Request IR-1:

Refer to GRA Appendix 12A, Cost of Service Study Process, section 3.1. How does the Company define customer-related costs?

Response IR-1:

Please refer to the description of NS Power's Cost of Service Methodology, included in SR-01 Attachment 1a, which provides as follows.

> Customer-related costs are those costs that vary with the number of customers served. Examples of these costs include retail operating and maintenance (O&M) costs of customer care representatives in the Company's contact and billing centres or the capital-related costs of certain elements of distribution infrastructure such as customer meters, service drops or that portion of the feeder investment which is driven by the need to bring electric service to geographically dispersed customer locations.[1]

The Company's definition aligns with that provided in NARUC Electric Utility Cost Allocation Manual which defines customer costs as those which are directly related to the number of customers served[2] and also as those distribution system costs which under the Minimum-Size Method, if adopted in the cost of service studies for treatment of distribution costs as is the case with NS Power, classify a portion of costs of poles and wires associated with a minimum loading requirements of the customer as customer-related[3].

For more detailed discussion of the customer-related distribution costs under the Minimum-Size Method used by NS Power please refer to Section 6.2.2 of the Elenchus Report included in Appendix 12B. Also, Section 7.1 of the Elenchus Report provides a rationale for classification of all retail costs of NS Power to the customer-related category.

[1] SR-01 Attachment 01a, page 4, lines 13-18.
[2] NARUC Electric Utility Cost Allocation Manual, January 1992, B Classification of Costs, page 20.
[3] NARUC Electric Utility Cost Allocation Manual, January 1992, A. The Minimum-Size Method page 90 and 91.

Request IR-2:

Refer to GRA Appendix 12A, Cost of Service Study Process, section 5.1.

(a) Describe and provide all sensitivity analysis and modelling the Company has conducted to conclude that "increased granularity would not necessarily create a more precise or effective COSS."

(b) Explain narratively how the results of the analyses provided in part (a) demonstrate that "increased granularity would not necessarily create a more precise or effective COSS."

(c) Provide examples of inconsistencies within the COSS that may begin to arise due to increased granularity.

(d) What proportion of the Company's generation assets does the proposed SLF approach classify to energy and what proportion to demand?

(e) Identify the tab and cells in the Company's COSS (SR-01 Attachment 2) or other attachment that calculate the SLF. If not already provided, provide all underlying data supporting the calculation, in live, unlocked Excel file format with all links and formula intact.

(f) What proportion of the Company's generation assets would the Company's current generation classification approach to classify to energy and what proportion to demand? Provide all underlying data supporting the calculation, in live, unlocked Excel file format with all links and formula intact.

(g) In live, unlocked Excel file format with all links and formula intact, please provide an alternate version of the COSS (for each of 2026 and 2027) using the Company's current generation classification.

Response IR-2:

(a) The statement is meant to highlight that increased granularity does not always result in a more precise or effective COSS. COS studies are meant to provide fairness and transparency and provide a basis for rate design. Increasing the level of granularity can create drawbacks if it becomes excessively detailed and complex for stakeholders to understand. It also can contribute to rate volatility. Both issues are addressed and mitigated through the use of a revenue to cost ratio range of 95 to 105. In addition, some costs are difficult to measure precisely. Using a high degree of mathematical precision to allocate costs that are uncertain can lead to a seemingly exact number that may not be any more accurate than a less granular model.

(b) Please refer to part (a).

(c) In adoption of a generic approach to the treatment of generation costs in its COSS, NS Power was guided by simplicity, existing precedents in Canadian electric utility industry, and rate stability. Under a granular approach there is a potential for a bigger fluctuation in assigned generation costs to rate classes due to variation in the ratio of classified generation costs to energy and demand in reflection of the changing generation mix from one rate case to another. At the time of conversion from fossil fuel-generation to renewable sources of generation, where the replaced generation is retained in the interim to provide a limited capacity service, the granular functionalization and classification of generation may result in unnecessary fluctuation of assigned costs to rate classes, and therefore fluctuation in rates paid by customers between rate cases. This would happen because rate classes differ in their cost sensitivity to the amount of investment classified to energy versus demand. The class cost fluctuations, although reflective of the short-lived changes in generation mix arrangements, would provide signals to customers to change their usage of energy and demand which would not bring any long-term reductions in system costs as they are driven by other than customer consumption considerations such as environmental policies, for example.

(d) The proportions of the Company's generation assets classified to energy and demand under the proposed SLF approach are 54.7 percent and 45.3 percent in 2026 and 51.8 and 48.2 percent in 2027, respectively. The shift in these proportions between these two test years is due to displacement of PHP's energy purchases of 0.5 TWh, which represents 5 percent of the total system load, from NS Power with a third-party owned wind generation in 2027.

(e) Please refer to cell J24, "Exh 9a Annual" tab of 2026-2027 GRA SR-01 Att 02 PCON and 2026- 2027 GRA SR-01 Att 03 PCON

(f-g) Please refer to cells I25 and J25 in Exh 2b of the 2026 COSS and 2027 COSS, included in Confidential Attachments 1 and 2, for the portion of the Company's generation assets classified to energy and demand under the current approach.

Please refer to the 2026 and 2027 COS fuel cost calculations, included in Confidential Attachments 3 and 4, for the fuel cost allocation results under the current methodology for generation classification. Attachment 5 includes summary comparing class cost allocation results between these calculations and those filed in NS Power's Application on September 17, 2025.

2026-2027 GRA Synapse IR-02 Confidential Attachment 1 has been removed due to confidentiality.

2026-2027 GRA Synapse IR-02 Confidential Attachment 2 has been removed due to confidentiality.

2026-2027 GRA Synapse IR-02 Confidential Attachment 3 has been removed due to confidentiality.

2026-2027 GRA Synapse IR-02 Confidential Attachment 4 has been removed due to confidentiality.

2026-2027 GRA Synapse IR-02 Attachment 5 has been filed electronically.

Request IR-3:

Refer to GRA Appendix 12B p.24. Explain and provide examples of how the current methodology would cause "materially different rate impacts to different classes depending on when investments in those assets take place." How might the rate impacts differ across NSPI's various classes?

Response IR-3:

Under the current granular approach, classification of generation costs would be subject to more variation between rate cases as the Company continues to make its transition to cleaner and greener, non-dispatchable sources of generation such as wind and solar in the next decade. In the initial stage of this transition as wind generation replaces energy produced by steam generation made up of coal- and oil-fired baseload generation, more of total generation costs would be classified to generation as 82 percent of wind investment is being classified to energy versus 74 percent of coal under the granular approach.[1] In the later stage as new gas-dispatchable generation and energy storage start displacing capacity provided by the current steam generation (which would operate in the interim at lower capacity factors) leading to their complete retirement, there might be a reversal of this trend resulting in a decrease in the overall amount of investment in generation classified to energy. Please refer to "Classification of Generation" section of Technical Conference No. 4 presentation from April 10, 2024 in Appendix 12A(3) (pages 112 to 122).

Rate classes with lower load factors, such as residential and small commercial customers, would experience lower costs in the early stage of conversion followed by higher costs later compared to the cost changes they would have experienced under the generic approach proposed in this Application. The reverse would be true for higher load factor classes, such as the Large Industrial class.

[1] Please refer to slide on page 121 of "Classification of Generation" section of Technical Conference No. 4 presentation from April 10, 2024 in Appendix 12A(3) for graphical presentation of the long-term trend of generation mix at NS Power.

Request IR-4:

Refer to GRA Appendix 12A, Cost of Service Study Process, section 5.3.

(a) Provide the Board's Decision on the Cost of Service proceeding in 1995 (NSPI864).

(b) Explain why reduced dependence on coal fired generation located in Cape Breton is making classification of transmission based on SLF less relevant over time.

(c) The Company states that "Transmission costs…can be thought of as being incurred solely for the purpose of providing the required capacity on the system to respond to…demand." Explain why the Company does not think of transmission as providing energy.

(d) Explain how the shift to wind generation moves the system from radial to network design. Use map(s) of the Company's system to illustrate this change.

(e) If not provided in part (d), provide a map or illustration of the Company's system demonstrating how the Company's network system design intends "to connect multiple renewable generation sites."

(f) Does the Company consider its wind generation to be "distant generation sites"? Why or why not?

(g) Explain why system demand will increasingly be the driver of NS Power's system costs as the system changes to accommodate more renewable energy.

(h) Is NSPI's transmission system designed to minimize energy losses? Explain why or why not.

(i) Is NSPI's transmission system designed to function over extended hours of high loading? Explain why or why not.

(j) In live, unlocked Excel file format with all links and formula intact, please provide an alternate version of the COSS (for each of 2026 and 2027) using SLF to classify transmission costs into demand and energy.

Response IR-4:

(a) Please refer to Attachment 1.

(b) As coal-fired baseload generation, predominantly located in Cape Breton, is being gradually replaced by both non-dispatchable renewable resources and new dispatchable generation sources located all over the province, the radial nature of NS Power's current transmission corridor between the center of production in Cape Breton and center of consumption in Halifax, will be gradually replaced by a network type of transmission system connecting distributed sources of generation, in many cases located in closer proximity to centers of consumption. The presence of network type of transmission lessens the argument used by the Board in its 1995 COSS decision that transmission should be seen as an extension of baseload generation and therefore be classified in the same manner. Please refer to "Classification of Transmission" section of Technical Conference No. 4 presentation which took place as part of the COSS stakeholder process, from April 10, 2024 in Appendix 12A(3) (pages 123 to 126). The COSS stakeholder process involved customer representatives (including their consultants), NSEB staff, NSEB Counsel and Synapse.

(c) A common view in the North American electric industry is that transmission costs are driven by the capacity of transmission wire conductors as its costs are primarily a function of the physical size of the conductor and not its length. This is particularly true of the network type of transmission system that will gradually replace the current radial nature of

NS Power's transmission system. The transmission system is designed and operated to meet peak system demand requirements. The associated costs are driven by the system peak demand; the amount of energy that is delivered through the transmission system does not materially impact the costs that need to be incurred to serve that peak, which are in turn recovered from ratepayers. Most Canadian utilities[1] as well as the Open Access Transmission Tariff (OATT) classify all transmission costs to demand.

Please refer to section **5.2.1 General Transmission** in Elenchus Report in Appendix 12B for discussion of this matter.

(d) Choice of location for wind generation farms is motivated in part by the presence of appropriate wind project development conditions including wind regime, the availability of land, setbacks from communities, distance from suitable transmission facilities, and costs of integrating the wind farm into the NS Power transmission system (i.e., cost of Network Upgrades). To accommodate wind generation projects new transmission lines and substations often need to be constructed from existing transmission corridors to the associated interconnection customer substations, expanding the current transmission system and spreading out generation resources across the province.

(e) Please refer to Attachment 2, which depicts current and planned major transmission and generation facilities in Nova Scotia. In this image the more distributed nature of wind facilities can be observed relative to that of existing coal generation stations in Cape Breton and Trenton. In addition, the map on NS Powers website, Clean Energy Sources| Nova Scotia Power, also depicts the locations of current wind farms in Nova Scotia, including distribution connected facilities, and how they are distributed around the province. For future wind or other generation facilities System Impact Studies (SIS) identify the needed network upgrades and interconnection facilities for each site. The requirements vary by study, and which upgrades advance depends on which generators are built. SIS studies can

[1] Appendix 12B Elenchus Report, 5.2.1.3 Elenchus Opinion

be found on the OASIS site at [Generator Interconnection Study Reports| Nova Scotia Power]; this listing notes the county in which each facility is located, highlighting the geographic diversity of proposed new facilities.

(f) The Company does not consider its wind generation to be "distant generation sites". The phrase "distant generation sites" was used in evidence to describe the proximity of coal facilities in Cape Breton relative to the provincial load centre, Halifax. While some wind farms are located in Cape Breton, the majority of the installed wind capacity is on the mainland. In addition, rather than the majority of the generation being centralized in a small number of locations, as with the current thermal generation fleet, existing and proposed wind farms are distributed around province which in general places the generation closer to the communities it is used in.

(g) Historically NS Power's transmission system was built to the capacity necessary to enable the flow of energy from coal fired thermal generation units in Cape Breton and Trenton to the province's load centre in Halifax. This generation was dispatchable up to nameplate capacity under normal system conditions. Displacing the energy and capacity provided by these thermal plants with a larger penetration of variable renewable generation (e.g. wind) requires a much larger generation fleet capacity. At present, the Effective Load Carrying Capability (ELCC) of new wind resources is 10 percent of nameplate capacity. In other words, to obtain 10 MW of firm capacity from wind requires the installation of 100 MW of wind generation capacity, along with all required interconnection facilities and network upgrades. In addition, new synchronous condensers, fast acting gas/oil fired combustion turbines, and battery storage systems are required to integrate the variable generation and to provide the essential grid services needed to maintain the stability of the transmission system, all of which had previously been provided by the thermal units.

As such, a peak demand growth, driven by the growing electrification in the province, will necessitate investments in new firm capacity and the transmission expansion necessary to support this new firm capacity.

(h) NS Power's transmission system was built to enable the flow of energy from coal fired thermal generation units in Cape Breton and Trenton to the provinces load centre in Halifax. Nova Scotia had an abundant supply of coal, and generation was built as close to that supply as practical and not specifically to minimize transmission losses. In the Valley and Western regions, transmission was primarily built to serve load and to enable use of the available run of river hydro resources.

(i) NS Power's transmission system assets (conductors, switches, breakers) are designed to run continually at 100 percent of their rated values. The rating of any line is restricted to the most limiting component, device, or protection rating on that line. Transmission lines in Nova Scotia Power's system are designed to operate within their thermal ratings during N-0 (normal) system conditions, and within emergency limits under N-1 (first contingency) conditions.

(j) Please refer to the 2026 COSS and 2027 COSS included in Confidential Attachments 4 and 5 as well as the summary of the cost allocation results to rate classes in Confidential Attachment 3.

Rose

DECISION **NSPI864**

NOVA SCOTIA UTILITY AND REVIEW BOARD

IN THE MATTER OF THE PUBLIC UTILITIES ACT

- and -

IN THE MATTER OF A GENERIC HEARING respecting **COST OF SERVICE AND RATE DESIGN** for **NOVA SCOTIA POWER INC.**

BEFORE: R. A. Robertson, F.C.A., Chairman
L. D. Garber, Vice-Chair
J. L. Harris, Q.C., Member
M. G. Johnson, F.C.A., Member

COUNSEL:

NOVA SCOTIA POWER INC.
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STORA FOREST INDUSTRIES LTD.
George Cooper, Q.C.

SCOTT MARITIMES LIMITED
John Stringer, LL.B.

BOWATER MERSEY PAPER COMPANY LTD.
Gerald Godsoe, Q.C. and Charles Reagh, LL.B.

ECOLOGY ACTION CENTRE
Howard Epstein, LL.B.

SOLAR NOVA SCOTIA
Norval Balch, Ph.D.

KENTVILLE ELECTRIC COMMISSION
Dennis Kehoe, P.Eng.

THE BOARD
S. Bruce Outhouse, Q.C.

DECISION DATE: **September 22, 1995**

Document: 18822

WITNESSES: **NSPI**
L. J. Sweett, P. Eng., Vice President
A.E. Dominie, Manager Rates & Regulations
Larry Brockman, EMA Consultants

NOVA SCOTIA UTILITY AND REVIEW BOARD
George C. Baker, P.Eng., Hiltz & Seamone
John Chamberlin, Ph.D.
Executive Vice President, Barakat and Chamberlin Inc.

FORMAL INTERVENORS

Stora Forest Industries Ltd.
Scott Maritimes Limited
Robert Sarikas, Ph.D.
Senior Vice President, Foster Associates, Inc.

Bowater Mersey Paper Company Ltd.
Sharon Chown and Robert Knecht
Industrial Economics, Incorporated

Ecology Action Centre
Howard Epstein, LL.B., Executive Director

Solar Nova Scotia
Norval Balch, Ph.D., Chairman

Kentville Electric Commission
Dennis Kehoe, P.Eng., Director, Electric Operations

INFORMAL INTERVENORS:

I.W.K. Children's Hospital
Mr. William Fisher and Mr. Frank Fahey

Camp Hill Medical Centre
Mr. Charlie Roberts

Investment Property Owners Association of Nova Scotia
Ms. Sonya Meisner and Mr. Alan Renfrew

Wentworth Valley Limited Partnerships
Mr. Peter Wilson

Various Municipal Utilities
Mr. Dennis Kehoe, P.Eng.

INTRODUCTION

Nova Scotia Power Inc., hereinafter referred to as "NSPI" or the "Company", pursuant to a Board Order dated November 10, 1992, submitted evidence on various aspects of Cost of Service and Rate Design. The evidence was heard by the Board after due public notice, commencing on April 26, 1993 and continuing on April 27, 29 and 30 and May 3, 4, 5, 6 and 7, 1993.

Three witnesses appeared for the Company, two for the Board, six for Formal Intervenors, and seven witnesses gave evidence on behalf of the Informal Intervenors. The names and occupations of the various witnesses are shown on the preceding page. A number of letters were received by the Board which expressed views on the matter.

In its IRP Order NSUARB-P-865, dated March 8, 1994, the Board directed NSPI to utilize its proposed cost of service methodology for study purposes, with the modification that all costs associated with the fuel conversion to coal at Point Tupper and costs associated with environmental compliance be charged to energy. The Board also ordered the Company to undertake an investigation into Cost Reducing Rate Designs that were consistent with the approach outlined in a National Association of Regulatory Utility Commissioners (NARUC) report entitled "Aligning Rate Design Policies With Integrated Resource Planning".

The Board has determined that changes in rate structures should be reviewed in the upcoming NSPI rate hearing and addresses only Cost of Service methodologies in this decision.

In the Notice of Public Hearing dated January 11, 1993 the Board outlined the following four primary areas relating to Cost of Service Methodology to be addressed during the generic hearing:

1. Methods of attributing costs to functions of generation, transmission and distribution,

2. Methods of relating costs of electricity to demand, energy use and number of customers served,

3. Methods of allocating costs on a seasonally-differentiated basis, and

4. Methods of allocating costs to customer classes.

The Company, in its prefiled evidence, proposed the following:

1. The use of the Equivalent Peaker method for calculating the energy/demand classification split for production costs.

2. The unbundling of transmission from production cost, and the identified demand cost to be allocated on the basis of a three coincident peak (3CP) methodology.

3. A modification of the presentation of the results of the Cost of Service Study to show separately, by class, the classified energy, demand and customer costs.

4. The allocation of fuel costs on a monthly rather than an annual basis.

5. If the Equivalent Peaker approach is rejected, the allocation of "average costs" (energy related costs) and "excess costs" (demand related costs) be made on an average demand and 3CP demand approach respectively.

6. The determination of seasonal costs as reflected in the Equivalent Peaker Study.

The evidence and arguments presented by NSPI, the Intervenors and the Board on these matters are addressed under the following headings:

Functionalization	-	the categorization of assets and other accounting costs by utility function i.e. production, transmission, etc.
Classification	-	the identification of rate-base fixed assets as either demand, energy or customer related costs.
Allocation	-	the assignment of costs to each customer class.
Seasonality	-	the recognition of the seasonal nature of costs.

Functionalization

Mr. Dominie, Manager, Rates and Regulation, stated in his prefiled testimony that the current NSPI functionalization is based on "the traditional PUB Chart of Accounts" which he considers adequate and that any further changes would not be warranted.

In its rate decision of March 24, 1993 the Board instructed NSPI to retain independent accounting consultants to examine the format of the Company's present accounting records and prepare a Uniform System of Accounts for consideration by the Board.

The Board in an earlier rate decision stated that virtually all regulated investor-owned public utilities maintain accounting records for regulatory purposes and that their accounts are generally based on the model Uniform Accounts of the National Association of Regulatory Utility Commissioners (NARUC) and the closely related Uniform System of Accounts used by the Federal Energy Regulatory Commission (FERC).

Classification

In his testimony and accompanying exhibits, Mr. Dominie presented six cost of service alternatives with the following classification methodologies:

1. Existing Method. This method assumes 100% Classification to demand.

2. Average and Excess under the New Presentation Format. This method classifies steam and hydro rate-base assets to energy utilizing the annual system load factor. The remaining costs are classified to demand.

3. Equivalent Peaker (3CP). This method classifies steam and hydro production plant costs assuming the demand related costs will not exceed that of an equivalent peaking plant (combustion turbine which is used as a proxy). All remaining costs are classified to energy.

4. Average and Excess,(3CP). This method classifies steam and hydro production plant rate-base assets to demand and energy utilizing the annual load factor to determine the energy portion of the costs. Remaining costs are classified to demand.

5. Average and Excess (Pre-split 30% to Energy). This method arbitrarily classifies 30% of steam and hydro generation rate-base assets to energy.

6. Average and Excess (With Weighted Allocation). This Classification method is identical to (2) and (4) above; differences occur only in allocation.

The demand/energy classification ratios of total steam and hydro rate-base assets are used to determine the demand and energy components of transmission for all classification alternatives analysed.

Mr. Brockman testified that the Equivalent Peaker Method of classification for generation plant is a more fair and rational approach. Regarding transmission, Mr. Brockman agrees with NSPI's "coal by wire" concept (i.e. locating plants at the coal site rather than at the load centre) of assigning rate base value of certain transmission lines to energy.

Dr. Sarikas testified that NSPI has been expressing a determination to maximize the classification of costs to energy. He expressed the opinion that there is no objective rationale for this shift to energy. He further stated that the introduction of an equivalent peaker method will result in an additional shift to energy. He is also of the opinion that the Average and Excess (A&E) method is an allocation methodology and not a classification methodology. With reference to NSPI's proposed classification of some transmission lines as energy related, Dr. Sarikas indicated that the approach is not reasonable since transmission lines are required for reliability.

Ms. Chown testified that utilities in some jurisdictions with large investments in hydraulic and nuclear capacity have reclassified a large portion of fixed costs to energy. In these instances, major capital investments were made in order to minimize fuel costs. Since in her opinion this has not been the case in Nova Scotia, Ms. Chown recommended rejection of NSPI's reclassification of fixed costs to energy. Utilizing a Canadian survey of demand-energy classification splits for generation and transmission, Ms. Chown found that NSPI's proposed changes would result in it becoming an outlier compared to other Canadian Utilities. She also noted that the overall average classification to demand is 46.54%. NSPI's current level is 43.57%. The new proposals would result in a 21.5% demand classification. She submitted that this is sufficient reason for NSPI's recommendations to be questioned.

Mr. Outhouse, in his cross-examination of Ms. Chown, entered Exhibit N-22, an excerpt from the Board's Decision issued March 3, 1992 on NSPC's Rate Application. The comment being referred to was as follows: "Inter-utility comparisons are of value only if all relevant circumstances are similar among the utilities being compared." Ms. Chown defended the table, stating that while the various utilities do have widely different systems, the demand/energy splits are not widely different. NSPI's current position within that range appears appropriate. The move to reclassify more costs to energy results in NSPI moving outside the range and should be a cause for concern. In addition she further recommended rejection of NSPI's proposal since it ignores the fuel for capital trade-off. Equivalent peaker methods require a large number of debatable assumptions which could produce vastly different results.

Ms. Chown recommended a fixed/variable approach for classifying generation and transmission costs. The concept of the fixed/variable approach to cost classification as it pertains to generation and transmission was described by Ms. Chown in her testimony. Fixed costs include depreciation, taxes and return on invested capital. All of these costs are classified as demand related. Variable costs include fuel and operating and maintenance costs and are classified as energy related. Ms. Chown also recommended that a long run marginal cost of service study be conducted and the results be used to determine how the resulting fixed/ variable cost split compares to the present fixed/variable split for embedded costs. Ms. Chown further recommended that all transmission costs be considered demand related.

Mr. Baker testified that the Peaker Method is the most reasonable for classification of generation fixed costs. There are two approaches that could be used, those relating to system planning and those relating to system operation. The peaker proxy method is related to the former. He stated that in conjunction with this method the difference in fuel costs between gas turbines and base load plants should be capitalized and added to the demand related costs.

Mr. Baker proposed that transmission costs should be classified in conformity with generation i.e., same proportions of demand and energy.

Dr. Chamberlin stated that long run marginal costs should be used to determine demand/energy splits. He further stated that the determination of whether an equivalent peaker is appropriate cannot be done without knowing the Company's marginal cost. Under cross-examination by Mr. Reagh, he testified that if a utility is not adding capacity in the short term, a peaker method would overstate the marginal capacity cost since it is based on the assumption of an immediate addition.

Allocation

Mr. Dominie filed six studies as exhibits on the following methods of allocation:

1. Existing Method. Average and Excess methodology is used to assign rate base assets and fixed cost responsibility to customer classes. Allocation is done on a non-coincident peak basis, whereby the annual peak is used to assign costs to each customer class, regardless of whether or not the class peak coincides with the annual system peak. Variable costs are allocated directly to each customer class on a kW.h basis.

2. Average and Excess under the New Presentation Format. This method is similar to method 1; however the allocation is applied to the portion of the rate base assets that have been classified to demand.

3. Equivalent Peaker (3CP). This method allocates demand related rate-base assets to customer classes based on the ratio of customer

class demand to total system demand, utilizing the class average for the three winter month coincident peaks.

4. Average and Excess (3CP). The method of allocation is identical to method 3.

5. Average and Excess Classification (Pre-split 30% to Energy). The method of allocation is identical to method 1.

6. Average and Excess Classification (Weighted Coincident and Non-Coincident Peak (NCP) Demand Allocation). This method of allocation is similar to method 1, however, the average of the coincident and non-coincident peaks is used as the basis of assigning rate base assets to customer classes.

Mr. Brockman stated in his prefiled evidence that the proposed allocation of peak demand related portions of generation and transmission plant using the three winter months coincident peaks will result in a fairer and less arbitrary allocation of excess demand costs than with non coincident peaks as is done at present.

Energy related costs are allocated to customer classes based on the ratio of customer class energy generation requirements to total system energy requirements. Customer costs are specifically identified for each class and pro-rated according to the number of customers in the class.

The allocation process involves the assignment of demand, energy and customer related costs to the various customer classes. These costs comprise the total required revenue for the test period i.e. operating, maintenance, administration costs, depreciation, taxes and return.

Allocation of energy and customer costs can be pro-rated to the various customer classes since statistics are readily available for both energy and the number of customers. Energy cost allocations are based on energy sales increased by losses incurred in the lines and transformers. This results in an estimate of the amount of energy produced at the generator for each of the customer classes. Customer related costs are generally allocated using the average number of customers in the year.

The allocation of demand related costs to the customer classes is generally accomplished through one of the following four methods (or variations thereof):

1. Coincident Peak Method(s)
2. Non-Coincident Peak Method(s)
3. Average and Excess Method(s)
4. Probabilistic Method

Dr. Sarikas, during cross-examination by Mr. Outhouse, stated that he would not be opposed to recognition of energy in the allocation of fixed costs to the customer classes, provided that there is not an overstating or double counting of the energy cost. For example, a fixed/variable classification methodology coupled with the traditional average and excess demand cost allocation method would be acceptable. A percentage classification of fixed costs to energy would be acceptable providing an average and excess allocation is not used. A non-energy related allocation such as coincident peak or non-coincident peak would be acceptable to Dr. Sarikas.

Ms. Chown essentially agreed with the proposed allocation approach recommended by NSPI, i.e. allocation of demand costs using three coincident peak months.

Mr. Kehoe testified that allocation procedures become incredibly complex when one tries to influence how customers will use electricity in the future. He stated that future changes should be ignored and costs assigned based on the utilization of existing resources.

Regarding allocation methodologies Mr. Baker stated there are three basic methods: non-coincident demands (simplest and very common, 15 or more years ago), coincident peak method (causality approach) and average and excess method (exacts some charge from both NCP and CP). He is of the opinion that the A&E method is the least attractive since it charges off-peak customers with a peak charge. A fourth method was also mentioned by Mr. Baker, the Probability of Peak or Probability of Negative Margin. Responsibility is calculated on the basis of hour-by-hour load data for all customer classes. The method imposes considerable analytic requirements. This point was also made by Mr. Brockman in his direct evidence.

In his conclusion, Mr. Baker stated that the CP method is better, but for purposes of transition he recommends consideration be given to a combination of A&E and CP methods (50%-50%) with perhaps the weighting of the A&E allocation gradually falling off. Mr. Baker stated that many jurisdictions produce two cost of service studies, to assist in arriving at a decision. According to Mr. Baker, the same method should be used to allocate transmission costs as is used to allocate generation costs.

In response to questioning by the Board, Dr. Chamberlin stated that some regulators require both embedded and marginal cost of service studies so that the marginal study can be used as a check on the embedded study as well as provide assistance in actual rate design.

Dr. Chamberlin offered as an alternative for consideration, an allocation of demand, energy and customer costs based upon marginal costs. He qualified this by stating that the approach would be more justified when the system is capacity constrained.

Under direct examination by Mr. Outhouse, Dr. Chamberlin described the use of marginal costs as an alternative method of determining cost of service. It is a method which looks forward rather than backward. He stated that marginal cost rates are efficient because they pass on to customers the cost consequences of their use. Under cross-examination by Mr. Cooper, Dr. Chamberlin indicated that the speed with which NSPI moves toward using marginal costs in cost of service studies would depend on the differences in the implications between embedded costs and marginal costs and also on the lead time required for commitment of new plant.

Seasonality

In his prefiled testimony, Mr. Dominie proposed that in all future filings, and regardless of methodology, fuel costs should be allocated to customer classes on a monthly basis rather than on an annual basis. This would ensure that cost variation is appropriately attributed to causative usage. Schedule 3-1, attached to Mr. Dominie's evidence, shows a comparison of the revenue to cost ratios resulting from an annual energy allocation versus a monthly allocation of fuel costs.

Mr. Dominie's prefiled evidence discussed seasonal costs. He observed that the accommodation of seasonality changes to cost of service would require the identification of the following on a peak/non-peak basis:

(a) line loss differences

(b) purchased power fixed costs

(c) grid sales

(d) direct and incrementally costed rates.

Mr. Baker stated that the equivalent peaker method proposed by Mr. Dominie has a weakness for purposes of determining seasonal costs and that a loss of load probability method should be used for the allocation of seasonal based costs to customer class.

Ms. Chown stated that an allocation technique utilizing three coincident peak months would correct the present lack of seasonal orientation caused by the current methodology which relies on a non-coincident peak allocator. Ms. Chown agreed with Mr. Dominie that there is not a significant amount of seasonal variation in energy costs.

Dr. Chamberlin argued, to the contrary, that there is significant seasonal cost variation, and that further study is required to determine whether a three month period is long enough to adequately define the peak months.

Under cross-examination by Mr. Reagh, Dr. Chamberlin discussed the effect of seasonality on capacity costs, stating that these costs are driven by the load during different time periods which results in a decision to add capacity in order to maintain the reliability of the system. In response to a question by the Board, Dr. Chamberlin stated that he didn't think the investigation of the seasonal rate option was sufficiently complete regarding the definition of the winter months and whether or not shoulder months should be included.

BOARD ANALYSIS AND FINDINGS

Functionalization

There was little discussion of functionalization during the hearing. Mr. Dominie submitted in his prefiled testimony that the current chart of accounts is adequate to provide separation between the various related responsibilities. The Board directed the Company to retain independent accounting consultants in it's March 24, 1993 NSPI Rate Decision and considerable work has been done since that time. Of particular relevance to this proceeding is the definition of generation accounts and operations and maintenance accounts vis-a-vis the fixed and variable classifications. Regardless of which classification method is adopted, the method of functionalization should be appropriate for a privately owned utility, and provide data in a format that can be readily utilized for classification and other purposes.

Classification

The Board heard many opinions on the question of the best method of classifying generation and transmission assets into demand and energy categories. The various opinions are based on three somewhat different methodologies:

1. Fixed/Variable Split
2. Average and Excess
3. Equivalent Peaker

The latter two methods are referred to in Mr. Dominie's evidence. The first method is recommended by Ms. Chown as the preferable classification methodology for all generation and transmission rate-base assets. It is also a method utilized by Mr. Dominie for gas turbine plant in his six examples.

Prior to presenting the Board's findings with regard to the subject of classification, a discussion of the concepts is necessary in order to establish a framework for the decision.

The cost of service study includes the classification of costs into the three causal elements being considered for eventual tariff design, these being demand related costs, energy related costs and customer related costs. The costs being classified can be subdivided into fixed and variable. Fixed costs are those which are expected to remain constant in relation to the quantity of electricity produced (typically those costs related to fixed assets such as return, taxes, depreciation and interest. Other types of fixed costs would include the salaries of plant operating staff, etc.). Fuel and maintenance expenses are considered to be variable costs since the quantity and therefore the cost of fuel will vary with electricity output. Planned maintenance of generation plant is based on hours of operation, and the costs are normally considered variable. Costs such as those associated with metering, billing and administration are generally considered to vary with the number of customers.

The amount of fixed and variable costs to be assigned to demand, energy and customer categories is judgmental to some degree and varies from utility to utility. The simplest technique is to assign all fixed costs to demand and all variable generation and transmission costs to energy. Various techniques have evolved in recent years that have had the effect of transferring portions of fixed costs to energy (and/or of transferring variable costs to demand). The application of various classification techniques was a focal point of testimony in the hearing.

The six sample cost of service studies contained in Mr. Dominie's prefiled evidence are based on two variations in methodology for classification: the average and excess demand method and the equivalent peaker method. The former is equivalent to using an annual system load factor.

To utilize the average and excess demand method it is necessary to compare system peak demand to average demand (total energy divided by hours). The difference between peak demand and average demand is defined as excess demand. The amount of production and transmission plant classified as energy related is equal to the average demand divided by peak demand times rate-base assets. The remainder, or the portion corresponding to excess demand, becomes demand related rate-base assets.

The above calculation applies to steam and hydro plants only, as combustion turbines were purchased for peaking and reserve applications and therefore are assumed to be 100% demand related. The equivalent peaker methodology uses the cost of a benchmark combustion turbine plant to determine the proportion of hydro and steam plant to be classified as demand related.

One of the major differences of opinion at the hearing was the classification of generation and transmission rate-base assets. This results in a need to determine what portion of fixed costs should be classified as energy and the appropriate allocation of demand related costs to each customer class. For example, a transmission line to a remote base-load plant built to provide least-cost energy to the load centre has an energy related intent. The actual cost incurred, however, is a function of the physical size of the conductor, which relates to its demand capability.

It has been argued that by classifying these fixed costs as 100% demand related and then allocating them to the customer classes by the average and excess method introduces an energy weighting to the fixed costs. Indeed the same result would be obtained if the system load factor were used to classify the energy related portion of the fixed costs and coincident peak was used for the allocation of the resulting demand related portion.

The utilization of a peaker approach as recommended by NSPI for classification is somewhat impractical for the following reasons:

(a) It is very difficult to determine a representative cost estimate for a peak load plant. It has been pointed out by NSPI in their reply argument to Stora that cost estimates are used in planning studies. However, in planning studies, an optimum size and type of peaking plant has been determined. In addition one has the option and indeed obligation to examine price sensitivities.

(b) The difference in cost between base-load plant and peaking plant could vary significantly year by year according to market conditions and currency fluctuations.

(c) The cost of a proxy peaker plant would be current cost while the remainder of the plant costs would be a summation of historical costs.

The Board considers that the reason for differing opinions as to the classification methodology stems from the interpretation of the causal element of joint costs contained in the rate base. Plant may be built for either capacity or energy reasons, or both. Motivational causation represents the planning aspect that went into the selection of the plant. Whether or not to recognize this element of causation has been one of the contentious issues of this hearing.

If one addresses only cost causation, the recommended methodology for classification of rate-base assets would be to assign 100% to demand. The capital cost of a generation plant is demand related. The amount of energy produced during the year does not impact the capital cost. An exception to this statement is hydro plants where water storage facilities may be sized for energy production reasons.

It is the Board's opinion that there is an element of energy related cost causation in past generation planning that is present in the NSPI system today. Ms. Chown acknowledges the need for energy recognition in cases such as hydro or nuclear plants, where large capital investments have been made to minimize energy costs. The Board considers that the same rationale applies to the siting of coal fired plants in Cape Breton, as the site was chosen for a combination of reasons which culminated in the least cost solution at that time.

With reference to the proposed equivalent peaker method, the Board is of the opinion that it is an inconsistent calculation because the current cost of a combustion turbine is being compared to the historical cost of other generating plant in order to define a reasonable percentage classification to demand. In order for this method to be properly utilized, assuming one agrees with the method, it would appear that the rate base value for the existing generation plant would have to be converted to current cost levels. Since NSPI is not required to revalue its assets each year, it is the opinion of the Board that the equivalent peaker method is not acceptable.

The Board does not reject the notion that cost of service should reflect to some extent the intent of the asset and therefore an energy portion of fixed cost, and is of the opinion that fixed costs of steam and hydro generation plant should be classified on the basis of annual system load factor. The annual system load factor is to be calculated on the basis of gross energy generation and annual coincident peak including interruptible load.

Regarding transmission line rate-base assets, it is the Board's opinion that these assets cannot be totally separated from generation; i.e., whatever causal effects there are in generation also apply to transmission. It is the opinion of the Board that the identification of specific lines as "coal by wire" is too subjective for a cost of service study and for this reason should be rejected. The Board's decision is that the portion of transmission applicable to energy will be determined by the energy proportion of total generation rate-base assets.

The Board reviewed Dr. Chamberlin's testimony regarding long run marginal costs and the requirement in some jurisdictions that the utility perform complete embedded and marginal cost of service studies. The Board recognizes that marginal costs can play a significant role as a benchmark in reviewing the classification of embedded costs by causation at the point of generation and at various voltage levels in the system, and also in rate design. For this reason, the Board requests NSPI to provide the long run marginal cost of demand and energy at the point of generation and at various voltage levels in the system at future rate hearings.

Allocation

The significant question in the choice of allocation methodologies is which technique best assigns responsibility for demand related costs to each of the customer classes. Energy related costs and customer related costs are currently assigned on a pro rata basis utilizing total annual sales, system losses, and average annual number of customers. In reviewing the evidence, the alternative methods for demand cost allocation include:

1. non-coincident peak,
2. coincident peak,
3. average and excess,
4. loss of load probability method.

The Board views the non-coincident peak method as a less sophisticated approach. NSPI has recommended a 3 Coincident Peak Method which indicates a belief that its load research is capable of producing a reasonable distribution of peak amongst the customer classes for the three months in which the highest monthly peaks occur.

The average and excess method utilizes the peak demand and average demand (annual energy divided by annual hours) to arrive at another allocation of demand costs, thus bringing energy recognition into the analysis. The Board has noted Mr. Baker's assessment of the four methodologies, particularly his opinion that the average and excess method is the least attractive since it charges off-peak customers with a peak charge. The Board is of the opinion that although the probability method has merit, the analytic requirements as pointed out by both Mr. Baker and Mr. Brockman give cause for concern. Mr. Kehoe has pointed out that NSPI has over 35,000 data points which could be used for hourly analysis. The Board notes the consensus among Mr. Baker, Ms.Chown and Mr. Brockman regarding the coincident peak allocation technique. The witnesses essentially approve the three coincident peak method being recommended by NSPI. The Board also noted Dr. Sarikas's testimony regarding the recognition of energy in the allocation of fixed costs to customer class, provided that there is not an overstating or double counting of the energy cost.

The Board is of the opinion that the "3 Coincident Peak" method should be used for allocating the demand portion of the fixed costs by customer class.

The Board considers the determination of class responsibility for coincident peak to be important. Future cost of service studies should contain complete details as to the methods used to determine class load factors, intraclass coincidence factors, interclass coincidence factors, and system loss factors, as well as descriptions and results of any load surveys carried out for the purposes of determining customer class responsibility for the three monthly system peaks.

Seasonality

The Board is of the opinion that seasonal cost variations must be defined within the context of the approved cost of service methodology.

SUMMARY OF DECISION

The method of functionalization should be appropriate for a privately owned utility, and provide data in a format that can be readily utilized for classification and other purposes.

The Board is of the opinion that classification of the cost of service should reflect to some extent the intent of the asset and therefore fixed costs will have both energy and demand related portions. The Board directs that (i) all generation costs associated with environmental compliance and fuel conversion are to be classified as energy related; (ii) annual fixed costs associated with steam and hydro generation plant rate base assets are to be classified to energy on the basis of annual system load factor; (iii) the remaining costs are to be classified as demand related; and (iv) the portion of transmission fixed costs classified as energy related is to be determined by the annual system load factor.

The Board requests NSPI to provide at future rate hearings the long run marginal cost of demand and energy at the point of generation and at various voltage levels in the system.

The Board directs that a "3 Coincident Peak" method be used for allocating the demand portion of the fixed costs of generation and transmission plant rate base assets to the customer classes.

The Board considers the determination of class responsibility for coincident peak to be a matter of importance. Future cost of service studies should contain complete details as to the methods used to determine class load factors, intraclass coincidence factors, interclass coincidence factors, system loss factors and details of supporting load surveys.

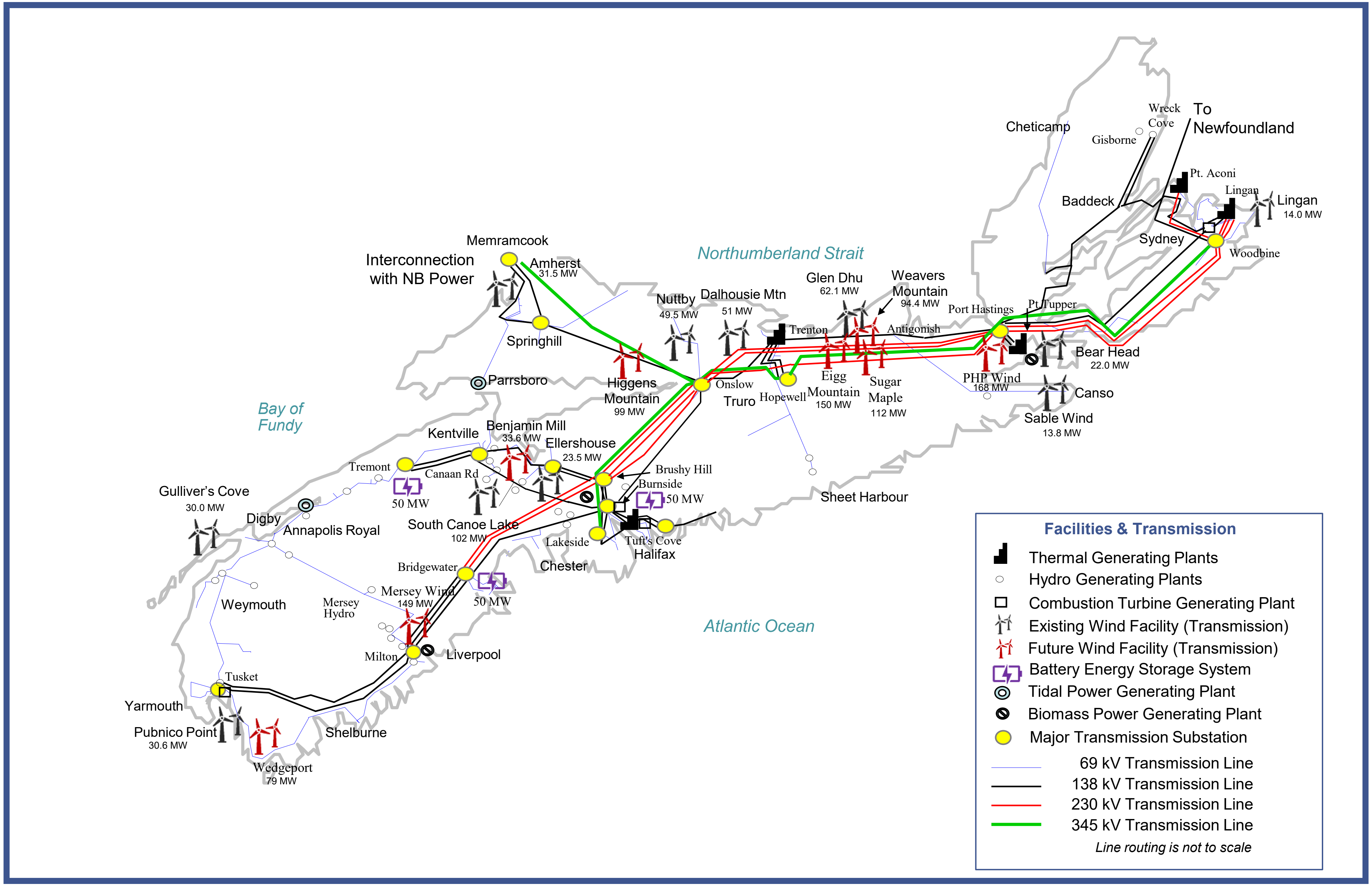
An Order will issue accordingly.

DATED at Halifax, Nova Scotia this 22nd day of September, 1995.

Robert A. Robertson, F.C.A., Chair

Linda D. Garber, Vice-chair

John L. Haris, Q.C., Member


To Newfoundland
Wreck Cove
Gisborne
Cheticamp
Pt. Aconi
Lingan
Lingan
14.0 MW
Baddeck
Sydney
Woodbine
Memramcook
Interconnection with NB Power
Amherst
31.5 MW
Springhill
Northumberland Strait
Nuttby
49.5 MW
Dalhousie Mtn
51 MW
Glen Dhu
62.1 MW
Weavers Mountain
94.4 MW
Port Hastings
Pt Tupper
Trenton
Antigonish
Bear Head
22.0 MW
Parrsboro
Higgens Mountain
99 MW
Onslow
Truro
Hopewell
Eigg Mountain
150 MW
Sugar Maple
112 MW
PHP Wind
168 MW
Canso
Sable Wind
13.8 MW
Bay of Fundy
Kentville
Benjamin Mill
33.6 MW
Ellershouse
23.5 MW
Tremont
Canaan Rd
Brushy Hill
Burnside
50 MW
50 MW
Sheet Harbour
Gulliver's Cove
30.0 MW
Digby
Annapolis Royal
South Canoe Lake
102 MW
Lakeside
Tuft's Cove
Halifax
Chester
Bridgewater
50 MW
Weymouth
Mersey Hydro
Mersey Wind
149 MW
Atlantic Ocean
Milton
Liverpool
Tusket
Yarmouth
Pubnico Point
30.6 MW
Shelburne
Wedgeport
79 MW
Facilities & Transmission
Thermal Generating Plants
Hydro Generating Plants
Combustion Turbine Generating Plant
Existing Wind Facility (Transmission)
Future Wind Facility (Transmission)
Battery Energy Storage System
Tidal Power Generating Plant
Biomass Power Generating Plant
Major Transmission Substation
69 kV Transmission Line
138 kV Transmission Line
230 kV Transmission Line
345 kV Transmission Line
Line routing is not to scale

2026-2027 GRA Synapse IR-04 Confidential Attachment 3 has been filed electronically.

2026-2027 GRA Synapse IR-04 Confidential Attachment 4 has been filed electronically.

2026-2027 GRA Synapse IR-4 Confidential Attachment 5 has been filed electronically.

Request IR-5:

Refer to GRA Appendix 12A, Cost of Service Study Process, section 5.7.

(a) Could the Company classify transmission costs to demand and energy based on SLF under the OATT? Why or why not?

(b) If the answer to part (a) is no, explain why the Company can propose to change other transmission approaches under the OATT but could not change classification.

Response IR-5:

(a) Classification of transmission costs to energy and demand under the OATT would not be appropriate for the following reasons.

(i) Classifying transmission costs by the system load factor is not consistent with cost causality principles and with the methodology used by Canadian utilities to classify transmission costs. Please refer to responses to parts (b) and (c) of Synapse IR-4.

(ii) NS Power provides non-discriminatory Open Access Transmission Tariff (OATT) to buy and sell power in the wholesale market. The current OATT design, approved for use by the [NSEB] in 2005, classifies all transmission costs to demand consistent with the design of OATT in North America.

(b) Classification of all transmission costs to demand under the OATT is a logical consequence of demand-only rate structure under the OATT. This is a foundational matter of the OATT design. The Company is of the view that the COSS-based determination of transmission costs aligns more closely with the true costs of transmission service than the formulaic approach used currently under the OATT and which is a source of unnecessary variation in transmission costs paid for by customers in the bundled and unbundled markets of Nova Scotia.

Request IR-6:

Refer to GRA Appendix 12A, Cost of Service Study Process, section 6.1.

(a) For each distribution sub-function classified using the minimum system study, identify the portions of the sub-function determined to be customer- and demand-related.

(b) What is the kW or kVA capacity of the minimum size equipment the Company used for each distribution sub-function classified using the minimum system study?

(c) Has the Company included subtransmission, trunkline, upstream, or backbone primary feeders in the overhead & underground lines that it classified using the minimum system methodology?

(d) Does the plant accounting data for overhead & underground lines isolate the costs of trunkline, upstream or backbone primary feeders from the rest of the plant in those accounts?

(e) Identify the tab and cells in the Company's COSS (SR-01 Attachment 2) or other attachment in which the Company conducts the minimum system study. If not already provided, provide the study and all underlying data supporting the study, in live, unlocked Excel file format with all links and formula intact.

(f) In live, unlocked Excel file format with all links and formula intact, please provide an alternate version of the COSS (for each of 2026 and 2027) in which poles & fixtures and overhead & underground lines are classified as 100% demand-related.

Response IR-6:

(a) Please refer to the 2026 COSS and 2027 COSS tabs included in 2026-2027 GRA SR-01 Attachment 2 PCON EO.

- Exh 3c shows classification of primary and secondary voltage pole investment by customer and demand.
- Exh 3e shows classification of primary and secondary voltage overhead wire investment by customer and demand.
- Exh 3g shows classification of primary and secondary voltage underground wire investment by customer and demand.

(b) NS Power does not characterize the minimum size equipment by kW or kVA capacity. The equipment is sized to ensure suitable voltage at the extent of each feeder, given the maximum design rating of the feeder. Please refer to the response to CA DR-67 included in Appendix 12 A. For discussion of how NS Power's minimum system study model sets the minimum equipment size please refer to CA DR-61.

(c) The Company included only distribution lines defined at NS Power as serving voltage at 25 kV and below. These lines do not include sub-transmission which is defined as lines at 69 kV.

(d) No, the plant accounting data for overhead & underground lines does not isolate the costs of trunkline, upstream or backbone primary feeders from the rest of the plant in those accounts.

(e) The requested analysis was provided as Attachment 1 to Synapse IR-32 in the 2023-2024 GRA proceeding (M10431). It has also been filed electronically in response to CA DR-66 included in Appendix 12A.

(f) Please refer to NSEB IR-128.

Request IR-7:

Refer to GRA Appendix 12A, Cost of Service Study Process, section 6.1 and GRA Appendix 12B p.37 and 39.

(a) Has the Company calculated the load carrying capability, or the "minimal demand" that can be met by its hypothetical minimum system comprised of minimum specifications? If yes, provide the calculation in live, unlocked Excel file format with all links and formula intact and narratively explain how the Company did so.

(b) If the answer to part (a) is no, please explain how the Company might conduct the described calculation.

Response IR-7:

(a) The Company has not calculated the load-carrying capability, or the "minimal demand" that can be met by its hypothetical minimum system comprised of minimum specifications.

(b) To accurately calculate the load-carrying capability of a hypothetical minimum system, a detailed electrical model would need to be developed to represent the parameters and constraints of each system component (e.g., service conductors, transformers, primary lines, and associated equipment). The load-carrying capability of these components would vary by location depending on magnitude and spatial distribution of connected loads, as well as system topology (e.g., conductor lengths, number of customers per segment). A simplified spreadsheet using typical primary line and service lengths would not be representative of an actual power system.

Developing a detailed load-flow model of the entire network for this purpose would not be practical. Comprehensive secondary network data are limited, and rebuilding all primary network models to reflect minimum system standards would require significant engineering effort for limited analytical value.

The specific approach to such a calculation would depend on the intended use of the results and the acceptable level of assumption error. One possible method would be to model a notional minimum system using average conductor lengths, transformer sizes, and customer counts per network component. The maximum kW that a system built entirely to minimum design specifications could carry without exceeding thermal ampacity, voltage variation, or design standard limits could then be approximated from this model. However, this result would be purely theoretical and not representative of a real distribution system, as it would assume perfectly optimized loading. A comparable model of the average system might also be required to assess relative capability and derive meaningful outputs from the exercise, adding significant additional effort.

Request IR-8:

Refer to the Company's COSS. Using the most granular data available, provide a summary of individual customer maximum demands for each customer class (ex: in the form of a box and whisker plot, or boxplot).

Response IR-8:

The Company has not analyzed individual customer maximum demands for each customer class at this time. Class level maximum demand forecasts (i.e. "class non-coincident demand") can be found in the Company's COSS, 2026-2027 GRA SR-01 Attachment 2 PCON EO, Tab Exh 9a Annual, Column "(4) CLASS NON-COINCIDENT DMD. (KW)".

Request IR-9:

Refer to GRA Direct Evidence p.86.

(a) Describe the extent of AMI meter installations in the Company's territory What portion of each customer class has AMI installations? If the answer is less than 100%, explain if the Company plans to roll out advanced metering to all customers, and provide the timeline for the rollout.

(b) Does the Company classify, or intend to classify, AMI meter costs as customer-related?

(c) If applicable, provide the matter number and Board order approving the Company's AMI investment.

Response IR-9:

(a) As provided in NS Power's 2024 AMI Opt-out Costs Report (Appendix 13C), over 531,000 AMI meters have been installed as of April 1, 2025. A breakdown of AMI installations, by customer class, as of April 1, 2025 is provided below.

Customer Rate Class	**Count of Installed AMI Meters**
Residential	495,847
Commercial (Small General, General, Large General)	37,705
Industrial (Small, Medium, Large, and Interruptible)	1,981
Charitable Organizations, and Street and Recreational Lighting	2,451
Total	**537,984**

The Company does not expect AMI meters to roll out to 100 percent of customers. A number of customers have opted out of AMI meters and/or over-the-air (OTA) billing for a variety of reasons. These customers continue to receive manual meter reads, which is the basis for the proposed non-standard meter service fee. As noted in the Board's December 17, 2024 Letter, NS Power has "essentially fulfilled" its obligations under s. 3AB(1) of the Electricity Act and will continue coordinating installations for new and opt-in customers.[1]

(b) The AMI investments and costs are spread among a variety of categories such AMI meters, overhead IT and General Property. The AMI meter investment costs are all classified to customer. Those recorded under General Property are re-functionalized to distribution and then spread between demand- and customer-related categories based on average weightings of these two categories. The overhead IT costs associated with AMI are functionalized to all four service areas of Generation, Transmission, Distribution and Retail and then classified in accordance with investment weighting in these service areas. Please also refer to Synapse IR 1.

(c) The Board approved NS Power's AMI Project Application on June 11, 2018 as part of M083449. The Board Order, dated June 28, 2018, is provided as Attachment 1.

[1] M10639 – Board Letter re. NS Power 2023 AMI Opt-out Costs Report, 317636. December 17, 2024.

ORDER **M08349**

NOVA SCOTIA UTILITY AND REVIEW BOARD

IN THE MATTER OF THE PUBLIC UTILITIES ACT

- and -

IN THE MATTER OF AN APPLICATION by **NOVA SCOTIA POWER INCORPORATED** for approval of Capital Work Order CI# 47124 for its Advanced Metering Infrastructure Project in the amount of $133,228,952

BEFORE: Peter W. Gurnham, Q.C., Chair
Roberta J. Clarke, Q.C., Member
Steven M. Murphy, MBA, P.Eng., Member

ORDER

WHEREAS Nova Scotia Power Incorporated (NS Power) made application to the Board on October 19, 2017, for approval of capital work order CI# 47124 for its Advanced Metering Infrastructure (AMI) Project in the amount of $133,228,952;

AND WHEREAS the Board issued an Order advising that this matter would be considered in a paper hearing, and outlined the timeline for this proceeding which was subsequently revised by an Amended Order;

AND WHEREAS the following parties participated in the process: Affordable Energy Coalition, Consumer Advocate, Ecology Action Centre, EfficiencyOne, the Industrial Group, Municipal Electric Utilities of Nova Scotia Cooperative, Nova Scotia Department of Energy, Roswall Inc., the Planetary Association for Clean Energy Inc., and the Small Business Advocate;

AND WHEREAS the Board issued a Decision on June 12, 2018, approving Capital Item #47124 for NS Power's AMI Project in the amount of $133,228,952 in accordance with Section 35 of the *Public Utilities Act* subject to the findings in the Decision;

AND WHEREAS the Board directed NS Power to file a first Compliance Filing by June 26, 2018, advising when it will file its time varying pricing tariffs;

AND WHEREAS NS Power filed a Compliance Filing on June 26, 2018;

IT IS HEREBY ORDERED THAT:

1. Capital Item #47124 for NS Power's AMI Project in the amount of $133,228,952 is approved, subject to the findings in the Board's Decision.

2. NS Power is directed to provide a detailed accounting of the use of the capital work order contingency. Such accounting is to include identification of costs associated with each item spent under the contingency, as well as an explanation describing the reason for requiring each item and shall be filed semi-annually with the Board.

3. NS Power is directed to file its time varying pricing tariffs with the Board on June 30, 2020, and in the interim, to provide an update to Board staff on December 31, 2018, and every six months thereafter.

4. NS Power is directed to establish and file with the Board in a Compliance Filing by August 31, 2018, any cost of opting-out of AMI technology and continuing with non-standard meter service.

5. NS Power is directed, in its August 31 Compliance Filing, to provide its detailed plan of how it will inform customers of the process to opt-out of installation of meters under the AMI Project.

6. NS Power is permitted to recover the undepreciated costs of the existing meters on a straight-line basis over five years; however, NS Power is not permitted to earn a return on equity for those meters.

7. NS Power is directed to take into account the concerns of low income consumers, as well as small business customers, as it implements AMI and to consider the comments of the Affordable Energy Coalition and Small Business Advocate regarding time-of-day usage tariffs and prepayment plans as they impact on such customers.

8. NS Power is directed to ensure that all information regarding the health and safety standards and requirements of the AMI system be made available to customers as part of the Customer Engagement Plan, and that NS Power customer service staff are familiar with the information and will make it available to any customer who desires it, whether prior to opting-out or otherwise.

DATED at Halifax, Nova Scotia, this 28th day of June, 2018.

Bruce A. Kiley

Clerk of the Board

Request IR-10:

Refer to GRA Direct Evidence p.81. Identify the tab and cells in the Company's COSS(s) indicating that if "customer charges were to be set directly based on changes in the customer-related costs from the 2026-2027 COSS, they would show about a 50 percent increase in 2026 followed by a minor single digit increase in 2027."

Response IR-10:

Please refer to NSEB IR-133.

For the estimates of customer charges set directly based on customer-related costs from the 2026-2027 COSS please refer to the following cells in Exh 6 of the 2026-2027 SR-01 Att 02 PCON.xlsx and 2026-2027 SR-01 Att 03 PCON.xlsx. Please refer to NSEB IR-133 for a comparison of tabulated charges of the Domestic and Small General Tariffs under these two customer charge scenarios.

Request IR-11:

Refer to GRA non-confidential PR-01.

(a) Explain why the energy charges for Small General Tariff, General Tariff, Small Industrial Tariff (and any others) are lower for usage beyond the first 200 kilowatt-hours per month. Explain how rates that decrease as monthly consumption increases reflects cost causation.

(b) For general and industrial rate classes, narratively explain how the Company decides how much revenue to collect via energy charges versus demand charges.

(c) Identify the tab and cells in the Company's COSS that report the energy-related and demand-related revenue requirements per customer class.

(d) Identify the attachments, tabs, and cells in which the Company calculates energy and demand charges based on energy- and demand-related revenue responsibilities by class. If not already provided, provide the calculation and all underlying data, in live, unlocked Excel file format with all links and formula intact.

Response IR-11:

(a) The energy charge rate structure under the Small General Tariff, General Tariff, and Small Industrial Tariff reflect what is known in the utility industry as a declining block rate design. It provides more stability in the recovery of utility's fixed costs and offers a lower blended unit cost for higher overall customer usage. This rate structure has been in effect at NS Power for many decades.

In the case of the Small General Tariff, which is made up of the customer and two energy charges, the presence of a higher first energy block charge was justified specifically on the grounds of introducing more stability in the recovery of the distribution costs, most of which are demand-related, in view of lacking a demand charge under this tariff.

In the case of the General and Small Industrial Tariffs, made up of the demand and the two energy charges, the presence of a higher first energy block charge was justified on the grounds of a requirement of an up-front recovery of the class customer-related costs and those demand-related costs which are not recovered by the demand charge.

(b) The Company increases the energy and demand charges currently in effect by an across-the-board factor to match class revenue responsibilities determined through the application of a revenue to cost ratio process as described in 2026-2027 GRA SR-01 Attachment 1b. In the case of the Domestic and Small General rate classes, which have a customer charge but do not have a demand charge each, the customer charge is determined in a separate process and the across-the-board factor is applied only to energy charges.

(c) Please refer to column "I" of Exh 6.1 for a summary of class costs by energy and demand categories within each service area or Exh 6 which provides details behind all the demand, energy and customer-related costs.

(d) The energy and demand charges are not based on energy and demand revenue responsibilities as determined in the cost-of-service studies. Rather, the current charges are increased across the board to match total class revenues as determined through the application of a revenue-to-cost ratio process as described in 2026-2027 GRA SR-01 Attachment 1b. Please refer to part (b).