Electricity Market Impacts of the Proposed Northern Pass Transmission Project

Supplemental Report

PREPARED FOR

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PREPARED BY

Samuel A. Newell

Jürgen Weiss

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THE Brattle GROUP

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Executive Summary

In this supplementary report, we address issues that have arisen since the filing of our report on December 31, 2016, subsequently revised on February 10, 2017 to incorporate a corrected assumption. In particular, we respond to the analysis presented in London Economics International's (LEI's) updated report, filed February 15, 2017; we also update our own analysis to incorporate information that has newly become available, including the results of the most recent Forward Capacity Auction (FCA 11), as well as various statements made by Eversource and/or Hydro-Québec with relevance to the Northern Pass Transmission (NPT) project.

We continue to find that LEI's analysis of NPT's *energy market* benefits is reasonable. However, its much larger estimate of *capacity market* benefits overlooks many inherent uncertainties and contains a conceptual error, resulting in estimated benefits that exceed reasonable expectations of what New Hampshire can count on. LEI does not consider uncertainties about NPT itself and about the capacity market that have more downside than upside relative to their optimistically high estimate. LEI assumes without support that NPT will qualify and clear in ISO New England's (ISO-NE) capacity market. They assume NPT will substantially depress capacity prices with limited response by other capacity suppliers exiting the market and muting the price impact. And they assume that long-term capacity market prices will rise significantly above the long-run marginal cost of capacity. This economic error exaggerates the benefits of NPT prolonging surplus conditions and low prices (in comparison to Base Case prices that rise sooner, to LEI's unrealistically high long-term price). Correcting for this error by assuming prices only rise to the long-run marginal cost of capacity cuts out almost half of LEI's estimated benefits. In summary, LEI's analysis fails to appropriately reflect the inherent uncertainty New Hampshire customers face about how much the NPT project will benefit them, but instead chooses a single set of assumptions and a conceptual error that result in optimistically large electricity market benefits.

In our updated analysis, we analyze the same four plausible scenarios developed in our prior report.[1] We incorporate several updates to our prior analysis, but two are most significant. First,

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1 For reference, our four scenarios are: (1) NPT expands the supply of clean energy into New England without displacing other similar projects, and provides 1,000 megawatts (MW) of capacity, and in response some existing supply may exit temporarily and moderate NPT's price impact; (2) Similar to

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we use information from the recently concluded FCA 11 to update our capacity market supply curve. FCA 11 added new resources and demonstrated the willingness of existing resources to stay in the market at low prices. Taking these observations as indicators of future conditions increases our estimates of NPT's benefits in Scenarios 1 and 2.

Second, we incorporate information from LEI's updated report and Eversource that NPT and associated network upgrades will [redacted]. This somewhat reduces the benefits of NPT to New Hampshire customers, but not enough to increase the upward effect of the updated supply curve.

Across the four scenarios and under our reference assumptions regarding market conditions, we found that NPT could provide New Hampshire customers with retail rate savings between 0 and 0.28 ¢/kWh (in constant 2020 dollar terms) on average from 2020 to 2032. These savings are in relation to 2016 baseline retail rates of roughly 18 ¢/kilowatt-hour (kWh). Per household, expected annual bill savings could be as little as zero or as great as $21.[2] Aggregating over all electricity customers in New Hampshire, expected annual bill savings could be between zero and $34 million. Over the 13 years analyzed, these savings are worth between zero and $307 million at a 7% discount rate, as shown in Table ES-1. Table ES-1 shows how much of the benefits derive from energy market impacts versus capacity market impacts. Note that these energy market impacts do not include some possible additional benefits during extreme market conditions, in which having more resources (via NPT) could provide additional benefits to customers.

As in our original report, we conducted sensitivity analyses of how benefits would change under different assumptions about uncertain market conditions. We updated our original sensitivity cases and also introduced new sensitivities to address questions raised by LEI and Eversource and

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Scenario 1, but NPT induces 500 MW of existing generation capacity to retire permanently; (3) NPT does not qualify and/or clear in ISO-NE's capacity market, but it still delivers clean energy; (4) NPT displaces competing clean energy projects, thus providing no more clean energy or capacity than if NPT were not constructed, resulting in no impacts other than having a line in New Hampshire rather than somewhere else.

2 We assume 621 kWh per month (kW-mo). U.S. Energy Information Administration (2016), 2015 Average Monthly Bill—Residential. Available at http://www.eia.gov/electricity/sales_revenue_price/pdf/table5_a.pdf.

others at our Technical Session in March regarding the effects of large amounts of unexpected entry and exit. Most cases analyzed change the estimated benefits by 30% or less. Under the most extreme case analyzed, in which much higher capacity prices are required to attract new generation investment when eventually needed (which NPT delays), the Scenario 1 benefits could increase to 0.5 ¢/kWh, $37 per year per household, $66 million per year statewide, with a $572 million net present value. The results of our sensitivity analysis are shown in parentheses in Table ES-1 and as light blue circles in Figure ES-1, which also compares our estimates to LEI's.

Table ES-1: Average Annual New Hampshire Customer Savings from 2020 to 2032

Scenarios	Energy Market Savings *$ million/year*	Capacity Market Savings *$ million/year*	Total Market Savings *$ million/year*
Scenario 1: NPT expands the supply of clean energy and clears 1,000 MW of capacity	**$8** ($5 - $8)	**$26** ($15 - $58)	**$34** ($20 - $66)
Scenario 2: Similar to Scenario 1 but NPT induces 500 MW of existing generation to retire	**$8** ($6 - $8)	**$13** ($7 - $29)	**$21** ($14 - $37)
Scenario 3: NPT expands the supply of clean energy but does not provide any capacity	**$8**	**$0**	**$8**
Scenario 4: NPT displaces competing clean energy projects	**$0**	**$0**	**$0**

[redacted]

wholesale prices. We show a longer timeframe to capture the full potential capacity market benefits of NPT, which endure longer in our updated analysis.

This report also incorporates additional research and analysis to inform the likelihood of our various scenarios. In particular, we analyzed how NPT might be evaluated by ISO New England (ISO-NE) to determine whether NPT would be able to qualify and clear in its capacity auctions (to inform the likelihood of Scenario 3). We conclude that while Hydro-Québec may not have enough existing surplus winter capacity to qualify. However, it is likely that Hydro-Québec could add sufficient resources over time, either by building additional hydroelectric ("hydro") generation facilities or through agreements with other entities with excess winter capacity. Importantly though, the cost of such incremental capacity would need to be factored into the Internal Market Monitor's determination of NPT's offer floor price. We estimate that if the source of incremental capacity is new hydro dams, there is little chance NPT's offer floor price could be low enough to clear the market. However, with an arrangement with other entities providing winter capacity, NPT's offer floor price could be low enough to clear under some conditions, particularly if it is recognized for its clean energy attributes through a credit similar to Renewable Energy Credits (RECs). The outcome will depend on the case NPT presents to, and the determinations made by, the Internal Market Monitor, which cannot be predicted with certainty at this time.

Statements made by Hydro-Québec regarding the opportunity to win either the Massachusetts or similar procurements further confirms that revenues beyond expected energy and capacity market revenues will potentially be needed to make NPT viable. It also increases the likelihood of our Scenario 4, where NPT is competing with other similar projects that will be built if NPT is not. In this case, NPT should not be considered to provide electricity benefits that would not otherwise occur; the only impacts would be those associated with a project being built in the proposed NPT corridor through New Hampshire as opposed to elsewhere (and any other special terms NPT may offer).[3]

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[3] Furthermore, the recent rejection by the New Hampshire Public Utilities Commission of the proposed Power Purchase Agreement (PPA) between PSNH and Hydro-Québec removes potential differences between NPT and other projects, from New Hampshire's perspective. Specifically, the lack of a PPA renders irrelevant the discussion in our original report about allocating emissions reductions to New Hampshire based on the PPA and its inclusion of environmental attributes.

Despite our analysis and our research informing likelihoods of the various scenarios, it is unreasonable to assign specific, numeric probabilities to our four scenarios. Doing so would require an empirical basis, in the form of a large number of previous similar cases that would allow us to determine the likelihood of our future scenarios based on past outcomes. Such an empirical track record does not exist. The uncertainties we discuss involve future policy choices, case-specific actions by entities like ISO-NE, and unpredictable responses by market participants.

Given the uncertainties, it is challenging for New Hampshire to know how much electricity market benefit customers can expect to enjoy if NPT is constructed. We can only say that it could be a range, from zero to a quarter-cent, or even a half-cent per kWh retail rate savings at the outer edge—which would be a meaningful reduction, but not enough to fundamentally change electric rates in New Hampshire. To *count on* anything at the higher end of the range would require ascribing a minimal probability to Scenarios 3 and 4 (where NPT does not qualify and clear and where NPT displaces a similar competing project, respectively) *and* assuming market conditions that place NPT's impact at the higher end.

I. Scope of This Supplemental Report

Earlier in this proceeding, we submitted a report, *Electricity Market Impacts of the Proposed Northern Pass Transmission Project*, on December 31, 2016, followed by a revision on February 10 correcting one input assumption. This Supplemental Report responds to London Economics International's (LEI's) updated report dated February 15, 2017 (with correction issued March 17, 2017). We update our own analysis of Northern Pass Transmission's (NPT's) capacity market price impacts using newly-available information from ISO New England's (ISO-NE's) latest capacity auction and from LEI. We also expand our analysis to address issues raised in LEI's Technical Session on February 28, 2017 and in our own Technical Session on March 2, 2017.

Our response to LEI's updated report addresses LEI's assumptions regarding the ability of NPT to qualify and clear in ISO-NE's capacity market, and the supply dynamics affecting NPT's impact on capacity market prices (See Section II).

The update to our own estimates of NPT's price impacts follows the same methodology as before. We focus especially on capacity market impacts, since they are potentially the largest source of benefit for New Hampshire customers, but also the most uncertain. To account for the uncertainties, we continue to analyze a range of market conditions and four plausible scenarios: (1) NPT expands the supply of clean energy into New England without displacing other similar projects, and it provides 1,000 MW of capacity, and in response some existing supply may exit temporarily and moderate NPT's price impact; (2) Similar to Scenario 1, but NPT induces 500 MW of existing generation capacity to retire permanently; (3) NPT expands the supply of clean energy into New England without displacing other similar projects, but it does not qualify as capacity or does not clear any capacity in ISO-NE's capacity market and so has no capacity market impact; (4) NPT displaces competing clean energy projects, thus providing no more clean energy or capacity than if NPT were not constructed, resulting in no impacts other than having a line in New Hampshire rather than somewhere else.

We also address LEI's announced forthcoming analysis of whether NPT-enabled capacity is likely to qualify and clear in ISO-NE's capacity auction by conducting our own analysis of those issues. This informs the plausibility of Scenarios 1 and 2, in which NPT does impact capacity market prices, versus Scenario 3, in which NPT does not. We discuss the likelihood of Scenario 4, given updated information regarding the clean energy procurements in which NPT is competing.

Our updated estimates of NPT's price impacts in Scenarios 1 and 2 account for two main sources of new information. First, in ISO-NE's latest capacity auction (FCA 11), conducted in February 2017 for delivery in 2020–2021, more capacity offered and cleared in the auction at lower prices than we had forecast. This has implications for future capacity prices both with and without Northern Pass. [redacted] This means NPT is less likely to cause a local capacity surplus that depresses prices in New Hampshire, Vermont, and Maine relative to Southern New England.

Finally, we update our sensitivity analysis of how benefits would change under different assumptions regarding uncertain capacity market conditions, and we add some new sensitivity analyses to address questions the Applicant and other parties raised in our Technical Session: whether the value of NPT's capacity price impacts in Scenarios 1 and 2 would be greater if New England unexpectedly lost a large generator, or less if New England gained a very large amount of new renewable resources.

II. Critiques of LEI Updated Report

Here we respond to LEI's updated analysis released 6 weeks after our original report. LEI's updated analysis indicates NPT would reduce New Hampshire customers' electricity costs by an average of $62 million per year over an 11-year timeframe, with 86% deriving from capacity market price reductions and 14% from energy market price reductions. As with LEI's original analysis, we find that LEI's updated *energy market* analysis is generally reasonable is reasonable. However, its much larger estimate of *capacity market* benefits overlooks many inherent uncertainties about NPT itself and about the capacity market that have more downside than upside relative to their optimistically high estimate. By limiting its analysis to a single optimistic set of assumptions, its results are on the high end of plausible outcomes: LEI assumes NPT-enabled imports will fully qualify as reliable capacity in ISO-NE's capacity market. They assume that the capacity will be allowed to offer at a low enough price to clear in ISO-NE's capacity auctions and reduce market clearing prices. LEI assumes only a limited moderating effect from existing capacity exiting in response to NPT-induced price reductions. Finally, LEI makes mechanical and conceptual errors that overstate how high capacity prices would rise when new capacity is needed (which NPT could delay, creating benefits for customers), thus overstating the benefits from NPT.

A. LEI's Assumption that NPT Capacity Qualifies and Clears

LEI's assumption that NPT capacity qualifies and clears in ISO-NE's capacity market is possible but unsupported and perhaps optimistic. In fact, ISO-NE's default assumptions are the opposite until proven otherwise. Resources do not qualify until a designated resource or sufficient pool-wide surplus is demonstrated. And the default offer of Elective Transmission Upgrades, such as NPT would be, is the auction price cap—that is, too high to clear and affect the clearing price.

LEI has not yet provided any basis for its critical assumptions that NPT capacity will qualify and be allowed to offer at prices below [redacted]kW-mo (the minimum price in its analysis), but from discussions during Technical Sessions we understand they will in their Supplemental Testimony.

We will show in Section III.A that it is possible that NPT could qualify and clear, but there is no guarantee that it will. Several factors appear to be too uncertain at this time. LEI's assumption reflects a best case in the range of uncertainty and hence should be deemed optimistic.

B. LEI's Limited Supply Response to NPT

LEI's updated analysis suggests that as NPT enters and reduces capacity prices by an average of [redacted] over ten years, little existing supply exits in response: LEI assumes no generation retires, only that 117 MW of generation exits for one year, and imports from New York decrease by 500 MW for four years. LEI assumes that all other existing capacity stays in the market in spite of reduced prices. For example, a 400 MW generator would earn $69 million less over ten years with NPT than without NPT. But LEI does not explicitly address whether this would push more capacity over the edge of unprofitability and induce it to leave the market.

LEI has not provided its data, model, or analysis to support its assertion that there would not be more (or less) capacity exiting and moderating NPT's price impact. Specifically, LEI never provided its capacity market supply curves, nor the underlying data it used to construct those. Nor has LEI conducted any uncertainty analysis. In fact, the amount of supply response is quite uncertain. It depends on the offer prices of existing generators, which depend on factors that are known only to the generator owners and will evolve over time. One can attempt, as LEI says it did, to construct likely offer prices based on estimates of suppliers' avoidable fixed costs and capital expenditures, expected net energy revenues, performance penalty exposures, optionality, portfolio bidding strategies, and opportunity costs in other markets. However, all of these factors are uncertain and can vary widely among plants and among generic public data sources. There is limited public data on the idiosyncratic costs and performance of each plant, so many assumptions are required.

The notion that capacity markets and suppliers' decisions are inherently uncertain and unpredictable is demonstrated by LEI's own Base Case forecasts, when compared to the real world. For example, its original 2015 report forecasted capacity prices [redacted] higher than the realized prices in FCA 10 and FCA 11, respectively.[4] Its forecast did not anticipate the retirement of the 677 MW Pilgrim Nuclear Station (prior to FCA 10) or the retirement of the 383 MW Bridgeport Harbor 3 coal plant (for the upcoming FCA 12) or the entry of 1,459 MW of new gas-fired combined-cycle generation in FCA 10.[5] And its new forecast differs substantially from its initial forecast, with significantly lower prices, elimination of energy efficiency (in spite of ISO-NE's *increased* forecast), retirement of 534 MW coal-fired steam in New Hampshire plants in 2021 instead of 907 MW gas-fired steam plants in Massachusetts, and the eventual entry of new simple-cycle instead of efficient combined-cycle gas generation, at offer prices that are [redacted]

These changes demonstrate the inability to perfectly predict future market conditions and suppliers' decisions at any point in time and therefore the need to recognize and at least test the effect of uncertainties. Yet LEI does not examine uncertainties about any major aspect of the analysis: not regarding NPT's ability to qualify and clear in the capacity market, and not

[redacted]

5 1,459 MW of new generation in FCA 10. ISO New England (2017), Markets: Results of the Annual Forward Capacity Auctions, https://www.iso-ne.com/about/key-stats/markets#fcaresults, accessed April 13, 2017.

regarding the market's response and price formation resulting from NPT. For example, LEI did not consider the possibility that the plants they now predict will retire may instead decide to stay online absent NPT, and that only NPT's price impact would push them into retirement—thus offsetting much of the price impact LEI projected for NPT. In our own analysis, by contrast, we examine a range of possible outcomes, recognizing the presence and importance of major uncertainties.

C. LEI's High Prices When New Entry Occurs

LEI made mechanical and conceptual errors that overstate how high capacity prices rise when new capacity is needed, thus exaggerating the customer benefits from NPT delaying this rise in prices.

A fundamental concept in economics is that the expected price of any commodity should eventually equal the long-run marginal cost of providing that commodity. Yet LEI inexplicably projects clearing prices rising to and plateauing in FCA 15 to FCA 21 at levels on average [redacted] kW-mo higher than its assumed long-run marginal cost (the levelized Net Cost of New Entry, or "Net CONE"). Figure 1 shows how LEI's updated base case prices remain above their projected Net CONE for the majority of the time period analyzed.

[redacted]

When challenged about this mismatch at the Technical Session in February, LEI explained it was because of "lumpiness": generators come in specific unit sizes, and if one more unit entered, the price would fall below Net CONE, and the entrant would lose money, so the market tends to clear short. However, LEI's approach is based on an apparent misunderstanding of ISO-NE's market clearing mechanics, a failure to apply basic economic principles, and false precision.

LEI modeled ISO-NE's auction clearing mechanics incorrectly. In the "lumpiness" situation LEI describes (and assuming all new resources offer at Net CONE), ISO-NE's clearing engine will indeed select whole units but may end up either short or long. The outcome depends on whether or not the lumpy unit passes the "welfare test," in which the market clearing engine aims to maximize social welfare.[6] If the lumpy unit is cleared, prices will be set at its offer price, not below, in spite of the surplus (the clearing point resides above the demand curve, as in FCA 10).[7] If not, clearing prices will rise above the lumpy unit's offer price, to the level of the next higher offer if that resource passes the welfare test, or vertically up from the last cleared resource to the price indicated on the demand curve. LEI finds that in each case in which a new, lumpy unit may enter the auction the unit does not clear and prices rise above its offer price.[8] While theoretically possible, it is highly unlikely that in each of the twelve instances modeled (eight auctions in LEI's Base Case and four in the Project Case), the "welfare-maximizing" outcome was not to clear the last unit. It would take an extraordinary set of circumstances. More likely, LEI did not apply the capacity auction mechanics properly.

LEI failed to apply a basic economic sanity test. Even if LEI were correct about the clearing mechanics under the particular circumstances it modeled, its forecast of prices would not make

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6 By clearing the lumpy unit, the market clears more capacity but at a lower price; without the unit, less capacity clears at a higher price. To determine which outcome maximizes social welfare, the Market Clearing Engine analyzes the loss of social surplus in each case. For an example of the social surplus test, see Brewster, Matt (2014), FCM Sloped Demand Curve: Conforming changes for FCA10, NEPOOL Markets Committee, October 7–8, 2014, p. 11. Available at: https://www.iso-ne.com/static-assets/documents/2014/10/a02_item_5_iso_presentation_10_07_14.pptx.

7 ISO New England (2016), Testimony of Robert G. Ethier on behalf of ISO New England Inc., before the Federal Energy Regulatory Committee, in the matter of ISO New England Inc., Docket No. ER16-1041-000, February 29, 2016. Attachment to Letter to The Honorable Kimberly D. Bose, Secretary, Federal Energy Regulatory Commission, Electronic filing: ISO New England Inc., Docket No. ER16-1041-000, Forward Capacity Auction Results Filing, February 29, 2016, pp. 5-8. Available at: https://iso-ne.com/static-assets/documents/2016/02/er16-___-000_2-29-16_fca_10_results_filing.pdf.

8 We come to this conclusion because there are no auctions in LEI's analysis in either the Base Case or Project Case in which the auction clearing price is equal to the new gas entry price (Net CONE).

economic sense relative to its assumptions about the long-run marginal cost of new capacity (Net CONE). If lumpiness led to prices clearing perpetually above Net CONE, any generator entering today would earn super-normal returns over its economic life. Such an outcome is inconsistent with expectations in a competitive market with no major barriers to entry. If it were true, a competitive entrant would realize it could enter the market below Net CONE expecting to more than compensate in later auctions, such that revenues would exceed Net CONE on average over its lifetime. Instead, the economic equilibrium to project is that suppliers will be willing to enter until expected prices fall to Net CONE on average. In contrast, LEI's forecast does not result in an equilibrium outcome and hence would not be expected to occur in a competitive market.[9]

LEI's analysis incorporates false precision. Given the uncertainty of a few hundred MW more or less in all of the supply/demand factors, it is false precision to assume that in 10 years the market has room for one unit of a specific size but not zero or two. One could model all possible scenarios with some scenarios adding one more or less unit in each specific year, but the average would have to pass an economic sanity test that investors are not expected to earn super-normal (or sub-normal) returns. The answer would be the same on average as if one modeled non-lumpy entry, as we did in our analysis (even though we recognize that actual entry occurs in chunks).

The result of these errors is to overstate NPT's potential customer benefits. We estimate that if LEI had used an expected clearing price equal to Net CONE in the years when new capacity is needed, its estimate of NPT's benefits would have been approximately half as large, all else equal.[10]

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9 LEI's result of prices permanently above the cost of entry would only be consistent with a competitive market if, due to the lumpiness of entry, a single entry would result in all post-entry years' prices below the average price needed to just earn the cost of capital, Net CONE. However, since LEI assumes multiple entries over time, this condition is not met.

10 By setting the clearing price at Net CONE in each auction in which LEI projected prices above Net CONE, the average annual New England-wide savings drop from $567 million to $294 million. This would be a nearly 50% reduction. We calculate the $30 million/year increase for New Hampshire based on a similar impact in New Hampshire and the updated capacity market benefits of $60 million/year. Frayer, Julia, Eva Wang, and Ryan Hakim (2017), Update of the Electricity Market Impacts Associated with the Proposed Northern Pass Transmission Project, prepared for Northern Pass Transmission, LLC, March 17, 2017, p. 7. ("LEI 2017 Updated Report").

III. Updated Capacity Market Analysis

Unlike LEI's analysis which provides a single, optimistically high estimate of capacity market impacts, we analyze important uncertainties and develop a range of plausible outcomes. We continue to model four scenarios, as described in our original report. In addition to these scenarios, we perform sensitivity analysis on key assumptions about the capacity market affecting price impacts in Scenarios 1 and 2.

Here we supplement our original analysis by: (1) extending our research and analysis of whether NPT is likely to qualify and clear in the ISO-NE's capacity auctions, in response to comments from LEI in the technical session; (2) updating our analysis of capacity market impacts by incorporating newly available information from ISO-NE's most recent capacity auction (FCA 11) and information obtained from LEI during the technical session regarding NPT's enhancement of New England's North-South Interface; and (3) conducting additional "sensitivity analyses" of NPT impacts under alternative Base Case assumptions, including a large unexpected generation retirement or the addition of large amounts of renewable generation, in response to questions from the Applicant and others during the technical conference.

A. NPT Qualification and Clearing

As explained in our original report, a threshold question for whether NPT has any capacity market impacts is whether NPT can qualify for and clear ISO-NE's capacity auctions. *Qualification* is based on demonstrating the ability and commitment to reliably provide energy whenever ISO-NE might need it. In particular, this means that NPT has to demonstrate that it has firm access to sufficient capacity resources in summer and in winter, either based on dedicated resources or overall system capacity in Hydro-Québec, and/or supported by agreements with third parties. *Clearing* depends on offering capacity at or below the market price (such as $5/kW-mo or below), but without offering at an artificially low price. ISO-NE's Internal Market Monitor will review the offer to ensure it reflects the full cost of providing that capacity, without being reduced by subsidies that can allow the resource to out-compete other resources and artificially suppress market prices. Qualification and clearing are closely linked because qualifying may require investments in new generation and transmission that are costly and that would have to be included in the capacity offer price. Failing either one would mean NPT has no capacity market benefits for New Hampshire customers, as reflected in Scenario 3 of our capacity market analysis.

1. Qualification

For imported resources to qualify for ISO-NE's capacity market, NPT will have to demonstrate an affiliation with shippers who have rights to a specific resource or a pool of capacity that has enough surplus (beyond what's needed to serve native demand and any other obligations) to be reliably available for export throughout the year.[11]

The Applicants have not yet presented evidence in this proceeding about whether or how they will demonstrate to ISO-NE that they have sufficient excess capacity to meet the qualification criteria. At the Technical Session in February, LEI claimed that the Transmission Service Agreement (TSA) provides the "paper trail." However, we do not see anything in the TSA that describes a promise to provide qualified capacity or a description of the resources that will be used to qualify. We therefore can only rely on publicly-available information to investigate whether and how NPT capacity might qualify. Here we add to the research contained in our original report, but we continue to find that publicly-available information is inconclusive.

Due to Québec's cold climate and reliance on electric heating, the province's electric demand is far higher in winter than in summer. As a consequence, Hydro-Québec has plentiful surplus capacity in the summer but not necessarily in the winter. To have enough year-round capacity to qualify for ISO-NE's capacity market, NPT would have to show that Hydro-Québec has more *existing capacity* than needed to meet its own winter needs, that it plans to *build* sufficiently more in the future, and/or that it will *acquire or partner* with other resources with excess winter capacity. These various possibilities have different implications for costs and the ability to clear (as addressed in the following sub-section). We therefore focused our research and analysis to inform these distinct possibilities.

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11 "An Elective Transmission Upgrade with an Interconnection Request for Capacity Network Import Interconnection Service under Schedule 25 of Section II of the Transmission, Markets and Services Tariff shall be included in the FCM (1) after it has established a contractual association with an Import Capacity Resource and that Import Capacity Resource has met the Forward Capacity Market qualification requirements or (2) after it has met the requirements of an Elective Transmission Upgrade with Long Lead Time Facility treatment pursuant to Schedule 25 of Section II of the Transmission, Markets and Services Tariff." ISO New England (2016), Market Rule 1, Section III.13.1.3. Available at https://www.iso-ne.com/participate/rules-procedures/tariff/market-rule-1.

Evidence from forward-looking supply-demand reports and other publicly-available information is inconclusive with respect to the availability of surplus capacity during the winter. First of all, most of the discussion in Québec around surplus "capacity" actually relates to energy, not ISO-NE's definition of capacity per se. LEI's testimony assumes that NPT would deliver [redacted] GWh annually of energy over a 1,090 MW line with a 1,000 MW capacity supply obligation.[12] Hydro-Québec's 2016 Annual Report states that due to relatively slow domestic demand growth, "11.3 TWh will be available each year for the next 10 years."[13] Hence, on an energy rather than capacity basis, Northern Pass alone would use up most of this surplus energy on average. It is unclear from the 2016 Annual Report whether this energy would be available during New England's winter peak demand conditions. The same annual report also highlights ongoing discussions with New York about increasing supply and efforts to increase demand in Québec, for example, by attracting data centers.[14]

A press article from October 20, 2016 states that the 11.3 terawatt-hours (TWh) surplus was significantly larger than previous years' surplus of 6.7 TWh in 2014 and 4.3 TWh in 2013,[15] both lower than the amount of energy assumed to be delivered via NPT by LEI. It also states that a 7-year contract with Ontario had been concluded to absorb 2 TWh of the surplus going forward.[16] The article further states that as part of the contract Hydro-Québec would gain access to 500 MW of capacity notably during winter months, when demand is high.

Importantly for the question of whether or not there is sufficient excess *capacity* to meet peak needs, the article goes on to say that "today Hydro-Québec is often forced to buy energy at high

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12 LEI 2015 Report.

13 The Annual Report discusses sales of excess energy to Ontario, but does not clarify whether the 11.3 TWh of excess energy are before or after accounting for sales to Ontario. Hydro-Québec (2017), 2016 Annual Report, 1st quarter 2017, p. 12. Available at: http://www.hydroquebec.com/publications/en/docs/annual-report/annual-report-2016.pdf.

14 *Ibid*, p. 12.

15 Geneviève Lajoie (2016), "L'Ontario achètera des surplus d'Hydro-Québec," Le Journal de Québec, October 12, 2016. Available at http://www.journaldequebec.com/2016/10/20/lontario-achetera-des-surplus-dhydro-quebec.

16 The article (in French) states that the contract is for the delivery of 14 TWh over 7 years. *Ibid.*

prices to fill its energy needs in the winter, during peak demand."[17] There is at least some evidence that Hydro-Québec itself acknowledges a shortage of capacity in the winter months. Notably, in its 2016-2020 Strategic Plan,[18] Hydro-Québec states that while it has sufficient energy to meet local demand in Québec, it is short of capacity from its own resources and has to buy additional capacity during winter peak periods. The plan expresses the goal to reduce expensive capacity purchases through its contract with Transcanada Énergie from the liquefied natural gas powered Bécancour plant.[19] The Strategic Plan further states that the goal is to shrink the capacity deficit by 1,000 MW by 2020.[20] It also states that to fill this capacity deficit and to create additional opportunities for exports, Hydro-Québec will add the final 640 MW and associated transmission to the Romaine hydro facility, will make additional investments in upgrades to existing hydro facilities to increase capacity by 500 MW by 2025, and will decide, by 2020, what will be the next large-scale hydro project.[21] Finally, the strategic plan calls for additional investments in energy efficiency (in Québec) to reduce the capacity gap.[22]

Similarly, a recent report on renewables and intertie opportunities for Hydro-Québec and Ontario suggests that the peak capacity shortfall in Québec is expected not to exceed 2,000 MW

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17 *Ibid.*: "À l'heure actuelle, Hydro-Québec est souvent contrainte d'acheter à gros prix de l'énergie aux États-Unis pour combler ses besoins d'électricité l'hiver, en période de pointe."

18 Hydro-Québec (2016), Strategic Plan 2016-2020: Setting New Sights with our Clean Energy, 2016. Available at: http://www.hydroquebec.com/publications/en/docs/strategic-plan/plan-strategique-2016-2020.pdf While not explicitly stated, the document appears to be a corporate level strategy document.

19 "However, we need more capacity during peak periods.[…] That's why we want to reduce our costly imports by having the TransCanada Énergie generating station in Bécancour converted to liquefied natural gas and using it as a peaking plant." *Ibid.*, p.7. Note that the contract with Bécancour seems no longer in force, due to a failure to gain regulatory approval by the Quebéc regulator (http://www.lecourriersud.com/actualites/economie/2016/10/28/d-autres-options-pour-la-centrale-thermique.html, accessed April 14, 2017).

20 "Through new energy efficiency programs and initiatives, we can also shave up to 1,000 MW from the peak capacity needs forecast for 2020." *Ibid.*

21 *Ibid.*

22 *Ibid.*, p.8

by 2025, a shortfall partially driven by the requirement for reserve capacity to firm up intermittent resources both in Ontario and Québec.[23]

In sum, the evidence we were able to identify suggests that Hydro-Québec may currently be short on capacity in the winter peak period. However, it is likely that Hydro-Québec could still qualify by committing to acquire additional capacity in the future. It could plan to build more hydro facilities (although we do not know how long that would take). Or perhaps qualification could be supported by bilateral arrangements with other entities, such as in Ontario[24] or generators in New England with excess winter capacity.

We summarize our findings as follows:

1. Hydro-Québec likely does not currently have enough existing resources to be able to qualify as year-round capacity via NPT (in addition to its existing obligations).
2. Public data sources are inconclusive about whether Hydro-Québec plans to add enough resources for NPT to qualify as year-round capacity, but Hydro-Québec's public statements suggest that it could build additional capacity if needed to support its own load plus future sales. Either way, if exports depend on building new dams, that will affect the offer floor price, below, and would take significant time.
3. NPT probably could qualify as year-round capacity based on Hydro-Québec's summer surplus and partnering with other entities to qualify, and doing so would affect the offer floor price, as discussed below.

Another issue for qualifying (even for summer capacity) is being deemed deliverable by ISO-NE. ISO-NE tests for deliverability by analyzing whether the project would overload any transmission facilities or cause any voltage or stability problems when delivering full power during peak conditions. If ISO-NE identifies any violations, the new resource would have to upgrade the transmission network in order to be deemed deliverable. We are not aware of this study having been completed, but it could pose additional costs for qualifying.

23 Marc Brouillette (2016), Renewables and Ontario/Québec Transmission System Interties, An Implications Assessment, Final Report, June 16, 2016, p.ii. Available at: https://cna.ca/wp-content/uploads/2014/05/expanding-ontario-and-quebec-tx-interties-final-report-june-16-2016.pdf.

24 Whether or not such an arrangement would be consistent with the requirements under the current Transmission Service Agreement, including the requirement for "clean" power, is unclear and may depend on the power sources under such a sharing agreement.

2. NPT Offer Floor Price

If NPT qualifies for the capacity auction, its offer price will be subject to mitigation by the Internal Market Monitor. The Internal Market Monitor will assess NPT as an Elective Transmission Upgrade (ETU), which is treated similarly to new generation. However, an ETU's default offer price is the price cap in the auction—far too high for the resources to clear and affect the price—unless the importer demonstrates that its costs net of unsubsidized energy revenues are lower.[25]

Our original report raised this issue but did not estimate the price that the Internal Market Monitor may allow NPT to offer into the capacity market because we did not have all the information and could not know what judgments the Internal Market Monitor would make. However, we understand that LEI will be analyzing this issue in its Supplemental Testimony, so here we provide our own perspective on the potential offer prices that the Internal Market Monitor might allow. We estimate the offer price under several assumptions for how NPT could present its net costs and the various ways the Internal Market Monitor might consider them.

If NPT only had to recover its transmission, including those costs covered under the TSA, the allowed cost-based offer price would be very low, with a levelized transmission cost of $18/kW-mo (assuming a 40-year economic life) minus $33/kW-mo in estimated energy revenues, for a net cost below zero.[26] But generation is also needed to support capacity imports, and the key question is: what is the source of the generation and what is its cost? If Hydro-Québec has to build new dams to have enough to export, which seems consistent with their statements discussed above in the prior section,[27] the costs of doing so will add $44/kW-mo of capital costs, making the overall cost too high to compete in the capacity market.[28]

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25 The ETUs are included in the "all other technology types" category with an Offer-Review Trigger Price (ORTP) at the auction starting price of $14/kW-mo. ISO New England (2016), Market Rule 1: Appendix A Market Monitoring, Reporting and Market Power Mitigation, Section III.A.21.1.1. Available at https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_append_a.pdf.

26 As we explain in more detail below, the transmission costs are based on the annual revenue requirements released by the Applicant and the energy revenues are based on LEI's projected ISO-NE energy prices.

[redacted]

Continued on next page

On the other hand, if exports across NPT will be based on surplus energy from existing Hydro-Québec generation facilities (and/or from new resources that are planned for reasons other than export), calculating an offer floor price is less straightforward. The offer floor price could vary from $0/kW-mo to $13/kW-mo or even higher if the Internal Market Monitor decided to use a higher cost-of-capital or shorter economic life than 40 years. The outcome depends on three main factors: the opportunity costs of foregone energy revenues from reducing sales to New York or neighboring Canadian provinces; the cost or revenue sharing with third parties providing winter capacity, if any; and whether the Internal Market Monitor might allow NPT credit for its clean energy attributes.[29]

The possibility of the accounting for clean energy credits presents the greatest possibility for NPT to clear. In calculating an offer floor price for renewable resources, the Internal Market Monitor includes Renewable Energy Credit (REC) payments as a revenue credit, similar to energy revenues. The current Renewable Portfolio Standards in New England (with the exception of Vermont) do not, however, allow large-scale hydro to qualify for RECs, so this credit may not apply to NPT. And any above-market premium buyers pay under contract, presumably to compensate for clean energy attributes of the project, may not serve as a proxy since the ISO-NE tariff requires such revenues to be "broadly available" in the market rather than targeted to specific resources.[30] There are three possible concepts by which the Internal Market Monitor

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[redacted]

28 The cost of new hydro generation is based on recent reported costs for the Romaine units. See Brouillette (2016), p. 4.

29 The opportunity cost of *capacity* may also be a consideration, but as a commercial matter rather than as a term to add in the Internal Market Monitor's calculation. The shipper will not likely sell into New England's three-year forward capacity market if it expects to be able to earn a higher price selling into New York's (non-forward) capacity market.

30 Market Rule 1, Section III.A.21.2 (b)(i) states: "The Internal Market Monitor will exclude any out-of-market revenue sources from the cash flows used to evaluate the requested offer price. Out-of-market revenues are any revenues that are: (a) not tradable throughout the New England Control Area or that are restricted to resources within a particular state or other geographic sub-region; or (b) not available to all resources of the same physical type within the New England Control Area, regardless of the resource owner. Expected revenues associated with economic development incentives that are offered broadly by state or local government and that are not expressly intended to reduce prices in the

Continued on next page

might conceivably admit credits, however. One is by considering that open solicitations in which NPT is participating, such as Massachusetts' just-released Clean Energy RFP, allow many resources to compete, so perhaps the term "broadly available" may apply. Second, the recently proposed Clean Energy Standard in Massachusetts would broadly incorporate clean generation, including from hydro power from Hydro-Québec, so one could consider the value of a "Clean Energy Credit" under that Standard, although there are limited details currently available to project the value of credits for this program. The third concept would be to recognize that if Massachusetts did not procure clean energy through a project such as NPT, it would have to buy more RECs to achieve the same reduction in carbon emissions. The price of RECs (recently assumed to be around $26.5/MWh going forward) would represent customer savings from not having to buy as many RECs.[31]

We consider all of these variables in presenting the following plausible supply cases that the Internal Market Monitor might face: (1) Hydro-Québec has sufficient existing surplus to serve New England year round, but the opportunity cost of that energy is uncertain; (2) Hydro-Québec only has sufficient capacity in the summer to serve New England, so capacity revenues must be shared with a third party that can provide winter capacity; (3) Hydro-Québec must build new hydro generation to serve New England year-round. Table 1 shows that in the case with no clean energy credits attributed to NPT only the scenario with existing surplus and a relatively low energy opportunity cost of $22/MWh will result in a low enough offer to ensure clearing in FCA 12. On the other hand, if clean energy credits equivalent to the recent REC price can be claimed, most cases will result in a mitigated offer of $0/kW-mo, except in the case with new generation. The details of the offer floor price calculation are documented below.

Continued from previous page

Forward Capacity Market are not considered out-of-market revenues for this purpose." ISO New England (2016), Market Rule 1: Appendix A Market Monitoring, Reporting and Market Power Mitigation, Section III.A.21.2. Available at https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_append_a.pdf.

31 Concentric Energy Advisors (2017), ISO-NE CONE and ORTP Analysis, January 13, 2017, p. 79. Released along with ISO-NE FERC filing on updated ORTP values, available at https://www.iso-ne.com/static-assets/documents/2017/01/cone_and_ortp_updates.pdf.

Table 1: Projected NPT Offer Floor Price Prices

Case	Assumptions		NPT Offer Floor Price	
	Energy Cost	Revenue Earned by HQ	No Clean Energy Credit	$26.5/MWh Clean Energy Credit
	$/MWh	*%*	*$/kW-mo*	*$/kW-mo*
Existing Year-Round Surplus				
Low Energy Cost	$22	100%	$0.6	$0.0
High Energy Cost	$28	100%	$4.4	$0.0
Summer Surplus combined with Third Party's Winter Capacity				
High Revenue Earned	$28	75%	$5.9	$0.0
Low Revenue Earned	$28	33%	$13.2	$0.0
New Generation Needed to Support Year-Round Surplus				
New Hydro Energy Cost	$65	100%	$29.3	$11.5

The bottom line is that NPT will have trouble clearing the capacity market unless its offer is based on existing generation with a low end opportunity cost and/or some form of revenue credit for the project's environmental attributes. The actual allowed offer will depend on what Hydro-Québec submits to the Internal Market Monitor and how the Internal Market Monitor addresses the issues we have outlined. Until that process is completed, the outcome will be uncertain.

Analytical Details

To estimate NPT's allowed offer prices, we use a similar Excel workbook to the one the Internal Market Monitor provides market participants for justifying their offers for ETUs.[32] The workbook accounts for the basic building blocks of costs for an ETU: the cost of all new transmission facilities are included in the fixed costs category; the costs of energy generation in terms of the levelized costs of new facilities or the opportunity cost of existing capacity; and the expected energy market and clean energy credit revenues, if applicable. A simplified version of the calculation is illustrated in Table 2 below.

32 Plugging our values for costs and revenues into the Internal Market Monitor's workbook resulted in very similar results.

[redacted]

Our estimates for the possible offer floor price for NPT rely on the following information:

Transmission Costs. We use the annual revenue requirements provided by the Applicant in its confidential response to data requests, with a minor adjustment to account for the delay in the construction of the line, keeping the present value of the revenue requirements the same in real terms.[33] We also account for the transmission upgrades on the Canadian system to deliver power over NPT by grossing up the revenue requirements by 28% based the relative capital costs of each section ($450 million for Canadian upgrades vs. $1,600 million for NPT).[34] The resulting levelized costs of transmission are $217 million/year, which equates to about an 11% charge rate for recovering capital and ongoing fixed costs. Dividing by 1,000 MW of assumed capacity yields transmission costs of $18.0/kW-mo. The assessed cost could be higher, however, if the Internal Market Monitor reconstructed transmission revenue requirements based on a riskier *merchant* cost of capital, or if additional upgrades are necessary for NPT to be deemed deliverable.

Generation Capacity Costs (if applicable). If Hydro-Québec needs to build a new dam for exporting power across NPT, then the applicable energy costs reflect the costs of building a new

33 Schedule of Estimated Annual Revenue for Northern Pass received in response to NEPGA Request Nos. 2 and 4, SPNHF Request No. 23, Environmental NGOs Request No. 39 and Non-Abutters Request No. 25.

34 The cost of the Canadian upgrades are assumed to be CAD 600 million, which we convert to U.S. dollars ($) based on an exchange rate of CAD 0.75 per $1. The Northern Pass, Clean Energy RFP Overview: Providing Clean Energy and Unmatched Benefits to New England Customers, p. 3. Available at http://northernpass.us/assets/clean-energy-rfp/FINAL%20NP%20BID%20SUMMARY%20-%20NH.pdf.

hydro facility. A 2016 report estimated the levelized costs of Romaine facilities to be $60/MWh (or CAD 80/MWh).[35] The cost could be higher, however, if the Internal Market Monitor calculated its own levelized cost based on a merchant cost of capital that is likely higher than the cost of capital assumed in the 2016 report. Alternatively, Hydro-Québec may be able to acquire additional winter capacity at a price below the cost of constructing new hydro facilities, for example by increasing the capacity of its existing capacity swap with Ontario discussed above or by making arrangements with generators in New England that have excess capacity in the winter, as discussed below. We are not aware of any current plans to use such an arrangement, but we are aware of Hydro-Québec continuing to plan the construction of new hydro facilities, as discussed above.

Energy Opportunity Costs (if applicable). In the case where NPT capacity is based on existing supply, that capacity can export energy to New England and earn the energy revenues discussed below, but at an opportunity cost of not selling the same energy into other markets. For example, if Hydro-Québec decreases energy exports to New York in order to increase energy exports to ISO-NE, the foregone revenues in New York are the opportunity costs. [redacted] Hydro-Québec may wish to do so if there is a more valuable use for that energy either in an alternative market or in future hours in ISO-NE. This value is similar to our calculation of future New York Zone D annual average energy prices, which is the most likely alternative market for Hydro-Québec exports.[37] It is conceivable that the opportunity cost could be lower under alternative assumptions due to changing market dynamics

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35 Shown here in U.S. dollars ($) based on an exchange rate of CAD 0.75 per $1. Source reports value in CAD. Brouillette (2016).

[redacted]

37 Recent energy prices in New York's Zone D have been approximately 60% of New England energy prices, based on Brattle analysis of SNL Financial data. 60% of LEI's price forecast for New England suggests a price of $27/MWh available in New York if relative price patterns continue.

in New York or due to transmission constraints. [redacted]

Energy Revenues. We estimated the potential market revenues for energy transferred over Northern Pass based on the New England energy prices LEI reported in its updated analysis.[38] We make a minor adjustment of the load-weighted locational marginal prices (LMPs) to account for the assumed time profile of energy flows across NPT (100% capacity during peak hours and 50% capacity in non-peak hours). This adjustment results in generation-weighted average LMPs that are about 97% of the load-weighted prices. To account for revenues beyond the time horizon LEI modeled, we extend their prices past 2029 using the average annual growth rate between 2019 and 2029 [redacted]. Finally, we translate all future energy revenues into a levelized, single year value with the same present value. The result is [redacted]/MWh.

Clean Energy Credits. We do not know whether and how the Internal Market Monitor will consider recognizing a credit for NPT's clean energy attributes, as discussed above. To account for this uncertainty we analyze two cases: one in which NPT is not credited for its clean energy attributes; and one in which NPT is recognized at the $26.5/MWh REC value assumed in the Internal Market Monitor's recent update of Offer Review Trigger Prices.[39]

Adjustment for Composite Offers (if applicable). If Hydro-Québec does not have surplus winter capacity itself, NPT may wish to submit a composite offer with other resources, as discussed in the prior section. We test two cases that differ by the amount of the capacity market revenues that NPT will receive within the composite offer. In the first, we assume that as a summer resource NPT would receive its pro-rata share of revenues for the four months during the summer commitment period (33%), which triples the offer price floor for NPT. In the second case, we assume that the split between summer and winter capacity value will reflect market conditions for winter capacity. We use the relative values expressed in New York's seasonal capacity market as an indicator of potential market conditions (ISO-NE does not have a seasonal

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38 LEI 2017 Updated Report, p. 21.

39 Concentric Energy Advisors (2017), ISO-NE CONE and ORTP Analysis, January 13, 2017, p. 79. Released along with ISO-NE FERC filing on updated ORTP values, available at https://www.iso-ne.com/static-assets/documents/2017/01/cone_and_ortp_updates.pdf.

market to observe). Based on this approach, the summer capacity is more valuable and NPT would receive about 75% of all the capacity revenues.[40]

B. Capacity Price Impacts

If NPT adds resources that would not otherwise exist and if it qualifies and clears this capacity in New England's capacity market, it will reduce capacity prices. The magnitude of the reduction will depend on the shape of the market's demand and supply curves, since the market clearing price is determined by their intersection and how the intersection point changes as NPT shifts the supply curve. The demand curves are fairly steep, such that a 1,000 MW increase in supply could decrease prices substantially if other suppliers did not responsively exit. But supply curves express the prices at which suppliers will offer to enter or exit the capacity market; they express how much more or less capacity suppliers are willing to provide as the price changes. The more other suppliers exit as the price starts to decrease, the less the price impact of NPT will be. Estimating this effect is the critical matter in predicting the price impact of NPT in Scenarios 1 and 2. In Scenario 3 NPT does not significantly affect capacity prices since NPT does not qualify and clear in that scenario. In Scenario 4 NPT continues not to have any electricity market impacts, irrespective of any changes to assumed market conditions.

In this section we summarize the new information available since we submitted our original report in December 2016 and how it changes our supply curve and demand curve assumptions. We then present the results of our analysis, including the sensitivity to a range of plausible assumptions.

1. Supply Curve Updates

Predicting the shape of the supply curve is inherently uncertain since it depends on the economics and bidding strategy of every individual resource in the market—which are known only to the resource owners at the time they form their offers before each auction. We and other analysts do have some understanding of the suppliers' economics and how they may evolve over

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[40] Based on New York ISO (NYISO) installed capacity (ICAP) prices for Summer 2016 and Winter 2016/17, we found that 83% of the annual capacity market value in New York Control Area (NYCA) is from selling summer capacity and 70% based on G-J prices. NYISO (2017), Installed Capacity: View Strip Auction Summary. Available at: http://icap.nyiso.com/ucap/public/auc_view_strip_detail.do.

time. However, our ability to predict the economics of individual resources is limited by incomplete public data on the idiosyncratic characteristics of individual resources and their bidding strategies, as discussed in Section II.B above. Thus the best approach to analyzing the market is to develop a reasonable supply curve based on the information available and then to test a range of possible assumptions reflecting the inherent uncertainties. Here we present our analysis based on our reference assumptions; Section III.B.4 presents our sensitivity analyses with alternative assumptions about market conditions.

As in our original report, we construct a likely supply curve based on several public sources of information. Our sources include data from the capacity auctions, rules and statements from ISO-NE's Internal Market Monitor regarding supply offers, and the underlying factors that generation owners consider in forming their capacity market offers.

In this supplemental report we incorporate new information from Forward Capacity Auction 11 (FCA 11), which was conducted in February 2017. FCA 11 cleared at a price of $5.30/kW-mo, which was $1.70/kW-mo lower than the price in FCA 10 and $1.15/kW-mo lower than we had predicted in our original report.[41] The decline in the market-clearing price was driven by the entry of 1,400 MW with offers below $5.30, whose price impact was moderated by the exit of 1,100 MW of existing supplies—a large amount of displacement but less than our supply curve shape would have predicted as a response to so much entry and declining prices.[42,43] New low-cost capacity included 671 MW of new energy efficiency and active demand response, 406 MW of new imports (primarily from Québec), and 310 MW of uprates to existing generators.[44]

41 ISO New England (2017), Forward Capacity Auction #11 Results Summary, March 2017. Available at https://www.iso-ne.com/static-assets/documents/2017/03/ccp_2020_21_fca_11_cso_flow_diagram.pdf.

42 Some of the apparent generation "displacement" is actually a repowering of the 149 MW Milford unit with a 202 MW upgraded plant.

43 We calculated changes in capacity by comparing the capacity supply obligations in FCA 10 to those in FCA 11. The list of resources that qualified and cleared both auctions can be found at ISO New England (2017), Forward Capacity Market. Available at https://www.iso-ne.com/markets-operations/markets/forward-capacity-market.

44 Hydro-Québec imports increased by 100 MW over the New Brunswick intertie and 275 MW over Phase II from FCA 10. *Ibid.*

Displaced capacity included 530 MW imports from New York's Roseton plant, 90 MW of other imports, and 290 MW of generation.[45]

The outcome of FCA 11 reveals that there is more low-cost supply available than we had thought, including from existing generators that proved more willing to remain in the market as prices fell.[46] If this willingness to endure low prices continues, capacity prices will remain low as long as surplus supply conditions prevail. As such, NPT's potential to further depress prices is limited in the short term, but it may help maintain such low prices longer, through the mid-to-late 2020s, when prices would otherwise rise (absent NPT) with load growth and generator retirements.

Our updated analysis accounts for this new information by fitting our initial supply curves to the few supply curve points ISO-NE published from FCA 11. Following each auction, ISO-NE releases the results of each round as the auction "clock" descends toward the market clearing price where supply and demand match. Figure 2 below shows the revealed supply curve points (red dots) and how we used them to adjust our supply curve (teal line) from our original analysis (grey line).[47] We continue to construct our supply curve in three sections, but with some changes from the original analysis, as described in the following paragraphs.

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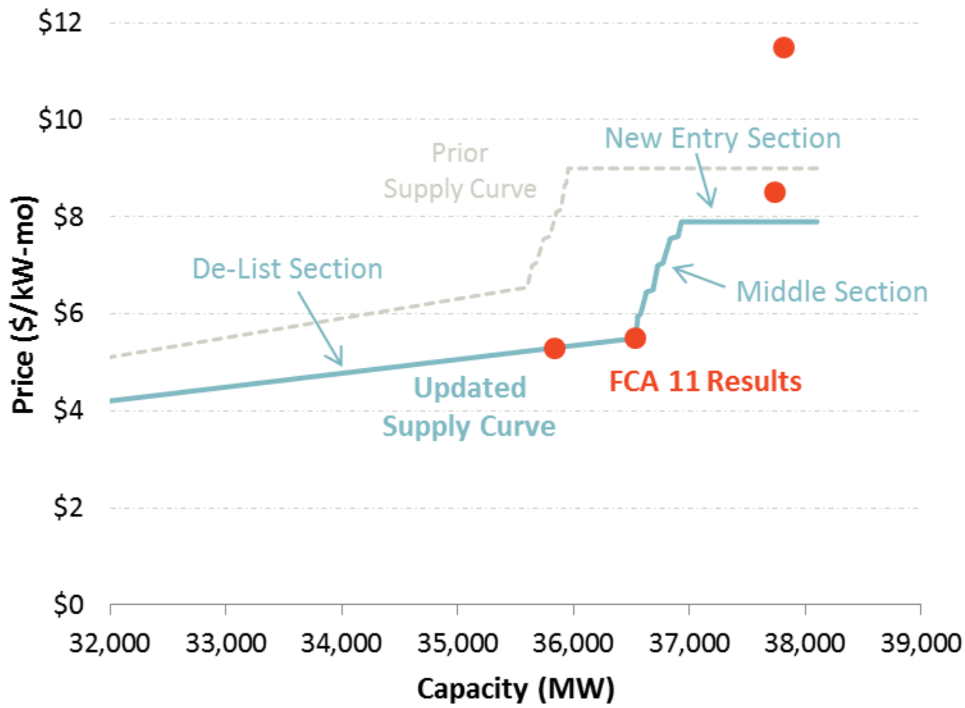
45 Rosetone 1 (530 MW) and two resources over the New Brunswick intertie (Bayside and Control Area Backed resources) cleared in FCA 10, but did not clear in FCA 11. The 290 MW of existing generation that did not clear in FCA 11 includes 149 MW of Milford capacity that was uprated and reclassified as a larger 202 MW "new" unit. *Ibid.*

46 ISO-NE also revised downward its view of the reservation price of existing generators. Bradley, Gregg (2017), FCM Dynamic Delist Bid Threshold (DDBT), February 7, 2017. Available at https://iso-ne.com/static-assets/documents/2017/02/a7_presentation_fcm_dynamic_delist_bid_threshold.pptx.

47 Our prior analysis fit a supply curve to the clearing point in FCA 10. That auction cleared at a higher price and did not reveal any supply curve information below the $7.03/kW-mo clearing point.

Figure 2: FCA 11 Results and Updated Supply Curve



Lower ("De-List") Section. We refer to the bottom section as the "de-list section" because it primarily includes existing units that may exit the market using static or dynamic de-list bids. We construct this section by interpolating and extrapolating from the bottom two points in FCA 11. This section of the curve is similar to our original analysis but shifted downward consistent with FCA 11's revelation of little capacity de-listing above $5.50. The de-list section thus starts at a lower price ($5.50 instead of $6.50) and descends from there at a similar but slightly more gradual slope. As a result, the top 5,000 MW of this section of the supply curve, which largely corresponds to the old oil- and gas-fired generators we referred to in the original analysis, is now centered on $4.80/kW-mo (instead of $5.50/kW-mo), and the bottom price of this section is $4.10/kW-mo instead of $4.50/kW-mo. These lower offer prices are consistent with FCA 11 and with statements from the Internal Market Monitor that if it had updated the dynamic de-list bid threshold (DDBT) for FCA 12 (corresponding to the average mitigated offer of those 5,000 MW) the value would have been about $1/kW-mo lower than the $5.50 it reported for FCA 9.[48] Our sensitivity analysis tests both lower and higher starting points and slopes.

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48 Although the DDBT will not change for FCA 12 due to timing issues, the Internal Market Monitor calculated that the DDBT would have decreased from $5.50/kW-mo in FCA 11 to $4.55/kW-mo in

Continued on next page

Middle Section. We construct this section with the relatively steep "core shape" we used in our original analysis, shifted to the right to align with the $5.50/kW-mo data point from FCA 11, as shown above in Figure 2. Other shapes might also be reasonable, and our sensitivity analyses examine the effect of an alternative straight-line interpolation between the $5.50 and $8.50 points from FCA 11.

[redacted]

Starting from the initial supply curve described above, we shift the curve in future auctions consistent with our original analysis: (1) we shift it rightward to reflect assumed new renewable and energy efficiency resources and leftward to reflect assumed retirements; and (2) we raise the de-list section over time as exposure to performance penalties increases the cost of taking on a capacity supply obligation. We maintain the lower section at the same prices until the performance penalty rate increases in FCA 16 from $3,500/MWh to $5,455/MWh.[49] We then increase the de-list section's top price by $0.4/kW-mo in FCA 16 to reflect the impact of the higher penalty rate. Note that this is a smaller jump than in our prior analysis because of newly-available information from ISO-NE regarding its assumptions on the parameters affecting

Continued from previous page

FCA 12 due to a lower projected number of scarcity hours and the lower FCA starting price offsetting the impact of the higher penalty performance rate. Bradley (2017).

49 *Ibid.*

generators' exposure to penalty rates.[50] We recognize that these assumptions are subject to uncertainty, so we present alternatives as sensitivity analyses in Section III.B.4 below.

2. Demand Curve Updates

Demand curves are determined administratively by ISO-NE rules. The construction of the demand curves is relatively straightforward, but we make two changes from our original analysis.[51] [redacted]. The change contracts the demand curves downward, as shown below in Figure 3, and results in slightly lower clearing prices compared to our original analysis.

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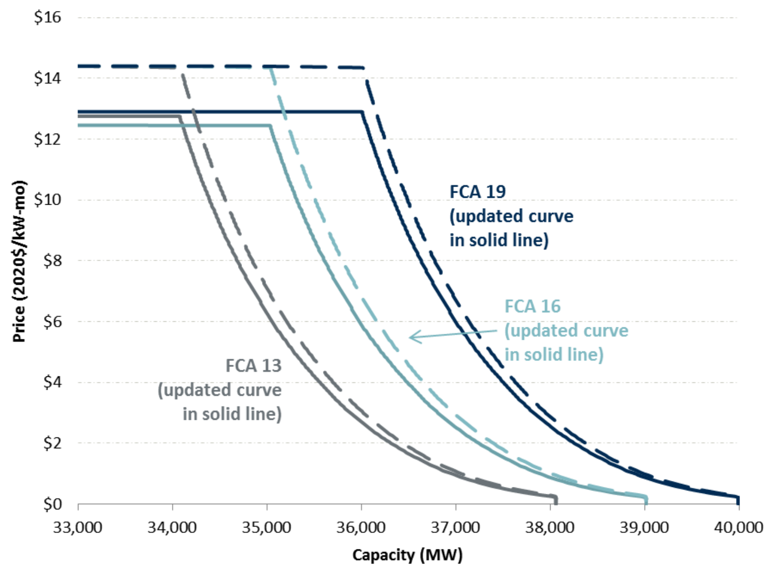
50 The assumed increase in de-list bids is based on an analysis similar to our original analysis. The values are lower primarily due to a decrease in the system balancing ratio from 92% to 75% and a related increase in the assumed availability from 55% to 60%. The lower balancing ratio is based on confirmation from ISO-NE through its customer service desk that 75% is the balancing ratio used in the Internal Market Monitor's calculations. We also updated the future scarcity hours based on the projected excess capacity in the Base Case and the future auction starting price.

51 ISO-NE released a revised version of the FCA 11 demand curves in September 2016 that results in a minor shift of 5 MW on average of the demand curves to the right. ISO New England (2016), FCA 11 Revised Demand Curve, September 28, 2018. Available at https://www.iso-ne.com/static-assets/documents/2016/09/a2_fca11_demand_curve_revised.xlsx.

52 LEI 2017 Updated Report, Figure 19, p. 32.

Figure 3: Updated System Demand Curves



[redacted]

53 LEI 2017 Updated Report, p. 14.

[redacted]

3. Updated Capacity Market Impacts

Similar to our original analysis, we simulated each auction by intersecting the estimated supply and demand curves described above. We adjusted the timeframe of our analysis to start in FCA 12 based on the in-service date LEI assumed in its updated report.[54] We extended our analysis from 11 years to 13 years to include all of the potential capacity benefits. Due to the starting point of more capacity surplus from FCA 11, it takes longer for the capacity prices in the Project Case to converge with prices in the Base Case.

Base Case. Figure 5 shows that throughout the period analyzed our Base Case prices are lower in our updated analysis by an average of about $1.8/kW-mo.[55] Over the first five auctions, the low prices reflect the downward shift of the de-list section of the supply curve, as indicated by the results of FCA 11. The difference is greater after FCA 16 when the performance penalty rate increases the de-list section of the supply curve less than in our original analysis (due to differences in assumed market conditions and plant performance affecting penalty exposures, as noted above). [redacted]

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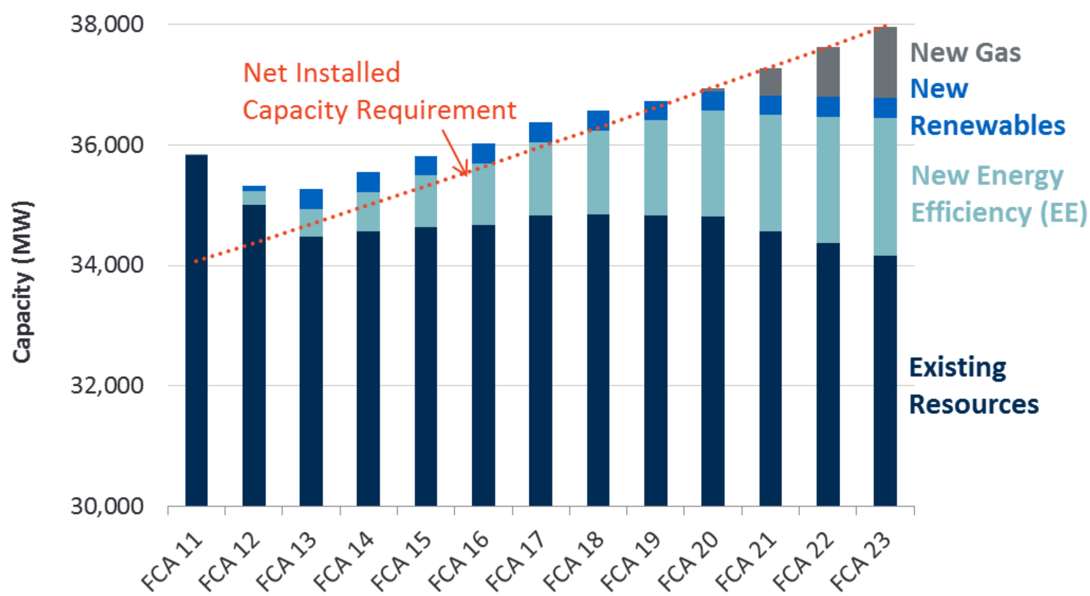
54 LEI 2017 Updated Report, p. 19.

55 We assume that the original base case prices would remain at $9/kW-mo in FCA 22 and FCA 23.

[redacted]

Similar to our original analysis, Figure 6 and Table 4 below show that we project a decline in cleared capacity in the first few auctions due to the transition to the MRI demand curves. The cleared capacity starts increasing in FCA 14 due to new energy efficiency resources as well as some existing resources that did not clear in earlier auctions returning to the market.[56] New gas-fired generation now enters the market starting in FCA 20. New entry occurs four auctions later than in our original analysis due to an increase in existing resources observed in FCA 11.

Figure 6: Base Case Supply and Demand Balance



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56 Renewable additions increased slightly due to a minor adjustment in the calculation of renewable capacities to satisfy the regional Renewal Portfolio System (RPS) mandates.

Table 4: Base Case Supply Projection

	FCA 11 2020-21	FCA 12 2021-22	FCA 13 2022-23	FCA 14 2023-24	FCA 15 2024-25	FCA 16 2025-26	FCA 17 2026-27	FCA 18 2027-28	FCA 19 2028-29	FCA 20 2029-30	FCA 21 2030-31	FCA 22 2031-32	FCA 23 2032-33
Peak Demand (MW)													
Summer Peak net of PV	29,600	29,864	30,137	30,415	30,691	30,966	31,247	31,530	31,816	32,104	32,395	32,689	32,985
Net ICR	**34,075**	**34,378**	**34,693**	**35,013**	**35,331**	**35,648**	**35,971**	**36,297**	**36,626**	**36,958**	**37,292**	**37,630**	**37,972**
***Annual* Additions/Exits (MW)**													
Existing Resources	**-**	**-833**	**-525**	**84**	**76**	**28**	**164**	**17**	**-10**	**-18**	**-251**	**-200**	**-200**
Retirements (non-price responsive)	-	-583	-200	-200	-200	-200	-200	-200	-200	-200	-200	-200	-200
Price Responsive Exits	-	-250	-325	-	-	-	-	-	-	-	-51	-	-
Price Responsive Entrants	-	-	-	+284	+276	+228	+364	+217	+190	+182	-	-	-
New EE	**-**	**+235**	**+220**	**+206**	**+192**	**+179**	**+179**	**+179**	**+179**	**+179**	**+179**	**+179**	**+179**
New Renewables	**-**	**+90**	**+240**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
New Solar PV	-	+19	-	-	-	-	-	-	-	-	-	-	-
New Onshore Wind	-	+71	-	-	-	-	-	-	-	-	-	-	-
New Offshore Wind	-	-	+240	-	-	-	-	-	-	-	-	-	-
New Natural Gas-Fired Generation	-	-	-	-	-	-	-	-	-	+51	+407	+359	+362
Total Annual Additions/Exits		**-507**	**-65**	**+290**	**+268**	**+207**	**+343**	**+196**	**+169**	**+212**	**+335**	**+338**	**+341**
Total Cleared Capacity (MW)	**35,835**	**35,328**	**35,263**	**35,553**	**35,821**	**36,027**	**36,370**	**36,566**	**36,735**	**36,947**	**37,282**	**37,620**	**37,961**

NPT Scenario 1. Scenario 1 assumes NPT adds 1,000 MW in FCA 12 and does not cause other plants to retire. It does, however, temporarily displace existing capacity that would have cleared in the absence of NPT, which moderates the price impact. We model this effect by shifting the Base Case supply curve 1,000 MW rightward and establish a new clearing point. Figure 7 shows that the net effect is to reduce prices relative to the Base Case, by $0.25/kW-mo on average through FCA 17—and the effect is uniform throughout New England because the increased Northern New England's Maximum Capacity Limit prevents Northern New England from price-separating, as discussed in the prior section. The price impact is modest while the market clears along the relatively flat de-list section of the supply curve. In the later years, between FCA 18 and FCA 22, the price difference increases to an average of $1.40/kW-mo, providing the majority of overall savings to New Hampshire customers. The savings arise because the Base Case has climbed off the de-list section of the supply curve and prices rise along the steeper middle section of the curve until they level off at the price of new entry; NPT provides additional supply that shifts the supply curve rightward and keeps the market clearing in the de-list section of the supply curve and delays the rise in prices for three years. NPT's price impact in these years is larger than our original analysis because the de-list section of the supply curve is lower.

Altogether, NPT provides $26 million per year of savings for New Hampshire ratepayers. Figure 7 shows the prices relative to the Base Case, and Table 5 shows the changes in cleared capacity, similar to the corresponding table in our original report.

[redacted]

Table 5: Scenario 1 Difference in Capacity from Base Case

	FCA 12 2021-22	FCA 13 2022-23	FCA 14 2023-24	FCA 15 2024-25	FCA 16 2025-26	FCA 17 2026-27	FCA 18 2027-28	FCA 19 2028-29	FCA 20 2029-30	FCA 21 2030-31	FCA 22 2031-32	FCA 23 2032-33
Difference from Base Case (MW)												
Northern Pass	+1,000	+1,000	+1,000	+1,000	+1,000	+1,000	+1,000	+1,000	+1,000	+1,000	+1,000	+1,000
Retirements	-	-	-	-	-	-	-	-	-	-	-	-
New Natural Gas-Fired Generation	-	-	-	-	-	-	-	-	-51	-459	-818	-1,000
Other Price Responsive Additions/Exits	-940	-940	-940	-940	-930	-940	-840	-680	-519	-261	-92	-
Total Difference in Cleared Capacity	**+60**	**+60**	**+60**	**+60**	**+70**	**+60**	**+160**	**+320**	**+430**	**+280**	**+90**	**-**

Figure 8 shows three example auctions to further demonstrate the market clearing dynamics with and without NPT in Scenario 1. While the price differences are small in FCA 12 (and other early auctions), the difference becomes greatest in FCA 20 before converging in FCA 23.

[redacted]

NPT Scenario 2. Scenario 2 assumes that the addition of 1,000 MW from NPT causes 500 MW of existing resources to permanently retire in FCA 12; as in Scenario1, some other existing capacity that would have cleared in the absence of NPT is displaced temporarily. Figure 9 shows prices just $0.15/kW-mo below the Base Case through FCA 17. The price difference increases starting in FCA 18 to an average of $0.85/kW-mo through FCA 21 before prices converge in FCA 22.

Scenario 2 results in $13 million per year of savings for New Hampshire ratepayers. While Figure 9 shows the prices relative to the Base Case, Table 6 shows the changes in cleared capacity, similar to the corresponding table in our original report.

[redacted]

Table 6: Scenario 2 Difference in Capacity from Base Case

	FCA 12 2021-22	FCA 13 2022-23	FCA 14 2023-24	FCA 15 2024-25	FCA 16 2025-26	FCA 17 2026-27	FCA 18 2027-28	FCA 19 2028-29	FCA 20 2029-30	FCA 21 2030-31	FCA 22 2031-32	FCA 23 2032-33
Difference from Base Case (MW)												
Northern Pass	+1,000	+1,000	+1,000	+1,000	+1,000	+1,000	+1,000	+1,000	+1,000	+1,000	+1,000	+1,000
Retirements	-500	-500	-500	-500	-500	-500	-500	-500	-500	-500	-500	-500
New Natural Gas-Fired Generation	-	-	-	-	-	-	-	-	-51	-459	-500	-500
Other Price Responsive Additions/Exits	-460	-480	-470	-480	-460	-470	-380	-240	-239	-11	-	-
Total Difference in Cleared Capacity	**+40**	**+20**	**+30**	**+20**	**+40**	**+30**	**+120**	**+260**	**+210**	**+30**	**-**	**-**

NPT Scenario 3. In Scenario 3 we assume NPT does not qualify or clear in the capacity auction, so the capacity price impacts are minimal. It is possible that NPT could reduce energy prices and thus raise generators' capacity supply offers, but the effect would be very small for any resources that do not generate frequently and earn substantial net energy revenues. Such is the case for capacity-price-setting existing generators submitting de-list offers in the early years and for combustion turbines (CTs) as new entrants in the later years. Since we now assume CTs will be the new entrants, as discussed in Section IV, capacity price impacts for Scenario 3 are minimal. For reference, our prior analysis assumed entry by combined-cycle units (CCs) and showed a modest capacity price *increase* in Scenario 3.

NPT Scenario 4. Scenario 4 continues not to have any electricity market impacts, irrespective of any changes to assumed market conditions.

Comparison to Prior Analysis. Our updated capacity market savings are greater than in our prior analysis because our updated assumptions (informed by FCA 11) allow prices to stay very low in surplus capacity conditions that NPT perpetuates. Figure 9 shows this dynamic and the longer timeframe it takes the Base Case and the Project Case prices to converge, given the greater initial surplus. The fact that such dramatic changes can occur in such a short time between our prior report and this supplemental report demonstrates the inherent uncertainty in predicting capacity prices and capacity price impacts.

[redacted]

Table 7 summarizes the differences in capacity market benefits to New Hampshire customers. Savings increased by $8 million/year in Scenario 1, $3 million/year in Scenario 2, and $2 million/year in Scenario 3. Note that the table shows 13-year average impact rather than the 11-year averages shown in our prior report in order to capture the longer-term impact in our updated analysis.[57]

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[57] The 11-year impacts in our prior analysis were $22 million/year in Scenario 1, $11 million/year in Scenario 2, and -$7 million/year in Scenario 3. Newell, Samuel and Jurgen Weiss (2017), Electricity Market Impacts of the Proposed Northern Pass Transmission Project, prepared for The New Hampshire Counsel for the Public, p. ix ("Newell and Weiss (2017)").

Table 7: Comparison of Prior and Updated *Capacity Market* Savings
($ million annual savings for New Hampshire customers over 13 years)

Scenarios	**Prior Analysis** *$ million/year*	**Updated Analysis** *$ million/year*	**Difference** *$ million/year*
Scenario 1: NPT expands the supply of clean energy and clears 1,000 MW of capacity	**$19**	**$26**	**+ $8**
Scenario 2: Similar to Scenario 1 but NPT induces 500 MW of existing generation to retire	**$10**	**$13**	**+ $3**
Scenario 3: NPT expands the supply of clean energy but does not provide any capacity	**-$6**	**$0**	**+ $6**
Scenario 4: NPT displaces competing clean energy projects	**$0**	**$0**	**$0**

4. Sensitivity Analyses to Market Conditions

Inputs to the capacity market analysis are uncertain, particularly regarding the future offer prices of existing resources and the prices at which new resources will enter the auction. For this reason, we test the impact of alternative assumptions. We test the same four variables as our original report regarding supply curve parameters, and we add three others concerning: (1) unexpected changes in Base Case supply due to retirements or greater-than-expected entry; (2) the shape of the middle section of the supply curve; and (3) the possibility that Northern New England's Maximum Capacity Limit does not increase. As before, we test the effect of these alternatives only on Scenarios 1 and 2; Scenarios 3 and 4 will have zero or near-zero capacity market benefits under any market conditions.

Table 8 shows the capacity market savings for New Hampshire ratepayers in Scenario 1 and Scenario 2 for each sensitivity case. As shown, capacity market benefits are sensitive to the price of new entry, with the highest value tested more than doubling the benefits. Benefits are not as sensitive to the other variables, with most other tests showing benefits between about plus and minus 30% of the reference values for each Scenario. The remainder of this section describes the alternative assumptions for each sensitivity case and their impacts on capacity market savings.

Table 8: Sensitivity Analysis of Capacity Market Savings in Scenarios 1 and 2
($ million average annual savings for New Hampshire customers over 13 years)

	Assumptions			Scenario 1			Scenario 2		
Sensitivity	Low	Reference	High	Low	Reference	High	Low	Reference	High
Base Case Supply Assumptions									
Non-Price Retirements	400 MW/year	**200 MW/year**	100 MW/year	$15	**$26**	$19	$7	**$13**	$13
Supply Shock in FCA 12	+1,000 MW	**0 MW**	-1,000 MW	$20	**$26**	$22	$12	**$13**	$12
Supply Curve Assumptions									
De-List Section Slope	Half as steep	**Based on FCA 11 Results**	Twice as steep	$25	**$26**	$27	$12	**$13**	$13
De-List Section Top Price	+$1.0/kW-mo	**0**	-$1.0/kW-mo	$18	**$26**	$34	$9	**$13**	$16
Middle Section Shape	Linear	**Core Shape**	-	$24	**$26**	-	$13	**$13**	-
New Entry Price	$7.0/kW-mo	**LEI Forecast**	$12.0/kW-mo	$16	**$26**	$58	$8	**$13**	$29
Demand Curve Assumptions									
NNE Max Capacity Limit Increase	-	**+ 575 MW**	+ 0 MW	-	**$26**	$28	-	**$13**	$14

Non-Price Retirements. In our analysis, we assume a steady rate of retirement of aging generation. As described in our original report, we assume 200 MW retires per year, consistent with actual retirements over the past seven years.[58] Since future retirements are uncertain, we test the impact of either half as many retirements (100 MW/year) or twice as many (400 MW/year). With less retirement, the customer benefits of NPT decrease because surplus capacity conditions last many years even without NPT, which reduces the number of years with significant price differences in the 13 years modeled (some of the impact occurs beyond 13 years). Somewhat surprisingly, greater retirements also reduce customer benefits of NPT. This is primarily because the faster rate of retirements contracts the period of largest benefits, as shown in Figure 11 below. This reduces NPT savings by $11 million/year Scenario 1 and $6 million/year in Scenario 2.

58 Newell and Weiss (2017), pp. 26–28.

[redacted]

Supply Shocks. In response to questions raised at our Technical Session in March, we include alternative assumptions about the amount of capacity in the Base Case. We analyze the impact of shifting the supply curve by 1,000 MW to the right to represent the potential entry of low cost resources,[59] by 1,000 MW to the left to represent the potential loss of a major power plant(s), and by 2,000 MW to the left to further test the potential for price spikes absent NPT entry. The impacts on NPT's capacity market savings are similar to the different retirement assumptions above, with the savings *decreasing* in both cases for similar reasons.

- *1,000 MW entry in FCA 12.* Additional Base Case supply would extend the period of low-priced surplus-capacity conditions and delay the need for new gas entry to FCA 23 in the Base Case. As a result, some of NPT's price impacts occur beyond the time period considered in this analysis, as shown in Figure 12a. NPT's market benefits during the study period therefore decrease by $6 million in Scenario 1 and $1 million in Scenario 2.
- *1,000 MW exit in FCA 12.* A 1,000 MW retirement would not cause a price spike and increase NPT's benefits, as shown in Figure 12b.[60] This is because 1,000 MW is not enough to absorb the current surplus and raise prices to the cost of new entry. Instead, it simply advances NPT's most significant price impacts forward, with prices then converging with the Base Case in FCA 20 instead of FCA 23, reducing the number of

59 This could represent 4,000 MW of renewable capacity assuming they receive capacity credit for 25% of their nameplate capacity due to their intermittency. For simplicity, we assume all entry occurs in FCA 12.

60 In Figure 12a, note that the Base Case (no NPT) with 1,000 MW additional capacity has the same prices as Scenario 1 (with 1,000 NPT) under reference assumptions, since both of these cases add 1,000. Similarly, in Figure 12b, Scenario 1 (with NPT) minus 1,000 MW other capacity coincides with the Base Case.

years of benefits. This slightly reduces NPT's 13-year average benefits, by $4 million/year in Scenario 1 and by $1 million/year in Scenario 2.

- *2,000 MW exit in FCA12.* Even if 2,000 MW exited, there is sufficient surplus currently in the market such that new resources would still not be needed until FCA 14. Prices would not spike in FCA 12 as one might expect, but rise to a price similar to FCA 10 before climbing to the assumed new entry price of approximately $8/kW-mo two auctions later. (If such a supply shock occurred without so much surplus, prices could spike, but likely not much above Net CONE as long as there are ample offers from new entrants. With ISO-NE's 7-year price lock-in option available to new entrants, developers are likely to be poised to enter if prices start to spike even a little.)

[redacted]

De-List Section Slope and Height Adjustments. Our construction of the de-list section of the supply curve relied primarily on results from FCA 11. Here we test two variables describing how de-list bids could change in the future: the slope and the height of the de-list section, as defined by the top price in that section.

- For the slope, doubling the steepness makes supply less elastic and increases NPT's customer savings by $2 million/year in Scenario 1 and less than $1 million/year in Scenario 2; halving the slope makes supply more elastic and reduces the benefits by $1 million/year in Scenario 1 and $1 million/year in Scenario 2. Figure 13 shows that in both cases the impact on the savings is limited because the majority of the benefits occur when prices rise off the de-list section to the higher sections of the supply curve, which remain the same in this sensitivity.

[redacted]

- For the height, shifting the de-list section downward by $1/kW-mo increases NPT's benefits by $8 million/year in Scenario 1 and $3 million/year in Scenario 2. Figure 14 shows that the substantial improvement reflects a greater price gap between surplus capacity conditions (which NPT prolongs) and eventual new entry prices. In contrast, shifting the de-list section upward by $1/kW-mo decreases the savings by $8 million/year in Scenario 1 and $4 million/year in Scenario 2.

[redacted]

Middle Section Shape. We continue to utilize the "core shape" from our original analysis for representing the middle section of the supply curve between the relatively flat de-list section at lower prices and the new entry section at higher prices. This supply curve shape assumes that a relatively limited amount of capacity enters as prices rise from $5.50 to the new entry price, as shown above in Figure 2. Since this shape is uncertain, we tested an alternative with a linear middle section of the supply curve based on the FCA 11 data points in this region.[61] Figure 15 shows that this alternative only slightly reduces NPT's benefits by narrowing the price difference

61 In this alternative case, we still set the new entry price to $8/kW-mo but use the FCA 11 results for constructing the supply curve between $5.50/kW-mo and $8.00/kW-mo.

between the Base Case and the Project cases when the Base Case has risen off the de-list section. NPT's capacity market benefits decrease by $2 million/year in Scenario 1 and by less than $1 million/year in Scenario 2.

[redacted]

New Entry Price. In our updated analysis we reduced our reference assumption for Net CONE from $9/kW-mo to LEI's forecast of Net CONE (around $8/kW-mo). The $8 corresponds to ISO-NE's latest estimate of Net CONE for a CT. Furthermore, it is close to the prices at which actual capacity has entered the market in recent auctions. However, we test a larger range of potential Net CONE values that could prevail over time. As in our original report, we test a range of $7–$12/kW-mo, corresponding to the range ISO-NE considered in a recent analysis of its own. The low end of the range is consistent with the price at which several generators entered in FCA 10. We do not believe the top end of the range is very likely in the near-term, but it may represent the outer envelope of plausibility in the longer term. It represents the possibility that investors will require a higher capacity price in order to enter if they face low energy prices and also anticipate very low future energy and capacity revenues after they enter, for example if energy efficiency and clean energy are anticipated to dominate the market and depress future prices. With a high entry price of $12/kW-mo, NPT's capacity savings would more than double. The high entry price increases the gap between Base Case prices when new capacity is needed, and the low surplus-condition prices that NPT could prolong, as shown in Figure 16. In contrast, at the lowest new entry price of $7/kW-mo, savings decrease by $10 million/year in Scenario 1 and $5 million/year in Scenario 2.

[redacted]

NNE Maximum Capacity Limit Increase. We adopted in this update LEI's and Eversource's assumption that NPT and associated network upgrades will increase the transfer capability between Northern New England and the rest of the system by 575 MW, which will correspondingly increase the amount of capacity that can be added in NNE without depressing prices there relative to the rest of New England. It is possible, however, that ISO-NE's assessment will differ from LEI's and Eversource's. We therefore test the assumption that the interface limit does not change, and Northern New England is more susceptible to depressed prices in the event of surplus capacity. In that case, NPT's capacity market benefits increase by $2 million/year in Scenario 1 and $1 million/year in Scenario 2 due to the locational discount in NNE prices that average $0.10/kW-mo from FCA 12 to FCA 18. Note that the effect of the NNE export constraint is less than in our prior analysis (i.e., comparing our February 2017 report with our December 2016 report) because of our updated supply assumptions that result in lower system prices. At lower system prices, the NNE demand curve shifts down and reduces the discount applied to capacity in Northern New England.

[redacted]

IV. Updated Energy Market Impacts

As in our original report, we adopt LEI's analysis of energy market benefits since we find their methodology and results to be reasonable (while accounting for only a small fraction of the total benefits claimed by LEI). Here we adopt LEI's updated results submitted six weeks after our original report, in which the average energy market benefits are $9 million/year (in 2020 dollars) over an 11-year time period. Expressed as a 13-year average to be consistent with our capacity market analysis, the benefits are as shown in the table below.[62] Note that the updated benefits are lower because LEI's updated forecast is lower.

Table 9: Comparison of Prior and Updated *Energy Market* Savings
($ million annual savings for New Hampshire customers over 13 years)

Scenarios	Prior Analysis *$ million/year*	Updated Analysis *$ million/year*	Difference *$ million/year*
Scenario 1: NPT expands the supply of clean energy and clears 1,000 MW of capacity	$9	$8	- $1
Scenario 2: Similar to Scenario 1 but NPT induces 500 MW of existing generation to retire	$10	$8	- $3
Scenario 3: NPT expands the supply of clean energy but does not provide any capacity	$12	$8	- $4
Scenario 4: NPT displaces competing clean energy projects	$0	$0	$0

One factor that can affect the energy market savings is the type of generation that enters the market in the late 2020s when new capacity is needed and clears the capacity market. LEI's updated analysis assumes CTs are built with 1,000 MW more added in the case without NPT than the case with NPT. While CTs may enter in the future (one recently cleared in FCA 10), we still

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62 The LEI energy market benefits for New Hampshire reported here appear lower than the $9 million annual energy market impact presented in Figure 1 of their updated report because we converted their results from nominal dollars to 2020 dollars (which reduces the amounts by about 5%), extended the savings to 13 years, and accounted for the price-insulating effect of long-term contracts, as LEI did when translating wholesale market savings to customer retail savings (which further reduces the amounts by about 2.5%). These adjustments are necessary to present our results and LEI's results in comparable terms.

believe that CCs are more likely, as they are the dominant technology today in New England and throughout the U.S. CCs cost slightly more per kW to build, but they are more efficient and generate more often and earn higher net energy revenues. CC entry would keep energy prices lower than if CTs enter the market. NPT would thus have slightly less net energy price impact since its own downward pressure on prices would be offset by building less CC capacity.

Nevertheless, the distinction between CCs and CTs is minor in the overall analysis of NPT's benefits to New Hampshire customers. We therefore adopt LEI's assumptions (with CT entry) and estimated energy impacts, as presented in Table 9 above, in order to focus on our more material differences. Alternatively, assuming CC entry would decrease NPT's total benefits by only approximately $2 million/year in Scenario 1, $3 in Scenario 2 and $1 in Scenario 3, with no difference in Scenario 4.

One reason we are comfortable adopting the higher estimate is that even this higher estimate could understate energy market impacts by not accounting for occasional extreme conditions. Under extreme weather conditions or common-mode failure of resources, energy prices become more sensitive to changes in supply and NPT is likely to have more value. These benefits are difficult to quantify (especially impacts on natural gas markets), as discussed in our prior report.

V. Updated Impacts on Electric Customers' Costs and Suppliers' Revenues

A. Savings for New Hampshire Electricity Customers

Across the four scenarios, we found that NPT could provide New Hampshire customers with expected retail rate savings between 0 and 0.28¢/kWh (in constant 2020 dollar terms) on average from 2020 to 2032. These savings are in relation to 2016 baseline retail rates of roughly 18 ¢/kWh. Per household, annual bill savings could be as little as zero or as great as $21.[63] Aggregating over all electricity customers in New Hampshire, annual bill savings could be between zero and $34 million. Over the 13 years analyzed, these savings are worth between zero and $307 million at a 7% discount rate. In the most extreme case analyzed in our sensitivity

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63 We assume 621 kWh per month. U.S. Energy Information Administration (2016), 2015 Average Monthly Bill—Residential. Available at http://www.eia.gov/electricity/sales_revenue_price/pdf/table5_a.pdf.

analysis, in which much higher capacity prices are needed to attract new generation investment when eventually needed (which NPT delays), the savings could be as high as 0.5 ¢/kWh, $37 per year per household, $66 million per year statewide, with a $572 million net present value. All of our savings estimates are summarized in Table 10. Estimates based on our reference assumptions are shown in bold, and the range of estimates based on alternative assumptions in our sensitivity analyses are shown in parentheses.

Table 10: Average Annual New Hampshire Customer Savings from 2020 to 2032

Scenarios	Energy Market Savings *$ million/year*	Capacity Market Savings *$ million/year*	Total Market Savings *$ million/year*	NPV of Market Savings *$ million*	Average Rate Impact *¢/kWh*	Average Residential Bill Savings *$/year*
Scenario 1: NPT expands the supply of clean energy and clears 1,000 MW of capacity	**$8** ($5 - $8)	**$26** ($15 - $58)	**$34** ($20 - $66)	**$307** ($202 - $572)	**0.28** (0.19 - 0.50)	**$21** ($14 - $37)
Scenario 2: Similar to Scenario 1 but NPT induces 500 MW of existing generation to retire	**$8** ($6 - $8)	**$13** ($7 - $29)	**$21** ($14 - $37)	**$192** ($139 - $328)	**0.19** (0.12 - 0.32)	**$14** ($9 - $24)
Scenario 3: NPT expands the supply of clean energy but does not provide any capacity	**$8**	**$0**	**$8**	**$75**	**0.06**	**$5**
Scenario 4: NPT displaces competing clean energy projects	**$0**	**$0**	**$0**	**$0**	**0.00**	**$0**

B. Reductions in Suppliers' Net Revenues

Reduced energy and capacity prices also reduce supplier revenues. Table 11 summarizes our estimates of the 13-year average annual reduction in gross revenues for New Hampshire suppliers: $0 to $46 million across our four Scenarios under the reference assumptions, and up to $85 million under the most extreme sensitivity with a much higher cost of new entry. Table 12 decomposes the revenue impacts on New Hampshire suppliers by resource type. Due to its high capacity factor, the Seabrook nuclear plant loses the most revenue, ranging from no loss in Scenario 4 to a $0.75/kW-mo loss in Scenario 1 (under reference assumptions).

Table 11: New Hampshire Supplier Revenue Impacts

Scenarios	13-Year Average *$ million/year*	NPV *$ million*
Scenario 1: NPT expands the supply of clean energy and clears 1,000 MW of capacity	**-$46** (-$33 to -$85)	**-$418** (-$314 to -$744)
Scenario 2: Similar to Scenario 1 but NPT induces 500 MW of existing generation to retire	**-$29** (-$23 to -$49)	**-$275** (-$221 to -$442)
Scenario 3: NPT expands the supply of clean energy but does not provide any capacity	**-$13**	**-$127**
Scenario 4: NPT displaces competing clean energy projects	**$0**	**$0**

Table 12: New Hampshire Supplier Revenues Impacts by Resource Type

		Scenario 1		Scenario 2		Scenario 3	
Resource	Capacity *MW*	NPV of Revenue Impact *2020$ million*	Levelized Revenue Impact *2020$/kW-mo*	NPV of Revenue Impact *2020$ million*	Levelized Revenue Impact *2020$/kW-mo*	NPV of Revenue Impact *2020$ million*	Levelized Revenue Impact *2020$/kW-mo*
Natural Gas	1,209	-$121	-$0.64	-$80	-$0.43	-$38	-$0.20
Nuclear	1,246	-$146	-$0.75	-$104	-$0.53	-$60	-$0.31
Hydro	501	-$45	-$0.57	-$27	-$0.34	-$8	-$0.10
Wind	183	-$4	-$0.15	-$3	-$0.12	-$3	-$0.09
Coal	533	-$43	-$0.51	-$25	-$0.30	-$6	-$0.07
Other	241	-$25	-$0.68	-$18	-$0.48	-$11	-$0.28
Oil	502	$0	$0.00	$0	$0.00	$0	$0.00
NH Total	**4,416**	**-$384**	**-$0.56**	**-$257**	**-$0.37**	**-$126**	**-$0.18**

VI. Further Exploration of the Likelihood of Our Scenarios

In this section, we further discuss the relative likelihood of the four scenarios we analyzed. We do so in light of new information contained in recent press releases and news articles related to NPT and Hydro-Québec, in part already referenced in Section III.A.1 above.

Recent statements by Hydro-Québec could suggest that NPT will only be built if it successfully receives a long-term procurement contract in a solicitation,[64] such as the one under Section 83 D of the Green Communities Act in Massachusetts[65] requiring Massachusetts distribution utilities to sign long-term contracts with up to 9,450,000 megawatt-hours of clean hydro or Class I renewable energy resources.[66] We believe that reliance on such solicitations would imply that our Scenario 4 is more relevant than it would be absent reliance on solicitations.

The statement that NPT depends on winning a solicitation also increases the likelihood that, in the absence of NPT, similar hydro or renewable contracts would be awarded, *i.e.*, our Scenario 4. Focusing on the Massachusetts procurement, but acknowledging that similar reasoning would apply to other procurements, there are three potential outcomes to be considered: (a) another project is selected instead of NPT; (b) NPT is selected as the only project that can demonstrate net economic benefits; (c) NPT is selected because it is the most economical among several bids for projects with net economic benefits; or (d) no project is selected because none of the submitted bids can demonstrate net economic benefits, as required by the Massachusetts procurement.

If there is any chance of the last outcome in the Massachusetts and other similar procurement, then NPT would not be built and hence none of the benefits or costs of NPT would materialize. If the first outcome occurs, NPT would similarly realize no costs or benefits unless it is selected in future solicitations. In that case the impacts of NPT on energy and capacity markets would

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64 See for example News Release, Eversource Energy and Hydro-Québec Reaffirm Commitment to Northern Pass Project and Clarify Cost Recovery Structure, Manchester, New Hampshire, March 31, 2017.

65 See for example Fitchburg Gas and Electric Light Company d/b/a Unitil, Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid, NSTAR Electric Company and Western Massachusetts Electric Company each d/b/a Eversource Energy, Notice of Filing and Request for Comments, D.P.U. 17-32, February 6, 2017. Available at https://www.nationalgridus.com/media/pdfs/our-company/d-p-u-17-32-notice-of-filing-(2-6-2017).pdf.

66 *Ibid.*; The Notice describes the proposed terms and qualifying resource types. At a 90% capacity factor, this translates into 1,200 MW of hydro power. See Ron Gerwatowski, Practical Implications of the Mass. Omnibus Energy Bill and Other Energy Market Issues, presented for Boston Green Ribbon Commission October 21, 2016, p. 5. Available at http://www.greenribboncommission.org/wp-content/uploads/2016/10/Practical-Implications-of-the-Mass.-Omnibus-Energy-Bill-and-Other-Energy-Market-Issues.pdf.

likely be at least somewhat muted by diminishing returns, and there would still be the question of what would have happened if NPT had not been selected.

The most interesting outcomes to consider are (b) and (c). Outcome (c) is precisely the outcome we examine in our Scenario 4: in the absence of NPT another similar project would be built and very similar electricity market impacts to those resulting from NPT would occur anyway. Outcome (b) is the opposite and rules out Scenario 4. For outcome (b) to occur, NPT would have to be the lowest cost hydro or renewable project from the perspective of Massachusetts ratepayers, with all other projects being sufficiently more expensive to fail the net economic benefits test (or NPT could prevail based on non-price terms).[67]

Given the significant number of projects in various stages of development discussed in our original report and the recent addition of another competing project sponsored by National Grid,[68] given further that Hydro-Québec is the likely upstream supplier under at least a subset of these proposals, and given finally that the announced cost estimates for the transmission portion of some of the alternative projects are significantly below those of NPT, there is at least some doubt about the likelihood of outcome (d). Instead, the available evidence[69] suggests that it is at least plausible that in the absence of NPT being selected in the Massachusetts or any similar RFP at least one alternative project would be selected. This outcome would mean that the electricity market benefits of NPT would be those we analyzed in Scenario 4.

In spite of all of the above, we do not believe it is reasonable to assign specific, numeric probabilities to any of our four scenarios. Doing so would require an empirical basis, in the form of a large number of previous similar cases that would allow us to determine the likelihood of our

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67 The precise evaluation criteria are still unknown. The law requires the distribution companies only to enter *cost-effective* long-term contracts and includes as criteria the ability to guarantee delivery in winter months. Massachusetts Department of Public Utilities (2017), Competitively Solicited Long-Term Contracts for Clean Energy, 220 C.M.R. § 24.05, March 24, 2017. Available at http://www.mass.gov/courts/docs/lawlib/220-229cmr/220cmr24.pdf.

68 See Granite State Power Link (2017), Granite State Power Link, A Ready Pathway to Clean Energy. Available at http://www.granitestatepowerlink.com, accessed April 13, 2017 and Kyle Plantz, "This Week Has Seen Major Setbacks For Eversource, Northern Pass. Here's Why," *NH Journal*, March 28, 2017. Available at http://www.insidesources.com/eversource-puc-ppa-northern-pass/.

69 The evidence includes the multiple competing projects as well as the desire by states in New England to acquire more non-emitting resources to meet long-term decarbonization goals.

future scenarios based on past outcomes. Such an empirical track record does not exist. The uncertainties we discuss involve future policy choices, case-specific actions by entities like ISO-NE and unpredictable responses by various market participants.

Nonetheless, whatever subjective probabilities any one evaluator, including in particular the Site Evaluation Committee (SEC), placed on our Scenarios 1 through 4, the more recent statements by Hydro-Québec as reported by the press should increase the likelihood of Scenario 4. Given that a number of alternative projects exist that could presumably deliver the same clean energy benefits to New England, and given that Hydro-Québec's recent statements suggest that it will require a successful bid either with Massachusetts or as a result of a similar procurement, it is difficult to believe that NPT would be the one and only project that will be deemed economically beneficial. Nonetheless, since no bids have been submitted or accepted and since the evaluation criteria in Massachusetts and elsewhere are as of yet not fully known, it remains possible that scenarios other than Scenario 4 are the relevant ones.

Another way for the SEC to evaluate the subjective probabilities of any of our four scenarios occurring and to compare our range of estimated electricity market (and GHG) benefits to LEI's is to recognize that for NPT to deliver the kinds of electricity market benefits estimated by LEI and represented in our Scenarios 1 and 2 requires an assessment that the probability of our Scenarios 3 and 4 is essentially zero. Put differently, one needs to believe with near 100% certainty that NPT will qualify and clear in the New England capacity auctions. One also has to believe that, absent NPT, no other comparable project would be selected in any of the solicitations that NPT (and Hydro-Québec) count on to make the project economically viable. Even in that case, LEI's estimated benefits are high because of their erroneous long-term pricing assumption and their optimistic assumptions about supply response. LEI's estimate is higher than any of our scenarios under reference assumptions. It is at the high end of the range of outcomes in our sensitivity analyses representing a broad set of possible market conditions.