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September 7, 2022

Ms. Luly Massaro, Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

Re: In Re: Narragansett Electric Company, d/b/a Rhode Island Energy
Docket 4978 – Last Resort Service Rate Filing

Dear Ms. Massaro:

Enclosed herewith please find an original and nine copies of the Direct Testimony of John Dalton On Behalf of the Rhode Island Office Of Energy Resources.

Please be advised that an electronic copy of this document has been sent to the service list. Thank you for your attention to this matter.

Sincerely,

Joseph A. Keough, Jr.

Enclosures

cc: Docket 4978 Service List (via electronic mail)

BEFORE THE
STATE OF RHODE ISLAND
PUBLIC UTILITIES COMMISSION

PRE-FILED DIRECT TESTIMONY OF
JOHN DALTON
ON BEHALF OF THE
RHODE ISLAND OFFICE OF ENERGY RESOURCES

September 7, 2022

I. INTRODUCTION AND BACKGROUND

Q. Mr. Dalton, please state your name, business address and the nature of your business.

A. My name is John Dalton. I am President of Power Advisory LLC (Power Advisory). My business address is 22 Devens Street, Concord, Massachusetts. Power Advisory is an electricity sector focused management consulting firm specializing in electricity market analysis and strategy, power procurement, energy policy development, regulatory support, and electricity project feasibility assessment.

Power Advisory's clients include power planning and procurement agencies, regulatory agencies, generation project developers, government agencies, public advocates, and electric utilities.

Q. What is your professional and academic background?

A. I am an electricity market analyst with over thirty years of experience in the electricity sector. I specialize in energy market analysis, electricity policy analysis and development, power procurement and contracting, generation project evaluation, and strategy development. I am experienced in the evaluation and analysis of electricity markets and of generation technologies and projects within these markets. I have extensive experience in restructured electricity markets and with regulated utilities.

With respect to regulators and other agencies imbued with a public interest, I have worked for the Ontario Energy Board, the Vermont Public Service Board (predecessor to the Vermont Public Utility Commission), the South Carolina Public Service Commission, the Maine Public Utilities Commission, the Alberta Utilities Consumer Advocate, the Massachusetts Attorney General, the Ontario Ministry of Energy, the Alberta Department of Energy, the New Hampshire Department of Energy, and the Rhode Island Office of Energy Resources.

I have served as a consultant to the electricity sector for over twenty-five years with various firms and prior to this served as an economist with the Massachusetts Energy Facilities Siting Council where I reviewed electric utility demand forecasts, supply plans and applications for the construction of new facilities. Prior to this, I served as an economist with the Massachusetts Department of Environmental Protection.

In 2007, I started Power Advisory. With offices in Boston and Toronto, we regularly work across North America for all electricity sector market participants including system operators, governments and regulators.

I have a BA in Economics from Brown University and an MBA from Boston University. I have taken courses in resource planning methods and regional planning at the Massachusetts Institute of Technology and Boston University. A copy of my curriculum vitae is provided as Schedule JD-1.

Q. Have you testified before state regulatory commissions or courts to provide expert testimony?

A. Yes. I have testified in over twenty-five proceedings across North America and was qualified to speak as an expert in those proceedings on issues ranging from the need for and comparative economics of new electric generating facilities, competitive procurement programs for energy, capacity, and environmental attributes, wholesale electricity market prices, electricity resource planning issues, electricity rates, transmission pricing policy, and the likely competitiveness of wholesale power markets. A list of proceedings in which I provided expert testimony is provided at the end of my curriculum vitae (Schedule JD-1).

Q. Have you testified before the Rhode Island Public Utilities Commission (PUC or Commission) before?

A. Yes, I have. In May 2019, I testified on behalf of the OER and Division of Public Utilities and Carriers (Division) in the proceeding regarding the Petition for Approval of Proposed Power Purchase Agreement for Offshore Wind Energy (Docket No. 4929). My testimony focused on the project's economic and reliability benefits as well as conformance with state policies.

II. OVERVIEW

Q. On whose behalf are you testifying in this proceeding?

A. I am appearing on behalf of the Rhode Island Office of Energy Resources (OER).

Q. What was the scope of the testimony that OER asked you to provide?

A. OER asked me to provide my expert opinion on the different alternatives available for addressing the rate impacts associated with the proposed Last Resort Service (LRS) rates the Narragansett Electric Company d/b/a Rhode Island Energy (RI Energy) filed with the Rhode Island Public Utilities Commission that are scheduled to take effect October 1, 2022. These LRS rates are for residential, commercial and industrial customers, and run for six months for residential and commercial customers and three months for industrial customers.

In my testimony, I assess the various bill impact mitigation options available; evaluate their impact on customer bills and assess potential implications including cost shifting risk as well as potential constraints that RI Energy has raised regarding its billing system.

Q. Please summarize your Direct Testimony.

A. First, I review the proposed residential LRS rate increase, which would result in a bill increase of $51.95 per month, or 46.7% for a residential customer using 500 kWh compared to existing rates. Compared to the Winter 2021-22 LRS rates, the proposed residential LRS rates represent an increase of $35.99 per month, or 28.5% for a residential customer using 500 kWh. The lower increase in rates relative to the Winter 2021-22 period reflects seasonal pricing differentials in New

England and is a more meaningful rate comparison given that winter rates are typically higher than summer rates.

Next, I review the two primary options available to mitigate the bill impacts of the higher Winter 2022-23 LRS rates. This includes using available funds from the May 19, 2022 Settlement Agreement between the Rhode Island Attorney General, PPL Corporation and PPL Rhode Island Holdings (May 2022 Settlement Agreement) and Regional Greenhouse Gas Initiative Allocation Plan funds (RGGI Funds) obtained by Governor Daniel J. McKee to offset the increase in the LRS rate. RI Energy has estimated that the Settlement Agreement would have a value of $63.72 for electric customers as a one-time credit. If this credit were spread evenly over the 6 months in October – March period, this would be a monthly credit of $10.62 per customer. The bill impact relative to the previous winter period LRS rates would $25.37 per month for a residential customer consuming 500 kWh or about a 20.0% increase relative to the previous winter period LRS rates.

The RGGI Funds that Governor McKee has proposed to provide to low-income customers would provide about $104.84 and would represent a monthly bill credit of about $17.47 per month if implemented over a six-month period. I estimate that the cumulative bill impact for low-income customers consuming 500 kWh per month would be about $2 to 3 per month or 2 to 3% compared to the Winter 2021-22 LRS rate.

RI Energy "strongly recommends that it provides all the bill credits as one-time credits" given the risk of customers not receiving the full credit and administrative challenges of ensuring they receive the full credit and concern regarding the use of IT resources when it is trying to transition the IT systems as part of the merger.

While I understand that there will be additional administrative costs and effort associated with spreading out these two credits over six months, the level of effort is roughly in proportion to the number of months over which the credit is spread. Therefore, the costs and effort associated with spreading this credit could be reduced by limiting the number of months over which it is spread. These costs should be weighed in terms of the benefits that customers will realize from being able to better manage the budgeting challenges posed by these bill increases.

The second option to mitigate bill impacts is to employ various rate proposals that result in longer LRS rate averaging periods or shifting higher Winter 2022-23 LRS costs to the next 6-month LRS period beginning April 2023. Both options pose risks associated with cost shifting to LRS customers if a municipal aggregation community elects to begin contracting for competitive supply outside of RI Energy's LRS in the next LRS pricing period. Other utilities have managed this risk by making the costs that are shifted non-bypassable. The PUC could consider if this approach should be pursued in Rhode Island.

III. REVIEW OF LAST RESORT SERVICE

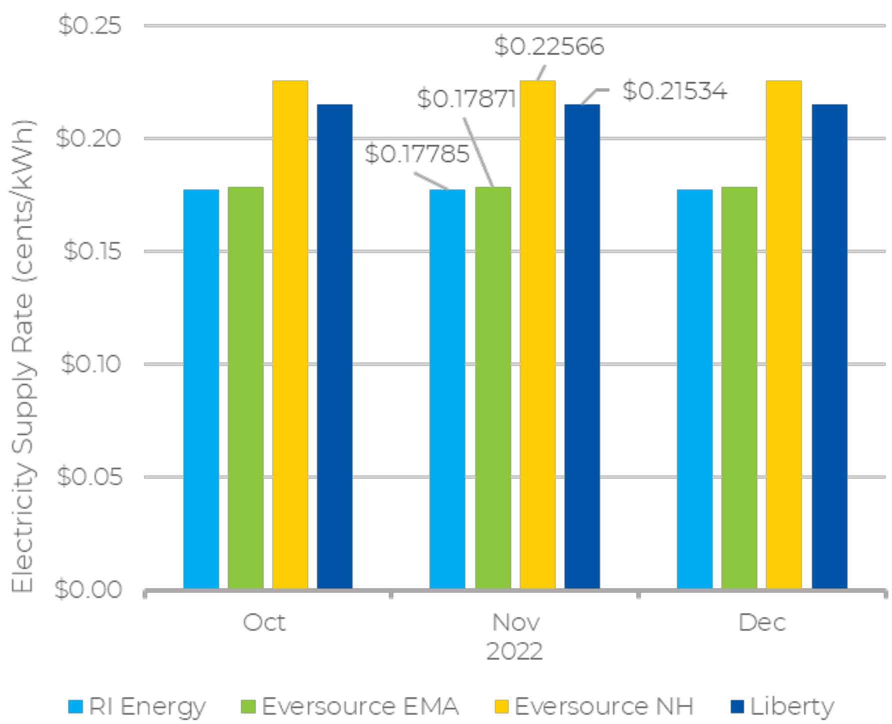
Q. Please review how Last Resort Service is provided in Rhode Island.

A. LRS is provided to all retail electric customers that are not served by a competitive retailer or through Standard Offer Service. This represents a high proportion of residential and small commercial customers. Customers that are served by communities that elect to implement a municipal aggregation program do not receive LRS. Municipal aggregation programs and their potential implications for the various bill mitigation options are discussed in greater detail below.

Residential and commercial customers have two six-month rate periods from April through September and from October through March. Residential customers pay a fixed-price rate that is a weighted average of the actual monthly contract prices over the six-month period. To reduce the potential for price volatility, individual contracts are procured at different times and are dollar-cost averaged to create a blended supply rate. The LRS rates for residential and commercial customers are a blend of four separate procurements and 10% spot market prices.

RI Energy contracts with LRS suppliers at discrete intervals prior to when service would begin and by so doing realizes the benefit of different electricity market pricing at these different time intervals. This dollar cost averaging reduces customers' exposure to market prices at any one-time interval. RI Energy's LRS rates are anticipated to be lower than the rates offered by many other New England utilities for other comparable services, as presented in Figure 1. In large part this is given the blended rate from four separate procurements.

Figure 1: Selected New England Utility Residential Customer Electricity Supply Rates (October 2022 – December 2022)



Q. Given these increases in electricity supply rates have other states proposed programs to offset the increases?

A. Yes. In New Hampshire Governor Sununu has proposed $60 million to offset these increases. This funding requires legislative approval.

Q. Please explain what has caused the significant increase in LRS rates.

A. Electricity prices are highly correlated with natural gas prices because natural gas-fired generators are often the marginal resource that sets wholesale electricity prices in the ISO-New England electricity market. There has been an increase in natural gas prices since the spring of 2021.

In 2021 there were significant increases in global liquified natural gas (LNG) prices, and in New England during cold winter days LNG typically is the marginal supply source that sets natural gas prices when natural gas pipelines are constrained.

In addition, in early 2022 US natural gas prices began to increase in response to the war in the Ukraine. Specifically, reduced natural gas supply from Russia significantly increased the demand for LNG in Europe. US LNG exports increased significantly, increasing the demand for natural gas in the US, which in turn increased domestic natural gas prices. Furthermore, prices for LNG, which is a global commodity, increased dramatically, increasing futures prices for natural gas as well as electricity.

Q. Please review the increase in residential and commercial rates in RI Energy's LRS rate filing.

A. The proposed residential LRS rate would result in a bill increase of $51.95 per month, or 46.7% for a residential customer using 500 kWh compared to existing rates. Compared to the Winter 2021-22 LRS rates, the proposed residential LRS rates represent an increase of $35.99 per month, or 28.5% for a residential customer using 500 kWh.[1] The lower increase in rates relative to the Winter 2021-22 period reflects seasonal pricing differentials in New England. This is a more meaningful rate comparison given that winter rates are typically higher than summer rates.

The proposed Commercial LRS rate for a small commercial customer would vary based on usage and reflect rate increases ranging from 40.7% to 51.1% compared to existing rates.

IV. REVIEW OF OPTIONS FOR MITIGATING WINTER 2022-23 LRS BILL IMPACTS

Q. What are the primary options that are available to mitigate the bill impacts of the higher Winter 2022-23 LRS rates?

A. There are two primary options available to mitigate the bill impacts of the higher Winter 2022-23 LRS rates.

(1) Use available funds to offset the increase in the LRS rate. This includes the customer bill credits from the May 2022 Settlement Agreement and the RGGI Funds procured by Governor Daniel J. McKee to reduce rates to low-income consumers. These funds can be applied over the six-month Winter LRS Rate Period to reduce the proposed increase.

[1] The Narragansett Electric Co. d/b/a Rhode Island Energy - 2021 Last Resort Service (LRS) Procurement Plan, Docket No 4978, filing letter from Andrew S. Marcaccio to Luly E. Massaro, p. 2 of 3.

(2) Employ various rate proposals that result in longer LRS rate averaging periods or shifting higher Winter 2022-23 LRS costs to the next 6-month LRS period beginning April 2023.

These rate options have different risks and challenges and are reviewed further below.

Q. Please review how the $32.5 million negotiated credit for electric customers from the May 2022 Settlement Agreement could be used to mitigate bill impacts from the higher Winter 2022-23 LRS rates.

A. The Settlement Agreement provides: "PPL shall provide a credit to all of Narragansett's electric and gas distribution customers in the total amount of $50 million." Based on the relative number of electric distribution customers and gas distribution customers, PPL will credit $32.5 million to electric customers and $17.5 million to gas customers. Each electric customer will receive the same credit, and each gas customer will receive the same credit.

RI Energy has estimated that this one-time credit will have a value of $63.72 for electric customers. If this credit were spread evenly over the 6 months in October – March period, this would be a monthly credit of $10.62 per customer. The bill impact for a residential customer consuming 500 kWh per month relative to the previous winter period LRS rates would be about $25.37 per month for a residential customer consuming 500 kWh or about a 20.0% increase.

Q. Does RI Energy agree that this credit should be spread over six months?

A. No, RI Energy "strongly recommends that it provides all the bill credits as one-time credits in the full amount to each customer account" due to the following risks, challenges and impacts it identified:

- "There is a risk of customers not receiving the full credit. The company will have to manually track accounts that customers close over the course of the six-month period and track whether those customers opened an account at a new premise, which will be a labor-intensive and difficult process. As a result, spreading the credit over six months creates a risk that customers who are eligible for the credit will not end up receiving the full credit amount." (Docket No. 22-07-GE, Response to PUC 1-9)[2].

- "Delayed use of credit to cover current and overdue charges. The Company's arrearages have significantly increased both during and after the Commission's orders regarding collected [sic] related to the COVID-19 pandemic. These credits can be used now for accounts in collections, or held on the account for any customer wishing to use the credit during the colder months. If the credit is spread over six months, it will delay customers' ability to take advantage of the benefits that will flow from the credit." (Docket No. 22-07-GE, Response to PUC 1-9).

RI Energy also expressed concern on the use of IT resources when it is trying to transition the IT systems as part of the merger.

[2] Docket 22-07-GE is a companion docket in which RI Energy filed a Tariff Advice to implement the May 2022 Settlement Agreement.

Q. Can you provide a perspective on the concerns that the Company raised?

A. Certainly. First of all, in terms of the risk of customers not receiving the full credit tracking customer accounts does not appear to be particularly difficult. However, I understand that it can be time consuming. RI Energy needs to establish whether new customers during the Winter LRS Rate Period were previously a LRS customer. As RI Energy has indicated there will be additional administrative costs and effort associated with spreading out this credit over six months. I understand that the level of effort is roughly in proportion to the number of months over which the credit is spread. Therefore, the costs and effort associated with spreading this credit could be reduced by limiting the number of months over which it is spread. These costs should be weighed in terms of the benefits that customers will realize from being able to better manage the budgeting challenges posed by these bill increases.

While RI Energy has proposed sequencing one-time credits to assist customers in managing the bill impacts, this will still leave customers with the challenge of paying their bills when these credits are not available and higher LRS rates are in effect. I believe that a recuring monthly credit will better allow customers to manage these higher rates.

RI Energy has also proposed expanding its marketing of budget billing, whereby customer bills are based on the average monthly energy use and current rates. While this program will help participating customers manage the increase in

LRS rates, there is evidence that the customers that are most in need of assistance with respect to managing these bill impacts, i.e., low-income customers and other hard-to-reach customers, are less likely to take advantage of such a program. A National Regulatory Research Institute paper notes that one challenge is "reaching the sometimes difficult-to-reach low-income target audiences, and achieving sufficient trust, so that potential participants will accept the available support".[3] (Stanton, Tom. (2020, December). Solar Energy that Pays for Low-Income Customers and Communities. NRRI Insights.)

Q. Are there other considerations associated with this credit?

A. Yes, with the credit paid on a per customer basis, its ability to offset the LRS rate will be greater for low consumption customers. A residential customer using 500 kWh per month would have a bill increase of $35.99 relative to the Winter 2021-22 period. This credit would reduce the increase by 20%, with the reduction in the rate increase scaling to the customer's consumption. Furthermore, RI Energy has indicated that it will take three to four months to implement the required changes to its billing system to allow a monthly credit to be offered.

However, RI Energy indicated that it could provide a monthly residential bill credit through a reduction of the customer charge during the months of November 2022 through April 2023. RI Energy indicates there are some

[3] While this paper focused on solar programs for low-income customers, the challenges of reaching these customers to participate in a budget billing program is the same.

complications with this approach. One issue is that the credit realized by low-income customers would be smaller given how the 25% discount for low-income customers is applied.

It is important that the reduction in bill credit realized by low-income customers is somehow offset such that the full value of this $32.5 million is realized by RI Energy customers. This is an issue that the PUC should ask RI Energy to propose a solution to if the PUC elects to direct RI Energy to pursue this approach.

This loss in the value of the credit is offset in part by the availability of $3.8 million in RGGI Funds that Governor McKee has proposed to provide to low-income customers. This proposal would provide about $104.84 for RI Energy low-income customers (i.e., served under the A-60 rate) and would represent a monthly bill credit of about $17.47 per month if implemented over a six-month period to further offset the October – March 2022-23 LRS rate increase. (RI Energy Response to PUC 6-1). The cumulative bill impact for low-income customers (A-60 Rate Customers) consuming 500 kWh per month would be about $2 to 3 per month or 2 to 3% compared to the Winter 2021-22 A-60 LRS rate.[4] If these RGGI Funds were spread over a shorter window, the monthly credit would be higher. I understand that OER seeks to have this credit allocated over several months,

[4] The actual Winter 2021-22 Monthly Typical Bills (Schedule 3) filed in Docket No. 4978 do not appear to conform to the typical monthly bill used by RI Energy to calculate bill impacts. Therefore, I am not able to precisely estimate these bill increases.

at a minimum, to more effectively mitigate low-income customer bill impacts in the winter period.

Q. What options are available to further mitigate these LRS rate increases?

A. There are two primary rate options that could be used to further mitigate these LRS rate increases: (1) longer LRS rate averaging periods could be used; or (2) higher Winter 2022-23 LRS costs could be shifted to the next 6-month LRS pricing period beginning April 2023. Both options may pose risks associated with cost shifting to LRS customers if a municipal aggregation community elects to begin contracting for competitive supply outside of RI Energy's LRS in the next LRS pricing period. This risk is further examined below.

Q. What is municipal aggregation?

A. Municipal aggregation is where local governments procure power or more typically engage a third-party to procure power on behalf of their residents, businesses, and municipal accounts from a non-regulated supplier while still receiving transmission and distribution service from their existing utility provider.

Q. Please review Rhode Island's Municipal Energy Aggregation law.

A. The Rhode Island General Assembly passed the state's Municipal Energy Aggregation law in 2018. (RI Gen L § 39-3-1.2 (2018)) This law provides that "A town may initiate a process to authorize aggregation by a majority vote of a town meeting or of the town council. A city may initiate a process to authorize aggregation by a majority vote of the city council, with the approval of the mayor, or the city manager." (RI Gen L § 39-3-1.2 a.) Among other things, the law also requires the city or town to: (1) notify electric customers that they will be automatically enrolled in the aggregation program unless they opt out; (2) develop an aggregation plan that will be reviewed at a public hearing; and (3) file the plan with the PUC for its final review and approval.

The first application for municipal aggregation was filed with the PUC in 2020. Seven Rhode Island cities and towns have developed municipal aggregation programs and secured approval from the PUC including Narragansett, Newport, Portsmouth, South Kingston, Providence, and Central Falls. I understand that none of these communities has solicited bids from non-regulated power producers and reported to the PUC the results of the solicitation and the resulting agreement with the non-regulated power producers.

Q. Why is municipal aggregation significant with respect to RI Energy's LRS rates?

A. This is significant because rate proposals that defer costs to the next LRS pricing period pose a risk of cost shifting if a municipal aggregation community leaves LRS in the LRS pricing period to which costs were shifted. The likelihood of this occurring is increased by the fact that the LRS rate in this period will be higher than it otherwise would have been as a result of the cost shifting to reduce the Winter Period LRS rate.

These cost shifting risks were outlined in a RI Energy response to a data request:

> "If customers who are on LRS during the deferral period receive supply through a municipal aggregation plan or a nonregulated power producer during the recovery period, there will be a smaller pool of customers remaining on LRS to contribute towards the deferred LRS amounts through higher LRS rates in effect during the April 2023 through September 2023 period." (RI Energy Response to AG 1-5)

Specifically, the LRS customers that leave LRS in the next LRS pricing period (April – September) are likely to cause a revenue shortfall whereby some of the LRS supply costs that were shifted to the next pricing period are not recovered. In effect, new municipal aggregation customers could avoid costs that were deferred to the next LRS pricing period. RI Energy indicates that this revenue shortfall could be recovered through the Revenue Decoupling Mechanism (RDM) and recovered from all customers. (RI Energy Response to AG 1-5). Under this approach RI Energy customers that remain on LRS would also be paying for the revenue shortfall contributed by the new municipal aggregation customers. This would be unequitable, with customers remaining on LRS bearing a share of the costs that municipal aggregation customers would have otherwise paid. The inequity is the LRS customers would have already paid for their share of these costs and would be required to also contribute to the costs that new municipal aggregation customers were able to largely avoid.

Q. What is the magnitude of this risk?

A. RI Energy performed an analysis "of the impact of six of the approved municipal aggregations (the Town of Narragansett was not included) switching to competitive suppliers in April 2023 and therefore not directly paying for the deferred winter costs. For the Residential Group only, the Company estimates that it would under-recover $12.6 million associated with the municipal aggregations' deferred winter costs. Per current regulations, the Company would not directly recover that $12.6 million from the migrating customers; rather it would be recovered from other customers." (RI Energy Response to AG 1-1)

Q. Have other utilities managed the risks posed by municipal aggregation in a time of escalating LRS or default service rates?

A. Yes. This risk and the potential consequences of this scenario were so significant that a Massachusetts utility (i.e., Unitil) moved these costs into a separate charge not associated with LRS service to eliminate the opportunity to avoid them. The PUC could consider if this approach should be pursued in Rhode Island.

Unitil proposed a residential basic service (Massachusetts' equivalent to LRS) rate for December 2021 through May 2022 that was to increase the rate of $0.09554 per kWh to $0.19880 per kWh, or approximately 108 percent. This rate was approximately 74 percent higher than the prior winter's basic service rates.

One contributor to this elevated rate was that it was based on the procurement of 100% of customers' requirements in one procurement, rather than the prior practice of procuring 50% of customers' requirements in two successive procurements. Unitil explained that it elected to procure 100% of its customers' requirements in one solicitation given the uncertainty associated with the implementation of the City of Fitchburg's municipal aggregation proposal. Customers in the City of Fitchburg represented 77% of Unitil's basic service customer rate.

Due to the uncertainty of the City of Fitchburg's municipal aggregation program, Unitil noted that suppliers were unable to offer fixed price basic service supply for twelve months consistent with the traditional manner for procuring basic service. Unitil noted that if it sought fixed price basic service supply for the full twelve-month period, the pricing received would have included significant risk premiums to cover the uncertainty of the potential significant load migration associated with the City of Fitchburg's load aggregation.

Q. What rate strategy did Unitil use to avoid cost shifting risks associated with municipal aggregation?

A. The Massachusetts Attorney General proposed a one-time deferral of 50 percent of the increase associated with the proposed basic service rate charge over the prior winter's charge. Under this proposal Unitil would recover the deferred portion of the winter rate (December 2021 through May 2022) during the next basic service period (June 2022 through November 2022).

Ultimately, Unitil and the AG negotiated a "Joint Mitigation Proposal". Under this mitigation proposal, the company implemented a fixed basic service rate of $0.15650 per kWh for residential and small general service customer groups, along with associated variable monthly rates. Any unrecovered costs (estimated to be approximately $3.2 million) would be collected from all distribution customers through the Company's Basic Service Adjustment rate beginning June 1, 2022 for a seven-month period ending December 31, 2022.

This alternative strategy minimized the risk associated with the ability to recover costs attributable to deferring a portion of the higher costs to the next rate period. Under this alternative approach, all distribution customers would pay for the costs of this deferral through the Basic Service Adjustment rate. Therefore, if the City of Fitchburg implemented its municipal aggregation proposal customers served under this proposal would continue to be responsible for the costs that they would otherwise have avoided.

The Massachusetts DPU noted that "changing basic service rates by delaying cost recovery from the current basic service term to another term would not be in the ratepayers' best interests, would disrupt the competitive market, might result in higher basic service bid prices in the future, could shift costs to non-basic service customers". (D.P.U. 21-BSF-A4, p. 11)

However, the DPU noted that "the circumstances regarding the upcoming winter season are unique". Therefore, it approved the Joint Mitigation Proposal recognizing that the basic service rate approximated the rate that would have been realized if Unitil employed its traditional procurement approach. Furthermore, the DPU approved allocating the remaining costs to Basic Service Account for collection over a seven-month period. The DPU reasoned that "Basic service acts as a safety net for all customers regardless of whether they currently receive generation service from the basic service provided. Accordingly, all customers of electric distribution companies benefit from the availability of basic service and therefore, cost causation may be attributed to customers who actually take basic service and, to some extent, to those customers who are eligible to do so (even if they choose not to) and on whose behalf an electric distribution company secures the insurance fallback of basic service eligibility." (D.P.U. 21-BSF-A4, p. 14)

Q. Has Rhode Island employed alternative rate options to mitigate rate impacts of LRS or Standard Offer Service in the past?

A. Yes. National Grid proposed a significant increase in its Standard Offer Service (SOS) rates for the 2018-19 winter. The Standard Offer rate proposal called for the residential rate to rise from 8.486¢ to 12.129¢ per kWh (43% increase) and small commercial rate to rise from 8.190¢ to 11.876¢ per kWh (45% increase).

Given the magnitude of these rate increases, National Grid recommended that the PUC consider a 12-month Residential SOS rate, through September 2019, to allow the rate impact to be lessened by smoothing it out over a longer period. Under this proposal, there would be a 12-month SOS rate averaged over this period.

The Division filed an alternative recommendation that the PUC moderate the impact on ratepayers by spreading a portion of the higher rates over a twelve-month period to lessen the rate impact and the unrecovered portion of the supply cost be recovered by increasing rates for those classes for the months of April through September 2019 (Summer Period). This resulted in a 30% increase in the Residential Standard Offer rate for the Winter 2018-19 period. The Division indicated that its proposed reduced rates for the Winter Period were low enough to produce a meaningful reduction from the high unmitigated seasonal rate, but not so low as to increase the likelihood of high levels of customer migration when the resulting higher summer Standard Offer rates took effect.

Under this proposal, some of the costs associated with the Winter Period rate were moved to the Summer Period rate to result in a Winter Period rate that was lower than it otherwise would be but would continue to be higher than the Summer Period rate.

The Division noted that its proposal balanced the four competing objectives of (i) moderating the rate impact for the Winter Period, (ii) retaining a significant seasonal price signal for the higher cost Winter Period, (iii) limiting the magnitude of the under-collection that would be created from any Winter Period mitigation proposal, and (iv) reducing the Spring migration risk.

It is important to note that this approach was employed at a time when there was little likelihood of municipal aggregation. As discussed above, while the municipal aggregation legislation was enacted in 2018, the first municipal aggregation plan wasn't filed with the PUC until 2020. Therefore, there was not the same risk of cost shifting from municipal aggregation in 2018 as currently exists, with seven cities and towns poised to implement their municipal aggregation plans.

Q. Are there rate strategies that can be employed to mitigate the potential for cost shifting to LRS customers?

A. Yes. RI Energy suggested that any LRS supply costs that had been shifted to the Summer 2023 LRS rate period that were not recovered in this period could be recovered in the RDM account where these costs would be recovered from all customers. RI Energy points out that LRS customers would pay their pro rata share of these costs that are allocated to the RDM account even though they didn't contribute to this revenue shortfall, making this unequitable.

An alternative strategy would be to allocate *all* of the Winter 2022-23 LRS supply costs that are to be shifted to the Summer 2023 Period to the RDM account. This alternative is also problematic because the LRS supply costs that are to be shifted to the Summer 2023 Period would be recovered from all RI Energy customers, rather than all LRS customers. This could be avoided by allocating these LRS supply costs to customers that took LRS service in the Winter 2022-23 period, including those that switched to a third-party supplier. I understand that this would require changes to RI Energy's billing system, but this option should be considered.

Q. What other approaches can be used to mitigate the rate and bill impacts of the increases in the Winter 2022-23 LRS rate?

A. There are a range of approaches that can be used to mitigate the rate and bill impacts of the increases in the LRS rates. These were outlined in a memo that the Division submitted as part of National Grid's Standard Offer Rate filing in Docket 4692 and represent a reasonable range of options to mitigate the impacts of the increases in the Winter 2022-23 LRS rate.

The first option would be to establish a 12-month fixed LRS rate (from October 2022 through September 2023) that averages the Winter and Summer Period rates across a 12-month period. This allows the rate impact to be lessened by smoothing it out over a longer period. However, with LRS supply contracted for 6-month periods for residential and commercial customers and not all of the supply for the April through September period contracted, there is a customer migration risk, recognizing the LRS power supply costs are likely to be lower in the second 6-month period than in the first. As a result, customers that leave LRS after the winter period would likely realize a benefit of lower winter period rates and then be able to avail themselves of a lower summer period rate, which is likely to result in an under collection of LRS supply costs. This is likely to increase the opportunity for cost shifting. A second disadvantage of this option is that it further departs from cost-based pricing and eliminates seasonal price differentials.[5] This results in less efficient customer consumption decisions.

The second option is to spread a portion of the higher winter period rates over a twelve-month period, with the unrecovered portion recovered by increasing rates in the next LRS period (April through September 2023). This is a more of intermediate rate proposal since there will continue to be seasonal price differentials. The critical questions are what is an appropriate winter rate and the accompanying level of LRS supply costs that should be moved to the Summer Period. This option has similar customer migration risks as option 1,

[5] By averaging prices over a six-month period (for residential and commercial customers) the existing LRS pricing framework also departs from strict cost-based pricing as does any pricing framework that isn't tied to real-time prices.

with the magnitude of the risks influenced in part by the level of LRS supply costs that are moved to the Summer Period. By maintaining a seasonal price differential this option maintains a more appropriate price signal than option 1, but departs from cost-based pricing principles. This option is more consistent with the principles of gradualism.

The third option is to establish an optional "Fixed Term Average Rate" that allows customers to opt for a fixed 12-month LRS rate, but requires the customer making the choice to remain on utility service for the 12-month fixed-rate period to eliminate the customer migration risk and resulting cost shifting inequities. However, it does eliminate the seasonal pricing signal and there are administrative costs and complexities associated with such a proposal, which are likely to make it impossible to implement within the time available for the forthcoming Winter 2022-23 Period. However, this could be a future solution (e.g., the winter of 2023-2024) where there is a meaningful risk of high LRS rates. (See RI Energy's response to PUC 5-5).

Q. Does this conclude your Direct Testimony?

A. Yes, it does. However, I reserve the right to address any further changes RI Energy makes or issues, or which the Division or other intervenors raise in this filing. Also, to the extent that any further issues are raised through ongoing data requests, I reserve the right to address these issues as well. Finally, if I discover or otherwise learn of additional issues that could impact the LRS rates proposed in this Docket, I reserve the right to address those issues.

John Dalton
President

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SUMMARY

A senior electricity market analyst and electricity policy consultant with over thirty-years of experience in energy market analysis, power procurement, project valuation, and strategy development. Experienced in the evaluation and analysis of electricity markets and the competitive position of generation technologies and projects within these markets including the assessment of the competitiveness of the underlying market, the development of power market price forecasts, the implementation of power procurement processes, and the development and evaluation of renewable energy policies. Frequent speaker on these subjects at energy industry conferences.

Professional History

Navigant Consulting
Reed Consulting Group
R.J. Rudden Associates Inc., 1987-1988
Massachusetts Energy Facilities Siting Council, 1984-1987
Massachusetts Department of Environmental Protection, 1981-1984

Education

Boston University, MBA, 1987
Brown University, AB, Economics, 1980

PROFESSIONAL EXPERIENCE

Market Assessment

- Developed and supported numerous market price forecasts for wholesale power markets across North America. Price forecasts were used to support generation project development efforts, project financings and acquisitions, regulatory policy development, and power procurement efforts.
- Demonstrated the need for electric generation projects in filings submitted to various state and provincial regulatory agencies. Evaluated the cost of a wide range of different generation technologies for a number of clients. Defended analyses in prepared and oral testimony before these state agencies.
- Conducted wholesale power market analyses across North America for a wide range of market participants. Analysis included identifying likely competitors and pricing, security provisions, and general terms and conditions of various power supply options. Evaluated pricing required to compete in the market.
- Advised the Ontario Electricity Financial Corporation with the management of its non-utility generation contracts. Advice included addressing the policy issues associated with balancing concerns with the sanctity of existing contracts and the desire to minimize stranded debt as well as to use the contracts as a source of competitive discipline for the incumbent provincial electric utility.
- Managed a team that was retained by a large power generation company to develop a market assessment and wholesale power market price forecast for the Alberta market. Our assessment focused on issues affecting the fundamentals of the Alberta power market, including the future demand supply balance, growth in demand, market interconnections, and potential new generation capacity additions.

- Retained by the financial advisors for the developer of a proposed new combined cycle gas turbine project in Alberta to establish the toll between the Corporate entity participating in the income fund and the parent. Defended forecast assumptions and the modelling approach before investors as part of a public offering.
- Directed the use of ProSym in a proceeding before the Alberta Energy and Utilities Board (AEUB) to estimate the costs of transmission congestion and the benefits of increasing the transfer capability of the North South transmission interface. Modeling assumptions and methodology were successfully defended before the AEUB.
- Advised numerous generation project developers across North America on opportunities offered by participating in the relevant wholesale power market and various power supply procurement RFPs. Evaluated market risks and outlined strategies for managing these risks most efficiently.
- Analyzed and critiqued the supply planning methodologies of electric and gas utilities, focusing on the appropriateness of the supply planning models and methods. Provided recommendations for improving supply planning methods which were designed to assist the utilities in addressing the uncertainties associated with long-range planning. Prepared recommendations for the refinement of demand forecasting methods for electric and natural gas utilities. Analyzed and evaluated the statistical and quantitative projection methods used, including end-use and econometric forecasting techniques.
- Evaluated electric generating technologies on the basis of the capital and operating costs, technological risk, and environmental impact, identifying a preferred alternative in light of these considerations. Defended the selection process before a regulatory agency.
- Prepared strategic plan for a number of electric and natural gas market participants which evaluated the state/provincial and federal regulatory climate for cogeneration and generation projects, market prices and risks and recommended a competitive strategy.

Offshore Wind

- Served on a New York State Energy Research & Development Authority (NYSERDA) team that was responsible for independently assessing the non-price scores for OSW projects bid in response to the NYSERDA OSW RFP. This included assessing the project viability including transmission interconnection arrangements, project development schedule, permitting plan, developer experience, wind resource assessment, and port and vessel strategies. Also reviewed the economic development benefit claims by OSW developers and their strategies for utilizing New York ports in their proposals. Project required independently assessing the reasonableness and credibility of project-specific spending and job creation benefits from the development of a New York State OSW supply chain.
- Assisted the Rhode Island Office of Energy Resources (OER) with the evaluation of OSW proposals received by the Massachusetts electric distribution companies. National Grid which serves Rhode Island has elected to negotiate a contract to purchase energy and RECs from a 400 MW OSW project that participated in the 83C RFP. Performed an economic analysis of proposal pricing including reviewing project benefits and assessed project development risks. Testified on behalf of OER regarding the project's economic and reliability benefits as well as conformance with state policies.
- Completed an assessment of the US Northeast and Mid-Atlantic OSW developments to identify opportunities for the Atlantic Canada industrial supply chain for Marine Renewables Canada. The scope of the assessment was comprehensive, covering the projects contracted to date, state procurement plans, project components and expenditures, OSW developer supplier contracting structures, known supplier relationships with the advanced developments, barriers to supply chain participation, US port infrastructure, implications for purpose built vessels, state and developer investments in local supply chain and infrastructure as well as specific strategies for Atlantic Canadian market entry.
- Profiled all known OSW generation and transmission developers with a position in the US market for NJR Clean Energy Ventures. Assessed their expected participation in forthcoming procurements and potential partnership opportunities. Provided a high-level review of the Southern New England, New York, and New Jersey markets. The reviews focused on the policy frameworks, physical resource regimes, transmission options and developments to date.
- Provided a review of the Southern New England, New York, and New Jersey offshore wind markets, focusing on the policy frameworks, physical resource regimes, transmission options, and developments to date for multiple clients.
- Authored a white paper contrasting the reliability of an offshore transmission network relative to transmission based on generator lead line proposals and estimated the potential incremental economic value of such a network in a whitepaper for a confidential client. This required a current understanding of offshore transmission technology, proposed network designs, historic transmission performance such as outages, and the Eastern US wholesale electricity systems.

- Participated in a consortium that evaluated the North American offshore wind market for Vestas Offshore Wind. Lead the Power Advisory team that was responsible for the market opportunities in Canada, focusing on Ontario and British Columbia. We reviewed the status of Ontario's Feed-In Tariff and its implications for the likely pace of offshore wind project development in Ontario.

Market Structure Development and Evaluation

- Advised the governments of Ontario, New Brunswick, Nova Scotia, Western Australia, and Manitoba regarding the restructuring of their wholesale power markets and possible market structures to achieve a workably competitive wholesale market.
- Responsible officer for market design project for the Province of New Brunswick. Navigant Consulting assisted the Market Design Committee and its subcommittees in providing the Minister of Natural Resources and Energy with recommendations on the implementation of electricity restructuring. Issues addressed included developing a market design that addresses concerns with the potential for the exercise of market power and enables New Brunswick to integrate with its interconnected markets. The Market Design Committee addressed development of the electricity market including its design, structure and rules. Navigant Consulting provided advice on the issues to be addressed, prepared issue papers and presentations, created strawmen for resolution of issues, and developed guidelines and direction for the creation of market design rules and protocols.
- Project manager for an assignment with the Province of New Brunswick to assist with the development of its ten-year energy policy. The cornerstone of this energy policy was the framework for restructuring its wholesale and retail electric markets. Advised regarding developments in other wholesale and retail markets and the prospects for meaningful competition in New Brunswick's wholesale and retail markets. Navigant Consulting advised regarding benefits offered by wholesale and retail competition; strategies for protecting New Brunswick consumers from market dislocations and higher prices; appropriate regulatory frameworks for the wires businesses and the prospects for achieving a workably competitive wholesale market in New Brunswick and the resulting market design requirements; and policies for addressing stranded costs raised by market restructuring.
- Markets and economics expert for a project with Western Power, the state-owned fully integrated utility that serves the vast majority of Western Australia. Advised regarding potential changes to the wholesale and retail electric power markets to enhance the competitiveness of these markets. Alternative market structures were evaluated and assessed in an effort to determine the market structure that offers the greatest societal net benefits. Offered proposed market structure changes that would accommodate government policy objectives of allowing greater levels of retail contestability and new entrants to satisfy the market's need for additional capacity. Evaluated restructuring reforms that had been implemented in a range of different markets that were of a similar size as Western Australia.
- Advised the Energy Strategy Working Group regarding the development of an electricity restructuring policy for the Province of Nova Scotia. Reviewed the experience with respect to the wholesale and retail market restructuring in California, New England, PJM, and Alberta and based on this experience outlined lessons learned and potential implications for electric restructuring Nova Scotia. Outlined the arguments for considering the restructuring of Nova Scotia's electricity market, reviewed contrasting market models, and discussed the critical constraints on wholesale and retail market restructuring in Nova Scotia.
- Provided numerous presentations regarding the experiences with the restructuring of wholesale power markets and the lessons learned. Markets evaluated have included California, Alberta, New York, New England, PJM, Victoria, and England and Wales.
- Served as independent expert regarding cost and availability of clean energy alternatives to Site C hydroelectric project. Presented findings before BC Utilities Commission Site C Review Committee.
- Drafted and defended an expert report that was filed before the Nova Scotia Utility and Review Board (UARB). Report assessed a preferred plan (the Maritime Link, which would deliver power from Muskrat Falls through Newfoundland and Labrador across the Maritime Link and into Nova Scotia) and two alternative plans (more domestic generation or more imports) across a wide range of sensitivity cases covering demand growth, electricity, natural gas and fuel prices, and various supply scenarios. The analysis also assessed the interaction of each alternative with adjacent markets for export and import opportunities and considered the impact of renewable energy obligations in these markets on sales options that would be available. Analysis and results were subjected to information requests and cross-examination and successfully defended before the UARB in a formal hearing.
- Conducted a market study evaluating the economic benefits of a major HVDC transmission interconnection between the three provinces: Alberta, Saskatchewan and Manitoba. A critical element of this market study was developing a market price forecast of electricity prices and production costs in the three provinces with and without the proposed transmission facilities.

- For NB Power provided an independent review of their 2017 and 2014 Integrated Resource Plans (IRPs), which was filed with Government. Review focused on methods, assumptions, consultation activities and reasonableness of results.
- Reviewed Manitoba Hydro's NFAT application and offered comments to client on deficiencies in the application. Comments focused on reasonableness of assumptions, methods and models. Reviewed comments provided by other parties in the proceeding.
- Developed independent analysis of resource alternatives available to Nova Scotia to comply with various emission control requirements. Work involved developing a comprehensive model that assessed the relative cost of the different resource alternatives that were available to the Province. In a subsequent project, the model was used compare the effective cost of the Maritime Link to other resource alternatives. Defended this analysis before the provincial regulator.
- Testified on behalf of an IPP on the reasonableness of an electric utility's integrated resource planning process and the corresponding investment in the repowering of a natural gas-fired generation resource. A primary focus of the testimony was on the deficiencies in the utility's economic evaluation methodologies and resulting biases from these methods.

Project Valuation

- Served as Project Manager for assignments requiring the development of valuation estimates for numerous energy projects. Projects typically entailed modeling revenues and costs to predict cash flows and calculate the cumulative present worth of after-tax cash flows. The overall viability of projects were assessed by reviewing the status of project permitting efforts and financial commitments, the major provisions of power purchase agreements and steam purchase agreements.
- Managed a project to provide an independent valuation of a multi-unit generating portfolio as part of a refinancing for the portfolio. Oversaw and managed the development of an electricity market price forecast and estimate of the fair market value of the proposed portfolio. Defended analyses before credit rating agencies and lenders.
- Completed a comprehensive valuation of an oil-sands cogeneration project. As part of this effort, the team examined various market scenarios and potential spot market volatility and the subsequent impact on the client's electricity commodity costs.
- Performed detailed analyses of numerous generation projects' financial feasibility. Analyses considered alternative financing schemes and identified strategies for enhancing project values.
- Evaluated the economic and financial feasibility of a number of different generation projects for project developers, project hosts, and a gas utility. Assisted in the development of a cogeneration feasibility assessment model.
- Developed an estimate of the capital and operating costs of a wide range of generating technologies as part of a comprehensive assessment of the costs of new entry. Also estimated the appropriate cost of equity using the capital asset pricing model and debt and capital structure based on market information for merchant generators.
- Oversaw the development of numerous electricity distribution company valuation models. Used models to derive an estimate of the fair market value of the LDCs. Defended analysis before utility boards and management.
- Developed quantitative and qualitative analyses of generating assets in support of numerous generation asset acquisitions. Assisted in the management and coordination of multiple facets of the due diligence process, including technical engineering assessments, environmental, fuel supply, etc. Experience includes a broad range of fuels / technologies, including wind and other renewables.

Competitive Procurement Support

- Advised on the development of over 25 RFPs for power supplies and demand-side resources for electric utilities across North America, serving as project manager for well over half of these RFPs. Support covered the full range of RFP support services including advising regarding the appropriate form of the RFP and evaluation process to secure resources that best satisfy the client's objectives, drafting the RFP, developing the evaluation framework, marketing the RFP process to prospective bidders and negotiating with bidders.
- Testified before the Alberta Utilities Commission on the appropriate structure for the Alberta Electric System Operator's competitive procurement process. The applicant adopted the many of the recommendations made in rebuttal testimony and the Commission directed the applicant to revise its proposal to conform to other recommendations. A primary focus of the testimony was how to enhance competitive tension in the procurement process for the benefit of electricity consumers.

- Managed a multi-disciplinary team that served as the Renewable Electricity Administrator for the Province of Nova Scotia responsible for procuring 300 GWh of renewable energy through a competitive procurement process.
- Advised the Vermont Public Service Board on the development of a market-based mechanism for the procurement of renewable energy. Legislation identified a reverse auction as a possible procurement mechanism. This along with other procurement methods were evaluated to determine the method that would be serve customers. Alternatives were evaluated by contrasting the product and other distinguishing characteristics, degree of price transparency, requirements for bidders, with each alternatives evaluated in terms of efficiency of outcomes given the anticipated level of competition.
- Offered testimony before the Massachusetts Department of Public Utilities on a utility RFP process. Authored reports on the evaluation of proposals.
- Reviewed the performance of the Alberta PPA Auction and critically assessed elements of the PPAs and the auction design which caused the auction to reduce the value secured for the generation assets that were auctioned.
- Outlined the pro and cons of different frameworks that could be used for the sale of surplus energy and reviewed whether these sales frameworks were appropriate for the products being offered and the relevant market.
- Advised the Western Australia Electricity Restructuring Task Force with respect to the performance of auctions in Ireland for the sale of capacity and energy. Reviewed the structure of the auction how it could be employed in Western Australia to mitigate the market power of the incumbent state generator.
- Managed numerous competitive solicitations for renewable energy resources and energy efficiency projects. Projects involved the development of frameworks for evaluating these energy alternatives and for comparing them on a consistent basis with conventional electricity supplies. Analyses considered the relative environmental impacts, reliability benefits, and cost-effectiveness of alternatives.
- Acted as Project Manager for several assignments to serve as the independent evaluator of conventional generation, renewable resource and demand-side RFPs. Responsible for determining whether proposals satisfy the threshold requirements in the RFP and for scoring all proposals. Also responsible for identifying the short-list of proposals, conducting bid clarification meetings with shortlisted bidders, and recommending to the selection of winning bidders.

Transmission Facility Review and Pricing Proceeding Support

- Advised the staff of the Ontario Energy Board on the evaluation of the proposal for a 1,250 MW HVDC line between Quebec and Ontario and served as a participating staff member for the Massachusetts Energy Facilities Siting Board's evaluation of the 2,000 MW HVDC interconnection between Massachusetts and Quebec.
- Advised OEB staff on the review of evidence presented by Hydro One in its application for two 240 kV transmission lines to alleviate the Queenston Flow West constraint.
- Advised clients in Saskatchewan, Newfoundland and Labrador, and Alberta on transmission pricing issues. Testified in the Alberta Transmission Congestion Pricing Principles proceeding.
- Led a consulting team that assisted with the preparation of the East-West Electrical Transmission Grid Study. Authored subsequent updates to this study for Natural Resources Canada.
- Advised a client regarding the elements of a comprehensive electricity export policy framework. Advice focused on economic and social issues arising from the development of export oriented transmission infrastructure to support the development generation for export.
- Provided testimony on Northeast power markets and transmission issues and consequential damages in a civil case in New York. Evaluated the implications of the loss of a transmission facilities on the power system adequacy.
- Advised a number of clients on the issues associated with the development of merchant transmission facilities. Projects included reviewing the status of merchant project development efforts, merchant project structures, key success factors for merchant plant development and a review of merchant plant development opportunities worldwide.

Renewable Energy Policy Development and Evaluation

- Advised governments of Ontario, New Brunswick, Nova Scotia, and Manitoba on policies for the promotion of renewable energy technologies.

- Advised the Ontario Select Committee on Alternative Fuels on the most promising renewable technologies, identified barriers to their development and adoption and proposed policies for overcoming these barriers.
- Directed a project for a group of municipalities in Manitoba that evaluated the economic opportunity offered by wind projects in Manitoba and identified policies to promote the development of Manitoba's wind resources.
- Evaluated a Continental Renewable Portfolio Standard (RPS) that would span the US and Canada. Project included reviewing the RPS designs for all the major RPS programs in the US and evaluating the changes in electricity trade and resulting electricity cost savings from relaxing various RPS provisions.
- Advised the Ontario Power Authority on the development of a standard offer for renewable energy technologies.
- Delivered a presentation on Canadian policies to promote the development of wind energy projects. Presentation reviewed federal and all relevant provincial programs and policies to promote the development of wind energy projects.
- Developed recommendations for the Manitoba Sustainable Energy Association on policies to promote the adoption of renewable energy technologies in Manitoba. Reviewed the relative advantages and disadvantages of standard offers versus RFPs and made recommendations regarding the appropriate applications of each.
- Advised numerous electricity generation development companies on the implications and opportunities presented by renewable energy policies. Developed strategic plans for a wide range of renewable energy technologies including large scale wind, landfill gas, biomass, anaerobic digestion, and small hydro.
- Evaluated electricity wholesale market and REC prices that would apply to landfill gas projects and reviewed US federal policies that benefited these projects including the production tax credit.
- Reviewed the general market for the development of renewable energy projects in Canada and contrasted market conditions with those in other countries.
- Led the development of a multi-client study that evaluated the opportunities for wind project development in Ontario under existing federal and provincial programs.
- Contrasted state RPS programs by identifying eligible technologies, eligibility requirements for projects in different jurisdictions, strategies for assessing compliance, RPS targets, and penalty provisions for failure to achieve the target.

Speaking Engagements

- "Strategies for Enhancing the Value of Your Asset", IBC Conference, (November, 1999)
- "Electricity Restructuring Lessons Learned: Implications for Ontario", Ontario Energy Marketers Association (April, 2001)
- "Electricity Power Prices in the Deregulated Ontario Market, 2001 CERI Conference, (October, 2001)
- "Electricity Restructuring in the US and Eastern Canada", World Bank/CREG/CERI Conference, (November, 2001)
- "Prices and Price Volatility in the Ontario Wholesale Power Market" PowerFair 2002, (May, 2002)
- "Pricing Fundamentals in the Ontario Wholesale Power Market" PowerFair 2003, (August, 2003)
- "The Economics of Power Generation in Atlantic Canada", 2003 Atlantic Power Summit (October, 2003)
- "Future Opportunities in the Maritimes", 2003 Ontario Energy Contracts Conference, (November, 2003)
- "A Perspective on Ontario's Evolving Wholesale and Retail Power Market Structures", PowerFair 2004, (May, 2004)
- "Canadian Policies to Promote Wind Project Development" EUCI's 4th Wind Energy and Power Markets Conference (September, 2004)
- "Effectively Navigating Ontario's RFP Processes" Power ON Conference, (October, 2004)
- "Enhancing the Performance of the Maritimes Market", 2004 Atlantic Power Summit, (November, 2004)
- "What Will the Ontario Landscape Look Like?", 2005 Ontario Energy Contracts Conference, (January, 2005)
- "Policies to Promote the Adoption of Renewable Energy Technologies in Manitoba", Manitoba Sustainable Energy Association, (April, 2005)
- "Outlook for Ontario Electricity Supply & Pricing", PowerFair 2005, (May, 2005)
- "Key Risks Affecting Ontario Electricity Consumers", AMPCO General Member Seminar (November, 2005)

- "What Kind of Market Structure Would Spark New Investment?" Canadian Institute's Generation Adequacy in Ontario Conference (April 19, 2006)
- "Where are Electricity Pricing Going" Insight Information, Ontario Power Forum (June 15, 2006)
- "Transmission Planning and Policy Development: An Update", APPrO Conference (November 15, 2006)
- "Recent Developments in Transmission Access and Pricing" Insight Information's Grid Reliability and Competition in the Power Sector (December 12, 2006)
- "Renewables in Ontario" Insight Info Conference (June 14, 2007)
- "Report Card on Ontario's Electricity Market" Ontario Energy Association Annual Conference (September 6, 2007)
- "Opportunities for Selling Renewable Power into the New England Market" Insight Info's 5th Annual Atlantic Power Summit (September 26, 2007)
- "New England Market Opportunities and the Prospects for Increased Inter-Regional Trade" Canadian Institute's Atlantic Energy Conference (May 28, 2008)
- "Cost Recovery and Return on Equity for Transmission Investment in the U.S.", Canadian Electricity Association Transmission Council (February 25, 2009)
- "Ontario's Feed In Tariff in the Context of North American Renewable Energy Policies", 2009 OEA Industry Leaders' Roundtable (April 30, 2009)
- "Transmission as Barrier to Wind Power Exports from the Maritime Provinces to the US Northeast", Canadian Wind Energy Association Wind Matters Conference (May 20, 2009)
- "Electricity Transmission Enhancements to Capitalize on Opportunities for Renewable Resource Development", Renewable Energy Conference 2009 (May 28, 2009)
- "Lessons Learned in the Design of Standard Offer and Feed-in Tariff Programs" Vermont Public Service Board Standard Offer Workshop (July 10, 2009)
- "Impact of the Current Economic Climate on North American Renewable Energy Investment", Rothesay Energy Dialogue 2009 (July 14, 2009)
- "Evaluation of Opportunities and Barriers to Wind Power Exports from the Maritime Provinces to the US Northeast", CanWEA 2009: Infinite Possibilities (September 21, 2009)
- "Stakeholder Conference Presentation on the Cost of Capital", Ontario Energy Board (September 22, 2009)
- "Opportunities Offered by the New England Power Market", Insight Info's 7th Annual Atlantic Canada Power Summit (October 5, 2009)
- "Assessment of Ontario's Green Energy Act and its Implications for Ontario", PowerLogic ION Users Conference 2009 (October 23, 2009)
- "Securing Regulatory Support for Smart Grid Investments", Canadian Electricity Association Customer Council (November 24, 2009)
- "Creating a Policy Environment that Supports New Transmission Development", Canadian Institute's Transmission and Integrating New Power into the Grid, (April 19, 2010)
- "Policies for Facilitating Transmission Investment" 2010 OEA Energy Leader's Roundtable, (April 21, 2010)
- Clean Energy Dialogue Conference, U.S. Department of Energy and Natural Resources Canada, (May 20, 2010)
- "Providing Revenue Stability for Offshore Wind: PPAs, RFPs and FITs", Insight Info's Freshwater Wind 2010 (July 19, 2010)
- "Market and Economic Barriers to Electricity Storage", Canadian Electricity Association Generation Council Meeting,, (September 16, 2010)
- "Opportunities Offered by the New England Power Market", Canadian Wind Energy Association: Growing Wind Energy in Atlantic Canada, (September 22, 2010)
- "Considerations for Implementing Feed in Tariffs in Atlantic Canada", 8th Annual Atlantic Canada and US NE Power Summit (October 26, 2010)
- "The Role of Cross Border Trade in Achieving Regional Renewable Energy Objectives", Council of State Governments Energy Plenary (August 8, 2011)

- “Overview of RFP Process for the Procurement of 300 GWh of Renewable Energy from IPPs”, The Nova Scotia Feed In Tariff Forum (September 22, 2011)
- “Procuring Renewable Electricity under Long-Term Contracts: Balancing Customer and Developer Interests”, Atlantic Canada and NE US Power Summit 2011 (October 20, 2011)
- “Assessing the Competitiveness of Atlantic Canada’s Renewable Energy Sector”, Rothesay Energy Dialogue (October 26, 2011)
- “Nova Scotia’s 2012 Renewable Energy RFP: Delivering Value for Customers”, 8th Canadian German Wind Energy Conference (February 23, 2012)
- “Employing Competition to Procure Transmission: Lessons Learned from Other Markets”, IPPSA 18th Annual Conference (March 12, 2012)
- “Future Opportunities for IPPs in Atlantic Canada”, Halifax 2012 FIT Forum (September 24, 2012)
- “Procurement Programs for Long-term Contracts for Renewable Energy Projects in New England”, Northeast Energy and Commerce Association, 10th Annual Renewable Energy Conference, (March 28, 2013)
- “Market Issues Associated with Wind Integration”, Canadian Wind Energy Association and Natural Resources Canada, (September 18, 2013).
- “Evidence Regarding Future Declines in the Cost of Wind”, CanWEA 2014 Annual Conference (October 28, 2014)
- “Renewable Energy Credits and Harmonizing Renewable Energy Trading”, EUCI US and Canada Cross Border Trade Conference (April 9, 2015)
- “Opportunities offered by Northeast Electricity Markets for Canadian Wind Projects”, CanWEA Spring Forum (April 5, 2016)
- “US Northeast Market Opportunities for US & Canada Wind”, EUCI’s U.S./Canada Cross Border Summit (March 1, 2017)
- “Emerging Trends in North American Energy: Focusing On New England’s Electricity Market”, East Coast Energy Connection (June 7, 2017)
- “Implications of Expansion of “Non-Traditional” Resources for Northeast Power Markets”, Northeast Energy & Commerce Association’s Power Markets Conference (November 14, 2017)
- “Northeast Power Markets Outlook: Clean Energy Perspective”, EUCI US Cross-Border Energy Summit: 2018 (March 12, 2018)
- “Competitive Transmission Procurement Processes”, IESO 2018 Technical Planning Conference (September 13, 2018)
- “Opportunity for Offshore Wind in Canada, Reflecting on US Developments”, Marine Renewables Canada 2018 Annual Conference (November 21, 2018)
- “Emerging Eastern United States Offshore Wind Market”, Offshore Global Finance 2019: Amsterdam, (March 28, 2019)
- “Navigating US OSW Procurement Processes”, US Offshore Wind 2019, (June 10, 2019)
- “Benefits of Independent Offshore Transmission Development for US OSW”, Offshore Wind Transmission, US 2019, (September 18, 2019)
- “Opportunities for Atlantic Canada Supply Chain in US Northeast OSW”, MRC & NEIA Info Session Offshore Wind Supply Chain Opportunities, (October 29, 2019)
- “Offshore Wind Procurement: Opportunities Abound”, Business Network for Offshore Wind Virtual IPF 2020, (April 21, 2020)
- “Benefits & Risks of Independent OSW Transmission & Competitive Procurement”, Reuters Events Transmission Planning for OSW Webinar, (April 28, 2020)
- “Offshore Wind Value Proposition for New Hampshire & Procurement Alternatives”, Clean Energy NH: Offshore Wind Series, (August 18, 2020)
- “Understanding the Corporate PPA Landscape Across Canada: A Jurisdictional Review with Power Advisory”, Business Renewables Centre Canada, (October 27, 2020)

List of Expert Testimony

- New Brunswick Energy and Utilities Board, New Brunswick Power Transmission Revenue Requirements and Open Access Transmission Tariff, (Matter No. 513),(July 2022)
- Newfoundland and Labrador Board of Commissioners of Public Utilities, Rate Mitigation Options and Impacts of Muskrat Falls, (October 2019)
- Rhode Island Public Utilities Commission, Petition for Approval of Proposed Power Purchase Agreement for Offshore Wind Energy, (Docket No. 4929), (May 2019)
- Louisiana Public Service Commission, Joint Application by Various Entergy Companies for Approval to Construct the St. Charles Power Station, and for Cost Recovery, (Docket No. U-33770) (January 2016)
- Alberta Utilities Commission, Regulated Rate Option Service Providers Generic Proceeding on Energy Price Setting Plans, (Proceeding 2941), Establishing the Appropriate Return Margin for the Regulated Rate Option (October 2014)
- Ontario Support Court, Ogichidaakwe (Grand Chief) Diane M. Kelly on her own behalf, on behalf of all members of the Anishinaabe Nation in Treaty 3 and on behalf of Grand Council Treaty 3, Grand Council Treaty 3, Chief Lorraine Cobiness, Chief Janice Henderson, Chief Kimberly Sandy-Kasprick, and Chief Earl Klyne, on their own behalf and on behalf of Grand Council Treaty #3, Chiefs in Assembly versus Ontario Minister of Energy and Ontario Power Authority, (Court File No. 411/11) (March 2014)
- Alberta Utilities Commission, Alberta Electric System Operator's 2014 General Tariff Application (Proceeding 2718), Proposed Approach for Designating Transmission Projects (February 2014)
- Province of Quebec Superior Court, Churchill Falls (Labrador) Corporation Limited v. Hydro-Québec, Evaluation of the Power Purchase Contract for the Churchill Falls Project when Negotiated and under Current Market Conditions, (September 2013)
- Nova Scotia Utility and Review Board, Nova Scotia Power's Application to Build the Maritime Link (ML-2013-01), (June 2013)
- Vermont Public Service Board, Investigation into the Development of Standard Offer
- Prices for Sustainably Priced Energy Enterprise Development (SPEED) Program, (Docket No. 7874), (January 2013)
- Vermont Public Service Board, Investigation into the Establishment of a Standard Offer
- Prices for Baseload Renewable Power under the SPEED Program (Docket No. 7782), (May 2012)
- Vermont Public Service Board, Investigation into the Establishment of a Standard Offer
- Prices for certain existing Hydroelectric Plants under the Sustainably Priced Energy Enterprise Development (SPEED) Program (Docket No. 7781), (February 2012)
- Vermont Public Service Board, Investigation into the Review of a Standard Offer
- Prices for Qualifying Sustainably Priced Energy Enterprise Development (SPEED) Resources (Docket No. 7780), (November 2011)
- New Hampshire Public Utilities Commission, Concord Steam Corporation, Application of Public Service Company of New Hampshire for Approval of the Power Purchase Agreement with Laidlaw Berlin BioPower LLC (Docket DE 10-195), (December 2010)
- Ontario Energy Board, Hydro One Networks Inc. 2010-2011 Electricity Transmission Revenue Requirement and Rates Application, (Docket EB-2010-0002), (September 2010)
- Vermont Public Service Board, Investigation Re: Establishment of a Standard Offer
- Program for Qualifying Sustainably Priced Energy Enterprise Development ("SPEED") Resources (Docket No. 7533), (December 2009)
- United States District Court for Eastern California, Global Ampersand, LLC v. Crown Engineering & Construction, Inc., Damage Cost Analysis for Chowchilla and El Nido Biomass Projects (July 2009)
- Florida Public Service Commission: Florida Power & Light Company Application for Approval of Standard Offer Contract and Tariff (Docket NO. 080193-EQ), (December 2008)

- Louisiana Public Service Commission: Application of Entergy Louisiana, LLC for Approval to Repower Little Gypsy Unit 3 Electric Generating Facility and for Authority to Commence Construction and for Certain Cost Protection and Cost Recovery (Docket No. U-301922) (September 2007)
- Alberta Energy and Utilities Board: Transmission Congestion Management Principles Proceeding, testified on behalf of TransAlta Corporation (EUB 2002-099)
- New Brunswick Public Utilities Board: Generic Proceeding on the Need for Proposed Facilities, testified on behalf of New Brunswick Power Corporation Re: forecast of electricity market prices in New England (2001)
- New Jersey Board of Public Utilities: Proceeding regarding the competitive implications of restructuring electricity markets on behalf of Orange and Rockland Utilities (1998)
- New York Public Service Commission: Proceeding regarding competitive implications of restructuring electricity markets on behalf of Orange and Rockland Utilities (1997)
- Federal Energy Regulatory Commission: Review of Competitive Implications of Proposed Merger between Delmarva Power & Light and Atlantic City Electric, testified on behalf of Delmarva Power & Light and Atlantic City Electric (1996)
- Rhode Island Energy Facilities Siting Board: Application of Aquidneck Power Ltd. To Build a Natural Gas-fired Generating Facility (1995)
- Massachusetts Department of Public Utilities: Review of the Commonwealth Electric Company's Competitive Procurement Process for Demand-Side Resources, testified on behalf of Commonwealth Electric Company (91-234)
- Massachusetts Energy Facilities Siting Council: Review of Application by MassPower to build an electric generating facility, testified on behalf of MassPower on the Need and Impacts relative to alternative generation technologies of the proposed project (20 DOMSC 301 (1990))
- Massachusetts Energy Facilities Siting Council: Review of Application by Northeast Energy Associates to build an electric generating facility, testified on behalf of Northeast Energy Associates on the impacts and costs relative to alternative generation technologies (16 DOMSC 335 (1987))

CERTIFICATION

I hereby certify that on September 7, 2022, I sent a copy of the within to all parties set forth on the attached Service List by electronic mail and copies to Luly Massaro, Commission Clerk, by electronic mail and hand delivery.

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