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June 4, 2015

Via Electronic Mail & 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: 2013 Amended General Rate Application of Newfoundland and Labrador Hydro

Please find enclosed the original and twelve (12) copies of the updated Pre-filed Testimony of Patrick Bowman and Hamid Najmidinov in respect of the above noted Application.

We trust you find the foregoing satisfactory.

Yours very truly,

POOLE ALTHOUSE

Dean A. Porter

DAP/lp
Enclosure
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cc: Mr. Geoffrey P. Young, Senior Legal Counsel, Newfoundland and Labrador Hydro
Mr. Thomas J. Johnson, Consumer Advocate
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UPDATED PRE-FILED TESTIMONY OF

P. BOWMAN AND H. NAJMIDINOV

IN REGARD TO NEWFOUNDLAND & LABRADOR HYDRO

2013 AMENDED GENERAL RATE APPLICATION

(Re: April 28, 2014 Pre-Filed Testimony of P. Bowman and H. Najmidinov)

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

June 4, 2015

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

LIST OF APPENDICES

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 Amended General Rate Application (the "Amended Application" or "Amended GRA") by Hydro to the Board of Commissioners of Public Utilities ("Board" or "PUB").

This testimony reflects updates and adjustments to the Pre-Filed Testimony prepared by Messrs. Bowman and Najmidinov dated April 28, 2014 arising due to the Amendments contained in the 2013 Amended GRA as compared to the original 2013 GRA filed by Hydro July 20, 2013.

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, parts of the following information was reviewed:

- The 2013 General Rate Application filed on July 30, 2013 and the November 10, 2014 Amended 2013 General Rate Application;
- 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 on January 28, 2015, 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 a limited extent to the Annual Hydro Capital Budgets and the previous Hydro General Rate Application filings.

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

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.

InterGroup's review has focused on the revenue requirement and Cost of Service ("COS") for Test Year 2015 consistent with Hydro's Amended Application, as adjusted by the response to TIR-NP-NLH-008 which indicates that for all intents and purposes, the GRA is to be based on the lower cost of fuel identified as part of the 2015 interim rates process[2] ($65.63/bbl). This filing reflects that new updated lower fuel price.

1.1 SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

In the April 28, 2014 InterGroup Pre-Filed Testimony, a number of conclusions and recommendations are provided. The materials below are organized to update and reconcile the current views of Messrs. Bowman and Najmidinov with those provided in the earlier Pre-Filed Testimony, as well as to set out new conclusions and recommendations related to the Amended GRA.

At the outset, it is important to note that the rate impacts on Industrial Customers in this Amended GRA remain high. Over the 3 year period from August 2013 to September 2016 (when Amended GRA rates are expected to be fully phased in), Industrial Customers will see rate impacts that range from 36% to 103% (and but for the recent fuel price drop, would have equalled 62% to 142%). As of July 1, 2015 Industrial Customers will be paying an interim rate that is not yet at the full Amended GRA levels – further increases of approximately 11% to 41% are still required if Hydro's Amended GRA proposals are adopted in full. For this reason, the Amended GRA proposals ought be viewed with a high degree of caution to ensure rate impacts are maintained at the lowest level reasonable with safe and reliable utility service.

It must also be noted that this rate impact comes at a time when industrial loads have been dramatically below 2007 levels, the last time rates were set, saving considerable quantities of expensive Holyrood fuel and yielding all customer classes significant savings in fuel costs[3]. Although loads have started to climb with the addition of Vale and Praxair, in 2015 the industrial load forecast remains at only 70% of the 2007 levels.

As a result of changes arising from the updated information in the Amended GRA, the following table updates the recommendations from the April 28, 2014 version of the Pre-Filed Testimony:

[2] Note however that the 2015 COS filed as part of the interim rates process does not yet fully incorporate the new lower cost of fuel into all areas (e.g., rate base amounts for fuel inventory). In this regard, there is no precise COS available reflecting the proposed Hydro revenue requirement in this GRA.

[3] 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.

April 28, 2014 Pre-Filed Testimony	Updated Conclusions and Recommendations
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 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.	Holyrood fuel conversion factors remain a concern. Hydro has proposed an even lower level for 2015, of 607 kW.h/bbl based on a new approach to regression. Hydro's approach is inferior due to the short and non-representative input data time horizon used. However the largest concern relates not to gross unit efficiency *per se*, but to Holyrood station service. Also, Hydro has also not included any benefits of a delayed but now imminent project to install Variable Frequency Drives on exhaust fans which is forecast to save 8 kWh/bbl. In addition, however, Hydro has proposed a new Holyrood Conversion Rate Deferral Account which means that ratepayers collectively will bear the costs of whatever change in conversion factor arises in future compared to GRA levels, positive or negative. Such an account would normally be of concern as it relates to items reasonably within the utility's risk profile. However, for the current hearing given the transitional role of Holyrood, this approach may be accepted. The issue for the current application therefore becomes one of determining a reasonable efficiency for 2015 for the purpose of setting base rates, rather than precise forecasting. Due to a poor approach to forecasting station service, an adjustment of net efficiency from 607 kW.h/bbl to 622 kW.h/bbl is recommended.
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	Of the two issues highlighted, one has been resolved by moving to a 2015 test year from a 2013 (i.e., the failure to recognize large interest cost savings arising in 2014). This is now built into rates and is no longer at issue. In regard to the other matter noted, Hydro continues to project that an RSP balance of $133 million owed to NP's customers (as well other components of the RSP scheduled to be paid out) is carried past the end of 2015, and is paid a notional "interest" equal to the weighted average cost of capital (6.8%). In practice, it appears appropriate to set 2015 Revenue Requirement

April 28, 2014 Pre-Filed Testimony	**Updated Conclusions and Recommendations**
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%.	based on this balance being paid out in 2015, with the cash required for the payout being financed by long-term debt (3.6%). The difference to the annual debt cost is on the order of $5 million.
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.	This recommendation is not relevant to the 2015 COS as the loads are based entirely on forecasts and as such do not show anomalous results of mixing actuals and forecasts as was seen in the 2013 study.
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 factor, 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.	For Test Year 2015, the noted customers (Vale and Praxair) have transitioned to a mode of operation more typically consistent with high load factor industrials. As a result, no adjustments are necessary to the 2015 COS.
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	This set of recommendations has changed materially given new facts. For Industrial Customers, there are now offerings adopted by Hydro that fulfills the recommendations

April 28, 2014 Pre-Filed Testimony	Updated Conclusions and Recommendations
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.	for equivalent opportunities from 2013, and therefore this issue is resolved. The inappropriate use of NP curtailable load has been recognized by Hydro and addressed in a preliminary way by the Board's interim order P.U.47 (2014) for the winter of 2014/15. The interim solution adopted, however, is an inferior approach, and a comprehensive coordinated approach between the two utilities should be adopted that reflects fair and equitable treatment for both NP and IC, including in COS matters. With respect to the recommendation to reject Hydro's proposal to raise the NP demand charge from \$4/kW/month to \$9.13/kW/month, Hydro has changed the proposal to only raise the charge to \$5.50/kW/month, which helps address this issue, though additional progress to a \$5.00/kW/month level is recommended.
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.	This issue remains of significant concern particularly as the system moves closer to the initiation of Labrador infeed power. It is clear that a component of the Holyrood operation is for times where economic (i.e., fuel efficient) dispatch is not possible due to transmission limitations and system capacity constraints. This suggests a greater share of Holyrood's overall costs are not directly energy-related, but instead are more capacity-related than in the past. Further, in this hearing Hydro is proposing to alter the approach to classifying Holyrood capital and O&M costs to increase the energy-related weighting compared to past practice. This is not advisable and moves in the wrong direction for the system evolution. Specifically, Holyrood will be transitioning to an entirely capacity-related weighting as soon as the Labrador infeed is established, so Hydro's proposal should be rejected and a new classification based on an increased demand-related share should be adopted.

April 28, 2014 Pre-Filed Testimony	Updated Conclusions and Recommendations
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.	No change
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.	Hydro's original proposal to raise the NP demand charge from \$4/kW/month to \$9.13/kW/month has now changed to only raise the charge to \$5.50/kW/month. A move to adjust this to \$5.00/kW/month would provide substantial additional benefits to the NP rate design.
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.	This recommendation has not changed. Hydro has altered its proposal slightly (stabilization is via deferral account, not part of RSP, also an annual cost variance threshold is proposed) but this has not changed the conclusion in this pre-filed testimony.
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	This recommendation has not changed.

April 28, 2014 Pre-Filed Testimony	**Updated Conclusions and Recommendations**
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.	
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.	This recommendation has not changed. The oil savings through 2015 is now up to 40,000 barrels.
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[4] 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	This recommendation has not changed. The frequency converter costs now are proposed to comprise over 21% of the costs to CBPP.

[4] 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).

April 28, 2014 Pre-Filed Testimony	**Updated Conclusions and Recommendations**
CBPP to Hydro, and is now proposed to increase to 16%, a 40-fold increase.	
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.	Options to realign the responsibility for the entire frequency converter cost, operation and potentially ownership should be thoroughly considered. The Frequency Converter cost escalation for O&M since 2007 is not supported, except by coarse and counterintuitive allocation methods, and should be rejected. Frequency Converter capital invested since 2007 cannot be shown to be prudently acquired, given reductions in performance, and should not be included in rate base. The remaining costs of the Frequency Converter should not be Specifically Assigned, but considered to be of a general, legacy system benefit, and charged to ratepayers broadly. The IC peak demand should be reduced by 4.5 MW for COS purposes (the difference between the normal Frequency Converter rating of 18 MW and the peak usage of 22.5 MW), consistent with the same type of COS reduction provided to NP for its rarely operated but still operable thermal generation.
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	No change

April 28, 2014 Pre-Filed Testimony	**Updated Conclusions and Recommendations**
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.	
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.	Hydro has adjusted their proposal to reflect that the 7 year recovery should be on a discrete basis rather than a rolling basis. This is a reasonable adjustment. It does not however address the original recommendation that for programs that provide benefits expected to last to 10 years or longer, a 10 year period should be used rather than 7 years.
NEW ITEMS	
	As the Labrador infeed comes into service, Holyrood power will increasingly be used only for capacity constraint reasons, much like the current gas turbines. While the earlier testimony proposed an initial increase in Holyrood's costs allocated to demand (via a fuel allocation), as the Labrador infeed moves closer it is now more appropriate to start to implement this allocation with a defined move towards classifying more of Holyrood's capital to capacity (much like the current gas turbines). An initial step to increase the Holyrood non-fuel allocation from 76% demand to 88% demand (50% closer to the situation once the Labrador infeed is completed) is appropriate for rate transition and stability reasons.
	The 2015 GRA COS was originally prepared on the basis of fuel costs at $93.32/bbl. This has since been revised downward to $65.63/bbl. A revised Revenue Requirement has been provided that adjusts the costs of fuel consumed for this lower price in Appendix B of Hydro's January 28, 2015 Interim Rates application. However, no COS has been provided to fully reflect the updated fuel price, and cost allocation is not updated to reflect that the inventory carrying cost of fuel will also be much lower in 2015 at the updated price. This

April 28, 2014 Pre-Filed Testimony	Updated Conclusions and Recommendations
	update should be included in the final GRA approvals including adjusted fuel inventory balances.

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 almost half of the overall industrial class of customers on Hydro's Island Interconnected System ("industrial class" or "IC").

The members of the IIC Group are large energy consumers who are presently in production, and operate 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 2015 Test Year). It is expected that Teck will close its mining activities in 2015 with ramping down energy requirements for parts of the 2015 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 as yet share a number of the characteristics of the IIC Group operations; namely, they are in a stage of ramping up loads leading to the Test Year for this GRA application. While there may be a convergence in some issues of concern between the IIC Group and Vale and Praxair, this may not apply to all issues. Vale is separately represented in this proceeding.

The customers that comprise the IIC Group have a forecast of 289 GW.h of firm electricity in 2015 (about 4.1% 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 621.4 GW.h[5], with an estimated $36.1 million[6] in total allocated costs (an average unit cost of 5.82 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)[7]. This extends the trend of decreasing industrial load, which totalled 1,388 GW.h as of the 2001 GRA[8]. 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; and

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[5] Sales numbers are from Hydro's Amended 2013 GRA, Volume I, Section 2: Regulated Activities, Schedule II: Actual and Forecast Electricity Requirements for 2007 to 2015. The breakdown of the sales forecast by customers is provided in response to IC-NLH-028 (Rev1), Attachment 1.

[6] $42.6 million as per Hydro's Amended GRA, Volume II, Exhibit 13, 2015 COS, Schedule 1.3.1, page 1 of 3 less $6.4 million estimated impact of lower fuel prices as per Hydro's January 28, 2015 Interim Rate Application.

[7] 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.

[8] 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, and the expected closing of Teck; partially offset by 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 to supply surplus power to Hydro, most notably during 2014 during the period of system supply constraints.

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 the 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 2015 COS study), and the overall rate design proposed in the 2013 Amended 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 operating and maintenance and administrative 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 4.1% of the Island Interconnected System energy, 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. Cost of Service methods are intended to reflect primarily the revenue requirement and system configuration for the Test Year in question, but properly also consider longer-term trends or system direction to help maintain some stability in cost measures and reflect where system costs allocations are headed in relatively foreseeable future periods (during which the same rates will often apply, in between GRAs).

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 revenue requirement of 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 less, for example, to the interaction of the RSP with revenue requirement).

3.0 OVERVIEW OF HYDRO'S AMENDED GRA

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

- Amended 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 for a 2007 Test Year (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 2015 Test Year forecasts as well as based on shortfalls occurring in 2014. Hydro's GRA effectively requests the approval by the Board of the 2014 and 2015 revenue requirement, a 2015 Cost of Service study for the purpose of setting rates and a proposed rate design, and a 2014 Cost of Service for the purpose of determining an allocation of the 2014 shortfall.

The approach is somewhat unusual in Canadian ratemaking, in that the GRA effectively requires approval of many adjustments and shortfalls that precede the GRA hearing by a substantial period. The effective need to restate and reallocate amounts which arose in some cases back to 2013 is unfortunate. In addition, the final rates that will arise in relation to the GRA will likely not be in place until late 2015, which brings the applicable period for the rates very close to a known impending material change in the Island Interconnected system cost structure for the start of 2018, due to the delivery of Muskrat Falls power.

While the current GRA reflects the requirements of OC direction, the rates proposed in the current GRA are subject to PUB approval. The OC directions specify that the rates approved for IIC Group must be phased-in over a "rate phase in period"[9] which ends in fall 2016. 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.

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

3.2 OVERALL IMPACT

The Amended GRA requests approval of a revenue requirement from rates of $661.4 million, which is 54% higher than the approved 2007 Test Year[10]. For the Island Interconnected System ("IIS"), the allocated revenue requirement has increased from $381.9 million to $585.0 million, or 53%. These increases are well above the degree of IIS system load growth over this period, which cumulatively is only 12.7%[11].

Following the filing of the Amended GRA, Hydro provided an updated PIRA forecast for fuel prices as part of the 2015 Interim Rates application. This filing indicates a fuel price for 2015 which is $65.63/bbl as compared to $93.32/bbl in the Amended GRA. It is understood that the update of this fuel price is now considered to properly form part of the requested approvals and rate proposals for this Amended GRA process (although the majority of the revenue requirement filing, other than parts of the Cost of Service, has not been updated)[12]. As a result of these amendments, the 2015 revenue requirement from rates is now about $587 million (37% higher than 2007) with the IIS at $512.3 million (34% higher than 2007).

As a result of the significant increase to revenue requirement, with limited growth in load, the base rate impacts in the current GRA are 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 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'. It is a measure of how far input costs for companies have moved, and how quickly.

The 2013 Amended GRA proposes <u>base rate</u> impacts on IIS customers that are substantial for the main classes when compared to the 2006 GRA, as follows[13]:

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

[11] Revenue requirement numbers for IIS are from Schedule 1.1; and growth from 6,184 GW.h to 6,970 GW.h per Schedules 1.3.2 of the respective Test Year cost of service studies for 2007 and 2015, as found in IC-NLH-002 (2007 COS) and Exhibit 13 of Hydro's 2013 Amended GRA, Volume II.

[12] Hydro's February 25, 2015 submission re: 2015 Interim Rates noted at page 2: "Since Hydro filed its Amended Application on November 10, 2014, the forecast cost of No. 6 fuel at Holyrood has decreased materially. Hydro's Amended Application was based upon an average No. 6 fuel of $93.32 per barrel while the most recent fuel forecast provided by PIRA indicates an average fuel cost of $65.63 per barrel for 2015. Based upon the 2015 Test Year forecast, the revised fuel cost reduces Hydro's 2015 Test Year Cost of Service by approximately $73 million. As such, the proposed increase to customer rates in 2015, as requested in Hydro's Amended Application, is no longer supported by the 2014 fuel cost forecast."

[13] Per IC-NLH-089 Rev.1.

- **Newfoundland Power ("NP"):** NP's base rates are forecast to increase (based on consistent 2015 load) from $415.4 million to $461.7 million[14], or an increase of 11.1%.
- **Industrial Customers:** The Industrial Customer base rates[15] excluding specifically assigned charges are similarly proposed to increase, in this case from about $30.0 million to $34.5 million, or an increase of 15%[16].
  - 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 18.1% for the class[17]. In total, the IC increase is 63% higher than the increase to NP.

All of the above changes do not yet reflect the full impact on Industrial Customers arising from changes to the RSP, as shown in Section 3.4 below.

At the time of the original 2013 GRA filing, the base rate increase to Industrial Customers was calculated at 31.9% (not including specifically assigned charges). At that time, the Pre-Filed Testimony of Bowman and Najmidinov noted that this was far above the increases to NP, that the disparity had not been sufficiently explained, and that had Industrial Customers faced the same percentage increase as NP, the Industrial Customers rates would be $2.7 million lower than proposed. This drove a substantial concern and analysis in the original Pre-Filed Testimony to attempt to address this difference. In the 2015 proposal, a gap remains but the impact is considerably reduced compared to the original issue.

Despite the somewhat reduced concern regarding the disparity between IC and NP, there remains a strong basis for concern over (1) the degree of base rate increases approaching 15% for the industrial class, (2) the increase in specifically assigned charges, as well as (3) the full degree of rate impacts for longstanding Industrial Customers since 2013.

3.3 MAJOR COST CHANGES

By far the most dominant factor affecting Hydro's cost structure changes is 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 about $25 million since 2007 as detailed in Section 4 below[18]. The other major driver of cost increases is major load growth on the NP system of almost 1,000 GW.h This scale of load growth far exceeds the losses of Industrial Customers since 2007, and is almost 4 times the

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[14] As per IC-NLH-089 Rev.1 Attachment 1 page 1 of 3 and Appendix B of Interim Rates Application with revised fuel prices dated January 28, 2015.

[15] 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 until September 2016.

[16] As per IC-NLH-089 Rev 1 Attachment 1 page 2 and Appendix B of Interim Rates Application with revised fuel prices dated January 28, 2015. The calculations exclude specifically assigned charges.

[17] As per IC-NLH-089 Rev 1 Attachment 1 page 2 and Interim Rates Application with revised fuel prices dated January 28, 2015 (Evidence, page 16).

[18] The average price of fuel consumed for 2007 Test Year was $55.47/bbl, as compared to $65.63/bbl in the current GRA, an increase of $10.16/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 $25 million.

size of Vale's load by 2015. As an incremental load to be served by Holyrood, the added NP load would consume almost $108 million in fuel.

As an offset to the growth in Holyrood costs, Hydro has entered into other agreements to secure power, which saves over $64 million in Holyrood fuel[19] but adds approximately $22 million in purchase power costs.

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 (which is assumed in the Revenue Requirement to continue through 2015), and (iv) the conversion of previous IPP arrangements at Star Lake and the Exploits River to a new fixed price level. The net effect is that Government actions which may otherwise be presented as a potential material benefit to ratepayers (e.g., temporary establishment of lower cost IPP arrangements with Nalcor through 2016, lowering of the Debt Guarantee Fee to a level more reflective of the benefit it provides)[20] have significantly been offset by other Government recoveries and charges to Hydro, so that the ultimate net ratepayer benefit is substantially reduced.

Additionally, Hydro proposes a substantial expansion to the number of variables from which Hydro is cost protected via "recovery mechanisms"[21]. This includes a number of variables where Hydro notes a concern for adverse impacts on its earnings in future years (such as fuel prices, Holyrood efficiency and any purchased power cost escalation or volume variance). 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 large balances owing via the RSP are paid out and financed with new low cost debt), (ii) 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

Including all effects, such as RSP changes, the requested rate changes for Industrial Customers between August 2013 and September 2016 (a period of 36 months) total approximately 70%[22]. A significant portion of these impacts relate to one-time adjustment to the Rate Stabilization Plan ("RSP") in September 2013.

[19] This includes new power purchases for wind and Nalcor hydro, offset by some reductions in purchase power from non-Nalcor suppliers or conversion of previously non-Nalcor sources to Nalcor.

[20] 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. In response to CA-NLH-270, Hydro stated that the "discussions are continuing and are not anticipated to be concluded with ownership transfer until 2016" and "a purchase price of 4 cents/kWh is assumed for the 2015 Test Year".

[21] Hydro's 2013 Amended GRA Application, Section 3: Finance, page 3.45.

[22] $42.5 million as proposed by Hydro at 2015 COS rates (IC-NLH-089 Rev 1, Attachment 1) compared to August 2013 rates with RSP current plan in place or about 70% with lower fuel prices as provided in Hydro's Interim Rates Application (Hydro's January 28, 2015 Interim Rates Application adjusted the revenue requirement to reflect reduced fuel price forecast from $93.32/bbl to $65.63/bbl. This fuel price adjustment reduces the revenue required from Island Industrial Customers by about $6.4 million as per Appendix B of Hydro's Interim Rate application).

Excluding the RSP adjustment, island industrial rate increase is at average of 18.1%[23], ranging 14% and 44% for each industrial customer[24].

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 mutes to some degree the full impact, the dollars proposed to be reallocated within the RSP for the purposes of the phase in were already being held for Industrial Customers benefit, so Government has not in practice imposed any new benefits or protection for customers that did not already exist. In practice, the Government order significantly reduced the funds being tracked to the benefit of the Industrial Customers, which may have provided for more options for rate mitigation had the transfer not been initiated to cross-subsidize other customer classes.

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 far less than half the level as of the 2007 Test Year (from 762 GW.h to 289 GW.h)[25], which has resulted in material grid-wide savings for all customers, as the quantity of No. 6 fuel required to serve the Island has been reduced by 780,000 barrels [at 607 kW.h/bbl conversion rate]. These load changes provide a net cost saving of $51 million at today's fuel prices (or $43 million at the prices from the 2006 GRA)[26].

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.

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[23] The rate impact with lower fuel prices as per Hydro's January 28, 2015 Interim Rates application and excluding RSP adjustments effective September 1, 2013.

[24] Depending on load characteristics of each industrial customer the full 2015 COS rate will have different rate impacts with higher rate impact to Teck (44%) and CBPP (34%) with lowest for NARL and Praxair (about 14-15%). These rate increase impacts include increase in specifically assigned charges.

[25] IC-NLH-028 Rev1 and Hydro's Amended 2013 GRA, Regulated Activities, Schedule II.

[26] 473 GW.h load reduction at 607 kW.h/bbl Holyrood conversion factor, $65.63/bbl fuel price as per Hydro's 2015 Interim Rates application, 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;
- Hydro's Capital Structure and Return on Rate Base; and
- Fuel Inventory Price Update.

4.1 COMPARISON TO THE 2007 TEST YEAR

The proposed 2015 Test Year revenue requirement set out in Finance Schedule III of the Application is $662.5 million[27] at the originally proposed $93.32/bbl reduced to $587.3 million at the revised fuel price of $65.63/bbl. This is an increase of $155.6 million or 36% from the approved 2007 Test Year[28] revenue requirement of $431.1 million. The comparison is shown in Table 4-1 below, which compares the total revenue requirement by category for the 2007 and 2015 Test Years.

[27] However, note that the Revenue Requirement for 2015 shown in Schedule 1.1 of Cost-of-Service is $661.395 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. Please see footnote #7 on page 3.10 of Hydro's Amended GRA for reconciliation.

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

Table 4-1: Comparison of Hydro's 2007 and 2015 Forecast Revenue Requirement and Revenue from Rates[29]

	2007 Test Year	2015 Test Year Proposed	*Increase/ (Decrease)*
Expenses			
Operating expenses			
Salaries and Fringe Benefits	58,457	88,888	*30,431*
System Equipment Maintenance	20,579	26,825	*6,246*
Office Supplies Expenses	2,106	2,804	*698*
Professional Services	4,418	9,494	*5,076*
Insurance	1,881	2,607	*726*
Equipment Rentals	1,369	3,066	*1,697*
Travel Expenses	2,332	3,717	*1,385*
Misc Expenses	4,530	5,772	*1,242*
Building Rentals and Maintenance	825	1,217	*392*
Transportation	1,994	2,245	*251*
Cost recoveries	-2,199	-7,069	*-4,870*
Allocated to non-regulated customer	-2,874	-1,387	*1,487*
Net Operating Expenses	93,418	138,178	*44,760*
Fuel			
No. 6 Fuel	136,867	244,914	*108,047*
Diesel Fuel and Other	11,119	19,466	*8,348*
Gas Turbine Fuel	450	3,474	*3,023*
Less RSP Deferral		-34	*-34*
Total Fuel Expenses	148,436	267,820	*119,384*
Fuel supply deferral		1,991	*1,991*
Purchased Power	38,327	63,254	*24,927*
Amortization	38,825	63,792	*24,967*
Accretion of asset retirement obligation		878	*878*
Other income and expenses	1,366	4,074	*2,708*
Less: COS exclusions		-323	*-323*
Return on Ratebase	110,707	122,811	*12,104*
Total Revenue Requirement	**431,079**	**662,475**	***231,396***
Less: Other Revenues	2,021	2,508	*487*
Revenue Required from Rates	**429,058**	**659,967**	***230,909***
Adjusted for lower No. 6 fuel price		**-72,669**	***-72,669***
Revenue Required from Rates	**429,058**	**587,298**	***158,240***

[29] The table prepared based on Hydro's Amended 2013 GRA, Volume I, Finance Schedule III. Total Revenue Requirement for 2015 Test Year per Cost of Service is $661.4 million. Please see footnote #7 on page 3.10 of Hydro's Amended GRA for reconciliation. Hydro's January 28, 2015 Interim Rates Application adjusted the revenue requirement to reflect reduced fuel price forecast from $93.32/bbl to $65.63/bbl. This fuel price adjustment reduces the No. 6 fuel cost by $72.669 million as provided in Appendix B of Hydro's Interim Rate application. In response to TIR-NP-NLH-008 Hydro stated that not all amounts in the revised cost of service study [for interim rates application] have been updated to reflect the lower cost of fuels and Hydro will reflect all the changes in the cost of –service study filed for Board's final order. Gas Turbine fuel costs from Schedule 2.1.A of 2007 and 2015 COS.

4.2 BULK POWER COSTS

Table 4-1 shows that the largest change in Hydro's cost structure since 2006 GRA relate to annual supply bulk power cost. This includes fuel costs, particularly No. 6 fuel for Holyrood, as well as purchased power and diesel. Prior to the lowering of the 2015 benchmark fuel price, these categories comprised nearly $144 million in added costs since 2007 ($119 million for fuels, plus $25 million for purchased power). With the lower fuel price included, the net impact has been cut in half, to $71 million. Of this $71 million, $8 million relates to diesel fuel (generally not relevant to the Island Interconnected System, except as a unique item not linked to energy supply requirements but rather regional reliability). The remaining $63 million cost increase arises from a mix of items that inherently affect the use of Holyrood ($35.4 million for #6 fuel, and $27.4 million for other supply sources such as purchased power and gas turbine fuel), as shown in Table 4-2 below.

Table 4-2: Changes to Fuel Forecast by Cause - 2007 to 2015 Test Years at Lower Fuel Prices[30]

	Holyrood Generation	Fuel Efficiency	Barrels	Fuel Consumption Price	Calculated Total Fuel Expense	***Net Change to Fuel Expense***	Purchased Power and Gas Turbine Fuels Costs Increase
	GW.h	kWh/bbl	bbl	$/bbl	$000	$000	$000
2007 Test Year, Holyrood Generation	**1,554.5**	**630**	**2,467,460**	**$55.47**	**136,867**	-	-
Change due to Fuel Price change	1,554.5	630	2,467,460	$65.63	161,939	*25,072*	-
Change due to Long-Term Average Hydro change	1,423.0	630	2,258,683	$65.63	148,237	*-13,702*	-
Change due to increase in Power Purchases (not Nalcor)	1,303.1	630	2,068,429	$65.63	135,751	*-12,486*	12,364
Change due to increase in Nalcor-related Power Purchases	806.9	630	1,280,762	$65.63	84,056	*-51,695*	9,838
Change due to Gas Turbine load change	798.5	630	1,267,460	$65.63	83,183	*-873*	3,033
Change due to Fuel Efficiency change	798.5	607	1,315,486	$65.63	86,335	*3,152*	-
Change due to Load Growth	1,593.0	607	2,624,382	$65.63	172,238	*85,903*	-
2015 Test Year, Holyrood Generation	**1,593.0**	**607**	**2,624,382**	**$65.63**	**172,238**	**35,371**	**25,235**
Capacity Assistance Cost							2,122
2015 Test Year	**1,593.0**	**607**	**2,624,382**	**$65.63**	**172,238**	**35,371**	**27,357**
Change due to Load Growth by customer							
Change due to Transmission Losses	33.1	607	54,530	65.63	3,579	*3,579*	-
Change due to Newfoundland Power	998.3	607	1,644,646	65.63	107,938	*107,938*	-
Change due to Rural	71.9	607	118,451	65.63	7,774	*7,774*	-
Change due to CBPP	-407.7	607	-671,664	65.63	-44,081	*-44,081*	-
Change due to Abitibi Con. - Grand Falls	-162.4	607	-267,545	65.63	-17,559	*-17,559*	-
Change due to Abitibi Con. - Stephenville	-5.7	607	-9,390	65.63	-616	*-616*	-
Change due to North Atlantic Refining	-21.5	607	-35,420	65.63	-2,325	*-2,325*	-
Change due to Aur Resources/Teck	-43.9	607	-72,323	65.63	-4,747	*-4,747*	-
Change due to Praxair	51.6	607	85,008	65.63	5,579	*5,579*	-
Change due to Vale	280.8	607	462,603	65.63	30,361	*30,361*	-
Total Load growth Impact						**85,903**	**-**

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 $25.1 million increase in revenue requirement.

[30] The table is prepared based on Hydro's 2013 Amended 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 1,423.0 GW.h or decrease of 131.5 GW.h which is calculated as a difference between 2014 forecast hydraulic generation at 4,603.6 GW.h and 2007 forecast at 4,472.1 GW.h from Regulated Activities, Schedule V. Holyrood No. 6 fuel cost per barrel for 2007 is from 2007 COS, Schedule 1.4.

This has been partially offset by an increase in the calculated long-term average hydraulic generation ($13.7 million savings), changes in third-party power purchases ($12.5 million in fuel savings for added wind and other changes, offset by $12.4 million in added power purchase costs), and due to power purchases related to supplies now under the control of Nalcor ($51.7 million in fuel savings, offset by $9.8 million in power purchase costs)[31].

The other substantive change in costs relates to the revised estimate of Holyrood efficiency, from 630 kW.h/bbl to 607 kW.h/bbl. This change serves to increase revenue requirement by $3.2 million.

The largest driver of fuel volume and cost increases, however, is load growth. Although the largest of the Industrial Customers have reduced their load (with CBPP load reductions driving $44.1 million in Holyrood fuel savings, and NARL driving $2.3 million in savings) the continued growth of Newfoundland Power and rural loads have more than offset this decline, combining for over $115.7 million in added fuel cost (before any allocation of added line losses). On a combined basis, the higher loads today as compared to 2007 Test Year drive $85.9 million in added fuel cost.

4.3 HOLYROOD FUEL CONVERSION FACTOR

Hydro's 2013 Amended GRA application proposes a 607 kW.h/bbl[32] 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. The Hydro proposal in this GRA is for a "gross efficiency" of 650 kW.h/bbl less 43 kW.h that is used within the Holyrood plant to produce this power. This net efficiency factor is lower than 2004 and 2007 approved efficiencies of 630 kW.h/bbl by 23 kW.h/bbl[33]. This value is also materially below the level proposed in the original 2013 GRA of 612 kW.h/bbl[34].

In addition, the current Amended 2013 GRA proposes a mechanism which is intended to provide protection for both Hydro and ratepayers if the fuel efficiency varies from the GRA forecast[35]. In concept, the deferral or stabilization mechanism is a temporary proposal (given Holyrood's impending role change) that offsets to some degree concerns regarding risks to customers of setting the Holyrood GRA fuel efficiency too low. While this mechanism will provide some protection if the GRA estimate of fuel efficiency proves incorrect, it still remains important to ensure that the best available estimate of Holyrood efficiency is used in the GRA approvals.

The determination of net fuel efficiency is in effect driven by two different factors – the gross fuel efficiency, and the station service. Both variables are addressed below. One common item that affects both components is that forecast 2015 Holyrood generation, at 1,593 GW.h/year is more than 21% higher than any year since before 2004[36]. As both of the major values (gross efficiency and station service) are sensitive

[31] This includes supplies that in 2007 were under the control of Abitibi Grand Falls, either as IPP suppliers to Hydro, or to supply the former industrial operation at Grand Falls.
[32] Net Holyrood production after station service (see for example IC-NLH-093 Rev 1 and NP-NLH-069 Rev 2).
[33] Conversion factor of 630 kW.h/bbl (Schedule 1.4 of 2007 COS).
[34] Conversion factor of 612 kW.h/bbl from Schedule 1.4 of 2013 COS.
[35] Regulated Activities, Schedule IX.
[36] NP-NLH-193.

to the unit loading[37], there are significant limitations to using recent years which are not representative of the Test Years to extrapolate for the purposes of forecasting values outside the analyzed range.

4.3.1 Gross Fuel Efficiency

Hydro notes that the conversion factor forecast at 607 kW.h/bbl net is linked to a gross efficiency of 650 kW.h/bbl at the gross unit level, based on a regression analysis using June 2009 to May 2014 actuals. This reflects a regression based on two variables: (1) unit average monthly gross loading (i.e. how hard the units were being run), and (2) fuel heat content. The calculations are provided in response to IC-NLH-160.

There are a number of issues with the approach taken by Hydro.

First, the period for the data is relatively short (5 years) and encompasses unit loadings well below the range expected in 2015 and 2016. This limits the value of the regression. In the original 2013 GRA a period of over 10 years was used[38] but even that period fails to capture many periods of loading similar to the 2015 Test Year.

Second, the use of a second variable for fuel efficiency in the regression (which increases complexity) is not required if the fuel heat content is known for the past periods. One only need normalize the efficiency into units of kW.h/btu of input fuel, materially simplifying the analysis. Then that unit can be converted back to kW.h/bbl based on the forecast heat content of the GRA fuel. Adding complexities that are not necessary to the regression both reduces its predictive value and makes the results more difficult to understand.

Third, the regression is calculated on the basis of fuel required as compared to unit loading. This gives a very high correlation (effectively the r-squared value) as, unsurprisingly, higher loading required more fuel. Fuel efficiency is only a very small component of the total fuel required, and is almost lost in this high r-squared value[39]. The proper assessment would be to complete a regression of load against the variable of concern (gross efficiency) which is a derivative of the total fuel used. When this adjustment is made, it become far clearer that Hydro’s data in fact does not represent a strong correlation.

The resulting comparison of efficiency, with the input fuel normalized to the same heat content expected as part to the current GRA, is shown in Figure 4-1 below.

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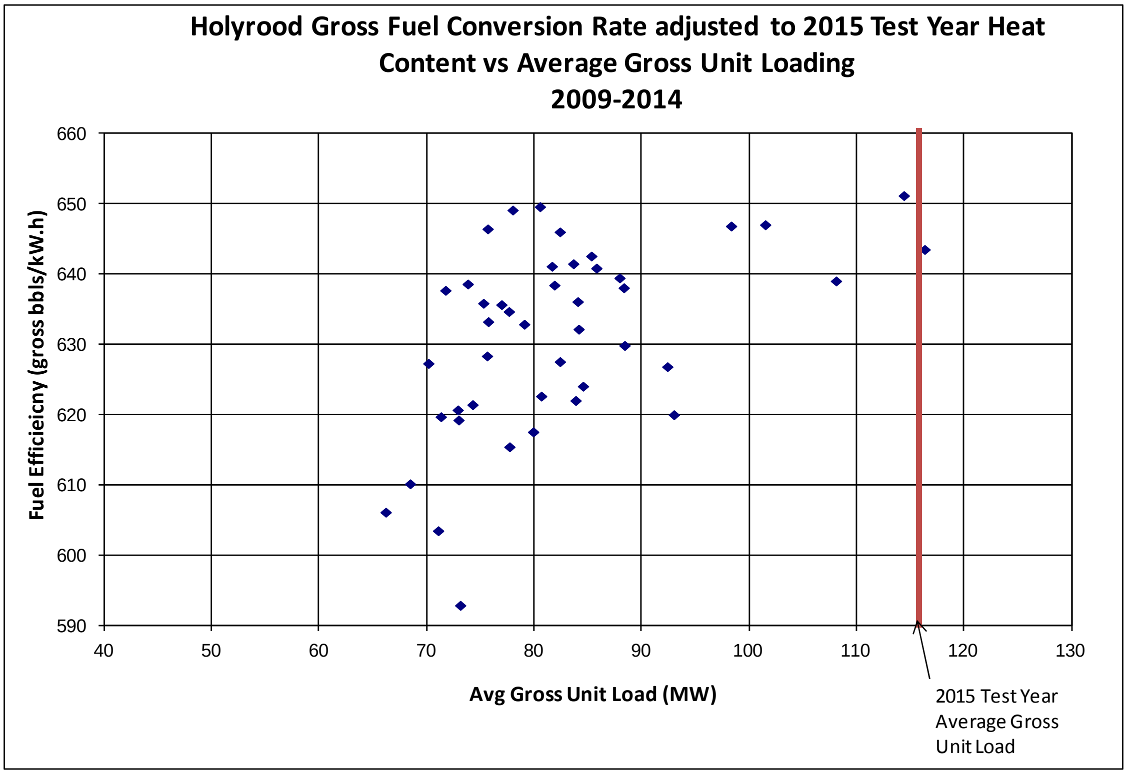
[37] See, for example, NP-NLH-339.

[38] See Hydro’s response to IC-NLH-159.

[39] For example, if one was to be driving a car, the highest correlated variable to how long one could go between fill ups (in hours) would be how far the car drove (as could be measured by average speed travelled), not the fuel efficiency of different ways of operating the car. The fill up frequency operating at 110 km/h would be higher than operating at 70 km/hour mostly because in one case the car goes 110 km and in the other it only goes 70 km – not because of differences of a few percentage points in fuel efficiency (e.g., l/100 km). If modelling this relationship, the fuel efficiency would have almost no effect on the statistical relationship modelling how quickly the tank would be empty where it would be overwhelmed by the overall distance travelled variable.

Figure 4-1: Holyrood Gross Fuel Conversion Rate adjusted to 2015 Test Year Heat Content vs Average Gross Unit Loading 2009-2014[40]



In short, with adjustment for these two modelling approaches in Hydro's data, the remaining regression analysis shows that there is no representative value in this approach to assessing the fuel efficiency in the Test Year given (1) the short 5 year period of input values (relatively few blue dots), (2) the non-representative nature of the input data to the loads levels to the Test Year which the regression is being applied (almost no blue dots at or above the red line level of load). Nonetheless, while Hydro's approach does not yield a strong predictive value, 650 kW.h/bbl is within the (wide) range that could be suggested by Figure 4-1 above for an average monthly gross loading of approximately 117 MW (a full linear regression would yield a slightly higher value, but this would be based on a very weak strength). Also, as noted below, more material concerns arise with respect to the adjustments assumed for station service than the potential range of variability in the above values. Given the proposal to adopt a temporary fuel efficiency deferral approach, the use of a 650 kW.h/bbl gross efficiency as proposed by Hydro in the Test Years is not unreasonable.

[40] Prepared based on data provided by Hydro in response to IC-NLH-160 [excel file]. Gross fuel efficiency is calculated based on adjusted Heat Content to 2015 Test Year value of 152,400 BTUs/gal.

4.3.2 Station Service

The station service power requirements of operating Holyrood itself are a major factor affecting the net efficiency (the energy that is available to be delivered to the system from the plant, for each unit of fuel consumed, given that a portion of the gross power produced is consumed by the plant itself). A lower station service, all other things being equal, would equal a higher net efficiency.

Hydro has used a factor of 6.61% of gross generation as an estimate of station service (approximately 43 kW.h/bbl)[41]. This value is based on the 5 year average from June 2009 to May 2014[42]. During this period, Holyrood generation was as low as half the output as forecast for 2015[43], and 2016 is forecast to be even higher by another 4%[44]. In short, the 5 year average fuel efficiency is not representative of the revenue requirement anticipated to arise in the Test Years.

The response to IC-NLH-161 shows the impact of varying this percentage from 5% up to 6.25%, indicating as much as 10 kW.h/bbl (43,000 bbls[45] or $2.8 million in Test Year Revenue Requirement[46]) turns on this estimate. Hydro also uses this same 6.61% as a forced value for analyzing the regression of previous year data, including the 5 year analysis used for the GRA purposes (NP-NLH-069 Rev. 1)[47], a 10 year forecast (NP-NLH-337) and a case from 2001-2005 (NP-NLH-334).

Looking at past data, it is apparent that 6.61% is not representative of expectations when Holyrood loads are as high as forecast for 2015 or 2016 as provided in Figure 4-2 below.

[41] Holyrood Gross Plant Production at 1,705.7 GW.h as per NP-NLH-188 Rev1 divided by forecast fuel consumption of 2,624,371 as per Hydro's 2013 Amended GRA, Regulated Activities, Schedule V equal to 650 kW.h/bbl (1,705,700,000 kW.h / 2,624,371 bbl=650 kW.h/bbl) less 607 kW.h/bbl net conversion factor proposed by Hydro.

[42] 2013 Amended GRA, Section 2: Regulated Activities, Page 2.75.

[43] For example, as provided in NP-NLH-188 Rev1 the net generation for 2010 was at 803 GW.h [between 885.3 GW.h and 957.4 GW.h for 2011 through 2013] compared to 1,593 GW.h forecast for 2015 Test Year.

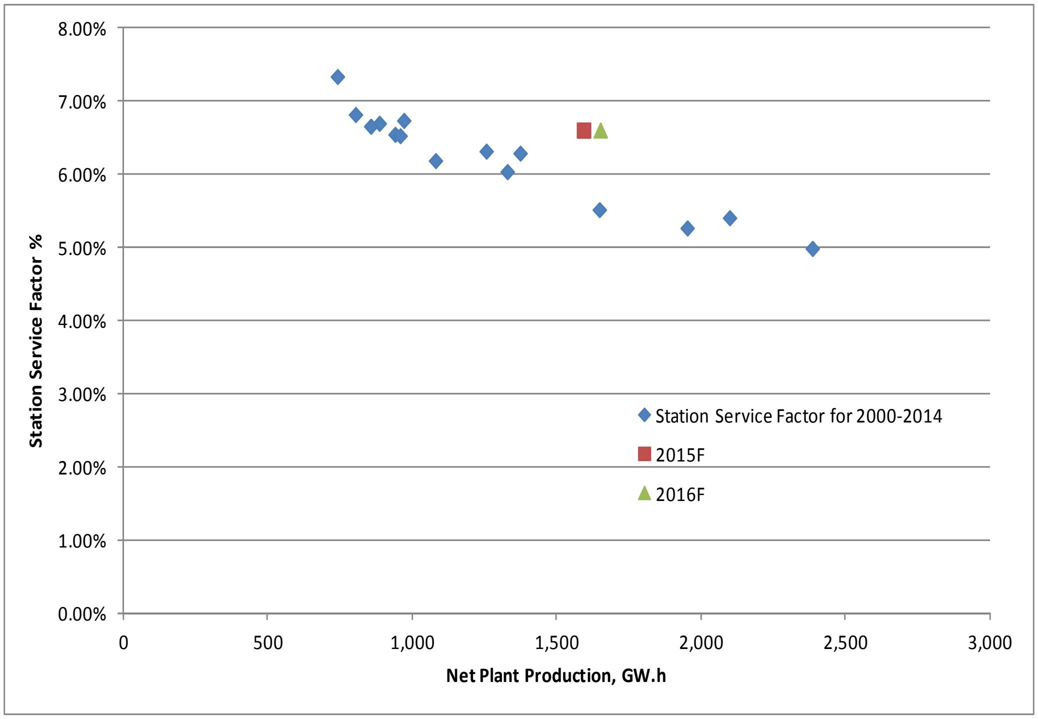
[44] 2016 forecast net generation at 1650.7 GW.h as provided in response to NP-NLH-188 Rev1 and CA-NLH-019 Rev1 compared to 1,593 GW.h proposed for 2015 Test Year.

[45] Please see Hydro's response to PUB-NLH-50 Rev2.

[46] 43,000 bbl at $65.63/bbl fuel price as per Hydro's January 28, 2015 Interim Rate application. At 2013 Amended GRA fuel price of $93.32/bbl the impact would be about 4 million.

[47] Note that an updated NP-NLH-069 Rev. 2 was issued without the backup data provided in IC-NLH-160. Although this represents a newer number, the change is minimal (6.56% versus 6.61%) and as the underlying data is not available, the Rev. 1 values were used above.

Figure 4-2: Holyrood Station Service Factor vs Net Production[48]



The results in Figure 4-2 indicate that if the 2015 values solely followed past trends, the station service should be on the order of 5.85% (36 kW.h/bbl used in station service, an improvement of 7 kW.h/bbl over the proposed GRA level which is the basis for the overall conversion factor of 607 kW.h/bbl net output[49]). However even though this value is below that proposed by Hydro, this value would only be reasonable if improvements had not been undertaken to Holyrood in the period since 2000. This is not the case.

In the original Pre-Filed Testimony, concern was noted over the information in response to IC-NLH-064, IC-NLH-093 and IC-NLH-138, where Hydro provided a list of initiatives undertaken and forecast to be completed to improve net fuel efficiency since the last GRA in 2007. A large number of these initiatives are targeted to reduce station service. These RFIs have now been updated to indicate recent additional projects and initiatives that were not identified in the original 2013 GRA filing. There is cost for ratepayers associated with those projects. For example, the Plant in Service value for Holyrood plant included in Hydro's rate base for 2015 GRA Cost of Service increased by over $64 million compared to 2007 Test Year[50]. Fuel saving initiatives, which would make up a portion of this added capital spending, would be expected to reduce the

[48] Prepared based on data provided by Hydro in response to NP-NLH-188 Rev1. Data includes 2000-2013 actuals, 2014, 2015 and 2016 forecasts.
[49] With 5.85% station service factor the gross generation would be about 1,686.2 GW.h [1,593 GW.h/(1+5.85%)]. This reduces the fuel consumption to about 2.595 million bbls or 614 kW.h/bbl at 1,593 GW.h net generation, which is 36 kW.h/bbl lower than gross generation efficiency at 650 kW.h/bbl noted on the previous page.
[50] Schedule 2.2A of 2007 COS at $192.5 million and 2015 COS at $256.9 million.

station service compared to past years to help offset the rate impacts of these projects. Based on Hydro's approach to this GRA, the benefits of these offsets are not being provided to ratepayers.

As one example, note that NP-NLH-191 indicates that Hydro is implementing a Variable Frequency Drive project, which is projected to increase the Holyrood efficiency by 8 kW.h/bbl. This project was originally scheduled for late 2014 or early 2015, and for some reason has now been delayed to late 2015 (per NP-NLH-191 Rev. 1). Regardless, this time period of late 2015 is when the new rates wold be expected to be in place, and as such is an appropriate consideration for this GRA.

In short, by using the average station service rate from the past five years, a period of load which is not representative of the Test Years, the station service estimate as a percentage is too high. It is also apparent that Hydro has not given full consideration to providing ratepayers with the benefits arising from the capital projects. On this basis, a material downward adjustment in the station service, to yield a net efficiency improvement of 15 kW.h/bbl (8 kW.h/bbl for capital investment, plus 7 kW.h per bbl for a better regression of station service projected levels), to 622 kW.h would be appropriate.

4.4 HYDRO'S CAPITAL STRUCTURE AND RETURN ON RATE BASE

Since the last GRA (2007 Test Year) the share of equity in Hydro's capital structure has increased substantially from 13.99% to 21.36% in the 2015 Test Year[51]. In addition, Hydro now reflects a higher ROE (from 4.47% in the 2007 COS to proposed 8.80% in the 2015 COS)[52]. 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, and serve to increase returns to Hydro's shareholder.

Hydro's Return on Rate Base has also changed as a result of rate base growth, and changes in the cost of debt. These two factors – policy items and capital cost items, combined serve to drive the changes in Return on Rate Base, as shown in Table 4-3 below.

[51] Schedule 1.1 of 2007 COS (as provided in response to IC-NLH-002) and 2015 COS, page 2 of 2.
[52] Schedule 1.1 of 2007 COS and 2015 COS, page 2 of 2.

Table 4-3: Changes to Return on Rate Base since the 2007 COS[53]

	Return on Rate Base ($)	Change ($)	Due to policy ($)	Due to costs ($)
2007 Return on Rate Base	110,809,988			
Change to Eliminate Rural ROE Exemption	112,134,421	1,324,433	1,324,433	
Growth in Rate Base	135,677,751	23,543,330		23,543,330
Change to Average Debt Costs	111,667,143	- 24,010,608		- 24,010,608
Change to Return on Equity and Equity Ratio	122,849,768	11,182,626	11,182,626	
Total Change		12,039,780	12,507,059	- 467,278

From Table 4-3, a significant portion of the increase in costs of Return on Rate Base is due to policy direction from Government.

The major savings item in Table 4-3 is the reduction in average debt costs, as the weighted average cost of debt is reduced from 6.905% to 4.938%[54].

A major item of note in the current GRA is the continuing inclusion of the large RSP balances within Hydro's 2015 capital structure. During the years 2013 through 2015, these balances lead to peculiar outcomes. Most notably, Hydro's total capital for financing rate base, on a mid-year basis, in 2015 is approximately $1.78 billion[55]. However, this capital is financing a mid-year rate base (assets) of $1.80 billion[56] plus Capital Work in Progress averaging $0.14 billion[57] (which is also financed by Hydro long-term capital). The result is approximately $160 million more in assets than in available capital. The largest part of this difference is the RSP balance[58]. In effect the RSP is functioning as an additional form of financing for rate base, or as a form of loan to Hydro, at the average WACC, increasing the required return from customers as part of base rates.

It is clear that within the timeframe of the GRA, nearly $200 million will no longer be financed as RSP balances. Per the December 2014 RSP report, the full RSP balance is almost $250 million, and it is likely that by year-end 2015 or early 2016, the majority of this balance will be dispersed amongst customer classes[59]. Hydro's response to IC-NLH-054 notes that no decision has been made on how the major RSP

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[53] 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 $312.7 million (from $1,489 million to $1,802 million) which would have impact of $23.6 million at 2007 weighted average cost of capital at 7.529%; average debt return reduced from 8.26% to 6.67% of by 1.59% which would be $24.1 million at $1,802 million rate base for 2015 and debt ratio of 83.59% for 2007; weighted average return on equity increased by 1.255% (from 0.625% to 1.879%) which would be $22.6 million at $1,802 million rate base for 2015 offset by impact of lower debt ratio (83.59% debt ratio from 2007 multiplied by 6.67% debt return would be 5.57% weighted average debt return compared to 4.94% as proposed by Hydro for 2015 or difference of 0.63% * $1,802 million rate base would be $11.4 million). All numbers are from Schedule 1.1 of the respective 2007 and 2015 Cost of Service studies.

[54] Schedule 1.1 of the respective 2007 and 2015 Cost of Service studies.

[55] The 2015 opening balance is $1.639 billion and closing is $1.916 billion, for a mid-year average of $1.777 billion, as per Hydro's Amended 2013 GRA, Finance Schedule I page 4 of 11.

[56] 2013 Amended GRA, 2015 COS, Schedule 1.1, page 2 of 2.

[57] Per 2013 Amended GRA Finance Schedule I page 5 of 11.

[58] The December 2015 RSP report confirms RSP balance at about $250 million [December 2014 RSP Report, page 3].

[59] Other than an ongoing portion of the hydraulic balance (75% of the year-end amount), all other amounts are likely to be either be paid out or transferred to current balances in their entirety.

payouts will be financed by Hydro, but given Hydro's cash position, it is clear that this financing will be provided in effect by added promissory notes or long-term debt. Even ignoring the cost advantages of the promissory notes, the refinancing of only $160 million[60] of the RSP balance moving from a WACC (RSP interest rate) of 6.817% to a 3.6% new long-term debt issuance interest rate will lead to immediate savings to Hydro of about $5 million[61] plus a greater share of debt in the capital structure. Some of this savings will arise as lower costs for Interest During Construction (IDC) on capital projects, but the vast majority will be savings to the financing of rate base. This is consistent with the values in NP-NLH-020 Rev. 1 which shows the cost of debt financing rate base dropping from $89.3 to $84.5 million from the year 2015 to the year 2016.

Unlike the 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 and equity ratio somewhat below the level included in Hydro's GRA by a new impact of approximately $5 million in revenue requirement.

4.5 FUEL INVENTORY PRICE UPDATE

The 2015 GRA COS was originally prepared on the basis of fuel costs at $93.32/bbl. This has since been revised downward to $65.63/bbl. A revised Revenue Requirement has been provided that adjusts the costs of fuel consumed for this lower price in Appendix B of Hydro's January 28, 2015 Interim Rates application. However, no COS has been provided for updated fuel price and cost allocation is not updated to reflect that the inventory carrying cost of fuel will also be much lower in 2015 at the updated price. This update should be included in the final GRA approvals.

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[60] $160 million would represent the solely the resolution of the NP refundable amounts plus the segregated Load Variation, each of which is to be addressed imminently within this GRA period.
[61] This is a difference of 3.2% in cost rate, on $160 million.

5.0 COST OF SERVICE

Hydro's 2015 Cost of Service study (2015 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 2015 COS for Island Interconnected seeks to allocate $585.0 million in revenue requirement[62] 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[63] regarding 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"[64]. However, the 2015 COS as proposed by Hydro in its GRA reflects an unfair distribution between some of the customer classes.

This section consists of the following:

- NP Load Factor;
- Impact of Transitional Industrial Customers to Industrial Rates;
- Demand/Capacity Cost Avoidance; and
- Holyrood Capacity versus Energy Classification.

For the 2015 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 2015 Test Year. Small methodology changes were adopted, including classifying wind 100% to energy[65], and changing the classification of Holyrood capital costs to give weight to the current year, which does not (this is addressed below).

As in past proceedings, it is important to review the Cost of Service not just from the perspective of precisely reflecting the 2015 Test Year, but also from the perspective that the rates to be charged arising from this Cost of Service study will be applied in 2016 and beyond. As such, the Cost of Service must also be checked for reasonableness to longer term system cost evolution.

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[62] Hydro's 2015 COS, Schedule 1.3.1, page 1 of 3.
[63] Hydro's 2013 Amended GRA, Volume II, Exhibit 9.
[64] Hydro's 2013 Amended GRA, Volume II, Exhibit 9, page 1.
[65] This change may be appropriate so long as Hydro continues to give wind no capacity credit in planning nor in economic decisions to enter into wind contracts. However, if Hydro does continue to use that approach to planning for wind, that assumption must be reviewed as well, as properly analyzed wind does provide some capacity benefit in terms of LOLH.

5.1 NP LOAD FACTOR

In response to IC-NLH-107 (Rev.1), Hydro notes that the load forecast for NP used by Hydro for the 2015 Test Year was prepared by NP and was dated April 11, 2014. Hydro was not able to confirm if this load forecast was used for other purposes or only for the purposes of Hydro's GRA.

In the original Pre-Filed Testimony, concern was raised that the NP load factor being used for Revenue Requirement and Cost of Service purposes was above 54%, which was not representative of any past history, and was patently too high.

Table 5-1 below summarizes the load forecasts for NP, Industrial Customers and Rural that were used for the 2007 Test Year (forecast), the proposed 2013 Test Year (partial forecast partial actuals), and actual 2013.

Table 5-1: Comparison of Load Forecasts: 2007 and 2013 Forecasts, and 2013 Actual[66]

	2007 Test Year			2013 Test Year			2013 Actuals Year		
	MW	GWh Sales	Load Factor	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%	1,276.3	5,605.7	50.1%
Rural	84.8	392.0	52.8%	93.9	447.3	54.4%	95.8	458.0	54.6%
Industrial	126.9	930.2	83.7%	79.6	408.4	58.6%	64.1	351.2	62.5%
Praxair				*5.7*	*4.3*	*8.6%*	*0.1*	*0.112*	*12.8%*
Vale Newfoundland				*13.9*	*34.3*	*28.2%*	*6.0*	*8.2*	*15.6%*
Corner Brook Pulp & Paper Co. Ltd.	*59.4*	*452.5*	*87.0%*	*20.0*	*80.1*	*45.7%*	*20.0*	*55.393*	*31.6%*
N. Atlantic Refining Ltd.	*30.5*	*245.3*	*91.8%*	*30.5*	*217.9*	*81.6%*	*28.1*	*215.488*	*87.5%*
Teck Resources	*10.0*	*64.3*	*73.4%*	*9.5*	*71.8*	*86.3%*	*9.5*	*72.032*	*86.6%*
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%**	**1,353.8**	**6,450.0**	**54.4%**	**1,436.2**	**6,414.9**	**51.0%**

As shown in Table 5-1, the concerns regarding NP's load factor in 2013 were borne out[67]. The table also shows the challenges associated with forecasting industrial customer loads during periods of transition (applied to Vale and Praxair) which also show some variation.

In response to IC-NLH-026, Hydro notes that the originally calculated forecast change in the NP load factor for 2013, from 50% historically to 54%, was likely influenced by NP's assessment of expected weather, NP generation, any change in NP system operations and any change in customer load characteristics.

Looking at an NP load factor that is being used today, calculated consistently off of native peak load (the highest peak on NP's system) adjusting for weather, and subtracting the normalized capacity value for NP's hydraulic generation that it supplies itself, the results are shown Table 5-2 below, including forecast 2015 (from IC-NLH-172).

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[66] Table is prepared based on Hydro's original 2013 GRA, Volume I, Regulated Activities Schedule II. The 2013 actual is from 2013 Amended 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.

[67] In addition, the original Pre-Filed Testimony indicated that there was a separate concern over the representativeness of the 2013 load, which focused on a December system peak rather than the more usual January peak, due to Vale's ramp-up. The above values, which indicate an NP load factor of 50.1% are still not representative of the appropriate adjustment to focus on NP's January peak (which, if using actuals, should be on a weather-adjusted basis).

Table 5-2: Comparison of NP Load Factors: 2005-2015[68]

	NP Native Peak (MW) Less Hydraulic Generation Credit (84.5 MW)		Energy Sales to NP (GWh)	Load factor
	Actual	Weather Adjusted	Actual	Weather Adjusted
2005	1,047	1,082	4,664	49.2%
2006	1,058	1,088	4,617	48.5%
2007	1,097	1,104	4,991	51.6%
2008	1,135	1,153	4,960	49.1%
2009	1,122	1,154	5,108	50.6%
2010	1,082	1,168	5,016	49.0%
2011	1,157	1,209	5,317	50.2%
2012	1,197	1,266	5,359	48.3%
2013	1,314	1,259	5,606	50.9%
2014	1,268	1,297	5,852	51.5%
			average	49.9%
2015 GRA forecast		1,295	5,924	52.2%
NP's 2013/14 GRA, September 2012		1,268	5,665	51.0%

As shown in Table 5-2, the forecasts prepared by NP for 2015 continue to show an optimistic load factor that is not representative of recent history. Also of note, the forecasts are not representative of NP's own numbers from its recent GRA (51.0%)[69], which indicate that the values used by Hydro for the 2015 year are based on 4.6% growth in energy from the period of NP's GRA, but only 2.1% growth in peak load. This type of weather-normalized growth difference between energy and demand would be unusual over a short period (less than 1 year).

In short, the load factor being used by Hydro for NP's load for 2015 continues to appear unreasonable and unsupportable, though not to the same degree as highlighted in the original Pre-Filed Testimony for 2013.

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[68] The table is prepared based on Hydro's response to IC-NLH-172. 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 Rev1 (page 4 of 10). Hydro's response to IC-NLH-051 Rev1 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); dispatch at total of 2.65 GW.h in 2014 (or 0.73% load factor of 41.5 MW capacity).

[69] The values shown for the NP's 2013/14 GRA are from the original filing. NP's 2013/14 GRA 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.

For the purposes of improving the representation of cost causation in the COS study, a normalized NP load factor more representative of the long-term average load factor of 49.9% should be used. Adjusting only the peak demand level would suggest that the forecast peak is understated by as much as 60 MW (and by more than 30 MW if the load factor is just to be brought down to the 51% used by NP in its last rate application). This is a very high level of adjustment. As load forecasting is understood to be a matter of acute attention as part of the System Supply Issues proceeding, further understanding of the improvements and recommendations of that process would help identify the best course of adjustment for the purposes of COS.

It is important to note that peak demand analysis for COS is prepared for the purpose of allocating cost responsibility to the various classes (e.g., it is not used to assess reliability, LOLH, or for other purposes). In the context of Hydro's COS study, the industrial customer peak demand loads which are used are based on the forecast Power on Order, which is a practical maximum demand that customers have committed to having supplied by Hydro. Hydro is not obliged to serve demand levels above the Power on Order, and in the event customers do exceed this level (only with the prior permission of Hydro), they can be interrupted on short notice, or at minimum will be expected to pay considerably higher costs for any energy served (under a different rate). In this regard, the industrial customer demand in the Cost of Service study should be understood to be a maximum demand that would ever be imposed by the customers on the system. As a load characteristic intended to be comparable, NP's demand levels used in the cost of service study should show similar conservatism.

5.2 IMPACT OF TRANSITIONAL INDUSTRIAL CUSTOMERS TO INDUSTRIAL RATES

In the original Pre-Filed Testimony, a major issue of concern was the treatment of different members of the industrial class within the 2013 Cost of Service study. In particular, customers who were transitioning to production, but were not yet in production, had atypically low load factors which was skewing cost allocation to the class to the detriment of existing industrials. A number of possible solutions were proposed, including severing the class as the two groups of industrials were not "like" customers (the main theoretical basis for making a group of customers into a class).

In the 2015 COS, based on forecast 2015 loads, this issue is no longer relevant. Hydro's 2013 Cost of Service methodology reflected the loads related to transitional industrial customers that was representative of major phase-in stages, and not any form of operating mode (e.g., the Vale load factor was 28%, Praxair at 8%[70]). In the 2015 COS, this issue has been largely addressed (e.g., Vale load factor of 65%, Praxair at 98%). Further the 2015 COS also appropriately models the expected peak system month, as it is based entirely off of consistent forecasts, rather than a mix of actuals and forecasts as was the case for the 2013 COS. As a result, these issues are no longer an item of concern. As a result, there is no need in the 2015 COS to pursue the types of adjustments put forward in the original Pre-Filed Testimony. It is also noted that Hydro has come a similar conclusion in the response to IC-NLH-140 Rev.1.

[70] Please see Table 5-1.

5.3 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 expected 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.

As of 2013, Industrial Customers were not offered a curtailable load program. However, since that time such offerings have been made available to Vale and to CBPP. As a result one of the key concerns in the earlier Pre-Filed Testimony (that the programs were not offered to customers on a fair basis between NP and Industrial Customers) has been largely addressed.

The remaining issue relates to the treatment of NP's curtailable load for COS purposes.

With respect to the analysis of COS issues, a primary consideration for each topic is whether each group of customers is being treated equally and fairly (non-discriminatory). On COS theory, often there is more than one approach that can be taken in COS analysis that may each have some aspects of validity. In some cases, more than one approach may be acceptable so long as they are equally applied to every customer group. The challenge with respect to the availability of curtailable loads on the Island system is that Hydro's proposal does not treat each load on a non-discriminatory basis. NP's curtailable load is proposed to receive a credit in MW related to the reduced peak demand (which pushes material costs off to the rural and industrial customer classes), while industrial customer curtailable load is credited with a dollar value payment, which is funneled back in the COS such that all customers (including industrial customers) pay for the credit. The net result is not fair nor reasonable.

Hydro has exacerbated this issue with their application of September 19, 2014 (which was approved by the Board only on an interim basis in Order P.U. 47 (2014) pending review of the issues at a GRA).

For clarity, the NP curtailable load program is described in NP`s 2013/14 GRA as providing a once per year credit of $29/kV.A[71] 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[72]). The amount of curtailable load on NP's system is understood to be upwards of 10 MW or more[73]. NP makes the decision when to curtail its loads, although in many cases this request occurs in response to a request from Hydro due to system supply constraints. The NP curtailable load can play any of three roles:

1) The NP curtailable load is valuable when supplied at times that Hydro requests, for system support.

2) The curtailable load can also be of benefit to NP's customers (not Hydro's) when used to address bona fide distribution system constraints.

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[71] NP's 2013/14 GRA, Schedule A page 7 of 10 http://www.pub.nf.ca/applications/NP2013GRA/files/applic/Application-VolumeI.pdf.
[72] 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)".
[73] IC-NLH-127 Rev 1. 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.

3) Finally, outside of system emergencies, the NP curtailable load is available to NP to avoid peak demand charges by inconveniencing customers with interruptions at times where no system constraint is present. Specifically, if it can be timed to occur at NP's system peak, an individual NP initiated curtailment can cause the NP costs from Hydro for the year to be reduced by $48/kW under the previous rate design, and $66/kW under the proposed rate design[74]. This use of the curtailable load is of extreme concern, as it means both (a) that customers are being inconvenienced for no underlying system constraints (plenty of power is available) and (b) the limited number of curtailments permitted under the program are used up by NP trying to artificially avoid peak demand charges from Hydro, leaving less curtailments available for true system emergencies. In effect, the actions of NP risks the reliability of system supply to all customers solely in order to avoid peak load payments otherwise due to Hydro.

Hydro recognized the counterproductive and inappropriate use of curtailments by NP as noted under #3 above, leading to a decision by Hydro to file its application of September 19, 2014. This application sought to address curtailment availability for the winter of 2014/15. Unfortunately, Hydro sought the wrong solution – rather than seeking to prevent NP's practice of dispatching the system inappropriately, Hydro sought to compensate NP as if they were dispatching the system inappropriately so that they in fact did not have to actually carry through with the inappropriate interruptions.

A contrary view of the options available to Hydro was put forward in the IC argument, as set out in Appendix D attached to this Pre-Filed Testimony.

The curtailable program is broadly similar to a previous Hydro offering to industrial customers, known as Interruptible B and to the present curtailable offerings to CBPP and Vale. The industrial programs allow industrial customers to provide curtailable load to Hydro in exchange for an annual payment[75]. In short, the various NP and industrial programs are highly similar, 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 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 (a strong incentive to curtail early) – this is not the same for smaller customers who are typically shed much later in the system response sequence.

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. Similarly, the current Vale and CBPP contracts are not used as the

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[74] The proposed rate design is based on $5.5/kW demand rate. $66/KW is $5.5/KW times 12 months. The billing determinants for the year are shown in IC-NLH-111 Rev1 Attachment 1 page 3 as 15,122,049 kW per the 2015 COS. 15,122,049 kW-months is 12 times of 1,260,171 kW, which is the annual non-coincident peak shown in IC-NLH-029 Rev1 as the annual peak NCP, confirming this 1,260,171 peak load level is used for all 12 months for revenue forecasting purposes.
NP further explains this wholesale rate savings in the response to CA-NP-188 from the 2010 NP GRA. The RFI response is available at http://www.pub.nf.ca/applications/NP2010GRA/index.htm.

[75] 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. Hydro signed Capacity Assistance agreements with CBPP and Vale. The annual payments for providing capacity assistance is $1.680 million for CBPP [up to 60 MW] and $0.442 million for Vale [up to 15.8 MW]. Please see PUB-NLH-461 and PUB-NLH-394.

basis for any downward adjustment to capacity in the COS study. Specifically, the industrial customer's full Power on Order (i.e., expected peak outside of curtailments) has always been used for COS allocation, not the Power on Order less interruptible load.

There are a number of issues with the Hydro COS proposal regarding 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[76], 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 mixed. 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 called on NP's curtailable loads twice from 2008 to October 2013, and on both occasions the curtailments were refused by NP[77]. More recently, Hydro notes that the last 6 curtailment requests were fulfilled[78]. In regard to the earlier unfulfilled requests, NP's 2010 GRA (CA-NP-188) notes that curtailments have successfully occurred approximately 90% of the time over the previous five years, indicating that NP has used this program a large number of times for its own purposes (i.e., to manage their peak loads and demand costs), in contrast to Hydro's eight requests for system support reasons.

3. 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 and industrial curtailable customers continue to be users of the capacity assets in almost all hours, including most of the critical hours of the year. As a result, Hydro's approach to effectively free NP from payment for $48 for each kW of curtailable load (under the previous rate) or $66/kW (under the proposed rate) is excessive given: (a) NP still largely receives firm power to serve this load, (b) the net cost for NP is only $25/kW and (c) a portion of this cost is reflecting value on NP's system, by using the curtailments to manage distribution system issues, rather than Hydro's bulk power 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. The solutions proposed in the IC argument regarding the September 2014 Hydro application on NP's curtailable rate (per Appendix D) remain valid, namely[79]:

1) The rate schedule for wholesale service to NP should be adjusted to ensure that any curtailment under the Curtailable Service Option does not lead to a reduction in the amounts NP would pay in

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[76] 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."
[77] IC-NLH-72.
[78] IC-NLH-072 Rev1.
[79] http://www.pub.nl.ca/applications/InterimApprovalofUtilityRate/corresp/IC-IntervenorSubmission.pdf, pages 6 and 7.

demand charges. Specifically, the definition of "Native Load" in the "Utility" rate schedule should be adjusted to add a part (c) which adds in to the calculation the sum of loads curtailed (averaged over the same 15 minutes that the power delivered and generation are measured).

a. This would serve to ensure that despite any Bill Avoidance curtailments that are initiated by NP, there would be no bill benefits provided.

b. As to incentive, this approach would eliminate the incentive for NP to misuse the program, and retain full availability of the limited curtailments for bona fide system requirements.

2) The Curtailable Service Option of Newfoundland Power ("NP") should be revised to prohibit curtailments where there is no bona fide system constraint on either the generation and transmission system (as directed by Hydro) or the distribution system (as directed by NP) that threatens delivery of power to firm service customers.

a. This provision would require an adjustment to the NP Curtailable Service Option rate schedule.

b. The proposed revision would serve to protect NP's Curtailable Service customers from excessive interruptions, yielding the same benefits to curtailment availability for true system emergencies.

In addition to these recommendations, the appropriate and entirely non-discriminatory approach to treating NP and IC loads is to establish an annual payment to NP from Hydro for the availability of all curtailable loads, comparable to the approach for IC. Such payment would become a capacity related cost in the Hydro COS study, and all customers would pay a share based on their use of capacity. No theoretical "credit" would be included in the COS study for any peak MW, which otherwise permits NP to not pay for assets that serve their customers. This would be entirely consistent with the treatment of the current industrial curtailable loads, and in that manner would be entirely non-discriminatory. This is also consistent with the established principle applied in the case of the former Interruptible B. The level of the payment from Hydro to NP should reflect the value of the capacity on Hydro's system, but in any event should be only a portion of the amounts that NP pays to its customers for their interruptible loads. The remainder of the costs NP pays their customers should go into NP's revenue requirement as a distribution reliability cost.

5.4 HOLYROOD CAPACITY VERSUS ENERGY CLASSIFICATION

In the Cost of Service study, Hydro classifies the costs of Holyrood as follows:

1) 100% of Holyrood's production costs for fuel are classified to Energy[80] (as opposed to capacity). This is consistent with past GRAs, and with typical practice for bulk fuel related expenses. Such a classification is consistent with the concept that any kW.h used by any customer (or use that is avoided) at basically any time throughout the year ultimately finds its way one-for-one to either an increase or a reduction in the quantity of fuel used.

[80] Hydro's 2015 COS Schedule 4.1.

2) Holyrood Rate Base assets (capital cost) is proposed to be classified to Demand and Energy at 72.24% demand and 27.76% energy. This is the 5 year average operating capacity factor for the plant, including forecast 2014 and 2015. This approach is a change from past practice, which used the 5 years prior to the COS year, rather than the last 5 year inclusive of the COS year. Had the longstanding approach been used, the percentages would be 23.89% to energy and 76.11% to demand[81].

3) The same ratios as in #2 above are used also for classifying Operating and Maintenance Expense and Depreciation, so the effects of the methodology change are compounded.

In contrast to the above, the assets and 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. This is a standard and appropriate Cost of Service method for fuels used for emergency, standby, and peaking units such as the Gas Turbines.

In the Original Pre-Filed Testimony, a concern was raised regarding the Holyrood classification. In general, Holyrood is now playing an increasing role that is distinguished by time period during the year (e.g., winter operation at high and efficient levels to help provide energy, versus should operation at lower and less efficient levels but no option not to run to provide transmission support/capacity). Cost characteristics that give rise to a pure energy allocation represent the value of a kW.h regardless as to when it is delivered in a year (all kW.h are treated equally). When costs are driven not just by a generic time-indifferent kW.h, but linked in time to serving a particular load condition, then allocation is not properly an absolute 100% energy. This can arise due to a peak or reliability-driven load (which have become more acute on the Island), or a shoulder load when the transmission system cannot otherwise deliver reliable power (such as now occurs in spring and fall). A 100% energy allocation does not properly reflect this cost driver.

As a result, the Original Pre-Filed Testimony suggested some move away from 100% energy for more components of Holyrood's costs. The rationale was that since the current classification method for Holyrood fuel and capital was first adopted, there was 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 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 new 100 MW turbine at Holyrood[84] and a new Bay D'Espoir to Avalon transmission line[85]. The initial Capital Budget application on the transmission line by Hydro[86] 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

[81] 2010-2013 actuals as per 2013 COS and 2014 forecast as per 2015 COS, Schedule 4.3.
[82] Hydro's 2015 COS Schedule 4.1.
[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.

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 fuel efficiency would be maximized, 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 the notable issue that 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). NP-NLH-194 Rev.1 notes that for 2015 some of the lower loading issues are reduced due to the 100 MW turbine, but not all.

These above system characteristics underline that even when Holyrood is being used, at least a portion of this use in the Test Year (and the years leading up to the Test Year) is not simply an energy-driven cost. For example, at times of the year increased load in the western part of the province can and would be supplied by hydraulic generation, while at those same times increased load in the Avalon will drive added Holyrood use. Also, if Holyrood were only operated for energy production reasons, it would not be dispatched at the lower loading levels, but rather at a much higher level for shorter periods consistent with higher efficiency and less fuel cost.

As a simplifying approach, the original Pre-Filed Testimony suggested that some of the Holyrood fuel cost should be considered a capacity related cost, more akin to a Gas Turbine.

Three major changes arise for 2015 compared to 2013 that affect this proposal:

1) For the 2015 COS, Hydro has proposed to alter the longstanding COS approach and now classifies a greater share of Holyrood costs (Rate Base, O&M and depreciation) to energy than to demand.

2) The initiation into service of the 100 MW turbine means that Holyrood is less often loaded to inefficient dispatch levels than was forecast for 2013[87].

3) The system is now just a few years away from Holyrood's role changing to one of 100% backup and reliability, a 100% demand cost allocation (similar to the gas turbines today).

As a result of these changes, it would be more appropriate today to focus solutions to the issue of over classifying Holyrood costs to energy through revising the approach to classifying Rate Base (and related costs that follow Rate Base, namely O&M and depreciation). As Holyrood is headed to a role that is entirely backup and reliability by the time the Labrador Infeed comes on-line, this means a 100% demand classification will prevail within a few years (similar to methods used by BC Hydro for their Burrard thermal GS which currently plays a similar role to Holyrood after 2017). Altering the COS approach so as to move from 76.11% demand to 72.24% demand (as proposed by Hydro) moves in the wrong direction compared to system cost projections, and should be rejected. Such an approach would lead to rate instability.

A more appropriate move today would be to recognize the transitional role of Holyrood in 2015 through altering the COS method in the opposite direction as proposed by Hydro. In short, rather than moving farther down in demand classification for Rate Base, a move halfway towards a 100% demand classification would be directionally more appropriate. This would be consistent with a demand classification of

[87] For example, Hydro's 2013 Amended GRA, Section 1, page 1.13 notes that combustion turbine at Holyrood will facilitate a more efficient operation of the Holyrood Thermal Generating Plant. Also response to V-NLH-092.

approximately 88%. If this were adopted, and given the initiation of the 100 MW gas turbine, it could remain appropriate to classify 100% of Holyrood fuel to energy consistent with Hydro's 2015 COS.

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 2015 Test Year revenue required from rates for Island Interconnected is $546.2 million, including $461.7 million from NP after deficit and revenue credit allocation, and $36.1 million from the industrial class[88].

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;
- New Energy Supply Cost Deferral Account; 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.

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

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.

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[89], 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"[90].

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 a high degree of rate impacts, and (b) be obsolete by the time of the Labrador infeed.

6.2 NP RATE DESIGN

As part of the GRA filing, and similar to the 2013 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. The rate design however has changed markedly since the original 2013 proposal. Most notably, Hydro has

[89] Hydro 2013 GRA, Volume II, Exhibit 9.
[90] Page 4.7 of Hydro's 2013 GRA.

backed away from its relatively extreme proposal in the 2013 original GRA to increase NP's demand charge by 128%.

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

- Hydro is proposing a demand rate based on negotiation with NP and initial estimates of marginal costs per NP-NLH-118 Rev.1 (increasing from $4.00/kW/month to $5.50/kW/month as compared to $9.12/kW/month in the original 2013 proposal)[91] while this increase is far less than the 128% in the original GRA proposal, it remains at 36.5% which is substantial.

- A first block energy quantity remaining at 250 GW.h/month (compared to a proposed move to 280 GW.h/month[92] in the original 2013 GRA).

- A proposed first block rate designed to collect the NP revenue requirement once demand charges and second block rates are taken into account (increasing from 3.246 cents/kW.h to 3.411 cents/kW.h – as compared to a decrease to 2.786 cents/kW.h proposed in the original 2013 GRA.

- A proposed second block rate which is designed to recover the costs not recovered through demand and first block energy charges. This is a change from past practice, as follows:

    - The current second block rate is 8.805 cents/kW.h as set in the 2006 GRA. This rate is precisely equal to the incremental cost of fuel at Holyrood in that GRA.

    - Hydro proposes an increase to either 11.622 cents/kW.h (with oil at $93.92/bbl) or 9.446 cents/kW.h[93] (with fuel price at $65.63/bbl). In each case, this value is below the incremental cost of fuel at Holyrood (15.37 cents/kW.h at $93.92/bbl and 10.81 cents/kW.h at $65.63/bbl).

Hydro's current proposals are an improvement over the proposal in the 2013 GRA, which proposed the second block rate at only 58% of the incremental cost of Holyrood fuel[94]. However, they continue to reflect a material change in principle from the 2006 GRA. In the current proposals, the first block rate is designed based on a set of principles, while the second block rate is solely a derivative to secure the needed annual revenue – this is reverse to the 2007 principles which set the 2nd block rate as the priority item and let the 1st block rate be calculated as a derivative. The 2007 principles are preferable, as the 1st block rate does

[91] 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".

[92] 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".

[93] Hydro's January 28, 2015 Interim Rates Application, Rate Schedules page UT-4 shows the second block rate at 9.446 cents/kW.h with fuel price at $65.63/bbl. However, that is based on assumption that the first block rate would be 3.411 cents/kW.h or as the same as the first block rate calculated with $93.92/bbl fuel price. With lower fuel price the revenue required from energy will change which would impact the calculation of the first block rate. Please see Table 6-1 for details of calculations and assumptions.

[94] The original 2013 GRA proposed NP second block rate at 10.4 cents/kW.h which is about 58% of Holyrood average fuel price at 17.768 cents/kW.h in the original 2013 GRA filing.

not provide any price signal to NP, given that it is designed to never operate at the margin for consumption in any month.

A preferred approach today would remain rooted in the 2007 principles, namely that the second block rate is linked to the Holyrood incremental cost. This would mean discarding Hydro's proposal for a new set of principles for designing the first block rate, and reverting to this rate being a derivative.

A preferred rate design for 2015 is shown in the final column of Table 6-1 below. This involves retaining the 280 GW.h per month first block from the original 2013 GRA, and a somewhat reduced demand charge impact of $5.00/kW/month (rather than $5.50/kW/month as proposed by Hydro). The end result is a first block rate that remains a small increase compared to the 2007 rate (and similar to that proposed by Hydro for 2015). The calculations for each of the relevant rate designs is shown in Table 6-1 below, which provides the 2007 Test Year values, the 2013 proposal, the 2015 Test Year with $93.92/bbl fuel price and $65.63/bbl fuel price, as well as the revised proposal noted above (including a 622 kW.h/bbl Holyrood efficiency per Section 4.3 above).

Table 6-1: NP First and Second Block Rates: 2015 vs. 2007[95]

	2007 Test Year		2013 Test Year		2015 Test Year with $93.92/bbl fuel price	2015 Test Year with $65.63/bbl fuel price		2015 Test Year with $65.63/bbl fuel price [with 2007 GRA principle and higher first block consump.]	
Sales									
Total (MWh)	4,925,800		5,594,300		5,924,100	5,924,100		5,924,100	
First Block (MWh)	3,000,000	250 GW.h/month	3,360,000	280 GW.h/month	3,000,000	3,000,000	250 GW.h/month	3,360,000	280 GW.h/month
Second Block (MWh)	1,925,800	L1 - L2	2,234,300	L1 - L2	2,924,100	2,924,100	L1 - L2	2,564,100	L1 - L2
Demand:									
Demand Revenue Requirement			127,044,995						
Billing Units (kW)	13,026,840		13,929,036		15,122,049	15,122,049		15,122,049	
Rate ($/kW/mo.)	**4.00**		**9.12**		**5.50**	**5.50**		**5.00**	
Energy (First Block):									
Total Revenue Requirement	319,063,647		453,005,298		525,318,632	461,749,061		461,749,061	
Less: Demand Revenue	52,107,360	L5 x L6	127,032,808	L5 x L6	83,171,270	83,171,270	L5 x L6	75,610,245	L5 x L6
Revenue Requirement to be Recovered Through Energy Rates	266,956,287	L7 - L8	325,972,490	L7 - L8	442,147,362	378,577,792	L7 - L8	386,138,816	L7 - L8
Non-Fuel Energy Costs:									
Energy Revenue Requirement			267,676,715		305,414,747	241,845,176			
Less Allocated Holyrood Fuel Costs									
Total Holyrood Fuel Costs			200,692,615		245,426,358	172,757,525			
Newfoundland Power Trans. Energy Allocation Ratio			0.8673		0.8452	0.8452			
Allocated Holyrood Fuel Costs			174,067,395	L11 x L12	207,425,771	146,008,616	L11 x L12		
Non-Fuel Energy Costs:			$ 93,609,320	L10 - L13	97,988,976	95,836,560	L10 - L13		
Customer Costs					4,330,885	4,330,885			
First Block Energy Consumed (MWh)	3,000,000	L2	3,360,000	L2	3,000,000	3,000,000	L2	3,360,000	L2
Rate (Cents/kWh)	**3.246**	L19 / L15	**2.786**	(L14 + L15) / L16	**3.411**	**3.339**	(L14 + L15) / L16	**3.440**	L19 / L15
Energy (Second Block):									
Total Revenue Requirement	319,063,647	L7	453,005,298	L7	525,318,632	461,749,061	L7	461,749,061	L7
Less: Demand Revenue	52,107,360	L8	127,032,808	L8	83,171,270	83,171,270	L8	75,610,245	L8
Less: First Block Revenue	97,394,182	L18 - L19 - L21	93,609,600	L16 x L17	102,330,000	100,170,000	L16 x L17	115,589,165	L18 - L19 - L21
Second Block Energy Revenue	$169,562,105	L22 x L26	$232,362,890	L18 - L19 - L20	$339,817,362	$278,407,792	L18 - L19 - L20	$270,549,651	L22 x L26
Second Block Energy Consumed (MWh)	1,925,800	L3	2,234,300	L3	2,924,100	2,924,100	L3	2,564,100	L3
Rate (Cents/kWh)	**8.805**	L21 / L22	**10.400**	L21 / L22	**11.622**	**9.522**	L21 / L22	**10.551**	L21 / L22
Average No. 6 Fuel Cost per Barrel	$55.47		$108.74		$93.32	$65.63		$65.63	
Efficiency Factor (kWh per Barrel)	630		612		607	607		622	
Holyrood Generation Fuel Cost (Cents/kWh)	**8.805**	L24/L25 x 100	**17.768**	L24/L25 x 100	**15.374**	**10.812**	L24/L25 x 100	**10.551**	L24/L25 x 100

[95] Table is prepared based on Hydro's Schedule 1.4 of 2007 COS and 2015 COS. The total revenue requirement with lower fuel price for 2015 Test Year at $461.749 million is from Hydro's January 28, 2015 Interim Rate filing, Appendix B, Page 1 of 1. The energy revenue requirement in Line 10 with lower fuel price for 2015 Test Year is calculated based on Hydro's January 28, 2015 Interim Rate filing, Appendix B, Page 1 of 1 [$305,414,747 – ($525,340,174 - $461,749,061) = $241,845,176]. The fuel price of $65.63/bbl is from Hydro's January 28, 2015 Interim Rate filing. Hydro's January 28, 2015 Interim Rates Application, Rate Schedules page UT-4 shows the second block rate at 9.446 cents/kW.h with fuel price at $65.63/bbl. However, that is based on assumption that the first block rate would be 3.411 cents/kW.h or as the same as the first block rate calculated with $93.92/bbl fuel price. With lower fuel price the revenue required from energy will change which would impact the calculation of the first block rate. The Holyrood conversion rate of 622 KW.h/bbl as per Section 4.3 of this evidence.

This revised NP rate design for 2015, in light of oil prices at $65.63/bbl, shows a significant improvement over the proposals in the original 2013 GRA and the 2015 Amended Application, for a number of reasons:

1. The degree of increase in the demand charge has been substantially reduced. This is more consistent with normal regulatory objectives of rate and price signal stability particularly 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 some expense of revenue stability for NP. This is because most end-use customers on the NP system are charged rates that are primarily comprised of energy charges[96]. 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). With a more modest price escalation as is now proposed, these issues are largely addressed.

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, until the recent interim order regarding NP's curtailable program for the winter of 2014/15, 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 would have only been exacerbated by the original proposal to dramatically increased demand charge. While a $5.00/kW demand charge retains some incentives for NP to operate inefficiently with their customers, the potential for adverse outcomes is much smaller.

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 highly uncertain at the present time due to the Labrador infeed, there does not appear to be any benefits of breaking this linkage for cost allocation purposes. Under the original 2013 GRA proposed second block rate design, NP's second block rate was about 7.368 cents/kW.h lower than Holyrood fuel cost at 17.768 cents/kW.h[97] (compared to the 2007 rate which matches the Holyrood fuel cost). Hydro's updated proposals still suffered from a break in this linkage. The updated proposal largely addresses this issue.

In short, the NP rate proposal in the Amended GRA filing is a major improvement on the proposals in the original 2013 GRA, but the small revision proposed above aids in maintaining a strong principled linkage to the approach taken in 2007.

[96] Hydro's 2013 GRA, RFI NP-NLH-119.
[97] Please see Table 6-1.

6.3 RATE STABILIZATION PLAN PROPOSALS

Hydro's GRA provides a proposal to revise the RSP in a number of ways, largely consistent with the July 30, 2013 RSP Application.

One key change is to revise the allocation methods for the load variation provision[98].

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[99].

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 led to an inappropriate allocation of risk to customers[100] 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[101] 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 on a go-forward basis 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

[98] Hydro's 2013 RSP Application.
[99] Hydro's 2013 RSP Application, pages 2 and 3.
[100] IC Evidence of C.F Osler and P. Bowman, September 2, 2003.
[101] The July 30, 2013 RSP application notes that nearly $160 million in RSP balance was crystallized.

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).

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 NEW ENERGY SUPPLY COST DEFERRAL ACCOUNT

Hydro's Amended Application proposes to establish a new Energy Supply Cost Deferral Account for the Island Interconnected system[102] that is intended to protect Hydro from variations in the costs for all sources of energy other than Holyrood and Hydro's own hydraulic generation (which is already stabilized via the

[102] Hydro's 2013 Amended GRA, page 3.48.

RSP). The account would operate to permit Hydro to seek Board approval to recover (or refund) amounts that occur in a year beyond a limit of $500,000 at risk annually.

In the original GRA filing, these same provisions were proposed to occur within the RSP instead of in their own deferral account.

The proposal to address variations in purchased power and other thermal (gas turbine, diesel) 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 (e.g., hydrology). It is not apparent why Hydro did not retain the original proposal to include this within the RSP, which would be an appropriate mechanism covering the period until the initiation of the Labrador Infeed.

In regard to proposals to protect Hydro from price changes for Power Purchase Agreements' ("PPA") power (through the RSP or deferral account), 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)[103] and a second related to Exploits purchases, that has no formal escalator, but which had prices fixed only until June 30, 2014[104]. Per PUB-NLH-8 Rev.1, after this date the future for the Nalcor plants under PPAs is uncertain but no change is expected until 2016 (PUB-NLH-365).

The proposal to protect Hydro from simple price escalation on IPP purchases does not appear to follow underlying or deferral account principles (inflationary pressures occur in all aspects of Hydro's operation, and are not similarly stabilized or deferred). With respect to the non-Exploits purchases, it would not appear to be consistent with the intent of the RSP or deferral accounting 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 Rev.1 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 combined cost for a portion of assets added to Hydro's gross plant partway through a non-Test Year (including Rate Base assets, O&M costs, depreciation, etc.). More importantly, to the extent that the Exploits generation faces a material change in price, such change is not an uncontrollable external market force but rather a policy decision imposed by Hydro's own shareholder. A deferral account to protect the utility from decisions of its own shareholder would not be appropriate. 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 prices to the RSP or deferral accounts as it causes uncertainty and a high degree of exposure for ratepayers.

[103] For example, Hydro notes at page 3.49 of its 2013 Amended 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."

[104] Page 2.4 of Hydro's 2013 GRA; OC2013 -088 as provided in response to PUB-NLH-002, Attachment 1 Page 1 of 1.

6.5 CBPP GENERATION CONTRACT

Under the industrial contracts that existed at the time of the 2006 GRA, the same format was largely used for CBPP and for other customers who did not own their own generation. 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 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)[105].

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[106] 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 (by virtue of this same contract format) 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 at some loading levels (converts each unit of water into energy), 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 by CBPP to produce less energy than is necessary. By virtue of this inefficient operation, CBPP

[105] See CA-NLH-005 Attachment 1 in respect of Section 2.02, 3.02, 3.03.
[106] 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.

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. Finally, as less hydro power is being produced from CBPP's generation, Hydro became required to generate more kW.h with Holyrood, at a net cost to all ratepayers.

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, 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[107]. 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 net load served by Hydro 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 calculated.

The report on the impacts of the pilot contract revision (Exhibit 4 to the GRA, updated as part of the Amended GRA) notes that over the years from 2009 to 2015, the revision will have saved the island approximately 40,000 barrels of No. 6 oil[108]. 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 $364,000[109] over the entire period from June 2009 to 2015. 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] 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% added charge to recover variable charges is by definition

[107] Hydro's 2013 Amended GRA Exhibit 4.
[108] Hydro's 2013 Amended GRA Exhibit 4 pages 7 and 8.
[109] Hydro's 2013 Amended GRA Exhibit 4 page 3. From a loss of the ten percent administration fee on non-firm purchases.
[110] Hydro's 2013 GRA, Rate Schedules, Industrial Non-firm, page 7 of 47.

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 service 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.

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 Amended GRA, this is proposed to increase to $0.891 million per year[111].

In this proceeding there are five 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. Under the present proposal, the costs for the Frequency Converter now make up over 21% of CBPP's bill from Hydro.

2) Despite rapidly escalating capital costs, recent capital improvements have not provided any benefit of operational or maintenance efficiencies.

3) 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 short-term capability.

4) The unit's costs remain 100% allocated to CBPP. This was an approach adopted when costs of the unit, and the specifically assigned costs of the unit as a share of the overall cost of CBPP power purchases, were by several orders of magnitude lower and more in-line with the Hydro industrial customer norm.

5) 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 Cost of Service credit for the capacity resources they can provide to the grid.

Hydro's arguments in respect of the direct allocation of the unit to CBPP and the assertion, effectively, of a complete absence of relevance or value of the unit to other ratepayers is akin to arguing its only purpose is to permit CBPP generation to reach CBPP load. In this manner, Hydro is effectively arguing the unit is divorced from the grid, and unrelated to any aspect of Hydro's delivery of power to CBPP. In this manner, the unit is not like the other "Specifically Assigned" assets in the COS, which are components of the grid (transmission, transformation) which are required for Hydro to get its power to the customer. Such an assertion serves to question whether the asset is even properly considered a component of the utility's rate base at all, as this term is commonly understood, or whether Hydro's service is more akin to a contract non-utility service.

In short, the very nature of the service being provided by Hydro to CBPP, under the factual picture Hydro attempts to portray, is suspect. The current situation for CBPP is the worst of both worlds – they are

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

effectively required to pay all costs that Hydro elects to incur with respect to the Frequency Converter without limit (a blank cheque), but receives effectively very little or no input to these capital and O&M costs or COS allocations (unlike, say, under a bipartite contract for any other service that CBPP purchases, where they would typically have many associated protections).

This section consists of the following:

- Background;
- Status Since the Last GRA;
- Role of the Frequency Converter;
- Proposed 2015 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 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 the frequency 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.

[112] Please see Appendix C.

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 2015 Test Year proposed level of $891,045 per year, or over 21% of what CBPP pays for power purchases from Hydro, over a 50-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. The latest information is that a new condition assessment is being performed[114], but that the report has not yet been drafted.

Hydro's 2011 Capital Budget[115] 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)[116]. 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." Hydro has since clarified that the unit is only 25 MVA, not 28 MVA as claimed by Acres[117].

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

- **Spending:** Since 2006, based on Acres assessment as well as Hydro's own assessment[118], Hydro indicates it has spent approximately $4.2 million[119] on the frequency converter. Although the current method of allocating these costs is 100% to CBPP, Hydro notes at IC-NLH-100 that it does

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[113] IC-NLH-41 Rev.2 from the 2001 GRA.
[114] IC-NLH-194.
[115] Volume I, page C-151.
[116] 2007 Capital Budget, RFI PUB-NLH-44, http://www.pub.nf.ca/hydro2007cap/files/rfi/PUB-44.pdf.
[117] IC-NLH-162.
[118] 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.
[119] Based on projects included in Hydro's Capital Budget Applications.

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 25 MVA. In other recent documents, Hydro indicates the currently usable capacity of the Frequency Converter is 20 MW[120]. 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"[121]. The use of the 18 MW cap[122] also appears inconsistent with all assessments and evidence to date, including the 2013 Capital Budget Application which noted that Hydro "…completed an Engineering Condition Assessment study in 2005 and to this date (2010) most of the recommendations have been completed"[123] which one may reasonably expect to mean that the units were restored to proper working order. Instead, IC-NLH-194 notes a new condition assessment is being completed and results are due for May 2015 (understood to not yet be available).

Of particular note is the most recent capital project on the Frequency Converter to incorporate a remote vibration monitoring system. In respect of this project, it was 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"[124].

This capital project was intended to reduce "labour intensive" checks in respect of this vibration issue. As such, the project is of operational benefit to the system as a whole (and all Hydro's customers), by releasing Hydro "labour" for other tasks. In addition, the reduction of labour intensive activity should appear as a reduction in the specifically assigned O&M to CBPP. Moreover, consistent with normal regulatory practice, CBPP should not bear the cost burden of previous work that caused or failed to resolve the vibration problem.

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[120] 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.
[121] CA-NLH-005 Attachment 1 page 3.
[122] This cap is cited at times as 18 MW, and at times as 19 MVA, such as in IC-NLH-162.
[123] NLH 2013 Capital Budget Application, page D-180.
[124] NLH 2013 Capital Budget Application, page D-164 to D-165.

In more recent RFIs, Hydro has altered its portrayal of the project, noting that the original work that caused the vibration issue was "…rectified in accordance with Hydro's specifications by the contractors before completing the contract…"[125] and that Hydro does not consider this work to have been of substandard quality[126]. Although this Hydro specification was apparently met, Hydro then engaged a separate contractor to investigate and rectify vibration issues in 2010 with the apparent result that the unit was operating "…within an acceptable vibration zone"[127].

7.3 ROLE OF THE FREQUENCY CONVERTER

The CBPP operation includes generation resources that are described in Hydro's filed materials[128]. Specifically, CBPP reports that their generation consists of 81 MW of 60 Hz hydro generation and 56 MW of 50 Hz hydro generation (Hydro reports this total as 135 MW in IC-NLH-186). In 2015 this generation is allocated on a forecast basis as shown in Table 7-1.

Table 7-1: Simplified CBPP 2015 Load Forecast and Hydraulic Generation Allocation (MW)

	60 Hz	50 Hz
Load Forecast in Mill	108	12
Available from CBPP Hydraulic at full gate/full flow	81	56
Surplus/Shortfall	-27	44
Frequency Converted	18	-18
Net Surplus/Shortfall	-9	26
Power On Order from NLH	*9*	
Unused, or Used for Steam Boiler Elements		*26*

For 2013, the CBPP mill projected the need for 108 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 27 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 and must be used for lower value purposes. These units will either (a) be shut off to maximize water available for 60 Hz generation (which is not always possible), (b) be dispatched to produce 50 Hz power

125 IC-NLH-189.
126 IC-NLH-190.
127 IC-NLH-189.
128 Hydro's Review of Supply Disruptions and Rotating Outages Report, Volume II, Schedule 11, page 12 "Coordination and Communication with Customers". March 24, 2014.

for a boiler (generally a lower value use of power), or (c) lead to hydraulic 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. If this mode of operation (22.5 MW) was available at all times, the CBPP Power on Order calculation above could be revised. In addition, if this level of output was available only at a very limited number of acute peak hours on the system, the CBPP coincident peak load for COS purposes could be reduced by 4.5 MW (in order similar to Hydro's proposal with respect to crediting NP for their available, but rarely dispatched, thermal generation).

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. While this power may not have been of particular value on the Island when Hydro's system similarly has surplus water, in the coming years with load growth (or with interconnection that permit power trading) this power will take on a significant value.

7.4 PROPOSED 2015 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 $0.891 million/year at proposed 2015 rates.

Table 7-2 below provides a breakdown of the specifically assigned charges as proposed in 2015 COS compared to 2007 COS.

Table 7-2: Comparison of CBPP Specifically Assigned Charges: 2015 COS vs 2007 COS ($)[129]

CBPP Specifically Assigned Charges Breakdown	2007 COS (Existing until Aug. 31, 2013)	2015 COS	Increase
Operating and Maintenance Expense	140,472	328,703	188,231
Depreciation	59,112	185,081	125,969
Return on Debt	134,076	265,294	131,218
Return on Equity	12,130	100,973	88,843
Gains/Losses on Disposal of Fixed Assets	(included in Other)	12,134	12,134
Other (includes credits and revenue related costs)	1,377	-1,140	-2,517
Total	**$347,167**	**$891,045**	**$543,878**

[129] Prepared based on Schedule 3.3A of 2007 COS (provided by Hydro in response to IC-NLH-002, 2013 GRA) and 2015 COS.

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 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, IC-NLH-145, and IC-NLH-145 Rev.1 which show no change in the 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 2015 forecast maintenance material and supplies for this business unit which shows a decrease from 2007 actuals to 2015 forecast in real dollar terms. 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 134% as suggested in the filing.

Cost of Service style allocation methods are intended to provide a means to simplify cost tracking of expenses, but still provide a result that is representative 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[130]. At minimum, the CBPP specifically assigned charge should be reduced by $188,231/year.

7.5 CONCLUSIONS

The proposed allocation of the Frequency Converter is not fair nor reasonable. Options to realign the responsibility for the entire frequency converter cost, operation and potentially ownership should be thoroughly considered. As an example, it may be most appropriate for the converter to cease being a rate base asset, and become part of a simple contractual service provided to CBPP by Hydro, over which CBPP would be given a high degree of control and input in management and capital spending decisions. Alternatively, the two parties may find the best outcome is for CBPP to take over ownership of the asset.

For the current GRA, as a result of the above noted factors regarding the Frequency Converter, a series of adjustments should be undertaken:

1. **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 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

[130] 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.

PUB; however, there does not appear to be any references in the respective Capital Budget 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 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. This change would reduce the Frequency Converter charge by approximately $358,000/year.

2. **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. This would reduce the Frequency Converter cost by $188,000/year.

3. **Not Specifically Assign:** For the remaining $347,000/year, the amounts should not be specifically assigned to CBPP. 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% of rates paid by CBPP). The financial impact today is materially different (21% of rates paid by 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).

    a. The impact of this allocation would be to reduce the specifically assigned cost to CBPP compared to what Hydro has proposed, and an increase to energy rates to all Island Interconnected customers compared to the GRA proposal of less than 0.07% (less than 5 one-thousands of a cent/kW.h).

    b. This proposal is also consistent with the arguments set out in Appendix C, as previously submitted by the IIC Group in 2001.

    c. As a comparison of the value provided, the frequency converter even in its currently derated state permits 158 GW.h of annual energy to be delivered to the 60 Hz grid that would otherwise be captive on the 50 Hz side. As 60 Hz power, it serves to reduce the net load on Hydro's system, and save Holyrood generation. This power is over 5 times that provided by all CDM activities to date, and the net cost to ratepayers would be one-third of that for CDM ($0.35 million/year for the Frequency Converter power of 158 GW.h, compared to $1 million/year for the CDM amortization, for 32 GW.h).

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 receive grid service at peak times higher than otherwise could be required. The limited converter 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 6 MW to insulate the industrial class from the negative effects due to the underperformance of the Frequency Converter compared to nameplate ratings (19 MVA permitted versus 25 MVA nameplate).

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[131].

Hydro notes that pursuant to Board Orders No. 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. Based on Table 3.9 in the original GRA, the December 31, 2013 ending balance of CDM costs would be $4.8 million after $0.2 million amortization forecast in 2013[132]. For 2015, the Amended GRA shows a December 2015 closing balance of $7.0 million[133].

Hydro's 2013 GRA application seeks approval of amortizing and recovering in rates CDM costs over a rolling seven year period[134]. The Amended GRA adjusts the amortization approach to propose a discrete 7 year amortization period rather than the rolling 7 year period[135].

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[136]. 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, Hydro 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 and IC-NLH-083 Rev.1).

- 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

[131] Hydro's 2013 GRA, Volume I, page 4.22.
[132] 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.
[133] Hydro's 2013 Amended GRA, Volume I, Table 3.10 on page 3.21.
[134] Hydro's 2013 GRA, Volume I, Rate Schedules, pages 20-21 of 47.
[135] Hydro's 2013 Amended GRA, Volume I, page 1.12R.
[136] Hydro's 2013 GRA, IC-NLH-48.

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).

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[137].

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 2015 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), would save 4.114 cents/kW.h in reduced monthly bills[138], and the RSP would be credited with 6.70 cents/kW.h (10.81 cents/kW.h[139] Holyrood savings less 4.114 cents/kW.h in reduced revenue). Per the proposed new RSP rules, this 6.70 cents would be allocated to all customers, with 8.9% going to the industrial RSP[140], or 0.59 cents. For simplicity, assume the industrial customer in question is 25% of the industrial load – their allocation of this RSP amount is 0.15 cents/kW.h and their resulting net benefit from the CDM measure would be 4.264 cents/kW.h for each year until the next GRA [4.114 cents/kW.h plus 0.15 cents/kW.h]. The remainder of the system-wide cost savings, a full 6.546 cents/kW.h[141] (61% of the savings), would accrue to NP, rural customers and (to a much smaller degree) other industrial 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 4-5 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 9.446 cents/kW.h[142]. The RSP would be credited with 1.364 cents/kW.h, of which NP and rural would be allocated approximately 1.24 cents/kW.h. The net savings to NP from their 1 kW.h CDM savings would be 10.69 cents/kW.h. Only 0.12 cents/kW.h (1.1% of the savings) would accrue to the industrial customers.

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[137] 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.

[138] The energy rate for IC from Hydro's January 28, 2015 Interim Rates application.

[139] \$65.63/bbl as per Hydro's Interim Rates application and 607 kW.h/bbl Holyrood conversion factor as proposed by Hydro in 2013 Amended GRA.

[140] Assuming the 2015 Test Year loads used for allocation (energy allocation factor from 2015 COS, Schedule 3.1A).

[141] The difference between 10.81 cents/kW.h and 4.264 cents/kW.h.

[142] The second block energy rate for NP from Hydro's January 28, 2015 Interim Rates application.

- 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.

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"[143]. 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"[144] 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 COS 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.

[143] 2013 Amended GRA Exhibit 12 page A2.
[144] 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 including General Rate Applications and most recently the Needs For and Alternatives To (NFAT) review. 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.

APPENDIX B:

HAMID NAJMIDINOV'S QUALIFICATIONS

InterGroup® CONSULTANTS

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,** provided support for the socio-economic impact assessment; KCN communities Population Projection Model support and updates; project employment estimates analysis; Northern Aboriginal employment estimates, including modeling based on employment demand and supply analysis and updates; project construction employment income analysis.

- **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), development of a Cost of Service model and report.

- **For Industrial Customers of Newfoundland and Labrador Hydro** (2014-current), support in analysis for Newfoundland Hydro's 2013 GRA, including review of revenue requirement, cost of service, RSP, interim rate applications and other proposals, prepare requests for information and pre-filed evidence.
- **For Viability Analysis of a South-East Alaska and Yukon Economic Development Corridor** (2014-current), performing financial and quantitative data analysis and modeling assessments as required to assess the viability of the Skagway-Whitehorse economic development corridor options under relevant load and resource project scenarios.

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.

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 and organized property sales auctions for potential investors.

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 on state property management efficiency.

APPENDIX C:

FREQUENCY CONVERTERS BACKGROUND FROM THE 2001 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[144], the parties acknowledged in Article 9.01 that Hydro would continue to provide the converter at Hydro's

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

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[145]. 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.

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

APPENDIX D:

IIC GROUP SUBMISSION ON HYDRO’S APPLICATION FOR THE APPROVAL RATES CHARGED TO NEWFOUNDLAND POWER

IN THE MATTER OF the *Electrical Power Control Act*, 1994, R.S.N.L. 1994, Chapter E-5.1 (the "EPCA") and the *Public Utilities Act*, R.S.N.L. 1990, Chapter P-47 (the "Act") and regulations thereunder;

AND IN THE MATTER OF an Application by Newfoundland and Labrador Hydro, for the approval, pursuant to Sections 70(1) and 71 of the Act, and the rate to be charged to Newfoundland Power.

To: The Board of Commissioners of Public Utilities

INTERVENORS' SUBMISSION OF THE ISLAND INDUSTRIAL CUSTOMERS GROUP

The Island Industrial Customers of Newfoundland and Labrador Hydro ("IIC") submit that the relief requested by Newfoundland and Labrador Hydro ("Hydro") should not be granted. In the alternative, the Board of Commissioners of Public Utilities ("Board") should direct the following:

1) The rate schedule for wholesale service to NP should be adjusted to ensure that Curtailable Service Option curtailments do not lead to a reduction in the amounts NP would pay in demand charges[1].
2) The Curtailable Service Option of Newfoundland Power ("NP") should be revised to prohibit curtailments where there is no bona fide system constraint on either the generation and transmission system (as directed by Hydro) or the distribution system (as directed by NP) that threatens delivery of power to firm service customers.

The IIC submit that the issues at hand with respect to curtailable load are substantive and relate to the full scope of role, use, value and equitable access to curtailable service programs for all customer classes. While the ideal disposition of Hydro's Application would have been to have all issues subjected to a full review in a Hydro GRA (long-delayed and now of indefinite status), the IIC agree that NP's current use of

[1] Specifically, the definition of "Native Load" in the "Utility" rate schedule should be adjusted to add a part (c) which adds in to the calculation the sum of loads curtailed (averaged over the same 15 minutes that the power delivered and generation are measured)

the Curtailable Service Option must be addressed prior to the upcoming winter to ensure the capacity resource represented by curtailable load is available for its proper and intended use in helping address system emergencies. This submission focuses on that limited and temporary issue.

The IIC note that the previous 2013 GRA did draw competing submissions on how to best deal with NP curtailable load from the range of expert reports that were filed (but not tested).

Background

Newfoundland Power ("NP") offers its commercial customers a program that allows the utility to curtail their load for short periods (the "Curtailable Service Option") in exchange for a bill credit to these NP customers of $29/kVA[2] per year (approximately $25/kW[3]). The program is limited to 6 hours duration for each individual curtailment event, and no more than 100 hours per year total curtailment. If the customer does not curtail as contracted, there is a penalty whereby a percentage of the annual credit the customer would receive is foregone.

This program is presently used in 2 ways.

- **Reliability Enhancing Interruptions:** First, NP will curtail the customer loads when there is a bona fide system constraint (generation or transmission/distribution) so as to help maintain firm service deliveries to other customers. These curtailments typically occur in response to a request to NP from Hydro as the main provider of generation and transmission, although NP initiated events to help address distribution system emergencies are also possible.
- **Bill Avoidance Interruptions:** Second, NP will curtail the loads at times when the NP system peak is approaching the level anticipated to be the highest point for the year, in order to lower the NP peak demand for billing purposes. These interruptions play no role in economic or efficient system dispatch, and lead to no bona fide cost savings on the overall system. The curtailments only serve to reduce the bill that NP will pay for its wholesale power, in effect lowering Hydro's

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[2] Attachment A to PUB-NP-093 from the Supply Issues proceeding
[3] 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)".

245256 v2

revenues despite no offsetting savings of any system costs. The savings to NP from a lowered peak demand affect the bills issued for effectively the entire year, at $4/kW, or $48/kW each year.

The present application is driven by a concern over the use of the second type of interruption noted above, the Bill Avoidance Interruptions. Use of the curtailable provision for these types of interruptions can undermine the availability of this resource for the critical Reliability Enhancing Interruptions in 2 ways. First, there is a maximum annual limit on hours of interruption (100 hours). If this maximum annual limit of 100 hours has been expended on bill avoidance, the capacity resource will not be available for reliability needs. Second, customers who sign on to the program are inconvenienced by interruptions. Excessive use of interruptions, particularly for bill avoidance purposes, can make the program less appealing to customers who will either choose not to curtail (and forego the modest penalty), or will cancel their enrollment in the program entirely.

Hydro's application seeks the approval of the Board to alter the calculation of "billing demand" in the rate schedule for sales to Newfoundland Power ("NP"). Specifically, Hydro seeks to amend the calculation of peak demand so as to lower the charges to NP as if NP had interrupted its customers at the peak hour (without any need to actually trigger this interruption). Hydro's assertion is that with such adjustment, the full financial net benefits of the Bill Avoidance Interruptions will already be provided to NP, so there will be no incentives for actually initiating such interruptions, and as a result, Hydro expects greater availability of the program for the Reliability Enhancing Interruption purposes.

IIC Submission

It is the position of the IICs that the NP Curtailable Service Option, properly configured, can provide a modest yet beneficial capacity resource to the system. Although only 8-10 MW[4], this resource can be triggered at times of system constraints. This capacity resource is presently included in Hydro's generation dispatch stacking order as Step #10, after all generation resources have been maximized (Steps #1-#6), all non-firm power deliveries have been curtailed (Step #7), and initial voltage reduction

[4] Hydro Application, item 6.

245256 v2

shave been initiated (Steps #8-#9) but one step before industrial customers begin to be forced to shed firm load (Step #12) or subsequently, non-industrial customers are forced to shed firm load (step #13)[5].

The IIC agree that the capacity resource provided by the NP Curtailable Service Option is only of value if it is available for the Reliability Enhancing Interruption purpose, and acknowledge that use of curtailments for Bill Avoidance purposes could in theory undermine this availability.

The question of substance, however, is how to best achieve the objective of maximizing availability of the Curtailable Service Option for its proper and intended purposes – aiding system reliability.

The IIC submit that guidance on the matter at hand is provided in the EPCA, 1994, notably sections 3(b)(i) and 3(b)(iii):

> *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,*
>
> ...
>
> *(iii) that would result in power being delivered to consumers in the province at the lowest possible cost consistent with reliable service,*

The principal intent of EPCA, 1994 section 3 (b) (i) and (iii) is that the system must be managed and viewed on a consolidated basis, with an aim to minimizing overall consolidated costs, ensuring efficiency in overall consolidated system operation, and in maximizing reliability and availability of power.

These aims can be assessed in light of each of the current uses of the NP Curtailable Service Option:

- **Reliability Enhancing Interruptions:** The use of the program for reliability driven interruptions is entirely consistent with the provisions of EPCA, 1994 section 3. In particular, dropping loads where customers have elected to receive a lower priority of service (and are appropriately compensated), increases the efficiency of the system dispatch, increases reliability for firm power

[5] Per IC-NLH-1 Attachment 1, page 4-5. Note that step 11 is understood to be not presently valid, as the temporary measure is noted to have expired.

245256 v2

customers, and reduces the overall costs of delivering reliable power to the province. The cost reduction arises as other more expensive options for providing the equivalent capacity can be avoided.

- **Bill Avoidance Interruptions:** In contrast to reliability enhancing interruptions, interruptions that are initiated by NP to reduce its own wholesale power bill are not consistent with the underlying principles of the EPCA, 1994 section 3. In particular, there is no net cost reduction associated with these interruptions, even though the reliability of service has been reduced (due to these curtailable customers being interrupted, and being unavailable to aid in later emergency conditions) contrary to the principles underlying EPCA, 1994 subsection 3(b)(iii). In addition, the customers forego the opportunity to use power that is readily available for their purposes and for which they would pay the going energy rate, contrary to the principles underlying EPCA, 1994 subsection 3(b)(i) (economic efficiency includes the principle that all justifiable uses of power for which the customer is willing to pay the going rate should be made available). The net effect of these interruptions is described by Hydro as NP seeking to "minimize the cost of serving its customers"[6], but in these cases where there is no underlying cost saving to the system, such actions are not cost minimization, they are simply cost transference to other classes – an economic concept that has been described as "beggar thy neighbour".

In short, the consolidated operation of the Island Interconnected system is harmed when NP initiates Bill Avoidance Interruptions – costs do not decrease, revenues required to pay for the system are decreased, customers are unable to use power they would like to use, and there is a net reduction in reliability for all customer classes. Under these circumstances, the Bill Avoidance Interruptions have nothing to do with minimizing cost. Bill Avoidance Interruptions instead distort a program intended to aid during emergencies, and resulting in an increase in NP profits during non-emergency situations.

The IIC further note that not only does this distortion of the NP curtailable load program to reduce NP power bills without any underlying savings in consolidated system costs, but in additional the NP

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[6] IC-NLH-3

245256 v2

curtailable load program is used to justify reducing cost allocation to NP via the Cost of Service study, per V-NLH-1. This further underlines the concerns about inappropriate cost transference to other classes from NP's distortion of the Curtailable Service Option.

Finally, the IIC note that the effective credit proposed by Hydro crystallizes a net benefit to NP of \$48/kW/year of curtailable load[7]. As NP's cost of this curtailable load is only \$25/kW/year, these incentives for maximizing profit to NP at the expense of Hydro's revenues (and other customers who ultimately have to cover these lost revenues) are excessive.

IIC Conclusion

The submission of the IIC is that the economic incentive for NP to distort the Curtailable Service Option must be corrected, in order to preserve the maximum benefit of this program to its intended use for system reliability. The appropriate means to achieve this is not as proposed by Hydro in this Application. The approach proposed by Hydro would, in effect, serve to crystallize and guarantee a benefit to NP as if NP was reducing its peak Native Load through use of its curtailable load, This in effect would reward NP for the elimination of Bill Avoidance Interruptions, a practice which was not appropriate or efficient in the first place, and for which NP need not be compensated if the practice is eliminated. Instead, an appropriate solution at the present time could take one of two forms: (a) prohibit the ability for NP to profit from inefficient (and in the IIC's view inappropriate) use of the Curtailable Load Option, and/or (b) prohibit the inefficient and inappropriate NP use of the Curtailable Load Option in the first place. It is the submission of the IIC that the PUB should pursue both measures, as follows:

1) The rate schedule for wholesale service to NP should be adjusted to ensure that any curtailment under the Curtailable Service Option does not lead to a reduction in the amounts NP would pay in demand charges. Specifically, the definition of "Native Load" in the "Utility" rate schedule should be adjusted to add a part (c) which adds in to the calculation the sum of loads curtailed (averaged over the same 15 minutes that the power delivered and generation are measured).
    a. This would serve to ensure that despite any Bill Avoidance curtailments that are initiated by NP, there would be no bill benefits provided.

[7] \$4/kW/month, applied over the entire year.

245256 v2

b. As to incentive, this approach would eliminate the incentive for NP to inefficiently and inappropriately use the program, and retain full availability of the limited curtailments for bona fide system requirements.

2) The Curtailable Service Option of Newfoundland Power ("NP") should be revised to prohibit curtailments where there is no bona fide system constraint on either the generation and transmission system (as directed by Hydro) or the distribution system (as directed by NP) that threatens delivery of power to firm service customers.

   a. This provision would require an adjustment to the NP Curtailable Service Option rate schedule.

   b. The proposed revision would serve to protect NP's Curtailable Service customers from excessive interruptions, yielding the same benefits to curtailment availability for true system emergencies.

In theory, either of the above two approaches could address the imminent issue, but it is recommended that both be considered to ensure the implementation is successful.

The IIC recognize that issues over appropriately balancing the allocation of the $29/kVA/year cost of the NP program must be considered in due course. One such option was highlighted in the question posed in CA-NLH-4 in the present Application (have Hydro directly pay for a portion of the credit to the NP Curtailable customers, and reflect this as a power purchase in the COS study). This option could have merit, but other options also exist. Such issues are appropriately addressed in Hydro's pending GRA and are not directly relevant to the issue at hand – ensuring the NP Curtailable Service Option load is available for its intended reliability enhancement purpose in the upcoming winter.

The IIC also note that it is a reasonable expectation that Hydro will offer curtailable service options of a similar or equivalent nature to its industrial customers.

245256 v2

DATED at St. John's, Newfoundland and Labrador, this 27th day of October, 2014.

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245256 v2

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245256 v2