NON-CONFIDENTIAL

Request IR-1:

What is the historical justification for the allocation of rates among user groups, particularly small business groups (Small General Tariff Code 10, General Tariff Code 11, and Small Industrial Tariff Code 21)? Please provide any documentation with respect to this question.

Response IR-1:

Revisions to Cost of Service and Rate Design processes are generally developed through COSS and/or Rate Design proceedings overseen by the UARB. The last COSS proceeding was held in 1995. The last Rate Design proceeding was completed in 2003.

Please refer to the following sections of the filed evidence (DE-03 - DE-04) for information concerning the ratemaking approach that leads to the determination of the small business rates: 9.0 Cost of Service, 10.2 Rate-setting Process Overview, 10.3 Revenue Allocation Process and Results, and 10.5 Proposed Rates.

For additional information on the allocation of revenue responsibilities among rate classes please refer to section 2.4 Findings of the UARB's decision on the Generic Rate Design Hearing[1] included in Attachment 1.

[1] NSPI 2003 Rate Design Case, UARB Decision, NSUARB-NSPI-P-878, August 1, 2003, pages 15-17.

DECISION **NSUARB-NSPI-P-878**
2003 NSUARB 91

NOVA SCOTIA UTILITY AND REVIEW BOARD

IN THE MATTER OF THE PUBLIC UTILITIES ACT

- and -

IN THE MATTER OF A GENERIC RATE DESIGN HEARING

BEFORE: John A. Morash, C.A., Chair
Margaret A. M. Shears, Vice-Chair
John L. Harris, Q.C., Member
Kulvinder S. Dhillon, P.Eng., Member

COUNSEL: **NOVA SCOTIA POWER INCORPORATED**
James L. Connors, Q.C.
Vice President, Regulatory Affairs, Emera Inc.

CANADIAN MANUFACTURERS AND EXPORTERS - NOVA SCOTIA DIVISION
Dick Smyth, Vice-President

ELECTRICITY CONSUMERS ALLIANCE OF NOVA SCOTIA
John Woods, P. Eng., Executive Director

HALIFAX REGIONAL MUNICIPALITY
Mary Ellen Donovan
Karen Brown

MICHELIN et al.
Robert G. Grant, Q.C.
Nancy G. Rubin

MUNICIPAL ELECTRIC UTILITIES OF NOVA SCOTIA CO-OPERATIVE
Donald Regan
Albert Dominie

NOVA SCOTIA DEPARTMENT OF ENERGY
James B. Isnor

STORA ENSO PORT HAWKESBURY LIMITED and
BOWATER MERSEY PAPER COMPANY LIMITED
George T. H. Cooper, Q.C.
David S. MacDougall
James McDuff, Articled Clerk

TRENTONWORKS LIMITED and
MARITIME STEEL & FOUNDRIES LIMITED
John C. MacPherson, Q. C.
Ben R. Durnford

HEARING DATES:	June 2,3,4 and 6, 2003
FINAL SUBMISSIONS:	June 18, 2003
LIST OF WITNESSES:	APPENDIX - A
LIST OF INTERVENORS:	APPENDIX - B
BOARD COUNSEL:	S. Bruce Outhouse, Q.C.
BOARD COUNSEL'S CONSULTANT:	Dr. John Stutz, Vice-President Tellus Institute
DECISION DATE:	**August 1, 2003**
DECISION:	**Various Generic Rate Design recommendations approved by the Board with modifications.**

TABLE OF CONTENTS

1.0 INTRODUCTION

[1] This decision is further to a public hearing conducted by the Nova Scotia Utility and Review Board (the “Board”), after due public notice, on June 2, 3, 4 and 6, 2003 in the matter of certain issues relating to rate design and the methodology used by Nova Scotia Power Incorporated (“NSPI”, “the Company”, “the Utility”) to calculate rates for electric service.

[2] NSPI is a regulated public utility and is the successor to Nova Scotia Power Corporation, a crown corporation which was privatized in 1992. As of January 1, 1999, NSPI became the principal subsidiary of Nova Scotia Power Holdings Incorporated, now known as Emera Incorporated (“Emera”).

[3] NSPI is engaged in the production and supply of electrical energy. It distributes electricity through a province-wide system and, as at December 31, 2002, served approximately 450,000 customers including six municipal electric utilities. Its electric revenues for the year 2002 were $869.1 million and its total assets as at December 31, 2002 were $2.9 billion.[1]

[4] In 2002, the Board heard an application by NSPI for the approval of certain revisions to its rates, charges and regulations. The Board issued a number of directives to NSPI in its decision on the rate application dated October 23, 2002 and subsequent Order dated December 3, 2002. One of the Board directives required a separate generic rate design hearing:

[1]Emera 2002 Annual Report pp. 15, 17, 41

7.6.1 Board Directives

1. In light of the large number of issues raised concerning the AARs, the Interruptible Credit and the other rates, the Board has decided to conduct a separate rate design proceeding, to be held in 2003. The "ground rules" for the proceeding will include the following:
   - The current Cost of Service methodology will be accepted and NSPI's COSS model will be used. Data inputs can be adjusted, but not methodology.
   - Each party proposing rate design changes for the existing rates will submit two Summary Exhibits, similar to Exhibit N-152, JS-10 which was filed in this proceeding by Dr. Stutz, showing the specific charges proposed compared to the charges approved in this proceeding. One exhibit will be based on NSPI's current class revenue requirements, the other on the party's preferred class revenue targets.
   - NSPI will provide standard billing determinants, similar to those in SEB-IR-125. Each party will use those determinants to show the revenues produced by the rates presented in the Summary Exhibit.

2. Similar ground rules will be developed to govern the examination of the AARs.

3. Within the framework established by the ground rules, the parties will have the opportunity to propose changes in rate design, including those proposed by Drs. Rosenberg, Stutz and MEUNSC in this proceeding. In order to minimize effort, parties will be allowed to enter testimony, exhibits and responses to information requests from the present proceeding into evidence in the rate design proceeding.

(Board Decision, October 23/02, P-875, pp.130-131)

[5] As a result of another of the Board's directives in its decision dated October 23, 2002, NSPI initiated pre-hearing technical conferences in advance of rate proceedings. On February 12 and 13, 2003, NSPI convened a cost of service and rate design technical conference for interested parties. Included as part of these sessions was a discussion of issues proposed for consideration as a part of the generic rate design hearing.

[6] Following the technical conferences, on February 26, 2003, the Board issued its initial Order, identifying the issues to be considered at the generic rate design hearing. These were as follows:

1. **Cost-Based Rates.** What is the appropriate standard for a cost-based rate? Should the standard differ for above- and below-the-line rates? What measurements (i.e., revenue/cost ratios or comparisons with incremental or marginal costs) should be used to test whether and to what extent rates are cost-based? If a rate is not cost-

based, how might that affect the conditions for its availability?

2. **Marginal Costs.** How should marginal costs be computed? Should adjustments be made for the effects of export sales or economic interruption on ELIIR? What role, if any, should marginal costs play in setting the charges included in above-the-line rates?

3. **Interruptibility.** Are NSPI's procedures for valuing supply interruptibility appropriate? If not, how should they be changed? Should the amount of load eligible for supply interruptibility be limited? If so, to what extent? Should the credit for supply interruptibility be modified? If so, how?

4. **Customer Charges.** Which of NSPI's rates should have customer charges? Should customer charges be set in a uniform fashion? If so, how?

5. **Price Signals.** Are the below-the-line rates other than ELIIR sending the price signals they were designed to send? If not, what are the options for modifying the rates to provide the appropriate price signals?

(Board Order, February 26/03, pp.1-2)

The Order also indicated that the Board would consider adding other rate design issues which might be proposed by interested parties and set out the schedule for notice of the public hearing.

[7] Directions on Procedure for the Generic Rate Design Hearing were issued on February 26, 2003. Included in that document was a schedule for the hearing, establishing a timetable for filings and information requests and responses, as well as two additional technical conferences to be convened by NSPI: one in March 2003 to deal with the issues set out in the Board Order; and the second conference in April 2003 to review the responses to information requests.

[8] After considering submissions with respect to additional issues, the Board issued a revised Order and Directions on Procedure, dated March 13, 2003, which added the following issue to the five noted above:

6. **Boundary Between the Small General and General Rates.** Is the 12,000 kW.h limit for service on the Small General Rate appropriate? If not, how should that limit be adjusted?

(Board Order, March 13/03, p.3)

[9] Twenty-nine intervenors filed a notice of intent to participate in the hearing. Stora Enso Port Hawkesbury Limited and Bowater Mersey Paper Company

Limited ("SEB"); Michelin North America (Canada) Inc. *et al* ("Michelin") representing 9 intervenors; TrentonWorks Limited *et al*. ("TrentonWorks"), representing 2 industrial customers; the Electricity Consumers Alliance of Nova Scotia ("ECANS"); the Municipal Electric Utilities of Nova Scotia Co-operative ("MEUNSC"); the Nova Scotia Department of Energy ("NSDOE"); Canadian Manufacturers and Exporters - Nova Scotia Division ("CME") and the Halifax Regional Municipality ("HRM") participated actively in the hearing. The Board also received an informal submission from the Canadian Federation of Independent Business ("CFIB"). A full list of intervenors is attached as Appendix "B" to this decision.

2.0 COST-BASED RATES

2.1 Overview

[10] The following questions were identified under the umbrella of cost-based rates in the Board's March 13, 2003 Order:

- What is the appropriate standard for a cost-based rate?
- Should the standard differ for above and below-the-line rates?
- What measurements (i.e., R/C ratios or comparisons with incremental or marginal costs) should be used to test whether and to what extent rates are cost-based?
- If a rate is not cost-based, how might that affect the conditions for its availability?

[11] Utility rate-making is a process of calculating the required revenue based upon specific assumptions and projections, and determining how this revenue requirement can be recovered from the various customer classes. Although there is flexibility as to how the various rates are designed, certain principles guide rate-making. The most widely accepted statement of these principles is set out in a publication written by Dr. James Bonbright entitled **Principles of Public Utility Rates** as follows:

CRITERIA OF A SOUND RATE STRUCTURE

1. The related, "practical" attributes of simplicity, understandability, public acceptability, and feasibility of application.

2. Freedom from controversies as to proper interpretation.

3. Effectiveness in yielding total revenue requirements under the fair-return standard.
4. Revenue stability from year to year.

5. Stability of the rates themselves, with a minimum of unexpected changes seriously adverse to existing customers. (Compare "The best tax is an old tax.")

6. Fairness of the specific rates in the apportionment of total costs of service among the different consumers.

7. Avoidance of "undue discrimination" in rate relationships.

8. Efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use:

   (a) in the control of the total amounts of service supplied by the company;

   (b) in the control of the relative uses of alternative types of service (on-peak versus off-peak electricity, Pullman travel versus coach travel, single-party telephone service versus service from a multi-party line, etc.).

   (Exhibit N-10, Ex. JS-2, James Bonbright, **Principles of Public Utility Rates**, Columbia University Press, 1961, p.291)

[12] In its Directions on Procedure, the Board directed that the methodology used by NSPI to produce its Cost of Service Study (COSS) would not be subject to review in this proceeding. It is worth noting, however, that from the Board's perspective the principal purpose of a COSS is to allocate a utility's embedded (accounting) costs among the customer classes in accordance with the costs incurred to serve those classes. The linkage between the COSS and customer rates lies in the premise that the rates for a particular rate class should recover the cost to serve that class (i.e. a class revenue/cost (R/C) ratio of 1.0). Secondly, all the customers in a particular rate class should be served at the same rate. Rates for the great majority of NSPI's customers are set based on this approach. The Board refers to rates set in this manner as "above-the-line rates". They include Residential, General and Industrial rates. For many years the Board has directed NSPI to strive to achieve above-the-line rates which will produce a R/C ratio of between 0.95 and 1.05.

[13] A rate may also be designed to accomplish a specific objective such as to reduce load at peak periods by interrupting service to selected customers, to shift load from peak periods to off-peak periods or to retain a load in order to maintain a contribution

to fixed costs. The determination of such a rate may involve the use of formulas. Such formulas may contain a mixture of embedded costs, marginal costs (costs of producing one more unit of output) and incremental/avoided costs (changes in costs associated with an increase/decrease in some variable). The Board refers to these formula rates as “below-the-line rates” (or “annually adjusted rates”, since they are re-set each year). Currently, NSPI has customers on four below-the-line rates: Generation Replacement and Load Following (GRLF) Rate, Industrial Expansion Interruptible Rate (IEIR), Mersey System (Mersey) Rate and Real Time Pricing (RTP) Rate. In a decision dated January 28, 2003, the Board approved an additional below-the-line rate, the Extra Large Industrial Interruptible Rate (ELIIR), which comes into effect on January 1, 2004. Below-the-line rates are approved on an individual basis rather than as part of a general rate application, based upon a review of the inputs to the formula.

2.2 Evidence and Submissions - NSPI

[14] NSPI, in its direct evidence, takes the position that no new standard need be defined with respect to determining if a rate is cost-based. NSPI stated that it does not have any concerns with the procedures which have been used in the past whereby the Board has used discretion as to the appropriateness of the methodology used in determining rates.[2]

[2] Exhibit N-1, p.60

[15] NSPI further noted that, while it may be argued that a rate which falls outside of the 0.95 to 1.05 R/C range is not cost-based, the Board, has in the past, approved rates outside of this range. In addition, NSPI stated that, based upon existing Board approved rates, availability criteria are "...not necessarily a function of any particular determination of whether the rate is defined as 'cost-based'."[3] Examples include the GRLF rate which is based on marginal cost and is restricted to customers with their own generation facilities, and the residential time-of-use rate which is limited in its availability to those customers whose heating systems utilize "...time shifting technology approved by the Company."[4]

[16] Mel Whalen, NSPI's Director of Regulatory Affairs and Rates, explained why NSPI does not see the need to define a standard for cost-based rates to be used in the Board approval process for above-the-line or below-the-line rates:

> Q. But you recognize that, in the past, rates have been approved which are not cost-based -- not in the traditional sense of embedded costs?
>
> A. (Whalen) I guess it depends on how you define "cost-based." And, of course, that's what the whole issue is about. When we look at a rate such as the Mersey rate, we say that is a cost-based rate. It's defined in a certain way. We say the same about the GRLF. Certainly, the way the costs are defined in those cases is different from the way costs are defined in terms of the above-the-line rates. It's not so much the costs are defined differently. It's just that the costs that are allocated to those rates are different. And, in the past, we have presented the merits of those rates in public forums such as this. And the Board has been able to deal with that and make an appropriate decision. And we believe they could continue to do that.
>
> (Transcript, June 3/03, pp.272-273)

2.3 Evidence and Submissions - Intervenors

[17] There was considerable agreement among the parties as to the appropriateness of NSPI's approach to developing rates. This section, therefore, will focus

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[3] Exhibit N-1, p.6

[4] Exhibit N-1, p.6

on that evidence which suggests a different approach would be desirable.

[18] Board Counsel's consultant, Dr. John Stutz, Vice-President, Tellus Institute, recommended that the Board adopt a standard for the purpose of determining whether a rate be accepted as being "cost-based". He described three requirements which should be met in order for a rate to be termed cost-based:

1. The **value of the benefits** provided by those on the rate can be determined directly, based on standard utility planning and costing assumptions and procedures.
2. The **cost to serve** those on the rates can be determined, using the Board - Approved COSS methods and assumptions, in the same fashion as for the above-the-line rates.
3. Division of the cost-to-serve minus the value of the benefits into the revenues from the rate produces a **revenue-to-cost (R/C) ratio** near 1.0.

(Exhibit, N-10, p.15)

[19] Dr. Stutz contended that the above standard is appropriate for both above-the-line rates and below-the-line rates and he developed R/C ratios for the below-the-line rates which range from 58.8% (Mersey) to 81.2 % (RTP).[5] He stated in his rebuttal evidence that his analysis of cost-based rates could be applied to the ELIIR as well to provide the Board with information on the cost to serve that customer class.[6] Dr. Stutz submitted that if it is determined that a rate is not cost-based and, therefore, not allocated a fair share of the cost to serve, the availability of the rate should be limited. He further commented that, in order to obtain service on a non-cost-based rate, evidence should be required that "...absent the non-cost-based alternative, current or reasonably anticipated usage will be lost, and that other ratepayers will be at least as well off with that usage as

[5]Exhibit N-10, Ex. JS-5

[6]Exhibit N-11, p.7

without it”.[7]

[20] In Dr. Stutz’s opinion the information provided by an analysis of below-the-line rates based on the embedded cost of service could prove very useful to the Board. When questioned by James Connors, Counsel for NSPI, on the practical value of such an analysis, Dr. Stutz stated:

> Well, with regard to the existing rates, it will allow the Board to understand better what it has, in effect purchased through the approval of the below-the line rates....It might guide the Board in future decisions.....I’m particularly interested in the possibility that we will modify below-the-line rates or add new below-the-line rates. If we were to do that, of course, this kind of analysis would, in my view, be an invaluable aid to the Board in assessing such a proposal. Having said that, I’m not suggesting to you, as your example might suggest, that if the Board were presented with either a new or modified below-the-line rate that was not cost-effective, it would reject it. In my view, for a below-the-line rate, due discrimination is the appropriate test. And I say in my testimony that if there’s due discrimination, then there’s a basis for the Board accepting the rate. In deciding whether to accept a rate based on due discrimination, the Board might like to know how far from full cost the rate is. I believe my procedures would help them answer that question.
>
> (Transcript, June 4/03, pp.332-335)

[21] Dr. Alan Rosenberg of Brubaker & Associates Inc., who testified on behalf of SEB, also commented on the issue of cost-based rates. He provided the following definition of a cost-based rate in his rebuttal evidence:

> A cost-based rate is one that recovers an equitable share of all of NSPI’s costs of providing service **that are properly attributable to that rate**, net of the value of any benefits the rate may provide.
>
> (Exhibit, N-8, p.2, emphasis in original)

Dr. Rosenberg added that his definition of a cost-based rate adds a clause to Dr. Stutz’s definition to provide for situations which may exist where a customer may not utilize all of the utility’s cost structure.

[22] His position on the appropriateness of calculating R/C ratios for below-the-line rates, as suggested by Dr. Stutz, is:

> I have two concerns with the appropriateness of doing that calculation. One is, "Well, what are you going to do with it after it's -- after you do the exercise?" And I believe Dr. Stutz says, "Well, it's useful information to the Board." And you know, you may want to have that type of

[7] Exhibit N-10, p.18

> information, but my -- I guess my bigger concern is that if you do that, the -- you may have to, as I say, sharpen your cost-of-service pencil. Dr. Stutz believes that you can do that, that it's not an onerous exercise to do that, although I think he did say you might have to change the model. I won't -- I can't tell you what's onerous and what's not because that's a subjective opinion, but certainly it would require some analysis.
>
> (Transcript, June 6/03, pp.506-507)

[23] Dr. Rosenberg explained that he had some difficulty with Dr. Stutz's calculation of R/C ratios for below-the-line rates as set out in Ex. JS-5 of Exhibit N-10 in terms of the calculation of the cost of service and benefit attributed to each of the classes.[8] His direct evidence further comments on the difficulty of using the cost of service study analysis to evaluate rates such as the ELIIR[9], and, at the hearing, he stated that:

> ...for below-the-line rates, the cost of service study is not the best tool for making that evaluation.
>
> (Transcript, June 6/03, p.531)

[24] Dr. Rosenberg agreed with Dr. Stutz's recommendation set out above as to the eligibility requirements if a rate is not cost-based. However, he commented that "...it may not be a simple task to determine whether or not a particular customer satisfies those criteria".[10]

2.4 Findings

[25] The Board has considered the evidence presented on the issue of cost-based rates and notes that there appears to be significant agreement among most of the parties with respect to NSPI's approach to developing rates.

[8] Transcript, June 6/03, pp.529-530

[9] Exhibit N-7, pp.7-8

[10] Transcript, June 6/03, p.503

[26] It is apparent that there is considerable disagreement as to how one should determine whether a rate is, or is not, cost-based. There are problems with respect to the definition and measurement of benefits and costs, especially for below-the-line rates. The Board believes that a rigid standard may not be the most appropriate approach and that the discretion and flexibility exercised in the past by the Board when analyzing both existing and proposed rates should continue.

[27] The Board finds that NSPI's present rate-making methodology is adequate and notes that cost-based standards can differ. It is also clear that, while the objective of a R/C ratio within the 0.95 to 1.05 bandwidth is desirable for above-the-line rates, it is not an absolute pre-requisite for approval of a rate. The Board believes that there may be circumstances where a rate which is not fully cost-based can be approved under the principle of due discrimination, fairness and equity. The Board retains the discretion under the **Public Utilities Act** (the **Act**) to determine whether a rate is justified, based upon its impact on other ratepayers.

[28] The Board notes NSPI's objection to the type of analysis suggested by Dr. Stutz in determining whether a rate is cost-based:

> Even if all parties in a proceeding could agree with the results of the modified cost of service model, the benefits appropriate to a particular rate, and even a revenue/cost ratio for that rate (an unlikely scenario), the decision of the Board may not be different from the decision it makes using current procedures. Arguably, there may be another piece of information available to the Board, but it would be just that, one more piece of information. In approving any new rate, the Board already considers the cost basis on which the rate is developed, the benefits it provides, and the impacts it may have on other customers. As noted by NSPI in its Direct Evidence, the Board has exercised its discretion in the past on a case by case basis. NSPI sees no need to change current procedures to be more prescriptive, given the efforts required to do so and the limited benefits it might provide.
>
> (NSPI, Final Brief, p.3)

While the Board believes that the analysis of rates on cost-based standards suggested by Dr. Stutz would be informative, it does not believe it is necessary for NSPI to undertake such an analysis at this time.

[29] The Board does approve the test proposed by Dr. Stutz for determining eligibility to receive service under a non-cost based rate, namely:

> "Obtaining service on a non-cost-based rate should require **evidence** that, absent the non-cost-based alternative, current or reasonably anticipated usage will be lost, and that other ratepayers will be at least as well off with that usage as without it."
>
> (Exhibit N-10, p.18)

In the future, if the Board decides that a proposed new rate or a modified existing rate is not cost based, then this test will be applied.

3.0 MARGINAL COSTS

3.1 Overview

[30] The Board asked the following questions with respect to marginal costs in its March 13, 2003 Order:

- How should marginal costs be computed?
- Should adjustments be made for the effects of export sales or economic interruption on ELIIR?
- What role, if any, should marginal costs play in setting the charges included in above-the-line rates, or in determining the total revenues to be obtained from those rates?

[31] Marginal cost can be defined as the cost of supplying an increment of some variable.[11] This variable could relate to an additional kW of demand (marginal capacity cost), an additional kWh of energy (marginal energy cost) or an additional customer (marginal customer cost). Short run marginal costs do not impact capital costs (i.e., there is no change in the plant and equipment necessary to supply the increment) whereas long run marginal costs involve a change in capital costs.

[32] NSPI follows methods described in the **Electric Utility Cost Allocation Manual** published by the National Association of Regulatory Commissioners (NARUC). Marginal energy costs are developed using the production cost modeling method and marginal capacity costs are developed using the peaker deferral method.[12]

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[11] Exhibit N-1 p.9

[12] Exhibit N-10, p.20

[33] Marginal costs used in rate-setting procedures are forward looking and, to a large degree, depend on engineering estimates and simulation models for their determination.[13] It should be noted that marginal energy costs are the only marginal costs which directly affect NSPI's rates.[14] For that reason, the Board will focus on marginal energy costs in this decision.

[34] NSPI uses marginal costs directly in calculating the GRLF rate and the RTP rate. In addition, the ELIIR, which comes into effect on January 1, 2004, introduces the concept of economic interruptibility which will affect the calculation of marginal costs.

3.2 Evidence and Submissions - NSPI

[35] NSPI uses an avoided cost methodology to determine marginal energy cost in the Load Following (LF) rate. The Strategist simulation model is used to determine total energy requirements in a 'base case' year and the load is reduced by 25 MW decrements in each hour of the year with a recalculation of the cost of supplying the remaining total energy requirement. NSPI states that it uses the 25 MW decrement to determine the marginal energy cost in the LF rate as this represents approximately the load which is supplied under the rate.[15]

[36] NSPI also uses the Strategist model to calculate marginal cost for the RTP adders, based upon the model's determination of the most economic unit to dispatch in order to supply the additional energy. NSPI uses the "GenCost" model to calculate the marginal costs used to provide price signals to RTP customers. It focuses on a shorter

[13] Exhibit N-1, p.9

[14] Exhibit N-1, p.18

time frame than does the Strategist model.

[15] Exhibit N-1, p.12

[37] In its pre-filed evidence, NSPI proposed to exclude export sales from the calculation of the RTP adders and 20-minute ahead prices. NSPI agreed that “exports generally have an upward pressure on marginal cost, since more load on the system will generally place higher cost units on the margin”.[16] However, it did not recommend excluding exports from the calculation of the GRLF rate although it proposed to “...include the lesser of the average of the most recent 5 years of exports or the current year’s forecast.”[17] In its rebuttal evidence, NSPI reluctantly agreed to exclude exports from the calculation of marginal costs for purposes of setting the GRLF rate as well, given the unanimous view of the intervenors that exports should be excluded. It stated that:

> NSPI would like to point out, that removing the impact of export sales from the marginal costs has the effect, in a rate case year, of transferring revenue responsibility for the amount of revenue that would have been contributed from below-the-line customers with respect to the increase in price attributable to exports to above-the-line customers (most of whom are not represented by the participants in this proceeding). If exports had been excluded in 2002, this transfer would have been $0.8 million. For 2003, the transfer is estimated to be $2 million. For 2004, it is expected that this transfer will reduce to $0.2 - 0.3 million. In deciding whether or not to approve this transfer, the UARB will need to decide whether such transfer is in the public interest. NSPI has no evidence to offer on this point.
>
> We would also note that, in our view, any decision with respect to the removal of exports from the calculation of the GRLF rate should apply beginning 2004. In particular, our change of position here is offered without prejudice to any evidence supplied elsewhere with respect to 2003 AAR’s.
>
> (Exhibit N-2, p.3)

[38] NSPI also stated that:

> b) Notwithstanding the above proposal, NSPI is not changing its proposal that, for the purposes of setting the annual fuel budget and its use in determining above-the-line rates, the Industrial Expansion Interruptible Rate and ELIIR, the costs and benefits of exports will be included as NSPI proposed in its direct evidence, i.e., exports will be set at the lesser of the current export forecast or the average of the last five years actual exports.
>
> c) In Section 8 of its response to UARB IR-2 and in its May 12 Direct Evidence, NSPI presented its methodology for including the benefits of gas sales in the fuel budget

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[16] Exhibit N-1, p.19

[17] Exhibit N-1, p.20

> used to develop both above-the-line and below-the-line rates (page 21, lines 9-17) and its proposal to reflect the benefits of gas in the calculation of marginal costs (p.21, line 19 to p. 22, line 21). No intervenor has expressed concern with either the current method of including the benefits of gas sales in the annual fuel budget nor the proposed modification to include those benefits in marginal cost. NSPI assumes intervenors accept both the current and proposed practice.
>
> (Exhibit N-2, pp.3-4)

[39] NSPI pointed out that the energy charge under the ELIIR is calculated using NSPI's annual budgeted costs including fuel costs. It proposes to include the benefits of gas sales and exports in the fuel budget. Economic interruptibility will be introduced when ELIIR comes into effect. Economic interruptibility will have the effect of lowering marginal costs and, consequently, the GRLF and RTP rates. It is NSPI's position that the effect of ELIIR should be included in the calculation of marginal energy costs.[18]

[40] With respect to the Board's third question, NSPI noted that, of the above-the-line rates, only the Residential Time of Use rate was designed on the basis of marginal energy costs. It recommended against requiring all above-the-line rates to be designed on this basis as the need to recover the embedded revenue requirement would undermine any theoretical advantages of setting rates equal to marginal cost. However, it proposed that:

> ....short run marginal energy costs, averaged over some appropriate time frame such as the next five years, should be considered in the design of energy charges for above-the-line rates.
>
> (Exhibit N-1, p.25)

It noted that energy charges in rates for residential customers are currently much higher than short run marginal costs while energy charges for larger customers such as Large General or Large Industrial customers are closer to marginal costs. Economic efficiency

[18] Exhibit N-1, p.25

from a societal point of view would be enhanced by setting all energy charges closer to marginal costs. NSPI agreed that customer impacts would have to be weighed in moving towards more efficient rate structures.

3.3 Evidence and Submissions - Intervenors

[41] Dr. Stutz recommended that exports be excluded from the calculation of costs used to set the RTP and GRLF rates. In response to questions from the Board, he agreed that export sales could lower rates for above-the-line customers but it is inappropriate to favour one group of customers at the expense of another group all of whom form part of the native load served by the Utility. No Nova Scotia customer should be disadvantaged by reason of sales to out-of-Province customers. NSPI has always given priority to serving native load before making export sales and its system was designed and built to serve Nova Scotia customers, not out-of-Province customers. In endorsing Dr. Stutz's view, SEB said:

> In other words, the quid pro quo for having a statutory monopoly within a particular jurisdiction is the duty to serve the customer load in that jurisdiction in priority and preference to load in other jurisdictions.
>
> (SEB, Final Argument, p.6)

[42] Dr. Stutz agreed with NSPI that marginal energy costs should take into consideration the effects of economic interruptibility associated with the ELIIR. He further agreed with the Company's proposed calculation of marginal costs based on gas prices as "...Neither the sale of electricity or gas for export should affect the calculation of marginal energy costs".[19]

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[19] Exhibit N-10, p.22

[43] Dr. Stutz disagreed with NSPI's suggestion that economic efficiency at the societal level would be enhanced by setting energy charges for above-the-line rates closer to short-run marginal costs. He stated that the result of this approach for residential rates would be less efficient rather than more efficient rates because of the need to increase customer charges or introduce declining block structures in order to recover the revenue requirement. Further, equity problems would be created by moving residential energy charges closer to short run marginal costs because the recovery of demand costs would be shifted from large to small customers.[20]

[44] Dr. Stutz stated in his direct evidence that he agrees with the following position expressed by the Board in its 1996 rate decision:

> It is the Board's opinion that rates should never be set below short-run marginal cost, and that long-run marginal costs should be used as a guide in deciding the degree and extent to which long-run cost consideration should be used to temper the wide fluctuations that can exist in the year-to-year levels of short-run marginal costs. The Board must exercise judgement in assigning the appropriate weights to short-run and long-run marginal costs.
> (Exhibit N-10, pp.23-24)

[20]Exhibit N-11, p.10

For purposes of determining whether rates are set below short run marginal cost, he proposed that the "short run marginal cost test (SRMC)" be used. The test is simply that the "average revenue per kWh, exclusive of revenue from customer charges, should not be less than the average marginal energy cost".[21] If a rate does not produce sufficient revenue, exclusive of fixed monthly charges, to cover the cost of producing the last kWh then the rate has not been set above short-run marginal cost.[22] He noted that there could be reasons for accepting a proposed rate even though it fails the SRMC test. A rate might fail the test but still meet the due discrimination standard and be found to be beneficial to all ratepayers. However, any rate failing the SRMC test should be carefully examined. He recommended that the Company should be required to periodically apply the SRMC test to all of its rates.

[45] Dr. Rosenberg advocated that export sales should always be excluded when calculating incremental costs for native load customers. He noted that it was only in 2002 that NSPI began to include an estimate of its exports in the calculation of cost for purposes of setting the LF rate[23]. He agreed that the effects of economic interruptibility under the ELIIR should be included in the calculation of marginal costs for below-the-line rates.

[46] In his direct evidence, Dr. Rosenberg submitted that a load decrement

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[21]Exhibit N-10, p.24

[22]Exhibit N-10, p.24

[23]Exhibit N-7, p.37

of 75 MW should be used in calculating avoided cost for the LF rate as opposed to the 25 MW decrement currently used by NSPI.[24] In his rebuttal evidence, he revised his recommendation to a decrement of 58 MW which he stated is "...half-way between the maximum GRLF load, and the average GRLF load".[25] In its final argument, SEB argued that 25 MW is not a "reasonable representation" of the load supplied under the LF rate.[26]

[47] Dr. Rosenberg did not make any recommendations with respect to the role that marginal costs should play in the setting of above-the-line rates. He pointed out that:

> That question raises a host of issues that cannot be succinctly answered. For example, since NSPI's revenue requirement is ultimately grounded in its embedded cost, any suggestion to use marginal costs, either for rate design or for class revenue targets, must also state how those marginal costs will be reconciled to the embedded revenue requirement. One way is to adjust equi-proportionally. Another way, supported by some economists, is to use Ramsey pricing.
>
> (Exhibit N-7, pp.60-61)

[48] The evidence of the other parties focussed on the issue of exports. There was a consensus that exports should not be included in the marginal cost calculation of the GRLF and RTP rates.

3.4 Findings

[49] The Board has reviewed the evidence presented with respect to marginal costs. The major issue in dispute is whether exports should be included or excluded in the calculation of marginal (incremental) costs. The Board agrees with Dr.

[24] Exhibit N-7, p.48

[25] Exhibit N-8, p.20

[26] SEB, Final Argument, p.12

Stutz and Dr. Rosenberg that protection of the native load should be the primary consideration and, therefore, exports should be excluded from these calculations. The Board notes that NSPI proposes the exclusion be effective for the 2004 year. The question of whether exports should be included in the calculation of annually adjusted rates in 2002 and 2003 is still in dispute, however, and is the subject of a separate proceeding.

[50] After reviewing the evidence, the Board finds that NSPI's present method of calculating the marginal (avoided) cost for the GRLF rate using 25 MW decrements is appropriate. The Board also agrees with NSPI's position that the marginal cost associated with the RTP rate should be based on the cheaper unit if NSPI shuts down a unit for economic reasons.

[51] The Board notes that there was no opposition to either NSPI's present method of including gas sales, based on forward curves, in its annual fuel budget or its proposed methodology for handling gas sales in the calculation of marginal costs. The Board approves both these methodologies as described. Also, based upon the evidence provided, the Board agrees that the effect of the ELIIR should be included in the marginal energy cost calculation.

[52] The Board continues to consider that rates should be set at or above short-run marginal costs. The SRMC test recommended by Dr. Stutz is a useful tool for making this determination and the Board recognizes the benefits of periodically performing the test as he recommended. The Board directs NSPI to perform this test for all its above and below-the-line rates. NSPI's report should describe the methodology it has followed in calculating short-run marginal costs as well the results of applying the test. The report

should be filed by April 30, 2004, and annually on April 30 thereafter.

4.0 INTERRUPTIBILITY

4.1 Overview

[53] The following questions with respect to interruptibility were raised by the Board in its March 13, 2003 Order:

- Are NSPI's procedures for valuing supply interruptibility appropriate? If not, how should they be changed?
- Should the amount of load eligible for supply interruptibility be limited? If so, to what extent?
- Should the credit for supply interruptibility be modified? If so, how?
- Should "voluntary" interruptions receive credits? If so, how should these credits be determined?

[54] NSPI currently offers interruptible service as a rider to the above-the-line Large Industrial Rate and as part of three below-the-line rates - the GRLF rate, the Industrial Expansion Interruptible Rate (IEIR), and the recently approved ELIIR.

[55] NSPI provided a useful outline of the development of Interruptible Rates as follows:

> The services offered under the Large Industrial Rider and the GRLF Rates were, prior to 1989, offered under the same "Interruptible" rate. In 1989, the rate was split into two separate rates when the GRLF rate was introduced and the Interruptible Rate was redesigned. During the period 1989-1996, the Interruptible Rate was a separate rate, but in the UARB Rate Case Decision of 1996 was combined with the Large Industrial Rate and offered as a rider to that rate. When these rates were combined, the Interruptible Rate, which previously had no demand charge but instead had declining block energy charges, was re-designed to have only a demand and energy charge. The energy charge was set to be the same as the energy charge of the Large Industrial Rate, and the demand charge was determined by applying a credit to the Large Industrial Rate demand charge. The credit was set in 1996 to be $3.43/kVA/month. It was derived on the basis that interruptible customers allow NSPI to forego building peaking capacity and the resulting savings should be passed along to those interruptible customers. Details of the calculation of the $3.43 are included in response to UARB IR-4.
>
> This approach to setting a demand charge based on a credit linked to a CT was a different approach from what had been used in the 1989-1996 period. During that time, the "credit" applied to the Interruptible Rate was determined within the Cost of Service Study (COSS). In essence, none of the demand portion of fixed cost was allocated to the Interruptible class, and this was reflected in the Interruptible Rider design.
>
> (Exhibit N-1, pp.28-29)

[56] The credit described above is applied only to the Large Industrial Interruptible Rate. There is no credit applied to the GRLF rate, IEIR and the ELIIR. In these cases, demand-related generation and transmission costs are not allocated to the customers, resulting in a reduced revenue requirement.[27]

[57] In response to Board IR-3, NSPI provided a table which indicates that, for 2003, NSPI will have an installed capacity of 2261 MW, an estimated system or total peak of 2011 MW and an interruptible load of 400 MW. This produces a reserve margin of 12.4% assuming all load is firm and a reserve margin of 40.3% if the interruptible load is taken into account. For planning purposes, NSPI's objective is to maintain a reserve margin of 20%. In order to meet the criteria set out by the North American Electric Reliability Council and as a part of the Interconnection Agreement with NB Power, NSPI must also maintain 125 MW of 10 minute reserve.[28]

4.2 Evidence and Submissions - NSPI

[58] NSPI proposes to calculate the interruptible credit using the same methodology as was accepted by the Board in its 1996 rate decision, the one exception being that it now wishes to determine the value of the credit based on a 183 MW combustion turbine (CT) rather than the 50MW CT used in 1996. NSPI argues that a 183 MW CT provides a better match with the co-incident peak load served under the interruptible rider of approximately 200 MW.[29] Mr. Whalen explained NSPI's position as follows:

[27]Exhibit N-10, p.20

[28]Exhibit N-5, RIR-10

[29]Exhibit N-1, p.29

> I think the right place to start is to say – to try and answer the question, "What generation would you need to replace this interruptible load if this interruptible load were to go firm." And in answering that question, we have compared – we have assumed that we would build a CT that would be comparable in size to that load, and then we have done the calculations on that basis. Now, that leaves aside some of the other issues that we've talked about this morning. It assumes that you would need to replace that load with the CT. And that has been our assumption. So, it's more of saying, "If this load were to go firm, and you needed to replace it with a combustion turbine, what would be the size of the combustion turbine?" And we believe that would be something in the order of one eighty-three megawatts.
>
> (Transcript, June 3/03, pp.282-283)

Mr. Whalen stated in response to a question from counsel for Michelin that the coincident peak interruptible load served under the interruptible rider in 1996 was 167 MW and in 2002 it was 159MW.[30]

[59] NSPI's direct evidence sets out the derivation of the value of the interruptible credit based upon the capital cost of a 183 MW CT. The capital cost of the unit is $90.78 million with a 35 year life and a "real cost of money" of 6.94%, which translates to an annual charge of $7.105 million or a unit cost of $47 per kW per year. The unit cost is multiplied by the system coincident load served under the interruptible rider (199.5 MVA) and the result is divided by the total demand related billing determinants (3043 MWA months) to yield a credit of $3.08/kVA/month, which can be compared to the present credit of $3.43/kVA/month.[31] In its rebuttal evidence, NSPI recalculated the proposed credit to take income tax into account and determined that the credit should be adjusted upwards to approximately $3.50/kWA/month.[32] In NSPI's view, this result is sufficiently close to the level of the present credit to support leaving the credit where it is.[33]

[60] NSPI also requested that the Board address the following questions.

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[30]Transcript, June 2/03, p.136

[31]Exhibit N-1, p.30

[32]Exhibit N-2, p.6

[33]Exhibit N-2, p.5 and NSPI, Final Brief, p.7

> NSPI would ask the Board, in its decision in this case, to address two issues with respect to the calculation of the credit, even if it chooses to keep the credit at the current level. These issues are:
>
> - Whether the credit should be calculated on the basis of a 50 MW CT or a larger unit which better matches the load served under the Interruptible Rider.
> - Whether a nominal or real interest rate should be used in the calculation.
>
> (NSPI, Final Brief, p.8)

[61] NSPI stated that, ideally, the amount of interruptible load should be limited to an amount equal to a 20% reserve less the 125 MW of ten minute reserve. In response to UARB IR-14C (Exhibit N-4), NSPI indicated that currently this amount is approximately 350 MW. NSPI further indicated in response to UARB IR-3 that, for planning purposes over the next several years, 400 MW is being used as the "non-firm load".[34] The same response set out a "total supply interruptibility" for March 2003 of 474 MW distributed among the following rate classes as follows:

Large Industrial rate-Interruptible Rider	238 MW
GR & LF	73 MW *
Industrial Expansion rate	163 MW

*Assuming all customers were taking maximum GR

(NSPI response to UARB IR-3)

[62] In response to a request from Board Counsel, NSPI filed Undertaking U-9 which shows that, for the years 2003 to 2015, only in 2007 does NSPI require any above-the-line (interruptible rider) interruptible load to meet its targeted 20% reserve margin.

[34] Exhibit N-4, UARB IR-3

[63] NSPI does not propose to offer credits for voluntary interruptions, based on its view that the present credit is sufficient to cover any costs the customer incurs as a result of voluntary interruptions.[35] Mr. Whalen further indicated, during cross-examination by Counsel for SEB, that NSPI views the benefits received from voluntary interruptions to be small and, that in some cases, they may cost the Company money.[36]

[64] In its rebuttal evidence NSPI asserted that the interruptible credit should be applied to the ratcheted demand as long as the demand charge remains ratcheted.[37]

[65] The relationship between the risk of being interrupted and the value of the credit versus the burden of the credit on other customer classes was also the subject of discussion. Both James Isnor, Counsel for NSDOE, and Al Dominie, representing MEUNSC, observed that the risk of being interrupted differs for the various customers and each questioned NSPI on the subject of linking the credit to the risk. Mr. Dominie asked:

> Q – it would seem to me that the ones with the higher probability or the higher risk of interruption would get the larger share of the credit and those with the lower probability of interruption would get a smaller credit or a smaller piece of the pie. Is that fair?
>
> A. (Whalen) Well, as we discussed – as I discussed earlier with the previous – in our previous discussion, we don't currently have a mechanism of putting the risk profiles in that. I mean, certainly that's something that could be considered if, you know, various stakeholders in this proceeding wanted to do that....So, even though we could certainly wipe the slate clean, if you will, here in terms of interruptibility and just recognize that we do have 400 megawatts and recognize that, you know, we– that may be more than we require or – and– in doing the calculation and then spread the calculation across all of the loads, and in that calculation you could include, if you wanted to, some kind of a risk profile.
>
> (Transcript, June 3/03, pp. 223-224)

[35] Exhibit N-1, p.36

[36] Transcript, June 2/03, p.65

[37] Exhibit N-2, p.6

[66] With respect to the burden of the credit on other customers, Mr. Whalen, under cross-examination by Counsel for NSDOE, stated:

> I would agree that as the credit paid to the other interruptible customers increases, the burden on other customers increases, and vice versa.
>
> (Transcript, June 3/03, p.191)

4.3 Evidence and Submissions - Intervenors

[67] A number of the intervenors commented on the value of NSPI's interruptible credit and the methodology which should be used to calculate the credit.

[68] Dr. Stutz provided an exhibit in his direct evidence (Exhibit N-10, Ex. JS-6) in which he calculated what he considers to be the value of NSPI's supply interruptibility for 2003. NSPI would require approximately 152 MW of additional capacity in order to meet its 20% reserve margin of 127 MW (based on an anticipated peak load of 2011 MW).[38] Using an annual capital recovery factor of 7.83%, and dividing the calculated annual avoided cost of $7.105 million by the 400 MW of total interruptible load in 2003, his estimate "...gives an upper bound for the value for interruptibility, $17.76 per kW of interruptible load. Based on the total usage of 2,802 GWH on the three rates providing supply interruptibility....the value of interruptibility is less than $.0025 per kWh in 2003."[39]

[69] Despite his view that the present interruptible credit is too high, concerns relating to the principles of rate stability, equity and undue discrimination led Dr.

[38] Exhibit N-11, pp.11-12

[39] Exhibit N-10, p.27

Stutz to recommend no reduction in the credit.[40] During cross-examination, Dr. Stutz responded as follows to a question by Counsel for NSDOE:

> Q. In your considerations of those two principles, did you consider the other ratepayers who would be burdened by the excess of interruptible load?
>
> A. Absolutely. And I'm –as you might be able to tell from the way my ultimate recommendation is framed, if I could have found a way that I was comfortable reducing the credit, I would have. But when I looked at the evolution, and in particular, when I looked at the fact that the one place we could reduce it, the large industrial interruptible load, had in fact historically been supplying what appeared to be needed and then was sort of superseded by the interruptibility on the below-the-line rates–when I looked at the whole historical situation, I just couldn't justify it.
>
> (Transcript, June 4/03, p.388)

[70] Dr. Stutz further addressed the equity issue in the following exchange with Mr. Dominie:

> Q. And in my discussion yesterday with the corporation's panel, I didn't indicate what perhaps my own estimates were, but I do agree with you that I would expect them to come in considerably lower than the credit presently enjoyed by the customers on the interruptible rider. Given that scenario ---
>
> A. Yes.
>
> Q. --- and the fact that there is a higher risk of interruption or higher probability of interruption enjoyed by the below-the-line customers and they may be getting the least value for their interruptibility, would that solve some -- or put you in a comfort level where perhaps a move now towards some programmed reduction in the credit for the above-the-line customers should commence at the earliest possible opportunity?
>
> A. No. Unfortunately, it would -- it wouldn't, for this reason. My reading of the history is that the above-the-line customers depend upon those credits as much as the below-the-line customers depend upon their below-the-line rates. When we put in the below-the-line rates, I think in -- certainly for the industrial expansion interruptible rate, there was some assumption of due discrimination. We knew we were giving these folks a break, in essence. We limited the amount of load that could go on the rates. To then turn around and say that because we have those rates and we're already buying the interruptibility there, the folks who used to provide it are now just out of luck, I can't accept that.
>
> (Transcript, June 4/03, pp.397-398)

[71] Concerning NSPI's need for interruptible load, Dr. Stutz provided two exhibits as a part of his rebuttal evidence (Exhibit N-11, Ex. JS-15 and 16) which deal with this issue. Based on projections for the period from 2003 to 2015, Ex. JS-15 shows that NSPI has more than sufficient capacity to meet its 20% margin and 125 MW of ten minute

[40] Exhibit N-10, p.30

reserve. In addition, Ex. JS-16 shows that from December 2000 to February 2003, NSPI required non-firm load in the range of 28 MW to 235 MW. When asked whether access to the interruptible rider by new customers should be limited, Dr. Stutz responded as follows:

> ...We don't need to sign up any more unnecessary interruptibility. I didn't suggest it in my evidence, but I think it should at least be considered. I would say the counter argument is this. The below the line rates are specifically set out to accommodate expansion, and there's nothing about them which would prevent additional load were it otherwise to qualify to join those rates. So let's say that – I don't mean to pick on them, but let's say Stora or Bowater were to expand their mills, and that expansion were dependent upon service on ELIIR. They would qualify for ELIIR and we would be adding more interruptibility below the line. It's hard for me to say, "Let's shut off the people above the line if we're not doing anything below the line," so I think limitation has merit, but it's a tricky issue.
>
> (Transcript, June 4/03, pp.456-457)

[72] When questioned by the Board as to the reasonableness of NSPI's use of the peaker methodology to determine the avoided costs used in the calculation of the credit, Dr. Stutz said this:

> When using the Peaker Methodology one must consider the linkage between resource decisions for the current year and those in future years. Examining NSPI's resource plans, presented in Highliner IR-3, one sees that NSPI plans to add substantial capacity after 2003. However, as NSPI explains in response to Technical Conference IR-9, the principal driver for these additions is emissions constraints. Reserve margins do not become a driver for additional capacity until 2018. Thus, in NSPI's case, the linkage between the resource choice in 2003 and future resource decisions through 2018 appears to be weak. In this situation use of Peaker Methodology is reasonable.
>
> (Exhibit N-10, pp. 27-28)

[73] In his opening statement, Dr. Stutz agreed with NSPI's use of the real cost of money for purposes of determining the annual avoided cost of additional generating capacity:

> The second point I wanted to address was the interruptible credit. I think everyone who's testified agrees that the value of interruptibility is gauged by looking at the capacity you would need to build in the future or have built in the past in order to serve the interruptible load or to have capacity available to serve the interruptible load, however you want to put it. So, the value of interruptibility depends, in a general way, on the avoided capacity. Everything we've done here, all the calculations presented by any of the parties seem to be premised on that very general notion. Now, in order to think about that notion, you have to think about two things. One is, how much capacity would you have needed or would you need in the future, and how much would you pay for it? And here, there is wide disagreement. I can see

> arguments that you would need none of the interruptible rider capacity. I can also see arguments that you would need a fraction of it, perhaps sixty percent. So, depending on whether you look forward or backward and how you weigh the evidence, that's where you'd end up. There's also a question of what to pay for the capacity. Mr. Hopkins,I, the company, Dr. Rosenberg all have offered evidence on this. All I'll say about it is that using the same general approach, there are widely varying methods for computing the unit value. The only thing about it that I want to clarify is my view on one somewhat arcane point. That is the choice between nominal and real levelled cost. I think if you look in the literature,you will find that both are used. As you'll gather from my preference for the company as opposed to the other approaches, I tend to lean in the direction of the real rather than the nominal, but I acknowledge that both appear in the literature...
>
> (Transcript, June 4/03, pp.326-328)

[74] Dr. Stutz stated that he does not believe that voluntary interruptions should receive credits, as customers on the interruptible rates are "already more than adequately compensated" through the rates they are charged.[41]

[75] In his opening statement at the hearing, Dr. Rosenberg summarized his position with respect to the methodology used to determine the value of the interruptible credit:

> Ideally we should have the right amount of interruptibility and the right credit. I take the position that two wrongs do not make a right. In other words, I hold that the two questions, what is the value of interruptibility and what is the level of credit, are two distinct and separate questions. And while the amount of interruptibility may influence the latter decision, it should not distort the former decision.
>
> (Transcript, June 6/03 p.492)

[76] With respect to the amount of interruptibility, Dr. Rosenberg indicated that, based upon the figures for the past winter which were supplied by NSPI in response to UARB IR-14 (Exhibit N-4), "...the reserve margin would have been only 26% – still over 20%, but not by that much.".[42] Dr. Rosenberg further stated, during the hearing, that in his view "...it is not that NSPI has too much interruptibility, it is that it has too much capacity

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[41] Exhibit N-10, p.30

[42] Exhibit N-8, p.14

plus interruptibility."[43]

[77] On the question of limiting the amount of load eligible for interruptibility, Dr. Rosenberg stated the following in his direct evidence:

> ...I believe it would be reasonable to close the rider until there is more balance between need and the supply of interruptibility....Another step would be to raise the eligibility requirements for the interruptible rider on a go forward basis, because it is more economical for the utility to work with a small number of large interruptible loads than to work with a large number of small interruptible loads.
>
> (Exhibit N-7, p.52)

[43] Transcript, June 6/03, p.493

[78] While Dr. Rosenberg agreed with NSPI that interruptibility can be viewed as a substitute for adding a combustion turbine for purposes of determining the amount of the interruptible credit[44], he indicated in his direct evidence that he had concerns with the methodology used. He does not agree with basing the avoided cost calculation on a 183 MW CT unit as opposed to a 50 MW unit, the unit size which the Board approved in its 1996 rate decision. He submitted that there is "... no evidence that the interruptible credit is avoiding a 183 MW unit, rather than a 50 MW unit."[45] He also stated that he is concerned that NSPI did not include fixed O&M costs in its calculation of avoided costs based upon the Company's belief that the costs are similar under either scenario of running a CT unit or administering the interruptible credit. He indicated that there is no supporting evidence for this statement and further, if the presumption were true, it would suggest that, as there is less "administration" involved in interrupting a small number of large customers rather than a large number of small customers, the large customers should receive a larger credit.[46]

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[44]Transcript, June 6/03, p.514

[45]Exhibit N-7, p.56

[46]Exhibit N-7, p.56

[79] Dr. Rosenberg stated that the avoided cost of interruptibility should not be limited to avoided generation costs of the CT unit, but should also include avoided transmission costs, to the extent that interruptible customers enable NSPI to avoid bulk transmission upgrades.[47] He does not agree with the use of real carrying costs (i.e. economic carrying costs or ECC) to determine the annual avoided cost in the calculation of the credit. He is concerned that the economic carrying cost only looks at one year and ignores the on-going value of interruptible loads. Secondly, NSPI's practice of "resetting" the charge back to year one every few years "overturns" the basis of the charge.[48] Dr. Rosenberg suggests that a levelized cost should be used in the calculation.[49]

[80] The issue of how carrying costs should be calculated was also the subject of cross-examination by Board Counsel who filed, as Exhibit N-23, an excerpt from the NARUC **Electric Utility Cost Allocation Manual** dealing with the development of marginal production costs using the Peaker deferral method. The exhibit used the real carrying cost in the calculation. When questioned as to whether the real carrying cost would be appropriate in the calculation of the credit, Dr. Rosenberg stated:

> The real carrying cost would not be appropriate to calculate the credit because it is reset at each rate case, and so therefore it will never–the credit will never equal to the actual revenue requirement of the combustion turbine, which it was meant to do. This is a different exercise. This exercise is to calculate the marginal capacity cost for those instances where a utility may wish to set rates or have rates be guided by marginal cost principles.
>
> (Transcript, June 6/03, pp. 501-502)

[81] Dr. Rosenberg recommended that the interruptible credit be fixed for

[47] Exhibit N-7, p.53

[48] Exhibit N-8, p.11

[49] Exhibit N-7, p.54

the next 35 years.[50] He acknowledged in response to a question from Counsel for NSPI that he was not aware of any Canadian regulatory precedent for fixing the credit for such a lengthy period.[51]

[50]Exhibit N-8, p.18

[51]Transcript, June 6/03, pp.496-497

[82] Dr. Rosenberg also expressed his dissatisfaction with the capital cost recovery factor of 7.83% which Dr. Stutz used in his Ex. JS-6, referred to above, and he suggested that a levelized carrying cost of 10.525% rate is required.[52] He does not agree with the methodology used in Ex. JS-6 which divides the annual capital cost necessary to recover the cost of a CT (i.e. the annual revenue requirement) by the total amount of non-firm load (400MW). His view is that the value and the amount of interruptibility should not be confused.[53] The annual revenue requirement should, in fact, be divided by the required interruptible load of 152.5 MW.

[83] Dr. Rosenberg calculated the avoided cost, based upon a levelized carrying cost to be $52.21/kW/year and indicated that, had NSPI also used a levelized carrying cost in its calculations with the same assumptions, the credit would be $4.11/kW/month.[54]

[84] Dr. Rosenberg believes that voluntary interruptions should receive credits. He indicated that the value of the credit should be determined by a bidding process conducted over the internet in response to a solicitation by NSPI, or the credit should be equal to 90% of the cost of any emergency purchases at the time of the interruption.[55]

[85] William Hopkins of Navigant Consulting Inc. presented evidence on behalf of Michelin concerning interruptibility. While he agrees with the use of a CT unit to

[52]Exhibit N-8, p.12

[53]Exhibit N-8, p.13

[54]Exhibit N-8, p.18

[55]Exhibit N-7, p.56

determine the avoided cost associated with interruptibility[56], he opposed the use of a 183 MW unit rather than a 50 MW unit. In his opinion, the proposed larger size unit “is not a good approximation of what actually would have been built”.[57]

[56]Exhibit N-18, p.8

[57]Exhibit N-18, p.9

[86] Like Dr. Rosenberg, Mr. Hopkins also believes that NSPI's calculations result in a credit which is too low. He faults NSPI for not properly accounting for the real costs of capital by, for example, not including various fixed cost elements such as fixed O&M expenses. He also considers that marginal transmission costs related to the system's peak should be considered in establishing the interruptible credit.[58] Based on his calculations, Mr. Hopkins submitted that the "proper credit" for interruptible load should fall within a range from $5.75/kW/month based on a 186.5 MW unit to $7.53/kW/month based on a 49.5 MW unit. He further indicated that the addition of transmission related costs would increase the credit by $2.50/kW/month.[59]

[87] Mr. Hopkins recommended that the suggested increase in the credit:

> ...could be accomplished in a gradual manner over a period of several years to avoid significant revenue shifts to other customers at a single point in time..
>
> (Exhibit N-18, p.13)

[88] Mr. Hopkins responded to questions from Board Counsel on the issue of reserve margins as follows:

> Q. Mr. Hopkins, do you know anything about this system that would lead you to believe that NSPI requires a reserve margin of between 32 and 50 percent?
>
> A. I have no information on their reserve margin requirements. I've seen what they have said, and as I've expressed and as I understand what they have said, they have said they have a requirement to maintain a minimum of a 20 percent reserve margin. They've also indicated that they have a target of reliability of a loss of load probability of one day in 10 years, and I don't know what that yields. And they've also indicated, I think, that they have some economic concerns about interrupting their customers and the impacts of that. Many companies do. And at times, that yields a much higher reserve still, so without – as I said, I have not looked at their system as to their reserve margins and I think it is not as simplistic as just saying 20 percent times a number.
>
> (Transcript June 3/03, p.304)

[58] Exhibit N-18, p.10

[59] Exhibit N-18, p.12

[89] A number of the other parties also presented their views on the interruptible credit. In Exhibits N-31 and N-32, Michelin submitted rebuttal evidence which focused on the negative implications associated with any decrease in the credit.

[90] Michelin also made the following points with respect to the appropriate size of the CT unit to be avoided:

> NSPI proposes to calculate its avoided costs on the basis of a 183 MW CT combustion turbine unit arguing that it constitutes a better match to the approximately 200 MW of coincident load served under the interruptible rider. This is the same argument that was advanced, but not decided in the 2002 General Rate Case.
>
> Before the Board changes the basis for the avoided CT unit, it should be satisfied itself, that circumstances respecting the load on the interruptible rider have changed since 1996. This is not the case. In 1996, when the issue was fully argued, the Board approved the credit based on an avoided 50 MW CT unit. The panel confirmed in cross-examination that the coincident peak interruptible load served above the line in 1996 was 167 MW and at the present time it is 159 MW (Mr. Whalen, Transcript, p.136). Accordingly, there is not a significant change in the above-the-line interruptible load driving the change in the comparative unit.
>
> Secondly, as stated by Mr. Hopkins, the proposed larger size unit is not a good approximation of what actually would have been built by NSPI. Mr. Whalen agreed NSPI quite possibly would have increased its generation by 50MW increments as required over time rather than constructing one unit (Transcript, p.167). In addition while the 2003 resource plan shows a planned 250 MW CT in 2008, it is driven by environmental constraints (Mr. Whalen, Transcript, p.289). It is not being constructed for peaker capacity.
>
> (Michelin, Final Submission, pp.2-3)

[91] Michelin went on to submit that the Board should follow Mr. Hopkins' advice with respect to properly accounting for all costs which would actually be avoided:

> If this Board accepts that the appropriate comparative avoided peaker unit is a 183 MW unit and the Board accepts NSPI's methodology but wishes the credit to better reflect the "real" costs which are avoided, then the Board is urged to adopt the calculation of the interruptible credit as demonstrated in Exhibit WHR-IR (Rebuttal of Mr. Hopkins, Exhibit N-19). In that Exhibit, Mr. Hopkins corrects the calculation using levelized fixed charges in place of the real cost of money and adds in annual fixed O&M at $6.00/KW. The total annual value divided by the demand billing determinants as provided by NSPI results in a monthly credit of $4.65/KVA. It is respectfully submitted that this corrected calculation more appropriately reflects the real costs avoided through the large industrial interruptible class.
>
> (Michelin, Final Submission, pp.10-11)

[92] CME recommended that credit should be given for voluntary interruptions. Formal procedures would have to be put in place to make this possible.[60] While ECANS stated in its direct evidence that it believes that the credit is appropriate, it indicated that as long as the demand charge on the interruptible rider remains ratcheted, the credit should be applied to the ratcheted demand. ECANS submitted, however, that demand billed under the interruptible rider should not be ratcheted as in its opinion:

> ...billing ratchets and interruptibility are mutually exclusive and are not meant to co-exist. (Exhibit N-25, p.5)

[93] NSDOE, in its final submission states that:

> The Department does not advocate a reduction or limitation on the availability of interruptible load nor a reduction of the current interruptible credit at this time.
>
> Interruptible load is a valuable feature for NSPI; its system and its customers as a whole, and this must be recognized within appropriate limits.
>
> The Department believes that valuing the credit due to interruptible customers, as NSPI does, through the use of the peaker deferral method is reasonable.
>
> At the present time it appears that there is excess value being attributed to the credit for interruptible rider customers. In an ideal situation, NSPI indicated that it would be matching the value of this credit (estimated for 2002 at $9.4 million) with its annual cost of the deferred peaker or $7.1 million[2].
>
> Dr. Stutz is also of the view that the credit for interruptible load is higher than might be cost justified[3].
>
> While it appears clear that NSPI is paying more overall for the interruptible feature to the above-the-line and below-the-line classes of customers than the value that such customers bring to the system, today's situation has developed over time for various reasons.
>
> Given the present situation the Department cannot see that increasing the value of the interruptible credit is prudent or justified at this time. However, to reduce the interruptible credit downward or limit its availability would be unduly disruptive to existing customers and would depart from the principle of rate stability.
>
> The Department supports the position of Dr. Stutz being that the interruptible credit remain at its current level and not be raised.[4]
>
> [2]See response to UARB - IR 4 and the transcript pp. 186-191 (Whalen) questions 16-31.
> [3]See transcript p. 387 questions 179-183.

[60]Exhibit N-24, p.3

[4]See Dr. Stutz's direct evidence at page 30, lines 16-18.

(NSDOE, Final Submission, pp.3-4)

4.4 Findings

[94] The Board has carefully reviewed the evidence with respect to interruptibility. A variety of opinions have been expressed with respect to both the value of the interruptible credit and the underlying methodology used to calculate the credit, as well as the optimum amount of interruptible load.

[95] The Board notes that, apart from the question of size of the unit, there were no objections to the use of the peaker deferral methodology to determine the cost of the capacity NSPI would have to build without the interruptible load. However, both Dr. Rosenberg and Mr. Hopkins suggest that the calculation of avoided cost should include other costs such as avoided transmission. Dr. Rosenberg and Mr. Hopkins state that a levelized cost should be used in the calculation, not the real carrying cost used by NSPI and recommended by Dr. Stutz. There was also discussion as to the inclusion of fixed operating and maintenance costs, insurance costs and depreciation. These varied opinions resulted in a wide range of suggested values for the credit.

[96] The Board recognizes that NSPI's reserve margin is in excess of actual requirements. This was discussed at length during the hearing and is best illustrated in Undertaking U-9 filed by NSPI. The right-hand column shows the interruptible load needed to meet a 20% reserve margin:

	Reserve	Reserve	UARB IR-3 Interruptible

Year	Installed Capacity (MW)	Peak Load (MW)	Non-Firm Load (MW)	(%) With Non-Firm	(%) Without Non-Firm	Needed to Maintain 20%
2003	2261	2011	400	40.3	12.4	**127**
2004	2261	2068	405	35.9	9.3	**184**
2005	2281	2083	409	36.3	9.5	**182**
2006	2281	2098	409	35.1	8.7	**197**
2007	2281	2126	409	32.8	7.3	**225**
2008	2531	2154	409	45.0	17.5	**45**
2009	2651	2185	409	49.3	21.3	**(24)**
2010	2651	2215	409	46.8	19.7	**6**
2011	2651	2245	409	44.4	18.1	**36**
2012	2651	2277	409	41.9	16.4	**68**
2013	2651	2309	409	39.5	14.8	**100**
2014	2651	2341	409	37.2	13.2	**132**
2015	2651	2372	409	35.0	11.8	**163**

Note: Peak Demand and Installed Capacity is from Strategist Base Case

The below-the-line interruptible load is estimated to be 220 MW in the years 2003-2015, so the above-the-line interruptible is necessary to meet the total interruptible requirement only in 2007.

(Undertaking U-9)

The table indicates that the above-the-line interruptible load projected to be needed in 2007 is 5 MW and in other years is not required at all.

[97] Differing views were expressed at the hearing with respect to the amount of load which should be eligible for interruption. While both Dr. Stutz and Dr. Rosenberg agree that there may be an excess of interruptible load, Dr. Rosenberg initially suggested limiting the interruptible load while Dr. Stutz expressed concern that such a course of action could create problems in respect to rate stability and undue discrimination.

[98] The Board notes that SEB, in its rebuttal brief, submits that:

> It should be remembered that the direct evidence of all parties was filed simultaneously, as was the rebuttal evidence. With the exception of the Muni's, it now seems clear that few if any parties (other than NSPI) had any difficulty with leaving the credit at the $3.43 level (subject to an increase for income taxes). Nor do they have any difficulty with leaving the rider open to new applicants, a position with which NSPI agrees. That being so, it is neither Dr. Rosenberg's nor SEB's recommendation that the rider be closed, or that the eligibility requirements be changed.
>
> (SEB, Rebuttal Brief, p.2)

[99] While the Board agrees that the amount of load eligible for

interruptibility and the value of the credit are two separate issues, it is important to consider these issues in the appropriate context. The interruptible rate developed over time and, consequently, any changes to the amount of eligible load or the credit at this point could result in significant negative consequences, both of a direct and indirect nature.

[100] Accordingly, the Board sees little merit in changing the existing methodology for arriving at the $3.43 interruptible credit at this time. The Board has also considered the discussion during the hearing with respect to linking the value of the credit to the risk of interruption and the issue of the burden which would be placed on other ratepayers by increasing the credit. The Board agrees with Dr. Stutz that changes in the credit at this time could have impacts in terms of rate stability, equity and undue discrimination.

[101] The Board also finds that the demand charge on the Interruptible rider should continue to be ratcheted and that the interruptible credit should be applied to the ratcheted demand as well.

[102] With respect to the question of the appropriate size of the avoided unit, the Board considers that the use of a 183 MW CT rather than a 50 MW CT better matches the size of the generating unit that would be required to substitute for the loss of the interruptible load. The Board, therefore, approves NSPI's proposed change to a 183 MW CT unit for purposes of calculating the credit. The Board also agrees with NSPI's proposal to use the real cost of money in its calculation as opposed to the approaches suggested by other Intervenors.

[103] As to the amount of load eligible for interruptiblity, the Board agrees with NSPI that a 20% reserve margin less the 125 MW of ten minute spinning reserve is an appropriate target. Again, the Board agrees with Dr. Stutz's view that reductions or limitations in the amount of eligible load could raise issues of rate stability and undue discrimination.

[104] The Board has considered the information presented with respect to the issue of giving the interruptible customer a credit for voluntary interruption. The Board finds that the introduction of such a credit is not warranted at this time.

5.0 CUSTOMER CHARGES

5.1 Overview

[105] The following questions were raised regarding customer charges:

- Which of NSPI's rates should have customer charges?
- Should customer charges be set in a uniform fashion?
- If so, what costs should be recovered by these charges?

[106] The NARUC **Electric Utility Cost Allocation Manual** defines the following distribution plant as partly customer related and partly demand related:

- Land and Land Rights
- Structures and Improvements
- Poles, Towers and Fixtures
- Overhead Conductors and Devices
- Underground Conduit
- Underground Conductors and Devices
- Line Transformers

(Exhibit N-1, p.41)

NSPI uses the "minimum-size method" to classify the customer costs. This method of defining customer costs was approved by the Board in 1977 as an acceptable method of classifying distribution plant.[61]

[107] Although NSPI's COSS assigns customer costs to all of the above-the-line rates, only the following rates have specific customer charges, (termed "base" charges in NSPI's rate manual):

i) The Domestic Rate
ii) The Domestic Time of Use Rate
iii) The Small General Rate

(Exhibit N-1, p.39 and Exhibit N-10, p.33)

The other rates have demand and energy charges only.

[61] Exhibit N-1, pp.40-41

[108] The current customer (base) charges are $10.83 per month for the Domestic Service Rate (Rate Codes 02,03,04); $18.82 per month for the Domestic Service Time-of-Day Rate (Rate Code 06); and $12.65 per month for the Small General Rate (Rate Code 10).[62]

5.2 Evidence and Submissions - NSPI

[109] NSPI stated in its direct evidence that it does not see the need to include customer charges in all of its rate classes nor does it see a need to eliminate the existing customer charges. NSPI provided an analysis of customer related costs assigned to each of the classes which indicates that as a percent of total operating expenses, customer expenses are highest for the Domestic and Small General classes at 15.4% and 26.0%, respectively. The other classes, with the exception of the unmetered rate at 10.8%, have assigned customer related expenses as a percentage of total operating expenses ranging from 1.0% to 6.0%.[63]

[110] NSPI presented the following table which shows what the monthly customer charge would be for each of the rate classes if the customer related costs of serving each class were converted directly into monthly customer charges:

[62] NSPI Rates and Regulations, Issued November 2002

[63] Exhibit N-1, p.39

Class	Customer-Related Expense ($M)	No. of Customers	Monthly Customer Charge	Monthly Charge as Percent of Typical Bill
Domestic	5	404,923	$12.25	15.6
Small General	2.33	14.945	12.98	26.2
General	9.95	17,436	47.56	5.2
Large General	0.40	16	2,098.96	1.6
Small Industrial	1.06	2035	43.53	6.2
Medium Industrial	1.27	206	512.54	3.5
Large Industrial	2.33	32	6,062.50	3.1
Municipal	0.13	6	1,750.00	1.0
Unmetered	1.84	7321	20.90	10.9

(Exhibit N-1, p.40)

[111] For the classes that presently do not have a customer charge, the charge would range from $20.90 per month for the umetered rate to $6,062.50 per month for the large industrial rate. The table also shows the monthly customer charge as a percentage of a typical bill. NSPI pointed out that "...customer charges are smaller percentages of typical bills in classes that currently have no customer charge."[64]

[112] It is NSPI's position that there should be no change to the present cost

[64] Exhibit N-1, p.40

of service method used to determine customer related expenses.[65]

[113] In its rebuttal evidence, NSPI contends that for the classes which presently have a customer charge, an appropriate price signal is being sent by the charge. The elimination of the customer charge could result in low consumption customers being subsidized by larger customers where the revenue from the low consumption customers does not cover the cost of NSPI's capital investment to serve them. NSPI further argued that the elimination of the customer charge would result in a price signal which would favour the substitution of other fuels such as wood or oil for end uses such as space and water heating.

[114] In its final brief, NSPI states that:

> NSPI strongly suggests that with respect to customer charges, the issues of equity and efficiency raised by Dr. Stutz, although important, are not significant enough to overturn the status quo, which has been in place for decades, at a time when addressing these issues will simply compound the increases that are expected in the near term due to other factors.
>
> We recommend to the Board that there be no changes to existing customer charges, either to add new charges or to delete (or modify) existing charges.
>
> (NSPI, Final Brief, p.10)

5.3 Evidence and Submissions - Intervenors

[65] Exhibit N-1, p.41

[115] Dr. Stutz considers that changes to the current customer charges are, in principle, desirable. Exhibit N-10 (Ex. JS-9) demonstrates that the Residential and Small General Classes have the lowest average customer related costs and that their monthly customer charges are based on close to full recovery of these costs. The other above-the-line rates have higher average customer costs but do not have monthly customer charges at all.[66] In his view this result is inequitable.

[116] Dr. Stutz's considers that the price signals sent by NSPI's present customer charges discourage both the conservation of electricity and customer efforts to manage their electric load. He points out that the inclusion of a customer charge in the rate produces an average price that declines as consumption increases and he suggests that, as a result, customers will tend to ignore the amount of electricity that they use.[67] The customer charge as applied by NSPI is, in his view, inefficient as well as being inequitable.

[117] Dr. Stutz suggested four alternatives to NSPI's present customer charges:

1. Eliminate all customer charges;
2. Set customer charges to recover all the customer- related costs allocated to each rate class by the COSS;
3. Set customer charges to recover the costs associated with investment in service drops and meters, and the expenses directly associated with meter reading and billing;
4. Reduce current customer charges by 10 percent.

(Exhibit N-10, p.34)

[66] Exhibit N-10, p.33

[67] Exhibit N-10, p.33

Dr. Stutz acknowledged during the hearing that a fifth alternative is to leave the customer charges as they presently exist.[68]

[118] Dr. Stutz expressed his preference for the first alternative as the goal of greater efficiency would be best advanced by that alternative. He conceded, however, that the adoption of alternative 1 would result in a considerable increase in bills for some customers, as would alternatives 2 and 3 to a lesser extent, as shown on his Ex. JS-11. The exhibit indicates that the maximum bill increase under alternative 4, however, would be only 1.7% while the maximum decrease would be 5.3%.

[119] Dr. Stutz conceded in cross-examination that, if his first alternative were adopted, 32% of residential customers would see an increase in their bills. Customers having an annual consumption greater than 10,000 kWh would likely see their bills increase. He also agreed that the residential customers with the largest consumption tend to be churches and charitable organizations such as volunteer fire departments and Royal Canadian Legions, as well as residential customers who use electricity to heat their homes.[69]

[68] Transcript, June 4/03, p.351

[69] Transcript, June 4/03, pp.364-367

[120] Dr. Rosenberg's opinion is that a fixed customer charge should be included in all of NSPI's rates as all rate classes have customer costs associated with metering, billing and collection and administration.[70] He stated it is his belief that:

> ...recovering customer-related expenses through fixed monthly charges best provides revenue stability and equity among the classes.
>
> (Exhibit N-7, p 62)

[121] While Dr. Rosenberg recommended that full cost-based customer charges be applied to large accounts, he stated that in the case of smaller customers, other issues, such as rate impact, must be considered.

[122] Mr. Hopkins opposed the introduction of a $6,000 customer charge to the Large Industrial rate, stating that the demand charge provides a means to recover fixed customer costs and that such a charge would negatively impact smaller customers within the class.[71]

[123] CME's position is that all ratepayers should be subject to a customer charge, but that the issue of rate shock should be considered when imposing the charge.[72] ECANS takes the position that if customer charges are introduced for the other rate classes they should be based on identifiable costs found in the cost of service study.

5.4 Findings

[124] After careful review of the evidence presented on the issue of customer charges, including Bonbright's principles of equity, efficiency and rate stability, the Board is not prepared to initiate changes to NSPI's current customer charges at this time.

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[70] Exhibit N-7, p.61, Transcript, June 6/03, p.520

[71] Exhibit N-19, p.5

[72] Exhibit N-24, pp.3-4

[125] The Board recognizes that, in terms of interclass equity, NSPI's present practice of selectively applying customer charges to some of the rate classes is probably not ideal. Clearly, equity among all rate classes can be achieved through either the elimination of all customer charges or the addition of customer charges to all above-the line rates.

[126] The Board agrees with Dr. Stutz that the inclusion of a customer charge may not send a strong price signal in terms of promoting energy efficiency. Dr. Stutz also conceded, however, in his response to questions from NSPI's Counsel, that the Board must decide whether this is an appropriate time to make changes to the current customer charges.

[127] When considering alternatives to the present customer charges, the Board must balance the desirability of achieving greater equity and efficiency with the goal of maintaining rate stability for the larger customers who currently pay customer charges.

[128] The Board is of the view that this is not an appropriate time to adopt any of the alternatives suggested by Dr. Stutz. However, in order to gradually introduce a greater degree of efficiency into the existing rates with customer charges, the Board directs that, at the next hearing for a general increase in rates, NSPI not increase the existing customer charges beyond their present level.

6.0 PRICE SIGNALS

6.1 Overview

[129] The following issues were raised with respect to price signals:

- Are the below-the-line rates other than ELIIR sending the price signals they were designed to send?
- If not, what are the options for modifying the rates to provide the appropriate price signals?

[130] The purpose of designing a rate with a price signal is to encourage a particular action by the customers receiving service on that rate.

[131] NSPI has six below-the-line rates, all of which are optional - Mersey, GRLF, IEIR, RTP, ELIIR and the Load Retention rate (LRR). There are no customers currently on the LRR or ELIIR. NSPI expects that customers will transfer from IEIR to ELIIR when it comes into effect in 2004.[73] Dr. Stutz observed that all rates convey a price signal to some degree. However, the GRLF rate and the Mersey rate were not specifically designed to send a price signal.[74] The GRLF rate was introduced in 1989 to provide back-up service to customers with their own generation. The Mersey rate is based upon a specific historical relationship between NSPI and the Mersey Hydro System which was developed to serve the Bowater Mersey Paper Mill, the particulars of which are set out in a 1986 agreement.[75]

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[73] Exhibit N-1, p.49

[74] Exhibit N-10, p.37

[75] Exhibit N-1, pp.43-44, 46-47

[132] The IEIR, which was approved by the Board in 1996, was developed by NSPI to utilize surplus capacity by sending a price signal to attract new load.[76] The RTP rates were approved by the Board in 2000 and were designed to encourage peak-reduction and load-shifting which would allow NSPI to defer the construction of new generating facilities and thus benefit other ratepayers. The RTP varies each hour and reflects the varying costs of production through the day. It allows customers to change their energy consumption as the hourly price changes. RTP rates are the sum of NSPI's actual hourly marginal energy costs plus designated fixed cost adders for on-peak and off-peak usage.[77]

6.2 Evidence and Submissions - NSPI

[133] NSPI's evidence focused on the price signals sent to customers on the RTP rates. NSPI states that these rates are sending the price signals that they were designed to send. In response to SEB IR-2b (Exhibit N-5), NSPI stated that the estimated energy to be shifted from on-peak to off-peak for the years 2001 to 2009 is 154 Gwh. In response to High Liner Foods IR-1 (Exhibit N-4), NSPI set out its on-peak and off-peak marginal energy costs for the five year period, 1998 to 2002. Both on and off-peak marginal energy costs have increased over this period with the increases in the fall of 2002 being particularly significant. NSPI commented as follows in its direct evidence:

> However, since the fall of 2002, NSPI's marginal costs in the off-peak period have been unattractive to some customers to the point where the incentive to modify their consumption pattern by moving load to the off-peak period is no longer sufficient to achieve that result.
> (Exhibit N-1, p.50)

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[76]Exhibit N-1, p.49

[77]Exhibit N-1, p.50

[134] NSPI discussed several alternatives to the existing RTP rate to address the issue of improving the price signal to encourage load shifting. These options included:

i) Two-part RTP
ii) Collars/Hedges
iii) Budget Billing
iv) Link the RTP to the Customer's Alternate Rate
v) Design New Load Shifting Rates

(Exhibit N-1, pp.50-52)

[135] Based on its review of the above options, NSPI proposed to "...add riders to the RTP rates which would provide customers with an alternative to the current RTP rates."[78] The design of the proposed Extra High Voltage (EHV) rider would decouple the price from actual marginal costs and the currently defined peak and off-peak time periods. The rider "...will allow the customer to choose a fixed price for shifted load as opposed to the more volatile marginal energy costs".[79]

6.3 Evidence and Submissions - Intervenors

[136] In his direct evidence, Dr. Stutz noted that the substantial load on the IEIR suggests that the price signal provided by the rate attracted load as it was designed to do. However, the fact that the ELIIR was required suggests that the IEIR "...was not providing the price signal needed for Stora and Bowater to continue or expand their operation."[80] While he noted that the price signal provided by the RTP rates has worked in

[78] Exhibit N-1, p.54

[79] Exhibit N-1, p.54

[80] Exhibit N-10, p.38

the past, he suggested that the current price signal being sent by the RTP rate to customers is to "...shift load off the RTP rate and, as a consequence, not to make the effort or incur the expense required to shift usage or load".[81]

[137] In his rebuttal evidence (Exhibit N-11), Dr. Stutz recommended that a two-part RTP be adopted, based upon NSPI's conceptual approach described in its direct evidence:

> RTP customers should be billed on their alternative rate, and provided a credit equal to a percentage of the value created by their load shifting. Here, the "value" is the fuel saving and the export sales margin that shifting allows NSPI to achieve.
>
> (Exhibit N-11, p.20)

[81] Exhibit N-10, p.38

[138] At the hearing, Dr. Stutz noted his understanding that NSPI's proposal would see 75% of the load shifting value go to the RTP customers with the remaining 25% apportioned to NSPI and the ratepayers.[82] He indicated that he would prefer that only 50% of the load shifting value be offered to the customers served on the RTP rate.[83]

[139] Under cross-examination, Dr. Stutz explained his position as follows:

> Well, it has to do with the overall design of the rate. Implicit in my comments is the assumption that ratepayers are being kept whole, in part, by the operation of the alternative, and in part by the sharing. And since I'm interested in their being kept whole, I'm interested in –how shall I put it– a more favourable division for them. Now, if we designed a rate where, by design, the customers above the line were kept whole through the alternative, if the alternative were built to produce that result, I could be comfortable with a different sharing, maybe one even less than twenty-five percent to ratepayers. If I was absolutely convinced that the alternative rate protected the ratepayers, it could go down to zero. It's all a question of putting the two together and ensuring the ratepayers are protected.
>
> (Transcript, June 4/03, pp.348, 349)

Dr. Stutz also agreed that the concept of apportioning the load shifting value is consistent with regulatory principles.

[140] Dr. Rosenberg stated that his main concern with NSPI's proposed RTP rate is that it is unacceptable to its customers and therefore NSPI should go "...back to the drawing board."[84] In his direct evidence, he discussed the attributes of a well-designed RTP rate and submitted that the rate should be re-designed. He recommended that both a one-part and a two-part RTP rate be adopted.

[82] Transcript, June 4/03, p.345

[83] Exhibit N-11, p.20

[84] Exhibit N-8, p.21

[141] Some of the other parties commented on the price signal issue, in particular with reference to the RTP rate. ECANS was of the view that the below-the-line rates, with the exception of ELIIR, send the price signal that they were intended to send, and, further, that more analysis is required, especially from a transmission perspective, with respect to the determination of the RTP rates.[85]

[142] CME indicated that it is in favour of below-the-line rates provided they are adjusted annually and "...do not impact other customers", because the customers on the rates enjoy lower prices although they "usually have to take on more risk".[86] CME also recommended that the price signals provided by the below-the-line rates be consistent over a sufficiently long period of time to allow the necessary investment by the customers taking service under the rates to achieve the results that the price signals are designed to encourage.[87]

[143] NSPI's proposed changes to the RTP rates were the subject of discussion prior to and during the hearing in an effort to reach a consensus on an acceptable set of RTP rates. While a specific rate design was not agreed upon, NSPI, SEB and Dr. Stutz, agreed to continue discussions and attempt to develop a rate for presentation to the Board during the next general rate case. This agreement was set out in Exhibit N-22 and reads as follows:

> **Nova Scotia Power/Bowater Mersey/Stora Enso/Dr. John Stutz**
>
> **Statement Regarding RTP**
>
> We have agreed to develop an alternative load shifting rate option, the principles of which are:
>
> 1. Under this option the customer who shifts load will never pay more than the customer would have paid under the customer's real alternative rate.

[85] Exhibit N-25, p.6

[86] Exhibit N-24, p.4

[87] Exhibit N-24, p.4

> 2. The rate will be the customer's best option without shifting, less the value to NSPI of the shift.
>
> 3. Above the line customers will be kept whole.
>
> The parties will continue their discussions and ask the Board not to make a final decision on RTP issues pending the presentation by NSPI of a specific proposed rate option in the next general rate case consistent with these principles.
>
> (Exhibit N-22)

6.4 Findings

[144] The Board notes that the evidence presented during the hearing focused on the problems associated with the RTP rate. The Board concludes that there are no major concerns with respect to the price signals associated with the other below-the-line rates and, therefore, no modifications to other rates are required at this time. The Board recognizes that there were a variety of concerns presented with respect to the RTP rate and it appears clear that the rate, as presently structured, does not function as intended.

[145] The Board is satisfied that the principles set out in the above Statement form a suitable basis for the development of an acceptable RTP rate design. Accordingly, the Board agrees to defer the RTP rate design issue until the charges for the ELIIR are approved. It is the Board's understanding that the parties will continue to work towards reaching a consensus on the RTP rate design. The Board also agrees with the comments of several Intervenors, who were not involved in the negotiations resulting in the Statement, that "...the next round of RTP discussions involve all existing and former RTP customers, potential new RTP customers and any interested stakeholders".[88] The burden will, of course, be on NSPI to justify its proposed rate to the Board.

[88] ECANS, Final Submission, p.4

7.0 BOUNDARY BETWEEN THE SMALL GENERAL AND GENERAL RATES

7.1 Overview

[146] The boundary issue was distilled to the following questions:

- Is the 12,000 kWh limit for service on the Small General Rate appropriate?
- If not, how should that limit be adjusted?

[147] NSPI serves approximately 15,000 customers under the Small General Rate (Code 10). Typical customers taking service under the rate are small businesses such as corner stores, hair salons and pizza parlors. The rate is available to commercial customers whose annual electric consumption is less than 12,000 kWh and for which there are no other applicable rates.[89] The rate consists of a base charge of $12.65 per month and a two block energy charge of 9.53 cents/kWh for the first 200 kWh per month and 8.38 cents/kWh for the remaining kWh consumption.[90]

[148] NSPI serves approximately 19,000 customers under the General Rate (Code 11) such as hospitals, service stations, shopping malls, hotels and restaurants. The rate is available to commercial customers with annual electric consumption of 12,000 kWh or greater, monthly demand less than 2,000 kW, and for which there are no other applicable rates. The rate includes a monthly demand charge of $7.29/kW and a two block energy charge. The first 200 kWh per month per kW of maximum demand are priced at 7.75 cents per kWh. All additional energy is priced at 5.48 cents per kWh.[91]

[149] The annual energy consumption of the customers taking service under the General Rate ranges from 12,000 kWh to nearly 10,000,000 kWh, suggesting that they

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[89] NSPI Rates and Regulations, Issued November 2002

[90] Exhibit N-1, p.55

[91] Exhibit N-1, p.55

do not form a homogeneous group.[92]

7.2 Evidence and Submissions - NSPI

[92]Exhibit N-1, p.55

[150] NSPI proposes that the boundary between the Small General Rate class and the General Rate class be increased from the present 12,000 kWh per year to 32,000 kWh per year. In Exhibit N-1, NSPI proposed that the change be phased in by increments of 5,000 kWh per year over a four year period in order to cushion customer and revenue impacts of the change.[93] In its final brief, NSPI revised its proposal as follows:

> In its Direct Evidence (page 58, line 24), NSPI proposed that the change from 12,000 kWh to 32,000 kWh be phased in over a four year period, to address revenue impacts. However, given the relatively small magnitude of the revenue impacts and given that a phase-in would delay moving some customers to the more appropriate rate for up to three more years, it may be that such a phase-in is inappropriate. NSPI notes that neither Dr. Stutz nor ECANS recommended such a phase-in. NSPI is modifying its proposal, therefore, and subject to UARB approval, will increase the boundary from 12,000 kWh to 32,000 kWh in a single step.
>
> (NSPI, Final Brief, p.13)

[151] NSPI compared the energy usage of Residential customers with that of General Rate customers in its response to Technical Conference IR-19 (Exhibit N-5). The response indicates that there are similarities between a significant number of Residential customers and the smaller General Rate customers. NSPI said the following in its response to IR-19:

> The vast majority of residential customers consume less than 35,000 to 40,000 kWh per year. Customers consuming more than this amount are often churches, social clubs, or other non-residential consumers who are eligible for the domestic rate.
>
> A majority of commercial customers also fall below 35,000 kWh per year. Most of those would likely be served at 120/240 volts and most would be single phase. From a cost of service perspective, the cost to serve these customers would likely be similar to the cost of serving residential customers.
>
> Intuitively it might be appropriate to raise the Small General threshold upward to perhaps 30,000 or 35,000 kWh.
>
> (NSPI, Exhibit N-5, Response to IR-19)

[93] Exhibit N-1, p.62

[152] NSPI concluded that its analysis would suggest that the smaller General Rate customers should be "...served under a rate structure that is similar to the Residential rate; i.e., it should have only a monthly base charge and energy charges, but no demand charge."[94]

[153] NSPI pointed out that General Rate customers are subject to demand metering unlike Small General Rate customers. It stated that it has one of the highest concentrations of demand meters of any electric utility in the country. They are more expensive to install and maintain than are energy-only meters. Furthermore, demand charges are perceived as unfair and are not understood by many of the smaller customers on the General Rate.[95]

[154] When questioned by the Board, NSPI confirmed that the proposed boundary change would result in both the Small General Class and General Class being more homogeneous.[96]

[155] In response to UARB IR-9, (Exhibit N-4), NSPI calculated that the cumulative net revenue loss to NSPI from increasing the boundary in 5,000 kWh increments varies from $1.1 million at the 17,000 level to $6.3 million at the 62,000 kWh level. At the proposed 32,000 kWh boundary, the impact would be a $3.6 million decrease in revenue.

[156] NSPI noted that the movement of customers as a result of the proposed change "...would likely modify revenue/cost ratios of both Rate 10 (current R/C = 1.0) and Rate 11 (current R/C = 1.08) and this could lead to some adjustment of rates in future rate

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[94]Exhibit N-1, p.56

[95]Exhibit N-1, p.57

[96]Transcript, June 3/03, p.281

hearings.[97]

[157] John MacPherson, Counsel for TrentonWorks, *et al.*, questioned NSPI during the hearing with respect to the $3.6 million revenue loss associated with the proposed boundary change:

Q. And the amount of revenue lost of 3.6 million, it's proposed that that would be spread over all classes and absorbed by all classes.

A. (Boutilier) That would be the subject of the next hearing as to how that would get allocated across which class, and I think it would depend upon the revenue to cost ratios and other issues that would be brought up at that kind of a hearing.
(Transcript, June 2/03, p.160)

[158] In response to a question from the Board regarding Mr. Hopkins' concern that a change in the boundary is inappropriate due to revenue losses and the resulting impact on other customers, NSPI stated:

(Whalen) We don't disagree with the observation of Mr. Hopkins. We are simply looking at a group of customers in this class. And we see there's a group of customers that we believe are not in the class that fits them best. And we believe moving them to a rate – to a small general rate is a better fit. It moves them with customers who are more like the group that we're talking about in terms of load characteristics and that sort of thing. So, we believe this group of customers is actually now perhaps paying more than they should. Of course, when you move them, there are some impacts. So we're not disagreeing with that. But we believe that in order to correct what we believe is perhaps unfair for this group of customers, at this point, you have to deal with the revenue change.
(Transcript, June 3/03, p.280-281)

[159] NSPI presented the following table which illustrates the customer impacts of the proposed boundary change:

Boundary	**Cumulative Number of Customers Transferred to Rate 10**	**Cumulative Number of Customers With Bill Increases**	**Cumulative Number of Customers With Bill Decreases**	**Customer Impacts (%)see note**

[97] Exhibit N-1, p.58

Boundary	Cumulative Number of Customers Transferred to Rate 10	Cumulative Number of Customers With Bill Increases	Cumulative Number of Customers With Bill Decreases	Customer Impacts (%)see note
17000	2913	282	2631	(24.9) 11.2
22000	5014	516	4498	(23.9) 9.4
27000	6556	676	5880	(23.3) 8.4
32000	7895	832	7063	(22.6) 7.8

(Exhibit N-1, p. 59)

Note: In the last column, the bracketed figures indicate the percentage of transferring customers whose rates would decrease while the figures not in brackets indicate the percentage of transferring customers whose rates would increase.

7.3 Evidence and Submissions - Intervenors

[160] Dr. Stutz's view is that in determining whether the 12,000 kWh limit is appropriate, the issues of equity and efficiency must be considered. He posed the following questions:

1. **Equity.** Does the 12,000 kWh limit treat small commercial customers in the same way as other, similar customers are treated?

2. **Efficiency.** Does the 12,000 kWh limit result in small commercial customers receiving more appropriate price signals?

(Exhibit N-10, p.41)

[161] With respect to equity, Dr. Stutz found that the level at which demand metering is required for commercial customers is low for NSPI compared to other utilities.[98] He further found that "...about 17 percent of Residential customers would be demand metered if a 12,000 kWh limit were set for service on the non-demand-metered residential

[98] Exhibit N-10, Ex. JS-13

rates".[99]

[99] Exhibit N-10, p.42

[162] With respect to efficiency, Dr. Stutz explained that the price signal sent by demand metering is associated with the concept of controlling peak demand, and it can be very difficult for small businesses which lack the resources to invest in load management technology to respond to that signal. He submitted that "...a shift from kW and kWh charges to kWh charges alone may provide small customers a better price signal to reduce demand than a rate with energy and demand charges."[100]

[163] Dr. Stutz presented a table (Ex. JS-12), as part of Exhibit N-10, which shows the consequences of raising the boundary for the Small General rate from 12,000 kWh/year to 62,000 kWh/year in increments of 5,000 kWh. It sets out the associated revenue loss, average reductions in rates for the 'transferred' customers and the required across-the-board increase necessary to recover the associated revenue losses for each of the possible limit levels. He concluded from the table that "...the benefits (i.e., percentage decrease in the average bill due to a shift) are greatest and the across-the-board increases smallest when the limit is increased modestly".[101]

[100]Exhibit N-10, p.42

[101]Exhibit N-10, p.41

[164] Based upon his review, Dr. Stutz recommended that the boundary be raised. Although he stated that the amount of increase is ultimately a matter of judgement, he recommended that the boundary be set at 35,000 kWh/year. He noted that, if the revenue deficiency referred to above were to be recovered through an across-the-board increase for all above-the-line rate classes, the increase would be approximately 0.5%. In his rebuttal evidence, after further considering the concern expressed by Mr. Hopkins and CME over the revenue loss which would have to be recovered, Dr. Stutz recommended that the boundary be set at 32,000 kWh rather than 35,000 kWh which "...lowers the revenue impact by about $360,000."[102]

[165] In response to a question as to whether it is equitable to spread the revenue requirement resulting from a boundary change to the other rate classes, Dr. Stutz replied:

> I think it's equitable. I think what's happened is that we're treating these customers in a way that's different from the way we treat small residential customers. It's different from the way other utilities treat customers similar to these customers. So I think what's happened is that we've imposed the demand metering requirement on these customers which other utilities wouldn't see and which residential customers of a similar size wouldn't see and which the customers, rightly or wrongly – I'm sure the company would debate this – see as an imposition. So I think we're just burdening them in a way that it isn't fair, given the way we treat others, to burden them.
>
> (Transcript, June 4/03, p.401)

[166] Mr. Hopkins opposed any increase in the boundary between the Small General and General Rate classes. He submitted that the closer rates track the costs incurred the more equitable and efficient the rates will be. Utility costs have two components, demand (fixed) and energy (variable). The presence of a demand meter allows both of these components to be precisely measured "and the cost billed

[102] Exhibit N-11, p.23

accordingly".[103] He further pointed out that the proposed boundary change will result in revenue losses from the transferred customers that have not been shown to be offset by cost savings. In his view there is no justification for recovering the lost revenues from other customers.

[103]Trentonworks et al, Written Submission, p.14

[167] CME argued that no change be made to the present boundary between the Small General and General classes as any change will result in revenue losses.[104] ECANS, on the other hand, submitted that while the boundary should ultimately be set at 60,000 kWh, a move to at least 36,000 kWh is warranted at this time.[105]

7.4 Findings

[168] Based upon the evidence presented, the Board is of the opinion that the boundary between the Small General Rate and the General Rate should be raised to 32,000 kWh per year.

[169] The Board directs that the change be phased in over two years, with the availability limit for service under the Small General rate being increased to less than 22,000 kWh/year in the first year and to less than 32,000 kWh/year in the second year. The phase-in period will not unduly delay the benefits of the change to the great majority of customers (up to 22.6% decrease for 7895 customers) who will move to the Small General rate but will cushion the impact of the change on the small number of customers who will be adversely affected (up to 7.8% increase for 832 customers) by the move. In addition, it will cushion the revenue impact on NSPI resulting from an immediate jump in the boundary from 12,000 kWh/year to 32,000 kWh/year.

[170] The Board directs that the phase-in commence on January 1, 2004. NSPI should submit appropriate amendments to the two affected rates and the Board will issue an Order directing the implementation of the change as indicated.

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[104] Exhibit N-24, p.4

[105] Exhibit N-25, pp.7-8

8.0 OTHER

8.1 Technical Conferences

[171] In the Board's October 23, 2002 General Rate Decision, NSPI was directed to hold technical conferences. The Board is pleased to see that progress in this area has been made at the present proceeding and is continuing in advance of the next general rate case. The discussions and information presented during the technical conferences appear to have focused the parties involved on the relevant issues. In addition, the technical conferences provide an opportunity for understanding and agreement in a number of areas, thereby shortening the formal hearing process. The Board expects that this process will continue for future proceedings and the Board wishes to thank all the parties for their participation and helpful input throughout this proceeding.

An Order will issue accordingly.

DATED at Halifax, Nova Scotia, this 1st day of August, 2003.

John A. Morash, C.A., Chair

Margaret A.M. Shears, Vice-chair

John L. Harris, Q.C., Member

Kulvinder S. Dhillon, P.Eng., Member

APPENDIX A

LIST OF WITNESSES

Nova Scotia Power Incorporated	Mary E. Lambert Director of Energy Fuels and Risk Mgt. Nova Scotia Power Inc. Melvin Whalen Director of Regulatory Affairs and Rates Nova Scotia Power Inc. Robert P. Boutilier Industrial Market Leader Marketing and Sales Division Nova Scotia Power Inc.
Board Counsel's Consultant	Dr. John Stutz Consultant
Stora Enso Port Hawkesbury Limited and Bowater Mersey Paper Company Limited	Dr. Alan Rosenberg Consultant
TrentonWorks et al. and Michelin et al.	William R. Hopkins Consultant

APPENDIX B

LIST OF INTERVENORS

Nova Scotia Power Incorporated	Mr. James L. Connors, Q.C. Vice President, Regulatory Affairs Emera Inc. & Mr. Melvin Whalen Director, Regulatory Affairs & Rates
Banook Associates & Eskasoni Band Council	Mr. Robert Leth & Mr. Carey Rolfe
Bowater Mersey Paper Company Limited	Mr. George T. H.Cooper, Q.C. & Mr. David MacDougall
Canadian Federation of Independent Business	Ms. Leanne Hachey, Policy Analyst
Canadian Manufacturers & Exporters Nova Scotia Division	Mr. Dick Smyth, Vice-President
The Canadian Salt Company Limited	Mr. Robert G. Grant, Q.C. & Ms. Nancy G. Rubin & Mr. A. W. Davidson, Facility Manager
Capital District Health Authority	Ms. Nancy Milford, Director Risk Management & Legal Services & Mr. Greg McGrath, Director Environmental Services
Dalhousie University	Mr. Larry Hughes, Ph.D., Professor & Mr. Howlan Mullally & Mr. Jeff Bell & Ms. Marjolaine Cote
Electricity Consumers Alliance of Nova Scotia (ECANS)	Mr. John Woods, P.Eng. Executive Director

Gasworks Energy Corp.	Mr. Dwight E. Jeans
Halifax Grain Elevator Limited	Mr. Robert G. Grant, Q.C. & Ms. Nancy G. Rubin & Elke Juckes
Halifax Regional Municipality	Ms. Mary Ellen Donovan & Ms. Karen Brown HRM Legal Services
Mr. Rhys Harnish	Mr. Rhys Harnish Hubbards, Nova Scotia
Heritage Gas Limited	Ms. Marilyn P. Wappel Senior Legal Counsel
High Liner Foods Inc.	Mr. Robert G. Grant, Q.C. & Ms. Nancy G. Rubin & Mr. Robert Barss
Imperial Oil	Mr. Robert G. Grant, Q.C. & Ms. Nancy G. Rubin & Mr. Brian M. Fairley, Dartmouth Refinery Manager
J. D. Irving Ltd., Saw Mills Division	Mr. Robert G. Grant, Q.C. & Ms. Nancy G. Rubin & Mr. Bruce Nicholson
Lewis Engineering Inc.	Mr. David Lea, P. Eng. Vice-President, Energy Services
Mactara Limited	Mr. Robert G. Grant, Q.C. & Ms. Nancy G. Rubin & Mr. Gordon Shupe, CFO
Maritime Steel and Foundries Ltd.	Mr. John C. MacPherson, Q.C., & Mr. Donald Cameron, President
Michelin North America (Canada) Inc.	Mr. Robert G. Grant, Q.C. & Ms. Nancy G. Rubin & Ms. Catherine A. McKean Senior Corporate Counsel
Minas Basin Pulp & Power Company Ltd.	Mr. Robert G. Grant, Q.C. & Ms. Nancy G. Rubin & Mr. Scott C. Travers, President & COO

Municipal Electric Utilities of Nova Scotia Co-operative (MEUNSC)	Mr. Don Regan Mr. Al Dominie
Natural Forces Technologies Inc.	Mr. Will Apold, M. Eng., P. Eng. President
Nova Scotia Department of Energy	Mr. James B. Isnor Senior Solicitor, Legal Services Division Nova Scotia Department of Justice & Mr. Allan Crandlemire Department of Energy & Mr. Scott McCoombs Energy Engineer
Oxford Frozen Foods Limited	Mr. Robert G. Grant, Q.C. & Ms. Nancy G. Rubin & Mr. Corey Sigut, P.Eng.
QUETTA Inc.	Mr. John H. Reynolds, P. Eng.
Renewable Energy Services Limited	Mr. Erik Twohig, President
Stora Enso Port Hawkesbury Limited	Mr. George T. H. Cooper, Q.C. & Mr. David MacDougall
TrentonWorks Limited	Mr. John C. MacPherson, Q.C. & Mr. Gary Mingo, Manager

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Request IR-2:

In response to the question above, IR-1, has NSP in the past researched, requested, or received reports, of the impact of rates and rate increases on small Business (Codes 10, 11, and 21)? If so, please provide any documentation with respect to this question.

Response IR-2:

Rate impacts on all classes and various consumption levels within classes are examined during rate applications. Please refer to CA IR-92.

NON-CONFIDENTIAL

Request IR-3:

What is the rationale for having small business (Codes 10, 11, and 21) pay more on a revenue-to-cost ratio than residential users, industrial users, and municipal users? On what information is this rationale based? Please provide any documentation with respect to this question.

Response IR-3:

Class revenue to cost ratios are examined during General Rate Applications, and the positions of various parties and consultants, as well as the UARB conclusions, are reflected in the Decisions in those matters. Differences among classes can arise from changes to cost allocation methodologies and cost drivers and differences in rate impacts among classes. Please refer to SBA IR-1.

NON-CONFIDENTIAL

Request IR-4:

On what basis is NSP proposing an approximate increase of 30%, from 7.1 M to 10.4 M in vegetative management costs? Does this include a "catch up" factor? What increases does NSP predict in the next five years in this category? Please provide any documentation with respect to this question.

Response IR-4:

Please refer to Liberty IR-56, Liberty IR-59, Liberty IR-60, and Liberty IR-144 for details and analysis on vegetation management. The increase sought is from $10.4 million to $13.8 million.

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Request IR-5:

With respect to your application(page 82) for a 3.4 million dollar increase for vegetation management, what is the basis for the requested increase specifically, what projections and/or opinions is the requested increase based on. Please provide all background information supporting the requested increase.

Response IR-5:

Please refer to Liberty IR-56, Liberty IR-59, Liberty IR-60, and Liberty IR-144.

NON-CONFIDENTIAL

Request IR-6:

Based on the proposed increase of OM & G Technical & Construction Services costs, what are the reasons or rationale for this category increasing by approximately 50% since 2009? Please provide any documentation with respect to this question.

Response IR-6:

Please refer to Appendix C, page 20 of the Application, Section 5.4.4, page 85, lines 14 to 19 and page 86, lines 9 to 16 of the Application. Also, please refer to Liberty IR-39 and Liberty IR-40.

NON-CONFIDENTIAL

Request IR-7:

Based on the proposed increase, of OM & G Sustainability costs, what are the reasons or rationale for this category increasing by approximately 50%, from 1.2 M to 2.0 M since 2009? Please provide any documentation with respect to this question.

Response IR-7:

Please refer to the Application, DE-03 – DE-04 Appendix C, Page 24 for an explanation of expense increases from 2009 Compliance to 2012 Forecast. NSPI is moving from coal generation toward cleaner and renewable sources of electricity. The primary increase in Sustainability OM&G costs relate to consulting associated with the Renewable Energy Standards compliance requirements. Please refer to NSDOE IR-5(a-b) for more information concerning these consulting expenses.

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Request IR-8:

What is the justification for NSP seeking an increase in ROE from 9.35% to 9.6% in times of austerity? Please provide any supporting documentation with respect to this question.

Response IR-8:

Nova Scotia Power's justification and supporting documentation for a change in ROE is provided in section 6.3 of Nova Scotia Power's Direct Evidence as well as in the evidence of Nova Scotia Power's expert, Kathleen McShane, provided at Appendix F of Nova Scotia Power's Direct Evidence.

NON-CONFIDENTIAL

Request IR-9:

How was the range of acceptability of Revenue-to-Costs of 95% to 105% derived? Given the present sophistication of modeling and forecasting, is there any reason why this range cannot be tightened, say from 98% to 102%? Please provide any documentation with respect to this question.

If there are no changes made to your existing return on equity (RoE), what would be the effect, if any, on the rates for the Small General Tariff Code 10, General Tariff Code 11, and Small Industrial Tariff Code 21? Please provide documentation to support your answer, include information before tax if the RoE is established.

Response IR-9:

The acceptability of the revenue to cost ratio range of 95 percent to 105 percent was reviewed and confirmed in the UARB's Decision in the Generic Rate Design Hearing.[1] Please refer SBA IR-1 for a copy of the Decision. Nova Scotia Power has not analyzed use of a different range of revenue to cost ratios.

Nova Scotia Power has not performed the above-referenced analysis to determine the effect on the rate for the Small General Class, the General Demand Class and the Small Industrial Class if ROE were to remain unchanged with all other changes as proposed. The requested increase in ROE represents an overall change in revenue requirement of $4.9 million on a total revenue requirement increase of $94.4 million. The impact on the change for each of the above-referenced classes would be less than a fraction of a percentage increase.

[1] Generic Rate Design Hearing, NSUARB-NSPI-P-878, UARB Decision, August 1, 2003.

NON-CONFIDENTIAL

Request IR-10:

With respect to your forecast application (page 119) for increased sales in your residential, commercial and industrial sections, please provide all background information on what your predictions are based, what assumptions were made concerning the use and specifically, in light of the fact that increased usage in 2010 was only 1.4 percent. Specifically provide background information for the 5.2 percent increase in residential sales which appear to have been constant at 1 percent over the last 5 years.

Response IR-10:

The load forecast methodology and assumptions are described in the 2011 Load Forecast Report included in the Application, in section SR-02.

To clarify the growth rates with respect to residential sales, it should be noted that although the growth in the residential sector has averaged approximately 1 percent over the past 5 years, the growth has not been constant. The table below shows the annual residential sector billed sales growth has varied from a high of 6.0 percent to a low of -3.2 percent.

<table>
<tr><th>Year</th><th>Residential Annual GWh</th><th>Annual Growth</th><th>5-yr Average Growth</th></tr>
<tr><td>2005</td><td>4112</td><td></td><td rowspan="6">1.2%</td></tr>
<tr><td>2006</td><td>3979</td><td>-3.2%</td></tr>
<tr><td>2007</td><td>4218</td><td>6.0%</td></tr>
<tr><td>2008</td><td>4232</td><td>0.3%</td></tr>
<tr><td>2009</td><td>4318</td><td>2.0%</td></tr>
<tr><td>2010</td><td>4216</td><td>-2.4%</td></tr>
</table>

The reference on page 119 of the Application also states that the 2012 residential sector is 5.2 percent higher than 2010. This is the equivalent of 2.6 percent annual growth.

The residential forecast model is affected by projections of:

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- household appliance efficiencies
- consumer goods sales
- number of electric space heat customers
- weather (number of heating degree-days)
- price of electricity
- historical trends.

Among these factors which affect residential energy consumption, the effect of the weather moving from a warmer than average year (2010) to the forecast of a typical year (in this case, colder for 2011 and forward) is the largest factor. The 2010 weather had a heating load requirement, measured in heating degree-days (HDD), that was 12 percent below the forecast average. This HDD difference alone accounts for 2 percent of the change.

NON-CONFIDENTIAL

Request IR-11:

With respect to housing starts referred to at 8-3, p 122, of your application, do they relate to Nova Scotia or all of Canada? If the latter, what is the impact on small business rates by including this projection in your application.

Response IR-11:

The housing starts identified are estimates for the province of Nova Scotia only. They are used in the load forecast only to assist in the projection of the number of residential customer accounts.

NON-CONFIDENTIAL

Request IR-12:

With respect to the Small General Tariff Rate Code 10, please explain with supporting documents why there is a need to increase energy charge for this tariff from the previous 2011 approved tariff of $0.13067 per kilowatt hour for the first 200 kilowatt hours per month and an increase from $0.11496 per kilowatt hour to $0.12274 per kilowatt hour for all additional kilowatt hours. Please explain the necessity to apply a demand side management cost recovery charge in addition to the energy charge for this tariff and provide documents to support your position.

Response IR-12:

Once the revenue requirement for the company has been identified, the next step in the rate-making process is to allocate recovery of that amount from the various customer classes, primarily based upon economic models referred to as the Cost of Service Study (COSS). The COSS allocates costs to the customer classes that are responsible for causing those costs, based upon various principles that are established from time to time by the UARB. Customer classes will have different components of their rates – a Customer charge, an Energy charge, and a Demand charge, or a combination of these components. The latter charge is different from the Demand Side Management charge, which applies to above the line customer classes and is used to fund energy efficiency and conservation programs administered by Efficiency Nova Scotia Corporation.

Once the COSS has been applied to the revenue requirement, these various components of customer rates are changed in order to allow recovery of the assigned costs from the customer class, based upon the load forecasted for the customer class. This forecasted recovery is demonstrated through the “proof of revenue” tables. The reason for the change in the energy rate noted in the question is that the change will allow recovery of the increased costs of serving the customer class in respect of the costs that relate to that specific rate component.

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Please refer to the Application, DE-03 – DE-04, Section 10.3.2 for the process and outcome of revenue responsibility allocation. The computation of individual charges is detailed in Proof of Revenue (OR-01).

NON-CONFIDENTIAL

Request IR-13:

With respect to the Small General Tariff Rate Code 10, as applicable to electric energy for use if the annual consumption is less than 32,000 kilowatts per year, for which no other rates are applicable. Please provide a full explanation with supporting documents as to how the amount of 32,000 kilowatts per year was arrived and what would the effect be on the minimal monthly charge if the annual consumption ceiling was increased to 60,000 kilowatts per year.

Response IR-13:

The 32 MWh threshold was approved by the UARB in the Rate Design hearing from 2003. Please refer to section 7.0 of the UARB's Decision (NSUARB-NSPI-P-878) on a Generic Rate Design Hearing, included as SBA IR-1 Attachment 1.

NSPI has not prepared rate analysis associated with the increase in availability threshold for Small General Tariff from 32,000 to 60,000 kWh for the purposes of this Application. An upward shift in the annual consumption ceiling of 32,000 kWh would result, in general, in a decrease in unit costs of both the Small General and General Classes. However, while the current Small General customers would see lower power costs as a result, those moved from the General to the Small General class, would see an increase. The total cost of power of the two classes combined would remain unchanged.

NON-CONFIDENTIAL

Request IR-14:

With respect to General Tariff Rate Code 11, please provide a full explanation with supporting documents why the need for an increase on demand charge from $9.34 per month per kilowatt of maximum demand to $9.618 per month per kilowatt of maximum demand.

Response IR-14:

Please refer to SBA IR-12.

NON-CONFIDENTIAL

Request IR-15:

With respect to the General Tariff Rate Code 11, please provide a full explanation of the need for an increase from 2011 approved tariff for the energy charge of $0.09464 per kilowatt hour for the first 200 kilowatt hours per month and $0.06824 per kilowatt hour for all additional kilowatt hours to your proposed request of $0.1027 per kilowatt hour for the first 200 kilowatt hours per month per kilowatt of maximum demand and $0.07265 per kilowatt hour for all additional kilowatt hours.

Response IR-15:

Please refer to SBA IR-12.

NON-CONFIDENTIAL

Request IR-16:

Please explain with supporting documents if the annual consumption ceiling was increased to 60,000 kilowatts per hour or greater, what would be the effect on the demand and energy charges on the minimum monthly bill for this tariff increase for 2012.

Response IR-16:

NSPI has not prepared this analysis for the purpose of this Application. Please refer to SBA IR-13.

NON-CONFIDENTIAL

Request IR-17:

With respect to Small Industrial Tariff Rate Code 21, please provide a full explanation with supporting documents why there is a need to change the demand charge from $0.06442 per month per kilovolt amp per maximum demand to $0.06928 per month.

Response IR-17:

Please refer to SBA IR-12.

Request IR-18:

With respect to the energy charge for Small Industrial Tariff, please provide an explanation why there is a need to increase for this charge from the last approved tariff in 2011 to $0.09061 per kilowatt hour for the first 200 kilowatt hours and $0.06921 per additional kilowatt respectively.

Response IR-18:

Please refer to SBA IR-12.

NON-CONFIDENTIAL

Request IR-19:

With respect to both the Small Industrial Tariff Rate Code 21 and General Tariff Rate Code 11, please provide an explanation with supporting documents for the meaning of "non-standard service provisions" as a special condition with respect to these two tariffs where NSP may require the customer to own any transformer normally provided by the company. In particular, what are the non-standard service provisions?

Response IR-19:

The "non-standard service provisions" referred to in the Special Condition 2 of the Small Industrial tariff are concerned with the treatment of customers' requests to have power supplied at lower voltage level than those considered standard within the low voltage classification. Please refer to regulation 2.7 Electric Service Availability and Standard Voltages in Attachment 1.

2.7 ELECTRIC SERVICE AVAILABILITY AND STANDARD VOLTAGES

The Company shall maintain electric service to customers by providing distribution facilities and services designed and constructed to accepted Utility Engineering Standards, including one supply to each building.

Customers shall not use these facilities in a manner that will cause unacceptable interference to the Company's system, and/or adversely affect other customers served from the same facilities.

The following electric service voltages are to be considered as standard within the low voltage classification:

Single-phase, 3-Wire, 120/240 volts
Three-phase, 4-Wire, 120/208Y volts
Three-phase, 4-Wire, 347/600Y volts

In addition, three-phase electric service may be provided at other voltages with special permission. Customer contributions will be required if additional costs are incurred.

For voltage variation limits, refer to C.S.A. standard - CAN-C235-83 or any subsequent revision.

Customers requiring three-phase electric service with connected load of 15 kW and under will be required to pay to the Company a capital contribution, as set forth in the Schedule of Charges, to cover the extra cost of transformers that must be installed to serve the three-phase load. Such contribution is in addition to that assessed to cover required line extensions. Should the necessary line and transformer facilities already exist at the location in question, no contribution will be required.

The electric service voltage provided under the Domestic rate to self-contained dwelling units, duplexes, condominiums and small apartment buildings shall be 3-Wire, 120/240 volts, except where there is a legitimate requirement for three-phase electric service.

Electric service shall normally be limited to one secondary voltage supply per duplex or other multi-unit residential building.

Under Regulation 2.11, the Company may require an underground primary voltage supply to serve such a building.

2.7 ELECTRIC SERVICE AVAILABILITY AND STANDARD VOLTAGES

Commercial loads which can be adequately supplied by a 30 ampere, 2-Wire supply may be served 2-Wire, 120 volts.

The Company may, at no charge to the customer, install a recording instrument to check a customer's voltage at the customer's supply point.

If the Company is satisfied with the customer supply voltage and if the customer for the customer's own purposes requests a recording instrument be installed, a charge for the installation of such recording equipment shall be applied as set forth in the Schedule of Charges.

NON-CONFIDENTIAL

Request IR-20:

Please provide a full explanation with supporting documentation as to how the costs of service to revenue ratio of 95 percent to 105 percent has been calculated as a reasonable range and include what factors NSPI has considered in attempting to keep within such a range for this application as it affects small business classes.

Response IR-20:

Please refer to SBA IR-1 Attachment 1 and the UARB's findings on the relevance of the band in setting rates in its Decision on GRA 2002, included as Attachment 1.

7.3.3 Findings

[287] For over 15 years, the Board has indicated that customer class R/C ratios should be in the range of 95% to 105%. Dr. Rosenberg and Dr. Stutz were the only two witnesses to address the R/C ratios. Both generally supported the 95% to 105% range adopted historically by the Board. Based on the evidence in this proceeding, the Board affirms its long-standing use of the 95% to 105% range for R/C ratios. While the Board affirms the commitment in its decision in NSPI's last rate case to limit the class revenue requirements so that no class has an R/C ratio of below 95% or above 105%, it also believes that, depending on the scale of a proposed rate increase, there may be justification for the Board to exercise some flexibility in the application of this general rule. Judgement must be exercised in balancing the R/C ratio objective with the desire to avoid rate shock.

[288] The Board finds that, to be reasonably applicable in a range of circumstances, the notion of rate shock must take into account the underlying average level of increase. Thus, in considering rate shock in this proceeding, the Board will rely on the approach proposed by Dr. Stutz. Generally speaking, in considering the issue of rate shock, the Board will continue to strive towards its stated objective of keeping R/C ratios in the 95% to 105% range, subject to the foregoing caveat. The Board will apply these principles in its review of NSPI's Compliance Filing.

NON-CONFIDENTIAL

Request IR-21:

With respect to NSP's interest in Point Tupper Wind Farm, what is the effect on the small business tariffs with supporting documents, having the OMG Financing and Depreciation costs recovered through the fixed rate component of Nova Scotia Power rates, rather than as currently being recovered through the fuel adjustment mechanism.

Response IR-21:

NSPI has not conducted such an analysis for the purpose of this Application. Please refer to NSDOE IR-4 and CA IR-146.

NON-CONFIDENTIAL

Request IR-22:

With respect to the costs of service, including determination of class revenue requirements, please explain fully with supporting documentation as to how Nova Scotia Power determined the percentage amount for the downloading of the specific rates applicable to small business, namely Small General Tariff Rate Code 10, General Tariff Rate Code 11 and Small Industrial Tariff Rate Code 21.

Response IR-22:

Please refer to the Application, DE-03 – DE-04, section 10.3.2 and Proof of Revenue (OR-01).

Request IR-23:

With respect to Pension Costs, please provide an explanation and documentation as to why there is such a large increase in pension costs applied to the 2012 General Rate Application and provide details of the pension plan or plans if there are more than one and the vesting requirements for members of the plan. Include in your explanation if all the pension costs are borne by the customers of NSP or if there is cost sharing with Emera and if so, what costs are attributed to the customers of NSP, and in particular, to the small business categories and how it affects rates that NSP are seeking in those small business tariffs.

Response IR-23:

Please refer to the Application, DE-03 – DE-04 pages 69-72, Liberty IR-80, Liberty IR-82, Liberty IR-162, and CA IR-118 for explanations and documentation of 2012 pension costs.

A summary of each of the plans is included in Appendix C of the December 31, 2010 Accounting Valuation Report. Please refer to Liberty IR-80 Attachment 1. Please refer to NPB IR-99 Attachment 17 and Attachment 19 to for a copy of the text for the NSPI registered pension plans.

Please refer to NPB IR-99 Attachment 21 for the SERP Plan text and Liberty IR-164 for additional information on the SERP.

The vesting requirements for the various plans are as follows:

- Registered Pension Plan (Defined Contribution) - immediate

- Registered Pension Plan (Defined Benefit), two years

- Acquired Companies Pension Plan - two years

- SERP, Exec, Discretionary – two years (same as registered plan)

- War Service – not applicable as all members are retired

- Long Service Award – must be eligible for an immediate unreduced pension (in general terms: age 55 with 85 points, or age 60 with two years of service) at the date that employment is terminated

- Post-Employment Health Benefits (Old Plan)- must be eligible for an immediate unreduced pension (in general terms: age 55 with 85 points, age 60 with two years of service) at the date that employment is terminated

- Post-Employment Health Benefits (New Plan) - termination occurs after age 55 with at least 10 years of service. Retirees are eligible for retiree benefits if they retire with an unreduced pension and with 10+ years of service, if they don’t have the service, they are not eligible.

The pension costs attributed to NSPI customers are in respect of NSPI employees only. Pension costs are attributed to customers based on the UARB approved cost of service methodology.

NON-CONFIDENTIAL

Request IR-24:

Please provide information as to how much of the increase to the Small Business Tariffs sought is attributable to pension costs and after tax considerations.

Response IR-24:

A general rate application allocates the entire forecasted revenue requirement to various customer classes through the Cost of Service Study. Components of the revenue requirement are not specifically allocated in such a manner as would allow a response to the request as proposed. NSPI has not prepared an analysis at such a level of detail.

NON-CONFIDENTIAL

Request IR-25:

Please provide a full explanation with supporting documents as to the effect on small business classes tariffs as a result of New Page Port Hawkesbury Corp. and Bowater Mersey Paper Company Ltd.'s applications to seek amendments to the load retention tariff.

Response IR-25:

The Application by NewPage and Bowater (P-202) outlines the effect (both rate percentage and revenue responsibility) on small business class tariffs and other customer classes that would be caused by NPB's request for a load retention tariff. NSPI has no further analysis of the effect of the NPB Application on small business class tariffs.