PRE-FILED TESTIMONY OF
C.F. OSLER and P. BOWMAN
IN REGARD TO NEWFOUNDLAND & LABRADOR HYDRO
GENERAL RATE REVIEW

Submitted to

The Board of Commissioners of Public Utilities

On behalf of

Island Industrial Customers

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1.0 INTRODUCTION

This testimony has been prepared for the four existing Island Industrial Customers and one potential Island Industrial Customer (collectively "IC") of Newfoundland and Labrador Hydro (Hydro) by InterGroup Consultants, Ltd. (InterGroup) by Mr. C.F. Osler and Mr. P Bowman. It is evidence for the public hearing into an Application (the "Application") by Hydro to the Board of Commissioners of Public Utilities (Board) dated May 2003.

The Island IC group includes the three large industrial companies currently operating in Newfoundland and Labrador on Hydro's Island Interconnected System and one potential industrial customer on this system. These companies are:

- Abitibi-Consolidated Company of Canada (two customer locations, at Grand Falls and Stephenville);
- Corner Brook Pulp and Paper Limited;
- North Atlantic Refining Limited; and
- Voisey's Bay Nickel Company Limited which is a potential industrial customer of Hydro.

Mr. Osler's qualifications are provided in Attachment A. Mr. Bowman's qualifications are set out in Attachment B. InterGroup was initially retained at the end of June 2001 to assist the IC in addressing the 2001 Hydro Rate Review, and subsequently assisted the Island IC in preparation for the current proceeding. Mr. Osler also submitted evidence on behalf of the IC in the 2001 proceeding.

In preparing this testimony, the following information has been reviewed:

- The Hydro Application filed May 21, 2003, including pre-filed testimony of Hydro staff and witnesses.

- The Hydro Amended Application filed August 12, 2003 reflecting the July 2003 direction from the Government of Newfoundland and Labrador with respect to rural rates, and a revised fair return on equity proposal of 9.75%.

- Most of the first round responses to Information Requests filed to Hydro from the Board, the IC, the Consumer Advocate (CA), Newfoundland Power (NP), and the Labrador Customers (LC).

- To a limited degree, the second round responses to the Information Requests filed to Hydro from the Board, the IC, the Consumer Advocate (CA), Newfoundland Power (NP), and the Labrador Customers (LC); however, given the volume of the responses and the limited amount of time that has been available for us to review them, this review has been severely restricted. Furthermore, several key responses filed to date by Hydro fail to provide sufficient information as yet to usefully answer the questions posed.

This is the second general review of Hydro's rates by the Board under the new regulatory regime established for Hydro during the mid-1990s. InterGroup has been asked to identify and evaluate issues relating to the following aspects of Hydro's filing, taking into account normal regulatory review procedures and principles appropriate for Canadian electric power utilities:

1. revenue requirements for 2004 as submitted by Hydro; and
2. cost of service and rate structures, particularly insofar as these rates affect the Island IC.

The Board's schedule for this proceeding directs that pre-filed testimony by Intervenors is to be filed by September 2, 2003. This testimony has been prepared in response to this direction and based on our review as conducted to date.

As noted, our review to date has been somewhat limited by the time available, certain availability of responses to the Information Requests filed by all parties, and the quantity of information required for a full understanding of the issues. This initial testimony focuses on summarizing the contents of the Application, identification of key issues related to the above matters, and an initial overview of these issues. Following a review and clarification as required of Hydro's responses, further analysis and testimony on these issues may be required.

1.1 SUMMARY

Focusing on appropriate overall rate levels in general, and the appropriate level of rates to industrial customers in particular, it is apparent that Hydro's current application, in combination with the proposed operation of the RSP, results in unacceptable short-term (test year) rate increases and medium-term (5 years) rate instability, including forecast rate decreases in subsequent years. A consistent assessment of the proposed revenue requirement in comparison to approved 2001 levels indicates a substantial increase in a number of costs that exceed expected levels of inflation and fail to reflect the Board's conclusions regarding productivity improvements. The Board would be well advised to test carefully the reasonableness of the proposed increases in light of the overall rate impacts being proposed.

The material filed by Hydro indicates substantial improvement has been made in addressing system supply shortfalls compared to the 2002 test year. Granite Canal, in particular, appears to be a useful asset that is likely to reflect long-term benefits to the system. However, a detailed review of revenue requirement, cost of service and rate design in this submission indicates an inconsistent response by Hydro to the new system configuration reflecting surplus capacity and energy.

Hydro's overall proposals reflect confirmation of appropriate cost allocations for such assets as the Great Northern Peninsula transmission. However, standards applied by Hydro in assessing other radial transmission system assets (including thermal generation assets) result in an improper allocation of costs to the IC group reflecting costs of generation and transmission assets that are proposed to be assigned as being of common benefit, despite these assets being neither used nor useful to service the Island Interconnected system. Aside from normal cost of service concerns related to Hydro's proposed approach, the Board also needs to review these proposals in the context of the legislative limitation on industrial customer rates from funding the rural subsidy.

Hydro's application reflects a limited consideration of long-term financial and system planning issues. In particular, Hydro has failed to supply a long-term financial plan along the lines required by the Board in P.U. 7 (2002-2003), and has inappropriately focused on short-term considerations in their decision not to continue the industrial Interruptible B rate despite the long-term system benefits that this type of capacity-shedding rate can provide.

The proposed rate design reflects an unreasonable (and potentially unintended) outcome as loads vary from GRA forecasts. The provisions regarding billing demands in the industrial contracts in particular are unduly onerous compared to rate designs for industrial customers in other jurisdictions, and compared to the treatment of NP load variation. The complicating factor of the Rate Stabilization Plan on load variations further detracts from any consistent or principled tracking of the costs load variations (particularly NP's) impose on the system.

In order to address the above concerns, this review in summary provides the following recommendations for the consideration of the Board:

1. The material effective increases in certain categories of revenue requirement since 2002, in particular operating and maintenance expenses, depreciation, return on debt and return on equity, reflect the need for a more thorough assessment of Hydro's operating costs and capital investment pace as they relate to rates. (Section 5)
2. There does not appear to be a reasonable basis at this time for Hydro's ratepayers to be faced with higher rates to reflect progression towards treating Hydro as equivalent to an investor-owned utility. (Section 5)
3. Assignments of the Burin Peninsula transmission assets and the GNP generation to common appears to be inappropriate, and reflect a cost allocation that is not consistent with the relative benefits that these assets provide to the various customer classes. (Section 6)
4. NP load forecasts need to be reviewed further in the proceeding to assess the extent to which NP's peak demands as currently forecast result in a reasonable allocation of demand costs, particularly in the context that the 2002 actual cost of service showed that the IC group paid more than $5 million in excess of its measured costs in 2002 and that NP paid almost $5 million below the amounts that should have been collected through rates.
5. Longer-term rate stability objectives suggest a need to assess the current application in the context of the rate adjustments forecast for the next number of years (a substantial increase in rates is forecast in the near term followed by a general reduction over the 2005 to 2007 period). (Section 6)
6. A NP two part rate should reflect Option B of Exhibit RDG-2, with a revised definition of "generation credit" to normalize hydraulic generation.
7. Industrial customer firm demand should reflect the greater of actual peak demand for the month or 80% of the peak established in the previous winter.
8. Industrial customer non-firm energy rates are reasonable as proposed, but non-firm demand should not attract any demand charges.

9. The RSP should be restructured as follows:
    a. The hydraulic component should be a separate fund with no collections or refunds until such time as a given trigger (plus or minus) is reached.
    b. The load variation component should be terminated. The residual balance should be incorporated into the fuel cost fund
    c. The fuel cost variation should be a separate fund. This fund should reflect the most timely pass-through of higher fuel costs that the Board determines is acceptable in light of concerns about rate predictability.
    d. The hydraulic and fuel cost funds should attract (or pay) interest at short-term debt rates.
    e. All riders for the fuel cost and hydraulic funds should be applied on an equal basis per kW.h to IC, NP and Rural.
10. The Interruptible B program should be continued status quo, and Hydro should be directed to study possible benefits arising from expansion of the program to other industrial customers.

Issues arising from Hydro's filing underline the relevance and role of the Board in ensuring that rates charged are fair and reasonable and consistently determined on a principled basis. The role of the Board in this regard is particularly relevant to large industrial power users who undertake substantive long term investment in the province.

2.0 INFORMATION ON ISLAND INDUSTRIAL CUSTOMERS

The Island IC group is comprised of large energy customers who operate with high load factors (i.e. they have relatively comparable levels of energy use throughout the day and throughout the year).

These customers are forecast to purchase over 1350 GW.h of electricity in 2004, or about 20% of the energy sold by Hydro at rates regulated by the Board, at a cost of over $65 million in 2004[1]. This represents a decrease in energy of about 2% from 2002 forecast levels, but an increase in costs of approximately 30%[2]. In each case, electricity costs make up a substantial portion of the operating costs of the customer's operation. In two cases, the customers have material hydro self-generation capability which can be from time to time used to supply surplus power to Hydro.

Industrial Customer concerns are focused around the following:

- Long-term stability and predictability in electricity rates.
- Fair allocation of costs between the various customer classes to be served, including a fair interpretation of the legislative limitation on industrial customer rates from funding the rural subsidy.
- Flexibility to tailor electrical service options to suit their operation to achieve an appropriately firm supply at the lowest cost for the load being served (i.e. using a mix of self-generation, Hydro firm power, Hydro interruptible power, curtailable service, etc.).
- Protection for customers from risky or government-initiated ventures or supply options that are not consistent with the provincial power policy objectives of efficiency and equitable power supply at the lowest possible cost.
- Lowest cost for power that can be achieved within the above considerations.
- Continued reliability of power supply for Island Interconnected customers.

Industrial customer concerns reflect the size of their capital investments in Newfoundland and Labrador, the long-term perspective essential to such investments and the major stake that these investments typically have in continued large-scale power purchases from Hydro. In addition, the industrial customer concerns reflect competitive pressures associated with selling industrial products to external markets.

[1] Includes forecast 2004 IC RSP adjustment of 1.04 cents/kW.h.

[2] The full year forecast rates for IC per Schedule D of Hydro's August 2002 filing in response to P.U. 7 (2002-2003) and P.U. 21 (2002-2003) yield $46.8 plus an RSP adjustment per P.U. 7 (2002-2003) of 0.28 cents/kW.h applied to firm load of 1,388.8 GW.h per Schedule G of Hydro's August 2002 filing in response to P.U. 7 (2002-2003) and P.U. 21 (2002-2003) yields $50.7 million on an annualized 2002 basis.

3.0 OVERVIEW OF HYDRO'S APPLICATION

Hydro's Application requests the Board's approval of matters in the following broad areas:

1. The rates to be charged for the supply of power and energy to Hydro's Wholesale Customer (NP), Hydro's Rural Customers and the IC as of January 1, 2004.
2. The rules and regulations applicable to the supply of electricity to Hydro's Rural Customers.

In contrast to the 2001 proceeding, Hydro apparently does not seek approvals for the contracts setting out the terms and conditions applicable to the supply of electricity to the IC[3], and has not included in the application any materials in relation to the Hydro's Capital Budget for 2004 or beyond. We are advised that a decision is pending from the Board on the 2004 Capital Budget of Hydro following a hearing recently conducted directed solely to that budget.

The Application is made pursuant to the Public Utilities Act (R.S.N. 1990, Chap P-47) the Electrical Power Control Act 1994 (EPCA, 1994) (S.N. 1994, Chap E-5.1), and the Hydro Corporation Act (R.S.N. 1990, Chap H-16).

3.1 CONTENTS OF THE APPLICATION

The Application filed by Hydro at May 21, 2003, as well as the Amended Application of August 12, 2003 are comparable in form and presentation to the 2001 application. The Application includes the rate schedules that Hydro proposes to apply starting in January 2004 and the rules and regulations regarding supply of power that Hydro proposes to apply starting January 2004.

Hydro has also filed pre-filed testimony of various staff and experts to address specific items which Hydro has chosen to expand upon.

Compared to the 2001 Application, Hydro's current Application reflects a number of material changes:

- ***Return on Equity:*** Hydro's August 12, 2003 revision to the current application reflects a proposal for a return on shareholder equity ("ROE") of 9.75%, equal to the return provided to the investor-owned utility Newfoundland Power (Hydro's May 2003 application had proposed a 10.75% ROE). This is a change from the 2001 application, which provided evidence that a fair Return on Equity for Hydro would be 11 to 11.5%[4] but only requested the Board to approve a Return on Equity of 3%.

- ***Price of #6 Fuel:*** Hydro's current application proposes to set rates based on a forecast 2004 price of #6 fuel of $29.20 per barrel, which is the forecast cost of #6 fuel for 2004 provided by Hydro's experts. In contrast, the 2001 application forecast a test year price of #6 fuel of $28 per

[3] Per IC-50.
[4] Wells, 2001 application, page 14.

barrel but only requested rates set based on a $20 per barrel price to mitigate short-term rate impacts, with the remaining $8 per barrel price of fuel proposed to be charged to the RSP for later recovery from customers. The Board's Decision in P.U. 7 (2002-2003) reflected the full updated forecast price of fuel in 2002 rates – the current application is consistent with that approach.

- ***System Costs Reflect Required Generation Plant:*** Hydro's current application, in the evidence of Haynes, reviews the current plant in service and its ability to service the forecast loads. The analysis indicates that the current plant is sufficient to meet all forecast loads until 2009 for energy and 2011 for capacity. In contrast, Hydro's 2001 application reflected a deficit in both capacity and energy supply for the test year, resulting in a plant in service that was calculated to be not of sufficient magnitude to properly service the test year loads.

- ***Review of Proper Cost-of-Service Assignment:*** Hydro's 2001 application reflected a proposed cost assignment of certain plant, primarily the Great Northern Peninsula ("GNP") interconnection and other radial transmission systems, that was not based on any reasonable analysis of whether the assets in fact provided any benefits to the customers to whom Hydro proposed to assign the costs. In the current application, Hydro has conducted an assessment of these radial transmission systems in an attempt to determine a proper cost allocation based on the relative benefits they provide to each customer group.

- ***Industrial Contracts:*** The 2001 application included proposed industrial contracts to govern the terms of service to the four industrial customers. The current application does not include any such contracts, and Hydro noted in IC-50 that it is not proposing any revisions to these documents from that last approved by the Board. Hydro also does not include any request to the Board to terminate the existing rate provided to Abitibi Stephenville for interruptible capacity (Interruptible B), even though Hydro proposes not to renew the rate for the winter of 2003/04[5].

- ***NP two part rate:*** The present application sets out an approach that could be used to develop a two-part (demand and energy) rate for NP, and Hydro indicates that it could implement this rate in 2004[6], even though the application does not request approval for the rate. Hydro's 2001 application indicated that, in response to the Board's repeated direction to develop an appropriate two-part rate to NP, it had reviewed the matter with NP and the two utilities had concluded that it was not appropriate.

3.2 ISSUES ARISING FROM THE APPLICATION

A number of key issues arising from the Application have been identified to date. These are reviewed in subsequent sections of this testimony under the following topics:

1. **Context:** The context for the Application and for review of the Application reflects a material change in Hydro's situation since the 2001 proceeding. The key contextual changes since 2001,

[5] IC-194.
[6] PUB-150.

particularly in regards to Island Interconnected system supply, are reviewed in section 4 of this evidence.

2. **Revenue Requirement and overall rate increases:** The overall revenue requirement and level of rate increases reflect materially higher costs than the approved revenue requirement for the 2002 test year. These and other matters related to regulated revenue requirements are reviewed further in section 5 of this evidence.

3. **Cost of Service:** The relative rate increases that have been requested from the various classes are calculated using a particular methodology that does not fully reflect the changes to Hydro's system supply since 2002 as well as current capacity surplus and load patterns. These matters are reviewed further in section 6 of this evidence.

4. **Rate Design and the Rate Stabilization Plan (RSP):** The collection of each customer's calculated portion of the revenue requirement reflects a certain structure for rates, which can have substantial impacts on the amounts customers end up paying under various conditions. Hydro's rate design for IC also requires an assessment of various matters in the industrial contracts, including the determination and billing for "Power on Order". In addition, the amounts customers pay is increasingly made up of material charges related to the RSP**.** Terms for operation of the RSP are included under the rate schedules included in Volume I of the Application. Matters relating to Rate Design and the RSP are reviewed further in section 7 of this evidence.

4.0 CONTEXT FOR REVIEW OF THE APPLICATION

This is Hydro's second review before the Board since the implementation of the new regulatory regime established for Hydro during the mid-1990s. The first review occurred in 2001, approximately 24 months ago.

The primary context for the current application, and the bulk of the issues that appear to arise from the current application, relate to the supply of bulk power on the Island Interconnected system. This reflects both Wells' assertion that the increases in costs largely arise due to new power sources coming on line, as well as major changes to the relationship between the generation plant available compared to the medium-term forecast island interconnected loads.

Newfoundland Hydro's Island Interconnected System is a mix of hydroelectric and thermal generation. Consistent with other non-interconnected hydro-thermal systems in Canada, Hydro appears to dispatch the system to maximize the energy generation from hydraulic resources and to minimize spilled water at these units. Holyrood thermal generation is dispatched as required to meet peak demand and energy requirements (based on longer-term forecasts of hydroelectric plant reservoirs and prudent water management), with a number of small and expensive peaking thermal units being available to assist in meeting critical extreme winter peaks. However the amount of energy produced by these peaking generators is to be minimized.

Correspondingly, variations in energy loads on such a system that is not interconnected to any other off-Island grid, result in easily quantifiable incremental impacts on fuel costs (particularly at Holyrood) when they occur during normal load periods, and very low incremental costs should they occur at times when surplus hydroelectricity is available (i.e. when Hydro would otherwise be spilling water as a result of other constraints, such as environmental). As a result, incremental energy sales programs, such as the industrial interruptible rate proposed by Hydro, can be priced appropriately to reflect these two conditions.

In comparison to the 2001 application, Hydro now forecasts that their current plant in service, and included in revenue requirement, is sufficient to meet all Island Interconnected loads until 2009-2011[7]. In order to ensure the system can meet the required supply under a variety of conditions, Hydro utilizes two planning criteria:

1. the energy available on the system from hydraulic sources and Holyrood, assuming a low water year, has to be sufficient to meet all forecast energy requirements, and
2. the capacity available on the system has to be sufficient to ensure a Loss-of-Load-Hours ("LOLH", a measure of system reliability) of no more than 2.8 hours per year[8].

[7] Hydro's application at Haynes, page 37 states that their next major plant expansion will be planned for 2010; however more recent information indicates an apparent commitment by Hydro to a large (25 MW) wind project in the near future.
[8] Haynes, page 36.

The test year system conditions reflected in Haynes, Table 8, are an energy surplus of 202 GW.h (almost the entire energy output of Granite Canal) and an LOLH of 1.1 hours. In other words, the current 2004 test year generation and transmission complement (and the 2004 test year revenue requirement) reflects a plant in service that is in excess of what is considered by Hydro to be required to properly service the 2004 loads.

In assessing Hydro's application package, and normal regulatory approaches to rate review for utilities of this nature, it is useful to consider approaches used in jurisdictions with utilities in similar overall conditions. The key characteristics of Hydro's system and corporate structure provide for identification of useful Canadian benchmarks in regards to revenue requirement issues, cost of service and rate structures. It is apparent that two Canadian jurisdictions have direct comparability to Hydro's Island Interconnected system in both physical layout (non-interconnected grid, i.e., not connected to any system for importing/exporting power, utilizing a mixture of hydraulic and thermal generation) and corporate structure (Crown-owned vertically-integrated, rate-regulated utilities primarily serving wholesale and industrial customers, but with some retail customers in smaller centres) – the Yukon Energy Corporation and the Northwest Territories Power Corporation. In addition, a second contingent of utilities share corporate structure similarities (Crown-owned vertically integrated, rate-regulated dominant utilities in their jurisdiction) but are not non-interconnected. In this case, useful comparisons for specific issues can be made to Manitoba Hydro[9], BC Hydro[10] and New Brunswick Power[11]. Where relevant, the comparable practices from a number of these other jurisdictions are highlighted within this submission.

4.1 FOLLOW UP TO 2001 APPLICATION

The current application is filed in part to address the requirements of P.U. 7 (2002-2003) coming out of the 2001 proceeding. That 2001 application was the first general review of Hydro's rates in nearly a decade, and the first under the new regulatory regime established for Hydro during the mid-1990s. As was to be expected given the large number of issues to be addressed, a number of issues raised in that proceeding were not fully canvassed or finalized by the time of the Board's Order. It was however, a first step in establishing "a stable regulatory environment"[12], and, as noted by the Board in P.U. 7 (2002-2003) "completes the first phase in the process to effectively regulate NLH"[13]. Specifically, the Board stated "The Board notes as well that this decision sets out several directives which are designed to lay the groundwork for the next phase on regulating NLH"[14] and noted Hydro's actions to "place the Board

[9] Manitoba Hydro until recently was more directly comparable in that it serviced both wholesale and retail customers. With the recent purchase of Winnipeg Hydro, the utility has an increased retail customer load and no wholesale customers.

[10] BC Hydro's rate regulation has been essentially suspended for much of the 1990s until very recently. It is currently undergoing a re-regulation, but there is little of relevant value from that rate review process to date.

[11] New Brunswick Power is undergoing a major re-structuring that is proposed to eliminate the vertically integrated nature of the Crown utility.

[12] P.U. 7 (2002-2003) page 161.

[13] Page 163.

[14] Page 163.

on notice that financial targets and other measures contained in the Application are temporary and will be fully addressed in the next application, scheduled for 2003"[15].

It is apparent that this 2003 proceeding is properly viewed as both a follow-up to the more interim nature of the 2001 proceeding, and at the same time a review to focus on longer-term plans and practices for Hydro. This view is consistent with the general IC inclination to focus on long-term rate stability and predictability.

Most notably, the 2003 review contrasts with the 2001 review in the following ways:

- ***Energy Policy Review:*** At the time of the 2001 proceeding, the Government of Newfoundland and Labrador had announced an intention to conduct an "Energy Policy Review" but had not released any final conclusions regarding the review. A number of material questions from the 2001 proceeding were left unaddressed pending resolution of this Energy Policy Review process. Examples from the Board's Order P.U. 7 (2002-2003) include the demand-energy rate for NP, overlap of services between Hydro and NP, a long-term plan for Hydro's financial structure, and the Rural Deficit. The Energy Policy Review process appears to have progressed since 2001[16], and although apparently not completed, the scope of the review appears to have been clarified.

- ***Financial Targets:*** Hydro's 2001 Application reflected a proposal for return on equity that was predicated on two factors. One was an assertion by Hydro that it "must and should have a normal return on equity in due course"[17] and a determination by Hydro that in assessment of this ROE "the corporation should not be viewed differently than any other utility, operated as a commercial entity, whether it be investor-owned or, as in the case of Hydro, Crown-owned", which, it asserted, would entail an ROE in the range of 11 to 11.5%. The second reflected Hydro's intent to "assist in offsetting the rate impacts resulting from increased fuel costs" by proposing a 3% ROE. In the Board's Decision from that proceeding, in regards to the request by Hydro to be treated as an investor-owned utility, it noted "NLH's request is premature in the absence of a sound plan by NLH of how it will achieve financial targets similar to an investor owned utility"[18]. In the current proceeding, Hydro has applied for a full return on equity equal to that provided by the Board to the investor-owned utility NP. Presumably, Hydro has determined it has satisfied the Board's requirement that a long-term sound financial plan be in place before ROEs of this type will be approved.

- ***Rate Stabilization Plan:*** The 2001 proceeding contained a significant quantity of review and analysis of the Rate Stabilization Plan operated by Hydro. In P.U. 7 (2002-2003), the Board noted "the concerns and issues surrounding the RSP raised by the intervenors, especially the CA and the IC, in particular concerns about the complexity of the plan and the interactions of the various components of the plan, especially the inclusion of the load variation provision". The Board

[15] Page 21.

[16] A Report on the Energy Policy Review was released in March 2002 along with a Stakeholder Consultation document, and Summary of Public Responses was provided in August 2002.

[17] Wells, 2001 Application, page 15.

[18] Page 42.

concluded that the "design and elements of the existing plan should be reviewed"[19]. At this time, the revised "new RSP" has been in operation for nearly a year and the first collection of these amounts is set to begin at January 1, 2004. It is apparent that the RSP has become an increasing source of rate instability, resulting in nearly half the 2004 rate increases to NP and more than half the increases to IC. The current proceeding will be required to review and provide confirmation of the balances in the New RSP, as well as address the appropriate means for collection of these balances in a stable way going forward.

- ***Interim Allocation of Certain Assets:*** The 2001 proceeding reviewed the cost of service allocation of a number of assets, primarily the Great Northern Peninsula transmission line (but also GNP generation, Burin Peninsula transmission, and Doyles-Port aux Basques transmission). In P.U. 7 (2002-2003), the Board concluded that it was "not prepared to confirm the change in assignment from NLH rural to common" proposed by Hydro. The Board required Hydro to undertake a study of the value of these assets to the grid in determining the proper cost of service allocation. In the present proceeding, the review by Hydro has been completed and filed, and final cost allocations for these various assets is required.

Many of the issues to be addressed in this proceeding reflect an opportunity to make incremental improvements over the 2001 approaches. As noted above, the Hydro's physical Island Interconnected infrastructure now reflects a stable plant that can service the needs of the grid beyond the short-term (until approximately 2010). Similarly, long-term and durable solutions to outstanding problems or details identified in this submission (i.e., cost of service, rate design, RSP) are required to likewise bring longer-term regulatory and rate stability to the system.

[19] Page 84. The Board's Decision notes that the Board would commission this study. We have not had the opportunity to review the results of any such study undertaken.

5.0 REVENUE REQUIREMENT AND OVERALL RATE INCREASES

The overall revenue requirement and level of rate increases requested are outlined by Hydro as "primarily driven by" increased costs associated with new sources of supply[20] and indicate that this will have the "largest single impact on rates for Hydro's customers arising from this application"[21]. Hydro indicates that the following factors impose material impacts on revenue requirement:

- power purchase costs, including new Power Purchase Agreements (PPAs) involving new facilities), will increase in 2004 by $18 million compared to the 2002 test year; and
- Granite Canal will increase costs by $11 million[22].

The addition of the new plant (i.e., Granite Canal and new PPAs) results in 87.3 MW of new capacity and 461.2 GW.h of new energy. Hydro also notes that other cost increases are putting upward pressure on revenue requirement in 2004, such as return on equity, interest costs and operating costs.

Looking specifically at the Island Interconnected system, there has been a material shift in revenue requirement by replacing bulk power costs that had previously been reflected primarily as #6 fuel[23] with costs that primarily arise as purchased power for the new PPAs, and return on debt, equity and depreciation for Granite Canal. As reviewed below, however, only 15% of the requested rate revenue increase for the Island Interconnected system reflects the new Granite Canal supply, the new PPAs and load growth since 2002. A further 35% of this increase reflects other increased energy generation supply costs, e.g. increased costs for fuel (primarily #6) and other purchased power costs.

It is also apparent that about 50% of the Island Interconnected rate increase requested does not relate in any way to Granite Canal, the new PPAs, the costs to supply load growth since 2002, or any other fuel cost or purchased power cost matters. As reviewed below in detail, this component of the revenue requirement increase is instead comprised of material increases in operating and maintenance expenses (7.9% over 2002), depreciation (6.7% outside of Granite Canal), interest costs (6.5% outside of Granite Canal) and return on equity (125% outside of Granite Canal). Within the context of only a two year interval since Hydro's last review, and record low inflation and debt financing rates, these increases suggest that it is relevant for the Board to assess the extent to which more rigorous cost control, capital spending restraint and productivity improvements are required within the utility.

The overall changes requested to the revenue requirement are reviewed below. Associated issues related specifically to the allocation of revenue requirements to different customer classes through cost-of service (COS) allocations, proposed rates and the RSP are addressed in subsequent sections of this testimony.

[20] Wells, page 1.
[21] Wells, page 2.
[22] Wells, page 2.
[23] See IC-204 and IC-205.

5.1 OVERVIEW OF PROPOSED REVENUE REQUIREMENT CHANGES

The proposed 2004 Hydro revenue requirement set out in Roberts Schedule II (1st revision) is $371.841 million. This is an increase of $54.781 million from the approved 2002 test year revenue requirement of $317.060 million (also shown in Roberts, Schedule II).

Looking specifically at the Island Interconnected system, the revenue requirement is more readily determined from the cost of service study. In particular, the respective cost of service studies and rate revenue schedules from 2002 and 2004 (1st Revision) reflect the following information for the Island Interconnected system:

Table 5.1: Island Interconnected Revenue Requirement and Rate Increase Requirement

	2002 Final	2004 Proposed	*Change*
Revenue Requirement[24]	$277,077,901	$327,951,968	*$50,874,067*
Rural Deficit and Revenue Credit[25]	$16,137,310	$17,317,373	*$1,180,063*
Revenue to be collected through rates[26]	$293,215,211	$345,269,341	*$52,054,130*
Revenues at approved 2002 rates[27]	$293,215,211	$305,545,600	*$12,330,389*
Shortfall	$0	$39,723,741	*$39,723,741*

The summary table above indicates that the requirement for higher rates to the Island Interconnected system reflects a need for $39.723 million in additional revenues compared to existing rates in place. We note that the revenue requirement above does not reflect an additional $5.97 million in costs (largely fuel) that would arise if the Board adopts SGE Acres recommendation regarding long-term normal hydraulic plant output[28].

In assessing the reasonableness of the Island Interconnected revenue requirement increases proposed by Hydro, there are three major items that are not readily isolated from the information in Roberts, Schedule II (or the cost of service study, page 1):

- ***Load growth:*** There has been a fairly material load growth on the Island Interconnected system by 2004 compared to the 2002 forecast, leading to a nearly 4.2% increase in the revenues Hydro receives at the rates currently in place (or about $12.33 million as noted in the table above).

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[24] Page 1 of Schedule G of Hydro's August 2002 filing in response to P.U. 7 (2002-2003) and P.U. 21 (2002-2003) for 2002 figures. Exhibit RDG-1 (1st revision) for 2004 figures.

[25] The additional amounts to be collected from overall Island Interconnected rates to finance the non-Island Interconnected Rural Deficit (i.e. reflects net impact of higher rates for NP to finance Rural Deficit and lower rates for Rural Interconnected as a result of Rural Rates policy).

[26] Table 2 of Hydro's August 2002 filing in response to P.U. 7 (2002-2003) and P.U. 21 (2002-2003) for 2002 figures. Table 4 of Banfield (1st revision) for 2004 figures. Includes rural deficit allocations, and excludes wheeling revenues.

[27] Table 2 of Hydro's August 2002 filing in response to P.U. 7 (2002-2003) and P.U. 21 (2002-2003) for 2002 figures. Table 4 of Banfield (1st revision) for 2004 figures. Includes rural deficit allocations, and excludes wheeling revenues.

[28] Haynes, page 30.

Associated with this increased load are costs to supply the load, particularly fuel, but also other variable costs.

- ***Sources of Supply:*** Two new sources of supply have been introduced since the 2002 test year:

    1. Granite Canal and
    2. the two new Power Purchase Agreements (PPAs).

    These new bulk power sources result in a shift in Hydro's costs compared to 2002. These sources of supply represent energy that would otherwise, in all likelihood, have had to be generated by fuel at Holyrood[29]. In other words, the comparison of 2004 revenue requirement to 2002 revenue requirement will indicate a substantial shift in costs primarily from #6 fuel and interruptible capacity purchases[30], to such items as Purchase Power costs (for the PPAs), and Depreciation, Interest and Return on Equity for Granite Canal.

A review of the 2004 proposed revenue requirement is most usefully focused on assessing Hydro's 2004 costs in terms of changes from the approved 2002 revenue requirement in two areas: changes related to the three major bulk power changes noted above, as opposed to changes related to other factors.

In determining the specific impact from each of the above three major bulk power factors, it is assumed that, in the absence of Granite Canal and the new PPAs, this generation would have been provided by Holyrood. Likewise, it is assumed that had the load growth not occurred, the reduced generation requirement would have been reflected in reduced generation required from Holyrood. Each of these assumptions is consistent with the Island Interconnected system operation; that is, load growth is basically supplied by increased generation at Holyrood[31], and new sources of supply do result in comparable quantities of generation avoided at Holyrood[32].

In assessing the degree to which the Island Interconnected revenue requirement and rate increase requirement has been driven by these three major factors, the following specific impacts have been noted:

[29] IC-204 and IC-205.

[30] Hydro asserts in IC-194 that the acquisition of new power from Granite Canal and the PPAs eliminates the need for the Interruptible B contract, which is reflected in the proposed revenue requirement as a $1.297 million savings compared to the 2002 test year.

[31] Consider, for example, the current treatment of load in the RSP, which assume all load variations result in equal variations in the quantity of thermal generation from Holyrood.

[32] IC-204 and IC-205.

- ***Granite Canal*[33]*:*** The in-service of Granite Canal by 2004 results in 224.0 GW.h of energy being produced by hydraulic generation rather than Holyrood[34]. The construction of Granite Canal has resulted in test year costs of $11.84 million per IC-251 (depreciation, return on equity and debt, and new hydraulic O&M), but savings of $10.483 million of Holyrood fuel and $1.008 million of Holyrood variable O&M[35]. Hydro has also proposed to eliminate the Interruptible B program as a result of the new generation, which results in an additional saving of $1.297 million in purchased power costs. The net impact of Granite Canal on the 2004 test year revenue requirement is a decrease of $0.948 million.

- ***PPAs*[36]*:*** The new Power Purchase Agreements result in additional costs to Hydro of $18.367 million in the 2004 test year for 237.2 GW.h of electricity. The Holyrood fuel and variable O&M savings as a result of these PPAs $11.101 million and $1.069 million respectively. The net impact of the PPAs in the test year is an increased 2004 revenue requirement of $6.197 million.

- ***Load growth of 254.2 GW.h*[37]*:*** The growth in load since the 2002 test year has driven a material increase in the #6 fuel and variable Holyrood O&M. The 2002 final cost of service indicates MW.h at generation of 6,483,046[38] compared to a 2004 MW.h at generation of 6,737,249[39], reflecting a load growth of 254.2 GW.h. Using the variable Holyrood costs from NP-130, this equates to an increased fuel cost to the Island Interconnected system of $11.90 million for fuel plus $1.14 million for variable O&M, or a total increased cost of $13.04 million.

A calculation of the portion of the 2004 Island Interconnected revenue requirement and rate increase requirement that is driven by the above factors as opposed to other matters is provided in Table 5.2.

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[33] Assuming the same quantity of energy had been supplied by Holyrood at the variable fuel and O&M costs outlined in NP-130. Assuming also that this would have eliminated Hydro's ability to propose an end to the Interruptible B program. We note from IC-374 that the variable O&M numbers in NP-130 are Hydro's planning estimate for costs (or savings) arising from variation in Holyrood generation for such items as system equipment maintenance and fuel additives. Hydro cautions this is not a short-term number. However, there are clearly savings from reduced Holyrood generation (or additional costs from increased Holyrood generation) and the 0.45 cents/kW.h is the best estimate available. It is also somewhat below the additional variable costs that IC face for non-firm purchases over and above the full costs of Holyrood fuel (which is a 10% premium over the Holyrood fuel costs of a forecast 4.68 cents/kW.h).
[34] IC-204 and IC-205.
[35] Using variable Holyrood fuel and O&M figures from NP-130.
[36] Assuming the same quantity of energy had been supplied by Holyrood at the variable fuel and O&M costs outlined in NP-130.
[37] Assuming all increases in quantity of bulk energy required from 2002 to 2004 were met by increases Holyrood generation at the variable fuel and O&M costs outlined in NP-130.
[38] Schedule G of Hydro's August 2002 filing in response to P.U. 7 (2002-2003) and P.U. 21 (2002-2003), Schedule 3.1A column 4.
[39] Per RDG-1 (Rev.1) Schedule 3.1A column 4.

Table 5.2: 2004 Island Interconnected Revenue Requirement versus Approved 2002 Revenue Requirement – Impact of Major Bulk Power Items versus other Factors

		A	B	C	D	E	F	G	H	I	J	K
				(A-B)	*Major Bulk Power Changes*						**sum (D:I)**	**(C-J)**
	($000)	2004 (Rev.1) rev. req.[40]	2002 approved revenue req.[41]	*difference*	*Granite Canal[42]*		*PPAs[43]*		*load growth[44]*		*difference – Major Items*	*difference – other*
					costs	*benefits*	*costs*	*benefits*	*costs*	*benefits*		
1	OM&A[45]	72,461	67,977	*4,484*	*30*	*(1008)*		*(1,069)*	*1,144*		*(903)*	*5,387*
2	#6 Fuel	84,820	81,662	*3,158*		*(10,483)*		*(11,101)*	*11,897*		*(9687)*	*12,845*
3	Diesel Fuel	55	39	*16*								*16*
4	Gas Turbine Fuel	265	351	*(86)*								*(86)*
5	Power Purchases	29,928	11,773	*18,155*		*(1,297)*	*18,367*				*17,070*	*1,085*
6	Depreciation	27,885	25,649	*2,236*	*510*						*510*	*1,726*
7	Expense Credits	(1,406)	(885)	*(521)*								*(521)*
8	Subtotal Expenses	214,007	186,566	*27,442*	*540*	*(12,788)*	*18,367*	*(12,170)*	*13,041*		*6,990*	*20,452*
9	Disposal Gain/Loss	515	875	*(360)*								*(360)*
10	Subtotal ex. Return	214,523	187,441	*27,082*	*540*	*(12,788)*	*18,367*	*(12,170)*	*13,041*		*6,990*	*20,092*
11	Return on Debt	98,968	83,978	*14,990*	*9,540*						*9,540*	*5,450*
12	Return on Equity	14,462	5,659	*8,803*	*1,760*						*1,760*	*7,043*
13	Total Rev. Req.	327,952	277,078	*50,875*	*11,840*	*(12,788)*	*18.367*	*(12,170)*	*13,041*		*18,290*	*32,585*
14	Rural Deficit	17,317	16,137	*1,180*								*1,180*
15	Total	345,269	293,215	*52,055*	*11,840*	*(12,788)*	*18,367*	*(12,170)*	*13,041*		*18,290*	*33,765*
16	Rev. at exist. rates	305,546	293,215	*12,331*						*12,331*	*12,331*	
17	Rate incr. req.	39,723	0	*39,723*						*(12,331)*	*5,959*	*33,765*

[40] From Exhibit RDG-1 (Rev.1), Schedule 1.1.

[41] From the final 2002 cost of service, Schedule G of Hydro's August 2002 filing in response to P.U. 7 (2002-2003) and P.U. 21 (2002-2003).

[42] The Granite Canal costs are per IC-251. It is not clear if the Return on Equity and Return on Debt components of IC-251 reflect RDG-1 or RDG-1 (Rev. 1). The above assumes the figures include the Revision 1 changes (the Return on Equity and Return on Debt figures in IC-251 do not exactly appear to reconcile with the $134,550,000 total capital cost applied to the WACC using either the original WACC or the Revision 1 WACC). The difference is likely to be quite small.

[43] PPA costs are per Haynes, Schedule X.

[44] Reflects 254.2 GW.h at the variable cost rates set out in NP-130.

[45] Operating Maintenance and Administration.

Table 5.2 details the $39.723 million Island Interconnected rate increase requirement from Table 5.1. This reflects a required $5.959 million rate increase to address the impact of three major bulk power supply developments: Granite Canal, the new PPAs and the load growth since 2002. The remaining $33,765 million Island Interconnected rate increase requirement reflects the following notable components:

- ***Operating, maintenance and administration expenses:*** The final approved 2002 operating, maintenance and administration expenses were $67.977 million. Proposed 2004 test year expenses are $72.461 million, an increase of $4.484 million. However, the proposed $4.484 million increase fails to reflect material savings that should arise in 2004 due to the new generations sources:
    - The in-service of Granite Canal should have increased hydraulic O&M by $0.03 million but reduced Holyrood O&M by approximately $1.008 million for reduced Holyrood output, for a net benefit to 2004 of $0.978 million.
    - The PPAs should have reduced Holyrood O&M by approximately $1.069 million
    - However, the load growth since 2002 should result in additional Holyrood O&M of approximately $1.144 million

  Net of the above amounts, the 2004 proposed operating, maintenance and administration expenses reflect an increase of $5.387 million or about 7.9% over 2002 levels.

- ***Fuel and Purchased Power:*** The 2004 test year fuel costs reflect an increase of $3.088 million over 2002 levels, primarily #6 fuel. Purchased power expense is forecast to increase $18.155 million over 2002 levels. The three major items reflect a likely saving of about $9.687 million in #6 in 2004 and account for $17.070 million of the purchased power expense increase. Absent these three items, increased costs for fuel and purchased power total $13.860 million, or 14.8%, compared to 2002.

- ***Depreciation expense:*** The 2004 depreciation expense of $27.885 million is a $2.236 million increase over 2002 levels. Granite Canal accounts for $0.510 million of the increase depreciation expense, leaving $1.726 million (a 6.7% over 2002 levels) related to other items.

- ***Return on Debt and Equity:*** The 2004 proposed revenue requirement reflects an increased cost for debt and equity of $14.990 million and $8.803 million respectively compared to 2002. Of this amount $9.540 million and $1.760 million relates to costs of debt and equity for the Granite Canal projects. Absent this one project, Hydro’s costs have increased since 2002 by $5.450 million for debt and $7.043 million for equity, reflecting increases of 6.5% and 125% respectively.

- ***Rural Deficit:*** The 2002 Island Interconnected rates reflected $16.137 million in excess of measured Island Interconnected costs related to the Rural Deficit from other systems. The Rural Deficit from other systems allocated to the Island Interconnected system has increased by $1.180 million in the 2004 application compared to 2002, up to $17.317 million.

In summary, Table 5.2 indicates that $5.959 million of the requested $39.723 million Island Interconnected rate increase (15%) is due to Granite Canal, the PPAs and load growth since 2002. This is in sharp contrast to Hydro's assertion that these items are the primary drivers of the rate increase requested. An additional $13.860 million (35%) reflects effectively increased costs for fuel (primarily #6) and other purchased power costs.

The remaining 50% of the Island Interconnected rate increase requested effectively reflects increased costs for operating and maintenance expenses, depreciation (outside of Granite Canal), return on debt and equity (outside of Granite Canal) and increased allocation of the Rural Deficit, offset by some small improvement in expense credits and reduced loss on disposals. These increases are in contrast to the summary at Wells, pages 1-3.

The material effective increases in each of these categories since 2002 (excluding Granite Canal, the new PPAs and the impacts of load growth noted above), in particular operating and maintenance expenses up 7.9%, depreciation up 6.7%, return on debt up 6.5% and return on equity up 125%, reflect the need for a more thorough assessment of Hydro's operating costs and capital investment pace as they relate to rates.

5.2 RETURN ON EQUITY

Hydro's revised application reflects a proposed return on equity of 9.75%, down from the May application proposal of 10.75%. Per Roberts, Schedule II (Rev. 1) this reflects a total Margin of $19.384 million, down from the May application of $21.179 million. As noted above, the increase in return on equity is a material component of the requested increase to Island Interconnected customers in 2004 (over $7 million of the approximately $40 million rate increase proposed excluding impacts from Granite Canal).

Hydro has also indicated that the Margin proposed in the May 2003 application of $21.179 million results in a regulated Interest Coverage of 1.23[46]. Hydro has not calculated the interest coverage for the revised ROE proposal, but based on the same interest cost balance it would approximate 1.21[47].

In the 2002 proceeding, Hydro requested an ROE of 3%, which was consistent with a 1.08 times interest coverage ratio (Hall, page 10). This was consistent with the interest coverage ratio approved in 1992[48] of 1.08 which had not been adjusted by the Board between 1992 and 2002. During that time, Hydro had reported that they had not had any difficulty arranging debt, or to have had any negative impact on the Province's credit rating[49].

[46] Per NP-2. This is based on $21.175 million margin on an interest cost of $92.764 million.
[47] This is based on $19.384 million margin on an interest cost of $92.764 million.
[48] Board's 1992 Report on Hydro's Rate Referral, page 111.
[49] See, for example, the response to IC-65 from the 2001 Application.

Hydro's proposals to the Board in regards to the level of Margin or ROE have been notably consistent for more than the last decade, and have received a consistent response from the Board, as follows:

- ***1990 Application[50]:*** Hydro indicated a debt:equity ratio of 83:17 in 1989, and indicated a target debt:equity ratio of 75:25. Hydro also requested an interest coverage of 1.15[51]. The Board approved a 1.03 interest coverage ratio for Hydro, and recommended that Hydro move slowly towards a goal of a debt:equity ratio of 80:20.

- ***1992 Application:*** Hydro proposed an interest coverage ratio of 1.10[52], but requested long-term guidance in excess of the interest coverage target proposed for that year, to confirm the long-term target of 1.15 to 1.25. Hydro also presented financial experts to support a debt:equity goal of 80:20, and ***indicated*** that its debt:equity had deteriorated since 1990 from 82:18 to 84:16. The Board allowed a 1.08 interest coverage and denied the request for further guidance[53]. Specifically, the Board again directed Hydro to move slowly towards attainment of the 80:20 debt:equity target.

- ***2001 Application:*** Hydro proposed a 3% ROE, which was equal to a 1.08 interest ***coverage***. Hydro's Application requested guidance that a "normal return on equity" similar to an investor-owned utility would be applied by the Board "in due course"[54]. The reported test year debt:equity ratio was 83:17[55].

  The Board, in P.U. 7 (2002-2003) confirmed the 3% ROE (1.08 interest coverage) for the 2002 test year. The Board also stated that "a determination on full return on rate base can be made based on a future request and in light of economic and capital market conditions prevailing at the time"[56]. Further, the Board concluded that "there is no statutory or evidentiary foundation for regulating NLH similar to an investor owned utility"[57] and concluded that "NLH's request is premature in the absence of a sound plan by NLH of how it will achieve financial targets similar to an investor owned utility"[58]. The Board re-confirmed the short-term target debt:equity ratio of 80:20.

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[50] Board's 1990 Report on Hydro's Rate Referral, pages 54-69.
[51] Board's 1990 Report on Hydro's Rate Referral, page 61.
[52] Board's 1992 Report on Hydro's Rate Referral, page 74.
[53] Board's 1992 Report on Hydro's Rate Referral, page 111.
[54] Wells, 2001 Application, page 15.
[55] Hall, 2001 Application, page 12.
[56] P.U. 7 (2002-2003), page 44.
[57] P.U. 7 (2002-2003), page 41.
[58] P.U. 7 (2002-2003), page 42. A more specific reference at pages 161-162 of the Decision indicates:

> "Until such time as NLH brings forward its comprehensive financial goals in an application, the Board is not in a position to deal with them. As demonstrated following the review of the evidence in relation to NLH's debt/equity ratio, … the Board notes Government's guarantee remains in place which will ensure NLH the same access to the capital markets that it has traditionally maintained.

The most notable conclusion of the Board in P.U. 7 (2002-2003) in regards to this issue arises at page 40, where the Board notes:

> NLH's position on this issue, however, is developed primarily as a consequence of the evidence and its interpretation of *EPCA*, Section 3(a)(iii) wherein it is the policy of the province … to enable NLH *'to earn a just and reasonable rate of return as constituted under the Public Utilities Act so that it is able to achieve and maintain a sound credit rating in the financial markets of the world'.*
>
> The Board notes NLH's credit rating, as attested to earlier, is dependent on the standing provincial policy which currently guarantees NLH's debt. (P.U. 7 (2002-2003) page 40)

Accordingly, it is not readily apparent how one draws a conclusion that the legislation leads to any required change in debt/equity ratio targets or in required margin/ROE - if anything, Hydro's current Application as well as other available evidence suggest the adequacy of the targets used for Hydro since 1990[59]. We also note that the current application maintains the requirement to collect via rates $14.453 million related to the debt guarantee fee to the Government of Newfoundland and Labrador[60].

In the current filing, there is no evidence that Hydro has addressed the Board's requirements that, prior to treatment as an investor-owned utility (including receiving a Return on Equity comparable to an investor-owned utility), Hydro must present to the Board a sound plan of how it will achieve suitable financial targets[61]. Notably, the 2001 proceeding included evidence that Hydro's 5 year plan was to

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> NLH's future intention to operate on a standalone basis similar to an investor-owned utility is entirely within the hands of NLH's management."

59 Addressing the credit rating issue directly, the response to IC-65 from the 2001 Application states:

> "It is impossible to conclude with any degree of precision at what level Hydro's debt ratio would negatively impact on the Province's credit rating. Based on the experience of other Crown Corporations, debt ratios of up to 90% in the short-term have been maintained without negative impact on the Province's credit rating. The debt rating agencies would tend to focus on the utility's ability to fully recover its debt service costs without running the risk of having to turn to the Provincial government for assistance. Stated alternatively, as long as Hydro's debt is guaranteed by the Province, the debt rating agencies' concerns are with assurance that Hydro is self-sufficient, i.e. Hydro will cover its total out-of-pocket costs, including interest expenses, from its own revenues, without risk of a short-fall."

60 Roberts, Schedule VII.

61 We also note that there remain a number of sections in the legislation that provide for terms that are otherwise inconsistent with the regulatory framework for investor-owned utilities in the Province and which reduce the discretion of the Board with respect to material matters, including: restriction on the Board in setting Hydro's rate base in section 17(2) of the Hydro Act; restriction on the Board regarding review the liabilities of the Corporation under the Hydro Pension Plan and determining whether such expenses are reasonable and prudent; restrictions on the Board regarding review of foreign currency losses and determining whether such expenses are reasonable and prudent; restrictions on the Board regarding review of ongoing amounts paid under contracts to non-utility generators (from Hydro's Request for Proposals 92-195) and determining whether such expenses are reasonable and

achieve an 82:18 debt:equity ratio by 2005[62]. In contrast, the current five year plan filed in CA-3 indicates a projected 2005 debt:equity of 85:15 progressing to 84:16 by 2007.

Hydro has filed evidence in Wells, Schedule II that maintaining a 75% payout ratio reflecting the current Hydro policy (and as assumed in the application per PUB-87) will not allow it to achieve a debt:equity ratio below 84:16 by 2008 *even if the 10.75% ROE was approved*. As a result, Hydro has proposed a 50% payout ratio to the Government of Newfoundland and Labrador[63]; however, this payout level, combined with a 10.75% ROE, will only achieve an 81:19 debt:equity by 2008. Finally, we note that continuation of a 3% ROE will make no material difference to Hydro's ability to progress on debt:equity levels by 2008 if the 75% payout is maintained (if a 50% payout were adopted, the increase to a 10.75% ROE would allow Hydro to progress to 81:19 by 2008, compared to 83:17 were the current 3% level to be maintained – it is not apparent what a 9.75% ROE would do to these calculations[64]).

Finally, all of the above analysis fails to reflect that Hydro's system planning notes a requirement for 600 GW.h of new energy supply by 2012 (nearly three times the size of Granite Canal)[65]. Capital spending to address the required additions will in all likelihood require substantial new debt issuances, which will only further deteriorate Hydro's debt equity ratio in the period beyond 2008[66]. Hydro has refused to comment on matters related to major capital spending commitments in the 6-10 year timeframe[67].

It is apparent that Hydro and the Board have similarly determined that progress towards an 80:20 debt:equity ratio has been merited since at least 1990. However, the record indicates that all efforts to date by Hydro and the Board have not allowed Hydro to make progress on this matter, and in fact Hydro's debt ratio has deteriorated from the 1990 levels of 83%. Even the most optimistic plans of Hydro (a 10.75% ROE and a reduced payout ratio of 50%) only reflect progress to an 81:19 level by 2008, just prior to a period of expected cash requirements for major investment in generation infrastructure, which would likely lead to deterioration in this ratio.

There does not appear to be a reasonable basis at this time for Hydro's ratepayers to be faced with higher rates to reflect progression towards treating Hydro as equivalent to an investor-owned utility. Progression in other areas such as a sound plan for financial targets, as required by the Board, does not

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prudent; restrictions on the Board from setting amortization periods in regards to the Hydro Pension Plan expenses and the foreign exchange losses; and, substantial utility operations of Hydro remain "non-regulated" even those directly connected to transmission systems servicing regulated customers.

[62] This is quoted at P.U. 7 (2002-2003), page 42.

[63] Wells, Schedule II, discussion paper page 6 of 7.

[64] The material filed by Hydro on this matter has not been updated to reflect the revised 9.75% ROE proposal.

[65] Hydro's five-year capital plans also reflect no capital expenditures on gas turbines, for example (IC-280) despite a lengthy discussion at Haynes, page 8-9 about the age and condition of these units.

[66] The exception is if these projects are either funded by others (Hydro has declined to comment, for example, on any role for the Government of Canada in transmission interconnections to Labrador (IC-255)) or are solely served by purchased power arrangements, with all developments being undertaken by parties other than Hydro.

[67] See, for example, IC-373, IC-387, IC-388, and IC-389.

appear to have been addressed. In addition, the continued provision of the government guarantee, along with the continued payment by ratepayers of nearly $15 million for this fee, appears to satisfy the requirements of the legislation that the Board provide Hydro with the ability to maintain a sound credit rating.

6.0 COST OF SERVICE

Hydro has applied for primary firm rates based on an embedded cost/cost of service based approach, consistent with previous practice in Newfoundland and most other Canadian jurisdictions with regulated power rates. Hydro has also applied for certain non-firm industrial power rates which are based on incremental cost principles.

As noted by Greneman (page 1), the application of normal utility cost and rate principles to the Newfoundland Hydro system has followed the industry standard embedded cost of service approach. In developing the overall revenue requirement that is being sought from each group of customers, Hydro has used a cost-of-service (COS) study with the output provided in Exhibit RDG-1. This study seeks to allocate among the various customer classes Hydro's full revenue requirement.

With a few material exceptions, the overall COS study methodology filed by Hydro appears to be generally consistent with accepted utility regulatory practice in other jurisdictions and the directions of the Board in P.U. 7 (2002-2003), and to accurately track the costs of Hydro's system and the customer classes to which these costs relate.

Concerns arise because Hydro's cost of service study, and the calculation of the revenue requirements to be allocated to each customer class, insufficiently recognizes the current Island Interconnected overall peak capacity supply and configuration in determining which customers benefit from various capacity resources. The current treatment results in two notable issues:

1. **Assignment of certain radial transmission and generation assets as being of benefit to all Island Interconnected customers:** Hydro provides three radial transmission lines (non-230 kV) which service both customer loads and interconnect relatively small generation plant. Hydro now proposes to assign the costs of diesel generation on one such system (the GNP) to all customers and to assign the transmission line itself on another of the systems (the Burin Peninsula) as similarly of common benefit. Each of these assignments appears to be inappropriate, and reflect a cost allocation that is not consistent with the relative benefits that these assets provide to the various customer classes.

2. **The provision of a "generation credit" to Newfoundland Power:** Hydro's cost of service study proposes to provide Newfoundland Power with a "credit" for the thermal generation capacity that Newfoundland Power maintains on the Island Interconnected system. This treatment results in two material changes that shift costs away from NP. One is to reduce NP's forecast peak to in essence give them credit for generation that they do not expect to use. The other is to artificially adjust downward the properly measured and forecast system load factor that Hydro is required to supply to reflect the same factor. Based on normal cost of service

practice in Newfoundland, there is no proper basis to make such an adjustment for either NP's peak demand or the system load factor.

This section reviews the relative changes in rates proposed for each group of customers, the impact of the current Island Interconnected supply situation on the proper application of cost of service principles, and the resulting costs of demand to various customers on the Island Interconnected system. A review of the specific issues with respect to radial transmission systems, the Newfoundland Power generation credit, and NP's Load Forecast and Load Factor follows.

6.1 RELATIVE CHANGES IN RATES

A summary of the proposed 2004 test year average rate increases as presented in the Application, in percentage terms, for each of the customer classes is provided in Table 6.1 below:

Table 6.1 – Base Rate and RSP Changes Proposed in the August 12 Application

Customer Class	Firm Base Rates	RSP[68]	Overall Increase
NP[69]	12.8%	11.3%[70]	24.1%
IC[71]	12.0%[72]	16.4%[73]	28.4%
Rural Island Interconnected[74]	7.4%[75]	NA	NA
Labrador Interconnected	7.2%[76]	NA	NA
Isolated Systems	7.4%[77]	NA	NA

68 RSP rate increases are projected based on 2004 forecast balances in the RSP. NP rate increases at July 1, 2004, IC at January 1 , 2004 per Banfield, 1st revision, page 15-16.

69 All increases are measured on an annualized basis as a percentage of total existing firm power rates. For NP the amount for 2004 at existing rates is $227,065,646 from Banfield Table 4 (1st revision) plus NP projected RSP at December 31, 2003 at 0.324 cents/kW.h times 4,741 GW.h yields a total annualized revenue of $242,427,782.

70 July 1, 2004 projected NP RSP rate of 0.902 cents/kW.h compared to December 31, 2003 RSP rate of 0.324 cents/kW.h is an increase of 0.578 cents/kW.h (per Banfield, Table 6 (1st revision). On a total forecast 2004 firm sales to NP of 4,741,400 MW.h yields an annualized increased of $27,405,292.

71 All increases are measured on an annualized basis as a percentage of total firm power rates. For IC the amount is $45,823,492 from Banfield Table 4 (1st revision) plus IC RSP of 0.423 cents/kW.h times 1,367 GW.h yields a total annualized revenue of $51,609,286.

72 The IC base rates for wheeling service are forecast to decrease by 4.7%.

73 January 1, 2004 projected IC RSP rate of 1.04 cents/kW.h compared to December 31, 2003 RSP rate of 0.423 cents/kW.h is an increase of 0.617 cents/kW.h. On a total forecast 2004 firm sales of 1,367,800 MW.h yields an annualized increased of $8,439,326.

74 Firm rate increases are measured on an annualized basis as a percentage of existing rates.

75 The 7.4% increase is based on the calculated NP increase to retail customers, as rural interconnected customers pay the same rates as NP customers.

76 The Labrador interconnected rate changes vary considerably by customer class and location.

77 Rates for government customers are requested to decrease by 12.6% on the isolated systems.

The rate increases requested by Hydro reflect an onerous impact on customers[78]. It is also notable that, based on the figures above, about half of the increase for NP, and in excess of half for IC, are coming from the RSP increases. In addition, the increases reflect a cost of service analysis that fails to incorporate at least two additional proposals Hydro has put forward: to lower the average hydraulic generation estimate (and raise the total fuel cost in the 2004 revenue requirement) to reflect "the longest reliable reference inflow sequence"[79], and to assign the GNP generation assets as being of common benefit to all Island Interconnected customers, not just Hydro Rural. Adoption of these two proposals would increase the rate increases required from IC and NP.

Rate stability and 'smoothing' objectives indicate the need to assess the Application in the context of its implications for future years. Hydro has provided information extending the NP and IC rate increases beyond 2004 to 2007, based on current forecasts and the impacts flowing from ongoing annual RSP adjustments, as follows (in cents/kW.h)[80].

Table 6.2 – Average Energy Rates (including RSP) from CA-3 (cents/kW.h)

Customer Class	**2003**	**2004**	*%*	**2005**	*%*	**2006**	*%*	**2007**	*%*
NP	5.04	6.03	*19.6%*[81]	6.36	*5.5%*	6.29	*(1.1%)*	6.07	*(3.5%)*
IC	3.80	4.85	*27.6%*[82]	4.98	*2.7%*	4.44	*(10.8%)*	4.60	*3.6%*

It is apparent that rates over the period to 2007 reflect a substantial increase in collections from customers in the near term, followed by a general reduction over the 2005 to 2007 period. The same table in CA-3 indicates the projected change in base rates is very smooth (generally less than 2% annually) and slowly upward trending following the 2004 run-up. The rate instability over this period is clearly being introduced by the Rate Stabilization Plan itself. In this regard, a complete review of the rate impacts stemming from the application need to consider both base rate and RSP impacts.

Specific COS and rate design issues related to the 2002 test year are noted below, focusing on matters relevant to Island IC ratepayers.

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[78] The rate increases calculated above reflect Hydro's filed cost of service study – Hydro also endorses SGE Acres recommendation to use a revised long-term hydraulic plant output average, which would increase the revenue requirement a further $5.97 million, and result in an additional 2.1% rate increase for NP and 2.7% for IC, per Haynes, page 30.

[79] Haynes, page 28.

[80] See response to CA-3.

[81] This appears to reflect an average rate throughout the year, using a blended RSP adjustment to reflect the July 1 rate change.

[82] The 4.85 cents/kW.h for 2004 appears to reflect the numbers from Banfield, Table 4. This equates to the sum of $52,018,920 firm plus $14,225,120 RSP for a total $66,244,040. On a load of 1,367,800 MW.h, this yields an average rate of 4.843 cents/kW.h. However, the 2003 value appears slightly high using the same approach (the approach would yield an average rate of 3.773 cents/kW.h). The difference may relate in some way to non-firm power.

6.2 IMPACT OF CURRENT SUPPLY CONDITIONS ON COST OF SERVICE APPROACH

The relative rate increases that have been requested from the various classes are calculated using a cost-of-service methodology that is very similar to the approved approach from the 2001 application. Hydro has proposed a number of minor variations, such as:

1. Hydro Place[83] is now charged to all systems, rather than just the Island Interconnected system.
2. General Plant is now charged based largely on labour ratios, rather than plant, which more accurately reflects the role and function of general plant.
3. Municipal taxes are directly recognized as being revenue related for all retail customers.
4. PUB costs are directly recognized as being revenue related for all customers.

The impact of the above four changes is summarized in CA-130. Each of the changes appears to be reasonable and consistent with normal cost of service principles.

Consideration of issues related to cost of service requires attention to the material changes that have occurred in the Island Interconnected System since Hydro's Cost of Service was last reviewed. In particular, we note the following comparison of the system capabilities:

Table 6.3 – 2002 and 2004 Capacity and Energy Availability (LOLH and Energy Balance)

	Test year[84]		**Number of years to next plant required[85]**
	LOLH	Energy Balance	
2002 Test Year (Budgell, Schedule X from the 2001 application)	3.97	(36) GW.h	5 years[86]
2004 Test Year (Haynes, Table 8 from the current application)	1.1	202 GW.h	6 years[87]

The LOLH is a measure of the generating capacity in place on the Island Interconnected system compared to the loads to be served. Hydro's planning criteria requires the Island Interconnected LOLH

[83] We understand this to be Hydro's head office building.
[84] Budgell reflects 2002 test year, Haynes reflects 2004.
[85] Next plant not yet approved or next purchased power contract not yet negotiated.
[86] Budgell, page 11 indicates a requirement for additional plant in 2007 on top of Granite Canal and the two new purchased power arrangements that were already committed at that time.
[87] Haynes, page 37 indicates a requirement for additional plant in 2010.

(measured in hours) not be above 2.8[88]. In other words, the current 2004 test year generating complement represents a plant in excess of that determined to be required by Hydro to service the Island Interconnected load[89]. This is distinct from the 2001 cost of service, where the costs for plant-in-service, based on Hydro's measures, did not reflect a generating complement technically capable of supplying the Island Interconnected load (demand or energy) to the acceptable reliability standard.

The current situation allows for a serious review of the Island Interconnected generating plant in service, what role each unit plays in providing the system with appropriate levels of reliability, and whether a portion of the generating complement is not in fact required for service to the entire grid (as opposed to perhaps being simply of local benefit to radial loads for the purposes of voltage control, supply during outages, etc.).

Clearly, Hydro has already begun their assessment of the Island Interconnected system from this perspective. The most notable example is the decision by Hydro to not renew the 'Interruptible B' contract with Abitibi Stephenville. This contract had been in place since 1993 and provided the ability for Hydro to interrupt, on short notice, up to 46 MW of load at Stephenville during the critical winter months. IC-194 sets out Hydro's reasoning in not renewing the contract as being based on the fact that the Island Interconnected System had sufficient capacity in place to meet the LOLH target until 2011. However, Hydro's review does not yet appear to have extended to an assessment, on a comparable basis, as to whether the Great Northern Peninsula backup diesel generation or NP backup thermal generation is likewise required to meet LOLH targets, and whether there is any basis for other customers on the Island Interconnected system to pay rates that reflect costs associated with these peaking plants.

6.3 COMPARISON OF COSTS OF CAPACITY

On the Island Interconnected system, Hydro proposes a particular combination of cost allocation and program offerings to address the requirements for capacity to meet peak supply. However, given the current situation of excess capacity until 2011, three matters merit review in this regard:

1. The allocation of GNP Generation as being of common benefit to the Island Interconnected system.
2. The allocation of Burin Peninsula transmission as being of common benefit to the Island Interconnected system, primarily as a result of the line servicing both NP and Rural ("under the guideline associated with the connection of two or more customers to the grid"[90]) but also as a result of connecting what is determined by Hydro to be significant generation to the grid.

[88] Haynes, page 36.

[89] Hydro's planning criteria ignore any energy capability of the peaking plant maintained by Hydro (i.e., gas turbines) and ignore the capability for Hydro to request capacity interruptions from industrial customers under a suitable interruptible demand program. Hydro has previously maintained 46 MW of interruptible demand with Abitibi Stephenville but has since determined they no longer intend to offer the rate.

[90] Exhibit JRH-3 page 21.

3. The provision to NP of a "generation credit" to recognize their thermal generation plant.

Each of these capacity-related matters is reviewed in more detail in the following sections and in Attachment H. The related decision by Hydro not to renew the Interruptible B offering is reviewed in Section 7.3 as well as in Attachment H.

A useful comparison to assess these three matters can be based on the amounts that are proposed to be paid by IC and NP (or would be paid by IC and NP) for various sources of system capacity to service peak demand. As none of the NP or Hydro thermal generation (other than Holyrood) is cited as providing any energy benefit to the grid, all benefits from GNP generation, Burin peninsula generation (outside of Paradise River), other NP thermal generation and IC Interruptible B relate only to their contribution to supplying peak winter demands[91].

Table 6.4 illustrates the comparative costs to the industrial customer group and NP related to various sources of capacity, in comparison to the costs of Hydro's gas turbines (which are used as a benchmark).

[91] The LOLH for summer months is basically zero and minimal for spring and autumn per IC-301. Each of these sources is available for the critical winter months. Interruptible B was available for December to March of each year.

Table 6.4 – Costs of Island Interconnected Peaking Capacity to NP and IC

	kW made available[92]	Cost to IC	Costs to NP[93]	Details
Hydro's Gas Turbines[94]	**128,000**	**$280,613 or $2.19/kW made available**	**$1,789,356 or $13.97/kW made available**	**Hydro's primary peaking capacity – first dispatched peaking units.**
GNP Generation[95]	14,700	$191,136[96] or $13.00/kW made available	$1,202,115 or $81.77/kW made available	Transmission assigned rural, but Hydro proposes to assign generation as common.
Burin Generation[97]	25,000	$231,709 for TL 219 as common[98] *plus* $332,910 for NP generation credit[99] *Total* – $564,619 or $22.58/kW made available	N/A	Hydro proposes to assign TL219[100] as common, plus pay additional amounts to NP via "generation credit" than if the capacity was not in service.
NP Generation Credit (thermal)[101]	45,500[102]	$738,386 or $16.23/kW made available	NP receives a net credit of $841,388	Hydro proposes to credit NP (charge IC) to reflect NP's thermal generation.
Interruptible B[103]	46,000	$163,913 or $3.60/kW made available	$1,045,600 or $22.73/kW made available	Hydro does not propose to offer during the test year.

92 Ignores hydraulic – small hydraulic generation on radial systems are primarily in service for energy reasons, so are of common benefit to the grid and should be assigned as common.

93 Prior to allocation of rural deficit. Costs to NP per kW are much higher than to IC as NP makes up 80.60% of the system peak, while IC make up 12.64%.

94 The full cost of Hydro's gas turbines is set out at IC-13 (Rev.) at row 15. This cost is allocated 100% on demand, which results in 80.60% of the costs to NP, 12.64% of the costs to IC, and 6.76% of the costs to Rural per RDG-1 (Rev.1) Schedule 3.1A.

95 This is only intended to reflect thermal generation – Roddickton mini-hydro should be assigned as common due to energy benefits to the system. Not clear if figures include the costs of mini-hydro, but the total revenue requirement of this unit, at $46,218 (IC-13 (Rev.)) makes up approx. 3% of the GNP generation revenue requirement.

96 Per JRH-3, Appendix B

97 This excludes Paradise River – TL 212 is assigned common as it interconnects the 8 MW hydro plant at Paradise River. There are also apparently three small (total 1.7 MW) NP hydro plants on the Burin peninsula – these assets are inconsequential to considerations of the appropriate assignment of the transmission line costs.

98 Per IC-228

99 Per IC-312

100 Hydro also proposes to assign TL 212, but as that line is required to service the Paradise River hydro plant, the allocation of it to common appears reasonable.

101 The information in this row is derived from IC-190 and IC-191. In those examples, NP is provided with a generation credit for their hydraulic generation equal to 77.5 MW compared to 79.3 MW in the cost of service, a difference of 1.7 MW. In other words, essentially all of the changes reflect in IC-190 and IC-191 compared to RDG-1 reflect the difference in the NP thermal generation. A portion of these amounts is also reflected in the row entitled "Burin Peninsula" – the amounts in the table rows are not additive.

102 This is shown in Exhibit RDG-2 at Appendix 3, and is net of capacity reserves. The gross NP thermal generation is 53.9 MW per the same exhibit.

103 Per IC-224

It is also of note that assigning the GNP generation to common results in an increased revenue requirement to Hydro of $44,986 as these assets are allowed a return on equity (there is no return on equity if the assets are specifically assigned to Rural)[104].

The table above illustrates the inconsistent impact on IC and NP from the various sources of peaking capacity. It is apparent that reliable and essential peaking capacity in the form of Hydro's gas turbines[105] (or the readily available Interruptible B capacity) results in less costs per kW to IC and NP than the costs proposed to be assigned to reflect so-called benefits from other peaking sources, despite these other sources being less useful as they are not on the backbone 230 kV transmission grid, are lower in the dispatch sequence[106], have longer startup times (in the case of NP's thermal generation)[107] and are smaller sources of capacity than Hydro's gas turbines[108].

Even the cost of brand new capacity additions to Hydro's system, quoted at $100/kW/year[109], would only result in $12.64 per installed kW being charged to the industrial customers, and that would reflect units under Hydro's complete control and dispatch. There is simply no basis to try to assign to IC $13.00 in costs per kW installed on the GNP, or $22.58 in costs as a result of each kW NP has installed on the Burin peninsula. There is also simply no basis to assign IC higher costs of $16.23 for each kW of thermal generation that NP has installed around the island, especially given NP is collecting the costs of this generation from its customers (via NP's revenue requirement[110]) who are the ones that primarily benefit from its presence (and given that this generation is not required to provide service improvement benefits to the reliability of the Island Interconnected grid).

6.4 ASSIGNMENT OF RADIAL TRANSMISSION AND GENERATION

6.4.1 Background on GNP Prudence and Cost Assignment

In the 2001 proceeding, Hydro proposed that any radial transmission line that had generation in place, as well as the costs of the generation itself, should be allocated to all Island Interconnected customers as being of common benefit so long as the generation could, even under light load conditions, exceed the radial load[111]. The Industrial customers disagreed with this cost-of-service approach for two reasons:

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104 IC-234

105 See, for example, IC- 396 indicating a 17.2 hours LOLH in 2004 (compared to target maximum of 2.8 hours) if the gas turbines were removed from service.

106 See below, and Appendix A of Exhibit JRH-3.

107 The exception is St. Anthony and Hawke's Bay diesels, their start-up time is 3 minutes compared to 8 minutes for the gas turbines; however, this difference is not likely to be material.

108 See IC-295.

109 Per IC-289.

110 Per IC-187 NP.

111 This is summarized in P.U. 7 (2002-2003) at page 112.

1. there was no basis to assign a transmission line as being of common benefit if the generation could only exceed the radial load under light (i.e., summer) conditions when that generation was simply not required on the main grid; and
2. the GNP transmission line in particular had not yet been demonstrated to be a prudent investment in the first place (the Board had decided in the previous hearing in 1995 that it did not have sufficient information to determine if the line was a prudent investment, and deferred that matter to Hydro's next rate hearing "for the purpose of determining recoverable costs"[112] – in this case the 2001 proceeding).

The Industrial customers called evidence in the 2001 proceeding indicating that a proper project review prior to construction would have demonstrated that the GNP project was marginal at best based on Hydro's financial and cost tests. Contrary to Hydro's assertion at IC-96 that the prudence of GNP costs was dealt with in the 2001 proceeding, or that the questions of prudence are no longer material to the current proceeding, the Board did not provide clear comment on the prudence of GNP interconnection costs in P.U. 7 (2002-2003). The Board did determine that Hydro's proposal to classify the GNP transmission and generation as being of common benefit was not acceptable.

In the present proceeding, Hydro has re-assessed the issue of GNP assignment[113] in exhibit JRH-3. In that exhibit, Hydro confirms, with respect to the GNP assets, that the GNP transmission is not of any common benefit to the Island Interconnected grid, so has determined it is appropriate to retain the transmission line as specifically assigned Rural. However, Hydro has now concluded that the GNP generation is of common benefit to the grid, and that all customers should share in the costs of this generation based primarily on their relative CP at generation[114].

Based on a review of the evidence in 2001 and the new evidence filed with the current proceeding, there appear to remain material questions outstanding as to whether the GNP interconnection, and the associated costs, was a prudent project for Hydro to undertake. However, so long as the costs of the transmission line remain assigned specifically to rural customers, this is not a matter that requires further consideration to protect the interests of industrial customers located elsewhere on the grid.

To the extent that Hydro now proposes to assign costs for generation that is located on the GNP, and that provides service almost entirely to GNP customers, as being of common benefit to the Island Interconnected grid including the industrial customers, the question of GNP prudence cannot be ignored.

As an example of the issues that must be addressed, the material in IC-399 is instructive. In particular, this response indicates the Island Interconnected system LOLH and Energy Balance that would arise if the GNP were not interconnected to the Island Interconnected grid. Comparing these results to Haynes,

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[112] See Board's report filed in response to CA-2 from the 2001 proceeding, page 189 (R11).

[113] Hydro has not filed any material in this proceeding to attempt to conclusively address the matter of whether the GNP interconnection reflects a prudent investment of $26.4 million in the first place.

[114] The bulk of the GNP generation is peaking plant classified to demand – CP at generation.

Table 8 indicates that, on a net basis, the GNP radial transmission line, including both loads and generation, has a net adverse impact on the Island Interconnected system. But for this radial line being interconnected, the Island LOLH would improve to 0.7 hours/year in the test year from 1.1 hours per year in Haynes, Table 8 and the Energy balance likewise would improve. Also notable, the requirement for future generation additions to the Island Interconnected grid would be delayed to 2012 from the currently forecast 2010. On balance, this type of information indicates a reason for concern, from the IC perspective, that costs for GNP assets will be assigned to the IC cost-of-service, even though these costs only arise as a result of a project that has a net adverse impact on the IC service quality.

The material below reviews the cost allocation of the GNP generation and illustrates, even if the GNP transmission was a prudent investment to undertake, that there is no credible basis to assign the costs of the GNP generation as being of common benefit. However, the question of who should pay for the GNP generation matter is even more conclusively determined if it is determined that the GNP interconnection project is an uneconomic venture that ought not to have its costs recovered automatically through rates.

6.4.2 Assessment of Radial Transmission and Generation in the Current Application

Hydro has undertaken a reassessment of certain generation and transmission costs on radial systems, included in the filing at Exhibit JRH-3. The exhibit reviews the generation and transmission configuration of three radial systems that have generation assets installed, and determines the following:

1. Great Northern Peninsula ("GNP") transmission should be assigned to rural customers, but the generation should be assigned common
2. Burin peninsula transmission should be assigned common
3. Doyles-Port aux Basques should be specifically assigned to Newfoundland Power.

Specific details regarding the GNP generation and the Burin Peninsula transmission are set out in Attachment H.

The review in exhibit JRH-3 appears to be incomplete in its analysis of the relative benefits and costs of the radial transmission and generation. The exhibit reviews, from both a system planning and a system operation perspective, the role of the generation assets, but it does not consider the relative benefits obtained in comparison to the cost implications for the various customer groups. It also appears to assume that the thermal generation in place, for example, in the GNP (14.7 MW of thermal[115]) would have to be replaced at a cost of $100/kW/year if it were not available to customers in its current form. This reasoning raises two serious concerns. First, there is no basis to suggest that any cost would have to be incurred to replace this generation in 2004 (if it were not already in service). Absent the GNP generation, the Island Interconnected LOLH only increases from 1.1 hours/year to 1.4 hours/year. This is

[115] It is not relevant in this sense to discuss the Roddickton mini-hydro. That unit provides energy benefits and so is readily considered to be of benefit of the Island Interconnected system and assigned to 'common'.

still well below the target maximum of 2.8 hours/year. Second, the assertion that the 14.7 MW of capacity would have to be replaced at a cost of $1.47 million to the system is incorrect. Hydro has previously contracted with Abitibi Stephenville for 46 MW or capacity (over three times the capacity made available by the GNP generation) for a cost of less than $1.47 million per year for essentially the same function[116].

In addition, the analysis fails to reflect the differential impact on IC versus other customer groups in regards to the radial plant assignment. With the current approach to financing the Rural Deficit, Newfoundland Power is basically indifferent to most issues of radial plant assignment, as they either pay the costs as common plant, or pay the costs as their share of the Rural Deficit[117]. However, under the provisions of the EPCA, 1994, Industrial Customer are prohibited from paying costs that are properly part of the costs of providing service to Rural customers. In this regard, assignment of radial plant is an issue that must be carefully considered to ensure that improper cost of service procedures are not resulting in cost allocations that are in contrary to the provisions of the legislation.

Based on a review of the evidence filed in this proceeding, and as set out in Attachment H, there appears to be no reasonable basis to assign any costs associated with the GNP thermal generation to any customers other than Hydro Rural. The proposed 'common' allocation results in assets that are properly providing service to rural customers being assigned to NP and IC. These assets have on occasion, prior to the major plant additions of Granite Canal and the two new PPAs (and during a period where the system had generation capacity shortages compared to Hydro's planning targets), been operated for one brief period in support of the entire grid[118]; however, this operation makes up less than one percent of the role that these units have played in providing service to Rural customers. Given that a common allocation results in over 90% of the costs of this plant being assigned to customers other than Rural, there is a clear disconnect between the customers who benefit and the customers who Hydro proposes should pay for the plant. In addition, there is a clear inconsistent cost impact from assigning GNP thermal generation to common, given that a greater quantity of capacity can be acquired at a lesser cost to IC and NP via such measures as the Interruptible B program.

There is also little basis to suggest that the Burin Peninsula transmission assets, outside of that portion required to interconnect Hydro's Paradise River generation to the grid, reflect sufficient benefit to the grid in the test year to assign them as common. As reviewed in Attachment H, the NP generation on the Burin peninsula is not required to meet the Island Interconnected peak demands in the test year, and therefore does not reflect any material benefit to the Island Interconnected customers outside the Burin Peninsula area. Hydro's own assessment from the 2001 proceeding was that the Burin transmission assets should be addressed in the same fashion as the GNP transmission and Doyles-Port aux Basques transmission

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[116] IC-216 indicates annual costs of $1.297 million to $1.354 million over the 1994 to 2002 period- it is presumed that 1993 reflects only a partial year of the program, costing $335,000.

[117] For example, the GNP generation allocation to common versus specifically assigned rural (a movement of approximately $1.4 million in costs per IC- 277) results in only an $11,830 impact on NP (per JRH-3, Appendix B).

[118] Per JRH-3 page 15, this occurred on January 30, 2003.

(both of which are proposed by Hydro to be specifically assigned and not considered to be of common benefit[119]). In addition, there seems to be no merit in Hydro's assessment that the transmission should be assigned to NP, IC and Rural simply because it serves both NP and Rural[120].

6.5 NP GENERATION CREDIT

A key item of complication in the cost of service is Newfoundland Power's own generation. In order to consider an appropriate treatment of the NP generation, it is important to recognize that there are two types of generating plant that NP maintains on the Island Interconnected system:

- ***NP Hydraulic generation:*** Comparable to Hydro's small hydraulic generation, NP's plants provide energy to the grid, and play some role in meeting demand peaks[121]. The hydraulic generation is presumably dispatched in almost all cases to maximize energy output, which would be consistent with the normal practices for economic dispatch of small hydro plants.

  As a result of their hydro generation being available to service a portion of their load from both an energy and capacity perspective, NP imposes a smaller burden on Hydro's network (and likely on Hydro's costs) than if NP did not possess the hydraulic generation and Hydro had to serve NP's full native load. Within a cost-of-service perspective it would be the normal practice to net the hydraulic energy off of the forecast total native energy NP required in determining the energy they require from Hydro's system. In addition, it would be normal practice to net the capacity that NP's hydraulic plant can reasonably provide off of NP's native peak to determine their peak demand for the purposes of cost allocation.

- ***NP Thermal generation:*** In contrast to hydraulic generation, NP's thermal generation plays no role in meeting the system energy requirements. The NP thermal generation is considered in determining the Island Interconnected capacity requirements, reflecting its ability to be operated at peak times. However, as noted above, the system is presently in a state of capacity surplus having recently added 87.3 MW of capacity at Granite Canal and the PPAs. In addition, the NP thermal generation is clearly located on the grid primarily to service radial loads in order to increase their local reliability[122], similar to the GNP generation that Hydro maintains. In addition,

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119 IC-267 from 2001 proceeding.

120 Assets that serve NP and IC but not rural are assigned to a separate "NP-IC" category and not charged to Rural customers so long as they have an original cost of at least 2% of Hydro total transmission and terminal station cost. The TL219 original cost is $14.199 million per IC-334, which is 3.3% of the total Island Interconnected transmission and terminal station Plant in Service of $430.697 million per RDG-1 (Rev. 1) Schedule 2.2A. Hydro was asked about this potential allocation for COS purposes, but declined to answer as the response claims the matter is "not relevant" (IC-337 and IC-338).

121 Per Haynes, Schedule II, NP hydraulic generation has a normal output of 424 GW.h and a firm generation of 323 GW.h. with a maximum peak capacity of 93.2 MW.

122 The NP Greenhill 25 MW gas turbine is located on the radial transmission line on the Burin Peninsula, the Wesleyville 15 MW gas turbine is located well off the main 230 kV grid on a long 69 kV radial line, and the "mobile" 7

IC-295 indicates that NP's thermal generation is very far down the list of available resources at times of system constraints, and is only dispatched after all Hydro's gas turbines, the St. Anthony diesel plant and the Hawke's Bay diesel plant have been brought on-line.

The cost-of-service approach used to date in Newfoundland is not designed to reflect peaks net of load shedding that only occurs on an infrequent basis. In particular, the System Operating Instruction in Appendix A of Exhibit JRH-3 indicates the following measures that are to be applied in the sequence set out below in times of system constraints:

1. Approach maximum on Hydro's hydraulic and steam generation
2. Request NP to maximize their hydraulic generation
3. Request Deer Lake Power and NUGS to maximize production
4. Notify industrial customers that non-firm power rates will start to be based on gas or diesel costs (higher cost than Holyrood). Ask NP to curtail their interruptible loads.
5. Start using standby generation[123]
    a. Hardwoods gas turbine (54 MW)
    b. Stephenville gas turbine (54 MW)
    c. Curtail Interruptible B load (46 MW)[124]
    d. Holyrood gas turbine (10 MW)
    e. Hawke's Bay diesel and St. Anthony diesel (13 MW)
    f. Two NP gas turbines (25 MW and 40 MW)
    g. Roddickton diesel (1.7 MW), NP mobile gas turbine (7 MW), various NP diesels (6.9 MW)
6. Interrupt non-firm industrial energy
7. Re-confirm steps 1-6
8. Reduce voltage at Hardwoods and Oxen Pond
9. Request industrial customers to shed non-essential loads
10. Request industrial customers to shed additional load
11. Request NP to start rotating feeders and start rotating Hydro rural feeders.

The above sequence beyond step 4 reflects activities that are infrequent at best. For example, exhibit JRH-3 notes that St. Anthony and Hawke's Bay diesels (step 5e) have been dispatched only once since the 1996 interconnection[125]. In addition, PUB-176 notes that on one occasion in the last ten years, two

MW gas turbine appears to be located on the Doyles-Port aux Basques radial line. The NP diesel appears to be located at Port aux Basques (2.5 MW), Port Union (0.5 MW) on the long Bonavista radial transmission line, with then remaining 4 MW located in St. John's or as portable units.

[123] Standby generation sequence per IC-295, sequencing of interruptible B reflects terms of contract.

[124] Interruptible B contract is not proposed to be in place for winter 2003/04 or beyond. The interruptible B terms provided that an interruption would occur after Hydro had dispatched 2 of its gas turbines and prior to dispatching the third.

[125] In contrast, IC-188 and IC-192 seem to indicate a more frequent operation of NP's thermal generation, which is lower on the dispatch sequence than St. Anthony and Hawke's Bay diesels. These requests seem to primarily reflect

industrial customers were requested to drop firm loads (step 9) of 15 MW each. The evidence on this matter indicates very little practical difference between the amount of dispatch beyond step 5(e) through to step 9.

Comparing the items on this list, the cost of service does not propose to in any way credit the peak loads forecast for the industrial customers to reflect effective capacity reduction that would occur in step 3[126] (as Corner Brook reduces their net load on the system by maximizing production from Deer Lake hydro), and in the 2001 application did not propose to credit the industrial peak loads to reflect step 5(c) or step 9. However, with respect to NP, Hydro does propose to net off of the NP loads a quantity of capacity sufficient to reflect the implementation of steps 2, 5(f) and 5(g) despite these being lower on the dispatch sequence than the IC load shedding at steps 3 and 5(c). In addition, in terms of the practical amount that each of these devices would be used, there is little difference between the items through much of the range from step 5(e) to step 9. Clearly the approach proposed by Hydro in regard to NP's generation reflects an inconsistent treatment of NP and IC loads.

The most striking comparison regarding NP's generation is shown in IC-187. As noted in that response, the thermal generation that NP maintains reflects a total annual cost (revenue requirement to NP's customers, as reviewed by the Board in NP's 2003 GRA) of $1,691,000. However, as shown in IC-190, this generation results in a credit to NP (a cost to IC and Rural[127]) of $995,488 in the test year. In other words, the cost of service approach proposed by Hydro results in IC and Rural effectively paying 59% of the costs of NP's peaking generation[128]. Even Hydro's own peaking generation, such as the gas turbines which are clearly of benefit to the entire grid, only result in 19.4% of the costs being paid for by IC and Rural customers[129].

In summary, there are only two potential rationales that could be offered as to why NP's thermal generation is considered as a credit to NP in the cost of service study:

- ***If NP's thermal generation could realistically be needed for dispatch/interruption at peak:*** One rationale for netting certain loads off of cost of service peaks is that they are not firm load that the utility has to supply at critical peak times. For example, the CFB Goose Bay secondary power is properly not included in the Labrador Interconnected cost of service capacity

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non-peak voltage support (i.e. occasions in April, October, etc,), rather than proper peak load shedding consistent with the normal rationales for CP adjustments in the cost-of-service.

126 Industrial customer peak loads for the purpose of the cost-of-service analysis are based only on Power on Order less normal diversity, as set out in IC-265. These calculations reflect the peak that the customer would expect to impose if running both their operation and any of their own generation at 'business as usual' levels.

127 Prior to reallocation of the Rural Deficit.

128 In addition, Hydro pays to NP all costs of fuel consumed when the units are actually run for system peaking support.

129 Per RDG-1 (Rev. 1) Schedule 3.1A, IC pays 12.64% and Rural pays 6.76% of peaking capacity costs, which are based on Production Demand allocators.

allocations[130] as secondary power does not place any firm demand peaks on the system (it is readily interrupted at the time of system peak). Applying this rationale to the NP thermal generation, however, does not indicate that they should be netted off of NP's firm loads based on overall assumptions adopted for the cost of service. First, the NP thermal generation units are well down in the capacity shortage dispatch sequence (below other capacity sources that are not netted off in the cost of service, such as increased Deer Lake Power output and the Interruptible B capacity). In addition these units are not dispatched until after St. Anthony and Hawke's Bay diesels have been put into service. Hydro has confirmed that the St. Anthony and Hawke's Bay diesels have only been used once in support of the Island Interconnected grid[131] (in contrast to 112 times for local transmission outages[132]), and that was before Granite Canal and the new PPAs were in service. In addition, a portion of NP's thermal generation is very small and of limited benefit to the system[133]. In summary, there is little credible basis to suggest that these units provide any material benefit to the Island Interconnected grid or would likely be needed for dispatch or interruption at this system's peak.

- ***If considering NP's thermal generation as a credit in the cost of service study prevents uneconomic dispatch or peak shaving by NP:*** The more common response from Hydro is that giving NP a full generation credit as if all their thermal capacity was operating at peak is necessary to prevent NP from needing to run these units to peak shave[134]. In other words, Hydro is asserting that if NP is already provided with the benefit reflecting 100% of the output of these units, there is no additional need for NP to actually run them at peak in order to reduce their own costs charged by Hydro – and that running them at peak would be less advantageous for all customers since it represents an uneconomic dispatch of the system generation. This rationale ignores the legislative framework for regulation by the Board. Any consideration of NP's generation, and any reduced rates or reduced bills that might arise as a result of this generation plant, need to first recognize the clear power policy of Newfoundland, as outlined in the EPCA, 1994 at section 3(b). Specifically, the Board must ensure all utility generation is operated in such a way as to "result in the most efficient production, transmission and distribution of power"[135] and "result in power being delivered to consumers in the province at the lowest possible cost consistent with reliable service"[136]. In other words, the provision of a "generation credit" for NP in order to prevent them from dispatching their generation in a way that lowers the overall system efficiency (and increases overall system costs) is simply unnecessary and inappropriate. The legislative direction to the Board already appears to ensure the Board will not allow NP to profit (at the expense of others) from reducing the efficiency of power generation in the Province.

[130] Per RDG-1 (Rev.1) Schedule 3.1E, row 1.
[131] JRH-3 page 15.
[132] Since 1996, per IC-235.
[133] For example, all of NP's diesel generation is 2.5 MW or less.
[134] Greneman, page 17.
[135] EPCA, 1994 section 3(b)(i).
[136] EPCA, 1994 section 3(b)(iii).

On balance, using the approach to cost-of-service as it has been generally applied in Newfoundland, there does not appear to be any credible basis to provide NP with any generation credit to reflect the thermal generation plant they have in service. It remains appropriate to provide such a credit for NP's hydraulic generation, but only to reflect the peak capacity that NP would provide to the system based on economic dispatch to maximize energy output (not full dispatch that is reflective of system capacity shortage conditions). In this regard, it appears from IC-306 that the NP hydraulic generation would be expected to be running at 77.5 MW of output, but Hydro is proposing to provide 81.6 MW of capacity credit reflecting peak output[137]. The 77.5 MW figure should be the only amount applied to NP's native peak in allocating capacity-related costs in the cost of service.

6.6 NP LOAD FACTOR

The 2002 actual cost of service filed in IC-1(c) compared to the test year cost of service in IC-1(a) reflects a materially different result for NP and IC. In particular, the results in IC-1(c) indicate that the IC group paid more than $5 million *in excess* of its measured costs in 2002 (including RSP adjustments)[138]. In contrast, NP's actual payments to Hydro were almost $5 million *below* the amounts that should have been collected via rates (including the Rural Deficit)[139]. This divergence reflects a number of different factors, and it is not a simple exercise to itemize and quantify the various factors. However, one factor that appears to be material relates to the NP actual load factor compared to the 2002 forecast that NP submitted to Hydro[140].

In allocating the costs of the Island Interconnected system, the primary factors that distinguish the portion of costs that are assigned to IC versus NP or Rural are the forecast peak demand and energy

[137] An additional update that further exacerbates the problems noted above is in regard to the calculated "capacity reserve" required on NP's generation. Hydro has recently determined (IC-306) that since Granite Canal and the PPAs are now in service, there is a reduced need for capacity reserve on the overall Island Interconnected system. In the 2001 GRA, and in the May 2003 application filed by Hydro, NP's total generation output was de-rated by 18.5% to reflect the need for maintaining capacity reserves. As a result, NP's total generation plant of 147.4 MW was only given a generation credit of 124.8 MW. However, with the increased capacity available, the system reserve has been reduced to 16%. The net effect is to increase the NP generation credit provided. In other words, although there is more reliable baseload system capacity available, which makes the NP generation *less likely* to actually be of any benefit, Hydro is proposing to *increase* the generation credit it provides to NP. This result is not consistent with reasonable cost allocations reflecting the physical system in place.

[138] IC-1(c) Schedule 1.2 reflects total revenues from IC of $55,855,978 including RSP adjustments in comparison to measured costs of $49,479,727.

[139] IC-1(c) Schedule 1.2 indicates NP's total revenues of $245,524,223 including RSP adjustments compared to target revenue of $250,294,459.

[140] We have not attempted to quantify the impact, however NP's share of peak demand increased from a forecast 78.57% of the Island Interconnected system to an actual 82.46%. The revenue requirement to be collected based on demand peak allocators is $91.7 million in the forecast 2002 cost of service and $95.8 million in the actual 2002 cost of service. In other words, this revised peak demand may account for $3.6 to $3.7 million of the shift in costs from NP to IC (about 70-75% of the approximately $5 million noted above).

values[141]. These values reflect Hydro's short-term load forecasts as set out in PUB-3, and appear to be simply Hydro's compilation of the demand and energy forecasts that each of the four ICs and NP provides to Hydro.

In determining the level of rates to be paid by each customer group, Hydro's cost of service determines the total costs to be assigned to each group (Schedule 1.2 of the Cost-of-Service, Exhibit RDG-1), and then divides these costs by the number of units which Hydro forecasts it will bill in the test year (Schedule 1.3 of the Cost-of-Service, Exhibit RDG-1). The source of data for both cost allocation and billing units is the load forecasts provided by the customers.

As an example, if the IC customer group revises their load forecast to Hydro by increasing their energy sales by, for example, 100 MW.h, then there will be two cost of service changes:

1. a revision to Hydro's revenue requirement (primarily Holyrood) to supply the extra load, and
2. more of the energy-related costs allocated to the IC group, as they will now make up a larger percentage share of the total system energy.

However, there will also be more billing units to divide this total cost into in determining the IC energy rate, so the net effect, in all likelihood, will be a slight increase in the energy rate to be charged to the IC customers. Likewise, a slight reduction in the energy consumption would affect the three variables noted above and result in a slight difference in the end energy rate.

With respect to demand units, there are very few incremental costs to affect the revenue requirement related to increased or decreased consumption. In this case, a higher forecast demand peak by IC will result in a greater share of the demand related costs being assigned to the IC group, but a higher number of billing units, such that in all likelihood the rate impact will likely be slightly upward.

The situation with respect to NP is somewhat different as a result of the energy-only rate. Since NP does not have a demand rate based on the number of billing demand units that they forecast to require, NP's demand forecast is only relevant to determining their share of the demand costs. In this case, a higher peak demand forecast by NP would lead to a higher energy rate (all else being equal), and a lower peak demand forecast by NP would lead to a lower energy rate.

In the case of IC, there is a strong incentive to provide accurate forecasts to Hydro, particularly for demand, as the Power on Order clause in their Industrial Contracts ensures:

- the customer is only assured of firm power for the amount of demand they specify in advance, any usage above this level can be interrupted and is priced on a variable basis

[141] RDG-1 (Rev. 1) indicates at Schedule 2.1 A that 88% of the Island Interconnected revenue requirement is allocated based on Production Demand, Transmission Demand or Production and Transmission Energy, with most of the remainder reflecting Rural specific assets.

such that the unit costs are very high at certain times (see Section 7 below)

- the customers actually pay for all demand that they forecast they will require, regardless of whether they actually use that level of demand or not (an effective take-or-pay provision).

As a result, there is little benefit to IC of providing forecasts that vary from actuals.

In the case on NP, the demand forecasts submitted do not in any way commit the utility to any given level of costs or take-or-pay provisions. In this case, the rate NP is to be charged would be reduced to the extent that a lower demand forecast is submitted.

During the 2001 proceeding, the cost of service originally filed was updated during the hearing to reflect a new NP load forecast. In that case, NP's peak demand forecasts, as they relate to the cost-of-service filed early in the proceeding, reflected a forecast peak of 953,251 kW at Transmission[142]. A later revision submitted by NP reflected a reduction in this peak demand forecast to 923,476 kW[143]. The final 2002 cost of service filed in IC-1(a) to the current proceeding retained this 923,476 kW peak value. However, the actual peak recorded by the actual 2002 cost of service study filed in IC-1(c) was 1,047,534 kW[144]. In each case the variability in the energy consumed was within a tight margin[145].

There has been insufficient time to review in detail the NP load forecasts filed in this proceeding compared to long-term NP load characteristics, the various 2002 NP load forecasts filed in the 2001 proceeding, and the more recent information regarding increased penetration of electric heat in the Newfoundland market. It is apparent that revisions to the NP load factor can have significant impacts on the cost of service allocations, and that NP has not been driven by the same considerations as the IC group in regards to ensuring peak demand forecasts are as accurate as possible. It is possible that the two part rate for NP will ensure incentives for more detailed NP peak demand forecasts. To the extent that this is not the case, the review of load forecasts within the proceeding will be required to assess the extent to which NP's peak demands result in a reasonable allocation of demand costs.

[142] Per Schedule 3.1A exhibit JAB-1 Rev. 1 from the 2002 proceeding.
[143] Per Schedule 3.1A exhibit JAB-1 Rev. 2 from the 2002 proceeding.
[144] Per Schedule 3.1A, IC-1(c).
[145] From a low of 4,602 GW.h in JAB-1 Rev.1 to a high of 4,692 GW.h in the IC-1(c) final cost of service study.

7.0 RATE DESIGN

Following the determination, via a properly conducted cost of service study, of the amounts to be paid by each customer class, it is necessary to design rates to recover these costs. In addition, a fundamental overall ratemaking concern relates to cost tracking, or ensuring that customers are charged rates that reflect the overall costs that their use of electricity imposes on the system under various potential load variations that may occur as the test year unfolds. Efficiency objectives related to sending effective price signals to ratepayers are also important - particularly when addressing variable cost items

The rate design reflected in Hydro's application contains a number of components, many of which are unchanged from the 2001 application. Key components of the Island Interconnected rate design include:

- the base firm power rates applied under the Newfoundland Power and Industrial Customer Rate Schedules;
- the Interruptible energy rates applied to IC for loads that exceed their high load factor firm base load requirement; and
- the Rate Stabilization Plan.

In terms of achieving a fair allocation of costs between IC, NP and Rural Interconnected customers, not only under GRA forecast loads but under variations that may reasonably arise from GRA loads, the current rate design is clearly inadequate. The following deficiencies in the proposed rate design are reviewed in detail in the section below:

- The NP energy only rate combined with the RSP load variation provision result in NP failing to cover costs associated with their load growth in the same fashion as IC. In addition, NP load growth results in charges to other customers (IC and Rural) via the RSP even if the other customers' loads came in at exactly GRA forecast levels. The net cost to NP from load growth is well below the costs to produce the incremental power to serve the load (shown to be at 3.37 cents/kW.h per section 7.2.4.1 below).
- The NP energy only rate results in NP receiving no rate impact from increasing the demand peaks they impose on the system.
- In addition to the NP generation credit reviewed in section 6[146], the tentatively proposed "Option A" two-part rate for NP[147] results in NP also receiving an additional billing demand benefit based on assuming all their generation is in operation at the time of the system peak.

[146] As noted in section 6, the cost of service treatment of the NP Generation Credit results in an inappropriate costing benefit to NP based on an assumption that all their generation is in operation at the time of the system peak, including thermal generation that is uneconomic to operate, as well as assuming all NP hydro is operating at full output, which is inconsistent with the provisions of the EPCA, 1994 3(b)(i) and 3(b)(iii).

- The industrial rate structure (unlike NP's energy-only or proposed two part rate structure) requires industrial customers to forecast their demand requirements and then face an effective take-or-pay provision on their forecasts.
- The industrial interruptible rate structure means that, unlike Newfoundland Power, the industrial customers have to pay the full incremental costs to service any load growth, plus additional energy and demand charges. There is no cost to NP from IC load growth above their pre-specified Power on Order levels (as this load growth is priced at incremental rates and is not included in the RSP), unlike the costs imposed on IC (via the RSP) for all NP load growth.
- The IC group faces substantial charges via the RSP when they reduce their load compared to forecast. This results in the group saving less than 1 cent/kW.h for each kW.h that they are able to reduce their load compared to the last GRA forecast. Almost 80% of the cost savings from reduced IC load are passed on to NP.
- The IC also face substantial additional burdens if one customer is to close, as the RSP will continue to charge the remaining IC customers for all of the firm energy revenue forecast in the previous GRA to be collected from that closed operation, but only credit the IC with about 21%[148] of the savings that arise from not serving this load[149].
- The inconsistent treatment of firming-up service and wheeling service results in the firming-up service being provided to NP at no cost whatsoever; in contrast, the wheeling service provided to IC is credited back to all customers for the test year forecast amounts, and any additional wheeling sales appear to be simply credited to Hydro's net income.

The net impact of the proposed combination results in a materially different and inconsistent approach to addressing ongoing load variation among the IC and NP. Far more preferential terms are proposed by Hydro to be provided to NP than IC.

In order to address the above noted inconsistencies and inappropriate price signals, the following rate design changes are merited:

[147] As outlined in Exhibit RDG-2.

[148] See, for example, RDG-1 (Rev. 1) Schedule 3.1A, which shows that IC firm sales make up 20.99% of the forecast Island Interconnected sales for the 2004 test year.

[149] This is confirmed at IC-363 and shown in detail at IC-364, where the pro forma closure of Abitibi Stephenville in May 2003 results in the monthly RSP charging the remaining IC customers $870,897 (which is the total lost revenue to Hydro compared to forecast as a result of Abitibi-Stephenville closing) and crediting the RSP in total with $1.504 million related to fuel savings as a result of this closure, of which only $305,164 is allocated to the IC (20.29%, with $1.1 million or 73.33% being credited to NP). In other words, were Abitibi Stephenville to close, the IC RSP would be charged with over $500,000 a month, for each month until the next GRA ($870,897 less $305,164), wile the NP RSP would receive credits of over $1.1 million a month until the next GRA.

- NP should face a two-part rate similar to Option B in Exhibit RDG-2; however, the "generation credit" should only reflect expected hydraulic output using normal hydraulic conditions and economic dispatch of generation (it should not reflect any thermal output).
- Industrial customer billing demands should be based on the actual highest firm demand in the billing month, or 80% of the highest demand from the previous winter, whichever is higher. This would eliminate the practice of billing customers based on forecast Power on Order demand levels.
- Industrial Interruptible energy charges should reflect the energy charge proposed by Hydro, but no demand charges.
- The Load Variation provision of the New RSP should be eliminated, and any current balances amalgamated into the Fuel component.
- The hydraulic component of the RSP should be treated separately, with a well-defined trigger set perhaps in the order of $35 million to $70 million. To the extent that the hydraulic component remains within this trigger (plus or minus), there is no basis for any charges/refunds to customers.

A separate rate design issue for the 2004 test year is the Interruptible B rate that Hydro proposes to terminate. For the past ten years, Hydro has provided a rate offering that allows one industrial customer to service a portion of their load using interruptible capacity. This means that the customer could have their otherwise firm power supply reduced by a substantial margin (46 MW) on short notice in order to assist Hydro in meeting key winter system peaks for the overall benefit of the Island Interconnected system. This type of rate is typically offered by utilities focused on the long-term benefits of this dispatchable capacity reduction resource. Hydro's intention to terminate the offering effective the 2003/04 winter season is not consistent with the longer-term view that is appropriate for this type of rate. Recognizing the important long-term benefits from this type of rate, it should be retained for the existing 46 MW subscribed to the rate, along with an investigation of the potential for further system benefits from expansion of the rate offering to other industrial customers.

7.1 THE PROPOSED NP AND IC RATE SCHEDULES

7.1.1 Newfoundland Power two part rate

The topic of a two-part rate (demand and energy components) for Newfoundland Power has been discussed for a considerable period of time, as noted in various materials filed, including Exhibit RDG-2. There does not appear to be any inconsistency in the Board's direction on this matter going back to before 1990 (and including the Board's reports on Hydro's 1990 GRA, 1992 GRA and the Board's Decision in Hydro's 2001 GRA) that a proper rate structure for NP should include demand and energy components.

In the current proceeding, Hydro has requested continuation of the energy-only rate in the proposed rate schedules. However, in response to PUB-150, Hydro has noted that outside of a number of limited issues (discussed in PUB-149), a two part rate along the lines of that discussed in Exhibit RDG-2 (Option A) could be applied to NP.

In particular, Exhibit RDG-2 summarizes a number of aspects of the two part rate that require examination and review in order to determine the proper rate form, as follows:

1. **Price Signal:** A two part rate for NP, similar to the existing multi-part rates for IC, can be used to send a correct price signal to NP regarding the costs of its consumption. This price signal can then be reflected in the retail rates designed by NP. This price signal is also addressed in RDG-2 as an incentive to minimize the island interconnected peak for the benefit of the entire system, as increased peak loads will result in higher demand charges to NP. The existing single part (energy-only) rate provides price signals to NP in regards to energy (kW.h) consumption, but no specific price signal in regards to peak (kW) consumption and the increased costs that arise from increased peak consumption. In contrast, as noted below, industrial customers pay demand charges for basically all "Power on Order" that they forecast they will require, plus increased demand costs either related to interruptible or maximum demands in excess of Power on Order when they exceed this level. To the extent that these industrial rates are appropriate and track valid incremental costs on the system, a similar rate structure seems appropriate for NP.

2. **Revenue stability and neutrality:** Exhibit RDG-2 expresses a concern that with a demand charge component of the NP rate, a certain level of new volatility will be introduced into Hydro's revenues. This is because, unlike energy charges, demand charges are not addressed by the load provision of Hydro's RSP. However, as noted in Section 7.2, there appears to be no proper basis for maintaining any load variation component of Hydro's RSP (demand or energy). To the extent that Hydro seeks to stabilize revenues related to weather-specific variables (specifically colder or warmer than normal winter peak conditions), there are a number of models that can be contemplated to accomplish this, based on such concepts as NP's own Weather Normalization Reserve. This normalization can either be applied to costing (i.e., charge NP for a weather-normalized peak) or to revenue-recognition (i.e., charge NP for actual peak, but credit a new Hydro "weather normalization provision" with any above or below normal revenues received, so that the provision balances out to zero over time with no riders to customers – to the extent that this gives rise to revenue/cost volatility to NP, the problem can be addressed via NP's own stabilization mechanism). The preferred method does appear to be the former; that is, a weather normalized peak demand charge to NP.

3. **Address NP Generation:** In measuring the demand costs and rates that are to be applied to NP, there is a need to consider an appropriate treatment NP's generation (both hydro, which is normally operated throughout the year, and peaking thermal, which rarely operates at all) in order to forecast the net load to be supplied by Hydro. Otherwise, as noted by Hydro in Exhibit RDG-2 section 4, an improper rate design might result in an ability for NP to profit from dispatching its generation in an economically inefficient manner. However, any

consideration of NP's generation, and any reduced rates or reduced bills that might arise as a result of this generation plant, needs to first recognize the clear power policy of Newfoundland, as outlined in the EPCA, 1994 at section 3(b). Specifically, the Board must ensure all utility generation is operated in such a way as to "result in the most efficient production, transmission and distribution of power"[150] and "result in power being delivered to consumers in the province at the lowest possible cost consistent with reliable service"[151]. In other words, the oft-repeated concerns that a poorly designed rate or generation credit for NP will result in NP dispatching their generation in a way that lowers the overall system efficiency (and increases overall system costs), in order to simply minimize Hydro's charges to NP, can be addressed. The Board not only appears to retain authority to price and set rates so as to ensure NP is not rewarded for such inefficiency-inducing behaviour, the Board appears to in fact be required to ensure such behaviour is not rewarded[152].

As a result of the above, Exhibit RDG-2 proposes that a two-part rate could be developed for NP incorporating the following key factors:

- Use the single winter peak to determine the demand charges during the year. To the extent that other months are lower than the winter peak, the demand charge would be based on the previous winter peak (i.e., a 100% ratchet on prior winter's peak).
- Normalize the winter peak for weather[153].
- Reflect a minimum demand equal to 98% of the test year loads, to ensure that load reductions do not result in material lost revenue to Hydro.

Our review and consideration of the above matters suggests that these three methodological approaches to demand billing for NP appear to be reasonable.

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[150] EPCA, 1994 section 3(b)(i)

[151] EPCA, 1994 section 3(b)(iii)

[152] Another example arises at Exhibit RDG-2 page 11, where there is a concern that if the demand rate is too high, it may "encouraged NP to add gas turbines for the sole purpose of shaving peak" which, the exhibit asserts, may result in adverse impacts in Hydro's revenues and "non-economic island based resource management". However, as noted above, this type of action by NP appears to be contrary to the EPCA, 1994, and as a result, it would seem imperative that the Board not only reject any opportunity for NP to lower its costs via this introduction of inefficiency, but also ensure that NP is not allowed to recover any costs associated with such generation at the time of an NP rate application. In this way, the Board both ensures the legislation is implemented and also solves the problems highlighted by this exhibit.

[153] The mathematical intent appears to be to ensure that NP pays for 12 months at the weather-adjusted system peak; however to accomplish this a complicated demand-charge calculation is set out in Exhibit RDG-2 page 15 which effectively charges for actual peak in January, February and March, charges for weather adjusted peak in April-December, and credits back during the April-December period all revenues arising in the January-March period relating to actuals peaks higher than the weather-adjusted peak.

The main concern that arises with respect to the proposed approaches to NP billing demand is comparable to the concern that arises with respect to the treatment of NP's generation in the cost of service as noted above. That is, the generation credit should not provide any benefit to NP related to any of their generation that is not properly dispatched at peak times (based on proper economic dispatch principles). Regardless of whether NP operated their thermal plant at peak or not, or whether they ramp up their hydro production at peak, if this additional generation is contrary to proper economic dispatch, they should not see a benefit from such gaming actions.

Exhibit RDG-2 sets out three possible approaches to addressing NP's generation (entitled Options A through C). Without specifically reviewing the details of each option, both Option A and C appear to reflect providing NP with credit for their hydraulic and thermal generation in both the cost of service and the rate design[154]. Option B isolates and does not provide credit for NP's thermal generation in the measurement of billing demands, but does for the cost of service. Option B also provides credit for NP's hydraulic generation in both billing demand and cost of service[155].

At present, none of Options A through C in Exhibit RDG-2 pages 7-9 appear to optimally address this issue. With respect to Billing Demand calculations set out at Exhibit RDG-2 page 25, Option B appears closest to a proper rate calculation and price signal for determining billing demand, in that it isolates and excludes NP's thermal generation from the calculation of their peak demands.

Option B reflects charging NP for a billing demand calculated as their highest Non-Coincident Peak imposed on Hydro's system, but adding back any thermal generation operating at the time of system peak. In other words, NP would not be able to operate their thermal generation to reduce their bills. However, at page 8 of the exhibit, Stone and Webster note concerns that Option B provides incentives to ineffectively operate (or game) NP's hydraulic generation.

This issue appears to be solved by simple recognition of the principles (and the Board's requirements) under EPCA, 1994 section 3(b)(i) and (iii) and the considerations outlined below. Specifically, there appears to be no basis to credit NP with generation (regardless of whether it was running at peak times) if that generation is not properly part of the least-cost economic dispatch to service the Island

[154] Option A provides the Generation Credit based on the total installed NP thermal generation for both cost of service and measurement of billing demands, so there is no need for NP to run the generation to get the credit. Option C appears from Appendix 3 of RDG-2 to provide NP with a substantial generation credit in the cost of service (reflecting a 1038.5 MW peak, or the NP native load of 1161.5 MW less 77.5 hydraulic and 45.5 thermal generation) and use a billing demand based on their net load to Hydro (so there is an incentive for NP to run the thermal generation at peak to reduce its net load to Hydro, even though this would be an uneconomic dispatch of the system). However, this does not appear consistent with the text of the exhibit which states at page 8 "No generation credit would be applied to NP's demand for either costing or billing demands". In both cases, it appears from Appendix 3 of RDG-2 that NP is given some form of credit to reduce its costs as a result of having installed generation that properly should not be credited in the Newfoundland cost of service or rate design process.

[155] For cost of service, Option B uses full potential hydraulic output less reserves, and for billing demands it uses actual hydraulic output at the time of system peak.

Interconnected load. NP's peak for billing purposes should reflect the native peak[156] less the *normal* NP hydraulic plant output[157] at peak times, which appears to be reflected in the COS at 77.5 MW[158]. Regardless of whether 77.5 MW is the right figure, a fixed value for the normal winter NP hydraulic generation, reflecting normal hydraulic conditions and optimum economic dispatch for these units, should be the *only* amount credited back to the NP native peak in determining the billing demands. Any NP hydraulic generation in excess of this amount either reflects a) weather (i.e. precipitation or other relevant weather values) outside of normal, or b) operation varying from optimum economic dispatch, and should not be properly reflected in the NP demand charge[159].

The end result is that no NP thermal generation (regardless of actual operation), and no NP hydraulic generation above principled analysis of economic dispatch, should be reflected in determining the NP billing demand. This would remove all concerns with respect to NP failing to operate consistent with economic dispatch, and would ensure NP is not given credit for generation that is not properly operated for this purpose.

In terms of the NP two part rate, the rate schedule proposed in Exhibit RDG-2 pages 15 to 16 appears to be sufficient to address the above concerns. The only addition required is to add the definition of "Generation Credit" which reflects the following:

> Generation Credit: "xxx MW[160], reflecting the forecast generation from NP's hydraulic generation at the time of winter system peak (using normal hydraulic conditions and economic dispatch of generation to maximize NP's annual hydraulic energy output)"

The specific number of MW could possibly be fixed at 77.5 MW for this proceeding, so long as it is reviewed and set in future proceedings based on an analysis of the proper peak-hour output of NP's

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156 Defined in Exhibit RDG-2 at page 15 as "the load supplied by Hydro to Newfoundland Power in any hour, plus the total generation by Newfoundland Power during that hour".

157 Haynes, Schedule II notes that NP hydraulic generation has an installed capacity of 93.2 MW, and Exhibit RDG-2 at page 25 notes an apparent reserve capacity of 18.5% (consistent with NP-126 from the 2001 proceeding). This equates to a total available capacity of 79.3 MW. Haynes Schedule II notes a average annual generation of 424 GW.h, which reflects an average annual capacity of 48.3 MW, and the COS appears (per Exhibit RDG-2 page 25) to reflect a credit of 77.5 MW. We assume that the 77.5 MW is the expected NP generation at the time of system peak, reflecting normal hydraulic conditions and economic NP hydraulic dispatch to maximize hydraulic energy generation over the course of the year.

158 This may in fact be higher than normal winter economic dispatch for the NP hydraulic generation. Regardless, a fixed value for the normal winter NP hydraulic generation, reflecting normal hydraulic conditions and optimum economic dispatch for these units, should be the only amounts credited back to the NP native peak in determining the billing demands.

159 Isolating the variation outside of normal due to precipitation is consistent with the weather normalization principles addressed above for winter temperatures, and variation due to uneconomic dispatch should not be properly credited back as any form of savings to NP.

160 This is to be determined via hydraulic modeling; in the interim, 77.5 MW appears to be the only estimate currently available.

hydraulic generation assuming economic dispatch of the Island Interconnected generation, and subject to review and approval by the Board.

7.1.2 Industrial Customer demand and energy rate form

The Island Interconnected industrial customers are high load factor operations. This means that the IC group generally has a very limited ability to consume additional energy without setting new (higher) demand peaks. In other words, for the IC group, the access to power to address load growth is tied to the availability of power (as firm or interruptible service) and the demand and energy charges that would be applied. This area of service is governed by the industrial contracts, and the determination of "Power on Order" in particular.

The Industrial contracts currently in place are not proposed by Hydro to be revised or updated[161]. As a result, the existing terms regarding demand and energy consumption, billing, etc. are apparently proposed by Hydro to remain as per the final contracts from the 2001 proceeding.

A detailed review of the existing contract provisions is set out in Attachment F.

In summary, industrial customers are provided with firm power up to the peak (kW) level specified in their annual Power on Order. The industrial customer must forecast this amount by October of the year prior to service (and this amount has to be confirmed by Hydro, who has the opportunity to reject the amount of firm Power on Order requested by November of the year prior to service). Throughout the calendar year, the prevailing Power on Order represents both the maximum firm supply (at firm rates) that the customer can rely on from Hydro, and also represents the amount that the customer will have to pay for via demand charges, whether they use that power or not. In other words, so long as a customer remains below their declared Power on Order for the year, there is no cost impact to the industrial customer of incremental demand consumption or increased peak loads.

The effective rates paid by an industrial customer on their firm service average between 3.758 and 3.956 cents/kW.h exclusive of RSP charges (see Attachment F).

If a customer's requirements during the year exceed the Power on Order, the customer will be supplied by Interruptible Power, but only if it is available from Hydro at the time requested. This Interruptible Power is supplied at higher variable energy rates than firm power, based on the customer paying rates in excess of the full incremental cost to supply the power at the time it is delivered. The forecast rates for Interruptible Power reflect approximately 6.219 cents/kW.h if supplied from Holyrood[162], and are forecast to be higher than 13 cents/kW.h[163] when diesel units are operating on the Island Interconnected System.

[161] Per IC-50.

[162] Includes demand charges, and reflects the forecast Interruptible consumption of Corner Brook Pulp and Paper in the 2004 test year.

[163] Per IC-175, the forecast Holyrood-based non-firm energy rate is between 5.150 cents/kW.h and 5.267 cents/kW.h, the forecast gas turbine based non-firm energy rate is between 10.684 cents/kW.h and 11.143

The access to Interruptible Power is limited by a Maximum Interruptible Demand peak. If the customer has need to exceed the Maximum Interruptible Demand peak for a temporary load excursion, they face rates under the contract for such temporary use of power that are extremely high (reflects the so-called Maximum Demand provision). The example noted in Attachment F results in an effective rate of 25.66 cents/kW.h.

7.1.2.1 Power on Order

In regards to Power on Order (i.e., the firm power provided by Hydro) the specific approach to industrial customer demand billing used by Hydro appears onerous compared to some other jurisdictions in Canada and contrary to normal price signal considerations. In particular, we note the following:

- ***Manitoba Hydro's*** billing demands to their industrial customers (General Service Large) only reflect the greater of the actual peak of the current month or 80% of the highest peak achieved in the previous December, January and February[164]. Where a customer is taking surplus power under the Surplus Energy Program ("SEP"), the demand charges for firm power are not applied to loads above the specified "Reference Demand" cut-off for SEP.

- ***Nova Scotia Power's*** Large Industrial Rate provides for demand charges on the maximum demand in the current month or the maximum actual demand of the previous December, January and February occurring in the previous 11 months[165].

- ***BC Hydro's*** industrial customers billing demands reflect the highest current period demand, or 75% of the highest peak in the previous winter, or 50% of the contract demand[166].

- In ***Yukon*** and ***Northwest Territories***, billing demands to industrial customers are based on either the highest current month firm peak or the highest firm peak of the previous twelve months, whichever is greater[167]. However, in this case, there is limited applicability of the Yukon

cents/kW.h and the forecast diesel based non-firm energy rate is 11.982 cents/kW.h. In addition, the interruptible energy rate proposed by Hydro includes an additional 10% premium over these thermal generation costs plus $1.50 per kW of demand.

[164] There are also rarely used provisions that the billing demand cannot be less than 25% of contract demand, or 25% of the highest measured demand in any of the previous 12 months. Per Manitoba PUB Order 53/96.

[165] Per NS Power Large Industrial Rate Schedule.

[166] BC Hydro Electric Tariff, Schedule 1821

[167] This is per Rate Schedule 39 for Yukon Energy and the Giant Mine rate tariff for NWT (in addition in Yukon, there is a contract minimum demand for industrial customers which is not normally relevant). A comparable 100% ratchet provision in Newfoundland would ensure that a customer's demand charges are not as high as the Power on Order if their usage has been below that level for 12 months. In this case, depending on the specific load profile, a comparative analysis would show that there can be months where the demand charges are higher under the Newfoundland approach and likewise months that may lead to higher demand charges under the Yukon and NWT approach. However, the Yukon and NWT approach would remove the requirement for the customer to specify a Power on Order under the current effective take-or-pay system in Newfoundland.

and Northwest Territories approaches as these jurisdictions do not offer an interruptible power program and so there is no need to clarify the cut-off between firm demand and interruptible demand (such as accomplished by the Manitoba Hydro Reference Demand noted above).

The above jurisdictions, by relying on maximum monthly demand peaks to a significant extent, ensure there are consistent and appropriate price signals to the industrial customers of the costs that result from demand consumption. For example, in Manitoba so long as a customer is above the 80% ratchet level, each extra kW peak they impose on the system results in additional charges on their bill. However, the customer is only responsible for paying for demand peaks they actually impose on the system, not peaks they forecast up to 14 months earlier[168]. This approach to demand billing appears to reflect more consistent cost causation principles than the Power on Order take-or-pay demand billing approach adopted by Hydro to date.

7.1.2.2 Interruptible Power

The interruptible power provisions under the industrial contracts are more onerous than those usually encountered for industrial interruptible energy programs in other jurisdictions. It is important to note that Interruptible industrial rate offerings are not unique to Newfoundland Hydro. A number of these programs, including those provided by Hydro in IC-222, are summarized in Attachment G.

In the interruptible energy programs noted in Attachment G, the energy rates for interruptible power are typically higher than the specific incremental costs to supply the power[169]. These energy rates are generally comparable to Newfoundland Hydro's proposed 10% premium over the incremental fuel costs incurred.

However, Newfoundland Hydro is the only utility that includes a demand charge component in their program. There does not appear to be any sensible basis for charging a customer for demands that, by definition, will not impose new peak demand costs on the system (as these loads will be interrupted at times of constrained system peak demands). To the extent that these loads are expected to cover in excess of the incremental costs they impose on the system (to reflect some contribution towards the fixed costs of the system), this is already covered in the 10% premium charged on the energy rate, similar to the other three utilities reviewed.

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[168] For example, in reference to the 80% ratchet mechanism, Manitoba Hydro has objected to removal of the ratchet otherwise customers may lose an incentive for discipline regarding the peaks they impose on the system.

[169] For example, 3% plus .12 cents/kW.h in Nova Scotia, 0.9 cents/kW.h on-peak and 0.3 cents/kW.h off-peak in New Brunswick, and 10% plus transmission losses and plus 0.06 cents/kW.h in Manitoba. In the case of Manitoba, this is the relevant provision of the Manitoba Hydro Surplus Energy Program when supplied from Manitoba Hydro generation (as opposed to purchased power or foregone export sales, which are not relevant in Newfoundland). Manitoba Hydro also charges $100 per month to customers who take surplus energy.

With the 10% premium included, the rates paid for interruptible energy are higher on a per kW.h basis than the costs for high-load factor firm power. However, the loads to be served by interruptible power are considerably different than the loads that a customer would seek to serve with firm power:

- the availability of the interruptible power is riskier,
- the price for the interruptible power can change both quickly and dramatically, and
- the uses reflect opportunistic loads that are capable of being interrupted on short notice.

As a result, the interruptible power loads are likely to have a very low annual load factor. A customer would not be likely to have such loads served by firm power, as the low load factors would result in very high effective rates (due to annual demand charge ratchets, and the limitations of the Power on Order approach).

It is clear that interruptible power is an essential part of the rate offering to industrial customers. The provision of this power, at an energy rate 10% above the incremental costs, provides benefits to both the industrial customer using the power, and to the rest of the system (and likewise the rates paid by the other customers on the system). There does not appear to be any basis to levy a demand charge for this service.

7.1.2.3 Industrial Customer Summary

The Industrial Customer rate provisions in Newfoundland reflect an onerous combination of demand and energy charges. In order to ensure that the bills paid by industrial customers fairly reflect the costs they impose on the system, the following adjustments to the industrial contracts are merited:

- The customer's demand charges in any given month should reflect the greater of actual peak for that month, or 80% of the peak the customer established in the previous winter (December, January and February[170]). This is the same provision as currently used in Manitoba (80% winter ratchet), which also a winter peaking load[171], and above the firm demand provisions in BC (75% winter ratchet) and above the 70% ratchet that is to apply to industrial service in Manitoba as a result of recent Manitoba PUB ruling.
- The rate for Interruptible Power above the Power on Order should retain the proposed energy charges, but should not be subject to demand charges. This is comparable to the approach to interruptible billing in Manitoba and New Brunswick.

The customer would still be required to set a Power on Order, and this figure would continue to be the cut-off between firm power (on which the customer pays firm demand and energy rates) and

[170] This reflects the fact that the Newfoundland system can peak in any one of these three months, and approximately 95% of the LOLH arises in these three months in 2004 per IC-301.

[171] The most recent Board Order in Manitoba (Order 7/03) determined it was appropriate to reduce the ratchet to 70% on April 1, 2003 and eliminate the ratchet on April 1, 2004; however, this order has been stayed pending a Review and Variance application by Manitoba Hydro.

interruptible power (on which the customer only pays interruptible energy rates). The customer would have incentive to set the Power on Order at the level that reflects full supply of their mission-critical high-load factor operations, but below the opportunistic, interruptible low load factor operations.

The interruptible power would continue to cover all variable costs of generation plus a margin, so it would be appropriate to continue to account for all fuel used to supply the interruptible load outside of the RSP.

7.2 RATE STABILIZATION PLAN

As reviewed in the 2001 Hydro Rate Review, the RSP has formed a substantial portion of customer's bills since its inception. More recently, at May 2003, the RSP charge comprised 15% of the total IC energy rate[172] and based on the rates proposed by Hydro in the application, this is projected to increase to more than 27% of the total IC energy rate at January 1, 2004[173]. Clearly, the RSP is an important element of Hydro's overall rate structure that is before the Board in the Application.

The RSP is included as a specific rate schedule in Volume I of Hydro's Application.

Based on the information reviewed below, as well as in Attachments C and D to this testimony, it is apparent that the new RSP and all balances therein (deriving from September 2002 forward) are best viewed as an interim mechanism pending the Board's decision in this rate case proceeding[174]. This allows for a sensible and coherent review of the new RSP charges to date, the balances included therein and the optimum approaches to addressing the future operation as well as existing balances.

Concerns identified at this time that appear to have a material impact on the revenues Hydro proposes to collect and the charges imposed on the IC group relate primarily to five areas:

1. The ***'Load Variation'*** component of the RSP continues to be inappropriate in regards to normal prospective rate-setting practice.

2. The ***'Hydraulic Production Variation'*** component is a long-term stabilization mechanism that should not be collected and/or refunded on a two-year cycle, but rather focus on staying within a sensible operating range over the long-term.

3. The ***'Fuel Cost Variation'*** component is a short-term deferral that should be addressed in the most expeditious way tolerable to ensure timely price signals and minimum inequities. There also

[172] The IC RSP charge at May 2003 was 0.423 cents per kW.h per the May 2003 RSP report. The IC base energy rate was 2.388 cents/kW.h, for a total IC energy rate of 2.811 cents/kW.h.

[173] The IC RSP rate forecast for January 1, 2004 is 1.04 cents/kW.h per Banfield page 20. The IC base energy rate proposed for January 1, 2004 is 2.765 cents/ kW.h for a total forecast IC energy rate of 3.805 cents/kW.h.

[174] This would ideally include consideration of any conclusions available from the study discussed by the Board in P.U.7 (2002-2003) as well as evidence called by various parties to the current proceeding.

does not appear to be any benefit from the complexities associated with using differing monthly fuel price forecasts as opposed to simple annual averages.

4. The ***mechanism for collection*** need not include a complicated NP/IC breakdown.

5. The ***interest rate*** charged/paid by Hydro should reflect the short-term nature of the RSP asset/liability to Hydro.

This evidence provides an overview of the RSP as it was reviewed in the 2001 proceeding, reviews the creation of the 'Old RSP' and 'New RSP' accounts per P.U. 7 (2002-2003), followed by a detailed review of the New RSP operation to date. This is followed by discussion on the five concerns noted above.

On balance, our review indicates that the new RSP maintained by Hydro should be adjusted as follows:

- The ***hydraulic component*** of the new RSP, comprising somewhere on the order of $11 million as of the end of May, 2003, should be isolated into a hydro stabilization fund. The hydro stabilization fund should continue to operate in basically the same way as the existing RSP hydraulic provision. No collections or refunds should be undertaken on this fund until such time as an adequate trigger, likely in the $50 to $100 million dollar range (positive or negative), is reached. Interest on the balances should be charged or credited at an appropriate short-term rate.

- The ***fuel cost component*** of the RSP, comprising nearly $45 million at May 2003, should be isolated in a fuel price stabilization fund. This fuel price stabilization fund should ***continue*** to operate in basically the same manner as the existing fuel cost variation component of the RSP. Balances that accrue in this fund should be charged and/or refunded to customers using an equal per kW.h rider for IC and NP[175] in an expeditious manner, recognizing the need for rate predictability and smoothing. Interest on the balances should be charged or credited at an appropriate short-term rate.

- The ***load portion*** of the new RSP should be terminated. The small existing balance (about $2.7 million owing to customers) should be rolled into the overall fuel cost stabilization fund noted above to assist in mitigating the impact of the substantial existing balance in that account.

The end result of applying this approach would be somewhere on the order of $42 million owing from customers as of the end of May, 2003 for the fuel price stabilization fund, which should be pursued from customers on an equal NP/IC rider basis going forward before the balance grows larger with further fuel use and interest charged by Hydro.

[175] Rural riders would reflect the retail riders put in place by NP to pass through the Hydro-NP rider.

7.2.1 Overview from 2001 Proceeding and Creation of New RSP

The RSP was a major topic of review at the 2001 Hydro rate proceeding, comprising a substantial number of Information Requests, a considerable amount of evidence from intervenors, and many days worth of testimony. The evidence of Mr. Osler regarding the RSP in the 2001 Hydro rate proceeding focused on 3 primary considerations:

1. that the balances in the RSP deriving from operation of the Plan since 1985 be restated from 1992 onwards in part to reflect elimination of the Average and Excess Demand approach, and the elimination of the two disconnected industrial customers (Albright and Wilson and Royal Oak mines)[176];

2. that the fuel price used for rate setting purposes and for calculating the RSP fuel price variance component target more regular review and adjustment than had been the case since 1992, and that it be designed to reasonably reflect current market conditions[177]; and,

3. the elimination of load component of the RSP for all customers[178].

In its Decision P.U. 7 (2002-2003), the Board rejected point 1 above. The Board utilized the then best available forecast price of fuel for the purpose of setting rates and ordered Hydro to submit its next General Rate Application no later than December 31, 2003, which fully addresses point 2 above. On point 3 above (the elimination of the load variation provision), the Board noted as follows:

> "The Board does however note the concerns and issues surrounding the RSP raised by the intervenors, especially the CA and the IC, in particular concerns about the complexity of the plan and the interactions of the various components of the plan, especially the inclusion of the load variation provision. The Board also agrees that the existing RSP and its operation is difficult to understand.
>
> The Board is convinced, based on the evidence and issues raised at the hearing, that the design and elements of the existing plan should be reviewed. To that end the Board will commission a study of the RSP, which will include a review of the plan since its implementation, together with the operational issues raised by the intervenors at the hearing. The Board will decide based on the results of that study what action should be taken."[179]

[176] Pre-filed 2nd Supplementary Testimony of C.F. Osler (2001 Hydro Rate Review), page 8.
[177] Pre-filed Supplementary Testimony of C.F. Osler (2001 Hydro Rate Review), page 36.
[178] NLH-99.
[179] Decision P.U. 7 (2002-2003), page 84.

The above-mentioned study, to the extent it may have been completed, has not yet been made available for review in preparing this testimony.

The Board's Decision basically divides the RSP into two components – the "old RSP" comprising the balance as at August 31, 2002 and the "new RSP" comprising all activity from September 1, 2002 onwards. The old RSP, as reviewed below, is currently being collected by a rider from each of NP and IC on a straight-line basis over five years. To date, we are not aware of any initiation of riders or recollection of the new RSP balances reported by Hydro.

As a result of the above, the 'new RSP' balances are currently comprised solely of amounts Hydro calculates to be properly charged to the Plan, including interest, with no charges or riders having been assessed on customers to date. All justification for these charges derive from the Board's decision in P.U.7 (2002-2003) which recognized the lack of finality in regards to the optimum long-term structure and operation of the RSP at page 84, where it noted "The Board is convinced, based on the evidence and issues raised at the hearing, that the design and elements of the existing plan should be reviewed". As a result, it is apparent that the new RSP and all balances therein (deriving from September 2002 forward) are best viewed as an interim mechanism pending the Board's decision in this rate case proceeding[180]. This allows for a sensible and coherent review of the new RSP charges to date, the balances included therein and the optimum approaches to addressing the balances that have arisen.

7.2.2 Old RSP Versus New RSP

The Board's Decision in P.U. 7 (2002-2003) effectively divides the RSP into two components – the "old RSP" comprising the balance as at August 31, 2002 and the "new RSP" comprising all activity from September 1, 2002 onwards:

- ***Old RSP:*** The old RSP balances are carried forward in two portions, one for NP and one for IC. The Board's Decisions sets out that these balances are designed to be recovered over five years using a straight-line recovery method. The Old RSP balance was locked in at $105.838 million181 comprising $28.638 million for the IC and $77.200 million for NP. The initial rate set by the Board in P.U. 7 (2002-2003) for recovery of the Old RSP balance was 0.177 cents/kW.h for NP and 0.280 cents/kW.h for IC182. However, the rates set in P.U. 7 (2002-2003) were insufficient to recover the Old RSP balance within the directed five year timeframe. As a result, the IC rate was adjusted at December 31, 2002 to 0.423 cents/kW.h183 (an increase of 51% on the RSP portion of the IC energy rate, or 5.4% on the overall IC energy rate184). The NP rate remained at 0.177

[180] This would ideally include consideration of any conclusions available from the study discussed by the Board in P.U.7 (2002-2003) as well as evidence called by various parties to the current proceeding.
[181] August 2002 RSP Report page 16.
[182] September 2002 RSP Report page 19.
[183] January 2003 RSP Report page 19.
[184] The IC base energy rate at December 31, 2002 was 2.388 cents/kW.h. The effect of the RSP rate change was to increase the IC overall energy rate from 2.668 cents/kW.h to 2.811 cents/kW.h.

cents/kW.h until July 1, 2003 when it increased to 0.324 cents/kW.h185 (an increase of 83%, or a wholesale energy rate increase of 3.0%186).

It is not apparent how the "straight-line" recovery method is being applied by Hydro. A normally applied straight-line method would be expected to result in setting an RSP rider measured in cents/kW.h that would be equal for the five year period. It appears from Banfield page 20 to 21 that the IC "old RSP" rate is forecast to rise from 0.423 cents/kW.h to 0.43 cents/kW.h (presumably at December 31, 2003) and the NP "old RSP" rate is to rise from 0.324 cents/kW.h to 0.344 cents/kW.h at July 1, 2004. There also seems to be an unexplained adjustment included in the old RSP balance from December 2001 which purportedly relates to a Deer Lake power purchase that increases the balance in the fund by $179,000, $110,000 from IC and $69,000 from NP[187] that would seem to merit addition review.

- ***New RSP***: At September 1, 2002, Hydro initiated a new RSP to address all amounts from that point forward. Up to the end of May 2003, that new RSP had resulted in charges of $54.020 million including all RSP components plus interest. No collections had yet begun by that time on the new RSP. A detailed analysis of the balances in the new RSP is set out below.

  Hydro now forecasts that the new RSP will give rise to a requirement for an additional 0.61 cents/kW.h "new RSP" charge for the IC effective December 31, 2003 in addition to the 0.43 cents/kW.h old RSP charge. For NP, the projected new RSP charge effective July 1, 2004 is 0.558 cents/kW.h in addition to the 0.344 cents/kW.h old RSP charge[188]. By December 31, 2003, the projected new RSP balance is $67.0 million comprised of $16.8 million for IC and $50.2 million NP[189].

There has been insufficient time to review the materials filed in respect of the old RSP balances and the collection to date, including the extent to which it reflects the Board's direction to collect the outstanding balance over five years on a straight-line basis. The new RSP is reviewed below in some detail, as well as in Attachment C.

7.2.3 Operation of the New RSP

The concept of a rate stabilization mechanism as it is applied in other similar jurisdictions (i.e. non-interconnected grids that generate electricity with a mix of hydro and petroleum, such as Yukon or the Northwest Territories) is to provide protection for both ratepayers and the utility from variations in such uncontrollable variables as water availability and petroleum prices. In each case, the utility and the

185 per Banfield, page 21.

186 The NP base energy rate at July 1, 2003 was 4.789 cents/kW.h. The effect of the RSP rate change was to increase the NP overall energy rate from 4.966 cents/kW.h to 5.113 cents/kW.h.

187 For example, see footnote 2 from January 2002 RSP report.

188 Banfield, pages 20 and 21.

189 Banfield, page 20.

regulatory body normally set rates based on their best estimation of the costs to provide service over the test year, and the rate stabilization mechanism adjusts for any difference that occurs in utility revenues or costs due solely to these uncontrollable variables. From our understanding of the RSP, this is generally the way it was designed to work when the Board created it in 1985[190].

In this regard, the new RSP operates similarly to the RSP that existed from about 1985 up to August 2002 with a few notable exceptions[191]:

- The hydraulic and fuel price components operate basically the same as the previous RSP except that the variables assumed for fuel prices, long-term average hydraulic generation and fuel efficiency at Holyrood have been updated to reflect P.U. 7 (2002-2003) and P.U. 21 (2002-2003).
- The load provision reflects updated test year load forecasts and rates per P.U. 7 (2002-2003) and P.U. 21 (2002-2003).
- There is no longer an RSP cap of $50 million for the NP balance owing.
- The fuel-related amounts are now divided based on 12 months-to-date energy sales, with no Average and Excess Demand reallocation or demand-related cost rebalancing.

The net result is a material simplification of the operation of the RSP. However, the fund continues to be more complicated than seems necessary given the ability of other similar jurisdictions to operate without this level of analysis or tracing being required (see Attachment D regarding sample stabilization mechanisms from other jurisdictions).

The materials made available to date show the new RSP operation from its initiation at September 2002 to May 2003, a period of 9 months. This operation is summarized in detail in Attachment C and in the table below.

[190] However, a number of additional details in the Newfoundland and Labrador Hydro RSP set it apart from the types of mechanisms seen elsewhere, as discussed in Attachment D to this testimony.
[191] Other minor changes include inserting the mini-hydro plants in the RSP, excluding any interruptible energy sales or fuel used for that purpose, and establish RSP collection energy rates based on 12 month-to-date sales.

Table 7.1: Operation of the New RSP from September, 2002 to May 2003

$ millions	**Hydro**	**%**	**NP**	**%**	**IC**	**%**
Hydraulic	**$11.316**	***21.23%***	$8.249	*23.52%*	$2.344	*16.39%*
Load	**($2.689)**	***(5.04)%***	($5.848)	*(16.67)%*	$2.800	*19.57%*
Fuel Price	**$44.677**	***83.82%***	$32.667	*93.15%*	$9.160	*64.03%*
Total	**$53.304**	***100%***	$35.068	*100%*	$14.305	*100%*
Rural Reallocation	***$(0.507)***		*$3.422*		*$0*	
Interest	***$1.244***		*$0.939*		*$0.305*	
Other Adjustments	***$(0.021)***		*$(0.015)*		*$(0.004)*	
Revised Total	***$54.020***		*$39.415*		*$14.605*	

Key observations in regards to the above are as follows:

- ***Fuel Price:*** The Fuel Price variation component makes up the largest part of the overall Hydro new RSP balance to date (at about 84%). This provision has been climbing at between $1.1 million and $8.4 million per month (plus interest accruing on the balances).

- ***Hydraulic:*** Hydraulic variation is a material component of the new RSP balance to date (at about 21%); however this hydraulic variance is well below the types of triggers or thresholds that are normally considered for hydro stabilization funds, including the previous (pre-1985) $36 million trigger applied for Newfoundland and Labrador Hydro[192] (with no adjustment to this figure for inflation or load growth since that time).

- ***Load Variation:*** The load variation provision is a small part of Hydro's overall RSP, but comprises nearly one-fifth of the amounts owning from IC, and credits NP with about one-sixth of the RSP that would otherwise be owing from that customer in the absence of this provision.

- ***Collection from Customers:*** No recollection of these balances has been initiated, and none is proposed for IC until January 1, 2004 and for NP until July 1, 2004[193]. As this balance reflects nine months of operation of the new RSP to the end of May 2003, this means that an additional seven months of operation will occur before IC is assessed a charge for the new RSP, and an additional 13 months until NP is assessed any 'new RSP' rate.

[192] This is referenced in Board Decision P.U. 7 (2002-2003) at page 79. Likewise, the Northwest Territories Power Corporation maintains a hydro stabilization fund with a trigger of $3 million on a total long-term average annual hydro generation of 177.5 GW.h, and Yukon Energy's comparable "Diesel Contingency Fund" uses a trigger of $4.04 million on annual hydro generation of 351 GW.h – on a comparable basis, Newfoundland Hydro's trigger (on 4,582 GW.h long-term average per Haynes Schedule II) would approximate $77 million and $53 million respectively.

[193] Reflects Banfield, page 20 and 21.

- ***Interest:*** The nine month period has resulted in about $1.24 million in interest to Hydro at a 7.157% cost of capital – a further seven to thirteen months until the first 'new RSP' riders are implemented will result in a drastic increase in this interest provision, including a proposal from Hydro to increase the effective interest rate to 8.440%[194] effective the date of rate implementation currently proposed for January 1, 2004 (despite short-term interest rates being at record low levels).

7.2.4 Concerns with the New RSP

Based on the above review, it is apparent that a number of aspects of the new RSP raise concerns that merit attention.

7.2.4.1 Load Variation

The 'Load Variation' component of the RSP is an anomaly among Canadian utilities that we are aware of, and is not the normal practice for assignment of the load risk. Our review of Canadian electrical utilities, particularly focused on integrated Crown utilities, indicates that in almost all cases (7 of 8 Crown utilities) all risks with respect to load reside with the utility[195]. This is in part illustrated by the fact that none of these utilities maintain any form of account or trust that accumulates amounts related to variations in annual or monthly sales from the load forecast[196]. More importantly, for the one utility that does have a Rate Stabilization Account that in any way addresses load variation (BC Hydro), as well as two utilities which previously operated as Crown utilities with similar accounts (Ontario Hydro and Nova Scotia Power), none appears to have applied any differential collection to individual customer groups related to the accounts (i.e. would suggest no difference in application to NP versus IC).

The load variation mechanism used by Newfoundland Hydro results in three major problems:

1. it removes Hydro's risks with respect to its load forecast;
2. it results in inappropriate price signals and cost allocations to customers; and,
3. it necessitates complicated IC versus NP accounting and collection.

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[194] This arises from Greneman, Exhibit RDG-1, Schedule 1.1, page 2, row 17.

[195] This includes SaskPower, Manitoba Hydro, New Brunswick Power, Hydro Quebec, Northwest Territories Power Corporation, Yukon Energy Corporation, and Nunavut Power Corporation. The one exception (BC Hydro) involves a special Rate Stabilization Account that is not at all comparable to the RSP approach (see next footnote).

[196] In one case (BC Hydro) a special Rate Stabilization Account is established by Provincial Government direction which is effectively an *earnings and dividend* stabilization mechanism. In this way, it does implicitly stabilize BC Hydro's earnings for load variation among other factors, but unlike the Newfoundland Hydro RSP, it does not lead to charges and/or refunds to customers. Certain of the Crown utilities have at various times in the past had similar stabilization accounts, such as the Ontario Hydro Account for Stabilization of Rates and Contingencies, or the Nova Scotia Power Corporation Rate Stabilization Reserve. However, similar to BC Hydro's Rate Stabilization Account, each of these reserves was intended to stabilize overall earnings for the Corporation from all factors (neither specifically addressed load variation in the format of the Newfoundland Hydro RSP), to our knowledge neither account ever resulted in charges or refunds to customers, and neither of these two mechanisms continues to exist.

Each of these major problems is elaborated on below. To address these problems, and to conform with normal COS and rate design principles, is recommended that the load variation provision be deleted from the RSP.

7.2.4.1.1 The Load Variation provision removes all of Hydro's risks associated with its load forecast

- ***Assigns risks onto customers rather than Hydro:*** The load variation provision ensures that any variation in Hydro's net income related to variations in load is charged back to customers – that is Hydro's earnings are completely insulated from any variation due to load developments. This is inconsistent with normal regulatory practice in a jurisdiction where rates are set on a prospective basis[197]. As reviewed in NLH-99 from the 2001 proceeding, the overall load provision resulted in $18.816 million in additional income to Hydro from 1992 to 2000. In contrast, the new RSP operating over the nine month period from September 2002 to May 2003 has resulted in $2.689 million being credited back to customers (reduced net earnings to Hydro) related to the load provision[198].

- ***Assigns costs of load variation to specific customer groups:*** In addition to the removal of any load-related risk related to Hydro's own load forecast, the load variation provision of the RSP as it is practiced by Newfoundland Hydro takes the total amounts derived from insulating Hydro from load risks, and specifically assigns these amounts to individual customer groups. Using the September 2002 to May 2003 period as an example, Hydro's net credit to customers of $2.689 million via the RSP Load provision results in $5.848 million being provided to NP, and $2.800 million being charged to IC.

7.2.4.1.2 The Load Variation provision results in inappropriate price signals and cost allocations

As reviewed in detail in Attachment C, the operation of the load variation provision in the RSP means that rates paid by customers for incremental increases or decreases in consumption compared to the load forecast are counter-intuitive and without any reasonable foundation:

- ***NP load growth:*** The 207.9 GW.h increase in NP's load compared to forecast over the nine months of the new RSP has resulted in an effective rate to NP on this new load of 2.97 cents/kW.h[199], while also effectively charging IC 0.83 cents/kW.h[200] for each kW.h that NP used

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[197] The prospective method of regulation is the norm for fully regulated utilities. An alternative is retrospective regulation based on actual performance of the utility achieved in a given year, but we are not aware of any jurisdictions that regulate their Crown electric utilities (or any other type of utility) on this basis.

[198] See Table 7.1 above.

[199] See Attachment C. This excludes the rural deficit reallocation and excludes the fuel price variance portion arising from increased NP use.

over forecast. The effective rate to NP is well below the approved NP firm energy rate of 4.789 cents/kW.h and below the average cost of Holyrood fuel to supply this load (using GRA approved fuel prices) of 4.062 cents/kW.h[201]. Further, over this period the true cost of Holyrood fuel has been as high as 80% above this GRA fuel price[202]. As a result, there is a inappropriate price signal to NP (or the eventual retail customers) with respect to increasing consumption.

- ***IC load reduction:*** The 69.1 GW.h load reduction for IC compared to load forecast over the nine months of the new RSP has resulted in an effective savings to the IC group of only 0.829 cents per kW.h that the load was reduced. This is well below the normal IC approved rate of 2.388 cents/kW.h[203] that one would normally expect the customers to save by reducing their load. Further, this 0.829 cents/kW.h[204] is then spread across all four customers in the IC group, so the individual customer that actually reduces their load saves costs *well below* this level. In contrast, the load reductions by industrial customers result in savings to NP of 3.00 cents/kW.h for each kW.h saved. Given that the cost of fuel saved as a result of this load reduction is 4.091 cents/kW.h[205] based on 2001 GRA forecast fuel prices, and that actual fuel prices have been as high as 80% above this level, this is clearly an inappropriate price signal to the industrial customers for reducing their load during this period.

A further complication of the price signal in the RSP is that NP's existing rate is an energy-only structure. This results in a portion of the rate NP pays for each kW.h they consume being properly related to the demand peaks (kW) they impose on the system rather than the costs of supplying energy (kW.h). The load provision of the RSP, however, credits back to NP all revenues paid on the incremental load growth, with no attempt to isolate what portion of the rates paid are properly designed to compensate Hydro for incremental costs of supplied increased demand. This is inconsistent with IC, whose rate includes a demand and energy portion.

The clearest example of the inappropriate price signals arising from the load component is illustrated in IC-327, the forecast RSP accounting for 2005-2007. The response indicates that over the three year

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[200] See Attachment C. This excludes the rural deficit reallocation and excludes the fuel price variance portion arising from increased NP use.

[201] The cost of Holyrood fuel to supply the NP 207.9 GW.h load growth is calculated from Table C2 of this testimony, dividing the sum of $1.596 million (column H row 4) plus $6.849 million (column H row 9) divided by the 207.9 GW.h figure.

[202] In February 2003 the actual fuel price was $44.44 per barrel per the February RSP report, compared to a GRA forecast fuel price of $24.64.

[203] See Attachment C. This excludes the rural deficit reallocation and excludes the fuel price variance portion arising from increased NP use.

[204] See Attachment C. This excludes the rural deficit reallocation and excludes the fuel price variance portion arising from increased NP use.

[205] The cost of Holyrood fuel saved as a result of the IC 69.1 GW.h load reduction is calculated from Table C2 of this testimony, dividing the sum of $0.053 million (column H row 18) plus negative $2.880 million (column H row 23) divided by the 69.1 GW.h figure.

period, NP is projected to exceed their overall GRA test year forecast energy by a total 274.1 GW.h[206] while IC is forecast to vary only a small amount from GRA forecast (6.1 GW.h, with the majority of this due solely to 2004 forecasts being based on a 366 day year).

In the detailed set of tables provided in IC-327, the key conclusion is that, based on the long-term load forecast currently in place, Hydro proposes to operate the load component of the RSP to give rise to the following impacts solely related to the NP load growth over the period:

Table 7.2 Impact on Forecast NP Load Growth in 2005-2007 on RSP ($millions)

	Refund credit to NP RSP	**Charge to RSP for fuel to serve increased NP load**			**Total Credit (Charge) NP RSP**	**Total Credit (Charge) IC RSP**
		Total[207]	***Allocation to NP[208]***	***Allocation to IC***		
2005	$1.376	($1.128)	*($0.822[209])*	*($0.236[210])*	$0.554	($0.236)
2006	$4.799	($3.948)	*($2.893[211])*	*($0.817[212])*	$1.906	($0.817)
2007	$8.791	($7.518)	*($5.527[213])*	*($1.541[214])*	$3.264	($1.541)
Total	$14.966	($12.594)	*($9.242)*	*($2.594)*	$5.724	($2.594)

In other words, the above indicates a net credit to NP of $5.7 million via the RSP (2.09 cents/kW.h for each unit of load growth for the full 274.1 GW.h growth), while charging IC $2.6 million (0.95 cents/kW.h for each extra kW.h that NP consumes). Given that the above RSP forecast reflects an energy-only NP rate of 5.46 cents/kW.h[215], the net effect of the RSP adjustment is to reduce NP's incremental costs for the additional 274.1 GW.h they are forecast to consume to 3.37 cents/kW.h and require IC customers to pay an incremental cost of NP's consumption of 0.95 cents/kW.h. This results is clearly not consistent with normal rate structure operation, and is contrary to the implied structure of Hydro's rates, which, per the proposed Rate Schedule for NP and IC, reflect a fixed per-unit cost for all firm energy consumption, including incremental load growth.

7.2.4.1.3 The Load Variation provision gives rise to complicated IC versus NP accounting

For utilities that maintain either fuel price and/or hydraulic stabilization accounts, such as Yukon Energy or the Northwest Territories Power Corporation reviewed in Attachment D, there is no accounting

[206] 25.2 GW.h in 2005, 87.9 GW.h in 2006 and 161.0 GW.h in 2007 per IC-327 pages 8, 19 and 31 respectively.
[207] The IC component of load variation makes up about 1.2% of this amount.
[208] Excludes rural deficit allocation.
[209] 72.89% to NP in 2005 per IC-327 page 10.
[210] 20.90% to IC in 2005 per IC-327 page 10.
[211] 73.28% to NP in 2006 per IC-327 page 22.
[212] 20.69% to IC in 2006 per IC-327 page 22.
[213] 73.52% to NP in 2007 per IC-327 page 34.
[214] 20.50% to IC in 2007 per IC-327 page 34.
[215] See, for example, page 8 of IC-327

required to separate the charges to any particular group of customers. The amounts deferred in the various stabilization accounts are allowed to proceed until such time as a refund/collection is required (generally on a prompt basis for fuel price deferrals, and very infrequently, if ever, for hydraulic stabilization accounts). At that time the adjustment is applied equally to all kW.h sold without distinction between customer groups, as the charges relate to an energy-related cost.

In the Newfoundland Hydro system, this would entail determining the total forecast kW.h sales to IC and NP over the period that an outstanding balance is projected to be collected. The total balance to be collected would be divided by this kW.h sales to IC and NP to determine a single rider. Using the above example, Hydro's Fuel Cost RSP at May 2003 totalled $44.677 million excluding interest to date[216]. If using a 24 month collection period (to be consistent with P.U. 7 (2002-2003)), the IC and NP sales would be about double the 12 month totals from the May 2003 RSP report, or about 11,984 GW.h. The result of the division is an example of a 0.372 cents/kW.h rider for 24 months. As a result of 0.372 cents/kW.h being applied to all wholesale sales to NP, there would be a corresponding retail rider (likely slightly higher than this level, to account for distribution losses) that would likewise be applied to Hydro's rural customers[217]. As a result, Hydro's collections to be used in paying down the RSP balance would include 0.372 cents/kW.h on all kW.h sold to IC and NP, plus a slightly higher rider on Hydro's rural customers.

7.2.4.1.4 The Load Variation provision results in inconsistent treatment of special rates to NP and IC (wheeling and firming-up)

A very small portion of Hydro's revenue requirement is made up of two special purposes charges – one available to industrial customers who seek to "wheel" power across Hydro's transmission lines, and one available to NP, who on occasion purchases power from Hydro which Hydro has purchased from an industrial customer on an interruptible basis and seeks to have Hydro "firm-up" this supply. In each case, Hydro develops a rate that reflects the embedded cost of Hydro's plant that is required to provide the service (gas turbines, transmission and terminal stations for firming up, transmission and terminal stations for wheeling).

The cost of service and rate treatment for revenues derived from these two rates is substantially different. For wheeling service, Hydro credits the Island Interconnected revenue requirement with the full forecast revenues[218], and any amounts charged in excess of this amount appears to be simply a credit to Hydro's net income. The revenues derived from wheeling rates in the past 5 years are set out in CA-

[216] Ideally the amount to be collected would target the full current balance, plus the forecast RSP fuel-related charges for some next number of months, plus the expected interest that would accrue on that balance during the collection period, such that at some point in the future the Fuel Price RSP would be projected to come back down to zero.

[217] This is to reflect the normal practice of changing Hydro's rural customer rates at the same rates implemented for NP's customers.

[218] $70,964 per RDG-1 Schedule 1.1 line 14.

151[219] reflecting revenues as high as $414,522 in 2002. This compares to a forecast of $6,950 in the original 2001 application, and a forecast $0 in the final cost-of-service from the 2001 application[220].

In contrast, although firming up revenues are forecast at $0 in the cost of service, any revenues actually received are credited in full to the NP RSP[221]. In other words, any and all amounts paid by NP for the firming-up service are credited directly back to NP such that the firming up service is provided to them at a net cost of zero. Other customers likewise see no benefit from the firming up revenues, despite the fact that the other customers are paying for the assets that allow this service to be provided.

In each case, the revenues from these special rates are quite minimal on a forecast basis. Actual wheeling revenues can be substantial, as noted above, but it appears actual firming-up revenues are typically very small. Despite the dollar impact, the different treatment in the two rates is an additional indication of the distinct and preferential treatment of NP compared to IC.

On balance, there is no basis to address load variation from wheeling revenues or firming up revenues as a specific credit to any group of customers. The inconsistent impact of the RSP Load Variation provision in regards to these two rates would also be properly addressed by eliminating the RSP load variation component.

7.2.4.2 Hydraulic Production Variation

The hydraulic variation component of the RSP is a long-term stabilization mechanism that should not be collected and/or refunded on a two-year cycle, but rather focus on staying within a sensible operating range over the long-term. With proper long-term hydro generation forecasts, it would be expected that the hydro production component would *never* lead to additional charges or refunds to customers.

Despite this theoretical basis, the hydraulic component of Hydro's RSP, over the period 1992 to 2000, refunded to customers somewhere on the order of $78 million[222] (due to high water), but the nine-month period from September 2002 to May 2003 has resulted in about negative $11.3 million (due to low water) that Hydro proposes to start charging to customers starting December 2003 (for IC, July 2004 for NP).

During the early part of the 1980's, Hydro maintained a separate provision for hydraulic variation (a 'Water Equalization Provision'). According to Board Decision P.U. 7 (2002-2003) "The water equalization account had a maximum provision of $36,000,000 which was considered sufficient to absorb the adverse

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[219] The amounts in CA-151 reflect $137,243 in 1998, $230,012 in 1999, $185,367 in 2000, $350,957 in 2001 and $414,552 in 2002.

[220] The final cost of service reflecting P.U. 7 (2002-2003) and P.U. 16 (2002-2003) dated August 2002 at Schedule 1.1 line 14.

[221] Also see CA-67 which notes that no firming-up revenue is forecast, and all actual revenues are refunded via the RSP.

[222] This figure comes from the sum of the December RSP reports from the nine-year period, but was summarized in NLH-99 from the 2001 proceeding.

affects of a reoccurrence of the three consecutive driest years on record"[223]. Hydro's current evidence at Haynes, Schedule II indicates that the difference between average hydro conditions (4582.2 GW.h) and firm energy availability (presumably the measure of energy available in the driest year contemplated, at 3846.0 GW.h) is 736.2 GW.h per year. Using the 'three dry years' approach noted above, this would result in somewhere on the order of 2208.6 GW.h in variation over 3 years[224]. Using current fuel price forecasts[225] and Holyrood efficiency estimates[226], this would equate to a modern trigger of about $103 million.

Comparable hydro stabilization accounts in other non-interconnected jurisdictions suggest triggers on the order of $43 million to $77 million[227]. Using any of the approaches, the current $11.3 million balance owing from customers is well within the normal expectations of hydro variability and does not appear to merit any collections from customers in the near term (and ideally no collections until such time as water conditions return to normal or above normal levels).

In terms of price signals, refunds or collections of hydraulic production variances are not a particularly useful part of sending appropriate price signals to customers on the Newfoundland system. This is because in both low water conditions and high water conditions, the incremental generation on the system is basically Holyrood. In other words, a customer reducing their consumption during lower than average flow conditions is not saving the system any more costs than a person reducing their consumption during higher than average flows. This is in contrast to the fuel cost variation component, which should be properly viewed in part as a means to send an important and timely price signal to customers.

7.2.4.3 Fuel Cost Variation

Completely in contrast to the hydraulic variation component notes above, the fuel cost variation is a short-term deferral account that should properly result in some 'smoothing' of the costs of fuel, but still lead to adjustments in the most expeditious way tolerable to ensure timely price signals and minimum inequities.

The record in Newfoundland seems to indicate a basis for concern over smoothing versus deferral. The concept of smoothing fuel cost variations is a requirement to prevent massive and routine rate revisions that are intolerable to customers and difficult to manage for the utility. The pre-1985 Fuel Adjustment

[223] P.U. 7 (2002-2003) page 79.

[224] The level might reasonably be somewhat below this, as the "three driest years on record" does not necessarily need presume three consecutive repeats of the driest year on record.

[225] $29.20 per barrel for 2004 per Haynes Schedule VIII.

[226] 624 kW.h per barrel for 2004 per Haynes Schedule VII

[227] The Northwest Territories Power Corporation maintains a hydro stabilization fund with a trigger of $3 million on a total long-term average annual hydro generation of 177.5 GW.h, and Yukon Energy's comparable "Diesel Contingency Fund" uses a trigger of $4.04 million on annual hydro generation of 351 GW.h – on a comparable basis, Newfoundland Hydro's trigger (on 4,582 GW.h long-term average per Haynes Schedule II) would approximate $77 million and $53 million respectively.

Clause in Newfoundland appears to be a prime example of inadequate smoothing, as fuel price changes appear to have been flowed through monthly resulting in, among other things, a complete inability for customers to plan for or project their electricity costs. In contrast, the extreme response to inadequate smoothing is continual deferral of fuel cost increases in order to ensure rates only rise on an overly-smoothed basis. The present new RSP appears to err somewhat in this fashion.

The new RSP has accumulated about $44 million related to fuel cost variation in nine months (to May 2003), and Hydro appears to propose no implementation of riders to recollect this amount (along with interest on the outstanding balance) until at least December 2003 for IC and July 2004 for NP (a further seven months and thirteen months respectively). This means that for NP customers, the rider that is started in July 2004 is only at that time starting to address the actual costs of fuel from as early as September 2002, and the two-year proposed collection means that this balance will not be fully addressed until June 2006.

A properly administered fuel cost variation account needs to be isolated from proper long-term stabilization accounts (such as the hydraulic variation provision) and ensure that higher costs for fuel get passed through to customers in a timely way consistent with normal rate design objectives that rates are change predictably and gradually to the extent possible. Within the context of the other cost changes arising in the present proceeding, it will be essential to assess the degree to which the deferred fuel cost balances amounts can be discharged in a more timely fashion than that proposed by Hydro to date.

7.2.4.4 Mechanism for Collection

As noted above, with the elimination of the load provision, there is no need or advantage to maintaining any form of separate NP/IC accounting for the RSP components. In the two other non-interconnected jurisdictions in Canada that utilize hydro (each of which has a mixture of Crown and investor-owned utilities, with the Crown utility both selling directly to customers and having wholesale sales to an investor-owned utility retailer), separate hydraulic and fuel stabilization accounts are used for stabilization, and each account is designed to be managed as a single balance for all customers, such that once a trigger is reached, an equal rider is applied to all sales.

7.2.4.5 Interest Rate

The RSP asset/liability to Hydro is not consistent with a long-term investment of the type normally considered to be part of ratebase, or assets that are financed by long-term capital (long-term debt and/or equity). In this regard, it is not apparent that Hydro's weighted average cost of capital is the appropriate interest rate to be charged on outstanding balances.

Looking at the comparable fuel and water stabilization funds maintained by other utilities, it is apparent that there are a number of other approaches that have been utilized by regulators:

- ***Yukon Energy Diesel Contingency Fund:*** This fund which is primarily a hydraulic variance stabilization fund, is managed as a trust outside of rate base, and earns or charges interest based on the prevailing investment/borrowing rate appropriate for short-term investments.

- ***Yukon Energy's Fuel Adjustment account:*** The Fuel Adjustment account maintained by Yukon Energy (as well as the separate fuel adjustment account maintained by the private utility The Yukon Electrical Company Limited) does not earn or pay interest at all[228]. Each Yukon utility is directed to implement fuel rider adjustments on a co-ordinated and timely periodic basis, as required to ensure that balances in these fuel accounts are adjusted periodically to maintain the balance at as low a level as is reasonable.

- ***Northwest Territories Power Corporation Diesel Stabilization Fund:*** NTPC's diesel price stabilization funds charge or credit interest at the prevailing short-term debt rates, measured as the monthly prime lending rate less 50 basis points.

- ***Northwest Territories Power Corporation Hydro Stabilization Fund:*** NTPC's hydraulic ***stabilization*** fund charges or credits interest at the prevailing short-term debt rates, measured as the monthly prime lending rate less 50 basis points.

- ***Nunavut Diesel Stabilization Fund:*** Nunavut Power maintains a diesel price stabilization fund that was broken out of NTPC's consolidated NWT/Nunavut account at the time of the division of the two companies. The Nunavut Utilities Board has reviewed the operation of this fund and approved riders to collect outstanding balances. The Board did not change the previous NTPC approach of charging or crediting interest at the prevailing short-term debt rates, measured as the monthly prime lending rate less 50 basis points.

- ***Centra Gas Manitoba's Purchased Gas Variance Account:*** The Centra Gas Manitoba gas price variance account uses a short-term carrying cost rate to accrue interest.

- ***Idaho Power's Power Cost Adjustment:*** Idaho Power's operation in Idaho maintains a Power Cost adjustment mechanism to address hydraulic and power acquisition price stabilization[229]. This account accrues interest at a rate tied to short-term rates while amounts are being charged to the account, and accrues no interest during periods where the account is being re-collected back from customers.

In summary, we have not been able to identify any such funds outside of Newfoundland that use a full weighted average cost of capital, or any long-term debt or equity cost rate, in calculating interest on the balance.

[228] As another example, the BC Hydro Rate Stabilization Account does not earn interest of any sort. However, as noted above this account is not comparable to the Newfoundland Hydro RSP.

[229] Both fuel costs and purchased power costs. The mechanism specifically excludes load changes from the calculation.

7.3 INTERRUPTIBLE B

The Interruptible B program previously offered by Hydro up to 2003 is outlined in Attachment H. Hydro now proposes to no longer offer this component of its industrial rates.

The specific details of the Interruptible B rate program are set out in Attachment H. Briefly, this program was in place under a contract from December, 1993 to March, 2003, and provided Hydro with the ability to call upon Abitibi Stephenville, at any time during the four winter months between the hours of 0800 and 2200, to reduce their power consumption by up to 46 MW for up to 10 hours. The interruption could be initiated on one hour's notice. This type of program is similar to interruptible capacity rate offerings by other utilities, as outlined in Attachment G to this submission.

Use of a curtailable program by large industrial customers requires a portion of their load to be served by this lower quality power (defined to be of lower quality than firm power since it can be interrupted on short notice). In order to enable their operations to utilize this low quality power, there can be substantial required investment in capital, development of operating procedures, and staff training. The quantities of power in question (46 MW) form a substantial part of the capacity that is normally consumed by the customer. Subscription to Interruptible B can require changes to many facets of a large organization in order to optimally respond to the requirement for a curtailment. This type of program cannot be easily implemented on short notice (i.e., changing program availability from year to year).

In the case of Manitoba's Curtailable Service program discussed in Attachment G, this rate offering is reviewed and approved by Public Utilities Board, and is made available to all qualified industrial participants[230] (up to a maximum subscription limit). A recent review by the Manitoba Public Utilities Board regarding renewal of the program concluded that the program was to be renewed on a permanent basis[231]. The Manitoba PUB had previously concluded that the program would benefit both Manitoba Hydro and its overall ratepayers[232] (not just the industrial customers who subscribe to the program). Manitoba Hydro, in a submission to the PUB regarding the Curtailable program, specifically noted that the program benefits arise from the long-term participation of the loads, and as such the program had to be viewed in terms of retaining the loads and the program participants over the long-term. Specifically, Manitoba Hydro's rebuttal evidence filed in the 2002 Status Update Filing before the Manitoba PUB notes, at page 35:

> "It is a fact that Manitoba Hydro's curtailable rate offerings have always relied, to a certain extent, on the longer term benefits, even where current program duration may not be sufficient to capture these benefits and, in fact, even during the period that the program was experimental. However, Manitoba Hydro's experience is also that most curtailable load can be expected to be available in the longer term, provided that some

[230] Customers must have a minimum of 5 MW of curtailable load.
[231] Manitoba PUB Order 7/03.
[232] Manitoba PUB Order 148/93.

recognition is given to the longer term benefits in the early years to justify the necessary customer investment to be able to participate. ”

In contrast, Newfoundland Hydro appears to have determined that it will ignore long-term benefits from curtailable load. Hydro has confirmed that a program such as Interruptible B would be among the items considered to address future capacity shortages[233].

It is apparent that Hydro is not in a capacity constrained situation at the current time. To the extent that Hydro has determined it is appropriate to retain all currently installed peaking generation plant in revenue requirement as used and useful assets, there is a clear recognition that although these assets are not required to retain the LOLH below the target maximum of 2.8 hours in the short-term, they may reflect a longer-term benefit to the Island Interconnected system. The same rationale supports continuation of the Interruptible B program on an uninterrupted basis.

The response to CA-156-IC indicates that Abitibi Stephenville has approached Hydro to renew the Interruptible B program for another 10 years, at the same terms and conditions as the ten-year contract from 1993 to 2003. This proposal reflects a discount to Abitibi on the power costs they would otherwise pay, and results in the discount remaining constant for 20 years (with no provision for inflation or other escalation). Recognizing the long-term benefits of a rate of this type, it is apparent that the Board should ensure Hydro offers the Interruptible B rate to Abitibi Stephenville as proposed (i.e., on the same terms and conditions as for the previous agreement)[234]. It is also apparent that Hydro should be directed to study the long term avoided cost benefits arising from expanding the rate program to other industrial customers, and consider the maximum additional Interruptible B that it could make available to other industrial customers in the future[235].

[233] NP-138.

[234] This does not specifically address whether the rate would be required to be offered to all industrial customers on the same basis. If that were determined to be the case, the 46 MW of subscription should be made available, and allocated to all industrial customers that are interested using some reasonable approach to apportionment. The rest of the proposal as it reflects expansion beyond 46 MW is valid in either case.

[235] Hydro has confirmed that it has not investigated the expansion of the program in NP-139.

ATTACHMENT A – RESUME - CAMERON F. OSLER

PRESIDENT AND SENIOR CONSULTANT

EDUCATION: Simon Fraser University
M.A. (Economics) 1968

University of Toronto Law School
1964-1965

University of Manitoba
B.A. (Philosophy) 1964

PROFESSIONAL HISTORY:

1974 - Present Founding partner and President of InterGroup Consultants Ltd. (formerly InterGroup Consulting Economists Ltd.). Director, CBT Energy Inc. (2000 - Present)

Strategic planning and multi-disciplinary project team management experience, based on resource and regional economics expertise relating to mining, energy (particularly hydro-electric generation and renewable liquid energy fuels), and downtown tri-government urban development projects.

Detailed project experience is outlined below separately under each of the following headings:

- Utility Regulation – Expert Analysis and Testimony at Hearings
- Strategic Planning & Multi-disciplinary Project Team Management - Resource, Regional and Urban Development Projects
- Socio-Economic and Environmental Assessment & Related Public Consultation – Mining, Hydro-electric, Forestry and Other Major Projects
- Compensation & Monitoring Related to Resource Project Impacts
- Resource Rent, Royalty and Tax Policy – Related Expert Evidence
- Other Strategic Planning and Assessment

Utility Regulation – Expert Analysis and Testimony at Hearings

- **For the Island Industrial Customers of Newfoundland Hydro (2001),** expert testimony before the Board of Commissioners of Public Utilities of Newfoundland and Labrador regarding the Newfoundland and Labrador Hydro 2001 General Rate Application.

- **For the Manitoba Industrial Power Users Group (1987-1999),** expert testimony before the Manitoba Public Utilities Board in Manitoba Hydro electricity rate hearings, including rate applications in 1987/88, 1989, 1990, 1991, 1992, 1994, 1995, and 1998, and the Manitoba Hydro Major Capital Projects hearing in 1990. Represented MIPUG at hearings before the Board in 1999 to approve the purchase of Centra Gas by Manitoba Hydro.

- **For the Yukon Energy Corporation (1989-2002)**, expert testimony before the Yukon Utilities Board on planning major capital projects (1992) and on electricity costing and rates related to rate applications by Yukon Energy Corporation (1989, 1991, 1993, 1996, 1997, 1998). Also, expert testimony before the Yukon Territorial Water Board in regards a renewal water licence for the Aishihik Generation Station (2001/02)

- **For the Bruce Municipal Telephone System in the early 1990s,** expert economic evidence to the Ontario Telephone Service Commission related to the cost of equity capital.

- **For Government of Yukon, expert testimony before the National Energy Board in 1985**, expert testimony on costs and rates pertaining to the Northern Canada Power Commission.

- **For IPSCO during the 1980s**, expert testimony before Saskatchewan Utilities Regulatory Commission hearing on the first and second rate applications by Saskatchewan Power Commission.

- **For Stelco, INCO and the Motor Vehicle Manufacturers' Association of Canada, in the 1977-1979 Ontario Energy Board hearings HR5,** examining Ontario Hydro's electricity costing and pricing principles; provided consulting advice and expert testimony on the issues and options pertaining to that hearing.

- **For a consortium (The Consumers' Gas Company, Union Gas, Northern and Central Gas and the Ontario Ministry of Energy), a 1974 report on natural gas requirements throughout Canada;** provided expert testimony before the National Energy Board on this report.

Strategic Planning & Multi-disciplinary Project Team Management - Resource, Regional and Urban Development Projects

- **For the City of Winnipeg and Neeginan Development Corporation (1998),** project director responsible for preparation of the Development Plan for the Thunderbird House project on Main Street.

- **For Spirit of Manitoba Inc. and Manitoba Entertainment Complex Inc. (1994-1995),** responsible for management of all aspects of a project to develop a new downtown entertainment complex and to retain the Winnipeg Jets Hockey Club in Winnipeg; managed the multi-disciplinary team carrying out negotiations, siting, design, costs, feasibility planning, environmental assessments, and other work required to secure approvals under tight deadlines specifically for the new arena component of the project.

- **For The Forks Renewal Corporation (a corporation owned by Canada, Manitoba and Winnipeg) during the late 1980's and early 1990's,** Development Coordinator responsible for planning and directing initial development and financial activities (1987-1993), including negotiation of land exchange agreements, preparation of a Phase I Concept and Financial Plan, site planning and Stage One projects, roads and services; ongoing financial and strategic planning counsel.

- **For Government of Yukon (Department of Economic Development, Mines & Small Business) (1985-1987),** management of multi-disciplinary team carrying out financial, economic, legal and strategic planning work relating to the devolution and transfer to Yukon of the Northern Canada Power Commission assets and operations in Yukon; participation in all related negotiations.

- **For the East Yard Task Force (comprised of the governments of Canada, Manitoba and Winnipeg) (1985-1986),** general advisor and manager for all consultant work (planning and architectural, engineering, financial and legal) related to the redevelopment of a major rail yard area in downtown Winnipeg.

- **For North Portage Development Corporation (1984-1987),** economics and financial counsel during the initial development phase; coordinator for work relating to corporate financial plans, selection of major developers (retail, housing and office projects), and negotiation of long-term agreements (land lease, development and other related agreements) with each of the selected developers.

- **For Canadian Methanol Canadien during the 1980s**, participation in an executive capacity in a partnership venture involving Inter-City Gas Corporation and The M100 Group to develop methanol vehicle fuel [management of multidisciplinary project team involving engineers, planners, financial, legal, and other professionals to demonstrate and develop hybrid (natural gas and wood feedstock) methanol production facilities as well as different market uses for methanol (including use in flexible fuel passenger vehicles)].

- **For the Government of Canada in the late 1970s,** project director of a major multi-disciplinary study to examine the feasibility of producing liquid fuels (including methanol) from biomass feedstock resources throughout Canada; this study included examination of liquid fuel production options involving the joint use of either electricity or natural gas along with biomass feedstock. The multi-disciplinary consulting team included firms with chemical engineering and forestry expertise.

Socio-Economic and Environmental Assessment & Related Public Consultation – Mining, Hydro-electric, Forestry and Other Major Projects

- **For Manitoba Hydro (1999 – Present),** Study Leader responsible for socio-economic assessment and planning work as well as public involvement activities in a multi-disciplinary Consultant Management Team retained to assist Manitoba Hydro in the conduct of the environmental assessment programs associated with future planning for three potential hydroelectric generating stations in northern Manitoba, including site selection and environmental assessments for the associated transmission facilities.

- **For uranium mining companies in northern Saskatchewan during the 1990s**, project director for consultants regarding socio-economic impact assessment, economic impact and cost-benefit assessments, and public consultation design and implementation for the Rabbit Lake expansions (Cameco Corporation, 1991-1993), the McArthur River developments (Cameco Corporation, 1993-1996), the Cigar Lake developments (Cigar Lake Mining Corporation, 1993-1996), and the Rabbit Lake extension (Cameco Corporation, 1999-); provided related evidence and expert witness testimony for the Rabbit Lake federal environmental review panel hearing and the McArthur River developments federal-provincial environmental review panel hearings. Provided advisory review for InterGroup's similar socio-economic and economic impact assessments, and public consultation work for COGEMA related to Cluff Lake mine projects during this period.

- **For Yukon Energy Corporation (1992-1996**), advisory reviews of environmental impact assessment work for re-licensing of the Aishihik hydro-generation facility.

- **For Cameco, Cigar Lake Mining Corporation and COGEMA (1993-1994),** facilitation of an agreement in principle for an impact management agreement involving seven Athabaska communities (this was one element of the socio-economic/public consultation EIS work related to the McArthur River and CLMC projects).

- **For Repap Manitoba, Inc. (1989-1991)**, project management of the socio-economic impact assessment, and design and implementation of an extensive public consultation program, for the proposed Phase 1 Manitoba expansion.

- **For aggregate producers in Ontario during the 1980's and early 1990s,** socio-economic impact and resource policy evaluations relating to proposed aggregate developments in southern Ontario (Puslinch, Milton and Niagara Escarpment Planning Area); provision of resource economics expert testimony before the Ontario Municipal Board on behalf of TCG Materials Limited and on behalf of Armbro Aggregate.

- **For the City of Winnipeg in the 1990s**, socio-economic impact assessment for the new Charleswood and Main/Norwood bridge developments (two separate assignments; provided advisory review for other InterGroup principals who directed this work, as well as assistance in coordination of hearing testimony for the regulatory review of the Charleswood bridge project.

- **For the Moosonee Development Area Board (early 1990s),** socio-economic counsel in an intervention relating to potential impacts of Ontario Hydro's proposed hydro generation development of the Moose River Basin.

- **For Manitoba Hydro in the late 1980s and 1990s,** senior advisory review as required by other InterGroup principals carrying out the following assignments: socio-economic impact assessment and public consultation program for the Conawapa hydro generating station EIS (1989-1993); socio-economic impact assessment and public consultation program for the Split Lake transmission line project (joint study with the First Nation, early 1990's); socio-economic impact assessment and public consultation program for the siting and the EIS related to the Winnipeg-Brandon transmission line and Neepawa substation projects (1995-1997); study to review environmental externality and compensation cost modeling for hydro-generation and related transmission line projects (1996-1997). Deputy

Project Director for initial environmental assessments study for third Bipole Transmission Lines (1986-1987).

- **For Manitoba Hydro in the early-to-mid 1980s,** various investigations with respect to the environmental and socio-economic impacts related to planning of new power generation projects in northern Manitoba, including deputy project director for the Burntwood River Environmental Overview Study (1980-1984), and review of InterGroup's work (carried out by senior staff) to prepare the socio-economic assessment and conduct public consultation for the Limestone hydro-electric generating station EIS.

- **For Alcan in the early 1980s,** management of investigations with respect to the socio-economic impacts of a proposed aluminum smelter in Manitoba.

- **For Key Lake Mining Corporation in the early 1980s,** expert testimony before the Commission of Enquiry on socio-economic impacts associated with the uranium project at Key Lake.

- **For Amok Ltd., in the 1977 Saskatchewan hearings on uranium developments,** provided expert testimony before the Bayda Commission of Enquiry on socio-economic impacts associated with the Amok mining project at Cluff Lake.

Compensation & Monitoring Related to Resource Project Impacts

- **For Tsay Keh Dene Treaty Society (2001-2003),** negotiation of framework agreement to address flooding impacts of the BC Hydro Williston Lake/Bennett Dam project.

- **For Kwadacha First Nation (2001-2003),** expert utility economics and socio-economics assistance in respect of negotiation of framework agreement to address flooding impacts of the BC Hydro Williston Lake/Bennett Dam project.

- **For Manitoba Hydro in the 1990s,** expert socio-economic and resource economics assistance with respect to claims by the community of South Indian Lake (early 1990's) and by Northern Flood Agreement communities, including the Cross Lake First Nation (1999 - Present), related to post-project development impacts from hydroelectric power development.

- **For uranium mining companies (1999),** project director for the preparation of a draft work plan for a community vitality monitoring program for northern communities in Saskatchewan affected by uranium mining development; the work plan requirement arose out of federal-provincial environmental impact panel hearings on the McArthur River and Cigar Lake mining projects; the work plan was prepared for a working committee with representatives from the three uranium mining companies (Cameco Corporation, COGEMA, and Cigar Lake Mining Corporation0, the Saskatchewan Northern Mines Monitoring Secretariat, and the northern Saskatchewan Health Districts.

- **For BC Hydro (early 1990s),** evaluation of a trust fund proposed to compensate five Lillooet Nation Bands for damages from hydroelectric generation and transmission activities.

- **For the Beaufort Sea Steering Committee (early 1990s),** review of wildlife compensation program options in the event of an oil spill in the Beaufort Sea.

- **For Manitoba Hydro (1989-1990),** project management of an independent post-project evaluation of the Grand Rapids Project impacts on Aboriginal communities, including direction of the socio-economic component of the evaluation.

Resource Rent, Royalty and Tax Policy – Related Expert Evidence

- **For Regional Municipality of Ottawa Carleton (RMOC) in the mid-1990's,** expert resource and regulatory economist evidence before the Ontario Municipal Board on By-Law 234/92, which imposed compensation payments on private landfill operators in the Region.

- **For a group of pipeline companies in Ontario (1989-1992),** assistance with coordination of expert evidence in an arbitration, and provision of expert evidence on methodology to determine annual rent for pipeline use of a transmission corridor owned by Ontario Hydro.

- **For Sun Oil in the 1970s,** counsel on preparation of a brief to the Government of Canada on the proposed Federal Land Regulations for Oil and Gas Lands.

- **For the Canadian Potash Producers' Association in the 1970s and early 1980s,** expert assistance with taxation discussions with Saskatchewan authorities, analysis of the proposed government takeover of the potash industry, and liaison with legal counsel.

- **For the Uranerz-Inexco joint venture in the 1970s,** participation in discussions between the Saskatchewan Government and the uranium industry concerning uranium taxation revisions; provided economic counsel for these discussions.

- **For the Mining Association of British Columbia in the 1970s**, expert testimony before the Commission of Enquiry into property taxation in that province.

- **For the Mining Association of Canada in the 1970s**, preparation of analytical models for comparison of different mineral taxation structures.

- **For Canadian Industrial Oil and Gas Ltd. In the 1970s**, analysis of the public policy aspects of Saskatchewan Bill 42 relating to taxation (advice to legal counsel related to a court case).

Other Strategic Planning and Assessment

- **For Manitoba Hydro (1999 – Present),** assistance on various matters, including policy reviews related to debris management programs and planning related to US market consultations.

- **For the Yukon Energy Corporation and the Yukon Development Corporation (1987-ongoing),** financial and strategic planning counsel on major issues, including rate policy planning (see also Utility Regulation), major capital planning issues (see also Environmental Assessment), management agreement arrangements, and negotiations between YEC and various owners of the Faro mine.

- **For the Northern Manitoba Economic Development Commission (1991-1992),** participation in the preparation of two reports, contributing to the Commission's Sustainable Economic Development Plan for Northern Manitoba for the 1990s.

- **For Regional Municipality of Ottawa Carleton (RMOC) during the 1990s,** economic assessments of options to extend the life of the Trail Road Landfill site.

- **For Metropolitan Toronto (late 1980s),** economic analysis of the best available technology for the utilization of the landfill gas resources at the Keele Valley Landfill site.

- **For a western energy company (early 1990s),** preparation of a Cost-Benefit Analysis of a 160 MW co-generation project, assessment of the implications of the project for Manitoba Hydro, and participation in the discussions between the company and Manitoba Hydro.

- **For Western Economic Diversification (late 1980s),** assessment of Winnipeg tri-government development corporation cash flow scenarios.

- **For the Government of Manitoba during the late 1980s and early 1990s,** advice and assistance in the preparation of proposal calls for the redevelopment of a historically significant site in Winnipeg, as well as participation in the developer selection and negotiation process.

- **For the Canadian Electrical Association in the late 1970s,** management of interdisciplinary team investigations with respect to the impacts of proposed federal atmospheric emission control guidelines on Canadian electrical generating industry thermal power stations.

1968 - 1974 MANAGER AND SENIOR CONSULTANT, Hedlin Menzies/Acres Consulting Services (Winnipeg)

RESEARCH ECONOMIST, Hedlin Menzies & Associates Ltd. (Winnipeg)

Project manager of major studies involving regional resource and cost-benefit impact policy issues relating to prairie manufacturing, prairie elevator and transportation rationalization, Manitoba Hydro northern development activities, Canadian energy requirements and research and development priorities, alternative export policies for natural gas, Canadian Merchant Marine development options, alternative rail route options in the Yukon and northern British Columbia, and various mineral resource policy options pertaining to mining development and taxation.

Sessional lecturer on mineral economics for one year at the University of Manitoba's Natural Resources Institute.

RESEARCH PAPERS:

"The Process of Urbanization in Canada, 1600-1961." Simon Fraser University (M.A.) Thesis. 1968.

"Technological Change and the Economics of Agricultural Development." Simon Fraser University (M.A.) Thesis. 1968.

"Economic Analysis of Short-Term Alternatives Regarding Southern Indian Lake in Manitoba" (joint work with Dr. A.M. Lansdown, P.Eng., 1969).

"A New National Development Policy for Canada: The Relevance of Western Canada." Prepared for the Liberal Conference on Western Objectives. 1973.

"Canada's Gains and Losses from Oil Export Taxes" (joint work with Dr. R.W. Fenton, 1973).

"Resource Management Factors Influencing Mineral Development in North Central Canada." Paper presented to the annual western meeting of the Canadian Institute of Mining and Metallurgy, Winnipeg, October 7, 1974.

"Energy, Provincial Rights and Canadian Unity." 1973.

"An Evaluation of 'An Energy Policy for Canada' " (joint work with Dr. R.W. Fenton, 1973).

"Resource Management Factors Influencing Manitoba Mining." Natural Resources Institute, University of Manitoba. 1974.

"Liquid Fuels from Renewable Resources in Canada: Systems Economic Studies." Paper presented to the Institute of Gas Technology Symposium on Energy from Biomass and Wastes, Washington, DC. August 1978.

"Canadian Scenario for Methanol Fuel." Paper presented to the Alcohol Fuels Technology Third International Symposium, California, January 1979.

"Socio-Economic Impacts from Potential Canadian Methanol Fuel Development." Paper presented to the IV International Symposium on Alcohol Fuels Technology, Brazil. October 1980.

"Canadian Methanol Development Using Natural Gas and Wood Feedstocks." Paper presented to the First IEA Conference on New Energy Conservation Technologies and their Commercialization, Berlin. April 1981.

"Methanol as an Alternative Automotive Fuel: CMC's Approach and Experience." Paper presented to the West Coast International Meeting of the Society of Automotive Engineering, Vancouver, BC. August 1983.

"Status of CMC Fuel Methanol Production and Market Development Programs." Paper presented to the VI International Symposium on Alcohol Fuels Technology, Ottawa. May 21-25, 1984.

ATTACHMENT B – RESUME – PATRICK BOWMAN

CONSULTANT

EDUCATION: MNRM (Natural Resource Management), University of Manitoba, 1998. Specialized in Resource Economics and Land-Use Policy

BA (Human Development and Outdoor Education), Prescott College, 1994.

PROFESSIONAL HISTORY:

InterGroup Consultants Ltd., Winnipeg, MB

1998 – Present *Research Analyst/Consultant*

Regulatory economic analysis and socio-economic impact assessment experience, primarily in the energy field.

Utility Regulation

Conducted research and analysis for regulatory reviews of electrical and gas utilities in four Canadian provinces. Prepare evidence and review testimony for regulatory hearings. Assist in utility capital and operations planning to assess impact on rates and long-term rate stability.

- **For Yukon Energy Corporation (1998-present)**, analysis and support of regulatory proceedings and normal regulatory filings before the Yukon Utilities Board. Prepare analysis of major transmission line project and design flexible financing mechanism to reduce "rate shock" to ratepayers.

- **For Yukon Development Corporation (1998-present)**, prepare analysis and submission on energy matters to Government round table on competitiveness of Yukon economy. Coordinate development of options for government rate subsidy program.

- **For Northwest Territories Power Corporation (2000-present)**, provide technical analysis and counsel regarding General Rate Application. Assist in preparation of evidence, filings before the Northwest Territories' Public Utilities Board, appearance to provide expert testimony, and related issues.

- **For Manitoba Industrial Power Users Group (1998-present)**, prepare analysis, evidence and argument for regulatory proceedings before Manitoba Public Utilities Board representing large industrial energy users. Submission of expert testimony and appear before commission. Assist in regulatory analysis of the purchase of local gas distributor by Manitoba Hydro. Assist industrial power users in dealings with Manitoba Hydro regarding alternative rate structures and surplus energy rates.

- **For Nexen Chemicals, Inc. (2000)**, review options for subscribing to curtailable service rates.

- **For Columbia Power Corporation/Columbia Basin Trust and Municipal Interveners (2000),** review evidence and prepare analysis on major transmission line project for Public Convenience and Necessity hearing before the British Columbia Utilities Commission.

- **For the City of Yellowknife (1999)**, prepare preliminary analysis of policy options and planning process for development of a municipal piped propane distribution system.

- **For the Government of the Northwest Territories (1999)**, prepare analysis of policy alternatives to facilitate supply of natural gas to local communities in the event of a Mackenzie Valley pipeline being constructed.

- **For INCO Manitoba Division (1998-present)**, prepare analysis of energy costs under various alternative industrial rate options. Provide recommendations on preferred energy rate options.

- **For Industrial Customers of Newfoundland and Labrador Hydro (2001-02),** prepare analysis and assist in preparation of evidence for Newfoundland Hydro GRA before Newfoundland Board of Commissioners of Public Utilities representing large industrial energy users.

Socio-Economic Impact Assessment and Mitigation

Primarily involved in socio-economic planning and assessment work for new northern hydroelectric generation and transmission projects in Manitoba, forestry harvest planning in Manitoba and Saskatchewan, and impact mitigation programs in northern Manitoba. Also conducted assessment of socio-economic impacts of policy options for floodplain management, and strategic planning for resource management board.

- **For Manitoba Hydro Power Major Projects Planning Department (1999-present)**, review and analysis of socio-economic impacts of proposed new northern generation stations and associated transmission. Assist Manitoba Hydro and northern First Nations in impact assessment and management options, including mitigation and compensation mechanisms.

- **For Manitoba Hydro Mitigation Department (1999-present)**, provide analysis and process support to implementation of mitigation programs related to past northern generation projects. Assist in preparation of materials for independent inquiry into northern hydro developments. Provide analysis and support to Manitoba Hydro in addressing compensation claims.

- **For International Joint Commission (1998)**, analysis of current floodplain management policies in the Red River basin, and assessment of the suitability of other floodplain management policies.

- **For Nelson River Sturgeon Co-Management Board (1998)**, an assessment of the performance of the Management Board over five years of operation and strategic planning for next five years.

- **For two separate forestry harvest proposals and one uranium mining operation**, identification and analysis of expected socio-economic impacts of various forest/deposit management plans. Preparation of socio-economic portions of submissions to regulatory authorities.

Government of the Northwest Territories, Yellowknife, NT

1996 - 1998 *Land Use Policy Analyst*

Conducted research into protected area legislation in Canada and potential for application in the NWT. Primary focus was on balancing multiple use issues, particularly mining and mineral exploration, with principles and goals of protection.

Natural Resources Institute, Winnipeg, MB

1996 - 1998 *Researcher*

Conducted research on surface rights allocation and access for mining, with particular emphasis on implications of government actions undermining mineral rights tenures.

Undertook analysis of Manitoba's Registered Trapline System and implications for Aboriginal trappers; also, an economic assessment of the property rights system inherent in the provincial Registered Trapline System policy and its implications on efficiency in allocation of the furbearer resource.

PUBLICATIONS: G*overnment Withdrawals of Mining Interests* in Great Plains Natural Resources Journal. University of South Dakota School of Law. Spring 1997.

Legal Framework for the Registered Trapline System in Aboriginal Trappers and Manitoba's Registered Trapline System: Assessing the Constraints and Opportunities. Natural Resources Institute. 1997

Land Use and Protected Areas Policy in Manitoba: An evaluation of multiple-use approaches. Natural Resources Institute. (Masters Thesis). 1998

Electrical Rates in Yukon. Submission by Yukon Development Corporation to Yukon "Government Leader's Economic Forum Series" on Tax Reform and Competitiveness. 1999.

Review of Red River Basin Floodplain Management Policies and Programs. Prepared for Red River Basin Task Force of the International Joint Commission. 1998.

ATTACHMENT C – DETAILED ANALYSIS OF 'NEW' RATE STABILIZATION PLAN

To date, the RSP monthly reports from September 2002 to May 2003 have been made available for analysis. This covers the first nine months of Hydro's operation of the 'new RSP' as established by P.U. 7 (2002-2003).

HYDRAULIC VARIATION COMPONENT

The hydraulic variation component requires three variables to calculate the monthly values – the cost of service long-term forecast hydro generation, the actual monthly hydro generation and the forecast price of #6 fuel. The variation in hydro, defined as the difference between long-term forecast hydro generation and actual hydro generation, is translated in a quantity of fuel (using the approved Holyrood efficiency of 615 kW.h/barrel). Using the approved price of #6 fuel, the cost of the hydraulic generation variance from forecast can be determined.

For the months of September 2002 to May 2003, this is set out in the top portion of Table C1 attached (rows 1 to 12). Column A is the forecast long-term average generation, column B is the actual generation and column C is the variance (calculated as column B minus column A). The approved cost of fuel is shown in column D which yields the cost of the hydraulic variance in column E. The nine months in question indicate seven with below forecast generation and two above forecast (March 2003 and May 2003). The net impact on Hydro is $7.02 million in 2002 and $4.29 million in 2003. The RSP is charged with these amounts as an appropriation to Hydro's income.

Columns G to I show the allocation of these amounts among NP, IC and Rural based on the December, 2002 12 months-to-date sales for those portions arising in 2002, and the May, 2003 12 months-to-date sales for those portions arising in 2003[236].

The net result of the hydro variance is $8.25 million charged to NP's RSP account, $2.34 million to the IC RSP, and $0.72 million to Rural (which is then re-allocated back to NP and Labrador based on a calculated rural deficit ratio)[237]. Rural amounts allocated to Labrador appear to be written off while rural amounts allocated back to NP are added to the NP RSP balance to be collected.

The hydraulic component of the RSP has no need for an NP/IC distinction.

FUEL COST VARIATION COMPONENT

The fuel cost variation component for the nine months of available data is similarly set out in Table C1 (rows 13 to 24). The fuel variation likewise require only three variables to calculate the RSP amounts –

[236] These ratios will be re-calculated monthly until December 2003, when the year-to-date total will be locked in as an allocation to each of the customer groups.
[237] We have not specifically reviewed the rural deficit re-allocation ratios.

the approved forecast cost of fuel (column A), the actual cost of fuel (column B) and the actual barrels consumed (column D). Column C sets out the difference between forecast and actual price of fuel, and column E is the total fuel cost variance (the variance in price per barrel times the number of barrels). In this case, all nine months had actual prices of fuel above the forecast cost (by as much as $19.80 per barrel in February 2003).

Similar to the hydraulic variation component, the fuel variation is allocated among the customer groups using 12 months-to-date sales at columns G to I.

The hydraulic component of the RSP has no need for an NP/IC distinction.

LOAD VARIATION COMPONENT

The Load variation component is set out at Table C2. In this case, the RSP is required to be calculated separately for IC and NP.

- ***Newfoundland Power:*** The top of the Table (rows 1 to 14) sets out the NP calculation based on the NP COS sales (column A) compared to the actual NP sales (column B) to determine the monthly variance (column C). This variance gives rise to a revenue variance (columns D and E) and a fuel cost variance (columns F and G) predicated on the simple assumption that all incremental sales growth or reductions result in additions or savings to the quantity of fuel that would otherwise be burned at Holyrood on a one-to-one basis.

  The sum of the values shown in column E and column G are the changes in Hydro's earnings that arise as a result of the NP load variation. For example, in this case NP's extra load growth of about 207.9 GW.h (the sum of column C, rows 1 to 9) gives rise to $9.936 million in additional revenue to Hydro[238] and $8.445 million in extra costs to Hydro at Holyrood[239]. The net impact on Hydro is $1.511 million in additional net revenues during this nine month period.

  The allocations of these amounts are set out in row 10-14 and columns I-K. In simple terms, the full revenue that arises from the extra sales to NP ($9.956 million) is credited directly back to this customer. Then the $8.445 million in extra fuel costs to serve this load is allocated among NP, IC and Rural using the ratios reflected in columns I to K, such that NP is charged with only $6.182 million of the extra fuel consumed to serve their load growth, IC is charged $1.725 million as a result of NP's load growth, and Rural is charged $0.539 million[240].

  On an overall basis, NP's extra loads cause three impacts on NP – an extra cost of $9.956 million in the rates they pay during the year, an RSP credit equal to the full and exact $9.936 million that

[238] Table C2, Column E row 10.

[239] Table C2, column H rows 4 and 9. The RSP Load Variation provision reflects the 2001 GRA forecast prices of #6 fuel

[240] Most of this amount is assigned to the NP RSP, although a portion is assigned to Labrador and apparently written off by Hydro

they paid in their rates, and an RSP charge of only $6.182 million[241]. On the 207.9 GW.h, this represents a net cost of NP's increased consumption of 2.97 cents/kW.h[242]. For the IC, the net impact of NP's increased consumption is a cost of $1.725 million, or a *cost* of 0.83 cents/kW.h for every extra kW.h that NP consumes[243].

- ***Industrial Customers:*** For the IC loads, the results are set out in rows 15 to 28. The IC load variation over this nine month period is a load *decrease* compared to forecast of about 69.1 GW.h[244] which gives rise to a lost revenue to Hydro of $1.649 million compared to forecast[245]. This load reduction also gives rise to a fuel savings (using the 2001 GRA prices of #6 fuel) of $2.827 million[246] for a net impact on Hydro of a $1.178 million savings.

  The allocation of these amounts at columns I to K illustrate that the fuel cost savings of $2.827 million is credited $2.073 million to NP, $0.573 million to IC and $0.180 million to Rural.

  The net effect of the IC load variation on the IC group is, similar to the NP case noted above, threefold. First the IC reduce their energy costs by $1.649 million during the year as a result of the decreased sales. Second, the IC are charged the full and complete $1.649 million that they saved during the year via their RSP account. Finally, as a result of the $2.827 million fuel savings arising from the reduced load, the IC is credited with $0.573 million[247]. For NP, the IC load reduction results in no revenue-related impact, but a credit is provided related to the fuel saved totalling $2.073 million[248].

  The net result is that IC customers pay the full normal rate for the load that they *did not consume*, less only the $0.573 million credited back via the RSP fuel portion. This equates to a cost savings to the IC customers of only 0.83 cents for each kW.h that they avoided consuming[249]. NP, on the other hand, saves 3.00 cents for each kW.h that the IC do not consume compared to forecast[250]. The problem is further compounded when considering that the 0.829 cents/kW.h that the IC group saves is spread out over 4 customers – for the customer that is able to implement (or forced to implement) load reductions, the savings that they see is likely

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[241] Prior to Rural RSP reallocation.
[242] $6.182 million divided by 207.9 GW.h.
[243] $1.725 million divided by 207.9 GW.h. All of the above NP load discussion ignores the fuel cost variation component of the RSP – once those are considered, NP's load growth will have also caused additional costs to the IC and Rural customers via the RSP, as the fuel consumed to supply this load growth will result in charges to the fuel cost component of the RSP as well.
[244] The sum of Table C2 column C rows 15 to 23
[245] Table C2, column E row 24
[246] Table C2, column H rows 18 and 23.
[247] Table C2, column J row 26.
[248] Table C2, column I row 26.
[249] $0.573 million divided by 69.1 GW.h.
[250] $2.073 million divided by 69.1 GW.h.

well below one-half of one-cent per kW.h (or perhaps on the order of one-tenth the benefits that NP receives as a result of the industrial customer load reduction)[251].

On a net "overall Hydro" basis, the total revenue variation arising as a result of load changes during this nine month period is only $2.689 million in total for NP and IC (this reflects a positive variance, i.e., a net benefit to Hydro). Instead, the fuel cost variation component of the RSP seeks to credit back to NP $5.848 million[252] while charging IC $2.800 million[253] and charging Rural $0.359 million[254].

TOTAL NEW RSP RESULTS

Due to the complexities that remain in the RSP, it is difficult to illustrate the full required level of detail on a single sheet. However, to ensure these values reported in this Attachment reconcile back to the May 2003 RSP report, Table C3 combines the above reporting in a slightly less detailed fashion.

- Rows 1 to 6 of Table C3 illustrate the total RSP impacts on Hydro. The hydraulic impacts are as noted in Table C1 totalling $11.316 million[255]. Likewise the load impacts are summarized at $2.689 million[256] consistent with Table C2, and the fuel cost impacts are at $44.677 million[257] equal to the reported value in Table C1. The sum of the three components totals $53.304 million at column N row 1. In order to reconcile with the May 2003 RSP report, Column N shows that an additional $1.244 million in interest is added[258], $0.507 million is assigned to Labrador and written off[259], $0.021 million in Rural adjustment is applied[260] and a minimal amount of firming sales revenue is credited[261]. The total RSP balance then equals $54.020 million, consistent with the May, 2003 RSP report.

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[251] Additionally, this result is prior to considering the fuel variation component of the RSP. Once included, the actual fuel cost savings to Hydro (and credited back to the RSP) arising from the IC load reduction are well above the $2.827 million noted in Table C2; however, only a very small portion of this additional savings will arise to the industrial customer that was able to reduce their load.

[252] The sum of Table C2 column I row 14 of $3.775 million and column I row 28 of $2.073 million

[253] The sum of Table C2 column J row 14 of $1.725 million and column J row 28 of $1.076 million.

[254] The sum of Table C2 column K row 14 of $0.539 million less column K row 28 of $0.180 million. This amount is subsequently reallocated to Labrador and NP.

[255] Table C3, column A row 1.

[256] Table C3, column I row 1.

[257] Table C3, column L row 1.

[258] This interest value is calculated by applying the monthly equivalent of 7.157% to the previous month's closing balance.

[259] The sum of the December, 2002 YTD Labrador assignment of $184,516 reported in the December 2002 RSP report plus the May, 2003 YTD assignment of $322,822 from the May 2003 RSP report.

[260] This entirely arises in September 2002 ($19,552 per the September 2002 RSP report) and October 2002 ($1,066 per the October 2002 RSP report).

[261] The sum total of firming sales revenue appears to be $374. It appears this is the sum total of revenues arising from the application of this rate. If this is correct, it is apparent that Hydro receives zero net revenues from providing this service, but instead credits all revenues received from NP back to NP's RSP account, meaning that the service is provided to NP at no cost. If so, it is not apparent why there is any calculation of the firming rate necessary or approvals requested within the 2003 Rates Application.

- Rows 7 to 22 derive the respective NP and IC balances. Specifically rows 7 to 12 calculate the NP balance of $35.068 million prior to assignment of $0.939 million in interest, $3.422 million in rural deficit, and a credit of $0.015 million in Rural Adjustment and a minimal amount for firming revenues, to result in a new RSP balance for NP of $39.415 million consistent with the May 2003 RSP report.
- Rows 13 to 17 set out the IC RSP reflecting only the three RSP components reviewed above totalling $14.305 million, plus interest of $0.305 million and an unexplained Rural Adjustment credit of $0.004 million to arrive at $14.605 million consistent with the May 2003 RSP report.
- Rows 18 to 22 address the comparable aspects of the Rural RSP. The balance from the three components (with the revenue component of the load variance not being applied to Rural) yields $3.931 million (less a Rural Adjustment of $0.001 million), of which $3.422 million is assigned to NP and $0.507 million is assigned to Labrador.

Table C1: New RSP September 2002 to May 2003 by component

Hydraulic Component

		A	B	C	D	E	F	G	H	I
		Cost of Service generation (GW.h)	Actual generation (GW.h)	Hydro Variance (GW.h) (B-A)	COS Fuel Cost ($/bbl)	Charge to (credit to) RSP ($millions) (C / 615 x D)	Annual Total ($millions)			
1	September, 2002	307.54	268.00	39.54	25.94	1.67		**Allocation Ratios**		
2	October, 2002	302.08	276.73	25.35	26.27	1.08		*NP*	*IC*	*Rural*
3	November, 2002	301.90	260.51	41.39	26.47	1.78		*72.64%*	*20.98%*	*6.39%*
4	December, 2002	436.40	379.21	57.19	26.80	2.49	7.02	5.10	1.47	0.45
5	January, 2003	429.30	377.75	51.55	24.11	2.02				
6	February, 2003	405.21	385.96	19.25	24.64	0.77				
7	March, 2003	399.21	410.37	(11.16)	24.80	(0.45)		*NP*	*IC*	*Rural*
8	April, 2003	366.43	311.57	54.86	25.12	2.24		*73.33%*	*20.29%*	*6.38%*
9	May, 2003	348.04	355.10	(7.06)	25.36	(0.29)	4.29	3.15	0.87	0.27
10								**Total Allocation**		
11								*NP*	*IC*	*Rural*
12								8.25	2.34	0.72

Fuel Cost Component

		Cost of Service fuel cost ($/bbl)	Actual fuel cost ($/bbl)	Cost Variance ($/bbl) (B-A)	Actual Barrels (000's)	Charge to (credit to) RSP ($millions) (C x D)	Annual Total ($millions)			
13	September, 2002	25.94	33.80	7.86	213	1.68		**Allocation Ratios**		
14	October, 2002	26.27	36.44	10.17	356	3.62		*NP*	*IC*	*Rural*
15	November, 2002	26.47	36.02	9.55	460	4.39		*72.64%*	*20.98%*	*6.39%*
16	December, 2002	26.80	35.98	9.18	440	4.04	13.73	9.97	2.88	0.88
17	January, 2003	24.11	39.63	15.52	513	7.96				
18	February, 2003	24.64	44.44	19.80	426	8.44				
19	March, 2003	24.80	43.56	18.76	445	8.35		*NP*	*IC*	*Rural*
20	April, 2003	25.12	41.95	16.83	302	5.08		*73.33%*	*20.29%*	*6.38%*
21	May, 2003	25.36	31.76	6.40	175	1.12	30.95	22.69	6.28	1.97
22								**Total Allocation**		
23								*NP*	*IC*	*Rural*
24								32.67	9.16	2.85

Table C2: New RSP September 2002 to May 2003 by component (con't)

Load Component - NP

		A	B	C	D	E	F	G	H	I	J	K
		NP Forecast Load (GW.h)	NP Actual Load (GW.h)	NP Variance (GW.h)	NP energy rate (cents/kW.h)	NP Revenue Charge to (credit to) RSP ($millions)	Forecast Price of Holyrood (cents/kW.h)	NP Fuel Charge to (credit to) RSP ($millions)	Annual total fuel cost ($millions)			
				(B-A)		(C x D)		(C x F)				
1	September, 2002	259.10	272.20	13.10	(4.789)	(0.627)	4.22	0.553		**Allocation Ratios**		
2	October, 2002	330.00	351.48	21.48	(4.789)	(1.029)	4.27	0.917		*NP*	*IC*	*Rural*
3	November, 2002	382.80	412.85	30.05	(4.789)	(1.439)	4.30	1.293		*72.64%*	*20.98%*	*6.39%*
4	December, 2002	535.00	508.21	(26.79)	(4.789)	1.283	4.36	(1.167)	1.596	1.159	0.335	0.102
5	January, 2003	522.60	548.66	26.06	(4.789)	(1.248)	3.92	1.022				
6	February, 2003	484.10	515.31	31.21	(4.789)	(1.495)	4.01	1.251				
7	March, 2003	473.90	541.03	67.13	(4.789)	(3.215)	4.03	2.707		*NP*	*IC*	*Rural*
8	April, 2003	379.30	413.42	34.12	(4.789)	(1.634)	4.08	1.393		*73.33%*	*20.29%*	*6.38%*
9	May, 2003	326.20	337.73	11.53	(4.789)	(0.552)	4.12	0.476	6.849	5.022	1.390	0.437
10			*total revenue variation ($millions)*			*(9.956)*				**Total Allocation**		
11										*NP*	*IC*	*Rural*
12										6.182	1.725	0.539
13									plus: revenue	(9.956)	-	-
14									net impact	(3.775)	1.725	0.539

Load Component - IC

		A	B	C	D	E	F	G	H	I	J	K
		IC Forecast Load (GW.h)	IC Actual Load (GW.h)	IC Variance (GW.h)	IC energy rate (cents/kW.h)	IC Revenue Charge to (credit to) RSP ($millions)	Forecast Price of Holyrood (cents/kW.h)	IC Fuel Charge to (credit to) RSP ($millions)	Annual total fuel cost ($millions)			
				(B-A)		(C x D)		(C x F)				
15	September, 2002	104.55	108.67	4.11	(2.388)	(0.098)	4.22	0.173		**Allocation Ratios**		
16	October, 2002	114.28	123.45	9.17	(2.388)	(0.219)	4.27	0.392		*NP*	*IC*	*Rural*
17	November, 2002	116.00	110.13	(5.87)	(2.388)	0.140	4.30	(0.253)		*72.64%*	*20.98%*	*6.39%*
18	December, 2002	117.79	111.83	(5.96)	(2.388)	0.142	4.36	(0.260)	0.053	0.0382	0.0110	0.0034
19	January, 2003	118.93	115.49	(3.44)	(2.388)	0.082	3.92	(0.135)				
20	February, 2003	109.24	107.20	(2.04)	(2.388)	0.049	4.01	(0.082)				
21	March, 2003	120.69	118.07	(2.61)	(2.388)	0.062	4.03	(0.105)		*NP*	*IC*	*Rural*
22	April, 2003	116.89	76.12	(40.77)	(2.388)	0.974	4.08	(1.665)		*73.33%*	*20.29%*	*6.38%*
23	May, 2003	117.69	96.04	(21.65)	(2.388)	0.517	4.12	(0.893)	(2.880)	(2.112)	(0.584)	(0.184)
24			*total revenue variation ($millions)*			*1.649*				**Total Allocation**		
25										*NP*	*IC*	*Rural*
26										(2.073)	(0.573)	(0.180)
27									plus: revenue	-	1.649	-
28									net impact	(2.073)	1.076	(0.180)

Table C3: New RSP September 2002 to May 2003 by NP, IC and Rural

Total RSP

	A	B	C		D	E	F	G	H	I	J	K	L	M	N
	Hydraulic RSP			***Load RSP***							***Fuel Price RSP***			***Total RSP***	
	Variance (GW.h)	Average Fuel Cost ($/kW.h)	Hydraulic variance ($)		Load Variance (GW.h)	Average price of Fuel ($/kW.h)	Fuel Variance ($)	Average Revenues ($/kW.h)	Revenue Variance ($)	Total Load Variance ($)	Average Variance ($/bbl)	# of barrels	Fuel Price Variance ($)		Net RSP
1	(271)	0.04177	(11,316,035)		139	0.04046	(5,617,998)	0.05983	8,307,044	2,689,046	(13.41)	3,330,447	(44,677,444)		(53,304,433)
2														Interest	(1,243,840)
3														W/O labrador	507,338
4														Rural Adjustment	20,618
5														Secondary (firming)	374
6														Total RSP	(54,019,943)

NP RSP Share

	A	B	C		D	E	F	G	H	I	J	K	L	M	N
	Hydraulic RSP			***Load RSP***							***Fuel Price RSP***			***Total NP RSP***	
	Variance (GW.h)	Average Fuel Cost ($/kW.h)	Hydraulic variance ($)		Load Variance (GW.h)	Average price of Fuel ($/kW.h)	Fuel Variance ($)	Average Revenues ($/kW.h)	Revenue Variance ($)	Total Load Variance ($)	Average Variance ($/bbl)	# of barrels	Fuel Price Variance ($)		Net RSP
7	(198)	0.04176	(8,249,424)							5,847,925	(13.43)	2,432,033	(32,666,638)		(35,068,137)
8														Interest	(939,287)
9				*NP load variance*	*208*			*0.04789*	*9,956,152*	*9,956,152*				Reassign Rural	(3,422,469)
10				*NP Share of system load variance*	*102*	*0.04046*	*(4,108,227)*			*(4,108,227)*				Rural Adjustment	14,977
11														Secondary (firming)	374
12														Total RSP	(39,414,543)

IC RSP Share

	A	B	C		D	E	F	G	H	I	J	K	L	M	N
	Hydraulic RSP			***Load RSP***							***Fuel Price RSP***			***Total IC RSP***	
	Variance (GW.h)	Average Fuel Cost ($/kW.h)	Hydraulic variance ($)		Load Variance (GW.h)	Average price of Fuel ($/kW.h)	Fuel Variance ($)	Average Revenues ($/kW.h)	Revenue Variance ($)	Total Load Variance ($)	Average Variance ($/bbl)	# of barrels	Fuel Price Variance ($)		Net RSP
13	(56)	0.04179	(2,344,350)							(2,800,455)	(13.36)	685,893	(9,160,368)		(14,305,172)
14														Interest	(304,553)
15				*IC load variance*	*(69)*			*0.02388*	*######*	*(1,649,108)*				Rural Adjustment	4,325
16				*IC Share of system load variance*	*28*	*0.04048*	*(1,151,347)*			*(1,151,347)*				Total RSP	(14,605,401)
17															

Rural RSP Share

	A	B	C		D	E	F	G	H	I	J	K	L	M	N
	Hydraulic RSP			***Load RSP***							***Fuel Price RSP***			***Total Rural RSP***	
	Variance (GW.h)	Average Fuel Cost ($/kW.h)	Hydraulic variance ($)		Load Variance (GW.h)	Average price of Fuel ($/kW.h)	Fuel Variance ($)	Average Revenues ($/kW.h)	Revenue Variance ($)	Total Load Variance ($)	Average Variance ($/bbl)	# of barrels	Fuel Price Variance ($)		Net RSP
18	(17)	0.04177	(722,261)							(358,424)	(13.41)	212,521	(2,850,439)		(3,931,124)
19														Reassign Rural NP	3,422,469
20				*Rural load variance*	*N/A*			*N/A*	*N/A*	*N/A*				Reassign Labrador	507,338
21				*Rural Share of system load variance*	*9*	*0.04046*	*(358,424)*			*(358,424)*				Rural Adjustment	1,317
22															0

ATTACHMENT D – REVIEW OF RATE STABILIZATION MECHANISMS IN SIMILAR JURISDICTIONS

A brief review of other jurisdictions highlighted the following rate stabilization approaches aimed at addressing similar concerns to the Newfoundland RSP. The list proceeds from the utilities/jurisdictions most comparable with Hydro to those least comparable with Hydro.

CANADIAN JURISDICTIONS WITH CROWN ELECTRIC UTILITIES, NON-INTERCONNECTED GRIDS AND A MIXTURE OF HYDRO AND DIESEL GENERATION

- ***Yukon Energy Diesel Contingency Fund:*** This fund, which is primarily a hydraulic variance stabilization fund, addresses water flow variances from the average annual levels (based on long-term modelling) to the extent that such variances affect Yukon Energy diesel generation costs. The fund is managed as a trust outside of rate base, and earns or charges interest based on the prevailing investment/borrowing rate appropriate for Yukon Energy short-term investments. Once a trigger of $4.04 million (positive or negative) is hit, the fund is expected to trigger refunds or charges to customers on an equal per kW.h basis. The fund has not previously hit the trigger.

- ***Yukon Energy's Fuel Adjustment account:*** The Fuel Adjustment account maintained by Yukon Energy addresses diesel price variation from the last GRA forecast. A similar account is maintained by The Yukon Electrical Company Limited, the primary local retailer of power (with some small installed diesel generation). These accounts do not earn or pay interest at all. Each Yukon utility is directed to implement fuel rider adjustments on a co-ordinated and timely periodic basis, as required to ensure that balances in these fuel accounts are adjusted periodically to maintain the balance at as low a level as reasonable. Charges (or refunds) to customers are addressed on an equal cents per kW.h basis for all consumption throughout Yukon.

- ***Northwest Territories Power Corporation Diesel Stabilization Funds:*** NTPC's diesel price stabilization funds address variances in fuel price from the last GRA forecast. One fund is maintained for each of the larger grids and a single conglomerated fund is maintained for the group of non-interconnected communities. The funds charge or credit interest at the prevailing short-term debt rates, measured as the monthly prime lending rate less 50 basis points. Refunds or collections to customers are addressed on an equal per kW.h charge.

- ***Northwest Territories Power Corporation Hydro Stabilization Fund:*** NTPC's hydraulic stabilization fund addresses water flow variances from long-term forecast. The fund charges or credits interest at the prevailing short-term debt rates, measured as the monthly prime lending rate less 50 basis points. The fund has a trigger of $3 million (positive or negative) at which point an equal charge/rebate in cents per kW.h is expected to all customers on the grid. The fund has not previously hit the established trigger.

CANADIAN JURISDICTION WITH CROWN ELECTRIC UTILITIES, RELYING ON FUEL FOR GENERATION

- ***Nunavut Diesel Stabilization Fund:*** Nunavut Power has maintained a diesel price stabilization fund that was broken out of NTPC's consolidated NWT/Nunavut account at the time of the division of the two companies. The Nunavut Utilities Board has reviewed the operation of this fund and approved riders to collect outstanding balances. The Board did not change the previous NTPC approach of charging or crediting interest at the prevailing short-term debt rates, measured as the monthly prime lending rate less 50 basis points. Any amounts collected from or refunded to customers are addressed on an equal cents/kW.h rider/refund for all sales.

CANADIAN JURISDICTION WITH CROWN GAS DISTRIBUTOR

- ***Centra Gas Manitoba's Purchased Gas Variance Account:*** The Centra Gas Manitoba purchased gas variance account (PGVA) is not directly comparable to any aspect of the Hydro RSP except for the purposes of considering carrying costs. The PGVA uses a short-term carrying cost rate to accrue interest.

AMERICAN JURISDICTION RELYING ON MIX OF HYDRO AND FOSSIL FUEL GENERATION (SELF-GENERATED OR PURCHASED POWER)

- ***Idaho Power's Power Cost Adjustment:*** Idaho Power's operation in Idaho maintain a Power Cost adjustment mechanism to address hydraulic and power acquisition price stabilization[262]. This account accrues interest at a rate tied to short-term rates while amounts are being charged to the account, and accrues no interest during periods where the account is being re-collected back from customers. Charges or refunds to customers are done on an equal cents/kW.h basis.

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[262] Both fuel costs and purchased power costs. The mechanism specifically excludes load changes from the calculation.

ATTACHMENT E – REVIEW OF LOAD STABILIZATION APPROACHES IN OTHER JURISDICTIONS

There appear to be only two regulatory mechanisms that seem in any way related to the Newfoundland Hydro RSP load variation provision, but both have material differences that clarify they are not comparable.

- ***Weather Normalization:*** Certain utilities (primarily gas utilities, however apparently also Newfoundland Power) maintain weather normalization provisions that adjust the utility earnings for load variation related solely to actual weather conditions being different than the long-term average. There are two material reasons how this differs from the Newfoundland Hydro RSP load provision. The first is that the use of these provisions is conceptually limited to one variable which, like hydraulic generation fluctuates annually up or down, but over the long-term achieves a certain stable mean[263]. Second, these provisions do not appear to result in charges or refunds to customers but rather a long-term balancing of inflows and outflows, and in particular do not result in differential charges to various groups of customers.

- ***Revenue Decoupling:*** A technique that has been used in various jurisdictions that is mechanically similar to the load variance provision is something called 'revenue decoupling'. In order to ensure utilities' earnings are not adversely affected by DSM and conservation activities (due to decreased sales), certain jurisdictions have experimented with ensuring utility revenue is held whole for any reductions due to this one single factor (DSM load reductions). However, we are not aware of any such mechanism ever being applied to a Crown electric utility in Canada, and in addition the entire basis for this approach is to encourage conservation – as reviewed in Section 7, the effective incremental rates faced by Hydro's customers as a result of the Load Variation provision in fact achieve the opposite, they strongly discourage conservation and load reductions (particularly for the IC group).

[263] In the case of Newfoundland Power the measure is degree-days.

ATTACHMENT F – INDUSTRIAL CUSTOMER FIRM SERVICE

Industrial customer service contracts basically reflect four components to the service, each comprising different rates and terms:

- *Power on Order*, or the portion of the customer's load served by firm power at firm rates
- *Interruptible Power*, or the portion of the customer's load above the specified Power on Order, resulting in non-firm service and rates
- any *Maximum Demands* in excess of the contract limits on Interruptible Power, effectively representing short-term load excursions that are not firm service, but are charged at very high effective rates for the power received
- for those customers with their own generation, a separate *Generation Outage Power.*

This material reviews Power on Order, Interruptible Power and Maximum Demands. We have not specifically focused on Generation Outage Power, as this is a unique term available to only two customers.

"Power on Order"

The existing Industrial contracts provide a requirement for each industrial customer to specify a value called Power on Order for each year. This Power on Order value is measured in kW at peak, and operates roughly in the following way:

- ***Customer's own forecast:*** The Power on Order is each industrial customer's forecast of the firm demand peak it expects to impose on the system in the coming year.

- ***Specified in advance:*** The Power on Order value must be specified, in writing, by October 1 of each year for application to the following calendar year.

- ***Cannot decrease during year:*** The Power on Order value specified in October does not have to be the same during the calendar year – it can change at specified times during the year, but these intra-year changes may only be increases, not decreases[264].

- ***Subject to maximum:*** Each industrial customer has an absolute maximum Power on Order it is allowed to specify[265] without providing "adequate notice in order that Hydro may make suitable extensions or additions to the system"; the period of such notice is not specifically quantified in the contracts.

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[264] An exception is if the customer installs new generation, and provides Hydro with 36 months written notice, it can reduce its Power on Order during the calendar year.

[265] This maximum value is 90 MW for Abitibi Stephenville, 45 MW for North Atlantic Refining, 70 MW for Corner Brook, and 40 MW for Grand Falls.

- ***Subject to confirmation from Hydro:*** Even if the customer's specified Power on Order submitted in October is below the specified contract maximum level, Hydro can notify the customer by November 1 of the year before service is to be provided that it cannot meet the full customer-specified Power on Order266.

- ***Exceeding the Power on Order:*** If a customer has a requirement to consume more power than the Power on Order provides, they must have agreement from Hydro[267] and Hydro is not obliged to provide that additional power and may interrupt it at any time. If the additional power is made available, the customer will pay the non-firm rate for all consumption above the Power on Order up to the interruptible demand maximum[268]. The non-firm rate and terms for this service are addressed in the section below. If the customer's requirement is in excess of the Interruptible Demand maximum, these additional amounts become part of the Maximum Demand measurement, which is also addressed below.

- ***Customer billed for at least the Power on Order each month:*** For each month of service during the year, and regardless of actual use, the industrial customer will pay their demand rate based on the full amount of the Power on Order, unless one of the following is higher:
    - ***Ratchet Provision:*** If the customer's Power on Order in a given month is lower than 75% of the prior year's Power on Order (or 15,000 kW below the prior year's Power on Order, whichever is lower), the customer instead pays their demand charge on this higher ratcheted billing demand. This effectively prevents reductions in the Power on Order from being too large from year to year.
    - ***Actual Maximum Firm Demand:*** As addressed below, if the customer's actual monthly demand is in excess of the Power on Order plus Maximum Interruptible Demand available (which requires agreement from Hydro, and Hydro is not obliged to provide that additional power), then the customer pays additional demand charges based on the amounts in excess of the Power on Order for that month and all subsequent months in the year.

- ***Special Circumstances:*** There is a provision in the contracts that generally provides that energy supply (on the part of Hydro) and/or requirement to purchase energy (on the part of the customer) is suspended if the works of either party is suspended "in whole or in part by reason of war, rebellion, civil disturbances, strikes, serious epidemics, fire or other fortuitous events". If it is the customer that is prevented from taking power, the billing demand will be reduced to reflect this interruption, but billing demand will not be lower than 85% of Power on Order. If it

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[266] The specific text states that "if Hydro cannot fully comply…" with the Power on Order declared by the customer "it will, as soon as practical and in any event not later than November 1 of the year in which the declaration was made, advise the Customer of the extent to which it can comply."

[267] The contracts provide for a request from the customer to Hydro prior to consumption, if practicable, otherwise notification to Hydro as soon as practicable after initiation of consumption. Hydro will advise the customer if such interruptible power will be made available.

[268] The Interruptible Demand maximum is 25% of the Power on Order if the Power on Order is less than 20000 kW, 5000 kW if the Power on Order is 20001 kW to 50000 kW, and 10% of the Power on Order if the Power on Order is greater than 50000 kW.

Hydro that is prevented from delivering power, then there is no such lower limit on billing demand reductions.

The net effect on the monthly bill (i.e., ignoring deferred amounts in the RSP for now) is that industrial customers who decrease their loads from forecast save the energy rate on the kW.h not consumed (proposed at 2.765 cents/kW.h) but save nothing on demand charges. Even if the customer is able to forecast a reduction in energy requirements by October 1 of the year prior to the reduced requirement, the ability to save the demand charges associated with the reduced use is limited to ratchet provisions on the reduced Power on Order. In addition, the customer is not able to save any demand charges whatsoever (even if forecast at October 1 of the prior year) if they, at any time in the calendar year prior to the load reduction, have exceeded their Power on Order above the available Interruptible Demand.

In situations where load is reduced due to special circumstances facing the industrial customer (i.e., strikes or fire), there is a limited ability to save on demand charges due to the 85% downside limit on reductions below Power on Order.

The resulting average costs per kW.h to IC for firm power service (i.e., loads up to the Power on Order) depends on the load factor of the loads to be served. Using the proposed rates in the May 21, 2003 application (ignoring the RSP adjustment) and the forecast load factors, the average costs per kW.h range as follows:

- Load Factor of 90%[269]: 3.758 cents/kW.h[270]
- Load Factor of 75%[271]: 3.956 cents/kW.h[272]

To use an example, Corner Brook Pulp and Paper has a Power on Order forecast for the test year of 56 MW. This compares to a contract maximum Power on Order of 70 MW, so there is room for Corner Brook to increase their Power on Order in future years if there is a requirement for more power. In the test year, Corner Brook will be provided with a Maximum Interruptible Power of 5.6 MW. In the event that Corner Brook's peak in any given month exceeds 61.6 MW[273] (the sum of Power on Order and Maximum Interruptible Power), the additional power above 61.6 MW is served as Maximum Demand.

Interruptible Power

When an industrial customer has a requirement for an increased load compared to Power on Order, the initial block of increased load is required to be served at the interruptible rate. This rate operates outside the RSP, and ensures that the industrial customer pays:

[269] Per PUB-3, each of Abitibi Stephenville, North Atlantic Refining and Corner Brook Pulp and Paper are very close to a 90% annual load factor compared to Power on Order peak demands.

[270] Each kW of Power on Order results in $78.48 in demand costs, and reflects 7906 kW.h at a 90% load factor for an energy cost of $218.59. The total cost of $297.07 reflects an average energy rate of 3.758 cents/kW.h

[271] Per PUB-3, Abitibi Grand Falls is very close to a 75% annual load factor compared to Power on Order peak demand.

[272] Each kW of Power on Order results in $78.48 in demand costs, and reflects 6588 kW.h at a 75% load factor for an energy cost of $182.16. The total cost of $260.64 reflects an average energy rate of 3.956 cents/kW.h

[273] Ignoring peaks caused by outages at Corner Brook's own generation.

- 100% of the incremental costs of supplying the energy (no lower than a forecast 5.510 cents/kW.h at Holyrood, but as high as a forecast 11.982 cents/kW.h for Diesel[274])
- plus 10% over the incremental energy supply costs to reflect "an allowance for incidental operating costs of staff and facilities involved in dealing with the request and subsequent processing of the bill, an allowance for non-fuel items such as lube oil and fuel additives, and transmission losses"[275]
- plus $1.50 per kW to reflect "some value of the assets in place to provide the non-firm service"[276]

In the previous application (IC-44) Hydro also noted the specific requirement for interruptible rates to be higher than incremental costs in order to provide "an allowance for profit".

Compared to high load factor firm service at a rate approximating 3.758 to 3.956 cents/kW.h, the interruptible rates are costly on a per kW.h basis. There is only one customer forecast to consume interruptible power in Hydro's GRA load forecast[277]; Corner Brook Pulp and Paper is forecast (in the month of August) to consume 800 MW.h and use 5.6 MW of demand. The cost of service in Exhibit RDG-1 (Schedule 1.2 page 2 of 6) reflects a forecast cost for this power of $49,752, or an average cost per kW.h of 6.219 cents/kW.h. However, given the approach to Power on Order used in Newfoundland, were there no interruptible power available, Corner Brook would be required to serve this load with firm power by specifying a higher Power on Order or Maximum Demand, which would result in costs of between $205,240 and $461,608[278] or between 25.65 and 57.70 cents/kW.h.

Maximum Demands

Any power required in excess of the Maximum Interruptible Power available remains available to be interrupted at Hydro's discretion, but is served at Hydro's firm IC rates including billing demand ratchets. As such load excursions above the maximum interruptible power are likely to be rare (and therefore at a very low load factor), the resulting demand charge peaks they cause for the customer can result in the power being extremely expensive. The extreme example is if a customer exceeds their maximum interruptible demand by 1 kW for 1 hour in January for a total consumption of 1 kW.h – the resulting cost would be 1 kW.h apparently charged at the firm energy rate (2.765 cents) plus 12 months of demand for the extra kW ($6.54 times 12, or $78.48) for a total $78.51 for a single kW.h of power.

A more practical example is the one-time requirement of Corner Brook Pulp and Paper (forecast for August 2004) currently forecast to be served by Interruptible Power – if a similar type of one-time load

[274] Per IC-175, the forecast Holyrood-based non-firm energy rate is between 5.150 cents/kW.h and 5.267 cents/kW.h, the forecast gas turbine based non-firm energy rate is between 10.684 cents/kW.h and 11.143 cents/kW.h and the forecast diesel based non-firm energy rate is 11.982 cents/kW.h.

[275] IC-59

[276] CA-68

[277] PUB-3

[278] The 5.6 MW load in August to service 800 MW.h would likely have to be part of Power on Order for either all 12 months, or if a Power on Order increase were allowed in August for a total of 5 months. This would result in a demand charge of between $183,120 and $439,488 as well as energy charges of $22,120, for a total cost of between $205,240 and $461,608.

peak requirement were to arise in excess of the Maximum Interruptible Demand (i.e., in the test year, if a 5.6 MW peak were required above the 61.6 MW level), this power would be served by firm IC rates. As noted above, the cost would be in the effective range of 25.66 cents/kW.h[279]. This represents a load with an annual load factor of 1.63%, which is very low, but likely representative of the types of short-term load excursions that might arise on this type of service.

The net effect is that, in practical terms, the industrial customers must remain well below their Maximum Interruptible Demand cut-off, otherwise they risk having relatively minor and short-lived load excursions into Maximum Demand that result in very costly bill impacts.

[279] Assuming the power is used in August – if used in January the average cost would be 57.70 cents/kW.h as noted above.

ATTACHMENT G - REVIEW OF INDUSTRIAL INTERRUPTIBLE RATE OFFERINGS FROM OTHER UTILITIES

Many jurisdictions in Canada maintain interruptible rate programs available to industrial customers. These rates tend to generally fall into three categories:

1. **Interruptible Energy:** This type of rate offering is similar to the current Newfoundland Hydro Interruptible Demand/Energy component of the IC contracts discussed in Attachment F. Other examples provided in response to IC-222 are the Nova Scotia Power Industrial Expansion Interruptible Rate[280], the New Brunswick Power Surplus Energy Charge, and the Manitoba Hydro Surplus Energy Program. These three utilities offering an interruptible energy service do not charge any demand rate for this service. Energy rates are typically higher than the specific incremental costs to supply the power (3% plus .12 cents/kW.h in Nova Scotia, 0.9 cents/kW.h on-peak and 0.3 cents/kW.h off-peak in New Brunswick, and 10% plus transmission losses and plus 0.06 cents/kW.h in Manitoba[281]), but are comparable to Newfoundland Hydro's proposed 10% premium.

   A separate category of interruptible rates, often referred to as secondary energy, reflects power that is made available to general service or industrial customers from hydraulic generation that would otherwise be spilled. Newfoundland Hydro appears to offer such a secondary rate, as noted in the industrial contracts, but there is little reference to this rate in the materials filed. In other jurisdictions, surplus hydro is typically made available on an interruptible basis at rates that comprise only an energy component (no demand charge), for example, Rate Schedule 32 in Yukon and the Taltson excess power rate in NWT.

2. **Interruptible Capacity:** This type of offering would apply to rates that operate similarly to Newfoundland Hydro's now terminated Interruptible B rate. These rates offer a demand charges discount for a customer who offers a portion of their capacity that can be interrupted on short notice for limited periods of time to address system constraints. Examples provided in response to IC-222 include the Nova Scotia Power Interruptible Rider (rate code 25) or the Manitoba Hydro Curtailable Rate Program.

3. **Special Purpose:** This type of offering would be comparable to the Generation Outage Demand provided to two IC customers by Newfoundland Hydro, and also BC Hydro Schedule 1880 service provided in response to IC-222.

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[280] Rate code 18; however, there are significant restrictions on the application of this rate, such as the load served has to be "new" or "expanded" load as approved by the regulator.

[281] This is relevant provision of the Manitoba Hydro Surplus Energy Program when supplied from Manitoba Hydro generation (as opposed to purchased power or foregone export sales, which are not relevant in Newfoundland). Manitoba Hydro also charges $100 per month to customers who take surplus energy.

ATTACHMENT H – COMPARISON OF ISLAND INTERCONNECTED CAPACITY SOURCES

GREAT NORTHERN PENINSULA DIESEL GENERATION

The Great Northern Peninsula diesel plant comprises 14.7 MW at three sites – 8 MW at St. Anthony, 5 MW at Hawke's Bay and 1.7 MW at Roddickton[282]. These units primarily service the local loads at time of transmission system outages. This is reflected in the response to IC-235, which notes that the Hawke's Bay and St. Anthony diesel units have operated 112 times since 1996 to support local loads. In contrast, since the interconnection, the units have only operated once in support of the Island Interconnected system (January 30, 2003)[283] and that was prior to the in-service of Granite Canal or the new PPAs, which have added 87.3 MW capacity to the system[284] (almost 6 times the thermal generation on the GNP).

In addition, Table 3-3 from Exhibit JRH-3 indicates that absent the GNP generation, the Island Interconnected LOLH only increases from 1.1 hours/year to 1.4 hours/year in 2004, and the requirement for capacity additions is only advanced from 2011 to 2009 (also note that this 2009 result of 3.0 hours LOLH is barely above the 2.8 hours target maximum LOLH, and Hydro plans to add additional capacity in 2010 regardless due to energy balance shortfalls, per Haynes, page 37).

The issue of GNP generation, and whether to retain a specific amount of generation versus decommissioning the various units appears to have been reviewed in detail during the late 1990's. In particular, we note the response to IC-104 provides a copy of Hydro's application to the Board dated November, 1999 to decommission the Roddickton Woodchip plant and Roddickton Diesel plant, both sources of generation that existed on the GNP. In that application (page 2) Hydro specifically notes: "Normally, upon interconnection, Hydro decommissions all diesel generating capacity which supported the formerly isolated area. The St. Anthony/Roddickton area electrical load is situated at the end of a long radial transmission line. In this case, Hydro has decided to retain the 8800 kW diesel generation at St. Anthony as backup generation for this area"[285]. In addition, a detailed analysis was conducted by Acres International[286] regarding the backup diesel generating plant in the GNP area, which concluded that the existing generating plant was providing reduced total outage durations for St. Anthony (in particular) but also Roddickton and to some degree Hawke's Bay[287]. In contrast, there is no basis to support a

[282] Per JRH-3 Table 2-1.

[283] Per JRH-3, page 15.

[284] Per JRH-1, Schedule II. Hydro has not specifically addressed how this system constraint would have been addressed had Granite Canal and the PPAs been in service, but it is apparent that on a normal basis, the requirement for operating the diesel generation on the GNP has been reduced by the addition of this new capacity.

[285] It appears the difference between the 8800 kW cited here as the St. Anthony diesel capacity and the 8000 kW cited in JRH-3 is a mobile diesel generation unit that is now situated at Roddickton.

[286] filed in IC-231.

[287] "System Performance Review for Great Northern Peninsula" by Aces International, page v. Filed in IC-231.

conclusion that the units would be of any material benefits to non-GNP customers in 2004 now that Granite Canal and the two new PPAs are in service.

The cost of service treatment of common assets versus those specifically assigned is a key aspect in considering the allocation of these GNP generation costs. The GNP diesel assets appear to account for $1.402 million of the 2004 Island Interconnected revenue requirement. As these costs would presumably be classified 100% to demand, the resulting costs (prior to Rural Deficit reallocation) of the generation is as follows:

($millions)	Assigned to Common[288]	Specifically Assigned Rural
NP	$1.165	$0
IC	$0.182	$0
Rural	$0.098	$1.403
Total[289]	$1.445	$1.403

The most striking impact of the common allocation is the reduction in costs assigned to the rural customers from 1.4 million (100% of the cost) to $98,000 (6.8% of the cost). This is clearly not consistent with the relative benefits received from these assets.

INTERRUPTIBLE B

The Interruptible B rate program with Abitibi Stephenville was in place from December, 1993 to March, 2003. This program provided Hydro with the ability to call upon Abitibi Stephenville, at any time during the four winter months between the hours of 0800 and 2200, to reduce their power consumption by up to 46 MW for up to 10 hours. The interruption could be initiated on one hour's notice.

The ability to interrupt capacity at times of peak offers a number of clear benefits to the operation of the grid:

- ***The capacity is guaranteed to be available.*** With standby generation plant, there is the potential for the plant to be out-of-service or to break-down when required for service.

- ***The capacity is made available on the high voltage backbone transmission grid.*** In comparison, radial generation is more typically located at the end of long and isolated transmission systems, which themselves may be problematic at times of system constraints.

- ***The capacity interrupted in fact frees up the full capacity subscribed plus the transmission losses that had been associated with serving this power.*** In the case of Abitibi Stephenville's Interruptible B load, 46 MW plus the associated transmission losses was

[288] Allocated based on the production demand allocation ratios in column 3, exhibit RDG-1, Schedule 3.1A.
[289] The $1.403 million cost when assigned Rural is outlined in IC-13 (Rev.) line 20. The $1.445 million cost when assigned common is the total cost when assigned rural plus $44,986 for return on equity per IC-234.

made available by the customer interrupting their load. In contrast, additional grid generation, such as the gas turbines only supply their net capacity to the grid.

BURIN PENINSULA TRANSMISSION ALLOCATION

The Burin Peninsula is a long radial system serving primarily NP load, as well as a small quantity of Hydro rural customers. The loads are set out in IC-339 as 246,770 MW.h for NP (99.5% of the load) and 1,309 MW.h for Hydro rural (0.5% of the load). There are no IC loads on the Burin Peninsula. The system is made up of two roughly parallel transmission lines that are connected at the southern terminus to form a loop.

Hydro has proposed in Exhibit JRH-3 that the Burin Peninsula be assigned common, the same as in P.U. 7 (2002-2003). However, the primary basis for this recommended allocation appears to be that the line services both NP and Rural customers. However, based on other tests for NP-IC Sub-transmission assets, given that the system makes up a material asset value, it would appear that this factor would only lead to a joint NP-Rural allocation, with no basis to assign any costs to IC[290]. As an apparent secondary basis, Hydro asserts that the Burin Peninsula has been assigned common in the past due to "significant generation" being interconnected, but since that time 15 MW of NP generation has been removed and 8 MW of Hydro hydraulic (Paradise River) has been added.

The matter of the Burin Peninsula allocation was considered in brief in the 2001 proceeding. Specifically, Hydro noted in IC-267: "In addition to the assets requested in IC-88[291], the assets on the Burin Peninsula are currently assigned Common by virtue of connecting remote generation on a radial system that reaches the 230 kV grid. Hydro's proposed plan allocation now treats the GNP and the Doyles-Bottom Brook assets consistently with those assets. If the principle of plant assignment related to 'connecting remote generation on a radial system that reaches the 230 kV grid' is modified, the Burin Peninsula assets should receive similar treatment to the GNP and the Doyles-Bottom Brook assets."

The two transmission lines on the Burin peninsula do not necessarily provide the same function. Specifically, we note that the first line, TL212, is the line that connects the Paradise River hydro plant, and continues to the Linton Lake Terminal Station (per IC-332) well past the Paradise River plant. The other radial line, TL219 does not play any material role in connecting Paradise River to the Island Interconnected grid, except during transmission outages of TL212[292]. TL 219 accounts for the bulk of the costs on the Burin Peninsula.

Outside of the Paradise River plant, the only material generation on the Burin Peninsula is NP's 25 MW gas turbine. In past Hydro GRAs there had been 40 MW of NP thermal generation on the Burin peninsula,

[290] Specifically, Exhibit JRH-3 notes that transmission assets comprising more than 2% of Hydro's plant in service that only service NP and IC are assigned only to those two customer groups, not to Rural customers. By a comparable test, the Burin assets would properly be assigned NP-Rural and not IC. Hydro was asked about this possibility in IC-337 and IC-338, but declined to answer as the response claims the matter is "not relevant".

[291] That IR refers to the Doyles-Port aux Basques system.

[292] IC-333.

but the other 15 MW has since been relocated. As reviewed above, and within the GNP assessment from the 2001 proceeding (including the Board's direction in P.U. 7 (2002-2003) to assign the GNP transmission assets to Rural), radial peaking generation in this range does not result in an automatic assignment of transmission to common.

To the extent that there is any basis for arguing that interconnection of generation is a credible rationale for assigning the Burin transmission assets to common, this only appears to have any merit in relation to TL212. There is no real need for a TL219 backup transmission line to interconnect an 8 MW plant (Granite Canal, which is 40 MW, is not backed up by a second line). In addition, the Paradise River plant reflects $21 million in plant in service located only a small distance down the Burin Peninsula[293] - this does not provide a basis for assigning an additional $19 million of transmission plant[294] ranging the full length of the Burin Peninsula as being of common benefit. Even the TL212 assets at best only merit assignment of the portion north of Paradise River as common; however, Hydro appears to suggest this is not possible in their accounting system, and the impact on cost allocation is likely to be small.

In summary, there is no credible basis to assign any assets on the Burin Peninsula outside of TL212 as being of common benefit.

[293] See Haynes Schedule III and Reeves, Schedule II.
[294] Per IC-334.