its forecast with this Net CONE value);

2. Daymark assumed more generic entry at a lower price, which resulted in lower long-run capacity prices;

3. Daymark's analysis exhibited a high level of oversupply, which resulted in lower short-term capacity prices than LEI.

Figure 4 below compares LEI's wholesale electricity market benefits to Daymark's analysis.

Figure 4. Comparison of LEI's analysis and Daymark's analysis of wholesale electricity market benefits

	LEI Analysis		Daymark Analysis (1086 Case)	
	Maine	New England	Maine	New England
15-yr NPV, $2023 million				
Energy market benefits	$122	$1,197	$384	$2,839
Capacity market benefits	$223	$2,962	$292	$3,891
Total electricity market benefits	$346	$4,160	$676	$6,730
15-yr annual average, $nominal million				
Energy market benefits	$14	$134	$44	$384
Capacity market benefits	$19	$255	$27	$355
Total electricity market benefits	$33	$388	$71	$739

Note: LEI's energy market results are based on the average of 20 iterations (see Section 6.1) and were found to be statistically significant in all years of the modeling horizon.

1.6 Comparison of LEI's and USM's macroeconomic benefits

LEI compared its projection of macroeconomics benefits against the projection made by USM and included in the CPCN application (see Figure 5). LEI's analysis of the development and construction period is based on the updated project cost provided by CMP and USM,[17] and the results are generally close to the findings presented by USM. However, LEI notes that the development and construction benefits for Maine are highly correlated to the amount of local spending CMP expects during the installation of the project. CMP provided an estimate that is higher than what LEI has observed in other engagements involving other HVDC transmission projects. LEI recognizes that local spending around the capital costs for an HVDC transmission project will vary depending on location, amount of site preparation, availability of local skilled labor, as well as custom design elements of the project itself. That said, if the local spending amount for NECEC is lower than what CMP has estimated, then the macroeconomic benefits to Maine will be lower, and vice versa.

For the operations period, LEI's estimated macroeconomic benefits are similar to USM's for the State of Maine. A comparison of the results shows that LEI's estimated incremental jobs are lower than those estimated by USM by only 11%, or 37 jobs, per year (329 from the USM study vs. 291

[17] ODR-003-011_Attachment_1_CONFIDENTIAL (2017-232). In the updated construction cost estimate, the development period is 2017 and 2018, and the construction period is 2019-2022. In the original cost estimates, the development period was 2017 and the construction period was 2018-2022.

from the LEI study). In terms of GDP, LEI's results are slightly higher than USM's, primarily because of the additional wholesale capacity market benefits included in LEI's study. However, the inclusion of wholesale capacity market benefit is predicated on NECEC clearing the FCA. If NECEC fails to clear in the FCA (due to MOPR or other circumstances), the wholesale electricity market benefits will be much smaller (due to $0 wholesale capacity market benefits). Under such circumstances, the macroeconomic benefits will be further reduced by about 70% in both Maine and New England. Moreover, if NECEC fails to clear in the FCA but clears in the SA, it would trigger an additional 340MW retirement in New England, which will negatively impact both the New England and Maine economies.

New England wide, LEI's estimated economic benefits are much lower than USM's results. LEI estimated an annual average of 1,826 incremental jobs for all six states, which is 1,909 jobs, or 51%, less than USM's results. LEI's estimate for annual average GDP increase is $205.3 million, which is $200.9 million (or 50%) lower than USM's results. This difference arises mainly because LEI's analysis includes an estimate of the contract cost of the project, to be paid by Massachusetts retail electric ratepayers, as well as the macroeconomic impacts related to early power plant retirement (in Connecticut), triggered by the project's sale of capacity.

Figure 5. Comparison of LEI's analysis and USM's analysis

Benefit categories	LEI Analysis		USM Analysis	
	Maine	New England	Maine	New England
Jobs - development and construction period (Annual average for 2017-2022)				
Direct	856	N/A	868	N/A
Indirect and Induced	775	N/A	824	N/A
Total	1,631	N/A	1,691	N/A
Jobs - operations period (Annual average for 2023-2037)				
Total	291	1,826	329	3,735
GDP - development and construction period (Annual average for 2017-2022), fixed 2009$ million				
	$98.2	N/A	$94.1	N/A
GDP - operations period (Annual average for 2023-2037), fixed 2009$ million				
	$29.1	$205.3	$25.8	$406.2

Note:

1. Economic impacts in terms of incremental jobs and GDP presented in the table are the annual average of the modeling periods in LEI's study, namely 2017-2022 for the construction period and 2023-2037 for the operations period.
2. The incremental jobs and GDP in New England do not include those created by O&M activities of the NECEC project (indicated in the table as "N/A"), since the macroeconomic impacts of O&M spending is modeled within Maine, to be consistent with USM's approach.

The discrepancies in the macroeconomic benefits over the operations period between the two studies are driven by multiple factors as LEI and USM used different policy variables in the REMI PI+ model.[18] However, the biggest difference in the USM and LEI results stems from the inputs.

First, USM's analysis of the electricity cost savings was based on wholesale energy price reductions and these reductions were estimated based on inflated fuel price assumptions. LEI's

[18] For modeling electricity cost savings, LEI used "Consumer Price – Electricity" whereas USM used "Consumer spending – Reallocate consumption: Electricity."

analysis was based on the most up-to-date and realistic fuel price assumptions, and considered changes in both wholesale energy and capacity markets caused by the project.

Second, LEI estimated retail electric cost savings that capture the actual electricity cost reductions that end-users (electric ratepayers) will experience in the region. USM's electricity market benefits were based solely on wholesale energy price reductions, which are higher than retail price reductions, and hence resulted in overestimated macroeconomic benefits across the New England region.[19]

Third, LEI also considered the macroeconomic impacts of the contract costs borne by Massachusetts ratepayers by way of the contract award done for 83D RFP, and the impact of early power plant retirement triggered by the NECEC.[20] See Section 5 for a detailed comparison of LEI and USM analyses.

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[19] Over the modeling period, LEI's analysis shows that New England retail customers are exposed to 88% of wholesale energy price changes and 93% of capacity market price changes. Although LEI assumed that Maine retail consumers are exposed to 100% of wholesale price changes, reduced electricity market benefits in other states in New England will also have some negative impacts on the Maine economy.

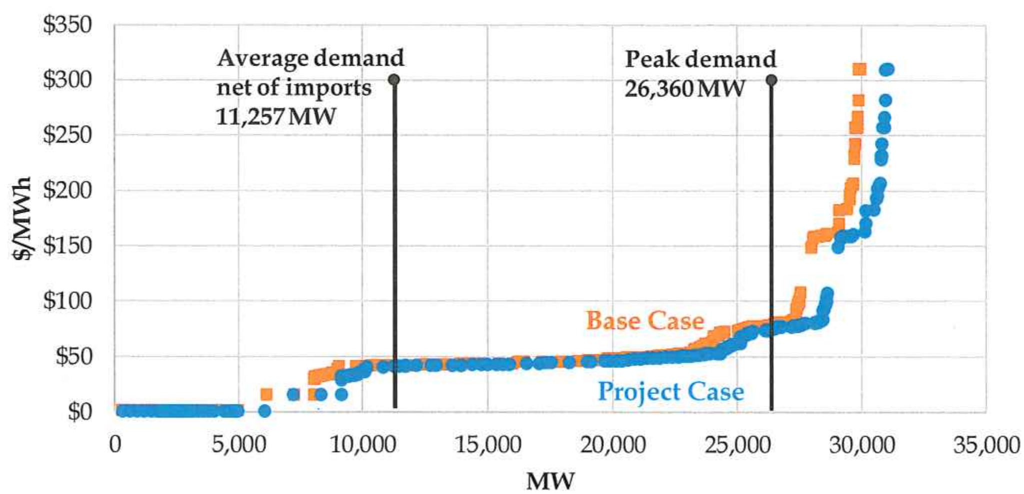
[20] LEI has also forecasted deferred new entry of generation plants in New England due to the project. Such impacts were not modeled in LEI's analysis, because the deferred investment is only for a few years, whereas plant closures imply permanent reduction in employment.

2 Wholesale Electricity Market and Environmental Benefits of NECEC

LEI estimates that NECEC would provide Maine $346 million (in 2023 dollars) in wholesale electricity market benefits over the first 15 years of operation (2023-2037). Of this amount, $122 million is expected to come from wholesale energy market savings (average of $14 million per year in nominal dollars) and $223 million is expected to come from capacity market savings (average of $19 million per year in nominal dollars), assuming NECEC clears the primary auction in FCA #14. LEI estimates that if the severe weather conditions that occurred in 2013 were to re-occur in the future, NECEC would have the ability to reduce wholesale energy market costs for Maine ratepayers by $4.3 million over a five-day period during the summer 2013 heat wave and $6.0 million over a five-day period during the winter 2013/14 polar vortex. LEI also estimates that NECEC would reduce CO_2 emissions from New England generators by approximately 3.6 million metric tons.

ISO New England ("ISO-NE") oversees and administers the competitive wholesale electricity markets for the six states of New England. It operates a day-ahead and real-time energy market, a forward capacity market ("FCM"), an ancillary services market, and a market for financial transmission rights. LEI's analysis focused on the most significant cost components of the wholesale electricity markets, which include the wholesale energy and capacity markets. Pursuant to Avangrid's commitment under the MA RFP, LEI assumed that NECEC delivers energy around the clock, totaling [redacted] GWh per year (spread evenly across all hours).[21] LEI also assumed that the shippers on NECEC would offer as price takers in the wholesale energy market in order to fulfill their contractual obligations to Massachusetts. By virtue of these energy sales, other more expensive generation resources will not be dispatched and consequently, the market clearing price for energy (i.e., Locational Marginal Prices ("LMPs")) will decline, as suggested in the illustrative supply curve diagram below.

Figure 6. Example of the internal supply curve for New England in 2027



[21] LEI understands that NECEC was selected as part of the Massachusetts 83D RFP, providing up [redacted] GWh of energy annually into the New England wholesale energy market; this value was also confirmed by Mr. Jared des Rosiers during the April 5, 2018 Technical Conference.

LEI understands that NECEC is not selling capacity as part of the long-term commitment under Massachusetts' 83D RFP.[22] LEI evaluated the possibility of wholesale capacity market benefits using the latest capacity market rules as of the first quarter of 2018. Recently, FERC approved ISO-NE's proposed CASPR rules.[23] The objective of CASPR is to develop a transparent, market-based approach that results in competitive capacity pricing and accommodates the entry of new capacity resources that have been sponsored through various state policy initiatives, without shifting the costs of one state's subsidies to another state's consumers.[24] To best satisfy these objectives, ISO-NE proposed conducting the capacity market in two stages. In the first stage (known as the primary auction), the ISO would clear the FCA as it does today, with new resources subject to the existing MOPR rules.[25] In the second stage, which immediately follows the primary auction, ISO-NE would administer a new, voluntary secondary market known as a substitution auction. In the substitution auction, existing capacity resources that obtained capacity supply obligations ("CSOs") in the primary auction and are willing to exit all ISO-NE-administered markets permanently may transfer their CSOs (in their entirety) to Sponsored Policy Resources ("SPRs") that did not acquire a CSO in the primary auction. The transferring resources must pay the SPR a portion of their capacity revenue (the clearing price in the substitution auction), and then permanently retire from all ISO-NE-administered markets. As such, existing resources represent the "demand" in the substitution auction, and new SPRs represent the "supply."

As a result of being selected for the Massachusetts 83D RFP, NECEC would qualify as a SPR. LEI did not conduct an analysis to estimate NECEC's MOPR. Such an analysis could be used to determine whether a new resource could clear the FCA. CMP did not provide sufficient data for LEI to perform such analysis. LEI's capacity market benefits assume that NECEC's MOPR is sufficiently low that the project would clear the primary auction at the [redacted]/kW-month estimated price level for FCA #14. However, if NECEC does not clear the primary auction and has to go into the substitution auction, then the FCA price would not be affected and there would not be any wholesale capacity market benefits from NECEC. Because an equivalent amount of capacity would need to exit all ISO-NE administered markets in the substitution auction in order for an SPR to clear, adding 1,090 MW of capacity from NECEC would result in 1,090 MW of permanent retirements.

2.1 LEI's Base Case view of wholesale energy and capacity prices

LEI employed its proprietary simulation model, POOLMod, to develop a wholesale energy price forecast for the Base Case and Project Case. The FCA Simulator, a proprietary modeling tool created by LEI, was used to forecast capacity market prices under the Base Case and Project

[22] The Energy Diversity Act directs Massachusetts Electric Distribution Companies ("EDCs") to jointly and competitively solicit proposals for and to enter long-term contracts for Clean Energy Generation and/or RECs only, associated with clean energy in an annual amount of [redacted] MWh.

[23] ER18-619-000 Revisions to ISO-NE Tariff Related to Competitive Auctions with Sponsored Policy Resources. <https://www.iso-ne.com/static-assets/documents/2018/01/er18-619-000_caspr_filing.pdf>

[24] ISO-NE. *Competitive Auctions with Subsidized Policy Resources: ISO Discussion Paper*. April 2017. < https://www.iso-ne.com/static-assets/documents/2017/04/caspr_discussion_paper_april_14_2017.pdf>

[25] Under the MOPR, capacity market bids below the minimum price thresholds set by the ISO will clear only if they passed a unit-specific review by the ISO's market monitor where any "out-of-market" revenues - such as bilateral contracts with Massachusetts - would be excluded in its bid analysis. Under CASPR, the Renewable Technology Resource ("RTR") MOPR exemption would be phased out.

Case.[26] In order to isolate and estimate the potential benefits that NECEC can provide to Maine, LEI developed energy and capacity price forecasts in New England without the addition of any large Elective Transmission Upgrade ("ETU") such as NECEC or any equivalent project.

2.1.1 Gas prices are a key factor driving future energy price trends in New England

Because the dominant fuel in New England is natural gas (therefore in most hours, natural gas-fired generation is marginal), energy price levels are mostly impacted by natural gas prices. LEI relied on the Algonquin Citygate price as the estimate of the delivered natural gas price for gas-fired generators in New England. LEI relied on the forward markets for projecting the starting values for Algonquin Citygate gas prices for 2018 and 2019.[27] From 2020 and onward, LEI projected the Algonquin Citygate gas price based on a supply hub price plus a transportation adder to New England calculated by LEI's proprietary Levelized Cost of Pipeline ("LCOP") model.[28] To derive that monthly profile, LEI applied the historical five-year (2013-2017) seasonality of Algonquin Citygate prices.[29] Figure 7 below shows the monthly delivered natural gas prices used in LEI's wholesale energy market modeling.

Figure 7. Monthly Algonquin Citygate prices (historical and LEI's outlook)

[redacted]

Source: SNL (2014-2017) and LEI's LCOP (2018-2037)

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[26] Detailed descriptions of POOLMod and FCA Simulator can be found in Section 6 and detailed assumptions used in the modeling can be found in Section 7.

[27] LEI used the three-month average of daily forwards (January 1, 2018 – March 31, 2018), as reported by OTC Global Holdings ("OTCGH") for the 2018 and 2019 monthly prices.

[28] The LCOP model assumes that price spreads between any two gas pricing hubs cannot, in the long run, persist above the levelized cost of building a new pipeline between the two hubs. The LCOP model assumes that if the price spread rises above the levelized cost of building a pipeline between any two hubs for three consecutive years, then a pipeline will be built between the two hubs to reduce the price spread.

[29] LEI used historical seasonality in monthly prices rather than the seasonality of the forward curve. Historical seasonality reflects the actual experience in the market; using an average of 2013-2017 captures warmer-than-normal, colder-than-normal, and normal winters. The difference between using the historical method versus using the seasonality of the current forward curve is very small, except for February, when the historical method projects slightly higher prices (e.g., $10 per MMBtu for Algonquin Citygate in 2018 and 2019) than the forward curve projects (about $9 per MMBtu for Algonquin Citygate in 2018 and 2019). The historical method captures the larger impact of cold weather at the end of the season (in February), when gas inventories tend to be relatively depleted.

The Base Case energy price forecast for the ISO-NE control area largely resembles the trend in natural gas prices as shown below in Figure 8. Two factors, however, should be noted, which affect the energy market trends slightly. Between 2023 and 2029, implied market heat rates improve as a result of the addition of offshore wind resources (as a consequence of Massachusetts' 83C RFP) and also as a result of declining total demand. Then, beginning in 2030, a reduction in New York import volumes due to the retirement of Ginna (2030) and Fitzpatrick (2035) nuclear stations necessitates more local gas-fired generation in New England and increases the implied market heat rates. LEI also retired Millstone 2 in 2035[30] when its nuclear license expires; this plant retirement has a similar effect on energy market prices as the New York retirements (and changing pattern of imports).

Figure 8. LEI's Base Case energy and natural gas price forecasts

[redacted]

2.1.2 Peak demand growth and CONE are key determinants of capacity price in New England

LEI's capacity market analysis requires a forecast of future Net Installed Capacity Requirement ("NICR"), Net CONE, and consideration of supply changes (new entry and retirements). LEI's NICR is a function of ISO-NE's CELT 2017 peak demand net of behind-the-meter solar PV.[31] The Base Case and Project Case rely on the same peak demand forecast (CELT 2017) and therefore have the same NICR.

LEI's Net CONE is based on ISO-NE's estimate of Net CONE for a combustion turbine in its latest published Net CONE and Offer Review Trigger Price ("ORTP") study.[32] LEI then forecasted the Net CONE by escalating the gross CONE by the inflation rate from the Bureau of Labor Statistics's Producer Price Index for Turbine and Turbine Generator Set Units Manufacturing, and inflating the energy and ancillary services offset by the trend in wholesale energy price growth from LEI's simulation modeling results. As a result of these calculations, the Net CONE differs slightly between the Base Case and the Project Case.

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[30] Millstone 3's nuclear license expires in 2045, and Seabrook is currently looking to extend its license to 2050.

[31] ISO-NE, CELT 2017.

[32] ISO-NE FERC Filing ER-17- 795-000. January 13, 2017.

For supply assumptions, results from New England's most recent FCA, FCA #12, showed that New England is oversupplied for the 2021-2022 capability period by approximately 1,103 MW. The amount of oversupply has grown over time - after FCA #9, New England was only oversupplied relative to NICR by 506 MW for the capability period of 2018-2019. Because much of the peak demand (net of behind-the-meter solar PV) growth is offset by the growth in energy efficiency, LEI's analysis projected that even in the Base Case, no new generation would be needed until FCA #18 (2027). This projection assumed offshore wind SPRs would clear in the substitution auction, and therefore would not impact capacity clearing prices. In the short-term, LEI assumed that coal would exit the Base Case by FCA #14, based on LEI's estimate of coal units' net going-forward costs. LEI also assumed that Mystic 7 would exit in FCA #13, as it has already submitted a retirement de-list bid. ISO-NE is seeking to retain Mystic 8 and 9 for fuel security reasons, based on the latest available information at the time that LEI was conducting its independent analysis. Therefore, LEI assumed Mystic 8 and 9 would participate in the ISO-NE markets in FCA #13 and onwards.[33]

In the long-run, capacity prices are expected to converge towards Net CONE as shown below in Figure 9. New entry in the form of combustion turbines (in 50 MW increments) was added to the New England power system. As such, the long run qualified capacity is almost identical to the NICR.

Figure 9. LEI's Base Case capacity prices and Net CONE

[redacted]

2.2 Projected energy market benefits

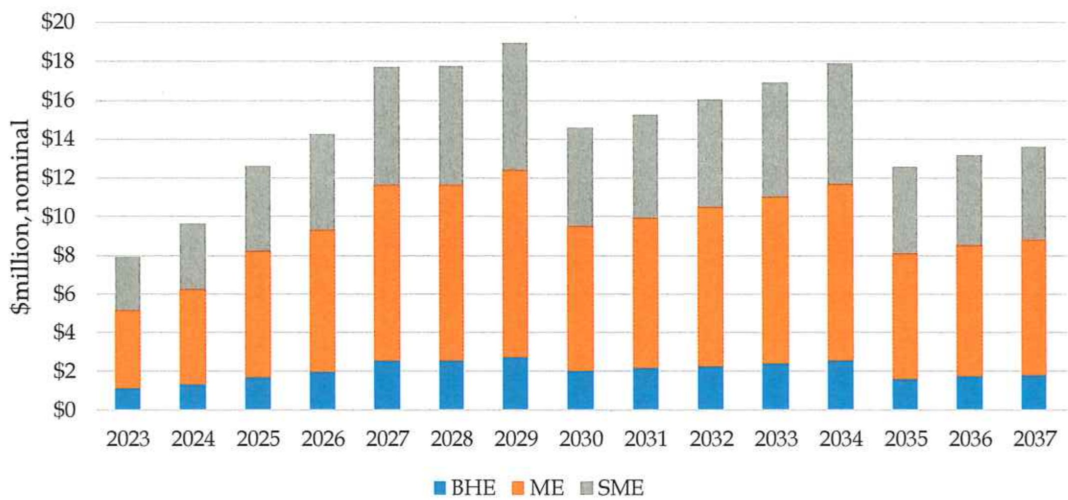
After developing the Base Case, LEI ran a simulation model to estimate the LMP impact of injecting [redacted] GWh of energy into New England over NECEC. LEI estimates that wholesale energy prices will decline by approximately [redacted] per MWh across New England in nominal dollars over the first 15 years of operations (2023-2037). For Maine, wholesale energy prices are

[33] On April 3, 2018, ISO-NE released a memo to the NEPOOL Participants Committee citing near-term fuel security concerns. These concerns prompted ISO-NE to request FERC to waive ISO's Tariff to allow the ISO to retain Mystic 8 and 9 to maintain fuel security on the system.

expected to decline by a weighted average of [redacted] per MWh in nominal dollars (load-weighted average of Bangor Hydro Electric, Maine, and Southern Maine) over the same timeframe. This is equivalent to wholesale energy market benefits of roughly $14 million annually (nominal dollars) for Maine, or $134 million annually (nominal dollars) for all wholesale load across the six states in New England on average for the forecasted timeframe.

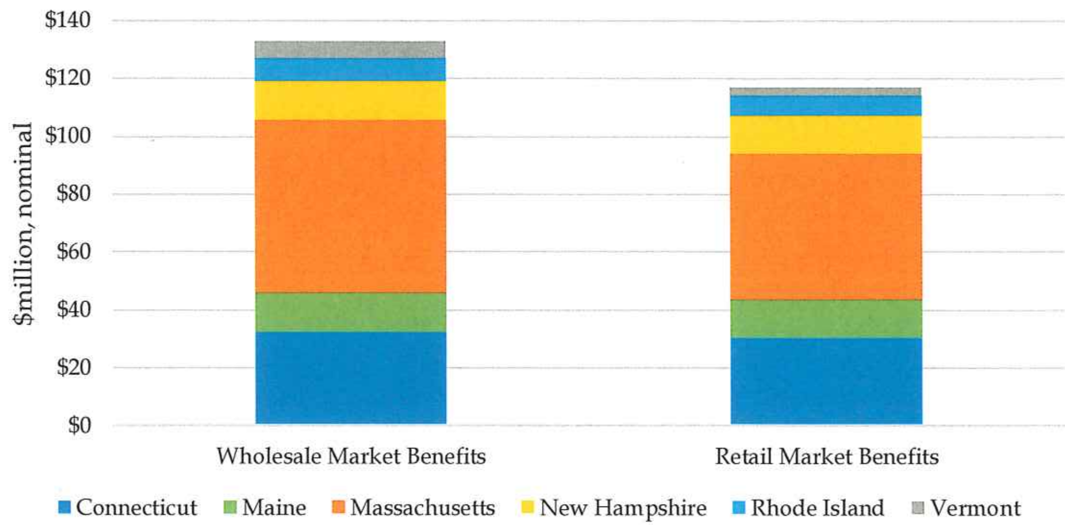
The 15-year NPV of NECEC's wholesale energy market benefit over the same timeframe is $122 million (in 2023 dollars) for Maine and $1.2 billion (in 2023 dollars) for all of New England. Figure 10 below shows the annual energy market benefits for the Maine zones over the first 15 years of operations. LEI also estimated the market impacts for retail customers in Maine and New England, which is shown in Figure 11. This accounts for the energy and capacity under long-term contracts or self-supply.

Figure 10. Annual wholesale energy market benefits in Maine



Note: The three Maine zones modeled include Bangor Hydro Electric ("BHE"), Maine ("ME"), and Southern Maine ("SME").

Figure 11. Annual average wholesale versus retail energy market benefits by state



Note: Retail energy market benefits in New England are lower than wholesale market benefits because some portion of energy or capacity is under contract or self-supply.

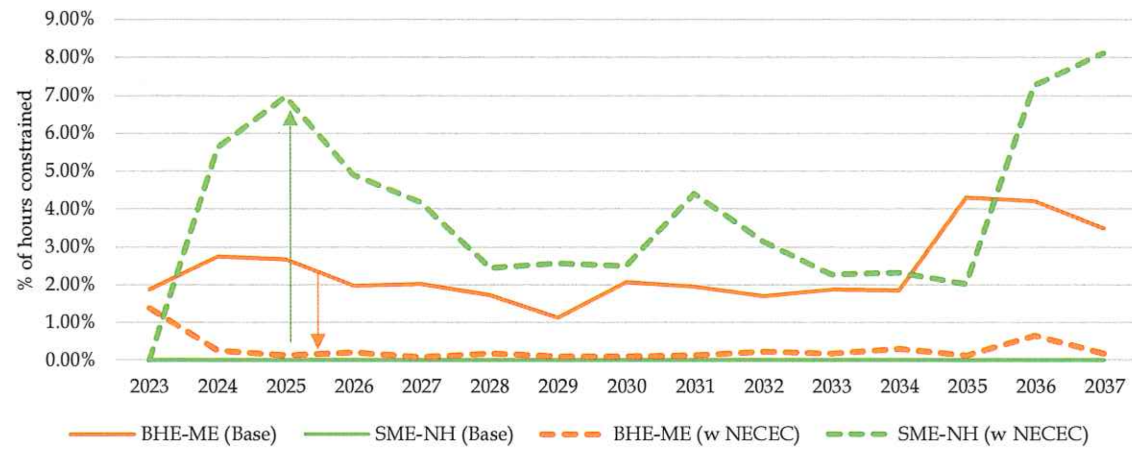
As indicated in ISO-NE's CELT 2017 forecast, overall energy demand is expected to decline as a result of energy efficiency and solar PV resources. Against this backdrop of falling demand, LEI also expects that Massachusetts will procure 1,600 MW of offshore wind between 2024 and 2027, resulting in even less need for thermal generation within New England. During the shoulder months (September - November, and April - May), off-peak demand in New England can be particularly low (about 8,000 MW in some hours). When coupling the large amounts of renewable energy with low demand, LEI found that the injection of nearly 1,090 MW around the clock through NECEC can reduce average off-peak prices considerably, as opposed to just average peak prices. LEI, therefore, observed increasing energy market benefits during that period.

LEI also found that the nuclear retirements in New England and New York will require higher-cost generation to run in New England. This caused LMPs in the Project Case to rise slightly faster than in the Base Case, particularly during the off-peak hours. As such, even though the nuclear retirements cause price levels to rise in both the Base Case and Project Case, the energy market benefits decline in 2030 and 2035, because of the higher *relative* price level increase in the Project Case.

In LEI's wholesale energy market analysis, the energy market benefits do not fully dissipate because new resources added in the Base Case (combustion turbines) are not inframarginal in most hours. If inframarginal generation resources (i.e. baseload resources such as combined cycle gas turbines) were added in the Base Case, LEI expects that the energy market benefits would dissipate over time towards zero (if, over time, [redacted] TWh of baseload energy is added in the Base Case, the LMP would be the same as in the Project Case).

As noted above, the LMP reduction in Maine is slightly higher than the rest of New England. The reason is that LEI's modeling indicated that some minor congestion would occur along the Maine - New Hampshire interface. LEI adopted Daymark's assumptions of increasing the transfer limit of the SME-NH interface by 1,000 MW from 1,600 MW to 2,600 MW.[34] LEI's flow duration curve indicates that on average, approximately 4.3% of hours are constrained along this interface. Figure 12 shows the congestion along the Orrington South and SME-NH interfaces.

Figure 12. Percentage of hours BHE-ME and SME-NH interfaces are binding



2.3 Projected capacity market benefits

LEI's modeling results indicate that 1,090 MW of qualified capacity from NECEC clearing in the primary auction of the FCM will decrease capacity prices by an average of [redacted] per kW-month (nominal dollars) in New England for six years between FCA #12 - #19 (2023–2029). This represents wholesale capacity market benefits of roughly $19 million annually for Maine (nominal dollars), or $255 million annually for all wholesale load across the six states in New England over the 15-year modeling timeframe (nominal dollars). In NPV terms, the 15-year wholesale energy market benefit is equivalent to $223 million for Maine, and $2.9 billion for all of New England (in 2023 dollars). If NECEC's MOPR price is higher than the clearing price and NECEC is cleared in the substitution auction, then there would be no capacity market benefits. Figure 13 below shows the capacity market benefits split between Maine and the rest of New England. Maine's benefits are relative to its share of peak load, which is approximately 7.5% on average.

[34] CMP response to ODR-003-019

Figure 13. Annual wholesale capacity market benefits

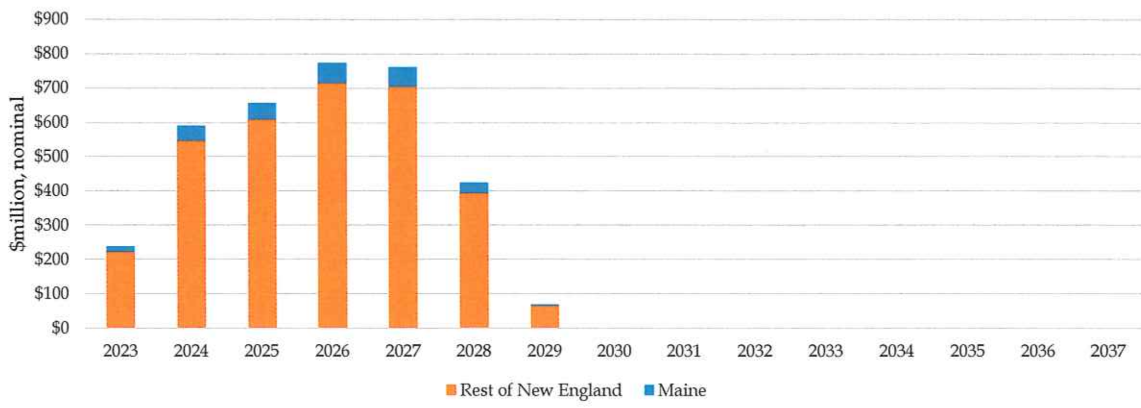
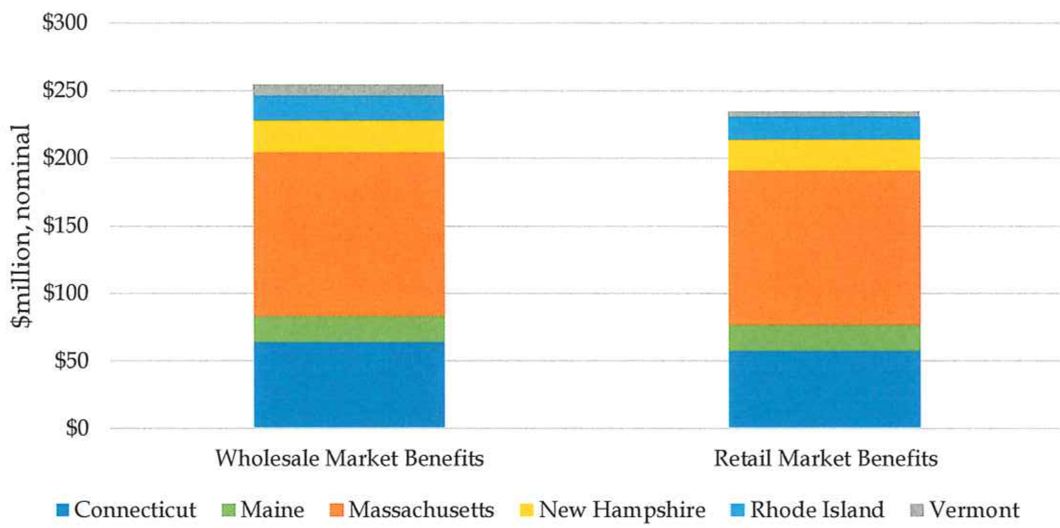


Figure 14. Annual average wholesale versus retail capacity market benefits by state



Note: Retail capacity market benefits in New England are lower than wholesale market benefits because some portion of capacity is under contract or self-supply.

As noted previously, NECEC may need to clear in the substitution auction, for example, if its custom MOPR price turns out to be above the capacity market clearing price ([redacted]/kW-month in LEI's estimate). It may also qualify in subsequent primary auctions (FCAs), and result in capacity market benefits in the future (although the magnitudes of those benefits have not been studied in this report). However, if NECEC were to clear in the primary auction of FCA #14, LEI estimates that given the current level of supply and demand in the FCM, NECEC would displace approximately 750 MW of existing capacity resources in the FCM. This is because New England is currently already oversupplied, particularly given the growth in energy efficiency in the past two auctions, FCA #11 and #12. The most recent FCA, FCA #12, cleared at $4.63/kW-month, which is the lowest price in five years. However, this low price was sustained due to ISO-NE retaining Mystic 7 and 8 for local reliability needs in Boston. Were Mystic 7 and 8 allowed to exit FCA #12, capacity prices would have been higher.

In order to estimate the level of market response, LEI prepared proxy retirement de-list bids (taking into account future expected energy and capacity revenues as specified in ISO-NE's retirement de-list workbook). These bids include fixed O&M, risk premiums, and incremental capital expenditures based on a mix of publicly available information, third-party commercially available data, and LEI's original research. While there is uncertainty about the exact price of the retirement de-list bids for New England generators, FCA #12 does provide some indication that at least some plants are looking to retire or de-list in the $2/kW-month to $5/kW-month range.

In LEI's modeling, supply and demand are expected to rebalance over the next few FCAs and supply (total CSO) roughly equals demand (NICR). By ISO-NE's design, the resulting capacity price at this level of supply would equal the Net CONE. The Net CONE represents the break-even price that the most cost-effective resource would require to be economic. Therefore, in the long run, new resources should enter the market when it is economic, which is when the capacity price is at Net CONE.

Similar to the Base Case, the capacity market under the Project Case would also rebalance. Because 1,090 MW of new capacity from NECEC is only offset by 750 MW of retirements, approximately 340 MW of *incremental* capacity is added. The size of this incremental capacity relative to peak load growth means that it will take *longer* for the capacity price to reach long-run equilibrium. By 2030, both the Base Case and the Project Case rebalance towards the net CONE in LEI's modeling of NECEC, and the capacity market benefits end.[35]

2.4 Insurance value from NECEC due to weather-driven events

In periods of system stress, NECEC can provide significant additional value to electric ratepayers across New England because they can extinguish or partially dampen the higher energy prices associated with extremely high demand or high fuel prices. New supply projects like NECEC could offset very high-cost generation. For example, when load peaks over repeated days during New England's summertime or when the gas infrastructure is highly constrained and gas supply is limited (and expensive), the energy flows on NECEC can provide a source of lower-cost energy that cannot otherwise be generated by local resources in New England. NECEC can serve as a form of "insurance" against the financial impact of such events, protecting consumers from at least a portion of the higher market costs that are a consequence of such events. Through backcast simulation modeling, LEI recreated past market conditions that exhibited very high energy prices under summer and winter stress events. LEI then added expected energy imports that would be available through NECEC into the backcast supply mix and thereby evaluated the wholesale market cost savings produced by NECEC under such system stress conditions.

2.4.1 Summer system stress event

Between July 15 and July 19, 2013, New England experienced a prolonged heat wave. During this period, more expensive peaking units were dispatched to serve the higher electricity load in the

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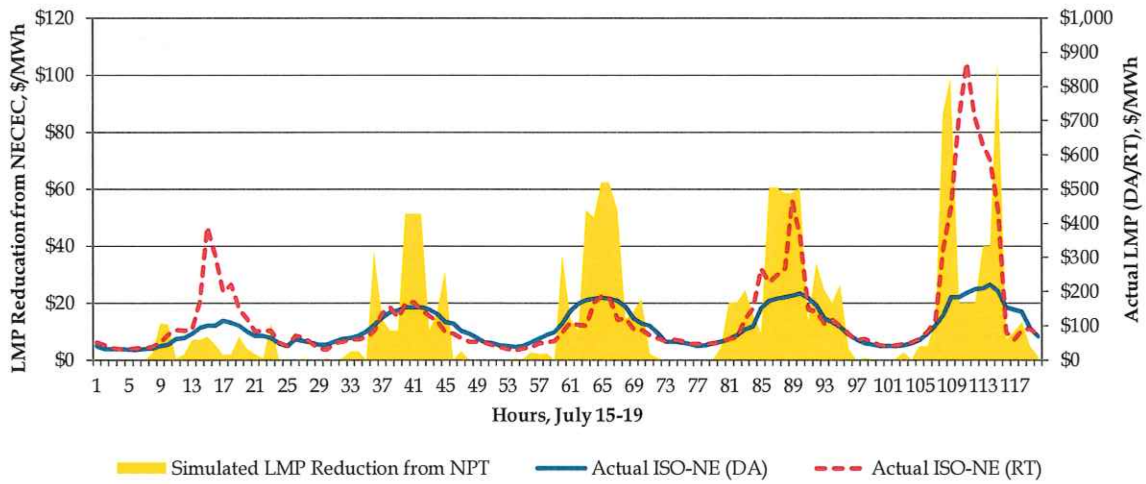
[35] LEI's analysis shows a very small difference of 13 MW in the total amount of cleared capacity beyond FCA #19. This results solely from the differences between the amount of capacity that enters in the Base Case (50 MW increments) and the amount of market response in the Project Case. Therefore, LEI assumes that the benefits beyond FCA #19 are zero.

region. Day-Ahead ("DA") and Real-Time ("RT") wholesale energy prices rose markedly in comparison to the normal range of energy prices for this time of the year. For example, Real-Time LMPs exceeded $400/MWh for seven hours on July 19th, while the typical LMP during this month is only $40/MWh (based on the prior two years). The weather was a big contributor to the high prices, as peak load surpassed 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 24 years.[36] In addition to high LMPs on this day, ISO-NE had a capacity deficiency, which resulted in the ISO-NE declaring an "OP4" event.[37] There were 4,724 MW of generator outages and reductions over the peak hour of the day that contributed to system stress and ultimately the OP4 declaration.[38]

If such summer extreme weather were to re-occur, energy flowing on NECEC could have reduced energy prices by more than $20/MWh on average across New England over this period. In summary, during this five-day heat wave, LEI estimates that the "insurance" value that NECEC could have provided New England consumers is approximately $51.7 million.

Figure 15. Illustration of LMP reductions associated with NECEC's energy flows during a summer system stress event



Note: The hourly DA and RT LMPs shown are sourced from actual ISO-NE data. The LMP reduction is based on market simulations using actual conditions (actual hourly levels of demand, actual hourly interchange between neighboring markets, and actual reported costs for various fuel types).

2.4.2 Winter system stress event

The winter of 2013/14 was extreme in terms of natural gas prices in New England as well as low temperatures. Periods of severe cold weather resulted in increased gas demand from Local Distribution Companies ("LDCs", entities that source natural gas on behalf of their retail

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[36] ISO-NE. *2015 Regional System Plan*, pg. 34

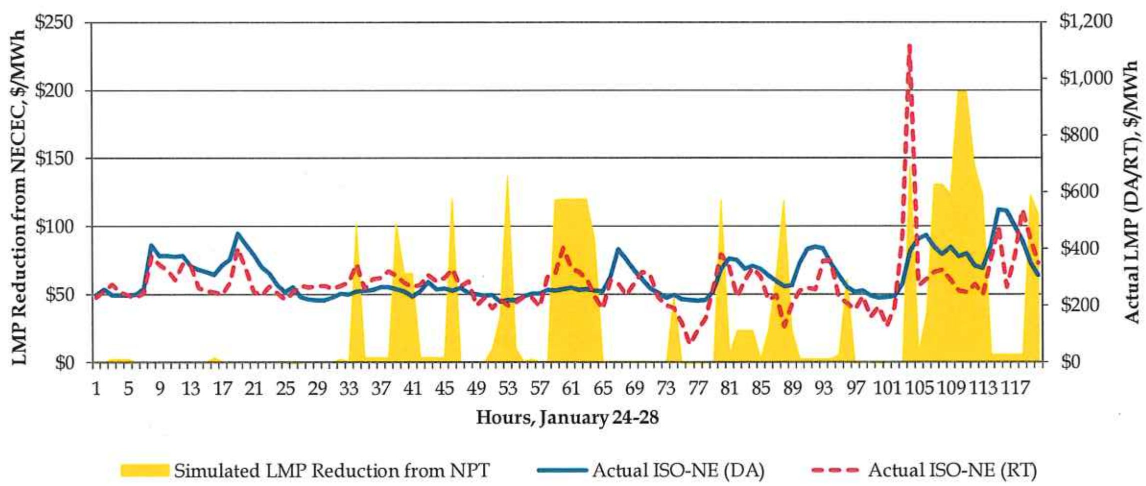
[37] Operation Procedure No. 4 ("OP4") establishes criteria and guides for actions during capacity deficiencies, as directed by ISO-NE, such as when available resources are insufficient to meet the anticipated load plus operating reserve requirements.

[38] ISO-NE. 2014 Third Quarter - Quarterly Markets Report.

customers for heating load) and, consequently, physical limits on the region's natural gas pipeline network emerged. These fuel delivery constraints, along with a number of unplanned outages at other generators, led to exceptionally high delivered natural gas prices, and, as a result, very high wholesale energy prices.[39] In addition, ISO-NE's Winter Reliability Program ("WRP") caused oil-fired generation to displace gas-fired generation during some periods, resulting in unusual changes in the generators' merit order where oil was setting prices.

The $24.5/MMBtu average 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, 2014). 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. These oil-fired units contributed to system security during these Polar Vortex events, particularly in January 2014. However, emissions of various pollutants increased as a result of oil-fired generation of electricity. And, nonetheless, both DA and RT energy prices were high, relative to historical prices during the winter peak.

Figure 16. Illustration of LMP reductions associated with NECEC's energy flows during winter system stress event



Note: The hourly DA and RT LMPs shown are sourced from actual ISO-NE data. The LMP reduction is based on market simulations using actual conditions (actual hourly levels of demand, actual hourly interchange between neighboring markets, and actual reported costs for various fuel types).

Based on LEI's simulation-based backcast, NECEC could have reduced energy prices during such conditions by $37/MWh on average over this five-day period. LEI estimates that this equates to an implied "insurance" value for consumers across New England of approximately $72.3 million over a five-day period.

ISO-NE's most recent Operational Fuel-Security Analysis suggests that fuel security, particularly during the high-demand cold spells, presents the foremost risk to current and future power

[39] ISO-NE. *Cold Weather Operations*. Peter Brandien. April 1, 2014.

system reliability. ISO-NE also noted that a resource mix with higher levels of liquefied natural gas ("LNG"), imports, and renewables shows less system stress than its reference case, and that "to achieve these levels of LNG, imports, and renewables, firm contracts for LNG delivery, assurances that electricity imports will be delivered in winter, and aggressive development of renewables, including expansion of the transmission system to import more clean energy from neighboring systems, would be required."[40]

2.5 Environmental benefits

The results of LEI's modeling show that NECEC reduces annual CO_2 emissions from New England generators by approximately 3.6 million metric tons.[41] The CO_2 emissions reduction is fairly constant over time because of the assumed level of energy flows on NECEC and the similarity in the emissions footprint of the generating resources that are being displaced by the energy flows on NECEC. This average is approximately equivalent to removing 767,000 passenger vehicles from the road based on estimates by the Environmental Protection Agency.[42]

However, the 3.6 million metric tons of CO_2 reductions estimate are based on how much CO_2 is reduced from internal New England generators. There is also substantial scientific and policy debate on how to estimate possible CO_2 emissions from large hydroelectric resources that would flow through NECEC. LEI acknowledges that large hydroelectric resources may emit carbon due to the decomposition of biological material in a 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 lbs./MWh.[43] This figure is higher than the actual historical system-wide profile of CO_2 emissions reported by Hydro Québec of 239 metric tons/TWh (approximately 0.5 lbs./MWh).[44] Although the emissions profile of new large hydroelectric plants is 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 NECEC. Based on a lifecycle rate of 136 lbs./MWh, LEI estimates that this results in approximately [redacted] metric tons based on [redacted] GWh. This value, however, still contrasts significantly with the emissions associated with a natural gas-fired generation, which can typically emit between 700-1,000 lbs./MWh (depending on the heat rate).

Figure 17 below shows the CO_2 emissions reductions for New England over the modeling timeframe. As noted previously, as a result of nuclear retirements in New York and New England, more local fossil-fuel generation is required in 2030 and 2035. As a result, similar to the

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40 ISO-NE, Operational Fuel-Security Analysis, January 17, 2018. <https://www.iso-ne.com/static-assets/documents/2018/01/20180117_operational_fuel-security_analysis.pdf>

41 According to the calculator available on the Environment Protection Agency website, this is equivalent to removing approximately 675,000 passenger vehicles per year. ***See***. "Calculations and References." <https://www.epa.gov/energy/ghg-equivalencies-calculator-calculations-and-references#vehicles>. Accessed December 28, 2016.

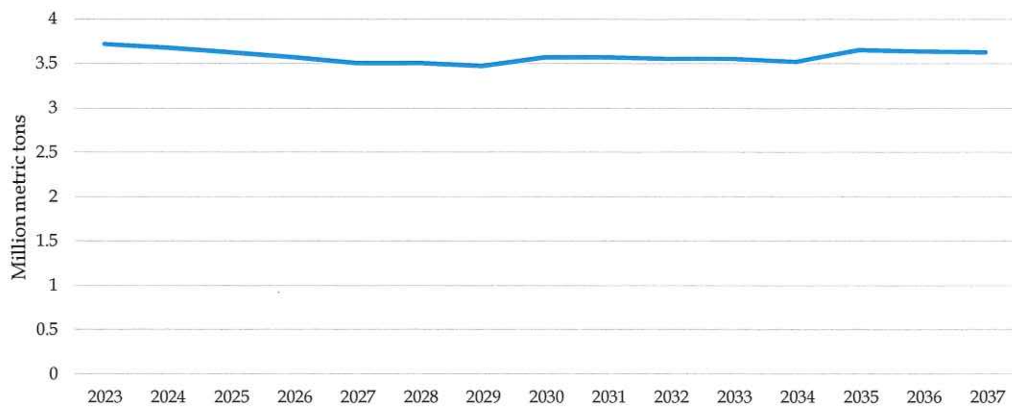
42 EPA, Greenhouse Gas Equivalencies Calculator. <https://www.epa.gov/energy/greenhouse-gas-equivalencies-calculator>

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

44 Hydro Québec Production's Electricity Facts. 2013.

energy market benefits, the emissions reductions fall slightly in 2030 and 2035 as more of that fossil-fuel generation is required in the Project Case relative to the Base Case.

Figure 17. Projected CO_2 emissions reduction for New England



3 Macroeconomic Benefits Analysis of NECEC

This section discusses the methodology adopted by LEI in its independent analysis of the macroeconomic results surrounding the construction and operations of NECEC. LEI estimated the development and construction impacts of the project using CMP's estimate of local spending and the timetable of construction (2017-2022). Maine would expect an average 1,631 jobs per year, and a $98.2 million GDP increase over this period. LEI then estimated the macroeconomic impact of the electricity savings created by NECEC once it starts operating in 2023. During the first 15 years of operations (2023-2037), LEI projects 272 new jobs per year and a $27.1 million increase in GDP per year for Maine related to the project's O&M activities and ratepayers' electricity savings.

LEI used a suite of proprietary wholesale electricity market modeling tools (described in detail in Section 2.1) and the widely-accepted PI+ macroeconomic model by REMI to analyze the macroeconomic impact of the NECEC project on the local economy in Maine, as well as the impacts on the entire New England region. Section 3.1 below explains the modeling tools and analytical methodology used in LEI's macroeconomic analysis. Section 3.2 and Section 3.3 present the local and regional economic impacts of the project during the construction and operations periods, respectively.

3.1 The modeling tool and analytical methodology

3.1.1 REMI PI+

LEI analyzed the macroeconomic benefits of the proposed transmission investment using a regional economic modeling tool, the REMI PI+ model. The REMI PI+ model was developed by the Regional Economic Modeling, Inc. ("REMI"). REMI PI+ is a dynamic simulation-based model of local (state and county) level economic activity. It is commonly used to model and measure the impact of various supply and demand shocks (new infrastructure is like a supply shock) and policy changes on the local economic activity and labor markets.[45]

LEI used the same PI+ software (in terms of regional configuration and industry depth) as USM for analyzing the macroeconomic impacts of the NECEC project. This eliminated any discrepancies in results that may have otherwise been caused by differences in model vintages and/or granularity of the representation of local economy. Specifically, LEI used a seven-region, 70-sector regional model of the Maine economy for studying the economic impacts of construction and operations spending associated with the project in Maine, and a six-region, 20-

[45] The REMI PI+ model is a regional economic model that incorporates basic Input/ Output ("I/O") functionality in a Computable General Equilibrium model with advanced Economic Geography and other econometric time-series modeling capabilities, and regression techniques. Economic shocks and policy changes can be captured and simulated in the REMI's PI+ model through adjustment of different categories of policy variables. These variables are interconnected through geographical linkages and industrial ties, and affect each other through direct and indirect economic impacts. Such dynamic impacts are ultimately reflected in the modeling results, through changes in population, trading activities, economic outputs, employment, product prices and labor compensation rates.

sector regional model of the six New England states for estimating wholesale electricity market impacts.

3.1.2 Analytical methodology

LEI analyzed the macroeconomic impacts of the project during the development and construction period and the operations period separately, as the economic activities and the socio-economic impacts across these two periods are different.

During the development and construction period, a transmission project's capital expenditure has direct economic impacts on the local economy, through boosting demand and economic activities in the construction sector and related supporting sectors. The result of local spending to install infrastructure is increased local GDP and new jobs.

During the operations period, a transmission project's local spending on operations and maintenance ("O&M") activities creates direct local jobs and contributes to local GDP growth. Meanwhile, the reduced wholesale electricity market costs lower electricity consumers' bills, increase households' disposable income, and decrease businesses' operations costs, which can have a widespread and long-lasting positive impact on the local economy.

In estimating the macroeconomic impacts from the wholesale electricity market, LEI employed its proprietary simulation model, POOLMod, and its FCA simulator, to forecast wholesale energy and capacity prices in ISO-NE, with and without the project. After converting the wholesale electricity benefits into retail electricity savings, these results are then fed into the 6-region REMI PI+ model for New England and modeled as reductions in energy costs for commercial, industrial, and residential consumers.

3.2 LEI's independent analysis for the development and construction period

The most critical input during the development and construction period is the project cost, including the total level, how it is broken down between local and non-local spending, how it is broken down between labor and material, and how it is broken down between different industries and sectors. LEI's analysis of the development and construction period (2019-2022) is based on the most updated project cost provided by USM and CMP,[46] which is estimated to be a total of $573.9 million across the development and construction period of 2017-2022 (a 2% increase from the original estimated local project cost of $561.9 million).

The preferred approach to developing project cost is to break it down into detailed granular labor and material expenditure categories. However, LEI was limited by the lack of detail in the cost estimates provided by CMP, and therefore modeled the construction cost at a more aggregated level. LEI modeled the project costs as increased industry sales in relevant sectors, including the power and communication structures construction; management of companies and enterprises; architectural, engineering, and related services; as well as professional, scientific, and technical

[46] ODR-003-011_Attachment_1_CONFIDENTIAL_(2017-232). In the updated construction cost estimate, the development period is 2017 and 2018, and the construction period is 2019-2022. In the original cost estimates, the development period was 2017 and the construction period was 2018-2022.

services. The project expenditure is allocated by year and by region based on information provided by USM and CMP.

Results shown in Figure 18 below suggest that the project is expected to create an average of 1,631 jobs every year during the development (2017-2018) and construction periods (2019-2022) in Maine, of which 856 jobs are directly created due to the project, and 775 indirect and induced jobs are created through increased local spending by the project's construction workers and in sectors that provide supporting material and services to the development and construction activities. In addition to the new jobs, the Maine economy is expected to see a GDP surge by a total of $589 million over these years, or $98.2 million on an annual average basis.

Figure 18. LEI's estimated macroeconomic impacts of the NECEC project during the development and construction period based on the updated project cost

Economic Impact Category	Unit	Development		Construction				Annual Average
		2017	2018	2019	2020	2021	2022	
Direct Employment	Individuals	48	103	754	1,716	1,621	892	856
Indirect & Induced Employment	Individuals	67	119	653	1,409	1,500	900	775
Total Employment	Individuals	115	222	1,407	3,126	3,121	1,792	1,631
GDP	Millions of Fixed 2009 $	$8.8	$14.7	$84.8	$184.0	$189.1	$107.7	$98.2

The increase in new jobs and GDP related to the development and construction of the project is temporary. Once the construction is completed and the project enters commercial operations, such economic benefits will dissipate (and sometimes a negative employment change in the local economy can be observed as a natural effect of the economy rebounding from an economic shock).

Moreover, although the new jobs created by development and construction of the project are located in Maine, the positions are not necessarily filled by local Maine residents. The new jobs consist of a mix of full-time and temporary jobs and can be held by Maine residents or by migrant workers that move to Maine specifically for this project, and who might move out of the region right after the construction work is completed.

3.3 LEI's independent analysis of the operations period

LEI took a comprehensive view of the macroeconomic impacts of the NECEC over the 15-year modeling period. Specifically, LEI took into consideration the impacts due to O&M activities of the project, ratepayer's savings created by energy and capacity price reductions, the project's contract costs borne by the Massachusetts ratepayers, and early retirement of generating plants triggered by the project. Figure 19 and Figure 20 provide an itemized macroeconomic impact summary for Maine and for all of the New England states.

As shown in Figure 19, Figure 19. Aggregated economic benefits in Maine during the operations period (2023-2037)during the period of 2023-2037, Maine is expected to see an increase of 291 total jobs per year, of which 38 direct jobs are directly created by supporting O&M activities related to the project, and 309 jobs are generated through indirect and induced effects from ratepayers' electricity cost savings. The GDP increase in Maine during this period is expected to be on average

$29.1 million per year. The net contract costs with NECEC's award of the contract from the 83D RFP will be borne by Massachusetts electric ratepayers. However, the contract costs will reduce the retail electric savings that Massachusetts consumers would have otherwise seen. Due to the close linkages between the state economies in New England, this will have a negative impact on the Maine economy, causing an average of 55 job lost per year, and GDP loss of $4.9 million per year during the 15 years modeled. The generation units that are expected to retire early as a result of the NECEC participating in the FCM are located in Connecticut. Therefore, these generation retirements will have only a minor impact on Maine, reducing the new job count by three jobs and pulling GDP benefits down by $0.3 million per year during the modeling period.

Figure 19. Aggregated economic benefits in Maine during the operations period (2023-2037)

Economic Impact Category	Economic Impact item	Operations 2023-2027	2028-2032	2033-2037	2023-2037 Average
Employment (Individuals)	O&M	38	38	38	38
	Ratepayers' savings	732	263	-59	312
	Contract Cost	-112	-54	-1	-55
	Early Retirement	-3	-3	-3	-3
	Total	**655**	**244**	**-25**	**291**
GDP (Millions of Fixed 2009 $)	O&M	$2.2	$2.3	$2.4	$2.3
	Ratepayers' savings	$61.0	$30.4	$4.5	$31.9
	Contract Cost	-$8.9	-$5.2	-$0.7	-$4.9
	Early Retirement	-$0.2	-$0.3	-$0.3	-$0.3
	Total	**$54.0**	**$27.2**	**$5.9**	**$29.1**

Note: Economic impacts in terms of incremental jobs, GDP, and total compensation are presented in the form of annual average of corresponding modeling period.

As shown in Figure 20 below, during 2023-2037, an increase of 1,826 total jobs per year is expected to be created across all of the New England states, primarily through ratepayers' electric cost savings. The six states in New England are expected to see their GDPs increase by $205.3 million per year on average through the modeling period. The macroeconomic impacts from incorporating the contract cost of the project (paid by Massachusetts electric ratepayers) and the early retirement of several units (located in Connecticut) have a more significant effect on New England as a whole than Maine. Specifically, the contract cost of the project is expected to reduce 2,355 jobs and $288.3 million GDP per year in New England; the early power plant retirement triggered by the project is expected to lead to a reduction of 392 jobs and lower GDPs by $72.4 million every year in all states in New England.

LEI's results using REMI PI+ also show that during the outer years of the modeling period (2033-2037), Maine and New England are expected to see economic losses. This is primarily because LEI's electricity market modeling results show huge energy and capacity cost savings in the first five years, which immediately results in macroeconomic benefit hikes for local and regional economies. In the latter years, as the wholesale energy and capacity markets recalibrate to reach new equilibriums, the electricity market benefits will decline. As a result, the Maine and New

England economies will go through a rebound effect, meaning that after an economic shock, economies will shrink rapidly back to or even below the pre-shock status.

LEI has also analyzed the cost savings that NECEC could create for electric ratepayers by enhancing grid reliability and protecting ratepayers against energy shortages and electricity price hikes under extreme weather conditions. However, LEI cannot predict when such extreme weather conditions would materialize and therefore did not incorporate these additional wholesale electricity market benefits into any specific year of the modeling time frame. As a result, these additional wholesale electricity market benefits are not captured in the macroeconomic benefits during the operating period of the project.

Figure 20. Aggregated economic benefits from electricity market in New England (2023-2037)

Economic Impact Category	Economic Impact item	Operations			2023-2037 Average
		2023-2027	2028-2032	2033-2037	
Employment (Individuals)	O&M	N/A	N/A	N/A	N/A
	Ratepayers' savings	10,777	3,685	-742	4,573
	Contract Cost	-4,267	-2,433	-367	-2,355
	Early Retirement	-426	-394	-357	-392
	Total	**6,084**	**858**	**-1,465**	**1,826**
GDP (Millions of Fixed 2009 $)	O&M	N/A	N/A	N/A	N/A
	Ratepayers' savings	$1,091.6	$526.7	$79.5	$565.9
	Contract Cost	-$432.0	-$314.4	-$118.4	-$288.3
	Early Retirement	-$68.6	-$72.6	-$76.1	-$72.4
	Total	**$591.0**	**$139.8**	**-$115.0**	**$205.3**

Note: Economic impacts in terms of incremental jobs, GDP, and total compensation are presented in the form of annual average of corresponding modeling period.

3.4 LEI's independent analysis of municipal tax revenue

LEI estimated the potential tax revenue received by affected municipalities. As shown in Figure 21, assuming the project's taxable value (i.e. approximately $1 billion) provided by CMP is reliable, the listed municipalities are expected to receive around $18.1 million in annual tax revenue paid by the NECEC project.

LEI's analysis is based on the taxable value of the project in each municipality provided by USM in response to data request EXM-003-008 (see Column "Additional Valuation" in Figure 21) and the 2016 municipal full value tax rate[47] estimated by the Department of Administrative and Financial Services of the Maine state government.

[47] 2016 Equalized Tax Rate is derived by dividing 2016 Municipal Commitment by 2018 State Valuation with adjustments for Homestead and Business Equipment Tax Exemption ("BETE") and Tax Increment Financing ("TIF"). Full Value Tax Rates Represent Tax per $1,000 of Value.

However, the actual tax revenue is subject to the taxable valuation assessed by each municipality and the adjusted property tax rates (i.e. mill rates) in each of these municipalities. Specifically, how mill rates will change is subject to a combination of several factors, including the budget plan of the municipality (e.g. how much revenue to be collected, the amount of government spending in public services, other sources of revenue), the change in market value of other properties, etc. In fact, any estimates will only provide a proxy for the actual tax rate change and tax revenue received by each affected municipality.

Figure 21. LEI's estimated municipal tax revenue from NECEC

Municipality	Municipal Full Value Tax Rates ($ per $1000 of property value)	Additional Valuation ($Million)	Additional Tax Revenue ($Million)
Alna	$17.82	$18.91	$0.34
Anson	$19.17	$21.95	$0.42
Caratunk	$7.39	$13.96	$0.10
Chesterville	$16.23	$2.19	$0.04
Cumberland	$15.40	$15.60	$0.24
Durham	$16.49	$3.31	$0.05
Embden	$13.20	$20.23	$0.27
Farmington	$19.70	$22.62	$0.45
Greene	$14.69	$20.75	$0.30
Industry	$13.48	$10.69	$0.14
Jay	$21.24	$22.18	$0.47
Leeds	$15.86	$26.77	$0.42
Lewiston	$27.54	$304.79	$8.39
Livermore Falls	$20.75	$24.96	$0.52
Moscow	$16.50	$41.98	$0.69
New Sharon	$17.71	$4.87	$0.09
Pownal	$15.99	$85.99	$1.37
Starks	$15.46	$19.00	$0.29
Whitefield	$15.63	$56.84	$0.89
Wilton	$20.90	$2.52	$0.05
Windsor	$15.30	$8.54	$0.13
Wiscasset	$18.76	$26.61	$0.50
Woolwich	$13.01	$5.72	$0.07
Unorganized Territories and Townships	$8.08	$227.71	$1.84
Total		**$1,008.67**	**$18.09**

Sources:
Municipal Full Value Tax Rates: Department of Administrative and Financial Services of the Maine state government. < http://www.maine.gov/revenue/propertytax/municipalservices/fullvaluerates.pdf>
Additional Valuation: Provided by USM in response to data request EXM-003-008. Based on tax revenue estimated by CMP.

In addition, LEI's estimates show the potential revenues for municipalities for one year at the beginning of the project's commercial operations period. Over the life of a transmission project, once operational, its taxable value will slowly decline due to depreciation. Therefore, property tax payments by NECEC and the local tax relief it could provide will be larger in the early years and gradually decline over the life of the project.[48]

[48] There may be a residual market value which could establish a floor.

4 Comparison of LEI and Daymark Wholesale Electricity Markets Analysis

LEI finds that key differences between LEI's and Daymark's energy market forecasts are primarily due to the compounded effect of Daymark's use of low availability of generators in the summer, high delivered natural gas prices, the inclusion of various adders to the natural gas price, and the CELT 2016 demand forecast. The differences in capacity market price forecasts are primarily due to Daymark's improper calibration of the penalty factor, the low entry prices for new capacity resources, and the level of oversupply assumed in the Base Case. However, Daymark's CO_2 emissions reductions are roughly in line with LEI's estimate.

CMP's CPCN application included the Daymark Report which estimated the wholesale market benefits (Exhibit 5). Similar to LEI's approach, Daymark looked at the differences between a Base Case without NECEC and a Project Case in which NECEC is built. The following sections discuss LEI's findings of the key differences between LEI's and Daymark's price forecasts and resulting benefits.

4.1 Comparison of electricity market and environmental benefits

At a high level, the premise of Daymark's report is that NECEC would lower wholesale energy and capacity market costs for Maine consumers through a reduction in energy market and capacity market prices. Daymark's analysis also qualitatively discussed other benefits that the project could provide, such as CO_2 emissions reductions, ancillary services cost reductions, increases in REC supply, and reduced congestion costs. Figure 22 below shows the energy market price forecasts for LEI and Daymark. On average, Daymark's Base Case energy prices are 68% higher than LEI's.

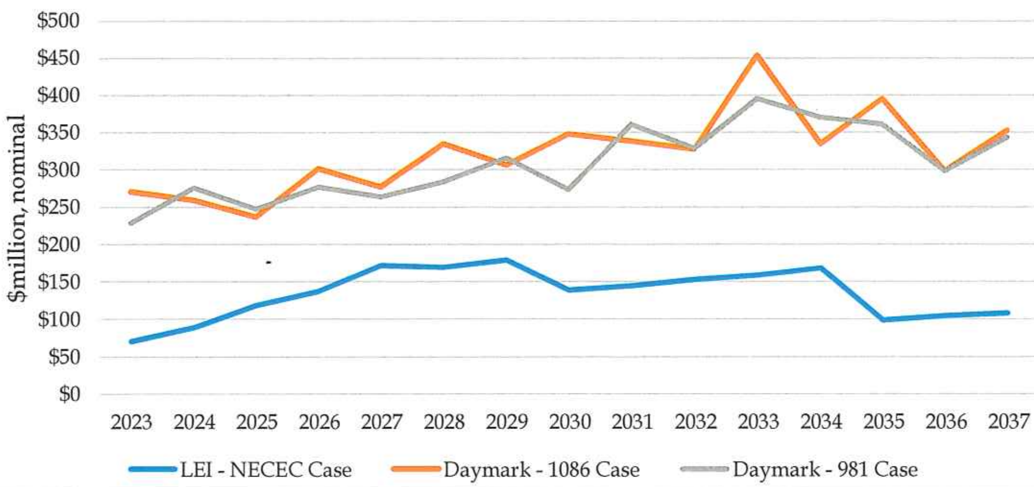
Figure 22. Comparison LEI's and Daymark's wholesale energy price forecasts for Maine

[redacted]

Note: LEI's prices shown above are a weighted average of the three Maine zones modeled. Daymark's price shown is for the ME zone.

Figure 23 below shows the energy market benefits for New England. It shows that on average, Daymark's 1086 NECEC Case energy market benefits are 141% higher than in LEI's. In reviewing the detailed assumptions of Daymark's analysis, there are a number of key drivers that lead Daymark to forecast higher wholesale energy prices and therefore higher energy market benefits for NECEC.

Figure 23. Comparison of LEI's and Daymark's wholesale energy benefits for New England



4.1.1 LEI calculated the impact of Daymark's assumptions on energy prices

LEI calculated the impact of each of Daymark's assumptions on Daymark's New England energy market benefits, compared with LEI's. LEI performed this calculation by layering each of the four Daymark assumptions (or "drivers") on top of LEI's own estimate of the energy market benefits (LEI baseline) (see Figure 24).[49]

- First, LEI adopted the natural gas index price contained in AEO 2016. This increased LEI's energy market benefits by approximately 38% above LEI's baseline estimate (which relied on AEO 2017).
- Second, LEI included Daymark's "regional adder" on top of the index natural gas price from AEO 2016 for Northern New England generators. This increased the energy market benefits by 45% above LEI's baseline.
- Third, LEI found that approximately 33% of Daymark's energy market benefits were attributed to the month of July, where Daymark had modeled some extremely high energy prices. LEI determined from the implied market heat rates (see Figure 32) that this dynamic in Daymark's modeling is explained largely by a combination of a super peaker adder (on gas prices) and the simplified approach Daymark took in AURORA to represent generator availability. By applying a 33% increase in energy market benefits as a proxy

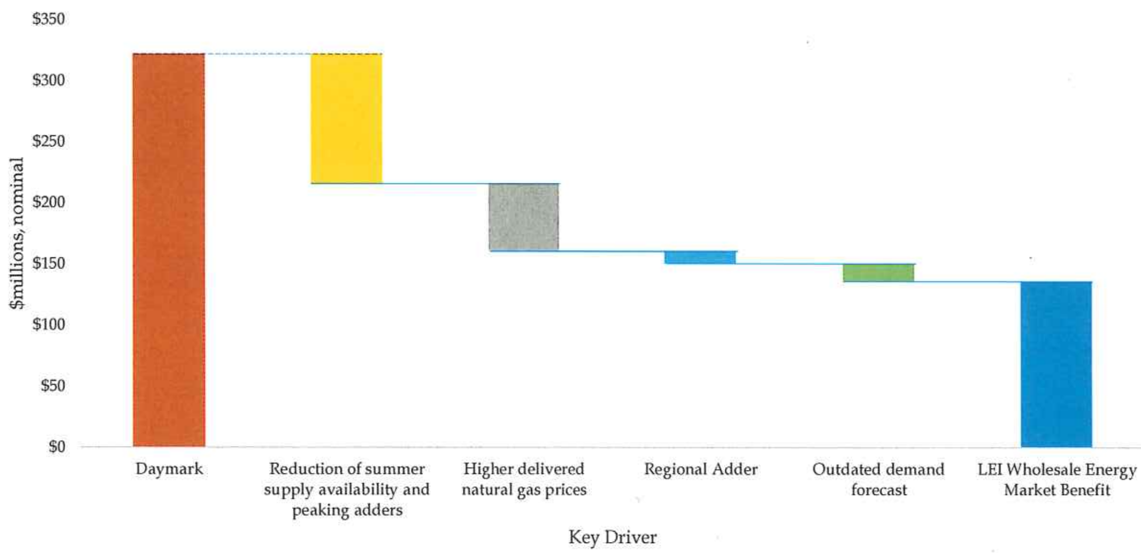
[49] In testing the impact of the various drivers of energy market benefits, LEI only conducted one single seed. Therefore, LEI's baseline shown differs slightly from the average of the 20-seeds.

for the super peaker adder and the summer availability, the energy market benefits increased to 119% above LEI's baseline estimate.

- Lastly, LEI estimated that the contribution to Daymark's energy market benefits from the higher demand forecasts in CELT 2016 increased the energy market benefits to roughly 129% above LEI's baseline estimate.

By stacking these increments on top of LEI's baseline, most of Daymark's higher energy market benefits could be accounted for. Overall, for the reasons described below, LEI believes that these four assumptions significantly overestimate the energy market benefits.

Figure 24. Illustration of LEI's estimate of the impact of key assumptions in Daymark's annual average energy market benefits in New England



Note: The key drivers shown above are scaled to illustrate the relative impact of each driver in Daymark's analysis

4.1.2 Daymark's simplified modeling of maintenance and forced outages by de-rating monthly availability creates perpetually tight summer supply conditions, high summer LMPs, and therefore high LMP reductions

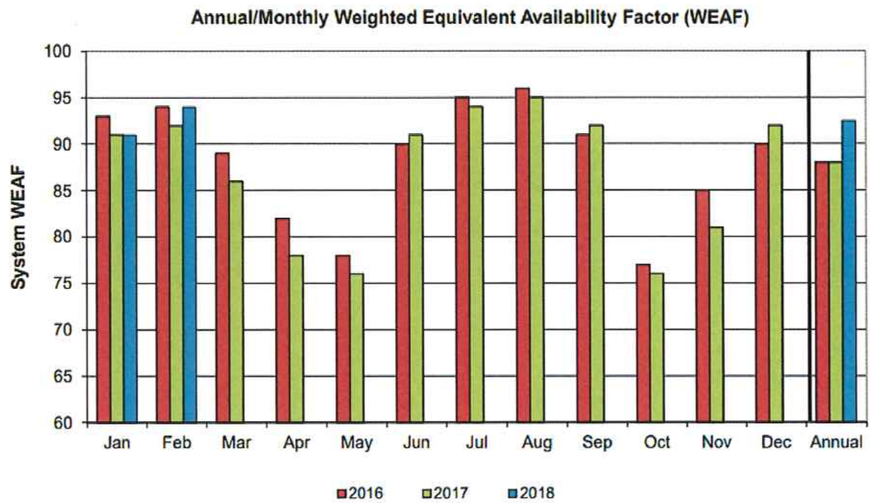
LEI understands that AURORA "limits the amount of capacity available to dispatch to reflect a normalized amount of forced outage per hour such that the annual generation of AURORA units reflect the annual forced outage rate assumed for that unit."[50] It is well understood that for thermal units, warm ambient air temperature typically reduces unit performance. As a result, the Seasonal Claimed Capability ("SCC"), which represents the amount of capacity determined by ISO-NE's capability audits during the summer and winter months, are typically lower in the summer than in the winter. However, while capacity supply is lowest during the summer, this is

[50] Daymark response to ODR-003-021. Daymark also noted in the April 5, 2018 technical session that the de-rating also reflects maintenance, not just forced outages.

when demand is highest. Therefore, most units will typically avoid maintenance during the summer – particularly intermediate resources that will run much more often during the summer and therefore earn energy market revenues.

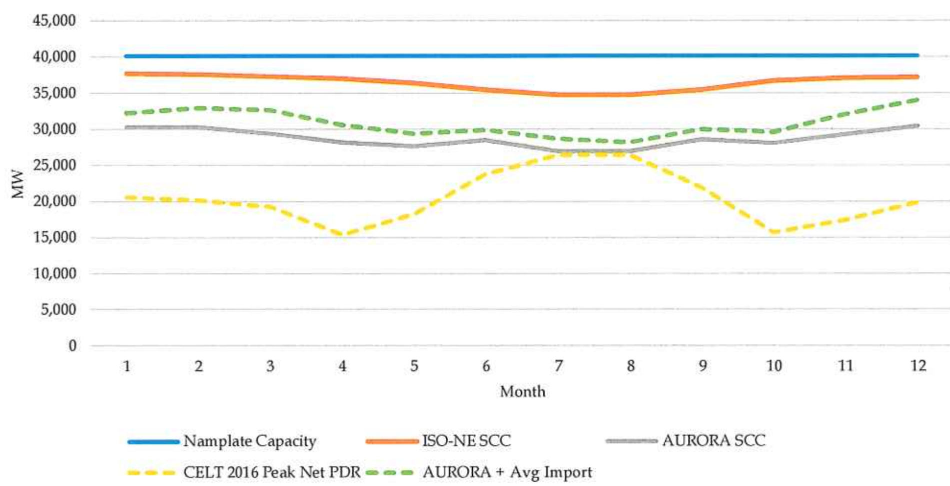
Forced outages are much less predictable than maintenance and can vary by plant and technology type. If a unit experiences a forced outage, its available capacity will fall to zero (unless it is only a partial de-rate). In other periods, when a unit is not on forced outage, then the available capacity is high. For planning purposes, ISO-NE calculates what is known as the weighted average equivalent availability factor ("WEAF") for units in New England. As shown in Figure 25, the highest rates of monthly availability typically occur in the summer when resources are needed the most to meet demand.

Figure 25. System unit availability in New England



Source: NEPOOL Committee Meeting Report, March 2018. <https://www.iso-ne.com/static-assets/documents/2018/03/20180302_npc_addl.pdf>

Figure 26. Daymark's assumed monthly supply and demand in ISO-NE's energy market, 2023



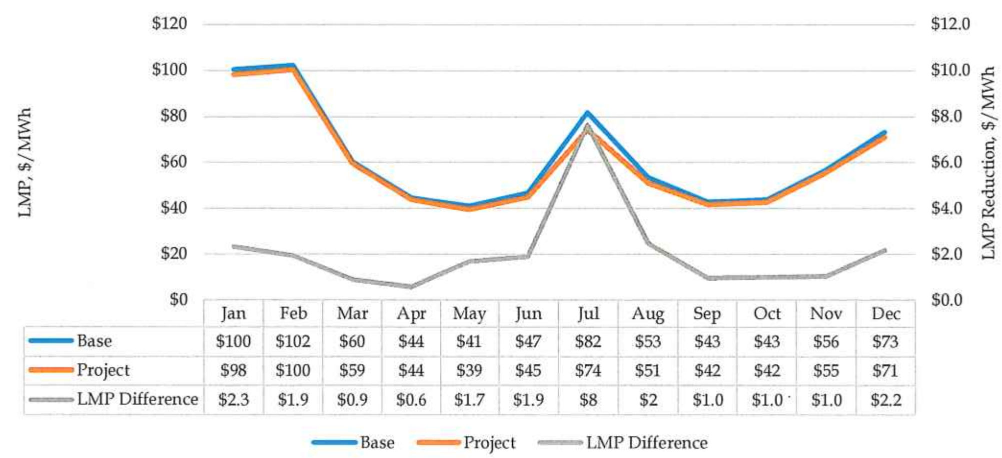
Source: ODR-003-021, CELT 2016. AURORA + Avg Import includes the average hourly import volume per hour

In analyzing the amount of capacity available in Daymark's energy market modeling against the monthly peak demand in each month based on CELT 2016, LEI found that capacity is very tight in the summer months, likely requiring highly expensive generation to run in order to meet demand. Figure 26 shows the monthly supply and demand in ISO-NE's energy market in 2023. The blue line represents total nameplate capacity, while the orange line shows the capacity based on SCC.[51] The grey line is the capacity available for dispatch based Daymark's approach to de-rating units. This represents a reduciton of 18% to 24% in capacity from the ISO-NE SCC values across all months.

The implication of having such tight supply when demand is highest is that it requires resources from the steep portion of the generation supply curve (causing high energy market prices). Because the marginal unit is from the steep portion of the curve, the flows from NECEC could have very large price reduction effects. While LEI believes such tightness is possible during extreme weather or load conditions, LEI finds it unlikely that this would reoccur every single year as Daymark's analysis implies. Daymark's high energy prices are also incongruent with historical monthly energy prices (see the implied market heat rates in Figure 32).

Figure 27 below shows an example of the average monthly LMP reductions in the first year that NECEC is in service from Daymark's analysis. Because of the very steep supply curve in July, NECEC is able to reduce LMPs much more effectively than in other months, when demand crosses the flatter part of the supply curve. This issue grows over time, as natural gas prices and demand rise.

Figure 27. LMP reductions in Daymark's analysis, 2023



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Base	$100	$102	$60	$44	$41	$47	$82	$53	$43	$43	$56	$73
Project	$98	$100	$59	$44	$39	$45	$74	$51	$42	$42	$55	$71
LMP Difference	$2.3	$1.9	$0.9	$0.6	$1.7	$1.9	$8	$2	$1.0	$1.0	$1.0	$2.2

Source: ODR-003-022.

4.1.3 Daymark's natural gas price methodology overestimates the cost of gas in New England

Both LEI's and Daymark's analysis use EIA's Henry Hub outlook albeit in different ways. In the short-term (2018 and 2019) LEI relied on the forward markets for projecting Henry Hub gas

[51] Ibid.

prices. LEI depends on forwards only to the extent they are liquid, and liquidity drops off dramatically after two years. For the longer term, the eventual increase in gas prices in the EIA's AEO 2018 Reference Case forecasts is consistent with the four key North American natural gas supply and demand trends discussed in Section 7.3. However, LEI believes that EIA's typically conservative outlooks for natural gas production growth have led it to ignore the impact of strong production on gas prices in the near term. EIA's Reference Case outlooks have shifted downward substantially in recent years (see Figure 56 in Section 7).

Daymark's New England natural gas index outlook is significantly higher than LEI's as shown below in Figure 28 because Daymark used EIA AEO prices directly (absolute levels) while LEI adjusts it forecast for near-term realities (by using forwards in the near term), and then escalates its forecast using the AEO growth rates. EIA's Reference case outlooks have been under-forecasting gas supply and over forecasting near-term Henry Hub prices for several years, which is why LEI chooses not to use Henry Hub absolute price levels in our gas price outlook.

Furthermore, Daymark has said that their model used the AEO 2017 outlook (Figure IV-3 on their report).[52] However, LEI checked Daymark's gas index price provided on April 2018 as a response to a DR (ODR-003-015_Att_1), as well as Figure IV-3 in the Daymark report, and the data in the figure is from AEO 2016 outlook and not from AEO 2017. If Daymark used the AEO 2016 outlook, their gas price outlook is 7% higher than if they used AEO 2017.

Figure 28. LEI versus Daymark Henry Hub and New England price outlook

[redacted]

Source: LEI and Daymark Report Exhibit NECEC-5

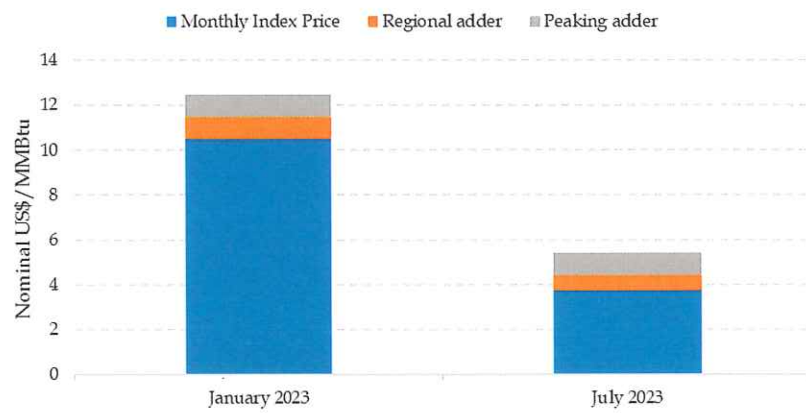
4.1.4 Daymark's New England natural gas index price outlook is an average market price and therefore should not include adders

Daymark's New England natural gas forecast is a New England annual average price, referred to by Daymark as an "index price," a monthly shaping factor, and a set of adders to create separate

52 ODR-EXM-003-024.

natural gas outlooks for plants located in northern New England and for peaking plants (see Figure 29).

Figure 29. Daymark New England January and July natural gas prices in 2023 (recreated by LEI)



Source: Recreated with data from Daymark Report, Exhibit NECEC-5 and answers to DRs[53]

Regional adder

The regional adder is an additional layer of gas price cost applied to generators located in northern New England (Maine, New Hampshire, and Vermont). Daymark explained that they developed this adder in the process of calibrating their model; the added cost is needed to replicate the pattern of generation by the plants in these regions.[54] Daymark calculated the regional adder based on the annual backhaul rate for firm transmission ("FT") from the Maritimes and Northeast Pipeline ("M&NE") scaled for each month by the Portland Natural Gas Transmission System ("PNGTS") monthly rate multiplier. This approach implicitly assumes northern New England plants use FT services for natural gas delivery all the time. However, most plants use interruptible transmission ("IT"), which has lower rates than FT.

Peaking unit adder

On top of the regional adder, Daymark applied another adder to plants that they argued generate only during peak days or hours. According to Daymark, the adder aims to represent the higher cost of procuring fuel during high demand periods, when peaking units are burning gas. This adder creates a separate natural gas outlook for the peaking units in Figure 30 (column "Resources in Class").

[53] Index Price from IECG-003-003_Att_1 CONFIDENTIAL (2017-00232); Monthly adder from EXM-002-016_Att_1; Regional adder from EXM-002-018_Attachment_1_(2017-232); and Peaking adder from Daymark Report Exhibit NECEC-5, Table IV-1 (Page 49 of 98).

[54] Transcript 5 Tech Session CONFIDENTIAL, pg. 122-123

Figure 30. Daymark peaking unit adder

Natural Gas Delivery Class	Fuel Adder (2017$/MMBtu)	Resources in Class
Peaking	$0.89	New Haven Harbor Units 2-4 (151MW); Androscoggin Energy Center CT03 (51MW); Swanton Peaking Generation Project #10 (40MW); Algonquin Windsor Locks (38MW); Lowell Cogeneration #GEN1-2 (32MW); Capital District Energy Center STG (29MW); Waters River #1 (20MW); Pawtucket Power #1 (20MW); 15 smaller units totaling 33MW.
Super Peaking	$1.74	Devon 11-14 (161MW); Cleary Flood #9a (106MW).
Standard (Non-Peaking)	$0.00	All Remaining units.

Table IV-1. NMM Peaking Unit Fuel Price Adder Assumptions

Source: Daymark Report Exhibit NECEC-5. Table IV-1 (Page 49 of 98)

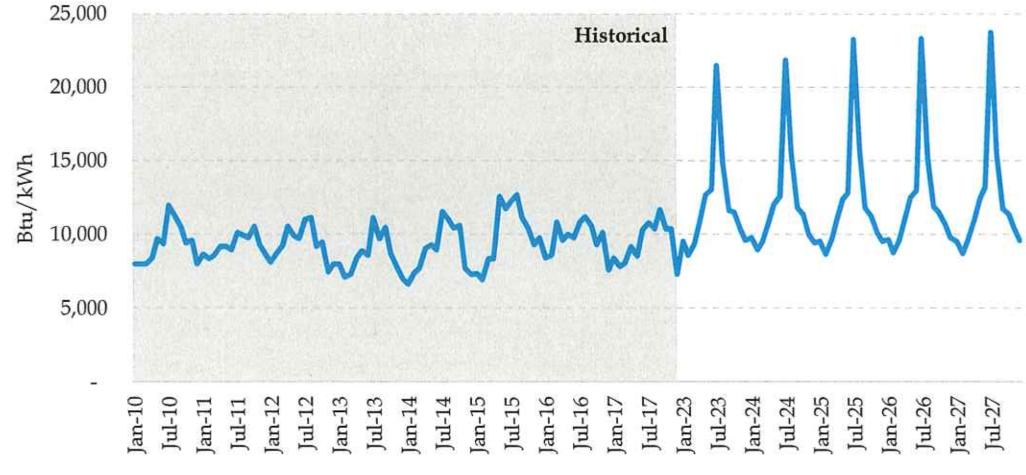
LEI believes this methodology does not accurately represent the pattern of operations of peaking units and the inherent gas (fuel) costs that these units would face. The Androscoggin Energy Center CT03, for example, operates throughout the entire year, not just at peak demand hours in the summer (see Figure 31). In fact, it has run most in September, when natural gas prices are typically low, and December when gas prices have not yet reached their seasonal (January and February) peaks. In Daymark's model, this unit is paying a premium above the monthly price for every hour it runs.

Figure 31. Androscoggin Energy Center CT03 generation profile (accumulated generation by month from 2012 to 2017)

Source: Ventyx Velocity Suite

When compounding the impact of tight summer supply, a high natural gas price for New England, and peaking adders, the result is extremely high implied market heat rates that far exceed historical evidence as shown in Figure 32 below.

Figure 32. New England monthly implied heat rate – historical and Daymark outlook



Source: SNL (2010-2017) and Daymark (2023-2027)[55]

4.1.5 Daymark used a higher energy demand forecast

One other key difference is that as described in pg. 4 of the Daymark Report, Daymark used the CELT 2016 forecast, as Section 2.3.1.2 of the MA 83D RFP notes that "[t]he reference case system topology will be based on the 2016 ISO New England Capacity, Energy, Load and Transmission (CELT) report." Total demand net of energy efficiency and behind-the-meter solar PV in CELT 2017 is approximately 4-5% lower than in CELT 2016. Because the energy market costs are a direct function of the level of energy demand, higher energy demand will result in higher energy market benefits.

4.2 Comparison of capacity market benefits[56]

Capacity market benefits stem from the fact that NECEC would result in lower capacity prices. Figure 33 below shows the capacity prices in the Base Case and Project Case in LEI's and Daymark's analysis, against the Net CONE.[57] It shows that LEI's long-run capacity prices are higher as a result of LEI's higher Net CONE assumption (based on the extrapolation of ISO-NE's Net CONE assumption) estimate for FCA #12, while Daymark extrapolated the Net CONE based on the results of FCA #10 in which the FCA concluded with new entry at $7.03/kW-month. On

[55] Historical data was calculated with the monthly average of New England Internal Hub DA LMP prices and Algonquin prices. Daymark's implied heat rate was calculated with Daymark's Base Case LMP price outlook provided on ODR-003-022_Att_1 and Daymark's gas index price outlook provided on ODR-003-015_Att_1.

[56] LEI did not conduct a MOPR analysis of NECEC to determine whether it would clear the primary auction as CMP did not provide sufficient data for LEI to perform such an analysis. In this section, all the comparisons are based on the assumption that NECEC would clear in the primary auction for FCA #14. However, if NECEC clears the through the substitution auction, then the wholesale capacity market benefits would fall to zero and therefore the electricity market benefits to electric ratepayers would be smaller.

[57] LEI understands that Daymark used the ISO-determined Net CONE for the purposes of setting the price cap. However, the assumed entry prices for new capacity used a modified Net CONE or investment trigger price, which is what is shown in Figure 33 of the Daymark Report.

top of the lower net CONE assumption, Daymark's outlook projects that New Entry constantly clears below its "modified Net CONE" value, leading to lower long-run capacity prices.

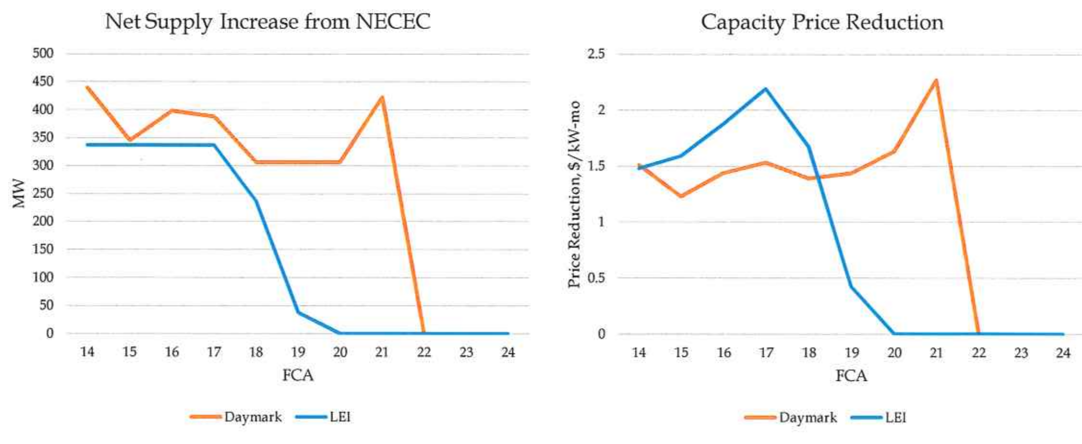
Figure 33. Comparison LEI's and Daymark's wholesale capacity price forecasts

[redacted]

Note: Daymark's capacity market analysis for NECEC concluded after FCA 24. However, only eight years of benefits (up to FCA #21) were included.

Daymark's analysis projects that the capacity market benefits will end after eight years (FCA #14 - #21) when the first generic new entry enters the Base Case in FCA #22. In LEI's model, the convergence of the Base Case and Project Case converges after six years, two years earlier. As shown on the left side of Figure 34, despite 1,090 MW of capacity, NECEC only results in 300 - 400 MW of *incremental* capacity in New England because of market response. Over time, new resources will be added to the system in the Base Case first, until the point where the Base Case and Project Case reach approximate parity.

Figure 34. Comparison of net supply from NECEC and capacity price reduction



Note: For this figure, LEI applied a value of zero for FCA #23 and #24 to Daymark's figures, to account for the fact that no capacity market benefits are assumed in these years.

The wholesale capacity price reduction on the right side of Figure 34 also shows a similar trend, whereby the highest capacity market price reductions occur when there is the greatest level of oversupply in the Project Case relative to the Base Case. Over the first few years, Daymark projects a smaller price-reducing impact than LEI. This is because Daymark's capacity market assumptions lead to a propensity to accept oversupply, as discussed in more detail below. The following sections explain the major differences in capacity market price levels, and the wholesale capacity market benefits between the LEI and Daymark reports.

4.2.1 LEI calculated the impact of Daymark's assumptions on capacity prices

Figure 15 below demonstrates LEI's calculation of approximately how much each assumption (or driver) discussed below contributed to New England capacity market benefits. LEI layered each of the three drivers on top of LEI's estimate of the capacity market benefits (LEI baseline).[58] Because the timeframe for benefits is different between LEI's and Daymark's analyses, LEI compared the *cumulative* capacity market benefits.

- First, LEI changed the price for new entry to Daymark's modified Net CONE. This lowered the long-term capacity prices and reduced LEI's cumulative capacity market benefits by 26%.

- Second, LEI use Daymark's level of cleared capacity in the Base Case and Project Case (which does not include FCA #12 results and more recent retirement de-list bids). Combined with Daymark's lower investment trigger prices for new capacity, the difference in starting points increased the capacity market benefits to 11% above LEI's estimate.

- Third, LEI adjusted the penalty factor to the constant value that Daymark used in their analysis. This increased the wholesale capacity market benefits to 35% above LEI's capacity market benefits.

By stacking these components on top of LEI's baseline, LEI obtained a similar level of capacity market benefits as Daymark. Despite the low entry prices that Daymark assumed for new generation (which has the effect of reducing the capacity market benefits), LEI believes that when the drivers are taken together, the overall capacity market benefits are overstated in the Daymark analysis, given market developments since Daymark wrote their report. In addition, if the project does not clear in the FCA, then LEI would expect capacity market benefits to go to zero, as the goal of the substitution auction under CASPR is to create a one-for-one swap of capacity such that capacity prices to ratepayers do not change.

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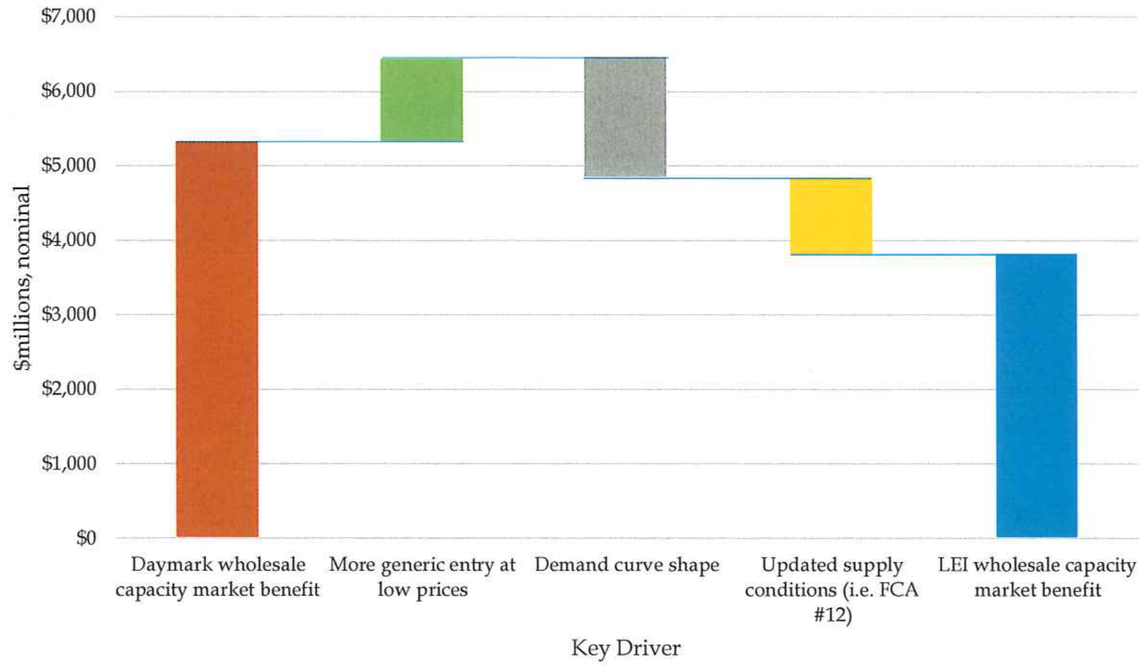
[58] In testing the impact of the various drivers of energy market benefits, LEI only conducted one single seed. Therefore, LEI's baseline shown differs slightly from the average of the 20-seeds.

Figure 35. LEI's estimate of key driver impacts in Daymark's cumulative capacity market benefits in New England



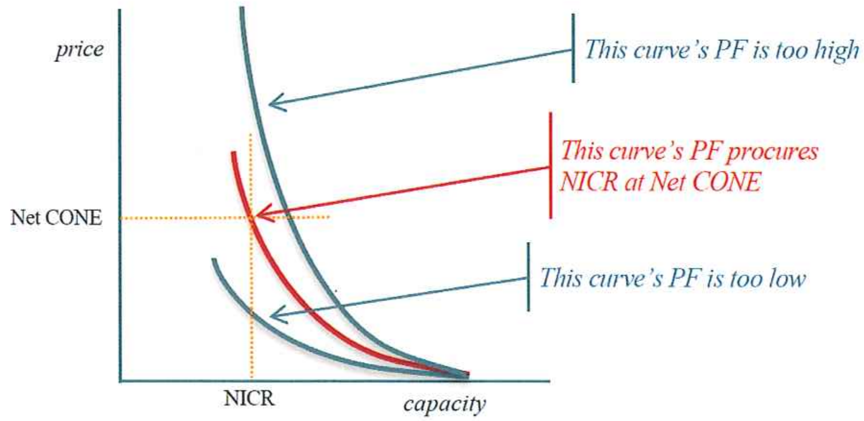
Note: The key drivers shown above are scaled to illustrate the relative impact of each driver in Daymark's analysis

4.2.2 Daymark's capacity prices are not accurately calibrated to account for changes to Net CONE and NICR over time, resulting in a capacity price that takes longer to reach long-run equilibrium and prolonging capacity market benefits

To account for changes each year, Daymark shifted the demand curve to the right by the growth in NICR. Daymark also adjusted the price cap (set at 1.6x Net CONE) to adjust for Net CONE growth over time. By ISO-NE's design, this should steepen the demand curve to properly send accurate price signals in the market, since it must attract new investment that becomes more expensive over time.

However, as described in Section 6.2, the capacity price is the penalty factor multiplied by the MRI, and therefore the penalty factor used will directly impact the capacity price. In order to scale the MRI curve properly and account for the growth of Net CONE, the penalty factor must be adjusted such that if the market procures *exactly* the same amount of capacity as NICR, the resulting capacity price should clear exactly at Net CONE. Figure 36 below is from one of ISO-NE's technical memos regarding where the penalty factor should be set.

Figure 36. Setting the penalty factor



Source: ISO-NE. FCM Zonal Demand Curve Methodology – Revised Edition. December 7, 2015.

While Daymark does increase the price cap to account for the growing Net CONE, it does not adjust the penalty factor to scale the MRI curve properly. The impact of not adjusting the penalty factor will result in capacity prices that take longer to rise (essentially, the capacity price will be too high relative to the level of cleared capacity). As shown previously in the right side of Figure 34, the capacity price reduction rises in LEI's curve even though the oversupply in the Project Case relative to the Base Case is constant. This demonstrates that the penalty factor is being adjusted along with the Net CONE growth. As a result, capacity prices rise faster in LEI's analysis, and therefore the market rebalances faster as well.

A second issue with Daymark's model is that the penalty is actually calibrated for a much higher Net CONE of $10.95/kW-month. This was easily tested by determining the clearing price when the qualified capacity is equal to NICR. This further adds to the fact that Daymark's model is not properly calibrated to develop capacity prices that are consistent with the quantity levels assumed.

4.2.3 Daymark's modified Net CONE for new entry leads to lower long-run capacity *price levels* and persistent oversupply in the capacity market

ISO-NE calculated that the Net CONE for FCA #12 was $8.04/kW-month, based on its estimate for a combustion turbine. Daymark notes that the "ISO estimates reflect generic assumptions and forecasts of costs and revenues, and generally does not reflect actual bids from market entrants. In fact, several new resources cleared the market in FCA 10, when the clearing price was just over $7.00/kW-mo. This indicates that new generation projects are viable when clearing prices are lower than the ISO-NE Net CONE value."[59] However, Daymark did not note that several of the units that cleared FCA #10 were developed at brownfield sites (i.e. Bridgeport Harbor and Canal), or have been able to make use of tax incentives in the form of bonus depreciation.[60] Because actual

[59] Daymark Report, pg. 10.

[60] 30% bonus depreciation is allowed for units in service by 2019.

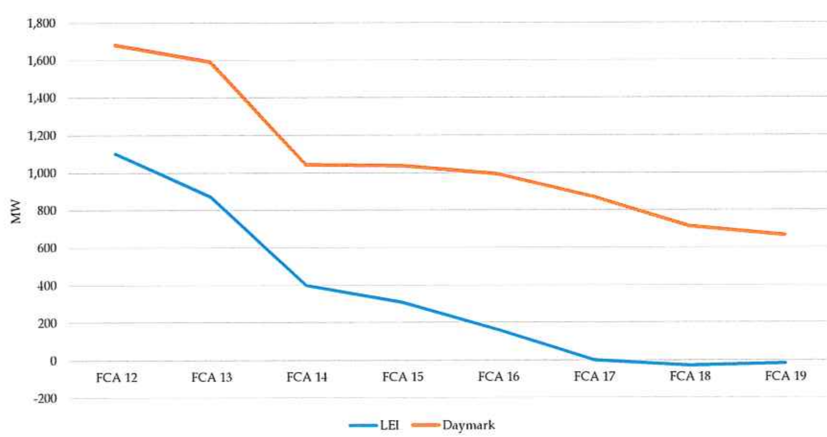
bids can vary significantly from project to project, LEI's analysis adopted ISO-NE's estimates which was vetted through the ISO Markets Committee.

The impact of using Daymark's reduced Net CONE is that the new entry enters the FCM in the Base Case sooner. Because Daymark assumes that there are no capacity market benefits after new entry enters the FCM in the Base Case, a lower Net CONE to trigger new entry actually *reduces* capacity market benefits. LEI estimates that the capacity market benefits in FCA #22 in Daymark's analysis would be even higher than in FCA #21 if they used a higher price for new investment (see Figure 34). However, this does not imply that Daymark's analysis is conservative. Rather, LEI believes Daymark's capacity market analysis is not formulating capacity prices correctly as discussed in the previous section due to the PF.

4.2.4 Daymark's analysis exhibited a high level of oversupply, resulting in lower short-term capacity prices than LEI's analysis

Another issue that LEI considered was whether Daymark's starting point for analysis (FCA #12) adopted reasonable assumptions. The latest auction that occurred at the time Daymark prepared its analysis was FCA #11. In FCA #12, total demand resources grew by 390 MW from 3,210 MW to 3,600 MW. However, this growth in demand was offset by the dynamic de-list of Mystic 9. As a result, FCA #12 was only oversupplied by 1,103 MW, while in Daymark's starting point for the analysis, FCA #12 was 1,685 MW above its assumed NICR. LEI believes that the effect of this oversupply in Daymark's analysis for FCA #12 carries into FCA #14, resulting in lower capacity prices than LEI's, particularly over the first few FCAs that NECEC is in service. This is shown below in Figure 37, whereby Daymark's oversupply is long-lasting, resulting in lower capacity market prices in their Base Case and Project Case and therefore a longer capacity price difference.

Figure 37. Comparison of net oversupply relative to NICR in LEI's and Daymark's Base Case



LEI believes that the reason Daymark's model exhibited such a high degree of oversupply is due to the fact that the penalty factor is set too high. For example, while FCA #12 cleared with 1,103 MW above NICR at $4.63/kW, Daymark's analysis suggests FCA #12 would have cleared with

1,685 MW above NICR at $[redacted]/kW-month.[61] This incorrect price formation carries over in future years.

By FCA #14, ISO-NE is expected to implement the full MRI curve. All else being equal, compared to the transition curve, LEI expects capacity prices to drop due to the convex shape of the MRI demand curve. In LEI's Base Case, this caused some resources to retire in FCA #14, namely the remaining coal units. As discussed previously, because the penalty factor in Daymark's analysis was set too high, the resulting capacity price was also too high relative to the level of oversupply. It is likely that if the penalty factor was calibrated appropriately, capacity prices (in both Daymark's Base Case and Project Case) would drop, causing more de-lists or retirements in the Base Case and Project Case.

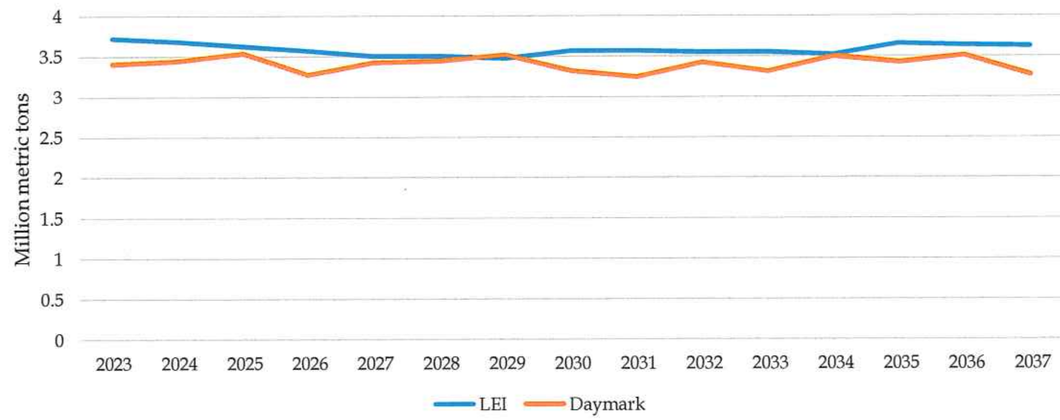
4.3 CO_2 emissions reductions

CO_2 emissions reductions are a function of the emissions rates of the resources that NECEC will replace. By and large, New England's generation is natural gas-fired, meaning that NECEC is likely to displace [redacted] GWh of natural gas generation, which typically has emissions rates of approximately 700-1,000 lbs./MWh.

LEI finds that Daymark's estimate of 3.4 million metric tons is reasonable, but perhaps slightly conservative. Based on Daymark's own analysis, supply conditions in New England can become very tight during the summer, which would likely result in more oil-fired generation, which typically has a higher emission rate than natural gas units. Therefore, intuitively, since the energy flows are comparable, Daymark's tight supply conditions should, at least in theory, yield higher CO_2 emissions. The most likely explanation is that there are slight differences between the emissions rates assumed for the resources that are being offset by NECEC between LEI's and Daymark's models, although the results suggest that it is not much. Figure 38 below shows the CO_2 emissions reductions in LEI's and Daymark's analysis side-by-side.

[61] LEI understands that for FCA #12, Daymark used the MRI curve to establish a capacity price and added $1.6/kW-month.

Figure 38. Comparison of CO_2 emissions reductions in LEI's and Daymark's analysis



5 Comparison of LEI and USM Macroeconomic Benefits Analysis

This section provides LEI's evaluation of USM's analysis based on a side-by-side comparison of LEI's and USM's results. LEI finds USM's analysis for the development and construction period to be reasonable, although the relatively high local share of the development and construction cost remains subject to some uncertainty in terms of realization of those positive macroeconomic impacts to Maine. During the operations period, USM over-estimated the macroeconomic benefits of the operations of NECEC, because it relied on inflated electricity market benefits provided by Daymark. The inputs USM used in its macroeconomic model for measuring the electricity market benefits were also incomplete as they ignored the capacity market benefits, contract costs, and the impact of early retirement. During the first 15 years of operations period (2023-2037), LEI projects 272 new jobs per year and $27.1 million GDP increase per year for Maine related to the project's O&M activities and ratepayers' electricity savings.

For the macroeconomic impacts during the development and construction period, the differences between LEI's and USM's results are fairly minor. However, LEI is concerned about the assumed high share of the project cost USM attributed to activity Maine. Limited by the lack of granularity in the cost estimates provided by CMP, LEI cannot verify if the 60% local cost share is reasonable. If the local share of the project's cost turns out to be 10% lower, the estimated macroeconomic benefits in terms of incremental jobs and GDP for Maine will drop by 10%.

LEI found the macroeconomic impacts during the operations period, especially with regards to the ratepayers' benefits in USM's study are overstated in certain ways, and incomplete in other respects. First, the wholesale energy market benefits estimated by Daymark and used by USM for modeling macroeconomic benefits are based on higher fuel price forecasts and an artificially inflated supply shortfall in the summer months. These flaws in the energy market modeling results have led to an overestimation of macroeconomic impacts.

Second, USM only studied the impact of wholesale energy cost reductions and did not consider the impacts from the capacity market,[62] the contract costs borne by Massachusetts ratepayers, the early retirement of generation capacity triggered by the project, and deferred investment in local new generation due to introducing lower-cost resource to the New England power market.[63] All these factors should be considered in an integrated manner for analyzing the project's impacts on the Maine and New England regional economy. A detailed discussion of the operations period analysis is presented in Sections 5.3 and 5.4.

5.1 Comparison for the development and construction period

LEI's analysis is based on the updated project cost and is compared with USM's modeling results which are based on the original project cost. For the purpose of an apples-to-apples comparison,

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[62] As mentioned in footnote 56, in this section, all the comparisons are based on the assumption that NECEC would clear the primary auction for FCA #14. However, if NECEC clears the FCA through the substitution auction, then an equivalent amount of supply would need to exit the FCA and the capacity market benefits would be zero. And the macroeconomic benefits would be reduced.

[63] Lastly, USM did not convert the wholesale capacity impact into a retail rate impact figure, which is more appropriate in evaluating the impact of NECEC on New England's retail consumers.

LEI also modeled the original project costs using LEI's approach and compared the results with USM's approach (see Appendix C).

As shown in Figure 39, in general, LEI's estimates for macroeconomic benefits for the development and construction period are similar to USM's results. LEI's estimated annual average job creation is 4% lower than USM's results, and LEI's estimated GDP increase is 4% higher than USM's results. The difference in total compensation is marginal.

Figure 39. Side-by-side comparison of the development and construction period

Economic Impact Category	Unit	Annual Average (2017-2022)		Differences
		USM	LEI	
Direct Employment	Individuals	868	856	-1%
Indirect & Induced Employment	Individuals	824	775	-6%
Total Employment	Individuals	1,691	1,631	-4%

Economic Impact Category	Unit	Total (2017-2022)		Annual Average (2017-2022)		Differences
		USM	LEI	USM	LEI	
GDP	Millions of Fixed 2009 $	$564.8	$589.0	$94.1	$98.2	4%
Total Compensation	Millions of Nominal $	$435.7	$433.6	$72.6	$72.3	0%

The small differences in results can be explained by two factors. First, LEI's analysis is based on the updated local project cost estimates, which are 2% higher than the original project cost estimates. This may lead to slightly higher overall GDP and job increases for Maine in LEI's analysis. Second, LEI used more detailed industrial sectors for modeling the development and construction costs, based on the available cost breakdown provided by USM and CMP. This resulted in minor differences in the macroeconomic outcomes given that the project investment is captured and modeled through different interconnections among relevant sectors in the REMI PI+ model.

5.2 Drivers of differences between LEI's and USM's analysis of the development and construction period

LEI's major concern about USM's analysis for the development and construction period is the high share of the project's local spending in Maine provided by CMP, which leads to inflated macroeconomic benefits. LEI has two minor concerns with regard to the modeling methodology and how the results were presented. Aside from these, LEI finds USM's analysis for the development and construction period to be reasonable.

5.2.1 USM assumes an unusually high share of local spending of the project cost

The share of local expenditures (i.e., Maine) estimated in the original cost estimate comprises 56.2% of the project costs, while 60.4% of the updated total project costs are estimated to be local. USM compared the local share of the NECEC project cost with that of the Maine Power Reliability Program ("MPRP") project, whose share of local spending was estimated to be 67% and claimed that local share estimate of the NECEC project is reasonable. However, the two projects (NECEC and MPRP) are very different. MRPP is a 345kV line while NECEC project is an HVDC transmission line. HVDC projects generally require more skilled labor and equipment to be sourced from other states.

Without more detailed project estimates than those provided by CMP, LEI cannot determine if the local cost estimates are reasonable. However, comparing to what LEI has observed in other engagements involving other HVDC transmission projects, this local share appears to be on the high end. If the actual project spending was to be 10% lower, then it would be expected to see a drop by approximately 10% in the projected macroeconomic benefits as well, based on LEI's prior analysis.

5.2.2 Jobs created by the project should not be considered cumulatively

USM's report shows cumulative job increases for the development and construction periods.[64] However, the REMI PI+ model outputs job increases in the term of Job-Year, meaning that a job created in the first year of the construction period and lasting for the entire four years of the construction period will appear as a job increase in every year. Therefore, showing the cumulative number of new jobs is misleading to readers who are not familiar with the characteristics of REMI PI+ models. Presenting the annual average employment change is a better and more meaningful metric to understand the macroeconomic impact of the project. Therefore, the Table 1.1 on page 1 of the USM report should read as "during the development and construction periods, the NECEC project is expected to generate 1,691 total jobs per year between 2017 and 2022" not 10,147 total jobs between 2017 and 2022.

5.2.3 USM modeled construction cost at a very general level

USM modeled project cost at a general level by using only three cost categories, namely (i) construction, (ii) management of companies and enterprises, and (iii) professional scientific, and technical services. Using general categories of inputs in the REMI modeling might result in inaccurate outcomes. For example, the REMI PI+ model will take the total amount of project spending in the construction sector and then automatically spread and allocate it to subsectors of construction based on the configurated input/output relationship among these sub-sectors, which include power infrastructure construction, residential structure construction, and educational and recreational structure, etc. Some of these sub-sectors such as residential structure construction, are not relevant to the project and may distort the modeling results.

Given that the 70-sector PI+ model allows us to model project cost with more granularity, LEI chose a set of more detailed and relevant policy variables for modeling the construction cost impacts on the Maine economy. LEI also tested modeling the original project cost at a more detailed level and compared the results with USM's estimates based on the same set of project cost estimates, for the purpose of an apples-to-apples comparison. Results show that LEI arrived at local job creation estimates that are about 6% lower than USM's estimates (see Appendix C). LEI's estimate of GDP increase is 2.5% higher while the total compensation increase is 1.5% less than USM's estimates.

In conclusion, LEI finds USM's macroeconomic analysis for the development and construction period might be over-estimated given the high assumed percentage of local (Maine) spending.

[64] See Column "Total" in Table 1.1 on pg. 1 of the USM Report, 4.1 on pg. 9 of the same USM Report, and Table 10 on pg. 4.3 of the USM's Report.

LEI also wants to stress that the new jobs and GDP increases in the development and construction period are temporary and will dissipate once the construction is completed. Furthermore, not all the new jobs will be filled by Maine residents, but would also have migrants who would temporarily move to Maine to work on this project.

5.3 Comparison of the macroeconomic impacts during the operations period

As shown in Figure 40 and Figure 41 below, LEI's estimates for the macroeconomic impacts during the operations period due to the NECEC project is significantly higher than USM's estimates in the first five years of the operations of the project, but is lower for the latter period. In fact, LEI's modeling results show that during 2033-2037, Maine and New England are expected see economic losses. This is mainly due to the fact that LEI included the contract costs while USM did not, and is also because of the rebound effect as discussed in Section 3.3.

Figure 40. Estimated macroeconomic impacts on employment in Maine during the operations period (2023-2037)

Scenario	Economic Impact Category	Unit	Operations 2023-2027	2028-2032	2033-2037	2023-2037 Average
USM's Results (a)	Total Employment	Individuals	357	351	278	329
	GDP	Millions of Fixed 2009 $	$22.7	$27.7	$27.1	$25.8
LEI's Results (b)	Total Employment	Individuals	655	244	-25	291
	GDP	Millions of Fixed 2009 $	$54.0	$27.2	$5.9	$29.1
Differences [(b-a)/a]	Total Employment	%	83%	-30%	-109%	-11%
	GDP	%	137%	-2%	-78%	12%

Figure 41. Estimated macroeconomic impacts on GDP and compensation in New England during the operations period (2023-2037)

Scenario	Economic Impact Category	Unit	Operations 2023-2027	2028-2032	2033-2037	2023-2037 Average
USM's Results (a)	Total Employment	Individuals	4,129	3984	3091	3,735
	GDP	Millions of Fixed 2009 $	$365.1	$432.2	$421.3	$406.2
LEI's Results (b)	Total Employment	Individuals	6,084	858	-1,465	1,826
	GDP	Millions of Fixed 2009 $	$591.0	$139.8	-$115.0	$205.3
Differences [(b-a)/a]	Total Employment	%	47%	-78%	-147%	-51%
	GDP	%	62%	-68%	-127%	-49%

Note:
1. USM's results are based on wholesale energy market cost savings, while LEI's estimates are based on retail electricity market savings (including energy and the capacity markets), also adjusted for the net contract costs of the 83C RFP award being paid by Massachusetts electric ratepayers, and early retirement of generating plant.
2. Economic impacts from O&M in New England are not included in either USM's or LEI's aggregated results shown in Figure 40 and Figure 41, but are included in the Maine results, since those impacts were estimated within Maine.
3. Economic impacts in terms of incremental jobs and GDP are presented in the form of annual average of corresponding modeling period.

5.4 Drivers of differences from LEI and USM's analysis of the operations period

While the total macroeconomic benefits for Maine in terms of incremental GDP and jobs in the USM study and LEI study do not differ much, the analytical approach and results are quite different when looking at them component by component.

As illustrated in Figure 42 and Figure 43 below, including capacity market benefits significantly increase the total macroeconomic benefits in LEI's analysis. On the other hand, LEI's results show lower wholesale energy market benefits as compared to USM's study (which was based on inflated fuel prices). However, there are other opposing differences that net out the impact between two studies. For example, LEI's inclusion of capacity market benefits creates a higher job and GDP impact. On the other hand, taking into consideration the impacts from the contract cost paid by Massachusetts ratepayers lowers the macroeconomic benefits in Maine. In addition, the early retirement of generating plants will negatively impact the Maine economy as well. Although retail electricity consumers in Maine are assumed to be exposed to the entire amount of wholesale electricity price changes, retail consumers in other states in New England are expected to enjoy only a portion of the wholesale electricity cost savings and less macroeconomics benefits than if modeled with wholesale market savings. Such reduced macroeconomic benefits in other New England states will also impact the Maine economy.

Figure 42. Breakdown of macroeconomic benefits for the operations period between the USM and LEI studies in Maine, annual average jobs (2023-2037)

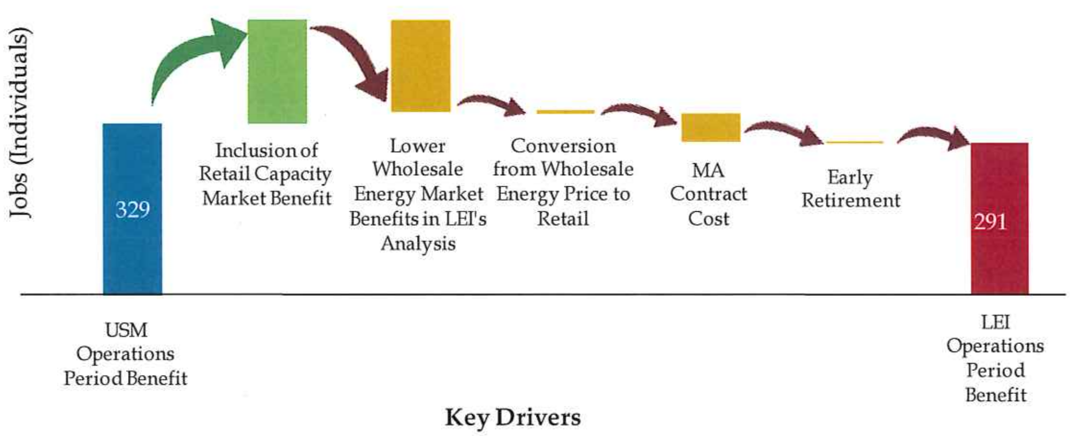

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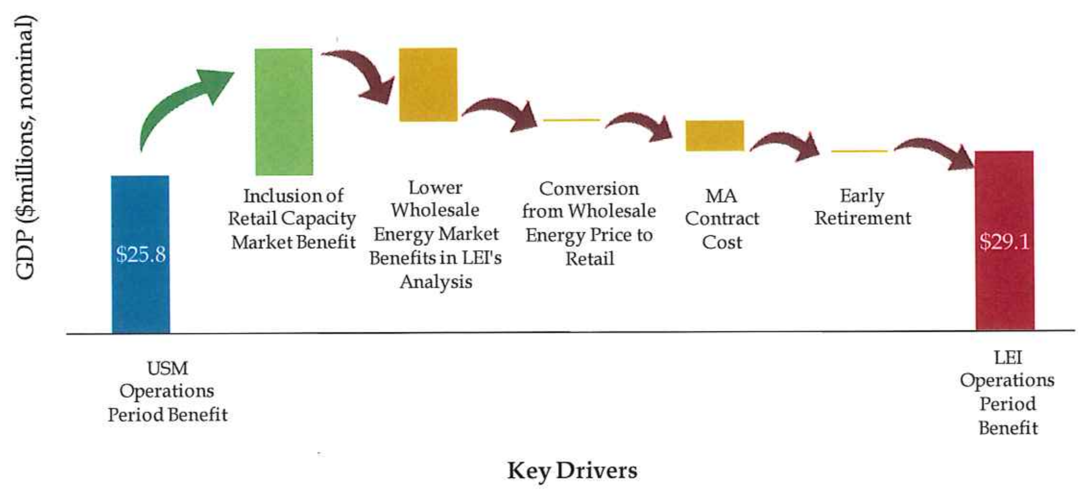
Figure 43. Breakdown of macroeconomic benefits for the operations period between the USM and LEI studies in Maine, annual average GDP (2023-2037)



Note: The "USM Operations Period Benefit" includes annual average incremental jobs and GDP during the operations period from O&M spending of the project and wholesale energy market benefit from the project. The "LEI Operations Period Benefit" includes annual average incremental jobs and GDP during the operations period from O&M spending of the project and retail electricity market benefit from the project.

5.4.1 Different components of ratepayers' savings between two studies

Figure 44 and Figure 45 provide a comparison between USM's and LEI's estimates for the electricity market benefits. [65] There are three main differences between LEI's and USM's electricity market savings and LEI documents the differences in the following sections.

The wholesale vs. retail energy market savings

USM adopted Daymark's wholesale energy market savings and fed that into the macroeconomic model. However, this approach is incomplete as it does not correctly reflect the electricity price change experienced by the ratepayers. In order to properly evaluate the impact of NECEC 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. 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

[65] Aside from the conversion from wholesale price change to retail price changes, LEI further adjusted for net contract costs in Massachusetts, as well as potential early generation retirement triggered by the NECEC project in New England (discussed fully in Section 5.4.2 and Section 5.4.3 below).

and capacity terms of that contract would also limit retail customers' exposure to wholesale market prices. Based on LEI's research on the presence of long-term contracts in New England and regulated self-supply arrangements, LEI concluded that retail customers in Maine are exposed to 100% of the wholesale energy price changes, whereas in other five New England states, retail electricity consumers are exposed to 88% of wholesale energy price changes and 93% of capacity market price changes, on average, over the forecast timeframe. While LEI correctly used the retail electricity market benefits (including both energy and capacity markets), USM only included the wholesale energy market benefits.

Adoption of the inflated energy market savings from Daymark's "special case" analysis

USM's analysis of ratepayers' savings from the project is built upon the outputs of a "special case" of energy market modeling performed by Daymark. This special case is different from the electricity market cost savings presented in Daymark's report. On average, during the 2023-2042 period, the oil price and gas price in the "special case" is 9% and 24% higher than the oil and gas prices, respectively, that are used in the base case in Daymark's report.[66] The wholesale energy cost reduction in Maine in the "special case" is 1% higher than the results presented in Daymark's report.[67] For New England as a whole, the wholesale energy market benefits are 26% higher than what presented in Daymark's study on an annual average basis. Under a higher fuel and electricity prices scenario, injecting low or zero cost price resources into the electricity market will trigger more significant price reductions, which would then lead to greater macroeconomic benefits. Therefore, the macroeconomic benefits presented by Daymark are prone to overestimation given the higher wholesale energy market savings from the "special case."

Capacity market benefits were omitted in USM's analysis

USM assumed zero capacity market benefits even though Daymark analyzed the capacity market impacts of the project in their study, rendering their analysis for electricity market benefits incomplete.

Although USM's and LEI's results are comparable in terms of 15-year annual average for the period of 2023-2037, the components from each study are different. LEI's results present a higher benefit (almost double) than USM's during the first 5 years because of the inclusion of the capacity market benefits. Excluding capacity market benefits, LEI's results for retail energy benefit from the project will be about 70% lower for incremental jobs and GDP. Also, if the project fails to clear in the FCA but clears in the SA, it will cause an additional 340MW retirement in New England. Such early retirement, if included in the macroeconomic analysis, will result in even lower macroeconomic benefits in all the New England states.

LEI results show that during the end of the modeling period of 2033-2037, Maine and New England are expected to see economic losses. As explained earlier, this is primarily because LEI's electricity market modeling results show high capacity cost savings in the first five years, which results in economic benefits for local and regional economies. In the latter years, as the market

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[66] Results for the low gas price, 981MW committed project case.

[67] Results for the low gas price, 981MW committed project case.

recalibrates itself to reach a new equilibrium, such benefits dissipate starting from 2030 over time. Similarly, the energy price reductions start to decline from 2034 onward in LEI's modeling. As a result, the Maine and New England economies will go through a rebound effect, meaning that after an economic boost, economies will shrink back to their steady state size or even below the pre-shock status.

Figure 44. Estimated macroeconomic impacts in Maine due to electricity market savings (2023-2037)

Scenario	Economic Impact Category	Unit	Operations 2023-2027	2028-2032	2033-2037	2023-2037 Average
USM's Results (a)	Total Employment	Individuals	319	313	240	291
	GDP	Millions of Fixed 2009 $	$20.5	$25.3	$24.7	$23.5
LEI's Results (b)	Total Employment	Individuals	732	263	-59	312
	GDP	Millions of Fixed 2009 $	$61.0	$30.4	$4.5	$31.9
Differences [(b-a)/a]	Total Employment	%	129%	-16%	-125%	7%
	GDP	%	197%	20%	-82%	36%

Figure 45. Estimated macroeconomic impacts in New England due to electricity market savings (2023-2037)

Scenario	Economic Impact Category	Unit	Operations 2023-2027	2028-2032	2033-2037	2023-2037 Average
USM's Results (a)	Total Employment	Individuals	4,129	3984	3091	3,735
	GDP	Millions of Fixed 2009 $	$365.1	$432.2	$421.3	$406.2
LEI's Results (b)	Total Employment	Individuals	10,777	3,685	-742	4,573
	GDP	Millions of Fixed 2009 $	$1,091.6	$526.7	$79.5	$565.9
Differences [(b-a)/a]	Total Employment	%	161%	-8%	-124%	22%
	GDP	%	199%	22%	-81%	39%

Note:
1. Economic impacts in terms of incremental jobs and GDP are presented in the form of annual average of corresponding modeling period.
2. LEI's results represent macroeconomic benefits from retail energy and capacity market impacts, while USM's results are based on wholesale energy market impacts.

5.4.2 Contract cost borne by the Massachusetts ratepayers are not considered in USM's analysis

Under the Massachusetts 83D clean energy Request for Proposal ("Clean Energy RFP"), contract costs of the project, if selected, will be passed through and paid for by consumers of the electric distribution utilities in Massachusetts. However, the project's contract cost borne by Massachusetts ratepayers are not factored into the macroeconomic impact analysis conducted by USM.

Taking into consideration the contract costs, Massachusetts ratepayers would see less electricity price reductions brought by the project. As a result, Massachusetts would see lower job and GDP increases from electricity market savings during the modeling period, compared to the results shown in Table 5.1 of USM's report. Furthermore, as Massachusetts is the biggest economy in New England, economic shocks in Massachusetts will ripple through and impact other New England states that are economically and geographically connected with Massachusetts.

LEI has estimated how the RFP contract cost[68] of the NECEC project will affect the Maine economy as well as the New England economy as a whole. As shown in Figure 46, ratepayers in Maine are expected to see 55 jobs lost and reduction in GDP by $4.9 million per year during 2023-2037.

When looking at New England as a whole, the net contract costs will result in 2,355 job losses and a $288.3 million reduction in GDP every year during 2023-2037.

Figure 46. Estimated macroeconomic impacts in Maine and New England due to contract cost

Region	Economic Impact Category	Unit	Operations 2023-2027	Operations 2028-2032	Operations 2033-2037	2023-2037 Average
Maine	**Total Employment**	Individuals	-112	-54	-1	-55
	GDP	Millions of Fixed 2009 $	-$8.9	-$5.2	-$0.7	-$4.9
New England	**Total Employment**	Individuals	-4,267	-2,433	-367	-2,355
	GDP	Millions of Fixed 2009 $	-$432.0	-$314.4	-$118.4	-$288.3

[68] Net contract cost is calculated by adding up the transmission cost of the Project and the hedge benefits. Transmission cost is calculated by multiplying the committed energy [redacted] by the estimated bid price for transmission [redacted] provided by CMP in response to ODR-001-034. Then the hedge benefit of the contract is calculated by taking the hourly energy price in the Project Case netting it against the indicative bid price for energy [redacted] in the contract, as provided by CMP in response to ODR-003-016, and then multiplying all this by the committed energy. LEI modeled the indicative price of energy because CMP could not provide more accurate data. The transmission cost and the hedge benefit are added together to yield the net contract costs. LEI estimates the net contract cost to be a total of [redacted] on an annual average basis, during the modeling period of 2023-2037.

5.4.3 Early plant retirement and deferred local investment are not included in USM's analysis

Introducing lower-cost energy and capacity into the local energy market will potentially trigger early retirement of local generation capacity. The projected early retirements are expected to prevail whether NECEC clears the primary auction (FCA) or the substitution auction.[69] Such early retirement will cause loss of employment and reduction in economic activity in the utility sector and then induced effects in other sectors of the economy.

Daymark's analysis found that "the impact of the additional capacity supply also advances the retirement of a small amount of capacity in the region that was dependent on capacity revenue for viability." Yet, such early retirement caused by the project was not factored into USM's macroeconomic impact analysis. This leads to overestimation of employment and GDP increase for the operations period of the project.

LEI modeled early retirement of generation capacity triggered by the project as loss of jobs during the year of retirement in the Project Case until the end of the modeling period (2037) or until the original planned retirement of that plant, whichever is earlier.[70] Figure 47 below shows that the impacts are not significant in Maine - about two jobs are lost and $0.2 million reduction in GDP per year is incurred. New England as a whole is expected to see on average 251 job losses per year and loss in GDP of $46.4 million per year during the modeling period of 2023-2037.

Aside from the early retirements, LEI expects a total of 550MW of new gas generation capacity in Massachusetts to be displaced or deferred due to the NECEC. Unlike closure of a plant, which will lead to permanent and certain loss in employment, deferral of investment in new entry is only for a few years and therefore is not included in LEI's modeling. These deferred or displaced investments, if incorporated in the macroeconomic modeling, will have additional negative impacts on local employment and GDP in New England and in Maine.

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[69] In the substitution auction, NECEC must swap with an equivalent amount of resources in order to obtain a CSO.

[70] LEI forecasted that [redacted] will be retired earlier than the original planned retirement date (no announced retirement date yet) in 2030 due to the NECEC. Based on employment from Bureau of Labor Statistics and the installed capacity data from the 2018 CELT ISO-NE Annual Energy and Summer Peak Forecast, LEI estimated that labor demand for fossil fuel generation sector is approximately 0.05 jobs/MW in Connecticut. Therefore, LEI modeled 39 job losses in the Utilities sector in Connecticut to estimate the macroeconomic impacts from the [redacted] retirement in the 6-region REMI PI+ model for New England.

Figure 47. Estimated macroeconomic impacts in Maine and New England due to early retirement triggered by NECEC

Region	Economic Impact Category	Unit	Operations 2023-2027	2028-2032	2033-2037	2023-2037 Average
Maine	Total Employment	Individuals	-3	-3	-3	-3
	GDP	Millions of Fixed 2009 $	-$0.2	-$0.3	-$0.3	-$0.3
New England	Total Employment	Individuals	-426	-394	-357	-392
	GDP	Millions of Fixed 2009 $	-$68.6	-$72.6	-$76.1	-$72.4

5.4.4 Jobs created by ratepayers' benefits should not be considered "direct jobs"

LEI found the direct job increase due to ratepayers' benefits presented in USM's report incorrect and misleading. USM in their report on Pg. 11, Table 5.1 showed that between 2023 and 2042, the project was expected to create 89 direct jobs per year on average. However, ratepayers' benefits do not create jobs through direct investment; rather they create local benefits through increasing households' disposable income and lowering local businesses' operations costs. Therefore, new jobs related to ratepayers' benefits should be categorized as "indirect and induced jobs" rather than "direct jobs."[71, 72]

5.5 Comparison of the tax revenue estimates

LEI's estimates for municipal tax revenue received from NECEC are $18.09 million a year for Maine communities. This is comparable with USM's estimates of $18.38 million[73]. This is because both analyses are based on the same valuation of the projects' taxable value provided by CMP, and the mill rates used by LEI and USM are about the same[74].

Again, as explained fully in Section 3.4, the actual tax payment from the NECEC will depend on the taxable valuation assessed by each municipality and the adjusted property tax rates (i.e. mill

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71 In macroeconomic language, "direct jobs" are considered as jobs created as a result project investment (e.g. construction workers). Jobs created by increased demand in sectors that provide supporting services and goods are considered as "indirect jobs" (e.g., truck drivers that deliver cement used for the construction of the project). Jobs created through the increased spending of local residents are categorized as "induced costs" (construction workers spend the salary earned from the project in local restaurants, leading to increased demand for new workers in the restaurant).

72 The report's author, Mr. Ryan Wallace, agreed during the technical session held on April 5, 2018, that they used different definitions for interpreting the "direct job" impacts during construction period and the operations period. He also mentioned that the jobs created by ratepayers' savings should technically be considered as "indirect and induced jobs."

73 See USM's report, Section 6.

74 LEI used the Estimated 2016 Municipal Full Value Tax Rates reported by the Department of Administrative and Financial Services of the Maine state government. USM used the actual mill rate for each municipality for 2016.

rates) in each of these municipalities, which is determined by a number of factors, such as the budget plan of the municipality, the change in market value of other properties, etc.

How the tax revenue will further affect the local economy in the affected municipalities and in the State of Maine as a whole is determined by the actual tax revenue received by the municipal governments and their budget plan. They can use the tax revenue to pay off government debts, which will not have direct impacts on the local economy. Alternatively, they could increase government spending in providing common goods as services (e.g. education and healthcare), which will create macroeconomic benefits. Since such budget decision is unknown and varies from municipality to municipality, LEI did not model such impacts in the REMI PI+ model.

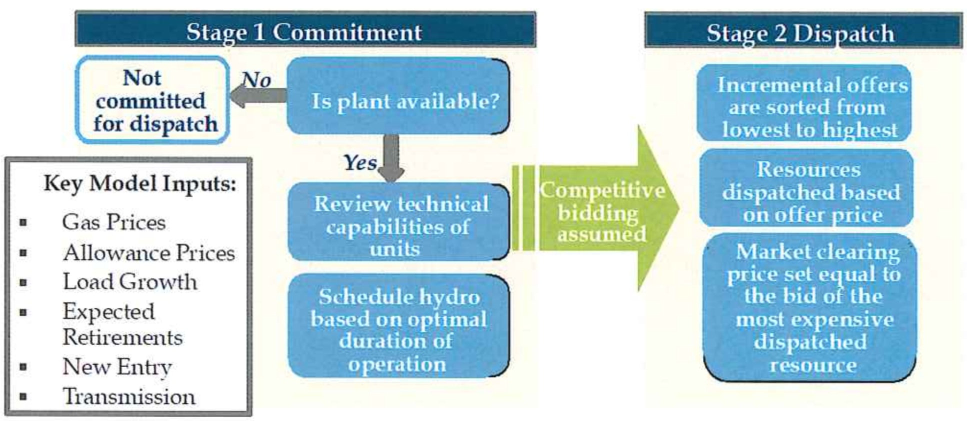
In any case, tax payments from the NECEC project are expected to decline over the projects' life as the taxable value of the project depreciates. Therefore, in later years of the project's operations period, the actual tax revenue received by the affected municipalities is expected to be lower than the estimates presented in LEI's and USM's studies.

6 Appendix A: LEI Modeling Tools

6.1 Overview of the energy market forecasting model

LEI employed its proprietary simulation model, POOLMod, to develop the wholesale energy price forecast. POOLMod simulates the dispatch of generating resources in the market subject to least cost dispatch principles to meet projected hourly load, 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 48. POOLMod's two-stage process



In addition, POOLMod is a transportation-based model, giving it the ability to take into account transmission limits on the network. The New England Control Area is modeled on a zonal basis, consistent with ISO-NE's own economic models and analyses for system planning purposes. POOLMod has been used to support millions of dollars in merger and acquisition ("M&A") deals, market design support, and contract evaluations.[75] It is a general model that can be applied to many different markets but calibrated to suit the specific characteristics of New England and reflect ISO-NE's energy market rules.

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

[75] In addition to bespoke consulting engagements, LEI performs semi-annual forecasts using its POOLMod for 12 wholesale power markets. These forecasts, known as LEI's Continuous Modeling Initiative ("CMI"), examine recent market developments, draw on the latest information and data available, and apply LEI's proprietary modeling tools to provide a 10-year energy, and where applicable, capacity market price outlooks.

such, LEI ran 20 iterations of the energy model for 2023-2037 for the Base Case and the Project Case where the timing of these generation outages varied within each year (although the same number 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, LEI can test whether the price impact caused by NECEC 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 concluded that the observed energy price differences in all years are statistically significant.

6.2 Overview of the capacity market forecasting model

For the capacity market analysis, LEI used the FCA Simulator, a proprietary modeling tool developed by LEI to replicate the offer strategy of suppliers in the auction, which includes offers from existing and new suppliers of capacity. New suppliers in the FCA are assumed to offer at their technology-specific Net CONE. As such capacity prices are projected to converge towards the Net CONE forecast associated with a gas-fired generator. This Net CONE is not kept constant but grows over time based on expected inflation, technological/cost improvements, and the change over time in future energy and ancillary services revenues. Existing suppliers will drive price outcomes in LEI's simulation of the FCA in periods when total existing supply exceeds the projected NICR, subject to retirement decisions (which may drive prices to new entry levels).

LEI's analysis also took into account the convex demand curves aimed to address the shortcomings of the linear downward sloping demand curve that was used for FCA #9 and #10. The new set of demand curves – known as Marginal Reliability Impact ("MRI") curves – take on a curved or convex shape so as to reflect the nonlinear relationship between quantity and ISO-NE's willingness to pay for the marginal improvement in reliability associated with adding new capacity.[76]

An MRI curve has a steeper slope left of the NICR value because the marginal impact of adding one additional resource is high. Once supply crosses to the right over the NICR level on the MRI, the curve has a flatter slope to signify that the marginal impact of adding one additional resource is lower. The linear demand curve assumes implicitly that each additional MW has the same marginal reliability impact. Figure 49 below shows an illustrative example of the MRI curve against the downward sloping demand curve for FCA #10 based on ISO-NE's indicative demand curve example.[77]

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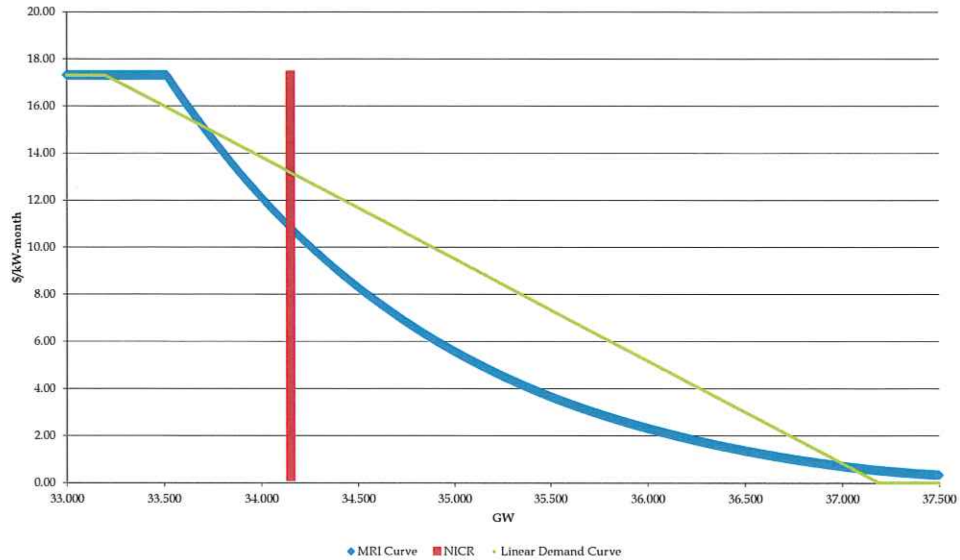
[76] For more details, see ISO-NE's December 7, 2015 technical memorandum to the NEPOOL Markets Committee on the FCM Zonal Demand Curve Methodology.

[77] ISO-NE Indicative Demand Curve Values for FCA 10 Zones. <https://www.iso-ne.com/static-assets/documents/2016/01/a02_iso_indicative_demand_curve_values_fca10_zones_01_06_16.xlsx>. Demand curves for FCA #12 have been released, however, as explained in this section, a function of the MRI curve is the Net CONE, which requires coefficients to construct a polynomial curve. These coefficients are not explicitly

Figure 49. Illustrative example of the linear demand curve and MRI curve



To obtain the capacity clearing price in the FCA, the following equation must be applied against the MRI curve:

$$Price_{System}(Quantity_{System}) = -Penalty\ Factor\ \times MRI$$

PF, refers to the Penalty Factor, which LEI sets each year such that the clearing price capacity at NICR will equal Net CONE (where the Loss-of-Load Expectation is 0.1 days/year), consistent with ISO-NE's methodology. Therefore, at any given level of Quantity (i.e. the amount of resources that clear the FCA), the price can be determined by the MRI at that particular quantity and the PF.

In practice, the MRI would change over time as new resources enter and exit the system and demand grows. ISO-NE's engineering-based approach to build up the MRI produces a set of coefficients that are used to plot the convex demand curve for each capacity zone. While the shape of the zonal convex demand curves produced for each auction may change slightly each year, ISO-NE expects these curves to be quite stable from year to year.[78] LEI therefore used the latest available coefficients from ISO-NE[79] to create the MRI demand curve, and then shifted the curves to the right each year (to account for growth in NICR), and scaled the curves using expected Net CONE values.

In order to test whether price separation would occur in the import-constrained ("NNE") or export-constrained (SENE) zones, LEI considered the representative Maximum Capacity Limit ("MCL") and Local Sourcing Requirements ("LSR") parameters calculated by ISO-NE through

published for the FCA #12 curves, and therefore LEI continues to use the coefficients for the FCA #10 MRI curve. As noted in ISO-NE's demand curve filings, the MRI is expected to remain fairly stable.

78 See Pg. 6 of Christopher Geissler and Matthew White Testimony on behalf of ISO-NE. Docket ER16-1434-000.

79 LEI used the coefficients from the *ISO Indicative Demand Curve Values for FCA Zones*, March 2, 2016. See footnote 77.

FCA #17.[80] LEI then shifted the local demand curve to the right by the quantity change in the MCL or LSR. For example, a 100 MW increase in the MCL would yield a rightward shift of the NNE demand curve by 100 MW. However, as a result of LEI's retirements schedule in the Project Case, LEI found that no price separation is expected to occur with the introduction of NECEC's 1,090 MW, based on the current market topology and approved zonal definition in the FCM. LEI understands that ISO-NE is currently in the process of considering Maine as a separate export-constrained zone from the rest of New England. However, LEI is unaware of any local demand curves that have been produced by ISO-NE specifically for Maine to determine whether price separation would occur and how much.

6.3 Integration of energy and capacity market models

The capacity market model is integrated with LEI's energy market simulation, POOLMod, in that decisions to introduce new resources or retire existing resources in the capacity market is then also reflected in the energy market simulations. Furthermore, the energy market outcomes (energy prices) directly affect the Net CONE for new entrants that the ISO-NE is assumed to use to calibrate the MRI curves. Therefore, checking if a new entrant is economic or whether retirements are needed is an iterative process. Similarly, potential energy market and capacity market profits, as modeled, were compared to the breakeven prices required for new entrants, in order to simulate economic new entry. New entry and retirement decisions were then accounted for in both the FCA simulations and the energy market simulations.

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[80] FCA 12 values are found in ISO-NE's *Proposed Installed Capacity Requirement (ICR) Values for the 2021-2022 Forward Capacity Auction (FCA #12)*, August 17, 2017 and FCA #13-#17 values are found in ISO-NE's *Future Representative Capacity Requirements for CCP 2022-2023 through CCP 2026-2027*, May 24, 2017 as well as the ISO-NE Draft 2017 Regional System Plan. These three zones are the ones currently defined, but in the future, there may be new boundaries for import and export constrained zones, no only one single capacity zone. However, this is not known today.

7 Appendix B: Electricity Market Assumptions

The table below provides the key assumptions utilized in the development of the inputs for the natural gas and wholesale electricity markets forecasts, the key markets these assumptions affect, and the degree of price impacts these assumptions have.

Figure 50. Summary of key modeling assumptions

Assumption	Approach
Network Topology[i]	LEI divided the ISO-NE Control Area into 11 sub-zones, corresponding to observed historical major transmission congestion. Thermal limits were based on the operating limits provided by Daymark and CMP for the Base Case and Project Case. Apart from the Maine interfaces, all other transfer limits were based on ISO-NE data.
Load Growth[ii]	ISO-NE's 2017 CELT Report provided the demand outlook until 2026. Beyond this, LEI extrapolated the demand for each zone using a three-year rolling average growth rate.
Load Shape[iii]	Forecasted hourly load shape by ISO-NE for 2017 under ISO-NE P50 (weather normalized) forecast
Existing Resources	Summer/winter capacity for energy market simulations are taken from the CELT 2017 Report. Capacity supply obligations are taken from FCA #12 results. Plant parameters such as fuel type, heat rate, emissions rates, variable O&M, maintenance and forced outage rates were sourced from third party data providers, which aggregate data from EIA, NERC, FERC, and the EPA. Energy schedules for hydro plants were developed from 10-year average historical production profile, if reported. For smaller hydro plants that are not required to report monthly generation, an average was used as a proxy, based on profiles of neighboring, similar facilities
New Entry/ Retirements	Planned short-term thermal new entry was based on resources that cleared FCA #12. Additional thermal resources were added, when the projected economics (in the capacity and energy markets) justified such additions. Generic renewable new entry was added pursuant to states' renewable renewable portfolio standards ("RPS") goals. However, new on-shore wind in northern parts of Maine was capped at 1,000 MW to account for transmission constraints
Natural Gas	Natural gas prices were derived based on LEI's proprietary Levelized Costs of Pipeline ("LCOP") forecast model. LEI relied on the forward market for projecting locational gas prices in the near term and a fundamental analysis using a reference point plus a transportation adder to project gas prices in the long run
Other Fuels[iv]	Residual and distillate prices were based on NYMEX forwards and the AEO 2018 growth rates for crude oil. Coal prices were modeled for each coal plant based on actual historical costs and EIA's growth rate for regional coal supplies
Carbon Allowance Prices[v]	The average of January - March forward RGGI prices were used until 2020. LEI then adopted the results of No National Policy Model Rule Scenario by RGGI
Interchange[vi]	Imports and exports were modeled on based on historical interchange from recent years, 2015-2017.

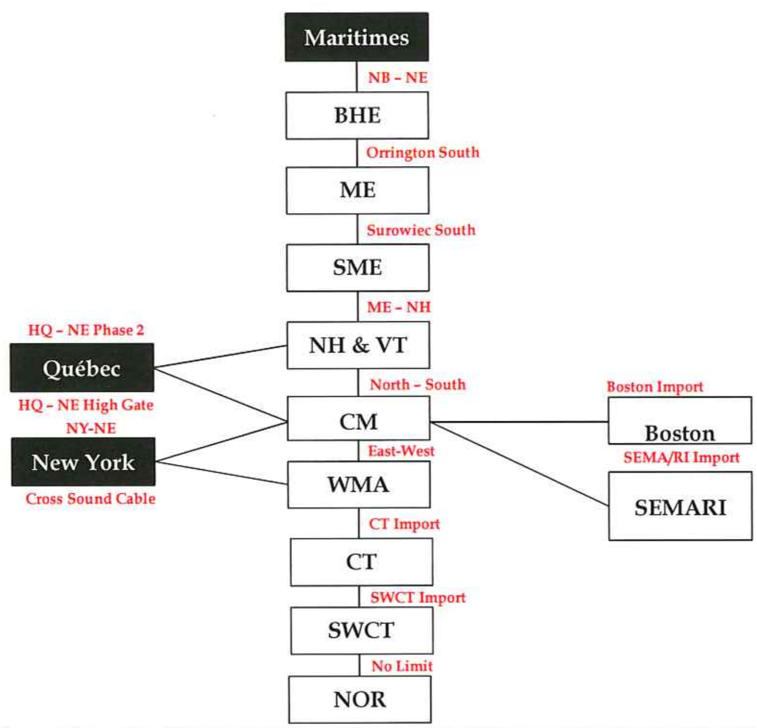
Notes:
i) Daymark response to ODR-003-019
ii) ISO-NE CELT Forecast Data 2017, <https://www.iso-ne.com/static-assets/documents/2017/05/forecast_data_2017.xlsx>
iii) ISO-NE 2017-2026 *NE Region Hourly Load Forecast*, <https://www.iso-ne.com/static-assets/documents/2017/05/rsp17_iso_eei.txt>
iv) EIA, *Annual Energy Outlook 2017*. <https://www.eia.gov/outlooks/aeo/>
v) Draft 2017 Model Rule Policy Scenario Overview. September 25, 2017. <https://www.rggi.org/docs/ProgramReview/2017/09-25-17/Draft_IPM_Model_Rule_Results_Overview_09_25_17.pdf>
vii) ISO-NE, External Interface Metered Data. <https://www.iso-ne.com/isoexpress/web/reports/grid/-/tree/external-interface-metered-data>

7.1 Market topology

LEI's model of the New England power grid uses 11 zones in ISO-NE as shown below in Figure 51: (i) Bangor Hydro Electric ("BHE"); (ii) Maine ("ME"); (iii) Southern Maine ("SME"); (iv) New Hampshire/Vermont ("NH/VT"); (v) Central Massachusetts ("CM"); (vi) Western Massachusetts ("WMA"); (vii) Connecticut, ("CT"); (viii) Southwest Connecticut ("SWCT"); (ix) Norwalk ("NOR"); (x) Northeast Massachusetts/Boston ("NB"); (xi) Southeast Massachusetts/Rhode Island ("SEMARI"). This 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.[81]

LEI adopted CMP's estimates of the transfer limits along the three Maine interfaces, based on Daymark's response to response to ODR-003-019. This includes upgrades made when NECEC is in service.

Figure 51. Regional transmission interface limits



[81] For long-term planning purposes, ISO-NE models the ISO-New England Control Area ("NECA") on the basis of thirteen sub-regions defined by binding transmission constraints. For modeling, the market topology is simplified, while being consistent with ISO-NE's approach. NH and VT are modeled as one zone, and SEMA and RI are modeled as one zone.

7.2 Load Growth

LEI adopted ISO-NE's CELT forecast, which includes its 10-year forecast of peak demand and total demand. The gross demand projections are lower than previous CELT reports due to ISO-NE's revised outlook on actual consumption in recent years, and expectations of passive demand response ("PDR") and behind the meter solar PV.

LEI specifically used ISO-NE's peak demand and total demand forecasts from ISO-NE's CELT 2017 for its P50 case that represents the expected or 50/50[82] outlook; this covers the period of 2017 to 2026. Energy efficiency and behind-the-meter solar PV are treated as a reduction in demand for the energy market simulation purposes. For the capacity market, incremental energy efficiency is treated as a supply resource, not a reduction from NICR. Beyond 2026, LEI extrapolated ISO-NE's demand forecasts using a three-year rolling average growth rate.

For the hourly load profile, LEI used ISO-NE's hourly load forecast for 2017 for each sub-region under the P50 case. Based on this sub-regional hourly load shape, LEI forecasted the hourly load shape in future years by scaling the shape with the forecasted peak load and total energy demand in those years.

7.3 Natural gas projections

LEI identified four key drivers of for natural gas price in North America. Three of these point to strong growth in supply; one of them points to growth in demand:

- Continued development of Marcellus and Utica shale plays in the Eastern United States
- Continued growth in crude oil and natural gas production from Permian Basin in West Texas
- Growing gas production in Western Canada
- Growing demand for gas in the form of LNG and pipeline exports

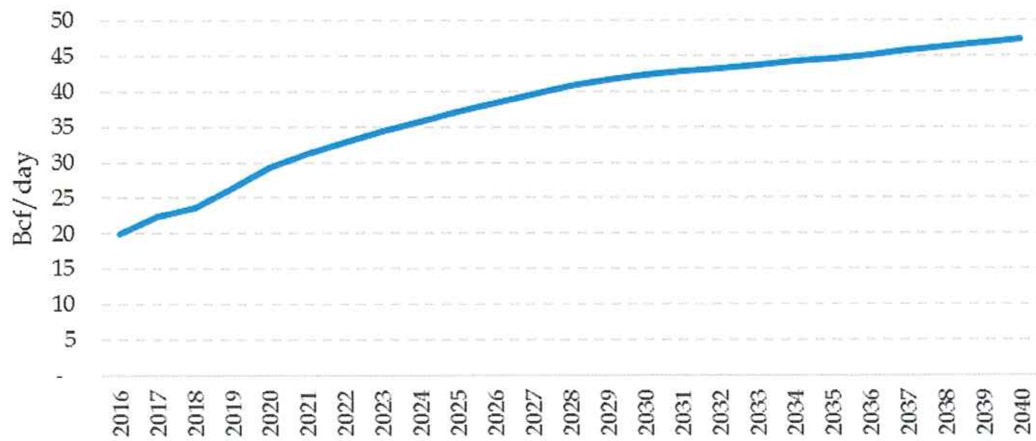
7.3.1 Supply-side drivers

Continued development of Marcellus and Utica shale plays in the Eastern US is one of the key drivers of North American gas prices. Though Energy Information Administration ("EIA") has tended to be conservative in its supply outlooks from the East region, in its Annual Energy Outlook ("AEO") 2018, EIA projected that dry gas production in the East would grow from 22 billion cubic feet ("Bcf") per day in 2017 to 47 Bcf per day in 2040, at a compound annual growth rate ("CAGR") of 3.3% (see Figure 52). These two Appalachian shale gas plays have remained

[82] By definition, the 50/50 load forecast is an expected weather forecast – peak load under the 50/50 load forecast has a 50% chance of being exceeded. Major assumptions and conditions, including weather, are assumed to approach or approximate the long run average.

resilient to low natural gas prices and are projected to continue to drive total US production in the long term, especially as pipeline takeaway capacity expands.

Figure 52. EIA AEO 2018 Reference Case outlook for dry gas production in East region



Source: EIA AEO 2018 Reference Case

In West Texas, Permian Basin recent gas production growth is based on associated gas, which is gas that is produced from oil-directed wells, essentially as a by-product. This production does not depend much on natural gas prices—the gas is recovered with the oil, and producers need to find a home for it. The US Geological Survey ("USGS") estimates that recoverable shale gas resources in the Midland Basin portion of Texas' Permian Basin could exceed 16 trillion cubic feet of natural gas, a substantial 40% of the recoverable natural gas resources from Marcellus and Utica.[83] Thus, LEI expects ongoing growth in crude oil production in the Permian Basin to keep Henry Hub gas prices in check.

As shown in Figure 53, AEO 2018 Reference Case projects that crude oil production from Southwest (the region which includes the Permian Basin) will grow from two million barrels per day to four million barrels per day from 2017 to 2040, while natural gas production is projected to grow from 10 Bcf per day in 2017 to 14 Bcf per day in 2040.

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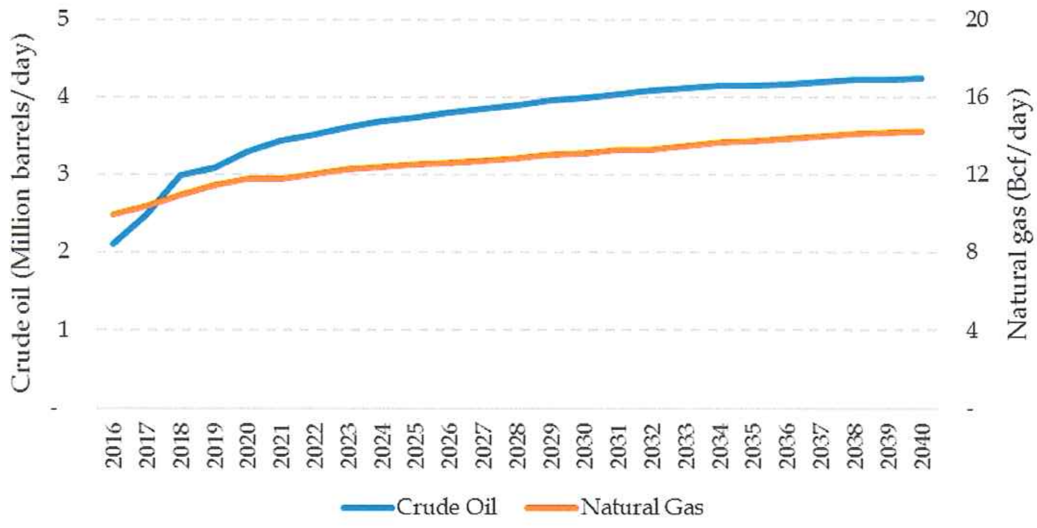
[83] USGS. Assessment of undiscovered continuous oil resources in the Wolfcamp shale of the Midland Basin, Permian Basin Province, Texas, 2016. November 2016. <https://pubs.usgs.gov/fs/2016/3092/fs20163092.pdf>

Figure 53. EIA AEO 2018 Reference Case outlook for crude oil and natural gas production in the Southwest region



Source: EIA AEO 2018 Reference Case

Furthermore, there is growing natural gas production in Western Canada's Montney and Duvernay shales which will also help maintain downward pressure on gas prices. Natural gas net exports from Canada to the US have increased from 5.4 Bcf per day in 2012 to 5.8 Bcf per day in 2017.[84] Natural gas production from Western Canada has increased from 13.6 Bcf per day in 2012 to 15.4 Bcf per day in 2017.[85]

7.3.2 Demand-side drivers

In the long term, increasing global demand for natural gas is likely to provide a potentially large market for US exports of natural gas via pipeline to Mexico, and in the form of liquefied natural gas ("LNG") to overseas markets. This demand can eventually support the recovery of US Henry Hub prices from the current low levels.

According to the AEO 2018 Reference Case, the US became a net exporter of natural gas in 2017, driven by declining pipeline imports, growing pipeline exports and growing exports of LNG.[86] In AEO 2018, EIA projects that exports of natural gas through pipelines to Mexico will increase from 4.3 Bcf per day in 2017 to 6.6 Bcf per day in 2040.[87] US natural gas exports to Mexico have doubled since 2009 and are expected to continue increasing through at least 2029 due to the

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[84] National Energy Board. *2017 Natural Gas Exports and Imports Summary.*

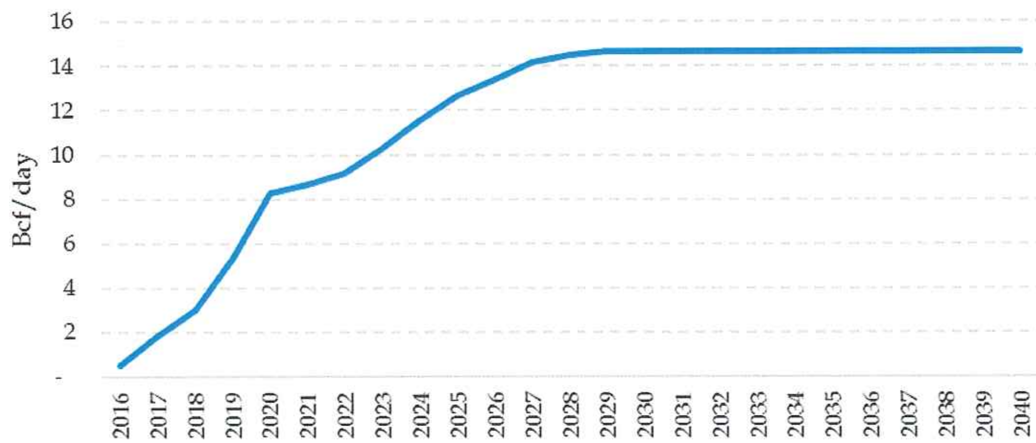
[85] National Energy Board. *Marketable Natural Gas Production in Canada.*

[86] EIA AEO 2018. Table 62. Natural Gas Imports and Exports. <https://www.eia.gov/outlooks/aeo/data/browser/#/?id=76-AEO2017&cases=ref2017&sourcekey=0>

[87] EIA AEO 2018. Table 62. Natural Gas Imports and Exports. <https://www.eia.gov/outlooks/aeo/data/browser/#/?id=76-AEO2017&cases=ref2017&sourcekey=0>

pipelines that are currently under construction. The growth of projected natural gas exports is also supported by new LNG terminals recently completed, and others currently under construction and in early stages of development. EIA's outlook estimates LNG exports to grow from less than 1 Bcf per day in 2017 to 15 Bcf per day in 2040, at a CAGR of 9.5% (see Figure 54).

Figure 54. EIA AEO 2018 Reference Case outlook for liquefied natural gas exports



Source: EIA AEO 2018 Reference Case

With the retirement of coal and nuclear power plants, it could be assumed that demand for natural gas from the US electric power sector would be poised to increase dramatically. However, the EIA AEO 2018 does not project strong growth in gas demand from the power sector (see Figure 55). This weak growth is mainly owing to EIA's projected annual growth of power demand of 0.7% on average.

Figure 55. EIA AEO 2018 Reference Case outlook for gas consumed in electricity generation

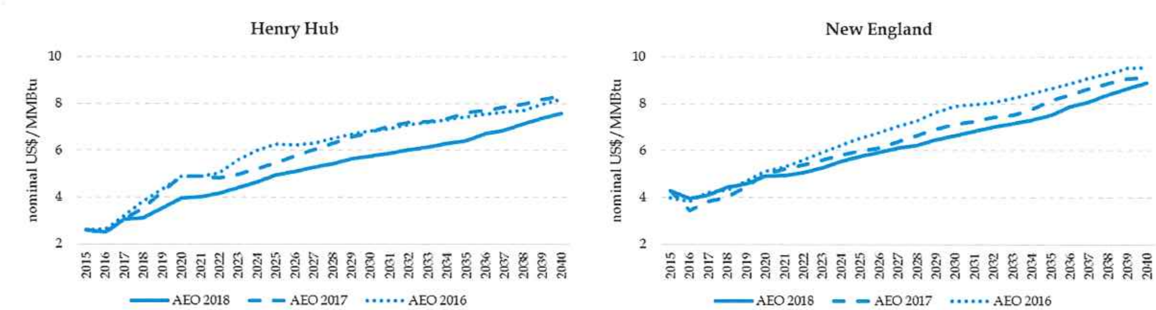
Source: EIA AEO 2018 Reference Case

The 3.1 Bcf per day of demand growth from the power sector from 2018 to 2040 is not enough to make a dent in the abundant supply of US natural gas.

7.3.3 LEI's outlook for Henry Hub gas prices

For the longer term, the eventual increase in gas prices in the EIA's AEO 2018 Reference Case forecasts is consistent with the four key North American natural gas supply and demand trends discussed above. However, LEI believes that EIA's typically conservative outlooks for natural gas production growth have led it to miss the impact of strong production on gas prices in the near term. EIA's Reference case outlooks have shifted downward substantially in recent years (see Figure 56). AEO 2016 reference case for Henry Hub price forecast was 20% lower on average than the AEO 2015 (nominal basis, 2023-2040); AEO 2017 was 2% lower than AEO 2016, and the recently published AEO 2018 is 13% lower than AEO 2017. EIA's New England outlooks have also shifted downward. On a nominal basis, for the years 2023-2040, the AEO 2017 outlook was 7% lower than the AEO 2016; and AEO 2018 is 5% lower than AEO 2017. AEO 2018 reference case compound annual growth (nominal basis, 2023-2040) for Henry Hub is 3.4% and for New England is 3.2%.

Figure 56. Vintages of AEO Reference cases, Henry Hub and New England outlooks



There are two main drivers for the lower outlook in AEO 2018[88] compared with AEO 2017:

- greater natural gas volumes of low-cost resources available for production, particularly in the Marcellus shale gas play and the tight oil plays in the Permian Basin; and
- lower per unit cost of production to reflect increased rates of technological drilling progress.

Given the strong supply-side drivers, LEI believes that robust gas price recovery projected by AEO 2018 Reference Case in the near term (specifically, in next two to four years) may not materialize. Therefore, LEI chose to use the AEO 2018 Reference Case annual trend, but not the absolute price level, in LEI's long-term outlook for Henry Hub prices. LEI applied this trend to

88 EIA. "Oil and Natural Gas Resources and Technology." March 26, 2018. <https://www.eia.gov/outlooks/aeo/section_issues.php#grt>

the 2019 futures market price, to create our projection of Henry Hub prices for 2020 and beyond (see Figure 57).

Figure 57. LEI's natural gas price forecast

[redacted]

7.3.4 LEI's outlook for New England gas prices

In LEI's power sector modeling, the Algonquin Citygate price serves as the delivered natural gas price for gas-fired generators in New England.

In the near term (first two years of the outlook (2018 and 2019)), LEI relied on the forward markets for projecting Algonquin Citygate gas prices. LEI used the three-month average of daily forwards (January 1, 2018 - March 31, 2018), as reported by OTC Global Holdings ("OTCGH") for the 2018 and 2019 monthly prices.

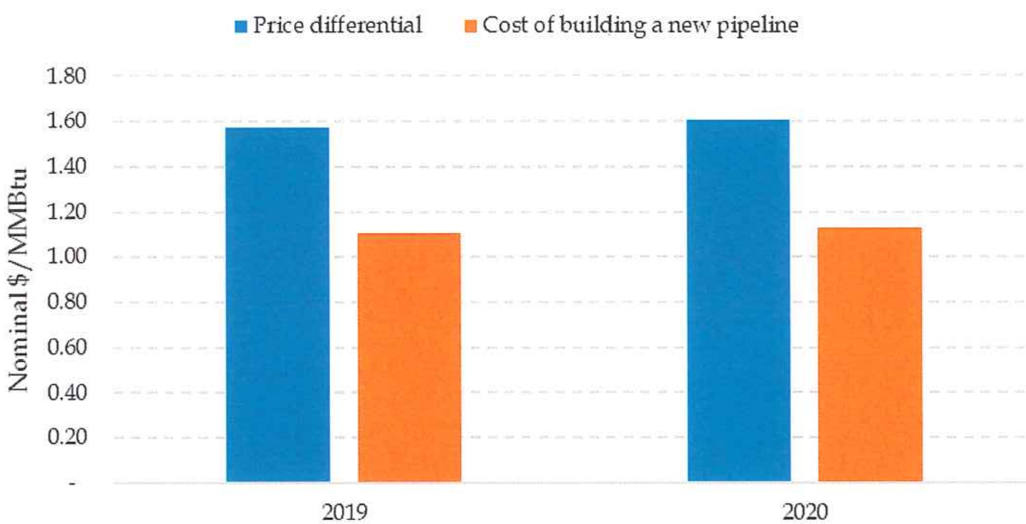
From 2020 and onward, LEI projected the Algonquin Citygate gas price based on a supply hub price plus a transportation adder to New England calculated by LEI's proprietary Levelized Cost of Pipeline ("LCOP") model. The LCOP model assumes that price spreads between any two gas pricing hubs cannot, in the long run, persist above the levelized cost of building a new pipeline between the two hubs. The LCOP model assumes that if the price spread rises above the levelized cost of building a pipeline between any two hubs for three consecutive years, then a pipeline will be built between the two hubs to reduce the price spread.

Traditionally, Henry Hub has been the reference point for the North American gas market. However, due to the relatively low-cost shale gas production from Marcellus and Utica, these locations now supply much more gas to New England than the Gulf Coast does. LEI, therefore, chose Dominion South (a hub located in the Marcellus region) as the reference point for projecting Algonquin Citygate gas prices. LEI projects Dominion South to trade at a discount to Henry Hub, reflecting the ongoing need to add pipeline capacity from the Marcellus to market regions. LEI projects Dominion South prices to increase at the same rate as Henry Hub, based on the 2018 EIA AEO, although they reflect the persistent discount.

For 2018 and 2019, the transportation adder to arrive at the Algonquin price is the difference in the futures price between Dominion South and Algonquin Citygate gas hub.

For 2020 and 2021, the LCOP indicates that new pipeline capacity will be needed. This is the result of the first three years of the outlook for Algonquin prices relative to Marcellus area prices. The difference between Algonquin and TETCO M3 prices from 2019 and 2020 is around $1.6 per MMBtu, and the cost of building a pipeline is $1.12 per MMBtu (see Figure 58). This price signal induces a pipeline expansion. The LCOP model "expands" pipeline capacity, by, in effect, reducing the basis to the LCOP, in 2021. Although in practice pipeline expansions are not perfectly timed to meet market demand, the LCOP model represents a long-term equilibrium which is appropriate for a long-time horizon such as the 2018-2037 for the NECEC analysis.

Figure 58. LCOP Algonquin and TETCO M3 price differential and pipeline cost



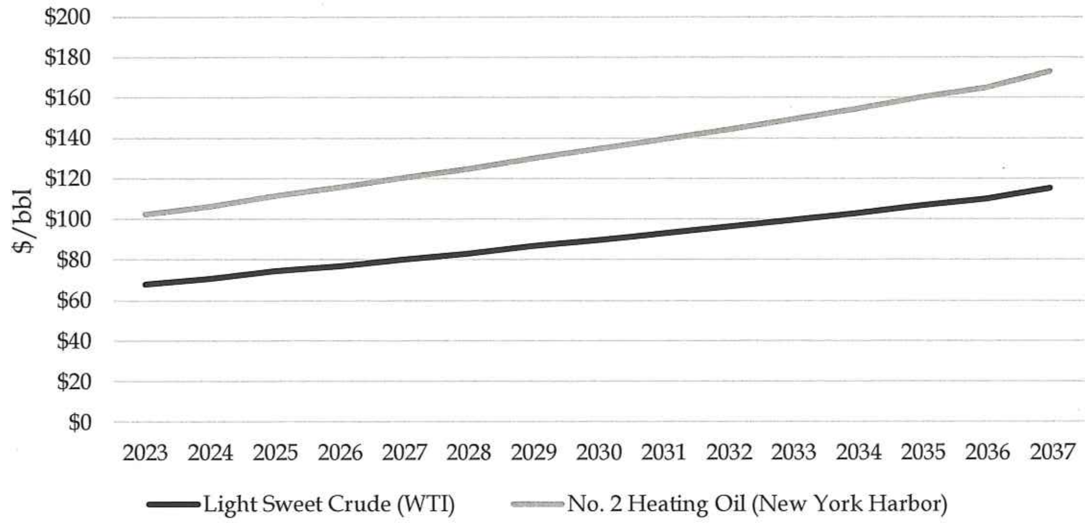
Source: LCOP

LEI projects the Algonquin Citygate price to increase from $3.6 per MMBtu in 2018 to $6.78 per MMBtu in 2037 (in nominal terms). The Algonquin Citygate prices are on average $2.0 per MMBtu higher than Dominion South (a point which is further away from Algonquin Citygate than TETCO M3, so it has a correspondingly higher cost to build a pipeline), reflecting the long-term transportation adder generated by LEI's LCOP model.

7.4 Other fuels

Although natural gas-fired resources are price setting for the vast majority of hours, oil-fired resources occasionally do run, although this typically accounts for less than 1% of total generation. The distillate oil price 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. The residual oil price was developed based on a multi-year average of the ratio of residual and distillate oil prices. Figure 59 below shows the natural gas and oil prices over the modeling timeframe.

Figure 59. Forecast of various oil prices



Given the diversity in coal sourcing, quality, and price, LEI developed plant-specific coal price outlooks. LEI began with an estimate of 2017 actual delivered costs, taking into account the type of coal used at each plant (since each coal plant has different sulfur content levels and different contracts for price and transportation). LEI then escalated the estimated costs with the longer-term trends for the commodity using coal-based inflation rates from AEO 2018.[89] Notably, all coal units are projected to be retired by 2023 in the region, based on the analysis described in Section 7.7 below.

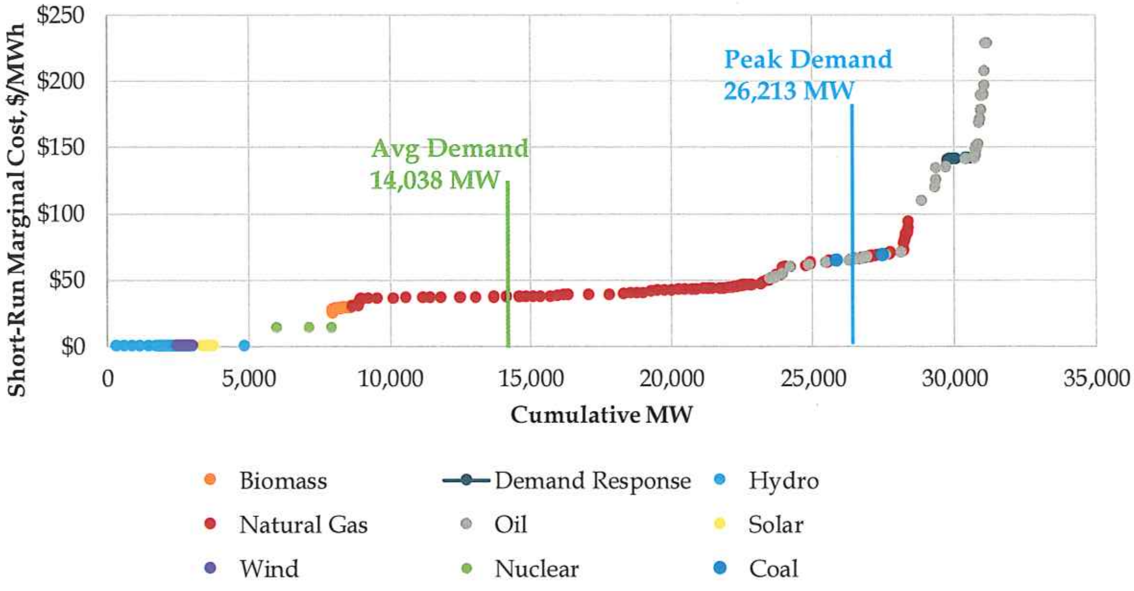
7.5 Existing Supply

Existing supply (for the energy market simulations) in New England was based on the ISO-NE 2017 CELT, which provides plant-specific demonstrated capacity ratings for both summer and winter seasons, as of May 2017. LEI supplemented this data with plant parameters (heat rates, variable O&M, forced outage rate, etc.) from commercially available databases. LEI also added in changes in the resource mix based on FCA #12 results.

The system-wide supply curve in Figure 60 shows that gas-fired plants are the main price setting units for average load, and oil is expected to set prices during the highest load hours. Note that the chart below shows the indicative internal supply curve which is adjusted (seasonal ratings, maintenance, forced outage) for availability, and therefore may understate the capacity in any given hour when units are available at full capacity. It does not incorporate imports from neighboring markets.

[89] EIA, *Annual Energy Outlook 2017*, Table 66. Coal Production and Minemouth Prices by Region.

Figure 60. Indicative energy market supply curve of New England resources for 2021



Note: Supply curve is adjusted for availability but not for transmission constraints; illustration excludes imports and exports.

For the capacity market, LEI assumed that all the resources that cleared FCA #12 (including imports and demand response) remain in the market as existing resources unless the modeling suggests units will retire. Going forward, incremental energy efficiency from ISO-NE's forecast will be included as supply in the FCA simulations.

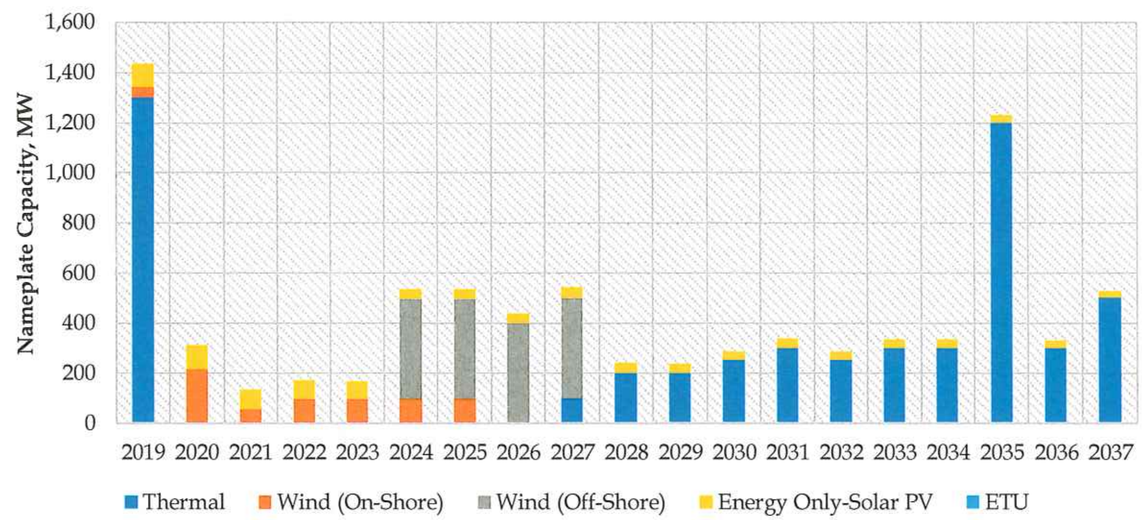
7.6 New entry

Over the long term, LEI assumed that generators make economically rational ("just-in-time") capacity investment decisions timed to load growth and earnings potential across the wholesale electricity markets. In considering new entry, the modeling has taken the following criteria into account, namely: (1) state procurements of clean energy resources and Renewable Portfolio Standards ("RPS"); and (2) the economics of new entry based on LEI's FCA Simulator and (3) the NICR (growth in demand).

7.6.1 State procurements of clean energy

LEI factored in contracted and expected resources from the various state solicitations for clean energy. This includes all renewables from the Clean Energy RFP, CT-2-20 MW, as well as any resources cleared up to FCA #12. Future resources procured in MA RFP Sections 83C will be assumed to compete in the energy market but will only participate in the capacity market if they clear through the substitution auction. Lastly, the full amount of solar PV energy only resources based on the ISO-NE's 2017 Solar PV Forecast was assumed to participate in the energy market (only).[90] LEI found that by combining the energy output from these various solicitations and projections, New England exceeded RPS requirements by the mid-2020s. While a forecast for Renewable Energy Credits ("RECs") is not part of this report, LEI expects that the resulting REC prices would reflect that oversupply and be significantly lower than they have been over the last several years. Figure 61 below shows the schedule of new resources included in LEIs forecast.

Figure 61. New entrants included in LEI's Base Case forecast (MW)



7.6.2 Economics of new entry and Net CONE

Ultimately, the mix of new entry is a function of market economics (i.e. profitability of generators) and policy priorities, as well as political realities (i.e. coal is unlikely to be a realistic candidate for these markets given the lack of commercial capability for carbon sequestration in New England, even though it could be competitive at high gas prices). The new entry decisions are conditioned on modeled outcomes such that additional new entry is introduced if and when it is economically feasible given the simulated market dynamics.

ISO-NE posits that the Net CONE has come down based on more recent information and that a combustion turbine is, in fact, cheaper than a combined cycle power plant. The Net CONE is an important parameter in the FCM, as it directly affects the administrative price cap and impacts the slope of the demand curve. All else being equal, a lower starting Net CONE value will result in lower capacity market prices. LEI's forecast used the FERC-approved Net CONE values as an input to the FCA simulations. To calculate the Net CONE, LEI started with ISO-NE's current cost of new combustion turbines ($8.04/kW-month for FCA #12), then escalated the capital costs with inflation (plus a 2% technology efficiency improvement every four years) and inflated the energy and ancillary services offset by the trends in energy market prices.

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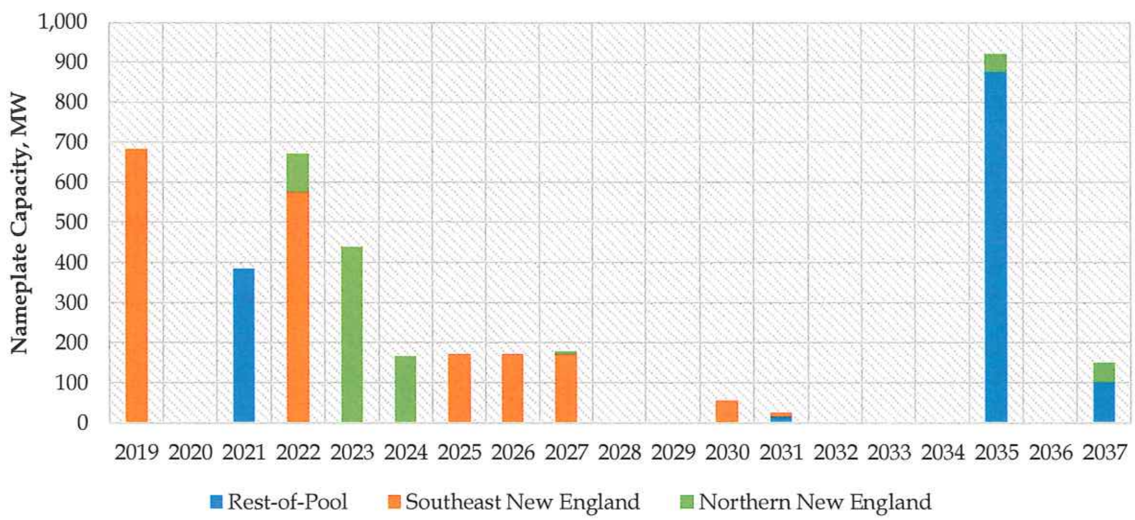
[90] Behind the meter solar PV based on ISO-NE's 2017 Solar PV Forecast will be assumed to reduce demand.

Due to the addition of nearly 2.5 GW of new gas-fired units that cleared in FCA #9 and #10, 1.7 GW clean energy resources (planned onshore wind to meet the states' RPS and offshore wind per MA RFP 83C), energy efficiency across New England states according to ISO-NE's forecast, and slow demand growth, additional generators are unlikely to enter the market in the short term without more offsetting retirements as forecasted energy and capacity prices remain below levels necessary to motivate and fully remunerate a new generation entrant.[91]

7.7 Retirements

LEI incorporated all announced retirements into the analysis as of Q1 2018, which includes Pilgrim Nuclear Power Station (retirement date of June 2019) and Bridgeport Harbor 3 (retirement date of July 2021), as well as any other de-list bids for FCA #12. Given Exelon's decision to retire Mystic 7, 8, and 9, and the fact that ISO-NE is seeking to retain Mystic 8 and 9, LEI only retired Mystic 7 in this forecast.[92]

Figure 62. Retirements included in LEI's Base Case forecast (MW)



Note: Some retirements include Active DR resources that filed for submitted retirement de-list bids for FCA #12

In addition, LEI reviewed the minimum going forward costs of existing power plants and assumed that if resources are not expected to meet their minimum going forward costs for three consecutive years, then they would retire. This approach is consistent with how the IMM reviews

[91] LEI understands that in the past, some resources have been able to clear well below the ISO-determined Net Cone values, although these resources tended to be brownfield units, had good connections to existing pipelines or transmission infrastructure, or were able to make use of certain tax advantages. LEI does not expect these opportunities to be available in the future, and therefore expects thermal units not to clear until beyond the modeling timeframe.

[92] ISO-NE memo. *Discussions of Near-Term Fuel Security Concerns*. NEPOOL Participants Committee. April 3, 2018.

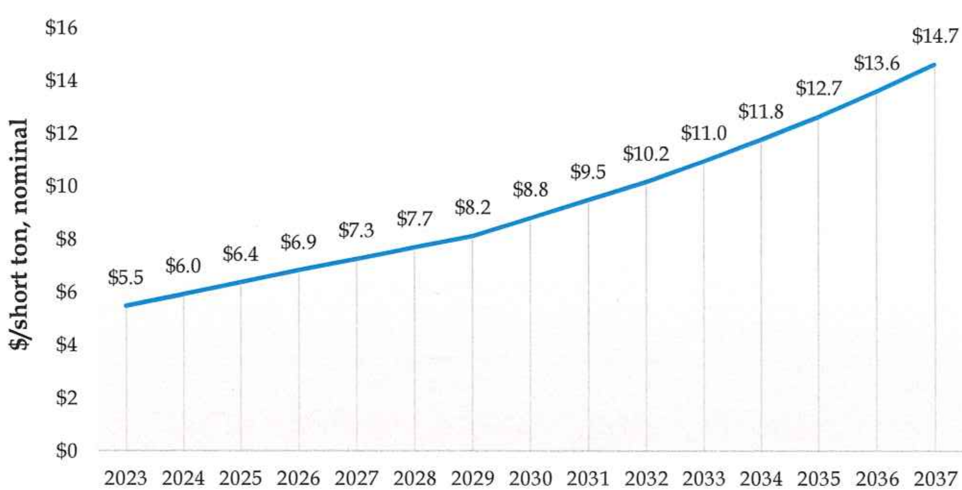
retirement de-list bids when testing for the economic life of an asset.[93] Based off this analysis, LEI found that nearly 3,100 MW of resources would retire by the mid-2020s (including the 1,250 MW that has already announced retirements or submitted retirement delist bids such as Pilgrim nuclear plant and Bridgeport Harbor 3).

However, this capacity reduction will be more than offset by the 4,200 MW of new thermal and renewable generation that is expected over the next several years in LEI's forecast (clearing in FCA #9 - FCA #18), which still results in oversupply on a net basis for New England. Figure 62 below shows the retirements by year that are included in LEI's forecast, with most retirements occurring in the early 2020s.

7.8 Carbon allowance costs

LEI expects that the regional greenhouse gas emissions trading program, RGGI, would continue over the modeling timeframe. Under RGGI, power plants with an installed capacity of over 25 MW must reduce their CO_2 emissions by 50% by the year 2020 relative to their 2005 emissions level. LEI assumes that all ISO-NE states will auction 100% of their CO_2 allowances under RGGI. Each plant is required to purchase an allowance to offset each ton of CO_2 it emits. The RGGI cap declines 2.5% each year from 2018 to 2020. Therefore, forwards for carbon allowance prices have been used in the modeling up to 2020. Beyond 2020, LEI adopted the results of "No National Policy Model Rule Scenario" forecast by RGGI in September 2017.[94] This results in a $5.5/short ton price in 2023 rising to a $14.7/short ton price in 2037, in nominal dollars, as shown below.

Figure 63. Carbon emissions allowance price projection



Sources: RGGI, Draft 2017 Model Rule Policy Scenario Overview. September 25, 2017.

[93] ISO-NE Forward Capacity Market Retirement Reforms. Docket ER16-551-000. <https://www.iso-ne.com/static-assets/documents/2015/12/er16-551-000_retire_reforms.pdf>

[94] RGGI, Draft 2017 Model Rule Policy Scenario Overview. September 25, 2017.

7.9 Import and export flows

ISO-NE is well interconnected with surrounding regions, with ties to the New Brunswick, Québec, and New York power markets. External resources available for imports are modeled on an aggregate rather than an individual unit basis. New England had traditionally been a net exporter, but since 2011 has become a net importer. LEI expects imports from Québec (mainly from hydroelectric resources) to continue into the future at historical levels. Imports from Québec to New England occur via the interties of NE-HQ Phase II and NE-HQ Highgate.

To model the interchange between ISO-NE and external regions, LEI reviewed historical hourly interchange data. Exports to New York, through the Cross-Sound Cable ("CSC") at Shoreham and Northport, are also expected to continue at historical levels due to the projected continuation of tight in-city reserve margins (New York City and Long Island) and the average between 2015-2017 were used.[95]

Over the past four years, trends in the net interchange level from ISO-NE to NYISO via the Roseton intertie have changed. For modeling purposes, the Roseton target was based on the average interchange of 2015-2017 levels until 2030, when nuclear retirements in New York are expected to reduce imports from New York on only the Roseton line by approximately two-thirds. However, this is beyond the modeling horizon for this forecast, and while LEI does not expect all nuclear plants in New York to retire within the modeling horizon, such an event may cause a reversal in flows from New England to New York in the mid-2030s.

LEI expects imports from the Canadian Maritimes to be similar to 2015-2017 levels where Point Lepreau nuclear plant resumed operation in New Brunswick in November 2012, subject to existing transmission constraints from New Brunswick to Maine, Maine to Southern Maine, and Southern Maine to New Hampshire.

Figure 64. Net annual imports with neighboring regions

	Northport (NY)	Roseton (NY)	Shoreham (CSC)	New Brunswick	Phase II (HQ)	Highgate (HQ)
Total GWh	-404	5,102	-1,675	4,411	11,382	1,821

Note: Positive numbers imply net imports, and negative numbers imply net exports. Beginning in 2030, imports along the Roseton interface drop by approximately 5.1 TWh, then reverse to a net import of 1.8 TWh in 2035.

Source: ISO-NE historical interchange data, LEI analysis

[95] In addition, the Norwalk Harbor – Northport, NY, 138 kV cable (NNC) replacement project (formerly known as the 1385 cable) was placed in service during 2008. Since its operation, a significant amount was exported from NE to NY.

8 Appendix C: Comparison of Macroeconomic Impact Estimates

Figure 65. A year-by-year comparison of LEI's and USM's economic impact estimates based on the original project cost estimates – Incremental jobs during the development and construction period

Scenario	Category	Unit	Development 2017	Construction 2018	2019	2020	2021	2022	Annual Average
USM	Direct Employment	Individuals	48	281	569	1,775	1,811	723	868
	Indirect & Induced Employment	Individuals	67	252	585	1,517	1,695	824	824
	Total Employment	Individuals	115	533	1,154	3,292	3,506	1,547	1,691
LEI	Direct Employment	Individuals	48	268	545	1,677	1,713	680	822
	Indirect & Induced Employment	Individuals	67	239	563	1,401	1,570	758	766
	Total Employment	Individuals	115	507	1,108	3,078	3,283	1,438	1,588
% Diff	Direct Employment	%	0%	-4%	-4%	-6%	-5%	-6%	-5%
	Indirect & Induced Employment	%	0%	-5%	-4%	-8%	-7%	-8%	-7%
	Total Employment	%	0%	-5%	-4%	-6%	-6%	-7%	-6%

Figure 66. A year-by-year comparison of LEI's and USM's economic impact estimates based on the original project cost estimates – Incremental GDP during the development and construction period

Scenario	Category	Unit	Development 2017	Construction 2018	2019	2020	2021	2022	Total	Annual Average
USM	GDP	Millions of Fixed 2009 $	$ 8.8	$ 30.0	$ 69.0	$ 177.4	$ 194.2	$ 85.3	$ 564.8	$ 94.1
	Total Compensation	Millions of Nominal $	$ 5.9	$ 22.0	$ 52.6	$ 132.4	$ 150.6	$ 72.2	$ 435.7	$ 72.6
LEI	GDP	Millions of Fixed 2009 $	$ 8.8	$ 30.8	$ 70.5	$ 183.0	$ 199.3	$ 86.8	$ 579.0	$ 96.5
	Total Compensation	Millions of Nominal $	$ 5.9	$ 21.9	$ 52.6	$ 130.5	$ 148.1	$ 70.2	$ 429.2	$ 71.5
Difference	GDP	%	0.0%	2.6%	2.1%	3.1%	2.6%	1.7%	2.5%	2.5%
	Total Compensation	%	0.0%	-0.5%	-0.1%	-1.4%	-1.7%	-2.7%	-1.5%	-1.5%