UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Constellation Mystic Power, LLC	)	Docket No. ER18-1639-000

COMMENTS AND REQUEST FOR HEARING AND SETTLEMENT PROCEDURES OF THE NEW ENGLAND STATES COMMITTEE ON ELECTRICITY

June 6, 2018

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Pursuant to Rule 211 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("Commission" or "FERC"), 18 C.F.R. § 385.211, and the Commission's Combined Notice of Filings #1 issued May 16, 2018, the New England States Committee on Electricity ("NESCOE")[1] files these Comments in response to the filing made on May 16, 2018, by Constellation Mystic Power, LLC ("Mystic") (the "Application") of a Cost-of-Service Agreement among Mystic, Exelon Generation Company, LLC ("ExGen")[2] and ISO New England Inc. ("ISO-NE" or the "ISO") (the "Agreement").[3]

As discussed below, the Agreement has not been shown to be just and reasonable. NESCOE therefore requests that the Commission set this matter for hearing and settlement judge procedures and hold the hearing in abeyance pending the conclusion of the settlement process. Establishing settlement procedures will allow all interested parties and Commission staff to obtain the information needed to review and propose necessary changes to the Agreement.

The proposed Agreement would provide cost-of-service compensation to Mystic and associated fuel supply for continued operation of its Mystic 8 and 9 gas-fired generating units

1 NESCOE filed a motion to intervene in this docket on May 16, 2018.

2 Mystic and ExGen are both subsidiaries of Exelon Corporation, referred to collectively herein as "Exelon."

3 Capitalized terms not defined in this pleading are intended to have the meaning given to such terms in the ISO-NE Transmission, Markets and Services Tariff (the "Tariff").

("Mystic 8 & 9"), which ISO-NE has requested be retained "to ensure the fuel security necessary for reliable operation of the New England electric grid"[4] for the period of June 1, 2022 to May 31, 2024 (*i.e.*, the thirteenth and fourteenth Forward Capacity Auction ("FCA 13 and FCA 14") Capacity Commitment Periods ("CCPs")). Mystic asks that if the Commission does not accept the Agreement as filed, it issue an order within 60 days that narrowly defines the scope of the proceeding and establishes a process to resolve any issues on an expedited basis. Mystic seeks an order accepting the Agreement prior to December 21, 2018, with an effective date of June 1, 2022.

These Comments are supported by the Affidavit of James F. Wilson, appended as Attachment A ("Wilson Affidavit").

I. INTRODUCTION

The Application is related to the Tariff Waiver Petition filed by ISO-NE on May 1, 2018, in Docket No. ER18-1509-000. In the Petition, ISO-NE asked the Commission for waiver of certain Tariff provisions to permit the ISO to retain Mystic 8 & 9 to address reliability risks related to fuel security over the two-year period corresponding with FCAs 13 and 14. ISO-NE explained that it believes the waiver is necessary because the Tariff permits the ISO to retain resources seeking to retire only to address local transmission security issues, not for fuel security reasons. NESCOE did not take a substantive position on the Petition,[5] and various New England states filed separate pleadings in that docket. Likewise, various New England states may also file separate pleadings in this proceeding.

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4 Petition of ISO New England Inc. for Waiver of Tariff Provisions, *ISO New England Inc.*, Docket No. ER18-1509 (May 2, 2018) ("Tariff Waiver Petition" or "Petition"), at 4.

5 Comments of the New England States Committee on Electricity, *ISO New England Inc.*, Docket No. ER18-1509 (May 23, 2018), at 2.

Before the Commission can approve the Application, the Commission must ensure that the rates, terms and conditions of Agreement are just and reasonable. The Application contains numerous exhibits and testimony and presents questions of first impression in the form of a complex customer-funded fuel supply arrangement. In the limited time to review and analyze the complex filing, NESCOE has identified a number of issues where, based on the information available, components of the proposed costs to be recovered under the Agreement are not supported and thus have not been shown to be just and reasonable. Among other things:

- Much of the information surrounding ExGen's acquisition of the Everett Marine Terminal ("Everett") liquefied natural gas ("LNG") facility has not been provided, making it difficult for NESCOE and the Commission to confirm Mystic's claims that the arrangements are the "least cost" option and to meaningfully analyze all of the components of the proposed Fuel Supply Agreement;

- The Fuel Supply Agreement is a very non-standard fuel supply arrangement, with one customer of the supplier bearing all cost net of revenue from other customers; a more common and simpler arrangement would allocate a fixed amount of the Everett's fixed cost to Mystic 8 & 9;

- There are inconsistencies and questions raised by Mystic's proposed future capital expenditures;

- Aspects of Mystic's proposed annual fixed revenue requirements for the Mystic units are not adequately supported and there are questions regarding certain rate base components, the method of calculating expenses and the support for certain expenses;

- There are flaws in Mystic's development of its proposed return on equity and its proposed capital structure;

- Components of Mystic's proposed fuel supply charge, both fixed and variable, are unsupported and raise questions;

- The different incentives and penalties proposed in the Agreement may have unintended consequences and merit further investigation;

- Mystic's proposal that the Stipulated Variable Costs—which are not adequately supported and explained—would only be able to be changed by a Federal Power Act ("FPA") Section 206 filing is unsupported;

- Mystic does not adequately explain its proposal for the Fuel Supply Agreement to pass all of Everett's costs, net of credits, through to Mystic 8 & 9 without adequate incentives to manage the LNG facility, which serves other customers in addition to Mystic 8 & 9;
- Various proposed terms and conditions of the Agreement appear to unreasonably shift some, or in some cases *all*, of the risk of Mystic's decision-making with respect to fuel management away from shareholders and onto customers.

NESCOE's Comments discuss many examples highlighting areas where the Application is not sufficiently supported, assertions are not adequately explained, and aspects of the Agreement lack clarity. The items in the list above and discussed in the Comments are not intended to be exhaustive but, instead, illustrate why the Commission should not acquiesce to Mystic's request to accept the Application as it stands or unreasonably narrow the issues in any settlement procedures the Commission establishes. The Commission should recognize that the states whose consumers would ultimately bear the risk of Mystic's fuel supply decisions were not parties to negotiations around the Agreement. Particularly in connection with the novel fuel supply proposal, it is inherently unreasonable to "narrow" the issues before weighing the economic interests of consumers—who ultimately pay the bill—alongside Exelon's interest in protecting its shareholders and ISO-NE's interests in easing fuel constraints.

NESCOE notes that its ability to review the full cost-of-service information was limited by the fact that Mystic sought privileged treatment for parts of the Application, and Mystic did not provide the redacted materials to NESCOE until less than a week before the comment date.[6] Additionally, and critically, there are substantial omissions from the filing that are essential to being able to evaluate the Fuel Supply Agreement, Exhibit MYS-004 to the Testimony of William B. Berg. These documents include a transaction confirmation to a "Base Contract" that

[6] NESCOE submitted its non-disclosure certificates to counsel for Exelon on May 23, 2018. NESCOE received some, but not all, of the redacted documents on May 30, 2018. Exelon subsequently provided the outstanding materials to NESCOE at counsel's request after the Chief Judge issued an order adopting the protective order on May 31, 2018.

is excluded from Exhibit MYS-004; the Intercompany Services Agreement between ExGen and Mystic; the proposed form of Intercompany Services Agreement between ExGen and Everett LNG; the proposed form of the LNG Terminal Services Agreement; and any details on the disputed Fuel Supply Agreement between Mystic and Everett are also excluded. The terms of purchase and purchase price for the Everett LNG facility, not made available to NESCOE prior to the deadline for filing comments, are integral to an assessment of the justness and reasonableness of the cost-based components in the proposed Fuel Supply Agreement.

One complicating factor in these proceedings is that certain data and documentation may not be in Exelon's possession. NESCOE understands that ExGen is in the process of acquiring, but does not currently own, Everett, for which it is proposing a cost-based fuel supply agreement between affiliates to-be, Mystic and Constellation LNG, LLC ("Constellation LNG").[7] Mystic represents that the transaction is scheduled to close sometime during the fourth quarter of 2018.[8] Everett is owned and operated by Distrigas of Massachusetts LLC, a subsidiary of Engie Gas & LNG Holdings LLC ("Engie"), that has moved to intervene in proceedings. If the Commission issues an order that sets the filing for hearing, holds the hearing in abeyance, and sends the matter to settlement judge procedures, NESCOE requests that the Commission also provide guidance with respect to discovery procedures that would be required for the Commission to issue an order before December 21, 2018, as Mystic requests. In order for customers to be able to fully evaluate all aspects of the Application, it is critical that participants be able to seek discovery—and that Exelon provide adequate and timely responses—to be able to determine that the costs and other aspects of the Application are just and reasonable.

[7] Transmittal Letter at 7.

[8] *Id*.

NESCOE's discusses below issues it has identified to date but emphasizes that this review is preliminary and the Commission should not limit the scope of the proceeding to just issues identified by interested parties in the compressed time available and without full information provided.

II. THE SCOPE OF THE PROCEEDING SHOULD NOT BE LIMITED IN THE WAY THAT MYSTIC REQUESTS.

NESCOE urges the Commission to allow states and other parties to access, understand, and evaluate the entire proposal from a consumer perspective before "narrowing" the issues to align with Mystic's preferred scope of the proceeding. According to Mystic, the only subjects at issue are whether Mystic's full cost-of-service is appropriately calculated and supported, and whether the agreed upon, modified terms of the form of cost-of-service Agreement are just and reasonable.[9] Although NESCOE agrees that these issues are part of what the Commission must evaluate in order to make substantive findings on the proposed Agreement, these are not the only issues that require scrutiny.

A. The Contract Term Is Relevant to the Justness and Reasonableness of the Agreement.

Mystic contends that the two-year term of the contract is outside the scope of this proceeding, arguing that it is addressed in the Tariff Waiver Petition proceeding.[10] NESCOE does not take a position at this time on whether the Agreement should be for two years. It should be noted that in the Tariff Waiver Petition, ISO-NE sought a waiver of the relevant provisions of its Tariff to the extent necessary to permit ISO-NE to retain Mystic 8 & 9 under a two-year cost of service agreement, and Commission approval of that request would not constitute approval of

[9] Transmittal Letter at 5.

[10] *Id*.

the Agreement itself.[11] However, the fact that the proposed Agreement is for a two-year term is very much related to whether the Agreement is just and reasonable when viewed in the context of the other rate and non-rate provisions of the Agreement. Mystic proposes not only to recover revenue requirements (and future capital expenditures) for Mystic 8 & 9, but also for the LNG facility it will soon own. These additional arrangements impose substantial costs on consumers. The fact that Mystic seeks revenues, including for its fuel source, for a guaranteed two-year term, without refreshed reliability analysis by ISO-NE during that period reflecting implementation of ISO-NE's Pay for Performance mechanism in 2018, warrants scrutiny and should not be excluded from any hearing and settlement procedures.

B. Exelon's Future Capital Expenditures Are Very Much at Issue in This Proceeding.

Mystic contends that one of the issues "clearly beyond the scope of this proceeding" is "[w]hether it is appropriate to include recovery for future capital expenditures in the Agreement."[12] Mystic cites to the Petition at pages 27-28 as support for this statement.[13] It is unclear from the Application whether Mystic is asserting that the justness and reasonableness of the capital expenditures should not be part of this proceeding. NESCOE agrees that the Petition sought waiver of the provision in ISO-NE's market rules (Tariff Section III.13.2.5.2.5.2) that requires a FPA Section 205 filing for future capital expenditures that is separate from the Section 205 cost-of-service filing.[14] ISO-NE sought waiver of this provision "solely for the purpose of expedience" in order to permit Exelon to include in its Section 205 cost of service filing for Mystic 8 & 9 any capital expenditures it thinks necessary in accordance with the Tariff

[11] Tariff Waiver Petition at 25 (seeking waiver of Section III.13.2.5.2.5).

[12] Transmittal Letter at 5.

[13] *Id*. at 5 n.23.

[14] Tariff Waiver Petition at 27.

provision.[15] However, ISO-NE emphasized that it did not request waiver of the standard that Section III.13.2.5.2.5.2 requires to meet to qualify for recovery of its capital expenditures, *i.e.*:

> The capital expenditures filing must explain "why the capital expenditure is necessary in order to meet the reliability need identified by the ISO," and must demonstrate "that the expenditure is reasonably determined to be the least-cost commercially reasonable option consistent with Good Utility Practice to meet the reliability need identified by the ISO."[[16]]

Mystic's filing includes proposed capital expenditures for 2022, 2023 and 2024.[17] The justness and reasonableness of these capital expenditures and whether they meet the ISO Market Rule's standards are clearly within the scope of this proceeding, and NESCOE addresses these below in Section III.B.

C. Given the Reason for the Agreement and Mystic's Proposed Substantial Modifications to the *Pro Forma* Cost-of-Service Agreement, the Whole Agreement—Not Just Those Provisions Mystic Proposes To Change—Must Be Evaluated.

Mystic contends that the issue of whether unmodified terms of ISO-NE's *pro forma* cost-of-service agreement[18] are just and reasonable is not at issue because "they have already been found to be so."[19] Mystic's attempt to cherry pick which aspects of its Agreement are within the scope of this proceeding should be rejected. The premise of ISO-NE's Tariff Waiver Petition is that ISO-NE determined that the reliability need for which Mystic was needed (fuel security) is

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[15] *Id*. at 28. ISO-NE also stated that "[c]ombining the two contemplated Section 205 filings into a single case . . . will afford interested parties the ability to address all cost of service matters relating to Mystic 8 & 9 in a single proceeding." *Id.*

[16] *Id*. at 27 (citing Market Rule 1, Section III.13.2.5.2.5.2(b)).

[17] Prepared Direct Testimony and Exhibits of William B. Berg, Exhibit MYS-001 ("Berg Testimony") at 19-23; Berg Testimony, Exhibit MYS-005, Capital Costs of Mystic 8 & 9 and Everett ("Exh. MYS-005").

[18] The ISO's *pro forma* cost-of-service agreement is Appendix I to Section III, Market Rule 1 in the ISO Tariff.

[19] Transmittal Letter at 6 (citing *ISO New England Inc.*, 125 FERC ¶ 61,102 (2008)).

not covered by the Tariff,[20] and that in light of this unique circumstance, it should not simply be assumed that all of the unmodified provisions of the *pro forma* cost-of-service agreement remain just and reasonable. Additionally, the modifications that Mystic proposes to the ISO's *pro forma* cost-of-service agreement are substantial. Among other things, the Agreement includes recovery of costs related to fuel supply arrangements with Mystic's affiliate (the details of which NESCOE has not been able to evaluate fully because of the little time NESCOE had to review the redacted portions of the Application and because some information, such as the Intercompany Agreement, were not included in the filing at all). The substantial revisions that Mystic proposes, which are more beneficial to Mystic than to customers, could significantly change the character and impact of the remaining, unmodified terms of the *pro forma* agreement. Additionally, since ISO-NE developed its *pro forma* cost-of-service agreement, there have been significant redesigns to its market rules, such as Pay for Performance, that fundamentally change the ways that resources are compensated in the market.

Putting aside the question of whether it would have been more appropriate for Mystic to have filed the deviations from the *pro forma* cost-of-service agreement pursuant to FPA Section 206[21] (with the cost-of-service provisions to support a rate filed pursuant to Section 205), Mystic chose to file, pursuant to Section 205, an agreement that is substantially different than the *pro forma* agreement. Mystic's attempts to fence off various portions of the Agreement are misplaced, and the Agreement in its entirety is at issue. Accordingly, NESCOE urges the

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20 Tariff Waiver Petition at 4.

21 *See, e.g., Norwalk Power, LLC*, 120 FERC ¶ 61,048, P 58 (2007) (the supplier first "bears the burden to . . . establish that Market Rule 1 as currently filed with the Commission is unjust and unreasonable with regard to the compensation of generating facilities needed, as relevant here, for reliability in Connecticut"), *order on reh'g and clarification*, 122 FERC ¶ 61,273 (2008).

Commission to reject Mystic's request to limit the scope of any hearing and settlement judge procedures to only those provisions of the cost-of-service agreement that Mystic has modified

III. MYSTIC'S PROPOSED COSTS FOR THE CONTRACT EFFECTIVE PERIOD HAVE NOT BEEN SHOWN TO BE JUST AND REASONABLE.

A. Overview of the Components of the Supplemental Capacity Payment

The proposed Agreement would provide a Supplemental Capacity Payment that generally provides for cost recovery for Mystic 8 & 9 and for the Everett LNG facility. As shown in Schedule 3 of the Agreement, and described in Mystic witness Berg's testimony,[22] the Monthly Supplemental Capacity Payment equals the Maximum Monthly Fixed Cost Payment less a Winter Fuel Security Penalty and less Revenue Credits, which include Capacity Performance Penalties/Incentives.

The Maximum Monthly Fixed Cost Payment consists of:

- The Annual Fixed Revenue Requirement ("AFRR") of the Mystic units, which Mystic proposes to be $218,974,263 for the 2022/2023 CCP and $186,951,485 for the 2023/2024 CCP;
- The Monthly Fuel Supply Cost, which in turn consists of:
    - Fixed costs and return on investment of Everett;
    - Variable Operations and Maintenance ("O&M") costs of Everett;
    - Pass-through of various fees ("new regulatory costs," pipeline transportation costs, costs/credits associated with diversion or cancellation of cargos; an administrative fee for administrative services required to arrange for fuel supply; and credit and collateral costs);
    - Daily gas sales costs;
    - Credit for forward-third party sales;

[22] Berg Testimony at 9-10, 14-19.

- An "Actual Fuel Cost Adjustment," based on the difference between the Stipulated Variable Costs and actual fuel costs.[23]

Mystic also proposes to recover future capital expenditures for not only the Mystic 8 & 9 but for the Everett facility as well.

The Monthly Fuel Supply Cost warrants very close scrutiny, as it is a novel cost recovery mechanism not included in the *pro forma* agreement. The Monthly Fuel Supply Cost is the monthly full fixed and variable cost recovery for the Everett LNG facility, including cost recovery for management decisions concerning fuel inventory and costs associated with fuel sales to third parties. The costs to be flowed through this new recovery mechanism are set by the proposed intra-affiliate Transaction Confirmation attached as Exhibit MYS-004 (and which is not the complete contract). In addition to full fixed and variable cost recovery for the Everett LNG facility, this Fuel Supply Cost component in the Supplemental Capacity Payment also would provide for additional fuel cost recovery through an Actual Fuel Cost Adjustment. The Actual Fuel Cost Adjustment would recover the difference between components of the Stipulated Variable Costs and the commodity cost of fuel charged to Mystic by its Everett LNG affiliate.

Netted against the Maximum Monthly Fixed Cost Payment is (1) a Winter Fuel Security Penalty, and (2) Revenue Credits. The Revenue Credits include revenues earned in the Forward Capacity Market and Capacity Performance Payments (as calculated under Section 3.6 of the proposed Agreement), infra-marginal revenues earned in the New England markets (as calculated under Section 4.4), and any other revenues reported to the ISO.

Based on NESCOE's preliminary analysis, the various components comprising the Supplemental Capacity Payment have not been shown to be just and reasonable.

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[23] *Id.* at 10.

B. The Projected Capital Expenditures Require Close Scrutiny.

As a threshold matter, an issue of material fact that the Commission should set for hearing and settlement procedures is whether full cost recovery of the Everett LNG facility *plus* the cost of $13.575 million in new capital investment flowed through the Monthly Fuel Supply Charge is just and reasonable.[24] The Everett LNG facility, as far as NESCOE is aware, is not planning to retire, which raises a fundamental question as to whether the full cost recovery of the Everett LNG facility from New England electricity consumers is reasonable. Additionally, with respect to capital expenditures to be made between June 2019 and May 2022, Mystic has failed to demonstrate whether recovery of such payments is just and reasonable in light of Mystic's existing capacity supply obligations prior to FCAs 13 and 14.

The proposed capital expenditures also raise a number of questions. First, the projected capital expenditures do not demonstrate any consideration of whether the expenditures will in fact be needed to keep Mystic 8 & 9 operational through May 31, 2024. The projected capital additions for Mystic 8 & 9 total more than $64,000,000 during the two-year term of the Agreement,[25] with an additional $18,000,000 in capital expenditures for Everett.[26] The need for many of these projects is variously described as "[b]ased on annual equipment inspections and known service-duty wear," or "[b]ased on equipment age."[27] While preventive maintenance at regularly scheduled intervals may be good practice for equipment that is planned to remain in service for a significant period of time, Mystic has not demonstrated that it is reasonable to

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24 *See* Prepared Direct Testimony and Exhibits of Alan C. Heintz, Exhibit MYS-008, Costs of Service Study at 13, line 25 ("Exh. MYS-008").

25 Exh. MYS-005 at 5.

26 *Id*. at 7.

27 *Id*. at 3-7.

replace and/or refurbish parts on the same schedule when the units are slated to be retired in two years.

Even if, as Mr. Berg testifies, each of the projected capital expenditures, except those related to compliance with North American Electric Reliability Corporation ("NERC") standards, comes directly from the long-term planning budget for Mystic 8 & 9,[28] that does not demonstrate that each of those expenditures remains necessary and prudent in the face of a decision to retire the units imminently. This testimony raises a number of questions, including:

- Will it be just and reasonable to spend nearly $4,000,000 in 2023 to replace inlet screens at Mystic 8[29] when the unit will be removed from service during the first half of the following year?
- Why will it be necessary to spend more than half a million dollars in 2024, on the verge of shutting the units down, to replace batteries and upgrade the building roof at Mystic 8?[30]
- Has the projected $12,000,000 expenditure to move/replace auxiliary boiler from retired Mystic Unit 7[31] been compared to the cost of installing a new auxiliary boiler?
- Does the $12,000,000 include the cost of removing the boiler from Mystic 7? If so, why would this cost be allocated to the operation of Mystic 8 & 9, rather than to Mystic 7's retirement?

It is also unclear what is covered by some of the projected capital expenditures. For instance, it is generally unclear whether capital expenditures include overhead adders in addition to the actual estimated cost of each capital expense item. More specifically, Mystic has budgeted $5.5 million in 2019 for "Replacement of emission controls catalysts in the HRSGs" for Mystic 8,

[28] Berg Testimony at 19:15-20.

[29] Exh. MYS-005 at 5.

[30] *Id*.

[31] *Id*.

and an equal amount for the same project for Mystic 9 in 2021.[32] It is unclear whether this contemplates a complete replacement of the SCR catalyst and CO catalyst; whether the estimated cost is based on competitive pricing; and whether there have been previous replacements of the HRSG emission control catalysts and, if so, how much the replacements cost. Further, the issue of whether these pre-FCA13 capital expenses are necessary to satisfy Mystic's existing capacity supply obligations must be addressed.

Another aspect of the filing that requires clarification is an apparent discrepancy between Mystic witnesses Berg and Heintz regarding projected capital expenditures for Mystic 8 & 9 in calendar year 2022. Mr. Berg lists capital expenditures for that year of $53,782,629.[33] Mr. Heintz, on the other hand, identifies $12,000,000 as "CapEx included in the rates" and $29,282,629 as "Current Year CapEx" for a total of $41,282,629.[34] Setting Mystic's filing for hearing and settlement procedures will permit these types of apparent discrepancies to be clarified so that the Commission and customers can understand what exactly customers are being asked to pay for in connection with the Agreement and whether the request is just and reasonable.

In addition, Exhibit MYS-003 lists two major maintenance projects, expected to cost $9 million each, to be performed on Mystic 8 in 2021,[35] and two such projects for Mystic 9 in 2022.[36] These projects are said to be needed in the years in which they are scheduled due to "annual equipment inspection and known service-duty wear."[37] Mystic does not explain,

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[32] *Id*. at 3-4.

[33] *Id.* at 1.

[34] Exh. MYS-008 at 3.

[35] Exh. MYS-005 at 3-4.

[36] *Id.* at 5.

[37] *Id.* at 3-4, 5.

however, whether the service intervals for these items are based on hours of operation or starts (or both), whether they are based on manufacturers' instructions, and what prior experience has been in the life cycle of each gas turbine. It appears that some of these capital costs ought to be removed as they are O&M related and it is unclear why Mystic did not do so.

C. The Proposed AFRR for Mystic 8 & 9 Has Not Been Shown To Be Just and Reasonable.

1. Various Components of Mystic's Rate Base Are Unsupported.

Schedule 3 to the Agreement provides for Mystic to receive as part of the Supplemental Capacity Payments the estimated AFRR amounts of $218,974,263 for 2022/2023 and $186,951,485 for 2023/2024 that are capped (subject to exceptions). The support for these amounts in the Application fails to provide a substantial basis for concluding that these amounts are just and reasonable. To the contrary, the Application provides ample reason to suspect that Mystic's cost-of-service estimates are overstated.

a. Accumulated Deferred Income Taxes

Mystic's proposed treatment of Accumulated Deferred Income Taxes ("ADIT") is inadequately explained. First, Mystic does not appear to have included a deferred regulatory liability for any excess deferred income taxes related to the Mystic units. Second, the ADIT calculation does not include any consideration for the projected capital additions subsequent to June, 2022. If ratepayers are required to pay for these capital additions, there may be a significant impact on ADIT, and Mystic does not appear to address this.

b. Gas Inventory Level

Mystic witness Heintz notes, Mystic is required to maintain a level of gas inventory on hand, which is included in rate base.[38] Mr. Heintz then states that, for purposes of this filing, "The gas inventory is *assumed* to be on average 50% of the 3.4 BCF resulting in average inventory levels of $15.7 million."[39] Mr. Heintz provides no rationale for choosing one half of Everett's storage capacity,[40] and no historical data is provided from which the reasonableness of Mr. Heintz's assumption could be judged. There is thus no basis upon which the Commission could conclude that this rate component is just and reasonable. Moreover, given that the need for Mystic 8 & 9 is fuel security during the winter months,[41] the basis for requiring customers to pay for a fuel inventory of 50% of capacity year-round warrants further evaluation.

c. Cash Working Capital

Mystic proposes to use one-eighth of annual O&M expenses as a default value for cash working capital.[42] While the Commission generally accepts one-eighth in lieu of a lead/lag study,[43] it is unclear why an electric utility the size of Exelon would not have available a lead/lag study. Because such a study would be expected to show negative cash working capital,[44] the Commission should include this in the issues of material fact it sets for hearing and settlement.

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38 Prepared Direct Testimony and Exhibits of Alan C. Heintz, Exhibit MYS-006 ("Heintz Testimony") at 12:21-22.

39 *Id*. at 12:23-13:2 (emphasis added).

40 Berg Testimony at 5:12-13.

41 Transmittal Letter at 16-17.

42 Heintz Testimony at 9:5-8.

43 *C.f. Duke Energy Guadalupe Pipeline, Inc.*,123 FERC ¶ 61,057 (2008), *order on reh'g*, 131 FERC ¶ 61,037 (2010) (disallowing cash working capital for pipeline cost-based rates in the absence of a fully developed lead lag study).

44 *See, e.g.*, Application, *Entergy Texas Inc.'s Statement of Intent and Application for Authority to Change Rates,* PUCT Docket No. 48371 (May 15, 2018); Application, *Application of Southwestern Public Service Company for Authority to Change Rates,* PUCT Docket No. 47527 (Aug. 21, 2017).

2. A Number of Expense Items Are Not Fully Explained or Supported.

a. O&M Expenses and Use of 2017 Test Year with 2.5 Percent Escalation

Like Mystic's capital expenses, the request for O&M expenses includes a number of items that are either unclear, unsupported, or both. For example, Mystic witness Heintz explains that he started with the actual O&M expenses for 2017, and then escalated those expenses by 2.5% per year to get the estimates for the years 2022-2024.[45] Mystic does not provide O&M expenses for years prior to 2017, so it is not possible to judge whether the use of 2017 as a starting point is representative of O&M expenses in a typical year or what portions of the O&M line items presented are variable versus fixed costs. The failure to provide such figures also makes it impossible to determine whether O&M expenses have in fact escalated by approximately 2.5% annually, or if Mystic's projections are overstated. Nor does Mystic's proposal take into account the fact that maintenance expenses would be expected to fall as the units' retirement dates approach, as there is no need to do maintenance beyond what is necessary to keep the units operating until May 31, 2024. Additionally, using a single escalation factor for all O&M may result in the duplication of certain costs that are also being proposed as capital related in this filing, depending on how such costs are currently treated in the 2017 O&M amounts.

b. Labor Expense

Mystic's filing also raises questions about the reasonableness of its claimed labor expense. First, the amount of overtime is 35.8% of the base pay amount.[46] That amount appears unusually high when considering that a regulated utility typically includes such expenses in the range of

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[45] Heintz Testimony at 9:16-17.

[46] This is the 2017 test year amount which is then escalated based on 2.5%.

13-22 %.[47] Incentive pay is similarly high, at approximately 15% of base pay.[48] Cost-of-service based rates for non-management electric company employees approved by state commissions typically exclude portions of both short-term and long-term incentive pay that are awarded to employees based on financial measures that benefit shareholders.[49]

Contracting O&M expenses also seem on the high side, at about 46% of total O&M expenses.[50] A review of workpapers provided did not set forth the precise nature of the functions to be performed pursuant to the contracts in question.

c. Corporate A&G Expenses

The budgeted amount for corporate Administrative and General ("A&G") expenses is another item that appears to unreasonably high. For 2017, Mystic allocated more than $8.4 million to A&G expense, nearly one-quarter of the total $34.6 million of O&M expenses.[51] According to Mystic witness Heintz, the A&G expenses are determined by use of a wage and salary allocator to allocate to Mystic a portion of the overhead expenses of Exelon, ExGen, and Constellation Holdings, LLC ("Constellation Holdings").[52] Although Mr. Heintz states that the use of a labor allocator for this purpose is "[i]n accordance with Commission precedent,"[53] he

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[47] *See, e.g.*, Application, *Application of Southwestern Public Service Company for Authority to Change Rates*, PUCT Docket No. 47527 (Aug. 21, 2017); Application, *Entergy Texas, Inc.'s Statement of Intent and Application for Authority to Change Rates*, PUCT Docket No. 48371 (May 15, 2018); Application, *Application of Southwestern Electric Power Company for Authority to Change Rates*, PUCT Docket No. 46449 (Oct. 17, 2016).

[48] Exh. MYS-008 at 6.

[49] *See, e.g.,*Order on Rehearing, *Application of Southwestern Electric Power Company for Authority to Change Rates*, PUCT Docket No. 46449 (Mar. 19, 2018); Order No. 87591, *In the Matter of The Application of Baltimore Gas and Electric Company for Adjustments to its Electric and Gas Base Rates*, Md. PUC Case No. 9406 (June 6, 2016).

[50] This is the 2017 test year amount which is then escalated based on 2.5%.

[51] Exh. MYS-008 at 7:40-8:1.

[52] Heintz Testimony, at 9:22-10:12.

[53] *Id*. at 9:22-23.

neither cites to any particular precedent nor provides an independent basis upon which the Commission could determine that use of a labor allocator for this purpose is consistent with cost causation. Setting this matter for hearing and settlement procedures would permit the justness and reasonableness of Mystic's allocation of A&G expenses, especially those of Mystic's upstream affiliates, to be evaluated.

d. Depreciation Expense

NESCOE is unable to determine whether the proposed depreciation expense is just and reasonable, as the filing does not include the actual depreciation rates. It appears that dismantlement costs are included in the depreciation expense. However, no detail on the dismantlement cost is provided, including on whether those costs are net of salvage. NESCOE is additionally concerned that projected plant in service appears to include plant additions, but no retirements.

Without additional information, the Commission and parties to this proceeding will not be able to determine the reasonableness of Mystic's depreciation expense as well as its apparent position that no plant retirements will take place from 2022 to 2024. These issues can be fully vetted through hearing and settlement procedures.

3. Mystic's Proposed Return on Equity/Capital Structure Raise Issues.

Several aspects of Mystic's proposed return on equity ("ROE") and capital structure raise issues of material fact that cannot be satisfactorily determined without a hearing or settlement procedures.

a. Proxy Group

First, Mystic witness Olson makes adjustments to his proxy group—in particular, excluding all companies with less than $2 billion in revenues—that are not supported by

Commission precedent. Indeed, Mr. Olson does not even claim that his adjustment is compliant with the Commission's DCF methodology. Nor does Mr. Olson provide cost of capital information for the companies he excluded, making it impossible to determine from his testimony how the exclusions affected his proposed zone of reasonableness. Similarly, Mr. Olson cites no Commission precedent supporting his decision to exclude Hawaiian Electric because Hawaii is not located on the U.S. mainland.[54]

b. Failure To Use Exelon's Capital Structure

Next, Mr. Olson's ROE analysis relies on a mismatch between the DCF analysis, which measures the cost of capital, and his proposed capital structure. Mr. Olson's DCF analysis begins by developing a proxy group of companies with risk profiles similar to Exelon Corporation, Mystic's ultimate parent.[55] However, he does not use Exelon's capital structure, which as of March 2018, was more reasonably split 50%-50% between long-term debt and equity.[56] Instead, he uses the capital structure of Mystic's immediate parent, ExGen, which has a capital structure of 67.28 % equity and only 32.72% debt. That appears to be an equity-heavy structure for an electric generating company, and Mr. Olson proposes to use it without any determination that ExGen's riskiness is similar to that of his proxy group. Likewise, Mystic does not explain its decision not to use Exelon's capital structure, nor has it cited any Commission precedent for mixing and matching affiliates as Mr. Olson has done.

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54 Prepared Direct Testimony and Exhibits of Charles E. Olson, Exhibit MYS-010 ("Olson Testimony") at 14:6-7.

55 *Id*. at 4:8-10.

56 Exelon Corp., Annual Report (Form 10Q) (Mar. 31, 2018)

c. Unsupported Claim of Continued Anomalous Capital Market Conditions and Placement of ROE at Midpoint of Upper Half of Zone of Reasonableness

Mr. Olson also fails to offer support for his claim that capital market conditions remain anomalous.[57] The entirety of Mr. Olson's analysis in this regard is that "Long-term government bond yields are clearly below where they would be without the earlier actions of the major central banks. The logical conclusion is that capital markets are anomalous."[58] However, the Commission's findings of anomalous market conditions have not simply been based on a determination that bond yields were below where they would have been had the Federal Reserve not taken some action within the last decade. To the contrary, when the Commission determined in Opinion No. 551 that capital market conditions were anomalous, it based that conclusion on its findings that "[b]ond yields remained at *historically low* levels during the study period."[59] Here, by contrast, Mr. Olson offers no historical analysis comparing bond yields during the 2017 test year to historical trends, and he offers no evidence regarding projected bond yields for the 2022-2024 period during which the Agreement will be in effect. The record thus offers no basis upon which the Commission could conclude that capital market conditions remain anomalous.

Even if there were a basis for such a conclusion, Mr. Olson's placement of the ROE at the midpoint of the upper of half of the zone of reasonableness[60] is questionable. The Commission has found "that where anomalous market conditions give us reason to have less confidence in DCF methodology outputs, it is reasonable to consider alternative methodologies

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57 Olson Testimony at 18:7.

58 *Id.* at 18:14-16.

59 *Ass'n. of Bus. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, 156 FERC ¶ 61,234 at P 121 (2016), *reh'g denied*, 156 FERC ¶ 61,060 (2016) ("Opinion No. 551") (emphasis added).

60 Olson Testimony at 19:3-4.

and state-commission approved ROEs in determining a just and reasonable ROE."[61] Only upon finding that the results of alternative DCF methodologies and comparisons with state commission approved ROEs indicated that the DCF was producing results that were unreasonably low did the Commission determine that it should choose a point higher than the midpoint of the range. Here, Mystic provides no alternative DCF analyses and no evidence as to state commission approved ROEs and thus has failed to support its proposal to place the ROE above the midpoint of the range, the result indicated by the Commission's standard two-step DCF analysis.

Mr. Olson's recommendation that the ROE be set at the midpoint of the upper half of the range requires further evaluation for other reasons as well. First, Mr. Olson ignores the fact that the Commission relies on the midpoint of the zone of reasonableness only when it is setting a single ROE for a group of utilities. However, "for a single electric utility of average risk, the best measure of central tendency is the median."[62] Mr. Olson offers no evidence to demonstrate why the median of a properly calculated zone of reasonableness would not provide a just and reasonable return for Mystic. Finally, Mr. Olson's reliance on Opinion No. 551 in this regard[63] is also unavailing. In finding that capital market conditions there were anomalous, and that placement of the ROE at the upper midpoint was justified, the Commission relied on its earlier findings in Opinion No. 531.[64] However, the D.C. Circuit vacated FERC's finding in that regard:

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[61] Opinion No. 551 at P 127.

[62] *So. Cal. Edison Co*., 131 FERC ¶ 61,020 at P 92 (2010), *aff'd in relevant part S. Cal. Edison Co. v. FERC*, 717 F.3d 177 (D.C. Cir. 2013).

[63] Olson Testimony at 18:20.

[64] *Martha Coakley v. Bangor Hydro-Elec. Co*., 147 FERC ¶ 61,234 (2014), Opinion No. 531-A, *order on paper hearing*, 149 FERC ¶ 61,032 (2014), Opinion No. 531-B, *order on reh'g*, 150 FERC ¶ 61,165 (2015), *vacated by Emera Maine v. FERC*, 854 F.3d. 9 (D.C. Cir. 2017) ("Opinion No. 531").

> FERC essentially chose the midpoint of the upper half of the zone because it determined that once it concluded that an upward adjustment from the midpoint of the zone of reasonableness was appropriate, the midpoint of the upper half of the zone was the only available ROE …. Such conclusory reasoning does not establish "a rational connection" between the record evidence and FERC's decision.[[65]]

There is thus no basis for accepting Mystic's proposed ROE as just and reasonable, and it should be set for hearing and settlement.

D. The Monthly Fuel Supply Cost for the Everett LNG Facility Has Not Been Shown to Be Just and Reasonable.

1. The Fixed O&M and Return on Investment Components of the Fuel Supply Cost Are Unsupported.

The Fuel Supply Agreement provides for Mystic to pay to its affiliate, Constellation LNG, the following amounts for Fixed O&M and Return on Investment:

Contract Year 2022:	$7,328,074/month
Contract Year 2023:	$6,856,381/month
Contract Year 2024:	$6,658,432/month[66]

The Application provides insufficient support for the derivation of these amounts. Mystic provides no information regarding historical O&M expenses, or how (if at all) the operation of the plant under Exelon's ownership might differ from operation under the previous owner. Additionally, because the return on investment is based on the same 10.26% ROE that Mystic proposes for Mystic 8 & 9,[67] the return expense for Everett suffers from the same infirmities discussed above regarding Mr. Olson's analysis.

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65 *Emera Maine v. FERC*, 854 F.3d. 9, 30 (D.C. Cir. 2017).

66 Exh. MYS-004 at 2.

67 Olson Testimony at 3:20-21; Exh. MYS-008 at 14:3.

The stated justification for O&M expenses for Everett likewise suffers from many of the same problems as Mystic's claim for O&M expenses related to Mystic 8 & 9. Once again, Mystic simply starts with the 2017 actual expense and escalates by 2.5% per year,[68] without any differentiation among costs that are fixed and those that are variable, and provides no historical data from which one might judge whether the 2017 figures were representative. There is no basis to establish that the cost of operating and maintaining Everett can reasonably be expected to escalate by 2.5% annually through 2025. The lack of support for the 2.5% escalation factor is equally troublesome in Mystic's use of this escalation factor for A&G expenses related to Everett.[69] Indeed, it may be less supportable as an escalator for Everett expenses, given that historical figures were incurred under different corporate ownership.

The rate base amounts claimed for Everett also warrant further evaluation. The 2017 net plant is claimed to be $60,000,000, but it is not clear if that is based on book value or the purchase price. If it is the purchase price, Mystic should not be allowed to earn a return on an amount in excess of the net plant on the books of the previous owner. In any event, Mystic has not explained why it plans additions between now and 2025 that will increase plant in service by more than 50% of the current value.[70]

The Application also raises questions regarding Mystic's claim for cash working capital related to Everett. Mystic provides no explanation for the fact that, in addition to claiming an allowance for one-eighth of O&M expenses, it also adds an additional amount for "Fuel Lag."[71] As Mystic has chosen to use the "one-eighth" method rather than presenting a lead/lag study, the

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[68] Heintz Testimony at 13:9-10.

[69] *Id.* at 13:20-22.

[70] Exh. MYS-008 at 13:1

[71] *Id.* at 13:10-11.

Commission should require Mystic to explain why the one-eighth method should not be considered a proxy for all cash working capital requirements, including fuel.

Next, the ADIT calculation does not show any impacts from the planned capital additions subsequent to June, 2022. Mystic's proposal is that ratepayers will be expected to pay for these additions in total in the year of the capital expense. Therefore, to the extent that Mystic reflects such capital additions in accordance with GAAP for purposes of developing its federal income tax returns, one would expect the reporting of a significant ADIT liability.

Finally, it is unclear whether 2047 is the appropriate retirement year to be used to calculate Everett's depreciation expense. Mr. Heintz states that he used the same remaining life for Everett as for Mystic 8 & 9, since Everett's "main functions is to supply fuel to Mystic 8 and 9,"[72] but this gives short shrift to Everett's other customers. Setting this matter for hearing and settlement procedures would permit this issue to be explored fully.

2. The Variable O&M Costs of the Fuel Supply Agreement Are Likewise Unsupported.

The Fuel Supply Agreement would provide that Mystic reimburse Everett LNG each month for the "variable operating costs" of Everett LNG pursuant to an LNG Terminal Services Agreement (that has not been made available as part of the Application). These variable costs would be passed through to customers without mark-up as a Fuel Supply Cost in the proposed Agreement. Mystic has not provided any information about the variable costs, nor has it provided the proposed LNG Terminal Service Agreement.

[72] Heintz Testimony at 14:2-3.

3. The Various Proposed Pass-Through Fees That Are Part of the Fuel Supply Cost Raise Additional Questions

a. New Regulatory Costs

More information is needed about the expected new regulatory costs, which would be passed through to customers without mark-up as a Fuel Supply Cost in proposed Agreement.

b. Administrative Services Fee

The Fuel Supply Agreement would provide that Mystic reimburse Everett LNG each month for a $127,750 fee charged to Everett LNG by ExGen for unspecified services pursuant to an Intracompany Services Agreement. This fee would be passed through to customers without mark-up as a Fuel Supply Cost in proposed Agreement. Mystic has not provided any information to support the fee, and the proposed Intracompany Service Agreement has not been provided. Nor has Mystic explained whether any portion of the fee would be allocated to other customers of Everett LNG.

c. Credit and Collateral Costs

The Fuel Supply Agreement would provide that Mystic reimburse Everett LNG each month for the "actual credit and collateral costs associated with purchases of LNG to serve [Mystic] and Third-Party Customers," and those costs are passed through to customers without mark-up as a Fuel Supply Cost in proposed Agreement. The Fuel Supply Agreement states that Everett LNG pays the credit and collateral costs to ExGen pursuant to an Intercompany Services Agreement, but Mystic has not provided a copy of that agreement. Mystic has not explained why credit and collateral costs associated with purchases of LNG to serve Third-Party Customers are just and reasonable and should be included as a Fuel Supply Cost under the proposed Agreement.

d. Pipeline Transportation Agreement Costs

The Fuel Supply Agreement provides that Mystic reimburse Everett LNG each month for "demand and commodity charges associated with any pipeline transportation agreements" for the transport and sale of gas to Third-Party Customers. These costs are passed through to customers without mark-up as a Fuel Supply Cost in proposed Agreement. Mystic has not explained why costs associated with transactions with Third-Party Customers are just and reasonable and should be included as a Fuel Supply Cost in the proposed Agreement. Some of these commitments are used to serve other customers, not Mystic, and the costs of certain of the pipeline commitments could potentially exceed their value.[73]

e. Diversion Costs

The Fuel Supply Agreement would provide that Mystic reimburse Everett LNG for any "net fees associated with the diversion of one or more LNG cargo ships scheduled to deliver LNG" and provides for the possibility of a credit should Everett LNG incur a "net benefit" from diverting scheduled LNG cargo ship deliveries. These costs, and potentially credits, are passed through to customers without mark-up as a Fuel Supply Cost in proposed Agreement. These costs could result from sales to other Everett LNG customers, in particular from a customer exercising its right under a Forward Option Transaction to not take delivery.[74] There is no standard of care in the Fuel Supply Agreement that would require Everett LNG to minimize the costs of diversion fees passed through the Fuel Supply Agreement. Mystic provides no information to explain what a "net benefit" is and how it would be calculated, should that event occur.

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73 Affidavit of James F. Wilson in Support of the Comments of NESCOE ("Wilson Affidavit") at P 39.

74 *Id.* at P 40.

f. Daily Gas Sales

The Fuel Supply Agreement would pass through every loss or gain from daily gas sales to Third-Party Customers as a Fuel Supply Cost, without regard for why that transaction is made, *e.g.*, whether the purpose of sales are to manage fuel inventory during the winter period, that the sale was more economic than operating the Mystic 8 & 9 units, or any other reason.

g. Third-Party Sales Credit for Demand Charges

As discussed below in Section IV.B, Mystic's proposal for a Seller's Incentive for Third-Party sales credits raises significant questions.

h. Actual Fuel Cost Adjustment

Unlike the *pro forma* agreement under which a Resource would recover all fuel costs through the Stipulated Variable Cost formula, Mystic's proposed Agreement contains new provisions that purport to "allow[] for the credit or debit of any differences between the fuel cost components of the Stipulated Variable Costs" and the actual commodity cost of the fuel. The Actual Fuel Cost Adjustment modifies cost recovery permitted by the *pro forma* Stipulated Variable Cost. The Actual Fuel Cost Adjustment is noted in Schedule 3 and in Section 4.2 of the Agreement, but it is not explained in any detail. The Stipulated Variable Costs are discussed below in Section III.E.

If the Commission authorizes a second fuel cost recovery mechanism, the "fuel cost components" in Part 2 of Schedule 3 should be defined and include the Stipulated Variable Cost's Fuel Index Price, the Fuel Variable/Other Costs, the Fuel Opportunity Cost, and the Operating Permit Adder.

As proposed, the Revenue Credit in Section 4.4.1 of the Agreement is Energy Revenue less Stipulated Variable Costs which includes the Fuel Opportunity Cost. Since the Actual Fuel

Cost Adjustment does not adjust for the Fuel Opportunity Cost, there is no refund of the Fuel Opportunity Cost through the Actual Fuel Cost Adjustment in part (2) of Schedule 3 or through the Revenue Credit. In effect, when the Fuel Opportunity Cost is positive, Mystic retains that value as a windfall profit. NESCOE does not believe this to be the intent of either ISO-NE or Exelon, but this issue illustrates that even those entities who have spent much more time than NESCOE has been afforded to review the complex set of agreements can miss material aspects of the Agreement. Settlement and hearing procedures are critical to allowing ISO-NE, Exelon, and interested parties to work through these types of issues.

Likewise, Section 4.2 of the proposed Agreement does not define "actual fuel costs." Greater specificity is needed before Applicants should be permitted to seek recovery of the full commodity cost of fuel. The only definition of "actual fuel costs" is in the Fuel Supply Agreement and that does not appear to be reasonable because it (i) could be modified by Exelon without Commission review, and (ii) does not specify a proposed calculation for determining the weighted average cost of fuel. Another concern is that nothing in the proposed Agreement would require Mystic to produce documentation necessary for the ISO to verify actual fuel cost.

E. The Proposed Stipulated Variable Costs Have Not Been Shown To Be Just and Reasonable.

1. Overview

The proposed Agreement provides that Mystic would offer energy and reserves at the Stipulated Variable Cost, as defined by Section 3.4.1.[75] The Stipulated Variable Cost is a self-adjusting formulary rate that consists of a Stipulated Start Up Cost, a Stipulated No-Load Cost,

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[75] Mystic is required to set its Supply Offer to the Stipulated Variable Cost. The term "Reserves," used, *e.g.*, in Section 3.4 of the proposed Agreement ("For each day, the Lead Market Participant shall offer for sale energy and ancillary services (which include Regulation and Reserves) into the New England Markets . . . ") is not defined.

and a Stipulated Marginal Cost. Each component is also a self-adjusting formulary rate. For instance, the Stipulated Marginal Cost is the product of the Incremental Heat Rate and the Fuel Price, plus Variable O&M. The Stipulated Variable Cost may be updated by Mystic at the most frequent time interval permitted by the Tariff. The Stipulated Variable Cost is a critical element of the Agreement, as it will determine when the plants run.[76]

2. The Formula for Stipulated Variable Costs Can Only Be Changed Pursuant to Section 206 of the Federal Power Act.

As noted elsewhere, Mystic has proposed very substantial changes to the *pro forma* cost-of-service agreement. In at least one instance, Mystic has proposed a change the Commission cannot, and certainly should not, accept.

Section 11.11 of the *pro forma* agreement recognizes that the reimbursement mechanism for RMR units is in the form of a formula rate, and it provides that "the formula for calculating Stipulated Variable Costs shall be established pursuant to an FPA Section 205 proceeding to be initiated by application of Owner provided, however, that any application for changes to the formula for calculating Stipulated Variable Costs shall be made only under Section 206." This is consistent with the nature of formula rates. As the Commission has often noted, "[t]he filed rate in this circumstance is the formula."[77] Challenges to the justness and reasonableness of the filed rate, as opposed to challenges to the implementation of the formula rate, are required to be brought pursuant to Section 206.[78]

Mystic, however, proposes to delete the reference to Section 206, and to authorize itself to seek changes to the formula pursuant to Section 205, which would enable those changes to

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76 Wilson Affidavit at P 47.

77 *Cal. Indep. Sys. Operator Corp*, 90 FERC ¶ 61,315 at 62,042 (2000), *aff'd Pub. Utils. Comm'n of Cal. v. FERC*, 254 F.3d 250, 254 (D.C. Cir. 2001).

78 *Pub. Serv. Elec. and Gas Co.*, 124 FERC ¶ 61,303 at P 18 (2008) (citing *Pub. Utils. Comm'n*, 254 F.3d at 258).

take effect automatically after 60 days, subject only to the Commission's authority to reject the filing or suspend for a maximum of five months. Thus, any measure of certainty provided by formula rates would become a one-way street: customers would still be relegated to the lengthy FPA Section 206 process if the formula produced excessive rates, but Mystic could effectuate a favorable change within 60 days (or less, if the Commission waived the notice requirement).

This is neither just and reasonable nor consistent with the Commission's statement in accepting the *pro forma* agreement as a part of the ISO Tariff. In so doing, the Commission stated explicitly, "consistent with Article 11.11 of the *pro forma* Cost of Service Agreement, any application for changes to the formula for calculating Stipulated Variable Costs shall only be made under Section 206."[79] Having been accepted by the Commission as a part of the ISO Tariff, the requirement to make a Section 206 filing to change the formula is itself a part of the ISO's filed rate, and if Mystic wishes to change the ISO's Tariff to afford itself Section 205 rights, it must file a complaint pursuant to Section 206 and demonstrate that the existing provision in the *pro forma* is unjust and unreasonable.

3. There Is Insufficient Information in the Application for the Commission to determine whether Mystic's proposed Stipulated Variable Cost Is Just and Reasonable.

The Stipulated Variable Cost definition includes a "fuel opportunity cost" component that can capture two important circumstances: (i) when regional natural gas prices, represented by the Algonquin Gas Transmission price, are high, and the Everett sendout may be more valuable delivered to the pipelines than to the plants, and (ii) when there is a limited supply of fuel and the fuel should be valued at a price higher than its replacement cost.

[79] *ISO New England*, 125 FERC ¶ 61,102 at P 110 (2008).

Although including opportunity costs in the Stipulated Variable Cost may, in theory, contribute to achieving the most valuable use for the Everett supply, the details of Mystic's proposed opportunity cost provisions raise some issues.[80]

First, some, but generally not all, of the Everett sendout that can serve Mystic 8 & 9 could, if the plants are not dispatched, instead be delivered to the New England natural gas markets through Everett's pipeline interconnections. Therefore, regional natural gas prices may serve as an "opportunity cost" for some, but not all of the Mystic capacity. To accurately represent the opportunity cost of Mystic generation, two Stipulated Variable Costs and offer prices would need to be calculated: one corresponding to the volumes that could otherwise go to pipelines and the other for volumes that could not.[81]

Second, while in theory assigning an opportunity cost to scarce supply is a sound concept, again, there are no details about how this opportunity cost would be set. This is a complex and important question. These opportunity costs adders can lead to inefficient use of the resource and have real world cost impacts too.[82] Furthermore, while the Stipulated Variable Costs with opportunity costs may result in the plants not being dispatched at times because the fuel is more valuable in the natural gas markets (as represented by the Algonquin Citygate price), there is no guarantee that Constellation LNG will offer the supplies to the natural gas markets at such times. The Fuel Supply Agreement does not provide any obligation or incentive for Constellation LNG to engage in such short-term sales.[83]

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[80] Wilson Affidavit at P 48.

[81] *Id.* at P 49.

[82] *See id.* at P 50.

[83] *Id*. at P 51.

The proposed Agreement completely revises certain components determining the value of the above-mentioned Stipulated Variable Costs and may not be just and reasonable. For instance, the proposed Agreement changes how the Fuel Price would be calculated in Section 3.4.1, and would include a Fuel Price Index, a Fuel Variable/Other Costs, Emissions Cost, Fuel Opportunity Cost Adder, and Operating Permit Adder. The Fuel Index Price would be set at a current daily price based on either "a world LNG index" (with no further detail provided) or the weighted average cost of gas at the Everett LNG facility (subject to the discretion of the ISO Market Monitor and providing no detail as to how that average cost would be calculated).

A new Fuel Opportunity Cost would adjust the Fuel Index Price upward to the AGT (Citygate) fuel index price and/or provide another adjustment to account for "a limited supply of fuel, as approved by ISO and ISO Market Monitoring."[84] The Application contains no information to explain how an opportunity cost associated with low storage tank levels would be determined, or why opportunity costs could be deployed during times when fuel security is not a reliability issue.

IV. MYSTIC'S APPLICATION RAISES UNANSWERED QUESTIONS ABOUT WHETHER THE FUEL SUPPLY AGREEMENT AS STRUCTURED IS JUST AND REASONABLE

A. Mystic's Premise That Everett is the Least Cost Option Requires Further Evaluation.

The premise of the Application is that Everett is the most economical fuel supply for Mystic 8 & 9. This claim warrants further examination. Mr. Berg testified that Everett was determined to be least cost based on the two-year need identified by ISO-NE.[85] As Mr. Wilson points out, however, the suggestion that a non-affiliate would price based on the next cheapest

[84] Agreement § 3.4.1.4.

[85] Berg Testimony at 11:12-15.

alternative basically assumes that the non-affiliate would exercise market power against Mystic 8 & 9 for the two years.[86] ISO-NE and its stakeholders seek a longer-term fuel security solution for New England, and Mr. Berg is "optimistic" that this will result in the Everett facility and the Mystic plants remaining in service over the long term.[87] Using a longer amortization period for the potential up-front costs of investments to develop alternatives might show them to be lower cost than Everett over the long term. And a rational non-affiliate operating Everett might choose to supply Mystic 8 & 9 at a lower price closer to the cost of the plants' long-run alternatives, with the goal of potentially maintaining the plants as customers over the long-term, not just for two years.[88] Therefore, the underlying costs of Everett, and of Mystic 8 & 9's alternatives to Everett, over the short-run and long-run, warrant further evaluation.[89] While it may be the case that Mystic 8 & 9 do not have an alternative to Everett in the near term, the proposed relationship between the plants and Everett, under the proposed Fuel Supply Agreement, appears to risk passing unnecessary costs through to customers.[90]

B. The Seller's Incentive, Related to the Credit for Third-Party Sales, Requires Close Scrutiny.

The Everett facility serves local gas distribution companies and marketers in addition to Mystic 8 & 9.[91] Maximizing the value of the Everett facility appears to be a complex task, involving management of short-term and longer-term contractual commitments and managing LNG deliveries, among other challenges. The Fuel Supply Agreement calls for passing through

86 Wilson Affidavit at P 27.

87 Berg Testimony at 11:18-12:1.

88 Wilson Affidavit at P 27.

89 *Id.* at P 27.

90 *Id.* at P 8.

91 *Id.* at PP 18-20.

to Mystic all of Everett's costs net of the revenues from other customers, however, that agreement does not appear to provide incentives for Constellation LNG to minimize the costs passed through by maximizing the value of Everett in the marketplace. In particular, the Fuel Supply Agreement provides no incentive or requirement for shorter-term sales (*i.e.*, less than three months) to other customers, while a "Seller's Incentive," the details of which raise many questions, is provided for longer-term transactions.

Mr. Berg states that the Seller's Incentive for these transactions was not proposed by Mystic, but was added to the Fuel Supply Agreement at the request of ISO-NE.[92] The longer-term transactions will represent the more valuable services because they allow customers to plan on the deliverability to meet peak day needs.[93] The Seller's Incentive is proposed to be 50% of the "fixed payments" due from the customer minus the "contract incremental cost" and a "tank congestion charge." The contract incremental cost is calculated as the fraction of the "anticipated total variable cost" of a 3 Bcf LNG cargo represented by the transaction (a 1 Bcf transaction would be allocated 1/3 of the cost). The "tank congestion charge" represents additional cost that may result due to additional LNG cargos and the resulting potential need for uneconomic sales to accommodate such cargos; the charge is to be set based on a monte carlo simulation (Fuel Supply Agreement, Schedule A provides a "conceptual outline" of how the charge would be determined). The Seller's Incentive is calculated at the time of "contract execution" and there is no subsequent adjustment of it, except in instances of Seller non-performance.[94]

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92 Berg Testimony at 16.

93 Wilson Affidavit at P 30.

94 *Id.* at P 31.

The proposed Seller's Incentive in the Fuel Supply Agreement is not clearly defined and raises many questions, including:

- Various elements of the Seller's Incentive calculation are not clearly defined. It is not clear how "anticipated" variable costs would be determined, or exactly which types of possible contract charges would be considered "fixed payments." Nor are the various assumptions and inputs to the monte carlo simulation described.[95]

- The formula for the Seller's Incentive (based on fixed payments net of allocated "anticipated" variable costs and congestion charge) may not accurately represent the value of the transaction, from which an incentive payment may be warranted. Such transactions may result in increased (or decreased) risk of having to divert cargoes, may require firm pipeline transportation, and may reduce opportunities for other, potentially more profitable transactions, among a few of the potential costs or benefits of transactions that may not be captured in the formula.[96]

- To the extent the Seller's Incentive does not accurately determine the value of the transaction, removing the 50% portion of the net revenue for the Seller's Incentive may leave the transaction uneconomic. That is, the transaction may actually increase not decrease the total cost passed through to customers under the Fuel Supply Agreement.[97]

- The Seller's Incentive formula may even afford Exelon opportunities to structure forward transactions to maximize incentive payments, and these structures may result in inefficiencies and added cost passed through the Fuel Supply Agreement.

- The Fuel Supply Agreement prohibits the seller from entering into forward transactions with prices "less than Seller's cost of LNG supply… at the time of execution…", another contract provision that is not clearly defined.[98]

C. The Sendout Value Raises Questions.

Setting aside the boiloff gas, Everett has roughly 815 MMcf/d of sendout capacity, of which Mystic 8 & 9 represent 250 MMcf/d, or 31%.[99] While the LNG-based commodity, if priced based on world LNG prices, will generally be expensive compared to the pipeline

95 *Id.* at P 33.

96 *Id.* at P 34.

97 *Id.* at P 35.

98 *Id.* at P 36.

99 *Id.* at P 19.

alternatives, Everett's customers will value the facility's ability to reliably deliver supplies even when the pipelines are constrained (such as during extreme cold), thereby providing incremental peak day deliverability to the Boston region. Local Distribution Companies ("LDCs") will likely be willing to pay relatively high prices for secure peak-period deliverability even if they actually call on the deliverability relatively rarely. Therefore, while details of Everett's sources of revenue are not available, a facility of this type might recover fixed costs based on the maximum sendout committed to different customers (as do pipelines, with straight fixed-variable rates). While the ISO's testimony in the Tariff Waiver Petition states that Mystic 8 & 9 have recently accounted for about two-thirds of Everett's sendout,[100] Everett's value and cost recovery may be more closely related to the sendout capacity, not actual sendout volumes.[101]

D. Details About Contractual Arrangements with other Customers Are Missing from the Application.

Details about the nature of the contractual arrangements between Everett and its various customers are not available. However, Everett's current owner, Engie, continues to pursue short and long term contracts for winter and summer firm peaking gas with a customer mix that includes LDCs, power generators, and marketers.[102] As one example, Boston Gas Company (d/b/a/ National Grid), an LDC, recently considered a proposal from Engie to meet an incremental capacity need.[103]

Different customers would typically seek somewhat different services, depending upon the load profile and portfolio of other firm assets, which may include firm flowing gas supply

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100 Testimony of Richard L. Levitan and Sara Wilmer on behalf of ISO New England, Inc., Tariff Waiver Petition, Exhibit ISO-2 at 7.

101 Wilson Affidavit at P 19.

102 *Id.* at P 20 n.7.

103 *Id.* at P 20.

and LNG storage-based services, among others. In particular, some LDCs may be more willing to commit in advance to firm deliveries from Everett to replenish their LNG storage, while other LDCs may seek an option on supplies from Everett that would only be called upon if needed during a colder than normal winter. This is suggested by the Fuel Supply Agreement, which anticipates both Forward Sale and Forward Option transactions (page 4). Some customers may seek relatively more deliverability over a short period, while others may be able to spread the received volumes over a longer period of time. Some customers may be willing to accept responsibility for cargo diversion costs, while others may prefer such costs to be rolled into demand charges. Some of Everett's customers may have multi-year contractual commitments, or may enter into similar arrangements with Everett each year that are renewed annually.[104] In providing services to its various customers, Everett faces various forms of competition. In addition to the pipelines serving the region, New England has three operating LNG import terminals and a total of 16 Bcf of LNG storage capacity at 46 facilities. The LNG storage facilities can be replenished by trucks loaded within or outside the region.[105] This information suggests that maximizing the value of the Everett facility in the marketplace is a fairly complex problem involving providing a variety of services to a variety of customers and managing the LNG storage and deliveries to support those services. Managing the facility in a commercially sound manner will entail various tradeoffs at times. Decisions about scheduling additional cargoes, and cancelling or diverting cargoes, will involve trade-offs between current costs and future costs and risks.[106]

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[104] *Id.* at P 21.

[105] *Id.* at P 23.

[106] *Id.* at P 24.

Whether the proposed arrangement under the Fuel Supply Agreement is likely to result in reasonable costs passed through to customers merits further evaluation. Such evaluation should consider many facts that have not been presented in the Mystic Application, such as:

- The demand for Everett's services by other customers, the particular services likely to be most in demand, and the potential profitability;
- The potential impact on operations and costs of additional short-term and long-term commitments to other customers, including "tank congestion" costs, among other potential impacts;
- The costs of the various pipeline transportation commitments, and the benefits they provide;
- The costs associated with cargo diversions, and the amount of flexibility in the LNG supply chain to divert cargoes, or to schedule additional cargoes when needed;
- The costs associated with sales of power or gas at a loss to reduce storage to accommodate an incoming cargo, and how such sales will be coordinated between the plants and the Everett facility.[107]

An alternative approach to the Fuel Supply Agreement, that would be simpler, more common, and more transparent, would entail a fixed monthly payment (for instance, based on Mystic 8 & 9's portion of Everett's firm sendout capacity), and leave all other costs and revenues associated with Everett's services to other customers to Constellation LNG. Such an approach would leave Constellation LNG with full incentives to maximize the value of the facility through the services provided to other customers.[108]

V. THE REVENUE CREDITS REQUIRE FURTHER SUPPORT

The proposed Agreement includes new penalty-type incentives that would potentially reduce the monthly Supplemental Capacity Payment that Mystic would receive. The maximum

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[107] *Id.* at P 10.

[108] *Id.* at P 11.

penalty assessed to Mystic in any month pursuant to these provisions would be $18.49 million, except during the three winter months when the maximum penalty would be $30 million. The maximum total penalties during a Capacity Commitment Period would be $110.30 million, which is about one-half of the AFRR in Capacity Commitment Period 2022/2023.

A. The Capacity Performance Payments and Penalties Should Be Carefully Examined.

As described by Section 4.4.2 of the proposed Agreement, Section 3.6 would govern calculation of positive and negative Capacity Performance Payments and the contribution of those payments toward the Revenue Credit. Thus, the ISO-NE Tariff provisions determining Capacity Performance Payments would no longer apply to Mystic 8 & 9. These alternative provisions regarding Capacity Performance Payments must be closely scrutinized to ensure that all revenues that would usually be credited to Mystic 8 & 9 for performance under the Tariff are credited in favor of customers in the calculation of the Revenue Credit (so that the Supplemental Capacity Payment charged to New England customers is appropriately reduced).

Pursuant to Section 3.6, payments would first be credited against penalties, and net payments would be credited against costs, while negative payments (penalties) would be borne by Mystic. This provision leaves the incentive for performance in place while removing the incentive for over-performance by passing the incentive payments through to customers.[109]

It is unclear that this modification of the treatment of these payments will be in the customers' interest. If leaving the incentive in place could at times lead to additional over-performance, it is possible customers would benefit more from this additional generation than from the crediting of such incentive payments.[110]

[109] *Id.* at P 41.

[110] *Id.* at P 42.

B. The Winter Fuel Security Penalty Raises Questions, Has the Potential for Unintended Consequences, and May Not Be Needed.

Section 3.7 of the proposed Agreement would subject Mystic to a Winter Fuel Security Penalty ("Winter Penalty") when conditions are such that there are very high natural gas prices and very low Everett storage. As Mr. Wilson explains, the Winter Penalty triggers if the following conditions occur:

- Natural gas prices in the Boston area exceed a certain price;
- The storage level at the Everett facility falls below a specified level
- There is no imminent delivery scheduled at Everett; and
- The Mystic 8 & 9 units' Capacity Performance Score is negative.[111]

The maximum the Winter Penalty would be is $30 million per month in the winter months, which is supposed to provide Mystic an incentive to ensure that, if such a natural gas price spike is possible, Everett maintains at minimum level of inventory (at least 510 MMcf) unless a delivery is imminent. [112]

Although the intended purpose of the Winter Penalty is clear, it is less clear whether it is needed or whether it may have unintended consequences. NESCOE has concerns that it may distort management of the Everett facility and could lead to inefficient use of the Everett storage under scarcity circumstances. In particular, under Section 3.4.1.4 of the Agreement, the Stipulated Variable Cost that drives the dispatch of the Mystic plants includes a "fuel opportunity cost" that may reflect "the opportunity cost associated with a limited supply of fuel." If the fuel opportunity cost is set in a manner that takes into account the relevant information (*e.g.*, anticipated weather and plant demand, natural gas market conditions, the storage level and likely

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[111] *Id.* at P 43.

[112] *Id.*

schedule of replenishment, among other considerations), this approach could result in efficiently dispatching (or not dispatching) the plants under circumstances of low storage. Thus, Mystic may have sufficient incentive to manage storage effectively without the Winter Penalty.[113] Additionally, there is the possibility that the Winter Penalty could provide Mystic an incentive to try to freeze the storage at the triggering level (510 MMcf), thus withholding sendout from the Mystic plants, other Everett customers, and the natural gas markets, to avoid the Winter Penalty. This may not be the efficient choice at times, or the choice that best contributes to reliability, for instance such as in the last days of an extended cold snap.[114]

If the Commission decides to retain the Winter Penalty in some form, the triggering conditions for the Winter Penalty raise additional questions and issues of material fact:

- It is unclear whether it is appropriate for the penalty to apply when a "Capacity Scarcity Conditions" exist outside the Capacity Zone in which the Mystic Resources are located.[115]

- It is not clear how some of the triggering conditions, *e.g.*, certain volumes in the storage tank at the LNG terminal at certain times, provide a greater assurance of performance (*i.e.*, if the triggering conditions are set so high that they would rarely trigger, those conditions provide little additional incentive). Or, as discussed above, the conditions could provide a reason to withhold sendout.

- It is unclear how these conditions would be verified under the disclosure provisions in Section 3.8 (which, as discussed below, may be insufficient) and without providing ISO-NE with clear authority under contract to audit the LNG terminal in Section 6.2.

- Mystic provides no support for the values triggering the penalty or affecting the calculation of the penalty. For instance, there is no information about why gas prices must increase above $17.50/MMBtu gas price. The basis for that rate and other triggering values should be explained and factually supported.

[113] *Id.* at P 44.

[114] *Id.* at P 45.

[115] Capacity Scarcity Conditions may occur in one or more Capacity Zones that have a zonal real-time reserve requirement (*e.g.*, SENE or NNE zones, or can occur system-wide indicating that reserves are inadequate at a system-wide level).

In addition, with respect to the calculation of the penalty rate as the sum of the Reserve Constraint Penalty Factors ("RCPFs"), more information is required to understand why Mystic has proposed fixed rates for the RCPFs that may be different than the RCPFs effective during the requested two-year term of the agreement. In short, without a better understanding of these issues including the triggering conditions, it is difficult to understand the contractual risks and benefits to consumers, and therefore, whether these provisions are just and reasonable.

VI. MYSTIC HAS NOT SHOWN THE SUBSTANTIALLY MODIFIED FORM OF COST-OF-SERVICE AGREEMENT TO BE JUST AND REASONABLE.

Mystic proposes many changes to the *pro forma* Agreement in the Tariff and views these alterations as "just and reasonable and necessary to enable Mystic 8 & 9 to continue to meet ISO-NE's fuel security need."[116] In the time available, NESCOE preliminarily identifies the following issues.

A. The Commission Should Consider Requiring the Agreement To Provide for a Formula Rate with a True-Up so That the Expenses Ratepayers Pay Do Not Exceed the Actual Cost of Ensuring Fuel Security.

For a contractual term that begins four years in the future, Mystic has started with expenses incurred during 2017 and escalated those costs by 2.5% annually through the end of the two year term of the contract. *See* Section III.C.2.a, *supra*. It is of course impossible to know if each of the projects for which Mystic has budgeted will prove to be necessary, and whether Mystic's cost projections will prove to be accurate. That is even more true with regard to the projected capital expenses for Everett, which are based on information provided by the current owner.[117] As a result, even assuming that Mystic has not erred on the high side in formulating its estimates of future expenses, it is likely that actual expenses for the years 2022 to 2024 will

[116] Transmittal Letter at 16-17.

[117] Berg Testimony at 20:3-9.

differ significantly from projected expenses, especially considering that some of those expenses will relate to operation of an LNG facility which Mystic and its affiliates have no experience in operating.

This is not simply a theoretical concern. In one case in which the just and reasonable rates to be recovered under an RMR generating contract were litigated, the Presiding Judge found, and the Commission affirmed, that the use of budgeted capital expenditures resulted in the utility being compensated for *nine times* the amount of its actual capital expenditures.[118] The proposed rates in that docket proved to "greatly exceed[]"[119] the utility's actual costs. To avoid allowing the generator in that case to obtain a windfall, the Commission affirmed the Presiding Judge's determination that the fixed-cost component of the RMR units' compensation should be based on actual costs.[120] Unlike in the MISO proceeding, where the actual costs were already a matter of the historical record, in this docket, the Commission will not have the benefit of being able to compare projected expenditures to actuals, even if it were to be litigated. That is because, unlike *Midcontinent Independent System Operator, Inc.*, ISO-NE has a three-year forward capacity market, and units that seek to retire must give three years' notice of their retirement plans. To avoid permitting Mystic 8 & 9 to collect excessive rates, the excessive nature of which may not become apparent until 2022 at the earliest, NESCOE urges the Commission to consider requiring annual true-ups to actual prudently-incurred costs, including costs related to operation of Everett. This would protect ratepayers from paying excessive rates and would also protect Mystic from the threat of having to incur prudent expenses it might be unable to recover, in

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118 *Midcontinent Indep. Sys. Operator, Inc.*, 161 FERC ¶ 61,059 at PP 14, 28 & n.79 (2017).

119 *Id*. at P 28.

120 *Id*. The Commission held that RMR "compensation must not exceed a resource's going-forward costs or a full cost-of-service, depending on the Tariff language in effect at the time." *Id*. at P 30.

connection with facilities it wishes to retire. Indeed, Mystic itself has proposed a true-up to actual expenses when incurrence of Additional Expenses, defined as "costs associated with O&M Items in excess of the Fixed O&M Expenses,"[121] becomes necessary to recover from a Forced Outage.[122] Use of a true-up mechanism is at least as necessary with regard to the very substantial level of planned capital expenditures.

The use of a true-up mechanism is also particularly appropriate to protect ratepayers in view of proposed Section 7.2, "Additional and Other Expenses," which states that Mystic and its affiliates are not required to incur any Additional Expenses, and that if they do incur certain costs not reimbursable under the Agreement, they "shall be entitled to make a Section 205 filing to recover those costs at the Commission." Mystic should be authorized, at most, to make a Section 205 filing to *seek* to recover unreimbursed costs. That aside, it is not just and reasonable for the Agreement to provide that (i) in the event Mystic's expenses exceed its expectations, Mystic is entitled to seek to recover the shortfall, but (ii) if costs are less than expectations, Mystic is entitled to keep the windfall. "Heads we win, tails you lose" is not just and reasonable ratemaking. This approach invites a "budget high and spend less" mindset, putting consumers at risk of overpayment and underperformance.

B. Section 2.2, Term and Termination of Agreement

In its transmittal, Mystic describes the term of the agreement as "two 12-month terms."[123] This representation is contrary to Section 2.2 of the Agreement that specifies the agreement "shall remain in effect *for at least* two 12-month Capacity Commitment Periods." The phrase "at

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[121] Agreement, § 1.1.1.

[122] *Id.*, § 7.1(e).

[123] Transmittal Letter at 22.

least" should be deleted from Section 2.2 to remove any confusion about the minimum term of the agreement.

The proposed Agreement modifies the *pro forma* agreement to require each extension beyond the initial term to be in whole-year increments, and it removes the *pro forma* language that would have allowed ISO-NE to terminate the agreement within 120 days' notice. Moreover, a new Section 2.2.1 of the Agreement requires that ISO provide more than three years' notification to Mystic of its election to extend the agreement for reliability. Together these modifications appear to limit the ability of ISO-NE to assess the continued reliability need for the units and remove flexibility to terminate the agreement once that determination has been made that the units are no longer needed for reliability. NESCOE urges the Commission to direct ISO-NE to seek approval before extending the agreement and to make periodic *(e.g.*, quarterly) compliance filings reporting on the fuel security concerns affecting reliability that caused ISO to reject the Retirement De-List Bids for these units and necessitated this Agreement.

The termination provisions in the proposed Agreement's Section 2.2.2 are mostly unchanged and therefore the same in material respects as the *pro forma* agreement. However, these *pro forma* conditions intended to ensure Resource availability to resolve local transmission security issues may not be suited to this Agreement's regional reliability purpose for two reasons. First, Section 2.2.2 would allow ISO-NE to terminate the Agreement only if the Resource falls short of an availability metric indicating capability to provide capacity supply services. It is not clear whether these conditions for termination, which the Commission found appropriate for a cost-of-service agreement necessary to resolve local transmission security issues, are appropriate for the fuel security issues that are the purpose of this Agreement. For instance, the termination condition applies to the 12-month period, and would not permit ISO-NE to terminate if Mystic 8

& 9 fail to perform during the critical three-month winter period even though management of winter fuel security is the primary purpose of this agreement.[124] In addition, the provision as proposed could be useless because it applies to "*the* Resource,"[125] while the Agreement covers two units and the *pro forma* language in Section 2.2 allowing for partial termination by ISO with respect to one unit now has been struck.[126]

Second, the Agreement does not provide any option for termination by ISO due to an extended outage resulting from a *force majeure* event. ISO-NE should have a right to terminate for Mystic's inability to provide fuel security for an extended period due to force majeure in light of the requested extended term of the agreement to at least two Capacity Commitment Periods.

C. Section 3.5, Self-Scheduling, Raises Questions.

Consistent with the *pro forma* agreement, Section 3.5 of the proposed Agreement permits Mystic to request to self-schedule for operational and maintenance reasons, as well as for fuel management purposes, "[a]s long as a fuel limitation does not result." The *pro forma* language for fuel management is modified to allow Mystic's affiliate to sell fuel to third parties or to reject a fuel shipment. Sales to third parties or rejection of a shipment are permitted if Mystic "reasonably believes that action will reduce overall cost to ratepayers."[127] The transmittal provides no information explaining the criteria Mystic would apply to assess whether an alternative to self-scheduling would "reduce overall cost to ratepayers," or even how Mystic

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[124] Tariff Waiver Petition at 2 (stating the "threat" to "reliable operation of the New England electric system" is "most critical during the winter months, when the region's pipelines are most constrained").

[125] The Agreement defines Mystic 8 and Mystic 9 as "each a 'Resource' and collectively the 'Resources.'" Recitals Paragraph A.

[126] Attachment B, Public Redacted Blackline Showing Changes from the ISO Tariff Form Cost-of-Service Agreement to the Submitted Agreement, at 24.

[127] In this respect the Fuel Supply Agreement between Everett LNG and Mystic is deficient because it lacks provisions that provide authority to Mystic and/or ExGen to direct Everett LNG to undertake actions to implement this provision and "reduce overall costs to ratepayers."

would not self-schedule but would direct its affiliate to sell fuel to third parties or reject a fuel shipment. (The Fuel Supply Agreement provides no answers.) While the provision gives sole discretion to ISO-NE to accept or reject a request to self-schedule, the proposed Agreement does not require approval or even require notification to ISO-NE in connection with these other fuel management decisions. There is no reporting requirement that would enable the Commission to monitor actions taken, and to direct Mystic to take corrective action if needed.

Section 3.5 of the proposed Agreement would allow ExGen to "self-schedule" Mystic 8 & 9 under vaguely-defined circumstances (including, "as long as a fuel limitation does not result") and subject to ISO approval. This provision recognizes that when this is done for fuel management purposes, alternatively, Constellation LNG could sell fuel to other parties or divert a cargo; and the choice rests upon whether Mystic and/or Constellation LNG "reasonably believes that action will reduce overall costs to ratepayers." It is not clear how the coordination between affiliates would occur under such circumstances. It may be more efficient to accomplish tank level reductions through adjustment to the Stipulated Variable Cost, analogous to the adjustment when fuel is scarce. This provision warrants further elaboration.[128]

D. Section 3.8, ISO-NE Access to Information.

The new reporting requirements in Section 3.8 suggests an intent to provide ISO-NE with 24/7 access to fuel supply information. The proposed language would require Exelon's LNG affiliate to provide accurate and timely information in response to an ISO request, but this language falls short and only obliges Exelon to "provide [an operations] contact" for the Everett LNG facility and "authorize that contact to promptly provide" the information requested. As the upstream owner of Everett, Exelon should be held to a higher obligation than merely agree to

[128] Wilson Affidavit at P 52.

“provide” and “authorize” communications with ISO. Accordingly, NESCOE recommends that the Commission require the Everett LNG facility to enter into a separate agreement with ISO-NE (which could be appended to the Agreement). The purpose of this separate agreement would be to give ISO-NE access to the facility, allow an ISO-contracted third party to conduct audits, and require that the facility provide accurate information and timely responses to the ISO.

E. Section 3.9, Modification

The provisions in Section 3.9 would preclude Mystic from modifying the Fuel Supply Agreement without providing ISO with a copy in advance and would require an informational filing to the Commission in this docket. In addition, “any modification to the conceptual method for calculating any margin on any third-party sales of LNG” would require the prior written consent of ISO. Sales to third-parties of LNG that is re-gasified through Everett would materially affect the Monthly Fuel Supply Cost. The Fuel Supply Cost and the AFFR are principle components of the Supplemental Capacity Payment, and must be just and reasonable. Therefore, any modifications to the Fuel Supply Agreement must be made through a Section 205 filing at the Commission. The Commission, not ISO-NE, is the appropriate entity under the FPA to approve any changes to the contract.

F. Section 6.2, Audit Provisions

Likewise, the audit provisions in Section 6.2 of the proposed Agreement simply provide that ISO “may” perform audits, and are not adequate to assure that the rates customers pay are consistent with the terms in the proposed Agreement and the Fuel Supply Agreement. The Commission should require an annual audit under the oversight of an independent third-party to assess the impact of the third-party transactions. The audit report and recommendations should be filed with the Commission in this docket.

G. Section 7.1.2, Disclosure of Extended Forced Outage and Recovery of Additional Expenses

In the event of a Forced Outage, Section 7.1.2(a) provides that Mystic "[g]enerally . . . shall be entitled" to take the Resources out of operation or reduce the net capability of the units.[129] The *pro forma* requires prompt notification to ISO of a Forced Outage that is anticipated to last more than ten days. The proposed Agreement modifies the *pro forma*'s requirement so that under Section 7.1.2(b), Exelon would not need to provide prompt notification to ISO *unless* the outage is anticipated to last for more than 25 days. This proposed modification to the *pro forma* language appears inconsistent with ISO-NE's interest in maintaining fuel security because ISO's analyses forecast that Mystic's unavailability would result in mandatory reliability violations for depletion of ten-minute operating reserves and rolling blackouts during the short winter term.[130] The ten-day period in the *pro forma* agreement should be reinstated, and perhaps the period should be shortened to three days during the winter months when the very circumstances giving rise to the need for the Agreement are most likely to exists and the system is acutely vulnerable.

Section 7.1.2(e) provides an option to approve additional expenses to recover from a forced outage in lieu of shutting down the Resources. NESCOE opposes the proposed language in the proposed Agreement that modifies the *pro forma* requirement that Mystic would be "obligated to use its best efforts to minimize Additional expenses." In lieu of a "best efforts" requirement, Applicants would lower the standard to a "commercially reasonable" requirement. The best efforts standard is just and reasonable, approved by the Commission as part of the rule

[129] Whereas changes to the *pro forma* Section 7.1.1 language providing for planned outages allows Exelon to take "one or both of the Resources" out of operation or reduce the net capability of "one or both of the Resources," Section 7.1.2(a) does not provide an option to take "one or both of the Resources" out of operation or take a reduction to net capability.

[130] Tariff Waiver Petition at 3.

changes to harmonize the forward capacity market with cost-of-service compensation in Docket ER08-1209-000, and Applicants have not provided any justification for altering the approved language.

If, however, ISO-NE decides that the forced outage warrants shutting down one or more Resources and, as a result of that decision Mystic believes that it will fail to recover its costs incurred and unable to be avoided, Section 7.2 is modified to provides a process for Applicants to petition the Commission for cost recovery—Applicants "shall be entitled to make a Section 205 filing." The Commission should clarify that the process in Section 7.2 provides an opportunity for Applicants to petition the Commission for recovery of requested costs, with all parties reserving rights to protest that application. Lastly, as in Section 7.1.2(e), the Commission should require Applicants to make "best efforts" to avoid costs for which they seek recovery.

H. Disclosure of Changes to Resource Characteristics in Schedule 2

Schedule 2 sets out the characteristics and operating parameters of the facilities, including, *e.g.*, ramp rates, minimum run time, notification time, and start up time. Any change to these characteristics must be reported to ISO "immediately" under Section 6.1.2. of the *pro forma* agreement. In light of the fuel security purpose of this agreement, and the proposed extended term of agreement, the Commission should require that Exelon or Mystic make a simultaneous compliance filing in this docket to notify the Commission of changes to Schedule 2 and to provide interested parties with access to the revised Schedule 2 under the terms of the standing protective order.

I. Section 5.2, Market Monitoring and Adjustments to Resource Offers

Section 5.2 reasonably provides that ISO Market Monitoring will "automatically" adjust any Supply Offer in excess of Stipulated Variable Cost back down to the Stipulated Variable

Cost level. It is unclear, however, why the ISO Market Monitoring action is "subject to prior consultation" with Mystic. The purpose of a "consultation" requirement (which suggests a dialogue) has not been explained, and more information is needed to understand why adjustments that would not be automatic should not be subject to just a one-way notice requirement.

Section 5.2 does not provide for ISO Market Monitoring to make adjustments to the Stipulated Regulation Offer in Section 3.4.1.7. This may be because the proposed Agreement strikes the *pro forma* language in Section 3.4.1.7 that would establish the maximum rate that Mystic is permitted to offer for Regulation services. In addition, new language has been added to Section 4.4.3 suggesting that the Stipulated Regulation Offer represents the "variable costs of producing revenues for Regulation," which is incomprehensible. Mystic has not provided any information to explain why the entire Stipulated Regulation Offer, which by definition in Section 3.4.1.7 is virtually unbounded, is fully subtracted from the Revenue Credit.

J. Section 3.10, Minimization of Out-of-Market Impacts

A new requirement in Section 3.10 directs Mystic to cooperate with ISO "in good faith, in light of the fuel supply available to the Resources, to minimize the market impacts of reliability commitments in the energy market." This language is general and the intent of this provision is unclear. The fuel supply available to Mystic and to other market participants is controlled by Everett LNG, which is not a party to the proposed Agreement. The Commission should require Mystic and ISO-NE to provide substantially more information about the expectations of good faith "cooperation" and any related performance that ISO-NE expects from Mystic in order to "minimize the market impacts," as set out in this Section.

K. Section 11.1.1, Notification of Transactions Affecting Ownership of Resources.

NESCOE requests that the Commission direct Applicants to provide an informational filing in this docket concerning any transaction involving the Resources that would be subject to the Commission's review under FPA Section 203. Language setting forth this obligation could be included in Section 11.1.1 of the Mystic Agreement, which provides that the prior written consent of ISO is required to assign the contract. Given the stringent performance requirements unique to this agreement coupled with the underlying objective to provide regional fuel security, ISO-NE should not make a unilateral decision to assign the agreement to another entity without at minimum an opportunity for other parties to provide input on the proposed assignee. Among other considerations would be the need to demonstrate creditworthiness. Moreover, the assignee should not be permitted to increase the ROE.

VII. THE COMMISSION SHOULD PROTECT AGAINST MYSTIC TOGGLING BETWEEN COST-OF-SERVICE AND MARKET RATES

Mystic is allowed only to seek full cost of service because it has submitted a Retirement De-List Bid, meaning that once ISO no longer needs it for reliability that its units must exit all New England markets, consistent with ISO-NE's market rules. The purpose of the exit provision is to prevent units from "toggling" between cost-of-service- and market rates. However, if Mystic wishes to continue to operate after released by ISO, it would not be entitled to cost-of-service compensation. Mystic acknowledges that the Tariff currently does not provide the ability for Mystic 8 & 9 to recover costs after the cost-of-service terms ends.[131] Mystic states that it is willing "to provide a 'clawback' process to refund *certain* capital expenditures incurred during

[131] Transmittal Letter at 16.

the reliability term if the units remain in service past the termination date."[132] Mystic states that this item could be addressed in settlement. NESCOE agrees that this issue should be addressed as part of the settlement/hearing process and, if the Commission sets the case for settlement/hearing, it should direct that the process include consideration of this provision.[133]

However, what Mystic is offering is insufficient and not consistent with what the Commission has required of other generators with RMR agreements. NESCOE emphasizes that the clawback offer that Mystic loosely makes only seems related to certain capital expenditures. Mystic does not explain which of the incremental capital expenditures it proposes to refund or provide any support for this proposal. This falls well short of the protection that the Commission requires. The Commission requires strong "anti-toggling" provisions. For example, the Commission required the New York Independent System Operator, Inc. to propose rules to "eliminate, or at least minimize, incentives for a generator needed for reliability to toggle between receiving RMR compensation and market-based compensation for the same units."[134]

It is important to recognize that the facilities are able to seek full cost-of-service only because they are retiring. If the Commission subsequently allows the Mystic units to return to the Forward Capacity Market, it must ensure that customers receive refunds between the going-forward costs and full cost of service. As the Commission has explained, "[r]equiring RMR generators seeking to return to the market to repay revenues received pursuant to an RMR agreement in excess of the generator's going-forward costs is necessary to remove the incentive

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[132] *Id*. (emphasis added).

[133] *See, e.g.*, *ISO New England Inc.*, 125 FERC ¶ 61,102 at PP 44-48; *N.Y. Indep. Sys. Operator, Inc.*, 150 FERC ¶ 61,116 at P 21, *N.Y. Indep. Sys. Operator, Inc.*, 155 FERC ¶ 61,076 at P 116, *reh'g order*, 161 FERC ¶ 61,189 (2016).

[134] *N.Y. Indep. Sys. Operator, Inc*., 155 FERC ¶ 61,076, P 116 (2016)

to toggle . . . ."[135] The specific details regarding a "clawback" provision should be included in the inquiry into the justness and reasonableness of the proposed Agreement in the hearing and settlement judge procedures.

VIII. CONCLUSION

NESCOE urges the Commission not to approve as just and reasonable the proposed Agreement as filed. Instead, NESCOE urges the Commission to set this matter for hearing, hold the hearing in abeyance, and establish settlement judge proceedings. The Commission must not give short shrift to a full evaluation of whether the filing is just and reasonable. In light of the provisions in the Agreement that were not adequately supported in the Application, issues which have not been adequately explained, and many components of the Agreement in need of clarity, NESCOE urges the Commission not to resolve any issues of based on the pleadings. To do so would disadvantage intervenors, including NESCOE, who had a short amount of time to review a complex and unique set of arrangements. Instead, NESCOE urges the Commission to find that the Agreement has not been shown to be just and reasonable and to set this matter for hearing and settlement judge procedures. Through settlement procedures all interested parties and Commission staff can obtain the information needed and propose changes to the arrangements necessary to ensure the Agreement and costs thereunder are just and reasonable.

WHEREFORE, for the reasons discussed herein, NESCOE respectfully requests that the Commission set this matter for hearing, hold the hearing in abeyance, and establish settlement procedures.

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[135] *N.Y. Indep. Sys. Operator, Inc.*, 161 FERC ¶ 61,189, P 83 (2017).

Respectfully Submitted,

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Date: June 6, 2018

ATTACHMENT A

AFFIDAVIT OF JAMES F. WILSON

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Constellation Mystic Power, L.L.C.	)))	Docket No. ER18-1639-000

AFFIDAVIT OF JAMES F. WILSON
IN SUPPORT OF THE COMMENTS OF
NEW ENGLAND STATES COMMITTEE ON ELECTRICITY

Contents

AFFIDAVIT OF JAMES F. WILSON
IN SUPPORT OF THE COMMENTS OF
NEW ENGLAND STATES COMMITTEE ON ELECTRICITY

I. Introduction

1. My name is James F. Wilson. I am an economist and independent consultant doing business as Wilson Energy Economics. My business address is 4800 Hampden Lane Suite 200, Bethesda, MD 20814.

2. I have over thirty years of consulting experience in the electric power and natural gas industries. Many of my past assignments have focused on the economic and policy issues arising from the introduction of competition into these industries, including restructuring policies, market design, market analysis and market power. Other recent engagements have included resource adequacy and capacity markets, contract litigation and damages, forecasting and market evaluation, pipeline rate cases and evaluating allegations of market manipulation. I also spent five years in Russia in the early 1990s advising on the reform, restructuring, and development of the Russian electricity and natural gas industries for the World Bank and other clients. I have submitted affidavits and presented testimony in proceedings of the Federal Energy Regulatory Commission ("Commission"), state regulatory agencies, and U.S. district court. I hold a B.A. in Mathematics from Oberlin College and an M.S. in Engineering-Economic Systems from Stanford University. My curriculum vitae, summarizing my experience and listing past testimony, is Attachment JFW-1 attached hereto.

3. I have been involved in electricity restructuring and wholesale market design for over twenty years in PJM, New England, Ontario, California, MISO, Russia, and other regions. With regard to the New England and PJM markets, I have also been involved in a broad range of other market design issues over the past several years.

4. On May 16, 2018, Constellation Mystic Power, LLC ("Mystic") submitted a proposed Cost of Service Agreement ("COSA") between Mystic, Exelon Generation Company, LLC ("ExGen"), and ISO New England Inc. ("ISO-NE") to the Commission for approval ("Mystic Filing"). The proposed COSA provides for cost-of-service compensation to Mystic for continued operation of the Mystic 8 and 9 natural gas-fired generating units ("Mystic 8 & 9") for the period of June 1, 2022 to May 31, 2024, pursuant to ISO-NE's request that the units continue operating to ensure fuel security during this period. Mystic states (p. 1) that without the proposed agreement the units would be retired.

5. The Mystic Filing states that Mystic 8 & 9 presently have only one source of fuel, the Everett Marine Terminal liquified natural gas ("LNG") import facility ("Everett"), and that Exelon Corporation ("Exelon"), Mystic and Exgen's parent, is in the process of acquiring Everett from Distrigas of Massachusetts, LLC. Under a proposed Fuel Supply Agreement ("FSA"; Exhibit MYS-004 to the Testimony of William B. Berg), Constellation LNG, LLC ("Constellation LNG"), an Exelon subsidiary, would operate Everett and pass all of Everett's costs, adjusted for certain credits, through to Mystic.

6. I was asked by the New England States Committee on Electricity to review and evaluate the provisions of the COSA and FSA and identify any issues they might raise regarding the efficient and cost-effective operation of Mystic 8 & 9 and Everett. I have not reviewed these facilities' costs. In performing my assignment, I relied upon the Mystic Filing, supporting testimony, and other publicly-available information. As I will note, many relevant facts were not available.

II. Summary

7. My review has identified several issues with regard to the COSA and FSA that merit further exploration and may suggest changes to these agreements to ensure efficient operation of these facilities in a manner that minimizes the costs passed through to consumers.

8. The Mystic Filing claims that Everett is the most economical fuel supply for Mystic 8 & 9. This claim warrants further examination. However, one key fact is clear – the conclusion is based on the two-year duration of the COSA. Recognizing that Mystic believes a market-based fuel security approach for New England might result in Mystic 8 & 9 and Everett remaining in operation over the long term,[1] the plants may have other, more economical long-term fuel supply options. Based on the Mystic Filing's characterization of Mystic's fuel supply options, the Mystic Filing further suggests that the proposed FSA is a good deal because a "rational non-affiliate" would consider the plants' (lack of) near-term alternatives, and charge even more. While it may be the case that Mystic 8 & 9 do not have an alternative to Everett in the near term, the proposed relationship between the plants and Everett, under the proposed FSA, seems to risk passing unnecessary costs through to customers.

9. The Everett facility serves local gas distribution companies and other customers in addition to Mystic 8 & 9. Maximizing the value of the Everett facility appears to be a fairly complex task, involving management of short-term and longer-term contractual commitments and managing LNG deliveries, among other challenges. The FSA calls for passing through to Mystic all of Everett's costs net of the revenues from other customers, however, the FSA does not appear to require or provide incentives for Constellation LNG to minimize the costs passed

[1] See, for instance, Berg Testimony at 11:18-11:22.

through by maximizing the value of Everett in the marketplace. In particular, the FSA provides no incentive or requirement for shorter-term sales to other customers, while for longer-term transactions (over 3 months forward), a "Seller's Incentive" is defined, the details of which raise many questions. At the same time, the FSA would pass through pipeline firm transmission costs and LNG cargo diversion costs, which costs may be primarily related to sales to other customers.

10. Whether the proposed arrangement under the FSA is likely to result in efficient operation and reasonable cost passed through to customers merits further evaluation. Such evaluation would have to consider many facts that have not been presented in the Mystic Filing and supporting testimony, such as:

- The demand for Everett's services by other customers, the particular services likely to be most in demand, and the potential profitability;
- The potential impact on operations and costs of additional short-term and long-term commitments to other customers, including "tank congestion" costs, among other potential impacts;
- The costs of the various pipeline transportation commitments, and the benefits they provide;
- The costs associated with cargo diversions, and the amount of flexibility in the LNG supply chain to divert cargoes, or to schedule additional cargoes when needed;
- The costs associated with sales of power or gas at a loss to reduce storage to accommodate an incoming cargo, and how such sales will be coordinated between the plants and the Everett facility.

11. An alternative approach to the fuel supply, that would be simpler, more common, and more transparent, would entail a fixed monthly payment (for instance, based on Mystic 8 & 9's portion of Everett's firm sendout capacity), and leave all other costs and revenues associated with Everett's services to other customers to Constellation LNG. Such an approach would leave Constellation LNG with full incentives to maximize the value of the facility through the services provided to other customers.

12. With regard to the COSA, it provides for modifications to the Capacity Performance payments and penalties under the ISO-NE tariff that may not be in the interest of customers. The COSA calls for eliminating incentive payments by crediting them against costs, and an enhanced Winter Fuel Security Penalty that may be redundant with other provisions to provide for conservation of fuel when scarce.

13. The COSA appropriately calls for reflecting certain "opportunity costs" in the prices used to offer Mystic 8 & 9 into the New England energy markets; however, there appears to be at least one flaw in how the opportunity cost is determined.

14. In addition to the various issues noted above, both the COSA and FSA have other provisions that are unclear, and in some cases reference terms that are not defined.

15. The next section of this affidavit provides some available background information on the Mystic and Everett facilities, while the final two sections elaborate on the questions and concerns raised by the COSA and FSA.

III. Background

A. Mystic 8 & 9

16. Mystic 8 & 9 are natural-gas fired combined cycle generating stations located near Boston, Massachusetts with a combined summer capacity of 1,417 MW (Mystic Filing, p. 6). ISO-NE's recent Operational Fuel-Security Analysis ("OFSA Report")[2] found that loss of the Mystic 8 & 9 capacity could result in load shedding under some circumstances.

17. Mystic has been supplied by Everett under a long term natural gas supply contract that was attractively priced (Algonquin Citygate price minus $.20/MMBtu).[3] While the gas supply contact contract was through 2027,[4] apparently it has or will be terminated, and the Mystic Filing suggests that during the period at issue in this proceeding the plants would be supplied at world LNG prices (Mystic Filing, p. 25).

B. The Everett Marine Terminal

18. While Mystic 8 & 9 are presently supplied exclusively by Everett, Everett has supplied other customers, such as New England local gas distribution companies ("LDCs"). Recent testimony by Richard L. Levitan and Sara Wilmer of Levitan & Associates, Inc. on behalf of ISO-NE in a related proceeding ("LAI Testimony")[5] describes Everett's sendout capacity as follows (pp. 9-11):

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[2] ISO New England, *Operational Fuel-Security Analysis for Discussion*, January 17, 2018, p. 43.

[3] Mystic Development, LLC, Docket No. ER06-427-000, Proposed FERC Electric Tariff filing, December 29, 2005, p. 12.

[4] Declaration of Jeff Hunter, Manager, Executive Vice President and Chief Financial Officer of EBG Holdings, LLC, August 18, 2010 in Re: Boston Generating, LLC et al, Debtors, U.S. Bankruptcy Court Southern District New York, Case No. 10-14419 (SCC), p. 20.

[5] Testimony of Richard L. Levitan and Sara Wilmer on behalf of ISO New England, Inc., submitted May 1, 2018 in FERC Docket No. ER18-1509.

- Approximately 715 MMcf/d sustainable vaporization capacity, of which the maximum sendout to each physical connection is as follows:
    - 276 MMcf/d to the Algonquin Gas Transmission pipeline;
    - 163 MMcf/d to the Tennessee Gas Pipeline system;
    - 233 MMcf/d to Boston Gas;
    - 250 MMcf/d to Mystic 8 & 9.
- The equivalent of another 100 MMcf/d in the form of capacity to load LNG onto trucks.
- 50 MMcf/d to Boston Gas in the form of boiloff gas.

19. Thus, setting aside the boiloff gas, Everett has roughly 815 MMcf/d of sendout capacity, of which Mystic 8 & 9 represent 250 MMcf/d, or 31%. While the LNG-based commodity, if priced based on world LNG prices, will generally be expensive compared to the pipeline alternatives, Everett's customers will value the facility's ability to reliably deliver supplies even when the pipelines are constrained (such as during extreme cold), thereby providing incremental peak day deliverability to the Boston region. LDCs will be willing to pay relatively high prices for secure peak-period deliverability even if they actually call on the deliverability relatively rarely. Therefore, while details of Everett's sources of revenue are not available, a facility of this type might recover fixed costs based on the maximum sendout committed to different customers (as do pipelines, with straight fixed-variable rates).[6] While the LAI Testimony states (p. 7) that Mystic 8 & 9 have recently accounted for about two-thirds of

[6] A comparison could also be made to natural gas storage facilities, whose services would allocate costs based on both sendout and storage capacity measures. However, Everett's storage is used to back up the sendout and likely is not allocated to specific customers.

Everett's sendout, Everett's value and cost recovery may be more closely related to the sendout capacity, not actual sendout volumes.

20. Details about the nature of the contractual arrangements between Everett and its various customers are not available. However, Everett's current owner, Engie, continues to pursue short and long term contracts for winter and summer firm peaking gas with a customer mix that includes LDCs, power generators, and marketers.[7] As one example, Boston Gas Company (d/b/a/ National Grid), an LDC, recently considered a proposal from Engie to meet an incremental capacity need.[8]

21. Different customers would typically seek somewhat different services, depending upon the load profile and portfolio of other firm assets, which may include firm flowing gas supply and LNG storage-based services, among others. In particular, some LDCs may be more willing to commit in advance to firm deliveries from Everett to replenish their LNG storage, while other LDCs may seek an option on supplies from Everett that would only be called upon if needed during a colder than normal winter. This is suggested by the FSA, which anticipates both Forward Sale and Forward Option transactions (p. 4). Some customers may seek relatively more deliverability over a short period, while others may be able to spread the received volumes over a longer period of time. Some customers may be willing to accept responsibility for cargo diversion costs, while others may prefer such costs to be reflected in demand charges. Some of

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[7] Steve Taake, Manager, Gas Marketing, Engie, presentation to the NGA Regional Market Trends Forum, May 3, 2018, slide 9; available at http://www.northeastgas.org/pdf/s_taake_2018.pdf.

[8] Petition for Approval of Contracts with Tennessee Gas Pipeline, LLC & Portland Natural Gas Transmission System, Massachusetts Department of Public Utilities Case No. D.P.U 17-174, Initial Brief of National Grid, April 5, 2018, pp. 14-15.

Everett's customers may have multi-year contractual commitments, or may enter into similar arrangements with Everett each year that are renewed annually.

22. The LNG storage capacity at Everett is 3.4 BCF, while a typical cargo ship delivers 3.0 BCF to the terminal (Mystic Filing, p. 21). Accordingly, the storage must be brought under 0.5 BCF when a delivery is imminent. As the COSA (Section 3.5) and FSA (p. 3) anticipate, this may at times require sendout from Everett to Mystic 8 & 9 and/or to interconnected pipelines at a loss, to reduce tank levels. In addition, a scheduled cargo that is unwanted or cannot be accommodated can be diverted to another destination, which can result in substantial "diversion costs" (FSA p. 3).

23. In addition, in providing services to its various customers, Everett faces various forms of competition. In addition to the pipelines serving the region, New England has three operating LNG import terminals and a total of 16 Bcf of LNG storage capacity at 46 facilities.[9] The LNG storage facilities can be replenished by trucks loaded within or outside the region.

24. This information suggests that maximizing the value of the Everett facility in the marketplace is a fairly complex problem involving providing a variety of services to a variety of customers and managing the LNG storage and deliveries to support those services. Managing the facility in a commercially sound manner will entail various tradeoffs at times. Decisions about scheduling additional cargoes, and cancelling or diverting cargoes, will involve trade-offs between current costs and future costs and risks.

[9] Comments of the Northeast Gas Association in FERC Docket No. ER18-1509, filed May 18, 2018. p. 2.

IV. Provisions in the Fuel Supply Agreement that Merit Further Evaluation

A. Full Recovery of Everett Cost Net of Earnings from Other Customers

25. Under the FSA, Mystic 8 & 9 would pay, in addition to the cost of the LNG to supply the plants, a monthly "Fuel Supply Cost" to recover the full cost of operating Everett, including a return on investment and various other charges net of certain credits (Berg Testimony, 9:10 to 9:16; FSA at 5). In allocating the full cost of Everett to Mystic 8 & 9, the FSA would also generally credit the net earnings from other customers to this cost (pp. 3-4).

26. The Mystic Filing states (p. 2) that the current contractual relationship between Everett and Mystic is in dispute, and that Exelon chose to purchase Everett to avoid costly and uncertain litigation. Mystic further represents (p. 17) that the proposed arrangement with Everett is the least-cost alternative for fuel supply for Mystic 8 & 9 under the two-year COSA. The Mystic Filing and Berg Testimony (Mystic Filing p. 18, Berg Testimony, p. 18) claim that a "rational non-affiliate" owner of Everett would push the prices charged to Mystic 8 & 9 close to the plants' "next cheapest alternative", which would be "significantly higher" than the proposed cost-of-service rate under the FSA.

27. These claims raise many questions that warrant further examination. However, it is notable that the Berg Testimony states that Everett was determined to be least cost based on the *two-year need* identified by ISO-NE (Berg Testimony, 11:12 to 11:15), and the suggestion that a non-affiliate would price based on the next cheapest alternative basically assumes the non-affiliate would exercise market power against Mystic 8 & 9 for the two years. ISO-NE and its stakeholders seek a longer-term fuel security solution for New England, and Mr. Berg is "optimistic" that this will result in the Everett facility and the Mystic plants remaining in service over the long term (Berg Testimony, 11:18-12:1). Using a longer amortization period for the potential up-front costs of investments to develop alternatives might show them to be lower cost

than Everett over the long run. And a rational non-affiliate operating Everett might choose to supply Mystic 8 & 9 at a lower price closer to the cost of the plants' *long-run* alternatives, with the goal of potentially maintaining the plants as customers over the long-term, not just for two years. Therefore, the underlying costs of Everett, and of Mystic 8 & 9's alternatives to Everett, over the short-run and long-run, warrant further evaluation. As noted in the previous section, Mystic 8 & 9 represent about 31% of Everett's maximum sendout capacity. The fixed cost recovery for a facility whose primary value is as a peaking service would typically follow the firm deliverability commitments.

B. Services Provided to Other Customers of the Everett Facility

28. The FSA does not appear to provide strong incentives or clear rules about how the Everett facility will be operated to maximize its value and minimize the net cost that will be passed through to Mystic. As described in the previous section of this affidavit, efficient management of the facility is a complex problem. The following paragraphs identify concerns about whether the provisions of the FSA will result in efficient operation of the Everett facility.

29. For shorter-term sales (less than three months in advance) to parties other than Mystic, all costs and revenues are passed through the FSA (FSA, pp. 3-4). This arrangement affords Constellation LNG no incentive to make such transactions, which at times could be highly valued in the market. Nor does the FSA require such sales. Therefore, it is unclear that such transactions will occur when they are economic and when circumstances allow. Such transactions, especially during winter periods when the pipelines serving New England can be constrained, would help to meet regional natural gas demands and contribute to fuel security while moderating natural gas prices.

30. For the longer-term Forward Transactions (entered into 3 or more months in advance), the FSA calls for revenues and costs to again pass through to Mystic, however, for these transactions there is a "Seller's Incentive." The Berg Testimony states (p. 16) that the Seller's Incentive for these transactions was not proposed by Mystic, but was added to the FSA at the request of ISO NE. The longer-term transactions will represent the more valuable services because they allow customers to plan on the deliverability to meet peak day needs.

31. The Seller's Incentive is proposed to be 50% of the "fixed payments" due from the customer minus the "contract incremental cost" and a "tank congestion charge." The contract incremental cost is calculated as the fraction of the "anticipated total variable cost" of a 3 Bcf LNG cargo represented by the transaction (a 1 bcf transaction would be allocated 1/3 of the cost). The "tank congestion charge" represents additional cost that may result due to additional LNG cargos and the resulting potential need for uneconomic sales to accommodate such cargos; the charge is to be set based on a monte carlo simulation (FSA, Schedule A provides a "conceptual outline" of how the charge would be determined). The Seller's Incentive is calculated at the time of "contract execution" and there is no subsequent adjustment of it, except in instances of Seller non-performance.

32. A well-designed incentive mechanism can improve a contractual arrangement in which otherwise there might be no incentive to engage in valuable transactions. However, it can be difficult to design an incentive mechanism that aligns the buyer's and seller's interests. A poorly-designed incentive mechanism can, among other possible flaws, create opportunities for the seller to earn incentives through transactions that are not in the buyer's interest. The proposed Seller's Incentive in the FSA is not adequately defined and raises many questions.

33. First, various elements of the Seller's Incentive calculation are not clearly defined. It is not clear how "anticipated" variable costs would be determined, or exactly which types of possible contract charges would be considered "fixed payments." Nor are the various assumptions and inputs to the monte carlo simulation described.

34. Second, the formula for the Seller's Incentive (based on fixed payments net of allocated "anticipated" variable costs and congestion charge) may not accurately represent the value of the transaction, from which an incentive payment may be warranted. Such transactions may result in increased (or decreased) risk of having to divert cargoes, may require firm pipeline transportation, and may reduce opportunities for other, potentially more profitable transactions, among a few of the potential costs or benefits of transactions that may not be captured in the formula.

35. Third, to the extent the Seller's Incentive does not accurately determine the value of the transaction, removing the 50% portion of the net revenue for the Seller's Incentive may leave the transaction uneconomic. That is, the transaction may actually increase not decrease the total cost passed through to customers under the FSA.

36. Fourth, the Seller's Incentive formula may even afford Constellation LNG opportunities to structure Forward Transactions to maximize incentive payments, and these structures may result in inefficiencies and added cost passed through the FSA. The FSA prohibits the seller from entering into forward transactions with prices "less than Seller's cost of LNG supply… at the time of execution…", another contract provision that is not clearly defined.

37. To summarize, the FSA provides no incentive and no requirement to make the Everett capacity available for short-term transactions. For the more valuable longer-term transactions, there is again no requirement of any kind, and the "Seller's Incentive", while

perhaps a good idea in principle, is not clearly defined and raises many concerns. Further details about the proposed Seller's Incentive would be needed to determine whether it would benefit the consumers who will ultimately bear the costs transferred through the FSA.

C. Other Provisions of the Fuel Supply Agreement

38. A few additional provisions of the FSA raise questions.

39. First, the FSA (p. 3) calls for all costs associated with pipeline transportation agreements to be passed through. However, some of these commitments are used to serve other customers, not Mystic, and the costs of certain of the pipeline commitments could potentially exceed their value.

40. The FSA (p. 3) also calls for passing through all costs resulting from the diversion of LNG cargoes. These costs could result from sales to other customers, in particular from a customer exercising its right under a Forward Option Transaction to not take delivery.

V. Provisions in the Cost of Service Agreement that Merit Further Evaluation

A. Capacity Performance and Winter Fuel Security Penalties

41. COSA Section 3.6 states that Mystic 8 & 9 would be subject to Capacity Performance payments and penalties under the ISO-NE tariff. Payments would first be credited against penalties, and net payments would be credited against costs, while negative payments (penalties) would be borne by Mystic. This provision leaves the incentive for performance in place while removing the incentive for over-performance by passing the incentive payments through to customers.

42. It is unclear that this modification of the treatment of these payments will be in the customers' interest. If leaving the incentive in place could at times lead to additional over-

performance, it is possible customers would benefit more from this additional generation than from the crediting of such incentive payments.

43. COSA Section 3.7 subjects ExGen to a special Winter Fuel Security Penalty ("WFSP") under circumstances of very high natural gas prices and very low Everett storage. Specifically, the WFSP can be imposed if Boston-area natural gas prices (Algonquin Gas Transmission) exceed the Henry Hub price by $17.50/MMBtu and Everett storage is below 510 MMcf and a delivery is not imminent. Under such circumstances, The WFSP applies if the plants' Capacity Performance Score[10] is negative. When applicable, the WFSP is calculated in the same manner as Capacity Performance Payments,[11] aggregating the Mystic 8 and Mystic 9 performance, to a maximum of $30 million per month in the winter months. This provision gives ExGen an incentive to ensure that, if such a natural gas price spike is possible, Everett maintains at least 510 MMcf unless a delivery is imminent.

44. It is not clear that the WFSP is needed, and it may distort management of the Everett facility and lead to inefficient use of the Everett storage under scarcity circumstances. Section 3.4.1.4 of the COSA calls for including, in the Stipulated Variable Cost that drives the dispatch of the Mystic plants, a "fuel opportunity cost" that may reflect "the opportunity cost associated with a limited supply of fuel." If the fuel opportunity cost is set in a manner that takes into account the relevant information (anticipated weather and plant demand, natural gas market conditions, the storage level and likely schedule of replenishment, among other considerations), this approach may result in efficiently dispatching (or not dispatching) the plants under circumstances of low storage. Mystic may have sufficient incentive to manage storage

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[10] ISO-NE Tariff, Market Rule 1 Section III.13.7.2.4.

[11] ISO-NE Tariff, Market Rule 1 Section III.13.7.2.5 and III.13.7.2.6.

effectively without the WFSP, and the WFSP may be somewhat redundant with the opportunity cost provision.

45. As noted above, it is apparently necessary to reduce storage levels at times to accommodate LNG deliveries. The WFSP, triggered at 510 MMcf, could provide ExGen an incentive to try to freeze the storage at that level, withholding sendout from the Mystic plants, other Everett customers, and the natural gas markets, to avoid penalties. This may not be the efficient choice at times, or the choice that best contributes to reliability, for instance in the last days of an extended cold snap.

46. The WFSP could also have an impact on other Everett customers, by changing the incentives for use of the storage when the tank is low and natural gas prices high, and perhaps also changing the consequences for serving some customers in favor of others.

B. Mystic 8 & 9 Dispatch and Stipulated Variable Cost

47. Section 3.4 defines the "Stipulated Variable Cost" ("SVC") that serves as the Mystic 8 & 9 plants' offer price into ISO-NE's energy markets. The SVC is a critical element of the COSA, as it will determine when the plants run.

48. The SVC definition includes a "fuel opportunity cost" component that can capture two important circumstances: (i) when regional natural gas prices, represented by the Algonquin Gas Transmission price, are high, and the Everett sendout may be more valuable delivered to the pipelines than to the plants, and (ii) when there is a limited supply of fuel and the fuel should valued at a price higher than its replacement cost under the circumstances. In principle, including opportunity costs in the SVC can contribute to achieving the most valuable use for the Everett supply. However, the opportunity cost provisions raise some issues.

49. First, some, but generally not all, of the Everett sendout that can serve Mystic 8 & 9 could, if the plants are not dispatched, instead be delivered to the New England natural gas markets through Everett's pipeline interconnections. Therefore, regional natural gas prices may serve as an "opportunity cost" for some, but not all of the Mystic capacity. To accurately represent the opportunity cost of Mystic generation, two SVCs and offer prices would need to be calculated, one corresponding to the volumes that could otherwise go to pipelines, and the other for volumes that could not.

50. Second, while assigning an opportunity cost to scarce supply is a sound concept, there are no details about how this opportunity cost would be set. This is a complex and important question. A highly conservative methodology could result in withholding the plants from the markets when their output is valuable.

51. Furthermore, while the SVC with opportunity costs may result in the plants not being dispatched at times because the fuel is more valuable in the natural gas markets (as represented by the Algonquin Citygate price), there is no guarantee that Constellation LNG will offer the supplies to the natural gas markets at such times. The FSA, as noted above, does not provide any obligation or incentive for Constellation LNG to engage in such short-term sales.

C. Other Cost of Service Agreement Provisions

52. Section 3.5 of the COSA allows ExGen to "self-schedule" Mystic 8 & 9 under vaguely-defined circumstances (including, "as long as a fuel limitation does not result") and subject to ISO approval. This provision recognizes that when this is done for fuel management purposes, alternatively, Constellation LNG could sell fuel to other parties or divert a cargo; and the choice rests upon whether Mystic and/or Constellation LNG "reasonably believes that action will reduce overall costs to ratepayers." It is not clear how the coordination between affiliates

would occur under such circumstances. It may be more efficient to accomplish tank level reductions through adjustment to the Stipulated Variable Cost, analogous to the adjustment when fuel is scarce. This provision may warrant further elaboration.

53. Section 3.10 of the COSA calls for ExGen to "cooperate with ISO… to minimize the market impacts of reliability commitments in the energy market." The nature of this "cooperation" is not clear. This provision seems to suggest some discretion would be exercised by ExGen under some circumstances to offset the price suppressive impacts of reliability commitments, perhaps by raising the offer prices of other ExGen generation. The potential actions anticipated by this provision should be further detailed.

54. This concludes my affidavit.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Constellation Mystic Power, L.L.C.	)	Docket No. ER18-1639-000
	)	

I, James F. Wilson, being first duly sworn, certify that the Affidavit in Support of the Comments of the New England States Committee On Electricity was prepared by me or under my supervision; and that the statements and facts set forth therein are true and correct to the best of my knowledge, information, and belief.

James F. Wilson

Subscribed and sworn before me, a Notary Public in and for the State of Maryland

this 5th day of June, 2018.

ANDRAE HAMPTON
NOTARY PUBLIC
DISTRICT OF COLUMBIA
Expiration Oct 14, 2020

Notary Public
My Commission expires: 10/14/20

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SUMMARY

James F. Wilson is an economist with over 30 years of consulting experience, primarily in the electric power and natural gas industries. Many of his assignments have pertained to the economic and policy issues arising from the interplay of competition and regulation in these industries, including restructuring policies, market design, market analysis and market power. Other recent engagements have involved resource adequacy and capacity markets, contract litigation and damages, forecasting and market evaluation, pipeline rate cases and evaluating allegations of market manipulation. Mr. Wilson has been involved in electricity restructuring and wholesale market design for over twenty years in California, PJM, New England, Russia and other regions. He also spent five years in Russia in the early 1990s advising on the reform, restructuring and development of the Russian electricity and natural gas industries.

Mr. Wilson has submitted affidavits and testified in Federal Energy Regulatory Commission and state regulatory proceedings. His papers have appeared in the *Energy Journal*, *Electricity Journal*, *Public Utilities Fortnightly* and other publications, and he often presents at industry conferences.

Prior to founding Wilson Energy Economics, Mr. Wilson was a Principal at LECG, LLC. He has also worked for ICF Resources, Decision Focus Inc., and as an independent consultant.

EDUCATION

MS, Engineering-Economic Systems, Stanford University, 1982

BA, Mathematics, Oberlin College, 1977

RECENT ENGAGEMENTS

- Evaluated the potential impact of an electricity generation operating reserve demand curve on a wholesale electricity market with a capacity construct.
- Developed wholesale capacity market enhancements to accommodate seasonal resources and resource adequacy requirements.
- Evaluation of wholesale electricity market design enhancements to accommodate state initiatives to promote state environmental and other policy objectives.
- Evaluation of proposals for natural gas distribution system expansions.
- Various consulting assignments on wholesale electric capacity market design issues in PJM, New England, the Midwest, Texas, and California.
- Cost-benefit analysis of a new natural gas pipeline.
- Evaluation of the impacts of demand response on electric generation capacity mix and emissions.
- Panelist on a FERC technical conference on capacity markets.
- Affidavit on the potential for market power over natural gas storage.
- Executive briefing on wind integration and linkages to short-term and longer-term resource adequacy approaches.

- Affidavit on the impact of a centralized capacity market on the potential benefits of participation in a Regional Transmission Organization (RTO).
- Participated in a panel teleseminar on resource adequacy policy and modeling.
- Affidavit on opt-out rules for centralized capacity markets.
- Affidavits on minimum offer price rules for RTO centralized capacity markets.
- Evaluated electric utility avoided cost in a tax dispute.
- Advised on pricing approaches for RTO backstop short-term capacity procurement.
- Affidavit evaluating the potential impact on reliability of demand response products limited in the number or duration of calls.
- Evaluated changing patterns of natural gas production and pipeline flows, developed approaches for pipeline tolls and cost recovery.
- Evaluated an electricity peak load forecasting methodology and forecast; evaluated regional transmission needs for resource adequacy.
- Participated on a panel teleseminar on natural gas price forecasting.
- Affidavit evaluating a shortage pricing mechanism and recommending changes.
- Testimony in support of proposed changes to a forward capacity market mechanism.
- Reviewed and critiqued an analysis of the economic impacts of restrictions on oil and gas development.
- Advised on the development of metrics for evaluating the performance of Regional Transmission Organizations and their markets.
- Prepared affidavit on the efficiency benefits of excess capacity sales in readjustment auctions for installed capacity.
- Prepared affidavit on the potential impacts of long lead time and multiple uncertainties on clearing prices in an auction for standard offer electric generation service.

EARLIER PROFESSIONAL EXPERIENCE

LECG, LCC, Washington, DC 1998–2009.
<u>Principal</u>

- Reviewed and commented on an analysis of the target installed capacity reserve margin for the Mid Atlantic region; recommended improvements to the analysis and assumptions.
- Evaluated an electric generating capacity mechanism and the price levels to support adequate capacity; recommended changes to improve efficiency.
- Analyzed and critiqued the methodology and assumptions used in preparation of a long run electricity peak load forecast.
- Evaluated results of an electric generating capacity incentive mechanism and critiqued the mechanism's design; prepared a detailed report. Evaluated the impacts of the mechanism's flaws on prices and costs and prepared testimony in support of a formal complaint.
- Analyzed impacts and potential damages of natural gas migration from a storage field.
- Evaluated allegations of manipulation of natural gas prices and assessed the potential impacts of natural gas trading strategies.
- Prepared affidavit evaluating a pipeline's application for market-based rates for interruptible transportation and the potential for market power.
- Prepared testimony on natural gas industry contracting practices and damages in a contract dispute.
- Prepared affidavits on design issues for an electric generating capacity mechanism for an eastern US regional transmission organization; participated in extensive settlement discussions.
- Prepared testimony on the appropriateness of zonal rates for a natural gas pipeline.
- Evaluated market power issues raised by a possible gas-electric merger.
- Prepared testimony on whether rates for a pipeline extension should be rolled-in or incremental under Federal Energy Regulatory Commission ("FERC") policy.

- Prepared an expert report on damages in a natural gas contract dispute.
- Prepared testimony regarding the incentive impacts of a ratemaking method for natural gas pipelines.
- Prepared testimony evaluating natural gas procurement incentive mechanisms.
- Analyzed the need for and value of additional natural gas storage in the southwestern US.
- Evaluated market issues in the restructured Russian electric power market, including the need to introduce financial transmission rights, and policies for evaluating mergers.
- Affidavit on market conditions in western US natural gas markets and the potential for a new merchant gas storage facility to exercise market power.
- Testimony on the advantages of a system of firm, tradable natural gas transmission and storage rights, and the performance of a market structure based on such policies.
- Testimony on the potential benefits of new independent natural gas storage and policies for providing transmission access to storage users.
- Testimony on the causes of California natural gas price increases during 2000-2001 and the possible exercise of market power to raise natural gas prices at the California border.
- Advised a major US utility with regard to the Federal Energy Regulatory Commission's proposed Standard Market Design and its potential impacts on the company.
- Reviewed and critiqued draft legislation and detailed market rules for reforming the Russian electricity industry, for a major investor in the sector.
- Analyzed the causes of high prices in California wholesale electric markets during 2000 and developed recommendations, including alternatives for price mitigation. Testimony on price mitigation measures.
- Summarized and critiqued wholesale and retail restructuring and competition policies for electric power and natural gas in select US states, for a Pacific Rim government contemplating energy reforms.
- Presented testimony regarding divestiture of hydroelectric generation assets, potential market power issues, and mitigation approaches to the California Public Utilities Commission.
- Reviewed the reasonableness of an electric utility's wholesale power purchases and sales in a restructured power market during a period of high prices.
- Presented an expert report on failure to perform and liquidated damages in a natural gas contract dispute.
- Presented a workshop on Market Monitoring to a group of electric utilities in the process of forming an RTO.
- Authored a report on the screening approaches used by market monitors for assessing exercise of market power, material impacts of conduct, and workable competition.
- Developed recommendations for mitigating locational market power, as part of a package of congestion management reforms.
- Provided analysis in support of a transmission owner involved in a contract dispute with generators providing services related to local grid reliability.
- Authored a report on the role of regional transmission organizations in market monitoring.
- Prepared market power analyses in support of electric generators' applications to FERC for market-based rates for energy and ancillary services.
- Analyzed western electricity markets and the potential market power of a large producer under various asset acquisition or divestiture strategies.
- Testified before a state commission regarding the potential benefits of retail electric competition and issues that must be addressed to implement it.
- Prepared a market power analysis in support of an acquisition of generating capacity in the New England market.
- Advised a California utility regarding reform strategies for the California natural gas industry, addressing market power issues and policy options for providing system balancing services.

ICF RESOURCES, INC., Fairfax, VA, 1997–1998.
<u>Project Manager</u>

- Reviewed, critiqued and submitted testimony on a New Jersey electric utility's restructuring proposal, as part of a management audit for the state regulatory commission.
- Assisted a group of US utilities in developing a proposal to form a regional Independent System Operator (ISO).
- Researched and reported on the emergence of Independent System Operators and their role in reliability, for the Department of Energy.
- Provided analytical support to the Secretary of Energy's Task Force on Electric System Reliability on various topics, including ISOs. Wrote white papers on the potential role of markets in ensuring reliability.
- Recommended near-term strategies for addressing the potential stranded costs of non-utility generator contracts for an eastern utility; analyzed and evaluated the potential benefits of various contract modifications, including buyout and buydown options; designed a reverse auction approach to stimulating competition in the renegotiation process.
- Designed an auction process for divestiture of a Northeastern electric utility's generation assets and entitlements (power purchase agreements).
- Participated in several projects involving analysis of regional power markets and valuation of existing or proposed generation assets.

IRIS MARKET ENVIRONMENT PROJECT, 1994–1996.
<u>Project Director, Moscow, Russia</u>

Established and led a policy analysis group advising the Russian Federal Energy Commission and Ministry of Economy on economic policies for the electric power, natural gas, oil pipeline, telecommunications, and rail transport industries (*the Program on Natural Monopolies,* a project of the IRIS Center of the University of Maryland Department of Economics, funded by USAID):

- Advised on industry reforms and the establishment of federal regulatory institutions.
- Advised the Russian Federal Energy Commission on electricity restructuring, development of a competitive wholesale market for electric power, tariff improvements, and other issues of electric power and natural gas industry reform.
- Developed policy conditions for the IMF's $10 billion Extended Funding Facility.
- Performed industry diagnostic analyses with detailed policy recommendations for electric power (1994), natural gas, rail transport and telecommunications (1995), oil transport (1996).

<u>Independent Consultant stationed in Moscow, Russia, 1991–1996</u>

Projects for the WORLD BANK, 1992-1996:

- Bank Strategy for the Russian Electricity Sector. Developed a policy paper outlining current industry problems and necessary policies, and recommending World Bank strategy.
- Russian Electric Power Industry Restructuring. Participated in work to develop recommendations to the Russian Government on electric power industry restructuring.
- Russian Electric Power Sector Update. Led project to review developments in sector restructuring, regulation, demand, supply, tariffs, and investment.
- Russian Coal Industry Restructuring. Analyzed Russian and export coal markets and developed forecasts of future demand for Russian coal.
- World Bank/IEA Electricity Options Study for the G-7. Analyzed mid- and long-term electric power demand and efficiency prospects and developed forecasts.
- Russian Energy Pricing and Taxation. Developed recommendations for liberalizing energy markets, eliminating subsidies and restructuring tariffs for all energy resources.

Other consulting assignments in Russia, 1991–1994:

- Advised on projects pertaining to Russian energy policy and the transition to a market economy in the energy industries, for the Institute for Energy Research of the Russian Academy of Sciences.
- Presented seminars on the structure, economics, planning, and regulation of the energy and electric power industries in the US, for various Russian clients.

DECISION FOCUS INC., Mountain View, CA, 1983–1992
Senior Associate*,* 1985-1992*.*

- For the Electric Power Research Institute, led projects to develop decision-analytic methodologies and models for evaluating long term fuel and electric power contracting and procurement strategies. Applied the methodologies and models in numerous case studies, and presented several workshops and training sessions on the approaches.
- Analyzed long-term and short-term natural gas supply decisions for a large California gas distribution company following gas industry unbundling and restructuring.
- Analyzed long term coal and rail alternatives for a midwest electric utility.
- Evaluated bulk power purchase alternatives and strategies for a New Jersey electric utility.
- Performed a financial and economic analysis of a proposed hydroelectric project.
- For a natural gas pipeline company serving the Northeastern US, forecasted long-term natural gas supply and transportation volumes. Developed a forecasting system for staff use.
- Analyzed potential benefits of diversification of suppliers for a natural gas pipeline company.
- Evaluated uranium contracting strategies for an electric utility.
- Analyzed telecommunications services markets under deregulation, developed and implemented a pricing strategy model. Evaluated potential responses of residential and business customers to changes in the client's and competitors' telecommunications services and prices.
- Analyzed coal contract terms and supplier diversification strategies for an eastern electric utility.
- Analyzed oil and natural gas contracting strategies for an electric utility.

TESTIMONY AND AFFIDAVITS

PJM Interconnection, L.L.C., FERC Docket No. ER18-1314 (Capacity repricing or MOPR-Ex), Affidavit in Support of the Protests of DC-MD-NJ Consumer Coalition, Joint Consumer Advocates, and Clean Energy Advocates, May 7, 2018.

In the Matter of the Application of DTE Electric Company for Authority to Implement a Power Supply Cost Recovery Plan in its Rate Schedules for 2018 Metered Jurisdictional Sales of Electricity, Michigan Public Service Commission Case No. U-18403, Direct Testimony on behalf of Michigan Environmental Council and Sierra Club, April 20, 2018.

Virginia Electric and Power Company's Integrated Resource Plan filing, Virginia State Corporation Commission Case No. PUE-2017-00051, Direct Testimony on behalf of Environmental Respondents, August 11, 2017; testimony at hearings September 26, 2017.

Ohio House of Representatives Public Utilities Committee hearing on House Bill 178 (Zero Emission Nuclear Resource legislation), Opponent Testimony on Behalf of Natural Resources Defense Council, May 15, 2017.

In the Matter of the Application of Atlantic Coast Pipeline, Federal Energy Regulatory Commission Docket No. CP15-554, Evaluating Market Need for the Atlantic Coast Pipeline, Attachment 2 to the comments of Shenandoah Valley Network *et a*l, April 6, 2017.

In the Matter of the Application of DTE Electric Company for Authority to Implement a Power Supply Cost Recovery Plan in its Rate Schedules for 2017 Metered Jurisdictional Sales of Electricity, Michigan Public Service Commission Case No. U-18143, Direct Testimony on behalf of Michigan Environmental Council and Sierra Club, March 22, 2017.

In the Matter of the Petition of Washington Gas Light Company for Approval of Revised Tariff Provisions to Facilitate Access to Natural Gas in the Company's Maryland Franchise Area That Are

Currently Without Natural Gas Service, Maryland Public Service Commission Case No. 9433, Direct Testimony on Behalf of the Mid-Atlantic Propane Gas Association and the Mid-Atlantic Petroleum Distributors Association, Inc., March 1, 2017; testimony at hearings, May 1, 2017.

In the Matter of Integrated Resource Plans and Related 2016 REPS Compliance Plans, North Carolina Utilities Commission Docket No. E-11 Sub 147, Review and Evaluation of the Peak Load Forecasts and Reserve Margin Determinations for the Duke Energy Carolinas and Duke Energy Progress 2016 Integrated Resource Plans, Attachments A and B to the comments of the Natural Resources Defense Council, Southern Alliance for Clean Energy, and the Sierra Club, February 17, 2017.

In the Matter of the Tariff Revisions Designated TA285-4 filed by ENSTAR Natural Gas Company, a Division of SEMCO Energy, Inc., Regulatory Commission of Alaska Case No. U-16-066, Testimony on Behalf of Matanuska Electric Association, Inc., February 7, 2017, testimony at hearings, June 21, 2017.

PJM Interconnection, L.L.C., FERC Docket No. ER17-367 (seasonal capacity), Prepared Testimony on Behalf of Advanced Energy Management Alliance, Environmental Law & Policy Center, Natural Resources Defense Council, Rockland Electric Company and Sierra Club, December 8, 2016; Declaration in support of Protest of Response to Deficiency Letter, February 13, 2017.

Natural Resources Defense Council, Sierra Club, and Union of Concerned Scientists v. Federal Energy Regulatory Commission, U.S. District Court of Appeals for the D.C. Circuit Case No. 16-1236 (Capacity Performance), Declaration, September 23, 2016.

Mountaineer Gas Company Infrastructure Replacement and Expansion Program Filing for 2016, West Virginia Public Service Commission Case No. 15-1256-G-390P, and Mountaineer Gas Company Infrastructure Replacement and Expansion Program Filing for 2017, West Virginia Public Service Commission Case No. 16-0922-G-390P, Direct Testimony on behalf of the West Virginia Propane Gas Association, September 9, 2016.

Application of Chesapeake Utilities Corporation for a General Increase in its Natural Gas Rates and for Approval of Certain Other Changes to its Natural Gas Tariff, Delaware P.S.C. Docket No. 15-1734, Direct Testimony on behalf of the Delaware Association Of Alternative Energy Providers, Inc., August 24, 2016.

Virginia Electric and Power Company’s Integrated Resource Plan filing, Virginia State Corporation Commission Case No. PUE-2016-00049, Direct Testimony on behalf of Environmental Respondents, August 17, 2016; testimony at hearings October 5, 2016.

In the Matter of the Application of DTE Electric Company for Authority to Implement a Power Supply Cost Recovery Plan in its Rate Schedules for 2016 Metered Jurisdictional Sales of Electricity, Michigan Public Service Commission Case No. U-17920, Direct Testimony on behalf of Michigan Environmental Council and Sierra Club, March 14, 2016.

In the Matter of the Application Seeking Approval of Ohio Power Company’s Proposal to Enter into an Affiliate Power Purchase Agreement for Inclusion in the Power Purchase Agreement Rider, Public Utilities Commission of Ohio Case No. 14-1693-EL-RDR: Direct Testimony on Behalf of the Office of the Ohio Consumers’ Counsel, September 11, 2015; deposition, September 30, 2015; supplemental deposition, October 16, 2015; testimony at hearings, October 21, 2015; supplemental testimony December 28, 2015; second supplemental deposition, December 30, 2015; testimony at hearings January 8, 2016.

Indicated Market Participants v. PJM Interconnection, L.L.C., FERC Docket No. EL15-88 (Capacity Performance transition auctions), Affidavit on behalf of the Joint Consumer Representatives and Interested State Commissions, August 17, 2015.

ISO New England Inc. and New England Power Pool Participants Committee, FERC Docket No. ER15-2208 (Winter Reliability Program), Testimony on Behalf of the New England States Committee on Electricity, August 5, 2015.

Joint Consumer Representatives v. PJM Interconnection, L.L.C., FERC Docket No. EL15-83 (load forecast for capacity auctions), Affidavit in Support of the Motion to Intervene and Comments of the Public Power Association of New Jersey, July 20, 2015.

In the Matter of the Tariff Revisions Filed by ENSTAR Natural Gas Company, a Division of SEMCO Energy, Inc., Regulatory Commission of Alaska Case No. U-14-111, Testimony on Behalf of Matanuska Electric Association, Inc., May 13, 2015.

In the Matter of the Application of Ohio Edison Company et al for Authority to Provide for a Standard Service Offer Pursuant to R.C. 4928.143 in the Form of an Electric Security Plan, Public Utilities Commission of Ohio Case No. 14-1297-EL-SSO: Direct Testimony on Behalf of the Office of the Ohio Consumers' Counsel and Northeast Ohio Public Energy Council, December 22, 2014; deposition, February 10, 2015; supplemental testimony May 11, 2015; second deposition May 26, 2015; testimony at hearings, October 2, 2015; second supplemental testimony December 30, 2015; third deposition January 8, 2016; testimony at hearings January 19, 2016; rehearing direct testimony June 22, 2016; fourth deposition July 5, 2016; testimony at hearings July 14, 2016.

PJM Interconnection, L.L.C., FERC Docket No. ER14-2940 (RPM Triennial Review), Affidavit in Support of the Protest of the PJM Load Group, October 16, 2014.

In the Matter of the Application of Duke Energy Ohio for Authority to Establish a Standard Service Offer in the Form of an Electric Security Plan, Public Utilities Commission of Ohio Case No. 14-841-EL-SSO: Direct Testimony on Behalf of the Office of the Ohio Consumers' Counsel, September 26, 2014; deposition, October 6, 2014; testimony at hearings, November 5, 2014.

In the Matter of the Application of Ohio Power Company for Authority to Establish a Standard Service Offer in the Form of an Electric Security Plan, Public Utilities Commission of Ohio Case No. 13-2385-EL-SSO: Direct Testimony on Behalf of the Office of the Ohio Consumers' Counsel, May 6, 2014; deposition, May 29, 2014; testimony at hearings, June 16, 2014.

PJM Interconnection, L.L.C., FERC Docket No. ER14-504 (clearing of Demand Response in RPM), Affidavit in Support of the Protest of the Joint Consumer Advocates and Public Interest Organizations, December 20, 2013.

New England Power Generators Association, Inc. v. ISO New England Inc., FERC Docket No. EL14-7 (administrative capacity pricing), Testimony in Support of the Protest of the New England States Committee on Electricity, November 27, 2013.

Midwest Independent Transmission System Operator, Inc., FERC Docket No. ER11-4081 (minimum offer price rule), Affidavit In Support of Brief of the Midwest TDUs, October 11, 2013.

ANR Storage Company, FERC Docket No. RP12-479 (storage market-based rates), Prepared Answering Testimony on behalf of the Joint Intervenor Group, April 2, 2013; Prepared Cross-answering Testimony, May 15, 2013; testimony at hearings, September 4, 2013.

In the Matter of the Application of The Dayton Power and Light Company for Approval of its Market Rate Offer, Public Utilities Commission of Ohio Case No. 12-426-EL-SSO: Direct Testimony on Behalf of the Office of the Ohio Consumers' Counsel, March 5, 2013; deposition, March 11, 2013.

PJM Interconnection, L.L.C., FERC Docket No. ER13-535 (minimum offer price rule), Affidavit in Support of the Protest and Comments of the Joint Consumer Advocates, December 28, 2012.

In the Matter of the Application of Ohio Edison Company, et al for Authority to Provide for a Standard Service Offer in the Form of an Electric Security Plan, Public Utilities Commission of Ohio Case No. 12-1230-EL-SSO: Direct Testimony on Behalf of the Office of the Ohio Consumers' Counsel, May 21, 2012; deposition, May 30, 2012; testimony at hearings, June 5, 2012.

PJM Interconnection, L.L.C., FERC Docket No. ER12-513 (changes to RPM), Affidavit in Support of Protest of the Joint Consumer Advocates and Demand Response Supporters, December 22, 2011.

People of the State of Illinois *ex rel*. Leon A. Greenblatt, III v Commonwealth Edison Company, Circuit Court of Cook County, Illinois, deposition, September 22, 2011; interrogatory, Feb. 22, 2011.

In the Matter of the Application of Union Electric Company for Authority to Continue the Transfer of Functional Control of Its Transmission System to the Midwest Independent Transmission System

Operator, Inc., Missouri PSC Case No. EO-2011-0128, Testimony in hearings, February 9, 2012; Rebuttal Testimony and Response to Commission Questions On Behalf Of The Missouri Joint Municipal Electric Utility Commission, September 14, 2011.

PJM Interconnection, L.L.C., and PJM Power Providers Group v. PJM Interconnection, L.L.C., FERC Docket Nos. ER11-2875 and EL11-20 (minimum offer price rule), Affidavit in Support of Protest of New Jersey Division of Rate Counsel, March 4, 2011, and Affidavit in Support of Request for Rehearing and for Expedited Consideration of New Jersey Division of Rate Counsel, May 12, 2011.

PJM Interconnection, L.L.C., FERC Docket No. ER11-2288 (demand response "saturation"), Affidavit in Support of Protest and Comments of the Joint Consumer Advocates, December 23, 2010.

North American Electric Reliability Corporation, FERC Docket No. RM10-10, Comments on Proposed Reliability Standard BAL-502-RFC-02: Planning Resource Adequacy Analysis, Assessment and Documentation, December 23, 2010.

In the Matter of the Reliability Pricing Model and the 2013/2014 Delivery Year Base Residual Auction Results, Maryland Public Service Commission Administrative Docket PC 22, Comments and Responses to Questions On Behalf of Southern Maryland Electric Cooperative, October 15, 2010.

PJM Interconnection, L.L.C., FERC Docket No. ER09-1063-004 (PJM compliance filing on pricing during operating reserve shortages): Affidavit In Support of Comments and Protest of the Pennsylvania Public Utility Commission, July 30, 2010.

ISO New England, Inc. and New England Power Pool, FERC Docket No. ER10-787 (minimum offer price rules): Direct Testimony On Behalf Of The Connecticut Department of Public Utility Control, March 30, 2010; Direct Testimony in Support of First Brief of the Joint Filing Supporters, July 1, 2010; Supplemental Testimony in Support of Second Brief of the Joint Filing Supporters, September 1, 2010.

PJM Interconnection, L.L.C., FERC Docket No. ER09-412-006 (RPM incremental auctions): Affidavit In Support of Protest of Indicated Consumer Interests, January 19, 2010.

In the Matter of the Application of Ohio Edison Company, et al for Approval of a Market Rate Offer to Conduct a Competitive Bidding Process for Standard Service Offer Electric Generation Supply, Public Utilities Commission of Ohio Case No. 09-906-EL-SSO: Direct Testimony on Behalf of the Office of the Ohio Consumers' Counsel, December 7, 2009; deposition, December 10, 2009, testimony at hearings, December 22, 2009.

Application of PATH Allegheny Virginia Transmission Corporation for Certificates of Public Convenience and Necessity to Construct Facilities: 765 kV Transmission Line through Loudon, Frederick and Clarke Counties, Virginia State Corporation Commission Case No. PUE-2009-00043: Direct Testimony on Behalf of Commission Staff, December 8, 2009.

PJM Interconnection, L.L.C., FERC Docket No. ER09-412-000: Affidavit On Proposed Changes to the Reliability Pricing Model On Behalf Of RPM Load Group, January 9, 2009; Reply Affidavit, January 26, 2009.

PJM Interconnection, L.L.C., FERC Docket No. ER09-412-000: Affidavit In Support of the Protest Regarding Load Forecast To Be Used in May 2009 RPM Auction, January 9, 2009.

Maryland Public Service Commission et al v. PJM Interconnection, L.L.C., FERC Docket No. EL08-67-000: Affidavit in Support Complaint of the RPM Buyers, May 30, 2008; Supplemental Affidavit, July 28, 2008.

PJM Interconnection, L.L.C., FERC Docket No. ER08-516: Affidavit On PJM's Proposed Change to RPM Parameters on Behalf of RPM Buyers, March 6, 2008.

PJM Interconnection, L.L.C., Reliability Pricing Model Compliance Filing, FERC Docket Nos. ER05-1410 and EL05-148: Affidavit Addressing RPM Compliance Filing Issues on Behalf of the Public Power Association of New Jersey, October 15, 2007.

TXU Energy Retail Company LP v. Leprino Foods Company, Inc., US District Court for the Northern District of California, Case No. C01-20289: Testimony at trial, November 15-29, 2006; Deposition, April 7, 2006; Expert Report on Behalf of Leprino Foods Company, March 10, 2006.

Gas Transmission Northwest Corporation, Federal Energy Regulation Commission Docket No. RP06-407: Reply Affidavit, October 26, 2006; Affidavit on Behalf of the Canadian Association of Petroleum Producers, October 18, 2006.

PJM Interconnection, L.L.C., Reliability Pricing Model, FERC Docket Nos. ER05-1410 and EL05-148: Supplemental Affidavit on Technical Conference Issues, June 22, 2006; Supplemental Affidavit Addressing Paper Hearing Topics, June 2, 2006; Affidavit on Behalf of the Public Power Association of New Jersey, October 19, 2005.

Maritimes & Northeast Pipeline, L.L.C., FERC Docket No. RP04-360-000: Prepared Cross Answering Testimony, March 11, 2005; Prepared Direct and Answering Testimony on Behalf of Firm Shipper Group, February 11, 2005.

Dynegy Marketing and Trade v. Multiut Corporation, US District Court of the Northern District of Illinois, Case. No. 02 C 7446: Deposition, September 1, 2005; Expert Report in response to Defendant's counterclaims, March 21, 2005; Expert Report on damages, October 15, 2004.

Application of Pacific Gas and Electric Company, California Public Utilities Commission proceeding A.04-03-021: Prepared Testimony, Policy for Throughput-Based Backbone Rates, on behalf of Pacific Gas and Electric Company, May 21, 2004.

Gas Market Activities, California Public Utilities Commission Order Instituting Investigation I.02-11-040: Testimony at hearings, July, 2004; Prepared Testimony, Comparison of Incentives Under Gas Procurement Incentive Mechanisms, on behalf of Pacific Gas and Electric Company, December 10, 2003.

Application of Red Lake Gas Storage, L.P., FERC Docket No. CP02-420, Affidavit in support of application for market-based rates for a proposed merchant gas storage facility, March 3, 2003.

Application of Pacific Gas and Electric Company, California Public Utilities Commission proceeding A.01-10-011: Testimony at hearings, April 1-2, 2003; Rebuttal Testimony, March 24, 2003; Prepared Testimony, Performance of the Gas Accord Market Structure, on behalf of Pacific Gas and Electric Company, January 13, 2003.

Application of Wild Goose Storage, Inc., California Public Utilities Commission proceeding A.01-06-029: Testimony at hearings, November, 2001; Prepared testimony regarding policies for backbone expansion and tolls, and potential ratepayer benefits of new storage, on behalf of Pacific Gas and Electric Company, October 24, 2001.

Public Utilities Commission of the State of California v. El Paso Natural Gas Co., FERC Docket No. RP00-241: Testimony at hearings, May-June, 2001; Prepared Testimony on behalf of Pacific Gas and Electric Company, May 8, 2001.

Application of Pacific Gas and Electric Company, California Public Utilities Commission proceeding A.99-09-053: Prepared testimony regarding market power consequences of divestiture of hydroelectric assets, December 5, 2000.

San Diego Gas & Electric Company, *et al*, FERC Docket No. EL00-95: Prepared testimony regarding proposed price mitigation measures on behalf of Pacific Gas and Electric Co., November 22, 2000.

Application of Harbor Cogeneration Company, FERC Docket No. ER99-1248: Affidavit in support of application for market-based rates for energy, capacity and ancillary services, December 1998.

Application of and Complaint of Residential Electric, Incorporated vs. Public Service Company of New Mexico, New Mexico Public Utility Commission Case Nos. 2867 and 2868: Testimony at hearings, November, 1998; Direct Testimony on behalf of Public Service Company of New Mexico on retail access issues, November, 1998.

Management audit of Public Service Electric and Gas' restructuring proposal for the New Jersey Board of Public Utilities: Prepared testimony on reliability and basic generation service, March 1998.

PUBLISHED ARTICLES

Forward Capacity Market CONEfusion, Electricity Journal Vol. 23 Issue 9, November 2010.

Reconsidering Resource Adequacy (Part 2): Capacity Planning for the Smart Grid, Public Utilities Fortnightly, May 2010.

Reconsidering Resource Adequacy (Part 1): Has the One-Day-in-Ten-Years Criterion Outlived Its Usefulness? Public Utilities Fortnightly, April 2010.

A Hard Look at Incentive Mechanisms for Natural Gas Procurement, with K. Costello, National Regulatory Research Institute Report No. 06-15, November 2006.

Natural Gas Procurement: A Hard Look at Incentive Mechanisms, with K. Costello, Public Utilities Fortnightly, February 2006, p. 42.

After the Gas Bubble: An Economic Evaluation of the Recent National Petroleum Council Study, with K. Costello and H. Huntington, Energy Journal Vol. 26 No. 2 (2005).

High Natural Gas Prices in California 2000-2001: Causes and Lessons, Journal of Industry, Competition and Trade, vol. 2:1/2, November 2002.

Restructuring the Electric Power Industry: Past Problems, Future Directions, Natural Resources and Environment, ABA Section of Environment, Energy and Resources, Volume 16 No. 4, Spring, 2002.

Scarcity, Market Power, Price Spikes, and Price Caps, Electricity Journal, November, 2000.

The New York ISO's Market Power Screens, Thresholds, and Mitigation: Why It Is Not A Model For Other Market Monitors, Electricity Journal, August/September 2000.

ISOs: A Grid-by-Grid Comparison, Public Utilities Fortnightly, January 1, 1998.

Economic Policy in the Natural Monopoly Industries in Russia: History and Prospects (with V. Capelik), Voprosi Ekonomiki, November 1995.

Meeting Russia's Electric Power Needs: Uncertainty, Risk and Economic Reform, Financial and Business News, April 1993.

Russian Energy Policy through the Eyes of an American Economist, Energeticheskoye Stroitelstvo, December 1992, p 2.

Fuel Contracting Under Uncertainty, with R. B. Fancher and H. A. Mueller, IEEE Transactions on Power Systems, February, 1986, p. 26-33.

OTHER ARTICLES, REPORTS AND PRESENTATIONS

Seasonal Capacity Technical Conference, Federal Energy Regulatory Commission Docket Nos. EL17-32 and EL17-36, *Pre-Conference Comments* April 11, 2018; panelist, April 24, 2018.

Panel: Demand Response, Organization of PJM States Spring Strategy Meeting, April 9, 2018.

Panel: Energy Price Formation, Organization of PJM States Spring Strategy Meeting, April 9, 2018.

Panel: Regional Reliability Standards: Requirements or Replaceable Relics? Harvard Electricity Policy Group Ninetieth Plenary Session, March 22, 2018.

Panel: Transitioning to 100% Capacity Performance: Implications to Wind, Solar, Hydro and DR; moderator; Infocast's Mid-Atlantic Power Market Summit, October 24, 2017.

Panel: PJM Market Design Proposals Addressing State Public Policy Initiatives; Organization of PJM States, Inc. Annual Meeting, Arlington, VA, October 3, 2017.

Post Technical Conference Comments, State Policies and Wholesale Markets Operated by ISO New England Inc., New York Independent System Operator, Inc., and PJM Interconnection, L.L.C., FERC Docket No. AD17-11, June 22, 2017.

Panel: How Can PJM Integrate Seasonal Resources into its Capacity Market? Organization of PJM States, Inc. Annual Meeting, Columbus Ohio, October 19, 2016.

IMAPP "Two-Tier" FCM Pricing Proposals: Description and Critique, prepared for the New England States Committee on Electricity, October 2016.

"Missing Money" Revisited: Evolution of PJM's RPM Capacity Construct, report prepared for American Public Power Association, September 2016.

Panel: PJM Grid 20/20: Focus on Public Policy Goals and Market Efficiency, August 18, 2016.

Panel: What is the PJM Load Forecast, Organization of PJM States, Inc. Annual Meeting, October 12, 2015.

PJM's "Capacity Performance" Tariff Changes: Estimated Impact on the Cost of Capacity, prepared for the American Public Power Association, October, 2015.

Panel: Capacity Performance (and Incentive) Reform, EUCI Conference on Capacity Markets: Gauging Their Real Impact on Resource Development & Reliability, August 15, 2015.

Panel on Load Forecasting, Organization of PJM States Spring Strategy Meeting, April 13, 2015.

Panelist for Session 2: Balancing Bulk Power System and Distribution System Reliability in the Eastern Interconnection, Meeting of the Eastern Interconnection States' Planning Council, December 11, 2014.

Panel: Impact of PJM Capacity Performance Proposal on Demand Response, Mid-Atlantic Distributed Resources Initiative (MADRI) Working Group Meeting #36, December 9, 2014.

Panel: Applying the Lessons Learned from Extreme Weather Events – What Changes Are Needed In PJM Markets and Obligations? Infocast PJM Market Summit, October 28, 2014.

Panel on RPM: What Changes Are Proposed This Year? Organization of PJM States, Inc. 10th Annual Meeting, Chicago Illinois, October 13-14, 2014.

Panel on centralized capacity market design going forward, Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators, Docket No. AD13-7, September 25, 2013; post-conference comments, January 8, 2014.

Economics of Planning for Resource Adequacy, NARUC Summer Meetings, Denver, Colorado, July 21, 2013.

The Increasing Need for Flexible Resources: Considerations for Forward Procurement, EUCI Conference on Fast and Flexi-Ramp Resources, Chicago, Illinois, April 23-24, 2013.

Panel on RPM Issues: Long Term Vision and Recommendations for Now, Organization of PJM States, Inc. Spring Strategy Meeting, April 3, 2013.

Comments On: The Economic Ramifications of Resource Adequacy Whitepaper, peer review of whitepaper prepared for EISPC and NARUC, March 24, 2013.

Resource Adequacy: Criteria, Constructs, Emerging Issues, Coal Finance 2013, Institute for Policy Integrity, NYU School of Law, March 19, 2013.

Panel Discussion – Alternative Models and Best Practices in Other Regions, Long-Term Resource Adequacy Summit, California Public Utilities Commission and California ISO, San Francisco, California, February 26, 2013.

Fundamental Capacity Market Design Choices: How Far Forward? How Locational? EUCI Capacity Markets Conference, October 3, 2012.

One Day in Ten Years? Economics of Resource Adequacy, Mid-America Regulatory Conference Annual Meeting, June 12, 2012.

Reliability and Economics: Separate Realities? Harvard Electricity Policy Group Sixty-Fifth Plenary Session, December 1, 2011.

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PROFESSIONAL ASSOCIATIONS

United States Association for Energy Economics

Natural Gas Roundtable

Energy Bar Association

May 2018

CERTIFICATE OF SERVICE

In accordance with Rule 2010 of the Commission's Rules of Practice and Procedure,

I hereby certify that I have this day served by electronic mail a copy of the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, DC this 6th day of June, 2018.

/s/ Phyllis G. Kimmel

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