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April 25, 2014

Dear Ms. Blundon,

Re: Financial Consultants Report
Board of Commissioners of Public Utilities
Newfoundland and Labrador Hydro
2013 General Rate Application

We are herewith enclosing one (1) original copy and twelve (12) copies of the above noted report.

We trust this information to be satisfactory.

Yours sincerely,
Grant Thornton LLP

Steve Power, CA
Partner
/tb

Board of Commissioners of Public Utilities

Financial Consultants Report

Newfoundland and Labrador Hydro

2013 General Rate Application
April 25, 2014

Contents

Introduction

This report to the Board of Commissioners of Public Utilities ("the Board") presents our observations, findings and recommendations with respect to our financial analysis of the pre-filed evidence of Newfoundland and Labrador Hydro ("the Company") ("Hydro") which was submitted to the Board in connection with its 2013 General Rate Application ("GRA") seeking approval for changes in rates for each of its customers.

Scope and Limitations

The scope of our financial analysis with respect to Hydro's 2013 General Rate Application and pre-filed evidence is as follows:

1 Review the proposed financial targets including return on equity, debt to capital structure and return on forecast average rate base.

2 Conduct a review of actual and forecast capital expenditures, revenues, expenses, net earnings, return on rate base and return on equity for the years ended December 31, 2007 to 2012, and forecast for December 31, 2013.

3 Examine the methodology and assumptions used by the Company for estimating revenues, expenses and net earnings.

4 Review the Company's calculation of estimated average rate base for the year ending December 31, 2013.

5 Verify the Company's calculation of the proposed rate of return on rate base and return on common equity for the year ending December 31, 2013.

6 Conduct an examination of operating expenses, depreciation and finance charges to assess their reasonableness and prudence in relation to sales of power and energy and assess compliance with Board Orders where applicable.

7 Verify the calculation of proposed rates necessary to meet the estimated revenue requirements in the 2013 test year.

8 Review the components and activity of the Rate Stabilization Plan (RSP) included in the Application.

9 Review the intercompany charges and shared services activity included in the test year data.

10 Review the proposed treatment of deferral accounts, including the Conservation and Demand costs.

11 Review proposed treatment of actuarial gains and losses on Employee Future Benefits.

12 Review the proposed regulatory treatment of Hydro's Asset Retirement Obligation.

13 Review proposed amortization and recovery mechanism for Hydro's Isolated System diesel fuel and power purchase costs.

14 Review of Hydro's proposal related to changes in functional oriented Key Performance Indicators.

The nature and extent of the procedures which we performed in our analysis varied for each of the items noted above. In general, our procedures were comprised of:

- enquiry and analytical procedures with respect to financial information in the Company's records;
- examining, on a test basis where appropriate, documentation supporting amounts included in the Company's Application;
- assessing the reasonableness of the Company's explanations; and
- assessing the Company's compliance with Board Orders.

The procedures undertaken in the course of our financial analysis do not constitute an audit of the Company's financial information and consequently, we do not express an opinion on the financial information.

The financial statements of the Company for the year ended December 31, 2012 have been audited by Deloitte & Touche LLP, Chartered Accountants, who have expressed their opinion on the fairness of the statements in their report dated April 23, 2013. In the course of completing our procedures we have, in certain circumstances, referred to the audited financial statements and the historical financial information contained therein.

On March 14, 2014, Hydro provided an update to the 2013 GRA to reflect the actual financial numbers for 2013. On April 16, 2014, Hydro provided Revision 1 of Hydro's submission on March 14, 2014. Where appropriate, the report was updated to include 2013 actuals and explanations of variances from 2013 test year. Actual results for 2013 have not been audited.

Forecasting Methodology and Assumptions

Based on information provided by Hydro, the Company's 2013 forecast of revenue and expenses was developed through the normal operating budget process which commenced in early 2012 and was essentially completed by the end of that year. Certain assumptions in relation to load and fuel for the 2013 forecast were further updated in early 2013. In addition, the 2013 forecast incorporates certain assumptions which reflect Hydro's best estimate of future economic conditions and events.

Our approach in this area of our review focused on the following three objectives:

1 Review the methodology used by the Company for forecasting revenues and expenses;

2 Review the assumptions made by management with regard to future economic conditions and events; and,

3 Ensure that these assumptions are properly incorporated into the forecasts.

Methodology

The methodology used by Hydro in preparing the 2013 forecast is consistent with the approach for the 2006 rate hearing and, as noted above, is based on the normal budgeting process. The budgeting process followed by Hydro is fairly comprehensive. The main steps or components in preparation of the operating budget are as follows:

- The annual budget process commences in July of each year with the issue of detailed budget instructions.

- Operating expenses are budgeted at the Business Unit level. Salaries and benefits, professional fees and operating projects which represent 90% of the operating expense budget were zero based. Other budget expense accounts were escalated at the annual inflation rate of 2.2% over the 2012 budget and adjusted for non-recurring differences.

- The budget is subject to various levels of review and approval by Managers, Vice-Presidents, the Leadership Team and finally, the Board of Directors of Hydro.

- Load forecasts are prepared by the System Planning department based on forecast information received from Newfoundland Power and the industrial customers, as well as, Hydro's own forecast for rural systems. The load forecast is used to generate a revenue budget based on existing rates. For 2013, the proposed new rates were applied to the load forecast to determine the forecast revenue.

- Based on the load forecast, the systems operations department determines the hydraulic/thermal split for generation and calculates and prepares the fuel budget. The purchased power estimates from CF(L)Co. and the non-utility generators (NUGS) are also determined at this time.

- The depreciation expense budget is prepared by the Capital Asset Accounting department based on the capital budget and projected in-service dates for construction projects in progress.

- Depreciation and accretion expense associated with asset retirement obligations are estimated based on timing of the settlement of the obligation.

- Cash expenses associated with operating expense, fuel, power purchases, capital expenditures and revenue inflows are provided to the Treasury department which, based on an interest model, generates a forecast of borrowing requirements and estimated interest expense.

- Capital budgets are submitted to the Board of Directors and PUB for approval.

- Long-term debt related payments are forecast based on debt repayment schedules.

- All elements of the operating budget are consolidated at this stage and forecast income statement and balance sheet information is submitted to the Leadership Team for their review and approval. After approval at this stage both the operating and capital budgets are submitted to the Board of Directors for final review and approval.

As a result of our review, we have determined that the overall methodology used by Hydro for forecasting revenue, expenses and net income is reasonable and appropriate. Our observations with respect to individual expense estimates and revenue from rates are included within the respective sections of our report that follows.

Review of Assumptions

The key assumptions made by management in developing the test year forecast relate to the following areas:

- the price of No. 6 Fuel for consumption at the Holyrood thermal generating station, the price of No. 2 fuel for consumption at the Interconnected standby generating plants, and price of diesel for consumption at the diesel plants located throughout isolated parts of Labrador and the island. We requested to review PIRA's No. 6 Fuel price forecast, however under the license agreement for retainer services with PIRA Energy Group, the Company stated they are prohibited from releasing PIRA's proprietary content within the public domain and therefore could not provide PIRA's forecast for the price of No. 6 Fuel;

- Nalcor Energy, operating the Provincial Government's hydroelectric assets on the Exploits River, at Buchans and at Star Lake, supplies the energy to Hydro throughout the forecast period;

- a conversion factor of 612 kWh/bbl for average efficiency at the Holyrood thermal plant;

- hydraulic production determined by the April 19, 2013 VISTA model using the forecast methodology as recommended and outlined in Hatch's August 19, 2011 letter: Modelling Approach for Determining System Capability;

- the expected power purchases from the non-utility generators;

- the hydraulic/thermal production split to meet remaining forecast load;

- the load forecasts for Newfoundland Power, the industrial customers and rural interconnected and isolated customers; and

- interest rate projections for short and long-term financing;
- negotiated salary increases;
- labour transactions associated with providing or receiving services from or to other lines of business are governed by the Intercompany Transaction Costing Guidelines;
- recovery costs associated with Common Service business units to all lines of business in Nalcor are included in Hydro;
- expenses associated with the Conservation and Demand Management (CDM) Program have been deferred and the recovery mechanism is proposed in the application;
- employee future benefits expense included in operating expenses included actuarial losses, current service costs, interest and other costs;
- expenses relating to the GRA hearing have been deferred and amortized over a three year period beginning January 1, 2013;
- depreciation and accretion expense associated with Asset Retirement Obligations (AROs) relating to Holyrood and PCBs are included in operating costs;
- determination of the surplus balance in the RSP is as of June 30, 2013. The balance in the Newfoundland Power RSP Surplus is forecast to be paid out in 2014;
- certain assets at the Holyrood Thermal Generating Station have been included in amortization expense using accelerated depreciation;
- no actual 2013 costs have been used in the determination of the revenue requirement with exception of fuel expense based on fuel price forecasts as of April 2013;
- 2013 revenue requirement and 2012 actuals have been presented in accordance with P.U. 13 (2012) and fiscal years 2007 to 2011 have not been restated.

Where appropriate, Hydro has used information from independent sources and/or expert consultants to establish the assumptions for the above noted items.

The nature of some of the assumptions noted above is that they are constantly being revised and updated by the experts (e.g. fuel prices, interest rates). The load forecasts for Newfoundland Power and the industrial customers are also updated periodically.

Incorporation of Assumptions into Forecasts

The incorporation of the key assumptions into the forecasts was reviewed and agreed to the various schedules included in the Company's pre-filed evidence and other supporting schedules and information provided. Based upon the results of our procedures we confirm that the assumptions have been appropriately incorporated into the forecasts.

We note that assumptions used in the test year forecast were developed in 2012 and early 2013. As with any forecast, actual results will differ and these differences can be material.

Revenue and Energy Forecasts

Hydro forecasts its revenue based on the total GWh requirements for each of its industrial customers, its utility customer (Newfoundland Power) and its rural customers. These GWh requirements are generally based on operating load forecasts provided in the spring and fall of each year. The fall's operating load forecast allows Hydro to make its initial projections for the following year. This projection is then updated midway through that year when the spring operating load forecast is received. In addition to the fall and spring load forecasts obtained from its industrial customers and Newfoundland Power, these customers also supply Hydro with expected annual production levels and a five year load forecast. The annual production levels help to explain increases or decreases in the anticipated load whereas the five year load forecast allows Hydro to incorporate potential revenues into its own future plans.

In generating the 2013 forecast of energy requirements, Hydro relied on the operating load forecasts provided by its industrial customers and its utility customer. For the remaining industrial customers, Hydro used its knowledge of each specific industrial end user as well as historical results as its main guide to forecast its energy requirements.

Forecasting energy requirements for rural customers is largely based on historical data. In preparing this forecast a separate projection is prepared for each area of service, namely the island interconnected, the Labrador interconnected and isolated diesel systems. In forecasting the energy requirements for the island interconnected, Hydro relies on a long term econometric model. This model uses both current and historical data to calculate GWh requirements for the coming year. Forecasting for the Labrador interconnected is based largely on historical trends as opposed to using an econometric model. These trends are then normalized for any unusual weather patterns such as extremely cold or warm winters. Hydro will also incorporate any relevant factors relating to general service customers that may affect load into its equation such as new requests for service, increases in production levels and the installation of new equipment. When forecasting for rural customers whose energy requirements are produced by diesel, Hydro will use much of the same techniques as used in forecasting the Labrador interconnected. However in doing so, Hydro tends to prepare more detailed forecasts by focusing on each community.

In order to identify any significant trends with respect to sales, we have compared the actual revenues for 2007 to 2013 with the forecast revenues for 2013. The results of this analysis of revenue by customer are as follows:

Table 1: Revenue by customer

(000)'s	Actuals 2007	Actuals 2008	Actuals 2009	Actuals 2010	Actuals 2011	Actuals 2012	Forecast 2013	Actuals 2013	Variance '13F-'12	Variance '13A-'13F
Industrial										
North Atlantic	$ 11,560	$ 12,044	$ 10,669	$ 10,189	$ 9,381	$ 11,432	$ 13,863	$ 10,517	$ 2,431	$ (3,346)
Abitibi - GF	4,937	5,151	3,352	-	-	-	-	-	-	-
Abitibi - Stephenville	285	-	-	-	-	-	-	-	-	-
Corner Brook	19,857	13,762	6,940	5,842	4,198	5,767	6,967	3,987	1,200	(2,980)
Teck Resources	2,812	3,198	3,282	3,530	3,585	3,593	4,689	3,600	1,096	(1,089)
Vale						5	2,863	414	2,858	(2,449)
Praxair							570	7	570	(563)
	39,451	34,155	24,243	19,561	17,164	20,797	28,952	18,525	8,155	(10,427)
Canadian Forces Base	3,951	5,719	1,350	4,025	4,038	1,554	877	333	(677)	(544)
									-	-
Utility	324,229	321,518	336,626	328,492	355,895	360,961	453,010	385,837	92,049	(67,173)
Rural										
Happy Valley/Wabush	14,245	14,186	14,522	13,479	14,853	15,884	22,330		6,446	
Island Diesel	1,498	1,484	1,538	1,375	1,406	1,424	1,606		182	
Island Interconnected	38,907	40,268	39,064	39,592	41,741	43,944	48,376		4,432	
Labrador Diesel	5,737	5,979	6,157	6,177	6,441	6,368	7,857		1,489	
Southern Labrador	1,776	1,885	2,029	2,073	2,258	2,246	2,729		483	
	62,163	63,802	63,310	62,696	66,699	69,866	82,898	68,090 [1]	13,032	(14,808)
Total revenue from rates	429,794	425,194	425,529	414,774	443,796	453,178	565,737	472,785 [2]	112,559	(92,952)
Add: Other revenue	1,983	2,197	2,218	2,287	2,317	2,116	2,350	2,343	234	(7)
Revenue requirement per Finance Schedule I	$ 431,777	$ 427,391	$ 427,747	$ 417,061	$ 446,113	$ 455,294	$ 568,087	$ 475,128	$ 112,793	$ (92,959)
Percentage change yr over yr		-1.02%	0.08%	-2.50%	6.97%	2.06%	24.77%	-16.36%		

Note 1: The breakdown of revenues from Rural customers was not provided for actual 2013.
Note 2: The variance between 2013 actuals and 2013 test year is made up of two components - the difference in GWh sold, and the difference arising from the fact that the rates proposed in the forecast were not incorporated in the 2013 actuals. The increase in actual GWh sold was 236 GWh compared to 2012 actual, but 120 GWh less than forecast.

The forecast revenues in 2013 are $112.8 million higher than 2012 actuals or 24.8%. The significant increase is primarily due to the increase in rates incorporated in the 2013 forecast. The forecast of 2013 revenue from rates, using existing rates, is $483.3 million (Table 4.4, p.4.16 of the pre-filed evidence, excluding RSP) compared to the $565.7 million revenues forecast using proposed rates. Therefore, $82.4 million of increases noted above are due to the proposed increase in rates. The 2013 forecast revenue at existing rates is $30.1 million (6.6%) higher than the 2012 actuals. These increases would be primarily attributable to changes in load for utility, rural, and industrial customers. Actual 2013 revenue was at existing rates, and was $19.6 million (4.3%) higher than 2012 actuals. This was primarily due to a 3.5% increase in GWh sold.

In order to identify any trends with respect to forecast load and energy sales, we have compared the actual energy sales (GWh) for 2007 to 2013 with the forecast energy sales for 2013. We have also reconciled the total sales forecast to the total GWh generated through hydroelectric, thermal, diesel and purchases of energy. The results of our analysis are as follows:

Table 2: Energy sales (GWh) by customer and reconciliation to energy generated (GWh)

(GWh)	Actuals 2007	Actuals 2008	Actuals 2009	Actuals 2010	Actuals 2011	Actuals 2012	Forecast 2013	Actuals 2013	Variance '13F-'12	Variance '13A-'13F
Industrial										
North Atlantic	243	256	220	206	185	240	218	216	(23)	(2)
Abitibi - GF	122	126	12	-	-	-	-	-	-	-
Abitibi - Stephenville	3	-	-	-	-	-	-	-	-	-
Corner Brook	397	283	98	92	55	97	80	55	(17)	(25)
Teck Resources	51	61	65	71	72	72	72	72	(0)	0
Vale	-	-	-	-	-	-	34	8	34	(26)
Praxair	-	-	-	-	-	-	4	-	4	(4)
	816	726	394	370	311	410	408	351	(1)	(57)
Department of National Defence	63	61	19	56	51	18	10	3	(8)	(7)
Iron Ore Company	257	337	162	303	129	180	260	201	79	(59)
Utility	4,991	4,960	5,108	5,016	5,318	5,359	5,594	5,606	235	12
Rural - Island Interconnected and Labrador Interconnected	895	910	919	877	968	991	1,042	1,033	50	(9)
	7,022	6,994	6,602	6,622	6,777	6,958	7,314	7,194	356	(120)
Transmission and distribution losses - Island Interconnected and Labrador Interconnected	257	288	261	291	290	302	324	322	22	(2)
	7,279	7,282	6,863	6,913	7,067	7,260	7,638	7,516	378	(122)
(GWh)										
Island Interconnected										
Hydroelectric	4,690	4,771	4,200	4,274	4,512	4,595	4,534	4,688	(62)	155
Thermal	1,256	1,080	940	803	885	856	1,127	957	272	(170)
Diesel	(10)	(8)	(8)	(11)	(9)	(4)	3	(1)	7	(4)
Power Purchases									-	-
NP at Hydro Request	-	-	1	-	-	-	-	1	-	1
ACI-GF Secondary	64	30	7	-	-	-	-	-	-	-
Star Lake	148	148	149	136	130	144	141	141	(4)	-
Rattle Brook	12	14	16	17	19	15	15	15	0	-
Corner Brook P&P	-	-	7	4	4	6	-	9	(6)	9
Corner Brook Cogen	93	74	56	52	51	48	51	56	3	5
Exploits River	137	177	180	112	-	-	-	-	-	-
St. Lawrence Wind	-	8	101	100	110	104	105	96	1	(8)
Fermeuse Wind	-	-	54	83	88	91	84	96	(7)	11
Nalcor GF, BF and Buchans	-	-	-	-	511	586	622	600	36	(22)
	453	450	569	505	911	994	1,017	1,013	23	(4)
	6,389	6,293	5,700	5,571	6,301	6,441	6,681	6,657	240	(24)
Labrador Interconnected										
Diesel	(3)	(2)	(2)	(2)	(3)	(1)	1	1	2	0
Power Purchases	893	991	752	913	783	820	956	858	136	(98)
	890	989	750	911	780	819	957	859	138	(98)
Total	7,279	7,282	6,451	6,482	7,081	7,260	7,638	7,516	378	(122)
Difference (Note 1)	-	-	413	431	(14)	-	-	-		

Note 1: The variances between the energy required and the energy purchased in the years 2009, 2010, and 2011, relate to energy received from Nalcor Exploits base generation which was stored rather than purchased, due to the Abitibi Mill closure in February, 2009.

Energy sales were forecast to increase overall in 2013 by 378 GWh from 2012 actuals. The largest portion of the increase in the number of GWhs in 2013 relates to an increase in energy sales of 235 GWh to Hydro's utility customer, Newfoundland Power. Hydro is also forecasting an increase of 50 GWh in energy sales to rural customers. Newfoundland Power represents Hydro's largest customer with 76.5% of total GWh forecast to be sold in 2013 before transmission and distribution losses. Newfoundland Power's consumption in 2013 is forecast to increase by 235 GWh or 4.4% over the actual GWh sold in 2012. While the energy requirements for the forecast year is based on Newfoundland Power's operating load forecast provided in 2012, the increase for 2013 is reflective of weather related energy sales and energy sales associated with Newfoundland Power customer growth.

Along with these increases in sales, Hydro is also forecasting an increase in sales to various industrial customers, including Iron Ore Company of Canada (IOCC), Vale and Praxair. This projected increase in energy sales consists of energy sales associated with customer growth.

Hydro has forecast an increase in energy sales to IOCC of 79 GWh. This represents 57.3% of the total forecast increase in energy sales to Labrador Interconnected Systems. An increase of 16.8% is anticipated for the 2013 Labrador Interconnected load requirements relative to 2012. This reflects the increase in consumption at IOCC mentioned above and the commencement of construction at the Muskrat Falls site.

Energy sales to Vale are forecast to increase to 34 GWh in 2013. 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 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 anticipated 2013 energy consumption of 4 GWh.

Decreases totalling 40 GWh are forecast for North Atlantic Refining Limited and Corner Brook Pulp and Paper.

In addition to the analysis of revenue by customer noted above, we also recalculated the 2013 forecast revenue from rates to ensure the proposed new rates together with the forecast loads agree with the test year revenue requirement. No discrepancies were noted in completing these procedures.

The actual increase in GWh sold was 122 GWh less than forecast. The decrease in sales to Corner Brook Pulp and Paper was greater than forecast by 25 GWh, the increase in sales to Iron Ore Company was 59 GWh less than forecast, and Vale used only 8 GWh instead of the forecast 34 GWh, a difference of 26 GWh. These three customers accounted for 110 GWh of the 122 GWh variance.

Cost of Capital

Capital Structure

Hydro's 2013 forecast capital structure and projected balance sheet which provides the basis for these calculations is detailed in the pre-filed evidence (finance schedule 1, pg. 2 of 11 and pg. 4 of 11).

Our procedures performed in this area focused on verifying the calculations of regulated average capital structure, and assessing the reasonableness of the data incorporated in the calculations and the methodology used by the Company. Specifically, our procedures included the following:

- agreed all carry-forward data to supporting documentation;
- agreed all forecast data to supporting documentation to ensure it is internally consistent with the pre-filed evidence and other forecast information; and
- verified the clerical accuracy of the calculations of regulated average capital structure.

The Company's calculation of regulated capital structure for 2007 to 2013 is as follows:

Table 3: Regulated capital structure (2007-2012 and 2013 test year)

(000,000)'s	As at December 31													
	2007	%	2008	%	2009	%	2010	%	2011	%	2012	%	Test Year 2013	%
Debt	$ 1,188	82.6%	$ 1,152	81.5%	$ 981	72.0%	$ 957	72.6%	$ 933	71.7%	$ 957	70.9%	$ 985	69.3%
Asset Retirement obligations, funded	-	0.0%	-	0.0%	-	0.0%	-	0.0%	2	0.1%	4	0.3%	7	0.5%
Employee future benefits, funded	40	2.8%	42	3.0%	44	3.2%	48	3.7%	54	4.1%	57	4.2%	64	4.5%
Equity	211	14.7%	220	15.5%	337	24.7%	313	23.7%	312	24.0%	331	24.5%	365	25.7%
	$ 1,439		$ 1,413		$ 1,362		$ 1,318		$ 1,300		$ 1,349		$ 1,421	

(000,000)'s	Average											
	2008	%	2009	%	2010	%	2011	%	2012	%	Test Year 2013	%
Debt	$ 1,170	82.0%	$ 1,067	76.9%	$ 969	72.3%	$ 945	72.2%	$ 945	71.3%	$ 971	70.1%
Asset Retirement obligations, funded	-	0.0%	-	0.0%	-	0.0%	1	0.1%	3	0.2%	6	0.4%
Employee future benefits, funded	41	2.9%	43	3.1%	46	3.4%	51	3.9%	55	4.2%	60	4.4%
Equity	215	15.1%	278	20.1%	325	24.2%	312	23.9%	322	24.3%	348	25.1%
	$ 1,426		$ 1,388		$ 1,340		$ 1,309		$ 1,325		$ 1,385	

The company's actual calculation of regulated capital structure for 2013 is below, along with a comparison to the calculation for test year 2013.

Table 4: Regulated capital structure (2012-2013 and 2013 test year)

(000,000)'s	As at December 31					
					Test Year	
	2012	%	2013	%	2013	%
Debt	$ 957	70.9%	$ 918	69.6%	$ 985	69.3%
Asset Retirement obligations, funded	4	0.3%	7	0.6%	7	0.5%
Employee future benefits, funded	57	4.2%	62	4.7%	64	4.5%
Equity	331	24.5%	332	25.2%	365	25.7%
	$ 1,349		$ 1,319		$ 1,421	

(000,000)'s	Average					
					Test Year	
	2012		2013		2013	
Debt	$ 945	71.3%	$ 937	70.3%	$ 971	70.1%
Asset Retirement obligations, funded	3	0.2%	6	0.4%	6	0.4%
Employee future benefits, funded	55	4.2%	59	4.4%	60	4.4%
Equity	322	24.3%	332	24.9%	348	25.1%
	$ 1,325		$ 1,334		$ 1,385	

Consistent with the Company's calculation of return on equity, equity included in the capital structure shown above excludes Accumulated Other Comprehensive Income.

Prior to 2009, Hydro's debt to equity ratio had been trending towards the 80:20 target ratios with 2008 showing a ratio of 81.5:18.5. In 2009, Nalcor provided a $100 million equity injection of contributed capital resulting in a significant reduction in leverage to a ratio of 72.0:28.0. As can be seen from the above table, the debt to equity ratio remained relatively consistent from 2009 to 2012 and is forecast to decrease slightly further in 2013 test year. The improvement of the debt to equity ratio for actual 2013, is slightly less than forecast with debt of 69.6% (test year – 69.3%) and equity of 25.2% (test year – 25.7%).

Also in 2009 the Government of Newfoundland and Labrador Order in Council 2009-063 as filed by Hydro in response to NP-NLH-056 provided that the "*capital structure approved by Newfoundland and Labrador Hydro should be permitted to have a maximum proportion of equity as was most recently approved for Newfoundland Power*" (which is currently 45% equity and 55% debt). However, the Company's internal target capital structure is comprised of 75% debt and 25% common equity for regulated operations. Hydro has noted that in order to maintain this target ratio the company implemented the following dividend policy approved by Hydro's Board of Directors in 2009:

> "*Corporation annually on or before March 31 of each year, pay a dividend on its common shares if the percentage of debt to debt plus equity in the capital structure of the corporation on a regulated basis at the end of the immediately*

preceding fiscal year was less than 75% and that the amount of the dividend in that case will be equal to the amount that would be necessary to bring the percentage of debt to debt plus equity up to 75% at December 31st of the immediately preceding year, as if the dividend in question had been on that date."

According to Hydro, the corporate regulated capital structure used in the calculation of the regulated dividend is based on a rating agency methodology which differs from the calculation of the capital structure as reported in Hydro's Annual Return 14. For 2009 and 2010, regulated capital structure was calculated based on Dominion Bond Rating Service approach to calculating debt and total capital and for 2011 and 2012 the Standard and Poor's methodology was used. Regulated dividends of $30.9 million and $21.2 million were paid on March 31, 2010 and March 31, 2011 relating to fiscal year ended December 31, 2009 and December 31, 2010, respectively. No regulated dividends were paid on March 31, 2012 or March 31, 2013. In response to IC-NLH-042 Hydro provided the detailed calculation of the level of dividends under the rating agency methodologies.

Based upon our procedures, we did not note any discrepancies in the calculation of Hydro's capital structure.

Embedded Cost of Debt

Hydro's calculation of its embedded cost of debt is included in the pre-filed evidence (finance schedule IV Page 1 of 1). We have reviewed these calculations as well as agreed the individual components to supporting documentation including the average total debt, debt guarantee fee, and amortization of foreign exchange losses and accretion of long-term debt. Our specific comments in relation to the debt guarantee fee are included under a separate heading that follows.

The embedded cost of debt for actual 2012, test year 2013 and actual 2013 is as follows:

Table 5: Embedded cost of debt

(000's)	Actual 2012	Test Year 2013	Actual 2013
Interest on Long-Term Debt	$ 90,450	$ 90,450	$ 90,450
Accretion of Long-Term Debt	499	540	540
Amortization of Foreign Exchange Loss	2,157	2,157	2,157
Debt Guarantee Fee	3,693	3,735	3,735
Other Interest	704	226	14
	97,503	97,108	96,896
Less:			
Interest on Sinking Fund Assets	(18,025)	(19,302)	(19,434)
Net Interest	$ 79,478	$ 77,806	$ 77,462
Average Total Debt (Note 1)	$ 944,822	$ 970,880	$ 937,454
Embedded Cost of Debt	8.41%	8.01%	8.26%

Note 1: The average total debt reported in the 2012 annual return 15 was $944,937,000, a difference of $115,000. The difference relates to adjustments to the 2012 regulated debt for $105,000 on the mark-to-market of the sinking fund and $125,000 on Hydro's promissory notes [Average is calculated as $230,000/2 = $115,000]. The correction had no impact on the 2012 reported embedded cost of debt and the revised 2012 balance was appropriately reported in the calculation of the 2013 forecast embedded cost of debt.

The methodology and approach used to calculate the 2013 embedded cost of debt is consistent with 2006 GRA.

Hydro's $125,000,000 Series V debentures which bear interest at 10.5% are due for repayment in 2014. Hydro expects to refinance or issue new debt at more favourable interest rates. In Hydro's response to PUB-NLH-53 Hydro has estimated its marginal cost of long-term debt at 4.138% as of August 31, 2013. Marginal cost of debt is the cost of another unit of debt raised.

Debt Guarantee Fee

We reviewed the Guarantee Fee Analysis prepared by Scotiabank, dated October 2013. Our comments are based on our experience determining the fees paid for loan guarantees made by parent companies on behalf of their foreign subsidiaries, Canadian law, guidance from the Organisation for Economic Co-operation and Development and the United Nations, as well as jurisprudence from the Tax Court of Canada and Federal Court of Appeal, specifically the *GE Capital* case, in which methodologies for pricing guarantee fees were extensively examined.[1]

For issuing an unconditional guarantee for all of Hydro's debt, the Province of Newfoundland and Labrador (the "Province") charges Hydro a fee equal to 25 bps of the outstanding debt scheduled to mature within 10 years and a fee of 50 bps of the outstanding debt scheduled to mature after 10 years.

The approach used by Scotiabank to measure the value of the guarantee provided by the Province to Hydro is akin to the "yield approach" relied on by Justice Hogan in *GE Capital.* The approach used by Scotiabank compared the yields on bonds issued by the Province with the yields on bonds issued by three Canadian regulated utilities as well as the DEX Universe Utility Index.[2] The differences were believed to represent the 'cost savings' associated with the Province's guarantee, and these 'cost savings' formed the basis for the guarantee fee recommendation. Scotiabank also examined the guarantee fees charged by eight other provinces for use of their respective guarantees. Scotiabank ultimately concluded that the fees charged by the Province to Hydro were still reasonable.

In recent years, methods to price guarantee fees charged by related parties have been subject to substantial scrutiny during international tax examinations and in the courts. As a result of this scrutiny, the yield approach has become the method most often used by transfer pricing practitioners to price guarantee fees between related parties. In the context of Hydro, the first step of the yield approach involves determining the benefit or "cost savings" attributed to the guarantee. This is measured as the difference between the yields on bonds issued by the Province and those issued by Hydro, as a standalone entity. The second step involves apportioning the benefit between the recipient and the guarantor to share in the cost savings, since charging the recipient an amount equal to the benefit would eliminate the incentive for obtaining the guarantee.

All of the bonds issued by Hydro currently have an unconditional provincial guarantee associated with them. Consequently, the yield on those bonds cannot be used to measure the benefit of the guarantee. For this reason, Scotiabank uses the yield on bonds issued by three Canadian utilities as a proxy for the yields on the bonds issued by Hydro, as a standalone entity. However, for this proxy to derive a reliable result, it must be the case that the three Canadian utilities have the same credit rating as Hydro, as a standalone entity.

Since Hydro does not have a standalone credit rating, Scotiabank is implicitly assuming that Hydro has the same credit rating as the three companies without providing any evidence to support such an assumption.

In the event that Hydro did have the same credit rating as one or more of the Canadian utilities used by Scotiabank, three additional issues would rise. First, the three Canadian utilities used have different credit ratings so an adjustment would have to be made to account for the effect of that difference on the yields on the bonds they issued. Second, two of the companies are publicly traded and one of the companies is owned

[1] See *General Electric Capital Canada Inc. v. The Queen, 2009 TCC 563 (Tax Court of Canada)*; and *The Queen v. General Capital Canada Inc. (2010) F.C.A. 344 (Federal Court of Appeal).*
[2] Guarantee Fee Analysis, October 2013, Scotiabank, Pages 3-5.

by a provincial government with a stronger credit rating than the Province. Consequently, adjustments for the relative effect of the implicit support provided would have to be considered. Finally, any effects on the yields from differences in the term to maturity, optionality (i.e.: demand/call options; prepayment options; conversion options), and market-of-issuance would also have to be considered. Without conducting a thorough analysis, it is difficult to determine the impact that these considerations would have on the results derived or conclusions drawn by Scotiabank.

Finally, Scotiabank did not apportion the benefit of the 'cost savings' between the recipient and guarantor. The payment of the entire 'cost savings' associated the guarantee back to the guarantor in the form of a guarantee fee eliminates the incentive for obtaining the guarantee. The average difference between the yield on short-term debt issued by the Province and that issued by the three Canadian utilities ranged from 31.7 bps to 33.0 bps.[3] The 25 bps guarantee fee paid by Hydro for short-term debt implies a 'cost savings' split of 79/21 to 76/24 for the Province/Hydro, respectively.

By comparison, the average difference on long-term debt yields ranged from 35.6 bps to 47.8 bps, already below the 50 bps paid by Hydro.[4] Apportioning the benefits of the guarantee would lower these ranges further, which may bring into question the 50 bps guarantee fee paid by Hydro on long-term debt.

Based on our analysis, further examination is required to determine an appropriate methodology to apportion the benefit of the guarantee between Hydro and the Province on both short-term and long-term debt yields. We recommend that the Board advise Hydro to propose an equitable methodology to apportion this benefit.

[3] Guarantee Fee Analysis, October 2013, Scotiabank, Page 3.
[4] Guarantee Fee Analysis, October 2013, Scotiabank, Page 3.

Regulated Interest Coverage

Regulated interest coverage for 2013 test year has been calculated at 1.27 times as follows:

Table 6: Interest coverage

(000's)	2010	2011	2012	2013 Test Year	2013
Interest on long-term debt	$ 90,500	$ 90,500	$ 90,500	$ 90,500	$ 90,500
Accretion, long-term debt	400	500	500	500	500
Amortization of FX Loss	2,200	2,200	2,200	2,200	2,200
RSP interest expense	10,200	12,200	13,200	14,400	17,100
Other	1,400	4,600	4,600	4,500	4,100
Gross interest and finance charges (Note 1)	$ 104,700	$ 110,000	$ 111,000	$ 112,100	$ 114,400
Income from operations	$ 6,600	$ 20,600	$ 16,900	$ 33,400	$ 200
Gross interest and finance charges	104,700	110,000	111,000	112,100	114,400
Less: Interest during construction	(1,200)	(1,500)	(2,700)	(3,200)	(2,200)
Adjusted income	$ 110,100	$ 129,100	$ 125,200	$ 142,300	$ 112,400
Interest Coverage	**1.05**	**1.17**	**1.13**	**1.27**	**0.98**

Note 1: The calcuation of interest coverage as previously reported in Hydro annual reviews years 2010 to 2012 included the gross interest and finance charges less interest during construction. However, the full gross interest and finance charges is included as the inclusion of interest during construction provides for a more accurate interest coverage ratio.

The calculation of corporation interest coverage (which includes non-regulated activity) was not available as only regulated operations was provided as part of the 2013 test year data.

Regulated interest coverage for 2013 test year has increased compared to 2012. The largest variance is with respect to income from operations, which has increased by $16,500,000 compared to 2012. This factor, partially offset by a $1,200,000 increase in RSP interest expense compared to 2012, translates into an improved interest coverage ratio forecast for 2013.

The actual interest coverage ratio for 2013 is lower than test year forecast due to a decrease of $33,200,000 in income from operations.

Regulated Equity and Return on Equity

Our procedures in this area focused on verification of the data incorporated in the calculations and on the methodology used by the Company. Specifically, the procedures which we performed included the following:

- agreed all carry-forward data to supporting documentation including the 2012 audited financial statements and internal accounting records, where applicable;
- agreed forecast component data (earnings applicable to common equity, dividends, regulated earnings, etc.) to supporting documentation to ensure it is internally consistent with the pre-filed evidence;
- checked the clerical accuracy of the continuity of regulated common equity as forecast for 2013;
- re-calculated the rate of return on common equity for 2013 and ensured it was in accordance with established practice and applicable Board Orders.

In order to provide a basis of comparison for the 2013 average common equity and return on average common equity, we have prepared the following summary for 2010 to 2013 test year and actual 2013:

Table 7: Return on book equity

(000)'s		2010	2011	2012	2013 Test Year	2013 Actual
Shareholder's equity	(Note 1)					
2013					$ 364,531	$ 331,383
2012				$ 331,174	$ 331,174	$ 331,174
2011			$ 312,096	$ 312,096		
2010		$ 312,647	$ 312,647			
2009		$ 336,943				
Average equity		$ 324,795	$ 312,372	$ 321,635	$ 347,853	$ 331,279
Regulated earnings	(Note 1)	$ 6,604	$ 20,599	$ 16,900	$ 33,357	$ 209
Return on book equity		**2.03%**	**6.59%**	**5.25%**	**9.59%**	**0.06%**

Note 1: The shareholder's equity and regulated earnings for 2012, 2013 and test year 2013, do not include cost of service exclusions.

The rate of return on book equity calculated in the above summary for the 2013 test year is 9.59%. In its Application Hydro proposed a regulated return on equity of 8.80% for the 2013 test year, which is a component of the Company's weighted average cost of capital (WACC). Hydro's allowed return is calculated as its rate base multiplied by its WACC (or allowed rate of return). The difference in rate of return on book equity of 9.59% and Hydro regulated return on equity of 8.80% arises due to differences between the Company's average rate base and average invested capital balances.

The following table provides a reconciliation of Hydro's allowed return (regulated earnings) of $33.4 million and rate of return on book equity of 9.59% (in above summary):

Table 8: Reconciliation of return on book equity from regulated rate of return on equity

Reconciliation of return on book equity from regulated rate of return on equity

('$000,000)			
Average 2013 book equity			$ 347.9
Regulated rate of return on equity (%)			8.80%
Allowed return on regulated equity			$ 30.6
Add: Excess average rate base over average invested capital (**Note 1**)	$34.1 X	WACC (7.83%)	2.7
			$ 33.3
		Rounding	0.1
Allowed Return			$ 33.4
Average 2013 book equity			$ 347.9
Rate of return on book equity			9.60%

Note 1
The following is a reconcilation of the difference in the 2013 test year average rate base and average invested capital:

2013 Test Year	
Average Rate Base	$ 1,564.1
Average Invested Capital*	1,530.0
Difference	$ 34.1
Reconciliation:	
Plant (work in progress and assets not in use)	$ 9.8
Materials and supplies (actual vs.Rate Base allowance)	12.7
Working capital (actual vs. Rate Base allowance)	9.4
Other	2.2
	$ 34.1
***Average Invested Capital is comprised of the following:**	
Net average regulated debt	$ 970.9
Average RSP balance	185.0
Less: Average work in progress	(40.0)
	$ 1,115.9
Average Zero Cost Capital	66.1
Average Shareholder's equity	348.0
	$ 1,530.0

Average work in progress is calculated as test year interest during construction divided by embedded cost of debt ($3.2 million / 8.01 % = $40.0 million).

The regulated return on equity of 8.80% is consistent with Newfoundland Power's return on equity of 8.80% which was approved in Board Order No. P.U. 13(2013). Pursuant to Order in Council 2009-063, the Government directed that Hydro would set a target return on equity the same as was most recently set for

Newfoundland Power in calculating its return on rate base or calculated through the Newfoundland Power Automatic Adjustment Mechanism. In PUB-NLH-057 Hydro noted that it anticipates future adjustments to its return on equity would only occur as a result of a Hydro GRA, as opposed to future adjustments resulting from a change in Newfoundland Power's allowed return on equity following a subsequent GRA or through the use of an Automatic Adjustment Formula.

The actual shareholder's equity and regulated earnings for 2013 are lower than expected due to a decrease of $33,200,000 in income from operations. The significant decrease in operating income resulted from a $93,000,000 decrease in revenues, offset by a decrease of $59,800,000 in expenses. The variance in energy sales was primarily due to the 2013 test year sales having twelve months of new rates as compared to the actuals with twelve months of existing rates. The variance in expenses is primarily relating to a decrease of $63,400,000 in fuels partially offset by an increase in interest expense of $3,400,000. Further commentary on revenue requirement variances from test year and actual 2013 is discussed further in our report. This variance resulted in a significantly lower return on book equity of 0.06% for 2013.

Based upon our review, we did not note any discrepancies in the calculations of regulated average equity and regulated rate of return on equity. As previously noted, Hydro has requested a rate of return on equity in its Application of 8.80%.

Weighted Average Cost of Capital

The forecast rate of return on rate base is based on the forecast weighted average cost of capital ("WACC"). Hydro's calculation of the WACC is included in the pre-filed evidence on Table 3.7. The inputs to this calculation are the average forecast capital structure and the forecast cost of the individual components of invested capital. Our comments with respect to each of these factors have been provided in the preceding sections.

A comparison of the WACC for actual 2012, 2013 test year, and actual 2013 is included in the table below.

Table 9: WACC

	Actual 2012			Test Year 2013			Actual 2013		
	Percent	Cost	WACC	Percent	Cost	WACC	Percent	Cost	WACC
Debt	71.3	8.26%	5.89%	70.1	8.01%	5.62%	70.3	8.26%	5.81%
Asset retirement obligations	0.2	0.00%	0.00%	0.4	0.00%	0.00%	0.4	0.00%	0.00%
Employee Future Benefits	4.2	0.00%	0.00%	4.4	0.00%	0.00%	4.4	0.00%	0.00%
Equity	24.3	4.47%	1.09%	25.1	8.80%	2.21%	24.9	4.47%	1.11%
	100.0		6.98%	100.0		7.83%	100.0		6.92%

The WACC is forecast to increase in 2013 primarily due to a higher return on equity offset partially by a lower average cost of debt.

Based upon our review, we did not note any discrepancies in the calculation the Hydro's test year WACC of 7.83%.

Average Rate Base and Return on Rate Base

The Company's calculation of its forecast average rate base and rate of return on rate base for the 2013 test year is included in Finance Schedule I of the pre-filed evidence. Our procedures with respect to verifying the calculation of the average rate base were directed towards the assessment of the reasonableness of the data incorporated in the calculations and the methodology used by the Company. Specifically, the procedures which we performed included the following:

- agreed all carry-forward data to supporting documentation including the 2012 audited financial statements and internal accounting records, where applicable;
- agreed forecast data (capital expenditures, depreciation, etc.) to supporting documentation to ensure it is internally consistent with the pre-filed evidence;
- checked the clerical accuracy of the continuity of the rate base as forecast for 2013;
- recalculated the forecast average rate base for 2013; and
- reviewed the methodology used in the calculation of the average rate base with reference to the Public Utilities Act, the Hydro Corporation Act and Board Orders.

Details of the 2013 forecast average rate base and return on average rate base with comparative data for 2007, 2008, 2009, 2010, 2011, and 2012 are presented in the following table:

Table 10: Average rate base, return on rate base and rate of return on average rate base (2007-2012 and 2013 test year)

(000's)	2007	2008	2009	2010	2011	2012	Test Year 2013
Plant investment (Note 4)	$ 2,016,315	$ 2,044,397	$ 2,082,460	$ 2,136,058	$ 2,191,991	$ 1,510,588	$ 1,633,080
Less: Accumulated depreciation (Note 4)	(570,225)	(603,362)	(632,085)	(669,742)	(707,241)	(88,865)	(140,043)
CIAC's (Note 4)	(96,396)	(96,143)	(96,749)	(97,257)	(98,054)	(14,052)	(22,269)
ARO's	-	-	-	(11,395)	(17,976)	(19,685)	(17,320)
Net capital assets	1,349,694	1,344,892	1,353,626	1,357,664	1,368,720	1,387,986	1,453,448
Balance previous year	1,345,766	1,349,694	1,344,892	1,353,626	1,357,664	1,368,720	1,387,986
Average	1,347,730	1,347,293	1,349,259	1,355,645	1,363,192	1,378,353	1,420,717
Less: average net assets not in use (Note 1)	-	-	-	(777)	(423)	(1,428)	(3,005)
	1,347,730	1,347,293	1,349,259	1,354,868	1,362,769	1,376,925	1,417,712
Cash working capital allowance (Note 2)	3,496	3,548	2,668	3,092	4,625	7,810	5,336
Fuel inventory	25,874	34,389	20,817	29,908	33,680	50,308	50,885
Supplies inventory	21,699	22,561	23,567	24,089	24,096	25,339	24,701
Deferred charges	84,725	81,996	76,870	71,925	68,048	65,670	65,451
Average rate base (Note 1)	$ 1,483,524	$ 1,489,787	$ 1,473,181	$ 1,483,882	$ 1,493,218	$ 1,526,052	$ 1,564,085
Return on rate base:							
Unadjusted return on regulated equity	$ 2,711	$ 8,874	$ 17,211	$ 6,604	$ 20,599	$ 16,900	$ 33,357
Cost of service exclusions (Note 3)	-	-	-	-	-	113	48
Net interest	103,242	87,610	83,440	86,766	90,844	89,961	89,043
Return on rate base	$ 105,953	$ 96,484	$ 100,651	$ 93,370	$ 111,443	$ 106,974	$ 122,448
Rate of return on average rate base	7.14%	6.48%	6.83%	6.29%	7.46%	7.01%	7.83%

Note 1: In P.U. 2 (2012) the Board fixed and determined the 2010 rate base to be $1,484,659,000. Hydro has restated 2010 to exclude average net assets not in service from the average rate base.

Note 2: Per Finance Schedule I, page 5 of 11, of the pre-filed evidence, the 2009 cash working capital allowance has been restated since the 2009 annual review. Due to a variance in the calculation for the HST adjustment, the allowace has decreased from 2,965,000 to 2,668,000. This change resulted in a decrease of $297,000 in the calculation of average rate base, however it has not impacted the 2009 rate of return on rate base of 6.83%. The difference was determined to be not material by Hydro and the 2009 annual return was not re-filed.

Note 3: The 2012 cost of service exclusion includes an amount for the depreciation of assets not in service. This amount was not included in the 2012 annual review. This change resulted in a decrease of $113,000 to the calculation of return on rate base and an increase of 0.01% in the rate of return on rate base.

Note 4 : In P.U. 13 (2012), the Board approved the use of the carrying value of Hydro's property, plant and equipment as deemed cost at January 1, 2011. As a result, the 2012 balances of plant investment, accumulated depreciation and CIAC's reflect adjustments to deemed cost at January 1, 2011.

As detailed above, the average rate base is forecast to increase by $38,033,000 in 2013.

The most significant increase to rate base can be attributable to net capital assets. Total additions, net of CIAC's of $7 million and insurance proceeds of $0.8 million, are forecast in the amount of $105.0 million, of which $21.3 million of assets are included in work in progress and are excluded from 2013 rate base. Forecast capital expenditures is discussed further in the capital expenditures section of this report.

The increase in average net assets not in service in forecast 2013 over 2012 of $1,577,000 relates primarily to the project to replace the Fuel Oil Heat Tracing system at the Holyrood Thermal Generating Station. The average net assets for this project, which is excluded from rate base for 2012, was $388,000 for 2012 and is forecast to be $1,427,000 for 2013, an increase of $1,039,000.

The cash working capital allowance is forecast to decrease by $2,474,000 primarily due to an adjustment of $41.1 million made to power purchases in 2012 in order to reflect the 2009 and 2010 accruals for energy purchases relating to Star Lake and Exploits Non-Utility Generators (NUGs). According to the Company, this was an unusual circumstance where cash payments for its power purchases were not made for a significant portion of the year, and therefore, an adjustment was necessary in order to reflect the correct calculation of working capital allowance for 2009 and 2010.

The cost of service exclusion includes an amount relating to the depreciation of assets not in service. The depreciation amount is expected to increase by $19,000 in 2013 to $132,000; however, the total exclusion is expected to decrease due to a RSP adjustment of $84,000. This adjustment relates to the portion of the hydraulic variation that is assigned to the Labrador Interconnected System which must be excluded from the cost of service calculation, resulting in a net exclusion of $48,000.

The 2013 forecast of $50.9 million for average fuel inventory is relatively consistent with the 2012 actual balance of $50.3 million. However this balance has increased significantly when compared to amounts filed between 2007 and 2011, when average fuel inventory ranged from $20.8 million to $34.4 million. According to Hydro, the main reason for the increase is the cost of No. 6 fuel used in Holyrood.

In 2013 forecast, supplies inventory and deferred charges are forecast to remain stable with slight fluctuations over prior year actuals. Deferred charges are discussed further as a separate section of this report.

The following table is a summary comparing the 2013 test year average rate base and return on average rate base to the company's actual results for 2013.

Table 11: Average rate base, return on rate base and rate of return on average rate base (2013 test year compared to 2013 actual)

(000's)	**Test Year 2013**	**2013**	**Variance (Actual - Test Year)**
Plant investment	$ 1,633,080	$ 1,603,351	$ (29,729)
Less: Accumulated depreciation	(140,043)	(138,317)	1,726
CIAC's	(22,269)	(15,786)	6,483
ARO's	(17,320)	(16,715)	605
Net capital assets	1,453,448	1,432,533	(20,915)
Balance previous year	1,387,986	1,387,986	-
Average	1,420,717	1,410,260	(10,458)
Less: average net assets not in use	(3,005)	(7,102)	(4,097)
	1,417,712	1,403,158	(14,555)
Cash working capital allowance	5,336	5,875	539
Fuel inventory	50,885	48,949	(1,936)
Supplies inventory	24,701	25,763	1,062
Deferred charges	65,451	64,627	(824)
Average rate base	$ 1,564,085	$ 1,548,372	$ (15,714)
Return on rate base:			
Unadjusted return on regulated equity	$ 33,357	$ 209	$ (33,148)
Cost of service exclusions	48	528	480
Net interest	89,043	92,394	3,351
Return on rate base	$ 122,448	$ 93,131	$ (29,317)
Rate of return on average rate base	7.83%	6.01%	-1.81%

The decrease of rate of return on average rate base of 1.81% is due to the decrease in return on rate base, partially offset by a decrease in average rate base. The actual average rate base for 2013 is lower than forecast by $15,714,000. This decrease is primarily due to a decrease in net capital assets, an increase in average net assets not in use, and a decrease in fuel inventory, slightly offset by an increase in supplies inventory. According to Hydro, the decrease in net capital assets was primarily due to the carry-over of 2013 projects to 2014, as well as lower costs than budgeted on completed projects. The variance between 2013 forecast and actual capital expenditures is discussed further in the capital expenditures section of this report. The increase in average net assets not in use is primarily due to Holyrood Unit #1 and Labrador City 25 kV terminal stations. The decrease in the return on rate base primarily resulted from a decrease in return on regulated equity, partially offset by an increase in net interest.

Based upon the results of our procedures we note the following:

- In P.U. 5 (2012) the Board approved the capital expenditures relating to the project 'To Replace the Fuel Oil Heat Tracing system at the Holyrood Thermal Generating Station'. The Board has ordered that recovery of this project's associated costs will not be allowed at this time. The Order required Hydro to separate and record these costs in an account, the disposition of which will be considered by the Board should Hydro make subsequent application for recovery of some or all of the associated costs. In accordance with this Order, Hydro has excluded capital cost additions from its rate base calculation in relation to Holyrood fuel oil heat tracing costs for 2012 and 2013 test year.

- In 2013 test year the Company recorded net asset retirement costs of $17,320,000 which is associated with the Holyrood Thermal Generating Station and the disposal of Polychlorinated Biphenlys. The Company has included these costs in the cost of property, plant and equipment but has excluded the amount from rate base in 2013 test year and prior years. In P.U. 29 (2012) the Board ordered that Hydro shall appropriately recognize and record asset retirement obligations in accordance with International Financial Reporting Standards and stated that regulatory treatment of the particular asset retirement obligations included in the application will be appropriately considered in the context of a general rate application. We have reviewed the treatment of these costs separately in our report.

- In 2012 the Company used $1,374,000 of the 'Allowance for Unforeseen Items' account to cover the cost of capital expenditures relating to the Black Tickle Diesel Fire Restoration Project. On March 14, 2012, the community of Black Tickle experienced a power outage as a result of a fire at the diesel plant. In September of 2012, Hydro filed a report to the Board regarding the use of the 'Allowance for Unforeseen Items' account for the Black Tickle Diesel Fire Restoration Project. Included in this report was a description of the background and purpose of the project, the nature and scope of the work completed on the project thus far, a timeline setting out all relevant project dates, and an estimation of the total costs to be incurred upon completion of the project in early 2013. On January 3, 2013, the Board wrote a letter to Hydro requesting the Company file a detailed report in relation to the Black Tickle fire restoration project on or before April 1, 2013. Upon receipt of this report, the Board would advise as to how this matter would proceed. In April 2013, Hydro filed a report to the Board in response to this letter. Currently, the Board has not made a final decision on the 2012 average rate base and it remains uncertain if these costs can be included in the 2012 and 2013 test year rate base.

- In 2011 the Company included $2,001,920 ($1,483,000 - Increase Generation Capacity, and $519,000 – Baie Verte Peninsula Ice Storm) in capital assets that were included in the 'Allowance for Unforeseen Events'. Currently, the Board has not made a final decision on the 2011 average rate base and it remains uncertain if these costs can be included in the 2011, 2012 and 2013 test year rate base.

- Included in 2013 test year capital expenditures is $245,000 relating to the remediation of Black Tickle Diesel Plant, which also remain uncertain if these costs can be included in the 2013 test year rate base. In P.U. 31 (2013) the Board denied the request to increase the Allowance for Unforeseen items for 2013 capital expenditures in relation to the Black Tickle diesel plant restoration on the basis that a determination had not been made as to whether the use of the Allowance for Unforeseen Items was in accordance with the Capital Budget Guidelines.

The following table provides a summary of the project costs that are included in 2013 test year average rate base for which approval remains uncertain regarding inclusion in the 2013 test year average rate base:

Table 12: Project costs for which approval remains uncertain

Project	2011 Actual	2012 Actual	2013 Test Year	Total	2013 Actual	Total Actual
Increase Generation Capacity	$1,483,000	-	-	$1,483,000	-	$1,483,000
Ice Storm – Baie Verte Peninsula	519,000	-	-	519,000	-	519,000
Black Tickle Diesel Fire Restoration Project	-	1,374,000	245,000	1,619,000	147,000	1,521,000
TOTAL	**$2,002,000**	**$1,374,000**	**$245,000**	**$3,621,000**	**$147,000**	**$3,523,000**

In P.U. 42 (2013), the Board did not approve the 2012 average rate base. In P.U. 42 (2013) the Board determined that the Board will address Hydro's 2012 average rate base and 2011 average rate base in a separate process. In addition, Hydro's 2013 capital spending in relation to the Black Tickle diesel plant restoration will also be addressed in this process.

As a result of completing our procedures we noted certain project costs, as included in Table 12, for which approval remains uncertain regarding inclusion in the 2013 test year average rate base.

Range of Return on Rate Base

Hydro is 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 Associates, Inc. supporting this position was filed as Exhibit 6 in the Application. 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 under the previously established range would translate to an allowable range of 7.68% to 7.98%. The proposed allowable range of return on rate base would be increased to a range of 7.58% to 8.08%, i.e. ±25 bps.

The following table illustrates the various financial impacts associated with ranges of return on rate base of 30 and 50 basis points.

Table 13: Comparison of ranges of rate of return on rate base: 30 and 50 basis points

Comparison of Range of Rate of Return ('000s)		
	30 basis points (±15 bps)	**50 basis points (±25 bps)**	**Difference**
Average Rate Base	$ 1,564,085	$ 1,564,085	$ -
Rate of Return on Rate Base	$ 122,448	$ 122,448	$ -
Net Income	$ 33,357	$ 33,357	$ -
Return on Rate Base	7.83%	7.83%	-
Return on Equity (ROE)	8.80%	8.80%	-
Return on Rate Base - high	7.98%	8.08%	0.10%
Return on Rate Base - low	7.68%	7.58%	-0.10%
Additional Return = half of bps range	$ 2,346	$ 3,910	$ 1,564
Additional Return as % of Net Income	7.03%	11.72%	4.69%
Resultant ROE range - high	9.40%	9.80%	0.40%
Resultant ROE range - low	8.20%	7.80%	-0.40%
Implied range of ROE	120 bps (± 60 bps)	200 bps (±100 bps)	80 bps

We have reviewed the pre-filed evidence, including Foster Associates, Inc. Report in Exhibit 6 and offer the following comments:

Higher threshold on upper limit

This proposed change in range of return would have no impact on the determination of the overall revenue requirement for 2013 test year as, the allowed return, as ordered by the Board for setting rates, is the mid-point of the allowed range. Expanding the range of allowed return does however, result in a higher threshold for the upper limit of allowed return on rate base. For 2013, this proposed expansion of the range would represent an increase in the dollar amount of allowed return of approximately $1,564,000 (50 basis points – 30 basis points ÷ 2 x $1,564,085,000).

Allowed return on rate base and return on equity

The proposed range of 50 basis points for rate of return on rate base assumes a 200 basis point range (±100 bps) for rate of return on regulated common equity, compared to the current 30 basis point range having an implied 120 basis point range (±60 bps) of return on common equity for 2013.

The following table shows the ranges and the impact on the return on equity with a range of 50 basis points (± 25 bps) compared to 30 basis points (±15 bps):

Table 14: Ranges and the impact on the return on equity

	2013 TEST YEAR							
	25 +/- bps				15 +/- bps			
ALLOWED RETURN ON RATE BASE								
	Percent	Cost	WACC		Percent	Cost	WACC	
Debt	70.1	8.01%	5.62%		70.1	8.01%	5.62%	
Asset retirement obligations	0.4	0.00%	0.00%		0.4	0.00%	0.00%	
Employee Future Benefits	4.4	0.00%	0.00%		4.4	0.00%	0.00%	
Equity	25.1	8.80%	2.21%		25.1	8.80%	2.21%	
	100.0		7.83%		100.0		7.83%	
UPPER END OF RANGE								
	Percent	Cost	WACC		Percent	Cost	WACC	
Debt	70.1	8.01%	5.62%		70.1	8.01%	5.62%	
Asset retirement obligations	0.4	0.00%	0.00%		0.4	0.00%	0.00%	
Employee Future Benefits	4.4	0.00%	0.00%		4.4	0.00%	0.00%	
Equity	25.1	9.80%	2.46%	+100 bps	25.1	9.40%	2.36%	+60 bps
	100.0		8.08%	+ 25 bps	100.0		7.98%	+15 bps
LOWER END OF RANGE								
	Percent	Cost	WACC		Percent	Cost	WACC	
Debt	70.1	8.01%	5.62%		70.1	8.01%	5.62%	
Asset retirement obligations	0.4	0.00%	0.00%		0.4	0.00%	0.00%	
Employee Future Benefits	4.4	0.00%	0.00%		4.4	0.00%	0.00%	
Equity	25.1	7.80%	1.96%	-100 bps	25.1	8.20%	2.06%	+60 bps
	100.0		7.58%	- 25 bps	100.0		7.68%	- 15 bps

The Foster Associates, Inc. report discusses that while the range proposed has increased, referring to the P.U. 40 (2004) and the 2003 capital structure, the implied range of return on equity of ±100 basis points is narrower. The authorized 15 bps range from P.U. 40 (2004) has an implied range of return on common equity of approximately ± 120 basis points or 1.2% due to Hydro lower common equity ratio in 2003 compared to 2013 Test Year.

The same can be illustrated for the 2007 targeted capital structure. The range approved in P.U. 8 (2007) also had an allowable range of return on rate base of ± 15 bps. The implied range of return on common equity is approximately ± 125 basis points (or 1.25%) due to Hydro's lower common equity ratio in 2007 compared to 2013 Test Year.

Utility Comparison

A comparison of the range of return on rate base and implied range of return on equity of Hydro and Newfoundland Power since the 2004 test year is detailed in following table:

Table 15: Comparison of range of return on rate base and implied range of return on equity – Hydro and Newfoundland Power

Newfoundland and Labrador Hydro				2013 Test Year	
	2004 Test Year	2007 Test year		Based on existing*	Proposed
Range of Return on Rate Base	±15 bps	±15 bps		±15 bps	±25 bps
Implied Range of Return on Equity	±122 bps	±125 bps		±60 bps	±100 bps

* In P.U. 40 (2004) and P.U. 8 (2007) the Board approved a range of rate of return on rate base for Hydro of 30 basis points (±15 basis points).

Newfoundland Power	2004 Test Year	2008 Test Year	2010 Test Year	2013 Test Year	2014 Test Year
Range of Return on Rate Base	±18 bps	±18 bps	±18 bps	±18 bps	±18 bps
Implied Range of Return on Equity	±40 bps	~± 38 bps	±40 bps	±40 bps	±40 bps

As illustrated in above table, the allowed range of return on rate base for Newfoundland Power has been consistent at ±18 basis points with an implied range of return on equity of approximately ±40 basis points. Hydro's implied range of return on equity was approximately ±125 basis points in past two GRAs but will decrease to ±60 basis points if the current approved range of rate of return on rate base of ±15 basis points is applied. The proposed range of return on rate base of ±25 basis points provides an implied range of return on equity of ±100 basis points.

While the conceptual basis for using a range of return is applicable to both Hydro and Newfoundland Power, the differences between the two utilities would suggest that the size of the range of return should be based on the individual circumstances. Foster Associates, Inc. report addresses the differing characteristics of Hydro and Newfoundland Power, such as operating leverage, capital structure and income taxes, and the impact that these differences would have on return on rate base and return on equity. The impact was illustrated in Table 3 of the Foster Associates, Inc. report which shows that a 1% unanticipated increase in expenses would reduce Hydro's return on equity by more than twice as much as it would reduce the return on equity for a utility similar to Newfoundland Power. We agreed the variables included in this table and recalculated similar results. Generally this impact is not unexpected as Newfoundland Power has a stronger capital structure and is a taxable entity.

The variability of Hydro's regulated return on equity relative to Newfoundland Power is shown in the following table:

Table 16: Comparison of return on equity – Hydro and Newfoundland Power

Comparison of Return on Equity - Hydro and Newfoundland Power						
	Actual					
	2007	**2008**	**2009**	**2010**	**2011**	**2012**
Return on Equity - Hydro	1.3%	4.1%	6.2%	2.0%	6.6%	5.3%
Return on Equity - NP	8.7%	9.1%	9.0%	9.2%	9.0%	9.0%

Factors that may impact Hydro's Return on Equity to vary from Target

The examples provided in Foster Associates, Inc report represent potential variations in earnings that could be significant and include operating expenses, interest expense and higher or lower than expected electricity sales, particularly sales to industrial customers. Due to potential variations in earnings, the allowed range of return on rate base provides for greater rate stability and predictability. However, the use of an expanded range of return on rate base does not protect Hydro from the potential reduction in income that may occur. From a regulatory perspective, the only protection for Hydro from decreases in earnings is through rate adjustments. It is only to the extent there are offsetting earnings fluctuations (both ups and downs) over a period of years that the range of return would act to protect Hydro. Hydro is entitled to recover its cost of service and the appropriate manner in which to recover additional costs is through an application seeking rate relief.

Incentive Mechanism

The use of a range of return on rate base as an incentive mechanism to Hydro with cost management initiatives is an accepted concept in utility regulation. The use of an incentive range together with a period of regulatory lag can be beneficial to ratepayers in the long term. A range of rate of return can provide an incentive to the Company to improve productivity and generate operating efficiencies resulting in lower costs which would be passed on to ratepayers in a subsequent rate hearing. This is consistent with one of the two purposes of the range of allowed return on rate base as noted in P.U. 40 (2004) regarding an incentive mechanism to contain costs by improving productivity, benefiting ratepayers in the long term. The size of the range of return will depend on the assessment of the Board as to the degree of incentive it considers appropriate in the circumstances.

Excess Earnings Account

In its Application Hydro is not proposing any change in the definition of excess earnings as approved in P.U. 40 (2004) other than the change in range from ± 15 bps to ± 25 bps.

Other comments

Foster Associates, Inc. recommends that when the regulated earned return on equity exceeds the target return on equity (even if still earning a return on rate base within the allowed range) by more than one percentage point (100 bps), Hydro include in its annual return filing an explanation of the variance between the actual embedded cost of debt and the cost forecast for the test year and the variance between earned and target return on equity. This would be a similar reporting requirement as Newfoundland Power as was ordered in P.U. 19 (2003), however the threshold for additional reporting for Newfoundland Power is 50 bps.

Based on our review and analysis, while Hydro has proposed an increase in allowed range of return on rate base, the implied range of return on equity is narrower than the two previous GRAs. Additionally, Hydro's return on equity in comparison to Newfoundland Power is more variable when given a set increase in expenses due to the differing characteristics of the utilities, such as capital structure and income tax status.

We recommend that the Board consider a similar annual reporting requirement for Hydro as currently in place for Newfoundland Power when regulated earned return on equity exceeds the target return on equity by more than one percentage point.

2013 Revenue Requirement

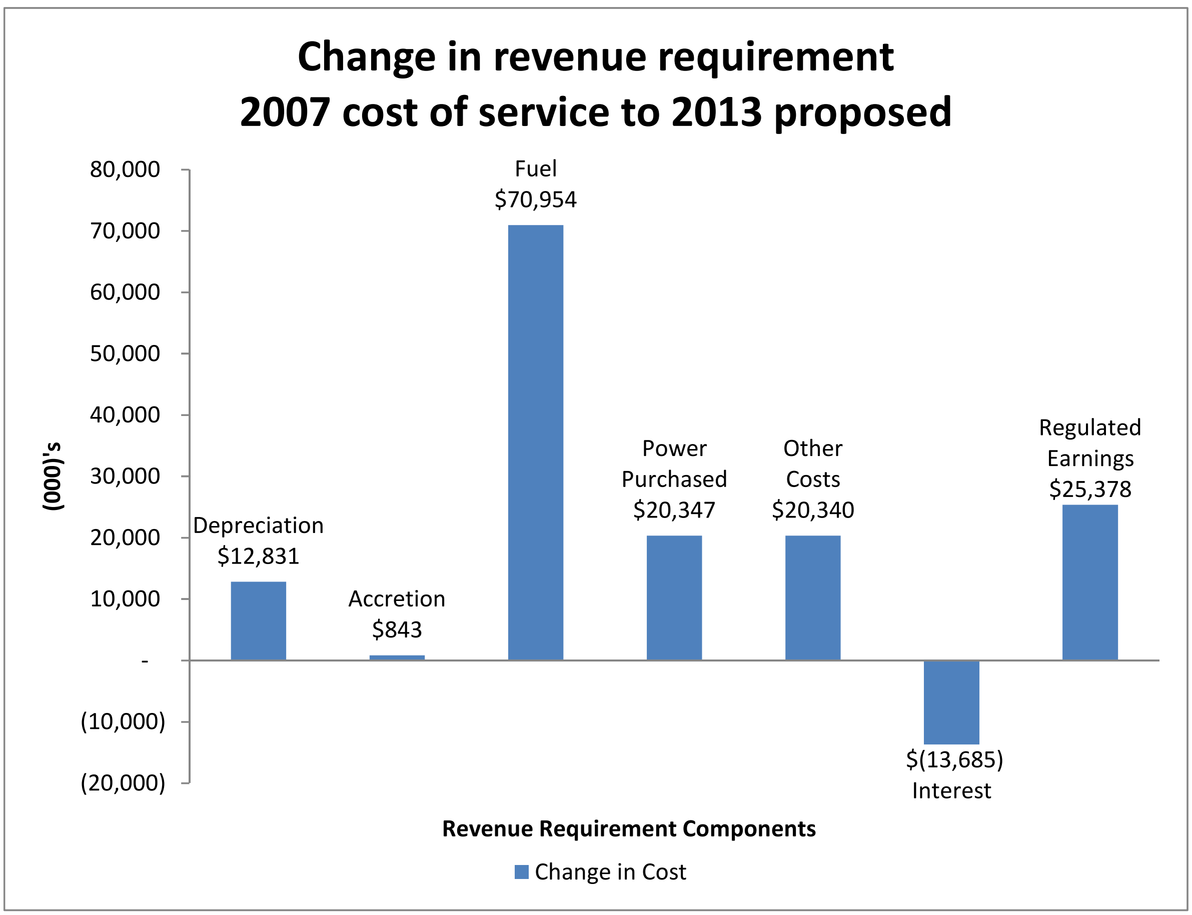
Comparison of 2007 Test Year and 2013 Test Year

The following table and graph summarize the changes in Hydro's revenue requirement from the 2007 Test Year to the 2013 Test Year.

Table 17: Change in revenue requirement from 2007 test year to 2013 test year

	(000)'s
2007 Revenue Requirement	**$ 431,079**
Increase (decrease)	
Depreciation	**12,831**
Accretion of ARO	**843**
Fuel	**70,954**
Power purchased	**20,347**
Other costs (net)	**20,340**
Interest	**(13,685)**
Regulated earnings	**25,378**
2013 Revenue Requirement	**$ 568,087**

Graph 1: Change in revenue requirement from 2007 test year to 2013 test year



The following table provides the cost per kWh for the 2007 Test Year and the 2013 Test Year.

Table 18: Cost per kWh – 2007 test year and 2013 test year

	Cost per kWh
Test Year 2007	0.0589
Test Year 2013	0.0777

The revenue requirement for the 2013 test year has increased over the 2007 test year by approximately $137.0 million or 31.8%. While each component of the 2013 revenue requirement has increased significantly over the 2007 test year (with the exception of interest), the largest contributor, representing 51.8% of the increase, is the cost of fuel.

Per page 2.48 of the evidence, the $71.0 million increase in the forecast fuel expense is due to both increasing supply requirements and fuel prices. For the 2007 test year, the average consumption price per barrel was $56.12. However, for the 2013 test year, PIRA Energy Group is estimating an average cost of $108.11 which results in an average consumption price of $108.74 per barrel. The "consumption price" is a blend of the cost of fuel in inventory at the beginning of the year with the cost of fuel purchased during the year.

The increase in power purchased of $20.3 million is primarily the result of energy purchases from wind generation projects in addition to changes in power purchase arrangements related to Exploits Generation. Commencing in 2011 and upon direction from the Province, the energy purchase rate for production at the Nalcor Exploits Facilities at Grand Falls-Windsor, Bishop's Falls, Buchans and Star Lake was made available to Hydro at 4 cents/kWh. The increase in power purchased is partially offset by reduced energy purchases from the CBPP co-generation unit.

The increase of $20.3 million in the other costs category has also contributed to the overall increase in the forecast revenue requirement. Per the pre-filed evidence, page 1.20, this increase has been close to inflationary levels, with inflation averaging 2.0% annually over the period, while the increase in other costs is forecast to average 2.3% annually. This increase is also largely tied to a rise in salary and fringe benefits resulting from an increase to general salaries and hourly rates from collective agreements for unionized and non-unionized employees. 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. Also, overtime costs have increased as a result of higher overtime relating to capital projects due to an increase in Hydro's capital program, and higher salary costs over that period.

As noted in the pre-filed evidence on page 3.20, the main reason for the increase in the depreciation expense of $12.8 million is reflected in Hydro's continued investment in the electrical system.

The final component of the 2013 revenue requirement is interest, which has offset the increase over the 2007 test year by $13.7 million. As outlined in the pre-filed evidence on page 3.4, this decrease is primarily due to a reduction of approximately $9.4 million in debt guarantee fees paid by Hydro. 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. In 2008, as a means of improving Hydro's net income, the Government waived Hydro's requirement to pay this fee while continuing to guarantee Hydro's debt. This waiver continued until 2011 when the fee was reinstated at a market rate. 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.

Comparison of 2013 Forecast to Prior Year's Actuals

The forecast revenue requirement for 2013 of $568 million is $112.8 million higher than 2012 actuals. Details on Hydro's revenue requirement for 2013 test year are included in the pre-filed Finance evidence Schedule III, page 1 of 2. The following table reproduces a portion of this detail showing a comparison of the 2013 forecast to the company's actual results for 2007 to 2012.

Table 19: Revenue requirement (2007-2012 and 2013 test year)

(000)'s	Actuals 2007	Actuals 2008	Actuals 2009	Actuals 2010	Actuals 2011	Actuals 2012	Forecast 2013	Variance '13F-'12
Depreciation	$ 38,342	$ 40,393	$ 41,744	$ 43,790	$ 45,217	$ 46,865	$ 51,656	$ 4,791
Accretion of asset retirement obligation	-	-	-	-	467	715	843	128
Fuel	150,281	149,854	136,933	137,994	131,276	132,003	219,390	87,387
Power Purchased	38,606	41,388	46,782	44,244	52,221	56,986	58,674	1,688
Other Costs								
Salaries and fringe benefits	70,171	73,123	76,381	82,517	87,556	90,907	96,583	5,676
System equip. maint.	23,525	22,282	22,122	21,748	21,512	20,261	21,495	1,234
Insurance	1,704	1,783	1,937	1,960	1,965	2,109	2,211	102
Transportation	2,776	3,046	3,038	3,056	3,377	3,600	3,623	23
Office supplies	2,262	2,182	2,161	2,100	2,307	2,230	2,571	341
Bldg. rentals and maint.	1,234	1,078	1,145	1,170	1,172	1,027	1,070	43
Professional services	3,865	4,443	3,612	4,215	6,092	7,324	7,022	(302)
Travel	2,942	2,854	2,910	2,755	2,977	2,979	3,156	177
Equipment rentals	1,081	1,493	1,721	1,738	1,636	1,699	1,731	32
Miscellaneous	4,246	4,359	8,065	3,829	4,736	5,144	6,380	1,236
Loss on disposal	902	2,580	1,267	687	925	5,396	1,304	(4,092)
Write down of assets	-	-	506	-	-	-	-	-
Sub-total	114,708	119,223	124,865	125,775	134,255	142,676	147,146	4,470
Allocations								
Other IOCC	(2,679)	(2,672)	(1,875)	(2,648)	(2,292)	(2,215)	(2,108)	107
Hydro capitalized	(12,044)	(15,461)	(17,164)	(20,716)	(21,276)	(20,723)	(20,692)	31
Cost recoveries	(1,390)	(1,815)	(4,190)	(4,748)	(5,198)	(7,874)	(9,222)	(1,348)
Subtotal	(16,113)	(19,948)	(23,229)	(28,112)	(28,766)	(30,812)	(32,022)	(1,210)
Total	98,595	99,275	101,636	97,663	105,489	111,864	115,124	3,260
Interest	103,242	87,610	83,440	86,766	90,844	89,961	89,043	(918)
Regulated earnings	2,711	8,874	17,211	6,604	20,599	16,900	33,357	16,457
Revenue requirement	$ 431,777	$ 427,394	$ 427,746	$ 417,061	$ 446,113	$ 455,294	$ 568,087	$ 112,793

Note 1:	Salaries and fringe benefits per table	$96,583
	Less: capitalized salaries included in allocations	(19,342)
	Salaries and fringe benefits per Schedule III, P. 1 of 2	$77,241
Note 2:	Transportation per table	$3,623
	Less: amount included in allocations	(1,350)
	Transportation per Schedule III, P. 1 of 2	$2,273
Note 3:	Interest per table	$89,043
	Regulated earnings per table	33,357
	Add: cost of service exclusions per Schedule III, P. 1 of 2	48
	Return on rate base per Schedule III, P. 1 of 2	$122,448

The following table is a summary comparing the 2013 test year revenue requirement to the company's actual results for 2007 to 2012.

Table 20: Summary of revenue requirement (2007-2012 and 2013 test year)

(000)'s	Actuals 2007	Actuals 2008	Actuals 2009	Actuals 2010	Actuals 2011	Actuals 2012	Forecast 2013	Variance '13-'12
Depreciation	38,342	40,393	41,744	43,790	45,217	46,865	51,656	4,791
Fuel	150,281	149,854	136,933	137,994	131,276	132,003	219,390	87,387
Power Purchased	38,606	41,388	46,782	44,244	52,221	56,986	58,674	1,688
Other Costs	98,595	99,275	101,636	97,663	105,489	111,864	115,124	3,260
Interest	103,242	87,610	83,440	86,766	90,844	89,961	89,043	(918)
Accretion of ARO	-	-	-	-	467	715	843	128
Regulated Earnings	2,711	8,874	17,211	6,604	20,599	16,900	33,357	16,457
	431,777	427,394	427,746	417,061	446,113	455,294	568,087	112,793

Based on the information in this summary, the most significant increase, which represents approximately $87.4 million or 77% of the total increase in the 2013 revenue requirement over 2012, is the cost of fuel. The cost of fuel is discussed in more detail later in this report.

Regulated earnings are another component of the revenue requirement forecast to increase significantly in comparison to 2012. The requested rate of return of 8.80% for the 2013 test year is significantly higher than the 5.25% earned in 2012 and represents an increase of $16.5 million in this component of the revenue requirement.

The following table shows a comparison of the 2013 test year revenue requirement to the company's actual results for 2013.

Table 21: Revenue requirement (2013 and 2013 test year)

(000)'s	Forecast 2013	Actuals 2013	Variance '13A-'13F
Depreciation	$ 51,656	$ 50,832	$ (824)
Accretion of asset retirement obligation	843	911	68
Fuel	219,390	155,957	(63,433)
Power Purchased	58,674	59,379	705
Other Costs			
Salaries and fringe benefits	96,583	96,431	(152)
System equip. maint.	21,495	22,005	510
Insurance	2,211	2,422	211
Transportation	3,623	3,578	(45)
Office supplies	2,571	2,595	24
Bldg. rentals and maint.	1,070	1,186	116
Professional services	7,022	5,874	(1,148)
Travel	3,156	3,338	182
Equipment rentals	1,731	1,877	146
Miscellaneous	6,380	5,218	(1,162)
Loss on disposal	1,304	3,634	2,330
Sub-total	147,146	148,158	1,012
Allocations			
Other IOCC	(2,108)	(1,945)	163
Hydro capitalized	(20,692)	(21,656)	(964)
Cost recoveries	(9,222)	(9,111)	111
Subtotal	(32,022)	(32,712)	(690)
Total	115,124	115,446	322
Interest	89,043	92,394	3,351
Regulated earnings	33,357	209	(33,148)
Revenue requirement	$ 568,087	$ 475,128	$ (92,959)

The following table summarizes the comparison of the 2013 test year revenue requirement to the company's actual results for 2013.

Table 22: Summary of revenue requirement (2013 and 2013 test year)

(000)'s	Forecast 2013	Actuals 2013	Variance '13A-'13F
Depreciation	51,656	50,832	(824)
Fuel	219,390	155,957	(63,433)
Power Purchased	58,674	59,379	705
Other Costs	115,124	115,446	322
Interest	89,043	92,394	3,351
Accretion of ARO	843	911	68
Regulated Earnings	33,357	209	(33,148)
	568,087	475,128	(92,959)

The table below provides an analysis of the breakdown of the cost of energy on the basis of the number of kWhs sold for the years 2007 to 2012, and the forecast for 2013.

Table 23: Total cost of energy and cost per kWh

Year	kWh sold and used	Depreciation	Fuel	Purchased Power	Other Costs	Interest	Accretion	Regulated Earnings	Total Cost of Energy	Cost per kWh
2007	7,028,000	38,342	150,281	38,606	98,595	103,242	-	2,711	431,777	0.0614
2008	7,004,000	40,393	149,854	41,388	99,275	87,610	-	8,874	427,394	0.0610
2009	6,612,000	41,744	136,933	46,782	101,636	83,440	-	17,211	427,746	0.0647
2010	6,627,000	43,790	137,994	44,244	97,663	86,766	-	6,604	417,061	0.0629
2011	6,758,000	45,217	131,276	52,221	105,489	90,844	467	20,599	446,113	0.0660
2012	6,964,000	46,865	132,003	56,986	111,864	89,961	715	16,900	455,294	0.0654
2013 F	7,314,000	51,656	219,390	58,674	115,124	89,043	843	33,357	568,087	0.0777

As shown, the cost of energy per kWh in the 2013 cost of service is forecast to increase by 18.81% over what was experienced in 2012, and 26.54% over what was experienced in 2007.

Additional analysis of the 2013 revenue requirement in comparison to actual results experienced by Hydro over the last several years are included in the following sections of our report.

Depreciation

Our procedures with respect to depreciation were focused on reviewing the rates of depreciation incorporated in the 2013 forecast to ensure compliance with the Gannett Fleming Depreciation Study dated November 2012 and compliance with Board Order P.U. 40 (2012). In addition, our procedures included reconciling the detailed depreciation schedule to the pre-filed evidence, agreeing the useful life of a sample of assets from Hydro's asset records to the Gannett Fleming depreciation study, and recalculating the depreciation for the assets in our sample.

On December 22, 2011 the Company submitted an application to the Board requesting a change in its depreciation methodology from its current sinking fund and straight line methodologies with fixed service lives for specific classes of assets to straight line depreciation calculated with group accounting methods using the average service life procedure applied on a remaining life basis. The straight-line method results in equal amounts of depreciation being charged to each period/year over an asset's useful life.

On November 14, 2012 a settlement agreement was executed and agreed to by Hydro, the Industrial Customers and the Consumer Advocate on matters pertaining to the application. The following was agreed to regarding Hydro's application of group depreciation to its assets:

- Hydro's proposal to switch from sinking fund depreciation methodology to straight line for all of its assets is appropriate.

- Hydro's proposal to use the average life group procedure applied on a remaining life basis with effect from January 1, 2011 is appropriate to determine depreciation expense from January 1, 2012 on a go-forward basis with the corresponding adjustment for 2011 to be made to opening retained earnings;

- Hydro's proposal to apply group depreciation rates to individual assets, rather than to total group investment, is acceptable;

- Hydro's current practice and proposal for the future to stop accruing depreciation once an asset is fully accrued is acceptable until varied by further Order of the Board; and

- Hydro's current practice and proposal to continue to book to its income statement, gains and losses, related to asset retirements is acceptable until varied by further Order of the Board.

In P.U. 40 (2012), the Board ordered Hydro to:

- Adopt the straight-line method of depreciation for all its assets, with group accounting methods using average service life procedure and applied on a remaining life basis, as outlined in the Gannett Fleming Study filed with the Board on December 3, 2012 and December 17, 2012; and

- Provide, at the time of its next depreciation study, a report on group accounting for selected groups of property as outlined in Schedule 1 of P.U. 40 (2012).

Hydro has forecast amortization expense of $51.7 million compared to $46.9 million in 2012 in accordance with the depreciation methodology approved in P.U. 40 (2012). A comparison of the actual depreciation expense from 2007 to 2013, as well as forecast for 2013, is detailed in the following table. The table also calculates depreciation costs as a percentage of net book value.

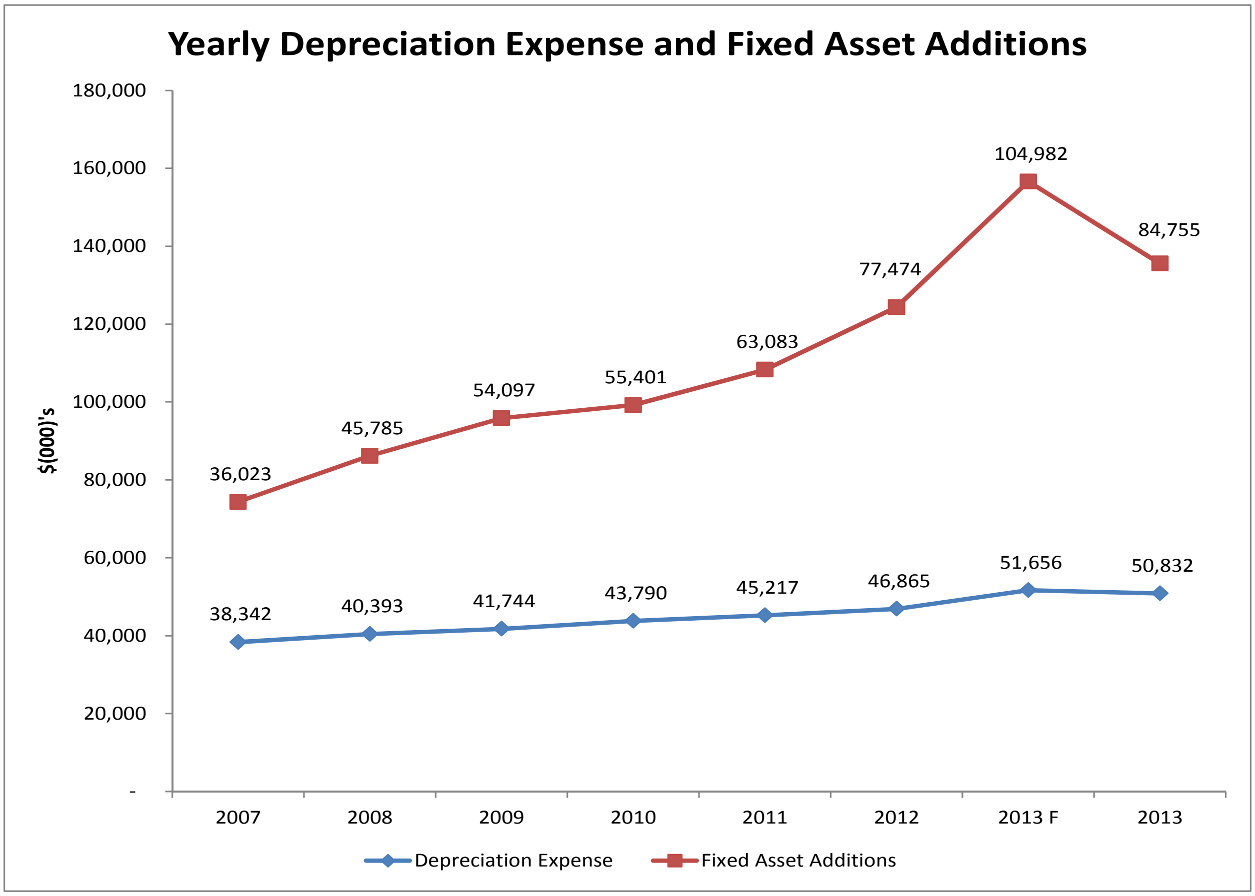
Table 24: Depreciation as a percentage of net book value

(000)'s	Actuals 2007	Actuals 2008	Actuals 2009	Actuals 2010	Actuals 2011	Actuals 2012	Forecast 2013	Actuals 2013	Variance '13F-'12	Variance '13A-'13F
Depreciation	38,342	40,393	41,744	43,790	45,217	46,865	51,656	50,832	4,791	(824)
Net book value	1,349,695	1,344,893	1,353,626	1,369,060	1,386,695	1,407,670	1,470,768	1,449,248	63,098	(21,520)
% of net book value	2.84%	3.00%	3.08%	3.20%	3.26%	3.33%	3.51%	3.51%	0.18%	0.00%
Change in % over prior year		0.16%	0.08%	0.11%	0.06%	0.07%	0.18%	0.18%		
Change in depreciation		2,051	1,351	2,046	1,427	1,648	4,791	3,967		

Depreciation expense for test year 2013 is forecast to be $4.8 million higher than 2012. This increase in depreciation expense reflects the forecast test year 2013 capital additions of approximately $105.0 million. In addition, assets which relate to the Holyrood Thermal Generating Station are being amortized on a straight-line basis until the year 2020, when the plant will be decommissioned.

Actual depreciation expense for 2013 increased by $4.0 million over 2012. This increase is slightly less than the increase forecast for 2013 test year. However, depreciation as a percentage of net book value for actual 2013 is consistent with test year 2013 at 3.51%. The decrease in depreciation from test year is due to fewer fixed asset additions (actual net book value at December 31, 2013 is $21.5 million lower than forecast), as a result of delayed in-service dates of capital projects.

Graph 2: Annual depreciation expense and fixed asset additions



As a result of completing our procedures, no significant discrepancies in the calculation of test year forecast depreciation were noted. As noted in the Capital Expenditures section of this report, however, the forecast 2013 capital expenditures were $20,227,000 greater than actual. This has resulted in test year 2013 forecast depreciation being $824,000 higher than actual.

Fuel Costs

Fuel expense for the 2013 test year of $219.4 million is forecast to increase by approximately $87.4 million over 2012 actuals. The various fluctuations within the fuel cost category have been noted below for the years 2007 to 2012, as well as the 2013 forecast and actual 2013:

Table 25: Fuel costs by category

(000)'s	Actuals 2007	Actuals 2008	Actuals 2009	Actuals 2010	Actuals 2011	Actuals 2012	Forecast 2013	Actuals 2013	Variance '13F-'12	Variance '13A-'13F
No.6 Fuel	107,369	123,734	80,585	100,674	135,136	164,001	200,314	171,786	36,313	(28,528)
Fuel Additives	100	109	89	178	126	44	-	13	(44)	13
Fuel Costs Indirect	83	57	69	63	61	75	115	380	40	265
Environmental Handling Fee	5	46	10	28	12	24	16	16	(8)	-
Ignition Fuel	298	323	244	296	389	389	246	495	(143)	249
Gas Turbine Fuel	399	1,515	1,015	1,197	395	877	803	1,427	(74)	624
Diesel Fuel Rural	10,486	15,005	12,631	12,224	16,013	15,927	17,980	17,155	2,053	(825)
Rate Stabilization Plan (RSP)	31,541	9,065	42,290	23,334	(20,856)	(49,334)	(84)	(35,315)	49,250	(35,231)
	150,281	149,854	136,933	137,994	131,276	132,003	219,390	155,957	87,387	(63,433)

Actual fuel costs for 2013 are $63.4 million lower than the amount forecast. This variance is primarily due to lower costs relating to No.6 fuel and the RSP. The decrease in No.6 fuel is primarily due to a decrease in the number of barrels consumed during the year. The actual number of barrels used in 2013 was 231,031 lower than the number of barrels included in test year which resulted in a $24.6 million decrease in fuel costs; there this was due to 170 fewer GWh of generation from the Holyrood Thermal Generation Plant than 2013 forecast. Also, the actual average price of fuel per barrel fell from $108.74 in test year to $106.63 in actual 2013 which resulted in a $3.9 million decrease in fuel costs. The change in RSP from forecast to actual 2013 is discussed in further detail in the RSP section of this report.

Significant fuel costs for test year 2013 are discussed in further detail below.

No.6 Fuel

The increase from 2012 to Forecast 2013 in No. 6 fuel of $36.3 million is primarily related to an increase in forecast thermal production in comparison to 2012, partially offset by a decrease in the forecast market price per barrel and a change in the conversion factor. According to Schedule V of Section 2 of the pre-filed evidence, Hydro is forecasting the consumption of 1,842,112 barrels of No. 6 fuel in order to produce 1,127.4 GWh of thermal power at Holyrood in 2013. This is an increase of 271.6 GWh and 413,775 barrels of fuel over 2012. The forecast of No.6 fuel expense takes into account a number of factors including: the price of fuel; the estimated energy to be generated using thermal production at Holyrood; and the fuel conversion factor (i.e. the number of kWh generated per barrel of No.6 fuel). The impact of each of these factors relating to the 2013 test year revenue requirement compared to 2012 is summarized below:

	2012 vs. 2013F ($000,000)
Decrease in the price of No.6 fuel/bbl	$ (11.2)
Change in conversion factor	(4.6)
Increase in thermal production	52.1
Net increase in No.6 fuel expense	$ 36.3

<u>Price per barrel:</u>

In its current Application, Hydro is forecasting an average market price of $108.11 per barrel for 2013. Hydro has obtained this forecast information from the PIRA Energy Group, based on price forecasts for March 2013. However, when the 2013 opening value of fuel inventory is taken into consideration, the consumption price per barrel of No.6 fuel is $108.74 for 2013 compared to $114.82 for 2012. The prices used by Hydro are derived by applying Hydro's contract discount to PIRA's New York Harbour price forecast and by applying a forecast for exchange. The decrease in this average market price over 2012 is largely related to changes in world market prices. The forecast prices also assume fuel contains 0.7% sulphur content, compared to higher percentages in 2012.

To calculate the incremental change in fuel cost associated with the price per barrel of fuel, Hydro used the forecast barrels of fuel to be consumed per the 2013 test year and multiplied it by the price of fuel forecast for 2013 and actual cost of fuel for 2012.

Number of barrels of No.6 fuel to be consumed in 2013:					1,842,112
Average fuel price for barrels forecast to be consumed for 2013 ($000)	$	108.74	/bbl	$	200,311
Average fuel price for barrels consumed in 2012 ($000)	$	114.82	/bbl	$	211,511
Decrease in fuel cost relating to fuel price per barrel				$	(11,200)

Fuel Conversion Factor

Hydro is forecasting a conversion factor of 612 kWh/barrel in the 2013 test year. The actual conversion factor for 2012 was 599 kWh/barrel. The decline in 2012 was due to lower production requirements as a result of reduced load and higher energy purchases that year. The increase in the factor for 2013 test year means fewer barrels of fuel will be required to generate the same amount of energy. Per page 2.47 of the pre-filed evidence, the conversion factor is forecast to improve in 2013 due to higher production requirements and higher average unit output levels.

To calculate the impact that this change has on the revenue requirement for 2013 in comparison to 2012, Hydro used the forecast net production of thermal energy in 2013, calculated the difference in the number of barrels of fuel that would be required for each conversion factor and multiplied the result by the price of fuel consumed for 2012.

Net thermal production forecast for 2013:		1,127.40	GWh
Number of barrels @ 612 kWh per barrel		1,842,157	
Number of barrels @ 599 kWh per barrel		1,882,137	
Increase in number of barrels		(39,980)	
Average price per barrel consumed for 2012	$	114.82	
Decrease in fuel cost relating to conversion factor ($000)	$	(4,590)	

As highlighted above, the increase in the conversion factor decreases the number of barrels required in the production of thermal energy and in turn decreases the fuel expense.

Net Thermal Production

Thermal production in 2013 is forecast to increase by 271.60 GWh in comparison to 2012. To calculate the impact that the change in hydraulic production has on the revenue requirement for 2013 in comparison to 2012, Hydro used the difference in forecast net production of thermal energy between 2012 and 2013, and calculated the increase in the number of barrels of fuel that would be required using the 2012 conversion factor of 599 kWh/barrel.

Net thermal production forecasted for 2013		1,127.40	GWh
Net thermal production for 2012		855.80	GWh
Net increase in thermal production		271.60	GWh
Increase in barrels required @ 599 kWh per barrel	$	453,422	
Average price per barrel consumed in 2012	$	114.82	
Increase in fuel cost relating to increased thermal production ($000)	$	52,062	

Diesel Fuel Rural

The $2.1 million increase in diesel fuel expense forecast for 2013 in comparison to 2012 is related to a volume increase of 1.25 million litres coupled with an increase in price per litre of $0.04 for diesel fuel. The following table provides a breakdown of actual and forecast energy requirements for the isolated systems as per Schedule IV in the pre-filed evidence.

Table 26: Energy requirements - Isolated systems

Diesel Fuel Rural

	2007 MWh	2008 MWh	2009 MWh	2010 MWh	2011 MWh	2012 MWh	2013 F MWh
Labrador Isolated							
L'Anse au Loup	17,556	18,495	20,363	20,912	23,292	22,049	24,767
Others	35,340	36,421	37,644	37,296	38,754	38,207	41,908
Subtotal	52,896	54,916	58,007	58,208	62,046	60,256	66,675
Island Isolated	8,043	8,707	8,943	7,528	7,876	7,621	7,957
Total	60,939	63,623	66,950	65,736	69,922	67,877	74,632
Year over year change %		4.40%	5.23%	-1.81%	6.37%	-2.92%	9.95%

Note: Isolated systems energy requirements for actual 2013 was not provided.

Actual diesel fuel costs for 2013 are $825,000 lower than the amount forecast. This variance is primarily due to the $1.4 million decrease in Labrador diesel fuel costs which resulted from lower than forecast growth in Mary's Harbour coupled with lower than forecast sales associated with construction of a cultural centre, a new pumphouse and recreational centres in coastal Labrador. This decrease was partially offset by a $326,000 increase in St. Anthony diesel fuel costs which resulted from increased production requirements due to the forced outage of Holyrood Unit No. 1.

Power purchased

The Company's power purchased cost continues its upward trend for the 2013 forecast with the highest cost expected for 2013 of $58.7 million. This forecast, which represents an increase of $1.7 million over 2012, is largely due to an increase in the costs of power purchased from the Non-Utility Generators (NUGs).

Actual power purchased costs for 2013 are $705,000 higher than the amount forecast. This variance is primarily due to the increase in NUGs costs, partially offset by the decrease in costs relating to CF(L)Co and L'Anse au Loup. These variances are discussed in further detail below.

The breakdown of power purchased by category is as follows:

Table 27: Power purchased costs by category

(000)'s	Actuals 2007	Actuals 2008	Actuals 2009	Actuals 2010	Actuals 2011	Actuals 2012	Forecast 2013	Actuals 2013	Variance '13F-'12	Variance '13A-'13F
Energy Costs - NUGS	31,177	34,362	41,673	38,831	46,127	50,368	51,756	52,944	1,388	1,188
Demand & energy - CF(L)Co	2,205	2,428	2,019	2,237	1,914	2,024	2,363	2,116	339	(247)
L'Anse au Loup	1,586	2,255	1,644	2,054	2,890	2,931	3,353	3,056	422	(297)
Island wheeling	492	607	556	591	601	646	662	676	16	14
Secondary energy	2,294	1,364	444	(74)	-	321	-	160	(321)	160
Capacity Expansion	761	265	352	491	581	400	295	206	(105)	(89)
Ramea Wind	60	101	94	114	108	162	155	188	(7)	33
CFLCO Interest	31	6	-	-	-	-	-	-	-	-
Ramea Hydrogen	-	-	-	-	-	134	90	33	(44)	(57)
	38,606	41,388	46,782	44,244	52,221	56,986	58,674	59,379	1,688	705

According to the table above, energy purchases from NUGs accounts for approximately 88% of the total forecast power purchased cost for 2013; this is consistent with prior years. The cost of power purchased from the NUGs continues to increase each year. In 2007 the costs totalled $31.2 million, and have increased to $50.4 million in 2012. For the 2013 forecast, increases in costs are anticipated due to an increase in the number of GWhs of power expected to be purchased for the year. The following table provides a breakdown of the six main non-utility generators which supply Hydro with power to service the Island Interconnected system for 2010 to forecast 2013.

Table 28: Non-utility generators – Island Interconnected (2010-2012 and 2013 test year)

	2010			2011		
	GWh	$ ('000s)	Avg cost per GWh	GWh	$ ('000s)	Avg cost per GWh
Star Lake	135.83	$ 11,232	$ 82,692	129.82	$ 5,193	$ 40,002
Rattle Brook	17.42	1,380	79,219	18.66	1,490	79,850
Corner Brook Cogen	51.54	5,469	106,112	50.5	5,917	117,168
Exploits River Project	112.40	8,664	77,082	-	-	-
St. Lawrence Wind (net of incentive credit)	100.46	6,451	64,215	110	7,091	64,464
Fermeuse Wind (net of incentive credit)	82.80	5,635	68,056	87.96	6,011	68,338
Nalcor Grand Falls, Bishops Falls and Buchans	-	-	-	510.63	20,425	40,000
Total Energy Costs - NUGs	500.45	$ 38,831	$ 77,592	907.57	$ 46,127	$ 50,825

	2012			2013F		
	GWh	$ ('000s)	Avg cost per GWh	GWh	$ ('000s)	Avg cost per GWh
Star Lake	144.45	$ 5,778	$ 40,000	140.87	$ 5,635	$ 40,001
Rattle Brook	14.63	1,181	80,725	15.00	1,236	82,400
Corner Brook Cogen	47.84	6,906	144,356	50.50	7,391	146,356
Exploits River Project	-	-	-	-	-	-
St. Lawrence Wind (net of incentive credit)	103.84	6,797	65,456	104.80	6,851	65,372
Fermeuse Wind (net of incentive credit)	91.20	6,270	68,750	84.41	5,778	68,452
Nalcor Grand Falls, Bishops Falls and Buchans	585.90	23,436	40,000	621.63	24,865	40,000
Total Energy Costs - NUGs	987.86	$ 50,368	$ 50,987	1,017.21	$ 51,756	$ 50,880

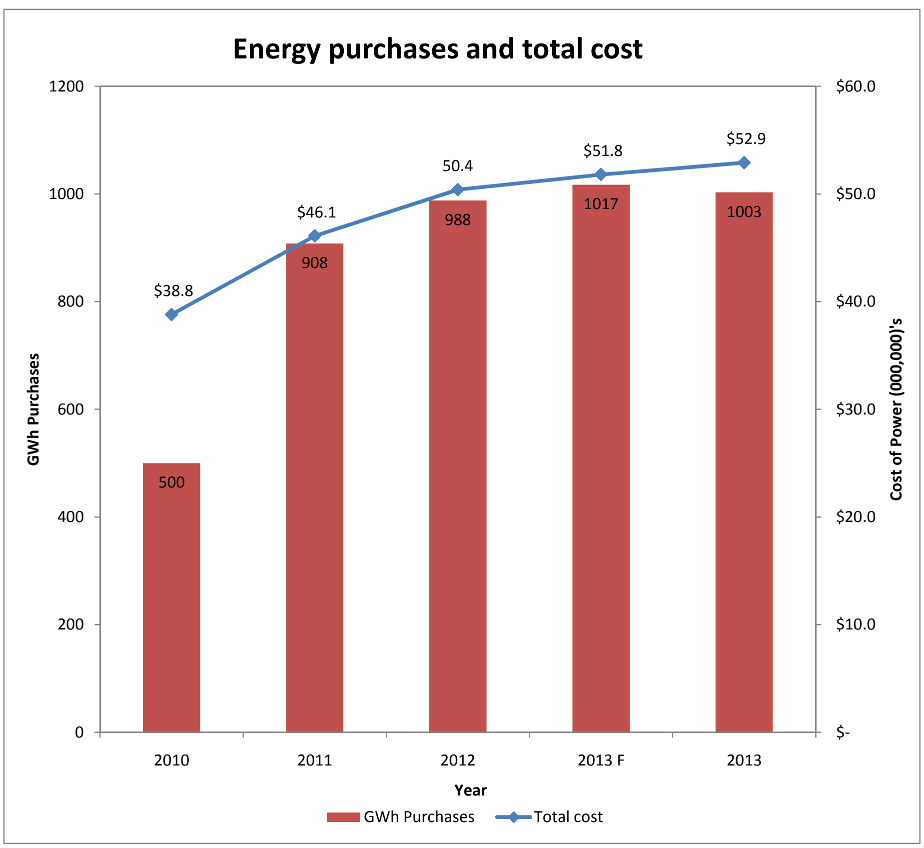
The energy purchase rate for production at the Nalcor Exploits Facilities was expected to remain constant at 4 cents/kWh in 2013 and did remain at this rate for 2013.

The following table provides a comparison of the 2013 test year purchases to the company's actual results for 2013.

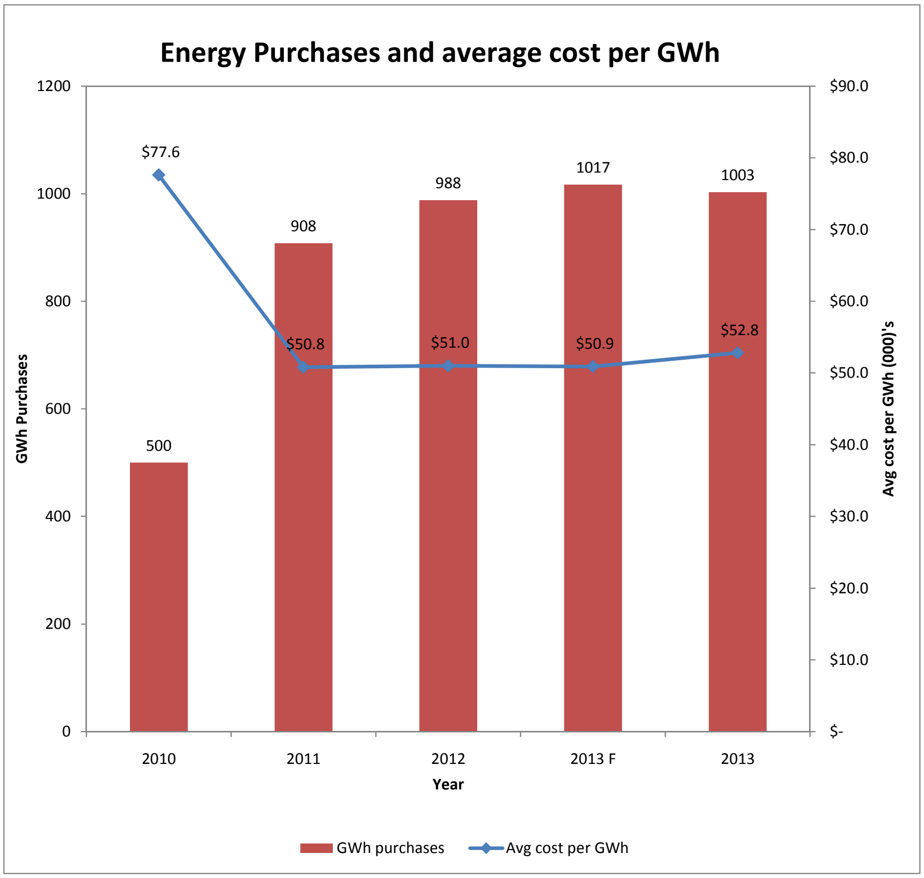
Table 29: Non-utility generators – Island Interconnected (2013 and 2013 test year)

	2013F			2013		
	GWh	$ ('000s)	Avg cost per GWh	GWh	$ ('000s)	Avg cost per GWh
Star Lake	140.87	$ 5,635	$ 40,001	140.61	$ 5,624	$ 39,997
Rattle Brook	15.00	1,236	82,400	14.76	1,229	83,266
Corner Brook Cogen	50.50	7,391	146,356	55.89	9,260	165,683
St. Lawrence Wind (net of incentive credit)	104.80	6,851	65,372	96.38	6,244	64,785
Fermeuse Wind (net of incentive credit)	84.41	5,778	68,452	95.52	6,598	69,075
Nalcor Grand Falls, Bishops Falls and Buchans	621.63	24,865	40,000	599.73	23,989	40,000
Total Energy Costs - NUGs	1,017.21	$ 51,756	$ 50,880	1,002.89	$ 52,944	$ 52,791

Graph 3: Energy purchases and total cost



Graph 4: Energy purchases and average cost per GWh



According to page 2.45 of the pre-filed evidence, the forecast for 2013 is based on Hydro's hydraulic generation model (VISTA) output for the Exploits Generation, the historical average data for the Rattle Brook and design estimates for the wind farms. As indicated in the table, the number of GWh to be purchased from NUGs is increasing and the average price per GWh is decreasing in the 2013 forecast in comparison to the 2012 actual results.

Actual 2013 costs relating to NUGs totalled $52,944,000, which is $1.2 million higher than the amount forecast. This variance is primarily due to an increase in costs relating to Corner Brook Cogen resulting from increased energy production from the co-gen unit and an increase in the actual average energy purchase rate from $14.64 cents/kWh to $16.57 cents/kWh. There was also an increase in purchase costs relating to Fermeuse Wind which was primarily due to the increased energy production from the wind project along with a 1% municipal tax which was not included in the forecast. These increases were partially offset by decreases in purchases from St. Lawrence Wind, due to operational issues at the wind farm, and Exploits River Project, as a result of decreased production at the Exploits River Facilities and the Buchans unit, along with numerous planned and forced outages to the units at Grand Falls and Bishop's Falls.

The forecast increase of $339,000 in Demand and energy – CF(L)Co expense from 2012 to 2013 forecast is primarily related to an expected increase in energy requirements from the Iron Ore Company of Canada (IOCC) and Hydro Rural Labrador requirements supported by CF(L)Co. Actual 2013 costs relating to CF(L)Co totaled $2,116,000, which is $247,000 lower than the forecast amount. This variance is primarily due to reduced NLH Labrador energy requirements from 935.30 GWh to 839.07 GWh. This is attributable to lower industrial sales at the Iron Ore Company of Canada, lower Secondary energy sales to CFB Goose Bay and lower system losses.

The costs for L'Anse au Loup are forecast to increase by $422,000 to $3,353,000 in 2013 due to expected increases in volume and price. Actual 2013 costs relating to L'Anse au Loup totalled $3,056,000, which is $297,000 lower than the forecast amount. This variance is primarily due to lower energy requirements and purchase prices than what were expected. Power purchase volumes were approximately 5% lower than forecast due to warmer than normal weather and partially due to lower sales growth than forecast. Purchase prices were lower than forecast as the fuel prices from which purchase prices are determined were approximately 3% lower than what was forecast for 2013.

The costs for secondary energy have not been forecast for the 2013 test year due to the inconsistent nature and variability of the reservoir storage requirements.

Interest

Interest expense for 2013 is forecast to decrease by $1.0 million overall compared to 2012. The following is a summary of forecast interest expense for 2013 as compared to actuals for 2007 to 2013:

Table 30: Interest expense

(millions)	Actuals 2007	Actuals 2008	Actuals 2009	Actuals 2010	Actuals 2011	Actuals 2012	Forecast 2013	Actuals 2013	Variance '13F-'12	Variance '13A-'13F
Gross interest	102.3	98.2	91.0	90.9	91.1	91.4	91.3	90.8	(0.1)	(0.5)
Debt guarantee fee	13.1	-	-	-	3.9	3.7	3.7	3.7	-	-
RSP	1.1	2.8	7.0	10.2	12.2	13.2	14.4	17.1	1.2	2.7
Amortization of debt discount and financing costs	0.7	0.5	0.4	0.4	0.5	0.5	0.5	0.5	-	-
Amortizaton of foreign exchange losses	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	-	-
Interest on cash borrowed from non-regulated activities	5.0	9.0	-	-	-	-	-	-	-	-
	124.4	112.7	100.6	103.7	109.9	111.0	112.1	114.3	1.1	2.2
Less:										
Interest earned	14.0	15.4	16.4	16.0	17.6	18.3	19.9	19.8	1.6	(0.1)
Interest attributable to CF(L)Co share purchase	0.9	-	-	-	-	-	-	-	-	-
Interest capitalized during construction	6.3	9.6	0.8	1.0	1.5	2.7	3.2	2.2	0.5	(1.0)
	21.2	25.0	17.2	17.0	19.1	21.0	23.1	22.0	2.1	(1.1)
	103.2	87.7	83.4	86.7	90.8	90.0	89.0	92.3	(1.0)	3.3

The debt guarantee fee, amortization of debt discount and financing costs and foreign exchange losses are all forecast to remain consistent into 2013.

The most significant item impacting net interest is the forecast increase in RSP interest costs in 2013 compared to 2012. This increase is primarily due to an increase in interest rates. The 2012 interest is calculated using a WACC of 7.529%, where the forecast interest is calculated using a forecast WACC of 7.83%.

The amount of interest earned is forecast to increase by $1.6 million compared to 2012. The sinking fund has increased by $8.2 million in contributions, resulting in increased interest earnings of $1.2 million. Also, interest on past due accounts is expected to increase by $385,000. According to Hydro, the 2013 forecast was based on an average of the last six years.

The amount of interest capitalized during construction is forecast to increase in 2013 by $0.5 million compared to 2012. The total interest capitalized during construction is driven by the amount of capital expenditures which is also forecast to increase during that same time period.

Other Costs

Finance Schedule I, page 9 of 11 of the pre-filed evidence, contains details of Hydro's "other costs" forecast for 2013 with comparative data from 2007 to 2012. Earlier in our report we provided a table which provides a breakdown of all the cost components which make up the revenue requirement including the "other costs" category. The following table provides a comparison of the 2013 forecasts to actuals from 2007 to 2013, broken down into the various accounts which form the "other costs" category.

Table 31: Other costs by category

(000)'s	Actuals 2007	Actuals 2008	Actuals 2009	Actuals 2010	Actuals 2011	Actuals 2012	Forecast 2013	Actuals 2013	Variance '13F-'12	Variance '13A-'13F
Other costs										
Salaries and fringe benefits	70,171	73,123	76,381	82,517	87,556	90,907	96,583	96,431	5,676	(152)
System equip. maint.	23,525	22,282	22,122	21,748	21,512	20,261	21,495	22,005	1,234	510
Insurance	1,703	1,783	1,937	1,960	1,965	2,109	2,211	2,422	102	211
Transportation	2,776	3,046	3,038	3,056	3,377	3,600	3,623	3,578	23	(45)
Office Supplies	2,262	2,182	2,161	2,100	2,307	2,230	2,571	2,595	341	24
Bldg. rental and maint.	1,234	1,078	1,145	1,170	1,172	1,027	1,070	1,186	43	116
Professional services	3,865	4,443	3,612	4,215	6,092	7,324	7,022	5,874	(302)	(1,148)
Travel	2,942	2,854	2,910	2,755	2,977	2,979	3,156	3,338	177	182
Equipment rentals	1,082	1,493	1,721	1,738	1,636	1,699	1,731	1,877	32	146
Miscellaneous	4,246	4,359	8,065	3,829	4,736	5,144	6,380	5,218	1,236	(1,162)
Loss on disposal	902	2,580	1,267	687	925	5,396	1,304	3,634	(4,092)	2,330
Write down of assets	-	-	506	-	-	-	-	-	-	-
Total	114,708	119,223	124,865	125,775	134,255	142,676	147,146	148,158	4,470	1,012
Percentage change		3.94%	4.73%	0.73%	6.74%	6.27%	3.13%	0.69%		
Allocations										
Other - IOCC	(2,679)	(2,673)	(1,875)	(2,648)	(2,292)	(2,215)	(2,108)	(1,945)	107	163
Hydro capitalized	(12,044)	(15,461)	(17,164)	(20,716)	(21,276)	(20,723)	(20,692)	(21,656)	31	(964)
Cost recoveries	(1,390)	(1,815)	(4,190)	(4,748)	(5,198)	(7,874)	(9,222)	(9,111)	(1,348)	111
Sub-total	(16,113)	(19,949)	(23,229)	(28,112)	(28,766)	(30,812)	(32,022)	(32,712)	(1,210)	(690)
Net total	98,595	99,274	101,636	97,663	105,489	111,864	115,124	115,446	3,260	322
Percentage change		0.69%	2.38%	-3.91%	8.01%	6.04%	2.91%	0.28%		

Note: "Loss on disposal", which is included above, is not included in Finance Schedule I, page 9 of 11.

In the table above we see that total other costs before allocations are forecast to increase by $4.5 million in 2013 test year over the 2012 actuals. On a net basis the costs for 2013 test year are forecast to exceed 2012 actuals by approximately $3.3 million.

We see that 2013 actual total other costs before allocations exceeded the 2013 forecast by $1.0 million. On a net basis, 2013 actuals exceed the 2013 forecast by $0.3 million.

In the table below we provide an analysis of total other costs on a kWh's sold and used basis for 2012 actuals, 2013 actuals and the 2013 forecast. This table shows that while forecast total other costs have increased, on a kWh basis, costs are forecast to decrease. Actual cost per kWh for 2013 came in lower than 2012 but higher than forecast. Total costs were relatively consistent with forecast (0.3% above forecast) but the total kWh's sold and used was 1.6% below forecast.

Table 32: Other costs per kWh

	2013 Actual			2013 Forecast			2012		
kWh sold and used	7,194,000			7,314,000			6,964,000		
	Cost	**Cost per kWh**	**% of Total**	**Cost**	**Cost per kWh**	**% of Total**	**Cost**	**Cost per kWh**	**% of Total**
Salaries and fringe benefits	96,431	0.0134	83.53%	96,583	0.0132	83.89%	90,907	0.0131	81.27%
System equip. maint.	22,005	0.0031	19.06%	21,495	0.0029	18.67%	20,261	0.0029	18.11%
Insurance	2,422	0.0003	2.10%	2,211	0.0003	1.92%	2,109	0.0003	1.89%
Transportation	3,578	0.0005	3.10%	3,623	0.0005	3.15%	3,600	0.0005	3.22%
Office Supplies	2,595	0.0004	2.25%	2,571	0.0004	2.23%	2,230	0.0003	1.99%
Bldg. rental and maint.	1,186	0.0002	1.03%	1,070	0.0001	0.93%	1,027	0.0001	0.92%
Professional services	5,874	0.0008	5.09%	7,022	0.0010	6.10%	7,324	0.0011	6.55%
Travel	3,338	0.0005	2.89%	3,156	0.0004	2.74%	2,979	0.0004	2.66%
Equipment rentals	1,877	0.0003	1.63%	1,731	0.0002	1.50%	1,699	0.0002	1.52%
Miscellaneous	5,218	0.0007	4.52%	6,380	0.0009	5.54%	5,144	0.0007	4.60%
Loss on disposal	3,634	0.0005	3.15%	1,304	0.0002	1.13%	5,396	0.0008	4.82%
	148,158	0.0206	128.34%	147,146	0.0201	127.82%	142,676	0.0205	127.54%
Other - IOCC	(1,945)	(0.0003)	-1.68%	(2,108)	(0.0003)	-1.83%	(2,215)	(0.0003)	-1.98%
Hydro capitalized	(21,656)	(0.0030)	-18.76%	(20,692)	(0.0028)	-17.97%	(20,723)	(0.0030)	-18.53%
Cost recoveries	(9,111)	(0.0013)	-7.89%	(9,222)	(0.0013)	-8.01%	(7,874)	(0.0011)	-7.04%
Total other costs (net)	115,446	0.0160	100.00%	115,124	0.0157	100.00%	111,864	0.0161	100.00%

As part of our review, we have analyzed each of these costs.

Salaries and fringe benefits

Gross payroll costs forecast for 2013 of $96.6 million are higher than 2012 levels by $5.7 million or 6.24%. These variations are outlined in the table below which summarizes salaries and fringe benefits costs incurred from 2007 to 2013 and the 2013 forecast.

Table 33: Salaries and fringe benefits by category

(000)'s	Actuals 2007	Actuals 2008	Actuals 2009	Actuals 2010	Actuals 2011	Actuals 2012	Forecast 2013	Actuals 2013	Variance '13F-'12	Variance '13A-'13F
Salaries	$ 48,335	$ 47,280	$ 44,374	$ 45,402	$ 48,706	$ 51,818	$ 59,106	$ 54,299	$ 7,288	$ (4,807)
Temporary salaries	-	-	5,900	6,700	7,034	6,272	6,381	6,706	109	325
Vacancy adjustment	-	-	-	-	-	-	(3,175)	-	(3,175)	3,175
	48,335	47,280	50,274	52,102	55,740	58,090	62,312	61,005	4,222	(1,307)
Other salary costs	-	1,269	2,009	3,009	668	562	479	839	(83)	360
Intercompany salaries	-	1,296	1,127	1,673	2,311	2,157	2,706	2,633	549	(73)
	48,335	49,845	53,410	56,784	58,719	60,809	65,497	64,477	4,688	(1,020)
Allowances	1,193	1,260	1,309	1,469	1,773	1,836	1,615	1,907	(221)	292
Directors fees	7	27	54	55	(3)	41	155	38	114	(117)
Overtime	6,109	7,580	7,778	8,675	9,460	10,633	8,604	12,282	(2,029)	3,678
Employee future benefits	5,861	5,559	4,334	6,098	7,247	6,970	9,314	6,790	2,344	(2,524)
Fringe benefits	7,065	7,007	7,029	7,254	7,672	8,064	8,613	8,409	549	(204)
Group insurance	1,460	1,719	2,336	2,052	2,546	2,403	2,643	2,372	240	(271)
Labrador travel benefit	141	126	131	130	142	151	142	156	(9)	14
Gross payroll costs	70,171	73,123	76,381	82,517	87,556	90,907	96,583	96,431	5,676	(152)
Less: capitalized salaries	(11,258)	(14,600)	(15,959)	(19,456)	(19,735)	(19,051)	(19,342)	(20,185)	(291)	(843)
Salaries and fringe benefits, net	$ 58,913	$ 58,523	$ 60,422	$ 63,061	$ 67,821	$ 71,856	$ 77,241	$ 76,246	$ 5,385	$ (995)

Per review of the table above the most significant variances between 2013 forecasts and 2012 actuals occur in the following categories of salaries:

- Increase in salaries in 2013F
- Vacancy adjustment in 2013F
- Increase in intercompany salaries in 2013F
- Decrease in overtime in 2013F
- Increase in employee future benefits in 2013F
- Increase in fringe benefits in 2013F

Salaries

The salaries component of salaries and fringe benefits has maintained its upward trend from 2009 to 2012 despite the fluctuations in the number of full time equivalent (FTE) employees. In 2009, Hydro employed a total of 804 employees, in 2010 the number of FTEs increased to an average of 809 FTEs. In 2011 and 2012 salaries continued to increase while the number of FTEs fell to an average of 805 and 801 respectively. The trend for increasing salaries is expected to continue in 2013 with an expected expenditure of $62.3 million. The average number of FTEs is also expected to rise above 2011 and 2012 averages to 818 positions.

Actual salaries for 2013 totalled $61,005,000 which is a decrease of $1,307,000 from forecast. This variance is primarily due to an increase in actual recharged labour costs over the 2013 forecast, offset by a decrease in the vacancy credit which is a budgeted number and is not included in 2013 actuals.

The breakdown of salaries by division is summarized below:

Table 34: Salaries by division (2007-2011)

(000)'s	Actuals 2007	Actuals 2008	Actuals 2009	Actuals 2010	Actuals 2011
Executive Leadership & Assoc.	$ 2,839	$ 348	$ 368	$ 334	$ 345
Human Resources & Org. Effect.	3,264	3,221	3,295	3,349	3,891
Finance/CFO	7,178	6,332	6,652	6,281	6,039
Project Execution & Tech Services	5,901	6,162	7,246	8,209	7,034
Regulated Operations	30,470	32,189	34,293	33,660	38,060
Corporate Relations	-	-	-	2,150	2,425
Recharged Salaries	(1,317)	(972)	(1,580)	(1,881)	(2,054)
	$ 48,335	$ 47,280	$ 50,274	$ 52,102	$ 55,740

Table 35: Salaries by division (2012-2013 and 2013 test year)

(000)'s	Actuals 2012	Forecast 2013	Actuals 2013	Variance ($) '13F-'12	Variance (%) '13F-'12	Variance ($) '13A-'13F	Variance (%) '13A-'13F
Executive Leadership & Assoc.	$ 367	$ 342	$ 506	$ (25)	-6.8%	$ 164	48.0%
Human Resources & Org. Effect.	4,136	4,605	4,486	469	11.3%	(119)	-2.6%
Finance/CFO	6,123	6,436	6,168	313	5.1%	(268)	-4.2%
Project Execution & Tech Services	6,565	8,411	7,103	1,846	28.1%	(1,308)	-15.6%
Regulated Operations	40,076	41,452	42,201	1,376	3.4%	749	1.8%
Corporate Relations	2,519	2,742	2,498	223	8.9%	(244)	-8.9%
Recharged Salaries	(1,696)	(1,676)	(1,957)	20	-1.2%	(281)	16.8%
	$ 58,090	$ 62,312	$ 61,005	$ 4,222	7.3%	$ (1,307)	-2.1%

Salary fluctuations were noted within several of the divisions when comparing the 2013 forecast to 2012, however the most significant increases occurred within the following divisions - Human Resources & Organizational Effectiveness, Regulated Operations and Project Execution & Tech Services.

According to Hydro, the forecast increase in the Human Resources & Organizational Effectiveness division is primarily due to wage and merit increases combined with an increase of 1.5 FTEs during the period.

According to Hydro, the increase in the Project Execution & Tech Services division is primarily due to wage and merit increases combined with an increase of 20.9 FTEs during the period. The actual 2013 salaries for this division are $1.3 million lower than the amount forecast. This variance is primarily due to a reduction of 16 FTEs from forecast.

The recharged salaries account relates to salaries that have been recharged in or out to other divisions for employees that have been working on projects that are outside of their regular department. If we were to review this account for the Company as a whole, the balance of salaries transferred in from other divisions and the balance of salaries transferred out to other divisions should net to zero. However, because a portion of salaries for those employees working on non-regulated activities must be eliminated from the revenue requirement, there will always be a credit balance in this account on a regulated basis. The forecast for 2013 is consistent with 2012.

Consistent with 2012, the Company has implemented a salary compensation matrix for non-union employees. This matrix illustrates a scale for salary increases and bonuses based on performance ranging from 0-10% (inclusive of a 4% general adjustment). The compensation matrix allows for pay adjustments above the scale maximum based on an employee's "rating of performance". Ratings of performance include Unacceptable, Improvement Required, Meets Expectations, Exceeds Expectations, and Exceptional.

As noted by the Company, all salary adjustment figures include a general scale adjustment of 4% and all are calculated as a percentage of current base salary. All salary adjustments are subject to a scale maximum. Those in Exceeds Expectations and Exceptional categories whose performance adjustment would exceed the scale maximum receive the balance in the form of a one-time cash bonus of 3% or 6%, respectively, of their base salary.

There have been no changes in the compensation matrix from 2012 to 2013.

Table 36: Compensation matrix

	Scale Adjustment - Below Scale Maximum	
Rating of Performance	**2013**	**2012**
Exceptional	10% (with cash payout of balance)	10% (with cash payout of balance)
Exceed Expectations	8.5% (with cash payout of balance)	8.5% (with cash payout of balance)
Meets Expectations	7% (to the scale maximum)	7% (to the scale maximum)

Full Time Equivalents

An analysis of full time equivalent employees (FTEs) by year and by division or department has proven to be useful in the past in assessing changes in salary costs or forecast of costs for future years. The table below is a detailed comparison of the average number of FTEs by division for 2007 to 2013 forecast. The table was compiled from quarterly FTEs provided by Hydro and taking the average for the year.

Table 37: FTEs by division

(000)'s	Actuals 2007	Actuals 2008	Actuals 2009	Actuals 2010	Actuals 2011	Actuals 2012	Forecast 2013	Actuals 2013	Variance '13F-'12	Variance '13A-'13F
Executive Leadership & Assoc.	13	7	6	5	4	4	5	5	1	-
Human Resources & Org. Effect.	59	54	53	58	63	62	64	65	2	1
Finance/CFO	101	93	91	88	87	83	87	81	4	(6)
Project Execution & Tech Services	77	78	87	94	78	75	95	79	20	(16)
Regulated Operations	524	525	527	524	532	537	526	538	(11)	12
Corporate Relations	39	40	40	40	41	40	41	39	1	(2)
	813	797	804	809	805	801	818	807	17	(11)

Note 1: Per NP-NLH-023, Section 3, Finance, page 3.14, Chart 3.3 of the Evidence stated the 2011 FTEs at 803. The net FTE has since been restated at 805.
Note 2: Per NP-NLH-023, Section 3, Finance, page 3.14, Chart 3.3 of the Evidence stated the 2013 Forecasted FTEs at 815. The net FTE has since been restated at 818.
Note 3: Total FTEs reported in the 2012 Annual Review differs from above. In the 2012 Annual Review, total average FTEs was calculated as an average of quarterly FTEs.

As shown, in comparison to 2012 the total FTEs for 2013 is expected to increase by 17 full time positions. Per CA-NLH-104, FTEs are budgeted to support the operational and capital requirements as well as to incorporate the provision for shared services allocated to other lines of business. Hydro's labour requirements are primarily driven by its focus on efficient operations, maintenance, renewal of aging assets through capital programs, as well as to provide new assets to meet growth in customer demand. In particular, the requirement for engineering expertise has increased to support the increase in capital expenditures. The 2013 forecast FTEs and internal labour expense were calculated using the 2012 year end FTEs and labour expense as the starting point.

The salary costs as detailed earlier in this report have been normalized for special payments outside of regular wage expense. The results of our analysis for 2007 to 2013 and the 2013 forecast are included in the following table:

Table 38: Average salary per FTE

(000)'s	Actuals 2007	Actuals 2008	Actuals 2009	Actuals 2010	Actuals 2011	Actuals 2012	Forecast 2013	Actuals 2013	Variance '13F-'12	Variance '13A-'13F
Salary costs (including temporary salaries)	$ 48,335	$ 47,280	$ 50,274	$ 52,102	$ 55,740	$ 58,090	$ 65,487	$ 61,005	$ 7,397	$ (4,482)
Vacancy adjustment	-	-	-	-	-	-	(3,175)	-	(3,175)	3,175
	$ 48,335	$ 47,280	$ 50,274	$ 52,102	$ 55,740	$ 58,090	$ 62,312	$ 61,005	$ 4,222	$ (1,307)
FTEs	813	797	804	809	805	801	818	807	17	(11)
Average salary per FTE	$ 59,453	$ 59,322	$ 62,530	$ 64,403	$ 69,242	$ 72,522	$ 76,176	$ 75,595		
% increase		-0.22%	5.41%	3.00%	7.51%	4.74%	5.04%	-0.76%		

The above analysis indicates that the average salary per FTE is expected to increase by 5.04% in 2013, which is primarily due to a general salary increase of 4% granted during the year.

Executive Salaries

The executive position of VP, Newfoundland and Labrador Hydro is expensed through Hydro's payroll. The table below outlines the portion of executive salaries, including the total hours and average billing rates, which were charged back to Hydro by Nalcor for 2010 to 2012, and forecast 2013:

Table 39: Executive salaries by position

	2013 Forecast			2012 Actual		
	Hours	Average Billing Rate	Recharge Amount	Hours	Average Billing Rate	Recharge Amount
President and CEO	175.0	$ 392.92	$ 68,761	154.5	$ 417.20	$ 64,457
VP, HROE	1,170.0	166.01	194,232	392.5	169.14	66,389
VP, Project Execution and Technical Services (1)	721.0	202.00	145,642	451.5	205.55	92,805
VP, Finance and CFO	97.0	202.72	19,664	48.0	208.69	10,017
VP, Corporate Relations	351.0	103.32	36,265	265.5	141.92	37,680
	2,514.0	$ 184.79	$ 464,564	1,312.0	$ 206.82	$ 271,348
% change	92%	-11%	71%	-31%	8%	-26%

	2011 Actual			2010 Actual		
	Hours	Average Billing Rate	Recharge Amount	Hours	Average Billing Rate	Recharge Amount
CEO	133.5	$ 402.45	$ 53,727	172.0	$ 362.31	$ 62,317
VP, HROE	996.0	161.36	160,719	1,165.5	152.31	177,515
VP, Project Execution and Technical Services (1)	697.0	195.36	136,168	192.5	186.59	35,919
VP, Finance and CFO	88.5	198.41	17,559	92.0	186.59	17,166
VP, Engineering Services (1)				1,249.0	131.38	164,093
	1,915.0	$ 192.26	$ 368,173	2,871.0	$ 159.18	$ 457,010
% change	-33%	21%	-19%	-1%	41%	40%

Note 1: In October 2010, the Vice President of the Project Execution and Technical Services division was hired, replacing the executive position of Vice President, Engineering Services.

In 2013, the total recharge amount from executives is forecast to increase by $193,216 (71%) compared to 2012 due to an increase of 1,202 hours (92%), partially offset by an 11% decrease in the weighted average billing rate.

The following table outlines the change in executive hours from Nalcor to Hydro and average billing rates from 2010 to forecast 2013:

Table 40: Comparison of hours and average billing rates

Hours					Variance Hours	Variance %
	2010	2011	2012	2013F	2013F-2012	2013F-2012
President and CEO	172.0	133.5	154.5	175.0	20.5	13.3%
VP, HROE	1,165.5	996.0	392.5	1,170.0	777.5	198.1%
VP, Project Execution and Technical Services	192.5	697.0	451.5	721.0	269.5	59.7%
VP, Finance and CFO	92.0	88.5	48.0	97.0	49.0	102.1%
VP, Corporate Relations	-	-	265.5	351.0	85.5	32.2%
VP, Engineering Services	1,249.0	-	-	-	-	
	2,871.0	1,915.0	1,312.0	2,514.0	1,202.0	91.6%

Average billing rate					Variance $	Variance %
	2010	2011	2012	2013F	2013F-2012	2013F-2012
President and CEO	$ 362.31	$ 402.45	$ 417.20	$ 392.92	$ (24.28)	-5.8%
VP, HROE	152.31	161.36	169.14	166.01	(3.13)	-1.9%
VP, Project Execution and Technical Services	186.59	195.36	205.55	202.00	(3.55)	-1.7%
VP, Finance and CFO	186.59	198.41	208.69	202.72	(5.97)	-2.9%
VP, Corporate Relations	-	-	141.92	103.32	(38.60)	-27.2%
VP, Engineering Services	131.38	-	-	-	-	-
Weighted average	$ 159.18	$ 192.26	$ 206.82	$ 184.79	$ (22.03)	-10.7%

As noted in the above table, the total time charged by Nalcor Executives decreased from 2010 to 2012 by 1,559 hours (54%). In 2013 test year, these hours were forecast to increase by 92% over 2012. Actual hours for 2013 were not available at the time of filing this report.

Executive billing rates are expected to decrease from 2012 to 2013 forecast on an individual basis ranging from -1.7% to -27.2%.

Capitalized Salaries

Capitalized salaries include the salaries and benefits of the Company's employees whose time is charged directly to capital projects, as well as departmental and non-departmental overhead. The gross payroll costs incurred from 2007 to 2013 and forecast for 2013 have been allocated to operations and capital as follows:

Table 41: Payroll charged to operating and capital

(000)'s	Actuals 2007	Actuals 2008	Actuals 2009	Actuals 2010	Actuals 2011	Actuals 2012	Forecast 2013	Actuals 2013	Variance '13F-'12	Variance '13A-'13F
Payroll charged to operating	58,913	58,523	60,422	63,061	67,821	71,856	77,241	76,246	5,385	(995)
Payroll charged to capital	11,258	14,600	15,959	19,456	19,735	19,051	19,342	20,185	291	843
	70,171	73,123	76,381	82,517	87,556	90,907	96,583	96,431	5,676	(152)

As shown, the capitalized payroll is forecast to increase in 2013 by $291,000 over 2012. The amount of capitalized salaries can vary widely from year to year depending on the type of capitalized projects and the requirement for manpower versus machine power. However, overall, capitalized salaries forecast for 2013 seem to be reasonably consistent with prior year. The actual payroll capitalized in 2013 is $843,000 higher than forecast, despite actual capital expenditures being $20,227,000 less than forecast.

Intercompany salaries

Intercompany salaries are forecast to increase by $549,000 or 25.4% over 2012. Actual intercompany salaries reported for 2013 were $73,000 less than forecast. According to Hydro, 2013 test year intercompany salaries were forecast using prior year's budgets.

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.

In order to gain a better understanding of forecast overtime, we have prepared a comparison of actual and budgeted gross overtime. This analysis is provided in the table below:

Table 42: Comparison of overtime – actual to budget

(000)'s	Actuals 2007	Actuals 2008	Actuals 2009	Actuals 2010	Actuals 2011	Actuals 2012	Actuals 2013
Overtime	6,109	7,580	7,778	8,675	9,460	10,633	12,282
Overtime budget	2,774	3,804	4,013	4,709	5,461	5,582	8,604 [1]
Over (under) budget ($)	3,335	3,776	3,765	3,966	3,999	5,051	3,678
Over (under) budget (%)	120.22%	99.26%	93.82%	84.22%	73.23%	90.49%	42.75%

Note 1: The 2013 "budget" figure is the Company's 2013 Test Year Forecast.

Based on the information provided above, Hydro's actual gross overtime costs exceed budgeted costs each year.

The 2013 forecast overtime costs of $8.6 million are $2.0 million lower than actual costs for 2012 and $3.7 million lower than actual costs for 2013. Management forecast these costs with the intention of reducing higher cost overtime through improved deployment of staff and expediting recruitment in 2013.

Employee future benefits

Employee future benefit costs relate to severance payments upon retirement and health benefits provided to retirees on a cost shared basis. These costs are forecast using actuarial methods and include assumptions as to future benefit costs and interest rate expectations. Employee future benefits are forecast to increase by $2.3 million from 2012 to 2013. This increase is primarily due to the inclusion of amortization of actuarial losses in the forecast. The Company's proposal related to this amortization is dealt with separately in this report.

Actual employee future benefit costs for 2013 are $2,524,000 lower than the amount forecast. This variance is primarily due to the amortization of actuarial losses of $2,224,000 included in test year. Actual amortization of actuarial losses for 2013 totalled $1,708,000 and was deferred, pursuant to Board Order P.U. 13 (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 $549,000 more than 2012 actual costs of $8.1 million, mainly due to increased premiums for EI and CPP and increased contributions to the PSPP in conjunction with salary increases.

As outlined in the table below, fringe benefits as a percentage of salaries are expected to be consistent with prior years.

Table 43: Fringe benefits as a percentage of salaries

(000)'s	Actuals 2007	Actuals 2008	Actuals 2009	Actuals 2010	Actuals 2011	Actuals 2012	Forecast 2013	Actuals 2013	Variance '13F-'12	Variance '13A-'13F
Salaries	$ 48,335	$ 47,280	$ 50,274	$ 52,102	$ 55,740	$ 58,090	$ 62,312	$ 61,005	$ 4,222	$ (1,307)
Fringe benefits	$ 7,065	$ 7,007	$ 7,029	$ 7,254	$ 7,672	$ 8,064	$ 8,613	$ 8,409	$ 549	$ (204)
	14.62%	14.82%	13.98%	13.92%	13.76%	13.88%	13.82%	13.78%	-0.06%	-0.04%

Vacancy credit

Included in the salary forecast for 2013 is a vacancy credit of $3,175,000. When compared to the $980,000 vacancy credit included in the 2007 test year, the difference is quite significant. Per CA-NLH-104, Hydro's method of forecasting vacancies combines a review of past vacancy experience, with a particular emphasis on the prior and current year trends. A vacancy analysis is done at least twice per year, taking into account the anticipated retirements, leave of absences, voluntary resignations, and new hires. Additionally, there is consultation with the area management teams to review the status of job competitions and assist in confirming expected file dates for positions in their respective area.

This vacancy adjustment has increased significantly due to the tightening labour market and associated difficulty in recruiting trades and technology positions, particularly in rural areas. In 2012, there were 34 retirements, 11 voluntary resignations, and three employees commenced a leave of absence. Hydro conducted

110 job competitions and had a provision for 27 vacancies on the 2012 budget. The actual vacancy was 52 FTEs. The vacancy forecast for 2013 was increased from 27 FTEs to 40 FTEs.

System equipment maintenance

System equipment maintenance costs have been forecast to increase by approximately $1.2 million in 2013 in comparison to 2012. The following table summarizes system equipment maintenance costs incurred from 2007 to 2013 and 2013 forecast.

Table 44: System equipment maintenance costs by category

(000)'s	Actuals 2007	Actuals 2008	Actuals 2009	Actuals 2010	Actuals 2011	Actuals 2012	Forecast 2013	Actuals 2013	Variance '13F-'12	Variance '13A-'13F
Maintenance material	22,117	20,815	17,899	17,780	10,961	9,784	11,074	11,278	1,290	204
Contract labour	-	-	-	-	7,312	8,378	8,654	8,676	276	22
Contract materials	-	-	-	-	57	21	101	120	80	19
Extraordinary repair amortization	-	-	2,715	2,582	1,644	605	-	-	(605)	-
	22,117	20,815	20,614	20,362	19,974	18,788	19,829	20,074	1,041	245
Tools and operating supplies	348	383	369	398	349	415	447	499	32	52
Freight expense	393	389	411	399	471	383	473	536	90	63
Lubricant, gases & chemicals	667	695	728	589	718	675	746	896	71	150
	23,525	22,282	22,122	21,748	21,512	20,261	21,495	22,005	1,234	510

The total maintenance material, extraordinary repair amortization, contract labour and contract materials cost are forecast to increase by $1.0 million in 2013 over 2012 actuals. Maintenance costs are incurred throughout all divisions with the majority of costs incurred in the Regulated Operations division. The following table provides a breakdown of Maintenance costs by division from 2007 to 2013 and 2013 forecast.

Table 45: System equipment maintenance costs by division

(000)'s	Actuals 2007	Actuals 2008	Actuals 2009	Actuals 2010	Actuals 2011	Actuals 2012	Forecast 2013	Actuals 2013	Variance '13F-'12	Variance '13A-'13F
Executive Leadership & Assoc.	98	63	71	3	-	-	7	-	7	(7)
Human Resources & Org. Effect.	19	75	135	190	46	26	107	29	81	(78)
Finance/CFO	1,184	1,071	1,173	1,317	1,212	1,306	1,589	1,364	283	(225)
Project Execution & Tech Services	142	147	131	189	161	133	235	774	102	539
Regulated Operations	20,674	19,459	19,104	18,483	18,377	17,185	17,728	17,792	543	64
Corporate Relations	-	-	-	180	178	138	163	115	25	(48)
	22,117	20,815	20,614	20,362	19,974	18,788	19,829	20,074	1,041	245

Based on the table above, maintenance costs incurred by the Finance/CFO division are forecast to increase by $283,000, or 22%, in 2013. This increase is primarily due to the age of Hydro Place, along with safety requirements resulting in increased costs for glass and electrical work, plumbing, snow clearing and HVAC. Also, Hydro forecasts additional costs related to paving, carpet and tiles maintenance, and landscaping in 2013.

Maintenance costs incurred by the PE&TS division are forecast to increase by $102,000, or 77%, in 2013. This variance was investigated due to the significant percentage increase over 2012. Hydro's response was that the increase was primarily due to higher planned expenditures in the test year.

The majority of the costs expended in all years occur within the Regulated Operations division. The following table provides a breakdown of maintenance material for the Regulated Operations division for the years 2007 to the 2013 forecast:

Table 46: Regulated Operations division costs by department

(000)'s	Actuals 2007	Actuals 2008	Actuals 2009	Actuals 2010	Actuals 2011	Actuals 2012	Forecast 2013	Variance '13F-'12
System Operation	170	186	215	2	3	3	2	(1)
Hydro Generation	1,583	1,328	1,190	1,385	1,392	2,153	1,780	(373)
Thermal Holyrood	11,802	11,023	10,664	9,437	9,599	7,433	7,979	546
Central operations	4,725	4,634	4,684	5,291	5,231	5,539	5,963	424
Labrador operations	1,252	1,476	1,429	1,323	1,331	1,132	1,020	(112)
Northern operations	1,142	812	922	1,045	821	925	984	59
	20,674	19,459	19,104	18,483	18,377	17,185	17,728	543

Note 1: A breakdown of the maintenance material for the Regulated Operations division was not provided for actual 2013.

The Labrador operations are forecast to experience a decrease of $112,000 in maintenance material costs in 2013. This decrease is primarily due to costs incurred in 2012 which are not forecast to reoccur in 2013, offset by a slight increase in other costs. Costs which occurred in 2012 that are not expected to reoccur include $89,000 relating to the Black Tickle fire and $38,000 relating to the voltage conversion on the Labrador City distribution line.

Maintenance costs in the Central operations department have been increasing in recent years with the forecast for 2013 exhibiting a similar pattern. Maintenance is broken down between routine (corrective and preventative) and operating projects. In 2013, Hydro has forecast maintenance costs to increase by approximately $424,000, or 8%, from 2012 levels. This increase is primarily related to a $180,000 increase in system equipment maintenance contract labour resulting from more operating project activity budgeted in 2013 for trail upgrade work, along with an additional $134,000 budgeted for increased TRO Services Vegetation Control contract labour. Also, in 2012, system equipment maintenance costs were approximately $77,000 lower than those budgeted for 2013, due to fewer requirements for corrective maintenance materials and non-maintenance material purchases.

The most significant portion of the cost expended in this division is within the Thermal Holyrood department. For further analysis, the breakdown of costs at the Holyrood thermal plant is as follows:

Table 47: Thermal Holyrood department costs by unit

(000)'s	Actuals 2007	Actuals 2008	Actuals 2009	Actuals 2010	Actuals 2011	Actuals 2012	Forecast 2013	Variance '13F-'12
Unit # 1	2,085	1,598	3,583	1,555	832	1,517	731	(786)
Unit # 2	1,484	2,158	1,170	477	2,708	1,668	2,274	606
Unit # 3	3,105	1,739	521	2,374	1,943	1,024	1,854	830
Annual routine maintenance (Note 1)	5,128	5,528	5,390	5,031	4,116	3,224	3,120	(104)
	11,802	11,023	10,664	9,437	9,599	7,433	7,979	546

Note 1: Annual routine maintenance includes Extraordinary repair amortization.
Note 2: A breakdown of the costs at the Holyrood thermal plant was not provided for actual 2013.

Maintenance costs at Holyrood are subject to a high degree of variability; however, for the 2013 forecast the main factor contributing to the increase in thermal plant costs is a major boiler overhaul scheduled for Unit 3.

The annual routine maintenance category includes the maintenance on Holyrood buildings and sites, common equipment, water treatment plant equipment and administration equipment. The forecast for 2013 is indicating a slight decline.

Professional services

For 2013, we compared the forecast amount to prior years, investigated any unusual fluctuations and assessed overall reasonableness of the forecast amounts. Professional services costs from 2007 to 2013 are as follows:

Table 48: Professional services costs by category

(000)'s	Actuals 2007	Actuals 2008	Actuals 2009	Actuals 2010	Actuals 2011	Actuals 2012	Forecast 2013	Actuals 2013	Variance '13F-'12	Variance '13A-'13F
Consultants	2,312	2,674	2,114	2,335	3,024	4,145	3,775	3,384	(370)	(391)
PUB Related Costs	620	801	939	882	1,934	1,835	1,862	1,244	27	(618)
Software Acquisitions & Maintenance	933	968	559	998	1,134	1,344	1,385	1,246	41	(139)
	3,865	4,443	3,612	4,215	6,092	7,324	7,022	5,874	(302)	(1,148)

Professional fees have increased by $3,157,000 or 82% from 2007 to forecast 2013. The increase is primarily attributable to the following; $1.0 million related to CDM programs (which is fully offset in cost recoveries), $0.4 million for environmental site assessments and remediation, an increase of $1.2 million in GRA and Board costs, and an increase of $0.4 million in software costs resulting from vendor price increases and maintenance associated with new software programs.

Consultants' fees (including audit and legal), which represent the largest portion of total professional fees, were approximately $4.1 million in 2012 and are forecast to be approximately $3.8 million in 2013. The decrease of $370,000 in forecast 2013 over 2012 is primarily the result of lower costs in the Regulated Operations division. Large variances were noted in the remaining divisions as well. Details by division are indicated in the table below:

Table 49: Consultants' fees by division

(000)'s	Actuals 2007	Actuals 2008	Actuals 2009	Actuals 2010	Actuals 2011	Actuals 2012	Forecast 2013	Actuals 2013	Variance '13F-'12	Variance '13A-'13F
Executive Leadership & Assoc.	275	217	231	99	90	201	111	191	(90)	80
Human Resources & Org. Effect.	286	317	465	639	846	777	1,027	707	250	(320)
Finance/CFO	335	423	263	285	277	494	350	335	(144)	(15)
Project Execution & Tech Services	175	231	316	331	311	477	420	233	(57)	(187)
Regulated Operations	1,241	1,486	839	592	910	1,157	667	778	(490)	111
Corporate Relations	-	-	-	389	590	1,039	1,200	1,140	161	(60)
	2,312	2,674	2,114	2,335	3,024	4,145	3,775	3,384	(370)	(391)

The increase in the Human Resources & Organizational Effectiveness division in forecast 2013 compared to 2012 is related to additional costs relating to the increase in environmental site assessments, an increase in environmental audits, and air dispersion in Holyrood.

The decrease in the Finance division in forecast 2013 compared to 2012 is primarily due to the additional costs incurred in 2012 relating to the Bell Aliant Pole Attachment Survey which will not be occurring in 2013.

The decrease in forecast 2013 compared to 2012 for the Regulated Operations division is primarily related to the costs incurred in 2012 relating to the Bell Aliant Pole Attachment Survey and the Holyrood decommissioning study, neither of which will be occurring in 2013. Also, additional consulting services were provided in 2012 relating to the Hydro Generation system.

The increase in the Corporate Relations division in forecast 2013 compared to 2012 is primarily due to an increase in the costs relating to the Industrial Conservation and Demand Management plan, as well as an increase in costs relating to the program concept development of the Joint Utility Program.

The actual consultants' fees incurred in 2013 were lower than expected, which resulted in a variance of $391,000 from 2013 test year. The costs relating to the environmental site assessments were $173,000 lower than forecast, and the costs relating to the air dispersion in Holyrood were $29,000 lower than forecast. Also, the costs relating to the Clarity Systems/intercompany project were $104,000 lower than forecast.

In 2011, PUB related costs increased by $1.1 million due to an RSP application, as well as increases in GRA consulting costs, and annual assessment costs. Since 2011, these costs have been fairly consistent. For 2012, PUB related costs (regulatory) totalled approximately $1.8 million, a decrease of 5.1% compared to 2011. For purposes of the 2013 General Rate Hearing, Hydro has estimated that there will be $1.9 million in 2013 for regulatory costs related to the Board. A listing of the major projects included under PUB related costs for 2013 forecast, along with a comparison to the Company's actual results for 2013, is set out below:

Table 50: PUB related costs

(000)'s PUB Related Costs	Forecast 2013	Actual 2013	Variance
PUB Annual Assessment	$ 650	720	$ 70
Consultants/Legal	718	405	(313)
GRA Costs and Amortization	333	-	(333)
Capital Budget	100	51	(49)
Annual Financial Reviews	60	68	8
Total	$ 1,861	$ 1,244	$ (617)

The variance between 2013 test year and actuals is primarily due to GRA costs and amortization. Hydro has proposed to defer and amortize $1.0 million in costs relating to the 2013 rate hearing over a three year period commencing in 2013, discussed in further detail in the Deferred Accounts section of this report.

Miscellaneous

The breakdown of items included in the miscellaneous expense category from 2007 to 2013 and forecast 2013 are as follows:

Table 51: Miscellaneous costs by category

(000)'s	Actuals 2007	Actuals 2008	Actuals 2009	Actuals 2010	Actuals 2011	Actuals 2012	Forecast 2013	Actuals 2013	Variance '13F-'12	Variance '13A-'13F
Business and payroll taxes	2,584	2,736	2,807	2,933	2,967	3,177	3,219	3,424	42	205
Bad debt expense	277	(37)	3,884	(631)	116	134	117	71	(17)	(46)
Staff training	820	800	730	668	647	780	953	842	173	(111)
Write offs	(43)	304	105	239	179	329	193	82	(136)	(111)
Employee expenses	353	302	332	347	427	354	404	398	50	(6)
Sundry costs	161	179	128	161	142	197	177	205	(20)	28
Diesel fuel Hydro	71	61	58	70	104	13	69	82	56	13
Energy management	15	6	13	36	148	154	1,240	109	1,086	(1,131)
Collection fees	8	8	8	6	6	6	8	5	2	(3)
	4,246	4,359	8,065	3,829	4,736	5,144	6,380	5,218	1,236	(1,162)

Miscellaneous expenses are forecast to increase in 2013 over 2012 actual by approximately $1.2 million or 24.0 %. This increase is primarily related to the forecast expenses in 2013 for Staff Training and Energy Management.

Staff training costs for the 2013 forecast have increased significantly from 2012 by approximately $173,000 or 22.2%. According to Hydro, this increase is primarily due to the discontinuation of the capitalization of training expenses related to new asset additions, as approved by the Board Order No. P.U. 13(2012). Also, according to Hydro, this increase relates to the timing of training programs as well as an increase in the number of participants.

The Energy Management expense forecast for 2013 is projected to increase by approximately $1.1 million in comparison to 2012, primarily due to delays in customer uptake in the energy demand management program in 2012. Customer participation is expected to increase in 2013, which would result in an increase in the CDM cost recoveries. Based on actual results for 2013, customer participation did not increase as costs were relatively consistent with 2012. This also resulted in a decrease in CDM cost recoveries in the Corporate Relations division, detailed in the Cost Recoveries section of this report. In its "Update of Financial Results and Forecasts", dated March 14, 2014, Hydro commented that the decrease is "primarily due to delays in customer participation in the Energy Demand Management Program".

These increases are partially offset by a forecast decrease in Write offs amounting to $136,000 in 2013 forecast compared to 2012. This decrease is due to unusually high write offs which occurred in 2012 as a result of inventory reviews. These write offs were not expected to reoccur in 2013.

Loss on Disposal

In 2013, loss on disposal of assets is expected to total approximately $1.3 million. A breakdown of this forecast is provided below:

Table 52: Loss on disposal costs by category

(000)'s	Actuals 2007	Actuals 2008	Actuals 2009	Actuals 2010	Actuals 2011	Actuals 2012	Forecast 2013	Actuals 2013	Variance '13F-'12	Variance '13A-'13F
Net book value of disposed assets	1,504	5,503	2,563	1,150	1,226	5,356	1,519	6,607	(3,837)	5,088
Asset removal costs	-	-	-	-	-	1,182	-	991	(1,182)	991
Disposal proceeds	(612)	(2,930)	(1,319)	(480)	(313)	(1,156)	(215)	(3,997)	941	(3,782)
Auction fees and expenses	10	7	23	17	12	14	-	33	(14)	33
	902	2,580	1,267	687	925	5,396	1,304	3,634	(4,092)	2,330

As is evident in the table above, the net book value of the disposed assets, which encompasses much of the costs associated with the loss on disposal of capital assets, tends to vary from year to year.

In 2012, the largest disposals related to partial asset disposals of the Cat Arm dam, Cat Arm road, Black Tickle Diesel Plant, Happy Valley North Plant, and the retirement of distribution poles. In 2012 Hydro created a general ledger account to separately identify capital asset removal costs. In 2012, removal costs of $1,182,000 were expensed, relating primarily to voltage conversion in Labrador and upgrade of Fuel Storage in St. Lewis.

In 2013, the largest disposals are expected to relate to the upgrade circuit breakers project, the upgrade power transformers project, and the overhaul of diesel engines, with forecast losses on disposal of approximately $387,000, $235,000, and $149,000 respectively.

Actual loss on disposal for 2013 totalled $3,634,000 which is $2,330,000 higher than the forecast amount. This variance is primarily due to disposals during the year which resulted from capital work completed on the restoration of Unit 1, along with the write off of the Holyrood Gas turbine, the disposal of the Labrador Substation, and asset removal costs not included in the forecast. These projects resulted in losses of $3.4

million, $0.8 million, $0.4 million, and $1.0 million respectively. These losses were offset by an increase in disposal proceeds relating to insurance proceeds of $3.5 million.

Other Cost Categories

In addition to the various categories of expenses commented on above, the other categories of operating expenses by breakdown were also analyzed for any unusual variances.

Table 53: Other cost categories

(000)'s	Actuals 2007	Actuals 2008	Actuals 2009	Actuals 2010	Actuals 2011	Actuals 2012	Forecast 2013	Actuals 2013	Variance '13F-'12	Variance '13A-'13F
Insurance	1,703	1,783	1,937	1,960	1,965	2,109	2,211	2,422	102	211
Transportation	2,776	3,046	3,038	3,056	3,377	3,600	3,623	3,578	23	(45)
Office Supplies	2,262	2,182	2,161	2,100	2,307	2,230	2,571	2,595	341	24
Bldg. rental and maint.	1,234	1,078	1,145	1,170	1,172	1,027	1,070	1,186	43	116
Travel	2,942	2,854	2,910	2,755	2,977	2,979	3,156	3,338	177	182
Equipment rentals	1,082	1,493	1,721	1,738	1,636	1,699	1,731	1,877	32	146
	11,999	12,436	12,912	12,779	13,434	13,644	14,362	14,996	718	634

These expenses are forecast to increase by $718,000 or 5.3%. The biggest variance between forecast 2013 and actual 2012 relates to office supplies. Office supplies expense is forecast to increase in 2013 by $341,000 or 15.3%. This increase is primarily related to an increase in safety campaigns as well as the purchase of additional communication equipment. Travel expense is forecast to increase in 2013 by $177,000 or 5.9%.

Actual 2013 amounts for other cost categories show an even larger variance. The expenses increased over 2012 by $1,352,000, or 9.9%, and over forecast 2013 by $634,000 or 4.4%. The largest variances from actual 2013 to forecast 2013 were: insurance, which came in at $211,000 more than forecast; travel, which amounted to $182,000 more than forecast; equipment rentals, which amounted to $146,000 more than forecast; and, building rental and maintenance, which came in at $116,000 more than forecast.

Cost Recoveries

Per Finance Schedule III, Page 1 of 2, cost recoveries are forecast to increase from $7.9 million in 2012, to $9.2 million in 2013 forecast. The breakdown of cost recoveries by division is as follows:

Table 54: Cost recoveries by division

(000)'s	Actuals 2007	Actuals 2008	Actuals 2009	Actuals 2010	Actuals 2011	Actuals 2012	Forecast 2013	Actuals 2013	Variance '13F-'12	Variance '13A-'13F
Executive Leadership & Assoc.	9	2	-	-	-	-	-	-	-	-
Human Resources & Org. Effect.	48	35	57	956	886	1,027	1,135	1,366	108	231
Finance/CFO	1,177	1,233	2,094	2,476	2,858	4,572	4,802	4,807	230	5
Project Execution & Tech Services	-	-	-	19	-	-	-	695	-	695
Regulated Operations	156	545	2,039	883	706	887	652	794	(235)	142
Corporate Relations	-	-	-	414	748	1,388	2,633	1,449	1,245	(1,184)
	1,390	1,815	4,190	4,748	5,198	7,874	9,222	9,111	1,348	(111)

Included in the forecast recoveries for 2013 is an amount of $4.0 million, compared to $3.7 million in 2012, which relates to recoveries from Intercompany Administration Fees. Also included in the forecast recoveries for 2013 is $2.0 million, compared to $1.8 million in 2012, which relates to recoveries from Churchill Falls. The forecast recoveries for 2013 also include an amount of $2.6 million, compared to $1.4 million in 2012, which relates to Conservation and Demand Management (CDM) Program deferrals.

The actual 2013 cost recoveries in the Project Execution & Tech Services division were $695,000 higher than the amount forecast. This variance was primarily due to an external recovery from the Department of Transportation and Works for work completed on Sandy Pond. The actual cost recoveries in the Corporate Relations division were $1,184,000 lower than the amount forecast. This variance was primarily due to delays in customer participation in the Energy Demand Management Program, which resulted in a decrease in actual 2013 energy management costs over forecast 2013, as well as a decrease in actual 2013 CDM cost recoveries over forecast 2013.

Cost Allocations

We reviewed Hydro's methodology relating to the procedures the Company has in place to allocate costs between regulated and non-regulated operations. We also reviewed how costs are allocated between shared services.

All non-regulated operations are reported to the Corporate Controller and the Treasurer who ensure that business units, and if applicable, work orders, are set up to track costs. Intercompany salary and benefits charged to and from Nalcor Energy and its subsidiaries are captured in the JD Edwards integrated suite of applications and a Lotus Notes Time Reporting application. These costs are recharged through the cost account '6014 – intercompany salaries' in the appropriate business units.

The Application did not include forecast amounts for non-regulated expenses. Forecasts were only provided for regulated expenses.

The following is a summary of non-regulated activities/costs /business units of the Company as filed in Exhibit 7 of the Application:

Subsidiaries

- Churchill Falls (Labrador) Corporation– BU#1958: Services from Hydro to CF (L) Co are rendered according to a services agreement dated January 1, 2010. According to the services agreement, all costs are charged according to Hydro's bill rates, fixed charge rate and an allocation of its intercompany administration fee. This is consistent with Nalcor's intercompany transaction costing methodology as filed in Exhibit 8 of the Application. In addition, prior to December 15 each calendar year, Hydro will provide a list of services to be provided, as well as an estimate of costs to be recovered through monthly billing. Billings are adjusted after actual costs for the year have been determined to the satisfaction of both parties.

- Lower Churchill Development Corporation Limited –BU#1953: This corporation is mainly inactive.

Business units in Hydro

- Export Sales – BU# 1950: Hydro purchases recall power and energy through an agreement with Churchill Falls. Surplus power is sold by Hydro to external markets. Systems Operations allocates the power purchase costs. All revenue and expenses are captured in Business Unit (BU) 1950 and excluded from regulated income.

- Supply of Power to the Iron Ore Company of Canada – BU# 1952: The portion of costs associated with IOCC is derived from the Cost-of-Service on the Labrador Interconnected system. Rates charged are based on a negotiated contract which is not approved by the Board. All revenues and expenses are captured in BU 1952 and excluded from regulated income. Any employee providing services to this activity will charge their time in accordance with Nalcor's intercompany transaction costing methodology as discussed above.

- Natuashish – BU# 1405: This business unit was established to track costs associated with the community of Natuashish on behalf of the federal government, on a cost recovery basis. All costs are charged at bill rates plus overheads to ensure full cost recovery. Any employee providing services to this activity will charge their time in accordance with Nalcor's intercompany transaction costing methodology.

- Star Lake – BU# 1970: Hydro operates this plant on behalf of Nalcor who is acting as agent of the Province. All revenues and expenses associated with this activity are captured in BU 1970 and excluded from regulated expenses. Any employee providing services to this activity will charge their time in accordance with Nalcor's intercompany transaction costing methodology.

- Exploits - BU # 2125, # 2127 and # 2129: Hydro is operating the Exploits generating facilities on behalf of Nalcor who is acting as an agent for the Province. All revenues and expenses associated with this activity are captured in BU # 2125, # 2127 and #2129 and are excluded from the determination of regulated income. Any employee providing services to this activity will charge their time in accordance with Nalcor's intercompany transaction costing methodology.

- Ramea Project – BU# 1406: In accordance with P.U. 31 (2007) no costs associated with the project at Ramea will be borne by ratepayers. All revenues and expenses associated with this activity are captured in BU# 1406 and excluded from regulated income. Any employee providing services to this activity will charge their time in accordance with Nalcor's intercompany transaction costing methodology.

- Conservation Demand Management – BU# 1949: In accordance with P.U. 7 (2008) Hydro will undertake energy conservation initiatives. All revenues and expenses associated with this activity are captured in BU# 1949 and excluded from regulated income. Any employee providing services to this activity will charge their time in accordance with Nalcor's intercompany transaction costing methodology.

- Cost Recovery Business Units: Hydro maintains a number of cost recovery business units to capture costs incurred by Hydro personnel on behalf of other lines of business, e.g. Lower Churchill Project, Oil and Gas, Bull Arm and Nalcor Energy. All costs associated with these activities are billed monthly to the lines of business and excluded from regulated income. Any employee providing services to this activity will charge their time in accordance with Nalcor's intercompany transaction costing methodology. The cost recovery units are as follows:

    a. Lower Churchill Project cost recovery – BU# 1961: Prior to 2008, capital job cost #10250 was set up to capture all costs associated with the current Labrador Hydro Project including an allocation of corporate overhead, salary charges and supplier costs. With the corporate restructuring in 2008, the Lower Churchill project construction work in progress assets were transferred to Nalcor.

    b. Oil and Gas cost recovery – BU#1962: This business unit was established to capture costs related to Nalcor's Oil and Gas division which holds and manages oil and gas interests in the Newfoundland and Labrador offshore.

    c. Bull Arm cost recovery – BU#1963: This business unit was established to capture costs related to Nalcor's Bull Arm site.

d. Nalcor Energy cost recovery – BU#1964: This business unit was established to capture costs related to Hydro costs charged to Nalcor Energy.

- Other Specific Non-Regulated Costs – BU#1955: This business unit has been established to capture various non-regulated costs, including:
  - Contributions and donations.
  - Advertising for corporate image building.
  - Companion travel costs.
  - Bad debt expenses incurred for specific reasons that are designated non-recoverable are excluded from the determination of regulated income.

Determination of Billing Rates

Bill rates for Hydro and its related companies are determined on a cost recovery basis designed to cover salary, benefits and vacation. There is no profit margin element to the billing rate. However, charges for external billings do incorporate a profit margin.

According to Hydro, the time sheet policy / guidelines are as follows:

> All Nalcor employees (except CF (L) Co employees) are to prepare weekly time sheets and code all paid hours (i.e. 37.5 or 40 per week) to a work order or to leave. Mandatory and prompt time sheet reporting for all Hydro Place employees was implemented effective Monday, April 19, 2010 (March 2011 outside Hydro Place). Previously, many employees had been required to record exceptional time only (leaves, overtime and charge-out hours). On a go forward basis all employees are required to record all time to a work order or as leave. Employees are responsible to record the 37.5 or 40 hour work week, plus any additional overtime and/or premiums. Time sheets are to be completed and submitted no later than the following week.

The billing rates were developed to include a base wage amount (hourly wage), a variable component and a fixed charge. The Company's billing rate is derived from a base wage amount and a variable component. The fixed charge is a separate charge based on each hour billed.

<u>Variable component</u>
The Company uses a proxy amount of 57% as the basis to determine bill rates which is calculated as follows: total salary costs and benefits (as described below) are divided by total billable hours. Billable hours are available hours less annual leave, training, sick leave statutory holidays or other time associated with paid leave. The ratio of the bill rate to the hourly rate is applied to the various pay grades to determine the charge out rates of employees. From 2007 to 2009 the rates were determined using total hours. Beginning in 2010, rates were determined using billable hours. In addition, starting in 2011, the rates were determined in aggregate for the Nalcor group of companies excluding CF (L) Co. According to Hydro, there is no change currently anticipated in the variable component of 57% for 2013 and beyond. They will continue to review their labor costs to ensure the billing rate is appropriately reflective of actual costs incurred.

The following costs were included in the analysis to determine the variable component:

Benefits

- Fringe benefit costs, e.g. CPP, EI, Public Service Pension Plan, Group Money Purchase Plan, Prior Service Matched PSPP, WHSCC.
- Insurances, e.g. Life, A D&D, Medical, Dental.
- Company costs, e.g. EE future benefits, payroll taxes, bonus, performance contracts, signing bonus.

Leaves

- Annual leave, medical travel and appointments, sick leave, training hours, floaters, family leave, compassion leave, jury duty, statutory holiday, union leave, banked overtime.

<u>Fixed Charge</u>

Effective October 1, 2009 the Company included a fixed charge for time charged to entities. The fixed charge was determined to be $80 per day for all Nalcor employees, or $10.67 per hour based on a 7.5 hour day for 2009-2011. In 2012 and 2013 forecast the fixed charge was determined to be $98 per day or $13.10 per hour based on a 7.5 hour day. The fixed charge component included the following costs in its analysis:

- *Hydro Place costs* e.g. Heat & Light, insurance, maintenance, reception, depreciation and interest.
- *Common Services* e.g. IT services such as software, servers & help desk, HR services such as payroll, recruitment, health, safety.
- *Employee related costs* e.g. Telephone & Fax, books & subscriptions, training, membership and dues, conferences, training.

According to Hydro, the fixed charge recovery is booked to account for the additional cost of having an employee available for service beyond salary and benefits. The fixed charge recovers costs originally charged in the administration fee allocation as well as other employee related costs described above. The fixed charge for Hydro is recorded in business unit # 2003 NLH Controller Dept under Account # 7141 'intercompany fixed charge' and is grouped under cost recoveries. The fixed charges netted to a credit of $233,615 in 2012 and a debit of $4,640 for 2013 forecast.

Common Service Costs Allocation

Certain departments based in Hydro provide common services to various lines of business of Nalcor. Hydro recovers costs incurred related to these common services through an administration fee.

The following table provides a summary of the intercompany administration fee and cost recoveries charged in Hydro to Nalcor various lines of business and CF (L) Co for the 2013 test year with comparative data for 2010, 2011, 2012 and 2013:

Table 55: Summary of intercompany administration fee and cost recoveries

Cost Recoveries	2013	2013F	2012	2011	2010	2013F-2012	2013-2013F
Intercompany Administration Fee							
Regulated recovery	**$ (3,999,398)**	**$ (3,964,826)**	$ (3,680,313)	$ (1,968,439)	$ (1,537,108)	$ (284,513)	$ (34,572)
Non-regulated expense (Note 1)	**-**	**-**	25,152	11,593	7,669	(25,152)	-
	$ (3,999,398)	**$ (3,964,826)**	$ (3,655,161)	$ (1,956,846)	$ (1,529,439)	$ (309,665)	$ (34,572)
Cost recovery							
CF (L) Co. (Note 2)	**$ (1,594,278)**	**$ (2,044,163)**	$ (1,756,218)	$ (1,475,491)	$ (1,550,963)	$ (287,945)	$ 449,885

Note 1: Non-regulated expense relates to Energy Marketing. Non-regulated expenses were not provided for the forecast year.

Note 2: The total 2010 cost recovery from CF (L) Co. also includes other cost recoveries of $110,228 in addition to the administration common cost allocation of $1,440,735.

Intercompany administration fees for regulated recovery and CF (L) Co. cost recoveries 2013 forecast have increased by $284,513 and $287,945 respectively compared to 2012. A further breakdown of these costs (a total variance of $572,458) by department is provided in the table below. The primary reason for the increase in administration fee in 2012 over 2011 of $1,711,874 relates to an increase of $1,041,086 in office space at Hydro Place due to a higher floor space allocation to the other lines of business which increased from 29,298 square feet in 2011 to 66,393 square feet in 2012 [total square footage of Hydro Place is 152,501]. In 2012 the rental rate for Hydro Place increased to $27.40 per square footage compared to $26.56 in 2011. Also contributing to the higher administration fee in 2012 was an increase in information systems of $560,437 which is mainly due to the per user rate increasing from $3,716 per user in 2011 to $4,911 per user in 2012.

The labour costs relating to the staff working in the common service business units are not charged to the other entities/lines of business since these costs are included in the administration fee calculation.

The following table provides a breakdown of the forecast 2013 common costs allocated to each line of business, along with comparative data for 2010, 2011, 2012 and 2013:

Table 56: Common cost allocation

Common cost allocation	2013	2013F	2012	2011	2010	2013F-2012	2013-2013F
Nalcor divisions (Note 1)	**$ 3,999,398**	**$ 3,964,826**	$ 3,680,313	$ 1,968,439	$ 1,537,108	$ 284,513	$ 34,572
CF (L) Co.	**1,594,278**	**2,044,163**	1,756,218	1,475,491	1,440,735	287,945	(449,885)
Hydro Regulated	**8,162,624**	**9,373,011**	8,763,626	8,214,370	6,907,456	609,385	(1,210,387)
Total common costs allocated	**$ 13,756,300**	**$ 15,382,000**	$ 14,200,157	$ 11,658,300	$ 9,885,299	$ 1,181,843	$ (1,625,700)

Note 1: Nalcor divisions include Oil and Gas, BullArm, Exploits, Menihek, Lower Churchill Project and Energy Marketing (non-regulated). Disaggregated cost allocations for the Nalcor divisions was not provided for the 2013 forecast year.

The following table provides a breakdown of costs by department for the 2013 forecast year, along with comparative data for 2010, 2011, 2012, and 2013:

Table 57: Breakdown of costs by department

Department / Costs (000's)	2013	2013F	2012	2011	2010	2013F-2012	2013-2013F
Total							
Human Resources	$ 1,796	$ 1,695	$ 1,688	$ 1,469	$ 1,471	$ 7	$ 101
Safety and Health	993	1,002	924	901	824	78	(9)
Information Systems	6,565	7,633	6,991	4,964	4,818	642	(1,068)
Office space and related costs	3,980	4,617	4,178	3,903	2,353	439	(637)
Telephone and LAN costs and other	422	435	419	421	419	16	(13)
	$ 13,756	**$ 15,382**	**$ 14,200**	**$ 11,658**	**$ 9,885**	**$ 1,182**	**$ (1,626)**
Hydro Regulated	**2013**	**2013F**	**2012**	**2011**	**2010**	**2013F-2012**	**2013-2013F**
Human Resources	$ 1,098	$ 1,028	$ 1,051	$ 942	$ 969	$ (23)	$ 70
Safety and Health	607	608	575	578	544	33	(1)
Information Systems	3,751	4,823	4,482	3,242	3,182	341	(1,072)
Office space and related costs	2,410	2,607	2,359	3,125	1,880	248	(197)
Telephone and LAN costs and other	297	307	296	327	332	11	(10)
	$ 8,163	**$ 9,373**	**$ 8,763**	**$ 8,214**	**$ 6,907**	**$ 610**	**$ (1,210)**
Other Lines of Business (Note 1)	**2013**	**2013F**	**2012**	**2011**	**2010**	**2013F-2012**	**2013-2013F**
Human Resources	$ 698	$ 667	$ 637	$ 527	$ 502	$ 30	$ 31
Safety and Health	386	394	349	323	280	45	(8)
Information Systems	2,814	2,810	2,509	1,722	1,636	301	4
Office space and related costs	1,570	2,010	1,819	778	473	191	(440)
Telephone and LAN costs and other	125	128	123	94	87	5	(3)
	$ 5,593	**$ 6,009**	**$ 5,437**	**$ 3,444**	**$ 2,978**	**$ 572**	**$ (416)**

Note 1: Other lines of business include Nalcor divisions and CF (L) Co.

As Hydro describes in PUB-NLH-169, PUB-NLH-192 and NLH-PUB-200, information systems costs in 2012 and 2013 forecast are overstated by $706k and $550k resulting in an overstatement of administration fee recoveries of $253k and $284k, respectively. Office space and related costs in 2012 and 2013 forecast are overstated by $205k and $188k resulting in an overstatement of administration recoveries of $89k and $82k, respectively. Therefore, the total overstatement of administration fee recoveries in 2012 and 2013 forecast is $324k and $284k, respectively. The overstatement of cost recoveries in the 2013 forecast results in a reduction in the revenue requirement of $284k and is a benefit to the ratepayer.

According to Hydro, the department/cost included in the determination of the administrative fee charged, along with the allocation basis, is summarized in the following table:

Table 58: Allocation basis of administration fee

Department/ Costs	Allocation Basis
Human Resources	FTE
Safety and Health	FTE
Information Systems	Average Users
Office space and related costs	Square footage
Telephone and LAN costs	Average Users

We address each of the departments/costs allocations in turn.

Human Resources

The Human Resources department is responsible for the administration and coordination of all employee related services. Operating costs incurred in providing Human Resources services are allocated to the lines of business based on a per full time equivalent ("FTE") basis. The 2013 forecast cost per FTE allocated to lines of business for Human Resources was $1,197 per FTE (2012 - $1,291).

Safety and Health

The Safety and Health department is responsible for occupational health services including coordinating corporate efforts with regard to employee safety, wellness, disability and sick leave management, and medical screening. Operating costs incurred in providing Safety and Health services are allocated to the lines of business on a per FTE basis. The 2013 forecast cost per FTE allocated to lines of business for Human Resources was $708 per FTE (2012 - $707).

Information Systems

The Information Systems ("IS") department is responsible for providing assistance and support in the areas of Software Applications, Planning and Integration and Business Solutions, maintenance and administration of the corporate wide computer infrastructure and network and provides technical support. Operating costs incurred in providing IS services are allocated to the lines of business on an average user basis. Depreciation expense and a return on rate base at the weighted average cost of capital ("WACC") for costs capitalized such as servers and software are allocated to each line of business on an average user basis. Costs specific to a particular line of business are charged to that line of business and are excluded from the determination of shared costs. The 2013 forecast cost per user allocated to lines of business for IS was $5,445 per user (2012 - $4,911).

Office Space

Each line of business occupying floor space at Hydro Place is charged a rental charge. The square footage rental rate reflects the average annual capital and operating cost for Hydro Place as determined by the following formula:

Rental Rate = Hydro Place operating costs + return on rate base + annual depreciation / (divided by) Hydro Place total square footage.

According to Hydro, the cost based rate includes the following expenses for Hydro Place:

- Annual depreciation for all common assets.
- System Equipment Maintenance and operating projects.
- Expenses relating to salaries, fringe benefits, group insurance and employee future benefits for Office Services, Building Maintenance and Transportation.
- Heat & Light.
- Office Supplies.
- Postage.
- Safety Supplies.
- Consulting expenses related to Hydro Place.
- Security Card Maintenance Contract.
- Return on Rate base at WACC for all common assets.

The 2013 forecast cost per square footage rental rate is $30.27 (2012 - $27.40).

Telephone Infrastructure (PBX) Costs

All lines of business are charged a share of Telephone Infrastructure (PBX) costs including long distance charges. The Local Area Network (LAN) costs provided by Network Services are divided by the total number of LAN ports to derive a cost per user. The telephone costs provided by Network Services are divided by the number of telephone, fax, and modem lines to derive a cost per telephone per user. The average number of users is the factor used for the allocated costs per line of business. For the 2013 forecast the cost per user allocated to lines of business for telephone and LAN costs was $497 (2012 - $496) per user.

The 2012 allocations for Human Resource, Safety and Health, and Information Systems are based on actual costs and would therefore be 'trued up' at year end. However, the PBX and LAN allocations are based on budget costs and there is no 'true up' adjustment on these allocations to reflect actual costs. The office space rental charge would be based on a cost recovery rate set for the year.

Based on our understanding of the methodology used by Hydro, we conclude that cost allocations are in accordance with Intercompany Transaction Costing Guidelines as filed in Exhibit 8 of the Application.

Rate Stabilization Plan

Summary of Hydro Proposals included in the 2013 General Rate Application

In the 2013 GRA, Hydro proposed the following changes to the RSP:

- 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;

- that changes be approved to the Rate Stabilization Plan so as to allocate the load variations among the customer groups based on energy ratios. 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;

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

- that changes be approved to the Rate Stabilization Plan so as to remove Section E - Historical Plan Balance.

In addition to the GRA, Hydro also filed a separate RSP application on July 31, 2013. The RSP application will address the Industrial Customers' rate phase-in as well as related rule changes to the RSP.

The Board has contracted a Cost of Service consultant to specifically review and provide a report on the changes proposed to the RSP in the GRA. Therefore, this report will not specifically comment on the changes proposed, instead it will address the RSP balance included in the GRA and the activity included in the 2013 test year, as well as the actual activity that occurred within the RSP during 2013.

History of the Rate Stabilization Plan

The Rate Stabilization Plan ("RSP") or ("the Plan") was established for Newfoundland and Labrador Hydro ("Hydro") effective January 1, 1986. The original objective of the RSP was to provide rate stability to customers by providing a mechanism to manage volatility in Hydro's revenue requirements due to events beyond their immediate control. When the RSP was implemented it provided for adjustments to recover differences between the forecast test year costs used to set rates and the actual costs attributable to:

1. differences in the price of No.6 Fuel;
2. variations in hydraulic production; and
3. variations in load.

Since the original inception, the RSP has been modified on several occasions. For a complete historical review of the RSP refer to our report in Appendix A "Board of Commissioners of Public Utilities – Historical Review of the Rate Stabilization Plan of Newfoundland and Labrador Hydro - January 1, 1986 to December 31, 2009 (updated to December 31, 2012)".

Rate Stabilization Plan – 2013 Test Year

Included in the Finance section of Hydro's GRA filing, Schedule 1 (page 7 of 11), the RSP balance at the end of December 2013 is forecast to be a balance owing to ratepayers of $168,361,000. The breakdown of the components included in the Plan as indicated in Schedule 1 (page 7 of 11) are as follows:

Component	($000s)
Hydraulic balance	$ 24,507
Utility balance	33,086
Industrial balance	679
Utility Surplus	87,340
Industrial Surplus	22,749
Total balance owing	$ 168,361

The preparation of the Plan included in the GRA would be based on various inputs in the Plan being rebased at test year values. Therefore activity within the RSP for the test year would be minimal as there would be no variations; the test year and "actual" would be the same. The rebased inputs of the plan for the 2013 test year are as follows:

- the hydraulic production is forecast to be 4,533.5 GWh
- the Holyrood No. 6 fuel conversion factor is forecast to be 612 kWh/bbl
- Average No. 6 fuel purchase price per barrel is forecast to be $108.11/bbl
- Firm energy sales to Newfoundland Power is forecast to be 5,594,300,000 kWh
- Firm energy sales to the Industrial Customers is forecast to be 408,400,000 kWh
- The interest rate used within the Plan is based on the forecast WACC of 7.83%
- The RSP rate used to determine the payment (refund) to the customer does not include a fuel rider for 2013 from January 1, 2013 to June 30, 2013. However, commencing July 1, 2013, there is a fuel rider based on a more recent fuel forecast dated April 19, 2013.

The RSP for the 2013 test year filed with the GRA also includes the impacts resulting from Order in Council, OC2013-089 dated April 4, 2013. In this Order, Hydro was directed to incorporate the following:

- Industrial customer rates would no longer be frozen effective July 1, 2013;
- Effective July 1, 2013, increases for industrial customers will be phased in over a three year period with the funding of this phase-in to be drawn from the load variation that had accumulated from January 1, 2007 to June 30, 2013;
- The load variation balance that had accumulated from January 1, 2007 to June 30, 2013 was ordered to be segregated out to another component of the Plan to be known as the "RSP surplus". This amount was later estimated to be approximately $141 million;

- The Industrial customer's portion of the RSP surplus was estimated to be $56.5 million;

- The Newfoundland Power portion of the RSP surplus was estimated to be $84 million ($141 million - $56.5 million). This surplus is to be refunded to ratepayers as direct payments or rebates. It shall not be in the form of an electricity rate adjustment. The Board of Commissioners of Public Utilities shall make the final determination on the details of the refund to the ratepayers;

- Effective July 1, 2013, all island industrial customers, with the exception of Teck Resources, will be subject to the same standard industrial rate, which would be the existing energy base rate, excluding the RSP adjustment rate currently in place; and

- Teck Resources rate increase will be phased-in, to a reasonable degree, in three equal annual percentage increase, and at the end of this period, the company will be subject to the standard industrial rate.

Review of the RSP Components

In our review of the balances of the various components of the 2013 Test Year RSP, the rebasing of the components and the specifics of the OC2013-089 noted above were taken into consideration.

Hydraulic Balance

As indicated in the RSP rules, each year the following occurs:

- 25% of the balance in the Plan at the end of the year as a result of the variation between the cost of service (test year) hydraulic production and the actual hydraulic production and 100% of the finance charges within the Hydraulic component throughout the year is allocated to the customers;

- 75% of the plan remains as the Hydraulic Balance.

As indicated previously, in the test year forecast there will be no hydraulic production variations as the "actual" and the test year will be the same. Therefore, the only activity happening throughout the 2013 test year in this component of the Plan are the finance charges.

		(000s)
Opening balance, January 1, 2013	$	32,676
Finance charges @ 7.83%		2,558
		35,234
Less: Allocation to customers		
-25% of balance before finance charges		(8,169)
-100% of finance charges		(2,558)
		(10,727)
Closing balance, December 31, 2013	$	24,507

- The amount noted above to be allocated to customers is allocated to the utility, industrial customers and rural customers based on the 12 month forecast kWh hours sold.
- The rural balance is then reallocated to the utility customer and the Labrador Interconnected using the following percentages – 88.73% to the utility and 11.27% to Labrador Interconnected. These percentages are determined in the 2013 test year cost of service study. It is the same portion that the Rural Deficit is allocated in the cost of service study.
- The portion reallocated to the Labrador Interconnected is written off to income by Hydro.

Utility Balance

The changes that would impact the Utility Balance in a test year forecast would be:

- the finance charges;
- the adjustments relating to the RSP rate that are in effect during the 2013 test year; and
- the utility's portion of the hydraulic allocation noted above.

However, as a result of OC2013-089 dated April 4, 2013, the Utility's portion of the load variation (retroactive to January 1, 2007) is also segregated from the Utility balance as of June 30, 2013 and moved to the RSP Surplus component.

		(000s)
Opening balance, January 1, 2013	$	64,905
Finance charges		3,787
Adjustment Jan- June		(15,571)
Adjustment July - Dec		(29,671)
Load variation adjustment		(328)
Hydraulic allocation		9,964
Closing balance, December 31, 2013	$	33,086

Based on our review of the balances noted above, we have verified the following:

- The finance charges are calculated using a forecast annual WACC of 7.83%.
- The adjustment for January, 2013 to June, 2013 is calculated based on (5.01) mills/kWh which is the "Current Plan" portion of the RSP Adjustment Rate that was approved by the Board in P.U. 15(2012). It would not include the fuel rider portion of the rate that was approved in this Order as the fuel rider is set to zero in a test year.

- The adjustment for July, 2013 to December, 2013 is calculated using the (11.01) mills/kWh which is the "Current Plan" portion of the RSP Adjustment Rate that was approved by the Board in P.U. 17(2013) and a fuel rider revised from zero to (0.93) mills/kWh. According to Hydro, the fuel rider does come into effect in July of the test year due to the updated fuel price forecast relative to the test year. This fuel rider is based on the April 2013 fuel forecast.
- The load variation adjustment of $328,000 represents the accumulated utility load variation from January 1, 2007 to June 30, 2013 (the utility's portion of the total estimated load variation of $141 million during this period) and segregated to an RSP Surplus Component. The amount of this adjustment has not been verified in our review of the 2013 GRA.
- The Hydraulic allocation is based on the test year kWh sales to Newfoundland Power and 88.73% of the amount allocated to the Rural customers.

Industrial Balance

The changes that would impact the Industrial Balance in a test year would be:

- the finance charges;
- the adjustments relating to the RSP rate that are in effect during the 2013 test year; and
- the Industrial Customer's portion of the hydraulic allocation noted in the Hydraulic Plan.

However, as a result of the Order in Council, OC2013-089 dated April 4, 2013, the Industrial Customer's portion of the load variation (retroactive to January 1, 2007) is also segregated from the Industrial Customer's balance as of June 30, 2013 and moved to the RSP Surplus component.

The total accumulated load variation balance from January 1, 2007 to June 30, 2013 was estimated to be $141,000,000. In the 2013 test year RSP, Hydro has indicated that the portion of this accumulated balance attributed to the Industrial Customers was $140,281,000. This portion is segregated from the Industrial Balance and allocated to the RSP Surplus component.

		(000s)
Opening balance, January 1, 2013	$	104,080
Finance charges		3,967
Adjustment Jan- June		(1,977)
Load variation adjustment		(140,281)
Balance due to Hydro, June 30, 2013		(34,211)
Allocated to Industrial Surplus Component		34,211
Adjusted balance, June 30, 2013		0
Hydraulic allocation		679
Closing balance, December 31, 2013	$	679

Based on our review of the balances noted above, we have verified the following:

- The finance charges are calculated using a forecast annual WACC of 7.83%
- The adjustment for January, 2013 to June, 2013 is calculated using the RSP adjustment rate refund of 0.785 cents per kWh that was set January 1, 2008 and has continued to be an interim rate up to June 30, 2013 in the GRA. This rate does not include Teck Resources or Vale; the RSP adjustment rate for

these customers is a refund of 2.00 cents per kWh, according to P.U.3 (2007) and P.U.6 (2012) respectively. In P.U.3 (2007), Teck Resources was known as Aur Resources Inc.

- The load variation adjustment of $140,281,000 represents the accumulated Industrial Customer load variation from January 1, 2007 to June 30, 2013 (the Industrial Customer's portion of the total estimated load variation of $141 million during this period) and segregated to an RSP Surplus Component. The amount of this adjustment has not been verified in our review of the 2013 GRA.
- The Hydraulic allocation is based on the test year kWh sales to Industrial Customers.

RSP Surplus Component

As noted above, Order in Council, OC2013-089 dated April 4, 2013, ordered that the accumulated load variation from January 1, 2007 to June 30, 2013 be segregated from the customer balances to an RSP Surplus component. This balance was estimated to be $141 million. As noted in the review of the activity during the test year for the customer plans, there was a portion removed from each plan as of June 30, 2013. OC2013-089 also ordered that of this total balance, $56,500,000 was to be moved to the Industrial Surplus component and the remainder, which is $84,109,000, was to be moved to the Utility Surplus component.

		(000's)
Amount segregated from:		
Industrial Customer balance	$	140,281
Utility Balance		328
Total RSP Surplus balance	$	140,609
Allocated to Industrial Surplus component		(56,500)
Allocated to Utility Surplus component		(84,109)
Closing balance		0

Utility Surplus

According to the information noted above, $84,109,000 of the RSP surplus was moved over to the Utility Surplus at the end of June, 2013. According to the 2013 test year RSP included in the GRA, this balance accumulates interest each month based on the forecast annual WACC of 7.83% included in the GRA. This balance represents an amount owing to the utility.

		(000's)
Allocation of RSP Surplus	$	84,109
Finance Charges (July-Dec, 2013)		3,230
Balance, December 31, 2013	$	87,339

The treatment of the balance accumulated in this component of the RSP will be addressed in a separate application to the Board.

Industrial Surplus

According to the information noted above, $56,500,000 of the RSP surplus was moved over to the Industrial Surplus at the end of June, 2013. As indicated in the Industrial Balance described earlier, the balance remaining in the Industrial Balance after the segregation of the load variation ($34,211,000) is to be eliminated using the $56,500,000 allocated from the RSP Surplus. The remaining balance of $22,289,000 is to be used to phase in the industrial customer rates over a three year period. The balance of this component also accumulates finance charges on a monthly basis using the forecast annual WACC of 7.83% included in the GRA.

		(000's)
Allocation of RSP Surplus	$	56,500
Elimination of Industrial Balance		(34,211)
Balance as of June 30, 2013		22,289
Finance Charges (July-Dec, 2013)		850
Teck Allocation		(390)
Balance, December 31, 2013	$	22,749

Order in Council - OC2013-207 dated July 16, 2013

As indicated in the GRA application, OC2013-089 dated April 4, 2013, was subsequently amended on July 16, 2013 and issued as OC2013-207. This Order in Council indicated the following amendments to OC2013-089:

- Industrial Customer rates were no longer frozen effective July 1, 2013, this date was extended to September 1, 2013;

- Commencement of the three year "phase in rates" for industrial customers was ordered to commence September 1, 2013 instead of July 1, 2013;

- The load variation adjustment that is to be segregated to the RSP Surplus component was extended from "January 1, 2007 to June 30, 2013" to "January 1, 2007 to August 31, 2013". As a result of this extension the accumulated amount increased from an estimate of $141 million to an estimate of $160 million; and

- The Industrial Customer's portion of the RSP Surplus changed from $56.5 million to $49 million and as a result of this change, Newfoundland Power's portion of the RSP Surplus changed from $84.1 million to $111 million ($160 million less $49 million to Industrial Customers).

As indicated in a footnote on Page 3.28 (Section 3: Finance) of Hydro's GRA, the RSP included in the GRA is based on the Order in Council, OC2013-089 dated April 4, 2013 and it was not updated based on the amendments included in OC2013-107 dated July 16, 2013. The footnote is as follows:

> ***"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."***

According to Hydro, the amendments noted above have been reflected in the separate RSP application that was filed by the Company on July 30, 2013. The RSP application is requesting approval, among other things, of changes to the Island Industrial customer rates and to the Rate Stabilization Plan rules. As noted previously, the details of this separate application will not be discussed in this report.

With regards to the GRA, the RSP balance will not have any impact on the base rates requested in the GRA. The RSP balance does not impact the proposed base rates required to earn the revenue requirement proposed in the GRA, and it is not a component of the Company's rate base. Also RSP interest is excluded from the calculation of embedded cost of debt. Therefore, the fact that the RSP has not been updated to reflect the amendments in OC2013-207, has no material impacts to the GRA application.

RSP Balances as of December 31, 2013

On March 14, 2014, Hydro filed an update of its actual financial results for 2013, as requested by the Board. This information also included the actual results of the RSP as of December 31, 2013. The RSP balance as of December 31, 2013 has a balance of $253,797,000 owing to ratepayers. The breakdown of the components included in the Plan as indicated in Schedule 1 (page 7 of 11) of this filing are as follows:

Component	($000s)
Hydraulic balance	$ (39,801)
Utility balance	(80,174)
Industrial balance	566
Segregated load variation	(8,200)
Utility Surplus	(115,330)
Industrial Surplus	(10,858)
Total balance owing to ratepayers	$ (253,797)

The balance in the RSP noted above is significantly higher ($85.5 million) than the RSP balance of $168,361,000 included in the GRA for the 2013 test year. The increase in the Plan is a result of a number of factors:

- The RSP included in the GRA is based on revised values for the various inputs included in the RSP. For example, the customer kWh load, price per barrel of No. 6 fuel, hydrology, and the Holyrood efficiency factor have all been updated to reflect the conditions forecast for the 2013 test year and the most recent cost of service study whereas, the December 31, 2013 actual is based on the 2007 test year values that were set in a previous GRA;

- Activity within the RSP for the test year would be minimal as there would be no variations; the test year and "actual" would be the same. However, since the proposed inputs for the 2013 test year were not approved by the Board during 2013, the actual RSP balance includes the variations from the 2007 test year data and the actual activity that occurred in 2013; and

- As noted previously in the this report, the RSP included in the GRA includes the directives that were issued in the Order in Council, OC2013-089 dated April 4, 2013, whereas the December 31, 2013 RSP includes the directives included in OC2013-089 dated July 16, 2013, which was issued as an amendment to OC2013-089, as well as P.U. 26(2013) and P.U. 29 (2013).

Highlights of the RSP for 2013 include:

- Favourable hydraulic conditions contributed to higher hydraulic production relative to the cost of service production resulting in fuel savings of $20.4 million. Actual net hydraulic production in 2013 was 4,693.8 GWh in comparison to the cost of service (2007) net hydraulic production of 4,472.1 GWh. The net hydraulic production included in the 2013 test year is 4,533.5 GWh.
- The Holyrood Operating Efficiency factor included in the calculation of the fuel savings in the Hydraulic plan is 630kWh/barrel, which was set in the 2007 cost of service. The actual Holyrood Operating Efficiency factor based on the Holyrood production in 2013 and the number of barrels of oil used was 594 kWh/barrel (957 GWh/1,611,080 barrels). The Holyrood Operating Efficiency factor included in the 2013 test year is 612 kWh/barrel. Schedule V (page 1 of 1) in the Regulated Activities section of the GRA provides the actual operating efficiency factors from 2007 to 2012. During this period it went from a high in 2008 of 625 kWh/barrel to a low in 2010 of 589 kWh/barrel.
- The average No. 6 fuel price in 2013 was approximately $106.63 per barrel in comparison to the cost of service (2007) price of $55.47 per barrel which resulted in a fuel variation of approximately $82.1 million due from customers. The 2013 test year average No. 6 fuel price is $108.74 per barrel.
- The Orders in Council from Government during 2013 as well as P.U. 26(2013) and P.U. 29 (2013) resulted in changes occurring in how the load variation and the Industrial balance were accounted for during the year. The actual activity that occurred within the load variation will be further explained in this section of the report.

The tables below provide a breakdown of the activity in the RSP for 2013 as well as a continuity of the various component balances.

Table 59: 2013 RSP activity

(000)'s	Hydraulic Variation	Fuel Variation	Load Variation	Rural Rate Alteration	Total
Hydraulic balance	$ (20,392)	$ -	$ -	$ -	$ (20,392)
Utility customers		76,994	(475)	(10,174)	66,345
Industrial customers		4,498	(18,569)	-	(14,071)
Segregated load variation			(8,116)		(8,116)
Labrador Interconnected	130				130
Net change 2013	$ (20,262)	$ 81,492	$ (27,160)	$ (10,174)	$ 23,896

Table 60: Continuity of the various RSP component balances

(000)'s	Balance Beginning of Year	Current Variation	Current Interest	Hydraulic Allocation	Refund (Recovery)	Load Allocations	Reallocate Industrial Balance (2)	Balance December 31st 2013
Hydraulic balance	$ (32,676)	$ (20,392)	$ (3,471)	$ 16,738	$ -	$ -	$ -	$ (39,801)
Industrial customers	(104,080)	(14,071)	(5,384)	(917)	2,397	160,750	(38,129)	566
Utility customers	(64,905)	66,345	(5,153)	(15,691)	(61,593)	823		(80,174)
Segregated load variation	-	(8,116)	(84)					(8,200)
Utility Surplus	-		(2,757)			(112,573)		(115,330)
Industrial Surplus	-		(263)		276	(49,000)	38,129	(10,858)
Labrador Interconnected (1)	-	130		(130)				-
Net change	$ (201,661)	$ 23,896	$ (17,112)	$ -	$ (58,920)	$ -	$ -	$ (253,797)

1 The amount is written off to net income.

2 This represents the August 31, 2013 balance of the Industrial balance

<u>P.U. 26 (2013)</u>

On July 30, 2013 Hydro, in compliance with the direction of the Orders in Council, filed an RSP Application requesting approval of, among other things, changes to the Island Industrial customer rates and the RSP rules.

On August 30, 2013, the Board issued P.U. 26 (2013) in response to this Application and to the directives in the Orders in Council OC2013-089 dated April 4, 2013, and OC2013-089 dated July 16, 2013. The Board considered this Order as an Interim Order as the Application process was still ongoing at this time but approvals were required for particular items to take effect as of August 31, 2013. In this Order, the Board directed the following:

- $49 million of the accumulated load variation component from January 1, 2007 to August 31, 2013 be credited to the Island Industrial customer's RSP balance; and

- transfer the remaining balance of the accumulated load variation component to the credit of the Newfoundland Power Inc. (utility) RSP balance.

The Board also ordered that the rates charged to all Island Industrial customers, to be effective for electrical consumption on and after September 1, 2013 were approved on an interim basis. According to "Schedule A" of this Order, the RSP adjustment rate was set a 0.00 cents per kWh.

In Table 60 above, under the column "Load Allocations", the load variation component that had accumulated from January 1, 2007 to August 31, 2013 were removed from each of the respective plans; $160.75 million from the Industrial plan and $0.823 million from the Utility plan. In accordance with the Order in Council and the Board Order, the $49 million was credited to the Industrial balance and the remainder, $112.573 million was credited to the Utility Plan.

The Board also noted in the Order, that other matters raised by the Application would be addressed in a subsequent Order of the Board.

<u>P.U. 29 (2013)</u>

On September 30, 2013, the Board issued P.U. 29 (2013). This Order was also in response to the Company's RSP Application that was filed on July 30, 2013 as noted above. In this Order, the Board notes that in response to request for information, CA-NLH-11, Hydro clarified its position with respect to certain of the issues raised in the Application, confirming that:

> *" i) the January 1, 2008 to August 31, 2008 rates can and should be made final at this time;*
>
> *ii) an Order implementing an RSP rate of (1.111)cents per kWh for Tech Resources Limited is required prior to October 1, 2013 to comply with the direction of Government and permit customer billing for September;*
>
> *iii) the proposed changes to the RSP related to the disposition of the August 31, 2013 accumulated load variation allocated in the Order No. P.U. 26 (2013) are required prior to the implementation of rates after the general rate application;*
>
> *iv) the proposed modifications to the RSP rules in relation to the way in which the load variation is allocated among customers in the RSP can be deferred to the general rate application providing that the load variation is segregated beginning on September 1, 2013; and*
>
> *v) a final Order as to rates for Island Industrial customers approved in Order No. P.U. 26(2013) would be sought by Hydro in due course."*

In the Order, the Board noted that the Orders in Council did not specifically set out the accounting treatment that is to be given to the August 31, 2013 accumulated load variation component. Hydro requested that for ease of administration, the accumulated load variation component for both the Industrial customers and Newfoundland Power be segregated. The Board approved this proposal, and as noted in Table 60, the $49,000,000 and the $112,573,000 were allocated to the Industrial Surplus and the Utility Surplus, respectively on September 1, 2013. The balance of the Industrial Plan on August 31, 2013, after the $160,750,000 of the accumulated load variation from January 1, 2007 to August 31, 2013 was removed from it, was a balance owing to Hydro of $38,129,000. As indicated in Table 60, this balance was allocated to the Industrial Surplus component and offset by the $49,000,000 credit in this component.

The directives from Government ordered that the funding for the three year Island Industrial customer rate phase-in be drawn from the accumulated load variation. In the RSP Application, Hydro applied for changes in the RSP rules to implement the phase-in, however, Hydro indicated in CA-NLH-11 that the proposed changes to the RSP rules are not required until the conclusion of the General Rate Application. In this Order, the Board said that at this time they were not going to approve the proposed changes to the RSP rules in relation to the phase-in of rates and allocation of the RSP surplus for Island Industrial customers, including the Teck Resources Limited. It was agreed that Hydro would accumulate the RSP rate for Teck Resources Limited ((1.111) cents/kWh) and segregate the balance from the components of the Industrial Customers RSP balance to be addressed by a future Order of the Board. In Table 60, the $276,000 of refunds included in the Industrial Surplus component is the accumulated amount that has been segregated relating to Teck Resources.

As indicated in the summary above of CA-NLH-11, Hydro confirms that the proposed modifications to the RSP rules in relation to the allocation of the load variation, such that year to date net load variation for both the Island Industrial customers and Newfoundland Power are allocated among the customer groups based on energy ratios, can be deferred to the General Rate Application. However, in the interim, Hydro asked for approval to segregate the load variations that occur from September 1, 2013 until the Board's decision on the proposed modification of the load variation allocation. In its Order, the Board did postpone consideration of the this proposed change to the RSP rules and ordered that beginning on September 1, 2013 the load variation amounts be segregated in a separate account until its disposition. The proposal relating to the change in the RSP rules with regards to how the load variation will be allocated among customer groups has been addressed by the Board's Cost of Service consultant, in his report.

Table 60 shows a balance in the "Segregated Load Variation" component of the RSP of $8.2 million. This balance is the load variation that has accumulated since September 1, 2013 as well as interest at an annual rate of 7.529% (2007 test year WACC). The breakdown between the customer groups is as follows:

	Utility Portion	Island Industrial Portion	Total
Load variation	$ 791,989	$ (8,908,486)	$ (8,116,497)
Finance charges	(1,202)	(82,796)	(83,998)
	$ 790,787	$ (8,991,282)	$ (8,200,495)

Based on the current allocations above, the Utility customer group has a balance owing to Hydro of $790,787 and the Island Industrial group has a balance owing from Hydro of $8,991,282 as of December 31, 2013. The finance charges noted above for the Utility portion is in a credit balance, as up to November 30, 2013, the Utility portion was also a balance owing from Hydro, however during the month of December 2013, the load variation caused the Utility portion to swing to a balance owing to Hydro.

Also included in this Order, the Board ordered the following:

- Island Industrial customer rates charged for electrical consumption from January 1, 2008 to August 31, 2013, and the Utility rate charged from January 1, 2011 to August 31, 2013 were approved on a final basis.

- The rates to be charged to Island Industrial customers to be effective for electrical consumption on and after September 1, 2013, were approved on an interim basis, as set out in Schedule B of the Order.

- Hydro shall file revised RSP rules reflecting the findings of the Board in this Order to be effective September 1, 2013 on an interim basis.

On October 18, 2013, Hydro filed an Application containing the revised RSP rules as requested in P.U. 29 (2013). In P.U. 32 (2013), the Board approved the revised RSP rules as proposed on an interim basis.

Newfoundland Power RSP Surplus

As noted earlier, the Company was directed in the Orders of Council that during the GRA process, the Company shall file a Rate Stabilization Plan surplus refund plan to ratepayers, excluding Island Industrial customers.

In compliance with the Order in Council, the Company filed an application on October 31, 2013, with a minor amendment filed on November 7, 2013 to address the Newfoundland Power RSP Surplus balance.

As of December 31, 2013, the balance of the Newfoundland Power RSP Surplus plan has accumulated to $115,330,000. This balance is made up of the $112,573,000 of the accumulated load variation from January 1, 2007 to August 31, 2013 ($161,573,000 -$49,000,000 to Industrial Customer plan), and monthly finance charges totalling $2,760,000, using an annual WACC of 7.529% (2007 test year WACC).

The Board issued P.U.9 (2014) on April 9, 2014 in response to this application. In this Order, the Board ordered that:

> ***"The Newfoundland Power Rate Stabilization Plan Surplus shall be refunded to all ratepayers, with the exception of the Island Industrial customers in the form of direct payment or rebate and in a manner to be approved by the Board"***

In its Order the Board also indicated that "all ratepayers, with the exception of the Island Industrial customers", will include Newfoundland Power customers and customers on each of Hydro's systems, including the Rural Island Interconnected, Island Isolated, Labrador Isolated, L'Anse au Loup, and the Labrador Interconnected.

The Order also indicates that Hydro has advised the Board that it is waiting on a ruling from the CRA on the HST treatment of the refund. It is also noted in the Order that the Board expects Hydro, Newfoundland Power and the Consumer Advocate to work jointly to determine a reasonable and appropriate approach in relation to the refund, that is consistent with the direction of Orders in Counsel, and file a consensus proposal with the Board for its consideration.

Key Performance Indicators

Functionally Oriented Financial KPIs

In P.U. 14 (2004), it was ordered that Newfoundland Hydro file with its annual financial report, commencing in 2004 until otherwise directed by the Board, an annual report outlining appropriate historic, current and forecast comparisons of reliability, operating, financial and other key targeted outcomes/measures including the additional KPIs accepted in P.U. 14 (2004), which include the following:

- Corporate operating, maintenance and administrative expense (OM&A) per MWh delivered;
- Generation OM&A per MW installed capacity;
- Generation OM&A per GWh generated;
- Transmission OM&A per transmission circuit km; and
- Distribution OM&A per distribution circuit km.

Hydro has been in compliance with this Board Order and has filed KPI reports with the Board since 2004. However, it has been noted by Hydro in its KPI reports that setting targets for functionally oriented (e.g. generation, transmission) financial KPIs, as identified above, require a Cost of Service (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.

Hydro has identified targets for functionally oriented financial KPIs only when a Test Year COS study has been available. According to the Company, forecast COS studies are a significant undertaking and are not completed as frequently as would be necessary to report meaningful KPI information. In response to inquiring if Hydro could report target functional KPIs on the basis of the most recent completed COS study, the Company explained that target KPIs based on the most recent COS study, are not meaningful KPI information as they would not represent what the Company is actually targeting in a subsequent year. Other KPI targets such as reliability targets are actually set and progress is measured by Hydro. Allocation factors from the Cost of Service Study would vary each year. Load and plant costs in particular, are significant inputs to the COS study and may change quite significantly from year to year.

Due to the significant effort and cost associated with generating a COS study to set targets for functionally oriented financial KPIs, Hydro is requesting the Board's approval to alter or amend P.U. 14 (2004) so that functionally oriented financial KPIs are not required to be provided on a forecast basis. Accordingly, the graphs presented in Section 3.3 of Appendix E in the Application have not been updated to include the functionally oriented financial KPIs for the 2013 Test Tear.

Peer Group Benchmarking

The Board in P.U. 8 (2007) directed Hydro to file a report no later than October 31, 2007, updating the progress of the development of an acceptable peer group for financial KPIs as of September 30, 2007. In the report filed by Hydro, two separate peer groups were identified through the United States Federal Energy Regulatory Association (FERC) – one for the generation KPIs and one for the transmission KPIs. Hydro stated that there was too much variability among the relative generation and transmission statistics of the utilities to arrive at a meaningful single set of peers. According to Hydro, no changes have been made to these acceptable peer groups in the 2012 Annual Report on KPIs, and the Company has not completed a study or report to evaluate any alternatives to its peer groups for its financial KPIs since the initial report that was prepared in accordance with P.U. 8 (2007).

We noted that, included in the Finance Section of the Application, Chart 3.1 on page 3.8, Hydro references Canadian regulated utilities as Hydro's peers. In discussions with Hydro, we asked if the Company would consider the Canadian regulated utilities referred to in this chart as a more appropriate peer benchmarking group than the US based peer group currently reported in its Annual KPI reporting, and whether this group would be an acceptable peer group for the purpose of benchmarking Hydro's financial KPI's. According to Hydro, based on preliminary discussions with the Canadian Electrical Association ("CEA"), the CEA has indicated that the collection of peer group Canadian Utility KPI data and Canadian Financial KPI data is currently unavailable.

Based on information provided by Hydro with regards to the need of having a COS study in order to set meaningful and useful functionally oriented financial KPI's targets, it appears reasonable to amend or alter P.U.14 (2004) to remove this requirement. However, the Board may consider requesting Hydro to determine if there are any other meaningful financial KPI's that are currently not reported to the Board, where the information is available to set targets, and would provide useful information to the Board.

Capital Expenditures

The following table details the actual versus budgeted capital expenditures from 2007 to 2013, and the forecast figures for 2013.

Table 61: Comparison of capital expenditures – actual to budget

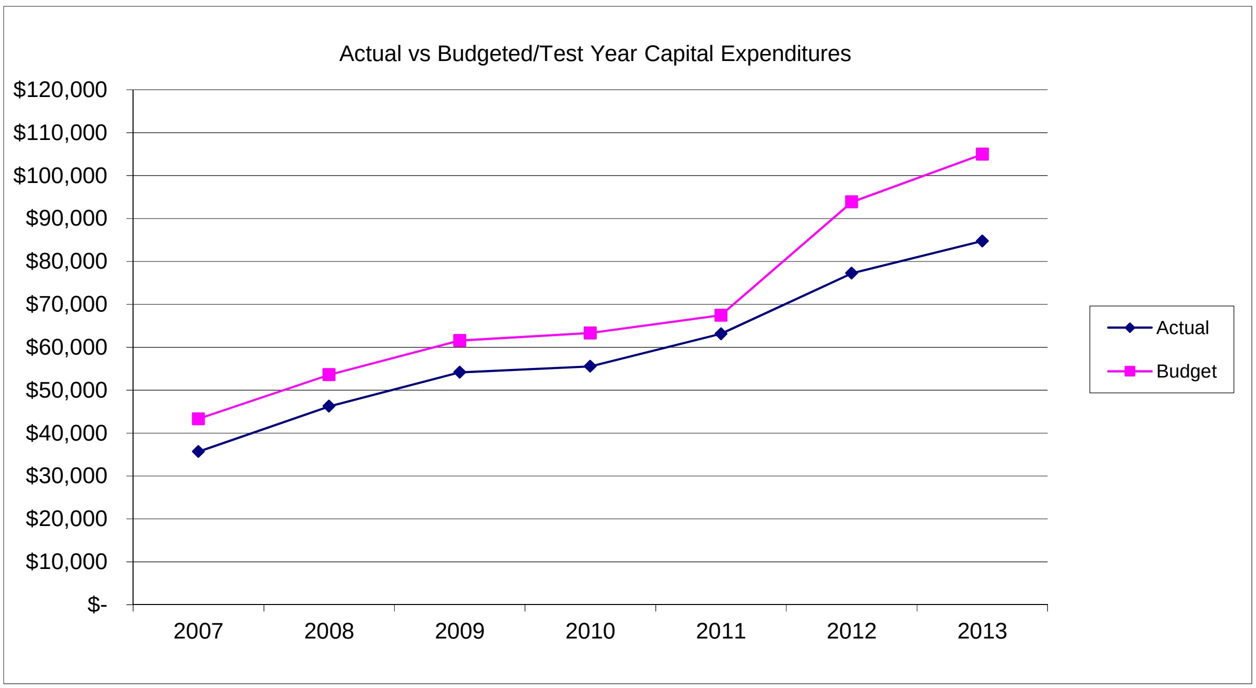
(000's)

	2007	2008	2009	2010	2011	2012	2013	
Actual 2007 - 2013	$ 35,669	$ 46,246	$ 54,152	$ 55,553	$ 63,116	$ 77,252	$ 84,755	1
Budget	$ 43,304	$ 53,579	$ 61,544	$ 63,297	$ 67,454	$ 93,840	$ 104,982	2
Over/Under Budget	-17.63%	-13.69%	-12.01%	-12.23%	-6.43%	-17.68%	-19.27%	

Note 1: This amount represents the gross capital expenditures reported in Hydro's 2013 Annual Return. It does not include insurance proceeds reported in the amount of $4,500,100. This is in accordance with the reporting requirements of Section 41 of the Public Utilities Act.

Note 2: The 2013 "budget" figure is the Company's 2013 Test Year Forecast.

Graph 5: Comparison of capital expenditures – actual to budget



The above graph demonstrates that from 2007 to 2013 the Company has been consistently under budget/forecast on its capital expenditures. According to Capital Budget Application Guideline #1900.6 issued by the Board: "Should the overall variance in any two years exceed 10% of the budgeted total the report should address whether there should be changes to the forecasting or capital budgeting process which should be considered". The Board has had meetings with the Company and has clarified that a 10% variance in either direction should be addressed in discussing the capital budget process.

Based on the information above, the Company's actual expenditures have been under budget every year, ranging from 6.43% under budget in 2011 to 23.17% under test year forecast in 2013.

We have reviewed the significant variances from 2007 to 2012 as part of our annual financial reviews, and our comments on these variances are contained in our annual review reports filed with the Board.

The Company filed a separate Application to the Board on August 8, 2012 with regards to its 2013 capital budget, and requested approval of its 2013 capital budget in the amount of $66,144,800. Subsequent to this application, on December 18, 2012 the Company withdrew four projects from its application, totalling $2,292,600, and on January 7, 2013 withdrew an additional project totalling $1,107,600. These projects all related to the Holyrood Thermal Generating Station. Subsequent to the withdrawals, projects for which the Company requested approval totalled $62,744,600.

On January 9, 2013, the Company made a written submission which divided its capital budget application into two phases, Phase I representing projects considered of a higher priority. The Board considered only those projects in Phase I commencing in 2013, and on January 23, 2013 issued P.U. 2 (2013) approving expenditures totalling $36,405,300, including projects to be completed in 2013 totalling $29,205,500, multi-year projects starting in 2013 with projected expenditures of $6,199,800 for 2013 and further expenditures in subsequent years, and $1,000,000 representing a 2013 Allowance for Unforeseen Events. Any outstanding issues arising from the consideration of the Company's 2013 Capital Budget and not addressed in P.U.2 (2013) were to be dealt with when the Board considered Phase II.

On February 26, 2013, the Board issued P.U.4 (2013). This Board Order approved the Company's 2013 Capital Budget in the amount of $62,272,500, including the amounts approved in Phase I. One project, "Front End Engineering Design" in the amount of $472,100 was not approved. In addition, the project "Install Automated Fuel Monitoring System, Upper Salmon" in the amount of $192,700 was approved, but recovery of costs will only be allowed upon verification of a waiver from current legislative requirements for weekly fuel dipping as proposed by the Company.

Subsequent to the filing of its 2013 Capital Budget Application, the Company requested and the Board approved the following supplementary 2013 capital expenditures in:

(i) Order P.U.1 (2013) in the amount of $284,100 for the refurbishment of the stop logs at the Burnt Dam Spillway;

(ii) Order P.U.12 (2013) in the amount of $5,198,000 for the refurbishment of the marine terminal at the Holyrood Thermal Generating Station;

(iii) Order P.U.15 (2013) in the amount of $3,823,600 for 2013 and $15,310,400 for 2014 to install additional 230 kV transformer capacity at the Oxen Pond Terminal Station;

(iv) Order P.U.20 (2013) in the amount of $8,015,800 for the replacement of the alternator on the Hardwoods Gas Turbine;

Capital expenditures approved by Board Orders up to the time of filing the GRA total $79,594,000. In addition, carryforwards from 2012 and earlier projects totalled $19,500,900, 2013 expenditures from 2012 Board Orders P.U. 25, 26 and 35 totalled an additional $3,736,800, and Hydro approved projects of less than $50,000 totalling $147,500, for a total of approved 2013 capital expenditures to the time of filing the GRA of $102,979,200.

Board Order P.U. 14 (2013) approved the expenditure of $12,809,700 for the refurbishment and repairs to Unit 1 at the Holyrood Thermal Generating Station. However, the Board further ordered that Hydro shall not include the expenditure in the rate base until a further Order of the Board. No expenditures with respect to this project are included in the test year forecast. Accordingly, for the purposes of this report, this project has not been included in "approved 2013 capital expenditures".

The forecast of 2013 capital expenditures included in this Application is $104,982,200 which is 11.9% higher than the 2012 approved capital expenditures, and 1.95% higher than the approved 2013 capital expenditures.

A reconciliation of the forecast 2013 capital expenditures of $104,982,200 included in the 2013 test year to the approved 2013 capital expenditures follows:

(000's)	Approved capital expenditures	Forecast Test Year
PU4 (2013)	$ 62,272.5	$ 62,272.5
PU25(2012)	2,251.6	2,252.1
PU26(2012)	1,295.5	1,295.0
PU35(2012)	189.7	189.5
Carryovers per carryover report	19,500.9	17,790.2
PU1(2013)	284.1	284.1
PU12(2013)	5,198.0	5,198.2
PU15(2013)	3,823.6	3,823.6
PU20(2013)	8,015.8	-
Projects under $50K	147.5	41.9
	$ 102,979.2	93,147.1
Add: 60 MW Gas Turbine - Holyrood		7,323.9
Add: Install 230 kV Transmission line - Bay d'Espoir to Western Avalon		4,532.7
Other adjustments		(21.5)
		$ 104,982.2

It is noted that Hydro has included in its test year forecast the amount of $11,856,600 in capital expenditures for which no application has been filed with the Board. This is made up of the amounts estimated for the 60 MW Gas Turbine - Holyrood, $7,323,900, and the installation of 230kV transmission line – Bay d'Espoir to Western Avalon, $4,532,700.

In CA-NLH-119, the Consumer Advocate asked "Please provide a forecast of expected 2013 capital expenditures using the most recent reported actuals and forecast to the end of the year." Hydro's response included actual expenditures to August 31, 2013. Its expected total expenditures to the end of 2013 totalled $98,547,400, which is 4.3% less than the approved 2013 capital expenditures and 6.1% lower than the test year forecast.

The breakdown provided by Hydro of the expected capital expenditures and approved 2013 capital expenditures with variances by asset category is as follows:

(000's)	Approved	Updated forecast	Variance
Generation	$ 21,331.9	$28,724.8	$ (7,392.9)
Transmission	11,462.1	12,269.1	(807.0)
Rural Systems	25,733.5	24,799.1	934.4
General Properties	7,768.1	7,247.4	520.7
Allowance	1,000.0	1,000.0	-
Projects approved	35,536.1	24,359.5	11,176.6
Projects under 50K	147.5	147.5	-
	$ 102,979.2	$98,547.4	$ 4,431.8

In CA-NLH-121, the Consumer Advocate asked "Please discuss Hydro's expectation to achieve its forecasted 2013 capital expenditure."

Hydro stated the forecast underspending is "…primarily a result of:

a. "Forecast completion of projects at less than the budget amount with the major drivers being:

   i. "Unit 1 Turbine and Generator Restoration – Holyrood project due to the scope being reduced after further inspection and an update of the forecast to include anticipated insurance proceeds;

   ii. "Refurbishment of the Marine Terminal – Holyrood project due to the contract price being lower than the estimate; and

   iii. "Upgrade Gas Turbine Plant Life Extension – Hardwoods project due to removal of alternator inspection in light of a planned alternator replacement;

b. "Carryover of projects to 2014 with a major contributor being the Replace Stator Winding Unit 1 – Bay d'Espoir project due to the late delivery of the spare winding in 2014; and

c. "Adjustments of multi-year projects for the amount being spent in 2013, with the major contributor being the reduction in spending on the Install Additional 230 kV Transformer Capacity project at Oxen Pond."

In its "Financial Results and Forecasts" report, filed on March 14, 2014, the statement of cash flows (Finance Schedule 1, Page 3 of 11), Hydro reports "Additions to property, plant and equipment" as $80,657,000. However, in its Capital Expenditures and Carryover Report December 31, 2013, and also in its 2013 Annual Return (Return 5), Hydro has reported its actual spending on capital projects in 2013 as $80,255,300 ($84,755,400 less insurance proceeds of $4,500,100). The difference amounts to $401,700. We have not reconciled this difference.

Using the figures from the Capital Expenditures and Carryover Report and the 2013 Annual Return, we find the actual 2013 capital expenditures are 23.87% less than the test year forecast of $104,982,000, 21.50% less than the expenditures approved at the time of filing the GRA of $102,979,200, and 16.27% less than its expected total expenditures of $98,547,400 as per the response to RFI CA-NLH-119 on August 31, 2013.

The following table summarizes these amounts:

Table 62: Variances from actual capital expenditures

(000's)

	Test Year Forecast Additions	Approved at Time of Filing for GRA	August 31st Estimate Per CA-NLH-119	Additions per Finance Schedule (1)	Actual Expenditures
	$ 104,982	$ 102,979	$ 98,547	$ 80,657	$ 84,755
Variance from actual ($)	$ (20,227)	$ (18,224)	$ (13,792)	N/A	
Variance from actual (%)	-23.87%	-21.50%	-16.27%	N/A	

Note 1: The Finance Schedule reported additions net of insurance proceeds.

In the 2012 Annual Review, it was noted that "over the 10 year period the annual variances between budget and actual capital expenditures are almost entirely due to under-spending as a result of not completing all projects approved each year. The Company attributes this to both unavoidable delays due to factors such as system constraints which are precipitated by changes in hydrology, equipment failures, etc. There are also cost increases and project delays being experienced due to the strong labour market. Hydro has noted that it is working to address these issues by reviewing its packaging of projects to encourage competitive bids, as well as attracting additional bidders."

Our 2012 Annual Review report was filed with the Board on October 31, 2013 included the following:

"We recommend that the Board consider requesting an update from Hydro as to actions taken by the Company to improve the accuracy of its capital budgeting process."

We note there have been several RFIs in the GRA on the Capital Budget process.

During 2013, subsequent to the filing of the GRA, the Company requested and the Board approved these supplementary 2013 capital expenditures:

(i) Order P.U. 31 (2013) in the amount of $207,000 as a supplementary amount to the Allowance for Unforeseen Items;

(ii) Order P.U. 33 (2013) in the amount of $388,700 for the replacement of a breaker at Hinds Lake generating station;

(iii) Order P.U. 38 (2013) in the amount of $1,263,400 to install a 16 MW diesel plant and other necessary infrastructure to ensure black start capability at the Holyrood Thermal Generating Station; and

(iv) Order P.U. 39 (2013) in the amount of $158,300 to purchase equipotential bonding and grounding equipment.

No expenditures related to these supplementary applications are included in the test year forecast expenditures.

Based on our review, the $104,982,000 forecast 2013 capital expenditures included in the rate base for Test Year 2013 are overstated, and include items for which no applications have been filed with the Board. The actual capital expenditures made in 2013 amounted to $84,755,400, less insurance proceeds of $4,500,100, for a net expenditure of $80,255,300. This also results in an overstatement of depreciation expense included in revenue requirement.

Deferred Accounts

The following table shows the transactions in the deferred charges account for 2010 to 2012 and those forecast for 2013:

Table 63: Deferred charges transactions

(000)'s	Forecast Balance Jan 1/13	Forecast Add. (Disp)	Forecast Amort.	Forecast Balance Dec 31/13	Actual Balance Dec 31/12	Actual Balance Dec 31/11	Actual Balance Dec 31/10
Realized foreign exchange losses	$62,551	$ -	($2,157)	**$60,394**	$62,551	$64,708	$66,865
Asbestos abatement	-	-	-	**-**	-	605	1,948
Boiler	-	-	-	**-**	-	-	302
Study costs	-	-	-	**-**	-	-	50
General Rate Application	-	1,000	(333)	**667**	-	-	-
Conservation Demand Program [1]	2,430	2,632	(219)	**4,843**	2,430	1,045	571
					-		
	$64,981	$ 3,632	($2,709)	**$65,904**	$64,981	$66,358	$69,736

Note 1: Amortization is based on the total forecast balance as at March 31, 2013, recoverable over 7 years. The recoverable amount is not part of the revenue requirement.

In the 2013 GRA, Hydro is proposing that the Board approve the following regulatory deferral accounts, recovery mechanisms and amortizations:

a) deferral of the 2013 Conservation Demand Program ("CDM") costs for inclusion in the recovery mechanism;
b) amortization and recovery in rates of CDM costs over a seven year period;
c) amortization and recovery in rates of Isolated System (including L'Anse au Loup) diesel fuel and power purchase cost variances from the approved test year; and
d) deferral and amortization over a three year period of the estimated $1.0 million in external regulatory costs related to the 2013 GRA.

Foreign Exchange Losses

Hydro continues to amortize costs associated with foreign exchange losses consistent with past practice.

External Regulatory Costs

Approximately $1.0 million in external regulatory costs are forecast to be incurred with respect to the current GRA and it has been proposed by Hydro that they defer and amortize these amounts over a three-year period starting in 2013. This treatment was also included in Newfoundland Power's 2013-2014 GRA and approved under Board Order P.U. 13 (2013).

The proposal will have a forecast revenue requirement impact of $333,000 in the years 2013, 2014 and $334,000 in 2015.

We conclude that a three year amortization period is consistent with past treatments approved by the Board.

Conservation Demand Management Costs

Hydro and Newfoundland Power have agreed to a second joint energy conservation plan to increase the level of customer energy savings. In the current GRA, Hydro is proposing regulatory approval for the CDM costs included in the deferred charges.

The CDM cost treatment was assessed in the report titled "Cost of Service Study/Utility and Industrial Rate Design Report" prepared by Lummus Consultants. In that report it was recommended that the CDM costs be deferred and recovered through the use of a rate rider rather than being included in the revenue requirement for the 2013 test year. The basis for this recommendation is that uneven amounts of CDM costs are incurred from year to year and therefore are more appropriately reflected by the rate rider to match recovery of these amounts.

Hydro is proposing that existing CDM costs as well as future CDM costs be deferred and recovered over a seven year period. Under Newfoundland Power's 2013-2014 GRA CDM costs were also amortized over a seven year period as approved by Board Order P.U. 13 (2013).

In the Application, Hydro applied for deferral of 2013 costs. This deferral was granted separately under Board Order P.U. 35 (2013). Deferrals for 2009 to 2012 CDM costs were also approved in previous Board Orders. Below is a summary of actual versus budget expenditures for 2009 to 2013. Budget amounts represent amounts previously approved for deferral by the Board.

The following table summarizes the actual versus budgeted Conservation Demand Program expenditures from 2009 to 2013.

Table 64: Comparison of Conservation Demand Program expenditures – actual to budget

(000's)	Actual 2013	Actual 2012	Actual 2011	Actual 2010	Actual 2009	Actual Total
Actual	$ 1,449,000	$ 1,385,000	$ 474,000	$ 412,000	$ 159,000	**$ 3,879,000**
Budget	2,632,000 [1]	1,673,000	840,000	2,300,000	1,800,000	**9,245,000**
Under Budget	$(1,183,000)	$ (288,000)	$ (366,000)	$(1,888,000)	$(1,641,000)	**$(5,366,000)**
% Under Budget	(45%)	(17%)	(44%)	(82%)	(91%)	**(58%)**

Note 1: In the General Rate Application, Hydro applied for deferral of $2,632,000. On November 1, 2013 Hydro filed an application with the Board requesting approval of the deferred recovery of its 2013 costs incurred in association with its energy conservation plan. In the November 1st application, Hydro estimated its 2013 costs to be $1.95 million, which is the amount the Board approved in P.U. 35 (2013).

We conclude that the Company's proposal for recovery of CDM costs is consistent with the treatment approved for Newfoundland Power in Board Order P.U. 13 (2013). We also note that in each of the five years, actual expenditures have been significantly under budget. We recommend that the Board consider requesting an update from Hydro as to actions taken by the Company to improve the budgeting process and to address the apparent lack of participation in the Conservation Demand Management Program as compared to budget.

Diesel Unit Cost Variance Deferral Account

In Hydro's 2013 General Rate Application, Hydro is proposing the use of a Diesel Unit Cost Variance Deferral Account. Hydro has stated that the purpose of this account will be to provide customers with the benefits of any decreases in diesel fuel price. As well, during periods of increasing diesel fuel prices this deferral account will also protect Hydro's earnings from fuel cost increases.

Hydro has indicated that they are seeking approval of a deferral and cost recovery account related to the diesel fuel prices as volatility in fuel prices has continued since the last GRA. According to Hydro's evidence they have experienced an increase in the total cost per litre of more than 50% since 2007.

In Table 4.8 on page 4.24 (Section 4: Rates and Regulation) of the Application, Hydro has calculated the diesel fuel variance from 2007 to 2012 in comparison to the information included in the 2007 test year. The average cost per litre of diesel fuel included in the 2007 test year was $0.73978 per litre. During the period 2007 to 2012, the actual average cost of diesel fuel went from a low of $0.74415 per litre in 2007 to a high in 2012 of $1.07926. The calculated variance is outlined in the table below:

Table 65: Diesel fuel variance

($000)s						
	2007	2008	2009	2010	2011	2012
Diesel fuel variance	$61	$3,866	$1,378	$1,633	$4,372	$4,960

In response to PUB-NLH-099, Hydro considers that with the level of volatility in fuel costs it is prudent to seek approval for such a deferral mechanism.

For the 2013 test year forecast, Hydro has forecast the average cost per litre of diesel fuel to be $1.12417 per litre.

In Table 4.9 on page 4.25 (Section 4: Rates and Regulation) of the Application, Hydro has illustrated that a 10% price variance from the 2013 test year forecast price per litre using the number of litres included in the forecast (15,824,754) would result in a variance of $1,740,723.

Hydro's proposal only encompasses diesel price variances and this deferral account does not attempt to capture any volume variance from units of diesel forecast to be purchased in the test year versus the actual units purchased in operating years. Hydro has indicated in its application that due to the fact that they operate 21 diesel systems with approximately three units each, many of which use a variety of conversion rates, it would be too difficult to accurately track volume variances. Hydro feels that due to the fact that the volume variances are based on an increase or decrease in the load from the test year that the change in revenue will offset any cost variances caused by fuel purchase volume variances.

In PUB-NLH-100, the Board noted that Hydro is not proposing to account for volume variances in diesel fuel costs that are due to load changes. The Board questioned if Hydro receives additional revenue as a result of variances in load in isolated systems from the test year, how did the Company propose that such additional revenue be treated? In its response to PUB-NLH-100, Hydro said that overall, there would be no benefit to Hydro resulting from an increase in load, as the cost of marginal supply exceeds the marginal revenue. The Company, in its response, also provided an example to illustrate the impact.

Hydro is proposing that the variance would be calculated on a monthly basis and be recorded in a Diesel Variance account, and at the same time (July 1st) that 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. Hydro also 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.

Proposed Definition

In its response to NP-NLH-38, Hydro has proposed the following definition for the Diesel Unit Cost Variance Deferral Account:

> *"This account shall be charged with variations between Test Year and actual diesel costs incurred on Hydro's isolated diesel systems, including L'Anse au Loup, on a monthly basis,*
>
> *The cost variance will be calculated as follows:*
>
> > *Litres of Actual Fuel consumed × (Actual Weighted Average Cost($) per litre - Cost of Service Weighted Average Cost ($) per litre)*
>
> *The diesel unit cost variation will be allocated between Newfoundland Power and Rural 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 Rural Labrador Interconnected will be written off to Hydro's net income or loss.*

Hydro also noted it will file an application with the Board no later than May 1st of each year for the disposition of any balance in this account. This recovery mechanism is not intended to be dealt with through the RSP.

In its response to NP-NLH-142, Hydro said that it will apply to have the amount included as an adjustment to Newfoundland Power's energy rate in a manner similar to how the RSP is applied. The following is an example that Hydro provided to illustrate how it would be calculated:

Assumed balance applicable to NP	$(1,000,000)
NP's 12 months to date March sales used for calculating the RSP rate (kWh)	5,433,230,398
Estimated Rate (mills per kWh)	(0.18)

In its response to CA-NLH-145, Hydro said that it does not intend to include monthly carrying costs in the calculation of deferral accounts.

This deferral and recovery mechanism appears to serve a similar purpose as other deferral accounts approved by the Board for Hydro and Newfoundland Power, such as the Rate Stabilization Plan, and the Rate Stabilization Account for Newfoundland Power. It will provide ratepayers with the benefit when the price of diesel fuel decreases and during periods of increasing diesel fuel prices this deferral account will also protect the Company's earnings from fuel cost increases.

Power Purchases Cost Variance Deferral Account

Hydro is also proposing the implementation of a deferral and recovery mechanism for purchased power on the isolated systems in its 2013 GRA. Similarly, to the purchase of diesel, the unit price of purchase power varies throughout the period based on a variety of market factors. As a result, there is a potential for significant variances between the purchase price per unit forecast in the test year and the purchase price per unit in the actual operational year. In its Application, Hydro indicated that the power purchase cost has increased from $1.7 million in 2007 to $3.2 million in 2012. Therefore, Hydro has suggested that the use of a deferral and recovery mechanism for power purchases on the isolated system is required. According to its response to PUB-NLH-102, Hydro is proposing that the power purchases in Ramea and in L'Anse au Loup are to be considered in this deferral and cost recovery mechanism.

The cost of power purchases on the isolated system for the 2007 test year was $1.73 million. During the period 2007 to 2012, the actual cost of power purchases went from a low of $1.66 million in 2007 to a high in 2012 of $3.22 million. The 2013 test year forecast for power purchases on the isolated system is $3.60 million.

In its response to NP-NLH-160, Hydro indicated that given the increased volume of power purchases in the 2013 test year, the Company considers it critical to recover or refund production related costs. Hydro also noted that it considers this proposed mechanism to be similar to Newfoundland Power's ability to recover energy supply costs variances through its Rate Stabilization Account.

Proposed Definition

In its response to NP-NLH-39, Hydro has proposed the following definition for the Power Purchases Cost Variance Deferral Account:

> *"This account shall be charged with variations between Test Year and actual power purchase costs incurred on Hydro's isolated diesel systems, including L'Anse au Loup, on a monthly basis,*
>
> *The cost variance will be calculated as follows:*
>
> *Actual Power Purchases Cost – Test Year Power Purchases Cost*
>
> *The power purchase cost variation will be allocated between Newfoundland Power and Rural 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 Rural Labrador Interconnected will be written off to Hydro's net income or loss.*

Hydro also noted it will file an application with the Board no later than May 1st of each year for the disposition of any balance in this account. This recovery mechanism is not intended to be dealt with through the RSP, and as noted in the diesel fuel variance deferral account, Hydro does not intend to include monthly carrying costs in the calculation of deferral accounts.

As indicated in the proposed definition, it appears that Hydro is proposing that the difference between the total actual power purchases cost and the total test year power purchases cost will be the amount charged to the deferral account for recovery; not just the difference in the actual unit cost and the test year unit cost. Therefore, if demand increases, Hydro will receive additional revenue based on the sale of power on the isolated system and the Company will also, if approved, recover the additional costs incurred to purchase the additional power required to meet the demand. This differs from the Diesel Unit Cost Variance Account as the variance calculated for this account is based on the actual unit price per litre of diesel fuel verses the test year unit price, not an increase in volume of litres purchased due to an increase in the demand for power.

The Board should consider whether the Company's definition for this recovery mechanism be based on a "per unit" basis verses the power purchases cost to provide electricity to the isolated systems.

Accounting Matters

On January 20, 2012 we issued our report "Adoption of IFRS for regulatory reporting, effective January 1, 2012" with a supplementary report issued on February 24, 2012. The report was in response to the December 23, 2011 application filed by the Company requesting approval of the adoption by Hydro of International Financial Reporting Standards ("IFRS") for regulatory reporting effective January 1, 2012 ("the IFRS Application").

In the IFRS Application Hydro specifically identified changes in accounting that would be required in order for the Company to adopt IFRS for regulatory purposes (certain of these items had been approved under previous Board Orders). The Company also proposed certain departures from IFRS be permitted, the most significant of these being related to RSP and deferred charges.

In its response to this application the Board issued P.U. 13 (2012) which approved the adoption of IFRS by Hydro for regulatory purposes effective January 1, 2012 along with certain exceptions.

Subsequent to the issuance of P.U. 13 (2012) significant developments occurred relating to the future of rate regulated accounting.

Historically IFRS was silent on the topic of rate-regulated activities. In 2008, the International Accounting Standards Board ("IASB") undertook a project to decide whether IFRSs should be amended to require the recognition of assets and liabilities arising from rate regulation and provide guidance on their measurement, and/or require disclosures that assist in the understanding of an entity's regulatory environment. The IASB paused the project in September 2010 and restarted it in September 2012. On September 18, 2012, the Canadian Accounting Standards Board ("AcSB") decided to defer the mandatory IFRS changeover date for entities with qualifying rate-regulated activities to January 1, 2014.

On January 3, 2013, the IASB decided to develop an interim IFRS for use until it completed its comprehensive project for rate regulated accounting. On February 14, 2013, the AcSB extended the existing deferral of the mandatory IFRS changeover date for entities with qualifying rate-regulated activities by an additional year to January 1, 2015.

On April 26, 2013, the IASB issued an Exposure Draft of a proposed interim standard on rate-regulated activities.

The Exposure Draft proposed to:

a. permit an entity that adopts IFRS to continue to use its previous GAAP accounting policies as accepted in their local jurisdiction, for the recognition, measurement and impairment of regulatory deferral account balances;
b. require the entity to present regulatory deferral account balances as separate line items in the statement of financial position and to present movements in those account balances as a separate line item in the statement of profit or loss and other comprehensive income; and
c. require specific disclosures to identify clearly the nature of, and risks associated with, the rate regulation that has resulted in the recognition of regulatory deferral account balances in accordance with the proposals.

The Exposure Draft noted that the standard would only be applicable for an entity's first IFRS financial statements. As a result if Hydro fully adopted IFRS in 2012 they would not be eligible for the relief outlined in the Exposure Draft. Therefore for 2012 the Company continued to use Canadian Generally Accepted Accounting Principles as codified in Part V of the CICA Handbook. However, as P.U. 13 (2012) had been issued, the Company applied the accounting policies that had been approved in this Board Order for regulatory reporting. In its December 31, 2012 audited non-consolidated financial statements Hydro has disclosed its regulatory assets and liabilities as well as regulatory adjustments recorded in the Statement of Income (See Note 5 of the 2012 financial statements). This disclosure outlines regulatory accounting adjustments which differ from Canadian GAAP including those that have been approved in P.U. 13 (2012). Hydro applied the same basis of accounting in 2013 as was used in the 2012 financial statements. In addition, Hydro is requesting in this Application, regulatory approval for items that were not outlined in P.U. 13 (2012). We address these items separately.

In 2014 the IASB issued IFRS 14 'Regulatory Deferral Accounts' which essentially approved the recommendations of the above noted Exposure Draft.

Asset Retirement Obligations

In its Application, Hydro is proposing to include costs related to the amortization and accretion of Asset Retirement Obligations ("ARO's") in its revenue requirement. The ARO's represent legal or constructive obligations associated with the retirement of long-lived assets. The estimated present value of an ARO is added to the original cost of the related asset ("Asset Retirement Cost" or "ARC"), and an offsetting liability is recognized. Over time, the ARC is depreciated and the ARO accretes toward its future value.

On July 16, 2012 we issued a report in relation to an application filed by Hydro related to Asset Retirement Obligations. Hydro had proposed to exclude the unamortized ARC from rate base and to include depreciation and accretion expense in revenue requirement. In our report we concluded "that the proposed regulatory treatment of the ARO represents a reasonable approach which will allow the Company to recover all costs associated with the ARO over time".

In P.U. 29 (2012) the Board ordered Hydro to recognize and record ARO's in accordance with IFRS but also noted that "the regulatory treatment of the proposed asset retirement obligation is denied at this time". In its decision the Board noted that "the issues surrounding the proposed asset retirement obligations are appropriately addressed in the context of a general rate application so that the assessment can be made and the impacts considered in the context of the relevant circumstances …".

The Company has described its ARO's in Section 3.8.5 of its Application. In addition, the Company has provided calculations to support the ARC, ARO, depreciation expense and accretion expense in its response to NP-NLH-091.

The following table illustrates the continuity of the Asset Retirement Costs and Asset Retirement Obligations from 2010 to the 2013 Test Year:

Table 66: Continuity of asset retirement costs and obligations

Asset Retirement Obligations ($000's)	2010	2011	2012	Forecast 2013
Asset Retirement Costs				
Opening		11,395	17,976	19,685
Holyrood ARO	11,395	5,567	3,753	(41)
PCB ARO		2,163		(44)
Holyrood Depreciation		(1,149)	(1,980)	(2,218)
PCB Depreciation			(64)	(62)
Closing	11,395	17,976	19,685	17,320
Asset Retirement Obligation				
Opening		11,395	19,593	24,032
Holyrood ARO	11,395	5,567	3,753	(41)
PCB ARO		2,163		(44)
Holyrood Accretion		468	648	776
PCB Accretion			68	67
Dispositions			(30)	(262)
Closing	11,395	19,593	24,032	24,528

The estimated undiscounted cash flows related to the Holyrood Thermal Generating Station have been agreed to the estimate included in the "Holyrood Thermal Generating Station Decommissioning Study" report issued by Stantec and included in NP-NLH-091 Attachment 2. The estimated undiscounted cash flows related to the PCP removal are based on internal estimates prepared by the Company.

In relation to this evidence we note the following:

- We have reviewed the calculations provided by the Company and recalculated the ARO and the ARC and have not found any discrepancies;

- Depreciation expense of $2.3 million and accretion costs of $0.8 million have been agreed to supporting schedules provided by the Company;

- The Company has calculated the ARO based on the guidance prescribed in CPA (formally CICA) 3110 rather than the IFRS standards (IAS 37 and IFRIC 1). One of the key differences between CPA 3110 and IFRS relates to the calculation of upward adjustments in the estimate of the obligation. Under CPA 3110 only the portion of the liability associated with the upward adjustment is discounted using the current discount rate, whereas under IFRS the whole obligation would be revalued annually using the current discount rate. The CPA guidance results in a more conservative impact on revenue requirement than the IFRS guidance. Applying the CPA standard, the total impact on revenue requirement is $3,123,000 compared to $3,262,000 under IFRS (a difference of $139,000);

- The report prepared by Stantec as provided by the Company in its response to NP-NLH-091 notes that the salvage value of the decommissioned materials has not been calculated. Under both Canadian GAAP and IFRS it is appropriate to exclude salvage value from the calculation of the ARO. However, the salvage value should be used in the calculation of the depreciation of the underlying assets (i.e.: salvage value would reduce depreciation). The Company has noted that it is anticipated that they would not receive any return for scrap materials. The Company also noted that this will be further refined as the project planning proceeds and Hydro moves closer to the actual demolition stage;

- The discount rate used in the calculation of ARO's can have an impact on the value of the reported ARC and the ARO along with the corresponding impact on revenue requirement. When the ARO associated with Holyrood was originally calculated in 2010 the discount rate used was 4.10%. This decreased to 2.90% in 2011 and to 2.78% in 2012. As previously noted the 2.90% and the 2.78% were applied to only the incremental adjustments to the ARO ($6.5 million in 2011 and $5.1 million in 2012 on an undiscounted basis). We recalculated the resulting depreciation expense and accretion costs assuming the discount rate remained at 4.10%. The resulting impact would have been a $19,000 decrease in revenue requirement;

- Estimates related to ARO's are inherently subject to uncertainty regarding the timing and amount of future cash outflows. When the Company initially recorded the ARO related to Holyrood in 2010 the expected undiscounted future cash outflows were $20.5 million. This has now increased to $32.1 million based on the most recent estimates prepared by Stantec. This estimate includes a 10% contingency ($2.9 million). In addition, Stantec has noted that the estimated costs would have an accuracy range of -10% to +30%;

- Including depreciation expense and accretion costs in revenue requirement will permit the Company to recover costs associated with decommissioning the related assets; and

- The Company has excluded the undepreciated ARC from rate base as there are no external costs (either debt or equity) associated with this asset.

Employee Future Benefits

The Company's proposal related to employee future benefits is outlined in Section 3.8.3 of the Application. In this section, the Company is proposing to include the amortization of cumulative actuarial gains and losses as part of the revenue requirement. This would be consistent with the accounting treatment followed prior to the implementation of P.U. 13 (2012). The Company has included $9,314,000 in employee future benefits in its 2013 forecast revenue requirement. This includes $2,224,000 related to the amortization of actuarial losses.

As previously noted, P.U. 13 (2012) approved the transition to IFRS effective January 1, 2012, with certain exceptions. The most significant difference between IFRS and Canadian GAAP for employee future benefits relates to the treatment of actuarial gains and losses. As Hydro has identified, under Canadian GAAP actuarial gains and losses above a certain threshold were amortized over the expected average remaining service life of the employee group and as a result, included in revenue requirement. Under IFRS these gains and losses are recognized in Other Comprehensive Income and are not be included in revenue requirement.

The Company has noted that by following P.U. 13 (2012) a portion of the expense associated with employee future benefits would not be included in revenue requirement. We concur that for 2013 under the accounting approved in P.U. 13 (2012) the components of expense related to employee future benefits consists of current service cost and interest and excludes any portion related to the amortization of actuarial gains and losses. We do note that this was identified by the Company in its IFRS Application which preceded the issuance of P.U. 13 (2012). At this time the Company did not propose any regulatory treatment, and no regulatory treatment was ordered to account for actuarial gains and losses.

Permitting the recognition of the amortization of actuarial gains and losses will create a long term difference between regulatory accounting and external financial reporting standards when the Company transitions to IFRS. However, it will permit the recovery of these costs on a timely basis.

In its response to CA-NLH-132 the Company provided the latest actuarial report available which was dated October 8, 2013. Estimated 2013 employee future benefit expense noted in this report was $8,671,000 – a decrease of $643,000 from the original test year forecast.

Appendix A – Historical Review of the Rate Stabilization Plan

Board of Commissioners of Public Utilities - Historical Review of the Rate Stabilization Plan of Newfoundland and Labrador Hydro

January 1st 1986 – December 31st 2009 (Updated to December 31, 2012)

Contents

Introduction

Newfoundland and Labrador Hydro's ("Hydro" or "the Company") Rate Stabilization Plan ("RSP") was established effective January 1, 1986 with the objective of providing rate stability to customers and providing a mechanism to eliminate volatility in Hydro's revenue requirement due to events beyond its control. As established, the RSP provided for adjustments to recover differences between the forecast test year costs used to set rates and the actual costs attributable to:

- differences in the price of No.6 Fuel;
- variations in hydraulic production; and
- variations in load.

The plan was modified in 1993 to include an adjustment to account for any variation in Hydro's rural revenues which may arise as Hydro's rural rates are changed, in accordance with Government policy, to reflect Newfoundland Power's rates. This provision was incorporated into the RSP as part of the 1993 generic cost of service hearing.

During 2001, the balance in Hydro's RSP increased to approximately $85.0 million as compared to $34.7 million in 2000. This dramatic increase in the RSP balance, together with the forecast cost of No. 6 fuel, generated significant concern and discussion with respect to the RSP during Hydro's 2001 General Rate Hearing. As a result of the Board Order P.U.7 (2002-2003), further changes were made in 2002 flowing from Hydro's 2001 General Rate Hearing. These changes are discussed in further detail in this report.

During the 2003 General Rate Hearing, the parties involved reached a settlement agreement on further proposed changes to the RSP. These changes included: allocating 25% of the hydraulic portion to be refunded to, or recovered from customers, each year; the introduction of the fuel rider, and changing the allocation of the fuel element of the load variation component to the customer class that caused the change in load. In P.U. 40 (2003) the Board approved the changes as outlined in the settlement agreement. These changes, along with several other modifications included in the settlement agreement and Board Order, are discussed in further detail in this report.

The Company filed a General Rate Application in 2006 and included in this application proposals for further changes to the RSP. These proposals were subject to the settlement negotiation process. The changes in the settlement agreements dated October 20, 2006 and November 23, 2006 were approved by the Board in P.U. 46 (2006) and P.U. 8 (2007).

The original scope of our engagement with respect to the Rate Stabilization Plan is to provide a report that will document the history of the Plan from its inception in 1985 to the end of 2009, including the following:

- History of the Plan including an outline of any changes to the methodology over the years and the authorization for these changes;
- Provision of a schedule of the annual results allocated between the Industrial Customers and Newfoundland Power since the inception of the Plan; and
- Description of the impact that the changes had on the annual balances of the Plan for the Industrial Customers and for Newfoundland Power, and any changes in the distribution of the costs and the benefits that have resulted from the changes that have taken place.

On April 8, 2013 we were asked by the Board to update this report to December 31, 2012 based on the activity that occurred relating to the RSP since December 31, 2009.

This report will highlight the changes that occurred in the RSP over the years and the results of these changes which the Board and other stakeholders may wish to consider in assessing whether further changes to Hydro's RSP are appropriate.

Appendix A of this report provides a schedule of the annual activity of the RSP and the annual balances allocated between the Industrial Customers and Newfoundland Power. This schedule begins in 1986, the year of the RSP implementation, up to and including December 31, 2012.

The Implementation of the Rate Stabilization Plan

Prior to the establishment of the RSP in 1986, Hydro used two separate accounts, a water equalization provision and a fuel adjustment charge, to adjust for variations in hydraulic and thermal production costs as compared to the test year forecasts that were used in the calculation of the rates Hydro charged its customers.

The water equalization provision was used to adjust costs of production due to variations in hydraulic generation which were caused by fluctuations in water availability. The fuel adjustment charge was a mechanism designed to pass on actual fuel costs to customers one month after they were incurred. This method of recovery resulted in significant volatility in electricity costs to customers, particularly in the winter months when consumption would be at its highest. During the early eighties fuel prices experienced substantial increases. This resulted in the public expressing discontentment due to significant increases in their monthly electricity bills as a result of the operation of the fuel adjustment charge.

In August, 1985 Hydro filed a referral to the Board of Commissioner of Public Utilities ("the Board") of proposed rates for the supply of electric power to Newfoundland Light & Power Co. Limited ("NP") and the Board of Trustees of The Power Distribution District of Newfoundland and Labrador ("PDD"). Included in this referral Hydro, as a means to address consumer concerns and reduce volatility in its revenue requirement, proposed the implementation of a RSP. The RSP would reduce volatility and improve stability of rates but ultimately all variations in costs would be borne by consumers. The RSP consolidated both the hydraulic and fuel adjustment charge accounts into a single plan.

In its report dated November 8, 1985 to the Government of Newfoundland and Labrador on the rate proposals filed by Hydro, the Board recommended that the RSP presented by Hydro be accepted, with some changes.

The components and details of the RSP that were implemented as of January 1, 1986 are as follows:

- Water Variation Provision: This component was similar to the Water Equalization Provision that was in operation prior to the RSP. Costs/savings were accrued, or being charged, to the provision depending upon whether hydro production was above or below average. The variation in cost due to water conditions was determined by comparing the monthly normal hydro generation, as used in the 1986 final cost of service, with actual monthly hydro generation. This variation in gigawatt hours was converted to the equivalent barrels of oil needed to produce the equivalent energy from thermal production and then multiplied by the price per barrel of oil included in the cost of service. In the 1986 cost of service oil was priced at $30 per barrel. This provision is referred to as the Hydraulic Production component in the monthly RSP reports.

- Fuel Cost Variation Provision: This component was used to account for the variations in the price of Bunker "C" fuel oil. It would compare the price per barrel of Bunker "C" included in the cost of service to the actual price per barrel for thermal production. Adjustments to the provision were calculated by multiplying the number of barrels of oil used for thermal production each month by the monthly fuel cost variation.

- Load Variation: This component was not approved as presented by Hydro in its rate proposals filed in August, 1985. Hydro presented a "coverage cap", which it proposed would prevent the company from over earning in situations where there was a decrease in load in comparison to the cost of service. The company proposed that Hydro's interest coverage on its retail customers be capped at 1.20, and any revenue in excess of this would be refunded to customers the following year when the financial statements had been finalized.

  The Board's recommendations indicated that "any earnings variation because of a difference between the estimated load and the actual load be included in the Rate Stabilization Plans of Hydro and NLP." (Page 88, Report to the Government of Newfoundland and Labrador on Rate Proposals Filed by Newfoundland and Labrador Hydro on August 6, 1985). The implementation of the Board's recommendations was discussed in a letter to the Board dated March 26, 1986 from Mr. Cyril Abery, President and Chief Executive Officer of Hydro. Based on this letter the load variation would be determined by comparing the monthly cost of service sales with the actual monthly sales, and multiplying the difference in gigawatt hours by the Holyrood mill rate based on the cost of fuel per barrel used in the cost of service study. The total revenue received due to the load variation would be deducted to determine the adjustment to be made to the load variation provision.

  In the letter dated March 26, 1986 Mr. Abery also proposed that variations arising from changes in the actual volume of secondary energy purchased for resale to retailers in comparison to the cost of service would also form part of the RSP. He indicated that this type of variation impacted directly on the load which Hydro would have to service from its own plants and hence impact Hydro's earnings.

  The load variation component of the RSP includes two components; a revenue component and a fuel component. These two components together adjust for the net contribution attributable to a variation in energy sales. With respect to the revenue component, if the actual energy sales are less than the cost of service sales the difference flows through the plan as a charge to the particular customer group (i.e. retail verses industrial), and vice versa, if the sales are greater than the cost of service sales, the difference is a credit for the particular customer group in the plan. The adjustment amount is determined by multiplying the difference in actual versus cost of service energy sales for each customer group by its respective energy mill rate. The fuel component of the load variation is calculated by taking the total sales in kWhs from both customer groups, comparing it to the total cost of service kWh sales and multiplying the difference by the thermal generation energy mill rate which is based on the cost of service oil price per barrel. If the actual sales are less than the cost of service, the fuel component is a credit to the plan and if the actual sales are greater this component is a charge to the plan.

  For example, in December 1986 the actual energy sales were greater than the cost of service sales for the retail group by 27.02 GWh and the industrial group sales were less than the cost of service by 4.78 GWh. The revenue component adjustment for the retail group was a credit to the plan of \$1,145,000 (27.02 GWh x 4.237¢/kWh), and the fuel component adjustment was a charge to the plan of \$1,351,000 ((27.02 x 5.0¢/kWh). The revenue component adjustment for the industrial group was a charge to the plan of \$104,000 (4.78 GWh x 2.168¢/kWh) and the fuel component adjustment was a credit to the plan of \$239,000 ((4.78 x 5.0¢/kWh).

Beginning in January, 1986 the cost of financing the RSP was calculated using Hydro's embedded cost of debt and added to the balance in the plan on a monthly basis.

The Board also accepted Hydro's recommendation of a \$50 million cap (positive or negative) on the plan that would obligate the Company, in the event that the cap was reached or exceeded, to come to the Board to review the operation of the plan.

Changes Recommended by the Board in its November 8, 1985 Report

In its report to the Government of Newfoundland and Labrador on November 8, 1985, the Board recommended the acceptance of Hydro's RSP with the following changes:

(a) One third of the balance in the RSP at the end of June each year commencing in 1987 would be amortized over the next twelve months. The amortization would be billed to NP on a kWh basis calculated using the kWh sold in the previous 12 months. This recovery would be debited or credited to the RSP on a monthly basis.

(b) Hydro was required to inform the Board of the amounts being accrued in each month, the balance accrued to date and the status of the amount being amortized.

(c) NP was required to calculate a rate adjustment per kWh by dividing the sum of the annual amortization to be billed by Hydro plus any balance in NP's rate stabilization account referred to in (d), by the total kWh sold in the previous twelve months and calculate the charge to be included in customers' bills in the following twelve months, and apply to the Board for approval of the July 1 rate adjustment resulting from this annual calculation.

(d) Under or over collections by NP would be carried forward in an interest bearing rate stabilization account.

(e) NP would report to the Board monthly the amount collected to date and the balance remaining.

(f) As noted above in the description of the load component, the Board recommended that any earnings variation because of a difference between the estimated load and the actual load be included in the RSP of Hydro and NP. This was recommended so that Hydro's earnings would not vary.

The Board was of the opinion that this plan would limit the amount of the RSP through the yearly adjustment. The rate adjustment would be made at the end of June so that the impact of a possible increase would be less severe than if the rate change happened in the winter. The Board indicated that the rate adjustment would be automatic and would not require a Hydro referral and a subsequent pass through hearing by NP.

Introduction of the Industrial Customers to the RSP

When the RSP was originally recommended for approval in the November 9, 1985 report, it only included the retail customers, not the Industrial Customers. However, in a letter dated March 26, 1986 from Mr. Cyril Abery to Mr. Gordon MacDonald, Chairman of the Board of Commissioners of Public Utilities, Mr. Abery proposed for the Board's approval the establishment of two separate RSPs, one for Hydro's retail customers (NP and PDD) and one for the Industrial Customers. Based on this letter it was noted that this was proposed as a result of discussions that Hydro had with NP due to concerns that NP had addressed regarding the approach used to determine the monthly balance in its RSP. The Board, however, did not give formal approval for this plan because at that time its authority was limited to hearing applications that had been referred to it by Hydro and making recommendations to the Provincial Government regarding the issues brought forward in those applications. The 1985 application and report dealt only with the rates to be charged by Hydro to NP and PDD, not to the Industrial Customers.

Mr. Abery indicated that the by establishing two segregated RSPs for retail and Industrial Customers it would allow Hydro to reflect the revenue that would have been collected from each customer group, had the actual results of load, hydro production and fuel price changes been known at the time the cost of service was prepared and filed with the Board. Hydro believed that this would result in the retail and Industrial Customers being treated fairly and independently of each other as it was based on the cost of service methodology approved by the Board.

The letter also indicated that Hydro felt that this proposed approach would be consistent with the recommendations made by the Board in its report dated November 8, 1985 and it would also satisfy the concerns expressed by NP.

Allocation of the Monthly Plan Activity

According to the March 26, 1986 letter from Hydro, it was noted that the calculation of the plan balances for the retail and Industrial Customers would be prepared monthly. The letter indicated that Hydro would recalculate the 1986 cost of service by customer, replacing the 1986 costs with the actual costs as they became available, related to any changes which may occur in both firm and secondary loads, hydro production and/or fuel prices. The difference between the revised cost of service derived using the actual costs and the 1986 final cost of service filed with the Board would indicate the adjustment to be made in the balance of the two plans.

The letter goes on to explain that the adjustment to the balance of the plan for each group, retail and industrial, would be derived monthly by comparing the revised cost of service for the specific group with the 1986 final cost of service filed with the Board for the same customer group net of revenue received due to any changes in firm energy sales.

March 6, 1989 Hydro Referral to the Board

On March 6, 1989, Hydro issued a referral to the Board for proposed rates to be charged to retail customers. This was approximately three years after the implementation of the RSP. According to the Board's June 1, 1989 Report to the Government of Newfoundland and Labrador relating to its recommendations on Hydro's proposed rates to be charged to retail customers, the only changes that Hydro proposed for the RSP was to rebase the cost of service price per barrel of oil from $30.00/bbl to $18.00/bbl and to use the blended price of oil in its tanks at the end of each month. The latter was considered to be fine-tuning and would have a minimal impact. The Board recommended that the RSP remain as it was with the exception of the two changes noted above.

According to pages 46 and 47 of the Board's June 1, 1989 report, Hydro was of the opinion "that the RSP was operating the way it was designed to operate and was proving to be a satisfactory tool". NP agreed that the Plan "…was operating as designed to do but questioned whether or not the amount in it by the end of June should be reduced by a one time payment to customers."…" and Mr. Joseph Hutchings, who was appointed by the Board to represent the general interest of the various classes of retail users of electricity, agreed with the other parties that "…the Plan was a good one and was working well."

February 6, 1990 Hydro Referral to the Board

On February 6, 1990, Hydro filed a referral to the Board of proposed rates for the supply of electric power to NP and rural customers. Based on the information included in the Board's June 11, 1990 Report to the Government of Newfoundland and Labrador, there was an issue of $8,941,000 in losses relating to PDD from April 1, 1989 to December 31, 1989 that was not covered by the Government subsidy. The Government fully subsidized PDD each year until March 31, 1989. However, beginning with the calendar year 1989 to 1991 the subsidy was going to be reduced each year, and in 1992 it would be eliminated. The RSP also had a positive balance of $40.1 million on June 30, 1989 and was projecting a positive balance of $19 million on June 30, 1990 (i.e. balance owing to ratepayers).

In its submission, Hydro submitted that these costs relating to the loss of the Government subsidy be deferred and recovered over a five year period. NP and the Consumer Advocate argued that some of the $19 million projected surplus balance in the RSP be used to eliminate this amount rather than deferring it over five years. Although the Board considered the possibility of charging the deficit caused by the reduction of the subsidy to the equity of Hydro, it, according to the report dated June 11, 1990 prepared by the Board, was prevented from making this recommendation by Section 4.3 of The Electrical Power Control (Amendment) Act ("EPCA").

Hydro was of the opinion that the surplus in the RSP should not be used to offset the deferred costs relating to the reduction of the subsidy. They indicated that the purpose of the RSP was to smooth variations caused by variations in fuel prices, climatic conditions and load and that it had performed extremely well over the previous four years in achieving this purpose.

The Board recommended in its June 11, 1990 Report to Government that the $8,941,000 loss for PDD from April 1, 1989 to December 31, 1989 be charged to the RSP. The Board was of the opinion that this offset would not interfere with the integrity of the RSP and it was the most suitable way of dealing with the unforeseen loss of the Government subsidy.

November 12, 1991 Hydro Referral to the Board

On November 12, 1991, Hydro filed a referral to the Board of proposed rates for the supply of electric power to NP and rural customers. Based on the information included in the Board's April 13, 1992 Report to the Government of Newfoundland and Labrador that summarized the information presented to the Board and the Board's recommendations on the rates proposed by Hydro in its referral, there were two items included in the referral that impacted the operation of the RSP. Firstly, Hydro made a referral that the purchase price of Bunker "C" oil used for the purpose of the RSP be decreased from $18 per barrel to $14 per barrel effective January 1, 1992.

Secondly, under a provision of the EPCA Chapter 40 of the 1989 Statutes of Newfoundland Hydro was permitted to defer costs it incurred during 1991 which would, unless recovered from its customers, cause Hydro to recover less than the interest coverage approved as a result of the 1990 Rate Referral. This deferral was estimated to be $9,015,000 and Hydro was recommending in its referral that this balance be written off against the balance in the RSP allocated to Newfoundland Power as of January 1, 1992.

In addition to these two Hydro referrals, NP had submitted during the hearing that the extra revenue Hydro would receive because of rate adjustments received by NP between Hydro hearings should flow to the RSP between Hydro rate referrals and flow back to customers. Hydro's rural rates on the Island Interconnected and Isolated systems have been primarily based on NP rates. Therefore, when a rate adjustment for NP had been approved by the Board, Hydro's rural customers received the same rate change without a rate referral having been filed by Hydro.

Purchase Price of Bunker "C" Oil

In its April 13, 1992 Report to Government, the Board recommended that the purchase price of Bunker "C" oil used for the purpose of the RSP be changed to $12.50 per barrel. This recommendation differed from Hydro's $14 per barrel due to falling oil prices from the time the referral was filed with the Board and the conclusion of the hearing.

The $9 million of Costs Deferrals in the 1991 Revenue Shortfall

As noted on page 38 of the Board's Report to Government, during 1991 Hydro operated under the authority of the EPCA Chapter 40 of the 1989 Statutes of Newfoundland and revised January 1, 1990. Section 4.1 (c) states the following:

> "4.1 Notwithstanding the other provisions of this Act, the Hydro Corporation shall include in its forecast costs filed with the Public Utilities Board
>
> > (c) the costs incurred after March 31, 1989, including fees or charges paid to the Crown, which have been deferred by the Hydro Corporation and which would, unless recovered from its customers, cause the Hydro Corporation to recover less than the minimum margin of profit approved by the Public Utilities Board under clause B of subparagraph (i) of paragraph (d) of section 3 in the year in which the costs were incurred."

Under this provision, Hydro was permitted to defer costs that were in accordance with this Section of the EPCA however the EPCA was amended in December, 1991 to eliminate Hydro's right to the deferral of costs incurred after 1991. Hydro explained that if the deferred costs were to be recovered in the 1992 test year, the proposed rate increase to NP would be approximately 11%. However if the deferral was recovered through the RSP, then the proposed rate increase would be approximately 3.8%. Therefore, the recovery of the deferral through the RSP would lessen the impact of the rate increase that Hydro required from NP in 1992.

NP had indicated during the hearing that Hydro's proposal to offset the deferral in the RSP was reasonable. It also proposed that that the July 1st RSP adjustment be based on the balance in the RSP account on December 31 of the previous year and, to facilitate this request, NP proposed that the deferral be rolled into the RSP on December 31, 1991.

The Board recommended in its April 13, 1992 Report to Government that costs of up to $9,015,000 incurred in 1991 be deferred and written off against the balance in the RSP allocated to NP as of December 31, 1991.

Revenue from NP Rate Changes

Hydro's rural rates on the Island Interconnected and Isolated systems have been primarily based on NP rates. Therefore, when a rate adjustment for NP has been approved by the Board, Hydro's rural customers received the same rate change without a rate referral having been filed by Hydro.

During the hearing, NP submitted that the extra revenue Hydro would earn because of rate adjustments received by NP between Hydro hearings should flow to the RSP and flow back to customers. They indicated that this would effectively reduce the subsidy being paid by NP and Industrial Customers until the next Hydro rate referral rather than increasing Hydro's net income.

Hydro did not consider NP's proposal to be appropriate; it proposed that any earnings in excess of its test year interest coverage be refunded to customers. NP did not agree with the cap on the interest coverage, as this approach allowed Hydro, when it was not in an over-earning situation, to apply the additional revenue against expenses that were not included in the forecast revenue requirement upon which rates were set and ratepayers would not see the direct benefit of the additional revenue. Also, as a result of the 1990 NP pass through of Hydro's rate increase, the Board approved the inclusion of a provision in NP's Rate Stabilization Account ("RSA") to ensure it did not over or under collect revenue as a result of Hydro's rate increase.

According to page 100 of the April 13, 1992 Report to Government, the Board agreed with NP that the extra revenue received as a result of rate adjustment between rate referrals should be credited to the RSP.

The Board recommended that at the upcoming hearing on Hydro's cost of service methodology, it should present for the Board's consideration a provision to be included in the RSP which would credit the RSP with any additional revenue received as a result of NP's rate adjustments.

June 26, 1992 Referral to the Board

On June 26, 1992, Hydro filed a referral to the Board for the proposed cost of service methodology, and a proposed method for adjusting its RSP to take into account the variation in Hydro's rural revenues resulting from variations in the rates set by the Board to be charged by NP to its customers. The latter was a recommendation of the Board resulting from the November 12, 1991 rate referral.

In its pre-filed evidence and during the hearing, Hydro presented a provision to be included in the RSP so that the plan would be credited with the additional revenue received by Hydro as a result of NP's rate adjustments between rate referrals. The provision presented, as noted in the Board's February, 1993 Report to Government (page 63), was as follows:

1. "The additional revenue be calculated on a monthly basis;
2. The additional revenue be determined by rate class, using the individual components of each rate;
3. The additional revenue be calculated using the actual billings for each month less the revenue which would have resulted from rates in existence in the test year when the cost of service was approved;
4. This policy become effective with the next NP rate alteration, subsequent to the conclusion of this hearing, and
5. The policy applies to all alterations (increase and decreases) to NP rates that could result in a change in Hydro's rural revenues."

According to the information in the Board's 1993 Report to the Government of Newfoundland and Labrador, NP agreed with Hydro's proposal, however NP noted that Hydro should develop a mathematical approach with all variables defined which would explain how the automatic adjustments were to be calculated and it should be set out in its Rules and Regulations. NP noted that this was a practice that they followed.

The Board recommended that the provision set out above be included in the RSP along with NP's proposal that a mathematical equation with all variables defined be included in Hydro's Rules and Regulations.

2001 General Rate Review

On May 31, 2001, Hydro filed an Application with the Board for a general rate review. This Application began the first comprehensive review of Hydro since it became fully regulated in 1996. Included in this Application were several proposed changes to the operation of the RSP as well as rebasing the variables (price of fuel, Holyrood efficiency factors, test year Hydraulic production, etc.) included in the RSP as a result of an updated cost of service. During the hearing of this Application there was extensive discussion relating to the RSP, including the complexity of the plan, the balance outstanding and the recovery of this balance, and the future operation of the plan.

Hydro proposed a number of changes to the operation of the RSP. They were as follows:

a) Hydraulic Production Variation

- Addition of mini-hydro plants to the calculation of hydraulic production variation.
- Holyrood conversion factor to be changed from 605 kWh/bbl to 610 kWh/bbl.
- The forecast hydraulic production included in Hydro's test year cost of service would also require a change in the calculation of the Hydraulic Production Variation. In its Application, Hydro's proposed 2002 test year forecast of hydraulic production of 4,285.00 GWh from 4,205.32 GWh.

b) Load Variation

- Interruptible energy no longer included in the plan. Barrels related to this energy were also proposed to be excluded from the fuel price variation calculation (along with the existing exclusion for barrels related to emergency sales).

c) Customer Splits:

- No longer base the RSP split on Test Year Cost of Service Study; instead use the 12 month-to-date invoiced /bulk transmission energy used, as well as Test Year Rural Deficit Allocation.

d) Rate Calculation

- Energy rates to be established on the same basis as the customer split, i.e. 12 month-to-date invoiced /bulk transmission energy.

e) Other

- The purchase price of No.6 Fuel used for the purposes of the RSP be changed from $12.50 per barrel to $20 per barrel to be effective January 1, 2002.
- Change the finance charge from Hydro's embedded cost of debt to Hydro's weighted average cost of capital ("WACC").
- Increase the RSP cap for NP from $50 million to $100 million.

P.U. Order No. 7 (2002-2003)

As a result of the hearing related to Hydro's 2001 General Rate Review on June 7, 2002 the Board issued Order No. P.U. 7 (2002-2003) which included a number of orders related to Hydro's proposals and other issues that arose during the hearing.

The Board approved all of the proposals noted above with the exception of the following:

a) Holyrood Fuel Efficiency Factor: The Board ordered an efficiency factor of 615 kWh/bbl as opposed to the 610kWh/bbl as proposed by Hydro.

b) 2002 Test Year Hydraulic Forecast: The Board ordered a test year hydraulic forecast of 4,425 GWh as opposed to the 4,285 GWh proposed by Hydro.

c) Purchase Price of No. 6 Fuel: The Board also ordered that the cost of service price for No. 6 fuel to be used in the RSP for calculating the fuel price variation would be an annual average fuel price of $25.47/bbl as opposed to $20/bbl that was proposed by Hydro. The price set by the Board was based on the monthly 2002 fuel forecast prices that were filed in Table 1 of R.J. Henderson's, 2nd Supplementary Evidence. The Board also ordered Hydro to file updated 12 month fuel forecasts as part of its quarterly reporting to the Board.

d) Retail Cap: The Board ordered the elimination of the $50 million cap as opposed to increasing the cap to $100 million as proposed by Hydro.

Recovery of the Balance in the RSP

According to Hydro the method of recovering the balance in the RSP that was set in 1985 had been working well. The balance was recovered from the customers over a three year period using a declining balance method. However, during the hearing there was discussion as to whether a shorter time frame should be considered due to the increasing balances in the plan. In its final argument submission, Hydro indicated that it was not opposed to a shorter time frame but did note the impact on customers of using an accelerated recovery method.

As a result of trying to balance the issue of matching the recovery of costs in the period that the costs were incurred and the overall impact on customer rates, the Board's orders included the following:

- The Board did not allow any additional recovery of the existing RSP balance until 2003. The RSP mill rate for the Industrial Customers was reset to the rate that was effective January 1, 2001 for the remainder of 2002 and the RSP mill rate for NP remained at the rate that was effective July 1, 2001. The NP mill rate would be in effect until July 1, 2003.
- The existing balances in the RSP were fixed as of the end of the month prior to the effective date of rate implementation based on the current methodology. This occurred August 31, 2002 for NP and the Industrial Customers, and this balance became known as the "Old Plan". Any balances that would accumulate in the plan after August 31, 2002 would be known as the "New Plan".

- The recovery of the "Old Plan" was to be recovered over a five year period commencing in 2003 using a straight line recovery method. Interest was accumulated and maintained on the balance using the WACC.
- The recovery or credits of balances that accumulated in the "New Plan" would be calculated using a straight line method over a two year period. This would be effective January 1, 2004 for the Industrial Customers and July 1, 2004 for NP.

2003 General Rate Review

On May 21, 2003, Hydro filed an Application with the Board for a general rate review. This Application did not include any major proposals with respect to the operation of the RSP other than rebasing the price of fuel, hydraulic production, Holyrood efficiency factor and load forecast as a result of the updated cost of service included with the Application. However, while the hearing was ongoing representatives for Hydro, NP, the Industrial Customers and the Consumer Advocate were engaged in settlement discussions separate from the hearing, and without participation of Board staff or Board Counsel, relating to certain amendments to the RSP.

On November 13, 2003, Hydro filed proposed amendments to the RSP (Consents #2 and #3) requesting that the Board approve these amendments to be effective January 1, 2004. The parties that participated in the settlement discussions consented to the filing of the proposed amendments with the exception of the Industrial Customers, who took no position with respect to the amendments of the provisions that related to the recovery of the plan balances. On December 15, 2003, the Board issued Order No. P.U. 40 (2003), ordering that the proposed amendments be effective as of January 1, 2004. The RSP continued to include the four main elements, that being, hydraulic, fuel, load and rural rate alteration; however there were changes within the components. The amendments also included changes in the calculation of the recovery or refund of plan balances.

Hydraulic Variation Component

The calculation of the hydraulic variation component did not change but it would be tracked separately from the other components. However only 25% of the annual balance in the hydraulic variation component, plus 100% of financing charges for that year, would be recovered from or refunded to customers each year. This amount, which is defined as the "Hydraulic customer assignment" would be removed from the Hydraulic Variation Account at the end of each year.

As indicated in Hydro's Rules and Regulations relating to the formulae used to calculate the activity in the RSP, the hydraulic customer assignment would be allocated among the Island Interconnected customer groups of NP, Industrial Customers and the Rural Island Interconnected. The allocation would 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 that would be allocated to the Rural Island Interconnected will be re-allocated between NP and the regulated Labrador Interconnected customers in the same proportion that the Rural Deficit is allocated in the approved Test Year Cost of Service study. The Labrador Interconnected portion is written off to Hydro's net income.

The portion of the hydraulic customer assignment allocated to NP and the Industrial Customers would be included with the RSP balances for each of these groups as of December 31st of each year.

The reason provided for this proposed change was that, due to the nature of the hydraulic cycle, it had been contemplated that this part of the RSP may never have to be recovered from or refunded to customers. However, after Hydro's analysis, using historical data of the amount that could potentially accumulate in this component and the possible effect on Hydro's risk and its balance sheet, it was agreed by the parties that 25% of the balance, plus 100% of financing charges for that year, be assigned annually to customers for collection or refund.

Fuel Cost Variation Component

The calculation of the activity for the fuel component did not change, however it was noted that the large balances accumulating in the RSP in recent years were the result of significant differences between the test year price of fuel and the actual price of fuel. Prior to the start of this hearing the test year price of fuel was an annual average price of $25.47/bbl and the actual average price of fuel in December 31, 2003 was $31.05.

The parties involved in the settlement discussions agreed that a mechanism was needed to address this issue on a go forward basis. A fuel rider, which takes into account the forecast price of fuel was the mechanism proposed in Consent # 2 and approved by the Board. The determination of the fuel rider is included under the "Fuel Price Projection" in Hydro's Rules and Regulations relating to the RSP.

A fuel price projection is calculated using forecast oil prices provided by the PIRA Energy Group and the current US exchange rates to determine the fuel rider for the rate adjustments. This would occur in April each year for NP, to be included with the RSP adjustment effective July 1st and for the Industrial Customers it would occur in October each year to be included with the RSP adjustment effective January 1st.

The calculation basically determines the difference between the average forecast price for the following 12 months and the test year price and multiplies this difference by the number of barrels of fuel forecast to be consumed at the Holyrood generating station for the test year.

According to the Rules and Regulations, the Industrial Customer allocation of the forecast fuel price change will be based on the 12 months to date kWh as of the end of September and is the ratio of the Industrial Firm invoices energy to the total of: Utility Firm and Firmed-Up Secondary energy, Industrial Firm invoiced energy and the Rural Island Interconnected bulk transmission energy. The NP customer allocation is calculated in the same manner with the exception of the allocation being based on the 12 months to date kWh as of the end of March.

Load Variation Component

The change in this component of the RSP was to treat the fuel costs component of the load variation in the same manner as the revenue component. The revenue variation component is assigned to the customer class which caused the variation, however previously the fuel cost variation was treated as common costs and shared proportionately among the customer classes regardless of the class that caused the variation. It was allocated using customer energy ratios.

By treating the fuel costs in the same manner as the revenue variation, it meant that the fuel cost variation resulting from the load variation would be assigned fully to the appropriate customer class, and as a result the customer class that caused the change in the load would be assigned the cost or recovery of the fuel associated with the change.

<u>Rural Rate Alteration</u>

This component of the RSP is calculated to account for changes in Rural revenues which occur as a result of changes in NP rates. This is due to the fact that Rural rates on the Island Interconnected and Isolated systems are primarily based on NP rates.

During this hearing, there was a mediation agreement titled "Parties Agreement on Cost of Service and Rate Design Issues", filed with the Board, that included settlement on various items included in Hydro's application. Included in this agreement was an additional provision to be added to the Rural Rate component of the RSP: "Hydro will adjust the Rural Rate Alteration component based on its projection of the 5 year phase-in of Labrador rates and the revenue credit available from secondary energy sales to CFB Goose Bay." This component was referred to as the "Rural Labrador Interconnected Automatic Rate Adjustments" and is contained in Section 1.3 (b) of Hydro's Rules and Regulations relating to the RSP.

<u>Recovery of Plan Balances – Current and Historical Plans</u>

As a result of the amendments included in the Consents which were subsequently approved in P.U. 40 (2003), the activity of the RSP commencing in January 2004 was allocated to a new plan that would be known as the "Current" plan. The balances in the "old" plan that accumulated up to August 31, 2002 and the balance that accumulated in the "new" plan for the period September 1, 2002 to December 31, 2003 were combined into a plan that would be known as the "Historical" plan.

The "Current" Plan

The recovery of the balance in this plan would occur over a one year amortization period rather than a two year amortization. The adjustment rate would be established to target a zero balance in the customer plans at the end of each recovery period. This change was recommended to help alleviate increasing balances in customer RSP balances.

The RSP adjustment rate would be comprised of two components. The first component was set to recover the customer balances annually and would be calculated as follows:

- <u>NP customers</u>: This balance would be the existing plan balance as of March 31st, less any projected recovery/refund of the balances for April, May and June, plus the estimated financing costs (using WACC) of the plan balance to the end of the next recovery period.

- <u>Industrial Customers:</u> This balance would be the existing plan balance on December 31st plus the projected financing costs of the plan balance for the next twelve months.

The second component of the adjustment rate would be the fuel rider that was previously discussed in this report. The total adjustment rate would be the rate derived from the plan balance plus the fuel rider. The Industrial Customers' rate is effective January 1st of each year and the NP rate is effective July 1st.

The "Historical" Plan

This plan was the result of the combination of the NP and Industrial Customers' balances outstanding up to August 31, 2002 and the balances that accumulated in the plan from September 1, 2002 to December 31, 2003.

As a result of the negotiations between the parties, it was proposed that to reduce the immediate impact on customers' rates, both of these RSP balances would be added together and would be recovered over a four year period commencing January 1, 2004 for the Industrial Customers and July 1, 2004 for NP. This proposal was approved by the Board in P.U. 40 (2003).

Rebasing of Variables

As part of the updated cost of service included in this Application, a number of variables included in the operation of the RSP are rebased or set as a result of the new test year. The variables that were approved by the Board for the 2004 test year were as follows:

a)	Price of No. 6 Fuel:	average annual price of $26.59/bbl
b)	Holyrood Conversion Factor:	630kWh/bbl
c)	Hydraulic Production:	4,582.15 GWh
d)	Load Forecast:	6107.50 GWh

Ongoing Monitoring

As a result of the changes approved in P.U. 40 (2003), the Board directed Hydro to complete a review of the operation of the RSP for the period January 1, 2004 to December 31, 2005. The Board indicated in the Order that the review should assess the effectiveness of the revised RSP, including an assessment of the impact on customers in terms of rates based on the outstanding plan balance as of December 31, 2005. The Board directed Hydro to file this report to the Board no later than June 30, 2006.

2006 General Rate Review and Other RSP Activity During 2006

On August 3, 2006, Hydro filed a general rate application with the Board for approval, among other items, of the rates to be charged for the supply of power and energy to its customers as of January 1, 2007. As previously noted in P.U. 14 (2004), the Board ordered Hydro to prepare a report on the operation of the RSP for the period January 1, 2004 to December 31, 2005. Hydro filed this report on June 30, 2006 and, as part of its August 2006 application, Hydro requested that the changes proposed in the June 30, 2006 report be approved by the Board. Hydro also included other proposals for the Board's approval in addition to those included in the June report.

As part of the hearing process of the application there were several settlement agreements filed by the parties participating in this process. These agreements were the result of a negotiation process related to various issues presented in the application. The first agreement, "Agreement of Cost of Service, Rate Design and Rate Stabilization Plan" was filed October 6, 2006 and on November 23, 2006 the "Revenue Requirement Agreement", the "Supplementary COS, Rate Design and Other Issues Agreement" and the "Labrador Interconnected Rates Agreement" were filed with the Board.

June 30, 2006 Report – Review of the Operation of the RSP

The changes proposed by Hydro in this report were as follows:

- Fuel rider: When new test year base rates are implemented, if the fuel rider forecast is more current, a fuel rider which incorporates the new forecast should be implemented at the same time as the change in base rates.
- Load variation: Change the customer allocation for the load variation provision such that both the revenue and fuel components of the load variation are allocated between NP and the Industrial Customers based on the customer energy ratios. In Hydro's 2003 general rate application, the parties agreed that both the revenue and fuel components would be assigned where the load variation occurred (i.e. assigned to the customer class caused the load variation).
- Historical Plan Balances: Hydro indicated a willingness to extend the recovery period for the historical RSP, provided that there is an agreement among customers and there was consideration given to the issue of intergenerational equity.
- Aur Resources (i.e.: Teck Cominco): If the Board granted this company the proposed exemption from the historical RSP adjustment rate for 2006, this exemption should continue until the Industrial customer Historical Plan is eliminated.
- Diesel Fuel Impacts: Hydro believed that the variations in the uncontrollable price of diesel fuel presented an unreasonable net income risk to Hydro. As a result of this risk Hydro believed it should have some protection of this risk through the RSP.

Other Proposals in the 2006 General Rate Application

The application also included other proposals related to the operation of the RSP. These were as follows:

- Change the treatment of NP's allocated share of the CFB Goose Bay Revenue Credit whereby NP's portion of this credit would be removed from NP's base rates and refunded to NP though the RSP based on secondary revenue.
- Changes to the RSP to reflect the operation of the proposed annual automatic adjustment mechanism for Hydro's rate of return on rate base.

October 20, 2006 Parties Agreement

This Agreement titled, "The Parties' Agreement on Cost of Service, Rate Design and Rate Stabilization Plan" included agreement on several of the RSP issues to be put forward for the Board's approval.

The Parties agreed with Hydro's proposal relating to the fuel rider, that when new test year rates are implemented, if the fuel rider forecast is more current, a fuel rider which incorporates the new forecast should be implemented at the same time as the change in base rates. In P.U. 8 (2007), the Board accepted this approval in principle since it could not be used until the next general rate application (Hydro's RSP adjustment rates for January 1, 2007 were already implemented). The Board indicated in its Order that to ensure the purpose and language of this provision is appropriate for the next test year, this item should be discussed in the RSP review that was also included in this Agreement.

The Parties also agreed that the current provisions of the RSP should continue as approved for all hydraulic, fuel and load related components and all recovery related calculations with the exception of the following three issues which were not agreed upon:

1. Whether the potential effects of the variations in rural diesel fuel costs and rural power purchase costs on Hydro's net income should be protected by the operation of the RSP;
2. Whether there should be any limitations on the potential effects of the full or partial closure of the CFB Goose Bay facility on Hydro's net income; and
3. The disposition of the forecast hydraulic production variation balance in the RSP.

The Agreement also indicated that the Parties agreed that the RSP would be reviewed with the intent to review the design objectives of the current RSP. The Agreement indicated that no later than October 31, 2007, Hydro would host a Technical Conference, to be attended by the Parties and others as determined by the Parties, to discuss the re-design of the RSP and the Industrial Customer rate design. The Board agreed that a review of the RSP design would be appropriate and ordered in P.U. 8 (2007) that Hydro file with the Board, no later than May 31, 2007, a copy of the terms which are proposed for the RSP review, setting out the terms of reference, the specific review objectives, a list of participants, a planned timeline, and an outline of the review process.

<u>November 23, 2006 – Parties Agreement on Revenue Requirement</u>

In this Agreement, the Parties agreed on the disposition of the Hydraulic Production Variation balance as of December 31, 2006 and put forward the following proposals for the Board's consideration and approval:

Newfoundland Power

- Effective December 31, 2006, NP's portion of the actual RSP Hydraulic Production Variation balance as of December 31, 2006 would be allocated to NP's Historical RSP Balance
- Effective January 1, 2007, Hydro would decrease the RSP rate charged to NP as a result of the reduction in NP's Historical RSP balance as noted above. This would enable Hydro to amortize the collection of the reduced Historical RSP balance over 18 months (January 1, 2007 to July 1, 2008) and recognized that the RSP rates would be reset on July 1, 2008 in accordance with the normal operation of the RSP.
- Effective January 1, 2007, NP would reduce the RSA adjustment it charged its customers to reflect the change in the RSP rate noted above.

Industrial Customers

- The normal annual 25% allocation of the Industrial Customers' share of the actual Hydraulic balance as of December 31, 2006 would be incorporated in customer rates effective January 1, 2007 in accordance with the existing RSP rules, and
- The portion of the Industrial Customers' share of the actual Hydraulic credit balance, net of the allocation outlined above would be transferred, effective December 31, 2006, to the Industrial Customers' Historical RSP and used to reduce any charge, or increase any credit, which would otherwise be applied effective January 1, 2008 to the rates of the Industrial Customers under the current RSP rules.

<u>November 23, 2006 – Parities Agreement on COS, Rate Design and Other Issues</u>

In this Agreement, the Parties (including Hydro) agreed to withdraw two proposals that had been put forward by Hydro in its Application. The first withdrawn proposal related to the proposed change to the treatment of NP's allocated share of the CFB Goose Bay Credit. The Parties indicated that the current treatment of the CFB Goose Bay Revenue Credit would continue for the purpose of this Application, except to the extent of the proposed modification included in the agreement "Labrador Interconnected Rates" that was also filed on November 23, 2006. The second withdrawn proposal related to the introduction of a new provision in the RSP which would collect additional Rural Diesel fuel and power purchase costs from NP or similarly refund the savings to NP.

It was agreed by the Parties that these proposals would be discussed as part of the RSP review that was agreed to in the October 20, 2006 Agreement.

November 23, 2006 – Parties Agreement on Labrador Interconnected Rates

In this Agreement the Parties, with the exception of the Industrial Customers who took no position on this issue, put forward the following proposal to the Board relating to the operation of the RSP:

- "A sufficient portion of the CFB Goose Bay Revenue Credit will be used to maintain existing rates paid by the Rural customers on the Labrador Interconnected system for 2007. The revenue shortfall to Hydro from maintaining existing rates will be recovered through the RSP. The RSP rules pertaining to the Rural Rate Alteration (Rural Labrador Interconnected Automatic Rate Adjustments) will be modified to reflect the foregoing and to facilitate the phasing in of the CFB Goose Bay revenue credit for secondary energy sales to reduce the Rural Deficit. The modified RSP rules will be submitted to the Board for approval."

Government Directive

On September 29, 2006, the Government of Newfoundland and Labrador ("the Government") issued an Order in Council to the Board pursuant to section 5.1 of the EPCA, which directed the Board as follows:

> *"The Board of Commissioners of Public Utilities is directed to adopt a policy that, if Newfoundland and Labrador Hydro applied to the Board on or before October 1, 2006 for a change in the Industrial Customers Rate Stabilization Plan which is not on the normal schedule for adjustments to that Plan, such change being associated with the withdrawal of a significant industrial customer and including a contribution to the historic portion of the Plan to offset implications of this withdrawal, the Board shall approve the application and, if the application is made on or before September 22, 2006 , the Board shall apply procedures so that changes in Industrial Customer electricity rates are implemented no later than October 1, 2006;…"*

Hydro did file an application to the Board on September 22, 2006 for approval of the revised 2006 Industrial Firm Energy rates that reflected changes to the Industrial Customers' RSP as a result of the closure of Abitibi Consolidated – Stephenville Division and the Order in Council noted above. These changes were approved by the Board in P.U. 31 (2006) as directed by the Government and the revised rate became effective as of October 1, 2006. The approved adjustments to the Industrial Customers' RSP were as follows:

- The calculation of the fuel rider was revised to adjust the 2004 Test Year barrels of No. 6 fuel forecast to be consumed at the Holyrood Generating Station to reflect a reduction in load resulting from the closure of Abitibi Consolidated Inc – Stephenville Division;
- A modification of the calculation of the Historical Plan RSP recovery rate to reflect a $10 million contribution from the Government to the plan on account of the closure of Abitibi Consolidated Inc – Stephenville Division; and
- The Industrial Customer kWh sales (2004 Test Year) were adjusted to reflect the closure of Abitibi Consolidated Inc – Stephenville Division.

Order No. P.U. 46 (2006)

Hydro filed a Revised Application on December 6, 2006 that incorporated the Settlement Agreements and the Government Directives and it filed a further application on December 20, 2006 requesting Board approval of the revisions to the RSP rules to reflect the intent of the December 6, 2006 Government Directive related to the rural rate alterations, the Settlement Agreements and the Revised Application.

Due to the timing of this hearing the Board was not in a position to issue a final order before January 1, 2007. However, on December 29, 2006, the Board issued P.U. 46 (2006). In this Order the Board did not approve all of the proposed changes but approved those which were appropriate in the context of the approval of interim rates that were to be effective January 1, 2007. The Board approved the following on an interim basis:

> "i. Changes to the monthly amount of the 2007 automatic rate adjustment for the Rural Labrador Interconnected system resulting from the phase-in of the CFB Revenue Credit from secondary sales to CFB Goose Bay to the rural deficit, leaving the CFB Revenue Credit applied to the rural deficit in Hydro's final 2007 test year cost of service and future years to be determined later by final Order of the Board; and
>
> ii. The use of a reserve account to maintain the December 31, 2006 RSP Hydraulic Variation balance, net of the normal 25% December 31, 2006 allocation, with normal RSP financing charges applied, until the balance is disposed of later by final Order of the Board."

Order No. P.U.8 (2007)

This Decision and Order of the Board in the matter of Hydro's 2006 General Rate Application was issued April 12, 2007.

In this Order the Board indicated that it was satisfied that the allocation of a portion of the CFB Goose Bay Revenue Credit during the extended phase-in of uniform Labrador Interconnected rates was reasonable and consistent with regulatory principles and approved Hydro's proposed methodology for this allocation. However, the Board included in the Order that Hydro would be required to file supporting calculations with each annual application for approval of changes to Labrador Interconnected rates. The Board noted that the RSP rules submitted by Hydro included specific elements of the rates beyond 2007 for the Labrador Interconnected customers, since the Board indicated that future rates would require approval of the Board upon application by Hydro. The Board also ordered Hydro to revise the RSP rules to remove reference to the specific amounts in the Rural Rate Alteration for the years beyond 2007.

The Board also approved the distribution of the balance of the reserve account established in P.U. 46 (2006) in accordance with the special adjustment to the RSP Hydraulic Production Variation balance that was proposed in the Settlement Agreements. This one-time adjustment was set out in Schedule B of this Order and Hydro was required to revise the RSP rules that were submitted to exclude the reference to this one-time adjustment. Since this Order was not issued until April 12, 2007, Hydro adjusted the 2007 opening balances for NP's Current RSP Plan and Historical Plan, as well as the 2007 opening balance of the Industrial Customer's Historical Plan to reflect the distribution of the Hydraulic Plan balance as of December 31, 2006.

The changes to the rules in the RSP that Hydro submitted for approval also included references to the proposed Automatic Adjustment Mechanism ("AAM") that Hydro had proposed for the setting of future rates. The Board did not approve the use of an AAM at this time and therefore Hydro was ordered to revise the RSP rules to remove the reference to the AAM.

Rebasing of Variables

As part of the updated cost of service included in this Application, there were a number of variables that are included in the operation of the RSP that were rebased or set as a result of the new test year. The variables that were approved by the Board for the 2007 test year were as follows:

a)	Price of No. 6 Fuel:	average annual price of $55.11/bbl
b)	Holyrood Conversion Factor:	630kWh/bbl
c)	Hydraulic Production:	4,472.07GWh
d)	Load Forecast:	5,820.10GWh

Order No. P.U. 32 (2006)

On September 18, 2006, Hydro filed an application to the Board requesting approval to recover, through the RSP, the cost of No. 6 fuel burned at the Holyrood Generating Station with a sulphur content not exceeding 1% by weight instead of the lower cost of fuel with a sulphur content of 2% which was previously included in rates.. This approval was required in order for Hydro to be in compliance with a Certificate of Approval issued by the Department of Environment and Conservation which prohibited Hydro from burning any fuel with sulphur content greater than 1% by weight.

On October 20, 2006, the Board issued P.U. 32 (2006) approving the recovery by Hydro of the cost of burning 1% sulphur content No. 6 fuel at Holyrood through the RSP effective immediately.

RSP Activity During 2007

Order No. P.U. 1 (2007)

On January 20, 2006, the Board issued P.U. 1 (2006) approving interim rates for Aur Resources Inc. (now known as Teck Cominco), a new industrial customer that began operating at the Duck Pond Mine in Central Newfoundland. These interim rates included the Historical Plan balance portion of the RSP. On January 18, 2007, the Board issued P.U.1 (2007) approving the exclusion of the portion of the rate relating to the Historical Plan balance of the RSP, and Hydro was also ordered to refund or credit Aur Resources the difference between the rates approved in P.U. 1 (2006) and the rates approved in this Order.

As a result of this Order, the 2007 opening balance of the Industrial Customer Historical Plan balance was increased by $129,103 to reflect the refund of $125,726 to Aur Resources for amounts collected from January 20, 2006 to December 31, 2006 and the related financing charges of $3,377.

Rural Rate Alteration

Beginning January 2007, the Rural Rate Alteration included a monthly amount of $92,560. This amount related to the phase-in of the application of the credit from secondary energy sales to CFB Goose Bay to the Rural deficit. This was included in the November 23, 2006 Settlement Agreement "Labrador Interconnected Rates" and approved by the Board in P.U.8 (2007). The RSP Regulations received final approval in Order P.U. 14 (2007) which was issued May 17, 2007.

Historical Plan Balance – Industrial Customers

As ordered in P.U. 40 (2003) as a result of the Settlement Agreement filed in relation to the 2003 General Rate Hearing, the balances in the "new" and "old" plans were consolidated as of December 31, 2003 and the balance was to be recovered over a four year period. As of December 31, 2007, there was a credit balance in the Industrial Customers' portion of the Historical Plan balance of $1,382,494 and, in accordance with Section E of the RSP rules, this balance was transferred to the Industrial Customers' Current Plan. The recovery of NP's portion of the Historical Plan Balance continued until June 30, 2008.

RSP Activity During 2008

Industrial Customers' RSP Rate

In accordance with Section C of the RSP Regulations, Hydro is required to calculate a fuel price projection that includes forecast fuel price changes and determine the annual fuel rider for the rate adjustments. This is required to be calculated in October of each year for the Industrial Customers.

The amount of the forecast fuel price change and the details of an estimate of the fuel rider based on 12 months to date kWh sales to the end of September is required to be reported to the Industrial Customers', NP and the Board by the 10th working day in October.

The RSP adjustment rate including the fuel rider for Industrial Customers' is to be calculated each year with an effective date of January 1st. On December 20, 2007, Hydro filed an application with the Board requesting that the rates currently in place for the Industrial Customers' would continue on an interim basis. The Board issued P.U. 34 (2007) approving that the rates for the Industrial Customers that were in effect for 2007 would continue after January 1, 2008 until the Board ordered final rates for the Industrial Customers in 2008. These interim rates continued throughout 2008. Therefore, the fuel rider has not been included in the Industrial Customers' RSP adjustment rate, as 2007 rates were based on a 2007 test year with no fuel rider component.

It is important to note that the 2007 RSP adjustment rates that were set as of January 1, 2007 were as follows:

- The RSP adjustment rate for the Current Plan was a refund of 2.0 cents per kWh
- The RSP adjustment rate for the Historical Plan was a recovery of 1.215 cents per kWh.

As a result of the completion of the Industrial Customer Historical Plan balance, these rates were combined to a refund rate of 0.785 cents per kWh on the Current plan balance effective January 1, 2008. The refund rate for Teck Cominco continued at 2.0 cents per kWh as this company was excluded from the recovery of the Historical plan.

Rural Rate Alteration

Beginning January 2008, the Rural Rate Alteration included a monthly amount of $32,433. This amount related to the phase-in of the application of the credit from secondary energy sales to CFB Goose Bay to the Rural deficit. This received final approval in Order P.U. 33 (2007) which was issued December 21, 2007.

Historical Plan Balance – NP Customers

The recovery of NP's portion of the Historical Plan Balance concluded June 30, 2008. At this time there was a credit balance in the Plan of $2,238,025 that was transferred to the Current Plan in accordance with Section E of the RSP Regulations.

RSP Activity During 2009

Industrial Customers' RSP Interim Adjustment Rate

On December 11, 2008 Hydro filed an Application to the Board for approval to continue the existing RSP adjustment rates with the exception of Teck Cominco. The rates for this industrial customer would increase to the same level as the other Industrial Customers as the Historical Plan balance no longer existed. The Application also requested a revision to the RSP rules and regulations for Hydro's Industrial Customers to remove the reference to the Historical Plan balance.

On December 17, 2008 the Industrial Customers made a submission to the Board requesting that the interim rates be continued, with the existing differential for Teck Cominco, until March 31, 2009. The Industrial Customers' request was made to allow time for parties to request information and file evidence, and they suggested that Hydro should be required to file an application for final rates at least thirty days prior to the expiration of the interim rates.

On December 24, 2008, the Board issued P.U. 37 (2008) allowing the Industrial Customers rates to continue on an interim basis until March 31, 2009 and the Order also required Hydro to file an application by January 30, 2009 to finalize the interim rates for the Industrial Customers.

On January 16, 2009 Hydro filed an application requesting an extension of the filing deadline for an application to finalize rates until June 30, 2009 and approval to continue using interim rates for the Industrial Customers until the Board is able to deal with the application when it is filed.

The Board issued P.U. 6 (2009) on January 30, 2009 approving the continuation of the interim rates until the Board issues an Order with respect to the finalization of the rates. The Board also approved Hydro's request to extend the filing deadline of the application to finalize the interim rates to June 30, 2009.

On June 30, 2009, Hydro filed an application with the Board concerning the RSP components of the rates to be charged to Industrial Customers. In its application, Hydro indicated that it had updated and completed its analysis of the fuel and load variation caused by the events in the pulp and paper industry that are described below and that the application of the existing RSP rules to calculate rates for Industrial Customers would result in significant and unreasonable rate volatility. Therefore, in this application, Hydro proposed that the rates for Teck Cominco Limited be the same as those in effect for the other Island Industrial Customers and that the existing interim rates currently in effect for these customers' be made final.

The Board did not hold a hearing specific to this Application, however a preliminary hearing relating to the Industrial Customer's interim rates and the Board's jurisdiction with regards to the finalization of these rates and the impact on the other island customers was held on June 14, 2010 which will be discussed in further detail in the section "RSP Activity for 2010".

Industrial Customer Load Requirements

During the 4th quarter of 2008 to the 2nd quarter of 2009, there were significant announcements and events within the pulp and paper industry in the Province due to a deterioration of the global newsprint market. These events can be summarized as follows:

- On December 4, 2008, Abitibi Consolidated Inc announced it would be closing the paper mill in Grand Falls-Windsor as of March 31, 2009. As a result of the announced closure on December 16, 2008, the Government of Newfoundland and Labrador introduced and passed into law the *Abitibi –Consolidated Rights and Assets Act*. As a result of this legislation, the hydro electric generating assets owned by Abitibi were repatriated. In its June 30, 2009 Application, Hydro indicated that the impact of the repatriation of these assets on Island Interconnected electricity rates could not be estimated at this time.
- On January 7, 2009, Kruger Inc., owner of the Corner Brook Pulp and Paper mill, announced its intention to reduce its newsprint production by 25,000 tonnes in the first half of 2009. It indicated that this downtime would be spread across its three Canadian mills which included the mill in Corner Brook.
- On June 24, 2009, Kruger announced that it was going to idle its No. 4 paper machine in Corner Brook. This machine was shut down in March, 2009 for what was to have been an eight week period, but in this announcement the Company indicated that the shutdown would continue indefinitely. Two paper machines remain active at the Corner Brook mill.

These events have had a significant impact on the load requirements of the Island Industrial Customers. The December 2009 RSP report compiled by Hydro indicates that the actual kWh sales included in the load variation component for Industrial Customers for 2009 was 384,777,985 kWh as compared to the cost of service sales of 894,300,000 kWh. The cost of service sales are based on the 2007 Test Year Cost of Service that was approved in P.U.8 (2007). This significant reduction in load resulted in a credit balance of $25,874,401 (amount owing to Industrial Customers) being added to the Industrial Customers RSP plan balance. The overall outstanding RSP balance owing to Industrial Customers as of December 31, 2009 is $36,874,648.

In the accompanying letter to the June 30, 2009 Application, Hydro made reference to the proposal made in its June 30, 2006 report, "Review of the Operation of the Rate Stabilization Plan" which covered the period January 1, 2004 to December 31, 2005, relating to a change in the method of allocating the load variation component of the RSP. The proposal was stated as follows:

> *"Hydro intends to propose a change in the method of allocating the load variation component of the RSP such that both the revenue and the fuel components of the load variation will be allocated between NP and IC using customer energy allocation ratios. In effect, the customers will be allocated with Hydro's bottom line impact in the same proportion as energy costs are shared in as test year Cost of Service."*

As indicated earlier in this report, this proposal was included in Hydro's 2006 General Rate Application and, as a result of negotiations between the parties involved in this hearing, a Settlement Agreement titled "Parties Agreement on the Cost of Service, Rate Design and Rate Stabilization Plan" indicated that the RSP would be reviewed with the intent to better reflect the design objectives of the RSP. It noted that the review would include whether the load variation component of the RSP was a necessary component in the plan. A Technical Conference was scheduled to be held no later than October 31, 2007 where the redesign of the RSP would be discussed. According to Hydro, discussions were held during 2007 and 2008 with NP, the Industrial Customers and the Consumer Advocate on changes to the RSP rules but there was no consensus during those discussions.

Hydro indicated in its letter dated June 30, 2009 that it was its intention to file this proposed change relating to the load variation with the Board no later than the filing of its next General Rate Application. Hydro also noted in the letter that the June 30, 2009 Application did not contain any proposed changes to the components of the RSP, however the Board might wish to consider the following:

> *"…suspension of the existing load variation allocation rules and holding in abeyance current and future load variation amounts until such time as Hydro can develop a proposal to address the current anomalies in the RSP…."*

Hydro has included the following note on the Plan Highlights of the December 31, 2009 RSP Report:

> *"Disposition of the load variation is one of the issues to be considered by the Public Utilities Board in a pending hearing. This may impact the balances owing to customers in the current plan."*

Rural Rate Alteration

On December 22, 2008, the Board issued Order P.U. 34(2008) which approved the change of the monthly amount of the automatic rate adjustment in the Rural Rate Alteration in the RSP from $32,433 to ($5,766) effective January 1st, 2009.

This amount relates to the phase-in of uniform rates for the Labrador Interconnected customers.

RSP Activity During 2010

Industrial Customers' RSP Interim Adjustment Rate

As previously noted, on June 30, 2009, Hydro filed an Application with the Board concerning the RSP rates to be charged to Industrial Customers. In this Application, Hydro proposed that the rates for Teck Cominco Limited be the same as those in effect for the other Island Industrial Customers and that the existing interim rates currently in effect for these customers be made final.

The Board published a Notice of the Application and set the hearing date for this Application for May 17, 2010. Interventions were filed by Hydro's Industrial Customers, Abitibi Consolidated Company of Canada (a former industrial customer of Hydro), Newfoundland Power and the Consumer Advocate, Mr. Thomas Johnson. Expert evidence was filed by the various interveners on September 9, 2009 and all information requests were issued and answered.

On May 11, 2010, the Board notified the parties participating in the hearing that the public hearing would not proceed as scheduled. The Board indicated that after a review of the information on record, it had been determined that the Application and supporting evidence was inadequate and may not address all of the issues associated with the Application. However, the Board set a date for a counsel meeting to be held to ensure that the issues would be addressed in a fair and timely manner.

On May 25, 2010, the Board advised the parties in writing that a preliminary hearing would be held on June 24, 2010.

On June 2, 2010, Hydro submitted a letter based on the results of the counsel meeting. The letter set out an agreed upon list of issues for the Board's consideration that should be dealt with in the preliminary hearing. The issues for the Board's consideration were as follows:

> *"Does the Board have the jurisdiction to issue an order which changes how the Rate Stabilization Plan (RSP) operated before the date of the order and, if so, does this jurisdiction extend to any aspect of the operation of the RSP, including the rate charged to customers, the determination of the balance(s) in the RSP, and how these balances are allocated to customers or customer classes? In particular:*
>
> - *Does legislation or common law give the Board any specific relevant authority or alternatively, restrict the Board's authority?*
> - *What would generally accepted sound public utility practice as set out in s.4 of the EPCA require?*
> - *Are there any concerns in relation to vested rights, i.e. does the language of the RSP create a right/obligation in each of the customers or customer classes? If so at what point does this right/obligation accrue? Does this mean that credits/debits allocated to each customer in accordance with the plan are the responsibility of or to the benefit of customers in the class at the time of the accumulation or does the Board have the jurisdiction to order alternative disbursements of the balances?*
> - *Does the issuance of Order Nos. P.U. 34(2007), P.U. 27(2008), P.U. 6(2009), the filing of Hydro's application on June 30, 2009, or any other order of the Board impact the jurisdiction of the Board?"*

The preliminary hearing was held on June 14, 2010 to receive submissions from the parties on the question of whether the Board has the jurisdiction to change the manner in which the RSP operated, including the rates charged, the determination of the balance(s) in the RSP and how these balances are allocated to customer classes.

Order No. P.U. 25 (2010)

On August 26, 2010, the Board issued P.U. 25 (2010) which addressed its decision arising from the preliminary hearing. In this Order the Board indicated that "All parties agree that the Board has the jurisdiction to set final rates for the Industrial Customers as of January 1, 2008. Hydro, Newfoundland Power and the Consumer Advocate submit that, in establishing these final rates, the Board also has the jurisdiction to deal with the manner of how those rates, and in particular the RSP rates, are calculated as of the date of any interim order, including the disposition of any balances in the RSP arising. The Industrial Customers submit that s. 75 of the *Act* only allows the Board to set interim rates and that the rules and regulations affecting those rates cannot be made interim. The Industrial Customers argue that the Board's jurisdiction with respect to the disposition of any balances in the RSP is confined to the existing RSP rules and regulations." (Pg. 7, Order P.U.25(2010)).

The significant issues facing the Board was whether it had the jurisdiction to change the prior rules, regulations and rate structure that were used to set the final RSP adjustment rates of NP and the interim rates of the Industrial Customers; and whether the savings that had generated in the RSP as a result of the interim Industrial Customer rates can be shared among NP and the Industrial Customers or only the Industrial Customers.

The Board's conclusion as a result of the preliminary hearing was as follows:

"The Board finds that in the circumstances its jurisdiction to make orders in relation to how the RSP operated in prior years is limited. Given the manner in which this matter was brought forward the Board does not have the jurisdiction to change how Newfoundland Power's RSP operated in prior years, either in terms of the rates charged or the resulting balances. The Board does have the jurisdiction to issue an order which sets just and reasonable rates for the Industrial Customers for 2008 and 2009, including the Industrial Customers' RSP rates and how the Industrial Customers RSP operated for these years. The Board also finds that it has jurisdiction to determine whether any overpayment as a result of the interim rates is to be refunded to the Industrial Customer group or placed in a reserve account to the benefit of the Industrial Customer group…."

As a result of this Decision of the Board, an appeal was filed by Hydro and the Consumer Advocate. They were of the opinion that the Board had incorrectly interpreted *the Public Utilities Act*, particularly *section 75*, by concluding that it did not have the jurisdiction to allocate the savings in the RSP as a result of the Industrial Customers interim rates to customers other than certain Industrial Customers.

The Supreme Court of Newfoundland and Labrador, Court of Appeal released its decision on this matter on June 19, 2012.

The Court allowed the appeal and indicated in its decision that the Board's decision in declining jurisdiction was incorrect.

In the Court's conclusion in its decision, paragraph 157, page 47, the Court stated the following:

"We conclude that the Board has jurisdiction to deal with and dispose of remaining amounts in the RSP in accordance with the broad powers contained in the legislation, which include , but are not limited to, refunding it to the Industrial Customers. But these powers are not necessarily confined to disposing of the RSP fund balances solely to the benefit of one

class of customers, in this case the Industrial Customers. This is not to say, of course, that the Board should include customers other than the Industrial Customers as beneficiaries, only that the Board has the jurisdiction and authority to, and should, consider the submissions of all interested parties on this issue, taking into account generally accepted sound public utility practice and the imperative of setting just and reasonable rates that are non-discriminatory."

According to the Court of Appeal, Order No. P.U. 25 (2010) is set aside and this matter is now back to the Board for a hearing and determination in accordance with the decision.

Order No. P.U. 39 (2010)

Since issuing P.U. 25 (2010), the Board also issued P.U. 39 (2010) on December 30, 2010, which related to the matters of the RSP components of the rates to be charged to the Island Industrial Customers and an application received from the Consumer Advocate on November 15, 2010 for the approval of changes to the Rate Stabilization Plan. In this Order, the Board ordered that the RSP rate charged to Newfoundland Power (0.221 cents per kWh) that was effective July 1, 2010 as ordered in P.U.18(2010), was approved as an interim rate as of January 1, 2011. The Board also approved that the current methodology of the Rate Stabilization Plan was approved on an interim basis as of January 1, 2011 pending a further review by the Board.

Rural Rate Alteration

On December 21, 2009, the Board issued Order P.U. 45(2009) which approved the change of the monthly amount of the automatic rate adjustment in the Rural Rate Alteration in the RSP from ($5,766) to ($47,847) effective January 1st, 2010.

This amount relates to the phase-in of uniform rates for the Labrador Interconnected customers.

RSP Activity During 2011

Order No. P.U. 1 (2011)

On January 19, 2011, the Board issued P.U. 1 (2011) in response to an application from Hydro relating to an Order in Council that directed changes to be made to the RSP to reduce the balance of the RSP attributable to the Industrial Customer load variation in the amount of $10,000,000 effective September 30, 2010 and that this amount be reimbursed to the Government of Newfoundland and Labrador.

The $10,000,000 reduction in the Industrial Customer load variation was adjusted by Hydro in the RSP plan in the opening Industrial Customer load variation balance for 2011.

The Board also indicated in its Order that it had approved on an interim basis the RSP rules that were attached to the Order.

Order No. P.U. 10 (2011)

On April 14, 2011, Hydro filed an application for the approval of the RSP component of the rates to be charged to NP effective July 1, 2011.

The Board issued P.U. 10(2011) on May 27, 2011 ordering on an interim basis that the RSP adjustment rate of 0.931 cents per kWh, which is in accordance with the methodology of the interim RSP previously approved by the Board, be charged to NP effective as of July 1, 2011.

Rural Rate Alteration

On December 15, 2010, the Board issued Order P.U. 33(2010) which approved the change of the monthly amount of the automatic rate adjustment in the Rural Rate Alteration in the RSP from ($47,847) to ($98,295) effective January 1st, 2011.

This monthly amount relates to the phase-in of uniform rates for the Labrador Interconnected customers, and this amount continues to be in effect as of the date of this report.

RSP Activity During 2012

Order No. P.U. 6 (2012)

On December 22, 2011, Hydro filed an application for the approval of certain rules and regulations pertaining to the supply of electrical power and energy to Vale Newfoundland & Labrador Limited ("Vale"), an industrial customer.

The Board issued P.U. 6(2012) on March 9, 2012 approving the Service Agreement for Vale and ordered the interim rate that currently applies to Teck Resources Limited be applied to Vale, pending a final order to be made by the Board. This interim rate includes the portion of the RSP adjustment rate for the current portion of the plan but nothing for the historical portion.

Order No. P.U. 15 (2012)

On April 24, 2012, Hydro filed an application for the approval of the RSP component of the rates to be charged to NP effective July 1, 2012.

The Board issued P.U. 15(2012) on May 24, 2012 ordering on an interim basis that the RSP adjustment rate of 1.555 cents per kWh, which is in accordance with the methodology of the interim RSP previously approved by the Board, be charged to NP effective as of July 1, 2012 .

Overall RSP Balance as of December 31, 2012

Based on the information included in Hydro's quarterly report for the quarter ended December 31, 2012, the balance in the RSP is an amount owing to customers of $201,661,147. The breakdown of this amount is as follows:

Due to utility customer	$ 64,905,401
Due to industrial customer	104,079,983
	168,985,384
Hydraulic balance	32,675,763
Total RSP balance	$ 201,661,147

As previously noted, the disposition of the load variation is one of the issues to be considered by the Board in a pending hearing. Therefore, the outcome of this hearing may impact the balances owing to customers that are noted above.

Impact of Changes on the Annual Plan Balances for Newfoundland Power and the Industrial Customers

There have been many changes that have occurred with regards to the operation of the RSP since its inception in 1985, nevertheless the RSP still contains the three main components that were originally included, namely the Hydraulic Production Variation, the Fuel Cost Variation and the Load Variation. However, there have been changes that have occurred within the operation of each of these components.

It is also important to note that in P.U.39 (2010) the Board ordered that the current methodology of the Rate Stabilization Plan was approved on an interim basis as of January 1, 2011 pending a further review by the Board.

Hydraulic Production Variation

As a result of the proposed amendments that were filed with the Board on November 13, 2003 during the hearing of Hydro's 2003 General Rate Application, the parties involved agreed that only 25% of the annual balance in the hydraulic variation component, plus 100% of financing charges for that year, would be recovered from or refunded to customers each year. The remaining portion of the Hydraulic Variation Account would be tracked as a separate plan balance. The reason for this change was that over the nature of the hydraulic cycle this part of the RSP may never have to be recovered from or refunded to customers; theoretically it should work out to zero over the cycle.

Since 2004, when the 25% annual assignment to the customer class was approved by the Board, the Hydraulic Production Variation has been in a credit balance which means the actual hydraulic production has exceeded the cost of service hydraulic production in each year. The annual customer assignment is prorated to the customer class based on the 12 month kWh sales from each class, including the Rural customers which is then reallocated between NP and the Labrador Interconnected customers. This reallocation is based on the same ratio which the Rural Deficit was allocated in the approved Cost of Service Study, which is 89.10% and 10.90% respectively.

Each year the portion allocated to NP is increasing as a result of the lower energy requirements experienced by the Industrial Customers. It is important to note that because the actual Hydraulic Production has exceeded the Cost of Service Hydraulic Production, the portion assigned to the customer classes each year represents an amount owed to customers. Hydro indicated during the 2003 General Rate Hearing that the amount of Hydraulic Production included in the 2004 Test Year Cost of Service is based on the average expected from historical hydrological records and, theoretically, the balance in the Hydraulic Plan should tend to zero over an extended period of time. The portion assigned to the Current Plan each year since 2004 (with the exception of 2006 noted below) is as follows:

	25% Annual Assignment	Assignment to NP	%	Assignment to IC	%	Credit Balance Accumulated in Hydraulic Plan
2004	$ 2,225,594	$ 1,722,445	77.39%	$ 487,788	21.92%	$ 5,521,528
2005	$ 4,261,844	$ 3,393,171	79.62%	$ 839,170	19.69%	$ 10,625,444
2006	$ 6,642,336	$ 5,726,000	86.20%	$ 867,115	13.05%	$ 15,977,692
2007	$ 6,064,061	$ 5,262,203	86.78%	$ 758,949	12.52%	$ 14,820,468
2008	$ 12,652,056	$ 11,117,816	87.87%	$ 1,440,578	11.39%	$ 30,902,837
2009	$ 13,759,961	$ 12,758,921	92.72%	$ 895,664	6.51%	$ 32,181,286
2010	$ 16,928,216	$ 15,716,572	92.84%	$ 1,082,803	6.40%	$ 40,360,369
2011	$ 15,054,221	$ 14,164,335	94.09%	$ 771,512	5.12%	$ 32,737,147
2012	$ 14,296,260	$ 13,242,223	92.63%	$ 942,297	6.59%	$ 32,675,763

Note 1: The remaining % of the annual assignment is allocated to the Labrador Interconnected customers and written off to income in Hydro.

Note 2: In P.U. 7 (2008) the Board approved the proposal put forward in the November 23, 2006 Settlement Agreement "Parties Agreement on Revenue Requirement" that the full balance in the Hydraulic Plan as of December 31, 2006 be allocated to each customer class and applied to the Historical Plan balances for each customer class. Therefore, starting January 1, 2007 the opening balance in the Hydraulic Plan was zero. The 2006 annual assignment of $5,726,000 for NP was also allocated to its Historical Plan in 2006. The Industrial Customers annual assignment was assigned to its Current Plan.

Fuel Cost Variation

The fuel cost variation component of the RSP began accumulating a significant balance owing from customers starting in the year 2000 when the 12 month year to date balance of this component as of December 31, 2000 was approximately $29 million. At December 31, 2001 the 12 month year to date balance accumulated to approximately $57 million. During 2001, Hydro filed a General Rate Application with a 2002 Test Year Cost of Service. Since 1992 the cost of service price of No. 6 fuel used in the RSP was $12.50/bbl however the price of fuel had increased significantly over the years, and in 2000 the actual price of No. 6 fuel was an average of $30.92 per barrel, and in 2001 the price averaged $29.69 per barrel. This increase of the cost of fuel compared to the 1992 cost of service price led to the significant balances owing from customers. In P.U. 7 (2002-2003), the cost of service price of fuel was set at $26.80/bbl.

Rebasing the fuel price should have helped alleviate the significant balances that were accumulating on an annual basis in this component of the RSP, however as of December 31, 2002 the year to date 12 month balance in the fuel variation component was approximately $46 million and December 31, 2003 the year to date balance was approximately $36.5 million. The actual price of No. 6 fuel in 2002 went from a low of $24.33/bbl to a high of $36.44/bbl and in 2003 the actual price went from a low of $30.77/bbl high to a high of $44.44/bbl. It should also be noted that the price of fuel was not the only factor causing the increasing balances in the fuel variation component. During this time Hydro was also experiencing poor hydraulic results which resulted in lower hydraulic energy production due to low water levels in its reservoirs. As a result of the low water levels there was a requirement to produce more thermal energy at its Holyrood Generating Station thereby consuming a higher number of barrels than that included in the cost of service.

The parties involved in the settlement discussions resulting in the proposed RSP amendments that were filed on November 13, 2003 during the 2003 General Rate Hearing proposed that a fuel rider mechanism should be put in place to address the differences in the cost of service price of fuel and the actual price of fuel between general rate hearings. This proposal was approved by the Board. This fuel rider was calculated annually for NP and the Industrial Customers, and the result was included in the annual rate adjustment for the Industrial Customers effective January 1st and for NP effective July 1st of each year.

The fuel rider component of the rate adjustment, which is based on forecast fuel prices for the upcoming year, is calculated each year for the Industrial Customers and NP commencing January 1, 2005 and July 1, 2005, respectively. The purpose of the fuel rider is to help alleviate rising balances in the Plan due to changes in fuel prices between Test Years and to provide customers with more appropriate and timely price signals. The tables below summarize the amount of the fuel cost variation that has been collected each calendar year with the use of a fuel rider. The first table is a summary of the Industrial Customers' fuel rider performance since its implementation on January 1, 2005.

Industrial Customers Fuel Rider Performance

	Fuel Cost Variation	Sales (kWh)	Fuel Rider $/kWh	Amount Collected Via Fuel Rider
2005	$ 3,207,375	1,236,901,333	0.00196	$ 2,424,327
2006	3,356,991	749,100,463	0.00640	4,794,243
2007	(722,338)	771,198,558	-	-
2008	3,159,108	690,182,871	-	-
2009	(294,414)	384,777,985	-	-
2010	1,606,183	370,319,827	-	-
2011	2,470,757	310,873,875	-	-
2012	5,575,655	409,614,546	-	-
	$ 18,359,317	4,922,969,458	-	$ 7,218,570

As 2007 was a test year, the RSP adjustment rate that was set for the Industrial Customers effective January 1, 2007 did not include a fuel rider and, as noted previously in this report, this customer class has been charged an interim rate for the RSP adjustment since January 1, 2008 (based on January 1, 2007 rates), therefore there has not been a fuel rider component to this rate since 2006. During 2005 and 2006, while the fuel rider was in operation, the amount collected represented 110% of the fuel price variation. In 2007, the fuel price variation resulted in a credit balance of $722,338. The primary reasons for this balance is that from January to June the actual average No. 6 fuel costs was less than the cost of service fuel cost and during this year the hydraulic production exceeded the cost of service production by 217,363,830 kWh (4,689,433,830 kWh vs. 4,472,070,000 kWh). In 2008, the hydraulic production continued to exceed the cost of service. However increasing oil prices experienced during 2008 (the actual average No. 6 fuel cost was $71.59/bbl whereas the cost of service cost was $55.47/bbl) resulted in a fuel variation of $27,745,268 with the industrial customer's portion of this variation being $3,159,108 (11.4%). In 2009, the hydraulic production exceeded the cost of service production and fuel prices declined from 2008. From January, 2009 to October, 2009 the actual average

No.6 fuel cost per barrel was lower than the cost of service fuel cost, with an average actual cost for the year of $52.51 in comparison to $55.47 average cost of service No. 6 fuel cost per barrel. This activity resulted in a credit balance of $294,414 for the Industrial Customers. From 2010 to 2012, the hydraulic production continued to exceed the cost of service, however oil prices continued to be well in excess of the cost of service of $55.47/bbl. The actual average cost per barrel for 2010, 2011, and 2012 was $73.90/bbl, $91.92/bbl and $114.80/bbl, respectively.

The table below is a summary of the NP's fuel rider performance since its implementation on July 1, 2005.

Newfoundland Power Fuel Rider Performance				
	Fuel Price Variation	Sales (kWh)	Fuel Rider $/kWh	Amount Collected Via Fuel Rider
July 2005 - Dec 2005	$ 10,089,729	2,063,542,258	0.00428	$ 8,831,961
Jan 2006 - June 2006	14,061,261	2,530,610,023	0.00428	10,831,011
July 2006 - Dec 2006	8,106,645	2,086,254,289	0.00938	19,569,065
Jan 2007 - June 2007	(7,564,857)	2,782,177,657	0.00938	26,096,826
July 2007 - Dec 2007	2,556,498	2,208,540,936	0.00054	1,192,612
Jan 2008 - June 2008	15,959,018	2,790,457,593	0.00054	1,506,847
July 2008 - Dec 2008	8,421,747	2,169,295,259	0.00609	13,211,008
Jan 2009 - June 2009	(5,769,325)	2,804,613,659	0.00609	17,080,097
July 2009 - Dec 2009	1,575,336	2,306,580,558	0.00691	15,938,472
Jan 2010 - June 2010	15,324,871	2,807,241,041	0.00691	19,398,036
July 2010 - Dec 2010	7,988,415	2,205,696,537	0.00990	21,836,396
Jan 2011 - June 2011	28,170,718	2,934,562,364	0.00990	29,052,167
July 2011 - Dec 2011	22,147,344	2,382,932,711	0.01634	38,937,120
Jan 2012 - June 2012	54,938,113	3,014,222,843	0.01634	49,252,401
July 2012 - Dec 2012	23,417,313	2,345,094,025	0.02056	48,215,133
	$ 199,422,826	$ 37,431,821,753	-	$ 320,949,152

Since the implementation of the fuel rider, this mechanism collected 161% of the fuel cost variation allocated to NP over the past 7.5 years. Based on the information above, there were periods of time over the 7.5 years where the fuel rider component collected significantly more than the fuel price variation. As indicated previously in this report, the fuel rider for NP is calculated based on forecast oil prices provided by Hydro as of the end of March each year and the rate becomes effective July 1st of each year. Hydro received its short term and long term fuel price projections from PIRA. The two periods that resulted in a credit fuel price variation occurred in the six months prior to the fuel rider change. In both of these periods the actual cost of No.6 Fuel per barrel was lower than the cost of service however the fuel rider was based on a forecast that predicted an increase in fuel prices over the cost of service. The other reason for the lower fuel price variations in comparison to that collected is the excess of the actual hydraulic production over the cost of service production over the last 8 years and therefore less fuel was required to be burned at the Holyrood Generating Station.

Load Variation

Although the allocation of the load variation component changed several times over the years, the allocation of the revenue component of the load variation did not change since the inception of the RSP. The revenue component is allocated based on which customer class caused the change in the load. The allocation of the fuel component of the load variation did experience several changes; these changes can be summarized as follows:

> 1985 to August 31, 2002: Fuel component was allocated based on the latest Cost of Service that had been approved.

> September 1, 2002 to December 31, 2003: Fuel component was allocated based on energy allocation ratios.

> January 1, 2004 to Present: Fuel component is allocated on the same basis as the revenue component which is 100% to the customer class that caused the change in load. This change was a result of the proposed amendments that were filed November 13, 2003 based on agreement from all the parties involved in the 2003 General Rate Hearing (Hydro, NP and the Island Industrial Customers).

As noted previously, Hydro did propose in its 2006 General Rate Application that the revenue and fuel component of the load variation be allocated to the customer class using energy allocation ratios, however it was agreed in the settlement negotiations that this would be addressed in the agreed review of the design of the RSP, which to date has not occurred.

The change in allocating the fuel component to the customer class where the change in load occurred was considered to improve the fairness of the allocation of the load variation because the costs would now be allocated between NP and the Industrial Customers based on causality.

The table below presents the allocation of the load variation between customer classes since 2004.

Allocation of Load Variation

	Revenue Component ($)	Fuel Component ($)	Total Load Variation ($)		Revenue Component ($)	Fuel Component ($)	Total Load Variation ($)
2004				**2009**			
NP	(4,683,406)	3,988,531	(694,875)	NP	(15,753,937)	15,600,947	(152,990)
IC	(1,869,566)	3,154,692	1,285,126	IC	18,730,029	(44,604,431)	(25,874,402)
			590,251				(26,027,392)
2005				**2010**			
NP	5,115,147	(4,813,948)	301,199	NP	(7,877,321)	7,603,975	(273,346)
IC	2,618,789	(4,350,803)	(1,732,014)	IC	19,261,511	(45,756,045)	(26,494,534)
			(1,430,815)				(26,767,880)
2006				**2011**			
NP	7,325,661	(7,225,568)	100,093	NP	(34,488,751)	34,503,188	14,437
IC	15,667,463	(27,209,222)	(11,541,759)	IC	21,446,744	(50,958,072)	(29,511,328)
			(11,441,666)				(29,496,891)
2007				**2012**			
NP	(5,684,950)	5,938,791	253,841	NP	(37,287,599)	37,190,035	(97,564)
IC	4,525,209	(10,787,285)	(6,262,076)	IC	17,817,037	(42,365,127)	(24,548,090)
			(6,008,235)				(24,645,654)
2008				**Total 2004-2012**			
NP	(2,983,192)	2,956,940	(26,252)	NP	(96,318,348)	95,742,891	(575,457)
IC	7,503,346	(17,818,525)	(10,315,179)	IC	105,700,562	(240,694,818)	(134,994,256)
			(10,341,431)				(135,569,713)

As noted above, since 2006 the Industrial Customer class has experienced credit balances (amounts owing to customers) which have been significant. The amount of variation from 2006 to 2007 decreased because 2007 was a test year which allowed the load forecasts to be rebased based on the approved cost of service. The 2007 load forecasts for the Industrial Customers would have excluded any load requirements for Abitibi Consolidated – Stephenville Division as the closure of that operation occurred in the Fall of 2005. The cost of service load forecast for the Industrial Customers decreased by 440,500,000 kWh from 2006 to 2007. However in 2007 the actual sales were lower than the cost of service and they continue to be significantly lower in comparison to the cost of service. Based on the information in the above table, the net load variation owing to the Industrial Customers group over the past nine years is $134,994,256. The actual kWh sales for the Industrial Customers group compared to the cost of service from 2004 to 2012 are summarized below:

Industrial Customers			
	Cost of Service Sales (kWh)	Actual Sales (kWh)	Sales Variance (kWh)
2004	1,360,529,201	1,432,581,251	72,052,050
2005	1,334,800,000	1,236,901,333	(97,898,667)
2006	1,334,800,000	749,100,463	(585,699,537)
2007	894,300,000	771,198,558	(123,101,442)
2008	894,300,000	690,182,871	(204,117,129)
2009	894,300,000	384,777,985	(509,522,015)
2010	894,300,000	370,319,827	(523,980,173)
2011	894,300,000	310,873,875	(583,426,125)
2012	894,300,000	409,614,546	(484,685,454)

The significant variance in load in 2006 relates to the closure of the Abitibi mill in Stephenville and the significant variance in 2009 to 2012 relates to the closure of the Abitibi mill in Grand Falls –Windsor as well as the shutdown of one paper machine at Corner Brook Pulp and Paper. As noted above in 2012, the sales variance has decreased from the prior year by 98,740,671 kWh, this is the result of Vale Newfoundland and Labrador Limited receiving power under a Service Agreement that was approved by the Board in P.U.6 (2012).

The load variation for NP has not been experiencing the same degree of variation as that of the Industrial Customers. Based on the table included on page 34, the net load variation for NP over the past nine years is a balance owing to NP of $575,457. The table below summarizes the activity within this customer class for the past nine years.

Newfoundland Power			
	Cost of Service Sales (kWh)	Actual Sales (kWh)	Sales Variance (kWh)
2004	4,608,500,000	4,708,712,512	100,212,512
2005	4,772,700,000	4,664,093,036	(108,606,964)
2006	4,772,700,000	4,616,864,312	(155,835,688)
2007	4,925,800,000	4,990,718,593	64,918,593
2008	4,925,800,000	4,959,752,852	33,952,852
2009	4,925,800,000	5,111,194,217	185,394,217
2010	4,925,800,000	5,015,509,878	89,709,878
2011	4,925,800,000	5,317,495,075	391,695,075
2012	4,925,800,000	5,348,222,439	422,422,439

As indicated in the above table, for most of the years, the actual sales have exceeded the cost of service, and on an overall basis for the past nine years the net sales variance is a net increase of 1,023,862,914 kWh. This overall increase is primarily attributable to the increase in growth that NP has been experiencing over the past six years, particularly in the urban areas of the Province, and the fact that the load forecasts have not been rebased since this growth has occurred.

Hydro included an analysis of the various customer load variation methodologies in its June 30, 2006 Report on the operation of the RSP for the period January 1, 2004 to December 31, 2005. In this Report, Hydro concluded that, based on its analysis, changing the customer allocation method so that both the revenue and the fuel are allocated based on customer energy ratios would tend to result in an allocation more aligned with the cost of service treatment. As noted previously, Hydro has indicated in its June 30, 2009 Application that this proposal will be included in its next general rate application.

Refund/Recovery Method

The other component of the RSP that experienced changes over the years was the method of recovering or refunding the balance from (to) customers. The recovery method changed from a three year declining balance recovery to a recovery of the current plan over a two year straight line amortization to a one year recovery period. The plan also split into a "Current Plan" and "Historical Plan", with the Historical plan balance being collected over a 4 year straight line amortization period commencing January 1, 2004 for the Industrial Customers and July 1, 2004 for NP.

Summary of the Operation of the RSP

As previously noted, the RSP was established in 1986 with the objective of providing rate stability to customers and providing a mechanism to eliminate volatility in Hydro's revenue requirement due to events beyond its control, such as the price of No. 6 fuel, variations in hydraulic production and variations in load requirements.

Based on the information included in Appendix A, the RSP appeared to be operating reasonably well until fiscal 2001. During the period of 1990 to 2000, oil prices were increasing as compared to the cost of service price of fuel. However, during this period, Hydro was experiencing hydraulic production in excess of the cost of service which resulted in a credit to the plan which offset a portion of the fuel cost variation.

From 2000 to 2001, the plan balance increased from a balance owing from customers of $34.7 million to $85.1 million, and by December 31, 2003, the plan had accumulated to a balance of $155.7 million (owing from customers). During this period, fuel prices continued to increase and exceeded the cost of service price of fuel, even though it had been rebased for the 2002 test year. Compounding this, Hydro also experienced poor hydraulic production due to low water levels in its reservoirs.

Although the Order arising from the 2001 General Rate Application implemented changes to the Plan which included splitting the plan into two sections, creating different collection periods, and changing the recovery/refund period of the newly incurred balance to two years, the problems continued.

More changes occurred during the general rate hearing relating to the 2004 test year primarily due to the significant balance that had accumulated in the plan. During this hearing, the parties involved negotiated changes to the RSP and presented them to the Board for approval. As a result the structure of the split was changed and it became a Current Plan and a Historical Plan. This was done to allow the recovery of the significant balances that had accumulated in the RSP up to December 31, 2003 over a longer amortization period to reduce the impact of overall rates to NP and the Industrial Customers. Approval was also given to recover/refund the balance in the Current plan over one year.

The RSP activity relating to the Current Plan commenced January 1, 2004, and at the end of the year the plan had accumulated a balance owing from customers of $3.1 million. With the exception of December 31, 2004, the Current Plan has been in a credit balance and as of December 31, 2012, it has accumulated to a balance owing to customers of approximately $201.7 million (this includes the Hydraulic balance of $32.7 million). This is due to a number of reasons:

- The hydraulic production has exceeded the cost of service production each year since 2004. With the exception of one year, 2006, 25% of this annual balance is allocated to NP and the Industrial Customers each year and the remaining portion continues to grow in the Hydraulic plan.

- Load requirements for the Industrial Customers have decreased dramatically in comparison to the cost of service primarily due to the events that have occurred within the pulp and paper industry in the Province.

- The Industrial Customers have been charged interim rates relating to the RSP since January 1, 2008 (based on January 1, 2007 rates). These rates do not reflect the recent activity on the RSP.

- During 2007 and 2009, the RSP adjustment rate for NP included a fuel rider. During those years, however, the fuel cost variance was in a credit balance, which means that for a portion of 2007 and 2009 the actual price of fuel was less than the cost of service. Therefore, NP was paying a fuel rider to alleviate the increasing cost of fuel in excess of the cost of service price but in reality the price had decreased below the cost of service price. Also, there were many occasions that the forecast fuel price that was used to set the fuel rider was higher than the actual cost of fuel used during the period.

Although the 2006 General Rate Application resulted in a negotiated settlement that included a plan to review the RSP and there was Board approval of this settlement, this review has not been completed.

On June 30, 2009, Hydro filed an application concerning the RSP components of the rates to be charged to Industrial Customers. In this application, the Company had indicated that based on the analysis that it had completed of the fuel and load variations caused by the recent events, the existing RSP rules used to calculate rates for the Industrial Customers would result in significant and unreasonable rate volatility.

The Board set a hearing date of May 17, 2010 for this Application, however on May 10, 2010 the Board notified the parties participating in the hearing that the public hearing would not proceed as scheduled due to the lack of supporting evidence relating to the issues associated with the Application.

The Board proceeded with a preliminary hearing on June 24, 2010 to receive submissions from the parties on the question of whether the Board has the jurisdiction to change the manner in which the RSP operated, including the rates charged, the determination of the balance(s) in the RSP and how these balances are allocated to customer classes. The Board's conclusion in P.U. 25 (2010) as a result of the preliminary hearing was as follows:

> *"The Board finds that in the circumstances its jurisdiction to make orders in relation to how the RSP operated in prior years is limited. Given the manner in which this matter was brought forward the Board does not have the jurisdiction to change how Newfoundland Power's RSP operated in prior years, either in terms of the rates charged or the resulting balances. The Board does have the jurisdiction to issue an order which sets just and reasonable rates for the Industrial Customers for 2008 and 2009, including the Industrial Customers' RSP rates and how the Industrial Customers RSP operated for these years. The Board also finds that it has jurisdiction to determine whether any overpayment as a result of the interim rates is to be refunded to the Industrial Customer group or placed in a reserve account to the benefit of the Industrial Customer group…."*

Hydro and the Consumer Advocate filed an appeal as a result of the Board's decision and on June 19, 2012, the Supreme Court of Newfoundland and Labrador, Court of Appeal released its decision on this matter. The Court allowed the appeal and indicated in its decision that the Board's decision in declining jurisdiction was incorrect and that P.U. 25 (2010) was set aside.

According to the Court of Appeal, this matter is now back to the Board for a hearing and determination in accordance with the decision.

As previously indicated in the report, in P.U. 39(2010), the Board ordered that the current methodology of the Rate Stabilization Plan was approved on an interim basis as of January 1, 2011 pending a further review by the Board.

The Board has requested that Hydro address the issues of the RSP at its next general rate application.

Appendix A – Annual RSP activity and balances

Appendix A: RSP History - Activity and Balances

(In thousands of dollars)

	Annual Activity								(Recovery)/	Plan Balances			
	Hydraulic	Fuel Cost	Load	RRA	Financing	Other		Total	Refund	NP	IC	Hydraulic	Total
1986	12,045	(11,814)	(2,506)	-	267	-		(2,008)	-	(1,889)	(119)	-	(2,008)
1987	54,280	(35,044)	(1,582)	-	709	-		18,363	(68)	8,063	8,222	-	16,285
1988	(726)	(34,175)	62	-	170	-		(34,669)	(245)	(18,498)	(131)	-	(18,629)
1989	15,341	(33,097)	1,378	-	(3,508)	-		(19,886)	5,704	(31,004)	(1,807)	-	(32,811)
1990	13,619	3,175	(1,781)	-	(1,666)	8,941	1	22,288	10,010	(4,445)	3,932	-	(513)
1991	(2,757)	(4,853)	(3,054)	-	(326)	-		(10,990)	3,803	(10,530)	2,830	-	(7,700)
1992	(198)	3,469	1,482	-	(111)	6,488	2	11,130	664	593	3,505	-	4,098
1993	(4,668)	7,397	1,834	(26)	746	-		5,283	47	3,825	5,636	-	9,461
1994	(17,077)	3,509	2,315	(120)	32	-		(11,341)	(2,120)	(5,610)	1,575	-	(4,035)
1995	(3,733)	19,015	1,820	(134)	537	-		17,505	(694)	6,900	6,016	-	12,916
1996	(7,419)	21,805	2,441	(140)	2,005	-		18,692	(1,506)	21,002	9,160	-	30,162
1997	(8,545)	24,507	(560)	(478)	3,346	-		18,270	(7,103)	27,644	13,734	-	41,378
1998	(967)	12,068	3,435	122	4,150	-		18,808	(11,227)	33,009	15,776	-	48,785
1999	(15,859)	9,128	5,050	(394)	3,223	-		1,148	(15,427)	21,436	12,892	-	34,328
2000	(16,614)	29,359	521	(880)	2,774	(862)	3	14,298	(13,734)	22,684	12,056	-	34,740
2001	5,243	56,879	(3,506)	125	4,438	-		63,179	(11,152)	60,300	24,768	-	85,068
2002	6,967	46,113	(5,313)	(326)	7,189	184	4	54,814	(13,921)	92,060	32,711	-	124,771
2003	4,130	36,534	(2,846)	(227)	10,333	-		47,924	(16,669)	114,790	40,914	-	155,704
2004 Current	(7,362)	12,665	590	(949)	79	(12)	4	5,015	(1,951)	4,909	3,713	(5,521)	3,101
Historical					10,459	5	4	10,464	(32,236)	101,660	32,273		133,933
Total	(7,362)	12,665	590	(949)	10,538	(7)		15,479	(34,187)	106,569	35,986	(5,521)	137,034
2005 Current	(8,646)	16,289	(1,431)	(2,329)	(309)			3,574	(18,660)	120	(1,296)	(10,625)	(11,801)
Historical					8,768			8,768	(37,835)	79,781	25,086		104,867
Total	(8,646)	16,289	(1,431)	(2,329)	8,459	-		12,342	(56,495)	79,901	23,790	(10,625)	93,066
2006 Current	(10,678)	25,715	(11,442)	(4,337)	(2,067)			(2,809)	(35,396)	(19,268)	(14,406)	(15,978)	(49,652)
Historical					6,412	(10,000)	5	(3,588)	(38,285)	53,893	9,101		62,994
Total	(10,678)	25,715	(11,442)	(4,337)	4,345	(10,000)		(6,397)	(73,681)	34,625	(5,305)	(15,978)	13,342
2007 Current	(19,761)	(5,772)	(6,008)	1,862	(3,097)	(1,383)	6	(34,159)	23,918	(14,659)	(8,829)	(14,820)	(38,308)
Historical					1,972	(21,585)	7	(19,613)	(32,839)	12,053	-		12,053
Total	(19,761)	(5,772)	(6,008)	1,862	(1,125)	(22,968)		(53,772)	(8,921)	(2,606)	(8,829)	(14,820)	(26,255)
2008 Current	(26,383)	27,745	(10,341)	(245)	(2,937)	(2,238)	8	(14,399)	(440)	(10,330)	(11,994)	(30,903)	(53,227)
Historical					191			191	(14,482)	-	-	-	-
Total	(26,383)	27,745	(10,341)	(245)	(2,746)	(2,238)		(14,208)	(14,922)	(10,330)	(11,994)	(30,903)	(53,227)
2009 Current	(12,006)	(4,523)	(26,027)	(1,152)	(7,026)			(50,734)	(18,301)	(52,940)	(36,875)	(32,181)	(121,996)
2010 Current	(21,252)	25,112	(26,768)	(1,312)	(10,231)	(521)	9	(34,963)	(2,323)	(56,238)	(62,611)	(40,360)	(159,209)
2011 Current	(3,250)	53,479	(29,497)	(4,381)	(12,236)	9,948	10	14,063	(25,359)	(55,940)	(81,653)	(32,737)	(170,330)
2012 Current	(10,831)	84,592	(24,646)	(7,038)	(13,187)			28,890	(60,439)	(64,905)	(104,080)	(32,676)	(201,661)

The information from this table for the years 1986 to 2005 was obtained from the June 30, 2006 report "Review of the Operation of the Rate Stabilization Plan For the Period January 1, 2004 to December 31, 2005". Appendix A: RSP History - Activity and Balances. For the years 2006 - 2012 the information was obtained from the December 31st RSP reports prepared by Hydro.

Note 1: This is the 1989 PDD loss be applied against the RSP.

Note 2: This is the 1991 retail cost deferral.

Note 3: This is the correction of Industrial Rural deficit allocation.

Note 4: These are billing adjustments.

Note 5: This is the $10 million contribution from the Government of Newfoundland and Labrador towards the Industrial Customers Historical balance.

Note 6: This is the balance in the Industrial Customers Historical Account that was transferred to the Current Plan at the expiration of the Historical Plan on December 31, 2007.

Note 7: This represents the Hydraulic Balance as of December 31, 2006 that was allocated to the Historical Plans (NP and the Industrial Customers). This was approved by the Board in P.U. 8 (2007) that was issued April 12, 2007. Hydro revised the opening 2007 balances to account for this allcoation.

Note 8: This is the balance in the NP Historical Account that was transferred to the Current Plan at the expiration of the Historical Plan on June 30, 2008.

Note 9: This was due to an error of approximately $500,000 in the calculation of station services readings in 2009, and approximately $21,000 was the result of an error in the installation of a meter at the Massey Drive Terminal Station.

Not 10: This is the $10 million paid to the Government for Newfoundland and Labrador from the Industrial Customer RSP balance. This was a 2011 opening balance adjustment as the repayment was effective September 30, 2010. There was also a billing error of approximately $52,000 that offset the $10 million payment.

Appendix B – Time line of RSP activity

Purpose

Appendix B provides a brief synopsis of the major changes to the RSP from implementation to December 31, 2012. Details on these changes are contained in the report.

January 1, 1986 - The Implementation of the Rate Stabilization Plan

- Implementation of the RSP with the following components:
  - Hydraulic Production Component: Captures impacts of hydro production due to variances between expected average and actual water conditions.
  - Fuel Cost Variation Component: Captures impacts of variances between forecast and actual fuel costs.
  - Load variation: Captures impacts of variance between forecast load and actual load. Consists of 2 components:
    - Revenue component – variance allocated to customer group causing the variance.
    - Fuel component – allocated based on the approved cost of service.

- Cost of financing the RSP based on Hydro's embedded cost of debt, added to RSP on a monthly basis.
- $50 million cap set on the plan before triggering a review.
- Refund/Recovery of RSP balance based on a three year declining balance method.
- Automatic rate adjustments to occur at June 30 of each year.
- Establishment of separate plans for retail customers and Industrial Customers.
- Reporting mechanisms established.

March 6, 1989 Hydro Referral to the Board

- Rebasing of fuel cost and minor adjustment requiring use of blended price of oil.

February 6, 1990 Hydro Referral to the Board

- $8.941,000 loss for PDD from April 1, 1989 to December 31, 1989 charged to the RSP.

November 12, 1991 Hydro Referral to the Board

- Rebasing of fuel cost.
- The 1991 retail cost deferral was written off against the RSP allocated to NP.

June 26, 1992 Referral to the Board

- Rural Rate alteration added to RSP.
- Rules and Regulations updated to include a mathematical approach for automatic adjustments.

2001 General Rate Review – Board Order P.U. 7 (2002-2003)

- Hydraulic Production Variation
    - Addition of mini-hydro plants.
    - Holyrood conversion factor set at 615kWh/bbl.
    - Forecast hydraulic production for the 2002 test year set at 4,425 GWH.
- Load Variation
    - Interruptible energy removed from RSP.
- Customer Splits:
    - Based on 12 month-to-date invoiced /bulk transmission energy as well as Test Year Rural Deficit Allocation.
- Rate Calculation
    - Energy rates established on 12 month-to-date invoiced /bulk transmission energy.
- Rebasing of fuel cost.
- Finance charge based on WACC.
- Elimination of $50 million retail cap.
- Additional recovery of the existing RSP balance delayed until 2003.
- RSP split between old plan (existing balances in the RSP as of August 31, 2002 to be recovered over five years) and the “New Plan” (RSP activity commencing September 1, 2002 to be recovered over two years).

2003 General Rate Review – Board Order P.U. 40 (2003)

- Hydraulic Variation Component: Recovery/refund limited to 25% of the annual balance plus 100% of financing charges.
- Fuel Cost Variation Component: Introduction of the fuel rider based on forecast oil prices.
- Load Variation Component: Allocation of the fuel costs component of the load variation to be based on the customer class that caused the load variation.
- Rural Rate Alteration: Addition of the Rural Labrador Interconnected Automatic Rate Adjustments (re: CFB Goose Bay).
- Recovery of Plan Balances – Current and Historical Plans
    - The “Current” Plan
        - RSP activity commencing January 1, 2004.
        - Recovery of the balance over a one year amortization period.
    - The “Historical” Plan
        - RSP activity prior to January 1, 2004
        - Recovered over a four year period commencing January 1, 2004 for the Industrial customers and July 1, 2004 for NP.

<u>2003 General Rate Review – Board Order P.U. 14 (2004)</u>

- Rebasing of fuel, Holyrood conversion factor, hydraulic production and load forecast.

<u>2006 General Rate Review and Other 2006 RSP Activity</u>

- Agreement in principal on use of fuel rider forecast during test year.
- Agreement for review of RSP with respect to design objectives.
- Agreement on the disposition of the Hydraulic Production Variation balance as of December 31, 2006.
- Labrador Interconnected Rates - allocation of a portion of the CFB Goose Bay Revenue Credit during the extended phase-in of uniform Labrador Interconnected rates to maintain existing rates. The revenue shortfall to Hydro from maintaining existing rates to be recovered through the RSP.
- Rebasing of fuel, Holyrood conversion factor, hydraulic production and load forecast.
- Approval to recover the cost of burning 1% sulphur content No. 6 fuel at Holyrood through the RSP.
- Approved, as directed by a Government Directive, of the following adjustments to the Industrial Customers RSP as a result of the closure of Abitibi Consolidated Inc – Stephenville Division:
  - Revisions of calculation of the fuel rider
  - Modification of the calculation of the Historical Plan RSP recovery rate to reflect a $10 million contribution from the Government; and
  - Adjustment of the Industrial Customer kWh sales used in 2004 Test Year.

<u>RSP Activity During 2007</u>

- Adjustment of rates for Aur Resources to exclude Historical Plan impacts.
- Rural Rate Alteration adjusted to include a monthly amount of $92,560.
- Industrial Customer's recovery of the Historical Plan balance expired with a $1,382,494 transferred to the Current Plan.

<u>RSP Activity During 2008</u>

- Rural Rate Alteration adjusted to include a monthly amount of $32,433.
- Interim rates put in place for Industrial Customers based on 2007 rates.
- NP's recovery of the Historical Plan balance expired with a credit balance of $2,238,025 transferred to the Current Plan.

<u>RSP Activity During 2009</u>

- Rural Rate Alteration adjusted to $5,766/month.
- Industrial Customer rates continued to be based on interim rates.
- On June 30, 2009, Hydro filed an application with the Board concerning the RSP components of the rates to be charged to Industrial Customers.

RSP Activity During 2010

- Rural Rate Alteration adjusted to $47,847/month.
- The Board held a preliminary hearing on the question of whether the Board has the jurisdiction to change the manner in which the RSP operated.
- The Board's decision in P.U. 25(2010) relating to this hearing was appealed.
- Industrial Customer rates continued to be based on interim rates.
- Board ordered that the NP RSP adjustment rate as of July 1, 2010 was approved as an interim rate effective January 1, 2011.
- Board ordered that the current methodology of the RSP was approved on an interim basis effective January 1, 2011 pending a further review by the Board.

RSP Activity During 2011

- Rural Rate Alteration adjusted to $98,295/month.
- Board ordered payment of $10,000,000 from the Industrial Customer RSP balance to the Government of Newfoundland and Labrador, to be effective September 30, 2010.
- Industrial Customer rates continued to be based on interim rates.
- NP RSP adjustment rate effective July 1, 2011was approved as an interim rate.

RSP Activity During 2012

- The Board approved the Service Agreement for Vale Newfoundland and Labrador Limited and an interim rate.
- Court of Appeal decision released – indicated that the Board's decision in P.U. 25(2010) was incorrect. According to the Court of Appeal, Order No. P.U. 25 (2010) is set aside and this matter is now back to the Board for a hearing and determination in accordance with the decision
- Industrial Customer rates continued to be based on interim rates.
- NP RSP adjustment rate effective July 1, 2012 was approved as an interim rate.