Exhibit No. NES-028

Answering Testimony 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
	)	

PREPARED ANSWERING TESTIMONY OF JAMES F. WILSON
ON BEHALF OF THE
NEW ENGLAND STATES COMMITTEE ON ELECTRICITY

AUGUST 23, 2018

TABLE OF CONTENTS

LIST OF EXHIBITS

		CUI/ PRIV-HC
NES-028	Answering Testimony of James F. Wilson	N
NES-029	Resume of James F. Wilson	Y
NES-031	Mystic Responses:	
p. 1	Mystic Response to NES-MYS-1-64	N
pp. 2-3	Mystic Response to NES-MYS-9-24	Y
p. 4	Mystic Response to S-MYS-9.22	Y
p. 5	Mystic Response to S-MYS-9.24	N
pp. 6, 7	Mystic Response to NEER-MYS-1-4b	N
pp. 8-10	CUI_PRIV-HC Mystic Response to NES-MYS-4-1 Tank Congestion Cost Model	Y
p. 11	Mystic Response to ENC-CM-4-7	N
p. 12	Mystic Response to NEER-MYS-2-9	N
p. 13	Mystic Response to NES-MYS-11-25	Y
p. 14	Mystic Response to NES-MYS-11-26	Y
p. 15	Mystic Response to NES-MYS-11-29	Y
NES-032	CUI-PRIV-HC EDF-ENG-1-1 Firm Transport Agreement.Oct-01-1998.pdf (Excerpt)	Y
NES-033	Engie, NGA Regional Market Trends Forum, Steve Taake	N
NES-034	Tank Congestion Model Results	Y
NES-035	Engie, Presentation to Northeast Fuels Conference, Ed Cahill	N
NES-036	ENGIE Response to NES-ENG-1-15	N
NES-037	Mystic Response to NES-MYS-1-44, TRC Environmental Corp., Independent Engineering Review Project Jones – Distrigas Terminal, February 12, 2018, section 2.2	Y
NES-038	ISO Response to NES-ISO-1-1	Y

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SUMMARY

Mr. Wilson's testimony evaluates aspects of the Cost of Service Agreement ("COSA") among Constellation Mystic Power, LLC ("Mystic"), Exelon Generation Company, LLC, and ISO New England Inc. ("ISO-NE") filed by Mystic on May 16, 2018, with a focus on the proposed Amended and Restated Fuel Supply Agreement ("FSA"; Exhibit MYS-016). Under the proposed FSA, Constellation LNG, LLC ("Constellation LNG"), an Exelon Corporation subsidiary, would supply fuel to Mystic from the Everett Marine Terminal liquified natural gas ("LNG") import facility ("EMT") for the period from June 1, 2022 to May 31, 2024 ("COSA Period").

Mr. Wilson explains that under the proposed FSA, Mystic would essentially treat EMT as nothing more than a dedicated fuel delivery system for Mystic 8&9, notwithstanding EMT's long history of serving other customers. The FSA would pass all of EMT's costs through to Mystic while providing no requirement and little or no incentive for Constellation LNG to manage EMT cost-effectively and provide needed services to other customers.

Mr. Wilson concludes that the approach to Mystic fuel supply reflected in the FSA is fundamentally flawed and would lead to excessive cost passed through the COSA to consumers. He notes that operating EMT efficiently and realizing its full value is a complex task, because customers desire firm and flexible supply, while the relatively

small storage capacity requires careful management of LNG vessel deliveries, sendout to customers, and resulting tank storage levels. However, under the FSA as proposed by Mystic, Constellation LNG would not bother with these challenges, and would simply pass all EMT and Constellation LNG costs through to Mystic and to customers through the COSA.

Mr. Wilson recommends that the flawed approach to Mystic's fuel supply be rejected, and a simpler, more straightforward and more standard approach to the fuel supply relationship be used. In particular, he recommends a fuel supply agreement that addresses only the fuel supply to Mystic, and entails three main charges:

1. A Demand Charge, to recover 39.16% of the EMT fixed cost from Mystic, consistent with the Mystic plants' maximum daily volume as a fraction of EMT's certificated capacity;
2. Commodity Charges for volumes taken, based on a world LNG price index; and
3. A Reliability Charge, to cover (in expectation) various additional costs and risks related to providing firm, reliable and flexible fuel supply to Mystic.

The recommend approach would also entail provisions to address tank management and penalties should Constellation LNG fail to provide fuel security. Under the proposed approach, Constellation LNG would be free to serve other customers on a commercial basis, retaining all profits from such services.

Mr. Wilson explains that his recommended approach would lead to more efficient operation of EMT and lower cost passed through to consumers than the FSA as proposed by Mystic. The recommended approach would fully restore Constellation LNG's incentives to maximize the value of EMT through the provision of services to Mystic and other customers.

Mr. Wilson's testimony also discusses the Tank Congestion Model provided through discovery, and how it could be enhanced to be a tool to determine the recommended Reliability Charge. Finally, his testimony summarizes the changes to the COSA and FSA that would be needed to implement his recommended approach to the FSA.

Mr. Wilson also provides recommendations on certain provisions of the COSA and FSA, should the Commission approve the FSA as proposed by Mystic. In particular, with regard to the "Seller's Incentive" under the FSA, he recommends a more modest sharing percentage, such as 25%, be approved.

PREPARED ANSWERING TESTIMONY OF JAMES F. WILSON
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I. INTRODUCTION AND QUALIFICATIONS

Q 1: Please state your name, position and business address.

A: 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, Maryland 20814.

Q 2: Please describe your experience and qualifications.

A: I have thirty-five 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" or "FERC"), state regulatory agencies, and U.S. district court. I have a B.A. in Mathematics from Oberlin College and an M.S. in Engineering-Economic Systems from Stanford University.

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. I have also been involved in natural gas pipeline, storage, distribution, procurement and market issues in regions across North America. My curriculum vitae, summarizing my experience and listing past testimony, is Exhibit NES-029.

II. PURPOSE AND SCOPE OF TESTIMONY

Q 3: On whose behalf are you testifying in this proceeding?

A: I prepared this testimony on behalf of the New England States Committee on Electricity, Inc. ("NESCOE"). NESCOE is the Regional State Committee for New England and is governed by a board of managers appointed by the Governors of the six New England states. Its stated mission is to represent the interests of the citizens of the New England region by advancing policies that will provide electricity at the lowest reasonable cost over the long-term, consistent with maintaining reliable service and environmental quality.

Q 4: Please summarize the circumstances that have led to this proceeding and your testimony.

A: On May 16, 2018, Constellation Mystic Power, LLC ("Mystic") submitted a Cost of Service Agreement ("COSA") among Mystic, Exelon Generation Company, LLC ("ExGen"), and ISO New England Inc. ("ISO-NE") ("Mystic Filing"). The Mystic Filing is the subject of this proceeding, Docket No. ER18-1639-000. In a related proceeding (Docket No. ER18-1509-000), on May 1, 2018, ISO-NE sought waiver of provisions of the ISO-NE Transmission, Markets and Services Tariff ("Tariff") to enable it to enter into the COSA for the purpose of ensuring fuel security. On July 2, 2018, the Commission denied the requested waiver and instituted a proceeding under Federal Power Act Section 206 (Docket No. EL18-182-000) calling for ISO-NE to address short-term and longer-term fuel security issues or show cause that the Tariff is just and reasonable and the filing of a short and/or long-term solution is unnecessary. On July 13, 2018, the Commission accepted and suspended the COSA subject to refund and the outcome of the proceeding in Docket No. EL18-182-000, made findings on some issues and provided guidance on others, and established hearing procedures to further evaluate the COSA ("Hearing Order"). Mystic filed supplemental testimony on July 30, 2018.

The proposed COSA would provide 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 ("COSA Period"). 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 ("EMT"), and that Exelon Corporation ("Exelon"), Mystic and ExGen's parent, is in the process of acquiring EMT from Distrigas of Massachusetts, LLC ("Distrigas"), a subsidiary of the multinational energy company Engie S.A. Under a proposed Amended and Restated Fuel Supply Agreement ("FSA"; Exhibit MYS-016), Constellation LNG, LLC ("Constellation LNG"), an Exelon subsidiary, would supply Mystic 8&9 with fuel, and pass all of EMT's and Constellation LNG's costs, adjusted for certain credits, through to Mystic and ultimately to consumers.

Q 5: Have you previously testified in these related proceedings?

A: Yes. My affidavit on behalf of NESCOE was submitted in Docket No. ER18-1639-000 on June 6, 2018.[1] And in a related complaint proceeding, Docket No. EL18-154-000, testimony I prepared was attached to NESCOE's protest filed on June 6, 2018.[2]

Q 6: What is the purpose and scope of your testimony at this time?

A: I was asked by NESCOE to review and evaluate aspects of the Fuel Supply Charge (Fuel Supply Cost) to be recovered under Schedule 3 of the COSA, and related provisions in the COSA, addressing issues that were set for hearing (Hearing Order, PP 34-38). In particular, I evaluate the structure of the Fuel Supply Agreement (FSA) and whether it would contribute to the efficient and cost-effective operation of Mystic 8&9 and EMT, minimizing the cost passed through to customers through the Fuel Supply Charge. I also evaluate the proposed 50 percent seller's incentive (FSA, p. 4) that was specifically set for hearing (Hearing Order, P 38). I have not reviewed Mystic's or EMT's costs.

In performing my assignment, I reviewed and relied upon the Mystic Filing, Mystic's supporting and supplemental testimony (witnesses William B. Berg and Michael M. Schnitzer), responses to discovery requests received to date, and other publicly-available information.

[1] *Constellation Mystic Power, Inc.*, Comments and Request for Hearing and Settlement Procedures of the New England States Committee on Electricity, Attachment A, Affidavit of James F. Wilson (June 6, 2018).
[2] *New England Power Generators Association, Inc. v. ISO New England Inc.*, Protest of the New England States Committee on Electricity, Attachment A, Affidavit of James F. Wilson (June 6, 2018).

III. SUMMARY AND RECOMMENDATIONS

Q 7: What developments have led to this proceeding?

A: Earlier this year, Mystic 8&9's owner, Exelon, indicated that it would retire these units. However, ISO-NE found, as a result of it Operational Fuel-Security Analysis study ("OFSA Report"),[3] that loss of the Mystic 8&9 capacity could result in load shedding under some circumstances.[4] Accordingly, ISO-NE seeks to retain the units at least through May 31, 2024, leading to the COSA. While NESCOE and other stakeholders have identified some concerns about ISO-NE's analysis, [5] a review or evaluation of the need for Mystic 8&9 is outside the scope of this testimony.

Q 8: Please summarize your evaluation of the Fuel Supply Charge and the FSA.

A: The FSA is fundamentally flawed. Mystic is essentially proposing, through the proposed FSA, to treat EMT as nothing more than a dedicated fuel delivery system for Mystic 8&9. Notwithstanding EMT's long history of serving other customers, the FSA would pass all of EMT's costs through to Mystic, and provide no incentive and no requirement for Constellation LNG to make short-term merchant sales to other customers (for longer-term sales, there is a rather questionable "Seller's Incentive", which was added at ISO-NE's request).

Operating EMT efficiently and realizing its full value is a complex task; customers desire firm and flexible supply, while the relatively small storage capacity requires careful management of deliveries and tank levels. The FSA essentially proposes that

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[3] ISO New England, *Operational Fuel-Security Analysis for Discussion*, January 17, 2018, p. 43.
[4] Petition of ISO New England Inc. for Waiver of Tariff Provisions, Docket No. ER18-1509-000, May 1, 2018 p. 3.
[5] See, e.g., *Reply Comments of the New England States Committee on Electricity*, Grid Resilience in Regional Transmission Organizations and Independent System Operators, Docket No. AD18-7-00 (May 9, 2018), at 10-13.

Constellation LNG will not bother with this, and will simply pass all EMT costs through to Mystic and to customers through the COSA.

I recommend that this flawed approach to Mystic's fuel supply be rejected, and a simpler, more straightforward and standard approach to the fuel supply relationship be established.

Q 9: Please summarize your recommended approach to the Fuel Supply Charge and FSA.

A: I recommend a fuel supply agreement that provides for the supply of fuel to Mystic 8&9, and involves three main charges:

1. A Demand Charge, to recover a portion of EMT's fixed costs. I propose that Mystic be responsible for 39.16% of the EMT fixed cost, consistent with Mystic 8&9's maximum daily volume as a fraction of EMT's certificated capacity.
2. Commodity Charges for actual volumes taken, based on a world LNG price index.
3. A Reliability Charge, to cover (in expectation) various additional costs and risks related to providing firm, reliable and flexible fuel supply.

Q 10: Under your recommended approach to the FSA, what other provisions would it include?

A: The FSA should include provisions to assist Constellation LNG (as Seller) in providing the firm and flexible service desired by Mystic (as Buyer) without incurring excessive cost, and to give Seller strong incentives to provide the desired firm and flexible service:

1. As under the FSA as proposed by Mystic, Buyer would allow reflecting fuel scarcity in its fuel price used for plant dispatch to assist in tank management (a higher price to conserve fuel, or a lower price to reduce tank levels, when needed).
2. Seller would incur penalties should Seller be unable to supply Buyer the full quantity nominated by Buyer on any day.

Q 11: Please explain how you propose that the Reliability Charge be set.

A: The Reliability Charge would be determined each year before the winter season based on a probabilistic simulation of EMT operations to provide reliable and flexible service to Mystic. The simulation model for this purpose would be very similar to the "Tank Congestion Charge" model anticipated under the FSA (p. 4 and Schedule A) for use in evaluating third-party sales. The FSA (p. 4) calls for ISO-NE to approve the methodology for calculating the Tank Congestion Charge by six months before the commencement of the COSA; that same process should be followed for finalizing the model to determine the Reliability Charge.

Q 12: Why is this a superior approach to the FSA and Fuel Supply Charge?

A: Compared to the FSA as proposed, this alternative approach will lead to more efficient operation of EMT and lower cost passed through to consumers. It is also simpler and based on more common commercial terms.

1. The approach follows the straight fixed variable ("SFV") structure common in the natural gas industry;
2. It focuses on the service provided to the Buyer (Mystic) by the Seller (Constellation LNG), and does not implicate Seller's other customers in any direct way;

3. It fully restores Constellation LNG's incentives to maximize the value of EMT through the provision of services to Buyer and other customers;

4. It imposes the actual costs and risks associated with LNG supply and tank management on Seller, who is in the best position to manage those costs and risks, while still compensating Seller for such costs and risks in expectation;

5. It affords Seller the flexibility to use the dispatch of Buyer's power plants (Mystic 8&9) for tank management, while holding Seller accountable for the costs of such actions;

6. It imposes appropriate consequences on Seller for any failure to achieve fully reliable fuel supply;

7. It results in a more reasonable cost for Mystic's customers through the COSA, by only allocating a fair share of fixed costs, and giving Constellation LNG full incentive to realize the value of EMT.

Q 13: What changes would be required to the FSA and COSA to implement this recommendation?

A: This recommended approach would require corresponding changes to the FSA and COSA to ensure that the cost of (fuel) service flows through to customers, and the credits and penalties are appropriately handled consistent with the cost-of-service intent of the COSA. I provide a framework for the implementation of the recommendation and identify changes that would be needed, which could be developed through a compliance filing in this proceeding.

Q 14: If the Commission nevertheless approves the FSA as proposed by Mystic, do you have comments on the provisions of the FSA or COSA?

A: Yes. Section VII of my testimony provides recommendations on certain provisions of the COSA and FSA, including the fuel opportunity cost reflected in the Stipulated Variable Cost under the COSA and the Seller's Incentive under the FSA, among others.

Q 15: Please explain your recommendations with respect to the Seller's Incentive.

A: The Seller's Incentive is troubling because it is calculated at the time a deal is made and is not revisited. But the FSA provides the Seller (Constellation LNG) no incentive to minimize the losses that might result, should weather and market conditions go against the deal. All costs are passed through to Mystic and on to consumers.

As to the 50% sharing percentage, some of the circumstances here (risk and uncertainty, and Constellation LNG's apparent disinterest in such transactions) would normally suggest a higher percentage is appropriate. However, as noted above, Constellation LNG is not at risk for the outcomes of these deals, and lacks incentive to manage the outcomes. I recommend a more modest sharing percentage, such as 25%.

Q 16: How is the remainder of your testimony organized?

A: The next section of my testimony provides background on Mystic 8&9 and EMT, focusing on the challenges that must be addressed to realize the full value of EMT. Section V provides a critique of the proposed FSA, explaining why it is flawed and a fundamentally different approach to the FSA would be beneficial. Section VI describes my recommended approach to the FSA, explaining the details and potential benefits. Section VII discusses other provisions of the COSA and FSA as proposed by Mystic, and Section VIII discusses the Tank Congestion Cost Model provided through discovery.

IV. BACKGROUND

Q 17: Please describe the Mystic 8&9 generating plants.

A: Mystic 8&9 are natural-gas fired combined cycle generating stations located in Everett, Massachusetts near Boston, with a combined summer capacity of 1,417 MW (Mystic Filing, p. 6).

Mystic 8&9 began operation in 2003, and are exclusively supplied by EMT, having no other pipeline connections. They have been supplied under a long-term natural gas supply contract with Distrigas that was attractively priced (Algonquin Citygate price minus $.20/MMBtu).[6] In 2007, the supply contract was restated and extended through 2027,[7] however, apparently it has been or will be terminated. During the June 2022 through May 2024 COSA Period at issue in this proceeding, the plants would be supplied at world LNG prices (Mystic Filing, p. 25).

Q 18: How are Mystic 8&9 likely to operate during the COSA Period?

A: When supplied at world LNG prices, Mystic 8&9 are likely to run much less frequently than they have in recent years. Figure JFW-1 shows recent forward prices for Algonquin Citygates ("AGT") and the Dutch Title Transfer Facility virtual trading hub, "TTF." TTF plus $1/MMBtu is a good proxy for world LNG prices delivered to Boston.

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[6] Proposed Electric Tariff, Original Volume No. [2], *Mystic Development, LLC,* Docket No. ER06-427-000, December 29, 2005, p. 12.

[7] *See* United States Bankruptcy Court, Southern District of New York, Declaration of Jeff Hunter, Manager, Executive Vice President and Chief Financial Officer of EBG Holdings LLC, in Support of Chapter 11 Petitions and First Day Pleadings, at 39; Discovery Response ENC-CM-1-17, Supplemental Response B dated August 13, 2018.

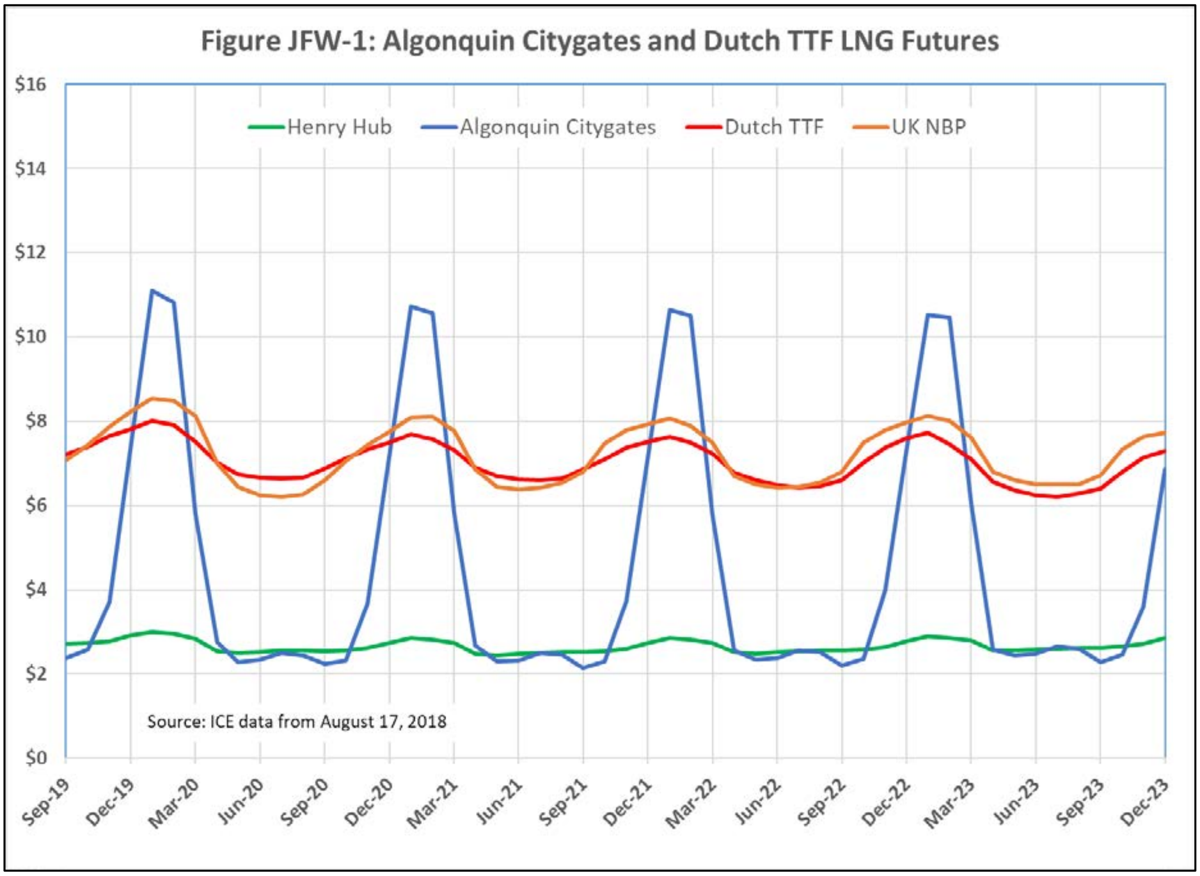

Figure JFW-1: Algonquin Citygates and Dutch TTF LNG Futures

According to these futures prices, world LNG prices are expected to be considerably higher than AGT in all months of the year except January and February. The pattern is similar for 2018-2019 and all years through 2022-2023.

Of course, AGT prices may spike during summer hot spells, during cold periods in early or late winter, or at other times. And ISO-NE may dispatch Mystic 8&9 for reliability reasons at times. However, with the loss of the fuel supply priced at a discount to AGT, it should be expected that Mystic 8&9 will run less often.

Q 19: Please describe EMT's history.

A: Distrigas' EMT began operation in 1971,[8] receiving and storing LNG and distributing regasified natural gas to the Boston Gas distribution system and, by displacement, to the Algonquin Gas Transmission ("Algonquin", "AGT") and Tennessee Gas Pipeline ("Tennessee") interstate pipelines. From 1971 to 2001, Distrigas, via EMT, supplied various New England local gas distribution companies ("LDCs") and other customers. EMT added additional vaporization systems in the 1990s and direct interconnections to Algonquin[9] and Tennessee.[10] In 2001, Distrigas was authorized to further expand its vaporization capacity at EMT and provide service to the new Mystic 8&9 electric generation plants.[11]

Q 20: Please describe EMT's capacity to store and deliver supplies.

A: The LNG storage capacity at EMT is 3.4 Bcf (Mystic Filing, p. 21).

The FERC-certificated vaporization capacity of EMT is 715,000 MMBtu/day,[12] which can be sustained without interruption and allows for redundancy and maintenance.[13] [redacted]

[8] *Order Approving Abandonment and Granting Authorization Under Section 3 of the Natural Gas Act, Distrigas of Massachusetts LLC, Docket No. CP08-49 (2008).*
[9] Order Issuing Certificate and Show Cause, *Algonquin Gas Transmission Company*, Docket No. CP91-1111 (1991), and Order Issuing Certificate, *Distrigas of Massachusetts Corporation*, Docket No. CP91-2243 (1991).
[10] Order on Rehearing and Denying Request for Stay, *Tennessee Gas Pipeline*, Docket No. CP96-164-001, and *Distrigas of Massachusetts Corporation*, Docket No. CP96-254-001 (1997).
[11] 94 FERC ¶ 61,008, *Order Issuing Certificate,* issued January 10, 2001 in Docket No. CP00-447-000.
[12] One Bcf of natural gas (a volume measure) is approximately equivalent to 1,000,000 MMBtu (heat value).
[13] Exh. No. NES-031, p. 1 (NES-MYS-1-64).
[redacted]

Distrigas currently holds three firm downstream pipeline/LDC transportation contracts: 170,000 MMBtu/d on Algonquin,[15] 40,000 MMBtu/d on Tennessee,[16] and **[BEGIN CUI/PRIV-HC]** [redacted] **[END CUI/PRIV-HC]** The maximum potential sendout on these routes will be greater than these firm amounts.

EMT also delivers boiloff gas to the Boston Gas system and can deliver LNG in liquid form at rates up to the equivalent of 100,000 MMBtu per day.[18]

Q 21: Please describe the services Distrigas via EMT provides to its customers.

A: Until 2008, Distrigas via EMT provided firm and interruptible services under Commission-approved rate schedules with negotiated prices subject to rate caps. In 2008, the Commission approved Distrigas' request to cancel its tariff and provide all services under negotiated market-based rates.[19] This change was consistent with the Commission's policy regarding LNG import terminals, under which imported LNG is treated as an unregulated first sale of natural gas.[20]

Distrigas continues to pursue short- and long-term contracts for winter peaking and summer LNG refill supply with a diverse customer base that includes LDCs, power generators, and marketers.[21] As one example, Distrigas recently made a proposal to

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[15] Algonquin Gas Transmission, LINK®System Informational Postings, Index of Customers, accessed August 23, 2018.
[16] *Tennessee Gas Pipeline Company, LLC, Informational Postings, Index of Customers, accessed August 23, 2018*
[redacted]
[18]Exh. No. NES- 35 (Ed Cahill, Presentation to the Northeast Energy and Commerce Association Fuels Conference, September 28, 2016, page 8).
[19] 124 FERC ¶ 61,039, *Order Approving Abandonment and Granting Authorization Under Section 3 of the Natural Gas Act*, issued July 17, 2008 in Docket No. CP08-49-000.
[20] *See*, for instance, *Hackberry LNG Terminal, L.L.C.*, 101 FERC ¶ 61,294 (2002).
[21] Exh. No. NES-033 (Steve Taake, Manager, Gas Marketing, Engie, presentation to the NGA Regional Market Trends Forum, May 3, 2018, available at http://www.northeastgas.org/pdf/s_taake_2018.pdf.).

Boston Gas Company (d/b/a/ National Grid), an LDC, to meet an incremental capacity need.[22]

Q 22: What do Distrigas' customers value in the EMT facility?

A: Imported LNG will generally be expensive compared to the pipeline alternatives during all but the coldest periods of the year, as shown earlier in Figure JFW-1..

Distrigas' customers will value EMT's ability to reliably deliver supplies when the pipelines are constrained (such as during extreme cold, when AGT prices may be high), thereby providing incremental peak day deliverability to Boston and the New England region. LDCs may be willing to pay relatively high prices for secure peak-period deliverability even if they actually call on the deliverability relatively rarely.

Details of Distrigas' contractual relationships, customers, and anticipated revenues were not provided through discovery due to confidentiality concerns. However, it can be expected that much of EMT's revenue is related to the firm deliverability option during periods of peak demand rather than sales of the LNG commodity.

Q 23: Does Distrigas face competition in providing these services?

A: Yes. In addition to the pipelines serving the region, New England is served by two additional operating LNG import terminals and a total of 20 Bcf of LNG storage capacity at 46 facilities.[23] The LNG storage facilities can be replenished by trucks loaded at facilities, including EMT, within or outside the region.

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[22] 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.

[23] Exh. No. NES- 35 (Ed Cahill, Presentation to the Northeast Energy and Commerce Association Fuels Conference, September 28, 2016, page 4).

Q 24: Please describe the challenges Distrigas faces in providing firm and flexible services to its customers.

A: The LNG storage capacity at EMT is only 3.4 Bcf, which is only about five days of supply at the certificated capacity (715,000 MMBtu/d, or about 0.7 Bcf/d).

When a delivery is imminent, Distrigas must ensure the EMT storage tanks are low enough to be able to accept the anticipated delivery quantity in full (substantial contractual penalties can result if a portion of the delivery cannot be received). Ships can deliver as much as 3 Bcf to EMT; to receive 3 Bcf, the tank would have to be at 0.4 Bcf or lower, close to the minimum level of approximately **[BEGIN CUI/PRIV-HC]** [redacted] **[END CUI/PRIV-HC]**[24]

The need to reduce tank levels to accommodate incoming cargoes may, at times, require sendout from EMT to Mystic 8&9 and/or to the interconnected pipelines that is not demanded by any customer, and would be loss-making.

EMT has at times been able to schedule additional cargoes on relatively short notice.[25] However, the ability to schedule additional deliveries with short lead-time is limited, especially during winter when global demand for LNG is strongest. Among other challenges, newer LNG tankers are generally **[BEGIN CUI/PRIV-HC]** [redacted]

[24] CUI/PRIV-HC Exh. No. NES-031, p. 4 (Response to S-MYS-9.22) (minimum tank level is **[BEGIN CUI/PRIV-HC]** [redacted] **[END CUI/PRIV-HC]**.

[25] Exh. No. NES-036 (Response to NES-ENG-1-15) (acknowledging the ability to arrange cargoes on short notice at times).

[redacted]

[END CUI/PRIV-HC]

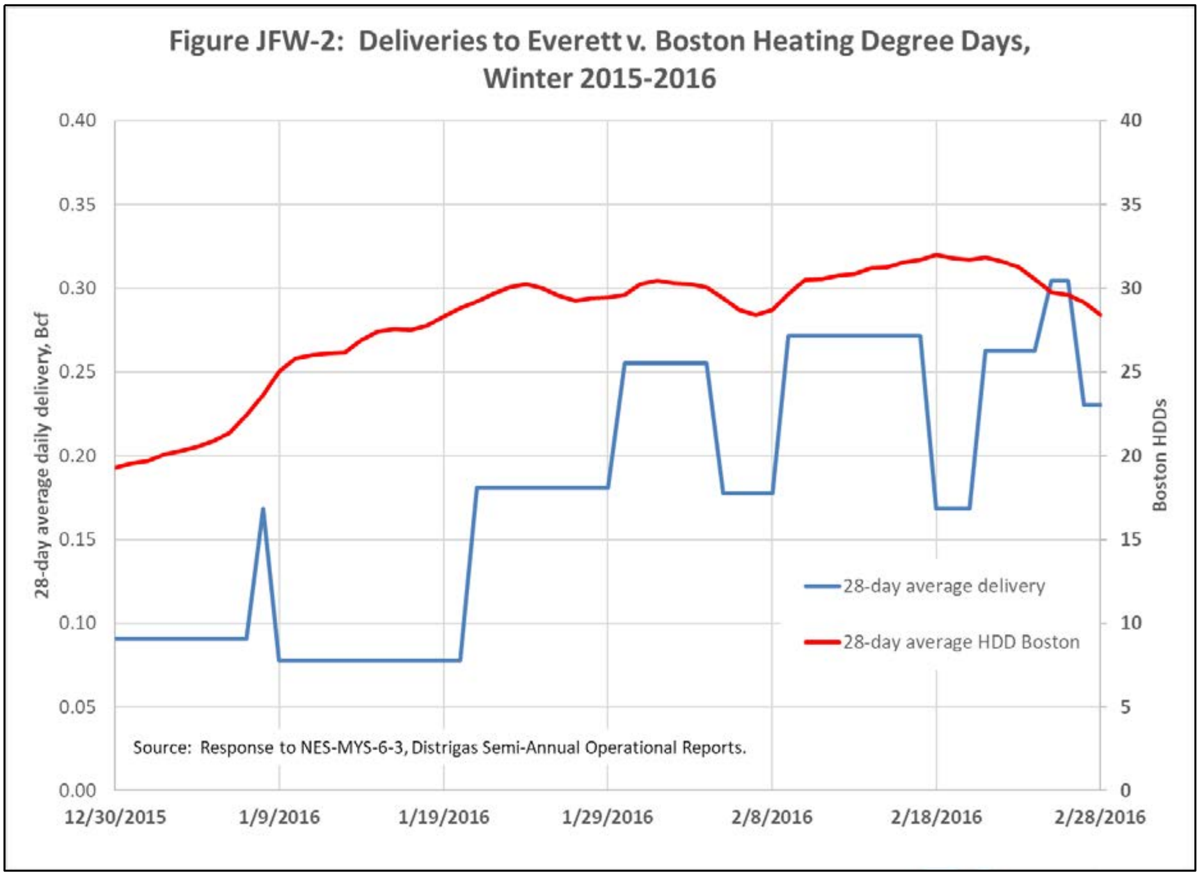
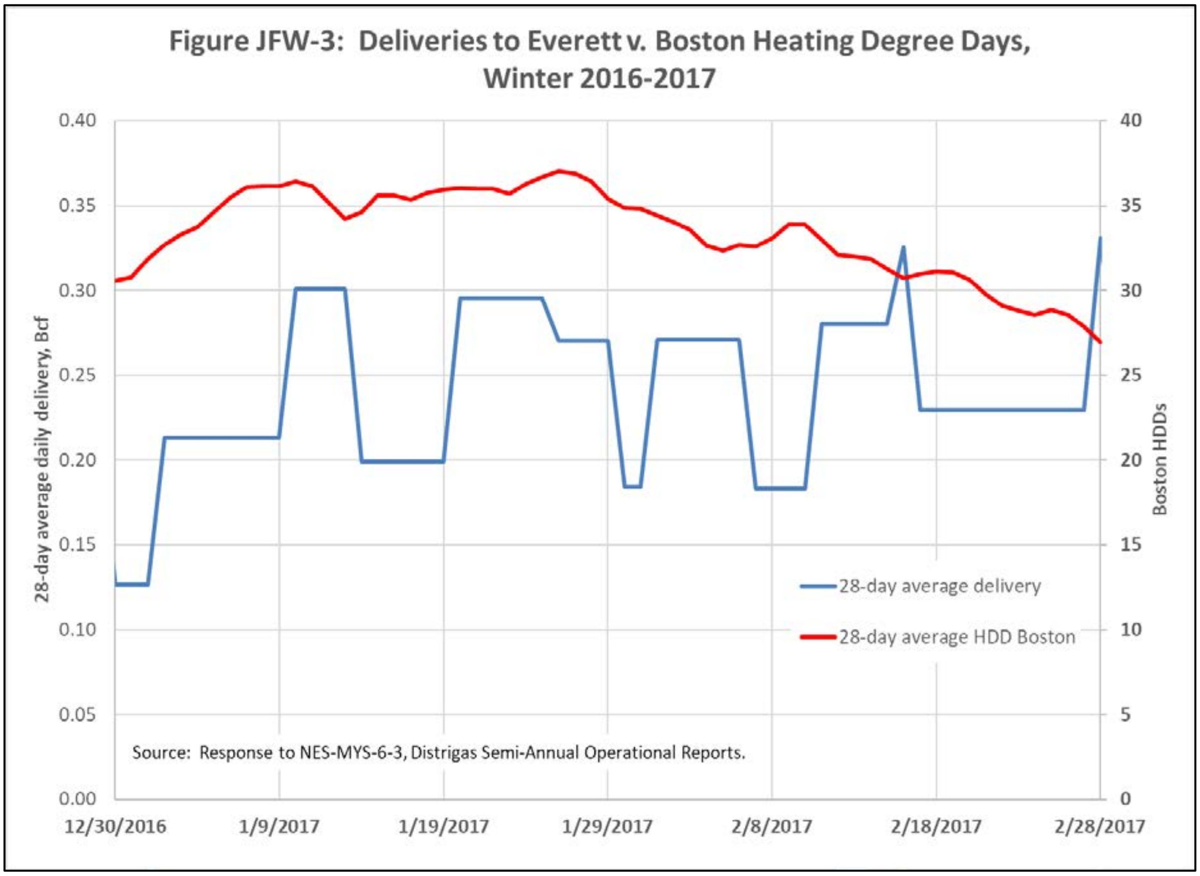


Figure JFW-2: Deliveries to Everett v. Boston Heating Degree Days, Winter 2015-2016

Thus, determining the portfolio of firm and flexible services that customers seek and the facility can provide in a commercially sound manner, and fulfilling those services, is fairly complex. Decisions about additional customer commitments, cargo scheduling, cancelling or diverting cargoes, and tank management will involve trade-offs between current costs and future costs and risks.

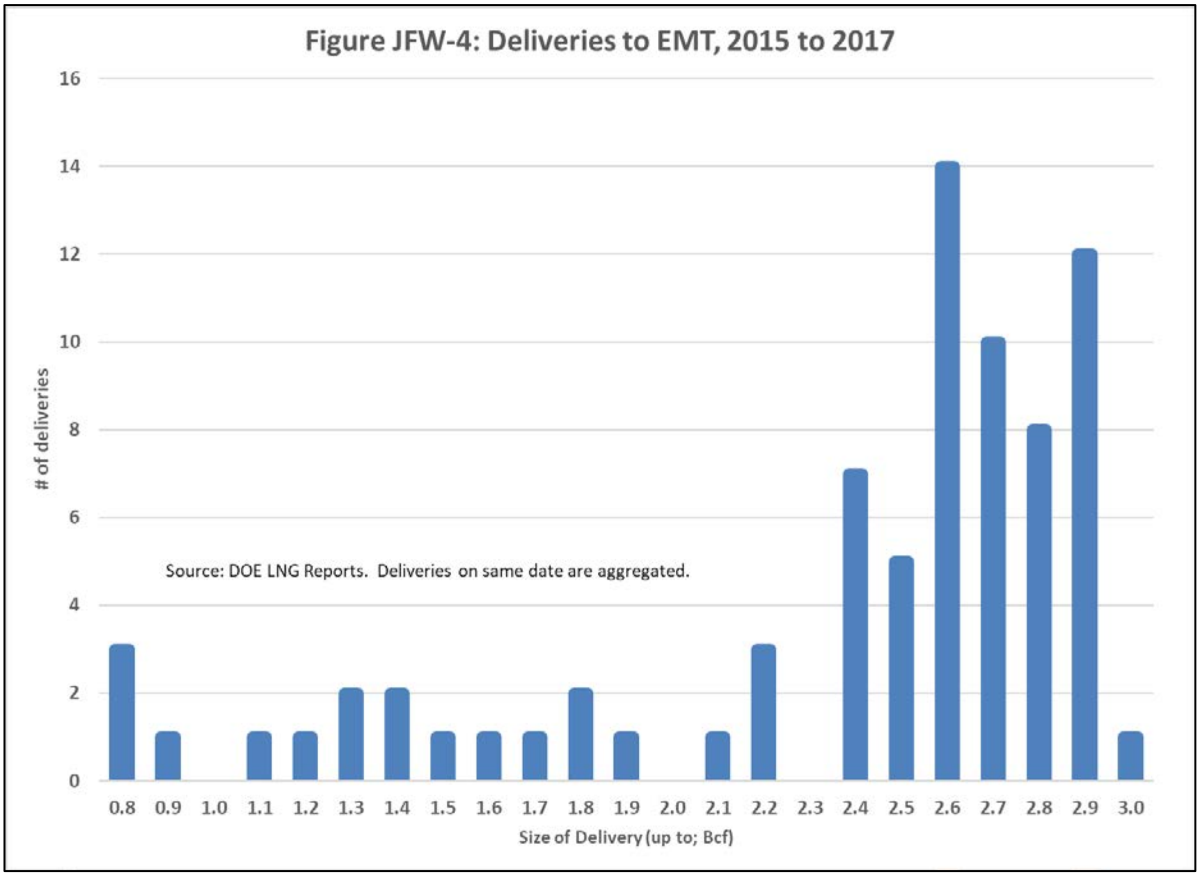
[redacted]



Q 25: Was Engie able to adjust LNG deliveries in response to temperature and demand conditions?

A: Engie apparently has been able to make some adjustments. This is suggested by the pattern of deliveries over the 2015-2016 and 2017-2018 winters, illustrated in Figures JFW-2 and JFW-3, respectively. These figures compare the 28-day rolling average deliveries to EMT to the 28-day rolling average Heating Degree Days for Boston (a measure of cold conditions, which drive winter gas demands).

In 2015-2016 (Figure JFW-2), the winter season started off relatively mild, but got cold and stayed relatively cold from mid-January through March. The deliveries to EMT matched this pattern, relatively low until mid-January and then higher for the remainder of the winter.



In 2016-2017 (Figure JFW-3), the temperature pattern was quite different, but the deliveries again followed the temperature pattern. The early winter was considerably colder, but late winter was milder. The deliveries to EMT matched the conditions – rising much earlier, and also dropping off earlier, than in 2015-2016.

Q 26: Mystic's witness Schnitzer focuses on 3 Bcf cargoes, which require the tank to be drawn to a very low level. Has EMT mainly received 3 Bcf cargoes in recent years?

A: No. Mr. Schnitzer cites "discussions" with Engie, not any historical data, as the source for his focus on 3 Bcf cargoes.[28] Figure JFW-4 summarizes the daily amounts delivered to EMT during 2015 to 2017, based on delivery data provided to the U.S. Department of

[28] Exh. No. NES-031, p. 5 (Response to S-MYS-9.24).

Energy ("DOE").[29] Most deliveries have been in the 2.3 to 2.9 Bcf range, and many have been under 2 Bcf. The median cargo size, in each of the years 2015, 2016 and 2017, was about 2.5 or 2.6 Bcf according to the DOE data.

Somewhat smaller cargoes provide much greater flexibility at EMT. For instance, to receive a 2.5 Bcf cargo (the median size delivered to EMT in 2017), the tank would have to be at 3.4 – 2.5 = 0.9 Bcf or lower compared to 0.4 Bcf or lower to receive 3 Bcf.

The time pattern of deliveries shown in the DOE data also suggests flexibility in the scheduling of cargoes. This may reflect, among other adjustments, swaps of incoming cargoes for other cargoes at slightly different dates.[30]

Q 27: How did Engie achieve this flexibility in the supply to EMT?

A: The full details are not known. However, Engie suggests that some flexibility was available due to Engie's operation as part of a larger portfolio of supply contracts and shipping capacity.[31]

Q 28: Will Constellation LNG also be able to achieve such flexibility in the deliveries to EMT?

A: To operate EMT efficiently, Constellation LNG will need to be able to flexibly supply EMT, as Engie has done. Constellation LNG may also seek a large portfolio of supply contracts and shipping capacity, or partner with an entity with such a portfolio, to accomplish this flexibility. As the LNG markets become increasingly flexible over the

[29] U.S. Department of Energy LNG Reports, available at https://www.energy.gov/fe/listings/lng-reports.
[30] Exh. No. NES-031, pp. 6-7 (Response to NEER-MYS-1-4b).
[31] Exh. NES-036, p. 1 (Response to NES-ENG-1-15).

coming years, Constellation LNG should have new options for flexibly and cost-effectively supplying EMT and its customers.

Q 29: Please elaborate on how LNG markets are becoming increasingly flexible.

A: Trends in international LNG markets are summarized in a recent report by the International Energy Agency ("IEA").[32] In this report, IEA notes (p. 382) that the way natural gas is traded internationally is changing, mainly as a result of the large-scale ramp up of LNG exports from the United States. The report notes (pp. 386-391) that while historically LNG trade was characterized by inflexible offtake agreements with destination restrictions and take-or-pay clauses, the flexibility of contract provisions and LNG flows is increasing.

In particular, the report notes the role of aggregators acting as intermediaries and mitigating the risk of both producers and consumers (p. 390). According to the report, aggregators, who are typically international energy companies that have multiple LNG supply sources to serve a range of existing and new customers, hold about half of the volume of the LNG contracts concluded between 2010 and 2016. The report specifically mentions Engie as one of these aggregators.

Q 30: If Constellation LNG fails to arrange for some flexibility in its fuel supply, what impact will this have on its ability to serve Mystic and other customers?

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[32] International Energy Agency, Outlook for Natural Gas, Excerpt from World Energy Outlook 2017, OECD, 2018, available at
http://www.iea.org/publications/freepublications/publication/WEO2017Excerpt_Outlook_for_Natural_Gas.pdf.

A: To the extent Constellation LNG fails to arrange for some flexibility in its LNG procurement and, as a result, operates EMT in a less efficient manner, this would result in higher cost and less value from EMT.

Q 31: If Constellation LNG fails to arrange for some flexibility in its fuel supply, who will bear the increased cost of service that results?

A: This higher cost would be a result of Exelon's decisions to acquire EMT, and to operate it in a less efficient manner than did Engie. Constellation LNG should not be permitted to pass this cost increase on to Mystic and through to New England consumers.

Q 32: Mystic 8&9 has been EMT's largest-volume customer recently; if the Mystic 8&9 plants are retired, will this result in a huge drop in EMT's business?

A: Not necessarily. Were Mystic 8&9 to retire, the generation would be lost, but New England's demand for electricity would continue. Other power generators, including many gas-fired power generators, would undoubtedly experience an increase in demand for their output, in particular, in hours when, in earlier years, Mystic 8&9 had been operating. Some of the generators that fill in for Mystic 8&9 may have higher heat rates, and, accordingly, require more MMBtus to produce the same electricity. EMT may have new power generation customers if Mystic 8&9 retire.

V. REVIEW OF THE PROPOSED FUEL SUPPLY AGREEMENT (FSA)

Q 33: Please describe the proposed Fuel Supply Agreement.

A: 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 EMT, including a return on investment and various other charges net of certain credits.

In allocating the full cost of EMT to Mystic 8&9, the FSA would also generally credit the net earnings from transactions with other customers served through EMT. For shorter-term merchant sales (less than three months in advance), all costs and revenues would be passed through the FSA (FSA, pp. 3-4).

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 50% "Seller's Incentive" (FSA, pp. 3-5). The Seller's Incentive is calculated at the time of "contract execution" based on the anticipated net revenue from the transaction, and there is no subsequent adjustment of it, except in instances of Seller non-performance. The Seller's Incentive is a feature that was not proposed by Mystic, but was added to the FSA at the request of ISO-NE.[33]

The FSA (p. 3) also calls for all costs associated with pipeline transportation agreements downstream of EMT, and all costs resulting from diversion of LNG deliveries, to be passed through to Mystic.

Q 34: Please comment on the structure of the Fuel Supply Agreement.

A: Mystic is essentially proposing, through the proposed FSA, to treat EMT as nothing more than a dedicated fuel delivery system for Mystic 8&9. Notwithstanding EMTs long history of serving other customers, the FSA would provide no incentive and no requirement for Constellation LNG to make short-term merchant sales to other customers. For the more valuable longer-term transactions, there would be no

[33] Exhibit No. MYS-019 at 25.

requirement to make such services available, and it is unclear that the proposed "Seller's Incentive" would be effective.

To maximize the value of the EMT facility, the operator must negotiate a portfolio of forward commitments that realize the value of the firm deliverability while not over-promising the firmness of service. Through the critical winter season, in the face of uncertain weather, gas demands, and prices, the operator must manage LNG deliveries, manage performance under firm commitments, manage tank levels, and take advantage of short-term sales opportunities that arise, among other challenges. Managing the facility in a commercially sound manner will almost continuously entail various tradeoffs between current and future costs and risks. However, the FSA eliminates nearly all incentive for Constellation LNG to take on and manage these challenges and to operate EMT in a manner that will realize its full value in the marketplace. As a result, the FSA would result in excessive cost passed through to Mystic, and ultimately to New England consumers. Thus, the structure of the FSA is fundamentally flawed.

Q 35: Please elaborate on why the Seller's Incentive may be ineffective.

A: While a well-designed incentive mechanism can improve a contractual arrangement in which incentives otherwise might be lacking, it can be very difficult to design an effective incentive mechanism, especially under circumstances involving uncertainty and risk as exist here. And a poorly-designed incentive mechanism can distort decision-making and/or create opportunities to earn incentives through uneconomic transactions. The Seller's Incentive pertains only to longer-term transactions, and the incentive is calculated based on an evaluation of each deal at the time of execution. The Seller is not held accountable for the actual outcomes, and the actual costs net of revenues are passed through to customers. Thus, the Seller's Incentive does not repair the lack of incentive under the FSA to manage EMT effectively.

I do not see much, if any, prospect for improving the FSA by modifying the incentive provisions.

Q 36: Please summarize your conclusions regarding the FSA as proposed by Mystic.

A: The FSA is fundamentally flawed. The value of EMT, and in particular the potential revenues and costs from providing services to other customers, will be fully under Constellation LNG's control. It follows that Constellation LNG should be at risk for these decisions and also stand to benefit from performing this function well. While there is uncertainty and risk involved, Constellation LNG is in the best position to manage EMT's costs. But there must be an incentive to do so.

I recommend that Mystic's approach to fuel supply under the FSA be rejected, and a simpler, more efficient, and more common approach to the fuel supply relationship be established. This recommended approach is described in the next section of my testimony.

A later section of my testimony provides additional, more specific comments on certain provisions of the FSA and COSA as proposed by Mystic.

VI. RECOMMENDED ALTERNATIVE APPROACH TO THE FSA

Q 37: Please describe what this section of your testimony will address.

A: In this section I describe my recommended approach to the Fuel Supply Agreement. I first provide an overview, then explain the details, and, finally, summarize the benefits of the proposed approach.

Q 38: Please provide an overview of your recommended approach to the FSA.

A: I propose a more standard type of fuel supply agreement that is focused on the fuel supply service provided by Constellation LNG ("Seller") to Mystic ("Buyer"), and the appropriate charges and other provisions for that service. Under this approach, the FSA would have the types of provisions common in such agreements, and would not have provisions pertaining to Seller's transactions with its other customers. Seller would be free to provide services to other customers, and to retain all net revenues from such services, as Distrigas, EMT's current owner, has done for many years.

The proposed approach would also result in EMT's costs being recovered from all of its various customers, rather than shifting all of these costs to Mystic (and, through the COSA, to electricity consumers). The recommended approach eliminates the need for the artificial incentives and restrictions included in Mystic's proposed FSA and results in a more straightforward, efficient and understandable contractual relationship.

Q 39: Please identify the charges Mystic would pay under this approach to the FSA.

A: The proposed approach involves three main charges:

1. A **Demand Charge**, which recovers an appropriate portion of EMT's fixed costs (costs that are generally independent of the volumes provided). EMT's maximum

daily sendout to Mystic is 280,000 MMBtu/d,[34] which is 39.16% of EMT's FERC certificated capacity of 715,000 MMBtu/d. I propose that the FSA call for Buyer to pay a fixed Demand Charge based on 39.16% of the approved amount for the various fixed cost categories (page 2 of the FSA lists fixed O&M, Variable O&M, return on investment, new regulatory costs, administrative services, credit and collateral costs, and pipeline transportation agreement costs; I propose that these cost categories be included in the total cost for the calculation of the Demand Charge).

2. **Commodity Charges** for actual volumes taken. The Commodity Charge each day would be based on a pre-specified world LNG price point (such as the Dutch Title Transfer Facility virtual trading hub, "TTF"), near the time of delivery, resulting in a Reference Fuel Price for each day. Pricing based on Reference Fuel Prices, rather than Seller's actual weighted average cost of gas ("WACOG"), charges the Buyer a fair market price while leaving Seller with full incentive to acquire supplies as economically as it can.

3. A **Reliability Charge**, to cover (in expectation) various additional costs and risks related to providing firm, reliable and flexible fuel supply, which is most challenging during the winter season. The Reliability Charge, discussed further below, would be fixed in advance of each winter season. While the usual practice in such an agreement might be to reflect such costs and risks through a higher Demand Charge,

[34] 94 FERC ¶ 61,008, Order Issuing Certificate, issued January 10, 2001 in Docket No. CP00-447-000, p. 6.

it will be clearer to separate out the fixed cost recovery from the costs related to reliable service.

Q 40: What other provisions do you recommend in the FSA?

A: The FSA should include provisions to assist Seller in providing the firm and flexible service desired by Buyer without incurring excessive cost, and to give Seller strong incentives to provide the firm and flexible service:

1. Buyer would commit to providing annual, monthly, and weekly demand forecasts, and to update those forecasts on an ongoing basis.

2. Buyer would generally offer the Mystic generation into the New England wholesale electric energy market based on the Reference Fuel Price at any time. However, as under the FSA as proposed by Mystic, at times a different dispatch fuel price could be used, primarily for tank management purposes:

   (1) To help reduce tank levels when needed due to an incoming cargo, Seller would have the right to require Buyer to base its offer into electricity markets on a fuel price lower (or even zero) than the Reference Fuel Price, when feasible. However, Seller would credit buyer for the amount of any electricity market losses (negative margins) that result from such operation.

   (2) To help maintain tank levels when supplies are becoming scarce, Seller would have the right to require Buyer to base its offer into electricity markets on a fuel price higher than the Reference fuel price, to reflect the fuel scarcity and reduce the likely dispatch (consistent with ISO-NE’s fuel opportunity cost policies),

when feasible. However, Seller would credit Buyer for the amount of any lost opportunity that results from such dispatch.

(3) In addition, at times when the Reference Fuel Price is below AGT, the AGT price would be used for dispatch of Mystic 8&9, to the extent the fuel could be sold at the AGT price if conserved as a result of reduced dispatch. Buyer would receive the gains from such sales, calculated based on the Reference Fuel Price.

3. Should Seller be unable to supply Buyer the full quantity nominated by Buyer on any day, Seller would incur penalties as applicable:

(1) A Winter Fuel Outage Penalty (during the winter season) or Non-Winter Fuel Outage Penalty (other times of the year);

(2) If Buyer incurs any Pay for Performance or other penalties from the ISO New England markets that are a consequence of the fuel outage, Seller bears these penalties (they become credits under the FSA).

The penalty provisions should include stop-loss amounts, as do the penalties proposed under the COSA.

Q 41: How would the Winter Fuel Outage Penalty you propose as part of the FSA relate to the Winter Fuel Security Penalty under the COSA?

A: The Winter Fuel Outage Penalty should correspond to the Winter Fuel Security Penalty in the COSA. If the two penalties are basically the same, together they would impose the Winter Fuel Security Penalty on Constellation LNG as fuel supplier rather than Mystic. Penalties collected by Mystic from Constellation LNG under the FSA would be passed through to consumers through the COSA.

Q 42: How would the charges and credits you recommend be treated under the COSA?

A: These charges and credits should be treated under the COSA consistent with the cost-of-service intention behind the COSA. This will of course require corresponding changes to the COSA, along with the FSA. I have provided a framework for the implementation and identified changes that would be needed, which could be developed through a compliance filing in this proceeding.

With regard to the COSA, the agreement should incorporate the various charges and credits in the following manner:

1. The Demand Charge, Commodity Charges, and Reliability Charges are costs of the fuel service that (offset by associated Mystic revenues) should pass through the COSA to consumers;

2. The credit to Buyer for electricity market losses due to tank management (2.1 above) make Buyer whole for the losses, so do not need to be separately handled;

3. The lost electricity market opportunity cost (2.2 above) and gains from opportunity gas sales (2.3 above) should pass to consumers, offsetting other costs through the COSA;

4. Winter or Summer Fuel Outage Penalty payments or Pay for Performance payments by Seller to Buyer should first offset the corresponding penalties imposed on Mystic, as applicable, and any additional amount should pass to consumers, offsetting other costs through the COSA.

Q 43: Please explain your proposed Reliability Charge.

A: The purpose of the Reliability Charge is to cover Seller's costs and risks (other than fixed costs and commodity costs addressed by the Demand Charge and Commodity Charges, respectively), in providing firm and reliable, yet flexible, service to Buyer. The Reliability Charge would be set in advance and cover Seller's costs in expectation (not after-the fact, actual costs), and Seller would profit to the extent Seller is able to provide the required services at lower cost than the Reliability Charge.

In particular, the Reliability Charge would cover the Seller's expected costs for tank management, and the risk of exposure to penalties if the tank management is unsuccessful and results in a fuel outage. Tank management costs include the potential credits to Buyer when the Buyer dispatches Mystic at prices different from the Reference Fuel Prices for tank management purposes.

Tank management costs may also include costs resulting from Seller's choices to delay, downsize, cancel, or divert a scheduled cargo, or to procure an additional cargo at a cost above the Reference Fuel Price. These costs are not compensated as incurred, but the possibility that such costs may be incurred is anticipated in the Reliability Charge.

Q 44: How would the Reliability Charge be determined?

A: The Reliability Charge could be determined based on a probabilistic simulation of EMT operations to provide service to Mystic (a Reliability Charge Model, or "RC Model"). The RC Model would estimate the additional costs that must be incurred (beyond the cost of commodity) to provide service to Mystic.

Through discovery, Mystic provided a Tank Congestion Model ("TCC Model"), prepared by Mystic's witness Schnitzer, which is an example of such a simulation.[35] The FSA as proposed by Mystic anticipated using a tool such as the TCC Model to determine a Tank Congestion Charge as part of the Seller's Incentive calculation (FSA, p. 4 and Schedule A). The TCC Model **[BEGIN CUI/PRIV-HC]** [redacted] **[BEGIN CUI/PRIV-HC]** However, for the TCC Model to serve as the RC Model and accurately represent the costs that should go into the Reliability Charge, certain enhancements would be needed.

The FSA (p. 4) calls for ISO-NE to approve the methodology for calculating the Tank Congestion Charge by six months before the commencement of the COSA; that same process should be followed for finalizing the model to determine the Reliability Charge. The TCC Model, and the enhancements that would be needed for it to be able to determine the Reliability Charge, are discussed in a later section of this testimony.

Q 45: What process would be followed to determine the Reliability Charge?

A: The process to determine the Reliability Charge could proceed as follows (similar to the process suggested in the FCA to update the TCC Model). Each summer the RC Model's input parameters would be updated (Algonquin Citygate and world LNG forward prices; perhaps other assumptions). Then the RC Model would be run to simulate the cost to serve Mystic. The Reliability Charge would be based on a least-cost strategy with respect to the number and scheduling of cargoes in advance.

[redacted]

Q 46: Wouldn't this approach expose Seller to substantial weather-related risk?

A: Both Buyer demands and AGT prices tend to reflect weather conditions. Sellers' reliability-related costs could be very different in an unusually cold winter than during a normal or mild winter.

To address this concern, one approach could be to determine Reliability Charges applicable to Normal, Cold and Warm winters (with precise definitions give to those three categories[36]). Then the Reliability Charge could initially be set to the value determined by the RC Model for Normal winter conditions, but if, after the winter, the winter has met the definition of a Cold or Warm winter, there would be a true-up to the correct Reliability Charge value.

This approach would substantially mitigate Seller's weather-related risk. Of course, Seller could always further hedge its risk using natural gas forward prices or options, weather derivatives, or other hedging products or strategies.

Q 47: You anticipate that Seller will provide services to other customers in addition to Buyer. How would the Reliability Charge take this into account?

A: The Reliability Charge should reflect the costs to provide reliable and flexible service to Buyer. Thus, the RC Model simulation to determine the Reliability Charge should focus only on service to Buyer. While Seller will serve other customers, and such service could result in additional reliability-related costs, Seller should seek to recover those additional costs through its commercial relationships with other customers.

[36] Mystic's witness Schnitzer defines a Cold or a Warm winter as the 10th or 90th percentile of winter average temperature, respectively. Exh. No. NES-031, p. 11 (Response to ENC-CM-4-7).

Overall, there is likely a portfolio effect, such that the total reliability-related cost to serve a portfolio of customers is less than the sum of the reliability-related costs to serve each customer, due to some diversity in the customers' load patterns and service requirements.

Q 48: What are the advantages of this approach to the FSA?

A: As noted, compared to the current FSA, this alternative approach is a simpler and more common approach to the fuel supply arrangement, that should also be more efficient, resulting in lower cost passed through to customers:

1. The approach follows the straight fixed variable ("SFV") structure common in the natural gas industry. It thus reflects the Commission's successful approach to pipeline and storage regulation, which protects consumers while relying on markets and incentives to a great extent.

2. It focuses on the service provided to Buyer by Seller, and does not implicate Seller's other customers in any direct way.

3. It relies upon other commercial terms that are common in such contracts (flexibility to address special circumstances, with costs imposed on the party in the best position to manage the costs; Seller incurs penalties for failure to supply, etc.)

4. It fully restores Seller's incentives to maximize the value of the facility through the provision of services to Buyer and other customers.

5. It imposes the actual costs and risks associated with supply and tank management on Seller, who is in the best position to manage those costs and risks, while still compensating Seller for such costs and risks in expectation.

6. It affords Seller the needed flexibility to use the dispatch of Buyer's power plants for tank management, while holding Seller accountable for the costs of such actions.
7. It imposes appropriate consequences on Seller for any failure to achieve fully reliable fuel supply.
8. It results in a more reasonable cost for Mystic's customers through the COSA, by only allocating a fair share of fixed costs, and giving Constellation LNG full incentive to realize the value of EMT.

Q 49: Mystic's witness Schnitzer argues that it is appropriate for Mystic to bear all of EMT's costs. How do you respond?

A: I disagree. Witness Schnitzer observes that Mystic is dependent upon EMT, and similar to an on-site fuel supply, with a high level of operational integration and interconnectedness (Exhibit No. MYS-014 at pp. 21-23). He argues that due to the interconnectedness, it is not feasible to separate out facilities or costs that are "not necessary" to serve Mystic, so all of the costs should be imposed on Mystic through the FSA.

However, such interconnectedness and interdependence does not lead to the conclusion that all of EMT's costs should be imposed on Mystic 8&9 (by the same logic, all of EMT's costs should be imposed on just Mystic 8 or on Mystic 9). Throughout the natural gas industry there is such interdependence. Circumstances where the operations of a pipeline or storage facility are strongly impacted by one or a few large customers are very common, and do not require that the large customer own or bear all of the costs of the pipeline or storage facility.

Furthermore, Mystic 8&9 can receive no more than 40% of EMT's sustainable, certificated capacity. The remaining EMT capacity (at least 60%, and usually more) is available to other customers, including gas distribution companies and also electric generators, who under Mystic's proposal could benefit from the fuel supply while bearing none of EMT's cost.

VII. CONSIDERATIONS REGARDING PROVISIONS OF THE COSA AND FSA AS PROPOSED BY MYSTIC

Q 50: What topics will this section of your testimony cover?

A: This section of my testimony discusses other considerations regarding certain provisions of the COSA and FSA as proposed by Mystic.

The prior section of my testimony recommends a fundamentally different approach to the fuel supply relationship and FSA. If that approach is adopted, there should be no need to wrestle with the issues addressed below. However, to the extent the Commission continues to evaluate the FSA that Mystic has proposed, there are a number of considerations it must take into account. This section of the testimony addresses those considerations.

Q 51: Which provisions of the COSA and FSA will you address in this section of your testimony?

A: This section will discuss:

1. Fuel opportunity cost in the Stipulated Variable Cost;
2. The Winter Fuel Security Penalty;

3. The (lack of) seller incentive for short-term sales;
4. The structure of the Seller's Incentive for long-term sales;
5. The 50% sharing percentage for the Seller's Incentive.

There are other aspects of the COSA and FSA that also raise concerns (such as use of WACOG for dispatch and provisions regarding "market impacts of reliability commitments", among others), but this section focuses on the above list.

Q 52: Please describe the "fuel opportunity cost" included in the Stipulated Variable Cost.

A: COSA 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.

The SVC definition includes a "fuel opportunity cost" component that can capture two important circumstances: (i) when regional natural gas prices, represented by the AGT price, are high, and the EMT 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 under the circumstances. Including opportunity costs in the SVC is important for achieving the most valuable use for the EMT supply.

Q 53: Please comment on the first circumstance that leads to fuel opportunity cost – high AGT price.

A: When AGT prices are high, some of the EMT 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 EMT's pipeline interconnections. Therefore, regional natural gas prices may serve as an "opportunity cost" for some of the Mystic capacity. However, it may often be the case that not all of the conserved fuel can be sold. EMT's pipeline capacity may already be committed to sales to other customers, or there may be insufficient capacity or demand downstream to accept the supplies.

To accurately represent the opportunity cost of Mystic generation, it should at times be offered in two blocks, with two SVCs and resulting offer prices: one corresponding to the volumes that could otherwise go to the pipelines, and the other for volumes that could not, and for which the AGT price is not an opportunity cost.

I also note that this approach to the SVC only makes sense if Constellation LNG will, in fact, strive to offer the conserved supplies to the natural gas markets at such times. The FSA does not provide any obligation or incentive for Constellation LNG to engage in such short-term sales. Consequently, unless such incentives are added to the COSA and FSA, there should be a requirement to document each circumstance when the opportunity cost provision is used, and the disposition of the supply that was conserved as a result.

Q 54: Please comment on the second circumstance that leads to fuel opportunity cost – fuel scarcity.

A: ISO-NE is developing a methodology for determining opportunity costs for fuel-limited resources that would apply to Mystic 8&9.[37] It is important to get this right; a highly conservative methodology could result in withholding the plants from the markets when

[37] Memo from Jon Lowell to NEPOOL Markets Committee, *Opportunity Costs for Resources with Inter-temporal Production Limitations*, July 27, 2018, available at https://www.iso-ne.com/static-assets/documents/2018/07/a3_iso_memo_re_opportunity_costs.pdf.

their output is valuable, while an overly restrictive policy could prevent Constellation LNG from conserving scarce fuel when needed.

Q 55: Please describe the proposed Winter Fuel Security Penalty.

A: COSA Section 3.7 imposes a special Winter Fuel Security Penalty under circumstances of very high natural gas prices and very low EMT storage. Specifically, the Winter Fuel Security Penalty can be imposed if Boston-area natural gas prices (Algonquin Gas Transmission) exceed the Henry Hub price by $17.50/MMBtu, EMT storage is below 510 MMcf, and a delivery is not imminent. Under such circumstances, this penalty applies if the plants' Capacity Performance Score[38] is negative. When applicable, the penalty is calculated in the same manner as Capacity Performance Payments,[39] aggregating the Mystic 8 and Mystic 9 performance, to a stop-loss maximum of $30 million per month in the winter months. This provision gives Mystic an incentive to ensure that, if such a natural gas price spike is possible, Constellation LNG maintains at least 510 MMcf unless a delivery is imminent.

Q 56: Please comment on the Winter Fuel Security Penalty.

A: The trigger at 510 MMcf could provide Constellation LNG an incentive to try to freeze the storage at that level to avoid penalties, withholding supply to the Mystic plants, to other Constellation LNG customers served by EMT, and to the natural gas markets. This may not be the efficient choice, or the choice that best contributes to reliability, at some times, for instance in the last days of an extended cold snap.

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

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

This concern could be addressed to some extent with a graduated volume trigger. For example, when the other conditions for the Winter Fuel Security Penalty are met, 20% of the Winter Fuel Security Penalty would apply if the tank level reaches 550 MMcf, increasing by 20% for each 50 MMcf up to 100% of the penalty if the tank level falls to 300 MMcf.

Q 57: Please comment on the seller incentive for short-term merchant sales.

A: For shorter-term sales (less than three months in advance) to parties other than Mystic, 100 percent of the costs and revenues would be 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 would 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. A small seller incentive for such transactions, such as 10%, warrants consideration.

Q 58: Please describe the seller incentive for forward third party sales.

A: 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,” that was added at ISO-NE’s request. These longer-term transactions will be valued because they allow customers to plan on the deliverability to meet peak day needs.

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; and the Tank Congestion Cost Model is discussed in a later section of this testimony). 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.

Q 59: Please comment on the structure of the Seller's Incentive.

A: The Seller's Incentive formula may afford Constellation LNG opportunities to structure Forward Transactions that appear profitable, and earn an incentive payment, at the time of the deal, but ultimately raise the cost passed through to consumers. 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…", but this may not be sufficient to ensure that these deals are in the customers' interest. Should conditions develop such that the deals cause losses (for example, in a warm winter), Constellation LNG would have no incentive to minimize the *actual* costs incurred to divert cargoes or dump excess supply.

An alternative approach could be for the incentive to reflect actual outcomes under each deal, rather than the evaluation at the time of the deal. However, that approach would raise other concerns.[40]

Q 60: Turning now to the 50% sharing rule, what was the rationale for proposing 50% as the seller's incentive?

A: ISO-NE "did not perform a formal analysis to establish the proposed 50% margin-sharing for third-party LNG sales" and instead it was based on ISO-NE's suggestion "to Mystic that the owner's share must be high enough to provide a sufficient incentive for Mystic to engage in such sales given the risks identified by Mystic."[41] ISO-NE states that "[t]he 50-50 margin split was agreed to largely as a placeholder with the understanding that it would be further reviewed and, perhaps, negotiated by all parties in the cost-of-service proceeding."[42]

Q 61: What considerations should guide the choice of such a sharing percentage?

A: There are a number of considerations, a few of which were mentioned in the quotes above from ISO-NE:

1. The complexity of the action that is being incented; a low Seller's share is appropriate for harvesting "low-hanging fruit," while a higher percentage is warranted for complex and difficult actions;

2. The risk faced by the Seller; a higher incentive is warranted under riskier conditions;

[40] *See*, for instance, Exh. No. NES-031, p. 12 (Response to NEER-MYS-2-9) (noting conflict of interest and commodity risk issues).
[41] Exh. No. NES-038 (Response to NES-ISO-1-1).
[42] *Id*.

3. The Seller's interests and risk aversion; if the action being incented is contrary to the Seller's interests, or the Seller is highly risk averse, a higher Seller percentage may be necessary to gain the desired conduct.

Q 62: Please comment on the proposed 50% sharing percentage.

A: The circumstances here involve somewhat complex transactions, and some risk; this would normally call for a higher sharing percentage. However, under the FSA the Seller does not bear the risk of the transactions. While managing the transactions in a least-cost manner is potentially complex, which would also warrant a higher sharing percentage, the Seller is not at risk for the actual outcome of the transactions, and therefore has no incentive to carefully manage these outcomes. So these considerations ultimately do not suggest a high sharing percentage.

As to the Seller's interests and risk aversion, this is perhaps the most important consideration. If Constellation LNG is highly risk averse and disinclined to engage in third party transactions (as suggested by the fact that initially, no incentive mechanism was proposed), that would suggest that a relatively high sharing percentage is needed to overcome this inertia. However, Constellation LNG might choose to enter into multiple forward transactions, and schedule many additional cargoes to fulfill them, exposing customers to substantial risk if winter conditions and market prices render the supplies unwanted.

Based on these considerations, if this approach to the FSA is pursued and the Seller's Incentive provision is included, I believe a more modest sharing percentage, such as 25%, is appropriate under these circumstances.

VIII. EVALUATION OF THE TANK CONGESTION COST MODEL

Q 63: Please describe the Tank Congestion Cost Model ("TCC Model").

A: The FSA mentions, as part of the Seller's Incentive calculation, a "Tank Congestion Charge" (FSA p. 4 and Schedule A). Through discovery, Mystic provided the current version of the model, developed by witness Schnitzer to determine the charge.[43] The TCC Model performs a Monte Carlo simulation of Constellation LNG's gas supply to its customers over a single winter period, representing the following aspects of the problem:

[BEGIN CUI/PRIV-HC]

[redacted] **[END CUI/PRIV-HC]**

[redacted]

Based on **[BEGIN CUI/PRIV-HC]** [redacted] **[END CUI/PRIV-HC]**

Q 64: What are the key determinants of the Tank Congestion Cost, in this model?

A: I find that the results are quite sensitive to the following assumptions: **[BEGIN CUI/PRIV-HC]**

[redacted] **[END CUI/PRIV-HC]**

Q 65: Does Witness Schnitzer stand by the TCC Model's structure and assumptions?

A: **[BEGIN CUI/PRIV-HC]** [redacted] **[END CUI/PRIV-HC]**

Q 66: Do you agree that the TCC Model accurately simulates Tank Congestion Cost?

A: No. This is a fairly complex problem and the model captures key aspects of it. However, some key aspects are missing. Most notable are the following: **[BEGIN CUI/PRIV-HC]**

[redacted]

[redacted]

[redacted].

[redacted] **[END CUI/PRIV-HC]**

As with any simulation, there are other simplifications (such as the decision rules for tank management) but these two shortcomings may be the most significant.

Q 67: What action does the TCC Model assume will be taken when there is insufficient supply?

A: The model assumes **[BEGIN CUI/PRIV-HC]** [redacted] **[END CUI/PRIV-HC]**

Q 68: What TCC is predicted by the TCC Model, as it currently is configured?

A: The model was provided with price and other assumptions that suggest a mean TCC of **[BEGIN CUI/PRIV-HC]** [redacted] **[END CUI/PRIV-HC]**

[redacted]

Q 69: Is this an accurate estimate of the mean Tank Congestion Cost?

A: This estimate is **[BEGIN CUI/PRIV-HC]** [redacted] **[END CUI/PRIV-HC]**

Q 70: You mentioned there were shortcomings in the TCC Model for the purpose of calculating the Reliability Charge under your recommended approach to the FSA. Please identify the shortcomings.

A: In addition to the quite significant shortcomings noted above, there are other shortcomings for this purpose. In particular, the model would have to simulate the proposed penalties when the tank hits the minimum level ("stock out"), because the Reliability Charge would need to compensate Seller for the expected value of such penalties. Also, the model would need to be extended to non-winter periods, although the extra costs of reliable service are likely very low outside the winter period.

[redacted]

Q 71: The FSA (p. 4) calls for ISO-NE to approve the methodology for calculating the Tank Congestion Charge six months before the commencement of the COSA; would that process also be appropriate for the Reliability Charge?

A: Yes. This language acknowledged that the TCC Model would need to be further developed to fulfill the role the FSA anticipated for it. I have described some of the shortcomings of the current version of the TCC Model. Similarly, further work would be needed to develop the TCC Model, or another tool, to calculate the Reliability Charge.

Q 72: Does this complete your testimony?

A: Yes it does.

Exhibit No. NES-029

Exhibit No. NES-029
Docket No. ER18-1639-000

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Principal, Wilson Energy Economics

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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.

Exhibit No. NES-029
Docket No. ER18-1639-000

ICF RESOURCES, INC., Fairfax, VA, 1997–1998.
Project Manager

- 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.
Project Director, Moscow, Russia

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).

Independent Consultant stationed in Moscow, Russia, 1991–1996

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

Virginia Electric and Power Company’s 2018 Integrated Resource Plan filing, Virginia State Corporation Commission Case No. PUE-2018-00065, Direct Testimony on behalf of Environmental Respondents, August 10, 2018.

In the Matter of the Application of Duke Energy Ohio for an Increase in Electric Distribution Rates, etc., Public Utilities Commission of Ohio Case No. 17-32-EL-AIR et al, Direct Testimony on Behalf of the Office of the Ohio Consumers’ Counsel, June 25, 2018; deposition, July 3, 2018; testimony at hearings, July 19, 2018.

In the Matter of the Application of DTE Gas Company for Approval of a Gas Cost Recovery Plan, 5-year Forecast and Monthly GCR Factor for the 12 Months ending March 31, 2019, Michigan Public Service Commission Case No. U-18412, Direct Testimony on behalf of Michigan Environmental Council, June 7, 2018.

Constellation Mystic Power, L.L.C., FERC Docket No. ER18-1639-000 (Mystic Cost of Service Agreement), Affidavit in Support of the Comments of New England States Committee on Electricity, June 6, 2018.

New England Power Generators Association, Complainant v. ISO New England Inc. Respondent, FERC Docket No. EL18-154-000 (re: capacity offer price of Mystic power plant), Affidavit in Support of the Protest of New England States Committee on Electricity, June 6, 2018.

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; reply affidavit, June 15, 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 2017 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 2016 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.

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Exhibit No. NES-029
Docket No. ER18-1639-000

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PROFESSIONAL ASSOCIATIONS

United States Association for Energy Economics

Natural Gas Roundtable

Energy Bar Association

August 2018

<u>Exhibit No. NES-031</u>

Exhibit No. NES-031
Docket No. ER18-1639-000

NES-MYS-1-64: Regarding Everett, please provide the capacity of the vaporizer(s) supplying gas to:

a. Mystic 8 & 9,

b. NGrid's LDC,

c. Gas-fired generators connected to the Algonquin natural gas pipeline, and

d. Gas-fired generators connected to the Tennessee natural gas pipeline.

RESPONSE:

Everett is connected to the Distribution Network of Boston Gas (dba National Grid), Algonquin Gas Transmission, Tennessee Gas Pipeline, and the Mystic Generating Station Units 8 & 9. Additionally, LNG truck loading facilities are available to deliver liquid LNG. The LNG Terminal is operated as an integrated facility, with each of its separate vaporization systems interconnected so that multiple systems are capable, and are normally operated in a manner, of delivering LNG to multiple delivery points.

Additionally, since the terminal operates on a 24/7/365 basis (with only a one-day annual outage to test Emergency Shutdown Systems) redundancy is available for each pipeline connection to provide reliability and allow for maintenance to be performed in a prudent manner in accordance with regulations and good practice.

The terminal has four separate vaporization systems that were installed at different times and operate at different operating pressures, and are interconnected. The individual vaporizers in the aggregate have a total capacity of 1035 MMBTU/day. They are as follows:

- HPE System 4 x 150 MMBTU/day
- HP System 2 x 75 MMBTU/day
- MP System 3 x 50 MMBTU/day
- LP System 3 x 45 MMBTU/day

The FERC Certificated capacity is 715 MMBTU/day which can be sustained without interruption allowing both for redundancy and maintenance. Amounts of Vaporized LNG in excess of 715 MMBTU can be delivered to any pipeline or all of them in the aggregate at any given time. Thus, the LNG Terminal is limited by the downstream capacity of the pipeline systems and the Mystic Station individually and in the aggregate and is designed in a manner that the Terminal is never a limiting factor in the amount of vaporized LNG that can be delivered.

Prepared by or under the supervision of Michael M. Schnitzer
July 31, 2018

CUI-PRIV-HC

REDACTED

S-MYS-9.24 In reference to MYS-014, p.5, lines 8-9: what support or materials does Mr. Schnitzer rely on for his statement that LNG ships that deliver to Everett "carry about 3 BCF of LNG per cargo"? Please provide copies of any materials or documents relied on by Mr. Schnitzer for this statement.

RESPONSE: Mr. Schnitzer is relying on discussions with Engie during the course of contract and asset purchase discussions, and on discussions during a pre-acquisition Everett site visit.

Prepared by or under the supervision of Michael M. Schnitzer
August 15, 2018

NEER-MYS-1-4 The Gas Supply Costs/Fees section of the FSA specifies Diversion Costs and Daily Gas Sales that envision the likelihood that LNG procured in advance of the winter season may not be required to meet sales obligations to Mystic. In the event that Mystic does not need the gas supply scheduled in advance, the FSA envisions that Daily Gas Sales, or a pre-scheduled LNG cargo may be diverted which may also result in financial losses.. In addition, it is also possible that the Mystic facility will consume vaporized LNG at a resulting marginal cost to generate electricity that is greater than prevailing electric energy prices and operate at a loss (i.e., earn negative margins on its wholesale electric energy sales). In response to each subpart, if Constellation LNG intends to retain the existing policies at Everett, please explain your understanding of those policies.

a. How will Constellation LNG determine the least cost approach for managing situations where it must move gas out of the tank(s) to make room for a scheduled incoming shipment?

b. How will Constellation LNG determine when it is economical to divert a shipment as opposed to selling gas uneconomically or burning gas at Mystic uneconomically?

c. Has Constellation LNG developed policies, economic evaluation processes, or formulas to manage instances where stored LNG must be evacuated uneconomically? If so, please provide the policy, evaluation processes, or formulas that will be used.

d. Do the parties to the Mystic Agreement anticipate any prudence review of such decisions?

OBJECTION: Mystic objects that this request is vague and ambiguous, specifically as to what Exhibit, testimony, or data response the "Daily Gas Sales" is in reference to. Subject to and without waiving same, Mystic will make a good faith effort to respond by August 16, 2018.

RESPONSE:

a. The least cost approach will be informed by the estimated power prices and AGT prices over the period remaining until the next shipment as well as the daily vaporization capability over that same period.

b. Generally, diversion of a shipment will not be an attractive option, unless it is part of a "swap" for another cargo at a slightly later date. Otherwise, the interval to the next cargo will likely be too long to maintain the reliability of deliveries. That said, when "surplus" gas accumulates in significant quantities, Constellation LNG will evaluate whether diversion and/or a diversion/swap might be economic.

c. The policy will be to develop a maximum inventory curve with N days until the next cargo. So long as tank volumes are below the maximum inventory curve, no stored LNG "must be evacuated uneconomically". Uneconomic evacuation will be undertaken as necessary to keep tank inventories from exceeding the maximum inventory curve.

d. The Mystic Agreement is a FERC-jurisdictional agreement. FERC policies and precedents would govern any challenge of the prudence of "such decisions."

Prepared by or under the supervision of Michael M. Schnitzer
August 16, 2018

CUI-PRIV-HC

REDACTED

ENC-CM-4-7: Referring to the testimony and exhibits of Michael M. Schnitzer submitted in support of CM's July 30, 2018 filing in this proceeding, Exhibit MYS-014 at p. 8, Table 2, please provide Mr. Schnitzer's empirical definition of "cold" and "warm" winters.

RESPONSE: As used in Mr. Schnitzer's testimony, "cold" and "warm" winters are the 10^{th} and 90^{th} percentile winters by average winter temperature, respectively.

Prepared by or under the supervision of Michael M. Schnitzer
August 9, 2018

NEER-MYS-2-9 In reference to Page 25, lines 1-8 of the Testimony of Michael Schnitzer: Please state whether Exelon considered any other alternative methods for calculating the Seller's Incentive under the Third-Party Sales Credit for Demand Charges. If it did, please explain each approach considered and the basis for selecting the proposed approach over other alternatives.

OBJECTION: Mystic objects to this request to the extent it requests attorney client privileged or attorney work product information. Subject to and without waiving same, Mystic will make a good faith effort to respond by August 17, 2018.

RESPONSE: Exelon considered an "ex post" incentive structure based on "actual" margins, but rejected that option for two reasons. First, an ex post calculation of the "actual" sale margin creates a potential conflict of interest between "Mystic" sales and third party sales in real time. When tank management vaporization sales are required, an ex post calculation would allow Constellation LNG to flow through losses if sold to Mystic, but not if sold to third parties. Such a structure is unworkable and Mystic believes the IMM would have concerns with it. Second, Exelon is not willing to enter into an incentive structure where it is exposed to commodity risk, which would be the result of an ex post incentive structure. It is willing to enter into an ex ante "origination" incentive structure of the type described in Mr. Schnitzer's testimony and bear credit and delivery risk. See also response to ENECOS-CM-4-3 at Bates No. 000008191.

Prepared by or under the supervision of Michael M. Schnitzer
August 17, 2018

Exhibit No. NES-032

CUI-PRIV-HC

REDACTED

Exhibit No. NES-033


NGA Regional Market Trends Forum
Steve Taake
Manager - Gas Marketing
May 3, 2018

The Case for LNG in New England

- In the near to mid-term, New England has a peaking gas supply issue; not a baseload issue
- Even with current pipeline expansion plans, LNG has an important role to meet this peak demand
- Pipeline expansions are largely designed to meet LDC heating load requirements; LNG provides the necessary flexibility to meet both LDC peaking and the needs of power generation
- LNG provides the necessary real-time volume/pressure flexibility to accommodate changes in system demand

2017 Price Highlights ISO-NE*

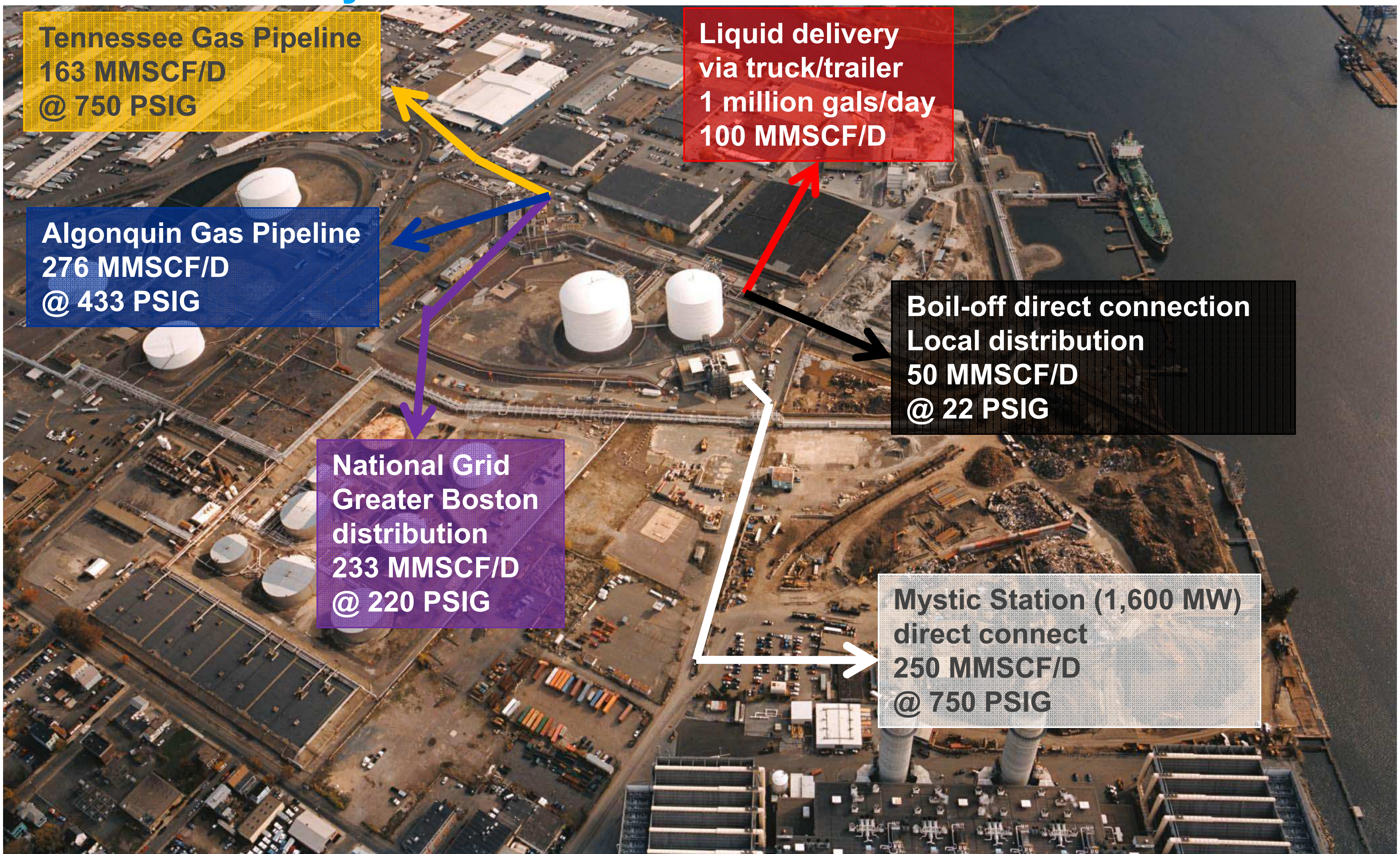
- Average annual electricity and gas prices are LOW. "Second-Lowest since 2003"
- "Second lowest annual average price of wholesale energy in 15 years: $33.94/MWh"
- "Second lowest annual natural gas price; $3.72/MMBtu"
- "August and June 2017 were among the 10 lowest-price months since 2003: $23.77/MWh during August and $23.93/MWh during June"
- Prices suggest there is not a baseload issue

Everett Marine Terminal: Peaking Service

- The Everett LNG Import Terminal aka Distrigas opened in 1971 as a peak shaving facility to help meet New England's natural gas demand
- Distrigas is the longest-operating import terminal in the US, and the only continuously operating one
- Storage capacity:
  - 3.4 Bcf
- Vaporization capacity:
  - 715 million cubic feet/day – sustainable
  - 1 billion cubic feet/day – maximum installed
- Trucking capacity:
  - 100 million cubic feet/day
  - 4 Truck Racks
- Open 24 hours a day 7 days per week

Exhibit No. NES-033
Docket No. ER18-1639-000

Everett Marine Terminal: Capability to serve key systems simultaneously



Winter 2017-18 LNG Recap

- This winter's peak day was Saturday, January 6
- During the peak, the combined vapor sendout of the Everett and Canaport facilities provided New England with 1.21 Bcf of gas…a volume greater than the largest proposed pipeline project
  - In addition, Everett loaded out 20 trucks or 18,600 MMBtu bring the total LNG contribution to 1.23 Bcf
  - This number does not account for local LDC vaporization
- For the winter season, the Everett and Canaport facilities provided New England pipeline system a total of 21.5 Bcf of gas; nowhere near the historic record of 60+ Bcf
  - This number does not account for Mystic 8-9 gas or trucked LNG
- Additional capacity is available even on peak days; existing facilities' capacity should be used prior to building incremental capacity

Everett Marine Terminal: Winter Flexibility and Reliability

- The terminal has inherent short-term flexibility in it's connections to AGT, TGP, and Boston Gas; Gas can be sent where it's needed the most
- In the mid-term, the terminal can also adapt to extraordinary situations like this winter's "bomb cyclone where New England experienced two weeks of sustained below freezing temperatures
- During the bomb cyclone, ENGIE quickly adjusted and moved up inbound 2018 cargos to December and January to meet the unexpected demand bringing in four cargos (~11 Bcf) around that event alone!
- ENGIE quickly acquired two additional spot cargos which it brought in on behalf of customers.
- Our own peak day was January 6th where we sent out a total of 657,000 MMBtu
- Additional gas was on hand and vaporization was available had we known if Mystic 8-9 was going to be dispatched
- The total gas brought in for this winter was 32.5 Bcf on 13 ships

Everett Marine Terminal: Facility Flexibility

- Installed Vaporization with redundancy is 1.04 Bcf/day
  - Hourly capability into Algonquin Gas Transmission:
    - 19.2 MMSCF/hr
  - Hourly capability into Tennessee Gas Pipeline:
    - 20 MMSCF/hr
  - Hourly capability into National Grid:
    - 13.4 MMSCF/hr
- Flexibility is helpful as Power Generation Facilities looking for uneven hourly deliveries

Going Forward

- We're continuing to sign short and long term contracts for Winter and Summer <u>Firm</u> Peaking Gas:
  - Winter Firm Vapor and/or Liquid Services
  - Combination Vapor/Liquid Services
  - Summer LNG Refill
- Our customer mix:
  - LDC's to ensure reliable service for their customers
  - Power Generators ISO-NE in light of "Pay for Performance"
  - Marketers with AMA agreements for LDC's
- We have recently extended contracts for our firm transportation quantity on TGP/AGT
- We are continuing to serve the Mystic Power Plant

Final Thoughts – the Case for LNG in New England

- Fundamentally, NE has a winter peaking problem - true 47 years ago as today

- ENGIE believes strongly that New England should first unlock potential of underutilized existing natural gas infrastructure to help solve winter peak issue
  - Long term contracts for firm service rather than seasonal
  - ISO-NE Winter Reliability Program rightly includes LNG as well as oil, dual fuel, DR
  - 20 Bcf of stored LNG in New England
  - ISO-NE Pay for Performance proposal should go a long way toward resolving these issues
  - Market should pursue policy to ensure pipes full East to West to better assess real needs West to East
  - New pipe solves baseload growth issue; LNG solves peaking problem.

- LNG can be economically delivered to the New England market during peak periods provided commitment is made with enough time to facilitate logistics

- The market needs proper mechanisms in place for power generators to recover the cost of flexible fuel supply during peak demand periods

- LNG is available on a short-term, seasonal basis or on a longer-term basis as needed

Exhibit No. NES-034

CUI-PRIV-HC

REDACTED

Exhibit No. NES-035

Exhibit No. NES-035
Docket No. ER18-1639-000

ENGIE

NECA Fuels Conference

Ed Cahill
Vice President - Marketing,
Sales & Transportation
September 28, 2016

North America Key Facts

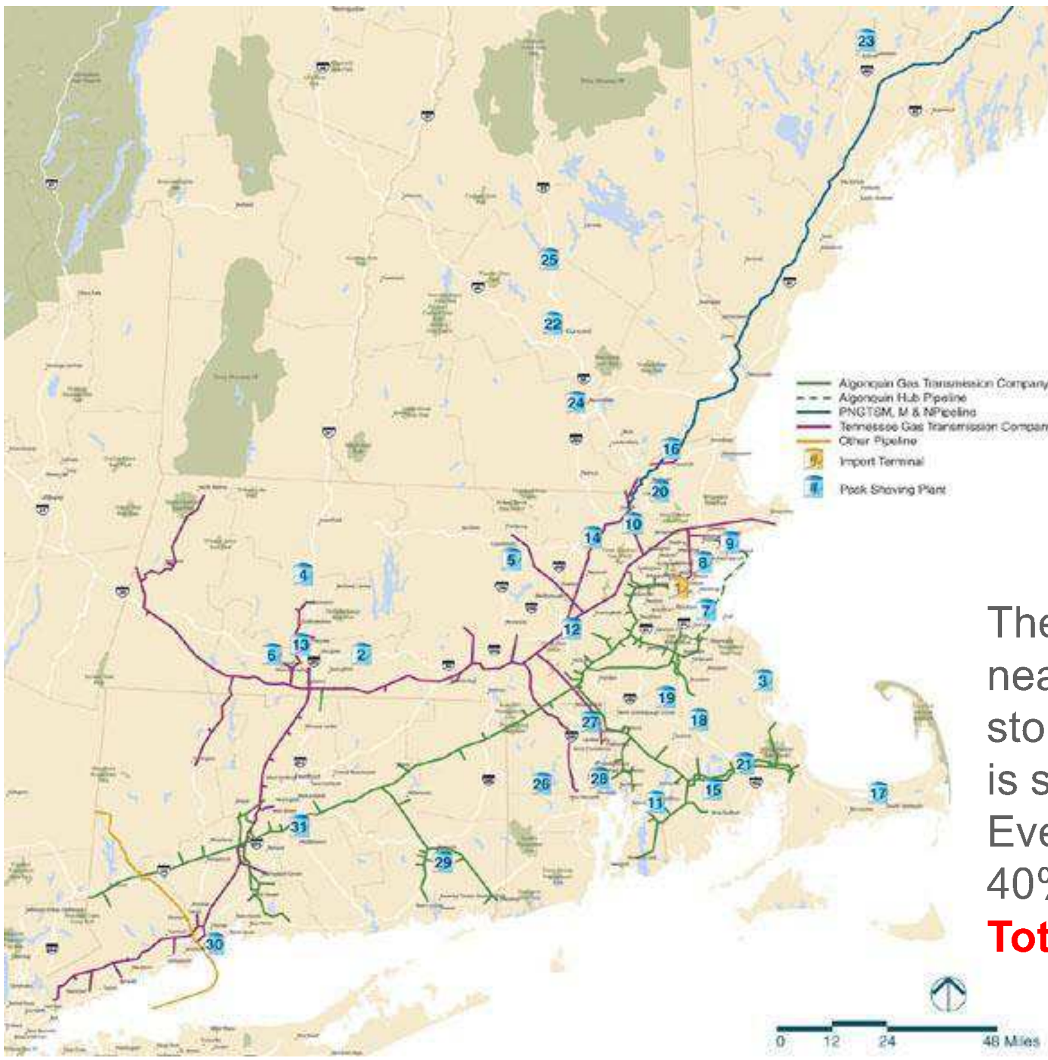
- **$4.9 billion** (U.S.) 2015 annual revenues; approximately **3,500 employees** working in the region.
- **No. 1** LNG terminal player in the United States and among the most active LNG trucking operations in the world.
- Managing **12 Bcf** of natural gas pipeline and salt dome storage in the central U.S. and Canada.
- **No. 3** largest non-residential retail electricity supplier in the United States serving commercial, industrial and institutional customers in 14 markets, including nearly 50 percent of *Fortune* 100 companies. Growing customer base of residential and small business electricity customers (from 0 to 150,000 today in 2 years) under the Think Energy® brand.
- Generating power from a diverse fuel mix portfolio in which nearly **90 percent** produces no carbon emissions, or very few.
- **Top 5** wind operator in Canada and in the regional renewables portfolio, operating facilities with a generation capacity of nearly **1,000 MW.**
- Helped customers identify and achieve more than **$4.1 billion** in energy savings in commercial, industrial, institutional and municipal sectors and processing **$20 billion** in energy billing costs.

The Case for LNG in New England

- New England has a peaking gas supply issue, not a baseload issue in the near to mid-term (Particularly true with AGT's AIM project with a November 1, 2016 start date adding 342,000 MMBtu)
- Even with current pipeline expansion plans, LNG has an important role to meet peak demand
- Pipeline expansions are largely designed to meet LDC heating load requirements; LNG provides the necessary flexibility to meet both LDC peaking and the needs of power generation
- Use of LNG as a peaking fuel in power markets is hindered not so much by global gas markets but by the existing regulatory structure

Exhibit No. NES-035
Docket No. ER18-1639-000

Importance of LNG in Greater Boston & New England



The Everett Terminal directly connects into:

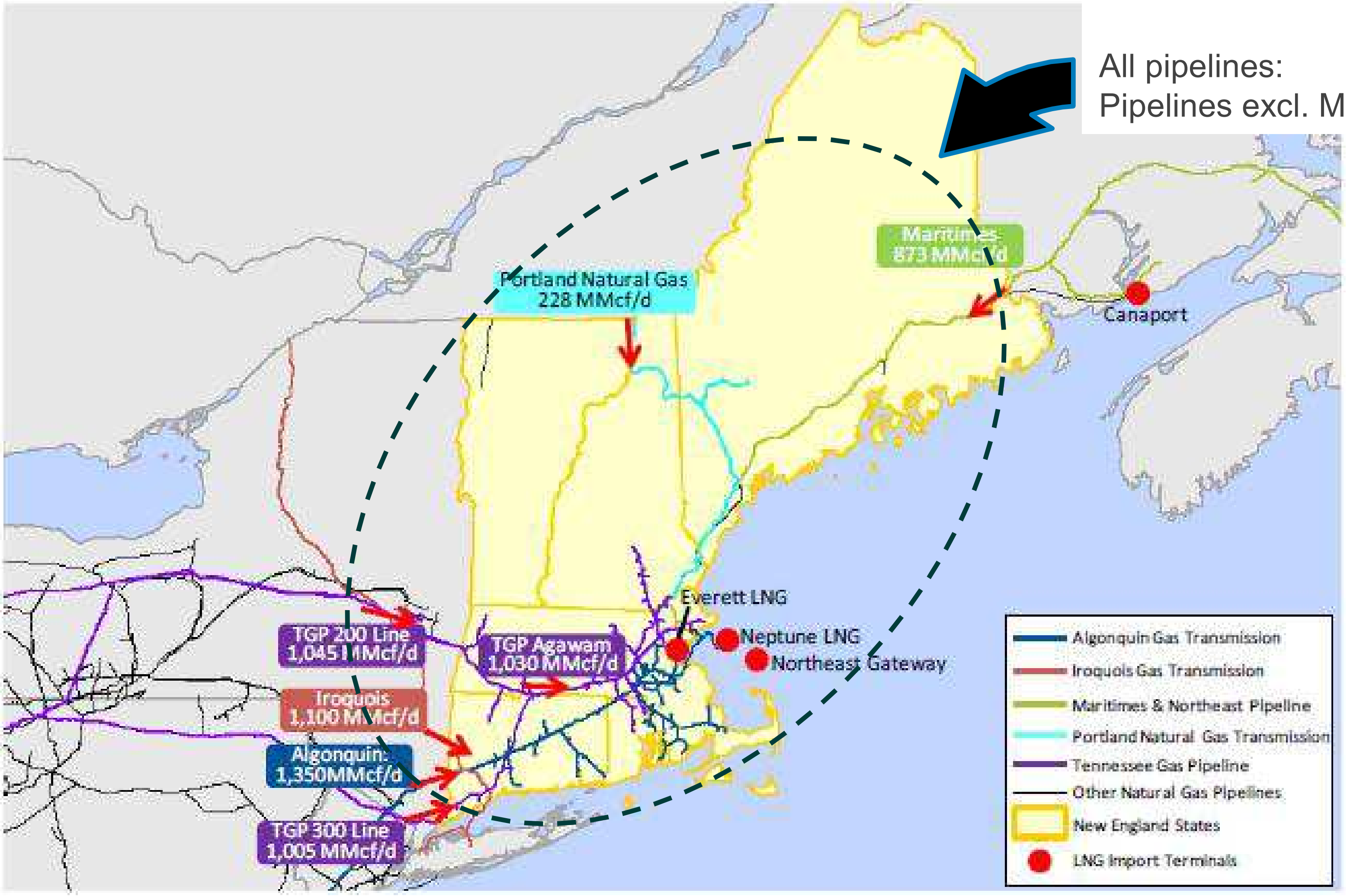
Algonquin Pipeline
Tennessee Gas Pipeline
National Grid local distribution system
Mystic Power Station

The Everett Terminal supplies LNG via truck to nearly all of the 46 customer-owned LNG storage tanks in region. (LNG is how natural gas is stored in New England.) Today, LNG from Everett and these facilities can meet as much 40% of the natural gas demand on peak days. **Total LNG storage in New England is 20 Bcf.**

Exhibit No. NES-035
Docket No. ER18-1639-000

Key pipelines serving New England can deliver up to 4.2 Bcf/d

	bcf/d*
All pipelines:	4.2
Pipelines excl. M & NE:	3.4

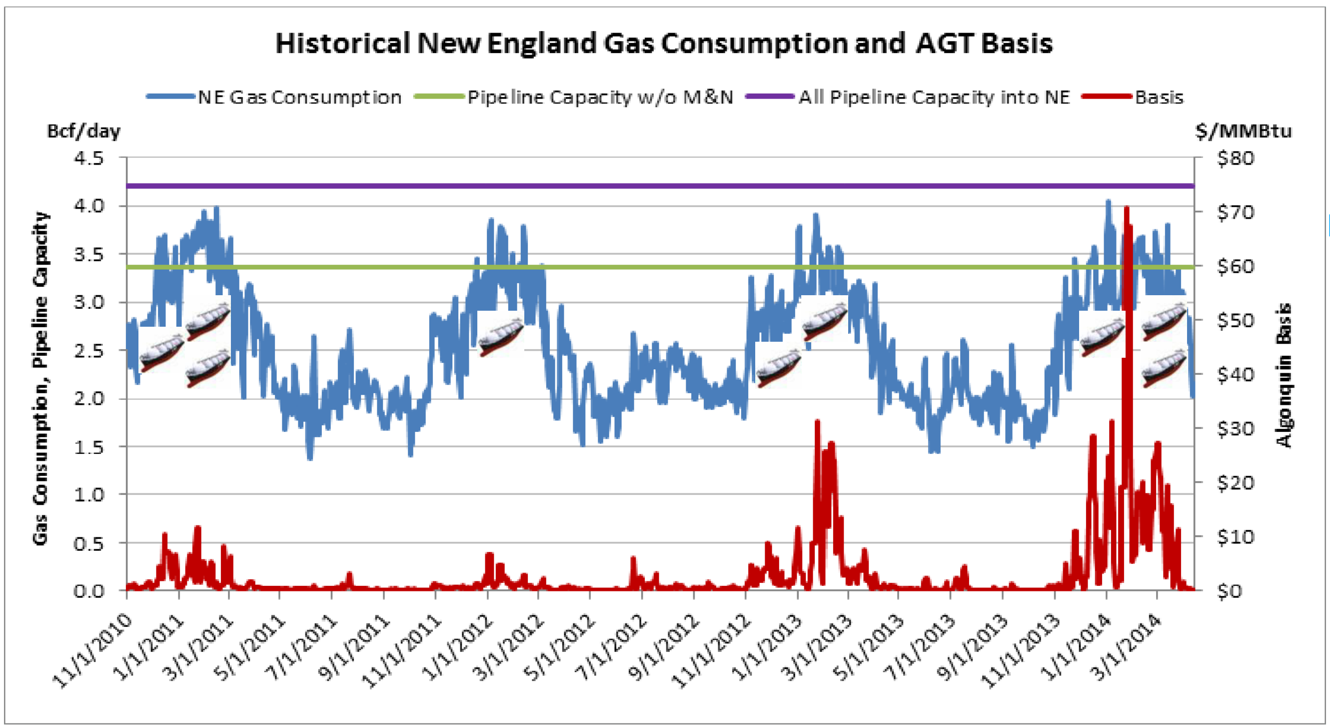


Capacity constraints exist west to east, but not east to west

* GDF SUEZ estimates
Source: map from Black & Veatch (referencing Energy Velocity, LCI Energy Insight, Pipeline Electronic Bulletin Boards)

Winter 13/14

- Winter 13/14 really wasn't very different from a New England perspective, what was different was that the whole East Coast was impacted at the same time and with similar severity, so supply was constrained throughout the region



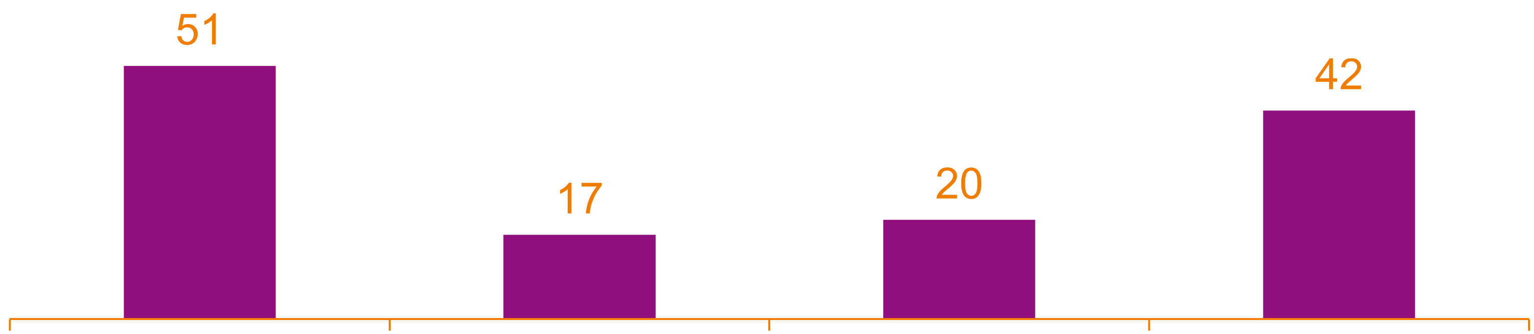
- **Peak Day Criteria 3.4 Bcf/day**

 # Peak Days & Peak Consumption

2010/2011	51	8.5 BcF
2011/2012	17	2.5 Bcf
2012/2013	20	3.3 Bcf
2013/2014	42	7.0 Bcf

Peak consumption can and should be met with peak supply, equivalent of just 1-3 LNG cargoes

Peak Consumption Days*



Winter period	Nov '10 - Mar '11	Nov '11 - Mar '12	Nov '12 - Mar '13	Nov '13 - Mar '14
Peak Consumption (bcf)	8.5	2.5	3.3	7.0

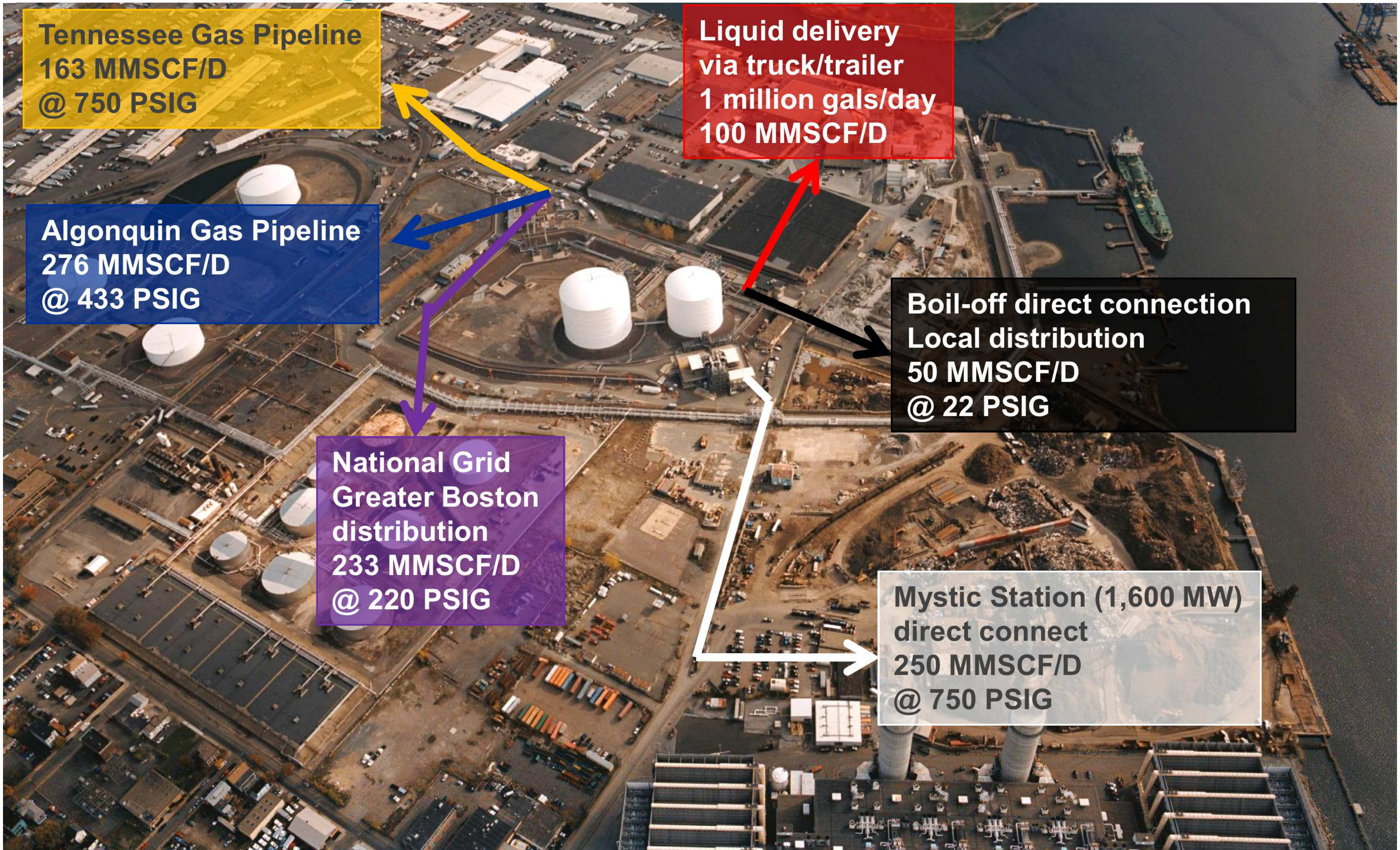
Approximate LNG cargoes

- New England **needs winter peaking** capacity**, with or without a baseload pipeline solution**; in fact, increased gas demand for both heating and power generation will likely make the peaking requirement even greater
- **Distrigas** Peak Send-Out of 0.5 bcf/day (excluding Mystic 8/9) **could easily accommodate** additional volume during Nov-Mar period

* Defined as period when demand exceeds 3.4 bcf/d of pipeline capacity excl. Maritime and NE

Exhibit No. NES-035
Docket No. ER18-1639-000

Everett Marine Terminal: capability to serve key systems simultaneously



Going Forward

- Repositioning Company back to its original conception
  - Winter/Summer Firm Peaking Vapor
  - Winter Firm Liquid Services
  - Combination Vapor/Liquid Services
  - Summer LNG Refill
- Mystic Power Plant
- Customers Mix is Changing
  - Continue to Serve LDC’s
  - Power Generators ISO-NE “Pay for Performance”
  - Marketers with AMA agreements
- Will continue to contract for and increase the firm Transportation quantity on TGP/AGT

Final Thoughts – the Case for LNG in New England

- Fundamentally, NE has a winter peaking problem - true 40 years ago as today
- ENGIE believes strongly that Region should first unlock potential of underutilized existing natural gas infrastructure to help solve winter peak issue
  - ISO-NE Winter Reliability Program rightly includes LNG as well as oil, dual fuel, DR
  - ISO-NE Pay for Performance proposal will also go long way toward resolving these issues
  - Market should pursue policy to ensure pipes full East to West to better assess real needs West to East
  - New pipe solves baseload growth issue; LNG solves peaking problem
- LNG can be economically delivered to the New England market during peak periods provided commitment is made with enough time to facilitate logistics
- The market needs proper mechanisms in place for power generators to recover the cost of flexible fuel supply during peak demand periods
- LNG is available on a short-term, seasonal basis or on a longer-term basis as needed

Exhibit No. NES-036

NES-ENG-1-15. With respect to Steve Taake's presentation available at http://www.northeastgas.org/pdf/s_taake_2018.pdf, provide details about how Engie moved up inbound cargoes (slide 7) including how long in advance of planned delivery did this occur, how many days the cargoes were advanced, and the extra cost incurred.

Response: Subject to and without waiving their August 9 Objections, EGLNG and DOMAC provide the following response:

EGLNG has historically maintained, or has operated as part of, a larger portfolio that provides LNG supply contracts and shipping capacity sufficient to allow for the flexibility referred to in Mr. Taake's presentation.

Prepared By: Counsel
Date: August 13, 2018

<u>Exhibit No. NES-037</u>

CUI-PRIV-HC

REDACTED

Exhibit No. NES-038

Responses of ISO New England Inc. to
NESCOE's First Set of Data Requests
Docket No. ER18-1639-000
Response Date: August 8, 2018

DATA REQUESTS

NES-ISO-1-1. Please provide ISO-NE's analysis or other materials on third-party LNG sales which led ISO-NE to identify that shareholder retention of 50 percent of the margin from forward sales is the optimal percentage to reduce costs to consumers of the proposed Mystic Cost of Service Agreement.

Response:

ISO-NE did not perform a formal analysis to establish the proposed 50% margin-sharing for third-party LNG sales. Rather, ISO-NE suggested to Mystic that the owner's share must be high enough to provide a sufficient incentive for Mystic to engage in such sales given the risks identified by Mystic. An important consideration is the opportunity cost faced by Exelon in negotiating and managing any third-party agreements. If the expected profit to Exelon from third-party sales is below the expected profit of other opportunities, there will be little incentive for Exelon to seek out and negotiate third-party LNG sales. The 50-50 margin split was agreed to largely as a placeholder with the understanding that it would be further reviewed and, perhaps, negotiated by all parties in the cost-of-service proceeding.

Prepared by or Under the Supervision of:

Robert Ethier, Vice President, Market Operations

This response is true and accurate to the best of the preparer's knowledge, information, and belief after reasonable inquiry.

VERIFICATION

Pursuant to 28 U.S.C. § 1746, I, James F. Wilson, state under penalty of perjury that the foregoing testimony is true and correct to the best of my knowledge, information and belief.

James F. Wilson

Executed this 23 day of August, 2018