STATE OF NEW HAMPSHIRE

SITE EVALUATION COMMITTEE

DOCKET NO. 2015-06

JOINT APPLICATION OF NORTHERN PASS TRANSMISSION, LLC AND PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE D/B/A EVERSOURCE ENERGY FOR A CERTIFICATE OF SITE AND FACILITY

PREFILED DIRECT TESTIMONY OF

WILLIAM S. FOWLER

ON BEHALF OF THE NEW ENGLAND POWER GENERATORS ASSOCIATION, INC.

December 30, 2016

I. QUALIFICATIONS

Q. **Please state your name and address.**

A. My name is William S. Fowler. My business address is 20 Main Street, Acton, MA 01720.

Q. **What is your occupation?**

A. I am the President of Sigma Consultants Inc. ("Sigma"). In that capacity, I manage corporate strategy and direction for our 13 employees. Sigma provides consulting services on a wide variety of issues, including market rule development, generation project development, new interconnections, transmission assessments to optimize deliverability, market analysis, and advice and due diligence concerning generation acquisition. The great majority of my time is spent working for clients in the New England Power Pool ("NEPOOL").

Q. **Please describe your experience in working in the electric power industry.**

A. I have worked in the electric power industry for 35 years. For the past 18 years, I have represented supplier interests in the ISO New England ("ISO-NE") stakeholder process. I participated in the negotiation of the original Forward Capacity Market ("FCM") settlement and the development of virtually all capacity rules since then, including the most recent demand curve discussions. I have been a voting member of the NEPOOL Reliability Committee and its predecessors since 1998, and a voting member of the NEPOOL Markets Committee since 2003.

Q. Have you recently testified in other electric market matters?

A. Yes, I filed testimony in a case before the Federal Energy Regulatory Commission (FERC) ER16-1434 related to details of ISO-NE's proposed changes to certain features of New England's capacity markets.

Q. **Please describe your academic background.**

A. I received a Bachelor of Science degree in Electrical Engineering from the Massachusetts Institute of Technology in 1981.

II. SUMMARY OF TESTIMONY

Q. **Please summarize your testimony.**

A. In my testimony, I will discuss several major issues relating to projected capacity savings described in the public testimony of Julia Frayer ("Frayer Testimony") and the report issued by London Economics International ("LEI Report") related to the construction of the Northern Pass Transmission ("NPT") line in New Hampshire. First, I will discuss flaws with the analysis done by LEI and discussed in the LEI Report that led to significant overstatement of the capacity market benefits from the NPT project. I will then describe how ISO-NE's wholesale capacity market functions and the challenges that NPT will likely face in providing capacity benefits at all. The Frayer Testimony and LEI Report largely ignore these limiting factors, including their: (1) use of an incorrect and outdated FCM market design to forecast prices; (2) failure to apply ISO-NE's Minimum Offer Price Rule ("MOPR"); (3) failure to incorporate known transmission constraints that exist in and around New Hampshire, which are likely to limit the ability of NPT

to qualify to sell capacity, and (4) failure to recognize transmission constraints that will affect the pricing of capacity based on the location of NPT's injection into the New England grid. Next, I will discuss the likely effect that an additional 1,000 MW[1] of capacity from NPT will have on the existing generators operating here in Northern New England, including New Hampshire. Finally I will touch on the interaction of capacity and energy markets.

Q. **What is your view of the wholesale market benefits as a result of NPT predicted by LEI?**

A. The Frayer Testimony and LEI Report significantly overestimate the wholesale market benefits that can be attributed to the construction of NPT, because they inaccurately reflect design of the ISO-NE wholesale markets. LEI estimates that NPT will produce average annual wholesale market benefits of $851 - $866 million for New England and $81 - $82.5 million for New Hampshire:[2] These numbers break down as:

- energy market benefits of $80 to $100 million for NE and $8.2 to $10.2 million for NH
- capacity market benefits of $843 to $848 million for NE and $79.6 to $80.1 million for NH

As discussed more fully below, these estimates of wholesale market benefits, particularly for capacity, were derived by flawed analyses and unrealistic assumptions, leading to a significant exaggeration of those benefits. For example, LEI:

[1] The proposed capability of the NPT line is 1090 MW; however, the LEI Report suggests that only 1,000 MW of capacity would be sold. "Furthermore, it was assumed that shippers on NPT would seek to provide and get qualified to sell 1,000 MW, which is slightly below its nominal rating of 1,090 MW." LEI Report page 34. My testimony is based on this 1,000 MW stated level.
[2] See Figure 1 of the LEI Report.

- modeled capacity based on an outdated FCM design that has been rejected by the FERC and replaced with a different design;
- assumed that NPT shippers would receive 1,000 megawatts[3] ("MW") of "qualified" capacity credit without taking into consideration that existing market rules may prevent that capacity from participating in the market.[4] This despite capacity market benefits amounting to approximately 90% of their claimed wholesale market benefits;
- irrationally assumed that NPT shippers would offer their capacity at a price of $0;
- failed to consider the impact of FCM zones on pricing; and
- assumed that there would be no meaningful short- or long-term market response to lower prices.

Savings in the wholesale markets translate into savings seen by consumers in their retail bills. If the actual savings in the *wholesale* costs in New England and in New Hampshire are substantially less than estimated by LEI, so too are the *retail* benefits. As discussed more fully below, I will explain how LEI arrived at an estimate that incorrectly inflates the projected savings from the NPT line, and also describe corrections that should be undertaken to produce a realistic estimate of any projected savings.

[3] One megawatt is 1,000 kilowatts and can power approximately 500 homes.
[4] When asked through interrogatories whether LEI had considered factors that affect such qualification, including the MOPR and transmission constraints on deliverability, LEI responded that they were not considered. See, e.g., Applicants' Response to NEPGA 1-16, NEPGA 1-17, and NEPGA 1-18.

Q. How does New England's wholesale capacity market work?

A. At the highest level, New England's wholesale capacity market allows all suppliers of electric capacity (i.e., plants that generate electricity, demand response and imports) to offer into an annual auction run by ISO-NE, the federally regulated Independent System Operator of the New England electric system. The purpose of the auction is to ensure that New England's electric grid has sufficient supply to power the 7,100,000 customers it serves. The auction is run each February for delivery in a one-year time period starting June 1 of the year three years forward (i.e., starting 39 months after the auction). For example, Forward Capacity Auction #11 ("FCA 11") will be run in February 2017 for deliveries June 1, 2020 through May 31, 2021 (the "20-21 Commitment Period," which I will generically refer to as the Delivery Year). This lead time before the Delivery Year allows developers who are willing to build new capacity to compete with existing facilities when offering their capacity into the auction.

The vast majority of the electric generators who participate in New England's wholesale markets are not guaranteed cost recovery through a utility's rate base. Rather, competitive generators must earn their revenue to remain economically viable through competition with other generators in New England. They do so by: (a) selling their energy into a daily wholesale energy market; (b) providing other products, known as ancillary services, that are needed to keep the electric system reliable; and (c) earning revenue from the capacity market.

To prepare for the Forward Capacity Auction, generators typically estimate the amount of revenue they might make by selling energy and ancillary services during the Delivery Year. Subtracting those anticipated revenues from their total expected costs yields the minimum

amount of money they must earn from the capacity market to stay economically viable. That amount of money is then expressed in dollars per kilowatt-month, calculated by dividing the money needed, by the kilowatts of capacity the generator provides, and dividing again by 12 months. The result would provide the basis for the price at which the unit offers into the FCM. A capacity award carries with it considerable operational and financial risk; that risk must also be factored into a generator's FCM offer.

New England's capacity market is operated as a "descending clock auction." The auction opens at a price that is high enough to assure that essentially all capacity suppliers are willing to participate – typically in the $13 to $17/kW-month range. ISO-NE then reduces the price by a certain increment, and gives all suppliers an opportunity to "drop out" of the auction. If the remaining supply is more than what ISO-NE needs, ISO-NE lowers the price in another auction round, again giving suppliers a chance to exit. ISO-NE continues to lower the price until it has just enough supply offers to meet the electrical demand. At that point of equilibrium, the auction stops, and the price per kilowatt-month is set for that Delivery Year.

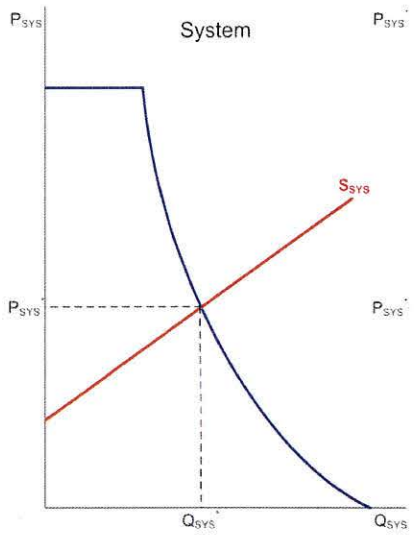
With some limitations, generators are able to withdraw from the auction when the price drops below the level that they feel they need to remain viable. Once they withdraw, they may not re-enter that year's auction, and they will not receive any capacity revenue during the Delivery Year. Because generators rely on capacity revenue to meet their overall operational revenue requirement, failure to clear in the FCA may ultimately lead a plant to retire. The generators/suppliers that have remained in the auction receive a Capacity Supply Obligation (CSO) for the Delivery Year. While the CSO carries with it a revenue stream based on the

auction clearing price, it also carries with it the obligation to make the plant economically available to ISO-NE for the full Delivery Year. ISO-NE imposes severe penalties on resources with a CSO that fail to produce energy when ISO-NE needs it. I will discuss these penalties later.

Importantly, the FCM recognizes the locational value of capacity supplies. It does this through modeling and pricing of individual zones. ISO-New England currently recognizes four potential zones: Connecticut, Southeast New England (including eastern Massachusetts and Rhode Island), Northern New England (New Hampshire, Maine and Vermont), and Rest of Pool (essentially central and western Massachusetts). ISO-NE conducts the FCM auctions in a way that monitors the supply in each zone, and can ultimately clear each zone at different prices based on relative surplus or scarcity in each area.

ISO-NE can purchase slightly more or less capacity than the minimum amount that it needs, depending on the price and incremental benefit to reliability. To do this, ISO-NE uses demand curves to determine the relationship between price and quantity of capacity to procure. In economic terms, the FCM will clear at the intersection of the supply and demand curves. There are separate demand curves for the System as a whole and each zone. Figure 1 below shows a generic demand curve. The "S_{sys}" line is the system-wide supply curve – it represents the price at which generators are willing to sell capacity. The demand curve can be read as "at a price of $Y (per kW-month), ISO will purchase X MW. As shown on the chart, ISO would purchase Q_{sys} MWs, at a price of P_{sys}.

Figure 1 – Generic Demand Curve



If there is a shortage of capacity either in the New England system as a whole or in any particular zone, ISO-NE will buy fewer MWs at a higher price. If there is a surplus of capacity, it will buy more capacity at a lower price. The auction will procure an incremental MW of capacity so long as it provides a reliability benefit consistent with the price reflected in the Demand Curve. It is common for the FCM to produce multiple prices – higher prices in zones with scarcity, and lower prices where there is a surplus.

Q. What did LEI do to arrive at their overestimate of the capacity benefits that consumers would realize from the construction of NPT?

A. As stated earlier, LEI performed their calculations using an outdated and now inaccurate FCM market design, ignoring the importance of many requirements of the FCM, and otherwise using overly optimistic assumptions in their estimates. For example, LEI:

- Assumed that 1,000 MW of capacity offers over NPT would be "qualified" and accepted by ISO-NE without regard to transmission limitations or the Minimum Offer Price Rule;
- Assumed that the 1,000 MW of supply would be "price takers"[5] in the capacity auction;
- Ignored the zonal construct of the FCM, assuming instead that the 1,000 MW would add to the supply of capacity in the whole of New England and cause the FCM to clear at a lower price New England-wide, according to a system-wide (not zonal) demand curve;[6]
- Assumed that no generators would decide to temporarily delist or retire due to the lower capacity prices;[7] and
- Incorrectly calculated the total wholesale capacity benefit due to NPT as the difference in capacity clearing prices with and without NPT multiplied by the total amount of capacity that ISO-NE buys for serving the load in all of New England.

Q. **What should LEI have done to correctly reflect the realities of NPT in the Forward Capacity Market?**

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[5] "The shippers are assumed to be price takers in the ISO-NE wholesale electricity market, in order to ensure that the value of the energy and capacity is optimized." LEI Report, page 35

[6] "On the capacity side, we expect a similar dynamic when the additional 1,000 MW of new capacity associated with NPT enters the FCM. Capacity clearing prices in the FCA will move down as NPT increases the total volume of supply and the New England system's reserve margin (making the ISO-NE wholesale electricity market more reliable)." LEI Report, page 35.

[7] "Under the Project Case, however, we do not anticipate retirements of existing generation as the overall capacity prices are still sufficient to remunerate existing generation for their minimum going forward fixed costs, as we discuss further in Section 10." LEI Report, page 36.

A. First, LEI should use the correct FCM market design when making any capacity-related calculations. The market models used by LEI to calculate projected savings are outdated and now irrelevant in determining projected cost savings. Reliance on projected estimates based on those models is erroneous and misleading. Second, LEI should have addressed how and why they believe that a capacity sale over NPT could pass ISO-NE's MOPR. Third, they should have investigated the ability of capacity to pass ISO-NE's capacity deliverability standard, and adjusted capacity downward to account for deliverability risk. Fourth, LEI should have recognized the obligations and penalty risk of nonperformance if awarded a CSO, and factored that cost and risk into expected FCM offers (versus the assumption that shippers will offer as price-takers); fifth, LEI should have recognized how NPT capacity deliveries into New Hampshire (to the extent those deliveries are allowed given issues listed above) will be affected by appropriate modeling of FCM zones; and sixth, LEI should have recognized that any material capacity sales by NPT will have a significant impact on revenues and ultimate viability of other generators in the three-state zone which includes New Hampshire. Should those generators retire, not only would any residual capacity price benefit be transitory, but net long-term economic losses to the area could be significant. All of these factors, which I will discuss, will reduce the potential capacity benefits, if any, which may be created by NPT.

III. THE WHOLESALE CAPACITY MARKET AND THE MINIMUM OFFER PRICE RULE

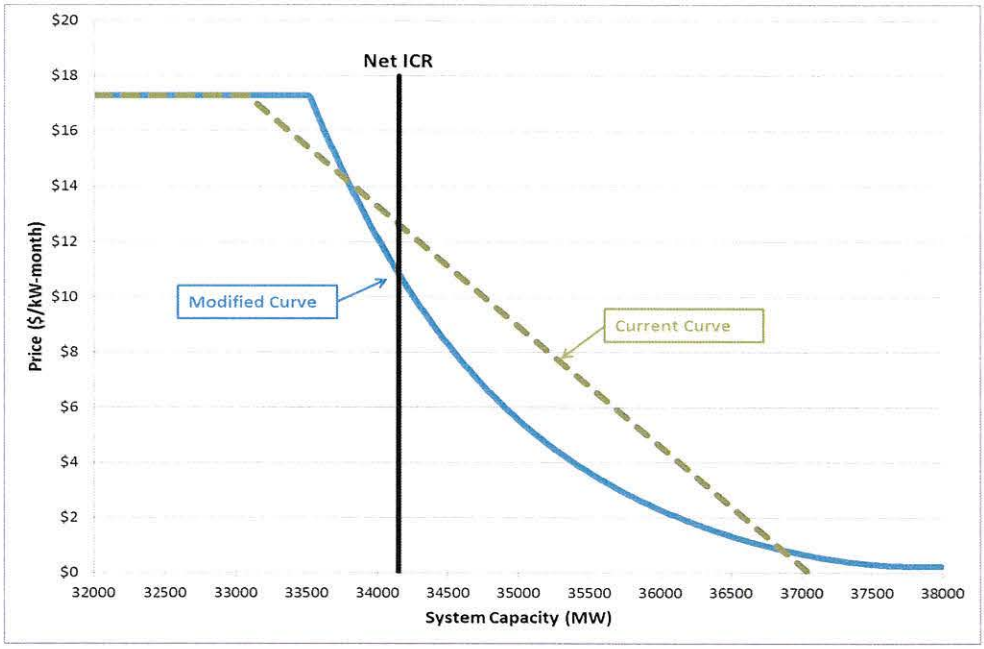
Q. You state that LEI has used an incorrect market design for the FCM. Please explain.

A. LEI bases its capacity market forecasts on the straight-line, system-wide demand curve that was approved by the FERC for FCA-9 (See LEI report at Section 5.6). That design did not include separate demand curves for zones, and (at the time) New Hampshire was considered part of the Rest of Pool zone. However, that market design was completely overhauled and replaced in 2015-16. Specifically, on May 29 2015, the FERC approved revisions to FCM zones so that going forward, New Hampshire would be considered part of the (export-constrained) Northern New England Zone, and not Rest of Pool as LEI has assumed.[8] Then on June 28, 2016, the FERC ordered an FCM redesign, in which (a) the straight-line (system-wide) demand curve would be replaced with a new, convex (non-linear) curve tied to different price points; (b) each zone would have its own, non-linear convex or concave demand curve; and (c) there would be a 2-3 year transition as the new curves phased in.[9]

The effect of these changes is dramatic. The chart below shows how the new system demand curve (labeled as the "Modified Curve") compares to the old one ("Current Curve"), given inputs for FCA 10.[10]

[8] 151 FERC P.61,183.
[9] 155 FERC P.61,319.
[10] https://www.iso-ne.com/static-assets/documents/2015/12/a09_iso_presentation_12_10_15.pptx at slide 50.

Figure 2
Indicative FCA-10 Demand Curves Showing Impact of 2016 Rule Changes



The chart shows that, under the new curves, the price is approximately $2/kW-month lower at Net-ICR (ISO-NE's minimum target purchase amount). The relationship between excess capacity and price, fundamental to any calculation of capacity market benefits, is much different now than it was under the FCM design assumed in the LEI Report and Frayer Testimony. LEI should update its analysis to use the actual rules and market design NPT would face if it seeks to offer capacity into the FCM.[11]

[11] Another critical variable in forecasting FCM price is the assumed "Net Cost of New Entry" or Net CONE. LEI estimates a Net CONE value of $10.81/kW-month, escalating (see LEI Report at page 98). ISO-NE is now recommending that Net CONE be reset to $8.04/kW-month effective FCA-12; while that value has not yet been approved by the FERC, it should be considered in any updated analysis.

While the impact of the new, non-linear *system* demand curve is significant, the importance of the approved *zonal* demand curve for Northern New England is much more so; I will address that later.

Q. **Please explain why shippers on NPT will be constrained on the price at which they can offer capacity into the Forward Capacity Auctions.**

A. A critical factor affecting the amount of wholesale capacity market benefits that NPT might generate is the application of ISO-NE's MOPR, a key part of the Forward Capacity Market that LEI ignored.[12]

The MOPR was incorporated into the FCM as a way to protect the market, and the generators in New England that depend on revenue from competitive wholesale market rates, from price suppression caused by resources that receive out-of-market subsidies. The MOPR is designed to ensure that FCM offer prices are based on market-based revenues only; out-of-market subsidies may not be used to lower offers below those true market-based levels. NPT had previously sought such a subsidy through its bid in the Clean Energy RFP and publicly stated in this docket that it intends to seek the same in the Massachusetts RFP to be issued in April of 2017.[13] NPT is currently proposing that same type of subsidy through a no-bid 100 MW power purchase

[12] See response to NEPGA 1-17

[13] See N.H. SEC Docket 15-06, Applicants' Motion for Further Confidential Treatment, October 28, 2016 at 1 (discussing results of Clean Energy RFP and Applicants' intent to submit a response to the Massachusetts RFP in April 2017.

agreement (PPA) that is currently before the New Hampshire Public Utilities Commission ("PUC").[14]

It appears that NPT expects to receive out-of-market revenue from state-backed contracts or other sources sufficient to pay its costs that are not met by market-based sales. This could have happened if NPT had been successful in the recent Clean Energy RFP held by the three southern states. It could also happen if NPT is successful in RFPs to be held by Massachusetts' utilities following the enactment of Massachusetts's *An Act to Promote Energy Diversity*. If that occurs, consumers in Massachusetts, through their electric distribution rates, will pay for all or a part of the annual costs of the NPT line. New Hampshire consumers may as well, should the PUC approve the proposed 100 MW PPA. To the extent NPT receives *any* revenue from these proposed contracts, NPT would not be able to offer into the FCA at a price of $0/kW-month; instead it must offer at some higher price.

Mechanically, the Independent Market Monitor (IMM) of ISO-NE, who reviews all offers into the capacity auction, will establish the minimum price above which NPT must offer. That price will be based on the costs that NPT would have to recover, if it had no subsidies, from the capacity market to supplement what it would receive from the other wholesale markets. Depending on the IMM-established price, NPT might not clear in the capacity auction because its true market-based price is too high; in that case it would receive $0 in capacity payments, and its effect on state and regional capacity prices would be $0. Under current rules, the default

[14] See N.H. Docket DE 16-693.

minimum offer price for an Elective Transmission Upgrade[15] project like NPT is the FCM Starting Price plus $0.01. So for FCA-11, the default offer would be $18.63/kW-month.[16] To offer at less than that, the proponent must prove to the IMM that its offer is entirely market-based, stripped of any out-of-market subsidies. If indeed NPT were to offer at $18.63, then based on LEI's forecast it seems extraordinarily likely that NPT would *never* clear the FCM.[17]

The application of the MOPR to NPT adds considerable uncertainty, which LEI failed to take into account. Because the LEI Report and Frayer Testimony ignore this critical challenge to NPT clearing in the FCM, NPT has not shown how or whether *any* portion of NPT could actually clear in the capacity auction, and thus whether it could lower capacity prices in the region *at all*.

IV. TRANSMISSION-RELATED CONSTRAINTS

Q. Please explain how transmission constraints will limit the amount of capacity that NPT could qualify for in the FCM

A. A key component of the FCM is *capacity deliverability*. At its core, the principal is that ISO should not pay two generators for capacity if, based on transmission topology, only one of those generators can operate at a time. ISO runs a series of simulations prior to each FCM to confirm that simultaneous operation of all capacity resources inside each load zone is possible.

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[15] An Elective Transmission Upgrade is ISO-NE's classification for entities like Northern Pass – a transmission facility that is not needed for reliability, but instead being proposed for private purposes.
[16] See ISO-NE Market Rule 1 Appendix A Section 21.
[17] See LEI report at Section 5; note that LEI's future clearing price estimates are redacted (Figure 21) however, the indicative chart in the Frayer Testimony (Figure 2) indicates a clearing price of just over $6/kW-month.

To the extent that transmission constraints limit the ability of a new resource (such as NPT) to run at full output while simultaneously running other, nearby generators at their maximum, then the new resource will be required to upgrade the transmission system, or else will have all or part of their resource disqualified from the FCM. The details of this test are complicated, and spelled out in ISO-NE's Planning Procedure 10.[18]

ISO routinely disqualifies new resources based on failure to pass this deliverability test (see, for instance the Informational Filings ISO-NE files 90 days prior to each auction, which lists some of the resources that are so disqualified). Generically, I would expect a resource as large as NPT, interconnecting to the grid north of the Massachusetts border, to have difficulty passing the deliverability test without funding additional transmission upgrades.

Site-specific insight can be gained through review of the System Impact Study that ISO-NE conducted for NPT as part of its initial (energy only) interconnection study in 2013. System Impact Studies investigate the ability of the grid to absorb power from a new injection. I have reviewed the NPT System Impact Study, and my concern about deliverability is heightened.[19] I believe that this is not only indicative of a potential problem, but inconsistent with a fundamental presumption in the LEI Report.

Ultimately ISO-NE will need to conduct its capacity deliverability study if and when NPT requests entry to an FCM. Given the critical importance of this test, together with the results of

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[18] https://www.iso-ne.com/static-assets/documents/rules_proceds/isone_plan/pp10/pp10.pdf

[19] See Section 4.5 and Table 4-4 in the "Final Report – Northern Pass Transmission Project," available at https://smd.iso-ne.com/trans/sys_studies/tariff/nh/p348_hvdc_tie_des_cantons_to_deerfield_sis_report_dec2013.pdf. Note that this document is considered Critical Energy Infrastructure Information, and may only be obtained if ISO-NE has granted CEII assess to the user.

the System Impact Study, the failure of the LEI Report and Frayer Testimony to mention the deliverability test is another critical flaw, much like its failure to consider the risk and potential cost of being subject to MOPR review by the IMM.

Like the MOPR, if the project fails the capacity deliverability test, it cannot receive a CSO, cannot receive capacity revenues, and would have essentially $0 impact on capacity markets.

Q. Please explain how the obligations and penalty risks of a CSO might affect a resources's willingness to offer into the FCM at low prices, or even take on a CSO at all.

A. In 2014, following the winter of the Polar Vortex, ISO-NE embarked on a major overhaul to the FCM that added far more stringent penalties for generator non-performance than had existed before. Under a capacity market design known as Pay for Performance, capacity suppliers will be subject to penalties that begin at $2,000/megawatt-hour ("$/MWh") in June 2018, rising to $3,500/MWh in June 2021, and finally to $5,455/MWh in June 2024 for failure to deliver energy when ISO-NE needs it most. To put these penalties into context, the average cost of energy in New Hampshire in 2016 (through November) is approximately $26/MWh.[20] There are no exceptions to these penalties, even for a failure to deliver that results from entirely unforeseeable events or for reasons completely outside a generator's control.

Facing the extensive penalties of Pay for Performance, those who contract to bring energy from

[20] A megawatt-hour is 1,000 kilowatt-hours. Divide the $26/MWh by 1000 to get 2.653 cents/kilowatt-hour. See ISO-NE Average Annual Wholesale Load Cost spreadsheet, available at https://www.iso-ne.com/isoexpress/web/reports/load-and-demand/-/tree/yearly-wholesale-load-cost-report

HQ into New England on NPT may not want to risk taking on a CSO when the supply of their energy is nearly 1,000 miles north of Boston.[21]

That risk is illustrated by several recent "reliability events" where HQ suddenly curtailed all deliveries into New England. On July 3, 2013 four HQ transmission lines tripped leading to the loss of 3,500 MW of load in Quebec and the curtailment of 3,370 MW of exports to New York, Ontario, New Brunswick and New England.[22] During this event ISO-NE had to scramble to replace deliveries of 1,750 MW from HQ. Again on December 4, 2014, ISO-NE was required to take emergency actions from 4:15 pm to 8:45 pm when all imports from HQ were lost.[23] Had these events occurred under Pay for Performance in, say 2021, and NPT shippers held a CSO, the penalties would have been enormous: a 4.5 hour outage with 1,000 MW of Capacity Supply Obligation would cost as much as $15.75 million in penalties. HQ is a provincially-owned utility and its service obligations are first and foremost to its provincial customers. In instances where there is inadequate supply, for whatever reason, I would expect HQ to serve its Quebec customers at the expense of its exports, as was the case during these recent HQ curtailments.

For most generators, the risk of Pay for Performance penalties is a significant factor in pricing FCM participation. For HQ, I would expect it to be even more so. The reason is size. If a 500 MW generator trips or is forced off-line, that may not occur during a system emergency, so no penalty is assessed. But total deliveries from HQ can be much, much larger: 1090 MW over NPT, plus as much as 2000 MW over the Phase II lines, which are also used to deliver HQ

[21] My understanding is that HQ's Romaine project, which is approximately 1,000 miles north of Boston, has been cited as the source of energy to be delivered on NPT.
[22] ISO-NE COO Report to NEPOOL Participants Committee in August 2013.
[23] ISO-NE COO Report to NEPOOL Participants Committee in January 2015.

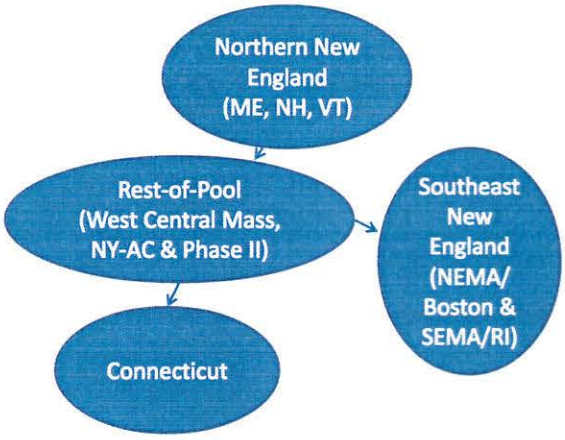
energy into New England. Losing that many MWs at one time is virtually certain to force scarcity and emergency conditions across New England. Large HQ losses, like those referenced above, will almost certainly result in large penalties to capacity delivered over NPT.

Given the magnitude of these penalty risks, I would expect shippers over NPT to think twice about seeking a Capacity Supply Obligation. If indeed they are willing to take the risk, at a minimum I would expect that risk to be reflected in a higher offer price into the FCM auction, and certainly not the "price taking" offer suggested by LEI.

Q: You state that LEI failed to properly account for the zonal nature of the FCM in their analysis. Please explain.

A: While the New England Transmission System is generally robust, there are well-known and significant limitations on the ability to move large amounts of power across the system. The FCM design recognizes that certain areas of New England may be surplus, and others short of capacity at any one time. By modeling separate capacity zones, the FCM is able to send a locational signal based on local need: a higher price to areas that are short of capacity, and a lower one to areas of surplus. Pursuant to FERC's May 29, 2015 Order, we recognize four potential capacity zones: Northern New England ("NNE") (New Hampshire, Maine and Vermont), Southeast New England ("SENE") (eastern Massachusetts and Rhode Island), Connecticut, and Rest of Pool (central and western Massachusetts). NPT interconnects with the grid at Deerfield, NH. It would therefore be considered part of the NNE capacity zone. See Figure 3 below:

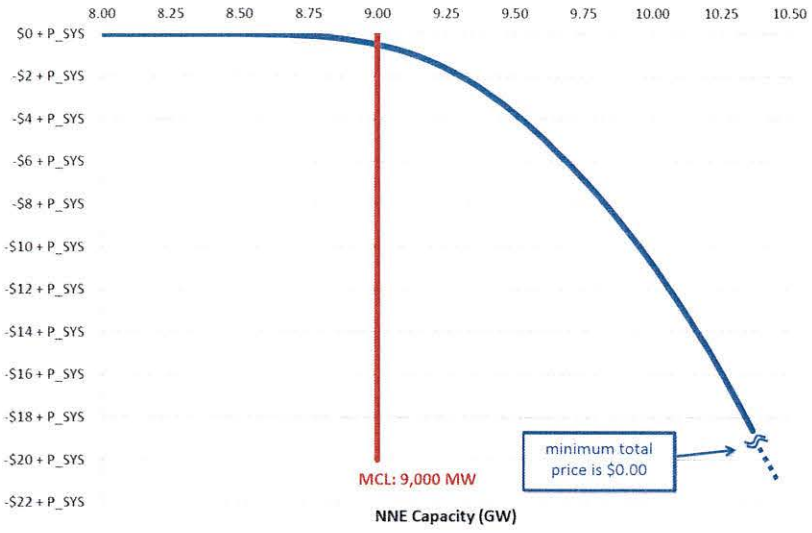
Figure 3
New England Capacity Zones[24]



There are three types of zones. There is the base zone (Rest of Pool), two "import constrained" zones (CT and SENE) and an "export constrained" zone (NNE). The import-constrained zones reflect load centers, where there is typically less generation than electricity demand, and thus the need to import capacity; NNE is export-constrained, meaning that there is more generation than demand, so we expect capacity to export out of that zone. The zonal price that the FCM clears for Rest of Pool sets the base price for New England. Generators inside the import-constrained zones receive a premium above the Rest of Pool price. Generators inside NNE (which would ultimately include NPT) receive a *deduction* from the Rest of Pool price. The amount of premium or deduction depends on the amount of surplus or deficit each zone has versus its target; that price adjustment is in turn based on the local demand curve discussed earlier. For an export constrained zone such as NNE, the larger the surplus, the larger the price deduction. The chart below shows the FCA 11 demand curve for the export-constrained NNE zone.

[24] source: https://www.iso-ne.com/static-assets/documents/2016/11/a5_fca_12_zonal_development.pdf

Figure 4
FCA-11 Northern New England Demand Curve[25]



On the figure, the Y axis represents the price subtraction (or subtrahend) in $/kW-month. So "-$4 + P_SYS" means that the price is $4/kW-month below the System (Rest of Pool) price. The X axis is total MW capacity in NNE. "MCL" represents a value above which the surplus gets significant, and the price penalty grows large.

If NPT were able to overcome the FCM qualification challenges I described previously and actually enter the FCM, its price impact on the NNE zone would be significant. ISO has published the FCA-11 export-constrained demand curve values for NNE, which we can use to see that impact.[26] The price subtrahend for NNE is based on the amount of capacity that clears, and the fixed demand curve. If we assume that all currently existing capacity in NNE remains in

[25] Source: ISO-NE presentation available at https://www.iso-ne.com/static-assets/documents/2016/08/PSPC08252016_FCA11_MRI_Demand_Curves.pdf

[26] See: https://www.iso-ne.com/static-assets/documents/2016/08/PSPC08252016_FCA11_Demand_Curves_Values.xlsx. This Excel sheet was used to determine price impacts.

the FCM (8,243 MW)[27] plus the recent average capacity imports from New Brunswick (181 MW in FCA 10) and over the Vermont Highgate Tie to HQ (58 MW in FCA 10),[28] and there are zero new entrants, the total capacity in NNE is 8,482 MW (or 8.48 GWs). This makes NNE slightly surplus, and the price subtrahend will be $0.00 (on Figure 4, the price subtrahend for 8.48 GWs is $0). However, if we were to add 1000 MW of NPT capacity into the zone, the subtrahend would be **$3.60/kW-month**. This means that, if, say, Rest of Pool clears at $7.03/kW-month (the most recent, FCA-10 auction result), the NNE zone would clear at ($7.03 - $3.60) = $3.43/kW-month; that would be the price paid to all resources in NNE, including NPT.

Importantly, the impact of this price suppression would be limited to NNE, not zones to the south. Once an export-constrained zone is surplus, adding additional supply to that zone will have little impact on prices and quantities that clear in the other zones. A proper calculation of capacity benefit would have to fully account for this actual market design.

We cannot, however, stop the calculation here. The above price differences would only hold if all other NNE generators were indifferent to the price drop, and were content to continue to supply capacity at a very low price. The chances of that are virtually nil.

Q. **How do you believe the market would respond to 1000 MW of NPT capacity entering the NNE zone?**

[27] See https://www.iso-ne.com/static-assets/documents/2016/08/PSPC08252016_FCA11_ICR_Values_Results.pdf
[28] FCA 10 import volumes into NNE from: https://www.iso-ne.com/static-assets/documents/2016/02/fca_10_result_report.pdf.

A. As a threshold matter, it is unrealistic to believe that all generators in NNE will stay in an FCM auction, no matter how low the price goes. Even if they have not signaled a permanent retirement, taking on a CSO for a single year has significant risk and obligations, as I discussed above. Any generator that cannot cover its going forward cost and Pay for Performance penalty risk would be expected to exit the auction (exiting the auction is known as "delisting"). The price at which such generators delist from the auction can become an effective floor price – and would prevent the price from dropping the full $3.60/kW-month that the demand curve on its own would indicate.

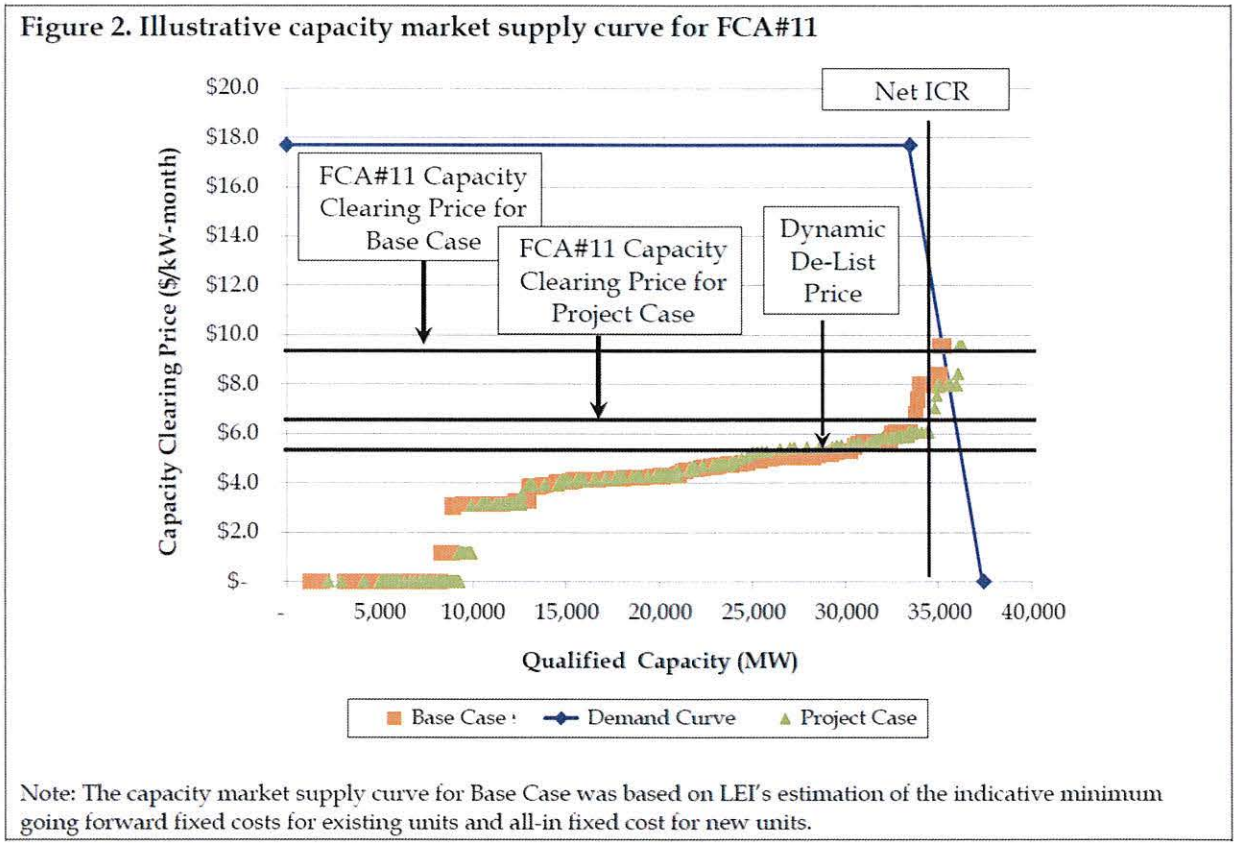
One of the assumptions that allowed LEI to maximize its estimated wholesale capacity benefit was that the drop in the auction clearing price would not induce *any* other generator to delist. This assumption is critical because if generators totaling the same 1,000 MWs that NPT added to the supply had retired (or just delisted for a single year), there would be little or no difference in total capacity supply and auction clearing prices would be the same with or without NPT.

LEI states that they considered but dismissed this concern. Specifically the Frayer testimony[29] argues that, while capacity prices would fall, they would typically remain above $5.50/kW-month, which they consider to be a level below which retirements or delists are likely. So they posit that there would be no retirements or delists. This conclusion cannot be supported.

First, LEI's own data argue to the contrary. Figure 2 of the Frayer testimony shows their estimates of generator costs versus clearing prices, as well as their estimate of NPT's price suppression. That chart is reproduced below.

[29] See Testimony of Julia Frayer at 16-17.

Figure 5
Copy of LEI Capacity Pricing Curves[30]



All of the green triangles (generators) priced above the "FCA11 Capacity Clearing Price for Project Case" (about $6.50/kW-month) would, by definition, be out of the money, and candidates to retire.

Importantly, when we properly consider the operation of the current FCM and its zonal demand curves, the stress on local generators is far greater than LEI predicts. This derives from LEI's failure to account for the way zones concentrate the impact of price suppression. If we assume a

[30] Frayer Testimony Figure 2

$7.03/kW-month Rest of Pool clearing price[31] and a $3.60 NPT-caused price deduction for the NNE zone, the resulting capacity price to NNE resources is $3.43/kW-month. This is *far* below the $5.50/kW-month level that LEI argues may trigger retirements.

Over the past several years, we have seen many large generator retirements across New England, including most recently the Pilgrim nuclear plant and the Brayton Point fossil-fueled station; the clearing prices in the FCM auctions in which these facilities delisted (retired) were well above $5.50/kW-month. It would seem unrealistic to assume that no new generators would retire when facing prices in the $3-4/kW-month range.

Should we see generator retirements in NNE that offset NPT's capacity injection, the wholesale capacity benefits due to NPT would be non-existent. And we could see other negative economic consequences. For example it is possible that generators that are less expensive than NPT might be forced to retire since (depending on how the MOPR is applied) they would not enjoy the same out-of-market revenues that NPT may receive through, for example, the Massachusetts RFP and the New Hampshire PPA. In addition, having NPT essentially replace an equivalent amount of local generation could lead to a major, net negative impact as we lose local jobs, taxes and revenue from these facilities forced into premature retirement. While the NPT line may provide temporary construction jobs, the full-time jobs and tax revenue associated with it will most likely be located across the border in Canada. That is not the case when local generation is forced to retire.

[31] $7.03/kW-month was the actual clearing price from the most recent auction, FCA-10 conducted in February, 2016.

Q: Are there any other factors that should be considered in net electric benefits?

A. Yes, at least one. The Frayer testimony states that NPT operation will result in "Energy Market Benefits" of $80 to $100 million year across New England, and $8.2 to $10.2 million for New Hampshire.[32] Because supporting testimony is redacted, I have not had an opportunity to review these estimates, so I have no opinion on their validity. However, like the capacity market discussion above, it would be incorrect to assume that there will be no market reaction to lower energy prices. The common wisdom, which I support, is that when generators see lower energy prices, they must earn greater money in the capacity market, or retire. ISO-NE fully recognizes this dynamic, and is doing quantitative analysis on the matter right now. See their presentation to the December 14, 2016 New England Planning Advisory Committee posted at https://www.iso-ne.com/static-assets/documents/2016/12/2016_economic_study_fca_sow_pac_121416_a07.pdf (esp. slide 5).

I therefore believe that most energy market benefit would be offset by increases to capacity market payments; and therefore would not really represent an overall benefit to consumers.

[32] Frayer testimony Figure 1.

Q. Please summarize your points

A. The LEI Report makes several errors and relies on an outdated market design in its forecast of electric market benefits to New Hampshire and New England. The LEI Report ignores the operation of the ISO-NE MOPR and capacity deliverability standard, either of which could disqualify NPT from receiving any capacity benefits whatsoever. The LEI Report fails to properly account for the risks of taking on a CSO, the operation of the FCM's zonal demand curves, and a rational market response to whatever price suppression ultimately does develop. In addition, the LEI Report incorrectly assumes that no existing generators will retire based on that price suppression. For these reasons I believe that the wholesale capacity market benefits as described in the LEI Report are greatly exaggerated.

Q. **Does this complete your testimony?**

A. Yes.