DOCKET NO. NSPI-P-202

NOVA SCOTIA UTILITY AND REVIEW BOARD

In the Matter of: An Application by NewPage Port Hawkesbury Corp. and Bowater Mersey Paper Company Ltd. for Approval of Amendments to Nova Scotia Power Inc.'s Load-Retention Tariff and for a Specific Load-Retention Rate Effective January 1, 2012

DIRECT TESTIMONY OF

PAUL CHERNICK

ON BEHALF OF

THE NOVA SCOTIA CONSUMER ADVOCATE

Resource Insight, Inc.

AUGUST 30, 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 (PBR) 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 over 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. ("NSPI") 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 (NSUARB P-128.10),
- Heritage Gas's 2010 rate case (NSUARB NG-HG-R-10),
- Nova Scotia Power's 2010 depreciation rates proceeding (NSUARB-P-891),
- the Renewable Energy Community-Based Feed-in Tariffs (COMFIT) proceeding (NSUARB BRD-E-R-10),
- Nova Scotia Power's 2012 General Rate Application.

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 clients asked that I review the reasonableness of the Load Retention Tariff (LRT) proposed by NPPH and Bowater Mersey (collectively, "NPB") and the implications of that proposal for residential ratepayers.

Q: Please summarize the LRT proposal.

A: The LRT proposed by NPB would reduce the 2012 energy charge for these two customers from the current Standard Energy Charge rate of $62.28/MWh, and NSPI's proposed Standard Energy Charge of $71.09/MWh, to $55.60/MWh. NPB bases this proposal on NSPI's current projection of average incremental fuel and variable O&M cost, averaged over the year, plus an adder of $2/MWh that NPB characterize as a contribution to fixed costs. In 2013–2016, the LRT would increase at $4.975/MWh annually, so that the levelized rate over 2012-2016 would equal NSPI's estimate of the levelized marginal costs of serving this load, including running costs plus limited incremental generation capital costs (Rosenberg Direct Evidence, p. 11). See Table 1.

Table 1: Proposed LRT Energy Charges (Dollars per MWh)

	Incremental Rate	Adder	Total
2012	$53.60	$2.00	$56.60
2013	$58.57	$2.00	$60.57
2014	$63.55	$2.00	$65.55
2015	$68.52	$2.00	$70.52
2016	$73.50	$2.00	$75.50

The proposed LRT would lack the real-time pricing of the Extra-Large Industrial (ELI) rate and would not have any other incentives to control the time of use of these customers' energy use.

The proposed LRT would also lack the $20,700/month customer charge in the current and proposed ELI rate.

Q: What specific issues does your testimony address?

A: I address the following issues regarding the LRT:

- Nova Scotia Power's estimate of the incremental costs of continuing to serve the NPB load in 2012–2016.
- Comparison of the effect on the costs borne by other customer classes under various circumstances, including the following:
  - The entire NPB load is shut down,
  - The entire NPB load remains on the system at the proposed LRT.
  - The fate of the NPB load is uncertain under both the ELI and the LRT.
- The effects on costs of the changes in the rates and terms for the NPB load.

Q: Please summarize your conclusions.

A: My major conclusions are as follows:

- The marginal costs of serving the NPB load are likely to be greater than the estimate developed by NSPI.
- Correcting the errors in the NSPI analysis indicates that other ratepayers would be better off without the NPB load than with the load at the LRT rate, at least in 2012, the only year for which NSPI and NPB have provided revenue analyses.
- The loss of the real-time-pricing feature of the ELI rate would increase costs to all customers.
- The proposed steep increases in the LRT from 2012 to 2016 would make the LRT more attractive in 2012 and 2013, compared to a levelized rate or one that increases more gradually over time. But the higher rates in 2015 and 2016 may defeat much of the purpose of the load retention tariff. If the mills wind up taking less energy in 2015 and 2016 than in 2012 and 2013,

the sales-weighted rate would be lower than NPB assumes in its filing, further reducing the LRT contribution to covering marginal costs.[1]

- NewPage Pt. Hawkesbury and Bowater Mersey have not demonstrated the necessity for the very large reduction in rates it requests, or shown that those lower rates would keep the mills on line.

Q: What are implications of NewPage's recent announcement regarding its Port Hawkesbury mill for the design of the LRT?

A: On August 22, 2011, NewPage Corporation announced that,

> based on its assessment of current market and economic conditions, it has decided to take downtime on both paper machines at its Port Hawkesbury mill in Nova Scotia, Canada. The downtime will begin September 10 for the mill's PM1 newsprint machine and September 16 for the PM2 supercalendered machine. NewPage will provide future updates on the mill based on an ongoing review of the situation and economic conditions during the anticipated downtime.
>
> The decision was based on a combination of factors, including unfavorable exchange rates between the U.S. and Canadian dollars and high utility and shipping costs, which have rendered its Port Hawkesbury mill operations unprofitable for more than a year. ("NewPage to Initiate Downtime at Port Hawkesbury Mill," NewPage Corporation press release)

Certain of NewPage's internal analyses, such as in Confidential Attachment NewPage-Larkin-10, suggest that a long-term shutdown of the mill (triggering severance payments and other costs) would be more expensive than continued operation of the mill.

At this point, it is not clear how long the downtime will continue. Press reports quote the Richmond County Warden John Boudreau as saying

[1]Depending on market conditions in 2015 and 2016, the proposed LRT schedule could also result in NPB requesting further rate relief in those years, and never compensating other ratepayers for the undercollections in 2012 and 2013.

> "The company is adamant that it's a hot shutdown,"…which means paper machines will be maintained and can quickly be restarted. "They're repeating it nice and loud and that means that they're looking to turn those machines back on in the near future, and that's good news."[2]

Other press coverage reflects the lack of any indication of permanent or long-term closure:

> Since NewPage is not calling the shutdown permanent, the workers' questions about severance pay, pensions and early retirement are going unanswered. And the matter of the potential bankruptcy of NewPage's parent company, NewPage Corp. of Miamisburg, Ohio, is adding extra uncertainty….
>
> When NewPage announced Monday that it would be idling the mill indefinitely, it didn't include any advice for workers on how to rethink their financial plans or say what kind of timeline to expect for developments at the mill.
>
> NewPage Port Hawkesbury and its workers' union, Local 972 of the Communications, Energy and Paperworkers Union, say that's because nothing is set in stone. Even the planned dates of the two paper machines' shutdowns, Sept. 9 and Sept. 16, are projections. No employees have received layoff notices yet.
>
> It's too early to talk about severance pay, said NewPage spokeswoman Patricia Dietz. The company is busy preparing answers for staff as best it can, she said. In the fall, the company will look at its next step.
>
> "There was no announcement regarding permanent closure, so the question of severance isn't being addressed," Dietz said. "However, employees do have many questions that need to be addressed, and we are gathering what information we can to share with them next week."
>
> Under NewPage's collective agreement, severance is paid after the mill has been idle for three months, said union representative Don MacKenzie.[3]

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[2]Nancy King, "NewPage plans to 'turn those machines back on in the near future' says Richmond County warden," Cape Breton Post, August 25, 2011.

[3]Selena Ross, "No NewPage answers; Uncertainty for workers at Point Tupper mill," Chronicle Herald, August 27, 2011.

In short, the downtime may end in 2011, or early in 2012, so the LRT remains relevant for NewPage, as well as for Bowater.

Q: Please summarize your recommendations.

A: I recommend that the Board reject the LRT as filed. The loads currently served on the ELI rate should remain on that rate to preserve the benefits of the real-time pricing feature. If a case can be made that a rate reduction for these customers is appropriate, that reduction can be implemented as part of the ELI rate.

Before the Board can be in a position to determine whether any rate discount is in the public interest, it will need to see two analyses that have not been provided. First, NSPI must develop a realistic estimate of the marginal cost of serving the NPB load over the period for which a rate discount is requested, including the following elements:

- an updated base case reflecting the proposed Federal rules requiring coal-unit retirement, NSPI's abandonment of the Lingan low-sulfur coal project and biomass co-firing, and a reasonably re-optimized supply plan meeting environmental and renewable-energy-standard ("RES") requirements with feasible resources;
- an updated case without the NPB load, reflecting the deferral or avoidance of fixed costs related to continued operation of units that could be shut down, environmental projects that would not be required, and RES projects that would not be required without the extra load.

Second, some party (either NSPI or NPB) must develop a reasonable risk model, demonstrating that other ratepayers would be better off on an expected-value basis with the discounted ELI rate (and a higher probability of retaining more NPB load and bearing the associated marginal costs) than with the full ELI rate (with higher margins for whatever NPB load is served by NSPI).

III. Marginal Costs of Serving the NPB Load

Q: What categories of costs would be incurred to serve the NPB load in 2012–2016 that would be avoidable if the mills shut down in those years?

A: The marginal or avoidable generation costs would include the following:

- fuel,
- lost export sales,
- variable O&M,
- capital investment to keep baseload plants on line (either for routine maintenance, repair, or environmental compliance),
- incremental investments and purchases of renewable energy to meet RES requirements.

In addition, serving the NPB load will probably require additional transmission to integrate incremental RES, while maintaining flexibility in coal-plant output. Since Port Hawkesbury is east of NSPI's major transmission constraints, usage by Bowater Mersey is most likely to require transmission upgrades.

Finally, the continued operation of the mills imposes on NSPI costs of metering, data management, billing, and other customer-service costs.

Q: In his footnote 4, Dr. Rosenberg claims, "Because these mills are fully interruptible, there should be no incremental capacity-related, i.e., fixed, costs associated with serving these two customers." Do you agree?

A: No. Dr. Rosenberg conflates the concepts of capacity-related costs and fixed costs. Most of NSPI's incremental generation investments and commitments are related to providing least-cost energy consistent with environmental constraints and the RES. Neither the existing ELI rate nor the proposed LRT would allow NSPI to interrupt NPB loads to avoid violating emission caps or RES requirements. Without NPB loads, NSPI would be able to avoid installing expensive environmental retrofits, building new wind and hydro plants, purchasing additional wind energy, and continuing operating expenses for some coal units.

Dr. Rosenberg actually includes in his post-2012 LRT some marginal capital costs identified by NSPI, so he actually uses this argument only in justifying a 2012 price below NSPI's estimate of marginal costs.

A. *Nova Scotia Power's Estimate of Marginal Cost*

Q: Where is NSPI's estimate of the marginal cost of serving the NPB presented in the record?

A: Dr. Rosenberg's Appendix C summarizes NSPI's estimate of avoided costs. NSPI provides additional detail on the avoided costs in NSPI-HRM IR-2, Attachment 1, which are summarized below in Table 2 and Table 3.

Table 2: NSPI Estimate of Avoided Costs (Dollars per MWh)

	Fuel	Non-Fuel Operating	Capital Recovery	Total
2012	$52.70	$3.26	$3.52	$59.48
2013	$52.70	$3.25	$5.82	$61.77
2014	$54.53	$3.37	$5.97	$63.86
2015	$56.13	$3.24	$5.71	$65.08
2016	$56.36	$3.34	$5.50	$65.20

Table 3: NSPI Estimate of Avoided Costs (Millions of Dollars)

	Fuel	Non-Fuel Operating	Capital Recovery	Total
2012	$125.7	$7.8	$8.4	$141.9
2013	126.1	7.8	13.9	147.8
2014	130.9	8.1	14.3	153.4
2015	135.2	7.8	13.8	156.8
2016	136.3	8.1	13.3	157.7

In addition, NSPI ran Strategist just for 2012, using different assumptions than in the Appendix C runs, and estimated avoided operating (but not capital) costs. The estimated avoided operating cost, $53.60/MWh, is stated in Rosenberg's testimony (page 10, line 14), and the annual total operating costs with and without NPB loads are provided in NSPI-HRM IR-3. In NSPI-Multeese IR-1(k), NSPI lists numerous inputs that differ between the runs that produced the values in Appendix C and those that produced the $53.60/MWh value, but does not quantify any of them. Table 4 compares the operating costs for the two runs.

Table 4: Comparison of NSPI's Estimates of 2012 Avoided Operating Costs

	Operating Costs				
	Without NPB	With NPB	Difference	**NPB Load**	**$/MWh**
Rosenberg Appendix C	$549,623	$683,143	$133,520	2,386.0	$55.96
NSPI-HRM IR-3	$510,506	$638,141	$127,635	2382.7	$53.57
	−7.1%	−6.6%	−4.4%	−0.1%	−4.3%

The difference in avoided costs due to the operating-cost differences between the two Strategist runs is $2.39/MWh. In addition, Rosenberg Appendix C includes $3.52/MWh of capital costs, for a total of $59.48/MWh in 2012 avoided costs.

Additional detail on NSPI's estimates of avoided costs are provided attachments to NSPI-Multeese IR-1 detailing the change in output by plant.

Q: Did NPB properly apply NSPI's estimate of the avoided cost?

A: No. From Appendix C to Dr. Rosenberg's testimony and from NSPI-Multeese IR-1 Attachment 1 and 3, it is apparent that NSPI computed these avoided costs per MWh of NPB energy requirements, which equal NPB sales plus 2.04% losses.[4] There is nothing wrong with estimating the avoided cost per MWh of energy

[4] I assume that the same is true for the $53.60/MWh estimate.

requirements, but it is not the same as the cost per MWh of sales. Yet Dr. Rosenberg proposes to base LRT rates per MWh sold on NSPI's estimate of avoided cost per MWh of energy requirements.

The cost per MWh sold to NPB would be 2.04% higher than the value reported in Rosenberg Appendix C. Dr. Rosenberg should have increased all the avoided costs by 2.04% for sales before designing the LRT.

Q: Are the NSPI estimates of avoided costs based on least-cost supply plans with and without the NPB load?

A: No. According to Rosenberg Appendix C (repeated in HRM IR-2 Attachment 1), "resource plans were re-dispatched NOT re-optimized" (original emphasis). On discovery, NSPI clarified that the plans with and without NPB loads were developed for the IRP50 fuel prices, and that when Strategist was rerun with the updated fuel-price forecasts from the 5-year Business Plan, "The plans were not re-optimized with these revised fuel prices to determine if the timing or types of resources selected would change" (NSPI-Multeese LR IR-1(c)). The updated fuel forecast in the 5-year business plan reduced gas prices and increased coal prices. (NSPI-Multeese IR-3 Confidential Attachment 1) With the lower gas prices and smaller gas-coal price differentials, some investments assumed in the IRP to maintain coal output may not be economic, resulting in more gas use, higher coal-plant heat rates, higher prices for the remaining coal use, and/or other increases in energy costs.

In addition, as I discuss in III.D and III.E, it appears that not all avoidable capital investments and contractual obligations were removed from the non-NPB case.

Q: Are the revenue requirements in 2012–2016 the only effect of the incremental load of the measures that would be required to serve NPB in 2012–2016?

A: No, for the following three reasons.

- The commitments made in 2012–2016 to serve NPB will continue to increase revenue requirements after 2016, even if NPB loads decline or disappear.
- Given falling loads and increased renewables, investments in conventional generation that are delayed past 2016 may never occur.
- Nova Scotia Power may commit to investments after 2016 based on its load in the 2012-2016 period.

The NSPI estimates of marginal costs do not reflect any of these continuing effects of meeting the NPB load in 2012-2016. "The effect beyond 2016 of changes to capital cost assumptions has not been incorporated into the Load Retention Tariff Pricing Mechanism" (NSPI-Multeese LR IR-1(f)).

B. Comparison to NSPI Estimate of DSM Avoided Costs

Q: How do the marginal costs that NSPI estimated for the NPB load compare to the avoided costs that NSPI estimated for DSM?

A: For the NPB load, NSPI estimated levelized marginal costs of $62.89/MWh over 2012–2016. For DSM, NSPI estimated levelized avoided costs of $166/MWh over 2010–2026, 260% of the estimate of NPB marginal costs. In NSPI-Avon IR-3, NSPI explains the differences between these estimates as follows:

- The DSM avoided costs were estimated for an increment of load above the base-case forecast, while NPB's marginal costs were estimated for a decrement below that forecast. This difference would tend to result in NPB's marginal costs being somewhat lower than the DSM avoided costs.

- "The DSM avoided costs considered the time period 2010 to 2032. The NPB avoided costs considered the five year period 2012 to 2016." This is a valid difference in principle. Since NSPI's estimate of avoided DSM cost in 2012–2016 was over $100/MWh (NSPI-CA IR-8 Confidential Attachment 1), the time period accounts for somewhat over half the reported difference.
- The DSM avoided costs were estimated based on 2009 IRP fuel prices, while NPB's estimate is based on updated coal and natural-gas prices in the NSPI Five Year Business Plan. These prices are provided in NSPI-Multeese IR-3 Confidential Attachment 1.

Q: Is it possible that these three factors reasonably account for the difference between NSPI's estimates of DSM avoided costs and NPB marginal costs?

A: That is possible. However, the NPB marginal costs appear to be understated due to NSPI's failure to fully reflect the avoidance of investments and commitments required to meet environmental and RES requirements, as discussed in Sections III.D and III.E. The longer-term analysis of DSM may have included avoidance of more of those investments and commitments.

C. Failure to Model Exports

Q: How did NSPI model export sales in the Strategist runs from which it estimated the NPB marginal costs?

A: In those runs, NSPI assumed that no exports would occur in either the base case or the case with no NPB loads.

Q: What is the effect of ignoring exports?

A: In the absence of the NPB load, rather than turning down unneeded power plants and saving only fuel and variable O&M, NSPI would sometimes export power at prices higher than the avoidable operating costs. For FAM purposes, NSPI assumes that exports are equal to a half of the potential output of Tufts Cove 2 and 3 that is not used to meet domestic load (DE03–DE-04, pp. 20–21; NSPI-Avon IR-18 in NSUARB P-892). In 2006, when NewPage was shut down for an extended period, export sales were 406 GWh, compared to the 34 GWh NSPI forecasts for 2012 in its rate application (DE03–DE-04, p. 123)

According to NSPI's estimates, serving the NPB load would require an additional average of about 600 GWh of Tufts Cove generation annually (NSPI-Multeese IR-1 Attachments 1 and 3). If half of that would have been resold, and if NSPI earns a margin of $10/MWh on exports, lost exports would add some $3 million to the marginal cost of serving the NPB load.

D. Environmental and Other Costs of Continued Coal-Plant Operation

Q: How do environmental constraints affect the marginal costs of serving the NPB load?

A: Environmental constraints affect the marginal costs in two ways. First, environmental requirements may increase dispatch costs by requiring more expensive fuels (e.g., low-sulfur coal), increasing operating costs (e.g., for reagents and periodic maintenance), and reducing net generation (e.g., using electricity to run scrubbers). Second, meeting emission limits while serving higher loads may require additional fixed costs, such as adding scrubbers, baghouses, and other control equipment.

Q: Are there environmental costs of the first type that are not included in NSPI's estimate of the cost of serving the NPB load?

A: Yes. The notes to Rosenberg Appendix C state that "The run does not incorporate recent changes to…the proposed Federal framework." The response to NSPI-Multeese IR-1(m) clarifies that "The proposed Federal framework refers to the Federal Government proposal to retire coal units when they reach their 45 year life. Neither of these assumptions was incorporated in the analysis of Appendix C."

The requirement to retire coal units at age 45 was informal at the time NSPI estimated the marginal cost of serving the NPB load, but has since been formally proposed ("Reduction of Carbon Dioxide Emissions from Coal-Fired Generation of Electricity Regulations," Environment Canada, Canada Gazette Part I, August 27, 2011). These proposed regulations would require the retirement of Trenton 5, or a substitute unit, by December 2015. Since NSPI expects Trenton 5 to operate at a greater capacity factor than Lingan, it is likely that NSPI would choose to retire a Lingan unit, rather than Trenton 5.

The retirement of any of the coal units is likely to increase the marginal fuel and operating cost of the NSPI system, and hence increase the marginal cost of serving the NPB load.

Q: Are there environmental costs of the second type that are not included in NSPI's estimate of the cost of serving the NPB load?

A: Yes. NSPI's latest capital plan includes $60 million in baghouse investments at Lingan 3 and 4, to be requested during 2011 (2011 Annual Capital Expenditure Plan, December 23, 2010, p. 13).

With the NPB load, NSPI expects that, the combined capacity factor for the four Lingan units would be about 49% in 2012, falling to 36% in 2016. Without the NPB load, Lingan's capacity factor would drop to 20% in 2012 and 10% in 2016. It seems likely that the loss of the NPB load would eliminate the need for the baghouse investments. Under the proposed Federal rules, Trenton 5 would reach the presumed retirement date in 2015 and Point Tupper in 2018, requiring retirement of those units or substitute units. The Lingan units, with their high retrofit costs and low capacity factors, would be obvious candidates for retirement.

Nova Scotia Power's projection of generation capital costs remain substantial, averaging about $250 million annually through 2015 (ibid., p. 48). While I have not seen a detailed breakdown of these investments, they probably include additional environmental retrofits that can be deferred if NSPI generation levels were much lower.

Q: Are there other costs of operating NSPI's coal plants that would be increased by the continuation of the NPB load?

A: Yes. Utilities must make O&M expenditures and periodic capital investments to keep power plants on line. For example, in the current rate case, NSPI estimates O&M costs of about $67 million for the steam plants (DE-03—DE-04 Appendix C, p. 27), or about $43/kW-year and about $6 million per coal unit. In the ACE proceeding, NSPI projected about $40 million in capital to maintain the steam plants (plus another $12.7 million for Pt. Aconi), excluding some major investments related to renewable and environmental requirements, which I discuss elsewhere in this testimony.

Without the NPB load, two or three coal units can be retired, avoiding many of the capital costs, as well as the O&M costs of those units.

Q: Does NSPI's estimate of the marginal costs of serving the NPB load include the effects on dispatch costs of a coal-unit retirement in 2015, a reasonable allowance for avoided environmental retrofits due to lower output, and the ability to mothball or retire additional coal units in response to lower loads?

A: Nova Scotia Power recognizes marginal costs only for the second of these three categories. The base case, with NPB load, includes $20 million in 2010 investment for "LS, Low BTU Coal Burn (Lin 1-4)," but not in the case without the

NPB load (NSPI-Multeese IR-1(c) and 1(d)). Since the project was scheduled for 2010, it is not clear why NSPI thought it would be cancelled in response to a reduction in load in 2012. This project was never implemented and has since "been placed on hold pending further certainty" about the "Federal Government's announced interest in limiting the operating lives of coal plants,", and should not be in either case (NSPI-Multeese IR-4(a-c)).

This cost allowance is much smaller than the costs of the Lingan baghouses, let alone all the other environmental retrofits which would be unnecessary without the NPB load.

E. Renewable Energy Costs

Q: What Renewable Energy Standard (RES) requirements did NSPI model in its Strategist runs estimating the marginal cost of serving the NPB load?

A: That is not clear. The notes to Rosenberg Appendix C state that "The run does not incorporate recent changes to Provincial RES requirements…." The response to NSPI-Multeese IR-1(m) clarifies that "Recent changes to Provincial RES requirements refer to the renewable energy requirements in 2015 and 2020 as outlined in the Renewable Electricity Plan in April 2010." It is not clear what renewable energy requirements NSPI modeled for 2015, other than the 25% requirement in the Renewable Electricity Plan.

Q: What effect would loss of the NPB load have on NSPI's need for renewable energy through 2016?

A: Nova Scotia Power has procured enough renewable energy to meet its RES obligations through 2014. Starting in 2015, NSPI will need to supply 25% of its energy requirement with renewables. According to DE-03-DE-04 Appendix A in NSPI's rate filing, its committed resources, including 388 GWh from the Port

Hawkesbury biomass plant, are 359 GWh short of its RES obligation for 2015, with the NPB load. In addition, NSPI has previously added a 200 GWh safety margin to its RES target for 2015, to ensure that it meets its requirements (see Docket No. P-128, NSPI-CA IR-30, Attachment 1). According to IR NSPI-CA IR-1 Attachment 1, NSPI expects that those same committed resources would be 315 GWh greater than its RES obligation, without the NPB load.[5] Thus, all the renewables currently planned through 2016 could be eliminated, and some commitments canceled, were the NPB load to disappear.

Q: What incremental renewable energy projects did NSPI assume would be required to serve the NPB load?

A: The only differences in renewable energy commitments in the Strategist runs with and without the NPB load is that the latter omits the capital and operating costs of 4.2 MW Marshall Falls Hydro and some unspecified amount of biomass co-firing. In the run without the NPB load, cofiring is reduced (NSPI-Multeese IR-1d), but not eliminated (NSPI-Multeese IR-1c). But NSPI does not consider co-firing of biomass to be a viable RES technology:

> Given the Provincial Government's recent restrictions on co-firing biomass, Nova Scotia Power has suspended engineering and testing of this technology. While these projects will not proceed, the requirement for low emitting generation will remain. At this time, it appears the effect of the change from one form of renewable or low emitting generation to another will be limited to the differences between the generation characteristics of the fuel supply (e.g. biomass vs. wind) and the timing of the associated backup generation requirement. (NSPI-Multeese 4e)

[5] These committed resources do not include any that may be added under the COMFIT program, independent of NSPI's need for renewables to meet the RES.

Q: What renewable energy projects should NSPI have considered in computing the marginal cost of serving NPB load?

A: The major commitments NSPI faces for renewable-energy compliance include the following investments:

- The Port Hawkesbury biomass plant under construction at the NewPage Mill.
- Some $360M for three wind plants to be completed in 2013 and 2014 (ACE 2011 IR NSPI-NPB IR-4(a)).
- Some 300 MWh of renewable energy that would otherwise be acquired through RFPs to be administered by the new Renewable Electricity Administrator.

Since loss of NPB load would leave NSPI with an RES surplus, these costs should be avoidable even with only committed resources (Port Hawkesbury and existing plants and contracts).

Q: Has NSPI examined the cost-effectiveness of completing the Port Hawkesbury plant?

A: No. In response to questions regarding "whether NSPI has determined whether completion of the NPPH biomass plant would be needed or cost-effective in the absence of the NPB electric load, the NewPage steam load, and the NewPage biomass supply" and "NSPI's best estimate of the costs avoidable through cancelation of the NPPH biomass plant, including capital and operating costs," NSPI responded by stating that the Board had approved the project (NSPI-CA IR-2 and 4).

Q: Does the Board's approval of the project obviate the need for continued prudent management of the project?

A: No. Conditions have changed dramatically with NewPage and Bowater's position that they need a further rate discount to continue operating. Without the NPB load, NSPI would not need the Port Hawkesbury plant to meet the 2015 RES. The economics of the plant were also sensitive to the operation of NewPage for the following reasons:

- The mill waste was assumed to be a source of discounted waste wood.
- NewPage was to manage procurement of additional biomass under an indexed contract, using its expertise in procuring forest products in eastern Nova Scotia.
- The operations contract was premised on NewPage's being able to share operation and maintenance staff between the mill and the power plant.
- The sale of steam to NewPage would increase the efficiency and reduce the cost of the electricity to NSPI.

Much of the costs of the project are sunk, including the price NSPI paid to acquire NewPage's existing boiler. Any utility has an obligation to monitor conditions and manage development of projects, even once they are approved by the Board. I find NSPI's cavalier attitude toward its responsibilities to be very troublesome.

Q: What levelized costs have NSPI estimated for the wind projects it owns?

A: The company reports that the Nuttby project will cost $84.54/MWh (Nuttby Application, September 2009, p. 16), the Point Tupper Wind Project will cost $91.65/MWh (Point Tupper Application, February 23, 2010, p. 16), and that Digby will cost $86.71/MWh (Digby Application, July 23, 2010, p. 25). Adding in $7.50/MWh for the loss of the ecoEnergy credit would raise these costs to $92/MWh, $98/MWh and $94/MWh.

In addition, as suggested in NSPI-Multeese 4(e), NSPI believes that wind resources will require significant integration costs, and even backup capacity.

Q: Please describe the RFP process for renewable energy supplies.

A: The Nova Scotia Department of Energy describes the program as follows:

> As legislated in the 2010 amendments to the Electricity Act, Nova Scotia will produce 25% of total electricity from renewable energy by 2015. To enable the province to achieve this goal, a minimum of 300 GWh will be procured from Independent Power Producers (IPPs). The 2010 amendments call for the government to appoint a Renewable Electricity Administrator (REA) to oversee a competitive bidding process for this renewable energy from IPPs. Having an independent entity oversee such a process is intended to promote fairness, transparency, and efficiency. In July 2011, the government appointed Power Advisory LLC to serve as the REA after a competitive application process. (http://www.nsrenewables.ca/competitive-bidding/renewable-electricity-administrator)

According to Canadian Clean Energy Conferences, the "Renewable Electricity Administrator…, John Dalton of Power Advisory, expects February will be the proposal submission deadline for the province's new RFP for wind projects. The administrator will conduct a bid process for at least 300 GWh of new wind projects."[6]

These contract projects are also part of the cost of serving the NPB load.

[6] Web page for Nova Scotia Feed-In-Tariff Forum, forhttp://create.sendtex.be/121/?m1=1y11bhx4se70x1cbhfslpxylbxyy&m2=13d5, accessed August 24, 2011.

F. *Marginal non-generation costs*

Q: Does NPB impose non-generation costs on NSPI?

A: Yes, including at least working capital and customer service costs.

Q: What customer service costs are associated with serving NPB?

A: It is difficult to extract customer-specific costs from the data routinely provided by NSPI. In the rate case, NSPI describes the Customer Service cost category as including

> the customer care centre, billing and payment services, meter services, credit and collections, customer communications and quality assurance, customer relations, heating solutions, large customer management and load and revenue forecasting. (Docket No. NSPI P-892 filing, DE-03–DE-04, p. 82)

NewPage and Bowater are likely to impose significant costs in communications, customer relations, and large-customer management. As is obvious in the current proceeding, NSPI engages in discussions and negotiations with NPB, and performs studies for those customers, to an extent that would be very rate for other classes.

For 2012, NSPI allocates $0.4 million in customer-related expenses to the ELI rate class, mostly for "marketing and sales" (which I assume is essentially the same as "large-customer management") and meter data services. A significant portion of these costs are likely to be marginal costs of continuing to serve the NPB load.

IV. Effect of the LRT on Rates charged to other classes

A. *Simple Analysis of NPB*

Q: What analysis does NPB present regarding the effect of the proposed LRT on the revenue to be collected from other customers?

A: Dr. Rosenberg's Appendix D was prepared by NSPI. That analysis purports to show that were the NPB load not included in the rate case, the other rate class would pay $33 million more in 2012 than in NSPI's rate proposal, all else equal. With the LRT, the cost increase to other customers would be only $4 million lower, or $29 million.

However, NPB's LRT proposal is only slightly better for the other ATL rate classes than the departure of the NPB load, even if all of the following were to come to pass:

- NSPI were to receive its requested increase in revenue requirements in the 2012 rate case,
- the Board were to project that NSPI's sales to NPB in 2012 would be zero without the LRT, and
- the costs avoided by the loss of the NPB load were as stated in Appendix D.

See Table 5.

Table 5: Effect on other Classes in 2012 of Losing NPB Load versus Adopting LRT Proposal

	NSPI Proposal (Base) Revenue (Million $)	NSPI Proposal with Loss of NPB Loads			NPB LRT Proposal			Increase from LRT as % of NPB Loss
		Revenue (Million $)	Change from Base		Revenue (Million $)	Change from Base		
			Million $	Percent		Million $	Percent	
Residential	$639	$654	$15	2.4%	$652	$14	2.1%	89%
ATL-NPB	$1,228	$1,261	$33	2.7%	$1,257	$29	2.4%	88%
Grand Total	$1,408	$1,280	($128)		$1,408	$0		

Source: all revenue estimates from Rosenberg Appendix D.

Note that the incremental cost to other classes in 2012 of losing the NPB load, as compared to retaining the NPB load under the LRT, is quite small, about 0.3% of revenues. Also, the cost to those classes from the LRT is nearly 90% of the cost of losing the NPB load, even with the three assumptions listed above.

B. Correcting Avoided Costs

Q: What revenues and avoided costs did NSPI use in Rosenberg Appendix D?

A: Nova Scotia Power explains the derivation of Appendix D as follows:

> For the purposes of "Alternate scenario predicated on the absence of the NP & BM Loads" NSPI used the revenue requirement of $1,208.5. It was arrived at by reducing the revenue requirement of $1,338.9 million, as filed in 2012 GRA, by the amount of avoided cost of $130.4 million associated with serving NP and BM. (NSPI-Multeese IR-2a)

The $1,338.9 million revenue requirement includes all classes except the LED rates, net of fuel-adjustment mechanism ("FAM") BA revenue, as explained in the rate case:

> The total revenue forecast for 2012, based on current ATL and Miscellaneous Service rates, projected BTL rates, inclusive of forecast Export revenues, but absent new LED streetlight rates is $1,244.5 million. Compared to the 2012 revenue requirement of $1,338.9 million, this represents a revenue shortfall of $94.4 million. (NSUARB-NSPI-P-892, DE-03-DE-04, p. 140)
>
> The figures of $1,244.5 and $1,338.9 million are arrived at by subtracting the forecasted FAM BA revenue of $50.2 million for 2012 from the total revenues of $1,294.7 (present rates) and $1,389.1 (proposed rates) million displayed in the financial table FOR-01. (footnote 43)

Q: Are the revenue and marginal costs assumed in Appendix D consistent with the values specified in

A: In fact, the values in NSPI-Multeese IR-2a and the rate filing are not the same as either of the following estimates:

- the avoided costs in Appendix C, which reports $133.1 million in avoided operating costs (which are consistent with the avoided operating cost data in NSPI-Multeese IR-1 Attachments 1–4) and a total avoided cost of $141.9 million,
- the rate analysis in the analysis in Appendix D, which assumes $1,406.9 million for the revenue requirement with NPB loads (apparently including the FAM BA revenues), and reduces the revenue requirement by $128.1 million in the case without NPB. These discrepancies are summarized in Table 6.[7]

Table 6: Discrepancies in NSPI Revenue Analysis (Millions of Dollars)

Source	2012 Revenue Requirement With NBP	2012 Revenue Requirement Without NBP	Avoided Cost	Increase from Appendix D
NSPI-Multeese IR-2a and GRA filing	$1,389.1	$1,294.7	$130.4	$2.3
Appendix C				
Operating			$133.1	$5.0
Total			$141.9	$13.8
Appendix D	$1,406.9	$1,278.8	$128.1	–

Hence, while Rosenberg Appendix D purports to show $4.0 million in 2012 savings to other ratepayers from the LRT, compared to losing all NPB load, NSPI's estimate of marginal costs indicates that other ratepayers would pay $9.8 million *more* ($4.0–$13.8) with the LRT than without the NPB load.

[7] Oddly, in Appendix D, NSPI reports changes in revenues from some below-the-line classes from the NSPI proposal to the without-NPB case, even though there is no obvious relationship to NPB sales. Revenues from LED capital costs fall 1.7%, while revenues from miscellaneous services rise 0.5%. With the NPB rate proposal, Appendix D reports that LED revenues would equal the revenues without NPB (still below the NSPI base case) and the miscellaneous service revenues would be another 0.1% higher than in the no-NPB case. While the net effect of these classes' revenue on the analysis is small, I cannot determine whether NSPI made other undocumented changes in the revenue analysis.

Q: What information have NPB filed regarding the effect of the LRR on other ratepayers after 2012?

A: They do not appear to have provided any serious analysis of the effects. Dr. Rosenberg says,

> In each ensuing year, these two customers would pay another $9.5 million (assuming the same mill load as in 2012) contribution to fixed costs. Thus, the benefit to the other ATL customers would be $13.5 million in 2013 ($4 million plus $9.5 million), $23 million in 2014, $32.5 million in 2015 and $42 million in 2016. (Rosenberg Direct, p. 15)

These supposed benefits assume that the marginal costs of serving NPB load would remain constant over time. In fact, NSPI estimates that those marginal costs would rise about $5.9 million in 2013, $5.5 million in 2014, $3.4 million in 2015, and $0.9 million in 2016.[8] As discussed above, the net benefit of marginal costs of serving the NPB load in 2012 is –$9.8 million, and the net benefits in other years would be as shown in Table 7.

Table 7: Benefits to non-NPB Customers of the LRT versus no NPB Load

	Rosenberg Claim[a]	Marginal Costs[b]	Marginal-Cost Adjustment[c]	Corrected Estimate[d]
2012	$4.0	$141.9	−$13.8	−$9.8
2013	$13.5	$147.8	−$19.7	−$6.2
2014	$23.0	$153.4	−$25.2	−$2.2
2015	$32.5	$156.8	−$28.7	$3.8
2016	$42.0	$157.7	−$29.6	$12.4
Total	$115.0			−$2.0

Notes:
[a] Rosenberg Direct, p. 15
[b] Rosenberg Appendix C
[c] $128.1 million embedded in Rosenberg estimate–[b]
[d] Sum of values from Rosenberg Direct, P. 15, and Rosenberg Appendix C

[8] Dr. Rosenberg's estimate of the $9.5 million in incremental annual LRT revenues ignores the very slow growth NSPI projects for NPB, as well as potential changes in the Mersey Contract prices. I accept his estimate for the purposes of this discussion.

Simply applying NSPI's estimate of marginal costs from Rosenberg Appendix C wipes out Dr. Rosenberg's estimated benefit of $115 million.

Q: How would you expect the cost to ratepayers of not having the NPB load on the ELI to change over time?

A: The cost to other customers of having most NPB load served on the LRT, rather than NSPI's proposed ELI rate, would be pushed upward to the extent that the ELI rate would have tended to rise over time, given the following trends:

- Nova Scotia Power's projection of falling sales due to energy-efficiency;
- rising fuel costs per MWh;
- new costs of meeting the RES, including payments under the COMFIT, purchase of power under RFPs administered by the provincial Renewables Administrator, and the capital and operating costs of new NSPI-owned hydro and wind plants, as discussed in Section III.E,
- costs of additional environmental retrofits, including those identified in Section III.D,
- inflation in the costs of labour, material, and purchased services.

C. Uncertainty Regarding the Effectiveness of the LRT

Q: Is it clear that NewPage and Bowater will use no power in 2012–2016 under the existing ELI rate and that NewPage and Bowater will continue operation at recent levels under the LRT?

A: No. Neither NewPage nor Bowater specifically asserts that its Nova Scotia facilities will shut down without the LRT. Nor does either company guarantee that its facilities will continue operating with the LRT.

Bowater says the "If the Load Retention Tariff and proposed rate are approved,… the probability of continuing our operations is also increased, as we will have a measure of stability for our largest input cost" (Bowater Mersey's direct evidence, p. 6).

Q: What other outcomes are possible?

A: Over various periods in 2012–2016, various combinations of the following may occur.

- The energy usage by NPB under the LRT may be the same as it would be under the ELI rate, at recent typical load levels, or some lower or higher level.
- The energy usage by NPB under the LRT may be higher than it would have been under the ELI rate, but usage in either case may be much higher than zero and lower than historical levels.
- One or both facilities may be shut down for long periods with either the LRT or the ELI rate, due to such factors as demand, shipping costs and currency exchange rates.

Q: What sort of analysis is necessary to reflect this range of possibilities?

A: The Board should consider the probabilities of various outcomes, or the expected value of revenues, under the rate alternatives

As shown in Table 7 above, even using the understated avoided costs in Rosenberg Appendix D, the costs shifted to other ratepayers by the proposed LRT is about 90% of the net burden to those customers of the total loss of the NPB load.[9] Hence, if the probability of retaining the NPB load with the ELI rate is more than a 10%, or if the probability of retaining the NPB load with the LRT rate is less than 90%, or if NPB would use enough energy under the ELI rate so that its

[9]With corrected avoided costs, the customers would be better off losing all the NPB load rather than retaining it on the LRT. even

bills would be even 10% of the NSPI base case, then other customers will be better off with the ELI rate than the with the LRT.

Q: Have NPB or NSPI conducted an analysis of the expected value of benefits of the LRT to other ratepayers, under these uncertainties?

A: No.

V. Effects of the Proposed Rate Structure

A. Loss of incentive to reduce or shift load

Q: How do price incentives under the proposed LRT differ from those under the existing rate?

A: Since the proposed LRT has a single energy charge that is constant over all hours of the year, it would eliminate the existing incentive to reduce usage in high-cost periods. As NSPI explains:

> Under the ELI 2P-RTP tariff, customers would have been encouraged to avoid running above their CBL levels when high cost production units were dispatched on the margin. If they chose to remain at full load the fuel costs associated with the high cost units would have accrued to their billing. Under the proposed tariff structure there is no incentive for this class to reduce load when light oil fired combustion turbines are dispatched. It is uncertain how often the customers will be at high load when high cost production units are in operation. (NSPI-Liberty IR-8(a))

Q: Does the historic usage of the NPB customers indicate that the real-time-pricing mechanism may have affected the cost of serving NPB's load?

A: Yes. NSPI provided historic hourly loads of the two NPB customers (NSPI-CA IR-14 and 15, Confidential Attachments) and historic hourly marginal costs (NSPI-CA IR-12, Confidential Attachment 1). Comparison of average load-weighted price under the following two situations provides some measure of the effect of price on load levels:

- A simple average of hourly prices over the month, based on a flat load shape. NPB's cost-benefit analysis assumes that it would have a 100% load factor under both the NSPI ELI and the proposed LRT.
- The weighted average of hourly prices over the month, weighted by the actual usage of the NPB customers.

Q: What is the result of this comparison?

A: In twelve months through June 2011, the actual weighted hourly marginal cost was less than the unweighted average, indicating that NPB customers loads tended to be lower during higher-cost hours. The variable marginal cost of serving NPB loads at a 100% load factor would have been 1.4% or $1.5 million higher than serving NPB's actual annual load; see Table 8.

Table 8: Comparison of Marginal Running Cost, Flat Load Shape and as Used by NPB, July 2010 to June 2011 (Thousands of Dollars)

	20-Minute Ahead Marginal Cost		
	@ 100% LF	As Used	Difference
Jul	$8,751	$8,740	$10
Aug	8,299	8,270	30
Sep	8,318	8,248	71
Oct	8,332	8,238	93
Nov	7,493	7,373	120
Dec	10,345	10,019	327
Jan	12,916	12,429	487
Feb	9,513	9,332	181
Mar	9,984	9,927	57
Apr	9,645	9,620	25
May	9,945	9,910	35
Jun	9,105	9,018	87
Annual Total	$112,647	$111,124	$1,523

From the data available, I cannot determine whether any of the reduction in load in high-priced hours results from load interruptions. In addition, the hourly load varies due to non-price factors, such as operating cycles and equipment outages.

From these data, it appears that the real-time pricing feature in the ELI rate has some effect on NPB power usage patterns, reducing total costs. This benefit would be lost under the proposed LRT.

Indeed, there is no assurance that NPB, freed of any time-of-use incentive, would have load shapes that are essentially flat. One or both firms may find it economic to move some operations from three shifts to two, or to curtail operations on weekends, or to perform maintenance in summer months, pushing more usage into high-cost hours.

B. Pattern of Rates Over Time

Q: What problem is created by NPB's proposal for steep increases in the LRT from 2012 to 2016?

A: This rate structure, which sets rates well below marginal costs in 2012, would expose NSPI and other ratepayers to the risk of subsidizing NPB in the early years of the LRT, and making additional investments and commitment on the assumption that NPB will continue to take power, only to have one or both mills shut down or sharply curtail usage in the later years. This series of events would expose other rate classes to the risk of paying many years of costs imposed by NPB, without any opportunity to recover those costs.

C. Payment Risk

Q: What payment risks would NSPI face under NPB's proposed LRT?

A: Under the LRT, rather than providing a deposit, NPB would be required to pay their bills on a weekly basis, rather than monthly. NSPI does not consider that weekly payments "offer the same security and address the credit exposure risk as a deposit as described in Regulation 6.6.” (Avon IR-2(c)) The total weekly bill for NPB averages $2,138,000. If the customers appeal, NSPI might not be able to disconnect them for at least an additional 24 days, by which time their debt would grow to over $9 million. Should the mill owner then declare bankruptcy, collection of those arrearages may be at risk.

Q: Does this conclude your testimony?

A: Yes.