NP 2016/2017 General Rate Application
Consent - #2
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Board of Commissioners of Public Utilities Financial Consultants Report Newfoundland Power Inc. 2016-2017 General Rate Application Hearing

January 28, 2016

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Introduction and Scope

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 Power Inc. ("the Company") ("Newfoundland Power"), which was submitted to the Board on October 16, 2015 in support of its 2016/2017 General Rate Application ("GRA" or "Application").

Scope and Limitations

The detailed scope of our financial review of the Company's pre-filed evidence is as follows:

Review of the following as detailed in Newfoundland Power Inc.'s 2016/2017 General Rate Application:

- Review of the changes to the evaluation of customer energy conservation programs.
- Review the calculation of depreciation based upon the updated Depreciation Study.
- Review the proposal to recover the forecast 2016 revenue shortfall over a three year period.
- Review the proposal to recover Board and Consumer Advocate costs associated with the application, over a three year period.

Review of 2016 and 2017 financial forecast including the following:

- Examine the Company's chart of accounts to determine whether it complies with the System of Accounts prescribed by the Board.
- Examine the methodology and assumptions used by the Company for estimating revenues, expenses and net earnings and determine whether they are reasonable and appropriate.
- Conduct a review of actual and forecast capital expenditures, revenues, expenses, net earnings, and return on rate base and return on common equity for the years ending December 31, 2013 and December 31, 2014 (actual), and for the years ending December 31, 2015, December 31, 2016 and December 31, 2017 (forecast).
- Verify the Company's calculation of the proposed rate of return on rate base, cost of capital and return on common equity for the years ending December 31, 2016 and December 31, 2017.
- Verify the calculation of proposed rates necessary to meet the estimated revenue requirements in the 2016-2017 test years.
- Review the Company's calculation of estimated average rate base for the years ending December 31, 2016 and December 31, 2017.

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

- enquiry and analytical procedures with respect to financial information in the Company's records;
- 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 years ended December 31, 2013 and December 31, 2014 have been audited by Ernst & Young LLP, Chartered Accountants. The auditors have expressed their unqualified opinion on the fairness of the statements in their reports for each year. 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.

Supply Cost Recovery Mechanisms

In P.U. 32 (2007) the Board approved the Company's proposal to replace the Purchased Power Unit Cost Variance Reserve ("PPUCVR") with the Demand Management Incentive Account ("DMI Account"). In this Order the Board also approved a change to the rate stabilization clause to provide for the recovery of the energy supply cost variance clause ("ESCVC") through the rate stabilization account ("RSA") for the period 2008 to 2010. Board Order P. U. 43 (2009) approved the DMI Account and the ESCVC for continued use. Both of these mechanisms provide the Company with the ability to recover its costs associated with the variability in purchased power costs inherent in the demand and energy wholesale rates. Board Order P.U. 43 (2009) also instructed Newfoundland Power to file as part of its next GRA a report on the performance of the DMI Account. The Company filed a report "Supply Cost Mechanisms" in its 2013/2014 GRA concluding that current mechanisms which provide for the Company's recovery of prudently incurred supply costs remain consistent with sound public utility practice and current Canadian regulatory practice and provide reasonable incentives for the Company to foster customer conservation of demand and energy. The company also concluded incentives have yielded tangible results that benefit customers.

In addition, the Company proposed a regulatory accounting change as part of the 2013/2014 GRA. The Company proposed crediting or recovering year-end balances in the Weather Normalization Reserve annually through the RSA, similar to the operation of the other supply cost mechanisms. The Company also proposed the amortization of the 2011 year-end balance in the Weather Normalization Reserve.

In P.U. 13 (2013), the Board approved these proposed changes.

As part of the 2016/2017 GRA, the report "Supply Cost Mechanisms" was included in the Application in Volume 2, Section B: Reports. The conclusion to the report states "*This review indicated that current mechanisms which provide for the Company's recovery of prudently incurred supply costs remain consistent with sound public utility practice and current Canadian regulatory practice. The review also indicated existing mechanisms provide reasonable incentives for the Company to foster customer conservation of demand and energy. These incentives have yielded tangible results that benefit customers. As a result, the Company is not proposing any changes to these regulatory mechanisms.*" The Company also noted in its review the current supply cost mechanisms meet local regulatory policy objectives.

The supply cost mechanisms are discussed below.

Demand Management Incentive Account

In P.U. 44 (2004) the Board approved the establishment of a reserve mechanism as proposed by Newfoundland Power in relation to Newfoundland and Labrador Hydro's ("Hydro") proposed demand and energy rate structure. This reserve mechanism was the PPUCVR and it was used to limit variability demand supply to 1% of test year demand supply cost before a cost deferral is initiated. Its definition and inclusion in the Company's system of accounts was approved in P.U. 35 (2005). In P.U. 32 (2007) the Board approved the establishment of the DMI Account to replace the PPUCVR, including approval of a definition of the DMI Account to be included in the Company's System of Accounts. The key difference between the reserves is that the PPUCVR was based on a combination of demand and energy costs, and the variance factor was based on forecast amounts which were updated each year, while the DMI Account is solely based on demand costs and the variance factor is based on the test year. The DMI Account requires a demand cost variance in excess of +/-1% of test year demand costs before a cost deferral is initiated. This Account, as it is solely related to demand management, provides transparency in the purchased power costs variability relating to peak demand.

According to P.U. 32 (2007) the Company is required to file an application with the Board no later than the 1st day of March each year for the disposition of any balance in the DMI Account. The Board has the discretion to determine the disposition of the reserve balance.

The following is a summary of the DMI Account from 2011 to 2014:

Table 1: Demand Management Incentive Account 2011-2014

	DMI Account				
	2011	2012	2013	2014	Totals
(000's of dollars)					
Demand/Supply Cost Variance	2,346	1,331	(965)	1,222	3,934
Deadband/DMI	(545)	(545)	582	(594)	(1,102)
Customer Savings (Costs)	1,801	786	(383)	628	2,832
Tax Effects	(549)	(228)	111	(182)	(848)
DMI Account Balance	1,252	558	(272)	446	1,984

The Board approved the disposition of the 2011 to 2014 DMI Account Balance to the RSA. As noted in the table above, the total demand cost variance from 2011 to 2014 was $3.9 million which resulted in customer savings of approximately $2.8 million.

For 2011 through 2012, the +/-1% range for evaluating the Demand Supply Cost Variance to determine the DMI Account transfer was $545,000 based on a test year billing demand of 1,135,850 kW. For 2013 and 2014, the 1% range is $582,000 and $594,000 based on a test year billing demand of 1,212,890 kW and 1,237,480. The 1% range for 2015 is forecast to be $594,000 and $642,000 for 2016 and 2017 respectively based on a test year billing demand of 1,237,480 kW.

Energy Supply Cost Variance Clause ("ESCVC")

The ESCVC allows for annual variations from the test year in the 'energy' portion of power supply costs to be deferred for recovery through the RSA in the succeeding year. This mechanism was implemented in order to address the supply cost dynamics that exist on the system with the purpose of capturing the change in energy supply costs related to the difference between the marginal energy supply costs and the average energy supply cost, known as the 'Energy Supply Cost Variance' ("ESCV"). In addition, the recovery of variances in energy supply costs through the RSA allows the Company to recover its incurred energy supply costs without the requirement of filing a general rate application.

The following table presents Newfoundland Power's marginal supply costs from Hydro and the average supply costs recovered in customer rates for 2013 to 2017E:

Table 2: Energy Supply Cost Variance (₵/kWh) 2013-2017

	Energy Supply Cost (¢/kWh)					
	2013	2013	2014	2015F	2016E	2017E
	(Note 1)	(Note 2)	(Note 3)	(Note 3)	(Note 4)	(Note 4)
Average Test Year Energy Supply Cost	5.622	5.868	5.906	5.906	6.379	6.379
Wholesale Rate 2nd Block Price (Note 5)	8.805	8.805	8.805	8.805	9.509	9.509
Energy Supply Cost Variance	**3.183**	**2.937**	**2.899**	**2.899**	**3.130**	**3.130**

Note 1: Based on January to June 2010 Test Year forecast using purchased power rates approved P.U. 8 (2007).

Note 2: Based on July to December 2013 Test Year forecast using purchased power rates approved P.U. 8 (2007).

Note 3: Based on 2014 Test Year forecast using purchased power rates approved P.U. 8 (2007).

Note 4: Based on 2014 Test Year forecast using purchased power rates approved P.U. 17 (2015).

Note 5: Hydro's wholesale 2nd block price of 8.805 ¢/kWh was approved in P.U. 8 (2007). Hydro's wholesale rate of 9.509 ¢/kWh was approved in P.U. 17 (2015).

The above table shows that the cost to Newfoundland Power of additional energy supply required to serve new customers is greater than the average energy supply cost reflected in customer rates. This trend has been present since the ESCV mechanism was initially approved in 2007. Newfoundland Power has indicated that the annual shortfall of approximately 3.0¢/kWh is expected to continue, at a minimum, until interconnection to the North American grid.

The table below provides the detailed calculations of the ESCV for 2013 through 2017E:

Table 3: Total Energy Supply Cost Variance 2013-2017

	Energy Supply Cost Variances					
	2013 Jan - June	2013 July - Dec	2014	2015E	2016E	2017E
Actual/Forecast Purchases (kWh)	3,180,000,000	2,498,100,000	5,816,600,000	5,884,100,000	5,920,200,000	5,937,600,000
Test Year Annual Purchases (kWh)	2,928,600,000	2,503,800,000	5,753,200,000	5,753,200,000	5,753,200,000	5,753,200,000
Difference	251,400,000	(5,700,000)	63,400,000	130,900,000	167,000,000	184,400,000
Energy Supply Cost Variance (cents/kWh)	3.183	2.937	2.899	2.899	3.130	3.130
Energy Supply Cost Variance (in '000s dollars)	$8,002	($167)	$1,838	$3,795	$5,227	$5,772

The RSA is either increased or reduced by the ESCV.

In P.U. 32 (2007) the implementation of the ESCVC of the RSA was approved for the period from 2008 to 2010 and the Board stated that it would review the operation and impact of the Energy Supply Cost Variance in the RSA in the next GRA. In P.U. 43 (2009) the ESCVC was approved for continued use. In years 2013 through 2017E, the result from the Energy Supply Cost Variance provided a transfer to the RSA for amounts to be recovered from customers ranged from a high of $7,834,653 in 2013 to a low of $1,837,966 in 2014 as a result of the Company's energy purchases from Hydro being higher than the test year forecast.

In the absence of the 2016/2017 GRA, the forecast for 2016 and 2017 would be a transfer of approximately $5.2 million and $5.8 million to the RSA which would be recovered over the period from July 1, 2017 to June 30, 2018 and July 1, 2018 to June 30, 2019, respectively. However, in the 2016/2017 Application, the Company proposes that the forecast wholesale supply costs will be rebalanced with customer rates except for the Energy Supply Cost Variance for January through June 2016 which the Company is proposing to be recovered through the RSA. Consequently, there is an Energy Supply Cost Variance forecast for 2016 of $4.5 million relating to January through June 2016 and no Energy Supply Cost Variance forecast for 2017. The company has noted the effect of balancing the 2016 and 2017 test year supply costs with revenue from rates accounts for 0.9% of the 3.1% increase proposed in the customer rates effective July 1, 2016.

Weather Normalization Reserve

Newfoundland Power's Weather Normalization Reserve normalizes the effects of weather and hydrology on the Company's sales and purchased power expense. The purpose of the Reserve was to ensure that the Company did not experience an earnings windfall or shortfall as a result of weather conditions. The Reserve includes two components, the Hydro Production Equalization Reserve which was approved in Order No. P.U. 32 (1968), and the Degree Day Normalization Reserve which was approved in Order No P.U. 1 (1974). In P.U. 13 (2013), the Board approved the amortization of the 2011 balance in the weather normalization reserve. The Board also approved the disposition of annual balances in the weather normalization reserve to the RSA.

The following is a summary of the Weather Normalization Reserve Account from 2013 to 2016E:

Table 4: Weather Normalization 2013-2016

	Weather Normalization Reserve			
	2013	2014	2015E	2016E
(000's of dollars)				
Opening Balance of Weather Normalization Reserve	(4,803)	(5,058)	(1,640)	1,036
Annual Operation of the Weather Normalization Reserve	(1,712)	33	1,036	-
Annual Transfer to the RSA (Note 1)	(216)	1,712	(33)	(1,036)
Amortization of 2011 Balance (Note 2)	1,673	1,673	1,673	-
Closing Balance Weather Normalization Reserve (Note 3)	(5,058)	(1,640)	1,036	-

Note 1: In P.U. 13 (2013) the Board Approved the disposition of the annual balance in the Weather Normalization Reserve through the RSA.

Note 2: In P.U. 13 (2013) the Board approved the amortization of the 2011 Weather Normalization Reserve balance of approximately $5.0M over three years commencing 2013.

Note 3: The 2013 reserve was approved in P.U. 11 (2014). The 2014 reserve was approved in P.U. 11 (2015).

We have reviewed the calculations supporting the DMI account, the ESCVC and the Weather Normalization Reserve and conclude that these reserve mechanisms appear to be working in accordance with relevant Board Orders.

Regulatory Deferral Accounts

Newfoundland Power has a number of regulatory amortizations approved by the Board which impact the revenue requirement. The amortization of regulatory deferrals is summarized in the table below:

Table 5: Amortization of Regulatory Deferrals 2013-2017

	Amortization of Regulatory Deferrals				
($000s)	**2013**	**2014**	**2015F**	**2016F**	**2017F**
2011 & 2012 Cost Recovery Deferrals	$ 1,575	$ 1,575	$ 1,575	-	-
2012 Cost of Capital Recovery Deferral	829	829	829	-	-
2013/2014 Hearing Costs Deferral	321	322	322	-	-
Weather Normalization Reserve	(2,335)	(2,335)	(2,335)	-	-
2013 Revenue Shortfall (Note 1)	(3,172)	1,586	1,586	-	-
2016/2017 Hearing Costs Deferral	-	-	-	400	400
2016 Revenue Shortfall (Note 2)	-	-	-	(3,276)	1,638
Revenue Requirement Impact	**$ (2,782)**	**$ 1,977**	**$ 1,977**	**$ (2,876)**	**$ 2,038**

Source: Table 4-17 of Newfoundland Power - 2016/2017 General Rate Application.
Note 1: The 2013 balance includes a deferral of $3,965,000 less amortization of $793,000 (3,965,000*6/30).
Note 2: The 2016 balance includes a deferral of $4,095,000 less amortization of $819,000 (4,095,000*6/30).

Previously Approved Regulatory Deferrals

The 2015 forecast amortization of regulatory deferrals consists of accounts that were previously approved by the Board as follows:

- **2011 & 2012 Cost Recovery Deferrals:** The Cost Recovery Deferral balance relates to the conclusion of several regulatory amortizations which expired in 2010. In P.U. 30 (2010), the Board approved the deferred recovery, until a further Order of the Board, of $2,363,000 in 2011 due to the conclusion in 2010 of the amortizations. In P.U. 22 (2011), the Board approved the deferred recovery, until a further Order of the Board, of an additional $2,363,000 in 2012 due to the conclusion in 2010 of the amortizations. In P.U. 13 (2013) the Board approved the amortization over three years of the amount of $4,726,000 related to previously approved deferrals. As a result amortization of $1,575,333 annually commenced in 2013.

- **2012 Cost of Capital Recovery Deferral:** The cost of capital recovery deferral account relates to the deferred recovery of $2,487,000 reflecting the difference between the 8.38% return on equity currently in customer electricity rates and the 8.80% return on equity approved in P.U. 17 (2012). In P.U. 13 (2013) the Board approved a three year amortization of the cost of capital recovery deferral. Amortization of this account commenced in 2013.

- **2013/2014 Hearing Costs Deferral:** In P.U. 13 (2013) the Board approved the deferral of cost related to 2013/2014 GRA as well as amortization of this deferral over a three year period commencing in 2013. Actual costs incurred and deferred were approximately $965,000 which results in annual amortization of $322,000 in 2015.

- **Weather Normalization Reserve:** The Weather Normalization Reserve reduces earnings volatility by adjusting purchased power expense and electricity sales revenue to eliminate variances in purchases and sales caused by the difference between normal and actual weather conditions. In P.U. 13 (2013) the Board approved the amortization of the December 31, 2011 year-end balance of the weather normalization account of $7,006,000 over a three year period beginning in 2013, representing an amortization of approximately $2,335,000 each year.

- **2013 Revenue Shortfall:** In P.U. 13 (2013) the Board approved the deferral and amortization over three years of amounts related to Newfoundland Power's shortfall in the recovery of revenue requirements for 2013. As a result of this order and updated revenue forecast subsequently filed by Newfoundland Power in an Application Filed in Compliance with Order No. P.U. 13 (2013), an amount of $3,965,000 has been deferred. This was amortized over a 30 month period commencing July 1, 2013.

Proposed Regulatory Deferrals

Newfoundland Power has proposed, in the 2016/2017 General Rate Application, that the Board approve the following additional deferrals for 2016 and 2017:

(a) amortize the recovery over a three year period of an estimated $1,200,000 in Board and Consumer Advocate costs related to the Application; and

(b) amortize the recovery over a three year period of a forecast 2016 revenue shortfall of an estimated $4,095,000.

We conducted an examination of each of the regulatory deferral accounts and amortizations proposed in this Application.

- **2016/2017 General Rate Application Costs:** With respect to the costs relating to the 2016/2017 GRA, the Company is proposing that these costs be recovered in customer rates evenly over a 3 year period from 2016 to 2018. This is consistent with previous Board Orders including P.U. 7 (1996-1997), P.U. 36 (1998-1999), P.U. 19 (2003), P.U. 32 (2007), P.U. 43 (2009), and P.U. 13 (2013). The Company estimates costs associated with the 2016/2017 General Rate Application proposal will have a forecast revenue requirement impact of $400,000 in the years 2016, 2017, and 2018.

- **2016 Revenue Shortfall:** Based upon a July 1, 2016 implementation, customer rates designed to recover the 2017 revenue requirement would result in a $4,095,000 shortfall in recovering the 2016 revenue requirement. The Company is proposing this shortfall be recovered over a 30 month period commencing July 1, 2016. This is consistent with the process to recover the 2013 revenue shortfall approved in P.U. 13 (2013).

Based on our review and analysis, nothing has come to our attention to indicate the regulatory deferrals and amortizations included in the Application are unreasonable or not in accordance with Board Orders.

Conservation and Demand Management ("CDM") Cost Deferral

In the 2013/2014 GRA, the Company proposed the following definition for the Conservation and Demand Management Cost Deferral Account:

> *"This account shall be charged with the costs incurred in implementing the CDM Program Portfolio. These costs include the CDM Program Portfolio costs incurred by Newfoundland Power for: detailed program development, promotional materials, advertising, pre and post customer installation checks, incentives, processing applications and incentives, training of employees and trade allies, and program evaluation costs. This account shall also be charged the costs of major CDM studies such as comprehensive customer end use surveys and CDM potential studies that cost greater than $100,000. Transfers to, and from, the proposed account will be tax-effected. This account will maintain a linkage of all costs recorded in the account to the year the cost was incurred. Recovery of annual amortizations of costs in this account shall be through the Company's Rate Stabilization Plan or as otherwise ordered by the Board."*

In P.U. 13 (2013) the Board approved the definition for the Conservation and Demand Management Cost Deferral Account and the amortization of annual customer energy conservation program costs over seven years with recovery through the RSA. P.U. 13 (2013) further ordered that the Company file a report in relation to its conservation program and the review process on or before April 1, 2014. The Company has filed its *2013 Conservation and Demand Management Report* on March 31, 2014 in compliance with P.U. 13 (2013).

According to information filed with the Application, the Company and Hydro recently reassessed the portfolio of customer energy conservation programs. This resulted in the creation of the *Five-Year Energy Conservation Plan: 2016-2020*. The principal changes in the plan relate to (i) discontinuation of certain residential incentives, namely the Appliance and Electronics component of the Small Technologies program (in 2017) and the conclusion of the Instant Rebates program based on conversion of the lighting market to LED (in 2018); (ii) introduction of a new residential benchmarking program to promote customer behavior change and more efficient use of electricity; and (iii) expansion of commercial customer programs.

In the 2016/2017 GRA, the Company is proposing a change in the methodology used to evaluate the cost effectiveness of customer energy conservation programs. Prior to the 2016/2017 GRA, conservation programs were evaluated in accordance with P.U. 7 (1996-1997) where the Board required customer conservation programs to be evaluated with respect to a Total Resource Cost ("TRC") test and Ratepayer Impact Measure ("RIM") test. The Company has interpreted P.U. 7 (1996-1997) to require a TRC of 1.0 and a RIM of 0.8 as described in *Newfoundland Power Inc. – 2009 Conservation Cost Deferral Application, Section 2: Proposed Customer Program Portfolio* filed with the Board October 29, 2008.

The Company's *Five-Year Energy Conservation Plan: 2016-2020* evaluates the cost effectiveness of customer energy programs based upon the TRC test, as a primary means of economic screening, and the Program Administrator Cost ("PAC") test as a secondary means of economic screening. The Company requires a score of 1.0 to pass the PAC test. The Company has noted it expects to implement the changes in customer energy program evaluation in the 2016 and 2017 test period.

In response to PUB-NP-021 and PUB-NP-022 the Company has described the TRC, RIM and PAC tests and the reasons for using the PAC test in replacement of the RIM test:

> **TRC Test:** *"The TRC test evaluates customer energy conservation programs from the perspective of the utility and the customer, including program participants and non-participants. It considers all costs incurred by the utility, plus all costs incurred by customers, compared to the benefits of avoided utility supply costs."*

> **RIM Test:** *"The RIM test provides an indication of the impact of energy efficiency programs on utility rates with a focus on those customers that do not participate in the energy efficiency programs. The costs considered in the RIM test include all the expenditures by the utility, as well as the lost revenues to the utility as a result of lower sales. The benefits include the avoided utility supply costs."*

PAC Test: *"The PAC test, or Utility Cost test, assesses program cost effectiveness from the program administrator, or utility, perspective. It compares the costs incurred by the utility to the benefits of avoided utility supply costs. This test is consistent with the way utilities typically evaluate the cost effectiveness of supply-side resources, and allows comparison of efficiency and supply alternatives.*

In PUB-NP-021 the Company disclosed that the RIM test is declining in usage, noting that only one Canadian utility is using RIM as a primary test. Citing external sources, the Company noted that only 2% of United States jurisdictions use RIM as a primary screening test. Citing sources from the U.S. Environmental Protection Agency, the Company notes the RIM test results in *"limited energy efficiency investment, as it is the most restrictive of the five cost-effectiveness tests."* Citing the U.S. National Efficiency Screening Project, the Company notes a report conducted states "*the rate impacts from efficiency resources are essentially a matter of customer equity, but the RIM test is not a good indicator of customer equity: It is overly narrow, ignores many of the benefits of energy efficiency programs, is inconsistent with the assessment of supply- side resources, does not necessarily reflect the actual impact on rates, and deprives customers of the opportunity to lower their bills through energy efficiency measures."*

In PUB-NP-021 the Company further elaborated on what it considers to be a key reason for decline in usage of the RIM test noting that "*when a utility's customer rates are higher than the marginal cost of supply which would be avoided, the RIM test calculation will typically result in a cost-benefit ratio of less than one. In other words, each kilowatt hour conserved results in lost revenue to the utility which exceeds the value of its avoided supply. This situation exists in many jurisdictions, causing potential programs to fail the RIM economic screening."*

The Company has noted in response to PUB-NP-021 (footnote 4) that "*all of Newfoundland Power's residential customer energy conservation programs in 2016 would not pass the RIM test. This is primarily due to forecast reductions in the marginal costs arising from the Muskrat Falls project. Currently, the marginal energy cost primarily reflects fuel burned at Holyrood. By contrast, the Muskrat Falls project, which is expected to have high fixed costs, is expected to have low marginal energy costs."*

In response to PUB-NP-022, the Company, in conjunction with citing the Ontario Independent Electricity System Operator, describes the TRC test as *"providing a holistic view of efficiency as a resource."* The Company's negative points of TRC, citing the same source, note the TRC test has been *"criticized for not considering customers non-energy benefits."*

In response to PUB-NP-022 citing the Ontario Independent Electricity System Operator, the Company notes *"the PAC test primarily ensures that the utility is offering programs that result in least cost electricity service."* The Company did not provide negative commentary points on the PAC test. In examination of the cited source reference there was no commentary from the Ontario Independent Electricity System Operator that directly stated *"the PAC test primarily ensures that the utility is offering programs that result in least cost electricity service."* The cited source described the strength of PAC is *"the PAC test does not include an estimate of lost revenue, and is therefore not complicated by uncertainty in rates in the short or long term."* The cited source described the weakness of PAC is *"it does not capture the participant costs or potential rate impacts of CDM."*

In response to PUB-NP-022 the Company noted that application of the RIM test would result in elimination of the Company's residential customer energy conservation programs in 2016 described in the *Five-Year Energy Conservation Plan: 2016-2020.* The Company notes the programs passed economic screening based on the TRC and PAC tests.

The following tables provide the forecast energy savings (Page 2-16 of the GRA) and customer energy costs (Page 2-17 of the GRA) for the Company's customer energy conservation programs for 2009 to 2017F:

Table 6: Energy Conservation Programs – Energy Savings 2009-2017

Energy Conservation Programs
Energy Savings
2009 to 2017F
(GWh)

	2009-2014	2015F	2016F	2017F	Total
Residential	129.3	57.5	71.7	93.2	**351.7**
Commercial	15.4	9.8	16.6	24.8	**66.6**
Total	**144.7**	**67.3**	**88.3**	**118.0**	**418.3**

Table 7: Energy Conservation Programs – Costs 2009-2017

Customer Energy Conservation
Costs
2009 to 2017F
($000s)

	2009-2014	2015F	2016F	2017F	Total
General	4,388	767	778	801	**6,734**
Program	16,523	5,876	6,544	7,231	**36,174**
Total	**20,911**	**6,643**	**7,322**	**8,032**	**42,908**

The Company has noted that for total 2016 Program costs of $6,544,000, residential program costs of $5,203,000 would be eliminated under the RIM test.

The following table provides a breakdown of operating costs before tax that include the customer energy conservation costs for 2009 to 2017F as provided by the Company, and agreed to total customer energy conservation costs presented in the previous table:

Table 8: Customer Energy Conservation Costs 2009-2017

	Customer Energy Conservation Costs Operating Cost by Breakdown			
(000's)	**2009 - 2014**	**2015F**	**2016F**	**2017F**
Regular & Standby	$ 6,134	$ 1,490	$ 1,793	$ 1,836
Temporary Labour	96	55	-	-
Overtime	137	68	97	98
Total Labour	**$ 6,367**	**$ 1,613**	**$ 1,890**	**$ 1,934**
Operating Materials	$ 121	$ -	$ -	$ -
Travel	219	78	85	81
Miscellaneous	1,123	300	447	431
Conservation	7,497	2,819	2,792	2,895
Education, Training, Employee Fees	182	10	54	56
Other Company Fees	707	736	653	1,248
Postage & Freight	9	-	-	-
Advertising	4,686	1,087	1,401	1,387
Total Non-Labour	**$ 14,544**	**$ 5,030**	**$ 5,432**	**$ 6,098**
Total	**$ 20,911**	**$ 6,643**	**$ 7,322**	**$ 8,032**

The following table provides the impact of the proposed annual customer energy conservation program cost deferrals and amortizations for 2016 to 2020:

Table 9: Conservation Program Costs – Forecast Deferrals and Amortizations 2016-2020

	Conservation Program Costs Forecast Deferrals and Amortization				
(000's)	**2016**	**2017**	**2018**	**2019**	**2020**
Deferral	(6,544)	(7,231)	(6,038)	(5,143)	(3,981)
Amortization	1,894	2,828	3,861	4,724	5,459

Amortization presented in the table is calculated over seven years as ordered in P.U. 13 (2013). Amortization is forecast to increase through this period from $1,894,000 in 2016 to $5,459,000 in 2020. As further ordered in P.U. 13 (2013), the Company is recovering these costs through annual RSA factor adjustments which will increase customer rates as opposed to being included in revenue requirements which would be reflected in the Company's base rates.

Based upon our review of the Company's Conservation and Demand Management Cost Deferral Account, we note amortizations of conservation deferrals and transfers to the RSA presented in the GRA are accurate based on an amortization period of seven years approved by the Board. As noted above, the Company is proposing in the 2016/2017 GRA to change economic screening tests from a TRC test and RIM test (currently approved by the Board), to a TRC test, as primary means of economic screening, and a PAC test as a secondary means of economic screening. Based on our review we note the results of the TRC test and the PAC test have been used by the Company to determine inclusions to the Conservation and Demand Management Cost Deferral Account.

Automatic Adjustment Formula

In P.U. 16 (1998-99) and P.U. 36 (1998-99) the Board ordered the use of the automatic adjustment formula to set an appropriate rate of return on rate base for the Company on an annual basis ("the Formula").

When the use of the Formula was first approved in P.U.16 (1998-99), the Board noted the following (Source: P.U. 16 (1998-99), page 103): *"the Board is of the view that there is merit to a formula, in light of the cost burden of a full cost of capital hearing and the potential savings to consumers which could be realized. The Board also believes that the adoption of an automatic adjustment mechanism will create greater predictability, which will thereby reduce the risk of regulatory uncertainty. In the opinion of the Board, a mechanism to facilitate an annual review at modest costs will be of benefit to the ratepayer and to the Company."*

P.U. 16 (1998-99) also addressed the fact that circumstances could change "so as to render the use of the automatic adjustment formula to be inappropriate." The Board went on to provide examples of such circumstances on page 104 of P.U. 16 (1998-99):

a. *"deterioration in the financial strength of the Company, resulting in an inappropriately low interest coverage;*
b. *changes in financial market conditions which would suggest that the Formula is not accurately reflecting the appropriate return on equity; and*
c. *fundamental changes in the business risk of the Company."*

In P.U. 19 (2003) the Board ordered the continuation of the use of the Formula to set the rate of return on average rate base and therefore customer rates for 2005 to 2007. This decision also included the move to the Average Rate Base Method ("ARBM") and the use of the three most recent series of long-term Government of Canada bonds in determining the risk-free rate. In P.U. 32 (2007) the Board approved changes to the Formula to reflect the full adoption of the ARBM for calculating average rate base and ordered the continued use of the Formula for a period of not more than three years following the 2008 test year. In P.U. 43 (2009) the Board ordered that, unless the Board ordered otherwise, the rate of return on rate base for 2011 and 2012 was to be set using the Automatic Adjustment Formula, and that the Company was to apply in each of 2010 and 2011 for the application of the Automatic Adjustment Formula to the rate of return on rate base and, if required, for a revised Schedule of rates, tolls and charges effective January 1, 2011 and January 2012, respectively.

In its "Reasons for Decision: Order No. P.U. 43 (2009)", the Board stated "The Board believes that the Automatic Adjustment Formula is fundamental to the multi-year regime in place in this province and contributes to regulatory predictability and certainty."

In P.U. 12 (2010), the Board ordered that the risk-free rate used to calculate the forecast cost of equity for use in the Automatic Adjustment Formula was to be determined by adding the average of the 3-month and 12-month forecast of 10-year Government of Canada bonds in the preceding November and the average observed spread between 10-year and 30-year Government of Canada bonds for all trading days in the preceding October. In P.U. 32 (2010), the Board approved a rate of return on rate base for the Company for 2011 of 7.96% in a range of 7.78% to 8.14% resulting from the use of the Formula. In P.U. 36 (2010), the Board approved a revised schedule of rates, toll and charges which reflected a 0.63% average decrease in customer rates resulting from the Formula Order.

In P.U. 25 (2011), the Board ordered the suspension of the operation of the Formula to establish a rate of return on rate base for Newfoundland Power for 2012. The Board also ordered the continued use, on an interim basis, of the current return on rate base of 7.96% in a range of 7.78% to 8.14% until a further Order of the Board. The continued use of the current Customer Rates approved by P.U. 12 (2011) was approved on an interim basis with effect from January 1, 2012. The process and timing to be followed to determine a just and reasonable rate of return on rate base for Newfoundland Power for 2012 and with respect to the filing of Newfoundland Power's next General Rate Application was ordered to be established by a further direction of the Board.

In P.U. 17 (2012), the Board approved a proposed rate of return on average rate base for 2012 of 8.14% in a range of 7.96% to 8.32%, and ordered that the Company's current customer rates be considered the final rates from January 1, 2012.

During the 2013/2014 GRA, the Board came to the similar conclusion. In assessing the continued use of the Formula for the Company, the Board concluded that (Source: P.U. 13 (2013), page 36):
"…the evidence is clear that the formula as it is currently structured may not result in a fair return for Newfoundland Power in the current circumstances. Long-term Canada bond yields are abnormally low which is particularly problematic in the operation of the automatic adjustment formula. In the absence of a clear relationship between the long-term Canada bond yield and the cost of equity it is difficult to see that the established return can be appropriately adjusted for 2015 without the exercise of further judgement…".

In P.U. 13 (2013) the Board stated that *"…the Board is not discontinuing the use of the automatic adjustment formula and, in the absence of a further Order of the Board, it will be used to establish a fair return for Newfoundland Power following its next general rate application…".*

In its Application, the Company is proposing "that the Board continue to refrain from the use of an Automatic Adjustment Formula for setting the allowed rate of return on rate base for Newfoundland Power, in years subsequent to 2017, for the reasons set out in the evidence filed in support of the Application." The Company has noted that "since Order No. P.U. 13 (2013), there has not been an appreciable change in long Canada bond yields. Further, bank forecast do not appear to indicate that a return to more normal long Canada bond yields is imminent". As such, the Company concludes that "the current circumstances do not justify the Board ordering the use of the Formula to establish a fair return for Newfoundland Power beyond 2017".

The appropriateness of the Company's proposal to discontinue the use of the Formula will be reviewed by the cost of capital experts participating in this hearing.

Return on Rate Base and Equity, Capital Structure and Interest Coverage

Calculation of Average Rate Base

The Company's calculations of its forecast average rate base for the years ending December 31, 2015, 2016 and 2017 are included on Exhibit 3 Page 5 of 9 and Exhibit 6 of the pre-filed evidence. Our procedures with respect to verifying the calculation of average rate base were directed towards the assessment of the reasonableness of the data incorporated in the calculations and the methodology used by the Company. Specifically, the procedures which we performed included the following:

- agreed all carry-forward data to supporting documentation including prior years 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 pre-filed evidence and other areas of the forecast;

- checked the clerical accuracy of the continuity of the rate base as forecast for 2015, 2016 and 2017;

- recalculated the forecast rate base for 2015, 2016 and 2017; and

- agreed the methodology used in the calculation of the average rate base to the Public Utilities Act and relevant Board Orders to ensure it is in accordance with established policy and procedure.

The following table summarizes the 2016 and 2017 average rate base as existing and as proposed:

Table 10: Average Rate Base 2016-2017

	2016				2017			
(000's)	Existing	Impact		Proposed	Existing	Impact		Proposed
Net Plant Investment	$ 987,712	$ (450)	(1)	$ 987,262	$ 1,043,286	$ (1,367)	(1)	$ 1,041,919
Add:								
Defined Benefit Pension Costs	95,025	-		95,025	89,552	-		89,552
Cost Recovery Deferrals								
Credit Facility Costs	48	(20)	(2)	28	32	(32)	(2)	-
Seasonal/TOD Rates	55	(20)	(3)	35	42	(42)	(3)	-
Hearing Costs		400	(4)	400	-	600	(4)	600
Revenue Shortfall		1,163	(5)	1,163	-	1,745	(5)	1,745
Conservation	10,014	-		10,014	13,227	-		13,227
Customer Finance Programs	1,136	-		1,136	1,136	-		1,136
Weather Normalization Reserve (a)	518			518	-	-		-
	106,796	1,523		108,319	103,989	2,271		106,260
Deduct:								
Other Post Employee Benefits	42,656	-		42,656	48,947	-		48,947
Customer Security Deposits	700	-		700	700	-		700
Accrued Pension Obligation	5,149	-		5,149	5,513	-		5,513
Future Income Taxes	1,999	(119)	(6)	1,880	3,400	(361)	(6)	3,039
Excess earnings	48	(24)	(7)	24	48	(48)	(7)	-
	50,552	(143)		50,409	58,608	(409)		58,199
Average Rate Base Before Allowances	1,043,956	1,216		1,045,172	1,088,667	1,313		1,089,980
Cash Working Capital Allowance	7,096	1,388	(8)	8,484	7,124	1,146	(8)	8,270
Materials and Supplies Allowance	6,514	161	(9)	6,675	6,650	164	(9)	6,814
Average Rate Base at Year End	$ 1,057,566	$ 2,765		$ 1,060,331	$ 1,102,441	$ 2,623		$ 1,105,064

(a) The Company has presented the balance as a negative figure in the deductions from rate base in Exhibits 3 and 6 of the Application. In effect, this is an addtion to rate base and has been presented as an addtion to average rate base for presentation purposes in this table.

(1) Net Plant Investment – The reduction of Net Plant Investment relates primarily to the proposed change in depreciation rates as a result of the 2014 Gannett Fleming Report. Under the proposed rates, the depreciation expense will increase by approximately $0.9 million in both 2016 and 2017. Impact on average rate base for 2016 and 2017 is $450,000 and $1,367,000 respectively.

(2) Credit Facility Costs – For test year revenue requirement purposes, unamortized credit facility costs are included in the calculation of the Company's weighted average cost of capital. Between test years, any additional costs incurred associated with amendments to the credit facility are reflected in rate base as they have not yet been reflected in the Company's weighted average cost of capital and/or customer rates. Impact on average rate base for 2016 and 2017 is $20,000 and $32,000 respectively.

(3) In P.U. 8 (2011) the Board approved the Optional Seasonal Rate Revenue and Cost Recovery Account. Pursuant to P.U. 8 (2011), "on December 31st of each year from 2011 until further order of the Board, this account shall be charged with: (i) the current year revenue impact of making the Domestic Seasonal – Optional Rate available to customers and (ii) the operating costs associated with implementing the Domestic Seasonal – Optional and the Time-of-Day Rate Study" The Company has eliminated the need for this deferral balance at December 31, 2015, reflecting the adjustment in the proposed rate designs for the 2016/2017 GRA.

(4) The increase in Cost Recovery Deferrals – Hearing Costs relates to the expectation that $1.2 million will be incurred by the Board and Consumer Advocate related to the Application. The Company is proposing these costs be recovered in customer rates evenly over a 3 year period from 2016 to 2018.

(5) Based upon a July 1, 2016 implementation, customer rates would result in $4,095,000 shortfall in recovering the 2016 revenue requirement. In this Application, the Company is proposing a revenue amortization to recover this shortfall over 30 months commencing July 1, 2016. The proposed amortization has an impact on average rate base for 2016 and 2017 of $1,163,000 and $1,745,000 respectively.

(6) The increase in Future Income Taxes is the result of the change in depreciation rates as discussed above. Impact on average rate base for 2016 and 2017 is $119,000 and $361,000 respectively.

(7) In P.U. 23 (2013) the Board approved the definition of the Excess Earnings Account. In 2013, Newfoundland Power's regulated earnings exceeded the upper limit of allowed regulated earnings by $49,000 after tax. The average rate base originally filed in the 2013 used an understated average rate base which produced an excess earnings liability of $68,000 ($49,000 after tax). This balance has been amortized in the 2016 test year, lowering the forecast revenue requirement. The proposed amortization has an impact on average rate base for 2016 and 2017 of $24,000 and $48,000 respectively.

(8) The increase in the cash working capital allowance is mainly a result of an increase in the HST adjustment due to the end of the residential rebate to consumers and a change in the cash working capital factor due to an increase in net lag days caused mainly by changes in timing and payment of corporate income taxes compared to the 2013 lead/lag study. As part of the Application, the Company has updated its calculations of the Rate Base Allowances to reflect changes that occurred since the last detailed review in the 2013/2014 GRA. The Company revised the Cash Working Capital factor from 1.7% for the 2013/2014 test years to 1.3% for the 2016/2017 test years. The Company has noted that a HST increase from 13% to 15% was used in the calculation of the cash working capital allowance for 2016 and 2017. We note that the HST rate in effect as of the date of our report is 13%. In response to our requests, the Company calculated the cash working capital allowance using a 13% rate which resulted in a cash working capital allowance of $8,320,000 (a decrease of $164,000) for 2016 and $8,135,000 (a decrease of $135,000) for 2017.

(9) The increase in the materials and supplies allowance is a result of a lower expansion factor deduction used in the proposed average rate base. The Company has revised the Materials Allowance expansion factor to 20.6% for the 2016/2017 test years versus 22.5% calculated for the 2013/2014 test years. The Company noted in pre-filed evidence that the change in expansion was based on a review of actual inventories in 2014 used for expansion projects.

Based upon the results of the above procedures, except as described below, we did not note any discrepancies in the calculation of the average rate base, and therefore conclude that the forecast average rate base included in the Company's pre-filed evidence is in accordance with established practice. We also conclude that the proposed average rate base accurately reflects the Company's proposals with respect to the updated depreciation study, regulatory deferral accounts and the updated calculations related to the rate base allowances.

We note that the Company has used a HST rate of 15% to calculate the cash working capital allowance proposed for 2016 and 2017. The HST rate in effect as of the date of our report is 13%.

Return on Rate Base

Our procedures with respect to verifying 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 2013 to 2014 actual return on rate base, the Company's forecast rate of return on rate base for 2015 to 2017, the Company's proposed return on rate base for 2016 and 2017 and the upper and lower end of range as set by the Board:

Table 11: Return on Average Rate Base 2013-2017

	Actual 2013	Actual 2014	Forecast 2015	Forecast 2016	Forecast 2017	Proposed 2016	Proposed 2017
Actual Return on Average Rate Base	8.10%	7.83%	7.45%	6.96%	6.61%	7.66%	7.64%
Upper End of Range set by the Board	8.10%	8.06%	7.68%			7.84%	7.82%
Lower End of Range set by the Board	7.74%	7.70%	7.32%			7.48%	7.46%

In P.U. 25 (2011) the Board approved the suspension of the operation of the Formula to establish a rate of return on rate base for 2012. In P.U. 23 (2013) the Board approved a rate of return on average rate base for 2013 of 7.92% in a range of 7.74% to 8.10% and a rate of return on average rate base for 2014 of 7.88% in a range of 7.70% to 8.06%. In P.U. 51 (2014) the Board approved a 2015 rate of return on average rate base of 7.50%, in a range of 7.32% to 7.68%. The Company is proposing the Board approve a return on average rate base for 2016 of 7.66%, within a range of 7.48% to 7.84% and for 2017 of 7.64%, within a range of 7.46% to 7.82%.

Based upon the results of the above procedures, we did not note any discrepancies in the Company's calculation of the return on average rate base, and therefore conclude that the forecast return on average rate base included in the Company's pre-filed evidence has been calculated in accordance with established practice. We also conclude that the proposed rate of return on average rate base accurately reflects the proposals in this Application as well as the Company's targeted return on equity of 9.50% which will be addressed by cost of capital experts participating in this hearing.

Capital Structure

In P.U. 43 (2009) the Board confirmed its previous position regarding the capital structure for Newfoundland Power comprised of 45% equity, 54% debt and 1% preferred equity. In P.U. 13 (2013), the Board maintained its position for equity not to exceed 45% of capital structure.

Average forecast common equity for 2015 through 2017, including the proposed average common equity for 2016 and 2017 per the pre-filed evidence, is below the approved maximum, and accordingly, no calculation for deeming excess common equity as preferred equity is required.

In its pre-filed evidence, the Company is proposing to maintain a capital structure which is consistent with the structure established by Board Order P.U. 16 (1998-99), P.U. 19 (2003), P.U. 32 (2007), P.U. 43 (2009) and P.U. 13 (2013).

Based on our recalculations of the components of the capital structure, the Company's projected average capital structure for 2015 through 2017 is as follows:

Table 12: Capital Structure 2013-2017

	Actual 2013	Actual 2014	Forecast 2015	Forecast 2016	Forecast 2017	Proposed 2016	Proposed 2017
Debt	54.35%	54.85%	54.72%	54.38%	54.39%	54.25%	54.32%
Preferred Equity	0.97%	0.92%	0.88%	0.84%	0.81%	0.84%	0.81%
Common Equity	44.68%	44.23%	44.40%	44.78%	44.80%	44.91%	44.87%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

The above table shows that the Company's forecast average common equity for 2015 to 2017 is below the 45% maximum approved by the Board. The debt portion of the cost of capital for 2016 and 2017 proposed is 6.15% and 6.12% respectively. We recalculated the debt portion of the cost of capital using the average debt, included in the average capital structure above, and the finance charges presented in Exhibit 5 (Page 7 of 9).

The proposed capital structure for 2016 and 2017 is consistent with the position confirmed by the Board in P.U. 13 (2013). The above calculations of capital structure are consistent with Exhibit 3 (Page 6 of 9) and Exhibit 5 (Page 6 of 9) presented in the 2016/2017 GRA.

Calculation of Average Common Equity and Return on Average Common Equity

Newfoundland Power has noted that, based on expert evidence filed with the GRA which indicates a fair return, it is targeting a 2016 and 2017 return on equity of 9.5%.

Similar to the approach used to verify the rate base, our procedures in this area focused on verification of the data incorporated in the calculations and on the methodology used by the Company. Specifically, the procedures which we performed included the following:

- agreed all carry-forward data to supporting documentation, including audited financial statements and internal accounting records where applicable;

- agreed forecast data (earnings applicable to common shares; dividends; regulated earnings; etc.) to supporting documentation to ensure it is internally consistent with the pre-filed evidence and other areas of the forecast;

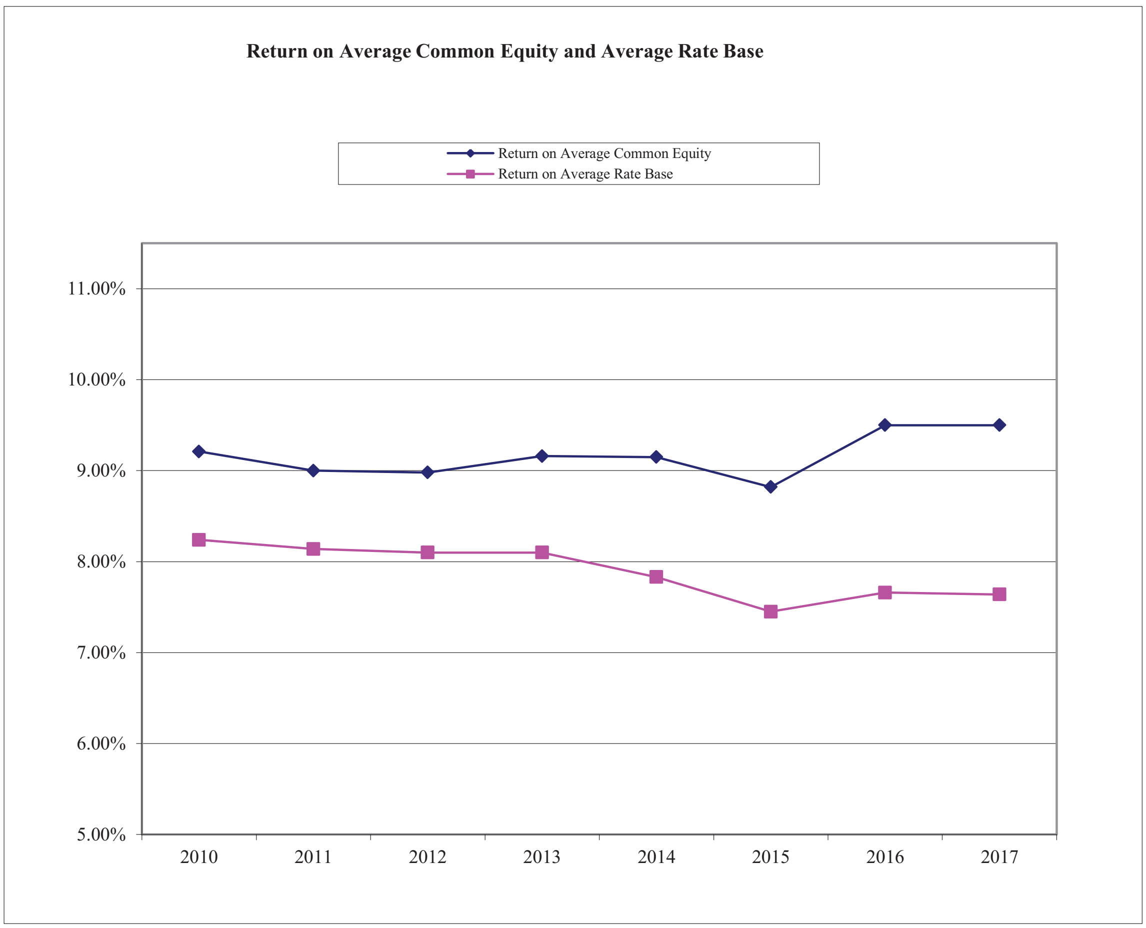
- checked the clerical accuracy of the continuity of common equity; and,

- recalculated the forecast rate of return on common equity for 2015, 2016 and 2017 to ensure it is in accordance with established practice.

The following is a comparison of the actual return on average common equity from 2010 to 2014, forecast for 2015 and proposed 2016 and 2017 with the actual return on average rate base for 2010 to proposed 2017.

Table 13: Average Common Equity vs. Return on Average Rate Base 2010-2017

	2010	2011	2012	2013	2014	Forecast 2015	Proposed 2016	Proposed 2017
Return on Average Common Equity	9.21%	9.00%	8.98%	9.16%	9.15%	8.82%	9.50%	9.50%
Return on Average Rate Base	8.24%	8.14%	8.10%	8.10%	7.83%	7.45%	7.66%	7.64%
Spread between actual returns	0.97%	0.86%	0.88%	1.06%	1.32%	1.37%	1.84%	1.86%



As demonstrated by the graph above, the proposed 2016 and 2017 return on average rate base results in an increase in the spread between the return on average common equity and return on average rate base as compared to the previous years shown.

Based upon the results of the above procedures, we did not note any discrepancies in the calculation of the forecast and proposed rate of return on average common equity for 2015, 2016 and 2017. The 2016 and 2017 proposed rate of return on common equity will be addressed by the cost of capital experts participating in this hearing.

Interest Coverage

The level of interest coverage experienced by the Company in 2013 and 2014, and as forecast, is as follows:

Table 14: Interest Coverage 2013-2017

(000's)	2013	2014	Forecast 2015	Existing 2016	Proposed 2016	Existing 2017	Proposed 2017
Income before taxes	47,043	48,635	49,055	45,701	56,116	42,541	58,498
Interest on long term debt	35,123	36,327	35,027	35,439	35,439	37,091	37,091
Interest during construction	(893)	(1,435)	(974)	(1,071)	(1,071)	(1,089)	(1,089)
Other interest and amortization of debt discount costs	1,377	880	1,298	976	1,037	642	747
Total	$ 82,650	$ 84,407	$ 84,406	$ 81,045	$ 91,521	$ 79,185	$ 95,247
Interest on long term debt	$ 35,123	$ 36,327	$ 35,027	$ 35,439	$ 35,439	$ 37,091	$ 37,091
Other interest and amortization of debt discount costs	1,377	880	1,298	976	1,037	642	747
Total	$ 36,500	$ 37,207	$ 36,325	$ 36,415	$ 36,476	$ 37,733	$ 37,838
Interest coverage (times)	**2.3**	**2.3**	**2.3**	**2.2**	**2.5**	**2.1**	**2.5**

In P.U. 43 (2009) the Board was satisfied with the Company's interest coverage ratio of 2.5 times given the Company's capital structure and return on regulated equity. In 2013 and 2014, interest coverage decreased to 2.3 times respectively. The forecast ratios for 2015, 2016 and 2017 under existing rates are 2.3, 2.2 and 2.1 times respectively. As indicated above, the proposals included in this Application result in interest coverage for 2016 and 2017 of 2.5 times respectively.

The level of interest coverage will be reviewed by the cost of capital experts participating in this hearing.

Forecasting Methodology and Assumptions

The Company's forecast of revenue and expenses for 2015, 2016 and 2017 is based on the expected operating and capital requirements, as well as assumptions, which reflect the best estimate of future economic conditions and events. There are seven months of actual data included within the 2015 forecast. The Company has noted in its response to CA-NP-196 that it does not currently plan to update its revenue and expense forecast relative to the Application prior to the conclusion of the matter.

Our approach to this item of the terms of reference focused on three main objectives:

1. to assess the incorporation of assumptions into the forecast presented by management with regard to future economic conditions and events;
2. to assess the major assumptions disclosed in Exhibits 3 and 5 of the Application for consistency with forecast information reflected throughout the Application; and
3. to assess the the methodology used by the Company for forecasting revenues and expenses.

Assessment of assumptions

The assumptions used by management were assessed based on reference to and corroboration with information available through independent third parties, including the Conference Board of Canada and Canada Mortgage and Housing Corporation ("CMHC"). The assumptions were also reviewed for consistency with the information included in the pre-filed evidence.

As a result of our review, we have determined that the assumptions used by management in forecasting revenue and expenses are based upon and incorporate data from independent sources, where applicable, and are consistent with the information included in the pre-filed evidence.

Since the Company filed its Application, CMHC has released its 4th Quarter report. We did note that in this report, CMHC has decreased its forecast housing starts for 2015 to 1,600 from 1,950 and its forecast housing starts for 2016 to 1,600 from 1,900.

Incorporation of assumptions into forecast

The incorporation of the stated assumptions into the forecast was assessed through a review of the exhibits included in the pre-filed evidence and other supporting schedules and information provided by the Company. Based upon the results of our procedures we can confirm that the assumptions disclosed in Exhibits 3 and 5 of the GRA are consistent with the forecast information included throughout the GRA.

Methodology

The Customer, Energy and Demand Forecast forms the foundation of the Company's planning process. The forecast is a key input in developing estimates of capital expenditures required, and directly addresses the estimation of future revenue from electrical sales and expenditures on purchased power.

The Company's methodologies for forecasting as described in the Customer, Energy and Demand Forecast are consistent with those used in the 2013 hearing except as noted by the company in response to CA-NP-197.

The Company has noted in response to our specific requests, as well as CA-NP-197, that Newfoundland Power typically develops its corporate forecast via an iterative process whereby departmental inputs are consolidated into a corporate forecast. Once the corporate forecast is consolidated and agreed to by the departmental directors, it is reviewed and, where appropriate, adjusted by the Executive. In regard to CA-NP-197 the Company disclosed *"the development of the 2016/2017 test period budget did not follow the typical process. Upon receipt of Order No. P.U. 23 (2015), management had 3 months to develop the application and evidence, including the test year budgets, for the 2016/2017 General Rate Application. To expedite development of the 2016/2017 test period budget, it was decided to expedite the typical iterative process by having the Company's 3 Vice-Presidents actively engaged in the budget development from the outset."*

The guidelines used by the Company in its budgeting process indicate that an inflation factor is to be used when the future cost of a budget item is unknown. If the future cost of an item is known then that would be considered the budgeted cost. The Company indicated that the GDP deflator was a key assumption used in developing the 2016 and 2017 forecast of non-labour operating expenses.

The Company's capital and operating budget is prepared each year as part of an overall planning process. The budget process utilizes a computer system which consists of three modules. These modules include the labour forecast, departmental budgets and capital projects. The 2016 forecast of capital expenditures is consistent with the capital budget application submitted to the Board and approved in P.U. 28 (2015). Capital expenditures forecast for the subsequent year were based on the 2016 capital budget.

As a result of our review, we have determined that the overall methodology used by the Company for estimating revenue, expenses and net earnings is similar to the process and methodology used in the 2013/2014 General Rate Application except as noted by the Company in response to CA-NP-197. Our observations and comments with respect to individual expense estimates and revenue from rates are included within the operating expense and proposed revenue from rates sections of our report.

Capital Expenditures

The following table details the actual versus budgeted capital expenditures from 2010 to 2014, and the forecast figures for 2015 to 2017.

The table and graph below demonstrates that from 2010 to 2014 the Company has been consistently over budget on capital expenditures in all years except for 2011. 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". Based on the information below, the Company did not exceed 10% of its budget for the years 2010 to 2014.

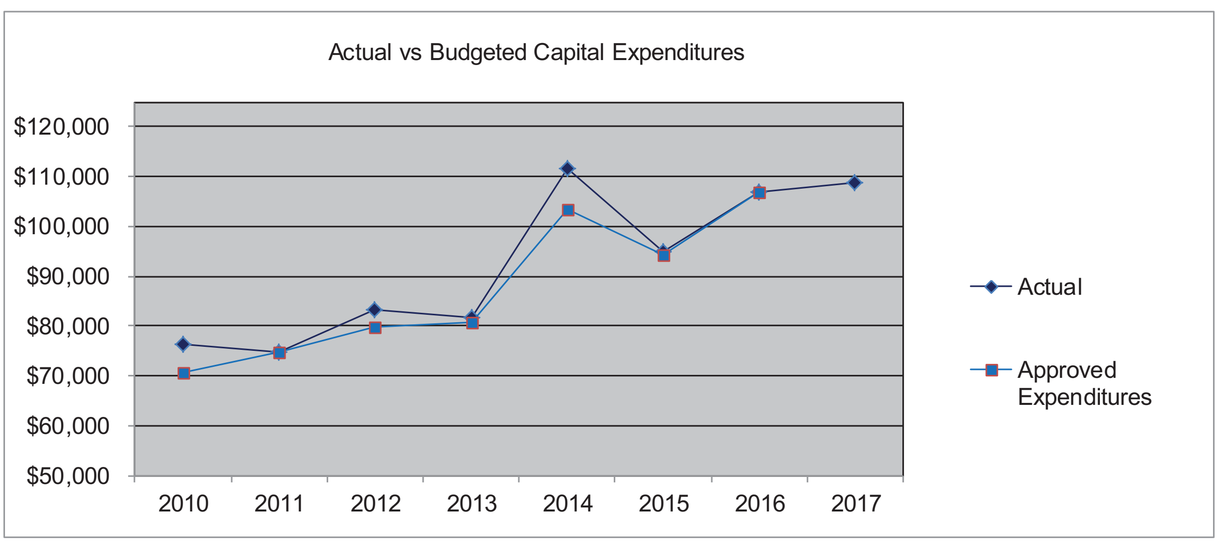
From 2010 to 2014, the total capital expenditures have been higher than budget by an average of 4.45% (high: 2010 = 8.08%%; low: 2011 = -0.13%).

We have reviewed the significant variances from 2010 to 2014 as part of our annual financial reviews and our comments on these variances are contained in our annual review reports filed with the Board.

Table 15: Capital Expenditures 2010-2017

	2010	2011	2012	2013	2014	2015 Note 1	2016 Note 1	2017 Note 1
Actual (Note 2, Note 4)	$ 72,972	$ 72,846	$ 79,290	$ 80,013	$ 109,429	$ 95,102	$ 107,053	$ 108,926
Carry Over (Note 3)	3,523	1,954	4,116	1,720	2,079	-	-	-
	$ 76,495	$ 74,800	$ 83,406	$ 81,733	$ 111,508	$ 95,102	$ 107,053	$ 108,926
Approved Expenditures	$ 70,779	$ 74,894	$ 79,690	$ 80,788	$ 103,572	$ 94,211	$ 107,028	N/A
Over Budget	8.08%	-0.13%	4.66%	1.17%	7.66%	0.95%	0.02%	N/A

Note 1: The actual figures for 2015 to 2017 are the forecast.
Note 2: Actual represents the actual expenditures on projects approved in that year.
Note 3: Carry over represents expenditures in subsequent years on projects approved in that year.
Note 4: Actual figures disclosed in the GRA (Table 3-10) excluded expenditures for unforeseen items and general expenses capitalized. These amounts were subsequently requested from the Company and have been included in the figures presented.



In P.U. 40 (2014) the Board approved expenditures of $94,211,000 for the 2015 capital program. This represents a decrease of approximately 9.04% compared to the 2014 approved capital expenditures of $103,572,000.

The reason for the decrease is mainly due to the Bell Island submarine cable system of $14,520,000, approved in P.U. 43 (2013), and a decrease in Heart's Content Plant Refurbishment of $5,735,000 approved in P.U. 27 (2013). These decreases are offset by increases for new multi-year projects approved in 2015 of $8,356,000.

The proposed forecast of 2016 capital expenditures included in this Application is $107,053,000 which is 0.02% higher than the company's capital budget request of $107,028,000 filed on June 23, 2015 and approved by the Board in P.U. 28 (2015). The 2016 approved capital expenditures represents an increase of approximately 13.60% compared to the 2015 approved capital expenditures of $94,211,000. The increase is mainly due to 2016 approved expenditures for Pierre's Brook Plant Penstock and Surge Tank of $15,012,000.

The Company is proposing forecast capital expenditures of $108,926,000 for 2017 which is an increase of 1.77% in comparison to the approved capital expenditures in 2016 and an increase of 1.75% in comparison to the proposed forecast for 2016.

Depreciation

P.U. 13 (2013) contained the following orders related to depreciation:

- Newfoundland Power's proposal to adjust the depreciation expense to amortize the accumulated reserve variance of approximately $2.6 million over the account's composite remaining life is approved.
- Newfoundland Power's proposal to use the depreciation rates recommended in the 2010 Depreciation Study was approved.
- Newfoundland Power shall file its next depreciation study relating to plant in service as of December 31, 2014 with its next general rate application.

Based upon our review, it appears that Newfoundland Power has complied with the items outlined above. Newfoundland Power has submitted an updated depreciation study in the pre-filed evidence supporting the 2016/2017 General Rate Application.

The 2014 Depreciation Study was undertaken by Gannett Fleming Valuation and Rate Consultants, Inc. ("Gannett Fleming") and has an effective date of December 31, 2014. In the Depreciation Study, Gannet Fleming calculated deprecation rates based on the *"straight line method using the equal life group ("ELG") procedure and were applied on a whole life basis. Additionally, an adjustment to depreciation expense was made to amortize, over the account's remaining life, the difference between the Company's book accumulated depreciation and the theoretical reserve."* This approach is consistent with the procedures that were outlined in the 2010 Depreciation Study and approval in P.U. 13 (2013).

Gannett Fleming's calculated accrued deprecation as of December 31, 2014 is $659.6 million. This is $13.8 million or 2.1 percent greater than the Company's accrued depreciation of $645.8 million. Gannett Fleming has noted that this is within the five percent tolerance level. According to Gannett Fleming, this tolerance level is the industry's most commonly used method for adjusting depreciation. In the 2014 Depreciation study Gannett Fleming notes that, *"calculated accrued depreciation is used as a measure to assess the adequacy of the Company's book accumulated depreciation amount. The calculated accrued depreciation should not be viewed in exact terms as the correct reserve amount. Rather it should be viewed as a benchmark or a tool used by the depreciation professional to assess the standing of the book accumulated depreciation amount based on the most recent available information."*

Gannett Fleming refers to the difference between the calculated accrued depreciation and the book value of accrued depreciation as the reserve variance. As noted above, the reserve variance identified in the 2014 Depreciation Study is $13.8 million. Gannett Fleming has identified that the reserve variance exceeding the five percent threshold for each individual plant account is approximately $12.2 million. In the 2014 Depreciation Study, Gannett Fleming has indicated that the reserve variance which "*exceed five percent of the calculated accrued depreciation are amortized over the composite remaining useful life of the assets. Accounts for which the composite remaining lives are less than five years, the amortization period used to minimize the reserve variance was set at five years which is the period of time between depreciation studies. This was done to reduce the annual fluctuations to depreciation expense related to the reserve variance amortizations for accounts with composite remaining lives"*. We have reviewed the calculation in the Gannett Fleming report supporting the $12.2 million reserve variance and have found no discrepancies. We have also recalculated the amortized reserve variance and have found no discrepancies. The treatment of the reserve variance is consistent with the 2010 Depreciation Study which was approved in P.U. 13 (2013).

The following tables summarize depreciation expense, including the true-up adjustment, for the years from 2013 to 2017 under both the 2010 and the 2014 Depreciation Study for comparative purposes.

Table 16: Depreciation 2013-2017

Depreciation ('000)	**2013**	**2014**	**2015**	**2016**	**2017**
Existing - 2010 Depreciation Study (Note 1)	$ 46,964	$ 49,288	$ 51,941	$ 54,634	$ 57,640
Proposed - 2014 Depreciation Study (Note 2)	46,964	49,288	51,941	55,535	58,573
Variance	$ -	$ -	$ -	$ 901	$ 933

Note 1: Existing depreciation costs include an $89,000 reserve variance adjustment resulting from the 2010 depreciation study.

Note 2: Proposed depreciation costs include an $626,000 reserve variance adjustment resulting from the 2014 depreciation study.

Depreciation amounts and rates incorporated in the 2016 and 2017 forecast are based upon the recommendations of the 2014 Depreciation Study. Specifically we performed the following:

- agreed all depreciation rates, including the true-up provision, to those recommended in the depreciation study and the Company's pre-filed evidence;
- recalculated the Company's estimate of depreciation expense for 2016 and 2017; and,
- assessed the overall reasonableness of the estimate of depreciation and true-up amounts for 2016 and 2017.

Based on our review of depreciation expense, we conclude that the depreciation rates used to calculate the proposed forecast for 2016 and 2017, including the true-up provision, agree to those recommended in the 2014 Depreciation Study and the Company's pre-filed evidence. We have recalculated the depreciation expense for 2016 and 2017 without identifying any material errors and conclude that the depreciation expense is calculated in accordance with the rates prescribed in the 2014 Depreciation Study.

2016/2017 Test Year Financial Forecast

Based on the evidence included in Exhibit 9 of the Company's pre-filed evidence, Newfoundland Power has indicated it requires an increase in revenue requirement of approximately $8.7 million in 2016 and $20.1 million in 2017. This increase is based on the proposals that the Company has put forward relating to regulatory deferrals, a rate of return on average rate base of 7.66% in 2016 and 7.64% in 2017 and a rate of return on common equity of 9.5% in 2016 and 2017. The factors contributing to the increase can be summarized as follows:

Table 17: Components of 2016 Proposed Rate Change

Components of 2016 Proposed Rate Change

(000's)	Existing (Including Elasticity)	Changes	Proposed	Rate Change %
Return on Rate Base	$ 73,651	$ 7,563	$ 81,214	1.13
Other Costs				
Power Supply Costs	448,198	(1)	448,197	
Operating Costs	58,123	400	58,523	0.06
Employee Future Benefit Costs	22,176	-	22,176	
Amortization of Deferred Recoveries	-	(3,276)	(3,276)	-0.49
Depreciation	54,634	901	55,535	0.13
Income Taxes	15,487	3,098	18,585	0.46
	598,618	1,122	599,740	
Total Costs and Return	672,269	8,685	680,954	
Adjustments				
Other Revenue	(4,842)	37	(4,805)	0.01
Interest on Security Deposits	24	-	24	
2013 Excess Earnings	-	(68)	(68)	-0.01
Energy Supply Cost Variance Adjustments	(5,227)	701	(4,526)	0.10
Transfers to RSA	(1,254)	(640)	(1,894)	-0.10
	(11,299)	30	(11,269)	
2016 Revenue Requirement from Rates	**660,970**	**8,715**	**669,685**	1.30
RSA	(6,275)	(1)	(6,276)	
MTA	16,207	198	16,405	0.03
Billed to Customers	$ 670,902	$ 8,912	$ 679,814	1.33

Table 18: Components of 2017 Proposed Rate Change

Components of 2017 Proposed Rate Change

(000's)	Existing (Including Elasticity)	Changes	Proposed	Rate Change %
Return on Rate Base	$ 72,927	$ 11,489	$ 84,416	1.71
Other Costs				
Power Supply Costs	447,927	-	447,927	
Operating Costs	59,770	400	60,170	0.06
Employee Future Benefit Costs	17,892	-	17,892	
Amortization of Deferred Recoveries	-	1,638	1,638	0.24
Depreciation	57,640	933	58,573	0.14
Income Taxes	14,918	4,680	19,598	0.70
	598,147	7,651	605,798	
Total Costs and Return	671,074	19,140	690,214	
Adjustments				
Other Revenue	(4,770)	(62)	(4,832)	-0.01
Interest on Security Deposits	24	-	24	
Energy Supply Cost Variance Adjustments	(5,772)	5,772	-	0.86
Transfers to RSA	1,887	(4,715)	(2,828)	-0.70
	(8,631)	995	(7,636)	
2017 Revenue Requirement from Rates	662,443	20,135	682,578	2.99
RSA	(6,276)	(1)	(6,277)	
MTA	16,234	501	16,735	0.07
Billed to Customers	$ 672,401	$ 20,635	$ 693,036	3.07

In our review, we have addressed the major components of revenue requirement noted above, with the exception of the return on equity, and our specific comments on each are outlined in the various individual sections of this report. The appropriateness of the return on common equity will be addressed by the cost of capital experts participating in this hearing.

Previous sections of this report have reviewed the impacts on revenue requirement relating to changes in supply cost recovery mechanisms, amortization of deferred regulatory accounts and depreciation.

The following section reviews forecast operating expenses. Schedule 1 of our report presents the total cost of energy to kWhs sold from 2013 to 2014 and the forecast total cost of energy to forecast kWhs for 2015, 2016 and 2017. The table and graph show that the total cost of energy per kWh increased by 1.6% from 2013 to 2014 ($0.1049 to $0.1066) and is forecast to increase by 8.1% from 2014 to proposed 2017 ($0.1066 to $0.1152). This increase is primarily attributable to the increase in purchased power costs, depreciation, as well as, the increase in the return on common equity to 9.5% included in this Application.

The effect of all of the factors noted in Newfoundland Power's Application reflect an increase in revenue requirement from rates of $8,715,000 in 2016 and $20,135,000 in 2017, which the Company is proposing to obtain by increasing rates effective July 1, 2016 by an average of 3.1%.

Operating Expenses

Using the information presented in Schedule 1 and Schedule 2 of our report, the operating costs per customer from actual 2013 to proposed 2017 are as follows:

Table 19: Operating Costs by Customer 2013-2017

	Actual 2013	Actual 2014	Forecast 2015	Proposed 2016	Proposed 2017
Number of customers as at year end	255,618	258,879	261,093	263,089	264,931
Gross operating expenses (000's)	82,090	83,867	83,869	82,331	78,396
Net operating expenses (000's)	79,265	81,171	81,212	80,699	78,062
Gross operating expense per customer	$ 321.14	$ 323.96	$ 321.22	$ 312.94	$ 295.91
Net operating expense per customer	$ 310.09	$ 313.55	$ 311.05	$ 306.74	$ 294.65

Based on the above information, the gross operating expense per customer increased by 0.88% from 2013 to 2014 and is forecast to decrease by 8.66% from 2014 to proposed 2017. Net operating expense per customer increased by 1.12 % from 2013 to 2014 and is forecast to decrease by 6.03% from 2014 to proposed 2017.

Our review of operating expenses was conducted using the breakdown of expenses as outlined in Exhibit 2 of the pre-filed evidence. This exhibit provides details of the actual operating expenses for the years 2013 and 2014 as well as the forecast for 2015, 2016 and 2017.

The relationship of operating expenses to the sale of energy (expressed in kWh) is presented in Schedule 2 of our report. The table and graph show that the cost per kWh remained stable at $0.0142/kWh from 2013 to 2014 and is forecast to decrease to $0.0131/kWh by 2017. This is primarily due to a decrease of gross operating expenses of $5,471,000. The biggest contributor to the decrease relates to employee future benefits which decreased by $6,352,000 from 2014 to 2017. Excluding employee future benefits, gross operating expenses increased by $881,000 (1.1%) from 2014 to 2017. Net operating expenses, excluding employee future benefits increased by $3,243,000 (4.0%) from 2014 to 2017.

Our observations and findings based on our detailed review of the individual expense categories are noted below. Where we have identified unusual trends or other concerns with forecast expenses, we have noted these in the respective sections of our report that follow.

Operating Expenses - Key Variances

Based upon analytical review of Exhibit 2, "Operating Costs by Breakdown" of the Company's pre-filed evidence the following key variances between 2014 actual and 2017 forecast have been noted along with explanations provided by the Company:

- Vehicle expense – The Company has indicated in the Application that vehicle expense reflects lower fuel costs, and a reduction in vehicle costs resulting from Automatic Meter Reading ("AMR") project. The AMR is expected to decrease 2016 vehicle expense by $90,000, 2017 vehicle expense by $150,000.

- Operating materials – The Company has indicated that 2014 operating materials were higher than 2013 primarily due to higher maintenance costs related to the Topsail Penstock Repairs. Forecast for 2015, 2016 and 2017 are more comparable to the 2013 actual results.
- Uncollectible bills - The Company is forecasting uncollectible bills to represent 0.20% of revenue from rates. This is a decrease from the 2014 actual results which reflected uncollectible bills as 0.24% of revenue from rates. Newfoundland Power has indicated that this was the result of an increase to revenue from rates in the first quarter of 2014 due to weather conditions. Due to restrictions associated with weather conditions and temperatures, there was a delay in disconnecting customers with overdue balances. As a result, the Company`s 2015 through 2016 forecast is based on historical rates as opposed to 2014 actual results.
- Advertising costs – The Company has indicated that increases in advertising costs for 2016 and 2017 forecast reflect initiatives outlined in the Five-Year Conservation Plan: 2016-2020 as well as additional educational initiatives.

Based upon our review and analysis, nothing has come to our attention to indicate that the 2015, 2016 and 2017 forecast operating expenses are unreasonable on an overall basis.

Executive Compensation

The following table provides a summary and comparison of executive compensation for forecast 2015, 2016 and 2017 with actuals for 2013 and 2014.

Table 20: Average Compensation Per Executive 2013-2017

	Base Salary	Incentive (Note 1)	Other (Note 2)	Total	% Change
Forecast 2017					
Total executive group	$ 1,178,801	$ 508,292	$ 132,647	$ 1,819,740	2.5%
Average per executive	$ 294,700	$ 127,073	$ 33,162	$ 454,935	2.5%
Forecast 2016					
Total executive group	$ 1,150,050	$ 495,895	$ 129,412	$ 1,775,357	2.5%
Average per executive	$ 287,513	$ 123,974	$ 32,353	$ 443,839	2.5%
Forecast 2015					
Total executive group	$ 1,122,000	$ 483,800	$ 126,256	$ 1,732,056	-16.4%
Average per executive	$ 280,500	$ 120,950	$ 31,564	$ 433,014	-16.4%
2014 *(3)*					
Total executive group	$ 1,268,257	$ 672,000	$ 131,845	$ 2,072,102	2.6%
Average per executive	$ 317,064	$ 168,000	$ 32,961	$ 518,026	2.6%
2013					
Total executive group	$ 1,195,019	$ 698,000	$ 126,744	$ 2,019,763	
Average per executive	$ 298,755	$ 174,500	$ 31,686	$ 504,941	

Note 1: The forecast periods incentive payments are based on achieving 100% of target. For 2013 and 2014, payouts exceed 100% of target.
Note 2: The "other" category of the annual compensation package includes items such as vehicle benefits or car allowance, insurance benefits, and self-directed RRSP employer contributions.

Note 3: The 2014 figures include compensation for both Earl Ludlow and Gary Smith. Earl Ludlow was President and CEO of Newfoundland Power until August 1, 2014 at which time he became Executive Vice President, Eastern Canadian and Carribean Operations, Fortis Inc. Gary Smith became President and CEO of Newfoundland Power effective August 1, 2014. Prior to August 1, 2014, he was Vice President, Customer Operations & Engineering.

In response to CA-NP-199, the Company indicated that they used Hay Group Limited (the "Hay Group") to provide external expertise to assist with the review of salaries and wages for the executive and senior management employees. On February 16, 2015 the Hay Group provided a report entitled "Executive Compensation – 2015 Estimated Market Actual Salary Median." The report provides an estimate of the market annual salary levels in 2015 for members of Newfoundland Power's executive team. This analysis was based upon Commercial Industrial market data in effect on May 1, 2014. The Hay Group report recommends that the Company's executive salary be compared to actual salaries paid by the commercial industrial market reference group. The Company's current executive salary policy is based upon the median of actual salary for the reference group, while limiting salaries to 110% of the median.

In 2015, the Company's executive salary policy versus the actual base salary for executives is outlined in the table below:

Table 21: Executive Compensation – Actual vs. Policy

Position	Base Salary	Salary Policy	Difference	Base as % of Policy
President & CEO	$ 350,000	$ 359,100	$ (9,100)	97%
VP Engineering & Operations	226,000	266,000	(40,000)	85%
VP Finance & CFO	273,000	257,800	15,200	106%
VP Regulation & Planning	273,000	257,800	15,200	106%
Total	**$1,122,000**	**$1,140,700**	**$ (18,700)**	**98%**

Source: As per the Company's response to CA-NP-206

We have agreed the base salary presented in the table above to the approved minutes from the meeting of the Board of Directors held on February 27, 2015. We have also confirmed that the stated salary policy balances outlined in the table above agree to the February 16, 2015 Hay Group report.

Salaries and Benefits

A detailed comparison of the number of full-time equivalent ("FTE") employees for 2013 to forecast 2017 is as follows:

Table 22: Full-time Equivalents

	Actual 2013	Actual 2014	Forecast 2015	Forecast 2016	Forecast 2017
Permanent	600	616	609	622	618
Temporary	56	49	52	43	34
Total	656	665	661	665	652
Managerial FTE`s	276	285	281	285	285
% managerial	42%	43%	43%	43%	44%
Union FTE`s	330	334	331	331	331
% union	50%	50%	50%	50%	51%

The Company provided detailed information concerning the method used to forecast test year FTEs and labour expense, as well as assumptions used to determine forecast vacancies as part of its pre-filed evidence for this GRA in the report dated October 2015 entitled "Labour Forecast 2015-2017". In this report, Newfoundland Power has stated that they expect current labour requirements to be consistent from year to year. The Company has noted that this is primarily due to the fact that the Company matches overall capacity and capability with anticipated work requirements when managing its workforce.

The 2015 forecast shows a decrease of four FTE's. This primarily reflects 37 projected retirements, 19 of these employees are to be replaced, and 9 regular new hires. The 2016 forecast reflects 39 projected retirements, with 30 of these employees being replaced, plus 13 new hires. Finally, the 2017 forecast reflects an overall reduction of 13 FTE's primarily due to the completion of the AMR project.

As part of our review we completed an analysis of the average salary per FTE, including and excluding executive compensation (base salary and STI). The results of our analysis for 2013 to forecast 2017 are included in the table below:

Table 23: Salary Cost per Full Time Equivalent

	Salary Cost Per FTE				
	Actual	**Actual**	**Forecast**	**Forecast**	**Forecast**
(000's)	**2013**	**2014**	**2015**	**2016**	**2017**
Salary costs	$59,784	$62,275	$63,701	$66,286	$67,445
Benefit costs (net)	(7,502)	(7,448)	(7,618)	(7,927)	(8,066)
Other adjustments	(571)	(646)	(609)	(629)	(649)
Base salary costs	51,711	54,181	55,474	57,730	58,730
Less: executive compensation	(1,893)	(1,932)	(1,794)	(1,646)	(1,687)
Base salary costs (excluding executive)	$49,818	$52,249	$53,680	$56,084	$57,043
FTE's (including executive members)	656	665	661	665	652
FTE's (excluding executive members)	652	661	657	661	648
Average salary per FTE	$76	$79	$81	$84	$87
% increase		3.46%	3.36%	3.85%	3.74%
Average salary per FTE (excluding executive members)	$76	$79	$82	$85	$88
% increase		3.45%	3.36%	3.85%	3.75%

In the "Labour Forecast 2015-17" report, the Company has noted that the 2016 and 2017 salary increase is based on a weighted average salary increase of 3.25 percent.

An analysis of salaries and wages by type of labour and by function within the Company is as follows:

Table 24: Salary Costs by Function 2013-2017

(000`s)	Actual 2013	Actual 2014	Forecast 2015	Forecast 2016	Forecast 2017
Type					
Internal labour	$ 59,784	$ 62,275	$ 63,701	$ 66,286	$ 67,445
Overtime	5,228	6,968	5,114	5,580	5,762
	65,012	69,243	68,815	71,866	73,207
Contractors	13,613	18,286	13,759	12,381	11,513
Total	$ 78,625	$ 87,529	$ 82,574	$ 84,247	$ 84,720
Function					
Operating	$ 35,918	$ 37,871	$ 36,687	$ 38,193	$ 39,034
Capital miscellaneous	42,707	49,658	45,887	46,054	45,686
Total	$ 78,625	$ 87,529	$ 82,574	$ 84,247	$ 84,720

Our review of salaries and benefits included an analysis of the year-to-year variance, consideration of the trends in labour costs and discussion of the significant variances with Company officials.

Short-Term Incentive ("STI") Program

Newfoundland Power's Executives and Directors participate in the Company's Short-Term Incentive ("STI") program. The Company has indicated that the underlying rationale for the STI program is to incent senior management performance by making a significant portion of total compensation dependent on performance.

The Company currently monitors several corporate performance measures. In response to Requests for Information PUB-NP-007, the Company has provided the following description of the performance measures:

- **Controllable Operating Cost per Customer**: This measure is based on budgeted controllable operating expenses. The Company has noted that because such costs are beyond the short-term control of management, inter-company charges, PUB assessments, pension costs and retirement allowances, are excluded from the target.

- **Earnings:** This measure represents corporate earnings as per the year-end audited financial statements. The target is based on the Company's earnings budgeted for the year.

- **Duration of Outages (SAIDI):** This measure represents the reliability of the power system in terms of the duration of outages experienced by customers.

- **Customer Satisfaction:** This measure represents Newfoundland Power's customer satisfaction rating which is obtained through independently conducted quarterly surveys of customers with respect to the Company's service.

- **Regulatory Performance:** This measure is dependent on regulatory activity for the year. The quality, timeliness and effectiveness of the regulatory filings are included in the assessment of regulatory performance.

- **Safety (All Injury Frequency Rate):** This measure is the number of preventable injuries per 200,000 hours of work and is a combination of both the number of preventable medical aid and lost time injuries.

The following table outlines the actual results for corporate performance for 2013 and 2014 and targets for 2015:

Table 25: Short-Term Incentive Targets 2013-2015

Measure	Actual 2013	Actual 2014	Forecast 2015
Controllable Operating Cost per Customer	$ 217.6	$ 223.9	$ 231.6
Earnings	36.5m	37.3m	37.7m
Duration of Outages (SAIDI)	2.23	2.44	2.3
Customer Satisfaction	85.90%	83.50%	84.70%
Regulatory Performance	150%	150%	Subjective
Safety (All Injury Frequency Rate)	0.52	0.51	0.69

Note 1: The Company has indicated that targets for 2016 and 2017 have not been finalized and approved by the Board of Directors at the time of this report.

In 2013, First Call Resolution was replaced with Regulatory Performance. The Company indicated that Regulatory Performance is evaluated on a subjective basis as it is difficult to apply statistical or cost based analyses. The 2014 STI results were adjusted to remove the impact of Hydro's Supply Loss in January 2014 and reliability was adjusted for the impact of severe winds in 2014. Additionally, STI results were adjusted at the discretion of the Board to reflect the corporate and operational efforts and performance during the supply shortage issues in 2014. For 2014, the key determinants of the result of 150% were as follows: (i) the company's participation in the Board's investigation into system reliability initiated in 2014 including the findings in the Board's consultant's December 2014 report; (ii) the 2015 capital budget application, and; (iii) the Company's efforts in participating in Newfoundland & Labrador Hydro's General Rate Application.

The forecast STI payment includes assumptions regarding the corporate performance as outlined in the table above. The Company forecast performance is based upon achieving 100% of targets.

The Company's STI program also includes an individual performance measure for Executives and Directors. This measure is used to reinforce the accountability and achievement of individual performance targets.

The weight between corporate performance and individual performance differs between the managerial classifications, as outlined in the following table:

Table 26: Short-Term Incentive Performance Weightings

Classification	Corporate Performance	Individual Performance
President and CEO	70%	30%
Vice-Presidents	50%	50%
Directors	50%	50%

The individual measures of performance for Executive and Directors are developed in consultation with the individuals and their respective executive member. Performance measures for the executive members, President and CEO are approved by the Board of Directors. Each measure is reflective of key projects or goals, and focuses on departmental or divisional priorities. The program operates to provide 100% payout of established STI pay if the Company meets, on average, 100% of its performance targets. The STI pay for 2014 is established as a percentage of base pay for the three employee groups. For 2014, measures relating to 'controllable operating costs/customer', 'earnings', 'safety' and 'regulatory performance' metrics were met, however the 'customer satisfaction' and "SAIDI" metrics fell below target.

The following table illustrates the target as a percentage of base pay, together with the actual STI payouts for 2013 and 2014 as well as for forecast results for 2015, 2016 and 2017:

Table 27: Short Term Incentive Payout as a Percent of Base Pay 2013-2017

	STI Payout						
	Target 2013	Actual 2013	Target 2014	Actual 2014	Target 2015	Target 2016	Target 2017
President	50%	70.0%	40-50%	64.0%	50%	50%	50%
Vice-Presidents	35-40%	52.1%	35%	44.8%	40%	40%	40%
Directors	15%	21.2%	15%	19.2%	15%	15%	15%

Target rates for STI payouts have changed from the targets used in 2014. In the response to CA-NP-199, the Company has included a letter, dated February 16, 2015, from the Hay Group regarding "Executive compensation program updates". In this letter, the Hay Group recommends the changes to targets for the President and the Vice-Presidents as outlined in the table above.

In dollar terms, the actual STI payouts for 2013 to 2014 and forecast payouts for 2015, 2016, and 2017 are summarized in the below table:

Table 28: Short Term Incentive Payout by Category 2013-2017

	Actual 2013	Actual 2014	Forecast 2015	Forecast 2016	Forecast 2017
President	$ 294,000	$ 258,000	$ 175,000	$ 179,000	$ 184,000
Vice-Presidents	404,000	373,000	309,000	317,000	325,000
Directors	302,000	345,000	262,000	268,000	275,000
Total	$ 1,000,000	$ 976,000	$ 746,000	$ 764,000	$ 784,000

Note 1: In 2014, the payout to the President includes two payments as a new president was appointed August 1, 2014.

In accordance with P.U. 19 (2003) the Company has classified STI payouts in excess of 100% of target as a non-regulated expense. In the response to PUB-NP-007, the Company has stated that 2015, 2016 and 2017 forecast of the regulatory portion of the STI are based on achieving 100% of targets.

Employee Future Benefits

The Company maintains plans for its employees which provide for benefits upon retirement. The Company has grouped these into two broad categories: pension plans and other post-employment benefits (OPEBs) plans.

The components of employee future benefits expense are as follows:

Table 29: Employee Future Benefit Breakdown 2013-2017

(000's)	Actual 2013	Actual 2014	Forecast 2015	Forecast 2016	Forecast 2017
Pension Expense	$14,744	$13,276	$17,715	$13,404	$9,600
OPEBs Expense	10,880	10,968	8,678	8,772	8,292
	$25,624	$24,244	$26,393	$22,176	$17,892

Company Pension Plan

For 2015, 2016 and 2017, we reviewed the estimates supporting the forecast gross charge for pension expense of $17,715,000, $13,404,000 and $9,600,000 respectively. The 2015 expense is forecast to be $4,439,000 higher than the 2014 actual of $13,276,000. The 2016 pension expense is forecast to decrease by $4,311,000 from 2015 with a further decrease of $3,804,000 in 2017.

The components of pension expense are as follows:

Table 30: Pension Expense Breakdown – 2013-2017

(000's)	Actual 2013	Actual 2014	Forecast 2015	Forecast 2016	Forecast 2017
Pension Expense per Actuary	$12,744	$11,084	$15,323	$10,802	$6,755
PUP/SERP	560	568	579	592	608
Group and Individual RRSPs	1,453	1,633	1,825	2,022	2,253
Less: Offset	(13)	(9)	(10)	(10)	(10)
Total Pension Expense	$14,744	$13,276	$17,717	$13,406	$9,606
		-10%	33%	-24%	-28%

Overall, pension expense for 2015 is higher than 2014 primary caused by variation in the discount rate used. A decrease from 5% to 4% in this discount rate was principally responsible for the increase in 2015 defined benefit pension plan expense. According to the Company, the decline in pension plan expense for 2016 and 2017 forecast is influenced by a combination of factors including; increases in plan assets due to increased solvency payments, returns on plan assets, and an increase in the proportion of plan assets invested in fixed income instruments. The discount rate is forecast to remain stable. We have compared forecast expense for 2015-2017 to support provided by the Company's actuaries and have found no discrepancies.

The Company's pension uniformity plan is meant to eliminate the inequity in the regular pension plan related to the limitation on the maximum level of contributions permitted by income tax legislation. In effect, the pension uniformity plan tops up the benefits for senior management so that they receive benefits equivalent to the benefit formula of the registered pension plan. The Board ordered in P.U. 7 (1996-97) that the pension uniformity plan be allowed as reasonable, prudent, and properly chargeable to the operating account of the Company.

As a result of the closure of the Defined Benefit Pension Plan, all new employees are required to participate in the Defined Contribution Plan (Individual RRSPs). The employer's portion of the contributions to the Group RRSP is calculated as 1.5% of the base salary paid to the plan participants. Individual RRSPs will increase year over year with the number of new hires at the Company. The increase in Group and Individual RRSPs from 2013 to 2017F is due to wage increases and new hires. Group and Individual RRSPs are forecast by the Company using an estimated compensation increase factor of approximately 4% for 2015, 2016 and 2017 forecast.

Other Post-Employment Benefits (OPEBs)

In its 2010 General Rate Application, the Company proposed the implementation of the accrual method of accounting for OPEBs expenses. The proposal included a deferral mechanism to capture annual variances arising from changes in the discount rate and other assumptions, and recommendations related to the recovery of the transitional balance associated with the adoption of accrual accounting for OPEBs costs. In P.U. 31 (2010) the Board decided the Company should use the accrual method of accounting for OPEBs costs and income tax related to OPEBs as of January 1, 2011.

The Board also required that the transitional balance for OPEBs expense be amortized using the straight-line method over a period of 15 years. The Board also approved the creation of the OPEBs Cost Variance Deferral Account to limit the variability of the OPEBs costs due to changing assumptions such as discount rates.

The components of OPEBs expense for 2013 to 2014 and forecast for 2015, 2016 and 2017 are as follows:

Table 31: Other Post-Employment Benefits Breakdown 2013-2017

(000's)	Actual 2013	Actual 2014	Forecast 2015	Forecast 2016	Forecast 2017
OPEBs Accrual	$7,957	$8,038	$4,627	$4,754	$4,880
Amortization of Transitional Amounts	3,504	3,504	4,932	4,932	4,368
Less: Amount Capitalized	(581)	(574)	(881)	(917)	(956)
Total OPEBs Expense	$10,880	$10,968	$8,678	$8,769	$8,292

The discount rate used to prepare the 2015, 2016 and 2017 forecast was 4%, which represents a decrease of 1.5% from 2015. These rates are consistent with those used to prepare the pension forecast above. We have compared forecast expense for 2015-2017 to support provided by the Company's actuaries and have found no discrepancies.

Severance and Other Employee Benefits

The severance and other employee benefit costs from 2013 to 2014 and forecast 2015, 2016 and 2017 are as follows:

Table 32: Terminations and Severance 2013-2017

(000)'s	Actual 2013	Actual 2014	Forecast 2015	Forecast 2016	Forecast 2017
Terminations and Severance	$84	$58	$72	$74	$75

Finance Charges

Our procedures with respect to interest on long term debt and other interest included a recalculation of interest charges and assessment of reasonableness based on debt outstanding.

The following table summarizes the various components of finance charges:

Table 33: Finance Charges 2013-2017

(000's)	Actual 2013	Actual 2014	Forecast 2015	Proposed 2016	Proposed 2017
Interest					
Long-term Debt	$ 35,123	$ 36,327	$ 35,027	$ 35,439	$ 37,091
Other	1,092	645	1,071	842	558
Amortization					
Debt Issue Expense	302	254	245	219	213
Interest Charged to Construction	(483)	(776)			
Equity Portion of AFUDC	(410)	(659)	(973)	(1,071)	(1,089)
Total Finance Charges	$ 35,624	$ 35,791	$ 35,370	$ 35,429	$ 36,773
Year over year percentage change		0.47%	-1.18%	0.17%	3.79%

Forecast finance charges proposed for 2016 are expected to increase from 2015 due to an increase in net debt resulting from the redemption and reissuance of debt in 2016. The redeemed loan carries a 10.9% rate and Newfoundland Power is forecasting a 5% interest rate on the debt issuance that year. This is comparable to the market rates based on interest rate forecast from the major Canadian banks.

The Company has forecast average short-term borrowing rate to be 1.71% for 2015, 1.83% for 2016, and 2.55% for 2017. We have reviewed the short-term interest rates included in the Company's assumptions and they are consistent with interest rate forecast from the five major banks in Canada.

Based upon our analysis, nothing has come to our attention to indicate that the forecast finance charges for 2015 and the proposed finance charges for 2016 and 2017 are unreasonable.

Income Tax Expense

Our review of income tax expense included a recalculation of income taxes based on substantively enacted corporate income tax rates for Federal and Provincial jurisdictions and an assessment of reasonableness based on forecast income and substantively enacted rates for 2013 and 2014 actuals, the 2015 forecast and proposed forecast for 2016 and 2017.

Table 34: Income Tax Expense 2013-2017

	Actual 2013	Actual 2014	Forecast 2015	Forecast 2016	Forecast 2017	Proposed 2016	Proposed 2017
Income Before Tax (000s)	$ 53,422	$ 56,030	$ 56,531	$ 53,790	$ 51,102	$ 64,394	$ 67,265
Income Taxes (000s)	$ 14,866	$ 16,201	$ 16,210	$ 15,486	$ 14,889	$ 18,585	$ 19,598
Effective Income Tax Rate (%)	27.83%	28.91%	28.67%	28.79%	29.14%	28.79%	29.14%
Statutory Income Tax Rate (%)	29.00%	29.00%	29.00%	29.00%	29.00%	29.00%	29.00%

The income tax figure presented above is after adjustment for non-regulated expenses.

The Company's effective income tax rate is comparable to the statutory income tax rate in effect at the time of the Application and remains consistent between the existing and proposed forecast.

Based upon our analysis, income tax expense for forecast 2015 and proposed 2016 and 2017 appear consistent with changes in the substantively enacted corporate income tax rates and forecast increases in net income.

Intercompany Charges

Our review of Intercompany Charges included the following specific procedures:

- assessed the Company's compliance with P.U. 19 (2003), P.U 32 (2007) and P.U. 43 (2009); and
- compared charges for 2015, 2016 and 2017 forecast to previous years and obtained explanations for unusual fluctuations and trends.

As part of the 2014 annual review, we reviewed Fortis Inc.'s methodology to estimate its recoverable expenses over the first three quarters as well as its "true up" calculation for the 4th Quarter. We noted during our review that Fortis Inc. continues to allocate its recoverable costs based on its subsidiaries' assets. There were no changes to the methodology in 2014.

- Fortis Inc. estimated its net pool of operating expenses for 2014, in Q4 2013, as part of its annual business planning process and determined its estimated billings based on the pro-rata portion of such net costs using the estimated assets of subsidiaries. For Quarters 1 through 3, Fortis Inc. billed evenly based upon 25% of the estimated annual amount.
- Fortis Inc. used actual year-to-date expenditures up to November and estimated December's expenses for the determination of its actual "true up" calculation. Fortis also used actual assets at November 30, 2014 in this calculation.

The following table provides a breakdown of inter-corporate charges from affiliates from 2013 to 2014, including forecast charges for 2015, 2016 and 2017:

Table 35: Charges from Affiliates including Fortis Inc. 2013-2017

Intercompany transactions	Actual 2013	Actual 2014	Forecast 2015	Forecast 2016	Forecast 2017
Charges from Affiliates including Fortis Inc.					
Trustee & Shareplan Costs	$ 53,000	$ 48,000	$ 40,000	$ 42,000	$ 44,000
Hotel/Banquet Facilities	52,961	26,927	3,113	-	-
Staff Charges	-	34,372	69,425	30,000	30,000
Miscellaneous	97,339	202,237	82,200	91,000	93,000
Total	$ 203,300	$ 311,536	$ 194,738	$ 163,000	$ 167,000
Year over year percentage change		53%	-37%	-16%	2%

The most significant observations from our analysis of charges to affiliated companies from 2013 to 2017 are as follows:

- Hotel and banquet facility charges historically have included costs associated with using the hotel and banquet facilities of various hotels owned and operated by Fortis Properties. In 2015 Fortis Properties was sold and therefore there are no longer intercompany transaction related to this service.
- Staff charges 2015 forecast is higher than 2014 due to the short-term replacement of an employee, who was on long term disability, with an employee from Fortis Properties. It is expected the replacement will end before 2016 and as a result the Company's forecast for 2016 and 2017 staff charges are based on 2014 actuals.

- Miscellaneous costs from Fortis Inc. are comparable year over year with the exception of 2014. In 2014, the increase in miscellaneous charges to Fortis Inc. is primarily due to the transfer of unused vacation accrual of $108,844 when the former president moved from Newfoundland Power to Fortis. This charge is the transfer of a liability and does not represent a 2014 expense as it was expensed over the employee's service period at Newfoundland Power.

The following table provides a breakdown of inter-corporate charges to affiliates to 2013 to 2014, including forecast charges for 2015, 2016 and 2017:

Table 36: Charges to Affiliates including Fortis Inc. 2013-2017

Intercompany transactions	**Actual 2013**	**Actual 2014**	**Forecast 2015**	**Forecast 2016**	**Forecast 2017**
Charges to Affiliates including Fortis Inc.					
Printing & Stationary	$ 352	$ 364	$ 50	$ 50	$ 50
Postage	24,565	25,704	24,000	25,000	25,000
Staff Charges	176,034	134,078	144,000	139,000	143,000
Staff Charges - Insurance	262,693	68,494	35,000	8,000	8,250
IS Charges	18,669	18,934	19,000	20,000	21,000
Pole Installations	572	769	250	250	250
Miscellaneous	23,754	88,415	21,400	55,000	55,000
Total	$ 506,639	$ 336,758	$ 243,700	$ 247,300	$ 252,550
Year over year percentage change		-34%	-28%	1%	2%

The most significant observations from our analysis of charges to affiliated companies from 2013 to 2017 are as follows:

- Staff Charges – Insurance decreased significantly due to the retirement of Fortis' Director of Risk Management who was employed by Newfoundland Power. This position was moved to Fortis Inc. after this retirement resulting in significantly fewer charges relating to this position during the year.
- Miscellaneous charges to Fortis show an increase in 2014 followed by a forecast reduction. The Company has indicated that the 2014 fluctuation was related to the sale of a vehicle to Fortis Inc. resulting from the transfer of the former president from Newfoundland Power to Fortis.

Based upon our analysis, intercompany charges are calculated using a methodology that is consistent year over year. As a result of our review, nothing has come to our attention that would lead us to believe that forecast intercompany charges are unreasonable.

Purchased Power

We have reviewed the Company's purchased power expense forecast for 2015, 2016 and 2017 and have investigated the reasons for any fluctuations and changes. We recalculated the cost per kilowatt-hour charged by Newfoundland and Labrador Hydro and found purchased power charges to be consistent with the established rates provided. Forecast purchase power expense assumes that the updated demand charge effective on July 1, 2015 will remain stable for 2016 and 2017.

Table 37: Purchased Power 2013-2017

(000's)	**Actual 2013**	**Actual 2014**	**Existing 2015**	**Existing 2016**	**Existing 2017**
Purchases From Hydro	$ 392,928	$ 404,550	$ 425,670	$ 449,006	$ 450,829
Amortization of WNR	(2,335)	(2,335)	(2,335)	-	-
DMI	(383)	628	-	-	-
	$ 390,210	$ 402,843	$ 423,335	$ 449,006	$ 450,829
Year Over Year % Change		3.24%	5.09%	6.06%	0.41%

	Actual 2013	**Actual 2014**	**Existing 2015**	**Proposed 2016**	**Proposed 2017**
Purchases from Hydro	$ 392,928	$ 404,550	$ 425,670	$ 448,197	$ 447,927
Amortization of WNR	(2,335)	(2,335)	(2,335)	-	-
DMI	(383)	628	-	-	-
	$ 390,210	$ 402,843	$ 423,335	$ 448,197	$ 447,927
Year Over Year % Change		3.24%	5.09%	5.87%	-0.06%

Purchase power expense is expected to increase due to the implementation of revised rates for as of July 1, 2015. This increase is also compounded by forecast sales growth in 2015 and 2016. However, Company expects growth to be lower there after due to a declining provincial economy as the Vale hydromet facility construction wind-down and the Hebron offshore platform is completed.

Based upon our analysis, purchased power forecast for 2015, 2016 and 2017 appears consistent with billing rates from Newfoundland and Labrador Hydro and forecast increases in energy sales.

Non-Regulated Expenses

Our review of non-regulated expenses included the following procedures:

- assess the Company's Compliance with Board Orders;
- compared non-regulated expenses for the 2015, 2016 and 2017 forecast to prior years and investigated any unusual fluctuations.

Table 38: Non-regulated Expenses 2013-2017

Non-regulated expenses ('000)	Actual 2013	Actual 2014	Forecast 2015	Forecast 2016	Forecast 2017
Labour Costs	$ 658	$ 754	$ 695	$ 526	$ 659
Intercompany Charges	1,131	1,669	1,607	2,147	2,245
Community Relations and Other	234	360	285	290	295
Corporate Advertising	19	18	25	26	26
Non-regulated Expenses Before Tax	2,042	2,801	2,612	2,989	3,225
Less: Income Taxes	592	812	757	867	935
Less: Part VI.1 Tax	12,814	-	-	-	-
Non-regulated Expenses After Tax	$ (11,364)	$ 1,989	$ 1,855	$ 2,122	$ 2,290

The 2015, 2016 and 2017 non-regulated expenses have been forecast at $2,612,000, $2,989,000 and $3,225,000 (before tax) respectively, as compared to $2,801,000 in 2014.

The significant fluctuation between 2013 and 2014 is due to the Part VI.1 tax adjustment. This alteration is a result from the payment by Fortis of dividends on its preferred shares. The Company noted that Part VI.1 tax is unrelated to its regulated operations and is dependent on Fortis Inc.'s corporate tax planning and preferred share dividend payment, and the Company's capacity to cover this tax. The amount for 2013 represented a one-time income tax recovery related to the enactment of proposed corporate income tax rate changes.

In compliance with P.U. 19 (2003) the Company has classified short term incentive payouts in excess of 100% of target payouts as non-regulated expense. For 2016 and 2017, the Company has estimated that performance will be at 100% of targets and therefore the expectation is that the STI payout will not exceed 100%. Details on the short term incentive payouts are included in this report under the heading STI Program.

Based upon our review and analysis, nothing has come to our attention to indicate that the amounts reported as non-regulated expenses, as summarized above, are unreasonable or not in accordance with Board Orders.

Proposed Forecast Revenue

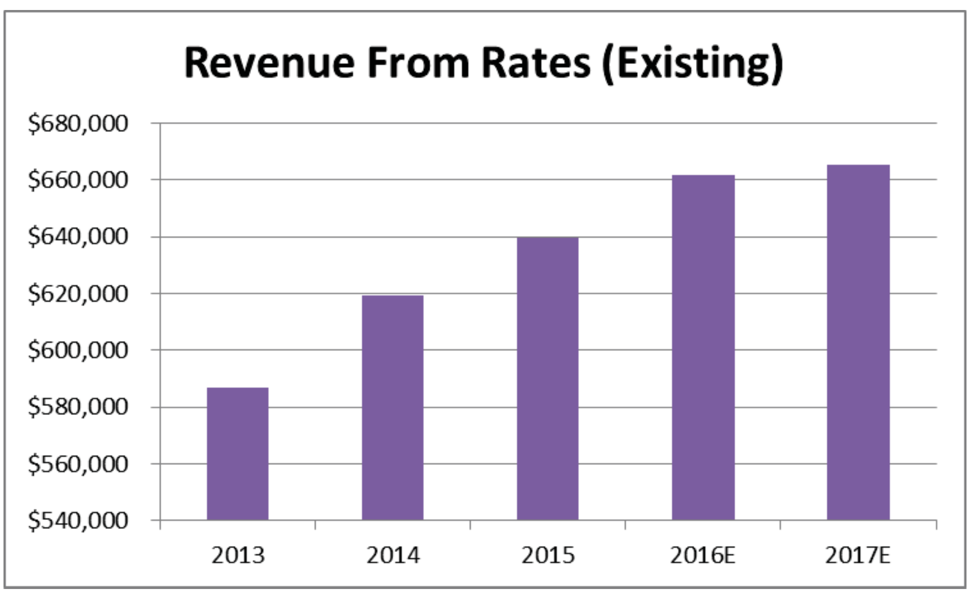
Revenue from Rates

We have compared the actual revenues for 2013 to 2014 to the forecast revenues using existing rates for 2015 to 2017 to assess any significant trends. The Company has indicated in its Application that the revenue forecast is based on the "Customers, Energy and Demand Forecast" dated August 2015. The results of this analysis by rate class are as follows:

Table 39: Existing Revenue from Rates 2013-2017

(000's)	Actual 2013 (Note 1)	Actual 2014	Forecast 2015	Forecast 2016	Forecast 2017
Residential	$ 367,550	$ 390,614	$ 404,082	$ 419,804	$ 423,256
General Service					
0-100 kw	81,625	82,080	84,783	88,154	88,821
110-1000 kva	83,223	88,789	93,707	96,515	97,510
Over 1000 kva	36,961	39,743	38,609	38,705	36,979
Streetlighting	14,633	15,262	15,522	15,691	15,755
Discounts Forfeited	2,844	3,016	2,970	2,906	2,925
Revenue From Rates	$ 586,836	$ 619,504	$ 639,673	$ 661,775	$ 665,246
Year over year % change		5.57%	3.26%	3.46%	0.52%

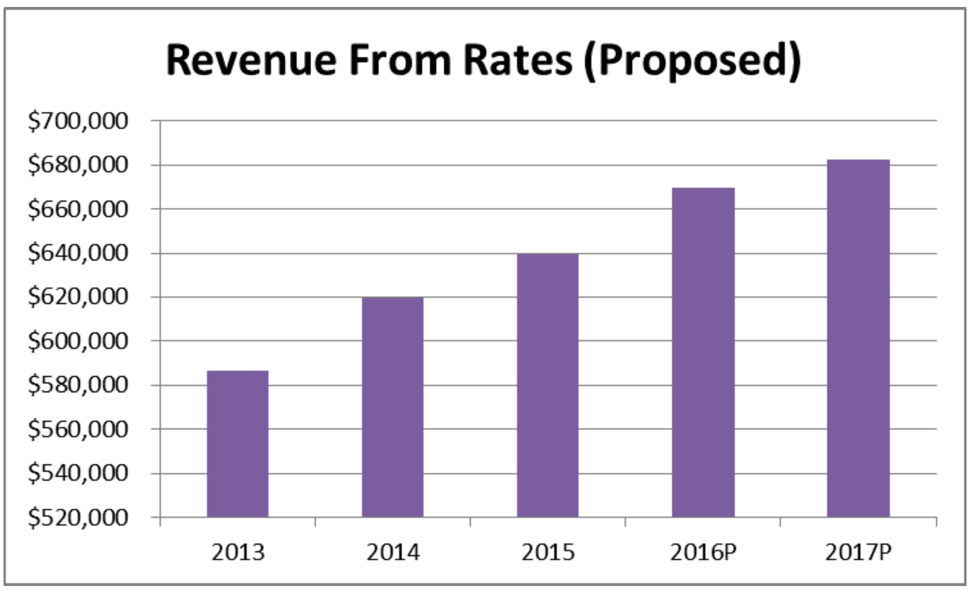
Note 1: Includes an ($68k) adjustment related to excess earnings.



The table below summarizes the actual revenues for 2013 to 2014 to the forecast revenues using proposed rates for 2016 to 2017 to assess any significant trends:

Table 40: Proposed Revenue from Rates 2013-2017

(000's)	Actual 2013	Actual 2014	Forecast 2015	Proposed 2016	Proposed 2017
Residential	$ 367,550	$ 390,614	$ 404,082	$ 425,495	$ 435,908
General Service					
0-100 kw	81,625	82,080	84,783	89,278	91,273
110-1000 kva	83,223	88,789	93,707	96,766	98,058
Over 1000 kva	36,961	39,743	38,609	39,279	38,101
Streetlighting	14,633	15,262	15,522	15,931	16,237
Discounts Forfeited	2,844	3,016	2,970	2,936	3,001
Revenue From Rates	$ 586,836	$ 619,504	$ 639,673	$ 669,685	$ 682,578
Year over year % change		5.57%	3.26%	4.69%	1.93%



The Company's revenues have been increasing by various percentages since 2013. The Company has noted the following reasons for the changes in the revenue levels from 2013 to 2017:

- The 5.6% increase in 2014 over 2013 was primarily due to customer and sales growth along with the rate increase on July 1, 2013 as a result of the 2013/2014 GRA for Newfoundland Power. These rates were in effect for 12 months in 2014 versus six months in 2013.
- The 2015 forecast increase in revenue of 3.3% over 2014 is primarily due to the July 31, 2015 rate increase, as well as customer and sales growth.
- The 2016 forecast increase in revenues using existing rates in effect is 3.5% over the 2015 forecast. Under the new rates proposed in this Application, the increase in revenues for 2016 is forecast at 4.7%, which is a combination of customer and sales growth, and the proposed rate increase of 3.1%.

- The 2017 forecast increase in revenues using existing rates in effect is 0.5% over the 2016 forecast. Under the new rates proposed in this Application, the increase in revenues for 2017 over proposed 2016 is 1.9%, which is a combination of customer and sales growth and the proposed rate increase of 3.1% being enacted the entire twelve months. The proposed rates would take effect July 1, 2016.

The number of customers and the GWh's sold to these customers for 2013 to 2014 and forecast 2015 to 2017 and proposed 2016 and 2017 are as follows:

Table 41: Customers and Electricity Sold 2013-2017

	Actual 2013	Actual 2014	Forecast 2015	Forecast 2016	Forecast 2017
Customers	255,618	258,879	261,093	263,089	264,931
% Change		1.28%	0.86%	0.76%	0.70%
GWh Sold	5,763	5,899	5,963	5,993	6,018
% Change		2.36%	1.09%	0.50%	0.42%

	Actual 2013	Actual 2014	Forecast 2015	Proposed 2016	Proposed 2017
Customers	255,618	258,879	261,093	263,089	264,931
% Change		1.28%	0.86%	0.76%	0.70%
GWh Sold	5,763	5,899	5,963	5,985	5,990
% Change		2.36%	1.09%	0.36%	0.09%

As the above table indicates, from 2013 to 2014 the number of customers increased by 1.28%. This trend is forecast to continue for 2015 to 2017 forecast with an annual rate increase of 0.86%, 0.76%, and 0.70%, respectively. GWhs sold increased by 2.36% from 2013 to 2014. The Company has forecast growth in GWhs sold of 1.09%, 0.50%, and 0.42% for 2015, 2016, and 2017 under existing rates. The decrease in GWhs sold from existing to proposed forecast is related to the elasticity effects of the rate increase.

In reviewing the 2015 and 2017 forecast revenues, we agreed all forecast amounts to supporting schedules provided by the Company. In addition, we calculated the average revenue forecast per customer by rate class to assess its reasonableness. We also analyzed all revenue items for any significant or unusual variances.

Based on our procedures nothing has come to our attention to indicate the forecast revenues from rates for 2015, 2016 and 2017 appear unreasonable.

Other Revenue

The Company's other revenue from 2013 to 2014 and forecast for 2015, 2016, and 2017 is as follows:

Table 42: Other Revenue 2013-2017

($000s)	Actual 2013	Actual 2014	Forecast 2015	Forecast 2016	Forecast 2017
Pole Attachment	$ 1,525	$ 1,687	$ 1,705	$ 1,722	$ 1,761
Provisioning Work	1,039	1,080	729	698	688
Customer account interest	996	1,092	983	992	998
Interest on RSA	1,019	255	61	34	(63)
Wheeling Charges	672	696	705	696	685
Miscellaneous	2,194	760	728	700	701
Total	**$ 7,445**	**$ 5,570**	**$ 4,911**	**$ 4,842**	**$ 4,770**
Year to year % change		(25.18%)	(11.83%)	(1.41%)	(1.49%)

($000s)	Actual 2013	Actual 2014	Forecast 2015	Proposed 2016	Proposed 2017
Pole Attachment	$ 1,525	$ 1,687	$ 1,705	$ 1,722	$ 1,761
Provisioning Work	1,039	1,080	729	698	688
Customer account interest	996	1,092	983	992	998
Interest on RSA	1,019	255	61	-	-
Wheeling Charges	672	696	705	696	685
Miscellaneous	2,194	760	728	700	701
Total	**$ 7,445**	**$ 5,570**	**$ 4,911**	**$ 4,808**	**$ 4,833**
Year to year % change		(25.18%)	(11.83%)	(2.10%)	0.52%

The tables above indicate the following variances:

- Provisioning work - The Company has indicated that provisioning work forecast for 2015, 2016 and 2017 shows a decline from 2014 actual revenue as a result of the Bell Aliant Fibre OP project which was substantially complete in 2014.
- Customer account interest - This account mainly reflects the balance and aging of customer accounts. Typically, there is a relationship between the interest on overdue accounts and uncollectible bills, which are mainly the number of customer accounts referred to a collections agency and/or declared bankruptcy. During 2014, uncollectible bills increased by approximately $0.6 million and interest on overdue accounts increased by approximately $0.1 million.

- Interest on RSA - The average outstanding balance for 2013 was much higher than the 2014 average balance. Transfers to the RSA for 2013 related to PEVDA, OPEVDA and the ESCV were approximately $3 million higher than in 2014. Higher balances for the first six months of 2013 resulted in higher interest costs. For the last six months, the 2013 balances were similar to 2014 due to 2013 July 1st RSP/RSA rate change.
- Miscellaneous – There is a variance of $1.4 million between 2013 and 2014, which is primarily due to the 2013 sale of land of $1.3 million. In addition, customer jobbing revenue was higher by approximately $70,000 in 2013.

Based on our procedure nothing has come to our attention to indicate the forecast other revenues for 2015, 2016 and 2017 appear unreasonable.

Proposed Revenue from Rates

The Company is proposing that the Board approve rates, tolls and charges effective for service provided on and after July 1, 2016, to provide an average increase by class in electrical rates of 3.1%, based upon:

a) a forecast average rate base for 2016 of $1,060,331,000 and for 2017 of $1,105,064,000;
b) a rate of return on average rate base for 2016 of 7.66% in the range of 7.48% to 7.84% and for 2017 of 7.64% in a range of 7.46% to 7.82%; and
c) a forecast revenue requirement to be recovered from electrical rates, following implementation of the proposals set out in paragraphs 11 of the Application, of $669,685,000 for 2016 and $682,578,000 for 2017.

We have reviewed the Company's proposed rates effective July 1, 2016. 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; and,

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

The following table compares July 1, 2015 rates to July 1, 2016 proposed rates by class including RSA and MTA:

Table 43: Existing and Proposed Rates, Tolls & Charges

Board of Commissioners of Public Utilities
Newfoundland Power Inc. - Verification of Revised Rates
Comparison of Existing and Proposed Rates, Tolls & Charges

	Existing RATES July 1, 2015	PROPOSED RATES July 1, 2016	CHANGE ($)	CHANGE (%)
DOMESTIC				
Total Customers for Class (000's)	226,839	228,654	1,815.00	0.80%
DOMESTIC - RATE # 1.1				
Basic Customer Charge (Monthly)				
Not Exceeding 200 AMP service	$ 15.70	$ 16.26	$0.56	3.57%
Exceeding 200 AMP Service	$ 20.70	$ 21.26	$0.56	2.71%
Energy Charge - All Kilowatt Hours (Cents/kWh)	$ 0.10573	$ 0.10959	$0.00386	3.65%
Minimum Monthly Charge				
Not Exceeding 200 AMP service	$ 15.70	$ 16.26	$0.56	3.57%
Exceeding 200 AMP Service	$ 20.70	$ 21.26	$0.56	2.71%
Prompt Payment Discount	1.50%	1.50%		0.00%
DOMESTIC - RATE # 1.1S				
Basic Customer Charge (Monthly)				
Not Exceeding 200 AMP service	$ 15.70	$ 16.26	$0.56	3.57%
Exceeding 200 AMP Service	$ 20.70	$ 21.26	$0.56	2.71%
Energy Charge - All Kilowatt Hours (Cents/kWh)				
Winter Seasonal	$ 0.11526	$ 0.11912	$0.00386	3.35%
Non-Winter Seasonal	$ 0.09276	$ 0.09662	$0.00386	4.16%
Minimum Monthly Charge				
Not Exceeding 200 AMP service	$ 15.70	$ 16.26	$0.56	3.57%
Exceeding 200 AMP Service	$ 20.70	$ 21.26	$0.56	2.71%
Prompt Payment Discount	1.50%	1.50%		0.00%
G.S. 0-100 kW (110 kVA) - RATE # 2.1				
Total Customers for Class (000's)	22,157	22,255	98.00	0.44%
Basic Customer Charge (Monthly)				
Umetered	NA	$17.65	NA	NA
Single Phase	$21.93	$21.65	-$0.28	-1.28%
Three Phase	NA	$27.65	NA	NA
Demand Charge Regular				
Winter	$0.0910	$0.0934	$0.0024	2.64%
Other	$0.0660	$0.0684	$0.0024	3.64%
Energy Charge - All Kilowatt Hours (Cents/kWh)				
First 3,500 kilowatt-hours	$0.10534	$0.10861	$0.00327	3.10%
All excess kilowatt-hours	$0.07791	$0.08033	$0.00242	3.11%
Maximum Monthly Charge	$0.18775 plus B.C.C.	$0.19345 plus B.C.C.	$0.00570	3.04%
Minimum Monthly Charge				
Umetered	NA	$17.65	NA	NA
Single Phase	$21.93	$21.65	-$0.28	-1.28%
Three Phase	$36.03	$33.65	-$2.38	-6.61%
Prompt Payment Discount	1.50%	1.50%		0.00%

Table 43: Existing and Proposed Rates, Tolls & Charges (Con`t)

Board of Commissioners of Public Utilities
Newfoundland Power Inc. - Verification of Revised Rates
Comparison of Existing and Proposed Rates, Tolls & Charges

	Existing RATES July 1, 2015	PROPOSED RATES July 1, 2016	CHANGE ($)	CHANGE (%)
G.S. 110-1000 kW - RATE # 2.3				
Total Customers for Class (000's)	1,216	1,223	7.00	0.58%
Basic Customer Charge (Monthly)	$50.08	$50.41	$0.33	0.66%
Demand Charge Regular				
Winter (kW)	$7.86	$7.88	$0.02	0.25%
Other (kW)	$5.36	$5.38	$0.02	0.37%
Energy Charge (Cents/kWh)				
First 150 kWh	0.09156	0.09213	$0.00057	0.62%
All Excess kWh	0.07286	0.07329	$0.00043	0.59%
Maximum Monthly Charge (Cents/kWh + BCC)	0.18775 plus B.C.C.	0.19345 plus B.C.C.	$0.0057	3.04%
Minimum Monthly Charge	$50.08	$50.41	$0.3300	0.66%
Prompt Payment Discount	1.50%	1.50%	$0.00	0.00%
G.S. 1000 kVA - RATE # 2.4				
Total Customers for Class (000's)	63.00	63.00	-	0.00%
Basic Customer Charge (Monthly)	$85.13	$87.71	$2.58	3.03%
Demand Charge Regular				
Winter (kVA)	$7.41	$7.57	$0.16	2.16%
Other (kVA)	$4.91	$5.07	$0.16	3.26%
Energy Charge (Cents/kWh)				
First 75,000 kWH	0.08605	0.0887	$0.00265	3.08%
All Excess kWH	0.07041	0.07258	$0.00217	3.08%
Maximum Monthly Charge (Cents/kWh + BCC)	0.18775 plus BCC	0.19345 plus BCC	$0.01	3.04%
Minimum Monthly Charge (kVA of max. demand)	$85.13	$87.71	$2.58	3.03%
Prompt Payment Discount	1.50%	1.50%	$0	0.00%
STREET & AREA LIGHTING RATES				
Total Customers for Class (000's)	10,818	10,894	76.00	0.70%
FIXTURES				
Sentinel/Standard				
High Pressure Sodium				
100W	$16.78	$17.38	$0.60	3.58%
150W	21.13	21.36	$0.23	1.09%
250W	29.88	29.51	-$0.37	-1.24%
400W	41.17	40.36	-$0.81	-1.97%
Post Top				
High Pressure Sodium				
100W	18.20	18.80	$0.60	3.30%
Poles				
Wood	$7.24	$6.59	-$0.65	-8.98%
30' Concrete or Metal, direct buried	10.46	9.43	-$1.03	-9.85%
45' Concrete or Metal, direct buried	14.74	15.46	$0.72	4.88%
25' Concrete or Metal,PT, direct buried	7.99	7.01	-$0.98	-12.27%
Underground Wiring				
All sizes and types of fixtures	$12.80	$16.05	$3.25	25.39%

Based on our procedures, we find that the revenue requirement proposed by the Company is calculated based upon the revised Schedule of Rates, Tolls and Charges effective July 1, 2016 and the factors proposed in this Application.

System of Accounts

Section 58 of the *Public Utilities Act* permits the Board to prescribe the form of accounts to be maintained by the Company.

The objective of our review of the Company's accounting system and code of accounts was to ensure that it can provide information sufficient to meet the reporting requirements of the Board. We have observed that the Company has in place a well-structured, comprehensive system of accounts and reporting structure. The system allows for adequate flexibility to allow the Company to meet its own and the Board's reporting requirements.

On March 28, 2014, the Company filed a summary of revisions to its system of accounts with the Board, along with a copy of the revised System of Accounts as part of the Company's 2013 Annual Report. The Company indicated that the revisions were mainly due to changes arising from specific Board Orders. The revisions consisted of the addition of new accounts, the deletion of older accounts that have been replaced by other accounts or are no longer being used, as well as changes to account descriptions. We have confirmed with the Company that no further changes have been made since this time.

Based upon our review of the Company's financial records, we have found that they are in compliance with the system of accounts prescribed by the Board. The system of accounts is comprehensive and well-structured and provides adequate flexibility for reporting purposes.

Newfoundland Power Inc.

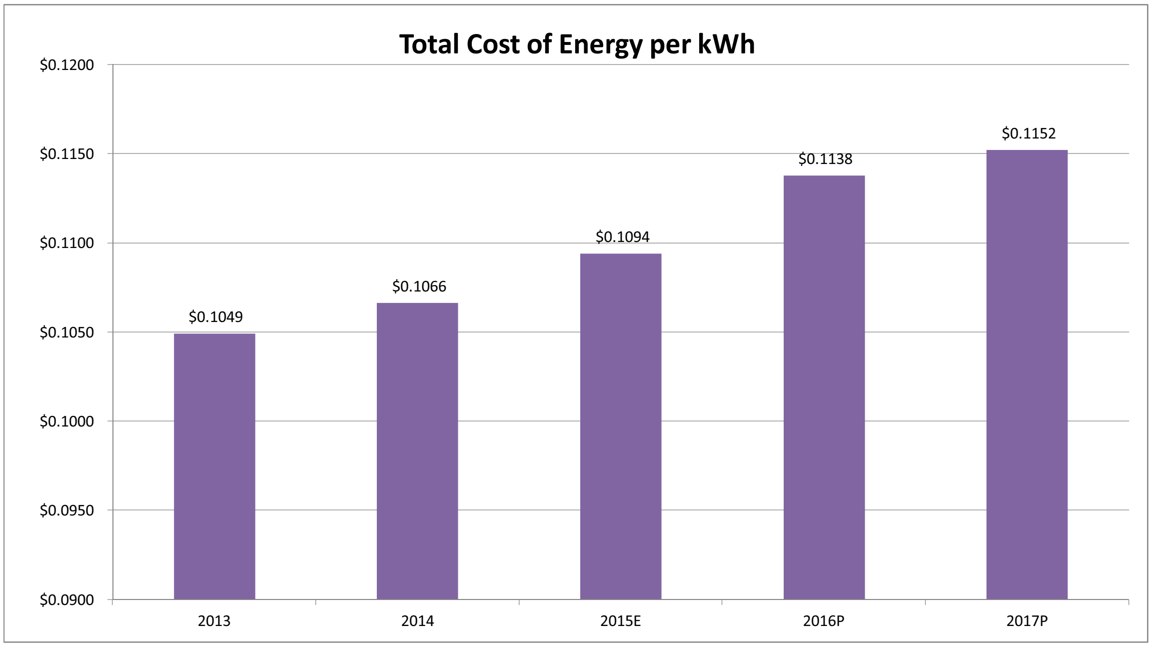
Comparison of Total Cost of Energy to kWh Sold

(000)'s

Year	kWh sold	Operating Expenses	Purchased Power	Depreciation / Deferrals	Finance Charges	Income Taxes	Net Income	Total Cost of Energy	Cost per kWh
2013	5,763,000	$ 79,265	$ 390,210	$ 46,196	$ 35,624	$ 14,866	$ 38,556	$ 604,717	$ 0.1049
2014	5,899,000	$ 81,171	$ 402,843	$ 53,278	$ 35,791	$ 16,201	$ 39,829	$ 629,113	$ 0.1066
2015E	5,963,000	$ 81,212	$ 423,335	$ 55,931	$ 35,370	$ 16,210	$ 40,321	$ 652,379	$ 0.1094
2016P	5,985,000	$ 80,699	$ 448,197	$ 52,259	$ 35,429	$ 18,585	$ 45,809	$ 680,978	$ 0.1138
2017P	5,990,000	$ 78,062	$ 447,927	$ 60,211	$ 36,773	$ 19,598	$ 47,667	$ 690,238	$ 0.1152

*2013 to 2015 is based on information provided in Exhibit 3 of the supporting materials to the GRA.

**2016 to 2017 is based on information provided in Exhibit 5 of the Supporting Materials to the GRA.



Newfoundland Power Inc. **Schedule 2**

Comparison of Gross Operating Expenses to kWh Sold

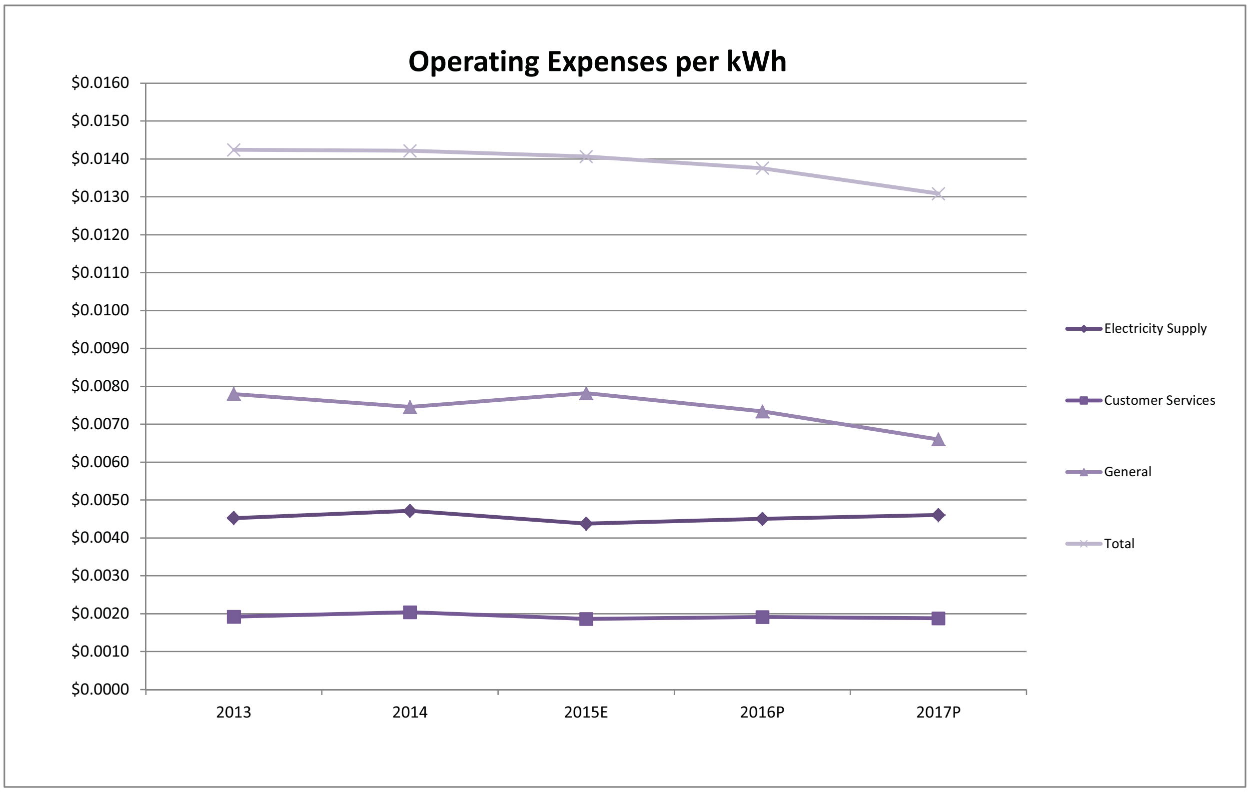
(000's)

		Electricity Supply		Customer Services		General *		Totals	
Year	kWh sold	Cost	Cost per kWh	Cost	Cost per kWh	Cost	Cost per kWh	Cost	Cost per kWh
2013	5,763,000	$ 26,072	$0.0045	$ 11,072	$0.0019	$ 44,946	$0.0078	$ 82,090	$0.0142
2014	5,899,000	$ 27,817	$0.0047	$ 12,042	$0.0020	$ 44,008	$0.0075	$ 83,867	$0.0142
2015E	5,963,000	$ 26,112	$0.0044	$ 11,108	$0.0019	$ 46,649	$0.0078	$ 83,869	$0.0141
2016P	5,985,000	$ 26,961	$0.0045	$ 11,449	$0.0019	$ 43,921	$0.0073	$ 82,331	$0.0138
2017P	5,990,000	$ 27,575	$0.0046	$ 11,271	$0.0019	$ 39,550	$0.0066	$ 78,396	$0.0131

* Based on information in Exhibit 1 of the supporting materials to the GRA.

* General expenses also include employee future benefits costs, non-regulated expenses, and amortization of hearing costs.

*** 2015 to 2017 is based on information in Exhibit 1 of the Supporting Materials to the GRA.



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