newfoundland labrador
hydro
a nalcor energy company

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January 22, 2016

The Board of Commissioners of Public Utilities
Prince Charles Building
120 Torbay Road, P.O. Box 21040
St. John's, NL A1A 5B2

Attention: Ms. Cheryl Blundon
Director Corporate Services & Board Secretary

Dear Ms. Blundon:

Re: Newfoundland and Labrador Hydro – 2013 General Rate Application
Final Submission – Revision 1

Enclosed please find the original plus 12 copies of the revised page 46 of Newfoundland and Labrador Hydro's final submission in relation to the above-noted matter as there was a typographical error in relation to one of the numbers used.

Should you have any questions, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

Tracey Pennell

Tracey L. Pennell
Legal Counsel

TLP/bs

cc: Gerard Hayes – Newfoundland Power
Paul Coxworthy - Stewart McKelvey Stirling Scales
Thomas J. O'Reilly, Q.C. - Cox & Palmer
Dennis Browne, Q.C. – Browne Fitzgerald Morgan & Avis
Thomas Johnson, Q.C. - Consumer Advocate
Yvonne Jones, MP Labrador
Senwung Luk – Olthuis, Kleer, Townshend LLP
Genevieve M. Dawson – Benson Buffett

IN THE MATTER OF the *Electrical Power Control Act,* 1994, SNL 1994, Chapter E-5.3 (the "*EPCA*") and the *Public Utilities Act*, RSNL, 1990, Chapter P-47 (the "*Act*"), as amended, and Regulations thereunder; and

IN THE MATTER OF a general rate application filed by Newfoundland and Labrador Hydro on July 30, 2013; and

IN THE MATTER OF an amended general rate Application filed by Newfoundland and Labrador Hydro on November 10, 2014; and

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Newfoundland and Labrador Hydro

2013 General Rate Application
Closing Submissions

December 23, 2015

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Table of Contents

A. DEFINED TERMS

The following terms appear in either the GRA Submission or the Prudence Review Submission and are as defined below.

Term	Definition
Act	*Public Utilities Act,* SNL 1990, Chapter P-47 (as amended)
Admin Fee	Administration Fee
Amended Application	Hydro's Amended Application, filed on November 10, 2014
ATCO	*ATCO Gas and Pipelines Ltd. v. Alberta (Utilities Commission)*, 2015 SCC 45
bbl	Barrel
BCUC	British Columbia Utilities Commission
Board	Public Utilities Board (NL)
BTU	British Thermal Unit
CBPP	Corner Brook Pulp and Paper
CDM	Conservation and Demand Management
CF(L) Co	Churchill Falls (Labrador) Corporation Limited
CIAC	Contribution in Aid of Construction
COS	Cost of Service
Cost Deferral Application	*Cost Deferral Application*, filed by Hydro on July 10, 2015 (as subsequently amended)
CPP	Canada Pension Plan
CT	Combustion Turbine
CT Application	*Application, Supply & Install of 100MW Combustion Turbine Generator*, filed by Hydro on April 10, 2014

Term	**Definition**
Deloitte	Deloitte Canada
EFB	Employee Future Benefits
EI	Employment Insurance
EPC	Engineering, Procurement and Construction
EPCA	*Electrical Power Control Act, 1994*, SNL 1994, Chapter E-5.1 (as amended)
Exploits	Exploits Generation
FTE	Full Time Equivalent
GHG	Greenhouse Gas
Government	Government of Newfoundland and Labrador
GRA	*General Rate Application*, filed by Hydro on July 30, 2013 (as subsequently amended)
GWh	Gigawatt hours
HTGS	Holyrood Thermal Generating Station
Hydro	Newfoundland and Labrador Hydro
Hydro Reply Evidence	Hydro's Reply Evidence on the Prudence Review, filed by Hydro on August 7, 2015
Ibid.	Provides a footnote reference that was cited in the preceding footnote
IIC	Island Industrial Customer
IIS	Island Interconnected System
IS	Information Systems
ITC Guidelines	Intercompany Transaction Costing Guidelines
KPI	Key Performance Indicators

Term	**Definition**
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt Hour
La Capra	La Capra and Associates Inc. (currently Daymark Energy Advisors)
Labrador Towns	Labrador Towns, consisting of Labrador City, Wabush, Happy Valley-Goose Bay and North West River
Liberty	Liberty Consulting Inc.
Liberty Final Report	Liberty's Final Report in the Prudence Review, filed by Liberty on July 7, 2015
Liberty Reply Evidence	Liberty's Reply Evidence in the Prudence Review, filed by Liberty on September 17, 2015
LIS	Labrador Interconnected System
LOLH	Loss of Load Hours
MWh	Megawatt Hours
Nalcor	Nalcor Energy Inc.
NARL	North Atlantic Refinery Limited
NP	Newfoundland Power
NSP	Nova Scotia Power Inc.
O&M	Operating and Maintenance
OEB	*Ontario (Energy Board) v. Ontario Power Generation Inc.*, 2015 SCC 44
OEM	Original Equipment Manufacturer
Outage Inquiry	*Investigation and Hearing into Supply Issues and Power Outages on the Island Interconnected System*

Term	**Definition**
Parties	Hydro and GRA intervenors
PM	Preventative Maintenance
Prudence Review	*Newfoundland Labrador Hydro Prudence Review*
PSPP	Public Service Pension Plan
RFI	Request for Information
ROE	Return on Equity
RSP	Rate Stabilization Plan
RTV	Room Temperature Vulcanization
SEM	System Equipment Maintenance
Settlement Agreement	Settlement Agreement among the Parties, filed with the Board on August 14, 2015
Supplemental Settlement Agreement	Supplemental Settlement Agreement among the Parties, filed with the Board on September 28, 2015
Teck	Teck Resources Limited
TwinCo	Twin Falls Power Corporation Limited
UARB	Utility and Review Board
Vale	Vale Newfoundland and Labrador
WACC	Weighted Average Cost of Capital

B. BACKGROUND

Hydro's last GRA was filed on August 6, 2006, resulting in a final Order issued on April 12, 2007.[1] Since then much has changed and much has been accomplished. In particular, Nalcor was incorporated, Hydro became Nalcor's subsidiary and a number of additional Nalcor subsidiaries have since been incorporated. In addition, the Muskrat Falls hydroelectric project, including the Labrador-Island Link and Maritime Link, has since been sanctioned and construction of these projects is well underway.

Corporate restructuring did not change the fundamental nature of Hydro's business, nor did restructuring change Hydro's mandate to generate, transmit and distribute safe and reliable power and energy to its customers at least cost. Instead, restructuring provided new opportunities for Hydro to benefit its customers by sharing services with its affiliates. To take advantage of these opportunities, Hydro adopted a matrix organizational model, resulting in both savings and efficiencies in the way Hydro operates its business.

As noted by Mr. Young, counsel for Hydro, in his opening remarks:

> *Hydro's duty as an electrical utility is to provide safe and reliable service to its customers at reasonable cost. The purpose of this General Rate Application is to provide Hydro with electricity rates that will provide the necessary revenue to carry out that duty. Those rates must provide Hydro with sufficient revenues to ensure its reasonable expenses can be paid and must provide Hydro with sufficient margin so that Hydro can access debt in the marketplace on reasonable terms.*[2]

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[1] Order No. P.U. 8(2007).

[2] September 9, 2015 Transcript, pages 12-13.

Despite various challenges faced by Hydro in responding to the system interruptions in January 2013 and 2014, Hydro has accomplished much since the last GRA. This was highlighted by Mr. Martin, CEO in his direct evidence:

> *New generation would be required with supporting infrastructure. So throughout the decision process, a decision was made to address this need through the combustion turbine that was recently pushed into service and the Muskrat Falls Labrador Island Link Project. These projects were sanctioned, and as I mentioned, they're either in service with respect to the new combustion turbine or they're under construction as we speak with Muskrat Falls and the Labrador Island Link.*
>
> *We have accomplished these efforts and initiatives which are required in the context of safety performance significantly improving over that same period of time. Last year for the first time in Newfoundland and Labrador Hydro's history, there was zero lost time incidents. From an environmental performance perspective, Holyrood emissions have been significantly reduced in respect to the sulphur dioxide NOx and particulate. GHG is still the same issue it was in the past, needs to be dealt with. Now in addition to that with respect to our ISO 14001 certification, we've increased our record of meeting our annual targets from an average of 75 percent to now we are sustained meeting those targets in between a 98 to 100 percent level each year.*
>
> *The key reliability indicators for direct customer service have stabilized. We are focused there on measures maintaining the ability to supply the customer. I offer, for example, some of the key performance measures that we are tracking. With respect to the bulk transmissions system, we're looking at the 230 kV system in two parts. Part A, the transformer and circuit breaker performance, we are outperforming the Canadian average, and on the 230 kV transmission system,*

> *we're generally aligned with the CEA averages, more volatility, but over time aligned.*[3]

As has been discussed in the hearing, Hydro has experienced growth in operating expenses since 2007. Demand growth and the requirement for new generation, coupled with aging assets requiring significant reinvestment have put pressure on Hydro's earnings. As Mr. Martin testified:

> *Our next step was evident. We took a step back, established the condition based assessment for all of the assets, we developed a comprehensive 20 year outlook for each of those assets, we prepared an initial budget and a schedule against this plan over a 20 year period, we then stood back and resourced the plan understanding what level of resources would be required to carry it out, we optimized that resource levelling, and we established the plan and locked it in place. This plan has yielded an outlook which has more than doubled our capital expenditures for sustaining capital from 2005 of approximately 35 million. We've more than doubled that per year and that will continue over time. It's an absolutely [sic] requirement to maintain these assets and keep them at a point where they offer acceptable reliability to the customer.*
>
> *In addition to additional capital, regular annual maintenance work is increasing, it has to increase, the assets need it. The increase in ongoing maintenance costs will continue to increase as these assets continue to age and we seek to maintain their reliability.*[4]

Hydro continually balances reliability and least cost in fulfilling its mandate to provide safe, least cost, reliable service. Hydro respectfully submits that it has exercised due care in the

[3] September 9, 2015 Transcript, pages 59-60.
[4] September 9, 2015 Transcript, pages 58-59.

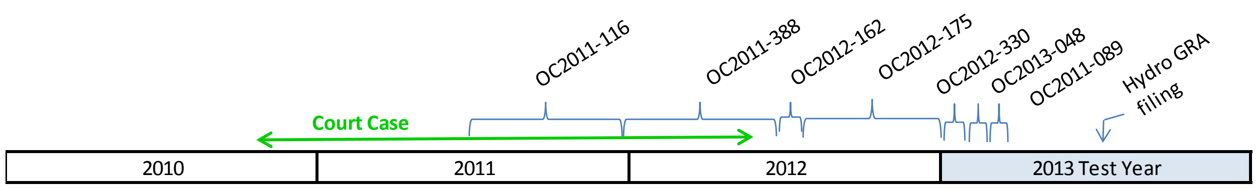
management of costs, but the reality of its infrastructure needs necessitates asking for the relief sought at this time.

B.1 PROCEDURAL HISTORY

B.1.1 Timing of GRA Filing

Hydro's GRA filing on July 30, 2013 resulted in a period of almost seven years since its previous filing on August 3, 2006.[5] Hydro believes that a period of three years is an appropriate period between GRA filings.[6] The delay in the GRA filing is recounted in Hydro's response to NP-NLH-369[7] and depicted graphically in Chart 1 below.

Chart 1



There were developments materially affecting Hydro's load, costs and revenues, commencing in 2007 with the closure of a paper machine in Corner Brook and followed by the closure of the Grand Falls paper mill announced in late 2008 and carried out in 2009, that made filing a GRA in that timeframe problematic. Due to the operation of the RSP and the potential rate volatility for the IICs, on January 16, 2009, Hydro applied to the Board for an Order to extend the deadline for filing a GRA until June 30, 2009 and to continue the existing IIC rates. In response, the Board issued an order approving the continuation of the rates, rules and regulations for the IICs on an interim basis, and directing Hydro to make an application to finalize the interim rates, rules and regulations by June 30, 2009.[8]

[5] For a more thorough account of these matters, please see Hydro's response to NP-NLH-369.
[6] PUB-NLH-074 and PUB-NLH-075.
[7] NP-NLH-369, page 3, line 8 to page 5, line 10.
[8] Order No. P.U. 6(2009).

Hydro filed an Application on June 30, 2009, in which it did not seek changes to the RSP rates. Hydro stated "…that application of the existing RSP rules to calculate rates for Industrial Customers would result in significant and unreasonable rate volatility...". Notice of the Application and the hearing date were published, interventions were filed and over several months, RFIs were issued and answered.

The Board held a hearing on June 14, 2010 to consider issues pertaining to the Board's jurisdiction with regard to that matter. The Board found that its jurisdiction with regard to some of the issues was limited.[9] On September 17, 2010, Hydro and the Consumer Advocate appealed this decision to the Court of Appeal, arguing that the Board did have jurisdiction over the RSP amounts. The appeal on the matter of the Board's decision was heard in December of 2010; a decision on the appeal was rendered by the Court in June of 2012, reversing the Board's decision.

Notwithstanding that some issues remained unresolved and were before the Court, in late 2010, the Board took steps to recommence and resolve the outstanding IIC rates and RSP matters. These processes were underway when the Lieutenant Governor in Council directed the Board to defer consideration of these matters and directing Hydro to file a GRA by December 31, 2011.[10] A subsequent Government directive delayed the GRA filing until June 30, 2012.[11]

Following the Court of Appeal decision in June 2012, a series of Government directives further changed the GRA filing date:

- OC2012-162 delayed the GRA filing until July 16, 2012;
- OC2012-175 delayed the GRA filing until December 31, 2012;
- OC2012-330 delayed the GRA filing until February 28, 2013;
- OC2013-048 delayed the GRA filing until March 31, 2013;

[9] Order No. P.U. 25(2010).
[10] OC2011-116.
[11] OC2011-388.

- OC2013-083 delayed the GRA filing until April 15, 2013; and
- OC2013-089, OC2013-090 and OC2013-091 dated April 4, 2013, which resulted in Hydro's eventual GRA filing on July 30, 2013.[12]

References have been made during the GRA proceeding to Hydro's responsibility for the delay in filing its GRA. Hydro points out that the initial directive, OC2011-116 dated April 19, 2011, was to the Board, and directed the deferral of consideration of all matters before the Board at that time pertaining to IIC rates and rate adjustments. Since the IICs are such a significant and integral component of Hydro's Cost of Service study, this directive effectively delayed the GRA filing.

Subsequent to the issuance of the Government directives on April 4, 2013 on the given rates policy matters, Hydro filed its GRA on July 30, 2013, less than four months later. The length of time between GRA filings has been cited as the dominant reason for Hydro's extended GRA hearing process. These delays occurred outside of Hydro's management control, and the delays therefore do not provide grounds for granting Hydro less than full cost recovery or impairing Hydro's opportunity to earn a reasonable return on its rate base.

B.1.2 Interim Applications

Hydro's original GRA proposed to adjust rates effective January 1, 2014. Hydro's position at the time was that delayed implementation of customer rates beyond January 1, 2014 would result in a material revenue shortfall. To provide an opportunity for recovery of the forecast cost to serve, Hydro filed an Interim Rates Application with the Board on November 18, 2013. The Board did not approve Hydro's application stating that the "the proposals in the Interim Rates Application raise complex and comprehensive issues which in the Board's view should be addressed before interim rates are established".[13]

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[12] For OC2012-162, OC2012-175, OC2012-330, OC2013-048, OC2013-083 and OC2013-089 refer to CA-NLH-024, Attachments 9, 10, 12, 13, 14 and 15 respectively.
[13] Order No. P.U. 40(2013), page 3, lines 18-20.

To address the concerns with the Interim Rates Application, Hydro filed an amended Interim Rates Application on February 11, 2014. In Order No. P.U. 13(2014), the Board denied Hydro's Amended Interim Rates Application.

Throughout the current GRA process, Hydro has continued to file interim rate applications to provide an opportunity to recover the cost of serving customers and limit the revenue deficiencies to be required to be recovered from customers in future. These are as follows:

- Application filed May 12, 2014, denied by Order issued September 17, 2014;[14]
- Application filed on November 28, 2014, approved by Order issued December 24, 2014 (approving the 2014 revenue deficiency deferral account and segregating $45.9 million, denying other aspects of the application);[15]
- Application filed January 28, 2015, denied by Order issued May 8, 2015,[16] but approving specific portions and amounts effective July 1, 2015, as follows:
  - An interim increase of 8.0% in the base rate for NP;
  - An interim increase of 50% of the proposed increase in the rates for Government Diesel customers;
  - An interim increase of 10.0% in the base rate for IICs;
  - Changes to the RSP rules to allow a transfer from the IIC RSP surplus and to implement an IIC RSP rate so that there is an effective interim increase of 2.7% in IIC rates, including Teck; and
  - Changes to the RSP rules to allow a transfer from the IIC RSP surplus to fund the full amount of the 2014 year-end IIC RSP current balance.
- Application filed October 28, 2015 for approval of interim IIC electricity rates to be effective January 1, 2016, which was approved.[17]

With respect to these various interim rates and revenue deficiency applications, Hydro states that these were all made within its rights and duties to assure that it attains rates that allow it

[14] Order No. P.U. 39(2014).
[15] Order No. P.U. 58(2014).
[16] Order No. P.U. 14(2015).
[17] Order No. P.U. 35(2015).

to recover its costs and attain a reasonable rate of return as is required by the relevant legislation. Delayed rate implementation of customer rates beyond January 1, 2014 has resulted in Hydro incurring a shortfall of more than $100 million in cost recovery.[18] Hydro submits these costs were prudently incurred in providing service to customers and Hydro should be provided the opportunity to recover these costs, subject to the Board testing of these costs.

B.1.3 Innu Nation's Stated case

The Innu Nation and Hydro made submissions to the Board with respect to the Board's jurisdiction to grant the remedial relief requested by the Innu Nation with respect to compelling Hydro to provide service to customers in Natuashish. On September 4, 2015, the Board advised the parties that this matter was more appropriately dealt with in a separate proceeding and has since taken steps to retain counsel with regard to stating a case to the Court of Appeal pursuant to section 101 of the Act. Hydro therefore makes no further submissions on this matter at this time.

B.1.4 Approval of Settlement Agreements

There are two settlement agreements before the Board in this matter, the Settlement Agreement dated August 14, 2015 and the Supplemental Settlement Agreement dated September 28, 2015. Most of the issues settled relate to cost of service matters. Achieving these agreements enabled Hydro, the Parties, and the Board to reduce the length of the hearing and to forego the *viva voce* testimony of several expert witnesses.

These agreements were reached after detailed and involved negotiations. They constitute the common positions of the parties on these issues. All Parties were represented by learned and competent counsel and advised by experts. Hydro wishes to note its appreciation to the parties and to Board staff and external counsel whom assisted and cooperated in this matter. The settlement agreements are before the Board for its consideration.

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[18] This reflects a $45.9 million shortfall based on the proposed 2014 Test Year Revenue Requirement and a $60.5 million shortfall based on the proposed 2015 Test Year revenue requirement.

Hydro joins the other Parties and Board external counsel in recommending their acceptance.

C. LEGISLATIVE REQUIREMENTS

C.1. LEGISLATION AND ORDERS IN COUNCIL

Hydro's Application seeks approval of rates under the Board's authority existing under sections 70 and 71 of the *Act*.

In carrying out its duties under the Act, pursuant to section 4 of the *EPCA*, the Board is required to implement the power policy stated in sections of the *EPCA*.

In addition to the rate and rule setting powers of the Board that exist under sections 70 and 71, the *Act* gives powers and guidance to the Board with respect to a number of determinations it has to make with regard to the rate setting process. These include the setting of rate base (section 78), the setting of return on rate base (section 80), and the determination and approval of a number of accounting matters (e.g., sections 67, 68, and 69).

Both the *Act* and the *EPCA* (section 4.1 of the *Act* and section 5.2 of the *EPCA*) contain provisions whereby the Lieutenant Governor in Council is empowered to exempt certain activities of public utilities from the Board's jurisdiction. The *EPCA* contains provisions (found in section 5.1) that empower the Lieutenant Governor in Council to give direction to the Board on power policy and rate setting matters.

Directions have been given to the Board under this section of the *EPCA* with regard to a number of rates policy issues. Attachments to CA-NLH-024 (Revision 1, March 23, 2015) provide 25 Orders in Council including:

- OC2003-347, with regard to the subsidization of rural rates;
- OC2009-063, with regard to Hydro's rate of return on equity;
- OC2013-089 (as amended by OC2013-207) with regard to the RSP Surplus; and

- OC2011-116, OC2011-388, OC2012-162, OC2012-175, OC2012-330, OC2013-048, OC2013-083 and OC2013-108 with regard to the timing of Hydro's GRA.

In addition, under OC2013-257 Hydro's activities with regard to the Exploits generation assets have been made exempt from the Board's jurisdiction and the Board was directed to include in Hydro's operating account the associated energy costs.

Three Orders in Council merit separate discussion because they concern matters of central relevance to the GRA.

C.1.1 OC2003-347 - Subsidization of Rural Rates

This Order in Council continues the longstanding policy of Government with respect to isolated rural rates. Notably, the policy directs the Board to set rates for Hydro's Isolated Customers such that "lifeline rates" are continued for domestic residential customers, preferential rates are provided to fish plants and to churches and community halls. OC2003-347 also directs that the Rural Deficit be charged to NP and Hydro's Rural Labrador Interconnected Customers. Pursuant to an Order in Council that is not directly relevant to the present proceedings but which was considered by the Board in Order No. P.U. 8(2007), the Board adopted a policy that Government department customers be charged rates designed to recover the full cost of service.

C.1.2 OC2009-063 - Return on Equity

This Order in Council directs the Board to set the same target ROE as most recently set for Newfoundland Power. The ROE is used in the determination of the setting of the return on rate base under section 80 of the *Act*.

The Lieutenant Governor in Council has directed that the Board, in calculating the return on rate base for Hydro, set the same target ROE as was most recently set for NP, either through a

GRA or calculated through the NP Automatic Adjustment Mechanism.[19] In Board Order No. P.U. 13(2013), the Board determined that NP's target return on common equity in 2015 would be 8.8%.[20]

Hydro submits that, in accordance with the Government's directive, the ROE to be used in this case for calculating Hydro's return on rate base is 8.8%.

In order to give effect to the spirit and intent of this directive, care must be taken to ensure that Hydro's return is not eroded or encroached upon by offsetting the return with some other amount or component of Hydro's costs. The Order in Council provides no authority to do so and none should be inferred.

In particular, Hydro objects to the suggestion made by the Consumer Advocate in its Issues List and cross-examination to the effect that the rate of return should be reduced or offset by some amount so as to effect a reduction in the Rural Deficit to be recovered from customers. To fully appreciate why this could clearly not be the intention of Government, a brief regulatory and legislative history of the Rural Deficit is useful. To this end, reference can be made to subparagraph 3(a)(iv) of the *EPCA*, which indicates that post 1999, the IICs are not required to fund a portion of the Rural Deficit.

Perhaps more useful for an understanding of this issue is the antecedent legislative provision, now repealed by the present *EPCA*, found in the *Electrical Power Control Act*, RSN 1990, C. E-5:

> ***Forecast costs***
>
> ***5.*** *Notwithstanding the other provisions of this Act, the hydro corporation shall include in its forecast costs filed with the public utilities board*
>
> > *(a) the amount to be allocated to retailers of the difference between the revenues and costs for the period April 1, 1989 to December 31, 1989 of*

[19] OC-2009-063.

[20] Order No. P.U. 13(2013), page 37.

the power distribution district related to the supply of power to its customers except those customers served from the Labrador interconnected electrical grid;

(b) the amount to be allocated to retailers of the difference between the annual revenues and costs of the hydro corporation, excluding all costs and revenues related to the supply of power to customers served from the Labrador interconnected electrical grid;[21] *and*

(c) the costs incurred after March 31, 1989, including fees or charges paid to the Crown, which have been deferred by the hydro corporation and which would, unless recovered from its customers, cause the hydro corporation to recover less than the minimum margin of profit approved by the public utilities board under subparagraph 3(c)(ii) in the year in which the costs were incurred.

Subsidies

6. *In determining the amounts to be included under paragraphs 5(a) and (b), the public utilities board shall take account of subsidies paid or payable by the Crown to the power distribution district until December 31, 1989 and to the hydro corporation after December 31, 1989 of $20 million for the period April 1, 1989 to March 31, 1990 and $10 million for the period April 1, 1990 to March 31, 1991.*

This legislative history provides an account of how the rural subsidy came into being as a fiat of the legislature and how it was treated. Prior to 1989, the Government fully funded the Rural Deficit incurred by the Power Distribution District in serving what are now Hydro's Rural Customers. The Power Distribution District was wound up at that time and its operations were absorbed into Hydro. Government made the above legislative change in 1989 to require that

[21] Legislation was subsequently modified (*EPCA*, 1994) requiring the Rural Deficit to also be recovered from customers on the Labrador Interconnected System.

the Board set rates such that Hydro would recover the Rural Deficit not from Government, as had been the case with the Power Distribution District, but from Hydro's customers, notably NP. As stated above and as can be seen from subparagraph 3(a)(iv) of the *EPCA*, until 1999 Hydro also recovered a portion of this deficit from the IICs.

The collection of the Rural Deficit from NP and from Hydro's Labrador Interconnected Customers, and not from Government, has been an ongoing regulatory issue. Hydro's collection of the Rural Deficit in this manner was an established and understood fact long before the directive as to Hydro's rate of return (OC-2009-063) was issued. Indeed, under paragraph (v) of Order in Council OC2003-347 it is expressly stated that this manner of funding is to "continue".

OC2009-063 is silent with regard to offsetting or reducing Hydro's ROE with a subsidy to fund the Rural Deficit (or by any other cost). The Consumer Advocate's expert witness, Mr. D. Bowman, accepts that Hydro now has what he calls a "mandated ROE" commensurate with that of NP, but suggests that the Board should consider directing a portion of Hydro's return toward payment of the Rural Deficit.[22] Hydro submits that the directive would be meaningless and ineffective if the Board could deny Hydro the mandated ROE by taking away some or all of the required return to serve other purposes.

The Consumer Advocate's proposition that Hydro fund a contribution to the Rural Deficit out of its rate of return cannot be reconciled with Government directives and the intentions implicit in them. First, it would restrict Hydro's recovery of the Rural Deficit from NP and from its Labrador Interconnected Customers (which is contrary to paragraph (v) of OC2003-347). Second, it would also amount to Government contributing toward the Rural Deficit since the funds would come from reduced earnings to which Government is entitled as Hydro's shareholder.

[22] Pre-filed Evidence of C. Douglas Bowman dated June 1, 2015, page 33.

C.1.3 OC2009-063 – Rate Base to Include Rural Assets

This directive also requires that the whole of Hydro's rate base be used for the purpose of setting Hydro's Rate of Return, including those assets deployed in the service of its rural customers. This Order in Council directs that a change occur from prior Board ordered policy whereby rural assets were excluded from rate base for the purpose of determining Hydro's rate of return.

C.2 2014 AND 2015 ALLOWED RETURN

OC2009-063 clearly and unambiguously states when the provisions of its direction regarding Hydro's ROE are to be implemented. The directive says that the Board shall adopt the policies set out therein for all future GRAs by Hydro, commencing with the first GRA by Hydro after January 1, 2009. The first GRA by Hydro after January 1, 2009 was the application in this case made by Hydro on July 30, 2013, requesting new rates to become effective January 1, 2014; and amended on November 10, 2014, requesting cost recovery for 2014 and new rates for 2015. According to the plain words of the Government directive, the Board is to adopt the polices set out in OC23009-063 in this GRA. It follows that the target ROE for both 2014 and 2015 must be the return most recently set by NP, namely, 8.8%.

C.3 TEST YEARS

Paragraph 3(a) (ii) of the EPCA reads as follows:

> *3. It is declared to be the policy of the province that*
> *(a) the rates to be charged, either generally or under specific contracts, for the supply of power within the province*
> *(ii) should be established, wherever practicable, based on forecast costs for that supply of power for 1 or more years,*

This provision provides ratemaking guidance to the Board and indicates that test years — "wherever practicable" — should be forecast test years. There are two circumstances where this requirement would not apply: (i) where the Board is specifically directed otherwise under section 5.1 of the *EPCA*; and (ii) where the Board in applying proper ratemaking principles deems that, for some reason, the use of a forecast test year is not practicable.

There were Government directives issued in the present matter as to the test year to be used. The first of these was OC2013-089 (replaced by OC2013-091 but unchanged in this regard), which was issued in April of 2013 and which directed that the Board use a 2013 Test Year. The test year aspect of the directive was rescinded by OC2014-319.

Hydro filed its GRA on July 30, 2013 in compliance with OC2013-089, as amended. When Hydro filed its GRA the Government-mandated test year was half over, so the GRA's 2013 Test Year was not a completely forecast test year.

Following its 2013 filing based on the mandated 2013 Test Year, Hydro filed for interim relief with the Board on several occasions as previously noted. Due to the passage of time without receiving an approved rate change and due to changes with respect to a number of cost elements, on June 6, 2014 Hydro advised the Board that it would be filing an amended GRA, which it did on November 10, 2014. That filing used (i) a 2014 Test Year for the purpose of testing the basis for Hydro's claimed 2014 revenue deficiency and (ii) a 2015 Test Year for the purpose of setting rates on a going forward basis. At the time of its filing, the 2015 Test Year was completely a forecast test year.

Although 2015 is now drawing to a close, this does not impair the relevancy or value of the test year information before the Board. Some modifications to the capital asset forecast used in the 2015 Test Year are required to determine the revenue deficiency for 2015. These adjustments are required to reflect the revenue requirement impact of delayed completion of some 2014 capital projects.[23] See Section D.1.2.3.

[23] See PUB-NLH-487.

For the purpose of rate setting, the 2015 Test Year remains the proper basis to be used for rate setting for the coming period starting in 2016.

C.4 PHASE IN OF INDUSTRIAL RATES

OC2013-089 and OC-2013-090 require the use of the RSP Surplus to phase-in of IIC rates over a three-year period. The phase-in period started September 1, 2013. The Board has used interim orders to achieve the phase-in. Upon approval of final GRA rates, Hydro will propose the conclusion of the rate phase-in to become effective September 1, 2016.

D. ISSUES AND ARGUMENT

In this section Hydro addresses:

- Issues affecting return;
- Revenue requirement issues;
- Cost of Service and Rates issues;
- Deferral and recovery mechanisms; and
- Management of the Rural Deficit.

Section D.1: Issues Affecting Return

D.1.1 Settled Matters

D.1.1.1 Allowable Range of Return on Rate Base

The Parties agreed the allowable range of return on rate base for Hydro will be ±20 basis points.[24]

D.1.2 Remaining Issues

D.1.2.1 Adjustment of Hydro's ROE

- ***Future changes to Hydro's 8.8% ROE should be implemented in a Hydro GRA.***

[24] Settlement Agreement, page 2, paragraph 7.

It has been suggested that, at such time as the Board reaches a decision to change the target ROE for NP, the Board could adopt an adjustment process to flow through the new ROE to Hydro.[25] Hydro proposes that any future changes to its ROE be implemented in a Hydro GRA.[26] This avoids implementation of new rates solely to give effect to an ROE change and means that the outcome of ROE changes can be implemented together with other impacts of a GRA decision. Further, the approach of implementing any future ROE changes in a Hydro GRA is consistent with the language of the Government directive, which sets out policies to be adopted by the Board "for all future General Rate Applications" by Hydro.

D.1.2.2 Assets in Rate Base

- ***For purposes of determining the revenue requirement for setting rates for 2016, Hydro's 2015 Test Year total plant in service is reasonable and should not be adjusted.***

Hydro's rate base is comprised of its investment in capital assets in use, deferred charges, fuel inventory, materials and supplies inventory, and cash working capital allowances.[27]

A detailed explanation of the updated 2015 capital expenditure amount has been provided in Hydro's evidence.[28] The increase in 2015 Test Year additions to plant in service is primarily due to the carry-forward of the in-service dates for the CT and other capital assets that were originally scheduled to go into service in 2014 but have now gone into service in 2015.

As stated in Undertaking No. 158:

> *The forecast additions to plant in service in comparison to the cumulative 2014 and 2015 Test Years is an underspend of less than 1%. Hydro does not propose to make the corresponding adjustment for rate setting purposes for 2016 given that the forecast assets in service in 2015 are consistent with the 2015 Test Year, all of*

[25] November 16, 2015 Transcript, page 72.
[26] *Ibid*.
[27] Amended Application, Finance Evidence, Schedule I, page 5 of 11.
[28] *Ibid*.

> *the 2015 additions which were tested in the Hearing and will be in service for a full year in 2016, the planned growth in Hydro's capital program and the impact on return on rate base forecasted for 2016 in as outlined in PUB-NLH-487.*[29]

The fact that the in-service dates of certain capital assets carried over from 2014 to 2015 should not impact Hydro's opportunity to begin recovering these costs in 2016. Further, Hydro undertook a very significant amount of capital spending in 2014 and 2015 to place the Holyrood CT and other used and useful assets into service, and Hydro should not be financially disadvantaged by the exclusion of this in-service capital for the purposes of rate setting.

If the impact of the delayed capital additions is not included in the 2015 Test Year for the purposes of rate setting, Hydro's 2016 forecast return on rate base would be 6.18%, which is below the lower end of the target range of return on rate base.[30]

D.1.2.3 Delayed In-Service Date of Capital Additions

- ***Adjustments to the Test Year plant in service to reflect delayed in-service dates are required only for the determination of net income deficiency.***

Hydro's 2014 additions to plant in service were less than expected. This difference reflected a delay in the in-service date of the Holyrood CT and the carry-over of other capital projects.[31] Grant Thornton identified $148 million of capital assets that did not go into service in 2014 as expected[32] and $110 million of this amount relates to the CT.[33] Hydro proposes adjusting the 2014 revenue deficiency to take into account the capital assets that were expected to be placed in-service during 2014 but were not.[34] In addition, to account for additions to plant in service

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[29] Undertaking No. 158.
[30] PUB-NLH-487 (Revision 1, October 5, 2015).
[31] CA-NLH-326.
[32] Grant Thornton Financial Consultants Report, June 12, 2015, page 115, Table 87.
[33] PUB-NLH-487 (Revision 1, October 5, 2015).
[34] Undertaking No. 148.

that were delayed from 2014 to 2015, Hydro proposes to adjust the return for the 2015 net income deficiency by $5.1 million, as outlined in the 2015 Cost Deferral Application.[35]

To account for these delayed in-service dates, adjustments related to rate base should be made to determine the 2014 revenue deficiency and the 2015 revenue deficiency. However, as previous stated, adjustments related to rate base are not required and should not be made for setting rates for 2016 and beyond.

The delay in bringing assets into service has the effect of reducing 2014 Test Year revenue requirement by $2.1 million.[36] Excluding these capital additions for the 2015 Test Year would reduce revenue requirement by $5.1 million.

Section D.2: Revenue Requirement Issues

D.2.1 Settled Matters

D.2.1.1 Actuarial Gains/Losses in Employee Future Benefits

The Parties agreed the Board should approve Hydro's proposed accounting treatment to include actuarial gains and losses in EFBs in the 2015 Test Year.[37]

D.2.1.2 Expenses Associated with Asset Retirement Obligations

The Parties agreed the Board should approve Hydro's proposal to include depreciation and accretion expenses associated with asset retirement obligations with the amounts reduced from $3.1 million and $3.2 million for the 2014 and 2015 Test Years, respectively, as proposed in the Amended Application, to $2.6 million and $2.6 million, respectively. [38]

[35] Cost Deferral Application, page 5.
[36] PUB-NLH-487, (Revision 1, Oct 5-15).
[37] Settlement Agreement, page 2, paragraph 8.
[38] Settlement Agreement, page 2, paragraph 9.

D.2.1.3 2015 Test Year Hydroelectric Energy Production

The Parties agreed to the methodology Hydro used to estimate its average annual hydroelectric energy productions and agreed that the Board should approve the 2015 hydraulic production calculation forecast of 4,604 GWh for all purposes, including the calculation of No. 6 fuel expense for the 2015 Test Year and for the RSP.[39]

D.2.1.4 2015 Test Year Depreciation Expense

The Parties agreed the depreciation methodology used to determine depreciation expense in the 2015 Test Year is appropriate.[40] Grant Thornton's review of Hydro's Amended Application included procedures to ensure that the depreciation rates used in the 2014 and 2015 Test Years are in compliance with the Gannett Fleming Depreciation Study and in compliance with Board Order No. P.U. 40(2012). In addition, Grant Thornton carried out other procedures, such as reconciling the detailed depreciation schedule to the pre-filed evidence.[41] As a result of completing its procedures, Grant Thornton noted no significant discrepancies in the calculation of the 2014 or 2015 Test Year depreciation forecasts.[42]

Grant Thornton noted that certain project costs are subject to the Prudence Review.[43] Subject to the decision of the Board with regard to the prudence of certain costs, Hydro submits that its 2014 and 2015 Test Year depreciation expense should be approved.[44]

D.2.1.5 CDM Cost Deferral and Recovery

The Parties agreed the Board should approve Hydro's proposal to defer and amortize annual customer energy conservation program costs, commencing in 2015, over a discrete seven year

[39] Settlement Agreement, page 2, paragraph 10.
[40] Settlement Agreement, page 2, paragraph 11.
[41] Grant Thornton Financial Consultants Report, June 12, 2015, page 45.
[42] Grant Thornton Financial Consultants Report, June 12, 2015, page 47. The 2014 Test Year depreciation expense of $55.2 million reflects $239 million of assets that were expected to go in service in 2014 (CA-NLH-116). The total of $239 million for 2014 expected in-service assets includes the Holyrood CT, which actually did not go into service until early 2015. The delay in assets going into service, including the Holyrood CT, is $0.4 million in 2014 (Grant Thornton Financial Consultants Report, 2013 Amended General Rate Application, June 12, 2015, page 46).
[43] Grant Thornton Financial Consultants Report, June 12, 2015, page 31.
[44] Amended Application, Finance Evidence, Schedule II, page 1 of 1, line 19.

period in a CDM Cost Deferral Account. In the Supplemental Settlement Agreement, the Parties agreed the Board should approve Hydro's proposed CDM Cost Recovery Adjustment, which provides for recovery of the costs charged annually to the CDM Cost Deferral Account.[45]

D.2.1.6 GRA Costs

The Parties agreed the Board should approve Hydro's proposal to the Parties agreed the Board should approve Hydro's proposal to recover GRA costs (in an amount to be determined) over a three year period using straight-line amortization.

D.2.2 Remaining Issues

D.2.2.1 Operating and Maintenance Expenses

Salaries and Benefits

- ***Hydro's salary and benefits expenses for the 2014 and 2015 Test Years reflect prudent management decisions concerning the staffing levels necessary to maintain safe and reliable service, and Hydro's commitment to offer the competitive compensation packages necessary to recruit and retain a highly skilled workforce.***

Hydro's 2014 Test Year salary and benefits expense is $78.0 million. This amount includes a number of elements, such as salaries, overtime, capital labour costs, benefits, and cost recoveries. Excluding the other elements that make up the total salary and benefits amount, the 2014 cost of salaries is $73.2 million and the 2014 benefits expense is $18.1 million. In the 2015 Test Year, the salary and benefits expense is $85.8 million, the cost of salaries is $77.9 million and the benefits expense is $23.5 million.[46]

Employee benefits include fringe benefits, EFBs and group insurance.[47] Fringe benefits generally are CPP, EI, PSPP and Workers Compensation premiums and contributions paid by Hydro.[48] EFBs relate to severance payments upon retirement and health benefits provided to retirees on

[45] Supplemental Settlement Agreement, page 3, paragraph 12.
[46] Amended Application, Regulated Activities Evidence, page 2.33, Table 2.4.
[47] Amended Application, Regulated Activities Evidence, page 2.33, Table 2.4.
[48] Amended Application, Regulated Activities Evidence, pages 2.36, lines 19-21.

a cost-shared basis.[49] Group insurance benefits provide Hydro employees with health, dental, life insurance and accidental death and dismemberment coverage.[50]

The total cost of employee benefits in the 2014 Test Year is an increase of $3.6 million over 2007 actual costs of $14.5 million. The total cost of employee benefits in the 2015 Test Year is an increase of $9 million over 2007 actual costs.[51] The cost of fringe benefits, in particular, was driven higher in 2014 and then again in 2015 by increased premiums for EI and CPP and increased contributions to the PPSP, in combination with salary increases discussed below. As well, there is an additional expense of $2.5 million in 2015 associated with PSPP changes announced by the Government that result in higher employer contributions.[52]

In the 2015 Test Year, the cost of EFBs is $2.5 million higher than 2007 actual costs; this increase includes actuarial losses of $1.6 million.[53] The Settlement Agreement recommends that the Board approve recognition of these costs in the 2015 Test Year.

In 2006, based on an analysis of its workforce and the external labour market, Hydro identified the importance of focusing on recruitment and retention of skilled employees. The factors that dictated the need for a focused recruitment and retention strategy included the following:

- Significant anticipated retirements during the coming five to ten years;
- Large scale construction projects within the province and Western Canada;
- Changing labour force demographics, specifically, an aging population and fewer labour market entrants; and
- Stable or declining participation trends in the trades and engineering occupations.[54]

[49] Amended Application, Regulated Activities Evidence, page 2.37, lines 7-8.
[50] Amended Application, Regulated Activities Evidence, page 2.37, lines 20-21.
[51] Amended Application, Regulated Activities Evidence, page 2.33, Table 2.4.
[52] Amended Application, Regulated Activities Evidence, pages 2.36, lines 21-23 to 2.37, lines 1-4.
[53] Amended Application, Regulated Activities Evidence, page 2.37, lines 13-15.
[54] Amended Application, Introduction Evidence, Section 1.2.3, page 1.15, lines 14 - 19.

Over the period from 2007 to August 31, 2014, there were 238 retirements from Hydro and it is anticipated that, between 2014 and 2022, 40% of Hydro's current workforce will be eligible for retirement.[55] The fact that employees who leave Hydro are often among the most experienced and knowledgeable members of the workforce adds emphasis to Hydro's focus on minimizing voluntary turnover.[56]

Hydro's forecast costs for salary and benefits reflect a need for Hydro to offer a compensation package that takes into account the labour market in the Province. As well, it has been necessary for Hydro to address differentials in the wages that it offers, as compared to NP and other Atlantic Canada utilities. These wage differentials arose primarily because of the government's previous wage restraints that were applied to Hydro.[57]

Thus, in recent years, Hydro has made adjustments to salaries and wages that are necessary and appropriate to fulfill key business purposes. First, these adjustments are necessary in order to meet Hydro's central concern to ensure it is paying fairly and competitively as an employer. Ensuring that Hydro's employees are paid fairly is a matter both of equity and of good business practice.[58] Second, Hydro must be able to attract and retain the people needed to run its operations effectively.[59] In order to attract and retain the employees that it needs, Hydro aims to pay its employees fairly and equitably relative to their peers in the industry and, in particular, the Atlantic Canada utility industry. As Mr. McDonald for Hydro noted: "[t]here's no reason in this world why anyone of our people who are highly qualified people in Hydro should be paid any less or differently from a comparison perspective than anybody with any of these other utilities."[60]

[55] Amended Application, Introduction Evidence, pages 1.15, lines 22 to 24.
[56] Amended Application, Introduction Evidence, pages 1.15, lines 26-28 to page 1.16, lines 1-2.
[57] Amended Application, Regulated Activities evidence, page 2.34, lines 9 - 16.
[58] September 16, 2015 Transcript, pages 169-170.
[59] September 16, 2015 Transcript, pages 169-170.
[60] September 17, 2015 Transcript, pages 76-77.

The labour market in the Province has experienced salary increases well beyond inflation over the years from 2007 to 2015. Without even taking into account the skilled and specialized employees that Hydro needs in many areas, Hydro is faced with the reality that average weekly earnings in the Province have escalated by 35% over that period of time.[61]

In order to be able to attract and retain talented and specialized employees in these market conditions, Hydro must be in a position to compete with its primary comparators on salaries and wages. For comparative purposes, Hydro looks to other utilities, primarily in Atlantic Canada and most notably, NP. As an example, the wage rate of a line worker at Hydro in 2015 is $38.17 per hour. This compares to $39.10 per hour at NP and the Atlantic Canada utility average in 2015 of $38.42.[62]

In managing towards the Atlantic Canada utility average as the benchmark for employee compensation, Hydro has taken a conservative approach. The evidence reveals a number of areas where Hydro has been "much more conservative" than the recommendations of its expert compensation consultant.[63]

The expert consultants who collect information on employee compensation provide a range of data points for particular job categories and, in utilizing this information, some companies have adopted a philosophy described in the evidence as "broad-banding". While Hydro is aware of this practice, it decided to stay with, or "steward" towards, mid-points. For certain job categories ("Hay 15" through "Hay 18"), Hydro's expert consultant cast the data on a national basis, but Hydro asked that the numbers be scaled back to Atlantic Canada data.[64] When the expert consultant recommended that Hydro immediately take steps to address job categories ("Hay 11" through "Hay 18") in which Hydro was lagging relative to the other Atlantic Canada utilities, Hydro decided to correct the lag naturally through the salary administration process.

[61] September 16, 2015 Transcript, pages 143-144.
[62] September 16, 2015 Transcript, page 145.
[63] September 16, 2015 Transcript, page 164.
[64] September 16, 2015 Transcript, pages 160 and 162.

This took on average two years, rather than the immediate correction recommended by the consultant.[65] The expert consultant recommended that short term incentives be made available down to a certain level of job category ("Hay 13"), but Hydro decided not to "dip down that far in the organization" with incentive pay.[66] The expert consultant recommended that employees be able to earn beyond the posted target amount for short-term incentives, but Hydro decided to cap payouts at the stated amounts.[67]

Overtime

- ***Hydro's overtime costs reflect the aging of Hydro's assets in the face of increased customer and increased reliability expectations. Hydro has made a productivity commitment by constraining overtime costs in the 2015 Test Year and going forward until Hydro's next GRA.***

Hydro incurs overtime costs as it carries out work to fulfill its mandate of providing least cost reliable service. The need for overtime varies depending on the circumstances at any particular time. Where possible, Hydro minimizes overtime through work planning and filling vacant positions. Nevertheless, the drivers of overtime costs include emergencies – which may arise due to weather and equipment related outages – labour shortages and capital project requirements. Overtime is also required to plan outages at times which are least inconvenient to customers such as weekends and early mornings As well, overtime occurs because of compensation paid to shift workers who must work on statutory holidays and it is necessary at times to minimize customer outages or to minimize customer service interruption risks.[68]

Hydro's overtime costs included in the 2014 Test Year are $12.2 million, which is $6.0 million higher than actual overtime costs in 2007. Of the 2014 Test Year overtime amount, $5.4 million is capitalized, compared to an actual amount of $1.7 million that was capitalized in 2007. The

[65] September 16, 2015 Transcript, pages 162-163.
[66] September 16, 2015 Transcript, page 164.
[67] September 16, 2015 Transcript, page 165.
[68] Amended Application, Regulated Activities Evidence, page 2.35.

net impact of these variances is that operating overtime costs in the 2014 Test Year are $2.3 million higher than actual 2007 costs. In 2014, higher overtime costs were driven by incremental work requirements arising from the January 2014 outage as well as emergency call-outs. The higher amount of capitalized overtime in 2014 is primarily due to an increase in Hydro's capital program and higher salary costs during the period.[69]

Hydro's overtime costs included in the 2015 Test Year are $10.1 million, or $2.1 million less than the 2014 Test Year amount. Of the 2015 Test Year amount, $5.2 million is capitalized, which is an increase of $3.5 million over the actual amount of $1.7 million that was capitalized in 2007. The net impact of these variances is that operating overtime costs in the 2015 Test Year are only $0.4 million higher than actual 2007 costs. As well, operating overtime costs in the 2015 Test Year are $2.1 million less than in the 2014 Test Year.[70]

Hydro is experiencing pressure on its overtime costs for a number of different reasons. The aging of Hydro's assets and the need to get generation back up quickly when problems arise with these assets, the growth of demand on the system, the need to complete capital projects within tight timelines, and the need to minimize impacts on the power system and on customers, all contribute to a growing and pressing requirement for overtime.[71] A more specific example of these pressures on overtime costs is the Holyrood facility, where there has been an increase in electrical maintenance, instrumentation and mechanical maintenance to address the increasing corrective maintenance requirements that are becoming evident at the plant.[72]

Hydro has made a productivity commitment by constraining overtime costs in the 2015 Test Year and going forward until Hydro's next GRA.[73] As already stated, operating overtime costs included in the 2015 Test Year for rate-setting purposes are $2.1 million lower than 2014

[69] *Ibid*.
[70] *Ibid*.
[71] September 23, 2015 Transcript, page 168.
[72] September 23, 2015 Transcript, page 171.
[73] September 23, 2015 Transcript, page 170-171.

operating overtime costs and only $0.4 million more than actual costs in 2007. Hydro will limit overtime costs through efforts such as improved efficiency in the planning, scheduling and execution of work and the redeployment of resources in certain key areas.[74]

Vacancies

- ***Hydro's 2014 and 2015 Test Years demonstrate an inverse relationship between the vacancy allowance and the amounts spent on overtime and labour; Hydro's vacancy allowance of 40 FTEs for the 2015 Test Year is the correct number for the long term.***

Hydro uses a number of factors to determine an appropriate vacancy allowance to apply to its salary budget based on a combination of previous vacancy experience, most recent labour conditions (trending on job competitions), and anticipated retirements and turnovers.[75] Hydro experienced higher vacancy than anticipated in 2014. The 2014 Test Year includes a vacancy adjustment of 20 FTEs as outlined in Undertaking No. 145, which is estimated to be the equivalent of $1.7 million at an average salary of $85,000 per FTE.[76] However, with consideration of extraordinary factors including Hydro's deferral of apprentice hiring and the impact of work covered through contract labour and overtime, the 2014 vacancy rate would be normalized to less than 40.[77] Hydro did not achieve savings relative to the 2014 Test Year due to the higher 2014 vacancy allowance as a result of increased overtime and contract costs incurred resulting from the higher number of vacant positions.[78]

The 2015 Test Year includes an appropriate vacancy allowance of 40 FTEs or $3.3 million.[79] While the company's vacancy experience is currently higher than its budgeted allowance, the vacancy allowance is appropriate as Hydro has incurred additional costs again in 2015 relating to managing its vacancies with the use of overtime, contract labour, etc., as outlined in

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[74] September 23, 2015 Transcript, pages 170-171.
[75] CA-NLH-104 (Revision 1, Dec 18-14), page 2, lines 9-22.
[76] See CA-NLH-104, Revision 1, page 2, lines 9 – 22.
[77] September 16, 2015 Transcript, page 176-177.
[78] See Undertaking No. 146.
[79] See response to IC-NLH-005 (Revision 1, Dec 3-14).

Undertaking No. 146. As well, Hydro notes in testimony by Mr. McDonald that while the vacancy rate is higher in 2015, it is Hydro's position that an allowance of 40 FTEs is appropriate for the longer term (i.e., exclusion of extraordinary factors).[80]

Hydro reviews its resource requirements and makes prudent decisions based on circumstances and priorities that benefit Hydro customers. Hydro's costs include all factors affecting resourcing of work and is not limited to strictly salaries and wages less vacancy allowance. Hydro will continue to reallocate work where appropriate using a mix of temporary resources, contract labour and overtime.

Intercompany Charges

- ***Intercompany services provide significant benefits to Hydro's customers. The charges for these services are subject to transaction costing guidelines that have been reviewed favorably by Hydro's independent auditor and the Board's financial consultant.***

Since the last GRA, Hydro has become a subsidiary of Nalcor Energy, which has a number of other subsidiaries. Nalcor has adopted a matrix model approach to the sharing of its services and activities with its affiliates.[81] To the extent that resources were based within Hydro and could be effectively shared with affiliates without impeding Hydro's use of those resources, Hydro has been able to recover the costs of those resources from its affiliates, thereby lowering the overall cost of providing electrical service.[82] These cost savings have come in the form of increased recoveries from the Admin Fee as well as the sharing of resources.

The sharing of services is subject to ITC Guidelines.[83] The ITC Guidelines set parameters for the sharing of services among the Nalcor lines of business through the Admin Fee as well as the costs associated with the provision of services via the Corporate Services group.

[80] September 16, 2015 Transcript, page 180, lines 17-20.
[81] September 9, 2015 Transcript, pages 73-76.
[82] PUB-NLH-141.
[83] Amended Application, Volume II, Exhibit 8.

Through the shared services model, Hydro is able to benefit from the optimization and efficiency of certain services being provided on a shared basis to affiliates within the Nalcor organization. Provision of shared services at cost facilitates the sharing of services and supports the optimal and most efficient use of resources. Accordingly, Hydro does not charge a mark-up on intercompany transactions.[84]

Deloitte conducted an independent review and noted that a common or shared services model allows organizations such as Nalcor and its affiliates to optimize assets and resources to provide efficient or specialized services at potentially lower costs than each individual entity replicating the asset or service.[85] Deloitte concluded "the methodologies and practices adopted by Nalcor are fair and reasonable and in line with other utilities."[86]

In the GRA, the Board retained Grant Thornton to provide a report and testimony by Mr. Rolph on Hydro's shared services model and inter-company transactions policy. Grant Thornton also conducted a review of "the reasonableness of the methods used by Hydro and its affiliates to determine the amounts charged by and to Hydro".[87] Based on a survey of other Canadian regulated utilities, Mr. Rolph did not identify any significant issues or problems with the application of the shared services model as applied by Hydro and found that the approach used provides value to Hydro and to its affiliates.[88] In its conclusions, Grant Thornton indicated that, among other things, Hydro and its affiliates derive value from the corporate services rendered by each other.[89]

The specific findings reported by Grant Thornton as a result of its review include the following:

[84] CA-NLH-083.
[85] NP-NLH-024, Attachment 1, page 3.
[86] NP-NLH-024, Attachment 1, page 4.
[87] Grant Thornton Expert Report, June 1, 2015, page 1, section 1.3, where it is said that this Report "builds on" the previous Grant Thornton Report dated April 25, 2014.
[88] Grant Thornton Expert Report, June 1, 2015 page 59.
[89] Grant Thornton Expert Report, June 1, 2015, page 59.

Common Services:[90]

- Using an indirect charge method to determine an arm's length price for the common services Hydro renders to its affiliates is reasonable;
- Allocating the HR and safety and health related costs to be recovered using FTEs as the allocator is reasonable;
- Allocating the IS related costs to be recovered using average number of users as the allocator is reasonable;

Common Expenses:[91]

- Allocating the building rental costs using square footage occupied as the allocator is reasonable;
- Allocating the telephone infrastructure-related cost using the average number of users is reasonable;
- Treating these common expenses as flow through costs and charging them back without a mark-up is reasonable;

Corporate Services[92]

- It is reasonable for Hydro and its affiliates to use a direct charge method;
- The labour rates used to recover the costs appear to be fully burdened; and
- Unless the ultimate recipient of the corporate service is an energy project involving private interest, not applying a mark- up to the costs of rendering corporate services to be recovered is reasonable.[93]

Grant Thornton noted that the common services related to the Admin Fee might not be fully burdened.[94] Hydro acknowledged this point[95] and provided evidence indicating that the impact

[90] Grant Thornton Expert Report, June 1, 2015, page 2.
[91] Grant Thornton Expert Report, June 1, 2015, pages 2-3.
[92] Grant Thornton Expert Report, June 1, 2015, page 3.
[93] The ultimate recipients of corporate services do not include any energy projects involving "private" interests. CF(L)Co is the only recipient of corporate services that is not ultimately owned 100% by the Province (November 17, 2015 Transcript, pages 81-83). Transactions between Hydro and CF(L)Co do not include a mark-up in accordance with the contract between them (NP-NLH-214) and, in any event, the impact of any such mark-up would be $41,000 and $44,000 in the 2014 and 2015 Test Years, respectively (Undertaking 152).
[94] Grant Thornton Expert Report, June 1, 2015, page 2.

of calculating a fully burdened Admin Fee is $105,000 in the 2014 Test Year and $115,000 in the 2015 Test Year.[96]

Hydro has demonstrated significant benefits to ratepayers from the Admin Fee. The amounts recovered by Hydro through the Admin Fee for the provision of services to Nalcor affiliates are $5.6 million in the 2014 Test Year and $5.7 million in the 2015 Test Year.[97] Hydro has estimated a benefit of $9.1 million from the initial transfer of staff from Hydro to Nalcor.[98] Hydro's customers benefit from the sharing of services with Nalcor, rather than Hydro employing its own dedicated full-time resources to provide those services.

Grant Thornton's annual review of Hydro also encompassed a review of non-regulated activity.[99] No issues regarding non-regulated transactions or cost allocations have been brought forward by Grant Thornton, or indeed by any party to this proceeding.

System Equipment Maintenance

- ***Hydro's increased SEM costs are justified by Hydro assuming responsibility for costs previously incurred by TwinCo; by new demands imposed by the newly installed Holyrood CT; and by the increased preventative and corrective maintenance, including vegetation management.***

General

Hydro's actual costs for SEM were $7.5 million in 2007. These costs have increased by $3.2 million in the 2014 Test Year and by a further $4.1 million in the 2015 Test Year.[100]

[95] November 16, 2015 Transcript, page 10.
[96] Undertaking No. 151.
[97] PUB-NLH-169 (Revision 4, Dec 3-15).
[98] NP-NLH-084.
[99] PUB-NLH-140, Attachment 1, pages 5-6.
[100] Amended Application, Regulated Activities Evidence, pages 2.45-2.46.

There are a number of key drivers of Hydro's increased requirements for spending on SEM. Two of the primary drivers that increase the SEM costs in the 2015 Test Year forecast are the costs previously incurred by TwinCo and the costs associated with the new Holyrood CT. Other drivers of higher SEM costs are initiatives focused on improving transmission and distribution reliability performance, including vegetation management.

TwinCo Assets

CF(L)Co continues to operate and maintain the transmission assets previously owned by TwinCo on Hydro's behalf.[101] The 2015 Test Year includes forecast operating and maintenance costs of approximately $2.8 million for the transmission lines and the terminal station.[102] The work giving rise to these costs was previously done for TwinCo by CF(L)Co and now is done for Hydro by CF(L)Co. Hydro worked very closely with CF(L)Co to develop the budget amounts based on CF(L)Co's experience with the costs to maintain and operate the assets over the past number of years.[103]

Hydro provided detailed support for the 2015 Test Year forecast operating and maintenance costs.[104] No issue has been raised during this proceeding about these costs.

Holyrood CT

Hydro's SEM costs for the 2015 Test Year include costs of $1 million associated with maintenance of the new CT, as well as an additional $1.6 million in respect of the extended (two year) warranty that provides for technical oversight and coaching from the Engineering, Procurement and Construction contractor related to the operation and maintenance of the unit.[105] Hydro submits that the operating and maintenance costs applicable to the Holyrood CT are reasonable for the provision of reliable service to customers.

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[101] PUB-NLH-367.
[102] Amended Application, Regulated Activities Evidence, pages 2.12 and 2.46; PUB-NLH-367.
[103] September 24, 2015 Transcript, pages 38-40.
[104] PUB-NLH-367.
[105] Amended Application, Regulated Activities evidence, page 2.46.

Preventative and Corrective Maintenance

The cost increase to improve transmission and distribution reliability performance and maintenance in 2014 is primarily related to the completion of $1.0 million in preventative and corrective maintenance backlog work associated with critical power transformers, air blast circuit breakers and protection and control systems costs associated with the completion of the preventive and corrective maintenance backlog for 2015 were forecast to be $1.2 million. However, as these costs are not considered to be reflective of normal operating conditions, Hydro proposes a deferral of the costs over a five-year amortization period beginning in 2015 and the 2015 Test Year includes $0.2 million of related amortization.[106]

Hydro's vegetation management costs increased by $1.4 million in the 2014 Test Year, as compared to 2007; and by an additional $0.5 million in the 2015 Test Year.[107] The higher costs of vegetation management result from both an increase in contractor costs and a greater amount of work. The contractor for Hydro's vegetation management work was selected through a public tender process and the outcome of the process was a higher contract cost than that which was reflected in Hydro's 2007 costs.[108] As well, Hydro found that additional vegetation management is needed on dams and dykes and along transmission lines after a number of interruptions were experienced due to tree contact:

> *JOHNSON, Q.C.:*
>
> *Q. Okay. As regards vegetation management, that's referenced on page 2.46, line 21, further increase of a half million dollars related to vegetation management. That's a fairly significant increase in the cost for vegetation management. I think you'll agree.*

[106] Amended Application, Regulated Activities Evidence, pages 2.45-2.47 and 3.23.
[107] Amended Application, Regulated Activities Evidence, page 2.46.
[108] September 24, 2015 Transcript, page 37.

MR. HENDERSON:

A. It is, and it is specifically to address vegetation management requirements of the company. We had experienced a number of customer interruptions due to tree contact and we had a look and saw that we needed to put in some extra effort there to stay ahead of what we were experiencing, which was a -- we weren't staying ahead of the growth of vegetation along our transmission lines and also on our dams and dikes, so we had to put in a bit more, and there was also an increase in the contract costs. When we went to tender for that, the costs have gone up as well.[109]

Professional Services

- ***Hydro's expenditures for professional services reflect ongoing increases in regulatory activity. In addition, Hydro is incurring increased costs for asset assessments, and the development of operations, maintenance and retirement plans tailored to Hydro's aging asset portfolio.***

The cost of Professional Services in the 2014 Test Year is $10.6 million, which is an increase of $6.8 million over 2007 actual costs. The 2015 Test Year cost of Professional Services declined from the 2014 Test Year to $8.4 million which is $4.6 million higher than 2007 actual costs.[110] The major causes of the increase in Professional Services expenses from 2007 to the 2014 Test Year were higher consulting costs ($5 million more than 2007) and GRA and Board related costs ($2.9 million more than 2007). Consulting costs were higher for a number of reasons, one of which was the Outage Inquiry (accounting for $2 million of consulting costs in 2014). GRA and Board related costs in the 2014 Test Year were higher as a result of a marked increase in the volume of applications and regulatory activity.[111]

[109] September 24, 2015 Transcript, pages 36-37.
[110] Amended Application, Regulated Activities Evidence, pages 2.39-2.40 and Table 2.7.
[111] Amended Application, Regulated Activities Evidence, page 2.40.

Consulting costs are $3.4 million higher in the 2015 Test Year than in 2007 for reasons that include regulatory studies and filings, environmental work and safety and health related programs and condition assessments. GRA and Board related costs are $1.7 million higher in the 2015 Test Year compared to 2007 actual costs because of an increased volume of applications and regulatory activity.[112]

One driver of higher consulting costs is a requirement for condition assessments of assets to verify the timing of overhauls and replacements under the long term asset plan. Another driver is the need to evaluate the extent to which Hydro's operating and maintenance activities should be adjusted or modified to take into account the condition of assets.[113]

External GRA Costs

- ***The external GRA costs reflected in the 2014 and 2015 Test Years are reasonable and full cost recovery is justified in light of the level of recent regulatory activity during this period.***

Hydro's 2014 Test Year revenue requirement includes $1 million in external GRA costs. Hydro's 2015 Test Year revenue requirement includes $333,333 in deferred rate hearing costs (also known as deferred regulatory costs),[114] reflecting the recovery of $1 million of GRA costs amortized on a straight-line basis over a three-year period.[115] As part of their settlement agreement, the Parties agreed to Hydro recovering its GRA costs evenly over a three-year period.[116] The External GRA Costs are included in the professional services costs discussed above.

The amount to be recovered remains at issue. Hydro proposes that the Board approve an update to the 2015 Test Year GRA costs to permit recovery of the actual costs incurred.

[112] *Ibid*.
[113] September 22, 2015 Transcript, pages 99-100.
[114] Amended Application, Finance Evidence, Schedule I, page 9, line 28.
[115] Amended Application, Finance Evidence, page 3.22, lines 7 to 13; IC-NLH-053 (Revision 1).
[116] Settlement Agreement, August 14, 2015, pages 4, paragraph 18.

Hydro notes the timing of Hydro's current GRA was determined primarily by the Government's direction on rates policy.[117] Moreover, it is quite likely the cost of one conducting one GRA in seven years may compare favorably to the cost of conducting two GRAs either three years apart:

> *With regard to regulatory efficiency, Hydro believes there is a trade-off when longer periods occur between GRAs. Because, typically, the prime reason to file a GRA is the need to increase customer rates, the decision to take other steps which results in fewer GRAs will usually result in fewer rate increases to customers and lower overall regulatory costs due to the avoidance of GRAs in the intervening years. It appears to be true that there is an increased complexity and scope of GRAs that occur after several years have passed but, overall, Hydro believes deferring GRAs when it is reasonable to do so reduces the regulatory costs borne by the customer.*[118]

Hydro submits the Amended Application became necessary because of changes in its forecast costs since filing the 2013 GRA. The prudent course of action was to amend the application rather than concluding the GRA and filing another GRA immediately thereafter:

> *MR. O'BRIEN:*
> *Q. Okay, let me ask you sort of - I'll take you a year later then to the point where there was a decision made at Hydro, I guess, to amend the filing for 2013 to update it, I guess, in November of 2014. Can you give me your recollections as to the reasons why that was done and who was involved with making that decision?*
>
> *MR. HENDERSON:*
> *A. That was - the people who were involved in that would have been myself, and the CFO, Mr. Sturge, the General Manager of Finance, and the Rates and*

[117] NP-NLH-369.
[118] CA-NLH-002, page 2, lines 17 to 24.

> *Regulatory Manager. It was presented to me, the financial outlook for the coming year, we had updated some financial plan information, and given the length of time that it had occurred with respect to the 2013, which was the test year, versus where we were seeing things were going, with that length of time that had transpired, we felt that in terms of Hydro's financial outlook, it looked to be - it was most appropriate to file with additional information to update and go forward with the 2014 and 2015 test year. If that wasn't the case, it was very likely that we would have to turn around and have another application right after the 2013 one, you know, with the 2013 test year, and that would have certainly been, I'll say, inefficient in the sense of us going through the regulatory process and we thought at that time the appropriate thing to do was to file for 2014 and 2015 test year.*[119]

Hydro has agreed with other parties that it will file its next GRA no later than March 31, 2017.[120] In preparation for the next GRA, Hydro has agreed that it will file a marginal cost study no later than December 31, 2015; a cost of service methodology report no later than March 31, 2016; and a report on the Rate Stabilization Plan and supply cost recovery mechanisms no later than June 15, 2016.[121] Furthermore, Hydro and the other parties have agreed that a generic Cost of Service hearing will be held following the filing of these reports.[122]

The busy regulatory calendar for 2016 supports the level of regulatory costs included in the 2015 Test Year as it is expected to continue at the 2015 Test Year level for 2016.

CDM

- ***Hydro's CDM initiatives are cost justified and consistent with the provision of least cost reliable service.***

[119] September 23, 2015 Transcript, page 6, line 14 to page 7, line 21.
[120] Settlement Agreement, August 14, 2015, page 5, paragraph 23(d).
[121] Settlement Agreement, August 14, 2015, page 5, paragraph 23(a) to (c).
[122] Settlement Agreement, August 14, 2015, page 5, paragraph 23.

For the Island Interconnected System, Hydro delivers energy efficiency programs in a joint effort with NP under the takeCHARGE initiative.[123] The utilities use the Total Resource Cost test (a cost-benefit analysis) to evaluate the economics of the energy efficiency programs.[124]

CDM Plan initiatives include activities to encourage behavioural change by customers, the provision of rebates, marketplace promotions and other efforts targeted at reducing reliance on electricity.[125]

Under the takeCHARGE brand, Hydro also has implemented CDM programs such Isolated Systems Community Energy Efficiency Program and the Isolated Systems Business Efficiency Program, which target isolated diesel communities. The measures implemented by Hydro in isolated communities have achieved total energy savings of 4.3 GWh from 2012 to 2014.[126] Hydro's CDM initiatives in isolated diesel communities help to constrain the growth of the Rural Deficit.

Hydro also maintains the Industrial Energy Efficiency Program to assist in determining the appropriate program design and components for an industrial customer energy efficiency initiative.

Hydro's initiative to improve energy efficiency at its own facilities has been implemented at many facilities across the Province and at Hydro's head office in St. John's. The internal energy conservation steps taken by Hydro have resulted in an estimated 9.5 GWh of energy savings from 2009 to 2014.[127]

[123] PUB-NLH-313.
[124] The economic tests are updated annually for the programs and are included in NP's CDM reports that are filed annually with the Board.
[125] Amended Application, Introduction Evidence, page 1.14.
[126] IN-NLH-241, Attachment 1, page 6, Table 2.
[127] IN-NLH-239, page 3 of 4, Table 2.2.

Other Income and Expenses

- ***Hydro should be allowed full recovery of its Other Income and Expenses, because the claimed Test Year amounts are within expected levels and unchallenged.***

In this application, "other income and expense" refers to costs associated with the loss on disposal, removal cost and insurance.[128] Hydro's 2014 Test Year and 2015 Test Year amounts for "other income and expense" are $2.1 million and $4.1 million respectively.[129] As can be seen from the Grant Thornton's report, the forecast asset disposal costs of $2.1 million and $4.1 million for the two respective years include a number of constituent elements, such as the net book value of assets that are being retired, proceeds on disposal of assets and removal costs.[130] Hydro's treatment of these asset disposal costs is in accordance with Board Order P.U. 40(2012).

The evidence shows that the 2014 and 2015 Test Year amounts for other income and expenses fall in line with the three-year average of the actual loss on disposal ($3.3 million).[131] Hydro's evidence explains how the forecast costs were developed on the basis of a project-by-project assessment of work that results in the retirement of existing assets.[132]

No intervenor raised any issues with the other income and expense category of costs and Hydro submits that the costs as set out in its evidence[133] should be approved.

D.2.2.2 Supply Costs

- ***Supply costs for 2015 Test Year should reflect a No. 6 fuel cost of $64.41 (Cdn) per barrel.***
- ***Supply costs incurred at HTGS should be based on a 2015 Test Year fuel conversion factor of 607 kWh/bbl.***

[128] NP-NLH-319.
[129] Amended Application, Finance Evidence, Schedule III, page 1 of 2, line 32.
[130] Grant Thornton Financial Consultants Report, June 12, 2015, page 84, Table 72.
[131] NP-NLH-319.
[132] NP-NLH-318.
[133] Amended Application, Finance Evidence, Schedule III, page 1 of 2, line 32.

- ***Hydro's Capacity Assistance agreement costs for the 2014 and 2015 Test Years benefit customers and should be approved for inclusion in Hydro's revenue requirement.***
- ***Supply Costs on the Isolated Systems and the Labrador Interconnected System are reasonable.***

Overview

Hydro's supply costs principally consist of purchases of No. 6 fuel for Holyrood, purchases of diesel and gas turbine fuel, and power purchases from other suppliers. Table 1 provides the proposed 2015 Test Year fuel costs that Hydro recommends for use in setting customer rates reflecting the correspondence provided to the Board on October 28, 2015.

Table 1 Supply Costs by Type for 2015 Test Years
($ Millions)

Supply Cost	**2015 Test Year**
No. 6 Fuel (net of RSP deferral)[134]	$169.0
Diesel and gas turbine fuel[135]	21.4
TOTAL	190.4
Fuel Supply Deferral[136]	2.0
NET FUEL COST	**192.4**
Power purchases[137]	59.9
TOTAL SUPPLY COST	**251.3**

The elements of Hydro's supply costs are discussed separately below.

[134] Amended Application, Finance Evidence, Schedule III, line 23 and line 24.
[135] Amended Application, Finance Evidence, Schedule III, line 26.
[136] Amended Application, Finance Evidence, page 3.12, Table 3.3 Reflects a 5-year amortization of 2014 capacity related supply costs of $9.65 million.
[137] Amended Application, Finance Evidence, Schedule III, line 26.

Island Interconnected Supply Costs

No. 6 Fuel

Forecast production at the HTGS is a function of forecast load less Hydro's own hydraulic generation, power purchases, and standby generation as shown in Table 2.

Table 2

Island Interconnected Supply		
Line No.	**Particulars**	**Energy (GWh)**
1	**NLH Hydroelectric Generation**	**4,604**
2	Power Purchases	
3	Nalcor Exploits and Star Lake	776
4	Wind	189
5	CBPP Cogen	51
6	Rattle Brook	15
7	**Total Power Purchases**	**1,031**
8	NLH standby generation	
9	GTs and CTs	11
10	Diesels	0
11	**Total Standby Generation**	**11**
12	Total Island Supply Requirement	7,239
13	Less Total Non - Holyrood	(5,646)
14	**Holyrood Energy Requirement**	**1,593**

Therefore, the forecast 'Holyrood Energy Requirement' determines the test year quantity of No. 6 fuel to be consumed. The forecast cost of No. 6 fuel is a function of forecast fuel cost, volume of fuel consumed, and the fuel conversion factor.

The 2015 Test Year the price of fuel was estimated to be $93.32 per barrel. However, the forecast price of fuel has declined since the filing of the Amended Application. Hydro filed with the Board on October 28, 2015 an updated fuel price projection for 2016. The revised 2015 Test Year forecast No. 6 fuel cost per barrel reflecting the 2016 forecast fuel price is $64.41 ($Cdn).

This cost is based on an average of the forecast 2016 No. 6 fuel price of $69.40 per barrel ($Cdn)[138] and the forecast 2015 year-end average inventory cost of $55.35 per barrel ($Cdn). Hydro submits that the cost of $64.41 per barrel of No. 6 fuel should be used by the Board when setting rates that come in effect in 2016 as this price reflects Hydro's most recent forecast cost.

No. 6 Fuel: Effect of Hydrology

The volume of fuel used at Holyrood is a function of the level of hydrology forecast. Hydro's forecasted hydraulic production was agreed to by all parties in the Settlement Agreement. Hydro proposes the Board accept this level of hydraulic production for the purpose of setting rates in 2016.

No. 6 Fuel: Conversion

The forecast of Holyrood fuel consumption, and ultimately Holyrood production costs, is affected by the energy conversion factor for a barrel of No. 6 fuel. The Board, in 2007, set this conversion factor at 630 kWh per barrel of No. 6 fuel consumed.[139] Since that time, Hydro has never achieved the fuel conversion rate of 630 kWh/bbl. In fact, during this period, with the exception of 2008, Hydro has not achieved a fuel conversion factor greater than 614 kWh per barrel.[140] To the extent that the actual fuel conversion factor has been lower than the 2007 Test Year level, the additional Holyrood production costs have been borne by Hydro.

Mr. P. Bowman on page 27 of his pre-filed evidence, dated June 4, 2015 states:

> *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*

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[138] The forecast No. 6 fuel price of $69.40 per barrel differs from the $69.15 per barrel provided in the IIC RSP fuel rider calculation filed October 15, 2015 because the forecast fuel price for 2016 is based on a forecast conversion rate from $US to $Cdn and the fuel price in the fuel rider calculation requires the use of a historical conversion rate based on approved RSP rules.

[139] See Order No. P.U. 8(2007).

[140] See hydro's Amended Application, Section 2, Schedule V, Page 1 of 1.

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.

Mr. P. Bowman has proposed two adjustments to Hydro's proposed fuel conversion rate of 607 kWh/bbl: (i) an adjustment of +7 kWh/bbl for a change in the approach for determining the level of Holyrood station service; and (ii) an adjustment of +8 kWh/bbl for the installation of new variable frequency drives on the unit forced draft fans.

Excluding the new capital improvements, Mr. P. Bowman has proposed a conversion rate of 614 kWh/bbl.[141] Hydro submits that the historical performance of the HTGS in recent years (since 2010 in particular) has been nowhere near this level, per Table 2.21 on page 2.75 of the Amended Application:

Table 3

Holyrood Fuel Conversion Performance and Hydro Financial Impact
2009 - 2014

	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Forecast
Fuel Consumption ('000 bbls)	1,534.7	1,363.2	1,469.2	1,428.3	1,611.0	2,334.5
Actual Fuel Conversion Rate (kWh/bbl)	612	589	603	599	594	588
2007 TY Fuel Conversion Rate (kWh/bbl)	630	630	630	630	630	630
Hydro's Financial Loss ($ million)	2.4	4.9	3.5	3.9	5.1	8.8

This deterioration in performance continues in 2015, with Hydro forecasting a fuel conversion factor of 597 kWh/bbl.[142] While Mr. P. Bowman has proposed a different approach for

141 607 kWh/bbl + 7 kWh/bbl.
142 See Schedule 3, Appendix D of Hydro's Amended 2015 Cost Deferral Application.

determining the station service factor used in calculating the net fuel conversion rate in 2015; it ultimately remains another approach, and one which does not lead to a reconciliation with Hydro's actual fuel conversion performance from the past seven years.

With respect to the +8 kWh/bbl that Mr. P. Bowman has forecasted for the new capital improvements at the HTGS, Hydro submits that this level of improvement, in relation to the average Holyrood unit loading forecast for the test year, is overstated. Mr. Goulding, for Hydro, in his testimony stated:

> *Yes, and although the preliminary data says this load point does indicate savings of 7 to 8 kilowatt hours per barrel, from a test year perspective it would have to be lower because we're going in with a higher average loading, and the analysis that we've done, and again it's very limited at this point, is that the benefit is in the order of 4 to 5 kilowatt hours per barrel.* [143]

Hydro submits that if this improvement were to be included in the forecast fuel conversion factor for 2016, a level of +4 kWh/bbl would be more appropriate than the +8 kWh/bbl as suggested by Mr. Bowman.

Hydro submits that the 607 kWh/bbl proposed in the test year is appropriate for setting rates in 2016. While this fuel conversion rate does not take into account the +4 kWh/bbl due to the new variable frequency drives, the historical conversion rate shows there is greater risk of achieving a lower conversion rate than a higher one.

Hydro submits that approval of the Holyrood Conversion Deferral to capture variances in the HTGS conversion factor would ensure that neither Hydro nor customers are advantaged or disadvantaged by changes in the fuel conversion factor between test years. This matter is dealt with in Section D.4.1.3.

[143] October 21, 2015 Transcript, pages 120, line 23 to 121, line 6.

Power Purchases

Hydro purchases power and energy from other suppliers to meet Hydro's customers' requirements on the Island Interconnected System. Power purchase expense included in the 2014 and 2015 Test Years is $60.3 million and $57.4 million respectively.[144] Included in power purchase expense are costs associated with capacity assistance agreements.

The primary reason for the increase in power purchases costs relative to the 2007 Test Year is due to the addition of wind and Exploits power. These power purchases have benefited customers through reduced HTGS fuel requirements. Hydro submits these power purchases are reasonable and the associated costs should be included in the 2015 revenue requirement.

Liberty, in its review of prudence issues dated July 5, 2015, stated that the CBPP Capacity Assistance Agreement for 2014 made "…a major contribution to system reliability…" and that "[t]here is therefore no reason for Liberty to challenge the prudency of that agreement".[145]

Hydro also entered into capacity assistance agreements with CBPP and Vale prior to the 2014-15 winter season. Hydro made a total of three requests for capacity assistance during the 2014-2015 Winter Period. These capacity requests helped to maintain generation reserves and, in the case of the March 4, 2015 events, lessened the outage impact on customers.

Hydro submits that the Capacity Assistance agreement costs for the 2014 and 2015 Test Years benefit customers and should be approved for inclusion in Hydro's revenue requirement.

Gas Turbine and Diesel

Hydro operates a number of gas turbines and diesel units on the Island Interconnected System, which provide additional long term generation capacity and increased generation reserves. The

[144] Section 2, Regulated Activities, Schedule VI, Page 1 of 1.
[145] Liberty Consulting, Review of Prudence Issues, Dated July 6, 2015, Page 20.

cost of diesel and gas turbine fuel has been included in the 2014 and 2015 Test Years at $6.4 million and $3.6 million respectively.[146]

Included in these forecast fuel costs for 2015 is the cost of operating the new Holyrood CT. In contrast to forecast production levels included in the 2015 Test Year, Hydro has been running the Holyrood CT at minimum output levels during peak periods of the day to provide enhanced system reliability. This operational practice began in 2015 in response to enhanced reliability assessments following the March 4, 2015 outage event, and has resulted in increased fuel consumption at the Holyrood CT relative to the 2015 Test Year forecast. Hydro submits that the cost of Island Interconnected gas turbine and diesel fuel be approved in conjunction with the proposed Energy Supply Account so that Hydro has the opportunity to recover prudently incurred supply costs on the island interconnected system.

Isolated Systems Supply Costs

The primary source of power supply for Hydro's isolated systems throughout the Province is diesel generation. The cost of diesel and gas turbine fuel has been included in the 2014 and 2015 Test Years at $23.2 million and $21.9 million respectively.[147]

Hydro, in its letter to the Board dated October 28, 2015, provided an updated 2015 Test Year forecast cost based on the most recent cost of diesel fuel of $20.0 million. No issues were raised by any party to the hearing with respect to these costs. Hydro submits that these items should be accepted for inclusion in revenue requirement by the Board.

Labrador Interconnected Supply Costs

The majority of all energy consumed on the Labrador Interconnected System is purchased from CF(L)Co. Power purchase costs from CF(L)Co are forecast to be $2.1 million and $1.9 million for 2014 and the 2015, respectively. No issues were raised by any party to the hearing with respect

[146] Section 2, Regulated Activities, Schedule V, page 1 of 1.
[147] Section 2, Regulated Activities, Schedule VIII, page 1 of 1.

to these costs. Hydro submits that these items should be accepted for inclusion in revenue requirement by the Board.

D.2.2.3 Financing Costs

- ***The debt guarantee provides substantial value to customers. The level of the debt guarantee fee payments are reasonable and are provided in response to a Government directive.***
- ***The timing of the RSP Surplus disposition in 2016 is currently uncertain. No adjustment to Hydro's 2015 Test Year financing cost is necessary.***

General

Hydro's 2014 Test Year interest expenses are $89.7 million and Hydro's 2015 Test Year interest expenses are $89.2 million. The 2014 Test Year interest expense is $13 million less than the 2007 Test Year; the 2015 Test Year is $13.5 million less.[148]

Three issues have arisen concerning Hydro's financing costs. Two concern Hydro's debt guarantee fee payments to Government:

- Is Hydro obligated to pay the fee; and
- Should it be apportioned, with only part of Hydro's payments recognized for rate-setting purposes.

Hydro's debt guarantee fee payments respond to a directive to Hydro from Government. The obligation argument is relevant only to the extent the Board has authority over rate recovery, and the Board should exercise that authority to allow recovery, as the Board has done consistently, because the fee is reasonable and provides direct benefits to ratepayers.

The Board should reject apportionment consistent with the findings reached by Hydro's financial advisor, Scotiabank.[149] The evidence promoting apportionment does not recognize

[148] Amended Application, Finance Evidence, page 3.17, Table 3.7, line 2.

the enhanced access to capital markets furnished by the guarantee and it rests on an overly narrow view of the time frame for assessing benefits.

The third issue centers on the interest accruing in Hydro's RSP accounts, hypothesizing an interest expense reduction Hydro might realize should the RSP accounts be paid out and the disbursed funds replaced with long-term debt. Hydro submits that this issue is premature, as it rests on decisions the Board has not yet been made concerning the disposition of RSP balances.

Debt Guarantee Fee: Basis for Payment

The debt guarantee fee is an annual fee Hydro pays Government in return for Government guaranteeing Hydro's debt obligations. The fee has been in effect for approximately 20 years, and for most of that time the fee equaled 1% of Hydro's outstanding debt obligations.[150] In 2008, as a means of temporarily improving Hydro's net income, the Government waived Hydro's requirement to pay the fee while continuing to guarantee Hydro's debt. This waiver continued until 2011 when the Government issued OC2011-218, directing that the fee be reinstated at a market rate of 25 basis points for short-term obligations and 50 basis points for long-term obligations.[151]

Hydro has always included its debt guarantee fee payments in its revenue requirement.[152] The Board always has permitted rate recovery, while acknowledging the debt guarantee's "fundamental importance" and "key role" in Hydro's overall financial condition and specific ability to access capital markets.[153]

[149] PUB-NLH-061, Attachment 1.
[150] Amended Application, Finance Evidence, page 3.31, lines 10-12.
[151] PUB-NLH-058, Attachment 1, paragraph ii. Short-term obligations have a term to maturity of ten years or less; long-term obligations have a term to maturity longer than ten years.
[152] Amended Application, Finance Evidence, page 3.31, lines 12-13.
[153] November 16, 2015 Transcript, Page 16, lines 7-23 (quoting from Order No. P.U. 7(2002-2003) page 35, and Order No. P.U. 14(2004) page 29. See also Amended Application, Finance Evidence, page 3.31, line 13.

Hydro pays the debt guarantee fee (and has reflected payment in the 2014 and 2015 Test Years) because Government, has directed Hydro to do so.[154] NP questioned whether OC2011-218 imposed a legal obligation to pay, since the statutory requirement to pay was not carried forward when the Hydro Corporation Act, 2007[155] repealed and replaced the previously governing, 1990 statute.[156]

Hydro's position is that paying the debt guarantee fee is justified because doing so complies with a stated Government policy — OC2011-218 — and because the fee is a fair exchange for the benefits debt guarantee provides to Hydro's customers.[157] Mr. Pelley testified that the Board should grant recovery of the debt guarantee fee because of the guarantee's continuing importance to credit market access. Further, Scotiabank's independent analysis confirmed that Government's new fees (fees much lower than those previously approved by the Board) were reasonable.[158]

Debt Guarantee Fee: Apportionment

Grant Thornton for the Board did not take issue with how Scotiabank measured the reduction in yield spread approach to measuring the value of the debt guarantee,[159] but criticized Scotiabank for not apportioning the cost savings by comparing these spreads to the fees Hydro pays to obtain them.[160] Scotiabank found that for short-term debt, the cost savings attributable to the Government guarantee averaged between 31.7 and 33.0 basis points ("bps"). According to Grant Thornton, a complete analysis would compare these savings to what Hydro would have to pay Government to obtain them. Of the 31.7 to 33.0 bps reduction in short-term yields, Hydro would be returning between 76 and 79 percent to Government via the 25 bps debt guarantee fee. For long-term debt, the yield spread was 35.6 to 47.8 bps, so in

[154] In accordance with OC2011-218.
[155] SNL 2007, c H-17.
[156] Id., section 40, repealing Hydro Corporation Act, RSNL 1990, c H-16.
[157] NP-NLH-254.
[158] November 16, 2015 Transcript, pages 15, line 18 to 17, line 13; and pages 73, line 11 to 82, line 3.
[159] Grant Thornton Report on 2013 Amended General Rate Application, June 12, 2105, page 19, lines 22-24.
[160] November 16, 2015 Transcript, page 96, lines 2 to 11; pages 175, line 12 to 176, line 25 and Grant Thornton Report on 2013 Amended General Rate Application, June 12, 2015, page 20, lines 16-18.

Grant Thornton's view the 50 bps debt guarantee fee would more than exceed the savings it would generate.[161]

Grant Thornton's apportionment analysis does not to account for a central benefit of Government's debt guarantee: market access. Government utilities across Canada benefit from the creditworthiness of their respective government by either obtaining a debt guarantee which is recovered through rates (Québec), or by borrowing directly from their provincial governments (British Columbia, Ontario, Manitoba). These provinces either extend guarantees or borrow funds on their utilities' behalf because credit markets view governments as among the most creditworthy of counter parties.[162] As Scotiabank observed, governments and those with government guarantees can access capital markets when others cannot, and they can do so on more flexible terms:

> *There are two additional features of a Guarantee has that are very difficult to value, namely; that during periods of stress in the credit markets, a guarantee from a government entity provides for unrestricted market access and that a guarantee allows for more flexibility as to maturity.*[163]

The benefits of access may be hard to quantify, but the value of this central feature of Canadian utility financing and regulation cannot be denied.

Grant Thornton inferred that for long-term debt Government's 50 bps fee is too high because the basis spreads they examined were less than 50 bps for the period. This inference does not recognize the value of enhanced market access and increased flexibility; it also implies the period it examined captures all market conditions. As Mr. Pelley testified, yield spreads fluctuate over time:

[161] Grant Thornton Report on 2013 Amended General Rate Application, page 20, lines 7-15.
[162] November 16, 2015 Transcript, pages 13, line 14 to 14, line 24; pages 82, line 4 to 90, line 22.
[163] PUB-NLH-061, Attachment 1, page 6.

> *[O]ne thing I recognize is the basis point spreads that [Grant Thornton is] quoting here are based on looking at the market over a certain period of time. That's not to say that if we expanded that window, that there's not times that those spreads are probably 70 or 80 basis points or 100. If you look at it over a long cross-section of time, such that, you know - like, all you're trying to do is say - you're trying to look at a period of time and say what's reasonable.*
>
> *Okay, you know, they're quoting here 35.6 to 47.8, and all they're saying from that is in their view, based on that, 50 is not unreasonable, but from my position, I'm not concerned that 50 is too high for the reason I just gave. These spreads fluctuate over time. There will be times when actually your long term, let's say, your greater than ten year spread to your question, may be less than 50 basis points, in which case the fee - I don't want to describe it this way, but you could say "too high", but then there would be other periods of time where the spreads could be 70 or 80 basis points. So you're trying to capture a concept that's fluctuating in time with a single number. There's always going to be some discrepancy.*[164]

Government started imposing the debt guarantee fee approximately 20 years ago,[165] and the Board has consistently recognized that the guarantee provides value to ratepayers.[166] The benefits have not changed, and with the market-based fee, the cost of the guarantee has fallen substantially. Hydro's 2014 Test Year includes a debt guarantee payment of $3.7 million, $5.3 million less than the fee would have been under the previous, 1% requirement. For the 2015 Test Year, Hydro's payment is $4.4 million, $7.5 million less than the previous 1% requirement.[167] Hydro sees no reason for apportionment.

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[164] November 16, 2015 Transcript, pages 94, line 3 to 95, line 5. See also November 19, 2015 Transcript, pages 28, line 3 to 29, line 6.
[165] Amended Application, Finance Evidence, page 3.31, lines 10-12.
[166] November 16, 2015 Transcript, page 16, line 5 to page 17, line 2.
[167] Amended Application, Finance Evidence, page 3.32, lines 7-11.

RSP Interest

Hydro's 2014 Test Year interest expenses include $18.2 million of interest on Hydro's RSP balances; the 2015 Test Year includes $12.4 million.[168] Per the RSP rules, interest on RSP balances accrues at Hydro's WACC. For the 2014 Test Year, Hydro's WACC, also equal to Hydro's return on rate base, is 7.12%; for the 2015 Test Year, the WACC is 6.82%.[169]

Comparing Hydro's total capital for financing rate base against the combination of sum of Hydro's mid-year rate base plus capital work in progress, Mr. P. Bowman for the IICs hypothesizes that the RSP balances are functioning as an additional form of capital financing for Hydro, bearing interest at Hydro's WACC. Mr. P. Bowman then speculates that upon refunding the RSP balances Hydro will substitute these funds with long-term borrowing at a significantly lower rate,[170] resulting in immediate savings to Hydro.[171]

When the IICs asked Hydro how it was going to finance the refund of the NP surplus, Hydro responded, "As this matter has not yet been ruled on by the Board, no decision has been made with regard to financing."[172] Hydro still considers the timing of the RSP Surplus disposition to be uncertain.

D.2.2.4 Productivity and Cost Management

- ***By instituting a shared services model, Hydro has improved productivity and efficiency to the benefit of customers through more effective use of its employees.***
- ***Hydro has demonstrated a corporate culture that emphasizes cost consciousness and efficient operations.***

[168] Amended Application, Finance Evidence, schedule I, Page 10, line 2.
[169] Amended Application, Finance Evidence, page 3.17, line 7 (Table 3.7).
[170] As of November 20, 2014, Hydro estimated its marginal cost of long-term debt at 3.558%. Grant Thornton Report on 2013 Amended General Rate Application, page 17, line 18 to page 18, line 2 (referencing PUB-NLH-53 (Revision 1)).
[171] Pre-Filed Evidence of P. Bowman and M. Najmidinov, pages 28-29; Ex. 2, pages 11-12; and September 30, 2015 Transcript page 100, lines 7-17 and pages 108, line 12 to 111, line 2.
[172] IC-NLH-054, lines 7-8.

- ***A productivity allowance is not warranted because Hydro has achieved meaningful productivity gains. Inflation provides an implicit productivity allowance as the 2015 Test Year is being used to set rates for 2016.***

Since 2007, Hydro's operating labour costs have increased by just 0.01 cents per kWh (one one-hundredth of a cent) on an inflation-adjusted basis, from 0.83 cents per delivered kilowatt-hour in 2007 to 0.84 cents per delivered kilowatt-hour in the 2015 Test Year.[173] This has been achieved while Hydro has been forced to manage cost pressures in areas that have a significant impact on Hydro's overall costs.

Hydro's evidence explains many specific areas where additional productivity and efficiency have been achieved. The shared services model is an example of measures that have been implemented to improve productivity and efficiency. As a result of the shared services model, employees are utilized in the most effective manner, which works to the benefit of Hydro. Another example is work planning and scheduling. Hydro identified this as an area in which efficiency improvements could be made and it has implemented changes to work scheduling, as well as execution, in order to be more efficient in its asset management and maintenance.[174]

Furthermore, in the context of elaborating on actions taken by Hydro that contain the growth of the Rural Deficit, Hydro provided evidence of numerous Hydro-wide cost control initiatives.[175] While Hydro-wide "Initiatives with Rural Deficit Impacts"[176] do indeed limit the growth of the Rural Deficit, they are measures that more generally result in cost savings and tend to increase Hydro's productivity and efficiency. As well, in addition to the initiatives that were explained in the context of the Rural Deficit, Hydro's evidence provides examples of many other cost saving initiatives.[177]

[173] CA-NLH-328, page 2.
[174] September 23, 2015 Transcript, pages 133-136 and 145.
[175] NP-NLH-098 (Revision 1, Dec 9-14).
[176] NP-NLH-098 (Revision 1, Dec 9-14), Attachment 1.
[177] NP-NLH-057 (Revision 1, Mar 23-15).

The Consumer Advocate's questions about some of Hydro's specific productivity success stories touched on whether the measurable financial outcomes of certain initiatives are of a relatively small magnitude.[178] However, Hydro would be remiss if, in its efforts to find productivity gains, it were to ignore potential gains that are individually of a relatively small size. Hydro focuses on finding least-cost ways to provide safe and reliable service and does not dismiss potential productivity gains simply because their magnitude may be perceived to be small. The cumulative effect of small savings is meaningful and reduces overall costs to customers.

Hydro managers are responsible for ensuring work is being done as efficiently as possible. Each manager is responsible for a budget and generally, there is a financial person to support management of cost control.[179] As Mr. R. Henderson explained in this extended exchange with the Consumer Advocate, cost control at Hydro is not something to be relegated to specified individuals or directives; rather, cost control is a central element of Hydro's culture that permeates activities throughout the organization:

> *JOHNSON, Q.C.:*
> *Q. And can you explain how Hydro identifies efficiency initiatives within its organization?*
>
> *MR. HENDERSON:*
> *A. What we do is through again the budgeting process, through our planning process in which we develop our five year strategic plan as a key input, we look at that to identify initiatives that we could undertake to make us more efficient. So through that strategic planning process, we would be looking at what we will be doing in terms of improvements on a continuous improvement basis, and then through the budgeting process, we would establish that as well with monitoring what goes forward in the budget in trying to keep costs within inflationary pressures, to try to stay within what is expected inflation, and that's done*

[178] September 23, 2015 Transcript, pages 144-145.
[179] September 23, 2015 Transcript, pages 135-137.

through the budgeting process. So through that, you drive actions to try to bring out efficiencies.

JOHNSON, Q.C.:
Q. Mr. Henderson, to your knowledge, has made, I mean, a directed effort to identify efficiencies, or as Mr. O'Brien put it, to try to do more with less? I mean, a directed effort to identify such efficiencies within Hydro? Are you aware of any such directed effort?

MR. HENDERSON:
A. In terms of directed efforts, what we would be doing is through that budgeting process, through our work execution, looking at our long term asset plans, is looking for least cost solutions to everything that we do. So that would be part of looking at each capital proposal, any efficiency gains would be sought through that, so it's through a number of different avenues. There isn't a one subscribed "this is an efficiency improvement program", it's expected each and every manager is working to establish their work to be done in the most efficient manner. That challenge occurs through the strategic planning process, it occurs through the budgeting process, to ensure that those types of things are done.

One area that we've been focusing on, in particular, and I think I may have spoken to Mr. O'Brien about that, is the work scheduling and planning area where we feel that there is gains to be made there that we're setting out objectives there to improve the amount of work that we complete in terms of work execution, which is all around asset management and maintenance to get more done, and to schedule it efficiently so that the cost to that annual maintenance work is at the least cost.

JOHNSON, Q.C.:
Q. But, I guess, it's - what you've explained to us in terms of what you do is not part of a directed effort, and, I guess, you would agree that what you've done and what you've described has led to a circumstance where costs have outstripped inflation by about 30 odd percent, right?

MR. HENDERSON:
A. There's a number of things that are happening within the company related to the condition of our facilities, the aging of our assets, our capital investment program, the environment in which we work, our employees work, all of those items are putting upward cost pressure certainly to Hydro, and that we seek to manage those as efficiently as we can.

JOHNSON, Q.C.:
Q. Well, as part of seeking to manage them as efficiently as you can, can you explain why a directed effort has not been made? I mean, we talked about organizational excellence and, you know, high cost controlled environment. Can you explain why a directed effort has not been given, given the importance of identifying efficiency initiatives?

MR. HENDERSON:
A. Well, we have done a number of things over the3 years to look for those types of things, and we continue to look for those initiatives. To establish, I'll say, a separate initiative to pull people out of their jobs and go at that, we've opted not to do it that way, we do it through each manager who's expected to do that in their own work environment to ensure that they're doing it as efficiently as possible. We, as I said, work planning and scheduling was one area that we felt from an operations standpoint we can make improvements and are embarking

on that as a critical piece to do our work execution in terms of our asset management and maintenance more efficiently.

JOHNSON, Q.C.:
Q. So you indicated that you opted not to go the route of a directed effort. When was that decided upon?

MR. HENDERSON:
A. Well, I say that and it's somewhat - I'll say, it's by default, that we didn't do it. I mean, the way we are doing it and looking after our facilities, as I said, is through challenges to each of our managers to stay within inflation with their operating budgets.

JOHNSON, Q.C.:
Q. If I could ask you to go to 229. . . . Yes, Page 7 of 19. These are the general managers and managers who report to you, and I don't have to read them, they're there on the screen. Is any of your managers specifically tasked in their job description with cost control? Is there a go to manager on, you know, the cost controls within your organization?

MR. HENDERSON:
A. The cost controls, there are - in terms of cost controls and cost management, each manager has a responsibility, they have a budget that they have to manage. They have people in their groups - I think in almost every case there is a financial person that works alongside with them to help manage their budgets, help them to exercise the cost control that they need by providing them reports and data on how things are going relative to the budget, how they are managing their expenses.[180]

[180] September 23, 2015 Transcript, page 145.

Hydro has also included in the 2015 Test Year a challenging reduction in overtime expenses from historic levels.[181] Hydro has constrained 2015 operating overtime expenses even though it is experiencing growing and pressing requirements for overtime. Using 2013 overtime costs as a point of comparison - since those costs were not affected by the January 2014 outage - actual costs in 2013 were $12.3 million, while Hydro has reduced overtime costs to $10.1 million in the 2015 Test Year.[182]

Hydro aims to reduce its overtime costs through redeployment of staff and recruitment initiatives.[183] Because the achievement of this challenge has been assumed in the 2015 Test Year, there will be a negative impact on Hydro's income to the extent that the challenge is not met, while rates set on the basis of the 2015 Test Year will retain the benefit of the assumed overtime reduction.[184]

Another built-in productivity challenge relates to the timing of implementation of final rates for Hydro. Final rates will be based on a 2015 Test Year, but, given the timing of a Board decision, will not become effective until 2016. The lack of any adjustment to recognize the inflationary impact on costs from 2015 to 2016 effectively operates a productivity allowance for Hydro.[185]

Section D.3: Cost of Service and Rates

D.3.1 Settled Matters

D.3.1.1 Future Studies

There are a number of matters on cost of service and rate design to be addressed by the Board prior to the implementation of customer rates reflecting the costs of the Labrador-Island interconnection.[186] The rate-related matters include:

[181] CA-NLH-328, page 2.
[182] September 22, 2015 Transcript, page 97.
[183] September 23, 2015 Transcript, pages 165-171.
[184] CA-NLH-328, page 2.
[185] October 7, 2015 Transcript, page 106.
[186] Amended Application, Rates and Regulation Evidence, pages 4.4 - 4.6.

- A review of the embedded cost of service methodology;
- The completion of a marginal cost study and rate design review; and
- A review of Hydro's regulatory mechanisms for the recovery of supply costs.

Hydro has committed to filing a number of reports to permit the Board to conduct a comprehensive review of each of these items.

The Parties agreed the Board should in its Order direct Hydro to file:

(a) A marginal cost study no later than December 31, 2015;
(b) A cost of service methodology report no later than March 31, 2016;
(c) A report on the RSP and supply cost recovery mechanisms no later than June 15, 2016; and
(d) A GRA no later than March 31, 2017 for rate changes based on a 2018 Test Year.

The Parties also agreed a generic cost of service hearing should be held following the filing of the reports outlined in (a) to (c) above.[187]

D.3.1.2 Cost of Service Methodology

In the initial Settlement Agreement, the Parties agreed on the cost of service methodologies in Exhibit 13 (2015 Test Year Cost of Service) with respect to functionalization, classification and allocation, subject to nine exceptions:[188]

(a) The treatment of the curtailable load of NP;
(b) The classification of wind energy purchases;
(c) The classification of all Holyrood fuel costs;
(d) NP's load factor;
(e) The specific assignment of the frequency converter to CBPP, the calculation of that charge and any credit in the Cost of Service study associated with the frequency converter;

[187] Settlement Agreement, paragraph 23.
[188] Settlement Agreement, page 3, paragraph 13.

(f) The calculation of the capacity factor for the HTGS;

(g) The allocation methodology for the Rural Deficit;

(h) The basis on which specifically assigned charges to customers is calculated; and

(i) The use of the forecast 2015 load for rate-setting purposes.

Items (a) through (f) were resolved in the Supplemental Settlement Agreement.[189] Items (g), (h), and (i) were contested in the current GRA requiring those matters to be decided on by the Board.

In the Supplemental Settlement Agreement, the Parties also agreed on the requirement and the scope of a Cost of Service Methodology Review to be completed in 2016:

> *The Cost of Service Methodology Review to be completed in 2016 will include a review of: (i) all matters related to the functionalization, classification and allocation of transmission and generation assets and power purchases (including the determination whether assets are specifically assigned and the allocation of costs to specifically assigned assets) and (ii) the approach to CDM cost allocation and recovery.*[190]

All Parties agreed that with respect to the new cost items in the current GRA, the Board should approve that (i) wind purchases be classified as 100% energy-related and (ii) the costs associated with Hydro's capacity assistance agreements with Vale and CBPP shall be treated as production demand-related and allocated to each class of service based on a single coincident peak allocator.[191] With the exception of the allocation of (i) the Rural Deficit and (ii) operating

[189] Supplemental Settlement Agreement, page 2, paragraphs 7(a)-(e) and 8.

[190] Supplemental Settlement Agreement, page 3, paragraph 13. For further discussion of the cost of service examination, refer to Settlement Agreement, page 5, paragraph 23.

[191] Settlement Agreement page 3, paragraph 14(b). This settlement provision is agreed to notwithstanding the generality of the parties' agreement with the functionalization, classification and allocation contained in Hydro's COS Study.

and maintenance costs to specifically assigned assets, the Parties have agreed that the existing cost of service methodology be maintained consistent with the last GRA.

D.3.1.3 Cost of Service Data for KPI Reporting

The Parties also agreed Hydro should continue to report functionally oriented KPIs as required by the Board in Order No. P.U. 14(2014); however, such reporting will be based on the most recent Test Year Cost of Service study that is approved by the Board and not on a forecast basis. [192] The agreed approach reduces the administrative requirement to complete a Cost of Service study annually to support KPI reporting.

D.3.1.4 Rates and RSP Issues

The initial Settlement Agreement and the Supplemental Settlement Agreement provided agreement on the following rates and RSP issues:

- (a) The current rate design for IICs should continue to apply as Hydro proposed in the Application.[193]
- (b) The rate design for NP will be determined using the following approach:
    - (i) The demand charge will equal $4.75 per kW of billing demand;
    - (ii) The end block energy rate will be determined based on the 2015 Test Year No. 6 fuel price divided by the 2015 Test Year Holyrood fuel conversion factor (both to be determined by the Board); and
    - (iii) The approved 2015 Test Year revenue requirement not recovered through the demand change and the end-block energy charge will be used to compute the first block energy charge. [194]
- (c) Hydro's wholesale rate will include a curtailable load credit as proposed in its Amended Application.

[192] Settlement Agreement, page 4, paragraph 22.
[193] Settlement Agreement, page 3, paragraph 15.
[194] Supplemental Settlement Agreement, page 3, paragraph 10.

(d) If the load variation component is maintained as an element of the RSP, year-to-date net load variations for NP and IICs shall be allocated among the customer groups based upon energy ratios, with effect from the date to be determined by the Board.[195]

(e) The proposed CDM Cost Recovery Adjustment should be approved to provide for recovery of costs charged annually to the CDM Cost Deferral Account.[196]

(f) The generation credit agreement between Hydro and CBPP, which the Board approved on a pilot basis in Order No. P.U. 4 (2012), should be continued on a pilot basis at this time.[197]

(g) There shall continue to be an industrial wheeling rate with the specific rate to be calculated in accordance with the methodology proposed by Hydro as may be modified by the Board in an Order arising from the GRA.[198]

D.3.2 Remaining Cost of Service Issues

D.3.2.1 General

A cost of service methodology establishes the approach to use in the allocation of costs to be recovered from customers. Application of the cost of service methodology to the test year costs provides the amount of costs allocated to each customer class through customer rates. The current cost of service methodology was approved by the Board in 1993 subsequent to a cost of service methodology hearing.

At the current GRA, Hydro proposed cost of service approaches for new cost items (i.e., wind purchases and capacity assistance agreements) as well as changes to currently approved methodologies due to changing circumstances (i.e., Rural deficit Allocation and Holyrood capacity factor).

[195] Settlement Agreement, page 3, paragraph 16.
[196] Supplemental Settlement Agreement, page 3, paragraph 12.
[197] Settlement Agreement page 3, paragraph 19. The status of the agreement will be reviewed in the COS generic hearing referred to referred to in paragraph 23 of the Settlement Agreement.
[198] Settlement Agreement, page 4, paragraph 20. The status of the agreement will be reviewed in the cost of service generic hearing referred to in paragraph 23 of the Settlement Agreement.

As stated, Hydro will be filing a cost of service methodology review in 2016 which will deal with, among other items, cost of service issues arising from the Labrador-Island interconnection.

The initial Settlement Agreement and the Supplemental Settlement Agreement provided agreement on most cost of service methodology issues. The cost of service methodology items not agreed upon in the current GRA include the:

- Basis for the allocation of the Rural Deficit;
- Basis for the allocation of operating and maintenance costs to specifically assigned assets for the use in determining specifically assigned charges to IICs; and
- IIC load forecast to be used in the 2015 Test Year.

D.3.2.2 Rural Deficit Allocation

- ***In the interest of fairness, the Rural Deficit should be allocated based on revenue requirement.***

Background

In its original Application, Hydro used the Rural Deficit allocation approach approved in February 1993 as a result of the Cost of Service Methodology hearing.[199] In CA-NLH-166, the Consumer Advocate asked Hydro to comment on the fairness of the methodology. In conducting a fairness assessment, Hydro reviewed past statements of the Board with respect to the treatment of the Rural Deficit.

On page 84 of the 1993 COS Methodology Report, the Board provided guidance on assessing fairness for the Rural Deficit allocation when it stated:

> *Fairness cannot be assessed as due to the method used but instead we must assess fairness on the basis of the result, a shared burden among the classes of customers that is fair to all and not discriminatory.*

[199] For the origins of the mini cost of service approach, refer to Amended Application, Evidence page 4.7, footnote 5.

In Order No. P.U. 7(1996-97) following NP's General Rate Application, the Board stated[200]:

> *The matter of whether or not the transfer of the Rural Subsidy from Government to Hydro and then on to its customers is a tax or cross-subsidy between utility customers was debated before the Board and dealt with in its report entitled "Referral by Newfoundland and Labrador Hydro for the Proposed Cost of Service Methodology" in February 1993. The Board's conclusion in that Report was that the Rural Subsidy was not a tax, but a form of cross-subsidization even though it was in the extreme.*

In that same Order, the Board also stated:

> *The Board confirms its previous opinion in the February 1993 … that the Rural Subsidy is a form of cross-subsidization, and must be dealt with as all other expenses.*

No specific direction has been provided by Government on the methodology for allocation of the Rural Deficit other than to exempt Industrial Customers from subsidizing Hydro's Rural Customers.

This is the first GRA in which: (i) uniform rates are in place for customers on the LIS; and (ii) none of the Secondary Revenue Credit is applied to reduce the revenue requirement for the LIS.[201]

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[200] Order No. P.U. 7(1996-97), page 89.

[201] Rates for Labrador Interconnected customers did not reflect recovery of any of the Rural Deficit until September 2002. In 2002, approximately $5.0 million of the Rural Deficit was allocated to the LIS, but the impact of this initial allocation was largely offset by the application of a revenue credit of $3.7 million from secondary energy sales to CFB Goose Bay. In Order No. P.U. 7(2002-2003), the Board decided that the Secondary Revenue Credit should be applied to reduce the Rural Deficit, rather than being applied as a credit against the cost of service for the LIS. Because of the potential for large customer impacts as a result of this change, the Board required Hydro to propose a plan for implementation, in combination with a plan to implement uniform rates for Labrador City, Happy Valley-Goose Bay and Wabush. By 2011, the phase-out of the CFB Goose Bay Secondary Revenue Credit was been completed concurrently with the phasing in of uniform rates for Labrador Interconnected

Fairness Assessment

Hydro's review of the fairness of the Rural Deficit allocation methodology was based on the customer impacts of recovering the $64.1 million forecast[202] 2015 Test Year Rural Deficit from customers on the LIS and from customers of NP.

Table 4 provides a comparison of the Rural Deficit impact per customer under the existing method compared to an allocation based on revenue requirement and an allocation based on the number of customers served.[203]

Table 4

Average Annual Cost per Customer Comparison[204]

	Existing Method	Revenue Requirement Method	Number of Customers Method
Labrador Interconnected	$653.15	$207.60	$235.23
Newfoundland Power	$216.64	$236.46	$235.23
Difference	($436.51)	$28.86	$ –

Under the existing methodology, customers on the LIS would bear average annual Rural Deficit costs of $653.15, roughly three times more than the $216.64 that would be borne by customers of NP.[205]

The revenue to cost ratio for Labrador Interconnected customers in the 2015 Test Year under the existing methodology is 1.42, while the revenue to cost ratio for NP customers is 1.12.[206]

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customers. See Amended Application, Rates and Regulation Evidence, page 4.14, footnote 21; NP-NLH-407 and October 5, 2015 Transcript, pages 161-164.

[202] Amended Application, Volume II, Exhibit 13, Schedule 1.2, Page 1 of 6, column 5, line 14.

[203] Amended Application, Rates and Regulation Evidence, page 4.10, Table 4.3.

[204] Total 2015 Test Year deficit allocated divided by number of customers on LIS and number of customers served by NP.

[205] Amended Application, Evidence, page 4.8, lines 12-18. As Hydro noted, "[t]he higher deficit allocation per customer is primarily related to the attributes of the Existing Methodology that provides for increased deficit allocation to the system with higher average energy usage." Amended Application, Evidence, page 4.8, line 18 to Page 4.9, Line 2. For documentation of Labrador Interconnected customer's higher average energy use, refer to Amended Application, Evidence, page 4.9, footnote 9.

The relatively higher allocation of the Rural Deficit to Labrador Interconnected customers than to NP customers occurs under the existing methodology primarily because higher average energy usage drives a greater allocation of the Rural Deficit. The higher average use for customers on the LIS primarily results from living in an area of the Province where the climate is colder.[207] Hydro believes that the existing methodology does not produce a reasonable sharing of the Rural Deficit between Labrador Interconnected customers and NP customers.

Fairness in rates is commonly assessed based on revenue to cost ratios. The use of revenue requirement as a basis of Rural Deficit allocation results in the revenue to cost ratio in the 2015 Test Year Cost of Service Study for Hydro Rural Labrador Interconnected Customers being equal to the revenue to cost ratio for NP (i.e., 1.13).[208] Use of revenue requirement as the allocator results in an average allocated annual cost per customer that that is slightly higher for NP customers than for customers on the LIS.[209]

Hydro also evaluated the use of the number of customers as the allocator. If an allocation based on the total number of customers is used, the average annual cost per customer of the Rural Deficit for Labrador Interconnected and NP customers is the same.[210] While this approach would eliminate the difference in average cost per customer between the customers of NP and on the LIS, the use of the number of customers as an allocator would create fairness concerns between classes on the same system.[211] If the Rural Deficit within a system was allocated on the number of customers, the vast majority of the Rural Deficit would be allocated to the Domestic class within each system because Domestic customers comprise the largest number of customers.

Hydro is proposing the Rural Deficit commencing January 1, 2014 be allocated by system, based upon revenue requirement. Hydro's proposed approach would allocate

[206] Amended Application, Rates and Regulation Evidence, page 4.9, Table 4.2.
[207] Amended Application, Rates and Regulation Evidence, page 4.10, lines 1-4.
[208] Amended Application, Volume II, Exhibit 13, Schedule 1.2, page 1, column 8, line 3.
[209] Amended Application, Rates and Regulation Evidence, page 4.10, lines 16-18 and page 4.10, Table 4.3.
[210] Amended Application, Rates and Regulation Evidence, page 4.10, Table 4.3.
[211] Amended Application, Rates and Regulation Evidence, page 4.11 and footnote 13, page 4.11.

on average an additional $19 per year to NP's customers. This represents an additional 0.7% increase for these customers.[212]

The revenue requirement methodology proposed by Hydro gives consideration both to the lower rates and higher usage of Labrador Interconnected customers, whereas the existing methodology focuses more on the lower rates and thereby shifts more costs to customers on the LIS.[213] The impact of Hydro's proposed methodology is that the Rural Deficit will comprise 8% of customer charges from NP's customers, and 12% of charges to retail customers on the LIS.[214] On an absolute dollar basis, NP customers on average would pay somewhat more than Labrador Interconnected customers,[215] but on the basis of percentage of revenue requirement the impact would be higher for Labrador Interconnected customers. Using the revenue requirement allocation method, the allocated cost per customer is $236.46 for customers of NP and $207.60 for customers on the LIS. This difference reflects 14% higher average cost to serve NP's customers.[216] Hydro submits that this is a fair overall result and is more reasonable than the outcome of the existing methodology.

Position of Intervenors

All of the expert witnesses who gave evidence on this issue, except for Mr. Brockman on behalf of NP, support a change from the existing allocation methodology. Mr. Greneman indicated that fairness in the allocation of the rural deficit is most equitably apportioned on revenues, which gives consideration to both of the revenue components (i.e., electricity rate and customer load requirements).[217]

Dr. Feehan for the Labrador Towns said that the current approach should be replaced by one that ensures a more equal outcome and one of the alternative methods that he proposed for

[212] October 9, 2015 Transcript, page 95, line 7 to page 96, line 11.
[213] October 5, 2015 Transcript, pages 198-199.
[214] October 5, 2015 Transcript, pages 199-200.
[215] Amended Application, Rates and Regulation Evidence, page 4.10, Table 4.3.
[216] October 6, 2015, Transcript, page 95, lines 17 - 24.
[217] NP-NLH-414.

consideration is comparable to one of the alternatives evaluated by Hydro.[218] Mr. D. Bowman for the Consumer Advocate indicated that allocation of the Rural Deficit on the basis of either revenue requirement or the number of customers is preferred over the current allocation methodology.[219] Mr. Raphals for the Innu Nation recommended a fresh look at the methodology for the allocation, as proposed by Hydro.[220] Dr. Wilson for the Board stated "[e]ither a revenue or per customer allocation would appear to be more equitable than the existing allocation."[221]

Mr. Brockman for NP appeared to consider Hydro's use of revenue to cost ratios in its fairness assessment as inappropriate. He indicated Hydro's approach was a "strange usage of revenue to cost ratios".[222] Hydro respectfully submits that Mr. Brockman's statement is perplexing. Hydro has presented the revenue to cost ratios to isolate the impact of the Rural Deficit on each customer group in the same manner in each GRA since 1990. Mr. Brockman has participated in most, if not all, of those proceedings.[223]
Mr. Brockman should recognize that the revenue to cost ratios for both NP's customers and the customers on the LIS are above 1.0 because the revenue to cost ratio for Hydro Rural Customers is 0.51.[224]

The revenue to cost ratios show the ratio of the revenues collected based on the test year forecast to the cost to provide service based on the allocation methodology approved by the Board. No other experts expressed concerns with the use of revenue to cost ratios in evaluating the fairness of the existing Rural Deficit allocation methodology. Hydro submits the revenue to

[218] Amended Application, Rates and Regulation Evidence, page 4.12, lines 6-11.
[219] Amended Application, Rates and Regulation Evidence, page 4.12, lines 13-19.
[220] Amended Application, Rates and Regulation Evidence, page 4.12, lines 21-23.
[221] NLH-PUB-007.
[222] September 29, 2015 Transcript, page 202, lines 21-22.
[223] Mr. Brockman's witness profile states that he has presented evidence on behalf of NP, concerning cost of service, rate design and least cost planning in Hydro's 1990, 1992, 2001, 2003 and 2006 general rate referrals, as well as in Hydro's 1992 generic cost of service hearing, the 1995 Rural Rate Inquiry and Hydro's 2009 and 2013 Applications concerning the RSP and Industrial Rates.
[224] Amended Application, Volume II, Exhibit 13, Schedule 1.2, page 1 of 6, column 8, line 14.

cost ratio provides valuable information to the Board in evaluating the fairness of the Rural Deficit.

Mr. Brockman believes the current allocation methodology is reasonable.[225] In the allocation of customer-related costs, the existing methodology effectively assumes there are more customers on the LIS than the number of customers served by NP. Mr. Brockman also considers this a reasonable approach.

Mr. Brockman states it is difficult to assess "fairness" in the allocation of the Rural Deficit. His difficulty appears to be because the Rural Deficit is not causally related to the customers responsible for funding it.[226] Because of the disconnect between the customers creating the costs and the customers that have to pay the costs, Mr. Brockman appears unwilling to consider revenue to cost ratios and customer impacts in evaluating the fairness of the Rural Deficit allocation methodology.

Summary

The Regulatory Framework provided in Appendix A of Order No. P.U. 8(2007) included the fundamental principles used by the Board as a guide to rational decisions. Hydro submits that fair cost apportionment and the end result are the regulatory principles that should be considered by the Board in assessing the fairness of the Rural Deficit allocation methodology. The Regulatory Framework provides the following description of each:

> Fair Cost Apportionment
>
> *Fairness of specific rates in the apportionment of total costs of service among the different ratepayers should be such so as to avoid arbitrariness, capriciousness, inequities or discrimination. Under this principle, customers in similar situations should be treated equally (horizontal equity), while those in different situations should be treated differently (vertical equity). This principle would not deny cross-*

[225] NLH-NP-022.
[226] NLH-NP-022.

> *subsidization of rates among customers of equal circumstances but such subsidization should not cause undue discrimination. The principle of horizontal equity (i.e. equals treated equally) is set forth in Section 73(1) of the Act which requires that "all tolls, rates and charges shall always, under substantially similar circumstances and conditions in respect of service of the same description, be charged equally to all persons and at the same rate, …". Furthermore, the aspect of undue discrimination also has statutory reinforcement in Section 3(a)(i) of the EPCA which declares it to be "…the policy of the province that the rates to be charged ………should be reasonable and not unjustly discriminatory."*
>
> End Result
>
> *In compliance with the legislation, the end result must be fair, just and reasonable from the perspective of both the consumer and utility.*

The Regulatory Framework also states that: "*[t]he Board has discretion to choose the approach to setting rates as long as it observes the legislation and sound utility practices.*" The Board has been provided no legislative direction on the Rural Deficit allocation methodology (other than the exemption of funding from the IICs). Therefore, the Board is required to adhere to sound utility practice in its determination of a fair approach to the apportionment of the Rural Deficit with the objective of achieving an end result which must be fair, just and reasonable from the perspective of both the consumer and utility.

Hydro submits that the existing Rural Deficit allocation methodology is not fair to Hydro Rural customers on the LIS. Hydro submits that the evidence before the Board in the GRA supports the use of revenue requirement as a fair and reasonable basis for allocation of the Rural Deficit in the cost of service methodology.

D.3.2.3 Allocation of O&M Costs to Specifically Assigned **Assets**

- ***Hydro's O&M costs attributable to specifically assigned assets should be allocated according to their relative value stated in constant 2015 dollars, rather than original cost.***

In the current cost of service methodology, the cost of capital assets that are used solely for the provision of service to a single customer are functionalized as specifically assigned. Specifically assigned costs are to be recovered from the customer for which the related assets provides service. There are currently transmission assets in service that are specifically assigned to IIC's. Customers are required to pay specifically assigned charges that recover the cost of return, depreciation and operating and maintenance costs for specifically assigned assets. For customers that paid a contribution for 100% of the capital investment, the specifically assigned charge would only recover the operating and maintenance costs. The specifically assigned charges are updated in each GRA Test Year.

In the 2015 COS study, direct O&M costs are classified/allocated based on the original cost of the plant in service (which is accounted for in the in-service year dollars). Administrative and General O&M expenses are classified/allocated based on a series of calculations using plant in service and direct O&M.

Mr. Dean argued that using original cost to pro rate O&M expense assigns too much cost to newer facilities, like the specifically assigned facilities constructed for Vale:

> *The prorating of O&M costs using plant in service without accounting for the time value of money has the potential to achieve inequitable results. This possibility is heightened with an electrical system consisting of new and old assets as one is comparing vastly different original costs. … As such, the total of Vale's plant in service measured in 2012 dollars is being prorated against plant in service values that are based on 1960's dollars.* [227]

[227] Pre-filed Evidence of Mr. Dean, June 4, 2015, page 10, line 16 through page 11, line 2.

To correct the situation, Mr. Dean argued that O&M apportionment should be based on assets valued in constant dollars.[228]

Hydro acknowledges that the existing methodology may not be ideal in allocating O&M costs to specifically assigned charges. This is because there is an inherent inverse relationship whereby older plant that cost less at the time of installation, generally requires more O&M than more expensive newer plant. [229] An alternate approach to the allocation of the direct transmission portion of O&M expense to specifically assigned charges is to use current dollars (2015 $) as a basis to reallocate the direct transmission O&M expense calculated in the 2015 Test Year COS study between specifically assigned charges and common.[230]

Based on its 2015 Test Year COS Study, Hydro calculated how much the O&M cost allocations to specifically assigned assets would change if the allocations were based on transmission assets values stated in constant 2015 dollars instead of original costs. The result of the analysis transferred approximately $600,000 of O&M costs from specifically assigned costs to common costs. The materiality of the customer impact of using current dollars rather than original costs as the basis for O&M cost allocation to specifically assigned assets supports Mr. Dean's position with respect to the concerns with the current approach.[231]

The use of the approach proposed by Mr. Dean is comparable to the method used by NP in determining the amount of O&M costs reflected in the cost factors that apply in determining CIAC from customers for distribution line extensions.[232] The CIAC cost factors reflect operating and maintenance costs based on a percentage of indexed asset costs.[233] This approach was

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[228] Pre-filed Evidence of Mr. Dean, June 4, 2015, page 12, lines 3-5.
[229] V-NLH-083 (Revision 1, June 23, 2015), page 1, lines 17-24. October 6 Transcript, pages 58, line 12 to 59, line 1.
[230] See Amended Application, Volume II, Exhibit 13, Schedule 2.4A, Page 1 of 2, Col 5, Line 11 and Col 18, Line 11 for the total direct transmission O&M expense under the current COS methodology (i.e., $5,522,963 + $1,285,395 = $6,808,358).
[231] Undertaking No. 45.1, Attachment 1 includes an updated 2015 Test Year Cost of Service model which reflects the impacts of using the revised methodology for allocating specifically assigned O&M expense proposed in V-NLH-083 (i.e., reflecting indexed plant values).
[232] Response to V-NLH-125.
[233] The CIAC cost factors are submitted annually by NP for approval by the Board.

implemented following the 1997 hearing on the CIAC Policy and replaced the previous approach that was based on the use of original costs.[234] The contexts are different, but the reason for using indexed costs to allocate O&M costs is the same and supports Board approval of Vale's position on O&M cost allocation.

Hydro provided the 2015 Test Year COS Study reflecting the use of indexed asset costs for the purpose of allocation of O&M costs to specifically assigned assets. Hydro submits this approach provides a fairer result and should be adopted for the cost of service methodology in the current GRA. The Cost of Service Methodology review scheduled for 2016 will provide an opportunity to perform a more comprehensive review the overall approach to determining specifically assigned charges to the IICs. [235]

D.3.2.4 IIC Load Forecast for 2015 Test Year

- ***Hydro's proposed IIC rates are reasonable; normalization for expected industrial load is unwarranted.***

Hydro's proposed rates reflect the 2015 forecast load for the IICs in the 2015 Test Year. Mr. D. Bowman, expert for the Consumer Advocate, presented evidence that the rates derived for the 2015 load forecast for IICs are not just and reasonable. Mr. D. Bowman recommended that the Board adjust the test year to reflect loads during the 2015 to 2017 period.[236]

Hydro disagrees with Mr. D. Bowman's assessment. Mr. Fagan for Hydro stated:

> *The proposed firm demand rate and firm energy rate for IC, in combination with the operation of the RSP, are reasonable for recovering the cost of serving the IC class for the period 2015 to 2017. As the IC load increases, the new customers will pay increased demand cost as a result of their increased*

[234] October 6, 2015, Transcript, page 62, lines 7-9.
[235] October 6, 2015 Transcript, pages 78, line 15 to 79, line 22.
[236] Pre-filed Evidence of Mr. D. Bowman, June 1, 2015, pages 23-24. For Mr. D. Bowman's direct testimony on this issue, refer to September 30, 2015 Transcript, pages 21, line 25 to 24, line 16.

> *demand requirements. The customers will also pay increased energy charges based on the firm energy rate and the additional RSP charges to recover increased fuel costs due to their load growth.*
>
> *Normalization to reflect higher future loads in the allocation of the 2015 Test Year revenue requirement will result in reflecting the future cost of serving IC load in current rates. Allocation of a higher proportion of costs to Industrial Customers based on the 2017 forecast will have the effect of materially increasing the rates to be charged IIC and result in over-recovering the cost of serving Industrial Customers in both the test year and in future years.*
>
> *The load forecast reflected in the 2015 Test Year includes Vale and Praxair as high load factor customers and therefore no normalization is required.*[237]

The analysis provided in Undertaking No. 44 indicates that normalization to reflect higher future loads in the allocation of the 2015 Test Year revenue requirement will result in reflecting the future cost of serving IIC load in current rates. Allocation of a higher proportion of costs to IIC based on the 2017 forecast will have the effect of materially increasing the rates to be charged IIC and result in rates that over-recover the cost of serving IIC.

The presence of increased forecast load beyond 2015 for the IICs is not sufficient, in itself, to warrant normalization. Normalization is warranted only when the Test Year rates are anomalous and normalization will address the anomaly.

The load forecast reflected in the 2015 Test Year includes Vale and Praxair as high load factor customers and therefore no normalization is required. Hydro submits that the IIC load forecast used in the 2015 Test Year is appropriate for establishing reasonable rates.

[237] October 5, 2015 Transcript, pages 99, line 6 to 100, line 9.

D.3.3 Remaining Rates Issues

D.3.3.1 General

Hydro has not proposed material changes in customer rate designs in the Amended Application. The settlement agreements reflect a continuation of current rate designs for NP and the IICs pending conclusion of the planned studies discussed in Section D.3.1.1. These studies scheduled for completion over the next 12 months will provide updated information on marginal costs, cost allocation issues, rate designs and supply cost recovery mechanisms.

The Settlement Agreement and the Supplemental Settlement Agreement provided agreement on many rates issues. The rates issues not reflected in the agreements include:

- The continuation of the load variation component in the RSP;
- The disposition of the RSP load variation component balance that accumulated for the period September 1, 2013 to December 31, 2014;
- The deferred rate increases proposed to apply to Hydro Rural customers on Isolated Systems; and
- The proposed Labrador Industrial Transmission Rate.

D.3.3.2 RSP Load Variation Component

- ***The load variation component of the RSP should be maintained.***

The IIC load is forecast to grow materially in 2016 and 2017 because two new IICs are in the process of becoming fully operational (250 GWH cumulative load growth over 2016 and 2017).[238] The generation utilized to serve the IIC load growth between Test Years will be supplied by from Holyrood.

The cost incurred to serve this additional load based on the Amended Application is approximately 15¢ per kWh.[239] The additional energy revenues from IIC under the proposed rate are based on an energy rate of 5.151¢ per kWh. The load variation component in the RSP

[238] Undertaking No. 45.1
[239] Amended Application, Rates and Regulations Evidence, page 4.22, line 23.

allows Hydro to recover the net loss on sales growth to the IICs. For the period 2016 and 2017, the load variation permits Hydro to recover approximately $42 million in fuel costs that will not be recovered through the IIC base rate.[240]

Mr. P Bowman has recommended elimination of the Load Variation Component in the RSP. [241] However, Mr. P. Bowman also states "…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".[242] The Settlement Agreement provides for a review of all components of the RSP in 2016 in addition to a review of the IIC rate design. Hydro submits it is not appropriate to eliminate the RSP load variation component prior to the implementation of a new IIC rate design that permits reasonable recovery of the marginal cost to provide service to the IIC.

D.3.3.3 Disposition of the Balance in the RSP Load Variation Component

- ***The balance accumulating in the RSP load variation component that has accumulated since September 1, 2013, should be allocated among Hydro's customer groups based on energy ratios.***

In the Settlement Agreement, all Parties agreed that if the load variation component is maintained as an element of the RSP, year-to-date net load variations for NP and IICs shall be allocated among the customer groups based upon energy ratios, with the effective date to be determined by the Board.[243]

The amounts that accumulated in the RSP load variation component for the period 2007 to August 31, 2013 have been transferred to the RSP surplus for disposition in accordance with the Government directive. The forecast balance in the RSP load variation component as of

[240] The forecast load growth for IIC and the forecast RSP load variation component transfers are provided in Undertaking No. 44.
[241] Pre-filed testimony of P. Bowman and H. Najmidinov, June 4, 2015, page 47, lines 27 - 28.
[242] Pre-filed testimony of P. Bowman and H. Najmidinov, June 4, 2015, page 48, lines 19 - 21.
[243] Settlement Agreement, page 3, paragraph 16.

December 31, 2014 is approximately a $33 million credit to customers.[244] Hydro is proposing to allocate this balance based on an energy ratio allocation effective September 1, 2013, which would result in an allocation of approximately $31 million to NP and approximately $2 million to the IICs.[245]

Mr. D. Bowman for the Consumer Advocate recommended that "the Board order that the money that has accumulated in the load variation component of the Island Industrial Customer RSP account since September 1, 2013 be transferred to the RSP account of Newfoundland Power."[246]

Hydro disagrees with Mr. D. Bowman's recommendation. The use of energy ratios for allocation of fuel savings resulting from load variation balances that accumulated for that period is consistent with the manner that RSP fuel price variations were allocated in the RSP for that same period.[247] Therefore, Hydro submits that it is appropriate that the RSP rules related to the allocation of the load variation component be modified such that the year-to-date net load variation for both NP and IC is allocated among the customer groups based upon energy ratios effective is September 1, 2013.[248]

D.3.3.4 Implementation of the Deferred Rate Increase

- ***The Board should approve the proposed above average increases in customer rates for Hydro Rural non-Government Domestic and General Service customers on isolated systems.***

In the Amended Application, the proposed rate increases for Hydro Rural non-Government Domestic and General Service customers on isolated systems are higher than the average

[244] Per Order No. P.U. 29(2013), load variation is to be segregated in a separate account within the RSP.
[245] Load variations transfers for 2015 on an interim basis will need to be recalculated to reflect the approved 2015 Test Year rates and the 2015 Test Year fuel cost assumptions.
[246] Pre-filed evidence of D. Bowman, June 1, 2015, page 14, lines 12-15.
[247] Amended Application, Evidence, Section 4.71.
[248] The amounts that accumulated in the load variation component for the period 2007 to August 31, 2013 have been transferred to the RSP Surplus for disposition in accordance with the Government directive.

increase proposed for the Hydro Rural Island Interconnected customers. The proposed above average increases result from the combined effect of (i) the 2015 Test Year forecast change in rates for Island Interconnected customers and (ii) the increase in rates to implement the 2007 rate change that was deferred as a result of Government directives.

The non-lifeline portion of the Domestic energy rate[249] and both small and large general service diesel rates[250] were proposed to increase by 15% in 2007 to reflect the increased cost of fuel since the previous GRA. However, the 2007 proposed rate increase was not implemented in 2007 as a result of OC2006-512. Additional Government directives have been provided each year, which have continued to defer the 2007 rate increases. The most recent Government directive on this matter provides that in 2016 the customer rates shall be those that would have come into effect but for the Government directives.

Hydro submits that approval of higher than average increases for Hydro Rural non-Government Domestic and General Service customers is consistent with the Government directive on this matter.

D.3.3.5 Labrador Industrial Transmission Rate

- ***Hydro's proposed transmission demand charge for service to Labrador Industrial Customers should be approved.***

Hydro has proposed a transmission demand charge to be applied to Labrador Industrial Customers. The calculation of the demand charge is based on the portion of the transmission revenue requirement determined in accordance with the COS functionalization, classification and allocation methods previously approved by the Board.[251]

[249] For Domestic Customers, the 15% is applicable to only non-lifeline energy rates. The 2007 deferred rate increase for Domestic Customers would have resulted in an overall increase of 4%.
[250] Prior to 2007, there was no annual RSP adjustment reflecting the rate change to the customers of NP.
[251] Amended Application, Rates and Regulations Evidence, page 48.

Hydro notes that the Billing Demand definition in the proposed Labrador Industrial Transmission Rate does not address the treatment of Labrador Industrial interruptible load. Hydro will be filing an application in January 2016 to address this matter in the terms of the rate. This modification will not impact the calculation of proposed firm transmission demand charge based on the 2015 Test Year costs.

Hydro submits that the Board should approve the methodology used by Hydro to compute the proposed Labrador Transmission demand charge of $1.25 per kW per month.

D.3.3.6 Uniform Rates for Labrador Interconnected Customers

- ***The proposed uniform rates for Labrador Interconnected System customers are reasonable.***

In Order No. P.U. 7(2002-2003), the Board approved that Hydro develop a plan to phase-in uniform rates for customers on the LIS. The phase-in of uniform rates on the LIS was concluded in 2011. Prior to 2011, different rate schedules applied to customers in Labrador East and Labrador West.[252]

Mr. P. Raphals, the expert representing the Innu Nation, recommended that a rate rider should be considered to apply to customers in Labrador West due to the magnitude of the capital costs resulting from the Labrador City distribution upgrade.[253] This recommendation is effectively requesting the Board to reverse its decision on uniform rates that which was only recently implemented.

Hydro notes that in Order No. P.U. 7(2002-2003), the Board did not approve the proposal of the Labrador West customers requesting for Hydro to maintain a separate set of rates for Labrador

[252] Because of the potential large customer impacts of making this rate change, the Board required Hydro to propose a plan for implementation at its next rate hearing in combination with a plan to implement uniform rates for Labrador City, Happy Valley-Goose Bay and Wabush. The current GRA is the first hearing before the Board in which the Secondary Revenue Credit is fully credited to the Rural Deficit.

[253] Pre-filed Evidence of Philip Raphals, June 23, 2015, page 37.

West. The application of a single set of rates on the LIS is consistent with the use of a single cost of service study for the LIS, as approved by the Board. Hydro believes the evidence before the Board does not demonstrate that the uniform rate schedules proposed by Hydro result in rate discrimination to customers in Labrador East. Therefore, Hydro submits that Mr. Raphals' recommendation for a rate rider to apply to customers in Labrador West should be denied.

Section D.4: Supply Cost Rated Deferral and Recovery Mechanisms

D.4.1 Hydro's Proposed Supply Cost Related Deferrals

- ***Hydro should have a reasonable opportunity to recover supply costs prudently incurred in providing service to customers.***
- ***Receiving a government-directed ROE also does not justify denying or restricting Hydro's use of these accounts due to decreased business risk; the Canadian utilities with supply related deferral accounts often have target returns on equity higher than the 8.8% directed for Hydro.***

Hydro has proposed three new supply related deferrals in the Amended 2013 GRA:

- The Isolated Systems Energy Supply Cost Variance Deferral Account (Isolated Systems Deferral);
- The Energy Supply Cost Variance Deferral Account (Energy Supply Deferral); and
- The Holyrood Fuel Conversion Factor Deferral Account (Holyrood Conversion Deferral).

Recovery of supply costs through deferral mechanisms is common practice in regulatory jurisdictions across Canada.[254] Further, regulatory precedent also exists for the approval of such deferral accounts in the context of a government directed return on equity. Specifically, BC Hydro's return on equity has been set by a government directive and BC Hydro was subsequently granted approval by the BCUC for a deferral account to capture variances in non-

[254] PUB-NLH-388.

heritage supply costs.[255] Hydro submits that these precedents are supportive of the aforementioned deferral accounts proposed in the 2013 Amended GRA.

D.4.1.1 Isolated Systems Deferral

Hydro has proposed the Isolated Systems Deferral to capture variances from the 2015 Test Year in the cost of supplying customers on Hydro's Isolated Systems. Hydro's cost of supplying these customers is primarily based on the cost of diesel fuel.[256] Diesel fuel is a commodity and is priced based on market factors beyond Hydro's control. Since Hydro's 2007 GRA, the price of diesel fuel has experienced significant price volatility, as noted in the following chart found on page 3.47 of Hydro's Amended Application:

Chart 2

Diesel Fuel Price Variability

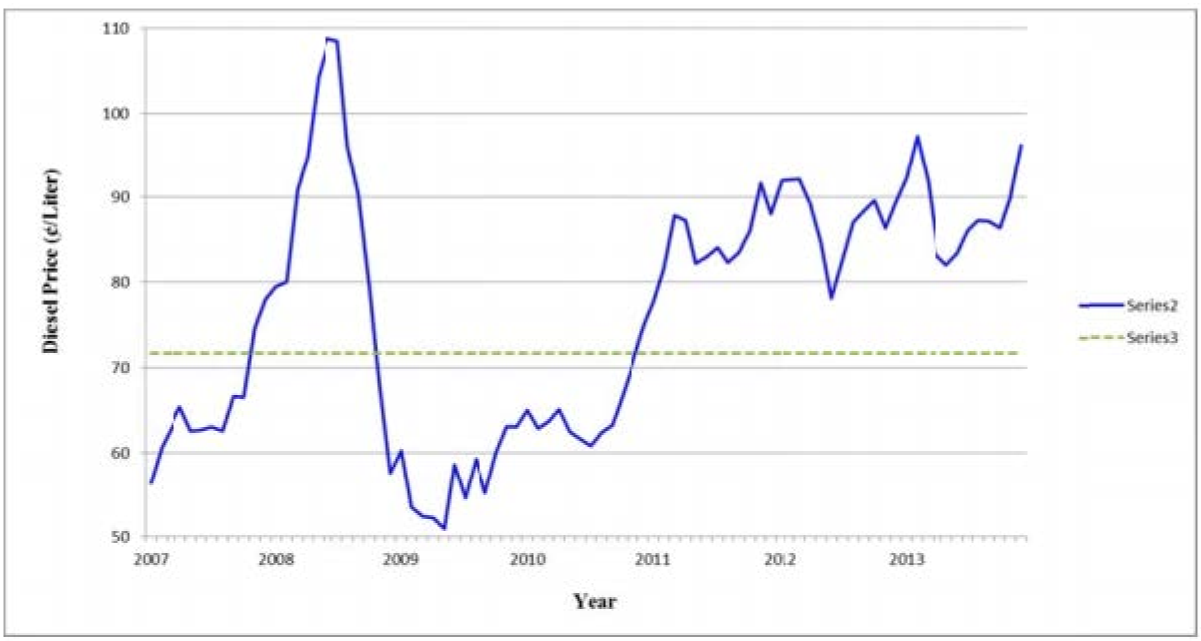


Chart 2 shows the level of volatility Hydro has experienced in the price of diesel fuel between test years. This level of risk has been material since the 2007 Test Year, is beyond

[255] November 18, 2015 Transcript, pages 114-120 as well as Undertaking No. 167.

[256] The Isolated Systems Account also captures variances in supply costs on isolated systems where costs are based on the price of diesel fuel.

management's control, and is appropriate to be dealt with through the proposed deferral account.

D.4.1.2 Energy Supply Deferral

Since Hydro's last GRA in 2007, Hydro has acquired a number of new supply sources. These new supply sources, including Exploits, wind generation, and the Holyrood CT have benefited customers either through increased reliability or reduced cost of service. However, variances in Hydro's now more broad supply mix can have a material impact on Hydro's financial results in a given year.

Without the proposed Energy Supply Account Hydro will be financially disadvantage as a result of: (i) variances beyond its control; (ii) providing greater reliability of service to customers and; (iii) economically optimizing the Holyrood CT in conjunction with the HTGS. These scenarios are discussed in detail below. Hydro submits that approval of this account is consistent with regulatory practice and in the best interest of customers and the utility.

D.4.1.3 Holyrood Conversion Deferral

Hydro has proposed a fuel conversion rate of 607 kWh/bbl for the purpose of setting base rates in the 2015 Test Year, a reduction from 630 kWh/bbl approved in the 2007 Test Year. Since 2007, Hydro has never achieved the 2007 Test Year conversion rate. In fact, the average conversion rate over this period has been 602 kWh/bbl.[257] Table 2.21 on Page 2.75 showed the financial impact to Hydro as a result of the variance in Holyrood Conversion Rate from the 2007 Test Year, which is shown below:

[257] Calculated as the simple average annual rate from 2007 through 2014 per Hydro's Amended Application, Section 2, Schedule V, page 1 of 4.

Table 5

Holyrood Fuel Conversion Performance and Hydro Financial Impact 2009 - 2014						
	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Forecast
Fuel Consumption ('000 bbls)	1,534.7	1,363.2	1,469.2	1,428.3	1,611.0	2,334.5
Actual Fuel Conversion Rate (kWh/bbl)	612	589	603	599	594	588
2007 TY Fuel Conversion Rate (kWh/bbl)	630	630	630	630	630	630
Hydro's Financial Loss ($ million)	2.4	4.9	3.5	3.9	5.1	8.8

Table 5 shows that for five of the six years Hydro incurred additional fuel costs of $3.5 million or greater as a result of the reduction in the fuel conversion rate approved in the 2007 Test Year. Hydro notes that $3.5 million represents approximately 20 basis points in the range of return on rate base.[258]

The most recent estimate of Holyrood's conversion rate is 597 kWh/bbl, and the difference between this estimate and the conversion rate used to calculate the 2015 Test Year results in a $2.4 million revenue shortfall to Hydro.[259] Hydro, in the Amended Application, stated this deterioration of the conversion factor was due primarily to factors beyond Hydro's control. These factors include lower production requirements at Holyrood as a result of reduced system loads, higher energy purchases, and higher levels of hydraulic generation.[260] Hydro submits that the utility should not be at risk for material supply cost variances that are beyond its control.

Mr. P. Bowman, in his pre-filed evidence, states the creation of this deferral would be acceptable:

> *In addition, however, Hydro has proposed a new Holyrood Conversion Rate Deferral Account which means that ratepayers collectively will bear the costs of*

[258] Transcript, October 6, page 91, line 22 to page 92, line 4.
[259] Hydro's Amended 2015 Cost Deferral Application, page 1, Appendix D.
[260] Amended 2013 GRA, page 2.74.

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.[261]

In addition to the factors affecting production levels at Holyrood, the BTU content of the fuel affects the conversion factor and therefore Hydro's costs. Mr. R. Henderson's in his testimony states:

The element here of this that people should be aware of is that we, from buying the fuel, we're buying BTU content which is what is the real heating value of the fuel to produce electricity. So we are paying for the BTUs. The problem for Hydro with this is that that fuel price variability goes into the RSP to customers. It does not come back to Hydro and Hydro suffers the consequence in a lower conversion factor and so, the manner in which the BTU -- the kilowatt hours per barrel number is fixed, but the BTU content varies. Hydro is taking that while it doesn't obtain any benefit, but the pricing improvement that you get by getting lower BTU falls out into the price of oil which goes through the RSP and benefits customers. So there's a disconnect, if you like, in terms of the benefit to customers versus the impact to Hydro.[262]

Hydro has established in its No. 6 fuel supply arrangement a No. 6 fuel purchase price that can vary based on the BTU content of fuel delivered. This practice ensures customers are protected for changes in the BTU content of delivered fuel through the RSP. However, without the proposed Holyrood Conversion Deferral Hydro will continue to be financially disadvantaged for a lower BTU content as the conversion factor assumed in rates will not change with the actual BTU content of the fuel being consumed at the HTGS.

[261] Pre-filed evidence of P. Bowman dated June 4, 2015, page 3.
[262] Testimony of R. Henderson, September 23, 2015, pages 90-91.

D.4.2 Financial Incentives and System Optimization

- ***Hydro's proposed Energy Supply Deferral and the Holyrood Conversion Deferral foster system wide generation dispatching decisions that benefit customers through enhanced reliability.***

Hydro submits that approval of these proposed deferral accounts would provide Hydro with appropriate financial incentives to operate its system on a reliable, least cost basis. Further, they will ensure Hydro is not financially disadvantaged for optimizing the system for the benefit of customers.

D.4.2.1 Reliability

Hydro operates its generating plants to provide reliable service to its customers, by providing sufficient reserves to minimize impacts on customers for single contingency equipment outages. The growth in demand in recent years has resulted in a greater reliance on combustion turbines for this purpose. The addition of the Holyrood CT provides Hydro a greater ability to secure reliable operation for such contingencies. Hydro is currently operating the Holyrood CT to provide additional security of supply. This practice began after the events of March 4, 2015 and is consistent with Liberty's findings of the same.[263] A further example of this, presented to the Board during Hydro's GRA hearing, was the required annual planned outage of all units at the HTGS to complete common plant equipment maintenance. Having no units operating on the Avalon Peninsula exposes customers on the Avalon Peninsula to an outage in the event that a transmission line was forced out of service.

In the past, during the annual total plant outage at the HTGS, Hydro would keep the Hardwoods CT available if such a contingency occurred. The Hardwoods plant does not have sufficient capacity to cover completely customer load requirements, thus leaving some customers exposed to an interruption during a line out contingency. With the addition of the Holyrood CT, and in response to this interruption risk, Hydro has been running the Holyrood CT at minimum

[263] See Liberty Consulting's Report dated October 22, 2015, page 7, Section 2.

output levels during peak periods of the day to provide enhanced reliability. This operational practice began in 2015 in response to enhanced reliability assessments following the March 4, 2015 outage event.

Without the proposed Energy Supply Account Deferral, higher costs resulting from increased generation at the Holyrood CT to provide this higher standard of reliability would be borne by Hydro with no opportunity to recover the additional cost from customers. This scenario creates a financial disincentive for Hydro to operate the Holyrood CT in excess of the forecast test year levels, regardless of whether operation of the Holyrood CT results in more reliable service to customers. Hydro submits that approval of the proposed deferral accounts is consistent with the provision of reliable service to customers.

D.4.2.2 System Optimization

There are times when Hydro has the opportunity to optimize economically the operation of the Holyrood CT in conjunction with the HTGS.[264] A scenario where a unit at the HTGS can be brought offline for a week and the Holyrood CT is only used at peak times during that week can result in net fuel cost savings for customers through the RSP.[265]Without the proposed Energy Supply Deferral, Hydro would be negatively impacted financially for optimizing the system in this fashion, as the HTGS fuel savings would accrue inside the RSP and flow to customers while all additional CT costs incurred would be borne entirely by Hydro.

Hydro currently operates the Holyrood CT and HTGS to provide the most reliable, least cost service to customers. Hydro submits that approval of these supply deferrals will ensure Hydro is financially incentivized to provide least cost service to customers on a system wide basis, not just from specific supply sources.

[264] GRA Transcript, October 20, pages 132-136.
[265] GRA Transcript, September 23, 2015, page 98.

D.4.3 Intervenor Evidence

Two experts in their pre-filed evidence provided opinions against approval of the requested deferral accounts. Mr. D. Bowman for the Consumer Advocate and Mr. Wilson for the Board both opposed the creation of these deferrals in the context of Hydro's ROE.

Mr. D, Bowman, on page 5 of his pre-filed evidence states:

> *I recommend that the Board deny Hydro's proposal to establish new supply cost variance accounts referred to as the "Isolated Systems Supply Cost Variance Deferral Account", the "Energy Supply Cost Variance Deferral Account" and the "Holyrood Conversion Rate Deferral Account". There is no justification for transferring these risks to consumers when Hydro has been assured a much higher, and uncontested, return on equity fixed by Government Directive OC2009-063.*

Hydro submits that Mr. D. Bowman's conclusion is inconsistent with (i) regulatory precedent in Canada for utilities with government directed ROE; (ii) regulatory precedent for utilities in Canada generally; and (iii) utilities in this province.

As noted previously, the BCUC in Decision G-96-04 granted approval of a deferral account, which transferred the risk and benefits of supply costs variances to customers. This approval was subsequent to Heritage Special Directive No. 2, which set BC Hydro's return on equity to the same levels as the most comparable investor-owned utility, grossed up for income tax.[266]

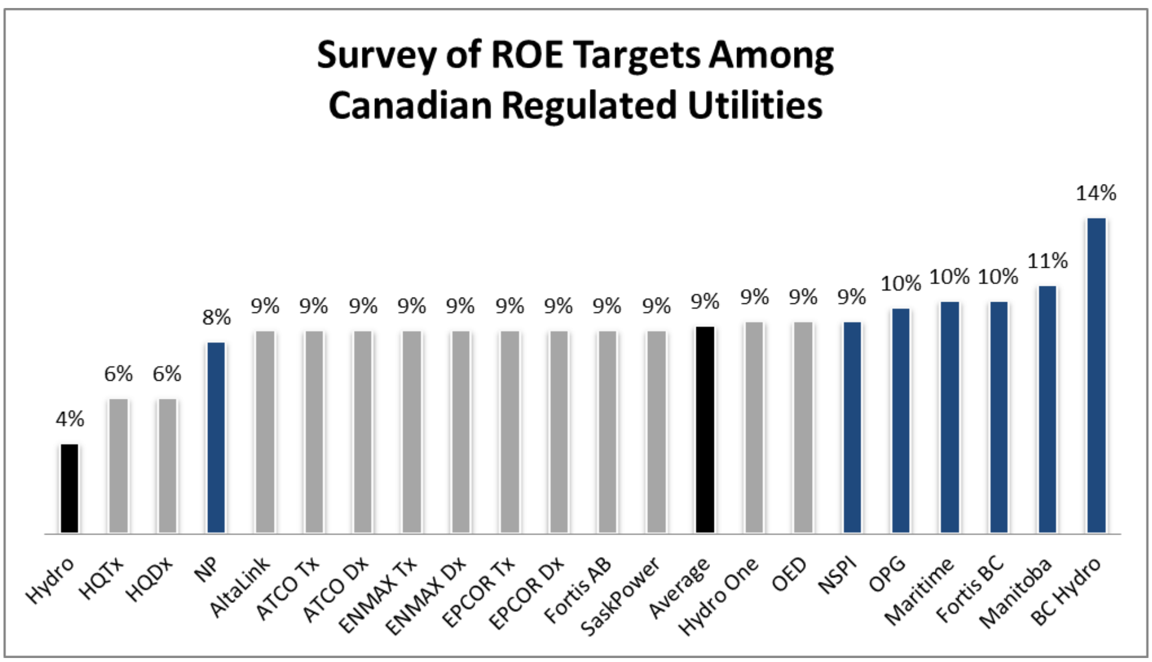
Hydro notes that OC2009-063 sets Hydro's return on equity to that of NP, the only investor-owned regulated utility in this jurisdiction. Hydro submits that Mr. D Bowman's statement that "there is no justification for transferring these risks to consumers when Hydro has been assured a much higher, and uncontested, return on equity fixed by Government Directive OC2009-

[266] Undertaking No. 167.

063"is not consistent with Canadian regulatory precedent for utilities with a government directed ROE.

Mr. D. Bowman's statement is also contradictory to utility practice in other jurisdictions across Canada. Mr. D. Bowman has only considered the change in Hydro's ROE from 2007. He has not considered whether these risks existed at the time that ROE was approved nor has he considered whether these deferrals are consistent with an ROE of 8.8% when compared to other utilities across Canada. Page 3.35 of Hydro's Amended Application provided a chart showing the ROE targets of other Canadian utilities. This chart is presented below, with utilities with approved supply deferrals per Hydro's response to PUB-NLH-388, noted in blue:

Chart 3



Hydro submits that based on utility practice across Canada, as presented in the above noted chart, supply deferrals are in fact quite common for Canadian utilities with a higher approved ROE than Hydro has proposed in this application. This is again inconsistent with Mr. Bowman's statement from page 16 of his pre-filed evidence:

> *There is no justification for transferring these risks to consumers when Hydro has been assured a higher, and uncontested, return on equity fixed by Government Directive OC2009-063. In fact, just the opposite is true - with a higher return on equity, Hydro should take on more risk.*

Finally, Hydro submits that Mr. Bowman's statements are not consistent with utility practice in this province. The Board has historically approved supply deferrals for both Hydro and NP, through the RSP and Rate Stabilization Account respectively. Hydro submits that regulatory precedent exists in this province for deferral of supply costs at the same level of return on equity as NP.

The evidence presented by Dr. Wilson with respect to Hydro's requested supply deferrals in relation to ROE, is largely similar to that of Mr. D. Bowman. Hydro disagrees with Dr. Wilson's testimony for the same reasons.

In the context of Hydro's Amended Application, Mr. D. Bowman's and Dr. Wilson's discussions on Hydro's incentive to manage supply costs are incomplete. Hydro has proposed a +/- $500,000 dead band on two of the three accounts. This represents a +/- $1,000,000 incentive, each fiscal year, for Hydro to limit the supply costs incurred. Hydro submits that this level of risk is sufficient incentive to manage these specific supply costs in a given year.

Section D.5: Management of the Rural Deficit

D.5.1 Amount of the Rural Deficit and Controllable Costs

- ***The Rural Deficit as a percentage of revenue requirement is stable.***

Hydro provides service to over 40 remote diesel communities.[267] It owns and operates 21 diesel-generating plants serving 4,600 customers on Isolated Systems. Hydro also directly

[267] November 23, 2015 Transcript, page 20.

serves 23,700 customers on the IIS. The Rural Deficit is the difference between the cost of providing service to these Rural Customers and the revenues collected from those customers.

The Rural Deficit has grown from $40.8 million in the 2007 Test Year to a forecast of $64.1 million in the 2015 Test Year. The growth in the amount of the Rural Deficit has resulted primarily from fuel costs, rather than from increases in costs that are controllable by Hydro. Controllable costs, which are primarily operating expenses, have remained relatively consistent from year to year, despite increasing wages and general inflationary pressure on material supply costs and other costs.[268] As illustrated in Chart 1 in Hydro's March 2015 Rural Deficit Annual Report, the Rural Deficit has been relatively consistent year over year when the impact of fuel costs (and the ROE established by Government directive) is removed.[269]

While the absolute dollar amount of the Rural Deficit has grown since 2007, it is important to put the total dollar amount into context. Evidence provided by NP makes it clear that the Rural Deficit allocated to NP was greater as a percentage of NP's total revenue requirement in 2002 than in either 2007 or 2015.[270] NP's allocation of the Rural Deficit as a percentage of its total revenue requirement declined from slightly more than 15.5% in 2002 to approximately 11.5% in 2007.[271] Under the proposed allocation methodology, NP's allocation of the Rural Deficit in 2015 falls in line with the 2007 percentage (i.e., approximately 11.8% of NP's total 2015 revenue requirement).[272]

[268] Amended Application, Regulated Activities Evidence, pages 2.82-2.83.
[269] Information Exhibit #8, page 3 and Chart 1.
[270] NLH-NP-019. See also October 7, 2015 Transcript, pages 129-130.
[271] In the response to NLH-NP-019, NP provided a bar chart showing the Rural Deficit allocated to NP as a percentage compared to NP's "remaining revenue requirement" and it also provided the dollar amounts for NP's total revenue requirement, including the Rural Deficit for 2002, 2007 and 2015. The actual percentages (NP's allocation of the Rural Deficit as a percentage of NP's total revenue requirement) for 2002 and 2007, and for 2015 under Hydro's proposed methodology, can be calculated using the information provided in the Pre-filed Evidence and Exhibit of Mr. Brockman, pages 8-9 together with the dollar amounts in NLH-NP-019.
[272] October 7, 2015 Transcript, page 130.

D.5.2 Customer Awareness and the Rural Deficit

- ***The Board should proceed cautiously in considering the addition of a line item on customer bills demonstrating the impact of the Rural Deficit.***

Dr. Feehan proposed that the amounts customers contribute to the Rural Deficit should be expressed on their bills because this would contribute to good public policy and, more specifically, inform any future public policy debate about the continuation of the Rural Deficit policy.[273] In response to a question from Board Hearing Counsel, Dr. Feehan also said that he saw no reason why the people receiving the subsidy should not see that on their bills just like the people who are paying the subsidy.[274]

The proposal that customers be made aware of who is contributing to the Rural Deficit and who is paying the cost of it gives rise to a number of implications that should be taken into account before any decision is made to adopt Dr. Feehan's suggestion. A decision to communicate information about which customers pay for the Rural Deficit and which customers benefit from it could result in an approach to customer communications that is selective, unpopular, and, potentially, provocative and even misleading. As noted by Mr. Fagan for Hydro in his testimony, research with focus groups would be advisable to ensure no unforeseen consequences of this action.[275]

It is also important to note that the proposed communication of information would be selective because it would specifically address the cross-subsidization effect of the Rural Deficit even though some element of cross-subsidization is, quite apart from the Rural Deficit, inherent in rates.[276] Of course, it is unavoidable that there will be cross-subsidization in customer rates, because it is not practicable to attempt to isolate the precise costs of serving each individual customer. Most people know that there are economic differences in the cost to serve different

[273] October 5, 2015 Transcript, page 13.
[274] October 5, 2015 Transcript, pages 71-72.
[275] October 6, 2015 Transcript, page 49.
[276] October 6, 2015 Transcript, pages 44-45.

customers.[277] Presumably, under Dr. Feehan's proposal, NP customers would be told that they are paying a share of the Rural Deficit. However, if one were to do a cost of service study of NP's more rural regions, one would come up with a fairly large rural subsidy being received (not paid) by rural customers on NP's own system.[278] Identifying Rural Customers on the IIS as a subsidized group is not much different than breaking NP's cost of service study into regions and coming up with an NP rural deficit that represents cross-subsidization of NP's rural customers.[279]

When a proposal was put forward that a rural surcharge be introduced on the bills of NP in 1996, the proposition was opposed by all intervenors, it was a topic that received considerable attention in the media and was unpopular with customers.[280] The proposed communication would potentially be provocative as well. According to Mr. Fagan's testimony, his experience from the 1995 Rural Rate Inquiry indicated that customers in some of Hydro's rural areas are offended by the notion that, although their resources have been used to support the rest of the Province, there is perceived to be a need to highlight that their electricity rates are subsidized.[281]

The proposed communication would also potentially be confusing to customers because NP's customer would be told that they are paying the Rural Deficit when in fact it is likely that it costs more to serve customers in some of NP's rural areas than it does to serve customers in some of Hydro's rural interconnected areas.[282] Further, such communication has the potential to pit neighbouring communities against one another: those that are being "subsidized" (e.g., Baie Verte) and those who are "subsidizing" providing of services to isolated customers (e.g., Deer Lake).[283]

[277] October 6, 2015 Transcript, page 40.
[278] October 6, 2015 Transcript, page 37.
[279] October 6, 2015 Transcript, pages 47-48.
[280] October 6, 2015 Transcript, page 39.
[281] October 6, 2015 Transcript, pages 38-39.
[282] October 6, 2015 Transcript, pages 44-45.
[283] October 6, 2015 Transcript, pages 36-37.

It is perhaps easy to jump to a conclusion that there can be no harm in providing more information to customers about the Rural Deficit. As noted above, Hydro respectfully submits that Dr. Feehan's proposal has a number of implications that should be carefully considered before any decision is made to adopt that proposal. Further, if the Board decides that information should be communicated about the customers who pay the Rural Deficit and the customers who benefit from it, Hydro submits that consideration should be given to framing a message that conveys a perception of fairness to all parties.[284]

D.5.3 Conservation Measures to Control the Rural Deficit

- ***Hydro has continued its efforts to reduce the Rural Deficit by promoting energy efficiency in isolated communities.***

Hydro's Rural Deficit Annual Report of March 2015 summarizes many initiatives taken by Hydro to control the overall amount of the Rural Deficit.[285] These include a number of internal energy efficiency initiatives that were completed or launched by Hydro in 2014, as well as ongoing cost control measures that have been continued by Hydro. This Report also describes CDM program initiatives and capital initiatives pursued by Hydro to control the Rural Deficit.

Hydro's work on energy efficiency initiatives in isolated communities goes back as far as the early 1990s.[286] When implementation of Hydro's takeCHARGE partnership with NP began in 2009, the joint effort did not include programs targeted specifically at isolated communities, but the takeCHARGE programs were open to customers in isolated communities who were eligible for them.[287]

Hydro partnered with the Government on a pilot project in isolated communities in 2010 to 2011 and then followed up by launching two programs specifically targeted at these

[284] October 6, 2015 Transcript, pages 37-38 and 49. Hydro also suggested neutral wording, such as rate equalization policy adjustment, rather than using a work like "subsidy". See October 6, 2015 Transcript, page 37.
[285] Information #8.
[286] November 24, 2015 Transcript, page 3.
[287] November 24, 2015 Transcript, pages 2-4.

communities in 2012. The two initiatives are: (i) the Isolated Systems Community Energy Efficiency Program and (ii) the Isolated Systems Business Efficiency Program. Hydro delivers programs in isolated communities under the takeCHARGE brand, independently of its joint effort with NP.[288]

The Isolated Systems Community Energy Efficiency Program includes a number of features such as the provision of kits of small energy efficiency technologies to homes and businesses, coupons for discounts on a number of energy efficiency products, increased incentives for home insulation retrofits and work to assess the opportunity for, and challenges of, larger-scale home retrofits.

The Isolated Systems Community Energy Efficiency Program is a three-year program that is expected to result in total energy saving of 3.3 GWh/year and fuel cost savings of $1.1 million per year.[289] Under this program, both residential and commercial customers are provided with energy efficiency support and assistance that covers a wide range, including direct install of efficiency products, education and awareness, coupons and incentives.[290]

From 2012 to 2014, Hydro was able to reach 83% of its customers in isolated communities under the Isolated Systems Community Energy Efficiency Program.[291] At this point, Hydro has not embarked on a "whole home approach" to CDM in these communities because changes to a building envelope such as addition of insulation contribute to existing issues of water infiltration, mold and condensation and because of concerns that major home renovations are not within the purview of an electrical utility.[292]

The Isolated Systems Business Efficiency Program provides technical support and incentives to commercial customers. Extensive time and effort are required to bring commercial customers

[288] PUB-NLH-313.
[289] NP-NLH-098 (Revision 1, Dec 9-14), Attachment 2, page 8 of 10.
[290] PUB-NLH-313.
[291] November 23, 2015 Transcript, page 20.
[292] November 24, 2015 Transcript, pages 5-7 and 171-172.

through the process:[293] customers are given a free walk-through audit of a facility followed by a report on energy saving opportunities.[294] This is also a three-year program and an evaluation is planned after the third year of the program.[295]

The Isolated Systems Business Efficiency Program is expected to result in total energy savings of 180 MWh. By the end of 2012, more than 40 audits had been completed with recommendation reports provided to customers.[296] To date, 58 commercial customers have been visited under the Isolated Systems Business Efficiency Program.[297]

As part of its CDM efforts in isolated communities, Hydro also carries out energy efficiency improvements at its own facilities. Hydro's CDM team consults with and assists the Hydro Operations group in making Hydro's own operations in isolated communities more efficient.[298]

The estimated 2015 impact of Hydro's CDM initiatives on the Rural Deficit has been presented in evidence.[299] For the 2015 Test Year, savings from customer-focused energy efficiency measures (including 2013 actuals) are estimated to be 9.4 GWh, or, as a dollar amount, more than $1 million. For the 2015 Test Year, savings from internally focused energy efficiency measures (including 2013 actuals) are estimated to be 4.2 GWh, or more than $600,000. Hydro submits that its CDM activities have produced a successful outcome that contributes significantly to its efforts to constrain the amount of the Rural Deficit.

D.5.4 Cost Control Measures to Control the Rural Deficit

- ***Hydro has undertaken numerous initiatives resulting in cost savings or avoided cost in Rural Deficit areas.***

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[293] PUB-NLH-313.
[294] NP-NLH-098 (Revision 1, Dec 9-14), Attachment 2, page 9 of 10.
[295] *Ibid*.
[296] NP-NLH-098 (Revision 1, Dec 9-14), Attachment 2, page 9 of 10.
[297] November 23, 2015 Transcript, page 21.
[298] November 24, 2015 Transcript, page 175.
[299] NP-NLH-098 (Revision 1, Dec 9-14), Attachment 1, page 1 of 1.

Hydro has implemented many cost reduction initiatives to contain the growth of the Rural Deficit. In particular, given its mandate to provide least-cost, safe and reliable power to all its customers, Hydro strives to manage the costs of serving Rural Customers with a view to providing reliable service while minimizing the amount of the Rural Deficit.[300] Actions taken by Hydro that contain the growth of the Rural Deficit are explained in evidence prepared specifically for the purposes of this proceeding[301] and in the Rural Deficit Annual Reports, also on the record of this proceeding, that Hydro files each year with the Board.[302]

Hydro has undertaken both dedicated efforts aimed at controlling the Rural Deficit and Hydro-wide projects that result in cost savings or avoided costs in Rural Deficit areas.[303] In addition to the CDM program initiatives that are discussed above, efforts to control operating costs include internal energy efficiency initiatives and ongoing cost control measures.[304] Hydro has also implemented capital-spending initiatives that contribute to its effort to control the Rural Deficit.[305]

Examples of the numerous initiatives and programs undertaken by Hydro that result in cost savings or avoided costs in Rural Deficit areas include the following:

- Capturing waste heat;
- Monitoring diesel system fuel efficiency;
- Utilizing commercial flights where practical, rather than more expensive helicopter use;
- Using a fuel-efficient mix of engines to supply load;
- Enhancing the effectiveness of planning and scheduling to minimize outages and delays;
- Carrying out life cycle cost analysis for diesel engines;
- Implementing automatic meter reading;
- Installing in-line heaters at diesel plants; and

[300] Amended Application Regulated Activities Evidence, page 2.83.
[301] NP-NLH-098 (Revision 1, Dec 9-14), Attachment 1.
[302] NP-NLH-099 (Revision 2, Dec 9-14), Attachment 1; NP-NLH-098 (Revision 1, Dec 9-14), Attachment 2; and Information Exhibit #8.
[303] NP-NLH-098 (Revision 1, Dec 9-14).
[304] Information Exhibit #8, pages 3-5.
[305] *Ibid.*, page 8.

- Implementing e-billing and in-house printing of customer bills.[306]

In the case of many of Hydro's projects and initiatives, the reduction in the Rural Deficit by way of costs saved or avoided is not quantifiable.[307] Even so, the estimated 2015 Test Year total savings (resulting from only those reductions that are quantifiable) exceed $2 million.[308]

Section D.6: Other Issues

D.6.1 Customer Service Strategy

The Parties agreed Hydro's "Customer Service Strategic Roadmap 2015-2017" reflects appropriate customer service improvement objectives. The parties stipulated their agreement did not preclude additional customer service improvements being raised during the hearing of this Application or being considered by the Board.[309]

D.6.2 Issues Raised By the Nunatsiavut Government

On November 30, 2015, the Board heard testimony from two witnesses appearing on behalf of the Nunatsiavut Government: Darryl Shiwak, Nunatsiavut's Minister of Lands and Natural Resources; and Chris Henderson of Lumos Energy, Nunatsiavut's clean energy advisor,[310] who was offered as Nunatsiavut's expert on sustainable energy development in northern climates.[311] Minister Shiwak testified about socioeconomic conditions in Nunatsiavut's communities, particularly as regards energy affordability.[312] Minister Shiwak also discussed Nunatsiavut's current and future energy needs, the ongoing need for improvements to the diesel-generated electricity systems serving Nunatsiavut's communities, the impact of higher rates and his views on Muskrat Falls.[313] On cross-examination,[314] Minister Shiwak characterized

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306 Amended Application Regulated Activities Evidence, page 2.83.
307 NP-NLH-098 (Revision 1, Dec 9-14).
308 Total of amounts shown at NP-NLH-098 (Revision 1, Dec 9-14), Attachment 1.
309 Settlement Agreement, page 4, paragraph 21.
310 November 30, 2015 Transcript, pages 35, line 25 to 36, line 1.
311 November 30, 2015 Transcript, page 34, lines 1-13.
312 November 30, 2015 Transcript, pages 6, line 16 to 14, line 10.
313 November 30, 2015 Transcript, pages 14, line 11 to 23, line 8.

the takeCHARGE program as "a good program, but more needs to be done to get into the communities".[315]

Mr. C. Henderson's testimony previewed a report he began two years ago to assess Nunatsiavut's energy needs and resources, and to identify opportunities to reduce energy consumption and energy costs. Mr. C. Henderson advised that his report has generated a Nunatsiavut energy security plan, which will be made available to the Government, the Board, and interested stakeholders shortly.[316] Drawing on experience with other First Nations communities in northern climates, Mr. C. Henderson advocated a "more holistic energy community energy planning approach and a more holistic home energy efficiency and conservation approach,"[317] which Mr. C. Henderson developed in consultation with Hydro and the Board.[318] Mr. C. Henderson identified innovation opportunities for Hydro's diesel generation facilities,[319] and he elaborated on these opportunities during cross-examination.[320] Hydro believes the Board must give consideration to its regulatory framework when considering the Nunatsiavut Government's submissions.[321] Hydro appreciates the intervention of the Nunatsiavut Government and Minister Shiwak, and Mr. C. Henderson for the depth and evenhandedness of their testimony.

E. RATE IMPLEMENTATION

E.1 COMPLIANCE FILING

Subsequent to the final Order for the GRA, Hydro will make a compliance filing reflecting the Board's decisions. The compliance filing will finalize the revenue deficiency calculations for 2014 and 2015 and provide recovery proposals by customer class. COS studies for each year will be provided to determine the revenue deficiency by customer class.

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[314] November 30, 2015 Transcript, pages 23, line 24 to 28, line 2.
[315] November 30, 2015 Transcript, page 27, lines 1 to 2.
[316] November 30, 2015 Transcript, pages 35, line 18 to 36, line 25.
[317] November 30, 2015 Transcript, pages 41, line 23 to 42, line 1.
[318] November 30, 2015 Transcript, page 37, lines 3 to 6.
[319] November 30, 2015 Transcript, pages 44, line 11 to 45, line 25.
[320] November 30, 2015 Transcript, pages 57, line 11 to 67, line 16.
[321] Order No. P.U. 8(2007), Appendix A.

Delayed implementation of customer rates in 2016 will also contribute to a further revenue deficiency attributable to certain customer classes. The compliance application will provide a forecast 2016 revenue deficiency by customer class based on the 2015 Test Year sales forecast and include a proposal for appropriate recovery.

The compliance application will include proposals that reflect the Board's determinations in the final GRA Order for the finalization of the 2015 Test Year revenue requirement and 2015 Test Year rate base for use in the establishment of customer rates in 2016. This filing will include a 2015 Test Year COS Study reflecting the approved revenue requirements for use in establishing customer rates.

The final GRA Order will also permit Hydro to update the RSP balances for 2015 reflecting the updated 2015 Test Year inputs for fuel cost, hydrology, load, and customer rates. The RSP balances currently being reported on an interim basis reflect the 2007 Test Year inputs.

E.2 RECOVERY OF REVENUE DEFICIENCIES

The rates proposed in the GRA evidence do not reflect the recovery of the revenue deficiencies already incurred as the proposed rates are based upon recovery of 2015 Test Year costs. Subject to the Board's finalization of the amounts to be recovered, Hydro's compliance application will present proposals for recovery of the:

(i) 2014 Revenue Deficiency of $45.9 million as approved for deferral in Order No. P.U. 58(2014) with recovery being subject to the Board's subsequent determination;

(ii) 2015 Net Income Deficiency of $60.5 million per Hydro's Amended Cost Deferral Application, dated November 12, 2015, with recovery being subject to the Board's subsequent determination; and

(iii) Forecast 2016 revenue deficiency resulting from delayed implementation of customer rates beyond January 1, 2016.

One method to deal with the recovery of the revenue deficiencies to be approved by the Board is to recover the deficiency through higher rates to be paid by customers in the future (i.e., as a rate rider or cost recovery amortization).[322] Another method for consideration is to use the material fuel savings that have accumulated and are reflected as credit balances in the RSP. In the Amended Application, Hydro proposed the recovery of the 2014 deficiency through the use of the credit balances in the RSP.[323] Hydro believes using the RSP credit balances to recover revenue deficiencies is consistent with intergenerational equity in that it applies funds already recovered from customers to recover costs that have already been incurred to provide service to those customers.[324]

Mr. D. Bowman agreed that the methodology for disposing of RSP balances should be reviewed in light of the limited remaining operating time of the Holyrood thermal plant.[325] Mr. D. Bowman also recommended the use of the RSP credit balances to reduce the volatility of customer rates over the period to 2017.[326]

Mr. Brockman agreed with the use of RSP credit balances to avoid increasing future rates for costs already incurred. [327] Mr. Dean also agreed; he stated:

> *A recovery method that uses an existing balance is recommended over methods such as a rate rider that would affect future years. A rate rider would worsen the rate impact that the Industrial Customers are experiencing and would cause intergenerational inequity due to the changing dynamics within the Industrial Customer class.*[328]

[322] This is similar to the method approved by the Board in the case of NP in its 2013-2014 General Rate Application. In Order No. P.U. 13(2013), the Board approved the amortization of the forecast 2013 revenue shortfall over three years, commencing in 2013.
[323] At year-end 2014, there was a $35 million credit balance in the RSP load variation component and a $43 million credit in the RSP hydraulic component.
[324] October 5, 2015, Transcript, page 107, lines 10 – 25.
[325] Pre-filed evidence of C. Douglas Bowman dated June 1, 2015, page 14, lines 22 – 24.
[326] Pre-filed evidence of C. Douglas Bowman dated June 1, 2015, page 15, lines 19 – 22.
[327] September 28, 2015 Transcript, page 121, lines 1-20.
[328] Pre-filed evidence of Mr. Dean, dated June 4, 2015, pages 19, line 28 to 20, line 3.

As indicated earlier, the final GRA Order will permit Hydro to update the RSP balances for 2015. Hydro submits it is appropriate to utilize the 2015 year-end credit balances in the RSP load variation component and the hydraulic variations component, where appropriate, to limit the amount of revenue deficiency that will be recovered through rates from customers. Any portion of the revenue deficiencies not approved for recovery through the RSP should be proposed for recovery through future customer rates. This approach will likely be required for recovery of revenue deficiency attributable to customers on the Labrador Interconnected System.

F. CONCLUSION/ORDER REQUESTED

In conclusion, Hydro under the *Act*, and specifically under Sections 58, 64, 70, 71, 75, 76, 78 and 80, proposes the following, effective January 1, 2016. The following is divided into two sections: settled and non-settled matters.

F.1 SETTLED ISSUES

There were two settlement agreements filed with the Board in this matter. In that connection, Hydro seeks the Board's approval of those agreements, and more particularly, proposes that:

(1) The allowable range of return on rate base of +/- 20 basis points be approved;[329]

(2) Hydro's treatment to include actuarial gains and losses on Employee Future Benefits of $1.6 million in the 2015 Test Year as part of Hydro's revenue requirement be approved;[330]

(3) Hydro's Asset Retirement Obligations include depreciation and accretion expenses of $2.6 million and $2.6 million, respectively for the 2014 and 2015 Test Years be approved;[331]

[329] Item 7 of the Settlement Agreement.
[330] Item 8 of the Settlement Agreement.
[331] Item 9 of the Settlement Agreement.

(4) The total generation credit for NP be increased to 119,329 kW;[332]

(5) Hydro's proposal to defer and amortize annual customer energy conservation program costs, commencing in 2015, over a discrete seven year period in a CDM Cost Deferral Account, be approved;[333]

(6) The costs related to the Application be recovered in customer rates evenly over a three year period, commencing with the date that new rates approved in this proceeding become effective with the amount of such costs to be determined by the Board;[334]

(7) The Service Agreement between Hydro and CBPP, which was approved on a pilot basis by the Board in Order No. P.U. 4(2012), be approved to continue on a pilot basis;[335]

(8) An industrial wheeling rate calculated in accordance with the methodology proposed by Hydro in its Application be approved;[336]

(9) Hydro report functionally oriented key performance indicators as required by the Board in Order No. P.U. 14(2014) based on the most recent Test Year COS Study approved by the Board rather than on a forecast basis;[337]

(10) In preparation for the implementation of customer rates reflecting the costs of the Labrador-Island interconnection, Hydro will file with the Board the following:[338]

[332] Item 14(a) of the Settlement Agreement.
[333] Item 17 of the Settlement Agreement.
[334] Item 18 of the Settlement Agreement.
[335] Item 19 of the Settlement Agreement.
[336] Item 20 of the Settlement Agreement.
[337] Item 22 of the Settlement Agreement.
[338] Item 23 of the Settlement Agreement.

i. a marginal cost study no later than December 31, 2015;
ii. a cost of service methodology report no later than March 31, 2016; and
iii. a report on the Rate Stabilization Plan and supply cost recovery mechanisms no later than June 15, 2016;

(11) A generic cost of service hearing be held following the filing of the reports outlined in (10) above;

(12) Hydro file a GRA on or before March 30, 2017 proposing rates based on a 2018 Test Year;[339]

(13) the cost of service methodologies in Exhibit 13(2015 Test Year COS) be approved with respect to:

i. the treatment of the curtailable load of Newfoundland Power;
ii. the classification of wind energy purchases as 100% energy related;
iii. the classification of all Holyrood fuel costs to energy;
iv. the use of the load forecast provided by NP; and
v. the specific assignment of the frequency converter to CBPP Limited; [340]

(14) The calculation of the capacity factor for the Holyrood Generating Plant be based on a historical five-year period from 2010 to 2014, inclusive;[341]

(15) The demand charge to NP will equal $4.75 per kW of billing demand;[342]

(16) The end block energy rate to NP will be determined based on the 2015 Test Year No. 6 fuel price divided by the 2015 Test Year Holyrood fuel conversion Factor, both as are determined by the Board;[343]

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[339] Item 23(d) of the Settlement Agreement.
[340] Item 7 of the Supplemental Settlement Agreement.
[341] Item 8 of the Supplemental Settlement Agreement.
[342] Item 10(i) of the Supplemental Settlement Agreement.
[343] Item 10(ii) of the Supplemental Settlement Agreement.

(17) The approved 2015 Test Year revenue requirement that is not recovered through the NP demand and end-block energy charge will be used to compute the first block energy charge;[344]

(18) The wholesale rate charged to NP will include a curtailable load credit as proposed in the Amended Application;[345]

(19) Hydro's proposed CDM Recovery Adjustment be approved so as to provide for recovery of costs charged annually to the CDM Cost Deferral Account;[346]

(20) Costs associated with Hydro's capacity assistance agreements with Vale and Corner Brook Pulp and Paper Limited be treated as demand related in the 2015 Test Year COS Study;[347]

(21) If the load variation component is maintained as an element of the RSP, the allocation of year-to-date net load variations for NP and industrial customers among the customer groups be based upon energy ratios, with effect from the date to be determined by the Board (there is no settlement on the effective date—Hydro proposes that the effective date be September 1, 2013);

F.2 HYDRO’S PROPOSALS ON ISSUES NOT SETTLED

On the matters that were not settled by the parties and therefore did not constitute elements of either of the settlement agreements, in summary Hydro proposals are as follows.

F.2.1 Revenue Requirement

(1) Hydro's 2014 Test Year Revenue Requirement of $560,755,000 be approved;[348]

[344] Item 10 of the Supplemental Settlement Agreement.
[345] Item 11 of the Supplemental Settlement Agreement.
[346] Item 12 of the Supplemental Settlement Agreement.
[347] Item 14(b) of the Settlement Agreement.

(2) Hydro's adjusted 2015 Test Year Revenue Requirement of $579,577,352 be approved for the purpose of determining 2015 Revenue Deficiency;[349]

(3) Hydro's 2015 Test Year Revenue Requirement of $584,677,352 be approved for the purpose of setting customer rates;[350]

(4) Hydro's forecast capital structure for the 2014 Test Year be approved with a weighted average cost of capital of 7.32%;

(5) Hydro's forecast capital structure for the 2015 Test Year be approved with a weighted average cost of capital of 6.82%;

(6) Pursuant to Order in Council OC2009-063, for purpose of calculating Hydro's return on rate base, the return on equity last approved by Order No. P.U. 13 (2013), as a result of NP's general rate application, of 8.80% be approved for the 2014 Test Year and the 2015 Test Year;

(7) Hydro be allowed a rate of return on forecast average rate base for the 2014 Test Year of 7.12%;

(8) Hydro be allowed a rate of return on forecast average rate base for the 2015 Test Year of 6.82%;

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[348] Equals the $560,855,000 proposed 2014 Test Year Revenue Requirement in the Amended Application less $2,100,000 (i.e. the impact on 2014 Test Year Revenue Requirement resulting from adjustments to reflect delayed in-service dates of 2014 capital projects until 2015). See PUB-NLH-487.

[349] Equals the $662,475,000 proposed 2015 Test Year Revenue Requirement in the Amended Application less (i) $75,878,230 No. 6 fuel cost savings based on a Test Year No. 6 fuel cost of $64.41 per barrel (ii) less $5,100,000 (i.e. the impact on 2015 Test Year Revenue Requirement resulting from adjustments to reflect delayed in-service dates of 2014 capital projects in the 2015 rate base opening balance); (iii) less $1,919,418 Isolated supply costs savings referenced in the October 28, 2015 correspondence with the Board on projected 2016 fuel costs. See PUB-NLH-487.

[350] Equals the $662,475,000 proposed 2015 Test Year Revenue Requirement in the Amended Application less (i) $75,878,230 No. 6 fuel cost savings based on a Test Year No. 6 fuel cost of $64.41 per barrel; and (ii) less $1,919,418 Isolated supply costs savings referenced in the October 28, 2015 correspondence with the Board on projected 2016 fuel costs.

(9) The 2015 Test Year costs related to capacity assistance agreements be approved for inclusion in 2015 Test Year Revenue Requirement.

F.2.2 Deferral and Recovery Mechanisms

(10) The proposed Isolated Systems Supply Cost Variance Deferral Account be approved effective January 1, 2015;

(11) The proposed Energy Supply Cost Variance Deferral Account be approved effective January 1, 2015;

(12) The proposed Holyrood Conversion Rate Account be approved effective January 1, 2015.[351]

F.2.3 Amortizations

(13) An estimated $1.2 million (the final amount to be set after the conclusion of the hearing) in external regulatory costs be deferred and recovered over three years in accordance with the Settlement Agreement;[352]

(14) The regulatory treatment of Capacity Related Supply Cost Variances, whereby it would be amortized over a five-year period commencing in the 2015 Test Year, as proposed in Hydro's application filed October 8, 2014, be approved.[353]

F.2.4 Rate Base

(15) Hydro's average rate base for 2013 of $1,548,371 be approved.[354]

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[351] This account was requested, explained and described in Supplemental evidence filed by Hydro on January 14, 2015.

[352] Originally requested on page 3.22 of Hydro's Amended Application, updated to $1.2 million per line 35 of Undertaking 55.

[353] Pending a determination of this matter in the Prudence Review process

[354] Finance Evidence, Schedule I, page 5 of 11, line 21.

(16) Hydro's forecast average rate base for the 2014 Test Year of $1,618,867 be approved for determining 2014 revenue deficiency;[355]

(17) Hydro's forecast average rate base for the adjusted 2015 Test Year of $1,728,324 be approved for the purpose of approving 2015 revenue deficiency;[356]

(18) Hydro's forecast average rate base for the 2015 Test Year of $1,802,024 be approved for the purpose of approving rates;[357]

F.2.5 Rate Stabilization Plan

(19) Hydro will propose a plan for the finalization of the phase-in of IC rates to be filed with its compliance application;

(20) As there is no further Rural Labrador Interconnected Automatic Rate Adjustment, Section 1.3(b) be removed from the RSP Rules;

(21) The Section E – Historical Plan Balance be removed;

(22) The load variation component be maintained as an element of the RSP;

(23) The allocation of year-to-date net load variations for NP and industrial customers among the customer groups be based upon energy ratios, with effect from September 1, 2013;

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[355] Equals the $1,692,567,000 proposed 2014 Test Year rate base in the Amended Application less $73,700,000 (i.e. the impact on 2014 Test Year Rate Base resulting from adjustments to reflect delayed in-service dates of 2014 capital projects until 2015).

[356] Equals the $1,802,024,000 proposed 2015 Test Year rate base in the Amended Application less $73,700,000 (i.e. the impact on 2015 Test Year Rate Base resulting from adjustments to reflect delayed in-service dates of 2014 capital projects until 2015).

[357] Equals the $1,802,024 proposed 2015 Test Year rate base in the Amended Application.

F.2.6 Revenue Deficiency

(24) The RSP credit balance be used, where appropriate to offset the revenue deficiency that occurred due to delays in implementation of rate changes beyond January 1. 2014;

(25) The portion of the revenue deficiency not recovered using the RSP credit balance be deferred for future recovery through a rate rider or through a cost recovery amortization included in revenue requirement for determining rates.

F.2.7 General Rate and Cost of Service Matters

(26) The Labrador Transmission demand-related rate be set at \$1.25/kw/month;

(27) Commencing January 1, 2014 the Rural Deficit be allocated based on revenue requirement;

(28) Hydro use the indexed cost of assets in allocation of O&M costs to specifically assigned assets in the cost of service study for the 2014 and 2015 Test Years;

(29) The Board approve the 2015 load forecast for IIC for use in the 2015 Test Year COS Study;

(30) The average system losses used in the calculation of the energy charge to Industrial Customers for non-firm service be increased to 3.47%;

(31) The Board approve the proposed above average increases in customer rates for Hydro Rural non-Government Domestic and General Service customers on Isolated systems; and

(32) Upon hearing this Amended Application, the Board grant such alternative, additional or further relief as the Board shall consider fit and proper in the circumstances.

ALL OF WHICH IS RESPECTFULLY SUBMITTED.