Grant Thornton

Mr. Robert Byrne
Board of Commissioners of Public Utilities
120 Torbay Road
Prince Charles Building
St. John's, NL A1A 5B2

Grant Thornton LLP
Suite 300
15 International Place
St. John's, NL
A1A 0L4

T (709) 778-8800
F (709) 722-7892
www.GrantThornton.ca

July 31, 2014

Dear Mr. Byrne,

Re: Newfoundland Power Inc.
2015 Capital Budget Application

We have completed our review as requested in your letter dated July 18, 2014 relating to Newfoundland Power Inc.'s (the "Company's") 2015 Capital Budget Application as it pertains to the calculation of the 2013 actual average rate base and the calculations of the 2014 and 2015 forecast rate base additions, deductions and allowances.

The results of our review for each required task are noted below:

2013 AVERAGE RATE BASE CALCULATION

Pursuant to P.U. 32 (2007), the Board of Commissioners of Public Utilities (the "Board") approved the Company's proposal to complete its transition to the Asset Rate Base Method ("ARBM") commencing January 1, 2008. The actual average rate base for 2013 as calculated by the Company under the ARBM and provided in Schedule D of its Application is $915,820,000 which is an increase of $32,775,000 (3.7%) over the average rate base for 2012 of $883,045,000 and a decrease of $2,896,000 (0.32%) over the average rate base for test year 2013 of $918,716,000.

The net change in the Company's average rate base from 2012 to 2013 can be summarized as follows:

(000's)	**2013**	**2012**
Average rate base - opening balance	**$ 883,045**	$ 876,356
Change in average deferred charges and deferred regulatory costs	**4,575**	881
Average change in:		
Plant in service	**64,979**	22,922
Accumulated depreciation	**(23,813)**	(8,685)
Contributions in aid of construction	**(1,449)**	(370)
Weather normalization reserve	**(19)**	(1,425)
Other post employment benefits	**(8,158)**	(7,308)
Future income taxes	**(505)**	556
Rate base allowances	**(3,172)**	468
Other rate base components (net)	**337**	(350)
Average rate base - ending balance	**$ 915,820**	$ 883,045

Our procedures with respect to verifying the calculation of the average rate base were directed towards the verification 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 audited financial statements and internal accounting records, where applicable;
- agreed component data (capital expenditures; depreciation; etc.) to supporting documentation;
- checked the clerical accuracy of the continuity of the rate base for 2013; and
- agreed the methodology used in the calculation of the average rate base to the Public Utilities Act to ensure it is in accordance with Board Orders and established policy and procedure.

The average rate base of $915,820,000 filed in Schedule D of its Application differs from the average rate base of $915,612,000 as filed in Return 3 of the Company's 2013 Annual Report to the Board. The revisions included on Schedule D resulted in an overall increase of $208,000 in average rate base as compared to Return 3 due to the following:

- An increase in materials and supplies allowance of $272,000 as, according to the Company, Return 3 material and supplies allowance understated the final material and supplies costs in 2013 included in Schedule D.
- A decrease of $64,000 resulting from the exclusion of deferred credit facility costs in Schedule D. The deferred credit facility costs are included as a component of the

Company's weighted average cost of capital and are excluded from the average rate base calculation. Return 3 included the deferred credit facility costs in error.

Based upon the results of the above procedures we did not note any discrepancies in the calculation of the 2013 average rate base, and therefore conclude that the 2013 average rate base included in Schedule D of the Company's Application is accurate and in accordance with established practice and Board Orders.

RATE BASE ADDITIONS, DEDUCTIONS AND ALLOWANCES

In compliance with P.U. 19 (2003), Newfoundland Power Inc. has filed evidence with the Board pertaining to its forecast deferred charges, including pension costs, to be included in the calculation of the forecast average rate base for 2014 and 2015 in its 2015 Capital Budget application. The report also provides a comprehensive review of all additions, deductions and allowances included in the rate base, with the exception of plant investment. Each, in turn, is reviewed including the forecast deferred charges which are included in the rate base additions section.

RATE BASE ADDITIONS

The forecast additions to rate base for 2014 and 2015 and the actual additions in 2012 and 2013 as presented by the Company are as follows:

($000's)	**Actual 2012**	**Actual 2013**	**Forecast 2014**	**Forecast 2015**
Deferred Pension Costs	$ 100,113	$ 101,159	$ 103,831	$ 109,147
Credit Facility Issue Costs	239	-	-	-
Cost Recovery Deferral – Seasonal/TOD Rates	93	95	80	86
Cost Recovery Deferral – Hearing Costs	-	644	322	-
Cost Recovery Deferral – Amortizations	3,320	2,214	1,107	-
Cost Recovery Deferral – 2012 Cost of Capital	1,766	1,177	589	-
Cost Recovery Deferral – 2013 Revenue Shortfall	-	2,252	1,126	-
Cost Recovery Deferral – Conservation	227	2,085	4,912	7,548
Customer Finance Programs	1,446	1,363	1,450	1,450
Total Additions	$ 107,204	$ 110,989	$ 113,417	$ 118,231

Source: Newfoundland Power Inc. - 2015 Capital Budget Application
Report on *Rate Base: Additions, Deductions & Allowance*s - Table 1

Our comments with respect to the additions to rate base are noted below:

Deferred Pension Costs

Deferred pension costs are the result of the pension funding exceeding the pension expense as determined in accordance with the recommendations of U.S. GAAP.

According to the table below, the forecast pension plan funding for 2014 and 2015 is $13,755,000 and $13,836,000 and the forecast pension plan expense is $11,083,000 and $8,520,000 for 2014 and 2015 respectively. The difference between the funding and the expense, as indicated below, represents the increase in deferred pension costs forecast for 2014 and 2015.

($000's)	Actual 2012	Actual 2013	Forecast 2014	Forecast 2015
Deferred Pension Costs, January 1	$97,628	$100,113	$101,159	$103,831
Pension Plan Funding	13,638	13,791	13,755	13,836
Pension Plan Expense	(11,153)	(12,745)	(11,083)	(8,520)
(Decrease)/increase in Deferred Pension Costs	2,485	1,046	2,672	5,316
Deferred Pension costs, December 31	$ 100,113	$101,159	$ 103,831	$ 109,147

Source: Newfoundland Power Inc. - 2015 Capital Budget Application
Report on *Rate Base: Additions, Deductions & Allowance*s - Table 3

The forecast pension expense for 2014 and 2015 is $11,083,000 and $8,520,000 respectively compared to an actual expense in 2013 of $12,745,000. The actual and forecast pension expense included in the table above is consistent with calculations provided by the Company's actuary. Based on our review of information provided by the Company, the forecast pension expense is calculated in accordance with the recommendations of U.S. GAAP and relevant Board Orders.

The forecast pension funding for 2014 and 2015 is $13,755,000 and $13,836,000 respectively, compared to actual funding in 2013 of $13,791,000. According to the Company, pension funding for 2014 and 2015 is based on the latest actuarial report and assumes special funding payments of $10.7 million per year. The forecast funding amounts has been agreed to schedules provided by the Company's actuary.

Based on our review of forecast deferred pension costs, we confirm that we have not noted any discrepancies or unusual items.

Deferred Credit Facility Issue Costs

On March 27, 2012 the committed credit facility of $100 million was renegotiated on similar terms as the previous facility, with a decrease in pricing, and an extension to a five year term maturing in August 2017. Legal and other administration costs of $115,000 resulting from the amendment are being amortized over the life of the agreement beginning in 2012.

There have been no adjustments to the rate base for actual 2013 and for forecasted 2014 and 2015 for deferred credit facility issue costs. These costs are included as a component of the Company's weighted average cost of capital and therefore are already reflected in the rate of return on average rate base for these years.

Based on our review of forecast deferred credit facility issue costs, we confirm that we have not noted any discrepancies or unusual items.

Cost Recovery Deferral – Seasonal/TOD Rates

On July 1, 2011 the Board approved the creation of the Optional Seasonal Rate Revenue and Cost Recovery Account by way of P.U. 8 (2011). This account is 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.

Based on our review of forecast deferred seasonal/TOD rates, we confirm that we have not noted any discrepancies or unusual items. The forecast deferred seasonal/TOD rates are consistent with approved Board Orders.

Cost Recovery Deferral – Hearing Costs

In P.U. 13 (2013), the Board approved a three year amortization period for the recovery of hearing costs related to the Company's 2013 General Rate Application "in the amount of $1,250,000" beginning in 2013. The actual external costs incurred for the 2013 General Rate Application were $965,000.

Based on our review of forecast deferred cost recovery relating to hearing costs, we confirm that we have not noted any discrepancies or unusual items, and it is consistent with approved Board Orders.

Cost Recovery Deferral – 2010 Regulatory Amortizations

On November 29, 2010, the Board issued P.U. 30 (2010) to approve the deferred recovery of 2011 costs of $1,642,000 until a further Order of the Board.

On October 27, 2011, the Board issued P.U. 22 (2011) to approve the deferred recovery of 2011 costs of $1,677,000 until a further Order of the Board.

In P.U. 13 (2013) the Board approved the amortization of these deferrals over three years using the straight-line method, commencing in 2013.

Based on our review of forecast Cost Recovery Deferral – 2010 Regulatory Amortizations, we confirm that we have not noted any discrepancies or unusual items. Cost Recovery Deferral – 2010 Regulatory Amortizations are consistent with approved Board Orders.

Cost Recovery Deferral – 2012 Cost of Capital

The Board issued P.U. 17 (2012) approving the deferred recovery of the amount of the difference in revenue for 2012, an after tax amount of $1,766,000, relating to the determination of Newfoundland Power's 2012 cost of capital.

In P.U. 13 (2013), the Board approved the amortization of the deferral over three years using straight-line method, commencing in 2013.

Based on our review of forecast Cost Recovery Deferral – 2012 Cost of Capital, we confirm that we have not noted any discrepancies or unusual items, and it is consistent with approved Board Orders.

Cost Recovery Deferral – 2013 Revenue Shortfall

In P.U. 13 (2013), the Board approved the proposed amortization over three years, commencing in 2013, of the 2013 revenue shortfall resulting from the implementation of new rates after January 1, 2013.

In P.U. 23 (2013), the Board approved the revenue shortfall in the amount of $2,815,000.

Based on our review of forecast Cost Recovery Deferral – 2013 Revenue Shortfall, we confirm that we have not noted any discrepancies or unusual items, and it is consistent with approved Board Orders.

Cost Recovery Deferral – Conservation

In P.U. 13 (2009), the Board approved the creation of a Conservation Cost Deferral Account. This account provides for the deferred recovery of 2009 costs (net of tax) related to the implementation of the Conservation Plan. The actual costs incurred in 2009 were $948,000 (net of tax).

In P.U. 43 (2009), the Board approved the after tax recovery of the 2009 deferred conservation costs over the remaining four years of the five year Energy Conservation Plan. The unamortized balance of the actual conservation costs at December 31, 2011 was $454,000. This balance was to be amortized evenly over the two year period from 2012 to 2013.

On April 17, 2013, the Board issued P.U. 13 (2013) and approved the deferral of annual customer energy conservation program costs and the amortization of annual costs over seven years with recovery through the Rate Stabilization Account. The actual costs incurred in 2013 were $2,085,000 with an annual amortization of $298,000 beginning in forecast 2014.

Based on our review of forecast deferred cost recovery relating to conservation, we confirm that we have not noted any discrepancies or unusual items, and it is consistent with approved Board Orders.

Customer Finance Programs

As indicated by the Company, Customer Finance Programs are loans provided to customers for purchase and installation of products and services related to conservation programs and contributions in aid of construction.

As part of the Company's transition to Asset Rate Base Method (ARBM) in 2008, inclusion of certain other assets and liabilities was required, including Customer Finance Programs receivables. The 2014 and 2015 forecast Customer Finance Programs receivable balance is fairly consistent with 2013 and therefore appears reasonable.

RATE BASE DEDUCTIONS

The forecast deductions to rate base for 2014 and 2015 and the actual figures for 2012 and 2013 as presented by the Company are as follows:

($000's)	Actual 2012	Actual 2013	Forecast 2014	Forecast 2015
Weather Normalization Reserve	$ 4,803	$ 5,058	$ 2,090	$ -
Other Post-Employment Benefits	14,617	23,515	31,820	39,463
Customer Security Deposits	851	840	800	800
Accrued Pension Liabilities	4,020	4,325	4,684	5,080
Future Income Taxes	2,504	1,872	2,197	3,718
Demand Management Incentive Account	558	(272)	152	-
Total Deductions	$ 27,353	$ 35,338	$ 41,743	$ 49,061

Source: Newfoundland Power Inc. - 2015 Capital Budget Application
Report on *Rate Base: Additions, Deductions & Allowance*s - Table 12

Our comments with respect to the deductions to rate base are noted below:

Weather Normalization Reserve

In P.U. 13 (2013) the Board approved the disposition of the annual balance in the Weather Normalization Reserve Account through the Rate Stabilization Account. At this time the Board also approved the amortization of the 2011 ending balance in the Weather Normalization Reserve of $5,020,000 over three years beginning in 2013.

Based on our review of the forecast weather normalization reserve, we confirm that we have not noted any discrepancies or unusual items.

OPEBs Liability

On June 30, 2010, the Company submitted an application to the Board requesting approval for the 2011 adoption of accrual accounting for OPEBs for regulatory purposes. Under the accrual basis, OPEBs costs are recognized as an expense as employees earn the benefits that they will receive after retirement. The application also addressed treatment of the projected OPEBs transitional balance as at January 1, 2011 and the creation of an OPEBs Cost Variance Deferral Account. On December 10, 2011 P.U. 31 (2010) approved the adoption of the accrual method of accounting for OPEBs costs and income tax related to OPEBs effective January 1, 2011 and the amortization using the straight line method over a 15-year period of the transitional balance estimated to be $52,400,000. The actual transitional balance was $52,560,000 resulting in annual amortization of $3,504,000.

The total amount of the deduction to rate base related to OPEBs for 2013 is $23,515,000 with $31,820,000 and $39,463,000 forecasted for 2014 and 2015 respectively. The actual and forecast OPEBs are consistent with calculations provided by the Company's actuary.

Customer Security Deposits

Customer Security Deposits are provided by customers in accordance with the Schedule of Rates, Rules and Regulations.

As part of the transition to ARBM in 2008 the inclusion of Customer Security Deposits was required as a component of rate base. The 2014 and 2015 forecast Customer Security Deposits are comparable to the actual amount reported in 2013.

Accrued Pension Liabilities

Accrued pension liabilities represent the executive and senior management supplemental pension benefits comprised of a defined benefit plan (Pension Uniformity Plan - PUP) and a defined contribution plan (Supplementary Employee Retirement Plan - SERP). The balance represents the cumulative costs of these unfunded plans, net of associated benefit payments.

As part of the transition to ARBM in 2008 the inclusion of accrued pension liabilities was required as a component of rate base. The 2014 and 2015 forecast accrued pension liabilities are fairly comparable with actual amount reported in 2013.

Future Income Taxes

Future Income Taxes arise due to the Board's approval of the Company's use of tax accrual accounting related to plant investment, pension costs and other employee future benefit costs.

Based on our review of Future Income Tax balances, we confirm that we have not noted any material discrepancies or unusual items, and it is consistent with approved Board Orders.

Demand Management Incentive Account

In P.U. 32 (2007) the Board approved the Company's proposal to establish the Demand Management Incentive Account ("DMI"). In P.U. 13 (2013) the Board approved the transfer of $785,000 equal to the balance in the 2012 DMI account plus related income tax effects to the Rate Stabilization Account as at March 31, 2013.

In P.U. 7 (2014) the Board approved a debit transfer of $383,000 equal to the balance in the 2013 DMI account plus related income tax effects to the Rate Stabilization Account as at March 31, 2014.

Based on our review of forecast DMI, we confirm that we have not noted any discrepancies or unusual items, and it is consistent with approved Board Orders.

RATE BASE ALLOWANCES

The Rate Base allowances included in the Company's rate base are the Cash Working Capital ("CWC") allowance and the Materials and Supplies allowance. These represent the average amount of investor-supplied working capital necessary to provide service.

Based on our review of the Rate Base Allowances, we confirm that the Company has applied the methodology outlined in the Company's 2013 General Rate Application and we have not noted any discrepancies. Furthermore, we have not noted any unusual items in the the forecast for 2014 and 2015.

I trust this is the information you requested. If you have any questions, please contact me.

Yours sincerely,
Grant Thornton LLP

Steve Power, CA
Partner