BEFORE THE NOVA SCOTIA UTILITY AND REVIEW BOARD

In the Matter of an Application by Nova Scotia Power Incorporated for Approval of Certain Revisions to its Rates, Charges, and Regulations

(NSUARB M10431)

Evidence of
Melissa Whited

On Behalf of
Counsel to Nova Scotia Utility and Review Board

June 7, 2022

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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 ("Synapse"), located at 485 Massachusetts Avenue, Cambridge, MA 02139.

Q. Please describe Synapse Energy Economics.

A. Synapse Energy Economics (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 and M10176.

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 this evidence?

- My evidence addresses certain aspects of Nova Scotia Power's ("NS Power" or "the Company") General Rate Application, including cost allocation, rate design, the proposed demand-side management (DSM) and storm cost riders, the interruptible credit update, and the proposed decarbonization deferral account.

II. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

Q. Please describe your conclusions.

A. My conclusions are as follows:

- The Company's proposed increases to the customer charge for domestic and small general customers are not reasonable, as the increases are based on a flawed cost of service methodology. Further, the proposed increases to the customer charge would dampen customer incentives to conserve energy and invest in energy efficient technologies, while potentially also harming low-income customers.
- The Company's concerns regarding rates that support beneficial electrification are better addressed through dedicated electrification rates.
- NS Power's proposed DSM rider is generally reasonable, provided that the presentation on customer bills is consistent with the approach adopted for other cost recovery mechanisms.
- NS Power's proposed storm rider is asymmetrical and therefore unreasonable. Data indicate that in many years the annual storm costs are far below the level the Company proposes to include in base rates. The Company's storm cost rider would not account for the cumulative surplus in storm cost revenues but would instead allow the Company to petition for additional cost recovery when annual costs exceed the allowance.
- The proposed decarbonization deferral account ("DDA") is not reasonable, as its scope extends far beyond accelerated retirement costs. The mechanism would become a catch-all for many types of investments that would be reviewed in a piecemeal fashion, rather than through a holistic review of the Company's costs. The DDA would also add complexity to the Company's cost accounting, and it is unnecessary given the provisions of Accounting Policy 6350.

Q. What are your recommendations?

A. I recommend that the Board:

- Reject the Company's proposed increases to the customer charge for domestic and small general classes. Instead, the customer charge should be maintained at current levels.
- Direct the Company to begin development of an electrification rate with stakeholder input within the next 12 months, with a proposal to be submitted to the Board within 24 months.
- Approve the Company's proposed DSM rider but require that the presentation of the rider on customer bills be consistent with other cost recovery mechanisms, rather than singled out as a separate line item.
- Reject the Company's proposed asymmetrical storm cost rider and instead approve a two-way tracking mechanism with a threshold of $20 million.
- Reject the Company's proposed DDA, and instead direct the Company to address the costs associated with early retirement of thermal assets through Accounting Policy 6350.

III. COST ALLOCATION

Q. Do you have any concerns regarding the Company's proposed cost allocation?

A. Yes. As discussed in more detail by Dr. Pavlovic, consultant to the Board Counsel, the Company's cost of service study employs the minimum-size method, which has several significant shortcomings. When this method is modified so that poles and wires are reclassified as demand-related, the results of the cost of service study change such that not all classes are within the desired revenue-to-expense band of 95–105 percent. In particular, the Small Industrial class's revenue-to-expense ratio falls from 98.79 percent to 93.28 percent, and the Medium Industrial class's ratio falls from 98.39 percent to 92.94 percent. Conversely, the Unmetered class's ratio increases from 100 percent to 106.05 percent.

Q. Do you propose any modifications to bring the revenue-to-expense ratios back within the 95–105 percent band?

A. Yes. I propose that revenues from the Small Industrial and Medium Industrial classes be increased above the Company's proposal by 1.8 percent and 2.2 percent, respectively, to bring these classes back within the 95–105 percent band. I also propose a decrease in revenues from the Company's proposal for the Unmetered and Large Industrial classes of 3.1 percent and 1.8 percent, respectively, as these classes have the highest revenue-to-expense ratios. These changes relative to the revenues proposed by NS Power are shown in the table below.[1]

Table 1. Synapse proposed adjustments to revenue allocation

	NS POWER REVENUE ALLOCATION PROPOSAL		SYNAPSE PROPOSED REALLOCATION		
	RATE REVENUE	% REVENUE TO EXPENSES	RATE REVENUE	% REVENUE TO EXPENSES	% INCREASE (DECREASE)
DOMESTIC	$813,617	101.27	$813,617	101.27	0.0%
SMALL GENERAL	$51,068	96.86	$51,068	96.86	0.0%
GENERAL	$337,298	98.58	$337,298	98.58	0.0%
LARGE GENERAL	$47,665	99.99	$47,665	99.99	0.0%
SMALL INDUSTRIAL	$36,501	93.28	$37,174	95.00	1.8%
MEDIUM INDUSTRIAL	$61,253	92.94	$62,614	95.00	2.2%
LARGE INDUSTRIAL	$82,273	103.12	$80,797	101.27	-1.8%
MUNICIPAL	$5,313	100.09	$5,313	100.09	0.0%
UNMETERED	$18,841	106.05	$18,284	102.91	-3.0%
TOTAL	$1,453,830	100.00	$1,453,830	100.00	0.0%

[1] Calculated based on removing minimum system method and resultant calculations in the Company's cost-of-service study as shown in SR-01, Attachment 2, Exhibit 10.

IV. RATE DESIGN

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

A. The Company proposes to increase the customer charges for the Domestic and Small General classes. For customers in the Domestic class on the standard tariff, the Company proposes to increase the current charge of $10.83 per month to $21.99 per month by 2024, with the increase occurring in three smaller increments. For Domestic class customers on the Time-of-Day tariff, the Company proposes an increase in the customer charge from the current $18.82 per month to $21.99 per month, similarly phased in over three years. For Small General customers, the Company proposes to increase the fixed charge in three steps from $12.65 per month to $24.07 by 2024.[2]

Q. What reasons does the Company provide in support of its proposal to increase these customer charges?

A. The Company cites three reasons for its proposed customer charge increases. It argues that increasing the customer charges is necessary to better align rates and costs, to reduce cost-shifting between customers and promote economic decision-making, and to correct the "artificially high energy price" that is an outcome of the current customer charges, which disincentivizes customers from investing in vehicle and building electrification.[3]

Q. Do you support the Company's proposed rate changes?

A. No, I do not. As I will explain in greater detail in my testimony, I do not agree with the Company that the proposed rate changes will result in more cost-reflective rates. Moreover, I am concerned about the implications of the proposed customer charge

[2] N-16(C), page 99 of 121.
[3] N-16(C), page 99 of 121.

increase on key policy priorities in Nova Scotia, including conservation, energy efficiency, and expansion of customer-sited renewable generation. I am also concerned about adverse impacts on lower-income customers. While I agree with the Company that rate design is important for promoting beneficial electrification, I conclude that it would be better for the Company to develop dedicated electrification rates rather than to seek to incentivize electrification through a radical increase to the customer charge for all Domestic and Small General customers.

Q. Why does the Company conclude that increasing its customer charges would make its rates more cost-reflective?

A. This conclusion is based on the Company's Cost of Service analysis, and more specifically, on the application of the minimum-size method to determine the share of distribution system costs that should be classified as customer-related. According to the Company's minimum-size analysis, the cost-reflective customer costs are $21.75 per month for the Domestic class and $24.45 per month for the Small General class.[4]

Q. Do you support the minimum-system method for cost allocation used by the Company in its analysis?

A. No. As explained in the evidence of Dr. Karl Pavlovic, the minimum-size method is not consistent with the principle of cost causation.

Q. Why does the Company conclude that an increase in the customer charge is needed to address cost-shifting?

A. According to the Company, cost-shifting is occurring under the current rate structure because the present customer charge does not recover enough of the "fixed" distribution

[4] SR-01 Att 02 PCON Updated, Exh 6.1.

system costs. Rather, an excessive share of these costs is recovered through variable rates. The result, in the Company's view, is that lower-usage customers are being subsidized by higher-usage customers.[5] As further evidence, the Company notes that only 13 percent of the fixed costs allocated to the Domestic and Small General classes are recovered through fixed charges.[6]

Q. Do you agree that the current customer charges do not recover enough of the fixed system costs?

A. No. The application of the flawed minimum-size method underlies both the Company's finding that its current rates are not cost-reflective and its conclusion that the current rate structure is producing cost-shifting. I do not agree with either of these findings. Moreover, in its claim that the current customer charges recover only 13 percent of system fixed costs from the Domestic and Small General classes, it appears that the Company is including all distribution system costs, including those that are plainly driven by peak demand.

Q. Should demand-driven system capacity costs be recovered through fixed charges?

A. No.

Q. How do the customer-related costs change when distribution poles and wires are classified as demand-related, rather than customer-related?

A. As shown in the evidence of Dr. Pavlovic, the customer-related costs decline to $7.88 per month for the Domestic class and $10.56 per month for the Small General class.[7]

[5] NSPI response to NSUARB IR-161(b).
[6] NSPI response to NSUARB IR-160(a).
[7] M10431 Evidence of Karl Pavlovic, Consultant to Board Counsel, June 7, 2022, p. 12.

Q. Are there other reasons to favor lower customer charges for Small General class and Domestic class?

A. As I noted above, increasing the customers' charges as the Company proposes to do could have deleterious impacts on conservation and other related customer incentives. The proposed rate changes may also adversely affect lower-income customers.

Q. How would the proposed increase in the customer charge impact customer incentives to reduce energy consumption?

A. All else equal, a higher fixed charge means lower volumetric rates for customers. This is turn reduces the incentive for customers to invest in distributed energy resources (DERs) or engage in efficiency or conservation, because these customers stand to gain (or save) less from reducing their electricity consumption. Put another way, increased fixed charges reduce the control that customers have over their bills and correspondingly worsen the economics of demand-side measures for customers.

Q. Does the Company address these impacts on customer incentives to save energy?

A. The Company raises the opposite concern, suggesting that customers may make "uneconomic" decisions and over-invest in DERs as a result of "inflated volumetric class energy charges."[8] The Company therefore evinces the view that a reduction in investment in DERs that could result from an increase in the customer charge would be desirable if the customer charge increase meant that the resulting rate structure were more cost-reflective.

[8] N-16(C), page 98 of 121.

Q. Why do you suggest that the proposed rate changes could adversely impact lower-income customers?

A. The proposed customer charge increase will increase the monthly bills of lower-usage customers by the greatest proportion. My concern about adverse impacts to this segment is based on the insight that lower-income customers tend to use less energy than do higher-income households. This means that lower-income customers will experience more significant bill increases on average as a result of the Company's proposed customer charge increase.

Q. How does the Company address impacts on low-income customers?

A. The Company indicates that it does not have information on the relationship between energy consumption and household income.[9] However, the Company offers that it has proposed to phase in the proposed customer charge increase over three years in order to mitigate impacts on customers.[10]

Q. Does the Company's phased approach for increasing the customer charge allay concerns about impacts on low-income customers?

A. No. The Company's proposed phased approach will not mitigate the disproportionately adverse impact of the proposed customer charge increase on low-income, low-usage customers. Further, even with the proposed three step phase-in of the customer charge increase for the Domestic class, the customer charge would still rise by an average of nearly 27 percent each year between 2022–2024. This is a substantial increase for all customers on this rate.

[9] Response to NSUARB 161(b).
[10] N-16(C), page 99 of 121.

Q. Do you agree with the Company that current rates are disincentivizing customer adoption of electric vehicles and other electric appliances such as heat pumps, electric thermal storage heaters, and water heating?[11]

A. While I do not agree with the Company's assessment of the deficiencies in its own rate structure, I do agree with the Company's basic economic observation. All else equal, lower volumetric rates should induce more customers to adopt electric vehicles and other beneficial electric technologies. Thus, supporting electrification through rate design can be an effective means for encouraging customers to adopt such technologies while mitigating the extent to which incremental load drives up system capacity needs and associated costs. For example, tariffs with lower volumetric charges can encourage beneficial electrification because customers who adopt technologies such as electric vehicles and heat pumps will typically increase their electricity consumption substantially.

I note that electrification rates may be time-differentiated or not. Where rates are time-differentiated, they provide enhanced price signals that can help encourage customers to utilize new technologies in a manner that avoids increasing peak demand.

Electrification rates that do not include time-differentiated elements may still provide reduced volumetric prices by increasing the fixed charge. However, such tariffs should only be implemented carefully, as higher fixed charges reduce customer incentives to adopt energy efficiency measures. Further, as noted before, low-income customers tend to have lower-than average usage and could be harmed by such a tariff. Thus, tariffs with

[11] Response to Synapse IR-8(a).

higher fixed charges should generally be limited to customers who have invested in beneficial electrification technologies.

Q. What do you recommend with respect to electrification rates?

A. I recommend that the Company continue to pursue the development of rates that would encourage customers to invest in beneficial electrification technologies while mitigating grid impacts.[12] In particular, I recommend that the Company leverage the results of its Time-of-Day pilot in designing such rates and seek to propose the new electrification rates as soon as possible rather than waiting for its next general rate case.

Q. Do you have any other recommendations related to the Company's rate design?

A. I recommend that the Company study whether the declining block rate structure for general and industrial class rates is still appropriate. Other jurisdictions have recently phased out declining block rates, often citing similar concerns about the conservation incentives. Further, declining block rates are often not cost-effective. The Board should require the Company to collect data and to report back in a short time with results concerning the cost reflectivity of declining block rates and their impacts on conservation.

V. DSM RIDER

Q. What is the Company proposing in terms of a DSM cost recovery rider?

A. The Company is proposing to implement a DSM cost recovery rider to recover the costs of DSM programs implemented by the third-party program administrator, EfficiencyOne.

[12] Response to Synapse IR-8(c-d).

Each year, the rider would be updated with the budget for the upcoming year. Any under- or over-recoveries caused by deviations in actual costs or sales volumes would be recovered or refunded through a true-up mechanism (the balance adjustment, or "BA").[13] NS Power expects that the DSM rider would be presented as a separate line item on customer bills.[14]

Q. What rationale does the Company provide for the DSM cost recovery rider?

A. The Company is proposing the DSM cost recovery rider to better align recovery of DSM costs with actual program costs, rather than the positive or negative variances from cost forecasts accruing to NS Power. The Company notes that in its current application, it forecast DSM spending levels of $39.0 million for 2023 and 2024. Subsequently, EfficiencyOne filed a DSM application for spending levels of $53.1 million and $57.5 million for 2023 and 2024—a difference of nearly $33 million over two years.[15]

Q. Is the Company's proposal for a DSM cost recovery rider reasonable?

A. Generally, yes. Variances in actual DSM costs from those forecast by the Company or approved by the Board are not within the Company's control, and such variances may be rather large, as shown in the example above. However, it is not appropriate to present the rider as a separate line item on customers' bills unless this approach is applied equally to all other riders and rate adjustments, such as the fuel adjustment mechanism, storm cost rider, and amortization of DDA costs.

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[13] N-17(C), Appendix 12A, page 41.
[14] NSPI (NSUARB) IR-188.
[15] NSPI (NSUARB) IR-12.

Q. What do you recommend regarding the DSM cost recovery rider?

A. I recommend that the Board approve the rider as proposed but direct the Company to include any rider adjustments in the overall rates, rather than presenting them as a separate line item.

VI. STORM RIDER

Q. Please provide an overview of the Company's proposed storm rider.

A. NS Power proposes to include a base rate allowance for storm costs. The allowance for Level 1/Level 2 storms would be approximately $7.5 million annually, while the allowance for Level 3/Level 4 storm costs would be $10.3 million in 2022, $10.0 million in 2023, and $10.2 million in 2024. The Level 3/Level 4 storm cost allowance is based on the average storm restoration expense over the past five years, excluding the extreme event of Hurricane Dorian in 2019.[16] The Company proposes that if annual Level 3/Level 4 costs exceed the amount forecast, the Company would have the option of applying to the Board to recover the shortfall through the storm rider.[17]

Q. Would the storm rider also credit customers if the Company did not spend the forecasted level of costs?

A. No. The Company's proposal is asymmetrical in that it allows the Company to petition the Board for recovery of any Level 3 and Level 4 storm costs in excess of the amount included in revenue requirements but does not provide for credits to customers in the

[16] N-16(C), p. 104.

[17] The Company proposes that costs eligible for recovery under the rider include all non-capital preparation, response, and restoration Level 3/Level 4 storm costs. N-17(C), Appendix 12A (Concentric GRA Pricing Evidence), page 32.

event that the amount spent is less than the amount forecasted. The proposal also ignores the cumulative impacts of exceeding or underspending the annual storm cost allowance.

Q. If the storm rider had been applied to historical storm costs, what would have been the outcome?

A. Based on data for 2016–2020, the average annual Level 3 and Level 4 storm costs were $13.4 million.[18] For this timeframe, and assuming an annual allowance of $10.2 million, the Company would have had a deficit in its storm fund of $17 million at the end of the six-year period. However, storm costs are extremely volatile, and using a longer timeframe paints an entirely different picture. Over the period 2010–2021, Level 3 and Level 4 storm costs averaged only $7.5 million per year.[19] Thus, an annual allowance of $10.2 million would have produced a cumulative surplus for the Company of $32.8 million by the end of the 12-year period. The Company's proposed storm rider would not have accounted for this surplus, but instead would have allowed the Company to petition the Board for additional cost recovery in the two years in which storm costs exceeded the annual allowance. This is shown in the table below.

[18] Appendix 12A, Concentric (Dane & Rimal) GRA Pricing Evidence at page 33.
[19] Analysis of data provided in NSPI (NSUARB) IR-167 Attachment 1, page 1 of 9.

Table 2. Level 3 and 4 Storm Costs (Millions $)

Year	Level 3 & 4 Storm Costs	Approximate Storm Cost Allowance	Annual Surplus (Deficit)	Cumulative Surplus (Deficit)
2010	$9.2	$10.2	$1.0	$1.0
2011	$1.2	$10.2	$9.0	$10.1
2012	$0.0	$10.2	$10.2	$20.3
2013	$0.0	$10.2	$10.2	$30.5
2014	$6.7	$10.2	$3.5	$34.0
2015	$4.2	$10.2	$6.0	$40.0
2016	$10.2	$10.2	$0.0	$40.0
2017	$6.4	$10.2	$3.8	$43.8
2018	$19.0	$10.2	-$8.8	$34.9
2019	$22.3	$10.2	-$12.1	$22.8
2020	$9.1	$10.2	$1.1	$24.0
2021	$1.4	$10.2	$8.8	$32.8

Source: Analysis of data provided in NSPI (NSUARB) IR-167 Attachment 1, page 1 of 9.

Q. Is the Company's proposed storm rider reasonable?

A. No. As a general rule, riders should be used sparingly, as they reduce a utility's incentive to operate efficiently. Under traditional ratemaking, the utility must live within its allowed revenue requirement, which encourages the utility to find cost efficiencies. However, it is clear that Level 3 and Level 4 storm costs have been highly volatile in recent years, and that only addressing instances where storm costs exceed the allowance in rates may be undesirable because it would only focus on one side of the variance in costs. Thus, a rider can be a reasonable method for recovering major storm costs that are largely outside the control of the utility. However, I cannot support the Company's proposal, as it is asymmetrical and would unfairly benefit utility shareholders at the expense of ratepayers.

Q. What do you recommend instead?

A. Instead, I recommend that the Company's proposed storm cost rider be modified to use a symmetrical (two-way) tracking mechanism. Under this mechanism, actual expenditures would be tracked above or below the amount included in base rates. If actual storm costs exceed the amount in base rates, the difference would be recorded as a regulatory asset, while if the actual costs were less than included in rates, the difference would be recorded as a regulatory liability. Balances would be carried forward from year to year until the Company's next rate case, or until the balance reached $20 million, positive or negative. At that time, the balance would either be refunded to customers through rates, or the Company would be allowed to petition the Board for recovery of its prudently incurred costs that exceeded the allowance. Following a prudency determination, the balance would be amortized and recovered over a reasonable period, as determined by the Board.

Q. What are the benefits of your proposed two-way storm cost tracker over the Company's proposal?

A. Under the Company's proposal, there is no mechanism for tracking or returning amounts below the base rate allowance to customers; there is only a mechanism for allowing the Company to petition the Board for costs exceeding the allowance. A two-way storm cost tracker would account for costs both exceeding and below the allowed amount and track the cumulative balance. It would then only allow the Company an opportunity to recover costs when the cumulative balance exceeded a significant threshold. Further, revenues far exceeding actual costs would be refunded to customers.

Q. How did you determine a threshold of $20 million?

A. The $20 million amount represents approximately 1.3 percent of the Company's annual revenue requirement. Adjustments to rates to collect this amount would therefore be relatively small, so as to avoid significant rate impacts. Further, based on data from 2010– 2021, a threshold of $20 million would have allowed for three rate adjustments over 12 years to reflect over- or under-recovery of actual costs, which is a relatively manageable number of adjustments from an administrative perspective.

VII. DECARBONIZATION DEFERRAL ACCOUNT

Q. Please describe the Company's Decarbonization Deferral Account.

A. Federal Government and Provincial Government environmental goals and regulations require that NS Power retire its coal-fired assets and provide 80 percent of electricity from renewable generation by 2030.[20] The Company is seeking approval for the establishment of a regulatory asset that will include:

- Deferrals of incremental depreciation expense required to allow for full recovery, by year-end 2029, of the net book value of the Company's coal fired assets;[21]
- Accelerated decommissioning costs related to decommissioning thermal assets sooner;[22]
- Renewable generation asset and integration costs (or savings) that are incremental (or decremental) to the Company's revenue requirement and directly related to the energy transition;[23] and
- Transition costs including employee retraining or severance costs, fuel contract termination costs, and obsolete materials inventory.[24]

[20] N-16(C), page 48.
[21] N-16(C), page 48.
[22] Appendix 7A (John Reed DDA Evidence), p. 23.
[23] Appendix 7A (John Reed DDA Evidence), p. 24.
[24] Appendix 7A (John Reed DDA Evidence), p. 24.

NS Power proposes to include the DDA regulatory asset in rate base as the balance accumulates.[25] Currently, the Company estimates it will transition $372.3 million of net plant to the DDA by 2024.[26] However, this does not include amounts associated with several other generating units,[27] and it is subject to change as the Company refines its resource plan.[28] In addition, the Company proposes to reduce the DDA balance if any federal decarbonization or renewable energy funds become available, and by applying customers' share of any earnings that exceed the approved ROE band.[29]

Q. When would the costs accrued in the DDA be recovered from ratepayers?

A. The Company has not proposed a timeframe for recovery of these costs. Instead, it proposes to make a separate filing, most likely in a subsequent general rate application, where the amortization period would be determined subject to Board approval.[30] Regardless of the ultimate timeframe for cost recovery, the creation of the DDA would not impact the Company's revenue requirement in this proceeding.

Q. Why does the Company propose to recover the accelerated depreciation costs through a regulatory asset?

A. Assets are typically depreciated over their useful lives, which allows the owner to recover the cost of the investment by the time the asset is taken out of service. Sometimes, however, assets must be retired early. In this case, a key driver for retirement of certain

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[25] N-16(C), page 50.
[26] N-16(C), Figure 7-2, page 51.
[27] The Company states that it has not yet determined the timing of retirement for all of its units. The $372.3 million net plant estimate does not include amounts associated with Point Tupper Generation Station, Trenton Unit 6 and common plant, Tufts Cover Unit 3 and common plant, the Port Hawkesbury Biomass Plant, or the Company's combustion turbine fleet, as these assets are not currently planned for retirement by 2029. *See:* N-16(C), page 50.
[28] N-16(C), page 50.
[29] Appendix 7A (John Reed DDA Evidence), p. 25.
[30] Appendix 7A (John Reed DDA Evidence), p. 24.

thermal assets is a change in Federal and Provincial policy. The Company's proposal to accelerate depreciation of its coal plants and recover such costs through a regulatory asset would allow the costs to be recovered over a different timeframe than the remaining useful life of the assets. The Company claims that this approach provides greater flexibility to balance the impact on rates with the timely recovery of the assets.[31]

The Company clarifies that while the depreciation expense for these assets for the 2022–2024 revenue requirement would be calculated and recovered in rates in accordance with currently approved depreciation rates, the DDA account would accumulate additional expense associated with the accelerated depreciation of the assets by their expected retirement date, representing movement of the unrecovered amounts (the net book value) from plant-in-service to a regulatory asset.[32] Thus, the DDA will record the difference between the accelerated depreciation expense associated with the shortened economic lives of coal-fired assets and the depreciation expense currently reflected in base rates.[33]

Q. Why is the Company proposing to use the DDA to recover costs associated with the transition to renewables, rather than including such costs in its revenue requirement?

A. The Company claims that these costs "cannot be determined with sufficient confidence at this time."[34]

[31] N-16(C), page 49.
[32] N-16(C), page 49.
[33] Appendix 7A (John Reed DDA Evidence), p. 23.
[34] N-16(C), page 49.

Q. Would renewable resource costs be reviewed and subject to approval by the Board prior to being recovered through the DDA?

A. Yes. Witness Reed states that costs including depreciation expense, OM&G expenses, financing costs, and tax impacts recovered from the DDA would result from "analysis and determinations made in the Company's subsequent applications for approval of capital items or reconciliation of the DDA, and therefor subject to scrutiny in future regulatory proceedings and to NSUARB approval."[35]

Q. Is the Company entitled to full recovery of any assets that are retired early?

A. No. Assets that are no longer used and useful are removed from rate base. If an asset was prudently incurred, the utility may recover the remaining book value of that asset but is not necessarily allowed to earn a rate of return on the remaining asset value. For example, in the Board's decision in M08349 regarding the recovery of costs associated with retired meters, the Board found that NS Power "should not earn a return on assets that are no longer used and useful."[36]

Q. Is the Company's DDA proposal reasonable?

A. No. A regulatory asset can be a reasonable approach for recovering certain types of costs, but it should be used only where there is a demonstrated need for such an approach, such as for costs that would otherwise be stranded due to changes in legislation or regulatory policy. In contrast, the Company has proposed an extremely broad mechanism that would serve as a catch-all for many types of investments that are not yet well-defined. Such costs would be moved into rates outside of a general rate case proceeding without a

[35] Appendix 7A (John Reed DDA Evidence), p. 24.
[36] Nova Scotia Utility and Review Board, M08349 Decision, June 11, 2018, paragraph 178.

corresponding review of changes to other types of costs, resulting in piecemeal ratemaking. Further, the mechanism would increase the complexity of NS Power's cost accounting. Finally, a separate mechanism for recovering costs associated with accelerated depreciation is not needed, as Accounting Policy 6350 already provides a flexible means for recovering the accelerated depreciation expense associated with the early retirement of thermal generation and related assets.

Q. Is it reasonable to permit the Company to earn a return on the net book value of assets that are retired early?

A. Yes, it is reasonable for the Company to earn a return on assets that were prudently incurred, previously approved by the Board, and retired early to comply with new environmental mandates.

Q. Please elaborate on your concerns with the scope of the Company's proposed DDA.

A. The Company proposes to include the cost of new investments, such as new renewable resources, transmission and distribution facilities, and grid modernization in the DDA. This is a wide range of costs covering numerous aspects of the Company's business and the extent of which is currently unknown. Some of these costs, such as replacement power costs, are directly related to the requirement that NS Power transition to 80 percent renewable energy by 2030, while others are only tangentially related, such as grid modernization costs.

In practice, it will be difficult to constrain the types of costs that the Company seeks to recover through the DDA as the Company transitions to a modern, decarbonized energy grid along with the rest of the country. It is unreasonable to upend the traditional ratemaking paradigm to accommodate all of these costs, particularly since the Company already uses future test-years to set its revenue requirements and has the ability to recover the costs associated with assets that are no longer used and useful through alternative mechanisms.

Q. Please explain your concern that the DDA would treat costs in a piecemeal fashion.

A. "Piecemeal ratemaking," or "single-issue ratemaking" refers to adjusting rates to account for one type of cost while ignoring other changes in costs. Although the Company proposes that the DDA would also reflect cost reductions in categories of costs that are also linked to the energy transition,[37] the DDA would not account for cost reductions in other areas of operations. Piecemeal ratemaking therefore has the potential for abuse and may result in rates that are no longer just and reasonable. Therefore, I recommend that the costs of future investments should be considered holistically in a general rate application, rather than on a piecemeal basis in individual applications.

Q. What is the advantage of considering such costs within a general rate application?

A. A general rate application allows for the consideration of both increases and decreases in costs (whether in a related cost category or not), while also considering the allocation of costs across rate classes, the allowed rate of return and capital structure, and changes to rate design. Allowing a utility to recover costs through mechanisms outside of a general rate application does not allow for consideration of these other ratemaking aspects.

[37] Appendix 7A (John Reed DDA Evidence), p. 24.

Q. How would the proposed DDA increase complexity of cost accounting?

A. The DDA would add another layer of complexity to NS Power's cost accounting, with some renewable costs recovered through the DDA, some recovered through the fuel adjustment mechanism, and others recovered through the base rates.

Further, under the Company's proposal, the DDA would capture costs associated with the accelerated depreciation of thermal assets, as well as additional capital investments, OM&G expenses, labor costs, and various other types of costs over the energy transition. The DDA would therefore mix multiple types of costs, with various standards of accounting treatment, in one account. This undermines the transparency of costs in the account—a key purported benefit of the DDA.

Q. Is the DDA required to provide flexibility in terms of the timing of cost recovery?

A. No. The Company argues that its proposed DDA allows for flexibility in terms of the timing of cost recovery rather than simply depreciating the remaining plant balances over the shortened life of the assets, which allows for consideration of rate impacts on customers. While I agree that this flexibility is important, there already exists such a flexibility for assets that are no longer used and useful in the form of Accounting Policy 6350. According to the Company, the undepreciated cost of the asset would be amortized "over five years or over a reasonable period, subject to UARB approval." Thus, the Company should utilize this existing mechanism to recover the costs of assets that are retired before the end of their useful life.

Q. What do you recommend regarding the DDA?

A. I recommend that the Board reject the Company's proposed DDA and instead direct the Company to utilize Accounting Policy 6350 to amortize the remaining balance on the assets that are retired early.

Q. Does this conclude your testimony?

A. Yes, it does.