BEFORE THE NOVA SCOTIA UTILITY AND REVIEW BOARD

In the Matter of an Application by Riverport Electric Light Commission for
Approval of Amendments to its Schedule of Rates and Charges for the provision of electric supply and services to its customers and its Schedule of Rules and Regulations

(NSUARB M10810)

Evidence of
Melissa Whited

On Behalf of
Counsel to Nova Scotia Utility and Review Board

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I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, title, and employer.

A. My name is Melissa Whited. I am a Senior Principal at Synapse Energy Economics, Inc. ("Synapse"), located at 485 Massachusetts Avenue, Cambridge, MA 02139.

Q. Please describe Synapse Energy Economics.

A. Synapse is a research and consulting firm specializing in electricity and gas industry regulation, planning, and analysis. Our work covers a range of issues, including economic and technical assessments of demand-side and supply-side energy resources; energy efficiency policies and programs; integrated resource planning; electricity market modeling and assessment; renewable resource technologies and policies; and climate change strategies. Synapse works for a wide range of clients, including attorneys general, offices of consumer advocates, public utility commissions, environmental advocates, the U.S. Environmental Protection Agency, U.S. Department of Energy, U.S. Department of Justice, the Federal Trade Commission, and the National Association of Regulatory Utility Commissioners. Synapse's staff includes over 35 professionals with extensive experience in the electricity industry.

Q. Please summarize your professional and educational experience.

A. I have 13 years of experience in economic research and consulting. At Synapse, I have worked extensively on issues related to utility regulatory models and rate design. I have been an invited speaker in numerous industry conferences, including as a panelist for the National Association of Regulatory Utility Commissioners (NARUC) Subcommittee on Rate Design at the 2021 Winter Policy Summit and the 2018 Annual Meeting.

I have sponsored testimony before the Newfoundland and Labrador Board of Commissioners of Public Utilities, the Massachusetts Department of Public Utilities, the Illinois Commerce Commission, the New Hampshire Public Utilities Commission, the Georgia Public Service Commission, the Rhode Island Public Utilities Commission, the Maine Public Utilities Commission, the California Public Utilities Commission, the Hawaii Public Utilities Commission, the Public Service Commission of Utah, the Public Utility Commission of Texas, the Virginia State Corporation Commission, and the Federal Energy Regulatory Commission. I hold a Master of Arts in Agricultural and Applied Economics and a Master of Science in Environment and Resources, both from the University of Wisconsin-Madison. My resume is attached as Appendix A.

Q. Have you previously testified before the Nova Scotia Utility and Review Board?

A. Yes. I testified in Matter Nos. M09777, M10176, and M10431.

Q. On whose behalf are you providing evidence in this case?

A. I am providing evidence on behalf of Counsel to the Nova Scotia Utility and Review Board ("Board").

Q. What is the purpose of your evidence?

A. My evidence addresses certain aspects of the Riverport Electric Light Commission's ("RELC" or "the Utility") General Rate Application, including cost allocation, rate design, the proposed allowance for storm costs, and the proposed deferral account for purchased power cost increases.

II. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

Q. Please describe your conclusions.

A. My conclusions are as follows:

- RELC's cost of service study relies on the minimum system method, which inappropriately classifies a portion of distribution system costs as customer-related.
- The Utility's cost allocation factors are overly reliant on assumptions based on the judgement of RELC management and the Utility's consultant rather than actual data or analysis.
- The Utility's proposal to increase rates by an equal percentage across metered classes is not supported by the Utility's cost of service study and would perpetuate inter-class inequities.
- Increasing the service charge for the Domestic class is not justified on a cost-causation basis.
- The existing declining block rate structure is not supported by analysis and may lead to wasteful consumption and intra-class inequities.
- The Utility's proposed storm cost allowance is not adequately justified.
- In principle, the Utility's proposal for a deferral account for purchased power cost increases appears reasonable. The cost increases are both unknown and outside of RELC's control, the deferral account would help to mitigate further rate increases in the near-term, and the existing flow-through mechanism does not appear to apply in this case.

Q. What are your recommendations?

A. I recommend that the Board:

- Direct RELC to utilize the basic customer method for classifying distribution costs as demand- or customer-related. Under this method, conductors, spur lines, poles and fixtures, and transformer costs, are classified as 100 percent demand-related.

- Direct RELC to file a proposal within the next 18 months to enhance the data and analysis used to develop cost allocation factors and rates. The proposal should provide:
    - the estimated costs associated with conducting a load research study (either for RELC alone or jointly with other utilities);
    - the costs and benefits associated with alternatives to a load research study, such as using publicly available class coincidence statistics from other winter peaking utilities and the availability of data from the revenue meter used by Nova Scotia Power for billing purposes;
    - RELC's preferred option; and
    - RELC's proposed timeline for implementation.
- Direct RELC to conduct further analysis to determine appropriate customer weightings for its cost of service study, and to file this analysis in its next rate application.
- Direct RELC to adjust rates in a manner that better reflects each class's contribution to costs, as detailed in my evidence below. Assuming an overall rate increase of 32.5 percent, my proposal would adjust rates for each class as follows:
    - Domestic: 39.7 percent
    - Small General Service: 20.9 percent
    - General Service and Large General Service: 13.4 percent
    - Street Lighting: -11.1 percent
    - Yard Lighting: -30.7 percent
    - Cable Unmetered: -16.7 percent

- Reject RELC's proposal to increase all components of the Domestic rates by an equal percentage, and instead require RELC to maintain the Domestic class service charge at current levels and implement the rate increase for the Domestic class through volumetric rates only.
- Direct RELC to file a proposal to eliminate the declining block rate structure in its next rate application, unless such rate structure can be adequately supported by evidence that it is cost-reflective.
- Reject RELC's proposal for a storm cost allowance at this time.
- Approve the Utility's proposal for a deferral account but require that the Utility submit an application to the Board for approval to recover any amounts accumulated in the account under terms to be approved by the Board.

III. COST OF SERVICE STUDY

Q. What is the purpose of a cost of service study?

A. A cost of service study is used to assign the utility's revenue requirement to each customer or rate class in proportion to the costs imposed on the system by those customers. Thus, a cost of service study seeks to determine what costs are incurred to serve each class of customers.

Q. Please provide an overview of the Utility's cost of service study.

A. RELC's cost of service study follows three standard steps. First, costs are functionalized by separating utility plant and expenses according to the primary functions served. Second, the functionalized rate base and operating costs are classified according to the primary cost drivers: the number of customers on the system (customer-related costs), the need to meet peak demand (demand-related costs), and the amount of electricity consumed (energy-related costs). Finally, the costs are either directly assigned to customers or allocated using cost allocation factors based on class non-coincident and coincident demand, energy consumption, and number of customers. The ratio between each class's revenues and allocated costs (the revenue-to-cost ratio) provides a guide for determining changes in revenue and rates for each class.

Q. Do you have any concerns regarding RELC's cost of service methodology?

A. Yes, I have two primary concerns. First, the study assumes a 30 percent customer/70 percent demand split for classifying conductors, spur lines, poles and fixtures, and transformers. This assumption is based on the theory of a "minimum system." The minimum system method classifies costs by estimating the cost of building from scratch a hypothetical system employing the smallest size components typically installed, and then deeming those costs to be customer-related. As I describe below, the minimum system methodology suffers from numerous flaws. Second, I am concerned that numerous allocation factors used by RELC were developed based solely on the judgment of RELC management and RELC's consultant, rather than based on any actual data or analysis.

Q. Please explain your concerns with the minimum system method.

A. The minimum system method calculates the minimum size for each distribution plant type (e.g., poles and fixtures, conductors, transformers), and then classifies these costs as customer-related, while the remaining costs for each plant type are classified as demand-related. This approach is at odds with the definition of customer-related costs found in the widely-cited text, *Principles of Public Utility Rates* by Professor James Bonbright.[1] Professor Bonbright defines customer costs as the "operating and capital costs found to

[1] James Bonbright, Principles of Public Utility Rates (New York: Columbia University Press, 1961).

vary with number of customers regardless, or almost regardless, of power consumption."[2] The costs associated with conductors, spur lines, poles and fixtures, and transformers are primarily driven by the need to serve demand on the system, and thus it is not appropriate to classify these costs as customer-related.

Q. Why do some utilities propose to classify conductors, spur lines, poles and fixtures, and transformers as partially customer-related?

A. Professor Bonbright notes that the argument for classifying costs associated with a hypothetical "minimum system" as customer-related is that these costs vary with the area of the distribution system, and thus indirectly with the number of customers.[3] However, Bonbright argues that there is actually a "very weak correlation between the area (or the mileage) of a distribution system and the number of customers served by this system," given that in many cases an increase in customers does not require an expansion of the distribution system.

Q. Are there other reasons why it is generally inappropriate to use the minimum system method?

A. Yes. Additional shortcomings of the minimum system method have been widely documented. For example, multiple pages in the Regulatory Assistance Project's 2020 manual *Electric Cost Allocation for a New Era* are devoted to examining the flaws of the

[2] *Id.,* p. 347.
[3] *Ibid.*

minimum system method. Key critiques of the minimum system method from the RAP manual include the following:[4]

1) The hypothetical "minimum system," used as the basis for this cost allocation method, still has the ability to serve some load—often a large portion of a typical residential customer's load.

2) A large portion of the cost of the distribution system (e.g., the number of poles and length of conductors) is driven by the size of the territory served, rather than the number of customers.

3) The minimum system method generally uses commonly installed minimum sizes, rather than the smallest equipment ever used, currently in use, or that could be used. However, a key reason for using larger equipment is due to higher customer demands, and thus the minimum size currently in use does not represent the true minimum that would be required for a hypothetical minimum system.

4) The hypothetical minimum system is assumed to have the same number of units (number of poles, feet of conductors, etc.) as the actual system. In reality, both the size of equipment and the number of units is often driven in part by load.

[4] Jim Lazar, Paul Chernick, and William Marcus, "Electric Cost Allocation for a New Era: A Manual" (Regulatory Assistance Project, 2020), 145–49, https://www.raponline.org/wp-content/uploads/2020/01/rap-lazar-chernick-marcus-lebel-electric-cost-allocation-new-era-2020-january.pdf.

The manual concludes that the "minimum system analysis does not provide a reliable basis for classifying distribution investment and vastly overstates the portion of distribution that is customer-related."[5]

Q What method do you recommend using instead of the minimum system?

A I recommend using the basic customer method. Under this method, only the meter, service drop, and billing/collection costs would generally be classified as customer-related. These are those costs that increase or decrease with the number of customers on the system. Further, as stated by the Regulatory Assistance Project's manual, the "basic customer method for classification is by far the most equitable solution for the vast majority of utilities."[6]

Q. Is the basic customer method used by other jurisdictions?

A. Yes. The Regulatory Assistance Project's manual notes that the basic customer method is currently used by jurisdictions across the United States, including Arkansas, California, Colorado, Illinois, Iowa, Massachusetts, Texas, and Washington.[7]

Q. How would this methodological change impact the results of the cost of service study?

A. As discussed above, the Utility's cost-of-service study classifies 30 percent of distribution costs as customer-related. When these costs are reclassified as demand-related, the results of the cost-of-service study change as shown in following table. In this

[5] Lazar, Chernick, and Marcus, 146.

[6] Lazar, Chernick, and Marcus, "Electric Cost Allocation for a New Era: A Manual," 145.

[7] Lazar, Chernick, and Marcus, 145.

case, the costs allocated to the Domestic class increase by approximately 2.6 percent under the basic customer method, while costs allocated to other classes decrease.

Table 1. Comparison of Cost of Service Results using RELC's Method and the Basic Customer Method

70% Demand, 30% Customer

Costs ($)	Domestic	Small General Service	General Svc and Lg Gen Svc	Street Lighting	Yard Lighting	Cable
Purchased Power	1,182,205	63,953	140,962	7,091	1,282	7,722
OM&A	372,421	58,740	46,142	44,507	3,653	1,512
Amortization Exp.	49,716	6,487	6,925	5,790	386	210
Financial Costs	44,275	5,750	6,179	5,800	344	187
Total ($)	**1,648,617**	**134,930**	**200,209**	**63,188**	**5,664**	**9,631**

Basic Customer Method

Costs ($)	Domestic	Small General Service	General Svc and Lg Gen Svc	Street Lighting	Yard Lighting	Cable
Purchased Power	1,182,205	63,953	140,962	7,091	1,282	7,722
OM&A	405,954	38,269	46,448	33,495	1,663	1,147
Amortization Exp.	55,019	3,473	6,789	4,018	66	149
Financial Costs	49,010	3,059	6,057	4,219	58	132
Total ($)	**1,692,187**	**108,754**	**200,257**	**48,823**	**3,068**	**9,151**
Change	43,570	(26,176)	48	(14,365)	(2,596)	(481)

Q. Please elaborate on your second concern that many allocation factors are based on judgment rather than data.

A. In many cases, RELC was unable to provide any data or analysis to support the allocation factors used in its cost of service study. For example, in response to RELC (Synapse) IR-7 and IR-8, RELC states that the weightings for customer distribution and billing costs "reflect the judgment of management and BDR [RELC's consultant]. No analysis was carried out." Further, RELC states that it has "no hourly load data for any customer or customer class,"[8] and thus the demand allocators for coincident peak (CP) and non-coincident peak (NCP) for each class were largely developed using data for other utilities,[9] assumed coincidence factors, and load diversity adjustments.

Q. Is it reasonable to rely primarily on judgment and proxy data to develop allocation factors?

A. Generally, no. However, I recognize that RELC is a small utility and that the cost to conduct a detailed load research study may outweigh the benefits. Nevertheless, there are likely numerous opportunities to cost-effectively leverage data and analysis to develop more robust allocators. For example:

- To develop the weighting factor for billing costs, RELC should analyze the difference in meter costs for each customer class, differences in costs associated with billing frequency, and other such relevant factors.
- As noted in response to RELC (Synapse) IR-13(b), RELC could analyze data from the revenue meter used by NSPI for billing purposes and collect data from other winter-peaking utilities to support its coincident and non-coincident load assumptions.

In addition, RELC could investigate the costs of conducting a load research study (either independently or in conjunction with other nearby utilities) to determine the reasonableness of this option.

[8] Response to RELC (Synapse) IR-6.

[9] Response to RELC (NSUARB) IR-35 describes how the CP was estimated for Small General Service by adopting a CP factor from Berwick Electric Commission's Rate Study filed in M09820 on August 20, 2020. However, it is not clear whether the coincident peak factor from Berwick Electric Commission's rate study are based on actual meter data, or whether they represent estimates in themselves.

Q. What is your recommendation with respect to the allocation factors used in RELC's cost of service study?

A. I recommend that the Board direct RELC to file a proposal within the next 18 months to enhance the load data that it uses to develop cost allocation factors and rates. The proposal should provide:

- the estimated costs associated with conducting a load research study (either for RELC alone or jointly with other utilities);
- the potential for sharing the cost of a load research study with other nearby utilities, such as the Town of Mahone Bay;
- the costs and benefits associated with alternatives to a load research study, such as using publicly available class coincidence statistics from other winter peaking utilities and the availability of data from the revenue meter used by Nova Scotia Power for billing purposes;
- RELC's preferred option; and
- RELC's proposed timeline for implementation.

In addition, I recommend that the Board direct RELC to conduct further analysis to determine appropriate customer weightings, and to file this analysis with its next cost of service study.

IV. COST ALLOCATION

Q. Do you have any concerns regarding the Utility's cost allocation proposal?

A. Yes. RELC proposes to increase rates equally for all metered classes by 34.3 percent and reduce rates by 17 percent for yard lighting. However, this proposal is not consistent with the results of RELC's cost of service study. Under existing rates, several classes are substantially under-contributing to costs, while other classes are substantially overcontributing. RELC's proposal would result in several classes remaining well outside a revenue-to-cost (RTC) band of 95–105 percent, or even outside an RTC band of 90 – 110 percent, as shown in the table below.

Table 2. Revenue-to-Cost Ratios under RELC's Cost of Service Methodology

	Domestic	Small General Service	General Svc and Lg Gen Svc	Street Lighting	Yard Lighting	Cable
RTC Ratio under Existing Rates	73%	79%	98%	101%	148%	143%
RTC Ratio under RELC's Proposed Rates	96%	102%	129%	101%	125%	143%

Under the basic customer approach to classifying costs, the class revenue-to-cost ratios exceed the desired range to an even greater extent under both existing rates and RELC's proposed rates, as shown in the table below.

Table 3. Revenue-to-Cost Ratios under Basic Customer Methodology

	Domestic	Small General Service	General Svc and Lg Gen Svc	Street Lighting	Yard Lighting	Cable
RTC Ratio under Existing Rates	72%	92%	98%	123%	252%	149%
RTC Ratio under RELC's Proposed Rates	94%	121%	129%	123%	210%	149%

Thus, under either cost of service methodology, several classes remain well outside the desired RTC ratio range of 95 – 105 percent, or even 90 – 110 percent.

Q. Do you propose any modifications to bring the revenue-to-expense ratios within a more reasonable range?

A. Yes. I used a three-step process to develop an alternative cost allocation proposal.

First, for classes with an RTC ratio in excess of 120 percent, I determined the extent to which the RTC ratio exceeded 100 percent and reduced this by half. Thus, the RTC ratio for Yard Lighting was reduced from 252 percent to 176 percent, the RTC ratio for Cable was reduced from 149 percent to 124 percent, and the RTC ratio for Street Lighting was reduced from 123 percent to 112 percent.

The second step was to increase rates by an equal proportion for all remaining classes up to an RTC ratio cap of 110 percent. This resulted in the RTC ratio for all of the General Service classes (Small General Service, General Service, and Large General Service) reaching an RTC of 110 percent.

Finally, I allocated the remaining rate increase to any class that had not yet reached the RTC ratio cap of 110 percent. This resulted in additional rate increases for the Domestic class. The results of this allocation method (and the basic customer method for classifying costs) are shown in the table below.

Table 4. Proposed Cost Allocation Results

	Domestic	Small General Service	General Svc and Lg Gen Svc	Street Lighting	Yard Lighting	Cable
Change in Revenues	436,243	19,463	24,350	(5,692)	(2,333)	(2,225)
Change in Rates	39.7%	20.9%	13.4%	-11.1%	-30.7%	-16.7%
Resulting RTC Ratio	98%	110%	110%	112%	176%	124%

V. RATE DESIGN

Q. Please provide an overview of the Utility's rate design proposal.

A. The Utility proposes to maintain the same overall rate structures as currently in place and simply increase each rate component by an equal percentage.

Q. Do you agree with this approach?

A. No. An equal percentage rate increase for each rate component results in rates that are not necessarily reflective of how costs are incurred, and thus does not provide accurate price signals. In particular, a substantial increase to the service charge for the Domestic class is not justified by the cost of service results, and the Utility was unable to provide any cost analysis justifying its declining block rate structures.

Q. What do you propose with respect to the Domestic class service charge?

A. I recommend that the Domestic class service charge be maintained at its current level. Under the Basic Customer method, the customer-related cost per month is approximately $6.00 for the Domestic class. The current service charge of $12.36 is already approximately double the cost justified by the cost of service study. Even under the minimum system method used by RELC, the customer-related costs for the Domestic class total less than $14.00 per month.

Q. Please explain your concerns regarding RELC's declining block rates.

A. By pricing higher levels of consumption at a lower rate, declining block rates reduce the marginal cost of electricity consumption faced by customers. If such rates do not accurately reflect the costs associated with serving additional load, they may lead to lower-usage customers subsidizing higher-usage customers. Further, lower prices for higher levels of electricity consumption can lead to wasteful usage by reducing incentives for conservation and energy efficiency. This could eventually result in higher generation, transmission, and distribution costs for all customers. For these reasons, many jurisdictions have moved away from declining block rates, particularly for residential customers.

Q. Has RELC provided adequate cost justification for its declining block rates?

A. No. While RELC notes that, in theory, the declining block rate structure attempts to recover fixed costs through the service charge and first (highest-priced) energy block, the utility states that it has not carried out a study of the relationship between the allocated fixed costs of its classes and the costs recovered through the service charge and block price differentials.[10]

Q. What do you propose with respect to the declining block rate structure?

A. I recommend that the Board direct RELC to file a proposal to eliminate the declining block rate structure in its next general rate application, unless such rate structure can be adequately supported by evidence that demonstrates it is cost-reflective.

VI. STORM COSTS

Q. What is the Utility proposing in terms of storm costs?

A. The Utility is proposing to include an allowance in each annual budget of $15,000 to allow it to absorb storm costs, except in the most extraordinary cases.

Q. What is the average storm cost incurred by RELC?

A. RELC states that it has no records of historic storm costs, nor is it aware that it has ever applied for storm cost recovery during the last ten years.[11]

[10] Response to RELC (Synapse) IR-4.
[11] Response to RELC (Synapse) IR-17.

Q. Is the Utility's proposal for a storm cost budget allowance reasonable?

A. No, not at this time, as the costs are unsupported by any data. If the Utility is unable to absorb costs associated with storm recovery, it should submit a separate application to the Board.

VII. DEFERRAL ACCOUNT

Q. Please provide an overview of the Utility's proposed deferral account.

A. RELC proposes to maintain a deferral account to reflect any liability associated with power purchases from Nova Scotia Power commencing January 1, 2023, for which Nova Scotia Power has received or may receive approval from the Board to recover from RELC. If balances accumulate in this deferral account, RELC would later apply to the Board for approval to recover such balances through rates or rate riders.

Q. What concern is the deferral account intended to address?

A. In response to Synapse's IR-14(a), RELC explains that it is concerned that the Settlement reached in Nova Scotia Power's ongoing general rate application may result in rates that result in a shortfall for Nova Scotia Power and that will require RELC to make payments to Nova Scotia Power in a future year. If this occurs, RELC seeks the ability to recover such amounts from its customers through use of a deferral account.

Q. Does RELC have an approved flow-through mechanism that it could utilize instead of a deferral account?

A. While RELC notes that it has approval to flow through certain purchased power cost increases, it states that the formula is based on the past two years' purchases from Nova Scotia Power. Because RELC only purchased Back Up energy priced at marginal cost from Nova Scotia Power in the prior two years, RELC states that it "has not been determined that this mechanism could appropriately be employed."[12]

Q. Is the Utility's proposed deferral account reasonable?

A. RELC's proposal for a deferral account appears to be generally reasonable. Increased purchased power costs from Nova Scotia Power are both unknown and outside of RELC's control. Moreover, the deferral account would help to mitigate further rate increases in the near-term. Given that RELC's customers are facing considerable rate increases in 2023, a deferral account could help mitigate rate shock by deferring further rate increases for recovery in the future when purchased power costs are potentially lower. It is also not apparent that the existing flow-through mechanism could be leveraged in this case, as RELC previously purchased Back Up energy from Nova Scotia Power, rather than taking service on Nova Scotia Power's municipal rate.

Q. What do you recommend regarding the deferral account?

A. I recommend that the Board approve the RELC's deferral account proposal, but require that the Utility submit an application to the Board for approval to recover any amounts accumulated in the account over a period to be determined by the Board.

Q. Does this conclude your evidence?

A. Yes, it does.

[12] Response to RELC (Synapse) IR-14(a).