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April 28, 2014

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Via Electronic Mail and Courier

Newfoundland and Labrador Board
of Commissioners of Public Utilities
120 Torbay Road
P.O. Box 21040
St. John's, NL A1A 5B2

Attention: Ms. G. Cheryl Blundon, Director of Corporate Services and Board Secretary

Dear Ms. Blundon:

Re: Pre-filed Testimony of Patrick Bowman, InterGroup Consultants Ltd. Expert Consultant to the Island Industrial Customers Group in the Hydro 2013 General Rate Application

Further to the above noted matter, we enclose the original and 12 copies of the Pre-filed Evidence of Mr. Patrick Bowman, on behalf of the Island Industrial Customers Group.

We trust you will find the enclosed to be in order.

Yours truly,

Stewart McKelvey

Paul L. Coxworthy

PLC/sls

Enclosure

c. Thomas J. Johnson, Consumer Advocate
Gerard Hayes, Newfoundland Power
Thomas O'Reilly, Q.C., Vale Newfoundland and Labrador Limited
Geoffrey P. Young, Newfoundland & Labrador Hydro
Edward M. Hearn QC, Miller & Hearn
Nancy Kleer, Olthuis, Kleer, Townshend LLP
Yvonne Jones, MP, Labrador

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PRE-FILED TESTIMONY OF

P. BOWMAN AND H. NAJMIDINOV

IN REGARD TO NEWFOUNDLAND & LABRADOR HYDRO

2013 GENERAL RATE APPLICATION

Submitted to:

The Board of Commissioners of Public Utilities

on behalf of

Island Industrial Customers Group

Prepared by:

InterGroup Consultants Ltd.

500-280 Smith Street

Winnipeg, MB R3C 1K2

April 28, 2014

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1.0 INTRODUCTION

This testimony has been prepared for three Island Interconnected Industrial Customers (known collectively as the "IIC Group")[1] of Newfoundland and Labrador Hydro ("Hydro" or "NLH") by InterGroup Consultants Ltd. ("InterGroup") under the direction of Mr. P. Bowman with the support of Mr. H. Najmidinov. It is evidence for the public hearing into the 2013 General Rate Application (the "Application" or "GRA") by Hydro to the Board of Commissioners of Public Utilities ("Board" or "PUB").

The IIC Group includes three large industrial companies currently operating in Newfoundland and Labrador. These companies are:

- Corner Brook Pulp and Paper Limited ("CBPP");
- North Atlantic Refining Limited ("NARL"); and
- Teck Resources Limited ("Teck").

Mr. Bowman's qualifications are set out in Appendix A. Mr. Najmidinov's qualifications are set out in Appendix B. InterGroup was initially retained in June 2001 to assist in addressing the 2001 Hydro Rate Review, and subsequently assisted the Industrial Customers in the 2003 and 2006 Hydro Rate Reviews and the 2009 review of Industrial Customers Rate Stabilization Plan ("RSP"), submitting evidence for each application.

In preparation for this testimony, the following information was reviewed:

- The Hydro General Rate Application filed July 30, 2013;
- Request for Information (RFI) responses from Hydro to the requests of the IIC Group;
- A substantial majority of the RFI responses from Hydro to the requests of the other intervenors and the Board;
- Hydro's Interim Rates Application filed November 18, 2013 and related RFI responses;
- Hydro's Rate Stabilization Plan Application filed July 30, 2013 and related RFI responses; and
- Various regulatory filings from the PUB's website including to a limited extent the Annual Hydro Capital Budgets and the previous Hydro General Rate Application filings.

InterGroup has been asked to identify and evaluate issues of interest to industrial customers, generally, and to the IIC Group in particular, taking into account normal regulatory review procedures and principles appropriate for Canadian electric power utilities.

[1] This evidence refers to all industrial customers in Island Interconnected system as Industrial Customers, or IC.

InterGroup's review has focused on Test Year 2013, consistent with Hydro's filing and the Order-in-Council direction to Hydro (OC2013-091)[2] and the Board (OC2013-089, as amended by OC2013-207)[3]. Where relevant information for 2014 has been provided, it has been considered in the assessment of rates for the 2013 Test Year, but not in the form of a 2014 Test Year.

1.1 SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

The rate impacts on industrial customers in this GRA are extraordinarily high. The full bill impacts range from 66% to 118% depending on the customer. While a portion of these impacts are due to one-time adjustments to the RSP, absent this factor the increases to individual customers still range from 31% to 62%[4]. Even including the effects of the Government mandated "phase in", over the course of 2013-2015, industrial customers will face repeated and sustained increases, each increment of which would readily qualify as unacceptable rate shock in basically any regulated electrical rate setting context in North America. In total, by the end of this GRA process, the industrial customers will be paying $12.2 million more for power than under the previous rates for serving the same load (from $16.7 million to $28.9 million).

Rate shock is widely considered to be nearly antithetical to regulated ratemaking.

Finally it must be noted that this impact comes at a time when industrial loads have been dramatically dropping, saving considerable quantities of expensive Holyrood fuel, and yielding all customer classes significant savings in fuel costs[5].

Against this backdrop, a focused and sustained effort is required to ensure Hydro's GRA rates overall, and for industrial customers in particular, are at the lowest reasonable levels.

Among the underlying considerations is that the GRA and Cost of Service study (COS) are required to be based on a 2013 Test Year. However, the rates arising from the COS will not actually be applied until well into the 2014 year and beyond. As a result, it is necessary to test the 2013 Test Year to generally ensure that rates approved on this basis are not immediately stale, and reflective of unreasonable or unjustly discriminatory results, by the very time they are first approved.

This submission addresses the following recommendations and conclusions:

1.1 The conversion factor for calculating the required level of Holyrood fuel should not be adjusted downwards from 630 kW.h/bbl to 612 kW.h/bbl as proposed by Hydro. This adjustment leads to a much higher calculated required fuel quantity than the previous GRA estimate. The actual performance of Hydro's regression analysis suggests a level higher than 612 kW.h/bbl is

[2] http://www.exec-oic.gov.nl.ca/public/oic/details?order-id=93.

[3] Provided in PUB-NLH-051, attachments 15 and 17.

[4] The 62% impact is for Vale, who is receiving a new specifically assigned charge related to newly constructed assets. Even if this factor is removed, customers who are experiencing no new assets or services face increases ranging from 31 to 42% before the RSP changes, and a further approximately 30% for the RSP effect.

[5] Moreover, the recent OC direction from Government directs an unprecedented transfer of positive balances from the industrial customer RSP as a subsidy to NP and its customers.

merited. In addition, substantial improvements in this factor are expected by way of capital projects that are scheduled to be imminently completed. Consequently a higher level, potentially on the order of 618 kW.h/bbl, is recommended. Please see Section 4.3 for details.

1.2 Hydro's calculated 2013 return on rate base reflects a fleeting moment where two factors are driving up the average cost of capital. First, Hydro is effectively financing a large proportion of its rate base with the RSP balances ($180 million), on which it calculates an imputed cost notionally linked to both older high cost debt, and equity. In practice, these balances are to be refunded to customers quickly, and will be largely replaced by modern low cost debt. Further, the 2013 debt complement includes substantial high cost debt that is to be refinanced by summer 2014. While the majority of Hydro's other major cost changes in non-Test Years are stabilized via the RSP (e.g., fuel price, hydrology), this large positive variance is not – when it arises it will go directly to Hydro's financial returns. Rather than advocating an expansion of the RSP, it is reasonable that the 2013 Test Year return on rate base instead face a downward adjustment, proposed to be on the order of 7.5%. Please see Section 4.4 for details.

1.3 The Cost of Service study uses a 2013 load for NP that does not reflect an appropriate peak load level. This is because the peak loads for the first months of 2013 are based on actuals, without weather adjustment. This input should be adjusted. The impact of this change is two-fold: (1) the peak loads are corrected, and (2) February becomes the month for Coincident Peak allocation, rather than December in the current COS, which is appropriate. Please see Section 5.2 for details.

1.4 The COS is heavily skewed by the representation of the transitional industrial customers, Vale and Praxair, who are not in similar circumstances to the IIC Group members. Outside of the fact that these customers are in commissioning phases, not operations, these customers have two defining features that are unique: (1) their annual loads are not at a high load factors, and (2) the customers have unique contractual provisions approved by the PUB with regard to the demand charges during their commissioning phases. To properly reflect this in the COS, in a manner that does not entirely neuter the Board's decisions regarding demand charges during their commissioning phases, the COS should be adjusted to normalize their annual loads, along the lines shown in the response to IC-NLH-140. Please see Section 5.3 for details.

1.5 The NP Curtailable Service Option is a program that is appropriate for some uses (such as interruptions during *bona fide* system constraints) and not in others (such as artificially reducing NP's peak at a time when there is no economic rationale for interrupting the service to these customers, and the only outcome of the interruption is a shifting of costs to other customers). To address this, the curtailable load should not be permitted to reduce the NP peak load for COS purposes. Also, if the curtailable service option is concluded to be of true value to the bulk power system there should be equivalent opportunities for Hydro's industrial customers, much like Hydro's long cancelled Interruptible B option. Further, the COS representation of both of these offerings should parallel the methods used in the past for Interruptible B (i.e., costs to make incentive payments to customers are included in COS, but peak loads are calculated based on the non-interrupted levels). Also, this factor supports rejecting Hydro's proposals to further increase the NP demand charge at this time, to help reduce perverse incentives for inefficient system operation. Please see Section 5.4 for details.

1.6 Under the current system operating conditions, the use of fuel at Holyrood during many times of the year is materially different than for past GRAs. In particular, Holyrood increasingly plays a role operating at low and inefficient levels, not due to hydraulic insufficiency, but due to transmission and reliability issues. This means that a component of Holyrood's fuel consumption does not fit with the traditional 100% energy classification. Based on an initial coarse assumption regarding hours of use, this could result in approximately 11% of Holyrood fuel being properly classified to demand, subject to further confirmation of the appropriate mix of Holyrood loading. Please see Section 5.5 for details.

1.7 In respect of the industrial rate design, the current GRA does not propose to implement the conclusions of the 2007-2008 industrial rate design working group. Given the current issues facing the system including large increases for industrials, a transitioning load for Vale and Praxair, and a proposed development of the Labrador infeed, this is appropriate. Please see Section 6.1 for details.

1.8 With respect to NP rate design, Hydro proposes substantial changes to the underlying design philosophy compared to the previous GRA negotiated settlement. This is not advised. The NP demand charge proposals result in dramatic increases (128%) that are inconsistent with rate and revenue stability, and are not justified by the current system conditions. It appears Hydro has proposed the new design without consultation regarding the potential impacts it may cause. It also appears a preferred rate design may be available, as set out in IC-NLH-079, which is a better starting point for consideration during the course of this GRA review. Please see Section 6.2 for details.

1.9 Hydro's RSP is proposed to be expanded to add stabilization for power purchases in respect of Independent Power Producers (IPPs) in terms of both price and volume. The principles of the RSP would appear to support stabilizing the volume of the purchases. The RSP principles would not support including IPP price in the RSP, as Hydro portrays this price effect as being simply inflationary (i.e. not unstable). Further, a possible future material impact on IPP price relates to future (as yet uncertain) decisions by Nalcor and Government in respect of Exploits generation. It would not appear advisable to enshrine the use of the RSP to automatically flow through any potential impact of those decisions to customers without limit or future review. Please see Section 6.3 for details.

1.10 The load variation provision of the RSP should be eliminated. It is an anomaly in utility regulation and represents an inappropriate allocation of risks. In the alternative, if it is desired to retain the provision for the time being while Holyrood remains the incremental source of generation, the load variation allocation approach proposed by Hydro in their June 30, 2013 RSP application should be approved pending a future elimination of the provision once a Labrador infeed is established. Please see Section 6.3 for details.

1.11 Hydro has proposed to have a currently interim contract with CBPP confirmed as final. This should be approved. This contract includes a 2009 pilot project intended to better achieve generation efficiency on the island (as required by the *Electrical Power Control Act, 1994*), and to alleviate a longstanding constraint on CBPP that incented the company to dispatch its hydro generation in an inefficient manner, and, as a consequence, to have to rely on expensive non-firm purchases from Hydro for certain core functions. The revised contract has already resulted in net savings of 21,000 barrels of oil for the island (2009-2012) to the benefit of all customers, and with no net cost to any other customer class. Please see Section 6.4 for details.

1.12 The Corner Brook Frequency Converter is a required component of the overall system, providing both a legacy benefit to all customers, and an ongoing role to CBPP. The unit is presently materially underperforming, which drives substantial disadvantages to the overall system[6] and to CBPP, despite major investment in the years since the 2006 GRA. Hydro's proposal to include the capital spending in rate base should not be approved without the unit achieving full performance. Further, the proposal to specifically assign the costs of this asset to CBPP should be revisited and reversed, particularly given this decision was first made when the specifically assigned cost made up 0.4% of the costs paid by CBPP to Hydro, and is now proposed to increase to 16%, a 40-fold increase. Please see Section 7 for details.

1.13 Regardless as to the cost allocation of the Corner Brook Frequency Converter, it is clear that at times of system constraints (such as January 2014), the unit is not limited to the level that Hydro imposes via contract (18 MW) but rather can operate at a higher level (22.5 MW in the recent supply constraint). In order for CBPP to be given a full and proper reflection of the role its generation plays at times of system peaks and supply constraints, and to be consistent with the approach to valuing NP's hydraulic generation, the industrial peak used for the COS should be adjusted downwards by 4.5 MW. Please see Section 7 for details.

1.14 In respect of Conservation Demand Management (CDM), the proposal to collect program costs via an equal cents per kW.h charge should not be approved. In particular, the approach proposed leads to industrial customers seeing little of the benefit of their CDM activities, as compared to NP who sees the majority of the benefits from the CDM activities undertaken by both industrials and by NP. This was one of the situations that the 2007-2008 industrial rate redesign working group sought to address. Consideration should be given to targeting system savings arising from CDM activities to the major Hydro customer that achieves the savings, for some specified period of time (rather than generically flowing through the RSP). In the absence of such a mechanism, it represents a significant mismatch of benefits versus costs to allocate CDM costs on the basis of equal cents per kW.h to all loads on the system. Please see Section 8 for details.

1.15 Consideration should be given to amortizing CDM costs over 10 years, rather than the 7 years proposed, particularly for programs that achieve benefits expected to last to 10 years or longer. Please see Section 8 for details.

[6] Among the costs to the overall system is a significant limitation on the ability of CBPP to play a role in grid support to its full potential (such as in January 2014).

2.0 THE INTERGROUP ASSIGNMENT

InterGroup was retained to focus on the issues of interest to industrial customers generally, and to the IIC Group in particular. This section covers the following material:

- Overview of Island Industrial Customers; and
- Key Relevant Regulatory and Rate Making Principles.

2.1 OVERVIEW OF ISLAND INDUSTRIAL CUSTOMERS

The IIC Group is comprised of three customers who comprise a substantial majority of the overall industrial class of customers on Hydro's Island Interconnected System ("industrial class" or "IC").

Each member of the IIC Group is a large energy consumer who is presently in production, and operates with high load factors (i.e. they have relatively comparable levels of energy use throughout the day and throughout the year and are in full operation for the 2013 Test Year). There are two other Hydro industrial customers who are proposed to be part of the same industrial class (Vale and Praxair), who do not share a number of the characteristics of the IIC Group operations; namely, they are not presently in production and their loads do not operate at a high load factor in the Test Year for this GRA application. As a result there may be a convergence in some issues of concern between the IIC Group and Vale and Praxair, but possibly not all. Vale is separately represented in this proceeding.

The customers that comprise the IIC Group have a 2013 forecast of 370 GW.h of firm electricity in 2013 (about 5.7% of the total firm energy delivered by Hydro to the Island Interconnected system). The entire industrial class load (i.e. including Vale and Praxair) has a forecast firm load of 408 GW.h[7], with an estimated $29.0 million[8] in total allocated costs (an average unit cost of 7.1 cents/kW.h). This scale of industrial load is a marked decrease from the firm industrial forecast of 894 GW.h for the 2007 Test Year (comprising about 14.4% of Hydro's Island Interconnected system load at that time) at a cost at that time of $43.1 million (an average unit cost of 4.8 cents/kW.h)[9]. This extends the trend of decreasing industrial load, which totalled 1,388 GW.h as of the 2001 GRA[10]. This ongoing decrease in forecast energy requirements for the Industrial Customer class is due to the following:

- The complete shutdown of former industrial customers Abitibi-Consolidated Company of Canada at Grand-Falls and Abitibi-Consolidated Company of Canada at Stephenville;

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[7] Sales numbers are from Hydro's 2013 GRA, Volume I, Section 2: Regulated Activities, Schedule II: Actual and Forecast Electricity Requirements for 2007 to 2013 (July 30, 2013).

[8] Hydro's 2013 GRA, Volume I, Section 4: Rates and Regulations, Table 4.4.

[9] 894 GW.h sales from Schedule 1.3.2 and $43.1 million allocated cost for firm energy is from Schedule 1.3.1 of 2007 COS provided by Hydro in response to IC-NLH-002. 14.4% is calculated based on 894 GW.h industrial firm sales divided by 6,184 GW.h total Island Interconnected sales per Schedule 1.3.2 of 2007 COS.

[10] From Schedule 1.3.2 of Hydro's 2001 GRA at http://www.pub.nf.ca/hyd01gra/PostHearing/NLHResponseToPU7Revised.pdf.

- Reduced energy forecasts for CBPP and NARL over the course of the last number of years; partially offset by:
    - o The arrival of the Teck Duck Pond mine load; and
    - o The addition and ramping up of the new industrial customers, Vale and Praxair.

In the case of each of the IIC Group members, electricity costs make up a substantial portion of the operating costs of the customers' operation. CBPP also has material hydro self-generation capability, which is routinely used for base load supply to the customer's operation. This self-generation can and has been used from time to time used to supply surplus power to Hydro, most notably this past winter during the period of system outages.

Industrial Customers' concerns are normally 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 deficit;
- Rates that are representative of the costs to serve a class of operating companies;
- Flexibility to tailor electrical service options to suit their operation, so as 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.);
- Lowest cost for power that can be achieved within the above considerations; and
- Continued reliability of power supply for Island Interconnected customers.

The concerns of IIC Group reflect the size of their capital investments in Newfoundland and Labrador, the long-term perspective essential to such investments, and the major stake that a customer with these investments typically has in continued large-scale power purchases from Hydro.

2.2 KEY RELEVANT REGULATORY AND RATE-MAKING PRINCIPLES

The InterGroup assignment focuses on a review of the revenue requirement proposed by Hydro, the Cost of Service (including the specific components of the 2013 COS study), and the overall rate design proposed in the 2013 General Rate Application. In addition, InterGroup was asked to review issues surrounding the Corner Brook Frequency Converter and the Conservation and Demand Management (CDM) proposals.

Revenue Requirement: Hydro's revenue requirement should reflect the total necessary and prudent costs to fulfill their obligation to serve, and to provide safe and reliable energy to customers. This includes many typical utility cost items, as well as items that are unique to mixed hydro/thermal utilities. In a mixed hydro-electric and thermal generation utility the cost of fuel and water levels will drive costs in a given year, in a manner that is unpredictable and not under the control of the utility. The RSP component of Hydro's rate design is intended to "protect" both Hydro and ratepayers from risks related to variances in these areas. Other costs that are more readily managed, including OM&A costs and the depreciation for long-lived assets, do not provide the same instability risks to Hydro but still make up a substantial component of the overall cost structure for a given year. As the IIC Group has decreased in overall proportion to the total customer base for Hydro, and now makes up only approximately 5-6% of the Island Interconnected System, this submission focuses only on revenue requirement issues where these were determined to be material and of substantive concern.

Cost of Service: In order to fulfill normal ratemaking principles, the relative levels of rates charged to various customer classes by Hydro are to be developed based on principles of "cost of service". This involves determining a fair allocation of Hydro's costs to the various classes based on a consistent set of principles. This is the most widely accepted standard applied for regulated utilities to determine whether rates are just and reasonable. The Cost of Service concept retains the concept of used and useful – for example, if a customer class does not use a component of the system (e.g., distribution), its rates are not to include the costs of that component of the system; likewise if only one class benefits from specific assets (such as streetlights) all costs related to those assets are to be allocated to the relevant class. Also among the critical cost of service theory is the concept of the different "products" that the utility provides, most notably the distinct products of peak demand (including reliability), energy, and customer services, and the appropriate ways to track the cost causation of each of these aspects of the system.

Rate Design: For the review of rate design, it is imperative that a long-term perspective is balanced with the short-term as Hydro is forecast to interconnect the island of Newfoundland to the Labrador infeed. Prior to this event, total rates in place should reflect the current level of costs, and rate designs should reflect a balanced perspective regarding long-term price signals on the island. Based on the proper allocation of costs, a rate design can be developed to recover the appropriate level of costs from the various customer classes, as well as achieve key objectives such as stability, efficiency, etc. In this submission the RSP has been dealt with as a matter of rate design, as the matters of most concern relate to this aspect of the RSP (and much less, for example, to the interaction of the RSP with revenue requirement).

3.0 OVERVIEW OF HYDRO'S GRA

This section provides a preliminary overview of Hydro's GRA. It addresses the following areas:

- GRA Approach;
- Overall Impact;
- Major Cost Changes; and
- Rate Implications for Industrials.

3.1 GRA APPROACH

The current GRA is Hydro's first general rate review since 2006 with new rates becoming effective in 2007 (known as the 2006 GRA). This is the longest period without a GRA since material changes in Hydro's approach to setting revenue requirements and rate structures were implemented in 1999. The current GRA is being held pursuant to a series of Newfoundland Government Orders in Council ("OC") which provide specific requirements and constraints in regard to timing, the Test Year to be used, and the phase-in of industrial rate changes.

The GRA documents request approval of a revenue requirement and rate changes based on 2013 Test Year forecasts. This approach is consistent with the requirements of OC2013-089 (as amended by OC2013-207) and OC2013-091. Hydro's 2013 GRA requests the approval by the Board of the revenue requirement, a 2013 Cost of Service study, and a proposed rate design with the resulting new rates effective January 1, 2014[11].

The approach is somewhat unusual in Canadian ratemaking, in that the benchmark (and only) Test Year is not the year in which the rate will be applied. While this may be a requirement of the OCs, it is uncertain how this is to be tested against the ongoing requirement on the PUB to ensure rates at all times are reasonable and not unjustly discriminatory pursuant to the governing legislation[12] (i.e. in the event that 2013 calculated rates were determined to be unreasonable, or unjustly discriminatory for 2014 or 2015 or some other future period).

The rates in the current GRA are subject to PUB approval; however, the OC directions specify that the rates approved for IIC Group must be phased-in over a three year "rate phase in period"[13] starting in 2013. The OC does not in most cases specify the final rates to be approved or the precise rates to be charged during each year of the phase-in period.

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[11] Hydro's 2013 GRA, page 1.1.

[12] Paragraph 3(a)(i) of the *Electrical Power Control Act, 1994*, SNL 1994 Chapter E-5.1 and Section 82 of the *Public Utilities Act, RSNL 1990*, Chapter P-47.

[13] OC2013-089, Section 4 as provided in response to PUB-NLH-051 Attachment 15.

3.2 OVERALL IMPACT

The Application requests approval of a revenue requirement from rates of $565.7 million, which is 32% higher than the approved 2007 Test Year[14]. For the Island Interconnected System ("IIS"), the allocated revenue requirement has increased from $381.9 million to $501.1 million, or 31.2%. These increases are well above the degree of island system load growth over this period, which cumulatively is only 3.7%[15].

As a result of the significant increase to revenue requirement, with limited growth in load, the base rate impacts in the current GRA are very large particularly for the industrial customer class. A portion of the revenue requirement increase is due to factors, such as an increased price in fuel, fuel efficiency or water levels, which, if not recovered through base rates, will be recovered through the RSP. Consequently, for a full comparison of the bill impacts of the GRA, there is a need to consider where the impact from each revenue requirement change will take effect:

a) **The proposed increases to base rates since the last time base rates were set, in the GRA Test Year 2007:** The existing base rates fully recovered the revenue requirement at that time. The increase in base rates since that time is helpful for understanding the net longer-term impact on customers since 2007, for comparing effects between the various customer classes and as a cross-check on the reasonableness of the cost allocation methods.

b) **The net bill impacts on customers arising after consideration of all RSP and other effects (e.g., OC phase-in):** This perspective is important for assessing the short-term impacts on customers, including such concepts as 'rate shock'.

The 2013 GRA proposes base rate impacts on Island Interconnected System (IIS) customers that are materially inconsistent between the main classes when compared to the 2006 GRA, as follows[16]:

- **Newfoundland Power ("NP"):** NP's <u>base rates</u> are forecast to increase (based on consistent 2013 load) from $381.5 million to $453.0 million, or an increase of 18.7%[17].

- **Industrial Customers:** The industrial customer <u>base rates</u>[18] excluding specifically assigned charges are similarly proposed to increase, in this case from $20.6 million to $27.2 million, or an increase of 31.9%[19].

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[14] Hydro's 2013 GRA, Finance Schedule III (2007 Test Year at $429.1 million).

[15] Revenue requirement numbers for IIS are from Schedule 1.1; and growth from 6,184 GW.h to 6,412 GW.h per Schedules 1.3.2 of the respective Test Year cost of service studies for 2007 and 2013, as found in IC-NLH-002 (2007 COS) and Exhibit 13 of Hydro's 2013 GRA, Volume II.

[16] Per IC-NLH-089.

[17] As per IC-NLH-089 Attachment 1 page 1 of 3. Also note that as of December 2012, NP (unlike the IC) has a fuel price rider of $91.4 million/year (page 2 of 3) that will be eliminated when new GRA rates are implemented. This means that in practice the GRA represents a rate decrease for NP, and similarly for the Rural Island Interconnected customers whose total allocation drops from $50.0 million to $48.4 million.

[18] Note that as Per OC2013-089 the industrial customers will in practice be paying a phase-in rate and not the full GRA rates as noted above.

[19] As per IC-NLH-089 Attachment 1 page 2.

- o Note that in addition to the above, the industrial customers specifically assigned charges are proposed to increase by $1.1 million, bringing the total industrial customer cost impact from the current GRA to 36.1% for the class[20].

It is not immediately clear why the increase in industrial customer base rates of 31.9% (not including specifically assigned charges) is so far in excess of the increase to NP base rates over this same period – had industrial customers increased by the same 18.7% as NP rather than the proposed, the Industrial Customers rates would be $24.5 million[21] or $2.7 million lower than proposed. While some factors, such as the increase to forecast fuel price, can have a more significant impact on high load factor customers, there are various aspects of Hydro's application that should shift costs in a manner that is beneficial to industrial customers, such as the replacement of Holyrood fuel (which is typically assigned 100% to energy, which has a greater allocation to industrial customers) with purchased power from hydraulic generation from Nalcor (which is split between demand and energy allocations, which are more balanced in allocation to the different classes of customers).

3.3 MAJOR COST CHANGES

By far the most dominant factor affecting Hydro's cost structure is the increase in the price of No. 6 fuel for use at Holyrood. Absent any changes to the supply mix or load levels, this factor alone would have driven the Island Interconnected System costs up by nearly $131 million since 2007[22]. With Hydro's efforts at evolving the system towards less reliance on energy generated at Holyrood; including the addition of supply due to the transfer of the former Abitibi-Consolidated assets, and industrial load reductions, this impact has been reduced by nearly 50% (approximately $63 million)[23].

The relationship between Hydro and its shareholder, the Government of Newfoundland and Labrador, is one of the largest drivers of Hydro's cost structure in this GRA. These effects include (i) the newly dictated requirement for Hydro to earn, on behalf of its shareholder, a much higher Return on Equity (ROE) than has been awarded in past GRAs, (ii) the material recapitalization of Hydro to convert a significant portion of what was previously long-term debt into equity, (iii) the supply of power from the formerly Grand Falls related hydro power to Hydro as a fixed price Independent Power Producer (IPP) type arrangement, and (iv) the conversion of previous IPP arrangements at Star Lake and the Exploits River to a new fixed price level. Many of these impacts are offsetting. The net effect is that Government actions which may otherwise be presented as a potential material benefit to ratepayers (temporary establishment of lower cost IPP arrangements with Nalcor, through June 30, 2014)[24] have significantly

[20] As per IC-NLH-089 Attachment 1 pages 1 and 2.

[21] $20.6 million * (1 + 18.7%).

[22] The average price of fuel consumed for 2007 Test Year was $55.47/bbl, as compared to $108.74/bbl in the current GRA, an increase of $53.27/bbl. The 2007 Test Year required a forecast 2.467 million barrels of No. 6 fuel (please see Table 4-2 below). Had all other factors remained the same other than fuel price, the impact would have been $131.5 million.

[23] Please see Table 4-2 below for details.

[24] This includes the provision of 4 cents/kW.h power from Nalcor to Hydro, for power derived from assets that have not been publically tested to determine whether their net costs are 4 cents/kW.h, or potentially lower versus exceed this level. Copy of 0C2013-088 is provided in PUB-NLH-002, Attachment 1, page 1 of 1.

been offset by other Government recoveries and charges to Hydro, so that the ultimate net ratepayer benefit is reduced.

Additionally, Hydro proposes a substantial expansion to the number of variables from which Hydro is cost protected via "recovery mechanisms"[25]. This includes a number of variables where Hydro notes a concern for adverse impacts on its earnings in future years (such as diesel prices and any purchased power cost escalation). In contrast, there are a series of variables that are widely expected to improve for Hydro in future years, such as (i) debt costs (as high cost debt is refinanced, and as large balances owing via the RSP are paid out and financed with new low cost debt), (ii) Holyrood efficiencies (as loads grow and loading on the plant increases) and (iii) demand charge revenues (as loads grow, particularly NP and Vale). None of these potentially positive variables are proposed to be addressed via any "recovery mechanism" for future credit back to customers.

3.4 RATE IMPLICATIONS FOR INDUSTRIALS

The requested rate changes for industrial customers are severe in the 2013 GRA, with customers other than Teck facing 66%[26] increases from 2013 to 2015. Teck faces an increase of 118%[27] over this same period. A significant portion of these impacts relate to one-time required adjustment to the Rate Stabilization Plan ("RSP"). Excluding the RSP adjustment, industrial increases are between 31% and 62% for a combined impact on the class of $12.2 million[28].

In an effort to help alleviate these severe impacts on industrials, Government directed Hydro and the PUB to phase-in the proposed rate increases with a portion of the existing balance in the RSP. While this prolongs the full impact, there are two notable issues with using this approach:

1. The dollars proposed to be reallocated within the RSP for the purposes of the phase in were already being held for customer benefit, so Government has not in practice imposed any new benefits or protection for customers that did not already exist.

2. The resulting impacts, as proposed by Hydro, remain that customers will see three stepped and consecutive increases averaging over 20% each, with 30% increases at each step for Teck[29]. By any reasonable definition of "rate shock", these increases are problematic.

The proposed increases are especially problematic for the IIC Group given the savings this group has provided to the overall system. In contrast to upwards pressures on rates, these three customers have combined loads that have reduced to less than half the level as of the 2007 Test Year (from 762 GW.h to 370 GW.h)[30], which has resulted in material grid-wide savings for all customers, as the quantity of No. 6

[25] Hydro's 2013 GRA Application, Section 4: Rates and Regulation page 4.25.

[26] Appendix F of the Hydro's July 30, 2013 RSP filing: $24.3 million by September 1, 2015 and $14.6 million at existing rates.

[27] Appendix E of the Hydro's July 30, 2013 RSP filing: $4.7 million by September 1, 2015 and $2.2 million at existing rates.

[28] At 2007 rates, the costs to serve the 2013 load would be $16.7 million and at 2013 proposed full rates the total for the same load would be $29.0 million, all as per Appendix E and F of the Hydro's July 30, 2013 RSP filing.

[29] Appendix E and F of the Hydro's July 30, 2013 RSP filing.

[30] Hydro's 2013 GRA, Regulated Activities, Schedule II.

fuel required to serve the Island has been reduced by over 600,000 barrels. These load changes provide a net cost saving of $70 million at today's fuel prices (or $35 million at the prices from the 2006 GRA)[31].

Finally, Hydro's GRA reflects a continuing pattern of increasing the allocations to industrial customers of specifically assigned assets, which are asserted to only provide value to specific customers. This increase operates in addition to the rate impacts noted above, and serves to compound the pressures on individual industrial customers that have specifically assigned costs.

[31] 392 GW.h load reduction at 612 kW.h/bbl Holyrood conversion factor, $108.74/bbl fuel price proposed by Hydro in 2013 GRA and $55.47/bbl fuel price for 2006 GRA (Schedule 1.4 of 2007 COS).

4.0 REVENUE REQUIREMENT

This Section provides an overview of Hydro's proposed revenue requirement in comparison to the 2007 Test Year, as well as detailed comments in respect of areas of notable concern. It consists of the following:

- Comparison to the 2007 Test Year;
- Bulk Power Costs;
- Holyrood Fuel Conversion Factor; and
- Hydro's Capital Structure and Return on Rate Base.

4.1 COMPARISON TO THE 2007 TEST YEAR

The proposed 2013 Hydro revenue requirement set out in Finance Schedule III of the Application is $568.087 million[32]. This is an increase of $137.008 million or 31.8% from the approved 2007 Test Year[33] revenue requirement of $431.079 million as shown in Table 4-1 below, which compares the total revenue requirement by category for the 2007 and 2013 Test Years.

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[32] However, note that the Revenue Requirement for 2013 shown in Schedule 1.1 of Cost-of-Service is $567.818 million. The difference reconciled in tab "Reconciliation" of excel version of Cost-of-Service relating to different treatments of non-regulated revenues in Labrador, as well as other factors.

[33] As provided by Hydro in 2013 GRA, Finance Schedule III.

Table 4-1: Comparison of Hydro's 2007 and 2013 Forecast Revenue Requirement and Revenue from Rates[34]

	2007 Test Year	2013 GRA Proposed	*Increase/ (Decrease)*
Total Depreciation	**38,825**	**51,656**	***12,831***
Loss on disposal and accretion of ARO	**1,366**	**2,147**	***781***
Fuel			
No. 6 Fuel	136,867	200,315	*63,448*
Diesel Fuel and Other	11,569	19,159	*7,590*
Less RSP Deferral		-84	*-84*
Sub-Total Fuel	**148,436**	**219,390**	***70,954***
Purchased Power	**38,327**	**58,674**	***20,347***
Expenses			
Salaries and Fringe Benefits	58,457	77,241	*18,784*
System Equipment Maintenance	20,579	21,495	*916*
Office Supplies Expenses	2,106	2,571	*465*
Professional Services	4,418	7,022	*2,604*
Insurance	1,881	2,211	*330*
Equipment Rentals	1,369	1,731	*362*
Travel Expenses	2,332	3,156	*824*
Misc Expenses	4,530	6,380	*1,850*
Building Rentals and Maintenance	825	1070	*245*
Transportation	1,994	2,273	*279*
Cost recoveries	-2,199	-9,222	*-7,023*
Non-regulated customer	-2,874	-2,108	*766*
Net Operating Expenses	**93,418**	**113,820**	***20,402***
Less: COS exclusions		**48**	***48***
Return on Ratebase	**110,707**	**122,448**	***11,741***
Total Revenue Requirement	**431,079**	**568,087**	***137,008***
Less: Other Revenues	**2,021**	**2,350**	***329***
Revenue Required from Rates	**429,058**	**565,737**	***136,679***

4.2 BULK POWER COSTS

The largest changes to Hydro's cost structure since 2006 GRA relate to supply bulk power cost. This includes fuel costs, particularly No. 6 fuel for Holyrood, as well as purchased power and diesel.

For the Island Interconnected System, the costs related to fuel and purchased power have been affected by a series of interrelated changes that drive the $63.4 million increase noted above. These changes are set out in Table 4-2 below.

[34] The table is prepared based on Hydro in 2013 GRA, Finance Schedule III.

Table 4-2: Changes to Fuel Forecast by Cause - 2007 to 2013 Test Years[35]

	Holyrood Generation	Fuel Efficiency	Barrels	Fuel Price	Calculated Total Fuel Expense	***Net Change to Fuel Expense***	Purchased Power Costs Increase
	GW.h	kWh/bbl	bbl	$/bbl	$000	$000	$000
2007 GRA, Holyrood Generation	**1,554.5**	**630**	**2,467,460**	**$55.47**	**136,870**	-	-
Change due to Fuel Price change	1,554.5	630	2,467,460	$108.74	268,316	*131,446*	-
Long-Term Average hydraulic change	1,493.1	630	2,369,952	$108.74	257,713	- *10,603*	-
Increase in Power Purchases (not Nalcor)	1,373.8	630	2,180,603	$108.74	237,123	- *20,590*	9,352
Increase in Nalcor-related Purchases	890.8	630	1,413,921	$108.74	153,752	- *83,370*	9,311
Change due to Gas Turbine load change	891.0	630	1,414,238	$108.74	153,787	*35*	-
Change due to Fuel Efficiency change	891.0	612	1,455,833	$108.74	158,310	*4,523*	-
Change due to Load Growth	1,127.4	612	1,842,108	$108.74	200,314	*42,004*	-
2013 GRA, Holyrood Generation	**1,127.4**	**612**	**1,842,108**	**108.74**	**200,314**	**63,444**	**18,663**
Change due to Load Growth by customer							
Change due to Transmission Losses	34.4	612	56,209	108.74	6,112	*6,112*	-
Change due to Newfoundland Power	668.5	612	1,092,320	108.74	118,781	*118,781*	-
Change due to Rural	55.3	612	90,359	108.74	9,826	*9,826*	-
Change due to CBPP	-372.4	612	- 608,497	108.74	- 66,169	- *66,169*	-
Change due to Abitibi Con. - Grand Falls	-162.4	612	- 265,359	108.74	- 28,856	- *28,856*	-
Change due to Abitibi Con. - Stephenville	-5.7	612	- 9,314	108.74	- 1,013	- *1,013*	-
Change due to North Atlantic Refining	-27.4	612	- 44,771	108.74	- 4,869	- *4,869*	-
Change due to Aur Resources/Teck	7.5	612	12,255	108.74	1,333	*1,333*	-
Change due to Praxair	34.3	612	56,046	108.74	6,095	*6,095*	-
Change due to Vale	4.3	612	7,026	108.74	764	*764*	-
Total Load growth Impact						**42,004**	**-**

As shown in Table 4-2 above, the 2007 Holyrood generation was forecast at 1554.5 GW.h, at a 630 kW.h/bbl efficiency and an average consumption cost of $55.47/bbl. All other things being equal, the increase in fuel price since 2007 would have resulted in a $131.4 million increase in revenue requirement. This has been offset by an increase in the calculated long-term average hydraulic generation ($10.6 million savings), increased third-party power purchases ($20.6 million in fuel savings, offset by $9.4 million in power purchase costs), and due to power purchases related to Nalcor ($83.4 million in fuel savings, offset by $9.3 million in power purchase costs).

The other substantive change in costs relates to the revised estimate of Holyrood efficiency, from 630 kW.h/bbl to 612 kW.h/bbl. This change serves to increase revenue requirement by $4.5 million.

The largest driver of fuel volume and cost increases is load growth. Although the largest of the Industrial Customers have reduced their load (with CBPP load reductions driving $66.2 million in Holyrood fuel savings, and NARL driving $4.9 million in savings) the continued growth of Newfoundland Power and rural loads have more than offset this decline, combining for over $125 million in added fuel cost (before

[35] The table is prepared based on Hydro's 2013 GRA. Regulated Activities, schedules II, V and VI. Change in Holyrood generation reflects impact of increased/decreased supply source compared to 2007 Test Year. For example, long-term average hydraulic change reduces Holyrood generation from 1,554.5 GW.h in 2007 Test Year to 1,493.1 GW.h or decrease of 61.4 GW.h which is calculated as a difference between 2013 forecast hydraulic generation at 4,533.5 GW.h and 2007 forecast at 4,472.1 GW.h from Regulated Activities, Schedule V. Holyrood No. 6 fuel cost per barrel is from 2007 COS, Schedule 1.4.

any allocation of added line losses). On a combined basis, the higher loads today as compared to 2007 Test Year drive $42.0 million in added fuel cost.

4.3 HOLYROOD FUEL CONVERSION FACTOR

Hydro's 2013 GRA application proposes a 612 kW.h/bbl[36] net conversion factor (or fuel efficiency) for Holyrood generation. The concept of "net" conversion factor is that it includes the effects of station service loads in the calculation. This factor is lower than 2004 and 2007 approved efficiencies by 18 kW.h/bbl[37]. Hydro notes that the conversion factor forecast at 612 kW.h/bbl is based on a regression analysis using 2003-2012 actual unit average gross loading and fuel consumption rates, and forecast net unit loading at 87.5 MW and station service forecast at 6.56%. Hydro also notes that it has used the actual station service experience from 2008 to 2012 to derive the net fuel conversion factor[38].

In testing the regression developed by Hydro, the actual data provided by Hydro showed somewhat higher actual conversion factors than predicted by the regression when the Holyrood generation was at the annual level as forecast for 2013 GRA. For example, the average conversion factor for the level of load between 1,001 GW.h/year and 1,200 GW.h/year is 625 kW.h/bbl based on the actual data provided for 1997-2012[39]. Further, NP-NLH-193 shows for the four recent years with the most comparable levels of annual load to the 2013 Test Year (2008, 2009, 2007 and 2011) the proposed regression factor consistently under-forecasts the actual net conversion factor, as shown in Table 4-3.

Table 4-3: Holyrood Conversion Factor for Years with Comparable Annual Loading to Test Year 2013

		kW.h/bbl		
Annual Load (GW.h)	Year	Actual Conversion Factor	Predicted Conversion Factor	difference
948.9	2011	603	601	2
1005.7	2009	612	603	9
1127.4	2013 TY		612	
1151.5	2008	625	618	7
1340.3	2007	614	609	5
			average difference	5.75

As shown in Table 4-3, the regression done for the Holyrood forecast conversion factor averages 5.75 kW.h/bbl less than the average of the actual amounts for the pertinent years with a similar load to the 2013 Test Year.

In response to IC-NLH-064 and IC-NLH-138 Hydro also provides a list of initiatives undertaken and forecast to be completed to improve fuel efficiency since the last GRA. There is cost for ratepayers

[36] Net Holyrood production after station service (see for example IC-NLH-093 and NP-NLH-069).
[37] Conversion factor of 630 kW.h/bbl (Schedule 1.4 of 2007 COS).
[38] All are in Hydro`s responses to NP-NLH-069 and NP-NLH-192.
[39] See Hydro`s responses to NP-NLH-196.

associated with those projects. For example, the net book value for Holyrood plant included in Hydro's rate base for 2013 GRA increased by about $21.982 million compared to 2007 Test Year[40]. Fuel saving initiatives, such as the list provided by Hydro, would be expected to reduce the station service, leading to a higher net Holyrood efficiency even without improvements in the gross plant efficiency. By using the average station service rate from the past five years, it is not apparent that Hydro has given full consideration to providing ratepayers with the benefits arising from the capital projects.

Finally, it is important to note that fuel efficiency is an item which is not stabilized via the RSP. In short, if the forecast of Holyrood conversion factors is too low in a GRA, the benefits of a higher actual efficiency will flow to Hydro's net income.

For 2013, there is now data available that indicates the Holyrood plant operated at an actual efficiency of 594 kW.h/bbl in NP-NLH-304. This reflect a load of 957 GW.h, which trends towards the lower range in load shown in Table 4-3. It is not possible to calculate the efficiency that the regression analysis would have produced as the RFI response does not provide the average loading, which is the basis for the regression calculation. It is important to also note that the Holyrood production does not reflect 2013 Test Year assumptions for the hydraulic generation and Holyrood generation mix, but instead uses a much lower level of Holyrood generation, so is not directly relevant to a Test Year concept. Nonetheless, if the 2013 actual value were equivalent to the 2013 Test Year average loading (based on the annual load being comparable) then the variance would be negative 7 kW.h/bbl[41]. If this value were used as the first value in the above Table, the average variance over the sample set would be revised to 4 kWh/bbl (i.e., the regression still forecasts too low on average).

Also note that NP-NLH-191 indicates that Hydro is imminently implementing a Variable Frequency Drive project, which is projected to increase the Holyrood efficiency by 8 kW.h/bbl (from 619 kW.h/bbl to 627 kW.h/bbl). While not complete in 2013, this project appears to be ready for completion at approximately the same time as the GRA rates will be put into effect (late 2014).

The evidence supports setting Hydro's 2013 Test Year Holyrood efficiency at a level higher than 612 kW.h/bbl. A reasonable estimate would combine a correction for the experienced prediction factor, as well as adjustment for reductions in the station service that customers have invested in via the Capital Budgets. In the absence of a firm value, a reasonable compromise may be to adopt the 6 kW.h/bbl (rounded from 5.75 kW.h/bbl) adjustment from above and impose no quantified further adjustment for station service. Therefore the minimum Holyrood conversion factor for 2013 Test Year should be 618 kW.h/bbl, which decreases 2013 GRA revenue requirement by approximately $2 million[42]. This approach

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[40] Schedule 2.3A of 2007 COS at $41.379 million and 2013 COS at $63.362 million.

[41] Based on assumption that year to date load for 2013 as provided in NP-NLH-304 is at 957 GW.h which is 85% of 2013 Test Year load at 1,127 GW.h, and for regression analysis Hydro used 87.47 MW (NP-NLH-069) unit net average loading which leads to 74.3 MW for 2013 YTD load (84.47 MW * 85% = 74.3 MW). By using the calculation provided in Table 2 of NP-NLH-069, 74.3 MW unit average loading leads to predicted efficiency of 601 kW.h/bbl or about 7 kW.h/bbl higher than 594 kW.h/bbl provided in NP-NLH-304.

[42] Forecast Holyrood generation at 1,127.4 GW.h divided by 618 KW.h/bbl conversion factor and multiplied by fuel cost at $108.74 equals to $198.4 million fuel costs compared to $200.3 million as proposed by Hydro based on 612 kW.h/bbl conversion factor.

would remain a downward revision from the approved level in the 2007 Test Year level (630 kW.h/bbl), but would be more realistic given the forecast loading and generation mix.

4.4 HYDRO'S CAPITAL STRUCTURE AND RETURN ON RATE BASE

Since the last GRA (2006 GRA with 2007 Test Year) the share of equity in Hydro's capital structure has increased substantially from 13.99% to 25.12% in the 2013 Test Year[43]. In addition, Hydro now reflects a higher ROE (from 4.47% in the 2007 Cost Of Service [COS] to 8.80% in the 2013 COS)[44]. Finally, Hydro now includes a return on all assets in its revenue requirement, rather than only interconnected system costs. The three above changes since the 2006 GRA arise as a result of Government policy.

Hydro's Return on Rate Base has also changed as a result of rate base growth, and changes in the cost of debt, as shown in Table 4-4 below:

Table 4-4: Changes to Return on Rate Base since the 2007 COS[45]

	Return on Rate Base ($)	Change ($)	Due to policy ($)	Due to costs ($)
2007 Return on Rate Base	110,809,988			
Change to Eliminate Rural ROE	112,134,421	1,324,433	1,324,433	
Growth in Rate Base	117,762,845	5,628,424		5,628,424
Change to Average Debt Costs	114,546,597	- 3,216,249		- 3,216,249
Change to Return on Equity and Equity Ratio	122,447,757	7,901,161	7,901,161	
		11,637,769	9,225,594	2,412,176

From Table 4-4, a significant portion of the increase in costs of Return on Rate Base is due to policy direction from Government. The major savings item provided is the reduction in average debt costs, as the weighted average cost of debt is reduced from 8.260% to 8.014%[46].

A major item of note in the current GRA is the inclusion of the large RSP balances within Hydro's 2013 capital structure. During 2013, and to a greater degree 2014, these balances lead to some peculiar outcomes. Most notably, Hydro's total capital for financing rate base, on a mid-year basis, in 2013 is approximately $1.385 billion[47]. However, this capital is financing a mid-year rate base (assets) of $1.564

[43] Schedule 1.1 of 2007 COS (as provided in response to IC-NLH-002) and 2013 COS, page 2 of 2.

[44] The weighted average return on equity are from Schedule 1.1 of 2007 COS and 2013 COS.

[45] Per Schedule 1.1 (page 2 of 2) of the 2007 COS the Rural portion was at $212 million which would result in $1.324 million change at 0.625% weighted average return for 2007; the rate base has grown by $74.8 million (from $1,489 million to $1,564 million) which would have impact of $5.6 million at 2007 weighted average cost of capital at 7.529%; average debt return reduced from 8.26% to 8.01% of by 0.25% which would be $3.2 million at $1,564 million rate base for 2013 and debt ratio of 83.59% for 2007; weighted average return on equity increased by 1.586% (from 0.625% to 2.211%) which would be $24.8 million at $1,564 million rate base for 2013 offset by impact of lower debt ratio of $16.9 million (83.59% debt ratio from 2007 multiplied by 8.01% debt return would be 6.70% weighted average debt return compared to 5.62% as proposed by Hydro for 2013 or difference of 1.08% * $1,564 million rate base would be $16.9 million). All numbers are from Schedule 1.1 of the respective 2007 and 2013 Cost of Service studies.

[46] Schedule 1.1 of the respective 2007 and 2013 Cost of Service studies.

[47] The 2013 opening balance is $1.349 billion and closing is $1.421 billion, for a mid-year average of $1.385 billion, as per Hydro's 2013 GRA, Finance Schedule I page 4 of 11.

billion. The result is approximately $180 million more in assets than in available capital. The substantive difference is the RSP balance[48]. In effect the RSP is functioning as an additional form of financing for rate base, or as a form of loan to Hydro, increasing the required return.

It is clear that within the timeframe of the GRA, effectively all of the $180 million surplus noted above will no longer be financed via RSP balances. Per the February 2014 RSP report, the full RSP balance is over $250 million, and within 8 months (December 2014), it is likely that all but approximately $50 million of this balance will be dispersed amongst customer classes[49]. Hydro's response to IC-NLH-054 notes that no decision has been made on how the major RSP payouts will be financed by Hydro, but the best information available is shown in NP-NLH-251 Attachment 1 which shows that new financing will be sought through some addition of low cost promissory notes ($50 million) plus $150 million in new long-term debt financing forecast at 4.25%. Even ignoring the cost advantages of the promissory notes, the refinancing of $180 million from a 7.529% weighted average return on rate base to a 4.25% interest rate will lead to immediate savings to Hydro of about $6 million[50]. This is further confirmed by Hydro's response to IC-NLH-141 Attachment 1, where the average cost of all debt for the 2014 year (for Cost of Service purposes) is shown to decline from 8.014% to 7.173%, a savings of over $9 million in interest costs for Hydro (on the approximately $1.5 billion rate base financed 70% with debt)[51].

Unlike the vast majority of Hydro's future cost changes which are "stabilized" via the RSP (and further additional RSP protection sought in this proceeding), changes to the cost of debt are not passed through to customers but are rather direct impacts on the bottom line of Hydro. For this reason, consideration must be given to providing customers with an appropriate adjustment for the above factors. One option may be setting GRA rates based on a deemed debt rate somewhat below the level included in Hydro's GRA, for example 7.5%[52]. Alternatively, the Board may wish to set 2013 utility rates based on the 2013 Cost of Service, but for rates paid in 2014 impose a further line-item adjustment to the cost of Hydro's debt, to adopt the 7.173% debt rate for 2014 shown in IC-NLH-141 Attachment 1 Schedule 1.1.

Each of these alternatives would be preferable to a different potential solution based adding new complexity to the RSP for further items such as future cost of debt changes.

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[48] The December 2013 RSP report confirms the end RSP balance at in excess of $250 million.

[49] Other than an ongoing portion of the hydraulic balance, at less than 75% of the current $59 million balance, and a portion of the current $11 million Industrial RSP surplus intended to transition customer rates during 2015, all other amounts will either be paid out or transferred to current balances in their entirety.

[50] This is a difference of 3.3% in cost rate, on $180 million.

[51] IC-NLH-141 Attachment 1, Schedule 1.1, page 2 of 2. The difference between interest rates at 0.84% (8.14% and 7.17%) with 2013 GRA debt ratio of 70.1% would yield to about 0.59% lower average cost of debt and with $1.564 billion rate base for 2013 the savings would be about $9.2 million.

[52] This change would drive an approximately $5.6 million reduction to revenue requirement for 2013 (decrease of 0.36% on weighted average debt return, from 5.618% to 5.258%, at $1.564 billion rate base).

5.0 COST OF SERVICE

Hydro's 2013 Cost of Service study (2013 COS) is prepared for Hydro's five separate systems: Island Interconnected, Island Isolated, Labrador Isolated, L'Anse au Loup and Labrador Interconnected. This is consistent with past GRAs and with standard ratemaking practice to allocate cost by each system. This submission focuses on the Island Interconnected System.

The 2013 COS for Island Interconnected seeks to allocate $501.055 million in revenue requirement[53] to three major rate classes: Newfoundland Power (NP), industrial customers including the IIC Group as well as Vale and Praxair, and the Rural customer group (Rural).

Hydro provided a report prepared by Lummus Consultants International[54] on review of Hydro's COS, which states that COS "is the industry standard against which rates are judged to be equitably distributed among customer classes and hence, non-discriminatory"[55]. However, the 2013 COS as proposed by Hydro in its GRA reflects an unfair distribution between some of the customer classes.

This Section consists of the following:

- Comparison to 2007 Test Year;
- NP Load Factor;
- Impact of Transitional Industrial Customers to Industrial Rates; and
- Demand/Capacity Cost Avoidance.

For the 2013 COS, Hydro incorporated a methodology largely consistent with the 2007 COS. Updates were provided to the functionalization and classification ratios, the allocation factors based on customer load forecasts and the system load factor, to reflect the 2013 Test Year. As in past proceedings, it is important to review the Cost of Service not just from the perspective of precisely reflecting the 2013 Test Year, but also from the perspective that the rates to be charged arising from this Cost of Service study will be applied in 2014 and beyond. As such, the Cost of Service must also be checked for reasonableness to longer term system costs.

5.1 COMPARISON TO 2007 TEST YEAR

The 2013 Cost of Service study largely parallels the 2007 COS in form and substance. Notable changes arise due to various inputs, such as NP's load factor and Industrial Customers` peak demand for transition customers (each of which is addressed below).

At a high level, the most notable impact of the 2013 COS is the calculation of a demand charge for NP and Industrial Customers that are effectively similar ($9.12/kW for NP, $9.13/kW for Industrial

[53] Hydro's 2013 COS, Schedule 1.3.1, page 1 of 3.
[54] Hydro's 2013 GRA, Volume II, Exhibit 9.
[55] Hydro's 2013 GRA, Volume II, Exhibit 9, page 1.

Customers). This is a striking change from the 2006 GRA, or from the actual cost of service results for each intervening year, as shown in IC-NLH-2. Referring to the respective Schedule 1.3 from each Cost of Service study, the fully loaded demand cost for the Industrial class ranges from 34% to 91% of NP's demand charge provided in COS studies, averaging 73%[56]. It does not approach 100% in any year, much less exceed the NP rate. This is an indication that further investigation into the 2013 COS is required. As set out below, there are several anomalous factors being used in the 2013 COS contributing to this problem, which requires correction in the 2013 COS before rates are approved.

5.2 NP LOAD FACTOR

In response to IC-NLH-107, Hydro notes that the load forecast for NP used by Hydro for the 2013 GRA Test Year was prepared by NP and was dated March 22, 2013. Hydro was not able to confirm if this load forecast was used for other purposes or only for the purposes of Hydro's GRA. Hydro did not indicate that any due diligence was performed on this value, including any cross-check against the approved 2013 NP GRA.

Table 5-1 below summarizes load forecasts for NP, Industrial Customers and Rural that were used for 2007 and 2013 Test Years.

Table 5-1: Comparison of Load Forecasts: 2007 vs 2013[57]

	2007 Test Year			2013 Test Year		
	MW	**GWh Sales**	**Load Factor**	**MW**	**GWh Sales**	**Load Factor**
NP	1,121.5	4,925.8	50.1%	1,180.3	5,594.3	54.1%
Rural	84.8	392.0	52.8%	93.9	447.3	54.4%
Industrial	126.9	930.2	83.7%	79.6	408.4	58.6%
Praxair				*5.7*	*4.3*	*8.6%*
Vale Newfoundland				*13.9*	*34.3*	*28.2%*
Corner Brook Pulp & Paper Co. Ltd.	*59.4*	*452.5*	*87.0%*	*20.0*	*80.1*	*45.7%*
N. Atlantic Refining Ltd.	*30.5*	*245.3*	*91.8%*	*30.5*	*217.9*	*81.6%*
Teck Resources	*10.0*	*64.3*	*73.4%*	*9.5*	*71.8*	*86.3%*
Abitibi Price - Stephenville	*3.0*	*5.7*	*21.7%*			
Abitibi Price - Grand Falls	*24.0*	*162.4*	*77.2%*			
Total	**1,307.6**	**6,248.0**	**54.5%**	**1,335.3**	**6,450.0**	**55.1%**

The table above indicates that since the 2007 Test Year, Hydro expects that the NP coincident peak load has grown by 5.2% while the energy has grown by 13.6%. This causes the calculated NP coincident load factor to increase from 50.1% to 54.1%. At the same time the total load factor for industrial customers fell from 83.7% to 58.6% mostly due to low load factors for transitional industrial customers and a reduced load factor for Corner Brook Pulp and Paper (CBPP).

In response to IC-NLH-026, Hydro notes that the calculated change in the NP load factor from 50% to 54% is influenced by weather, NP generation, any change in NP system operations and any change in

[56] Based on COS Schedule 1.3 for each of the 2007-2012 actual years provided by Hydro in response to IC-NLH-002.

[57] Table is prepared based on Hydro's 2013 GRA, Volume I, Regulated Activities Schedule II. The load factors are calculated based on total sales (GW.h) divided by peak (MW) multiplied by number of hours in a year.

customer load characteristics. Looking at an NP load factor calculated consistently off of native peak load (the highest peak on NP's system) subtracting NP's hydraulic generation that it supplies itself, the results are shown Table 5-2 below.

Table 5-2: Comparison of NP Load Factors: 2005-2013[58]

	NP Native Peak (MW) Less Hydraulic Generation Credit (84.5 MW)			Energy Sales to NP (GWh)		Load factor	
	Actual	Weather Adjusted	Forecast	Actual	Forecast	Weather Adjusted	Forecast
2005	1,047	1,082	1,137	4,664	4,854	49.2%	48.8%
2006	1,058	1,088	1,120	4,617	4,793	48.5%	48.9%
2007	1,097	1,104	1,127	4,991	5,007	51.6%	50.7%
2008	1,135	1,153	1,151	4,960	5,053	49.1%	50.1%
2009	1,122	1,154	1,179	5,108	5,134	50.6%	49.7%
2010	1,082	1,168	1,199	5,016	5,129	49.0%	48.9%
2011	1,157	1,209	1,218	5,317	5,332	50.2%	50.0%
2012	1,197	1,266	1,248	5,359	5,530	48.3%	50.6%
					average	49.6%	49.7%
2013 GRA			1,180		5,594		54.1%
NP's 2013/14 GRA, September 2012			1,268		5,665		51.0%

As shown in Table 5-2 above, the 2013 forecast NP load factor at 54.1%, is substantially higher than the load factor in every year for the past 8 years (averaging 49.6% on an actual weather adjusted basis, and never higher than 51.6%). It is also higher than the 51.0% load factor approved in NP's recent 2013 GRA[59]. In short, the load factor being proposed by Hydro is unreasonable and unsupportable.

Further, as noted below, the current Cost of Service methodology uses an inconsistent reflection of the loads related to transitional industrial customers. This causes the Cost of Service coincident demand peak to be allocated on the basis of forecast December peak loads (when Vale and Praxair are forecast to have

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[58] The table is prepared based on Hydro's response to IC-NLH-012. Peak has been adjusted from the native level downwards by 84.5 MW to reflect NP's hydraulic generation credit as per IC-NLH-030 (page 4 of 10). Hydro's response to IC-NLH-051 shows NP's thermal generation dispatch was only at 0.402 GW.h in 2009 (or 0.11% load factor of 41.5 MW capacity); no dispatch for 2010-2012; dispatch at total of 0.832 GW.h in 2013 (or 0.23% load factor of 41.5 MW capacity).

[59] The values shown for the NP's 2013/14 GRA are from the original filing. NP's 2013/14 GRA Table 5-3 shows native peak for 2013 at 1,352.4 MW less 84.5 MW for NP's hydraulic generation would results net peak at 1,268 MW. Energy forecast at 5,665 GW.h is from NP's 2013/14 GRA, Customer, Energy and Demand Forecast, Appendix C, page 1 of 1.
http://www.pub.nf.ca/applications/NP2013GRA/files/applic/Application-VolumeI.pdf.
http://www.pub.nf.ca/applications/NP2013GRA/files/applic/Application-VolumeII.pdf.
As per Board Order P.U.13 (2013) these values were accepted as filed.
http://www.pub.nf.ca/orders/order2013/pu/pu13-2013.pdf.

ramped up to its highest levels), rather than the most traditional and appropriate February peak, when NP and overall system loads are more typically at their highest level[60].

A significant part of the underlying issue with the NP peak forecast is that the February value being used for load analysis, to determine which peak to use for Cost of Service purposes, is a 2013 actual load. Hydro makes clear in response to IC-NLH-105 that the NP February actual load was not reflective of typical weather conditions. Hydro also notes that the weather adjusted NP peak load was not used for the Cost of Service inputs. The impact of this anomaly is set out in Table 5-3 below:

Table 5-3: NP Coincident Peak Loads for December, February, and Weather Adjusted February 2013[61]

	NP Peak	December		February	February Weather Adj.
A	NP native peak	1,264,781		1,280,961	1,350,000
B	CP factor	99.6%		99.6%	99.6%
C=A*B		1,259,722		1,275,837	1,344,600
D	Less all generation credit	(120,208)		(120,208)	(120,208)
E=C+D	CP	1,139,514		1,155,629	1,224,392
F	Add back NP thermal	35,993		35,993	35,993
G=E+F	Trans. CP for COS	1,175,507	Schedule 3.1A	1,191,622	1,260,385
H=G*1.031	CP with trans. losses	1,211,954		1,228,569	1,299,463
I=-F	Less NP thermal	(35,993)		(35,993)	(35,993)
J=H+I	Production 1CP for COS	1,175,961	Schedule 3.1A	1,192,576	1,263,470

As shown in the above table, the NP net peak load used for Cost of service purposes is 1,175,961 kW. This compares to the February peak of 1,192,576 kW, and the weather normalized February peak of 1,263,470 kW. Under normal load conditions, the highest NP peak (in this case the NP February peak) would form the basis of the Cost of Service allocation, as this peak would drive the overall system wide coincident peak. However Hydro has not used this value, as the loads of the transitional industrial customers (Vale and Praxair) are almost nonexistent in February, but are forecast to be growing to significant levels by December. The more striking issue is that the February peak analyzed by Hydro is not appropriate for Cost of Service purposes as it does not reflect normal, or weather adjusted, conditions. Had the weather adjusted NP peak been used, the February peak would have been the dominant coincident peak for the system, and the full 1,263,470 kW value from the above table would

[60] The 2013 February peak is the highest peak for NP making up about 87% of total Hydro's peak (see IC-NLH-030, pages 4 and 5 of 10).

[61] Native peak loads are from IC-NLH-030, page 4 of 10; weather adjusted peak at 1,350 MW is from IC-NLH-154; the calculation in the table for December column is based on excel files (Loss Model and Load Model) provided by Hydro in response to PUB-NLH-114 and the calculations in February and February weather adjusted columns use the same approach as December column of the table. Transmission CP (line G) and Production 1CP (Line J) in December column of the table can be found in Schedule 3.1A of 2013 COS.

have been used in the Cost of Service study. This is the appropriate approach, and should be adopted in preparing a proper 2013 Cost of Service study for rate setting purposes that reflects fair and representative cost allocations across different customer classes.

5.3 IMPACT OF TRANSITIONAL INDUSTRIAL CUSTOMERS TO INDUSTRIAL RATES

The typical pattern of consumption for industrial customers, for use in the COS study, reflects two fundamental realities:

1. Industrial customers are high load factor customers; and
2. Industrial customers generally pay a fixed Power on Order charge throughout the entire year based on their highest individual annual peak expected to be required.

The result is that in a cost of service context, two important relationships are maintained.

First, industrial customers are customarily allocated a larger share of energy-related costs proportionally than demand-related costs. This general rule has been true in past Hydro's GRAs. For example in the 2007 Test Year, industrial customers were 14.4% of total energy forecast, but only 8.3% of peak demand forecast[62]. In the current study the gap is uncharacteristically closer – 6.3% of total energy forecast and 5.3% of peak demand forecast[63]. By 2014, the relationship begins to re-establish itself, with industrials as 8.8% of energy forecast and 4.8% of peak demand forecast[64].

Second, in the Hydro's cost of service studies, each peak unit of demand imposed on the system by an industrial customer is typically backed-up by 12 units of purchased demand via Power on Order. For example, if a customer has a 20 MW peak, that customer will purchase 240 MW-months of demand units. If the customer revises its Power on Order to 21 MW in the next year, the billing units would become 252 MW-months of demand units. As the peak demand increase drives costs to the class (the numerator in the unit rate calculation) and the billing unit increase affects revenue collection (the denominator in the unit rate calculation) changes in the peak demand of a normal industrial customer do not typically alter or skew the demand rate calculated for the entire class.

In the current GRA however, this relationship is undermined. This arises because of the transitional nature of the Vale and Praxair forecast loads. As set out in IC-NLH-110, these customers are presently in a construction and commissioning period where their loads are increasing towards production levels. For the construction and commissioning period, the Board (in Orders No. P.U. 6(2012) for Vale and No. P.U. 9(2013) for Praxair) approved that the normal Power on Order annual concept, under which a fully operational industrial customer would pay monthly bills based on their annual peak load, should not be applied. Had that normal Power on Order concept been applied, then in January when loads were still very low, the transitional industrial customers would have had to contract for their full expected

[62] Hydro's 2007 Cost of Service study, Schedule 3.1A.
[63] Hydro's 2013 Cost of Service study, Schedule 3.1A (Exhibit 13 for 2013 GRA).
[64] Hydro's 2014 Cost of Service study, Schedule 3.1A (IC-NLH-141 Attachment 1).

December peak (which is forecast to be substantially higher as the customer ramps up) and pay for this peak each month of the year. The Board determined that such an outcome would not be applied.

For Cost of Service purposes, however, this December peak is being applied by Hydro, to the material detriment of the entire industrial class. As reviewed above and provided in Figure 5-1 below, the 2013 COS coincident peak allocation factors use the highest monthly peak for Vale and Praxair at highest point of their ramp-up in 2013 forecast (December). This results in unreasonably low load factors (annual load factor at 28.2% for Vale and 8.6% for Praxair)[65] that are not representative of operations during the period which the requested rates will be applied. This also results in a large demand allocation (based on the December peak) but a much smaller number of billing units on which to collect the costs allocated, which skews the demand rate upward.

Figure 5-1: 2013 COS Industrial Peak Demand (Coincident Peak)[66]

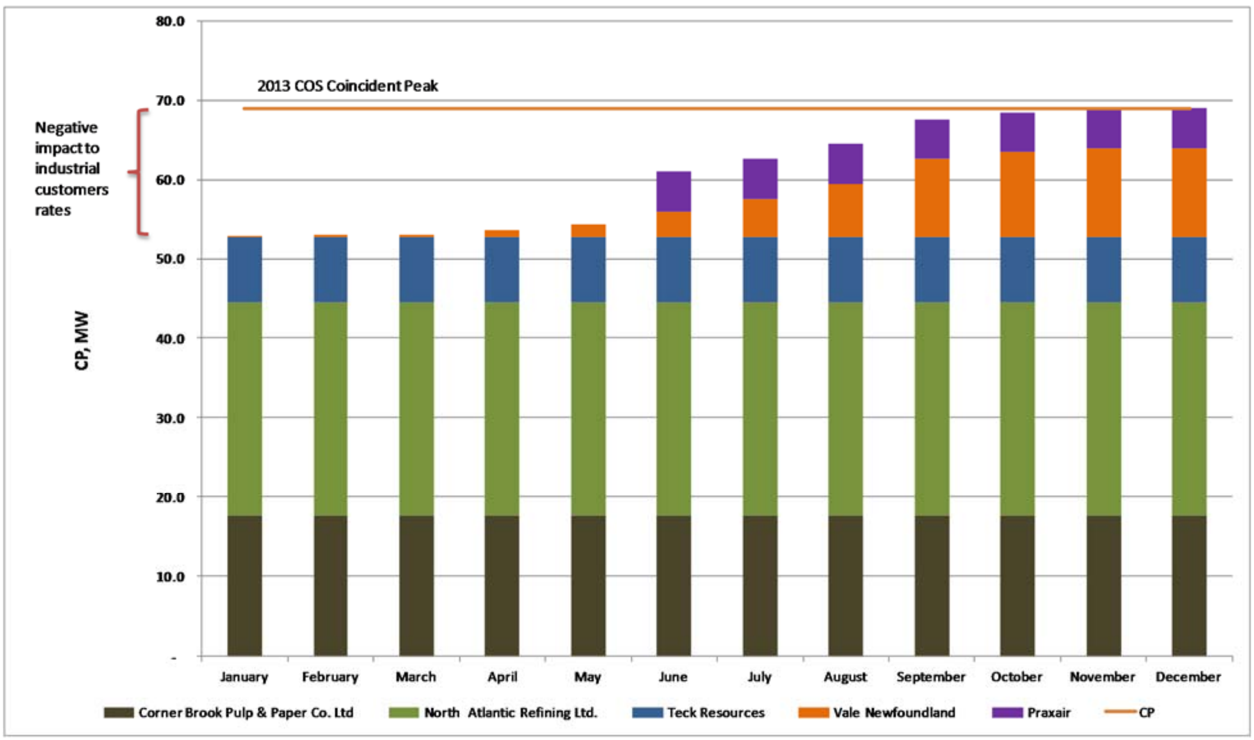
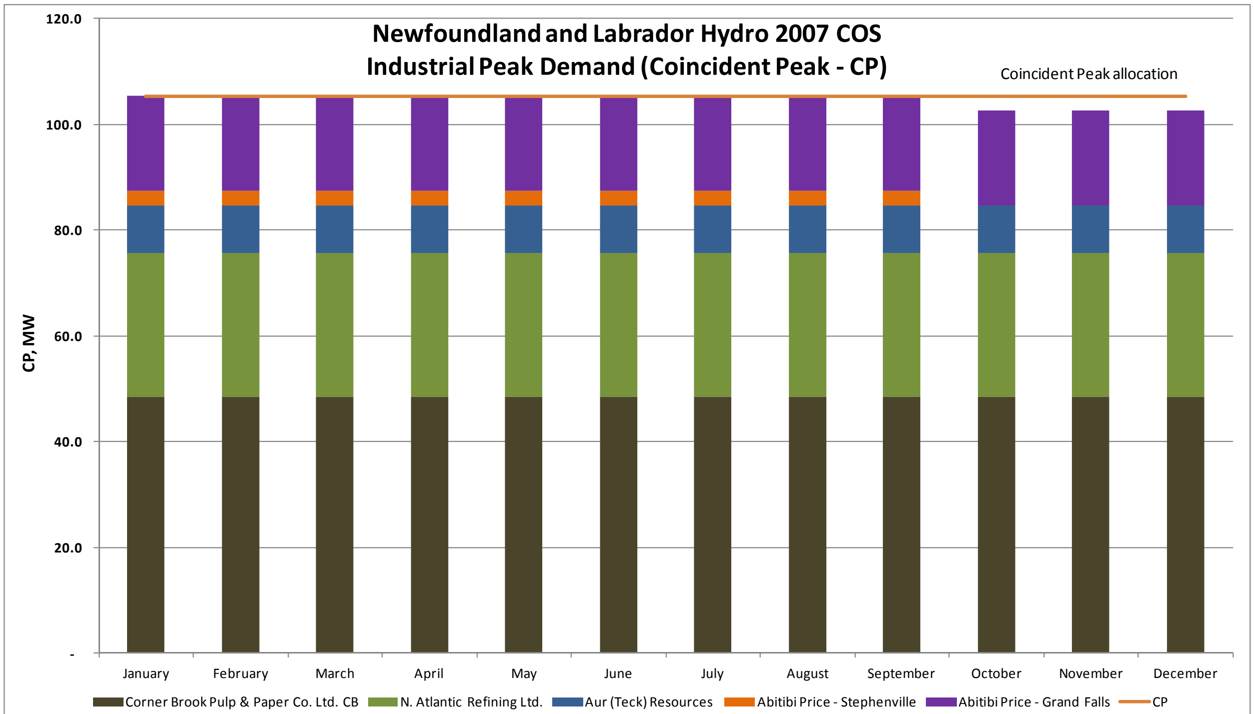


Figure 5-2 below provides coincident peak allocation factors used for 2007 COS, which as a comparison shows flat level of peak for the year, except peak for Abitibi Price – Stephenville which had no forecast demand from October to December of 2007.

[65] Please see Table 5-1 of this evidence.

[66] Figure 5-2 is prepared based on Coincident peak numbers for industrial customers provided by Hydro in response to PUB-NLH-114 (Load model).

Figure 5-2: 2007 COS Industrial Peak Demand (Coincident Peak)[67]



Source: 2006 GRA , NLH's response to RFI IC-NLH-153.

The issues arising from this load pattern are very material. Further, it is clear that the 2013 Cost of Service study as provided is not a fair or reasonable representation of the load patterns during the period in which the GRA energy rates will actually be applied (2014 onward when Vale and Praxair loads will be much different).

Two different sets of data were provided by Hydro to understand the anomaly:

1. **Different Cost Causation within the Industrial Class:** In response to IC-NLH-152, Hydro provides a breakdown of the proposed industrial rates to operating and pre-production (or transitional) industrial customers. The analysis provided by Hydro in this response shows that if the class were split into two - operating companies and pre-production companies - the demand rates for operating companies would be about $8.11/kW (compared to $9.13/kW proposed by Hydro in its 2013 GRA). However the demand rate to pre-production companies would be $15.47/kW[68]. The higher demand charges are an outcome of the unreasonably low load factors used in 2013 COS for the transitional industrials. In this case the transitional industrial customers

[67] Figure is prepared based on Hydro's response to IC-NLH-153 during 2006 GRA process.
[68] Demand charge estimate in 2013 COS for transitional industrial customers as per IC-NLH-152.

take on a large rate design burden related to months where the transitional customers have little to no peak load or sales[69].

As a solution however, the approach laid out in IC-NLH-152 is not appropriate for two reasons. First, the approach only serves to adjust the load characteristics within the industrial class arising from load normalization. This is insufficient, as a proper reflection of the normalized loads would also drive changes outside of the industrial class (for example, system load factor, demand cost allocation to all customers, including NP and rural). Second, the IC-NLH-152 approach is effectively simply applying through rate design the very same cost impacts that the Board directed to be avoided by Orders No. P.U. 6(2012) for Vale and No. P.U. 9(2013) for Praxair. In short, it would serve to entirely ignore the entire principle adopted by the Board for dealing with the temporarily anomalous load characteristics of transitional industrial customers. As a result, IC-NLH-152 does not provide a solution that can be applied in practice.

A variant on the approach set out in IC-NLH-152 is to revise the billing determinants for the transitional industrial customers as if they had sufficient Power on Order units all year to reflect the forecast December peaks. The Board Orders No. P.U. 6(2012) for Vale and No. P.U. 9(2013) for Praxair would be implemented in effect to say that they need not actually pay for these Power on Order units during months where their demand has never actually reached the full Power on Order level. This approach would have the effect of setting a demand charge at $8.11/kW for all industrial customers, but serve to leave a material shortfall in Hydro's Test Year earnings of approximately $850,000[70]. As a result, this approach is also problematic.

2. **Normalize Entire Cost of Service Study:** In response to IC-NLH-140, Hydro provides an alternative solution to the issues arising from transitional industrial customer loads. This request asked for a Cost of Service study that is run on a basis that "normalizes" the peak loads and load factors for Vale and Praxair to reflect a load factor more typical of a full operational industrial customer (and more representative of the load shape that these customers will experience once through their commissioning phases). In response to IC-NLH-140, Hydro notes that "[b]ased on the 2013 Test Year annual energy requirements for these two customers and ignoring the monthly energy profile, a "normalized" peak requirement for these customers would be 4.9 MW, compared with the 19.6 MW used in the 2013 Test Year." A full Cost of Service analysis is provided by Hydro in response to this IC-NLH-140, which shows an industrial demand rate adjusted from $9.13/kW in the original 2013 COS down to $7.59/kW, adjusting the industrial class revenue requirement by $1.288 million (from $28.955 million to $27.667 million). However, it appears that, this study appears to fail to include a recalculation of the coincident peak responsibility, which on a normalized basis should now occur in February 2013 not December

[69] For example, 0 MW demand billing determinant for Praxair for January through May; Vale peak demand only ranges between 1-3% of the peak used for allocation purposes for the first three months, ranges between 7-29% for the next three months.

[70] This is based on $15.47 per kW full cost for 115,400 kW peak demand for Vale and Praxair for 2013 as compared to paying $8.11/kW for the same consumption.

2013[71], which would result in greater reduction in the revenue requirement for industrial class than estimated above.

One of the underlying principles behind Cost of Service analysis is that it is never a precise tool for cost allocation. However, the analysis should reflect fair and reasonable estimation of the cost responsibility between customer classes for the periods in which the study is being applied. The solution to be used for Cost of Service purposes in this proceeding turns on the basic rationale underlying the Orders No. P.U. 6(2012) for Vale and No. P.U. 9(2013) for Praxair. Those Orders effectively say that for each month as the pre-production companies ramp up consumption, they will not pay their full combined Power on Order of 19.6 MW (based on December peaks), but rather only what they use in the months prior to December. The key question is what happens to the underlying costs of the demand that these customers did not use/pay for. The answer to this question can be found in one of the four following Options:

- Option 1: It is first allocated to the industrial class, but then largely (but not entirely) targeted back to Vale and Praxair in a higher unit charge ($15.47/kW; $8.11/kW for existing industrials).
- Option 2: It is loaded onto the costs of the industrial class broadly (to yield a demand rate for the class of $9.13/kW for all industrial customers, as is currently proposed by Hydro in the GRA).
- Option 3: The costs are meant to be unrecovered and become a net adverse impact on Hydro's bottom line (demand cost to all industrials of $8.11/kW for all industrials; net loss of $850,000 for Hydro).
- Option 4: Nothing – there is no "cost" as the power was not used in any way (resulting demand cost for industrials of $7.59/kW).

Option 1 above would appear to be entirely inconsistent with the principles of Orders No. P.U. 6(2012) for Vale and No. P.U. 9(2013) for Praxair. It would also prejudice the existing industrial customers as some of this cost still resides with the class generally. Option 2 is even less reasonable to the existing industrial customers, and Option 3 would appear inconsistent with the concept of a fair return being awarded to Hydro during a GRA. Only Option 4 reflects a reasonable interpretation as to the proper principle, and technical and regulatory considerations, arising from Orders No. P.U. 6(2012) for Vale and No. P.U. 9(2013) for Praxair. This Option is largely consistent with the cost of service study provided in response to IC-NLH-140.

Based on the above comparison, it is clear that the Hydro's 2013 Cost of Service study in Exhibit 13 is not a reasonable representation of the costs of a system with high load factor industrial customers. It is also clear that the existing high load factor industrial customers are being materially prejudiced by being included in a class with other customers who do not share like characteristics (most notably an equal Power on Order throughout the year). The most reasonable cost allocation approach available is set out

[71] In particular the NP peak load in Schedule 3.1 of the respective 2013 Cost of Service studies (original as per Exhibit 13, and revised as per IC-NLH-140) remains the same. This NP peak should have reverted to the somewhat higher February 2013 peak (see Section 5.2) rather than remaining the same in IC-NLH-140.

in IC-NLH-140, with further adjustments to also reflect a weather normalized February coincident peak allocation.

5.4 DEMAND/CAPACITY COST AVOIDANCE

The cost of capacity as measured in the COS study is a ratio – in the numerator is the total cost of resources related to providing demand or peak load service (in dollars), divided by the denominator of total coincident peak (in MW). Hydro does not use the actual system peak, but instead uses a peak provided in part by NP. Among the adjustments are a number of important revisions to the NP peak. One relates to NP's own generation (the NP "generation credit") and the other relates to NP's curtailable loads.

In contrast, industrial customers do not have similar generation credit provided in the Cost of Service study, and are not offered a curtailable load program.

For clarity, the NP curtailable load program is described in the NP`s 2013/14 GRA as providing a once per year credit of $29/kV.A[72] for each kV.A of load that a commercial customer agrees to allow to be "interruptible" for short term periods during the months of December to March of each year (approximately $25/kW[73]). As a result of this curtailment interruption, if it can be timed to occur at NP's system peak, the NP costs from Hydro for the year would be reduced by $48/kW under the previous rate design, and $109.56/kW under the proposed rate design[74]. NP further explains this wholesale rate savings in the response to CA-NP-188 from the 2010 NP GRA. The amount of curtailable load on NP's system is understood to be upwards of 9 to 10 MW[75]. The curtailable load is to be available when either Hydro requests it, for *bona fide* overall system support purposes, or when NP requests it for either local support purposes, or for lowering NP's peak in order to reduce the wholesale bill from Hydro. The response to IC-NLH-128 notes that Hydro would only be aware of curtailments where Hydro has requested the interruption, and would not be aware of events where NP has requested the interruption.

The curtailable program is broadly similar to a previous Hydro offering to industrial customers, known as Interruptible B. That program allowed industrial customers to provide up to 46 MW of curtailable load to Hydro in exchange for an annual payment of approximately the same value as now used by NP[76]. In short, the two programs are almost identical, with the exception that NP's occurs on a distribution system rather than transmission (so it can be of benefit in distribution system constraints on top of just bulk

[72] NP's 2013/14 GRA, Schedule A page 7 of 10 http://www.pub.nf.ca/applications/NP2013GRA/files/applic/Application-VolumeI.pdf.

[73] Per the response to CA-NP-188 from the 2010 NP GRA, which notes that "$29 per kVA is equivalent to approximately $25 per kW (at 90% power factor)".

[74] The proposed rate design is based on $9.13/kW demand rate. The billing determinants for the year are shown in IC-NLH-111 Attachment 1 page 4 as 13,929,036 kW-months per the COS, and 15,371,532 kw-months as native load (the difference being the generation credits provided in the NP wholesale rate design). 15,371,532 kW-months is 12 times of 1,280,961 kW, which is the annual non-coincident peak shown in IC-NLH-029 as the annual peak NCP, confirming this 1,280,961 peak load level is used for all 12 months for revenue forecasting purposes.

[75] IC-NLH-127 ("...8-10 MW subscribed under NP's curtailable load program"). NP's 2013/14 GRA, Volume II, Customer, Energy and Demand Forecast , Appendix C shows total curtailed load forecast for 2013 at 11.9 MW.

[76] The Interruptible B payment was approximately $1.3 million per year, or $28.2/kW. Per NP-NLH-136 from the 2003 NLH GRA which can be found at http://www.pub.nf.ca/hydro2003gra/index.htm.

power), and NP's program has many more (and smaller) customers, so there is more coordination needed, and more risks of some customers not complying with the request as compared to each industrial customer. This is particularly true as the industrial customer, at times of interruption, would be aware that if much more goes wrong on the system, they could very well be interrupted in any event pursuant to load shedding guidelines, unlike smaller customers who are typically shed much later in the system response sequence. Hydro cancelled the Interruptible B program at the 2003 GRA, as it concluded capacity resources were no longer valuable as Granite Canal came into service.

During the period it was in use, the Interruptible B program did not lead to any adjustments to the peak loads used for Cost of Service purposes. Specifically, the customer's full Power on Order was used for COS allocation, not the Power on Order less interruptible load.

In response to IC-NLH-129, Hydro notes that forecast NP peaks were provided by the customer and reflect NP peaks with the NP curtailable load curtailed.

There are a number of issues with the NP curtailable rate offering that give rise to concerns that it is primarily a means of gaming the wholesale rate structure:

1. The use of NP's forecast peak loads, net of curtailable loads, for Cost of Service purposes effectively means that NP is getting credit for 100% of the curtailable loads[77], regardless as to whether they are curtailed or not or if NP's customers will comply. It also means that NP is receiving the full credit in the COS for this peak reduction, which serves to reduce the denominator for the average cost of demand calculation, and drive up costs for the industrial customer class.

2. The actual performance of the NP curtailable loads for true system support purposes has been poor. System support at times of critical generation or transmission shortages is the only role for which there is a value of curtailable load on Hydro's system. In particular Hydro notes that it has called on NP's curtailable loads twice since 2008, and on both occasions the curtailments have been refused by NP[78]. NP's 2010 GRA (CA-NP-188) notes that curtailments have occurred approximately 90% of the time over the past five years, indicating that NP has used this program a large number of times for its own purposes (likely to manage their peak loads and demand costs), in contrast to Hydro's lone two requests.

3. The long-term value of the curtailments to the system wide generation resource is very low, once the Labrador infeed is completed. This long-term view is important as any rate design changes made today will send price signals to customers, effectively changing energy and peak usage as a result.

4. The value of the program is limited in that it cannot be used in summer. At times in summer the peak NP loads are such that Holyrood must be operated at a poor efficiency level to back up

[77] In response to IC-NLH-129, Hydro notes that "[t]he forecast NP native peaks, as provided by the customer and included in Hydro's response to IC-NLH-012, reflect NP peaks with the NP curtailable load curtailed."
[78] IC-NLH-72.

transmission lines[79] at a substantial cost to the overall system. Also, as noted in PUB-NLH-333, a curtailable load program has some risks of not reducing their loads when requested, as the customer always maintains control. For this reason, a curtailable resource is not the same value as a permanent reduction in peak load; however for COS purposes it is modelled as being of the same value.

5. Perhaps most important, the allocation of peak demand costs in the Cost of Service are meant to reflect the recoveries of the costs of the system assets (primarily system assets which provide peak and reliability services) from users of those assets. The NP curtailable load program has resulted in little to no identifiable savings on Hydro's system as compared to these same customers being regular firm power customers, however it does provide savings to NP. Hydro continues to conclude that it requires a 100 MW turbine at Holyrood (as per the concurrent Capital Budget application) and that filing suggests that load changes on the order of 10 MW will not change this proposed investment. As a result, Hydro's approach to credit to NP of $48/kW (under the previous rate) or $109.44/kW (under the proposed rate) is excessive given: (a) NP still largely receives firm power, (b) the net cost for NP is only $29/kW and (c) most of this cost is reflecting value on NP's system, by frequently using the curtailments to manage load internally, rather than Hydro's system.

The issues arising today were identified as a potential problem in a report commissioned by Hydro from NERA consulting for the 2006 GRA[80]. In that report, NERA concluded that there were limited savings to be had from peak load reductions. NERA noted that in the event that price signals arising from implementing any substantial demand charge on NP led to peak load reductions this would not be a desirable outcome. NERA further noted that:

> Implementation of the demand charge in this rate in January 2005 has triggered response by NP. The company has signed up approximately an additional 6 MW of curtailable load that can switch to the customers' backup generation, experimented with voltage reductions, and ensured better timing of their own hydro generation availability in and around peak days. NP has also undertaken a number of measures to improve customer awareness of conservation opportunities. Clearly NP is responsive to the new demand charge. However, since the size of the current demand charge is significantly above marginal generation and transmission capacity costs, NP may well be over-investing in demand-reducing measures.

NERA's concerns regarding over-investment appear to remain relevant regardless as the degree of adoption of marginal cost principles in Hydro's rates as they reflect basic incremental cost realities of Hydro's system.

Given the above considerations, the issues for the current hearing are how to address the perverse and asymmetrical effects of NP curtailable load program on Island Interconnected customers. That is, if there

[79] IC-NLH-086 provides Holyrood operation by month. NP-NLH-194 discussed the summer peak load issue and how it adversely affects Holyrood efficiency factors.

[80] NERA Economic Consulting. Implications of Marginal Cost Results for Class Revenue Allocation and Rate Design. July 2006. Provided in CA-NLH-033 in the Hydro's 2013 GRA.

are substantial system wide benefits from short-term capacity reductions, all customers should have the option to participate. If not, then the program is simply an artifact of charging a variable demand rate to NP in an environment where there are little to no savings from avoided demand. In short:

1. NP's use of curtailable load should not be permitted to reduce their peak cost allocation from Hydro's system for COS purposes. This is consistent with the degree of benefit the program has provided Hydro's other customers (no successful interruptions, and no avoided capital investment in the next 100 MW turbine unit at Holyrood), with the amount of reliability provided to the system as a result of the program and with ensuring that these loads (which are for nearly all practical effect and purpose firm customers) pay a fair allocation of system costs. This is also consistent with the established principle applied in the case of the former Interruptible B.

2. In order to address the "over-investment" issue noted by NERA, the previous NP demand rate of $4/kW should not be increased. This is further discussed below in respect on NP's rate design.

3. In the event Hydro and NP jointly conclude that there are system wide benefits from capacity interruption options, then such options should be provided to Hydro`s industrial customers who can choose to provide sufficient quantities of load. The costs of the credits can be provided by the utilities based on the relative degree of benefit to each system (e.g., Hydro customer credits can be paid 100% by Hydro and NP customer credits, which largely benefit NP for transmission and distribution, but on occasion can benefit the larger grid, should be split in some ratio that reflects these relative benefits). Cost allocation in the Cost of Service should be as per the previous Interruptible B; that is, no load adjustments from the "native" load level (i.e., the load absent interruption), but the dollar value of credits provided should become a system supply cost to be allocated appropriately to all Island Interconnected System customers.

5.5 HOLYROOD FUEL

In the Cost of Service study, Hydro classifies 100% of Holyrood's production costs for fuel to Energy[81] (as opposed to capacity). This is consistent with past GRAs, and with normal practice for fuel related expenses. Such a classification is consistent with the concept that any kW.h used (or avoided) at basically any time throughout the year ultimately finds its way to either an increase or a reduction in the quantity of fuel used. In contrast, fuels used for Hydro's Gas Turbines are classified to Demand[82], as these fuels are basically only used due to peak system loading, or reliability events. Again this is a standard and appropriate Cost of Service method for fuels used for emergency, standby, and peaking units such as the Gas Turbines.

However, since the current classification method for Holyrood fuel was first adopted, there has been a massive and dramatic shift in the load balance on the Island Interconnected System. The large loads at Stephenville, Grand Falls and a significant portion of the load at Corner Brook have declined, while the

[81] Hydro's 2013 COS Schedule 4.1.
[82] Hydro's 2013 COS Schedule 4.1.

loads on the Avalon Peninsula have increased (and are expected to further increase)[83]. At the same time, available generation for Hydro has increased substantially in parts of the province off the Avalon Peninsula (e.g., St. Lawrence wind IPP, Nalcor Exploits generation).

As a result, major system reconfiguration is underway, including a proposal for a new 100 MW turbine at Holyrood[84] and an imminent expected filing for a new Bay D'Espoir to Avalon transmission line[85]. The transmission line was the subject of an initial Capital Budget application by Hydro[86] which indicated in particular that: "For Bay d'Espoir East Loads in excess of 353 MW on a 15°C day, Hydro Must operate generation at its Holyrood Thermal Generating Station". The application further notes that Hydro is now bringing Holyrood generation on to the system at 70-80% of the load where Holyrood dispatch would be optimum and that Holyrood is being required to run "much earlier in the fall and later in the spring than would otherwise be required". This gives rise to two notable issues: (1) Holyrood is more often run at a very inefficient loading (also identified in response to NP-NLH-194 and in quarterly regulatory reports provided in response to LWHN-NLH-042 in this proceeding), and (2) Holyrood is required to be run even at times when sufficient water is available to supply the system, at risk of concurrent or subsequent spillage of this hydro capability (particularly under the current high water conditions).

The recent 100 MW Capital Budget Application also notes that this unit is needed for "Increased reliability and security for the Avalon Peninsula particularly during generation and transmission line contingencies" and that over the long-term this will provide "continued reliability and security for the Avalon Peninsula"[87].

These above system characteristics underline that at least a portion of Holyrood fuel in the test years is not simply an energy-driven cost. For example, at times of the year increased load in western part of the province can be supplied by hydraulic generation, while increased load in the Avalon will drive added Holyrood fuel. In short, for at least some portion of the Holyrood fuel, the system cost characteristics are much more similar to Gas Turbine fuel than the traditional Holyrood fuel classification used in previous GRAs. Further, this requirement for Holyrood to generate power at low levels for capacity and transmission backup reasons leads to a significant reduction in Holyrood efficiency[88] which is leading to a much higher cost allocation to the energy component of the system than is merited (as Holyrood generation operated for true Energy purposes is dispatched at a level consistent with a high efficiency loading given the flexibility inherent in hydro systems).

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[83] The Hydro Capital Budget Application to Upgrade the Transmission Line Corridor from Bay D'Espoir to Western Avalon specifically noted significant NP load growth between 2009-10 and 2010-11, at page 16-17. http://www.pub.nf.ca/applications/NLH2012Capital/files/application/NLH2012Application-VolumeII-Report10.pdf.

[84] As per the concurrent Hydro's Capital Budget Application.

[85] This project was submitted as part of the 2012 Capital Budget, but subsequently withdrawn pending further investigation.

[86] Upgrade Transmission Line Corridor proposal Bay D'Espoir to Western Avalon September 2011. http://www.pub.nf.ca/applications/NLH2012Capital/files/application/NLH2012Application-VolumeII-Report10.pdf.

[87] Hydro's Capital Budget Application for 100 MW Combustion Turbine. Page 30-31. http://www.pub.nf.ca/applications/NLH2014Capital/NLHCBSUPP2014/100MWTurbine/application/Application-ApprovaltoSupplyandInstall100MWGenerator-ConfidentialVer-2014-04-10.pdf.

[88] As per Quarterly Regulatory Reports as provided in LWHN-NLH-042 (for example, Attachment 6 to LWHN-NLH-042 Quarterly regulatory reports for 2012 pages 10 and E26).

Further consideration is required for determining the appropriate percentage allocation of Holyrood fuel to capacity. For example, as a rough estimate, if the Holyrood fuel consumed between May and September of 2013 were concluded to be a reasonable estimate of the capacity-related component of Holyrood generation then approximately 11% of Holyrood generation would be reclassified to Demand, or approximately $22 million[89].

[89] As per IC-NLH-086, about 11% of forecast Holyrood generations are for May through September (about 128 GW.h). In 2013 COS Schedule 2.1A Holyrood No. 6 fuel cost at $200.7 million and 11% would be about $22 million.

6.0 RATE DESIGN

The NLH proposed rate design calculates rates that are sufficient to collect the Revenue Requirement based on the Test Year load forecast. The 2013 Test Year revenue required from rates for Island Interconnected is $501.055 million, including $453.005 million from NP after deficit and revenue credit allocation, and $28.955 million from the industrial class[90].

The proposed rate design for customers on the Island Interconnected System largely follows the existing rate structure, and historical approaches applied to the island customers. With limited exceptions, this approach to rate design remains appropriate today. Hydro's GRA also provides a proposal to revise the RSP for various factors, as well as incorporating a requested approval from the July 30, 2013 RSP Application regarding the load variation allocation. Finally, Hydro's rate designs include provision for changes to the CBPP contract to ensure that the rates charged to this customer do not lead to distortions or incentives to inefficiently manage the island hydraulic resources. This CBPP contract change has already been implemented for a number of years on an interim basis and Hydro is seeking to have this change made a component of final rates.

Specific comment is provided in this section regarding the following rate design matters:

- Industrial Rate Design;
- NP Rate Design;
- RSP Proposals; and
- CBPP Contract Provisions.

6.1 INDUSTRIAL RATE DESIGN

The proposed industrial rate design is consistent with the approaches used to set industrial firm power rates since at least 2001. In this respect, the rate design has the beneficial attributes of transparency, customer understanding, and revenue stability. When dealing with high levels of rate shock being imposed on industrials due to revenue requirement changes, this degree of consistency is of high value.

It is noted that the proposed industrial rate design fails to incorporate the principles or approaches that were worked out over many months during 2007 by a working group comprised of representatives of Hydro and the IIC Group. That working group reviewed approaches to better reflect Holyrood fuel costs in industrial rates, in order to provide customers with a better price signal for matters such as securing CDM energy bill savings. The 2008 report ("2008 Final Report") of the working group was provided in Hydro's 2013 GRA filing at Exhibit 12.

While the IC rate design working group 2008 Final Report provides a summary of many substantive issues, there are two limitations in attempting to implement the results of the working group today.

[90] Hydro's 2013 COS, Schedule 1.3.1, page 1 of 3.

1. The report fails to reach agreement on many substantive areas such as how to address major load reductions, how to deal with CDM initiatives, and how this rate design might overlap with the RSP.
2. The entire report was prepared on the basis of perspectives at that time, including that Holyrood generation would be the incremental cost for the system for a substantial future period of time. These perspectives are no longer valid.

In the 2013 GRA, Hydro provided a report from Lummus Consultants International[91], which reviews the industrial rate design, the 2008 Final Report and the proposals for this GRA, and states:

> The planned load for Vale would add a level of complexity, and a lack of transparency, to the block sizes under a two block rate structure, for the customer in each year after the 2013 test year. The Vale load is anticipated to stabilize around the time of the Labrador Interconnection, where a different rate structure may be more appropriate. This suggests that implementation of a two block energy rate structure at this time may not be advisable. In light of the foregoing, it is recommended that the existing flat energy rate for the IIC continue.

Hydro notes that it agrees "with the recommendation in the Lummus report (Section 3 of Exhibit 9) that no changes to the IIC [industrial class] rate structure should be made until the future marginal cost structure is known"[92].

While it is unfortunate that the opportunity to implement a possible new industrial rate design was missed following the work done in 2007-2008, in the present circumstances, six years later, the conclusions of Lummus are appropriate. That is, with the major underlying changes occurring over the next few years to industrial loads (including the ramping up of some customers and the ramping down of others), as well as island incremental costs and the proposed system changes (including the interconnection to the Labrador infeed, it is not an advisable time to adopt the type of rate design proposed in the 2008 Final Report (or other alternative rate designs based on marginal costs, two block rates, or the incremental value of Holyrood fuel). This is because attempting to adopt the rate design concepts from 2008 would (a) exacerbate rate pressures on customers at a time when they are already experiencing extraordinary rate shock, and (b) be obsolete by the time of the Labrador infeed.

6.2 NP RATE DESIGN

As part of the GRA filing, Hydro proposes to maintain the basic structure of the rate design to NP by keeping a demand charge, and a first and second block energy charge. However, Hydro has based its proposal on a material change in the principles underlying the NP rate design, with possible adverse impacts for the Island Interconnected System.

[91] Hydro 2013 GRA, Volume II, Exhibit 9.

[92] Page 4.7 of Hydro's 2013 GRA.

The changes to the NP's rate design proposed by Hydro as follows:

- A demand rate based on Cost of Service allocation of the average costs of demand (increasing from $4.00/kW/month to $9.12/kW/month)[93];
- A first block energy quantity increasing from 250 GW.h/month to 280 GW.h/month[94];
- A proposed first block rate designed to recover non-fuel energy costs (decreasing from 3.246 cents/kW.h to 2.786 cents/kW.h or by 14.2%) compared to the 2007 approach where the first block rate was an outcome rate after demand and second block rates were calculated; and
- A proposed second block rate which is designed to recover the costs not recovered through demand and first block energy charges (increasing from 8.805 cents/kW.h to 10.4 cents/kW.h or 12% increase) compared to the 2006 GRA approach where the second block rate was the marginal fuel cost per kWh based on Test Year Holyrood fuel cost.

Table 6-1 below provides the calculation for NP's first and second block rates in 2007 COS and 2013 COS.

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[93] In response to RFI NP-NLH-120, where NP asked Hydro to explain how proposed rate design changes move towards closer alignment with the possible demand/energy relationship of the next least-cost supply source, Hydro notes that "[g]iven the interconnection results in the future elimination of Holyrood fuel costs with the replacement energy coming from Muskrat Falls, a hydroelectric source, energy costs may decrease and demand costs may increase".

[94] Report from Lummus Consultants International (2013 GRA, Volume II, Exhibit 9 states that "NP's monthly usage pattern over the three year period 2009-2011 is relatively consistent and does not dip below the 250 GWh first energy block threshold in any summer month. Additionally, based on the forecast load growth for 2013-2015, NP's consumption in the summer months is expected to remain above 280 GWh".

Table 6-1: NP First and Second Block Rates: 2013 vs. 2007[95]

Line #		2007 COS		2013 COS	
	Sales				
1	Total (MWh)	4,925,800		5,594,300	
2	First Block (MWh)	3,000,000	250 GW.h/month	3,360,000	280 GW.h/month
3	Second Block (MWh)	1,925,800	L1 - L2	2,234,300	L1 - L2
	Demand:				
4	Demand Revenue Requirement			127,044,995	
5	Billing Units (kW)	13,026,840		13,929,036	
6	**Rate ($/kW/mo.)**	**4.00**		**9.12**	L4 / L5
	Energy (First Block):				
7	Total Revenue Requirement	319,063,647		453,005,298	
8	Less: Demand Revenue	52,107,360	L5 x L6	127,032,808	L5 x L6
9	Revenue Requirement to be Recovered Through Energy Rates	266,956,287	L7 - L8	325,972,490	L7 - L8
	Non-Fuel Energy Costs:				
10	Energy Revenue Requirement			267,676,715	
	Less Allocated Holyrood Fuel Costs				
11	Total Holyrood Fuel Costs			200,692,615	
12	Newfoundland Power Trans. Energy Allocation Ratio			0.8673	
13	Allocated Holyrood Fuel Costs			174,067,395	L11 x L12
14	**Non-Fuel Energy Costs:**			$ 93,609,320	L10 - L13
15	First Block Energy Consumed (MWh)	3,000,000	L2	3,360,000	L2
16	**Rate (Cents/kWh)**	**3.246**	L19 / L15	**2.786**	L14 / L15
	Energy (Second Block):				
17	Total Revenue Requirement	319,063,647	L7	453,005,298	L7
18	Less: Demand Revenue	52,107,360	L8	127,032,808	L8
19	Less: First Block Revenue	97,394,182	L17 - L18 - L20	93,609,600	L15 x L16
20	Second Block Energy Revenue	$169,562,105	L21 x L25	$232,362,890	L17 - L18 - L19
21	Second Block Energy Consumed (MWh)	1,925,800	L3	2,234,300	L3
22	**Rate (Cents/kWh)**	**8.805**	L20 / L21	**10.400**	L20 / L21
23	Average No. 6 Fuel Cost per Barrel	$55.47		$108.74	
24	Efficiency Factor (kWh per Barrel)	630		612	
25	**Holyrood Generation Fuel Cost (Cents/kWh)**	**8.805**	L23/L24 x 100	**17.768**	L23/L24 x 100

Hydro notes in the GRA that the guiding principles of the 2013 NP rate design include maintaining continuity with the existing second block price signal, considering the demand rate in light of rising capacity costs, and designing the rates to recover NP's revenue requirement[96].

The NP rate design proposed by Hydro has a number of problematic characteristics:

1. The degree of increase in the demand charge is excessively large (128%). This is inconsistent with reasonable rate stability and price signals on a component of the cost structure that is inherently linked to capital assets.

2. The use of an NP demand charge is generally an appropriate utility price signal, but it comes at the expense of revenue stability. This is because most end-use customers on the NP system are charged rates that are primarily comprised of energy charges[97]. From Hydro's side the demand charge also offers upside instability as the revenues are not "stabilized" via the RSP (unlike NP's energy purchases).

[95] Table is prepared based on Hydro's Schedule 1.4 of 2007 COS and 2013 COS.

[96] 2013 GRA, Volume I, page 4.3.

[97] NP-NLH-119.

3. As noted above regarding NP's curtailable load program, the degree of demand charge already included in the NP rate design has led to a responsiveness that is at times unmerited and counter-productive. For example, NP has the incentive to interrupt service to their customers at peak times, in order to avoid demand charges, where there is basically no underlying cost avoided by way of this interruption. In the long-term this could serve to incorrectly lower coincident peak demand. This is an inferior outcome for the customer (who had no reason to be interrupted) for Hydro (who had their revenues reduced), and for the other customers on Hydro's system (who in future will be allocated a greater share of the demand-related costs on the system). Such price signal "responsiveness" reflects an underlying inefficiency in the system, and will only be materially exacerbated by the dramatically increased demand charge.

4. At the same time, the previous NP rate provided a second block price signal that bore a strong linkage to Holyrood fuel costs. While the longer-term marginal cost for the system may be uncertain at the present time due to the Labrador infeed, there does not appear to be any evidence about the implications or benefits of breaking this linkage for cost allocation purposes. Under the proposed second block rate design, NP's second block rate is about 7.368 cents/kW.h lower than Holyrood fuel cost at 17.768 cents/kW.h[98] (compared to the current rate which matches the Holyrood fuel cost).

The response to IC-NLH-079 sets out an alternate rate design that aligns with the key principles arrived at in the 2006 GRA; a modest demand price signal ($4.00/kW), a second block rate closer to Holyrood fuel prices (13.63 cents/kW.h, as opposed to the full 17.77 cents/kW.h) and a first block rate that maintains a reasonable positive value (2.79 cents/kW.h). If a second block rate that is closer to the Holyrood marginal cost were desired, the size of the first block cutoff could be raised in winter (to maintain the basic principle that first block units should be a quantity that will be purchased for the vast majority of energy consumption)[99].

It is difficult to impose a material change to a rate design without appropriate consultation and a full understanding of the implications. Given the response to NP-NLH-119 and other RFIs from NP, it does not appear there has been a full and fair consideration by Hydro of the implications of the proposed NP rate change prior to it being included in the GRA. At this time a superior option that maintains consistency with past approved rate designs would appear to be that set out in IC-NLH-079. This recommendation however is preliminary, subject to further review based on input received as part of the ongoing GRA process.

6.3 RATE STABILIZATION PLAN PROPOSALS

Hydro's GRA provides a proposal to revise the RSP, as well as incorporating a requested approval from the July 30, 2013 RSP Application. The key changes proposed are as follows:

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[98] Please see Table 6-1.

[99] For example, the first block monthly cutoff is proposed at 280 GW.h per month. However in the four winter months of December to March the level could be 500 GW.h per month and the same principle could be achieved, as per IC-NLH-028.

1. Include a new provision for variations in purchased power costs and volumes[100].
2. Revise the allocation methods for the load variation provision[101].

The proposal to include variations in purchased power volumes appears consistent with the underlying principles of the RSP in regard to protection for Hydro from factors that generally fall into the category of material, uncontrollable, set by external forces such as markets or weather, and inherently unstable variables (hydrology, fuel price, etc).

In regard to proposals to flow price changes for Power Purchase Agreements' ("PPA") power through the RSP, the evidence appears to indicate that there are in effect two types of PPA contracts: one set that sees price changes due to change in Consumer Price Index (CPI)[102] and a second related to Exploits purchases, that has no formal escalator, but which has prices fixed only until June 30, 2014[103]. Per PUB-NLH-8 after this date the future for the Nalcor plants under PPAs is uncertain.

The proposal to protect Hydro from simple price escalation on IPP purchases does not appear to follow the above noted underlying RSP principles. With respect to the non-Exploits purchases, it would not appear to be consistent with the intent of the RSP to provide protection for Hydro from simple inflationary increases, whether this for purchased power, salaries, or any other component of revenue requirement. In respect of the Exploits generation, the proposal is possibly unworkable if the letter attached to PUB-NLH-8 remains accurate (that the province intends to transfer the assets to Hydro's regulated operations) as it will not be easy to track the COS value of 4 cents/kW.h against a more indecipherable cost for a portion of assets added to Hydro's gross plant partway through a non-Test Year. More importantly, to the extent that the Exploits generation faces a material change in price, such change is not an external market force but rather a policy decision imposed by Hydro's shareholder. In the event the shareholder plans to explicitly have rates adjust to pay for higher costs for this power, there are ample tools available to it. It is neither necessary nor advisable for the PUB to approve the inclusion of Exploits generation costs to the RSP as it causes uncertainty and unlimited exposure for ratepayers.

In respect of the load variation provision, Hydro is proposing that the RSP rules related to the allocation of the load variation be modified such that the net load variation balances (dollars accrued) for both Newfoundland Power and the Industrial Customers be allocated among the customer groups based upon energy ratios[104].

The IIC Group has previously submitted evidence (e.g., the 2003 GRA, 2006 GRA) that from regulatory first principles, the load variation component of the RSP was an anomaly among regulated utilities, and

[100] Section 4.6 of Hydro's 2013 GRA application, Volume I.
[101] Hydro's 2013 RSP Application.
[102] For example, Hydro notes at page 4.19 of its 2013 GRA that "The terms of the various PPAs also provide for variations in the purchase price of power. Other than for Exploits power purchases, each of the PPA rates has a fixed component and a variable component. The variable component is escalated annually in accordance with the provisions of each of the contracts, based on the Consumer Price Index."
[103] Page 2.4 of Hydro's 2013 GRA; OC2013 -088 as provided in response to PUB-NLH-002, Attachment 1 Page 1 of 1.
[104] Hydro's 2013 RSP Application, pages 2 and 3.

led to an inappropriate allocation of risk to customers[105] and should be entirely eliminated. The RSP has been through a number of variants since it was first created in the late 1980s. Prior to the 2003 GRA, the load variation provision was applied in a very convoluted manner. The result was a counter-intuitive and perverse allocation of risk related to each customer's load among all of the other customers on the system. In particular, the industrial class was at excessive and unjustified risk for changes in NP's load (including both peak and energy).

This risk allocation was improved as part of the 2003 GRA. In that GRA, the RSP was revised such that each customer class was only at risk for load changes to the other customers within the class, not the entire Island Interconnected load, and also that the risk only extended to the net cost changes (net of revenue changes) associated with the load variations. While this approach was superior to the exposure that arose under the pre-2003 model (particularly for NP who no longer was exposed to any risk from changes to the industrial loads), it remained less than ideal for industrial customers, who were collectively at risk for changes to each other's loads. With time, history shows that this risk ultimately arose on the upside – large benefits accrued[106] from the risks the industrial customers collectively shared. As the Board is aware, instead of being allowed to benefit from the GRA approved load variation allocation, the majority of the balance was transferred away (per OC2013-089) as a new cross-subsidy to NP customers.

For the current GRA, the preferable outcome remains that there is no load variation provision in the RSP whatsoever. Without restating the considerable earlier evidence on this matter, in summary:

1. The load variation provision reflects an inappropriate risk sharing between Hydro as vendor and NP and the industrial customers as purchasers. The RSP provisions are inherently retroactive in effect – prices are charged after the fact for changes in conditions. The net impact is in essence approaching customers with a payable or receivable at year end arising from a different customer varying their load, which in any other setting would be clearly inappropriate. Sales volume risk is inherently a risk of a vendor, not of a purchaser.

2. The provision is anomalous among North American utilities. In response to V-NLH-1 in relation to the 2013 RSP proceeding, Hydro states:

   > Neither Hydro, nor its cost of service and rate design consultants, Lummus Consultants International Inc., are aware of any other utilities in North America that utilize a load variation component within their rate stabilization plan or fuel adjustment charge.

3. The effect of the load variation provision is not transparent (a customer paying for the provision in a given year cannot readily draw any linkage to the fact that the costs arise due to a different customer varying their load in a previous year) and not efficient (the costs being imposed on customers to collect the load variation amounts bear no relation to the cost of providing service in that year).

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[105] IC Evidence of C.F Osler and P. Bowman, September 2, 2003.

[106] The July 30, 2013 RSP application notes that nearly $160 million in RSP balance was crystallized.

4. The effect of the provision is that Hydro is insulated from added risks, and can avoid earnings variation and regulatory scrutiny for longer periods of time before it must have its accounts reviewed at a GRA.

It is possible that, notwithstanding the above issues, the Board may elect to retain the load variation provision for the time being. This could be justified on the basis that the provision has been a component of rates for many years, and remains of some value to stabilizing Hydro's income during a period when Holyrood (with its high incremental costs) continues to be a dominant part of the island power supply. For this reason, it is conceivable that the best time to eliminate the provision is upon initiation of the Labrador infeed, in the event a lower incremental cost of power is incorporated into the purchase rates.

Recognizing that the load variation component of the RSP may be continued for some time, there is a need to address the issue of risk allocation. While the 2003 revisions were a distinct improvement over the previous approaches, there remains room to improve upon the allocation methods. In particular, the likely best alternative available is the approach proposed by Hydro in its 2013 RSP application – that is the net load variation cost (after consideration of both cost and revenue impacts) is to be allocated among the customer groups based upon energy ratios. This approach most significantly mutes the cost and rate impacts associated with the provision since the net impacts are spread equally across the largest possible customer base. As such, it is the preferable design, in the event that the load variation provision is maintained.

6.4 CBPP CONTRACT

As part of the 2006 GRA, significant fairness issues were raised regarding the different treatment of hydraulic generation owned by different customers on the system. Notably, the generation of NP was treated in a particular manner that was significantly different than the generation of CBPP, in respect of:

1. Rate and contract based incentives for how the customer was to operate the generation; and

2. Provision of credits in the Cost of Service study to reflect the value of this generation.

The outcome was unfair to CBPP. In particular, CBPP was effectively economically incented (by way of NLH's contract and rate design) to operate its hydro generation in a manner that was inefficient, and to purchase excess quantities of power from Hydro ("non-firm" power) that was unnecessary under a properly structured rate.

Issues arise under the previous industrial contract framework due to it being inadequate to deal with industrial customer generation. That contract framework had been designed fundamentally based on for a normal customer who purchases 100% of their power from Hydro and did not self-generate. Under the contracts, each customer must specify a contracted peak load (a "Power on Order") and that becomes the capacity for which they pay each month. The customer is free to consume energy so long as they do not exceed this Power on Order level of capacity at any time. If the customer exceeds the Power on Order level:

a) Hydro can refuse to supply the power; and

b) If supplied, the customer will face demand charges for this new peak level for the following 12 monthly bills regardless of how often the customer uses this new peak level (or if it was only a single instance)[107].

Further, power consumed outside the normal firm Power on Order framework will be considered non-firm power. Non-firm power is an option for industrial customers to occasionally purchase energy from Hydro at a 10% premium to the full moment-to-moment marginal cost on the system. The non-firm rate is far higher[108] than power that the customer would otherwise contract for under the firm Power on Order.

In short, under the previous contract the incentive to the customer is to set a sufficiently high Power on Order that they will not exceed the level, but at the same time minimize the Power on Order level so that little to no load excursions will be necessary outside this range at any time over the entire upcoming year. This incentive, at its core, is to operate at a high load factor, and to operate with as "flat" a load as possible.

For a customer who owns their own generation, they are still under encouragement from Hydro to maintain a flat net load to the grid. They can achieve this by using their own hydro plant to follow their underlying load and in this manner shape their net load to Hydro into a flat pattern.

Unfortunately, this does not reflect the most efficient use of the CBPP's generation. This is because each hydro unit and plant has an overall efficiency curve that is more efficient (converts each unit of water into energy) at some loading levels, and less efficient at others. The best efficiency for a hydro plant, in terms of energy produced, is achieved by sticking to this loading optimization. The alternative of using the hydro plant to follow the load in the paper mill requires CBPP to depart from this optimization. As a result, more water is used to produce less energy than is necessary. By virtue of this inefficient operation, CBPP also ended up purchasing non-firm power from Hydro for some periods that would not have been required if its generation was being operated efficiently.

Along with being economically inferior, the situation was also contrary to public policy, by virtue of the unique provisions of the Electrical Power Control Act, 1994. Section 3(b)(i) of this Act states:

> 3. It is declared to be the policy of the province that …
>
> (b) all sources and facilities for the production, transmission and distribution of power in the province should be managed and operated in a manner …
>
> > (i) that would result in the most efficient production, transmission and distribution of power,

In short, industrial contracts which are structured to provide incentives to maintain a flat load, when imposed on customers who own their own hydraulic generation, lead to inefficient resource use,

[107] See CA-NLH-005 Attachment 1 in respect of section 2.02, 3.02, 3.03.

[108] Typically the full cost of Holyrood fuel, but at times the rate can be linked to gas turbines or diesel, as per the Industrial Non-Firm Rate Schedule in Hydro's GRA filing, Rates Schedules section, page 7 of 43.

underproduction of hydro power, excessive use of Holyrood generation, and excessive purchases of non-firm power by the customer - all contrary to the power policy of the province.

During the 2006 GRA Negotiated Settlement, Hydro agreed to engage with CBPP to attempt to resolve this issue. As a result of discussions, the record indicates that by April of 2009 a pilot "Generation Credit" agreement was approved which was likely to address this issue[109]. The basic approach is to permit CBPP freedom within any given month to operate their hydro generation at the most efficient level possible, without penalizing the company if this leads to a somewhat less flat load than would have otherwise occurred. The title however is somewhat of a misnomer – there is no "credit" provided per se, just a relaxation of the way that Power on Order and peak load costs are applied.

The report on the impacts of the pilot contract revision (Exhibit 4 to the GRA) notes that over the years from 2009 to 2012, the revision has saved the island more than 21,000 barrels of No. 6 oil. This benefit has been achieved without any net cost to any other party on the system. The benefits ultimately flow to all ratepayers in relation to their usage of energy (fuel oil is a cost allocated on Energy units in the Cost of Service study).

The only adverse impact noted was on Hydro's net revenues which suffered a total of $248,000 over the entire period from June 2009 to December 2013. This was a result of lower non-firm sales to CBPP. However, this value is suspect, as it solely arises from Hydro's inability to collect as much revenue through the extra 10% markup that it charges on non-firm power. This 10% charge is set out in the Rate Schedules[110] at as being a charge to recover "administrative and variable operating and maintenance charges" associated with the non-firm power. The entire concept of a 10% adder to recover variable charges is by definition meant to be approximately net zero to Hydro – if the sale does not occur then the costs do not occur. With less non-firm purchases there should be less underlying "variable" costs, hence no net loss.

It is acknowledged that the economics of the contract revision will be different following the Labrador infeed and may need to be reassessed at a future GRA. However, this is no reason to maintain an inappropriate contract with a self-generating customer, nor does it in any way change the power policy of the province regarding generation efficiency. The proposed contract resolves a long-standing inequity and should be approved as full and final.

[109] Hydro GRA Exhibit 4.
[110] Hydro's 2013 GRA, Rate Schedules, Industrial Non-firm, page 7 of 47.

7.0 CORNER BROOK PULP AND PAPER FREQUENCY CONVERTER

In the previous GRA, Hydro directly assigned $0.347 million per year to CBPP in charges related to the Corner Brook Frequency Converter. In the 2013 GRA, this is proposed to increase to $0.945 million per year[111].

In this proceeding there are four overlapping and related issues with respect to the Corner Brook Frequency Converter:

1) The costs of this Converter (both capital related costs, and allocated operating and maintenance costs) have increased by an extraordinary amount since the previous GRAs. According to the forecast costs recent capital improvements have not provided any operational or maintenance efficiencies.

2) Despite this massive investment, the unit continues to perform well below specifications, to the detriment of CBPP operations. Not only is underperformance compared to nameplate capacity an issue, but Hydro further restricts CBPP in the use of the unit to a level well below its current known capability.

3) The unit's costs remain 100% allocated to CBPP, consistent with an approach adopted when the costs of the unit were trivial by comparison.

4) The underperformance of the unit not only disadvantages CBPP's ability to make use of the device, but also to the detriment of the Island Interconnected System to receive valuable capacity/reliability resources from the CBPP generation, and for CBPP to receive appropriate credit for the capacity resources they can provide to the grid.

This Section consists of the following:

- Background;
- Status Since the Last GRA;
- Role of the Frequency Converter;
- Proposed 2013 Frequency Converter Costs; and
- Conclusions.

7.1 BACKGROUND

Corner Brook Pulp and Paper owns and operates an industrial operation as well as a hydraulic generation plant. Both components (mill and hydro plant) have resources that operate at the typical 60 Hz, as well as at 50 Hz. The 50 Hz resources were established at a time before the completion of the Bay D'Espoir

[111] Please see Table 7-2 of this section.

Generating Station, at a time when vast areas of the Island were not interconnected, and the various isolated zones of the island operated at a mixture of 50 Hz and 60 Hz power.

A detailed background on the function and role of the frequency converters is provided in Appendix C to this evidence.

During the 2001 GRA, information was provided that a primary component of the development of the Bay D'Espoir Generation Station and the core Island transmission grid in the 1960s was the need for large frequency converters. These units were required to integrate 50 Hz generation and loads with 60 Hz generation and loads. Without the converters, the grid would have had to be developed at a higher cost to provide permanent 50 Hz and 60 Hz generation and transmission through the various areas of the new Island Interconnected system. The development of the single frequency system would not have occurred had the frequency converters not been installed. In 2001, it was confirmed the benefits of converters as follows[112]:

i. The frequency converters allowed interconnection of the various loads to make the Bay D'Espoir and island transmission network possible; in particular, this allowed the benefit of "gridding" for the benefit of the entire Island.

ii. The frequency converters would provide additional benefits to the overall grid including frequency and voltage regulation.

Before the 2001 GRA, the cost associated with the frequency converter was assigned as "common" to all Island customers, reflecting that they were a historical asset that provided common, widespread and permanent benefits to the entire Island Interconnected System, as an integral part of the legacy decision to develop an integrated grid. Regardless as to which customers used 50 Hz power and which used 60 Hz power at a given moment in time, all customers benefit from the decision to invest in frequency converters as opposed to a Balkanized system.

In 2001, reflecting the view that less and less customers were using 50 Hz power, Hydro proposed that all costs should be specifically assigned to the remaining industrial customers, Abitibi and CBPP. At that time the cost of the frequency converter to CBPP was $69,031 per year[113], or approximately 0.4% of the total annual CBPP power purchases from Hydro. Note that this compares to the 2013 proposed level of $944,954 per year, or over 16% of what CBPP pays for power purchases from Hydro, a 40-fold increase in impact on CBPP since the time that the cost allocation method was last adjudicated. In that 2001 GRA, the Board approved the specific assignment of the converter to CBPP.

7.2 STATUS SINCE THE LAST GRA

Since the 2006 GRA, the Corner Brook Frequency Converter has been the subject of substantial condition assessment work and capital spending, without achieving expected levels of performance.

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[112] Please see Appendix C.
[113] IC-NLH-41 Rev.2 from the 2001 GRA.

Hydro's 2011 Capital Budget[114] notes that CBPP`s Frequency Converter is a 25 MVA rotating motor-generator set which was put in-service in 1967. During Hydro's 2007 Capital Budget review, Hydro provided a copy of the final report prepared by Acres International Limited on Condition Assessment of 50/60 Cycle Frequency Converter (September 1998)[115]. This document states that the unit was operating "at approximately 20 MVA maximum output, about 2/3 of its rating". The report also notes that "the machine should be able to operate up to its rating of 28 MVA if it were cleaned."

With regard to the above reports, two items are noted:

- **Spending:** Since 2006, based on Acres assessment as well as Hydro's own assessment[116], Hydro indicates it has spent approximately $4.2 million[117] on the frequency converter. Hydro's response to IC-NLH-099 provides a list of projects undertaken for Frequency Converter for the 2007-2011 years. Although the current method of allocating these costs is 100% to CBPP, Hydro notes at IC-NLH-100 that it does not make a practice of communicating or consulting with the affected customer in regard to the capital work or its rate impacts, except as part of the overall capital budget reviews.

- **Capability:** The above cited reports note that the nameplate capacity of the Frequency Converter is either 25 MVA or 28 MVA. No reconciliation of the difference between the 25 MVA and 28 MVA ratings have been provided. In other recent documents, Hydro indicates the capacity of the Frequency Converter is 20 MW[118]. Further, during the recent supply disruptions it is our understanding that Hydro recommended the converter be operated to a 22.5 MW level to provide benefit to other customers. In contrast to all of the above ratings, Hydro's contractual conditions imposed on CBPP's use of the Frequency Converter specify that the unit is to be restricted to 18 MW, which is cited as the "normal maximum capability of Hydro's 50/60 Hz frequency converter"[119]. The use of the 18 MW cap also appears inconsistent with all assessments and evidence to date, including the 2013 Capital Budget Application which noted that Hydro "…completed and Engineering Condition Assessment study in 2005 and to this date (2010) most of the recommendations have been completed"[120] which one may reasonably expect to mean that the units were restored to proper working order.

Of particular note, the most recent capital project on the Frequency Converter is a remote vibration monitoring system, which was intended to improve on the effectiveness and reduce the "labour intensive"

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[114] Volume I, page C-151.

[115] 2007 Capital Budget, RFI PUB-NLH-44, http://www.pub.nf.ca/hydro2007cap/files/rfi/PUB-44.pdf.

[116] Engineering Condition Assessment of the Corner Brook Frequency Converter prepared by Paul Nolan, TRO Engineering Department Newfoundland and Labrador Hydro. Hydro's 2006 Capital Budget Application, Section H3.

[117] Based on projects included in Hydro's Capital Budget Applications.

[118] As per NLH Review of Supply Disruptions and Rotating Outages Report, Volume II, Schedule 11, page 12 "Coordination and Communication with Customers". March 24, 2014. http://publicinfo.nlh.nl.ca/Isl%20Int%20System%20Hearing%202014/March%2024-14%20Reports/2%20Review%20of%20Supply%20Disruptions%20and%20Rotating%20Outages%20Volume%20II.pdf.

[119] CA-NLH-005 Attachment 1 page 3.

[120] NLH 2013 Capital Budget Application, page D-180.

manual vibration checks. The project also noted that previous capital work (since 2007) performed on this unit had been of poor quality. In the discussion in support of this project, Hydro notes:

> "Prior to any major improvements on the rotating assets at the Corner Brook frequency converter, there have been very few known problems identified with vibration. When upgrade work on the rotor and stator was performed in 2008, maintenance staff noticed that the upstairs rail would vibrate when the unit was on line. This was a condition that was not present prior to the refurbishment work. Considering the history of vibration problems, and the fact that the unit operated for over a year with an imbalance and misalignments, eventually resulting in a rotor pole failure, it is critical that an online vibration system be installed on this unit"[121].

7.3 ROLE OF THE FREQUENCY CONVERTER

The CBPP operation includes generation resources that are described in Hydro's filed materials[122]. Specifically, CBPP has 81 MW of 60 Hz hydro generation and 56 MW of 50 Hz hydro generation. In 2013 this generation is allocated on a forecast basis as shown in Table 7-1.

Table 7-1: Simplified CBPP 2013 Load Forecast and Hydraulic Generation Allocation (MW)

	60 Hz	50 Hz
Load Forecast in Mill	119	12
Available from CBPP Hydraulic at full gate/full flow	81	56
Surplus/Shortfall	-38	44
Frequency Converted	18	-18
Net Surplus/Shortfall	-20	26
Power On Order from NLH	*20*	
Unused, or Used for Steam Boiler Elements		*26*

For 2013, the CBPP mill projected the need for 119 MW of 60 Hz power and 12 MW of 50 Hz power. Using the hydraulic output of the CBPP resources at full gate, there is 81 MW of 60 Hz generation available. The shortfall of 38 MW must come from either CBPP 50 Hz power that is converted to 60 Hz, or from Hydro purchases. The 50 Hz generation shows a theoretical surplus of 44 MW after the allocation of 12 MW to the 50 Hz generator for use in the mill. This surplus is not available under all flow conditions. Under Hydro's current frequency converter restrictions, only 18 MW of this generation is able to be converted to 60 Hz power. The remaining 26 MW of 50 Hz generating capacity is therefore not available for dedication to mill loads. These units will either (a) be shut off to maximize water available for 60 Hz

[121] NLH 2013 Capital Budget Application, page D-164 to D-165.

[122] Hydro's Review of Supply Disruptions and Rotating Outages Report, Volume II, Schedule 11, page 12 "Coordination and Communication with Customers". March 24, 2014.

generation, (b) be dispatched to produce 50 Hz power for a boiler (generally a lower value use of power), or (c) lead to hydro spillage, depending on the flow condition.

The frequency converters also play a role in overall grid support. The best recent example was during the January power outages, when we understand from discussions with staff at CBPP and Hydro that Hydro adjusted the maximum operating parameters to 22.5 MW in order to maximize the generation made available to all customers to aid in continuity of service. These situations help underline that it is not just CBPP who is benefitting from the capacity delivered through the converter.

It is apparent that the 18 MW limitation imposed by Hydro is economically costly to CBPP, and at times costly to the remainder of the system either in terms of added Holyrood generation, or reduced reliability. At times of high water (as has been the case for much of the past five years) this has the effect of trapping a considerable amount of valuable hydraulic generation into either waste, or lower value uses.

7.4 PROPOSED 2013 FREQUENCY CONVERTER COSTS

Hydro proposes to recognize the annual cost of the Frequency Converter as an increase from $0.347 million/year at existing rates to $0.945 million/year at proposed 2013 rates.

Table 7-2 below provides a breakdown of the specifically assigned charges as proposed in 2013 COS compared to 2007 COS.

Table 7-2: Comparison of CBPP Specifically Assigned Charges: 2013 COS vs 2007 COS ($)[123]

CBPP Specifically Assigned Charges Breakdown	2007 COS (Existing until Aug. 31, 2013)	2013 GRA COS	Increase
Operating and Maintenance Expense	140,472	351,968	211,496
Depreciation	59,112	170,812	111,700
Return on Debt	134,076	301,001	166,925
Return on Equity	12,130	118,454	106,324
Gains/Losses on Disposal of Fixed Assets	(included in Other)	3,878	3,878
Other (includes credits and revenue related costs)	1,377	-1,161	-2,538
Total	**$347,167**	**$944,954**	**$597,787**

As the above table, illustrates the rate increase is proposed on the basis of costs in a number of areas, but the largest part of the increase is in O&M expenses. The O&M portion accounts for approximately 35% of the total increase in charges. As per the COS methodology, Hydro has assigned a share of the Island Interconnected O&M expenses to the frequency converter based on share of "average original cost" of the related capital asset. However, the increase in capital cost of the frequency converter is related to the replacement of parts and other overhead costs which, it does not appear, is expected to

[123] Prepared based on Schedule 3.3A of 2007 COS (provided by Hydro in response to IC-NLH-002, 2013 GRA) and 2013 COS.

add any O&M expenses (and in some cases, such as the remote vibration monitoring project, were to have resulted in lower O&M expenses). This is confirmed by Hydro responses to IC-NLH-144 and IC-NLH-145 which show no change in number of FTEs related to the department with responsibility for the facility (the increase in salaries and wages reflects only a general wage increase), and by a comparison of 2007 actual and 2013 forecast maintenance material and supplies for this business unit which shows a decrease from 2007 actuals to 2013 forecast. In short, other than coarse allocation methods, the evidence provides no rationale as to why the Frequency Converter O&M costs are calculated to rise 150% as suggested in the filing.

Cost of Service style allocation methods are intended to reflect a simplified, but still representative, allocation of underlying expenses. In the case of the Corner Brook Frequency Converter, this form of allocation method does not appear to be functioning as intended, as a reasonable proxy estimate. The result is causing a material impact on cost allocation. As such the simplified method should be replaced by a more detailed approach, which has not been undertaken. Pending such evidence, there is no reason to consider the 2013 O&M costs for the Frequency Converter to be higher than 2007 levels, particularly in light of the fact that a number of the capital projects were specifically noted as being intended to reduce operating costs[124].

7.5 CONCLUSIONS

As a result of the above noted factors regarding the Frequency Converter, a series of adjustments are appropriate to Hydro's GRA:

1. **Not Specifically Assign:** The approach of specifically assigning the Frequency Converter to CBPP was only adopted in 2001 (had been assigned as "common" for all periods up to this time) at a time when there was limited financial impact from this decision (0.4% rate impact on CBPP). The financial impact today is materially different (16% rate impact on CBPP). It is clear that the asset is used by CBPP for managing its power resources, but it is also used by all other Island Interconnected customers both during normal situations, when the CBPP generation provides stability and grid support, as well as during emergencies when the CBPP generation can be heavily used to maintain service to all ratepayers. Moreover, regardless as to "use", the asset reflects a necessary legacy component of the existing system, which would not have been able to deliver power cost benefits to all of today's ratepayers without the Frequency Converter having been an integral part of the investment (and further, as set out in Appendix C, without being part of Hydro's "permanent" commitment to the CBPP operator).

2. **Not Include Any Capital Spending Since 2007 in Rate Base:** Given the current contractual limits that Hydro has imposed on CBPP (18 MW) compared to the proper nameplate capacity of the unit (25-28 MVA), there is a clear basis for concern over unit underperformance and whether this degree of investment was prudently incurred. It is clear that each project was approved by the PUB; however, there does not appear to be any references in the respective Capital Budget

[124] For example, upgrades to the starting system and voltage regulator in 2008 were indicated to help address maintenance difficulties. NLH Capital Budget Application, 2008 Page B-87.

Applications that would apprise the Board that the investments were being made in order to achieve inferior unit performance. Until such time as the unit can consistently perform on a planning basis to the 25-28 MVA level (or at minimum the 22.5 MW level recently used in the emergency condition) the capital spending on the unit since 2007 should not be included in Rate Base as it fails the normal 'used, useful and prudently acquired' test.

3. **Revise Allocation of O&M:** The application of a standard cost of service methodology to determine the O&M cost allocation to this facility is driving an increasing allocation of O&M as a result of the new capital spending since 2007. However, there is no evidence that the capital spending drives any associated increase in true O&M activity; on the contrary, it appears at least some portion of the capital spending should have resulted in reduced O&M. For this reason, the cost of service methodology is not resulting in a fair and reasonable allocation of costs, and no added allocation of O&M costs (as compared to 2007) should be included for this facility until such time as Hydro can produce a detailed cost analysis for this facility that justifies the Cost of Service levels. For this reason, the 2013 allocation should be revised to limit the O&M cost responsibility allocation to the same $0.140 million per year level used in 2007.

4. **Revise IC Peak Load for COS:** For Cost of Service load data inputs, as discussed above in regard to peak loads, the inferior performance of the Frequency Converter is driving a need for CBPP to contract for a Power on Order level that is higher than otherwise could be required. Further, the excessively limited contract constraint (18 MW) as compared to the known operating level during a true capacity constrained period (22.5 MW) means that the industrial class is being allocated 4.5 MW of peak costs that should not be assumed to be imposed on the system at peak times. Just as other dispatchable peak capacity resources have been netted out of the Cost of Service load allocations (e.g., NP generation or interruptible loads, whether they actually run or are interrupted at peak times), the industrial load should similarly be revised downwards by at minimum 4.5 MW for this known capacity that can be made available at key times. Further consideration should be given to revising the industrial peak load downwards by 7-10 MW to insulate the industrial class from the negative effects due to the underperformance of the Frequency Converter compared to nameplate ratings of 25-28 MVA.

5. **Consider Revising Contractual Limit:** Consideration should be given to revisiting the 18 MW contractual limit on Frequency Converter use, and in the event this can be safely and reliability increased from the 18 MW level, CBPP should be given opportunity to revise its annual Power on Order at that time without any form of restriction or penalty.

8.0 CONSERVATION DEMAND MANAGEMENT (CDM) DEFERRED TREATMENT

Hydro in its 2013 GRA notes that "Hydro and NP have jointly developed and implemented a five-year Conservation and Demand Management (CDM) plan" and initiatives resulting from the plan include activities encouraging customers' behavioural change, the provision of rebates, marketplace promotions and other targeted efforts that will see lower reliance on electricity[125].

Hydro notes that pursuant to Order Nos. P.U 14(2009), No. P.U. 13(2010), No. P.U. 4(2011) and No. P.U. 3(2012), Hydro received approval to defer costs associated with CDM expenditures related to electricity conservation programs and based on Table 3.9, the December 31, 2013 ending balance of CDM costs would be \$4.8 million after \$0.2 million amortization forecast in 2013[126].

Hydro's 2013 GRA application seeks approval of amortizing and recovering in rates CDM costs over a seven year period in accordance with the methodology proposed in GRA[127]. Unlike other utility costs, Hydro seeks to have the CDM program costs fully recovered through a rider charged to all ratepayers on the basis of energy consumed, and as such not included in the general revenue requirement[128]. Only the smaller CDM administration costs would be included in revenue requirement.

Hydro in its responses to RFIs, notes that:

- The major portion of the expenses included in Hydro's revenue requirement and deferral account are directly related to Hydro's customers. Hydro and NP do, however, share, through a 15/85 ratio, the cost of certain common items, such as the takeCHARGE website and advertising costs (IC-NLH-082);
- Hydro's focus is on fuel savings through CDM. As a result has developed programs targeting energy savings, but there are no Hydro programs currently designed to reduce system peak. As of the end of 2012, Hydro estimates the impacts from these energy-focused programs on system peak as being less than 1 MW (IC-NLH-083);
- Hydro plans its CDM to save fuel for the overall system rather than for a particular customer class. Since all energy savings are manifested as savings in Holyrood fuel oil, all customers derive the benefit. Allocation of CDM on an energy basis is consistent with the cost of service allocation of fuel oil to all of Hydro's customer classes. Lastly, allocation of CDM on an energy basis is administratively straight forward and an accepted or established practise (IC-NLH-050); and
- The \$2.63 million in forecast CDM expenses for 2013 includes costs associated with the deferral account, and does not include non-regulated activities. Hydro will not achieve this expense in

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[125] Hydro's 2013 GRA, Volume I, page 4.22.

[126] Hydro's 2013 GRA, Section 3: Finance, page 3.30. In response to IN-NLH-010, Hydro notes the 2013 Test Year includes a half year of amortization.

[127] Hydro's 2013 GRA, Volume I, Rate Schedules, pages 20-21 of 47.

[128] IC-NLH-48.

2013 due primarily to lower than budgeted participation in the Industrial Energy Efficiency Program (IEEP) resulting in a much lower than expected payout of incentive funds (CA-NLH-130).

The approach of deferring and amortizing CDM related cost over a period of time is consistent with typical approaches used for rate setting in other jurisdictions. The amortization period proposed by Hydro is shorter than some peer utilities, which serves to increase the cost to the current customers[129].

Hydro's proposed CDM cost recovery approach is problematic with respect to customer incentives. It must be remembered that Hydro's costs for CDM are not the full costs that must be borne by the customer. In most cases the customer has material additional costs (sometimes magnitudes higher than that incurred by Hydro) in order to participate in CDM activities. Despite this, the net effect of a customer undertaking CDM is heavily skewed towards providing the benefits to NP and not to industrials, as follows:

- Outside of test years, the customer who achieves CDM conservation obtains savings on their energy bill equal to their incremental energy rate (and potentially demand rate). This reduction makes up only part of the savings in that year - in addition there is a benefit from reduced Holyrood fuel used in that year. For example, based on proposed 2013 values and RSP rules, an industrial customer participating in CDM would incur a substantial but unspecified cost to participate (e.g., investment in energy savings device), and would save 4.78 cents/ kW.h reduced, and the RSP would be credited with 12.99 cents/kW.h (17.77 cents/kW.h Holyrood savings less 4.78 cents/kW.h in reduced revenue). Per the proposed new RSP rules, this 12.99 cents would be allocated to all customers, with 6.33% going to the industrial RSP[130], or 0.82 cents. For simplicity, assume the industrial customer in question is 25% of the industrial load – their allocation of this RSP amount is 0.21 cents/kW.h and their resulting net benefit from the CDM measure would be 4.98 cents/kW.h for each year until the next GRA. The remainder of the systemwide cost savings, a full 12.79 cents/kW.h (72% of the savings), would accrue to NP and rural customers.

- At the next GRA, there would be a limited degree of rebalancing, but the net effect on the customer would be very similar – approximately 5 cents/kW.h savings of their CDM effort.

- In contrast to the above, if it were NP who saved 1 kW.h on their load due to CDM, their immediate savings would be 10.40 cents/kW.h (Hydro's proposed NP second block rate). The RSP would be credited with 7.37 cents/kW.h, of which NP and rural would be allocated approximately 6.90 cents/kW.h. The net savings to NP from their 1 kW.h CDM savings would be 17.3 cents/kW.h. Only 0.47 cents/kW.h (2.6% of the savings) would accrue to the industrial customers.

- Similar to the industrial customer above, the results at the next GRA due to this 1 kW.h of NP CDM energy saving would not be materially different than the results in between GRAs.

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[129] Hydro's response to PUB-NLH-312, Attachment 1, pages 4 and 5. BC Hydro defers and amortizes over 15 years, Manitoba Hydro over 10 years.

[130] Assuming the 2013 loads used for the Cost of Service. Per 2013 Cost of Service Schedule 3.1A.

The result of the above relationship is that the incentives for participation in CDM are materially different for NP versus industrials. NP sees substantially more benefit from their savings efforts, while industrials see substantially less. This was one of the prime motivations behind the attempt at developing a two-part industrial rate out of the last GRA – to ensure that industrials customers that are able to participate in CDM are able to "capture long-term system savings"[131]. Absent a successful measure to achieve this objective, it is not apparent that industrial customers are being provided fair and non-discriminatory opportunities to participate in CDM.

A large number of potential solutions exist, which merit further consideration. For example, one option is that for bona fide energy savings secured from Hydro's CDM activities, the Holyrood-related load variation savings arising from these activities should not flow through Hydro's RSP load variation provision, but rather through a customer-specific account. These amounts could then be used as a credit against amounts that the customer owes for Hydro's CDM costs, or potentially against firm power bills, for some specified period of time linked to the life of the energy savings achieved (potentially to a maximum number of years consistent with the CDM amortization). This would have the effect of encouraging greater customer participation in Hydro's CDM programs, and of ensuring that "marginal cost"[132] principles apply to all energy saved.

With such a solution in place, where each type of customer can see the same financial benefit for each kW.h of CDM, then Hydro's proposed approach to allocation of CDM costs (equally for every kW.h) can be reasonable. In the absence of such a solution, it is clear that an equal allocation of costs per kW.h should not be approved and a significantly higher allocation to NP should be implemented.

In addition, CDM costs should be amortized on a basis more consistent with peer utilities, in particular a 10-year amortization period, to better reflect the length of time that CDM measures reduce costs.

[131] NLH GRA Exhibit 12 page A2.

[132] The marginal cost for the purposes of valuing CDM is provided in CA-NLH-171.

APPENDIX A:
PATRICK BOWMAN'S QUALIFICATIONS

EDUCATION: **University of Manitoba**
MNRM (Natural Resource Management), 1998

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

PROFESSIONAL HISTORY:

InterGroup Consultants Ltd. **Winnipeg, MB**

1998 – Present *Research Analyst/Consultant/Principal*

Project development, regulatory and rates, economic analysis and environmental licencing, primarily in the energy field.

Utility Regulation

Conducted research and analysis for regulatory and rate reviews of electric, gas and water utilities in six Canadian provinces and territories. 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. Major clients included the following:

- **For Yukon Energy Corporation (1998-present)**, analysis and support of regulatory proceedings and normal regulatory filings before the Yukon Utilities Board. Appear before YUB as expert on revenue requirement matters, cost of service, rate design, and resource planning. Prepare analysis of major capital projects, financing mechanisms to reduce rate impacts on ratepayers, depreciation, as well as revenue requirements.

- **For Yukon Development Corporation (1998-present)**, prepare analysis and submission on energy matters to Government. Participate in development of options for government rate subsidy programs. Assist with review of debt purchase, potential First Nations investment in utility projects, and corporate governance.

- **For Northwest Territories Power Corporation (2000-present)**, provide technical analysis and support regarding General Rate Applications and related

Public Utilities Board filings. Assist in preparation of evidence and providing overall guidance to subject specialists in such topics as depreciation and return. Appear before PUB as expert in revenue requirement, cost of service and rate design matters, and on system planning reviews (Required Firm Capacity).

- **For Manitoba Industrial Power Users Group (1998-present)**, prepare analysis and evidence for regulatory proceedings before Manitoba Public Utilities Board representing large industrial energy users. Appear before PUB as expert in cost of service and rate design matters. Assist in regulatory analysis of the purchase of local gas distributor by Manitoba Hydro. Assist industrial power users with respect to assessing alternative rate structures and surplus energy rates.

- **For Industrial Customers of Newfoundland and Labrador Hydro (2001-present),** prepare analysis and evidence for Newfoundland Hydro GRA hearings before Newfoundland Board of Commissioners of Public Utilities representing large industrial energy users. Provide advice on interventions in respect of major new transmission facilities. Appear before PUB as expert in cost of service and rate design matters.

- **For NorthWest Company Limited (2004-2006),** review rate and rider applications by Nunavut Power Corporation (Qulliq Energy), provide analysis and submission to rate reviews before the Utility Rates Review Council.

- **For Municipal Customers of City of Calgary Water Utility (2012-2013),** analysis of proposed new development charges and reasonableness of water and wastewater rates.

- **For Nelson Hydro (2013-current)**, development of a Cost of Service model.

- **For City of Swift Current (2013-current)**, utility system valuation approach.

Project Development, Socio-Economic Impact Assessment and Mitigation

Provide support in project development, local investment opportunities or socio-economic impact mitigation programs for energy projects, including northern Manitoba, Yukon, and NWT. Support to local communities in resolution of outstanding compensation claims related to hydro projects.

- **For Yukon Energy Corporation (2005-current),** Participated in preparation of resource plans, including Yukon Energy's 20-Year Resource Plan Submission to the Yukon Utilities Board in 2005 (including providing expert testimony before the YUB), advisor on 2010 update. Project Manager for all planning phases of the Mayo B hydroelectric project ($120 million project) including environmental assessment and licencing, preliminary project design, preparation of materials for

Yukon Utilities Board hearing, joint YEC/First Nation working group on all technical matters related to project including fisheries, managing planning phase financing and budgets. Assistance in preparation of assessment documentation for Whitehorse LNG generation project.

- **For Northwest Territories Power Corporation (2010-current),** Participate in planning stages of $37 million dam replacement project; appear before Mackenzie Valley Land and Water Board (MVLWB) regarding environmental licence conditions; participate in contractor negotiations, economic assessments, and ongoing joint company/contractor project Management Committee. Provide economic and rate analysis of potential major transmission build-out to interconnect to southern jurisdictions. Conduct business case analysis for regulatory review of projects $400,000-$5 million, and major PUB Project Permit reviews of projects >$5 million.

- **For Northwest Territories Energy Corporation (2003-2005)**, provide analysis and support to joint company/local community working groups in development of business case and communication plans related to potential new major hydro and transmission projects.

- **For Kwadacha First Nation and Tsay Keh Dene (2002-2004):** Support and analysis of potential compensation claims related to past and ongoing impacts from major northern BC hydroelectric development. Review options related to energy supply, including change in management contract for diesel facilities, potential interconnection to BC grid, or development of local hydro.

- **For Manitoba Hydro Power Major Projects Planning Department (1999-2002)**, initial review and analysis of socio-economic impacts of proposed new northern generation stations and associated transmission. Participate in joint working group with client and northern First Nation on project alternatives (such as location of project infrastructure).

- **For Manitoba Hydro Mitigation Department (1999-2002)**, provide analysis and process support to implementation of mitigation programs related to past northern generation projects, debris management program. Assist in preparation of materials for church-led inquiry into impacts of northern hydro developments.

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

- **For Nelson River Sturgeon Co-Management Board (1998 and 2005)**, an assessment of the performance of the Management Board over five years of operation and strategic planning for next five years.

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.

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.

Patrick Bowman Utility Regulation Experience

Utility	Proceeding	Work Performed	Before	Client	Year	Testimony
Yukon Energy Corporation	Final 1997 and Interim 1998 Rate Application	Analysis and Case Preparation	Yukon Utilities Board (YUB)	Yukon Energy	1998	No
Manitoba Hydro	Curtailable Service Program Application	Analysis, Preparation of Intervenor Evidence and Case Preparation	Manitoba Public Utilities Board (MPUB)	Manitoba Industrial Power Users Group (MIPUG)	1998	No
Yukon Energy	Final 1998 Rates Application	Analysis and Case Preparation	YUB	Yukon Energy	1999	No
Westcoast Energy	Sale of Shares of Centra Gas Manitoba, Inc. to Manitoba Hydro	Analysis and Case Preparation	MPUB	MIPUG	1999	No
Manitoba Hydro	Surplus Energy Program and Limited Use Billing Demand Program	Analysis and Case Preparation	MPUB	MIPUG	2000	No
West Kootenay Power	Certificate of Public Convenience and Necessity - Kootenay 230 kV Transmission System Development	Analysis of Alternative Ownership Options and Impact on Revenue Requirement and Rates	British Columbia Utilities Commission (BCUC)	Columbia Power Corporation/Columbia Basin Trust	2000	No
Northwest Territories Power Corporation (NTPC)	Interim Refundable Rate Application	Analysis and Case Preparation	Northwest Territories Public Utilities Board (NWTPUB)	NTPC	2001	No
NTPC	2001/03 Phase I General Rate Application	Analysis and Case Preparation	NWTPUB	NTPC	2000-02	No - Negotiated Settlement
Newfoundland Hydro	2002 General Rate Application	Analysis, Preparation of Intervenor Evidence and Case Preparation	Board of Commissioners of Public Utilities of Newfoundland and Labrador (NLPUB)	Newfoundland Industrial Customers	2001-02	No
NTPC	2001/02 Phase II General Rate Application	Analysis, Preparation of Company Evidence and Expert Testimony	NWTPUB	NTPC	2002	Yes
Manitoba Hydro/Centra Gas	Integration Hearing	Analysis and Case Preparation	MPUB	MIPUG	2002	No
Manitoba Hydro	2002 Status Update Application/GRA	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2002	Yes
Yukon Energy	Application to Reduce Rider J	Analysis and Case Preparation	YUB	Yukon Energy	2002-03	No
Yukon Energy	Application to Revise Rider F Fuel Adjustment	Analysis and Case Preparation	YUB	Yukon Energy	2002-03	No
Newfoundland Hydro	2004 General Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	NLPUB	Newfoundland Industrial Customers	2003	Yes
Manitoba Hydro	2004 General Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2004	Yes
NTPC	Required Firm Capacity/System Planning hearing	Analysis, Preparation of Company Evidence and Expert Testimony	NWTPUB	NTPC	2004	Yes
Nunavut Power (Qulliq Energy)	2004 General Rate Application	Analysis, Preparation of Intervenor Submission	Nunavut Utility Rate Review Commission (URRC)	NorthWest Company (commercial customer intervenor)	2004	No
Qulliq Energy	Capital Stabilization Fund Application	Analysis, Preparation of Intervenor Submission	URRC	NorthWest Company	2005	No
Yukon Energy	2005 Required Revenues and Related Matters Application	Analysis, Preparation of Company Evidence and Expert Testimony	YUB	Yukon Energy	2005	Yes
Manitoba Hydro	Cost of Service Methodology	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2006	Yes
Yukon Energy	2006-2025 Resource Plan Review	Analysis, Preparation of Company Evidence and Expert Testimony	YUB	Yukon Energy	2006	Yes
Newfoundland Hydro	2006 General Rate Application	Analysis, Preparation of Intervenor Evidence	NLPUB	Newfoundland Industrial Customers	2006	No - Negotiated Settlement
NTPC	2006/08 General Rate Application Phase I	Analysis, Preparation of Company Evidence and Expert Testimony	NWTPUB	NTPC	2006-08	Yes
Manitoba Hydro	2008 General Rate Application	Analysis, Preparation of Company Evidence and Expert Testimony	MPUB	MIPUG	2008	Yes
Manitoba Hydro	2008 Energy Intensive Industrial Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2008	Yes
Yukon Energy	2008/2009 General Rate Application	Analysis, Preparation of Company Evidence and Expert Testimony	YUB	Yukon Energy	2008-09	Yes
FortisBC	2009 Rate Design and Cost of Service	Analysis and Case Preparation	BCUC	BC Municipal Electrical Utilities	2009-10	No
Yukon Energy	Mayo B Part III Application	Analysis, Preparation of Company Evidence	YUB	Yukon Energy	2010	No
Yukon Energy	2009 Phase II Rate Application	Analysis, Preparation of Company Evidence and Expert Testimony	YUB	Yukon Energy	2009-10	Yes
Newfoundland Hydro	Rate Stabilization Plan (RSP) Finalization of Rates for Industrial Customers	Analysis, Preparation of Intervenor Evidence	NLPUB	Newfoundland Industrial Customers	2010	Pending
Manitoba Hydro	2010/11 and 2011/12 General Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2010-11	Yes
NTPC	Bluefish Dam Replacement Project	Analysis, Preparation of Company Evidence and Expert Testimony	Mackenzie Valley Land and Water Board	NTPC	2011	Yes
NTPC	2012/14 General Rate Application	Analysis, Preparation of Company Evidence and Expert Testimony	NWTPUB	NTPC	2012	Yes
Manitoba Hydro	2012/13 and 2013/14 General Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2013	Yes

APPENDIX B:
HAMID NAJMIDINOV'S QUALIFICATIONS

HAMID NAJMIDINOV
RESEARCH CONSULTANT

EDUCATION: Bachelor of Science (Economics), Fergana State University, 2000

Accounting, Qadamjay Business College, 1995

PROFESSIONAL HISTORY:

InterGroup Consultants Ltd. **Winnipeg, Manitoba**

2009 – Present Research Analyst/Research Consultant

- **For Qulliq Energy Corporation,** actively involved in the preparation of Phase I and Phase II of 2010/11 and 2014/15 General Rate Applications, including preparation of sales and revenue forecast, revenue requirement, amortization and ratebase schedules, Cost of Service analyses, rate design and schedules; provide support in the preparation of Major Project Permit Applications and Fuel Stabilization Rider Applications.

- **For Northwest Territories Power Corporation,** support in developing monthly load and revenue forecasts for budget planning; proposed territory-wide levelized rate structure analysis; cost of service comparison and rates analysis between utilities in different jurisdictions; potential mini-hydro projects benefit cost analysis.

- **For Yukon Energy Corporation,** support in preparation of 2009 GRA Phase II application (bill impacts analysis; cost of service review; revenue-cost ratio analysis) and actively involved in preparation of 2012/13 GRA Phase I application; support in budget planning and in preparation of regulatory reports; support in preparation of Yukon Energy's 20-Year Resource Plan update (load forecast update; alternative generation benefit analysis); performed power benefit analysis for Mayo B and Mayo Lake projects; provided support in preparation and review process of LNG project Part III application; support in DCF/ERA application and analysis.

- **For Manitoba Hydro Keeyask GS Project,** KCN communities Population Projection Model support and updates; project employment estimates analysis; Northern Aboriginal employment estimates model updates.

- **For Vale – Regina Potash Project (Saskatchewan),** compiled an information package, containing review of Saskatchewan electricity and natural gas market; electricity and rates review and analysis between utilities in different jurisdictions; analytical information on natural gas prices, drilling, production and demand.

- **For Nelson Hydro** (2014-current), support in preparation of Cost of Service model.
- **For Industrial Customers of Newfoundland and Labrador Hydro** (2014-current), support in analysis for Newfoundland Hydro's 2013 GRA.

CSS North America Inc. **Toronto, Ontario**

2007 – 2009 Accounting and Sales Manager

- Member of the team that specializes in providing and installation of Intellidyne energy-saving economizers, Hi-Spectrum color corrected fluorescent lamps and Rami woven aluminum thermoshield night blinds. Prepare invoices, control payments; prepare cheques, collect bills and other expenses, tax accountant support; strategic planning.

State Property Committee **Uzbekistan**

2003 - 2007 Economist, Privatization Unit

- Analyzed processes related to denationalization and privatization of state business property; member of the working group for developing and submission for approval to the Government of Uzbekistan of state policy programs drafts on denationalization and privatization of state business; monitored and coordinated implementation of developed programs. Implemented programs targeting elimination of state business ownership monopoly; development of market based private ownership mechanisms; supporting the development of a new private-business social class; performed property estimates under appropriate evaluation method (expense/revenue/comparative) and organized property sales auctions for potential investors; drafted/reviewed investment agreements and monitored their implementation; analyzed pilot implementation of state policy programs, and prepared regular reports on improvements required.

Republican Real Estate Exchange
Regional Department **Uzbekistan**

2002 - 2003 Economic Analyst

- Reviewed and analyzed tendering and auction processes; prepared statistical reports on sales/bids trends and variances; performed market evaluation of properties; assisted the management in organizing auctions and tenders.

State Property Committee **Uzbekistan**

2000 - 2002 Statistical Analyst

- Performed data collection and analysis of state business property management; developing the methodological basis for legislation on state property management; preparing briefing notes to the Management on state business property management efficiency.

APPENDIX C:
FREQUENCY CONVERTERS BACKGROUND FROM THE 2011 GRA

The following appeared in the argument of the Industrial Customers in the 2001 GRA:

[Hydro's 2001 GRA, Final Submission of Industrial Customers, pages 37-41. The document can be found at http://www.pub.nf.ca/hyd01gra/filings/Jan21/FinArgue/IndFinArgue.pdf]

> What Hydro may wish to regard as simply a plant assignment issue - the treatment of frequency Converters - in fact illuminates the entire history of the development of electric power and the vital role which Industrial Customers have played in that development.
>
> The historical record is reflected in a number of documents, several of which have been produced in response to IC-NLH-56 and IC-NLH-219. Looking initially at the Preliminary Report on Integration of the Bay D'Espoir Power Development and Existing Power Systems into a Newfoundland Network prepared by The Shawinigan Engineering Company Limited for the Newfoundland Power Commission at IC-NLH-219, one notes that in 1963, 72% of the energy generated on the island of Newfoundland was 50 cycle. (p. 3). The consultants also make the significant assumption at p. 2 that areas of 50 cycles, specifically including Corner Brook and Grand Falls, may exist indefinitely. The report goes on to consider a number of schemes to create the grid, which is essentially the grid we have today as described by Mr. Reeves in his evidence. Consideration was given to having 50 cycle generation installed at Bay D'Espoir with conversion at various later dates. However, it was ultimately concluded that a single system with frequency converters as required had the lowest present worth cost, provided a source of emergency power from existing industrial generation facilities and assisted in voltage control. That scheme was recommended both in the initial report and the supplementary report, which notes further advantages at p. 5 including maximum utilization and economy of equipment, best facilitation of the network, improved frequency regulation, simplified and less expensive facilities at Bay D'Espoir, voltage control, no penalty for delayed conversion and no restriction on growth of the 50 cycle system.
>
> In the Power Commission's presentation to the Royal Commission on Electrical Power and Energy in July, 1965, reproduced as part of IC-NLH-56, (which incidentally has an excellent history of the development of the electrical power system in Newfoundland), the vital nature of the 50 cycle issue is highlighted at p. 13 in the final paragraph, and the major efforts of the predecessors of CBPP and Abitibi to assist in the process are acknowledged on p. 14. The presentation to the Atlantic Development Board of Jan. 1965 (also part of IC-NLH-56) confirms at p. 3 that conversion of the paper mills to 60 cycle was impractical and acknowledges the contribution of those customers in absorbing substantial conversion costs. Note also, under Item 6 on p. 14 that the Power Commission (Hydro's predecessor) indicates that two "permanent" frequency converters would be required.
>
> Even in 1982 when Hydro signed a power contract with Bowater Power[133], the parties acknowledged in Article 9.01 that Hydro would continue to provide the converter at

[133] IC-5 - 2nd attachment. From 2001 GRA.

Hydro's expense in order to "continue integration of the generating facilities of Hydro and the Customer and thereby derive benefits for both parties". The converter at Grand Falls is being decommissioned but the one at Corner Brook is still required, primarily to convert 50 cycle generation to 60 cycle for use in the mill, as discussed by Mr. Budgell[134]. Mr. Budgell acknowledges that the converter could serve a purpose in converting 50 to 60 cycle power to provide emergency power to the grid should Hydro require it. He questioned whether CBPP would actually provide same but he did not refer to the contract between CBPP's predecessor and Hydro dated May 15, 1977 (produced in response to IC-NLH-43) on which Hydro still relies in respect of secondary purchases from CBPP. That contract provides in Article 5 that Bowater Power will provide emergency service to Hydro within the limitations of its obligations and requirements. Accordingly, the frequency converter makes a substantial contribution to security on the entire grid, a benefit to all of Hydro's customers. Note also the answer to IC-NLH-58 which speaks of the generation of Industrial Customers contributing to the reliability of the interconnected system. Granting that their contribution is not as great as Bay D'Espoir as the answer suggests, that suggestion itself confirms that there is a contribution from the generation, and that contribution must rely, in part, on the frequency converters.

…

The broader issue, of course, is the historic pact between Hydro's predecessor and CBPP's predecessors which gave birth the grid we all enjoy today. The benefits of a single frequency of generation at Bay D'Espoir are still being felt today. It borders on scandalous to think that Hydro, having accepted the benefits of the costs absorbed by the paper mills in the 1960's in return for converters (which it referred to itself as "permanent"), should now be asking to shed itself of its concurrent obligation to maintain the converters. There were many understandings in place among these parties. Hydro wheels power over CBPP's lines to Newfoundland Power's customers at Pasadena and Marble Mountain (See IC-NLH-57) and receives no recompense; CBPP will need to revisit the issue of wheeling charges if other historic agreements are being abandoned. Hydro relies on its history to justify preferential rates for certain customers in Bay D'Espoir itself; its historic obligations to provide these converters are certainly much more concrete.

[134] Transcript, November 8, 2001 from p. 1 line 81 to p. 7 line 81.