ORIGINAL

Exhibit - N - 20

NSUARB File – NSPI – P-886

NOVA SCOTIA UTILITY AND REVIEW BOARD7

IN THE MATTER OF: *The Public Utilities Act*, R.S.N.S. 1989, c. 380, as amended

- and –

IN THE MATTER OF: An Application by Nova Scotia Power Incorporated for Approval of Certain Revisions to its Rates, Charges and Regulations

Direct Testimony and Exhibit of

Alan Rosenberg

On behalf of

Bowater Mersey Paper Company Limited
Stora Enso Port Hawkesbury Limited

REDACTED

December 20, 2006
Project 8695

RECEIVED
DEC 2 0 2006
Nova Scotia Utility and Review Board

BRUBAKER & ASSOCIATES, INC.
ST. LOUIS, MO 63141-2000

BAI

RECEIVED
JAN 15 2007
Nova Scotia Utility
and Review Board

MEMORANDUM

To: **David S. MacDougall, Esq.**
McInnes Cooper

January 10, 2007

Re: Clarifications and Errata Sheet for Direct Evidence of Alan Rosenberg

I would ask that you disseminate a point of clarification concerning Table 1, on page 11 of my direct evidence. That table portrays a comparison of various NSPI forecasts of its annual fuel expense per MWh, as contained in various Company applications, with actual results for those same calendar years. In reviewing the evidence of Dr. John Stutz, who also addressed this issue, I came upon a discrepancy for the calendar year 2005. Dr. Stutz showed a forecast of $29.56 per MWh, while my table showed a forecast of $32.17 per MWh.

In exploring the reason for the disagreement, it appears that my nomenclature for that line should be clarified. The actual application for the 2005 test year, which was dated (revised) June 23, 2004 did contain the figure $29.56. The $32.17 figure that appears in my table, appeared in a table in NSPI's 2006 application, dated July 5, 2005, which also included a forecast for calendar year 2005. Thus to be clear, I should have labeled that line "2006 Application", although the figure does portray NSPI's forecast for calendar year 2005. I apologize if this caused any undue confusion.

I am also enclosing an errata sheet for my testimony, although they do not impact or change my conclusions or recommendations. The revisions to Table 3 and Schedule 4, pages 1 through 3, were required because we inadvertently had neglected to convert a US dollar figure to Canadian dollars. I trust you will bring these revisions and clarifications to the attention of all parties.

BRUBAKER & ASSOCIATES, INC.

Alan Rosenberg

Alan Rosenberg

Attachments
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ORIGINAL

NOVA SCOTIA POWER INC.

Before the
Nova Scotia Utility and Review Board

Re: An Application by Nova Scotia Power Incorporated for Approval of Certain Revisions to its Rates, Charges and Regulations

Redacted Errata to

Direct Testimony of Dr. Alan Rosenberg

Page No.	Description
Page 12	Line 18, delete **[Redacted]**
	Footnote 8, delete "Liberty" and insert "SEB"
Page 18	Line 14, delete "$4.10" and insert "$4.30"
	Line 15, delete "12.4%" and insert "12.6%"
Page 20, Table 3	Line 1, delete "$10.7", insert "$9.2" Line 2, delete "$8.7", insert "$8.8" Line 3, delete "$19.4", insert "$18.0" Line 7, delete, "$38.7", insert "$37.3" Line 11, delete "$65.4", insert "$64.0"
Page 21	Line 18, add "pages 5-7" after (reference SEB IR-42, Attachment 3)
Page 29	Line 7, delete "$18.5 million" and insert "$18.3 million"
	Line 15, delete "$18.5 million" and insert "$18.3 million"
	Footnote 12, insert "page 96" after "otherwise."
Page 37	Line 10, delete the word "plant"
	Line 18, insert ", page 53" after "Chapter 4"
Page 38	Line 16, delete "Liberty IR-10" and insert "Liberty IR-10 Revised"

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Nova Scotia Utility and Review Board

Schedule 4, page 1 **[Redacted]**

Schedule 4, page 2 **[Redacted]**

Schedule 4, page 3 **[Redacted]**

(988319)

NOVA SCOTIA UTILITY AND REVIEW BOARD

IN THE MATTER OF: *The Public Utilities Act*, R.S.N.S. 1989, c. 380, as amended

- and –

IN THE MATTER OF: An Application by Nova Scotia Power Incorporated for Approval of Certain Revisions to its Rates, Charges and Regulations

Direct Testimony of Dr. Alan Rosenberg

1. INTRODUCTION & SUMMARY

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A My name is Dr. Alan Rosenberg. My business address is 1215 Fern Ridge Parkway, Suite 208; St. Louis, Missouri 63141-2000.

Q WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A I am a consultant in the field of public utility regulation with Brubaker & Associates, Inc. (BAI), energy, economic and regulatory consultants. Over the last eleven years, I have provided this Board with expert testimony on multiple occasions. My qualifications are attached as Appendix A.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A I am appearing on behalf of Stora Enso Port Hawkesbury Limited and Bowater Mersey Paper Company Limited, collectively SEB. These are NSPI's two largest customers and are an integral part of the Nova Scotia economy. These forest

product companies are in a very competitive global situation and the cost of electricity forms a large portion of the input cost to their manufacturing process.

Q WHAT IS THE SUBJECT MATTER OF YOUR EVIDENCE?

A I will address six broad issues. The first is a comparative analysis between the rates that NSPI is proposing for 2007 and the most recently applicable rates for various other utilities in the United States and Canada. The second issue deals with appropriate principles and some specific adjustments that should govern the amount of fuel to include in test year rates. The third issue deals with a normalization to a rate base item, the [redacted]. The fourth issue of my evidence contains my reasons why the Board should reject NSPI's proposal to defer fuel costs in the first quarter of 2007. Next I will give my reasons for rejecting a so-called "true up" for the ELI-2P RTP rate recently approved by the Board. The final topic of this evidence will be the results of the class Cost of Service Study (COSS) with appropriate refinements as justified and explained in this evidence.

2. COMPARATIVE ANALYSIS WITH OTHER NORTH AMERICAN UTILITIES

Q WHY IS A COMPARATIVE ANALYSIS OF NSPI'S PROPOSED RATES WITH OTHER UTILITIES IN THE UNITED STATES AND CANADA RELEVANT TO THIS PROCEEDING?

A In the first place, the stated Energy Strategy of the Province of Nova Scotia is that electrical energy should, among other things, be "affordable."[1] In my opinion, one of the best ways to measure affordability is to compare the price of electricity in Nova Scotia to the price of the comparable product/service in other parts of North America.

[1]Nova Scotia Energy Strategy Progress Report, Page 5.

Second, if a utility's prices are substantially higher than those of the majority of other utilities, it may signal that there is a problem with utility management, planning, strategy or execution, or that some costs are not used and useful. In Decision NSPI-P-875, the Board considered that my testimony respecting the concept of "used and useful" for the purpose of reviewing utility expenditures was "helpful" for the purpose of reviewing utility expenditures. I have reproduced the portion of my 2002 testimony on that subject as Appendix B for the Board's consideration.

Third, while established regulatory policy is that rates are set so that a utility is afforded a reasonable opportunity (but not a guarantee) to recover the costs that are prudently incurred, and that are used and useful, there is a broad degree of discretion available to the regulator by which to administer that policy. In other words, regulation is a balancing act meant to be fair to both the shareholders and the captive ratepayers. Items that are typically under the discretion of the regulator are, among other things:

- The reasonableness of forecasts,
- The capital structure and return on equity,
- Disallowances or Adjustments on the basis of imprudence or used and usefulness,
- Amortization schedules,
- Deferral or phasing in of increased expenses, and
- Incentive or target performance mechanisms.

Q WHERE DOES YOUR COMPARATIVE ANALYSIS APPEAR AND HOW IS IT STRUCTURED?

A The analysis appears on Exhibit AR-1, Schedule 1. I compared the proposed price per kilowatthour of Nova Scotia Power, as filed for in its rate application, with the most

recent price I could find for other utilities in the United States and Canada, and expressed the price as an index, with NSPI's proposed price taken as an index of 100 (percent). Thus if the price of Utility XYZ were, let us say 4 cents per kWh, and the comparable price proposed by NSPI were 5 cents, Utility XYX would have an index of 4 divided by 5 or 80. This indicates that its price is 20% less than NSPI's (or equivalently that NSPI is 25% more expensive than XYZ).

I conducted my analysis by comparing the proposed base ELIIR-2 rate with that of the most comparable rate I could find. While this analysis could possibly be expanded to other classes as well, I believe that, by and large, the same relationships would hold, i.e., NSPI's rates are becoming very expensive relative to much of North America.

Q WHAT COMPARABLE CUSTOMER CLASS DID YOU USE TO BENCHMARK THE ELIIR-2 CLASS?

A I used the largest interruptible industrial rate I could find, served at the highest transmission voltage and calculated the rate at a 90% load factor. If there was no interruptible rate, I used the firm rate and noted that by an asterisk. Of course, using a firm rate understates the disparity between that utility's rate and NSPI's rate.

Q WOULD YOU AGREE THAT THE GENERATING MIX (COAL, OIL, GAS, HYDRO) WOULD ALSO HAVE AN IMPACT ON A UTILITY'S RATES?

A Yes. That is a fair observation and I would agree that simply because one utility has higher rates than another may not be symptomatic of a problem. Nevertheless, I do believe that comparisons of the sort depicted in this evidence can convey useful information.

Q WHAT ARE THE RESULTS OF YOUR COMPARATIVE ANALYSIS?

A For the 41 other utilities that I looked at, all but two were less expensive than the comparable rate for NSPI. The Industrial Index for the other utilities ranged from 43 to 101, with a median index of 68, and an average index of 72.

Q WHAT CONCLUSIONS CAN REASONABLY BE DRAWN FROM YOUR ANALYSIS?

A I conclude that Nova Scotia's proposed rates would be considerably more expensive than those of representative utilities across much of North America.

Q ARE ANY OF THE OTHER UTILITIES SHOWN ON SCHEDULE 1 APPLYING FOR AN INCREASE IN 2007?

A To the best of my knowledge and belief, only seven have increases pending, and those are duly noted on the schedule. However, even if those increases were granted in full (and requested increases seldom are), those rates would still be less than what NSPI is suggesting for ELIIR-2.

Q WHAT FUEL COSTS ARE REFLECTED FOR THE OTHER UTILITIES ON SCHEDULE 1?

A The fuel costs are based on either the fuel costs contained in base rates or the fuel adjustment clause rates that were in effect for twelve months ended October 2006.

Q THE RATES FOR NSPI ARE BASED ON FORECAST RATES FOR 2007. IS SCHEDULE 1 STILL A FAIR COMPARISON?

A Yes. In the first place, as I discuss in the subsequent section of my testimony, fuel prices appear to have peaked in 2006. Consequently, I would not expect the prices that I had for the other utilities to change dramatically by next year. Secondly, the price differentials are so pronounced, that I am confident that the basic conclusions that I drew from this schedule would be unaffected.

Q ALL BUT TWO OF THE OTHER NORTH AMERICAN UTILITIES THAT YOU CHOSE TO INCLUDE IN YOUR COMPARATIVE ANALYSIS ARE LESS EXPENSIVE THAN NSPI. WOULD IT NOT BE POSSIBLE TO FIND OTHER UTILITIES IN NORTH AMERICA THAT ARE MORE EXPENSIVE THAN NSPI?

A Yes it would. However, many of those utilities are in states that have restructured (i.e., deregulated) and so are not directly comparable to NSPI.

3. FUEL ADJUSTMENT TO NORMALIZE FUEL COSTS ON A PROSPECTIVE BASIS

Q WHY ARE YOU ADDRESSING THE ISSUE OF FUEL?

A For the fourth time in five years, NSPI has filed an application with the Board for an increase in rates that is once again dependent upon a sharp increase in fuel costs. As a result, NSPI's rates have become increasingly non-competitive compared to many other regulated utilities across North America, particularly from the perspective of industrial customers. This is documented in Exhibit AR-1, Schedule 1. Thus, it is crucial that the fuel cost per MWh amount that is approved as the basis for NSPI's rates, is no larger than what NSPI's anticipated fuel costs are reasonably expected to be.

Q PLEASE SUMMARIZE YOUR EVIDENCE AND RECOMMENDATIONS WITH REGARD TO FUEL MATTERS.

A First, I show why fuel costs should not be based on 2007 forecasts alone, but should also look ahead at 2008 fuel costs. Second, I show that NSPI has historically over estimated its fuel costs in the context of rate applications. Third, I show that there is evidence that fuel costs for 2007 and 2008 could very well be less than the costs that NSPI employed for purposes of this rate filing. Fourth, I recommend an adjustment to the fuel costs that should be used for setting rates in this proceeding. In particular, I recommend that fuel costs should be at least $68 million less than that requested by NSPI. Fifth, I recommend that the Board adopt a balancing account that would serve to protect both NSPI and customers from large discrepancies between the actual fuel cost incurred and the amount that I recommend for purposes of setting new rates.

Q DO YOU ADDRESS ANY ISSUES OF POSSIBLE IMPRUDENCE OR UNNECESSARILY HIGH PURCHASED FUEL EXPENSE OR OTHER FACTORS THAT MAY UNDULY ESCALATE THE STATED FUEL COSTS?

A No. Those issues will be addressed by other witnesses for SEB, and perhaps by other stakeholders. Nevertheless, I would like to bring to the Board's attention four areas where NSPI's judgment may inappropriately skew its fuel cost forecast.

The first issue pertains to the fact that NSPI has not relied upon a specific market forecast for petcoke. Instead, it has simply imputed a future price for petcoke that lies at a level that makes NSPI indifferent to buying petcoke [redacted]. (Reference the response to SEB IR-5). Frankly, I do not see why such an assumption is appropriate and it may bias the fuel forecast upwards. Thus, I urge the

Board to fully explore this matter, although I am not in a position to make a specific recommendation on this issue at this time.

The second issue pertains to NSPI's claim to use a "consensus" forecast (instead of a single forecast) of solid fuel prices. In response to SEB IR-29, it shows that the "minimum" forecast for [redacted] imported coal is exactly the same as the "maximum" forecast. Thus, I do not fully understand the claim that this represents a consensus instead of a single source forecast. I recommend that this matter also be looked into. As explained later in this testimony, I do take issue with this so-called "minimum" solid-fuel forecast and I do quantify my concerns.

The third concern I have with NSPI's fuel forecast pertains to the maintenance schedule that NSPI is forecasting for its solid fuel fleet of plants. These are NSPI's lowest cost plants to run. Consequently, if NSPI is forecasting abnormally long maintenance periods, there will be abnormally high replacement costs when NSPI runs other plants in their stead. The experience of our firm is that in other jurisdictions that do not have fuel adjustment mechanisms (FAMs) (such as Utah and Missouri), the standard practice is to normalize maintenance time. Based on the six-year period 2001 through 2006, NSPI's coal plants have had an average of [redacted] plant-days down[2]. However, for 2007 NSPI is forecasting [redacted] plant-days down[3], or [redacted] plant-days longer than the historical norm. At an average plant size of [redacted] MW, and using a conservative estimate of the cost differential of [redacted] per MWh between the solid fuel plants and the replacement power, this differential could raise normal fuel costs in the test year by over $3 million.

[2] This was based upon the data provided in Confidential SEB IR-133, Attachment 1.

[3] This was calculated based upon the projection provided in response to Confidential UARB-3, Attachment 1.

The fourth issue I would bring to the Board's attention is the impact of the load growth assumptions of NSPI. NSPI states that the cost to serve this additional load growth is [redacted] per MWh. (Response to Avon IR-74) This would imply that NSPI is losing at least $1.4 million by this additional load. Ignoring the implications for NSPI's rate design for the moment, the question arises as to whether it is reasonable, as this data response suggests, that almost all of this load growth is occurring during the winter peak hours. If that is indeed the case, NSPI ought to be proposing a changed rate design that will curb that tendency.[4] On the other hand, if that is not the case, then it follows that NSPI is overstating its fuel forecast. In either case, it deserves the attention of the Board.

Q WHY SHOULD FUEL COSTS THAT FORM THE BASIS FOR THESE NEW RATES BE BASED ON 2007 AND 2008 FUEL COSTS?

A In Decision NSPI-P-875, in dealing with the subject of fuel costs based on a 2002 test year, the Board (on page 29, emphasis added) found as follows:

> It is an accepted principle, which the Board endorses, that rate-making should be prospective and not retroactive.
>
> * * * * * *
>
> Accordingly, the Board finds that the cost of fuel for the test year must be reduced in order to ensure that the costs *are more representative of the period during which the rates will be in place* (i.e., late 2002 and into 2003).
>
> * * * * * *
>
> The Board finds that to *normalize these coal costs on a go-forward basis for the balance of this year and into 2003, a 10% reduction in the test year costs for imported coal is reasonable and balanced.*

The two items of note here are: (1) even though the test year was 2002, the Board looked beyond the test year because it wanted the underlying costs to be more

[4] It would also be my opinion that NSPI should be urging changes to its cost of service methodology, which currently mutes the implications of increased peak usage.

representative or reflective of the time period when it expected the new rates would prevail; and (2) even if the costs for the test period are not in question, a normalization process is reasonable and balanced. I believe the same considerations that the Board used in that Decision are appropriate, relevant and required in this proceeding as well.

Q **WHY WOULD YOU EXPECT THE RATES THAT ARE ESTABLISHED IN THIS PROCEEDING TO BE IN EFFECT FOR MOST IF NOT ALL OF 2008 AS WELL?**

A For one thing, after this Decision, there should not be any large new amortization items coming into rates during this period. Furthermore, the most recent EIA consensus forecasts that we have access to, are not predicting any sharp increase in fuel costs. In fact, the most recent trend in fuel costs seems flat if not actually declining. (I will provide more detail on fuel forecasts later on in this section of the evidence.) Generally, absent extraordinary circumstance, utilities as a rule do not come in for rate increases every year. Consequently, it is almost certain that these rates would be in effect for at least the first third of 2008.

Moreover, because this application represents the fourth proposed increase in the span of just 6 years, just the law of averages would suggest that there would not be an increase in 2008. Finally, there is just a practical limit to how frequently a utility can keep coming in for rate increases without provoking a political backlash.

Q YOU STATED AT THE START OF THIS SECTION OF THE TESTIMONY THAT NSPI HAS HISTORICALLY OVER ESTIMATED ITS FUEL COSTS IN THE CONTEXT OF RATE APPLICATIONS. WHAT EVIDENCE DO YOU HAVE TO SUPPORT THAT ASSERTION?

A The evidence is shown on the following table.

TABLE 1

Fuel Cost Per MWh – Forecast Versus Actual

Application	Forecast Cost	Actual Cost	Overage
2002 Application	$29.74	$28.22	5.4%
2003 Application	$26.72	$22.76	17.4%
2005 Application	$32.17	$29.93	7.5%
2006 Application	$37.19	$30.83 *	20.6%
Average Over Forecast			12.7%

* NSPI is forecasting its actual 2006 fuel costs at [redacted]. However, this is mainly due to much lower sales, in part brought about by the Stora shutdown. The figure of $30.83 is my own estimate of what their fuel costs would have been under more normal conditions. The details of my estimate are shown on Exhibit AR-1, Schedule 2. (I should also note that in its information request SEB Question IR-63, SEB requested NSPI to provide a version of its Appendix A with a pro forma version for the Forecast 2006 year that employed the most recent data and also assumed normal weather and normal operations for Stora Enso. It refused to do so, necessitating this independent estimate.)

Q ASIDE FROM THE EMPIRICAL EVIDENCE THAT NSPI CONSISTENTLY OVERSTATES ITS FORECASTED FUEL COSTS, IS THERE REASON TO BELIEVE THAT NSPI HAS OVER-ESTIMATED ITS FUEL COSTS FOR 2007?

A Yes. There is additional and newer evidence that was seemingly ignored by NSPI.

First, NSPI used oil and gas forward prices as of July 31, 2006 although more up to date published forward curve data would show lower oil prices.

Second, NSPI seems to have disregarded or discounted the distinctly lower coal prices since the beginning of 2006. For example, consider the evidence on imported low sulfur coal. The 2006 committed MMBtu weighted average cost for NSPI, excluding transportation, was [redacted] per MMBtu.[5] For commitments in 2007, the comparable figure was [redacted] per MMBtu or 8% lower than the comparable for 2006.[6] Therefore, it is somewhat surprising that NSPI's forecast for 2007 does not show any noticeable decline in solid fuel costs from 2006. In fact, it shows an increase. The situation gets even more curious when we consider the low sulfur August 2006 bids for delivery in 2007. The MMBtu weighted average of the four bids was [redacted], or 21% lower than the [redacted] price for 2006.[7] In fact, the August 2006 bid from one [redacted] supplier was 20% lower than the 2007 committed price from that very same supplier. Yet NSPI's so-called "minimum" forecast for 2007 was [redacted] per MMBtu[8] or 15% higher than the August bids for 2007.

Third, NSPI does not appear to be using the most recent foreign exchange rate for 2007.

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[5] This was derived from the data provided in response to SEB IR-30.

[6] This was derived from the data provided in response to SEB IR-27.

[7] This was derived from the data provided in response to Liberty IR-64.

[8] This was derived from the data provided in response to SEB ~~Liberty~~ IR-29.

Q HAVE YOU LOOKED AT THE MOST RECENT FOREIGN EXCHANGE RATES FOR THE YEAR MARCH 2007 THROUGH MARCH 2008?

A Yes. The current exchange rate is $1.15 to the US dollar. As shown on Schedule 3, based on data valid as of December 4, the forward average foreign exchange rate for the period March 2007 through March 2008 between the US and Canadian dollars is 1.13. NSPI has used a rate of 1.18 for all of their fuel forecasts.

Q HAVE YOU ESTIMATED WHAT NSPI'S FUEL COSTS IN 2007 WOULD BE IF YOU WERE TO SIMPLY UPDATE CERTAIN INPUTS TO NSPI'S FILED FORECAST?

A Yes. We have performed an analysis on 2007 fuel costs which essentially substituted (for the uncommitted volumes) the average of the August 2006 bid responses as the future price for low and mid-sulfur coal (as supplied by NSPI in Liberty IR-64), substituted the actual price for the September 2006 contract for High Sulfur coal for delivery in 2007 (as supplied by NSPI in SEB IR-96), substituted December 11 natural gas and HFO prices for the July 31 prices that NSPI assumed, and adjusted the FX rate to $1.13 Canadian for the US dollar. I estimate that these changes alone would reduce NSPI's fuel costs by approximately $38.7 million, or almost 8% less than what NSPI is forecasting. The details are shown on Schedule 4.

Q DID YOU CHANGE NSPI'S FORECASTED PRICE FOR PETCOKE IN SCHEDULE 4?

A No, I did not. I used NSPI's so-called "minimum" forecast for petcoke.

Q WOULD YOU LIKE TO ADD ANY CAVEATS TO SCHEDULE 4?

A Yes. As I stated, the basis for pricing out the open tonnages of solid fuel in Schedule 4 are the average of the August 2006 and September 2006 bids and contracts for delivery in 2007. I understand that Mr. Gubbins, another expert witness for SEB, will present his own independent analysis of coal prices for 2007 which are less than those implied by the August 2006 bids. Obviously, if Mr. Gubbins' analyses are more credible and representative, those prices should be used instead of the August 2006 bid prices (or September 2006 actual contract).

I might also add that this analysis may understate the impact of the updated oil and gas forwards. The reason is that my analysis makes no change to the HFO/gas fuel mix at Tufts Cove. To the extent that this mix may be reoptimized to best arbitrage the oil/gas spread, the reduction from NSPI's forecast would be greater than indicated by this schedule.

Q HOW MUCH OF THE DECREASE THAT YOU CALCULATED IS ATTRIBUTABLE TO THE DIFFERENT FOREX RATE THAT YOU USED?

A Approximately $14 million of the $38.7 million is directly attributable to using 1.13 as the FOREX rate instead of 1.18.

Q ARE YOU AWARE THAT NSPI HEDGES ITS US DOLLAR REQUIREMENTS?

A Yes. NSPI states that its guidelines are to hedge 30% to 60% of each of the four forward years and only have a maximum of 30% open for the next 12 months. The hedges are mainly intended to protect NSPI, but they also serve to protect customers as well when they form part of the test year expense.

Q IN THAT CASE, DO YOU BELIEVE IT IS FAIR TO ADJUST THE TEST YEAR FUEL COST BY THE FULL AMOUNT OF YOUR CALCULATED REDUCTION?

A That is a judgment call for the Board. If the Board is convinced that NSPI acted prudently, and that the foreign exchange rate plays no role in the tendency for NSPI to overestimate its test year fuel costs, then I would agree that 70% of that $14 million could be included on test year expenses.

Q IN THE 2002 RATE CASE DECISION, IT STATES IN PARAGRAPH NUMBER 85,

> **If the rate-making process were based on the most up-to-date numbers, as opposed to forward-looking data derived from experience over the longer term, each month could bring innumerable changes to the revenue requirement. On balance, it is the Board's view that this is not an appropriate methodology to employ for rate-making purposes.**

IS IT NEVERTHELESS YOUR POSITION THAT THIS UPDATED INFORMATION IS PERTINENT INFORMATION THAT SHOULD BE CONSIDERED BY THIS BOARD?

A Absolutely. That statement was made in the context of disregarding a single month (January) of actual data that was warmer than normal. Clearly that has nothing to do with the concern that I have with NSPI's choice of questionable and/or stale data. Secondly, the Board also noted that its ruling had very little impact on the test year revenue requirement. In the current situation, the decision as to which fuel forecast will be relied upon, will have a significant impact on the test year revenue requirement. Third, to give NSPI unilateral and unlimited discretion as to the timing of the data upon which the fuel forecast is to be premised, is unfair to other intervenors since it would foreclose the possibility to use different information or different sources. Such an approach would present a strong incentive to any applicant to choose to calculate their forecast when fuel prices are at their apex. As well, it would be contrary to common sense to totally disregard the best information available simply

because that information becomes available subsequent to the date that NSPI chose for its filing. As stated in the NARUC Electric Utility Cost Allocation Manual:

> Regulatory agencies recognize that the rates they establish are likely to remain in effect for an indeterminate period into the future. Consequently, rates so established are usually developed using the **most current actual or projected cost and sales information for a selected time period.** The period used is normally 12 months in length – referred to as the test year or test period – and normally includes cost and sales data which are **expected to be representative of those that will be experienced** during the time the rates are likely to remain in effect. (Page 24, emphasis added)

Finally, I would note that in its letter of December 8, 2006, the Board directed NSPI to use its best efforts to supply SEB with responses to questions which relate to an update of information that NSPI used for purposes of its test year fuel forecast. The Board specifically noted that these questions, in its view, do not conflict with the Board's 2002 rate case finding.

Q WHAT EVIDENCE DO YOU HAVE THAT NSPI'S FUEL COSTS PER MWH IN 2008 WOULD BE LESS THAN ITS COST PER MWH FOR 2007?

A In the first place, the most recent outlook for fuel prices[9], as published by the Energy Information Administration of the United States Department of Energy (the same source NSPI witness Ms. Medine uses in her evidence) shows that fuel prices have peaked and are forecast to subside in 2007 and even more so in 2008. In the second place, current prices for fuel oil just recently hit a 17 month low. In the third place, as I noted earlier in this testimony, the empirical evidence on imported low sulfur coal shows a noticeable decline in the last 12-18 months. Thus, as the committed (or hedged) fuel costs are consumed (or settled), the replacement fuel prices should be considerably less. In the fourth place, for the past five years, the Canadian dollar has

[9] The information was recent as of the date this testimony was prepared, December 2006.

been strengthening against the US dollar. (This is shown graphically on Figure 2.13 of NSPI's own Direct Evidence.) Again, because future fuel purchases by NSPI will be pegged to a more current, and presumably lower, FOREX rate, that should also help to depress fuel costs in Canadian dollars.

Q **WAS NSPI ASKED TO PROVIDE FORECASTS FOR THE PERCENTAGE CHANGE IN FUEL PRICES FROM 2007 TO 2008?**

A Yes. This data was requested by SEB in its Question IR-59. The response referred to its response to Information Request UARB IR-20, which also asked for that information. Unfortunately, NSPI at first declined to provide this information, claiming it was "not relevant to establishing the 2007 test year revenue requirement." Subsequently, it did provide prices for 2008, but did not provide any percentage changes from one year to the next.

Q **DOES NSPI POSSESS ANY INFORMATION GERMANE TO THAT ISSUE?**

A Yes. When I was in the Confidential Data Room on November 21, I reviewed forecasts prepared by EVA, Ms. Medine's firm, and an independent forecasting organization, Energy Security Analysis, Incorporate (ESAI).

The most recent EVA publication that was made available was dated August 2006 and, if I transcribed it correctly, it had this to say.

Natural Gas: [redacted]

[redacted].

Oil: [redacted].

The most recent publication of ESAI that I could find in NSPI's Confidential Data Room contained the following forecast for Henry Hub gas.

TABLE 2

Description	2007	2008	2009
Base Case	[redacted]	[redacted]	[redacted]
High Case	[redacted]	[redacted]	[redacted]
Low Case	[redacted]	[redacted]	[redacted]

On ESAI's webpage, there was also a press release (dated November 1, 2006) which stated:

> ESAI's latest quarterly outlook on oil markets in 2007 and 2008 contends that refining margins in all three consuming regions are experiencing a **fundamentally driven contraction** and will be **significantly lower in the coming two years** compared to the last two. (emphasis added)

Clearly at least two sources of energy market intelligence that were available to NSPI are forecasting significantly lower non-solid fuel prices subsequent to 2006.

Q HAVE YOU BEEN ABLE TO QUANTIFY THE AMOUNT THAT NSPI'S FUEL COSTS WOULD DECREASE IN 2008, RELATIVE TO 2007, BASED UPON THE COST PER MMBTU PRICES PROVIDED BY NSPI IN THE BASE CASE ASSUMPTION FOR THEIR IRP PROCESS?

A Yes. I estimate that NSPI's fuel costs, per MWh, would fall by ~~$4.10~~ $4.30 per MWh or ~~12.4%~~ 12.6% on an apples-to-apples basis. My calculations are shown and documented on Exhibit AR-1, Schedule 5. (I am implicitly assuming a 10,000 heat rate to convert the charge in cost per MMBtu into a charge per MWh.)

Q BASED ON NSPI'S HISTORY OF OVER-FORECASTING ITS FUEL COSTS, AND THE EVIDENCE THAT SUGGESTS THAT 2008 FUEL COSTS, PER MWH, WILL RECEDE FROM 2007 LEVELS, WHAT NORMALIZING ADJUSTMENT ARE YOU RECOMMENDING FOR PURPOSES OF SETTING RATES IN THIS PROCEEDING?

A I suggest a reduction of 7% from NSPI's filed forecast on account of the tendency to overstate fuel projections as it relates to 2007. I also recommend a further 6% (which is approximately one-half the anticipated decrease from 2007 to 2008) decline to reflect the trend in fuel costs globally, for a total reduction of 13% or $65 million. In addition, I believe a further $3 million reduction is warranted to normalize maintenance downtime on the coal plants, brining my total recommended adjustment to $68 million. This is a fair and balanced normalization adjustment as is often done in ratemaking.

Q IS YOUR RECOMMENDATION FOR A $68 MILLION REDUCTION TO NSPI'S ESTIMATED TEST YEAR FUEL EXPENSES ALSO DERIVABLE FROM NSPI PROVIDED AND/OR PUBLICLY AVAILABLE DATA?

A Yes. A similar number can be derived from such sources. I believe an adjustment of this order of magnitude is corroborated and validated by the quantitative analysis that is detailed on Schedule 4 and Schedule 5 of my Exhibit, and as summarized by Table 3.

TABLE 3

Reduction to NSPI's Fuel Forecast

		Million $	
(1)	Solid Fuel 2007 Reduction	$9.2	Commodity Related
(2)		8.8	FOREX Related
(3)	= (1) + (2)	$18.0	Total Solid
(4)	Oil and Gas 2007 Reduction	13.8	Commodity Related
(5)		5.5	FOREX Related
(6)	= (4) + (5)	$19.3	Total Oil and Gas
(7)	= (3) + (6) Total Fuel Reduction in 2007	$37.3	(Schedule 4)
(8)	Reduction in 2008 Based on IRP Prices	$47.5	(Schedule 5)
(9)	One-half of 2008 Reduction	$23.7	
(10)	Maintenance Normalization	3.0	
(11)	Total Reduction Indicated (includes FOREX impact) (Line 7 + Line 9 + Line 10)	$64.0 Million	

Q DOES YOUR NORMALIZATION ADJUSTMENT INCORPORATE OR REFLECT ANY DISALLOWANCES OR REDUCTIONS, OR ANY OTHER MODIFICATIONS TO NSPI'S FUEL COSTS, BASED UPON IMPRUDENCE OR EVEN POSSIBLE BETTER FUEL MANAGEMENT?

A No. My recommended adjustment is based on essentially two observations. The first is NSPI's empirical tendency to over-forecast, and the second is the consensus downward movement in fuel prices. I am implicitly assuming that NSPI's management of its fuel portfolio is conforming with best practices and that there should be no disallowance on those grounds. Of course, other witnesses may speak

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to that issue and if the Board so finds, then a further reduction in allowed fuel costs may be appropriate as well.

Q WOULD YOU AGREE WITH MS. MEDINE THAT FUEL PRICES ARE VOLATILE?

A Fuel prices have exhibited inordinate price volatility in the last two years or so. Whether they will continue to do so in the future is a matter of speculation.

Q NEVERTHELESS, LET US ASSUME THAT FUEL PRICES ARE BOUND TO REMAIN VOLATILE AT LEAST THROUGH 2008. WHAT ASSURANCES CAN YOU GIVE THIS BOARD THAT YOUR RECOMMENDED FUEL NORMALIZATION ADJUSTMENT WILL NOT UNDULY JEOPARDIZE NSPI'S FINANCIAL HEALTH OR IMPERIL ITS ABILITY TO RAISE CAPITAL, OR IN SOME OTHER WAY UNDULY PENALIZE SHAREHOLDERS?

A First of all, despite the recent downgrade in its credit rating, Emera remains a financially healthy company. As Mr. Huskilson noted in the November 3, 2006 press release accompanying Emera's Third Quarter Earnings Report: "Emera continues to post solid financial results in 2006." The press release noted that the quarterly earnings improvement reflects higher earnings at the Company's largest subsidiary, NSPI. In a recent (November 2006) Investor Presentation, Emera noted the following bullet points (reference SEB IR-142, Attachment 3): pages 5-7

- Regulated assets, low risk profile
- Nova Scotia Power Overview
  - Low cost thermal based fleet enables competitive pricing
  - Strong earnings base supports dividend
  - Attractive allowed ROE

I would note that according to NSPI's own financial projections (Table 12 of Appendix A) it will earn at the [redacted] range of its allowed ROE – and this despite a $15.7 million fuel disallowance. Furthermore, according to NSPI's own Table 12, even with no change in current rates, i.e., with a zero increase, NSPI would have a cash interest coverage in 2007 that is greater than it had in 2005.

It should also be noted that NSPI acknowledges that it has not had any trouble to date in securing capital and it has not had to post any letters of credit in order to purchase fuel.

Furthermore, while I do agree that, all other things being equal, customers would prefer to see NSPI remain financially healthy, such a consideration has never been, and should not be, the paramount consideration of this Board. For example, in the most recent Decision, NSPI-P-875 (for the 2006 General Rate Proceeding), the Board found NSPI to be imprudent and disallowed $15.7 million in fuel costs. That finding may not have helped NSPI's bond ratings. Nevertheless, there can also be no doubt that ratepayers were made better off by this finding. Finally, NSPI always retains the option of filing for yet another increase in 2008 if it finds that the new rates are inadequate.

Q ASSUME, IF YOU WILL, THAT DESPITE SUCH REASONING, THE BOARD ACCEPTS YOUR FUEL NORMALIZATION ADJUSTMENT, BUT IS STILL UNCOMFORTABLE WITH THE POSSIBILITY THAT ACTUAL FUEL COSTS WILL MATERIALLY DEVIATE FROM THE AMOUNT OF FUEL THAT YOU SUGGEST FORM THE BASIS OF THE NEW RATES. IN THAT CASE, CAN YOU OFFER ANY SUGGESTIONS THAT MIGHT ASSUAGE SUCH CONCERNS?

A Yes. In that case, for the period April 2007 through December 2008[10] (in other words the period commencing with the expected effective dates of these new rates, and ending with the last month of the time horizon that I recommend be used to estimate fuel costs), NSPI should be directed to track differences in its actual fuel costs per MMBtu (net of profit on resold natural gas), and the fuel cost per MMBtu that is used to set the rates in this proceeding[11], times the volumes of MMBtu burned in that month. The price variance should be calculated separately for solid fuel and for gas/oil. If the cumulative balance of such differences never exceeds $10 million positive or negative (or approximately 2% of NSPI's annual fuel forecast in this case), no action would be taken. Shareholders would either absorb the difference if actual costs exceeded the ratemaking benchmark cost, or experience a gain should the opposite occur. However, once the cumulative balance exceeds this ±$10 million deadband, NSPI should be directed to defer 80% of any such excess difference, positive or negative, on its balance sheet, with an offsetting entry to its fuel costs. In the next subsequent rate application, or sooner if the Board otherwise directs, the

[10] December 2008 should be replaced by an earlier date if the Board authorizes another set of tariffs (not counting the ones emanating from this case) prior to that time.

[11] This rate may have to be adjusted upward to exclude any disallowances that the Board may order in this case.

Board could then decide how to recover (or refund) any debit (or credit) balance in this deferral account.

Q WHY ARE YOU PROPOSING A DEADBAND FEATURE AND A SHARING ATTRIBUTE IN THIS DEFERRAL MECHANISM?

A These features will give NSPI an incentive to minimize its fuel costs, because it will share in the benefits if it does so. Absent these features, NSPI would be indifferent to changes in the fuel cost because it might assume it could simply recover these costs, penny for penny, at a later date. With these features, NSPI's economic interests are more aligned with the interests of the customers.

Q IS THE DEFERRAL MECHANISM YOU HAVE JUST PROPOSED FOR THE BOARD'S CONSIDERATION THE SAME AS A FUEL ADJUSTMENT MECHANISM?

A No, it is not the same, although it does have some features in common with a FAM. Like a FAM it offers the utility a degree of protection should fuel costs significantly exceed the forecasted level in rates. Like a FAM it offers customers a degree of protection should fuel costs significantly decline from the forecasted levels. Like a FAM, it will reduce the risk to NSPI. Finally, like a well-designed FAM it has a deadband and a sharing mechanism.

However, there are also several features of this deferral mechanism that distinguish it from a FAM. First, it is not automatic. The utility must come before the Board in the context of another rate case before the deferral balances can be reflected in rates. Second, because the amortization of the deferral balances would be reflected in a cost of service study, it is more likely to be recovered in a manner that reflects costs. (For example, suppose that the deferral balances were created

much more heavily in the winter months. It would then be logical, in the cost of service study, to assign those balances in a like fashion.) Third, the calculations are predicated on the cost per MMBtu and not on the cost per MWh. Thus it will not be impacted by changes in fuel mix or plant maintenance. Finally, because the deferral balances will be considered for recovery in the context of a rate case, these costs remain more in the oversight of the Board and it also allows an opportunity for other stakeholders to review and challenge these costs if necessary.

4. RATE BASE ADJUSTMENT

Q DO YOU HAVE ANY CHANGES TO NSPI'S PROPOSED RATEMAKING RATE BASE?

A Yes. I recommend that the Board reduce the [redacted] that NSPI has included in rate base from $47.5 million to $9.3 million.

Q HOW DID NSPI DEVELOP [redacted] AMOUNT THAT IT IS PROPOSING TO INCLUDE IN RATE BASE?

A NSPI's proposed level of [redacted] of $47.5 million is determined by averaging the 2006 forecasted amount of [redacted] million with the 2007 forecasted amount of $9.3 million.

Q WHY DO YOU RECOMMEND THAT THE BOARD ONLY REFLECT THE 2007 $9.3 MILLION OF [redacted] IN RATE BASE AS OPPOSED TO THE AVERAGE 2006 AND 2007 AMOUNTS?

A The rates in this case will be put into effect in April 2007. It is appropriate to reflect a rate base amount that is more representative at the time that the rates will be in

effect. It is sound regulatory practice to annualize or normalize ratemaking costs. Since the [redacted] is projected to significantly decrease at the time the rates will be in effect, using the 2007 balance is appropriate.

In addition, it is not known when NSPI will file its next rate case. As a result, these rates may be in effect for several years. Allowing NSPI to include in rate base a provision for [redacted] that is $38.2 million in excess of their actual amount will provide them with earnings in excess of their allowed rates of return.

Q WHAT IS THE IMPACT OF YOUR PROPOSED ADJUSTMENT ON NSPI'S REVENUE REQUIREMENT?

A Reducing [redacted] that is included in rate base from $47.5 million to $9.3 million reduces NSPI's revenue requirement by $4.1 million. The development of this amount is shown on Schedule 6.

5. NSPI'S PROPOSAL TO RETROACTIVELY DEFER FUEL COSTS

Q WHAT IS NSPI'S PROPOSAL IN THIS MATTER?

A NSPI is requesting that it be allowed to defer the difference between its actual fuel costs for the first 4 months of 2007, to be recovered during 2008.

Q WHAT IS YOUR RECOMMENDATION ON HOW THE BOARD SHOULD RESPOND TO THIS EXTRAORDINARY REQUEST?

A The Board should reject this request. First, it represents retroactive ratemaking. Second, it constitutes single-issue ratemaking, also sometimes referred to as "cherry-picking". Third, it could very well result in NSPI recovering more in fuel than the

Company actually incurs. Fourth, despite its portrayal, this request is not needed to be fair to NSPI. In fact, it is decidedly unfair to NSPI's ratepayers. Finally, it would set a bad regulatory precedent.

Q WHAT IS RETROACTIVE RATEMAKING?

A Retroactive ratemaking is when customers are subject to rates that are set subsequent to the period when the customer actually used the electricity. It is a practice that is generally discouraged because the customer cannot make an informed decision concerning its consumption. If the NSPI request is granted, customers will have no idea what consumption during the first four months of 2007 will actually cost them until after the Decision in this case. For example, the current fuel cost per MWh, as approved in the 2006 Compliance filing is $33.23 per MWh. If the Board establishes a fuel cost of $34.23 per MWh in its 2007 Decision, the cost to customers will actually be $1.00 more than the tariff indicates, or about $4.6 million more that customers will have to pay, beyond what is in their tariffs. However, if the Board establishes a fuel cost of $38.19 per MWh, as NSPI proposes, the cost to customers will actually be almost $5.00 per MWh more than the tariff indicates. There is simply no way for customers to assess the consequences of their consumption choices.

Q WHAT IS SINGLE-ISSUE RATEMAKING?

A Single-issue ratemaking is when rates are changed in response to a change in a single component of the cost, without regard to other changes that may countervail the change in that single cost. For example, [redacted]

[redacted] Yet NSPI is not proposing to refund any of that excess recovery. To take another example, suppose the weather is extraordinarily cold for the first four months of 2007. NSPI would incur a higher cost of fuel per MWh for that period than would otherwise be the case. However, it would also take in more revenues than would otherwise be the case, all other things (besides the weather) being kept equal. Yet, under NSPI's proposal, customers would be on the hook for the extra fuel costs, but NSPI would be under no obligation to refund the higher than forecast revenues. Clearly, such a proposal would be against all interests of the customers.

Q **WHAT WOULD BE THE EFFECT IF FUEL HAD BEEN HANDLED AS SINGLE-ISSUE RATEMAKING IN 2006, BY DEFERRING THE DIFFERENCE BETWEEN ACTUAL COSTS AND THE COST UPON WHICH RATES WERE PREDICATED?**

A In the last Decision, based on a 2006 test year, the Board predicated NSPI's rates upon a fuel cost of $33.23 per MWh. During the first quarter of 2006, according to Emera's report to its shareholders, NSPI's actual cost was $25.06 per MWh. Multiplying the difference, or $8.17 per MWh, times the reported 3,132,000 MWh, yields a deferral credit of $25.6 million that would be due ratepayers.

Q **WHY COULD ACCEPTANCE OF THE COMPANY PROPOSAL RESULT IN NSPI RECOVERING MORE FUEL COST THAN IT ACTUALLY INCURS?**

A In Question SEB IR-75, NSPI was asked to explain in detail exactly how it proposes to calculate this deferral, assuming the Board approved their request. In its response

NSPI stated that it proposes the deferral be calculated by taking the approved average fuel expense per MWh in 2007 (NSPI is requesting a fuel expense of $38.19 per MWh), subtracting the approved fuel cost that the 2006 rates were predicated upon (which was $33.23 per MWh), and multiplying that difference (which in this case would be $4.96 per MWh) by the Q1 load forecast for 2007. Note that the entire deferral is based on forecasted fuel costs and *not actual fuel costs*. Thus, the request is not so much a deferral mechanism as it is a request for an additional ~~$18.5~~ $18.3 million in revenue for 2007 to be collected in the subsequent year.

Q BUT IF FUEL COSTS DO INCREASE IN 2007 AND NEW RATES ARE NOT PUT INTO EFFECT UNTIL APRIL 1, IS THAT NOT UNFAIR TO NSPI?

A No. Subject only to any legislative limitation that may come into force, NSPI has complete discretion as to when it files its rate cases. If new rates do not go into effect until April in 2007, it is because NSPI did not file its application until October 10. If the filing was tardy, the onus falls squarely on NSPI's management and thus is no reason for customers to pay an extra ~~$18.5~~ $18.3 million.

Q WHY WOULD THE PROPOSAL SET A POOR REGULATORY PRECEDENT?

A It would be poor regulatory precedent because:

- The request can only increase rates, not decrease them.
- Such a deferral could never be obtained by a non-regulated enterprise; and the raison d'etre of regulation is to serve as a surrogate for competition.
- It would remove (or at least severely reduce) the phenomenon of "regulatory lag", an important incentive for a regulated utility to improve efficiency.[12]

[12] Bonbright's Principles of Public Utility Rates defines "regulatory lag" as the "quite usual delay between the time when reported rates of profit are above or below standard and the time when an offsetting rate decrease or rate increase may be put into effect by commission order or otherwise." page 96

- It constitutes retroactive ratemaking
- It is single-issue ratemaking.
- The timing for the rate application is solely a decision of NSPI's management.

For these reasons, I strongly recommend that the Board reject this proposal.

6. NSPI'S PROPOSAL FOR A "TRUE-UP" FOR THE 2P-RTP RATE

Q WHAT IS NSPI'S PROPOSAL ON THIS ISSUE?

A The proposal is as follows:

> Therefore, NSPI requests the Board direct a true-up of fuel expense that is not recovered due to the operation of the 2P-RTP rate. This would be fuel expense that is approved for recovery by the Board but otherwise unfunded. This may occur due to unintended operation of the 2P-RTP rate in terms of the failure to match actual fuel costs to load shifting credits and debits. NSPI will monitor the operation of the 2P-RTP rate and report to customers and the Board the actual results relating to fuel expenses. At the end of the calendar year the amount of the loss, if any, will be recovered from 2P-RTP customers.

Q NSPI STATES THAT SINCE THE 2P-RTP RATE MECHANISM IS PREDICATED UPON COST SAVINGS TO NSPI BEING EQUAL TO THE COST SAVINGS TO THE CUSTOMER, IT THEREFORE "ANTICIPATES NO OPPOSITION TO THIS REQUEST". DO YOU OPPOSE THIS REQUEST?

A Yes, I unequivocally oppose this request.

Q PLEASE STATE THE GROUNDS FOR YOUR OPPOSITION.

A First, like NSPI's proposal to defer the difference between the current base rate of fuel and the new base rate of fuel in the first quarter of 2007, it constitutes retroactive ratemaking. If this request is approved, the customers on 2P-RTP will never know

exactly how their behaviour affects their bill. This is unfair to the customers who must make immediate decisions on load shifting. As I noted in the previous section of this evidence, regulators should prohibit retroactive ratemaking.

Second, like NSPI's proposal to defer the difference between the current base rate of fuel and the new base rate of fuel in the first quarter of 2007, it constitutes single-issue ratemaking.

Third, the request is premature as there is no history on this rate and so no evidence that this extraordinary device is needed in the first place.

Fourth, the request is discriminatory. NSPI is not requesting a "true-up" for any other customers or for any other purpose.

Fifth, it is unclear how NSPI would even calculate the "true-up" or apportion any credit or debit to each customer on the rate. In fact, during the discussions on 2P-RTP that led up to the ELIIR-2 hearings this fall, NSPI cited to their uncertainty as to how to apportion the Decremental savings or Incremental costs as one of their objections to instituting RTP. The details of how this would be done are totally lacking in their testimony and evidence. Moreover, NSPI's ability to properly calculate this so-called "true-up" is questionable given the following information request and NSPI's response:

> **Question SEB IR-63:** Please provide a version of Appendix A with the Forecast 2006 year (column (2)) replaced by a pro forma version that employs the most recent data and also assumes normal weather and assumes normal operations for Stora Enso.
>
> **Response SEB IR-63:** NSPI is unable to provide such a forecast. NSPI is not able to retroactively determine either the changes in unit dispatch or the mix and volume of fuels required to serve this load. Please refer to Liberty IR-73.

Finally, the Board has already ruled on this issue not more than three months ago. In its correspondence dated October 27, 2006 the Board specifically stated as follows:

> "In the Compliance Filing issued today, the Board declined to include a true-up mechanism. The Board, in the ELIIR decision, provided two mechanisms to ameliorate risk:
>
> 1. The risk protection mechanisms as contained in the rate;
>
> 2. An annual review on the anniversary date of approval of the rate to ensure the rate is operating fairly."

Thus there are at least six compelling reasons for rejecting NSPI's request on this issue.

7. COST OF SERVICE ISSUES AND REVENUE ALLOCATION

Q HAVE YOU CONDUCTED A FULLY ALLOCATED COST OF SERVICE STUDY?

A Yes. I believe that NSPI's cost study, while a good start, can be significantly improved upon. For each modification that I have made, I will explain and demonstrate why it improves the accuracy of the cost allocation process, i.e., it will more accurately reflect the cost that the users impose on the system.

Q ARE YOU AWARE THAT THE BOARD HAS RECENTLY DECLINED TO ENTERTAIN ANY CHANGES TO THE METHODOLOGICAL DECISIONS THAT IT FOUND IN ITS 1995 DECISION ON THE SUBJECT OF COST ALLOCATION?

A Yes, I am fully aware of that decision and of course will abide by that finding, although I respectfully disagree with it.[13] Thus, the cost analysis I present in this evidence fully

[13] In my testimony during the recent ELIIR hearings, I explain why the one-sided capital substitution method adopted by the Board in 1995 overallocates costs to any class with a load factor

conforms to and abides by the principles of the 1995 decision, as I understand the tenets of that decision. To wit, my analysis adheres to the following principles:

- Fixed environmental generation costs are classified entirely as energy related and allocated on annual energy usage.
- All fixed non-environmental generation costs of baseload plants are classified as both demand related and energy related, with the energy related portion being taken equal to the annual load factor of the system.
- All fixed generation costs of non-baseload plants are classified as entirely demand related.
- All fixed transmission costs are classified as both demand related and energy related, with the energy related portion being taken equal to the annual load factor of the system.
- All generation and transmission demand related costs are allocated on the basis of the three winter coincident peaks.
- All fuel costs are allocated on the basis of monthly energy usage.

Furthermore, my cost analysis, as does NSPI's, follows the guidelines on interruptibility credits as recently confirmed in the September 28 Decision on the ELIIR-2 rate.

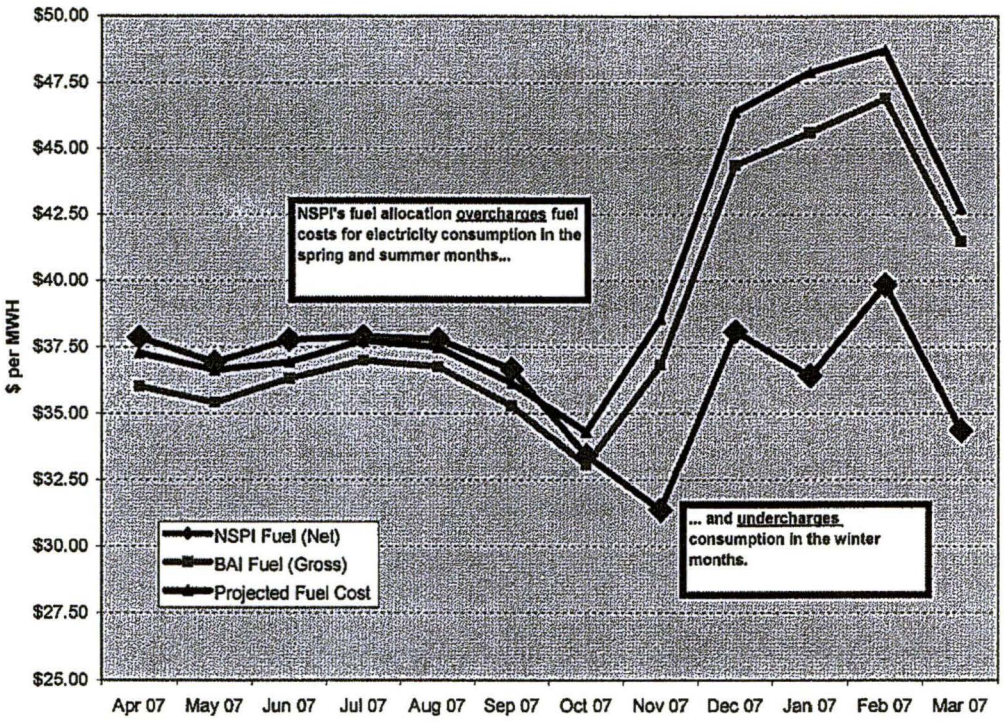
Q PLEASE EXPLAIN THE FIRST MODIFICATION THAT YOU HAVE MADE TO THE COMPANY'S FILED STUDY AND WHY YOU FOUND IT NECESSARY.

A The first modification pertains to the allocation of fuel costs. The monthly fuel costs that NSPI uses to allocate are disconnected with the actual costs per MWh of the fossil fuel burned per MWh, as can be seen from the following chart (Figure 1).

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greater than the system average load factor. These classes include not just the ELIIR and Large Industrial Class, but also the General, General Large, Small Industrial and Medium Industrial classes.

Figure 1
Comparison of Fuel Costs ($/MWH)



Costs shown on this chart are on a dollar per MWh basis. This chart compares fuel costs under NSPI's proposed recovery (the red line), versus the actual projected fuel costs (blue line) and my proposed fuel allocation method (teal line). The blue line represents NSPI's plant fuel costs less the fuel associated with exports. The denominator of the blue line is total fossil plant generation plus non-Mersey hydro, less energy associated with exports. As evident by this blue line, fuel costs exhibit a strong seasonality with higher costs shown for the months November through March. My fuel cost allocation, shown as the teal line, closely follows this seasonal pattern and thus provides a signal to customers of the fuel cost seasonality. NSPI's fuel costs shown as the red line, bear little relationship to seasonality or actual costs. In fact, NSPI's method of fuel allocation overcharges electricity consumption in the spring and summer months, and more importantly, undercharges consumption in the

winter months. Consequently, NSPI's fuel allocation fails to provide a meaningful price signal that truly reflects actual fuel costs. My proposed fuel allocation more closely matches the actual fuel costs, and thus provides a better price signal.

Q WHY DOES NSPI ARRIVE AT THEIR ANOMALOUS AND MISLEADING RESULT?

A As best I can determine (because NSPI does not provide intervenors with an electronic version of its workpapers), this inaccuracy is introduced because NSPI allocates the profit from its gas resales to the month when it actually makes the sales. Since NSPI's profits are greatest in the winter, this method has the perverse effect of artificially depressing the true consequence of using electricity in the winter as shown in the above chart. In fact, the paradox of NSPI's method is that the more expensive gas is (assuming that most of the gas is sold in the winter), the cheaper is the apparent cost of consuming electrical energy in the winter. This of course will not help bring about efficient DSM.

Q HOW DID YOU DERIVE YOUR MONTHLY FUEL COSTS?

A I essentially derived an actual cost per MWh of fuel burned by dividing the actual fuel cost in each month, as provided in NSPI's response to SEB IR-55, by the total MWh system requirement, multiplied that fuel cost by the retail sales, and then proceeded exactly as NSPI had done to allocate these costs to the various classes, as provided in its response to SEB IR-66. However, because the total fuel cost from Strategist did not include the profit on the resale of natural gas, it was necessary to subtract that profit in order to derive the final fuel allocator.

Q HOW DID YOU ALLOCATE THE PROFIT OF THE RESOLD GAS TO THE VARIOUS CLASSES?

A In the only logical way that I can see – by allocating these negative fuel costs on the basis of energy. In this manner, no class is unduly or arbitrarily favored or disadvantaged by the timing or profitability of the resale. It also does not distort the price signal.

Q DOES YOUR MODIFICATION OF THE FUEL ASSIGNMENT ADDRESS THE BOARD'S CONCERN THAT HIGH LOAD FACTOR CUSTOMERS MAY BE ALLOCATED TOO MUCH COST RESPONSIBILITY IN THE COST OF SERVICE STUDY?

A No, it does not. In the first place, my analysis is still a monthly analysis. The Board's concern focused on the imprecision inherent in not using an hourly allocation of fuel. Since hourly variations in load within any month can be nearly as great as the variation in average load between months, there is no question in my mind that the fuel allocation in my study understates the cost responsibility of classes that tend to peak when the system peaks. Moreover, because I have included the hydro dispatch in my analysis as well, and because hydro plants are run more when load, and hence fuel costs, are high, the "peakier" classes also receive a disproportionate share of the hydro benefits relative to the non-peaky classes. In short, while my fuel assignment is an improvement in the accuracy of the fuel costs, it is only a modest improvement.

Q PLEASE EXPLAIN THE SECOND MODIFICATION THAT YOU HAVE MADE TO THE COMPANY'S FILED STUDY.

A The 1995 allocation methodology prescribes that only baseload plants should have a portion (equal to the load factor of the system) reclassified from demand into energy. As Dr. Stutz noted in his Exhibit JS-10 in the recent ELIIR hearing when the subject of cost classification was raised:

> The Board's approved COSS methodology classifies a portion of generation and transmission costs as energy related. This reflects the fact that the cost *of baseload plant* and the associated transmission plant is incurred in part to reduce the cost of usage.

In this exhibit, Dr. Stutz proceeded to give an illustrative example of the Board's approved method, in which "a percentage of the baseload fixed costs equal to the load factor is classified as energy and not demand related and allocated accordingly".

Thus the question here is not one of methodology – as that has already been proscribed by the Board's 1995 Decision and is not at issue; rather the question is **which plants should be classified as "baseload"?** An informative treatise on this issue is found in the NARUC Electric Utility Cost Allocation Manual Chapter 4, page 53, (Embedded Cost Methods for Allocating Production Costs), Section IV (Methods for Classifying and Allocating Production Plant Costs), particularly in the section entitled A Digression on System Planning with Reference to Plant Cost Allocation.

> The utility can choose to construct one of a variety of plant-types: combustion turbines (CT), which are the least costly per kW of installed capacity, combined cycle (CC) units costing two to three times as much per KW as the CT, and *baseload units with a cost of four or more times as much as the CT per KW of installed capacity.*

Of course, the primary reason that the utility planner is willing to spend so much more per kW to build a baseload plant, is because the baseload plant produces energy at a much lower cost per kilowatthour. If the baseload plant runs long enough, the savings from the lower fuel costs more than offset the higher capital (or

fixed) costs. Thus, baseload plants typically run as much as possible, typically achieving capacity factors of 85 to 90 percent. In summary, baseload plants typically exhibit the following characteristics:

- High capital or fixed costs;
- Low fuel or variable costs
- Capacity factors of 85% or above

NSPI's coal plants are prototypical baseload plants. Non-baseload plants (usually referred to as peaking or cycling plants) exhibit just the opposite characteristics.

- Relatively low capital or fixed costs;
- High fuel or variable costs
- Capacity factors considerably less than 85%

Q YOU STATED THAT NSPI'S COAL PLANTS ARE PROTOTYPICAL BASELOAD PLANTS. WHAT EVIDENCE DO YOU HAVE FOR THAT STATEMENT?

A Besides my experience with other utilities – and virtually every utility that I have ever encountered considers coal (and nuclear) plants as baseload, we have the evidence of NSPI in this case. In response to ~~Liberty IR-10~~ Liberty IR-10 Revised, NSPI makes the following statements:

> The **solid fuel** fleet of generating assets at NSPI are generally **base loaded** and are minimally affected by load changes.
>
> This range of fuel consumption is driven by the **base load nature** of the **solid fuel** fleet.

Note that NSPI's observation about the base load nature is confined to the coal plants.

Q IS IT ALSO TRUE THAT THE OTHER GENERATING ASSETS – THOSE FUELED BY OIL AND GAS, INSTEAD OF SOLID FUEL – ARE MINIMALLY AFFECTED BY LOAD CHANGES?

A No it is not. Those statements are strictly applicable only to the solid fuel fleet of generating assets at NSPI.

Q NEVERTHELESS, IN ITS COST OF SERVICE STUDY, DOES NSPI TREAT ANY PLANTS AS "BASELOAD" THAT EXHIBIT MORE OF THE CHARACTERISTICS OF PEAKING PLANTS OR CYCLING THAN OF BASELOAD PLANTS?

A Yes. NSPI treats the LM6000s and Tufts Cove as baseload plants. In other words, in its classification method, the classification of the LM6000 plants and Tufts Cove are indistinguishable from the classification of its solid fuel fleet.

Q DO YOU AGREE WITH THE TREATMENT OF THE LM6000 COMBUSTION TURBINES IN A LIKE MANNER AS THE SOLID FUEL FLEET OF PLANTS?

A Absolutely not. I contend that these combustion turbines (CTs) are unqualifiedly peaking plants. In fact, combustion turbines are almost always considered peaking plants for the following reasons:

1. These plants are much more expensive to run than NSPI's baseload coal plants. In fact, even with the recent run up in coal costs that have drawn so much attention, the fuel cost of the LM6000's per MWh, are 2 ½ times that of NSPI's most expensive coal plants.

2. These plants are much cheaper to build than a baseload plant per kW. For example, the capital cost of the LM6000s is approximately $700 per kW. A coal plant would cost over three times that.

3. These plants have much lower capacity factors than the baseload plants. For example, while the Lingan plants have capacity factors of 85%, Point Aconi a capacity factor of 90% and Point Tupper 94%, the LM6000s are expected to have a capacity factor in 2007 of only 65%. In 2006 these plants had a capacity factor even lower than that.

Furthermore, (and because of the above facts) the reason that the LM6000's were put in was to meet peak demand. As NSPI's then Chief Operating Officer explained to the Board[14] when NSPI asked for permission to acquire the LM6000:

> Given the *dramatic increase in peak demand* and the lead-time for generation additions ... there remains only one technically and economically viable option to increase the generation capacity of our Province in time for next winter. That option is to advance to 2004 the construction of the LM6000 combustion turbine previously scheduled for addition in 2006.
>
> (Page 2 of 4, emphasis added)

Thus there can be no question that the economics of the LM6000 (low capacity costs and high fuel costs) make this machine suitable for meeting peak demand. Its purpose is not to save fuel, and thus it is unsuitable for a baseload plant. Consequently, the LM6000 should not be treated as a baseload plant in the cost study analysis.

Q ARE YOU ALSO AWARE THAT NSPI ALSO SOUGHT, BY USE OF ITS GENERATION EXPANSION PLANNING MODEL, TO JUSTIFY THE LM6000 PROJECT ON ECONOMIC GROUNDS?

A Yes, I am aware of that. However, in its responsive letter to the CEO[15] the Board rejected that rationale and affirmed the primary purpose and suitability of the LM6000 as a peaking unit. In part, that letter states:

> According to the (generation expansion planning) model, advancing the unit to January 2005 and the steam turbine to 2006 would not decrease the present value savings to the customers. In fact it would increase the savings by $100,000. While the Board takes some comfort from these results, *it must be observed that NSPI compared a limited range of options in the modeling exercise.* In particular, NSPI assumed that the required additional generating capacity must come from an LM6000. Hence in assessing NSPI's request for approval of

[14] Letter of Ralph Tedesco to Chairman Morash, dated March 2, 2004.

[15] Letter of the NSUARB to Ralph Tedesco, dated April 2, 2004.

> this project, *the Board places much greater weight on reliability considerations* than on NSPI's economic justification.
> (Letter of the Board, P-181, page 3, emphasis added)

Q ARE YOU AWARE OF ANY OTHER UTILITY THAT CONSIDERS COMBUSTION TURBINES, SUCH AS THE LM6000, AS BASELOAD PLANTS?

A No, I am not, although I have not conducted a formal survey on this topic. I am, however, aware of the converse situation. I recall that when PacifiCorp was seeking to meet its peak summer load in Utah, its technology of choice was an LM6000. As PacifiCorp noted in its 2003 Integrated Resource Plan:

> Simple-cycle Combustion Turbines (SCCTs) are modeled. These machines are true peakers and are represented by aero (aeroderivative) machines such as the LM6000 design from GE recently installed at West Valley and Gadsby. (Page 74)

Q ARE THERE ANY OTHER PLANTS OF NSPI THAT ARE TREATED BY NSPI AS BASELOAD PLANTS, BUT YET DO NOT HAVE THE DEFINING CHARACTERISTICS OF BASELOAD PLANTS?

A Yes, the economics of the Tufts Cove units are more much closely aligned with the LM6000 combustion turbines than that of the coal units. In fact Tufts Cove units 1, 2 and 3, have a combined capacity factor of only 56%, less even than the LM6000 units. Moreover, the average variable cost of these three Tufts Cove units is expected to be even more expensive than that of the LM6000s. I have prepared a chart, shown on Schedule 7, which compares the fuel cost as well as the 2007 capacity factors of NSPI's coal plants, with those of the LM6000s and Tufts Cove. Clearly the latter plants possess distinctly different economics from the former.

Consequently, in light of the above, it is much more consistent with the Board's 1995 methodology to treat the LM6000 as well as Tufts Cove as non-

baseload plant, and classify their fixed costs accordingly. Not only is it more consistent, but more importantly it better aligns cost allocation with the cost causation underlying economics of generation.

Q DOES THIS MEAN THAT IN YOUR REFINED COST STUDY, ALL OF TUFTS COVE'S FIXED COSTS ARE CLASSIFIED AS DEMAND RELATED?

A No. Consistent with Board findings, 100% of the Tufts Cove environmental costs are classified as totally energy related.

Q PLEASE EXPLAIN THE THIRD MODIFICATION THAT YOU HAVE MADE TO THE COMPANY'S FILED STUDY.

A In addition to the Mersey energy, which is priced according to a long-standing contract, and thus is a below-the-line rate, Bowater Mersey takes what is termed Additional Energy. For many years, this Additional Energy was taken under the GRLF rate, which is also a Below the Line rate. However, currently, and for the foreseeable future, Additional Energy is taken and priced under the exact terms and prices specified by the Large Industrial Rate with Interruptible Rider (LIRIR). This rate of course is an Above-the-Line rate. However, NSPI anachronistically treats this Additional Energy as still being Below the Line, and excludes this energy from the cost analysis. This of course is quite at odds with NSPI's philosophy in the recent ELIIR-2 case when it held that a rate is not really cost based unless it is directly derived from the familiar fully allocated cost analysis.

NSPI's treatment also makes for a complication. The amount of costs that are allocated to the Above the Line classes can only be known after the revenue from the Below the Line classes are known. However, because it treats the Additional Energy

as a Below the Line class, while the price is determined by the Above the Line analysis, it is trapped in a conundrum. In essence, it must chase its tail. That is, it must first guess at the price it will charge for the Additional Energy and must also guess at the amount of fuel and other costs it will directly assign to the Additional Energy, and then engage in what is known as an iterative process.

Q WHAT IS YOUR PROPOSED SOLUTION TO THIS PROBLEM?

A The solution is straight-forward in my view. The guesswork and the circular reasoning can be eliminated by simply moving the Additional Energy (and demand) into the same class or category as all the other Large Industrial interruptible rate energy and demand. This assures that everything that is priced on that rate is included in the cost analysis. The process is not only simpler, it is more accurate and transparent, and of course eliminates the need for guess-work or assumptions.

Q WHAT IS THE RESULT OF THE COST STUDY WITH YOUR THREE REFINEMENTS?

A The results are depicted in Exhibit AR-1, Schedule 8. Because the Large Industrial rate class in my study includes all of the energy sold under this rate, including the Additional Energy sold to Bowater Mersey, the total cost is not directly comparable to the total cost derived by NSPI's study (for this class alone – the other classes are directly comparable). Thus I have also shown the cost expressed in cents per kilowatthour to facilitate a more direct comparison.

Q DOES SCHEDULE 8 REFLECT THE LOWER FUEL COSTS THAT YOU RECOMMEND IN THE PRIOR SECTION OF YOUR TESTIMONY?

A No. This schedule is predicated on the Company's requested revenue requirement so that the Board can clearly see the impact of my refinement of the application of the Board's approved methodology. Obviously, any compliance study should be based upon a cost study that fully reflects the revenue requirement for 2007 and beyond as approved by the Board.

Q DOES THIS CONCLUDE THIS PORTION OF YOUR DIRECT TESTIMONY?

A Yes it does.

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Qualifications of Alan Rosenberg

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Alan Rosenberg. My business address is 1215 Fern Ridge Parkway, Suite 208, St. Louis, Missouri 63141.

Q WHAT IS YOUR OCCUPATION?

A I am a consultant in the field of public utility regulation and am a principal with the firm of Brubaker & Associates, Inc. (BAI), energy, economic and regulatory consultants.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I was awarded a Bachelor of Science Degree from the City College of New York in 1964 and a Doctorate of Philosophy in Mathematics from Brown University in 1969. Subsequently, I held an Assistant Professorship of Mathematics at Wesleyan University in Connecticut. In the summer of 1975, I was a Visiting Fellow at Yale University. From July, 1975 through January, 1981, I was Assistant Controller and Project Manager for a division of National Steel Products Company. My responsibilities there included supervision of management accounting, cost accounting and data processing functions. I was also responsible for internal control, general ledger systems, working capital levels, budget preparation, cash flow forecasts and capital expenditure analysis.

I have published in major academic journals and am a member of the International Association for Energy Economics. I was an invited speaker at the NARUC Introductory Regulatory Training Program and a panelist at a conference on LDC and Pipeline Ratemaking sponsored by the Institute of Gas Technology. I have

presented a paper on stranded costs at the 21st Annual International Conference of the International Association for Energy Economics. I have had two papers on transmission congestion pricing published in The Electricity Journal. I am also a Certified Energy Procurement Professional by the Association of Energy Engineers.

In January, 1982, I joined the firm of Drazen-Brubaker & Associates, Inc., the predecessor of Brubaker & Associates. Since that time, I have presented expert testimony on the subjects of industry restructuring, open access transmission, marginal and embedded class cost of service studies, prudence and used and useful issues, electric and gas rate design, revenue requirements, natural gas transportation issues, demand-side management, and forecasting.

I have previously testified before the Federal Energy Regulatory Commission as well as the public service commissions of Arizona, Connecticut, Delaware, Florida, Idaho, Illinois, Iowa, Massachusetts, Michigan, Montana, New Jersey, New Mexico, New York, North Carolina, Ohio, Pennsylvania, Rhode Island, Vermont, Virginia, Wyoming and the Provinces of Alberta, British Columbia, New Brunswick, Nova Scotia, and Saskatchewan in Canada. I have also testified before the Michigan Senate Technology and Energy Committee.

In addition to our main office in St. Louis, the firm also has branch offices in Phoenix, Arizona; Corpus Christi, Texas; and Plano, Texas.

Before the
Nova Scotia Utility and Review Board

Re:General Rate Application and Annual Rate Review, File P-875

NOVA SCOTIA POWER INC.

Direct Testimony of

Dr. Alan Rosenberg

On Behalf of

Stora Enso Port Hawkesbury Limited
and Bowater Mersey Paper Company Limited

March 25, 2002
Project 7726

Brubaker & Associates, Inc.
St. Louis, MO 63141

Q ARE THERE INDICATIONS OF POSSIBLE POOR JUDGEMENT ON THE PART OF NSPI?

A Yes. In its Annual Report for 2000, the Company states:

> All significant risk management activities for Emera are monitored by the Executive Risk Management Committee to ensure the resulting exposure is within predefined tolerance levels. The Board of Directors approves the strategic direction and annual risk management program parameters prior to implementation. (Annual Report, page 27)

Yet, when SEB inquired as to all reports or memoranda issued by Emera's Executive Risk Management Committee to its Board of Directors in 2001, NSPI responded that the information was "beyond the scope of this rate application," when it is clear that Risk Management, or the lack of it, is at the crux of this rate application.

Q RETURNING TO GENERIC PRINCIPLES OF REGULATION, PLEASE EXPLAIN THE *USED AND USEFUL* STANDARD.

A An element of rate base or an expense item is said to be used and useful if the asset or purchased item or commodity is both used by the utility in providing service, and useful for the customer.

Q WHAT IS THE DIFFERENCE BETWEEN THE TWO TERMS, USED AND USEFUL?

A Let us take an example. Suppose I am building a house and need a hammer. If I go to the hardware store and buy a gold plated hammer, I may *use* that hammer to bang nails. Nevertheless, not all that I spent on the hammer can be considered *useful* because a steel hammer would have done just as well for a much smaller cost. Of course, if the hammer was economic, but nevertheless sat idle, it would be useful but not used. Let us take another example. Suppose I am moving furniture and I rent a van, but only fill the van half full. The van is being *used* to move the furniture, but the entire rental cost of the van is not *useful* because a smaller (and presumably less costly) van would have sufficed.

Q CAN AN EXPENSE OR ASSET BE PRUDENTLY INCURRED BUT YET NOT PASS THE USED AND USEFUL TEST?

A Yes. Perhaps a classic example was a case where the Virginia State Corporation Commission found that Virginia Electric Power was prudent both in commencing construction on a nuclear plant and prudent in halting construction. Nevertheless the SCC found that the unfinished plant was not used and useful and the costs were shared between the utility and its ratepayers.

Q CAN THE USED AND USEFUL STANDARD BE APPLIED TO FUEL OR PURCHASED POWER CONTRACTS AS WELL AS TO PHYSICAL PLANTS?

A Yes. Not only did the Vermont Board apply this standard to a purchased power contract, but it noted that other jurisdictions had reached the same conclusion, namely the Minnesota Public Utility Commission and the New Mexico Public Utility Commission.[8]

Q WHAT ARE THE REGULATORY CONSEQUENCES FOR AN ASSET OR CONTRACT NOT FOUND TO BE USED AND USEFUL?

A In the Virginia case the Commission allowed the amortization of the nuclear costs over a 15 year period with no return on the unamortized portion. The consequences in Vermont were a 50/50 sharing of the uneconomic portion of the asset or contract costs.

> The Board has held in numerous decisions, consistent with *long standing rulings* of the United States Supreme Court, the policies applied by the Federal Energy Regulatory Commission, and with *orders of many other state commissions*, that ratepayers should not have to pay for utility investments **and purchases** that are not used and useful.[9]

[8] Docket No. E-001/GR-95-601, Interstate Power Company, (Minnesota PUC), June 26, 1996 and Re: Section 712 of the Energy Policy Act of 1992, New Mexico PUC, Case 2512, October 7, 1993.

[9] Vermont PSB Order No. 5983, page 242, emphasis added.

Q HOW HAVE REGULATORS APPLIED THE USED AND USEFUL STANDARD TO ARRIVE AT PARTICULAR DISALLOWANCES?

A In the case of the Hydro Quebec contract (Vermont) and in the case of the Millstone III nuclear plant (Massachusetts), the standard was the considered market value of a comparable resource that would serve the same purpose.

Q IS IT FAIR TO THE COMPANY TO DISALLOW COSTS THAT ARE ABOVE MARKET, WHEN REGULATORS USUALLY DO NOT ALLOW UTILITIES TO CHARGE CUSTOMERS THE HIGHER OF COST OR MARKET?

A In this case, I believe it is. In the first place, NSPI shareholders can profit if actual fuel costs are less than forecast. Remember that to a large extent NSPI controls if and when the Company comes in for a rate case. Secondly, NSPI does not seem to have had below market coal costs. Third, when it did have below market gas costs, it sold that gas for a profit – a profit that was solely for the benefit of shareholders. Thus the premise of the question is not quite applicable to NSPI. Moreover, the Vermont Board rejected that very argument.

> We reject this argument. Appropriate application of the used-and-useful standard to non-investment expenditures does not create a new set of asymmetric risks for which the Company shareholders have not been compensated. As the DPS pointed out, there is an "essential symmetry" embodied in the methods by which rates are set in Vermont. The return on equity that investors demand reflects the business and market risks that the Company faces – among them, the possibility that its contracts .... may impose costs upon it that may not be fully recoverable in the market price of the goods it sells. This is true of any competitive business, and it is this pressure upon firms that improved economic efficiency.[10]

It is my view that the UARB should impose the same discipline upon NSPI that a market would exact from a producer in the competitive arena. Regulation is intended to act

[10] Order No. 5983, page 247.

a surrogate or proxy for competition when actual competition is not yet available or practical.

Q WHAT IS YOUR VIEW ON THE TWIN ISSUES OF IMPRUDENCE AND USED AND USEFUL?

A My view of the issue is in accord with the sentiments expressed in the following excerpt from The Prudent Investment Test in the 1980's , a report prepared by associates of the National Regulatory Research Institute.

> Perhaps the most significant issue to be resolved about the nature of the prudent investment test is how it relates to the used and useful test. In one view the used and useful tests are two distinct tests.
>
> ********
>
> If the tests are distinct and both are applied and met, does the order of the application matter? Some would argue that the prudent investment standard should be applied first, and applied solely to the initial investment decision. Then the used-and-useful standard would be applied second, as a higher standard, once the investment is ready for rate base treatment. Here, the used-and-useful test substitutes for what competitive companies would call a market test of demand for their product.

In other words, while the prudence decision relates to what might have been if the utility had acted with more discretion, sagacity, reason or care, the used-and-useful standard concerns itself solely with the performance or economics of the resource. I do agree, however, that the tests are related in the sense that the larger the imprudence disallowance, the less of a used and useful adjustment is needed in order to narrow the gap between the requested cost and the market price.

Q ARE THE PRUDENCE STANDARD AND THE USED AND USEFUL STANDARD MUTUALLY EXCLUSIVE?

A No, the prudence standard and the used and useful test can be applied as two distinct tests. While the prudence standard focuses on the decision-making process of utility

management in committing to certain expenditures, the used and useful test examines whether the expenditure in question is (1) physically used and (2) useful to the ratepayers from an economic standpoint, after consideration of any non-price benefits.

A good example of this occurred when the Vermont Public Service Board clearly concluded that the decision of the Vermont Joint Owners to lock into a purchased power agreement with Hydro Quebec was imprudent ***and*** that the contract was not fully used and useful. In fact, the Board reached these independent conclusions in two distinct sections of the Docket No. 5983 order (sections 3 and 4). The Board's supplemental order in Docket No. 5983 further clarified the Board's conclusions, citing:

> The Rate Order's finding that there are two independent bases for disallowing portions of the Contract power costs: the Company's imprudence and the fact that the Contract is not used-and-useful under Vermont ratemaking principles.[11]

Q CAN YOU GIVE AN ILLUSTRATION OF HOW THE TWO TESTS CAN BE USED IN CONJUNCTION WITH ONE ANOTHER?

A Yes. Suppose that a utility builds a plant for $500 million, but that the regulators conclude, based on the facts known at the time the plant was built, that, had the utility acted prudently, it could have been built for $400 million. In that case, $100 million of the plant would be disallowed on the grounds of prudence. Further suppose that the regulators find that an equivalent amount of capacity, with similar availability could have been obtained for $350 million. In that case the extra $50 million would not be used and useful and would be shared between customers and shareholders.

Q HAVE OTHER REGULATORY COMMISSIONS CONSIDERED BOTH THE PRUDENCE AND THE USED AND USEFUL STANDARDS IN DECIDING WHETHER OR NOT TO ALLOW COSTS?

[11] Docket No. 5983, Order Re: Motion to Reconsider, p. 29.

A Yes. The National Regulatory Research Institute (NRRI) publication entitled, The Prudent investment Test in the 1980s, states:

> Review of recent state commission prudence inquiries involving electric and gas utilities reveals that in only a few cases do commissions rely clearly and solely on the concept of prudence for reaching a judgment. Rather, in most cases commissions also reference ***the used-and-useful test*** or some other test when deciding if questionable costs should be included in rates. [emphasis added][12]

Thus, it is clear that NRRI's research acknowledges the application of the prudence standard and the used and useful test as separate and complimentary regulatory tools.

Q ARE THERE ANY CANADIAN REGULATORY PRECEDENTS CONCERNING THE STANDARDS OF PRUDENCE AND "USED AND USEFUL"?

A Yes. In *Board of Commissioners of Public Utilities* v. *Nova Scotia Power Corp. et. al.*, (1976) 75 D.L.R. (3d) 72 (N.S.S.C.A.D.)., MacKeigan C.J.N.S. considered the *Public Utilities Act*, and stated, at p. 6 (QL):

> The expenses for rate-making purposes are only those the Board allows "as reasonable and prudent and properly chargeable to operating account" (s.42(2)). Other "just allowances" are prescribed by the Act and Regulations, e.g., annual depreciation charges (ss. 35-38).

In *Re: Newfoundland (Board of Commissioners of Public Utilities)*, [1998] N.J. No. 168 (Nfld. S.C.A.)., the Court considered the concepts of prudence and "used and useful", and stated at p.32:

> The just and reasonable return on rate base which the Board determines that the utility is entitled to earn annually is "in addition to those expenses which the Board may allow as reasonable and prudent and properly chargeable to the operating account...". **Thus, in the process leading up to the prospective setting of rates, the Board may look at the type and level of projected expenses of the utility in the test year and determine whether they are reasonable and, if not, only allow, for the purposes of calculation of a just and reasonable return on rate base, such types**

[12] The National Regulatory Research Institute, The Prudent Investment Test in the 1980s, April 1985, p. v.

and levels of expenses as are, in the opinion of the Board, reasonable. (Emphasis added)

Q IN YOUR OPINION, HOW SHOULD THIS BOARD ARRIVE AT AN APPROPRIATE DISALLOWANCE FOR THE PRUDENTLY ALLOWED PORTION OF NSPI'S COAL COSTS?

A Ms. Hennings has calculated what NSPI's coal costs would have been if they had been purchased at market prices. If the Board disagrees with the conclusion that NSPI has been imprudent, it would be my recommendation that the disallowance be one half of the difference between Ms. Hennings' calculated costs and NSPI's test year costs for coal, on the basis of the "used and useful" test. In my view, this would constitute a reasonable sharing of this burden between customers and shareholders. Based on my knowledge of the regulatory process, courts have allowed regulators broad discretion in disallowing costs as long as its deliberation process is just and reasoned and not arbitrary or capricious.

Q WHY SHOULD REGULATORS DISALLOW COSTS THAT ARE TOO HIGH?

A In competitive markets, when a producer pays too much (more than its competitors) for a raw product, the discipline of the market place forces the high costs onto the owners of the Company. If this happens too often, management either learns to do a better job or the Company goes out of business. Regulation is a proxy for competition, when real competition is not available. Thus to disallow unduly high costs is an integral part of a regulator's duty. It should not be forgotten, too, that forest products plants in Nova Scotia (such as SEPH and Bowater) will <u>not</u> be able to pass along these high costs.

Exhibit AR-1
Schedule 1

NOVA SCOTIA POWER INC.

Comparative Analysis of NSPI Rates with
Other Utilities in the United States and Canada
(U.S. Dollars)

Exhange Rate $ 1.15 CND = $1.00 U.S.

Line	Utility Company	State / Province		Large Industrial Interruptible Customer 50,000 kW Demand, 90% PF and 90% LF at Transmission Level ¢/kWh (1)	Index (2)
1	Empire District Electric Company	AR		5.27	101
2	Progress Energy Carolinas, Inc.	NC		5.24	100
3	**Nova Scotia Power**	**Nova Scotia**		**5.23**	100
4	Georgia Power Company[1]	GA		5.18	99
5	Progress Energy Carolinas, Inc.	SC		4.72	90
6	NB Power	New Brunswick		4.62	88
7	Southwestern Public Service Company	TX		4.56	87
8	Rocky Mountain Power [2]	UT	*	4.41	84
9	Southwestern Electric Power Company	LA	*	4.37	84
10	El Paso Electric Company	TX		4.36	83
11	Alabama Power Company	AL		4.28	82
12	SaskPower	Saskatchewan	*	4.25	81
13	Southwestern Electric Power Company	AR		4.22	81
14	South Carolina Electric & Gas Company	SC		4.20	80
15	Southwestern Electric Power Company	TX		3.98	76
16	Hydro Quebec	Quebec	*	3.95	75
17	Duke Energy Indiana	IN	*	3.94	75
18	Avista Corporation	ID	*	3.93	75
19	Kentucky Power Company [3]	KY	*	3.76	72
20	Virginia Electric and Power Company	VA		3.72	71
21	Tennessee Valley Authority	TN		3.60	69
22	Kentucky Utilities Company	KY		3.56	68
23	Appalachian Power	VA	*	3.54	68
24	Entergy Arkansas, Inc. [4]	AR		3.52	67
25	MidAmerican Energy - East System	IA		3.48	66
26	Aquila Networks - L&P [5]	MO	*	3.47	66
27	Monongahela Power Company	WV	*	3.45	66
28	Rocky Mountain Power	WY	*	3.42	65
29	Kingsport Power Company	TN	*	3.39	65
30	Duke Power Company	NC		3.38	65
31	AmerenUE [6]	MO	*	3.34	64
32	Kansas City Power and Light Company [7]	MO	*	3.26	62
33	Louisville Gas and Electric Company	KY		3.25	62
34	BC Hydro	British Columbia	*	3.19	61
35	Duke Power Company	SC		3.09	59
36	Rocky Mountain Power	WA	*	3.04	58
37	MidAmerican Energy - North System	IA		2.97	57
38	MidAmerican Energy - South System	IA		2.97	57
39	Appalachian Power	WV	*	2.95	56
40	Indiana Michigan Power Company	IN		2.93	56
41	Manitoba Hydro	Manitoba	*	2.70	52
42	Rocky Mountain Power (Special Contract)	ID		2.25	43
	Maximum				101
	Minimum				43
	Median				68
	Average				72

* Firm rate

[1] Pending rate increase of 6.2%

[2] Pending Phase 2 increase of 2.5%

[3] Pending rate increase of 21.0%

[4] Pending rate increase of 9.9%

[5] Pending rate increase of 22.1%

[6] Pending rate increase of 17.7%

[7] Pending rate increase of 11.5%

REDACTED

Exhibit AR-1
Schedule 2

NOVA SCOTIA POWER INC.

Estimation of Proforma Fuel Cost
For Normal Sales Volumes

Line	Description	Amount (000)	Source
	Nine months reduction due to Stora Enso shutdown and warmer weather		
1	Fuel	$ 74,500	Management Report, p8
2	GWh	1,026	Delta YTD Volume '05 vs '06
3	Avoided Cost per MWh	$ 72.61	Line 1 / Line 2
4	Compliance MWh	12,948	Table 8, Line 28 2006C
5	Forecast MWh	_____	Table 8, Line 28 2006F
6	Difference	_____	Line 4 - Line 5
7	Additional Fuel Cost	_____	Line 6 x Line 3
8	Fuel and Purchased Power	_____	Table 8, Line 26 2006F
9	Proforma Fuel and Power	$ 399,155	Line 7 + Line 8
10	Proforma Fuel Cost per MWh	$ 30.83	Line 9 / Line 4

Exhibit AR-1
Schedule 3

NOVA SCOTIA POWER INC.

US/Canada Exchange Rate

Line	Month	Exchange Rate
1	Mar 2007	1.1368
2	Jun 2007	1.1390
3	Sep 2007	1.1307
4	Dec 2007	1.1273
5	Mar 2008	1.1238
6	Average	1.1315

Source:
http://ifs.marketcenter.com
Data retrieved at Dec 4, 20:49:56 GMT

REDACTED

REDACTED

REDACTED

REDACTED

REDACTED

[REDACTED]

[REDACTED]

REDACTED

REDACTED

REDACTED

Exhibit AR-1
Schedule 5

Exhibit AR-1
Schedule 6

REDACTED

NOVA SCOTIA POWER INC.

Impact On Revenue Requirement For Reduction in In Rate Base

Line		Million
1	NSPI	$47.5
2	SEB	9.3
3	Rate Base Reduction	$38.2
4	Pre-Tax ROR	10.76%
5	Rev Req Impact	**$4.1**

NSPI Proposed Cost Of Capital

	Type	Ratio	Cost	Wgt Cost	Tax Factor	Wgt Cost
6	Debt	52.90%	7.84%	4.15%	1.000	4.15%
7	Preferred	9.60%	5.42%	0.52%	1.613	0.84%
8	Common	37.50%	9.55%	3.58%	1.613	5.78%
				8.25%		10.76%
9	Tax Rate	38.00%				

NOVA SCOTIA POWER INC.

Running Cost and Operating Characteristics of Thermal Plants

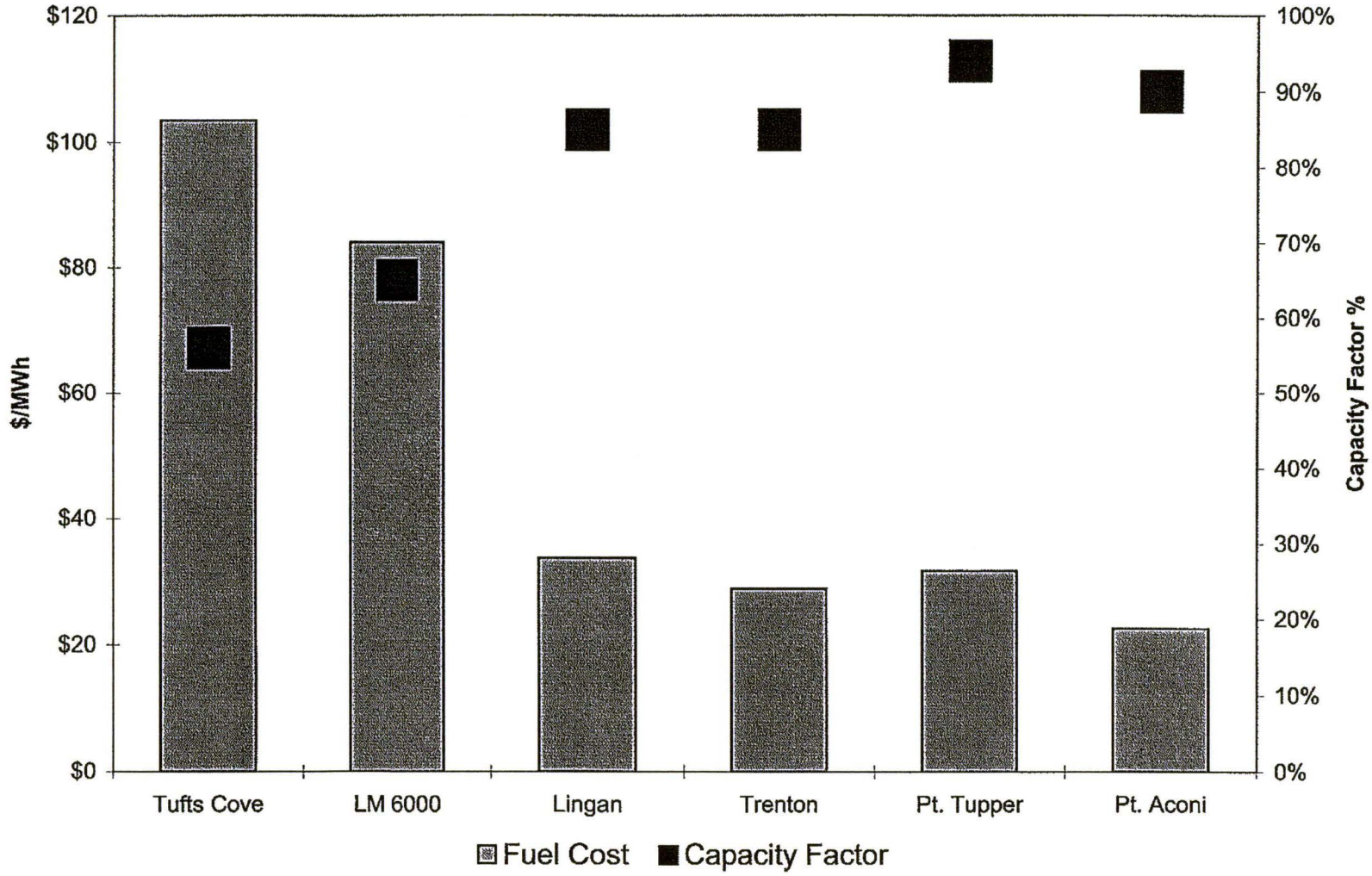


Exhibit AR-1
Schedule 7

COMPARISON OF NSPI COST OF SERVICE STUDY AS FILED WITH SEB REFINEMENTS

FOR THE YEAR ENDING DECEMBER 31, 2007
(IN THOUSANDS OF DOLLARS)

		AS REFINED			AS FILED		
LINE	RATE CLASS	MWH (1)	REVENUE REQUIREMENT (2)	COST $/MWH (3)	MWH (4)	REVENUE REQUIREMENT (5)	COST $/MWH (6)
(1)	DOMESTIC	4,257,452	$535,104	$125.69	4,257,452	$530,052	$124.50
(2)	SMALL GENERAL	241,815	30,074	$124.37	241,815	29,931	$123.78
(3)	GENERAL	2,478,553	239,987	$96.83	2,478,553	240,647	$97.09
(4)	LARGE GENERAL	421,375	35,686	$84.69	421,375	36,083	$85.63
(5)	SMALL INDUSTRIAL	253,266	24,110	$95.20	253,266	24,340	$96.11
(6)	MEDIUM INDUSTRIAL	585,153	49,470	$84.54	585,153	50,079	$85.58
(7)	LARGE IND *	1,258,231	85,165	$67.69	1,079,311	75,168	$69.64
(8)	EXTRA LI INTERR. -2	2,076,080	129,138	$62.20	2,076,080	131,499	$63.34
(9)	MUNICIPAL	196,279	16,789	$85.54	196,279	16,717	$85.17
(10)	UNMETERED	112,382	24,268	$215.94	112,382	24,174	$215.11
(11)	TOTAL ABOVE THE LINE	11,880,586	$1,169,791	$98.46	11,701,666	$1,158,691	$99.02
(12)	DIRECT EXP/REV		5,789			16,050	
(13)	RETURN ON DIRECT EXP		2,635			3,465	
(14)	TOTAL SYSTEM		$1,178,215			$1,178,206	

* Mersey Additional Energy treated as Above the Line in Columns 1 through 3, and treated as Below the Line in Columns 4 through 6.

Exhibit AR-1
Schedule 8