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# Attachment A

# Affidavit of Robert B. Stoddard on Behalf of the New England Power Generators Association, Inc.

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

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| New England Power Generators Association, Inc.<br><br>v.<br><br>ISO New England Inc. | Docket No. EL21-___ |

**AFFIDAVIT OF ROBERT B. STODDARD**
**ON BEHALF OF THE NEW ENGLAND POWER GENERATORS ASSOCIATION, INC.**

I, Robert B. Stoddard, depose and say:

## *I. Qualifications*

1. My name is Robert B. Stoddard. I am an economist and a managing director of Berkeley Research Group, LLC in its offices at 1800 M Street NW, Washington DC 20036. Until 2013 I led the energy practice at Charles River Associates, another global consultancy. My consulting work focuses on electricity industry restructuring, capital investment in power markets, and providing both strategic analyses and testimony for utilities, generation owners, and governments regarding the practical implications of market design. I have frequently testified to the Federal Energy Regulatory Commission (the "Commission") as well as to state utility commissions and legislatures on competitive market design, rates, and market power issues, particularly in the regions managed by the northeastern Regional Transmission Organizations. Related to this docket, I represented the Capacity Suppliers, a coalition of owners of New England generation, in the litigated Locational Installed Capacity Market proceeding.[1] I subsequently represented generation interests during the settlement proceedings to that case that resulted in the original design of the Forward Capacity Market ("FCM"); ISO New England Inc. ("ISO" or "ISO-NE") included my expert affidavit in its filing in support of the settlement. I served in a similar role in the near-contemporaneous development of the Reliability Pricing Model ("RPM") for the PJM Interconnection, L.L.C. ("PJM"). As shown in my full curriculum vitae, attached as Exhibit

[1] *Devon Power LLC et al.*, FERC Docket No. ER03-563-03.

B, I have continued actively assessing the success of these market designs and working for continuing improvements. I hold degrees in economics from Amherst College and Yale University.

## *II. Purpose and Summary*

2. I have been asked by the New England Power Generators Association ("NEPGA") to explain how the methodology for determining the net cost of new entry ("Net CONE") put forward by ISO New England Inc. ("ISO") and its consultants Concentric Energy Advisors ("CEA") diverges significantly from the requirements of ISO's Transmission, Market and Services Tariff ("Tariff") and from its prior practice and filings with the Commission.[2] I will also show that ISO's failure to follow its Tariff has a material effect on the value of Net CONE it is expected to file with the Commission later this month. Speaking at the request of NEPGA, I have raised these issues repeatedly at NEPOOL Markets Committee meetings since June, highlighting the market design issues raised by ISO's new approach and urging ISO to return to a reasonable approach that implements the clear language of the Tariff.

3. 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. From this, ISO subtracts an estimate of the profit margin that such a resource is likely to earn from sales of energy and ancillary services ("net EAS revenue") and other market revenues or penalties. Therefore, the estimate of net EAS revenues has a one-for-one impact on Net CONE and, consequently, a material impact on the outcome of the FCA.

4. Net CONE is a relative newcomer to the FCM design. In the original design that I helped forge, the demand curve was vertical at Net ICR, and the entire concept of Net CONE is absent. In 2014 ISO proposed to implement a demand curve beginning with the Forward Capacity Auction conducted in February 2015 ("FCA 9").[3] That filing established a sloped demand curve for the FCA as well as the values of the key parameters needed to implement it, including Net CONE, and a requirement to update these parameters triennially. In 2016, ISO filed to improve the shape of the system demand curve and to implement zonal

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[2] I is not my purpose here to discuss the flaws of the particular value for Net CONE that ISO will file, which I expect to explore in an affidavit responding ISO's filing anticipated later this month.

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

demand curves.[4] Also during 2016, but filed in 2017, ISO and stakeholders developed and filed the first triennial update to Net CONE.[5] During the course of 2020 the NEPOOL Markets Committee has been reviewing materials from ISO and its consultants for the second triennial update filing.

5. ISO's Tariff provides a clear definition of Net CONE: "Net CONE is an estimate of the Cost of New Entry, net of the first-year non-capacity market revenues, for a reference technology resource type and is intended to equal the amount of capacity revenue the reference technology resource would require, in its first year of operation, to be economically viable given reasonable expectations of the first year energy and ancillary services revenues, and projected revenue for subsequent years."[6] This definition was established in 2014 with the Demand Curve Design Filing and governed the initial Net CONE estimate and its first triennial update. ISO has failed to bring to the stakeholder meetings any proposal that is consistent with this requirement or any reasonable replacement rate.

6. ISO's proposed methodology 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. 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 inherent contradiction between the Tariff's requirements and ISO's proposed net EAS revenue methodology.[7] Specifically, the Tariff requires that Net CONE reflect reasonable estimates of first-year revenues and reasonable estimates of subsequent years' revenues. ISO does neither. Its new approach studies only one year, 2025; to model this one year, ISO did not even attempt to model conditions that are reasonably likely to prevail in that year. Nor has it studied how those revenues are likely to change over the subsequent economic lifetime of the proposed reference resource, despite known and likely transitions in how New England states generate electricity. Consequently, this estimation process is fundamentally flawed and inconsistent with the clear requirements of the Tariff.

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[4] *ISO New England Inc. and New England Power Pool Participants Committee*, Docket No. ER16-1434 (filed April 15, 2016) ("Demand Curve Improvement Filing").

[5] *ISO New England, Inc. Filing of CONE and ORTP Updates*, Docket No. ER17-795-000 (filed January 13, 2017). ("2017 CONE Update Filing")

[6] Tariff, Section I.2.2 (Definitions).

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

7. The impact of ISO's failure to follow its Tariff and instead to adopt an unreasonable approach to estimating Net CONE is significant. As I detail below, ISO's adjustment to restate historical energy prices to a hypothetical system at capacity balance trims about $0.21 per kW/month from Net CONE. Its failure to consider the likely erosion of these revenues as the resource mix on the New England system shifts over time is a more substantial effect that understates Net CONE by about $0.37 per kW/month. Its implausible assumption about scarcity hour frequency reduces Net CONE by at least another $0.29 per kW/month. Taken together, this modeling approach biases the Net CONE estimate downward by at least $0.812 to $1.022 per kW-month.[8]

8. This price suppression is "bias," not "error." 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 EAS net revenues above market expectations. Ignoring future LMP declines caused by the introduction of highly efficient combined cycle plants that have obtained either commercial operation or a Capacity Supply Obligation, the increasing role of zero-bid renewable energy generators, storage, and retirement of the highest cost units is also a one-sided adjustment. While all "reasonable estimates" will be erroneous, to a greater or lesser degree, an estimation process that has clear and substantial biases cannot be judged reasonable.

## *III. Methods ISO-NE Used to Calculate Net CONE in 2014 and 2017 Filings Aligned with the Tariff and Best Practice*

9. The Tariff's requirement to estimate Net CONE based on "reasonable expectations of the first-year energy and ancillary services revenues, and projected revenue for subsequent years" is a familiar task to anyone responsible for making a capital investment. Developing estimates of top-line revenue and cost-of-goods-sold are critical steps in any *pro forma* financial business model, whether one is considering buying a flower shop or a power plant. Consequently, power industry investors approach this important task thoughtfully and have, over the course of decades, evolved best practices to do so.

10. Broadly speaking, there are two approaches that commercial entities would consider using to estimate future net EAS earnings for a new or existing power plant. The first approach is to use forward prices from the market to project historical earnings into the future. ISO's consultants in the 2014 Demand Curve Design Filing, Dr. Newell of The Brattle Group ("Brattle") and Mr. Ungate of Sargent & Lundy, took this approach. Another standard

[8] The impacts are cumulative multiplicatively, not additively, hence the sum of their impacts is smaller than either impact separately.

approach is to use a market simulation model to forecast the future evolution of a power market and the resulting earnings to a particular generator. ISO's consultants, Concentric Energy Advisors ("Concentric"), used this latter approach in the 2017 CONE Update Filing. I have personally used both approaches to execute professional assignments. While there are pros and cons to each, both are grounded in the facts of current conditions and reasonable expectations as to how those conditions will change over the course of the investment horizon.

11. It is helpful to understand how these two approaches were applied in ISO's prior Net CONE filings to give context to the unfiled, proposed approach that ISO has supported through the recent stakeholder meetings for measuring EAS margins, including the scarcity hours premium.

*III.A. Net CONE Modeling in 2014*

12. The 2014 Brattle approach to computing net revenue offsets is described in their affidavit filed with the Demand Curve Design Filing. In summary, they "calculate the first year EAS margins for each candidate reference technology using historical margins for similar plants adjusted for differences in electricity prices indicated by available futures settlement prices." (pp-48-49)

- "We first identify existing units that are similar to our candidate CC and CT technologies for calculating historical EAS margins."
- "Next, we estimate the EAS margins the representative units earned from October 2011 through September 2013, which is the most recent three-year period for which all input data needed for our calculation was available." This estimate used settlement data from ISO, contemporaneous fuel and emissions costs, and Sargent & Lundy's estimates of variable O&M costs. Brattle adjusted these margins to account for heat-rate differences between the actual unit and the reference resource.
- "We then adjust historical margins for differences between historical on-peak prices and on-peak futures settlement prices, for two reasons: (1) to normalize the idiosyncratic market conditions that may have occurred in historical years, thus adding stability to the Net CONE calculation and improving the demand curve's performance; and (2) to reflect future market conditions. ... We project electricity prices at Mass Hub using futures settlement prices from ICE [the

Intercontinental Exchange]" for 2018, the first year of the first Capacity Commitment Period covered by the filing.

- "Finally, we consider the expected impact on revenue offsets of the proposed Pay for Performance (PFP) market rules and the Peak Energy Rent (PER) deduction on Net CONE. …. Both of these values are calculated based on an assumed number of scarcity hours (H) consistent with analysis ISO-NE conducted and our consideration of forward market heat rates."

13. Brattle examined the resulting net margin for a single year, 2018/19, which was the first year of the Capacity Commitment Period covered by ISO's filing. Thus, from the perspective of a resource participating in FCA 9, their estimate was a reasonable estimate of "the first year energy and ancillary services revenue" as required by the Tariff because it uses observable, tradeable market prices to estimate those revenues. ISO did not make any adjustment to the Brattle estimates in its filed rate.

14. Importantly, the 2014 Brattle Net CONE estimate recognized market conditions "as is" and not at some hypothetical capacity balance. In estimating revenues associated with scarcity hours, Brattle applied short-term market expectations to forecast the number of scarcity hours, a value that drives the other non-capacity market revenue offsets to Gross CONE, the Pay for Performance and scarcity energy net revenue forecasts.[9] In considering how to reconcile an ISO forecast of 21.2 hours (at criteria) against an historical average of only 3 hours, Brattle observed an implied declining heat rate in ICE energy and gas futures, and concluded that "declining market heat rates are hardly consistent with anticipating a large increase in scarcity hours, from the 3-hour recent historical average."[10] Based on its analysis of future market heat rates, Brattle adopted a forecast of 5.8 hours of scarcity for the purposes of computing Net CONE in 2014, only about one-quarter as many scarcity hours as ISO estimated would occur with capacity at criterion.

### *III.B. Net CONE Modeling in 2016/17*

15. In the first triennial update of Net CONE (developed with stakeholders in 2016 and filed in 2017), Concentric and ISO opted to use a different approach to develop a reasonable expectation of future EAS earnings. As Concentric's report summarizes: "The process to estimate the Energy and Ancillary Services ("EAS") offset for each candidate reference

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[9] ISO-NE Filing Demand Curve Changes, Testimony Samuel Newell and Kathleen Spees on behalf of ISO-NE Regarding a Forward Capacity Market Demand Curve at 59-60.

[10] *Id*.

technology consisted of three primary steps. First, in order to estimate energy revenues, a 20-year forecast of locational marginal prices ("LMPs") for the [relevant] load zone was developed via simulation. Second, revenues earned from participation in wholesale markets were estimated based on a projection of Ancillary Service ("AS") payment rates, the LMP forecast, and the variable expenses and operating characteristics of each resource. Third, cash flows from the sale of energy and AS were levelized using the financial model described in Section E."[11]

16. At the core of Concentric's analysis in 2016 was a simulation model, AURORAxmp, a widely respected commercial model. Like all such models, the robustness of its outputs depends on the quality of the inputs. Here, too, Concentric used reasonable sources for all the data inputs, including gas prices, emissions costs, loads, and growth in behind-the-meter solar. A key challenge in long-term market forecasting is the modeling of the evolution of the generators on the power grid. Concentric addressed this reasonably: it modeled entry of resources already cleared in a prior FCA, developed an estimate of new renewables that will be added in response to state environmental policies, and finally added new gas-fired generation as needed to maintain a 15 percent capacity reserve margin.[12] Thus—in stark contrast to ISO's new methodology—in its 2016 work Concentric modeled the system with the capacity surplus that was reasonably expected at the start of the period and then allowed the supply stack to evolve towards capacity balance. This approach is consistent with the Tariff definition because it made a considered appraisal of future unit additions and retirements based on all available evidence and then, when projected supply fell below the capacity requirement, Concentric reasonably assumed that the capacity market would successful bring forward enough capacity to meet that requirement. It did not, however, force the system into capacity balance in *every* year of its analysis because doing so would have been inconsistent with known facts and reasonable expectations.

17. In 2017, ISO-NE forecast future LMPs based on several expectations of changes in system and market conditions, including forecasts of delivered gas prices, emission allowances for carbon dioxide, load growth, plant additions and retirements, and future transmission additions including those to import energy from neighboring control areas.[13] For example,

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[11] 2017 Net CONE Update, Attachment 1 (the "2017 Net CONE Report"), p. 49.

[12] *Ibid.*, pp 54-56.

[13] 2017 Net CONE Report at 49. Cite to Stoddard affidavit.

Concentric applied the following adjustments to its energy and real-time reserves forecasts used in the 2017 Net CONE Update:

- Gas price adjustments based on industry forecasts, including a Massachusetts Supreme Court decision voiding EDC authority to contract for the Access Northeast project,[14] and several gas pipeline upgrades expected to be in-service in the future;[15]
- Adding new entry and retiring resources from the assumed energy and reserves markets supply stacks based on their expectations of when they would occur over the course of the 20-year forecast, including adding new wind resources to account for the negative impact on load growth due to behind-the-meter solar, adding new gas resources to maintain system reserve margins, the retirement of two nuclear resources at the expiration of their licenses, and modelled economic retirements;
- Forecast $CO_2$ allowance prices, modelling the Regional Greenhouse Gas Initiative (RGGI) regional budget for the power sector to obtain a RGGI participating state projection of $CO_2$ allowance prices in future years. [16]
- A load forecast based on ISO-NE's Capacity, Energy, Load, and Transmission report, which accounts for several forecast future conditions including incremental Passive Demand Response resources and behind-the-meter solar installations. [17]
- A transmission topology that added expected upgrades or merchant transmission project in their then-expected year of in-service, including the addition of a 1,000 MW transmission line between New Hampshire and Quebec "consistent with" Massachusetts legislation requiring contracting for land-based renewables. [18]

18. Concentric confirmed its intent in adjusting its forecasts based on expected changes in that it found "the objective of the CONE/Net CONE analysis is to calculate what a merchant developer would need to enter the market given reasonable expectations of future system conditions."[19] ISO's recalculation of Net CONE in 2017 therefore was consistent with the Tariff requirement to base the EAS Margins on reasonable expectations of first-year and future system conditions.

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[16] 2017 Net CONE Report at 52.

[17] CEA Report at 53.

[18] 2017 Net CONE Report at 58.

[19] 2017 Net CONE Report at 64.

19. Specifically, in 2016 Concentric examined how the New England system's condition was likely to be postured in the first year and, separately, each year thereafter. It then examined the reference resource's net EAS in each of these years, starting with years in which there was a capacity surplus and gradually converging to a capacity balance—while aging units retire and are replaced by new generators with lower or zero production costs. Although the *details* of Concentric's modeling were hotly contested by stakeholders, its general approach was entirely consistent both with commercial practice and the Tariff's definition of Net CONE as "reasonable expectations of the first year energy and ancillary services revenues, and projected revenue for subsequent years."

20. Neither ISO nor Concentric made any adjustment in the first triennial update of Net CONE to reduce the oversupply that was present in New England at that time, other than to model the system as evolving towards capacity balance over the 20 years it modeled. The last FCA covered by their work and by the associated Demand Curve Design Filing, FCA 11, cleared 35,835 MW of supply, 1,760 MW (5.2%) above Net ICR. Similarly, FCA 10 cleared 35,567 MW of supply, 1,416 MW (4.1%) above Net ICR, levels that are similar to the surplus supply in the most recent two FCAs. Concentric's modeling took that surplus as given and allowed the capacity balance to move back towards the Net ICR. So, while their estimated earnings in the later years of their modeling are at capacity balance, the initial years' earnings estimates for the reference resource were intended to model the system as it was reasonably expected to be in the first year of the reset period, that is, with surplus supply.

21. Additionally, Concentric purposefully adjusted the expected scarcity hours per year *downward* from the system at criterion scarcity hour forecast as the result of market fundamentals. Concentric forecast 6 and 11.3 scarcity hours for Years 1-3 and Years 4-20, respectively, by "review[ing] the most recent ISO NE projections of scarcity hours in New England" and "extrapolat[ing] a value of 6 hours of scarcity conditions per year over the next 3 years based on current excess capacity levels, and 11.3 hours over the balance of the forecast period."[20] Although one may question how Concentric arrived at 6 hours, in light of the very low number of historical shortage hours, the process used in 2016 explicitly recognized that first-year generator revenues (and revenues in some subsequent years) from Pay-for-Performance incentives and higher LMPs caused by a binding Reserve Constraint Penalty Factor would be lower than they would be on a system that was at capacity balance.

[20] 2017 Net CONE Report at 64.

## *IV. ISO'S APPROACH IN 2020*

22. In stakeholder discussions at the Markets Committee, ISO and Concentric have put forward a new approach to estimating net EAS 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 EAS margins with an emphasis on being transparent to stakeholders."[21] At the June meeting, we learned that Concentric had settled on an "approach that involves forward-looking adjustments to historical EAS price patterns, with both a DA and RT hourly dispatch model."[22] 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."[23]

23. To estimate the net EAS earnings for the purposes of estimating Net CONE, Concentric developed a simplified dispatch model for the reference resource based on historical LMPs and fuel prices in 2017-19. Because the 2020 reference resource 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.

24. This spreadsheet dispatch model was not run against the posted LMPs during the 2014–2017 study period. Instead, Concentric applied a scaling factor to historical LMPs called the Level of Excess Adjustment. This adjustment was designed to estimate what LMPs during study period *might have been* had there been no excess supply. These adjustment factors were developed through a four-step process:[24]

    - 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

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[21] 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>

[22] 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>

[23] *Id.*

[24] 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>.

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.[25] These LOE-adjusted 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, high on-peak hours (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-period, set the LOE Adjustment Factor to the ratio of the base case to the LOE-adjusted case. By construction, these factors will be less than or equal to 1.00. Divide historical LMPs by the appropriate LOE Adjustment Factor to yield the LMPs used in the spreadsheet model to estimate the net EAS revenues.

25. 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 …."[26] As Concentric states:

> Specifically, the Energy/Reserve Scarcity Adjustment sought to remove the impacts of administrative shortage pricing set by the Reserve Constraint Penalty Factor (RCPF), which is reflected in the historical prices during periods of scarcity. Scarcity pricing was then included as a separate adjustment based upon the expected number of scarcity hours being modeled, as described further below. Given that the RCPF only affects prices in the real-time market, a comparable adjustment had to be made to remove the expected impacts of

[25] Although the bid stacks are released to the public, Concentric used ISO-proprietary information to make this adjustment.

[26] 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").

energy and reserve revenue scarcity from the day-ahead LMPs. In an efficient market, the day-ahead and real-time prices converge in expectation, and in equilibrium the expected impact of real-time energy and reserve scarcity would be reflected in day-ahead LMPs.

The total market impact of the RCPF during the 2016-2019 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 yields in the day-ahead market, 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). [27]

26. Concentric provides a table showing 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 9/3/2019.[28] Reviewing the underlying data, there were 6.8 total hours (counting fractional hours), so an average of 2.27 hours/year during the test period.

27. 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."[29]

## *V. ISO's New Approach is Inconsistent with Prior Practice*

28. ISO's new approach that I describe in the prior section is a significant departure from the methodology used in ISO's 2014 and 2017 filings and with ISO's approach to economic studies conducted for other purposes.

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[27] CEA/MM Analysis at 58–59.

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

[29] *Ibid* p.62.

29. The new approach is superficially akin to the Brattle method of 2014. Each starts with an estimate of the hypothetical earnings of the reference resource in a historical three-year study period: Brattle used ISO-proprietary data on unit margins and adjusted these to align with the efficiency differences between those operating units and the reference resource, while Concentric in 2020 uses a simply dispatch model to compute margins from a given set of LMPs. Both approaches also then restate that initial estimate of net EAS revenues to account for the fact that the historical study period is not wholly indicative of future periods. Brattle use on-peak and off-peak futures settlement prices for the future period under study to adjust historical earnings, while Concentric adjusts historical prices to remove the effect of excess supply on both the supply stack and scarcity pricing. Both approaches then assume that this point estimate carries forward for all future years.

30. Although both the 2014 and 2020 methods estimate the net EAS revenues by adjusting estimated historical earnings, the nature of those adjustments differ sharply. The Brattle approach makes two adjustments: one for heat-rate, and the other based on settlement prices from ICE. The first is uncontroversial and mechanistic. The second is unbiased and complete, inasmuch as the Efficient-Market Hypothesis states that asset prices reflect all available information.[30] Consequently, using these futures prices provides an unbiased, market-based estimate of LMPs and, consequently, net EAS market earnings, in the future. By contrast, neither of Concentric's adjustments to test-period prices reflect reasonable expectations of market participants. The Level of Excess Adjustment adjusts only for one factor in the market: excess capacity supply. And it deliberately departs from the Tariff requirement to model reasonably expected earnings to a hypothetical view of what the future *could* look like if all excess supply instantly vanished. It furthermore ignores the market's expectations about how numerous other factors affecting the New England region will also affect future earnings. For example, Massachusetts has approved contracts with Hydro Québec for 1,090 MW of "incremental firm power," and the New England states have approved contracts for 2,800 MW of offshore wind. These new, zero-bid sources of energy supply which will affect the supply curves in the relevant years but do not factor into Concentric's LOE Adjustment Factors. Concentric's Energy/Scarcity Adder assumes without support a quintupling of scarcity pricing hours in New England, from an historical average of 2 hours/year to 11.3 hours/year for every year of the reference resource's life, consequently adding a substantial premium to the net EAS revenues:

[30] Fama, Eugene (1970). "Efficient Capital Markets: A Review of Theory and Empirical Work". Journal of Finance. 25 (2): 383–417.

\$0.80/kW-month.[31] By contrast, for the 2014 filing the Brattle Group performed an independent analysis to forecast scarcity hours. They observed an implied declining heat rate in ICE energy and gas futures, and concluded that "declining market heat rates are hardly consistent with anticipating a large increase in scarcity hours, from the 3-hour recent historical average."[32] Brattle thus adopted a forecast of 5.8 hours of scarcity. While Brattle implicitly used *all* information in the market to adjust historical margins to reflect expected future market conditions, ISO's 2020 approach makes the crude assumption, untethered from reasonably expected future market conditions, that the New England system and the adjacent Control Areas commence at criterion and remain there for the reference resource's 20-year life.

31. The difference between Concentric's approaches in 2016 and 2020 are similarly stark. In 2016 they used a detailed, forward-looking production-cost simulation model, with each year of a long-term horizon modeled separately with a good-faith attempt to include all foreseeable factors in the market. One particular detail is worth noting: the reference resource itself was included in the model, thereby taking proper account of the negative impact on LMPs its operation causes. In 2020, however, this same consultancy shifts to estimating net EAS revenues for a single future year based on historical earnings and a single-factor adjustment that increases LMPs by excluding certain units. Unlike their study in 2016, this year Concentric did not make any adjustments for future load growth, generator additions, and various impacts of state environmental policies on load shapes, distributed resources, and demand for renewable energy, despite the fact that these issues are even more salient today than they were three years ago. For the 2017 filing, Concentric "extrapolated a value of 6 hours of scarcity conditions per year over the next 3 years based on current excess capacity levels, and 11.3 hours over the balance of the forecast period."[33] In 2020, notwithstanding nearly universal expectations that the system will continue to have substantial excess supply on at least the same scale as was anticipated in 2016, Concentric now uses 11.3 scarcity hours in its Energy/Scarcity Adder and its Pay-for-Performance revenue estimate; because they model only one year, the implication is that these 11.3 hours/year occur in every year.

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[31] The section of the CEA/MM Analysis I quote in P 26 implies that each hour of scarcity reduces Net CONE by \$0.082; hence increasing the number of scarcity hours from 2 to 11.3 (an increase of 9.3 hours) adds 9.3 ×\$0.082 = \$0.800.

[32] ISO-NE Filing Demand Curve Changes, Testimony Samuel Newell and Kathleen Spees on behalf of ISO-NE Regarding a Forward Capacity Market Demand Curve at 59-60.

[33] 2016 CEA Report , p.64.

32. Concentric acknowledges that its new approach is a break with its prior modeling.

> Based on experience gained during the 2016 CONE/ORTP re-calculation, Concentric determined that using a production cost model involved complex calculations for energy revenues that were not transparent to stakeholders given the significant number of inputs, outputs, and assumptions involved, and a blunt historical add-on for ancillary services revenues since production cost models are not capable of modeling co-optimized energy and ancillary revenues. Concentric considered a simplified price forecast and the use of historical prices and ultimately determined that an EAS estimation methodology based on adjusted historical prices would produce reasonable EAS offsets and would afford greater transparency to ISO-NE stakeholders."[34]

33. While transparency is important, following the Tariff is essential. Moreover, the asserted reasons for the change do not bear close scrutiny. The claim that "production costs models are not capable of modeling co-optimized energy and ancillary [services] revenues" is poppycock. While I am not personally familiar with the capabilities of the AURORAxmp model used by Concentric, AURORA's developer, Energy Exemplar, has a second similar product, PLEXOS, which my firm licenses. PLEXOS is able to "model [ancillary services and] reserve provisions that are co-optimized with generation dispatch and unit commitment down to a sub-hourly level."[35] Another production cost model we use, ENELYTIX, also "offers users full control in defining the scope, requirements for, and market procurement of, ancillary services. When combined with decision cycle modeling, users can explicitly value uncertainty in market operations, observed through a deployment of reserves and its impact on prices and costs."[36] The fact that production cost models require a "significant number of inputs … and assumptions" is a feature, not a bug: the future is dynamic, and pretending otherwise is inconsistent with the Tariff definition and inconsistent with ISO's prior practice.

34. Moreover, for the purposes of economic planning, ISO uses sophisticated production cost modeling, similar to Concentric's approach for the 2017 Net CONE update. It has never, to the best of my knowledge and belief, used naïve extrapolations of the past for substantive analysis of future conditions. For example, in 2019 the New England States Committee on Electricity—which is the Regional State Committee representing the New

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34 CEA/MM Analysis p.57.

35 Energy Exemplar, PLEXOS Features and Capabilities <https://energyexemplar.com/plx-features/>

36 ENELYTIX <http://www.enelytix.com/home/solutions>

England states' utility regulators in the NEPOOL process—requested that ISO evaluate the impact of various levels of off-shore wind development on the regional grid and markets. ISO used a production cost model to reach its conclusions. As ISO stated:

> The analyses were conducted using ABB's GridView economic-dispatch program. The program is a complex simulation tool that calculates least-cost transmission-security-constrained unit commitment and economic dispatch under differing sets of assumptions and minimizes production costs for a given set of unit characteristics. The program explicitly models a full network, and New England was modeled as a constrained single area for unit commitment.

35. This example is not a special case. ISO routinely uses a production cost model to assess the economics of potential changes on market operations and costs.[37] Its reliance in this matter on a crude proxy is therefore unreasonable and unwarranted.

36. The approach ISO adopted in 2020 also makes no attempt to make a realistic assessment of scarcity hours in 2025 or, indeed, any particular year. It simply assumes that the New England system and its adjacent Control Areas are at criterion throughout. ISO was clear that this was a deliberate choice of using a system at criterion rather than the outcome of a thoughtful analysis of the likely capacity balance in future years.[38] This approach is a sharp departure from its practice in 2014 (when 5.8 scarcity hours/year were modeled rather than the at-criterion value of 21.2) and 2017 (when 6 scarcity hours/year were modeled until the system naturally reached capacity criterion, rather than 11.3 hours/year in all years).

37. The Commission should dismiss any assertion by ISO that its approach to modeling net EAS revenues this year is essentially unchanged. In neither prior filing did Net CONE include any adjustment to account for capacity supply imbalances even when there had been persistent and substantial excess supply in the market. In prior filings ISO's consultants made thoughtful and unbiased adjustments to the current facts on the ground to adjust for reasonably anticipated changes in market conditions, while in 2020 no such

[37] For example, "2016 Economic Study:

NEPOOL Scenario Analysis" < https://www.iso-ne.com/static-assets/documents/2017/11/final_2016_phase1_nepool_scenario_analysis_economic_study.docx>; "2017 Economic Study: Exploration of Least-Cost Emissions-Compliant Scenarios" < https://www.iso-ne.com/static-assets/documents/2018/10/2017_economic_study_final.docx>, "2019 Economic Study: Economic Impacts of Increases in Operating Limits of the Orrington-South Interface < https://www.iso-ne.com/static-assets/documents/2020/10/2019-renew-es-report-final.docx>,

[38] See, *e.g.* ISO's July presentation to the Markets Committee, slide 5, referenced above in fn. 24.

adjustment to historical earnings were made except an naïve exercise to slice off surplus capacity. The differences between the current approach and prior filings are not minor; they reflect a thorough-going revision not only to the *methodology* of computing Net CONE, but to the underlying *philosophy* ISO used to compute Net CONE. As I discuss below, this new philosophy and methodology are inconsistent with the plain language of the Tariff and result in material bias to the resulting Net CONE value.

## *VI. ISO's NEW APPROACH IS INCONSISTENT WITH ITS TARIFF*

38. ISO's approach in stakeholder discussions is inconsistent with the express definition of Net CONE in the Tariff. In particular, throughout the stakeholder process, ISO has made clear that it is not seeking to model net EAS earnings, including scarcity hour earnings, considering the system as it actually sits today or as it is reasonably likely to evolve. Instead, ISO has sought to model a notional "at equilibrium" system, in which there is no capacity excess.

39. ISO's "at equilibrium" approach is irreconcilable with the express definition of Net CONE in the Tariff. ISO's Tariff provides a clear definition of Net CONE: "Net CONE is an estimate of the Cost of New Entry, net of the first-year non-capacity market revenues, for a reference technology resource type and is intended to equal the amount of capacity revenue the reference technology resource would require, in its first year of operation, to be economically viable given reasonable expectations of the first year energy and ancillary services revenues, and projected revenue for subsequent years."[39] Nowhere do the words "equilibrium" or "long term" appear in this definition. To the contrary, the Tariff states and then *restates* that the adjustment is based on "first-year … revenues" and, for further clarity, that these should be "reasonable expectations" of such revenues.

40. The only plausible understanding of these black-and-white words of the Tariff are that the "reasonable expectations" should be those held by reasonable potential investors in capacity resources in New England. It is, after all, such investors that ultimately choose whether and when to develop or retire capacity resources. As further evidence, the ISO stated in its filing letter to the Demand Curve Design Filing, in which this definition of Net CONE was added to the Tariff, that "[relatively] stable prices that reflect market fundamentals are more likely to encourage investor confidence and incent new entry when needed …."[40]

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[39] Tariff, Section I.2.2 (Definitions).

[40] Demand Curve Design Filing, filing letter, p.7

41. How do investors form reasonable expectations of future earnings? As a consulting economist I have worked with dozens of such investors evaluating scores of capital decisions. I have, therefore, a clear view of how those expectations are formed. First and foremost, rational expectations are based in considering facts comprehensively. If our investigation begins by looking at historical earnings potential, then investors will require an analysis of how known or near-certain changes—such as new facilities that began or ceased operation recently, are under construction, or are under long-term contract—will affect historical margins. So also, reasonable investors assess how government policies, customer procurement practices, and technological trends are likely to impact future earnings on their investment. In short, before committing hundreds of millions of dollars to build a new power plant, the investor will examine *all* the relevant facts and trends to develop a wholistic, reasonable expectation of the earnings flow from the investment.

42. ISO's approach throughout the 2020 stakeholder process has resolutely refused to take such a comprehensive and fact-based view of "reasonable expectations of first year energy and ancillary services earnings." ISO not only models a system that has a tighter capacity balance than is reasonably expected but also a very different mix of resources. During the test years, 2017–2019, new renewables and efficient gas-fired generators became operational, while other units retired. ISO's approach makes no attempt to adjust for this shifting mix of resources over the test years. Nor does ISO attempt to adjust for the mix of resources going forward or a host of other factors that are highly relevant to an investor in a hypothetical gas-fired power plant. Even if, implausibly, the New England system is in formal capacity balance in 2025, that system will look very different than the system in 2017, 2018 or even 2019. State laws mandate such change, and those changes have impacts on future earnings of gas-fired generators, regardless of the level of capacity balance.

43. ISO's approach errs both in commission and omission.

44. The error of commission arises from the unreasonableness of ISO's adjustment to historical LMPs to account for excess supply conditions during the test period. I describe this process above. It is not unreasonable to model the impact of unit retirements when those retirements are reasonably like. Any such adjustment to the supply stack, however, must also model new entry that is reasonably likely. On both fronts, ISO's adjustment fails.

45. With regards to retirements, ISO makes adjustment through the "Level of Excess Adjustment Factors" that it applies to this historical study period (2017-19).[41] Enough units were modeled as retired in each of the three test years to eliminate the historical levels of excess supply, which ranged from 340 MW in the 2016-17 capacity commitment period to 2,006 MW in the 2019-20 period. This approach implicitly models the system's future resource mix to be the same as the historical mix, excluding enough incumbent resources to eliminate the surplus that has historically cleared in the FCAs. The choice of which resources exits is, therefore, important. ISO's "retirement tracker" spreadsheet shows 2,744 MW of resources that meet ISO's criteria for candidates for removal from its model, e.g. non-intermittent generators that had operated throughout the 2017-19 test period and had filed a full delist bid.[42]

46. Modeling retirements alone, however, ignores the fact that substantial additions are reasonably expected before 2025. These omissions are not trivial. Between now and 2025, Central Maine Power intends to energize the new New England Clean Energy Connect high-voltage DC interconnect to Québec to import over 1,000 MW of contracted hydro power. Massachusetts has committed to contract for 6 GW of offshore wind by 2035, of which a significant portion has already been committed under Section 83C and 83D process and is expected on-line before or during the FCAs covered by this filing. Other states have also stepped up their commitments to expand renewable energy and storage. Five of the six New England states, with slightly over 90 percent of ISO's load, have statutory mandates for increasingly stringent Renewable Portfolio Standards.[43] Meeting these states' mandates will require substantial additions of renewable energy. Because these resources typically offer energy at or below zero, their addition will have a material impact on LMPs.

47. By failing to present any analytic foundation to calculate net EAS earnings reasonably in 2020, ISO has denied stakeholders the opportunity to debate what adjustments should be made to historical earnings. A model frozen in time aside from unrealistic retirement

[41] ISO, "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. 4-10. Available at < >.

[42] Summer Claimed Capability. This total also includes one "full substitution auction demand" request of 54 MW.

[43] State shares of retail sales of electricity from U.S. Energy Information Administration https://www.eia.gov/electricity/data/browser/#/topic/5?agg=0,1 ; RPS standards from North Carolina State University, NC Clean Energy Technology Center, DSIRE database (https://www.dsireusa.org/).

assumptions, simply cannot produce a reasonable estimate of first year net energy and ancillary services earnings.

## VI. *ISO's new Approach results in a material downward bias in its Net CONE estimate*

48. As I discuss above, the approach to measuring net EAS revenues for the purposes of Net CONE calculation are at odds with the express language of the Tariff. Furthermore, as I discussed above, my principal concern is that this novel methodology is not only *wrong* but *biased*. This bias is material, and the direction of the bias—towards lower Net CONE—has an asymmetrically harmful impact to the market.

49. While the direction of the bias—namely, to lower the estimate of Net CONE—is clear, quantifying the size of Net CONE suppression is challenging. Ideally I would have replicated the approach used in 2016/17 by ISO and Concentric, to calibrate a production cost model of the New England system, insert the reference resource, and calculate 20 years' worth of EAS earnings for that Resource. We did not take this approach for two reasons. First, it would have been costly. Second and more importantly, any results would have been open to challenge because, as Concentric correctly notes, any such model requires numerous inputs and assumptions. In a stakeholder process, these inputs can be reviewed, debated and agreed, but filed unilaterally, even the best modeling work may be uncompelling evidence.

50. Instead, I develop an estimate of the size of the bias ISO's approach introduces into its Net CONE estimate by using materials from Concentric, both in this year's stakeholder process and from the previous 2016/17 Net CONE reset. Although I do not agree with how Concentric chose to execute these models, they have been reviewed by all stakeholders and, in the case of the 2017 Net CONE estimates, underlay the values that the Commission found just and reasonable.

51. I focus first on the net energy earnings projected for the reference resource. ISO's process imbeds two flaws in direct contravention of the Tariff.

52. First, 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. (I discussed the details of this process in P 24 above.) While certainly some retirements can be reasonably expected, we also reasonably expect several new additions of both capacity resources and behind-the-meter generation, as I discuss in PP 45–46. Concentric has provided the full spreadsheet model they used to compute energy earnings, and so it is straightforward to rerun their

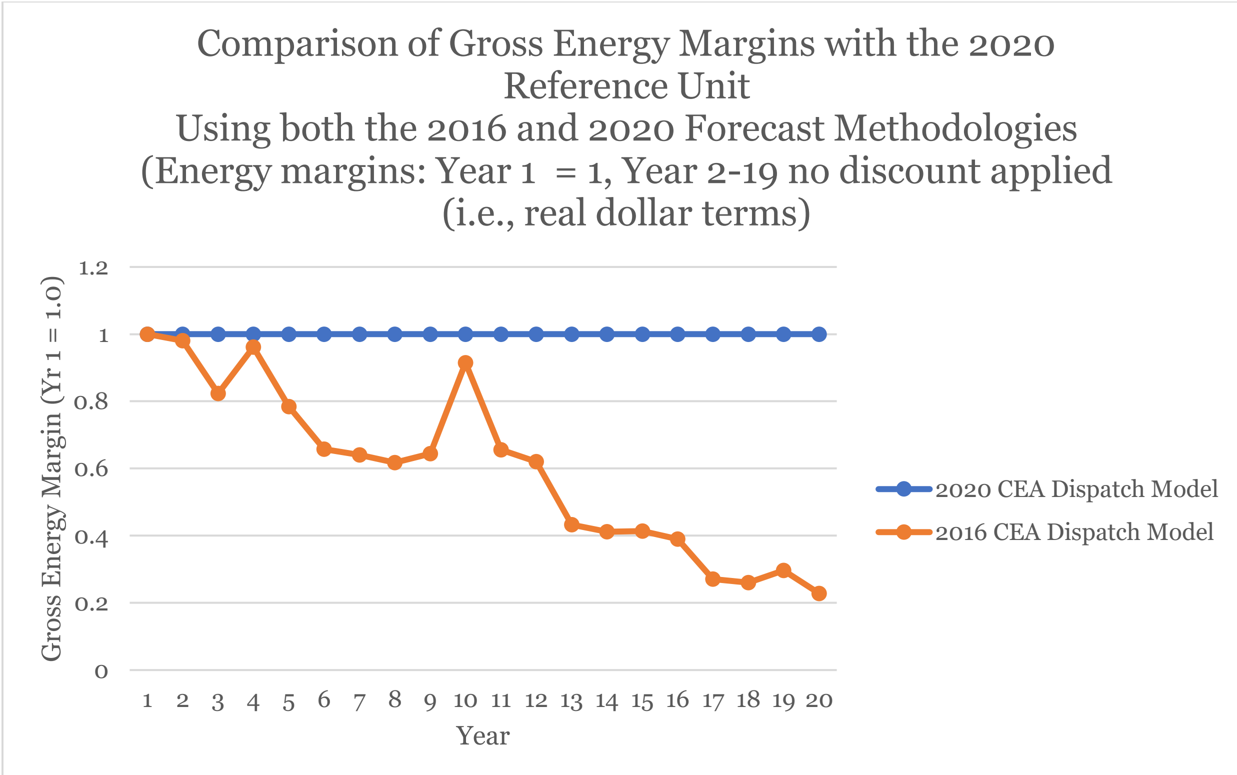
analysis without the Level of Excess adjustment. Without this adjustment, the estimate of Net CONE would be about $0.21/kW-month higher.

53. Second, the current process implicitly 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 to withdraw to bring the system into capacity balance. There has never been a period in the history of the New England grid where this assumption would have been sound. 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. The impact on future earnings of a gas-fired turbine from this transition to zero-bid intermittent resources will be profound, and yet remain unexamined by ISO this year.

54. Fortunately, this impact *was* examined in the previous Net CONE reset. As I discuss above, 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.

55. To better align the Concentric's 2016/17 model with the current proceedings, we updated the parameters of the modeled turbine to match those of the proposed 2020 reference resource. We then re-ran the model, restating the earnings in constant 2025 dollars.

56. The pattern we see 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. Chart 1 below plots this decay over the study period, where I plot each year's energy earnings 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.




57. As a way of scaling this impact on ISO's current Net CONE estimate, I constructed a time series of energy earnings, 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. I then calculated the effective net EAS offset 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. The result was $0.37/kW-month lower than the net EAS offset calculated using a constant first-year energy earnings.

58. Adjusting for *both* the impact of the artificial Level of Excess adjustment and the fictious constant-earnings assumption, the resulting net EAS offset is reduced by at least $0.53/kW-month. This figure is slightly less than the sum of the individual impacts ($0.21 and $0.37/kW-month, respectively) because these are multiplicative adjustments. Making this change would raise the estimate of Net CONE that Concentric has recommended from $7.02 to $7.55/kW-month, a 7.5% increase.

59. Although I cannot definitively value the impact on Net CONE created by the implausible assumption that scarcity hours quintuple from their historic levels, I can provide a conservative estimate of this impact. There are two sources of net EAS revenue linked to scarcity hours: the impact of the RCPF 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 Gross CONE of $2.023/kW-month.

60. 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 I apply 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 $0.791/kW-month, a reduction of $0.132/kW-month. If I apply 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 reduction becomes $0.225/kW-month.

61. With respect to the PfP component, I performed the same pair of but-for analyses. Each hour of scarcity is expected to increase net payments to generators by $0.0973/kW-month.[44] Thus in years with only 6 hours/year of scarcity, the PfP revenues would fall to $0.584/kW-month; under the historical average of 2.27 hours/year, PfP revenues would be only $0.221/kW-month. Capitalizing these four years into the 20-year cash flow model, I find that the PfP adjustment would be $0.943/kW-month with four years of 6 scarcity hours/year or $0.832/kW-month with four years of 2.27 scarcity hours/year.

62. These two scarcity-hour adjustments are additive with the each other and with the two adjustments to the LMPs discussed in PP 52–58. Thus, the total impact from restating all four factors ranges from $0.819/kW-month (assuming 6 scarcity hours/year for four years) to $1.022/kW-month (assuming the historical average of 2.27 hours/year for four years).

63. This range of estimates is conservative on several counts.

- First, as I noted earlier, the earnings decay reasonably foreseen in 2016 would now be considered optimistic in light of growing public demand for renewable energy resources, which tend to suppress energy prices in most hours.

- Second and related, I have not attempted to adjust earnings from reserves that the reference resource might sell. As a simple-cycle gas turbine, Concentric reasonably models it as receiving *all* of its reserve revenues either as ten-minute non-spinning

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[44] 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.

reserves or thirty-minute operating reserves. ISO has found, however, that these products are not what create value as renewables penetration increases: "This study also finds that ramping reserves and load-following reserves (LFRs) have a more significant impact on lowering system imbalances than [ten-minute spinning reserve]. … [F]urther study will evaluate alternate reserve products that have a monotonic (i.e., linear) relationship between the reserve product and system imbalances. Ramping reserves and load-following reserves have a monotonic relationship with imbalances, and further study could explore acquiring reserves to meet these reserve requirements"[45] Two conclusions follow: first, the asynchronous reserves that the reference resource can provide are not the sort of reserves ISO will need to integrate increasing volumes of renewables; and, second, that the reserve markets of today are unlikely to serve the region's need in the future. On both counts, high and constant ancillary services revenues should not be baked into Net CONE.

- Third, again related to the resource mix, Concentric has made no attempt to adjust for the changing resource mix within its 2017–19 test period. 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, also achieved 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 operation of the reference resource.

- Fourth, aside from the clumsy Level of Excess adjustment, Concentric made no attempt to adjust for new resources that are committed but not yet in service. These include the 2,601 MW (nameplate) of new generation that obtained a Capacity Supply Obligation in a prior Forward Capacity Auction 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 addition 110 MW of uncontracted capacity.

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[45] ISO, "2019 Economic Study: Offshore Wind Integration", June 30, 2020 < >

64. Although I do not have the ability to quantify the impact of these omissions, they all are directionally the same—namely, to result in lower earnings for a gas turbine in the future. Thus, adding these impacts to the already material $0.819-1.022/kW-month suppression I have been able to quantify underscores the seriousness of the failure of ISO to adopt a net EAS revenue calculation that comports with its Tariff.

65. This concludes my testimony at this time.

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

New England Power Generators Association, Inc.

v.

ISO New England Inc.

Docket No. EL21-___

**AFFIDAVIT OF ROBERT B. STODDARD**
**ON BEHALF OF NEW ENGLAND POWER GENERATORS ASSOCIATION**

I, Robert B. Stoddard, 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.

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Robert B. Stoddard