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Board of Commissioners of Public Utilities

Financial Consultants Report

Newfoundland and Labrador Hydro

2017 General Rate Application
December 4, 2017

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 2017 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 2017 General Rate Application and pre-filed evidence is as follows:

- Conduct a review of actual and forecast capital expenditures, revenues, expenses, net earnings, return on rate base and return on equity for the years ending December 31, 2015 and December 31, 2016 (actual), December 31, 2017 (forecast), and December 31, 2018 and December 31, 2019 (test year);
- Examine the methodology and assumptions used by the Company for estimating revenues, expenses and net earnings and determine whether they are reasonable and appropriate;
- Review the Company's calculation of estimated average rate base for the years ending December 31, 2018 and December 31, 2019;
- Verify the Company's calculation of the proposed rate of return on rate base and return on common equity for the years ending December 31, 2018 and December 31, 2019;
- Verify the calculation of proposed rates necessary to meet the estimated revenue requirements in the 2018 and 2019 test years;
- Review the Rate Stabilization Plan for changes to existing rules and regulations;
- Review the calculation of depreciation based upon the updated Depreciation Study;
- Review the working capital methodology and average rate base methodology reports;
- Review the proposal in relation to the automatic adjustment mechanism for target Return on Equity;
- Review the intercompany charges and shared services activity included in the test year data;
- Review the proposed treatment of deferral accounts including GRA costs, Cost of Service Hearing costs, Holyrood Inventory Allowance and 2018 Revenue Deficiency; and,
- Review the proposed treatment of the Off-Island Purchases deferral account.

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, 2016, have been audited by Deloitte & Touche LLP, Chartered Professional Accountants, who have expressed their opinion on the fairness of the statements in their report dated March 7, 2017. 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.

Our report is based on information contained in the 2017 General Rate Application filed on July 28, 2017, including Revisions 1, 2 and 3 filed on September 18, 2017, October 16, 2017, and October 27, 2017, respectively. A fourth revision was filed on November 27, 2017. This revision has not been reflected in our report. Subsequent to the release of our report we will review Revision 4 and provide any updates to our findings, as necessary.

Forecasting Methodology and Assumptions

The Company has noted that the 2018 and 2019 forecasts were projected using the same methodology as the normal operating budget process. In addition, the forecasts incorporate 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 regards to future economic conditions and events; and,

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

Methodology

The main steps or components in preparation of the operating budget, as described by Hydro, are as follows:

• Load forecasts are prepared and include forecast information received from Newfoundland Power and the Industrial Customers, as well as Hydro's own forecasts for rural systems;

• Based on the load forecasts, Resource Production and Planning determines the hydraulic/thermal split (production plan) for generation and calculates and prepares the fuel budget. The purchased power estimates are also determined at this time;

• Capital budgets are submitted to the Hydro Board of Directors and the Board of Commissioners of Public Utilities for approval;

• The capital asset amortization budget is prepared based on capital asset additions and projected in-service dates for construction projects in progress;

• Depreciation and accretion expenses associated with asset retirement obligations (AROs) are estimated based on timing of the settlement of the obligation;

• Projected operating expenses, fuel, power purchases, capital expenditures, and revenue inflows are used to generate a forecast of borrowing requirements and interest expense;

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

• Operating expenses are estimated based on the labour forecast and costs associated with maintenance and operational activity;

• Operating costs are prepared by business unit and submitted to general managers and ultimately to the Vice Presidents of each area;

• Once the operating costs are approved by the respective Vice President, they are submitted as part of Hydro's total budget;

• A series of reviews of operating costs with each of the Vice President, Finance, and the President are conducted;

• All elements are consolidated and forecast income statement and balance sheet information is prepared;

• Budgets are consolidated and reviewed in detail with the Executive team;

• Depending on cost levels, there may be multiple reviews and iterations until the final numbers are approved;

• The budget is subject to various levels of review and approval by Managers, Vice-Presidents, and the President of Hydro; and,

• Final review and approval is provided by the Hydro Board of Directors.

Review of Assumptions

The key assumptions made by management in developing the test year forecasts 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 diesel plants located throughout isolated parts of Labrador and the island;

• Based on the load forecast, Resource and Production Planning group determines the production plan 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;

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

• The conversion factor for annual average efficiency at the Holyrood thermal plant;

• Hydraulic production determined by the VISTA model which was used to calculate system losses based on the flow of energy between areas of Hydro's system using dynamic loss equations;

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

• The hydraulic/thermal production split to meet remaining forecast load;

• The production plans developed assume no interconnection to the North American grid;

• The application assumes the RSP operates as a test year for 2018 and 2019. Subsequent to the filing of the 2017 General Rate Application, Hydro proposed calculating the RSP for 2018 based on 2015 cost of service values for interim rate purposes;

• The test year revenue requirements assume no off-island purchases;

• Interest rate projections for short and long-term financing;

• Labour costs developed based on Hydro's assumptions as described in PUB-NLH-058;

• Salaries and benefits include a vacancy allowance for unfilled positions;

• Forecast FTEs and salary and benefit costs forecasted based on changes arising from the creation of a dedicated and separate executive team for Hydro and separate support functions for Hydro;

• Labour transactions associated with providing or receiving services from or to other lines of business are governed by the Intercompany Transaction Costing Guidelines;

• Recovery of costs associated with Common Service business units to all lines of business in Nalcor are included in Hydro;

• Interim rates to provide interim relief effective January 1, 2018 until December 31, 2018, in advance of final rates and the deferral and recovery of the revenue deficiency resulting from interim rates through a rate rider over a twenty-month period;

• Expenses related to the GRA hearing have been deferred and amortized over a three year period beginning January 1, 2018;

• Expenses related to the cost of service hearing costs have been deferred and amortized over a three year period beginning January 1, 2018;

• The inclusion of an allowance of $2.1 million per year in revenue requirement in relation to inventory at Holyrood and the creation of an inventory allowance;

• 50% of the debt guarantee fee payments excluded from revenue requirement;

• Depreciation rates and methodologies are based upon those recommended in the 2016 Depreciation Study;

• The Energy Supply, Holyrood Conversion and Isolated Systems deferrals are recovered in the RSP; and,

• Instituted a productivity allowance to manage operating costs to help offset other cost pressures.

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 2017. 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. According to Hydro, the 2018 and 2019 test year load forecasts for the Island Interconnected System reflect a combination of direct input from the Island Industrial customers (Vale, North Atlantic Refining Limited (NARL), Corner Brook Pulp and Paper Limited, Teck Resources Limited, and Praxair Canada Inc.) and Newfoundland Power. Hydro's internal analyses for the interconnected and isolated systems were prepared throughout 2016. Total load requirements are determined from analyses of overall system losses, station service, and demand diversity.

In order to identify any significant trends with respect to sales, we have compared the actual revenues for 2015 and 2016 with the forecast revenues for 2017, 2018 and 2019. The results of this analysis of revenue by customer are as follows:

Table 1: Revenue by customer (2015-2016, 2017 forecast and test years 2018 and 2019)

(000)'s	Actuals 2015	Actuals 2016	Forecast 2017	Test Year 2018	Test Year 2019	Variance '17F-'16	Variance '18TY-'17F	Variance '19TY-'18TY
Industrial (Note 1)								
North Atlantic	$ 11,485	$ 12,625	$ 13,577			$ 952		
Corner Brook	2,963	3,197	3,421			224		
Teck Resources	2,291	542	355			(187)		
Vale	7,447	10,446	15,707			5,261		
Praxair	1,930	2,198	2,234			36		
IOC	3,642	3,734	3,587			(147)		
Wabush	31	15	6			(9)		
GOP Energy	-	3	-			(3)		
	29,789	32,760	38,887	52,362	55,218	6,127	13,475	2,856
Utility	442,589	440,276	436,197	530,715	545,428	(4,079)	94,518	14,713
Rural								
Labrador Interconnected	18,347	18,457	20,022	21,398	22,527	1,565	1,376	1,129
Island Interconnected	47,868	55,082	49,123	52,987	53,527	(5,959)	3,864	540
Island Isolated	1,493	1,582	1,471	1,679	1,740	(111)	208	61
Labrador Isolated	7,580	8,285	7,971	9,321	9,656	(314)	1,350	335
L'Anse Au Loup	2,737	3,083	2,880	3,150	3,238	(203)	270	88
	78,025	86,489	81,467	88,534	90,688	(5,022)	7,067	2,155
Energy Sales	550,403	559,525	556,551	671,611	691,334	(2,974)	115,060	19,724
Add:								
Generation Demand Cost Recovery	1,262	1,288	1,213	1,482	1,442	(75)	269	(40)
Other revenue	1,825	1,863	2,068	2,088	2,109	205	20	21
CIAC revenue	356	773	1,847	1,618	1,658	1,074	(229)	40
Total revenue	$ 553,846	$ 563,449	$ 561,679	$ 676,799	$ 696,543	$ (1,770)	$ 115,120	$ 19,745
Total revenue per Finance Schedule II	$ 553,846	$ 563,449	$ 561,679	$ 676,762	$ 696,533			
Difference	-	-	-	37	10			
Percentage change yr over yr		1.73%	-0.31%	20.50%	2.92%			

Note 1: According to Hydro, a breakdown of industrial revenues by customer, based on 2018 and 2019 billings, is available. However, a breakdown of the cost of service revenue requirement by customer is not available for 2018 and 2019 test years.

The 2018 and 2019 forecast energy sales in the above table do not represent proposed revenue from rates to be collected from customers for these years as Hydro has not proposed full recovery of the revenue requirement from rates in 2018. Instead, Hydro has proposed that interim customer rates be implemented effective January 1, 2018, with the proposed increase providing recovery of only 70% of the increased revenue requirement for 2018. As a result, the proposed revenue from interim rates creates a revenue deficiency in 2018 that is effectively recovered in the implementation of final rates in 2019.

The forecast of 2018 revenue from rates, using existing rates, is $559.7 million (Table 5-7, pg. 5.39 of the pre-filed evidence, excluding RSP) compared to the $671.6 million test year energy sales (or revenue requirement from rates). The $111.9 million increased revenue requirement from existing rates represents the increase in revenue required to be recovered for 2018 revenue requirement from rates.

The forecast of 2019 revenue from rates, using existing rates, is $609.0 million (Table 5-8, pg. 5.40 of the pre-filed evidence, excluding RSP) compared to the $691.3 million test year energy sales (or revenue requirement from rates). The $82.3 million increased revenue requirement from existing rates represents the increase in revenue required to be recovered for 2019 revenue requirement from rates.

In order to identify any trends with respect to forecast load and energy sales, we have compared the actual energy sales (GWh) for 2015 and 2016 with the forecast energy sales for 2017, 2018 and 2019. Details of the actual energy sales for 2015 and 2016, and forecast energy sales for 2017, 2018 and 2019, can be found in the pre-filed Operations Schedules in the 2017 GRA. We have also reconciled the total sales forecast to the total GWh generated through hydroelectric, thermal, Gas Turbines/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) (2015-2016, 2017 forecast and test years 2018 and 2019)

(GWh)	Actuals 2015	Actuals 2016	Forecast 2017	Test Year 2018	Test Year 2019	Variance '17F-'16	Variance '18TY-'17F	Variance '19TY-'18TY
Industrial	499	511	643	726	743	133	83	17
Iron Ore Company	1,704	1,753	1,733	1,733	1,733	(20)	-	-
Wabush Mines	5	4	2	1	-	(1)	(1)	(1)
Utility	6,072	5,845	5,825	5,825	5,834	(20)	-	9
Rural - Island Interconnected and Labrador Interconnected	1,111	1,103	1,147	1,146	1,140	45	(1)	(6)
	9,391	9,215	9,351	9,430	9,450	136	80	20
Transmission and distribution losses - Island Interconnected and Labrador Interconnected	388	356	396	366	358	40	(30)	(8)
	9,779	9,570	9,747	9,797	9,808	176	50	11
(GWh)								
Island Interconnected								
Hydroelectric	4,823	4,380	4,602	4,601	4,606	221	(1)	6
Thermal	1,459	1,621	1,522	1,554	1,560	(99)	33	6
Gas Turbines/Diesel	41	121	57	41	41	(64)	(16)	-
Power Purchases								
NP at Hydro Request	1	2	-	-	-	(2)	-	-
Star Lake	135	136	140	141	142	5	1	1
Rattle Brook	14	15	15	15	15	-	-	-
Corner Brook P&P	9	9	-	-	-	(9)	-	-
Corner Brook Cogen	63	71	67	67	67	(4)	-	-
St. Lawrence Wind	95	103	105	105	105	2	-	-
Fermeuse Wind	87	87	84	84	84	(3)	-	-
Nalcor Exploits	560	495	587	615	615	92	28	-
	963	918	998	1,027	1,027	80	29	1
	7,286	7,039	7,178	7,223	7,235	138	45	13
Labrador Interconnected								
Diesel	(1)	(1)	-	-	-	1	-	-
Power Purchases	2,493	2,532	2,569	2,574	2,573	37	5	(1)
	2,492	2,531	2,569	2,574	2,573	38	5	(1)
Total	9,779	9,570	9,747	9,797	9,808	176	50	12

Note: Table excludes the isolated systems.

Energy sales were forecast to increase overall in 2017 by 136 GWh from 2016 actuals before transmission and distribution losses. The largest portion of the increase in the number of GWh in 2017 relates to an increase in energy sales of 133 GWh to Hydro's industrial customers. According to Hydro, this increase is primarily due to increases at Vale's nickel processing facilities and increased requirements at NARL. Hydro anticipates that Vale will continue to increase its levels of demand and energy consumption through 2017 until it reaches full production levels near the end of the year. Increased energy requirements at NARL are associated with higher production levels and resulting higher power demands. Hydro is also forecasting an increase of 45 GWh in energy sales to rural customers. This increase is primarily due to new data centre loads for Hydro's Labrador rural customers. Decreases totaling 41 GWh are forecast for Iron Ore Company of Canada (IOCC), Wabush Mines, and Newfoundland Power in 2017 compared to 2016 actuals. 20 GWh of the decrease is related to energy sales to Newfoundland Power relating to expected provincial economic conditions.

Energy sales were forecast to increase in 2018 by 80 GWh from 2017 forecasts before transmission and distribution losses. The largest portion of the increase relates to an increase of sales to industrial customers of 83 GWh. This is primarily due to increased requirements forecast for Vale and Praxair upon attaining full load levels at the end of 2017.

Energy sales were forecast to increase in 2019 by 20 GWh from 2018 forecasts before transmission and distribution losses. The largest portion of the increase relates to an increase of sales to industrial customers of 17 GWh. This is primarily due to increased production days at NARL, and increased energy requirements offset by efficiency gains at CBPP. Hydro is also forecasting an increase of 9 GWh in energy sales to Newfoundland Power.

Cost of Capital

Capital Structure

Hydro's 2017 forecast, 2018 test year and 2019 test year capital structure and projected balance sheet, which provides the basis for these calculations, is detailed in the pre-filed evidence (Finance Schedule 4-II, pg. 4 of 9 and pg. 2 of 9).

Our procedures performed in this area consisted of 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,
- reviewed the clerical accuracy of the calculations of regulated average capital structure.

The Company's calculation of regulated capital structure for 2015 to 2019 is presented in the following tables:

Table 3: Regulated capital structure (2015-2016, 2017 forecast and test years 2018 and 2019)

	As at December 31									
(000,000)'s					Forecast		Test Year		Test Year	
	2015	%	2016	%	2017	%	2018	%	2019	%
Debt	$ 1,125	72.7%	$ 1,216	72.7%	$ 1,725	77.8%	$ 1,853	77.7%	$ 1,855	76.3%
Asset Retirement obligations, funded	13	0.9%	15	0.9%	14	0.6%	14	0.6%	14	0.6%
Employee future benefits, funded	65	4.2%	66	3.9%	70	3.1%	73	3.0%	76	3.1%
Equity	344	22.2%	376	22.5%	409	18.5%	446	18.7%	485	20.0%
	$ 1,547		$ 1,673		$ 2,218		$ 2,386		$ 2,430	

	Average (%)			
(000,000)'s		Forecast	Test Year	Test Year
	2016	2017	2018	2019
Debt	72.7%	75.2%	77.7%	77.0%
Asset Retirement obligations, funded	0.9%	0.8%	0.6%	0.6%
Employee future benefits, funded	4.0%	3.5%	3.1%	3.1%
Equity	22.4%	20.5%	18.6%	19.3%
	100.0%	100.0%	100.0%	100.0%

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 82:18. In 2009, Nalcor provided a $100 million equity injection of contributed capital resulting in a significant reduction in leverage to a ratio of 72:28. As can be seen from the tables above, the average debt to equity ratio has increased in test years 2018 and 2019 to a ratio of 81:19 compared to a ratio of 78:22 in 2016. The increase in the debt to equity ratio in test years 2018 and 2019, compared to actual 2016, is primarily due to expenditures in property, plant and equipment financed through debt.

Also in 2009 the Government of Newfoundland and Labrador Order in Council 2009-063 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). In P.U. 49 (2016) the Board ordered that Hydro's common equity component in its capital structure for rate setting purposes is not to exceed 45%. Hydro's capital structure is 19% equity and 81% debt for test years 2018 and 2019.

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 Finance Schedule 4-II (pg. 4 of 9). No regulated dividends were paid on March 31, 2016, or March 31, 2017, relating to the year ends December 31, 2015, or December 31, 2016, nor are any regulated dividends forecasted in 2017, 2018 and 2019.

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 4-IV, pg. 1 of 1). We have reviewed these calculations as well as agreed the individual components to supporting documentation including the interest on long-term debt, debt guarantee fee, amortization of foreign exchange losses and interest on sinking fund assets. Our specific comments in relation to the debt guarantee fee are included under a separate heading that follows.

The Company's calculation of embedded cost of debt for actual 2015 and 2016, and forecast 2017, 2018 and 2019, is presented in the following table:

Table 4: Embedded cost of debt (2015-2016, 2017 forecast and test years 2018 and 2019)

(000's)	Actual 2015	Actual 2016	Forecast 2017	Test Year 2018	Test Year 2019
Interest on Long-Term Debt	$ 84,525	$ 82,431	$ 81,200	$ 99,330	$ 100,215
Accretion of Long-Term Debt	547	540	648	615	653
Amortization of Foreign Exchange Loss	2,157	2,157	2,157	2,157	2,157
Debt Guarantee Fee	4,514	4,524	4,127	7,359	8,254
Other Interest	161	641	3,869	890	1,584
	91,904	90,293	92,001	110,351	112,863
Less:					
Interest on Sinking Fund Assets	$ (13,450)	$ (13,952)	$ (12,295)	$ (11,057)	$ (11,331)
Interest Cost of Service Exclusions	(2,752)	(2,584)	(2,374)	(3,680)	(4,127)
Net Interest	$ 75,702	$ 73,757	$ 77,332	$ 95,614	$ 97,405
Average Total Debt	$ 1,115,446	$ 1,170,475	$ 1,471,379	$ 1,790,618	1,855,412
Embedded Cost of Debt	6.79%	6.30%	5.26%	5.34%	5.25%

The methodology and approach used to calculate the 2017 forecast, 2018 test year and 2019 test year embedded cost of debt is consistent with the 2013 Amended GRA.

Debt Guarantee Fee

In P.U. 49 (2016) the Board ordered Hydro to revise its debt guarantee fee to reflect a 50/50 apportionment of the calculated cost savings. Hydro complied with this directive in the Compliance Application. In calculating the debt guarantee fee for the 2018 and 2019 test years Hydro also apportioned the value of the debt guarantee fee 50/50 (ie: 50% of the fee was included as a cost of service adjustment and as such is excluded from revenue requirement).

The amount charged to Hydro for the debt guarantee fee on long term debt remained consistent with that charged in the previous GRA (ie: 50 bps). However, we note that in the Compliance Application for the previous GRA, Hydro reduced the amount included in revenue requirement to reflect 41 bps (which was further reduced by the 50/50 apportionment). The Company noted that this was in response to Undertaking 139 of the 2013 Amended GRA which requested Hydro to use a long-term debt guarantee fee range of 35 bps to 47 bps. In response, Hydro used the midpoint of 41 bps to reflect the range requested in the undertaking. The impact of using a guarantee of 50 bps vs 41 bps on long term debt had the following impact:

Table 5: Debt guarantee fee (2017 forecast and test years 2018 and 2019)

	Forecast 2017	Test Year 2018	Test Year 2019
GRA			
Debt guarantee fee	$ 4,127	$ 7,359	$ 8,254
Disallowed portion	(2,374)	(3,680)	(4,127)
Net debt guarantee per GRA	1,753	3,679	4,127
Undertaking 139 (2013 GRA)			
Debt guarantee fee	$ 4,127	$ 7,359	$ 8,254
Disallowed portion	(2,374)	(4,247)	(4,799)
Net debt guarantee per Undertaking 139 assumptions	1,753	3,112	3,455
Increase in debt guarantee fee	$ -	$ 567	$ 672

Hydro filed an Application with the Board on November 21, 2017 with respect to a 'Proposed Issue of Debt from the Province of Newfoundland and Labrador'. Hydro noted that it has historically issued bonds in the domestic capital market under a guarantee fee from the Province. Hydro is proposing to instead have the Province borrow on its behalf, and lend the proceeds to Hydro on identical terms and conditions. Hydro has noted that this would ensure least cost borrowings.

Hydro has confirmed that the revenue requirement for 2018 and 2019 were prepared under the assumption that Hydro issues its own bonds. The Company has estimated interest savings at $515,000 and $529,000 for the 2018 and 2019 test years, respectively, under the assumption that the province borrows on Hydro's behalf.

Debentures

The forecasted increase in average total debt in 2017 and test years 2018 and 2019 is primarily driven by new debt issuances summarized in the table below and in Finance Schedule 4-IV of the pre-filed evidence:

Table 6: New debt issuances (2017 forecast and test years 2018 and 2019)

(000's)

Year of Issuance	Interest Rate	Year of Maturity	Forecast 2017	Test Year 2018	Test Year 2019
2017	3.60%	2045	$300,000	$ 300,000	$ 300,000
2017	3.40%	2027	200,000	200,000	200,000
2017	4.18%	2047	300,000	300,000	300,000
2018	4.25%	2048	-	250,000	250,000
			$800,000	$1,050,000	$1,050,000

The embedded cost of debt is forecast to decrease from 6.30% in 2016 to 5.26%, 5.34% and 5.25% in 2017 and test years 2018 and 2019, respectively. This decrease reflects lower average coupon rates on the debt issuances summarized above and the retirement of higher rate, maturing debt. Hydro's Series X debt has an interest rate of 10.25% and is due to mature in 2017.

Interest Rates

According to Hydro, embedded cost of debt is forecast to decrease in 2017 and tests years 2018 and 2019 due to lower average coupon rates on debt issuances and the retirement of higher rate, maturing debt.

As discussed by Hydro in IC-NLH-127, interest rate forecasts were determined as follows:

- The 3.60% interest rate forecast for the issue due 2045 is based on the actual terms of issue as Series AF was reopened at its 3.60% coupon rate. We agreed the coupon rate to the term sheet relating to this issuance.

- The 3.40% interest rate forecast for the 10-year issuance due in 2027 was based on the average of the forecasts of interest rates on 10-year Government Bank of Canada Bonds by six Schedule A banks for the fourth quarter of 2017. A 135 basis point spread was then added. This spread is based on the 155 basis point spread experienced by Hydro in its most recent bond issue less a 20 basis point adjustment to reflect the reduced term. We recalculated the rate of 3.40% using information provided by Hydro.

- The 4.18% interest rate forecast for the 30-year issuance due in 2047 was based on the average of the forecasts of interest rates on 30-year Government Bank of Canada Bonds by six Schedule A banks for the fourth quarter of 2017. A 155 basis point spread was then added. This actual spread is based on the spread experienced by Hydro in its most recent bond issue. We recalculated the rate of 4.18% using information provided by Hydro.

- The 4.25% interest rate forecast for the 30-year issuance due in 2048 was based on the average of the forecasts of interest rates on 30-year Government Bank of Canada Bonds by six Schedule A banks for the first quarter of 2018. A 155 basis point spread was then added. This actual spread is based on the spread experienced by Hydro in its most recent bond issue. We recalculated the rate of 4.25% using information provided by Hydro.

Regulated Interest Coverage

In response to our request, Hydro submitted a calculation of the regulated interest coverage for actual 2015 and 2016, forecast 2017, and test years 2018 and 2019. Hydro's calculation is presented in the following table:

Table 7: Interest coverage (2015-2016, 2017 forecast and test years 2018 and 2019)

(000,000's)	Actual 2015	Actual 2016	Forecast 2017	Test Year 2018	Test Year 2019
Interest, as reported (Note 1)	$ 89.9	$ 88.2	$ 89.8	$ 108.2	$ 110.7
Add: Interest component of EFB benefit cost	3.4	3.4	3.2	3.4	3.5
Add: Accretion of asset retirement obligation	0.7	0.6	0.2	0.4	0.4
Interest, adjusted	$ 94.0	$ 92.2	$ 93.2	$ 112.0	$ 114.6
Net income, as reported	$ (0.7)	$ 28.2	$ 29.4	$ 31.0	$ 34.0
Add: Amortization (Note 2)	66.7	71.1	78.5	92.9	98.2
Less: CIAC, as reported	(0.4)	(0.8)	(1.8)	(1.6)	(1.7)
Less: Interest earned	4.8	7.5	(18.5)	(13.4)	(13.9)
Interest, as reported (Note 1)	89.9	88.2	89.8	108.2	110.7
Add: Interest component of EFB benefit cost	3.4	3.4	3.2	3.4	3.5
Add: Accretion of asset retirement obligation	0.7	0.6	0.2	0.4	0.4
EBITDA, adjusted	$ 164.4	$ 198.2	$ 180.8	$ 220.9	$ 231.2
Interest Coverage	**1.75X**	**2.15X**	**1.94X**	**1.97X**	**2.02X**

Note 1: Interest, as reported, includes interest on long-term debt, accretion of long-term debt, debt guarantee fee, and other interest.

Note 2: Amortization includes depreciation, as reported, amortization of GRA hearing costs, amortization of cost of service hearing costs, amortization of foreign exchange losses, and inventory allowance amortization.

In 2013, Hydro changed the calculation of its interest coverage to the Standard & Poor's ("S&P") EBITDA interest coverage methodology. The S&P methodology calculates interest coverage as earnings before interest, taxes, depreciation and amortization ("EBITDA") divided by interest. The EBITDA calculation is considered a proxy for cash earnings by S&P. S&P's definition of interest includes the gross amount of interest, including capitalized interest, but excludes interest earned (comprised of interest on sinking funds, interest on the RSP and interest capitalized during construction). It also includes interest on employee future benefits as well as accretion of asset retirement obligations. The calculations presented in the table have been performed using figures obtained from Finance Schedules 4-II and 4-V of the GRA.

Based upon our review, we did not note any discrepancies in the calculations of regulated interest coverage.

Regulated Equity and Return on Equity

Our procedures in this area focused on review 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 2015 and 2016 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 2017, and test years 2018 and 2019; and,
- recalculated the rate of return on common equity for forecast 2017, and test years 2018 and 2019, and ensured it was in accordance with established practice and applicable Board Orders.

To provide a basis of comparison for average common equity and return on average common equity, we have prepared the following summary for actual 2015 and 2016, as well as forecast 2017, test year 2018 and test year 2019. The following table presents the return on book equity calculated using shareholder's equity from Finance Schedule 4-II, pg. 4 of 9, and regulated earnings from Finance Schedule 4-II, pg. 5 of 9:

Table 8: Return on book equity (2015-2016, 2017 forecast and test years 2018 and 2019)

(000)'s	Actual 2015	Actual 2016	Forecast 2017	Test Year 2018	Test Year 2019
Shareholder's equity					
2019					$ 485,288
2018				$ 445,731	$ 445,731
2017			$ 409,394	$ 409,394	
2016		$ 376,323	$ 376,323		
2015	$ 343,589	$ 343,589			
2014	$ 335,696				
Average equity	$ 339,643	$ 359,956	$ 392,859	$ 427,563	$ 465,510
Regulated earnings	$ (656)	$ 28,231	$ 29,382	$ 31,013	$ 33,991
Cost of service exclusions	4,055	4,503	3,689	5,324	5,566
	$ 3,399	$ 32,734	$ 33,071	$ 36,337	$ 39,557
Return on book equity	**1.00%**	**9.09%**	**8.42%**	**8.50%**	**8.50%**

The rate of return on book equity calculated in the above summary for the 2018 and 2019 test years is 8.50%. In its Application, Hydro proposed a regulated return on equity of 8.50% for the 2018 and 2019 test years, which is a component of the Company's weighted average cost of capital (WACC) in Finance Schedule 4-II, pg. 4 of 9. Hydro's allowed return is calculated as its rate base multiplied by its WACC (or allowed rate of return).

The regulated return on equity of 8.50% is consistent with Newfoundland Power's return on equity of 8.50% which was approved in Board Order P.U. 18 (2016). 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.

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 8.50% for both test years 2018 and 2019.

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 4-9. The inputs to this calculation are the average forecast capital structure and the forecast cost of the individual components of invested capital which include embedded cost of debt and return on equity. Our comments with respect to each of these factors have been provided in the preceding sections.

A comparison of the WACC for actual 2015, actual 2016, forecast 2017, 2018 test year, and 2019 test year is included in the table below:

Table 9: WACC (2015-2016, 2017 forecast and test years 2018 and 2019)

	Actual 2015			Actual 2016			Forecast 2017			Test Year 2018			Test Year 2019		
	Percent	Cost	WACC	Percent	Cost	WACC	Percent	Cost	WACC	Percent	Cost	WACC	Percent	Cost	WACC
Debt	72.8	6.79%	4.94%	72.7	6.30%	4.58%	75.2	5.26%	3.96%	77.7	5.34%	4.15%	77.0	5.25%	4.04%
Asset retirement obligations	0.8	0.00%	0.00%	0.9	0.00%	0.00%	0.8	0.00%	0.00%	0.6	0.00%	0.00%	0.6	0.00%	0.00%
Employee Future Benefits	4.3	0.00%	0.00%	4.0	0.00%	0.00%	3.5	0.00%	0.00%	3.1	0.00%	0.00%	3.1	0.00%	0.00%
Equity	22.1	8.80%	1.95%	22.4	8.50%	1.90%	20.5	8.50%	1.74%	18.6	8.50%	1.58%	19.3	8.50%	1.64%
	100.0		6.89%	100.0		6.48%	100.0		5.70%	100.0		5.73%	100.0		5.68%

Compared to actual 2015 and 2016, WACC is forecast to decrease in 2018 and 2019 test years. The decrease from 2015 is primarily due to the lower average cost of debt, the change in Hydro's target return on equity from 8.80% to 8.50% and the change in the capital structure. The decrease from 2016 is primarily due to the lower average cost of debt and the change in the capital structure.

Based upon our review we did not note any discrepancies in the calculation of test year 2018 and test year 2019 WACC of 5.73% and 5.68%, respectively.

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 2018 and 2019 test years is included in Finance Schedule 4-II, pg. 5 of 9, of the pre-filed evidence. The procedures which we performed included the following:

- agreed all carry-forward data to supporting documentation including the 2015 and 2016 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 2017, and test years 2018 and 2019;
- recalculated the forecast average rate base for forecast 2017, and test years 2018 and 2019; 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.

Average Rate Base Methodology

In preparation for the GRA, Hydro engaged Christensen Associates Energy Consulting (CA Energy) to review the practices used by other utilities to establish rate base and provide recommendations or changes, if required, to Hydro's average rate base methodology. CA Energy recommended that Hydro continue to use beginning-of-year and end-of-year averaging for capital assets in service and 13-month averages for fuel, materials and supplies, and deferred charges. In addition, CA Energy recommended that significant capital additions which increase the cost of service systems' average rate base be included in both the opening and closing rate base for rate setting purposes. In P.U. 22 (2017), the Board authorized a full 12-month coverage of the capital charges on Hydro's Holyrood Gas Turbine Generating Unit for rate setting purposes for 2015 test year because it was in service for all of 2016, whereas the asset was only partially recovered during actual 2015 using the opening and closing method because it went into service in February, 2015. Hydro has not proposed any adjustment to rate base in the 2018 or 2019 test years related to significant capital additions.

Details of the test year 2018 and test year 2019 average rate base and return on average rate base with comparative data for actual 2015, actual 2016, and forecast 2017, as submitted in Finance Schedule 4-II, pg. 5 of 9, are presented in the following table:

Table 10: Average rate base, return on rate base and rate of return on average rate base (2015-2016, 2017 forecast and test years 2018 and 2019)

(000's)	Actual 2015	Actual 2016	Forecast 2017	Test Year 2018	Test Year 2019
Plant investment	$ 1,828,940	$ 1,964,595	$ 2,350,735	$ 2,568,379	$ 2,733,014
Less: Accumulated depreciation	(168,306)	(233,720)	(308,582)	(389,021)	(476,625)
CIAC's	(18,255)	(32,173)	(33,466)	(32,593)	(31,324)
ARO's	(14,381)	465	79	(307)	(693)
Net capital assets	1,627,998	1,699,166	2,008,765	2,146,457	2,224,372
Balance previous year	1,468,388	1,627,998	1,699,166	2,008,765	2,146,457
Average	1,548,193	1,663,582	1,853,966	2,077,611	2,185,414
Less: average net assets excluded from rate base	(10,732)	(16,676)	(16,246)	(8,820)	(6,415)
	1,537,461	1,646,906	1,837,720	2,068,791	2,178,999
Cash working capital allowance	6,995	5,304	7,582	2,772	2,255
Fuel inventory	44,052	35,473	67,287	76,472	74,369
Supplies inventory	29,279	32,146	33,135	33,034	32,884
Deferred charges	129,456	166,454	129,780	82,041	75,958
Average rate base	$ 1,747,243	$ 1,886,283	$ 2,075,503	$ 2,263,109	$ 2,364,465
Return on rate base:					
Net income	(656)	28,231	29,382	31,013	33,991
Cost of service exclusions:					
Depreciation on assets excluded from rate base	1,303	1,919	1,315	1,644	1,439
Interest cost of service exclusions	2,752	2,584	2,374	3,680	4,127
Net interest	94,059	95,294	71,107	93,295	94,863
Return on rate base	$ 97,458	$ 128,028	$ 104,178	$ 129,631	$ 134,420
Rate of return on average rate base	5.58%	6.79%	5.02%	5.73%	5.68%

The average rate base is forecast to increase by $189,220,000 in 2017 compared to 2016, $187,606,000 in 2018 test year compared to forecast 2017, and $101,356,000 in 2019 test year compared to 2018 test year.

Plant Investment

The most significant increase to rate base can be attributable to net capital assets. In forecast 2017, test year 2018 and test year 2019, total additions are forecast in the amount of $391.3 million, $223.0 million, and $168.7 million, respectively, which excludes assets included in work in progress. Capital expenditures are discussed further in the Capital Expenditures section of this report.

Asset Retirement Obligation

The estimated undiscounted cash flows related to the Holyrood Thermal Generating Station have been agreed to the estimate included in the "Decommissioning and Demolition of the Holyrood Generating Station" report issued by Stantec and included in Exhibit 8 of the pre-filed evidence.

In relation to this evidence we note the following:

- We have reviewed the calculations provided by the Company and recalculated the asset retirement obligations ("ARO") and the asset retirement costs ("ARC") and have not found any discrepancies;

- Depreciation expense and accretion costs have been agreed to supporting schedules provided by the Company;

- 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. The discount rate used by Hydro at December 31, 2016, and for forecast 2017, and test years 2018 and 2019 was 2.51% and 2.92% for the Holyrood and PCB AROs, respectively;

- Estimates related to ARO's are inherently subject to uncertainty regarding the timing and amount of future cash outflows. The expected undiscounted future cash outflows are $15.2 million based on the most recent estimates prepared by Stantec. This estimate includes a contingency of $1.9 million. We agreed that the undiscounted cash outflows were incorporated into Hydro's calculation of the Holyrood ARO;

- Hydro has not recognized an ARO on estimated Phase II costs of approximately $25.8 million. We enquired as to whether or not this is in compliance with obligations under IFRS and according to Hydro,

> "At this time, there is no legal requirement to dispose of the assets listed in Phase 2 while the Holyrood Generation Station is still an industrial site. As noted in PUB-NLH-068, the Holyrood Generating Station is expected to remain an industrial site for the foreseeable future with Unit 3 in synchronous condenser mode and the Holyrood Gas Turbine in operations. In addition, it was determined that there was no constructive obligation as there was too much uncertainty due to the length of time before decommissioning is required and potential changes in assumptions and/or legal requirements, as outlined in the 2017 GRA, Volume II, Exhibit 8, page 19 of 41:

Phase 2 activities could change based upon changes in assumptions, updates in regulation or directions from governing agencies such as the NLDEC, the Phase 2 costs are provided for information and comparative purposes only."

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

- The report issued by Stantec is dated November 15, 2016. According to Hydro, there has been no change in assumption, estimate or recognition to the Holyrood ARO under IFRS, based on the information available as of November 17, 2017.

Average Net Assets Excluded from Rate Base

The following table summarizes a breakdown of average net assets excluded from rate base for actual 2015 and 2016, forecast 2017, and test years 2018 and 2019, as provided in NP-NLH-085.

Table 11: Average net assets excluded from rate base (2015-2016, 2017 forecast and test years 2018 and 2019)

(000's)	Actual 2015	Actual 2016	Forecast 2017	Test Year 2018	Test Year 2019
P.U. 8 (2016) - Allowance for Unforeseen Items					
WAV Transformer T5 - Perform Upgrades	$ -	$ 659	$ 659	$ -	$ -
Re-Heat Boiler - Holyrood Unit 2	-	613	613	-	-
Re-Heat Boiler - Holyrood Unit 1	-	370	370	-	-
Transmission Line Reroutes - Sally's Cove	-	678	678	-	-
	-	2,320	2,320	-	-
P.U. 48 (2016) - Allowance for Unforeseen Items					
Penstock #1 Refurbishment - Bay D'Espoir	-	3,284	3,284	-	-
Access Roads Refurbishment - Bay D'Espoir	-	1,358	2,379	1,021	-
Allowance for Unforeseen	-	(1,000)	(1,145)	(145)	-
	-	3,642	4,518	876	-
Prudency Review Projects	7,427	8,468	7,522	6,382	5,170
Other	3,305	2,247	1,886	1,562	1,245
	$ 10,732	$ 16,677	$ 16,246	$ 8,820	$ 6,415

P.U. 8 (2016) Allowance for Unforeseen Items variance is to be addressed in a subsequent order of the Board following further application by Hydro. Hydro is expecting to file an application with the Board for inclusion of these assets in rate base in 2017.

P.U. 48 (2016) Allowance for Unforeseen Items variance is to be addressed in a subsequent order of the Board following further application by Hydro. Hydro is expecting to file an application for the Bay d'Espoir Access Road project in 2018 to be included in rate base subsequent to the granting of an approval for an easement from the Government on the road. Hydro has assumed that the Penstock #1 Refurbishment will be approved for recovery in 2017 and the Access Roads will be approved for recovery in 2017 and 2018. As per P.U. 33 (2015) and P.U. 8 (2016) the Board has approved an Allowance for Unforeseen items for $1.0 million each. Hydro has applied the allowances noted in P.U. 48 (2016) against P.U. 8 (2016) and P.U. 48 (2016) for the calculation of the average assets excluded from rate base.

If projects in P.U. 8 (2016) and P.U. 48 (4016) are not approved by the Board, the impact would be a reduction in rate base in 2018 test year of $5,962,000 ($2,320,000 + $4,518,000 - $876,000) and in 2019 test year of $6,838,000 ($2,320,000 + $4,518,000).

Cash Working Capital Allowance

During 2016, Hydro engaged CA Energy to review its working capital methodology. The review resulted in no changes to the existing methodology, however it was noted that, due to the completion of Muskrat Falls Project and the commencement of charges for Labrador Island Link, the lead/lag days will need to be revisited, and likely updated. The cash working capital allowance is forecast to increase in 2017 by $2,278,000 over actual 2016, primarily due to the HST adjustment factor resulting from increased capital expenditures in 2017. In 2018 test year, the cash working capital allowance is expected to decrease by $4,810,000 compared to forecast 2017, primarily as a result of an increase in the expense lag from 23.56 in forecast 2017 to 28.76 in 2018 test year due to increased lag days for power purchases and professional fees.

Hydro provided the calculations supporting the cash working capital allowance for forecast 2017, and test years 2018 and 2019. The result of these calculations differed from the cash working capital allowance as submitted in Finance Schedule 4-II, pg. 5 of 9. These differences have been summarized in the table below:

Table 12: Cash working capital allowance (2017 forecast and test years 2018 and 2019)

	Forecast 2017	Test Year 2018	Test Year 2019
As filed in Finance Schedule 4-II, pg. 5 of 9	$ 7,582,000	$ 2,772,000	$ 2,255,000
As calculated by Hydro	7,562,279	2,705,480	2,186,355
Difference	$ 19,721	$ 66,520	$ 68,645

Fuel Inventory

According to Hydro, the primary driver for the increase in average fuel over 2016 is higher forecast No. 6 fuel price per barrel for forecast 2017, and test years 2018 and 2019. The average purchase price of No. 6 fuel is forecast to be $78.84/bbl in 2017, $86.68/bbl in 2018, and $87.80/bbl in 2019, compared to $46.40/bbl in 2016.

Deferred Charges

The decrease of $36,674,000 in average deferred charges in forecast 2017 from actual 2016 relates primarily to the following deferral balances; the 2014 Cost Deferral (2016 - $37,707,000 vs. 2017 - $Nil), the 2015 Cost Deferral (2016 - $27,695,000 vs. 2017 - $Nil), and the Energy Supply Deferral (2016 - $38,663,000 vs. 2017 - $8,561,000).

The following table summarizes average deferred charges for actual 2015 and 2016, forecast 2017, and test years 2018 and 2019:

Table 13: Average deferred charges (2015-2016, 2017 forecast and test years 2018 and 2019)

(000,000's)	Balance Dec 31/15	Balance Dec 31/16	Forecast 2017	Test Year 2018	Test Year 2019
Realized Foreign Exchange Losses	$ 56.1	$ 53.9	$ 51.8	$ 49.6	$ 47.4
CDM Program	7.2	8.3	9.9	10.8	11.7
Deferred Foreign Exchange on Fuel	0.8	(0.2)	(0.2)	(0.2)	(0.2)
2014 Cost Deferral	37.7	37.7	-	-	-
2015 Cost Deferral	27.7	27.7	-	-	-
2016 Cost Deferral	-	5.0	-	-	-
Deferred Lease Costs	4.1	4.5	3.1	1.8	0.5
Phase II Hearing Costs	-	0.9	1.9	1.9	1.9
Deferred Hearing Costs	0.5	0.2	-	0.8	0.4
Asset Disposal	0.4	0.4	0.4	0.4	0.3
Energy Supply Deferral	14.2	38.7	8.6	-	-
Holyrood Conversion	3.6	5.7	3.4	-	-
Isolated Systems	-	(2.2)	0.8	-	-
Labrador RSP Refund	-	-	(0.4)	(0.2)	-
Deferred Power Purchase Deferral	-	-	(0.4)	(0.4)	(0.3)
Cost of Service Hearing Costs	-	-	-	0.3	0.2
Holyrood Inventory Impairment Allowance	-	-	-	(2.1)	(4.2)
2018 Revenue Deficiency	-	-	-	22.6	9.0
	$ 152.3	$ 180.6	$ 78.9	$ 85.3	$ 66.7
Average deferred charges		$ 166.5	$ 129.8	$ 82.1	$ 76.0

Deferred charges are discussed further as a separate section of this report.

Rate of Return on Average Rate Base

The procedures we performed with respect to the calculation of forecast return on average rate base included agreeing the data in the calculation to supporting documentation and recalculating the forecast rate of return to ensure it is in accordance with established practice and Board Orders.

The following table provides the 2015 and 2016 actual return on average rate base, the Company's forecast rate of return on average rate base for 2017 to 2019, and the upper and lower end of range as set by the Board/proposed:

Table 14: Rate of return on average rate base (2015-2016, 2017 forecast and test years 2018 and 2019)

	Actual 2015	Actual 2016	Forecast 2017	Test Year 2018	Test Year 2019
Rate of Return on Average Rate Base	5.58%	6.79%	5.02%	5.73%	5.68%
Upper End of Range set by the Board/Proposed	6.81%	6.81%	6.81%	5.93%	5.88%
Lower End of Range set by the Board/Proposed	6.41%	6.41%	6.41%	5.53%	5.48%

The rate of return on average rate base calculated in the above summary for the 2018 and 2019 test years is 5.73% and 5.68%, respectively, which agrees to the Company's weighted average cost of capital (WACC) filed in Finance Schedule 4-II, pg. 4 of 9. Please refer to the Cost of Capital section of our report for further analysis.

As a result of completing our procedures, we noted the following deferred charge balances have not yet been approved by the Board:

- **Deferred Foreign Exchange on Fuel;**
- **Energy Supply Deferral;**
- **Holyrood Conversion;**
- **Isolated Systems;**
- **Deferred Hearing Costs;**
- **Cost of Service Hearing Costs;**
- **Holyrood Inventory Allowance; and**
- **2018 Revenue Deficiency.**

We also noted the following plant investment items have not yet been approved by the Board:

- **WAV Transformer T5 – Perform Upgrades;**
- **Re-Heat Boiler – Holyrood Unit 1;**
- **Re-Heat Boiler – Holyrood Unit 2;**
- **Transmission Line Reroutes – Sally's Cove;**
- **Penstock #1 Refurbishment – Bay d'Espoir; and,**
- **Access Roads Refurbishment – Bay d'Espoir.**

The remaining components included in return on average rate base and rate of return on average rate base have been calculated in accordance in established practice.

2018 and 2019 Revenue Requirement

Comparison of 2015, 2018 and 2019 Test Years

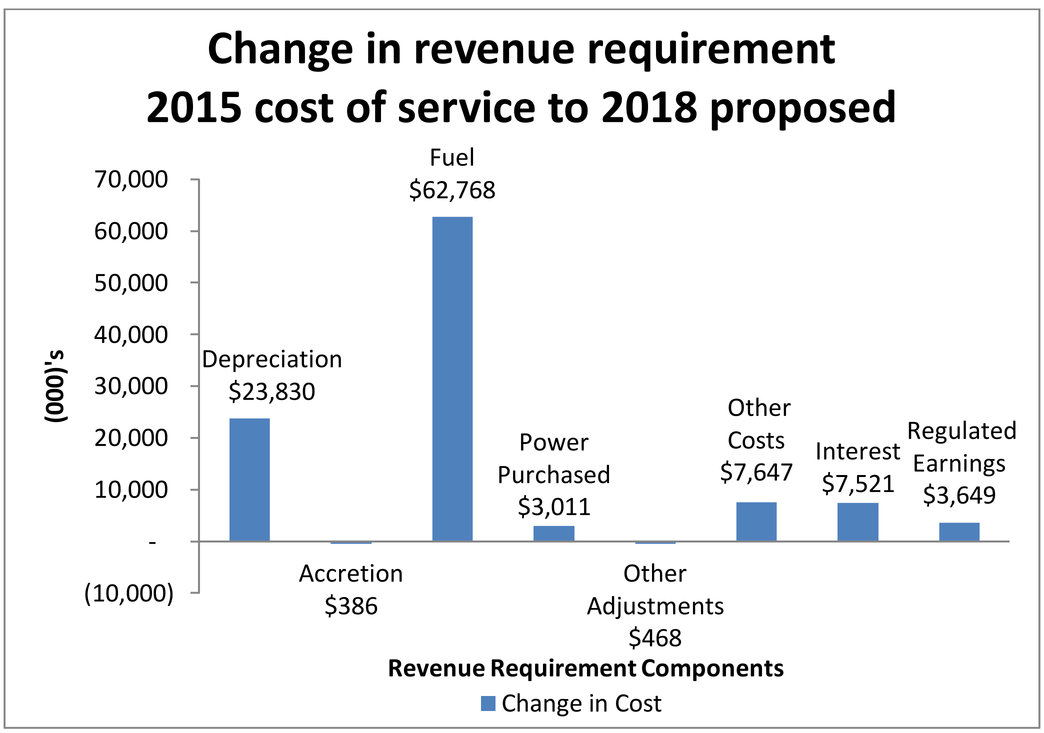
The following table and graphs summarize the changes in Hydro's revenue requirement from the 2015 test year to the 2018 and 2019 test years.

Table 15: Change in revenue requirement from 2015 test year to 2018 and 2019 test years

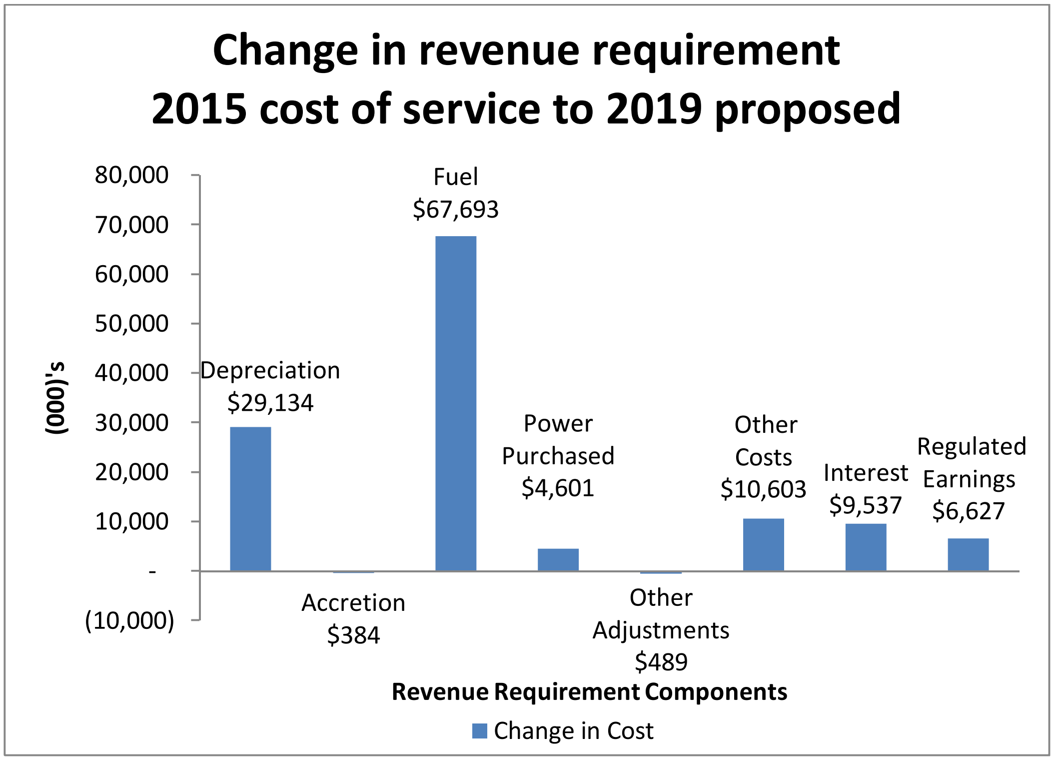
(000)'s	2018	2019
2015 Revenue Requirement[1]	$ 564,002	$ 564,002
Increase (decrease)		
Depreciation	23,830	29,134
Accretion of ARO	(386)	(384)
Fuel	62,768	67,693
Power purchased	3,011	4,601
Other adjustments[2]	(468)	(489)
Other costs (net)	7,647	10,603
Interest	7,521	9,537
Regulated earnings	3,649	6,627
Revenue Requirement	$ 671,574	$ 691,324

[1] 2015 revenue requirement consists of energy sales (excludes fuel rider of $39,141,000)
[2] Other adjustments includes CIAC revenue, other revenue and generation demand cost recovery

Graph 1: Change in revenue requirement from 2015 test year to 2018 test year



Graph 2: Change in revenue requirement from 2015 test year to 2019 test year



The following table provides the cost per kWh for the 2015, 2018 and 2019 test years:

Table 16: Cost per kWh – 2015, 2018 and 2019 test years

	Cost per kWh	
Test Year 2015	$	0.0732
Test Year 2018	$	0.0870
Test Year 2019	$	0.0893

The revenue requirement for the 2018 test year has increased over the 2015 test year by $107.6 million or 19.1% and the 2019 test year has increased over the 2015 test year by $127.3 million or 22.6%. While each component of the 2018 and 2019 revenue requirements has increased over the 2015 test year (with the exception of accretion of ARO and other adjustments), the largest contributor for both is the cost of fuel.

The $62.8 million and $67.7 million increases in the forecast fuel expense for 2018 and 2019, respectively, are primarily due to increases in costs for No.6 fuel as a result of increases in fuel price. For the 2015 test year, the average consumption price per barrel was $64.41 (excluding forecast fuel rider recovery). However, for the 2018 and 2019 test years the average consumption price per barrel is $86.41 and $87.11, respectively. The "consumption price" is a blend of the cost of fuel in inventory at the beginning of the year and the cost of fuel purchased during the year.

The forecast increase in power purchased of $3.0 million and $4.6 million in 2018 and 2019, respectively, is primarily the result of an increase in production at the Corner Brook Pulp and Paper Cogeneration Facility. There were also increases in costs associated with wind purchases primarily due to the conclusion of Eco Energy rebates from the Federal government.

The forecast increase of $7.6 million in 2018 and $10.6 million in 2019 in the other costs category is largely tied to a decrease in cost recoveries relating primarily to the Business System Admin Fee and the Nalcor Admin Fee.

As noted in the pre-filed evidence on page 4.6, the main reason for the forecast increase in the depreciation expense of $23.8 million in 2018 and $29.1 million in 2019 is associated with capital additions of approximately $753.7 million since the 2015 test year, partially offset by a reduction of $2.5 million associated with the new depreciation study.

Interest is forecast to increase over the 2015 test year by $7.5 million in 2018 and $9.5 million in 2019 primarily due to increases in interest on long-term debt, the debt guarantee fee and a decrease in interest capitalized during construction, which is removed from interest expense and therefore caused an increase in overall interest expense. The debt guarantee fee is an annual fee paid by Hydro in return for the Government's guarantee of its debt obligations. This increase was partially offset by a decrease in interest relating to the RSP.

Comparison of 2017, 2018 and 2019 Forecasts to Prior Year's Actuals

The forecast revenue requirement for 2018 of $671.6 million is $115.0 million higher than the 2017 forecast of $556.6 million. The forecast revenue requirement for 2019 of $691.3 million is $19.7 million higher than 2018 test year. Details on Hydro's revenue requirement for 2018 test year and 2019 test year are included in Finance Schedule 4-I and Schedule 4-II page 1 of 9, of the pre-filed evidence. The following table reproduces a portion of this detail showing a comparison of the 2018 and 2019 test years to the Company's actual results for 2015 and 2016, and the 2017 forecast.

Table 17: Revenue requirement (2015-2016, 2017 forecast and test years 2018 and 2019)

(000)'s	Actuals 2015	Actuals 2016	Forecast 2017	Test Year 2018	Test Year 2019	Variance '17F-'16	Variance '18TY-'17TY	Variance '19TY-'18TY
Depreciation	$ 63,222	$ 67,436	$ 76,028	$ 87,885	$ 93,189	$ 8,592	$ 11,857	$ 5,304
Accretion of asset retirement obligation	699	645	189	362	364	(456)	173	2
Fuel	220,359	210,950	179,623	250,232	255,157	(31,327)	70,609	4,925
Power Purchased	60,667	60,117	64,275	65,838	67,428	4,158	1,563	1,590
Other Costs								
Salaries and fringe benefits	114,153	107,674	109,363	111,333	112,902	1,689	1,970	1,569
System equip. maint.	31,928	25,048	25,694	26,228	26,796	645	534	568
Insurance	2,508	2,530	3,038	3,345	3,425	508	307	80
Transportation	3,317	2,943	3,127	3,251	3,361	184	124	110
Office supplies	2,762	2,249	2,307	2,516	2,520	58	209	5
Bldg. rentals and maint.	1,497	1,109	1,077	1,100	1,100	(32)	23	-
Professional services	14,407	6,662	8,846	9,112	8,825	2,184	266	(287)
Travel	3,250	1,984	2,442	2,757	2,759	458	315	2
Equipment rentals	4,218	4,197	3,591	3,749	3,746	(607)	158	(3)
Miscellaneous	5,901	5,098	5,761	5,905	5,985	663	143	81
Compliance Adjustments	(25,282)	(9,017)	-	-	-	9,017	-	-
Other income/expenses (Note 1)	(14,856)	(21,629)	2,157	2,157	2,157	23,786	-	-
Loss on disposal	4,118	7,083	4,360	2,081	2,081	(2,723)	(2,279)	-
Sub-total	147,921	135,931	171,762	173,533	175,658	35,831	1,771	2,125
Allocations								
Hydro capitalized	(25,114)	(32,213)	(29,956)	(28,152)	(28,159)	2,257	1,804	(7)
Cost recoveries	(7,906)	(3,369)	(949)	1,233	2,072	2,421	2,182	839
Subtotal	(33,020)	(35,582)	(30,905)	(26,918)	(26,087)	4,678	3,986	832
Total	114,901	100,349	140,858	146,615	149,571	40,509	5,757	2,957
Interest	94,654	95,721	71,324	94,817	96,833	(24,397)	23,493	2,016
Regulated earnings	(656)	28,231	29,382	31,013	33,991	1,151	1,631	2,978
Revenue requirement	$ 553,846	$ 563,449	$ 561,679	$ 676,762	$ 696,533	$ (1,770)	$ 115,083	$ 19,772
Reconcilation to Revenue Requirement (Energy sales)								
CIAC revenue	(356)	(773)	(1,847)	(1,618)	(1,658)			
Other revenue	(1,825)	(1,863)	(2,068)	(2,088)	(2,109)			
Generation Demand Cost Recovery	(1,262)	(1,288)	(1,213)	(1,482)	(1,442)			
Energy Sales	$ 550,403	$ 559,525	$ 556,551	$ 671,574	$ 691,324			

Note 1:

Other income/expenses:	2015	2016	2017	2018	2019
Other Expenses	3,950	(1,000)	-	-	-
(Gain)/Loss on AFS Settlement	(23)	23	-	-	-
Foreign Exchange (Gain)/Loss	1,717	2,605	2,157	2,157	2,157
Adjustment Sunnyside	-	(425)	-	-	-
Cost Deferrals	(20,500)	(22,832)	-	-	-
	(14,856)	(21,629)	2,157	2,157	2,157

Based on the information in this summary, the most significant increase relates to the cost of fuel, which represents approximately $70.6 million or 61.4% of the total increase in the 2018 test year revenue requirement as compared to the 2017 forecast and approximately $4.9 million or 24.9% of the total increase in the 2019 revenue requirement over 2018 test year. The cost of fuel is discussed in more detail later in this report.

The table below provides a calculation of the total cost of energy and the cost per kWh based on the kWh sold for the years 2015 and 2016, and the forecast for 2017, 2018 and 2019:

Table 18: Total cost of energy and cost per kWh (2015-2016, 2017 forecast and test years 2018 and 2019)

Year	kWh sold and used	Depreciation	Fuel	Purchased Power	Other Costs	Interest	Accretion	Regulated Earnings	Total Cost of Energy	Cost per kWh
2015	7,649,000	63,222	220,359	60,667	114,901	94,654	699	(656)	553,846	0.0724
2016	7,444,000	67,436	210,950	60,117	100,349	95,721	645	28,231	563,449	0.0757
2017F	7,695,000	76,028	179,623	64,275	140,858	71,324	189	29,382	561,679	0.0730
2018TY	7,777,000	87,885	250,232	65,838	146,615	94,817	362	31,013	676,762	0.0870
2019TY	7,798,000	93,189	255,157	67,428	149,571	96,833	364	33,991	696,533	0.0893

Note 1: Since Iron Ore Company of Canada (IOCC) and Wabush Mines are non-regulated customers, those sales have been removed in this table.

The cost of energy per kWh in the 2018 test year is forecast to increase by 19.2% over what was forecast for 2017, and 14.9% over what was experienced in 2016. The cost of energy per kWh in the 2019 test year is forecast to increase by 2.6% over the forecast for 2018, and 18.0% over what was experienced in 2016.

Additional analysis of the 2018 and 2019 revenue requirements in comparison to 2017 forecast and actual results experienced by Hydro over the last few years is included in the following sections of our report.

Depreciation

Our procedures were focused on reviewing rates of depreciation incorporated in the 2018 and 2019 test years to ensure compliance with the 2016 Concentric depreciation study dated October 2017, which forms part of this General Rate Application, Exhibit 11. Newfoundland and Labrador Hydro has applied to adopt the proposed accounting treatment outlined in the study effective January 1, 2018. In addition, our procedures included reconciling the detailed depreciation schedule to the pre-filed evidence, agreeing the annual depreciation rates and removal rates of a sample of assets from Hydro's asset records to the Concentric depreciation study, and recalculating the depreciation for the assets in our sample.

Our procedures also included reviewing the rates of depreciation incorporated in the 2017 forecast to ensure compliance with the Gannett Fleming Depreciation Study dated November 2012 and compliance with Board Order P.U. 40 (2012). In addition, for the 2017 forecast, our procedures also 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.

Hydro has forecast amortization expense of $76.0 million in 2017 and $87.9 and $93.2 in 2018 and 2019 test years, respectively, compared to an actual 2016 expense of $67.4 million. A comparison of the actual depreciation expense from 2015 to 2016, as well as 2017 forecast and 2018 and 2019 test years, is detailed in the following table. The table also calculates depreciation costs as a percentage of total average cost of fixed assets.

We do note that in response to NP-NLH-147 (Revision 1 – November 27, 2017) an error was noted related to Holyrood accelerated assets incorrectly including a combustor asset with the March 31, 2021 truncation date. The Company has noted the impact of the error is an understatement of depreciation expense in the 2019 test year of $0.8 million which Hydro intends to correct in the 2019 test year in its compliance filing. We have asked Hydro to confirm that this would be an understatement versus an overstatement. Their response is outstanding at this time.

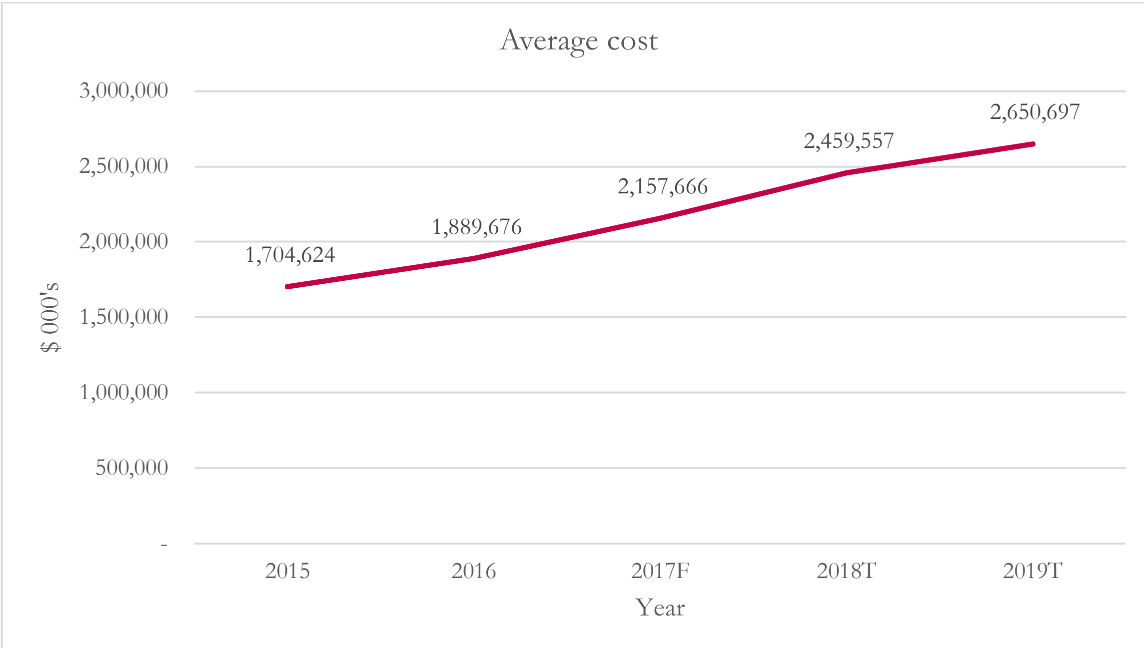
Table 19: Depreciation as a percentage of average cost (2015-2016, forecast 2017, and test years 2018 and 2019)

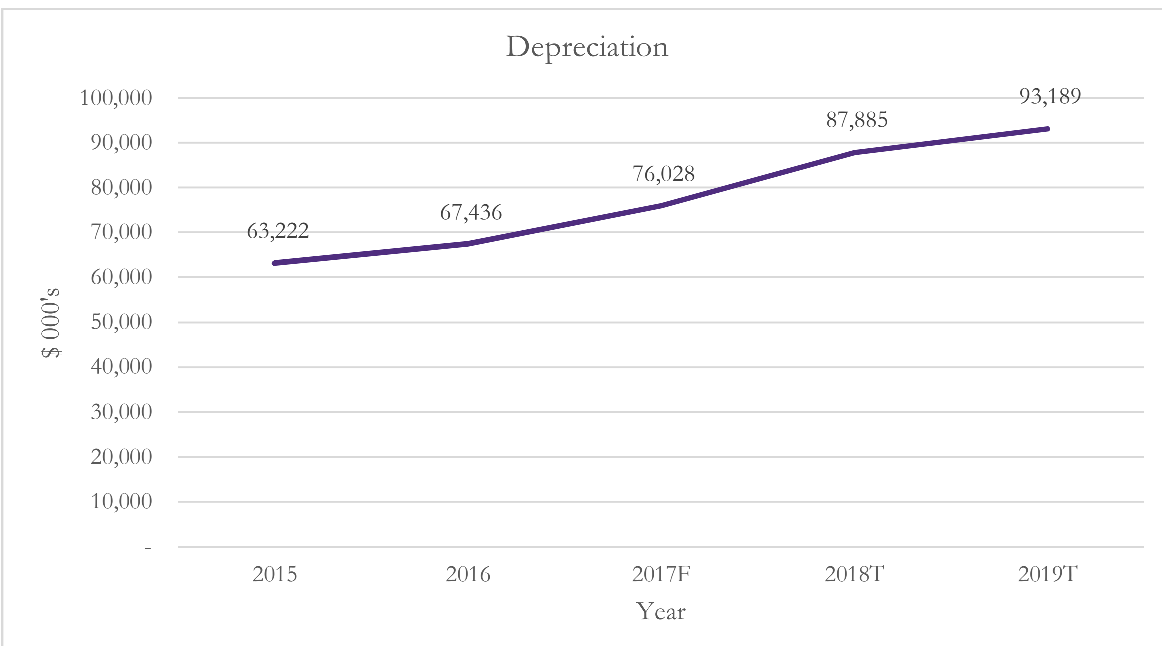
(000)'s	Actual 2015	Actual 2016	Forecast 2017F	Test year 2018T	Test year 2019T
Depreciation	63,222	67,436	76,028	87,885	93,189
Cost	1,814,756	1,964,596	2,350,735	2,568,379	2,733,015
Average cost	1,704,624	1,889,676	2,157,666	2,459,557	2,650,697
Depreciation as a % of average cost	3.71%	3.57%	3.52%	3.57%	3.52%
Change in depreciation as a % of average cost		-0.14%	-0.05%	0.05%	-0.06%
Change as a % of total depreciation		-3.93%	-1.28%	1.39%	-1.64%

As can be seen in the table above, depreciation as a percentage of average total cost of fixed assets is comparable from 2016 to the forecast year and test years (changes of approximately 0.05% percent from one year to the next).

The graphs below show that depreciation and total average cost follow the same trend; i.e.: the two are increasing at a consistent rate with one another, as is expected.

Graph 3: Average cost and annual depreciation expense (2015-2016, 2017 forecast and test years 2018 and 2019)





The table below shows a reconciliation of total cost of fixed assets used in the table above to the net book value of fixed assets as shown in the balance sheet (Finance Schedule 4-II, pg. 2 of 9).

Table 20: reconciliation of total cost of fixed assets used in the table above to the net book value of fixed assets as shown in the balance sheet (2015-2016, 2017 forecast and test years 2018 and 2019)

$ 000's	2015	2016	2017F	2018T	2019T
Cost	1,814,756	1,964,596	2,350,735	2,568,379	2,733,015
Accumulated amortization	(168,306)	(233,720)	(308,582)	(389,021)	(476,625)
Work in progress	43,355	89,697	71,760	51,306	30,488
Property, plant and equipment per balance sheet	1,689,805	1,820,573	2,113,913	2,230,663	2,286,878

Depreciation expense is forcasted to increase by $8.6 million in 2017 and by $11.9 million and $5.3 million for the 2018 and 2019 test years, respectively. The change in depreciation from one year to the next would be expected to be comparable to the total increase in fixed asset additions. In this case, fixed asset additions is considered to be the total capital expenditures incurred in a given year that is added directly to the rate base (property, plant and equipment) and the total amount of work in progress transferred to the rate base (property, plant and equipment) in the year.

The table below summarizes the change in depreciation and fixed asset additions for 2015-2016, forecast 2017 and test years 2018 and 2019. The table also calculates change in depreciation costs as a percentage of total fixed asset additions. As can be seen in the table below, change in depreciation as a percentage of fixed asset additions is comparable from 2016 to the forecast year and test years (changes of approximately 0.60% percent or less from one year to the next). Variances are the result of the timing of additions, as additions begin being amortized in the month that they are put into service; therefore, additions put into operation early in the year are amortized more than those put into operation near the end of the year.

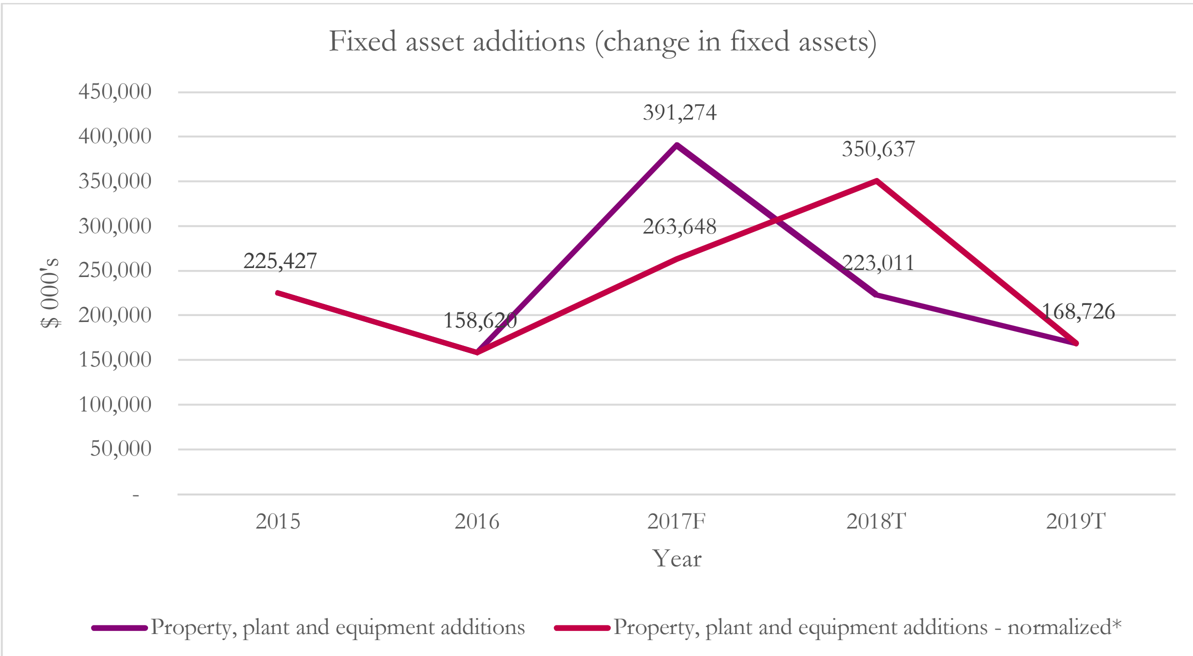
Table 21: Depreciation as a percentage of average cost (2015-2016, forecast 2017 and test years 2018 and 2019)

$ 000's	2015	2016	2017F	2018T	2019T
Depreciation	63,222	67,436	76,028	87,885	93,189
Change in depreciation	7,939	4,214	8,592	11,857	5,304
Property, plant and equipment additions	225,427	158,620	391,274	223,011	168,726
Property, plant and equipment additions - normalized*	225,427	158,620	263,648	350,637	168,726
Change in depreciation as a percentage of change in fixed assets	3.52%	2.66%	2.20%	5.32%	3.14%
Change in depreciation as a percentage of change in fixed assets - normalized*	3.52%	2.66%	3.26%	3.38%	3.14%
Change in percent from prior year - normalized*		-0.87%	0.60%	0.12%	-0.24%

*Normalized for the significant addition related to the 230 KV transmission line from Bay D'Espoir to Western Avalon with a cost of $255,253,000 added to Capital Assets in 2017; however, only depreciated for approximately 1/2 of the year. To normalize, 1/2 of the cost has been deducted from the 2017 additions and added to the 2018 additions.

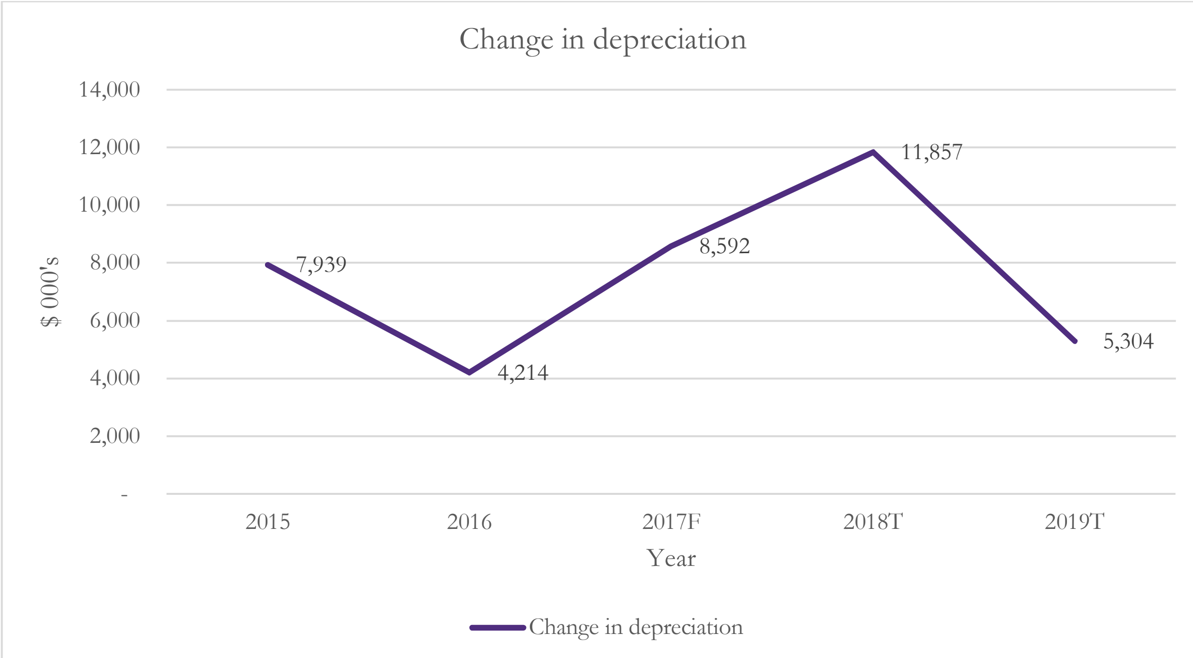
The graphs below show that the change in depreciation and normalized fixed asset additions follow the same trend; i.e.: the two increase and decrease at consistent rates with one another, as is expected.

Graph 4: Fixed asset additions* and annual depreciation expense (2015-2016, 2017 forecast and test years 2018 and 2019)



*Fixed asset additions is comprised of additions to Plant in Service, net of Contributions in Aid of Construction

*Normalized for the significant addition related to the 230 KV transmission line from Bay D'Espoir to Western Avalon with cost of $255,253,000 added to Capital Assets in 2017; however, only depreciated for approximately 1/2 of the year. To normalize, 1/2 of the cost has been deducted from the 2017 additions and added to the 2018 additions.



2016 Depreciation Study

The Company engaged Concentric Advisors Canada ULC to complete a full and complete depreciation study, which included a review and assessment of the electric generation, transmission and distribution systems as of December 31, 2015. Hydro has summarized the recommendations of this depreciation study in Chapter 4 of the Evidence as follows:

- Use of updated estimates of service lives of assets;
- Use of Average Service Life Group procedure applied on a remaining life basis for assets acquired prior to 2015;
- Use of Equal Life Group procedure applied on a remaining life basis for assets acquired in 2015 and after;
- Inclusion of asset removal costs in depreciation rates
- Inclusion of loss on asset disposal costs in depreciation rates.

With respect to these recommendations we offer the following comments:

- Both the Average Service Life and Equal Life Group depreciation methods are used by regulated utilities and are consistent with the requirements of IFRS. However, employing the use of both methods dependent on asset acquisition date does not appear to be in accordance with IFRS which notes in IFRS 16, paragraph 62 "…The entity selects the method that most closely reflects the expected pattern of consumption of the future economic benefits embodied in the asset. That method is applied consistently from period to period unless there is a change in the expected pattern of consumption of those future economic benefits".

- The recommendation of the use of a group method which would result in the inclusion of a loss on asset disposal costs in depreciation expense is consistent with IFRS.

- The inclusion of asset removal costs in depreciation rates (ie: having these costs added to the cost of the asset and depreciated) is consistent with IFRS.

We note the following as the result of completing our procedures:

- We traced the Iowa curves noted in Part II of the Depreciation Study to Part IV of the Depreciation Study to ensure consistency. No discrepancies were noted. We tested a sample of assets to ensure depreciation rates noted in Part IV of the Depreciation Study were used in the detailed depreciation expense calculated by the company. Based on our testing, several Holyrood assets with the March 31, 2021 truncation date continued to be amortized to the old truncation date of December 31, 2020 for the 2018 test year. The annual amortization was updated to reflect the new date for the 2019 test year. We have been advised by Hydro that this is being evaluated internally and if any adjustment is required it will be made in the compliance filing. No other discrepancies were noted.

- We traced all applicable information included in Table 1A and 1B of Part IV of the Depreciation Study to Part IV of the Depreciation Study. No discrepancies were noted.

- Assessing the reasonability of useful lives and depreciation rates was beyond the scope of our report.

- Regarding the 2017 forecast, we tested a sample of assets to ensure depreciation rates set out in the 2012 Depreciation Study were used to calculate forecast depreciation. We did note an error in the depreciation calculation for asset # 390138 – this asset was being depreciated using a useful life of 422 months compared to the 2012 Depreciation Study which indicated a useful life of 620.4 months. We have been advised that this error is being evaluated internally.

Depreciation Study Impact

The overall impact of the change in depreciation methodology on revenue requirements has been included as part of RFI PUB-NLH-70 and is included in the table below:

Table 22: Depreciation Study Impact Summary (as prepared by NL Hydro) - $000's

2015 Depreciation Study Impact Summary
($000's)

	2015 Depreciation Study			2018 Test Year		2019 Test Year	
	Expense	Change		Expense	Change	Expense	Change
Existing	60,624			88,728		93,953	
Per Life Change	57,187	(3,436)	Note 1	82,188	(6,541)	87,759	(6,194)
Net Salvage	64,342	7,155	Note 1	88,720	6,533	95,464	7,705
ELG	65,833	1,490		90,235	1,515	95,499	35
Loss on Disposal		(4,399)	Note 1	86,248	(3,987)	91,514	(3,985)
		810			(2,480)		(2,439)

Note 1: In the 2015 Depreciation Study (Volume II: Exhibit 11, page 7 of 628), the line is 'Losses on Retirement' which includes Loss on Disposal, Removal and Disposal Proceeds. To be consistent with Hydro's 2018 and 2019 Test Year presentation, Hydro has reclassed the removal costs of $1.0M to 'Net Salvage' and ($0.4M) to Per Life Change.

The breakdown of the existing figure for 2018 and 2019 tests years is as follows:

$ 000's	2018 Test Year	2019 Test Year
Depreciation	85,026	90,648
CIAC	(1,945)	(1,760)
Disposal Proceeds	(400)	(400)
Loss on disposal	3,987	3,987
Removal	2,060	1,478
Under Old	**88,728**	**93,953**

The reconciliation of the ending depreciation expense identified in the table above to the figures included in the income statement included in the GRA (schedule 4-II, page 1 of 9) is as follows:

$ 000's	2018 Test Year	2019 Test Year
Ending amount for test year in table above	86,248	91,514
Less CIAC revenue*	(1,618)	(1,658)
Regulatory adjustment Sunnyside transformer	(19)	(19)
Rounding	-	(2)
Actual depreciation per statement of income	**87,885**	**93,189**

*The CIAC revenue is deducted from the depreciation figure as it is disclosed separately in the statement under revenue.

As Hydro has described, the overall expected impact on the test year's revenue requirement, due to the changes described in the depreciation study, is a reduction of approximately $2.5 and $2.4 million. The above table notes the impact on expense related to each proposed change. As the changes are expected to be implemented effective January 1, 2018, there is no impact on the 2017 forecast.

Fuel Costs

The various fluctuations within the fuel cost category have been noted below for the years 2015 and 2016, as well as the 2017, 2018 and 2019 forecast.

Table 23: Fuel costs by category (2015-2016, 2017 forecast and test years 2018 and 2019)

(000)'s	Actuals 2015	Actuals 2016	Forecast 2017	Test Year 2018	Test Year 2019	Variance '17F-'16	Variance '18TY-'17TY	Variance '19TY-'18TY
No.6 Fuel	162,872	123,600	186,475	217,926	220,710	62,875	31,451	2,784
Fuel Additives	(1)	(13)	-	-	-	13	-	-
Fuel Costs Indirect	141	188	156	127	119	(32)	(29)	(8)
Environmental Handling Fee	53	32	32	61	29	-	29	(32)
Ignition Fuel	281	215	247	216	257	32	(31)	41
Gas Turbine Fuel	4,034	5,877	3,240	3,728	4,029	(2,637)	488	301
Holyrood GT	11,407	23,323	9,741	8,447	8,857	(13,582)	(1,294)	410
Diesel Fuel	16,406	14,267	17,919	19,727	21,156	3,652	1,808	1,429
Energy Supply, Isolated & Holyrood Conversion Deferrals	-	-	(12,778)	-	-	(12,778)	12,778	-
Fuel Supply Deferral	-	1,500	-	-	-	(1,500)	-	-
Rate Stabilization Plan (RSP)	25,166	41,961	(25,409)	-	-	(67,370)	25,409	-
	220,359	210,950	179,623	250,232	255,157	(31,327)	70,609	4,925

Fuel costs for 2018 test year are $70.6 million higher than the 2017 forecast. This variance is primarily due to higher costs relating to No.6 fuel, energy supply, isolated and Holyrood conversion deferrals, and the Rate Stabilization Plan. Forecast No. 6 Fuel costs for 2018 increased by $31.5 million compared to the 2017 forecast. This increase is primarily due to an increase in the price per barrel during the year. The forecast price per barrel used in 2018 is $86.41, compared to the price per barrel in the 2017 forecast of $73.91.

Significant fuel costs for forecast 2017 and test years 2018 and 2019 are discussed in further detail below.

No.6 Fuel

According to Operations Schedule 3-V of the pre-filed evidence, Hydro is forecasting the consumption of 2,522,893 barrels of No. 6 fuel in order to produce 1,522 GWh of thermal power at Holyrood in 2017. This is a decrease of 99 GWh and 141,126 barrels of fuel over 2016. For 2018 Hydro is forecasting the consumption of 2,522,118 barrels of No. 6 fuel in order to produce 1,554 GWh of thermal power at Holyrood. This is an increase of 32 GWh and a decrease of 775 barrels of fuel over 2017 forecast year. For 2019 Hydro is forecasting the consumption of 2,533,629 barrels of No. 6 fuel in order to produce 1,560 GWh of thermal power at Holyrood. This is an increase of 6 GWh and 11,511 barrels of fuel over 2018 test year. 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 2016 actual, 2017 forecast, and 2018 and 2019 test years' revenue requirement is summarized below:

	2017F vs. 2018TY ($000,000)	2018TY vs. 2019TY ($000,000)
Increase/decrease in the price of No.6 fuel/bbl	$ 31.5	$ 1.8
Change in conversion factor	(4.0)	-
Increase in thermal production	4.0	0.8
Net increase in No.6 fuel expense	$ 31.5	$ 2.6

Price per barrel:

On Operations Schedule 3-VII in the pre-filed evidence, Hydro is forecasting an average market price of $86.68 and $87.80 per barrel for 2018 and 2019, respectively. However, when the 2018 and 2019 opening values of fuel inventory are taken into consideration, the consumption price per barrel of No.6 fuel is $86.41 and $87.11, respectively, compared to $73.91 per barrel for 2017.

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 2018 test year and multiplied it by the price of fuel forecast for 2018 and forecast cost of fuel for 2017. Hydro did the same for 2019 by multiplying the forecast barrels of fuel to be consumed per the 2019 test year by the price of fuel forecast for 2019 and the price of fuel forecast for 2018.

Number of barrels of No.6 fuel to be consumed in 2018:			2,522,118
Average fuel price for barrels forecast to be consumed for 2018 ($000)	$ 86.41	/bbl	$ 217,936
Average fuel price for barrels to be consumed in 2017 ($000)	$ 73.91	/bbl	$ 186,410
Decrease in fuel cost relating to fuel price per barrel			$ 31,526

Number of barrels of No.6 fuel to be consumed in 2019:			2,533,629
Average fuel price for barrels forecast to be consumed for 2019 ($000)	$ 87.11	/bbl	$ 220,704
Average fuel price for barrels consumed in 2018 ($000)	$ 86.41	/bbl	$ 218,931
Increase in fuel cost relating to fuel price per barrel			$ 1,773

Fuel Conversion Factor

Hydro is forecasting a conversion factor of 616 kWh/barrel in the 2018 and 2019 test years. The forecast conversion factor for 2017 forecast year was 603 kWh/barrel and the conversion factor for 2016 was 608 kWh/barrel. The increase in 2018 and 2019 was due to higher production requirements as a result of increased load for those years. The increase in the factor for 2018 and 2019 test years means fewer barrels of fuel will be required to generate the same amount of energy.

To calculate the impact that this change has on the revenue requirement for 2018 test year in comparison to forecast 2017, Hydro used the forecast net production of thermal energy in 2018, 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 forecast 2017.

Net thermal production forecast for 2018:	1,554.40	GWh
Number of barrels @ 616 kWh per barrel	2,523,377	
Number of barrels @ 603 kWh per barrel	2,577,778	
Decrease in number of barrels	(54,401)	
Average price per barrel to be consumed for 2017	$ 73.91	
Decrease in fuel cost relating to conversion factor ($000)	$ (4,021)	

As highlighted above, in 2018 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.

The same conversion factor was used for the 2019 test year; therefore, the number of barrels required in the production of thermal energy is the same as in the 2018 test year and the change in fuel costs is $Nil.

Net Thermal Production

Thermal production in 2018 is forecast to increase by 32 GWh in comparison to forecast 2017. To calculate the impact that the change in hydraulic production has on the revenue requirement for 2018 in comparison to 2017, Hydro used the difference in forecast net production of thermal energy between 2017 and 2018, and calculated the increase in the number of barrels of fuel that would be required using the 2017 conversion factor of 603 kWh/barrel. Hydro used the same methodology to calculate the impact that the change in hydraulic production has on the revenue requirement for 2019 in comparison to 2018 test year by using the difference in forecast net production of thermal energy between 2018 and 2019, and calculating the increase in the number of barrels of fuel that would be required using the 2018 conversion factor of 616 kWh/barrel.

Net thermal production forecast for 2018	1,554.40	GWh
Net thermal production forecast for 2017	1,521.50	GWh
Net increase in thermal production	32.90	GWh
Increase in barrels required @ 603 kWh per barrel	54,561	
Average price per barrel to be consumed in 2017	$ 73.91	
Increase in fuel cost relating to increased thermal production ($000)	$ 4,033	

Net thermal production forecast for 2019	1,560.30	GWh
Net thermal production forecast for 2018	1,554.40	GWh
Net increase in thermal production	5.90	GWh
Increase in barrels required @ 616 kWh per barrel	9,578	
Average price per barrel to be consumed in 2018	$ 86.41	
Increase in fuel cost relating to increased thermal production ($000)	$ 828	

Gas Turbine Fuel

Gas turbine fuel costs are forecast to decrease by $2.6 million in 2017 over 2016 actuals. According to page 3.25 of the pre-filed evidence, higher unavailability at Holyrood and changes in Hydro's operating parameters resulted in increased production in 2016. The decrease in 2017 fuel costs is the result of the reliability benefit of the planned in service of a third transmission line from Bay d'Espoir to Western Avalon (TL267) which also carries into the 2018 and 2019 test years.

Holyrood Combustion Turbine (CT)

Holyrood CT fuel costs for 2017 are forecast to decrease by $13.6 million compared to 2016 actuals and fuel costs for the 2018 test year are forecast to decrease by $1.3 million compared to the 2017 forecast. According to page 3.25 of the pre-filed evidence, higher unavailability at Holyrood and changes in Hydro's operating parameters resulted in increased production in 2015 and 2016. The decrease in forecast 2017 fuel costs is also the result of the reliability benefit of the planned in service of a third transmission line from Bay d'Espoir to Western Avalon (TL267) and carries into the 2018 and 2019 test years. According to Hydro, in 2016 production at Holyrood CT was 113 GWh, compared to 44 GWh for the 2017 forecast, and 28 GWh for the 2018 test year.

Diesel Fuel

Diesel fuel costs are forecast to increase by $3.7 million in 2017 over 2016 actuals. According to Hydro, this increase is due to an 18% increase in the average weighted fuel price and a 7% increase in production. Diesel fuel costs are forecast to increase by $1.8 million in 2018 over the 2017 forecast. According to Hydro, this increase is due to a 10% increase in the average weighted fuel price and a 1% increase in production. Diesel fuel costs are forecast to increase by $1.4 million in 2019 over the 2018 forecast. According to Hydro, this increase is due to a 7% increase in the average weighted fuel price and a 0.3% increase in production.

Energy Supply, Isolated Systems & Holyrood Conversion Deferrals

The energy supply, isolated systems and Holyrood conversions deferrals are forecast to be $12.8 million in 2017. The energy supply, isolated systems and Holyrood conversion deferrals relating to 2015 and 2016 is included in "compliance adjustments" in our revenue requirement summary. These deferrals are discussed in more detail in the "Deferred Charges" section of our report.

Power purchased

The Company's power purchased cost for 2018 is expected to be $65.8 million, which represents an increase of $1.6 million over the 2017 forecast. This is largely due to an increase in the costs of power purchased from NUGS, the Corner Brook Pulp and Paper Curtailable and L'Anse au Loup. The Company's power purchased cost for 2019 is expected to be $67.4 million, which represents an increase of $1.6 million over the 2018 forecast. This is largely due to an increase in the costs of power purchased from NUGS and L'Anse au Loup. These variances are discussed in further detail below.

The breakdown of power purchased by category is as follows:

Table 24: Power purchased costs by category (2015-2016, 2017 forecast and test years 2018 and 2019)

(000)'s	Actuals 2015	Actuals 2016	Forecast 2017	Test Year 2018	Test Year 2019	Variance '17F-'16	Variance '18TY-'17F	Variance '19TY-'18TY
Energy Costs - NUGS	53,205	52,514	56,239	56,902	58,156	3,725	663	1,254
Demand & energy - CF(L)Co	1,676	1,528	1,416	1,429	1,428	(112)	13	(1)
CBPP, Vale & Praxair Capacity Assistance	2,056	2,638	2,612	3,130	3,130	(26)	518	-
L'Anse au Loup	2,679	2,367	3,126	3,433	3,754	759	307	321
Island wheeling	693	702	736	767	769	34	31	2
Secondary energy	174	231	-	-	-	(231)	-	-
Capacity Expansion	19	-	-	-	-	-	-	-
Ramea Wind	156	129	169	182	194	40	13	12
Ramea Hydrogen	9	8	13	31	33	5	18	2
Deferred fuel saving	-	-	(36)	(36)	(36)	(36)	-	-
	60,667	60,117	64,275	65,838	67,428	4,158	1,563	1,590

<u>NUGS</u>

According to the table above, energy purchases from NUGs accounts for approximately 86% of the total forecast power purchased cost for each of the 2018 and 2019 test years. The cost of power purchased from the NUGs continues to increase each year. In 2015 the costs totaled $53.2 million, and have increased to $58.2 million in 2019 test year. For the 2018 and 2019 test years, 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 2015 to the 2019 test year. The data for this table was compiled from Operations Schedule 3-VI in the pre-filed evidence.

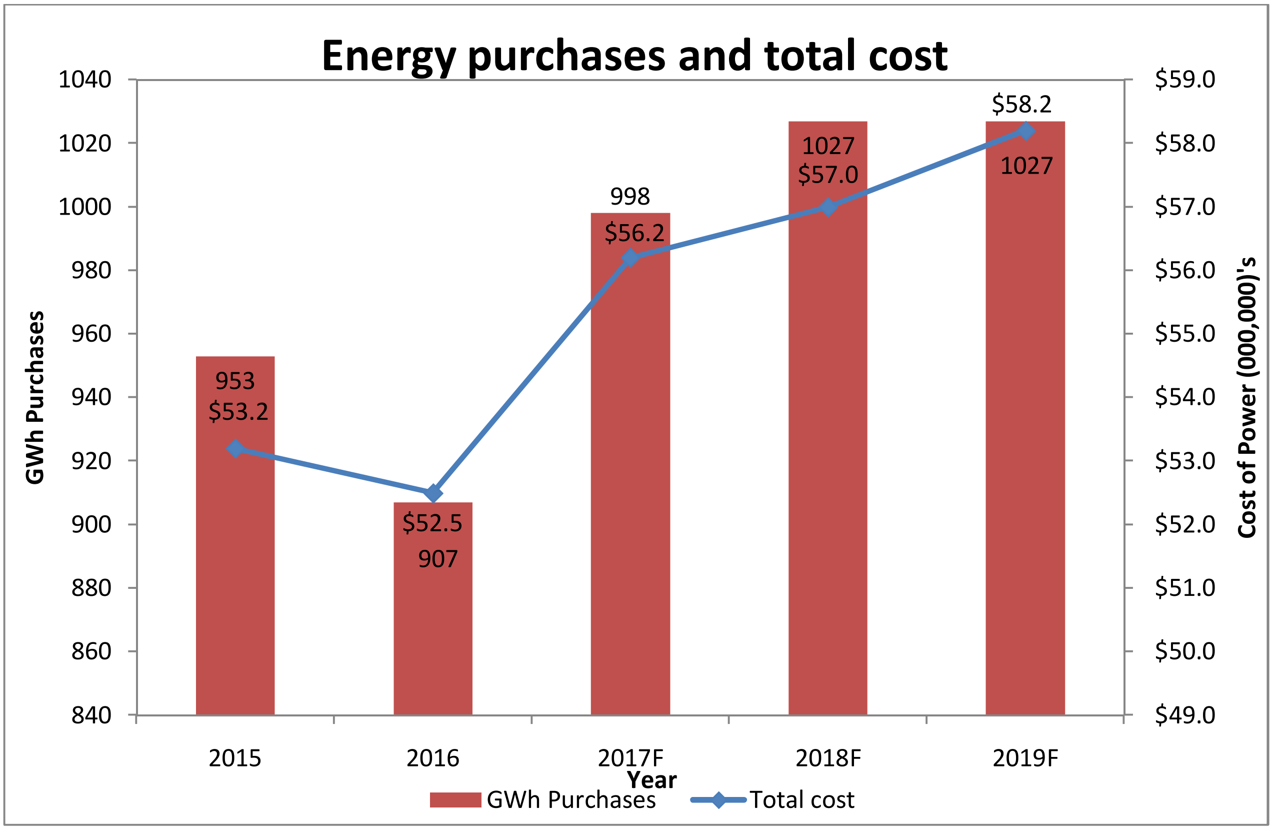
Table 25: Non-utility generators – Island Interconnected (2015 – 2016, 2017 forecast and test years 2018 and 2019)

	2015			2016		
	GWh	$ ('000s)	Avg cost per GWh	GWh	$ ('000s)	Avg cost per GWh
Star Lake	135.30	$ 5,413	$ 40,007	135.7	$ 5,429	$ 40,007
Rattle Brook	13.50	1,103	81,704	15.2	1,283	84,408
Corner Brook Cogen	62.50	11,879	190,064	70.6	13,317	188,626
St. Lawrence Wind (net of incentive credit)	94.80	6,340	66,878	103.1	6,592	63,938
Fermeuse Wind (net of incentive credit)	87.20	6,091	69,851	87	6,077	69,851
Nalcor Exploits	559.50	22,380	40,000	495.4	19,815	39,998
Total Energy Costs - NUGs	952.80	$ 53,206	$ 55,842	907.00	$ 52,513	$ 57,897

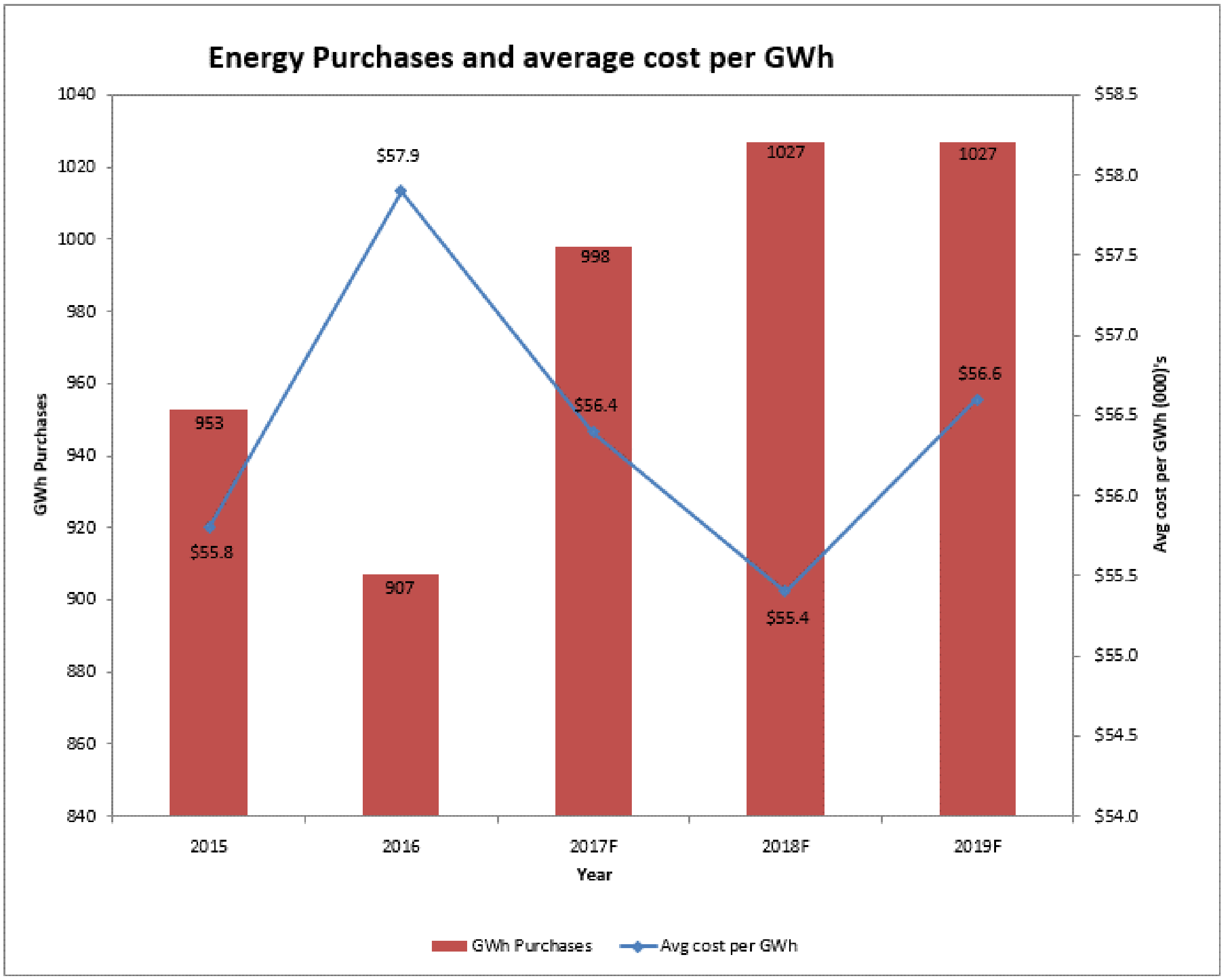
	2017F			2018TY		
	GWh	$ ('000s)	Avg cost per GWh	GWh	$ ('000s)	Avg cost per GWh
Star Lake	140.30	$ 5,610	$ 39,986	140.90	$ 5,635	$ 39,993
Rattle Brook	14.80	1,252	84,595	14.80	1,264	85,405
Corner Brook Cogen	66.50	12,934	194,496	66.50	12,536	188,511
St. Lawrence Wind (net of incentive credit)	104.80	6,975	66,555	104.80	6,946	66,279
Fermeuse Wind (net of incentive credit)	84.40	5,986	70,924	84.40	5,918	70,118
Nalcor Grand Falls, Bishops Falls and Buchans	587.00	23,482	40,003	615.10	24,603	39,998
Total Energy Costs - NUGs	997.80	$ 56,239	$ 56,363	1,026.50	$ 56,902	$ 55,433

	2019TY		
	GWh	$ ('000s)	Avg cost per GWh
Star Lake	142.00	$ 5,679	$ 39,993
Rattle Brook	14.80	1,282	86,622
Corner Brook Cogen	66.50	12,554	188,782
St. Lawrence Wind (net of incentive credit)	104.80	7,567	72,204
Fermeuse Wind (net of incentive credit)	84.40	6,479	76,765
Nalcor Grand Falls, Bishops Falls and Buchans	614.80	24,594	40,003
Total Energy Costs - NUGs	1,027.30	$ 58,155	$ 56,610

Graph 5: Energy purchases and total cost



Graph 6: Energy purchases and average cost per GWh



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 2018 test year in comparison to the 2017 forecast. For 2019, the number of GWh to be purchased from NUGS is consistent with the 2018 test year and the average price per GWh is increasing in comparison to the 2018 test year due to increases in St. Lawrence Wind and Fermeuse Wind.

<u>Corner Brook Pulp & Paper, Vale & Praxair Capacity Assistance</u>
The costs for CBPP, Vale and Praxair capacity assistance are forecast to increase by $518,000 in 2018 over 2017. According to Hydro, this increase is primarily due to an increase in cost of the CBPP capacity assistance from $2.1 million to $2.5 million in recognition of a proposed revised agreement for additional firm capacity assistance over a longer time period. The revised agreement has since been approved by the Board at a forecast cost of $2.6 million. The remainder of the variance is due to Vale capacity assistance in forecast period versus the amount achieved during winter testing in the current period.

<u>L'Anse au Loup</u>
The costs for L'Anse au Loup are forecast to increase by $759,000 in 2017 over 2016. According to Hydro, this is due to a 36% increase in the price of power purchases and a 3.5% decrease in purchased energy. The

costs for L'Anse au Loup are forecast to increase by $307,000 in 2018 over 2017. According to Hydro, this is due to a 9% increase in the price of power purchases and a 0.4% increase in purchased energy. The costs for L'Anse au Loup are forecast to increase by $321,000 in 2019 over 2018. According to Hydro, this is due to an 8% increase in the price of power purchases and a 0.8% decrease in purchased energy.

Interest

Interest expense for 2017 is forecast to decrease by $24.4 million overall compared to 2016. Interest expense for 2018 is forecast to decrease by $23.5 million overall compared to the 2017 forecast. Interest expense for 2019 is forecast to decrease by $2.0 million overall compared to the 2018 forecast. The following table summarizes interest expense for actual 2015 and 2016, forecast 2017, and the 2018 and 2019 test years.

Table 26: Interest expense (2015-2016, 2017 forecast and test years 2018 and 2019)

('000s)	Actuals 2015	Actuals 2016	Forecast 2017	Forecast 2018	Forecast 2019	Variance '17F-'16	Variance '18TY-'17F	Variance '19TY-'18TY
Gross interest	85,292	83,899	85,419	100,569	102,147	1,520	15,150	1,578
Debt guarantee fee	4,514	4,524	4,127	7,359	8,254	(397)	3,232	896
RSP	21,723	25,505	7,572	(248)	(390)	(17,933)	(7,820)	(142)
Amortization of debt discount and financing costs	547	540	648	615	653	108	(33)	38
	112,077	114,468	97,766	108,295	110,664	(16,702)	10,529	2,370
Less:								
Interest earned	(14,057)	(14,779)	(12,644)	(11,406)	(11,680)	2,134	1,239	(274)
Interest capitalized during construction	(3,366)	(3,968)	(13,798)	(2,072)	(2,152)	(9,830)	11,726	(80)
	(17,423)	(18,747)	(26,442)	(13,478)	(13,832)	(7,695)	12,964	(354)
	94,654	95,721	71,324	94,817	96,833	(24,397)	23,493	2,016

Net interest expense is forecast to decrease by $24.4 million in 2017 compared to 2016 actuals. The most significant items impacting the decrease in net interest in 2017 are the forecast decrease of $18.0 million in the RSP, and a $9.8 million increase in interest capitalized during construction. This was partially offset by a $2.0 million decrease in interest earned.

According to Hydro, the decrease in the RSP is due to a decrease in the average RSP liability, primarily due to the following:

i) restatement of the RSP to reflect the 2015 test year, resulting in a $76 million reduction in the plan effective January 1, 2017, as per P.U. 49 (2016);
ii) disposition of approximately 93% of the utility surplus;
iii) segregated loan balance of $49.8 million transferred to the current plan as of March 31, 2017 to help offset the July 1 rate increase; and
iv) forecast recovery of the supply cost deferrals from the RSP in September.

According to Hydro, the decrease in interest earned for the 2017 forecast is primarily due to the maturity of Series X in July 2017 that reduced sinking funds. Therefore, earnings from this particular series were only present for half the year in 2017.

According to Hydro, the increase in interest capitalized during construction for 2017 is primarily due to two transmission line projects (226 and 267), which had interest of $10.4 million capitalized, compared to only $0.9 million in 2016.

Net interest expense is forecast to increase by $23.5 million in the 2018 test year compared to forecast 2017. The most significant items impacting the increase in net interest in 2018 are the increase in gross interest of $15.2 million, the increase in the debt guarantee fee of $3.2 million, and the decrease in interest capitalized during construction of $11.7 million. This was partially offset by the decrease in the RSP of $7.8 million.

According to Hydro, the increase in gross interest is due to the 2018 test year including interest on long-term debt issuances for both 2017 and 2018. The increased cost of long term debt is due to a forecast $50 million debt issuance planned for February 2018, partially offset by the savings recognized from Series X maturing in July 2017, as discussed above.

According to Hydro, the forecast increase in the debt guarantee fee in 2018 is due to an increase in debt guaranteed by the provincial government as at December 31, 2017, which is the basis for the 2018 fee. The debt guarantee fee is calculated using prior year December 31 balances; therefore, the forecast debt issuance in 2017 results in an increase in the 2018 debt guarantee fee, which is partially offset by the maturity of Series X.

According to Hydro, the forecast decrease in the RSP for 2018 is primarily due to a full year impact of the reductions in 2017 to the average RSP balances. In addition, because 2018 is a test year there are no forecast cost of service variances, only interest and refund/recovery from customers, which resulted in a decrease in the RSP balance and related interest for 2018.

Interest capitalized during construction also decreased in 2018 compared to the 2017 forecast. According to Hydro, this was primarily due to a lower budget in 2018 compared to 2017 as a result of the transmission line projects (266 and 267) that will be in service at the end of 2017.

Net interest expense for the 2019 test year is relatively consistent with the 2018 test year.

Other Costs

The following table provides a breakdown of the various accounts which form the "other costs" category, for actual 2015 and 2016, forecast 2017, and test years 2018 and 2019:

Table 27: Other costs by category (2015-2016, 2017 forecast and test years 2018 and 2019)

(000)'s	Actuals 2015	Actuals 2016	Forecast 2017	Test Year 2018	Test Year 2019	Variance '17F-'16	Variance '18TY-'17F	Variance '19TY-'18TY
Other costs								
Salaries and fringe benefits	114,153	107,674	109,363	111,333	112,902	1,689	1,970	1,569
System equip. maint.	31,928	25,048	25,694	26,228	26,796	645	534	568
Insurance	2,508	2,530	3,038	3,345	3,425	508	307	80
Transportation	3,317	2,943	3,127	3,251	3,361	184	124	110
Office Supplies	2,762	2,249	2,307	2,516	2,520	58	209	5
Bldg. rental and maint.	1,497	1,109	1,077	1,100	1,100	(32)	23	-
Professional services	14,407	6,662	8,846	9,112	8,825	2,184	266	(287)
Travel	3,250	1,984	2,442	2,757	2,759	458	315	2
Equipment rentals	4,218	4,197	3,591	3,749	3,746	(607)	158	(3)
Miscellaneous	5,901	5,098	5,761	5,905	5,985	663	143	81
Compliance adjustments	(25,282)	(9,017)	-	-	-	9,017	-	-
Other income/expenses (Note 1)	(14,856)	(21,629)	2,157	2,157	2,157	23,786	-	-
Loss on disposal	4,118	7,083	4,360	2,081	2,081	(2,723)	(2,279)	-
Total	147,921	135,931	171,762	173,533	175,658	35,831	1,771	2,125
Percentage change		-8.82%	20.86%	1.02%	1.21%			
Allocations								
Hydro capitalized	(25,114)	(32,213)	(29,956)	(28,152)	(28,159)	2,257	1,804	(7)
Cost recoveries	(7,906)	(3,369)	(949)	1,233	2,072	2,421	2,182	839
Sub-total	(33,020)	(35,582)	(30,905)	(26,918)	(26,087)	4,678	3,986	832
Net total	114,901	100,349	140,858	146,615	149,571	40,509	5,757	2,957
Percentage change		-14.50%	28.76%	3.93%	1.98%			

Note 1:

Other income/expenses:	2015	2016	2017	2018	2019
Other Expenses	3,950	(1,000)	-	-	-
(Gain)/Loss on AFS Settlement	(23)	23	-	-	-
Foreign Exchange (Gain)/Loss	1,717	2,605	2,157	2,157	2,157
Adjustment Sunnyside	-	(425)	-	-	-
Cost Deferrals	(20,500)	(22,832)	-	-	-
	(14,856)	(21,629)	2,157	2,157	2,157

In the table above we see that total other costs before allocations are forecast to increase by $1.8 million in 2018 test year over the 2017 forecast and by $2.1 million in 2019 test year over the 2018 test year. On a net basis the costs for 2018 test year are forecast to exceed the 2017 forecast by approximately $5.8 million and the costs for 2019 test year are forecast to exceed the 2018 test year by approximately $3.0 million.

In the table below we provide an analysis of total other costs on a kWh's sold and used basis for 2015 and 2016 actuals, 2017 forecast, and 2018 and 2019 test years. This table shows that total other costs are forecast to increase and, on a kWh basis, costs are forecast to increase as well. The cost per kWh for 2018 test year is higher than the 2017 forecast and forecast total other costs for 2018 are 4.0% higher than 2017. The cost per kWh for 2019 test year is higher than the 2018 test year and forecast total other costs for 2019 are 2.0% higher than 2018.

Table 28: Other costs per kWh (2015-2016, 2017 forecast and test years 2018 and 2019)

	2015			2016		
kWh sold and used	7,649,000			7,444,000		
	Cost	Cost per kWh	% of Total	Cost	Cost per kWh	% of Total
Salaries and fringe benefits	114,153	0.0149	99.35%	107,674	0.0145	107.30%
System equip. maint.	31,928	0.0042	27.79%	25,048	0.0034	24.96%
Insurance	2,508	0.0003	2.18%	2,530	0.0003	2.52%
Transportation	3,317	0.0004	2.89%	2,943	0.0004	2.93%
Office Supplies	2,762	0.0004	2.40%	2,249	0.0003	2.24%
Bldg. rental and maint.	1,497	0.0002	1.30%	1,109	0.0001	1.11%
Professional services	14,407	0.0019	12.54%	6,662	0.0009	6.64%
Travel	3,250	0.0004	2.83%	1,984	0.0003	1.98%
Equipment rentals	4,218	0.0006	3.67%	4,197	0.0006	4.18%
Miscellaneous	5,901	0.0008	5.14%	5,098	0.0007	5.08%
Compliance adjustments	(25,282)	(0.0033)	-22%	(9,017)	(0.0012)	-8.99%
Other income/expenses	(14,856)	(0.0019)	-12.93%	(21,629)	(0.0029)	-21.55%
Loss on disposal	4,118	0.0005	3.58%	7,083	0.0010	7.06%
	147,921	0.0193	128.74%	135,931	0.0183	135.46%
Hydro capitalized	(25,114)	(0.0033)	-21.86%	(32,213)	(0.0043)	-32.10%
Cost recoveries	(7,906)	(0.0010)	-6.88%	(3,369)	(0.0005)	-3.36%
Total other costs (net)	114,901	0.0150	100.00%	100,349	0.0135	100.00%

	2017 Forecast			2018 Test Year		
kWh sold and used	7,695,000			7,777,000		
	Cost	Cost per kWh	% of Total	Cost	Cost per kWh	% of Total
Salaries and fringe benefits	109,363	0.0142	77.64%	111,333	0.0143	75.94%
System equip. maint.	25,694	0.0033	18.24%	26,228	0.0034	17.89%
Insurance	3,038	0.0004	2.16%	3,345	0.0004	2.28%
Transportation	3,127	0.0004	2.22%	3,251	0.0004	2.22%
Office Supplies	2,307	0.0003	1.64%	2,516	0.0003	1.72%
Bldg. rental and maint.	1,077	0.0001	0.76%	1,100	0.0001	0.75%
Professional services	8,846	0.0011	6.28%	9,112	0.0012	6.21%
Travel	2,442	0.0003	1.73%	2,757	0.0004	1.88%
Equipment rentals	3,591	0.0005	2.55%	3,749	0.0005	2.56%
Miscellaneous	5,761	0.0007	4.09%	5,905	0.0008	4.03%
Compliance adjustments	-	-	0.00%	-	-	0.00%
Other income/expenses	2,157	0.0003	1.53%	2,157	0.0003	1.47%
Loss on disposal	4,360	0.0006	3.10%	2,081	0.0003	1.42%
	171,762	0.0223	121.94%	173,533	0.0223	118.36%
Hydro capitalized	(29,956)	(0.0039)	-21.27%	(28,152)	(0.0036)	-19.20%
Cost recoveries	(949)	(0.0001)	-0.67%	1,233	0.0002	0.84%
Total other costs (net)	140,858	0.0183	100.00%	146,615	0.0189	100.00%

	2019 Test Year		
kWh sold and used	7,798,000		
	Cost	Cost per kWh	% of Total
Salaries and fringe benefits	112,902	0.0145	75.48%
System equip. maint.	26,796	0.0034	17.91%
Insurance	3,425	0.0004	2.29%
Transportation	3,361	0.0004	2.25%
Office Supplies	2,520	0.0003	1.69%
Bldg. rental and maint.	1,100	0.0001	0.74%
Professional services	8,825	0.0011	5.90%
Travel	2,759	0.0004	1.84%
Equipment rentals	3,746	0.0005	2.50%
Miscellaneous	5,985	0.0008	4.00%
Compliance adjustments	-	-	0.00%
Other income/expenses	2,157	0.0003	1.44%
Loss on disposal	2,081	0.0003	1.39%
	175,658	0.0225	117.44%
Hydro capitalized	(28,159)	(0.0036)	-18.83%
Cost recoveries	2,072	0.0003	1.39%
Total other costs (net)	149,571	0.0192	100.00%

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

Salaries and fringe benefits

Gross payroll costs forecast for 2017 of $109.4 million are higher than 2016 levels by $1.7 million or 1.6%. Gross payroll costs forecast for 2018 of $111.3 million are higher than 2017 forecast levels by $2.0 million or 1.8%. Gross payroll costs forecast for 2019 of $112.9 million are higher than 2018 forecast levels by $1.6 million or 1.4%.These variations are outlined in the table below which summarizes salaries and fringe benefits costs incurred from 2015 to 2016 and the 2017, 2018 and 2019 forecast.

Table 29: Salaries and benefits by category (2015-2016, 2017 forecast and test years 2018 and 2019)

(000)'s	Actuals 2015	Actuals 2016	Forecast 2017	Test Year 2018	Test Year 2019	Variance '17F-'16	Variance '18TY-'17F	Variance '19TY-'18TY
Salaries	$ 61,076	$ 61,639	$ 70,927	$ 72,464	$ 73,332	$ 9,288	$ 1,538	$ 868
Temporary salaries	8,343	7,287	8,047	7,617	7,773	760	(429)	156
Vacancy adjustment	-	-	(3,766)	(3,540)	(3,540)	(3,766)	226	-
	69,419	68,926	75,207	76,542	77,566	6,281	1,335	1,024
Other salary costs	1,722	1,004	849	830	856	(154)	(20)	26
Intercompany salaries	2,249	(105)	654	369	286	759	(285)	(83)
	73,390	69,825	76,711	77,741	78,707	6,886	1,030	967
Allowances	2,266	2,294	1,902	1,903	1,903	(392)	1	-
Directors fees	30	16	85	65	65	69	(20)	-
Overtime	17,823	14,919	9,567	9,850	9,887	(5,352)	283	37
Employee future benefits	6,619	6,946	6,285	6,490	6,705	(660)	204	215
Fringe benefits	11,513	11,122	12,296	12,422	12,597	1,174	126	175
Group insurance	2,347	2,377	2,353	2,699	2,875	(24)	346	176
Labrador travel benefit	165	175	164	164	164	(11)	-	(0)
Gross payroll costs	114,153	107,674	109,363	111,333	112,902	1,689	1,970	1,569
Less: capitalized salaries	(23,448)	(30,127)	(27,788)	(26,064)	(26,072)	2,338	1,724	(8)
Salaries and fringe benefits, net	$ 90,705	$ 77,547	$ 81,575	$ 85,268	$ 86,830	$ 4,028	$ 3,694	$ 1,562

Salaries

The salaries component of salaries and fringe benefits has maintained its upward trend from 2015 to 2019 test year. The breakdown of salaries by division is summarized below:

Table 30: Salaries by division (2015-2016, 2017 forecast and test years 2018 and 2019)

(000)'s	Actuals 2015	Actuals 2016	Forecast 2017	Test Year 2018	Test Year 2019	Variance ($) '17F-'16	Variance ($) '18TY-'17F	Variance ($) '19TY-'18TY
Executive Leadership	$ 757	$ 992	$ 1,570	$ 1,611	$ 1,654	$ 579	$ 40	$ 44
Finance	4,407	4,389	5,748	6,029	6,147	1,359	281	119
Engineering	12,280	8,800	12,374	12,939	13,231	3,574	565	292
Transmissions Operations	29,480	28,821	28,987	28,761	29,021	166	(226)	260
Productions Operations	16,750	18,167	19,322	19,488	19,662	1,155	167	173
Regulatory Affairs and Customer Service	8,535	8,883	8,509	8,780	8,979	(373)	271	198
Recharged Salaries	(2,790)	(1,126)	(1,303)	(1,066)	(1,128)	(177)	237	(62)
	$ 69,419	$ 68,926	$ 75,207	$ 76,542	$ 77,566	$ 6,283	$ 1,335	$ 1,024

Salary fluctuations were noted within several of the divisions when comparing the 2017 forecast to 2016 actuals, the 2018 test year to the 2017 forecast and the 2019 test year to the 2018 test year; however, the most significant increases occurred within the following divisions – Executive Leadership, Finance, Engineering, Production Operations, and Recharged Salaries.

According to Hydro, the $579,000 increase in the Executive Leadership division for the 2017 forecast compared to the 2016 year is primarily due to the Hydro reorganization. Per Hydro's response to PUB-NLH-033, Hydro added two new full time positions to this department in 2017. Executive compensation is discussed further in our report.

According to Hydro, the $1.4 million increase in the Finance division for the 2017 forecast compared to the 2016 year is primarily due to the Hydro reorganization. Per Hydro's response to PUB-NLH-033, Hydro added five new full time positions to this department in 2017 with the goal of ensuring organizational independence for Hydro related to financial management. Previously, these FTEs resided in Nalcor and provided services to Hydro. In addition to these five positions, Hydro also transferred 15 existing positions responsible for warehousing from Production and Transmission Rural Operations to the Finance Department. Hydro's response to NP-NLH-171 provides a detailed description of the changes in this division.

According to Hydro, the $3.6 million increase in the Engineering division for the 2017 forecast compared to the 2016 year is primarily due to the Hydro reorganization. Per Hydro's response to PUB-NLH-033, Hydro added 20 new full time positions to this department in 2017. The increase is also due to vacancies in 2016; most of which have been subsequently filled in 2017.

According to Hydro, the $1.2 million increase in the Productions Operations division for the 2017 forecast compared to the 2016 year is primarily due to the Hydro reorganization. Per Hydro's response to PUB-NLH-033, Hydro added six new full time positions to this department in 2017.

According to Hydro, the $177,000 increase in recharged salaries for the 2017 forecast compared to the 2016 year is primarily due related to an increase in charges out of Corporate Services & Regulatory Affairs (apprentices, environmental coordinators, and energy efficiency) to Non-Regulated line of businesses (LOBs), Exploits Generation and Star Lake.

According to Hydro, the $237,000 decrease in recharged salaries for the 2018 test year compared to the 2017 forecast is primarily related to a reduction in Apprentice Power System Operator FTEs and related charges out to Non-Regulated Hydro, Exploits Generation.

Consistent with prior years, 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 0-6.5% 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 adjustments are calculated as a percentage of current base salary and 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 2.5% or 5%, respectively, of their base salary.

There was a change in the compensation matrix from 2015 to 2016. The 2017 matrix is consistent with 2016.

Table 31: Compensation matrix

			Scale Adjustment - Below Scale Maximum		
Rating of Performance	**Expected Distribution**	**2016 Actual Distribution**	**2017**	**2016**	**2015 (inclusive of general scale adjustment)**
Exceptional	5%	4%	6.5% (with cash payout of balance)	6.5% (with cash payout of balance)	10% (with cash payout of balance)
Exceed Expectations	20%	19%	5.5% (with cash payout of balance)	5.5% (with cash payout of balance)	8.5 % (with cash payout of balance)
Meets Expectations	70%	63%	4% (to the scale maximum)	4% (to the scale maximum)	7% (to the scale maximum)
Improvement Required	5%	1%	0%	0%	0%
Unacceptable		0%	0%	0%	0%

Note 1: The remaining 13% in the "2016 actual distribution" column relates to staff who were not rated. Employees are not rated when they are eligible for performance contracts, or have missed significant time within the performance period due to retirement, leave of absence or illness, or if they were hired by the Company during the last quarter of the year.
Note 2: All salary adjustment figures include only merit adjusments; there is no general scale adjustment for 2016 and 2017.

Full Time Equivalents

An analysis of net 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 costs for future years. Net FTEs are Hydro based employees, plus or minus time charges from and to other Nalcor lines of business and exclude FTEs associated with administrative fees charged by Nalcor. The table below provides a detailed comparison of the number of net FTEs by division for 2015 to 2019. The table was compiled using net FTE details provided by Hydro.

Table 32: Net FTEs by division (2015-2016, 2017 forecast and test years 2018 and 2019)

(000)'s	Actuals 2015	Actuals 2016	Forecast 2017	Test Year 2018	Test Year 2019	Variance '17F-'16	Variance '18TY-'17F	Variance '19TY-'18TY
Transmission & Distribution & NLSO	352	336	334	329	329	(2)	(5)	-
Production	202	213	216	216	216	3	-	-
Engineering Services	82	78	98	98	98	20	-	-
Information & Operations Technology	57	15	28	28	28	13	-	-
Executive Leadership Hydro	7	6	9	9	9	3	-	-
Finance NL Hydro	48	48	69	68	68	21	(1)	-
Corporate Services & Regulatory Affairs	113	113	106	104	102	(7)	(2)	(2)
	861	809	860	852	850	51	(8)	(2)

As shown, in comparison to 2016 actuals the FTEs for 2017 is forecast to increase by 51 full time positions overall. Per page 3.4 of the pre-filed evidence, this increase includes the impact of the reorganization.

The Engineering Services division is slated to add 20 new full time positions in 2017. These 20 new positions are listed in PUB-NLH-033. The increase is also due to vacancies in 2016; most of which have been subsequently filled in 2017.

According to Hydro, the increase of 21 FTEs in the Finance division is due to the addition of 5 new full time positions added to this department, as noted in PUB-NLH-033. In addition to these five positions, Hydro also transferred 16 existing positions responsible for warehousing from Production and Transmission Rural

Operations to the Finance Department. Hydro's response to NP-NLH-171 provides a detailed description of the changes in this division.

The total FTEs for the 2018 and 2019 test years are fairly consistent with the 2017 forecast.

A comparison of average salary per net FTE for actual 2015 and 2016, forecast 2017, and test years 2018 and 2019 are included in the following table:

Table 33: Average salary per Net FTE (2015-2016, 2017 forecast and test years 2018 and 2019)

(000)'s	Actuals 2015	Actuals 2016	Forecast 2017	Test Year 2018	Test Year 2019	Variance '17F-'16	Variance '18TY-'17F	Variance '19TY-'18TY
Salary costs & Vacancy Adjustment (including temporary salaries)	$ 69,419	$ 68,926	$ 75,207	$ 76,542	$ 77,566	$ 6,281	$ 1,335	$ 1,024
Intercompany salaries	2,249	(105)	654	369	286	759	(285)	(83)
	$ 71,668	$ 68,821	$ 75,861	$ 76,911	$ 77,852	$ 7,040	$ 1,050	$ 1,991
FTEs	861	809	860	852	850	51	(8)	(2)
Average salary per net FTE	$ 83,238	$ 85,069	$ 88,210	$ 90,271	$ 91,591			
% increase		2.20%	3.69%	2.34%	1.46%			

The above analysis indicates that the average salary per net FTE is expected to increase by 2.34% and 1.46% in the 2018 and 2019 test years respectively.

<u>Nalcor Executive Salaries</u>

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 2015 and 2016:

Table 34: Nalcor executive salaries by position

	2016			2015		
	Hours	Average Billing Rates	Recharge Amount	Hours	Average Billing Rates	Recharge Amount
CEO	67.5	$ 487.90	$ 32,933	274.0	$ 454.76	$ 124,605
VP HR	221.5	172.53	38,215	1,369.0	165.53	226,608
VP Transition to Operations	108.5	200.60	21,765	-	-	-
VP Project Execution	-	-	-	621.5	226.47	140,749
VP Finance	15.0	244.00	3,660	170.5	227.43	38,777
VP Corporate Relations	259.5	173.49	45,021	724.5	161.24	116,820
VP Power Supply	17.0	244.00	4,148	-	-	-
VP Lower Churchill	5.0	244.00	1,220	-	-	-
VP Strategic Planning	-	-	-	-	-	-
VP Oil & Gas	9.0	244.00	2,196	9.0	228.00	2,052
	703.0	$ 212.17	$ 149,158	3,168.5	$ 205.02	$ 649,611
% change	-78%	3%	-77%			

During 2016, Hydro underwent a corporate reorganization that changed the structure of their executive and executive positions. The outcome of this change was the creation of a separate and dedicated executive team for Hydro. According to Hydro, this new executive structure reflects an organizational model required to operate the Company on an independent, stand-alone basis to ensure continued focus on Hydro's core mandate. Hydro has confirmed that no Nalcor executive salaries are forecast to be charged to Hydro in the forecast for 2017, or in the 2018 and 2019 test years. Salary expense for the executive leadership division increased by $579,000 from 2016 to the 2017 forecast as a result of this change in organizational structure.

Hydro Executive Salaries

The table below outlines the executive salaries provided by Hydro, by position, including the annual salary, salary earned, performance contract, gross salary and benefits for 2016, forecast 2017 and the 2018 and 2019 test years:

Table 35: Hydro executive salaries by position (2016, 2017 forecast and test years 2018 and 2019)

	2016					2017F				
	Salary Earned	Performance Contract[10]	Gross Salary	Benefits	Total[11]	Salary Earned	Performance Contract[10]	Gross Salary	Benefits	Total[11]
President[1]	$ 144,231	$ -	$ 144,231	$ 28,017	**$ 172,248**	$ 300,008	$ 60,002	$ 360,010	$ 55,264	**$ 415,274**
President[2]	154,161	39,170	193,331	29,805	**223,136**	-	-	-	-	**-**
Vice-President - Corporate Services & Regulatory Affairs[3]	140,100	25,687	165,787	31,271	**197,058**	190,905	38,181	229,086	37,566	**266,652**
Vice-President - Engineering Services[4]	140,406	16,745	157,151	32,524	**189,675**	199,992	39,998	239,990	42,568	**282,559**
Vice-President - System Operations and Planning[5]	140,498	20,417	160,914	29,087	**190,001**	-	39,923	39,923	1,659	**41,582**
Vice-President - Finance[6]	-	-	-	-	**-**	199,992	39,998	239,990	29,828	**269,819**
Vice-President - Transmission & Distribution & NL System Ops[7]	-	-	-	-	**-**	190,008	38,002	228,010	36,959	**264,969**
Vice-President - Production Operations[8]	62,992	-	62,992	11,301	**74,293**	190,008	38,002	228,010	41,301	**269,311**
Corporate Secretary & General Counsel[9]	50,938	7,731	58,669	12,791	**71,460**	180,902	18,090	198,992	40,145	**239,137**
Total	**$ 833,325**	**$ 109,749**	**$ 943,075**	**$ 174,795**	**$ 1,117,871**	**$ 1,451,815**	**$ 312,195**	**$ 1,764,010**	**$ 285,291**	**$ 2,049,302**

	2018TY					2019TY				
	Salary Earned	Performance Contract[10]	Gross Salary	Benefits	Total[11]	Salary Earned	Performance Contract[10]	Gross Salary	Benefits	Total[11]
President[1]	$ 305,683	$ 61,137	$ 366,820	$ 56,005	**$ 422,824**	$ 311,791	$ 62,358	$ 374,149	$ 56,794	**$ 430,943**
Vice-President - Corporate Services & Regulatory Affairs[3]	194,517	38,903	233,420	38,044	**271,465**	198,412	39,682	238,094	38,552	**276,647**
Vice-President - Engineering Services[4]	203,991	40,798	244,789	43,096	**287,885**	208,004	41,601	249,605	43,619	**293,224**
Vice-President - Finance[6]	203,991	40,798	244,789	43,096	**287,885**	208,004	41,601	249,605	43,619	**293,224**
Vice-President - Transmission & Distribution & NL System Ops[7]	193,597	38,719	232,316	40,234	**272,550**	207,867	41,572	249,439	43,601	**293,040**
Vice-President - Production Operations[8]	203,776	40,755	244,531	43,069	**287,600**	207,860	41,573	249,433	42,059	**291,492**
Corporate Secretary & General Counsel[9]	184,318	18,432	202,750	40,598	**243,348**	188,018	18,802	206,820	41,082	**247,902**
Total	**$ 1,489,873**	**$ 279,543**	**$ 1,769,416**	**$ 304,141**	**$ 2,073,557**	**$ 1,529,956**	**$ 287,189**	**$ 1,817,145**	**$ 309,326**	**$ 2,126,472**

[1]Retired April 2013 and rehired June 28, 2016.
[2]Transferred to Non-Regulated Line of Business June 20, 2016.
[3]New position effective date March 28, 2016.
[4]Position effective March 3, 2016; transferred from Nalcor effective March 28, 2016.
[5]Retired August 31, 2016.
[6]Hired January 3, 2017.
[7]Hired April 10, 2017, however, the position was forecast to be filled for full year.
[8]New position effective September 1, 2016. Transferred from BU 2018 to Executive Business Unit # 2000 September 26, 2016.
[9]New position effective September 1, 2016. Salary and benefit costs in Business Unit 2065, not Executive Business Unit 2000.
[10]Performance Contract for prior year paid in following year, i.e. 2015 Performance Contract paid in 2016.Assumed target percent of 20% for forecast and test years.
[11]Total compensation includes earnings from the effective date in an Executive position.

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 2015 to 2016 and forecast for 2017, 2018 and 2019 have been allocated to capital as follows:

Table 36: Payroll charged to capital (2015 – 2016, 2017 forecast and test years 2018 and 2019)

(000)'s	Actuals 2015	Actuals 2016	Forecast 2017	Test Year 2018	Test Year 2019	Variance '17F-'16	Variance '18TY-'17F	Variance '19TY-'18TY
Captial salaries	16,214	21,371	22,403	21,088	21,086	1,032	(1,315)	(2)
Capital overtime	7,234	8,756	5,385	4,976	4,986	(3,371)	(409)	10
	23,448	30,127	27,788	26,064	26,072	(2,339)	(1,724)	(1,716)

As shown, capitalized salaries are forecast to increase in 2017 by $1.0 million over 2016. According to Hydro, this is primarily related to Engineering Services, the reorganization of Hydro and vacancies during 2016, partially offset by a decrease in Finance and Production Operations.

Capitalized salaries are forecast to decrease in the 2018 test year by $1.3 million compared to the 2017 forecast. According to Hydro, this is primarily related to a decrease in capital related work within the Production Operations and Transmission Operations departments. Within Production, the variance is related to the Holyrood Thermal Generating capital budget declining as the asset transitions to post-steam and within Hydro Generation capital costs were higher in 2016 due to unplanned projects, and as a result 2017 forecasts were higher.

Capitalized overtime is forecast to decrease in 2017 by $3.4 million compared to 2016. According to Hydro, this is primarily due to Hydro's continued effort to reduce overtime worked by personnel year-over-year. Per Hydro's response to CA-NLH-141, there is a focused proactive effort by Hydro Executive and Senior Leadership to manage the amount of overtime.

Intercompany salaries

A breakdown of the intercompany salaries by charges in and out and by division was provided by Hydro for 2016, forecast 2017 and the 2018 and 2019 test years. The line of business where the labour originated was also provided for forecast 2017, and 2018 and 2019 test years. This information was agreed to the general ledger and is as follows:

Table 37: Intercompany salaries by division (2016 actuals and 2017 forecast)

Work Type Category	Division	2016 Actual Recharge Salary	2017 Forecast Recharge Salary	Difference $
Charge In	Corporate Services & Regulatory Affairs	$ 441,802	$ 284,040	$ (157,762)
	Engineering Services	688,597		(688,597)
	Executive Leadership Hydro	276,474		(276,474)
	Finance NL Hydro	478,797	126,251	(352,547)
	Production Operations	348		(348)
	Transmission Operations	40,523	1,101,969	1,061,445
Charge In Total		**$ 1,926,542**	**$ 1,512,259**	**$ (414,283)**
Charge Out	Corporate Services & Regulatory Affairs	$ (126,198)	$ (56,796)	$ 69,402
	Engineering Services	(185,175)	(164,304)	20,872
	Executive Leadership Hydro	(61,552)		61,552
	Finance NL Hydro	(1,582,469)	(628,201)	954,268
	Production Operations	(10,308)		10,308
	Transmission Operations	(65,797)	(8,975)	56,822
Charge Out Total		**$ (2,031,500)**	**$ (858,276)**	**$ 1,173,224**
Grand Total		**$ (104,958)**	**$ 653,983**	**$ 758,941**

Table 38: Intercompany salaries by division (2017 forecast and test years 2018 and 2019)

Inter-company Salary		2017	2018	2019
Hydro - Division labor is charged	**Other LOB's - Originating Labour**	**Forecast**	**Test Year**	**Test Year**
Corp Serv & Reg Affairs	Nalcor	263,325	157,918	78,153
Corp Serv & Reg Affairs	Churchill Falls	20,715	20,715	20,715
Finance NL Hydro	Nalcor	126,251	126,251	126,251
Transmission Operations	Churchill Falls	1,101,969	922,338	918,856
	Total	1,512,259	1,227,221	1,143,975

I/C Labour (Out)		2017	2018	2019
Hydro - Originating Labour	**Other LOB's - Division labor is charged**	**Forecast**	**Test Year**	**Test Year**
Corp Serv & Reg Affairs	Churchill Falls	56,796	56,796	56,796
Finance NL Hydro	Nalcor	144,046	164,045	164,045
Finance NL Hydro	Churchill Falls	395,068	390,476	395,068
Finance NL Hydro	Energy Marketing	20,000	-	-
Finance NL Hydro	Bull Arm	7,915	12,507	7,915
Finance NL Hydro	Oil&Gas	61,172	61,172	61,172
Transmission Operations	Nalcor	245	245	245
Transmission Operations	Churchill Falls	8,730	8,730	8,730
Engineering Services Hydro	Churchill Falls	164,304	164,304	164,304
	Total	858,276	858,275	858,275

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. Overtime costs in 2017 are forecast to decrease by $5.4 million over 2016. According to Hydro, this is primarily due to Hydro's continued effort to reduce overtime worked by personnel year-over-year. Per Hydro's response to CA-NLH-141, there is a focused proactive effort by Hydro Executive and Senior Leadership to manage the amount of overtime.

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 include assumptions as to future benefit costs and interest rate expectations. Forecasts are based off the 2016 actuarial report. Employee future benefits are forecast to decrease in 2017 by $660,000 over 2016. According to Hydro, this decrease is primarily due to overall gains in the program due to claims experience and plan demographics. This was partially mitigated by a decrease in the discount rate of 0.2%.

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 following tables present fringe benefits as a percentage of salaries for 2015 and 2016 actuals, and 2017, 2018 and 2019 forecasts.

Table 39: Fringe benefits as a percentage of salaries (2015-2016, 2017 forecast and test years 2018 and 2019)

(000)'s	Actuals 2015	Actuals 2016	Forecast 2017	Test Year 2018	Test Year 2019	Variance '17F-'16	Variance '18TY-'17F	Variance '19TY-'18TY
Salaries	$ 69,419	$ 68,926	$ 75,207	$ 76,542	$ 77,566	$ 6,281	$ 1,335	$ 1,024
Fringe benefits	$ 11,513	$ 11,122	$ 12,296	$ 12,422	$ 12,597	$ 1,174	$ 126	$ 175
	16.58%	16.14%	16.35%	16.23%	16.24%	0.21%	-0.12%	-0.11%

Fringe benefits as a percentage of salaries remains fairly consistent in all the years above. Fringe benefits are forecast to increase in 2017 by $1.2 million over 2016. According to Hydro, this is directly related to the increase in permanent and temporary salary costs as discussed above.

Vacancy credit

Included in the salary forecast for the 2018 and 2019 test years is a vacancy credit of $3.5 million. According to Hydro, in forecasting the vacancy allowance Hydro takes into account the anticipated retirements, leaves of absence, voluntary resignations, and new hires. To further assist in managing labor requirements, the Company has noted that Human Resources/Labor Relations consult regularly with the area management to review the status of job competitions and expected fill dates for positions in their respective areas. The vacancy allowance for the 2018 and 2019 test years was based on 40 vacancies.

System equipment maintenance

System equipment maintenance costs have been forecast to increase by approximately $534,000 in 2018 in comparison to the 2017 forecast and are forecast to increase by $568,000 in 2019 in comparison to the 2018 test year.

The following table summarizes system equipment maintenance costs incurred from 2015 to 2016 and forecast for 2017, 2018 and 2019:

Table 40: System equipment maintenance costs by category (2015-2016, 2017 forecast and test years 2018 and 2019)

(000)'s	Actuals 2015	Actuals 2016	Forecast 2017	Test Year 2018	Test Year 2019	Variance '17F-'16	Variance '18TY-'17F	Variance '19TY-'18TY
Maintenance material	12,711	9,713	10,964	10,999	11,075	1,251	35	76
Contract labour	16,421	13,117	12,664	12,960	13,456	(453)	296	495
Contract materials	339	356	255	290	290	(102)	35	-
	29,471	23,186	23,882	24,249	24,820	696	366	571
Tools and operating supplies	602	337	461	469	469	124	8	-
Freight expense	708	416	327	477	477	(89)	150	-
Lubricant, gases & chemicals	1,148	1,110	1,023	1,033	1,029	(86)	9	(3)
	31,928	25,048	25,694	26,228	26,796	645	534	568

Maintenance material costs are forecast to increase by $1.3 million in 2017 over 2016 actuals. According to Hydro, this is primarily due to targeted cost reductions and cost control and efficiency efforts in 2016. Costs are increasing again in 2017 because the 2016 cost reductions were not fully sustainable. The variance is also partially related to an increase in materials for thermal production, which is discussed in details later in the report.

Maintenance costs are incurred throughout all divisions. The following table provides a breakdown of Maintenance costs by division for 2015 to 2016, forecast 2017 and the 2018 and 2019 test years.

Table 41: System equipment maintenance costs by division (2015-2016, 2017 forecast and test years 2018 and 2019)

(000)'s	Actuals 2015	Actuals 2016	Forecast 2017	Test Year 2018	Test Year 2019	Variance '17F-'16	Variance '18TY-'17F	Variance '19TY-'18TY
Executive Leadership	-	2	3	3	3	1	-	-
Finance	1,107	986	1,144	1,169	1,194	158	25	25
Engineering	1,026	581	1,029	979	979	448	(50)	-
Transmission Operations	12,830	10,510	9,366	10,176	10,286	(1,144)	810	109
Production Operations	14,214	10,975	12,202	11,741	12,178	1,227	(461)	437
Regulatory Affairs and Customer Service	294	132	139	181	181	6	42	-
	29,471	23,186	23,882	24,249	24,820	696	366	571

The majority of the costs expended in all years occur within the Transmission Operations and Production Operations division.

The following table provides a breakdown of maintenance material for the Transmission Operations division for 2015 and 2016 actuals, and 2017, 2018 and 2019 forecasts:

Table 42: Transmission Operations division costs by department (2015-2016, 2017 forecast and test years 2018 and 2019)

(000)'s	Actuals 2015	Actuals 2016	Forecast 2017	Test Year 2018	Test Year 2019	Variance '17F-'16	Variance '18TY-'17F	Variance '19TY-'18TY
System Operation	15	3	8	5	6	5	(3)	1
Generation & Rural Planning	1	-	2	2	2	2	-	-
Western & Eastern Operation	2,490	1,666	1,337	2,099	2,151	(329)	762	52
Northern & Labrador Operations	10,324	8,841	8,019	8,070	8,127	(822)	51	57
	12,830	10,510	9,366	10,176	10,286	(1,144)	810	110

Maintenance costs for Western and Eastern Operations are forecast to decrease in 2017 by $329,000 compared to 2016. According to Hydro, this is primarily due to a change in the operating project cycle. 2016 included increased spending related to the setup of Transformer 1 at Cat Arm.

Maintenance costs for Western and Eastern Operations are forecast to increase in the 2018 test year by $762,000 over the 2017 forecast. According to Hydro, this is primarily due to a change in the operating project cycle. 2018 includes increased spending related to the relocation of a spare transformer, moving it from Hardwoods to Stephenville.

Maintenance costs for Northern and Labrador Operations are forecast to decrease in 2017 by $822,000 compared to 2016. According to Hydro, this is primarily due to a decrease in contract labour and a change in the operating project cycle. According to Hydro, 2016 included increased spending related to the Mud Lake reinforce embankment work which is partially offset by an increase in the 2017 Vegetation Management Program as costs are returning to normal levels.

The following table provides a breakdown of maintenance material for the Production Operations division for 2015 and 2016 actuals, and 2017, 2018 and 2019 forecasts:

Table 43: Production Operations division costs by department (2015-2016, 2017 forecast and test years 2018 and 2019)

(000)'s	Actuals 2015	Actuals 2016	Forecast 2017	Test Year 2018	Test Year 2019	Variance '17F-'16	Variance '18TY-'17F	Variance '19TY-'18TY
Hydro Generation	1,424	1,533	1,317	1,527	1,705	(216)	210	178
Thermal Holyrood	11,261	6,901	7,604	8,115	8,279	703	511	164
Gas Turbines	1,529	2,540	3,281	2,099	2,194	741	(1,182)	95
	14,214	10,975	12,202	11,741	12,178	1,227	(461)	437

Maintenance costs for the Thermal Holyrood department are forecast to increase by $703,000 in 2017 over 2016 actuals. According to Hydro, this increase is primarily due to an increase in scope of work on boiler overhauls in 2017. The annual work plan for 2017 included additional boiler cleaning and repair work which involved boiler contractor Babcock & Wilcox.

Maintenance costs for the Gas Turbines department are forecast to increase by $741,000 in the 2017 forecast compared to 2016 actuals. According to Hydro, this is primarily due to targeted cost reductions and cost control and efficiency efforts in 2016.

Maintenance costs for the Gas Turbines department are forecast to decrease by $1.2 million in the 2018 test year compared to the 2017 forecast. According to Hydro, this is primarily due to contract changes in relation to providing technical direction on the Holyrood CT in 2018.

A 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 44: Thermal Holyrood department costs by unit (2015-2016, 2017 forecast and test years 2018 and 2019)

(000)'s	Actuals 2015	Actuals 2016	Forecast 2017	Test Year 2018	Test Year 2019	Variance '17F-'16	Variance '18TY-'17F	Variance '19TY-'18T
Unit # 1	2,396	1,474	1,622	1,722	1,722	148	100	-
Unit # 2	2,939	1,287	1,424	1,952	1,624	137	528	(328)
Unit # 3	1,946	1,400	1,384	1,484	1,912	(16)	100	428
Annual routine maintenance (Note 1)	3,980	2,740	3,174	2,957	3,021	434	(217)	64
	11,261	6,901	7,604	8,115	8,279	703	511	164

Note 1: Annual rountine maintenance includes Extraordinary repair amortization.

According to Hydro, forecasting for System Equipment Maintenance costs is prepared by preventive and corrective program requirements, consultation with contractors on the upcoming annual work packages as well as knowledge and history of the equipment and processes.

Costs relating to Unit #2 are forecast to increase in 2018 by $528,000 over the 2017 forecast. According to Hydro, this is primarily due to an increased scope of work on boiler overhauls in 2018. As per the annual work plan, 2018 repairs are forecast to be more extensive than 2017 and includes additional cleaning. Costs relating to Unit #2 are forecast to decrease in 2019 by $328,000 compared to the 2018 test year. According to Hydro, this is primarily due to a decreased scope of work on boiler overhauls in 2019. As per the annual work plan, 2019 repairs are forecast to be less extensive than 2018 and include less cleaning.

Costs relating to Unit #3 are forecast to increase in 2019 by $428,000 over the 2018 test year. According to Hydro, this is primarily due to an increased scope of work on boiler overhauls in 2019. As per the annual work plan, 2019 repairs are forecast to be more extensive than 2018 and includes additional cleaning.

Costs relating to annual routine maintenance are forecast to increase by $434,000 in 2017 over 2016. According to Hydro, this is primarily due to changes in service contracts as a result of increased operational requirements, in particular, an increased scope of work on boiler overhauls (Units 1 and 2) in 2017.

Professional services

For 2018 and 2019 test years, we compared the forecast amount to prior years and investigated any unusual fluctuations. Professional services costs from 2015 to 2019 are as follows:

Table 45: Professional services costs by category (2015-2016, 2017 forecast and test years 2018 and 2019)

(000)'s	Actuals 2015	Actuals 2016	Forecast 2017	Test Year 2018	Test Year 2019	Variance '17F-'16	Variance '18TY-'17F	Variance '19TY-'18TY
Consultants	7,191	4,232	5,301	5,977	5,620	1,069	677	(357)
PUB Related Costs	5,587	2,371	2,600	1,950	2,000	229	(650)	50
Software Acquisitions & Maintenance	1,629	59	946	1,184	1,205	886	239	21
	14,407	6,662	8,846	9,112	8,825	2,184	266	(287)

According to Hydro, the $886,000 increase in software acquisitions and maintenance costs in the 2017 forecast over the 2016 year is primarily due to changes in the accounting structure. In 2017 Hydro specific software costs are incurred directly by Hydro, while in 2016 they were incurred through the admin fee. The increase is also due to additional Energy Management System ("EMS") costs in 2017 for maintenance/supporting software on the display wall in the Energy Control Centre ("ECC") control room.

Consultants' fees (including audit and legal), which represent the largest portion of total professional fees, were approximately $4.2 million in 2016 and are forecast to be approximately $5.3 million in 2017. According to Hydro, this is primarily due to an increase in CDM program cost, and an increase in regulatory costs driven by GRA legal costs.

Consultants' fees are forecast to increase from $5.3 million in 2017 to $6.0 million in the 2018 test year. According to Hydro, this is primarily due to an increase in environmental costs which relate to new requirements for TL-267 Environmental Monitoring as a condition of the release from the Environmental Assessment process.

Consultants' fees are forecast to decrease from $6.0 million in the 2018 test year to $5.6 million in the 2019 test year. According to Hydro, this is primarily due to a decrease in Hydro Production consulting costs, driven by the operating project cycle.

Details of consultants' fees by division are indicated in the table below:

Table 46: Consultants' fees by division (2015-2016, 2017 forecast and test years 2018 and 2019)

(000)'s	Actuals 2015	Actuals 2016	Forecast 2017	Test Year 2018	Test Year 2019	Variance '17F-'16	Variance '18TY-'17F	Variance '19TY-'18TY
Executive Leadership	352	86	159	180	180	73	21	-
Finance	111	22	162	127	143	140	(35)	16
Engineering	399	42	122	273	273	80	151	-
Transmission Operations	778	399	464	291	247	64	(172)	(45)
Production Operations	1,056	1,008	964	1,358	1,094	(44)	394	(264)
Regulatory Affairs and Customer Service	4,496	2,675	3,430	3,749	3,684	755	319	(65)
	7,191	4,232	5,301	5,977	5,620	1,069	677	(357)

Consultants' fees are forecast to increase by $1.1 million in 2017 compared to 2016 actuals. The two largest variances occurred in the Finance division and the Regulatory Affairs and Customer Service division.

According to Hydro, the $140,000 increase in the Finance division in the 2017 forecast is primarily due to targeted cost reductions and cost control and efficiency efforts in 2016. These cost reductions are outlined in Hydro's response to PUB-NLH-054.

According to Hydro, the $755,000 increase in the Regulatory Affairs and Customer Service division in the 2017 forecast is primarily due to an increase in CDM program cost and an increase in environmental costs which relate to new requirements for TL-267 Environmental Monitoring as a condition of the release from the Environmental Assessment process. These increases are partially offset by a decrease in Phase II outage costs.

Miscellaneous

The breakdown of items included in the miscellaneous expense category from 2015 to 2016 and forecast for 2017, 2018 and 2019 is as follows:

Table 47: Miscellaneous costs by category (2015-2016, 2017 forecast and test years 2018 and 2019)

(000)'s	Actuals 2015	Actuals 2016	Forecast 2017	Test Year 2018	Test Year 2019	Variance '17F-'16	Variance '18TY-'17F	Variance '19TY-'18TY
Business and payroll taxes	3,736	3,874	4,041	4,093	4,174	167	53	81
Bad debt expense	248	124	111	111	111	(13)	-	-
Staff training	783	390	675	716	716	284	41	-
Write offs	269	87	53	150	150	(34)	97	-
Employee expenses	568	354	217	229	229	(137)	12	0
Sundry costs	290	94	159	100	100	65	(59)	-
Diesel fuel Hydro	46	2	59	59	59	57	-	-
Energy management	(44)	170	440	440	440	270	(0)	-
Collection fees	5	3	7	7	7	4	-	-
	5,901	5,098	5,761	5,905	5,985	663	143	81

Miscellaneous expenses are forecast to increase in 2017 over 2016 actual by approximately $663,000 or 13.0%. This variance is primarily related to business and payroll taxes, staff training, and energy management.

Business and payroll taxes are forecast to increase by approximately $167,000 in 2017 over 2016 actual. According to Hydro, this primarily relates to an increase in payroll taxes which is related to the increase in permanent and temporary salary costs.

Staff training expenses are forecast to increase by approximately $284,000 in 2017 over 2016 actual. According to Hydro, as part of the targeted reduction in 2016, Hydro directed mandatory training only for that period; therefore, training expenses decreased by approximately $393,000 in 2016 compared to 2015. This was not fully sustainable on a long term basis and consequently training expenses increased again in 2017. While the training amount in 2017 was higher than 2016, it was approximately $108,000 lower than 2015. Per Hydro's response to PUB-NLH-054, these cost reduction measures were not sustainable because a level of employee training beyond what is mandatory is required in order for Hydro to maintain an engaged and trained workforce that is capable of operating, maintaining and managing a complex electrical system.

Energy management expenses are forecast to increase by approximately $270,000 in 2017 over 2016 actual. According to Hydro, this is due to anticipated increased participation in the industrial customers program.

Miscellaneous expenses forecast for the 2018 and 2019 test years are relatively consistent with the 2017 forecast.

Loss on Disposal

In 2018 and 2019 test years, loss on disposal of assets is expected to total approximately $2.1 million. A breakdown of this forecast is provided below:

Table 48: Loss on disposal costs by category (2015-2016, 2017 forecast and test years 2018 and 2019)

(000)'s	Actual 2015	Actual 2016	Forecast 2017	Test Year 2018	Test Year 2019	Test Year '17F-'16	Variance '18TY-'17F	Variance '19TY-'18TY
Net book value of disposed assets	4,013	6,795	3,987	-	-	(2,808)	(3,987)	-
Asset removal costs	763	271	723	-	-	452	(723)	-
Disposal proceeds	(766)	(196)	(350)	-	-	(154)	350	-
Other write offs	60	198	-	2,081	2,081	(198)	2,081	-
Auction fees and expenses	48	15	-	-	-	(15)	-	-
	4,118	7,083	4,360	2,081	2,081	(2,723)	(2,279)	-

Loss on disposals is forecast to decrease by approximately $2.7 million in 2017 over 2016 actuals. This decrease is primarily related to a decrease in the net book value of disposed assets of $2.8 million, offset by some other smaller variances. According to Hydro, the decrease is due to higher than normal retirements occurring in the 2016 year. These disposals were relating to the replacement of the combustor in the Holyrood combustion turbine ($2.1M), engine model D-3412 ($350K), penstock ($200K), and the replacement of radomes and instrument transformers ($200K).

In 2018 and 2019 test years, there are no loss on disposals recognized due to a new proposed method of recording asset retirements under the depreciation study completed by Concentric. Under the new methodology, the net salvage cost (amount of proceeds from sales less the cost to retire and remove the asset from operations) is factored into depreciation rates instead of recorded as a separate income statement line item.

The other write offs relate to the Holyrood Inventory Allowance, as explained on page 4.11 of the pre-filed evidence. Hydro states that as of December 31, 2016, Hydro had a $10.1 million inventory of spare parts to service the Holyrood plant; however, once Holyrood is converted to synchronous condenser mode, an estimated $6.8 million of inventory will no longer be required. Holyrood is currently scheduled to be converted to synchronous condenser mode by March 31, 2021. Hydro is proposing to record an inventory allowance from January 1, 2018 until March 31, 2021, and has included $2.1 million in each of the 2018 and 2019 test year revenue requirements. The Holyrood Inventory Allowance is discussed further in the Deferred Charges section of our report.

Other Cost Categories

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

Table 49: Other cost categories (2015-2016, 2017 forecast and test years 2018 and 2019)

(000)'s	Actuals 2015	Actuals 2016	Forecast 2017	Test Year 2018	Test Year 2019	Variance '17F-'16	Variance '18TY-'17F	Variance '19TY-'18TY
Insurance	2,508	2,530	3,038	3,345	3,425	508	307	80
Transportation	3,317	2,943	3,127	3,251	3,361	184	124	110
Office Supplies	2,762	2,249	2,307	2,516	2,520	58	209	5
Bldg. rental and maint.	1,497	1,109	1,077	1,100	1,100	(32)	23	-
Travel	3,250	1,984	2,442	2,757	2,759	458	315	2
Equipment rentals	4,218	4,197	3,591	3,749	3,746	(607)	158	(3)
	17,552	15,012	15,581	16,718	16,912	569	1,137	194

These expenses are forecast to increase by approximately $569,000 or 3.8% in 2017 over 2016 actuals. The biggest variances relate to insurance, travel, and equipment rentals.

Insurance expense is forecast to increase by $508,000. According to Hydro, this is due to a number of factors. The first factor that accounts for approximately $200,000 of the variance relates to the provincial retail tax implemented on insurance premiums effective July 1, 2016. The second factor that accounts for approximately $200,000 of the variance relates to a membership credit that is sometimes received, but is not guaranteed from year to year, and was therefore excluded from the 2017 forecast and 2018 and 2019 test years. The final factor that accounts for the remaining $100,000 relates to a general forecast increase in premiums which was forecasted over three years.

Travel expense is forecast to increase by $458,000. According to Hydro, this increase primarily relates to only operationally critical travel being conducted in 2016 as part of the targeted cost reductions. The 2017, 2018 and 2019 forecasts were adjusted to sustainable levels. Per Hydro's response to PUB-NLH-054, the cost reductions were not sustainable because as Hydro operates over a large geographic territory, their employees have to travel to maintain reliable, safe electric service. Supervisors and managers must also travel to ensure adequate supervision.

Equipment rentals are forecast to decrease by $607,000. According to Hydro, this is primarily due to the black start diesels whereby amortization for both 2015 and 2016 was recorded in 2016 pursuant to the approval in P.U. 49 (2016). In 2017, Hydro incurred $1.3 million of amortization relating to the black start diesels, compared to the $1.8 million in 2016. The adjustment to record the amortization on the black start diesels into the correct periods of reporting year for 2015 and 2016 is included in the 'Compliance Adjustments' included in our revenue requirement summary.

Other cost categories expenses are forecast to increase by approximately $1.1 million or 7.3% in the 2018 test year over the 2017 forecast. The larger variances relate to insurance and travel.

Insurance expense is forecast to increase by $307,000. According to Hydro, this is due to a general forecast increase in the premiums which was forecasted over three years.

Travel expense is forecast to increase by $315,000 and the variance is related to the same adjustment discussed above for the 2017 increase.

Other cost categories expenses forecast for the 2019 test year are relatively consistent with the 2018 test year.

Cost Recoveries

Cost recoveries are forecast to decrease by $2.2 million in the 2018 test year compared to the 2017 forecast. Cost recoveries are forecast to decrease by $839,000 in the 2019 test year compared to the 2018 test year. The breakdown of cost recoveries by division is as follows:

Table 50: Cost recoveries by division (2015-2016, 2017 forecast and test years 2018 and 2019)

(000)'s	Actuals 2015	Actuals 2016	Forecast 2017	Test Year 2018	Test Year 2019	Variance '17F-'16	Variance '18TY-'17F	Variance '19TY-'18TY
Executive Leadership	-	-	-	(20)	(22)	-	(20)	(1)
Finance	(1,420)	(2,206)	(946)	366	(345)	1,260	1,311	(710)
Engineering	(3,948)	2,513	2,033	2,840	4,382	(480)	808	1,541
Transmission Operations	(232)	(239)	(53)	(396)	(414)	187	(343)	(18)
Production Operations	(4)	(16)	(5)	(321)	(337)	11	(316)	(16)
Regulatory Affairs and Customer Service	(2,303)	(3,421)	(1,978)	(1,236)	(1,193)	1,443	742	43
	(7,906)	(3,369)	(949)	1,233	2,072	2,421	2,182	839

Cost recoveries in the Finance division are forecast to decrease by $1.3 million in 2017 compared to 2016, and $1.3 million in the 2018 test year compared to the 2017 forecast. According to Hydro, this is primarily due to an increase in the Business System Admin Fee, and a decrease in the Fixed Charge recovery.

Cost recoveries in the Finance division are forecast to increase by $0.7 million in the 2019 test year compared to the 2018 test year. According to Hydro, this is primarily due to a decrease in the Business System Admin Fee.

Cost recoveries in the Engineering division are forecast to decrease by $0.8 million in the 2018 test year compared to the 2017 forecast, and $1.5 million in the 2019 test year compared to the 2018 test year. According to Hydro, this is primarily due to an increase in the Nalcor Admin Fee.

Cost recoveries in the Production Operations division are forecast to increase by $0.3 million in the 2018 test year compared to the 2017 forecast. According to Hydro, this is primarily due to the productivity allowance.

Cost recoveries in the Regulatory Affairs and Customer Service division are forecast to decrease by $1.4 million in 2017 compared to 2016. According to Hydro, this is primarily the result of re-structuring Hydro. In 2016, Hydro charged Nalcor for common services provided for HR and Safety through an admin fee in cost recoveries, resulting in a credit to the hydro admin fee cost recovery lines. In 2017, these services are provided by Nalcor to all lines of business and accordingly, there is a billing to Hydro on the cost recovery line. Details on this restructuring are discussed in detail in the "cost allocation" section of our report.

Cost recoveries in the Regulatory Affairs and Customer Service division are forecast to decrease by $0.7 million in the 2018 test year compared to the 2017 forecast. According to Hydro, this is primarily due to deferred phase II outage costs, offset against the productivity allowance and Nalcor Admin Fee.

The breakdown of cost recoveries by nature for actual 2015 and 2016, 2017 forecast, and 2018 and 2019 test years is as follows:

Table 51: Cost recoveries by nature (2015-2016, 2017 forecast and test years 2018 and 2019)

(000)'s	Actuals 2015	Actuals 2016	Forecast 2017	Test Year 2018	Test Year 2019	Variance '17F-'16	Variance '18TY-'17F	Variance '19TY-'18TY
Churchill Falls	(1,702)	(587)	(34)	(36)	(23)	553	(2)	13
External	(766)	(923)	(481)	(481)	(481)	441	-	-
Intercompany Admin Fee - Hydro	(4,812)	(2,648)	(2,236)	(2,220)	(2,283)	412	17	(63)
Business System Admin Fee	-	253	1,029	2,542	1,894	776	1,513	(648)
Productivity Allowance	-	-	-	(1,039)	(1,102)	-	(1,039)	(63)
CDM Program Cost Deferral	-	(1,153)	(2,100)	(2,100)	(2,100)	(948)	-	-
Nalcor Admin fee	-	3,350	3,948	4,642	6,242	599	694	1,600
Deferred Phase II	-	(869)	(1,000)	-	-	(131)	1,000	-
Fixed Charge (Recovery)	(581)	(711)	(67)	(67)	(67)	644	-	-
Intercompany Vehicle Charge (Recovery)	(46)	(43)	-	-	-	43	-	-
Nalcor Fixed Charge	-	(39)	(7)	(7)	(7)	32	-	-
	(7,906)	(3,369)	(949)	1,233	2,072	2,421	2,182	839

The productivity allowance for the 2018 and 2019 test years is forecast to be $1.0 million and $1.1 million, respectively. According to Hydro, there is no calculation underlying the productivity allowance for the test years. It is a self-imposed target set by Hydro's Executive to reflect actions being taken to manage costs. There were no specific guidelines issued to staff with respect to this allowance.

Cost recoveries for CDM Program cost deferral are forecast to increase by $0.9 million in 2017 compared to 2016 actuals. Hydro has indicated that this increase primarily relates to the expansion of the isolated communities program and increased participation in the industrial customers program.

Cost recoveries related to Deferred Phase II are forecast to decrease by $1.0 million in the 2018 test year compared to the 2017 forecast. In response to LAB-NLH-013 Hydro stated that "due to the ongoing process and uncertainty of the projected final costs, the costs incurred to date of $0.9 million were used as a baseline in determining the forecast $1.0 million, as activity was expected to increase in 2017."

Cost recoveries related to Churchill Falls, Intercompany Admin Fee, Business System Admin Fee, Nalcor Admin Fee, Fixed Charge (Recovery), and the Nalcor Fixed Charge are all discussed in the Cost Allocations section below.

Cost Allocations

P.U. 49 (2016)

In P.U. 49, (2016) the Board required Hydro to file on or before March 31, 2017 a proposal in relation to annual reporting, starting in 2017, of its intercompany activity, including a description of all services rendered, the cost charged back to and from the affiliates, the amounts involved and the methods used for determining these amounts. The proposal was filed with the Board on March 30, 2017 and Hydro began to file quarterly intercompany transactions reports starting with Q2 of 2017, for the period ended June 30, 2017.

In P.U. 49, (2016) the Board also expected that Hydro would address in the next general rate application any impact of the intervening change in organization structure on intercompany charges and policies governing cost recoveries of such charges. According to Hydro, there has been no change in the underlying policies that govern intercompany transactions since the 2015 test year. The methods for charging costs among lines of business of Nalcor are outlined in Exhibit 5 of the pre-filed evidence. The change in corporate structure which occurred in 2016 and continued into 2017 resulted in the transfer of certain common service business units from Hydro to Nalcor and the creation of a separate and dedicated Executive team which resulted in a reduction in time charged by executives to and from Hydro. These changes are discussed in detail below.

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.

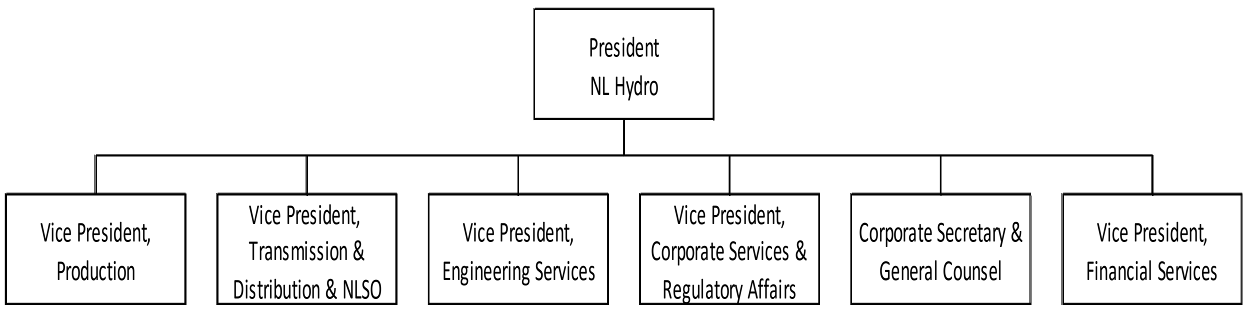
Hydro's Organizational Structure

In mid-2016, changes to Hydro's organizational structure were implemented which, according to Hydro, was to ensure focus on the regulated business and a clear separation from Nalcor, while continuing to provide safe, reliable, least cost service to customers. The outcome of this change was the creation of a separate and dedicated executive team for Hydro. According to Hydro, this new executive structure reflects an organizational model required to operate the Company on an independent, standalone basis, to ensure continued focus on Hydro's core mandate. Per Hydro's response to PUB-NLH-24, the process used in the creation of the separate and dedicated executive team and structure included: i) a review of the report, which included recommendations, by the Board's external consultant Liberty Consulting Group; ii) a review of Hydro's pre-2005 structure; and iii) a review of the structure of other regulated utilities across Canada, including Newfoundland Power Inc.

The revised executive structure includes a President of Hydro, who is accountable for all functions associated with delivering utility service, five Vice Presidents, and General Counsel. The President, each of the Vice Presidents, and General Counsel have no shared responsibilities with any other Nalcor line of business and are accountable directly to the President of Hydro. According to Hydro, the revised structure was designed to increase focus on system reliability and customer service, to enhance regulatory focus, and to ensure Hydro is prepared for the changes that will result from the interconnection to the North American grid.

The primary changes were:

- the creation of a separate and dedicated Executive team for Hydro. The organization chart below shows the new Executive structure of Hydro;
- reduced reliance on the parent company for services that were previously shared among the Nalcor lines of business; and,
- the transfer of certain functions that provided common services to all Nalcor lines of business and recovered costs through an Administration Fee from Hydro to Nalcor. The functions and specific services that were transferred include services in the area of Human Resources, Safety and Health, and Information Systems. Hydro now incurs a fee for these services from Nalcor. Information Systems services were transferred in 2016 and Human Resources and Safety and Health services were not transferred to Nalcor until 2017.



Per Hydro's response to PUB-NLH-26, the goal of the new organizational structure is to ensure organizational independence for Hydro related to operations management, financial management, performance accountability, regulatory oversight, and control and accountability for shared services. Improving business performance in these strategic areas will be an important measure of the new organization structure.

Examples of the measures that Hydro will use to evaluate the effectiveness of its new organizational structure and the Executive include:

- Safety performance;
- Reliability performance;
- Customer satisfaction;
- Financial performance and cost management; and
- Regulatory Compliance.

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 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). 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. Time is coded in 30 minute increments.

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.

Variable component

The Company uses a proxy amount of 68% 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. The rates were determined using billable hours and were determined in aggregate for the Nalcor group of companies excluding CF (L) Co.

According to Hydro, the variable component increased from 57% to 68% on January 1, 2016. As part of our 2016 annual review, Hydro provided documentation on the analysis prepared by Nalcor for the years 2013 to 2015 with a bill rate calculated at 68%. Hydro uses the 68% as the proxy amount for 2017 and 2018 test years.

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.

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. During 2016, Hydro transferred certain functions to Nalcor that provided common services to all lines of business. The functions and specific services that were transferred include services in the area of Information Systems. Hydro now incurs a fee for these services from Nalcor. In 2017 services relating to Human Resources and Safety and Health were transferred to Nalcor.

The following provides a summary of the administration fees and cost recoveries for the 2017, 2018, and 2019 forecasts with comparative data for 2016 actuals:

Costs Incurred (Recovered) by Nature

	2016	2017F	2018F	2019F	2017F-2016	2018F-2017F	2019F-2018F
Churchill Falls	$ (587)	$ (34)	$ (36)	$ (23)	$ 553	$ (2)	$ 13
Intercompany Admin Fee- Hydro	(2,648)	(2,236)	(2,220)	(2,283)	412	17	(63)
Business System Admin Fee	253	1,029	2,542	1,894	776	1,513	(648)
Nalcor Admin Fee	3,350	3,948	4,642	6,242	599	694	1,600
Fixed Charge (Recovery)	(711)	(67)	(67)	(67)	644	-	-
Nalcor Fixed Charge	(39)	(7)	(7)	(7)	32	-	-
	$ (382)	**$ 2,633**	**$ 4,854**	**$ 5,756**	**$ 3,015**	**$ 2,221**	**$ 902**

The above table shows an overall recovery in 2016, compared to overall expense in 2017 forecast, 2018 and 2019 test year due to increasing costs related to the Business System Admin fee and Nalcor admin fee.

<u>Intercompany Admin Fee – Hydro</u>

The following provides a breakdown of the common costs allocated to each line of business for the 2017, 2018 and 2019 forecasts with comparative data for 2016 actuals:

Common cost allocation	**2016**	**2017F**	**2018F**	**2019F**	**2017F-2016**	**2018F-2017F**	**2019F-2018F**
Nalcor (Note 1)	$ 2,647,851	**$ 2,236,340**	**$ 2,219,750**	**$ 2,282,700**	$ (411,511)	$ (16,590)	$ 62,950
CF (L) Co.	587,159	**34,180**	**36,380**	**23,150**	(552,979)	2,200	(13,230)
Hydro Regulated	3,718,829	**2,626,480**	**2,613,870**	**2,687,150**	(1,092,349)	(12,610)	73,280
Total common costs allocated	$ 6,953,839	**$ 4,897,000**	**$ 4,870,000**	**$ 4,993,000**	$ (2,056,839)	$ (27,000)	$ 123,000

Note 1: Nalcor includes its subsidiaries.

Intercompany administration fees forecast for 2017 regulated recovery have decreased by $411,511 and for CF(L) Co. cost recoveries have decreased by $552,979 over 2016 actuals. A further breakdown of these costs by department is provided below. The decrease in intercompany administration fees and CF(L) Co. cost recoveries is due to the transfer of common services to Nalcor as discussed above. Intercompany administration fees and CF(L) Co. cost recoveries forecast for the 2018 and 2019 test years remains fairly consistent with the 2017 forecast.

The following provides a breakdown of costs by department for the 2017, 2018, and 2019 forecasts with comparative data for 2016 actuals:

Total

Department / Costs (000's)	2016	2017F	2018F	2019F	2017F-2016	2018F-2017F	2019F-2018F
Human Resources	$ 1,777	$ -	$ -	$ -	$ (1,777)	$ -	$ -
Safety and Health	724	-	-	-	(724)	-	-
Information Systems	372	240	210	114	(132)	(30)	(96)
Office space and related costs	3,628	4,204	4,371	4,506	576	167	135
Telephone and LAN costs and other	453	453	288	373	-	(165)	85
	$ 6,954	**$ 4,897**	**$ 4,869**	**$ 4,993**	**$ (2,057)**	**$ (28)**	**$ 124**

Hydro Regulated

	2016	2017F	2018F	2019F	2017F-2016	2018F-2017F	2019F-2018F
Human Resources	$ 983	$ -	$ -	$ -	$ (983)	$ -	$ -
Safety and Health	400	-	-	-	(400)	-	-
Information Systems	174	114	106	60	(60)	(8)	(46)
Office space and related costs	1,925	2,303	2,367	2,440	378	64	73
Telephone and LAN costs and other	237	210	141	187	(27)	(69)	46
	$ 3,719	**$ 2,627**	**$ 2,614**	**$ 2,687**	**$ (1,092)**	**$ (13)**	**$ 73**

Other Lines of Business (Note 1)

	2016	2017F	2018F	2019F	2017F-2016	2018F-2017F	2019F-2018F
Human Resources	$ 794	$ -	$ -	$ -	$ (794)	$ -	$ -
Safety and Health	324	-	-	-	(324)	-	-
Information Systems	198	126	104	54	(72)	(22)	(50)
Office space and related costs	1,703	1,901	2,004	2,066	198	103	62
Telephone and LAN costs and other	216	243	147	186	27	(96)	39
	$ 3,235	**$ 2,270**	**$ 2,255**	**$ 2,306**	**$ (965)**	**$ (15)**	**$ 51**

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

Business System Administration Fee

According to Hydro, the Business System Administration Fee consists of program management costs as well as depreciation and software maintenance associated with the Business Transformation Program. The Business Transformation Program is being managed by Nalcor as a part of a shared program for all Nalcor companies including Hydro. The program includes three main projects: migrating the current Enterprise Resource Planning (ERP) system to JD Edwards (JDE) EnterpriseOne (E1); upgrading the Planning, Budgeting and Forecasting solution to Cognos TM1; and implementing an information management (IM) program. Details on these projects can be found in Hydro's response to NP-NLH-036. A portion of the costs relating to the Business Transformation Program are charged based on average users and the remainder are shared on a fixed fee basis among the lines of business.

The following provides a breakdown of the common costs allocated to each line of business for the 2017, 2018 and 2019 forecasts with comparative data for 2016 actuals:

Common cost allocation	2016	2017F	2018F	2019F	2017F-2016	2018F-2017F	2019F-2018F
Hydro Regulated	$ 253	**$ 1,029**	**$ 2,542**	**$ 1,894**	$ 776	$ 1,513	$ (648)
Other Lines of Business	381	**1,315**	**2,792**	**1,734**	934	1,477	(1,058)
Total common costs allocated	$ 634	**$ 2,344**	**$ 5,334**	**$ 3,628**	$ 1,710	$ 2,990	$ (1,706)

Total common costs allocated is forecast to increase by $3.0 million in the 2018 test year over the 2017 forecast. This increase is primarily due to increases in software support and maintenance and depreciation costs. Per Hydro's response to NP-NLH-179, the increase in software support and maintenance costs is primarily due to additional modules required under the JDE migration, software to facilitate treasury functions, and software to facilitate risk and audit management functions.

Depreciation costs are forecast to increase each year from 2016 to the 2019 test year. Per Hydro's response to NP-NLH-178 this is primarily due to the implementation of new software for the three capital projects discussed above. This software is being amortized over 120 months. According to Hydro's response to NP-NLH-185, Hydro incurs a share of the total cost and will utilize all the modules of the JD Edwards and Budgeting and Forecasting system and will be the sole user of the Customer Service module. A dedicated project team was established to assess the needs of the entire business and solutions were selected for the Enterprise Resource Planning system and the Budgeting and Forecasting based on what was determined to be the best approach for the business.

<u>Nalcor Administration Fee</u>

Nalcor charges Hydro an administration fee for services provided for Human Resources, Safety and Health, Information Systems, and Environment. As previously mentioned, changes to Hydro's organizational structure were implemented in 2016 resulting in the transfer of these services from Hydro to Nalcor. Information Systems services were transferred in 2016 and Human Resources, Safety and Health, and Environment services were not transferred to Nalcor until 2017.

The following provides a breakdown of costs by department for the 2017, 2018, and 2019 forecasts with comparative data for 2016 actuals:

Total

Department / Costs (000's)	2016	2017F	2018F	2019F	2017F-2016	2018F-2017F	2019F-2018F
Human Resources	$ -	$ 1,232	$ 1,292	$ 1,277	$ 1,232	$ 60	$ (15)
Safety and Health	-	795	794	800	795	(1)	6
Information Systems	6,489	5,931	7,158	9,759	(558)	1,227	2,601
Environment	-	101	104	105	101	2	2
	$ 6,489	**$ 8,058**	**$ 9,347**	**$ 11,941**	**$ 1,569**	**$ 1,289**	**$ 2,594**

Hydro Regulated

	2016	2017F	2018F	2019F	2017F-2016	2018F-2017F	2019F-2018F
Human Resources	$ -	$ 650	$ 603	$ 628	$ 650	$ (47)	$ 25
Safety and Health	-	419	371	393	419	(49)	23
Information Systems	3,350	2,826	3,620	5,168	(524)	794	1,548
Environment	-	53	48	52	53	(5)	3
	$ 3,350	**$ 3,948**	**$ 4,642**	**$ 6,242**	**$ 598**	**$ 694**	**$ 1,600**

Other Lines of Business (Note 1)

	2016	2017F	2018F	2019F	2017F-2016	2018F-2017F	2019F-2018F
Human Resources	$ -	$ 582	$ 689	$ 649	$ 582	$ -	$ (40)
Safety and Health	-	375	423	406	375	48	(17)
Information Systems	3,139	3,105	3,538	4,591	(33)	433	1,053
Environment	-	48	55	53	48	7	(2)
	$ 3,139	**$ 4,110**	**$ 4,705**	**$ 5,699**	**$ 972**	**$ 488**	**$ 994**

The total costs for Information Systems is forecast to increase in the 2019 test year by $3.8 million over the 2018 test year. This increase is primarily due to increases in salary and fringe benefits, and professional services costs. Per Hydro's response to NP-NLH-176, the increase in salary and fringe benefits is due to the transfer of the Business Solutions and Information Management business unit from the Business Systems Fee to the Nalcor Administration Fee in the 2019 test year, including seven FTEs. Per Hydro's response to NP-NLH-177, the increase in professional services is due to additional software maintenance costs associated with the operational status of the Business Transformation Program systems, cyber defense systems, and IT disaster recovery site.

Fixed Charge

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 the fixed charge was determined to be $98.25 per day or $13.10 per hour based on a 7.5 hour day for 2012-2016. For forecast 2017 and the 2018 and 2019 test years the fixed charge was determined to be $85.50 per day or $11.40 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 forecast fixed charges netted to a credit of $67,000 for 2017 and the 2018 and 2019 test years, compared to a credit of $711,000 in 2016.

Nalcor Fixed Fee

In addition to labour costs, a fixed rate will be applied to each hour of regular labour charged to lines of business. The fixed charge accounts for the additional cost beyond basic salary and benefits costs, of having an employee available to provide service. The fixed charge recovers costs originally charged in the Business System Administration Fee as well as other employee related costs, including:
- telephone and fax;
- books and subscriptions;
- membership fees and dues;
- conferences;
- training; and,
- employee expenses (e.g. overtime meal allowance).

The Nalcor fixed fee netted to a credit of $7,000 for 2017 and the 2018 and 2019 test years, compared to a credit of $39,000 in 2016.

Department Cost Allocations

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

Department/ Costs	Allocation Basis
Human Resources	FTE
Safety and Health	FTE
Environment	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 full time equivalents ("FTEs"). The 2018 and 2019 forecast cost per FTE allocated to lines of business for Human Resources are $716 and $746 respectively per FTE (2017 forecast - $731, 2016 actual - $1,187).

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 2018 and 2019 forecast cost per FTE allocated to lines of business for Safety and Health are $440 and $467 respectively per FTE (2017 forecast - $472, 2016 actual - $484).

Environment

The Environment department is responsible for coordinating corporate efforts with regard to environmental stewardship. Operating costs incurred in providing Environment services are allocated to the lines of business based on a per FTE basis. The 2018 and 2019 forecast cost per FTE allocated to lines of business for Environment are $57 and $61 respectively per FTE (2017 forecast - $60; 2016 actual - $Nil).

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. Nalcor's 2018 and 2019 forecast cost per user allocated to lines of business for IS are $3,804 and $5,432 respectively per user (2017 forecast - $2,693, 2016 actual - $3,020). Hydro's 2018 and 2019 forecast cost per user allocated to lines of business for IS are $112 and $63 respectively per user (2017 forecast - $109, 2016 actual - $191).

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 rental 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; and,
- Return on Rate base at WACC for all common assets.

The 2018 and 2019 forecast cost per square footage rental rate is $28.66 and $29.55, respectively, (2017 forecast - $27.57, 2016 actual - $23.79).

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.

Corporate Services Provision

According to Hydro, certain departments provide corporate services (or shared services) to other lines of business within Nalcor. The functions and departments that may share services across entities include:

- Leadership Team - executive management provides strategic oversight and general management. Excludes Hydro as Hydro has a separate Leadership team that supports Hydro only.
- Legal - the provision of legal and corporate secretary services provided by General Counsel.
- Internal Audit - this department provides auditing services as determined in an annual audit plan as part of the annual update of the Five-Year Internal Audit Plan.
- Engineering Services - this division provides services in all engineering disciplines and covers such items as:
    - a) Design, construction and project management;
    - b) Engineering studies, technical specifications and construction coordination;
    - c) Tender preparation and analysis including interaction with consultants; and
    - d) Review and resolution of maintenance problems.
- Environmental Services - this department's activities include auditing for compliance with government regulations and corporate policy, obtaining permits and approvals for proposed programs and advising on environmental matters.
- Financial Planning - this department provides services to facilitate the production, review and distribution of annual long-term financial plans. As well, they provide financial planning and analyses for various activities and scenarios.
- Risk and Insurance - this department provides services related to the placement, policy and claims administration, risk control and risk financing of the corporate insurance program.
- Finance - this department provides accounting and treasury services.
- Supply Chain Management - this department coordinates all efforts related to procurement process activities including tendering, purchasing and contract administration.

Labour costs relating to above activities would be charged to Hydro through intercompany salaries.

Rate Stabilization Plan

Schedule 4-II (Page 6 of 9) of the 2017 General Rate Application provides the balances of the components in the Rate Stabilization Plan ("RSP") for the 2015 Test Year, 2015 Actual, 2016 Actual, Forecast 2017, Test Year 2018 and Test Year 2019.

The balances provided in this Schedule for the 2015 and 2016 actuals relate to the operations of the RSP using the 2007 test year inputs. At the conclusion of the 2013 Amended General Rate Application, the Board issued P.U. 49(2016). This Order included the approval of the 2015 test year inputs for hydrology, fuel price, customer load and the weighted average cost of capital that would also impact the 2015 and 2016 RSP activity. Order No. P.U. 49(2016) also approved the 2015 test year Rural Deficit allocations and the energy allocation approach, such that the allocation of the year to date load variations in the RSP load variation component between Newfoundland Power and the Island Industrial Customers would be based on energy ratios effective September 1, 2013.

In its Compliance Application relating to P.U. 49 (2016), Hydro updated the operation of the 2015 and 2016 RSP based on the Order, with the exception of the 2015 test year price of No. 6 fuel per barrel, however the impact of these adjustments were not reflected in the RSP until the beginning of 2017. These adjustments reduced the RSP balance as of December 31, 2016 from $343.630 million to $267.188 million. The 2015 test year price of $64.41 per barrel of No. 6 fuel was not implemented in the RSP until the beginning of 2017.

As part of our review of Hydro's Compliance Application, we reviewed and agreed with Hydro's RSP revisions. In P.U. 16 (2017), the Board approved the revisions of the 2015 and 2016 RSP and agreed with Hydro's reasoning for not revising the 2015 test year price of No. 6 fuel in the 2015 and 2016 RSP.

Forecast 2017

Included in Chapter 4 of the GRA, Schedule 4-II (Page 6 of 9), the RSP balance at the end of December 31, 2017 is forecast to be a balance owing to ratepayers of $30,601,121. The breakdown of the components included in the Plan as indicated in Schedule 4-II (Page 6 of 9) is as follows:

Component	($000s)
Hydraulic balance	$ 595
Utility balance	18,098
Industrial balance	(2,101)
Utility Surplus balance	14,009
Total balance owing to ratepayers	$30,601

Based on our review of the RSP report to support the balances for the Forecast 2017 RSP, we have noted the following observations:

- The cost of service inputs are those approved for the 2015 test year.

- The monthly activity recorded in the Forecast 2017 does not include any 2017 actual results. The entire year is based on forecast information using the following assumptions:

    - Forecast hydraulic production of 4,601.5 GWh
    - Forecast utility load of 5,824.7 GWh, industrial customer load of 643.4 GWh and rural island customer load of 464.7 GWh
    - Forecast average fuel price of $73.91 per barrel of No. 6 fuel

- The 2017 opening balances have been adjusted to account for revisions to the 2015 and 2016 RSP activity as a result of P.U 49 (2016). The total adjustments relating to this revision resulted in a decrease in the RSP balance of $76.4 million as of December 31, 2016.

- P.U. 16 (2017), issued May 12, 2017 ordered that the Utility segregated load variation balance of $50,737,152 would be transferred to the Newfoundland Power Current Plan as of March 31, 2017 to mitigate the proposed July 1, 2017 RSP Adjustment rate increase. The balance transferred in the Forecast 2017 RSP is $49,790,417 vs the $50,737,152. The appropriate amount was transferred in the Actual 2017 RSP.

- The 2017 opening balances have also been adjusted for the 2014 to 2016 cumulative revenue sufficiency credit of $6,577,000 to the Newfoundland Power Current Plan, as per P.U. 22(2017), issued June 14, 2017.

- P.U. 22 (2017) also approved that the 2017 revenue deficiency of $804,000 to be recovered from Newfoundland Power would reduce the balance in Utility Current Plan in June 2017. This transaction is not reflected in the Forecast 2017 RSP. It is reflected in the Actual 2017 RSP.

- P.U. 24 (2017), issued June 20, 2017, ordered that the Industrial Customer segregated load variation balance of $3.247 million as of March 31, 2017 would be used to eliminate the 2014-2017 cumulative revenue deficiency of $1.527 million, make a one-time payment to NARL Refining Limited Partnership of $0.174 million, and the remaining $1.546 million be transferred to the Industrial Current Plan as of March 31, 2017 to mitigate the proposed July 1, 2017 RSP Adjustment rate increase. The March 31, 2017 balance in the Industrial Customer Segregated load variation included in the Forecast 2017 RSP was $3.171 million.

- The Newfoundland Power RSP Adjustment rate in 2017 Forecast RSP is the rate of (1.236) cents per kWh that was approved for the period July 1, 2016 to June 30, 2017, and the rate used effective July 1, 2017 is (0.371) cents per kWh which was approved in P.U 22(2017). This rate includes the (0.911) cents per kWh rate mitigation adjustment.

- The Industrial Customer RSP Adjustment rate in 2017 Forecast RSP is (0.061) cents per kWh, which includes the rate mitigation adjustment (0.313) cents per kWh. This was the rate approved in P.U. 26(2017).

- In a letter that Hydro provided to the Board on August 23, 2017, they proposed to recover the 2015-2016 deferred supply costs of $42.2 million from the RSP Hydraulic Variation balance, and any balance owing from customers as a result of this offset would be amortized at a rate of 25% per year, in accordance with the current RSP rules. This is different from the proposal that Hydro included in the Forecast 2017 RSP. The Forecast 2017 proposal results in the $42.2 million being fully recovered in 2017 by using the RSP Hydraulic balance and any remaining balance of the deferred supply costs being charged to the Current RSP balance for each customer, allocated based on customer sales for 2015 and 2016. The proposal included in the August 23, 2017 letter is consistent with the methodology proposed in Hydro's Recovery of 2015-2016 Deferred Supply Costs Application.

  Hydro did not update the RSP balances in the GRA Application based on the proposal noted in the letter dated August 23, 2017.

On November 29, 2017, the Board issued P.U. 39 (2017) and dismissed Hydro's Application relating to the 2015-2016 Deferred Supply Costs Recovery. According to this Order, it is the Board's view, that "the general rate application may be the most convenient forum to address the issues related to the recovery of the supply costs. This would permit the consideration of the issues in the context of additional information related to generation dispatch, hydrology and the factors affecting rates and account balances through the full range of processes available in a general rate application, including cross examination, and technical and settlement conferences."

2018 Test Year

The 2018 Test Year RSP Included in Chapter 4 of the GRA, Schedule 4-II (Page 6 of 9) is prepared starting with the closing balances of the Forecast 2017 RSP and the 2018 activity is calculated using the proposed 2018 test year inputs included in the GRA Application. However, in the letter that Hydro provided the Board on August 23, 2017, the Company is now proposing that the RSP continue to operate in 2018 using the 2015 test year inputs. In the GRA, Hydro is proposing that final customer rates will be based on 2019 Test Year costs, therefore the operation of the RSP for 2019 would reflect the 2019 Test Year inputs.

Hydro has not updated the 2018 Test Year RSP to reflect the proposal of using the 2015 Test Year inputs in 2018.

The preparation of the 2018 Test Year RSP also includes the recovery of the forecast 2017 deferred supply costs of $12.890 million, the breakdown between the various supply costs accounts are as follows:

	(000's)
➢ Isolated Systems	$ 0.876
➢ Energy Supply	8.585
➢ Holyrood conversion	3.429
Total Forecast Deferred 2017 Supply costs	$12.890

The Isolated Systems costs are allocated between Newfoundland Power and the Labrador Interconnected using the rural deficit allocations of 95.6% and 4.4% respectively, and the Energy Supply and Holyrood Conversion are allocated between Newfoundland Power, Industrial Customers and the Labrador Interconnected using the forecast 2017 energy sales.

Based on this allocation, $11.702 million and $1.115 million is allocated to the Newfoundland Power and Industrial Customer Current Plans, respectively, and $0.073 million is allocated to the Labrador Interconnected and written off.

In Order P.U. 49(2016), the Board approved the three supply deferral accounts noted above, however in this Order, the Board determined that the disposition of the balance in the accounts should be addressed in an annual application to the Board.

In the application relating to the recovery of the 2015-2016 supply deferral accounts, Hydro proposed that the historic supply costs be recovered from customers on the basis of their energy consumption in each respective year. Hydro also proposed that the 2015-2016 deferred supply costs be recovered using the RSP. This methodology is consistent with Hydro's allocation of the forecast 2017 deferred supply costs. As previously noted, on November 29, 2017, the Board issued P.U. 39 (2017) and dismissed Hydro's application relating to the recovery of the 2015-2016 supply deferral accounts.

2019 Test Year

The 2019 Test Year RSP included in Chapter 4 of the GRA, Schedule 4-II (Page 6 of 9) is prepared starting with the closing balances of the 2018 Test Year RSP (using the 2018 test year inputs) and the 2019 activity is calculated using the proposed 2019 test year inputs included in the GRA Application. Based on the observations noted in the Forecast 2017 RSP and the recent proposal of using the 2015 test year inputs for the 2018 RSP, the opening balances for the 2019 Test Year RSP will most likely be very different than the balances used in Schedule 4-II (Page 6 of 9).

The preparation of the 2019 Test Year RSP is based on various inputs in the RSP being rebased at 2019 test year values. Therefore activity within the RSP for the 2019 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 RSP for the 2019 test year are as follows:

- the hydraulic production is forecast to be 4,606.4 GWh
- the Holyrood No. 6 fuel conversion factor is forecast to be 616 kWh/bbl
- Average No. 6 fuel purchase price per barrel is forecast to be $87.11/bbl
- Firm energy sales to Newfoundland Power is forecast to be 5,833,600,000 kWh
- Firm energy sales to the Industrial Customers is forecast to be 743,300,000 kWh
- The interest rate used within the Plan is based on the forecast WACC of 5.68%
- The RSP adjustment rate used to determine the payment (refund) to the customer does not include a fuel rider as of January 1, 2019.

RSP Rate Mitigation Adjustments

P.U. 16(2017) and P.U 24(2017) approved RSP rate mitigation adjustments effective July 1, 2017 for both Newfoundland Power and the Industrial Customers, respectfully. The approved rate mitigation adjustment for Newfoundland Power was (0.911) cents per kWh and (0.313) cents per kWh for the Industrial Customers.

These rate adjustments were based on transfers of credit balances as of March 31, 2017 in the RSP Segregated Load Variation component for each customer group to offset the Current Plan balances of each customer group.

In accordance with the RSP rules, the RSP rate adjustment for Newfoundland Power will be updated July 1, 2018 and the Industrial Customer RSP rate adjustment is to be updated January 1, 2018. In its letter provided to the Board on August 23, 2017, Hydro notes that the Industrial Customers rate mitigation adjustment was calculated to provide the disposition of approximately $1.5 million from the RSP Segregated Load Variation component over a 12 month period. Based on this, Hydro believes that it would be reasonable to continue the RSP rate mitigation adjustment for the Industrial Customers until June 30, 2018 instead of discontinuing it on January 1, 2018.

In this letter, Hydro also noted that they recognize that the conclusion of the RSP rate mitigation adjustments noted above could cause material rate impacts, however, to consider this impact in isolation of the normal RSP adjustments would not present the complete picture of the final rate impact to customers. One component of the normal RSP adjustments is the fuel rate rider based on projected forecast fuel costs, and the other component is the activity recorded in the Current Plans based on actual hydrology, actual fuel prices and load in comparison to the test year inputs included in the RSP. As an example, Hydro noted that the fuel rider reflected in current customer rates is based on a forecast No. 6 fuel cost of $81.40/bbl, however according to Hydro the actual No. 6 fuel price for the month of July 2017 was $67.39/bbl. If the No.6 fuel costs continue to be lower than the forecast, fuel savings will be credited in the Current Plans and this could potentially reduce the impact on customer rates in 2018. These recent fuel forecast trends could also potentially reduce the RSP fuel rate rider that will be calculated in 2018.

Hydro does say that because of these uncertainties they are not able to accurately forecast the impact that the update of the normal RSP rate adjustments will have on customer rates, and if the actual information used to calculate the RSP adjustment rate indicates a potential for rate shock, they will provide the Board with options to deal with this circumstance.

Change in RSP rules - Rural Rate Alteration

In the 2017 General Rate Application, Chapter 5 (page 5.23), Hydro is proposing to modify the RSP rules used in the monthly calculations of the Rural Rate Alteration ("RRA").

As noted in the Application, "The RRA is a component of the RSP that transfers to Newfoundland Power the changes in Hydro Rural revenues that result from flowing through Newfoundland Power rate changes to Hydro Rural customers." Section B 1.3 of the rules describes the methodology that Hydro is required to follow when calculating the RRA. The current formula for the calculation is as follows:

$$(M-N)*O$$

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

Hydro is proposing to modify the rules to change the definition of "O" to Test Year units instead of Actual units. Hydro has noted in the Application that to comply with the current rule, they must calculate the RRA variance on more than 27,000 customer bills on a monthly basis, and that the compilation of the data and the preparation of the calculation is a very time consuming and tedious process. They noted that the change to Test Year units would materially reduce the administrative effort in the preparation of the monthly RSP reports.

In footnote 35 on page 5.23 of the Application, Hydro noted that "computing the 2016 RRA transfer using Test Year units instead of actual units resulted in a difference of 0.3%, which represents a variance of less than $25,000 on a 2016 RRA transfer of over $8.0 million."

Based on our review of the "Requests for Information" relating to this Application that have been issued to Hydro, there were no questions asked with regards to this proposed rule change.

Summary

Based on our review of the RSP reports for Forecast 2017, 2018 Test Year, and the 2019 Test Year, we note the following:

- We confirm that the Forecast 2017 RSP includes the appropriate 2015 test year inputs, and is in accordance with the Board Orders issued since the last GRA, with the exception of the inclusion of the $804,000 to be recovered from Newfoundland Power relating to the 2017 revenue deficiency as ordered in P.U. 22 (2017). Also, we noted some differences in amounts transferred as a result of Board Orders, between the Forecast and Actual RSP, due to the Forecast not being updated for the actual results.

- The Forecast 2017 RSP includes an alternative option to recovering the 2015-2016 deferred supply costs than the proposal included in the letter to the Board dated August 23, 2017. The proposal in this letter is consistent with the proposal included in the application that Hydro filed with the Board on October 11, 2017 for the Recovery of 2015-2016 Deferred Supply Costs, which the Board dismissed in P.U 39 (2017).

- The 2018 Test Year RSP included in this Application is based on 2018 test year inputs, however in the letter dated August 23, 2017, Hydro is proposing that the 2018 RSP operate using 2015 test year inputs.

- The 2018 Test Year RSP includes the recovery of the forecast 2017 deferred supply costs assuming that it will be added to the Current RSP plan balance in 2018 and be included in the calculation of the RSP adjustment each year. In P.U. 49 (2016), the Board determined that the disposition of the balance in the accounts should be addressed in an annual application to the Board, therefore, this recovery method of 2017 deferred supply costs will require Board approval in 2018. As previously noted, on November 29, 2017, the Board issued P.U. 39 (2017) relating to the recovery of the 2015-2016 deferred supply costs and dismissed Hydro's proposal to recover these costs through the RSP.

- The inputs in the 2019 Test Year RSP agree with those included in the GRA Application, however based on the observations noted in the Forecast 2017 RSP and the recent proposal of using the 2015 test year inputs for the 2018 RSP, the opening balances for the 2019 Test Year RSP will most likely be very different than the balances used in Schedule 4-II (Page 6 of 9).

Capital Expenditures

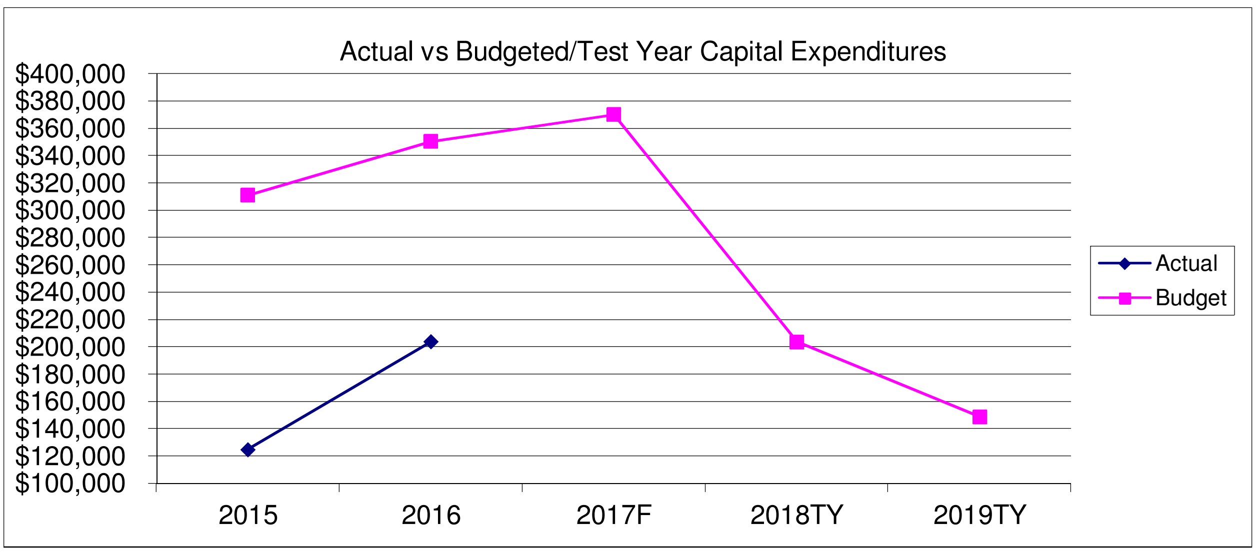
The following table details the actual versus budgeted capital expenditures from 2015 to 2016, and the forecast figures for 2017 and test years 2018 and 2019:

Table 52: Comparison of capital expenditures – actual to budget

(000's)	2015	2016	2017F	2018TY	2019TY
Actual 2015 - 2016	$ 125,119	$ 203,941			
Budget	$ 311,177	$ 350,602	$ 370,195	$ 203,872	$ 148,994
Over/Under Budget	-59.79%	-41.83%	N/A	N/A	N/A

Note: Capital expenditures presented above are net of CIACs.

Graph 7: Comparison of capital expenditures – actual to budget



The above graph demonstrates that for 2015 and 2016 the Company has been 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." Hydro has provided an explanation as to why the recent variances have occurred in the 2016 Capital Expenditures and Carryover Report. We have reviewed the significant variances for 2016 as part of our annual financial review.

In P.U. 45 (2016) the Board approved Hydro's 2017 capital budget application for the amount of $271,265,600. Subsequent to the filing of its 2017 Capital Budget Application, the Company requested and the Board approved the following supplementary 2017 capital expenditures in:

(i) Order P.U. 20 (2016) in the amount of $1,533,000 to reroute transmission line TL 227 and distribution line Sally's Cove L1;

(ii) Order P.U. 5 (2017) in the amount of $3,045,000 to construct a distribution feeder at the Bottom Waters Terminal Station;

(iii) Order P.U. 7 (2017) in the amount of $3,168,944 to lease, sublease and purchase transmission lines and electrical equipment to serve Labrador West;

(iv) Order P.U. 11 (2017) in the amount of $2,585,200 to replace equipment and complete a level 2 condition assessment of the synchronous condensers at Wabush Terminal Station;

(v) Order P.U. 13 (2017) in the amount of $2,361,500 to complete a major overhaul on Bay d'Espoir Unit 3 Turbine; and,

(vi) Order P.U. 13 (2017) in the amount of $9,063,700 to inspect and refurbish Bay d'Espoir Penstock 2.

Capital expenditures approved by the above Board Orders total $21,757,344. In addition, carryovers from 2016 and earlier projects totalled $38,255,700 and Hydro approved projects of less than $50,000 totalled $91,900, for a total of approved 2017 capital expenditures of $331,370,544.

The reconciliation of total approved projects to the capital expenditures for forecast 2017 along with explanations for significant reconciling items, as provided by Hydro, is as follows:

Table 53: Reconciliation of approved projects to 2017 capital expenditures

2017	
(000's)	Capital Expenditures
P.U. 45 (2016) (Capital Budget)	$ 271,265.6
P.U. 20 (2016)	1,533.0
P.U. 5 (2017)	3,045.0
P.U. 11 (2017)	2,585.3
P.U. 7 (2017)	3,168.9
P.U. 13 (2017)	9,063.7
P.U. 13 (2017)	2,361.5
Carryovers per carryover report	38,255.7
Projects under $50K	91.9
Total Approved Projects	**$ 331,370.6**
Reconciling Items	
Penstock #1 Weld Refurbishment - BDE	582.2
Labrador West Transmission Project (IDC)	813.9
TL - 267 Adjustment (CO #6)	36,869.0 [1]
TL - 266 Adjustment	559.2
Rounding	(0.1)
Total 2017 GRA forecasted capital expenditures	**$ 370,194.8**

Note 1: This proposal was due to internal change management on the TL-267 project. The project was approved under P.U. 53 (2014). According to Hydro, this was a cash flow change between fiscal years to advance funds from 2018 back into 2017, and not a change in overall project budget. According to Hydro, the Board has been advised of this change management.

The 2018 Capital Budget Application includes forecast capital expenditure for 2018 and 2019. The reconciliation of 2018 Capital Budget Application to the capital expenditures for test years 2018 and 2019, along with explanations for significant reconciling items, as provided by Hydro, is as follows:

Table 54: Reconciliation of 2018 Capital Budget Application to 2018 and 2019 capital expenditures

(000's)	2018	2019
2018 Capital Budget Application	$ 200,390.0 [1]	$ 146,657.0
Impact of removals under new depreciation methodology	2,060.1 [2]	1,476.9 [2]
Various project differences	1,422.0 [3]	859.8 [3]
Rounding		0.3
Total 2018 GRA forecasted capital expenditures	**$ 203,872.1**	**$ 148,994.0**

Note 1: Capital Budget Application - Revision 3 - 2017-10-03

Note 2: Consistent with the old methodology, removal costs are not capital expenditures. However, removal costs were included in the capital expenditure line item in the GRA cash flow. Removal costs were appropriately excluded from total capital expenditures referenced in the capital budget. As a result, Hydro was required to include the difference in the presentation as a reconciling item.

Note 3: This reconciling item relates to various capital projects where Hydro's forecasted captial expenditures in the GRA differ from the capital budget application due to timing of the filing of the Application.

The following table provides a breakdown of the total capital expenditures between those included in rate base and those included in Work in Progress:

Table 55: Breakdown of Capital Expenditures

(000's)	2017	2018	2019
Capital Expenditures Included in Rate Base	$ 391,274	$ 223,011	$ 168,726
Opening Work in Progress (Note 1)	(92,098)	(71,761)	(51,306)
Closing Work in Progress	71,761	51,306	30,487
CIACs	(742)	(744)	(390)
Removal Costs	-	2,060	1,477
Total Capital Expenditures	**$ 370,195**	**$ 203,872**	**$ 148,994**

Note 1: Opening Work in Progress for forecast 2017 excludes CIACs of $2,398,661.

Capital expenditures included in rate base above agree to the additions to rate base included in property, plant and equipment on Finance Schedule 4-II, pg. 5 of 9, in the GRA.

We recommend that the Board obtain from Hydro updated capital expenditure forecasts for 2017, 2018 and 2019. We also recommend that the Board request from Hydro the impact on revenue requirement and average rate base for 2018 and 2019 test years, as a result of these updated forecasts.

Deferred Accounts

The following tables shows the transactions in the deferred charges account for 2017 and the 2018 and 2019 test years:

Table 56: Deferred charges transactions for 2017

('000s)	Balance Jan 1/17	Reclass.	Additions	Recoveries	Amortization	Balance Dec 31/17
CDM Program	$ 8,363	$ -	$ 2,100	$ (600)	$ -	$ 9,863
Phase II Hearing Costs	869	-	1,000	-	-	1,869
Isolated Systems Supply Cost	(2,186)	-	838	2,186	-	838
Energy Supply Costs Deferral	38,663	-	8,561	(38,663)	-	8,561
Holyrood Conversion	5,733	-	3,419	(5,733)	-	3,419
GRA Hearing Costs	250	-	-	-	(250)	-
Holyrood Blackstart Diesal	4,471	-	-	-	(1,341)	3,130
Asset Disposal	387	-	-	-	(19)	368
Deferred Foreign Exchange - Inventory	(158)	-	-	-	-	(158)
Foreign Exchange	53,924	-	-	-	(2,157)	51,767
Deferred Power Purchase Deferral	-	-	-	(417)	-	(417)
2014 Cost Deferral	37,707	500		(38,207)	-	-
2015 Cost Deferral	27,659	200		(27,859)	-	-
2016 Cost Deferral	5,036	300		(5,336)	-	-
Labrador RSP Refund	-	(1,000)		602	-	(398)
Total deferred charges	**$ 180,718**	**$ -**	**$ 15,918**	**$ (114,027)**	**$ (3,767)**	**$ 78,842**
Current year opening	**$ 152,189**					**$ 180,718**
Average deferred charges	**$ 166,454**					**$ 129,780**

Table 57: Deferred charges transactions for 2018 and 2019 Test Years

('000s)	Balance Jan 1/18	Additions	Dispositions	Amortization	Balance Dec 31/18	Additions	Dispositions	Amortization	Balance Dec 31/19
Approved existing									
CDM Program	$ 9,863	$ 2,100	$ (1,200)	$ -	$ 10,763	$ 2,100	$ (1,200)	$ -	$ 11,663
Phase II Hearing Costs	1,869	-	-	-	1,869	-	-	-	1,869
Holyrood Blackstart Diesal	3,130	-	-	(1,341)	1,789	-	-	(1,341)	448
Asset Disposal	368	-	-	(19)	349	-	-	(19)	330
Foreign Exchange	51,767	-	-	(2,157)	49,610	-	-	(2,157)	47,453
Deferred Power Purchase Deferral	(417)	-	-	36	(381)	-	-	36	(345)
Labrador RSP Refund	(398)	-	200	-	(198)	-	198	-	-
Existing not yet approved									
Isolated Systems Supply Cost	838	-	(838)	-	-	-	-	-	-
Energy Supply Costs Deferral	8,561	-	(8,561)	-	-	-	-	-	-
Holyrood Conversion	3,419	-	(3,419)	-	-	-	-	-	-
Deferred Foreign Exchange - Inventory	(158)	-	-	-	(158)	-	-	-	(158)
Proposed									
GRA Hearing Costs	-	1,200	-	(400)	800	-	-	(400)	400
Cost of Service Hearing Costs	-	450	-	(150)	300	-	-	(150)	150
Holyrood Inventory Allowance	-	(2,082)	-	-	(2,082)	(2,082)	-	-	(4,164)
2018 Revenue Deficiency	-	22,578	-	-	22,578	-	(13,547)	-	9,031
Total deferred charges	**$ 78,842**	**$ 24,246**	**$ (13,818)**	**$ (4,031)**	**$ 85,239**	**$ 18**	**$ (14,549)**	**$ (4,031)**	**$ 66,677**
Current year opening	**$ 180,718**				**$ 78,842**				**$ 85,239**
Average deferred charges	**$ 129,780**				**$ 82,040**				**$ 75,958**

Approved Existing

Conservation Demand Management Costs

Pursuant to P.U. 49 (2016) Hydro received approval to defer 2016 costs related to the CDM Program. Actual costs deferred in 2016 were $1,154,000. In P.U. 22 (2017), the Board approved the CDM deferral account definition which stated that the account balance as at December 31 each year shall be recovered over a period of seven years using a CDM Recovery Adjustment and that recovery of annual amortizations of costs in this account shall be through an annual application. The rates came into effect and recovery of the balance will begin on July 1, 2017. We have recalculated the recoveries for forecast 2017, and test years 2018 and 2019.

In Hydro's current Application, they are forecasting costs in 2017, 2018 and 2019 test years of $2.1 million per year. Hydro has indicated the increase in CDM program deferral costs from $1,152,000 in 2016 to $2,100,000 in 2017 primarily relates to the expansion of the isolated communities program and increased participation in the industrial customers program.

Phase II Hearing Costs

In P.U. 13 (2016), Hydro received approval to defer costs for 2014, 2015 and subsequent years relating to Phase II of the investigation into the reliability and adequacy of power on the Island Interconnected system after the interconnection with Muskrat Falls generating station. Total costs of $0.9 million were deferred by Hydro in fiscal 2016. In 2017, Hydro is deferring an additional $1.0 million related to this account, for a total balance of $1.9 million. In response to LAB-NLH-013 Hydro stated that "due to the ongoing process and uncertainty of the projected final costs, the costs incurred to date of $0.9 million were used as a baseline in determining the forecast $1.0 million, as activity was expected to increase in 2017." Hydro has not proposed any amortization cost to be included in 2018 or 2019 revenue requirement.

Holyrood Blackstart Diesel

Pursuant to P.U. 38 (2013) Hydro received approval to defer lease costs associated with the 16 MW diesel plant and other necessary infrastructure estimated to be $5.8 million. Actual costs deferred in 2014 were $3.7 million. In 2015, Hydro deferred an additional $1.4 million. In 2016, pursuant to P.U. 17 (2016) and P.U. 23 (2016), Hydro received approval to defer additional lease costs of $1.3 million and $0.3 million, respectively. Actual cost incurred in 2016 was $1.6 million. In P.U. 49 (2016), the Board approved the amortization of the deferred balance over a period of five years beginning in 2015. Actual costs deferred in 2016 were $4.5 million, net of amortization. Amortization of $1,341,000 is included in forecast revenue requirement for test years 2018 and 2019.

Asset Disposal

In P.U. 49 (2016), the Board ordered that Hydro defer $0.4 million loss on disposal related to the Sunnyside transformer that was disposed in 2014. Hydro is required to recover the deferred asset in rate base and amortize the asset over a 22 year period, which commenced in 2015.

Foreign Exchange Losses

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

Deferred Power Purchase Deferral

In 1997, the Board ordered Hydro to defer $1.1 million related to reduced purchased power rates resulting from the interconnection of communities in the area of L'Anse au Clair to Red Bay to the Hydro-Quebec system and amortize the balance over a 30 year period. This deferral was added as a recovery in 2017 with remaining unamortized savings in the amount of $0.4 million deferred as a regulatory liability. Prior to 2017, this balance was excluded from rate base but should have been included. The inclusion of the liability in the forecast provides a benefit to customers of approximately $23,000 in 2018 [($417,000+381,000/2) * 5.73% (TY WACC)) =$22,863] and $21,000 in 2019 [(($381,000+$345,000)/2)*5.68% (TY WACC)) =$20,618].

Labrador RSP Refund

The nature of the reclass entry relating to the 2014, 2015 and 2016 cost deferrals and the Labrador RSP Refund is to adjust the balance in these accounts to reflect the ruling of the Board on Hydro's 2013 amended General Rate Application. In P.U. 49 (2016), the Board directed Hydro to revise the proposed recovery of the revenue deficiencies for 2014 to 2017 to include Hydro Rural Labrador Interconnect customers and Labrador Industrial Transmission customers.

The 2014 to 2016 cost deferral balances were adjusted to reflect the final rulings of the Board and the balance was recovered from the RSP. The Labrador portion remaining was refunded to Labrador Industrial Transmission customers ($0.609M) in September and the balance of ($0.467M) will be refunded to customers on the Labrador Interconnected System over a 30 month period from July 1, 2017 to December 31, 2019.

The table above includes a $1.0 million deferred regulated liability, which differs from the refund provided to customers by $76,000.

Existing not yet approved

Isolated Systems Supply Costs, Energy Supply Costs Deferral and Holyrood Conversion

In P.U. 49 (2016), the Board stated that the Energy Supply, Holyrood Conversion, and Isolated Systems deferral accounts should be approved effective January 1, 2015 with recovery of the account balances addressed in an annual application for disposition of the balance. In P.U. 22 (2017), the Board approved the Energy Supply, Holyrood Conversion, and Isolated Systems deferral account definitions which stated that an application is required annually by March 31. As the deferral account definitions were not approved until July 2017, an application was filed on October 11, 2017 by Hydro for approval of the recovery of the 2015 and 2016 balance of these accounts. On November 29, 2017, the Board issued P.U. 39 (2017) and dismissed this application. Therefore, these balances have not yet been approved by the Board. Hydro is proposing that these balances from 2015 and 2016 would be recovered through the RSP in 2017.

In 2017 Hydro has included the 2017 forecast balances for each of above deferral accounts. The procedures we performed on these balances included:

- Agreed component data (2017 forecast and test year data) to supporting documentation including the Company's 2017 forecast general ledgers; 2017 forecast data, 2015 test year;
- checked the clerical accuracy of the deferred account calculations; and,
- reviewed the formula used in the calculations of the deferral accounts to ensure in compliance with account definitions as approved in P.U. 22 (2017).

We noted small differences from the calculation provided and balances included in the deferral accounts as follows:

	Balance from:		
Deferral Account	**General Rate Application**	**Calculation prepared by Hydro**	**Variance**
Isolated Systems Supply Cost	$ 838,000	$ 876,000	$ (38,000)
Energy Supply Costs Deferral	8,561,000	8,586,000	(25,000)
Holyrood Conversion Rate	3,419,000	3,429,000	(10,000)
Total	**$ 12,818,000**	**$ 12,891,000**	**$ (73,000)**

Hydro has also proposed that the 2017 deferral account balances be recovered using the RSP in 2018.

If Hydro's proposals for recovery are not approved, the impact on the rate base would be a higher rate base which would translate to a higher return on rate base in test years 2018 and 2019.

Deferred Foreign Exchange - Inventory

Hydro purchases a significant amount of fuel for the Holyrood Thermal Generating Station (HGTS) in US dollars. Hydro has stated that RSP allows Hydro to defer variances in fuel prices, including foreign exchange fluctuations. According to Hydro the foreign exchange deferral is a change in accounting required due to adoption of IFRS. Prior to IFRS, Hydro recorded the full amount of the foreign exchange gain or loss in inventory. Upon adoption of IFRS, Hydro segregated the foreign exchange gain or loss which would require immediate change to the company's profit and loss instead of inventory. In order to keep accounting for the RSP consistent with prior years, Hydro created a regulatory asset/liability to segregate the foreign exchange gain or loss until the fuel is consumed at which time the fuel inventory used and the relevant deferred foreign exchange on inventory would be realized and flow through the RSP. It is not clear from the RSP rules if foreign exchange gains or loss should be reflected in inventory when converted to Canadian dollars from US dollars purchases. If the Board wanted to continue with the past practice to allow Hydro to flow foreign exchange losses and gains through the RSP upon consumption of fuel, we recommend that RSP rules be clarified to state that fuel converted to Canadian dollars includes foreign exchange losses and gains. We do note that while the Company has stated this change was due to implementation of IFRS, we are not aware of any differences between previously applied Canadian GAAP and IFRS that would result in an accounting difference.

Hydro has carried forward the deferred regulatory liability of $158,000 to 2017 forecast and 2018 and 2019 test years as a proxy as the Company does not estimate forecast exchange rate differences and as a result, the balance did not reverse. In this case, the inclusion of the liability in the forecast provides a small benefit to customers of approximately $9,000 for each of the test years [2018 – ($158,000 * 5.73% (TY WACC)) =$9,053; 2019 – ($158,000*5.68% (TY WACC)) =$8,974].

Proposed Deferrals

In the 2017 GRA, Hydro is proposing that the Board approve the following regulatory deferral accounts, recovery mechanisms and amortizations:

a) External Regulatory costs relating to the current GRA deferred and amortized over a three-year period;
b) External Regulatory costs associated with a cost of service methodology review hearing deferred and amortized over a three-year period;
c) Holyrood Inventory Allowance deferral account for inventory which will no longer be required once Holyrood is converted to synchronous condenser mode by March 31, 2021; and,
d) 2018 Revenue Deficiency account related to interim rates providing Hydro with partial recovery of costs, resulting in a shortfall in revenue requirement.

Each in turn will be addressed.

GRA Hearing Costs

Approximately $1.2 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 2018. The Board has allowed recovery of Application costs over a three-year period with the most recent approval outlined in P.U. 49 (2016).

The proposal will have a forecast revenue requirement impact of $0.4 million in the years 2018 to 2020.

Cost of Service Hearing Costs

Hydro filed its Cost of Service Methodology Review report with the Board on March 31, 2016, assuming that supply costs from the Muskrat Falls Project would be reflected in its 2019 costs for the full year. However, due to the delay in the project, Hydro proposed to delay the cost of service methodology hearing until after the 2017 GRA. The Board approved the delay in a letter dated September 9, 2016.

Hydro is proposing to defer up to $0.5 million and amortize these costs over a three year period commencing in 2018, which is consistent with the external regulatory costs amortization period.

Holyrood Inventory Allowance

Holyrood Thermal Generation Plant is currently scheduled to be converted to synchronous condenser mode by March 31, 2021. As of December 31, 2016, Hydro has $10.1 million inventory of spare parts to service the plant; however, once converted, Hydro has estimated $6.8 million of inventory will no longer be required. Therefore, Hydro is proposing to record an inventory allowance from January 1, 2018 until March 31, 2021, and has included $2.1 million in each of the 2018 and 2019 Test Year revenue requirement.

We note this treatment is inconsistent with the requirements of IFRS. Under IFRS, this loss would be recognized in 2021 when the assets were no longer of use.

In NP-NLH-082 Hydro provides the impact on average rate base and revenue requirement related to the Holyrood Thermal Generating Station inventory for 2015 test, 2015 and 2016 actual, 2017 forecast and 2018 and 2019 test years. In NP-NLH-083 Hydro provides the impact on Hydro’s earnings if the Holyrood Inventory Allowance is not approved by the Board.

2018 Revenue Deficiency

Hydro's Application is proposing interim rates be approved effective January 1, 2018 prior to approval of final rates. Interim rates will provide Hydro with partial recovery of costs resulting in a shortfall in revenue requirement of $22.6 million in 2018. Hydro is proposing to defer this amount, include the balance in rate base, and recover the balance over a 20 month period commencing January 1, 2019, and ending August 31, 2020. Hydro anticipates its customer base rates will be required to increase September 1, 2020, to provide recovery of Muskrat Falls Project costs. Therefore, this provided a 20 month period for the revenue recovery for the amortization of 2018 revenue deficiency.

Recalculation of the revenue shortfall using the proposed rate riders and monthly charge to customers within Hydro's Application Revision #3 filed on October 27, 2107 provided a revenue shortfall of $21,746,000, which is an overstatement of $832,000 of the 2018 revenue deficiency. According to Hydro, the 2018 revenue deficiency was estimated for the purposes of determining Hydro's test year revenue requirement prior to the finalization of proposed customer rates, thereby resulting in an overstatement in 2018 revenue deficiency of $832,000. Hydro has advised us that they will reconcile its approved 2018 test year revenue deficiency to that included in customer rates to be approved when it files its compliance filing to the 2017 GRA.

As a result of completing our procedures, we noted the following existing deferred charge balances have not yet been approved by the Board:

- **Deferred Foreign Exchange on Fuel;**
- **Energy Supply Deferral;**
- **Holyrood Conversion; and,**
- **Isolated Systems.**

We also noted the following are proposed by Hydro to be approved by the Board in the 2017 GRA:

- **Deferred Hearing Costs;**
- **Cost of Service Hearing Costs;**
- **Holyrood Inventory Allowance; and,**
- **2018 Revenue Deficiency – we noted an $832,000 overstatement in this deferral account.**

Automatic Return on Equity Adjustment

P.U. 49 (2016) ordered Hydro to file with its next GRA (and no later than June 30, 2017) a proposal in relation to an adjustment mechanism for its target return on equity. The Board concluded "that the target return on rate base for Hydro should be adjusted as Newfoundland Power's target return changes between general rate applications".

As part of its 2018/2019 GRA Hydro filed, in Exhibit 12 of its Application, its 'Automatic Return on Equity Adjustment Report' in compliance with the above noted order. In its report the Company noted that "upon the delivery of an order to change Newfoundland Power's rate of return on equity, Hydro would be required to update its return on equity to be equal to that of Newfoundland Power. This change would, in turn, cause a change in Hydro's weighted average cost of capital and return on rate base". We concur with this statement.

Hydro goes on to explain that to allocate this change among customer groups, it would be required to revise its approved test year cost of service for rate setting to reflect the revised test year return on rate base. Hydro proposes the following methodology to reflect changes in customer rates:

- Newfoundland Power – Hydro proposes that changes to the test year revenue requirement allocated would be applied through a change in the first block rate, as opposed to the current second block energy rate, which is set based on the test year price of Holyrood fuel and negotiation of the demand charge.

- Island Industrial Customers - Hydro will use the revised test year cost study to determine rates for demand, energy and specifically assigned charges.

- Hydro Rural Labrador Interconnected and Labrador Industrial Transmissions Customers – Hydro proposed to adjust customer rates by using the percentage change in test year revenue requirement for each class of service.

- Hydro Rural Customers – No change in the existing process. The rates are required to change when Newfoundland Power's return changes in order to certify its customers receive the same rates.

Hydro proposes that it will file an automatic adjustment with the Board within 10 business days following the approved Board Order of Newfoundland Power's ROE. The application will include the following:

- Revised test year WACC and rate of return on rate base;
- Finance schedules providing revised requirements from customer rates;
- Revised test year cost of service study identifying change in revenue requirement by customer class;
- Derivation of revised customer rates;
- Revised Excess Earnings Account Definition; and
- Proposed revised schedule of rates, tolls and charges.

In NP-NLH-160, Hydro was asked if they had considered any alternatives with regards to the adjustment mechanism for its target ROE to reflect any future changes to Newfoundland Power's approved target ROE for rate setting purposes. Hydro responded that the approach provided in their Automatic Return on Equity Adjustment Report (Exhibit 12) to be the only alternative available to meet the requirements of Board Order P.U. 49 (2016).

We conclude that the above noted methodology would have the effect of adjusting Hydro's target return on rate base to reflect changes in Newfoundland Power's target return changes between general rate applications. The timing of the filing should allow adequate time to allow for the revised supply costs to be incorporated into Newfoundland Power's customer rates.

Off-Island Purchase Deferral Account

Background

In its Application, Hydro is proposing to establish a deferral account which will include the cumulative net savings from accessing off-island power purchases prior to full commissioning of the Muskrat Falls Project. According to Hydro, this deferral account is being proposed to manage customer rates in advance of its next GRA when it anticipates it will be proposing rates to begin recovery of the Muskrat Falls Projects costs.

Hydro anticipates that the Labrador-Island Link (the "LIL") and the Labrador Transmissions Assets (the "LTA") will be available approximately two years in advance of the Muskrat Falls Plant due to delays in the project. According to Hydro, the use of the LIL and LTA during the proposed time period of 2018-2020 will benefit Hydro's customers through improved reliability and a reduction in supply cost.

As defined in Supplemental Evidence Schedule 6-I of the Company's pre-filed evidence, the proposed account shall be charged or credited on a monthly basis by the amount of the test year supply cost variances on the Island Interconnected System that result from off-island power purchases prior to the full commissioning of the Muskrat Falls Project.

Proposed Formula

The following calculation will determine the monthly transfers to the Off-Island Purchases Deferral Account to be determined by Hydro:

Fuel Consumption Savings + Fuel Inventory Savings – Cost of Off-Island Purchases

Fuel Consumption Savings shall be calculated as:
(A / B) x C

Where:
A = Off-Island Power Purchases at Point of Delivery (kWh);
B = Test Year Holyrood No. 6 Fuel Conversion Rate (kWh/barrel); and
C = Test Year Cost of No. 6 fuel ($ per barrel).

Fuel Inventory Savings shall be calculated as:
(D - E) x C x F

Where:
D = Test Year 13 month Average Volume of No. 6 Fuel Inventory in barrels;
E = Actual 13 month Average Volume of No. 6 Fuel Inventory in barrels (kWh/barrel); and
F = Test Year Weighted Average Cost of Capital.

Cost of Off-Island Power Purchases shall be calculated as:
G + H

Where:
G = Cost of Off-Island Power Purchases including transmission tariffs and delivery costs; and
H = Amounts paid by Hydro for use of Labrador Island Link and Labrador Transmission Assets.

Fuel savings in the formula above are generated from consumption savings from reduced Holyrood generation and inventory savings due to lower fuel inventory requirements. Hydro's test years in the GRA reflects the continued use of No. 6 fuel at Holyrood, where the deferral account will be credited with the reduced Test Year No. 6 fuel costs that result from accessing off-island power purchases.

Cost of off-island power purchases in the formula above are generated from the cost of off-island purchases and amounts paid by Hydro to Nalcor for use of the LIL and LTA. Hydro is proposing that the operating and maintenance costs incurred to use the LIL and LTA, the cost of supply for Recapture Energy and the cost incurred to achieve power purchases from other jurisdictions be treated as a deferred regulatory expense to be charged to the proposed Off-Island Purchases deferral account. Depreciation and interest expense is not included in the formula's cost and is discussed further below in other comments.

The account balance will attract interest calculated monthly based on Hydro's approved test year weighted average cost of capital. The disposition of any balance in the account will be determined upon future direction from the Board.

Deferral Estimate

In NP-NLH-004, Hydro was asked to identify the entity responsible for determining the costs to the Muskrat Falls Project transmission assets. The response noted that Nalcor's Power Supply division is responsible for determining the costs to operate and maintain the transmission assets of the Muskrat Falls Project, specifically the LIL and LTA. According to Hydro, the estimates provided are supported by research into the existing High Voltage, Direct Current (HVdc) transmission assets, which have high reliability requirements similar to those required of the LIL, and based on existing practices employed in Newfoundland and Labrador on Alternating Current (AC) assets. The cost estimates are displayed below.

In NP-NLH-115, Hydro was asked for their current estimate of the balance they may accumulate in the Off-Island Purchases Deferral account by December 31, 2018 and December 31, 2019. The estimate provided by Hydro is as follows:

Off-Island Deferral Account Estimate
$(000)

	Fuel Consumption Savings	**2018**	**2019**	**2020**
	CF(L) Co Recapture (GWh)[1]	520	859	41
	Muskrat Falls Pre-Commissioning (GWh)[1]	-	-	723
	Out-of-Province Purchases (GWh)	-	-	-
	Less: Losses LTA / LiL (GWh)	68	117	70
A	Delivery of Off-Island Power Purchases (GWh)[2]	452	742	694
B	Test Year Holyrood conversion rate (KWh/barrel)	618	616	616
C	Test Year Price of No. 6[3]	$ 64.41	$ 87.11	$ 87.11
X = (A / B) x C		**$ 47,141**	**$ 104,971**	**$ 98,201**
Fuel Inventory Savings				
D	Test Year No. 6 Inventory Barrels	634,795	600,125	629,732
E	Forecast No. 6 Inventory Barrels	624,751	591,999	124,811
C	Test Year Price of No. 6	$ 64.41	$ 87.11	$ 87.11
F	Test Year WACC[3]	6.61%	5.68%	5.68%
Y = (D - E) x C x F		**$ 43**	**$ 40**	**$ 2,498**
Cost of Off-Island Purchases				
	CF(L) Co Recapture	$ 1,016	$ 1,680	$ 127
	Muskrat Falls Pre-Commissioning	$ -	$ -	$ -
	Out-of-Province Purchases	$ -	$ -	$ -
G	Total Off-Island Purchases	$ 1,016	$ 1,680	$ 127
H	OpEx for LIL \ LTA	$ 27,300	$ 52,900	$ 35,700
Z = G + H		**$ 28,316**	**$ 54,580**	**$ 35,827**
I = X + Y - Z				
I	Off-Island Supply Deferral Transfer	$ 18,868	$ 50,432	$ 64,872
	Interest @ WACC[3]	$ 624	$ 2,539	$ 5,958
	Cumulative Off-Island Supply Deferral Balance	**$ 19,491**	**$ 72,462**	**$ 143,293**

Note 1: Off-island purchases expressed at Churchill Falls with losses expressed energy delivered to the Island Interconnected System.

Note 2: Expressed at Island Interconnected System.

Note 3: The 2018 Test Year price of No. 6 fuel and 2018 WACC reflects the 2015 Test Year.

In PUB-NLH-018, Hydro was asked to provide the estimate of costs for use of the LIL and LTA and power purchases that has been used in its determination of potential savings for customers from off-island purchases. The table below provides the estimated costs provided by Nalcor to Hydro for the use of the LIL and LTA prior to full commissioning of the Muskrat Falls Project:

Forecast Costs to Hydro for the Use of LIL and LTA ($ millions)

Operating Cost Type	2018	2019	2020
Operating Labour and Salaries	5.9	9.7	6.5
System Equipment and Maintenance	14.2	24.2	16.7
Corporate and Engineering Support Labour and Salaries	3.3	12.3	7.5
Administration and Other Costs	3.7	6.3	4.7
Environment	0.2	0.4	0.3
Total	27.3	52.9	35.7

Other Comments

In PUB-NLH-015, Hydro was asked when they anticipate a decision being made on reimbursement to Nalcor of depreciation and interest expense on the LIL and LTA assets and why Hydro is proposing a separate account for these expenses from the Off-Island Purchases deferral account which Hydro proposes will include other expenses associated with off-island purchases. The first part of the response was that there is no estimated decision date from Nalcor. As for the second response, Hydro anticipates that saving in the Off-Island Purchases deferral account will mitigate customer rate impacts in the initial period after the Muskrat Falls commissioning, while depreciation and interest expenses on the LIL and LTA assets represent expenses which would normally be matched with the benefit provided by these assets over their full useful life. As such, a separate deferral account for those expenses could allow a longer amortization period than what is proposed for the Off-Island Purchases deferral account.

In NP-NLH-119 Hydro provides commentary on how the Off-Island Purchases Deferral Account is forecast to operate in conjunction with the operation of the RSP and Hydro's supply cost variance accounts for 2017 forecast, 2018 and 2019 test years, and 2020 forecast. Hydro states that the activity related to off-island purchases will impact only the balance in the Holyrood Conversion Rate Deferral Account.

On December 4, 2017, Hydro's expert report is scheduled to be filed with the Board on the Off-Island Purchases Deferral Account.

If the cost of the Off-Island Purchases exceeds the Fuel Consumption and Inventory Savings, a recovery from customers will result based on the proposed definition. Our understanding of the intent of this account was to allow rate payers to benefit from the savings associated with off-island purchases. As such, the definition should be clarified to ensure no unintended consequences (i.e. that the account cannot have a negative balance).

Proposed Revenue from Rates

The Company is proposing that the Board approve rates, tolls and charges effective for service provided on and after January 1, 2018, rates be approved on an interim basis, and January 1, 2019, to provide an average increase by class in electrical rates, based upon:

a) a forecast average rate base for 2018 of $2,263,109,000 and for 2019 of $2,364,465,000;
b) a rate of return on average rate base for 2018 of 5.73% in the range of 5.53% to 5.93% and for 2019 of 5.68% in a range of 5.48% to 5.88%; and
c) a forecast revenue requirement to be recovered from electrical rates, following implementation of the proposals set out in the Application, of $673,056,000 (Energy sales plus Generation Demand cost recovery - $671,574,000+$1,482,000) for 2018 and $692,766,000 (Energy sales plus Generation Demand cost recovery - $691,324,000 + $1,442,000) for 2019.

We have reviewed the Company's proposed rates effective January 1, 2018 and 2019 in Revision #3 filed on October 27, 2017. Specifically, the procedures we have performed include the following:

1 A recalculation of the revenue that results from using the revised rates, ensuring that it agrees with the revenue requirement submitted by the Company;

2 Agreement of the factors used in the revenue calculations (number of customers, energy and demand usage, etc.) to those presented by the Company;

3 Agreement of the rates used in the revenue calculations to those in the proposed Revised Schedule of Rates, Tolls and Charges;

4 A recalculation of the percentage increase in revenue by rate class and the percentage increase in individual rates, tolls and charges;

5 Recalculation of proposed demand and energy deficiency rates charged to Island Industrial Customers and additional monthly charge to Newfoundland Power, effective January 1, 2019, to recover 2018 revenue deficiency;

6 Agreement of Hydro's proposal to adjust average system losses in the calculation of energy charge to Island Industrial customers for non-firm service is 3.34% is applied January 1, 2019;

7 A recalculation of specifically assigned charges to Industrial customers on the Island Interconnected applying the proposed methodology; and,

8 Agreement of proposed rules and regulations to evidence in support of this Application.

Throughout our work, we noted the following formatting errors within Schedule 5-VII, page 2 of 3, for both Rate 2.1 and 2.2 Unmetered and Single Phase monthly charges:

	Current Rate	Proposed January 1, 2018 Interim Rate	Proposed January 1, 2019 Interim Rate
Rate 2.1 and 2.2 General Service			
Unmetered ($ per month)	10.37	10.83	11.73
Single Phase ($ per month)	6.41	6.83	7.73

The following correction is required as the presentation of the rates are reversed within the Application:

	Current Rate	Proposed January 1, 2018 Interim Rate	Proposed January 1, 2019 Interim Rate
Rate 2.1 and 2.2 General Service			
Unmetered ($ per month)	6.41	6.83	7.73
Single Phase ($ per month)	10.37	10.83	11.73

Based on our procedures, we find that the 2018 and 2019 revenue requirement for rate setting proposed by the Company is calculated based upon the revised Schedule of Rates, Tolls and Charges effective January 1, 2018 on an interim basis and January 1, 2019, on a final rates basis, and the factors proposed in this Application (Revision 3 dated October 27, 2017). Also noted was a formatting exception as discussed above.

Future Changes in Accounting Policies

In Note 4 to the December 31, 2016 non-consolidated financial statements of Newfoundland and Labrador Hydro, the Company has disclosed future changes in accounting policies. The Company has disclosed that for the implementation of IFRS 15 – Revenue from Contracts with Customers, and IFRS 16 – Leases, that the application of these standards "may have a material impact on the amounts reported and disclosures made in Hydro's annual non-consolidated financial statements". The Company goes on to disclose that it is not practical to provide a reasonable estimate of the effect of these standards until a detailed review is completed. IFRS 15 is effective for annual periods beginning on or after January 1, 2018 and IFRS 16 is applicable for annual periods beginning on or after January 1, 2019.

We note that the implementation of these accounting standards could result in certain revenues and expenses recorded under a basis in the actual 2018 and 2019 financial statement which differ from those used to forecast 2018 and 2019 test years. The Company has noted that any accounting policy changes have been excluded from Hydro's test years. The Company has also noted that had the Company included the updated IFRS standards, there would have been no impact to Hydro's average rate base or revenue requirement.

Restrictions, Qualifications and Independence

Purpose

This report was prepared for the Board of Commissioners of Public Utilities in Newfoundland and Labrador. The purpose of our engagement was to review the 2017 General Rate Application filed by Newfoundland and Labrador Hydro on July 28, 2017 (including revisions filed on September 18, 2017, October 16, 2017, and October 27, 2017).

Restrictions and Limitations

This report is not intended for general circulation or publication nor is it to be reproduced or used for any purpose other than that outlined herein without our prior written permission in each specific instance. Notwithstanding the above, we understand that our report will be disclosed as a part of a public hearing process. We have given the Board our consent to use our report for this purpose.

Our scope of work is as set out in our engagement letter, which is referenced throughout this report. The procedures undertaken in the course of our review do not constitute an audit of Hydro's financial information and consequently, we do not express an opinion on the financial information provided by Hydro.

In preparing this report, we have relied upon information provided by Hydro. We acknowledge that the Board is bound by the Freedom of Information and Protection of Privacy Act and agree that the Board may use its sole discretion in any determination of whether and, if so, in what form, this Report may be required to be released under this Act.

We reserve the right, but will be under no obligation, to review and/or revise the contents of this report in light of information which becomes known to us after the date of this report.