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# Attachment B

# Affidavit of Matthew W. Tanner on Behalf of the New England Power Generators Association, Inc.

## Docket No. ER21-787-000

## Filed January 21, 2021

**UNITED STATES OF AMERICA**
**BEFORE THE**
**FEDERAL ENERGY REGULATORY COMMISSION**

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| ISO New England Inc. | Docket No. ER21-787-000 |

**AFFIDAVIT OF MATTHEW W. TANNER**
**ON BEHALF OF NEW ENGLAND POWER GENERATORS ASSOCIATION**

I, Matthew W. Tanner, depose and say:

## *I. Qualifications*

1. My name is Matthew W. Tanner. I am a managing director with Berkeley Research Group LLC in its offices of 1800 M St. NW, Washington, DC 20036. Prior to this, I led the wholesale markets group at Navigant Consulting, another global consulting firm. My expertise includes renewable integration, market transformation, power systems modeling & forecasting, utility resource planning, and risk simulation. I focus on evaluating underlying market drivers and regulatory and technological changes in the power sector and in helping maintain system reliability, reduce emissions, and minimize cost. As part of my work, I have simulated and forecasted power markets in New England and specifically helped clients understand the rules and requirements of the ISO New England ("ISO" or "ISO-NE") capacity market over the last decade. My clients use this information in support of their investment decisions for assets participating in the markets. I hold degrees from Princeton University and Texas A&M University.

2. In preparing this affidavit, I collaborated with Robert B. Stoddard, formerly a managing director of Berkeley Research Group, LLC. Mr. Stoddard spoke on behalf of the New England Power Generators Association ("NEPGA") at several New England Power Pool ("NEPOOL") Markets Committee meetings leading up to this docket and filed an expert affidavit in a recent complaint filed by NEPGA about that process.[1] Subsequent to that

[1] *New England Power Generators Association v. ISO New England, Inc.,* Docket No. EL21-26-000.

filing Mr. Stoddard has taken a position as an officer of a major energy company that is not a NEPGA member and, consequently, is restricted from testifying in this docket.

## *II. Purpose and Summary*

3. I have been asked by NEPGA to opine on whether certain assumptions ISO-NE used to calculate the net cost of new entry ("Net CONE") are consistent with the current definition of Net CONE in its Transmission, Markets, and Services Tariff ("Tariff"), whether those same assumptions comport with ISO-NE's proposed revised definition of Net CONE also filed in this proceeding, and whether those same certain assumptions are reasonable. I first incorporate by reference Robert B. Stoddard's Affidavit filed in support of NEPGA's Complaint, in which Mr. Stoddard explains that ISO-NE has not followed the plain meaning of its Tariff, nor its past practice in recalculating and reviewing with NEPOOL stakeholders the Net CONE value it has filed with the Commission in this proceeding. Mr. Stoddard's Affidavit supports NEPGA's request that the Commission find that ISO-NE has therefore violated its Tariff, which findings I likewise support. Below I will show that ISO-NE's failure to follow its Tariff has a material effect on the filed value of Net CONE, biasing the estimate downward. I also will show that the ISO-NE's new methodology for the calculation of Net CONE is inconsistent with the design of the market demand curve that was accepted by the Federal Energy Regulatory Commission ("FERC') and the methodology should not be accepted on this basis. Moreover, I will show that ISO-NE's inputs and assumptions are so patently biased that they meet neither the current Tariff definition of Net CONE, nor ISO-NE's proposed definition and should be rejected.

4. Net CONE is an essential parameter in ISO's Forward Capacity Market ("FCM"). It scales the FCM's demand curve vertically, so that the capacity price equals Net CONE when quantity cleared in the market equals the Net Installed Capacity Requirement ("Net ICR"). To develop an estimate of Net CONE, ISO selects a reference resource and estimates its associated annualized costs to compute a gross cost of new entry ("gross CONE"). From this, ISO subtracts an estimate of the profit margin that such a resource is likely to earn based on sales of energy and ancillary services ("net E&AS revenue") and other market revenues or penalties. Therefore, the estimate of net E&AS revenues has a one-for-one impact on Net CONE.

5. The importance of setting Net CONE correctly is that there are asymmetrical risks to reliability from setting the value too low compared to the economic risks of setting it too

high. As stated by Robert Ethier, presently Vice President, ISO-NE System Planning, in ISO-NE's sloped demand curve filing[2]:

> The fundamental reason for the asymmetry in the risks of over and underestimating Net CONE is, as noted above, that reliability is a highly non-linear function of capacity, while costs rise linearly with the quantity of capacity.

The implication of this relationship is that the bias in the methodology of ISO-NE's calculation of Net CONE is a material risk to the proper functioning of the capacity market to ensure reliability.

6. As explained in Mr. Stoddard's affidavit, the ISO's Tariff provides a clear definition of Net CONE while its proposed methodology introduced this year departs sharply from the approaches used in either the 2014 or 2017 filings or in economic studies ISO routinely performs for other purposes. I will show that ISO-NE's rebuttal of Mr. Stoddard's affidavit is unavailing, as it relies on mischaracterizations of the 2014 and 2017 approaches and out-of-context quotes from other proceedings. The new methodology developed by ISO and its consultant is fundamentally incapable of meeting the requirements of the Tariff, a fact ISO implicitly acknowledged by its proposal late in the stakeholder processes to rewrite the applicable section of the Tariff to remove the manifest contradiction between the Tariff's requirements and ISO's proposed net E&AS revenue methodology.[3]

7. Furthermore, as I will explain below, ISO-NE's justifications for using the new methodology are not consistent with the goals of good market design. It is also not consistent with the Marginal Reliability Impact ('MRI') of the capacity approach that was used and accepted by the FERC for the initial development of the demand curve. Additionally, the ISO-NE's assumptions are systematically biased to yield an artificially high revenue offset, further depressing Net CONE.

8. The impact of ISO-NE's failure to follow its Tariff and instead to adopt an unreasonable approach to estimating Net CONE is significant both in form and substance. The ISO-NE's entire approach is characterized by unreasonable assumptions that serve to increase the E&AS offset. In its Net CONE Filing,[4] ISO-NE claims that:

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[2] *ISO New England Inc. and New England Power Pool*, Docket No. ER14-1639-000 (filed April 1, 2014) ("Demand Curve Design Filing"), p 536.

[3] For clarity, this 2020 methodology includes the net earnings from market sales at market prices, a scarcity-hours premium, and Pay-for-Performance payments.

[4] ISO-NE Net CONE Filing, Docket No. ER21-787-000, 2021, p31.

> While the 2017 Net CONE Study's modeling approach differs from the present study…neither is unreasonable, nor implies fault in the other. Rather they reflect the reality that there are multiple different modeling techniques that can be applied to estimate E&AS revenue offsets.

It is true that there are multiple approaches that could properly estimate E&AS offsets, but as I will detail below, ISO-NE has used an approach that is unsupportable. There are too many incorrect underlying assumptions for it to be considered a reasonable estimate of the E&AS offset. Consequently, ISO-NE's new methodology also fails to meet the requirements of its proposed definition of Net CONE, which also demands that the revenue assumptions must be "reasonable expectations."

9. As explained in Mr. Stoddard's affidavit, ISO-NE created a hypothetical system at capacity balance untethered to what has actually occurred or what is reasonably expected to occur. They have done so to restate historical energy prices that unreasonably reduce Net CONE. The ISO removed resources from the energy supply offer curves without adding those resource that have (i) entered the market, or (ii) already obtained Capacity Supply Obligations ("CSO") and are reasonably expected to enter the market by Capacity Commitment Period 2025-2026.

10. The ISO further biases the calculation by not including the reference technology in the supply curves used to model energy and reserves in the Net CONE calculation. If the system is at criterion, it is expected that the Reference Unit will be incentivized to be built, and its very participation in the market will erode part of the value the Reference Unit is attempting to capture. In other words, by adding additional supply from the Reference Unit, the E&AS offset will decrease. ISO-NE does not account for this effect or explain why it has failed to do so.

11. ISO-NE compounds its errors by failing to consider the likely erosion of these revenues as the resource mix on the New England system shifts over time. Most of the New England states have statutory mandates to increase their reliance on renewable energy, which will most certainly have an impact on the future resource mix. Instead, ISO-NE holds the Reference Unit's first year revenues constant over the entire 20-year life of the facility. Stated differently, ISO-NE expects the Reference Unit to have the same profit-making potential in the last year of its life as the first. This approach simply ignores reality.

12. ISO-NE deviates from its prior practices and now makes implausible assumptions regarding scarcity hour frequency to further reduce Net CONE. As I will demonstrate, ISO-NE's forecast is not supported by the actual historical evidence and fails to consider

exogenous factors that ISO-NE itself has identified that tend to reduce the frequency of scarcity hours. The historical record demonstrates that not a single scarcity hour has occurred due to the modelled (i.e., peak load) conditions, yet ISO-NE attempts to maintain that 11.3 such hours will occur on average over the life of the Reference Unit. Again, ISO-NE is ignoring the evidence to create a biased result.

13. The total impact of these aforementioned biases leads to an overall overestimate of the E&AS offset of $0.76 – $0.96/kWm.[5] This price suppression is "bias," not "error" or variations of different expert consultancies. Eliminating the chronic capacity supply surplus in New England by fiat is not a reasoned or reasonable estimate of future supply conditions, and this assumption necessarily raises estimated E&AS net revenues above market expectations. While all "reasonable estimates" will be erroneous, to a greater or lesser degree, an estimation process that has clear and substantial biases that is demonstrably counterfactual cannot be judged reasonable.

14. ISO-NE's approach is not consistent with the way that any of the market participants that I advise make investment decisions. No entity would construct a set of revenue assumptions in the way ISO-NE has done and then hold those biased assumptions static for twenty years. A market participant considering developing or making an investment in new, needed capacity would take a very careful view of the current state of the market, the impact its own investment would have on that market, and the future evolution of the power market and the interaction between expected market prices and state policy. A developer or investor that did not do this would be unable to secure financing or get approval from their investment committee. This means that the Net CONE calculation is inconsistent with the Tariff requirement that the Reference Unit be economically viable at Net ICR.

## *III. ISO-NE's Approach in 2020*

15. ISO-NE's new approach for calculating Net CONE is inconsistent with both its current Tariff, past practice, and the proposed revision to its Tariff. It is a significant departure from the methodology used in ISO-NE's 2014 and 2017 filings and with ISO's approach to economic studies conducted for other purposes.

16. In stakeholder discussions at the Markets Committee, ISO-NE and ISO-NE's consultant retained to calculate Net CONE, Concentric Energy Advisors ("Concentric") have put

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[5] As is detailed in the technical appendix, this bias is on top of the $9,177,385 per year, or $2.26/kWm overstatement of E&AS revenue detailed in the Wilmer/Levitan Affidavit. *See* Wilmer/Levitan Affidavit at 62.

forward an approach to estimating net E&AS earnings. At the May meeting, Concentric told stakeholders that it was "reviewing previous methodologies and assessing alternative methods that provide a reasonable estimate of future expected E&AS margins with an emphasis on being transparent to stakeholders."[6] At the June meeting, it was reported that Concentric had settled on an "approach that involves forward-looking adjustments to historical E&AS price patterns, with both a DA and RT hourly dispatch model."[7] Critically, the key adjustment Concentric planned was "[d]eveloping forward-looking adjustment factors to historical energy prices to better reflect a system 'at criteria' … since recent historical energy prices in New England reflect significant supply in excess of criteria."[8] The details of Concentric's approach are described in the technical appendix - section VI.1.

## *IV. ISO-NE's Modeling of the System At Equilibrium is Flawed and will Not Achieve desired market outcomes*

17. As was discussed in Mr. Stoddard's affidavit, ISO-NE's approach to estimating Net CONE in the 2020 stakeholder process was fundamentally at odds with the plain language of its Tariff. ISO-NE's rebuttal of Mr. Stoddard's affidavit is unavailing, as it relies on mischaracterizations of the 2014 and 2017 approaches and out-of-context quotes from other proceedings. The justification for how the system is represented at equilibrium is flawed, it seems to focus on desired outcomes rather than good market design. Finally, the ISO's arguments that the 2020 methodology are consistent with past practice are unavailing. I discuss these issues below.

### *IV.1 ISO-NE's Justifications for Modeling the System at Equilibrium Are Unsupported*

18. ISO-NE makes two primary policy arguments in assuming system conditions are at long-term equilibrium and calculating E&AS revenues consistent with that assumption. First, ISO-NE concludes that using that approach is necessary to ensure that price signals incent new capacity to enter the market only when it is needed. Second, ISO-NE asserts that incentivizing entry when the system has excess capacity is not consistent with the 1-in-10 planning standard and therefore is not cost-effective.

19. ISO-NE's policy arguments miss the point. As an initial matter, it appears that ISO-NE's approach is outcome driven and ignores foundational market principles that underpin good market design. Specifically, the capacity market should be designed to procure an

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[6] Concentric, "ISO New England CONE and ORTP Analysis," May 12, 2020. p.33. Available at < https://www.iso-ne.com/static-assets/documents/2020/05/a7_cea_presentation_cone_and_ortp.pptx>

[7] Concentric, "ISO New England CONE and ORTP Analysis," June 10, 2020. p.53. Available at < https://www.iso-ne.com/static-assets/documents/2020/05/a7_cea_presentation_cone_and_ortp.pptx>

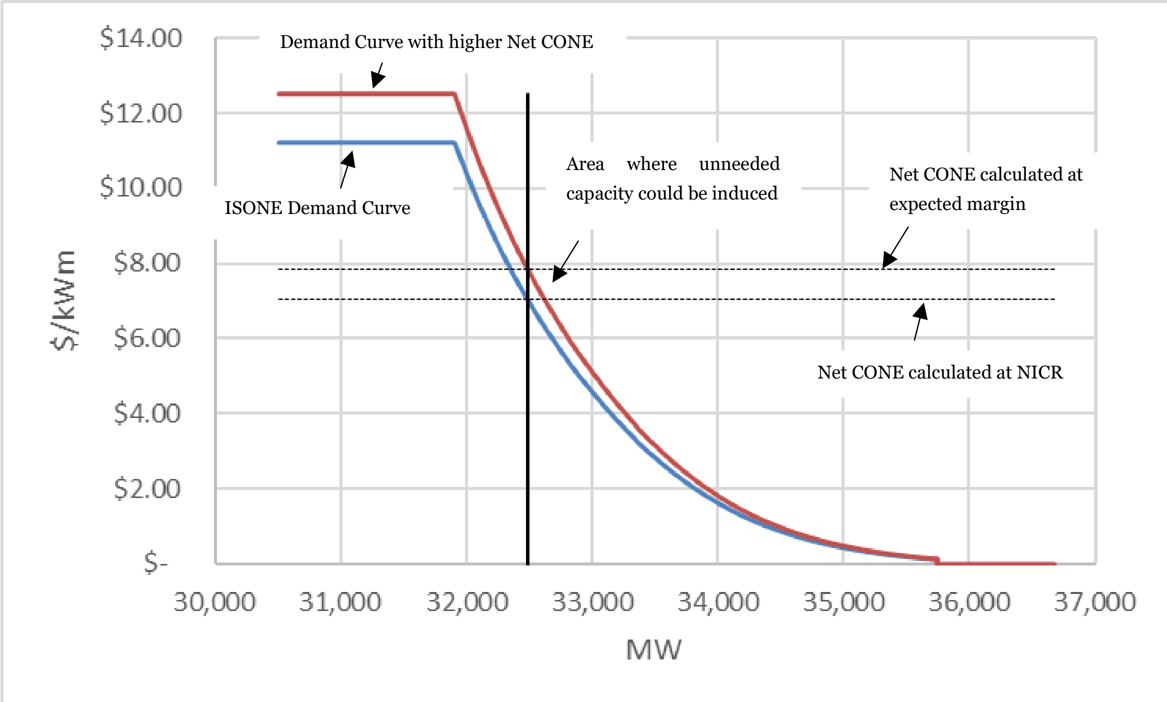
[8] *Id.*

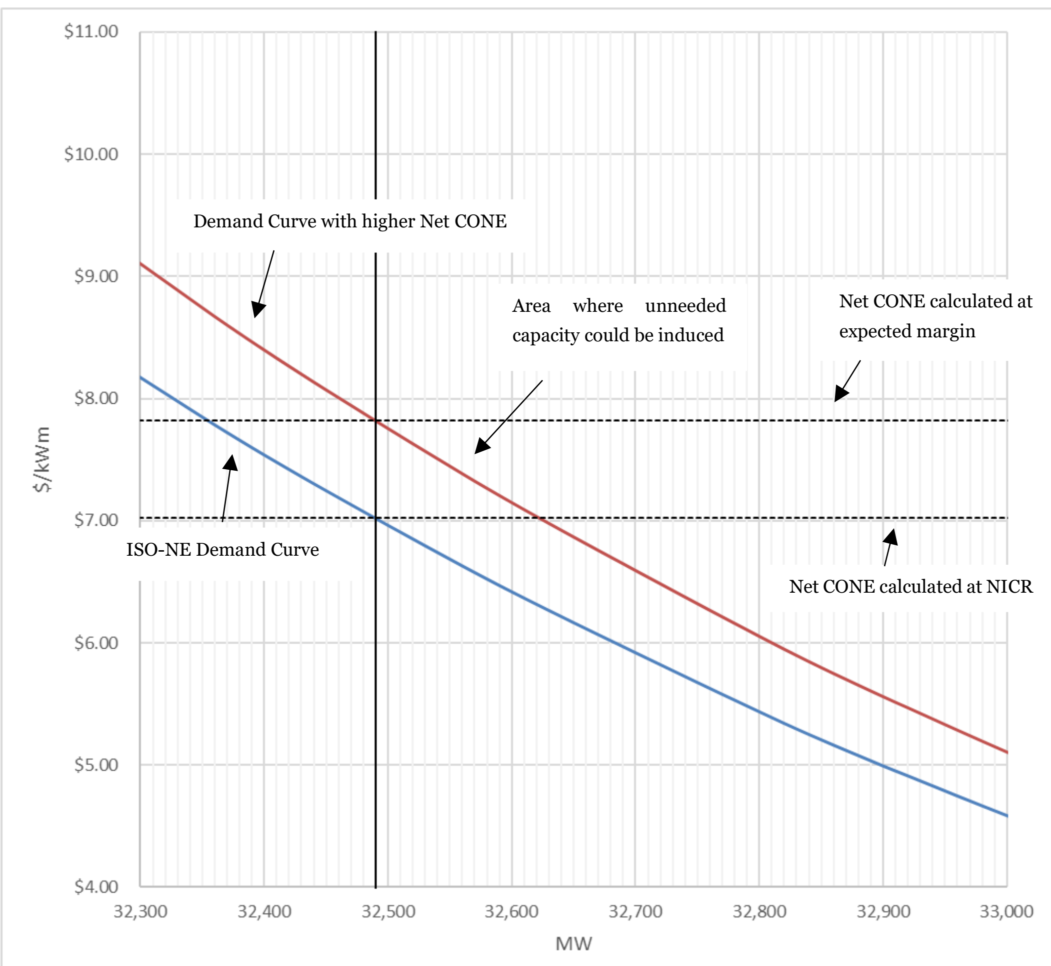
economically efficient amount of capacity. Yet, there is no evidence that ISO-NE even sought to evaluate whether the proposed methodology achieves efficient outcomes. Rather, ISO-NE has chosen a methodology that singularly seeks to drive down Net CONE in an apparent attempt to incent resource retirements, regardless of whether it does so efficiently.

20. Before providing a more technical consideration for why ISO-NE's approach is simply a flawed market design, I would like to more directly address the primary arguments raised by ISO-NE for why it has chosen this methodology. As I will demonstrate, these arguments simply are flawed, and do not justify this new methodology.

21. ISO-NE assumes that modeling the system at equilibrium is necessary to ensure entry occurs only when needed. Such assumption does not appropriately consider how ISO-NE's downward sloping demand curve works in practice. Every downward sloping demand curve will set a price less than Net CONE when the capacity market clears at a quantity greater than Net Installed Capacity Requirement ("ICR") and will thus deter new entry. While ISO-NE's argument implies that NEPGA's interpretation of Net CONE (with E&AS revenues based on reasonable expectations of actual capacity conditions) could set prices greater than Net CONE (with E&AS based on the system at equilibrium) and at quantities greater than Net ICR for some portion of the demand curve and induce entry when not needed, it is not possible in any practical circumstance (see attached figure).

22. The first figure shows the entire ISO-NE demand curve using either ISO-NE's assumptions or NEPGA's assumptions. The area on the NEPGA curve that is above the ISO-NE Net CONE but below the NEPGA Net CONE is the only region where ISO-NE's concern that unneeded capacity could be incentivized is possible. As is explained below, it is not a practical risk that the New England market will find itself in this very narrow area of the demand curve. Under the actual system condition 2,000 MW of existing resource would have to exit the market first before ISO-NE's perceived risk emerges and then a maximum of 140 MW of "unneeded" new capacity could enter the market. As explained below, the minimal impact and negligible probability of this condition occurring is outweighed by the consequences of inefficient retirements and entry decisions. The second figure shows an expanded chart of this same figure for clarity.


Demand Curve with higher Net CONE
ISONE Demand Curve
Area where unneeded capacity could be induced
Net CONE calculated at expected margin
Net CONE calculated at NICR
$14.00
$12.00
$10.00
$8.00
$6.00
$4.00
$2.00
$-
$/kWm
30,000
31,000
32,000
33,000
34,000
35,000
36,000
37,000
MW


Demand Curve with higher Net CONE
Area where unneeded capacity could be induced
Net CONE calculated at expected margin
ISO-NE Demand Curve
Net CONE calculated at NICR
$11.00
$10.00
$9.00
$8.00
$7.00
$6.00
$5.00
$4.00
$/kWm
32,300
32,400
32,500
32,600
32,700
32,800
32,900
33,000
MW

23. As the actual system conditions converge on the Net Installed Capacity Requirement ("Net ICR") ISO-NE's Level-of-Excess ("LOE") adjustment converges to 1.0 (i.e., there is no adjustment) and the demand curves scaled by Net CONE collapse into one. In the figure above, as the demand curves converge the quantity of "unneeded" new capacity also drives to zero. That is, calculating E&AS based on a reasonable expectation of first year revenues and future system conditions is equivalent to calculating E&AS based on a reasonable expectation of a system at long-term equilibrium when the actual system is close to Net ICR at the time Net CONE is recalculated.

24. Thus, the disagreement between NEPGA and ISO-NE is practically relevant only when the capacity market will clear with a sizeable surplus or deficit of capacity. Yet, ISO-NE does not address what we expect of the demand curve when the system faces those circumstances. And as I will demonstrate below, when the capacity market clears with a sizeable surplus of capacity, as is the case now, downward sloping demand curves will result in capacity clearing prices well below Net CONE calculated on any reasonable basis, and will serve to ensure that new capacity resources enter only when needed. Thus, ISO-NE's suggestion that setting the system at equilibrium is necessary to ensure entry occurs only when needed is simply not accurate.

25. I want to briefly consider a system with a sizable deficit of capacity, perhaps because of disorderly retirements. When there is a sizable deficit of capacity, the ISO-NE's interpretation of Net CONE will **over-pay for capacity** relative to NEPGA's interpretation because expected E&AS revenues in the first year of the Reference Unit's operation are expected to be greater than assumed under ISO's long-term equilibrium assumption.[9] In this case, ISO-NE's preferred interpretation of Net CONE will cost consumers more than needed to induce entry. That cannot be cost-effective, despite the ISO's suggestion otherwise.

26. Now, I want to consider the circumstances we are facing today, with ISO-NE facing a sizable capacity surplus. Initially, as I explained above, a downward sloping demand curve resolves any concerns about inducing entry when it is not needed. There are two fundamental market performance considerations to explore in those circumstances when the capacity market is expected to clear in excess of Net ICR. First, is capacity market

[9] Assuming there is insufficient entry to get to Net ICR. This is reasonable given the time needed to develop new generation in ISO-NE.

compensation for existing units supportive of previous entry decisions? Second, does the capacity market establish the right price signals to encourage efficient retirements?

27. Addressing the first consideration, ISO-NE's methodology does not reflect capacity market outcomes that would support previous entry decisions. To illustrate this point, consider an older vintage of the Reference Unit that entered say 5 or 7 years ago.[10] The Reference Unit's E&AS offset in the first delivery year should be fairly representative of this resource's energy and ancillary services revenues in that year. The E&AS offset at the time the resource entered would likely have assumed the capacity market had returned to close to long-term equilibrium (with an evolved resource mix) by year 5 or 7 of the resource's life. However, if, instead, the actual system has a substantial surplus, the older vintage resource will have actual energy and ancillary services revenues that are less than it would have expected when entering and less than incorporated into its capacity price in the entry year. ISO-NE's proposed Net CONE will not account for this surprise and will instead provide total compensation lower than the unit expected.

28. When the market design does not attempt to reflect actual future system conditions, entry decisions will not be efficient. Specifically, when entry is eventually needed, resources considering entry will take into account the potential for unexpected lower total compensation and require a higher first year capacity price to enter, if they are willing to enter at all. In contrast, the NEPGA interpretation incorporates a feedback mechanism that supports rational entry decisions consistent with the 1-in-10 standard.

29. The benefit of competitive markets to ratepayers is that no resource is guaranteed a revenue stream. However, when long standing practices are upended, investors will price additional risk premiums into their offers and ratepayers will pay more as a consequence. To be clear, NEPGA's interpretation of Net CONE is not about guarantees. It is instead about aligning the market's expectations when the entry decision was made by the investor and expected over the life of the resource.

30. Regarding the second consideration, ISO-NE's proposed methodology will likely not create the right retirement incentives, either. The ISO's interpretation of Net CONE will certainly induce *more* retirements than NEPGA's interpretation. During the stakeholder process, ISO seemed to suggest their methodology was at least in part intended to induce retirements, essentially finding that *more* retirements are necessarily efficient when the system has a surplus of capacity.

[10] Ignoring the price lock which is not part of the ISO-NE capacity market going forward.

31. However, that suggestion is an overly simplistic view of whether a retirement is economically efficient. A resource's retirement is efficient only if the resource's net cost of remaining in service is greater than the value to consumers of the resource remaining in service. Doing this evaluation requires interpreting the point on the demand curve away from Net ICR.

32. Most critically, and most telling, ISO-NE has not presented any arguments for how their new methodological approach will yield efficient retirements.

33. Thus, I disagree with ISO's view that its proposed methodology is the best approach to achieving expected outcomes of an efficient FCM. ISO-NE has not provided any evidence that the market design requires Net CONE to be calculated at long-term equilibrium when the capacity market is expected to clear away from Net ICR. In the following I provide an interpretation of the points on the demand curve corresponding to quantities greater than Net ICR.

### *IV.2 A Technical Evaluation of the MRI Curve And its application Further Demonstrates The Flaws in ISO's approach*

34. Unlike any other region, New England's capacity market has demand curves that are rooted in engineering and economic principles. They are (or, at least, attempt to be) true demand curves in the technical economic meaning of that term: that consumers are indifferent to being at any point on the curve. The purpose of the curve is to trace the set of reliability/cost tradeoffs that are equally valued.

35. Establishing this curve is a two-part process. First ISO-NE determines the shape of the curve through an "empirical exercise in engineering-economic analysis, which the ISO conducts using industry-standard reliability planning simulation models. The relationship between capacity and its incremental reliability impact on expected loss of load is known as the Marginal Reliability Impact ('MRI') of capacity."[11] Second, ISO-NE must map this MRI (which has incremental reliability on the $y$-axis) to an economic demand curve (with price also on the $y$-axis). It does so by scaling the MRI curve by a factor equal to "the ratio of Net CONE and the system's MRI value evaluated at the Net ICR capacity level."[12] When the system is away from Net ICR, the Demand Curve Improvement filing says very little about how to calculate Net CONE.

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[11] Prepared Testimony of Christopher Geissler & Matthew White on behalf of ISO New England Inc., Attachment 3 to the Demand Curve Improvement Filing, at 26:22–27:3. That testimony provides a more detailed explanation of this process at pp.36–39.

[12] *Id.* at 44:4–5.

36. The ISO's new approach does not consider this trade off at all but instead only considers a system that is at equilibrium immediately. As is detailed in the technical appendix - section VI.2, the methodology is underestimating the correct demand curve at the point the market is likely to clear – thereby inducing inefficient retirements. The design of the demand curve, as accepted by FERC, is supposed to explicitly consider the tradeoffs of capacity price and reliability, and energy cost benefits at all points on the curve. By not properly estimating the curve at other points, the demand curve is fundamentally underestimating the value of reliability which will prevent the market from operating as designed.

### *IV.3 ISO's ARGUMENTS THAT ITS 2020 METHODOLOGY IS CONSISTENT WITH LONG-STANDING PRACTICE ARE UNAVAILING*

37. ISO further supports its proposed methodology by claiming that the methodology is wholly consistent with its long-standing practice. ISO relies heavily on selective quotes from prior Net CONE filings as the basis for that claim.

38. First, ISO relies on a quote from the 2014 Demand Curve Filing that is not relevant to issues related to the calculation of Net CONE.[13] The quoted language explains Brattle's simulation of various demand curve shapes. The issue in question is whether the shape of the demand curve could support efficient entry. In discussing the demand curve performance simulations, Brattle did not discuss what system conditions they assumed to calculate the Net CONE used in the simulations. Mr. Stoddard's affidavit provides extensive detail on Brattle's method for calculating Net CONE, which the ISO did not refute in their filing. Importantly, Brattle's simulations show the capacity market clears at Net ICR *on average*, but not in every year or every simulation.[14]

39. ISO similarly relies on a quote from the 2016 Demand Curve Improvement Filing, but as above, the quote is similarly not relevant to issues related to the calculation of Net CONE. [15] The quote references expected bidding behavior under the Pay for Performance ("PfP") capacity market design. The ISO is contrasting the expectation of offers under PfP versus the expectation that existing resources will offer their going-forward capital costs without PfP.[16] If the ISO's expectations had been realized, the capacity market would always clear at Net ICR, and by happenstance this quote would be relevant for how Net CONE should

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[13] ISO 2020 Net CONE submittal letter at 26.

[14] See *e.g,* Brattle Demand Curve report at Table 5 (Docket ER14-1639)

[15] ISO 2020 Net CONE submittal letter at 26.

[16] ISO Demand Curve Improvements memo at 26.

be calculated. However, we now know this expectation was not realized, which undermines even the incidental relevance of the quote.

40. Finally, the ISO's description of the 2017 Net CONE study mischaracterizes the basis for the modeling assumptions. [17] ISO-NE asserts that the production cost model used to estimate energy prices assumed a system at capacity balance over the 20-year life of the Reference Unit. ISO is apparently suggesting that this modeling assumption is based on the reasonableness of assuming a system always at long-term equilibrium. However, a careful review of CEA's report makes clear that the assumption is simply a statement about the nature of the capacity surplus in 2017 and the expectation about how that capacity surplus would evolve by 2021. Specifically, CEA states:

> it is expected that much of the existing capacity excess, which began to dissipate over the most recent three capacity auctions and now stands at 1,416 MW, will continue to decrease over time. *Beyond year three*, ISO-NE does not expect current excess capacity conditions to persist and is modeling a system at equilibrium *after the three-year transition period* to the new FCM demand curve system ends.[18]

Further, as Mr. Stoddard's affidavit notes. The 2017 Net CONE study reduced the assumed scarcity hours in years 1 through 3 to reflect the expected excess capacity.

### *V. ISO's Methodology Results in Material Bias in the Net CONE Calculation*

41. The novel methodology used by ISO-NE to calculate Net CONE is systematically *biased* and therefore unreasonable. This bias is material, and the direction of the bias—towards lower Net CONE—has an asymmetrically harmful impact to the market. Further, I note that the source of the bias is related to ISO's failure to incorporate reasonable expectations about future system conditions into the Net CONE calculation. As such, the estimate of Net CONE violates both the current definition of Net CONE and ISO-NE's proposed revision to the definition of Net CONE as both definitions state that the Reference Units should be "economically viable given reasonable expectations" of system conditions.

42. In its 2020 methodology, ISO-NE looks at the question of how to set Net CONE and assumes a static, unchanging world, with technology, policy, and patterns of supply and demand impractically derived from a historical, three-year period. In light of the highly dynamic environment in the power markets today and in the future, the assumption of

[17] ISO 2020 Net CONE submittal letter at 31.

[18] CEA 2017 Net CONE Study Report at 64 (emphasis added)

stasis is unreasonable. ISO makes no adjustments to the Locational Marginal Price ("LMP") averages in the historical test period for, among other things:

- Changing composition of supply *within* the test period;
- Known changes to the composition of supply *after* the test based on observed changes in 2020 such as prior FCA results or state contracting;
- Known changes to the import capability (*e.g*. New England Clean Energy Connect);
- The effect that adding the reference unit will have on prices of energy, forward reserves, and operating reserves;
- Technical capabilities of the Reference Unit to operate within ISO-NE markets[19]; and
- The evolution of the generation mix over time to accommodate state policy and to reflect shifts in relative costs of generation technologies.

43. These omissions are material. In the 2016 stakeholder process, ISO-NE's consultant explicitly modeled many of these impacts over time. As I discuss below, that analysis showed material erosion in system average heat-rates and, in concert, declining energy margins over time that resulted in a material reduction in the E&AS offset. Since 2016, the pace of growth in renewables has quickened, including substantial, large-scale projects that will clearly lower LMPs relative to prices today. Consequently, a thorough long-term modeling exercise in 2020 would have most certainly shown a markedly larger decline in long-term profitability of gas-fired resources and, therefore, a higher Net CONE.

44. While it is challenging to estimate the size of the bias in ISO's approach,ISO-NE did provide a dispatch spreadsheet model that can be used to provide a conservative estimate. The analysis shows the materiality of the bias and provides clear evidence that the methodology used by ISO-NE is fundamentally flawed and should be revised. The following describes the analysis and the results of the estimate of the bias from the Net CONE calculation. It is important to note that all of the following impacts are in addition to the $2.26/kWm impacts calculated by Ms. Wilmer and Mr. Levitan.

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[19] See technical appendix, section VI.3 for summary of Mr. Levitan and Ms. Wilmer's affidavit regarding the capabilities of the Reference Unit and impacts on market revenues.

*V.1 Inherent biases in the LOE adjustment*

45. The current process creates a biased overestimate of reasonably expected first-year energy earnings by adjusting historical LMPs upwards by withdrawing energy offers from enough generators to bring the system to capacity balance. While the historical prices are adjusted upward for retirements, there are no adjustments for the price reductions that would occur due to resources being added. While certainly some retirements can be reasonably expected, we also reasonably expect several new additions of both capacity resources and behind-the-meter generation. The new resources being added to the system are zero-marginal cost generation or new thermal generation that is more efficient than existing marginal units. For example,

   - During the test period, 3,308 MW of new generation achieved commercial operation ("COD"), of which 775 MW (nameplate) was photovoltaics ("PV"). The two most efficient, large combined-cycle ("CCGT") plants in New England, Towantic and Bridgeport Harbor 5, also achieved their date of Commercial Operation ("COD") during this period. The price-lowering impact of these units is included in only that portion of the test period after they reached COD, even though they are expected to be in operation through the life of the Reference Unit.

   - New resources that are committed but not yet in service include the 2,601 MW (nameplate) of new generation that obtained a CSO in a prior FCA that had not achieved COD in 2019, which include the 804 MW Vineyard Wind project, approximately 770 MW (nameplate) of PV, and the 632 MW Killingly CCGT. Additionally, over 2,000 MW of additional offshore wind is under contract and expected to reach COD by 2025 or shortly thereafter. Moreover, the New England Clean Energy Connect is expected to go commercial in 2023, delivering 1,090 MW of round-the-clock firm, contracted power plus an additional 110 MW of uncontracted capacity.

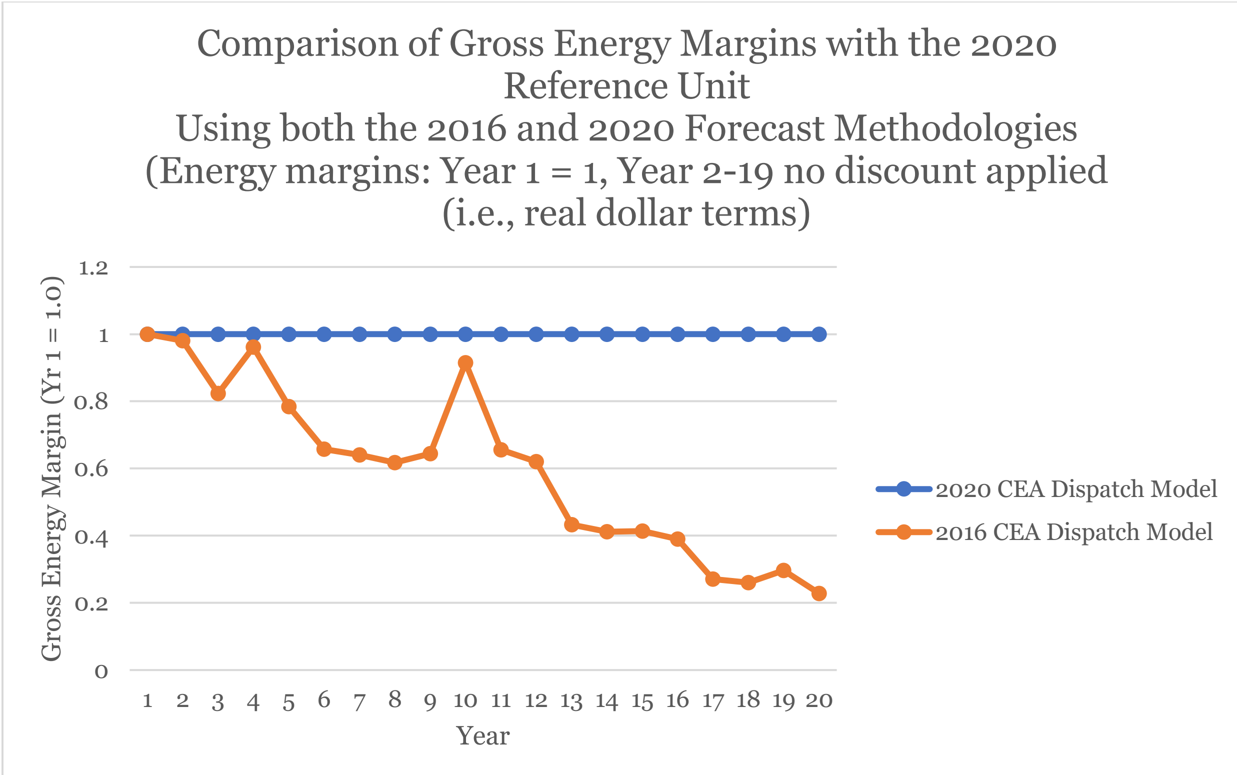
46. Adjusting prices upward by removing capacity but not reducing prices downward due to known capacity additions is a material bias to the LMPs used in ISO-NE's Net CONE calculation. Without this adjustment, the estimate of E&AS revenues would be decreased by at least $0.21/kWm and potentially more as this number is calculated only from removing resources to reach equilibrium and does not consider the impacts of new resource that were added during the test period and are expected to be added after as detailed above.

*V.2 Critique of the assumption of static resource mix*

47. Fundamentally, the current process assumes that the resource mix from 2025 to 2044 is unchanged from the average resource mix from 2017 to 2019, minus the resources selected by ISO-NE to withdraw to bring the system into capacity balance. Standing as we do today at the beginning of a major transition—led by state policy—away from fossil fuels, this assumption is particularly unsound.

48. Assuming the regional capacity supply stays in balance with demand, at least on average, is very different than assuming that *nothing changes* for a quarter-century. Equilibrium does not imply stasis. There has never been a decade, let alone nearly a quarter-century, in the history of the electric power industry that has been static. Some of these changes have been driven by technological innovation, such as the introduction of super-critical coal-firing, nuclear reactors, or advanced combined cycle gas turbines. Others have been driven by public policy, such as the uptake of natural gas as the primary fuel after the passage of the Natural Gas Policy Act and the milestone Commission Orders 436 and 636. Looking out at the technology and policy landscape today, no investor would think that the 2017–2019 test period used by ISO-NE is representative of how the system will look in 2025, let alone 2030 or 2040. The cost of renewable energy technologies has fallen sharply, a trend universally seen to continue. Innovation in storage, controllable loads, and other key integrative technologies continues apace. State policy mandates call for substantial increases in the reliance on zero-emitting generation. All these readily foreseeable dynamic forces in the electric power industry's future will clearly affect potential earnings of a gas-fired combustion turbine installed in 2025, and any potential investor would carefully evaluate the potential impacts of this dynamic environment on their investment returns.

49. The following chart shows the extent to which gross energy margins declined using the 2016 CEA Dispatch model developed for the Net CONE calculation.




50. A conservative estimate of the impact of assuming a static resource mix calculated by assuming the same decay in E&AS revenues as was calculated in 2016 results in a further $0.19/kWm, reduction in the estimate. The calculation of this is given in the technical appendix Section VI.4. Given that expected resource changes even greater now than in 2016, the actual impact of the resource changes to reduce E&AS revenue are likely much higher.

*V.3 Critique of the failure to include the Reference Unit*

51. In addition, even though it would be appropriate for representing a system at criteria, ISO-NE does not include the Reference Unit in the energy market supply stack. The size of the unit compared to the relatively small ISO-NE Real-Time balancing market results in another overstatement of the E&AS revenues available to the Reference Unit.

52. If Net CONE is calculated correctly and the system is at criteria then it would be expected that capacity plus E&AS revenues would be sufficient to incentivize the construction of the Reference Unit. The Reference Unit's E&AS revenues, as calculated by ISO-NE, are highly concentrated in the Real-Time energy market and the Forward Reserve Market.[20] Both of

[20] The analysis of Ms. Wilmer and Mr. Levitan demonstrates that the reference unit would be unable to participate in the FRM market so this analysis only considers real-time market price impacts.

these markets are small in size and the introduction of another, relatively large resource into these markets would be expected to have its own price-lowering impact. It is logically inconsistent to argue that the E&AS revenues as calculated by ISO-NE would properly incentivize this entry while not considering the market price impacts if the unit were built.

53. As described in the technical appendix, the 18% reduction applied to only the Real-Time energy gross margin reduced the overall E&AS offset by a further $0.08/kWm.

*V.4 Inherent biases in the forecasted scarcity hours*

54. The Concentric model also includes an assumption of E&AS revenue increases from an increase in scarcity hours. This forecast uses a system planning model that is predicated upon the New England Control Area and all adjacent control areas being at capacity balance. Furthermore, NEPGA presented empirical evidence that this model does not forecast scarcity hours with any reasonable statistical precision.[21] Without any empirical evidence, it is not appropriate to use the assumption that scarcity hours will quintuple from their historical levels.

55. Section VI. 5 calculates the impact of overstating the scarcity hours on the E&AS offset. Although NEPGA has demonstrated ISO-NE's forecast tool is severely flawed, for the sake of argument this analysis utilizes it in Years 5 and beyond. The overstatement serves to increase the estimate by at least $0.28 to $0.48/kWm.

*V.5 Cumulative impact of the biases in the ISO-NE approach*

56. Adjusting for all the inherent biases in the ISO-NE approach, the resulting Net CONE is reduced by at least $3.02 – $3.22/kWm. This includes the biases I described above and the $2.26/kWm bias identified by Ms. Wilmer and Mr. Levitan.

57. The fundamental concern is that all of these identified issues have the same directional impact—namely, to result in lower earnings for a gas turbine in the future. This underscores the seriousness of the failure of ISO-NE to adopt a net E&AS revenue calculation that is not fundamentally biased.

58. As previously stated, it is important to estimate the correct value of Net CONE and better to overestimate the value than to underestimate it. The new methodology shows systematic bias to materially suppress Net CONE. The result of this bias is a market that

[21] https://www.iso-ne.com/static-assets/documents/2020/11/a4_b_iv_preentation_nepga_amendment_csc_hours.pdf

is likely underpaying for capacity, which may have unintended consequences, and a Net CONE estimate that is inconsistent with the ISO-NE tariff.

59. This concludes my testimony at this time.

## *VI. Technical Appendix*

### *VI.1. Concentric's Approach to Estimated net E&AS Revenues*

60. To estimate the net E&AS earnings for the purposes of estimating Net CONE, Concentric developed a simplified dispatch model for the reference unit based on historical LMPs and fuel prices from 2017-19. Because the 2020 reference unit is proposed to be a gas turbine, it is a relatively straightforward spreadsheet analysis to dispatch the hypothetical unit against Day-Ahead and Real-Time LMPs based on its estimated operating costs and, from that two-settlement dispatch, compute net margins. These modeled net margins are then brought forward to 2025 by multiplying them with scalar inflation indexes for each year to account for actual and expected price inflation.

61. This spreadsheet dispatch model was not run against the posted LMPs during the 2017–2019 study period. Instead, for purposes of this filing, Concentric applied a scaling factor to historical LMPs called the Level of Excess ("LOE") Adjustment. This adjustment was designed to estimate what LMPs *might have been* during the study period had there been no excess supply. These adjustment factors were developed through a four-step process:[22]

- Construct a "base case" energy market supply curve, specific for each hour of the operating day, using the actual bid stack in the market. These base case energy market supply curves were then intersected with the day-ahead load forecast for each hour to develop base case LMPs.

- Reconstruct "LOE-adjusted" energy market supply curves, removing energy supply offers in amounts equal to the level of excess capacity cleared in the applicable FCA. The units' offers that were removed are based on non-intermittent generation resources that had filed retirement requests.[23] These LOE-adjusted

[22] This summary is based on ISO's presentation, "Cost of New Entry and Offer Review Trigger Prices: Energy and Ancillary Service Revenue Adjustments for Level of Excess Supply and Energy Security Improvements", July 14–15, 2020, pp. 7–8. Available at < https://www.iso-ne.com/static-assets/documents/2020/07/a5_b_i_iso_presentation_cone_ortp.pptx>.

[23] Although the bid stacks are released to the public, Concentric used ISO-proprietary information to make this adjustment and has not been willing to release the list of specific resources it removed for the purposes of making this LOE adjustment.

supply curves were then intersected with the day-ahead forecast for each hour to develop LOE-adjusted LMPs.

- For each of the 36 months in the study period, compute average LMPs for the base case and the LOE-adjusted case for three periods: off-peak hours, on-peak hours, and high on-peak hours (defined as a subset of on-peak hours, coincident with summer and winter intermittent reliability hours and all summer hours with a system-wide capacity scarcity condition).

- For each of these 108 (36 × 3) month-periods, set the LOE Adjustment Factor to the ratio of the base case to the LOE-adjusted case. Divide historical LMPs by the appropriate LOE Adjustment Factor to yield the LMPs used in the spreadsheet model to estimate the net E&AS revenues. By construction, the LOE factors are each less than or equal to 1.00. Thus, each of the forecast monthly LMPs are greater than (or in a small number of months equal to) the historical monthly LMPs.

62. Concentric made a second adjustment to historical LMPs, the "Energy/Reserve Scarcity Adjustment "to remove the impacts of energy and reserve scarcity under the excess supply conditions that have prevailed in New England …."[24] As Concentric states:

> The total market impact of the RCPF during the 2017-2019 period (the hours shown in Table 27) was $4,374.99 of energy and reserve scarcity revenue. In equilibrium, the expected real-time impact of the RCPF would be included in day-ahead LMPs. However, this impact is not observable in practice. Therefore, to maintain the historical convergence between day-ahead and real-time prices in expectation, the same amount of real-time energy and reserve scarcity revenue is reflected in the day-ahead market in all on-peak hours. Assuming the expected price impact of the RCPF is applied equally across all on-peak hours in the day-ahead market yields a downward adjustment to day-ahead LMPs of $0.36/MWh is applied in on-peak hours ($4,375/12,224 hours = $0.36/MWh). [25]

63. Concentric provides a table showing a total of six hours when scarcity pricing was triggered in the 3-year test period: HE 19 on 10/18/2016; HE 19 on 10/22/2016; and HE 16–19 on

[24] Concentric Energy Advisors and Mott MacDonald, "ISO-NE Net CONE and ORTP Analysis: An Evaluation of the Net Cost of New Entry and Offer Review Trigger Price Parameters to be used in the Forward Capacity Auction," Draft of November 30, 2020 provided to the NEPOOL Markets Committee (henceforth "CEA/MM Analysis").

[25] CEA/MM Analysis at 58–59.

9/3/2019.[26] Reviewing the underlying data, there were 6.8 total hours (counting fractional hours), which equates to an average of 2.27 hours/year during the test period.

64. After subtracting out its estimate of the historical scarcity premium in historical day-ahead LMPs, Concentric then adds back its estimate of the future scarcity premium. "The Energy/Reserve Scarcity adder for each CONE unit was based on the expected number of scarcity hours that the ISO system would experience at criterion, which is assumed to be 11.3 hours. With these assumptions, the Energy/Reserve Scarcity adjustment is $0.874/kW-month for the combined cycle and $0.923/kW-month for the simple cycle and aeroderivative."[27]

*VI.2 The Development of the MRI Curve*

65. While the ISO's filing would have the Commission believe that the only relevant point on the demand curve is the point represented by the price of Net CONE and a quantity of Net ICR [28], what makes ISO's approach unique among Regional and Independent Transmission Operators in the United States s is that every point on the demand curve has economic meaning. By construction, consumers are collectively indifferent to any price-quantity pair traced out by the MRI curve. That is, as the capacity quantity increases along the MRI curve, the cost of additional capacity is offset by the reduction in the cost of expected energy not served. In addition, consumers also get the benefits of lower energy costs as the quantity of cleared capacity increases. Thus, *total* earnings from *all* markets is the relevant metric—which is why the capacity price at Net ICR is set equal to Gross CONE less net E&AS margins, estimated at for a capacity-balanced system:

$$[1]\ Capacity\ Price\ (Net\ ICR) = Gross\ CONE - E\&AS\ Offset\ (Net\ ICR)$$

66. At capacity supply above or below Net ICR, not only does the marginal reliability value of the marginal resource change but consumer's energy cost benefits (proxied by the E&AS offset) also changes. All other things equal, increasing the capacity supply reduces expected net E&AS margins, and *vice versa*. Thus Equation 1 above generalizes to Equation 2:

$$[2]\ Capacity\ Price\ (Q) = (Gross\ CONE - E\&AS\ Offset\ (Q)) \times \frac{MRI(Q)}{MRI(Net\ ICR)}$$

[26] *Ibid* Table 27, p.59.

[27] *Ibid* p.62.

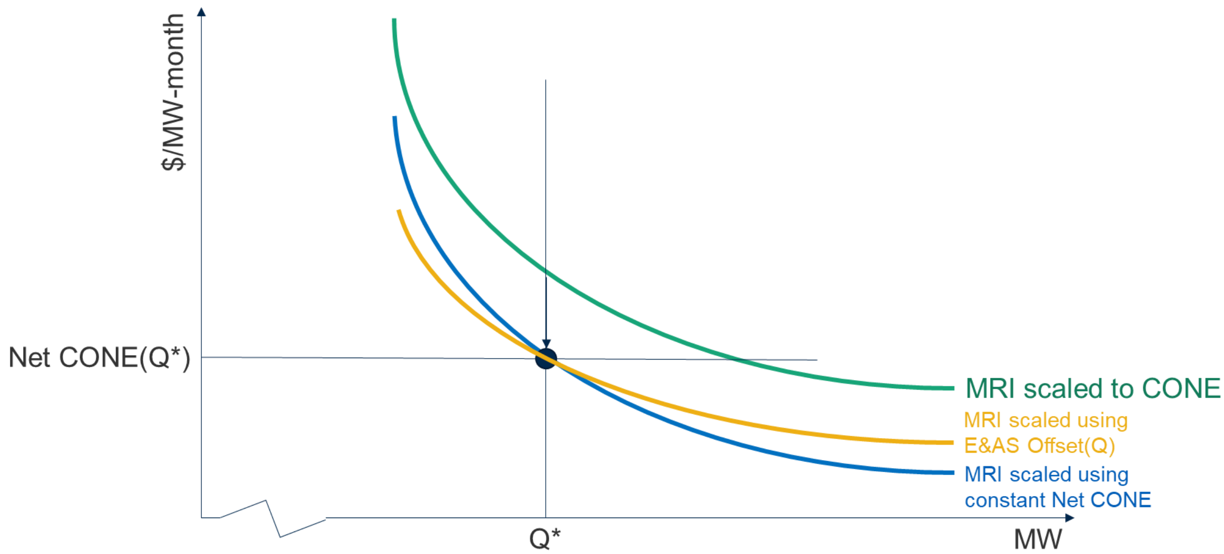
[28] ISO submittal at 29-30.

67. When Equation 2 holds, consumers are assured that the marginal resource's costs and reliability value and energy cost benefits are in balance. Suppose, hypothetically, that an existing generator anticipates requiring a significant investment to continue reliable operations in the future. For the owner to justify this capital outlay, it calculates it needs to earn $5/kW-month on average afterwards. The owner is indifferent, of course, as to which market supplies this revenue; it estimates, though, that the resource will earn $2/kW-month from E&AS margins, so it bids the capacity into the FCA at $3/kW-month. Suppose as well that, at the current surplus capacity supply level, the economic value of the MRI is $5.01/kW-month. Like the supplier, consumers are indifferent as to which market charges them this cost. In this example, the optimal outcome is for consumers to pay $3/kW-month in capacity payments to the supplier to fund the capital upgrade rather than to allow that resource to retire (assuming that they, like the supplier, expect to also pay $2/kW-month in net E&AS margins to the resource). If the capacity price is set using Equation 2, this condition is satisfied.

68. In contrast, ISO proposes a set of capacity prices that do not follow Equation 2 but rather a similar but importantly different version, Equation 3:

$$[3]\ Capacity\ Price\ (Q) = (Gross\ CONE - \ E\&AS\ Offset\ (Net\ ICR)) \times \frac{MRI(Q)}{MRI(Net\ ICR)}$$

69. The key difference between Equations 2 and 3 is the treatment of the E&AS Offset. Following Equation 2, the actual expected net E&AS margin is considered for each value along the demand curve and subtracted from the Gross CONE scaled by the relative MRI. In Equation 3, however, net E&AS margins are only evaluated at capacity balance (Net ICR), and both the reliability value and this margin are then scaled using the MRI curve. While this approximation is at least directionally correct (*i.e.* the implied net E&AS margin decreases as capacity supply increases), there is no compelling reason to use this approximation to understand the economic meaning of points on the demand curve away from Net ICR instead of relying directly on the ideal form, Equation 2. Figure 1 below shows how this gap may look in practice. Equation 2 is in yellow and Equation 3 is in blue.




70. With the adoption of MRI-based demand curves in 2016, the market design embraces the idea that the FCM should be able to support any level of capacity surplus or deficiency, depending on the marginal cost of capacity resources. Capacity suppliers will bid their resources into the FCA at their expected costs net of their expected net E&AS margin—given *actual* conditions in the market, not at some notional supply balance. If the capacity demand curve is drawn using Equation 3, as ISO proposes, the imbedded assumption of net E&AS margins differs from market expectations, and an inefficient quantity of capacity will clear. Referring back to the example above, if the implied net E&AS in the demand curve is $2.25/kW-month, rather than the $2/kW-month the supplier expects based on current market conditions, then the capacity price would be only $2.75/kW-month, insufficient to retain that resource.

71. It is more challenging to estimate net E&AS margins as a function of the installed capacity, rather than as a single, constant value. Nonetheless, it is not a difficult task if ISO had used the same sophisticated power system models it routinely uses for its system studies and studied a handful of simulations around the reasonably expected capacity balance in the three years covered by this Net CONE update. Short of this modeling approach, ISO could simply use an estimate of net E&AS earnings *without* a Level of Excess adjustment, working on the assumption that historical capacity supply margins are the best estimate of future near-term capacity supply margins.

72. The consequence of using Equation 3 rather than Equation 2 or a version of Equation 3 where the EAS offset is based on the expected clearing quantity to develop the demand curve is that the methodology is underestimating the correct demand curve at the point

the market is likely to clear – thereby inducing inefficient retirements. The design of the demand curve, as accepted by FERC, is supposed to explicitly consider the tradeoffs of capacity price and reliability and energy cost benefits at all points on the curve. By not properly estimating the curve at other points, the demand curve is fundamentally underestimating the value of reliability which will prevent the market from operating as designed.

*V.3 LAI Analysis of Technical Capabilities of Reference Unit*

73. In their affidavit[29], Sara Wilmer and Richard Levitan detail technical engineering requirements for the Reference Unit and the gas pipeline system that show that:

- The unit as detailed cannot operate without the addition of a gas compressor
- The fuel availability in ISO-NE means that without gas transportation system upgrades (not included in the calculation of CONE) gas will not be available for generation and instead the unit will have to use high cost ULSD as its fuel
- Without the gas transportation upgrades, the Reference Unit will not be able to participate in the FRM market which provides a significant amount of its revenue in the E&AS offset calculation

74. Furthermore, as explained in Mr. Stoddard's affidavit, even ignoring the technical requirements identified by Ms. Wilmer and Mr. Levitan, ISO-NE's adjustment to restate historical energy prices to a hypothetical system at capacity balance unreasonably reduces Net CONE. This impact identified by Mr. Stoddard results in an additional $0.21/kWm impact to Net CONE.

75. The analysis focuses first on the net energy earnings projected for the reference resource. ISO-NE's process imbeds multiple flaws identified by Ms. Wilmer, Mr. Levitan, and Mr. Stoddard. Concentric has provided the full spreadsheet model they used to compute energy earnings, and so it is straightforward to rerun their analysis while changing the assumptions around market participation, fuel availability for the Reference Unit, and the level of excess adjustment.

76. First, since there are no gas transportation system upgrades included, the Reference Unit requires gas compression to be able to operate without unbalancing the gas system. This gas compression adds parasitic load to the unit which reduces Net CONE by $0.23/kWm.

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[29] *See* Wilmer/Levitan Affidavit at 6, 8-10.

77. Second, it is a well-known feature of the ISO-NE power system that high power prices are highly correlated to limits on gas availability. The Reference Unit was developed assuming dual fuel capability rather than a firm gas contract. The implication is that when gas is in shortage conditions, this unit will not be able to procure supply and will have to operate on Ultra Low Sulfur Diesel fuel ("USLD"). The Reference Unit was redispatched using ULSD when there were historical gas shortages on the pipeline that the Reference Unit is assumed to connect to. The USLD prices used were the U.S. Energy Information Administration's forecast of prices, plus a transportation adder and tax rate provided by Ms. Wilmer and Mr. Levitan. The result is a further reduction of $0.83/kWm.

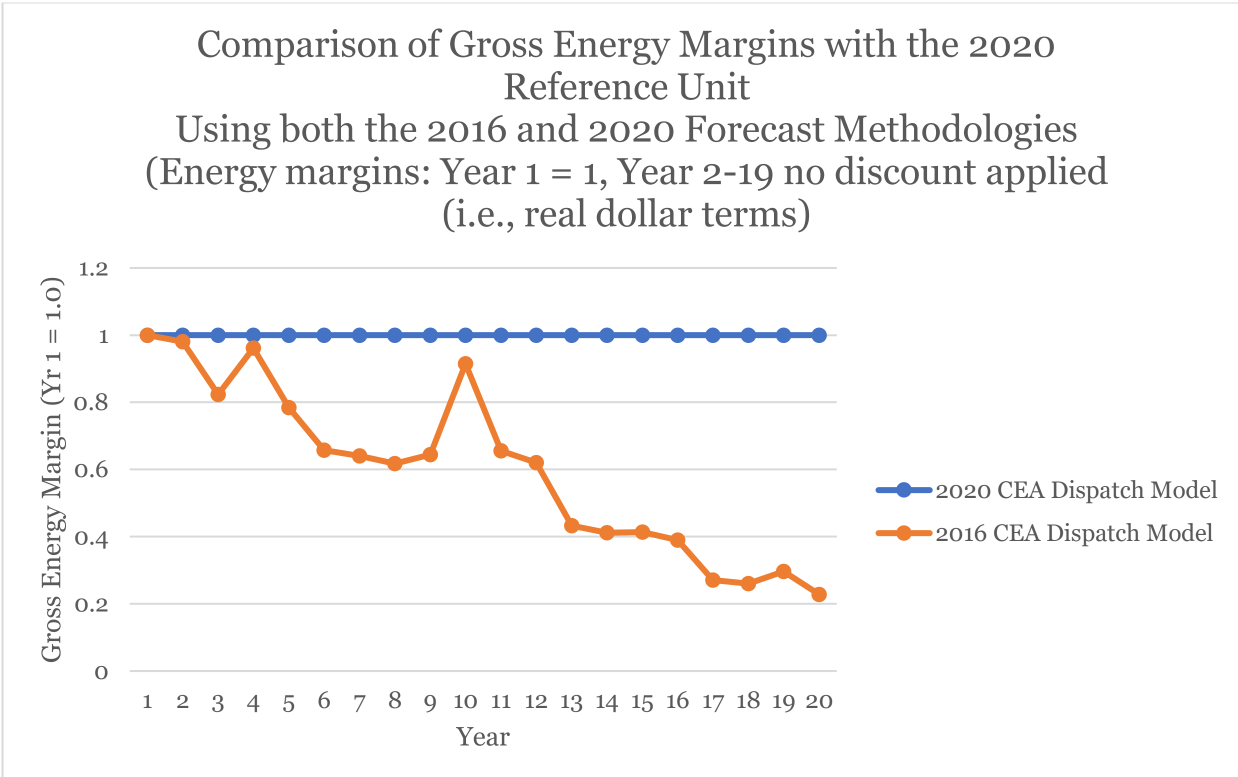
78. Third, Ms. Wilmer and Mr. Levitan show that it is not feasible for the project to participate in the FRM without gas upgrades. The financial impact of operating without an FRM contract is $1.20/kWm.

*VI. 4 Calculation of Impact of Long-term Resource Mix on E&AS Offset*

79. The impact of long-term resource mix changes *was* examined in the previous Net CONE reset. In the 2016/17 stakeholder process, Concentric developed a full 20-year model that sought to include a reasonable estimate of unit retirements and additions, including explicitly the addition of renewables (at both transmission- and distribution-level) to meet state policy objectives. State policy has become more ambitious in the interim, so this model provides a conservative estimate of the earnings impact to a gas-fired turbine in this dynamic environment.

80. To better align the Concentric's 2016/17 model with the current proceedings, the parameters of the modeled turbine were updated to match those of the proposed 2020 reference resource. The model was then rerun, restating the earnings in constant 2025 dollars.

81. The pattern seen in energy earnings is striking. First-year energy revenues are $2.04 million, but these quickly taper off to merely $0.46 million in year 20. Figure 3 below plots this decay over the study period, where each year's energy earnings is plotted as a percentage of the first-year earnings. For illustration, the chart also shows the 2020 assumption of constant energy earnings throughout the 20-year economic life of the reference resource.




82. As a way of scaling this impact on ISO-NE's current Net CONE estimate, a time series of energy earnings was used, starting with the Concentric estimate of $6.81 million in year 1 and then applying (multiplicatively) the 2016 study's pattern of erosion of energy earnings over the remaining 19 years. The effective first year energy revenues were then calculated by first computing the net present value of this series using a 6.14% discount rate (matching the discount rate in the 2020 Net CONE analysis) and then converting this NPV into a monthly payment and adding back in the ancillary services payments. The result was $0.19/kWm lower than the net E&AS offset calculated using a constant first-year energy earnings.

*VI.5 Calculation of Impact of Including the Reference Unit*

83. To calculate the impact of including the Reference Unit, I ranked hours by month, spark spread, and contribution to real-time energy gross margin and sampled hours from the highest margin contribution intervals to evaluate them in detail.

84. For these sampled hours I retrieved the actual real-time offers from the ISO-NE website, organized and ranked the offers starting with "must run" resources and ranked the segments in ascending price. Next, I retrieved the actual, final hourly LMPs for the sampled hours and located the marginal resource by cross-referencing the final hourly LMP energy component with the ranked incremental energy offers. Next I inserted the

Reference Unit into the supply stack and selected a new marginal resource where the cumulative megawatt quantity of supply offers from the actual stack and adjusted stack were equal. I then calculated the difference in the energy offers between these two stacks and reduced the real-time LMP in the ISO-NE Net CONE dispatch model by that magnitude to approximate the percent reduction in real-time energy gross margin caused by including the Reference Unit in the supply stack.

85. Based on those sampled hours' percent contribution to the overall Reference Unit's real-time energy gross margin for the Reference Unit, I applied a weighting factor to the percent reduction derived in the previous step. Summing the weighted reduction for the sampled hours yields an approximation of the overall impact to the real-time energy gross margin for the Reference Unit. The 18% reduction applied to the only real-time energy gross margin reduced the overall E&AS by a further $0.08/kWm.

*VI.5 Impact on Net E&AS Revenues from Scarcity Hour Assumptions*

86. Although the impact on Net CONE created by the implausible increase in scarcity hours cannot easily be calculated exactly, a conservative estimate of this impact can be provided. There are two sources of net E&AS revenue linked to scarcity hours: the impact of the RCPF DEFINE on LMPs and the expected earnings from the Pay for Performance mechanism. The CEA/MM Analysis values these two components at $0.923/kW-month and $1.100/kW-month, respectively, for a total reduction from Net CONE of $2.023/kW-month.[30]

87. With regard to the effect of the RCPF on LMPs, as noted above, Concentric's estimate of Net CONE calculated this $0.923/kW-month adder because it assumed 11.3 hours of scarcity pricing in all future years. If instead one applies Concentric's 2016 pattern of scarcity hours, with 6 scarcity hours in the first four years and 11.3 hours thereafter, the adder would be lowered to $0.67/kW-month, a reduction of $0.13/kW-month. If one applies the historical average from the three-year study period of 2.27 hours/year to the first four years of the forward-looking analysis, the adder would be lowered to $0.58/kW-month, a reduction of $0.22/kW-month.

[30] Note that the CEA values do not take into account the time value of money and also are based on the nominal capacity of the Reference Unit. After accounting for these factors, the CEA values for Pay for Performance and Energy/Reserve Scarcity Pricing are $1.08/kWm and $0.80/kWm, or a combined impact of $1.88/kWm.

88. With respect to the PfP component, the same but-for analyses can be completed. Each hour of scarcity is expected to increase net payments to generators by $0.08/kW-month.[31] Thus in years with only 6 hours/year of scarcity, the PfP revenues would fall to $0.49/kW-month; under the historical average of 2.27 hours/year, PfP revenues would be only $0.19/kW-month. Capitalizing these four years into the 20-year cash flow model, I find that the PfP adjustment would be $0.93/kW-month with four years of 6 scarcity hours/year or $0.82/kW-month with four years of 2.27 scarcity hours/year.

89. These two scarcity-hour adjustments are additive with each other and with the adjustments to the LMPs discussed above. Thus, the total impact from restating all factors ranges from $0.28/kW-month (assuming 6 scarcity hours/year for four years) to $0.48/kW-month (assuming the historical average of 2.27 hours/year for four years).

[31] This figure is the difference between average actual performance rate (0.98) and the capacity balancing ratio (0.847), multiplied by the Pay-for-Performance Rate ($8782/MWh), then divided by 12 and by 1000 to express the product as a monthly per-kW rate. Note that $0.0973 ×11.3 = 1.100, matching Concentric's calculation.

**UNITED STATES OF AMERICA**
**BEFORE THE**
**FEDERAL ENERGY REGULATORY COMMISSION**

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|---|---|
| ISO New England Inc. | Docket No. ER21-787-000 |

**AFFIDAVIT OF MATTHEW W. TANNER**
**ON BEHALF OF NEW ENGLAND POWER GENERATORS ASSOCIATION**

I, Matthew W. Tanner, under penalty of perjury, state that the contents of the foregoing Affidavit on behalf of the New England Power Generators Association are true, correct, accurate and complete to the best of my knowledge, information and belief.

______________________________
Matthew W. Tanner