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

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| ISO New England, Inc. | )<br>)<br>) | Docket No. ER-19-1428-000 |

**COMMENTS AND PROTEST OF THE MASSACHUSETTS ATTORNEY GENERAL**

The Attorney General of the Commonwealth of Massachusetts ("Massachusetts Attorney General") submits these Comments and Protest pursuant to Rule 211 of the Federal Energy Regulatory Commission's ("Commission") Rules of Practice and Procedure and the March 25, 2019 Combined Notice of Filings #1. The Massachusetts Attorney General timely moved to intervene in Docket No. ER19-1428 on March 26, 2019.

On March 25, 2019, the Independent System Operator for New England ("ISO-NE") filed for Commission approval of revisions to its Transmission, Markets and Services Tariff ("Tariff") to implement a new inventoried energy program ("IEP" or "Program") for the winters of 2023-2024 and 2024-2025 ("March 25 filing").[1]

The Commission should not approve the March 25 filing because it will result in unjust and unreasonable rates. First, ISO-NE has failed to demonstrate that the IEP will benefit customers. Specifically, ISO-NE asserts that the IEP may provide two benefits:

- it may decrease the likelihood of power plant retirements and consequently, the need for additional cost-of-service agreements ("COSA"); and
- it may improve the region's winter energy security by compensating resources that maintain inventoried energy in the winter.

As addressed further below, these benefits are admittedly uncertain and most likely illusory.

[1] ISO New England Inc., Inventoried Energy Program Filing, *ISO New England Inc.*, Docket No. ER19-1428-000 (March 25, 2019) ("March 25 filing").

Second, ISO-NE has failed to demonstrate that the benefits of the program warrant its costs.[2] Any customer benefit from the IEP would be in the form of an insurance policy – customers paying a premium to increase winter energy inventories in case of extreme conditions. However, ISO-NE has failed to provide cost data that would allow the Commission to determine whether the benefits of this insurance policy warrant its costs. Indeed, the only price provided by ISO-NE, the "indicative price," demonstrates that the same winter energy security benefits can be bought for less money with more certainty. In short, if the Commission authorizes the IEP, customers will either be paying something for nothing, or they will be buying an insurance policy that they could purchase for less money.

Third, the IEP is likely to create more problems than it solves. It will interfere and perhaps, conflict with, current market programs. Moreover, while nominally "market-based," the IEP lacks evidentiary support and is predicated on numerous unsubstantiated, and subjective design elements, which will result in arbitrary and discriminatory rates. For the reasons that follow, the Commission should reject ISO-NE's March 25 filing.

## I. COMMUNICATIONS

Pleadings and other communications regarding this proceeding should be addressed to the following persons on behalf of the Massachusetts Attorney General:

Sarah Bresolin Silver
Christina H. Belew
Assistant Attorneys General
Massachusetts Attorney General Office of Ratepayer Advocacy
One Ashburton Place
Boston, MA 02108-1598
(617) 963-2380
sarah.bresolin@mass.gov
christina.belew@mass.gov

[2] *Advanced Energy Management Alliance v. FERC*, 860 F.3d 656 (2017) (increased costs can be "just and reasonable" if the costs are warranted).

## II. COMMENTS AND PROTEST

### A. Background

The March 25 filing is one in a series of filings arising from ISO-NE's on-going efforts to address what it has identified as fuel and energy security concerns in New England. On May 1, 2018, pursuant to Rule 207(a)(5), ISO-NE filed a petition for waiver of various provisions of its Tariff in order to permit it to retain, for fuel security purposes, the Mystic 8 & 9 generating units owned by Constellation Mystic Power, LLC.[3] At the time, the ISO-NE Tariff did not allow for retention of a retiring units for fuel security reasons.

On July 2, 2018, the Commission denied the waiver request but directed ISO-NE to (1) file interim Tariff revisions by August 31, 2018 that provide for the filing of a short-term, cost-of-service agreement to address demonstrated fuel security concerns; and (2) submit by July 1, 2019, permanent Tariff revisions reflecting improvements to its market design to better address regional fuel security concerns.[4] The Commission further stated that ISO-NE proposals to revise its Tariff "should include a mechanism that addresses how resources retained for fuel security (e.g., under costs of service agreements) would be treated in the FCM."[5]

On August 31, 2018, ISO-NE filed proposed tariff changes that, among other matters, allowed ISO-NE to retain resources for fuel security reasons and to use short-term COSAs for

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[3] ISO New England Inc., Petition for Waiver of Tariff Provisions, *ISO New England Inc.*, Docket No. ER18-1509-000 (May 2, 2018) ("ISO-NE Waiver Petition").

[4] *See* Order Denying Waiver Request, Instituting Section 206 Proceeding, and Extending Deadlines, 164 P 61,003 (issued July 2, 2018) ("Waiver Order").

[5] *See* Waiver Order at P 58. The Commission ordered that if ISO-NE chose to revise its Tariff "such proposal should include an *ex ante* cost allocation proposal for resources retained under fuel security cost-of-service agreements."

such resources.[6] ISO-NE also proposed that retained resources utilizing a COSA be entered into the Forward Capacity Auction ("FCA") as price-takers.[7,8]

While ISO-NE acknowledged in its August 31 filing that its price-taker proposal would result in lower FCA prices and would not appropriately compensate resources that provide both resource adequacy and fuel security, ISO-NE urged the Commission to approve the proposal. ISO-NE told the Commission that ISO-NE would find some other way to address the price suppressive effect of its price-taker proposal and ensure that a resource retained for fuel security purposes (i.e., a resource with a COSA) would not be the only resource getting compensated to provide fuel security.[9] ISO-NE would devise a new mechanism to value fuel security attributes and to pay the generators that provide these attributes. According to ISO-NE, the IEP is that mechanism.

As presented here, however, there is no direct discussion about addressing price suppression. Nor is there an attempt to value fuel security attributes. Instead, according to ISO-NE the purpose of the IEP is to pay resources to maintain inventoried energy in the winter in the hopes of preventing retirements and improving winter energy security.

### B. ISO-NE's Inventoried Energy Program

ISO-NE is concerned that the regional grid may lack reliability during occasional extended cold periods in the winter. The IEP aims to provide the incentive for resources to

[6] ISO New England Inc., Compliance Filing to Establish a Fuel Security Standard, *ISO New England Inc.*, Docket No. ER18-2364-000 (August 31, 2018) ("August 31 filing").
[7] *Id.*
[8] On December 3, 2018, FERC approved ISO-NE's proposed Tariff changes, including the price-taker proposal. *See ISO New England Inc.*, 165 FERC ¶ 61,202 (December 3,2018) ("December 3 Order").
[9] ISO-NE explains that because the "price-taker treatment fails to compensate resources that provide both resource adequacy and fuel security" it is committing to "identify an alternative that can be applied for FCA 14 and 15 … to assess [is] an incremental payment for resources that can help the region meet its fuel security objectives." August 31 filing at 17-18; *See also* Testimony of Christopher Geissler on Behalf of ISO New England, Inc., March 25 filing, Docket No. ER19-1428-000 at 23 ("Geissler Testimony").

maintain inventoried energy – fuel or potential energy that can be converted to energy on demand – during these cold periods. The IEP will provide incremental compensation to resources that hold onto their inventoried energy during cold periods. The Program is voluntary and permits resources to bid either a forward rate and spot rate, where the spot rate is applied to deviations between the megawatt hours ("MWh") of inventoried energy maintained and the MWhs sold forward, or a spot rate only. Payments will be made to participating resources based on inventoried energy measured on the day after a scarcity event. The scarcity event is triggered on any day in December, January or February where the observed average of the high and low temperatures is less than or equal to 17 degrees Fahrenheit measured at the Bradley International Airport in Windsor Locks, Connecticut. Resource compensation for inventoried energy is capped at 72 hours of inventoried energy on hand so that the Program is not compensating participants for inventoried energy that is unlikely to be used to improve winter energy security.

### C. Stakeholder Process and Vote

During the approximate five months of stakeholder process, there were roughly six meetings where participants discussed forward and spot rate model assumptions, eligibility of resources, including retained resources, trigger condition criteria, program cost estimates, and the Tariff revisions necessary to implement the IEP. Several participants offered amendments to ISO-NE's proposal in committee including limiting the types of resources eligible to participate in the IEP, expanding the number of resources eligible to include resources actually providing energy during trigger conditions, and finalizing the forward settlement rate closer to the FCA.[10] These amendments were not adopted by ISO-NE.

[10] Amendments submitted by Energy New England, LLC, Union of Concerned Scientists, and PSEG Energy Resources & Trade LLC respectively, *available at* https://www.iso-ne.com/committees/markets/markets-committee/?open_projects_value=Interim%20Compensation%20Treatment%20-%20WMPP%20ID:%20133.
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At the final vote, NEPOOL participants soundly rejected ISO-NE's IEP. Only 32.67 percent of participants voted in favor of the IEP.[11] A proposal must receive a 60 percent Vote in favor to pass. The only amendment offered by stakeholders for vote at the Participants Committee, the Energy New England motion to amend the main motion so as to narrow the categories of resources eligible for interim compensation for inventoried energy, failed to pass with a 39.58 percent Vote in favor.[12]

### D. Federal Power Act Section 205 Standard of Review[13]

In reviewing section 205 filings, the Commission must determine whether the proposed rates are just and reasonable.[14] The applicant bears the burden of justifying a proposed rate change.[15] As ISO-NE is filing Tariff revisions for Commission approval, ISO-NE bears the burden to demonstrate that its Tariff changes are just and reasonable.[16]

The primary aim of the Federal Power Act ("FPA") is the protection of consumers from excessive rates and charges.[17] Thus, the Commission is charged with protecting customers from excessive rate changes. Setting just and reasonable rates and developing new programs necessarily involves consideration of consumer interests and the balancing of these interest with others.[18]

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[11] IS-NE, *supra* note 1, at 28.
[12] *See* NEPOOL Participants Committee Notice of Actions, March 13, 2019, at 1-2, *available at* https://www.iso-ne.com/static-assets/documents/2019/03/npc_noa_20190313.pdf.
[13] 16 U.S.C.A. § 824d.
[14] ISO New England, Inc., 113 FERC ¶ 61,055 (2005), P 21.
[15] *Id.* at P 22.
[16] See *NorthWestern Corp.*, 155 FERC ¶ 61,158, at PP 27–29.
[17] *Xcel Energy Servs. Inc. v. FERC*, 815 F.3d 947, 952 (D.C. Dir. 2016) at PP 2-3.
[18] *NextEra Energy Resources, LLC, et al., v. FERC*, 898 F.3d 14 (2018), at P 4 (quoting *Wisconsin Pub. Power Inc. v. FERC*, 493 F.3d 239, 262 (D.C. Cir. 2007) (per curiam) (quoting *Federal Power Comm'n v. Hope Nat. Gas Co*., 320 U.S. 591, 603 (1944)); *New York Indep. System Operator, Inc.*, 122 FERC ¶ 61,064, at P 54.

### E. The Commission Should Not Approve the IEP Because Any Claimed Customer Benefits Are Admittedly Uncertain, and Likely Illusory.

*1. The IEP will not prevent retirements.*

ISO-NE admits that it cannot guarantee that the IEP will "deter any particular resource that would otherwise be economic from retiring."[19] Instead, ISO-NE states that the IEP "*should* [emphasis added] decrease the likelihood that such resources pursue retirement."[20] However, the IEP is unlikely to prevent resources from retiring because it does not provide resources with enough additional revenue to make an uneconomic plant economic. The IEP only provides incremental compensation for two winter seasons at a relatively modest rate. Expected compensation is so modest, that other factors are more likely to drive retirement decisions than this Program.

In his testimony, Mr. Griffiths explains why the program will likely prove inconsequential for generators considering retirements. The value of the IEP to a resource considering retirement must be assessed in the context of that resource's overall financial viability and expectations of how profits will change in the coming years. Plant operators face a complex calculus when deciding to retire a generating resource.[21] Given the long useful lives of most generating resources, longer-term expectations around these different market drivers are critical. Moreover, given substantial year-to-year variability in market revenues, changes in short-term revenues are unlikely to drive retirement decisions.

Mr. Griffiths provides retrospective estimates of capacity and energy payments for a sample of "marginal" resources -- such as nuclear, coal, and large oil-steam – and then estimates

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[19] Geissler Testimony, *supra* note 9, at 9.
[20] *Ibid.*
[21] For a survey of possible retirement drivers, see: Mills, A. D., Wiser, R. H., & Seel, J. *Power Plant Retirements: Trends and Possible Drivers* (No. LBNL-2001083). Lawrence Berkeley National Lab, (2017), *available at:* http://eta-publications.lbl.gov/sites/default/files/lbnl_retirements_data_synthesis_final.pdf.

the incremental revenue that these units could receive under the IEP. Mr. Griffiths shows that using revenue estimates from 2014 through 2018, *ceteris paribus*, the IEP would only increase annual revenues for a baseload unit by an average of 1.8 percent. The benefits for seasonal resources such as coal and oil are larger, but still modest. Looking across ten such resources and five years of historic data, Mr. Griffiths notes that the IEP would increase unit revenues by an average of seven percent with incremental revenues ranging from one percent to 20 percent depending on the year and the unit. Across all surveyed units, the median incremental value of the IEP is four percent.

While oil and coal units receive relatively more value from the IEP than nuclear units, the incremental value is still *on average* modest. Even if these units participated in the IEP, somewhere between 80 to 98 percent of revenues would still be subject to market prices (or hedges based on market prices). As the past decade has shown, prices change substantially from year-to-year in both the energy and capacity markets.[22] For a large generator, market price fluctuations induce swings in the revenues on the order of tens of millions of dollars annually. Incremental IEP revenues would constitute only a small fraction in a generator's net financial position. Given the substantial swings in energy and capacity market revenues, it seems doubtful that a prudent resource owner would make retirement decisions based on the two years of incremental IEP revenues.

Separate from, and irrespective to the IEP outcome, operators will likely also put more weight on the long-term Energy Security Initiative ("ESI") scheme, specifically because it is *long-term.* The outcome of the long-term plan will change underlying market dynamics for

[22] For example, between 2012 to 2014, annual average energy prices increased from \$36.09/MWh to \$63.32/MWh; from 2014 to 2016, they dropped back to \$28.94.[22] Revenues from the capacity market are similarly unstable: over the past five FCAs prices have ranged from \$3.80/kW-Month to \$9.55/kW-Month, *available at* https://www.iso-ne.com/about/key-stats/markets#fcaresults.

years to come so a prudent operator would likely take a "wait-and-see" approach on ISO-NE Tariff changes, rather than make a quick decision to maintain or retire a unit based on two years of incremental IEP revenue.

Moreover, it is possible that IEP payments will provide no net incremental revenues to resources. In a February 28, 2019 memorandum, ISO-NE's Internal Market Monitor ("IMM") explained that it will factor the IEP revenues into its assessment of bids in the FCA.[23] Factoring in this revenue stream will tend to depress FCA bids and FCA clearing prices, all else equal. It is certainly possible that there will be no effect to the clearing price if the marginal unit cannot or does not intend to participate in the IEP. Because many resources are eligible to participate in the IEP, however, the likelihood that the FCA will clear lower is substantial. Therefore, increased revenues from the IEP might be partially or wholly offset by decreased capacity market revenues.

Finally, the FCA timeline calls into question whether the IEP will have any impact on retirement decisions. Indeed, ISO-NE's March 25 filing comes after the March 15, 2019 deadline to submit retirement de-list and permanent de-list bids for FCA 14.[24] Although, there are market participant retirement-related deadlines in June 2019 and August 2019, actions taken on both of these dates require that the decision to retire be made by March 15, 2019.

To this point, in the March 25 filing ISO-NE states that "having the program vetted by stakeholders…has allowed resources to consider the program's potential incremental revenue during the 2023-2024 winter in making their decision … to submit retirement de-list bids."[25]

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[23] The Internal Market Monitor of ISO New England Inc., Comments on Inventoried Energy Program, *ISO New England, Inc.*, Docket No. ER19-1428-000 (April 8, 2019).
[24] *See* Forward Capacity Auction #14 Schedule, *available at* https://www.iso-ne.com/static-assets/documents/2017/05/fca-14-timeline-5-9-2017.pdf.
[25] ISO-NE, *supra* note 1, at 7.

However, until the Commission issues an order approving the IEP, the revenue ISO-NE refers to cannot be relied upon. If ISO-NE believed that the IEP was essential for resources making retirement decisions for FCA 14, then it should have offered the Program earlier. Relying on the potential revenues that an un-filed and unapproved program may offer when deciding whether to retire a resource presents a significant risk that resources are unlikely to take.

*2. The IEP may not improve energy security.*

ISO-NE "cannot guarantee . . . that the program will incent specific resources to take precise actions that improve winter energy security . . . ."[26] While ISO-NE asserts that the IEP is "directionally correct," it may not change behavior in ways that improve energy security.[27] The IEP is voluntary, so ISO-NE does not know whether the Program will encourage resources to retain inventoried energy. The fixed compensation structure, set in advance, compounds this problem. The compensation rate for the IEP will be $82.49/MWh for the winters of 2023/24 and 2024/25. If market fundamentals change and the compensation rate becomes too low for resources to cover risk from IEP participation, then ISO-NE might see less participation than it desires.

Worse, the program has no demand-related design element, resulting in a "half market" structure. Because the IEP has no demand-curve element, or even a procurement target, there is no relationship between quantity and price.[28] While in other ISO-NE markets, insufficient supply leads to scarcity prices which should induce more suppliers to enter the market, the IEP's fixed compensation rate, paired with the lack of a demand metric, provides no market-based

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[26] *Id.* at 7.
[27] *Ibid.*
[28] ISO-NE does, however, include supply-side restrictions (e.g. 72-hours of fuel) to provide some limitations on quantity procured.

mechanism to encourage suppliers to participate if participation is lower than expected. If inventory really is required to enhance system reliability, the static compensation rate is a defect.

### F. The Commission Should Not Approve the IEP Because Its Costs are Unknown and ISO-NE's Indicative Price Demonstrates that there are Less Expensive Alternatives.

If one assumes that the IEP can succeed in increasing energy inventories (which, as addressed above, is uncertain), it may benefit customers to buy this winter energy insurance in case of extreme conditions. However, to make this determination, one would need to know how much it will cost customers to acquire these benefits. ISO-NE fails to provide this information. Instead, ISO-NE asks customers to pay for the IEP without knowing the price tag. Moreover, the "indicative price" that ISO-NE does provide demonstrates that the same winter energy insurance benefit can be bought for less money and with more certainty.

#### *1. ISO-NE has failed to demonstrate that the benefits customers may receive from the IEP warrant its costs.*

The March 25 filing contains so little discussion of customer benefits that any benefit to customers must be inferred. What can be inferred is that customers may receive a "reliability benefit" - a concept that is so ill defined that a cost-benefit analysis could not be performed for lack of any specific information.

In terms of costs, ISO-NE has made no effort to quantify the number of resources that would retain inventoried energy based on the IEP or the level of inventoried energy these resources would retain. ISO-NE has done no assessment of the problem, nor has it articulated what energy security attributes are uncompensated or measured the value of these attributes. Based on the data provided in the March 25 filing, it is impossible to calculate the IEP's actual cost to consumers.

In addition, ISO-NE has made no attempt to weigh customer benefit and costs because without customer benefit and cost analysis and information, it cannot. It is common sense that customers should only have to bear costs up to the point that is justified by customer benefit. In providing little cost and benefits information and making no attempt to weigh cost with customer benefits, ISO-NE has failed to demonstrate that any benefits customers may receive from the IEP warrant the costs they will pay.

*2. Any insurance benefits that the IEP may provide can be bought for less money.*

ISO-NE knows from its experience with the Winter Reliability Program ("WRP") that it can obtain inventoried winter fuel for far less money than it proposes to do under the IEP. Indeed, it appears that the IEP will cost four-to-five times more than the WRP.

ISO-NE witness Dr. Geissler states that indicative IEP program costs could amount to $148 million per year.[29] This is more than four times the cost of the last WRP.[30] Yet, ISO-NE has offered no evidence that the higher costs yield commensurately higher benefits, either in terms of stockpiled fuel inventories or enhanced reliability. As noted above, ISO-NE cannot guarantee any change in behavior; instead, it can merely argue that the IEP will lead to outcomes that are "directionally correct."

The central difference between the WRP and the IEP is that the former was "out of market" and the latter ISO-NE presents as a market mechanism. Yet, a central purpose of markets is to achieve the most economically efficient price. ISO-NE's proposals fails to do so.

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[29] Dr. Geissler indicates that "actual program costs could fall above or below the upper and lower bound estimates" because the "cost estimates make several assumptions about program participation, resource performance, and winter severity that may not hold." *See* ISO-NE, *supra* note 1, at 19; *see also* Geissler Testimony, *supra* note 9, at 66-68.

[30] ISO-NE reported the WRP's costs for the 2015/2016, 2016/2017 and 2017/2018 winters to range from $25 million to $35 million, *See* https://www.iso-ne.com/markets-operations/markets/winter-program-payment-rate; *see also* http://isonewswire.com/updates/2017/10/27/update-on-the-20172018-winter-reliability-program.html.

Charging customers more money than necessary just to label a program "market-based," is not just and reasonable.

## G. The IEP is Likely to Create More Problems than it Solves.

*1. The IEP may be duplicative, unnecessary and prevent the optimal functioning of prior capacity market modifications developed as part of the Pay-for-Performance program.*

Instead of solving a market problem, the IEP may interfere or undermine the efficacy of existing programs, particularly, Pay-for-Performance ("PfP"). The genesis of PfP was rising outage rates largely as a result of resources failing to meet their capacity supply obligations ("CSO") during periods of "system stress."[31] While the rationale for implementing PfP and the IEP is not identical, the overlap is substantial. PfP was implemented to "address fuel security" and to "ensure that [resources] have sufficiently reliable fuel supplies to operate when needed."[32] The IEP is meant to provide incentives for resources to retain inventoried energy during periods of system stress to improve winter energy security and to prevent resource retirements.

ISO-NE has also failed to explain why PfP will apparently provide adequate winter energy security incentives for the winters of 2018/19 through 2021/2022 but the IEP is required for 2023/24 and 2024/25.[33] In these first years, PfP is the only market tool that ISO-NE has to promote winter reliability; thereafter it can also rely on the Mystic COSA as well as the authority to retain resources for fuel security reasons granted by the Commission in the August 31 filing. This omission is particularly inexplicable because PfP's payment rate will rise from $2000/MWh

[31] Press Release. ISO-NE, (2018), *"Pay-for-Performance" capacity market incentives implemented as of June 1, 2018*, (June 11, 2018), *at* http://isonewswire.com/updates/2018/6/11/pay-for-performance-capacity-market-incentives-implemented-a.html.
[32] ISO-NE, *supra* note 4, at 53.
[33] The December 3 Order, *supra* note 8 (granted ISO-NE the authority to retain resources for fuel security reasons in FCAs 13 and 14 (2022/23-2023/24)). The Federal Energy Regulatory Commission ("Commission") has also questioned PfP's efficacy. However, these doubts are similarly speculative. *See* Waiver Order, *supra* note 4, at 53-54).

to $3,500/MWh starting June 1, 2021, well before the IEP period. If anything, PfP will have a greater impact on winter energy security in the IEP period than it does in the preceding years because of the higher phased in penalty rate. While the $3500/MWh rate is lower than the eventual highest PfP penalty payment rate of $5455/MWh that becomes applicable on June 1, 2024, it is still 75 percent higher than today's PfP rate. Further, during the Capacity Commitment Period ("CCP") that corresponds to FCA 15, while the IEP program is still in effect, PfP rates will have risen to the maximum $5,455 rate.

Finally, the IEP will confound ISO-NE's ability to assess PfP. The IEP's fuel inventory payment scheme will provide incremental incentive for resources to stockpile fuels, but these actions might have been taken to meet PfP requirements anyways. ISO-NE should wait and see how resources respond to PfP before implementing a new program. As it is, ISO-NE will have four years of data to provide insight into PfP efficacy before the first IEP compliance period.

### *2. The IEP lacks evidentiary support and is predicated on numerous unsubstantiated and subjective design elements, which will result in arbitrary and discriminatory rates.*

The Commission must reject proposals where the proponent has not provided the Commission with sufficient information to determine the effects of its proposed revisions.[34] The March 25 filing lacks the record evidence required for the Commission to adjudicate the just and reasonableness of the proposed program. The lack of evidence is primarily the result of ISO-NE's failure to perform meaningful analysis on several aspects of the IEP. ISO-NE has

[34] *See N. Me. Indep. Sys. Adm'r., Inc.,* 119 FERC ¶ 61,231 at PP17-18 (2007) (rejecting filing of proposed Tariff and Market Rules revisions finding that the Northern Maine Independent System Administrator "had not provided the Commission with sufficient information to determine the effects of its proposed revisions…[and] has failed to demonstrate that the proposed tariff revisions are just and reasonable, and, accordingly, has failed to satisfy its burden of proof under section 205 of the FPA."; *see also See, e.g., Puget Sound Energy, Inc.*, 132 FERC ¶ 61,128 at PP 31-35 (2010) (rejecting proposed tariff revisions upon finding that the filing party had not demonstrated that its proposed rate was just and reasonable); *N.Y. Indep. Sys. Operator, Inc.*, 131 FERC ¶ 61,074 (2010) (rejecting proposed tariff sheets on the basis that the filing party had not shown the proposed revisions were just and reasonable).

made no assessment of the quantity of inventoried energy that would be optimal for enhancing system reliability.[35] Nor has it provided an estimate of demand for the inventoried energy on a qualifying cold day.[36] In fact, ISO-NE provides no objective metric of the ostensible benefits of this Program at all.

In addition, while ISO-NE's objective to provide similar compensation for similar service appears to treat resources fairly, it is fundamentally misguided and discriminatory. The IEP provides compensation for resources to retain inventoried energy on the trigger days, but it provides no direct compensation to some resources that *actually* provide energy security on those days *e.g.* wind and solar resources and gas plants without firm pipeline capacity. By focusing on inputs (*i.e.* fuel) instead of outputs (*i.e.* MWhs) ISO-NE is purchasing the wrong product. Tellingly, ISO-NE recently refocused the ongoing ESI discussion to consider resource outputs instead of inputs.[37]

Further, the trigger ISO-NE chose to define the days on which inventoried energy will be measured is arbitrary. The testimony of Mr. Geissler notes that ISO-NE relies on a temperature based trigger condition because it is simple and transparent, but also acknowledges that the details of the trigger are fundamentally subjective.[38] Mr. Geissler does not explain why he relies on a proxy for system tightness instead of actual metrics of system tightness such as high day-ahead energy prices or ISO-NE's published days-ahead forecasts of energy or demand. Further, despite discussion about the historical relationship between temperature and gas prices, Mr. Gessler can only note that gas prices on trigger days are "higher, on average, than the seasonal

[35] Geissler Testimony, *supra* note 9, at 46.
[36] ISO-NE, *supra* note 1, at 7.
[37] Chapter 3, Design Principle 3, page 47, *available at* https://www.iso-ne.com/static-assets/documents/2019/04/a00_iso_discussion_paper_energy_security_improvements.pdf.
[38] Geissler Testimony, *supra* note 8, at 34, 39.

average."[39] Mr. Geissler provides little evidence that his proposed trigger consistently and correctly identifies the highest price gas days – merely that they are above average. While the trigger does capture the four days with gas prices in excess of $25/MMBtu, it only identifies 61 percent of days where prices were above $5/MMBtu.[40] These facts suggest that the trigger condition has problems with both false positives and false negatives – days when the weather is cold, but gas is relatively cheap; and days when gas is expensive, but the weather is mild. More generally, these claims suggest that the trigger does an inadequate job of identifying the days when system conditions will be tightest and the days when stored fuel would be most valuable for system reliability. The Commission should not approve the proposed rate which arises from an out-of-market program that is discriminatory and arbitrary.

## III. CONCLUSION

For the reasons stated herein, the Massachusetts Attorney General respectfully requests that the Commission reject ISO-NE's March 25 filing because it will result in unjust and unreasonable rates. Any claimed customer benefits are likely illusory. ISO-NE has not provided evidence to demonstrate that the IEP will either improve fuel security or prevent retirement of certain resources. Further, the Program's costs are unknown, and the indicative prices provided by ISO-NE show that there are less expensive alternatives for customers. Finally, the IEP may be duplicative and is likely to negatively impact the optimal functioning of the capacity market. ISO-NE's IEP is an out-of-market design that is discriminatory, arbitrary and unsupported by evidence. It is a thinly disguised ISO-NE give-away to certain generators unhappy with potential price suppression in FCAs 14 and 15 due to the inclusion of resources retained for fuel security as price-takers. Accordingly, as submitted, ISO-NE's March 25 filing does not satisfy the

[39] *Id.* at 41-42.
[40] *Id.* at 42.

section 205 burden to justify this proposal as just and reasonable and should, therefore, be rejected by the Commission.

Respectfully Submitted,

MAURA HEALEY
MASSACHUSETTS ATTORNEY GENERAL

*/s/ Sarah Bresolin Silver*
Sarah Bresolin Silver
Christina H. Belew
Assistant Attorneys General
Massachusetts Attorney General Office of the Ratepayer Advocacy
One Ashburton Place
Boston, MA 02108-1598
Phone: 617.963.2380
sarah.bresolin@mass.gov
christina.belew@mass.gov

April 12, 2019

# Exhibit 1

# Testimony of Benjamin Griffiths
# on Behalf of the Massachusetts Attorney General

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

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| ISO New England, Inc. | ) | Docket No. ER19-1428-000 |
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**TESTIMONY OF BENJAMIN GRIFFITHS**
**ON BEHALF OF THE**
**MASSACHUSETTS ATTORNEY GENERAL**

## I. IDENTIFICATION AND QUALIFICATIONS

**Q. Please state your name, title, and business address.**

A. My name is Benjamin Griffiths. I am an Energy Analyst working for the Massachusetts Attorney General's Office ("AGO") in the Energy and Telecommunications Division. My business address is One Ashburton Place, Boston, MA, 02108.

**Q. Please describe your responsibilities, work experience, and educational background?**

A. My primary responsibility at the AGO is to provide qualitative and quantitative analysis of proposals by the Independent System Operator for New England ("ISO-NE") and by New England Power Pool ("NEPOOL") stakeholders. I am a voting member at the NEPOOL Transmission Committee and an alternate member at the NEPOOL Reliability Committee. Prior to joining the AGO in 2018, I was employed by Resource Insight, Inc., where I worked on resource planning and utility rate design issues. In 2017, I received an M.S. in Energy & Earth Resources from the University of Texas at Austin. I have authored or co-authored reports, whitepapers, and a peerreviewed journal article on various electricity-related topics. I have worked on technical and policy issues since 2012.

## II. INTRODUCTION

**Q. What is the purpose of your testimony?**

A. The purpose of my testimony is to discuss why the inventoried energy program ("IEP") is unlikely to change the retirement decisions of market participants.

Through my analysis of market revenues available to "at risk" generators, I conclude that IEP revenues are likely insufficient to deter or defer retirement decisions from market resources that enhance winter energy security. IEP revenues would constitute only a small increase in revenues for oil, coal and nuclear units. While the IEP might offer different revenue profiles for other unit types, I focus on these units because they are large, firm-fuel units with uncertain futures.

While the IEP provides plant operators with more money – it is unlikely that this incremental revenue will change the *behavior* of these same operators. For this reason, the IEP's costs and benefits should be measured against previous winter reliability programs.

**Q: How is your testimony organized?**

A: My remaining testimony is presented in three sections (III-V). In Section III, I introduce the IEP and ISO-NE's assessment of the program. In Section IV, I (a) outline how resources make retirement decisions and (b) calculate the impact of the IEP revenues on overall generator revenues for a variety of coal, oil, and nuclear units. In Section V, I discuss whether the IEP will affect a marginal unit's retirement calculus.

## III. Background and Objectives of the Inventoried Energy Program

**Q: What is the purpose of the IEP?**

A: The stated purpose of ISO-NE's IEP is to pay resources to maintain inventoried energy in the winter in the hopes of preventing retirements and improving winter energy security.[1] This program would be in effect for the winters of 2023/24 and 2024/25. ISO-NE intends to have a long-term market-based solution in place thereafter.

**Q: How is the IEP structured?**

A: The IEP consists of five components: (1) a two-settlement structure to determine program settlements; (2) a forward rate representing the payment a Market Participant receives for each megawatt hour ("MWh") of inventoried energy sold forward; (3) a spot rate representing the payment rate applied to deviations between the inventoried energy maintained for each trigger condition, and that sold forward; (4) the trigger conditions at which time a participant's inventoried energy will be measured; and (5) a maximum duration that serves as a cap on the quantity of inventoried energy for which a resource is compensated. Inventoried energy is defined as "fuel or potential energy that a resource can convert to electric energy at the ISO's direction."[2]

**Q: Has ISO-NE provided any estimate of indicative revenues for resources participating in the IEP?**

A: Yes. As structured, resources participating in the IEP have two sources of incremental revenue: direct IEP forward or spot payments, and indirect increases to locational marginal prices ("LMP") induced by other IEP participants incorporating

[1] ISO New England Inc., Inventoried Energy Program, *ISO New England Inc.*, Docket No. ER-19-1428-000 (March 25, 2019) ("March 25 filing"), at 5-7.

[2] *Id.* at 8.

opportunity costs into their energy offers. On an annual basis, the direct payments are worth $82.49/MWh-stored, using the forward rate. The value of the increased LMP is harder to assess, but ISO-NE has suggested that winter energy prices would increase by an average of $0.65/MWh.[3]

## IV. IEP REVENUES ARE LIKELY INSUFFICIENT TO RETAIN RESOURCES

### *1. How do resources make retirement decisions?*

**Q: What are the factors that might drive retirement decisions?**

A: Plant operators face a complex calculus when deciding to retire a generating resource. They must develop expectations of future market revenues and volatility, plant costs, value of capital expenditures in other markets, environmental regulations, and many other factors.[4] Given the long useful lives of most generating resources, longer-term expectations around these different market drivers are critical. Moreover, given substantial year-to-year variability in market revenues, changes in short-term revenues are unlikely to drive retirement decisions.

**Q: Have any market participants opined on what drives resource retirement?**

A: Yes. Insufficient market revenues are cited as the primary driver of retirements by the New England Power Generators Association ("NEPGA"). On a fundamental level, NEPGA argues that energy and capacity prices are simply too low to sustain

[3] Geissler, Christopher. "Interim Compensation Treatment: Details of ISO's Interim Winter Energy Security Proposal." Markets Committee, NEPOOL (January 8,2019), at 56, *available at https://www.iso-ne.com/static-assets/documents/2019/01/a2_iso_presentation_interim_compensation_treatment_1.pptx.*

[4] For a survey of possible retirement drivers, see: Mills, A. D., Wiser, R. H., & Seel, J. *Power Plant Retirements: Trends and Possible Drivers* (No. LBNL-2001083). Lawrence Berkeley National Lab, (2017). *Available at:* http://eta-publications.lbl.gov/sites/default/files/lbnl_retirements_data_synthesis_final.pdf.

some resources: "Energy prices are low-even considering brief winter periods when demand for natural gas pushes up its cost in new England. Given these trends, capacity resources naturally are considering retirement."[5] In the shorter-term, NEPGA argues that price-suppression in the capacity market resulting from the Mystic Generating Station's cost-of-service agreement ("COSA") and other "ongoing market deficiencies" are the most likely factor driving "resources over the economic cliff."[6]

**Q: Are there specific factors in the ISO-NE control area that generators might consider to be of greater importance in making their retirement decisions than the IEP?**

A: Yes. First and foremost, generators would focus on expected market revenues. Market revenues drive plant economics, and the two primary sources of revenue to a generator in the ISO-NE control area are the energy and capacity markets. If retirement decisions are based on market fundamentals, then expected revenues from these markets will drive resource retirement decisions.

Second, participants may focus on the outcome of the long-term, market-based Energy Security Initiative ("ESI"), which is currently being designed by ISO-NE. ESI matters to potential retirement decisions because it will provide more certainty about where market revenues will head in the years to come. The final design and implementation of the long-term plan will change underlying market dynamics for years to come, so a prudent operator would likely take a "wait-and-see" approach on ESI market design changes, rather than make a quick decision to maintain or retire a unit based on two years of incremental IEP revenue.

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[5] *New England Power Generators Association, Inc.*, Request for Rehearing, Docket Nos. ER18-2364-000 & EL18-182-00 (January 2, 2019), at 22.

[6] Id at 4.

**Q: Does ISO-NE assert that the IEP will improve winter energy security or deter retirements?**

A: No. In its filing, ISO-NE states that it "cannot guarantee . . . that the program will incent specific resources to take precise actions that improve winter energy security."[7] Elsewhere, ISO-NE asserts that while the IEP is "directionally correct," it may not change behavior in ways that improve energy security.[8]

### *2. What impact would the IEP have on a generator's financial viability?*

**Q: Broadly speaking, how do you assess the impact of the IEP?**

A: In this section, I assess the magnitude of IEP revenues and then compare them to capacity and energy market revenues. For the sake of convenience, I compare *expected* IEP revenues to *actual* market revenues for the period 2014 through 2018. By using historic data to assess market revenues, I am able to investigate actual plant operation for a range of winter conditions. This approach relies on the assumption that market operation for the years with the IEP in place will be similar to the recent past.

The purpose of this analysis is not to provide a specific value of future IEP revenues so much as it is designed to give a sense of the IEP's magnitude in relation to other revenue sources. I am unable to report values for the most recent winter (2018/2019) because hourly generation data is not yet available.

**Q: Please summarize your findings. How would the IEP change market revenues for marginal power plants?**

[7] ISO-NE, *supra* note 1, at 7.
[8] *Ibid.*

A: The answer to this question is complex and relies on many assumptions, but based on analysis of the data from 2014 through 2018, it appears that IEP could increase revenues for plants by an average of 1.8 to 12 percent, with a median increase of 7 percent. Sections III.4 and III.5 below develop revenue profiles for a hypothetical nuclear power plant as well as a sample of actual coal and oil-steam units.

### *3. Methodology for estimating energy and capacity revenues*

**Q: Please describe your methodology for calculating capacity revenues in this analysis.**

A: Capacity revenues are calculated for each year by multiplying a unit's Capacity Supply Obligation ("CSO") by the Forward Capacity Auction ("FCA") clearing price for that year. Because capacity payments are based on June-May commitment periods, I convert payments into their calendar year equivalents. For example, for calendar year 2013, I take the month-weighted average of five months of capacity revenue from FCA 3 (January-May 2013) and seven months of capacity revenue from FCA 4 (June-December 2013).

For this analysis, I rely on capacity values for the existing resources in the rest-of-pool zone and assume that there are no Capacity Scarcity Conditions ("CSC") that would offer incremental charges or credits to a unit's baseline capacity revenues. Table 1 reflects annual revenues per megawatt ("MW") of CSO.

**Table 1: Capacity Market Revenues per MW of CSO**

| Commit. Year | FCA # | Clearing Price $/kW-Mo[9] | Calendar Year | Cal. Year Equiv. Price $/kW-Mo | Annual Revs $/MW-year |
|---|---|---|---|---|---|
| 2012/13 | 3 | 2.95 | | | |
| 2013/14 | 4 | 2.95 | 2013 | 2.95 | 35,400 |
| 2014/15 | 5 | 3.21 | 2014 | 3.06 | 36,700 |
| 2015/16 | 6 | 3.43 | 2015 | 3.30 | 39,620 |
| 2016/17 | 7 | 3.15 | 2016 | 3.31 | 39,760 |
| 2017/18 | 8 | 7.025 | 2017 | 4.76 | 57,175 |
| 2018/19 | 9 | 9.55 | 2018 | 8.08 | 96,925 |
| 2019/20 | 10 | 7.03 | 2019 | 8.50 | 102,000 |
| 2020/21 | 11 | 5.3 | 2020 | 6.31 | 75,710 |
| 2021/22 | 12 | 4.63 | 2021 | 5.02 | 60,250 |
| 2022/23 | 13 | 3.8 | 2022 | 4.28 | 51,410 |

**Notes:**
*Cal. Year Price (Year Y) = [(5/12) x FCA Price (Year Y-1/Y)] + [(7/12) x FCA Price (Year Y/Y+1)]*
*Annual Rev = Cal. Year Price x 12 months per year x 1000 kW per MW*

Table 1 illustrates that capacity market revenues are highly variable with annual revenues per MW rising from $35,400/year to $102,000/year and falling back to $51,410/year. Results from the most recent FCA, run in February 2019, are lower than the market has seen in recent years but certainly not unprecedent.

**Q: Please describe your methodology for calculating energy market revenues.**

A: Energy market revenues depend both on market prices and the times when a unit is operating. For this analysis I rely on hourly day-ahead market prices at the reference Trading Hub using data provided by ISO-NE's SMD Hourly Data Files. For point of reference, Table 2 reports hourly simple-average Day-Ahead LMP for the past seven years, using ISO-NE's SMD Hourly Data. Prices in the early 2000s were somewhat higher, but these values are now stale given their vintage.

[9] ISO New England Inc., *Forward Capacity Auction Results* (2018), *available at* https://www.iso-ne.com/static-assets/documents/2018/05/fca-results-report.pdf.

**Table 2: Average Annual Electricity Prices ($/MWh, Nominal)**

| Year | Avg. wholesale electricity price ($/MWh) |
|---|---|
| 2012 | $36.09 |
| 2013 | $56.06 |
| 2014 | $63.32 |
| 2015 | $41.00 |
| 2016 | $28.94 |
| 2017 | $33.94 |
| 2018 | $43.54 |

Unless a plant operates in all hours, it will not realize the market's average price. For example, coal and oil units operate infrequently and at times when prices tend to be higher than average.

I use two methods for assessing hourly plant operation. For coal and oil-steam units, I rely on hourly gross load figures provided by these units to the Environmental Protection Agency ("EPA") as part of continuous air emissions monitoring data reporting requirements.[10] This data provides unit-level data on an hourly basis, for all units larger than 25 MW. Pairing EPA hourly generation data with ISO-NE hourly price data allows for a faithful representation of how and when operators decide to run their units in response to changing system conditions. That said, by using observed generating data from previous years, my analysis assumes plant operation in future years will be similar to operation in the recent past.

Unlike resources with stack emission reporting requirements, nuclear power plants do not publish their hourly generation. So, for these units, I simply assume that these plants operate at their maximum capacity in all hours of the year. Assuming a non-zero forced outage rate for nuclear units would not materially change my results.

[10] U.S. Environmental Protection Agency, 2018. Air Markets Program Data. *Data Retrieved from*: https://ampd.epa.gov/ampd/.

### *4. IEP & market revenues for a nuclear unit*

**Q: How much energy and capacity revenue would a nuclear unit have received over the past four years, absent the IEP?**

A: Based on the values compiled in Section III.3, a hypothetical 500 MW nuclear power plant would have received an average of $211 million per year in energy and capacity revenues over the past five years, absent the IEP (See Table 3).

**Table 3: Revenue Streams for a Nuclear Unit**

| | Market Revenue ($mm/year) | | | IEP Revenue ($mm/year) | | | |
|---|---|---|---|---|---|---|---|
| **Year** | **Capacity** | **Energy** | **Total** | **Direct Payment** | **Increased LMP** | **Total** | **Incremental Value of IEP** |
| 2014 | 18.4 | 277.3 | 295.7 | 2.97 | 0.702 | 3.67 | 1.2% |
| 2015 | 19.8 | 179.6 | 199.4 | 2.97 | 0.702 | 3.67 | 1.8% |
| 2016 | 19.9 | 126.8 | 146.6 | 2.97 | 0.702 | 3.67 | 2.5% |
| 2017 | 28.6 | 148.7 | 177.2 | 2.97 | 0.702 | 3.67 | 2.1% |
| 2018 | 48.5 | 190.7 | 239.2 | 2.97 | 0.702 | 3.67 | 1.5% |
| Average | 27.0 | 184.6 | 211.6 | 2.97 | 0.702 | 3.67 | 1.8% |

**Notes:**
*Capacity Revenues = 500 MW x Annual Capacity Revenue per MW (Table 1)*
*Energy Revenues = 500 MW x 8760 Hours x Annual Average Electricity Price (Table 2)*
*IEP Direct Payment = 500 MW x 72 Hours x $82.49/MWh-season*
*IEP Increased LMP = 500 MW x $0.65/MWh x 2160 Winter Hours*
*Incremental Value = IEP Total / Market Revenues Total*

**Q: What incremental revenues would the IEP provide to a nuclear unit?**

A: The IEP would offer a 500 MW nuclear generator with at least three days' supply of fuel, direct payments of $2.97 million per year based on my calculations (See Table 3). Because of opportunity cost bidding, which is an additional effect of the IEP, this generator would also receive about $702,000 in incremental energy market revenues. Adding these sums, the IEP would increase plant revenues by about $3.7 million per year. For a baseload unit, the IEP would increase plant revenues by an average of 1.8 percent per year.

While the IEP would provide annual incremental revenues worth $3.7 million, energy and capacity market revenues varied by $149 million (from $146.6 million to

$295.7 million). Put differently, volatility in the energy and capacity markets has historically led to revenue swings 40-times larger than the IEP would provide. Given general market volatility and the small value that IEP incremental revenues would add for a baseload unit, it seems unlikely that an operator would make a retirement decision based on these revenues.

### 5. *IEP & market revenues for select coal and oil units*

**Q: How much energy and capacity revenue would coal or oil-steam units have received over the past four years, absent the IEP?**

A: Coal and oil-steam units operate with more heterogeneity than nuclear units, so the value of the IEP to these units will also be more varied. In this analysis, I estimate energy and capacity revenues for nine coal and oil units for the period 2014 through 2018. These units were selected for their size, vintage, fuel-type, energy inventory capability, and continued FCM participation. Table 4 tabulates revenues for each unit and for each year based on the capacity and energy estimation methodology outlined in Section III.3.

**Table 4: Energy and Capacity Revenues for Select Oil or Coal Units, (2014-2018, $mm)**

| Unit Name | CSO (MW) | Capacity Revenue ($mm) 2014 | 2015 | 2016 | 2017 | 2018 | Energy Revenue ($mm) 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Canal Station_1 | 562 | 20.6 | 22.3 | 22.4 | 32.1 | 54.5 | 73.3 | 19.5 | 2.0 | 1.8 | 16.8 |
| Canal Station_2 | 559 | 20.5 | 22.1 | 22.2 | 31.9 | 54.2 | 22.7 | 13.4 | 1.5 | 4.4 | 8.7 |
| Merrimack_1 | 108 | 4.0 | 4.3 | 4.3 | 6.2 | 10.5 | 42.6 | 22.0 | 7.6 | 7.4 | 14.5 |
| Merrimack_2 | 330 | 12.1 | 13.1 | 13.1 | 18.9 | 32.0 | 110.5 | 55.3 | 13.6 | 12.2 | 33.9 |
| Middletown_4 | 400 | 14.7 | 15.8 | 15.9 | 22.9 | 38.8 | 13.6 | 0.7 | 0.1 | 2.4 | 9.0 |
| Montville_6 | 399 | 14.7 | 15.8 | 15.9 | 22.8 | 38.7 | 7.9 | 5.8 | 0.7 | 3.5 | 10.6 |
| Schiller_5 | 43 | 1.6 | 1.7 | 1.7 | 2.4 | 4.1 | 23.1 | 14.4 | 10.2 | 10.8 | 10.0 |
| Schiller_6 | 48 | 1.8 | 1.9 | 1.9 | 2.7 | 4.6 | 14.6 | 7.6 | 2.2 | 2.6 | 5.8 |
| Stony Brook (Total) | 220 | 8.1 | 8.7 | 8.7 | 12.6 | 21.3 | 25.5 | 11.3 | 4.2 | 5.4 | 10.0 |
| Total | 2668 | 97.9 | 105.7 | 106.1 | 152.6 | 258.6 | 333.9 | 150.1 | 42.1 | 50.5 | 119.1 |

Revenues per MW are lower for the oil steam and coal units compared to the hypothetical baseload plant discussed above because of lower capacity factors. While these plants tend to earn more revenue than the baseload plant per MWh of output, they operate in many fewer hours. Energy revenues are significantly higher in years with cold winters (e.g. 2014, 2015, 2018) compared to years with mild winters (2016, 2017). The discrete energy and capacity values from Table 4 are integrated into a single market revenue value in Table 5.

**Table 5: Market Revenues from Energy & Capacity Payments ($mm/year)**

| | CSO | Energy + Capacity Revenue ($mm) | | | | | |
|---|---|---|---|---|---|---|---|
| **Unit Name** | **(MW)** | **2014** | **2015** | **2016** | **2017** | **2018** | **Avg** |
| Canal Station_1 | 562 | 94.0 | 41.8 | 24.4 | 34.0 | 71.3 | 53.1 |
| Canal Station_2 | 559 | 43.3 | 35.6 | 23.7 | 36.4 | 62.8 | 40.4 |
| Merrimack_1 | 108 | 46.6 | 26.3 | 11.9 | 13.6 | 24.9 | 24.7 |
| Merrimack_2 | 330 | 122.6 | 68.3 | 26.7 | 31.0 | 65.9 | 62.9 |
| Middletown_4 | 400 | 28.3 | 16.6 | 16.0 | 25.3 | 47.7 | 26.8 |
| Montville_6 | 399 | 22.6 | 21.6 | 16.5 | 26.3 | 49.3 | 27.3 |
| Schiller_5 | 43 | 24.7 | 16.1 | 11.9 | 13.3 | 14.2 | 16.0 |
| Schiller_6 | 48 | 16.3 | 9.4 | 4.1 | 5.3 | 10.4 | 9.1 |
| Stony Brook (Total) | 220 | 33.6 | 20.0 | 12.9 | 18.0 | 31.3 | 23.2 |
| Total | 2668 | 431.9 | 255.8 | 148.2 | 203.1 | 377.8 | 283.3 |

Across these units, annual revenues vary substantially, fluctuating by factors of two or four over the examined period.

**Q: What incremental revenues would the IEP provide these select oil and coal plants?**

A: As before, the IEP would provide direct and indirect revenues, where direct revenues reflect the value of the IEP's forward payment and indirect revenues reflect increased energy market prices induced by the IEP. For direct revenues, I assume that each unit offers three days of fuel into the IEP forward procurement. Indirect revenues are harder to assess for low capacity-factor resources, because opportunity cost adders depend on the coincidence of plant operation and trigger days. I assume that the plants operate at their full capacity on all hours of the ten expected trigger days, and that opportunity cost bidding raises hourly LMP by the full spot rate ($8.239/MWh).[11] These assumptions are conservative and it is likely that the plants would not necessarily be operating at full capacity on every trigger day, but this approach provides an upper-bound estimate on the IEP's LMP impact for coal and oil resources.

Table 6 calculates incremental IEP revenues for the nine sample units. The incremental value of the IEP, however, varies based on estimated energy and capacity market payments. Looking across the various units and years, the IEP would increase unit revenues by an average of 7 percent with incremental revenues ranging from 1 percent to 20 percent depending on year-to-year changes in energy and capacity revenues. For years with mild winters, the value of the IEP is higher, because energy market revenues are generally lower.

**Table 6: Total IEP Revenues and the Incremental Value of IEP Revenues**

| | | IEP Revenue ($mm/year) | | | Incremental Value of IEP | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Unit Name** | **CSO (MW)** | **Direct Payment** | **Increased LMP** | **Total** | **2014** | **2015** | **2016** | **2017** | **2018** | **Avg** |
| Canal Station_1 | 562 | 3.34 | 1.11 | 4.45 | 5% | 11% | 18% | 13% | 6% | 8% |
| Canal Station_2 | 559 | 3.32 | 1.11 | 4.42 | 10% | 12% | 19% | 12% | 7% | 11% |
| Merrimack_1 | 108 | 0.64 | 0.21 | 0.86 | 2% | 3% | 7% | 6% | 3% | 3% |
| Merrimack_2 | 330 | 1.96 | 0.65 | 2.61 | 2% | 4% | 10% | 8% | 4% | 4% |
| Middletown_4 | 400 | 2.38 | 0.79 | 3.17 | 11% | 19% | 20% | 13% | 7% | 12% |
| Montville_6 | 399 | 2.37 | 0.79 | 3.16 | 14% | 15% | 19% | 12% | 6% | 12% |
| Schiller_5 | 43 | 0.25 | 0.08 | 0.34 | 1% | 2% | 3% | 3% | 2% | 2% |
| Schiller_6 | 48 | 0.28 | 0.09 | 0.38 | 2% | 4% | 9% | 7% | 4% | 4% |
| Stony Brook | 220 | 1.31 | 0.44 | 1.74 | 5% | 9% | 13% | 10% | 6% | 8% |
| Total | 2668 | 15.85 | 5.28 | 21.13 | 6% | 9% | 13% | 9% | 5% | 7% |

*IEP Direct Payment = CSO x 72 Hours x $82.49/MWh-season*
*IEP Increased LMP = CSO x 10 Trigger Days x 24 Hours x $8.249/MWh IEP Spot Rate*

[11] Resources participating in the IEP can increase their energy offers to reflect the value of their inventoried energy. Higher energy offers could lead to higher energy market clearing prices. My analysis assumes the marginal unit in the market on triggering days increases their energy offers by the spot rate – indicating that the marginal unit is indifferent between receiving the IEP spot compensation or an equivalent increase in energy market revenues.

Unlike low-marginal-cost nuclear units, the large oil units likely receive lower energy rents because of their higher operating costs. In many hours when they are operating, oil units are either the system's marginal unit, or close to it. This suggests that the year-to-year volatility in energy-market revenues might be mostly offset by a commensurate increase in generation costs.[12] Oil units generally have high operating costs, high fuel costs, and low run-times. Measured against capacity revenues only, the forward IEP payment would only provide incremental revenue of 6 percent to 16 percent for the selected oil and coal units.

While oil and coal units receive relatively more value from the IEP than nuclear units, as evidenced by the percentage of incremental revenue they would receive versus that received by baseload units, the incremental value is still on average modest because market fundamentals still drive revenue volatility for these units. Thus, even if they are guaranteed some fixed revenue from the IEP, a majority of their revenue is still subject to this volatility. Put differently, even if these units participated in the IEP, 80 to 98 percent of their revenues would still be subject to market prices (cf. range in Table 6). Given the fluctuations in market revenues, the added certainty of the IEP is unlikely to materially change a unit's overall risk profile. While the IEP might provide an additional incentive to "wait and see" what happens to ISO-NE markets in the long run, it still seems doubtful that an operator would make a retirement decision based on these revenues alone. Even without the IEP, prudent generators would most likely take this course of action.

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[12] U.S. Energy Information Administration, Table 8.4: Average Power Plant Operating Expenses for Major U.S. Investor-Owned Electric Utilities, 2007 through 2017. *Available at:* https://www.eia.gov/electricity/annual/html/epa_08_04.html

### *6. Market revenue uncertainty is far more consequential to plant economics than IEP revenue certainty*

**Q: Incremental IEP revenues seem like they could materially change a unit's financial position. Do you have any examples of other market factors that would have a bigger effect on generator revenues than the IEP?**

A: Yes. While IEP revenues are not trivial for "at risk" generators, other market uncertainties are far more consequential. One simple example: electricity prices and the impact natural gas prices have on them in New England. Earlier in my analysis, I found that the IEP would increase revenues to a baseload unit by about $3.67 million per year. If that same 500 MW unit could realize energy prices $0.84/MWh higher, it would receive incremental revenue commensurate with the IEP. For point of reference, year-over-year price changes in the energy market are generally larger than $10/MWh – an order of magnitude larger than the equivalent IEP increase (cf. Table 2).

Small changes in natural gas prices could lead to similar outcomes. According to ISO-NE data, natural gas is marginal in more than 70 percent of all hours, so changes in gas prices have a significant impact on electricity prices.[13] Assuming that the marginal gas unit has an average heat-rate of 8MMBtu/MWh, if natural gas prices rose by $0.15/MMBtu, then power prices would rise to that $0.84/MWh breakeven value, derived above. Gas price forecasts for the IEP timeframe offer far broader price ranges. For example, the most recent Energy Information Administration ("EIA") Annual Energy Outlook ("AEO") provides seven natural gas price forecasts for the benchmark Henry Hub. For the period 2023-2025, the reference case price

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[13] ISO New England Inc. *2017 ISO New England Electric Generator Air Emissions Report* (2019), at Figure 4-7. *Available at:* https://www.iso-ne.com/static-assets/documents/2019/04/2017_emissions_report.pdf.

ranges from $3.13/MMBtu to $3.53/MMBtu, but the other scenarios have prices that range from $2.61/MMBtu to $4.66/MMBtu.[14]

Given that forecasts for any commodity are uncertain, the relatively small revenues associated with the IEP could be lost in the noise of forecasting uncertainty for existing market products.

**Q: How volatile are ISO-NE energy and capacity prices?**

A: As the past decade has shown, prices change substantially from year-to-year in both the energy and capacity markets. For example, between 2012 to 2014, annual average energy prices increased from $36.09/MWh to $63.32/MWh; from 2014 to 2016, they dropped back to $28.94 (Table 2). Revenues from the capacity market are similarly unstable: over the past five FCAs prices have ranged from $3.80/kW-Month to $9.55/kW-Month (Table 1). These price fluctuations induce swings in the revenues of large generators on the order of tens of millions of dollars annually.

Given the historic variability of market prices and the ongoing difficulty of forecasting these same prices, a prudent operator will likely evaluate various scenarios to assess how its unit would fare under different market conditions. Changes in market fundamentals – such as the retirement of a pivotal generator or modest price increases in natural gas – could lead to materially different outcomes for a marginal generator.

### *7. IEP Revenue Increases Might be Offset by Revenue Decreases in the FCM*

**Q: How might the IEP interact with the FCM?**

[14] U.S. Energy Information Administration. *Annual Energy Outlook 2019*, Table: Total Energy Supply, Disposition, and Price Summary; All Cases. *Available at* https://www.eia.gov/outlooks/aeo/data/browser/

A: The Internal Market Monitor's ("IMM") comments on the IEP indicate that revenues from the IEP will be included in FCA delist bid calculations. The IMM notes:

> To the extent that a participant expects to accrue positive net revenue from the interim program, a competitive De-List bid and New Supply Offer in the Forward Capacity Auction would account for this positive revenue stream in the calculation of the resource's net Going Forward Costs, just like any ancillary service revenue, and result in a lower priced bid or offer to better reflect a competitive price to obtain a Capacity Supply Obligation. [15]

Factoring in this revenue stream will tend to depress FCA bids by resources participating in the IEP and, consequently, the FCA clearing price. Because many resources are eligible to participate in the IEP there is a high likelihood that the FCA will clear at a lower price than the *status quo* without the IEP. That said, it is possible that there will be no effect on the clearing price if the marginal unit cannot or does not intend to participate in the IEP.

**Q: Is it possible that resources would end up no better off under the IEP than they do under the status quo?**

A: Yes. Increased revenues from the IEP might be partially or wholly offset by decreased capacity market revenues. The effect will be akin to taking money from your left pocket and putting (some, or all of) it into your right pocket; it does not make you any richer.

## V. CONCLUSION

**Q: What do you conclude from your assessment of the size and likely effect of IEP revenues?**

[15] The Internal Market Monitor of ISO New England Inc., Comments on Inventoried Energy Program, Docket No. ER19-1428-000 (April 8, 2019).

A: While retirement decisions are complex and multifaceted, it seems unlikely that the IEP will provide sufficient guaranteed revenue to change an operator's decision. At best, it might provide additional incentive to defer retirement until ISO-NE's long-term, market-based energy security proposal is fleshed out. Doubtlessly, operators would prefer more money to less, and the IEP might provide more money to some operators. ISO-NE has not, however, provided any evidence that the IEP *will* change operator behavior, either by changing how they procure fuel or whether they decide to retire. Given the lack of evidence provided by ISO-NE and the modest incremental revenues identified in the preceding analysis, it is more likely that the IEP will offer units incremental revenue and that these same units will default to the same "wait-and-see" approach that they would have done regardless.

**Q: Does this conclude your testimony?**

A: Yes.

I declare, under penalty of perjury, that the foregoing is true and correct to the best of my knowledge, information and belief.

Executed on April 12, 2019.

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Benjamin Griffiths

## CERTIFICATE OF SERVICE

In accordance with 18 C.F.R. § 385.2010 I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Boston, Massachusetts this 12th day of April, 2019.

*/s/ Sarah Bresolin Silver*
Assistant Attorney General
Massachusetts Attorney General
Office of Ratepayer Advocacy
One Ashburton Place
Boston, MA 02108-1598
Phone: 617.963.2407