DOCKET NO. NSPI-P-892

NOVA SCOTIA UTILITY AND REVIEW BOARD

In the Matter of: An Application by Nova Scotia Power Inc. for Approval of Depreciation Rates

DIRECT TESTIMONY OF

PAUL CHERNICK

ON BEHALF OF

NOVA SCOTIA CONSUMER ADVOCATE

Resource Insight, Inc.

AUGUST 5, 2011

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I. Identification and Qualifications

Q: Mr. Chernick, please state your name, occupation and business address.

A: I am Paul L. Chernick. I am the president of Resource Insight, Inc., 5 Water Street, Arlington, Massachusetts.

Q: Summarize your professional education and experience.

A: I received an SB degree from the Massachusetts Institute of Technology in June 1974 from the Civil Engineering Department, and an SM degree from the Massachusetts Institute of Technology in February 1978 in technology and policy. I have been elected to membership in the civil engineering honorary society Chi Epsilon, and the engineering honor society Tau Beta Pi, and to associate membership in the research honorary society Sigma Xi.

I was a utility analyst for the Massachusetts Attorney General for more than three years, and was involved in numerous aspects of utility rate design, costing, load forecasting, and the evaluation of power supply options. Since 1981, I have been a consultant in utility regulation and planning, first as a research associate at Analysis and Inference, after 1986 as president of PLC, Inc., and in my current position at Resource Insight. In these capacities, I have advised a variety of clients on utility matters.

My work has considered, among other things, integrated resource planning, the cost-effectiveness of prospective new generation plants and transmission lines, retrospective review of generation-planning decisions, ratemaking for plant under construction, ratemaking for excess and/or uneconomical plant entering service, conservation program design, cost recovery for utility efficiency programs, the valuation of environmental externalities from energy production and use, allocation of costs of service between rate classes and jurisdictions, design of retail and wholesale rates, and performance-based ratemaking and cost recovery in restructured gas and electric industries. My professional qualifications are further summarized in Exhibit PLC-1.

Q: Have you testified previously in utility proceedings?

A: Yes. I have testified more than 250 times on utility issues before regulators in thirty U.S. jurisdictions and five Canadian provinces. My previous testimony is listed in my resume.

Q: Have you testified previously before this Board?

A: Yes. I testified in the Board's review of the following cases:

- Nova Scotia Power's Demand Side Management Plan for 2010 and Demand Side Management Cost Recovery Rider in May 2009,
- the proposed purchased-power agreement between Nova Scotia Power Inc. and a biomass project to be constructed at the NewPage Pt. Hawkesbury ("NPPH") pulp and paper mill (NSUARB P-172),
- Nova Scotia Power's proposal to build the biomass project at NPPH (NSUARBP P-128.10),
- Heritage Gas's 2010 rate case (NSUARBP NG-HG-R-10),
- Nova Scotia Power 2010 depreciation rates proceeding (NSUARBP-P-891),
- the Renewable Energy Community-Based Feed-in Tariffs proceeding (NSUARBP BRD-E-R-10).

II. Introduction

Q: On whose behalf are you testifying?

A: My testimony is sponsored by the Nova Scotia Consumer Advocate.

Q: What is the purpose of your direct testimony?

A: My sponsors have asked me to evaluate the cost allocation and rate design proposals of Nova Scotia Power Inc. ("NPSI"), including the cost-of-service study ("COSS").

Q: What specific issues does your testimony address?

A: I address the following issues regarding the COSS:

- the classification of wind generation costs between energy and demand,
- the assignment of substation costs based on incorrect data on the cost of dedicated substations and on the classes served by such substations.

I also address aspects of NPSI's rate design proposals, primarily in terms of the incentive effects of rate design in promoting efficient use of energy and reducing the burden on ratepayers for energy-efficiency programs to achieve energy-savings targets.

Q: Please summarise your COSS recommendations.

A: With respect to the COSS, I recommend that the analysis be corrected to allocate the following costs as follows:

- all wind-power costs on energy,
- all substation costs on non-coincident demand.

Q: Please summarise your rate-design recommendations.

A: With respect to rate design, I recommend the following improvements:

- implementation of marginal-cost based rate design,
- reduction in the residential customer charge.

III. The Cost-of-Service Study

Q: What role should the study of embedded costs of service play in revenue allocation and rate design?

A: The study should serve only as a guide to cost allocation, not as a determinant. Consideration of marginal cost and incentive effects, not embedded cost, should be the primary basis of rate design.

Q: Does the Board agree that the COSS should be regarded as a guide, not a determinant, of allocation and rate design?

A: Yes. In the Board's view, the the use of the COSS in setting class revenue requirements involves some judgment (NSUARBP-NPSI-P-875 2002 NSUARB 59, p. 118).

Q: Have you identified specific problems with NPSI's COSS?

A: Yes. While the COSS deals well with some issues, particularly most generation and transmission classification issues, some of the approaches used in the study are faulty and do not reflect cost causality. In particular, NPSI's COSS has the following flaws:

- understating the energy-related portion of wind generation costs,
- understating the allocation of substations to certain classes served in whole or in part from dedicated substations.

Q: How do the COSS issues that you raise overlap with those considered by the Board in Docket No. NSUARBP-NPSI-P-883(2)?

A: In November 2006, the Board issued an order in which it determined that no separate cost-of-service-methodology proceeding was warranted at that time. In particular, the Board was asked to reconsider the classification and allocation of a portion of generation- and transmission-related fixed costs on the basis of energy, and to consider the allocation of certain energy-related variable costs, particularly fuel costs, on the basis of hourly rather than monthly usage (Order, p. 12). The Board declined to open a special proceeding on these issues. On the first point, the Board agreed with Dr. Stutz that

> The reason why the G&T facilities discussed in the 1995 decision were built has surely not changed since the 1995 decision was issued. Thus, there is no reason to believe that the Board, looking back over an additional 11 years, would reach a different conclusion concerning the historical basis of support for a joint (i.e., energy and demand) classification of these G&T facilities. (Order, pp. 12–13)

On the second point, the Board ordered NPSI to undertake an analysis of the effects of hourly allocation of variable costs.

In this testimony, I support the classification and allocation of generation fixed costs on energy, and I do not address the issue of hourly allocation of variable costs. The two COSS topics in this testimony are distinct from the issues raised in 2006, as follows:

- The classification of wind costs between energy and capacity is essentially a new issue. As of the end of 2006, NPSI had about 50 MW of wind on line, compared to some 280 MW on-line today. The Board did not mention the classification of wind costs in the 2006 order.

The issue of substation allocation arises because NPSI has not applied the approach used in the 1977, 1980, and 1993 studies, by failing to update the lists of dedicated substations and the classes served from dedicated substations, let alone the costs of dedicated substations.

A. Classification of Wind Generation

1. Classification

Q: What is the basis for NPSI's classification of wind-plant costs?

A: The Company explains:

> In Nova Scotia, the current installed wind generation has generally achieved approximately a 30 percent capacity factor, compared to nameplate rating. NPSI has used these results in the Cost of Service Study to assign 30 percent of wind assets to demand, with the remainder being assigned to energy. (CA IR-73a)

Q: Does this explanation make sense?

A: No. Capacity factor is not the only consideration in allocating the costs of power plants, but even to the extent it is relevant, NPSI has misapplied the concept. A resource with a low capacity factor would generally be a peaker, whose purpose and value are primarily demand-related, while a resource with a high capacity factor would generally be a baseload plant, whose purpose and value are primarily energy-related. In other words, if capacity factor means anything for cost allocation, it should indicate the importance of energy in the allocation. Yet NPSI uses capacity factor to estimate the *demand*-related portion of wind-generation costs.

Q: What considerations drive NPSI's acquisition of wind resources?

A: The Company is acquiring wind and other renewable resources to meet the renewable energy standard. The standard is stated as a percentage of energy generation: 5% of energy from post-2001 renewables in 2011 and 10% in 2013, rising to 25% of energy from total renewables in 2015 and 40% in 2020. NPSI has excess capacity and expects load to fall for the foreseeable future, as energy-efficiency efforts exceed natural load growth. Hence, the renewables are being added solely to meet energy-related requirements, and should be allocated entirely to energy.

Q: Do wind plants also contribute to meeting peak loads?

A: Yes. While wind-plant output is variable, wind contributes to power-supply reliability. For the 308 MW of nameplate wind capacity expected to be added by

2011, the 2009 NPSI IRP Update estimates a capacity value equivalent to 100 MW of "firm" capacity, by which NPSI appears to mean something like its fossil-fuelled generation fleet (NPSI 2009 Integrated Resource Plan Update Report, November 30, 2009, Appendix E Attachment 1 Page 18). Thus, the IRP estimated that each MW of wind provides about 0.32 MW of firm capacity.[1]

The Company suggests that even this capacity value estimate may be overstated.

> Discussions are taking place with the System Operator concerning the potential to assign a capacity value to wind generation based on the wind forecast. However, given that there are days with virtually no wind generation and that wind is non-dispatchable, there is no direct equivalency between installed wind capacity and MWs of gas-turbine capacity. (CA IR-31)

Q: If the wind plants do have a capacity value of 32% of a like amount of gas turbine, and if the capacity were needed, what is the maximum portion of the wind-plant cost would be allocable to demand?

A: Each kilowatt of wind would have a capacity value of 32% of the cost of a kilowatt of gas turbine. The IRP estimates that LM6000 gas turbines (which are not the least expensive peaking capacity) would cost about $1,000/kW, so the capacity value of the wind plant would be about $320/kW.

The COSS reports that its wind plant rate base for 2012 will be $249,265 for about 92 MW (1.3 MW at Grand Étang and Little Brook, 30 MW at Digby, 50 MW at Nuttby, and 11 MW for NPSI's share of Point Tupper), or over $2,500/kW, even after some depreciation. Hence, the maximum share of the wind investment that can be justified on the basis of its contribution to meeting peak demand would be $320 ÷ $2,500, or about 13%. The ratio for O&M would

[1] The same page of the IRP shows the estimated value of future wind resources rising to 0.4 firm MW per MW of nameplate wind.

be even lower. Exhibit 4 of the COSS projects O&M of $4/kW-year for the 98 MW of LM6000s at Tufts Cove; 32% of that O&M would be $1.30/kW-year. The same Exhibit projects O&M of $57/kW-year for the 92 MW of NPSI-owned wind. The demand-related portion of wind O&M is no more than 2%.

Q: How would you weight the capital and O&M costs to derive a single energy-and-demand classification factor?

A: Based on the cost analyses that NPSI has provided for Point Tupper and Nuttby, it appears that about 25% of revenue requirements for the wind plants is related to O&M, with the rest capital-related (depreciation, return, and taxes, including the EcoEnergy tax credit). Weighting the 2% O&M demand ratio by 25% and the 13% capital ratio by 75% produces an overall demand-related portion of total wind costs of 10%.

Q: How should NPSI classify wind costs between energy and demand?

A: All wind-power costs should be classified entirely as energy-related until the wind capacity (1) is needed and (2) allows NPSI to avoid conventional generation capacity. At that point wind-power costs should be classified as no more than 10% energy-related and at least 90% energy-related. Alternatively, once the wind resources have capacity benefit, Company-owned wind costs can be classified as no more than 2% demand-related for O&M and 13% demand-related for capital-related costs.

2. Allocation of Wind Expenses

Q: Have you been able to track the allocation of wind O&M through the COSS?

A: No. Wind O&M is reported in Exhibit 4 of the COSS (Functionalization of Operating Expenses), but disappears in Exhibit 5 (Classification of Operating

Expenses) and Exhibit 6 (Allocation of Operating Expenses). Since the comparison of revenues to expenses in Exhibit 10 uses the results of Exhibit 6, the wind expenses appear to have been omitted from the analysis.[2]

My efforts to track the fate of wind expenses in the COSS has been hampered by NPSI's decision to provide the COSS spreadsheet in a protected form that precludes tracking of dependent formulas. Hence, I cannot determine whether any subsequent formula captures the wind expenses in Exhibit 4.

B. Sub-Functionalization and Allocation of Substation Costs

Q: Have you found problems with NPSI's allocation of distribution costs?

A: Yes. The allocation of substation costs incorrectly applies the approach that NPSI has used in the past, resulting in understating the substation costs attributable to Large Industrial, ELI 2P RTP, and Municipal classes.

While the inputs to the generation allocation (load factor, the share of costs that are related to environmentla upgrades and fuel switching) are updated in each rate proceeding, the corresponding distribution inputs (the share of poles that carry secondary lines, the percent of overhead and underground line investment that is incurred for secondary lines, the customer-related portion of poles and lines, the relative cost of meters and services for various classes) have been held constant since the early 1980s or before. Some of these approaches and the input values may be outdated, but in most cases NPSI has applied the traditional ratios to updated functionalized costs. In the case of substations, NPSI has updated the costs of dedicated substations in a manner that is clearly incorrect and inconsistent with the previous methodology.

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[2]Curiously, total revenues equal total costs in Exhibit 10, even though the wind O&M do not seem to be in the costs.

Q: How did NPSI allocate the costs of substations?

A: Substation costs are separated into two components, as described by NPSI:

> The amounts invested in facilities that are dedicated to a single customer's use were identified and directly allocated to the customer's respective class. The remaining substation investment is allocated on the basis of primary demand levels. (SR-01 Attachment 1 Page 8)

More specifically, the non-dedicated substations are allocated on NPSI's estimate of non-coincident demand at primary.

Three classes—Large Industrial, ELI 2P-RTP, and Municipal—are allocated only dedicated substation costs, while Medium Industrial and General customers are allocated costs for both dedicated and non-dedicated substations, and the other classes are allocated only costs of non-dedicated substations.[3]

Q: Does NPSI correctly allocate substation costs?

A: No. There are at least two errors in NPSI's approach.

- Classes that are allocated only dedicated substation costs also use non-dedicated substations.
- The Company does not know which substations are dedicated, or what classes they are dedicated to.

Q: How do you know that classes that are allocated only dedicated substation costs are also served from non-dedicated substations?

A: The Company (CA IR-39) admits, "There are large industrial and municipal customers who are served from substations that also serve other classes. This is

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[3]While NPSI separates substation costs into "bulk" and "general" substation categories, the Company does not appear to know how it makes this separation, so it cannot track actual costs in these categories. (CA IR-171) It appears that NPSI uses ratios from the 1993 study (CA IR-38). Both categories are allocated in the same manner.

currently not reflected in Exhibit 3B….” In other words, these classes use equipment for which they are not charged.

Q: Does NPSI offer any excuse for this practice?

A: The Company says that it “has not attempted to change the basis of this schedule in this proceeding.” (CA IR-39).

Q: Is this excuse valid?

A: No. The “basis of this schedule” is that classes served from dedicated substations will be assigned the costs of those substations, and all classes served from non-dedicated substations will be allocated the costs of those substations. Maintaining fidelity to the “basis of this schedule” would require NPSI to apply that rule consistently as the mix of substations serving each class changes.

Q: Where does NPSI admit that it does not know which substations are dedicated, or what classes they are dedicated to?

A: The Company makes this remarkable admission in CA IR-37. In CA IR-170, NPSI clarifies that it does not keep track of which substations are dedicated, or their costs, or the classes that they serve:

> The work to produce a list of dedicated customer substations and transformers and to identify customers who use dedicated substations would require further data research and analysis which cannot be completed in the time allotted for responding to Information Requests.

Q: Has NPSI ever been able to identify the dedicated substations?

A: Yes. In 1977, the Company provided a detailed breakdown of the specific dedicated substations by class, identifying the customers served by each such substation (CA IR-183 Attachment 3 Pages 19–27).

Q: How has NPSI tracked the costs of the dedicated substations by class since 1977?

A: The Company has not explained how it updated the analysis from 1977 through 1993. The only documentation NPSI has provided for the computation of the costs of the dedicated substations is as follows:

> NPSI has kept the gross plant values for [dedicated and customer-owned substations] at constant dollar levels since 1996 and calculated their annual net plant values based on periodically updated depreciation rates. The annual net plant values of the two main categories A and D are modified to balance with the total net plant book value of all distribution substations. The modifications of [non-dedicated substations] are put into effect by applying on an annual basis periodically updated depreciation rates to the estimates of gross plant values of [non-dedicated substations] whose relative shares in the total gross plant value of all distribution substations, as simulated in these calculations, remain at approximately the same levels of 77 percent and 16 percent, respectively. (CA IR-172)

In other words, NPSI has gradually depreciated away the 1996 costs of the dedicated substations and assigned all additions (which would include new substations and transformers, replacements of aging and damaged equipment, and additional breakers, controls, and safety equipment) to the non-dedicated substations.

Q: Is it true that the non-dedicated substations' share of the gross plant has remained approximately constant?

A: I cannot tell, since NPSI has not provided these data. In any case, the non-dedicated station shares of the gross plant are of little relevance for the allocation of net plant shown in Exhibit 3b of the COSS. Under NPSI's approach, all retirements would be attributed to the non-dedicated plants, reducing both gross plant and accumulated depreciation and having no effect on net plant. As a result, the non-dedicated share of gross plant could remain stable while the non-dedicated share of net plant grows.

The share of net substation plant assigned to dedicated substations has dropped almost 50% since the 1993 COSS that was the basis for the Board's

1995 order and (I assume) the starting point for NPSI's computations "since 1996." See Table 1.

Table 1: Change in Net Substation Plant Assigned to Dedicated Substations

COSS	Non-Dedicated	Dedicated	Percent Dedicated
1978	$21,317	$1,819	4.4%
1980	$24,690	$1,678	4.4%
1993	$55,719	$2,550	4.4%
2012	$25,607	$598	2.3%

Sources: 1978 from CA IR-183 Attachment 3, p. 11; 1980 from CA IR-177 Attachment 1, p. 8; 1993 from CA IR-175 Attachment 1, p. 5; 2012 from SR-01 Attachment 1, p. 26.

The Company's estimate of the Large Industrial case NCP rose 89% from 1993 to 2012, yet the cost allocation of substations for that class declined by 65%. It appears that NPSI has been systematically reducing the share of substation costs assigned to the dedicated substations.

Q: How should the costs of distribution substations be allocated among classes?

A: Considering NPSI's lack of information about the actual costs (or even the identities) of the dedicated substations, the class served by each dedicated substation, and the load of the large industrial and municipal customers served from non-dedicated substations, it seems most reasonable to allocate all substation costs on some measure of demand. If, in the future, NPSI returns to its previous practice of tracking the costs of the dedicated substations, it can apply the pre-1996 allocation approach.

Q: What would be the effect of that change in allocation method?

A: Using the NCP allocator would increase the substation allocation to the three classes—Large Industrial, ELI 2P-RTP, and Municipal—to which NPSI assigned only its understated estimate of the dedicated substation costs and reduce the allocations to all other classes by about 15%. See Table 2. The percentage reductions are greatest for the General and Medium Industrial classes, to which NPSI allocates both dedicated and non-dedicated substations.

Table 2: Comparison of NPSI's Substation Allocation to Class NCP Allocation

	Class Non-Coincident Demand		NSPI Substation Allocation	
	kW	%	$	%
Domestic	1,177,490	50.2%	$15,467	59.0%
Small General	49,926	2.1%	656	2.5%
General	503,624	21.5%	6,624	25.3%
General Large	66,749	2.8%	827	3.2%
Small Industrial	52,126	2.2%	681	2.6%
Medium Industrial	85,528	3.6%	1,155	4.4%
Large Industrial	136,644	5.8%	375	1.4%
ELI 2P-RTP	206,548	8.8%	42	0.2%
Municipal	40,574	1.7%	28	0.1%
Unmetered	26,613	1.1%	350	1.3%

IV. Rate Design

Q: What rate-design changes do you address in this section of your testimony?

A: In the following section of this testimony I address the following rate design issues:

- implementation of marginal-cost based rate design,
- the level of the customer charge in the residential rate.

A. Marginal-Cost-Based Rate Design

Q: How should marginal costs be reflected in rate design?

A: Rates should be set, to the extent possible, so that the marginal rates faced by customers using the bulk of energy are as close as possible to marginal costs. For most customers, that will mean energy costs approximating marginal energy costs plus marginal capacity costs for generation, transmission and distribution. Demand charges do not provide efficient price signals for avoiding contributions to coincident peak and near-peak load.[4]

Q: What are NPSI's marginal costs?

A: The only estimate of NPSI's marginal costs that I have seen is NPSI's estimate of levelized avoided costs used in the 2011 and 2012 DSM Plans.[5] I have found several documents that discuss those values:

- Dunsky Energy Consulting reports that NPSI's 2011 estimate of avoided costs for 2010-2029 was $36.44/Gj, which would be $131.10/MWh or 13.11¢/kWh, plus $58.13/kW-yr, both in 2010 dollars (Evidence of NPSI, Docket No. P-884(3), Appendix C, February 25, 2010, p. 46).
- In the 2011 DSM Filing, NPSI reports "The levelized avoided cost of energy for DSM is estimated at $166/MWh" and "The levelized avoided cost of demand for DSM evaluation purposes is estimated at $79/kW of annual system peak. This value is based on deferring combined-cycle natural gas units." (Evidence of NPSI, Docket No. P-884(3), February 26, 2010, p. 12)
- NPSI (Multeese) IR-2 Attachment 2 in the 2011 DSM proceeding shows the derivation of the nominally-levelized avoided energy cost, as the difference in total NPV costs between the 2009 IRP Update cases with and without DSM, divided by the NPV of energy savings from the DSM. NPSI netted out the avoided capacity cost, estimated at $10/MWh or $79/kW-year, from the total cost difference.

[4] Demand charges can be charged based on the customer's contribution to load in peak hours, but those are rare.

[5] "The avoided costs used in the development of the 2012 DSM Plan are the same as those used for the 2011 DSM Plan." Multeese IR-5 in NSUARBP-E-ENSC-R-10.

- Exhibit N-19 and NPSI (Multeese) IR-2 Attachment 3 in the 2011 DSM proceeding shows the derivation of the nominally-levelized avoided capacity cost as $78.92/kW-year, assuming no avoided cost until 2018, then rising to $112.60/kW-year in 2010 dollars, and jumping again to $171.25/kW in 2018.

The values reported by NPSI are greater than those reported by Dunsky because they are in nominally-levelized dollars, rather than the real-levelized dollars reported by Dunsky.[6]

Q: Are these values appropriate for all energy-efficiency and rate-design purposes?

A: The values are appropriate in general, but they would be more useful if differentiated by season, time of use, year, and voltage level or class. For example, since NPSI estimates that line losses are greater for residential customers than other classes, the avoided and marginal costs for residential customers would also be somewhat greater than average.

Q: How do the tail-block energy rates for NPSI's tariffs compare to the marginal cost of energy?

A: The tail-block rates of the various major retail classes range from 36% to 65% of marginal cost. The energy costs are inflated by two years, to 2012 dollars, and adjusted from the average system energy loss factor of 6.88% to the class energy loss factor. The capacity costs are real-levelized over 2012–2031, adjusted from the average system demand loss factor of 10.71% to the class demand loss factor, and converted to $/MWh using the class load factor. See Table 3 below.

[6] Dunsky also included fewer years in the levelized capacity cost. Since Dunsky omitted the highest-value year, his avoided capacity cost was further reduced from NPSI's value.

Table 3: Energy Rates and Marginal Costs by Class

	Tailblock Rate[a]	Energy Line Losses[b]	Marginal Energy Cost $/MWh[c]	Demand Line Losses[d]	System Coincident Load Factor[e]	Marginal Capacity Cost $/MWh[f]	Total Marginal Cost $/MWh[g]	Tail-Block as Percent Marginal Cost[h]
Domestic	$127.87	10.05%	$178	15.24%	44.49%	$20.4	$198	65%
Small General	$122.74	9.54%	$177	11.26%	51.87%	$16.9	$194	63%
General	$72.65	6.67%	$172	7.69%	73.96%	$11.4	$184	40%
General Large	$71.15	6.62%	$172	7.12%	87.69%	$9.6	$182	39%
Small Industrial	$69.21	6.17%	$172	5.90%	89.03%	$9.3	$181	38%
Medium Industrial	$64.59	5.80%	$171	5.57%	87.44%	$9.5	$180	36%
Large Industrial	$64.32	4.76%	$169	4.24%	106.23%	$7.7	$177	36%

Notes

[a] From PR-01 Attachment 1.

[b] From COSS Exhibit 9a.

[c] $166/MWh, plus two years' inflation at 2%, to 2012$, times (1+energy line losses) ÷ 1.0688.

[d] From COSS Exhibit 9a.

[e] From COSS Exhibit 9a.

[f] Levelized cost of $76.2/kW-year for 2012–2031, from NSPI (Multeese) IR-2 Attachment 2 in 2012 DSM case, times (1+demand line losses) ÷ 1.1071, divided by 8.76 times the load factor.

[g] The sum of marginal energy cost and marginal capacity cost.

[h] The tail-block rate divided by the total marginal cost.

I excluded the municipal class (which does not directly control its energy use), the ELI 2P-RTP class,(for which the nominal tailblock rate is not really the marginal rate), unmetered load, Bowater Mersey (which is not Bowater's marginal supply), and the generation-replacement class (which probably has very different load shapes and avoided costs than the other classes).

The efficiency of all these rates would be increased by reducing customer charges, while increasing energy charges.

The improved price signals should encourage customers to make energy investments and operate equipment more carefully, reducing the burden on the ratepayer-funded energy-efficiency programs. In addition, since the customers' savings from energy-efficiency investments will be greater with higher tail-block energy rates, customers should be willing to invest more of their own funds in measures sponsored through the energy-efficiency programs. Many large customers can easily contribute the first year or two of bill savings to toward efficiency measures; higher tailblocks increase customer savings and hence the share that the customer is willing to finance.

Q: Do you have specific recommendations for rate design in this proceeding?

A: Yes. Reducing the residential customer charge by $1.05 per month, to $9.78 per month, would allow for a 1% increase in the energy charge above NPSI's proposal, to 12.915¢/kWh, assuming that the Company is allowed its requested rate increase. This rate redesign would provide a small step toward better incentives for energy efficiency, without unduly burdening larger customers. Table 4 summarizes the effect of this proposed change on bills for non-seasonal residential customers (Rate Codes 2 and 3), compared to NPSI's proposal. No customer would experience an additional increase of more than 1%, and most would experience much lower increases.

Table 4: Effect of Rate Redesign on Residential Bills

	Non-Heating	Heating	Combined
Percent of Customers With			
• Lower annual bill	78%	33%	73%
• Increases ≤ 0.5%	98%	78%	95%
Average Change	−0.25%	0.34%	−0.11%

This is a reasonable step toward more efficient rates.[7]

Q: Please summarize your recommendations to the Board on cost-allocation issues.

A: The Board should recognize that NPSI's existing cost-of-service methodology overstates the costs of serving residential customers in the following ways:

- classifying an excessive share of wind costs on demand,
- assigning unrealistically low substation costs to certain classes, based on incorrect data on the cost of dedicated substations.

The Company should be instructed to recompute the revenue-cost ratio with the following corrections:

- Classify all wind costs as energy-related.
- Allocate all substation costs on non-coincident demand.

Q: What are your recommendations to the Board on rate-design issues?

A: The Board should order NPSI to reduce the residential customer charge by $1.05 per month to allow for a greater increase in the energy charge. In addition, the Board should instruct NPSI to modify rates over the next several yearsI to increase tail-block energy rates to marginal costs, including environmental costs.

Q: Does this conclude your testimony?

A: Yes.

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[7]If the rate increase is less than requested, I suggest that the reduction in the customer charge still be $1.05/month, and that the energy charge be increased to recover the allowed revenues.