newfoundland labrador
hydro
a nalcor energy company

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July 30, 2013

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 of Corporate Services & Board Secretary

Re: Newfoundland and Labrador Hydro's 2013 General Rate Application

Background

Newfoundland and Labrador Hydro's (Hydro) last General Rate Application (GRA) received the Board's approval in Order No. P.U. 8 (2007) with new rates effective January 1, 2007. Industrial Customers' rates have remained unchanged and have been approved on an interim basis since January 1, 2008. Newfoundland Power's rates have been subject to annual Rate Stabilization Plan (RSP) adjustments which have been passed on to their customers and, with the exception of those served from the Labrador Interconnected System, they have been passed on to Hydro's Rural Customers. Labrador Interconnected customers have also received rate changes as the 2007 rates were phased in, with the final implementation of standard Labrador Interconnected rates on January 1, 2011.

Rate Stabilization Plan

A surplus in the RSP has accumulated primarily due to fuel savings at Hydro's Holyrood Thermal Generating Station that resulted from the shutdown of significant pulp and paper production on the Island. On April 19, 2011, an Order in Council (OC) was issued under the *Electrical Power Control Act, 1994* directing the Board to consider the RSP issue in the context of Hydro's next GRA. Therefore, in addition to the enclosed General Rate Application, Hydro is also filing an application concerning the accumulated surplus in the RSP. Further OCs, (OC2013-089 dated April 4, 2013, as amended by OC2013-207 dated July 16, 2013) provided guidance to the Board and Hydro as to the disposition of the RSP surplus and a phase-in of the Industrial Customer rate increase. The RSP application will address the Industrial Customers' rate phase-in as well as related rule changes to the RSP. During its GRA process, Hydro will file with the Board an RSP Surplus refund plan which will recommend a methodology to be used in refunding the amount of Newfoundland Power's RSP surplus.

The General Rate Application

The Application, prefiled evidence and supporting information are organized as follows:

Volume 1 – Application and Evidence

This Volume includes the Application, proposed rates rules and regulations and company evidence.

Volume 2- Exhibits

This Volume contains exhibits to support the evidence, and other exhibits required to be filed with Hydro's GRA.

Application Proposals

Hydro's Application includes the following proposals:

(1) that Hydro's forecast 2013 Test Year costs (before return on rate base) of $445,639,000 be approved;

(2) that pursuant to the directive to the Board, for purpose of calculating Hydro's return on rate base, the return on equity last approved by Order No. P.U. 13 (2013) from Newfoundland Power's general rate application, of 8.80 %, be approved;

(3) that Hydro be allowed a rate of return on forecast average rate base of 7.83%;

(4) that the allowable range of return on rate base of +/- 25 basis points be approved.

Regulatory and Accounting Proposals

In addition, the Application includes proposals as to the accounting and regulatory treatment of:

(1) Actuarial gains and losses on Employee Future Benefits;

(2) Hydro's Asset Retirement Obligations;

(3) Hydro's energy purchases in the RSP;

(4) Conservation Demand Management costs; and

(5) Diesel fuel and purchased energy costs for Hydro's isolated systems.

Rate Changes

The Application proposes a number of changes to customer rates. The customer rates proposed in this application were derived to provide the proposed 2013 revenue requirement. The rate proposals also reflect the Company's most recent cost of service study.

Proposed Island Interconnected, Island Isolated System, Labrador Interconnected, Labrador Isolated System and L'Anse au Loup System rate change percentages are outlined in the following table:

Proposed Effective Date January 1, 2014	
Rate Class	**Average Increase (Decrease)**
ISLAND INTERCONNECTED	
Newfoundland Power (NP) wholesale rate impact	(4.8%)
Estimated end consumers' rate[1] impact	(3.2%)
Estimated Rural Customers' rate impact	(3.2%)
Industrial Customers (IC)[2]	73.1%
ISLAND ISOLATED SYSTEMS	
Domestic	0.9%
General Service 0 - 10 kW	11.6%
General Service Over 10 kW	11.5%
Street and Area Lighting	(3.2%)
Government Departments	
General Service 0-10 kW	22.0%
General Service Over 10 kW	27.5%
Street and Area Lighting	16.8%
LABRADOR INTERCONNECTED	
Domestic	26.0%
General Service 0-10 kW	28.5%
General Service 10-100 kW	16.6%
General Service 110–1,000 kVA	16.9%
General Service Over 1,000 kVA	22.0%
Street and Area Lighting	42.8%
LABRADOR ISOLATED SYSTEMS	
Domestic[3]	0.9%
General Service 0 - 10 kW	11.6%
General Service Over 10 kW	11.5%
Street and Area Lighting	(3.2%)
Government Departments	
Domestic	17.7%
General Service 0 - 10 kW	22.0%
General Service Over 10 kW	27.5%
Street and Area Lighting	16.8%
L'ANSE AU LOUP SYSTEM	
Domestic[4]	(3.2%)
General Service 0 - 10 kW	(3.2%)
General Service Over 10 kW	(3.2%)
Street and Area Lighting	(3.2%)

[1] Estimated 67% pass through to retail level.
[2] Industrial Customers are subject to a phase-in of this rate as outlined in Hydro's RSP evidence filed separately. On September 1, 2013, year one of the phase-in begins and will result in a proposed average increase for Industrial customers of 22.4%.
[3] With the annual Northern Strategic Plan subsidy, domestic customers in coastal Labrador pay the equivalent electricity rates as Labrador Interconnected customers for their basic electricity needs. The proposed increase to Labrador Interconnected rates will mean that the average rate increase for domestic coastal Labrador customers, after the subsidy is considered, will be 20.4%.
[4] With the annual Northern Strategic Plan subsidy, residential customers in the L'Anse au Loup System pay the equivalent electricity rates as Labrador Interconnected customers for their basic electricity needs. The proposed increase to Labrador Interconnected Customers will mean that the average rate of increase for domestic L'Anse au Loup customers, after the subsidy is considered, will be 4.5%.

Access to Materials Filed

Within the next few days an Adobe portable document format (pdf) copy of this application will be available to all parties listed below and will be posted to Hydro's website at www.nlh.nl.ca. In addition, hard copies will be made available for viewing at Hydro's Regional offices.

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

Should you have any questions, please do not hesitate to contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

Geoffrey P. Young
Senior Legal Counsel

GPY/jc

cc: Gerard Hayes – Newfoundland Power
Paul Coxworthy – Stewart McKelvey Stirling Scales
Thomas Johnson – Consumer Advocate
Dean Porter – Poole Althouse

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Utilities Act, R.S.N. 1990, Chapter P-47
(the Act), and

IN THE MATTER OF a General Rate Application
(the Application) by Newfoundland and Labrador Hydro
for approvals of, under Section 70 of the Act, changes
in the rates to be charged for the supply of power and
energy to Newfoundland Power, Rural Customers and
Industrial Customers; and under Section 71 of the Act,
changes in the Rules and Regulations applicable to the
supply of electricity to Rural Customers.

TO: The Board of Commissioners of Public Utilities (the Board)

THE APPLICATION of Newfoundland and Labrador Hydro (the Applicant) states that:

1. Newfoundland and Labrador Hydro (Hydro) is a corporation continued and existing under the *Hydro Corporation Act, 2007,* is a public utility within the meaning of the Act and is subject to the provisions of the *Electrical Power Control Act, 1994*.

BACKGROUND

2. By Order No. P.U. 40(2003) the Board approved amendments to the Rate Stabilization, *inter alia*, to add provisions to deal with the Historical Plan Balance.

3. By Order No. P.U. 8(2007) the Board approved the forecast average rate base for 2007 at $1,489,323,000, allowed a rate of return on rate base (based on the 2007 Test Year) of 7.44% within a range of 7.29% to 7.59%, and approved a Schedule of Rates charged by Hydro to its customers.

4. Under the authority of the *Electrical Power Control Act, 1994*, the Lieutenant Governor in Council directed that the Board adopt a policy for Hydro's Non-

Government Rural Isolated Domestic and General Service customers which effectively deferred, until the present Application, the 2007 rate increase required for these customers.

5. By Order No. P.U. 18(2007) the Board amended the Corner Brook Pulp and Paper Limited Service Agreement.

6. By Order No. P.U. 21(2007) the Board approved a rates rebate for domestic customers served from the Labrador Isolated and L'Anse au Loup (Labrador Straits) systems.

7. By Order No. P.U. 34(2007) the Board approved, on an interim basis, rates to be charged by Hydro to its Island Industrial Customers.

8. By Order No. P.U. 11(2008) the Board approved, among other things, modifications to the fuel rider component of the Rate Stabilization Plan.

9. Under the authority of the *Electrical Power Control Act, 1994*, on March 17, 2009, the Lieutenant Governor in Council directed that the Board, upon Hydro's next General Rate Application, approve a return on rate base calculated using the rate of return on equity last approved for Newfoundland Power in a general rate application or through Newfoundland Power's Automatic Adjustment formula, that Hydro would earn a return on equity on its entire rate base including amounts related to rural assets, and that Hydro would be permitted to have the proportion of equity in its capital structure up to a maximum of the same approved for Newfoundland Power.

10. By Orders No. P.U. 37(2008) and No. P.U. 6(2009) the Board, among other things, continued on an interim basis the rates, rules and regulations for the Island Industrial Customers.

11. By Order No. P.U. 14(2009) the Board, among other things, approved a deferral account to allow for the recovery by Hydro of certain 2009 costs associated with an energy conservation program.

12. By Order No. P.U. 17(2009) the Board, among other things, approved, for a period of two years, amended rules and regulations of service for Corner Brook Pulp and Paper Limited.

13. By Order No. P.U. 20(2009) the Board approved the recovery of Hydro's costs of burning 0.7% sulphur content No. 6 fuel at the Holyrood Thermal Generating Station.

14. By Order No. P.U. 13(2010) the Board approved a deferral account to allow for the recovery by Hydro of certain 2010 costs associated with an energy conservation program.

15. By Order No. P.U. 33(2010) the Board approved changes to rates to be charged to Labrador Interconnected Customers following an adjustment to the Rural Rate Alteration, effectively completing the phase in of 2007 Test Year rates for these customers.

16. By Order No. P.U. 39(2010) the Board approved on an interim basis rates to be charged to Newfoundland Power as well as the Rate Stabilization Plan.

17. By Order No. P.U. 1(2011) the Board approved a modification to the Load Variation provision of the Rate Stabilization Plan rules and the repayment to Government from the Rate Stabilization Plan of $10,000,000.

18. By Order No. P.U. 4(2011) the Board approved a deferral account to allow for the recovery by Hydro of certain 2011 costs associated with an energy conservation program.

19. By Order No. P.U. 6(2011) the Board, among other things, approved an extension of the amended rules and regulations of service for Corner Brook Pulp and Paper Limited.

20. By Order No. P.U. 15(2011) the Board, among other things, approved a further extension of the amended rules and regulations of service for Corner Brook Pulp and Paper Limited.

21. By Order No. P.U. 3(2012) the Board approved a deferral account to allow for the recovery by Hydro of certain 2012 costs associated with an energy conservation program.

22. By Order No. P.U. 4(2012) the Board, among other things, approved on a pilot basis the amended rules and regulations of service for Corner Brook Pulp and Paper Limited and further ordered that a proposal be made with Hydro's next general rate application as to these rules and regulations of service.

23. By Order No. P.U. 6(2012) the Board approved, among other things, rates and rules and regulations of service to Vale Newfoundland & Labrador Limited.

24. By Order No. P.U. 13(2012) the Board approved, with certain exceptions, Hydro's adoption and use of International Financial Reporting Standards (IFRS) accounting standards for financial reporting for regulatory purposes.

25. By Order No. P.U. 29(2012) the Board determined that Hydro should appropriately recognize and record asset retirement obligations in accordance with IFRS, but approval of the regulatory treatment of the proposed asset retirement obligations was denied at that time.

26. By Order No. P.U. 39(2012), the Board approved changes to the Utility Rate Schedule including updates to the weather adjustment calculation.

27. By Order No. P.U. 40(2012), the Board approved, among other things, changes in Hydro's depreciation methodology and asset service lives.

28. By Order No. P.U. 9(2013) the Board approved, among other things, rates and rules and regulations of service to Praxair Canada Inc.

29. By Order No. P.U. 17(2013) the Board approved, on an interim basis, rates to be charged to Newfoundland Power under the Rate Stabilization Plan.

30. By Order No. P.U. 21(2013) the Board did not approve Hydro's application to defer its 2013 costs related to the energy conservation plan.

NEWFOUNDLAND AND LABRADOR HYDRO PROPOSALS

31. The Applicant makes Application under the Act, and specifically under Sections 58, 64, 70, 71, 76, 78 and 80 and proposes, effective January 1, 2014:

    (1) that Hydro's forecast 2013 Test Year costs (before return on rate base) of $445,639,000 be approved;

(2) that Hydro's forecast average rate base for 2013 of $1,564,085,000 be approved;

(3) that pursuant to the directive to the Board, that for purpose of calculating Hydro's return on rate base that the return on equity last approved by Order No. P.U. 13(2013), as a result of Newfoundland Power's general rate application, of 8.80% be approved;

(4) that Hydro be allowed a rate of return on forecast average rate base of 7.83%;

(5) that the allowable range of return on rate base of +/- 25 basis points be approved;

(6) that Hydro's treatment of actuarial gains and losses on Employee Future Benefits, as set out in evidence in support of this Application, be approved;

(7) that the Board approve the proposed regulatory treatment of Hydro's Asset Retirement Obligations as outlined in the evidence in support of this Application;

(8) that the total generation credit for Newfoundland Power be increased to 120,208 kW;

(9) that changes be approved to the Rate Stabilization Plan so as to include deferrals as to deviations from forecast costs for Hydro's energy supplies, as set out in evidence in support of this Application;

(10) that changes be approved to the Rate Stabilization Plan so as to remove calculations related to the Rural Labrador Interconnected Automatic Rate Adjustment;

(11) that changes be approved to the Rate Stabilization Plan so as to remove Section E – Historical Plan Balance.

(12) that Hydro be permitted to defer and recover its Conservation and Demand Management costs, as set out in evidence in support of this Application;

(13) that Hydro be permitted to defer its 2013 Conservation and Demand costs;

(14) that amortization and recovery mechanisms be approved for Hydro's Isolated System diesel fuel and power purchase costs, as set out in evidence in support of this Application;

(15) that Hydro be permitted to amortize the recovery over a three-year period of an estimated $1 million in Board, Consumer Advocate and other approved costs related to this Application;

(16) that the Island Industrial wheeling rate be discontinued;

(17) that the average system losses used in the calculation of the energy charge to Industrial Customers for non-firm service be increased to 3.36%, as stated on page 7 of the Rates Schedules attached to this Application;

(18) that the rules and regulations of service for Corner Brook Pulp and Paper Limited as set out in the Schedule to this Application, and as set out in evidence in support of this Application, be approved;

(19) that the rules and regulations for service to all Hydro Rural Customers as set out in the Schedule to this Application, and as set out in evidence in support of this Application, be approved;

(20) that the Board alter or amend Order No. P.U. 14(2004), and in particular Order item 16 thereof, so that functionally oriented financial Key Performance Indicators are not required to be provided on a forecast basis;

(21) that, generally, the Board approve the rates set out in the attached Schedule to this Application; and

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

32. Communications with respect to this Application should be directed to the attention of Geoffrey P. Young, Counsel to Newfoundland and Labrador Hydro.

DATED at St. John's in the Province of Newfoundland and Labrador this 30th day of July 2013.

NEWFOUNDLAND AND LABRADOR HYDRO

Geoffrey P. Young
Counsel for
Newfoundland and Labrador Hydro
P.O. Box 12400 Columbus Drive
St. John's, Newfoundland and Labrador, A1B 4K7
Telephone: (709) 737-1277
Facsimile: (709) 737-1782

IN THE MATTER OF the Public Utilities Act, R.S.N. 1990, Chapter P-47 (the Act), and

IN THE MATTER OF a General Rate Application (the Application) by Newfoundland and Labrador Hydro for approvals of, under Section 70 of the Act, changes in the rates to be charged for the supply of power and energy to Newfoundland Power, Rural Customers and Industrial Customers; and under Section 71 of the Act, changes in the Rules and Regulations applicable to the supply of electricity to Rural Customers.

AFFIDAVIT

I, Robert J. Henderson, Professional Engineer, of St. John's in the Province of Newfoundland and Labrador, make oath and say as follows:

1. I am Vice-President, Newfoundland and Labrador Hydro, the Applicant named in the attached Application.
2. I have read and understand the foregoing Application.
3. I have personal knowledge of the facts contained therein, except where otherwise indicated, and they are true to the best of my knowledge, information and belief.

SWORN at St. John's in the)
Province of Newfoundland and)
Labrador)
this 30th day of July 2013,)
before me:)

Barrister – Newfoundland and Labrador

Robert J. Henderson

THIS SERVICE AGREEMENT made at St. John's, in the Province of Newfoundland and Labrador on the day of .

BETWEEN: **NEWFOUNDLAND AND LABRADOR HYDRO**, a corporation and an agent of the Crown constituted by statute, renamed and continued by the Hydro Corporation Act, 2007, Revised Statutes of Newfoundland and Labrador, Chapter H-16, (hereinafter called "Hydro") of the first part;

AND **CORNER BROOK PULP AND PAPER LIMITED**, a company organized under the laws of Newfoundland and Labrador (hereinafter called the "Customer") of the second part.

WHEREAS Hydro has agreed to sell Electrical Power and Energy to the Customer and the Customer has agreed to purchase the same from Hydro according to the Rates, Rules and Regulations set by the Board of Commissioners of Public Utilities for the Province of Newfoundland and Labrador and by the terms of this Agreement;

AND WHEREAS the Customer has hydro-electric generating capability which the parties wish to be operated in a manner which optimizes energy production;

THEREFORE THIS AGREEMENT WITNESSETH that the parties agree as follows:

ARTICLE 1
INTERPRETATION

1.01 In this Agreement, including the recitals, unless the context otherwise requires,

(a) "**Amount of Power on Order"** means the Power contracted for in accordance with Article 2;

(b) "**Approved Planned Outage**" means an outage or reduction of capacity of the Customer's generation or transmission system undertaken by the Customer for scheduled maintenance and approved by Hydro not less than one week in advance of the start of that outage;

(c) **"Billing Demand"** means the components of the Customer's monthly Power consumption for which Demand charges apply as determined in accordance with Articles 3 and 10;

(d) “**Board”** means the Board of Commissioners of Public Utilities for Newfoundland and Labrador;

(e) “**Capacity Request**” means Hydro’s request to the Customer to provide an amount of capacity equal to its Generating Capacity;

(f) “**Customer’s Total 60 Hz Demand**” means the Demand at any particular time determined by adding the amount of the Generation Output, and the amount supplied to the Customer at the Hydro Delivery Points, less the amount received by Newfoundland Power at the Delivery Points to Newfoundland Power;

(g) “**Delivery Points to Newfoundland Power**” means the 66,000 Volt terminals of the station power transformers at Marble Mountain and Pasadena, both of which are serviced from Deer Lake Power’s L1 transmission line or at such other location or locations that Hydro and the Customer mutually agree in writing;

(h) **“Demand”** means the amount of Power averaged over each consecutive period of fifteen minutes duration, commencing on the hour and ending each fifteen minute period thereafter and measured by a demand meter of a type approved for revenue metering by the appropriate department of the Government of Canada;

(i) **“Electricity”** includes Power and Energy;

(j) **“Energy”** means the amount of electricity delivered in a given period of time and measured in kilowatt hours;

(k) **“Firm Energy**” means the Energy supplied during a month at the Hydro Delivery Points net of the Energy supplied at the Delivery Points to Newfoundland Power less Interruptible Energy, Generation Outage Energy, Oil-fired Boiler Replacement Energy and Secondary Energy. The Firm Energy exclusive of Frequency Converter Replacement Energy can in no case exceed the Amount of Power on Order for the period multiplied by the hours in that month;

(l) **“Firm Power”** means, except as varied by paragraph 3.02(a) and subject to Clause 3.03, the Demand normally associated with the Amount of Power on Order;

(m) “**Frequency Converter Replacement Energy**” means the reduced capability of Hydro’s 50/60 Hz frequency converter multiplied by the duration, in hours, of the outage or reduction in capability to Hydro’s 50/60 Hz frequency converter;

(n) "**Frequency Converter Replacement Power**" means the Power taken by the Customer in excess of the Amount of Power on Order due to an outage or reduction in capability to Hydro's 50/60 Hz frequency converter to a maximum of 18,000 kW, which is the normal maximum capability of Hydro's 50/60 Hz frequency converter;

(o) **"Generating Capacity"** means 99,100 kW, being the amount of Power the Customer is able to generate at 60 Hz from its hydraulic generating resources, or to generate at 50 Hz from its hydraulic generating resources and have converted to 60 Hz, but does not include capacity from generating facilities dedicated to the generation of power and energy for sale or transfer to Hydro or to a third party;

(p) **"Generation Outage"** means an outage or reduction of the Customer's Generating Capacity due to equipment failure, Approved Planned Outages or natural causes beyond the control of the Customer including but not limited to frazil ice and low intake water, but not including an outage to those facilities dedicated to the generation of power and energy for sale to Hydro or to a third party and not including an outage or reduction caused by Hydro's 50/60 Hz frequency converter;

(q) **"Generation Outage Demand"** means the Power taken by the Customer during a period of Capacity Request which exceeds the Amount of Power on Order and which is required to temporarily replace that Generating Capacity which is rendered unavailable to the Customer due to a Generation Outage;

(r) **"Generation Outage Energy"** means the Energy associated with Generation Outage Demand;

(s) **"Generation Output"** means the total amount of 60 Hz Demand supplied by the Customer at any time as measured at the generator terminals of its 60 Hz generators plus the amount of Demand measured at the 60 Hz terminals of the 50Hz – 60Hz frequency converter;

(t) **"Hydro Delivery Points"** means: (i) Hydro's 66,000 volt bus in its Massey Drive Terminal Station at Corner Brook, (ii) the line side insulators of the Customer's terminal structure near the east end of its Deer Lake Power Plant being the termination point of Hydro's 66,000 volt line, and (iii) the 66,000 volt 60 cycle bus and 50 cycle buses in the No. 1 and No. 2 Substation of the Customer, or at such other location or locations that Hydro and the Customer mutually agree in writing;

(u) **"Interruptible Demand"** means, that part of the Customer's Total 60 Hz Demand in any 15 minute interval, which exceeds the sum of

(i) The greater of the Generation Output and the Generation Capacity, and

(ii) The Amount of Power on Order,

and which may be interrupted, in whole or in part, at the discretion of Hydro, is supplied in accordance with Clause 4.01, and, for greater certainty, Interruptible Demand does not include any Demand associated with Oil-Fired Boiler Replacement Power, Frequency Converter Replacement Power or Secondary Energy;

(v) **"Interruptible Energy"** means the Energy associated with Interruptible Demand;

(w) **"Maximum Demand"** means the greatest amount of Power during the appropriate Month or part of a Month, as the case may be, averaged over each consecutive period of fifteen minutes duration commencing on the hour and ending each fifteen minute period thereafter, and measured by a demand meter of a type approved for revenue metering by the appropriate department of the Government of Canada;

(x) **"Month"** means a calendar month;

(y) **"Non-Firm Energy"** means Energy associated with Interruptible Demand, Generation Outage Demand, Oil-Fired Boiler Replacement Power and Supplemental Energy;

(z) "**Oil-Fired Boiler Replacement Power**" means the Power taken by the Customer during a period of a Capacity Request which exceeds the amount of Power on Order up to 15,000 kW, being the amount of Power the Customer requires from Hydro for use in its electric boiler to produce process steam, a load that the Customer is normally able to displace by using its No. 7 oil-fired steam boiler;

(aa) **"Power"** means the amount of electrical power delivered at any time and measured in kilowatts;

(bb) **"Province"** means the the Province of Newfoundland and Labrador;

(cc) **"Rate Schedules"** means the schedules of rates that are approved by the Board for the sale and purchase of Power and Energy;

(dd) **"Secondary Energy"** means that Energy Hydro is willing to sell, according to Clause 5.06, at a rate approved by the Board and which would be surplus to its needs and, if not sold, would likely result in spillage at one or more of Hydro's hydraulic generating stations;

(ee) **"Specifically Assigned Charge"** means the payment made by the Customer in each Month, calculated according to a method approved by the Board, for the use of Specifically Assigned Plant;

(ff) **"Specifically Assigned Plant"** means that equipment and those facilities which are owned by Hydro and used to serve the Customer only;

(gg) "**Supplemental Energy**" means all energy taken in a Month in excess of Firm Energy, Generation Outage Energy, Interruptible Energy, Oil-Fired Boiler Replacement Energy and energy supplied to the electric boiler for Secondary Energy.

1.02 Hydro and the Customer agree that they are bound by this Agreement and by the agreements and covenants contained in the Rates Schedules. In the event of a conflict between this Agreement and the Rates Schedules, the Rates Schedules shall have priority.

1.03 In this Agreement all references to dollar amounts and all references to any other money amounts are, unless specifically otherwise provided, expressed in terms of coin or currency of Canada which at the time of payment or determination shall be legal tender herein for the payment of public and private debts.

1.04 Words in this Agreement importing the singular number shall include the plural and vice versa and words importing the masculine gender shall include the feminine and neuter genders.

1.05 Where a word is defined anywhere in this Agreement, other parts of speech and tenses of the same word have corresponding meanings.

1.06 Wherever in this Agreement a number of days is prescribed for any purpose, the days shall be reckoned exclusively of the first and inclusively of the last.

1.07 The headings of all the articles are inserted for convenience of reference only and shall not affect the construction or interpretation of this Agreement.

1.08 Any reference in this Agreement to an Article, a Clause, a subclause or a paragraph shall, unless the context otherwise specifically requires, be taken as a reference to an article, a clause, a subclause or a paragraph of this Agreement.

1.09 This Agreement may be executed in two or more counterparts, each of which when so executed shall be deemed to be an original, but all of such counterparts together shall constitute one and the same instrument.

ARTICLE 2
AMOUNT OF FIRM POWER

2.01 Subject to this Agreement, Hydro agrees to deliver to the Customer and the Customer agrees to purchase from Hydro the Amount of Power on Order. Aside from times when Hydro has made a Capacity Request, Hydro agrees to make reasonable efforts to make available Supplemental Energy, which the Customer may use to facilitate its efficient generation of Energy, subject always to Hydro's capability to deliver it which Hydro shall determine in its sole discretion.

2.02 The Customer shall declare to Hydro in writing, not later than October 1 of each calendar year, its Amount of Power on Order for the following calendar year. Such declarations may provide for an Amount of Power on Order to apply throughout the calendar year, or may provide for one or more successive increases at specified times during the calendar year, but subject to Clause 2.05, may not provide for a decrease other than a decrease to take effect on January 1st of that following calendar year. The Amount of Power on Order shall in no event be greater than 75,000 kilowatts.

2.03 Hydro will supply all future Power requirements requested by the Customer additional to the 75,000 kilowatts provided, however, that the Customer's requests for such additional Power be made upon adequate notice in order that Hydro may make suitable extensions or additions to its system.

2.04 If Hydro cannot fully comply with a declaration of Amount of Power on Order made in accordance with Article 2.02 it will, as soon as practicable and in any event not later than November 1 of the year in which the declaration was made, advise the Customer of the extent to which it can comply. If more than one industrial customer requests an increase in their Amount of Power on Order and Hydro cannot in its judgment provide enough Power to satisfy all of the timely requests it has received, Hydro will offer additional Amounts of Power on Order to the industrial customers who made those requests in such amounts as are prorated in accordance to the quantity of additional Amounts of Power on Order in the timely requests it has received from those customers.

2.05 If the Customer increases its Generating Capacity such that it can decrease or eliminate the amount of Power it requires from Hydro, then, provided the Customer gives Hydro thirty-six Month's written notice of the reduction, the Customer may reduce or eliminate its Amount of Power on Order and its Billing Demand effective on the date that the new generation is to go into service as indicated in that written notice.

ARTICLE 3
PURCHASE AND SALE OF POWER AND ENERGY

3.01 The sale and purchase of Power and Energy shall be at such prices and upon such terms and conditions as are set out in the Rate Schedules and this Agreement.

3.02 Subject to Clause 2.05 and Article 10, the Customer's Billing Demands, which shall each be charged at the applicable rates as approved by the Board, shall comprise the following:

(a) the Billing Demand for Firm Power, which in each Month shall be the greater of:

(i) the Amount of Power on Order,

(ii) the lesser of 75% of the Amount of Power on Order for the prior calendar year and, the Amount of Power on Order for the prior calendar year less 20,000 kW,

(iii) the Amount of Power on Order plus the maximum excess Demand taken up to that time in that calendar year determined by the application of paragraphs (b) and (c) of this Clause 3.02,

(b) During periods when Hydro has not issued a Capacity Request the excess Demand is the amount of Interruptible Demand supplied by Hydro in excess of the maximum allowable Interruptible Demand;

(c) During periods in which Hydro has issued a Capacity Request the excess Demand is the amount of Demand supplied by Hydro in excess of the Amount of Power on Order, the maximum allowable Interruptible Demand, and as applicable, for each 15-minute demand interval during that period the maximum available Generation Outage Demand, the maximum Frequency Converter Replacement Power, and the electric boiler Demand for Oil-Fired Boiler Replacement Power.

3.03 Notwithstanding that the Billing Demand for Firm Power shall have, by operation of Clause 3.02, exceeded the Power on Order declared for that calendar year in accordance with Article 2, Hydro is not obliged to provide any amount of Power in excess of the Power on Order.

3.04 Notwithstanding anything to the contrary herein, the Customer shall pay in each Month its Specifically Assigned Charge, its applicable Demand charges, and its Energy charges. Its Energy charges shall comprise its Firm Energy, Frequency Converter Replacement Energy, Interruptible Energy, Generation Outage Energy, Oil-fired Boiler Replacement Energy, Secondary Energy and Supplemental Energy taken in that Month.

3.05 Supplemental Energy shall be charged at the Non-Firm Energy Rate for the Month.

3.06 Frequency Converter Replacement Energy shall be charged at Firm Energy rates for the Month but without a demand charge.

ARTICLE 4
INTERRUPTIBLE POWER

4.01 The Customer may in any Month take an amount of Interruptible Demand and Energy in addition to the Amount of Power of Order which shall be billed at the Non-Firm Demand and Energy rates approved by the Board. Provided the Amount of Power on Order is equal to or greater than 20,000 kW, the amount of Interruptible Demand and Energy available shall be the greater of 10% of the Amount of Power on Order and 5,000 kW. If the Amount of Power on Order is less than 20,000 kW, the Amount of Interruptible Demand and Energy available shall be 25% of the Amount of Power on Order. If Hydro is willing and able to serve the Customer's Interruptible Demand, then the following shall apply:

(a) The Customer shall, if practicable, make a prior request for, or otherwise as soon as practicable notify Hydro of its requirement, specifying the amount and duration of its Interruptible Demand requirements. Such request or notification may be made by telephone and confirmed by facsimile transmission to Hydro's officials at its Energy Control Centre, who shall advise the Customer if such Interruptible Power will be made available.

(b) If serving the Customer's Interruptible Demand would result in Hydro generating from, or increasing or prolonging generation from a standby or emergency energy source, then Hydro will so advise the Customer. If the Customer wishes to purchase Interruptible Demand and Energy at such a time or times, that Power and Energy shall be charged for as calculated by the method or formula approved by the Board.

(c) Notwithstanding anything contrary herein, if service of the Interruptible Demand is disrupted by Hydro or is curtailed by the Customer as a decision to reject the more expensive standby or emergency energy source (which for the purposes of this clause shall be deemed to be a reduction of Hydro of Interruptible Demand), the Billing Demand for Interruptible Power for the Month shall be determined as follows:

(i) If there is a total interruption of Interruptible Demand and Interruptible Energy by Hydro for a whole Month, the Customer shall not be required to make any payment for Interruptible Demand and Energy that Month.

(ii) If there is a total interruption of Interruptible Demand for part of a Month, the Billing Demand for that Interruptible Demand for that Month shall be reduced by a number of kilowatts bearing the same ratio to that Billing Demand as the number of hours during which the interruption occurs bears to the total number of hours in that Month.

(iii) If Hydro requires a reduction of Interruptible Demand for a whole Month, then, the reduced Billing Demand for Interruptible Demand for that Month shall be substituted for the Billing Demand for Interruptible Demand for the same Month, when determining the price of Power and Energy for that Month.

(iv) If Hydro requires the reduction of Interruptible Demand for part of a Month, then, subject to subparagraph (v) of this paragraph 4.01(c), there shall, when determining the price of Interruptible Power and Energy for the Months in which the reduction occurs, be substituted for the Billing Demand for Interruptible Demand for that Month, the number of kilowatts obtained by adding

(a) the reduced Billing Demand for Interruptible Demand for the part of the month during which the reduction was made, averaged over the whole of that Month;

to

(b) the Billing Demand for Interruptible Demand for the part of the Month during which no reduction was made, averaged over the whole of that Month.

(v) In any case arising under subparagraph (iii) or subparagraph (iv) of this paragraph 4.01(c), where a reduction of Interruptible Demand is made for a whole Month or part thereof and the Maximum Demand for Interruptible Demand over that same period is greater than the reduced Billing Demand for Interruptible Demand for that same period, then, instead of that reduced Billing Demand, that Maximum Demand for such period shall be substituted for the Billing Demand for Interruptible Demand for that period when determining the price of Power and Energy for the Month in which the reduction occurs, but, if in any period during which a reduction occurs, the Maximum Demand for Interruptible Demand is less than the reduced Billing Demand for Interruptible Demand, no account shall be taken of that Maximum Demand.

ARTICLE 5
GENERATION OUTAGE POWER AND SECONDARY ENERGY

5.01 In the event that the Customer experiences or requires a Generation Outage, in addition to its Power on Order and any applicable Interruptible Power it may be taking, it may take an amount of Generation Outage Demand and Energy at Non-Firm Rates. The availability of Generation Outage Demand shall be subject to Hydro's capability to deliver it, which Hydro shall determine at its sole discretion. The Generation Outage Demand taken in any instance shall not exceed the amount of generating capacity rendered unavailable because of the Generation Outage. If Hydro is willing and able to provide the Customer with Generation Outage Demand and Energy, then the following shall apply:

(a) The Customer shall, if practicable, make a prior request for, or otherwise as soon as practicable notify Hydro of its requirement, specifying the amount and duration of its Generation Outage Demand requirements. Such request or notification may be made by telephone and confirmed by facsimile transmission to Hydro's officials at its Energy Control Centre, who shall advise the Customer if such Generation Outage Demand will be made available. While requesting or taking Generation Outage Demand and Energy, the Customer shall notify Hydro of all circumstances and particulars as to the outage as soon as practicable and shall keep Hydro informed as those circumstances and particulars change. The Customer shall not make undue requests for Generation Outage Demand and Energy and it shall restore normal operating conditions as soon as reasonably possible.

(b) If serving the Generation Outage Demand would result in Hydro generating from, or increasing or prolonging generation from a standby or emergency energy source, then Hydro will so advise the Customer. If the Customer wishes to purchase Generation Outage Demand and Energy at such a time or times, that Power and Energy shall be charged for as calculated by the method or formula approved by the Board.

(c) Notwithstanding anything contrary herein, if service of the Generation Outage Demand is disrupted by Hydro or is curtailed by the Customer as a decision to reject the more expensive Energy provided from the standby or emergency energy source, the Billing Demand for the Generation Outage for that day shall be reduced in proportion to the number of hours in that day for which the more expensive energy was rejected.

(d) For billing purposes, a daily Generation Outage Demand shall be determined for each day which shall be calculated as the Maximum Demand taken during each day when Generation Outage Demand was taken, less the Billing Demand for Firm Power and less the Frequency Converter Replacement Power and Oil Fired Boiler Replacement Power taken during that fifteen minute interval and the maximum Interruptible Demand for that Month. The Generation Outage Demand billed shall be the amount calculated by totalling the daily Generation Outage Demands for the Month and dividing that total by the number of days in the Month.

Oil-Fired Boiler Replacement Power

5.02 In the event that the Customer experiences or requires an outage to its No. 7 oil-fired boiler, in addition to its Power on Order and any applicable Interruptible Power it may be taking, it may take an amount of Oil-Fired Replacement Power at Non-Firm Rates. The availability of Oil-Fired Boiler Replacement Power shall be subject to Hydro's capability to deliver it, which Hydro shall determine at its sole discretion. The Oil-Fired Boiler Replacement Power taken in any instance shall not exceed the amount of demand taken on the electric boiler needed to replace the amount of steam unavailable because of the No. 7 oil-fired boiler outage.

If Hydro is willing and able to provide the Customer with Oil-Fired Replacement Power, then the following shall apply:

(a) Subject to operational limitations, the Customer shall first maximize the amount of steam produced from all of its other oil-fired boilers during outages to the No. 7 oil-fired boiler so as to minimize the amount of demand taken on the electric boiler.

(b) The Customer shall, if practicable, make a prior request for, or otherwise as soon as practicable notify Hydro of its requirement, specifying the amount and duration of its Oil-Fired Boiler Replacement Power requirements. Such request or notification may be made by telephone and confirmed by facsimile transmission to Hydro's officials at its Energy Control Centre, who shall advise the Customer if such Oil-Fired Boiler Replacement Power will be made available. While requesting or taking Oil-Fired Boiler Replacement Power, the Customer shall notify Hydro of all circumstances and particulars as to the outage as soon as practicable and shall keep Hydro informed as those circumstances and particulars change. The Customer shall not make undue requests for Oil-Fired Boiler Replacement Power and it shall restore normal operating conditions as soon as reasonably possible.

(c) If serving the Oil-Fired Boiler Replacement Power would result in Hydro generating from, or increasing or prolonging generation from a standby or emergency energy source, then Hydro will so advise the Customer. If the Customer wishes to purchase Oil-Fired Boiler Replacement Power at such a time or times, that Power and Energy shall be charged for as calculated by the method or formula approved by the Board.

(d) Notwithstanding anything contrary herein, if service of the Customer's Electric Boiler is disrupted by Hydro or is curtailed by the Customer as a decision to reject the more expensive Energy provided from the standby or emergency energy source, the Billing Demand associated with the Oil-Fired Boiler Replacement Power for that day shall be reduced in proportion to the number of hours in that day for which the more expensive energy was rejected.

(e) For billing purposes, a daily Demand for the Oil-Fired Boiler Replacement Power shall be determined for each day which shall be calculated as the Maximum Demand taken during each day when Oil-Fired Boiler Replacement Power was taken, less the Billing Demand for Firm Power, the Generation Outage Demand and the Frequency Converter Replacement Power for that fifteen-minute interval and, the maximum Interruptible Demand for that Month. The Oil-Fired Boiler Replacement Demand billed, if applicable, shall be the amount calculated by totalling the daily Oil-Fired Boiler Replacement Demands for the Month and dividing that total by the number of days in the Month.

5.03 Generation Outage Energy and Oil-Fired Boiler Replacement Energy, and the associated Power, shall be charged at the Non Firm Energy Rate applicable during the period of the Capacity Request and Hydro shall notify the Customer of the applicable Non Firm Energy Rate at the time of the Capacity Request and shall give notice of any change in the rate which occurs during the Capacity Request period.

5.04 If the Customer is experiencing an unplanned Generation Outage or an unplanned outage to No. 7 oil-fired boiler during a Capacity Request period, then Hydro will supply the applicable Demand and Energy subject to Hydro's capability to deliver it which Hydro shall determine at its sole discretion. Hydro shall make reasonable efforts to supply such Demand and Energy.

5.05 The Customer shall by the end of each November verify its ability to provide the Generating Capacity by operating its generation so that the 60 Hz Generation Output and the Demand at the 60 Hz terminals of the frequency converter, simultaneously, equal or exceed the Generating Capacity for a period of one continuous hour. If the Generating Capacity is not verified the Customer's

Amount of Power on Order for the following calendar year shall increase by the amount of the shortfall.

5.06 If Hydro has surplus Energy capability and the Customer desires to purchase it, and provided that appropriate metering is in place, Hydro will deliver Secondary Energy to the Customer for use in its electric boilers. The quantity and availability of Secondary Energy shall be determined by Hydro in its sole discretion, however, once declared to be available, Secondary Energy shall remain available for a period of not less than 72 hours. The rate to be paid for Secondary Energy shall be determined by the Board.

ARTICLE 6
CHARACTERISTICS OF POWER SERVICE AND POINTS OF DELIVERY

6.01 The Power and Energy to be supplied under this Agreement will be delivered to the Customer at three (3) phase alternating current having normal frequencies of fifty (50) and sixty (60) cycles and at a voltage of approximately 66,000 and delivery will be made at the Hydro Delivery Points.

6.02 Hydro will exercise its best endeavours to limit variation from the normal frequency and voltage to tolerable values.

ARTICLE 7
POWER FACTOR

7.01 The Customer agrees to take and use the Power contracted for in this Agreement at a power factor of not less than ninety percent (90%) lagging at the point of delivery specified in this Agreement.

7.02 Should the power factor be consistently less than ninety percent (90%) lagging, the Customer, upon written notification from Hydro, agrees to install suitable corrective equipment to bring the power factor to a minimum of ninety percent (90%) lagging.

7.03 If the Customer should install static condensers to correct the lagging power factor, the equipment shall be so installed that it can be completely disconnected at the request of Hydro.

ARTICLE 8
METERING

8.01 The metering equipment and meters to register the amount of Demand and Energy to be taken by the Customer under this Agreement shall be furnished by Hydro and if required to be located on the Customer's premises will be installed by Hydro in a suitable place satisfactory to Hydro and provided by the Customer, and in such manner as to register accurately the total amount of Demand and Energy taken by the Customer under this Agreement.

8.02 If the metering is installed on the low side of transformers that are Specifically Assigned Plant or owned by the Customer, an appropriate adjustment will be made to account for losses in the transformers. Also, appropriate adjustments will be made to recognize the Power and Energy delivered to Newfoundland Power at Marble Mountain and Pasadena from the Customer’s generation and transmission systems.

8.03 The Customer shall have the right, at its own expense, to install, equip and maintain check meters adjacent to the meters of Hydro.

8.04 Authorized employees of Hydro shall have the right of access to all such meters at all reasonable times for the purpose of reading, inspecting, testing, repairing or replacing them. Should any meter fail to register accurately, Hydro may charge for the Demand and Energy supplied during the period when the registration was inaccurate, either,

(a) on the basis of the amount of Demand and Energy charged for

(i) during the corresponding term immediately succeeding or preceding the period of alleged inaccurate registration, or

(ii) during the corresponding term in the previous calendar year; or

(b) on the basis of the amount of Demand and Energy supplied as established by available evidence,

whichever basis appears most fair and accurate.

ARTICLE 9
LIABILITY FOR SERVICE

9.01 Subject to the provisions of the Rate Schedules and this Agreement, the Power and Energy herein contracted for will be made available for use by the Customer during twenty-four (24) hours on each and every day of the term of this Agreement.

9.02 The obligation of Hydro to furnish Power and Energy under this Agreement is expressly subject to all accidents or causes that may occur at any time and affect the generation or transmission of such Power and Energy, and in any such event, but subject to Clause 9.04, Hydro shall have the right in its discretion to reduce or, if necessary, to interrupt the supply of Power and Energy under this Agreement.

9.03 Hydro agrees to take all reasonable precautions to prevent any reduction or interruption of the supply of Power and Energy or any variation in the frequency or voltage of such supply, and whenever any such reduction, interruption or variation occurs, Hydro shall use all reasonable diligence to restore its service promptly.

9.04 (1) Subject to Clause 9.04(2) hereof, Hydro shall be liable for and in respect of only that direct loss or damage to the physical property of the Customer caused by any negligent act or omission of Hydro its servants or agents. Customer agrees that for the purpose of this Clause 9.04, "direct loss or damage to the physical property of the Customer" shall not be construed to include damages for inconvenience, mental anguish, loss of profits, loss of earnings or any other indirect or consequential damages or losses.

9.04 (2) Hydro's liability under subclause 9.04(1) applies only when the direct loss or damage to the Customer arising from a single occurrence exceeds the sum of $100,000.00. In no event shall the liability of Hydro exceed the sum of $1,000,000.00 for any single occurrence.

9.04 (3) Customer further agrees that any damages to which it may be entitled pursuant to clause 9.04(1) shall be reduced to reflect the extent to which such losses or damages could reasonably have been reduced if the Customer had taken reasonable protective measures.

9.05 Hydro shall have the right temporarily to interrupt its service hereunder in order to maintain or make necessary changes to its system, but, except in cases of emergency or accident, the service shall be interrupted only at such time or times as will be least inconvenient to the Customer, and Hydro shall use all reasonable diligence to complete promptly such repairs or necessary changes.

ARTICLE 10
REDUCED BILLING DEMAND

10.01 If at any time during the term of this Agreement the operation of the works of either party is suspended in whole or in part by reason of war, rebellion, civil disturbance, strikes, serious epidemics, fire or other fortuitous event, then, such party will not be liable to the other party to purchase or, as the case may be, to supply Power and Energy hereunder until the cause of such suspension has been removed and in every such event, the party whose operations are so suspended shall use all reasonable diligence to remove the cause of the suspension.

10.02 (1) For the purposes of this Clause 10.02,

a) the expression “reduced Billing Demand” means the number of kilowatts to which the Billing Demand is reduced in any of the circumstances referred to in subclauses (2) or (3) of this Clause 10.02, and

b) the expression Maximum Demand means

i. during periods where there is no Capacity Request, the Customer’s Total 60 Hz Demand less the Generation Capacity, and which in no instance can be less than zero.

ii. during a period for which a Capacity Request is in effect, the power delivered at the Hydro Delivery Points less power received by Newfoundland Power at the Delivery Points to Newfoundland Power.

(2) If the Customer is prevented from taking an amount of Power because of a suspension of its operations due to a reason listed in Clause 10.01, and any such interruption or reduction lasts for one hour or longer, then Hydro shall, on the request of the Customer, allow a proportionate reduction of the Billing Demand as calculated pursuant to subclauses (4) through (9) of this Clause 10.02, provided however that, except for reduced Billing Demands that occur pursuant to paragraphs 10.02(4)(b) or (c), in no such case shall the Billing Demand be reduced below 0.85 of the Amount of Power on Order unless Hydro is unable to deliver Power and Energy in accordance with this Agreement.

(3) If the supply of Power and Energy by Hydro is interrupted or reduced for any of the reasons referred to in Clause 9.02, 9.05 or 10.01, and any such interruption or reduction lasts for one hour or longer, then Hydro shall, on the request of the Customer, allow a proportionate reduction of the payment as calculated pursuant to subclauses (5) through (9) of this Clause 10.02.

(4) For those times when the Customer is prevented from taking an amount of Power because the Customer’s mill operations are suspended or curtailed due to a strike by the employees of the Customer, the Customer’s Billing Demand shall be calculated as follows:

(a) for the first 15 days of the strike and for that portion of the strike which exceeds 120 days, the Billing Demand shall be determined in the manner set out in subclauses (5) to (9) of this clause 10.02;

(b) for those whole Months during the period that commences following the first 15 days of the strike and ends not later than 120 days after the strike began, the reduced Billing Demand shall be the Customer's Maximum Demand in those Months;

(c) for those part Months that comprise periods that include;

(i) a period that commences following the first 15 days of the strike and ends not later than 120 days after the strike began,

together with one or both of

(ii) a period when the Customer is not affected by a strike or other suspension of its operations due to a reason listed in Clause 10.01,

and

(iii) a period where a strike has continued in excess of 120 days, or where the Customer is affected by any other suspension of its operations due to a reason listed in Clause 10.01,

the Customer's Billing Demand shall be determined by adding

(iv) the Maximum Demand for the part of the Month described in subparagraph (i) averaged over the whole of the Month,

(v) the greater of the Maximum Demand for Firm Power and the Amount of Power on Order for the part of the Month described in subparagraph (ii), if any, averaged over the whole of the Month

and

(vi) the reduced Billing Demand applicable to the period described in subparagraph (iii) averaged over the whole of the Month.

(5) If there is a total interruption of the supply of Power and Energy by Hydro for a whole Month, the Customer shall not be required to make any payment for that Month.

(6) If there is a total interruption of Power for part of a Month, the Billing Demand for that Month shall be reduced by a number of kilowatts bearing

the same ratio to that Billing Demand as the number of hours during which the interruption occurs bears to the total number of hours in that Month.

(7) If the reduction of Power is made for a whole Month, then, subject to clause (9) of this Clause 10.02, the reduced Billing Demand for that Month shall be substituted for the Billing Demand for the same Month, when determining the price of Power and Energy for that Month.

(8) If the reduction of Power is made for part of a Month, then, subject to subclause (9) of this Clause 10.02, there shall, when determining the price of Power and Energy for the Months in which the reduction occurs, be substituted for the Billing Demand for that Month, the number of kilowatts obtained by adding

(a) the reduced Billing Demand for the part of the month during which the reduction was made, averaged over the whole of that Month;

to

(b) the Billing Demand for the part of the Month during which no reduction was made, averaged over the whole of that Month.

(9) In any case arising under subclause (7) or subclause (8) of this Clause 10.02, where a reduction of Power is made for a whole Month or part thereof and the Maximum Demand for that same period is greater than the reduced Billing Demand for that same period, then, instead of the reduced Billing Demand, the Maximum Demand for such period shall be substituted for the Billing Demand for that period when determining the price of Power and Energy for the Month in which the reduction occurs, but, if in any period during which a reduction occurs, the Maximum Demand is less than the reduced Billing Demand no account shall be taken of that Maximum Demand.

(10) Where a Billing Demand, a reduced Billing Demand or a Maximum Demand for a part of a Month is to be averaged for the whole of that Month in accordance with subclause (8) of this Clause 10.02, the averaging shall be done by dividing the Billing Demand, the reduced Billing Demand or the Maximum Demand, as the case may be, by the total number of hours in the whole of that Month and multiplying the result by the number of hours to which the Billing Demand, the reduced Billing Demand or the Maximum Demand relates.

(11) In addition to the reductions in Billing Demand that may be made in accordance with this Article 10, Hydro may, in its sole judgment and discretion, make other Billing Demand adjustments from time to time to

decrease the Customer's bill to reflect unusual or unanticipated conditions or to facilitate the testing of equipment or processes by the Customer.

ARTICLE 11
CONSTRUCTION OR INSTALLATION OF TRANSMISSION LINES OR APPARATUS

11.01 For the consideration aforesaid, the Customer hereby grants to Hydro the right to construct transmission lines and accessory apparatus on locations approved by the Customer on, under or over the property of the Customer for the purpose of serving the Customer and the other customers of Hydro, together with the right of access to the property of the Customer at all times for the construction of such lines and apparatus and for the repair, maintenance and removal thereof, provided that nothing in this clause shall entitle Hydro to construct transmission lines and accessory apparatus on or over the Customer's property if such transmission lines are not directly connected with the Customer's premises or some part thereof.

11.02 The Customer shall not erect any building, structure or object on or over any right-of-way referred to in Clause 11.01 without the written approval of Hydro, but subject to that limitation the Customer shall be entitled to make fair and reasonable use of all lands subjected to the said right-of-way.

11.03 Any changes that the Customer may request Hydro to make in the location of any lines or apparatus constructed pursuant to Clause 11.01, shall be made by Hydro, but the Customer shall bear the expense of any such changes to the extent that such lines or apparatus supply Power to the Customer.

11.04 All transmission lines and apparatus of Hydro furnished and installed by it on the Customer's premises shall remain the property of Hydro, and Hydro shall be entitled to remove such transmission lines and apparatus on the expiry or termination of this Agreement.

11.05 For the purpose of using the power service of Hydro, the Customer shall install properly designed and suitable apparatus in accordance with good engineering practice, and shall at all times operate and maintain such apparatus so as to avoid causing any undue disturbance on the system of Hydro, and so that the current shall be approximately equal on all three of its phases.

11.06 If, at any time, the unbalance in current between any two of its phases is, in the judgment of Hydro, excessive to a degree that the power supply system of Hydro and/or the electrical equipment of any other customer of Hydro is adversely affected, then it shall be the responsibility of the Customer to take such reasonable remedial measures as may be necessary to reduce the unbalance to an acceptable value.

11.07 If, at any time during the term of this Agreement, Hydro desires to improve the continuity of power service to any of its customers, Hydro and the Customer will co-operate and use their best endeavours to carry out the improvements either by changes to existing equipment or additions to the original installations of either Hydro or the Customer.

11.08 The Customer shall not proceed with the construction of or major alterations of its equipment or structures associated with any terminal substation at which Power and Energy is being delivered until Hydro is satisfied that the proposals for such construction or alteration are in accordance with good engineering practice and the laws and regulations of the Province, provided that any examination of the Customer's proposals by Hydro shall not render Hydro responsible in any way for the construction or alteration proposed, even if electrical connection is made by Hydro, whether or not any changes suggested by Hydro shall have been made by the Customer.

ARTICLE 12
RESPONSIBILITY FOR DAMAGES

12.01 Beyond the point of delivery, the Customer shall indemnify and hold Hydro harmless with respect to any and all claims that may be made for injuries or damages to persons or property caused in any manner by electric current or by the presence or use on the Customer's premises of electric circuits or apparatus, whether owned by Hydro or by the Customer, unless and to the extent that such injuries or damages are caused by negligence on the part of the employees of Hydro.

12.02 Up to the point of delivery, Hydro shall indemnify and hold the Customer harmless with respect to any and all claims that may be made for injuries or damages to persons or property caused in any manner by electric current or by the presence or use on the Customer's premises of electric circuits or apparatus owned by Hydro and resulting from or arising out of the negligence of Hydro's employees or other persons for whom Hydro would in law be liable, unless and to the extent that such injuries or damages are caused by negligence on the part of the employees of the Customer.

12.03 If any of the transmission lines or apparatus installed by Hydro on the Customer's premises should be destroyed or damaged by the negligence of the Customer, its servants or agents, the Customer shall reimburse Hydro for the cost of their replacement or repair.

ARTICLE 13
PAYMENT OF ACCOUNTS AND NOTICE OF CLAIMS OF CUSTOMER

13.01 Hydro will render its accounts monthly and the Customer shall, within twenty (20) days after the date of rendering any such account, make payment in lawful money of Canada at the office of Hydro in St. John’s, Newfoundland, or in such other place in the said Province as Hydro may designate, without deduction for any claim or counterclaim which the Customer may have to claim to have against Hydro arising under this Agreement or otherwise.

13.02 All amounts in arrears after the expiration of the period of twenty (20) days referred to in Clause 13.01 shall bear interest at the rate of one and one-half (1-1/2%) percent per Month.

13.03 If the Customer is in default for more than thirty (30) days in paying any amount due Hydro under this Agreement, then, without prejudice to its other recourses and without liability therefore, Hydro shall, upon ten (10) days written notice to the Customer of its intention so to do, be entitled to suspend the supply of Power and Energy to the Customer until the said amount is paid, and if the supply is so suspended, the Customer shall not be relieved of its obligations under this Agreement.

13.04 The Customer and Hydro will submit to the other in writing every claim or counterclaim which each may have or claim to have against the other arising under this Agreement within sixty days of the day upon which the Customer or Hydro has knowledge of the event giving rise to such a claim.

13.05 The Customer and Hydro shall be deemed to have waived all rights for the recovery of any claim or counterclaim that has not been submitted to the other party pursuant to and in accordance with Clause 13.04.

ARTICLE 14
ARBITRATION

14.01 If a settlement of any claim made by the Customer in accordance with Clause 13.04 is not agreed to by both parties, the matters in dispute shall be submitted, within three months from the time the claim was submitted, for decision to a board of arbitrators consisting of three members, one to be named by each party to this Agreement and the third to be named by the two arbitrators so chosen, and the decision of any two members of the board of arbitrators shall be final and binding upon both parties.

14.02 The charges of the third member of a board of arbitrators who shall be the chairman of that board, shall be borne by the losing party, and the parties shall bear the costs or charges of their own appointees. Any arbitration hearing commenced under this Article shall be held in St. John's or such other place as the parties mutually agree.

14.03 If the two appointees of the parties are unable to agree upon the third arbitrator or chairman, the chairman shall be appointed upon application of either party to the Trial Division of the Supreme Court of Newfoundland and Labrador or a judge of that Division.

14.04 The period of delay for appointment by the parties to this Agreement of their respective nominees shall be seven days after notification by the other party to this Agreement of its nominee, and the period for agreement by the two nominees on the chairman shall be ten days.

14.05 The provisions of the Arbitration Act, Chapter A - 14 of the Revised Statutes of Newfoundland and Labrador, 1990, as now or hereafter amended shall apply to any arbitration held pursuant to this Article 14.

ARTICLE 15
MODIFICATION OR TERMINATION OF AGREEMENT

15.01 Except, where otherwise specifically provided in this Agreement and only to the extent so provided, all previous communications between the parties to this Agreement, either oral or written, with reference to the subject matter of this Agreement, are hereby abrogated and this Agreement shall constitute the sole and complete agreement of the parties hereto in respect of the matters herein set forth.

15.02 At any time during the currency of this Agreement, the Customer may terminate it by giving to Hydro two years previous notice in writing of its intention so to do.

15.03 Any amendment, change or modification of this Agreement shall be binding upon the parties hereto or either of them only if such amendment, change or modification is in writing and is executed by each of the parties to this Agreement by its duly authorized officers or agents and in accordance with its regulations or by-laws.

15.04 Subject to Article 10, if the Customer voluntarily or forcibly abandons its operations, commits an act of bankruptcy or liquidates its assets, then, there shall, forthwith, become due and payable to Hydro by the Customer, as stipulated and liquidated damages without burden or proof thereof, a lump sum equal to:

(a) 0.85 of its then current Billing Demand for Firm Power, at the Firm Power Demand rate, multiplied by 24;

plus

(b) the remaining net book value of Specifically Assigned Plant, less its salvage value.

ARTICLE 16
SUCCESSORS AND ASSIGNS

16.01 This Agreement shall be binding upon and enure to the benefit of the parties hereto and their respective successors and assigns, but it shall not be assignable by the Customer without the written consent of Hydro.

ARTICLE 17
GOVERNING LAW AND FORUM

17.01 This Agreement shall be governed by and interpreted in accordance with the laws of the Province, and every action or other proceeding arising hereunder shall be determined exclusively by a court of competent jurisdiction in the Province, subject to the right of appeal to the Supreme Court of Canada where such appeal lies.

ARTICLE 18
ADDRESS FOR SERVICE

18.01 Subject to Clauses 18.02 and 18.03, any notice, request or other instrument which is required or permitted to be given, made or served under this Agreement by either of the parties hereto, except for notices or requests pertaining to Interruptible Demand, Generation Outages or Secondary Energy, shall be given, made or served in writing and shall be deemed to be properly given, made or served if personally delivered, or sent by prepaid telegram or facsimile transmission, or mailed by prepaid registered post, addressed, if service is to be made

(a) on Hydro, to

The Secretary
Newfoundland and Labrador Hydro
Hydro Place
P.O. Box 12400
St. John's, Newfoundland
CANADA. A1B 4K7
FAX: (709) 737-1782
or

(b) on the Customer, to

Mill Manager
Corner Brook Pulp and Paper Limited
P.O. Box 2001
Corner Brook, Newfoundland
A2H 6J4

18.02 Any notice, request or other instrument given, made or served as provided in Clause 18.01 shall be deemed to have been received by the party hereto to which it is addressed, if personally served on the date of delivery, or if mailed three days after the time of its being so mailed, or if sent by prepaid telegram or facsimile transmission, one day after the date of sending.

18.03 Except for notices for Interruptible Demand, Generation Outage Demand, or Secondary Energy, whenever this Agreement requires a notice to be given or a request to be made on a Sunday or legal holiday, such notice or request may be given or made on the first business day occurring thereafter, and, whenever in this Agreement the time within which any right will lapse or expire shall terminate on a Sunday or legal holiday, such time will continue to run until the next succeeding business day. Notices or requests pertaining to Interruptible Demand, Generation Outages or Secondary Energy may be given and received by and to the appropriate nominees of the respective parties by voice or electronic communication provided that it is confirmed in writing and transmitted or delivered by facsimile, courier or mail as soon as practicable.

18.04 Either of the parties hereto may change the address to which a notice, request or other instrument may be sent to it by giving to the other party to this Agreement notice of such change, and thereafter, every notice, request or other instrument shall be delivered or mailed in the manner prescribed in Clause 18.01 to such party at the new address.

<u>IN WITNESS WHEREOF</u> Newfoundland and Labrador Hydro and the Customer has each executed this Agreement by causing it to be executed in accordance with its by-laws or regulations and by its duly authorized officers or agents, the day and year first above written.

<u>THE CORPORATE SEAL</u> of
Newfoundland and Labrador Hydro was hereunder
affixed in the presence of: ____________________________

____________________________ ____________________________
Witness

<u>DULY EXECUTED</u> by
Corner Brook Pulp and Paper Limited
in accordance with its Regulations
or By-Laws in the presence of:

____

____________________________ ____________________________
Witness

NEWFOUNDLAND AND LABRADOR HYDRO

UTILITY

Availability:

This rate is applicable to service to Newfoundland Power (NP).

Definitions:

"Billing Demand"

In the Months of January through March, billing demand shall be the greater of:

(a) the highest Native Load less the Generation Credit, beginning in the previous December and ending in the current Month; and
(b) the Minimum Billing Demand.

In the Months of April through December, billing demand shall be the greater of:

(a) the Weather-Adjusted Native Load less the Generation Credit, plus the Weather Adjustment True-up; and
(b) the Minimum Billing Demand.

"Generation Credit" refers to NP's net generation capacity less allowance for system reserve, as follows:

	kW
Hydraulic Generation Credit	84,215
Thermal Generation Credit	35,993
Total Generation Credit	120,208

In order to continue to avail of the Generation Credit, NP must demonstrate the capability to operate its generation to the level of the Generation Credit. This will be verified in a test by operating the generation at a minimum of this level for a period of one hour as measured by the generation demand metering used to determine the Native Load. The test will be carried out at a mutually agreed time between December 1 and March 31 each year. If the level is not sustained, Newfoundland Power will be provided an opportunity to repeat the test at another mutually agreed time during the same December 1 to March 31 period. If the level is not sustained in the second test, the Generation Credit will be reduced in calculating the associated billing demands for January to December to the highest level that could be sustained.

NEWFOUNDLAND AND LABRADOR HYDRO

UTILITY (continued)

"Maximum Native Load" means the maximum Native Load of NP in the four-Month period beginning in December of the preceding year and ending in March of the current year.

"Minimum Billing Demand" means ninety-nine percent (99%) of:

NP's test year Native Load less the Generation Credit.

"Month" means for billing purposes, the period commencing at 12:01 hours on the last day of the previous month and ending at 12:00 hours on the last day of the month for which the bill applies.

"Native Load" is the sum of:

(a) the amount of electrical power, delivered at any time and measured in kilowatts, supplied by Hydro to NP, averaged over each consecutive period of fifteen minutes duration, commencing on the hour and ending each fifteen minute period thereafter; and

(b) the total generation by NP averaged over the same fifteen-minute periods.

"Weather-Adjusted Native Load" means the Maximum Native Load adjusted to normal weather conditions, calculated as:

Maximum Native Load plus (Weather Adjustment, rounded to 3 decimal places, x 1000)

Weather Adjustment is further described and defined in the Weather Adjustment section.

"Weather Adjustment True-up" means one-ninth of the difference between:

(a) the greater of:
   - the Weather Adjusted Native Load less the Generation Credit, times three; and
   - the Minimum Billing Demand, times three; and

(b) the sum of the actual billed demands in the Months of January, February and March of the current year.

NEWFOUNDLAND AND LABRADOR HYDRO

UTILITY (continued)

Monthly Rates:

Billing Demand Charge:
Billing Demand, as set out in the Definitions section, shall be charged at the following rate:

$9.12 per kW of billing demand

Energy Charge:
First 280,000,000 kilowatt-hours* ....@ 2.786 ¢ per kWh
All excess kilowatt-hours* ....@ 10.400 ¢ per kWh

Firming-up Charge:
Secondary energy supplied by
Corner Brook Pulp and Paper Limited* ....@ 1.248 ¢ per kWh

RSP Adjustment:
Current Plan ....@ (1.101) ¢ per kWh

Total RSP Adjustment – All kilowatt-hours .... @ (1.101) ¢ per kWh

***Subject to RSP Adjustment:**

RSP Adjustment refers to all applicable adjustments arising from the operation of Hydro's Rate Stabilization Plan, which levelizes variations in hydraulic production, fuel cost, load and rural rates.

Adjustment for Losses:

If the metering point is on the load side of the transformer, either owned by the customer or specifically assigned to the customer, an adjustment for losses as determined in consultation with the customer prior to January 31 of each year shall be applied to metered demand and energy.

Adjustment for Station Services and Step-Up Transformer Losses:

If the metering point is not on the generator output terminals of NP's generators, an adjustment for Newfoundland Power's power consumption between the generator output terminals and the metering point as determined in consultation with the customer prior to the implementation of the metering, shall be applied to the metered demand.

NEWFOUNDLAND AND LABRADOR HYDRO

UTILITY (continued)

Weather Adjustment: This section outlines procedures and calculations related to the weather adjustment applied to NP's Maximum Native Load.

(a) Weather adjustment shall be undertaken for NP's actual Maximum Native Load.

(b) Weather adjustment shall be derived from Hydro's NP native peak demand model.

(c) By September 30th of each year, Hydro shall provide NP with updated weather adjustment coefficient incorporating the latest year of actuals.

(d) The underlying temperature and wind speed data utilized to derive weather adjustment shall be sourced to weather station data for the St. John's, Gander, and Stephenville airports reported by Environment Canada. NP's regional energy sales shall be used to weight regional weather data. Hydro shall consult with NP to resolve any circumstances arising from the availability of, or revisions to, Environment Canada's weather data and/or wind chill formulation.

(e) The primary definition for the temperature weather variable is the average temperature for the peak demand hour and the preceding seven hours. The primary definition for the wind weather data is the average wind speed for the peak demand hour and the preceding seven hours. Hydro will consult with NP should data anomalies indicate a departure from the primary definition on underlying weather data.

(f) Subject to the availability of weather data from Environment Canada, Hydro shall prepare a preliminary estimate of the Weather-Adjusted Native Load by March 15th of each year, and a final calculation of Weather-Adjusted Native Load by April 5th of each year.

General:

This rate schedule does not include the Harmonized Sales Tax (HST) which applies to electricity bills.

With respect to all matters where the customer and Hydro consult on resolution but are unable to reach mutual agreement, the billing will be based on Hydro's best estimate.

NEWFOUNDLAND AND LABRADOR HYDRO

INDUSTRIAL - FIRM

Availability:

Any person purchasing power, other than a retailer, supplied from the Interconnected Island bulk transmission grid at voltages of 66 kV or greater on the primary side of any transformation equipment directly supplying the person and who has entered into a contract with Hydro for the purchase of firm power and energy.

Rate:

Demand Charge:

The rate for Firm Power, as defined and set out in the Industrial Service Agreements, shall be $9.13 per month per kilowatt of billing demand.

Firm Energy Charge:

Base Rate* .... @ 4.782 ¢ per kWh

***Subject to RSP Adjustment:**

RSP Adjustment refers to all applicable adjustments arising from the operation of Hydro's Rate Stabilization Plan, which levelizes variations in hydraulic production, fuel cost, load and rural rates.

Specifically Assigned Charges:

The table below contains the additional specifically assigned charges for customer plant in service that is specifically assigned to the Customer.

	Annual Amount
Corner Brook Pulp and Paper Limited	$944,954
North Atlantic Refining Limited	$101,748
Teck Resources Limited	$215,009
Vale Newfoundland and Labrador Inc	$533,724

NEWFOUNDLAND AND LABRADOR HYDRO

INDUSTRIAL - FIRM (continued)

Adjustment for Losses:

If the metering point is on the load side of the transformer, either owned by the customer or specifically assigned to the customer, an adjustment for losses as determined in consultation with the customer prior to January 31 of each year, shall be applied.

General:

Details regarding the conditions of Service are outlined in the Industrial Service Agreements. **This rate schedule does not include the Harmonized Sales Tax (HST) which applies to electricity bills.**

NEWFOUNDLAND AND LABRADOR HYDRO

INDUSTRIAL – NON-FIRM

Availability:

Any person purchasing power, other than a retailer, supplied from the Interconnected Island bulk transmission grid at voltages of 66 kV or greater on the primary side of any transformation equipment directly supplying the person and who has entered into a contract with Hydro for the purchase of firm power and energy.

Rate:

Non-Firm Energy Charge (¢ per kWh):

Non-Firm Energy is deemed to be supplied from thermal sources. The following formula shall apply to calculate the Non-Firm Energy rate:

$$\{(A \div B) \times (1 + C) \times (1 \div (1 - D))\} \times 100$$

A = the monthly average cost of fuel per barrel for the energy source in the current month or, in the month the source was last used

B = the conversion factor for the source used (kWh/bbl)

C = the administrative and variable operating and maintenance charge (10%)

D = the average system losses on the Island Interconnected grid for the last five years ending in 2012 (3.36%)

The energy sources and associated conversion factors are:

1. Holyrood, using No. 6 fuel with a conversion factor of 612 kWh/bbl
2. Gas turbines using No. 2 fuel with a conversion factor of 475 kWh/bbl
3. Diesels using No. 2 fuel with a conversion factor of 556 kWh/bbl

Adjustment for Losses:

If the metering point is on the load side of the transformer, either owned by the customer or specifically assigned to the customer, an adjustment for losses as determined in consultation with the customer prior to January 31 of each year, shall be applied.

General:

Details regarding the conditions of Service are outlined in the Industrial Service Agreements. **This rate schedule does not include the Harmonized Sales Tax (HST) which applies to electricity bills.**

NEWFOUNDLAND AND LABRADOR HYDRO

RATE STABILIZATION PLAN

The Rate Stabilization Plan of Newfoundland and Labrador Hydro (Hydro) is established for Hydro's Utility customer, Newfoundland Power, and Island Industrial customers to smooth rate impacts for variations between actual results and Test Year Cost of Service estimates for:

- hydraulic production;
- No. 6 fuel cost used at Hydro's Holyrood generating station;
- customer load (Utility and Island Industrial); and
- rural rates.

The formulae used to calculate the Plan's activity are outlined below. Positive values denote amounts owing from customers to Hydro whereas negative values denote amounts owing from Hydro to customers.

Section A: Hydraulic Production Variation

1. **Activity:**
Actual monthly production is compared with the Test Year Cost of Service Study in accordance with the following formula:

$$\{(A - B) \div C\} \times D$$

Where:

A = Test Year Cost of Service Net Hydraulic Production (kWh)
B = Actual Net Hydraulic Production (kWh)
C = Test Year Cost of Service Holyrood Net Conversion Factor (kWh /bbl.)
D = Monthly Test Year Cost of Service No. 6 Fuel Cost ($Can /bbl.)

2. **Financing:**
Each month, financing charges, using Hydro's approved Test Year weighted average cost of capital, will be calculated on the balance.

3. **Hydraulic Variation Customer Assignment:**
Customer assignment of hydraulic variations will be performed annually as follows:

$$(E \times 25\%) + F$$

Where:

E = Hydraulic Variation Account Balance as of December 31, excluding financing charges
F = Financing charges accumulated to December 31

The total amount of the Hydraulic Customer Assignment shall be removed from the Hydraulic Variation Account.

NEWFOUNDLAND AND LABRADOR HYDRO

RATE STABILIZATION PLAN (INTERIM) (Continued)

4. Customer Allocation:

The annual customer assignment will be allocated among the Island Interconnected customer groups of (1) Newfoundland Power; (2) Island Industrial Firm; and (3) Rural Island Interconnected. The allocation will be based on percentages derived from 12 months-to-date kWh for: Utility Firm and Firmed-Up Secondary invoiced energy, Industrial Firm invoiced energy, and Rural Island Interconnected bulk transmission energy.

The portion of the hydraulic customer assignment which is initially allocated to Rural Island Interconnected will be re-allocated between Newfoundland Power and regulated Labrador Interconnected customers in the same proportion which the Rural Deficit was allocated in the approved Test Year Cost of Service Study.

The Newfoundland Power and Island Industrial customer allocations shall be included with the Newfoundland Power and Island Industrial RSP balances respectively as of December 31 each year. The Labrador Interconnected Hydraulic customer allocation shall be written off to Hydro's net income (loss).

Section B: Fuel Cost Variation, Load Variation and Rural Rate Alteration

1. Activity

1.1 Fuel Cost Variations

This is based on the consumption of No. 6 Fuel at the Holyrood Generating Station:

$$(G - D) \times H$$

Where:

D = Monthly Test Year Cost of Service No. 6 Fuel Cost ($Can /bbl.)
G = Monthly Actual Average No. 6 Fuel Cost ($Can /bbl.)
H = Monthly Actual Quantity of No. 6 Fuel consumed less No. 6 fuel consumed for non-firm sales (bbl.)

1.2 Load Variations

Firm: Firm load variation is comprised of fuel and revenue components. The load variation is determined by calculating the difference between actual monthly sales and the Test Year Cost of service Study sales, and the resulting variance in No. 6 fuel costs and sales revenues. It is calculated separately for Newfoundland Power firm sales and Industrial firm sales, in accordance with the following formula:

$$(I - J) \times \{(D \div C) - K\}$$

Where:

C = Test Year Cost of Service Holyrood Net Conversion Factor (kWh /bbl.)
D = Monthly Test Year Cost of Service No. 6 Fuel Cost ($Can /bbl.)
I = Actual Sales, by customer class (kWh)
J = Test Year Cost of Service Sales, by customer class (kWh)
K = Firm energy rate, by customer class

NEWFOUNDLAND AND LABRADOR HYDRO

RATE STABILIZATION PLAN (INTERIM) (Continued)

Secondary: Secondary load variation is based on the revenue variation for Utility Firmed-Up Secondary energy sales compared with the Test Year Cost of Service Study, in accordance with the following formula:

(J – I) x L

Where:

I = Actual Sales (kWh)
J = Test Year Cost of Service Sales (kWh)
L = Secondary Energy Firming Up Charge

1.3 Energy Supply Variation (Power Purchases, Diesel Production, Gas Turbine Production)

1.3.1 Quantity Variation

Activity:
For each source of energy supply other than hydraulic, actual monthly power purchase kWh are compared with the Test Year Cost of Service Study in accordance with the following formula:

{(AA– BB) ÷ CC} x DD

Where:

AA = Test Year Cost of Service Energy Supply (kWh)
BB = Actual Energy Supply (kWh)
CC = Test Year Cost of Service Holyrood Net Conversion Factor (kWh/bbl)
DD = Monthly Test Year Cost of Service No. 6 Fuel Cost ($Can/bbl)

1.3.2 Price Variation
This is based on the actual power purchased. For each energy supply, the variation will be calculated as follows

(EE – FF) x GG

Where:

EE = Monthly Test Year Energy Supply Cost ($Can)
FF = Monthly Actual Energy Supply Cost ($Can)
GG = Monthly Actual Energy Supply (kWh)

1.4 Rural Rate Alteration
Newfoundland Power Rate Change Impacts:
This component is calculated for Hydro's rural customers whose rates are directly or indirectly impacted by Newfoundland Power's rate changes, with the following formula:

(M – N) x O

NEWFOUNDLAND AND LABRADOR HYDRO

RATE STABILIZATION PLAN (INTERIM) (Continued)

Where:

M = Cost of Service rate
N = Existing rate
O = Actual Units (kWh, bills, billing demand)

2. Monthly Customer Allocation: Load and Fuel Activity

Each month, the year-to-date total for fuel price variation and the year-to-date total for Newfoundland Power and Industrial Customer load variations will be allocated among the Island Interconnected customer groups of (1) Newfoundland Power; (2) Island Industrial Firm; and (3) Rural Island Interconnected. The allocation will be based on percentages derived from 12 months-to-date kWh for: Utility Firm and Firmed-Up Secondary invoiced energy, Industrial Firm invoiced energy, and Rural Island Interconnected bulk transmission energy.

The year-to-date portion of the fuel price variation and the load variation which is initially allocated to Rural Island Interconnected will be re-allocated between Newfoundland Power and regulated Labrador Interconnected customers in the same proportion which the Rural Deficit was allocated in the approved Test Year Cost of Service Study.

The current month's activity for Newfoundland Power, Island Industrials and regulated Labrador Interconnected customers will be calculated by subtracting year-to-date activity for the prior month from year-to-date activity for the current month. The current month's activity allocated to regulated Labrador Interconnected customers will be removed from the Plan and written off to Hydro's net income (loss).

3. Monthly Customer Allocation: Rural Rate Alteration Activity

Each month, the rural rate alteration will be allocated between Newfoundland Power and regulated Labrador Interconnected customers in the same proportion which the Rural Deficit was allocated in the approved Test Year Cost of Service Study. The portion allocated to regulated Labrador Interconnected will be removed from the Plan and written off to Hydro's net income (loss).

4. Plan Balances

Separate plan balances for Newfoundland Power and for the Island Industrial customer class will be maintained. Financing charges on the plan balances will be calculated monthly using Hydro's approved Test Year weighted average cost of capital.

NEWFOUNDLAND AND LABRADOR HYDRO

RATE STABILIZATION PLAN (INTERIM) (Continued)

Section C: Fuel Price Projection

A fuel price projection will be calculated to anticipate forecast fuel price changes and to determine fuel riders for the rate adjustments. For industrial customers, this will occur in October each year, for inclusion with the RSP adjustment effective January 1. For Newfoundland Power, this will occur in April each year, for inclusion with the RSP adjustment effective July 1.

1. Industrial Fuel Price Projection:

In October each year, a fuel price projection for the following January to December shall be made to estimate a change from Test Year No. 6 Fuel Cost. Hydro's projection shall be based on the change from the average Test Year No. 6 fuel purchase price, in Canadian dollars per barrel, determined from the forecast oil prices provided by the PIRA Energy Group, and the current US exchange rate. The calculation for the projection is:

$$[\{(S - T) \times U\} - V] \times W$$

Where:

S = the September month-end PIRA Energy Group average monthly forecast for No. 6 fuel prices at New York Harbour for the following January to December

T = Hydro's average Test Year contract discount (US $/bbl)

U = the monthly average of the $Cdn / $US Bank of Canada Noon Exchange Rate for the month of September

V = average Test Year Cost of Service purchase price for No. 6 Fuel ($Can /bbl.)

W = the number of barrels of No. 6 fuel forecast to be consumed at the Holyrood Generating Station for the Test Year.

The industrial customer allocation of the forecast fuel price change will be based on 12 months-to-date kWh as of the end of September and is the ratio of Industrial Firm invoiced energy to the total of: Utility Firm and Firmed-Up Secondary invoiced energy, Industrial Firm invoiced energy, and Rural Island Interconnected bulk transmission energy.

The amount of the forecast fuel price change, in Canadian dollars, and the details of an estimate of the fuel rider based on 12 months-to-date kWh sales to the end of September will be reported to industrial customers, Newfoundland Power, and the Public Utilities Board, by the 10th working day of October.

NEWFOUNDLAND AND LABRADOR HYDRO

RATE STABILIZATION PLAN (INTERIM) (Continued)

2. Newfoundland Power Fuel Price Projection:

In April each year, a fuel price projection for the following July to June shall be made to estimate a change from Test Year No. 6 Fuel Cost. Hydro's projection shall be based on the change from the average Test Year No. 6 fuel purchase price, in Canadian dollars per barrel, determined from the forecast oil prices provided by the PIRA Energy Group, and the current US exchange rate. The calculation for the projection is:

$$[\{(X - T) \times Y\} - V] \times W$$

Where:

T = Hydro's average Test Year contract discount (US $/bbl)
V = average Test Year Cost of Service purchase price for No. 6 Fuel ($Can /bbl.)
W = the number of barrels of No. 6 fuel forecast to be consumed at the Holyrood Generating Station for the Test Year. For the 2007 Test Year, test year barrels are reduced by 589,208 based on the reduction in forecast Island Industrial customer load caused by the shutdown of one of the paper machines at Corner Brook Pulp and Paper and the shutdown of Abitibi Consolidated (Grand Falls).
X = the average of the March month-end PIRA Energy Group average monthly forecast for No. 6 fuel prices at New York Harbour for the following July to December, and the most recent long-term PIRA Energy Group average annual forecast for No. 6 fuel prices at New York Harbour for the following January to June.
Y = the monthly average of the $Cdn / $US Bank of Canada Noon Exchange Rate for the month of March.

The Newfoundland Power customer allocation of the forecast fuel price change will be based on 12 months-to-date kWh as of the end of March and is the ratio of Newfoundland Power Firm and Firmed-Up Secondary invoiced energy to the total of: Utility Firm and Firmed-Up Secondary invoiced energy, Industrial Firm invoiced energy, and Rural Island Interconnected bulk transmission energy. For the 12 months-to-date (April 2008 - March 2009) Industrial Firm invoiced energy is reduced by 87,991,636 kWh to reflect the forecast reduction in Abitibi Consolidated (Grand Falls) load.

The amount of the forecast fuel price change, in Canadian dollars, and the details of the resulting fuel rider applied to the adjustment rate will be reported to Newfoundland Power, industrial customers, and the Public Utilities Board, by the 10th working day of April.

Section D: Adjustment

1. Newfoundland Power

As of March 31 each year, Newfoundland Power's adjustment rate for the 12-month period commencing the following July 1 is determined as the rate per kWh which is projected to collect:

Newfoundland Power March 31 Balance
less projected recovery / repayment of the balance for the following three months (if any), estimated using the energy sales (kWh) for April, May and June from the previous year

NEWFOUNDLAND AND LABRADOR HYDRO

RATE STABILIZATION PLAN (INTERIM) (Continued)

plus forecast financing charges to the end of the 12-month recovery period (i.e., June in the following calendar year),

divided by the 12-months-to-date firm plus firmed-up secondary kWh sales to the end of March.

A fuel rider shall be added to the above adjustment rate, based on the Newfoundland Power Fuel Price Projection amount (as per Section C.2 above) divided by 12-months-to-date kWh sales to the end of March.

When new Test Year base rates come into effect, if a fuel rider forecast (either March or September) is more current than the test year fuel forecast, a fuel rider will be implemented at the same time as the change in base rates reflecting the more current fuel forecast and the new test year values.

Otherwise, the fuel rider portion of the RSP Adjustment will be set to zero upon implementation of the new Test Year Cost of Service rates, until the time for the next fuel price projection.

2. Island Industrial Customers
As of December 31 each year, the adjustment rate for industrial customers for the 12-month period commencing January 1 is determined as the rate per kWh which is projected to collect:

Industrial December 31 Balance

plus forecast financing charges to the end of the following calendar year,

divided by 12-months-to-date kWh sales to the end of December.

A fuel rider shall be added to the above adjustment rate, based on the Industrial Fuel Price Projection (as per Section C.1 above) amount divided by 12-months-to-date kWh sales to the end of December.

When new Test Year base rates come into effect, if a fuel rider forecast (either March or September) is more current than the test year fuel forecast, a fuel rider will be implemented at the same time as the change in base rates reflecting the more current fuel forecast and the new test year values. Otherwise, the fuel rider portion of the RSP Adjustment will be set to zero upon implementation of the new Test Year Cost of Service rates, until the time for the next fuel price projection.

Section E: RSP Surplus

1. August 31, 2013 Balance:
The net load variation for Newfoundland Power and the Industrial Customers from January 1, 2007 to August 31, 2013, including financing (the RSP Surplus), will be removed from the respective customer class balance, and allocated based upon direction provided by Government in Orders in Council OC2013-089 and OC2013-207. The balances which remain after this amount is removed will form the adjusted August 31, 2013 current plan balances for each customer class.

NEWFOUNDLAND AND LABRADOR HYDRO

RATE STABILIZATION PLAN (INTERIM) (Continued)

The Newfoundland Power allocated amount of the RSP Surplus will be held until such time as its disposition occurs in accordance with an Order of the Board of Commissioners of Public Utilities through a refund plan in accordance with Order in Council OC2013-089. The Industrial Customer class allocated amount will be used, firstly, to reduce the Industrial Customer class adjusted August 31, 2013 RSP balance to zero. The remaining Industrial Customer class allocated amount will be segregated and used, commencing September 1, 2013, in accordance with the rules below. Financing on the RSP Surplus balances will be calculated monthly using Hydro's approved Test Year annual weighted average cost of capital.

2. Island Industrial Customer RSP Surplus Balance:

The RSP Surplus balance allocated to the Industrial Customer class will be used to fund a phase-in of new Industrial Customer base rates effective September 1, 2013 using monthly adjustments determined as follows:

2.1 Island Industrial Customers excluding Teck Resources

The monthly adjustment for each month from September 1, 2013 to August 31, 2015 will be determined for each billing component (demand, energy and specifically assigned charge) for each Industrial Customer, except Teck Resources, as follows:

$$A = (B – C) X D$$

Where:

A = Monthly RSP Adjustment
B = Approved Island Industrial Customer base rate
C = Phase-In Industrial Customer rate, calculated in accordance with the formula below
D = Actual monthly Industrial Customer billing units

Phase-In Industrial Customer Rates – September 1, 2013 to August 31, 2014

The Phase-In Industrial Customer rates will be calculated for each of demand, energy, and each customer's specifically assigned charges. For Industrial Customers, except Teck Resources, the phase-in rates for the twelve months commencing September 1, 2013 will be the base rates approved in Hydro's 2007 Test Year. These rates are:

Demand Charge: $6.68 per month per kilowatt of billing demand
Firm Energy Charge: Base Rate 3.676 ¢ per kWh

Specifically Assigned Charges:	Annual Amount
Corner Brook Pulp and Paper Limited	$ 347,167
North Atlantic Refining Limited	$ 150,976
	$ 498,143

NEWFOUNDLAND AND LABRADOR HYDRO

RATE STABILIZATION PLAN (INTERIM) (Continued)

The RSP adjustment rate, which is applicable to energy sales, will be set to zero effective September 1, 2013. Subsequent to this date normal RSP adjustments will continue to apply.

Phase-In Industrial Customer Rates – September 1, 2014 to August 31, 2015
The Phase-In Industrial Customer rates for the twelve months commencing September 1, 2014 for each of demand, energy, and each customer's specifically assigned charges will be calculated as follows:

$$E = F \times (1 + G)$$

Where:
E = Phase-In Industrial Customer rate
F = Phase-In Industrial Customer rate in effect as of August 31 of the preceding year
G = Equal annual percentage required over the three-year phase-in period to achieve the total change between:

- Hydro's revenue from these customers calculated using the 2007 Test Year rates, including the RSP adjustment in effect August 31, 2013, and
- the revenue for those customers calculated using those rates approved by the Board based on Hydro's 2013 Test Year, excluding any RSP adjustment,

using the 2013 Test Year billing units.

Phase-In Industrial Customer Rates – September 1, 2015
Effective September 1, 2015, the Phase-In Industrial Customer rates will be the most recent Board approved Test Year rates.

The monthly adjustments and financing will be applied to the balance each month. At the end of the phase-in period, any remaining balance will be added to the Industrial Customer plan then in effect.

2.2 Teck Resources

The monthly adjustment for each month commencing September 1, 2013 until approval of 2013 Test Year base rates will be a rate per kWh, applied to actual monthly energy sales, calculated as follows:

$$H = (I + (J \times K))/K$$

NEWFOUNDLAND AND LABRADOR HYDRO

RATE STABILIZATION PLAN (INTERIM) (Continued)

Where:

H = Adjustment rate per kWh
I = Amount required to achieve one-third of the estimated change between:

- Hydro's revenue from this customer calculated using the 2007 Test Year rates including the RSP adjustment in effect on August 31, 2013, and
- the revenue from this customer calculated using those rates approved by the Board based on Hydro's 2013 Test Year excluding any RSP adjustment,

using the 2013 Test Year billing units.

J = RSP adjustment rate per kWh in effect on August 31, 2013
K = Teck Resources 2013 Test Year kWhs

Note: Once new base rates are approved based upon Hydro's 2013 Test Year, Hydro will apply for the disposition of any difference between the adjustment amounts calculated and the adjustment which would have been calculated using the 2013 approved Test Year rates. The difference will be refunded to, or collected from, Teck Resources, in a manner to be approved by the Board.

Upon the approval of 2013 Test Year rates and until August 31, 2015,Teck Resources Phase-In Industrial Customer monthly adjustment will be calculated in a manner similar to those specified above for the other Industrial Customers, as follows:

$$L = (M - N) X O$$

Where:
L = Monthly RSP Adjustment
M = Approved Island Industrial Customer base rate
N = Phase-In Teck Resources Industrial Customer rate, calculated in accordance with the formula below
O = Actual monthly Teck Resources billing units.

NEWFOUNDLAND AND LABRADOR HYDRO

RATE STABILIZATION PLAN (INTERIM) (Continued)

Phase-In Teck Resources Industrial Customer Rates – September 1, 2013 to August 31, 2014

The phase-in rates for the twelve months commencing September 1, 2013 will be the base rates approved in Hydro's 2007 Test Year plus the monthly rate per kWh adjustment as outlined above.

Demand Charge:	\$6.68 per month per kilowatt of billing demand
Firm Energy Charge:	
Base Rate:	3.676 ¢ per kWh
RSP Surplus Adjustment:	(1.111) ¢ per kWh
Net Energy Rate	2.565 ¢ per kWh
Specifically Assigned Charges:	
Teck Resources Annual Amount:	\$186,169

Phase-In Teck Resources Industrial Customer Rates – September 1, 2014 to August 1, 2015

Upon the approval of 2013 Test Year rates, Teck Resources Phase-In Industrial Customer rates for each of demand, energy, and specifically assigned charges will be calculated in the same manner as specified above for the other Industrial Customers except that the September 1, 2014 to August 31, 2015 rates will be calculated based upon the 2007 Test Year rates, with the energy charge reduced by the rate per kWh in effect as of September 1, 2013, as outlined above.

The calculation is:

$$P = Q \times (1 + R)$$

Where:
P = Phase-In Teck Resources rate
Q = Phase-In Teck Resources rate in effect as of August 31 of the preceding year
R = Equal annual percentage required over the three-year phase-in period to achieve the total change between:

- Hydro's revenue for this customer calculated using the 2007 Test Year rates including the RSP adjustment in effect on August 31, 2013, and
- the revenue for this customer calculated using those rates approved by the Board based on Hydro's 2013 Test Year, but excluding any RSP adjustment

using the 2013 Test Year billing units.

NEWFOUNDLAND AND LABRADOR HYDRO

RATE STABILIZATION PLAN (INTERIM) (Continued)

Phase-In Teck Resources Industrial Customer Rates – September 1, 2015

Effective September 1, 2015, Teck Resources will be charged the most recent Board approved Test Year rates consistent with the other Industrial Customers.

The monthly adjustments and financing will be applied to the balance each month. At the end of the phase-in period, any remaining balance will be added to the Industrial Customer plan then in effect.

NEWFOUNDLAND AND LABRADOR HYDRO

CONSERVATION AND DEMAND MANAGEMENT RECOVERY

The Conservation and Demand Management Cost Recovery Plan (the Plan) of Newfoundland and Labrador Hydro (Hydro) is established for Hydro's Utility customer, Newfoundland Power, and Island Industrial customers to recover Hydro's Conservation and Demand Management (CDM) program expenditures.

The CDM Recovery account shall be charged with the costs incurred in implementing the CDM Program Portfolio. The costs will include such items as detailed program development, promotional materials, advertising, pre and post customer installation checks, application and incentive processing, incentives, trade ally training, employee training, and program evaluation costs associated with programs in the CDM Program Portfolio.

The account will exclude any expenditure properly chargeable to plant accounts. The account shall also exclude conservation expenditures that are general in nature, such as costs associated with providing energy conservation awareness, responding to customer inquiries, planning, research and general supervision that are not associated with a specific program in the CDM Program Portfolio.

The account will exclude any expenditure related to programs or incentives that are fully recoverable from other parties, including government. Where a program or initiative is partially funded by other parties, the amount funded will be used to reduce the appropriate expenditures.

Costs associated with Labrador Interconnected customers will not be included for recovery, as programs for this system are based upon a cost structure which is significantly different from the other systems, and energy savings result in more energy being available for non-regulated sales.

Transfers to, and from, the proposed account will be tax-effected.

Hydro's program expenditures for 2009, 2010, 2011 and 2012 received Board approval for deferral. Additional expenditures will be recorded as incurred.

Recovery/Adjustment Period
The Plan balance as at March each year shall be recovered over a period of seven (7) years.

Plan Balance
The Plan Balance will be maintained separately for the Island Interconnected and Other Systems.

Assignment of Customer Balance for Recovery
The March 31 Plan balance to be removed from the plan and recovered (Recoverable Amount) in the next July 1- to June 30 period is calculated using the following formula:

NEWFOUNDLAND AND LABRADOR HYDRO

CONSERVATION AND DEMAND MANAGEMENT RECOVERY (Continued)

A/7

Where:

A = March 31 Plan balance
7 = Recovery period in years

The Island Interconnected Recoverable Amount will be allocated among the Island Interconnected customer groups of (1) Newfoundland Power; (2) Island Industrial Firm; and (3) Rural Island Interconnected. The allocation will be based on percentages derived from 12 months-to-date kWh for: Utility Firm and Firmed-Up Secondary invoiced energy, Industrial Firm invoiced energy, and Rural Island Interconnected bulk transmission energy.

The portion of the Island Interconnected Recoverable Amount which is initially allocated to Rural Island Interconnected will be added to the Other Plan Recoverable Amount, and then re-allocated between Newfoundland Power and regulated Labrador Interconnected customers in the same proportion which the Rural Deficit was allocated in the approved Test Year Cost of Service Study.

The Labrador Interconnected Recoverable Amount shall be written off to Hydro's net income (loss). The Plan Balance will be reduced by the Recoverable Amount.

Recovery Mechanism

Newfoundland Power:
The adjustment rate for each year will be determined as follows:
B = (C ÷ D)

Where:

B = adjustment rate ($ per kWh) for the 12-month period commencing the following July 1
C = Recoverable Amount assigned to Newfoundland Power as at March 31
D = energy sales (kWh) (firm and firmed-up secondary) to Newfoundland Power for the most recent 12 months ended March 31

Island Industrial Customers:
The adjustment rate for each year will be determined as follows:
E = (F ÷ H)

Where:

E = adjustment rate ($ per kWh) for the 12-month period commencing the following July 1
F = Recoverable Amount assigned to Island Industrial customers as at March 31
H = firm energy sales (kWh) to Industrial Customers, for the most recent 12 months ended March 31

NEWFOUNDLAND AND LABRADOR HYDRO

RULES AND REGULATIONS

APPLICABILITY:

These general Rules and Regulations apply to all Hydro Rural Customers.

1. INTERPRETATION:

(a) In these Rates and Rules the following definitions shall apply:

(i) "***Act***" means The Public Utilities Act, R.S.N. 1990, c.P-47 as amended from time to time.

(ii) "***Applicant***" means any person who applies for Service.

(iii) ***"Board"*** means the Board of Commissioners of Public Utilities of Newfoundland and Labrador.

(iv) "***Hydro***" means Newfoundland and Labrador Hydro.

(v) "***Hydro rural customers***" means regulated customers served by Hydro other than industrial customers and Newfoundland Power.

(vi) "***Customer***" means any person who accepts or agrees to accept Service.

(vii) "***Disconnected***" or "***Disconnect***" in reference to a Service means the physical interruption of the supply of electricity thereto.

(viii) "***Discontinued***" or "***Discontinue***" in reference to a Service means to terminate the Customer's on-going responsibility with respect to the Service.

(ix) "***Domestic Unit***" means a house, apartment or other similar residential unit which is normally occupied by one family, or by a family and no more than four other persons who are not members of that family, or which is normally occupied by no more than six unrelated persons.

(x) ***"Service"*** means any service(s) provided by Hydro pursuant to these Regulations.

(xi) "***Serviced premises***" means the premises at which Service is delivered to the Customer.

(xii) "***Government Departments***" means electric service accounts of Provincial or Federal government departments, agencies, boards, commissions, and crown corporations but excludes hospitals, fish plants, churches, schools, community halls, municipal buildings and like facilities.

NEWFOUNDLAND AND LABRADOR HYDRO

RULES AND REGULATIONS (Continued)

(b) Unless the context requires otherwise these Rates and Rules shall be interpreted such that:

(i) words imparting male persons include female persons and corporations.

(ii) words imparting the singular include the plural and vice versa.

2. **CLASSES OF SERVICE:**

(a) Hydro shall provide the following classes of Service:

ISLAND INTERCONNECTED AREA

1.1	Domestic
1.1S	Domestic Seasonal
1.3	Burgeo School and Library
2.1	General Service, 0-10 kW
2.3	General Service, 110 kVA (100 kW) - 1000 kVA
2.4	General Service, 1000 kVA and Over
4.1	Street and Area Lighting Service

ISLAND AND LABRADOR DIESEL AREA

1.2D	Domestic Diesel - Non-Government
1.2DS	Domestic Seasonal Diesel – Non-Government
2.1D	General Service Diesel - Non-Government, 0-10 kW
2.2D	General Service Diesel - Non-Government, 10 kW and Over
4.1D	Street and Area Lighting Service Diesel - Non-Government
1.2G	Domestic Diesel - Government Departments
2.1G	General Service Diesel - Government Departments, 0-10kW
2.2G	General Service Diesel - Government Departments, 10kW and Over
4.1G	Street and Area Lighting Service Diesel - Government Departments

LABRADOR INTERCONNECTED AREA

1.1L	Domestic
2.1L	General Service, 0-10 kW
2.2L	General Service, 10-100 kW (110 kVA)
2.3L	General Service, 110 kVA (100 kW) - 1000 kVA
2.4L	General Service, 1000 kVA and Over
4.1L	Street and Area Lighting Service
4.11L	Street and Area Lighting Service Labrador - Installed as of Sept. 1, 2002
4.12L	Street and Area Lighting Service Labrador– Customer Owned
5.1L	Secondary Energy

(b) The terms and conditions relating to each class of Service shall be those approved by the Board from time to time.

(c) Service, other than Street and Area Lighting Service, shall be metered except where the energy consumption is relatively low and constant and in the opinion of Hydro can be readily determined without metering.

(d) The Customer shall use the Service on the Serviced Premises only. The Customer shall not resell the Service in whole or in part except that the Customer may include the cost of Service in charges for the lease of space or as part of the cost of other services provided by the Customer.

3. APPLICATION FOR SERVICE:

(a) An Applicant, when required by Hydro, shall complete a written Electrical Service Contract.

(b) An application for Service, when accepted by Hydro, constitutes a binding contract between the Applicant and Hydro which cannot be assigned.

(c) The person who signs an application for Service shall be personally liable for Service provided pursuant thereto, unless that person has authority to act for another Person denoted as the Applicant on the application for Service.

(d) Hydro may in its discretion refuse to provide Service to an Applicant where:

(i) the Applicant fails or refuses to complete an application for Service.

(ii) the Applicant provides false or misleading information on the application for Service.

(iii) the Applicant or the Owner or an Occupant of the Serviced Premises has a bill for any Service which is not paid in full 30 days or more after issuance.

(iv) the Applicant fails to provide the security or guarantee required under Regulation 4.

(v) the Applicant is not the owner or an occupant of the Serviced Premises.

(vi) the Service requested is already supplied to the Serviced Premises for another Customer who does not consent to having his Service Discontinued.

(vii) the Applicant does not pay a charge described in Regulation 9 (b), (c) or (d).

(viii) the Applicant otherwise fails to comply with these Regulations.

(e) A Customer who has not completed an application for Service shall do so within 5 days of a request having been made by Hydro in writing.

4. <u>SECURITY FOR PAYMENT</u>:

(a) An Applicant or a Customer shall give such reasonable security for the payment of charges as may be required by Hydro. When the Customer has established two consecutive years of good credit history, the security deposit will be refunded with simple interest calculated at a Rate equivalent to the Rate paid from time to time by the chartered banks on over-the-counter withdrawal savings accounts.

(b) Hydro may in its discretion require special guarantees from an Applicant or Customer whose location or load characteristics would require abnormal investment in facilities or who requires Service of a special nature.

5. <u>SERVICE STANDARDS - METERED SERVICES</u>:

(a) Service shall normally be provided at one of the following nominal standard secondary voltages depending upon the requirements of the load to be served and the availability of a three phase supply:

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

Service at any other supply voltage may be provided in special cases at the discretion of Hydro.

(b) Service shall be supplied at single-phase 120/240 volts where the maximum demand is estimated by Hydro to be less than 75 kW. Where the maximum demand is estimated to be 75kW or greater, service shall normally be supplied at one of the standard three-phase voltages.

Hydro may, if requested by the Customer, provide a three-phase supply where the maximum demand is estimated to be less than 75 kW, if a contribution in aid of construction is paid to Hydro to cover the cost of transformers, equipment and any line extensions or upgrades required to provide the three-phase service.

To determine the contribution required, the cost to provide three-phase service will be reduced by the value of any single-phase plant supported by the projected revenue from the Customer, as calculated in accordance with Hydro’s distribution line contribution in aid of construction policy applicable to General Service Customers. Where the necessary equipment and transformer capacity already exist at the location in question, no contribution in aid of construction will be required to provide the three-phase service.

(c) Hydro shall determine the point at which power and energy is delivered from Hydro's facilities to the Customer's electrical system.

(d) Service entrances shall be in a location satisfactory to Hydro and, except as otherwise approved by Hydro, shall be wired for outdoor meters.

(e) Where Hydro has reason to believe that Service to a Customer has or will have load characteristics which may cause undue interference with Service to another Customer, the Customer shall upon written notice by Hydro provide and install, at his expense and within a reasonable period of time, the equipment necessary to eliminate or prevent such interference.

(f) (i) Any Customer having a connected load or a normal operating demand of more than 25 kilowatts, in areas where space limitations or aesthetic reasons make it impractical to use a pole mounted transformer bank, shall, on request of Hydro, install and maintain a padmount transformer and all associated underground wiring, or provide at his expense a suitable vault or enclosure on the Serviced Premises for exclusive use by Hydro for its equipment necessary to supply and maintain service to the Customer.

(ii) Where either the service requirements of a Customer or changes to a Customer’s electrical system necessitate the installation of additional equipment to Hydro’s system which cannot be accommodated in Hydro’s existing vaults or structures, the Customer shall, on request of Hydro, provide at the Customer’s expense such additional space in its vault or enclosure as Hydro shall require to accommodate the additional equipment.

(g) The Customer shall not use a Service for across the line starting of motors rated over 10 horsepower except where specifically approved by Hydro.

(h) For Services having rates based on kilowatt demand, the average power factor shall not be less than 90%. Hydro, in its discretion, may make continuous tests of power factor or may test the Customer's power factor from time to time. If the Customer's power factor is lower than 90%, the Customer shall upon written notice by Hydro provide, at his expense, power factor corrective equipment to ensure that a power factor of not less than 90% is maintained.

(i) Hydro shall provide transformation for Service up to 500 kVA where the required service voltage is one of Hydro's standard service voltages and installation is in accordance with Hydro's standards. In other circumstances, Hydro, on such conditions as it deems acceptable, may provide the transformation.

(j) All Customer wiring and installations shall be in compliance with all statutory and regulatory requirements including the Canadian Electrical Code, Part 1 and, where applicable, in accordance with Hydro's specifications. However, the provision of Service shall not in any way be construed as acceptance by Hydro of the Customer's electrical system.

(k) The Customer shall provide such protective devices as may be necessary to protect his property and equipment from any disturbance beyond the reasonable control of Hydro.

6. SERVICE STANDARDS - STREET AND AREA LIGHTING SERVICE:

(a) For Street and Area Lighting Service Hydro shall use its best efforts to provide illumination during the hours of darkness for a total of approximately 4200 hours per year. Hydro shall, subject to Regulation 9 (i) make all repairs necessary to maintain service.

(b) Hydro shall supply the energy required and shall provide and maintain the illuminating fixtures and lamps together with necessary overhead conductors, control equipment and other devices.

(c) Hydro shall not be required to provide Street and Area Lighting Service where, in the opinion of Hydro, the normal Service is unsuitable for the task or where the nature of the activities carried out in the area would likely result in damage to the poles, wiring or fixtures.

(d) Hydro shall provide a range of fixture sizes utilizing an efficient lighting source in accordance with current standards in the industry and shall consult with the Customer regarding the most appropriate use of such fixtures for any specific installation.

(e) The location of fixtures for Street and Area Lighting Service shall be determined by Hydro in consultation with the Customer. After poles and fixtures have been installed they shall not be relocated except at the expense of the Customer.

(f) Hydro does not guarantee that fixtures used for Street and Area Lighting Service will illuminate any specific area.

(g) Where the installation of fixtures is required in a location where there are no existing distribution poles the Customer shall pay any contribution in aid of construction as may be determined under Hydro's policy for the pole line extension required to supply electric service to the location of the fixtures.

(h) Hydro shall not be required to provide additional Street and Area Lighting Service to a Customer where on at least two occasions in the preceding twelve months, his bill for such Service has been in arrears for more than 30 days.

7. METERING:

(a) Service to each building shall be metered separately except as provided in Regulation 7(b).

(b) Service to buildings and facilities on the same Serviced Premises which are occupied by the same Customer may, subject to Regulation 7(c), be metered together provided the Customer supplies and maintains all distribution facilities beyond the point of supply.

(c) Except as provided in Regulation 7(d) Service to each new Domestic Unit shall be metered separately.

(d) Where an existing Domestic Unit is subdivided into two or more new Domestic Units, Service to the new Domestic Units may, in the discretion of Hydro, be metered together.

(e) Where four or more Domestic Units are metered together, the Basic Customer Charge shall be multiplied by the number of Domestic Units.

(f) Where the Service to a Domestic Unit has a connected load for commercial or nondomestic purposes exceeding 3000 watts, exclusive of space heating, the Service shall not qualify for the Domestic Service Rate.

(g) Hydro shall not be required to provide more than one meter per Service, however, sub-metering by the Customer for any purpose not inconsistent with these Regulations is permitted.

(h) Subject to Regulations 7(c) and 7(g) Service to different units of a building may, at the request of the Customer, be combined on one meter or be metered separately.

(i) Maximum demand for billing purposes shall be determined by demand meter or, at the option of Hydro, may be based on:

   (i) 80% of the connected load, where the demand does not exceed 100 kW, or

   (ii) the smallest size transformer(s) required to serve the load if it is intermittent in nature such as X-Ray, welding machines or motors that operate for periods of less than thirty minutes, or

   (iii) the kilowatt-hour consumption divided by an appropriate number of hours use where the demand is less than 10 kW.

(j) When charges are based on maximum demand the metering shall normally be in kVA if the applicable Rate is in kVA and in kW if the applicable Rate is in kW.

If the demand is recorded on a kVA meter but the applicable Rate is based on a kW demand, the recorded demand may be decreased by ten percent (10%) and the result shall be treated as the kW demand for billing purposes.

If the demand is recorded on a kW meter but the applicable Rate is based on a kVA demand, the recorded demand may be increased by ten percent (10%) and the result shall be treated as the kVA demand for billing purposes.

(k) The Customer shall ensure that meters and related equipment are visible and readily accessible to Hydro's personnel and are suitably protected. Unless otherwise approved by Hydro, meters shall be located outdoors and shall not subsequently be enclosed.

(l) If a meter is located indoors and Hydro employees are unable to obtain access to read the meter at the normal reading time for three consecutive months, the Customer shall upon written notice given by Hydro, provide for the installation of an outdoor meter at his expense.

(m) In the event that a dispute arises regarding the accuracy of a meter, and Hydro is unable to resolve the matter with the Customer then either the Customer or Hydro shall have the right to request an accuracy test in accordance with the requirements of the Electricity Inspection Act of Canada. Should the test indicate that the meter accuracy is not within the allowable limits, the Customer's bill shall be adjusted in accordance with the provisions of the said Act and all costs involved in the removal and testing of the meter shall be borne by Hydro. Should the test confirm the accuracy of the meter, the costs involved shall be borne by the party requesting the test. Hydro may require a Customer to deposit with Hydro in advance of testing, an amount sufficient to cover the costs involved.

(n) Metering shall normally be at secondary distribution voltage level but may at the option of Hydro be at the primary distribution level. When metering is at the primary distribution voltage (4-25KV) the monthly demand and energy consumption shall be reduced by 1.5%.

8. METER READING:

(a) Where reasonably possible Hydro shall read meters monthly provided that Hydro may, at its discretion, read meters at some other interval and estimate the reading for the intervening month(s). Areas which consist primarily of cottages will have their meters read four times per year and Hydro will estimate the readings for all other months.

(b) If Hydro is unable to obtain a meter reading due to circumstances beyond its reasonable control, Hydro may estimate the reading.

(c) If due to any cause a meter has not correctly recorded energy consumption or demand, then the probable consumption or demand shall be estimated in accordance with the best data available and used to determine the relevant charge.

9. **CHARGES:**

(a) Every Customer shall pay Hydro the charges approved by the Board from time to time for the Service(s) provided to the Customer or provided to the Serviced Premises at the Customer's request.

(b) Where a Customer requires Service for a period of less than three (3) years, the Customer shall pay Hydro in advance a "Temporary Connection Fee". The Temporary Connection Fee is calculated as the estimated labour cost of installing and removing lines and equipment necessary for the Service plus the estimated cost of non-salvageable material.

(c) Where special facilities are required or requested by the Customer or any facility is relocated at the request of the Customer, the Customer shall pay Hydro in advance the estimated additional cost of providing the special facilities and the estimated cost of the relocation less any betterment.

(d) The Customer shall pay Hydro in advance or on such other terms approved by the Board from time to time any contribution in aid of construction as may be determined by the methods prescribed by the Board.

(e) The Customer shall pay Hydro the amount set forth in the Rate for all poles required for Street and Area Lighting Service which are in addition to those installed by Hydro for the distribution of electricity. This charge shall not apply to Hydro poles and communications poles used jointly for Street and Area Lighting Service and communications attachments.

(f) Where a service is Disconnected pursuant to Regulation 12(a), b(ii), (c), or (d) and the Customer subsequently requests that the service be reconnected, the Customer shall pay a reconnection fee. Where a Service is Disconnected pursuant to Regulation 12(g) and an Applicant subsequently requests that the service be reconnected, the Applicant shall pay a reconnection fee. Applicants that pay the reconnection fee will not be required to pay the application fee. The reconnection fee shall be $20.00 where the reconnection is done during Hydro's normal office hours or $40.00 if it is done at other times.

(g) Where a Service, other than a Street and Area Lighting Service, is Discontinued pursuant to Regulation 11(a), or Disconnected pursuant to Regulations 12(a), b(ii), (c) or (d) and the Customer subsequently requests that the Service be restored within 12 months, the Customer shall pay, in advance, the minimum monthly charges that would have been incurred over the period if the Service had not been Discontinued or Disconnected.

(h) (i) Where a Street and Area Lighting Service is Discontinued pursuant to Regulation 11(a), (b), or (c), or 9(i), or when a Customer requests removal of existing fixtures, and/or poles, the Customer shall pay at the time of removal an amount equal to the unrecovered capital cost, plus the cost of removal less any salvage value of only the poles to be Discontinued or removed.

(ii) If a Customer requests the subsequent replacement of the fixture, either immediately or at any time within 12 months by another, whether or not of the same type or size, the Customer shall pay, in advance, an amount equal to the unrecovered capital cost of the fixture removed, plus the cost of removal, less any non-luminaire salvage, as well as the monthly charges that would have been incurred over the period if the Service had not been Discontinued.

(iii) Where a Street and Area Lighting Service is Discontinued, any pole dedicated solely to the Street and Area Lighting Service may, at the Customer's request, remain in place for up to 24 months from the date of removal of the fixture, during which time the Customer shall continue to pay the prescribed monthly charge for the pole.

(i) Where street and area lighting fixtures or lamps are wantonly, wilfilly, or negligently damaged or destroyed (other than through the negligence of Hydro), Hydro, at its option and after notifying the Customer by letter, shall remove the fixtures and the monthly charges for these fixtures will cease thirty days after the date of the letter. However, if the customer contacts Hydro within thirty days of the date of the letter and agrees to pay the repair costs in advance and all future repair costs, Hydro will replace the fixture and rental charges will recommence. If any future repair costs are not paid within three months of the date invoiced, Hydro, after further notifying the Customer by letter, may remove the fixtures. In all such cases the fixtures shall not be replaced unless the Customer pays to Hydro in advance all amounts owing prior to removal plus the cost of removing the old fixtures and installing the new fixtures.

(j) Where a Service other than Street and Area Lighting Service is not provided to the Customer for the full monthly billing period or where Street and Area Lighting Service is not provided for more than seven (7) days during the monthly billing period, the relevant charge to the Customer for the Service for that period may be prorated except where the failure to provide the Service is due to the Customer or to circumstances beyond the reasonable control of Hydro.

(k) Where a Customer's Service is at primary distribution or transmission voltage and the Customer provides his own transformation and all other facilities beyond the designated point of supply the monthly demand charge shall, subject to the minimum monthly charge, be reduced as follows:

For the Island Interconnected, L'Anse au Loup and Isolated service areas:

(i) for supply at 4 KV to 25 KV.. $0.40 per kVA

(ii) for supply at 33 KV to 138 KV.. $0.90 per kVA

For the Labrador Interconnected service area:

(iii) for supply at 4 KV to 25 KV.. $0.25 per kVA

(iv) for supply at 33 KV to 138 KV.. $0.60 per kVA

RULES AND REGULATIONS (Continued)

(l) Where a Customer's monthly demand has been permanently reduced because of the installation of peak load controls, power factor correction, or by rendering sufficient equipment inoperable, by any means satisfactory to Hydro, the monthly demands recorded prior to the effective date of such reduction may be adjusted when determining the Customer's demand for billing purposes thereafter. Should the Customer's demand increase above the adjusted demands in the following 12 months, the Customer will be billed for the charges that would have been incurred over the period if the demand had not been adjusted.

(m) Charges may be based on estimated readings or costs where such estimates are authorized by these Regulations.

(n) An application fee of $8.00 will be charged for all requests for Customer name changes and connection of new Serviced Premises. Landlords will be exempted from the application fee for name changes at Serviced Premises for which a landlord agreement pursuant to Regulation 11(f) is in effect.

10. BILLING:

(a) Hydro shall bill the Customer monthly for charges for Service. However, when a Service is disconnected or a bill is revised, Hydro may issue an additional bill.

(b) The charges for Street and Area Lighting Service may be included as a separate item on a bill for any other Service.

(c) Bills are due and payable when issued. Payment shall be made at such place(s) as Hydro may designate from time to time. Where a bill is not paid in full by the date that a subsequent bill is issued and the amount outstanding is $50.00 or more, Hydro will charge interest at a rate equal to the prime rate charged by chartered banks on the last day of the previous month plus five percent.

(d) Where a Customer's cheque or automated payment is not honoured by their financial institution, a charge of $16.00 may be applied to the Customer's bill.

(e) Where a Customer is billed on the basis of an estimated charge, an adjustment shall be made in a subsequent bill should such estimate prove to be inaccurate.

(f) Where between normal meter reading dates, one Customer assumes from another Customer the responsibility for a metered Service or a Service is Discontinued, Hydro may base the billing on an estimate of the reading as of the date of change.

(g) Where a Customer has been under billed due to an error on the part of Hydro or due to an act or omission by a third party, the Customer may, at the discretion of Hydro, be relieved of the responsibility for all or any part of the amount of the under billing.

11. DISCONTINUANCE OF SERVICE:

(a) A Service may be Discontinued by the Customer at any time upon prior notice to Hydro provided that Hydro may require 10 days prior notice in writing.

(b) A Service may be Discontinued by Hydro upon 10 days prior notice in writing to the Customer if the Customer:

(i) provided false or misleading information on the application for the Service

(ii) fails to provide security or guarantee for the Service required under Regulation 4.

(c) A Service may be Discontinued by Hydro without notice if the Service was Disconnected pursuant to Rule 12 and has remained Disconnected for over 30 consecutive days.

(d) When Hydro accepts an application for Service, any prior contract for the same Service shall be Discontinued except where an agreement for that Service is signed by a landlord under Regulation 11(f).

(e) Where a Service has been Discontinued, the Service may, at the option of Hydro and subject to Rule 12(a), remain connected.

(f) A landlord may sign an agreement with Hydro to accept charges for Service provided to a rental premise for all periods when Hydro does not have a contract for Service with a tenant for that premise.

12. DISCONNECTION OF SERVICE:

(a) Hydro shall Disconnect a Service within 10 days of receipt of a written request from the Customer.

(b) Hydro may Disconnect a Service without notice to the Customer:

(i) where the Service has been Discontinued.

(ii) on account of or to prevent fraud or abuse.

(iii) where in the opinion of Hydro the Customer's electrical system is defective and represents a danger to life or property.

(iv) where the Customer's electrical system has been modified without compliance with the Electrical Regulations.

(v) where the Customer has a building or structure under Hydro's wires which is within the minimum clearances recommended by the Canadian Standards Association.

(vi) when ordered to do so by any authority having the legal right to issue such order.

(c) Hydro may, in accordance with its Collection Policies, Disconnect a Service upon prior notice to the Customer if the Customer has a bill for any Service which is not paid in full 30 *days or more after issuance.*

(d) Hydro may Disconnect a Service upon 10 days prior notice to the Customer if the Customer is in violation of any provision of these Regulations.

(e) Hydro may refuse to reconnect a Service if the Customer is in violation of any provisions of these Rules or if the Customer has a bill for any Service which is unpaid.

(f) Hydro may disconnect a service to make repairs or alterations. Where reasonable and practical, Hydro shall give prior notice to the Customer.

(g) Hydro may disconnect the Service to a rental premises where the landlord has an agreement with Hydro authorizing Hydro to disconnect the Service for periods when Hydro does not have a contract for Service with a tenant of that premises.

13. PROPERTY RIGHTS:

(a) The Customer shall provide Hydro with space and cleared rights-of-way on private property for the line(s) and facilities required to serve the Customer.

(b) Hydro shall have the right to install, remove or replace such of its property as it deems necessary.

(c) The Customer shall provide Hydro with access to the Serviced Premises at all reasonable hours for purposes of reading a meter or installing, replacing, removing or testing its equipment, and measuring or checking the connected load.

(d) All equipment and facilities provided by Hydro shall remain the property of Hydro unless otherwise agreed in writing.

(e) The Customer shall not unreasonably interfere with Hydro's access to its property.

(f) The Customer shall not attach wire, cables, clotheslines or any other fixtures to Hydro's poles or other property except by prior written permission of Hydro.

(g) The Customer shall allow Hydro to trim all trees in close proximity to service lines in order to maintain such lines in a safe manner.

(h) The Customer shall not erect any buildings or obstructions on any of Hydro's easement lands or alter the grade of such easements by more than 20 centimetres, without the prior approval of Hydro.

14. HYDRO LIABILITY:

Hydro shall not be liable for any failure to supply Service for any cause beyond its reasonable control, nor shall it be liable for any loss, damage or injury caused by the use of Services or resulting from any cause beyond its reasonable control.

15. GENERAL:

(a) No employee, representative or agent of Hydro has authority to make any promise, agreement or representation, whether verbal or otherwise, which is inconsistent with these Regulations and no such promise, agreement or representation shall be binding on Hydro.

(b) Any notice under these Regulations will be considered to have been given to the Customer on the date it is received by the Customer or three days following the date it was delivered or mailed by Hydro to the Customer's last known address, whichever is sooner.

16. POLICIES FOR AUTOMATIC RATE CHANGES

(a) Island Interconnected System:

(i) As Newfoundland Power changes its rates, Hydro will automatically adjust all rates such that these customers pay the same rates as Newfoundland Power customers.

(b) L'Anse au Loup System:

(i) As Newfoundland Power changes its rates, Hydro will automatically adjust all rates such that these customers pay the same rates as Newfoundland Power customers.

(c) Isolated Systems:

(i) Isolated Rural Domestic customers, excluding Government departments, pay the same rates as Newfoundland Power for the basic customer charge and First Block consumption (outlined in Rate 1.2D). Rates charged for consumption above this block will be automatically adjusted by the average rate of change granted Newfoundland Power from time to time.

(ii) Rates for Isolated Rural General Service customers, excluding Government departments, will increase or decrease by the average rate of change granted Newfoundland Power from time to time.

(iii) As Newfoundland Power changes its rates, Hydro will automatically adjust Rural Isolated street and area lighting rates, excluding those for Government departments, such that these rates are the same as charged Newfoundland Power customers.

NEWFOUNDLAND AND LABRADOR HYDRO

RATE No. 1.2G

DOMESTIC DIESEL

GOVERNMENT DEPARTMENTS

Availability:

For Service to Government Departments throughout the Island and Labrador diesel service areas of Hydro, to a Domestic Unit or to buildings or facilities which are on the same Serviced Premises as a Domestic Unit and used by the same Customer exclusively for domestic or household purposes, whether such buildings or facilities are included on the same meter as the Domestic Unit or metered separately.

Rate:

Basic Customer Charge .... $53.50 per month

Energy Charge:
All kilowatt-hours .... @ 91.621 ¢ per kWh

Minimum Monthly Charge... $53.50

Discount:

A discount of 1.5% of the amount of the current month's bill, but not less than $1.00 or more than $500.00, will be allowed if the bill is paid within 10 days after it is issued.

General:

Details regarding conditions of service are provided in the Rules and Regulations.
This rate schedule does not include the Harmonized Sales Tax (HST) which applies to electricity bills.

NEWFOUNDLAND AND LABRADOR HYDRO

RATE No. 2.1G

GENERAL SERVICE DIESEL 0-10 kW

GOVERNMENT DEPARTMENTS (Continued)

Availability:

For Service (excluding Domestic Service) to Government Departments throughout the Island and Labrador diesel service areas of Hydro where the maximum demand occurring in the 12 months ending with the current month is less than 10 kilowatts.

Rate:

Basic Customer Charge .... $58.56 per month

Energy Charge:
All kilowatt-hours .... @ 84.673¢ per kWh

Minimum Monthly Charge... $58.56

Discount:

A discount of 1.5% of the amount of the current month's bill, but not less than $1.00 or more than $500.00, will be allowed if the bill is paid within 10 days after it is issued.

General:

Details regarding conditions of service are provided in the Rules and Regulations.
This rate schedule does not include the Harmonized Sales Tax (HST), which applies to electricity bills.

NEWFOUNDLAND AND LABRADOR HYDRO

RATE 2.2G

GENERAL SERVICE DIESEL OVER 10 KW

GOVERNMENT DEPARTMENTS (Continued)

Availability:

For Service (excluding Domestic Service) to Government Departments throughout the Island and Labrador diesel service areas of Hydro where the maximum demand occurring in the 12 months ending with the current month is 10 kilowatts or greater.

Rate:

Basic Customer Charge: .... $75.06 per month

Demand Charge:
The maximum demand registered on the meter in the current month............... @ $66.59 per kW

Energy Charge:
All kilowatt-hours.. @ 64.071 ¢ per kWh

Discount:

A discount of 1.5% of the amount of the current month's bill, but not less than $1.00 or more than $500.00, will be allowed if the bill is paid within 10 days after it is issued.

General:

Details regarding metering [in particular Regulation 7 (n)], transformation [in particular Regulation 9(k)], and other conditions of service are provided in the Rules and Regulations. **This rate does not include the Harmonized Sales tax (HST) which applies to electricity bills.**

NEWFOUNDLAND AND LABRADOR HYDRO

RATE 4.1G

STREET AND AREA LIGHTING SERVICE DIESEL

GOVERNMENT DEPARTMENTS (Continued)

Availability:

For Street and Area Lighting Service to Government Departments throughout the Island and Labrador Diesel service areas of Hydro, where the electricity is supplied by Hydro and all fixtures, wiring and controls are provided, owned and maintained by Hydro.

Monthly Rate:

	SENTINEL / STANDARD
MERCURY VAPOUR	
250W (9,400 lumens)	$85.32
HIGH PRESSURE SODIUM [1]	
100W (8,600 lumens)	57.31
150W (14,400 lumens)	85.32

[1] Only High Pressure Sodium fixtures are available for all new installations and replacements.

General:

Details regarding conditions of service are provided in the Rules and Regulations.
This rate schedule does not include the Harmonized Sales Tax (HST), which applies to electricity bills.

NEWFOUNDLAND AND LABRADOR HYDRO

RATE No. 1.1L

DOMESTIC

Availability:

For Service throughout the Labrador Interconnected service area of Hydro, to a Domestic Unit or to buildings or facilities which are on the same Serviced Premises as a Domestic Unit and used by the same Customer exclusively for domestic or household purposes, whether such buildings or facilities are included on the same meter as the Domestic Unit or metered separately.

Rate:

Basic Customer Charge: .... $9.02 per month

Energy Charge:
All kilowatt-hours .... @ 4.131 ¢ per kWh

Minimum Monthly Charge $9.02

Discount:

A discount of 1.5% of the amount of the current month's bill, but not less than $1.00, will be allowed if the bill is paid within 10 days after it is issued.

General:

Details regarding conditions of service are provided in the Rules and Regulations.
This rate schedule does not include the Harmonized Sales Tax (HST) which applies to electricity bills.

NEWFOUNDLAND AND LABRADOR HYDRO

RATE No. 2.1L

GENERAL SERVICE 0 - 10 kW

Availability:

For Service (excluding Domestic Service) throughout the Labrador Interconnected service area of Hydro, where the maximum demand occurring in the 12 months ending with the current month is less than 10 kilowatts.

Rate:

Basic Customer Charge: .... $13.43 per month

Energy Charge:
All kilowatt-hours .... @ 6.734 ¢ per kWh

Minimum Monthly Charge: Single Phase.. $13.43
Three Phase.. $20.00

Discount:

A discount of 1.5% of the amount of the current month's bill, but not less than $1.00, will be allowed if the bill is paid within 10 days after it is issued.

General:

Details regarding conditions of service are provided in the Rules and Regulations.
This rate schedule does not include the Harmonized Sales Tax (HST) which applies to electricity bills.

NEWFOUNDLAND AND LABRADOR HYDRO

RATE No. 2.2L

GENERAL SERVICE 10 - 100 kW (110 kVA)

Availability:

For Service (excluding Domestic Service) throughout the Labrador Interconnected service area of Hydro, where the maximum demand occurring in the 12 months ending with the current month is 10 kilowatts or greater but less than 100 kilowatts (110 kilovolt-amperes).

Rate:

Demand Charge:
The maximum demand registered on the meter in the current month..... @ $2.55 per kW

Energy Charge:
All kilowatt-hours.. @ 2.845 ¢ per kWh

Maximum Monthly Charge:

The Maximum Monthly Charge shall be 6.8 cents per kWh, but not less than the Minimum Monthly Charge.

Minimum Monthly Charge:

An amount equal to $1.05 per kW of maximum demand occurring in the 12 months ending with the current month, but not less than $20.00 for a three phase service.

Discount:

A discount of 1.5% of the amount of the current month's bill, but not less than $1.00, will be allowed if the bill is paid within 10 days after it is issued.

General:

Details regarding metering [in particular Regulation 7 (n)], transformation [in particular Regulation 9(k)], and other conditions of service are provided in the Rules and Regulations.
This rate schedule does not include the Harmonized Sales Tax (HST) which applies to electricity bills.

NEWFOUNDLAND AND LABRADOR HYDRO

RATE No. 2.3L

GENERAL SERVICE 110 kVA (100 kW) - 1000 kVA

Availability:

For Service (excluding Domestic Service) throughout the Labrador Interconnected service area of Hydro, where the maximum demand occurring in the 12 months ending with the current month is 110 kilovolt-amperes (100 kilowatts) or greater but less than 1000 kilovolt-amperes.

Rate:

Demand Charge:
The maximum demand registered on the meter in the current month .... @ $2.35 per kVA

Energy Charge:
All kilowatt-hours.. @ 2.455 ¢ per kWh

Maximum Monthly Charge:

The Maximum Monthly Charge shall be 6.8 cents per kWh, but not less than the Minimum Monthly Charge.

Minimum Monthly Charge:

An amount equal to $1.05 per kVA of maximum demand occurring in the 12 months ending with the current month.

Discount:

A discount of 1.5% of the amount of the current month's bill, up to a maximum of $500.00, will be allowed if the bill is paid within 10 days after it is issued.

General:

Details regarding metering [in particular Regulation 7 (n)], transformation [in particular Regulation 9(k)], and other conditions of service are provided in the Rules and Regulations. **This rate schedule does not include the Harmonized Sales Tax (HST) which applies to electricity bills.**

NEWFOUNDLAND AND LABRADOR HYDRO

RATE No. 2.4L

GENERAL SERVICE 1000 kVA AND OVER

Availability:

For Service (excluding Domestic Service) throughout the Labrador Interconnected service area of Hydro, where the maximum demand occurring in the 12 month period ending with the current month is 1000 kilovolt-amperes or greater.

Rate:

Billing Demand Charge:
The maximum demand registered on the meter in the current month.... @ $2.15 per kVA

Energy Charge:
All kilowatt-hours... @ 2.098 ¢ per kWh

Maximum Monthly Charge:

The Maximum Monthly Charge shall be 6.8 cents per kWh, but not less than the Minimum Monthly Charge.

Minimum Monthly Charge:

An amount equal to $1.05 per kVA of maximum demand occurring in the 12 months ending with the current month.

Discount:

A discount of 1.5% of the amount of the current month's bill, up to a maximum of $500.00, will be allowed if the bill is paid within 10 days after it is issued.

General:

Details regarding metering [in particular Regulation 7 (n)], transformation [in particular Regulation 9(k)], and other conditions of service are provided in the Rules and Regulations. **This rate schedule does not include the Harmonized Sales Tax (HST) which applies to electricity bills.**

NEWFOUNDLAND AND LABRADOR HYDRO

RATE No. 4.1L

STREET AND AREA LIGHTING SERVICE

Availability:

For Street and Area Lighting Service throughout the Labrador Interconnected service area of Hydro, where the electricity is supplied by Hydro and all fixtures, wiring and controls are provided, owned and maintained by Hydro.

Monthly Rate:

	SENTINEL / STANDARD
MERCURY VAPOUR[1]	
250W (9,400 lumens)	$ 19.28
HIGH PRESSURE SODIUM [2]	
100W (8,600 lumens)	14.28
150W (14,400 lumens)	19.28
250W (23,200 lumens)	25.42
400W (45,000 lumens)	32.85

[1] Fixtures previously owned by the Town of Wabush as of September 1, 1985, and transferred to Hydro in 1987.

[2] Only High Pressure Sodium fixtures are available for all new installations and replacements installed after September 1, 2002.

Special poles used exclusively for lighting service

Wood .... $ 4.86

General:

Details regarding conditions of service are provided in the Rules and Regulations.
This rate schedule does not include the Harmonized Sales Tax (HST) which applies to electricity bills.

NEWFOUNDLAND AND LABRADOR HYDRO

RATE No. 4.11L

STREET AND AREA LIGHTING SERVICE

Availability:

For Street and Area Lighting Service throughout the Labrador Interconnected service area of Hydro, where the electricity is supplied by Hydro and all fixtures, wiring and controls are provided, owned and maintained by Hydro existing as of September 1, 2002.

Monthly Rate:

	SENTINEL / STANDARD
HIGH PRESSURE SODIUM [1]	
100W (8,600 lumens)	$ 9.64

[1] Any new fixtures added will be at the rates set out in Rate 4.1L.

Special poles used exclusively for lighting service

Wood .... $ 4.86

General:

Details regarding conditions of service are provided in the Rules and Regulations.
This rate schedule does not include the Harmonized Sales Tax (HST) which applies to electricity bills.

NEWFOUNDLAND AND LABRADOR HYDRO

RATE No. 4.12L

STREET AND AREA LIGHTING SERVICE

Availability:

For Street and Area Lighting Service throughout the Labrador Interconnected service area of Hydro, where the electricity is supplied by Hydro and all fixtures, wiring and controls are provided, owned and maintained by the customer.

Monthly Rate:

	SENTINEL / STANDARD
HIGH PRESSURE SODIUM	
100W (8,600 lumens)	$ 5.86

Special poles used exclusively for lighting service

Wood .... $ 4.86

General:

Details regarding conditions of service are provided in the Rules and Regulations.
This rate schedule does not include the Harmonized Sales Tax (HST) which applies to electricity bills.

SECTION 1: INTRODUCTION

1.1 OVERVIEW

1.1.1 Current General Rate Application

Newfoundland and Labrador Hydro's (Hydro, or the Company) General Rate Application (GRA) requests new rates effective January 1, 2014[1]. Hydro's last GRA was filed in 2006 with new rates becoming effective January 1, 2007. Since that time there have been a number of factors affecting costs on the Island Interconnected and Labrador Interconnected Systems which have a significant influence on Hydro's rate request.

On the Island Interconnected System, there has been a significant increase in the price of fuel used at the Holyrood Thermal Generating Station (Holyrood), practically doubling since 2007. Rates for Newfoundland Power (NP) have increased over the period, through the Rate Stabilization Plan, and reflect the increased fuel price level. Rates for Industrial Customers (IC), however, have not been adjusted over that period and there is now a requirement to realign base rates with the cost of service for this customer class. Another influence on Island Interconnected electricity rates is the new wind and hydraulic generation that Hydro has accessed since 2007. It is estimated that in 2013 this renewable energy will result in approximately $74 million in fuel savings and a reduction in greenhouse gas emissions (GHGs) of 482,000 tonnes. These cost savings have a positive impact on Hydro's current rate request, in that rates are lower than they would have been absent these energy sources.

On the Labrador Interconnected System, there has been a significant increase in capital spending to ensure the continued delivery of safe and reliable electricity to customers. Over the 2007 to 2013 period, there have been capital expenditures of approximately

[1] Details on Hydro's requested rate changes are outlined in Section 4.

$39 million, primarily in system upgrading to meet customer needs, related to both increasing load and aging infrastructure. These expenditures, along with other cost increases, as discussed in the Finance evidence, have put upward pressure on electricity rates on the Labrador Interconnected System.

The evidence presented by Hydro in this filing outlines the following:

- Hydro's operating performance;
- The financial position and financial performance of the Company; and
- The rates being proposed based upon the 2013 Test Year revenue requirement.

These factors combine to meet the challenge of infrastructure renewal while maintaining electricity rates based on least cost, reliable service.

1.1.2 Background

Hydro is the primary generator and transmitter of electricity in the Province of Newfoundland and Labrador (the Province). In 2012, Hydro supplied roughly 87% of the electrical energy used in the Province serving, directly or indirectly, approximately 279,000 customers. Hydro has $1.4 billion[2] of capital assets located throughout the Province, spanning 1,000 kilometres from Nain, the northernmost community in Labrador, to Ramea on the south coast of Newfoundland and 1,200 kilometres from Hydro's most western service territory, Labrador City, to St. John's.

The Newfoundland and Labrador electrical grids were established principally in the late 1960s with the construction of the Bay d'Espoir hydraulic generating site on the island and the Churchill Falls project in Labrador during the early 1970s. As such, most of Hydro's generation and transmission assets are now more than 40 years old. Assets of

[2] Net book value as at December 31, 2012.

this type and vintage require increasing refurbishment and replacement which is the number one challenge faced by Hydro. Investment in Hydro's generation, transmission and distribution assets is essential in order to maintain reliable electricity service to customers. Hydro is not unique in this matter; the Canadian Electricity Association (CEA) also indicates that infrastructure renewal and new build are among the top challenges facing the Canadian electricity industry.

1.2 KEY CHALLENGES

1.2.1 Infrastructure Renewal

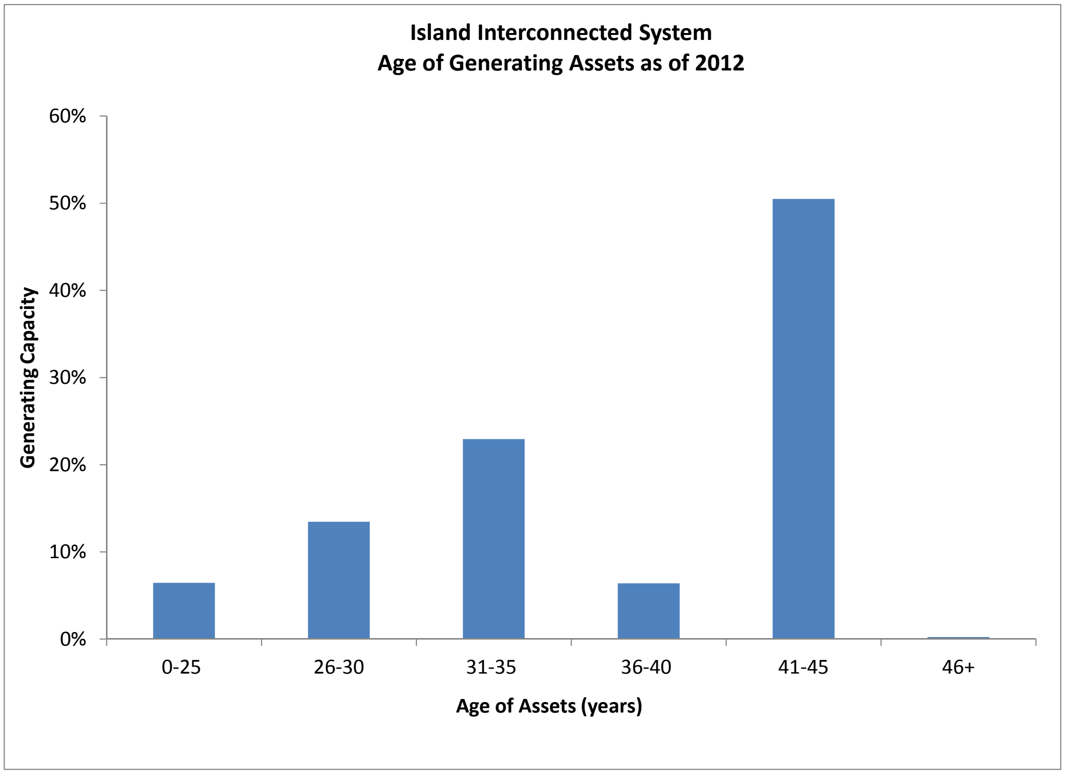
1.2.1.1 Aging Assets

Generation

As shown in Chart 1.1, most of Hydro's Island Interconnected generating assets are over 40 years old[3].

[3] Hydraulic asset components have service lives in the range of 45 to 100 years.

Chart 1.1



The hydraulic generating assets, which form a large part of Hydro's Island Interconnected generating capacity, are now a high value, low cost source of clean renewable energy since their original cost represents a fraction of the replacement cost of hydraulic assets today, and they therefore must be strategically maintained and refurbished to retain that value. Hydro's thermal plant at Holyrood is comprised of generating units and other infrastructure reaching the end of their service lives[4], with Units 1, 2, and 3 having been placed in-service in 1970, 1971 and 1980, respectively.

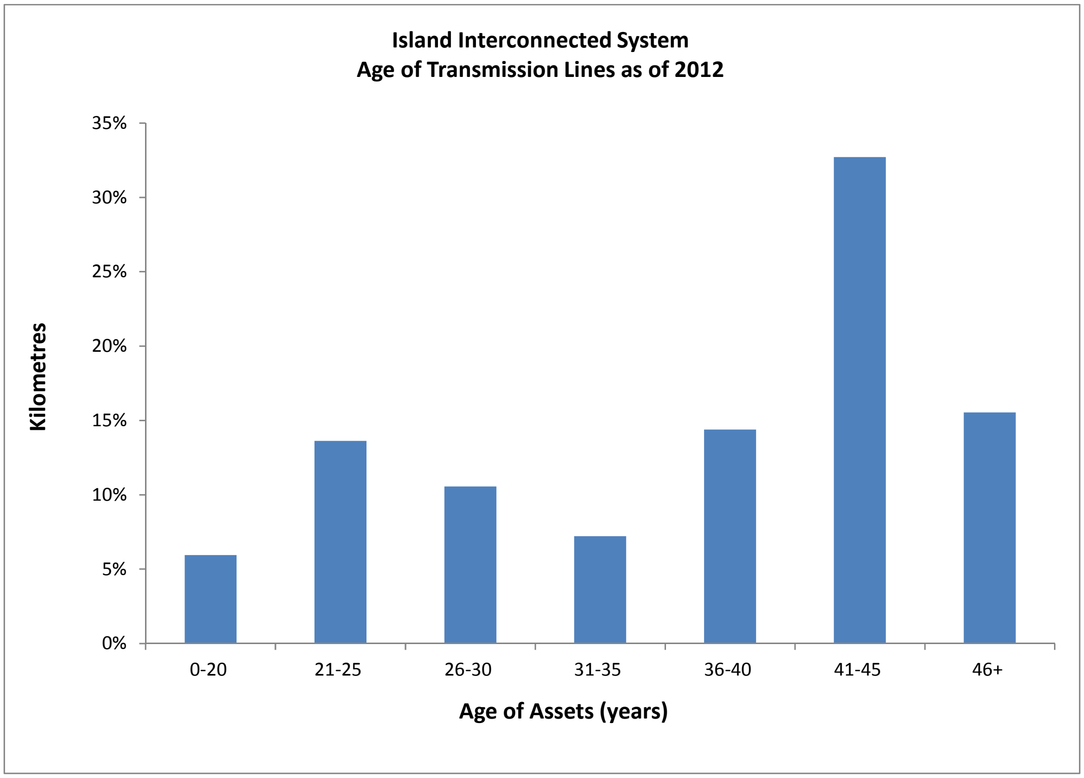
Transmission

The majority of Hydro's transmission system was constructed at the same time as the Bay d'Espoir facility in the late 1960s in order to connect this and other generation to load centers across the Province. As shown in Chart 1.2, many of Hydro's transmission

[4] Certain Holyrood thermal and marine assets have service lives ending in 2020.

lines are now greater than 40 years old and many components are reaching the end of their service lives[5]. This is also indicative of the age of Hydro's terminal station assets.

Chart 1.2

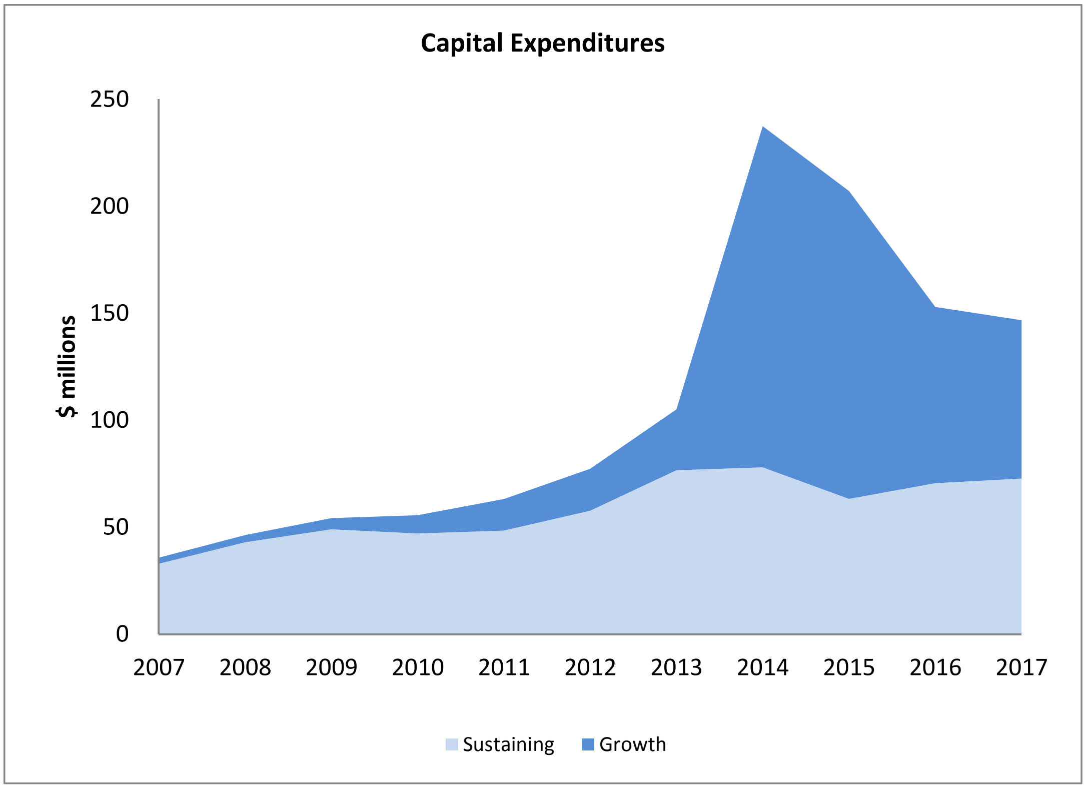


1.2.1.2 Increasing Expenditures

Aging assets require strategic operating and maintenance to optimize the useful life of the assets while maintaining operating expenses at the least cost consistent with reliable service. Capital replacements and refurbishment (sustaining capital) are required as normal deterioration of asset components occurs. As shown in Chart 1.3, Hydro is estimating a significant increase in capital expenditures over the period from 2007 to 2017, predominantly as a result of the increasing age of its asset base and load growth in some areas.

[5] Transmission asset components have service lives in the range of 30 to 65 years.

Chart 1.3



Infrastructure renewal and replacement is the key challenge faced by Hydro. The significant increase in the capital program has required redeployment of Hydro's workforce and increased engagement of contractors to meet the additional work requirements. Hydro's focus remains on safely providing least cost, reliable power, while managing these upward cost pressures.

1.2.2 Supplying Least Cost Power

Hydro's mandate is to provide least cost, reliable and safe electricity to its customers. Securing economic, renewable sources of electricity is the greatest positive impact that can be achieved in helping to mitigate customer rate increases.

Since 2007, Hydro has achieved this through:

- New sources of wind energy installed at St. Lawrence and Fermeuse;

- A reduction in the cost of energy from the former Star Lake Hydro and Exploits River Hydro Partnerships; and
- Access to additional Exploits generation which was previously used to supply the Abitibi Consolidated Inc. paper mill operations at Grand Falls-Windsor.

Each of these factors has had significant positive impact on Hydro's costs and GHGs. It is estimated that in 2013 the combined benefit will total approximately $74 million, based on Test Year forecasts for energy production utilization, No. 6 fuel prices and the Holyrood conversion rate. This represents 13.0% of Hydro's 2013 proposed revenue requirement of $568.1 million.

1.2.2.1 New Wind Purchases

The wind farms at St. Lawrence and Fermeuse began commercial operation in the fall of 2008 and spring of 2009, respectively. In 2012, 3% of the Island Interconnected System's net energy generation needs were supplied by wind. An equivalent level of energy production at Holyrood requires the consumption of nearly 310,000[6] barrels of oil and creates more than 160,000 tonnes of GHGs. In 2013, it is estimated that the forecast level of wind energy production, if generated at Holyrood, would cost customers an additional $17.1 million[7].

1.2.2.2 Exploits Generation

In 2008, the Government of Newfoundland and Labrador (the Government) passed the *Abitibi-Consolidated Rights and Assets Act* which, among other things, included the expropriation of the Star Lake, Buchans, Grand Falls and Bishop's Falls generating stations and associated assets (Exploits Generation). Subsequent to the 2008

[6] At the approved 2007 Test Year conversion factor of 630 kWh/bbl.
[7] At the 2013 proposed Holyrood conversion factor of 612 kWh/bbl and fuel costs of $108.74/bbl.

expropriation, on the direction of the Government, Hydro continued to apply power purchase rates and terms that had been in place with Star Lake Hydro and Exploits River Hydro Partnerships. It also did not purchase any energy which was previously used by Abitibi Consolidated Inc. (ACI). In 2011 and 2012, the Government changed the terms of the purchase arrangements and an additional block of energy that was previously used by ACI was made available to Hydro from Exploits Generation. In the 2013 Test Year, the Exploits Generation will continue to be made available to Hydro as a source of economical, renewable energy to the benefit of ratepayers, as the alternative source of this energy would be higher cost Holyrood fuel.

1.2.2.3 Conservation and Demand Management

Hydro and NP have jointly developed and implemented a five-year Conservation and Demand Management (CDM) plan and filed an updated plan in 2012. Initiatives resulting from the plan include activities encouraging customers' behavioural change, the provision of rebates, marketplace promotions and other targeted efforts that will see lower reliance on electricity. Lower electricity use results in less fuel being burned and a reduction in GHGs, while providing economic benefits for customers.

1.2.3 Employee Retention and Recruitment

In 2006, based on an analysis of its workforce and the external labour market, Hydro became increasingly concerned with its ability to recruit and retain the necessary skilled employees in the future. Retirements were continuing to increase as greater numbers of employees approached retirement age, and at the same time expected labour shortages were imminent, particularly in the technical/trades occupations. The following factors dictated the need for a focused strategy for recruitment and retention:

- Significant anticipated retirements during the coming five to ten years;
- Large-scale construction projects within the Province, as well as a very active and increasing construction program in 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.

Over the period from 2007 to 2012, Hydro experienced 193 retirements. Hydro will continue to experience significant retirement related turnover in key operational roles over the next five to ten-year period. Between 2013 and 2022, it is anticipated that 40% to 45% of the Company's current workforce will be eligible to retire.

These levels of turnover have had, and will continue to have, a major impact on recruitment activity at Hydro. Given that the employees leaving are often among the most experienced and knowledgeable, the Company's focus, from a retention and business sustainability standpoint, has been to minimize voluntary turnover.

Hydro has been proactive in ensuring the availability of a stable and qualified workforce to position the Company for success in carrying out its mandate. Several actions and initiatives, as described in Section 2, have been taken in the last several years to strengthen recruitment and retention at Hydro. However, a continuing focus will be required to meet new challenges in this area in the future.

1.3 ECONOMIC ENVIRONMENT

Hydro's forecasted financial performance is based on specific planning criteria and the following market factors and economic assumptions:

- The provincial economy which determines the level of electricity sales;
- World oil markets impacting delivered fuel prices, primarily No. 6 fuel used at Holyrood, and diesel fuel;

- General levels of inflation and pricing impacts due to supply and demand variables;
- Borrowing costs and access to capital markets; and
- Provincial and regional labour markets.

1.3.1 Provincial Economy

The general levels of economic activity in the Province, including the operating level of locally based firms and labour competition in internal and external markets, directly affect Hydro.

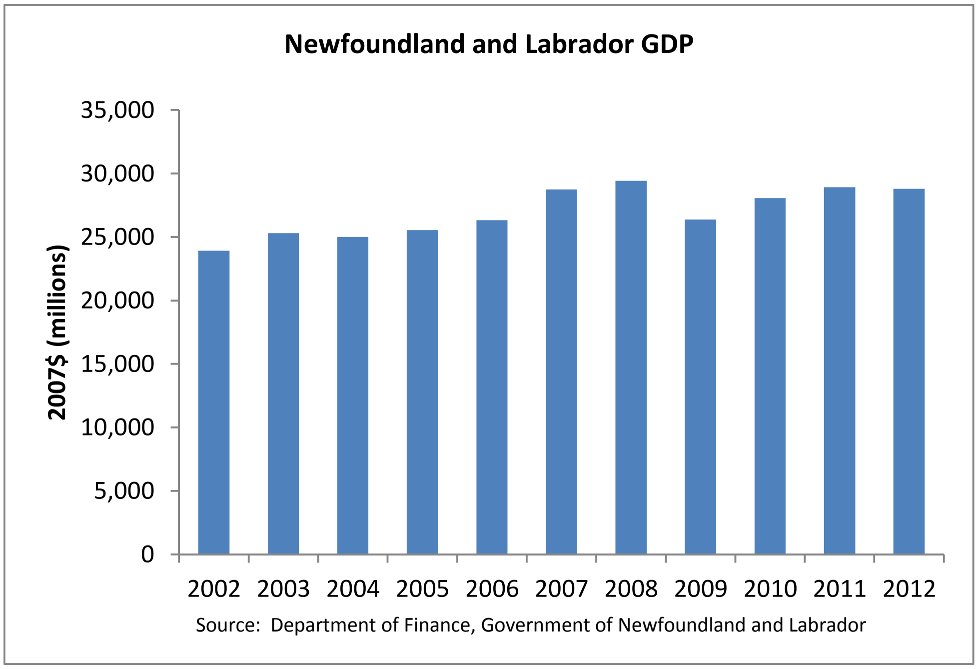
1.3.1.1 Medium-Term Outlook[8]

The Province posted a return to solid economic growth in 2010 and 2011 following the moderate decline in 2009 associated with the global recession.

In 2012, economic conditions in the Province remained robust despite the marginal decline in real Gross Domestic Product (GDP). The decline in real GDP in 2012 was primarily a result of lower oil production which more than offset gains in both investment and consumption. Chart 1.4 illustrates the Newfoundland and Labrador GDP since 2002.

[8] Five to ten-year outlook from the Department of Finance of Newfoundland and Labrador.

Chart 1.4



Gains in capital investment in 2012 over 2011 were a result of continued development of major projects, led by Vale Newfoundland and Labrador's (Vale) nickel processing facility in Long Harbour along with projects in the oil, mining and hydro-electric sectors also contributing to provincial growth. Commercial and residential expenditures contributed to increased levels of investment spending with housing starts totaling 3,885, the highest level in over 35 years.

Consumer retail spending was quite strong in 2012 with the value of sales increasing over 2011. Employment and wage gains, combined with high levels of consumer confidence, continued to support consumer spending. Employment grew by 2.3% and led to a decline in the unemployment rate and growth in the provincial personal income level.

Over the next few years, the economic environment is expected to be positive with GDP growth dependent on the timelines of major projects as well as natural resource production. Increased exports, investment and consumption are expected to more than offset a decline in government spending. High fossil fuel prices are encouraging offshore exploration and development options. Capital investment will remain at high levels due to major projects being developed as well as residential and non-resource commercial investment. It is anticipated that continued economic growth will sustain employment levels, support consumer confidence and result in net in-migration and a stable population through the medium-term. In summary, the outlook for medium-term electricity requirements in the Province remains largely positive.

1.3.1.2 Hydro's 2013 Forecast Electricity Sales

Due to the anticipated load growth from the 2007 Test Year to 2013, overall customer energy requirements are forecast to increase by 2.6%, despite the significant reduction[9] in industrial use by the pulp and paper industry on the island.

On the Island Interconnected System, there is forecast to be an increase in energy requirements of 236 GWh or 3.7% in the 2013 forecast compared to the 2007 Test Year. This overall increase is a result of increasing utility customer requirements partially offset by an overall decrease in Industrial Customer (IC) load. Lower IC load is associated with the closure of the ACI paper mill in Grand Falls-Windsor and reduced load at the Corner Brook Pulp and Paper (CBPP) mill due to the shutdown of two of its four paper machines in recent years. This reduced load will be offset somewhat by the new customer requirements at the Vale nickel processing facility at Long Harbour. The Vale terminal station was energized in June 2012 with first power taken by the customer in December 2012. In 2013, it is anticipated that Vale will increase its levels of demand and energy consumption until it reaches full production levels by the end of 2016. Another IC, Praxair Limited (Praxair), is expected to commence operations in 2013 and will supply oxygen for the Vale processing facility.

[9] Since the 2007 Test Year, the pulp and paper industry energy requirements have decreased by 87%.

On the Labrador Interconnected System, energy requirements in 2013 are forecast to be 54 GWh or 5.3% lower than in the 2007 Test Year, reflecting forecast decreases in sales to non-regulated customers in addition to a sharp reduction in secondary energy requirements at Canadian Forces Base (CFB) Goose Bay. This overall decrease in load is partially offset by increased forecast requirements for residential and commercial customers, including a new general service customer relating to construction for the Muskrat Falls Project.

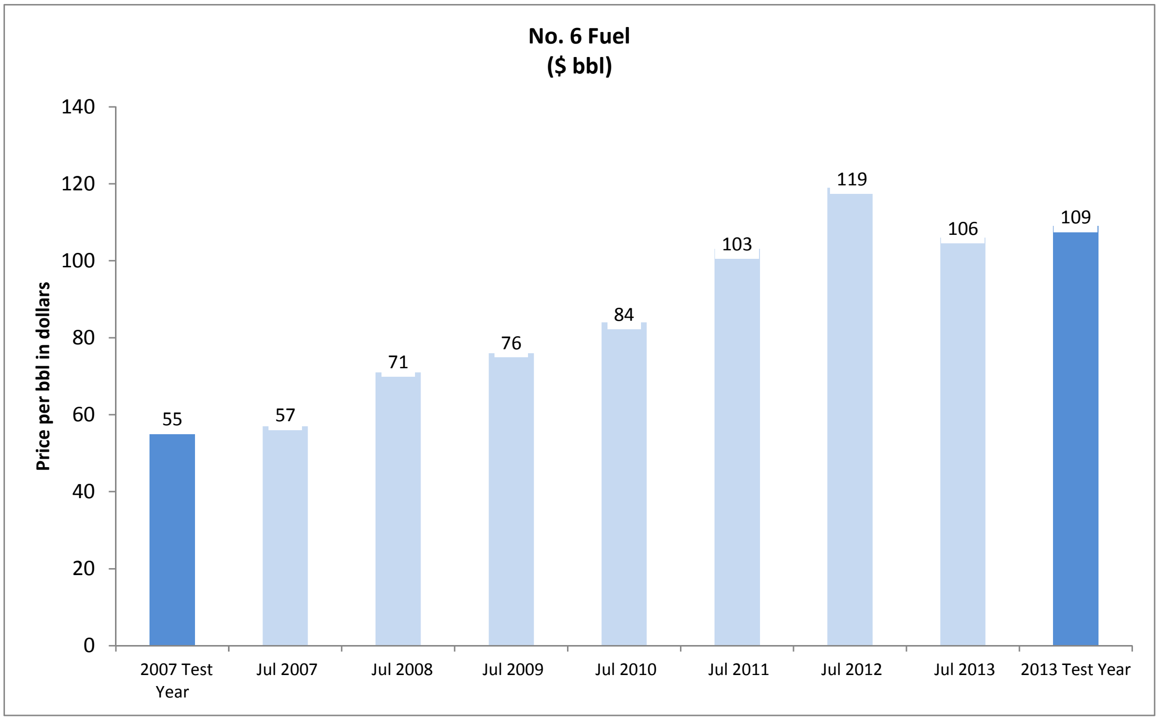
The net electricity requirements for isolated diesel systems are projected to increase by 13.5 GWh or 22.0% in 2013 relative to the 2007 Test Year. The primary driver is the increasing customer load in Labrador, in particular, on the L'Anse au Loup system. L'Anse au Loup has experienced strong electricity sales growth following the introduction of lower electricity rates as a result of the interconnection of the L'Anse au Loup system to Hydro Québec's Lac Robertson system. Over one-third of the homes on the L'Anse au Loup system now have electricity as the main heating source whereas prior to the rate change very few homes were heated by electricity. Given the cost to consumers of heating fuel compared to electricity costs, further conversion to electric heat is anticipated and additional capital expenditure will likely be required.

Detailed explanations of the load forecasts are found in the Regulated Activities evidence of this Application.

1.3.2 World Fuel Prices

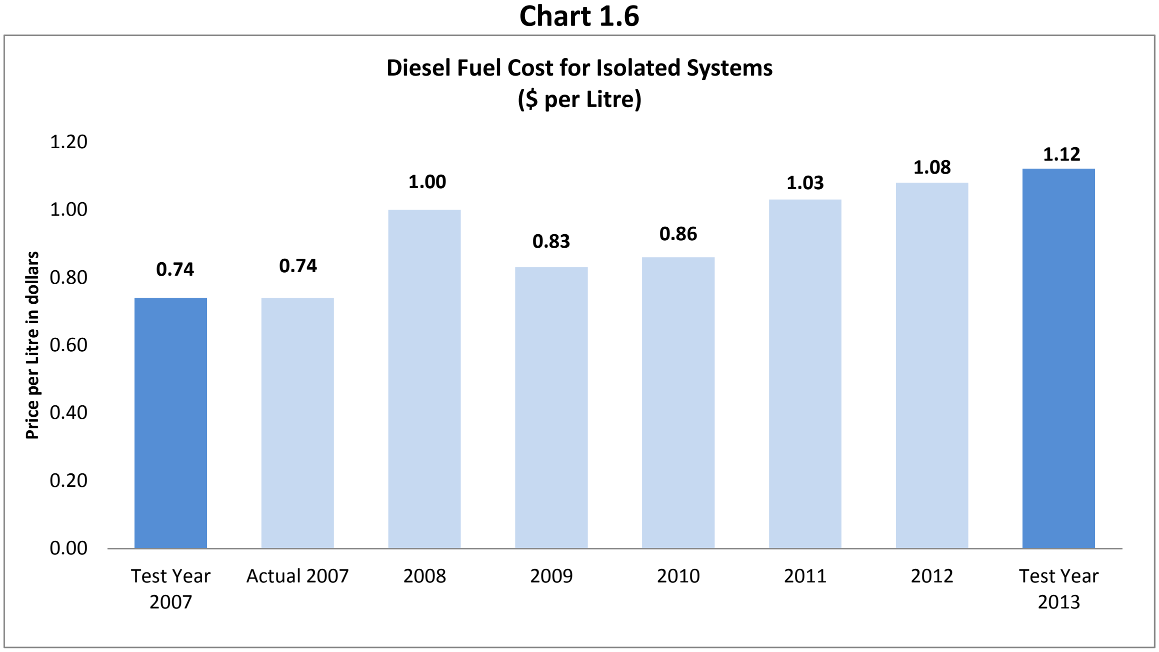
Since 2007, the costs of No. 6 and diesel fuels have risen sharply, as illustrated in Charts 1.5 and 1.6.

Chart 1.5



Note: July values are those values upon which the fuel rider is based. Prices are based upon the fuel in use at the time, which varied in sulphur content.

Chart 1.6



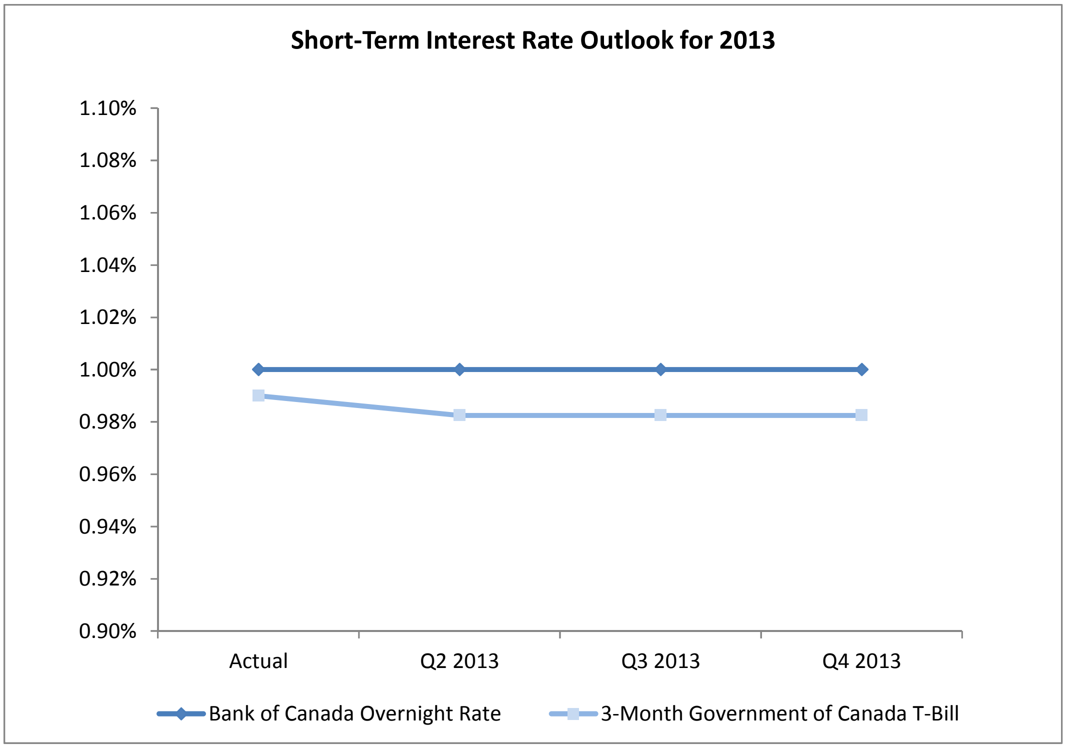
Rate impacts from monthly variances in the price of No. 6 fuel are smoothed for Hydro's customers by the Rate Stabilization Plan (RSP) which reduces short-term volatility by establishing an annual adjustment in customer rates. Forecast fuel prices are reflected annually in the fuel rider on customers' rates[10]. Diesel fuel prices included in the 2013 Test Year are substantially increased ($0.38 per litre) from the 2007 Test Year. While there is no recovery mechanism currently in place for diesel fuel, Hydro is proposing such a mechanism in this Application.

1.3.3 Borrowing Costs

An overview of the forecast for key short-term benchmark rates for 2013 is shown in Chart 1.7.

[10] Since January 1, 2007, the ICs have not received annual RSP rate adjustments.

Chart 1.7[11]



To the extent that Hydro has short-term borrowing requirements, interest expense will be directly impacted by prevailing rates in the short-term money markets, which determine Hydro's borrowing cost under its $300 million promissory note program and, to a lesser extent, the rate which Hydro pays on funds borrowed through its $50 million operating line of credit. In contrast, because Hydro's outstanding bond issues all have fixed interest rates, prevailing market rates for longer-term issues do not impact interest expense or the embedded cost of debt. Prevailing rates would only impact interest expense if Hydro issued new debt or refinanced existing debt, neither of which is planned for 2013. Hydro is continually assessing changes in its cash flows to determine whether its financing plan requires modification.

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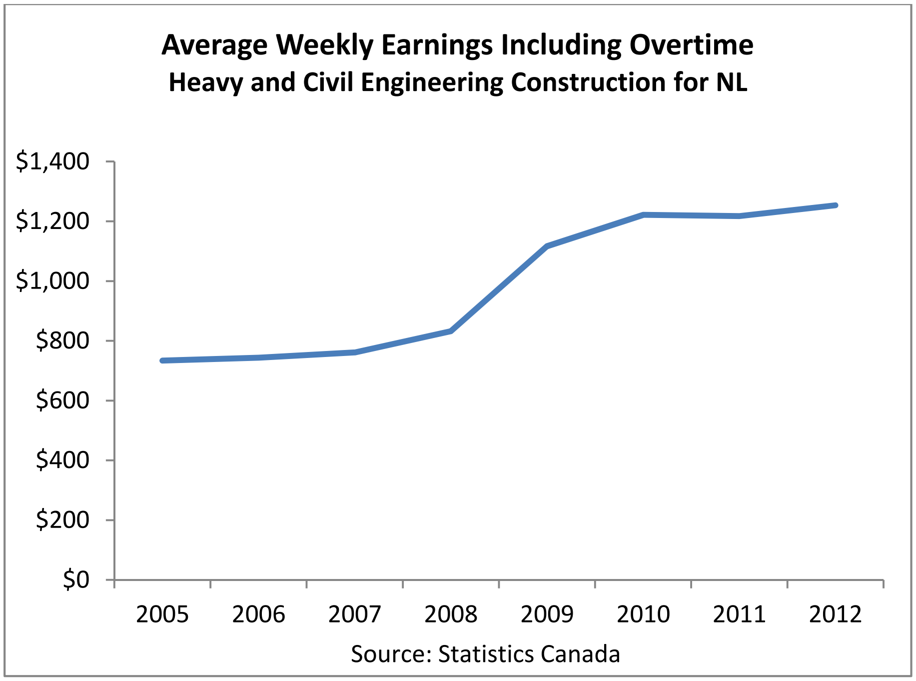
[11] Current data obtained from Bank of Canada as of April 2013. Data points for Q2-Q4 represent the average of the forecasts published by RBC Economics (April 5, 2013), Scotiabank (March 27, 2013), BMO Capital Markets (April 4, 2013) and CIBC World Markets (April 3, 2013).

1.3.4 Provincial Labour Markets

Provincial employment levels have generally been increasing since the mid-1990s. In 2009 employment declined by 2.9%, linked to the 2009 global recession. The recovery of job losses in Newfoundland and Labrador between 2009 and 2010 marked the shortest employment recovery from a recession since the mid-1970s and is indicative of the momentum in the provincial economy. More recent employment growth is largely driven by major project developments, increased consumer expenditures and public sector spending. Employment growth continued through 2011 and 2012 with job gains concentrated in full time employment. Employment grew to a record level in the Province in 2012 and the growth was second highest among the provinces. The unemployment rate declined to the lowest annual rate in more than 35 years. Accompanying the provincial labour market changes are signals that labour market conditions have "tightened"[12]. Chart 1.8 shows the trend in average weekly earnings for heavy and civil engineering construction labour in the Province from 2005 to 2012. These wage increases, in excess of 60% over the period, illustrate some of the external cost pressures to which Hydro has recently been exposed.

[12] Government of Newfoundland and Labrador, Department of Finance: Used in the context of this evidence, a tight labour market refers to a labour market where the availability of jobs is greater than the supply of workers causing employers to compete for employees.

Chart 1.8



Provincial labour markets are expected to continue to tighten in the next ten years and beyond due to an aging population, a shrinking labour supply and industrial growth. Skilled trades workers in construction are of particular interest in light of current and planned major project developments. The demand for skilled workers has been increasing and employment is expected to grow through the medium-term as the major project developments come on stream. Construction employment in 2012 was the highest ever reported for the Province. Other occupations that are expected to grow quickly in the Province in the medium-term include occupations required for processing, manufacturing, and utilities.

1.4 HYDRO'S BUSINESS STRATEGY

Hydro's business strategy for meeting its mandate of providing least cost reliable power is based on the following objectives:

- To pursue operational excellence in safety, environmental responsibility and reliability;

- To strengthen and maintain its financial performance;
- To develop and maintain a highly-skilled and motivated team of employees who are strongly committed to Hydro's success; and
- To provide, through operational excellence in asset and financial management, exceptional value to all energy consumers.

1.4.1 Financial Performance

Over the period 2013 to 2017, Hydro estimates that its total capital program will be approximately $800 million. As Hydro returns to the capital markets to fund its infrastructure renewal and new asset construction program, it is critical that it is in a sound financial position.

Prior to 2009, Hydro had the second highest percentage of debt in its capital structure of any major electric utility in Canada. Hydro also had the lowest approved return on equity (ROE) amongst its peer utilities. In order to reduce the debt level of Hydro, the Government in its 2008 – 2009 Budget included a $100 million equity injection that would "*bring Hydro more in line with similar utilities in Canada*"[13]. Also in 2009, the Government directed that Hydro would earn the same ROE as Newfoundland Power following Hydro's next GRA. These actions by the Government have improved and will continue to improve the financial position of the Company.

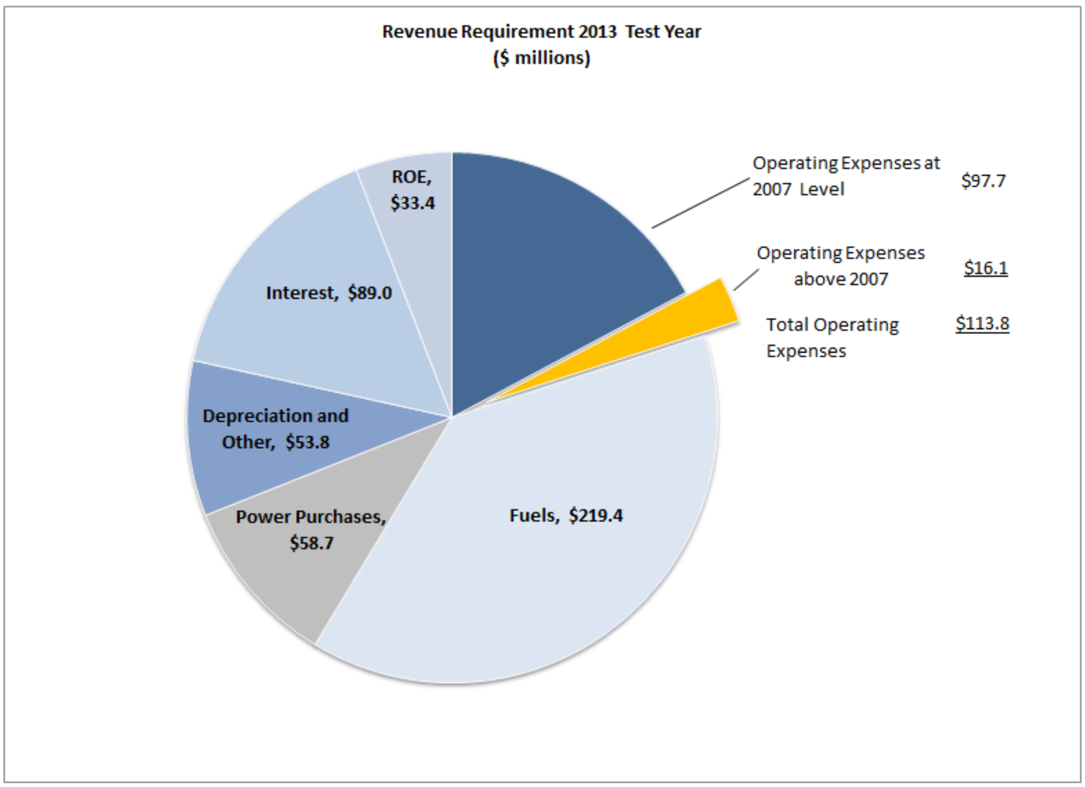
1.4.1.1 Cost Control

Fuel and interest costs, which comprise 54% of Hydro's revenue requirement in 2013, are subject to variability driven by global economic conditions and markets. Fuel volumes are largely uncontrollable in the short and medium-term as they are reflective

[13] Government of Newfoundland and Labrador Budget Speech, April 29, 2008.

of the provincial generation supply mix available to meet customers' requirements. In addition, a significant portion of remaining costs (e.g. interest, depreciation and power purchases) are driven by previous decisions and long-term power purchase arrangements can be fixed for a period of time. The primary area where Hydro can exercise cost control in the short-term pertains to Operating Expenses[14], which have increased by $16.1 million since 2007 as shown in Chart 1.9.

Chart 1.9

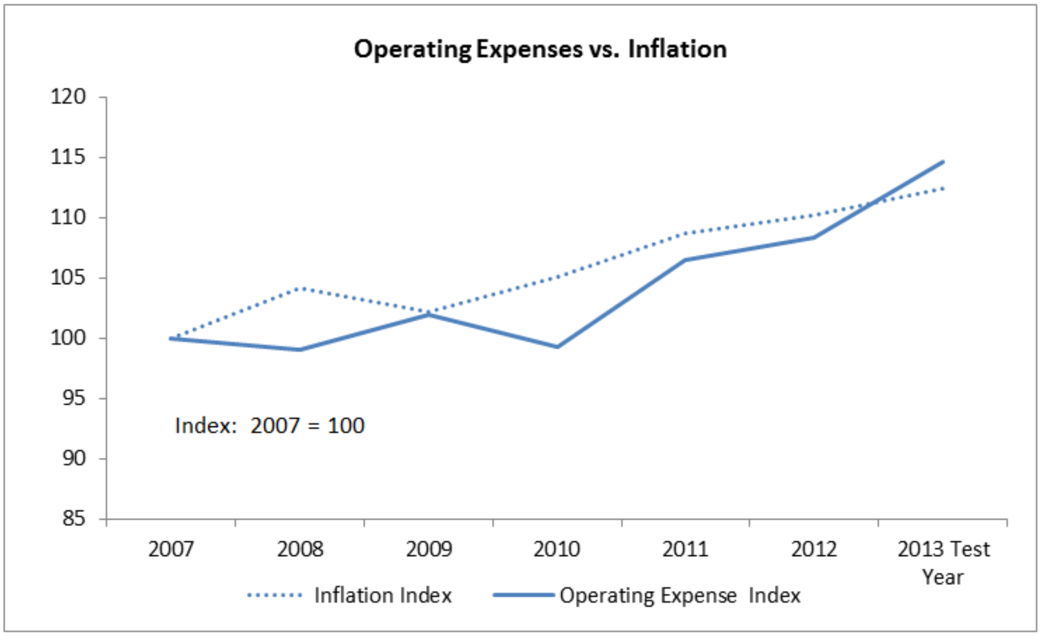


As shown in Chart 1.10, over the period 2007 to 2013, the increases in Hydro's Operating Expenses have been close to inflationary levels, with inflation averaging 2.0%

[14] Operating Expenses include salaries and benefits, system equipment maintenance, professional fees, travel and other costs and cost recoveries.

annually over the period, while the increase in Operating Expenses is forecast to average 2.3% annually.

Chart 1.10[15]



Hydro has prudently incurred and managed expenditures and achieved economies of scale through sharing services with Nalcor Energy (Nalcor). During this period, Hydro also increased its competitiveness in a tightening labour market and expanded its engineering workforce to meet the infrastructure renewal challenge.

[15] For comparative purposes the Operating Expense index excludes the effects of the impacts of accounting changes as approved in Order No. P.U. 13(2012). The period from 2007 to 2013 excludes major repairs and inspections at Holyrood. Both Operating Expenses and inflation are presented for comparison purposes indexed to the 2007 base.

1.4.1.2 Cost Allocation

In order to ensure that Hydro's customers pay the appropriate amount for electrical service, Hydro has an obligation to ensure that costs not associated with regulated electrical service are clearly separated and that Hydro's regulated customers pay only for those costs incurred in the provision of electricity to them. Hydro has a long history of involvement with non-regulated activities, including the administration of Churchill Falls (Labrador) Corporation (CF(L)Co) since 1985, involvement in the Lower Churchill Project since the 1970s, and other non-regulated activities. Policies and procedures governing the accounting for non-regulated activities have been in place, and have been subject to external review. With the establishment of Nalcor, intercompany activity has increased and it was recognized that intercompany guidelines, processes and costing methodologies would need to evolve.

Since 2007, there has been continual review of intercompany charges within Nalcor companies, including Hydro, resulting in a number of enhancements. Intercompany guidelines, processes and costing methodologies were updated to ensure they were appropriate and reflective of cost-based pricing. A number of positions and business operations were transferred from Hydro to Nalcor in order to more closely reflect organizational changes. In 2010, mandatory time sheets for all employees were introduced requiring employees to record all paid hours. Prior to this change, many of Hydro's employees were using an exceptional time sheet[16] recording basis. In October 2012, at the request of Nalcor, Deloitte & Touche LLP, an independent third party, completed a review of the processes and procedures used by Nalcor to recover costs among affiliates. A copy of this review was previously filed with the Board. Further

[16] Employees were not required to report hours unless on leave or doing work for capital jobs or other lines of business.

details on intercompany guidelines, processes and results are included in the Finance evidence.

1.4.2 Employees

Hydro's mandate is carried out by a highly-skilled workforce of trades workers, engineers and business professionals. As the population of rural Newfoundland and Labrador continues to decline, coupled with an anticipated shortage of workers in the engineering, trades and technical fields, not only in the Province, but nationally and internationally, there is increasing pressure on employee retention and recruitment in Hydro. In addition, the demographics of Hydro's workforce are such that, in some key areas, there is increasing retirement eligibility.

Recognizing these growing workforce pressures and the importance of a stable workforce, Hydro has been actively seeking ways to ensure its success in employee retention, recruitment and replacement. Since the last GRA in 2006, Hydro increased its wage and benefits package to become more competitive with industry and the other Atlantic Canada region electric utilities. This became particularly necessary after Hydro's wages were frozen in 2005 and then in 2006 employees received a general increase of 1.5% after which Hydro's wages were still not competitive. In an increasingly competitive labour market, it is critical that the Company provide a competitive compensation package for its employees to ensure that it continues to have a skilled and motivated workforce to carry out operations and meet the increasing demands of an expanding capital program.

With the expansion of Nalcor, there has been an opportunity to share services among Nalcor and its subsidiaries. Some employees have been transferred to Nalcor and there has been an overall achievement of economies of scale which has benefited Hydro. Hydro's evidence will outline how its workforce remuneration has changed and how it has been restructured to meet increasing challenges, while keeping overall costs near inflationary levels.

1.4.3 Asset Management[17]

Hydro is proactively addressing the strategic management of its $1.4 billion in capital assets. Successful management of these assets today, through appropriate infrastructure renewal and replacement, will optimize the value of assets for stakeholders into the future.

Hydro's Asset Management objectives include:

- Condition and performance of all key assets are known;
- Critical assets do not fail unexpectedly;
- Critical spare parts are identified and available;
- Condition inspections proactively identify the onset of failure;
- Key performance measures are in place for asset performance and the asset management process; and
- Key stakeholders understand and have confidence in the quality and integrity of Hydro's Asset Management approach and support or approve the investments required to meet service and customer expectations.

As outlined in Section 1.2, infrastructure renewal and replacement is the number one challenge faced by Hydro. The Company is addressing Asset Management from two perspectives: the physical assets themselves and the organization of personnel who are responsible for the assets.

[17] Asset management is the comprehensive management of asset requirements, planning, procurement, operations, maintenance, and evaluation in terms of life extension or rehabilitation, replacement or retirement to achieve maximum value for the stakeholders based on the required standard of service to current and future generations. It is a holistic, cradle-to-grave or lifecycle view on how Hydro manages its assets.

1.5 CONCLUSION

Hydro remains committed to least cost means to meet customers' electricity needs, including maintaining cost control and managing its assets effectively. Since 2007, strategic steps have been taken to improve Hydro's capital structure. Additionally, effective with the current GRA, the Province has directed that Hydro target the ROE granted to Newfoundland Power, and that this return would apply to Hydro's entire rate base. These measures align Hydro with other regulated utilities and strategically position the Company to face the challenge of funding its increasing capital investment.

Hydro's evidence outlines how its workforce has changed since 2007. The establishment of Nalcor in 2007 has enabled the sharing of services among the Nalcor companies resulting in cost savings to Hydro. Hydro also has a more competitive wage and benefit package to help enhance retention of its existing skilled workforce and to be competitive in attracting new workers. Overall, Hydro has controlled its operating costs so that they have remained near inflationary levels.

This evidence will demonstrate that the costs to be recovered in the proposed rates are appropriate to ensure that continued safe, environmentally responsible, reliable and least cost electricity supply is available to meet current demand and future growth.

SECTION 2: REGULATED ACTIVITIES

2.1 OVERVIEW

Hydro's service territory encompasses a broad geographic area with challenging operating and environmental conditions. Refurbishment and replacement of the extensive power system infrastructure[1] is the number one challenge faced by Hydro. This has had an impact on Hydro in terms of its asset management strategy and redeployment of its workforce in response to an increasing capital program. Increasing capital expenditures, in combination with increasing fuel consumption and dramatically higher fuel prices since 2007, create upward pressures on customers' rates.

The evidence presented under Regulated Activities outlines the following:

- The success Hydro has had in obtaining new, lower cost sources of renewable energy that have a significant benefit to customers and the environment through lower fuel consumption;
- Hydro's pursuit of operational excellence in safety, environmental responsibility, and reliability;
- Hydro's approach to asset management and the resulting changes in organizational structure;
- Workforce demographics and employee recruitment and retention initiatives;
- Operating expenses overview for the 2007 to 2013 period; and
- Hydro's load and power supply forecasts.

[1] An overview of the provincial electrical systems is provided in Exhibit 3.

2.2 NEW SOURCES OF ELECTRICITY AND OPTIMIZATION OF RESOURCES

2.2.1 Wind Power

The Province of Newfoundland and Labrador has a world-class wind regime that has been utilized on both the Island Interconnected and Isolated systems. Since 2007, Hydro has entered into new Power Purchase Agreements (PPAs) for wind energy on the Island Interconnected System. In addition, Hydro's PPA with Frontier Power for wind energy in Ramea remains in place.

On the Island Interconnected System, wind energy has been generated at St. Lawrence since October 2008 and at Fermeuse since April 2009. There is a PPA in place with NeWind Group Inc. for the St. Lawrence wind energy and a PPA with Elemental Energy for the Fermeuse wind energy. At each site, there are nine 3 MW wind turbines, for a total installed capacity of 27 MW. In each full year of operation, the St. Lawrence site has produced more than 100 GWh, while the site at Fermeuse has produced more than 80 GWh. In 2012, the total Island Interconnected wind generation purchased was 195 GWh. This level of energy production at Holyrood would require the consumption of nearly 310,000[2] barrels of oil, creating more than 160,000 tonnes of GHGs.

On the Island Isolated System, Hydro has a PPA with Frontier Power for wind generation at Ramea. Frontier Power has six - 65 kW wind turbines installed for a total capacity of 390 kW. From 2006 to 2012, the wind generation from Frontier Power has produced, on average, 9.4% of Ramea's annual energy requirements. In 2012, 561 MWh or 13.2% of Ramea's total energy requirements of 4,238 MWh were produced from Frontier Power's wind turbines. This resulted in a reduction of diesel fuel usage at Ramea of 159,000 litres with a displacement of 495 tonnes of GHGs.

[2] Based upon 630 kWh per barrel of fuel, as approved for Hydro's 2007 Test Year.

2.2.2 Exploits Generation

In December of 2008 the Government expropriated the generating assets at Grand Falls, Bishop's Falls, Buchans and Star Lake following the announced closure of the paper mill in Grand Falls-Windsor. Nalcor Energy received the license to operate the assets, and in February of 2009, cessation of paper-making operations resulted in there being surplus power and energy from the Grand Falls, Bishop's Falls and Buchans generating facilities. As directed by Government, the energy from Star Lake and the incremental generation (Incremental Generation) (i.e. greater than 54 MW) at Grand Falls and Bishop's Falls continued to be available to Hydro under the terms of the PPAs which were with the Star Lake Hydro Partnership and the Exploits River Hydro Partnership, respectively. The surplus power and energy result from the base generation (Base Generation) (i.e. 54 MW and less) at Grand Falls and Bishop's Falls and the production at the Buchan's hydroelectric plant, all of which were previously used by ACI to supply the paper mill operations.

Following the paper mill closure on February 12, 2009 and up to December 31, 2010, the Incremental Generation and Star Lake energy received by Hydro continued to be purchased at the rates specified in the PPAs, as directed by Government. The Base Generation energy was not purchased by Hydro because they held no value due to 1) load reductions at the Grand Falls and Corner Brook paper mills, and 2) new wind energy sources at St. Lawrence and Fermeuse. The combined effect of these Industrial Customer load reductions and new wind energy sources was sufficient for Holyrood to be reduced to minimum output.

Subsequent to the paper mill closure, Nalcor Energy was unable to reduce the flow of water in the Exploits River to store the water in the Red Indian Lake reservoir for later production, as this reservoir did not have sufficient space. Furthermore, it had to meet minimum flow requirements in the Exploits River. As a result, Hydro took receipt of the Base Generation rather than having the generating plants on the Exploits River shut down and the energy lost. This was done by displacing Hydro's hydraulic production, resulting in increased water levels in Hydro's reservoirs. This action, in effect, enabled the storage of the Base Generation for potential future disposition unless it caused water spillage from Hydro's reservoirs. If there was water spillage from Hydro's reservoirs, the equivalent energy in the spilled water would be deemed to be from the Base Generation and would no longer be available for future use. Spillage did occur in 2010 and 2011, resulting in all of the Base Generation energy produced up to the end of 2011, except 448 GWh, being spilled.

On July 25, 2011, Hydro received Government direction to pay for energy received from the Grand Falls, Bishop's Falls, Buchans and Star Lake facilities at 4¢/kWh, effective January 1, 2011. Further direction has been provided to Hydro, extending these arrangements until June 30, 2014.

The following table outlines the purchases from these facilities since February 12, 2009.

Table 2.1

Energy Purchases from Exploits Generation
February 12, 2009 - December 31, 2013 (Forecast)

	2009		2010		2011		2012		2013F	
	Energy (GWh)	Cost ($000)	Energy (GWh)	Cost ($000)	Energy (GWh)	Cost ($000)	Energy (GWh)	Cost ($000)	Energy (GWh)	Cost ($000)
Exploits River Project	161	12,427	112	8,664						
Star Lake	126	8,674	140	11,232	130	5,193	144	5,778	141	5,635
Nalcor Grand Falls, Bishops Falls and Buchans[(1)]	-	-	-	-	511	20,425	586	23,436	622	24,865
Totals	287	21,101	252	19,896	641	25,618	730	29,214	763	30,500

Notes:
1. The base energy from the Nalcor operated generation at Grand Falls, Bishops Falls and Buchans became available to the Island Interconnected System following shutdown of the paper mill on February 12, 2009.

The 2013 production level from the Exploits Generation is forecast to be 763 GWh. A detailed description of the methodology and assumptions used in the 2013 hydraulic generation forecast is in Section 2.7.

2.2.3 Conservation and Demand Management

During its 2006 GRA, Hydro outlined its planned approach regarding energy conservation. As described in Exhibit 1 of this evidence, an energy efficiency team has been established with a mandate to develop and implement demand and energy conservation programs both internally for Hydro and externally for customers. The following is a summary of the energy savings related to the activities completed as of December 31, 2012.

Table 2.2

Hydro's Annual Energy Savings (MWh)				
	2009	**2010**	**2011**	**2012**
Windows	12	37	61	136
Insulation	31	126	407	382
Thermostats	6	35	27	53
Coupon Program	-	64	256	-
Commercial Lighting	3	10	227	95
Industrial	-	-	165	3,172
Isolated Systems Energy Efficiency Program				1,673
Isolated Systems Business Efficiency Program				3
Total	**52**	**272**	**1,143**	**5,514**

CDM activities since 2007 include:

- Participation, along with NP, in the production of two five-year CDM plans;
- Participation in and promotion of rebate programs related to energy efficient products;
- Participation in government sponsored conservation activities;
- Establishment, in conjunction with NP, of the takeCHARGE brand for energy efficiency programs;
- Establishment of energy efficiency activities throughout Hydro’s facilities;
- Participation in trade shows and presentations; and
- Establishment of customer and class-specific programs.

2.2.4 Ramea Wind-Hydrogen-Diesel Facility

The Ramea Wind-Hydrogen-Diesel facility is a Research and Development (R&D) project, the capital costs for which were not incurred by the ratepayer. The construction and installation of the wind-diesel system was approved by Board Order No. P.U. 31(2007).

The scope of the project involved the supply, installation and commissioning of the following major components:

- Energy Management System;
- Hydrogen (H_2) Electrolyser;
- H_2 Internal Combustion Engine Genset – five 50 kW Units;
- H_2 Storage;
- System Integration components; and
- Wind Farm – three 100 kW Units.

The purpose of this R&D effort is to lay the groundwork for further study of the potential to provide a cost-effective, renewable energy alternative to remote diesel systems. Since 2007, the project has had a number of technical challenges that have delayed its completion. Most of the delays have been associated with late deliveries of specialized equipment or were a result of the challenges associated with this new technology. Nalcor will continue to study the economics of operating and maintaining this system while considering the environmental benefits of reduced diesel fuel consumption. The study will also provide for technical learning opportunities to develop techniques to fully optimize project components for possible future installations.

Despite delays and integration issues, the first energy was produced from the wind generation on December 12, 2009. Over the course of its operation, and up to December 31, 2012, 493 MWh of energy were produced for the community. This has resulted in a reduction in diesel fuel usage at Ramea of 138,000 litres and a displacement of 436 tonnes of GHGs.

2.3 OPERATIONAL EXCELLENCE

Hydro is focused on delivering value to the electricity consumers of the Province through operational excellence.

2.3.1 Safety and Health

Foremost among Hydro's goals is the safety of its employees, contractors, and the general public.

The Company has a targeted approach towards injury prevention, communication and awareness, and visible leadership and support at all levels. There is also a focus on supporting and recognizing the areas with exceptional safety performance to enable continued motivation and sustain a positive and strong safety culture.

A company-wide process for collecting and reporting hazards, near misses and both safe and unsafe practice observations remains a key component of Hydro's safety program. This Safe Workplace Observation Program (SWOP) focuses on reporting safety observations. This data is used to identify actions to continually improve safety for employees, contractors and the public. Hydro continues to strengthen its focus on the Work Protection Code[3] and Work Methods[4] which are two fundamental components of a utility's safety program. Hydro's safety program has been a joint union and company effort, and can attribute its current success to the broader involvement by both union and non-union workers. As a result of the data collected from the SWOP database, Hydro increased its engagement in enabling contractor safety, promoting public safety around electrical equipment, and standardizing and increasing awareness of permits

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[3] The Work Protection Code is a document containing rules which must be followed by all individuals required to perform work on transmission and distribution systems, auxiliary metering circuits, and at generating facilities. The rules and procedures ensure protection for individuals working in an environment into which harmful energy can be introduced.

[4] Work Methods are documents that instruct employees on how to properly perform critical tasks in a safe manner.

required to complete work near a transmission or distribution line. These efforts contribute to overall safety.

Hydro also has wellness programs for employees which have focused mainly on heart health, with initiatives including wellness clinics, stress management sessions, and fitness reimbursement programs for certain wellness related activities.

2.3.2 Environmental Performance and Air Emissions

Over the past few years, Hydro has improved its environmental performance, while maintaining the safe and reliable delivery of energy to residents of the Province. Hydro's commitment to the environment helps ensure a healthy and sustainable environment for future generations of Newfoundlanders and Labradorians.

To facilitate this environmental performance, Hydro continues to use the ISO 14001 Certified Environmental Management Systems, which provide a framework for an organization's environmental responsibilities and is an integral component of the organization's business operations and continuous improvement focus.

The environmental commitment to sustainable practices in its operations is demonstrated throughout the Company's activities. Hydro has integrated initiatives in alternative energy, energy conservation and community partnerships into its operations throughout the Province. Hydro also takes very seriously its responsibility to preserve sensitive habitats and vegetation and makes every effort to ensure minimal environmental impacts through its operations.

2.3.2.1 Environmental Management Areas

Currently there are four Environmental Management areas[5] within Hydro with identified environmental aspects. Environmental aspects are elements of a department's activities, products, or services that can interact with the environment. Significant

[5] Services Management, Thermal Generation, Hydro Generation and Transmission and Rural Operations.

environmental aspects are managed either through Environmental Management Programs or standard operating procedures.

In 2012, Hydro completed 96% of its Environmental Management Systems targets, which are initiatives undertaken to improve environmental performance.

2.3.2.2 Emissions

In 2012, approximately 84% of the net electricity supplied by Hydro was generated from clean hydroelectric power. However, to meet all the electricity demand each year, in supplementing Hydro's hydroelectric generation and purchases, a portion of the Island Interconnected System electricity still must come from fossil-fuel fired generation at Holyrood. From 2007 to 2012, 13-20% of the Island Interconnected System net energy requirements were supplied by Holyrood. Hydro also operates 25[6] diesel plants across the Province, primarily to supply isolated communities. In 2012, approximately 72% of the supply in these isolated areas was from fossil fuel generation.

The Company continues to incorporate alternative sources of energy into the Province's energy supply to reduce emissions from burning fossil fuels and the related costs. As stated previously, in 2012, Hydro purchased 195 GWh of clean energy from the two Island Interconnected wind projects.

Overall, thermal production at Holyrood decreased in 2012 by 3.4% from 2011, primarily due to decreased requirements from the plant for Avalon transmission support. The Holyrood plant produced just over 13% of the energy supplied by Hydro in 2012, down slightly from 14% in 2011. The decreased energy production from the Holyrood plant in 2012 resulted in a 2.5% decrease in carbon dioxide (CO_2) emissions. The decrease in CO_2 emissions is directly attributed to less fuel being consumed. The sulphur dioxide (SO_2) emissions from the plant in 2012 were equivalent to those experienced in 2011.

[6] Twenty-one Isolated diesel plants, and diesel units in St. Anthony, Hawkes Bay, Happy Valley-Goose Bay and Natuashish (which is operated by Hydro on behalf of the Mushuau Innu First Nation).

Total emissions for CO_2, and SO_2 for Holyrood, gas turbine facilities and isolated diesel generating stations are calculated using formulas approved by the provincial Department of Environment and Conservation. Hydro's overall air emissions are dominated by those resulting from production at the Holyrood Generating Station.

Emissions for the Island Interconnected System, including Holyrood, and interconnected gas turbines and the standby diesel plants are outlined in the following charts:

Chart 2.1

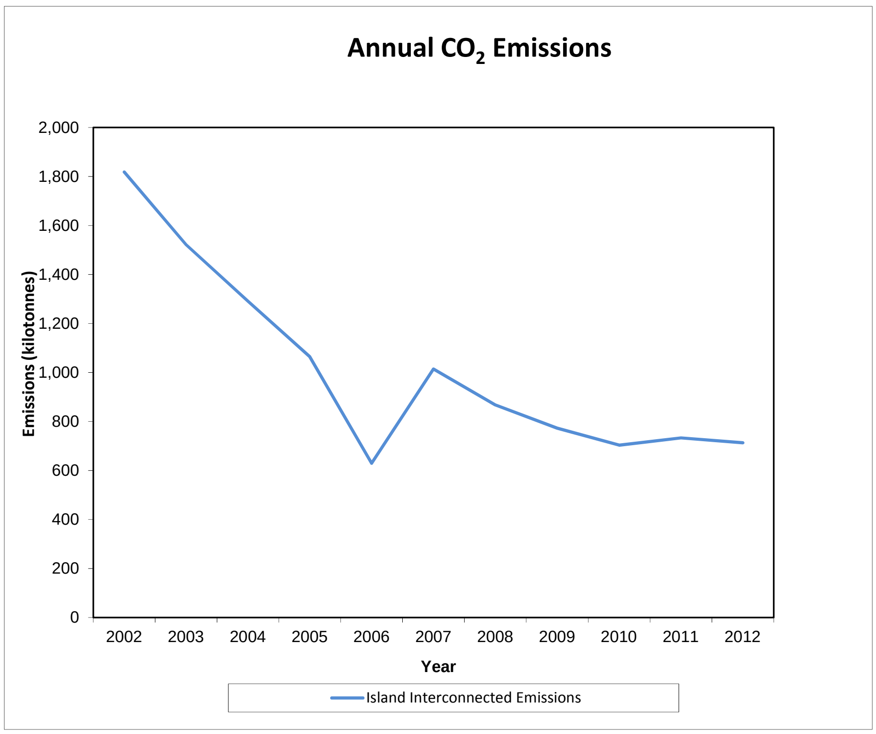
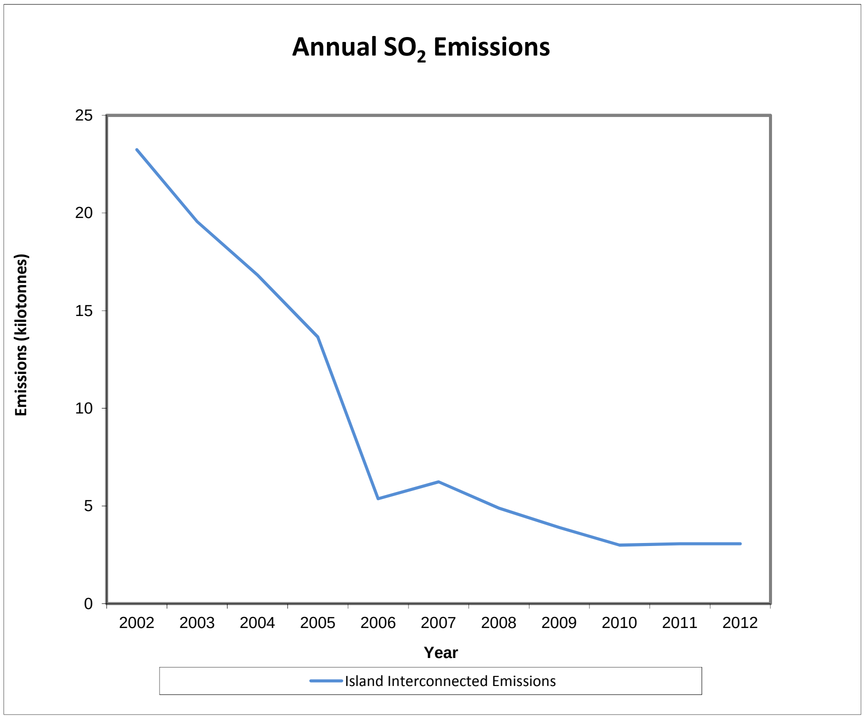


Chart 2.2



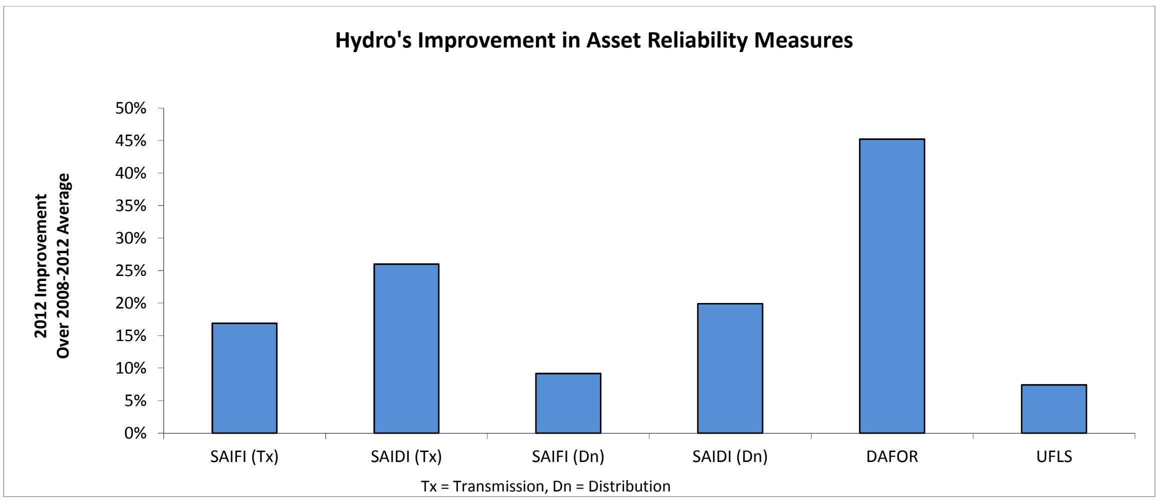
Emissions of CO_2 and SO_2 for Hydro's other systems were calculated to be approximately 41.3 and 0.05 kilotonnes, respectively.

2.3.3 Reliability

Hydro continues to focus considerable effort through capital investments and sound asset management practices on improving the service reliability of the bulk transmission system. The Company's transmission system performance, as measured by the System Average Interruption Frequency Index (SAIFI) improved by 17% in 2012 compared to the average performance for the 2008-2012 period. Against the same period, Hydro's transmission System Average Interruption Duration Index (SAIDI) improved by 26% in 2012. In the area of distribution performance, also measured by SAIFI and SAIDI, there were improvements of 9% and 20% in 2012 over the 2008 to 2012 average, respectively. The Derating Adjusted Forced Outage Rate (DAFOR) for generation improved by 45% in 2012 compared to the five-year performance for the 2008 to 2012 period. Hydro also tracks the number of underfrequency load shedding (UFLS) incidents to measure the number of events in which the shedding of customer load is required to counteract a generator trip. Against its five-year average, UFLS improved by 7% in 2012. It should be noted that in 2011 there were only three events recorded which was the best performance since these events started being recorded in 1998.

Hydro's performance on these asset reliability measures is summarized in Chart 2.3 below.

Chart 2.3



2.3.4 Asset Management and Capital Investment with an Aging Asset Base

Hydro's responsibility for reliable and least cost service to meet the needs of its customers is a challenging balance which is addressed through sound asset management. This approach requires that assets are kept in reliable working condition through a structured preventative maintenance program, with the required corrective maintenance and replacement or refurbishment when necessary. Asset replacements are planned based on condition assessments, maintenance and operating history, changing technology, expected service lives and knowledge of individual assets. Asset additions and upgrades are also determined through analysis of options to address the long-term, least cost supply of electricity.

The current condition of Hydro's asset base is a reflection of the history of the electricity industry in general and, in particular, the Province. In the 1960s, there was a significant expansion in assets to fulfill the mandate of the Newfoundland and Labrador Power Commission, Hydro's predecessor, which was to bring electricity to many areas of the Province and to build an infrastructure which connected the many diverse and isolated electrical systems in the Province. Many of the assets constructed during that time have now reached the end of their expected service lives and many others are approaching that point. Other major assets, such as hydroelectric plants like the Bay d'Espoir Generating Station, have not reached the end of their expected service lives, however, some of the components, auxiliary equipment and systems are at, or near, the end of their service lives. This, along with increasing upward pressure on labour and material market costs, has resulted in growth of Hydro’s capital investments which is expected to continue.

In 2010, Hydro updated its organizational structure to support a renewed Asset Management Strategy which aligns with:

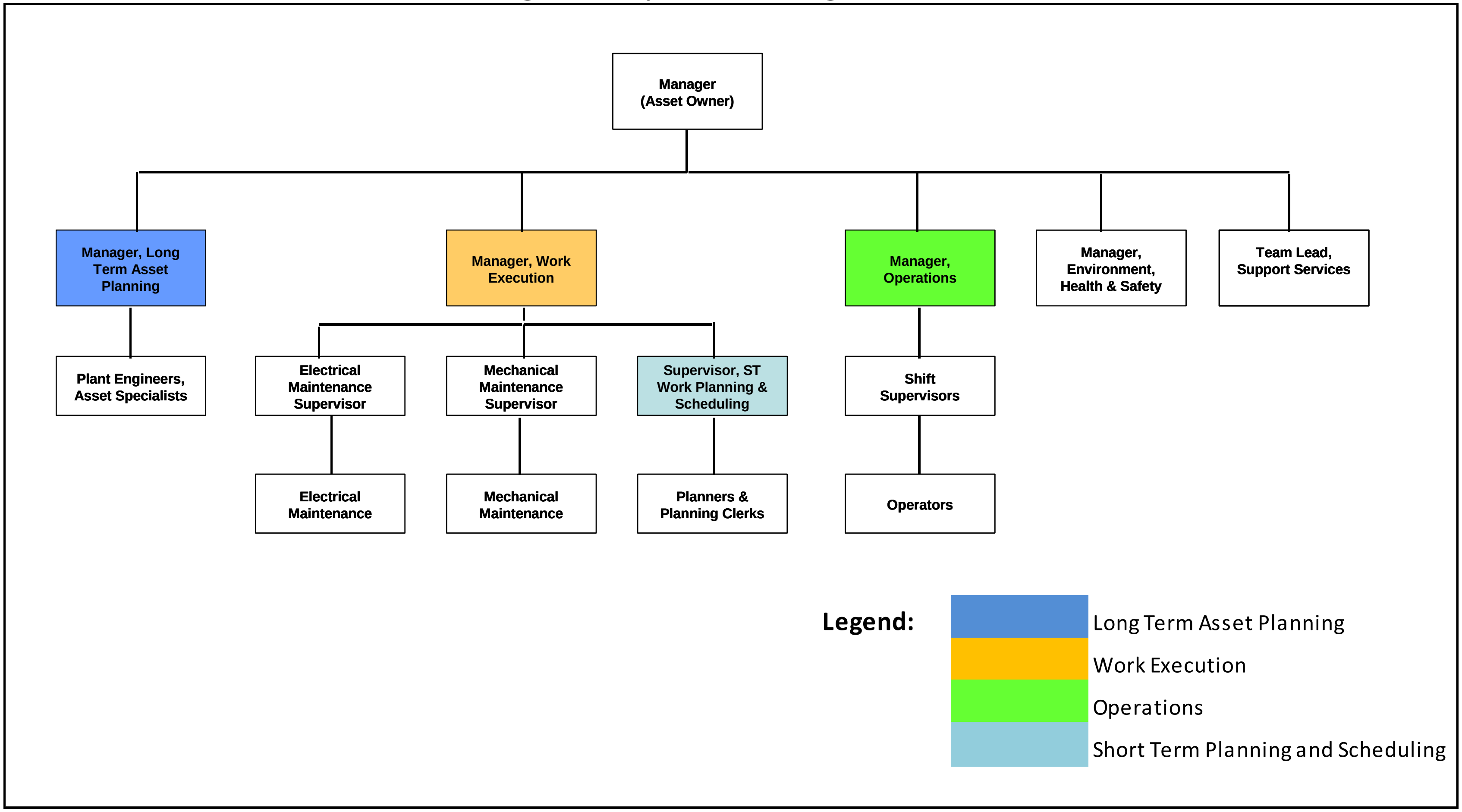
- Asset performance expectations;
- Consistent maintenance practices for similar assets; and
- Asset renewal or replacement programs.

As a result of this reorganization, five key functions have been established consistently throughout all operating departments.

1. Long-Term Asset Planning;
2. Short-Term Work Planning and Scheduling;
3. Work Execution;
4. Operations; and
5. Support Services.

Figure 2.1 shows a representative organizational structure reflecting these functions.

Figure 2.1
Asset Management Representative Organizational Structure



In addition to the changes in the operating departments, a centralized Office of Asset Management (OAM) was created in the Project Execution and Technical Services division. The OAM has responsibility for oversight and direction for asset management and provides support to the operating departments, ensuring a consistent implementation of asset management best practices throughout the Company.

The changes in roles are included in Exhibit 1, Organizational Responsibility.

In addition to the reorganization noted above, asset management activities have focused on:

- Reviewing the five year capital plan, updating both the content and timing of projects based on knowledge gained from inspections (e.g. onsite physical inspections as well as feedback from hands- on operators and maintainers) and targeted formal condition assessments;
- Refreshing the full 20 year capital plan;
- Preparing and executing plans to refresh:
    - critical spare requirements; and
    - standards, planning criteria and operating parameters;
- Developing metrics for asset management; and
- Developing a consistent approach to performing root cause failure investigation.

2.3.4.1 Holyrood

Holyrood is the second largest generating plant on the Island Interconnected System, and, as a thermal plant, is significantly more complex than its hydroelectric counterparts. Units 1, 2 and 3 were put in service in 1970, 1971, and 1980, respectively. Each has passed the normal 30-year design life for such a facility. Units 1 and 2 were modified in the late 1980s to increase their capacity from 150 to 170 MW each. This was achieved by availing of the overcapacity inherently designed in equipment of that vintage and by modifying the plant's auxiliary systems. Units of a similar age in other electric utilities have been retired or have been subjected to life assessment and extension studies. Those not retired received costly major refurbishments to extend their useful lives or have been redeveloped into other configurations, such as combined cycle power plants.

Maintaining Holyrood as a reliable source of energy and capacity for the Island Interconnected System is essential prior to the Labrador interconnection. The closure of the paper mill at Grand Falls, the reductions in load at CBPP and the development of two wind farms have resulted in reduced energy requirements from Holyrood in recent years. However, Holyrood remains a vital generation asset for capacity and energy, particularly in light of growing customer demand due to utility load increases and the ramp up of operations at the Vale nickel processing facility. It should also be noted that during a repeat of the critical dry sequence, annual required production from Holyrood would be significant, up to 3,000 GWh per year. In addition to ensuring reliability, environmental issues with the plant and various legislative and regulatory requirements contribute to ongoing significant expenditures at the facility.

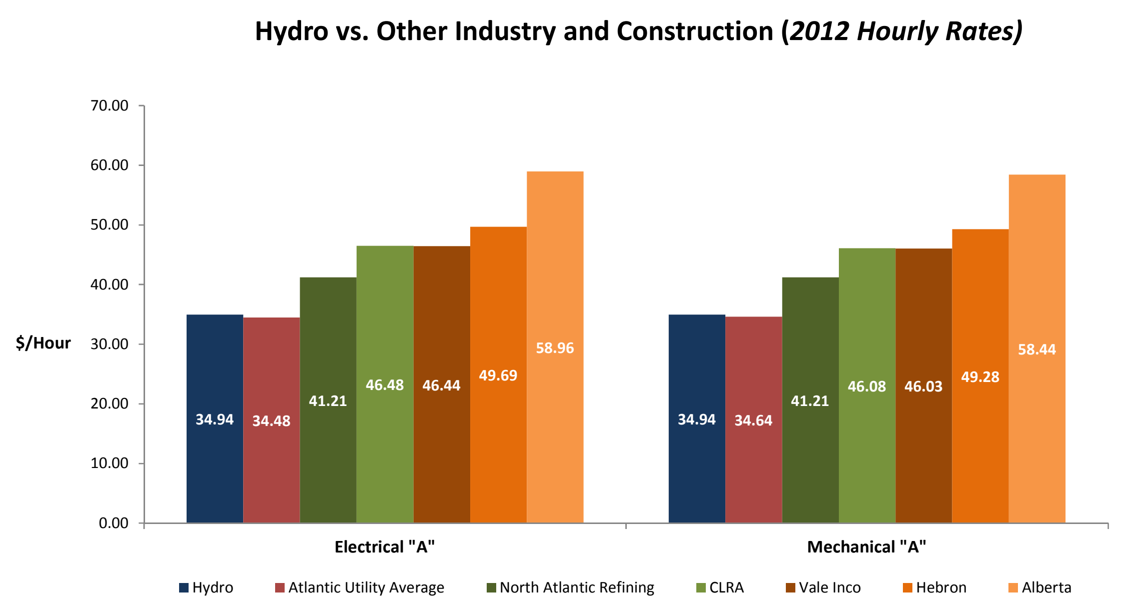
2.3.5 Maintaining a Skilled Workforce

A skilled and motivated workforce is critical for ensuring safe and reliable service to Hydro's customers. In 2006, a focus on recruitment and retention was initiated as there was increasing incidence of voluntary resignations. A key aspect of Hydro's recruitment and retention strategy has been to ensure the Company is competitive on salaries and wages in an increasingly tight labour market. Hydro has expended considerable effort to ensure its compensation is adequate to both attract and retain employees.

With respect to its unionized groups, Hydro negotiated two series of special wage adjustments in order to bring its employees' wages in line with NP and the average wages of other Atlantic Canada electric utilities. Over the period 2007-2009, trades and technology employees, who represent the significant majority of Hydro's operations group, received an additional $1.65/hour wage and benefit increase to help close this gap. In 2010, a further trades adjustment of approximately 4.8%, plus annual general adjustments of 6.5%, 4%, 4%, and 4% over the period 2010 to 2013 were negotiated in order to completely close the gap and achieve parity and competitive positioning with other Atlantic Canada electric utilities to aid in recruitment and retention efforts.

An additional factor for Hydro in applying these changes has been the rates paid in the provincial construction industry. Chart 2.4 presents a comparison of rates between Hydro, the average across the Atlantic Canada electric utilities and the provincial construction rates, using Electrical "A" and Mechanical "A" as reference points. While it is not necessary to fully match the construction rates in order to be competitive, it is imperative that the Company wage rates are in reasonable proximity from a recruitment and retention standpoint. Hydro will continue to monitor its positioning relative to these sectors.

Chart 2.4



Notes:
1. Construction Labour Relations Association (CLRA) and project construction rates are gross hourly rates i.e., they include allowances for vacation, holidays, pension, insurance, training, etc.
2. Hebron rates include a project premium of $3.00/hour, paid quarterly
3. Atlantic Utility Average is based on Hydro, NL Power, NS Power, and NB Power
4. Maintenance rates at NARL are a multi-skill rate which are ~ 7% above the basic rate, to compensate for performance of ancillary duties.

In its non-union group, annual general economic adjustments mirrored those that were provided to the Company's unionized employees over the period 2010 to 2012. In addition, in 2007 it was necessary to re-establish the historical wage differential between front-line supervisors and their trades and technology employees. In the absence of this adjustment, the differential of between 17% and 20% which existed before market adjustments initiated in 2007 would have eventually eroded to below 10%, causing difficulties from an internal recruitment and retention standpoint in relation to front-line supervisors.

Additionally, in 2012 a number of non-union salary scales were adjusted upwards by 1.3% to 7.9% based on an analysis of non-union salaries. The adjustments were required to ensure Hydro is more competitive with the external labour market.

All of the above compensation measures resulted in annual wage and salary increases which have been above the rate of inflation. However, in all cases, they have been implemented for sound recruitment and retention reasons, and to help ensure the sustainability of Hydro's operations. Increased recruitment needs driven by retirements, in the context of an increasingly tight and changing labour market, have compelled the Company to take the steps necessary to ensure it can minimize the loss of knowledge and skills. The electric utility industry is highly specialized and Hydro has taken action to compete for the people and skills it requires to maintain operations and complete its increasing capital program.

As in the past, Hydro will continue to take a multi-faceted approach to its recruitment and retention strategy, by emphasizing non-compensation initiatives as well as compensation-based approaches. This will include a continuing focus on Apprenticeship and Engineer in Training programs, assessing the possible redeployment of Full Time Equivalents (FTEs) when vacancies occur, focusing on employee engagement, and implementing organizational and process efficiencies where appropriate.

Hydro does anticipate that the challenge of maintaining wage and salary costs within inflationary levels will continue. High levels of recruitment, driven by retirements, high levels of construction and major project activity in the Province and elsewhere, and a shrinking labour force will continue to place pressure on wage and salary competitiveness.

2.4 OPERATING EXPENSES

This section provides an overview of Hydro's Operating Expenses by both cost category and functional areas. Cost category is comprised of three major classifications: Salaries and Benefits, System Equipment Maintenance (SEM) and Other Operating Expenses, shown in Schedule 1, page 9 of 11 in Section 3 of this evidence. Functional areas include Operations and Corporate Services. Operations is comprised of Transmission and Rural Operations (TRO), Generation, and System Operations[7]. Corporate Services includes Leadership and Associates, Human Resources and Organizational Effectiveness (HROE), Finance, Project Execution and Technical Services, and Corporate Relations. An overview of operational expenses by functional area is provided in Schedule 1 of this evidence.

Cost recoveries related to operating expenses are also discussed in this section. Cost recovery is related to services provided by Hydro to other Nalcor lines of business or external parties as well as CDM costs. The cost recovery methodology is explained in Section 3.4.2.

2.4.1 Operating Expenses by Cost Category

A breakdown of operating expenses by cost category is shown in Table 2.3.

[7] In April 2013, Hydro reorganized as indicated in Exhibit 1, page 5, Section 3.0. This reorganization is not reflected in this section of the evidence and costs as previously organized are included.

Table 2.3

Operating Expense by Cost Category
($millions)

Cost Category	**2007 Actual**	**Cost Recovery**	**2007 Net**	**2013 Forecast**	**Cost Recovery**	**2013 Net**	**Net Change**
Salaries and Benefits	58.9	(0.6)	58.3	77.2	(2.9)	74.3	16.0
System Equipment Maintenance	23.5	(0.4)	23.1	21.5	(0.8)	20.7	(2.4)
Other Operating Expenses	19.4	(0.2)	19.2	26.4	(3.6)	22.8	3.6
Total Operating Expenses Before Other Cost Recoveries	101.8	(1.2)	100.6	125.1	(7.3)	117.8	17.2
Other Cost Recoveries	-	(2.9)	(2.9)	-	(4.0)	(4.0)	(1.1)
Total Operating Expenses	**101.8**	**(4.1)**	**97.7**	**125.1**	**(11.3)**	**113.8**	**16.1**

Total operating expenses of $113.8 million for the 2013 forecast are $16.1 million higher when compared to $97.7 million for 2007. The change primarily relates to increases in salaries and benefits and other operating expenses. These were partially offset by increased cost recoveries and a reduction in SEM expenses, resulting from the expiration of amortization from previously deferred major extraordinary repairs.

2.4.1.1 Salaries and Benefits

As indicated in Table 2.3, the 2013 salaries and benefits expense forecast of $74.3 million is $16.0 million higher than the 2007 actual costs of $58.3 million, after cost recoveries. A further breakdown of the $16.0 million change in salaries and benefits by cost type is shown in Table 2.4 and an explanation of the major changes follows.

Table 2.4

Salary and Benefit Expenses ($millions)			
Cost Type	**2007 Actual**	**2013 Forecast**	**Change**
Salaries	49.5	67.5	18.0
Overtime	6.2	8.6	2.4
Gross Salaries	55.7	76.1	20.4
Capital Labour Costs	(11.3)	(19.4)	(8.1)
Total Salaries	44.4	56.7	12.3
Fringe Benefits	7.1	8.6	1.5
Employee Future Benefits	5.9	9.3	3.4
Group Insurance	1.5	2.6	1.1
Total Benefits	14.5	20.5	6.0
Total Salaries and Benefits, before cost recoveries	58.9	77.2	18.3
Cost Recoveries	(0.6)	(2.9)	(2.3)
Total Salaries and Benefits, net of Cost Recoveries	**58.3**	**74.3**	**16.0**

Salaries

As shown in Table 2.4, the 2013 forecasted salary costs of $67.5 million are $18.0 million higher compared to $49.5 million for the 2007 actual costs.

As discussed in Section 1 of the evidence, there is a tightening labour market in the Province, which has resulted in changes to the compensation packages offered to Hydro employees. Furthermore, during union negotiations in 2010, it was recognized that there were differentials in the wages offered by Hydro compared to NP and other Atlantic Canadian utilities, primarily due to Government's prior wage restraints, of which Hydro was a part. In order to attract and retain a qualified workforce, Hydro has provided wage and benefit increases over the 2007 to 2013 period, enabling Hydro to be competitive with market.

Since 2007, Hydro has negotiated two union agreements which have resulted in general salary increases and a number of hourly rate increases. The first negotiated union agreement resulted in increases of 3.0% effective April 1, 2007, 2008, and 2009 of each year and 6.5% effective April 1, 2010. The second resulted in increases of 4.0% on April 1, 2011, 2012, and 2013. Non-union personnel also received similar wage and benefit increases. Adjustments were made to front line supervisor's wage rates, to maintain wage differentials between them and their direct reports.

See Regulated Activities Section 2.3.5 for additional discussion on workforce management and salaries.

Overtime

Annual overtime costs vary based on circumstances such as emergencies, which may arise due to weather and equipment related outages, labour shortages and capital project requirements. The 2013 forecasted overtime costs of $8.6 million are $2.4 million higher compared to $6.2 million for the 2007 actual costs. This increase is a result of higher overtime relating to capital projects in the amount of $2.8 million, offset by a $0.4 million reduction in operating overtime. The increase in capital overtime is primarily due to an increase in Hydro's capital program and higher salary costs over that period.

Capital Labour Costs

Internal labour and overtime costs associated with Hydro's capital projects are capitalized. Table 2.5 shows the breakdown of capital labour costs.

Table 2.5
Capital Labour
($millions)

Cost Type	2007 Actual	2013 Forecast	Change
Capital Labour	(7.6)	(14.9)	(7.3)
Capital Overtime	(1.7)	(4.5)	(2.8)
Overhead Allocation	(2.0)	-	2.0
Total Capital Labour	**(11.3)**	**(19.4)**	**(8.1)**

The 2013 forecasted capital labour costs of $19.4 million are $8.1 million higher compared to $11.3 million for the 2007 actual capital labour costs. The increases in capital labour are primarily attributable to an increase in Hydro's capital program which has more than doubled since 2007, coupled with salary and benefit increases. In 2012, the Company discontinued the allocation of overhead to capital labour, as approved in Board Order No. P.U. 2(2012).

Fringe Benefits

Fringe benefits include Canada Pension Plan (CPP), Employment Insurance (EI), Public Service Pension Plan (PSPP), and Workers Compensation premiums and contributions paid by Hydro. The $8.6 million of fringe benefits included in the 2013 forecast is $1.5 million more than 2007 actual costs of $7.1 million, mainly due to increased premiums for EI and CPP and increased contributions to the PSPP in conjunction with salary increases previously described in this Section.

Employee Future Benefits

Employee future benefit (EFB) costs relate to severance payments upon retirement and health benefits provided to retirees on a cost-shared basis. These costs are forecasted using actuarial methods and include assumptions as to future benefit costs and interest rate expectations. The EFB costs of $9.3 million, included in the 2013 forecast, are $3.4 million higher than the 2007 actual costs of $5.9 million. This increase is primarily due to a reduced discount rate based upon the 2012 actuarial projections and an increasing number of plan members, coupled with higher medical costs. Section 3.8.3 includes a further discussion on EFBs.

Group Insurance

Group insurance benefits provide Hydro employees with health, dental, life insurance and accidental death and dismemberment coverage. Insurance costs for the 2013 forecast of $2.6 million are $1.1 million higher than the 2007 actual cost of $1.5 million. This is mainly due to higher employee salaries and associated life insurance premiums and self-insured experience claim increases for health and dental insurance.

Cost Recoveries

As shown in Table 2.4, cost recoveries related to salaries and benefits for the 2013 forecast of $2.9 million are $2.3 million higher when compared to the 2007 actual cost recoveries of $0.6 million. In 2007, Hydro was recovering salary and benefit costs primarily from CF(L)Co. Subsequent to 2007, additional salary and benefit costs were recovered from other Nalcor lines of business, primarily related to Safety and Health, HROE, Information Systems and Supply Chain services. Additionally, labour costs associated with the CDM program contribute to Hydro forecasting a total recovery of $2.9 million for salaries and benefits in the 2013 Test Year.

2.4.1.2 System Equipment Maintenance

As shown in Table 2.3, when the 2013 forecast of $20.7 million is compared to the 2007 actual cost of $23.1 million, SEM expenses have decreased by $2.4 million, primarily attributable to the following:

- A reduction of $2.1 million in amortization expenses for the Asbestos Abatement Program and Unit 2 boiler repairs at Holyrood that were fully amortized prior to 2013;
- A reduction of $1.7 million in overhaul expenses in the 2013 forecast due to the decision to capitalize major overhauls as approved by the Board in Order No. P.U. 2(2012); partially offset by an increase of $0.9 million in vegetation control program costs.

2.4.1.3 Other Operating Expenses

As shown in Table 2.3, the 2013 other operating expenses forecast of $22.8 million is $3.6 million higher than the 2007 actual costs of $19.2 million, after cost recoveries. A breakdown of the $3.6 million change in other operating expenses is shown in Table 2.6 and an explanation of the major changes follows.

Table 2.6

Other Operating Expenses ($millions)							
Cost Type	**2007 Actual**	**Cost Recovery**	**2007 Net**	**2013 Forecast**	**Cost Recovery**	**2013 Net**	**Change**
Insurance	1.7	-	1.7	2.2	-	2.2	0.5
Transportation	2.0	-	2.0	2.3	-	2.3	0.3
Office Supplies	2.3	-	2.3	2.6	(0.4)	2.2	(0.1)
Building Rental	1.2	-	1.2	1.1	(0.1)	1.0	(0.2)
Professional Services	3.9	(0.1)	3.8	7.0	(1.6)	5.4	1.6
Travel	2.9	-	2.9	3.2	(0.1)	3.1	0.2
Equipment Rental	1.1	-	1.1	1.7	(0.1)	1.6	0.5
Miscellaneous	4.3	(0.1)	4.2	6.3	(1.3)	5.0	0.8
Total Other Operating Expenses	**19.4**	**(0.2)**	**19.2**	**26.4**	**(3.6)**	**22.8**	**3.6**

Professional Services

As shown in Table 2.6, professional services have increased by $1.6 million from $3.8 million in 2007 actual costs to $5.4 million in the 2013 forecast, after cost recoveries. A detailed breakdown of professional services is provided in Table 2.7.

Table 2.7

Professional Services ($millions)			
	2007 Actual	**2013 Forecast**	**Change**
Consultants	2.2	3.7	1.5
GRA and Board Costs	0.6	1.8	1.2
Software Costs	1.0	1.4	0.4
Audit and Legal	0.1	0.1	-
Cost Recoveries	(0.1)	(1.6)	(1.5)
Total Professional Services	**3.8**	**5.4**	**1.6**

The increase is mainly due to:

- Consultant costs are forecasted to be $1.5 million higher in 2013 compared to the 2007 actual costs, mainly due to $1.0 million related to CDM programs, which is fully offset in cost recoveries and $0.4 million for environmental site assessments and remediation;

- GRA and Board costs in the 2013 forecast have increased by $1.2 million from the 2007 actual costs, primarily due to increases of $0.6 million in external fees related mainly to regulatory services, $0.3 million in the Board annual assessment and $0.1 million in amortization of GRA Costs;
- Software costs have increased by $0.4 million, primarily due to vendor price increases and additional maintenance associated with new software programs; and
- An offset, resulting from an increase of $1.5 million in cost recoveries, is primarily related to the deferral of CDM costs of $1.0 million and $0.5 million recovered from other Nalcor lines of business for professional services costs.

Miscellaneous Expenses

Miscellaneous costs have increased by $0.8 million from the $4.2 million in 2007 to the 2013 forecast of $5.0 million, after cost recoveries. This is mainly attributable to higher municipal and employer payroll taxes of $0.6 million and an increase of $0.1 million in training costs. Training expenses have increased primarily due to the discontinuation of the capitalization of training expenses related to new asset additions, as approved by the Board in Order No. P.U. 13(2012).

Insurance Costs

Insurance costs, which cover property/boiler and machinery, liability and excess, directors' and officers' liability, brokerage fees and other miscellaneous insurances, have increased by $0.5 million from the 2007 actual costs of $1.7 million to the 2013 forecast of $2.2 million. Increases in property and equipment replacement values are the primary contributor to the increase. Hydro anticipates an increase in insurance costs during its 2013 policy renewal process.

Equipment Rentals

Equipment rental costs are comprised of telecommunication costs, equipment rentals and computer bandwidth costs. The 2013 forecast net equipment rental cost of $1.6 million is $0.5 million more than the 2007 actual costs of $1.1 million. When a cost recovery from an external party of $0.4 million for 2013 is applied, the $0.5 million increase is reduced to $0.1 million.

2.4.1.4 Other Cost Recoveries

The increase of $1.1 million, shown in Table 2.3 in other cost recoveries is mainly attributable to $0.9 million for recovery of depreciation costs from other Nalcor lines of business.

2.4.2 Operating Expenses by Functional Area

The major functional areas are Operations and Corporate Services as shown in Schedule 1 of this evidence. Within Operations, costs are grouped into TRO, Generation, and System Operations. Corporate Services includes Leadership and Associates, HROE, Finance, Project Execution and Technical Services and Corporate Relations.

Table 2.8 shows the forecasted 2013 total operating expenses increase of $16.1 million over 2007 Actual costs.

Table 2.8
Operations and Corporate Services Operating Expenses (Net of Cost Recoveries) ($millions)

Operations	2007 Actual	2013 Forecast	Change
Generation (Thermal and Hydraulic)	32.1	33.6	1.5
System Operations	2.3	2.9	0.6
Transmission and Rural Operations (TRO)	34.5	44.6	10.1
Total Operations	68.9	81.1	12.2
Corporate Services	28.8	32.7	3.9
Total Operating Expenses	**97.7**	**113.8**	**16.1**

Increases of $10.1 million in TRO costs and $3.9 million in Corporate Services are the primary contributors to the increase of $16.1 million.

2.4.2.1 Operations

Transmission and Rural Operations

Transmission and Rural Operations has responsibility for the asset management of transmission and distribution systems and associated high voltage terminal stations, 21 isolated diesel systems, diesel units at Hawkes Bay, St. Anthony and Happy Valley-Goose Bay, three gas turbines, the telecommunications network and the mobile fleet.

A summary of operating expenses by cost category for TRO are noted in Table 2.9.

Table 2.9
Transmission and Rural Operations Operating Expenses ($millions)

Cost Category	2007 Actual	2013 Forecast	Change
Salaries and Benefits	20.8	29.7	8.9
SEM Expenses	7.5	8.5	1.0
Other Operating Expenses	6.4	7.1	0.7
Cost Recoveries	(0.2)	(0.7)	(0.5)
Total Operating Expenses	**34.5**	**44.6**	**10.1**

Total TRO Operating Expenses have increased $10.1 million from 2007 actual costs compared to the 2013 forecast. This is primarily due to increases in salary and fringe benefits of $8.9 million which includes the transfer of Inventory and Stores employees in

2010 from Finance. The increase in salaries is related primarily to $6.9 million of cumulative wage increases, including amounts related to the transferred employees, a $2.9 million increase in benefit costs, offset by a $1.0 million change in capitalized salaries.

System Equipment Maintenance expenses are higher by $1.0 million when 2007 actual costs are compared to the 2013 forecast primarily due to an increase in the vegetation control program costs of $0.9 million.

The TRO cost recoveries forecast for 2013 have increased by $0.5 million compared to 2007 actual, largely due to third party cost sharing of mobile radio equipment. A cost recovery of $0.4 million for cost sharing of mobile radio equipment was recorded as a credit in Other Operating Expenses in the 2007 actual costs, rather than as a cost recovery due to a change in classification.

Generation

Hydro's two primary sources of electricity generation on the Island Interconnected System are thermal and hydraulic.

Changes in Operating Expenses from 2007 actual costs to 2013 forecast are shown in Table 2.10.

Table 2.10

Generation Operating Expenses ($millions)			
Cost Category	**2007 Actual**	**2013 Forecast**	**Change**
Thermal Generation			
Salaries and Benefits	9.2	12.7	3.5
SEM Expenses	12.3	8.5	(3.8)
Other Operating Expenses	1.5	0.8	(0.7)
Thermal Generation	**23.0**	**22.0**	**(1.0)**
Hydraulic Generation			
Salaries and Benefits	6.6	8.8	2.2
SEM Expenses	1.7	1.9	0.2
Other Operating Expenses	0.8	0.9	0.1
Hydraulic Generation	**9.1**	**11.6**	**2.5**
Total Operating Expenses	**32.1**	**33.6**	**1.5**

Total Generation Operating Expenses have increased by $1.5 million from 2007 actual costs to the 2013 forecast primarily due to the following:

- An increase of $5.7 million in salaries and benefits costs primarily due to cumulative wage and benefit increases, negotiated union agreements and salary adjustments for front line supervisors to maintain wage differentials with direct reports. Other contributing factors include increases in employee future benefits costs, fringe benefits and group insurance.

- A reduction of $2.1 million in SEM expenses for amortization related to the Asbestos Abatement program and Unit 2 boiler repairs at Holyrood that were fully amortized prior to 2013; and

- A reduction of $1.7 million in SEM overhaul expenses in the 2013 forecast from the 2007 actual costs due to capitalization of major overhauls as approved by the Board in Order No. P.U. 2(2012).

System Operations

System Operations, comprised of the Energy Control Centre (ECC) and engineering support, manages the dispatch of energy across the provincial electrical systems. This includes the operation of the Island and Labrador Interconnected Systems to ensure safe, reliable and efficient delivery of power to customer delivery points.

Changes in System Operations Operating Expenses from 2007 actual costs to the 2013 forecast are noted in Table 2.11.

Table 2.11

System Operations Operating Expenses ($millions)

Cost Category	2007[8] Actual	2013 Forecast	Change
Salaries and Benefits	2.0	2.7	0.7
SEM Expenses	0.1	-	(0.1)
Other Operating Costs	0.2	0.2	-
Total Operating Expenses	**2.3**	**2.9**	**0.6**

Operating Expenses have increased $0.6 million from 2007 actual costs compared to the 2013 forecast. The change in expenses is largely attributable to increased salaries and benefits of $0.7 million.

2.4.2.2 Corporate Services

Hydro's Corporate Services[9] are comprised of Leadership and Associates, Human Resources and Organizational Effectiveness (HROE), Finance, Project Execution and Technical Services and Corporate Relations; all of which provide support to Hydro Operations and other Nalcor lines of business.

Changes in Corporate Services Operating Expenses by cost category from 2007 actual costs to the 2013 forecast are shown in Table 2.12.

[8] 2007 actual costs have been adjusted to reflect the 2012 transfer of Customer Services and Energy Efficiency responsibilities and costs to Corporate Relations, discussed in the Corporate Services Section 2.4.2.2.
[9] See Exhibit 1, page 7 for further details on organizational responsibility.

Table 2.12

Corporate Services Operating Expenses ($millions)

Cost Category	2007 Actual	2013 Forecast	Change
Salaries and Benefits	20.3	23.3	3.0
SEM Expenses	1.9	2.6	0.7
Other Operating Expenses	10.5	17.4	6.9
Cost Recoveries	(3.9)	(10.6)	(6.7)
Total Operating Expenses	**28.8**	**32.7**	**3.9**

Forecast Operating Expenses of $32.7 million for 2013 are $3.9 million higher than 2007 actual costs. A further explanation by cost category and department follows.

Salaries and Benefits

The 2013 forecast Salaries and Benefits in Corporate Services have increased by $3.0 million over 2007 actual costs. The change by department is shown in Table 2.13.

Table 2.13

Corporate Services Salaries and Benefits ($millions)

Department	2007 Actual	2013 Forecast	Change
Leadership and Associates	2.2	1.4	(0.8)
HROE	3.9	5.8	1.9
Finance	7.4	9.0	1.6
Project Execution and Technical Services	4.3	3.4	(0.9)
Corporate Relations	2.5	3.7	1.2
Total Salaries and Benefits	**20.3**	**23.3**	**3.0**

Leadership and Associates

Leadership and Associates is comprised of Executive, General Counsel/Corporate Secretary, and Internal Audit. Salaries and benefits costs within the Executive Leadership group are forecast to decrease by $0.8 million from the 2007 actual costs of $2.2 million to the 2013 forecast of $1.4 million. This decrease is primarily due to a net reduction of 8.0 FTEs and the associated salaries and benefits transferred to Nalcor during the period.

Human Resources and Organizational Effectiveness

Salaries and benefits expense for HROE is forecast to increase by $1.9 million from 2007 actual costs of $3.9 million to the 2013 forecast of $5.8 million. This increase is mainly due to cumulative wage and benefit increases since 2007 as well as a net increase of 3.4 FTEs related to apprentices, graduate trainees and safety initiatives.

Finance

Salaries and benefits expense for Finance is forecast to increase by $1.6 million from the 2007 actual costs of $7.4 million to the 2013 forecast of $9.0 million. This increase is primarily due to cumulative wage and benefit increases throughout this period, the discontinuation of capitalization of salaries of $1.1 million[10], offset by impacts relating to the transfer of 33.5 net FTEs which were transferred from Finance to both Nalcor and the TRO Operations functional area within Hydro.

Project Execution and Technical Services

Salaries and benefits expense for Project Execution and Technical Services is expected to decrease by $0.9 million from the 2007 actual costs of $4.3 million to the 2013 forecast of $3.4 million. From 2007 to 2013 an additional 17.3 FTEs were hired and salaries and benefits increased for all employees. These increases were reduced primarily due to higher capitalization of labour charges of $5.6 million resulting from growth in the capital program since 2007.

Corporate Relations

Corporate Relations include Corporate Communications and Shareholder Relations, Customer Service, and Energy Efficiency. Salaries and benefits for Corporate Relations are increasing by $1.2 million from the 2007 actual costs of $2.5 million[11] compared to the 2013 forecast of $3.7 million. In addition to the cumulative wage and benefits

[10] Approved in Board Order No. P.U. 2(2012).
[11] Includes 2007 costs related to the Customer Services and Energy Efficiency sections now transferred to Corporate Relations from System Operations and Planning.

increases, the establishment of an Energy Efficiency team has resulted in a net increase of 6.2 FTEs offset by a net decrease of 2.5 FTEs in Corporate Communications and Customer Services.

System Equipment Maintenance

System Equipment Maintenance costs related to Corporate Services are forecast to increase by $0.7 million from the 2007 actual costs of $1.9 million compared to the 2013 forecast of $2.6 million, mainly due to an increase in Hydro Place building maintenance costs and freight expenses. Hydro's intercompany administration fee has also increased, reflecting the recovery of a portion of these costs.

Other Operating Expenses

Other operating expenses related to Corporate Services are forecast to increase by $6.9 million from the actual costs in 2007 of $10.5 million to the 2013 forecast of $17.4 million primarily due to increases of $2.7 million in professional services (e.g. Board costs and external fees for regulatory services), $1.4 million in other expenses (e.g. municipal taxes, payroll taxes, office supplies), $2.3 million in CDM costs and $0.5 million in insurance.

Cost Recoveries

Corporate Services cost recoveries as shown in Table 2.12 have increased by $6.7 million from the 2007 actual recoveries of $3.9 million compared to the 2013 forecast of $10.6 million. This is primarily attributable to recovery from other Nalcor lines of business of administration fees of $3.3 million, depreciation of $0.9 million and a deferral in Hydro of CDM costs of $2.6 million.

2.5 LOAD FORECASTS AND NEW POWER SUPPLY

The 2013 load forecast used in this submission was prepared in the same manner as previous submissions to the Board. They reflect a combination of direct input from the Industrial Customers and NP, and Hydro's analysis for the interconnected and isolated systems. The total load requirement is determined from an analysis of overall system losses and demand diversity.

2.5.1 Island Interconnected Load Forecast

The 2007 Test Year load forecast, along with the actual power and energy requirements from Hydro for the Island Interconnected System for 2007-2012, and the operating load forecasts for 2013, are provided in Schedule II. Table 2.14 presents the annual changes in Hydro's electricity requirements for that period.

Table 2.14

Summary of Year-Over-Year Changes in Electricity Requirements 2007 to 2013 Island Interconnected System (GWh)

	2007 Test Year	Change in 2008	Change in 2009	Change in 2010	Change in 2011	Change in 2012	Change in 2013	2013 Test Year
NP	4,925.8	34.0	148.2	(91.8)	301.3	41.8	235.0	5,594.3
ACI Stephenville	5.7	(5.7)	-	-	-	-	-	-
ACI Grand Falls	162.4	(36.2)	(114.4)	(11.8)	-	-	-	-
Corner Brook Pulp and Paper	452.5	(169.6)	(185.0)	(5.8)	(37.5)	42.7	(17.2)	80.1
Vale	-	-	-	-	-	-	34.3	34.3
Praxair - Long Harbour	-	-	-	-	-	-	4.3	4.3
Other Industrial	309.6	7.6	(32.7)	(7.1)	(21.1)	56.0	(22.6)	289.7
Rural and Losses	588.4	19.3	3.1	6.0	41.4	13.5	6.4	678.1
Total Island Interconnected	6,444.4	(150.6)	(180.8)	(110.5)	284.1	154.0	240.2	6,680.8

In 2008, electricity requirements on the Island Interconnected System declined by 2.3% relative to the 2007 Test Year, primarily because of reduced consumption at CBPP. CBPP's No. 1 paper machine was shut down in November 2007. In 2009, there was a further decline in electrical requirements (2.9% relative to 2008) due to the closure of the Grand Falls newsprint mill in February 2009 and the shutdown of No. 4 paper machine at CBPP in March 2009. The load reduction for these ICs was partially offset by increased utility load in 2009. In 2010, there was a further decline in electricity requirements by 1.8% relative to 2009, primarily because of warmer weather patterns which reduced the requirements of NP's and Hydro's residential and general service customers (the Utility load).

In 2011, there was an increase in electricity requirements by 4.7% relative to 2010. This reflects a return to normal weather patterns and higher Utility load. The increase was partially offset by lower IC requirements, particularly at CBPP and North Atlantic Refining Limited (NARL).

The Vale terminal station was energized in June 2012, with first power taken by the customer in December 2012. It is anticipated that Vale will increase its levels of demand and energy consumption until it reaches full production levels by the end of 2016. In 2012 there was an increase in Island Interconnected load requirements of 2.4% over 2011. This load growth reflects the level of Utility load requirements and increased industrial consumption at CBPP and NARL.

In 2013, Hydro expects that another Industrial Customer, Praxair, will commence operations. Praxair will provide the oxygen requirements for the Vale nickel processing facility and it is expected to increase operations throughout the remainder of the year, with an anticipated 2013 energy consumption of 4.3 GWh at a peak of 5.7 MW. For 2013, Hydro is forecasting another increase in total Island Interconnected load requirements, 3.7% relative to 2012. This increase is primarily due to increased NP load and increased requirements for Vale and Praxair.

The Island Interconnected System's total electrical requirements in 2013 are expected to be 3.7% above the 2007 Test Year requirements primarily due to the utility load increase which has been partially offset by an overall decrease in industrial loads. Customer peak demand requirements exhibit the same general growth pattern as energy requirements with lower industrial and offsetting increases in utility requirements. Peak demand requirements for Newfoundland Power and Hydro Rural for 2013 reflect both weather normalization and expected growth.

2.5.2 Labrador Interconnected Load Forecast

The 2007 Test Year load forecast, the actual power and energy supplied to the Labrador Interconnected System by Hydro for 2007-2012, and the operating load forecast for 2013 are provided in Schedule III. Table 2.15 outlines the changes in Hydro's electricity delivery requirements for that period.

Table 2.15

Summary of Year-Over-Year Changes in Electricity Requirements 2007 to 2013 Labrador Interconnected System (GWh)

	2007 Test Year	Change in 2008	Change in 2009	Change in 2010	Change in 2011	Change in 2012	Change in 2013	2013 Test Year
Hydro Rural	505.5	(6.9)	4.6	(33.0)	60.5	14.8	48.8	594.3
CFB Goose Bay	77.4	(16.7)	(41.3)	37.0	(5.0)	(33.8)	(7.9)	9.7
IOC	312.5	24.7	(175.3)	141.0	(174.0)	51.3	79.3	259.5
Other[1]	115.6	(23.5)	(26.3)	15.4	(11.9)	6.5	17.7	93.5
Total Labrador Interconnected	1,011.0	(22.4)	(238.3)	160.4	(130.4)	38.8	137.9	957.0

[1] Other includes losses plus incidential sales to Wabush Mines, a non-regulated customer.

Hydro's overall electricity supply for the Labrador Interconnected System in 2008 declined by 2.2% relative to the 2007 Test Year, primarily due to reduced secondary energy consumption at CFB Goose Bay and lower system losses. The overall decline in 2008 was partially offset by increased consumption at IOC.

In 2009, the electricity supply declined sharply by 24.1% from the requirements in 2008 due to significantly reduced consumption at IOC and lower secondary energy loads at CFB Goose Bay. IOC experienced a lengthy shutdown in the summer of 2009 and reduced consumption for significant periods during the remainder of the year.

In 2010, the electricity supply increased over 2009 by 21.4%. This was primarily driven by loads that had increased again at IOC and CFB Goose Bay. The overall increase was partially offset by lower Hydro Rural requirements. The Hydro Rural load, with a high concentration of electric space heating, declined due to warmer overall weather patterns in the area.

In 2011, the total electricity requirements for the system were 14.3% lower than in 2010. This decrease is primarily driven by significantly reduced consumption at IOC, partially offset by a return to normal weather patterns which resulted in increased Hydro Rural requirements.

In 2012, Labrador Interconnected load requirements increased by 5.0% over 2011. This increase is primarily due to increased consumption levels at IOC and increased Hydro Rural requirements, partially offset by less reliance on secondary energy by CFB Goose Bay during 2012. CFB Goose Bay's electric boilers have been in operation since the 1980s. The customer has advised that it has installed oil fired boilers as a primary source but intends to continue taking small amounts of secondary energy for its electric boilers through to 2016.

An increase of 16.8% is anticipated for the 2013 load requirements relative to 2012. This reflects a further increase in consumption at IOC and the commencement of construction at the Muskrat Falls site. For 2013, Hydro's load forecast for the Labrador Interconnected System has decreased 5.3% from the 2007 Test Year. This reflects lower requirements at IOC, which have been partially offset by normalized weather, community load growth and the addition of the Muskrat Falls construction site.

2.5.3 Isolated Diesel Systems Load Forecasts

The 2007 Test Year load forecast, the actual power and energy requirements for Hydro's isolated systems for 2007-2012, and the operating load forecast for 2013 are provided in Schedule IV. Table 2.16 presents the changes in Hydro's electricity requirements for that period.

Table 2.16

Summary of Year-Over-Year Changes in Electricity Requirements 2007 to 2013 Isolated Diesel Systems (GWh)

	2007 Test Year	Change in 2008	Change in 2009	Change in 2010	Change in 2011	Change in 2012	Change in 2013	2013 Test Year
L'Anse Au Loup	16.9	1.6	1.9	0.5	2.4	(1.3)	2.8	24.8
Other Labrador Diesel	35.7	0.7	1.2	(0.3)	1.5	(0.6)	3.7	41.9
Island Diesel	8.6	0.1	0.2	(1.4)	0.4	(0.3)	0.4	8.0
Total Isolated	61.2	2.4	3.3	(1.2)	4.2	(2.0)	6.7	74.6

Electricity production across the Labrador Isolated diesel systems was higher in 2008 relative to the 2007 Test Year by 4.4%. There was a further increase of 5.6% in 2009 relative to 2008. The annual load increases are primarily driven by increased requirements in the L'Anse au Loup system caused by the construction of electrically heated homes and the conversion of existing homes to electric heat. The L'Anse au Loup system has experienced strong energy consumption growth as a result of a reduction in electricity rates upon the interconnection to Hydro-Québec's Lac Robertson system in 1996.

In 2007, the Government introduced an electricity rebate program for domestic customers in isolated Labrador coastal communities, including the communities on the L'Anse au Loup system. The Labrador rebate reduces customer electricity costs on the first block of energy and basic customer charge to the equivalent of costs paid by customers on Labrador Interconnected Systems. In 2011, the total production requirements for the Labrador Isolated diesel systems were 6.7% higher than that experienced in 2010. In 2012, the requirements were 3.1% lower, relative to 2011. For 2013, Hydro's load forecast for the Labrador Isolated diesel systems has increased by 26.8% from the 2007 Test Year. This reflects the overall increased requirements in the L'Anse au Loup system and the underlying load growth trend for many of the other Labrador Isolated Systems.

Across the Island Isolated Systems, the load has not exhibited the same growth pattern. There was a 15.7% decline in 2010 relative to 2009. The decline in 2010 is partly due to milder weather during 2010 and no production at the fish plant in Little Bay Islands. The fish plant and associated services had an annual consumption of approximately 1 GWh.

In 2011, the total production requirements for the Island Isolated diesel systems were 5.3% higher than in 2010. In 2012 they were 3.8% lower, relative to 2011. The forecast for 2013 reflects the permanent closure of the fish plant at Little Bay Islands and continued slow decline in the isolated communities.

2.5.4 New Power Supply

In order to ensure that the future capacity and energy requirements of the Island Interconnected System are met in a reliable and cost effective manner, Hydro regularly prepares long-term forecasts for the provincial power system and maintains a portfolio of projects with various levels of engineering feasibility.

The Company's assessment on the timing of the requirement for new investment for the Island Interconnected power supply and associated facilities is based on previously established generation planning criteria. These criteria set the minimum level for reserve capacity and firm energy to ensure an adequate power supply to meet the grid's firm load requirements. These criteria are:

- Energy: The Island Interconnected System should have sufficient generating capability to supply all of its firm energy requirements with firm system energy capability; and
- Capacity: The Island Interconnected System should have sufficient generating capacity to satisfy a LOLH[12] expectation target of not more than 2.8 hours per year.

For the Labrador Interconnected System, its firm requirements are compared with the 300 MW block of recalled power and associated energy available from CF(L)Co.

[12] Loss of Load Hours is a standard reliability measure in the utility industry.

2.5.4.1 Island Interconnected System

Table 2.17[13] presents the long-term planning load forecast and energy balances for the Island Interconnected System through to 2021. The load forecast reflects the longer-term view for the economy and incorporates the expected Utility load growth and the ramp up and sustained operation of the Vale nickel processing facility.

The existing system capacity has been adjusted to reflect the capacity values provided in 2011 by NP for their generating units, the derating/removal for service of Hydro's gas turbines and the addition of the two wind farms. There has been a total increase in NP's capacity of 3.1 MW which results from an increase in their hydraulic generation of 4.8 MW and a decrease in their diesel generation of 1.7 MW. Since the 2007 Test Year, each of the gas turbines at Hardwoods and Stephenville have been derated by 4 MW for a total of 8 MW, and the 10 MW gas turbine at Holyrood has been removed from service. The addition of the two 27 MW wind farms at St. Lawrence and Fermeuse in 2008 and 2009, respectively, have contributed to an increase in overall system capacity by 54 MW. The system firm energy capability has also been increased by 119 GWh to reflect the firm output of the two wind farms (167 GWh), partially offset by a reduction at the CBPP Co-Generation unit (48 GWh). Production at this unit has been reduced in recent years due to the reduction of operations at the CBPP mill and the resultant decrease in process steam requirements.

[13] Data is from Hydro's Generation Planning Issues Report, November 2012 Update, filed with the Board during Hydro's 2013 Capital Budget Application process.

Table 2.17

Island Interconnected System
Load Forecast and Capacity and Energy Balances

	Load Forecast		**Existing System**			
				Firm		**Energy**
	Peak	**Energy**	**Net Capacity**	**Capability**	**LOLH**	**Balance**
Year	**MW**	**GWh**	**MW**	**GWh**	**hrs/yr**	**(GWh)**
2013	1,570	7,990	1,946	8,940	0.33	950
2014	1,691	8,472	1,946	8,940	2.59	468
2015	1,721	8,745	1,946	8,940	**4.57**	195
2016	1,736	8,902	1,946	8,940	6.02	38
2017	1,755	8,921	1,946	8,940	7.59	19
2018	1,757	8,914	1,946	8,940	7.64	26
2019	1,760	8,949	1,946	8,940	8.09	-9
2020	1,766	9,016	1,946	8,940	8.85	-76
2021	1,781	9,113	1,946	8,940	11.34	-173
2022	1,801	9,243	1,946	8,940	15.12	-303

2.5.4.2 Labrador Interconnected System

The load forecast for Hydro's power supply to the Labrador Interconnected grid through to the year 2022 is shown in Table 2.18. Hydro supplies the firm and secondary load requirements of the Labrador Interconnected grid with its purchased 300 MW block from CF(L)Co. Energy that is surplus to the requirements on the Labrador Interconnected System is exported from the Province. It should be noted that the load forecast table includes the secondary and interruptible energy amounts (GWh) to IOC and Wabush Mines but does not include the demand requirements (MW) because of the non-firm nature of this load.

Table 2.18

Labrador Interconnected System Load Forecast and Available Surplus						
	Forecast		NLH Recall		Surplus	
Year	MW	GWh	MW	GWh	MW	GWh
2013	207	957	300	2,362	93	1,405
2014	216	1,159	300	2,362	84	1,203
2015	220	1,167	300	2,362	80	1,195
2016	222	1,159	300	2,362	78	1,203
2017	217	1,133	300	2,362	83	1,229
2018	222	1,140	300	2,362	78	1,222
2019	222	1,172	300	2,362	78	1,190
2020	223	1,175	300	2,362	77	1,187
2021	223	1,178	300	2,362	77	1,184
2022	224	1,180	300	2,362	76	1,182

Under the existing load growth patterns, the recall capability will satisfy the firm and secondary requirements of the Labrador Interconnected grid well into the future. The potential for additional industrial and related load growth in Labrador continues to exist but has not been forecast, as it is not yet certain.

2.5.4.3 Changes in Island Interconnected System Reserve and Newfoundland Power Generation Credit

The reserve of the Island Interconnected System has changed slightly, from 15.0% to 15.3%. When applied to NP's revised generation capability forecast for 2013, the generation credit becomes 120.21 MW. The calculation of NP's generation credit is shown in Table 2.19.

Table 2.19

NP Generation Credit (kW)	
Hydraulic Capacity	97,100
Thermal Capacity	41,500
Total	138,600
System Reserve	1.153
NP Generation Credit	120,208

2.5.4.4 Corner Brook Pulp and Paper Demand Credit Contract

In April 2009 the Board issued Order No. P.U. 17(2009) approving, on a pilot basis for a two-year period, a demand credit rate structure to be applied to Hydro's service agreement for CBPP. This service agreement format was intended to provide a price signal that would facilitate more efficient use of that customer's hydraulic generating resources in coordination with its pulp and paper mill operations.

In June and December 2011, Hydro completed assessments of the demand credit rate structure for the CBPP Service Agreement and determined that it provides hydraulic energy production efficiencies that permit lower energy production from Holyrood. The rate structure achieves these energy savings by providing an incentive for CBPP to operate its hydraulic generation resources in a manner which provides more efficient energy production rather than have CBPP maintain power production at levels that avoid incurring additional capacity charges. Reports with Hydro's findings were submitted to the Board requesting that the pilot agreement be permanently put in place.

In subsequent orders, P.U. 15(2011) and P.U. 4(2012), the Board approved extensions of the service agreement on a continued pilot basis until a further Order of the Board. Contained in Exhibit 4 of this Application is an updated request for approval of the service agreement with the following considerations as outlined by the Board:

> *…analysis in relation to potential and actual fuel savings at Holyrood, the efficiency factor at the Holyrood Thermal Generating Station, the Rate Stabilization Plan, and the allocation of costs in revenue requirement*.

With this Application, Hydro is recommending that the pilot agreement be made permanent.

2.5.4.5 Hydro's Application

Hydro is requesting the Board's approval for changing Newfoundland Power's generation credit to 120,208 kW; and changing the rules and regulations of service to CBPP so that the pilot agreement last approved in Order No. P.U. 4(2012), becomes permanent.

2.6 ENERGY SUPPLY EXPENSES

2.6.1 Island Interconnected System

The actual energy supply sources and fuel expenses for 2007-2012 and the forecast for the 2013 Test Year are summarized in Schedule V.

Hydraulic production for 2013 is forecast to be 4,533.5 GWh. This is the average expected production for 2013 using the methodology consistent with that previously approved by the Board and further described in Section 2.7.

Energy purchases in 2007 and 2008 were above the 2007 Test Year forecast of 415 GWh by 39 GWh and 36 GWh, respectively. The increase in 2007 was primarily due to higher secondary energy receipts from the ACI generation. In 2008, the increase was primarily attributable to increased production from the Exploits River Hydro Partnership and the start of commercial production in September of 2008 at the wind farm at St. Lawrence. In 2009, 2010, 2011, and 2012 energy purchases and receipts were above the 2007 forecast by 567 GWh, 534 GWh 490 GWh, and 579 GWh, respectively. This is primarily due to Exploits Generation that was previously used in the Grand Falls paper mill and the production from the St. Lawrence and Fermeuse wind farms, the latter of which started operation in April of 2009. The high levels of energy purchases and receipts in 2009 to 2012 were partially offset by decreased production at the CBPP co-generation unit. Generation from this unit has been reduced due to the shutdown of two of the four paper machines and the resulting decrease in process steam available to drive the co-generation unit.

The forecast energy purchases for 2013 are 1,017 GWh, which is based on Hydro's hydraulic generation model (VISTA) output for the Exploits Generation, the historical average data for Rattle Brook and design estimates for the wind farms. This is 602 GWh higher than the 2007 Test Year forecast. The 2013 forecast generation for the CBPP co-generation unit has been reduced from the 2007 Test Year to reflect experience since the shutdown of the paper machines. The purchase costs from all sources in 2013 are forecast to increase to $51.8 million from $33.5 million in 2007 actual costs. This overall increase results from the inclusion of the wind projects[14] and purchase of the Exploits Generation which has been partially offset by lower production levels at the CBPP co-generation unit.

The suppliers and related expenses for power purchases are presented in Schedule VI.

Holyrood meets the energy supply requirements beyond Hydro's hydraulic production and energy purchases. The primary factors affecting the plant's fuel expenses are its production level, fuel to energy conversion rate and fuel purchase price. These factors for 2007 to 2013 are included in Schedule V.

Energy production from Holyrood in 2007 and 2008 was 1,256 GWh and 1,080 GWh, respectively. In 2009 and 2010, production levels were at 940 GWh and 803 GWh, respectively. In 2011 and 2012, the output levels from the station were 885 GWh and 856 GWh, respectively. The forecast for 2013 is 1,127 GWh. The changes from the 2007 Test Year are due to load, power purchases and hydraulic production variances.

The actual energy conversion factors for 2007 and 2008 were 614 kWh/bbl and 625 kWh/bbl, respectively. In 2009 and 2010, the conversion performance was 612 kWh/bbl and 589 kWh/bbl, respectively. In 2011 and 2012, the performances were 603 kWh/bbl and 599 kWh/bbl, respectively. The decline in recent years is due to lower production requirements as a result of reduced system loads and higher energy purchases. All things being equal, a thermal unit operates most efficiently at higher levels of generation. A forecast conversion factor of 612 kWh/bbl is proposed for the 2013 Test Year. This forecast conversion factor results from a ten-year regression analysis of conversion factor versus Holyrood gross monthly average unit loading, with a station service factor of 6.6% applied to the gross energy production. The station service factor

[14] It should be noted that Hydro is receiving payment (total power purchase costs from wind are net of this payment) of 75% of the Federal ecoEnergy incentive credits from both wind projects ($0.0075/kWh) as per the PPAs. This credit is capped at a maximum wind farm production eligibility of 82.78 GWh per plant annually for a ten-year period from the start of commercial operations.

is based on the average experience over the past five year period (2008-2012). The conversion factor is forecast to improve in 2013 due to higher production requirements and higher average unit output levels.

The actual average fuel purchase prices for 2007 to 2012 and forecast for 2013 are $56.86, $70.23, $55.11, $75.74, $96.72, $115.26 and $108.11 per barrel, respectively. The forecast prices assume 0.7% sulphur content. The detailed monthly actual and forecast purchase prices are provided in Schedule VII. The fuel prices are referenced to the April 2013 Corporate forecast which is based on the March 2013 forecast of PIRA Energy Group.

The actual total Holyrood fuel expense was $107.4 million in 2007 and is forecast to rise to $200.3 million in 2013, an 87% increase over the six-year period and a 46% increase from the 2007 Test Year primarily driven by the increasing purchase prices.

2.6.2 Labrador Interconnected System

The majority of all energy consumed on the Labrador Interconnected System is purchased from CF(L)Co. The only exception is when the gas turbine and diesel generation in Happy Valley-Goose Bay are operated for Labrador Interconnected outages or system support. The actual power purchase costs from CF(L)Co ranged from $1.9 million to $2.4 million for each of the years from 2007 to 2012. The costs are forecast to be $2.4 million in 2013.

The other power purchase expenses for the Labrador Interconnected System relate to the annual costs for Hydro's share of expenses related to Twin Falls Power Corporation's (TwinCo) Wabush Terminal Station. These expenses were $0.76 million in 2007 and $0.27 million in 2008. In 2009 costs were $0.35 million and $0.49 million in 2010. In 2011 the costs were $0.58 million, while in 2012 they were $0.40 million. Costs are forecast to be $0.30 million in 2013. The variability of these costs is caused by variances in the major maintenance and equipment replacements undertaken by CF(L)Co on behalf of TwinCo for the station.

2.6.3 Isolated Systems

The primary source of power supply for Hydro's isolated systems throughout the Province is diesel generation. The Company has also availed of opportunities to supplement or displace diesel generation. On the L'Anse au Loup system, the Company displaces diesel generated energy by purchasing secondary energy from a regional Hydro-Québec hydroelectric plant. On the Ramea diesel system, Hydro continues with its energy receipts from wind generation. On the Mary's Harbour diesel system, until 2007, Hydro purchased energy from an independent hydro generator; the plant was shut down in 2007 and is in need of refurbishment. Schedule VIII presents Hydro's 2007 Test Year budgets, the actual diesel fuel and purchased power expenses for its isolated systems for 2007 to 2012, along with the forecast expenses for 2013. Diesel fuel and purchased power expenses have varied from $12.1 million in the 2007 Test Year to $19.0 million in 2012. This variability reflects the prices for petroleum in world markets. In 2013, the Company's isolated systems fuel and purchased power budgets are forecast to increase to $21.4 million due to increasing supply requirements and fuel prices.

2.7 HYDROELECTRIC PRODUCTION FORECAST

2.7.1 Introduction

This section describes the methodology used by Hydro to estimate its average annual hydroelectric energy production in the 2013 Test Year.

For the 2004 Test Year, Hydro prepared the average annual energy production forecast for hydraulic generation facilities using the 30 years of inflows from 1973 to 2002. However, during the 2003 GRA, Hydro's consultant, Hatch (formerly SGE Acres), provided evidence to confirm that it would be better to use the full hydrological record (dating back to 1950) after certain inconsistencies in the record had been resolved. In addition, Hatch recommended the use of a simulation model (SYSSIM), rather than a spreadsheet, to prepare the estimate. Hydro worked with Hatch to make the required adjustments to the hydrological record and to select and implement the SYSSIM model.

The average energy value provided for the 2007 Test Year was based on the revised record and the SYSSIM modeling.

In addition to its use in preparation of the 2006 GRA, Hydro used the SYSSIM model to estimate hydroelectric production for budgeting, fuel forecasting, and other planning activities. However, over time, the model seemed less able to accurately determine the contribution of the hydraulic resources compared to the required thermal production. The model still provided results, but changes to the input, for example adding new wind resources, did not have the anticipated effect on the hydroelectric and thermal production estimates. This problem seemed to have been caused, or at least worsened, by the decrease in industrial load as a result of the paper mill closures and paper machine shutdowns on the island.

In anticipation of this GRA, Hydro again retained Hatch to provide advice on how to proceed – whether changes were possible to improve the SYSSIM model of the Hydro system or whether a new methodology was required. Hatch's advice was to switch to the VISTA DSS model. A letter from Hatch, describing the evolution of their modeling techniques and outlining their recommended approach for use in the GRA is attached as Exhibit 5.

2.7.2 Vista DSS Model

2.7.2.1 Background

Hydro first implemented the Vista DSS in the 1990s. Initially, only the LT (long-term) Vista module was implemented; LT Vista provides guidance on optimized unit dispatch on a weekly time step. In the 2008-2009 period, Hydro implemented the ST (short-term) Vista module which provides more detailed optimized dispatch on an hourly time step. Part of the implementation of the ST module was to add inflow forecasting capability to the model. Currently, Hydro uses seven-day hourly precipitation and temperature forecasts to produce inflow forecasts for use in hourly modeling.

2.7.2.2 Use of Vista for GRA

When planning for the 2006 GRA, Hydro worked with Hatch to assess the best methodology for determining the average hydroelectric capability of its system. At that time, the use of Vista was considered, but not chosen. Since 2006, various changes as noted in Exhibit 5 have been made to Vista which makes it more suitable for use in studies and budget forecasts. In particular, in preparation for Hydro's use of Vista for this GRA, Hatch added a new option which allows a value to be assigned to water in storage at the end of the simulation period. This means target water levels do not have to be set and Vista can make more realistic decisions at the end of the simulation period.

2.7.3 System Assumptions

2.7.3.1 Hydrology

Simulations for the current GRA were run using all available hydrology from 1950 through 2010 inclusive, 61 years in total, as per Board Order No. P.U. 14(2004).

Inflows to each of Hydro's reservoirs are calculated daily from measured water levels and estimated outflows. At the end of each year, Hydro reviews the calculated inflows and makes any necessary adjustments. Adjustments include:

- Smoothing to remove calculated negative inflows, a common problem when back calculating inflows from water level changes; and
- Adjustments to the distribution of inflows between two reservoirs when the estimates of flow in the connecting canals are not well known.

Inflow data for recent years was added according to the methodologies recommended by Hatch during the last GRA.

2.7.3.2 Exploits Generation

Hydro's Vista model has always included generating plants on the Exploits River but prior to 2010 the generation was modeled as one pseudo plant of 92 MW for the combined output of Buchans, Grand Falls and Bishop's Falls. Star Lake was modeled separately, but still in a simplified form.

In 2010, Hatch was asked to develop a more realistic and complete representation of the Exploits plants in the Vista model. The Vista model now has realistic representations of each watershed and power plant. The total forecast generation included in 2013 is 763 GWh, as shown previously in Table 2.1.

2.7.3.3 Newfoundland Power and Non-Utility Generators (NUGS)

All hydroelectric generation sites on the Island Interconnected System are modeled in Vista.

NP's sites are modeled as one pseudo site with characteristics and input hydrology that result in a reasonable estimate of its generation. Several other small plants (Snook's Arm, Venam's Bight, Rattle Brook, and Roddickton mini-hydro) are included with NP's sites as they are too small to warrant modelling separately and have similar characteristics to NP's sites.

Deer Lake Power's plant on Grand Lake is modeled to a level of detail similar to that of Hydro's own system.

Estimates of generation from each wind farm and from CBPP's co-generation plant are included in the model as purchase contracts.

2.7.3.4 Thermal and Wind Generation

Holyrood was modeled similarly to the previous Application. It has a minimum production level set for each week of the year, reflecting the requirements for meeting peak loads and transmission constraints.

2.7.4 Impact on the Hydraulic Production Forecast

The hydraulic production forecast determined from the Vista model and used for 2013 in this Application is 4,533 GWh compared with the final forecast used in the 2007 Test Year of 4,472 GWh. The changes are due to an extension in the record of inflows to incorporate the data up until 2010, improvements in methodology and enhanced representation of the non-Hydro owned hydroelectric generation sources. The combined impact results in an increase in the annual average hydroelectric production estimate for 2013 of 61 GWh. It should be noted that Exploits Generation as described in Section 2.7.3.2 is included in power purchases as Hydro does not own these assets.

List of Schedules:

Schedule I	Operating Expenses by Functional Area 2007 to 2013
Schedule II	Actual and Forecast Electricity Requirements for 2007 to 2013 - Island Interconnected System
Schedule III	Actual and Forecast Electricity Requirements for 2007 to 2013 - Labrador Interconnected System
Schedule IV	Actual and Forecast Electricity Requirements for 2007 to 2013 - Isolated Systems
Schedule V	Energy Supply and Fuel Expense for 2007 to 2013 - Island Interconnected System
Schedule VI	Energy Purchases by Supplier for 2007 to 2013 - Island Interconnected System
Schedule VII	Monthly No. 6 Fuel Purchase Prices for 2007 to 2013
Schedule VIII	Isolated Fuel and Purchased Power Costs for 2007 to 2013

Newfoundland and Labrador Hydro
Operating Expenses by Functional Area
2007 - 2013
($000)

	Actual						Forecast
	2007	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
Operations							
Thermal Generation	20,870	19,528	18,467	18,192	20,433	19,932	22,018
Deferred Major Extraordinary Repairs	2,109	2,916	2,715	2,582	1,644	606	-
Hydro Generation	9,112	8,843	9,447	10,223	10,949	11,498	11,630
Generation	32,091	31,287	30,629	30,997	33,026	32,036	33,648
System Operations	2,184	2,491	2,176	2,415	2,316	2,594	2,849
Deferred Regulatory Costs	50	50	50	50	50	-	-
System Operations	2,234	2,541	2,226	2,465	2,366	2,594	2,849
Transmission and Rural Operations	34,541	36,067	35,165	38,054	40,342	43,415	44,617
Total Operations	68,866	69,895	68,020	71,516	75,734	78,045	81,114
Corporate Services							
Leadership and Associates	2,762	1,812	1,230	1,333	1,308	1,438	1,822
Human Resources and Organizational Effectiveness	6,608	6,452	6,775	6,020	7,526	7,509	8,783
Finance	11,908	11,859	11,150	11,350	12,301	11,758	12,711
Deferred Regulatory Costs	223	225	225	-	-	-	333
Allocation to non-regulated customer	(2,679)	(2,673)	(1,875)	(2,648)	(2,292)	(2,215)	(2,108)
Project Execution and Technical Services	4,922	4,292	4,861	4,662	4,180	3,927	4,668
Deferred Regulatory Costs	61	61	61	-	-	-	-
Corporate Relations	5,022	4,771	9,417	4,743	5,807	6,006	6,497
Total Corporate Services	19,457	18,535	23,839	18,107	19,996	19,476	22,101
Asset Writedown	-	-	505	-	-	-	-
Operating Expenses	**88,323**	**88,430**	**92,364**	**89,623**	**95,730**	**97,521**	**103,215**

Newfoundland and Labrador Hydro
Actual and Forecast Electricity Requirements for 2007 to 2013
Island Interconnected System

	2007 Test Year		2007 Actual		2008 Actual		2009 Actual		2010 Actual		2011 Actual		2012 Actual		2013 Forecast	
	MW	GWh	MW	GWh	MW	GWh	MW	GWh	MW	GWh	MW	GWh	MW	GWh	MW	GWh
Newfoundland Power	1,121.5	4,925.8	1,083.0	4,990.7	1,109.4	4,959.8	1,168.1	5,108.0	1,146.3	5,016.2	1,186.3	5,317.5	1,177.9	5,359.3	1,180.3	5,594.3
Hydro Rural Interconnected	84.8	392.0	79.9	400.0	88.9	411.7	87.5	415.3	81.7	406.5	95.5	437.6	88.8	445.6	93.9	447.3
Corner Brook Pulp and Paper	59.4	452.5	66.9	396.7	37.0	282.9	36.0	97.9	24.8	92.1	21.2	54.6	23.7	97.3	20.0	80.1
Abitibi Con. - Grand Falls	24.0	162.4	28.0	121.6	28.0	126.2	28.0	11.8	-	-	-	-	-	-	-	-
Abitibi Con. - Stephenville	3.0	5.7	1.2	3.1	-	-	-	-	-	-	-	-	-	-	-	-
North Atlantic Refining	30.5	245.3	31.8	243.4	32.4	256.0	31.4	219.9	31.0	206.3	30.8	184.6	30.9	240.4	30.5	217.9
Teck Resources	10.0	64.3	7.9	51.4	8.7	61.2	9.2	64.6	9.6	71.1	10.0	71.7	9.9	71.9	9.5	71.8
Vale	-	-	-	-	-	-	-	-	-	-	-	-	0.3	-	13.9	34.3
Praxair - Long Harbour	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.7	4.3
Total Deliveries	1,307.6	6,248.0	1,258.4	6,206.9	1,264.0	6,097.8	1,332.7	5,917.5	1,245.2	5,792.2	1,329.0	6,066.0	1,313.3	6,214.5	1,335.3	6,450.0
Transmission Losses	39.9	196.4	64.6	182.1	59.0	196.0	57.3	195.5	59.8	210.3	69.8	220.6	71.9	226.1	41.4	230.8
Hydro Island Requirement	1,347.5	6,444.4	1,323.0	6,389.0	1,323.0	6,293.8	1,390.0	6,113.0	1,305.0	6,002.5	1,398.8	6,286.6	1,385.2	6,440.6	1,376.7	6,680.8

Notes:
1. Required NLH Net Generation MW's are NLH system coincident MW's and include customer firm demand requirements only. MWs in 2013 are December forecast values.
2. Demands for Total Deliveries and Transmission Losses are coincident with system peak. Actual transmission losses include station services.
3. Actuals reflect rounded values to the nearest tenth of a GWh.

Newfoundland and Labrador Hydro
Actual and Forecast Electricity Requirements for 2007 to 2013
Labrador Interconnected System

	2007 Test Year		2007 Actual		2008 Actual		2009 Actual		2010 Actual		2011 Actual		2012 Actual		2013 Forecast	
	MW	GWh	MW	GWh	MW	GWh	MW	GWh	MW	GWh	MW	GWh	MW	GWh	MW	GWh
Hydro Rural Interconnected																
Happy Valley - Goose Bay	57.5	235.0	55.0	228.0	59.0	230.0	59.8	230.8	57.8	216.3	62.1	243.8	61.1	250.6	69.7	282.7
Churchill Falls	0.3	1.5		1.4		1.3		1.1		1.2		1.4		1.3	0.3	1.5
Wabush	15.1	62.0	15.7	63.8	17.6	66.1	17.5	67.6	16.1	62.7	17.5	72.8	18.0	77.4	17.8	79.6
Labrador City	50.6	207.0	49.0	201.5	49.0	201.2	51.5	203.7	48.5	190.0	50.8	212.7	50.5	216.2	51.4	230.5
Total	123.5	505.5	119.7	494.7	124.3	498.6	128.8	503.2	122.4	470.2	130.4	530.7	129.7	545.5	139.2	594.3
Department of National Defence	-	77.4	-	62.9	-	60.7	-	19.4	-	56.4	-	51.4	-	17.6	-	9.7
Iron Ore Company of Canada	82.0	312.5	88.8	257.1	95.4	337.2	82.6	161.9	90.8	302.9	83.2	128.9	63.4	180.2	92.0	259.5
Wabush Mines	-	0.2	-	0.2	-	0.2	-	0.1	-	0.1	-	0.1	-	0.1	1.4	0.1
Total Deliveries	170.4	895.6	162.4	814.9	173.9	896.7	165.0	684.6	171.0	829.6	182.1	711.1	182.6	743.4	184.2	863.6
Transmission Losses	21.6	115.4	22.3	75.0	25.8	91.9	44.1	65.7	24.2	81.1	39.7	69.2	21.3	75.7	23.2	93.4
Hydro Labrador Requirement	192.0	1,011.0	184.7	889.9	199.7	988.6	209.1	750.3	195.2	910.7	221.8	780.3	203.9	819.1	207.4	957.0

Notes:
1. The 2013 Forecast is sourced to the April 12, 2013 Labrador Operating Load Forecast.
2. Actual customer peaks are annual maximums. System peak excludes interruptible and secondary load. MWs in 2013 are December forecast values.
3. Demands for Total Deliveries and Transmission Losses are coincident with system peak.
4. Sales to CFB Goose Bay and Wabush Mines are secondary sales.
5. Actuals reflect rounded values to the nearest tenth of a GWh.

Newfoundland and Labrador Hydro
Actual and Forecast Electricity Requirements for 2007 to 2013
Isolated Systems

	2007 Test Year		2007 Actual		2008 Actual		2009 Actual		2010 Actual		2011 Actual		2012 Actual		2013 Forecast	
	kW	MWh	kW	MWh	kW	MWh	kW	MWh	kW	MWh	kW	MWh	kW	MWh	kW	MWh
Labrador Isolated																
Davis Inlet	1,468	6,629	-	-	-	-	-	-	-	-	-	-	-	-	-	-
L'Anse au Loup	3,740	16,884	12,513	17,556	4,451	18,495	4,463	20,363	4,688	20,912	4,931	23,292	5,043	22,049	5,566	24,767
Others	8,661	35,700	-	35,340	9,536	36,421	9,050	37,644	9,421	37,296	9,208	38,754	8,814	38,207	9,783	41,908
Total (excluding Davis Inlet)	12,401	52,584	12,513	52,896	13,987	54,916	13,513	58,007	14,109	58,208	14,139	62,046	13,857	60,256	15,349	66,675
Island Isolated	2,844	8,577	2,323	8,043	2,664	8,707	2,623	8,934	2,221	7,528	2,293	7,876	2,277	7,621	2,323	7,957
Total Isolated		61,161		60,939		63,623		66,941		65,736		69,922		67,877		74,632

Notes:
1. The 2013 Forecast is sourced to the Spring 2012 Rural Operating Load Forecast.
2. Peaks are non-coincident net annual maximums.
3. Net production excludes station services.
4. Operations ceased at Davis Inlet in early 2006, when the community moved to Natuashish.
5. Natuashish is operated by Hydro for the Department of Indian and Northern Affairs with full cost recovery.

Newfoundland and Labrador Hydro
Energy Supply and Fuel Expense for 2007 to 2013
Island Interconnected System

	2007 Test Year	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Forecast
Total Energy Requirement (GWh)[3]	6,444.4	6,389.0	6,293.7	6,113.0	6,002.4	6,286.6	6,440.7	6,680.8
Hydraulic Production (GWh)	4,472.1	4,689.4	4,771.0	4,199.5	4,273.8	4,512.4	4,595.0	4,533.5
Energy Receipts and Purchases (GWh)[1][2][4]	414.9	453.9	450.6	981.6	948.4	905.3	994.2	1,017.2
Gas Turbine/Diesels Production (GWh)	3.0	(10.0)	(8.1)	(7.9)	(10.6)	(8.5)	(4.3)	2.8
Holyrood Production (GWh)	1,554.5	1,255.6	1,080.2	939.9	803.1	885.3	855.8	1,127.4
Holyrood No. 6 Fuel Conversion Factor (kWh/bbl)	630	614	625	612	589	603	599	612
Holyrood No. 6 Fuel Consumption (bbl)	2,467,396	2,044,648	1,728,681	1,534,707	1,363,179	1,469,169	1,428,337	1,842,112
Average No. 6 Fuel Purchase Price ($/bbl)	56.71	56.86	70.23	55.11	75.74	96.72	115.26	108.11
No. 6 Fuel Production Cost ($000)	136,867	107,369	123,734	80,585	100,674	135,136	164,001	200,314
Gas Turbine/Diesel Production Cost ($000)	$528	$420	$1,370	$840	$1,120	$687	$596	$718

Notes:

1. After February 12, 2009, data includes Nalcor Exploits base generation at Grand Falls, Bishop's Falls and Buchans originally used for Grand Falls paper mill operations.
2. Energy received from Nalcor Exploits base generation was stored, rather than purchased, prior to 2011.
3. Total energy requirements excludes energy amounts transferred from Hydro to CBPP of 8.55 GWh, 12.30 GWh, and 30.34 GWh, in 2009, 2010 and 2011, respectively.
4. Total energy receipts and purchases excludes energy amounts transferred from CBPP to Hydro of 8.55 GWh and 22.36 GWh, in 2009 and 2011, respectively.

Newfoundland and Labrador Hydro
Energy Purchases by Supplier for 2007 to 2013
Island Interconnected System

Supplier	2007 Test Year GWh	2007 Test Year $000	2007 Actual GWh	2007 Actual $000	2008 Actual GWh	2008 Actual $000	2009 Actual GWh	2009 Actual $000	2010 Actual GWh	2010 Actual $000	2011 Actual GWh	2011 Actual $000	2012 Actual GWh	2012 Actual $000	2013 Forecast GWh	2013 Forecast $000
NP at Hydro Request	-	-	0.05	-	0.46	108	0.52	119	0.20	15	0.09	7	0.10	114	-	-
CBPP Secondary[(1)]	-	-	0.39	11	0.08	2	6.96	207	4.46	(74)	3.92	-	6.25	321	-	-
ACI-GF Secondary[(2)]	20.59	689	64.12	2,282	29.58	1,361	7.41	237	-	-	-	-	-	-	-	-
Star Lake[(4)]	142.45	10,432	147.79	10,813	147.69	10,940	148.50	10,255	135.83	11,232	129.82	5,193	144.45	5,778	140.87	5,635
Rattle Brook	14.59	1,128	11.91	913	13.69	1,131	15.59	1,202	17.42	1,380	18.66	1,490	14.63	1,181	15.00	1,236
Corner Brook Cogen	100.24	10,086	92.54	8,632	74.09	7,956	55.74	5,525	51.54	5,469	50.50	5,917	47.84	6,906	50.50	7,391
Exploits River Project	137.00	10,757	137.13	10,801	177.19	13,798	179.95	14,006	112.40	8,664	-	-	-	-	-	-
St. Lawrence Wind	-	-	-	-	7.82	536	100.64	7,248	100.46	7,072	110.00	7,777	103.84	7,383	104.80	7,472
St. Lawrence Wind Ecoenergy Incentive Credit[(3)]		-		-		-		(620)		(620)		(685)		(586)		(621)
Fermeuse Wind	-	-	-	-	-	-	53.74	4,443	82.80	6,255	87.96	6,674	91.20	6,952	84.41	6,398
Fermeuse Wind Ecoenergy Incentive Credit		-		-		-		(386)		(620)		(663)		(683)		(621)
Nalcor Grand Falls, Bishops Falls and Buchans[(4)]	-	-	-	-	-	-	-	-	-	-	510.63	20,425	585.90	23,436	621.63	24,865
Total Power Purchases	414.87	33,092	453.93	33,452	451	35,832	569	42,236	505	38,773	912	46,135	994	50,802	1,017	51,756

Notes:

1. Adjustment required in 2010 to account for June, 2009 metering issue
2. ACI-GF secondary ceased on February 12, 2009
3. Ecoenergy Incentive Credits are paid to Hydro quarterly at $0.0075/kwh on the eligible production (up to a maximum of 82.78 GWh annually)
4. Energy purchased from Nalcor generation at Grand Falls, Bishop's Falls, Buchans and Star Lake in 2011, 2012 and 2013 is at $0.04/kWh.

Newfoundland and Labrador Hydro
Monthly No. 6 Fuel Purchase Prices for 2007 to 2013
($/bbl)

	2007		2008	2009	2010	2011	2012	2013
	Forecast	Actual[(1)]	Actual[(1)]	Actual[(1)]	Actual[(1)]	Actual[(1)]	Actual[(1)]	Forecast
January	56.40	43.65	73.98	45.52	75.99	82.71	110.99	106.60
February	55.25	46.81	71.41	45.80	72.73	92.02	116.71	111.90
March	57.35	48.63	72.43	46.75	72.53	102.20	127.24	102.10
April	55.95						120.63	104.30
May	54.50	57.10						106.00
June	53.75		104.86					109.10
July	52.85	56.23						111.70
August	53.10	57.56						112.50
September	52.70							110.70
October	54.65					107.03		110.40
November	57.35	71.44	49.01	78.66	79.27	114.70	103.46	111.30
December	60.65	73.43	43.30	74.75	82.74			107.90
Weighted Purchase Price	56.71	56.86	70.23	55.11	75.74	96.72	115.26	108.11

Notes:
1. There were no purchases in months with a blank.

Newfoundland and Labrador Hydro
Isolated Fuel and Purchased Power Costs for 2007 to 2013
($000)

	2007 Test Year	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Forecast
Diesel Fuel								
Davis Inlet	1,564							
Other Hydro Diesel	10,391	10,340	14,937	12,522	12,266	15,642	15,791	17,790
Total (excluding Davis Inlet)	10,391	10,340	14,937	12,522	12,266	15,642	15,791	17,790
Purchased Power								
L'Anse au Loup	1,567	1,586	2,254	1,643	2,054	2,890	2,931	3,353
Ramea	121	60	101	94	114	108	296	245
Mary's Harbour	44	18	-	-	-	-	-	-
Total	1,732	1,664	2,355	1,737	2,168	2,998	3,227	3,598
Total	**12,123**	**12,004**	**17,292**	**14,259**	**14,434**	**18,640**	**19,018**	**21,388**

Notes:
1. Labrador and Island Isolated fuel purchases include additives in 2010 and 2011.
2. L'Anse Au Loup fuel purchases include deferred fuel savings.
3. 2013 Forecast sourced to April 2013 Isolated Fuel and Power Purchase budget.

SECTION 3: FINANCE

3.1 OVERVIEW

Hydro's base rates were last set effective January 1, 2007 and, in the absence of a GRA, this would result in a 2013 return on rate base of 6.68%, as shown in Schedule II, which is well below Hydro's approved return on rate base for rate making purposes of 7.44%, with a range of 7.29% to 7.59%. This return on rate base is also considerably lower than the return on rate base of 7.83% proposed in this Application which is based on an embedded cost of debt of 8.01% and a Return on Equity (ROE) of 8.80%[1]. In the absence of a GRA, and without the benefit of Exploits Generation power purchase arrangements, it is estimated that Hydro would incur a net loss of approximately $20.0 million in 2013.

Hydro's revenue requirement is the sum of the required return on rate base and other costs, which include operating expenses, fuels, power purchases and depreciation. The total revenue requirement for 2013 is forecasted to be $568.1[2] million. The 2013 revenue requirement is $136.3 million more than the actual $431.8 million revenue requirement in 2007. Much of this increase relates to fuel costs which are recovered through the RSP. Hydro is proposing to adjust its rates to recover, among other things, the following increases from the 2007 actual costs:

- Operating expenses $16.1 million;
- Depreciation and other costs $14.5 million; and
- Power Purchases $20.1 million.

[1] Based on NP's return on equity of 8.80% which was approved in Board Order No. P.U. 13(2013).

[2]

	(millions)
Total Revenue Requirement per Finance Schedule I, Page 6	$ 568.1
Less: Expense Credits	(2.4)
IOC Cost Recovery	2.1
Revenue Requirement per Cost of Service	$ 567.8

Along with the approval of its forecasted revenue requirement, Hydro proposes that the Board approve the forecasted average rate base for 2013 to be $1,564.1 million for the purpose of setting rates in this proceeding.

Hydro is also proposing an increase in the allowed range of return from +/- 15 basis points (bps) to +/- 25 bps based on changes in the capital structure and the new approach to setting target return on equity. A report from Foster and Associates supporting this position can be found in Exhibit 6.

Since its last GRA, measures were taken to improve both debt to total capital ratio and net income performance. In 2009, the Government, through Nalcor, contributed $100.0 million in equity to Hydro, helping reduce regulated debt from 81.5% of total regulated capital at December 31, 2008 to 70.9% at the end of 2012. Hydro is forecasting that at December 31, 2013 its regulated debt to total regulated capital ratio will be 69.3%.

In 2009, the Government directed that Hydro earn a market return on equity on its entire rate base and that, in the future, it would be permitted a larger portion of equity in its capital structure. These measures, designed to strengthen Hydro's long-term financial position and performance, become effective with Hydro's current GRA.

Furthermore, over the period from 2008 to present, the Government has taken specific actions which have improved Hydro's net income. Starting in 2008, the Government waived the debt guarantee fee until 2011 at which time it was reinstated, but at a reduced rate from that previously charged. Also in 2011, the Government allowed Hydro to utilize Exploits Generation at a cost of 4¢/kWh. The benefit of both of these net income initiatives will continue until new rates become effective and, at that time, these cost reductions will be passed on to customers in the form of lower rates than otherwise would occur.

Since Nalcor was established, a review of intercompany guidelines and practices has been carried out to ensure separation of regulated and non-regulated activities. Nalcor lines of business, including Hydro, operate under a shared services model. Resources are deployed to best meet the needs of the business and to achieve efficiencies. There has been a decrease in costs for Hydro as a result of achieving economies of scale through shared services, as discussed in Section 3.4.3.1. This benefit will be passed on to customers upon implementation of new rates.

The purpose of the Finance evidence is to outline the following:

- Hydro's financial position and performance;
- Hydro's financial objectives and targets;
- Intercompany charges and shared services;
- The details of Hydro's 2013 revenue requirement; and
- Other cost and accounting matters.

3.2 FINANCIAL POSITION AND PERFORMANCE

3.2.1 Return on Equity

In 2009, under the authority of Section 5.1 of the *Electrical Power Control Act*, *1994*, the Government directed that:

- In calculating the return on rate base, the same rate of return on equity would be set for Hydro as was set for NP;
- Hydro would earn ROE on its entire rate base, including amounts related to rural assets;
- Hydro would be permitted to have a proportion of equity in its capital structure up to a maximum of the same as is approved for NP; and
- These policies would become effective commencing with the first GRA after January 1, 2009.

3.2.2 Equity Contribution

In 2009, the Government, through Nalcor Energy, made a $100 million equity contribution to Hydro. These funds were included in the Government's 2008-2009 Budget[3] and the contribution from the Government was intended to strengthen Hydro's financial position. This action, in combination with a higher rate of return on equity, provides a strong foundation for future financial performance and positions Hydro to be able to finance a greater portion of its upcoming capital programs.

3.2.3 Financial Performance Initiatives

Over the period from 2008 to the present, the Government has undertaken the following initiatives to enhance Hydro's financial position:

- Reduction of required debt guarantee fee payments from Hydro; and
- Alterations to power purchase arrangements with respect to Exploits Generation.

3.2.3.1 Debt Guarantee Fee Initiative

The debt guarantee fee is an annual fee paid by Hydro in return for the Government's guarantee of its debt obligations. This fee, which has been in effect for approximately 20 years, was previously charged at 1% of Hydro's outstanding debt obligations, and is included in Hydro's revenue requirement and customer rates. In 2008, as a means of 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 directed that the fee be reinstated at a market rate.

[3] *"The Province will also provide a $100 million equity injection that will improve Newfoundland and Labrador Hydro's financial profile by reducing its level of debt. Our equity injection will also bring the Company more in line with similar utilities in Canada in terms of its ratio of debt to equity."* Government of Newfoundland and Labrador Budget Speech, April 29, 2008.

This direction was based on a market analysis undertaken by one of Hydro's capital market advisors in the fall of 2010 at the request of Hydro, as the last review that assessed the value of the fee was undertaken in 2008 under very different market conditions. The new analysis was based on a comparison of yields on bonds issued by the Province to bonds with similar maturities issued by a group of investment-grade utilities comparable to Hydro. The difference between the yield on the Province's bonds and those of the companies within the comparison set is reflective of the value of the guarantee fee. The analysis supported a debt guarantee fee in the range of 25-50 basis points (bps) per issue, depending on the remaining term to maturity. The rates under this new directive will result in significant savings passed on to ratepayers upon the setting of new electricity rates, as outlined in Table 3.1.

A summary of the impact of these measures is as follows:

Table 3.1

Newfoundland and Labrador Hydro
Net Income Benefits of Debt Guarantee Fee Waivers and New Debt Guarantee Formula
($ millions)

Newfoundland and Labrador Hydro Fiscal Year:	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	***2013 Forecast***
Balances as at December 31 of previous fiscal year:							
Long-term debt	$ 1,357.4	$ 1,151.1	$ 1,146.4	$ 1,141.6	$ 1,136.7	$ 1,131.5	*$ 1,125.9*
Current portion of long-term debt	8.3	208.3	8.4	8.2	8.2	8.2	*8.2*
	1,365.7	1,359.4	1,154.8	1,149.8	1,144.9	1,139.7	*1,134.1*
Sinking funds	(117.1)	(151.8)	(163.9)	(179.6)	(208.4)	(247.0)	*(263.3)*
	1,248.6	1,207.6	990.9	970.2	936.5	892.7	*870.8*
Promissory notes	63.2	7.1	163.1	-	-	-	*52.0*
Guaranteed debt outstanding at December 31 of the preceding fiscal year	$ 1,311.8	$ 1,214.7	$ 1,154.0	$ 970.2	$ 936.5	$ 892.7	*$ 922.8*
Debt guarantee fee @ 1% under old formula	**$ 13.1**	**$ 12.1**	**$ 11.5**	**$ 9.7**	**$ 9.4**	**$ 8.9**	***$ 9.2***
Actual debt guarantee fee paid for year[1]	13.1	-	-	-	3.9	3.7	*3.7*
Net impact	**$ -**	**$ 12.1**	**$ 11.5**	**$ 9.7**	**$ 5.5**	**$ 5.2**	***$ 5.5***

[1] Actual fee paid for 2011, 2012 and 2013 based on the new formula of 0.25% - 0.50% of outstanding debt

Increase in net income from debt guarantee fee waivers for 2008 - 2010	**33.3**
Increase in net income from new formula for 2011 - 2012	**10.7**
Reduction in 2013 forecast from new formula	**5.5**
Cumulative net income impact of debt guarantee fee initiatives	**$ 49.5**

The debt guarantee fee in the 2013 forecast is estimated to be $5.5 million lower than if it was based on 1% of Hydro's outstanding debt obligations, as was the case when rates were last set in 2007. In the 2013 forecast, the benefit of the lower debt guarantee fee will be passed on to ratepayers through a lower revenue requirement.

3.2.3.2 Power Purchases Initiative

As discussed in Section 2.2.2, in 2008, the Government passed the *Abitibi-Consolidated Rights and Assets Act* which, among other things, expropriated Exploits Generation assets. In 2011, the Government altered the arrangements for power purchases from Exploits Generation to enable Hydro to purchase the energy at 4¢ per kWh from all plants, including the Exploits generation which previously had supplied the paper mill, without which Hydro would have experienced a net financial loss for the year. In 2013, Exploits Generation will continue to be made available to Hydro at 4¢ per kWh. Holyrood fuel requirements and associated costs are forecasted to be less than they would otherwise be without the use of the Exploits Generation.

3.3 FINANCIAL OBJECTIVES AND TARGETS

The *Electrical Power Control Act*, *1994* directs that Hydro achieve and maintain a sound credit rating in the financial markets of the world. Hydro views a sound credit rating as one that achieves an appropriate balance between (a) maintaining the degree of financial stability required to deliver reliable electrical service in a safe manner, and (b) the overall cost of capital passed on to ratepayers. Beginning in 2008, the Government, in collaboration with Hydro, undertook initiatives to improve Hydro's financial position and financial performance. This is reflected in the rate of return on rate base and capital structure that has been directed, and is proposed in this Application.

In 2009, the Government directed that Hydro would be allowed to earn ROE equal to that of NP which is currently 8.80%. That rate represents a significant increase over Hydro's current ROE of 4.47%, which is one of the lowest in the country. In addition, the Government waived the debt guarantee fee for 2009 and 2010, and adjusted the method used to calculate the fee for 2011 and beyond to more closely reflect the market value of the guarantee.

In order to help improve Hydro's financial position, the Government provided a $100 million equity injection to improve the regulated capital structure. The Government has also directed that going forward, Hydro can increase the amount of equity in its regulated capital structure[4], up to a maximum of that approved for NP, which is currently 45%.

Currently, Hydro's dividend policy is aimed at maintaining debt at approximately 75%[5] of the regulated capital structure. This represents an improvement over previous years, when the debt to total capital ratio exceeded 80%.

Maintenance of a strong financial position and stable financial performance will be critical when Hydro returns to the capital markets.

3.3.1 Target Return on Equity

Return on Equity is a financial ratio determined by the net earnings available for distribution to shareholders after the payment of all expenses, including debt costs. An adequate level of return on equity is viewed as important by credit rating agencies because it allows flexibility to withstand unexpected and adverse economic circumstances that can put pressure on net earnings. Therefore, Hydro's ROE target plays a key role in meeting its objective of maintaining a sound credit rating.

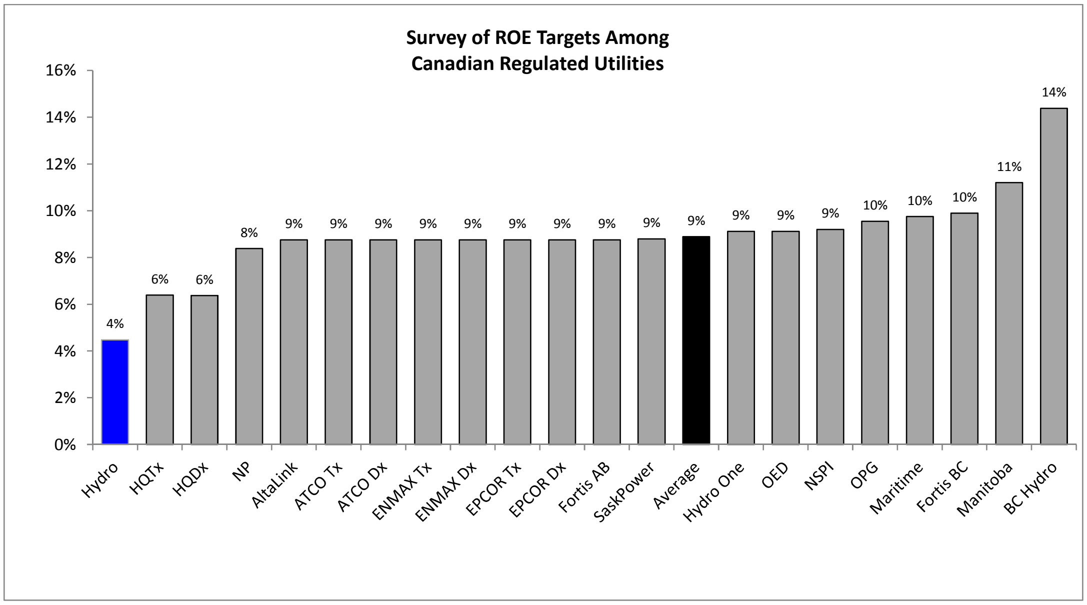
In 2004, the Board ruled that, as an interim measure, Hydro's approved ROE would be equal to its marginal cost of debt of 5.83%. During the 2006 GRA, a negotiated settlement was reached that based Hydro's ROE on that 2004 methodology. This

[4] The regulated capital structure referred to here differs from the regulated capital structure for rate making purposes, in that it does not include sources of customer-supplied capital, which is a regulatory concept. This approach is consistent with how external stakeholders (i.e. rating agencies) would assess Hydro's capital structure.

[5] In 2009, Hydro's Board of Directors approved a dividend policy whereby Hydro is to pay, on or before March 31 of each year, a dividend on common shares if the percentage of debt to debt plus equity in the regulated capital structure at the end of the preceding year is less than 75%. The amount of the dividend is to bring that percentage up to 75% based on the end of that previous fiscal year. As the dividend is not paid until March, the December 31 balance sheet for the previous fiscal year will not reflect a debt to debt plus equity ratio of 75%.

resulted in Hydro having an ROE target of 4.47% which, as illustrated in Chart 3.1, is well below that of its peers.

Chart 3.1[6]



In its November 2012 rating for Hydro, Dominion Bond Rating Service (DBRS) expected that an ROE of 8.80% would help improve Hydro's earnings and overall financial profile. Therefore, increasing Hydro's target ROE to NP's level will be an important step toward the objective of achieving and maintaining a sound financial position.

3.3.2 Capital Structure

Another important driver of financial stability is the proportion of debt in the capital structure of a company. Debt results in charges of interest and principal against the cash flows of a company. Hence, higher levels of debt impact a company's available cash flows. Providers of debt financing have a priority claim on the assets of the business should the business fail, whereas equity investors only have a residual claim. In addition, the return on an equity investment is subject to potential variability in the

[6] In Manitoba and Saskatchewan, regulatory decisions do not contain information on allowed cost of capital structure, as the Manitoba PUB and Saskatchewan Rate Review Panel do not approve or specify an allowed ROE. Rather, these bodies approve rates as proposed by Manitoba Hydro and SaskPower. Therefore, the ROEs for these entities represent the last-published target ROEs that fall out of the approved rates.

profits of a company. Consequently, capital structure targets also play a key role in maintaining a sound financial position.

Hydro's regulated capital structure for rate making purposes is comprised of net regulated debt[7], regulated equity, and customer-supplied capital, which includes a portion of Hydro's asset retirement obligations (AROs) and employee future benefits (EFBs). The inclusion of AROs and EFBs as customer-supplied capital is based on the nature of the underlying liabilities. With respect to the AROs and EFBs, Hydro recovers funds from ratepayers in advance of those funds being used to settle the liabilities in the future. The amounts are included in the regulated capital structure at zero cost.

A summary of Hydro's regulated capital structure for rate making purposes is presented in Table 3.2. The proportion of regulated debt in Hydro's regulated capital structure for rate making purposes has decreased significantly since 2006, driven largely by the equity contribution of $100 million in 2009.

Table 3.2

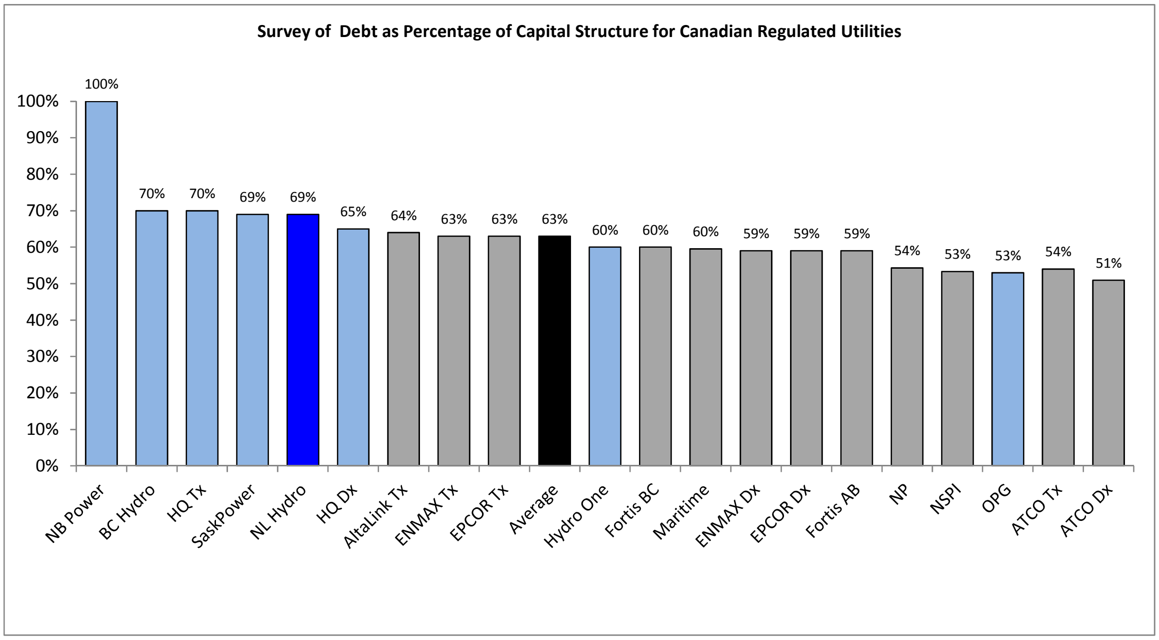
Newfoundland and Labrador Hydro
Proportion of Debt in Hydro's Regulated Capital Structure
($ millions)

	As at 31-Dec-06	As at 31-Dec-07	As at 31-Dec-08	As at 31-Dec-09	As at 31-Dec-10	As at 31-Dec-11	As at 31-Dec-12	*Forecast 31-Dec-13*
Promissory notes	63.2	7.1	163.1	-	-	-	52.0	*106.6*
Current portion of long-term debt	8.3	208.3	8.4	8.2	8.2	8.2	8.2	*8.2*
Long-term debt	1,357.4	1,151.1	1,146.4	1,141.6	1,136.7	1,131.5	1,125.9	*1,119.9*
Non-regulated debt pool	(43.3)	(40.4)	(18.0)	(3.5)	(5.5)	(5.1)	(7.2)	*(7.2)*
CF(L)Co Share Purchase debt	(18.8)	(6.0)	-	-	-	-	-	-
Sinking Funds, net of mark to market adjustment	(117.1)	(132.2)	(148.0)	(164.8)	(182.9)	(201.9)	(221.9)	*(242.6)*
Total regulated debt	**1,249.7**	**1,187.9**	**1,151.9**	**981.5**	**956.5**	**932.7**	**957.0**	***984.9***
Contributed capital (Regulated)	-	-	-	100.0	100.0	100.0	100.0	*100.0*
Retained earnings	205.8	211.0	219.7	236.9	212.6	212.1	231.2	*264.7*
Total regulated equity	**205.8**	**211.0**	**219.7**	**336.9**	**312.6**	**312.1**	**331.2**	***364.7***
Total regulated debt and equity	1,455.5	1,398.9	1,371.6	1,318.4	1,269.1	1,244.8	1,288.2	*1,349.6*
Employee future benefits, funded	35.5	39.8	41.9	44.0	48.3	53.6	56.9	*63.8*
Asset retirement obligations, funded	-	-	-	-	-	1.6	4.3	*7.2*
Total regulated capital	**1,491.0**	**1,438.7**	**1,413.5**	**1,362.4**	**1,317.4**	**1,300.0**	**1,349.4**	***1,420.6***
Regulated debt to total regulated capital	83.8%	82.5%	81.5%	72.0%	72.6%	71.7%	70.9%	69.3%
Average regulated debt to total regulated capital		***83.1%***	***82.0%***	***76.8%***	***72.3%***	***72.2%***	***71.3%***	***70.1%***

[7] Net regulated debt is equal to total debt less non-regulated debt less sinking funds.

For 2013, the proposed average percentage of regulated debt in the capital structure for rate making purposes is 70.1% as shown in Table 3.2. This remains reasonable when compared with the capital structures of a sample of other regulated utilities in Canada, as shown in Chart 3.2.

Chart 3.2[8, 9]



3.3.3 Credit Standing

In its November 2012 Credit Rating Report on Hydro, DBRS confirmed ratings on Hydro's long-term debt at A[10] and its short-term debt as R-1 (low). DBRS pointed out in their commentary that Hydro's ratings continued to be "*a flow through of the rating of the Province of Newfoundland and Labrador (the "Province"), which unconditionally guarantees the Company's debt.*"

[8] Debt percentages are based on available data published for utilities.

[9] Blue denotes a crown corporation.

[10] DBRS long-term debt ratings range from a low of D for a company in default, to a high of AAA, which denotes an exceptionally high financial capacity which is unlikely to be adversely affected by future events. Ratings above BBB are considered investment grade ratings. Short-term debt ratings follow a similar trend, ranging from R3 to R1 (high).

3.3.4 Target for Allowable Range of Return on Rate Base

Board Order No. P.U. 8(2007) provided Hydro with an allowed return on rate base of 7.44% and established an allowable range of return on rate base of +/- 15 bps. For 2013, Hydro is proposing a return on rate base of 7.83%, which would correspond to an allowable range of 7.68% to 7.98% based on the previously established range. However, given the impact of the measures taken by the Government to improve the capital structure and the new higher return on equity, Hydro is proposing the allowable range of return on rate base be increased to +/-25 bps. This request is supported by a report prepared by Ms. Kathy McShane of Foster and Associates, which is included as Exhibit 6.

3.3.5 Hydro's Application

Hydro is requesting the Board's approval of an allowable range of return on rate base of +/- 25 basis points.

3.4 INTERCOMPANY CHARGES AND SHARED SERVICES

As a result of the 2007 Energy Plan, a new crown corporation was established to take a lead role in the development of the Province's energy resources.

"*This Energy Corporation will be wholly owned by the Province and will be the parent company of Newfoundland and Labrador Hydro (NLH), Churchill Falls Labrador (CF(L)Co) Corporation, other subsidiaries currently owned by NLH and new entities created to manage the Province's investments in the energy sector. This will provide a structure that permits both regulated and non-regulated activities to exist and grow within separate legal entities"*[11].

The Corporation was subsequently named Nalcor Energy.

Hydro's mandate was expanded by its shareholder in 2005 and since that time new entities have been established. Nalcor assumed most of that expanded mandate and

[11] 2007 Energy Plan, Page 14.

has also entered into new lines of business. Newfoundland and Labrador Hydro is now a 100% owned subsidiary of Nalcor.

3.4.1 Hydro Activities

The activities currently taking place in Hydro include:

1. Operations

   The generation, transmission and distribution of electricity to serve customers on the Island Interconnected, Labrador Interconnected and Isolated Systems, including L'Anse au Loup.

2. Non-regulated Activities

   Certain non-regulated activities including the sale of Recall energy to external markets and to non-regulated customers in Labrador West. Detailed descriptions of non-regulated activities can be found in Exhibit 7.

3. Corporate Services

   The provision of services to support the regulated and non-regulated business of Hydro and other lines of business of Nalcor. This includes a range of activities including finance services, information services, supply chain management, human resources services, health and safety, as well as costs associated with the operation of Hydro Place.

3.4.2 Cost Recovery Methodologies

The expansion by Nalcor into lines of business other than electricity has resulted in changes in the organizational structure that has facilitated the sharing of resources among the Nalcor lines of business. The Nalcor companies have adopted cost-based methodologies for intercompany transactions and these transactions include labour charges, administration fees for services provided by Hydro to the other lines of business, as well as certain other costs and cost allocations.

The cost allocation methodologies employed adhere to the following principles:

Cost-based: Intercompany charges among lines of business are cost-based only.

Fair and reasonable: The result of allocations should fairly and reasonably reflect the cost of providing a service. The allocation of a cost should reflect a causal relationship between the provision of a service and the cost.

Accurate and traceable: The allocated charges should reflect the cost of the provision of services among entities with a reasonable degree of accuracy. Labour should be charged using time sheets based on work activity or, where there is cost sharing, the allocators should be a reasonable reflection of the cost driver.

Acceptable in a regulatory context: The methodology should be acceptable under a regulatory framework which demands a certain amount of rigour in development and design, taking into account the fact that results of the methodology may affect large groups of stakeholders, including end consumers of electrical energy in Newfoundland and Labrador.

Consistent with industry standards: The methodology should be consistent with industry standards and practices, where applicable, as well as best practices among Canadian utilities.

All costs charged across the lines of business are governed by the Intercompany Transaction Costing Guidelines attached as Exhibit 8.

3.4.3 Creation of the Nalcor Entity

3.4.3.1 Shared Services

Nalcor was created to "*permit(s) both regulated and non-regulated activities to exist and grow within separate legal entities*"[12]. Nalcor facilitates the sharing of personnel through a matrix organizational model as well as providing the ability to share costs

[12] 2007 Energy Plan, Page 14.

associated with Hydro's head office facilities. As a result, in 2008, there were 24 positions transferred from regulated Hydro to Nalcor, primarily in the areas of Executive Leadership, Corporate Communications, Internal Audit and Finance, as well as staff associated with non-regulated activities in Hydro such as business development. This has had a positive impact on Hydro as costs are able to be shared among the lines of business. The estimated savings for Hydro positions transferred from 2008 to 2013 is $9.1 million. This reduction in costs created a strategic opportunity for Hydro to:

- Expand its engineering and operations workforce; and
- Implement a retention and recruitment initiative, while keeping operating and maintenance costs close to inflationary levels.

Charts 3.3 to 3.5 shows net FTE information for regulated Hydro. Net FTEs in this chart represent:

- Hydro employees' time less time charged to other lines of business; plus
- Employees' time in other lines of business who charge time to Hydro.

Chart 3.3

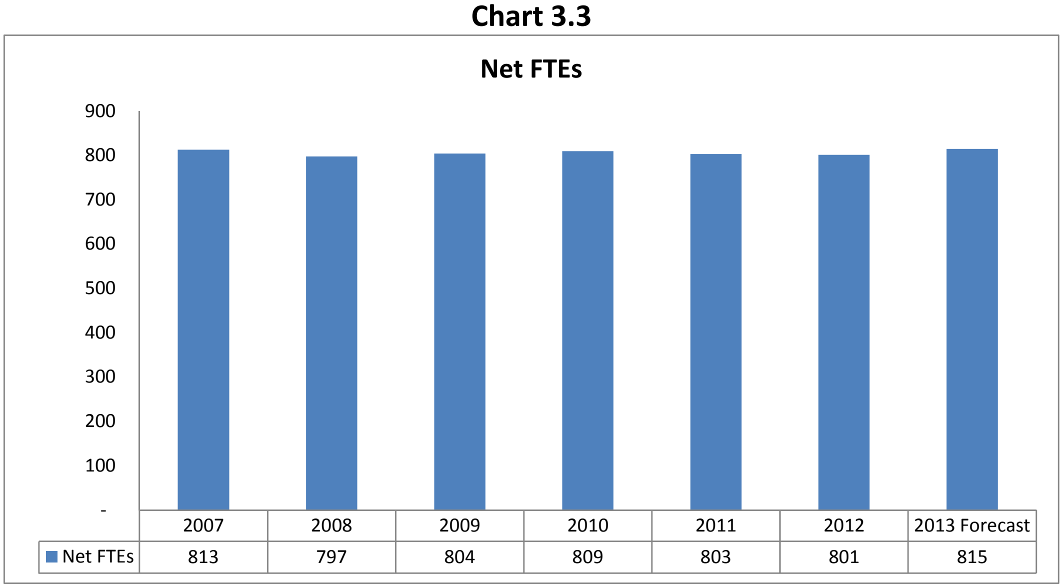


Chart 3.4

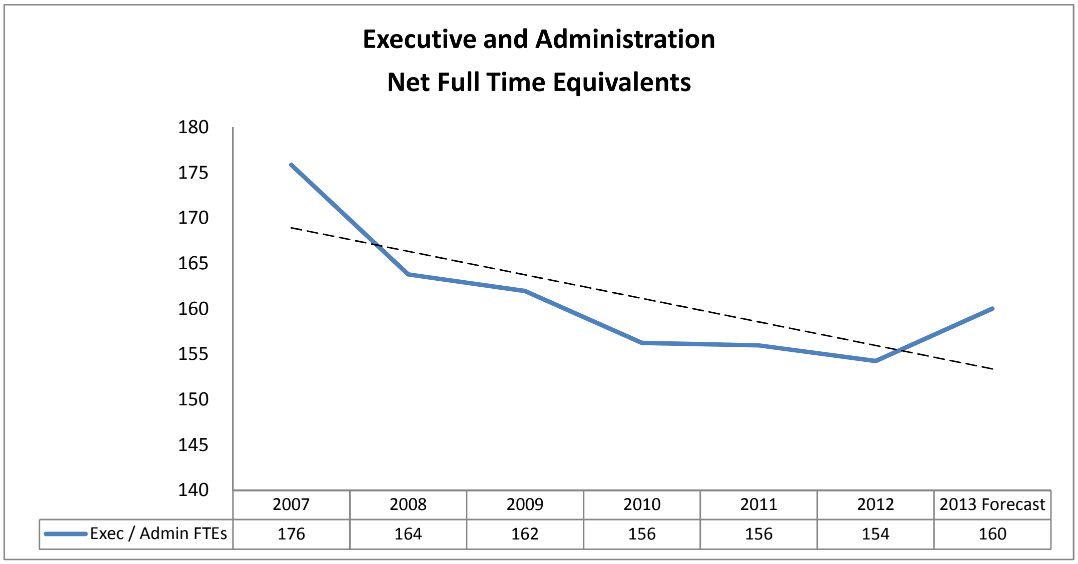
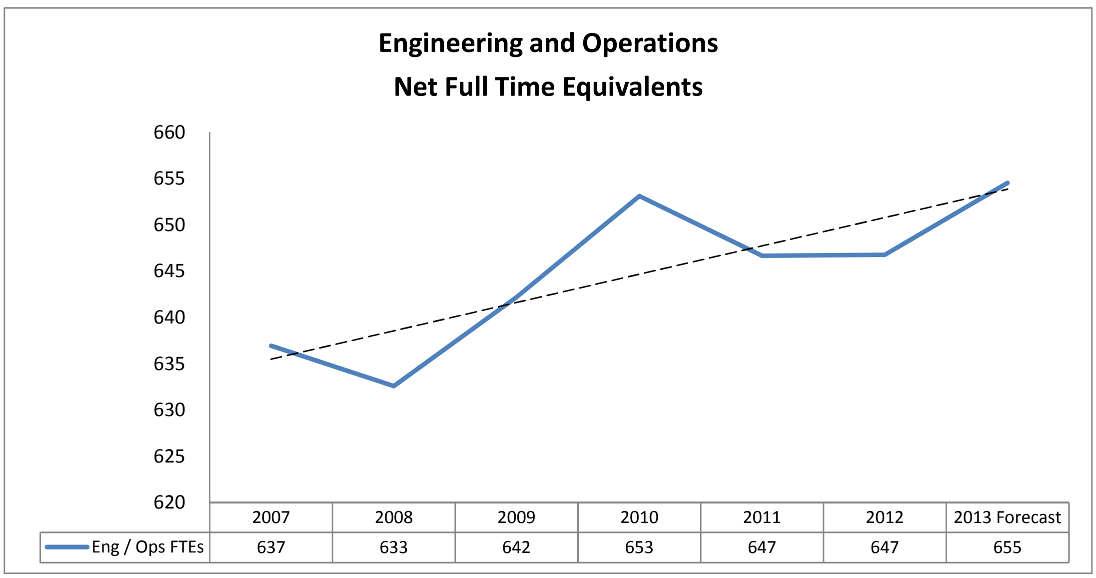


Chart 3.5

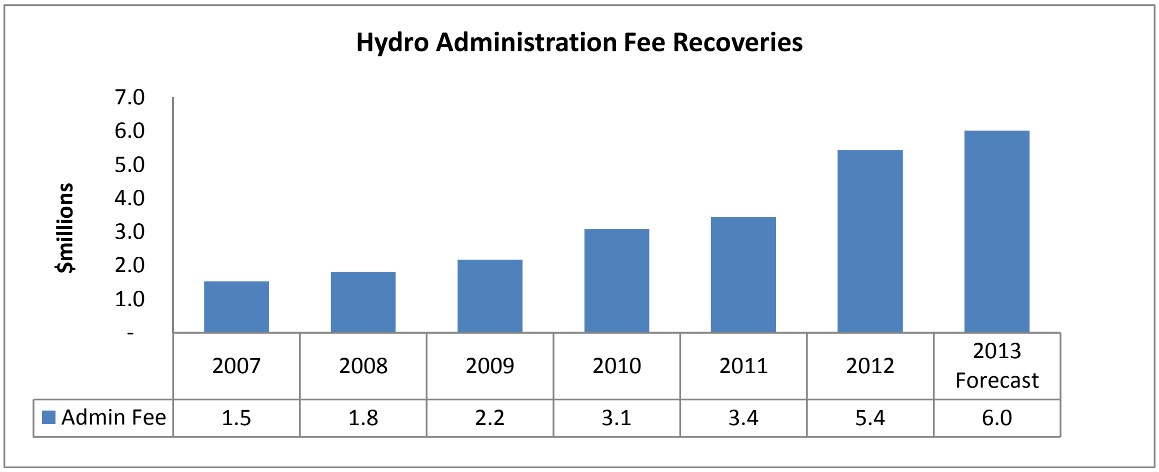


As can be seen from Chart 3.4, Executive and Administration net FTEs in Hydro have decreased from 2007 to 2013. This is mainly the result of FTEs having been transferred out of Hydro to Nalcor. Chart 3.5 shows that there has been an increase in Engineering and Operations net FTEs between 2007 and 2013. The sharing of services among the Nalcor entities has resulted in the ability to redeploy Hydro's workforce. Hydro has hired more of its own engineering staff where possible, rather than engaging external resources. Since 2007, total Hydro net FTEs have remained relatively consistent from 813 in 2007 to 815 in 2013.

3.4.3.2 Administration Fees

Hydro Place is the head office of both Hydro and Nalcor. As a result, Hydro is now able to share common costs at Hydro Place, including interest and depreciation, with other Nalcor entities. These costs are recovered through administration fees that Hydro charges to and recovers from Nalcor's other lines of business. Administration fee recoveries are shown in Chart 3.6.

Chart 3.6



There are also increased cost recoveries from shared services departments, such as HROE. For example, payroll staff in HROE have not increased, but the related costs are now shared by other lines of business. Additional information regarding the administration fee can be found in the Intercompany Transaction Costing Guidelines in Exhibit 8.

3.4.3.3 Intercompany Costs - Other

Certain other costs are incurred by Hydro to serve all lines of business. Table 3.3 outlines the types of costs and methods of allocation.

Table 3.3

Intercompany Costs - Other	
Type of Cost	**Allocation**
Advertising expenses administered by Nalcor	Allocated
Audit expenses	Direct billed
Bonus, performance contracts and signing bonuses	Bill rate
Branding costs administered by Nalcor	Not charged
Capital costs of Hydro Place emergency diesel power system	Admin fee
Capital costs of printers and fax machines	Admin fee
Cell phone expenses	Direct billed
Consultant costs associated with building	Admin fee
Corporate memberships	Allocated
Cost of postage machines	Admin fee
Directors expenses	Direct billed
Directors fees	Direct billed
Equipment for fitness centre and cafeteria	Admin fee
Freight and courier expenses	Direct billed
Group insurance – Administration costs	Admin fee
Group insurance – premiums	Direct billed
Heat and light expenses	Admin fee
Insurance expenses	Direct billed or allocated as per industry standard
Local area network (LAN) costs expenses	Admin fee
Long distance expenses	Admin fee
Nalcor annual report and annual general meeting expenses	Allocated across lines of business
Office equipment and maintenance expenses	Admin fee
Operating costs of Hydro Place emergency diesel power system	Not allocated
Postage expenses	Admin fee
Print forms and supplies	Admin fee
Purchase of miscellaneous office furniture	Admin fee
Rewards and recognition expenses	Admin fee
Routers, Multiplex (MUX), Switches acquisition costs	Admin fee
Safety supply expenses	Admin fee
Security system acquisition costs	Admin fee
Security system maintenance expenses	Admin fee
Telephone expenses	Admin fee
Telephone, LAN and wireless network acquisition costs	Admin fee
Treasury related fees	Direct billed
Wellness Program expenses	Admin fee

The allocation methods in Table 3.3 are defined as follows:

Administration fee (Admin fee) – Costs of common service business units, based in Hydro, that provide services to all Nalcor lines of business, are charged to the lines of business through an administration fee. Common service business units' costs include Human Resources, Safety and Health, Information Systems, Hydro Place office space and related costs and telephone and network costs. Further information is located in the Intercompany Transaction Costing Guidelines (Exhibit 8).

Allocated – Certain costs are allocated to lines of business using a causality based factor. For example, costs of the Human Resources department are allocated using FTEs. Further information is outlined in the Intercompany Transaction Costing Guidelines (Exhibit 8).

Bill Rate – Bill rate is the rate charged after a factor is applied to hourly wage rates to cover employee related costs such as fringe benefits, payroll taxes, bonuses and certain travel benefits. The factor is based on average total available working hours. Further information is outlined in the Intercompany Transaction Costing Guidelines (Exhibit 8).

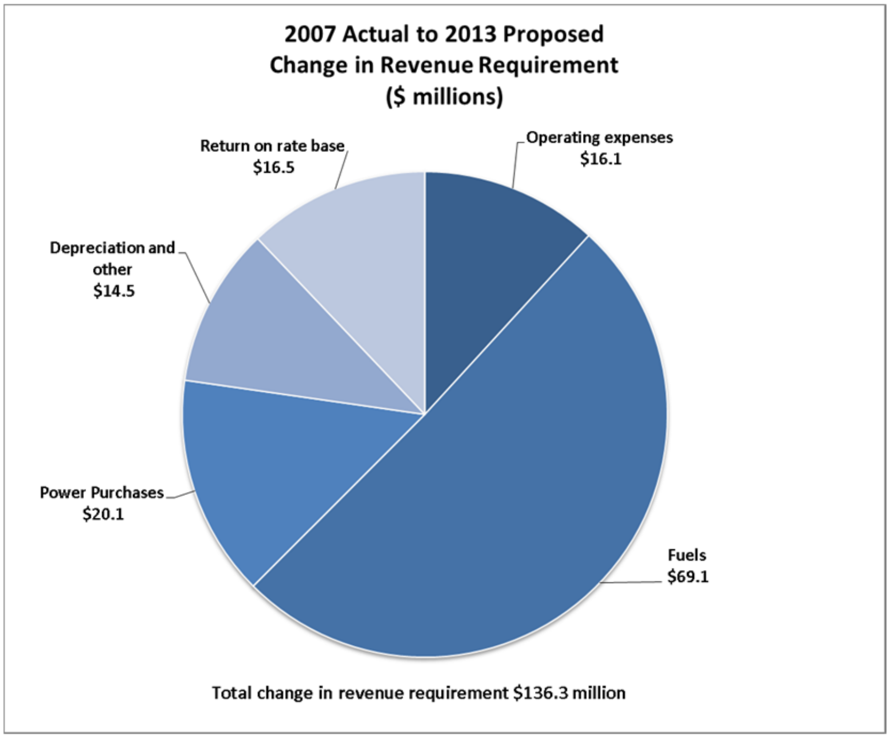
Direct billed – Direct billed refers to costs that are clearly related to a line of business and can be billed directly to that entity (one to one relationship).

Not allocated/charged – Not allocated/charged refers to costs that are specific to one entity only or are not charged to another line of business. For example, Nalcor branding costs are not charged to Hydro and costs associated with the on-site diesel unit in Hydro Place, which is associated with Hydro's Energy Control Centre, are accounted for by Hydro.

3.5 2013 REVENUE REQUIREMENT

Details of Hydro's forecasted revenue requirement are outlined in Schedule III, Page 1 of 2. The total forecasted revenue requirement in 2013 is $568.1 million, an increase of $136.3 million over the 2007 actual of $431.8 million. The major components of Hydro's revenue requirement are the costs of fuels, power purchases, depreciation and other, operating expenses and return on rate base. Chart 3.7 provides an overview of the $136.3 million change in Hydro's revenue requirement by component.

Chart 3.7



The categories of the revenue requirement in Schedule III, attached to this Section, provides Hydro's historical financial comparative results for 2007 and forecast results for 2013 based on the proposals set out in this Application. The following describes the more significant line items found on the Financial Results and Forecast Statement for 2007 and 2013 as shown on Schedule III, Page 1 of 2.

3.5.1 Operating Expenses

Operating expenses represent 20.0% of Hydro's 2013 revenue requirement. Operating expenses are forecasted to increase by $16.1 million or 16.5% from 2007 to 2013. Operating expenses for 2013 are discussed in Section 2.4.

3.5.2 Fuels

Fuel expenses for 2013 are based on the March 2013[13] price forecast of the PIRA Energy Group, Hydro's provider of fuel price forecasts. Fuel expenses in 2013 compared to

[13] Hydro will update its PIRA based fuel forecast in a revised filing during Hydro's GRA proceeding.

2007 are forecasted to increase by $69.1 million or 46.0%. Explanations regarding changes in fuel costs are contained in Section 2.6.

3.5.3 Power Purchases

Power purchases are forecasted to increase by $20.1 million or 52.0% over the period 2007 to 2013. This is primarily the result of energy purchases from two wind generation projects in addition to changes in power purchase arrangements related to Exploits Generation, offset by reduced energy purchases from the CBPP co-generation unit. As outlined in Section 1.2.2, it is estimated that, in 2013 the combined benefit of these new energy sources will total approximately $74.0 million in avoided fuel costs at Holyrood. Further explanation regarding power purchase costs is contained in Section 2.6.1.

3.5.4 Amortization and Other

Amortization expense and loss on disposal of assets forecasted for 2012 and 2013 have been computed using the methodology and service lives approved by the Board in Order No. P.U. 40(2012). Amortization and other costs are forecasted to increase by $14.5 million or 37.0% over the period 2007 to 2013. This increased depreciation expense is primarily due to Hydro's continued investment in its electrical systems.

3.5.5 Return on Rate Base

Board Order No. P.U. 8(2007) provided Hydro with an allowed return on rate base of 7.44% and a range of plus or minus 15 bps. As shown on Schedule 1, Page 5 of 11, and Table 3.4, actual return on rate base ranged from a low of 6.29% in 2010 to a high of 7.46% in 2011.

Table 3.4

Return on Rate Base						
	Actual					
	2007	2008	2009	2010	2011	2012
Return on Rate Base	7.14%	6.48%	6.83%	6.29%	7.46%	7.01%
Return on Rate Base in Order No. P.U. 8(2007)	7.44%	7.44%	7.44%	7.44%	7.44%	7.44%

Hydro proposes a rate of return on rate base for 2013 of 7.83%, which is applied to a forecasted average rate base of $1,564.1 million.

3.5.6 Return on Equity

The return on rate base set by the Board in Order No. P.U. 8(2007) reflected a return on equity of 4.47% as shown in Table 3.5.

Table 3.5

Return on Equity						
	Actual					
	2007	2008	2009	2010	2011	2012
Return on Equity	1.30%	4.12%	6.18%	2.03%	6.59%	5.25%
Return on Equity in Order No. P.U. 8(2007)	4.47%	4.47%	4.47%	4.47%	4.47%	4.47%
NP Return on Equity	9.75%	8.69%	9.00%	8.38%	8.38%	8.38%

Hydro’s actual ROE, shown in Table 3.5, ranged from a low of 1.30% in 2007 to a high of 6.59% in 2011, significantly less than NP’s ROE.

In 2009, the Government directed that Hydro be permitted to target an ROE equal to that set for NP effective with Hydro’s next general rate application. NP’s allowable ROE per Board Order No. P.U. 13(2013) is 8.80%.

3.5.7 Hydro’s Application

Hydro is requesting the Board’s approval of:

- its 2013 Test Year costs of $445,639,000 (before return on rate base);
- its forecast return on rate base of 7.83%; and
- its forecast return on equity of 8.80%.

3.6 2013 FORECAST RESULTS – EXISTING RATES

Schedule II, Page 1 of 1 contains the 2013 forecasted results assuming no change in rates as compared to those in the Test Year 2007.

Hydro's 2013 forecasted net income of $14.2 million would result in a return on rate base of 6.68% which is significantly below the lower end of Hydro's approved range of return on rate base of 7.29% (2007 test year return on rate base of 7.44% minus 15 bps).

3.7 RETURN ON RATE BASE

3.7.1 Forecast Rate Base

Hydro's rate base is comprised of its investment in capital assets, unamortized balances of deferred charges, fuel inventory, materials and supplies inventory and cash working capital allowances. Schedule I, Page 5 of 11, provides details of the rate base elements from 2007 to 2013. The average rate base for 2013 is forecasted at $1,564.1 million. This compares to an average rate base in 2007 of $1,483.5 million. Table 3.6 shows the changes in the components of rate base.

Table 3.6

Changes in Components of Rate Base
Year ended December 31
($000)

	2007 Actual	2013 Forecast	Change
Capital Assets - Current Year	1,349,694	1,453,448	103,754
Capital Assets - Previous Year	1,345,766	1,387,986	42,220
Unadjusted Capital Assets - Average	1,347,730	1,420,717	72,987
Less: Average net assets not in use	-	(3,005)	(3,005)
Capital Assets - Average	1,347,730	1,417,712	69,982
Cash Working Capital Allowance	3,496	5,336	1,840
Fuel	25,874	50,885	25,011
Materials and Supplies	21,699	24,701	3,002
Deferred Charges	84,725	65,451	(19,274)
Average Rate Base	**1,483,524**	**1,564,085**	**80,561**

3.7.1.1 Labrador Interconnected Rate Base

The net book value[14] of Labrador Interconnected capital assets, a major contributor to the Labrador Interconnected portion of rate base, has increased by $26.2 million from $42.4 million in the 2007 Test Year to $68.6 million in the 2013 Test Year, resulting in a significant impact on Labrador Interconnected rates. In 2008, a Labrador City Distribution System Upgrading Study[15] determined that a voltage conversion to 25 kV was the preferred technical and economic alternative to address load growth in Labrador City beyond the current capacity of the system. The proposed upgrade involves the reconfiguration of the substations and 46 kV sub-transmission lines supplying power to the area and a voltage conversion to the distribution lines that supply Hydro customers. In 2012, capital costs of $7.6 million related to the substations and $4.5 million related to the distribution assets were placed into service and in 2013 an additional $19.9 million related to the distribution assets are to be placed into service. These assets have been included in rate base and depreciation expense for 2013 has been calculated based upon the scheduled in service timing.

3.7.2 Forecast Capital Structure

Details of Hydro's capital structure are outlined in Schedule I, Page 4 of 11. There are four principal components of Hydro's regulated capital structure:

- Debt;
- Asset retirement obligations;
- Employee future benefits; and
- Shareholder's equity (retained earnings and contributed capital).

[14] The net book value has increased by $26.2 million, whereas the original cost from 2007 to 2013 has increased by approximately $39.0 million.
[15] Filed as part of Hydro's 2009 Capital Budget Application.

Hydro's regulated debt to total regulated capital ratio is forecasted to improve from 82.5% at the end of 2007 to a projected 69.3% by the end of 2013, as shown in Table 3.2.

Weighted average cost of capital is derived from the proportionate cost of the components of Hydro's capital structure. Hydro's forecasted embedded cost of debt for 2013 is 8.01% and the proposed ROE used in this filing is 8.80%. Details of the computation of Hydro's cost of debt are outlined in Schedule IV, Page 1 of 1 of this evidence. The proposed return on equity is based on the ROE for NP of 8.80% per Board Order No. P.U. 13(2013). The derivation of Hydro's weighted average cost of capital is presented in Table 3.7.

Table 3.7

Weighted Average Cost of Capital
Proposed December 31, 2013

	Cost Rate	**Average Capital Structure Ratios**	**Weighted Component**
Debt	8.01%	70.1%	5.62%
Asset Retirement Obligation	0.00%	0.4%	0.00%
Employee Future Benefits	0.00%	4.4%	0.00%
Equity	8.80%	25.1%	2.21%
Weighted Average Cost of Capital			**7.83%**

3.7.2.1 Forecast Debt

Hydro is projecting a decline in the balance of regulated debt outstanding from $1,187.9 million at December 31, 2007 to $984.9 million as at December 31, 2013, as shown in Table 3.2. This decline is primarily due to the maturity of the Series AA bond issue in 2008, which reduced debt outstanding by $200 million. Over the course of 2009 to 2011, Hydro was able to finance its capital expenditures without issuing new long-term debt.

3.7.2.2 Forecast Asset Retirement Obligation

Asset retirement obligations are considered by Hydro to be a zero cost component of its capital structure as shown in Table 3.7 above. The amount included in capital structure includes the portion of the AROs which is proposed to be recovered from customers (the funded portion) through inclusion in net income, through both depreciation of the asset retirement cost (ARC) and accretion of the ARO which is recorded as a liability. Further discussion of the treatment of the AROs is included in Section 3.8.5. The forecasted balance of funded ARO at the end of 2013 is $7.2 million, as shown in Schedule 1, Page 11 of 11. No ARO existed in 2007.

3.7.2.3 Forecast Employee Future Benefits

Employee future benefits (EFBs) are considered by Hydro to comprise part of its capital structure at zero cost as shown in Table 3.7. The amount included in capital structure includes the portion of EFBs which has been recovered from customers through inclusion in revenue requirement through EFB expense. Based upon the results of the 2012 actuarial valuation, the EFB liability, including amortized actuarial gains and losses, is forecasted to be $63.8 million at the end of 2013, as shown on Schedule 1, Page 8 of 11. Only the amortized portion of actuarial gains and losses has been included in revenue requirement. Further discussion of the treatment of EFB liabilities is included in Section 3.8.3.

3.7.2.4 Forecast Equity

Equity includes past earnings of Hydro and equity contributions to Hydro by its Shareholder, offset by dividends paid to its Shareholder. The forecasted equity of Hydro includes $264.5 million of retained earnings and $100.0 million of contributed capital at the end of 2013.

3.7.3 Forecast Return on Rate Base

The 2013 forecasted return on rate base is outlined in Schedule I, Page 5 of 11. The total forecasted return for 2013 is $122.4 million consisting of $33.4 million in net income and $89.0 million in interest.

The forecasted interest expense of $89.0 million for 2013 represents a decrease of $14.2 million as compared to $103.2 million in 2007. This decrease is primarily due to reductions of $9.4 million in debt guarantee fee, $11.0 million in interest on long-term debt and $7.9 million in interest earned on sinking funds, offset by a $13.3 million increase in interest expense related to the RSP.

The forecasted return on rate base is 7.83%. The calculation of the rate of return on rate base is outlined in Table 3.8.

Table 3.8

Return on Rate Base (RORB)[16]
Year ended December 31
($000)

	2013 Forecast
Net Income	33,357
Add: Interest	89,043
Add: Cost of Service Exclusions	48
Return on Rate Base	122,448
Average Rate Base	1,564,085
Rate of Return on Average Rate Base	**7.83%**
Allowable RORB Range (+/- 0.25)	7.58% to 8.08%

3.7.4 Hydro's Application

Hydro is requesting the Board's approval of its forecast average rate base of $1,564,085,000.

[16] Schedule I, Page 5 of 11 provides comparable 2007 Return on Rate Base.

3.8 OTHER COST AND ACCOUNTING MATTERS

3.8.1 Accounting Reporting Standards

In a separate application to the Board in 2011, Hydro requested approval to adopt International Financial Reporting Standards (IFRS). The application outlined that, as a rate-regulated enterprise, Hydro was required to adopt IFRS for periods beginning on or after January 1, 2012, for external financial reporting purposes. Specifically, Hydro made application that the Board accept the use of IFRS as its financial reporting standard. The application requested that Hydro be allowed to:

- Maintain existing accounting guidelines with respect to the reporting of RSP balances and activity;
- Maintain existing accounting guidelines with respect to the reporting of deferred costs subject to Board Orders; and
- Allow 2011 transitional differences arising from IFRS adoption to be adjusted in 2012 opening retained earnings.

In Order No. P.U. 13(2012), dated May 15, 2012, the Board approved the application and also ordered that Hydro:

- Include unamortized deferred revenue as a reduction from rate base; and
- Record the net insurance proceeds associated with capital projects of $50,000 or more as an offset against the cost of capital assets and as a reduction of the rate base value of those assets.

In early 2013, a decision was made by the Canadian Accounting Standards Board to develop an interim standard that would allow recognition of regulatory assets and liabilities as was the case under Canadian Generally Accepted Accounting Principles (GAAP) for first time adopters of IFRS. In addition, the mandatory date for adoption of IFRS was extended to January 1, 2015. In early 2013, Hydro chose to accept the deferral option for the year ended December 31, 2012. The approvals outlined in Order No. P.U. 13(2012) will be used as the basis for financial reporting.

3.8.2 Rate Stabilization Plan

On January 1, 1986, Hydro implemented the RSP which allows for annual rate adjustments related to the deferral of cost variances resulting from changes in fuel prices, hydraulic production and load. Rate adjustments for the amortization of the plan balance are implemented on July 1 of each year for NP. The rules of the RSP also prescribe similar adjustments for IC rates to be implemented on January 1 of each year. Since 2007, however, RSP rates for ICs have been frozen and were made interim by the Board effective January 1, 2008. Further details on the RSP activity over the period since 2007 is outlined in the "Rate Stabilization Plan Evidence" filed with the Board in a separate application.

On April 4, 2013[17], Government issued two Orders in Council (OCs) which address a portion of the balance which has accumulated in the RSP since 2007. From January 1, 2007 to August 31, 2013, an estimated $160 million related to the Load Variation component of the RSP, referred to as the RSP Surplus, will have accumulated. In accordance with the OCs, effective August 31, 2013, $49 million of the RSP Surplus is to be allocated to IC and the remaining amount, estimated at $111 million, is to be allocated to NP. For the purposes of this Application, the RSP Surplus is allocated in accordance with Government OCs[18] and no further distribution of these amounts is assumed. Further details on the RSP Surplus and proposed changes to the RSP rules are outlined in the RSP and IC Rates Evidence.

[17] Subsequently amended July 16, 2013.

[18] At the time of preparation of the GRA, the OCs dated April 4, 2013 were in effect and are thus reflected in the filing. Revised OCs have been issued by Government subsequently, however, given that there is no assumed payout of the RSP Surplus in 2013, there is no material effect on the rates derived and presented in the GRA evidence.

3.8.3 Employee Future Benefits

Hydro provides a severance payment upon retirement and group life insurance and health care benefits on a cost-shared basis to retired employees. The expected cost of providing these EFBs is accounted for on an accrual basis, and has been actuarially determined using the projected benefit method prorated on service and using management's best estimate of salary escalation, retirement ages of employees, and expected health care costs. Schedule I, Page 8 of 11, shows the details of Hydro’s EFB liability and obligation for the period 2007 through 2013.

Prior to 2011, the EFB liability included only the amortized portion of cumulative actuarial gains and losses with the remainder deferred and amortized to income over the expected average remaining service life of the employee group (referred to as the corridor method). To minimize regulatory and external accounting differences due to changes in accounting standards, the Board approved Order No. P.U. 13(2012). Under this Order, Hydro effectively deferred all actuarial gains and losses. Using this methodology, a portion of the expense associated with EFB’s would not be included in revenue requirement. The cumulative actuarial gains and losses are a significant component of the true cost of providing retirement benefits and of the overall costs associated with the provision of electrical service, and as such should be included in Hydro’s GRA.

As a result, Hydro is now proposing to include the amortization of cumulative actuarial gains and losses as part of the revenue requirement consistent with the methodology used to establish existing rates.

3.8.4 Deferred Charges

Deferred Charges are costs that are deferred to a future period, rather than being accounted for in the period in which they were incurred. Such costs are amortized over a prescribed period of time. Hydro amortizes such costs as noted in Table 3.9 for periods ranging from three to 28 years.

Hydro continues to amortize costs associated with foreign exchange losses consistent with past practice. Pursuant to Order Nos. P.U 14(2009), No. P.U. 13(2010), No. P.U. 4(2011) and No. P.U. 3(2012), Hydro received approval to defer costs associated with CDM expenditures related to electricity conservation programs for residential, industrial and commercial sectors.

An estimate of $1.0 million in external regulatory costs is forecasted to be incurred with respect to this GRA application and it is proposed that Hydro defer and amortize these costs over a three-year period, commencing in 2013.

Table 3.9

Deferred Charges ($millions)				
	Jan. 1, 2013 Opening Balance	Additions	Amortization	Dec. 31, 2013 Ending Balance
Foreign Exchange	62.6	-	2.2	60.4
CDM	2.4	2.6	0.2	4.8
General Rate Application	-	1.0	0.3	0.7
Total	65.0	3.6	2.7	65.9

3.8.5 Asset Retirement Obligations

Asset Retirement Obligations represent legal or constructive obligations associated with the retirement of long-lived assets. Accounting standards require that the estimated present value of the AROs be added to the original cost of the related asset [an Asset Retirement Cost, (ARC)] and an offsetting liability be recognized. Over time, the ARC is depreciated and the ARO increases (or accretes) toward its future value.

Hydro recorded a liability for decommissioning long-lived assets in the 2010 audited financial statements. In 2011, the financial reporting of accretion and depreciation expense on AROs commenced. Hydro applied to the Board in May 2012 to include depreciation and accretion expenses in its next GRA to start recovering the costs from ratepayers through revenue requirement. In Order No. P.U. 29(2012), the Board ordered that Hydro recognize and record asset retirement obligations and indicated that regulatory treatment of AROs would appropriately be considered within the context of a GRA. In 2012, Hydro continued to record and report, in the audited financial statements, AROs and corresponding expenses in accordance with Canadian GAAP.

3.8.5.1 Existing AROs

Hydro has recorded AROs for the following:

- Holyrood Dismantling and Cleanup Costs (Holyrood ARO):
  In 2010, planning for the conversion of Holyrood to a synchronous condenser operation was contemplated. This future conversion would require the decommissioning of certain components of the Holyrood facility. The Holyrood ARO was initially recorded in Hydro's 2010 financial statements using the best information at that time and was then updated in Hydro's 2011 financial statements with revised projections. In 2012, Hydro hired an external firm to prepare a report on the decommissioning of the Holyrood Thermal Generating Station (Exhibit 14) and updated the ARO in the 2012 financial statements based upon the results of the report. The total undiscounted estimated cash flows required to settle the Holyrood ARO at December 31, 2012 were $32.1 million. Payments to settle are expected to occur between 2020 and 2024.

- Transformers Containing Polychlorinated Biphenyls (PCBs) (PCB ARO):
  Hydro, like other CEA members, has a significant amount of sealed equipment (instrument transformers and bushings) with unknown levels of PCBs. Federal Government PCB Regulations SOR/2008-273, state in Section 16, the end-of-use date for equipment containing PCBs that are above 500 mg/kg was December 31, 2009. In 2009, Hydro applied for and, in 2010, was granted an extension to 2014 by Environment Canada (EC) to replace sealed equipment that is suspected to contain PCBs above 500 mg/kg. Hydro's application document to EC stated that due to the volume of equipment requiring replacement the plan was a "pro

forma" plan and a more realistic plan would be to extend the replacement to 2025. EC subsequently proposed an amendment on June 6, 2013 to the regulations which would increase the deadline from 2014 to 2025 and are accepting comments for 60 days. Hydro has recorded an ARO reflecting the legal obligation to dispose of sealed instrument transformers and bushings expected to contain PCBs. The total undiscounted estimated cash flows required to settle the PCB ARO at December 31, 2012 was $2.7 million. Cash payments to settle the obligations began in 2012 and are expected to continue until 2025.

Depreciation costs of $2.3 million and accretion costs of $0.8 million are included in the 2013 Test Year Revenue Requirement for AROs.

3.8.6 Hydro's Application

Hydro is requesting the Board's approval for the following:

- treatment of Asset Retirement Obligations as proposed in this section; and
- treatment of actuarial gains and losses on employee future benefits as proposed in this section.

List of Schedules

Newfoundland and Labrador Hydro
Financial Results and Forecasts
Statement of Income and Retained Earnings
($000)

		Actual						Proposed
		2007	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
1	**Revenue**							
2	Energy sales	429,794	425,196	425,528	414,774	443,796	453,178	565,737
3	Other revenue	1,983	2,197	2,218	2,287	2,317	2,116	2,350
4	**Total revenue**	431,777	427,393	427,746	417,061	446,113	455,294	568,087
5								
6	**Expenses**							
7	Operating expenses	97,693	96,694	100,369	96,976	104,564	106,468	113,820
8	Loss on disposal of property, plant, and equipment	902	2,580	1,267	687	925	5,396	1,304
9	Fuels	150,281	149,854	136,933	137,994	131,275	132,003	219,390
10	Power purchases	38,606	41,388	46,782	44,244	52,222	56,986	58,674
11	Amortization	38,342	40,393	41,744	43,790	45,217	46,865	51,656
12	Accretion of asset retirement obligation	-	-	-	-	467	715	843
13	Interest	103,242	87,610	83,440	86,766	90,844	89,961	89,043
14	**Total expenses**	429,066	418,519	410,535	410,457	425,514	438,394	534,730
15								
16	**Net income**	2,711	8,874	17,211	6,604	20,599	16,900	33,357
17								
18	**Retained Earnings**							
19	Balance at beginning of year	208,147	210,858	219,732	236,943	212,647	212,096	231,174
20	Opening adjustment - retained earnings	-	-	-	-	-	2,178	-
21	Dividends	-	-	-	(30,900)	(21,150)	-	-
22	**Balance at end of year**	210,858	219,732	236,943	212,647	212,096	231,174	264,531

Newfoundland and Labrador Hydro
Financial Results and Forecasts
Balance Sheet
($000)

		Actual						Proposed
		2007	2008	2009	2010	2011	2012	2013
1	**Assets**							
2	Current assets							
3	Cash and cash equivalents	-	-	10,942	37,760	6,685	2,480	-
4	Short-term investments	-	-	20,000	8,992	-	-	-
5	Accounts receivable	69,114	69,495	65,703	61,678	79,569	80,373	55,202
6	Current portion of regulatory assets	17,154	5,000	4,789	3,851	2,762	2,157	2,824
7	Inventory	60,925	42,993	49,964	53,390	54,258	51,673	74,077
8	Prepaid expenses	841	1,156	1,492	2,322	2,284	2,949	2,221
9		148,034	118,644	152,890	167,993	145,558	139,632	134,324
10								
11	Property, plant, and equipment	1,352,229	1,354,348	1,364,205	1,386,061	1,410,432	1,440,619	1,492,240
12	Sinking funds	151,765	163,881	179,613	208,381	246,966	263,330	284,010
13	Regulatory assets	81,308	74,626	69,324	65,885	63,597	62,824	63,096
14								
15	**Total assets**	1,733,336	1,711,499	1,766,032	1,828,320	1,866,553	1,906,405	1,973,670
16								
17	**Liabilities and shareholder equity**							
18	Current liabilities							
19	Promissory notes	8,016	4,557	-	-	-	52,000	106,606
20	Accounts payable and accrued liabilities	65,295	46,212	51,115	65,237	49,341	39,299	46,207
21	Accrued interest	30,566	28,667	28,667	28,667	28,667	28,667	28,667
22	Current portion of long-term debt	208,315	8,322	8,150	8,150	8,150	8,150	8,150
23	Current portion of regulatory liabilities	23,488	22,324	89,814	118,849	137,593	168,985	143,853
24	Deferred capital contribution	-	470	165	123	3,497	1,938	1,420
25	Due to related parties	182	450	21,441	37,224	49,258	1,873	6,704
26	Promissory notes - non-regulated	(33,421)	145,004	(3,531)	(5,521)	(5,118)	(7,217)	(7,217)
27		302,441	256,006	195,821	252,729	271,388	293,695	334,390
28								
29	Long-term debt	1,145,198	1,146,414	1,141,618	1,136,755	1,131,542	1,125,901	1,119,876
30	Regulatory liabilities	15,499	31,546	32,788	40,931	33,271	33,174	24,969
31	Asset retirement obligations	-	-	-	11,395	19,593	24,031	24,528
32	Employee future benefits	39,805	41,881	44,060	48,348	53,556	56,890	63,836
33	Contributed capital	-	-	100,000	100,000	100,000	100,000	100,000
34	Shareholder's equity / retained earnings	210,858	219,732	236,943	212,647	212,096	231,174	264,531
35	Accumulated other comprehensive income	19,535	15,920	14,802	25,515	45,107	41,540	41,540
36								
37	**Total liabilities and shareholder's equity**	1,733,336	1,711,499	1,766,032	1,828,320	1,866,553	1,906,405	1,973,670

Newfoundland and Labrador Hydro
Financial Results and Forecasts
Statement of Cash Flows
($000)

		Actual						Proposed
		2007	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
1	**Cash provided by (used in)**							
2	Operating activities							
3	Net income	2,711	8,874	17,211	6,604	20,599	16,900	33,357
4	Adjusted for items not involving cash flow							
5	Amortization	38,342	40,393	41,744	43,790	45,217	46,865	51,656
6	Accretion of long-term debt	675	479	394	426	460	498	540
7	Accretion of asset retirement obligation	-	-	-	-	467	715	843
9	Employee future benefits	4,268	2,560	2,179	4,288	5,208	4,521	6,946
10	Loss on disposal of property, plant and equipment	902	2,580	1,267	687	925	3,844	1,304
11	Other	(92)	-	-	-	-	92	-
12		46,806	54,886	62,795	55,795	72,876	73,435	94,646
13	**Changes in non-cash balances**							
14	Accounts receivable	(9,698)	(381)	3,792	4,025	(17,891)	(804)	25,171
15	Inventory	(15,482)	17,932	(6,971)	(3,426)	(868)	2,585	(22,404)
16	Prepaid expenses	244	(315)	(336)	(830)	38	(665)	728
17	Regulatory assets	49,744	18,836	5,513	4,377	3,377	1,378	(939)
18	Regulatory liabilities	(11,382)	14,883	68,732	37,178	11,084	31,295	(33,337)
19	Accounts payable and accrued liabilities	27,214	(19,083)	4,903	14,122	(15,896)	(10,042)	6,908
20	Accrued interest	-	(1,899)	-	-	-	-	-
21	Due to related parties	(3,288)	268	20,991	15,783	12,034	(47,385)	4,831
23		84,158	85,127	159,419	127,024	64,754	49,797	75,604
24	**Financing activities**							
25	Increase (decrease) in long-term debt	12,691	(188,692)	(172)	-	-	-	-
26	Increase (decrease) in deferred capital contribution	-	470	(305)	(42)	3,374	(1,559)	(518)
27	Increase in contributed capital	-	-	100,000	-	-	-	-
28	Dividends	-	-	-	(30,900)	(21,150)	-	-
29	(Decrease) increase in promissory notes - non-regulated	(49,483)	172,911	(148,535)	(1,990)	403	(2,099)	-
30	Increase in promissory notes	-	-	-	-	-	52,000	54,606
32	Transfer of employee future benefits to non-regulated	-	(484)	-	-	-	-	-
33		(36,792)	(15,795)	(49,012)	(32,932)	(17,373)	48,342	54,088
34	**Investing activities**							
35	Additions to property, plant and equipment	(36,023)	(45,785)	(54,097)	(55,401)	(63,083)	(77,474)	(104,982)
36	Decrease (increase) in short term investments	560	-	(20,000)	11,008	8,992	-	-
37	Proceeds on disposal of property, plant and equipment	602	693	1,229	463	301	1,200	317
38	Settlement of asset retirement obligation	-	-	-	-	-	-	(262)
39	Increase in sinking funds	(19,592)	(20,781)	(22,040)	(23,344)	(24,666)	(26,070)	(27,245)
40		(54,453)	(65,873)	(94,908)	(67,274)	(78,456)	(102,344)	(132,172)
41								
42	**Net (decrease) increase in cash**	(7,087)	3,459	15,499	26,818	(31,075)	(4,205)	(2,480)
43								
44	**Cash position, beginning of year**	(929)	(8,016)	(4,557)	10,942	37,760	6,685	2,480
45								
46	**Cash position, end of year**	(8,016)	(4,557)	10,942	37,760	6,685	2,480	-

Newfoundland and Labrador Hydro
Financial Results and Forecasts
Capital Structure
($000)

		Actual						Proposed
		2007	2008	2009	2010	2011	2012	2013
1	**Regulated capital structure**							
2	Long-term debt	1,353,513	1,154,736	1,149,768	1,144,905	1,139,692	1,134,051	1,128,026
3	Promissory notes	7,000	163,000	-	-	-	52,000	106,606
4	Promissory notes - related party	88	90	-	-	-	-	-
5	less: sinking funds	(151,765)	(163,881)	(179,613)	(208,381)	(246,966)	(263,330)	(284,010)
6	add: mark to market of sinking funds	19,535	15,920	14,802	25,515	45,108	41,425	41,425
7		1,228,371	1,169,865	984,957	962,039	937,834	964,146	992,047
8	Cost of service exclusions	-	-	-	-	-	-	-
9	Non-regulated debt pool	(40,421)	(17,996)	(3,531)	(5,521)	(5,118)	(7,217)	(7,217)
10	Net regulated debt	1,187,950	1,151,869	981,426	956,518	932,716	956,929	984,830
11	Asset retirement obligation	-	-	-	11,395	19,593	24,031	24,528
12	less: unfunded asset retirement obligation	-	-	-	(11,395)	(17,976)	(19,685)	(17,320) A
13	Employee future benefits	39,805	41,881	44,060	48,348	53,556	56,890	63,836
14	Contributed capital	-	-	100,000	100,000	100,000	100,000	100,000
15	Retained earnings cost of service exclusions	-	-	-	-	-	113	161
16	Retained earnings	210,858	219,732	236,943	212,647	212,096	231,174	264,531
17	**Total**	1,438,613	1,413,482	1,362,429	1,317,513	1,299,985	1,349,452	1,420,566
18								
19	**Regulated capital structure (%)**							
20	Debt	82.5%	81.5%	72.1%	72.6%	71.8%	70.9%	69.3%
21	Asset retirement obligation	0.0%	0.0%	0.0%	0.0%	0.1%	0.3%	0.5%
22	Employee future benefits	2.8%	3.0%	3.2%	3.7%	4.1%	4.2%	4.5%
23	Equity	14.7%	15.5%	24.7%	23.7%	24.0%	24.5%	25.7%
24	**Total**	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
25								
26	**Regulated average capital structure (%)**							
27	Debt		82.0%	76.8%	72.4%	72.2%	71.4%	70.1%
28	Asset retirement obligation		0.0%	0.0%	0.0%	0.1%	0.2%	0.4%
29	Employee future benefits		2.9%	3.1%	3.4%	3.9%	4.2%	4.4%
30	Equity		15.1%	20.1%	24.2%	23.8%	24.3%	25.1%
31	**Total**		100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
32								
33	**Weighted average cost of capital (WACC)**							
34	Embedded cost of debt		8.26%	8.26%	8.26%	8.26%	8.26%	8.01%
35	Asset retirement obligation		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
36	Employee future benefits		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
37	Equity		4.47%	4.47%	4.47%	4.47%	4.47%	8.80% B
38	**WACC**		7.45%	7.24%	7.06%	7.03%	6.98%	7.83%

A The asset retirement obligation is not part of capital structure until it has been funded by rate payers. As such, the unfunded amount is removed. The funded amount includes the depreciation and accretion charges that have been recorded in net income.
B 2013 return on equity based on NP's approved return on equity

Newfoundland and Labrador Hydro
Financial Results and Forecasts
Rate of Return on Rate Base
($000)

		Actual						Proposed
		2007	2008	2009	2010	2011	2012	2013
1	**Property, plant, and equipment**	1,352,229	1,354,348	1,364,205	1,386,061	1,410,432	1,440,619	1,492,240
2	add: accumulated depreciation	570,225	603,362	632,085	669,742	707,241	88,865	140,043
3	add: contributions in aid of construction	96,396	96,143	96,749	97,257	98,054	14,052	22,269
5	less: work in progress	(2,535)	(9,456)	(10,579)	(17,002)	(23,736)	(32,948)	(21,472)
6	**Capital assets in service**	2,016,315	2,044,397	2,082,460	2,136,058	2,191,991	1,510,588	1,633,080
7	less: asset retirement obligation	-	-	-	(11,395)	(17,976)	(19,685)	(17,320) A
8	less: contributions in aid of construction	(96,396)	(96,143)	(96,749)	(97,257)	(98,054)	(14,052)	(22,269)
9	less: accumulated depreciation	(570,225)	(603,362)	(632,085)	(669,742)	(707,241)	(88,865)	(140,043)
10	**Capital assets - current year**	1,349,694	1,344,892	1,353,626	1,357,664	1,368,720	1,387,986	1,453,448
11	**Capital assets - previous year**	1,345,766	1,349,694	1,344,892	1,353,626	1,357,664	1,368,720	1,387,986 B
12	Unadjusted capital assets - average	1,347,730	1,347,293	1,349,259	1,355,645	1,363,192	1,378,353	1,420,717
13	less: Average net assets not in use	-	-	-	(777)	(423)	(1,428)	(3,005)
14	**Capital assets - average**	1,347,730	1,347,293	1,349,259	1,354,868	1,362,769	1,376,925	1,417,712
15								
16	Cash working capital allowance	3,496	3,548	2,668	3,092	4,625	7,810	5,336
17	Fuel	25,874	34,389	20,817	29,908	33,680	50,308	50,885
18	Materials and supplies	21,699	22,561	23,567	24,089	24,096	25,339	24,701
19	Deferred charges	84,725	81,996	76,870	71,925	68,048	65,670	65,451
20								
21	**Average rate base**	1,483,524	1,489,787	1,473,181	1,483,882	1,493,218	1,526,052	1,564,085
22								
23	Unadjusted return on regulated equity	2,711	8,874	17,211	6,604	20,599	16,900	33,357
24	add: Cost of service exclusions	-	-	-	-	-	113	48
25	Net interest	103,242	87,610	83,440	86,766	90,844	89,961	89,043
26	**Return on rate base**	105,953	96,484	100,651	93,370	111,443	106,974	122,448
27								
28	**Rate of return on rate base**	7.14%	6.48%	6.83%	6.29%	7.46%	7.01%	7.83%

A Asset retirement obligation costs are not funded through debt or Hydro funds, but are to be fully recovered from rate payers over the life of the asset retirement obligation through depreciation. As such, we remove these costs from rate base.

B 2012 'Capital assets - previous year' value reflects Order No. P.U. 13 (2012).

Newfoundland and Labrador Hydro
Financial Results and Forecasts
Revenue Requirement Analysis
($000)

		Actual						Proposed
		2007	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
1	**Revenue requirement**							
2	Energy sales	429,794	425,196	425,528	414,774	443,796	453,178	565,737
3	Other revenue	1,983	2,197	2,218	2,287	2,317	2,116	2,350
4	**Total revenue requirement**	431,777	427,393	427,746	417,061	446,113	455,294	568,087
5								
6	**Expenses**							
7	Operating expenses	97,693	96,694	100,369	96,976	104,564	106,468	113,820
8	Loss on disposal of property, plant, and equipment	902	2,580	1,267	687	925	5,396	1,304
9	Fuels	150,281	149,854	136,933	137,994	131,275	132,003	219,390
10	Power purchases	38,606	41,388	46,782	44,244	52,222	56,986	58,674
11	Amortization	38,342	40,393	41,744	43,790	45,217	46,865	51,656
12	Accretion of asset retirement obligation	-	-	-	-	467	715	843
13	**Expenses prior to cost of service exclusions**	325,824	330,909	327,095	323,691	334,670	348,433	445,687
14	less: cost of service exclusions	-	-	-	-	-	(113)	(48)
15	**Total expenses**	325,824	330,909	327,095	323,691	334,670	348,320	445,639
16	**Return on rate base**	105,953	96,484	100,651	93,370	111,443	106,974	122,448
17								
18	**Average rate base**	1,483,524	1,489,787	1,473,181	1,483,882	1,493,218	1,526,052	1,564,085
19								
20	**Rate of return on rate base**	7.14%	6.48%	6.83%	6.29%	7.46%	7.01%	7.83%

Newfoundland and Labrador Hydro
Financial Results and Forecasts
Rate Stabilization Plan
($000)

		Actual						Proposed
		2007	2008	2009	2010	2011	2012	2013
1	**Historical rate stabilization plan balances**							
2	Utility	12,053	-	-	-	-	-	-
3	Industrial	-	-	-	-	-	-	-
4	**Total**	12,053	-	-	-	-	-	-
5								
6	**Current rate stabilization plan**							
7	Hydraulic	(14,820)	(30,903)	(32,562)	(40,399)	(32,737)	(32,676)	(24,507)
8	Utility	(14,652)	(10,330)	(53,069)	(56,251)	(55,940)	(64,905)	(33,086)
9	Industrial	(8,829)	(11,994)	(36,884)	(62,612)	(81,653)	(104,080)	(679)
10	Utility surplus	-	-	-	-	-	-	(87,340)
11	Industrial surplus	-	-	-	-	-	-	(22,749)
12	**Total**	(38,301)	(53,227)	(122,515)	(159,262)	(170,330)	(201,661)	(168,361)
13								
14	**Combined rate stabilization plan balances**	(26,248)	(53,227)	(122,515)	(159,262)	(170,330)	(201,661)	(168,361)
15								
16	**Average fuel cost per barrel**	$ 52.51	$ 71.59	$ 52.51	$ 73.90	$ 91.92	$ 114.80	$ 108.74

($000)

		Actual						Proposed	
		2007	2008	2009	2010	2011	2012	2013	
1	**Accrued employee future benefits liability**								
2	Balance at beginning of year	35,537	39,805	41,881	44,060	48,348	52,207	56,890	A
3	Current service	1,885	1,666	1,143	1,651	2,068	2,875	3,332	
4	Interest	3,057	3,079	3,197	3,767	4,036	4,137	3,758	
5	Amortization of actuarial losses	1,215	911	-	676	1,166	- B	2,224	
6	Amortization of past service costs	20	20	20	20	20	-	-	
7	Transfers	-	(1,456)	(43)	32	-	-	-	
8	Benefits paid	(1,909)	(2,144)	(2,138)	(1,858)	(2,082)	(2,329)	(2,368)	
9	**Balance at end of year**	39,805	41,881	44,060	48,348	53,556	56,890	63,836	
10	Unamortized losses	20,307	702	14,007	20,875	35,630	30,006	27,782	
11	**Accrued employee future benefits obligation**	60,112	42,583	58,067	69,223	89,186	86,896	91,618	
12									
13	**Funded employee future benefits balance**								
14	Balance at beginning of year	35,537	39,805	41,881	44,060	48,348	52,207	56,890	A
15	Employee future benefits expense	6,177	5,676	4,360	6,114	7,290	7,012	9,314	
16	Amortization of actuarial losses	-	-	-	-	-	-	-	
17	Transfers	-	(1,456)	(43)	32	-	-	-	
18	Benefits paid	(1,909)	(2,144)	(2,138)	(1,858)	(2,082)	(2,329)	(2,368)	
19	**Balance at end of year**	39,805	41,881	44,060	48,348	53,556	56,890	63,836	

A 2012 Balance at beginning of year reflects Order No. P.U. 13 (2012).
B Pursuant to Order No. P.U. 13(2012), Hydro deferred the amortization of actuarial gains and losses of $2,264.

Newfoundland and Labrador Hydro
Financial Results and Forecasts
Operating Expense by Cost Type
($000)

		Actual						Proposed	Year Over Year %
		2007	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2007 to 2013**
1	**Salaries and benefits**								
2	Salaries and benefits	56,741	58,263	61,933	65,692	68,304	70,901	76,022	
3	Employee future benefits	5,861	5,559	4,334	6,098	7,247	6,970	9,314	
4	Group insurance	1,459	1,719	2,336	2,052	2,546	2,403	2,643	
5	Overtime	6,108	7,580	7,778	8,675	9,462	10,633	8,604	
6	Capitalized salaries	(11,258)	(14,600)	(15,959)	(19,456)	(19,736)	(19,051)	(19,342)	
7		58,911	58,521	60,422	63,061	67,823	71,856	77,241	
8	Cost recoveries allocation	(577)	(624)	(1,256)	(1,942)	(2,040)	(2,603)	(2,950)	
9		58,334	57,897	59,166	61,119	65,783	69,253	74,291	4.11%
10									
11	**System equipment maintenance**								
12	System equipment maintenance	21,416	19,366	19,408	19,167	19,867	19,655	21,495	
13	Deferred major extraordinary repairs	2,109	2,916	2,714	2,581	1,643	606	-	
14		23,525	22,282	22,122	21,748	21,510	20,261	21,495	
15	Cost recoveries allocation	(392)	(372)	(614)	(418)	(279)	(739)	(807)	
16		23,133	21,910	21,508	21,330	21,231	19,522	20,688	-1.84%
17									
18	**Other operating expenses**								
19	Office supplies and expenses	2,262	2,182	2,161	2,100	2,307	2,230	2,571	
20	Professional services	3,532	4,109	3,278	4,165	6,042	7,324	6,689	
21	Insurance	1,703	1,783	1,937	1,960	1,965	2,109	2,211	
22	Equipment rentals	1,082	1,493	1,721	1,738	1,636	1,699	1,731	
23	Travel	2,942	2,854	2,910	2,755	2,977	2,979	3,156	
24	Miscellaneous expenses	3,962	4,389	4,174	4,454	4,614	5,003	6,254	
25	Building rental and maintenance	1,234	1,078	1,145	1,170	1,172	1,027	1,070	
26	Transportation	1,989	2,186	1,833	1,796	1,836	1,928	2,273	
27	Customer costs	285	(29)	3,892	(625)	122	141	126	
28	Deferred regulatory costs	334	334	334	50	50	-	333	
29		19,325	20,379	23,385	19,563	22,721	24,440	26,414	
30	**Cost recoveries allocation**	(240)	(266)	(458)	(1,362)	(1,662)	(2,518)	(3,525)	
31		19,085	20,113	22,927	18,201	21,059	21,922	22,889	3.08%
32									
33	**Total operating expenses before other cost recoveries**	100,552	99,920	103,601	100,650	108,073	110,697	117,868	2.68%
34									
35	**Other cost recoveries**	(2,859)	(3,226)	(3,232)	(3,674)	(3,509)	(4,229)	(4,048)	5.97%
36	**Total operating expenses**	97,693	96,694	100,369	96,976	104,564	106,468	113,820	2.58%

Newfoundland and Labrador Hydro
Financial Results and Forecasts
Net Interest
($000)

		Actual						Proposed
		2007	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
1	**Net Interest**							
2	Long-term debt	101,450	94,051	90,450	90,450	90,450	90,450	90,450
3	Interest on rate stabilization plan	1,125	2,746	7,026	10,244	12,237	13,188	14,395
4	Accretion of long-term debt	675	479	394	426	460	499	540
5	Amortization of foreign exchange losses	2,157	2,157	2,157	2,157	2,157	2,157	2,157
6	Debt guarantee fee	13,145	-	-	-	3,874	3,693	3,735
7	Other interest	2,398	10,434	(1,885)	(160)	(231)	705	226
8	Interest on sinking fund	(11,439)	(12,629)	(13,891)	(15,190)	(16,557)	(18,025)	(19,302)
9	Interest capitalized during construction	(6,269)	(9,628)	(811)	(1,161)	(1,546)	(2,706)	(3,158)
10	**Net interest**	103,242	87,610	83,440	86,766	90,844	89,961	89,043

Newfoundland and Labrador Hydro
Financial Results and Forecasts
Funded Asset Retirement Obligation
($000)

	Actual						Proposed
	2007	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
1 **Funded asset retirement obligation:**							
2 Opening	-	-	-	-	-	1,617	4,346
3 Accretion	-	-	-	-	468	715	843
4 Depreciation	-	-	-	-	1,149	2,044	2,280
6 Asset retirement obligation disposed	-	-	-	-	-	(30)	(262)
7 **Ending**	-	-	-	-	1,617	4,346	7,207

Newfoundland and Labrador Hydro
Income Statement at Existing Rates
($000)

		Test Year 2007	Actual 2007	Existing Rates 2013
1	**Revenue**			
2	Energy sales	429,058	429,794	477,072
3	Other revenue	2,021	1,983	2,350
4	**Total revenue**	431,079	431,777	479,422
5				
6	**Expenses**			
7	Operating expenses	93,418	97,693	111,046
8	Fuels			
9	No. 6 fuel	136,867	107,369	200,315
10	Rate stabilization plan deferral	-	31,540	(67,994)
11	Diesel and other	11,569	11,372	19,159
12	Total fuels	148,436	150,281	151,480
13	Power purchases	38,327	38,606	58,674
14	Amortization	38,825	38,342	51,656
15	Accretion	-	-	843
16	Loss on disposal of property, plant, and equipment	1,366	902	1,304
17	Interest	102,728	103,242	90,336
18	**Total expenses**	423,100	429,066	465,339
19				
20	**Net income before cost of service exclusions**	7,979	2,711	14,083
21	less: assets not in service depreciation	-	-	132
24		7,979	2,711	14,215
25				
26	Return on regulated equity	7,979	2,711	14,215
27	Net interest	102,728	103,242	90,336
28	**Return on rate base**	110,707	105,953	104,551
29				
30	**Average rate base**	1,489,323	1,483,524	1,564,707
31				
32	**Rate of return on rate base**	7.44%	7.14%	6.68%

Newfoundland and Labrador Hydro
Revenue Requirement Analysis - 2007 vs. 2013 Test Year
($000)

		Test Year 2007	Actual Year 2007	Proposed 2013	Actual to Proposed 2007 to 2013
1	**Revenue requirement**				
2	Energy sales	429,058	429,794	565,737	135,943
3	Other revenue	2,021	1,983	2,350	367
4	**Total revenue requirement**	431,079	431,777	568,087	136,310
5					
6	**Expenses**				
7	Operating expenses				
8	Salaries and fringe benefits	58,457	58,911	77,241	18,330
9	System equipment maintenance	20,579	23,525	21,495	(2,030)
10	Office supplies and expenses	2,106	2,262	2,571	309
11	Professional services	4,418	3,866	7,022	3,156
12	Insurance	1,881	1,703	2,211	508
13	Equipment rentals	1,369	1,082	1,731	649
14	Travel	2,332	2,942	3,156	214
15	Miscellaneous expenses	4,530	4,247	6,380	2,133
16	Building rental and maintenance	825	1,234	1,070	(164)
17	Transportation	1,994	1,989	2,273	284
18	Cost recoveries	(2,199)	(1,389)	(9,222)	(7,833)
19	Allocated to non-regulated customer	(2,874)	(2,679)	(2,108)	571
20	**Net operating expenses**	93,418	97,693	113,820	16,127
21	Fuels				
22	No. 6 fuel	136,867	107,369	200,315	92,946
23	Rate stabilization plan deferral	-	31,540	(84)	(31,624)
24	Diesel and other	11,569	11,372	19,159	7,787
25	Total fuels	148,436	150,281	219,390	69,109
26	Power purchases	38,327	38,606	58,674	20,068
27	Amortization	38,825	38,342	51,656	13,314
28	Accretion of asset retirement obligation	-	-	843	843
29	Loss on disposal	1,366	902	1,304	402
30	**Expenses before cost of service exclusions**	320,372	325,824	445,687	119,863
31	less: cost of service exclusions	-	-	(48)	(48)
32		320,372	325,824	445,639	119,815
33					
34	**Return on rate base**	110,707	105,953	122,448	16,495
35					
36	**Average rate base**	1,489,323	1,483,524	1,564,085	
37					
38	**Rate of return on rate base**	7.44%	7.14%	7.83%	

Newfoundland and Labrador Hydro
Rate Base - Existing vs. Proposed
($000)

		Test Year 2007	Actual 2007	Existing 2013	Proposed 2013
1	**Capital assets**	2,008,654	2,016,315	1,633,080	1,633,080
2	less: asset retirement obligation costs	-	-	(17,320)	(17,320)
3	less: contributions in aid of construction	(92,250)	(96,396)	(22,269)	(22,269)
4	less: accumulated depreciation	(559,855)	(570,225)	(140,043)	(140,043)
5	**Capital assets - current year**	1,356,549	1,349,694	1,453,448	1,453,448
6	**Capital assets - previous year**	1,354,631	1,345,766	1,387,986	1,387,986
7	Unadjusted Capital assets - average	1,355,590	1,347,730	1,420,717	1,420,717
8	less: Average net assets not in use	-	-	(3,005)	(3,005)
9	**Capital assets - average**	1,355,590	1,347,730	1,417,712	1,417,712
10					
11	Cash working capital allowance	3,030	3,496	6,190	5,336
12	Fuel	27,473	25,874	50,885	50,885
13	Materials and supplies	19,912	21,699	24,701	24,701
14	Deferred charges	83,318	84,725	65,219	65,451
15					
16	**Average rate base**	1,489,323	1,483,524	1,564,707	1,564,085

Newfoundland and Labrador Hydro
Forecast Average Cost of Debt
($000)

	Series	Interest Rate	Year of Issue	Year of Maturity	Actual 2012	Proposed 2013
1	Series V	10.50%	1989	2014	125,000	125,000
2	Series X	10.25%	1992	2017	150,000	150,000
3	Series Y	8.40%	1996	2026	300,000	300,000
4	Series AB	6.65%	2001	2031	300,000	300,000
5	Series AD	5.70%	2003	2033	125,000	125,000
6	Series AE	4.30%	2006	2016	225,000	225,000
7	Total debentures				1,225,000	1,225,000
8						
9	Promissory notes				52,000	106,606
10	Less:					
11	Sinking funds				(310,069)	(337,318)
12	Non-regulated debt pool				(7,217)	(7,217)
13	Unamortized debt discount and financing				(2,785)	(2,241)
14						
15	**Total debt**				956,929	984,830
16						
17	**Average debt**					970,880
18						
19	**Embedded cost of debt**					
20	Long-term debt		90,450			
21	Accretion of long-term debt		540			
22	Amortization of foreign exchange losses		2,157			
23	Debt guarantee fee		3,735			
24	Other interest		226			
25	Interest on sinking fund		(19,302)			
26	less: non regulated interest		-			
27						77,806
28						
29	**Embedded cost of debt**					8.01%

SECTION 4: RATES AND REGULATION

4.1 OVERVIEW

Hydro prepares Cost of Service studies for five systems[1]:

- Island Interconnected;
- Island Isolated;
- Labrador Isolated;
- L'Anse au Loup; and
- Labrador Interconnected.

Rates for these customers are grouped into the following classifications:

- Island Interconnected Utility (NP);
- Island Interconnected Industrial Customers;
- Island Interconnected and L'Anse au Loup Rural Customers;
- Island and Labrador Isolated Rural Customers;
    - Non-Government;
    - Government; and
- Labrador Interconnected Rural Customers.

On the Island Interconnected System, Hydro provides electricity service to Newfoundland Power and four Industrial Customers, Corner Brook Pulp and Paper Limited, North Atlantic Refining Limited, Teck Resources Limited and Vale

[1] Isolated diesel systems are combined by Island and Labrador.

Newfoundland and Labrador Limited. In 2013, Hydro expects Praxair will commence operations as an additional Industrial Customer. Hydro also serves 22,700 Rural Customers at the retail level on the Island Interconnected System.

On the Labrador Interconnected System, Hydro serves 10,500 Rural Customers and has sales to non-regulated customers. On the 21 isolated systems, including the L'Anse au Loup system, Hydro has 4,400 Rural Customers.

The Rates and Regulation evidence will cover:

- The rates proposed for NP and IC;
- The rates proposed for Rural Customers and the impacts on various customer classes;
- The 2013 revenues based on existing and proposed rates;
- The need for additional cost recovery and deferral mechanisms; and
- Clarification required on Hydro's annual KPI reporting.

4.2 RATES FOR NEWFOUNDLAND POWER

Pursuant to Board Order No. P.U. 14(2004) in July 2004, Hydro filed an Application to adjust the former energy-only rate structure charged to NP. The proposed rate structure at that time was a cost-based demand rate, as well as a two-block energy structure, with the second block based on the Holyrood test year fuel cost. In Order No. P.U. 44(2004), the Board approved a three-year phase in of the cost-based demand rate, and approved the energy charge rate structure. During Hydro's 2006 GRA, a demand rate of $4.00/kW/month was agreed upon by the parties, and the energy rate structure continued to have the second block priced based on the Holyrood test year fuel cost.

Fuel prices have risen steeply since the 2007 Test Year was reviewed. Current fuel cost, applied in the same manner as used in the 2003 and 2006 GRAs, would result in a second block rate of 177.68 mills/kWh[2]. As NP's rates are designed to recover the costs allocated to them using the approved Cost of Service methodology, it was apparent that application of the previously accepted methodology would result in a low, perhaps negative, first block price. Hydro engaged Lummus Consultants International Inc. (Lummus), formerly Shaw Group Consultants International Inc., to provide a recommendation on this, and several other issues, the results of which are contained in the report entitled "Cost of Service Study/Utility and Industrial Rate Design Report", attached as Exhibit 9. The guiding principles of the rate design review included maintaining a second block price signal, considering the demand rate in light of rising capacity costs, and designing the rates to recover NP's revenue requirement.

Hydro accepts Lummus's recommendations included in the report and is therefore proposing the following rate structure for NP:

[2] Energy (Second Block):

Average No. 6 Fuel Cost per Barrel	$108.74
Conversion Factor (kWh per Barrel)	612
Rate (Mills/kWh)	177.68

Table 4.1

Utility Rate Structure

Component	Unit	2007	Proposed	Comments
Demand	$/kW/month	4.00	9.12	2007 rate was negotiated; proposed rate is cost-based.
First Block	GWh/month	250	280	Block size designed to have few, if any, kWh recorded as a load variation in the RSP.
First Block	mills/kWh	32.46	27.86	2007 rate was the fallout rate after demand and second block rates were calculated; proposed rate is designed to recover non-fuel energy costs.
Second Block	mills/kWh	88.05	104.00	2007 rate was the marginal fuel cost per kWh based on Test Year Holyrood fuel cost; proposed rate is designed to send a marginal price signal and recover costs not included in demand or first block rates.

The calculation of NP's rate is summarized on Schedule 1.4 of the 2013 Cost of Service (COS) Study attached as Exhibit 13.

The proposed rates will result in an average base rate increase of 18.7% for NP and a 2013 revenue to cost ratio, including allocated rural deficit, of 1.14. The revenue to cost ratio reflects the proportion of revenues received compared to the cost of service. In conjunction with the elimination of the fuel rider, this represents a 4.8% decrease to NP, or an estimated 3.2% decrease at the end consumer level.

Hydro is also proposing a rate of 12.48 mills per kWh for firming up secondary energy purchased from CBPP and resold to NP as firm energy. The calculation is shown on Schedule 1.6 of the 2013 COS Study (Exhibit 13).

The proposed utility rate schedule applicable to NP is found on Pages 1 through 4 of the Rates Schedules section of this Application. The RSP adjustment has been updated to set the fuel rider to zero in accordance with Section D of the RSP rules, shown on Pages 13 to 14 of the Rates Schedules section of this Application.

Subsequent to Hydro's 2006 GRA, NP, the Consumer Advocate (CA), and Hydro entered into discussions concerning NP's rate structure, and in April 2008 submitted to the Board a report entitled "Review of Demand Billing to Newfoundland Power", a copy of which is included as Exhibit 11 to this evidence. That 2008 report contained a recommendation that NP's curtailable load be treated as a generation credit. Lummus's recommendation is that the curtailable load not be treated in that manner at this time. The rationale for this is included in Section 2.1 of the Lummus report attached as Exhibit 9. Hydro agrees with Lummus's recommendation.

In addition to these matters, Hydro is proposing further changes to the Utility Rate Schedule to adjust the Generation Credit to 120,208 kW, based on the revised credit described in Section 2.5.4.3 of the evidence.

4.2.1 Hydro's Application

Hydro is requesting the Board's approval for the following:

- Monthly rates to be charged to Newfoundland Power of:

  Demand Charge:

  $9.12 per kW of billing demand

  Energy Charge:

First 280,000,000 kilowatt-hours	@ 2.786 ¢ per kWh
All excess kilowatt-hours	@ 10.400 ¢ per kWh

  Firming-up Charge: @ 1.248 ¢ per kWh

- Removing the fuel rider from Newfoundland Power RSP rate.

4.3 RATES FOR INDUSTRIAL CUSTOMERS

Rates charged to Island IC for firm power and energy are designed to recover the directly assigned costs from the COS. Hydro has calculated a firm service rate comprised of a demand charge of $9.13 per kW of billing demand per month and an energy charge of 47.82 mills per kWh plus the appropriate specifically assigned charges[3] as outlined in Table 4.2. Praxair is not anticipated to have any material specifically assigned charges.

Table 4.2

Industrial Customer Specifically Assigned Charges

	2007	2013
CBPP	$347,167	$944,954
NARL	150,976	101,748
Teck	186,169	215,009
Vale	-	533,724
Total	**$684,312**	**$1,795,435**

Notwithstanding the rates shown above, in April and July 2013 the Government provided direction to the Board of Directors of Hydro regarding a phase in of the rate changes for the IC. That phase in, and the RSP rates for which Hydro is applying, are contained in a separate Application to the Board.

For non-firm service, Hydro is proposing to retain the previously approved calculation for the energy charge as outlined on Page 7 of 47 of the proposed Rates Schedule which is included with the Application under the Rates Schedules Tab. The loss factor used in this rate formula has been updated to the average Island Interconnected System losses for the five years ending in 2012. It has increased from 2.68% for the five-year period ending in 2005 to 3.36% for the five year period ending in 2012.

As there are no remaining ICs to whom the availability clause of Hydro's former Wheeling Rate applies, Hydro is proposing to no longer offer this rate.

[3] Specifically assigned charges are meant to recover the costs associated with assets used primarily by that customer.

The revised IC Rate Schedules are found on Pages 5 through 7 of the Rates Schedules section of this Application. No IC RSP rate has been included on the schedules at this time, pending the ruling of the Board on the RSP load variation allocation to these customers.

The IC rate structure was reviewed after Hydro's 2006 GRA, and a report entitled "Review of Industrial Customers Rate Design" was submitted to the Board in 2008. This report is included in this Application as Exhibit 12. Hydro requested that Lummus include this matter in their review (Exhibit 9), in light of the generation expansion plan for the Labrador Interconnection and the construction of a plant at Muskrat Falls, and the forecast load growth for Vale. Hydro agrees with the recommendation in the Lummus report (Section 3 of Exhibit 9) that no changes to the IC rate structure should be made until the future marginal cost structure is known.

4.3.1 Hydro's Application

Hydro is requesting the Board's approval for the following:

- Demand Charge:
  $9.13 per kW of billing demand
- Firm Energy Charge:
  Base Rate @ 4.782 ¢ per kWh
- Specifically Assigned Charges as follows:

	Annual Amount
Corner Brook Pulp and Paper Limited	$944,954
North Atlantic Refining Limited	$101,748
Teck Resources Limited	$215,009
Vale Newfoundland and Labrador Inc.	$533,724

- Adjusting the average system losses used in the calculation of the energy charge to Industrial Customers for non-firm service to 3.36%; and
- Discontinuing the Island Industrial wheeling rate.

4.4 RATES FOR RURAL CUSTOMERS

As stated previously, for rate-setting purposes, there are three distinct groups of Rural Customers:

- Island Interconnected and L'Anse au Loup Systems;
- Island and Labrador Isolated Systems; and
- Labrador Interconnected System.

Rates proposed in this Application for Rural Customers reflect the policies for rural rates as approved in Order No. P.U. 14(2007).

Excluding Government departments in isolated diesel areas, rates for Rural Customers on the Island Interconnected, L'Anse au Loup and Isolated Systems, including preferential rate customers, will continue to be based on NP rates[4].

Rates for Government departments in isolated diesel areas will continue to be based on costs. Rates for Labrador Interconnected Customers are also based on costs.

Hydro is proposing some minor changes in its Rules and Regulations, found on Pages 22 to 35 in the Rates Schedules section of this Application. These changes are:

- Section 1(a)(iii) revised to include the words "and Labrador" in the definition of the word "Board";

[4] Hydro has not incorporated into its GRA filing the rate design changes approved by the Board in Order No. P.U. (24)2013. Time did not permit the incorporation of the revised rate structures into the filing. This will be updated in a revised filing.

- Section 2: Classes of Service, revised to include Island Interconnected L'Anse au Loup class 1.1S – Domestic Seasonal and delete Island Interconnected – L'Anse au Loup class 2.2 General Service; Island and Labrador Diesel Areas revised to include 1.2DS – Domestic Seasonal Diesel – Non-Government; Happy Valley Goose Bay Interconnected Area and Labrador City/Wabush Interconnected Area classes removed; and Labrador Interconnected classes added;
- Section 7(f) amended to agree with Section 7(f) of NP's Rules and Regulations, for consistency between the utilities;
- Section 9(k) revised to change the reference to "Happy Valley Goose Bay, Labrador City and Wabush service areas" to "Labrador Interconnected service area"; and
- Section 10(d) amended to agree with Section 10(d) of NP's Rules and Regulations, for consistency between the utilities.

4.4.1 Island Interconnected and L'Anse au Loup Systems

Hydro's rates for Rural Customers on the Island Interconnected and L'Anse au Loup Systems are the same as rates charged to NP customers. It is estimated that Hydro's proposed rates for NP will see a flow-through decrease for these customers of approximately 3.2%, compared to the rates in effect on July 1, 2013. The Burgeo School rate class rate will also be decreased by 3.2%. The 2013 revenue to cost ratio for the Island Interconnected and L'Anse au Loup Rural Customers is projected to be 0.66 and 0.45, respectively.

4.4.2 Isolated Systems

For rate-setting purposes, there are three customer groups in the isolated systems:

1) Rural Domestic Customers, excluding Government Departments;
2) Rural General Service Customers, excluding Government Departments; and

3) Government Departments.

Hydro's rates for Rural Domestic Customers, excluding Government departments, are the same as NP's rates for the basic customer charge and first block consumption (lifeline consumption[5]), but non-lifeline consumption is adjusted by the average rate of change granted to NP[4].

Rates for Rural General Service Customers in the Isolated systems are adjusted by the average rate of change granted to NP.

An additional impact on rates for both rural Domestic and General Service Customers relates to a 15%[6] rate increase, effective January 1, 2007 (deferred rate increase) which was approved for these customers in the 2006 GRA, but through various directions from government has resulted in a deferral. Therefore, with this GRA, the deferred rate increase will be incorporated into Hydro's final rate schedules for these customers, which are proposed to take effect January 1, 2014.

Government rate classes in isolated systems pay cost-based rates and the 2013 cost recovery level for Government departments remains at 100%.

The 2013 revenue to cost ratio for customers on the Island and Labrador Isolated Systems, excluding L'Anse au Loup, is projected to be 0.17 and 0.23 respectively, or a combined revenue to cost ratio of 0.22.

4.4.3 Isolated Rural Domestic Customers – Excluding Government Departments

Isolated Rural Domestic Customers, excluding Government departments, have the same rates as NP customers for the basic customer charge and lifeline block consumption, and rates charged for consumption above the lifeline block are automatically adjusted by the

[5] The lifeline block is designed to provide Domestic Customers with access to electricity at non-discriminatory prices for essential services. Essential services include most electrical appliances and hot water heating, but not electric heat.

[6] For Domestic Customers, the 15% is applicable to only non-lifeline energy rates. The 2007 deferred rate increase for Domestic Customers would result in an overall increase of 4%.

average rate of change granted to NP. Hydro is also proposing rates that are based on these criteria adjusted for the deferred 2007 rate increase. It is estimated that the rate increase for these customers will be 0.9% compared to the rates in effect on July 1, 2013.

4.4.4 Isolated Rural Domestic Customers – Government Departments

Government departments are charged rates based on full cost recovery. These rates have not changed since 2007. Based on the combined costing for both Government and Non-Government Domestic Customers, it is proposed that the rate for Government Departments - Domestic (1.2G) will increase on average by 17.7% compared to the rates in effect on July 1, 2013.

4.4.5 Isolated Rural General Service Customers – Excluding Government Departments

As outlined in Section 16(c) (ii) of the Rules and Regulations for Rural Customers and as approved by the Board in Order No. P.U. 14(2007), rates for Isolated Rural General Service Customers, excluding Government departments, are automatically adjusted by the average rate of change granted NP from time to time. Hydro is proposing 2013 rates that are based on these criteria, adjusted for the deferred 2007 rate increase. The rate for small General Service Customers will increase on average by 11.6%. The rate for large General Service Customers will increase on average by 11.5%.

4.4.6 Isolated Rural General Service Customers – Government Departments

Government departments are charged rates based on full cost recovery. These rates have not changed since 2007. Based on the combined costing for both Government and Non-Government General Service Customers, the rate for small General Service – Government Departments (2.1G) will increase on average by 22.1%. The rate for large General Service Government[7] Departments (2.2G) will increase on average by 27.7%.

[7] Excludes hospitals and schools as outlined in P.U. 7(2002-2003), p. 130.

4.4.7 Isolated Rural Street and Area Lighting – Excluding Government Departments

Rates for Isolated Rural Street and Area lighting, excluding Government departments, are the same rates as NP rates for similar service. It is estimated that Hydro's current proposal for NP will see a flow-through decrease of approximately 3.2% compared to the rates in effect on July 1, 2013.

4.4.8 Isolated Rural Street and Area Lighting – Government Departments

Government departments are charged rates based on full cost recovery. These rates have not changed since 2007. Based on an allocation of the combined costing for both Government and Non-Government Street and area lighting service, it is proposed that rates will increase on average by 23.0%, compared to the rates in effect on July 1, 2013.

4.4.9 Labrador Interconnected

Based on the 2013 COS Study, filed as Exhibit 13, Hydro is proposing the following Labrador Interconnected rural rates as presented in Table 4.3.

Table 4.3

Labrador Interconnected Rate Change Comparison		
	Current Rates	**Proposed Rates**
Domestic 1.1		
Basic Customer Charge ($ per month)	7.15	9.02
Energy Charge (¢ per kWh)	3.280	4.131
General Service 2.1		
Basic Customer Charge ($ per month)	10.45	13.43
Energy Charge (¢ per kWh)	5.240	6.734
General Service 2.2		
Demand Charge ($ per kW per month)	2.20	2.55
Energy Charge (¢ per kWh)	2.433	2.845
General Service 2.3		
Demand Charge ($ per kVA per month)	2.00	2.35
Energy Charge (¢ per kWh)	2.103	2.455
General Service 2.4		
Demand Charge ($ per kVA per month)	1.75	2.15
Energy Charge (¢ per kWh)	1.733	2.098
Street Lights		
250W Mercury Vapour ($ per month)	13.50	19.28
100W High Pressure Sodium ($ per month)	10.00	14.28
150W High Pressure Sodium ($ per month)	13.50	19.28
250W High Pressure Sodium ($ per month)	17.80	25.42
400W High Pressure Sodium ($ per month)	23.00	32.85
Wood Poles ($ per month)	3.40	4.86
100W High Pressure Sodium Closed ($ per month)	6.75	9.64
100W High Pressure Sodium ($ per month)	4.10	5.86

In Order No P.U. 14(2004), the Board approved a five-year plan to implement uniform rates for Labrador Interconnected Customers using the following cost recovery targets:

- Domestic 95%;
- General Service 105% -115%; and
- Street Lighting 100%.

These targets have been applied in determining the above rates. Customer impacts are shown in Schedule I. Hydro’s 2006 GRA resulted in an Agreement on Labrador Interconnected Rates, wherein there was a rate plan for the Labrador Interconnected

Rural Customers so that in years 2008 through 2011, inclusive, rate changes were to be phased in so that by 2011:

(a) Rates would be based on the 2007 Test Year revenue requirement;

(b) Uniform rates would be charged to all Rural Customers on the Labrador Interconnected system; and

(c) The CFB Goose Bay revenue credit would be fully applied to the rural deficit.

Rates for the final year of the phased-in implementation were approved by the Board in Order No. P.U. 33(2010).

Based on the target cost recovery levels outlined above, the proposed rates schedules for 2013 are included in the Rates Schedules Tab of the Application. The 2013 revenue to cost ratio, including allocated rural deficit, for Labrador Interconnected Customers is 1.44. The ratio exceeds 1.0 as Labrador Interconnected Rural Customers pay a portion of the rural deficit in addition to their system costs.

During the budget preparation and rate design process, it was determined that the inclusion of Muskrat Falls Construction (MFC) as a Rate Class 2.4 General Service customer on the Labrador Interconnected System has a material impact on the class as a whole. MFC attracts significant demand costs to the class because of its large demand requirement at the end of the year, but does not have enough billable units to cover its estimated costs in 2013. MFC's forecasted 2013 usage pattern contains little consumption at the beginning of the year while "ramping-up" towards the end of the year. With the lack of billable units early in the year, the resulting average increase for the class would be approximately 41.4%, compared to the proposed average increase on the system of approximately 21.7%.

Since Hydro anticipates its test year rates will be in effect for more than one year, and MFC load is anticipated to remain at or near the test year peak, Hydro considered an alternative rate design. To mitigate undue impact on other customers within the class, Hydro has used the average of 2013 and 2014 MFC usage (kWs and kWhs) for rate design purposes to normalize the distribution of costs over billing units and effectively lower the 2013 increase for the class from 41.4% to 21.7%, which aligns with the system average increase.

4.4.10 Hydro's Application

Hydro is requesting the Board's approval for the following:

- Amending the rules and regulations for service to all Hydro Rural Customers as set out in this section;
- The rates for Isolated Rural Customers - Government as set out in Pages 36 to 39 of the Rates Schedules attached to this Application; and
- The rates for Labrador Interconnected Rural Customers as set out in Pages 40 to 47 of the Rates Schedules attached to this Application.

4.5 REVENUES AND RSP BASED ON EXISTING AND PROPOSED RATES

Table 4.4 summarizes the projected 2013 revenues and RSP based on the proposed and existing rates.

Table 4.4

Comparison of Revenues and RSP at Existing and Proposed Rates
2014

	Jul 1/13 Existing Rates	Jan 1/14 Proposed Rates	$ Change	% Change
Newfoundland Power				
Firm	$381,524,259	$453,009,608	71,485,349	18.7%
RSP	29,817,619	(61,593,243)	(91,410,862)	-306.6%
Total Firm NP	$411,341,878	$391,416,365	(19,925,513)	-4.8%
Industrial				
Firm	$21,277,568	$28,952,325	7,674,757	36.1%
RSP	(4,547,300)	-	4,547,300	-100.0%
Total Firm Industrial	$16,730,268	$28,952,325	12,222,057	73.1%
Industrial Non-Firm	-	-	-	0.0%
CFB Goose Bay	877,416	877,416	-	0.0%
Rural Island Interconnected	49,981,671	48,364,264	(1,617,407)	-3.2%
Rural Isolated Systems	8,769,492	9,461,516	692,024	7.9%
L'Anse au Loup	2,819,845	2,728,595	(91,250)	-3.2%
Rural Labrador Interconnected				
Domestic	10,539,517	13,275,638	2,736,121	26.0%
GS 2.1L 0 - 10 kW	345,523	444,040	98,517	28.5%
GS 2.2L 10 - 100 kW	2,092,676	2,440,610	347,934	16.6%
GS 2.3L 110 - 1000 kVA	2,948,842	3,446,780	497,938	16.9%
GS 2.4L Over 1000 kVA	1,884,055	2,293,616	409,561	21.7%
Street & Area Lighting	291,185	415,895	124,710	42.8%
Rural Labrador Interconnected Total	$18,101,798	$22,316,579	4,214,781	23.3%
Grand Total	$508,622,368	$504,117,060	(4,505,308)	-0.9%
Reconciliation to the Cost of Service, Sch 1.2, Page 1 of 6, Column 2, Line 15				
Revenue from Proposed Rates				$ 504,117,060
Newfoundland Power RSP				61,593,243
IOC Firm	$ 2,099,261			
IOC Non-firm	9,225			
Labrador Interconnected Industrial	$ 2,108,486			2,108,486
Total				$ 567,818,789
COS				$ 567,818,789

4.6 RATE STABILIZATION PLAN

The RSP was established for Newfoundland Power and Island Industrial Customers to smooth rate impacts for variations between Island Interconnected System actual results and Test Year Cost of Service estimates for:

- hydraulic production;

- No. 6 fuel cost used at Hydro's Holyrood generating station;
- customer load (Utility and Island Industrial); and
- rural rates.

As discussed in Sections 2 and 3, Hydro has been able, in recent years, to utilize more power purchased from hydraulic and wind generators. As shown in Section 2, Schedule V, power purchases account for approximately 15% of the 2013 forecast total energy requirements on the Island Interconnected System, while Holyrood production is expected to account for another 17%. There is a notable differential between the price of power purchases (4.0 to 14.6¢ per kWh), and the 2013 marginal price of 17.77¢ per kWh for energy produced at Holyrood[8]. Other variances, both quantity and price, in Island Interconnected supply costs result when diesel or gas turbine unit production varies from the Test Year assumption.

Holyrood production remains the marginal supply for energy on the Island Interconnected System, meaning that increases or decreases in power purchases vary the amount of fuel required to be consumed at Holyrood. The average embedded cost per kWh of Holyrood fuel included in the 2013 test year, and therefore included in forecast rates, is 17.77¢ per kWh. Variances in the quantity of the other sources of supply could also cause significant volatility in Holyrood fuel costs from year to year. As a result, Hydro is proposing to modify the RSP to include provisions for energy supply variations.

It is proposed that an "Energy Supply" provision be created such that any increase or decrease in test year energy supply for the Island Interconnected System be stabilized at a value calculated as the difference between the Test Year cost of that supply and the Test Year No. 6 fuel cost of supply. This provision would apply to variations in:

[8] Forecast Average No. 6 Fuel cost per bbl divided by Holyrood conversion factor ($108.74/612 = 17.77 ¢/kWh)

- Power purchases from wind generation;
- Power purchases from CBPP cogeneration;
- Power purchases from hydraulic generation;
- Diesel generation[9]; and
- Gas turbine generation[8].

The proposed calculation is illustrated in Table 4.5.

Table 4.5

Proposed Energy Supply Quantity Variation					
A	**B**	**C**	**D**	**E**	**F**
Cost of Service Energy Supply	**Actual Energy Supply**	**Variance**	**Cost of Service No. 6 Fuel Cost**	**Cost of Service Energy Supply Cost**	**Energy Supply Quantity Variation**
(kWh)	**(kWh)**	**(kWh)**	**($Can/bbl.)**	**($/kWh)**	**($)**
		(B - A)			$C \times \{(D/O^1) - E\}$
O^1 is the Test Year Holyrood Operating Efficiency kWh/barrel.					

The impact of a 50 GWh variance in power purchased from Exploits Generation is shown in Table 4.6.

[9] This generation is not normally called upon as a source of energy, but is used primarily for system peaking, area supply requirements, or energy requirements in the event of system generation constraints or outages.

Table 4.6

Energy Supply Quantity Variation Example Using Exploits Power Purchase Price					
A	**B**	**C**	**D**	**E**	**F**
Cost of Service Energy Supply	**Actual Energy Supply**	**Variance**	**Cost of Service No. 6 Fuel Cost**	**Cost of Service Energy Supply Cost**	**Energy Supply Quantity Variation**
(kWh)	**(kWh)**	**(kWh)**	**($ Can/bbl)**	**($/kWh)**	**($)**
		(B-A)			C x {(D/O[1]) - E}
50,000,000	100,000,000	50,000,000	108.74	0.04	6,883,987
O[1] is the Test Year Holyrood Conversion Factor kWh/bbl, 612 kWh/bbl.					

The magnitude of Hydro's Island Interconnected energy supply costs is such that Hydro also proposes to stabilize its prices. The terms of the various PPAs also provide for variations in the purchase price of power. Other than for the Exploits power purchases, each of the PPA rates has a fixed component and a variable component. The variable component is escalated annually in accordance with the provisions of each of the contracts, based on the Consumer Price Index. The rate for purchases from Exploits Generation has, to date, been set at 4¢/kWh. Fuel prices vary as well, based upon world oil markets.

Table 4.7 illustrates the proposed calculation for each energy supply cost.

Table 4.7

Proposed Energy Supply Price Variation				
A	**B**	**C**	**D**	**E**
Actual Quantity Energy Supply	**Cost of Service Energy Supply Cost**	**Actual Energy Supply Cost**	**Cost Variance**	**Energy Supply Price Variation**
(kWh)	**($/kWh)**	**($/kWh)**	**($)**	**($)**
			(C - B)	(A X D)

The proposed changes to the RSP rules are included in Section 1.3 of the RSP rules included in the Rates Schedules. As stated previously, Section 1.4(b) of the RSP rules has been removed as there is no further Rural Labrador Interconnected Automatic Rate

Adjustment. Also, references to the December 6, 2006 Government directive have been removed.

4.6.1 Hydro's Application

Hydro is requesting the Board's approval for the following:

- Including, in the RSP, deviations from forecast costs for Hydro's Island Interconnected energy supplies; and
- Removing, from the RSP, calculations related to the Rural Labrador Interconnected Automatic Rate Adjustment.

4.7 OTHER DEFERRAL AND RECOVERY MECHANISMS

Included in Hydro's revenue requirement are a number of costs which are substantially outside Hydro's control including fuel and power purchase costs. Hydro and its customers are protected from variances in the cost of fuel related to Holyrood generation through the RSP. As stated above, Hydro is also proposing to stabilize, through the RSP, its costs related to other supply sources on the Island Interconnected System.

Outside of the above mechanisms, Hydro remains exposed to variances in fuel cost related to diesel fuel used in isolated systems. As well, Hydro's power purchase unit costs in isolated systems vary based upon the price of fuel.

In addition to fuel costs, CDM program expenditures vary based upon circumstances often outside Hydro's control. They vary based upon customer uptake, and the IC expenditures may be variable as they are customized programs.

Hydro is seeking deferral and recovery mechanisms for:

- CDM program costs;
- Isolated Systems (including L'Anse au Loup) diesel cost variations;

- Isolated Systems (including L'Anse au Loup) power purchase variations; and
- External regulatory costs.

Hydro is also seeking to defer and amortize its external regulatory costs associated with this Application.

4.7.1 Background

The Board has approved a number of deferral mechanisms over the years, for both Hydro and Newfoundland Power. Among these mechanisms for Hydro are:

- Rate Stabilization Plan;
- Deferred Foreign Exchange Losses;
- Deferred Major Extraordinary Repairs;
- Deferred Study Costs;
- Deferred Energy Conservation Costs; and
- Deferred Purchased Power Savings.

In addition to Hydro's deferrals, NP has, from time to time, been permitted by the Board to defer the recovery of certain items. These include deferral or recovery mechanisms related to:

- Rate Stabilization Account (RSA);
- Revenue Shortfall Deferral;
- Weather Normalization Account, with both a reversing and non-reversing mechanism;
- Amortization True-Up Deferral;

- Pension Deferral;
- Replacement Energy Deferral;
- Deferred GRA Costs;
- Conservation and Demand Management Deferral;
- Municipal Tax Liability;
- Unbilled Revenue;
- Purchased Power Unit Cost Variance Reserve;
- Future Removal and Site Restoration Provision;
- Demand Management Incentive Account (DMI);
- Pension Expense Variance Deferral Account (PEVDA);
- Energy Supply Cost Variance Reserve (ESCVR);
- Other Post Employment Benefits (OPEBS) Variance Deferral Account;
- Cost Recovery Deferral Account; and
- Cost of Capital Deferral.

4.7.2 Proposed Deferral and Recovery Mechanisms

(i) Recovery of CDM Deferral and ongoing CDM Costs

As discussed in Section 2, Hydro and NP have jointly undertaken CDM activities since 2009. Hydro has received approval[10] from the Board to defer its 2009, 2010, 2011 and 2012 CDM program expenditures. To determine an appropriate recovery mechanism for these deferrals, and for future year expenditures, Hydro requested a review of this

[10] Order No. P.U. 14(2009); Order No. P.U. 13(2010); Order No. P. U. 4(2011); and Order No. P.U. 3(2012).

item by Lummus, its Cost of Service consultants. Lummus's recommendation is found in Section 4 of Exhibit 9. Hydro agrees with the recommendations of Lummus, and is proposing an annual (July 1) CDM adjustment to NP and IC rates to recover CDM costs, as stated on Pages 20 to 21 of the Rates Schedules. [11] It should be noted that Hydro's CDM program costs are not included as an expense in the determination of revenue requirement, but are proposed to be collected solely through this rate adjustment, similar to NP's RSA adjustment.

In January 2013, Hydro applied to the Board for approval to defer its 2013 program costs, for inclusion in the above recovery mechanism. The Board, in Order No. P.U. 21(2013), did not approve the deferral of these costs. Hydro is therefore again applying for deferral of these amounts, as they are not included in Hydro's revenue requirement but will, subject to approval of the Board, be recovered through the CDM cost recovery mechanism.

(ii) Diesel Cost Variation

Over the past several years, diesel fuel prices have been subject to the same upward pressures as Holyrood fuel costs. Chart 4.1 below illustrates Montreal rack prices for diesel fuel from 2007-2012.

[11] This recovery mechanism is similar to that proposed by NP in its September 2012 General Rate Application, Exhibit 14, page 3 of 4.

Chart 4.1
Market Background[12]

In one year, the average varied more than 50%[13]. Variances of this magnitude, which are inherent in today's fuel market, expose both Hydro and its customers to sizable risk without a means to compensate for the large variations, both positive and negative.

Hydro is proposing a Diesel Unit Cost Variance Deferral Account, in order to provide its customers with the benefit should diesel prices decrease and protect Hydro's earnings from fuel cost increases.

Fuel cost variances since the last GRA are illustrated in Table 4.8.

Table 4.8

Isolated Systems Diesel Fuel Cost Variance

	2007 TY	2007 A	2008 A	2009 A	2010 A	2011 A	2012 A	2013 B
Total Cost (000s)	$ 10,391	$ 10,395	$ 14,895	$ 12,555	$ 12,111	$ 15,547	$ 15,768	$ 17,790
Total Litres (000s)	14,046	13,969	14,908	15,108	14,164	15,106	14,610	15,825
Average Cost per Litre	$ 0.73978	$ 0.74415	$ 0.99913	$ 0.83102	$ 0.85506	$ 1.02919	$ 1.07926	$ 1.12417
Unit Price variance from Test Year Gain/(loss)		$ 0.00437	$ 0.25935	$ 0.09124	$ 0.11528	$ 0.28941	$ 0.33948	$ 0.38439
Total Variance (000s)		**$ 61**	**$ 3,866**	**$ 1,378**	**$ 1,633**	**$ 4,372**	**$ 4,960**	**$ 6,083**

[12] Data obtained from NRCan – Montreal Rack Prices 2007-Present.
[13] Illustrated Example: 2009 Yearly Average 56.89 cents, 2008 Yearly Average of 88.18 cents.

Table 4.9 below provides an example of an estimate of the variance to the customer or to Hydro with a 10% change in diesel fuel cost from 2013 Test Year cost.

Table 4.9

Diesel Fuel Cost Variation Example			
2013 Cost	**10% Variance**	**Litres**	**Total Variance**
$1.12	$0.11	15,824,754	$1,740,723

It is not proposed that Hydro account for volume variances in diesel costs, as increased or decreased load from the test year provides revenue shifts which partially offset the change in fuel costs. In addition, since the 21 diesel systems have at least three units each, and conversion rates differ from unit to unit, calculating these variances would present challenges.

(iii) Isolated Systems (including L'Anse au Loup) Purchase Power Variance Deferral

Due to their relationship to fuel costs, power purchase costs could also vary significantly in unit price from the Test Year unit price. As shown on Schedule VIII in section 2 of this evidence, the power purchase cost has increased from $1.7 million in 2007 to $3.2 million in 2012. On this basis, Hydro is also proposing a deferral and recovery mechanism for power purchases on its isolated systems.

(iv) GRA Costs

As stated in Section 3.8.5 of this evidence, Hydro is seeking to defer $1 million in external regulatory costs related to this Application, and amortize it over a three-year period, commencing in 2013.

4.7.3 Recovery Mechanisms

4.7.3.1 Diesel Unit Cost Variance

On a monthly basis, it is proposed that Hydro will calculate total unit cost variance for diesel consumption for the current month and record it in a Diesel Variance account. Hydro proposes that, at the same time rates related to CDM recovery and the RSP become effective, the disposition of the preceding year's Diesel Unit Cost Variance balance should also occur. This process will ensure that the variance is refunded to or recovered from customers in a fair and timely manner. It should be noted that the costs related to these rural customers primarily flow through to Newfoundland Power and its customers through the approved rural deficit allocation methodology.

It is proposed that the diesel unit cost variance be calculated as follows:

Table 4.10

Proposed Diesel Unit Cost Variation				
A	**B**	**C**	**D**	**E**
Actual Quantity Fuel Consumed	**Cost of Service Weighted Average Cost**	**Actual Weighted Average Cost**	**Cost Variance**	**Diesel Unit Cost Variation**
(litres)	**($/litre)**	**($/litre)**	**($)**	**($)**
			(C-B)	(A x D)

The diesel unit cost variation will be allocated between NP and Labrador Interconnected Rural Customers in the same proportion as the rural deficit was allocated in the approved Test Year Cost of Service Study.

The Labrador Interconnected customer allocation will be written off to Hydro's net income (loss).

4.7.3.2 Power Purchases Cost Variance

On a monthly basis, Hydro will calculate the total variance for total Isolated (including L'Anse au Loup) power purchases for the current month and record it in a Power Purchases Variance account. Hydro proposes that, at the same time rates related to CDM recovery and the RSP become effective, the preceding year's Power Purchases Cost Variance balance should also be disposed of. This process will ensure that the variance will flow through to customers in a fair and timely manner.

It is proposed that the power purchases cost variation be calculated as follows:

Table 4.11

Proposed Power Purchase Cost Variation		
A	**B**	**C**
Cost of Service Power Purchases	**Actual Power Purchases**	**Power Purchase Variation**
($)	**($)**	**($)** (B - A)

The power purchase cost variation will be allocated between NP and Labrador Interconnected Rural Customers in the same proportion which the rural deficit was allocated in the approved Test Year Cost of Service Study.

The Labrador Interconnected customer allocation will be written off to Hydro's net income (loss).

4.7.4 Hydro's Application

Hydro is requesting the Board's approval for the following:

- Deferring its 2013 CDM costs for inclusion in the recovery mechanism;
- Amortizing and recovering in rates CDM costs over a seven year period in accordance with the methodology set out in Page 20 of 21 of the Rates Schedules attached to this application;
- Amortizing and recovering in rates Hydro's Isolated System diesel fuel and power purchase cost variances from the approved Test Year; and
- Deferring and amortizing over three years an estimated $1 million in external regulatory costs related to this Application.

4.8 OTHER ITEMS

The Board, in Order No. P.U. 14(2004) directed Hydro to, among other things, file annually appropriate historic, current and forecast comparisons of reliability, operating, financial and other key targeted outcomes and measures, including KPIs. Hydro complied with this Order, by filing KPI reports. Commencing with its KPI report for 2004, Hydro noted that its functionally oriented (e.g. generation, transmission) financial KPIs require a COS study to allocate costs among systems and functional areas. This is primarily due to the nature of Hydro's TRO department, which serves multiple systems and functions.

Forecast COS studies are typically prepared by Hydro in support of rate cases, and the significant effort to produce such a study is not part of Hydro's annual budgeting process. As a result, Hydro is requesting modification of the Board's direction in Order No. P.U. 14(2004), to confirm that the "appropriate…forecast…KPIs" do not include the forecast of functionally oriented financial KPIs.

4.8.1 Hydro's Application

Hydro is requesting the Board's approval for altering or amending Order No. P.U. 14(2004) so that functionally oriented financial Key Performance Indicators are not required to be provided on a forecast basis.

Newfoundland and Labrador Hydro
Impact of Proposed Rates on Annual Electricity Costs for 2013
Government Departments
Domestic Diesel 1.2G

Dollars Change in Annual Costs	Percentage Change in Annual Costs: 17% to 19%	19% to 21%	21% to 23%	Total
$ 1 to $ 2,000	38.46%		7.69%	46.15%
$ 2,000 to $ 4,000	26.92%			26.92%
$ 4,000 to $ 6,000	19.23%			19.23%
$ 6,000 to $ 8,000	3.85%			3.85%
$ 8,000 to $ 8,100	3.85%			3.85%
Total:	**92.31%**	**0.00%**	**7.69%**	**100.00%**

Each number in the body of the table represents the proportion of customers with the combination of percent range at the top and dollar range to the left.

Note: This analysis is based on both existing and proposed rates applied against 2012 usage patterns and an average of 26 customers

Rates	Existing	Proposed
Basic Charge ($)	41.03	53.50
kWh Charge (¢)	78.100	91.621

Newfoundland and Labrador Hydro
Impact of Proposed Rates on Annual Electricity Costs for 2013
Government Departments
General Service 2.1G

Dollars Change in Annual Costs	Percentage Change in Annual Costs: 21% to 23%	23% to 25%	25% to 27%	Total
$ 1 to $ 1,000	6.98%	16.28%	4.65%	27.91%
$ 1,000 to $ 2,000	18.60%			18.60%
$ 2,000 to $ 3,000	27.91%			27.91%
$ 3,000 to $ 4,000	18.60%			18.60%
$ 4,000 to $ 5,000	6.98%			6.98%
Total:	**79.07%**	**16.28%**	**4.65%**	**100.00%**

Each number in the body of the table represents the proportion of customers with the combination of percent range at the top and dollar range to the left.

Note: This analysis is based on both existing rates and proposed rates applied against 2012 usage patterns and an average of 43 customers.

Rates	Existing	Proposed
Basic Charge ($)	44.82	58.56
kWh Charge (¢)	69.701	84.673

Newfoundland and Labrador Hydro
Impact of Proposed Rates on Annual Electricity Costs for 2013
Government Departments
General Service Diesel 2.2G

Dollars Change in Annual Costs	**Percentage Change in Annual Costs**			
	26% to 27%	**27% to 28%**	**28% to 29%**	**Total**
$ 3,000 to $20,000	33.33%	47.62%	9.52%	90.48%
$ 20,000 to $40,000		4.76%		4.76%
$ 40,000 to $60,000				0.00%
$ 60,000 to $65,000		4.76%		4.76%
Total:	**33.33%**	**57.14%**	**9.52%**	**100.00%**

Each number in the body of the table represents the proportion of customers with the combination of percent range at the top and dollar range to the left.

Note: This analysis is based on both existing and proposed rates applied against 2012 usage patterns and an average of 21 customers.

Rates	**Existing**	**Proposed**
Basic Service Charge ($)	66.37	75.06
kWh Charge (¢)	49.554	64.071
Demand $	53.68	66.59

Newfoundland and Labrador Hydro
Impact of Proposed Rates on Annual Electricity Costs for 2013
Labrador Interconnected
Domestic 1.1L

Dollars Change in Annual Costs	Percentage Change in Annual Costs 25.5% to 26.5%	Total
$ 1 to $ 200	24.76%	24.76%
$ 200 to $ 400	50.00%	50.00%
$ 400 to $ 600	23.94%	23.94%
$ 600 to $ 800	1.28%	1.28%
$ 800 to $ 900	0.03%	0.03%
Total:	**100.00%**	**100.00%**

Each number in the body of the table represents the proportion of customers with the combination of percent range at the top and dollar range to the left.

Note: This analysis is based on both existing rates and proposed rates applied against 2012 usage patterns and an average of 7,800 customers.

Rates	Existing	Proposed
Basic Charge ($)	7.15	9.02
kWh Charge (¢)	3.280	4.131

Newfoundland and Labrador Hydro
Impact of Proposed Rates on Annual Electricity Costs for 2013
Labrador Interconnected
General Service 2.1L

Dollars Change in Annual Costs	Percentage Change in Annual Costs: 28% to 29%	Total
$ 1 to $ 600	92.51%	92.51%
$ 600 to $ 1,200	6.19%	6.19%
$ 1,200 to $ 1,800	0.98%	0.98%
$ 1,800 to $ 2,400		0.00%
$ 2,400 to $ 2,700	0.33%	0.33%
Total:	**100.00%**	**100.00%**

Each number in the body of the table represents the proportion of customers with the combination of percent range at the top and dollar range to the left.

Note: This analysis is based on both existing rates and proposed rates applied against 2012 usage patterns and an average of 307 customers.

Rates	Existing	Proposed
Basic Charge ($)	10.45	13.43
kWh Charge (¢)	5.240	6.734

Newfoundland and Labrador Hydro
Impact of Proposed Rates on Annual Electricity Costs For 2013
Labrador Interconnected
General Service 2.2L

Dollars Change in Annual Costs	Percentage Change in Annual Costs: 16% to 17%	Total
$ 1 to $ 500	59.05%	59.05%
$ 500 to $ 1,000	28.73%	28.73%
$ 1,000 to $ 1,500	9.84%	9.84%
$ 1,500 to $ 2,000	1.91%	1.91%
$ 2,000 to $ 2,500	0.48%	0.48%
Total:	**100.00%**	**100.00%**

Each number in the body of the table represents the proportion of customers with the combination of percent range at the top and dollar range to the left.

Note: This analysis based on both existing rates and proposed rates applied against 2012 usage patterns and an average of 630 customers.

Rates	Existing	Proposed
kWh Charge (¢)	2.433	2.845
Demand ($)	2.20	2.55

Newfoundland and Labrador Hydro
Impact of Proposed Rates on Annual Electricity Costs For 2013
Labrador Interconnected
General Service 2.3L

Dollars Change in Annual Costs	Percentage Change in Annual Costs 16% to 17%	17% to 18%	Total
$ 100 to $ 5,000	69.80%	11.41%	81.21%
$ 5,000 to $ 10,000	17.45%		17.45%
$ 10,000 to $ 15,000	0.67%		0.67%
$ 15,000 to $ 20,000			0.00%
$ 20,000 to $ 25,000	0.67%		0.67%
Total:	**88.59%**	**11.41%**	**100.00%**

Each number in the body of the table represents the proportion of customers with the combination of percent range at the top and dollar range to the left.

Note: This analysis is based on both existing rates and proposed rates applied against 2012 usage patterns and an average of 149 customers.

Rates	Existing	Proposed
kWh Charge (¢)	2.103	2.455
Demand ($)	2.00	2.35

Newfoundland and Labrador Hydro
Impact of Proposed Rates on Annual Electricity Costs
Labrador Interconnected
General Service 2.4L

Dollars Change in Annual Costs	Percentage Change in Annual Costs: 21% to 22%	Total
$ 1 to $ 50,000	50.00%	50.00%
$ 200,000 to $ 250,000	50.00%	50.00%
Total:	**100.00%**	**100.00%**

Each number in the body of the table represents the proportion of customers with the combination of percent range at the top and dollar range to the left.

Note: This analysis is based on both existing rates and proposed rates applied against 2012 usage patterns and an average of 2 customers.

Rates	**Existing**	**Proposed**
kWh Charge (¢)	1.733	2.098
Demand ($)	1.75	2.15