REDACTED

Request IR-62:

Please update the response to Consumer Advocate IR-3.

Response IR-62:

Please refer to the figure below which has been updated for June.

Month	Actual ($M)	Budget ($M)
January	[redacted]	[redacted]
February	[redacted]	[redacted]
March	[redacted]	[redacted]
April	[redacted]	[redacted]
May	[redacted]	[redacted]
June	[redacted]	[redacted]

CONFIDENTIAL (Attachment Only)

Request IR-63:

Please provide the response to Consumer Advocate IR-8 in electronic spreadsheet format with all formulas and references intact.

Response IR-63:

Please refer to Confidential Attachment 1, filed electronically.

CONFIDENTIAL (Attachment Only)

Request IR-64:

Please update the response to Consumer Advocate IR-9.

Response IR-64:

Please refer to Confidential Attachment 1.

NON-CONFIDENTIAL

Request IR-65:

Referring to the response to Consumer Advocate IR-9, please explain why deferred taxes are not offset against the deferred charge base on which interest is calculated.

Response IR-65:

Deferred taxes represent a non-cash asset or liability. The interest is intended to compensate for the financing of cash items. The deferred charge reflects a cash asset. Furthermore, the deferred tax position reverses and reflects only timing differences.

NON-CONFIDENTIAL

Request IR-66:

Referring to the response to Consumer Advocate IR-9, please explain why interest is calculated on the end of month deferred charge balance rather than the average deferred charge balance for the month.

Response IR-66:

Interest is calculated on the ending balance rather than the average balance, as this is consistent with the accounting policy and methodology adopted for the calculation of FAM Interest and Allowance for Funds Used During Construction (AFUDC).

NON-CONFIDENTIAL

Request IR-67:

Referring to the response to Larkin IR-9, did the Company get permission from the NUARB to defer the Workforce Reduction Costs and include those deferred costs in rate base?

Response IR-67:

Please refer to Larkin IR-26. The deferral is in compliance with NS Power's Accounting Policy 6930, approved by the Board. Please refer to Larkin IR-9 Attachment 1 for the Accounting Policy.

NON-CONFIDENTIAL

Request IR-68:

Referring to the response to Larkin IR-9, please provide workpapers supporting the deferred Workforce Reduction Costs of $5.1 million. The response should show actual cash expenditures and accrued liabilities and should show how the costs were developed.

Response IR-68:

Please refer to Larkin IR-26.

REDACTED

Request IR-69:

Referring to the response to Larkin IR-9, please provide the financial justification for the Workforce Reduction program, for which the costs were incurred in February 2012. The response should include the number of employees comprising the Workforce Reduction and the annual savings associated with the Workforce Reduction, with all supporting workpapers and calculations.

Response IR-69:

Please refer to Larkin IR-26. The total cost of the workforce reduction program was [redacted]. The financial justification for the program is supported by the estimated cost savings based on annual salary and related benefit costs as detailed in Larkin IR-26.

NON-CONFIDENTIAL

Request IR-70:

Referring to the response to Larkin IR-9, please explain where the amortization of the Workforce Reduction Costs is recorded and where that amortization is reflected on Schedule FOR-1.

Response IR-70:

The amortization reduces the Workforce Reduction deferred asset balance (line 14 of RB-02-RB-16 of the Application) and is reflected within line 13 in FOR-01 of the Application under Operating Maintenance and General (OM&G). Within OM&G it is included in Appendix E page 55 account code 059.

NON-CONFIDENTIAL

Request IR-71:

Referring to the response to Larkin IR-9, does the Company's forecast of labour expenses for 2013 reflect the Workforce Reduction in February 2012? If the response is affirmative please provide workpapers and documentation showing how the Workforce Reduction is incorporated into the forecast of expenses for 2013.

Response IR-71:

Please refer to Larkin IR-26.

REDACTED

Request IR-72:

Referring to the response to Consumer Advocate IR-15, please provide the same analysis of Salaries and Benefits for 2011 and 2012.

Response IR-72:

	Value (in millions of dollars)	
Item	**2011**	**2012F**
Salaries (includes base, variable, overtime, premiums)	116.3	[redacted]
Fringe Benefits	17.5	
Total*	133.8	

*Note: See OE-02-OE-09/OE-13 line 4 column (2) and (3) of the Application

As stated in CA IR-15, salaries include all base pay, incentives, and overtime.

Fringe Benefit Costs includes:

- Health and Dental Insurance benefit
- Disability Insurance benefit
- Accidental Death and Dismemberment Insurance benefit
- Life Insurance benefit
- Canada Pension Plan costs
- Workers Compensation Board expense
- Employment Insurance premiums

NON-CONFIDENTIAL

Request IR-73:

Please update the response to Consumer Advocate IR-17.

Response IR-73:

Please refer to the figure below.

Year 2012:

Date	Total FTEs
June	1917

Please note that of the total 1,917 full time employees (FTEs); 160 are term union employees hired to complete seasonal work on plant maintenance and capital projects, 21 are co-op or summer students and 38 are Customer Service Representatives hired in our Customer Care Center to cover summer vacations.

REDACTED

Request IR-74:

Referring to the response to Consumer Advocate IR-19, please provide the dollar amounts of the expenses to which each escalation factor was applied.

Response IR-74:

For the Application, the escalation rates assumed apply to the 2012 forecast cost groupings shown below with some exceptions. There are some components of labour, such as Corporate Adjustments that are not subject to escalation as they are based on items such as accrued vacation. Corporate Support Transfers are based on specific business unit costs and appropriate allocation rates and are therefore not based on escalation.

Please refer to the figure below. The escalation rates apply to the following amounts of expenses.

Escalated Costs		
Cost Grouping	**2012F ($M)**	**Escalation Factor**
Union and Non-Union Labour (Escalated)	[redacted]	[redacted]
Other Non-Labour Escalated	[redacted]	2.53%
Fleet Fuel	[redacted]	2.57%
Insurance	[redacted]	5.00%
Total	[redacted]	
Other	[redacted]	
Total Operating Costs	[redacted]	

Request IR-75:

Referring to the response to Consumer Advocate IR-19, please provide supporting documentation for the escalation rates used for insurance for 2012 and 2013.

Response IR-75:

The 7.5 percent and the 5.0 percent escalation rates assumed for forecasting 2012 and 2013 insurance were estimates based on a general awareness of the insurance industry and events which may have been occurring in the insurance market at the time the forecasted rates were provided.

The insurance program is comprised of multiple insurance coverages to protect assets and operations. Due to the size and nature of the business, and due to the fact that some of the risks are specialized, it is rare that any single insurance company will underwrite all of NS Power's risk in any particular area of coverage. As a result, the coverage in most areas is provided by multiple insurers, some or all of whom will re-insure portions of the risk they assume through the global re-insurance market.

Insurance premiums are the largest component of the insurance costs. Premiums can vary from year to year (either up or down) and are subject to a number of factors including:

- The physical assets of NS Power, which are insured under the property and machinery breakdown policies, are on a repair/replacement cost basis. On an annual basis, these assets are subject to an escalation factor to reflect increasing costs of replacing/repairing assets.

- Loss experience of the insurers as a result of the industry in general. Insurers' claims experience with the 'energy' industry sector will affect the rates. Also, global catastrophe claims such as windstorm/hurricane, earthquake and flood losses may stress insurers' financial results. To recover, insurers and re-insurers may increase rates.

- In the case of property and machinery breakdown insurers, there were a number of additional NS Power capital investments including an additional Tufts Cove unit, Lower Water Street building refurbishment, biomass project, and various wind development projects.

- In the case of casualty insurers, company production and revenue are used by insurers to determine the rates.

- New assets are insured under construction policies until the asset is considered in service. Thereafter the asset is insured under the operational insurance program. The timing of the move from construction coverage to operational coverage will impact the costs of operational coverage in the year of the transition.

- NS Power claims experience will affect pricing. Available insurer capacity, a reduction or increase in the amount of exposure insurers are willing to take will impact coverage and pricing.

- Global financial market impact on insurers and re-insurers.

- Underwriters views of NS Power's loss prevention initiatives or the perception of the risk.

- The number and type of vehicles insured by the company can also impact auto premiums.

NON-CONFIDENTIAL

Insurance coverage is renewed on an annual basis with precise terms and pricing not confirmed until binding of the coverage. As such, in forecasting future years there is not precise data upon which to base forecasts.

In addition to premiums, the insurance forecast also includes broker's fees, legal fees/expenses for claims settlements, payment of deductibles, claims adjusting services, payout of claims, and experts who may be retained for insurance related matters.

REDACTED

Request IR-76:

Referring to the response to Larkin IR-12, Attachment 1, please explain the decrease in the amortization of actuarial losses from 2014 to 2015. The response should include all supporting documentation and workpapers.

Response IR-76:

The amortization of actuarial gains and losses is performed using a 10 percent corridor approach and taking into account the market related value of assets as permitted by the accounting standards. This methodology was adopted by NS Power in order to minimize the year to year volatility in pension expense. In general terms, the amount which must be amortized each year is equal to (a) divided by (b), where:

(a) is the amount by which (i) exceeds (ii):

(i) the net unamortized actuarial gain or loss, less the amount of any actuarial gain or loss not yet included in the market related value of assets;

(ii) 10 percent of the greater of the projected benefit obligation and the market related value of assets.

(b) is the average remaining service life of the active employee group

The amount of actuarial losses that must be recognized in pension expenses declines over the projection period since the projections assume virtually no new actuarial gains or losses. At the same time, the 10 percent corridor increases over the projection period. As such, the balance of the amount subject to amortization (part (a) in the above paragraph) gradually becomes smaller

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over the projection period. A smaller amount subject to amortization results in a smaller amount recognized as part of pension expense.

The following figures are in millions:

		2013	2014	2015	2016	2017
A	Net unamortized actuarial loss/(gain) at start of year	[redacted]				
B	Actuarial loss (gain) not yet included in Market Related Value					
C	Actuarial gain/loss subject to amortization (before Corridor)					
D	10% Corridor (10% of greater of market related value of assets and obligations)					
E	Actual amount subject to amortization in current year					
F	Average Remaining Service Period (ARSP)					
G	Current Year Component					
H	Remaining amount to be amortized					
I	Actuarial loss (gain) at end of period on					
J	- Asset Return loss (gain)					
K	- Accrued Benefit Obligation (experience and assumptions) loss (gain)					
L	Net unamortized actuarial loss/(gain) at end of year					

Figures rounded to nearest $ million.
Figures may not add up exactly due to rounding.

NON-CONFIDENTIAL

Request IR-77:

Referring to the response to Liberty IR-39, please show the effect of the Rate Stabilization Plan separately, with workpapers supporting the deferrals and amortization.

Response IR-77:

Please refer to Attachment 1. This schedule does not include the 2012 Fixed Cost Recovery deferral as approved in the 2012 GRA.[1]

[1] NSPI 2012 General Rate Application, UARB Decision, NSUARB-NSPI-P-892, November 29, 2011.

Fixed Cost Recovery Deferral Rate Stabilization Plan Only													
Millions of dollars													
2013	**Jan-13**	**Feb-13**	**Mar-13**	**Apr-13**	**May-13**	**Jun-13**	**Jul-13**	**Aug-13**	**Sep-13**	**Oct-13**	**Nov-13**	**Dec-13**	**2013 Total**
FCR Beginning Balance	-	2.267	4.533	6.800	9.067	11.333	13.916	16.183	18.449	20.716	22.983	25.249	-
Plus: Additions	2.267	2.267	2.267	2.267	2.267	2.267	2.267	2.267	2.267	2.267	2.267	2.267	27.200
Add: Interest Expense	0.015	0.030	0.045	0.060	0.075	0.090	0.107	0.123	0.138	0.153	0.168	0.183	1.187
FCR Ending Balance (including interest)	2.282	4.563	6.845	9.127	11.409	13.916	16.290	18.572	20.854	23.135	25.417	28.387	28.387
Future Income Taxes	0.707	0.712	0.717	0.721	0.726	0.731	0.736	0.741	0.745	0.750	0.755	0.759	8.800
2014	**Jan-14**	**Feb-14**	**Mar-14**	**Apr-14**	**May-14**	**Jun-14**	**Jul-14**	**Aug-14**	**Sep-14**	**Oct-14**	**Nov-14**	**Dec-14**	**2014 Total**
FCR Beginning Balance	28.387	30.612	32.837	35.062	37.287	39.512	43.178	45.403	47.628	49.853	52.078	54.303	28.387
Plus: Additions	2.225	2.225	2.225	2.225	2.225	2.225	2.225	2.225	2.225	2.225	2.225	2.225	26.700
Add: Interest Expense	0.203	0.218	0.233	0.248	0.262	0.277	0.302	0.316	0.331	0.346	0.361	0.375	3.473
FCR Ending Balance (including interest)	30.815	33.055	35.295	37.534	39.774	43.178	45.705	47.945	50.185	52.424	54.664	58.559	58.559
Future Income Taxes	0.753	0.757	0.762	0.767	0.771	0.776	0.783	0.788	0.792	0.797	0.802	0.806	9.353
2015	**Jan-15**	**Feb-15**	**Mar-15**	**Apr-15**	**May-15**	**Jun-15**	**Jul-15**	**Aug-15**	**Sep-15**	**Oct-15**	**Nov-15**	**Dec-15**	**2015 Total**
FCR Beginning Balance	58.559	58.559	58.559	58.559	57.726	56.892	58.358	57.525	56.691	55.857	55.023	54.189	58.559
Less: Amortiziation	-	-	-	(0.834)	(0.834)	(0.834)	(0.834)	(0.834)	(0.834)	(0.834)	(0.834)	(0.834)	(7.504)
Add: Interest Expense	0.389	0.389	0.389	0.383	0.378	0.372	0.382	0.377	0.371	0.365	0.360	0.354	4.510
FCR Ending Balance (including interest)	58.948	58.948	58.948	58.109	57.270	58.358	57.907	57.067	56.228	55.389	54.549	55.565	55.565
Future Income Taxes	0.121	0.121	0.121	(0.140)	(0.141)	(0.143)	(0.140)	(0.142)	(0.143)	(0.145)	(0.147)	(0.149)	(0.928)
2016	**Jan-16**	**Feb-16**	**Mar-16**	**Apr-16**	**May-16**	**Jun-16**	**Jul-16**	**Aug-16**	**Sep-16**	**Oct-16**	**Nov-16**	**Dec-16**	**2016 Total**
FCR Beginning Balance	55.565	54.731	53.897	53.064	52.230	51.396	52.660	51.826	50.993	50.159	49.325	48.491	55.565
Less: Amortiziation	(0.834)	(0.834)	(0.834)	(0.834)	(0.834)	(0.834)	(0.834)	(0.834)	(0.834)	(0.834)	(0.834)	(0.834)	(10.006)
Add: Interest Expense	0.364	0.358	0.352	0.347	0.341	0.336	0.344	0.339	0.333	0.328	0.322	0.317	4.080
FCR Ending Balance (including interest)	55.095	54.255	53.416	52.577	51.737	52.660	52.171	51.331	50.492	49.653	48.813	49.640	49.640
Future Income Taxes	(0.146)	(0.148)	(0.149)	(0.151)	(0.153)	(0.154)	(0.152)	(0.153)	(0.155)	(0.157)	(0.159)	(0.160)	(1.837)

2017	**Jan-17**	**Feb-17**	**Mar-17**	**Apr-17**	**May-17**	**Jun-17**	**Jul-17**	**Aug-17**	**Sep-17**	**Oct-17**	**Nov-17**	**Dec-17**	**2017 Total**
FCR Beginning Balance	49.640	48.806	47.972	47.138	46.304	45.471	46.499	45.665	44.831	43.997	43.163	42.330	49.640
Less: Amortiziation	(0.834)	(0.834)	(0.834)	(0.834)	(0.834)	(0.834)	(0.834)	(0.834)	(0.834)	(0.834)	(0.834)	(0.834)	(10.006)
Add: Interest Expense	0.324	0.319	0.313	0.308	0.302	0.296	0.303	0.298	0.292	0.287	0.281	0.276	3.599
FCR Ending Balance (including interest)	49.130	48.291	47.451	46.612	45.773	46.499	45.968	45.129	44.289	43.450	42.611	43.233	43.233
Future Income Taxes	(0.158)	(0.160)	(0.161)	(0.163)	(0.165)	(0.167)	(0.164)	(0.166)	(0.168)	(0.170)	(0.171)	(0.173)	(1.986)
2018	**Jan-18**	**Feb-18**	**Mar-18**	**Apr-18**	**May-18**	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**	**Oct-18**	**Nov-18**	**Dec-18**	**2018 Total**
FCR Beginning Balance	43.233	42.399	41.565	40.731	39.897	39.064	39.836	39.003	38.169	37.335	36.501	35.667	43.233
Less: Amortiziation	(0.834)	(0.834)	(0.834)	(0.834)	(0.834)	(0.834)	(0.834)	(0.834)	(0.834)	(0.834)	(0.834)	(0.834)	(10.006)
Add: Interest Expense	0.282	0.276	0.271	0.265	0.259	0.254	0.259	0.254	0.248	0.242	0.237	0.231	3.078
FCR Ending Balance (including interest)	42.680	41.841	41.002	40.162	39.323	39.836	39.262	38.422	37.583	36.744	35.904	36.305	36.305
Future Income Taxes	(0.171)	(0.173)	(0.175)	(0.176)	(0.178)	(0.180)	(0.178)	(0.180)	(0.182)	(0.183)	(0.185)	(0.187)	(2.148)
2019	**Jan-19**	**Feb-19**	**Mar-19**	**Apr-19**	**May-19**	**Jun-19**	**Jul-19**	**Aug-19**	**Sep-19**	**Oct-19**	**Nov-19**	**Dec-19**	**2019 Total**
FCR Beginning Balance	36.305	35.471	34.637	33.803	32.970	32.136	32.632	31.799	30.965	30.131	29.297	28.464	36.305
Less: Amortiziation	(0.834)	(0.834)	(0.834)	(0.834)	(0.834)	(0.834)	(0.834)	(0.834)	(0.834)	(0.834)	(0.834)	(0.834)	(10.006)
Add: Interest Expense	0.236	0.230	0.225	0.219	0.213	0.208	0.211	0.206	0.200	0.195	0.189	0.184	2.515
FCR Ending Balance (including interest)	35.707	34.867	34.028	33.189	32.349	32.632	32.010	31.171	30.331	29.492	28.653	28.814	28.814
Future Income Taxes	(0.185)	(0.187)	(0.189)	(0.191)	(0.192)	(0.194)	(0.193)	(0.195)	(0.196)	(0.198)	(0.200)	(0.202)	(2.322)
2020	**Jan-20**	**Feb-20**	**Mar-20**	**Apr-20**	**May-20**	**Jun-20**	**Jul-20**	**Aug-20**	**Sep-20**	**Oct-20**	**Nov-20**	**Dec-20**	**2020 Total**
FCR Beginning Balance	28.814	27.980	27.146	26.312	25.479	24.645	24.843	24.009	23.175	22.342	21.508	20.674	28.814
Less: Amortiziation	(0.834)	(0.834)	(0.834)	(0.834)	(0.834)	(0.834)	(0.834)	(0.834)	(0.834)	(0.834)	(0.834)	(0.834)	(10.006)
Add: Interest Expense	0.186	0.180	0.175	0.169	0.164	0.158	0.159	0.154	0.148	0.143	0.137	0.132	1.906
FCR Ending Balance (including interest)	28.166	27.327	26.487	25.648	24.809	24.843	24.169	23.329	22.490	21.651	20.811	20.714	20.714
Future Income Taxes	(0.201)	(0.203)	(0.204)	(0.206)	(0.208)	(0.209)	(0.209)	(0.211)	(0.212)	(0.214)	(0.216)	(0.218)	(2.511)

2021	**Jan-21**	**Feb-21**	**Mar-21**	**Apr-21**	**May-21**	**Jun-21**	**Jul-21**	**Aug-21**	**Sep-21**	**Oct-21**	**Nov-21**	**Dec-21**	**2021 Total**
FCR Beginning Balance	20.714	19.880	19.046	18.213	17.379	16.545	16.420	15.587	14.753	13.919	13.085	12.251	20.714
Less: Amortiziation	(0.834)	(0.834)	(0.834)	(0.834)	(0.834)	(0.834)	(0.834)	(0.834)	(0.834)	(0.834)	(0.834)	(0.834)	(10.006)
Add: Interest Expense	0.132	0.126	0.121	0.115	0.110	0.104	0.104	0.098	0.092	0.087	0.081	0.076	1.247
FCR Ending Balance (including interest)	20.012	19.173	18.334	17.494	16.655	16.420	15.690	14.851	14.011	13.172	12.333	11.956	11.956
Future Income Taxes	(0.218)	(0.219)	(0.221)	(0.223)	(0.224)	(0.226)	(0.226)	(0.228)	(0.230)	(0.232)	(0.233)	(0.235)	(2.715)
2022	**Jan-22**	**Feb-22**	**Mar-22**	**Apr-22**	**May-22**	**Jun-22**	**Jul-22**	**Aug-22**	**Sep-22**	**Oct-22**	**Nov-22**	**Dec-22**	**2022 Total**
FCR Beginning Balance	11.956	11.122	10.288	9.454	8.620	7.787	7.313	6.479	5.645	4.812	3.978	3.144	11.956
Less: Amortiziation	(0.834)	(0.834)	(0.834)	(0.834)	(0.834)	(0.834)	(0.834)	(0.834)	(0.834)	(0.834)	(0.834)	(0.834)	(10.006)
Add: Interest Expense	0.074	0.068	0.063	0.057	0.052	0.046	0.043	0.037	0.032	0.026	0.021	0.015	0.535
FCR Ending Balance (including interest)	11.196	10.356	9.517	8.678	7.838	7.313	6.522	5.683	4.844	4.004	3.165	2.485	2.485
Future Income Taxes	(0.236)	(0.237)	(0.239)	(0.241)	(0.242)	(0.244)	(0.245)	(0.247)	(0.249)	(0.250)	(0.252)	(0.254)	(2.936)
2023	**Jan-23**	**Feb-23**	**Mar-23**	**Apr-23**	**May-23**	**Jun-23**	**Jul-23**	**Aug-23**	**Sep-23**	**Oct-23**	**Nov-23**	**Dec-23**	**2023 Total**
FCR Beginning Balance	2.485	1.652	0.818	-	-	-	-	-	-	-	-	-	2.485
Less: Amortiziation	(0.834)	(0.834)	(0.834)	-	-	-	-	-	-	-	-	-	(2.485)
Add: Interest Expense	0.011	0.005	0.016	-	-	-	-	-	-	-	-	-	-
FCR Ending Balance (including interest)	1.663	0.823	0.000	-	-	-	-	-	-	-	-	-	0.000
Future Income Taxes	(0.255)	(0.257)	(0.254)	-	-	-	-	-	-	-	-	-	(0.765)

NON-CONFIDENTIAL

Request IR-78:

Please describe and quantify all deferrals that NSPI is proposing as part of the Rate Stabilization Plan.

Response IR-78:

Please refer to Multeese IR-63.

NON-CONFIDENTIAL

Request IR-79:

Please explain whether NSPI is proposing to continue deferring the revenue difference between full operation of the Bowater and Port Hawkesbury paper mill at the ELI rate and the revenue actually received from those mills under the load retention tariffs.

Response IR-79:

NS Power is proposing to defer recovery of all forecast costs that would not otherwise be recovered by the average overall 3 percent rate adjustments. With no forecast recovery from NewPage or Bowater, these costs are forecast to be recovered from remaining customers. Absent the Rate Stabilization Plan, the recovery of the Fixed Cost Recovery (FCR) deferral, agreed in the 2012 GRA Settlement Agreement[1] and approved by the Board, would need to be recovered from other customers. In addition, the 2013 fixed costs associated with NewPage (as no load was forecasted in 2013) and Bowater (difference between the fixed costs that would have been recovered under the ELI 2P-RTP and what would be recorded under the LRT) would also need to be recovered. The Rate Stabilization Plan defers both of these costs.

[1] NSPI 2012 General Rate Application, Settlement Agreement, NSUARB-NSPI-P-892, September 19, 2011.

NON-CONFIDENTIAL

Request IR-80:

Please provide NSPI's projection of its revenue requirement and required rate increase in 2015, considering the deferrals proposed as part of the Rate Stabilization Plan.

Response IR-80:

Please refer to Avon IR-3 Attachment 1, page 13 of 15 for a projection of NS Power's 2015 revenue requirement and associated rate change. Please refer to Liberty IR-39 for the Rate Stabilization Plan deferral recovery schedule.

NON-CONFIDENTIAL

Request IR-81:

Regarding DE-03 - DE-04 Appendix N Page 5, please explain why NSPI proposes a lower increase for the unmetered class than the 11.5% increase for all other classes, even though NSPI reports that the unmetered class return is lower than returns for three other classes that receive the across-the-board increase.

Response IR-81:

Consistent with the previous general rate application submissions of 2007, 2009 and 2012, NS Power proposes that the unmetered rate class revenues be set at cost of service or the revenue to cost ratio of 100 percent. The approach is premised by significant direct costs associated with streetlight fixture maintenance and capital, which account for about 40 percent of the total class costs. The approach yields a 10.3 percent increase instead of 11.5 percent.

NON-CONFIDENTIAL

Request IR-82:

Please provide the Cost of Service Study (SR-01) as an Excel file, with all formulae intact.

Response IR-82:

Please refer to Attachments 1 and 2, filed electronically.

NOVA SCOTIA POWER INC.

DETAILED LISTING OF C.O.S.S. INPUT INFORMATION

FOR THE YEAR ENDING DECEMBER 31, 2013

(IN THOUSANDS OF DOLLARS)

AVERAGE RATE BASE

		Line #
STEAM PLANT	935,811	11
STEAM PLANT - CWIP	111,859	12
STEAM ENVIRONMENTAL & FUEL CONVERSION PLA	338,691	13
Steam Enviromental & Fuel Conversion - CWIP	2,727	14
HYDRO PLANT	325,795	15
HYDRO PLANT - CWIP	14,752	16
HYDRO ENVIRONMENTAL & FUEL CONVERSION PLA	4,953	17
Hydro Enviromental & Fuel Conversion - CWIP	195	18
WIND PLANT	12,517	19
WIND PLANT - CWIP	3,549	20
WIND ENVIRONMENTAL & FUEL CONVERSION PLAN	178,591	21
Wind Enviromental & Fuel Conversion - CWIP	100	22
GAS TURBINE PLANT	6,025	23
GAS TURBINE PLANT - CWIP	574	24
GAS ENVIRONMENTAL & FUEL CONVERSION PLANT	-	25
Gas Enviromental & Fuel Conversion - CWIP	-	26
LM6000 PLANT	60,044	27
LM6000 PLANT - CWIP	2,662	28
LM600 ENVIRONMENTAL & FUEL CONVERSION PLAI	-	29
LM600 Enviromental & Fuel Conversion - CWIP	-	30
TRANSMISSION PLANT	417,922	31
TRANSMISSION PLANT - CWIP	15,757	32
Transmission ENVIRONMENTAL & FUEL CONVERSIOI	-	33
Transmission Enviromental & Fuel Conversion - CWI	-	34
DIST.PLT.- LAND	4,438	35
DIST.PLT.- EASEMENTS & SURVEY	16,044	36
DIST.PLT.- OTHER	2,103	37
DIST.PLT.- SUBSTATIONS	28,462	38
DIST.PLT.- POLES & FIXTURES	173,357	39
DIST.PLT.- O/H LINES	114,863	40
DIST.PLT.- U/G LINES	33,044	41
DIST.PLT.- LINE TRANSFORMERS	154,540	42
DIST.PLT.- SERVICES	57,705	43
DIST.PLT.- METERS	23,780	44
DIST.PLT.- STREET LIGHTING (Non LED)	15,950	45

NOVA SCOTIA POWER INC.

DETAILED LISTING OF C.O.S.S. INPUT INFORMATION

FOR THE YEAR ENDING DECEMBER 31, 2013

(IN THOUSANDS OF DOLLARS)

		Line #
DIST.PLT.- STREET LIGHTING (LED)	11,020	46
		47
GENERAL PROPERTY PLANT	226,797	48
GENERAL PROPERTY PLANT - CWIP	16,360	49
		50
WORKING CAPITAL & DEFERRED CHARGES		51
		52
WORKING CAPITAL - CASH FUEL	0	53
WORKING CAPITAL - CASH OTHER	43,271	54
WORKING CAPITAL - MAT. & SUP. FUEL	88,682	55
WORKING CAPITAL - MAT. & SUP. OTHER	28,089	56
DEFERRED CHARGES - Financing	75,865	57
DEFERRED CHARGES - Tax	21,479	58
DEFERRED CHARGES - Pension	66,431	59
DEFERRED CHARGES - Steam Assets	0	60
DEFERRED CHARGES - FAM Deferral	14,080	61
DEFERRED CHARGES - Other	4,175	62
DEFERRED CHARGES - Other (DSM)	2,133	63
DEFERRED CHARGES - Other (LED)	2,606	64
DEFERRED CHARGES - FCR	37,400	65
DEFERRED Credits - ARO Steam	(41,394)	66
DEFERRED Credits - ARO Hydro	(21,653)	67
DEFERRED Credits - ARO CT	(3,944)	68
DEFERRED Credits - ARO Transformers	(23,425)	69
DEFERRED Credits - ARO Wind	(10,400)	70
DEFERRED Credits - Other (Steam)	(6,589)	71
CONTRACT RECEIVABLE	0	72
		73
DEDICATED PLANT		74
DEDICATED STREETLIGHTS - LED	11,020	75
DEDICATED STEAM PLANT	0	76
DEDICATED HYDRO PLANT - Mersey	21,241	77
DEDICATED GAS TURBINE	0	78
DEDICATED TRANSMISSION PLANT	0	79
DEDICATED DIST.PLT.- LAND	0	80
DEDICATED DIST.PLT.- EASEMENTS & SURVEY	0	81
DEDICATED DIST.PLT.- OTHER	0	82
DEDICATED DIST.PLT.- SUBSTATIONS	0	83

NOVA SCOTIA POWER INC.

DETAILED LISTING OF C.O.S.S. INPUT INFORMATION

FOR THE YEAR ENDING DECEMBER 31, 2013

(IN THOUSANDS OF DOLLARS)

		Line #
DEDICATED DIST.PLT.- POLES & FIXTURES	0	84
DEDICATED DIST.PLT.- O/H LINES	0	85
DEDICATED DIST.PLT.- U/G LINES	0	86
DEDICATED DIST.PLT.- LINE TRANSFORMERS	0	87
DEDICATED DIST.PLT.- SERVICES	0	88
DEDICATED DIST.PLT.- METERS	0	89
DEDICATED DIST.PLT.- STREET LIGHTING	0	90
DEDICATED GENERAL PROPERTY PLANT	0	91
DEDICATED WORKING CAPITAL - CASH FUEL	0	92
DEDICATED WORKING CAPITAL - CASH OTHER - Me	221	93
DEDICATED WORKING CAPITAL - MAT. & SUP. FUEL	0	94
DEDICATED WORKING CAPITAL - MAT. & SUP. OTHE	0	95
SUBSTS.-DISTRIBUTION BULK POWER	24,109	96
SUBSTS.-DIST.DED.BULK POWER-DOMESTIC	0	97
SUBSTS.-DIST.DED.BULK POWER-SMALL GENERAL	0	98
SUBSTS.-DIST.DED.BULK POWER-GENERAL	0	99
SUBSTS.-DIST.DED.BULK POWER-GENERAL LARGE	0	100
SUBSTS.-DIST.DED.BULK POWER-SMALL INDUST.	0	101
SUBSTS.-DIST.DED.BULK POWER-MEDIUM INDUST.	100	102
SUBSTS.-DIST.DED.BULK POWER-LARGE INDUSTRI/	281	103
SUBSTS.-DIST.DED.BULK POWER-ELI 2P-RTP	0	104
SUBSTS.-DIST.DED.BULK POWER-MUNICIPAL	24	105
SUBSTS.-DIST.DED.BULK POWER-UNMETERED	0	106
SUBSTS.-DIST.C/O BULK POWER-DOMESTIC	0	107
SUBSTS.-DIST.C/O BULK POWER-SMALL GENERAL	0	108
SUBSTS.-DIST.C/O BULK POWER-GENERAL	26	109
SUBSTS.-DIST.C/O BULK POWER-GENERAL LARGE	0	110
SUBSTS.-DIST.C/O BULK POWER-SMALL INDUST.	0	111
SUBSTS.-DIST.C/O BULK POWER-MEDIUM INDUST.	3	112
SUBSTS.-DIST.C/O BULK POWER-LARGE INDUSTRIA	3	113
SUBSTS.-DIST.C/O BULK POWER-ELI 2P-RTP	0	114
SUBSTS.-DIST.C/O BULK POWER-MUNICIPAL	0	115
SUBSTS.-DIST.C/O BULK POWER-UNMETERED	0	116
SUBSTS.-DISTRIBUTION GENERAL	3,832	117
SUBSTS.-DIST.DED.GENERAL-DOMESTIC	0	118
SUBSTS.-DIST.DED.GENERAL-SMALL GENERAL	0	119
SUBSTS.-DIST.DED.GENERAL-GENERAL	0	120
SUBSTS.-DIST.DED.GENERAL-GENERAL LARGE	0	121
SUBSTS.-DIST.DED.GENERAL-SMALL INDUST.	0	122

NOVA SCOTIA POWER INC.

DETAILED LISTING OF C.O.S.S. INPUT INFORMATION

FOR THE YEAR ENDING DECEMBER 31, 2013

(IN THOUSANDS OF DOLLARS)

		Line #
SUBSTS.-DIST.DED.GENERAL-MEDIUM INDUST.	0	123
SUBSTS.-DIST.DED.GENERAL-LARGE INDUSTRIAL	0	124
SUBSTS.-DIST.DED.GENERAL-ELI 2P-RTP	0	125
SUBSTS.-DIST.DED.GENERAL-MUNICIPAL	0	126
SUBSTS.-DIST.DED.GENERAL-UNMETERED	0	127
SUBSTS.-DIST.C/O GENERAL-DOMESTIC	0	128
SUBSTS.-DIST.C/O GENERAL-SMALL GENERAL	0	129
SUBSTS.-DIST.C/O GENERAL-GENERAL	0	130
SUBSTS.-DIST.C/O GENERAL-GENERAL LARGE	0	131
SUBSTS.-DIST.C/O GENERAL-SMALL INDUST.	0	132
SUBSTS.-DIST.C/O GENERAL-MEDIUM INDUST.	4	133
SUBSTS.-DIST.C/O GENERAL-LARGE INDUSTRIAL	82	134
SUBSTS.-DIST.C/O GENERAL-ELI 2P-RTP	0	135
SUBSTS.-DIST.C/O GENERAL-MUNICIPAL	0	136
SUBSTS.-DIST.C/O GENERAL-UNMETERED	0	137
		138
Percentage of Transmission Plant > 69kV	76.6%	139
		140
OPERATING EXPENSES		141
		142
		143
OFFICE OF THE PRESIDENT		144
EXECUTIVE MANAGEMENT	1,146.9	145
CORPORATE SECRETARY	7,358.5	146
LEGAL SERVICES	1,171.4	147
		148
VP EXTERNAL RELATIONS		149
COMM. & PUBLIC AFFAIRS	2,076.8	150
		151
		152
CUSTOMER OPERATIONS:		153
		154
TRANSMISSION AND DISTRIBUTION		155
TRANSMISSION TOTAL	18,039.9	156
DISTRIBUTION TOTAL:		157
SUBSTATIONS	194.0	158
OVERHEAD LINES	25,349.7	159
UNDERGROUND LINES	439.7	160

NOVA SCOTIA POWER INC.

DETAILED LISTING OF C.O.S.S. INPUT INFORMATION

FOR THE YEAR ENDING DECEMBER 31, 2013

(IN THOUSANDS OF DOLLARS)

		Line #
LINE TRANSFORMERS	940.7	161
METERS	0.0	162
COMMUNICATIONS	5,630.2	163
STREET LIGHTING	3,693.5	164
CUSTOMER SERVICE TOTAL: (T & D)		165
-- BILLING & RECEIPTS:		166
(a) METER SERVICES -FIELD	0.0	167
-- CUSTOMER SERVICE:		168
(a) CUSTOMER SERVICE - CSFR	0.0	169
(b) ELECTRIC WIRING INSPECTION	0.0	170
		171
CUSTOMER SERVICE & MARKETING & SALES		172
-- ADMINISTRATION:		173
		174
(a) ADMINISTRATION	711.2	175
(b) ENERGY EFFICIENCY	476.2	176
(c) CUST. COMM. & QTY ASSURANCE	1,856.8	177
(d) CUSTOMER SOLUTIONS	0.0	178
		179
		180
		181
CALL CENTRE		182
		183
-- CALL CENTRE - CSR:		184
(a) CSR	7,016.2	185
(b) CUSTOMER COLLECTIONS	0.0	186
(c) ELECTRICAL WIRING INSPECTIONS	0.0	187
(b) CUSTOMER COLLECTIONS	373.7	188
(c) ELECTRICAL WIRING INSPECTIONS	4,456.9	189
		190
		191
		192
		193
REVENUE OPERATIONS		194
		195
-- BILLING & RECEIPTS:		196
(a) BILLING SERVICES	3,676.0	197
(b) PAYMENT SERVICES	703.2	198

NOVA SCOTIA POWER INC.

DETAILED LISTING OF C.O.S.S. INPUT INFORMATION

FOR THE YEAR ENDING DECEMBER 31, 2013

(IN THOUSANDS OF DOLLARS)

		Line #
(c) METER DATA SERVICES	467.6	199
(d) METER SERVICES - METER SHOP	598.5	200
(e) METER SERVICES - FIELD	6,104.5	201
(f) ELECTRICAL WIRING INSPECTIONS - FIELD	3,429.7	202
(g) ELECTRICAL INSPECTION	264.8	203
		204
-- CREDIT SERVICES:		205
BAD DEBT EXPENSE	5,736.4	206
		207
		208
		209
-- MARKETING & SALES:		210
(a) MARKETING & SALES	1,154.5	211
		212
		213
		214
		215
REGULATORY AFFAIRS	6,332.4	216
Technical & Construction Services		
General (all admin costs)	6,110.0	217
Generation	2,910.0	218
T&D	5,410.0	219
	14,430.0	220
Sustainability	1,508.1	221
		222
SENIOR VP & CFO		223
(a) INTERNAL AUDIT	1,696.3	224
(b) INVESTOR RELATIONS	283.3	225
(c) VP FINANCE & TREASURER	731.9	226
(d) TREASURER	785.2	227
(e) CORPORATE TAX	808.7	228
-- GM FINANCE		229
(a) CORPORATE CONTROLLER	2,443.7	230
(b) CORP. PERFORMANCE & BACK OFFICE	0.0	231
		232
VP ENTERPRISE SERVICES		233

NOVA SCOTIA POWER INC.

DETAILED LISTING OF C.O.S.S. INPUT INFORMATION

FOR THE YEAR ENDING DECEMBER 31, 2013
(IN THOUSANDS OF DOLLARS)

			Line #
-- PROCUREMENT & FACILITIES		9,991.2	234
-- INFORMATION TECHNOLOGY		11,737.3	235
			236
VP HUMAN RESOURCES			237
-- HUMAN RESOURCES		5,553.8	238
			239
POWER PRODUCTION			240
-- POWER PRODUCTION - FUEL		372,416.0	241
-- POWER PRODUCTION - OPERATING & MAINT.		60,104.0	242
-- POWER PRODUCTION - HYDRO PLTS.		9,565.5	243
-- POWER PRODUCTION - WIND		4,648.8	244
-- POWER PRODUCTION - LM6000		328.6	245
-- POWER PRODUCTION - BIOMASS		5,380.3	246
-- POWER PRODUCTION - OTHER GAS TURBINE		943.6	246
-- POWER PRODUCTION - GEN. DEVELOPMENT		0.0	247
-- POWER PRODUCTION - HEAD OFFICE		24,739.8	248
-- POWER PRODUCTION - GEN. SERV.		0.0	249
-- POWER PRODUCTION - H/R		0.0	250
-- POWER PRODUCTION - ENVIR. POLICY		0.0	251
-- POWER PRODUCTION - EXECUTIVE		0.0	252
-- POWER PRODUCTION - FUEL PROCUREMENT		3,819.1	253
-- PURCHASED POWER - REG FIXED (45%)		18,793.1	254
-- PURCHASED POWER - REG VARIABLE (55%)		22,969.4	255
-- PURCHASED POWER - WIND FIXED (30%)		18,247.9	256
-- PURCHASED POWER - WIND REG VARIABLE (70%		42,578.5	257
			258
OTHER EXPENSES		11,134.8	259
CURRENT YEAR INCENTIVE PLAN PAYOUT			260
DSM AMORTIZATION		2,150	261
FCR DEFERRAL		16,500	262
GRANTS IN LIEU OF TAXES		37,500	263
DEPRECIATION :			264
STEAM	63,508	60,187	265
ARO PROVISION		*3,321*	266
HYDRO	10,456	9,273	267
ARO PROVISION		*1,183*	268
WIND	8,186	8,157	269
ARO PROVISION		29	270

NOVA SCOTIA POWER INC.

DETAILED LISTING OF C.O.S.S. INPUT INFORMATION

FOR THE YEAR ENDING DECEMBER 31, 2013

(IN THOUSANDS OF DOLLARS)

			Line #
LM6000		2,084	271
GAS TURBINE - OTHER	1,183	936	272
ARO PROVISION		*247*	273
TRANSMISSION < 138kV	4,878	4,352	274
ARO PROVISION		*526*	275
TRANSMISSION > 69kV	15,967	14,246	276
ARO PROVISION		*1,721*	277
DISTRIBUTION - Non Streetlight Related		*45,933*	278
DISTRIBUTION -Streetlight Related		2,946	279
GENERAL PROPERTY		37,585	279
GLACE BAY RETIREMENT		**0**	280
INTEREST CHARGES		133,900	281
PREFERRED DIVIDENDS		8,000	282
CORPORATE TAXES		52,350	283
REGULATORY CONTINGENCY		**0**	284
FUEL RECOVERY		0	285
Normal Interruption Cost		***63.00***	286
Priority Interruption Cost		***72.45***	287
Interr. Rider Coincident Demand & CD Losses		***91,840***	288
ELI 2P-RTP Coincident Demand & CD Losses		***0***	289
Interr. Rider - Sum of Cust. Non-Coin. Dmds		***1,593,968***	290
ELI 2P-RTP - Sum of Cust. Non-Coin. Dmds		***3,886,432***	291
FIXED Interruptible Credit		***$3.43***	292
			293
OPERATING ALLOCATIONS			294
			295
ENERGY, FUELS & RISK MGMT. - THERMAL		100.00%	296
ENERGY, FUELS & RISK MGMT. - TRANSMISSION		0.00%	297
ENERGY, FUELS & RISK MGMT. - DISTRIBUTION		0.00%	298
ENERGY, FUELS & RISK MGMT. - RETAIL		0.00%	299
PERFORMANCE & REGULATION - THERMAL		36.00%	300
PERFORMANCE & REGULATION - TRANSMISSION		11.00%	301
PERFORMANCE & REGULATION - DISTRIBUTION		26.00%	302
PERFORMANCE & REGULATION - RETAIL		27.00%	303
CORPORATE FINANCE - THERMAL		36.00%	304
CORPORATE FINANCE - TRANSMISSION		11.00%	305
CORPORATE FINANCE - DISTRIBUTION		26.00%	306

NOVA SCOTIA POWER INC.

DETAILED LISTING OF C.O.S.S. INPUT INFORMATION

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(IN THOUSANDS OF DOLLARS)

		Line #
CORPORATE FINANCE - RETAIL	27.00%	307
CORPORATE COMMUNICATIONS - THERMAL	36.00%	308
CORPORATE COMMUNICATIONS - TRANSMISSION	11.00%	309
CORPORATE COMMUNICATIONS - DISTRIBUTION	26.00%	310
CORPORATE COMMUNICATIONS - RETAIL	27.00%	311
HR SERVICES - PRODUCTION	36.00%	312
HR SERVICES - TRANSMISSION	11.00%	313
HR SERVICES - DISTRIBUTION	26.00%	314
HR SERVICES - RETAIL	27.00%	315
CORPORATE GROUPS - PRODUCTION	36.00%	316
CORPORATE GROUPS - TRANSMISSION	11.00%	317
CORPORATE GROUPS - DISTRIBUTION	26.00%	318
CORPORATE GROUPS - RETAIL	27.00%	319
IT SERVICES - THERMAL	36.00%	320
IT SERVICES - TRANSMISSION	11.00%	321
IT SERVICES - DISTRIBUTION	26.00%	322
IT SERVICES - CUSTOMER	0.00%	323
IT SERVICES - ADMIN. & GEN.	27.00%	324
T&C - TRANSMISSION	**29.73%**	**325**
T&C - DISTRIBUTION	**70.27%**	**326**
FCR Deferral - Generation	**82.01%**	**327**
FCR Deferral - Transmission	**17.99%**	**328**
MARKETING & SALES ALLOCATOR - DOMESTIC	45.33%	329
MARKETING & SALES ALLOCATOR - SMALL GENERA	3.59%	330
MARKETING & SALES ALLOCATOR - GENERAL	8.37%	331
MARKETING & SALES ALLOCATOR - LARGE GENERA	1.79%	332
MARKETING & SALES ALLOCATOR - SMALL INDUST.	6.58%	333
MARKETING & SALES ALLOCATOR - MEDIUM INDUST	12.92%	334
MARKETING & SALES ALLOCATOR - LARGE INDUST.	19.62%	335
MARKETING & SALES ALLOCATOR - ELI 2P-RTP	0.00%	336
MARKETING & SALES ALLOCATOR - MUNICIPAL	1.79%	337
MARKETING & SALES ALLOCATOR - UNMETERED	0.00%	338
METER DATA SERVICES ALLOCATOR - DOMESTIC	5.39%	339
METER DATA SERVICES ALLOCATOR - SMALL GENE	5.27%	340
METER DATA SERVICES ALLOCATOR - GENERAL	12.46%	341
METER DATA SERVICES ALLOCATOR - LARGE GENE	16.17%	342
METER DATA SERVICES ALLOCATOR - SMALL INDUS	12.46%	343
METER DATA SERVICES ALLOCATOR - MEDIUM INDU	12.46%	344

NOVA SCOTIA POWER INC.

DETAILED LISTING OF C.O.S.S. INPUT INFORMATION

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(IN THOUSANDS OF DOLLARS)

		Line #
METER DATA SERVICES ALLOCATOR - LARGE INDU	23.35%	345
METER DATA SERVICES ALLOCATOR - ELI 2P-RTP	0.00%	346
METER DATA SERVICES ALLOCATOR - MUNICIPAL	12.46%	347
METER DATA SERVICES ALLOCATOR - UNMETEREI	0.00%	348
		349
DIRECT EXPENSES		350
		351
		352
FUEL	30,388	353
FUEL RECOVERY	0	354
PURCHASED POWER REGULAR - VARIABLE		355
PURCHASED POWER REGULAR - FIXED		356
PURCHASED POWER WIND - FIXED		357
PURCHASED POWER WIND - VARIABLE		358
THERMAL OPERATING & MAINT.	471	359
HYDRO OPERATING & MAINT.	2,185	360
TRANSMISSION < 138kV	0	361
TRANSMISSION > 69kV	391	362
DISTRIBUTION - SUBSTATIONS	0	363
DISTRIBUTION - OVERHEAD LINES		364
DISTRIBUTION - UNDERGROUND LINES	0	365
DISTRIBUTION - LINE TRANSFORMERS	0	366
DISTRIBUTION - METERS	0	367
DISTRIBUTION - COMMUNICATIONS	0	368
DISTRIBUTION - STREET LIGHTING	0	369
ADMIN. & GENERAL - BILLING & METER READING	0	370
ADMIN. & GENERAL - CUSTOMER SERVICE	0	371
ADMIN. & GENERAL - MARKETING & SALES	0	372
ADMIN. & GENERAL - CREDIT & COLLECTION	0	373
ADMIN. & GENERAL - OTHER	645	374
ASSIGNED DSM EXPENSES	86	375
OTHER OPERATING - DEP. - STEAM	0	376
OTHER OPERATING - DEP. - HYDRO	1,025	377
OTHER OPERATING - DEP. - TRANSMISSION < 138kV	0	378
OTHER OPERATING - DEP. - TRANSMISSION > 69kV		379
OTHER OPERATING - INTEREST NET	2,013	380
OTHER OPERATING - PREFERRED DIVIDENDS		381
OTHER OPERATING - INCOME TAXES		382

NOVA SCOTIA POWER INC.

DETAILED LISTING OF C.O.S.S. INPUT INFORMATION

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(IN THOUSANDS OF DOLLARS)

		Line #
OTHER OPERATING - GRANTS IN LIEU		383
		384
LED - Direct Expenses		385
Interest	557	386
Preferred Dividends	30	387
Common Equity	470	388
Equity Tax Cost	211	389
Large Corp Tax	271	390
Grants in Lieu of Property Tax	28	391
CCA Benefit	-210	392
Depreciation	604	393
Stranded Asset	0	394
		395
		396
		397
REVENUE		398
	656,557	399
Switch from Prelim to Actual	1	400
ELECTRIC REVENUE - DOMESTIC - REG	633,558	401
ELECTRIC REVENUE - DOMESTIC - ETS	22,999	402
ELECTRIC REVENUE - SMALL GENERAL	35,079	403
ELECTRIC REVENUE - GENERAL	307,787	404
ELECTRIC REVENUE - GENERAL LARGE	42,151	405
ELECTRIC REVENUE - SMALL INDUST.	31,739	406
ELECTRIC REVENUE - MEDIUM INDUST.	53,486	407
ELECTRIC REVENUE - LARGE INDUSTRIAL	82,327	408
ELECTRIC REVENUE - ELI 2P-RTP	0	409
ELECTRIC REVENUE - MUNICIPAL	20,394	410
ELECTRIC REVENUE - UNMETERED	24,633	411
EXPORT SALES	1,807	412
FX Interest		413
		414
OTHER ELECTRIC REVENUE - GREEN POWER SURC	0	415
LATE PAYMENT CHARGE - DOMESTIC	3,976	416
LATE PAYMENT CHARGE - SMALL GENERAL	121	417
LATE PAYMENT CHARGE - GENERAL	886	418
LATE PAYMENT CHARGE - GENERAL LARGE	0	419
LATE PAYMENT CHARGE - SMALL INDUST.	69	420

NOVA SCOTIA POWER INC.

DETAILED LISTING OF C.O.S.S. INPUT INFORMATION

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(IN THOUSANDS OF DOLLARS)

		Line #
LATE PAYMENT CHARGE - MEDIUM INDUST.	59	421
LATE PAYMENT CHARGE - LARGE INDUSTRIAL	0	422
LATE PAYMENT CHARGE - ELI 2P-RTP	0	423
LATE PAYMENT CHARGE - MUNICIPAL	0	424
LATE PAYMENT CHARGE - UNMETERED	17	425
MISCELLANEOUS REVENUE - DOMESTIC	1,772	426
MISCELLANEOUS REVENUE - SMALL GENERAL	108	427
MISCELLANEOUS REVENUE - GENERAL	12	428
MISCELLANEOUS REVENUE - GENERAL LARGE	0	429
MISCELLANEOUS REVENUE - SMALL INDUST.	0	430
MISCELLANEOUS REVENUE - MEDIUM INDUST.	0	431
MISCELLANEOUS REVENUE - LARGE INDUSTRIAL	0	432
MISCELLANEOUS REVENUE - ELI 2P-RTP	0	433
MISCELLANEOUS REVENUE - MUNICIPAL	0	434
MISCELLANEOUS REVENUE - UNMETERED	17	435
OTHER REVENUE		436
-- ELECTRIC WIRING INSPECTION	4,071	437
NON-OPERATING REVENUE:		438
-- CATV RENTALS	2,381	439
-- NSF CHEQUE CHARGE	63	440
-- GAIN ON SALE OF LAND	0	441
-- STEAM REVENUE	0	442
-- MISCELLANEOUS	1,227	443
-- OM&G Reclass due to US GAAP	6,365	444
-- Non Regulated Revenues for LWS - Block C	0	445
-Accounts Receivable Securitization	0	446
RETAIL SALES (Marketing)	1,438	447
COST OF GOODS SOLD (Retail)	1,000	448
		449
DIRECT REVENUE :		450
MERSEY CONTRACT:		451
-- MERSEY CONTRACT (up to 28MW)	9,935	452
-- MERSEY CONTRACT (28MW to 42MW)	10,283	453
GEN. REPL. / LOAD FOLL.:		454
-- GENERATION REPLACEMENT	1,095	455
-- LOAD FOLLOWING	0	456
LRT	19,895	457
		458

NOVA SCOTIA POWER INC.

DETAILED LISTING OF C.O.S.S. INPUT INFORMATION

FOR THE YEAR ENDING DECEMBER 31, 2013

(IN THOUSANDS OF DOLLARS)

		Line #
		459
		460
		461
		462
		463
		464
ALLOCATION FACTOR INFORMATION		465
		466
AVERAGE CUSTOMERS - DOMESTIC (SEASONAL)	13,979	467
AVERAGE CUSTOMERS - DOMESTIC	452,558	468
AVERAGE CUSTOMERS - SMALL GENERAL	23,894	469
AVERAGE CUSTOMERS - GENERAL	11,387	470
AVERAGE CUSTOMERS - GENERAL LARGE	18	471
AVERAGE CUSTOMERS - SMALL INDUST.	2,227	472
AVERAGE CUSTOMERS - MEDIUM INDUST.	197	473
AVERAGE CUSTOMERS - INDUSTRIAL LARGE	32	474
AVERAGE CUSTOMERS - ELLIR-2	0	475
AVERAGE CUSTOMERS - MUNICIPAL	8	476
AVERAGE CUSTOMERS - UNMETERED	9,504	477
VOLTAGE LEVEL DMD. REDUCTION SEC. - GENERAL	94.67%	478
VOLTAGE LEVEL DMD. REDUCTION SEC. - SM. INDU	90.39%	479
VOLTAGE LEVEL DMD. REDUCTION PRI. - MED. INDU	97.27%	480
LOSS FACTOR PERCENTAGE - SECONDARY	6.000%	481
LOSS FACTOR PERCENTAGE - PRIMARY	5.400%	482
LOSS FACTOR PERCENTAGE - TRANSMISSION	3.700%	483
		484
CUSTOMER WEIGHTING FACTORS		485
		486
DOMESTIC	1.00	487
SMALL GENERAL	1.00	488
GENERAL	5.00	489
LARGE GENERAL	100.00	490
SMALL INDUSTRIAL	5.00	491
MEDIUM INDUSTRIAL	25.00	492
LARGE INDUSTRIAL	100.00	493
ELI 2P-RTP	100.00	494
MUNICIPAL	100.00	495
UNMETERED	0.82	496

NOVA SCOTIA POWER INC.

DETAILED LISTING OF C.O.S.S. INPUT INFORMATION

FOR THE YEAR ENDING DECEMBER 31, 2013

(IN THOUSANDS OF DOLLARS)

		Line #
		497
FUEL COSTS		498
		499
DOMESTIC	160,541	500
SMALL GENERAL	8,615	501
GENERAL	88,113	502
LARGE GENERAL	14,250	503
SMALL INDUSTRIAL	9,289	504
MEDIUM INDUSTRIAL	17,827	505
LARGE INDUSTRIAL	32,571	506
ELI 2P-RTP	0	507
MUNICIPAL	6,889	508
UNMETERED	3,933	509
		510
		511
REVENUE TO COSS RATIO (CURRENT RATES)		512
		513
DOMESTIC	100.52	514
SMALL GENERAL	103.46	515
GENERAL	103.46	516
LARGE GENERAL	101.38	517
SMALL INDUSTRIAL	101.55	518
MEDIUM INDUSTRIAL	97.91	519
LARGE INDUSTRIAL	97.74	520
ELI 2P-RTP	91.33	521
MUNICIPAL	98.11	522
UNMETERED	101.26	523

NOVA SCOTIA POWER INC.

DETAILED LISTING OF C.O.S.S. INPUT INFORMATION

FOR THE YEAR ENDING DECEMBER 31, 2013

(IN THOUSANDS OF DOLLARS)

ALLOCATION FACTOR INFORMATION

	January	February	March	April	May	June	July	August	September	October	November	December	**Total**
(1) MWH SALES - DOMESTIC	517,950	449,378	449,949	359,741	323,119	264,738	266,176	260,709	261,087	300,666	351,855	467,841	4,273,209
(2) MWH SALES - SMALL GENERAL	25,350	23,282	22,297	18,910	17,328	16,501	17,006	17,119	15,500	17,287	18,096	22,601	231,277
(3) MWH SALES - GENERAL	233,732	219,217	225,450	195,069	183,886	185,946	201,108	195,548	181,397	189,718	198,211	226,013	2,435,295
(4) MWH SALES - GENERAL LARGE	33,329	30,888	33,709	30,768	31,839	31,669	36,217	36,538	34,106	33,150	31,996	32,087	396,295
(5) MWH SALES - SMALL INDUST.	22,560	21,628	21,692	20,695	20,858	21,775	22,135	22,093	20,651	19,020	20,861	24,192	258,161
(6) MWH SALES - MEDIUM INDUST.	42,925	38,731	41,333	41,190	40,700	42,608	42,569	42,615	41,507	41,853	40,988	41,753	498,772
(7) MWH SALES - INDUSTRIAL LARGE	75,073	70,670	75,867	74,845	75,137	71,592	80,192	85,980	80,788	79,011	78,957	73,313	921,426
(8) MWH SALES - ELI 2P-RTP	0	0	0	0	0	0	0	0	0	0	0	0	0
(9) MWH SALES - MUNICIPAL	20,071	19,070	19,062	15,531	13,912	12,806	14,128	13,928	13,606	14,663	16,406	19,464	192,648
(10) MWH SALES - UNMETERED	10,891	9,230	9,130	8,187	7,465	6,646	6,926	7,522	8,135	8,764	10,238	11,257	104,393
(11) MWH SALES - BOWATER MERSEY - CONTRACT	15,750	15,750	15,750	15,750	15,750	15,750	15,750	15,750	15,750	15,750	15,750	15,750	189,000
(12) MWH SALES - BOWATER MERSEY - ADD. ENERGY	15,498	12,474	15,498	14,490	15,498	14,490	15,498	15,498	14,490	15,498	14,490	15,498	178,920
(13) MWH SALES - GEN. REPL./ LOAD FOLL.	990	1,221	38	1,462	442	577	1,591	2,834	6,682	1,467	1,310	200	18,815
(14) MWH SALES - LRT	27,355	24,708	27,276	26,472	27,355	26,472	27,355	27,355	26,472	27,355	26,551	27,355	322,080
(15) MWH SALES - INDUST. EXPANSION INTERR.	0	0	0	0	0	0	0	0	0	0	0	0	0
(16) MWH SALES - EXTRA LI INTERRUPTIBLE	0	0	0	0	0	0	0	0	0	0	0	0	0
(17) MWH SALES - Real Time Pricing	0	0	0	0	0	0	0	0	0	0	0	0	0
(18) MWH SALES - Export Sales	0	0	0	0	0	0	0	0	0	0	0	0	0
(19) LINE LOSSES - DOMESTIC	53,918	48,025	45,031	31,749	28,556	18,794	18,845	20,977	17,560	24,612	31,127	53,779	392,973
(20) LINE LOSSES - SMALL GENERAL	2,419	2,302	2,192	1,692	1,567	1,174	1,269	1,490	1,123	1,283	1,500	2,197	20,209
(21) LINE LOSSES - GENERAL	14,242	13,715	14,999	11,465	11,539	10,350	11,586	12,390	9,466	11,234	11,170	16,524	148,680
(22) LINE LOSSES - GENERAL LARGE	2,123	1,881	2,199	1,840	2,033	1,645	2,082	2,454	1,651	1,986	1,857	2,293	24,044
(23) LINE LOSSES - INDUST. TO 249 KVA	1,215	1,239	1,359	1,183	1,271	1,098	1,093	1,254	975	1,061	1,167	1,662	14,577
(24) LINE LOSSES - INDUST. 250-3999 KVA	2,093	2,028	2,334	2,201	2,434	2,113	2,054	2,391	1,935	2,255	2,034	2,595	26,466
(25) LINE LOSSES - INDUSTRIAL LARGE	2,869	2,895	3,377	3,232	3,740	2,950	3,320	4,288	3,296	3,611	3,145	3,723	40,446
(26) LINE LOSSES - ELI 2P-RTP	0	0	0	0	0	0	0	0	0	0	0	0	0
(27) LINE LOSSES - MUNICIPAL	870	815	933	723	663	526	571	666	522	656	656	1,048	8,651
(28) LINE LOSSES - UNMETERED	1,134	941	885	763	792	693	721	794	719	732	925	1,224	10,323
(29) LINE LOSSES - BOWATER MERSEY - CONTRACT	320	320	320	320	320	320	320	320	320	320	320	320	3,837
(30) LINE LOSSES - BOWATER MERSEY - ADD. ENERGY	315	253	315	294	315	294	315	315	294	315	294	315	3,632
(31) LINE LOSSES - GEN.REPL. / LOAD FOLL.	20	25	1	30	9	12	32	58	136	30	27	4	384
(32) LINE LOSSES - LRT	555	502	548	537	555	537	555	555	537	555	544	555	6,538
(33) LINE LOSSES - INDUST. EXPANSION INTERR.	0	0	0	0	0	0	0	0	0	0	0	0	0
(34) LINE LOSSES - EXTRA LI INTERRUPTIBLE	0	0	0	0	0	0	0	0	0	0	0	0	0
(35) LINE LOSSES - REAL TIME PRICING	0	0	0	0	0	0	0	0	0	0	0	0	0
(36) LINE LOSSES - EXPORT SALES	0	0	0	0	0	0	0	0	0	0	0	0	0
(37) CLASS NON-COINCIDENT DMD. - DOMESTIC	1,016,646	1,037,311	890,747	790,074	675,840	662,472	583,480	585,948	555,501	669,062	778,802	969,221	**1,037,311**
(38) CLASS NON-COINCIDENT DMD. - SMALL GENERAL	54,862	56,182	50,921	44,776	40,048	40,159	39,118	41,577	38,189	39,126	45,606	56,092	**56,182**
(39) CLASS NON-COINCIDENT DMD. - GENERAL DEMAND	487,597	475,530	427,619	383,834	361,341	388,321	399,320	421,845	434,915	409,561	399,664	451,215	**487,597**
(40) CLASS NON-COINCIDENT DMD. - GENERAL LARGE	58,854	60,416	59,513	56,487	60,556	62,199	66,425	71,278	72,580	69,061	59,435	61,356	**72,580**
(41) CLASS NON-COINCIDENT DMD. - SMALL INDUST.	44,509	43,040	38,282	39,448	41,601	44,512	45,623	47,509	45,442	42,356	42,945	46,813	**47,509**
(42) CLASS NON-COINCIDENT DMD. - MEDIUM INDUST.	81,867	75,341	70,928	74,262	75,707	78,672	80,401	78,710	81,487	76,719	76,517	85,067	**85,067**
(43) CLASS NON-COINCIDENT DMD. - INDUSTRIAL LARGE	122,180	125,598	114,735	122,441	113,902	115,611	128,189	131,834	139,431	120,084	124,960	130,647	**139,431**
(44) **CLASS NON-COINCIDENT DMD. - ELI 2P-RTP**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
(45) CLASS NON-COINCIDENT DMD. - MUNICIPAL	39,325	40,959	33,573	29,188	24,728	24,169	25,679	26,569	27,387	26,728	31,220	37,053	**40,959**
(46) CLASS NON-COINCIDENT DMD. - UNMETERED	23,596	23,584	23,597	23,598	23,597	23,597	23,595	23,597	23,598	23,600	23,600	23,601	**23,601**
(47) CLASS NON-COINCIDENT DMD. - BOWATER MERSEY	42,000	42,000	42,000	42,000	42,000	42,000	42,000	42,000	42,000	42,000	42,000	42,000	**42,000**
(48) CLASS NON-COINCIDENT DMD. - GEN. REPL.	18,501	19,501	1,842	22,397	3,189	23,190	23,449	23,447	23,900	7,533	21,278	1,495	**23,900**
(49) CLASS NON-COINCIDENT DMD. - LRT	38,000	38,000	38,000	38,000	38,000	38,000	38,000	38,000	38,000	38,000	38,000	38,000	**38,000**
(50) CLASS NON-COINCIDENT DMD. - RTP	0	0	0	0	0	0	0	0	0	0	0	0	**0**
(51) CLASS NON-COINCIDENT DMD. - INDUST. EXPAN. INTERR.	0	0	0	0	0	0	0	0	0	0	0	0	**0**
(52) CLASS NON-COINCIDENT DMD. - EXTRA LI INTERRUPTIBLE	0	0	0	0	0	0	0	0	0	0	0	0	**0**
(53) CLASS NON-COINCIDENT DMD. - EXPORT SALES	0	0	0	0	0	0	0	0	0	0	0	0	**0**
(54) SYSTEM COINCIDENT DMD. - DOMESTIC	986,801	1,037,311	830,331	757,175	603,391	626,625	447,542	491,893	499,491	607,815	778,802	929,692	**1,037,311**
(55) SYSTEM COINCIDENT DMD. - SMALL GENERAL	38,371	36,474	38,948	22,123	31,697	24,764	36,273	34,073	32,243	28,337	30,135	35,553	**36,474**
(56) SYSTEM COINCIDENT DMD. - GENERAL	454,506	402,244	418,364	335,666	341,631	298,117	394,328	404,119	413,358	356,428	357,911	410,309	**402,244**
(57) SYSTEM COINCIDENT DMD. - GENERAL LARGE	51,738	51,111	54,731	48,002	56,207	46,800	65,040	67,686	68,709	54,753	53,242	53,773	**51,111**
(58) SYSTEM COINCIDENT DMD. - SMALL INDUST.	39,466	37,451	37,323	32,262	41,233	32,403	41,551	40,170	38,146	40,943	33,688	34,140	**37,451**

NOVA SCOTIA POWER INC.

DETAILED LISTING OF C.O.S.S. INPUT INFORMATION

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(IN THOUSANDS OF DOLLARS)

(59) SYSTEM COINCIDENT DMD. - MEDIUM INDUST.	72,186	70,459	63,227	62,834	67,981	65,531	74,473	70,531	70,768	71,300	69,961	72,584	**70,459**
(60) SYSTEM COINCIDENT DMD. - INDUSTRIAL LARGE	107,957	116,980	106,653	109,022	104,953	107,238	124,749	125,299	126,263	113,367	93,851	129,945	**116,980**
(61) ***SYSTEM COINCIDENT DMD. - ELI 2P-RTP***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	**0**
(62) SYSTEM COINCIDENT DMD. - MUNICIPAL	38,991	40,473	33,084	27,144	24,480	24,169	25,579	25,603	26,483	26,220	31,220	37,053	**40,473**
(63) SYSTEM COINCIDENT DMD. - UNMETERED	18,466	23,575	2,665	2,896	3,223	2,745	3,204	3,051	2,882	2,439	17,516	23,601	**23,575**
(64) SYSTEM COINCIDENT DMD. - BOWATER MERSEY	42,000	42,000	42,000	42,000	42,000	42,000	42,000	42,000	42,000	42,000	42,000	42,000	**42,000**
(65) SYSTEM COINCIDENT DMD. - GEN. REPL.	-117	37	-12	157	718	-29	2,428	17,804	23,047	1,483	19,707	389	**37**
(66) SYSTEM COINCIDENT DMD. - LRT	36,767	36,767	36,767	36,767	36,767	36,767	36,767	36,767	36,767	36,767	36,767	36,767	**36,767**
(67) SYSTEM COINCIDENT DMD. - RTP	0	0	0	0	0	0	0	0	0	0	0	0	**0**
(68) SYSTEM COINCIDENT DMD. - EXPORT SALES	0	0	0	0	0	0	0	0	0	0	0	0	**0**
(69) ***SYSTEM COINCIDENT DMD. - INTERRUPTIBLE***	***76,626***	***88,279***	***79,881***	***81,828***	***74,429***	***86,410***	***95,910***	***97,685***	***96,632***	***86,290***	***66,774***	***99,068***	
(70) **TOTAL COINCIDENT DEMAND**	***1,887,132***	***1,894,882***	***1,664,081***	***1,476,047***	***1,354,282***	***1,307,131***	***1,293,934***	***1,358,996***	***1,380,159***	***1,381,851***	***1,564,799***	***1,805,807***	
(71) VOLTAGE LEVEL DMD. REDUCTION SEC. - GENERAL													
(72) VOLTAGE LEVEL DMD. REDUCTION SEC. - SM. INDUST.													
(73) VOLTAGE LEVEL DMD. REDUCTION PRI. - MED. INDUST.													
(74) LOSS FACTOR PERCENTAGE - SECONDARY													
(75) LOSS FACTOR PERCENTAGE - PRIMARY													
(76) LOSS FACTOR PERCENTAGE - TRANSMISSION													
(77) DEMAND LINE LOSS ADJUSTMENT - DOMESTIC	132,497	151,817	102,130	86,496	63,195	67,290	34,783	45,898	38,931	61,450	91,539	134,615	**1,010,640**
(78) DEMAND LINE LOSS ADJUSTMENT - SMALL GENERAL	3,713	3,606	3,986	1,883	2,975	2,223	2,942	3,143	2,461	2,143	2,552	3,529	**35,156**
(79) DEMAND LINE LOSS ADJUSTMENT - GENERAL	33,669	27,729	32,252	21,292	24,100	19,713	26,809	30,489	27,099	24,176	22,540	34,141	**324,009**
(80) DEMAND LINE LOSS ADJUSTMENT - LARGE GENERAL	3,397	3,152	3,718	2,902	3,782	3,000	4,023	4,888	3,657	3,425	3,195	4,035	**43,174**
(81) DEMAND LINE LOSS ADJUSTMENT - SMALL INDUST.	2,243	2,185	2,437	1,850	2,661	1,991	2,167	2,375	1,853	2,464	1,907	2,359	**26,492**
(82) DEMAND LINE LOSS ADJUSTMENT - MEDIUM INDUST.	3,750	3,857	3,663	3,373	4,213	4,025	3,807	4,097	3,383	4,033	3,619	4,771	**46,592**
(83) DEMAND LINE LOSS ADJUSTMENT - LARGE INDUST.	4,204	4,904	4,791	4,700	5,219	5,420	5,336	6,313	5,199	5,202	3,466	7,106	**61,862**
(84) ***DEMAND LINE LOSS ADJUSTMENT - ELI 2P-RTP***													**0**
(85) DEMAND LINE LOSS ADJUSTMENT - MUNICIPAL	2,285	1,832	1,674	1,279	1,185	1,304	1,049	1,236	1,020	1,193	1,698	2,098	**17,854**
(86) DEMAND LINE LOSS ADJUSTMENT - UNMETERED	2,581	2,476	210	202	182	127	149	157	165	159	1,435	2,893	**10,737**
(87) DEMAND LINE LOSS ADJUSTMENT - BOWATER MERSEY	857	857	857	857	857	857	857	857	857	857	857	857	**10,282**
(88) DEMAND LINE LOSS ADJUSTMENT - GEN. REPL.	-2	1	0	3	15	-1	50	363	470	30	402	8	**1,338**
(89) DEMAND LINE LOSS ADJUSTMENT - LRT	750	750	750	750	750	750	750	750	750	750	750	750	**9,001**
(90) DEMAND LINE LOSS ADJUSTMENT - RTP	0	0	0	0	0	0	0	0	0	0	0	0	**0**
(91) DEMAND LINE LOSS ADJUSTMENT - EXPORT SALES	0	0	0	0	0	0	0	0	0	0	0	0	**0**
(92) ***DEMAND LINE LOSS ADJUSTMENT - INTERRUPTIBLE***	***2,757***	***3,561***	***3,440***	***3,381***	***3,528***	***4,351***	***4,061***	***4,901***	***3,876***	***3,843***	***2,228***	***5,279***	
													3CP
(93) REQUIREMENTS - DOMESTIC	1,119,298	1,189,128	932,461	843,671	666,587	693,915	482,325	537,790	538,422	669,265	870,342	1,064,308	**3,372,733**
(94) REQUIREMENTS - SMALL GENERAL	42,084	40,080	42,934	24,006	34,672	26,987	39,216	37,217	34,704	30,480	32,686	39,082	**121,245**
(95) REQUIREMENTS - GENERAL	488,175	429,973	450,616	356,958	365,731	317,830	421,137	434,607	440,457	380,605	380,451	444,450	**1,362,599**
(96) REQUIREMENTS - GENERAL LARGE	55,135	54,263	58,449	50,904	59,989	49,800	69,063	72,574	72,367	58,177	56,437	57,808	**167,207**
(97) REQUIREMENTS - INDUST. TO 249 KVA	41,708	39,635	39,760	34,112	43,894	34,394	43,718	42,545	39,999	43,408	35,595	36,500	**117,844**
(98) REQUIREMENTS - INDUST. 250-3999 KVA	75,936	74,316	66,890	66,207	72,194	69,555	78,281	74,628	74,152	75,333	73,580	77,354	**227,607**
(99) REQUIREMENTS - INDUSTRIAL LARGE	112,161	121,884	111,443	113,723	110,172	112,658	130,085	131,613	131,463	118,569	97,316	137,052	**371,097**
(100) REQUIREMENTS - ELI 2P-RTP	0	0	0	0	0	0	0	0	0	0	0	0	**-**
(101) REQUIREMENTS - MUNICIPAL	41,277	42,305	34,758	28,423	25,666	25,473	26,628	26,839	27,503	27,413	32,917	39,151	**122,733**
(102) REQUIREMENTS - UNMETERED	21,047	26,051	2,876	3,098	3,405	2,873	3,353	3,208	3,047	2,598	18,951	26,494	**73,592**
(103) REQUIREMENTS - BOWATER MERSEY	42,857	42,857	42,857	42,857	42,857	42,857	42,857	42,857	42,857	42,857	42,857	42,857	**128,570**
(104) REQUIREMENTS - GEN.REPL. / LOAD FOLL.	-119	38	-12	160	733	-30	2,478	18,167	23,518	1,513	20,109	397	**315**
(105) REQUIREMENTS - LRT	37,517	37,517	37,517	37,517	37,517	37,517	37,517	37,517	37,517	37,517	37,517	37,517	**112,552**
(106) REQUIREMENTS - RTP	0	0	0	0	0	0	0	0	0	0	0	0	**0**
(107) REQUIREMENTS - EXPORT SALES	0	0	0	0	0	0	0	0	0	0	0	0	**0**

NOVA SCOTIA POWER INC.
COST OF SERVICE STUDY ANALYSIS
R E F E R E N C E   G U I D E

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EXHIBIT 1

NOVA SCOTIA POWER INC.
SUMMARY OF REVENUE TO EXPENSE RECOVERY RATIOS

	2013	
CUSTOMER CLASS	PRESENT	PROPOSED
(1) DOMESTIC	100.52	99.00
(2) SMALL GENERAL	103.46	104.61
(3) GENERAL	103.46	103.48
(4) LARGE GENERAL	101.38	98.19
(5) SMALL INDUSTRIAL	101.55	102.55
(6) MEDIUM INDUSTRIAL	97.91	98.42
(7) LARGE INDUSTRIAL	97.74	95.55
(8) ELI 2P-RTP	91.33	N/A
(9) MUNICIPAL	98.11	97.39
(10) UNMETERED	101.26	100.00
(11) TOTAL	100.00	100.00

EXHIBIT 2

NOVA SCOTIA POWER INC.

FUNCTIONALIZATION OF AVERAGE RATE BASE

FOR THE YEAR ENDING DECEMBER 31, 2013

(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) GENERATION	(3) TRANSMISSION	(4) DISTRIBUTION	(5) RETAIL	(6) DIRECT CAPITAL
PRODUCTION PLANT						
(1) STEAM	$1,389,088	$1,389,088	$0	$0	$0	$0
(2) HYDRO	345,695	324,454	0	0	0	21,241
(3) WIND	194,757	194,757	0	0	0	0
(4) LM6000	62,706	62,706	0	0	0	0
(5) GAS TURBINE - OTHER	6,599	6,599	0	0	0	0
(6) TOTAL PROD. PLANT	1,998,845	1,977,604	0	0	0	21,241
(7) Transmission < 138kV	101,481	0	101,481	0	0	0
(8) Transmission > 69kV	332,198	0	332,198	0	0	0
(9) TRANSMISSION PLANT	433,679	0	433,679	0	0	0
DISTRIBUTION PLANT						
(10) LAND	4,438	0	0	4,438	0	0
(11) EASEMENTS & SURVEY	16,044	0	0	16,044	0	0
(12) OTHER	2,103	0	0	2,103	0	0
(13) SUBSTATIONS	28,462	0	0	28,462	0	0
(14) POLES & FIXTURES	173,357	0	0	173,357	0	0
(15) O.H. LINES	114,863	0	0	114,863	0	0
(16) U.G. LINES	33,044	0	0	33,044	0	0
(17) LINE TRANSFORMERS	154,540	0	0	154,540	0	0
(18) SERVICES	57,705	0	0	57,705	0	0
(19) METERS	23,780	0	0	23,780	0	0
(20) STREET LIGHTING	26,970	0	0	15,950	0	11,020
(21) TOTAL DIST. PLANT	635,306	0	0	624,286	0	11,020
(22) SUB-TOTAL	3,067,830	1,977,604	433,679	624,286	0	32,261
(23) GEN. PROPERTY PLANT	243,157	158,411	34,739	50,007	0	0
(24) TOT. PLT.IN SERVICE	3,310,987	2,136,015	468,418	674,293	0	32,261
Working Capital & Deferred Charges/Credits						
(25) CASH - FUEL	0	0	0	0	0	0
(26) CASH - OTHER	43,271	20,831	4,072	18,146	0	221
(27) MAT. & SUP. - FUEL	88,682	88,682	0	0	0	0
(28) MAT. & SUP. - OTHER	28,089	18,299	4,013	5,777	0	0
(29) DEF. CHG. - Financing	75,865	49,424	10,839	15,602	0	0
(30) DEF. CHG. - Tax	21,479	13,993	3,069	4,417	0	0
(31) DEF. CHG. - Pension	66,431	32,146	6,283	28,002	0	0
(32) DEF. CHG. - Steam Assets	0	0	0	0	0	0
(33) DEF. CHG. - Fuel Deferral	14,080	14,080	0	0	0	0
(34) DEF. CHG. - Other	8,914	4,853	596	859	0	2,606
(35) DEF. CHG. - FCR	37,400	30,673	6,727	0	0	0
(36) DEF. CR. - ARO Steam	(41,394)	(41,394)	0	0	0	0
(37) DEF. CR. - ARO Hydro	(21,653)	(21,653)	0	0	0	0
(38) DEF. CR. - ARO Wind	(10,400)	(10,400)	0	0	0	0
(39) DEF. CR. - ARO CT	(3,944)	(3,944)	0	0	0	0
(40) DEF. CR. - ARO Trans	(23,425)	0	(23,425)	0	0	0
(41) DEF. CR. - Other	(6,589)	(6,589)	0	0	0	0
(42) CONTRACT RECEIVABLE	0	0	0	0	0	0
(43) TOT.WORKING CAPITAL	276,806	189,002	12,173	72,803	0	2,827
(44) TOTAL AVE. RATE BASE	$3,587,793	$2,325,017	$480,591	$747,096	$0	$35,088

NOVA SCOTIA POWER INC.
CLASSIFICATION OF AVERAGE RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2013
(IN THOUSANDS OF DOLLARS)

	(1)	(2)	(3)	(4)
		INITIAL CLASSIFICATION		
	TOTAL COMPANY	DEMAND RELATED PLANT	ENERGY RELATED PLANT	CUSTOMER RELATED PLANT
GENERATION FUNCTION				
(1) STEAM PLANT	$1,389,088	$1,047,670	$341,418	$0
(2) HYDRO PLANT	324,454	319,306	5,148	0
(3) WIND PLANT	194,757	16,066	178,691	0
(4) LM6000 PLANT	62,706	62,706	0	0
(5) GAS TURBINE PLANT - OTHER	6,599	6,599	0	0
(6) TOTAL GENERATION PLANT	1,977,604	1,452,347	525,257	0
(7) GENERAL PROPERTY PLANT	158,411	116,337	42,074	0
(8) TOTAL PLANT IN SERVICE	2,136,015	1,568,684	567,331	0
Working Capital & Deferred Charges/Credits:				
(9) CASH - FUEL	0	0	0	0
(10) CASH - OTHER	20,831	5,704	15,127	0
(11) MAT. & SUPPLIES - FUEL	88,682	0	88,682	0
(12) MAT. & SUPPLIES - OTHER	18,299	13,439	4,860	0
(13) DEF. CHG. - Financing	49,424	36,297	13,127	0
(14) DEF. CHG. - Tax	13,993	10,276	3,717	0
(15) DEF. CHG. - Pension	32,146	8,802	23,343	0
(16) DEF. CHG. - Steam Assets	0	0	0	0
(17) DEF. CHG. - Fuel Deferral	14,080	0	14,080	0
(18) DEF. CHG. - Other	4,853	3,564	1,289	0
(19) DEF. CHG. - FCR	30,673	22,527	8,147	0
(20) DEF. CR. - ARO Steam	(41,394)	(31,220)	(10,174)	0
(21) DEF. CR. - ARO Hydro	(21,653)	(21,309)	(344)	0
(22) DEF. CR. - ARO Wind	(10,400)	(10,235)	(165)	0
(23) DEF. CR. - ARO CT	(3,944)	(3,944)	0	0
(24) DEF. CR. - Other	(6,589)	(4,970)	(1,619)	0
(25) CONTRACT RECEIVABLE	0	0	0	0
(26) SUB-TOTAL	189,002	28,931	160,071	0
(27) TOTAL GENERATION FUNCTION	**2,325,017**	**1,597,615**	**727,402**	**0**
TRANSMISSION FUNCTION				
(28) TRANSMISSION PLANT < 138kV	101,481	101,481	0	0
(29) GENERAL PROPERTY PLANT	8,129	8,129	0	0
(30) TOTAL PLANT IN SERVICE	109,610	109,610	0	0
Working Capital & Deferred Charges/Credits:				
(31) CASH - FUEL	0	0	0	0
(32) CASH - OTHER	974	423	551	0
(33) MAT. & SUPPLIES - FUEL	0	0	0	0
(34) MAT. & SUPPLIES - OTHER	939	939	0	0
(35) DEF. CHG. - Financing	2,536	2,536	0	0
(36) DEF. CHG. - Tax	718	718	0	0
(37) DEF. CHG. - Pension	1,503	653	850	0
(38) DEF. CHG. - Other	140	140	0	0
(39) DEF. CHG. - ARO Trans.	(5,481)	(5,481)	0	0
(40) SUB-TOTAL	1,328	(73)	1,401	0
(41) TOTAL TRANS. < 138kV	110,938	109,537	1,401	0

NOVA SCOTIA POWER INC.

CLASSIFICATION OF AVERAGE RATE BASE

FOR THE YEAR ENDING DECEMBER 31, 2013
(IN THOUSANDS OF DOLLARS)

	(1)	(2)	(3)	(4)
		INITIAL CLASSIFICATION		
	TOTAL COMPANY	DEMAND RELATED PLANT	ENERGY RELATED PLANT	CUSTOMER RELATED PLANT
(1) TRANSMISSION PLANT > 69kV	332,198	332,198	0	0
(2) GENERAL PROPERTY PLANT	26,610	26,610	0	0
(3) TOTAL PLANT IN SERVICE	358,808	358,808	0	0
Working Capital & Deferred Charges/Credits:				
(4) CASH - FUEL	0	0	0	0
(5) CASH - OTHER	3,098	1,345	1,753	0
(6) MAT. & SUPPLIES - FUEL	0	0	0	0
(7) MAT. & SUPPLIES - OTHER	3,074	3,074	0	0
(8) DEF. CHG. - Financing	8,302	8,302	0	0
(9) DEF. CHG. - Tax	2,351	2,351	0	0
(10) DEF. CHG. - Pension	4,781	2,076	2,704	0
(11) DEF. CHG. - Other	457	457	0	0
(12) DEF. CHG. - FCR	6,727	6,727	0	0
(13) DEF. CHG. - ARO Trans	(17,944)	(17,944)	0	0
(14) SUB-TOTAL	10,845	6,388	4,457	0
(15) TOTAL TRANS. > 69kV	369,653	365,196	4,457	0
(16) TOTAL TRANSMISSION FUNCTION	**$480,591**	**$474,733**	**$5,858**	**$0**

DISTRIBUTION FUNCTION

DISTRIBUTION PLANT:				
(17) LAND	4,438	3,024	0	1,414
(18) EASEMENTS & SURVEY	16,044	10,933	0	5,111
(19) OTHER	2,103	1,433	0	670
(20) SUBSTATIONS	28,462	28,462	0	0
(21) POLES & FIXTURES	173,357	112,682	0	60,675
(22) O.H. LINES	114,863	74,661	0	40,202
(23) U.G. LINES	33,044	21,479	0	11,565
(24) LINE TRANSFORMERS	154,540	154,540	0	0
(25) SERVICES	57,705	0	0	57,705
(26) METERS	23,780	0	0	23,780
(27) STREET LIGHTING	15,950	15,950	0	0
(28) TOTAL DISTRIBUTION PLANT	624,286	423,164	0	201,122
(29) GENERAL PROPERTY PLANT	50,007	33,897	0	16,110
(30) TOTAL PLANT IN SERVICE	674,293	457,061	0	217,232
Working Capital & Deferred Charges/Credits:				
(31) CASH - FUEL	0	0	0	0
(32) CASH - OTHER	18,146	6,558	0	11,588
(33) MAT. & SUPPLIES - FUEL	0	0	0	0
(34) MAT. & SUPPLIES - OTHER	5,777	3,916	0	1,861
(35) DEF. CHG. - Financing	15,602	10,576	0	5,026
(36) DEF. CHG. - Tax	4,417	2,994	0	1,423
(37) DEF. CHG. - Pension	28,002	10,120	0	17,882
(38) DEF. CHG. - Other	859	582	0	277
(39) SUB-TOTAL	72,803	34,746	0	38,057
(40) TOTAL DISTRIBUTION FUNCTION	**747,096**	**491,807**	**0**	**255,289**

NOVA SCOTIA POWER INC.

CLASSIFICATION OF RATE BASE

FOR THE YEAR ENDING DECEMBER 31, 2013

(IN THOUSANDS OF DOLLARS)

	(1)	(2)	(3)	(4)
		INITIAL CLASSIFICATION		
	TOTAL COMPANY	DEMAND RELATED PLANT	ENERGY RELATED PLANT	CUSTOMER RELATED PLANT
RETAIL FUNCTION				
DISTRIBUTION PLANT:				
(1) SERVICES	0	0	0	0
(2) METERS	0	0	0	0
(3) TOTAL RETAIL PLANT	0	0	0	0
(4) GENERAL PROPERTY PLANT	0	0	0	0
(5) TOTAL PLANT IN SERVICE	0	0	0	0
Working Capital & Deferred Charges/Credits:				
(6) CASH - FUEL	0	0	0	0
(7) CASH - OTHER	0	0	0	0
(8) MAT. & SUPPLIES - FUEL	0	0	0	0
(9) MAT. & SUPPLIES - OTHER	0	0	0	0
(10) DEF. CHG. - Financing	0	0	0	0
(11) DEF. CHG. - Tax	0	0	0	0
(12) DEF. CHG. - Pension	0	0	0	0
(13) DEF. CHG. - Other	0	0	0	0
(14) SUB-TOTAL	0	0	0	0
(15) TOTAL RETAIL FUNCTION	**0**	**0**	**0**	**0**
(16) TOTAL AVE. RATE BASE	**$3,552,705**	**$2,564,155**	**$733,260**	**$255,289**

NOVA SCOTIA POWER INC.

CLASSIFICATION OF AVERAGE RATE BASE

FOR THE YEAR ENDING DECEMBER 31, 2013

(IN THOUSANDS OF DOLLARS)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	INITIAL R/B CLASSIFICATION			FURTHER CLASSIFICATION			FULLY CLASSIFIED RATE BASE		
	DEMAND PLANT	ENERGY PLANT	CUSTOMER PLANT	DEMAND PLANT	ENERGY PLANT	CUSTOMER PLANT	DEMAND PLANT	ENERGY PLANT	CUSTOMER PLANT
GENERATION FUNCTION									
(1) STEAM PLANT	$1,047,670	$341,418	$0	($592,667)	$592,667	$0	$455,003	$934,085	$0
(2) HYDRO PLANT	319,306	5,148	0	(180,631)	180,631	0	138,675	185,779	0
(3) WIND PLANT	16,066	178,691	0	(11,246)	11,246	0	4,820	189,937	0
(4) LM6000 PLANT	62,706	0	0	(35,473)	35,473	0	27,233	35,473	0
(5) GAS TURBINE PLANT - OTHER	6,599	0	0	0	0	0	6,599	0	0
(6) TOTAL GENERATION PLANT	1,452,347	525,257	0	(820,017)	820,017	0	632,330	1,345,274	0
(7) GENERAL PROPERTY PLANT	116,337	42,074	0	(65,686)	65,686	0	50,651	107,760	0
(8) TOTAL PLANT IN SERVICE	1,568,684	567,331	0	(885,703)	885,703	0	682,981	1,453,034	0
Working Capital & Deferred Charges/Credits:									
(9) CASH - FUEL	0	0	0	0	0	0	0	0	0
(10) CASH - OTHER	5,704	15,127	0	0	0	0	5,704	15,127	0
(11) MAT. & SUPPLIES - FUEL	0	88,682	0	0	0	0	0	88,682	0
(12) MAT. & SUPPLIES - OTHER	13,439	4,860	0	(7,588)	7,588	0	5,851	12,448	0
(13) DEF. CHG. - Financing	36,297	13,127	0	(20,494)	20,494	0	15,803	33,621	0
(14) DEF. CHG. - Tax	10,276	3,717	0	(5,802)	5,802	0	4,474	9,519	0
(15) DEF. CHG. - Pension	8,802	23,343	0	0	0	0	8,802	23,343	0
(16) DEF. CHG. - Steam Assets	0	0	0	0	0	0	0	0	0
(17) DEF. CHG. - Fuel Deferral	0	14,080	0	0	0	0	0	14,080	0
(18) DEF. CHG. - Other	3,564	1,289	0	(2,012)	2,012	0	1,552	3,301	0
(19) DEF. CHG. - FCR	22,527	8,147	0	(12,719)	12,719	0	9,808	20,866	0
(20) DEF. CR. - ARO Steam	(31,220)	(10,174)	0	17,661	(17,661)	0	(13,559)	(27,835)	0
(21) DEF. CR. - ARO Hydro	(21,309)	(344)	0	12,055	(12,055)	0	(9,255)	(12,398)	0
(22) DEF. CR. - ARO Wind	(10,235)	(165)	0	5,790	(5,790)	0	(4,445)	(5,955)	0
(23) DEF. CR. - ARO CT	(3,944)	0	0	0	0	0	(3,944)	0	0
(24) DEF. CR. - Other	(4,970)	(1,619)	0	2,811	(2,811)	0	(2,158)	(4,431)	0
(25) CONTRACT RECEIVABLE	0	0	0	0	0	0	0	0	0
(26) SUB-TOTAL	28,931	160,071	0	(10,298)	10,298	0	18,633	170,369	0
							0	0	0
(27) TOTAL GENERATION FUNCTION	1,597,615	727,402	0	(896,001)	896,001	0	701,614	1,623,403	0
TRANSMISSION FUNCTION									
(28) TRANSMISSION PLANT < 138kV	101,481	0	0	(57,408)	57,408	0	44,073	57,408	0
(29) GENERAL PROPERTY PLANT	8,129	0	0	(4,599)	4,599	0	3,530	4,599	0
(30) TOTAL PLANT IN SERVICE	109,610	0	0	(62,006)	62,006	0	47,604	62,006	0
Working Capital & Deferred Charges/Credits:									
(31) CASH - FUEL	0	0	0	0	0	0	0	0	0
(32) CASH - OTHER	423	551	0	0	0	0	423	551	0
(33) MAT. & SUPPLIES - FUEL	0	0	0	0	0	0	0	0	0
(34) MAT. & SUPPLIES - OTHER	939	0	0	(531)	531	0	408	531	0
(35) DEF. CHG. - Financing	2,536	0	0	(1,435)	1,435	0	1,101	1,435	0
(36) DEF. CHG. - Tax	718	0	0	(406)	406	0	312	406	0
(37) DEF. CHG. - Pension	653	850	0	0	0	0	653	850	0
(38) DEF. CHG. - Other	140	0	0	(79)	79	0	61	79	0
(40) DEF. CR. - ARO Trans.	(5,481)	0	0	3,101	(3,101)	0	(2,381)	(3,101)	0
(41) SUB-TOTAL	(73)	1,401	0	650	(650)	0	577	751	0
(42) TOTAL TRANS. < 138kV	109,537	1,401	0	(61,356)	61,356	0	48,180	62,758	0

12,729 24,671

NOVA SCOTIA POWER INC.
CLASSIFICATION OF AVERAGE RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2013
(IN THOUSANDS OF DOLLARS)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	INITIAL R/B CLASSIFICATION			FURTHER CLASSIFICATION			FULLY CLASSIFIED RATE BASE		
	DEMAND PLANT	ENERGY PLANT	CUSTOMER PLANT	DEMAND PLANT	ENERGY PLANT	CUSTOMER PLANT	DEMAND PLANT	ENERGY PLANT	CUSTOMER PLANT
(1) TRANSMISSION PLANT > 69kV	332,198	0	0	(187,924)	187,924	0	144,274	187,924	0
(2) GENERAL PROPERTY PLANT	26,610	0	0	(15,053)	15,053	0	11,557	15,053	0
(3) TOTAL PLANT IN SERVICE	358,808	0	0	(202,978)	202,978	0	155,830	202,978	0
Working Capital & Deferred Charges/Credits:									
(4) CASH - FUEL	0	0	0	0	0	0	0	0	0
(5) CASH - OTHER	1,345	1,753	0	0	0	0	1,345	1,753	0
(6) MAT. & SUPPLIES - FUEL	0	0	0	0	0	0	0	0	0
(7) MAT. & SUPPLIES - OTHER	3,074	0	0	(1,739)	1,739	0	1,335	1,739	0
(8) DEF. CHG. - Financing	8,302	0	0	(4,697)	4,697	0	3,606	4,697	0
(9) DEF. CHG. - Tax	2,351	0	0	(1,330)	1,330	0	1,021	1,330	0
(10) DEF. CHG. - Pension	2,076	2,704	0	0	0	0	2,076	2,704	0
(11) DEF. CHG. - Other	457	0	0	(258)	258	0	198	258	0
(12) DEF. CHG. - FCR	6,727	0	0	(3,805)	3,805	0	2,921	3,805	0
(13) DEF. CR. - ARO Trans	(17,944)	0	0	10,151	(10,151)	0	(7,793)	(10,151)	0
(14) SUB-TOTAL	6,388	4,457	0	(1,678)	1,678	0	4,710	6,135	0
(15) TOTAL TRANS. > 69kV	365,196	4,457	0	(204,656)	204,656	0	160,540	209,113	0
(16) TOTAL TRANSMISSION FUNCTION	$474,733	$5,858	$0	($266,012)	$266,012	$0	$208,721	$271,870	$0

NOVA SCOTIA POWER INC.

CLASSIFICATION OF AVERAGE RATE BASE

FOR THE YEAR ENDING DECEMBER 31, 2013

(IN THOUSANDS OF DOLLARS)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	INITIAL R/B CLASSIFICATION			FURTHER CLASSIFICATION			FULLY CLASSIFIED RATE BASE		
	DEMAND PLANT	ENERGY PLANT	CUSTOMER PLANT	DEMAND PLANT	ENERGY PLANT	CUSTOMER PLANT	DEMAND PLANT	ENERGY PLANT	CUSTOMER PLANT
DISTRIBUTION FUNCTION									
DISTRIBUTION PLANT:									
(1) LAND	$3,024	$0	$1,414	$0	$0	$0	$3,024	$0	$1,414
(2) EASEMENTS & SURVEY	10,933	0	5,111	0	0	0	10,933	0	5,111
(3) OTHER	1,433	0	670	0	0	0	1,433	0	670
(4) SUBSTATIONS	28,462	0	0	0	0	0	28,462	0	0
(5) POLES & FIXTURES	112,682	0	60,675	0	0	0	112,682	0	60,675
(6) O.H. LINES	74,661	0	40,202	0	0	0	74,661	0	40,202
(7) U.G. LINES	21,479	0	11,565	0	0	0	21,479	0	11,565
(8) LINE TRANSFORMERS	154,540	0	0	0	0	0	154,540	0	0
(9) SERVICES	0	0	57,705	0	0	0	0	0	57,705
(10) METERS	0	0	23,780	0	0	0	0	0	23,780
(11) STREET LIGHTING	15,950	0	0	0	0	0	15,950	0	0
(12) TOTAL DISTRIBUTION PLANT	423,164	0	201,122	0	0	0	423,164	0	201,122
(13) GENERAL PROPERTY PLANT	33,897	0	16,110	0	0	0	33,897	0	16,110
(14) TOTAL PLANT IN SERVICE	457,061	0	217,232	0	0	0	457,061	0	217,232
Working Capital & Deferred Charges/Credits:									
(15) CASH - FUEL	0	0	0	0	0	0	0	0	0
(16) CASH - OTHER	6,558	0	11,588	0	0	0	6,558	0	11,588
(17) MAT. & SUPPLIES - FUEL	0	0	0	0	0	0	0	0	0
(18) MAT. & SUPPLIES - OTHER	3,916	0	1,861	0	0	0	3,916	0	1,861
(19) DEF. CHG. - Financing	10,576	0	5,026	0	0	0	10,576	0	5,026
(20) DEF. CHG. - Tax	2,994	0	1,423	0	0	0	2,994	0	1,423
(21) DEF. CHG. - Pension	10,120	0	17,882	0	0	0	10,120	0	17,882
(22) DEF. CHG. - Other	582	0	277	0	0	0	582	0	277
(23) SUB-TOTAL	34,746	0	38,057	0	0	0	34,746	0	38,057
(24) TOTAL DISTRIBUTION FUNCTION	$491,807	$0	$255,289	$0	$0	$0	$491,807	$0	$255,289
RETAIL FUNCTION									
DISTRIBUTION PLANT:									
(25) SERVICES	$0	$0	$0	$0	$0	$0	$0	$0	$0
(26) METERS	0	0	0	0	0	0	0	0	0
(27) TOTAL RETAIL PLANT	0	0	0	0	0	0	0	0	0
(28) GENERAL PROPERTY PLANT	0	0	0	0	0	0	0	0	0
(29) TOTAL PLANT IN SERVICE	0	0	0	0	0	0	0	0	0
Working Capital & Deferred Charges/Credits:									
(30) CASH - FUEL	0	0	0	0	0	0	0	0	0
(31) CASH - OTHER	0	0	0	0	0	0	0	0	0
(32) MAT. & SUPPLIES - FUEL	0	0	0	0	0	0	0	0	0
(33) MAT. & SUPPLIES - OTHER	0	0	0	0	0	0	0	0	0
(34) DEF. CHG. - Financing	0	0	0	0	0	0	0	0	0
(35) DEF. CHG. - Tax	0	0	0	0	0	0	0	0	0
(36) DEF. CHG. - Pension	0	0	0	0	0	0	0	0	0
(37) DEF. CHG. - Other	0	0	0	0	0	0	0	0	0
(38) SUB-TOTAL	0	0	0	0	0	0	0	0	0
(39) TOTAL RETAIL FUNCTION	0	0	0	0	0	0	0	0	0
(40) TOTAL AVE. RATE BASE	**$2,564,155**	**$733,260**	**$255,289**	**($1,162,013)**	**$1,162,013**	**$0**	**$1,402,142**	**$1,895,274**	**$255,289**

NOVA SCOTIA POWER INC.

ALLOCATION OF AVERAGE RATE BASE

FOR THE YEAR ENDING DECEMBER 31, 2013

(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
DEMAND CLASSIFICATION												
GENERATION FUNCTION												
(1) STEAM PLANT	$455,003	$258,496	$9,293	$104,434	$12,815	$9,032	$17,444	$28,442	$0	$9,407	$5,640	D-3A
(2) HYDRO PLANT	138,675	78,784	2,832	31,829	3,906	2,753	5,317	8,668	0	2,867	1,719	D-3A
(3) WIND PLANT	4,820	2,738	98	1,106	136	96	185	301	0	100	60	D-3A
(4) LM6000 PLANT	27,233	15,472	556	6,251	767	541	1,044	1,702	0	563	338	D-3A
(5) GAS TURBINE PLANT - OTHER	6,599	3,749	135	1,515	186	131	253	412	0	136	82	D-3A
(6) TOTAL GENERATION PLANT	632,330	359,239	12,914	145,134	17,810	12,552	24,243	39,527	0	13,073	7,838	
(7) GEN. PROPERTY PLANT	50,651	28,776	1,034	11,626	1,427	1,005	1,942	3,166	0	1,047	628	P-7
(8) TOTAL PLANT IN SERVICE	682,981	388,015	13,949	156,760	19,236	13,557	26,185	42,693	0	14,120	8,466	
Working Capital & Deferred Charges/Credits:												
(9) CASH - FUEL	0	0	0	0	0	0	0	0	0	0	0	D-3A
(10) CASH - OTHER	5,704	3,241	116	1,309	161	113	219	357	0	118	71	O-1
(11) MAT. & SUPPLIES - FUEL	0	0	0	0	0	0	0	0	0	0	0	D-3A
(12) MAT. & SUPPLIES - OTHER	5,851	3,324	119	1,343	165	116	224	366	0	121	73	P-7
(13) DEF. CHG. - Financing	15,803	8,978	323	3,627	445	314	606	988	0	327	196	P-7
(14) DEF. CHG. - Tax	4,474	2,542	91	1,027	126	89	172	280	0	92	55	P-7
(15) DEF. CHG. - Pension	8,802	5,001	180	2,020	248	175	337	550	0	182	109	O-1
(16) DEF. CHG. - Steam Assets	0	0	0	0	0	0	0	0	0	0	0	D-3A
(17) DEF. CHG. - Fuel Deferral	0	0	0	0	0	0	0	0	0	0	0	D-3A
(18) DEF. CHG. - Other	1,552	882	32	356	44	31	59	97	0	32	19	P-7
(19) DEF. CHG. - FCR	9,808	5,572	200	2,251	276	195	376	613	0	203	122	P-7
(20) DEF. CR. - ARO Steam	(13,559)	(7,703)	(277)	(3,112)	(382)	(269)	(520)	(848)	0	(280)	(168)	D-3A
(21) DEF. CR. - ARO Hydro	(9,255)	(5,258)	(189)	(2,124)	(261)	(184)	(355)	(579)	0	(191)	(115)	D-3A
(22) DEF. CR. - ARO Wind	(4,445)	(2,525)	(91)	(1,020)	(125)	(88)	(170)	(278)	0	(92)	(55)	D-3A
(23) DEF. CR. - ARO CT	(3,944)	(2,241)	(81)	(905)	(111)	(78)	(151)	(247)	0	(82)	(49)	D-3A
(24) DEF. CR. - Other	(2,158)	(1,226)	(44)	(495)	(61)	(43)	(83)	(135)	0	(45)	(27)	D-3A
(25) CONTRACT RECEIVABLE	0	0	0	0	0	0	0	0	0	0	0	D-3A
(26) SUB-TOTAL	18,633	10,586	381	4,277	525	370	714	1,165	0	385	231	
(25) TOTAL GEN. FUNCTION	701,614	398,601	14,329	161,037	19,761	13,927	26,899	43,857	0	14,505	8,697	
TRANSMISSION FUNCTION												
(28) TRANSMISSION PLANT < 138kV	44,073	25,039	900	10,116	1,241	875	1,690	2,755	0	911	546	D-3B
(26) GEN. PROPERTY PLANT	3,530	2,006	72	810	99	70	135	221	0	73	44	P-8A
(30) TOTAL PLANT IN SERVICE	47,604	27,045	972	10,926	1,341	945	1,825	2,976	0	984	590	
Working Capital & Deferred Charges/Credits:												
(31) CASH - FUEL	0	0	0	0	0	0	0	0	0	0	0	D-3B
(32) CASH - OTHER	423	240	9	97	12	8	16	26	0	9	5	O-2A
(33) MAT. & SUPPLIES - FUEL	0	0	0	0	0	0	0	0	0	0	0	D-3B
(34) MAT. & SUPPLIES - OTHER	408	232	8	94	11	8	16	25	0	8	5	P-8A
(35) DEF. CHG. - Financing	1,101	626	22	253	31	22	42	69	0	23	14	P-8A
(36) DEF. CHG. - Tax	312	177	6	72	9	6	12	19	0	6	4	P-8A
(37) DEF. CHG. - Pension	653	371	13	150	18	13	25	41	0	13	8	O-2A
(38) DEF. CHG. - Other	61	34	1	14	2	1	2	4	0	1	1	P-8A
(40) DEF. CR. - ARO Trans.	(2,381)	(1,352)	(49)	(546)	(67)	(47)	(91)	(149)	0	(49)	(30)	D-3B
(41) SUB-TOTAL	577	328	12	132	16	11	22	36	0	12	7	
(42) TOTAL TRANS. < 138kV	48,180	27,372	984	11,058	1,357	956	1,847	3,012	0	996	597	

NOVA SCOTIA POWER INC.

ALLOCATION OF AVERAGE RATE BASE

FOR THE YEAR ENDING DECEMBER 31, 2013

(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
(1) TRANSMISSION PLANT > 69kV	144,274	81,965	2,947	33,114	4,063	2,864	5,531	9,018	0	2,983	1,788	D-3A
(2) GENERAL PROPERTY PLANT	11,557	6,566	236	2,653	325	229	443	722	0	239	143	P-8B
(3) TOTAL PLANT IN SERVICE	155,830	88,530	3,183	35,767	4,389	3,093	5,974	9,741	0	3,222	1,932	
Working Capital & Deferred Charges/Credits:												
(4) CASH - FUEL	0	0	0	0	0	0	0	0	0	0	0	D-3A
(5) CASH - OTHER	1,345	764	27	309	38	27	52	84	0	28	17	O-2B
(6) MAT. & SUPPLIES - FUEL	0	0	0	0	0	0	0	0	0	0	0	D-3A
(7) MAT. & SUPPLIES - OTHER	1,335	758	27	306	38	27	51	83	0	28	17	P-8B
(8) DEF. CHG. - Financing	3,606	2,048	74	828	102	72	138	225	0	75	45	P-8B
(9) DEF. CHG. - Tax	1,021	580	21	234	29	20	39	64	0	21	13	P-8B
(10) DEF. CHG. - Pension	2,076	1,180	42	477	58	41	80	130	0	43	26	O-2B
(11) DEF. CHG. - Other	198	113	4	46	6	4	8	12	0	4	2	P-8B
(12) DEF. CHG. - FCR	2,921	1,660	60	671	82	58	112	183	0	60	36	P-8B
(13) DEF. CR. - ARO Trans	(7,793)	(4,427)	(159)	(1,789)	(219)	(155)	(299)	(487)	0	(161)	(97)	D-3A
(14) SUB-TOTAL	4,710	2,676	96	1,081	133	93	181	294	0	97	58	
(15) TOTAL TRANS. > 69kV	160,540	91,206	3,279	36,848	4,522	3,187	6,155	10,035	0	3,319	1,990	
(14) TOTAL TRANS. FUNCTION	208,721	118,578	4,263	47,906	5,879	4,143	8,002	13,047	0	4,315	2,587	
DISTRIBUTION FUNCTION												
(15) DISTRIBUTION PLANT - Non Stree	407,214	248,120	13,438	113,066	7,327	10,733	8,467	391	0	26	5,645	EXH. 3A
(16) DISTRIBUTION PLANT - Streetlight	15,950	0	0	0	0	0	0	0	0	0	15,950	EXH. 3A
	0	0	0	0	0	0	0	0	0	0	0	
(17) SUB-TOTAL	423,164	248,120	13,438	113,066	7,327	10,733	8,467	391	0	26	21,595	
(18) GEN. PROPERTY PLANT	33,897	20,654	1,119	9,412	610	893	705	33	0	2	470	P-9
	457,061	268,774	14,557	122,478	7,937	11,626	9,172	424	0	28	22,065	
Working Capital & Deferred Charges/Credits:												
(19) CASH - FUEL	0	0	0	0	0	0	0	0	0	0	0	P-9
(20) CASH - OTHER	6,558	3,354	182	1,552	166	149	189	1	0	0	966	O-3
(21) MAT. & SUPPLIES - FUEL	0	0	0	0	0	0	0	0	0	0	0	P-9
(22) MAT. & SUPPLIES - OTHER	3,916	2,386	129	1,087	70	103	81	4	0	0	54	P-9
(23) DEF. CHG. - Financing	10,576	6,444	349	2,936	190	279	220	10	0	1	147	P-9
(24) DEF. CHG. - Tax	2,994	1,824	99	831	54	79	62	3	0	0	42	P-9
(25) DEF. CHG. - Pension	10,120	5,175	280	2,395	256	230	292	1	0	0	1,491	O-3
(26) DEF. CHG. - Other	582	355	19	162	10	15	12	1	0	0	8	P-9
(27) SUB-TOTAL	34,746	19,537	1,058	8,963	747	856	857	19	0	1	2,707	
(28) TOTAL DIST. FUNCTION	491,807	288,311	15,615	131,441	8,684	12,482	10,029	442	0	29	24,773	
(29) TOTAL DEMAND	**$1,402,142**	**$805,491**	**$34,207**	**$340,384**	**$34,324**	**$30,552**	**$44,931**	**$57,347**	**$0**	**$18,849**	**$36,057**	

NOVA SCOTIA POWER INC.
ALLOCATION OF AVERAGE RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2013
(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) INDUSTRIAL LARGE	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
ENERGY CLASSIFICATION												
GENERATION FUNCTION												
(1) STEAM PLANT	$934,085	$435,955	$23,496	$241,417	$39,272	$25,482	$49,072	$89,866	$0	$18,807	$10,718	E-1A
(2) HYDRO PLANT	185,779	86,707	4,673	48,015	7,811	5,068	9,760	17,873	0	3,741	2,132	E-1A
(3) WIND PLANT	189,937	88,647	4,778	49,090	7,986	5,181	9,978	18,273	0	3,824	2,179	E-1A
(4) LM6000 PLANT	35,473	16,556	892	9,168	1,491	968	1,864	3,413	0	714	407	E-1A
(5) GAS TURBINE PLANT - OTHER	0	0	0	0	0	0	0	0	0	0	0	E-1A
(6) TOTAL GENERATION PLANT	1,345,274	627,865	33,839	347,690	56,559	36,699	70,674	129,426	0	27,086	15,436	
(7) GENERAL PROPERTY PLANT	107,760	50,294	2,711	27,851	4,531	2,940	5,661	10,367	0	2,170	1,236	P-10
(8) TOTAL PLANT IN SERVICE	1,453,034	678,158	36,550	375,541	61,090	39,638	76,335	139,793	0	29,256	16,672	
Working Capital & Deferred Charges/Credits:												
(9) CASH - FUEL	0	0	0	0	0	0	0	0	0	0	0	E-1A
(10) CASH - OTHER	15,127	7,060	381	3,910	636	413	795	1,455	0	305	174	O-4
(11) MAT. & SUPPLIES - FUEL	88,682	41,390	2,231	22,920	3,728	2,419	4,659	8,532	0	1,786	1,018	E-1A
(12) MAT. & SUPPLIES - OTHER	12,448	5,810	313	3,217	523	340	654	1,198	0	251	143	P-10
(13) DEF. CHG. - Financing	33,621	15,692	846	8,689	1,414	917	1,766	3,235	0	677	386	P-10
(14) DEF. CHG. - Tax	9,519	4,443	239	2,460	400	260	500	916	0	192	109	P-10
(15) DEF. CHG. - Pension	23,343	10,895	587	6,033	981	637	1,226	2,246	0	470	268	O-4
(16) DEF. CHG. - Steam Assets	0	0	0	0	0	0	0	0	0	0	0	E-1A
(17) DEF. CHG. - Fuel Deferral	14,080	6,571	354	3,639	592	384	740	1,355	0	283	162	E-1A
(18) DEF. CHG. - Other	3,301	1,541	83	853	139	90	173	318	0	66	38	P-10
(19) DEF. CHG. - FCR	20,866	9,738	525	5,393	877	569	1,096	2,007	0	420	239	P-10
(20) DEF. CR. - ARO Steam	(27,835)	(12,991)	(700)	(7,194)	(1,170)	(759)	(1,462)	(2,678)	0	(560)	(319)	E-1A
(21) DEF. CR. - ARO Hydro	(12,398)	(5,787)	(312)	(3,204)	(521)	(338)	(651)	(1,193)	0	(250)	(142)	E-1A
(22) DEF. CR. - ARO Wind	(5,955)	(2,779)	(150)	(1,539)	(250)	(162)	(313)	(573)	0	(120)	(68)	E-1A
(23) DEF. CR. - ARO CT	0	0	0	0	0	0	0	0	0	0	0	E-1A
(24) DEF. CR. - Other	(4,431)	(2,068)	(111)	(1,145)	(186)	(121)	(233)	(426)	0	(89)	(51)	E-1A
(25) CONTRACT RECEIVABLE	0	0	0	0	0	0	0	0	0	0	0	E-1A
(26) SUB-TOTAL	170,369	79,514	4,285	44,032	7,163	4,648	8,950	16,391	0	3,430	1,955	
(24) TOTAL GEN. FUNCTION	1,623,403	757,673	40,835	419,574	68,253	44,286	85,286	156,184	0	32,686	18,627	
TRANSMISSION FUNCTION												
(28) TRANSMISSION PLANT < 138kV	57,408	26,793	1,444	14,837	2,414	1,566	3,016	5,523	0	1,156	659	E-1B
(29) GENERAL PROPERTY PLANT	4,599	2,146	116	1,188	193	125	242	442	0	93	53	P-11A
(30) TOTAL PLANT IN SERVICE	62,006	28,939	1,560	16,026	2,607	1,692	3,258	5,965	0	1,248	711	
Working Capital & Deferred Charges/Credits:												
(31) CASH - FUEL	0	0	0	0	0	0	0	0	0	0	0	E-1B
(32) CASH - OTHER	551	257	14	142	23	15	29	53	0	11	6	O-5A
(33) MAT. & SUPPLIES - FUEL	0	0	0	0	0	0	0	0	0	0	0	E-1B
(34) MAT. & SUPPLIES - OTHER	531	248	13	137	22	14	28	51	0	11	6	P-11A
(35) DEF. CHG. - Financing	1,435	670	36	371	60	39	75	138	0	29	16	P-11A
(36) DEF. CHG. - Tax	406	190	10	105	17	11	21	39	0	8	5	P-11A
(37) DEF. CHG. - Pension	850	397	21	220	36	23	45	82	0	17	10	O-5A
(38) DEF. CHG. - Other	79	37	2	20	3	2	4	8	0	2	1	P-11A
(40) DEF. CR. - ARO Trans.	(3,101)	(1,447)	(78)	(801)	(130)	(85)	(163)	(298)	0	(62)	(36)	E-1B
(41) SUB-TOTAL	751	351	19	194	32	20	39	72	0	15	9	
(42) TOTAL TRANS. < 138kV	62,758	29,290	1,579	16,220	2,639	1,712	3,297	6,038	0	1,264	720	

NOVA SCOTIA POWER INC.

ALLOCATION OF AVERAGE RATE BASE

FOR THE YEAR ENDING DECEMBER 31, 2013

(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) INDUSTRIAL LARGE	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
(1) TRANSMISSION PLANT > 69kV	187,924	87,708	4,727	48,570	7,901	5,127	9,873	18,080	0	3,784	2,156	E-1A
(2) GENERAL PROPERTY PLANT	15,053	7,026	379	3,891	633	411	791	1,448	0	303	173	P-11B
(3) TOTAL PLANT IN SERVICE	202,978	94,733	5,106	52,460	8,534	5,537	10,663	19,528	0	4,087	2,329	
Working Capital & Deferred Charges/Credits:												
(4) CASH - FUEL	0	0	0	0	0	0	0	0	0	0	0	E-1A
(5) CASH - OTHER	1,753	818	44	453	74	48	92	169	0	35	20	O-5B
(6) MAT. & SUPPLIES - FUEL	0	0	0	0	0	0	0	0	0	0	0	E-1A
(7) MAT. & SUPPLIES - OTHER	1,739	812	44	449	73	47	91	167	0	35	20	P-11B
(8) DEF. CHG. - Financing	4,697	2,192	118	1,214	197	128	247	452	0	95	54	P-11B
(9) DEF. CHG. - Tax	1,330	621	33	344	56	36	70	128	0	27	15	P-11B
(10) DEF. CHG. - Pension	2,704	1,262	68	699	114	74	142	260	0	54	31	O-5B
(11) DEF. CHG. - Other	258	121	7	67	11	7	14	25	0	5	3	P-11B
(12) DEF. CHG. - FCR	3,805	1,776	96	983	160	104	200	366	0	77	44	P-11B
(13) DEF. CR. - ARO Trans	(10,151)	(4,738)	(255)	(2,623)	(427)	(277)	(533)	(977)	0	(204)	(116)	E-1A
(14) SUB-TOTAL	6,135	2,863	154	1,586	258	167	322	590	0	124	70	
(15) TOTAL TRANS. > 69kV	209,113	97,597	5,260	54,046	8,792	5,705	10,986	20,118	0	4,210	2,399	
(15) TOTAL TRANS. FUNCTION	271,870	126,887	6,839	70,266	11,430	7,417	14,283	26,156	0	5,474	3,119	
(16) TOTAL ENERGY	**$1,895,274**	**$884,560**	**$47,674**	**$489,839**	**$79,683**	**$51,703**	**$99,568**	**$182,340**	**$0**	**$38,160**	**$21,747**	

NOVA SCOTIA POWER INC.
ALLOCATION OF AVERAGE RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2013
(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) INDUSTRIAL LARGE	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
CUST. CLASSIFICATION												
DISTRIBUTION FUNCTION												
(1) DISTRIBUTION PLANT	$201,122	$176,667	$9,328	$10,432	$18	$2,140	$195	$60	$0	$6	$2,275	EXH. 3A
(2) GEN. PROPERTY PLANT	16,110	14,151	747	836	1	171	16	5	0	1	182	P-12
(3) TOTAL PLANT IN SERVICE	217,232	190,818	10,075	11,268	19	2,312	210	65	0	7	2,458	
WORKING CAPITAL:												
(4) CASH - FUEL	0	0	0	0	0	0	0	0	0	0	0	P-12
(5) CASH - OTHER	11,588	10,459	552	298	1	61	7	2	0	0	207	O-6
(6) MAT. & SUPPLIES - FUEL	0	0	0	0	0	0	0	0	0	0	0	P-12
(7) MAT. & SUPPLIES - OTHER	1,861	1,635	86	97	0	20	2	1	0	0	21	P-12
(8) DEF. CHG. - Financing	5,026	4,415	233	261	0	53	5	2	0	0	57	P-12
(9) DEF. CHG. - Tax	1,423	1,250	66	74	0	15	1	0	0	0	16	P-12
(10) DEF. CHG. - Pension	17,882	16,140	852	460	1	95	11	3	0	0	319	O-6
(11) DEF. CHG. - Other	277	243	13	14	0	3	0	0	0	0	3	P-12
(12) SUB-TOTAL	38,057	34,142	1,803	1,204	2	247	27	8	0	1	623	
(13) TOTAL DIST. FUNCTION	255,289	224,960	11,877	12,472	22	2,559	237	73	0	8	3,081	
RETAIL FUNCTION												
(14) DISTRIBUTION PLANT	0	0	0	0	0	0	0	0	0	0	0	EXH. 3A
(15) GEN. PROPERTY PLANT	0	0	0	0	0	0	0	0	0	0	0	P-13
(16) TOTAL PLANT IN SERVICE	0	0	0	0	0	0	0	0	0	0	0	
WORKING CAPITAL:												
(17) CASH - FUEL	0	0	0	0	0	0	0	0	0	0	0	P-13
(18) CASH - OTHER	0	0	0	0	0	0	0	0	0	0	0	O-7
(19) MAT. & SUPPLIES - FUEL	0	0	0	0	0	0	0	0	0	0	0	P-13
(20) MAT. & SUPPLIES - OTHER	0	0	0	0	0	0	0	0	0	0	0	P-13
(21) DEF. CHG. - Financing	0	0	0	0	0	0	0	0	0	0	0	P-13
(22) DEF. CHG. - Tax	0	0	0	0	0	0	0	0	0	0	0	P-13
(23) DEF. CHG. - Pension	0	0	0	0	0	0	0	0	0	0	0	O-7
(24) DEF. CHG. - Other	0	0	0	0	0	0	0	0	0	0	0	P-13
(25) SUB-TOTAL	0	0	0	0	0	0	0	0	0	0	0	
(26) TOTAL RETAIL FUNCTION	0	0	0	0	0	0	0	0	0	0	0	
(27) TOTAL CUSTOMER	**255,289**	**224,960**	**11,877**	**12,472**	**22**	**2,559**	**237**	**73**	**0**	**8**	**3,081**	
(28) TOTAL AVE. RATE BASE	**$3,552,705**	**$1,915,011**	**$93,758**	**$842,695**	**$114,028**	**$84,814**	**$144,737**	**$239,760**	**$0**	**$57,017**	**$60,884**	

NOVA SCOTIA POWER INC.

ALLOCATION OF AVERAGE DISTRIBUTION RATE BASE

FOR THE YEAR ENDING DECEMBER 31, 2013

(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
DEMAND												
(1) LAND	$3,024	$1,786	$97	$827	$88	$79	$102	$5	$0	$0	$41	P-3
(2) EASEMENTS & SURVEY	10,933	6,455	350	2,988	318	287	368	18	0	1	147	P-3
(3) OTHER	1,433	846	46	392	42	38	48	2	0	0	19	P-3
(4) SUBSTATIONS	28,462	16,129	874	7,584	1,065	735	1,320	365	0	24	367	EXH 3B
(5) POLES & FIXTURES	112,682	66,939	3,625	30,912	3,138	2,969	3,577	0	0	0	1,523	EXH 3D
(6) O.H. LINES	74,661	44,352	2,402	20,481	2,079	1,967	2,370	0	0	0	1,009	EXH 3F
(7) U.G. LINES	21,479	12,759	691	5,892	598	566	682	0	0	0	290	P-1
(8) LINE TRANSFORMERS	154,540	98,854	5,354	43,990	0	4,092	0	0	0	0	2,249	D-1
(9) SERVICES	0	0	0	0	0	0	0	0	0	0	0	---
(10) METERS	0	0	0	0	0	0	0	0	0	0	0	---
(11) STREET LIGHTING	15,950	0	0	0	0	0	0	0	0	0	15,950	DIRECT
(12) TOTAL DEMAND	423,164	248,120	13,438	113,066	7,327	10,733	8,467	391	0	26	21,595	
CUSTOMER												
(13) LAND	1,414	1,280	68	32	0	6	0	0	0.000	0	27	P-4
(14) EASEMENTS & SURVEY	5,111	4,629	244	116	0	23	1	0	0.000	0	97	P-4
(15) OTHER	670	607	32	15	0	3	0	0	0.000	0	13	P-4
(16) SUBSTATIONS	0	0	0	0	0	0	0	0	0.000	0	0	---
(17) POLES & FIXTURES	60,675	54,951	2,901	1,383	1	270	12	2	0.000	0	1,154	EXH 3D
(18) O.H. LINES	40,202	36,410	1,922	916	1	179	8	1	0.000	0	765	EXH 3F
(19) U.G. LINES	11,565	10,474	553	264	0	52	2	0	0.000	0	220	P-2
(20) LINE TRANSFORMERS	0	0	0	0	0	0	0	0	0.000	0	0	---
(21) SERVICES	57,705	47,959	2,532	6,034	0	1,180	0	0	0.000	0	0	C-2
(22) METERS	23,780	20,357	1,075	1,672	16	427	171	57	0.000	6	0	EXH 3G
(23) STREET LIGHTING	0	0	0	0	0	0	0	0	0.000	0	0	---
(24) TOTAL CUSTOMER	$201,122	$176,667	$9,328	$10,432	$18	$2,140	$195	$60	$0	$6	$2,275	
RETAIL												
(25) SERVICES	0	0	0	0	0	0	0	0	0	0	0	---
(26) METERS	0	0	0	0	0	0	0	0	0	0	0	---
(27) TOTAL RETAIL	0	0	0	0	0	0	0	0	0	0	0	
SUMMARY												
(28) LAND	4,438	3,066	164	859	88	86	102	5	0	0	68	P-3 & 4
(29) EASEMENTS & SURVEY	16,044	11,084	594	3,104	318	310	369	19	0	1	244	P-3 & 4
(30) OTHER	2,103	1,453	78	407	42	41	48	2	0	0	32	P-3 & 4
(31) SUBSTATIONS	28,462	16,129	874	7,584	1,065	735	1,320	365	0	24	367	EXH 3B
(32) POLES & FIXTURES	173,357	121,890	6,527	32,294	3,139	3,239	3,589	2	0	0	2,677	EXH 3D
(33) O.H. LINES	114,863	80,762	4,325	21,398	2,080	2,146	2,378	1	0	0	1,774	EXH 3F
(34) U.G. LINES	33,044	23,234	1,244	6,156	598	617	684	0	0	0	510	P-1 & 2
(35) LINE TRANSFORMERS	154,540	98,854	5,354	43,990	0	4,092	0	0	0	0	2,249	D-1
(36) SERVICES	57,705	47,959	2,532	6,034	0	1,180	0	0	0	0	0	C-2
(37) METERS	23,780	20,357	1,075	1,672	16	427	171	57	0	6	0	EXH 3G
(38) STREET LIGHTING	15,950	0	0	0	0	0	0	0	0	0	15,950	DIRECT
(39) TOTAL AVE. RATE BASE	**$624,286**	**$424,787**	**$22,766**	**$123,498**	**$7,345**	**$12,873**	**$8,662**	**$452**	**$0**	**$32**	**$23,871**	

EXHIBIT 3B

NOVA SCOTIA POWER INC.

ANALYSIS OF AVERAGE DISTRIBUTION SUBSTATION RATE BASE

FOR THE YEAR ENDING DECEMBER 31, 2013

(IN THOUSANDS OF DOLLARS)

	(1) TOTAL PLANT	(2) DIST. BULK PWR.	(3) DIST. DED. BULK PWR.	(4) DIST. GENERAL	(5) DIST. DED. GENERAL
(1) TOT. DIST. SUBSTATIONS	$28,462	$24,109	$436	$3,832	$86
ALLOCATION					
(2) DOMESTIC	16,129	13,917	0	2,212	0
(3) SMALL GENERAL	874	754	0	120	0
(4) GENERAL	7,584	6,522	26	1,037	0
(5) GENERAL LARGE	1,065	919	0	146	0
(6) SMALL INDUSTRIAL	735	634	0	101	0
(7) MEDIUM INDUSTRIAL	1,320	1,047	103	166	4
(8) LARGE INDUSTRIAL	365	0	284	0	82
(9) ELI 2P-RTP	0	0	0	0	0
(10) MUNICIPAL	24	0	24	0	0
(11) UNMETERED	367	317	0	50	0
(12) TOTAL	$28,462	$24,109	$436	$3,832	$86
ALLOCATION FACTOR		D-2	DIRECT	D-2	DIRECT

EXHIBIT 3C

NOVA SCOTIA POWER INC.

ANALYSIS OF AVERAGE POLE INVESTMENT

FOR THE YEAR ENDING DECEMBER 31, 2013
(IN THOUSANDS OF DOLLARS)

	(1) TOTAL PLANT	(2) PRIMARY DEMAND	(3) PRIMARY CUSTOMER	(4) SECONDARY DEMAND	(5) SECONDARY CUSTOMER
(1) TOTAL NET POLE COST	$173,357				
(2) PRIMARY ONLY (30%)	52,007	$52,007	$0	$0	$0
(3) 50% JOINT - PRI. (1)	60,675	30,337	30,337	0	0
(4) 50% JOINT - SEC. (1)	60,675	0	0	30,337	30,337
(5) TOTAL	$173,357	$82,345	$30,337	$30,337	$30,337

DEMAND COST - 50% }
} (1)
CUSTOMER COST - 50% }

EXHIBIT 3D

NOVA SCOTIA POWER INC.

ALLOCATION OF AVERAGE POLE INVESTMENT

FOR THE YEAR ENDING DECEMBER 31, 2013

(IN THOUSANDS OF DOLLARS)

	(1) TOTAL PLANT	(2) PRIMARY DEMAND	(3) PRIMARY CUSTOMER	(4) SECONDARY DEMAND	(5) SECONDARY CUSTOMER
(1) DOMESTIC	$121,890	$47,533	$27,469	$19,406	$27,483
(2) SMALL GENERAL	6,527	2,574	1,450	1,051	1,451
(3) GENERAL	32,294	22,276	691	8,636	692
(4) GENERAL LARGE	3,139	3,138	1	0	0
(5) SMALL INDUSTRIAL	3,239	2,165	135	803	135
(6) MEDIUM INDUSTRIAL	3,589	3,577	12	0	0
(7) LARGE INDUSTRIAL	2	0	2	0	0
(8) ELI 2P-RTP	0	0	0	0	0
(9) MUNICIPAL	0	0	0	0	0
(10) UNMETERED	2,677	1,081	577	442	577
(11) TOTAL	$173,357	$82,345	$30,337	$30,337	$30,337
ALLOCATION FACTOR		D-2	C-5	D-1	C-4

EXHIBIT 3E

NOVA SCOTIA POWER INC.

ANALYSIS OF AVERAGE WIRE INVESTMENT

FOR THE YEAR ENDING DECEMBER 31, 2013

(IN THOUSANDS OF DOLLARS)

	(1) TOTAL PLANT	(2) PRIMARY DEMAND	(3) PRIMARY CUSTOMER	(4) SECONDARY DEMAND	(5) SECONDARY CUSTOMER
(1) TOTAL NET WIRE COST	$114,863				
(2) PRIMARY ONLY (30%)	34,459	$34,459	$0	$0	$0
(3) 50% JOINT - PRI. (1)	40,202	20,101	20,101	0	0
(4) 50% JOINT - SEC. (1)	40,202	0	0	20,101	20,101
(5) TOTAL	$114,863	$54,560	$20,101	$20,101	$20,101

DEMAND COST - 50% }
} (1)
CUSTOMER COST - 50% }

EXHIBIT 3F

NOVA SCOTIA POWER INC.

ALLOCATION OF AVERAGE WIRE INVESTMENT

FOR THE YEAR ENDING DECEMBER 31, 2013

(IN THOUSANDS OF DOLLARS)

	(1) TOTAL PLANT	(2) PRIMARY DEMAND	(3) PRIMARY CUSTOMER	(4) SECONDARY DEMAND	(5) SECONDARY CUSTOMER
(1) DOMESTIC	$80,762	$31,494	$18,200	$12,858	$18,209
(2) SMALL GENERAL	4,325	1,706	961	696	961
(3) GENERAL	21,398	14,760	458	5,722	458
(4) GENERAL LARGE	2,080	2,079	1	0	0
(5) SMALL INDUSTRIAL	2,146	1,435	90	532	90
(6) MEDIUM INDUSTRIAL	2,378	2,370	8	0	0
(7) LARGE INDUSTRIAL	1	0	1	0	0
(8) ELI 2P-RTP	0	0	0	0	0
(9) MUNICIPAL	0	0	0	0	0
(10) UNMETERED	1,774	717	382	293	382
(11) TOTAL	$114,863	$54,560	$20,101	$20,101	$20,101
ALLOCATION FACTOR		D-2	C-5	D-1	C-4

EXHIBIT 3G

NOVA SCOTIA POWER INC.

ANALYSIS OF AVERAGE METER INVESTMENT

FOR THE YEAR ENDING DECEMBER 31, 2013

	(1) TOTAL CUSTOMERS	(2) UNIT METER COST	(3) TOTAL COST	(4) PERCENT	(5) METER COST ($000)
(1) DOMESTIC	452,558	$34.00	$15,386,972	85.60	$20,357
(2) SMALL GENERAL	23,894	34.00	812,396	4.52	1,075
(3) GENERAL	11,387	111.00	1,263,957	7.03	1,672
(4) GENERAL LARGE	18	657.00	11,826	0.07	16
(5) SMALL INDUSTRIAL	2,227	145.00	322,915	1.80	427
(6) MEDIUM INDUSTRIAL	197	657.00	129,429	0.72	171
(7) LARGE INDUSTRIAL	32	1,338.00	42,816	0.24	57
(8) ELI 2P-RTP	0	1,338.00	0	0.00	0
(9) MUNICIPAL	8	520.00	4,160	0.02	6
(10) UNMETERED	9,504	N/A	0	0.00	0
(11) TOTAL	499,825		$17,974,471	100.00	$23,780

EXHIBIT 4

NOVA SCOTIA POWER INC.

FUNCTIONALIZATION OF OPERATING EXPENSES

FOR THE YEAR ENDING DECEMBER 31, 2013

(IN THOUSANDS OF DOLLARS)

	(1) TOTAL EXPENSES	(2) PROD. EXPENSES	(3) TRANS. EXPENSES	(4) DIST. EXPENSES	(5) RETAIL EXPENSES	(6) DIRECT EXPENSES
POWER PRODUCTION						
(1) FUEL	$372,416	$342,028	$0	$0	$0	$30,388
PURCHASED POWER:						
(2) REGULAR	41,762	41,762	0	0	0	0
(3) WIND	60,826	60,826	0	0	0	0
(4) THERMAL - OPERATING & MAINT.	84,844	84,176	0	0	0	668
(5) HYDRO - OPERATING & MAINT.	9,566	7,364	0	0	0	2,202
(6) WIND - OPERATING & MAINT.	4,649	4,638	0	0	0	11
(7) BIOMASS - OPERATING & MAINT.	5,380	5,368	0	0	0	13
(8) LM6000 - OPERATING & MAINT.	329	328	0	0	0	1
(9) COMBUSTION TURBINE - OPER. & MAINT.	944	941	0	0	0	2
(10) ENERGY, FUELS & RISK MGMT.	3,819	3,810	0	0	0	9
(11) GENERATION DEVELOPMENT	0	0	0	0	0	0
(12) TOTAL PRODUCTION OPER. & MAINT.	109,530	106,624	0	0	0	2,906
CUSTOMER OPERATIONS:						
(13) TRANSMISSION & DISTRIBUTION	54,288	0	17,618	36,248	0	422
CUST. SERV. / MARKETING & SALES:						
(14) Qty. Ass., Comm., Call Ctr. & Rev. Ops.	37,026	0	0	599	36,428	0
OTHER OPERATING						
CORPORATE GROUPS:						
(15) EXECUTIVE MANAGEMENT	1,147	412	126	298	309	1
(16) CORP. SECRETARY & LEGAL SERVICES	8,530	3,068	937	2,215	2,301	9
(17) EXTERNAL RELATIONS & ENVIRONMENT	2,077	747	228	539	560	2
(18) REGULATORY AFFAIRS	6,332	2,277	696	1,645	1,708	7
(19) FINANCE GROUP	6,749	2,427	742	1,753	1,820	7
(20) ENTERPRISE SERVICES	21,728	7,814	2,388	5,643	5,860	24
(21) HUMAN RESOURCES	5,554	1,997	610	1,442	1,498	7
(22) TECHNICAL & CONSTRUCTION SERVICES	14,430	2,902	1,607	3,802	6,110	10
(23) SUSTAINABILITY	1,508	1,505	0	0	0	4
(24) SUB-TOTAL	68,055	23,148	7,333	17,337	20,166	70
(25) OTHER EXPENSES	11,135	4,004	1,224	2,892	3,003	12
(26) DIRECT ADMIN. & GEN. EXPENSE	0	(232)	(71)	(168)	(174)	645
(27) TOTAL OM&G EXPENSES	**280,034**	**133,545**	**26,104**	**56,908**	**59,423**	**4,054**
(28) COGS (NET OF SALES)	(438)	0	0	0	(438)	0
(29) DSM AMORTIZATION	2,150	2,059	0	0	0	91
(30) FCR DEFERRAL	16,500	13,532	2,968	0	0	0
(31) OTHER EXPENSES	0	0	0	0	0	0
(32) GRANTS IN LIEU OF TAXES	37,500	24,368	5,344	7,693	0	95
DEPRECIATION:						
(33) STEAM	63,508	63,359	0	0	0	149
(34) HYDRO	10,456	9,408	0	0	0	1,048
(35) WIND	8,186	8,166	0	0	0	19
(36) LM6000	2,084	2,079	0	0	0	5
(37) OTHER GAS TURBINE	1,183	1,180	0	0	0	3
(38) TRANSMISSION < 138kV	4,878	0	4,869	0	0	9
(39) TRANSMISSION > 69kV	15,967	0	15,938	0	0	29
(40) DISTRIBUTION - Non Streetlight Related	45,933	0	0	45,933	0	0
(41) DISTRIBUTION - Streetlight Related	2,946	0	0	2,342	0	604
(42) GENERAL PROPERTY	37,585	24,442	5,360	7,716	0	67
(43) INTEREST NET	133,900	85,794	17,734	27,568	0	2,804
(44) PREFERRED DIVIDENDS	8,000	5,206	1,076	1,673	0	45
(45) CORPORATE TAXES	52,350	34,021	7,032	10,932	0	365
(46) TOTAL EXPENSES	$1,197,725	$851,777	$86,424	$160,764	$58,986	$39,773
(47) NON-OPERATING REVENUE:						
(48) EXPORT SALES	(1,807)	(1,807)	0	0	0	0
(49) LATE PAYMENT CHARGE	(5,128)	0	0	0	(5,128)	0
(50) MISC. ELECTRIC	(1,909)	0	0	0	(1,909)	0
(51) OTHER REVENUE	(14,108)	(10,378)	(1,053)	(1,959)	(719)	0
(52) NET INCOME	123,837	77,978	16,118	25,056	0	4,685
(53) TOTAL NET EXPENSES	$1,298,611	$917,570	$101,490	$183,862	$51,230	$44,458

EXHIBIT 4 - Detail A

NOVA SCOTIA POWER INC.

FUNCTIONALIZATION OF OPERATING EXPENSES

FOR THE YEAR ENDING DECEMBER 31, 2013

(IN THOUSANDS OF DOLLARS)

		(1) TOTAL EXPENSES	(2) PROD. EXPENSES	(3) TRANS. EXPENSES	(4) DIST. EXPENSES	(5) RETAIL EXPENSES	(6) DIRECT EXPENSES
(1)	**FUEL**	$372,416	$342,028	$0	$0	$0	$30,388
	PURCHASED POWER:						
(2)	REGULAR	41,762	41,762	0	0	0	0
(3)	WIND	60,826	60,826	0	0	0	0
(4)	TOTAL	475,005	444,617	0	0	0	30,388
	POWER PRODUCTION						
(5)	THERMAL OPERATING & MAINT.	84,844	84,176	0	0	0	668
(6)	HYDRO OPERATING & MAINT.	9,566	7,364	0	0	0	2,202
(7)	WIND - OPERATING & MAINT.	4,649	4,638	0	0	0	11
(8)	BIOMASS - OPERATING & MAINT.	5,380	5,368	0	0	0	13
(9)	LM6000 OPERATING & MAINT.	329	328	0	0	0	1
(10)	COMBUSTION TURBINE - OPER. & MAINT.	944	941	0	0	0	2
(11)	FUEL PROCUREMENT	3,819	3,810	0	0	0	9
(12)	GENERATION DEVELOPMENT	0	0	0	0	0	0
(13)							
(14)	**TOTAL POWER PRODUCTION**	109,530	106,624	0	0	0	2,906
(15)	**SUSTAINABILITY**	1,508	1,505	0	0	0	4
	CORPORATE GROUPS						
(16)	EXECUTIVE MANAGEMENT	1,147	412	126	298	309	1
(17)	CORP. SECRETARY	7,359	2,646	809	1,911	1,985	8
(18)	LEGAL SERVICES	1,171	421	129	304	316	1
(19)	EXTERNAL RELATIONS	2,077	747	228	539	560	2
(20)	ENVIRONMENTAL POLICIES & PROGRAMS	0	0	0	0	0	0
(21)	Total Corporate Groups	11,754	4,227	1,292	3,053	3,170	12
	CUSTOMER OPERATIONS						
	TRANSMISSION & DISTRIBUTION:						
(22)	**TRANSMISSION:**						
(23)	**< 138kV**	4,221	0	4,214	0	0	8
(24)	**> 69kV**	13,819	0	13,404	0	0	415
	DISTRIBUTION:						
(25)	SUBSTATIONS	194	0	0	194	0	0
(26)	OVERHEAD LINES	25,350	0	0	25,350	0	0
(27)	UNDERGROUND LINES	440	0	0	440	0	0
(28)	LINE TRANSFORMERS	941	0	0	941	0	0
(29)	METERS (Meter Shop Only)	0	0	0	0	0	0
(30)	COMMUNICATIONS	5,630	0	0	5,630	0	0
(31)	STREET LIGHTING	3,694	0	0	3,694	0	0
(33)	**TOTAL DISTRIBUTION**	36,248	0	0	36,248	0	0
(34)	**TOTAL CUSTOMER OPERATIONS - T & D**	54,288	0	17,618	36,248	0	422
(35)	**TECHNICAL & CONSTRUCTION SERVICES**	14,430	2,902	1,607	3,802	6,110	10
	CUST. SERV. / MARKETING & SALES						
	ADMINISTRATION:						
(36)	CUSTOMER SERVICE - ADMIN.	711	0	0	0	711	0
(37)	ENERGY EFFICIENCY	476	0	0	0	476	0
(38)	CUST. COMM. & QTY ASSURANCE	1,857	0	0	0	1,857	0
(39)	CUSTOMER SOLUTIONS	0	0	0	0	0	0
(40)	**CALL CENTRE:**						
(41)	(a) CALL CENTRE - CSR's	7,016	0	0	0	7,016	0
(42)	(b) CALL CENTRE OPERATIONS	0	0	0	0	0	0
(43)	(c) CALL CENTRE - HALIFAX	0	0	0	0	0	0
(44)	(d) CALL NETWORK (COLLECTIONS)	374	0	0	0	374	0
(45)	(e) ELECTRICAL WIRING INSPECTION	4,457	0	0	0	4,457	0
(46)	**REVENUE OPERATIONS:**						
(47)	(a) BILLING SERVICES	3,676	0	0	0	3,676	0
(48)	(b) METER DATA SERVICES	468	0	0	0	468	0
(49)	(c) METER SERVICES - METER SHOP	599	0	0	599	0	0
(50)	(d) METER SERVICES - FIELD	6,105	0	0	0	6,105	0
(51)	(e) ELECTRICAL WIRING INSPECTION - FIELD	3,430	0	0	0	3,430	0
(52)	(f) PAYMENT SERVICES	703	0	0	0	703	0
(53)	(g) CREDIT SERVICES	0	0	0	0	0	0
(54)	(h) BAD DEBT EXPENSE	5,736	0	0	0	5,736	0
(55)	(i) MARKETING & SALES	1,154	0	0	0	1,154	0
(56)	(j) ELECTRICAL WIRING INSPECTION - H/O	265	0	0	0	265	0
(58)	**TOTAL CUST. SERV. / MARKETING & SALES**	37,026	0	0	599	36,428	0

NOVA SCOTIA POWER INC.
FUNCTIONALIZATION OF OPERATING EXPENSES
FOR THE YEAR ENDING DECEMBER 31, 2013
(IN THOUSANDS OF DOLLARS)

	(1) TOTAL EXPENSES	(2) PROD. EXPENSES	(3) TRANS. EXPENSES	(4) DIST. EXPENSES	(5) RETAIL EXPENSES	(6) DIRECT EXPENSES
(1) **REGULATORY AFFAIRS**	$6,332	$2,277	$696	$1,645	$1,708	$7
FINANCE GROUP						
(2) INTERNAL AUDIT	1,696	610	186	441	458	2
(3) INVESTOR RELATIONS	283	102	31	74	76	0
(4) DIRECTOR FINANCE	732	263	80	190	197	1
(5) TREASURER	785	282	86	204	212	1
(6) CORPORATE TAX	809	291	89	210	218	1
(7) GM FINANCE	0	0	0	0	0	0
(8) CORPORATE CONTROLLER	2,444	879	269	635	659	3
(9) CORP. PERFORMANCE & BACK OFFICE	0	0	0	0	0	0
(10) **TOTAL FINANCE**	6,749	2,427	742	1,753	1,820	7
ENTERPRISE SERVICES						
(11) PROCUREMENT & FACILITIES	9,991	3,593	1,098	2,595	2,695	11
(12) INFORMATION TECHNOLOGY	11,737	4,221	1,290	3,048	3,166	13
(13) **TOTAL ENTERPRISE SERVICES**	21,728	7,814	2,388	5,643	5,860	24
HUMAN RESOURCES						
(14) --HUMAN RESOURCES	5,554	1,997	610	1,442	1,498	7
(15) OTHER EXPENSES	11,135	4,004	1,224	2,892	3,003	12
(16) DIRECT ADM. & GEN. EXPENSE	0	(232)	(71)	(168)	(174)	645
(17) **TOTAL DIVISIONAL EXPENSES**	**280,034**	**133,545**	**26,104**	**56,908**	**59,423**	**4,054**
(18) **COGS (NET OF RETAIL SALES)**	**(438)**	**0**	**0**	**0**	**(438)**	**0**
(19) **DSM EXPENSES**	**2,150**	**2,059**	**0**	**0**	**0**	**91**
(20) **FCR DEFERRAL**	**16,500**	**13,532**	**2,968**	**0**	**0**	**0**
(21) **OTHER EXPENSES**	**0**	**0**	**0**	**0**	**0**	
CAPITAL RELATED EXPENSES						
(22) GRANTS IN LIEU OF TAXES	37,500	24,368	5,344	7,693	0	95
(23) DEPRECIATION :						
(24) STEAM	63,508	63,359	0	0	0	149
(25) HYDRO	10,456	9,408	0	0	0	1,048
(26) WIND	8,186	8,166	0	0	0	19
(27) LM6000	2,084	2,079	0	0	0	5
(28) GAS TURBINE - OTHER	1,183	1,180	0	0	0	3
(29) TRANSMISSION < 138kV	4,878	0	4,869	0	0	9
(30) TRANSMISSION > 69kV	15,967	0	15,938	0	0	29
(31) DISTRIBUTION - Non Streetlight Related	45,933	0	0	45,933	0	0
(32) DISTRIBUTION - Streetlight Related	2,946	0	0	2,342	0	604
(33) GENERAL PROPERTY	37,585	24,442	5,360	7,716	0	67
(34) GLACE BAY WRITE-OFF	0	0	0	0	0	0
(35) INTEREST NET	133,900	85,794	17,734	27,568	0	2,804
(36) PREFERRED DIVIDENDS	8,000	5,206	1,076	1,673	0	45
(37) CORPORATE TAXES	52,350	34,021	7,032	10,932	0	365
(38) **TOTAL OPERATING EXPENSES**	**1,197,725**	**851,777**	**86,424**	**160,764**	**58,986**	**39,773**
(39) NON-OPERATING REVENUE:						0
(40) GREEN POWER SURCHARGE	0	0	0	0	0	0
(41) EXPORT SALES	(1,807)	(1,807)	0	0	0	0
(42) LATE PAYMENT CHARGE	(5,128)	0	0	0	(5,128)	0
(43) MISC. ELECTRIC	(1,909)	0	0	0	(1,909)	0
(44) OTHER REVENUE	(14,108)	(10,378)	(1,053)	(1,959)	(719)	0
(45) **PROFIT/LOSS**	123,837	77,978	16,118	25,056	0	4,685
(46) **TOTAL NET EXPENSES**	**$1,298,611**	**$917,570**	**$101,490**	**$183,862**	**$51,230**	**$44,458**

EXHIBIT 4 - Detail B

Fixed Cost Contribution $4.00
Load 322
$1,288

	FUNCTIONALIZATION OF OPERATING EXPENSES BEFORE LRT						NON-FUEL RELATED EXPENSES BY THE FUNCTIONAL AREAS AFFECTED BY LRT								
	(1) TOTAL EXPENSES	(2) PROD. EXPENSES	(3) TRANS. EXPENSES	(4) DIST. EXPENSES	(5) RETAIL EXPENSES	(6) DIRECT EXPENSES	(1) TOTAL EXPENSES	(2) PROD. EXPENSES	(3) TRANS. EXPENSES	(4) DIST. EXPENSES	(5) RETAIL EXPENSES	(6) DIRECT EXPENSES	(7) WEIGHTS		(8) DIRECT LRT
(1) **FUEL**	$372,416	$342,028	$0	$0	$0	$30,388	$0	0					0.00%	0.00%	$0.00
PURCHASED POWER:															
(2) REGULAR	41,762	41,762	0	0	0	0	0	0					0.00%	0.00%	$0.00
(3) WIND	60,826	60,826	0	0	0	0	0	0					0.00%	0.00%	$0.00
(4) TOTAL	475,005	444,617	0	0	0	30,388	0	0					0.00%	0.00%	$0.00
POWER PRODUCTION															
(5) THERMAL OPERATING & MAINT.	84,844	84,373	0	0	0	471	84,373	84,373	0				15.34%	15.34%	$197.63
(6) HYDRO OPERATING & MAINT.	9,566	7,381	0	0	0	2,185	7,381	7,381	0				1.34%	1.34%	$17.29
(7) WIND - OPERATING & MAINT.	4,649	4,649	0	0	0	0	4,649	4,649	0				0.85%	0.85%	$10.89
(8) BIOMASS - OPERATING & MAINT.	5,380	5,380	0	0	0	0	5,380	5,380	0				0.98%	0.98%	$12.60
(9) LM6000 OPERATING & MAINT.	329	329	0	0	0	0	329	329	0				0.06%	0.06%	$0.77
(10) COMBUSTION TURBINE - OPER. & MAINT.	944	944	0	0	0	0	944	944	0				0.17%	0.17%	$2.21
(11) FUEL PROCUREMENT	3,819	3,819	0	0	0	0	3,819	3,819	0				0.69%	0.69%	$8.95
(12) GENERATION DEVELOPMENT	0	0	0	0	0	0	0	0	0				0.00%	0.00%	$0.00
(13)									0				0.00%	0.00%	$0.00
(14) **TOTAL POWER PRODUCTION**	109,530	106,875	0	0	0	2,655	106,875	106,875	0				19.43%	19.43%	$250.34
(15) **SUSTAINABILITY**	1,508	1,508	0	0	0	0	1,508	1,508	0				0.27%	0.27%	$3.53
CORPORATE GROUPS															
(16) EXECUTIVE MANAGEMENT	1,147	413	126	298	310	0	510	413	97				0.09%	0.09%	$1.19
(17) CORP. SECRETARY	7,359	2,649	809	1,913	1,987	0	3,269	2,649	620				0.59%	0.59%	$7.66
(18) LEGAL SERVICES	1,171	422	129	305	316	0	520	422	99				0.09%	0.09%	$1.22
(19) EXTERNAL RELATIONS	2,077	748	228	540	561	0	923	748	175				0.17%	0.17%	$2.16
(20) ENVIRONMENTAL POLICIES & PROGRAMS	0	0	0	0	0	0	0	0	0				0.00%	0.00%	$0.00
	11,754	4,231	1,293	3,056	3,173	0	5,222	4,231	990						$12.23
CUSTOMER OPERATIONS															
TRANSMISSION & DISTRIBUTION:															
(21) **TRANSMISSION:**															
(22) **< 138kV**	4,221	0	4,221	0	0	0	3,234	0	3234				0.59%	0.59%	$7.57
(23) **> 69kV**	13,819	0	13,428	0	0	391	10,286	0	10286				1.87%	1.87%	$24.09
DISTRIBUTION:															
(24) SUBSTATIONS	194	0	0	194	0	0	0	0	0				0.00%	0.00%	$0.00
(25) OVERHEAD LINES	25,350	0	0	25,350	0	0	0	0	0				0.00%	0.00%	$0.00
(26) UNDERGROUND LINES	440	0	0	440	0	0	0	0	0				0.00%	0.00%	$0.00
(27) LINE TRANSFORMERS	941	0	0	941	0	0	0	0	0				0.00%	0.00%	$0.00
(28) METERS (Meter Shop Only)	0	0	0	0	0	0	0	0	0				0.00%	0.00%	$0.00
(29) COMMUNICATIONS	5,630	0	0	5,630	0	0	0	0	0				0.00%	0.00%	$0.00
(30) STREET LIGHTING	3,694	0	0	3,694	0	0	0	0	0				0.00%	0.00%	$0.00
(31)									0				0.00%	0.00%	
(32) **TOTAL DISTRIBUTION**	36,248	0	0	36,248	0	0	0	0	0	0	0	0	0.00%	0.00%	$0.00
(33) **TOTAL CUSTOMER OPERATIONS - T & D**	54,288	0	17,649	36,248	0	391	13,519	0	13,519	0	0	0	2.46%	2.46%	$31.67
(34) **TECHNICAL & CONSTRUCTION SERVICES**	14,430	2,910	1,608	3,802	6,110	0	4,142	2,910	1232	0	0	0	0.75%	0.75%	$9.70
CUST. SERV. / MARKETING & SALES ADMINISTRATION:															
(35) CUSTOMER SERVICE - ADMIN.	711	0	0	0	711	0	0	0	0				0.00%	0.00%	$0.00
(36) ENERGY EFFICIENCY	476	0	0	0	476	0	0	0	0				0.00%	0.00%	$0.00
(37) CUST. COMM. & QTY ASSURANCE	1,857	0	0	0	1,857	0	0	0	0				0.00%	0.00%	$0.00
(38) CUSTOMER SOLUTIONS	0	0	0	0	0	0	0	0	0				0.00%	0.00%	$0.00
(39) **CALL CENTRE:**															
(40) (a) CALL CENTRE - CSR's	7,016	0	0	0	7,016	0	0	0	0				0.00%	0.00%	$0.00
(41) (b) CALL CENTRE OPERATIONS	0	0	0	0	0	0	0	0	0				0.00%	0.00%	$0.00
(42) (c) CALL CENTRE - HALIFAX	0	0	0	0	0	0	0	0	0				0.00%	0.00%	$0.00
(43) (d) CALL NETWORK (COLLECTIONS)	374	0	0	0	374	0	0	0	0				0.00%	0.00%	$0.00
(44) (e) ELECTRICAL WIRING INSPECTION	4,457	0	0	0	4,457	0	0	0	0				0.00%	0.00%	$0.00
(45) **REVENUE OPERATIONS:**															
(46) (a) BILLING SERVICES	3,676	0	0	0	3,676	0	0	0	0				0.00%	0.00%	$0.00
(47) (b) METER DATA SERVICES	468	0	0	0	468	0	0	0	0				0.00%	0.00%	$0.00
(48) (c) METER SERVICES - METER SHOP	599	0	0	599	0	0	0	0	0				0.00%	0.00%	$0.00
(49) (d) METER SERVICES - FIELD	6,105	0	0	0	6,105	0	0	0	0				0.00%	0.00%	$0.00
(50) (e) ELECTRICAL WIRING INSPECTION - FIELD	3,430	0	0	0	3,430	0	0	0	0				0.00%	0.00%	$0.00
(51) (f) PAYMENT SERVICES	703	0	0	0	703	0	0	0	0				0.00%	0.00%	$0.00
(52) (g) CREDIT SERVICES	0	0	0	0	0	0	0	0	0				0.00%	0.00%	$0.00
(53) (h) BAD DEBT EXPENSE	5,736	0	0	0	5,736	0	0	0	0				0.00%	0.00%	$0.00
(54) (i) MARKETING & SALES	1,154	0	0	0	1,154	0	0	0	0				0.00%	0.00%	$0.00
(55) (j) ELECTRICAL WIRING INSPECTION - H/O	265	0	0	0	265	0	0	0	0				0.00%	0.00%	$0.00
(57) **TOTAL CUST. SERV. / MARKETING & SALES**	37,026	0	0	599	36,428	0	0	0	0	0	0	0	0.00%	0.00%	$0.00

NOVA SCOTIA POWER INC.
FUNCTIONALIZATION OF OPERATING EXPENSES
DEDICATED DIST.PLT.- LINE TRANSFORMERS
(IN THOUSANDS OF DOLLARS)

	FUNCTIONALIZATION OF OPERATING EXPENSES BEFORE ELR						NON-FUEL RELATED EXPENSES BY THE FUNCTIONAL AREAS AFFECTED BY LRT								
	(1) TOTAL EXPENSES	(2) PROD. EXPENSES	(3) TRANS. EXPENSES	(4) DIST. EXPENSES	(5) RETAIL EXPENSES	(6) DIRECT EXPENSES	(1) TOTAL EXPENSES	(2) PROD. EXPENSES	(3) TRANS. EXPENSES	(4) DIST. EXPENSES	(5) RETAIL EXPENSES	(6) DIRECT EXPENSES	(7) EXPENSES		(8) DIRECT LRT
(1) **REGULATORY AFFAIRS**	$6,332	$2,280	$697	$1,646	$1,710	$0	$2,813	$2,280	534				0.51%	0.51%	$6.59
FINANCE GROUP															
(2) INTERNAL AUDIT	1,696	611	187	441	458	0	754	$611	143				0.14%	0.14%	$1.77
(3) INVESTOR RELATIONS	283	102	31	74	76	0	126	$102	24				0.02%	0.02%	$0.29
(4) DIRECTOR FINANCE	732	263	81	190	198	0	325	$263	62				0.06%	0.06%	$0.76
(5) TREASURER	785	283	86	204	212	0	349	$283	66				0.06%	0.06%	$0.82
(6) CORPORATE TAX	809	291	89	210	218	0	359	$291	68				0.07%	0.07%	$0.84
(7) GM FINANCE	0	0	0	0	0	0	0	$0	0				0.00%	0.00%	$0.00
(8) CORPORATE CONTROLLER	2,444	880	269	635	660	0	1,086	$880	206				0.20%	0.20%	$2.54
(9) CORP. PERFORMANCE & BACK OFFICE	0	0	0	0	0	0	0	$0	0				0.00%	0.00%	$0.00
(10) **TOTAL FINANCE**	6,749	2,430	742	1,755	1,822	0	2,998	$2,430	569				0.55%	0.55%	$7.02
ENTERPRISE SERVICES															
(11) PROCUREMENT & FACILITIES	9,991	2,598	2,698	3,597	1,099	0	4,664	$2,598	2066				0.85%	0.85%	$10.93
(12) INFORMATION TECHNOLOGY	11,737	3,052	3,169	4,225	1,291	0	5,479	$3,052	2428				1.00%	1.00%	$12.83
(13) **TOTAL ENTERPRISE SERVICES**	21,728	5,649	5,867	7,822	2,390	0	10,143	$5,649	4494				1.84%	1.84%	$23.76
HUMAN RESOURCES															
(14) --HUMAN RESOURCES	5,554	1,500	1,999	611	1,444	0	3,031	$1,500	1532				0.55%	0.55%	$7.10
(15) OTHER EXPENSES	11,135	4,009	1,225	2,895	3,006	0	4,947	$4,009	938				0.90%	0.90%	$11.59
(16) DIRECT ADM. & GEN. EXPENSE	0	(232)	(71)	(168)	(174)	645	(287)	($232)	-54				-0.05%	-0.05%	($0.67)
(17) **TOTAL DIVISIONAL EXPENSES**	**280,034**	**131,158**	**31,009**	**58,265**	**55,909**	**3,691**	**154,912**	**131,158**	**23,753**				28.17%	28.17%	$362.86
(18) **COGS (NET OF RETAIL SALES)**	**(438)**	**0**	**0**	**0**	**(438)**	**0**	**0**	$0	0				0.00%	0.00%	$0.00
(19) **DSM EXPENSES**	**2,150**	**2,064**	**0**	**0**	**0**	**86**	**2,064**	$2,064	0				0.38%	0.38%	$4.83
(20) **FCR DEFERRAL**	**16,500**	**13,532**	**2,968**	**0**	**0**	**0**	**0**	$0					0	0	0
(21) **OTHER EXPENSES**	**0**	**0**	**0**	**0**	**0**		**0**	$0	0				0.00%	0.00%	$0.00
CAPITAL RELATED EXPENSES															
(22) GRANTS IN LIEU OF TAXES	37,500	24,412	5,353	7,706	0	28	28,513	$24,412	4101				5.18%	5.18%	$66.79
(23) DEPRECIATION :									0						
(24) STEAM	63,508	63,508	0	0	0	0	63,508	$63,508	0				11.55%	11.55%	$148.76
(25) HYDRO	10,456	9,430	0	0	0	1,025	9,430	$9,430	0				1.71%	1.71%	$22.09
(26) WIND	8,186	8,186	0	0	0	0	8,186	$8,186	0				1.49%	1.49%	$19.17
(27) LM6000	2,084	2,084	0	0	0	0	2,084	$2,084	0				0.38%	0.38%	$4.88
(28) GAS TURBINE - OTHER	1,183	1,183	0	0	0	0	1,183	$1,183	0				0.22%	0.22%	$2.77
(29) TRANSMISSION < 138kV	4,878	0	4,878	0	0	0	3,736	$0	3736				0.68%	0.68%	$8.75
(30) TRANSMISSION > 69kV	15,967	0	15,967	0	0	0	12,230	$0	12230				2.22%	2.22%	$28.65
(31) DISTRIBUTION - Non Streetlight Related	45,933	0	0	45,933	0	0	0	$0	0				0.00%	0.00%	$0.00
(32) DISTRIBUTION - Streetlight Related	2,946	0	0	2,342	0	604	0	$0	0				0.00%	0.00%	$0.00
(33) GENERAL PROPERTY	37,585	24,486	5,370	7,730	0	0	28,599	$24,486	4113				5.20%	5.20%	$66.99
(34) GLACE BAY WRITE-OFF	0	0	0	0	0	0	0	$0	0				0.00%	0.00%	$0.00
(35) INTEREST NET	133,900	85,947	17,766	27,617	0	2,570	99,555	$85,947	13608				18.10%	18.10%	$233.20
(36) PREFERRED DIVIDENDS	8,000	5,216	1,078	1,676	0	30	6,041	$5,216	826				1.10%	1.10%	$14.15
(37) CORPORATE TAXES	52,350	34,081	7,045	10,951	0	273	39,477	$34,081	5396				7.18%	7.18%	$92.47
(38) **TOTAL OPERATING EXPENSES**	**1,197,725**	**849,903**	**91,433**	**162,221**	**55,472**	**38,697**	**459,518**	**391,754**	**67,764**	**0**	**0**	**0**	83.55%	83.55%	$1,076.37
(39) NON-OPERATING REVENUE:													0.00%	0.00%	$0.00
(40) GREEN POWER SURCHARGE	0	0	0	0	0	0	0	$0	0				0.00%	0.00%	$0.00
(41) EXPORT SALES	(1,807)	(1,807)	0	0	0	0	0	$0	0				0.00%	0.00%	$0.00
(42) LATE PAYMENT CHARGE	(5,128)	0	0	0	(5,128)	0	0	$0	0				0.00%	0.00%	$0.00
(43) MISC. ELECTRIC	(1,909)	0	0	0	(1,909)	0	0	$0	0				0.00%	0.00%	$0.00
(44) OTHER REVENUE	(14,108)	(10,345)	(1,113)	(1,975)	(675)	0	0	$0	0				0.00%	0.00%	$0.00
(45) **PROFIT/LOSS**	123,837	78,116	16,147	25,101	0	4,473	90,485	78,116	12369			0	16.45%	16.45%	$211.95
(46) **TOTAL NET EXPENSES**	#########	$915,867	$106,467	$185,347	$47,760	$43,170	$550,003	$469,870	$80,133	$0	$0	$0	100.00%	100.00%	$1,288.320

EXHIBIT 5
Page 1 of 3

NOVA SCOTIA POWER INC.
CLASSIFICATION OF OPERATING EXPENSES
FOR THE YEAR ENDING DECEMBER 31, 2013
(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DEMAND EXPENSES	(3) ENERGY EXPENSES	(4) CUSTOMER EXPENSES
GENERATION FUNCTION				
(1) FUEL	342,028	$0	$342,028	$0
(2) PURCHASED PWR REG - FIXED	18,793	6,009	12,784	0
(3) PURCHASED PWR REG - VAR.	22,969	0	22,969	0
(4) PURCHASED PWR WIND - FIXED	18,248	5,474	12,774	0
(5) PURCHASED PWR WIND - VAR.	42,578	0	42,578	0
(6) OPER. & MAINT. - STEAM	109,335	29,366	79,969	0
(7) OPER. & MAINT. - HYDRO/WIND/BI	22,561	6,060	16,501	0
(8) OPER. & MAINT. - LM6000	426	114	311	0
(9) OPER. & MAINT. - OTHER CT's	1,223	1,027	196	0
(10) DSM AMORTIZATION	2,059	658	1,401	0
(11) FCR DEFERRAL	13,532	4,084	9,449	0
(12) GRANTS IN LIEU OF TAXES	24,368	7,792	16,577	0
DEPRECIATION:				
(13) STEAM	63,359	20,754	42,605	0
(14) HYDRO	9,408	4,021	5,387	0
(15) WIND	8,166	202	7,964	0
(16) LM6000	2,079	903	1,176	0
(17) GAS TURBINE - OTHER	1,180	1,180	0	0
(18) GENERAL PROPERTY	24,442	7,815	16,627	0
(19) INTEREST NET OF AFUDC	85,794	25,890	59,904	0
(20) PREFERRED DIVIDENDS	5,206	1,571	3,635	0
(21) CORPORATE TAXES	34,021	10,266	23,754	0
NON-OPERATING REVENUE:				
(22) EXPORT SALES	(1,807)	0	(1,807)	0
(23) OTHER REVENUE	(10,378)	(1,623)	(8,755)	0
(24) RETURN (PROFIT/LOSS)	77,978	23,531	54,447	0
(25) TOTAL GENERATION	**917,570**	**155,095**	**762,476**	**0**
	917,570			
TRANSMISSION FUNCTION				
Transmission < 138kV:				
(26) O&M < 138kV	6,243	2,712	3,532	0
(27) GRANTS IN LIEU OF TAXES	1,234	536	698	0
DEPRECIATION:				
(28) TRANSMISSION	4,869	2,115	2,754	0
(29) GENERAL PROPERTY	1,254	545	710	0
(30) INTEREST NET OF AFUDC	4,094	1,778	2,316	0
(31) PREFERRED DIVIDENDS	248	108	141	0
(32) CORPORATE TAXES	1,623	705	918	0
NON-OPERATING REVENUE:				
(33) OTHER REVENUE	(246)	(107)	(139)	0
(35) RETURN (PROFIT/LOSS)	3,721	1,616	2,105	0
(36) TOTAL < 138kV	**23,040**	**10,006**	**13,034**	**0**

INTERMEDIATE CLASSIFICATION			
THERMAL O&M	$109,335		
HYDRO O&M	22,561		
LM6000 O&M	426		
OTHER CT's O&M	1,223		
NET THERMAL O&M	$133,545		
THERMAL O&M	$17,494		
HYDRO O&M	3,610		
LM6000 O&M	68		
OTHER CT's O&M	196		
THERMAL VARIABLE O&M	$21,367		
THERMAL O&M	$91,842		
HYDRO O&M	18,951		
LM6000 O&M	358		
OTHER CT's O&M	1,027		
NET THERMAL O&M D&E SPLIT	$112,178		
THERMAL O&M DMD. ALLOC. %	31.97%		
THERMAL O&M ENG. ALLOC. %	68.03%		
WIND O&M DMD. ALLOC. %	30.00%		
WIND O&M ENG. ALLOC. %	70.00%		
OTHER CT's O&M DMD. ALLOC. %	100.00%		
POLE & WIRE DMD/CUST SPLIT	65.00%		
	DEMAND	**ENERGY**	**CUSTOMER**
GEN. PROP. ALLOC. - GEN.	7,815	16,627	0
GEN. PROP. ALLOC. - TRANS. < 138 kV	545	710	0
GEN. PROP. ALLOC. - TRANS. > 69 kV	1,783	2,323	0
GEN. PROP. ALLOC. - DIST.	5,230	0	2,486
GEN. PROP. ALLOC. - RETAIL	0	0	0
	15,373	19,659	2,486

NOVA SCOTIA POWER INC.
CLASSIFICATION OF OPERATING EXPENSES
FOR THE YEAR ENDING DECEMBER 31, 2013
(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DEMAND EXPENSES	(3) ENERGY EXPENSES	(4) CUSTOMER EXPENSES
Transmission > 69kV:				
(1) O&M > 69kV	19,860	8,625	11,235	0
(2) GRANTS IN LIEU OF TAXES	4,110	1,785	2,325	0
DEPRECIATION:				
(3) TRANSMISSION	15,938	6,922	9,016	0
(4) GENERAL PROPERTY	4,106	1,783	2,323	0
(5) INTEREST NET OF AFUDC	13,640	5,924	7,716	0
(6) PREFERRED DIVIDENDS	828	359	468	0
(7) CORPORATE TAXES	5,409	2,349	3,060	0
NON-OPERATING REVENUE:				
(8) OTHER REVENUE	(807)	(350)	(456)	0
(9) FCR DEFERRAL	2,968	1,289	1,679	0
(10) RETURN (PROFIT/LOSS)	12,398	5,384	7,013	0
(11) TOTAL > 69kV	**78,450**	**34,071**	**44,379**	**0**
(12) TOTAL TRANSMISSION	**$101,490**	**$44,077**	**$57,413**	**$0**

EXHIBIT 5
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NOVA SCOTIA POWER INC.
CLASSIFICATION OF OPERATING EXPENSES
FOR THE YEAR ENDING DECEMBER 31, 2013
(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DEMAND EXPENSES	(3) ENERGY EXPENSES	(4) CUSTOMER EXPENSES
DISTRIBUTION FUNCTION				
BEFORE STREETLIGHTS				
(1) SUBSTATIONS	$300	$300	$0	$0
(2) OVERHEAD LINES	39,152	25,449	0	13,703
(3) UNDERGROUND LINES	679	441	0	238
(4) LINE TRANSFORMERS	1,453	1,453	0	0
(5) METERS	924	0	0	924
(6) COMMUNICATIONS	8,696	8,696	0	0
(7) GRANTS IN LIEU OF TAXES	7,528	4,900	0	2,629
DEPRECIATION:				
(8) DISTRIBUTION	45,933	31,135	0	14,798
(9) GENERAL PROPERTY	7,716	5,230	0	2,486
(10) INTEREST NET OF AFUDC	26,980	17,559	0	9,420
(11) PREFERRED DIVIDENDS	1,637	1,066	0	572
(12) CORPORATE TAXES	10,698	6,963	0	3,736
(13) RETURN (PROFIT/LOSS)	24,522	15,960	0	8,562
STREETLIGHTS				
non-LED				
(14) MAINTENACE	5,705	5,705	0	0
(15) GRANTS IN LIEU OF TAXES	164	164	0	0
(16) DEPRECIATION	2,342	2,342	0	0
(17) INTEREST NET OF AFUDC	589	589	0	0
(18) PREFERRED DIVIDENDS	36	36	0	0
(19) CORPORATE TAXES	233	233	0	0
(20) RETURN (PROFIT/LOSS)	535	535	0	0
Subtotal	9,604	9,604	0	0
(21) OTHER REVENUE	(1,959)	(1,368)	0	(591)
(22) TOTAL DISTRIBUTION	**183,862**	**127,386**	**0**	**56,476**
RETAIL FUNCTION				
(23) QTY. ASSURANCE. & COMM.	5,325	0	0	5,325
(24) CALL CENTRE	20,723	0	0	20,723
(25) BILLING SERVICES	6,430	0	0	6,430
(26) ELECT. WIRING INSPECT. - H/O	463	0	0	463
(27) METER DATA SERVICES	818	0	0	818
(28) METER READING - FIELD	10,678	0	0	10,678
(29) ELECT. WIRING INSPECT. - FIELD	5,999	0	0	5,999
(30) PAYMENT SERVICES	1,230	0	0	1,230
(31) CREDIT SERVICES	0	0	0	0
(32) BAD DEBT EXPENSE	5,736	0	0	5,736
(33) MARKETING & SALES	2,019	0	0	2,019
(34) COGS (NET OF RETAIL SALES)	(438)	0	0	(438)
(35) GRANTS IN LIEU OF TAXES	0	0	0	0
(36) DEPRECIATION:				
(37) DISTRIBUTION	0	0	0	0
(38) GENERAL PROPERTY	0	0	0	0
(39) INTEREST NET OF AFUDC	0	0	0	0
(40) PREFERRED DIVIDENDS	0	0	0	0
(41) CORPORATE TAXES	0	0	0	0
NON-OPERATING REVENUE:				
(42) LATE PAYMENT CHARGE	(5,128)	0	0	(5,128)
(43) MISC. ELECTRIC	(1,909)	0	0	(1,909)
(44) OTHER REVENUE	(719)	0	0	(719)
(45) RETURN (PROFIT/LOSS)	0	0	0	0
(46) TOTAL RETAIL	**51,230**	**0**	**0**	**51,230**
(47) TOTAL NET EXPENSES	**$1,254,153**	**$326,558**	**$819,889**	**$107,706**

NOVA SCOTIA POWER INC.

ALLOCATION OF OPERATING EXPENSES

FOR THE YEAR ENDING DECEMBER 31, 2013

(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
DEMAND CLASSIFICATION												
GENERATION												
(1) FUEL	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	D-3A
(2) PURCH. POWER REG - FIXED	6,009	3,414	123	1,379	169	119	230	376	0	124	74	D-3A
(3) PURCH. POWER WIND - FIXED	5,474	3,110	112	1,256	154	109	210	342	0	113	68	D-3A
(4) OPER. & MAINT. - STEAM	29,366	16,683	600	6,740	827	583	1,126	1,836	0	607	364	D-3A
(5) OPER. & MAINT. - HYDRO/WIND/BIOMASS	6,060	3,443	124	1,391	171	120	232	379	0	125	75	D-3A
(6) OPER. & MAINT. - LM6000	114	65	2	26	3	2	4	7	0	2	1	D-3A
(7) OPER. & MAINT. - OTHER CT's	1,027	584	21	236	29	20	39	64	0	21	13	D-3A
(8) DSM AMORTIZATION	658	374	13	151	19	13	25	41	0	14	8	D-3A
(9) FCR DEFERRAL	4,084	2,320	83	937	115	81	157	255	0	84	51	P-14
(10) GRANTS IN LIEU	7,792	4,427	159	1,788	219	155	299	487	0	161	97	P-7
(11) DEPRECIATION	34,875	19,813	712	8,005	982	692	1,337	2,180	0	721	432	EXH 6D
(12) INTEREST NET OF AFUDC	25,890	14,709	529	5,942	729	514	993	1,618	0	535	321	P-14
(13) PREFERRED DIVIDENDS	1,571	893	32	361	44	31	60	98	0	32	19	P-14
(14) CORPORATE TAXES	10,266	5,833	210	2,356	289	204	394	642	0	212	127	P-14
NON-OPERATING REVENUE:												
(15) OTHER REVENUE	(1,623)	(922)	(33)	(372)	(46)	(32)	(62)	(101)	0	(34)	(20)	O-8
(16) RETURN (PROFIT/LOSS)	23,531	13,368	481	5,401	663	467	902	1,471	0	486	292	P-14
(17) INTERR. RIDER DMD ADJ.	(5,786)	0	0	0	0	0	0	(5,786)	0	0	0	DIRECT
(18) ALLOC. OF INTERR. DMD. ADJ.	5,786	3,447	124	1,393	171	120	233	98	0	125	75	D-4
(19) ELI 2P-RTP DEMAND ADJ.	0	0	0	0	0	0	0	0	0	0	0	DIRECT
(20) ALLOC. OF ELI 2P-RTP DMD. ADJ.	0	0	0	0	0	0	0	0	0	0	0	D-4
(21) ELI 2P-RTP PRIORITY DMD ADJ.	0	0	0	0	0	0	0	0	0	0	0	DIRECT
(22) ALLOC. OF ELI 2P-RTP PRI. DMD. ADJ.	0	0	0	0	0	0	0	0	0	0	0	D-3B
(23) TOTAL GENERATION	155,095	91,559	3,291	36,990	4,539	3,199	6,179	4,007	0	3,332	1,998	
TRANSMISSION												
Transmission < 138kV												
(24) OPERATING & MAINT.	2,712	1,540	55	622	76	54	104	169	0	56	34	D-3B
(25) GRANTS IN LIEU	536	304	11	123	15	11	21	33	0	11	7	P-8A
(26) DEPRECIATION	2,659	1,511	54	610	75	53	102	166	0	55	33	EXH 6D
(27) INTEREST NET OF AFUDC	1,778	1,010	36	408	50	35	68	111	0	37	22	P-15A
(28) PREFERRED DIVIDENDS	108	61	2	25	3	2	4	7	0	2	1	P-15A
(29) CORPORATE TAXES	705	401	14	162	20	14	27	44	0	15	9	P-15A
NON-OPERATING REVENUE:												
(30) OTHER REVENUE	(107)	(61)	(2)	(25)	(3)	(2)	(4)	(7)	0	(2)	(1)	O-9A
(32) RETURN (PROFIT/LOSS)	1,616	918	33	371	46	32	62	101	0	33	20	P-15A
(33) TOTAL < 138kV	$10,006	$5,685	$204	$2,297	$282	$199	$384	$625	$0	$207	$124	

NOVA SCOTIA POWER INC.

ALLOCATION OF OPERATING EXPENSES

FOR THE YEAR ENDING DECEMBER 31, 2013

(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) ELI 2P-RTP	(9) MUNICIPAL	(10) UNMETERED	(11) ALLOCATION FACTOR
Transmission > 69kV												
(1) OPERATING & MAINT.	8,625	4,900	176	1,980	243	171	331	539	0	178	107	D-3A
(2) GRANTS IN LIEU	1,785	1,014	36	410	50	35	68	112	0	37	22	P-8B
(3) DEPRECIATION	8,705	4,946	178	1,998	245	173	334	544	0	180	108	EXH 6D
(4) INTEREST NET OF AFUDC	5,924	3,366	121	1,360	167	118	227	370	0	122	73	P-15B
(5) PREFERRED DIVIDENDS	359	204	7	83	10	7	14	22	0	7	4	P-15B
(6) CORPORATE TAXES	2,349	1,335	48	539	66	47	90	147	0	49	29	P-15B
NON-OPERATING REVENUE:												
(7) FCR DEFERRAL	1,289	732	26	296	36	26	49	81	0	27	16	P-15B
(8) OTHER REVENUE	(350)	(199)	(7)	(80)	(10)	(7)	(13)	(22)	0	(7)	(4)	O-9B
(9) RETURN (PROFIT/LOSS)	5,384	3,059	110	1,236	152	107	206	337	0	111	67	P-15B
(10) TOTAL > 69kV	34,071	19,356	696	7,820	960	676	1,306	2,130	0	704	422	
(11) TOTAL TRANSMISSION	44,077	25,041	900	10,117	1,241	875	1,690	2,755	0	911	546	
DISTRIBUTION												
Non SL												
(12) OPERATING & MAINT.	36,338	21,499	1,164	9,948	1,063	957	1,213	4	0	0	489	EXH 6A
(13) GRANTS IN LIEU	4,900	2,985	162	1,360	88	129	102	5	0	0	68	P-9
(14) DEPRECIATION	36,365	22,158	1,200	10,097	654	958	756	35	0	2	504	EXH 6D
(15) INTEREST NET OF AFUDC	17,559	10,639	576	4,850	320	461	370	16	0	1	326	P-16
(16) PREFERRED DIVIDENDS	1,066	646	35	294	19	28	22	1	0	0	20	P-16
(17) CORPORATE TAXES	6,963	4,219	228	1,923	127	183	147	6	0	0	129	P-16
NON-OPERATING REVENUE:												
(18) OTHER REVENUE	(1,368)	(757)	(41)	(347)	(28)	(33)	(32)	(1)	0	(0)	(129)	O-10
(19) RETURN (PROFIT/LOSS)	15,960	9,670	524	4,408	291	419	336	15	0	1	296	P-16
SL												
non-LED												
(20) OPERATING & MAINT.	5,705	0	0	0	0	0	0	0	0	0	5,705	EXH 6A
(21) GRANTS IN LIEU OF TAXES	164	0	0	0	0	0	0	0	0	0	164	P-9A
(22) Depreciation	2,342	0	0	0	0	0	0	0	0	0	2,342	EXH 6D
(23) INTEREST NET OF AFUDC	589	0	0	0	0	0	0	0	0	0	589	P-16B
(23) PREFERRED DIVIDENDS	36	0	0	0	0	0	0	0	0	0	36	P-16B
(25) CORPORATE TAXES	233	0	0	0	0	0	0	0	0	0	233	P-16B
(26) OTHER REVENUE												
(27) RETURN (PROFIT/LOSS)	535	0	0	0	0	0	0	0	0	0	535	P-16B
Subtotal	9,604	0	0	0	0	0	0	0	0	0	9,604	
(28) TOTAL DISTRIBUTION	127,386	71,057	3,849	32,535	2,536	3,101	2,915	81	0	5	11,306	
(29) TOTAL DEMAND	**$326,558**	**$187,658**	**$8,040**	**$79,642**	**$8,317**	**$7,175**	**$10,784**	**$6,843**	**$0**	**$4,248**	**$13,850**	

NOVA SCOTIA POWER INC.
ALLOCATION OF OPERATING EXPENSES
FOR THE YEAR ENDING DECEMBER 31, 2013
(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
ENERGY CLASSIFICATION												
GENERATION												
(1) FUEL	$342,028	$160,541	$8,615	$88,113	$14,250	$9,289	$17,827	$32,571	$0	$6,889	$3,933	DIRECT
(2) PURCH. POWER REG - FIXED	12,784	5,967	322	3,304	537	349	672	1,230	0	257	147	E-1A
(3) PURCH. POWER REG - VAR.	22,969	10,720	578	5,937	966	627	1,207	2,210	0	462	264	E-1A
(4) PURCH. POWER WIND - FIXED	12,774	5,962	321	3,301	537	348	671	1,229	0	257	147	E-1A
(5) PURCH. POWER WIND - VAR.	42,578	19,872	1,071	11,005	1,790	1,162	2,237	4,096	0	857	489	E-1A
(6) OPER. & MAINT. - STEAM	79,969	37,323	2,012	20,668	3,362	2,182	4,201	7,694	0	1,610	918	E-1A
(7) OPER. & MAINT. - HYDRO/WIND/BIOMASS	16,501	7,701	415	4,265	694	450	867	1,588	0	332	189	E-1A
(8) OPER. & MAINT. - LM6000	311	145	8	80	13	8	16	30	0	6	4	E-1A
(9) OPER. & MAINT. - OTHER CT's	196	91	5	51	8	5	10	19	0	4	2	E-1A
(10) DSM AMORTIZATION	1,401	654	35	362	59	38	74	135	0	28	16	E-1A
(11) FCR DEFERRAL	9,449	4,410	238	2,442	397	258	496	909	0	190	108	P-17
(12) GRANTS IN LIEU	16,577	7,737	417	4,284	697	452	871	1,595	0	334	190	P-10
(13) DEPRECIATION	73,760	34,425	1,855	19,063	3,101	2,012	3,875	7,096	0	1,485	846	EXH 6D
(14) INTEREST NET OF AFUDC	59,904	27,958	1,507	15,482	2,519	1,634	3,147	5,763	0	1,206	687	P-17
(15) PREFERRED DIVIDENDS	3,635	1,697	91	940	153	99	191	350	0	73	42	P-17
(16) CORPORATE TAXES	23,754	11,087	598	6,139	999	648	1,248	2,285	0	478	273	P-17
NON-OPERATING REVENUE:												
(17) EXPORT SALES	(1,807)	(843)	(45)	(467)	(76)	(49)	(95)	(174)	0	(36)	(21)	EXH 7
(18) OTHER REVENUE	(8,755)	(4,097)	(220)	(2,259)	(367)	(238)	(458)	(838)	0	(176)	(101)	O-11
(19) RETURN (PROFIT/LOSS)	54,447	25,411	1,370	14,072	2,289	1,485	2,860	5,238	0	1,096	625	P-17
(20) TOTAL GENERATION	762,476	356,760	19,190	196,783	31,928	20,759	39,917	73,026	0	15,354	8,757	
TRANSMISSION												
Transmission < 138kV												
(21) OPERATING & MAINT.	3,532	1,648	89	913	148	96	186	340	0	71	41	E-1B
(22) GRANTS IN LIEU	698	326	18	180	29	19	37	67	0	14	8	P-11A
(23) DEPRECIATION	3,464	1,617	87	895	146	94	182	333	0	70	40	EXH 6D
(24) INTEREST NET	2,316	1,081	58	599	97	63	122	223	0	47	27	P-18A
(25) PREFERRED DIVIDENDS	141	66	4	36	6	4	7	14	0	3	2	P-18A
(26) CORPORATE TAXES	918	429	23	237	39	25	48	88	0	18	11	P-18A
NON-OPERATING REVENUE:												
(27) OTHER REVENUE	(139)	(65)	(4)	(36)	(6)	(4)	(7)	(13)	0	(3)	(2)	O-12A
(28) RETURN (PROFIT/LOSS)	2,105	982	53	544	88	57	111	202	0	42	24	P-18A
(29) TOTAL < 138kV	13,034	6,083	328	3,369	548	356	685	1,254	0	262	150	
Transmission > 69kV												
(30) OPERATING & MAINT.	11,235	5,244	283	2,904	472	306	590	1,081	0	226	129	E-1A
(31) GRANTS IN LIEU	2,325	1,085	58	601	98	63	122	224	0	47	27	P-11B
(32) DEPRECIATION	11,339	5,292	285	2,931	477	309	596	1,091	0	228	130	EXH 6D
(33) INTEREST NET	7,716	3,601	194	1,994	324	211	405	742	0	155	89	P-18B
(34) PREFERRED DIVIDENDS	468	219	12	121	20	13	25	45	0	9	5	P-18B
(35) CORPORATE TAXES	3,060	1,428	77	791	129	83	161	294	0	62	35	P-18B
NON-OPERATING REVENUE:												
(36) FCR DEFERRAL	1,679	784	42	434	71	46	88	162	0	34	19	P-18B
(37) OTHER REVENUE	(456)	(213)	(11)	(118)	(19)	(12)	(24)	(44)	0	(9)	(5)	O-12B
(38) RETURN (PROFIT/LOSS)	7,013	3,273	176	1,813	295	191	368	675	0	141	80	P-18B
(39) TOTAL > 69kV	44,379	20,713	1,116	11,470	1,866	1,211	2,331	4,270	0	894	509	
(40) TOTAL TRANSMISSION	57,413	26,796	1,444	14,839	2,414	1,566	3,016	5,524	0	1,156	659	
(41) TOTAL ENERGY	**$819,889**	**$383,556**	**$20,635**	**$211,621**	**$34,342**	**$22,326**	**$42,933**	**$78,549**	**$0**	**$16,510**	**$9,416**	

NOVA SCOTIA POWER INC.

ALLOCATION OF OPERATING EXPENSES

FOR THE YEAR ENDING DECEMBER 31, 2013

(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
CUST. CLASSIFICATION												
DISTRIBUTION												
(1) OPERATING & MAINT.	$14,865	$13,417	$708	$383	$1	$79	$9	$3	$0	$0	$265	EXH 6A
(2) GRANTS IN LIEU	2,629	2,309	122	136	0	28	3	1	0	0	30	P-12
(3) DEPRECIATION	17,284	15,182	802	896	2	184	17	5	0	1	196	EXH 6D
(4) INTEREST NET OF AFUDC	9,420	8,301	438	460	1	94	9	3	0	0	114	P-19
(5) PREFERRED DIVIDENDS	572	504	27	28	0	6	1	0	0	0	7	P-19
(6) CORPORATE TAXES	3,736	3,292	174	182	0	37	3	1	0	0	45	P-19
NON-OPERATING REVENUE:												
(8) OTHER REVENUE	(591)	(524)	(28)	(25)	(0)	(5)	(1)	(0)	0	(0)	(8)	O-13
(9) RETURN (PROFIT/LOSS)	8,562	7,545	398	418	1	86	8	2	0	0	103	P-19
(10) TOTAL DISTRIBUTION	56,476	50,025	2,641	2,479	4	509	49	15	0	2	751	
RETAIL												
(11) METER READING & ELECTRIC INSPECT.	16,678	14,119	755	1,236	35	242	97	62	0	15	117	EXH 6A
(12) CUST. SERV. - H/O	5,325	4,807	262	125	0	24	2	0	0	0	104	C-7
(13) CALL CENTRE	20,723	16,657	879	2,096	66	410	181	118	0	29	287	C-3
(14) BILLING SERVICES	6,430	5,805	316	151	0	29	3	0	0	0	126	C-3
(15) ELECT. WIRING INSP. - H/O	463	418	23	11	0	2	0	0	0	0	9	C-7
(16) METER DATA SERVICES	818	44	43	102	132	102	102	191	0	102	0	O-16
(17) PAYMENT SERVICES	1,230	1,110	60	29	0	6	0	0	0	0	24	C-7
(18) CREDIT SERVICES	5,736	4,819	86	754	0	78	0	0	0	0	0	EXH 6C
(19) MARKETING & SALES	2,019	915	72	169	36	133	261	396	0	36	0	O-15
(20) COGS (NET OF SALES)	(438)	(395)	(22)	(10)	(0)	(2)	(0)	(0)	0	(0)	(9)	C-7
(22) GRANTS IN LIEU	0	0	0	0	0	0	0	0	0	0	0	N/A
(23) DEPRECIATION	0	0	0	0	0	0	0	0	0	0	0	N/A
(24) INTEREST NET OF AFUDC	0	0	0	0	0	0	0	0	0	0	0	N/A
(25) PREFERRED DIVIDENDS	0	0	0	0	0	0	0	0	0	0	0	N/A
(26) CORPORATE TAXES	0	0	0	0	0	0	0	0	0	0	0	N/A
NON-OPERATING REVENUE:												
(28) LATE PAYMENT CHARGE	(5,128)	(3,976)	(121)	(886)	0	(69)	(59)	0	0	0	(17)	EXH 7
(29) MISC. ELECTRIC	(1,909)	(1,772)	(108)	(12)	0	0	0	0	0	0	(17)	EXH 7
(30) OTHER REVENUE	(719)	(581)	(29)	(58)	(4)	(13)	(9)	(12)	0	(3)	(9)	O-14
(31) RETURN (PROFIT/LOSS)	0	0	0	0	0	0	0	0	0	0	0	N/A
(32) TOTAL RETAIL	51,230	41,971	2,217	3,705	266	942	578	756	0	180	616	
(33) TOTAL CUSTOMER	**107,706**	**91,996**	**4,858**	**6,184**	**270**	**1,450**	**627**	**771**	**0**	**182**	**1,368**	
(34) TOTAL NET EXPENSES	**$1,254,153**	**$663,210**	**$33,533**	**$297,447**	**$42,930**	**$30,951**	**$54,344**	**$86,163**	**$0**	**$20,941**	**$24,633**	

EXHIBIT 6A

NOVA SCOTIA POWER INC.

ALLOCATION OF DISTRIBUTION OPERATING EXPENSES

FOR THE YEAR ENDING DECEMBER 31, 2013

(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
DEMAND												
(1) SUBSTATIONS	$300	$170	$9	$80	$11	$8	$14	$4	$0	$0	$4	P-5
(2) OVERHEAD LINES	25,449	15,118	819	6,981	709	670	808	0	0	0	344	P-1
(3) UNDERGROUND LINES	441	262	14	121	12	12	14	0	0	0	6	P-1
(4) LINE TRANSFORMERS	1,453	929	50	414	0	38	0	0	0	0	21	D-1
(5) METERS	0	0	0	0	0	0	0	0	0	0	0	---
(6) COMMUNICATIONS	8,696	5,020	272	2,352	331	229	378	0	0	0	114	D-2
(7) STREET LIGHTING	5,705	0	0	0	0	0	0	0	0	0	5,705	DIRECT
(8) CUSTOMER SERVICE	0	0	0	0	0	0	0	0	0	0	0	---
(9) TOTAL DEMAND	42,043	21,499	1,164	9,948	1,063	957	1,213	4	0	0	6,194	
CUSTOMER												
(10) SUBSTATIONS	0	0	0	0	0	0	0	0	0	0	0	--
(11) OVERHEAD LINES	13,703	12,410	655	312	0	61	3	0	0	0	261	P-2
(12) UNDERGROUND LINES	238	215	11	5	0	1	0	0	0	0	5	P-2
(13) LINE TRANSFORMERS	0	0	0	0	0	0	0	0	0	0	0	--
(14) METERS	924	791	42	65	1	17	7	2	0	0	0	P-6
(15) COMMUNICATIONS	0	0	0	0	0	0	0	0	0	0	0	--
(16) STREET LIGHTING	0	0	0	0	0	0	0	0	0	0	0	--
(17) CUSTOMER SERVICE	0	0	0	0	0	0	0	0	0	0	0	EXHIBIT 6B
(18) TOTAL CUSTOMER	14,865	13,417	708	383	1	79	9	3	0	0	265	
RETAIL												
(19) METERS	0	0	0	0	0	0	0	0	0	0	0	N/A
(20) CUSTOMER SERVICE	16,678	14,119	755	1,236	35	242	97	62	0	15	117	EXHIBIT 6B
(20) TOTAL RETAIL	16,678	14,119	755	1,236	35	242	97	62	0	15	117	
SUMMARY												
(21) SUBSTATIONS	300	170	9	80	11	8	14	4	0	0	4	P-3
(22) OVERHEAD LINES	39,152	27,528	1,474	7,294	709	732	811	0	0	0	605	P-1
(23) UNDERGROUND LINES	679	477	26	127	12	13	14	0	0	0	10	P-1
(24) LINE TRANSFORMERS	1,453	929	50	414	0	38	0	0	0	0	21	D-1
(25) METERS	17,602	14,910	796	1,301	35	258	104	64	0	16	117	P-6
(26) COMMUNICATIONS	8,696	5,020	272	2,352	331	229	378	0	0	0	114	D-2
(27) STREET LIGHTING	5,705	0	0	0	0	0	0	0	0	0	5,705	DIRECT
(28) CUSTOMER SERVICE	0	0	0	0	0	0	0	0	0	0	0	EXHIBIT 6B
(29) TOTAL DISTRIBUTION	**$73,586**	**$49,035**	**$2,627**	**$11,566**	**$1,099**	**$1,277**	**$1,320**	**$68**	**$0**	**$16**	**$6,576**	

EXHIBIT 6B

NOVA SCOTIA POWER INC.

ALLOCATION OF CUSTOMER SERVICE FIELD EXPENSES

FOR THE YEAR ENDING DECEMBER 31, 2013
(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) METER READING	(4) WIRING INSPECTION
(1) DOMESTIC	$14,119	$8,703	$5,416
(2) SMALL GENERAL	755	460	295
(3) GENERAL	1,236	1,095	141
(4) GENERAL LARGE	35	35	0
(5) SMALL INDUSTRIAL	242	214	27
(6) MEDIUM INDUSTRIAL	97	95	2
(7) LARGE INDUSTRIAL	62	62	0
(8) ELI 2P-RTP	0	0	0
(9) MUNICIPAL	15	15	0
(10) UNMETERED	117	0	117
(11) TOTAL	$16,678	$10,678	$5,999
ALLOCATION FACTOR		C-6	C-7

EXHIBIT 6C

NOVA SCOTIA POWER INC.

ALLOCATION OF CREDIT SERVICES EXPENSES

FOR THE YEAR ENDING DECEMBER 31, 2013

(IN THOUSANDS OF DOLLARS)

	(1)	(2)	(3)	(4)	(5)
	---------------BAD DEBT EXPENSE-----------------			CREDIT	
	DIRECT	TO BE ALLOC.	TOTAL	SERVICES	TOTAL
(1) DOMESTIC	$4,819	$0	$4,819	$0	$4,819
(2) SMALL GENERAL	0	86	86	0	86
(3) GENERAL	0	754	754	0	754
(4) GENERAL LARGE	0	0	0	0	0
(5) SMALL INDUSTRIAL	0	78	78	0	78
(6) MEDIUM INDUSTRIAL	0	0	0	0	0
(7) LARGE INDUSTRIAL	0	0	0	0	0
(8) ELI 2P-RTP	0	0	0	0	0
(9) MUNICIPAL	0	0	0	0	0
(10) UNMETERED	0	0	0	0	0
(11) TOTAL	$4,819	$918	$5,736	$0	$5,736
ALLOCATION FACTOR	DIRECT	R-1		C-7	

DOMESTIC - 84 %

NOVA SCOTIA POWER INC.
ALLOCATION OF DEPRECIATION EXPENSES
FOR THE YEAR ENDING DECEMBER 31, 2013
(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
DEMAND CLASSIFICATION												
GENERATION FUNCTION												
(1) STEAM PRODUCTION	$20,754	$11,791	$424	$4,763	$585	$412	$796	$1,297	$0	$429	$257	D-3A
(2) HYDRO PRODUCTION	4,021	2,284	82	923	113	80	154	251	0	83	50	D-3A
(3) WIND PRODUCTION	202	115	4	46	6	4	8	13	0	4	3	D-3A
(4) LM6000 PRODUCTION	903	513	18	207	25	18	35	56	0	19	11	D-3A
(5) GAS TURBINE PROD. - OTHER	1,180	670	24	271	33	23	45	74	0	24	15	D-3A
(6) GENERAL PROPERTY	7,815	4,440	160	1,794	220	155	300	489	0	162	97	P-7
(7) TOTAL GENERATION FUNCTION	34,875	19,813	712	8,005	982	692	1,337	2,180	0	721	432	
TRANSMISSION FUNCTION												
(8) TRANSMISSION PLANT < 138kV	2,115	1,201	43	485	60	42	81	132	0	44	26	D-3B
(9) GENERAL PROPERTY	545	309	11	125	15	11	21	34	0	11	7	P-8A
TOTAL < 138kV	2,659	1,511	54	610	75	53	102	166	0	55	33	
(10) TRANSMISSION PLANT > 69kV	6,922	3,932	141	1,589	195	137	265	433	0	143	86	D-3A
(11) GENERAL PROPERTY	1,783	1,013	36	409	50	35	68	111	0	37	22	P-8B
(12) TOTAL > 69kV	8,705	4,946	178	1,998	245	173	334	544	0	180	108	
(13) TOTAL TRANSMISSION FUNCTION	11,364	6,456	232	2,608	320	226	436	710	0	235	141	
DISTRIBUTION FUNCTION												
(14) DISTRIBUTION PLANT - Non Streetligl	31,135	18,971	1,027	8,645	560	821	647	30	0	2	432	P-9
(14) DISTRIBUTION PLANT - Streetlight	2,342	0	0	0	0	0	0	0	0	0	2,342	Direct
(15) GENERAL PROPERTY	5,230	3,187	173	1,452	94	138	109	5	0	0	73	P-9
(16) TOTAL DISTRIBUTION FUNCTION	38,707	22,158	1,200	10,097	654	958	756	35	0	2	2,846	
(17) TOTAL DEMAND	**84,946**	**48,427**	**2,144**	**20,710**	**1,957**	**1,876**	**2,529**	**2,925**	**0**	**958**	**3,420**	
ENERGY CLASSIFICATION												
GENERATION FUNCTION												
(18) STEAM PRODUCTION	42,605	19,885	1,072	11,012	1,791	1,162	2,238	4,099	0	858	489	E-1A
(19) HYDRO PRODUCTION	5,387	2,514	136	1,392	226	147	283	518	0	108	62	E-1A
(20) WIND PRODUCTION	7,964	3,717	200	2,058	335	217	418	766	0	160	91	E-1A
(21) LM6000 PRODUCTION	1,176	549	30	304	49	32	62	113	0	24	13	E-1A
(22) GAS TURBINE PROD. - OTHER	0	0	0	0	0	0	0	0	0	0	0	E-1A
(23) GENERAL PROPERTY	16,627	7,760	418	4,297	699	454	873	1,600	0	335	191	P-10
(24) TOTAL GENERATION FUNCTION	73,760	34,425	1,855	19,063	3,101	2,012	3,875	7,096	0	1,485	846	
TRANSMISSION FUNCTION												
(25) TRANSMISSION PLANT < 138kV	2,754	1,285	69	712	116	75	145	265	0	55	32	E-1B
(26) GENERAL PROPERTY	710	331	18	183	30	19	37	68	0	14	8	P-11A
(27) TOTAL < 138kV	3,464	1,617	87	895	146	94	182	333	0	70	40	
(28) TRANSMISSION PLANT > 69kV	9,016	4,208	227	2,330	379	246	474	867	0	182	103	E-1A
(29) GENERAL PROPERTY	2,323	1,084	58	600	98	63	122	223	0	47	27	P-11B
(30) TOTAL > 69kV	11,339	5,292	285	2,931	477	309	596	1,091	0	228	130	
(31) TOTAL TRANSMISSION FUNCTION	14,803	6,909	372	3,826	622	404	778	1,424	0	298	170	
(32) TOTAL ENERGY	**88,562**	**41,334**	**2,228**	**22,889**	**3,723**	**2,416**	**4,653**	**8,520**	**0**	**1,783**	**1,016**	

NOVA SCOTIA POWER INC.
ALLOCATION OF DEPRECIATION EXPENSES
FOR THE YEAR ENDING DECEMBER 31, 2013
(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
CUSTOMER CLASSIFICATION												
DISTRIBUTION FUNCTION												
(1) DISTRIBUTION PLANT	14,798	12,998	686	768	1	157	14	4	0	0	167	P-12
(2) GENERAL PROPERTY	2,486	2,184	115	129	0	26	2	1	0	0	28	P-12
(3) TOTAL DISTRIBUTION FUNCTION	17,284	15,182	802	896	2	184	17	5	0	1	196	
RETAIL FUNCTION												
(4) DISTRIBUTION PLANT	0	0	0	0	0	0	0	0	0	0	0	P-13
(5) GENERAL PROPERTY	0	0	0	0	0	0	0	0	0	0	0	P-13
(6) TOTAL RETAIL FUNCTION	0	0	0	0	0	0	0	0	0	0	0	
(7) TOTAL CUSTOMER	**17,284**	**15,182**	**802**	**896**	**2**	**184**	**17**	**5**	**0**	**1**	**196**	
(8) TOTAL DEPRECIATION	**$190,792**	**$104,943**	**$5,174**	**$44,496**	**$5,682**	**$4,476**	**$7,198**	**$11,451**	**$0**	**$2,742**	**$4,631**	

EXHIBIT 7

NOVA SCOTIA POWER INC.

REVENUE ANALYSIS

FOR THE YEAR ENDING DECEMBER 31, 2013

(IN THOUSANDS OF DOLLARS)

	(1) REVENUE	(2) EXPORT SALES	(3) LATE PAYMENT CHARGE	(4) MISC. CUSTOMER REVENUE
ELECTRIC REVENUE				
(1) DOMESTIC	$656,557	$843	$3,976	$1,772
(2) SMALL GENERAL	35,079	45	121	108
(3) GENERAL	307,787	467	886	12
(4) LARGE GENERAL	42,151	76	0	0
(5) SMALL INDUSTRIAL	31,739	49	69	0
(6) MEDIUM INDUSTRIAL	53,486	95	59	0
(7) LARGE INDUSTRIAL	82,327	174	0	0
(8) ELI 2P-RTP	0	0	0	0
(9) MUNICIPAL	20,394	36	0	0
(10) UNMETERED	24,633	21	17	17
(11) SUB-TOTAL	1,254,153	$1,807	$5,128	$1,909
(12) EXPORT SALES	1,807			
(13) TOTAL ELECTRIC REVENUE	1,255,959			
NON-RATE REVENUE				
(14) LATE PAYMENT CHARGE	5,128			
(15) MISC. CUST. REVENUE	1,909			
(16) OTHER	14,108			
(17) TOTAL	21,145			
DIRECT REVENUE				
(18) BOWATER BASIC BLOCK	9,935			
(19) BOWATER ADDITIONAL ENERGY	10,283			
(20) GEN.REPL./LOAD FOLL	1,095			
(21) LRT	21,183			
(22) REAL TIME PRICING	0			
(23) LED	1,963			
(24) TOTAL	44,458			
(25) TRANSFER FROM (TO) RETAINED EARNINGS	(123,837)			
(26) TOTAL REVENUE	**$1,197,725**			
ALLOCATION FACTOR		E-1	DIRECT	DIRECT

EXHIBIT 8A

NOVA SCOTIA POWER INC.
DEVELOPMENT OF ALLOCATION FACTORS
FOR THE YEAR ENDING DECEMBER 31, 2013

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
(1) N.C. DEMAND SEC.	1,718,943	1,099,550	59,553	489,304	0	45,520	0	0	0	0	25,017	
(2) % RESPONSIBILITY	100.00%	63.97%	3.46%	28.47%	0.00%	2.65%	0.00%	0.00%	0.00%	0.00%	1.46%	D-1
(3) N.C. DEMAND PRI.	2,007,683	1,158,926	62,768	543,120	76,500	52,790	87,212	0	0	0	26,368	
(4) % RESPONSIBILITY	100.00%	57.72%	3.13%	27.05%	3.81%	2.63%	4.34%	0.00%	0.00%	0.00%	1.31%	D-2
(5) 3 CP DEMAND	5,936,656	3,372,733	121,245	1,362,599	167,207	117,844	227,607	371,097	0	122,733	73,592	
(6) % RESPONSIBILITY	100.00%	56.81%	2.04%	22.95%	2.82%	1.99%	3.83%	6.25%	0.00%	2.07%	1.24%	D-3A
(7) 3 CP DEMAND - LESS ELIIR - 2	5,936,656	3,372,733	121,245	1,362,599	167,207	117,844	227,607	371,097	0	122,733	73,592	
(8) % RESPONSIBILITY	100.00%	56.81%	2.04%	22.95%	2.82%	1.99%	3.83%	6.25%	0.00%	2.07%	1.24%	D-3B
(9) 3 CP DMD. - LESS INT. & ELIIR - 2	5,661,086	3,372,733	121,245	1,362,599	167,207	117,844	227,607	95,526	0	122,733	73,592	
(10) % RESPONSIBILITY	100.00%	59.58%	2.14%	24.07%	2.95%	2.08%	4.02%	1.69%	0.00%	2.17%	1.30%	D-4
(11) MW.h GEN. & PURCH.	9,997,846	4,666,182	251,486	2,583,975	420,339	272,739	525,238	961,872	0	201,299	114,717	
(12) % RESPONSIBILITY	100.00%	46.67%	2.52%	25.85%	4.20%	2.73%	5.25%	9.62%	0.00%	2.01%	1.15%	E-1A
(13) MW.h GEN. & PURCH. Less EHV	9,997,846	4,666,182	251,486	2,583,975	420,339	272,739	525,238	961,872	0	201,299	114,717	
(14) % RESPONSIBILITY	100.00%	46.67%	2.52%	25.85%	4.20%	2.73%	5.25%	9.62%	0.00%	2.01%	1.15%	E-1B
(15) AVERAGE CUSTOMERS	499,825	452,558	23,894	11,387	18	2,227	197	32	0	8	9,504	
(16) % RESPONSIBILITY	100.00%	90.54%	4.78%	2.28%	0.00%	0.45%	0.04%	0.01%	0.00%	0.00%	1.90%	C-1
(17) SECONDARY CUSTOMERS	490,066	452,558	23,894	11,387	0	2,227	0	0	0	0	0	
(18) WEIGHTING FACTOR		1.00	1.00	5.00	100.00	5.00	25.00	100.00	100.00	100.00	0.82	
(19) WEIGHTED TOTAL	544,522	452,558	23,894	56,935	0	11,135	0	0	0	0	0	
(20) % RESPONSIBILITY	100.00%	83.11%	4.39%	10.46%	0.00%	2.04%	0.00%	0.00%	0.00%	0.00%	0.00%	C-2
(21) AVERAGE CUSTOMERS	499,825	452,558	23,894	11,387	18	2,227	197	32	0	8	9,504	
(22) WEIGHTING FACTOR		1.00	1.00	5.00	100.00	5.00	25.00	100.00	100.00	100.00	0.82	
(23) WEIGHTED TOTAL	563,040	452,558	23,894	56,935	1,800	11,135	4,925	3,200	0	800	7,793	
(24) % RESPONSIBILITY	100.00%	80.38%	4.24%	10.11%	0.32%	1.98%	0.87%	0.57%	0.00%	0.14%	1.38%	C-3
(25) CUSTOMER SECONDARY	499,570	452,558	23,894	11,387	0	2,227	0	0	0	0	9,504	
(26) % RESPONSIBILITY	100.00%	90.59%	4.78%	2.28%	0.00%	0.45%	0.00%	0.00%	0.00%	0.00%	1.90%	C-4
(27) CUSTOMER PRIMARY	499,825	452,558	23,894	11,387	18	2,227	197	32	0	8	9,504	
(28) % RESPONSIBILITY	100.00%	90.54%	4.78%	2.28%	0.00%	0.45%	0.04%	0.01%	0.00%	0.00%	1.90%	C-5
(29) AVG. CUST. - LESS UNMETERED	490,321	452,558	23,894	11,387	18	2,227	197	32	0	8	0	
(30) WEIGHTING FACTOR		1.00	1.00	5.00	100.00	5.00	25.00	100.00	100.00	100.00	0.82	
(31) WEIGHTED TOTAL	555,247	452,558	23,894	56,935	1,800	11,135	4,925	3,200	0	800	0	
(32) % RESPONSIBILITY	100.00%	81.51%	4.30%	10.25%	0.32%	2.01%	0.89%	0.58%	0.00%	0.14%	0.00%	C-6
(33) AVERAGE CUSTOMERS ADJ SEASONAL	485,846	438,579	23,894	11,387	18	2,227	197	32	0	8	9,504	
(34) % RESPONSIBILITY	100.00%	90.27%	4.92%	2.34%	0.00%	0.46%	0.04%	0.01%	0.00%	0.00%	1.96%	C-7

NOVA SCOTIA POWER INC.
DEVELOPMENT OF ALLOCATION FACTORS
FOR THE YEAR ENDING DECEMBER 31, 2013

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
(1) POLE&WIRE INV.-DMD.	$187,343	$111,291	$6,028	$51,393	$5,217	$4,935	$5,947	$0	$0	$0	$2,532	
(2) % RESPONSIBILITY	100.00%	59.41%	3.22%	27.43%	2.78%	2.63%	3.17%	0.00%	0.00%	0.00%	1.35%	P-1
(3) POLE&WIRE INV.-CUST.	$100,877	$91,361	$4,824	$2,299	$2	$450	$20	$3	$0	$1	$1,919	
(4) % RESPONSIBILITY	100.00%	90.57%	4.78%	2.28%	0.00%	0.45%	0.02%	0.00%	0.00%	0.00%	1.90%	P-2
(5) SUB.,POLE&WIRE-DMD.	$215,805	$127,420	$6,901	$58,978	$6,281	$5,670	$7,267	$365	$0	$24	$2,899	
(6) % RESPONSIBILITY	100.00%	59.04%	3.20%	27.33%	2.91%	2.63%	3.37%	0.17%	0.00%	0.01%	1.34%	P-3
(7) SUB.,POLE&WIRE-CUST.	$100,877	$91,361	$4,824	$2,299	$2	$450	$20	$3	$0	$1	$1,919	
(8) % RESPONSIBILITY	100.00%	90.57%	4.78%	2.28%	0.00%	0.45%	0.02%	0.00%	0.00%	0.00%	1.90%	P-4
(9) SUBST. INVEST.-DMD.	$28,462	$16,129	$874	$7,584	$1,065	$735	$1,320	$365	$0	$24	$367	
(10) % RESPONSIBILITY	100.00%	56.67%	3.07%	26.65%	3.74%	2.58%	4.64%	1.28%	0.00%	0.08%	1.29%	P-5
(11) METER INVEST.-CUST	$23,780	$20,357	$1,075	$1,672	$16	$427	$171	$57	$0	$6	$0	
(12) % RESPONSIBILITY	100.00%	85.60%	4.52%	7.03%	0.07%	1.80%	0.72%	0.24%	0.00%	0.02%	0.00%	P-6
(13) DEMAND - GEN. PLANT	$632,330	$359,239	$12,914	$145,134	$17,810	$12,552	$24,243	$39,527	$0	$13,073	$7,838	
(14) % RESPONSIBILITY	100.00%	56.81%	2.04%	22.95%	2.82%	1.99%	3.83%	6.25%	0.00%	2.07%	1.24%	P-7
(15) DEMAND - TRANS. PLT. < 138kV	$44,073	$25,039	$900	$10,116	$1,241	$875	$1,690	$2,755	$0	$911	$546	
(16) % RESPONSIBILITY	100.00%	56.81%	2.04%	22.95%	2.82%	1.99%	3.83%	6.25%	0.00%	2.07%	1.24%	P-8A
(17) DEMAND - TRANS. PLT. > 69kV	$144,274	$81,965	$2,947	$33,114	$4,063	$2,864	$5,531	$9,018	$0	$2,983	$1,788	
(18) % RESPONSIBILITY	100.00%	56.81%	2.04%	22.95%	2.82%	1.99%	3.83%	6.25%	0.00%	2.07%	1.24%	P-8B
(19) DEMAND - DIST. PLANT	$407,214	$248,120	$13,438	$113,066	$7,327	$10,733	$8,467	$391	$0	$26	$5,645	
(20) % RESPONSIBILITY	100.00%	60.93%	3.30%	27.77%	1.80%	2.64%	2.08%	0.10%	0.00%	0.01%	1.39%	P-9
(19) DEMAND - DIST. PLANT	$15,950	$0	$0	$0	$0	$0	$0	$0	$0	$0	$15,950	
(20) % RESPONSIBILITY	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	P-9A
(23) ENERGY - GEN. PLANT	$1,345,274	$627,865	$33,839	$347,690	$56,559	$36,699	$70,674	$129,426	$0	$27,086	$15,436	
(24) % RESPONSIBILITY	100.00%	46.67%	2.52%	25.85%	4.20%	2.73%	5.25%	9.62%	0.00%	2.01%	1.15%	P-10
(25) ENERGY - TRANS. PLT. < 138kV	$57,408	$26,793	$1,444	$14,837	$2,414	$1,566	$3,016	$5,523	$0	$1,156	$659	
(26) % RESPONSIBILITY	100.00%	46.67%	2.52%	25.85%	4.20%	2.73%	5.25%	9.62%	0.00%	2.01%	1.15%	P-11A
(27) ENERGY - TRANS. PLT. > 69kV	$187,924	$87,708	$4,727	$48,570	$7,901	$5,127	$9,873	$18,080	$0	$3,784	$2,156	
(28) % RESPONSIBILITY	100.00%	46.67%	2.52%	25.85%	4.20%	2.73%	5.25%	9.62%	0.00%	2.01%	1.15%	P-11B
(29) CUSTOMER - DIST. PLANT	$201,122	$176,667	$9,328	$10,432	$18	$2,140	$195	$60	$0	$6	$2,275	
(30) % RESPONSIBILITY	100.00%	87.84%	4.64%	5.19%	0.01%	1.06%	0.10%	0.03%	0.00%	0.00%	1.13%	P-12
(31) CUSTOMER - RETAIL PLANT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
(32) % RESPONSIBILITY	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	P-13
(33) TOT.RATE BASE-DMD. (GEN.)	$701,614	$398,601	$14,329	$161,037	$19,761	$13,927	$26,899	$43,857	$0	$14,505	$8,697	
(34) % RESPONSIBILITY	100.00%	56.81%	2.04%	22.95%	2.82%	1.99%	3.83%	6.25%	0.00%	2.07%	1.24%	P-14
(35) TOT.RATE BASE-DMD. (TRANS. < 138kV)	$48,180	$27,372	$984	$11,058	$1,357	$956	$1,847	$3,012	$0	$996	$597	
(36) % RESPONSIBILITY	100.00%	56.81%	2.04%	22.95%	2.82%	1.99%	3.83%	6.25%	0.00%	2.07%	1.24%	P-15A
(37) TOT.RATE BASE-DMD. (TRANS. > 69kV)	$160,540	$91,206	$3,279	$36,848	$4,522	$3,187	$6,155	$10,035	$0	$3,319	$1,990	
(38) % RESPONSIBILITY	100.00%	56.81%	2.04%	22.95%	2.82%	1.99%	3.83%	6.25%	0.00%	2.07%	1.24%	P-15B
(39) TOT.RATE BASE-DMD. (DIST.) Non Streetlig	$475,857	$288,311	$15,615	$131,441	$8,684	$12,482	$10,029	$442	$0	$29	$8,823	
(40) % RESPONSIBILITY	100.00%	60.59%	3.28%	27.62%	1.82%	2.62%	2.11%	0.09%	0.00%	0.01%	1.85%	P-16
(41) TOT.RATE BASE-DMD. (DIST.) Streetlight	$15,950	$0	$0	$0	$0	$0	$0	$0	$0	$0	$15,950	
(42) % RESPONSIBILITY	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	P-16B
(43) TOT.RATE BASE-ENG. (GEN.)	$1,623,403	$757,673	$40,835	$419,574	$68,253	$44,286	$85,286	$156,184	$0	$32,686	$18,627	
(44) % RESPONSIBILITY	100.00%	46.67%	2.52%	25.85%	4.20%	2.73%	5.25%	9.62%	0.00%	2.01%	1.15%	P-17
(45) TOT.RATE BASE-ENG. (TRANS. < 138kV)	$62,758	$29,290	$1,579	$16,220	$2,639	$1,712	$3,297	$6,038	$0	$1,264	$720	
(46) % RESPONSIBILITY	100.00%	46.67%	2.52%	25.85%	4.20%	2.73%	5.25%	9.62%	0.00%	2.01%	1.15%	P-18A
(47) TOT.RATE BASE-ENG. (TRANS. > 69kV)	$209,113	$97,597	$5,260	$54,046	$8,792	$5,705	$10,986	$20,118	$0	$4,210	$2,399	
(48) % RESPONSIBILITY	100.00%	46.67%	2.52%	25.85%	4.20%	2.73%	5.25%	9.62%	0.00%	2.01%	1.15%	P-18B

EXHIBIT 8B
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NOVA SCOTIA POWER INC.
DEVELOPMENT OF ALLOCATION FACTORS
FOR THE YEAR ENDING DECEMBER 31, 2013

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
(1) TOT. RATE BASE-CUST. (DIST.)	$255,289	$224,960	$11,877	$12,472	$22	$2,559	$237	$73	$0	$8	$3,081	
(2) % RESPONSIBILITY	100.00%	88.12%	4.65%	4.89%	0.01%	1.00%	0.09%	0.03%	0.00%	0.00%	1.21%	P-19
(3) TOT.RATE BASE-CUST.(RETAIL)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
(4) % RESPONSIBILITY	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	P-20
(5) DMD. - OPER.EXP. - GEN.	$29,366	$16,683	$600	$6,740	$827	$583	$1,126	$1,836	$0	$607	$364	
(6) % RESPONSIBILITY	100.00%	56.81%	2.04%	22.95%	2.82%	1.99%	3.83%	6.25%	0.00%	2.07%	1.24%	O-1
(7) DMD. - OPER.EXP. - TRANS. < 138kV	$2,712	$1,540	$55	$622	$76	$54	$104	$169	$0	$56	$34	
(8) % RESPONSIBILITY	100.00%	56.81%	2.04%	22.95%	2.82%	1.99%	3.83%	6.25%	0.00%	2.07%	1.24%	O-2A
(9) DMD. - OPER.EXP. - TRANS. > 69kV	$8,625	$4,900	$176	$1,980	$243	$171	$331	$539	$0	$178	$107	
(10) % RESPONSIBILITY	100.00%	56.81%	2.04%	22.95%	2.82%	1.99%	3.83%	6.25%	0.00%	2.07%	1.24%	O-2B
(11) DMD. - OPER.EXP. - DIST.	$42,043	$21,499	$1,164	$9,948	$1,063	$957	$1,213	$4	$0	$0	$6,194	
(12) % RESPONSIBILITY	100.00%	51.14%	2.77%	23.66%	2.53%	2.28%	2.89%	0.01%	0.00%	0.00%	14.73%	O-3
(13) ENG. - OPER.EXP. - GEN.	$79,969	$37,323	$2,012	$20,668	$3,362	$2,182	$4,201	$7,694	$0	$1,610	$918	
(14) % RESPONSIBILITY	100.00%	46.67%	2.52%	25.85%	4.20%	2.73%	5.25%	9.62%	0.00%	2.01%	1.15%	O-4
(15) ENG. - OPER.EXP. - TRANS. < 138kV	$3,532	$1,648	$89	$913	$148	$96	$186	$340	$0	$71	$41	
(16) % RESPONSIBILITY	100.00%	46.67%	2.52%	25.85%	4.20%	2.73%	5.25%	9.62%	0.00%	2.01%	1.15%	O-5A
(17) ENG. - OPER.EXP. - TRANS. > 69kV	$11,235	$5,244	$283	$2,904	$472	$306	$590	$1,081	$0	$226	$129	
(18) % RESPONSIBILITY	100.00%	46.67%	2.52%	25.85%	4.20%	2.73%	5.25%	9.62%	0.00%	2.01%	1.15%	O-5B
(19) CUST. - OPER. EXP. - DIST.	$14,865	$13,417	$708	$383	$1	$79	$9	$3	$0	$0	$265	
(20) % RESPONSIBILITY	100.00%	90.26%	4.77%	2.57%	0.01%	0.53%	0.06%	0.02%	0.00%	0.00%	1.78%	O-6
(21) CUST. - OPER. EXP. - RETAIL	$40,726	$33,660	$1,670	$3,267	$199	$651	$289	$310	$0	$132	$550	
(22) % RESPONSIBILITY	100.00%	82.65%	4.10%	8.02%	0.49%	1.60%	0.71%	0.76%	0.00%	0.32%	1.35%	O-7
(23) TOT. EXP. - DMD. (GEN.)	$133,186	$75,666	$2,720	$30,569	$3,751	$2,644	$5,106	$8,325	$0	$2,753	$1,651	
(24) % RESPONSIBILITY	100.00%	56.81%	2.04%	22.95%	2.82%	1.99%	3.83%	6.25%	0.00%	2.07%	1.24%	O-8
(25) TOT. EXP. - DMD. (TRANS. < 138kV)	$8,497	$4,827	$174	$1,950	$239	$169	$326	$531	$0	$176	$105	
(26) % RESPONSIBILITY	100.00%	56.81%	2.04%	22.95%	2.82%	1.99%	3.83%	6.25%	0.00%	2.07%	1.24%	O-9A
(27) TOT. EXP. - DMD. (TRANS. > 69kV)	$27,748	$15,764	$567	$6,369	$782	$551	$1,064	$1,735	$0	$574	$344	
(28) % RESPONSIBILITY	100.00%	56.81%	2.04%	22.95%	2.82%	1.99%	3.83%	6.25%	0.00%	2.07%	1.24%	O-9B
(29) TOT. EXP. - DMD. (DIST.)	$112,260	$62,145	$3,366	$28,473	$2,273	$2,716	$2,611	$67	$0	$4	$10,604	
(30) % RESPONSIBILITY	100.00%	55.36%	3.00%	25.36%	2.02%	2.42%	2.33%	0.06%	0.00%	0.00%	9.45%	O-10
(31) TOT. EXP. - ENG. (GEN.)	$718,591	$336,290	$18,087	$185,437	$30,082	$19,562	$37,610	$68,800	$0	$14,471	$8,253	
(32) % RESPONSIBILITY	100.00%	46.80%	2.52%	25.81%	4.19%	2.72%	5.23%	9.57%	0.00%	2.01%	1.15%	O-11
(33) TOT. EXP. - ENG. (TRANS. < 138 kV)	$11,068	$5,166	$278	$2,861	$465	$302	$581	$1,065	$0	$223	$127	
(34) % RESPONSIBILITY	100.00%	46.67%	2.52%	25.85%	4.20%	2.73%	5.25%	9.62%	0.00%	2.01%	1.15%	O-12A
(35) TOT. EXP. - ENG. (TRANS. > 69 kV)	$36,143	$16,869	$909	$9,341	$1,520	$986	$1,899	$3,477	$0	$728	$415	
(36) % RESPONSIBILITY	100.00%	46.67%	2.52%	25.85%	4.20%	2.73%	5.25%	9.62%	0.00%	2.01%	1.15%	O-12B
(37) TOT. EXP. -CUST. (DIST.)	$48,505	$43,005	$2,271	$2,086	$4	$428	$41	$13	$0	$1	$656	
(38) % RESPONSIBILITY	100.00%	88.66%	4.68%	4.30%	0.01%	0.88%	0.09%	0.03%	0.00%	0.00%	1.35%	O-13
(39) TOT. EXP. -CUST. (RETAIL)	$42,308	$34,180	$1,721	$3,426	$235	$782	$549	$706	$0	$168	$541	
(40) % RESPONSIBILITY	100.00%	80.79%	4.07%	8.10%	0.56%	1.85%	1.30%	1.67%	0.00%	0.40%	1.28%	O-14
(41) MARKETING & SALES	99.99%	45.33%	3.59%	8.37%	1.79%	6.58%	12.92%	19.62%	0.00%	1.79%	0.00%	O-15
(42) METER DATA SERVICES	100.02%	5.39%	5.27%	12.46%	16.17%	12.46%	12.46%	23.35%	0.00%	12.46%	0.00%	O-16
(43) SECONDARY CUST. REVENUE	$374,604	$0	$35,079	$307,787	$0	$31,739	$0	$0	$0	$0	$0	
(44) % RESPONSIBILITY	100.00%	0.00%	9.36%	82.16%	0.00%	8.47%	0.00%	0.00%	0.00%	0.00%	0.00%	R-1

EXHIBIT 9A

NOVA SCOTIA POWER INC.

SALES, GENERATION AND DEMAND ANALYSIS

FOR THE YEAR ENDING DECEMBER 31, 2013

	(1) MWH SALES	(2) ENERGY LINE LOSSES	(3) ENERGY REQUIREMENT	(4) CLASS NON-COINCIDENT DMD. (KW)	(5) SYSTEM COINCIDENT FACTOR	(6) SYSTEM COINCIDENT DMD. (KW)	(7) DEMAND LINE LOSSES	(8) SYSTEM COIN. PEAK DMD. (KW)	(9) SYSTEM COINCIDENT L/D FACTOR	(10) MW	(11) 3CP Contribution
(1) DOMESTIC	4,273,209	9.2%	4,666,182	1,037,311	100.0%	1,037,311	14.6%	1,189,128	44.79%	3,372,733	56.8%
(2) SMALL GENERAL	231,277	8.7%	251,486	56,182	64.9%	36,474	9.9%	40,080	71.63%	121,245	2.0%
(3) GENERAL	2,435,295	6.1%	2,583,975	487,597	82.5%	402,244	6.9%	429,973	68.60%	1,362,599	23.0%
(4) GENERAL LARGE	396,295	6.1%	420,339	72,580	70.4%	51,111	6.2%	54,263	88.43%	167,207	2.8%
(5) SMALL INDUSTRIAL	258,161	5.7%	272,739	47,509	78.8%	37,451	5.8%	39,635	78.55%	117,844	2.0%
(6) MEDIUM INDUSTRIAL	498,772	5.3%	525,238	85,067	82.8%	70,459	5.5%	74,316	80.68%	227,607	3.8%
(7) LARGE INDUSTRIAL	921,426	4.4%	961,872	139,431	83.9%	116,980	4.2%	121,884	90.09%	371,097	6.3%
(8) ELI 2P-RTP	0	N/A	0	0	N/A	0	N/A	0	N/A	-	0.0%
(9) MUNICIPAL	192,648	4.5%	201,299	40,959	98.8%	40,473	4.5%	42,305	54.32%	122,733	2.1%
(10) UNMETERED	104,393	9.9%	114,717	23,601	99.9%	23,575	10.5%	26,051	50.27%	73,592	1.2%
(11) SUB-TOTAL	9,311,477	7.4%	9,997,846	1,990,237	91.3%	1,816,078	11.1%	2,017,635	56.57%	5,936,656	100.0%
(12) BOWATER MERSEY	367,920	2.0%	375,389	42,000	100.0%	42,000	2.0%	42,857	99.99%	128,570	
(13) GEN.REPL./LOAD FOLL.	18,815	2.0%	19,199	23,900	0.2%	37	2.0%	38	N/A	315	
(14) REAL TIME PRICING	0	N/A	0	0	N/A	0	N/A	0	N/A	0	
(15) LRT	322,080	2.0%	328,618	38,000	96.8%	36,767	2.0%	37,517	99.99%	112,552	
(16) TOTAL	10,020,291	7.0%	10,721,052	2,094,136	90.5%	1,894,882	10.7%	2,098,047	58.33%	6,178,093	

EXHIBIT 9A

NOVA SCOTIA POWER INC.

SALES, GENERATION AND DEMAND ANALYSIS

FOR JANUARY 2011

	(1) MWH SALES	(2) ENERGY LINE LOSSES	(3) ENERGY REQUIREMENT	(4) CLASS NON-COINCIDENT DMD. (KW)	(5) SYSTEM COINCIDENT FACTOR	(6) SYSTEM COINCIDENT DMD. (KW)	(7) DEMAND LINE LOSSES	(8) SYSTEM COIN. PEAK DMD. (KW)	(9) SYSTEM COINCIDENT L/D FACTOR
(1) DOMESTIC	517,950	10.41%	571,868	1,016,646	97.1%	986,801	13.43%	1,119,298	68.67%
(2) SMALL GENERAL	25,350	9.54%	27,769	54,862	69.9%	38,371	9.68%	42,084	88.69%
(3) GENERAL	233,732	6.09%	247,974	487,597	93.2%	454,506	7.41%	488,175	68.27%
(4) GENERAL LARGE	33,329	6.37%	35,452	58,854	87.9%	51,738	6.57%	55,135	86.43%
(5) SMALL INDUSTRIAL	22,560	5.38%	23,775	44,509	88.7%	39,466	5.68%	41,708	76.62%
(6) MEDIUM INDUSTRIAL	42,925	4.88%	45,017	81,867	88.2%	72,186	5.20%	75,936	79.68%
(7) LARGE INDUSTRIAL	75,073	3.82%	77,942	122,180	88.4%	107,957	3.89%	112,161	93.40%
(8) ELI 2P-RTP	0	N/A	0	0	N/A	0	N/A	0	N/A
(9) MUNICIPAL	20,071	4.34%	20,941	39,325	99.2%	38,991	5.86%	41,277	68.19%
(10) UNMETERED	10,891	10.42%	12,026	23,596	78.3%	18,466	13.98%	21,047	76.80%
(11) SUB-TOTAL	981,882		1,062,764	1,929,436	93.7%	1,808,482	10.41%	1,996,822	71.54%
(12) BOWATER MERSEY	31,248	1.83%	31,821	42,000	100.0%	42,000	2.04%	42,857	99.80%
(13) GEN.REPL./LOAD FOLL.	990	2.04%	1,010	18,501	-0.6%	-117	2.04%	-119	-1137.38%
(14) REAL TIME PRICING	0	N/A	0	0	N/A	0	N/A	0	N/A
(15) EXPORT SALES	0	N/A	0	0	N/A	0	N/A	0	N/A
(16) LRT	27,355	2.03%	27,910	38,000	96.8%	36,767	2.04%	37,517	99.99%
(17) TOTAL	1,041,475	7.88%	1,123,506	2,027,937	93.1%	1,887,132	10.07%	2,077,076	72.70%

EXHIBIT 9A

NOVA SCOTIA POWER INC.

SALES, GENERATION AND DEMAND ANALYSIS

FOR FEBRUARY 2011

	(1) MWH SALES	(2) ENERGY LINE LOSSES	(3) ENERGY REQUIREMENT	(4) CLASS NON-COINCIDENT DMD. (KW)	(5) SYSTEM COINCIDENT FACTOR	(6) SYSTEM COINCIDENT DMD. (KW)	(7) DEMAND LINE LOSSES	(8) SYSTEM COIN. PEAK DMD. (KW)	(9) SYSTEM COINCIDENT L/D FACTOR
(1) DOMESTIC	449,378	10.69%	497,403	1,037,311	100.0%	1,037,311	14.64%	1,189,128	62.25%
(2) SMALL GENERAL	23,282	9.89%	25,583	56,182	64.9%	36,474	9.89%	40,080	94.99%
(3) GENERAL	219,217	6.26%	232,932	475,530	84.6%	402,244	6.89%	429,973	80.62%
(4) GENERAL LARGE	30,888	6.09%	32,769	60,416	84.6%	51,111	6.17%	54,263	89.86%
(5) SMALL INDUSTRIAL	21,628	5.73%	22,867	43,040	87.0%	37,451	5.83%	39,635	85.85%
(6) MEDIUM INDUSTRIAL	38,731	5.23%	40,759	75,341	93.5%	70,459	5.47%	74,316	81.61%
(7) LARGE INDUSTRIAL	70,670	4.10%	73,566	125,598	93.1%	116,980	4.19%	121,884	89.82%
(8) ELI 2P-RTP	0	N/A	0	0	N/A	0	N/A	0	N/A
(9) MUNICIPAL	19,070	4.27%	19,885	40,959	98.8%	40,473	4.53%	42,305	69.95%
(10) UNMETERED	9,230	10.20%	10,172	23,584	100.0%	23,575	10.50%	26,051	58.10%
(11) SUB-TOTAL	882,095		955,936	1,937,961	93.7%	1,816,078	11.10%	2,017,635	70.50%
(12) BOWATER MERSEY	28,224	2.03%	28,797	42,000	100.0%	42,000	2.04%	42,857	99.99%
(13) GEN.REPL./LOAD FOLL.	1,221	2.04%	1,246	19,501	0.2%	37	2.04%	38	4912.19%
(14) REAL TIME PRICING	0	N/A	0	0	N/A	0	N/A	0	N/A
(15) EXPORT SALES	0	N/A	0	0	N/A	0	N/A	0	N/A
(16) LRT	24,708	2.03%	25,209	38,000	96.8%	36,767	2.04%	37,517	99.99%
(17) TOTAL	936,247	8.00%	1,011,188	2,037,462	93.0%	1,894,882	10.72%	2,098,047	71.72%

EXHIBIT 9A

NOVA SCOTIA POWER INC.

SALES, GENERATION AND DEMAND ANALYSIS

FOR MARCH 2011

	(1) MWH SALES	(2) ENERGY LINE LOSSES	(3) ENERGY REQUIREMENT	(4) CLASS NON-COINCIDENT DMD. (KW)	(5) SYSTEM COINCIDENT FACTOR	(6) SYSTEM COINCIDENT DMD. (KW)	(7) DEMAND LINE LOSSES	(8) SYSTEM COIN. PEAK DMD. (KW)	(9) SYSTEM COINCIDENT L/D FACTOR
(1) DOMESTIC	449,949	10.01%	494,980	890,747	93.2%	830,331	12.30%	932,461	71.35%
(2) SMALL GENERAL	22,297	9.83%	24,489	50,921	76.5%	38,948	10.23%	42,934	76.66%
(3) GENERAL	225,450	6.65%	240,449	427,619	97.8%	418,364	7.71%	450,616	71.72%
(4) GENERAL LARGE	33,709	6.52%	35,908	59,513	92.0%	54,731	6.79%	58,449	82.57%
(5) SMALL INDUSTRIAL	21,692	6.26%	23,051	38,282	97.5%	37,323	6.53%	39,760	77.92%
(6) MEDIUM INDUSTRIAL	41,333	5.65%	43,667	70,928	89.1%	63,227	5.79%	66,890	87.74%
(7) LARGE INDUSTRIAL	75,867	4.45%	79,244	114,735	93.0%	106,653	4.49%	111,443	95.57%
(8) ELI 2P-RTP	0	N/A	0	0	N/A	0	N/A	0	N/A
(9) MUNICIPAL	19,062	4.90%	19,995	33,573	98.5%	33,084	5.06%	34,758	77.32%
(10) UNMETERED	9,130	9.69%	10,015	23,597	11.3%	2,665	7.89%	2,876	468.10%
(11) SUB-TOTAL	898,488		971,796	1,709,914	92.7%	1,585,325	9.77%	1,740,187	75.06%
(12) BOWATER MERSEY	31,248	2.03%	31,882	42,000	100.0%	42,000	2.04%	42,857	99.99%
(13) GEN.REPL./LOAD FOLL.	38	2.04%	39	1,842	-0.7%	-12	2.04%	-12	-428.70%
(14) REAL TIME PRICING	0	N/A	0	0	N/A	0	N/A	0	N/A
(15) EXPORT SALES	0	N/A	0	0	N/A	0	N/A	0	N/A
(16) LRT	27,276	2.01%	27,824	38,000	96.8%	36,767	2.04%	37,517	99.68%
(17) TOTAL	957,051	7.78%	1,031,542	1,791,756	92.9%	1,664,081	9.40%	1,820,549	76.16%

EXHIBIT 9A

NOVA SCOTIA POWER INC.

SALES, GENERATION AND DEMAND ANALYSIS

FOR APRIL 2011

	(1) MWH SALES	(2) ENERGY LINE LOSSES	(3) ENERGY REQUIREMENT	(4) CLASS NON-COINCIDENT DMD. (KW)	(5) SYSTEM COINCIDENT FACTOR	(6) SYSTEM COINCIDENT DMD. (KW)	(7) DEMAND LINE LOSSES	(8) SYSTEM COIN. PEAK DMD. (KW)	(9) SYSTEM COINCIDENT L/D FACTOR
(1) DOMESTIC	359,741	8.83%	391,490	790,074	95.8%	757,175	11.42%	843,671	64.45%
(2) SMALL GENERAL	18,910	8.95%	20,603	44,776	49.4%	22,123	8.51%	24,006	119.20%
(3) GENERAL	195,069	5.88%	206,534	383,834	87.5%	335,666	6.34%	356,958	80.36%
(4) GENERAL LARGE	30,768	5.98%	32,608	56,487	85.0%	48,002	6.05%	50,904	88.97%
(5) SMALL INDUSTRIAL	20,695	5.72%	21,878	39,448	81.8%	32,262	5.73%	34,112	89.08%
(6) MEDIUM INDUSTRIAL	41,190	5.34%	43,391	74,262	84.6%	62,834	5.37%	66,207	91.03%
(7) LARGE INDUSTRIAL	74,845	4.32%	78,077	122,441	89.0%	109,022	4.31%	113,723	95.36%
(8) ELI 2P-RTP	0	N/A	0	0	N/A	0	N/A	0	N/A
(9) MUNICIPAL	15,531	4.65%	16,254	29,188	93.0%	27,144	4.71%	28,423	79.43%
(10) UNMETERED	8,187	9.32%	8,950	23,598	12.3%	2,896	6.97%	3,098	401.30%
(11) SUB-TOTAL	764,937		819,785	1,564,110	89.3%	1,397,122	8.87%	1,521,101	74.85%
(12) BOWATER MERSEY	30,240	2.03%	30,854	42,000	100.0%	42,000	2.04%	42,857	99.99%
(13) GEN.REPL./LOAD FOLL.	1,462	2.04%	1,492	22,397	0.7%	157	2.04%	160	1293.35%
(14) REAL TIME PRICING	0	N/A	0	0	N/A	0	N/A	0	N/A
(15) EXPORT SALES	0	N/A	0	0	N/A	0	N/A	0	N/A
(16) LRT	26,472	2.03%	27,010	38,000	96.8%	36,767	2.04%	37,517	99.99%
(17) TOTAL	823,111	6.81%	879,140	1,666,507	88.6%	1,476,047	8.51%	1,601,635	76.24%

EXHIBIT 9A

NOVA SCOTIA POWER INC.

SALES, GENERATION AND DEMAND ANALYSIS

FOR MAY 2011

	(1) MWH SALES	(2) ENERGY LINE LOSSES	(3) ENERGY REQUIREMENT	(4) CLASS NON-COINCIDENT DMD. (KW)	(5) SYSTEM COINCIDENT FACTOR	(6) SYSTEM COINCIDENT DMD. (KW)	(7) DEMAND LINE LOSSES	(8) SYSTEM COIN. PEAK DMD. (KW)	(9) SYSTEM COINCIDENT L/D FACTOR
(1) DOMESTIC	323,119	8.84%	351,675	675,840	89.3%	603,391	10.47%	666,587	70.91%
(2) SMALL GENERAL	17,328	9.05%	18,895	40,048	79.2%	31,697	9.39%	34,672	73.25%
(3) GENERAL	183,886	6.28%	195,425	361,341	94.6%	341,631	7.05%	365,731	71.82%
(4) GENERAL LARGE	31,839	6.39%	33,872	60,556	92.8%	56,207	6.73%	59,989	75.89%
(5) SMALL INDUSTRIAL	20,858	6.09%	22,129	41,601	99.1%	41,233	6.45%	43,894	67.76%
(6) MEDIUM INDUSTRIAL	40,700	5.98%	43,134	75,707	89.8%	67,981	6.20%	72,194	80.30%
(7) LARGE INDUSTRIAL	75,137	4.98%	78,877	113,902	92.1%	104,953	4.97%	110,172	96.23%
(8) ELI 2P-RTP	0	N/A	0	0	N/A	0	N/A	0	N/A
(9) MUNICIPAL	13,912	4.77%	14,576	24,728	99.0%	24,480	4.84%	25,666	76.33%
(10) UNMETERED	7,465	10.61%	8,258	23,597	13.7%	3,223	5.63%	3,405	325.99%
(11) SUB-TOTAL	714,244		766,841	1,417,319	89.9%	1,274,797	8.43%	1,382,309	74.56%
(12) BOWATER MERSEY	31,248	2.03%	31,882	42,000	100.0%	42,000	2.04%	42,857	99.99%
(13) GEN.REPL./LOAD FOLL.	442	2.04%	451	3,189	22.5%	718	2.04%	733	82.68%
(14) REAL TIME PRICING	0	N/A	0	0	N/A	0	N/A	0	N/A
(15) EXPORT SALES	0	N/A	0	0	N/A	0	N/A	0	N/A
(16) LRT	27,355	2.03%	27,910	38,000	96.8%	36,767	2.04%	37,517	99.99%
(17) TOTAL	773,289	6.96%	827,084	1,500,509	90.3%	1,354,282	8.06%	1,463,415	75.96%

EXHIBIT 9A

NOVA SCOTIA POWER INC.

SALES, GENERATION AND DEMAND ANALYSIS

FOR JUNE 2011

	(1) MWH SALES	(2) ENERGY LINE LOSSES	(3) ENERGY REQUIREMENT	(4) CLASS NON-COINCIDENT DMD. (KW)	(5) SYSTEM COINCIDENT FACTOR	(6) SYSTEM COINCIDENT DMD. (KW)	(7) DEMAND LINE LOSSES	(8) SYSTEM COIN. PEAK DMD. (KW)	(9) SYSTEM COINCIDENT L/D FACTOR
(1) DOMESTIC	264,738	7.10%	283,532	662,472	94.6%	626,625	10.74%	693,915	56.75%
(2) SMALL GENERAL	16,501	7.12%	17,675	40,159	61.7%	24,764	8.98%	26,987	90.96%
(3) GENERAL	185,946	5.57%	196,296	388,321	76.8%	298,117	6.61%	317,830	85.78%
(4) GENERAL LARGE	31,669	5.19%	33,313	62,199	75.2%	46,800	6.41%	49,800	92.91%
(5) SMALL INDUSTRIAL	21,775	5.04%	22,873	44,512	72.8%	32,403	6.15%	34,394	92.36%
(6) MEDIUM INDUSTRIAL	42,608	4.96%	44,721	78,672	83.3%	65,531	6.14%	69,555	89.30%
(7) LARGE INDUSTRIAL	71,592	4.12%	74,542	115,611	92.8%	107,238	5.05%	112,658	91.90%
(8) ELI 2P-RTP	0	N/A	0	0	N/A	0	N/A	0	N/A
(9) MUNICIPAL	12,806	4.11%	13,332	24,169	100.0%	24,169	5.39%	25,473	72.69%
(10) UNMETERED	6,646	10.42%	7,339	23,597	11.6%	2,745	4.64%	2,873	354.82%
(11) SUB-TOTAL	654,281		693,624	1,439,713	85.3%	1,228,393	8.56%	1,333,486	72.24%
(12) BOWATER MERSEY	30,240	2.03%	30,854	42,000	100.0%	42,000	2.04%	42,857	99.99%
(13) GEN.REPL./LOAD FOLL.	577	2.04%	589	23,190	-0.1%	-29	2.04%	-30	-2762.43%
(14) REAL TIME PRICING	0	N/A	0	0	N/A	0	N/A	0	N/A
(15) EXPORT SALES	0	N/A	0	0	N/A	0	N/A	0	N/A
(16) LRT	26,472	2.03%	27,010	38,000	96.8%	36,767	2.04%	37,517	99.99%
(17) TOTAL	711,570	5.69%	752,076	1,542,903	84.7%	1,307,131	8.16%	1,413,830	73.88%

EXHIBIT 9A

NOVA SCOTIA POWER INC.

SALES, GENERATION AND DEMAND ANALYSIS

FOR JULY 2011

	(1) MWH SALES	(2) ENERGY LINE LOSSES	(3) ENERGY REQUIREMENT	(4) CLASS NON-COINCIDENT DMD. (KW)	(5) SYSTEM COINCIDENT FACTOR	(6) SYSTEM COINCIDENT DMD. (KW)	(7) DEMAND LINE LOSSES	(8) SYSTEM COIN. PEAK DMD. (KW)	(9) SYSTEM COINCIDENT L/D FACTOR
(1) DOMESTIC	266,176	7.08%	285,021	583,480	76.7%	447,542	7.77%	482,325	79.43%
(2) SMALL GENERAL	17,006	7.46%	18,275	39,118	92.7%	36,273	8.11%	39,216	62.64%
(3) GENERAL	201,108	5.76%	212,694	399,320	98.8%	394,328	6.80%	421,137	67.88%
(4) GENERAL LARGE	36,217	5.75%	38,300	66,425	97.9%	65,040	6.19%	69,063	74.54%
(5) SMALL INDUSTRIAL	22,135	4.94%	23,228	45,623	91.1%	41,551	5.22%	43,718	71.41%
(6) MEDIUM INDUSTRIAL	42,569	4.82%	44,623	80,401	92.6%	74,473	5.11%	78,281	76.62%
(7) LARGE INDUSTRIAL	80,192	4.14%	83,512	128,189	97.3%	124,749	4.28%	130,085	86.29%
(8) ELI 2P-RTP	0	N/A	0	0	N/A	0	N/A	0	N/A
(9) MUNICIPAL	14,128	4.05%	14,699	25,679	99.6%	25,579	4.10%	26,628	74.20%
(10) UNMETERED	6,926	10.40%	7,647	23,595	13.6%	3,204	4.67%	3,353	306.50%
(11) SUB-TOTAL	686,458		727,998	1,391,831	87.1%	1,212,739	6.68%	1,293,806	75.63%
(12) BOWATER MERSEY	31,248	2.03%	31,882	42,000	100.0%	42,000	2.04%	42,857	99.99%
(13) GEN.REPL./LOAD FOLL.	1,591	2.04%	1,624	23,449	10.4%	2,428	2.04%	2,478	88.09%
(14) REAL TIME PRICING	0	N/A	0	0	N/A	0	N/A	0	N/A
(15) EXPORT SALES	0	N/A	0	0	N/A	0	N/A	0	N/A
(16) LRT	27,355	2.03%	27,910	38,000	96.8%	36,767	2.04%	37,517	99.99%
(16) TOTAL	746,652	5.73%	789,415	1,495,280	86.5%	1,293,934	6.39%	1,376,657	77.07%

EXHIBIT 9A

NOVA SCOTIA POWER INC.

SALES, GENERATION AND DEMAND ANALYSIS

FOR AUGUST 2011

	(1) MWH SALES	(2) ENERGY LINE LOSSES	(3) ENERGY REQUIREMENT	(4) CLASS NON-COINCIDENT DMD. (KW)	(5) SYSTEM COINCIDENT FACTOR	(6) SYSTEM COINCIDENT DMD. (KW)	(7) DEMAND LINE LOSSES	(8) SYSTEM COIN. PEAK DMD. (KW)	(9) SYSTEM COINCIDENT L/D FACTOR
(1) DOMESTIC	260,709	8.05%	281,686	585,948	84.0%	491,893	9.33%	537,790	70.40%
(2) SMALL GENERAL	17,119	8.71%	18,610	41,577	82.0%	34,073	9.22%	37,217	67.21%
(3) GENERAL	195,548	6.34%	207,938	421,845	95.8%	404,119	7.54%	434,607	64.31%
(4) GENERAL LARGE	36,538	6.72%	38,992	71,278	95.0%	67,686	7.22%	72,574	72.21%
(5) SMALL INDUSTRIAL	22,093	5.68%	23,347	47,509	84.6%	40,170	5.91%	42,545	73.76%
(6) MEDIUM INDUSTRIAL	42,615	5.61%	45,007	78,710	89.6%	70,531	5.81%	74,628	81.06%
(7) LARGE INDUSTRIAL	85,980	4.99%	90,269	131,834	95.0%	125,299	5.04%	131,613	92.19%
(8) ELI 2P-RTP	0	N/A	0	0	N/A	0	N/A	0	N/A
(9) MUNICIPAL	13,928	4.78%	14,594	26,569	96.4%	25,603	4.83%	26,839	73.09%
(10) UNMETERED	7,522	10.56%	8,316	23,597	12.9%	3,051	5.14%	3,208	348.39%
(11) SUB-TOTAL	682,053		728,758	1,428,867	88.4%	1,262,425	7.81%	1,361,021	71.97%
(12) BOWATER MERSEY	31,248	2.03%	31,882	42,000	100.0%	42,000	2.04%	42,857	99.99%
(13) GEN.REPL./LOAD FOLL.	2,834	2.04%	2,892	23,447	75.9%	17,804	2.04%	18,167	21.39%
(14) REAL TIME PRICING	0	N/A	0	0	N/A	0	N/A	0	N/A
(15) EXPORT SALES	0	N/A	0	0	N/A	0	N/A	0	N/A
(16) LRT	27,355	2.03%	27,910	38,000	96.8%	36,767	2.04%	37,517	99.99%
(17) TOTAL	743,490	6.45%	791,443	1,532,314	88.7%	1,358,996	7.40%	1,459,562	72.88%

EXHIBIT 9A

NOVA SCOTIA POWER INC.

SALES, GENERATION AND DEMAND ANALYSIS

FOR SEPTEMBER 2011

	(1) MWH SALES	(2) ENERGY LINE LOSSES	(3) ENERGY REQUIREMENT	(4) CLASS NON-COINCIDENT DMD. (KW)	(5) SYSTEM COINCIDENT FACTOR	(6) SYSTEM COINCIDENT DMD. (KW)	(7) DEMAND LINE LOSSES	(8) SYSTEM COIN. PEAK DMD. (KW)	(9) SYSTEM COINCIDENT L/D FACTOR
(1) DOMESTIC	261,087	6.73%	278,647	555,501	89.9%	499,491	7.79%	538,422	71.88%
(2) SMALL GENERAL	15,500	7.25%	16,622	38,189	84.4%	32,243	7.63%	34,704	66.53%
(3) GENERAL	181,397	5.22%	190,863	434,915	95.0%	413,358	6.56%	440,457	60.18%
(4) GENERAL LARGE	34,106	4.84%	35,758	72,580	94.7%	68,709	5.32%	72,367	68.63%
(5) SMALL INDUSTRIAL	20,651	4.72%	21,627	45,442	84.0%	38,146	4.86%	39,999	75.09%
(6) MEDIUM INDUSTRIAL	41,507	4.66%	43,443	81,487	86.9%	70,768	4.78%	74,152	81.37%
(7) LARGE INDUSTRIAL	80,788	4.08%	84,084	139,431	90.6%	126,263	4.12%	131,463	88.83%
(8) ELI 2P-RTP	0	N/A	0	0	N/A	0	N/A	0	N/A
(9) MUNICIPAL	13,606	3.84%	14,128	27,387	96.7%	26,483	3.85%	27,503	71.35%
(10) UNMETERED	8,135	8.84%	8,855	23,598	12.2%	2,882	5.72%	3,047	403.61%
(11) SUB-TOTAL	656,778		694,026	1,418,529	90.1%	1,278,345	6.55%	1,362,114	70.77%
(12) BOWATER MERSEY	30,240	2.03%	30,854	42,000	100.0%	42,000	2.04%	42,857	99.99%
(13) GEN.REPL./LOAD FOLL.	6,682	2.04%	6,819	23,900	96.4%	23,047	2.04%	23,518	40.27%
(14) REAL TIME PRICING	0	N/A	0	0	N/A	0	N/A	0	N/A
(15) EXPORT SALES	0	N/A	0	0	N/A	0	N/A	0	N/A
(16) LRT	26,472	2.03%	27,010	38,000	96.8%	36,767	2.04%	37,517	99.99%
(17) TOTAL	720,172	5.35%	758,708	1,522,429	90.7%	1,380,159	6.22%	1,466,005	71.88%

EXHIBIT 9A

NOVA SCOTIA POWER INC.

SALES, GENERATION AND DEMAND ANALYSIS

FOR OCTOBER 2011

	(1) MWH SALES	(2) ENERGY LINE LOSSES	(3) ENERGY REQUIREMENT	(4) CLASS NON-COINCIDENT DMD. (KW)	(5) SYSTEM COINCIDENT FACTOR	(6) SYSTEM COINCIDENT DMD. (KW)	(7) DEMAND LINE LOSSES	(8) SYSTEM COIN. PEAK DMD. (KW)	(9) SYSTEM COINCIDENT L/D FACTOR
(1) DOMESTIC	300,666	8.19%	325,278	669,062	90.9%	607,815	10.11%	669,265	65.33%
(2) SMALL GENERAL	17,287	7.42%	18,569	39,126	72.4%	28,337	7.56%	30,480	81.89%
(3) GENERAL	189,718	5.92%	200,952	409,561	87.0%	356,428	6.78%	380,605	70.97%
(4) GENERAL LARGE	33,150	5.99%	35,135	69,061	79.3%	54,753	6.25%	58,177	81.17%
(5) SMALL INDUSTRIAL	19,020	5.58%	20,081	42,356	96.7%	40,943	6.02%	43,408	62.18%
(6) MEDIUM INDUSTRIAL	41,853	5.39%	44,108	76,719	92.9%	71,300	5.66%	75,333	78.70%
(7) LARGE INDUSTRIAL	79,011	4.57%	82,622	120,084	94.4%	113,367	4.59%	118,569	93.66%
(8) ELI 2P-RTP	0	N/A	0	0	N/A	0	N/A	0	N/A
(9) MUNICIPAL	14,663	4.47%	15,319	26,728	98.1%	26,220	4.55%	27,413	75.11%
(10) UNMETERED	8,764	8.35%	9,495	23,600	10.3%	2,439	6.50%	2,598	491.33%
(11) SUB-TOTAL	704,131		751,560	1,476,298	88.2%	1,301,601	8.01%	1,405,846	71.85%
(12) BOWATER MERSEY	31,248	2.03%	31,882	42,000	100.0%	42,000	2.04%	42,857	99.99%
(13) GEN.REPL./LOAD FOLL.	1,467	2.04%	1,497	7,533	19.7%	1,483	2.04%	1,513	132.94%
(14) REAL TIME PRICING	0	N/A	0	0	N/A	0	N/A	0	N/A
(15) EXPORT SALES	0	N/A	0	0	N/A	0	N/A	0	N/A
(16) LRT	27,355	2.03%	27,910	38,000	96.8%	36,767	2.04%	37,517	99.99%
(17) TOTAL	764,201	6.37%	812,849	1,563,831	88.4%	1,381,851	7.66%	1,487,733	73.44%

EXHIBIT 9A

NOVA SCOTIA POWER INC.

SALES, GENERATION AND DEMAND ANALYSIS

FOR NOVEMBER 2011

	(1) MWH SALES	(2) ENERGY LINE LOSSES	(3) ENERGY REQUIREMENT	(4) CLASS NON-COINCIDENT DMD. (KW)	(5) SYSTEM COINCIDENT FACTOR	(6) SYSTEM COINCIDENT DMD. (KW)	(7) DEMAND LINE LOSSES	(8) SYSTEM COIN. PEAK DMD. (KW)	(9) SYSTEM COINCIDENT L/D FACTOR
(1) DOMESTIC	351,855	8.85%	382,982	778,802	100.0%	778,802	11.75%	870,342	61.12%
(2) SMALL GENERAL	18,096	8.29%	19,596	45,606	66.1%	30,135	8.47%	32,686	83.27%
(3) GENERAL	198,211	5.64%	209,382	399,664	89.6%	357,911	6.30%	380,451	76.44%
(4) GENERAL LARGE	31,996	5.80%	33,853	59,435	89.6%	53,242	6.00%	56,437	83.31%
(5) SMALL INDUSTRIAL	20,861	5.60%	22,028	42,945	78.4%	33,688	5.66%	35,595	85.95%
(6) MEDIUM INDUSTRIAL	40,988	4.96%	43,021	76,517	91.4%	69,961	5.17%	73,580	81.21%
(7) LARGE INDUSTRIAL	78,957	3.98%	82,102	124,960	75.1%	93,851	3.69%	97,316	117.17%
(8) ELI 2P-RTP	0	N/A	0	0	N/A	0	N/A	0	N/A
(9) MUNICIPAL	16,406	4.00%	17,063	31,220	100.0%	31,220	5.44%	32,917	71.99%
(10) UNMETERED	10,238	9.04%	11,163	23,600	74.2%	17,516	8.19%	18,951	81.81%
(11) SUB-TOTAL	767,607		821,190	1,582,748	92.6%	1,466,325	9.00%	1,598,276	71.36%
(12) BOWATER MERSEY	30,240	2.03%	30,854	42,000	100.0%	42,000	2.04%	42,857	99.99%
(13) GEN.REPL./LOAD FOLL.	1,310	2.04%	1,337	21,278	92.6%	19,707	2.04%	20,109	9.23%
(14) REAL TIME PRICING	0	N/A	0	0	N/A	0	N/A	0	N/A
(15) EXPORT SALES	0	N/A	0	0	N/A	0	N/A	0	N/A
(16) LRT	26,551	2.05%	27,095	38,000	96.8%	36,767	2.04%	37,517	100.31%
(17) TOTAL	825,708	6.63%	880,476	1,684,026	92.9%	1,564,799	8.56%	1,698,759	71.99%

EXHIBIT 9A

NOVA SCOTIA POWER INC.

SALES, GENERATION AND DEMAND ANALYSIS

FOR DECEMBER 2011

	(1) MWH SALES	(2) ENERGY LINE LOSSES	(3) ENERGY REQUIREMENT	(4) CLASS NON-COINCIDENT DMD. (KW)	(5) SYSTEM COINCIDENT FACTOR	(6) SYSTEM COINCIDENT DMD. (KW)	(7) DEMAND LINE LOSSES	(8) SYSTEM COIN. PEAK DMD. (KW)	(9) SYSTEM COINCIDENT L/D FACTOR
(1) DOMESTIC	467,841	11.50%	521,620	969,221	95.9%	929,692	14.48%	1,064,308	65.87%
(2) SMALL GENERAL	22,601	9.72%	24,799	56,092	63.4%	35,553	9.93%	39,082	85.29%
(3) GENERAL	226,013	7.31%	242,536	451,215	90.9%	410,309	8.32%	444,450	73.35%
(4) GENERAL LARGE	32,087	7.15%	34,380	61,356	87.6%	53,773	7.50%	57,808	79.94%
(5) SMALL INDUSTRIAL	24,192	6.87%	25,855	46,813	72.9%	34,140	6.91%	36,500	95.21%
(6) MEDIUM INDUSTRIAL	41,753	6.21%	44,348	85,067	85.3%	72,584	6.57%	77,354	77.06%
(7) LARGE INDUSTRIAL	73,313	5.08%	77,036	130,647	99.5%	129,945	5.47%	137,052	75.55%
(8) ELI 2P-RTP	0	N/A	0	0	N/A	0	N/A	0	N/A
(9) MUNICIPAL	19,464	5.39%	20,512	37,053	100.0%	37,053	5.66%	39,151	70.42%
(10) UNMETERED	11,257	10.87%	12,481	23,601	100.0%	23,601	12.26%	26,494	63.32%
(11) SUB-TOTAL	918,522		1,003,567	1,861,064	92.8%	1,726,650	11.33%	1,922,199	70.17%
(12) BOWATER MERSEY	31,248	2.03%	31,882	42,000	100.0%	42,000	2.04%	42,857	99.99%
(13) GEN.REPL./LOAD FOLL.	200	2.04%	204	1,495	26.0%	389	2.04%	397	69.22%
(14) REAL TIME PRICING	0	N/A	0	0	N/A	0	N/A	0	N/A
(15) EXPORT SALES	0	N/A	0	0	N/A	0	N/A	0	N/A
(16) LRT	27,355	2.03%	27,910	38,000	96.8%	36,767	2.04%	37,517	99.99%
(17) TOTAL	977,325	8.82%	1,063,564	1,942,559	93.0%	1,805,807	10.92%	2,002,970	71.37%

EXHIBIT 9B

NOVA SCOTIA POWER INC.

DETERMINATION OF CLASS NON-COINCIDENT KW DEMAND BY VOLTAGE LEVEL

FOR THE YEAR ENDING DECEMBER 31, 2013

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED
(1) NON-COIN. KW SEC.	1,621,645	1,037,311	56,182	461,608	0	42,943	0	0	0	0	23,601
(2) LOSSES 6.00%	97,299	62,239	3,371	27,696	0	2,577	0	0	0	0	1,416
(3) SUB-TOTAL	1,718,943	1,099,550	59,553	489,304	0	45,520	0	0	0	0	25,017
(4) NON-COIN. KW PRI.	1,904,823	1,099,550	59,553	515,294	72,580	50,085	82,744	0	0	0	25,017
(5) LOSSES 5.40%	102,860	59,376	3,216	27,826	3,919	2,705	4,468	0	0	0	1,351
(6) SUB-TOTAL	2,007,683	1,158,926	62,768	543,120	76,500	52,790	87,212	0	0	0	26,368
(7) NON-COIN. KW TRANS.	2,190,396	1,158,926	62,768	543,120	76,500	52,790	89,535	139,431	0	40,959	26,368
(8) LOSSES 3.70%	81,045	42,880	2,322	20,095	2,830	1,953	3,313	5,159	0	1,515	976
(9) TOTAL	2,271,441	1,201,806	65,091	563,215	79,330	54,743	92,848	144,590	0	42,474	27,343

EXHIBIT 9C

NOVA SCOTIA POWER INC.

DETAIL OF MONTHLY CLASS SYSTEM COINCIDENT KW DEMAND

FOR THE YEAR ENDING DECEMBER 31, 2013

MONTH	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUST.	(7) MEDIUM INDUST.	(8) LARGE INDUST.	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED	(12) MERSEY SYSTEM	(13) GRLF	(14) REAL TIME PRICING	(15) LRT
(1) JANUARY	**2,039,559**	**1,119,298**	**42,084**	**488,175**	**55,135**	**41,708**	**75,936**	**112,161**	**0**	**41,277**	**21,047**	**42,857**	**(119)**	**0**	**37,517**
(2) FEBRUARY	**2,060,530**	**1,189,128**	**40,080**	**429,973**	**54,263**	**39,635**	**74,316**	**121,884**	**0**	**42,305**	**26,051**	**42,857**	**38**	**0**	**37,517**
(3) MARCH	1,783,032	932,461	42,934	450,616	58,449	39,760	66,890	111,443	0	34,758	2,876	42,857	(12)	0	37,517
(4) APRIL	1,564,118	843,671	24,006	356,958	50,904	34,112	66,207	113,723	0	28,423	3,098	42,857	160	0	37,517
(5) MAY	1,425,898	666,587	34,672	365,731	59,989	43,894	72,194	110,172	0	25,666	3,405	42,857	733	0	37,517
(6) JUNE	1,376,313	693,915	26,987	317,830	49,800	34,394	69,555	112,658	0	25,473	2,873	42,857	(30)	0	37,517
(7) JULY	1,339,140	482,325	39,216	421,137	69,063	43,718	78,281	130,085	0	26,628	3,353	42,857	2,478	0	37,517
(8) AUGUST	1,422,045	537,790	37,217	434,607	72,574	42,545	74,628	131,613	0	26,839	3,208	42,857	18,167	0	37,517
(9) SEPTEMBER	1,428,488	538,422	34,704	440,457	72,367	39,999	74,152	131,463	0	27,503	3,047	42,857	23,518	0	37,517
(10) OCTOBER	1,450,216	669,265	30,480	380,605	58,177	43,408	75,333	118,569	0	27,413	2,598	42,857	1,513	0	37,517
(11) NOVEMBER	1,661,242	870,342	32,686	380,451	56,437	35,595	73,580	97,316	0	32,917	18,951	42,857	20,109	0	37,517
(12) DECEMBER	**1,965,453**	**1,064,308**	**39,082**	**444,450**	**57,808**	**36,500**	**77,354**	**137,052**	**0**	**39,151**	**26,494**	**42,857**	**397**	**0**	**37,517**
(13) TOT. SUMMED DMD.	19,516,033	9,607,511	424,146	4,910,991	714,966	475,268	878,427	1,428,139	0	378,352	117,000	514,282	66,951	0	450,206
(14) 3 C/P DEMANDS	**6,065,542**	**3,372,733**	**121,245**	**1,362,599**	**167,207**	**117,844**	**227,607**	**371,097**	**0**	**122,733**	**73,592**	**128,570**	**315**	**0**	**112,552**
(15)					**3 C/P INTERRUPTIBLE RIDER DEMANDS**			**275,570**							
(16)					**NET 3 C/P LARGE INDUST. DEMANDS**			**95,526**							

NOVA SCOTIA POWER INC.

REVENUE TO EXPENSE COMPARISON

FOR THE YEAR ENDING DECEMBER 31, 2013
(IN THOUSANDS OF DOLLARS)

	(1) TOTAL DMD.RELATED EXPENSES	(2) TOTAL ENG.RELATED EXPENSES	(3) UNIT COST ENG.RELATED (C / kW.h)	(4) TOTAL CUST.RELATED EXPENSES	(5) TOTAL OPER. EXPENSES	(6) TOTAL RATE REVENUE	(7) % REVENUE TO EXPENSES
(1) DOMESTIC	$187,658	$383,556	8.98	$91,996	$663,210	$656,557	99.00
(2) SMALL GENERAL	8,040	20,635	8.92	4,858	33,533	35,079	104.61
(3) GENERAL	79,642	211,621	8.69	6,184	297,447	307,787	103.48
(4) LARGE GENERAL	8,317	34,342	8.67	270	42,930	42,151	98.19
(5) SMALL INDUSTRIAL	7,175	22,326	8.65	1,450	30,951	31,739	102.55
(6) MEDIUM INDUSTRIAL	10,784	42,933	8.61	627	54,344	53,486	98.42
(7) LARGE INDUSTRIAL	6,843	78,549	8.52	771	86,163	82,327	95.55
(8) ELI 2P-RTP	0	0	0.00	0	0	0	0.00
(9) MUNICIPAL	4,248	16,510	8.57	182	20,941	20,394	97.39
(10) UNMETERED	13,850	9,416	9.02	1,368	24,633	24,633	100.00
(11) SUB-TOTAL	$326,558	$819,889	8.81	$107,706	1,254,153	1,254,153	100.00
(12) DIRECT EXP./ REV					39,773	44,458	N/A
(13) RETURN ON DIRECT EXP.					4,685	0	N/A
(14) TOTAL					$1,298,611	$1,298,611	100.00

NOVA SCOTIA POWER INC.

REVENUE TO EXPENSE COMPARISON

FOR THE YEAR ENDING DECEMBER 31, 2013
(IN THOUSANDS OF DOLLARS)

	(1) TOTAL DMD.RELATED EXPENSES	(2) TOTAL ENG.RELATED EXPENSES	(3) UNIT COST ENG.RELATED (C / kW.h)	(4) TOTAL CUST.RELATED EXPENSES	(5) TOTAL OPER. EXPENSES	(6) TOTAL RATE REVENUE	(7) % REVENUE TO EXPENSES
(1) DOMESTIC	$158,291	$351,282	8.22	$83,978	$593,551	$588,717	99.19
(2) SMALL GENERAL	6,793	18,895	8.17	4,436	30,125	31,454	104.41
(3) GENERAL	67,232	193,749	7.96	5,730	266,712	275,984	103.48
(4) LARGE GENERAL	7,065	31,435	7.93	270	38,770	37,796	97.49
(5) SMALL INDUSTRIAL	6,061	20,439	7.92	1,357	27,858	28,460	102.16
(6) MEDIUM INDUSTRIAL	9,146	39,301	7.88	618	49,064	47,960	97.75
(7) LARGE INDUSTRIAL	4,752	71,897	7.80	768	77,416	73,821	95.36
(8) ELI 2P-RTP	0	0	0.00	0	0	0	0.00
(9) MUNICIPAL	3,561	15,118	7.85	182	18,861	18,287	96.96
(10) UNMETERED	12,580	8,622	8.26	1,257	22,459	22,338	99.46
(11) SUB-TOTAL	$275,482	$750,739	8.06	$98,595	1,124,815	1,124,816	100.00
(12) DIRECT EXP./ REV					39,642	44,060	N/A
(13) RETURN ON DIRECT EXP.					4,418	0	N/A
(14) TOTAL					$1,168,876	$1,168,876	100.00

NOVA SCOTIA POWER INC.

DETAILED LISTING OF C.O.S.S. INPUT INFORMATION

FOR THE YEAR ENDING DECEMBER 31, 2014

(IN THOUSANDS OF DOLLARS)

		Line #
AVERAGE RATE BASE	98,458	
	3,299,714	
STEAM PLANT	1,030,984	11
STEAM PLANT - CWIP	14,185	12
STEAM ENVIRONMENTAL & FUEL CONVERSION PLA	325,329	13
Steam Enviromental & Fuel Conversion - CWIP	33	14
HYDRO PLANT	348,392	15
HYDRO PLANT - CWIP	18,245	16
HYDRO ENVIRONMENTAL & FUEL CONVERSION PLA	4,824	17
Hydro Enviromental & Fuel Conversion - CWIP	-	18
WIND PLANT	12,902	19
WIND PLANT - CWIP	17,697	20
WIND ENVIRONMENTAL & FUEL CONVERSION PLAN	170,483	21
Wind Enviromental & Fuel Conversion - CWIP	100	22
GAS TURBINE PLANT	5,939	23
GAS TURBINE PLANT - CWIP	574	24
GAS ENVIRONMENTAL & FUEL CONVERSION PLANT	-	25
Gas Enviromental & Fuel Conversion - CWIP	-	26
LM6000 PLANT	57,894	27
LM6000 PLANT - CWIP	13,523	28
LM600 ENVIRONMENTAL & FUEL CONVERSION PLAI	-	29
LM600 Enviromental & Fuel Conversion - CWIP	-	30
TRANSMISSION PLANT	449,439	31
TRANSMISSION PLANT - CWIP	16,715	32
Transmission ENVIRONMENTAL & FUEL CONVERSIOI	-	33
Transmission Enviromental & Fuel Conversion - CWI	-	34
DIST.PLT.- LAND	4,435	35
DIST.PLT.- EASEMENTS & SURVEY	16,882	36
DIST.PLT.- OTHER	2,190	37
DIST.PLT.- SUBSTATIONS	30,113	38
DIST.PLT.- POLES & FIXTURES	183,085	39
DIST.PLT.- O/H LINES	121,259	40
DIST.PLT.- U/G LINES	34,858	41
DIST.PLT.- LINE TRANSFORMERS	163,242	42
DIST.PLT.- SERVICES	60,998	43
DIST.PLT.- METERS	25,072	44
DIST.PLT.- STREET LIGHTING (Non LED)	10,251	45
DIST.PLT.- STREET LIGHTING (LED)	24,256	46

NOVA SCOTIA POWER INC.

DETAILED LISTING OF C.O.S.S. INPUT INFORMATION

FOR THE YEAR ENDING DECEMBER 31, 2014

(IN THOUSANDS OF DOLLARS)

		Line #
		47
GENERAL PROPERTY PLANT	216,887	48
GENERAL PROPERTY PLANT - CWIP	17,386	49
		50
WORKING CAPITAL & DEFERRED CHARGES		51
		52
WORKING CAPITAL - CASH FUEL	0	53
WORKING CAPITAL - CASH OTHER	27,900	54
WORKING CAPITAL - MAT. & SUP. FUEL	84,441	55
WORKING CAPITAL - MAT. & SUP. OTHER	28,661	56
DEFERRED CHARGES - Financing	65,674	57
DEFERRED CHARGES - Tax	9,838	58
DEFERRED CHARGES - Pension	82,097	59
DEFERRED CHARGES - Steam Assets	0	60
DEFERRED CHARGES - FAM Deferral	0	61
DEFERRED CHARGES - Other	1,976	62
DEFERRED CHARGES - Other (DSM)	529	63
DEFERRED CHARGES - Other (LED)	6,710	64
DEFERRED CHARGES - FCR	23,250	65
DEFERRED Credits - ARO Steam	(43,651)	66
DEFERRED Credits - ARO Hydro	(22,762)	67
DEFERRED Credits - ARO CT	(4,150)	68
DEFERRED Credits - ARO Transformers	(24,730)	69
DEFERRED Credits - ARO Wind	(10,861)	70
DEFERRED Credits - Other (Steam)	(6,577)	71
CONTRACT RECEIVABLE	0	72
		73
DEDICATED PLANT		74
DEDICATED STREETLIGHTS - LED	24,256	75
DEDICATED STEAM PLANT	0	76
DEDICATED HYDRO PLANT - Mersey	20,200	77
DEDICATED GAS TURBINE	0	78
DEDICATED TRANSMISSION PLANT	0	79
DEDICATED DIST.PLT.- LAND	0	80
DEDICATED DIST.PLT.- EASEMENTS & SURVEY	0	81
DEDICATED DIST.PLT.- OTHER	0	82
DEDICATED DIST.PLT.- SUBSTATIONS	0	83
DEDICATED DIST.PLT.- POLES & FIXTURES	0	84
DEDICATED DIST.PLT.- O/H LINES	0	85

NOVA SCOTIA POWER INC.

DETAILED LISTING OF C.O.S.S. INPUT INFORMATION

FOR THE YEAR ENDING DECEMBER 31, 2014

(IN THOUSANDS OF DOLLARS)

		Line #
DEDICATED DIST.PLT.- U/G LINES	0	86
DEDICATED DIST.PLT.- LINE TRANSFORMERS	0	87
DEDICATED DIST.PLT.- SERVICES	0	88
DEDICATED DIST.PLT.- METERS	0	89
DEDICATED DIST.PLT.- STREET LIGHTING	0	90
DEDICATED GENERAL PROPERTY PLANT	0	91
DEDICATED WORKING CAPITAL - CASH FUEL	0	92
DEDICATED WORKING CAPITAL - CASH OTHER - Me	233	93
DEDICATED WORKING CAPITAL - MAT. & SUP. FUEL	0	94
DEDICATED WORKING CAPITAL - MAT. & SUP. OTHE	0	95
SUBSTS.-DISTRIBUTION BULK POWER	25,725	96
SUBSTS.-DIST.DED.BULK POWER-DOMESTIC	0	97
SUBSTS.-DIST.DED.BULK POWER-SMALL GENERAL	0	98
SUBSTS.-DIST.DED.BULK POWER-GENERAL	0	99
SUBSTS.-DIST.DED.BULK POWER-GENERAL LARGE	0	100
SUBSTS.-DIST.DED.BULK POWER-SMALL INDUST.	0	101
SUBSTS.-DIST.DED.BULK POWER-MEDIUM INDUST.	91	102
SUBSTS.-DIST.DED.BULK POWER-LARGE INDUSTRI/	258	103
SUBSTS.-DIST.DED.BULK POWER-ELI 2P-RTP	0	104
SUBSTS.-DIST.DED.BULK POWER-MUNICIPAL	22	105
SUBSTS.-DIST.DED.BULK POWER-UNMETERED	0	106
SUBSTS.-DIST.C/O BULK POWER-DOMESTIC	0	107
SUBSTS.-DIST.C/O BULK POWER-SMALL GENERAL	0	108
SUBSTS.-DIST.C/O BULK POWER-GENERAL	25	109
SUBSTS.-DIST.C/O BULK POWER-GENERAL LARGE	0	110
SUBSTS.-DIST.C/O BULK POWER-SMALL INDUST.	0	111
SUBSTS.-DIST.C/O BULK POWER-MEDIUM INDUST.	3	112
SUBSTS.-DIST.C/O BULK POWER-LARGE INDUSTRIA	2	113
SUBSTS.-DIST.C/O BULK POWER-ELI 2P-RTP	0	114
SUBSTS.-DIST.C/O BULK POWER-MUNICIPAL	0	115
SUBSTS.-DIST.C/O BULK POWER-UNMETERED	0	116
SUBSTS.-DISTRIBUTION GENERAL	3,904	117
SUBSTS.-DIST.DED.GENERAL-DOMESTIC	0	118
SUBSTS.-DIST.DED.GENERAL-SMALL GENERAL	0	119
SUBSTS.-DIST.DED.GENERAL-GENERAL	0	120
SUBSTS.-DIST.DED.GENERAL-GENERAL LARGE	0	121
SUBSTS.-DIST.DED.GENERAL-SMALL INDUST.	0	122
SUBSTS.-DIST.DED.GENERAL-MEDIUM INDUST.	0	123
SUBSTS.-DIST.DED.GENERAL-LARGE INDUSTRIAL	0	124
SUBSTS.-DIST.DED.GENERAL-ELI 2P-RTP	0	125

NOVA SCOTIA POWER INC.

DETAILED LISTING OF C.O.S.S. INPUT INFORMATION

FOR THE YEAR ENDING DECEMBER 31, 2014

(IN THOUSANDS OF DOLLARS)

		Line #
SUBSTS.-DIST.DED.GENERAL-MUNICIPAL	0	126
SUBSTS.-DIST.DED.GENERAL-UNMETERED	0	127
SUBSTS.-DIST.C/O GENERAL-DOMESTIC	0	128
SUBSTS.-DIST.C/O GENERAL-SMALL GENERAL	0	129
SUBSTS.-DIST.C/O GENERAL-GENERAL	0	130
SUBSTS.-DIST.C/O GENERAL-GENERAL LARGE	0	131
SUBSTS.-DIST.C/O GENERAL-SMALL INDUST.	0	132
SUBSTS.-DIST.C/O GENERAL-MEDIUM INDUST.	4	133
SUBSTS.-DIST.C/O GENERAL-LARGE INDUSTRIAL	79	134
SUBSTS.-DIST.C/O GENERAL-ELI 2P-RTP	0	135
SUBSTS.-DIST.C/O GENERAL-MUNICIPAL	0	136
SUBSTS.-DIST.C/O GENERAL-UNMETERED	0	137
		138
Percentage of Transmission Plant > 69kV	76.6%	139
		140
OPERATING EXPENSES		141
		142
		143
OFFICE OF THE PRESIDENT		144
EXECUTIVE MANAGEMENT	1,159.9	145
CORPORATE SECRETARY	7,647.2	146
LEGAL SERVICES	1,185.3	147
		148
VP EXTERNAL RELATIONS		149
COMM. & PUBLIC AFFAIRS	2,101.9	150
		151
		152
CUSTOMER OPERATIONS:		153
		154
TRANSMISSION AND DISTRIBUTION		155
TRANSMISSION TOTAL	18,043.5	156
DISTRIBUTION TOTAL:		157
SUBSTATIONS	195.8	158
OVERHEAD LINES	24,793.0	159
UNDERGROUND LINES	443.7	160
LINE TRANSFORMERS	949.3	161
METERS	0.0	162
COMMUNICATIONS	5,681.6	163
STREET LIGHTING	3,727.3	164

NOVA SCOTIA POWER INC.

DETAILED LISTING OF C.O.S.S. INPUT INFORMATION

FOR THE YEAR ENDING DECEMBER 31, 2014
(IN THOUSANDS OF DOLLARS)

		Line #
CUSTOMER SERVICE TOTAL: (T & D)		165
-- BILLING & RECEIPTS:		166
(a) METER SERVICES -FIELD	0.0	167
-- CUSTOMER SERVICE:		168
(a) CUSTOMER SERVICE - CSFR	0.0	169
(b) ELECTRIC WIRING INSPECTION	0.0	170
		171
CUSTOMER SERVICE & MARKETING & SALES		172
-- ADMINISTRATION:		173
		174
(a) ADMINISTRATION	721.1	175
(b) ENERGY EFFICIENCY	480.8	176
(c) CUST. COMM. & QTY ASSURANCE	1,877.1	177
(d) CUSTOMER SOLUTIONS	0.0	178
		179
		180
		181
CALL CENTRE		182
		183
-- CALL CENTRE - CSR:		184
(a) CSR	7,081.6	185
(b) CUSTOMER COLLECTIONS	0.0	186
(c) ELECTRICAL WIRING INSPECTIONS	0.0	187
(b) CUSTOMER COLLECTIONS	377.2	188
(c) ELECTRICAL WIRING INSPECTIONS	4,498.4	189
		190
		191
		192
		193
REVENUE OPERATIONS		194
		195
-- BILLING & RECEIPTS:		196
(a) BILLING SERVICES	3,726.0	197
(b) PAYMENT SERVICES	712.8	198
(c) METER DATA SERVICES	474.0	199
(d) METER SERVICES - METER SHOP	606.6	200
(e) METER SERVICES - FIELD	6,187.5	201
(f) ELECTRICAL WIRING INSPECTIONS - FIELD	3,476.4	202
(g) ELECTRICAL INSPECTION	268.4	203

NOVA SCOTIA POWER INC.

DETAILED LISTING OF C.O.S.S. INPUT INFORMATION

FOR THE YEAR ENDING DECEMBER 31, 2014
(IN THOUSANDS OF DOLLARS)

		Line #
		204
-- CREDIT SERVICES:		205
BAD DEBT EXPENSE	5,703.5	206
		207
		208
		209
-- MARKETING & SALES:		210
(a) MARKETING & SALES	1,166.8	211
		212
		213
		214
		215
REGULATORY AFFAIRS	6,235.7	216
Technical & Construction Services		
General (all admin costs)	6,150.0	217
Generation	2,900.0	218
T&D	5,500.0	219
	14,550.0	220
Sustainability	1,526.6	221
		222
SENIOR VP & CFO		223
(a) INTERNAL AUDIT	1,731.6	224
(b) INVESTOR RELATIONS	291.7	225
(c) VP FINANCE & TREASURER	744.9	226
(d) TREASURER	793.4	227
(e) CORPORATE TAX	836.4	228
-- GM FINANCE		229
(a) CORPORATE CONTROLLER	2,464.5	230
(b) CORP. PERFORMANCE & BACK OFFICE	0.0	231
		232
VP ENTERPRISE SERVICES		233
-- PROCUREMENT & FACILITIES	10,128.6	234
-- INFORMATION TECHNOLOGY	12,125.6	235
		236
VP HUMAN RESOURCES		237
-- HUMAN RESOURCES	5,648.0	238
		239

NOVA SCOTIA POWER INC.

DETAILED LISTING OF C.O.S.S. INPUT INFORMATION

FOR THE YEAR ENDING DECEMBER 31, 2014

(IN THOUSANDS OF DOLLARS)

			Line #
POWER PRODUCTION			240
-- POWER PRODUCTION - FUEL		396,708.8	241
-- POWER PRODUCTION - OPERATING & MAINT.		61,184.8	242
-- POWER PRODUCTION - HYDRO PLTS.		9,786.9	243
-- POWER PRODUCTION - WIND		4,727.3	244
-- POWER PRODUCTION - LM6000		328.6	245
-- POWER PRODUCTION - BIOMASS		6,260.5	246
-- POWER PRODUCTION - OTHER GAS TURBINE		972.1	246
-- POWER PRODUCTION - GEN. DEVELOPMENT		0.0	247
-- POWER PRODUCTION - HEAD OFFICE		23,950.1	248
-- POWER PRODUCTION - GEN. SERV.		0.0	249
-- POWER PRODUCTION - H/R		0.0	250
-- POWER PRODUCTION - ENVIR. POLICY		0.0	251
-- POWER PRODUCTION - EXECUTIVE		0.0	252
-- POWER PRODUCTION - FUEL PROCUREMENT		3,908.9	253
-- PURCHASED POWER - REG FIXED (45%)		22,224.7	254
-- PURCHASED POWER - REG VARIABLE (55%)		27,163.5	255
-- PURCHASED POWER - WIND FIXED (30%)		20,272.9	256
-- PURCHASED POWER - WIND REG VARIABLE (70%		47,303.5	257
			258
OTHER EXPENSES		11,615.6	259
CURRENT YEAR INCENTIVE PLAN PAYOUT			260
DSM AMORTIZATION		1,058	261
FCR DEFERRAL		16,500	262
GRANTS IN LIEU OF TAXES		38,361	263
DEPRECIATION :			264
STEAM	65,371	62,000	265
ARO PROVISION		*3,371*	266
HYDRO	11,163	9,908	267
ARO PROVISION		*1,255*	268
WIND	8,186	8,157	269
ARO PROVISION		29	270
LM6000		2,084	271
GAS TURBINE - OTHER	1,202	953	272
ARO PROVISION		*249*	273
TRANSMISSION < 138kV	5,371	4,819	274
ARO PROVISION		*552*	275
TRANSMISSION > 69kV	17,580	15,773	276
ARO PROVISION		*1,807*	277

NOVA SCOTIA POWER INC.

DETAILED LISTING OF C.O.S.S. INPUT INFORMATION

FOR THE YEAR ENDING DECEMBER 31, 2014
(IN THOUSANDS OF DOLLARS)

		Line #
DISTRIBUTION - Non Streetlight Related	47,699	278
DISTRIBUTION -Streetlight Related	3,604	279
GENERAL PROPERTY	39,917	279
GLACE BAY RETIREMENT	**0**	280
INTEREST CHARGES	142,589	281
PREFERRED DIVIDENDS	8,000	282
CORPORATE TAXES	56,632	283
REGULATORY CONTINGENCY	**0**	284
FUEL RECOVERY	0	285
Normal Interruption Cost	***63.00***	286
Priority Interruption Cost	***72.45***	287
Interr. Rider Coincident Demand & CD Losses	***88,232***	288
ELI 2P-RTP Coincident Demand & CD Losses	***0***	289
Interr. Rider - Sum of Cust. Non-Coin. Dmds	***1,593,968***	290
ELI 2P-RTP - Sum of Cust. Non-Coin. Dmds	***3,886,432***	291
FIXED Interruptible Credit	***$3.43***	292
		293
OPERATING ALLOCATIONS		294
		295
ENERGY, FUELS & RISK MGMT. - THERMAL	100.00%	296
ENERGY, FUELS & RISK MGMT. - TRANSMISSION	0.00%	297
ENERGY, FUELS & RISK MGMT. - DISTRIBUTION	0.00%	298
ENERGY, FUELS & RISK MGMT. - RETAIL	0.00%	299
PERFORMANCE & REGULATION - THERMAL	36.00%	300
PERFORMANCE & REGULATION - TRANSMISSION	11.00%	301
PERFORMANCE & REGULATION - DISTRIBUTION	26.00%	302
PERFORMANCE & REGULATION - RETAIL	27.00%	303
CORPORATE FINANCE - THERMAL	36.00%	304
CORPORATE FINANCE - TRANSMISSION	11.00%	305
CORPORATE FINANCE - DISTRIBUTION	26.00%	306
CORPORATE FINANCE - RETAIL	27.00%	307
CORPORATE COMMUNICATIONS - THERMAL	36.00%	308
CORPORATE COMMUNICATIONS - TRANSMISSION	11.00%	309
CORPORATE COMMUNICATIONS - DISTRIBUTION	26.00%	310
CORPORATE COMMUNICATIONS - RETAIL	27.00%	311
HR SERVICES - PRODUCTION	36.00%	312
HR SERVICES - TRANSMISSION	11.00%	313
HR SERVICES - DISTRIBUTION	26.00%	314

NOVA SCOTIA POWER INC.

DETAILED LISTING OF C.O.S.S. INPUT INFORMATION

FOR THE YEAR ENDING DECEMBER 31, 2014
(IN THOUSANDS OF DOLLARS)

		Line #
HR SERVICES - RETAIL	27.00%	315
CORPORATE GROUPS - PRODUCTION	36.00%	316
CORPORATE GROUPS - TRANSMISSION	11.00%	317
CORPORATE GROUPS - DISTRIBUTION	26.00%	318
CORPORATE GROUPS - RETAIL	27.00%	319
IT SERVICES - THERMAL	36.00%	320
IT SERVICES - TRANSMISSION	11.00%	321
IT SERVICES - DISTRIBUTION	26.00%	322
IT SERVICES - CUSTOMER	0.00%	323
IT SERVICES - ADMIN. & GEN.	27.00%	324
T&C - TRANSMISSION	**29.73%**	**325**
T&C - DISTRIBUTION	**70.27%**	**326**
FCR Deferral - Generation	**81.10%**	**327**
FCR Deferral - Transmission	**18.90%**	**328**
MARKETING & SALES ALLOCATOR - DOMESTIC	45.33%	329
MARKETING & SALES ALLOCATOR - SMALL GENERA	3.59%	330
MARKETING & SALES ALLOCATOR - GENERAL	8.37%	331
MARKETING & SALES ALLOCATOR - LARGE GENERA	1.79%	332
MARKETING & SALES ALLOCATOR - SMALL INDUST.	6.58%	333
MARKETING & SALES ALLOCATOR - MEDIUM INDUS	12.92%	334
MARKETING & SALES ALLOCATOR - LARGE INDUST.	19.62%	335
MARKETING & SALES ALLOCATOR - ELI 2P-RTP	0.00%	336
MARKETING & SALES ALLOCATOR - MUNICIPAL	1.79%	337
MARKETING & SALES ALLOCATOR - UNMETERED	0.00%	338
METER DATA SERVICES ALLOCATOR - DOMESTIC	5.39%	339
METER DATA SERVICES ALLOCATOR - SMALL GENE	5.27%	340
METER DATA SERVICES ALLOCATOR - GENERAL	12.46%	341
METER DATA SERVICES ALLOCATOR - LARGE GENE	16.17%	342
METER DATA SERVICES ALLOCATOR - SMALL INDU	12.46%	343
METER DATA SERVICES ALLOCATOR - MEDIUM IND	12.46%	344
METER DATA SERVICES ALLOCATOR - LARGE INDU	23.35%	345
METER DATA SERVICES ALLOCATOR - ELI 2P-RTP	0.00%	346
METER DATA SERVICES ALLOCATOR - MUNICIPAL	12.46%	347
METER DATA SERVICES ALLOCATOR - UNMETERED	0.00%	348
		349
DIRECT EXPENSES		350
		351
		352
FUEL	30,997	353
FUEL RECOVERY	0	354

NOVA SCOTIA POWER INC.

DETAILED LISTING OF C.O.S.S. INPUT INFORMATION

FOR THE YEAR ENDING DECEMBER 31, 2014

(IN THOUSANDS OF DOLLARS)

		Line #
PURCHASED POWER REGULAR - VARIABLE		355
PURCHASED POWER REGULAR - FIXED		356
PURCHASED POWER WIND - FIXED		357
PURCHASED POWER WIND - VARIABLE		358
THERMAL OPERATING & MAINT.	471	359
HYDRO OPERATING & MAINT.	2,250	360
TRANSMISSION < 138kV	0	361
TRANSMISSION > 69kV	398	362
DISTRIBUTION - SUBSTATIONS	0	363
DISTRIBUTION - OVERHEAD LINES		364
DISTRIBUTION - UNDERGROUND LINES	0	365
DISTRIBUTION - LINE TRANSFORMERS	0	366
DISTRIBUTION - METERS	0	367
DISTRIBUTION - COMMUNICATIONS	0	368
DISTRIBUTION - STREET LIGHTING	0	369
ADMIN. & GENERAL - BILLING & METER READING	0	370
ADMIN. & GENERAL - CUSTOMER SERVICE	0	371
ADMIN. & GENERAL - MARKETING & SALES	0	372
ADMIN. & GENERAL - CREDIT & COLLECTION	0	373
ADMIN. & GENERAL - OTHER	659	374
ASSIGNED DSM EXPENSES	86	375
OTHER OPERATING - DEP. - STEAM	0	376
OTHER OPERATING - DEP. - HYDRO	1,056	377
OTHER OPERATING - DEP. - TRANSMISSION < 138kV	0	378
OTHER OPERATING - DEP. - TRANSMISSION > 69kV		379
OTHER OPERATING - INTEREST NET	2,074	380
OTHER OPERATING - PREFERRED DIVIDENDS		381
OTHER OPERATING - INCOME TAXES		382
OTHER OPERATING - GRANTS IN LIEU		383
		384
LED - Direct Expenses		385
Interest	1289	386
Preferred Dividends	69	387
Common Equity	1070	388
Equity Tax Cost	481	389
Large Corp Tax	613	390
Grants in Lieu of Property Tax	74	391
CCA Benefit	-618	392
Depreciation	1364	393
Stranded Asset	0	394

NOVA SCOTIA POWER INC.

DETAILED LISTING OF C.O.S.S. INPUT INFORMATION

FOR THE YEAR ENDING DECEMBER 31, 2014

(IN THOUSANDS OF DOLLARS)

		Line #
REVENUE		395
		396
Switch from Prelim to Actual	1	397
ELECTRIC REVENUE - DOMESTIC - REG	664,035	398
ELECTRIC REVENUE - DOMESTIC - ETS	25,733	399
ELECTRIC REVENUE - SMALL GENERAL	36,687	400
ELECTRIC REVENUE - GENERAL	321,964	401
ELECTRIC REVENUE - GENERAL LARGE	43,662	402
ELECTRIC REVENUE - SMALL INDUST.	33,495	403
ELECTRIC REVENUE - MEDIUM INDUST.	57,293	404
ELECTRIC REVENUE - LARGE INDUSTRIAL	86,844	405
ELECTRIC REVENUE - ELI 2P-RTP	0	406
ELECTRIC REVENUE - MUNICIPAL	21,483	407
ELECTRIC REVENUE - UNMETERED	23,989	408
EXPORT SALES	1,943	409
FX Interest		410
		411
OTHER ELECTRIC REVENUE - GREEN POWER SURC	0	412
LATE PAYMENT CHARGE - DOMESTIC	4,133	413
LATE PAYMENT CHARGE - SMALL GENERAL	126	414
LATE PAYMENT CHARGE - GENERAL	921	415
LATE PAYMENT CHARGE - GENERAL LARGE	0	416
LATE PAYMENT CHARGE - SMALL INDUST.	72	417
LATE PAYMENT CHARGE - MEDIUM INDUST.	62	418
LATE PAYMENT CHARGE - LARGE INDUSTRIAL	0	419
LATE PAYMENT CHARGE - ELI 2P-RTP	0	420
LATE PAYMENT CHARGE - MUNICIPAL	0	421
LATE PAYMENT CHARGE - UNMETERED	17	422
MISCELLANEOUS REVENUE - DOMESTIC	1,859	423
MISCELLANEOUS REVENUE - SMALL GENERAL	113	424
MISCELLANEOUS REVENUE - GENERAL	13	425
MISCELLANEOUS REVENUE - GENERAL LARGE	0	426
MISCELLANEOUS REVENUE - SMALL INDUST.	0	427
MISCELLANEOUS REVENUE - MEDIUM INDUST.	0	428
MISCELLANEOUS REVENUE - LARGE INDUSTRIAL	0	429
MISCELLANEOUS REVENUE - ELI 2P-RTP	0	430
MISCELLANEOUS REVENUE - MUNICIPAL	0	431
MISCELLANEOUS REVENUE - UNMETERED	17	432
OTHER REVENUE		433

NOVA SCOTIA POWER INC.

DETAILED LISTING OF C.O.S.S. INPUT INFORMATION

FOR THE YEAR ENDING DECEMBER 31, 2014

(IN THOUSANDS OF DOLLARS)

		Line #
-- ELECTRIC WIRING INSPECTION	4,469	434
NON-OPERATING REVENUE:		435
-- CATV RENTALS	2,421	436
-- NSF CHEQUE CHARGE	66	437
-- GAIN ON SALE OF LAND	0	438
-- STEAM REVENUE	0	439
-- MISCELLANEOUS	1,223	440
-- OM&G Reclass due to US GAAP	6,470	441
-- Non Regulated Revenues for LWS - Block C	0	442
-Accounts Receivable Securitization	0	443
RETAIL SALES (Marketing)	1,499	444
COST OF GOODS SOLD (Retail)	1,067	445
		446
DIRECT REVENUE :		447
MERSEY CONTRACT:		448
-- MERSEY CONTRACT (up to 28MW)	9,782	449
-- MERSEY CONTRACT (28MW to 42MW)	10,241	450
GEN. REPL. / LOAD FOLL.:		451
-- GENERATION REPLACEMENT	1,072	452
-- LOAD FOLLOWING	0	453
LRT	20,568	454
		455
		456
		457
		458
		459
		460
		461
ALLOCATION FACTOR INFORMATION		462
		463
AVERAGE CUSTOMERS - DOMESTIC (SEASONAL)	13,970	464
AVERAGE CUSTOMERS - DOMESTIC	456,991	465
AVERAGE CUSTOMERS - SMALL GENERAL	24,109	466
AVERAGE CUSTOMERS - GENERAL	11,349	467
AVERAGE CUSTOMERS - GENERAL LARGE	19	468
AVERAGE CUSTOMERS - SMALL INDUST.	2,221	469
AVERAGE CUSTOMERS - MEDIUM INDUST.	198	470
AVERAGE CUSTOMERS - INDUSTRIAL LARGE	32	471
AVERAGE CUSTOMERS - ELLIR-2	0	472

NOVA SCOTIA POWER INC.

DETAILED LISTING OF C.O.S.S. INPUT INFORMATION

FOR THE YEAR ENDING DECEMBER 31, 2014

(IN THOUSANDS OF DOLLARS)

		Line #
AVERAGE CUSTOMERS - MUNICIPAL	8	473
AVERAGE CUSTOMERS - UNMETERED	9,604	474
VOLTAGE LEVEL DMD. REDUCTION SEC. - GENERAL	94.67%	475
VOLTAGE LEVEL DMD. REDUCTION SEC. - SM. INDU	90.39%	476
VOLTAGE LEVEL DMD. REDUCTION PRI. - MED. INDU	97.27%	477
LOSS FACTOR PERCENTAGE - SECONDARY	6.000%	478
LOSS FACTOR PERCENTAGE - PRIMARY	5.400%	479
LOSS FACTOR PERCENTAGE - TRANSMISSION	3.700%	480
		481
CUSTOMER WEIGHTING FACTORS		482
		483
DOMESTIC	1.00	484
SMALL GENERAL	1.00	485
GENERAL	5.00	486
LARGE GENERAL	100.00	487
SMALL INDUSTRIAL	5.00	488
MEDIUM INDUSTRIAL	25.00	489
LARGE INDUSTRIAL	100.00	490
ELI 2P-RTP	100.00	491
MUNICIPAL	100.00	492
UNMETERED	0.82	493
		494
FUEL COSTS		495
		496
DOMESTIC	170,740	497
SMALL GENERAL	9,160	498
GENERAL	94,569	499
LARGE GENERAL	15,013	500
SMALL INDUSTRIAL	10,062	501
MEDIUM INDUSTRIAL	19,732	502
LARGE INDUSTRIAL	35,157	503
ELI 2P-RTP	0	504
MUNICIPAL	7,343	505
UNMETERED	3,937	506
		507
		508
REVENUE TO COSS RATIO (CURRENT RATES)		509
		510
DOMESTIC	99.00	511
SMALL GENERAL	104.61	512

NOVA SCOTIA POWER INC.

DETAILED LISTING OF C.O.S.S. INPUT INFORMATION

FOR THE YEAR ENDING DECEMBER 31, 2014
(IN THOUSANDS OF DOLLARS)

		Line #
GENERAL	103.48	513
LARGE GENERAL	98.19	514
SMALL INDUSTRIAL	102.55	515
MEDIUM INDUSTRIAL	98.42	516
LARGE INDUSTRIAL	95.55	517
ELI 2P-RTP		518
MUNICIPAL	97.39	519
UNMETERED	100.00	520

NOVA SCOTIA POWER INC.

DETAILED LISTING OF C.O.S.S. INPUT INFORMATION

FOR THE YEAR ENDING DECEMBER 31, 2014

(IN THOUSANDS OF DOLLARS)

ALLOCATION FACTOR INFORMATION

	January	February	March	April	May	June	July	August	September	October	November	December	Total	
(1) MWH SALES - DOMESTIC	516,258	447,869	448,408	358,526	321,861	263,546	264,900	259,435	259,862	299,381	350,596	466,588	4,257,230	
(2) MWH SALES - SMALL GENERAL	25,143	23,091	22,114	18,756	17,186	16,366	16,867	16,979	15,373	17,145	17,948	22,417	229,386	
(3) MWH SALES - GENERAL	233,512	219,011	225,239	194,886	183,713	185,771	200,920	195,364	181,226	189,540	198,025	225,801	2,433,009	
(4) MWH SALES - GENERAL LARGE	32,543	30,161	32,914	30,042	31,088	30,922	35,364	35,677	33,303	32,368	31,242	31,331	386,956	
(5) MWH SALES - SMALL INDUST.	22,744	21,804	21,869	20,864	21,028	21,952	22,315	22,273	20,819	19,175	21,031	24,389	260,263	
(6) MWH SALES - MEDIUM INDUST.	44,133	39,821	42,496	42,349	41,845	43,808	43,767	43,815	42,676	43,031	42,141	42,928	512,810	
(7) MWH SALES - INDUSTRIAL LARGE	74,672	70,292	75,457	74,438	74,730	76,496	79,763	85,523	80,361	78,588	78,531	72,922	921,772	
(8) MWH SALES - ELI 2P-RTP	0	0	0	0	0	0	0	0	0	0	0	0	0	
(9) MWH SALES - MUNICIPAL	19,935	18,948	18,941	15,463	13,868	12,778	14,080	13,883	13,566	14,607	16,324	19,337	191,729	
(10) MWH SALES - UNMETERED	10,205	8,648	8,555	7,671	6,995	6,227	6,490	7,048	7,623	8,211	9,592	10,548	97,813	
(11) MWH SALES - BOWATER MERSEY - CONTRACT	15,750	15,750	15,750	15,750	15,750	15,750	15,750	15,750	15,750	15,750	15,750	15,750	189,000	
(12) MWH SALES - BOWATER MERSEY - ADD. ENERGY	15,498	12,474	15,498	14,490	15,498	14,490	15,498	15,498	14,490	15,498	14,490	15,498	178,920	
(13) MWH SALES - GEN. REPL./ LOAD FOLL.	990	1,221	38	1,462	442	577	1,591	2,834	6,682	1,467	1,310	200	18,815	
(14) MWH SALES - LRT	27,355	24,708	27,276	26,472	27,355	26,472	27,355	27,355	26,472	27,355	26,551	27,355	322,080	**9,999,782**
(15) MWH SALES - INDUST. EXPANSION INTERR.	0	0	0	0	0	0	0	0	0	0	0	0	0	
(16) MWH SALES - EXTRA LI INTERRUPTIBLE	0	0	0	0	0	0	0	0	0	0	0	0	0	
(17) MWH SALES - Real Time Pricing	0	0	0	0	0	0	0	0	0	0	0	0	0	
(18) MWH SALES - Export Sales	0	0	0	0	0	0	0	0	0	0	0	0	0	
(19) LINE LOSSES - DOMESTIC	54,428	48,530	45,534	32,143	28,927	18,929	19,127	21,300	17,851	24,920	31,449	54,371	397,508	
(20) LINE LOSSES - SMALL GENERAL	2,441	2,320	2,212	1,706	1,581	1,175	1,278	1,501	1,130	1,295	1,513	2,223	20,375	
(21) LINE LOSSES - GENERAL	14,612	14,042	15,310	11,686	11,751	10,383	11,685	12,538	9,550	11,395	11,354	16,894	151,200	
(22) LINE LOSSES - GENERAL LARGE	2,140	1,893	2,204	1,837	2,020	1,611	2,047	2,415	1,620	1,964	1,847	2,305	23,904	
(23) LINE LOSSES - INDUST. TO 249 KVA	1,266	1,280	1,406	1,216	1,302	1,103	1,110	1,276	988	1,087	1,195	1,714	14,943	
(24) LINE LOSSES - INDUST. 250-3999 KVA	2,228	2,149	2,465	2,301	2,537	2,158	2,123	2,479	1,991	2,341	2,122	2,739	27,633	
(25) LINE LOSSES - INDUSTRIAL LARGE	3,001	2,990	3,471	3,280	3,779	3,194	3,315	4,283	3,269	3,625	3,174	3,826	41,207	
(26) LINE LOSSES - ELI 2P-RTP	0	0	0	0	0	0	0	0	0	0	0	0	0	
(27) LINE LOSSES - MUNICIPAL	886	832	945	732	667	526	577	668	526	659	657	1,059	8,735	
(28) LINE LOSSES - UNMETERED	1,106	913	849	720	739	633	670	745	667	692	887	1,197	9,819	
(29) LINE LOSSES - BOWATER MERSEY - CONTRACT	320	320	320	320	320	320	320	320	320	320	320	320	3,837	
(30) LINE LOSSES - BOWATER MERSEY - ADD. ENERGY	315	253	315	294	315	294	315	315	294	315	294	315	3,632	
(31) LINE LOSSES - GEN.REPL. / LOAD FOLL.	20	25	1	30	9	12	32	58	136	30	27	4	384	
(32) LINE LOSSES - LRT	555	502	548	537	555	537	555	555	537	555	544	555	6,538	
(33) LINE LOSSES - INDUST. EXPANSION INTERR.	0	0	0	0	0	0	0	0	0	0	0	0	0	
(34) LINE LOSSES - EXTRA LI INTERRUPTIBLE	0	0	0	0	0	0	0	0	0	0	0	0	0	
(35) LINE LOSSES - REAL TIME PRICING	0	0	0	0	0	0	0	0	0	0	0	0	0	
(36) LINE LOSSES - EXPORT SALES	0	0	0	0	0	0	0	0	0	0	0	0	0	**709,716**
(37) CLASS NON-COINCIDENT DMD. - DOMESTIC	1,013,128	1,036,540	887,289	787,516	673,187	665,640	580,449	583,793	552,662	666,350	776,138	965,934	1,036,540	
(38) CLASS NON-COINCIDENT DMD. - SMALL GENERAL	54,406	57,717	50,502	44,408	39,719	40,230	38,796	41,234	37,876	38,805	45,312	58,447	58,447	
(39) CLASS NON-COINCIDENT DMD. - GENERAL DEMAND	487,817	477,307	427,739	383,448	360,986	387,816	398,918	422,127	434,599	409,155	399,991	451,524	487,817	
(40) CLASS NON-COINCIDENT DMD. - GENERAL LARGE	57,463	58,667	58,108	55,152	59,127	60,712	64,855	69,711	70,885	67,431	58,137	60,007	70,885	
(41) CLASS NON-COINCIDENT DMD. - SMALL INDUST.	44,936	43,613	38,591	39,767	41,938	45,324	45,991	47,973	45,821	42,759	43,298	47,271	47,973	
(42) CLASS NON-COINCIDENT DMD. - MEDIUM INDUST.	85,129	77,859	72,921	76,348	77,834	80,855	82,658	81,056	83,798	78,875	78,808	87,602	87,602	
(43) CLASS NON-COINCIDENT DMD. - INDUSTRIAL LARGE	121,617	124,051	114,150	121,813	113,305	124,550	126,972	131,155	138,738	119,469	124,268	130,016	138,738	
(44) **CLASS NON-COINCIDENT DMD. - ELI 2P-RTP**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	0	
(45) CLASS NON-COINCIDENT DMD. - MUNICIPAL	39,114	40,907	33,399	29,110	24,677	24,358	25,639	26,526	27,312	26,663	31,119	36,870	40,907	
(46) CLASS NON-COINCIDENT DMD. - UNMETERED	22,108	22,097	22,110	22,110	22,109	22,109	22,108	22,110	22,110	22,112	22,112	22,113	22,113	
(47) CLASS NON-COINCIDENT DMD. - BOWATER MERSEY	42,000	42,000	42,000	42,000	42,000	42,000	42,000	42,000	42,000	42,000	42,000	42,000	42,000	
(48) CLASS NON-COINCIDENT DMD. - GEN. REPL.	18,501	19,501	1,842	22,397	3,189	23,190	23,449	23,447	23,900	7,533	21,278	1,495	23,900	
(49) CLASS NON-COINCIDENT DMD. - LRT	38,000	38,000	38,000	38,000	38,000	38,000	38,000	38,000	38,000	38,000	38,000	38,000	38,000	
(50) CLASS NON-COINCIDENT DMD. - RTP	0	0	0	0	0	0	0	0	0	0	0	0	0	
(51) CLASS NON-COINCIDENT DMD. - INDUST. EXPAN. INTERR.	0	0	0	0	0	0	0	0	0	0	0	0	0	
(52) CLASS NON-COINCIDENT DMD. - EXTRA LI INTERRUPTIBLE	0	0	0	0	0	0	0	0	0	0	0	0	0	
(53) CLASS NON-COINCIDENT DMD. - EXPORT SALES	0	0	0	0	0	0	0	0	0	0	0	0	0	
(54) SYSTEM COINCIDENT DMD. - DOMESTIC	983,362	1,036,540	826,992	754,661	600,903	629,524	446,200	490,139	497,196	605,415	776,138	927,091	1,036,540	
(55) SYSTEM COINCIDENT DMD. - SMALL GENERAL	38,108	35,922	38,677	21,980	31,474	24,808	36,043	33,849	31,986	28,144	29,941	35,197	35,922	
(56) SYSTEM COINCIDENT DMD. - GENERAL	454,711	403,748	418,481	335,936	341,706	300,830	394,684	404,390	413,057	356,584	358,203	410,591	403,748	
(57) SYSTEM COINCIDENT DMD. - GENERAL LARGE	50,514	49,632	53,507	46,953	54,946	46,157	63,625	66,198	67,104	53,536	52,079	52,591	49,632	
(58) SYSTEM COINCIDENT DMD. - SMALL INDUST.	39,844	37,551	37,673	32,581	41,617	32,994	41,966	40,562	38,465	41,333	34,022	34,474	37,551	
(59) SYSTEM COINCIDENT DMD. - MEDIUM INDUST.	74,312	72,050	65,086	64,715	69,976	68,050	76,710	72,633	72,776	73,407	72,057	74,747	72,050	
(60) SYSTEM COINCIDENT DMD. - INDUSTRIAL LARGE	105,347	113,095	105,208	107,639	103,834	115,566	123,570	124,091	124,733	112,118	93,876	129,317	113,095	

NOVA SCOTIA POWER INC.

DETAILED LISTING OF C.O.S.S. INPUT INFORMATION

FOR THE YEAR ENDING DECEMBER 31, 2014

(IN THOUSANDS OF DOLLARS)

ALLOCATION FACTOR INFORMATION

	January	February	March	April	May	June	July	August	September	October	November	December	Total	
(61) ***SYSTEM COINCIDENT DMD. - ELI 2P-RTP***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	**0**	
(62) SYSTEM COINCIDENT DMD. - MUNICIPAL	38,782	39,997	32,913	27,070	24,430	24,358	25,539	25,562	26,411	26,156	31,119	36,870	**39,997**	
(63) SYSTEM COINCIDENT DMD. - UNMETERED	17,302	22,088	2,497	2,713	3,020	2,572	3,002	2,859	2,700	2,285	16,412	22,113	**22,088**	
(64) SYSTEM COINCIDENT DMD. - BOWATER MERSEY	42,000	42,000	42,000	42,000	42,000	42,000	42,000	42,000	42,000	42,000	42,000	42,000	**42,000**	
(65) SYSTEM COINCIDENT DMD. - GEN. REPL.	-117	37	-12	157	718	-29	2,428	17,804	23,047	1,483	19,707	389	**37**	
(66) SYSTEM COINCIDENT DMD. - LRT	36,767	36,767	36,767	36,767	36,767	36,767	36,767	36,767	36,767	36,767	36,767	36,767	**36,767**	
(67) SYSTEM COINCIDENT DMD. - RTP	0	0	0	0	0	0	0	0	0	0	0	0	**0**	
(68) SYSTEM COINCIDENT DMD. - EXPORT SALES	0	0	0	0	0	0	0	0	0	0	0	0	**0**	
(69) ***SYSTEM COINCIDENT DMD. - INTERRUPTIBLE***	***74,173***	***84,734***	***78,577***	***80,573***	***73,472***	***86,137***	***94,864***	***96,610***	***95,287***	***85,179***	***66,926***	***98,589***	**84,734**	
(70) **TOTAL COINCIDENT DEMAND**	***1,880,932***	***1,889,429***	***1,659,789***	***1,473,173***	***1,351,391***	***1,323,597***	***1,292,535***	***1,356,853***	***1,376,242***	***1,379,228***	***1,562,319***	***1,802,148***		1,889,429
(71) VOLTAGE LEVEL DMD. REDUCTION SEC. - GENERAL														
(72) VOLTAGE LEVEL DMD. REDUCTION SEC. - SM. INDUST.														
(73) VOLTAGE LEVEL DMD. REDUCTION PRI. - MED. INDUST.														
(74) LOSS FACTOR PERCENTAGE - SECONDARY														
(75) LOSS FACTOR PERCENTAGE - PRIMARY														
(76) LOSS FACTOR PERCENTAGE - TRANSMISSION														
(77) DEMAND LINE LOSS ADJUSTMENT - DOMESTIC	132,179	151,958	102,152	86,467	63,423	61,668	35,190	46,288	42,431	61,564	91,288	134,656	**1,009,263**	
(78) DEMAND LINE LOSS ADJUSTMENT - SMALL GENERAL	3,744	3,604	4,002	1,914	2,985	2,002	2,931	3,142	2,451	2,157	2,569	3,552	**35,054**	
(79) DEMAND LINE LOSS ADJUSTMENT - GENERAL	33,932	28,282	32,493	21,561	24,279	17,014	26,690	30,409	26,751	24,244	22,700	34,550	**322,906**	
(80) DEMAND LINE LOSS ADJUSTMENT - LARGE GENERAL	3,405	3,144	3,704	2,891	3,724	2,516	3,909	4,758	3,516	3,367	3,161	4,033	**42,127**	
(81) DEMAND LINE LOSS ADJUSTMENT - SMALL INDUST.	2,307	2,235	2,496	1,897	2,681	1,699	2,166	2,389	1,850	2,476	1,946	2,436	**26,579**	
(82) DEMAND LINE LOSS ADJUSTMENT - MEDIUM INDUST.	3,944	4,022	3,851	3,520	4,357	3,486	3,888	4,216	3,444	4,146	3,743	4,995	**47,612**	
(83) DEMAND LINE LOSS ADJUSTMENT - LARGE INDUST.	4,946	4,854	4,860	4,713	5,224	4,769	5,246	6,237	5,061	5,165	3,562	7,210	**61,847**	
(84) ***DEMAND LINE LOSS ADJUSTMENT - ELI 2P-RTP***													**0**	
(85) DEMAND LINE LOSS ADJUSTMENT - MUNICIPAL	1,799	1,809	1,679	1,288	1,185	1,064	1,050	1,231	1,016	1,191	1,263	2,094	**16,670**	
(86) DEMAND LINE LOSS ADJUSTMENT - UNMETERED	2,274	2,394	191	194	164	101	151	156	155	147	1,391	2,738	**10,057**	
(87) DEMAND LINE LOSS ADJUSTMENT - BOWATER MERSEY	857	857	857	857	857	857	857	857	857	857	857	857	**10,282**	
(88) DEMAND LINE LOSS ADJUSTMENT - GEN. REPL.	-2	1	0	3	15	-1	50	363	470	30	402	8	**1,338**	
(89) DEMAND LINE LOSS ADJUSTMENT - LRT	750	750	750	750	750	750	750	750	750	750	750	750	**9,001**	
(90) DEMAND LINE LOSS ADJUSTMENT - RTP	0	0	0	0	0	0	0	0	0	0	0	0	**0**	
(91) DEMAND LINE LOSS ADJUSTMENT - EXPORT SALES	0	0	0	0	0	0	0	0	0	0	0	0	**0**	1,592,737
(92) ***DEMAND LINE LOSS ADJUSTMENT - INTERRUPTIBLE***	***3,388***	***3,498***	***3,488***	***3,388***	***3,545***	***3,465***	***3,987***	***4,831***	***3,766***	***3,811***	***2,322***	***5,366***		
													3CP	
(93) REQUIREMENTS - DOMESTIC	1,115,541	1,188,498	929,143	841,129	664,326	691,192	481,390	536,427	539,626	666,979	867,425	1,061,747	**3,365,786**	
(94) REQUIREMENTS - SMALL GENERAL	41,853	39,526	42,679	23,894	34,459	26,810	38,974	36,992	34,437	30,301	32,510	38,749	**120,127**	
(95) REQUIREMENTS - GENERAL	488,643	432,030	450,974	357,497	365,984	317,844	421,374	434,799	439,809	380,828	380,904	445,141	**1,365,814**	
(96) REQUIREMENTS - GENERAL LARGE	53,919	52,776	57,210	49,844	58,670	48,673	67,534	70,955	70,620	56,903	55,239	56,625	**163,320**	
(97) REQUIREMENTS - INDUST. TO 249 KVA	42,151	39,786	40,169	34,478	44,298	34,693	44,132	42,951	40,315	43,809	35,967	36,910	**118,848**	
(98) REQUIREMENTS - INDUST. 250-3999 KVA	78,256	76,073	68,937	68,235	74,332	71,536	80,598	76,849	76,219	77,553	75,800	79,742	**234,070**	
(99) REQUIREMENTS - INDUSTRIAL LARGE	110,293	117,949	110,068	112,351	109,058	120,335	128,816	130,328	129,794	117,283	97,438	136,527	**364,769**	
(100) REQUIREMENTS - ELI 2P-RTP	0	0	0	0	0	0	0	0	0	0	0	0	**-**	
(101) REQUIREMENTS - MUNICIPAL	40,581	41,806	34,592	28,358	25,615	25,422	26,589	26,793	27,426	27,347	32,382	38,964	**121,351**	
(102) REQUIREMENTS - UNMETERED	19,576	24,483	2,688	2,908	3,184	2,673	3,153	3,015	2,855	2,432	17,803	24,851	**68,910**	
(103) REQUIREMENTS - BOWATER MERSEY	42,857	42,857	42,857	42,857	42,857	42,857	42,857	42,857	42,857	42,857	42,857	42,857	**128,570**	
(104) REQUIREMENTS - GEN.REPL. / LOAD FOLL.	-119	38	-12	160	733	-30	2,478	18,167	23,518	1,513	20,109	397	**315**	
(105) REQUIREMENTS - LRT	37,517	37,517	37,517	37,517	37,517	37,517	37,517	37,517	37,517	37,517	37,517	37,517	**112,552**	
(106) REQUIREMENTS - RTP	0	0	0	0	0	0	0	0	0	0	0	0	**0**	
(107) REQUIREMENTS - EXPORT SALES	0	0	0	0	0	0	0	0	0	0	0	0	**0**	

NOVA SCOTIA POWER INC.	
2014 COST OF SERVICE STUDY ANALYSIS	
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EXHIBIT 1

NOVA SCOTIA POWER INC.
SUMMARY OF REVENUE TO EXPENSE RECOVERY RATIOS

	2014	
CUSTOMER CLASS	PRESENT	PROPOSED
(1) DOMESTIC	99.00	99.44
(2) SMALL GENERAL	104.61	104.40
(3) GENERAL	103.48	102.84
(4) LARGE GENERAL	98.19	98.66
(5) SMALL INDUSTRIAL	102.55	102.04
(6) MEDIUM INDUSTRIAL	98.42	97.28
(7) LARGE INDUSTRIAL	95.55	95.00
(8) ELI 2P-RTP	N/A	N/A
(9) MUNICIPAL	97.39	97.96
(10) UNMETERED	100.00	100.00
(11) TOTAL	100.00	100.00

EXHIBIT 2

NOVA SCOTIA POWER INC.

FUNCTIONALIZATION OF AVERAGE RATE BASE

FOR THE YEAR ENDING DECEMBER 31, 2014

(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) GENERATION	(3) TRANSMISSION	(4) DISTRIBUTION	(5) RETAIL	(6) DIRECT CAPITAL
PRODUCTION PLANT						
(1) STEAM	$1,370,531	$1,370,531	$0	$0	$0	$0
(2) HYDRO	371,461	351,261	0	0	0	20,200
(3) WIND	201,182	201,182	0	0	0	0
(4) LM6000	71,417	71,417	0	0	0	0
(5) GAS TURBINE - OTHER	6,513	6,513	0	0	0	0
(6) TOTAL PROD. PLANT	2,021,104	2,000,904	0	0	0	20,200
(7) Transmission < 138kV	109,080	0	109,080	0	0	0
(8) Transmission > 69kV	357,074	0	357,074	0	0	0
(9) TRANSMISSION PLANT	466,154	0	466,154	0	0	0
DISTRIBUTION PLANT						
(10) LAND	4,435	0	0	4,435	0	0
(11) EASEMENTS & SURVEY	16,882	0	0	16,882	0	0
(12) OTHER	2,190	0	0	2,190	0	0
(13) SUBSTATIONS	30,113	0	0	30,113	0	0
(14) POLES & FIXTURES	183,085	0	0	183,085	0	0
(15) O.H. LINES	121,259	0	0	121,259	0	0
(16) U.G. LINES	34,858	0	0	34,858	0	0
(17) LINE TRANSFORMERS	163,242	0	0	163,242	0	0
(18) SERVICES	60,998	0	0	60,998	0	0
(19) METERS	25,072	0	0	25,072	0	0
(20) STREET LIGHTING	34,507	0	0	10,251	0	24,256
(21) TOTAL DIST. PLANT	676,641	0	0	652,385	0	24,256
(22) SUB-TOTAL	3,163,899	2,000,904	466,154	652,385	0	44,456
(23) GEN. PROPERTY PLANT	234,273	150,270	35,009	48,995	0	0
(24) TOT. PLT.IN SERVICE	3,398,172	2,151,174	501,163	701,380	0	44,456
Working Capital & Deferred Charges/Credits						
(25) CASH - FUEL	0	0	0	0	0	0
(26) CASH - OTHER	27,900	13,449	2,607	11,611	0	233
(27) MAT. & SUP. - FUEL	84,441	84,441	0	0	0	0
(28) MAT. & SUP. - OTHER	28,661	18,384	4,283	5,994	0	0
(29) DEF. CHG. - Financing	65,674	42,125	9,814	13,735	0	0
(30) DEF. CHG. - Tax	9,838	6,310	1,470	2,057	0	0
(31) DEF. CHG. - Pension	82,097	39,907	7,736	34,455	0	0
(32) DEF. CHG. - Steam Assets	0	0	0	0	0	0
(33) DEF. CHG. - Fuel Deferral	0	0	0	0	0	0
(34) DEF. CHG. - Other	9,215	1,796	295	413	0	6,710
(35) DEF. CHG. - FCR	23,250	18,857	4,393	0	0	0
(36) DEF. CR. - ARO Steam	(43,651)	(43,651)	0	0	0	0
(37) DEF. CR. - ARO Hydro	(22,762)	(22,762)	0	0	0	0
(38) DEF. CR. - ARO Wind	(10,861)	(10,861)	0	0	0	0
(39) DEF. CR. - ARO CT	(4,150)	(4,150)	0	0	0	0
(40) DEF. CR. - ARO Trans	(24,730)	0	(24,730)	0	0	0
(41) DEF. CR. - Other	(6,577)	(6,577)	0	0	0	0
(42) CONTRACT RECEIVABLE	0	0	0	0	0	0
(43) TOT.WORKING CAPITAL	218,345	137,268	5,868	68,265	0	6,943
(44) TOTAL AVE. RATE BASE	$3,616,517	$2,288,442	$507,031	$769,645	$0	$51,399

NOVA SCOTIA POWER INC.

CLASSIFICATION OF AVERAGE RATE BASE

FOR THE YEAR ENDING DECEMBER 31, 2014

(IN THOUSANDS OF DOLLARS)

	(1)	(2)	(3)	(4)
		INITIAL CLASSIFICATION		
	TOTAL COMPANY	DEMAND RELATED PLANT	ENERGY RELATED PLANT	CUSTOMER RELATED PLANT
GENERATION FUNCTION				
(1) STEAM PLANT	$1,370,531	$1,045,169	$325,362	$0
(2) HYDRO PLANT	351,261	346,437	4,824	0
(3) WIND PLANT	201,182	30,599	170,583	0
(4) LM6000 PLANT	71,417	71,417	0	0
(5) GAS TURBINE PLANT - OTHER	6,513	6,513	0	0
(6) TOTAL GENERATION PLANT	2,000,904	1,500,135	500,769	0
(7) GENERAL PROPERTY PLANT	150,270	112,661	37,608	0
(8) TOTAL PLANT IN SERVICE	2,151,174	1,612,796	538,377	0
Working Capital & Deferred Charges/Credits:				
(9) CASH - FUEL	0	0	0	0
(10) CASH - OTHER	13,449	3,742	9,707	0
(11) MAT. & SUPPLIES - FUEL	84,441	0	84,441	0
(12) MAT. & SUPPLIES - OTHER	18,384	13,783	4,601	0
(13) DEF. CHG. - Financing	42,125	31,583	10,543	0
(14) DEF. CHG. - Tax	6,310	4,731	1,579	0
(15) DEF. CHG. - Pension	39,907	11,104	28,803	0
(16) DEF. CHG. - Steam Assets	0	0	0	0
(17) DEF. CHG. - Fuel Deferral	0	0	0	0
(18) DEF. CHG. - Other	1,796	1,347	450	0
(19) DEF. CHG. - FCR	18,857	14,138	4,719	0
(20) DEF. CR. - ARO Steam	(43,651)	(33,288)	(10,363)	0
(21) DEF. CR. - ARO Hydro	(22,762)	(22,449)	(313)	0
(22) DEF. CR. - ARO Wind	(10,861)	(10,712)	(149)	0
(23) DEF. CR. - ARO CT	(4,150)	(4,150)	0	0
(24) DEF. CR. - Other	(6,577)	(5,016)	(1,561)	0
(25) CONTRACT RECEIVABLE	0	0	0	0
(26) SUB-TOTAL	137,268	4,811	132,457	0
(27) TOTAL GENERATION FUNCTION	**2,288,442**	**1,617,608**	**670,834**	**0**
TRANSMISSION FUNCTION				
(28) TRANSMISSION PLANT < 138kV	109,080	109,080	0	0
(29) GENERAL PROPERTY PLANT	8,192	8,192	0	0
(30) TOTAL PLANT IN SERVICE	117,272	117,272	0	0
Working Capital & Deferred Charges/Credits:				
(31) CASH - FUEL	0	0	0	0
(32) CASH - OTHER	624	271	353	0
(33) MAT. & SUPPLIES - FUEL	0	0	0	0
(34) MAT. & SUPPLIES - OTHER	1,002	1,002	0	0
(35) DEF. CHG. - Financing	2,296	2,296	0	0
(36) DEF. CHG. - Tax	344	344	0	0
(37) DEF. CHG. - Pension	1,851	803	1,048	0
(38) DEF. CHG. - Other	69	69	0	0
(39) DEF. CHG. - ARO Trans.	(5,787)	(5,787)	0	0
(40) SUB-TOTAL	400	(1,002)	1,402	0
(41) TOTAL TRANS. < 138kV	117,672	116,270	1,402	0

NOVA SCOTIA POWER INC.

CLASSIFICATION OF AVERAGE RATE BASE

FOR THE YEAR ENDING DECEMBER 31, 2014
(IN THOUSANDS OF DOLLARS)

	(1)	(2)	(3)	(4)
		INITIAL CLASSIFICATION		
	TOTAL COMPANY	DEMAND RELATED PLANT	ENERGY RELATED PLANT	CUSTOMER RELATED PLANT
(1) TRANSMISSION PLANT > 69kV	357,074	357,074	0	0
(2) GENERAL PROPERTY PLANT	26,817	26,817	0	0
(3) TOTAL PLANT IN SERVICE	383,891	383,891	0	0
Working Capital & Deferred Charges/Credits:				
(4) CASH - FUEL	0	0	0	0
(5) CASH - OTHER	1,983	860	1,123	0
(6) MAT. & SUPPLIES - FUEL	0	0	0	0
(7) MAT. & SUPPLIES - OTHER	3,281	3,281	0	0
(8) DEF. CHG. - Financing	7,518	7,518	0	0
(9) DEF. CHG. - Tax	1,126	1,126	0	0
(10) DEF. CHG. - Pension	5,885	2,552	3,333	0
(11) DEF. CHG. - Other	226	226	0	0
(12) DEF. CHG. - FCR	4,393	4,393	0	0
(13) DEF. CHG. - ARO Trans	(18,943)	(18,943)	0	0
(14) SUB-TOTAL	5,468	1,013	4,456	0
(15) TOTAL TRANS. > 69kV	389,359	384,903	4,456	0
(16) TOTAL TRANSMISSION FUNCTION	**$507,031**	**$501,174**	**$5,857**	**$0**

DISTRIBUTION FUNCTION

	(1)	(2)	(3)	(4)
DISTRIBUTION PLANT:				
(17) LAND	4,435	3,023	0	1,412
(18) EASEMENTS & SURVEY	16,882	11,505	0	5,377
(19) OTHER	2,190	1,493	0	697
(20) SUBSTATIONS	30,113	30,113	0	0
(21) POLES & FIXTURES	183,085	119,005	0	64,080
(22) O.H. LINES	121,259	78,818	0	42,441
(23) U.G. LINES	34,858	22,658	0	12,200
(24) LINE TRANSFORMERS	163,242	163,242	0	0
(25) SERVICES	60,998	0	0	60,998
(26) METERS	25,072	0	0	25,072
(27) STREET LIGHTING	10,251	10,251	0	0
(28) TOTAL DISTRIBUTION PLANT	652,385	440,108	0	212,277
(29) GENERAL PROPERTY PLANT	48,995	33,052	0	15,942
(30) TOTAL PLANT IN SERVICE	701,380	473,160	0	228,220
Working Capital & Deferred Charges/Credits:				
(31) CASH - FUEL	0	0	0	0
(32) CASH - OTHER	11,611	4,180	0	7,432
(33) MAT. & SUPPLIES - FUEL	0	0	0	0
(34) MAT. & SUPPLIES - OTHER	5,994	4,044	0	1,950
(35) DEF. CHG. - Financing	13,735	9,266	0	4,469
(36) DEF. CHG. - Tax	2,057	1,388	0	669
(37) DEF. CHG. - Pension	34,455	12,402	0	22,052
(38) DEF. CHG. - Other	413	279	0	134
(39) SUB-TOTAL	68,265	31,558	0	36,708
(40) TOTAL DISTRIBUTION FUNCTION	**769,645**	**504,718**	**0**	**264,927**

NOVA SCOTIA POWER INC.

CLASSIFICATION OF RATE BASE

FOR THE YEAR ENDING DECEMBER 31, 2014

(IN THOUSANDS OF DOLLARS)

	(1)	(2)	(3)	(4)
		INITIAL CLASSIFICATION		
	TOTAL COMPANY	DEMAND RELATED PLANT	ENERGY RELATED PLANT	CUSTOMER RELATED PLANT
RETAIL FUNCTION				
DISTRIBUTION PLANT:				
(1) SERVICES	0	0	0	0
(2) METERS	0	0	0	0
(3) TOTAL RETAIL PLANT	0	0	0	0
(4) GENERAL PROPERTY PLANT	0	0	0	0
(5) TOTAL PLANT IN SERVICE	0	0	0	0
Working Capital & Deferred Charges/Credits:				
(6) CASH - FUEL	0	0	0	0
(7) CASH - OTHER	0	0	0	0
(8) MAT. & SUPPLIES - FUEL	0	0	0	0
(9) MAT. & SUPPLIES - OTHER	0	0	0	0
(10) DEF. CHG. - Financing	0	0	0	0
(11) DEF. CHG. - Tax	0	0	0	0
(12) DEF. CHG. - Pension	0	0	0	0
(13) DEF. CHG. - Other	0	0	0	0
(14) SUB-TOTAL	0	0	0	0
(15) TOTAL RETAIL FUNCTION	**0**	**0**	**0**	**0**
(16) TOTAL AVE. RATE BASE	**$3,565,118**	**$2,623,499**	**$676,691**	**$264,927**

NOVA SCOTIA POWER INC.
CLASSIFICATION OF AVERAGE RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2014
(IN THOUSANDS OF DOLLARS)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	INITIAL R/B CLASSIFICATION			FURTHER CLASSIFICATION			FULLY CLASSIFIED RATE BASE		
	DEMAND PLANT	ENERGY PLANT	CUSTOMER PLANT	DEMAND PLANT	ENERGY PLANT	CUSTOMER PLANT	DEMAND PLANT	ENERGY PLANT	CUSTOMER PLANT
GENERATION FUNCTION									
(1) STEAM PLANT	$1,045,169	$325,362	$0	($591,879)	$591,879	$0	$453,290	$917,241	$0
(2) HYDRO PLANT	346,437	4,824	0	(196,187)	196,187	0	150,250	201,011	0
(3) WIND PLANT	30,599	170,583	0	(21,419)	21,419	0	9,180	192,002	0
(4) LM6000 PLANT	71,417	0	0	(40,443)	40,443	0	30,974	40,443	0
(5) GAS TURBINE PLANT - OTHER	6,513	0	0	0	0	0	6,513	0	0
(6) TOTAL GENERATION PLANT	1,500,135	500,769	0	(849,929)	849,929	0	650,206	1,350,698	0
(7) GENERAL PROPERTY PLANT	112,661	37,608	0	(63,830)	63,830	0	48,831	101,439	0
(8) TOTAL PLANT IN SERVICE	1,612,796	538,377	0	(913,760)	913,760	0	699,037	1,452,137	0
Working Capital & Deferred Charges/Credits:									
(9) CASH - FUEL	0	0	0	0	0	0	0	0	0
(10) CASH - OTHER	3,742	9,707	0	0	0	0	3,742	9,707	0
(11) MAT. & SUPPLIES - FUEL	0	84,441	0	0	0	0	0	84,441	0
(12) MAT. & SUPPLIES - OTHER	13,783	4,601	0	(7,809)	7,809	0	5,974	12,410	0
(13) DEF. CHG. - Financing	31,583	10,543	0	(17,894)	17,894	0	13,689	28,436	0
(14) DEF. CHG. - Tax	4,731	1,579	0	(2,680)	2,680	0	2,051	4,260	0
(15) DEF. CHG. - Pension	11,104	28,803	0	0	0	0	11,104	28,803	0
(16) DEF. CHG. - Steam Assets	0	0	0	0	0	0	0	0	0
(17) DEF. CHG. - Fuel Deferral	0	0	0	0	0	0	0	0	0
(18) DEF. CHG. - Other	1,347	450	0	(763)	763	0	584	1,213	0
(19) DEF. CHG. - FCR	14,138	4,719	0	(8,010)	8,010	0	6,128	12,729	0
(20) DEF. CR. - ARO Steam	(33,288)	(10,363)	0	18,851	(18,851)	0	(14,437)	(29,214)	0
(21) DEF. CR. - ARO Hydro	(22,449)	(313)	0	12,713	(12,713)	0	(9,736)	(13,026)	0
(22) DEF. CR. - ARO Wind	(10,712)	(149)	0	6,066	(6,066)	0	(4,646)	(6,215)	0
(23) DEF. CR. - ARO CT	(4,150)	0	0	0	0	0	(4,150)	0	0
(24) DEF. CR. - Other	(5,016)	(1,561)	0	2,840	(2,840)	0	(2,175)	(4,402)	0
(25) CONTRACT RECEIVABLE	0	0	0	0	0	0	0	0	0
(26) SUB-TOTAL	4,811	132,457	0	3,315	(3,315)	0	8,126	129,142	0
							0	0	0
(27) TOTAL GENERATION FUNCTION	1,617,608	670,834	0	(910,445)	910,445	0	707,163	1,581,279	0
TRANSMISSION FUNCTION									
(28) TRANSMISSION PLANT < 138kV	109,080	0	0	(61,772)	61,772	0	47,308	61,772	0
(29) GENERAL PROPERTY PLANT	8,192	0	0	(4,639)	4,639	0	3,553	4,639	0
(30) TOTAL PLANT IN SERVICE	117,272	0	0	(66,411)	66,411	0	50,861	66,411	0
Working Capital & Deferred Charges/Credits:									
(31) CASH - FUEL	0	0	0	0	0	0	0	0	0
(32) CASH - OTHER	271	353	0	0	0	0	271	353	0
(33) MAT. & SUPPLIES - FUEL	0	0	0	0	0	0	0	0	0
(34) MAT. & SUPPLIES - OTHER	1,002	0	0	(568)	568	0	435	568	0
(35) DEF. CHG. - Financing	2,296	0	0	(1,300)	1,300	0	996	1,300	0
(36) DEF. CHG. - Tax	344	0	0	(195)	195	0	149	195	0
(37) DEF. CHG. - Pension	803	1,048	0	0	0	0	803	1,048	0
(38) DEF. CHG. - Other	69	0	0	(39)	39	0	30	39	0
(40) DEF. CR. - ARO Trans.	(5,787)	0	0	3,277	(3,277)	0	(2,510)	(3,277)	0
(41) SUB-TOTAL	(1,002)	1,402	0	1,175	(1,175)	0	173	226	0
(42) TOTAL TRANS. < 138kV	116,270	1,402	0	(65,236)	65,236	0	51,034	66,638	0

NOVA SCOTIA POWER INC.
CLASSIFICATION OF AVERAGE RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2014
(IN THOUSANDS OF DOLLARS)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	INITIAL R/B CLASSIFICATION			FURTHER CLASSIFICATION			FULLY CLASSIFIED RATE BASE		
	DEMAND PLANT	ENERGY PLANT	CUSTOMER PLANT	DEMAND PLANT	ENERGY PLANT	CUSTOMER PLANT	DEMAND PLANT	ENERGY PLANT	CUSTOMER PLANT
(1) TRANSMISSION PLANT > 69kV	357,074	0	0	(202,211)	202,211	0	154,863	202,211	0
(2) GENERAL PROPERTY PLANT	26,817	0	0	(15,186)	15,186	0	11,630	15,186	0
(3) TOTAL PLANT IN SERVICE	383,891	0	0	(217,397)	217,397	0	166,493	217,397	0
Working Capital & Deferred Charges/Credits:									
(4) CASH - FUEL	0	0	0	0	0	0	0	0	0
(5) CASH - OTHER	860	1,123	0	0	0	0	860	1,123	0
(6) MAT. & SUPPLIES - FUEL	0	0	0	0	0	0	0	0	0
(7) MAT. & SUPPLIES - OTHER	3,281	0	0	(1,858)	1,858	0	1,423	1,858	0
(8) DEF. CHG. - Financing	7,518	0	0	(4,257)	4,257	0	3,260	4,257	0
(9) DEF. CHG. - Tax	1,126	0	0	(638)	638	0	488	638	0
(10) DEF. CHG. - Pension	2,552	3,333	0	0	0	0	2,552	3,333	0
(11) DEF. CHG. - Other	226	0	0	(128)	128	0	98	128	0
(12) DEF. CHG. - FCR	4,393	0	0	(2,488)	2,488	0	1,905	2,488	0
(13) DEF. CR. - ARO Trans	(18,943)	0	0	10,728	(10,728)	0	(8,216)	(10,728)	0
(14) SUB-TOTAL	1,013	4,456	0	1,359	(1,359)	0	2,372	3,097	0
(15) TOTAL TRANS. > 69kV	384,903	4,456	0	(216,038)	216,038	0	168,865	220,494	0
(16) TOTAL TRANSMISSION FUNCTION	$501,174	$5,857	$0	($281,274)	$281,274	$0	$219,899	$287,132	$0

NOVA SCOTIA POWER INC.

CLASSIFICATION OF AVERAGE RATE BASE

FOR THE YEAR ENDING DECEMBER 31, 2014

(IN THOUSANDS OF DOLLARS)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	INITIAL R/B CLASSIFICATION			FURTHER CLASSIFICATION			FULLY CLASSIFIED RATE BASE		
	DEMAND PLANT	ENERGY PLANT	CUSTOMER PLANT	DEMAND PLANT	ENERGY PLANT	CUSTOMER PLANT	DEMAND PLANT	ENERGY PLANT	CUSTOMER PLANT
DISTRIBUTION FUNCTION									
DISTRIBUTION PLANT:									
(1) LAND	$3,023	$0	$1,412	$0	$0	$0	$3,023	$0	$1,412
(2) EASEMENTS & SURVEY	11,505	0	5,377	0	0	0	11,505	0	5,377
(3) OTHER	1,493	0	697	0	0	0	1,493	0	697
(4) SUBSTATIONS	30,113	0	0	0	0	0	30,113	0	0
(5) POLES & FIXTURES	119,005	0	64,080	0	0	0	119,005	0	64,080
(6) O.H. LINES	78,818	0	42,441	0	0	0	78,818	0	42,441
(7) U.G. LINES	22,658	0	12,200	0	0	0	22,658	0	12,200
(8) LINE TRANSFORMERS	163,242	0	0	0	0	0	163,242	0	0
(9) SERVICES	0	0	60,998	0	0	0	0	0	60,998
(10) METERS	0	0	25,072	0	0	0	0	0	25,072
(11) STREET LIGHTING	10,251	0	0	0	0	0	10,251	0	0
(12) TOTAL DISTRIBUTION PLANT	440,108	0	212,277	0	0	0	440,108	0	212,277
(13) GENERAL PROPERTY PLANT	33,052	0	15,942	0	0	0	33,052	0	15,942
(14) TOTAL PLANT IN SERVICE	473,160	0	228,220	0	0	0	473,160	0	228,220
Working Capital & Deferred Charges/Credits:									
(15) CASH - FUEL	0	0	0	0	0	0	0	0	0
(16) CASH - OTHER	4,180	0	7,432	0	0	0	4,180	0	7,432
(17) MAT. & SUPPLIES - FUEL	0	0	0	0	0	0	0	0	0
(18) MAT. & SUPPLIES - OTHER	4,044	0	1,950	0	0	0	4,044	0	1,950
(19) DEF. CHG. - Financing	9,266	0	4,469	0	0	0	9,266	0	4,469
(20) DEF. CHG. - Tax	1,388	0	669	0	0	0	1,388	0	669
(21) DEF. CHG. - Pension	12,402	0	22,052	0	0	0	12,402	0	22,052
(22) DEF. CHG. - Other	279	0	134	0	0	0	279	0	134
(23) SUB-TOTAL	31,558	0	36,708	0	0	0	31,558	0	36,708
(24) TOTAL DISTRIBUTION FUNCTION	$504,718	$0	$264,927	$0	$0	$0	$504,718	$0	$264,927
RETAIL FUNCTION									
DISTRIBUTION PLANT:									
(25) SERVICES	$0	$0	$0	$0	$0	$0	$0	$0	$0
(26) METERS	0	0	0	0	0	0	0	0	0
(27) TOTAL RETAIL PLANT	0	0	0	0	0	0	0	0	0
(28) GENERAL PROPERTY PLANT	0	0	0	0	0	0	0	0	0
(29) TOTAL PLANT IN SERVICE	0	0	0	0	0	0	0	0	0
Working Capital & Deferred Charges/Credits:									
(30) CASH - FUEL	0	0	0	0	0	0	0	0	0
(31) CASH - OTHER	0	0	0	0	0	0	0	0	0
(32) MAT. & SUPPLIES - FUEL	0	0	0	0	0	0	0	0	0
(33) MAT. & SUPPLIES - OTHER	0	0	0	0	0	0	0	0	0
(34) DEF. CHG. - Financing	0	0	0	0	0	0	0	0	0
(35) DEF. CHG. - Tax	0	0	0	0	0	0	0	0	0
(36) DEF. CHG. - Pension	0	0	0	0	0	0	0	0	0
(37) DEF. CHG. - Other	0	0	0	0	0	0	0	0	0
(38) SUB-TOTAL	0	0	0	0	0	0	0	0	0
(39) TOTAL RETAIL FUNCTION	0	0	0	0	0	0	0	0	0
(40) TOTAL AVE. RATE BASE	**$2,623,499**	**$676,691**	**$264,927**	**($1,191,720)**	**$1,191,720**	**$0**	**$1,431,780**	**$1,868,411**	**$264,927**

NOVA SCOTIA POWER INC.
ALLOCATION OF AVERAGE RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2014
(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
DEMAND CLASSIFICATION												
GENERATION FUNCTION												
(1) STEAM PLANT	$453,290	$257,585	$9,193	$104,526	$12,499	$9,095	$17,914	$27,916	$0	$9,287	$5,274	D-3A
(2) HYDRO PLANT	150,250	85,381	3,047	34,647	4,143	3,015	5,938	9,253	0	3,078	1,748	D-3A
(3) WIND PLANT	9,180	5,216	186	2,117	253	184	363	565	0	188	107	D-3A
(4) LM6000 PLANT	30,974	17,601	628	7,142	854	621	1,224	1,908	0	635	360	D-3A
(5) GAS TURBINE PLANT - OTHER	6,513	3,701	132	1,502	180	131	257	401	0	133	76	D-3A
(6) TOTAL GENERATION PLANT	650,206	369,484	13,187	149,934	17,929	13,047	25,695	40,043	0	13,322	7,565	
(7) GEN. PROPERTY PLANT	48,831	27,749	990	11,260	1,346	980	1,930	3,007	0	1,000	568	P-7
(8) TOTAL PLANT IN SERVICE	699,037	397,233	14,177	161,194	19,275	14,027	27,625	43,050	0	14,322	8,133	
Working Capital & Deferred Charges/Credits:												
(9) CASH - FUEL	0	0	0	0	0	0	0	0	0	0	0	D-3A
(10) CASH - OTHER	3,742	2,126	76	863	103	75	148	230	0	77	44	O-1
(11) MAT. & SUPPLIES - FUEL	0	0	0	0	0	0	0	0	0	0	0	D-3A
(12) MAT. & SUPPLIES - OTHER	5,974	3,395	121	1,378	165	120	236	368	0	122	70	P-7
(13) DEF. CHG. - Financing	13,689	7,779	278	3,157	377	275	541	843	0	280	159	P-7
(14) DEF. CHG. - Tax	2,051	1,165	42	473	57	41	81	126	0	42	24	P-7
(15) DEF. CHG. - Pension	11,104	6,310	225	2,560	306	223	439	684	0	227	129	O-1
(16) DEF. CHG. - Steam Assets	0	0	0	0	0	0	0	0	0	0	0	D-3A
(17) DEF. CHG. - Fuel Deferral	0	0	0	0	0	0	0	0	0	0	0	D-3A
(18) DEF. CHG. - Other	584	332	12	135	16	12	23	36	0	12	7	P-7
(19) DEF. CHG. - FCR	6,128	3,482	124	1,413	169	123	242	377	0	126	71	P-7
(20) DEF. CR. - ARO Steam	(14,437)	(8,204)	(293)	(3,329)	(398)	(290)	(571)	(889)	0	(296)	(168)	D-3A
(21) DEF. CR. - ARO Hydro	(9,736)	(5,533)	(197)	(2,245)	(268)	(195)	(385)	(600)	0	(199)	(113)	D-3A
(22) DEF. CR. - ARO Wind	(4,646)	(2,640)	(94)	(1,071)	(128)	(93)	(184)	(286)	0	(95)	(54)	D-3A
(23) DEF. CR. - ARO CT	(4,150)	(2,358)	(84)	(957)	(114)	(83)	(164)	(256)	0	(85)	(48)	D-3A
(24) DEF. CR. - Other	(2,175)	(1,236)	(44)	(502)	(60)	(44)	(86)	(134)	0	(45)	(25)	D-3A
(25) CONTRACT RECEIVABLE	0	0	0	0	0	0	0	0	0	0	0	D-3A
(26) SUB-TOTAL	8,126	4,618	165	1,874	224	163	321	500	0	166	95	
(25) TOTAL GEN. FUNCTION	707,163	401,850	14,342	163,068	19,499	14,190	27,946	43,551	0	14,488	8,227	
TRANSMISSION FUNCTION												
(28) TRANSMISSION PLANT < 138kV	47,308	26,883	959	10,909	1,304	949	1,870	2,913	0	969	550	D-3B
(26) GEN. PROPERTY PLANT	3,553	2,019	72	819	98	71	140	219	0	73	41	P-8A
(30) TOTAL PLANT IN SERVICE	50,861	28,902	1,032	11,728	1,402	1,021	2,010	3,132	0	1,042	592	
Working Capital & Deferred Charges/Credits:												
(31) CASH - FUEL	0	0	0	0	0	0	0	0	0	0	0	D-3B
(32) CASH - OTHER	271	154	5	62	7	5	11	17	0	6	3	O-2A
(33) MAT. & SUPPLIES - FUEL	0	0	0	0	0	0	0	0	0	0	0	D-3B
(34) MAT. & SUPPLIES - OTHER	435	247	9	100	12	9	17	27	0	9	5	P-8A
(35) DEF. CHG. - Financing	996	566	20	230	27	20	39	61	0	20	12	P-8A
(36) DEF. CHG. - Tax	149	85	3	34	4	3	6	9	0	3	2	P-8A
(37) DEF. CHG. - Pension	803	456	16	185	22	16	32	49	0	16	9	O-2A
(38) DEF. CHG. - Other	30	17	1	7	1	1	1	2	0	1	0	P-8A
(40) DEF. CR. - ARO Trans.	(2,510)	(1,426)	(51)	(579)	(69)	(50)	(99)	(155)	0	(51)	(29)	D-3B
(41) SUB-TOTAL	173	99	4	40	5	3	7	11	0	4	2	
(42) TOTAL TRANS. < 138kV	51,034	29,001	1,035	11,768	1,407	1,024	2,017	3,143	0	1,046	594	

NOVA SCOTIA POWER INC.

ALLOCATION OF AVERAGE RATE BASE

FOR THE YEAR ENDING DECEMBER 31, 2014

(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
(1) TRANSMISSION PLANT > 69kV	154,863	88,002	3,141	35,711	4,270	3,107	6,120	9,537	0	3,173	1,802	D-3A
(2) GENERAL PROPERTY PLANT	11,630	6,609	236	2,682	321	233	460	716	0	238	135	P-8B
(3) TOTAL PLANT IN SERVICE	166,493	94,611	3,377	38,393	4,591	3,341	6,580	10,254	0	3,411	1,937	
Working Capital & Deferred Charges/Credits:												
(4) CASH - FUEL	0	0	0	0	0	0	0	0	0	0	0	D-3A
(5) CASH - OTHER	860	489	17	198	24	17	34	53	0	18	10	O-2B
(6) MAT. & SUPPLIES - FUEL	0	0	0	0	0	0	0	0	0	0	0	D-3A
(7) MAT. & SUPPLIES - OTHER	1,423	809	29	328	39	29	56	88	0	29	17	P-8B
(8) DEF. CHG. - Financing	3,260	1,853	66	752	90	65	129	201	0	67	38	P-8B
(9) DEF. CHG. - Tax	488	278	10	113	13	10	19	30	0	10	6	P-8B
(10) DEF. CHG. - Pension	2,552	1,450	52	589	70	51	101	157	0	52	30	O-2B
(11) DEF. CHG. - Other	98	56	2	23	3	2	4	6	0	2	1	P-8B
(12) DEF. CHG. - FCR	1,905	1,083	39	439	53	38	75	117	0	39	22	P-8B
(13) DEF. CR. - ARO Trans	(8,216)	(4,669)	(167)	(1,894)	(227)	(165)	(325)	(506)	0	(168)	(96)	D-3A
(14) SUB-TOTAL	2,372	1,348	48	547	65	48	94	146	0	49	28	
(15) TOTAL TRANS. > 69kV	168,865	95,959	3,425	38,939	4,656	3,388	6,673	10,400	0	3,460	1,965	
(14) TOTAL TRANS. FUNCTION	219,899	124,959	4,460	50,708	6,063	4,412	8,690	13,543	0	4,505	2,558	
DISTRIBUTION FUNCTION												
(15) DISTRIBUTION PLANT - Non Stre	429,856	261,619	14,752	119,356	7,548	11,436	9,178	363	0	24	5,581	EXH. 3A
(16) DISTRIBUTION PLANT - Streetlig	10,251	0	0	0	0	0	0	0	0	0	10,251	EXH. 3A
	0	0	0	0	0	0	0	0	0	0	0	
(17) SUB-TOTAL	440,107	261,619	14,752	119,356	7,548	11,436	9,178	363	0	24	15,832	
(18) GEN. PROPERTY PLANT	33,052	20,116	1,134	9,178	580	879	706	28	0	2	429	P-9
	473,160	281,735	15,886	128,534	8,128	12,315	9,884	391	0	25	16,261	
Working Capital & Deferred Charges/Credits:												
(19) CASH - FUEL	0	0	0	0	0	0	0	0	0	0	0	P-9
(20) CASH - OTHER	4,180	2,128	120	986	103	96	124	0	0	0	623	O-3
(21) MAT. & SUPPLIES - FUEL	0	0	0	0	0	0	0	0	0	0	0	P-9
(22) MAT. & SUPPLIES - OTHER	4,044	2,461	139	1,123	71	108	86	3	0	0	53	P-9
(23) DEF. CHG. - Financing	9,266	5,639	318	2,573	163	246	198	8	0	1	120	P-9
(24) DEF. CHG. - Tax	1,388	845	48	385	24	37	30	1	0	0	18	P-9
(25) DEF. CHG. - Pension	12,402	6,313	356	2,925	306	284	368	1	0	0	1,849	O-3
(26) DEF. CHG. - Other	279	170	10	77	5	7	6	0	0	0	4	P-9
(27) SUB-TOTAL	31,558	17,556	990	8,069	672	778	811	14	0	1	2,667	
(28) TOTAL DIST. FUNCTION	504,717	299,291	16,876	136,603	8,800	13,093	10,695	405	0	26	18,929	
(29) TOTAL DEMAND	**$1,431,779**	**$826,101**	**$35,678**	**$350,379**	**$34,363**	**$31,695**	**$47,332**	**$57,498**	**$0**	**$19,020**	**$29,714**	

NOVA SCOTIA POWER INC.
ALLOCATION OF AVERAGE RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2014
(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) INDUSTRIAL LARGE	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
ENERGY CLASSIFICATION												
GENERATION FUNCTION												
(1) STEAM PLANT	$917,241	$427,538	$22,940	$237,360	$37,738	$25,278	$49,640	$88,450	$0	$18,413	$9,886	E-1A
(2) HYDRO PLANT	201,011	93,694	5,027	52,017	8,270	5,540	10,878	19,384	0	4,035	2,166	E-1A
(3) WIND PLANT	192,002	89,495	4,802	49,686	7,899	5,291	10,391	18,515	0	3,854	2,069	E-1A
(4) LM6000 PLANT	40,443	18,851	1,012	10,466	1,664	1,115	2,189	3,900	0	812	436	E-1A
(5) GAS TURBINE PLANT - OTHER	0	0	0	0	0	0	0	0	0	0	0	E-1A
(6) TOTAL GENERATION PLANT	1,350,698	629,578	33,781	349,528	55,571	37,223	73,098	130,248	0	27,114	14,558	
(7) GENERAL PROPERTY PLANT	101,439	47,282	2,537	26,250	4,173	2,795	5,490	9,782	0	2,036	1,093	P-10
(8) TOTAL PLANT IN SERVICE	1,452,137	676,859	36,318	375,778	59,744	40,018	78,588	140,030	0	29,150	15,651	
Working Capital & Deferred Charges/Credits:												
(9) CASH - FUEL	0	0	0	0	0	0	0	0	0	0	0	E-1A
(10) CASH - OTHER	9,707	4,524	243	2,512	399	268	525	936	0	195	105	O-4
(11) MAT. & SUPPLIES - FUEL	84,441	39,359	2,112	21,851	3,474	2,327	4,570	8,143	0	1,695	910	E-1A
(12) MAT. & SUPPLIES - OTHER	12,410	5,784	310	3,211	511	342	672	1,197	0	249	134	P-10
(13) DEF. CHG. - Financing	28,436	13,255	711	7,359	1,170	784	1,539	2,742	0	571	306	P-10
(14) DEF. CHG. - Tax	4,260	1,986	107	1,102	175	117	231	411	0	86	46	P-10
(15) DEF. CHG. - Pension	28,803	13,425	720	7,454	1,185	794	1,559	2,777	0	578	310	O-4
(16) DEF. CHG. - Steam Assets	0	0	0	0	0	0	0	0	0	0	0	E-1A
(17) DEF. CHG. - Fuel Deferral	0	0	0	0	0	0	0	0	0	0	0	E-1A
(18) DEF. CHG. - Other	1,213	565	30	314	50	33	66	117	0	24	13	P-10
(19) DEF. CHG. - FCR	12,729	5,933	318	3,294	524	351	689	1,227	0	256	137	P-10
(20) DEF. CR. - ARO Steam	(29,214)	(13,617)	(731)	(7,560)	(1,202)	(805)	(1,581)	(2,817)	0	(586)	(315)	E-1A
(21) DEF. CR. - ARO Hydro	(13,026)	(6,071)	(326)	(3,371)	(536)	(359)	(705)	(1,256)	0	(261)	(140)	E-1A
(22) DEF. CR. - ARO Wind	(6,215)	(2,897)	(155)	(1,608)	(256)	(171)	(336)	(599)	0	(125)	(67)	E-1A
(23) DEF. CR. - ARO CT	0	0	0	0	0	0	0	0	0	0	0	E-1A
(24) DEF. CR. - Other	(4,402)	(2,052)	(110)	(1,139)	(181)	(121)	(238)	(424)	0	(88)	(47)	E-1A
(25) CONTRACT RECEIVABLE	0	0	0	0	0	0	0	0	0	0	0	E-1A
(26) SUB-TOTAL	129,142	60,195	3,230	33,419	5,313	3,559	6,989	12,453	0	2,592	1,392	
(24) TOTAL GEN. FUNCTION	1,581,279	737,054	39,548	409,197	65,058	43,577	85,577	152,483	0	31,743	17,043	
TRANSMISSION FUNCTION												
(28) TRANSMISSION PLANT < 138kV	61,772	28,793	1,545	15,985	2,541	1,702	3,343	5,957	0	1,240	666	E-1B
(29) GENERAL PROPERTY PLANT	4,639	2,162	116	1,200	191	128	251	447	0	93	50	P-11A
(30) TOTAL PLANT IN SERVICE	66,411	30,955	1,661	17,186	2,732	1,830	3,594	6,404	0	1,333	716	
Working Capital & Deferred Charges/Credits:												
(31) CASH - FUEL	0	0	0	0	0	0	0	0	0	0	0	E-1B
(32) CASH - OTHER	353	165	9	91	15	10	19	34	0	7	4	O-5A
(33) MAT. & SUPPLIES - FUEL	0	0	0	0	0	0	0	0	0	0	0	E-1B
(34) MAT. & SUPPLIES - OTHER	568	265	14	147	23	16	31	55	0	11	6	P-11A
(35) DEF. CHG. - Financing	1,300	606	33	337	54	36	70	125	0	26	14	P-11A
(36) DEF. CHG. - Tax	195	91	5	50	8	5	11	19	0	4	2	P-11A
(37) DEF. CHG. - Pension	1,048	489	26	271	43	29	57	101	0	21	11	O-5A
(38) DEF. CHG. - Other	39	18	1	10	2	1	2	4	0	1	0	P-11A
(40) DEF. CR. - ARO Trans.	(3,277)	(1,527)	(82)	(848)	(135)	(90)	(177)	(316)	0	(66)	(35)	E-1B
(41) SUB-TOTAL	226	106	6	59	9	6	12	22	0	5	2	
(42) TOTAL TRANS. < 138kV	66,638	31,061	1,667	17,244	2,742	1,836	3,606	6,426	0	1,338	718	

NOVA SCOTIA POWER INC.
ALLOCATION OF AVERAGE RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2014
(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) INDUSTRIAL LARGE	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
(1) TRANSMISSION PLANT > 69kV	202,211	94,253	5,057	52,327	8,319	5,573	10,943	19,499	0	4,059	2,179	E-1A
(2) GENERAL PROPERTY PLANT	15,186	7,078	380	3,930	625	419	822	1,464	0	305	164	P-11B
(3) TOTAL PLANT IN SERVICE	217,397	101,332	5,437	56,257	8,944	5,991	11,765	20,964	0	4,364	2,343	
Working Capital & Deferred Charges/Credits:												
(4) CASH - FUEL	0	0	0	0	0	0	0	0	0	0	0	E-1A
(5) CASH - OTHER	1,123	523	28	291	46	31	61	108	0	23	12	O-5B
(6) MAT. & SUPPLIES - FUEL	0	0	0	0	0	0	0	0	0	0	0	E-1A
(7) MAT. & SUPPLIES - OTHER	1,858	866	46	481	76	51	101	179	0	37	20	P-11B
(8) DEF. CHG. - Financing	4,257	1,984	106	1,102	175	117	230	411	0	85	46	P-11B
(9) DEF. CHG. - Tax	638	297	16	165	26	18	35	61	0	13	7	P-11B
(10) DEF. CHG. - Pension	3,333	1,553	83	862	137	92	180	321	0	67	36	O-5B
(11) DEF. CHG. - Other	128	60	3	33	5	4	7	12	0	3	1	P-11B
(12) DEF. CHG. - FCR	2,488	1,160	62	644	102	69	135	240	0	50	27	P-11B
(13) DEF. CR. - ARO Trans	(10,728)	(5,000)	(268)	(2,776)	(441)	(296)	(581)	(1,034)	0	(215)	(116)	E-1A
(14) SUB-TOTAL	3,097	1,443	77	801	127	85	168	299	0	62	33	
(15) TOTAL TRANS. > 69kV	220,494	102,775	5,515	57,058	9,072	6,076	11,933	21,262	0	4,426	2,376	
(15) TOTAL TRANS. FUNCTION	287,132	133,836	7,181	74,303	11,813	7,913	15,539	27,688	0	5,764	3,095	
(16) TOTAL ENERGY	**$1,868,411**	**$870,890**	**$46,730**	**$483,499**	**$76,871**	**$51,490**	**$101,116**	**$180,171**	**$0**	**$37,506**	**$20,138**	

NOVA SCOTIA POWER INC.
ALLOCATION OF AVERAGE RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2014
(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) INDUSTRIAL LARGE	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
CUST. CLASSIFICATION												
DISTRIBUTION FUNCTION												
(1) DISTRIBUTION PLANT	$212,277	$186,613	$9,845	$10,887	$20	$2,235	$205	$63	$0	$7	$2,403	EXH. 3A
(2) GEN. PROPERTY PLANT	15,942	14,015	739	818	1	168	15	5	0	1	180	P-12
(3) TOTAL PLANT IN SERVICE	228,220	200,628	10,584	11,705	21	2,403	220	68	0	7	2,584	
WORKING CAPITAL:												
(4) CASH - FUEL	0	0	0	0	0	0	0	0	0	0	0	P-12
(5) CASH - OTHER	7,432	6,710	354	190	0	39	5	1	0	0	132	O-6
(6) MAT. & SUPPLIES - FUEL	0	0	0	0	0	0	0	0	0	0	0	P-12
(7) MAT. & SUPPLIES - OTHER	1,950	1,715	90	100	0	21	2	1	0	0	22	P-12
(8) DEF. CHG. - Financing	4,469	3,929	207	229	0	47	4	1	0	0	51	P-12
(9) DEF. CHG. - Tax	669	589	31	34	0	7	1	0	0	0	8	P-12
(10) DEF. CHG. - Pension	22,052	19,910	1,050	563	1	116	14	4	0	0	393	O-6
(11) DEF. CHG. - Other	134	118	6	7	0	1	0	0	0	0	2	P-12
(12) SUB-TOTAL	36,708	32,970	1,739	1,123	2	231	26	8	0	1	607	
(13) TOTAL DIST. FUNCTION	264,927	233,598	12,324	12,828	24	2,634	246	75	0	8	3,191	
RETAIL FUNCTION												
(14) DISTRIBUTION PLANT	0	0	0	0	0	0	0	0	0	0	0	EXH. 3A
(15) GEN. PROPERTY PLANT	0	0	0	0	0	0	0	0	0	0	0	P-13
(16) TOTAL PLANT IN SERVICE	0	0	0	0	0	0	0	0	0	0	0	
WORKING CAPITAL:												
(17) CASH - FUEL	0	0	0	0	0	0	0	0	0	0	0	P-13
(18) CASH - OTHER	0	0	0	0	0	0	0	0	0	0	0	O-7
(19) MAT. & SUPPLIES - FUEL	0	0	0	0	0	0	0	0	0	0	0	P-13
(20) MAT. & SUPPLIES - OTHER	0	0	0	0	0	0	0	0	0	0	0	P-13
(21) DEF. CHG. - Financing	0	0	0	0	0	0	0	0	0	0	0	P-13
(22) DEF. CHG. - Tax	0	0	0	0	0	0	0	0	0	0	0	P-13
(23) DEF. CHG. - Pension	0	0	0	0	0	0	0	0	0	0	0	O-7
(24) DEF. CHG. - Other	0	0	0	0	0	0	0	0	0	0	0	P-13
(25) SUB-TOTAL	0	0	0	0	0	0	0	0	0	0	0	
(26) TOTAL RETAIL FUNCTION	0	0	0	0	0	0	0	0	0	0	0	
(27) TOTAL CUSTOMER	**264,927**	**233,598**	**12,324**	**12,828**	**24**	**2,634**	**246**	**75**	**0**	**8**	**3,191**	
(28) TOTAL AVE. RATE BASE	**$3,565,118**	**$1,930,589**	**$94,731**	**$846,706**	**$111,257**	**$85,819**	**$148,694**	**$237,745**	**$0**	**$56,535**	**$53,042**	

NOVA SCOTIA POWER INC.
ALLOCATION OF AVERAGE DISTRIBUTION RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2014
(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
DEMAND												
(1) LAND	$3,023	$1,783	$101	$826	$86	$80	$105	$4	$0	$0	$38	P-3
(2) EASEMENTS & SURVEY	11,505	6,785	383	3,144	327	305	398	17	0	1	145	P-3
(3) OTHER	1,493	880	50	408	42	40	52	2	0	0	19	P-3
(4) SUBSTATIONS	30,113	17,077	963	8,037	1,102	786	1,422	339	0	22	364	EXH 3B
(5) POLES & FIXTURES	119,005	70,595	3,981	32,639	3,234	3,164	3,887	0	0	0	1,506	EXH 3D
(6) O.H. LINES	78,818	46,756	2,636	21,617	2,142	2,095	2,575	0	0	0	997	EXH 3F
(7) U.G. LINES	22,658	13,441	758	6,214	616	602	740	0	0	0	287	P-1
(8) LINE TRANSFORMERS	163,242	104,302	5,881	46,470	0	4,363	0	0	0	0	2,225	D-1
(9) SERVICES	0	0	0	0	0	0	0	0	0	0	0	---
(10) METERS	0	0	0	0	0	0	0	0	0	0	0	---
(11) STREET LIGHTING	10,251	0	0	0	0	0	0	0	0	0	10,251	DIRECT
(12) TOTAL DEMAND	440,107	261,619	14,752	119,356	7,548	11,436	9,178	363	0	24	15,832	
CUSTOMER												
(13) LAND	1,412	1,280	68	32	0	6	0	0	0.000	0	27	P-4
(14) EASEMENTS & SURVEY	5,377	4,871	257	121	0	24	1	0	0.000	0	102	P-4
(15) OTHER	697	632	33	16	0	3	0	0	0.000	0	13	P-4
(16) SUBSTATIONS	0	0	0	0	0	0	0	0	0.000	0	0	---
(17) POLES & FIXTURES	64,080	58,057	3,063	1,442	1	282	13	2	0.000	1	1,220	EXH 3D
(18) O.H. LINES	42,441	38,451	2,029	955	1	187	8	1	0.000	0	808	EXH 3F
(19) U.G. LINES	12,200	11,054	583	275	0	54	2	0	0.000	0	232	P-2
(20) LINE TRANSFORMERS	0	0	0	0	0	0	0	0	0.000	0	0	---
(21) SERVICES	60,998	50,780	2,679	6,305	0	1,234	0	0	0.000	0	0	C-2
(22) METERS	25,072	21,489	1,134	1,742	17	445	180	59	0.000	6	0	EXH 3G
(23) STREET LIGHTING	0	0	0	0	0	0	0	0	0.000	0	0	---
(24) TOTAL CUSTOMER	$212,277	$186,613	$9,845	$10,887	$20	$2,235	$205	$63	$0	$7	$2,403	
RETAIL												
(25) SERVICES	0	0	0	0	0	0	0	0	0	0	0	---
(26) METERS	0	0	0	0	0	0	0	0	0	0	0	---
(27) TOTAL RETAIL	0	0	0	0	0	0	0	0	0	0	0	
SUMMARY												
(28) LAND	4,435	3,062	168	858	86	86	105	5	0	0	65	P-3 & 4
(29) EASEMENTS & SURVEY	16,882	11,657	640	3,265	327	329	399	17	0	1	247	P-3 & 4
(30) OTHER	2,190	1,512	83	424	42	43	52	2	0	0	32	P-3 & 4
(31) SUBSTATIONS	30,113	17,077	963	8,037	1,102	786	1,422	339	0	22	364	EXH 3B
(32) POLES & FIXTURES	183,085	128,652	7,043	34,081	3,235	3,446	3,900	2	0	1	2,726	EXH 3D
(33) O.H. LINES	121,259	85,207	4,665	22,572	2,143	2,282	2,583	1	0	0	1,806	EXH 3F
(34) U.G. LINES	34,858	24,494	1,341	6,489	616	656	742	0	0	0	519	P-1 & 2
(35) LINE TRANSFORMERS	163,242	104,302	5,881	46,470	0	4,363	0	0	0	0	2,225	D-1
(36) SERVICES	60,998	50,780	2,679	6,305	0	1,234	0	0	0	0	0	C-2
(37) METERS	25,072	21,489	1,134	1,742	17	445	180	59	0	6	0	EXH 3G
(38) STREET LIGHTING	10,251	0	0	0	0	0	0	0	0	0	10,251	DIRECT
(39) TOTAL AVE. RATE BASE	**$652,385**	**$448,231**	**$24,597**	**$130,243**	**$7,568**	**$13,671**	**$9,383**	**$426**	**$0**	**$30**	**$18,235**	

EXHIBIT 3B

NOVA SCOTIA POWER INC.

ANALYSIS OF AVERAGE DISTRIBUTION SUBSTATION RATE BASE

FOR THE YEAR ENDING DECEMBER 31, 2014

(IN THOUSANDS OF DOLLARS)

	(1) TOTAL PLANT	(2) DIST. BULK PWR.	(3) DIST. DED. BULK PWR.	(4) DIST. GENERAL	(5) DIST. DED. GENERAL
(1) TOT. DIST. SUBSTATIONS	$30,113	$25,725	$401	$3,904	$83
ALLOCATION					
(2) DOMESTIC	17,077	14,827	0	2,250	0
(3) SMALL GENERAL	963	836	0	127	0
(4) GENERAL	8,037	6,957	25	1,056	0
(5) GENERAL LARGE	1,102	957	0	145	0
(6) SMALL INDUSTRIAL	786	682	0	104	0
(7) MEDIUM INDUSTRIAL	1,422	1,150	94	175	4
(8) LARGE INDUSTRIAL	339	0	260	0	79
(9) ELI 2P-RTP	0	0	0	0	0
(10) MUNICIPAL	22	0	22	0	0
(11) UNMETERED	364	316	0	48	0
(12) TOTAL	$30,113	$25,725	$401	$3,904	$83
ALLOCATION FACTOR		D-2	DIRECT	D-2	DIRECT

EXHIBIT 3C

NOVA SCOTIA POWER INC.

ANALYSIS OF AVERAGE POLE INVESTMENT

FOR THE YEAR ENDING DECEMBER 31, 2014

(IN THOUSANDS OF DOLLARS)

	(1) TOTAL PLANT	(2) PRIMARY DEMAND	(3) PRIMARY CUSTOMER	(4) SECONDARY DEMAND	(5) SECONDARY CUSTOMER
(1) TOTAL NET POLE COST	$183,085				
(2) PRIMARY ONLY (30%)	54,926	$54,926	$0	$0	$0
(3) 50% JOINT - PRI. (1)	64,080	32,040	32,040	0	0
(4) 50% JOINT - SEC. (1)	64,080	0	0	32,040	32,040
(5) TOTAL	$183,085	$86,965	$32,040	$32,040	$32,040

DEMAND COST - 50% }
} (1)
CUSTOMER COST - 50% }

EXHIBIT 3D

NOVA SCOTIA POWER INC.

ALLOCATION OF AVERAGE POLE INVESTMENT

FOR THE YEAR ENDING DECEMBER 31, 2014

(IN THOUSANDS OF DOLLARS)

	(1) TOTAL PLANT	(2) PRIMARY DEMAND	(3) PRIMARY CUSTOMER	(4) SECONDARY DEMAND	(5) SECONDARY CUSTOMER
(1) DOMESTIC	$128,652	$50,124	$29,021	$20,472	$29,036
(2) SMALL GENERAL	7,043	2,826	1,531	1,154	1,532
(3) GENERAL	34,081	23,518	721	9,121	721
(4) GENERAL LARGE	3,235	3,234	1	0	0
(5) SMALL INDUSTRIAL	3,446	2,307	141	856	141
(6) MEDIUM INDUSTRIAL	3,900	3,887	13	0	0
(7) LARGE INDUSTRIAL	2	0	2	0	0
(8) ELI 2P-RTP	0	0	0	0	0
(9) MUNICIPAL	1	0	1	0	0
(10) UNMETERED	2,726	1,069	610	437	610
(11) TOTAL	$183,085	$86,965	$32,040	$32,040	$32,040
ALLOCATION FACTOR		D-2	C-5	D-1	C-4

EXHIBIT 3E

NOVA SCOTIA POWER INC.

ANALYSIS OF AVERAGE WIRE INVESTMENT

FOR THE YEAR ENDING DECEMBER 31, 2014

(IN THOUSANDS OF DOLLARS)

	(1) TOTAL PLANT	(2) PRIMARY DEMAND	(3) PRIMARY CUSTOMER	(4) SECONDARY DEMAND	(5) SECONDARY CUSTOMER
(1) TOTAL NET WIRE COST	$121,259				
(2) PRIMARY ONLY (30%)	36,378	$36,378	$0	$0	$0
(3) 50% JOINT - PRI. (1)	42,441	21,220	21,220	0	0
(4) 50% JOINT - SEC. (1)	42,441	0	0	21,220	21,220
(5) TOTAL	$121,259	$57,598	$21,220	$21,220	$21,220

DEMAND COST - 50% }
} (1)
CUSTOMER COST - 50% }

EXHIBIT 3F

NOVA SCOTIA POWER INC.

ALLOCATION OF AVERAGE WIRE INVESTMENT

FOR THE YEAR ENDING DECEMBER 31, 2014

(IN THOUSANDS OF DOLLARS)

	(1) TOTAL PLANT	(2) PRIMARY DEMAND	(3) PRIMARY CUSTOMER	(4) SECONDARY DEMAND	(5) SECONDARY CUSTOMER
(1) DOMESTIC	$85,207	$33,197	$19,221	$13,559	$19,231
(2) SMALL GENERAL	4,665	1,872	1,014	765	1,015
(3) GENERAL	22,572	15,576	477	6,041	478
(4) GENERAL LARGE	2,143	2,142	1	0	0
(5) SMALL INDUSTRIAL	2,282	1,528	93	567	93
(6) MEDIUM INDUSTRIAL	2,583	2,575	8	0	0
(7) LARGE INDUSTRIAL	1	0	1	0	0
(8) ELI 2P-RTP	0	0	0	0	0
(9) MUNICIPAL	0	0	0	0	0
(10) UNMETERED	1,806	708	404	289	404
(11) TOTAL	$121,259	$57,598	$21,220	$21,220	$21,220
ALLOCATION FACTOR		D-2	C-5	D-1	C-4

EXHIBIT 3G

NOVA SCOTIA POWER INC.

ANALYSIS OF AVERAGE METER INVESTMENT

FOR THE YEAR ENDING DECEMBER 31, 2014

	(1) TOTAL CUSTOMERS	(2) UNIT METER COST	(3) TOTAL COST	(4) PERCENT	(5) METER COST ($000)
(1) DOMESTIC	456,991	$34.00	$15,537,694	85.71	$21,489
(2) SMALL GENERAL	24,109	34.00	819,706	4.52	1,134
(3) GENERAL	11,349	111.00	1,259,739	6.95	1,742
(4) GENERAL LARGE	19	657.00	12,483	0.07	17
(5) SMALL INDUSTRIAL	2,221	145.00	322,045	1.78	445
(6) MEDIUM INDUSTRIAL	198	657.00	130,086	0.72	180
(7) LARGE INDUSTRIAL	32	1,338.00	42,816	0.24	59
(8) ELI 2P-RTP	0	1,338.00	0	0.00	0
(9) MUNICIPAL	8	520.00	4,160	0.02	6
(10) UNMETERED	9,604	N/A	0	0.00	0
(11) TOTAL	504,531		$18,128,729	100.00	$25,072

EXHIBIT 4

NOVA SCOTIA POWER INC.

FUNCTIONALIZATION OF OPERATING EXPENSES

FOR THE YEAR ENDING DECEMBER 31, 2014

(IN THOUSANDS OF DOLLARS)

	(1) TOTAL EXPENSES	(2) PROD. EXPENSES	(3) TRANS. EXPENSES	(4) DIST. EXPENSES	(5) RETAIL EXPENSES	(6) DIRECT EXPENSES
POWER PRODUCTION						
(1) FUEL	$396,709	$365,712	$0	$0	$0	$30,997
PURCHASED POWER:						
(2) REGULAR	49,388	49,388	0	0	0	0
(3) WIND	67,576	67,576	0	0	0	0
(4) THERMAL - OPERATING & MAINT.	85,135	84,471	0	0	0	664
(5) HYDRO - OPERATING & MAINT.	9,787	7,519	0	0	0	2,267
(6) WIND - OPERATING & MAINT.	4,727	4,717	0	0	0	11
(7) BIOMASS - OPERATING & MAINT.	6,261	6,246	0	0	0	14
(8) LM6000 - OPERATING & MAINT.	329	328	0	0	0	1
(9) COMBUSTION TURBINE - OPER. & MAINT.	972	970	0	0	0	2
(10) ENERGY, FUELS & RISK MGMT.	3,909	3,900	0	0	0	9
(11) GENERATION DEVELOPMENT	0	0	0	0	0	0
(12) TOTAL PRODUCTION OPER. & MAINT.	111,119	108,151	0	0	0	2,968
CUSTOMER OPERATIONS:						
(13) TRANSMISSION & DISTRIBUTION	53,834	0	17,614	35,791	0	429
CUST. SERV. / MARKETING & SALES:						
(14) Qty. Ass., Comm., Call Ctr. & Rev. Ops.	37,358	0	0	607	36,751	0
OTHER OPERATING						
CORPORATE GROUPS:						
(15) EXECUTIVE MANAGEMENT	1,160	417	127	301	313	1
(16) CORP. SECRETARY & LEGAL SERVICES	8,833	3,176	971	2,294	2,382	9
(17) EXTERNAL RELATIONS & ENVIRONMENT	2,102	756	231	546	567	2
(18) REGULATORY AFFAIRS	6,236	2,243	685	1,620	1,682	6
(19) FINANCE GROUP	6,863	2,468	754	1,782	1,851	7
(20) ENTERPRISE SERVICES	22,254	8,003	2,445	5,780	6,002	24
(21) HUMAN RESOURCES	5,648	2,031	621	1,467	1,523	7
(22) TECHNICAL & CONSTRUCTION SERVICES	14,550	2,892	1,633	3,865	6,150	9
(23) SUSTAINABILITY	1,527	1,523	0	0	0	3
(24) SUB-TOTAL	69,171	23,509	7,468	17,655	20,470	69
(25) OTHER EXPENSES	11,616	4,177	1,276	3,017	3,133	12
(26) DIRECT ADMIN. & GEN. EXPENSE	0	(237)	(72)	(171)	(178)	658
(27) TOTAL OM&G EXPENSES	**283,098**	**135,601**	**26,286**	**56,898**	**60,177**	**4,137**
(28) COGS (NET OF SALES)	(432)	0	0	0	(432)	0
(29) DSM AMORTIZATION	1,058	970	0	0	0	88
(30) FCR DEFERRAL	16,500	13,382	3,118	0	0	0
(31) OTHER EXPENSES	0	0	0	0	0	0
(32) GRANTS IN LIEU OF TAXES	38,361	24,516	5,712	7,993	0	140
DEPRECIATION:						
(33) STEAM	65,371	65,222	0	0	0	149
(34) HYDRO	11,163	10,084	0	0	0	1,079
(35) WIND	8,186	8,167	0	0	0	19
(36) LM6000	2,084	2,079	0	0	0	5
(37) OTHER GAS TURBINE	1,202	1,199	0	0	0	3
(38) TRANSMISSION < 138kV	5,371	0	5,362	0	0	9
(39) TRANSMISSION > 69kV	17,580	0	17,549	0	0	31
(40) DISTRIBUTION - Non Streetlight Related	47,699	0	0	47,699	0	0
(41) DISTRIBUTION - Streetlight Related	3,604	0	0	2,240	0	1,364
(42) GENERAL PROPERTY	39,917	25,560	5,955	8,334	0	69
(43) INTEREST NET	142,589	89,216	19,767	30,005	0	3,601
(44) PREFERRED DIVIDENDS	8,000	5,082	1,126	1,709	0	83
(45) CORPORATE TAXES	56,632	35,985	7,973	12,102	0	572
(46) TOTAL EXPENSES	**$1,261,656**	**$899,739**	**$92,846**	**$166,981**	**$59,745**	**$42,345**
(47) NON-OPERATING REVENUE:						
(48) EXPORT SALES	(1,943)	(1,943)	0	0	0	0
(49) LATE PAYMENT CHARGE	(5,330)	0	0	0	(5,330)	0
(50) MISC. ELECTRIC	(2,003)	0	0	0	(2,003)	0
(51) OTHER REVENUE	(14,648)	(10,809)	(1,115)	(2,006)	(718)	0
(52) NET INCOME	124,745	76,898	17,038	25,862	0	4,948
(53) TOTAL NET EXPENSES	**$1,362,477**	**$963,884**	**$108,769**	**$190,837**	**$51,695**	**$47,292**

EXHIBIT 4 - Detail A

NOVA SCOTIA POWER INC.

FUNCTIONALIZATION OF OPERATING EXPENSES

FOR THE YEAR ENDING DECEMBER 31, 2014

(IN THOUSANDS OF DOLLARS)

		(1) TOTAL EXPENSES	(2) PROD. EXPENSES	(3) TRANS. EXPENSES	(4) DIST. EXPENSES	(5) RETAIL EXPENSES	(6) DIRECT EXPENSES
(1)	**FUEL**	$396,709	$365,712	$0	$0	$0	$30,997
	PURCHASED POWER:						
(2)	REGULAR	49,388	49,388	0	0	0	0
(3)	WIND	67,576	67,576	0	0	0	0
(4)	TOTAL	513,673	482,677	0	0	0	30,997
	POWER PRODUCTION						
(5)	THERMAL OPERATING & MAINT.	85,135	84,471	0	0	0	664
(6)	HYDRO OPERATING & MAINT.	9,787	7,519	0	0	0	2,267
(7)	WIND - OPERATING & MAINT.	4,727	4,717	0	0	0	11
(8)	BIOMASS - OPERATING & MAINT.	6,261	6,246	0	0	0	14
(9)	LM6000 OPERATING & MAINT.	329	328	0	0	0	1
(10)	COMBUSTION TURBINE - OPER. & MAINT.	972	970	0	0	0	2
(11)	FUEL PROCUREMENT	3,909	3,900	0	0	0	9
(12)	GENERATION DEVELOPMENT	0	0	0	0	0	0
(13)							
(14)	**TOTAL POWER PRODUCTION**	111,119	108,151	0	0	0	2,968
(15)	**SUSTAINABILITY**	1,527	1,523	0	0	0	3
	CORPORATE GROUPS						
(16)	EXECUTIVE MANAGEMENT	1,160	417	127	301	313	1
(17)	CORP. SECRETARY	7,647	2,750	840	1,986	2,063	8
(18)	LEGAL SERVICES	1,185	426	130	308	320	1
(19)	EXTERNAL RELATIONS	2,102	756	231	546	567	2
(20)	ENVIRONMENTAL POLICIES & PROGRAMS	0	0	0	0	0	0
(21)	Total Corporate Groups	12,094	4,350	1,329	3,141	3,262	12
	CUSTOMER OPERATIONS						
	TRANSMISSION & DISTRIBUTION:						
(22)	**TRANSMISSION:**						
(23)	**< 138kV**	4,222	0	4,215	0	0	7
(24)	**> 69kV**	13,821	0	13,399	0	0	422
	DISTRIBUTION:						
(25)	SUBSTATIONS	196	0	0	196	0	0
(26)	OVERHEAD LINES	24,793	0	0	24,793	0	0
(27)	UNDERGROUND LINES	444	0	0	444	0	0
(28)	LINE TRANSFORMERS	949	0	0	949	0	0
(29)	METERS (Meter Shop Only)	0	0	0	0	0	0
(30)	COMMUNICATIONS	5,682	0	0	5,682	0	0
(31)	STREET LIGHTING	3,727	0	0	3,727	0	0
(33)	**TOTAL DISTRIBUTION**	35,791	0	0	35,791	0	0
(34)	**TOTAL CUSTOMER OPERATIONS - T & D**	53,834	0	17,614	35,791	0	429
(35)	**TECHNICAL & CONSTRUCTION SERVICES**	14,550	2,892	1,633	3,865	6,150	9
	CUST. SERV. / MARKETING & SALES						
	ADMINISTRATION:						
(36)	CUSTOMER SERVICE - ADMIN.	721	0	0	0	721	0
(37)	ENERGY EFFICIENCY	481	0	0	0	481	0
(38)	CUST. COMM. & QTY ASSURANCE	1,877	0	0	0	1,877	0
(39)	CUSTOMER SOLUTIONS	0	0	0	0	0	0
(40)	**CALL CENTRE:**						
(41)	(a) CALL CENTRE - CSR's	7,082	0	0	0	7,082	0
(42)	(b) CALL CENTRE OPERATIONS	0	0	0	0	0	0
(43)	(c) CALL CENTRE - HALIFAX	0	0	0	0	0	0
(44)	(d) CALL NETWORK (COLLECTIONS)	377	0	0	0	377	0
(45)	(e) ELECTRICAL WIRING INSPECTION	4,498	0	0	0	4,498	0
(46)	**REVENUE OPERATIONS:**						
(47)	(a) BILLING SERVICES	3,726	0	0	0	3,726	0
(48)	(b) METER DATA SERVICES	474	0	0	0	474	0
(49)	(c) METER SERVICES - METER SHOP	607	0	0	607	0	0
(50)	(d) METER SERVICES - FIELD	6,188	0	0	0	6,188	0
(51)	(e) ELECTRICAL WIRING INSPECTION - FIELD	3,476	0	0	0	3,476	0
(52)	(f) PAYMENT SERVICES	713	0	0	0	713	0
(53)	(g) CREDIT SERVICES	0	0	0	0	0	0
(54)	(h) BAD DEBT EXPENSE	5,704	0	0	0	5,704	0
(55)	(i) MARKETING & SALES	1,167	0	0	0	1,167	0

(56) (j) ELECTRICAL WIRING INSPECTION - H/O	268	0	0	0	268	0
(58) **TOTAL CUST. SERV. / MARKETING & SALES**	37,358	0	0	607	36,751	0

NOVA SCOTIA POWER INC.
FUNCTIONALIZATION OF OPERATING EXPENSES
FOR THE YEAR ENDING DECEMBER 31, 2014
(IN THOUSANDS OF DOLLARS)

	(1) TOTAL EXPENSES	(2) PROD. EXPENSES	(3) TRANS. EXPENSES	(4) DIST. EXPENSES	(5) RETAIL EXPENSES	(6) DIRECT EXPENSES
(1) **REGULATORY AFFAIRS**	$6,236	$2,243	$685	$1,620	$1,682	$6
FINANCE GROUP						
(2) INTERNAL AUDIT	1,732	623	190	450	467	2
(3) INVESTOR RELATIONS	292	105	32	76	79	0
(4) DIRECTOR FINANCE	745	268	82	193	201	1
(5) TREASURER	793	285	87	206	214	1
(6) CORPORATE TAX	836	301	92	217	226	1
(7) GM FINANCE	0	0	0	0	0	0
(8) CORPORATE CONTROLLER	2,464	886	271	640	665	2
(9) CORP. PERFORMANCE & BACK OFFICE	0	0	0	0	0	0
(10) **TOTAL FINANCE**	6,863	2,468	754	1,782	1,851	7
ENTERPRISE SERVICES						
(11) PROCUREMENT & FACILITIES	10,129	3,642	1,113	2,631	2,732	11
(12) INFORMATION TECHNOLOGY	12,126	4,361	1,332	3,149	3,270	13
(13) **TOTAL ENTERPRISE SERVICES**	22,254	8,003	2,445	5,780	6,002	24
HUMAN RESOURCES						
(14) --HUMAN RESOURCES	5,648	2,031	621	1,467	1,523	7
(15) OTHER EXPENSES	11,616	4,177	1,276	3,017	3,133	12
(16) DIRECT ADM. & GEN. EXPENSE	0	(237)	(72)	(171)	(178)	658
(17) **TOTAL DIVISIONAL EXPENSES**	**283,098**	**135,601**	**26,286**	**56,898**	**60,177**	**4,137**
(18) **COGS (NET OF RETAIL SALES)**	**(432)**	**0**	**0**	**0**	**(432)**	**0**
(19) **DSM EXPENSES**	**1,058**	**970**	**0**	**0**	**0**	**88**
(20) **FCR DEFERRAL**	**16,500**	**13,382**	**3,118**	**0**	**0**	**0**
(21) **OTHER EXPENSES**	**0**	**0**	**0**	**0**	**0**	
CAPITAL RELATED EXPENSES						
(22) GRANTS IN LIEU OF TAXES	38,361	24,516	5,712	7,993	0	140
(23) DEPRECIATION :						
(24) STEAM	65,371	65,222	0	0	0	149
(25) HYDRO	11,163	10,084	0	0	0	1,079
(26) WIND	8,186	8,167	0	0	0	19
(27) LM6000	2,084	2,079	0	0	0	5
(28) GAS TURBINE - OTHER	1,202	1,199	0	0	0	3
(29) TRANSMISSION < 138kV	5,371	0	5,362	0	0	9
(30) TRANSMISSION > 69kV	17,580	0	17,549	0	0	31
(31) DISTRIBUTION - Non Streetlight Related	47,699	0	0	47,699	0	0
(32) DISTRIBUTION - Streetlight Related	3,604	0	0	2,240	0	1,364
(33) GENERAL PROPERTY	39,917	25,560	5,955	8,334	0	69
(34) GLACE BAY WRITE-OFF	0	0	0	0	0	0
(35) INTEREST NET	142,589	89,216	19,767	30,005	0	3,601
(36) PREFERRED DIVIDENDS	8,000	5,082	1,126	1,709	0	83
(37) CORPORATE TAXES	56,632	35,985	7,973	12,102	0	572
(38) **TOTAL OPERATING EXPENSES**	**1,261,656**	**899,739**	**92,846**	**166,981**	**59,745**	**42,345**
(39) NON-OPERATING REVENUE:						0
(40) GREEN POWER SURCHARGE	0	0	0	0	0	0
(41) EXPORT SALES	(1,943)	(1,943)	0	0	0	0
(42) LATE PAYMENT CHARGE	(5,330)	0	0	0	(5,330)	0
(43) MISC. ELECTRIC	(2,003)	0	0	0	(2,003)	0
(44) OTHER REVENUE	(14,648)	(10,809)	(1,115)	(2,006)	(718)	0
(45) **PROFIT/LOSS**	124,745	76,898	17,038	25,862	0	4,948
(46) **TOTAL NET EXPENSES**	**$1,362,477**	**$963,884**	**$108,769**	**$190,837**	**$51,695**	**$47,292**

EXHIBIT 4 - Detail B

FUNCTIONALIZATION OF OPERATING EXPENSES BEFORE LRT

NON-FUEL RELATED EXPENSES BY THE FUNCTIONAL AREAS AFFECTED BY LRT

Fixed Cost Contribution $4.00
Load 322
$1,288

	(1) TOTAL EXPENSES	(2) PROD. EXPENSES	(3) TRANS. EXPENSES	(4) DIST. EXPENSES	(5) RETAIL EXPENSES	(6) DIRECT EXPENSES	(1) TOTAL EXPENSES	(2) PROD. EXPENSES	(3) TRANS. EXPENSES	(4) DIST. EXPENSES	(5) RETAIL EXPENSES	(6) DIRECT EXPENSES	(7) WEIGHTS		(8) DIRECT LRT
(1) **FUEL**	$396,709	$365,712	$0	$0	$0	$30,997	$0	0					0.00%	0.00%	$0.00
PURCHASED POWER:															
(2) REGULAR	49,388	49,388	0	0	0	0	0	0					0.00%	0.00%	$0.00
(3) WIND	67,576	67,576	0	0	0	0	0	0					0.00%	0.00%	$0.00
(4) TOTAL	513,673	482,677	0	0	0	30,997	0	0					0.00%	0.00%	$0.00
POWER PRODUCTION															
(5) THERMAL OPERATING & MAINT.	85,135	84,664	0	0	0	471	84,664	84,664	0				15.00%	15.00%	$193.22
(6) HYDRO OPERATING & MAINT.	9,787	7,537	0	0	0	2,250	7,537	7,537	0				1.34%	1.34%	$17.20
(7) WIND - OPERATING & MAINT.	4,727	4,727	0	0	0	0	4,727	4,727	0				0.84%	0.84%	$10.79
(8) BIOMASS - OPERATING & MAINT.	6,261	6,261	0	0	0	0	6,261	6,261	0				1.11%	1.11%	$14.29
(9) LM6000 OPERATING & MAINT.	329	329	0	0	0	0	329	329	0				0.06%	0.06%	$0.75
(10) COMBUSTION TURBINE - OPER. & MAINT.	972	972	0	0	0	0	972	972	0				0.17%	0.17%	$2.22
(11) FUEL PROCUREMENT	3,909	3,909	0	0	0	0	3,909	3,909	0				0.69%	0.69%	$8.92
(12) GENERATION DEVELOPMENT	0	0	0	0	0	0	0	0	0				0.00%	0.00%	$0.00
(13)									0				0.00%	0.00%	$0.00
(14) **TOTAL POWER PRODUCTION**	111,119	108,398	0	0	0	2,721	108,398	108,398	0				19.20%	19.20%	$247.39
(15) **SUSTAINABILITY**	1,527	1,527	0	0	0	0	1,527	1,527	0				0.27%	0.27%	$3.48
CORPORATE GROUPS															
(16) EXECUTIVE MANAGEMENT	1,160	418	128	302	313	0	515	418	98				0.09%	0.09%	$1.18
(17) CORP. SECRETARY	7,647	2,753	841	1,988	2,065	0	3,397	2,753	644				0.60%	0.60%	$7.75
(18) LEGAL SERVICES	1,185	427	130	308	320	0	527	427	100				0.09%	0.09%	$1.20
(19) EXTERNAL RELATIONS	2,102	757	231	546	568	0	934	757	177				0.17%	0.17%	$2.13
(20) ENVIRONMENTAL POLICIES & PROGRAMS	0	0	0	0	0	0	0	0	0				0.00%	0.00%	$0.00
	12,094	4,354	1,330	3,145	3,265	0	5,373	4,354	1019						$12.26
CUSTOMER OPERATIONS															
TRANSMISSION & DISTRIBUTION:															
(21) **TRANSMISSION:**															
(22) **< 138kV**	4,222	0	4,222	0	0	0	3,234	0	3234				0.57%	0.57%	$7.38
(23) **> 69kV**	13,821	0	13,423	0	0	398	10,282	0	10282				1.82%	1.82%	$23.47
DISTRIBUTION:															
(24) SUBSTATIONS	196	0	0	196	0	0	0	0	0				0.00%	0.00%	$0.00
(25) OVERHEAD LINES	24,793	0	0	24,793	0	0	0	0	0				0.00%	0.00%	$0.00
(26) UNDERGROUND LINES	444	0	0	444	0	0	0	0	0				0.00%	0.00%	$0.00
(27) LINE TRANSFORMERS	949	0	0	949	0	0	0	0	0				0.00%	0.00%	$0.00
(28) METERS (Meter Shop Only)	0	0	0	0	0	0	0	0	0				0.00%	0.00%	$0.00
(29) COMMUNICATIONS	5,682	0	0	5,682	0	0	0	0	0				0.00%	0.00%	$0.00
(30) STREET LIGHTING	3,727	0	0	3,727	0	0	0	0	0				0.00%	0.00%	$0.00
(31)									0				0.00%	0.00%	
(32) **TOTAL DISTRIBUTION**	35,791	0	0	35,791	0	0	0	0	0	0	0	0	0.00%	0.00%	$0.00
(33) **TOTAL CUSTOMER OPERATIONS - T & D**	53,834	0	17,645	35,791	0	398	13,516	0	13,516	0	0	0	2.39%	2.39%	$30.85
(34) **TECHNICAL & CONSTRUCTION SERVICES**	14,550	2,900	1,635	3,865	6,150	0	4,153	2,900	1253	0	0	0	0.74%	0.74%	$9.48
CUST. SERV. / MARKETING & SALES															
ADMINISTRATION:															
(35) CUSTOMER SERVICE - ADMIN.	721	0	0	0	721	0	0	0	0				0.00%	0.00%	$0.00
(36) ENERGY EFFICIENCY	481	0	0	0	481	0	0	0	0				0.00%	0.00%	$0.00
(37) CUST. COMM. & QTY ASSURANCE	1,877	0	0	0	1,877	0	0	0	0				0.00%	0.00%	$0.00
(38) CUSTOMER SOLUTIONS	0	0	0	0	0	0	0	0	0				0.00%	0.00%	$0.00
(39) **CALL CENTRE:**															
(40) (a) CALL CENTRE - CSR's	7,082	0	0	0	7,082	0	0	0	0				0.00%	0.00%	$0.00
(41) (b) CALL CENTRE OPERATIONS	0	0	0	0	0	0	0	0	0				0.00%	0.00%	$0.00
(42) (c) CALL CENTRE - HALIFAX	0	0	0	0	0	0	0	0	0				0.00%	0.00%	$0.00
(43) (d) CALL NETWORK (COLLECTIONS)	377	0	0	0	377	0	0	0	0				0.00%	0.00%	$0.00
(44) (e) ELECTRICAL WIRING INSPECTION	4,498	0	0	0	4,498	0	0	0	0				0.00%	0.00%	$0.00
(45) **REVENUE OPERATIONS:**															
(46) (a) BILLING SERVICES	3,726	0	0	0	3,726	0	0	0	0				0.00%	0.00%	$0.00
(47) (b) METER DATA SERVICES	474	0	0	0	474	0	0	0	0				0.00%	0.00%	$0.00
(48) (c) METER SERVICES - METER SHOP	607	0	0	607	0	0	0	0	0				0.00%	0.00%	$0.00
(49) (d) METER SERVICES - FIELD	6,188	0	0	0	6,188	0	0	0	0				0.00%	0.00%	$0.00
(50) (e) ELECTRICAL WIRING INSPECTION - FIELD	3,476	0	0	0	3,476	0	0	0	0				0.00%	0.00%	$0.00
(51) (f) PAYMENT SERVICES	713	0	0	0	713	0	0	0	0				0.00%	0.00%	$0.00
(52) (g) CREDIT SERVICES	0	0	0	0	0	0	0	0	0				0.00%	0.00%	$0.00
(53) (h) BAD DEBT EXPENSE	5,704	0	0	0	5,704	0	0	0	0				0.00%	0.00%	$0.00
(54) (i) MARKETING & SALES	1,167	0	0	0	1,167	0	0	0	0				0.00%	0.00%	$0.00
(55) (j) ELECTRICAL WIRING INSPECTION - H/O	268	0	0	0	268	0	0	0	0				0.00%	0.00%	$0.00
(57) **TOTAL CUST. SERV. / MARKETING & SALES**	37,358	0	0	607	36,751	0	0	0	0	0	0	0	0.00%	0.00%	$0.00

NOVA SCOTIA POWER INC.
FUNCTIONALIZATION OF OPERATING EXPENSES
DEDICATED DIST.PLT.- LINE TRANSFORMERS
(IN THOUSANDS OF DOLLARS)

	FUNCTIONALIZATION OF OPERATING EXPENSES BEFORE ELR						NON-FUEL RELATED EXPENSES BY THE FUNCTIONAL AREAS AFFECTED BY LRT									
	(1) TOTAL EXPENSES	(2) PROD. EXPENSES	(3) TRANS. EXPENSES	(4) DIST. EXPENSES	(5) RETAIL EXPENSES	(6) DIRECT EXPENSES	(1) TOTAL EXPENSES	(2) PROD. EXPENSES	(3) TRANS. EXPENSES	(4) DIST. EXPENSES	(5) RETAIL EXPENSES	(6) DIRECT EXPENSES	(7) EXPENSES		(8) DIRECT LRT	
(1) **REGULATORY AFFAIRS**	$6,236	$2,245	$686	$1,621	$1,684	$0	$2,770	$2,245	525				0.49%	0.49%	$6.32	
FINANCE GROUP																
(2) INTERNAL AUDIT	1,732	623	190	450	468	0	769	$623	146				0.14%	0.14%	$1.76	
(3) INVESTOR RELATIONS	292	105	32	76	79	0	130	$105	25				0.02%	0.02%	$0.30	
(4) DIRECTOR FINANCE	745	268	82	194	201	0	331	$268	63				0.06%	0.06%	$0.76	
(5) TREASURER	793	286	87	206	214	0	352	$286	67				0.06%	0.06%	$0.80	
(6) CORPORATE TAX	836	301	92	217	226	0	372	$301	70				0.07%	0.07%	$0.85	
(7) GM FINANCE	0	0	0	0	0	0	0	$0	0				0.00%	0.00%	$0.00	
(8) CORPORATE CONTROLLER	2,464	887	271	641	665	0	1,095	$887	208				0.19%	0.19%	$2.50	
(9) CORP. PERFORMANCE & BACK OFFICE	0	0	0	0	0	0	0	$0	0				0.00%	0.00%	$0.00	
(10) **TOTAL FINANCE**	6,863	2,471	755	1,784	1,853	0	3,049	$2,471	578				0.54%	0.54%	$6.96	
ENTERPRISE SERVICES																
(11) PROCUREMENT & FACILITIES	10,129	2,633	2,735	3,646	1,114	0	4,728	$2,633	2095				0.84%	0.84%	$10.79	
(12) INFORMATION TECHNOLOGY	12,126	3,153	3,274	4,365	1,334	0	5,660	$3,153	2508				1.00%	1.00%	$12.92	
(13) **TOTAL ENTERPRISE SERVICES**	22,254	5,786	6,009	8,012	2,448	0	10,389	$5,786	4603				1.84%	1.84%	$23.71	
HUMAN RESOURCES																
(14) --HUMAN RESOURCES	5,648	1,525	2,033	621	1,468	0	3,082	$1,525	1557				0.55%	0.55%	$7.03	
(15) OTHER EXPENSES	11,616	4,182	1,278	3,020	3,136	0	5,160	$4,182	979				0.91%	0.91%	$11.78	
(16) DIRECT ADM. & GEN. EXPENSE	0	(237)	(72)	(171)	(178)	659	(293)	($237)	-56				-0.05%	-0.05%	($0.67)	
(17) **TOTAL DIVISIONAL EXPENSES**	**283,098**	**133,150**	**31,299**	**58,294**	**56,578**	**3,778**	**157,125**	**133,150**	**23,975**				27.83%	27.83%	$358.60	$358.60
(18) **COGS (NET OF RETAIL SALES)**	**(432)**	**0**	**0**	**0**	**(432)**	**0**	**0**	$0	0				0.00%	0.00%	$0.00	
(19) **DSM EXPENSES**	**1,058**	**972**	**0**	**0**	**0**	**86**	**972**	$972	0				0.17%	0.17%	$2.22	
(20) **FCR DEFERRAL**	**16,500**	**13,382**	**3,118**	**0**	**0**	**0**	**0**	$0					0	0	0	
(21) **OTHER EXPENSES**	**0**	**0**	**0**	**0**	**0**		**0**	$0	0				0.00%	0.00%	$0.00	
CAPITAL RELATED EXPENSES																
(22) GRANTS IN LIEU OF TAXES	38,361	24,559	5,721	8,007	0	74	28,941	$24,559	4383				5.13%	5.13%	$66.05	
(23) DEPRECIATION :									0							
(24) STEAM	65,371	65,371	0	0	0	0	65,371	$65,371	0				11.58%	11.58%	$149.19	
(25) HYDRO	11,163	10,107	0	0	0	1,056	10,107	$10,107	0				1.79%	1.79%	$23.07	
(26) WIND	8,186	8,186	0	0	0	0	8,186	$8,186	0				1.45%	1.45%	$18.68	
(27) LM6000	2,084	2,084	0	0	0	0	2,084	$2,084	0				0.37%	0.37%	$4.76	
(28) GAS TURBINE - OTHER	1,202	1,202	0	0	0	0	1,202	$1,202	0				0.21%	0.21%	$2.74	
(29) TRANSMISSION < 138kV	5,371	0	5,371	0	0	0	4,114	$0	4114				0.73%	0.73%	$9.39	
(30) TRANSMISSION > 69kV	17,580	0	17,580	0	0	0	13,466	$0	13466				2.39%	2.39%	$30.73	
(31) DISTRIBUTION - Non Streetlight Related	47,699	0	0	47,699	0	0	0	$0	0				0.00%	0.00%	$0.00	
(32) DISTRIBUTION - Streetlight Related	3,604	0	0	2,240	0	1,364	0	$0	0				0.00%	0.00%	$0.00	
(33) GENERAL PROPERTY	39,917	25,604	5,965	8,348	0	0	30,173	$25,604	4569				5.35%	5.35%	$68.86	
(34) GLACE BAY WRITE-OFF	0	0	0	0	0	0	0	$0	0				0.00%	0.00%	$0.00	
(35) INTEREST NET	142,589	89,369	19,801	30,056	0	3,363	104,536	$89,369	15167				18.52%	18.52%	$238.58	
(36) PREFERRED DIVIDENDS	8,000	5,091	1,128	1,712	0	69	5,955	$5,091	864				1.05%	1.05%	$13.59	
(37) CORPORATE TAXES	56,632	36,047	7,987	12,123	0	476	42,164	$36,047	6118				7.47%	7.47%	$96.23	
(38) **TOTAL OPERATING EXPENSES**	**1,261,656**	**897,799**	**97,969**	**168,480**	**56,146**	**41,262**	**474,396**	**401,740**	**72,656**	**0**	**0**	**0**	84.04%	84.04%	$1,082.68	$1,082.68
(39) NON-OPERATING REVENUE:													0.00%	0.00%	$0.00	
(40) GREEN POWER SURCHARGE	0	0	0	0	0	0	0	$0	0				0.00%	0.00%	$0.00	
(41) EXPORT SALES	(1,943)	(1,943)	0	0	0	0	0	$0	0				0.00%	0.00%	$0.00	
(42) LATE PAYMENT CHARGE	(5,330)	0	0	0	(5,330)	0	0	$0	0				0.00%	0.00%	$0.00	
(43) MISC. ELECTRIC	(2,003)	0	0	0	(2,003)	0	0	$0	0				0.00%	0.00%	$0.00	
(44) OTHER REVENUE	(14,648)	(10,776)	(1,176)	(2,022)	(674)	0	0	$0	0				0.00%	0.00%	$0.00	
(45) **PROFIT/LOSS**	124,745	77,030	17,067	25,906	0	4,742	90,103	77,030	13073			0	15.96%	15.96%	$205.64	
(46) **TOTAL NET EXPENSES**	**$1,362,477**	**$962,109**	**$113,860**	**$192,364**	**$48,140**	**$46,004**	**$564,499**	**$478,769**	**$85,729**	**$0**	**$0**	**$0**	100.00%	100.00%	**$1,288.320**	

EXHIBIT 5
Page 1 of 3

NOVA SCOTIA POWER INC.
CLASSIFICATION OF OPERATING EXPENSES
FOR THE YEAR ENDING DECEMBER 31, 2014
(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DEMAND EXPENSES	(3) ENERGY EXPENSES	(4) CUSTOMER EXPENSES
GENERATION FUNCTION				
(1) FUEL	365,712	$0	$365,712	$0
(2) PURCHASED PWR REG - FIXED	22,225	7,222	15,003	0
(3) PURCHASED PWR REG - VAR.	27,164	0	27,164	0
(4) PURCHASED PWR WIND - FIXED	20,273	6,082	14,191	0
(5) PURCHASED PWR WIND - VAR.	47,303	0	47,303	0
(6) OPER. & MAINT. - STEAM	109,873	29,991	79,881	0
(7) OPER. & MAINT. - HYDRO/WIND/BI	24,040	6,562	17,478	0
(8) OPER. & MAINT. - LM6000	426	116	310	0
(9) OPER. & MAINT. - OTHER CT's	1,262	1,060	202	0
(10) DSM AMORTIZATION	970	315	654	0
(11) FCR DEFERRAL	13,382	4,135	9,247	0
(12) GRANTS IN LIEU OF TAXES	24,516	7,967	16,550	0
DEPRECIATION:				
(13) STEAM	65,222	21,571	43,650	0
(14) HYDRO	10,084	4,313	5,770	0
(15) WIND	8,167	373	7,794	0
(16) LM6000	2,079	902	1,177	0
(17) GAS TURBINE - OTHER	1,199	1,199	0	0
(18) GENERAL PROPERTY	25,560	8,306	17,254	0
(19) INTEREST NET OF AFUDC	89,216	27,569	61,647	0
(20) PREFERRED DIVIDENDS	5,082	1,570	3,512	0
(21) CORPORATE TAXES	35,985	11,120	24,865	0
NON-OPERATING REVENUE:				
(22) EXPORT SALES	(1,943)	0	(1,943)	0
(23) OTHER REVENUE	(10,809)	(1,686)	(9,122)	0
(24) RETURN (PROFIT/LOSS)	76,898	23,763	53,135	0
(25) TOTAL GENERATION	**963,884**	**162,450**	**801,435**	**0**
	963,884			
TRANSMISSION FUNCTION				
Transmission < 138kV:				
(26) O&M < 138kV	6,290	2,728	3,562	0
(27) GRANTS IN LIEU OF TAXES	1,326	575	751	0
DEPRECIATION:				
(28) TRANSMISSION	5,362	2,325	3,036	0
(29) GENERAL PROPERTY	1,393	604	789	0
(30) INTEREST NET OF AFUDC	4,587	1,990	2,598	0
(31) PREFERRED DIVIDENDS	261	113	148	0
(32) CORPORATE TAXES	1,850	802	1,048	0
NON-OPERATING REVENUE:				
(33) OTHER REVENUE	(261)	(113)	(148)	0
(35) RETURN (PROFIT/LOSS)	3,954	1,715	2,239	0
(36) TOTAL < 138kV	**24,763**	**10,740**	**14,023**	**0**

INTERMEDIATE CLASSIFICATION

THERMAL O&M	$109,873		
HYDRO O&M	24,040		
LM6000 O&M	426		
OTHER CT's O&M	1,262		
NET THERMAL O&M	$135,601		
THERMAL O&M	$17,580		
HYDRO O&M	3,846		
LM6000 O&M	68		
OTHER CT's O&M	202		
THERMAL VARIABLE O&M	$21,696		
THERMAL O&M	$92,293		
HYDRO O&M	20,194		
LM6000 O&M	358		
OTHER CT's O&M	1,060		
NET THERMAL O&M D&E SPLIT	$113,905		
THERMAL O&M DMD. ALLOC. %	32.50%		
THERMAL O&M ENG. ALLOC. %	67.50%		
WIND O&M DMD. ALLOC. %	30.00%		
WIND O&M ENG. ALLOC. %	70.00%		
OTHER CT's O&M DMD. ALLOC. %	100.00%		
POLE & WIRE DMD/CUST SPLIT	65.00%		
	DEMAND	**ENERGY**	**CUSTOMER**
GEN. PROP. ALLOC. - GEN.	8,306	17,254	0
GEN. PROP. ALLOC. - TRANS. < 138 kV	604	789	0
GEN. PROP. ALLOC. - TRANS. > 69 kV	1,978	2,583	0
GEN. PROP. ALLOC. - DIST.	5,622	0	2,712
GEN. PROP. ALLOC. - RETAIL	0	0	0
	16,510	20,626	2,712

EXHIBIT 5
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NOVA SCOTIA POWER INC.
CLASSIFICATION OF OPERATING EXPENSES
FOR THE YEAR ENDING DECEMBER 31, 2014
(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DEMAND EXPENSES	(3) ENERGY EXPENSES	(4) CUSTOMER EXPENSES
Transmission > 69kV:				
(1) O&M > 69kV	19,996	8,672	11,324	0
(2) GRANTS IN LIEU OF TAXES	4,386	1,902	2,484	0
DEPRECIATION:				
(3) TRANSMISSION	17,549	7,611	9,938	0
(4) GENERAL PROPERTY	4,561	1,978	2,583	0
(5) INTEREST NET OF AFUDC	15,179	6,583	8,596	0
(6) PREFERRED DIVIDENDS	865	375	490	0
(7) CORPORATE TAXES	6,123	2,655	3,467	0
NON-OPERATING REVENUE:				
(8) OTHER REVENUE	(854)	(371)	(484)	0
(9) FCR DEFERRAL	3,118	1,352	1,766	0
(10) RETURN (PROFIT/LOSS)	13,083	5,674	7,409	0
(11) TOTAL > 69kV	**84,006**	**36,433**	**47,573**	**0**
(12) TOTAL TRANSMISSION	**$108,769**	**$47,173**	**$61,596**	**$0**

NOVA SCOTIA POWER INC.
CLASSIFICATION OF OPERATING EXPENSES
FOR THE YEAR ENDING DECEMBER 31, 2014
(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DEMAND EXPENSES	(3) ENERGY EXPENSES	(4) CUSTOMER EXPENSES
DISTRIBUTION FUNCTION				
BEFORE STREETLIGHTS				
(1) SUBSTATIONS	$306	$306	$0	$0
(2) OVERHEAD LINES	38,758	25,192	0	13,565
(3) UNDERGROUND LINES	694	451	0	243
(4) LINE TRANSFORMERS	1,484	1,484	0	0
(5) METERS	948	0	0	948
(6) COMMUNICATIONS	8,882	8,882	0	0
(7) GRANTS IN LIEU OF TAXES	7,887	5,135	0	2,751
DEPRECIATION:				
(8) DISTRIBUTION	47,699	32,178	0	15,521
(9) GENERAL PROPERTY	8,334	5,622	0	2,712
(10) INTEREST NET OF AFUDC	29,605	19,277	0	10,328
(11) PREFERRED DIVIDENDS	1,686	1,098	0	588
(12) CORPORATE TAXES	11,941	7,775	0	4,166
(13) RETURN (PROFIT/LOSS)	25,518	16,615	0	8,902
STREETLIGHTS				
non-LED				
(14) MAINTENACE	5,827	5,827	0	0
(15) GRANTS IN LIEU OF TAXES	106	106	0	0
(16) DEPRECIATION	2,240	2,240	0	0
(17) INTEREST NET OF AFUDC	400	400	0	0
(18) PREFERRED DIVIDENDS	23	23	0	0
(19) CORPORATE TAXES	161	161	0	0
(20) RETURN (PROFIT/LOSS)	344	344	0	0
Subtotal	9,102	9,102	0	0
(21) OTHER REVENUE	(2,006)	(1,395)	0	(611)
(22) TOTAL DISTRIBUTION	**190,837**	**131,723**	**0**	**59,114**
RETAIL FUNCTION				
(23) QTY. ASSURANCE. & COMM.	5,402	0	0	5,402
(24) CALL CENTRE	20,979	0	0	20,979
(25) BILLING SERVICES	6,537	0	0	6,537
(26) ELECT. WIRING INSPECT. - H/O	471	0	0	471
(27) METER DATA SERVICES	832	0	0	832
(28) METER READING - FIELD	10,856	0	0	10,856
(29) ELECT. WIRING INSPECT. - FIELD	6,099	0	0	6,099
(30) PAYMENT SERVICES	1,251	0	0	1,251
(31) CREDIT SERVICES	0	0	0	0
(32) BAD DEBT EXPENSE	5,704	0	0	5,704
(33) MARKETING & SALES	2,047	0	0	2,047
(34) COGS (NET OF RETAIL SALES)	(432)	0	0	(432)
(35) GRANTS IN LIEU OF TAXES	0	0	0	0
(36) DEPRECIATION:				
(37) DISTRIBUTION	0	0	0	0
(38) GENERAL PROPERTY	0	0	0	0
(39) INTEREST NET OF AFUDC	0	0	0	0
(40) PREFERRED DIVIDENDS	0	0	0	0
(41) CORPORATE TAXES	0	0	0	0
NON-OPERATING REVENUE:				
(42) LATE PAYMENT CHARGE	(5,330)	0	0	(5,330)
(43) MISC. ELECTRIC	(2,003)	0	0	(2,003)
(44) OTHER REVENUE	(718)	0	0	(718)
(45) RETURN (PROFIT/LOSS)	0	0	0	0
(46) TOTAL RETAIL	**51,695**	**0**	**0**	**51,695**
(47) TOTAL NET EXPENSES	**$1,315,185**	**$341,346**	**$863,030**	**$110,809**
	$1,315,185			
	199,449	89,223	91,993	18,232

NOVA SCOTIA POWER INC.
ALLOCATION OF OPERATING EXPENSES
FOR THE YEAR ENDING DECEMBER 31, 2014
(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
DEMAND CLASSIFICATION												
GENERATION												
(1) FUEL	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	D-3A
(2) PURCH. POWER REG - FIXED	7,222	4,104	146	1,665	199	145	285	445	0	148	84	D-3A
(3) PURCH. POWER WIND - FIXED	6,082	3,456	123	1,402	168	122	240	375	0	125	71	D-3A
(4) OPER. & MAINT. - STEAM	29,991	17,043	608	6,916	827	602	1,185	1,847	0	614	349	D-3A
(5) OPER. & MAINT. - HYDRO/WIND/BIOMASS	6,562	3,729	133	1,513	181	132	259	404	0	134	76	D-3A
(6) OPER. & MAINT. - LM6000	116	66	2	27	3	2	5	7	0	2	1	D-3A
(7) OPER. & MAINT. - OTHER CT's	1,060	602	21	244	29	21	42	65	0	22	12	D-3A
(8) DSM AMORTIZATION	315	179	6	73	9	6	12	19	0	6	4	D-3A
(9) FCR DEFERRAL	4,135	2,350	84	954	114	83	163	255	0	85	48	P-14
(10) GRANTS IN LIEU	7,967	4,527	162	1,837	220	160	315	491	0	163	93	P-7
(11) DEPRECIATION	36,664	20,834	744	8,454	1,011	736	1,449	2,258	0	751	427	EXH 6D
(12) INTEREST NET OF AFUDC	27,569	15,666	559	6,357	760	553	1,089	1,698	0	565	321	P-14
(13) PREFERRED DIVIDENDS	1,570	892	32	362	43	32	62	97	0	32	18	P-14
(14) CORPORATE TAXES	11,120	6,319	226	2,564	307	223	439	685	0	228	129	P-14
NON-OPERATING REVENUE:												
(15) OTHER REVENUE	(1,686)	(958)	(34)	(389)	(46)	(34)	(67)	(104)	0	(35)	(20)	O-8
(16) RETURN (PROFIT/LOSS)	23,763	13,503	482	5,480	655	477	939	1,463	0	487	276	P-14
(17) INTERR. RIDER DMD ADJ.	(5,559)	0	0	0	0	0	0	(5,559)	0	0	0	DIRECT
(18) ALLOC. OF INTERR. DMD. ADJ.	5,559	3,310	118	1,343	161	117	230	93	0	119	68	D-4
(19) ELI 2P-RTP DEMAND ADJ.	0	0	0	0	0	0	0	0	0	0	0	DIRECT
(20) ALLOC. OF ELI 2P-RTP DMD. ADJ.	0	0	0	0	0	0	0	0	0	0	0	D-4
(21) ELI 2P-RTP PRIORITY DMD ADJ.	0	0	0	0	0	0	0	0	0	0	0	DIRECT
(22) ALLOC. OF ELI 2P-RTP PRI. DMD. ADJ.	0	0	0	0	0	0	0	0	0	0	0	D-3B
(23) TOTAL GENERATION	162,450	95,623	3,413	38,803	4,640	3,376	6,650	4,539	0	3,448	1,958	
TRANSMISSION												
Transmission < 138kV												
(24) OPERATING & MAINT.	2,728	1,550	55	629	75	55	108	168	0	56	32	D-3B
(25) GRANTS IN LIEU	575	327	12	133	16	12	23	35	0	12	7	P-8A
(26) DEPRECIATION	2,930	1,665	59	676	81	59	116	180	0	60	34	EXH 6D
(27) INTEREST NET OF AFUDC	1,990	1,131	40	459	55	40	79	123	0	41	23	P-15A
(28) PREFERRED DIVIDENDS	113	64	2	26	3	2	4	7	0	2	1	P-15A
(29) CORPORATE TAXES	802	456	16	185	22	16	32	49	0	16	9	P-15A
NON-OPERATING REVENUE:												
(30) OTHER REVENUE	(113)	(64)	(2)	(26)	(3)	(2)	(4)	(7)	0	(2)	(1)	O-9A
(32) RETURN (PROFIT/LOSS)	1,715	974	35	395	47	34	68	106	0	35	20	P-15A
(33) TOTAL < 138kV	$10,740	$6,103	$218	$2,476	$296	$215	$424	$661	$0	$220	$125	

NOVA SCOTIA POWER INC.
ALLOCATION OF OPERATING EXPENSES
FOR THE YEAR ENDING DECEMBER 31, 2014
(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) ELI 2P-RTP	(9) MUNICIPAL	(10) UNMETERED	(11) ALLOCATION FACTOR
Transmission > 69kV												
(1) OPERATING & MAINT.	8,672	4,928	176	2,000	239	174	343	534	0	178	101	D-3A
(2) GRANTS IN LIEU	1,902	1,081	39	439	52	38	75	117	0	39	22	P-8B
(3) DEPRECIATION	9,589	5,449	194	2,211	264	192	379	591	0	196	112	EXH 6D
(4) INTEREST NET OF AFUDC	6,583	3,741	134	1,518	182	132	260	405	0	135	77	P-15B
(5) PREFERRED DIVIDENDS	375	213	8	86	10	8	15	23	0	8	4	P-15B
(6) CORPORATE TAXES	2,655	1,509	54	612	73	53	105	164	0	54	31	P-15B
NON-OPERATING REVENUE:												
(7) FCR DEFERRAL	1,352	768	27	312	37	27	53	83	0	28	16	P-15B
(8) OTHER REVENUE	(371)	(211)	(8)	(85)	(10)	(7)	(15)	(23)	0	(8)	(4)	O-9B
(9) RETURN (PROFIT/LOSS)	5,674	3,224	115	1,308	156	114	224	349	0	116	66	P-15B
(10) TOTAL > 69kV	36,433	20,704	739	8,401	1,005	731	1,440	2,244	0	746	424	
(11) TOTAL TRANSMISSION	47,173	26,806	957	10,878	1,301	947	1,864	2,905	0	966	549	
DISTRIBUTION												
Non SL												
(12) OPERATING & MAINT.	36,315	21,453	1,210	9,939	1,038	965	1,249	3	0	0	458	EXH 6A
(13) GRANTS IN LIEU	5,135	3,126	176	1,426	90	137	110	4	0	0	67	P-9
(14) DEPRECIATION	37,800	23,006	1,297	10,496	664	1,006	807	32	0	2	491	EXH 6D
(15) INTEREST NET OF AFUDC	19,277	11,668	658	5,326	343	510	417	16	0	1	338	P-16
(16) PREFERRED DIVIDENDS	1,098	665	37	303	20	29	24	1	0	0	19	P-16
(17) CORPORATE TAXES	7,775	4,706	265	2,148	138	206	168	6	0	0	136	P-16
NON-OPERATING REVENUE:												
(18) OTHER REVENUE	(1,395)	(776)	(44)	(356)	(28)	(34)	(33)	(1)	0	(0)	(123)	O-10
(19) RETURN (PROFIT/LOSS)	16,615	10,057	567	4,590	296	440	359	14	0	1	292	P-16
SL												
non-LED												
(20) OPERATING & MAINT.	5,827	0	0	0	0	0	0	0	0	0	5,827	EXH 6A
(21) GRANTS IN LIEU OF TAXES	106	0	0	0	0	0	0	0	0	0	106	P-9A
(22) Depreciation	2,240	0	0	0	0	0	0	0	0	0	2,240	EXH 6D
(23) INTEREST NET OF AFUDC	400	0	0	0	0	0	0	0	0	0	400	P-16B
(23) PREFERRED DIVIDENDS	23	0	0	0	0	0	0	0	0	0	23	P-16B
(25) CORPORATE TAXES	161	0	0	0	0	0	0	0	0	0	161	P-16B
(26) OTHER REVENUE												
(27) RETURN (PROFIT/LOSS)	344	0	0	0	0	0	0	0	0	0	344	P-16B
Subtotal	9,102	0	0	0	0	0	0	0	0	0	9,102	
(28) TOTAL DISTRIBUTION	131,723	73,904	4,167	33,872	2,561	3,258	3,101	76	0	5	10,779	
(29) TOTAL DEMAND	$341,346	$196,333	$8,537	$83,553	$8,502	$7,581	$11,615	$7,520	$0	$4,419	$13,286	

NOVA SCOTIA POWER INC.
ALLOCATION OF OPERATING EXPENSES
FOR THE YEAR ENDING DECEMBER 31, 2014
(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
ENERGY CLASSIFICATION												
GENERATION												
(1) FUEL	$365,712	$170,740	$9,160	$94,569	$15,013	$10,062	$19,732	$35,157	$0	$7,343	$3,937	DIRECT
(2) PURCH. POWER REG - FIXED	15,003	6,993	375	3,882	617	413	812	1,447	0	301	162	E-1A
(3) PURCH. POWER REG - VAR.	27,164	12,661	679	7,029	1,118	749	1,470	2,619	0	545	293	E-1A
(4) PURCH. POWER WIND - FIXED	14,191	6,615	355	3,672	584	391	768	1,368	0	285	153	E-1A
(5) PURCH. POWER WIND - VAR.	47,303	22,049	1,183	12,241	1,946	1,304	2,560	4,561	0	950	510	E-1A
(6) OPER. & MAINT. - STEAM	79,881	37,234	1,998	20,671	3,287	2,201	4,323	7,703	0	1,604	861	E-1A
(7) OPER. & MAINT. - HYDRO/WIND/BIOMASS	17,478	8,147	437	4,523	719	482	946	1,685	0	351	188	E-1A
(8) OPER. & MAINT. - LM6000	310	145	8	80	13	9	17	30	0	6	3	E-1A
(9) OPER. & MAINT. - OTHER CT's	202	94	5	52	8	6	11	19	0	4	2	E-1A
(10) DSM AMORTIZATION	654	305	16	169	27	18	35	63	0	13	7	E-1A
(11) FCR DEFERRAL	9,247	4,310	231	2,393	380	255	500	892	0	186	100	P-17
(12) GRANTS IN LIEU	16,550	7,714	414	4,283	681	456	896	1,596	0	332	178	P-10
(13) DEPRECIATION	75,646	35,260	1,892	19,575	3,112	2,085	4,094	7,295	0	1,519	815	EXH 6D
(14) INTEREST NET OF AFUDC	61,647	28,734	1,542	15,953	2,536	1,699	3,336	5,945	0	1,237	664	P-17
(15) PREFERRED DIVIDENDS	3,512	1,637	88	909	144	97	190	339	0	70	38	P-17
(16) CORPORATE TAXES	24,865	11,590	622	6,434	1,023	685	1,346	2,398	0	499	268	P-17
NON-OPERATING REVENUE:												
(17) EXPORT SALES	(1,943)	(906)	(49)	(503)	(80)	(54)	(105)	(187)	0	(39)	(21)	EXH 7
(18) OTHER REVENUE	(9,122)	(4,255)	(228)	(2,360)	(375)	(251)	(493)	(878)	0	(183)	(98)	O-11
(19) RETURN (PROFIT/LOSS)	53,135	24,767	1,329	13,750	2,186	1,464	2,876	5,124	0	1,067	573	P-17
(20) TOTAL GENERATION	801,435	373,832	20,057	207,325	32,940	22,070	43,313	77,175	0	16,089	8,633	
TRANSMISSION												
Transmission < 138kV												
(21) OPERATING & MAINT.	3,562	1,660	89	922	147	98	193	343	0	72	38	E-1B
(22) GRANTS IN LIEU	751	350	19	194	31	21	41	72	0	15	8	P-11A
(23) DEPRECIATION	3,825	1,783	96	990	157	105	207	369	0	77	41	EXH 6D
(24) INTEREST NET	2,598	1,211	65	672	107	72	141	251	0	52	28	P-18A
(25) PREFERRED DIVIDENDS	148	69	4	38	6	4	8	14	0	3	2	P-18A
(26) CORPORATE TAXES	1,048	488	26	271	43	29	57	101	0	21	11	P-18A
NON-OPERATING REVENUE:												
(27) OTHER REVENUE	(148)	(69)	(4)	(38)	(6)	(4)	(8)	(14)	0	(3)	(2)	O-12A
(28) RETURN (PROFIT/LOSS)	2,239	1,044	56	579	92	62	121	216	0	45	24	P-18A
(29) TOTAL < 138kV	14,023	6,536	351	3,629	577	386	759	1,352	0	281	151	
Transmission > 69kV												
(30) OPERATING & MAINT.	11,324	5,278	283	2,930	466	312	613	1,092	0	227	122	E-1A
(31) GRANTS IN LIEU	2,484	1,158	62	643	102	68	134	240	0	50	27	P-11B
(32) DEPRECIATION	12,521	5,836	313	3,240	515	345	678	1,207	0	251	135	EXH 6D
(33) INTEREST NET	8,596	4,007	215	2,224	354	237	465	829	0	173	93	P-18B
(34) PREFERRED DIVIDENDS	490	228	12	127	20	13	27	47	0	10	5	P-18B
(35) CORPORATE TAXES	3,467	1,616	87	897	143	96	188	334	0	70	37	P-18B
NON-OPERATING REVENUE:												
(36) FCR DEFERRAL	1,766	823	44	457	73	49	96	170	0	35	19	P-18B
(37) OTHER REVENUE	(484)	(226)	(12)	(125)	(20)	(13)	(26)	(47)	0	(10)	(5)	O-12B
(38) RETURN (PROFIT/LOSS)	7,409	3,454	185	1,917	305	204	401	714	0	149	80	P-18B
(39) TOTAL > 69kV	47,573	22,174	1,190	12,311	1,957	1,311	2,575	4,587	0	955	513	
(40) TOTAL TRANSMISSION	61,596	28,711	1,541	15,939	2,534	1,697	3,333	5,940	0	1,236	664	
(41) TOTAL ENERGY	**$863,030**	**$402,543**	**$21,598**	**$223,264**	**$35,474**	**$23,767**	**$46,647**	**$83,114**	**$0**	**$17,326**	**$9,297**	

NOVA SCOTIA POWER INC.
ALLOCATION OF OPERATING EXPENSES
FOR THE YEAR ENDING DECEMBER 31, 2014
(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
CUST. CLASSIFICATION												
DISTRIBUTION												
(1) OPERATING & MAINT.	$14,756	$13,323	$703	$377	$1	$78	$10	$3	$0	$0	$263	EXH 6A
(2) GRANTS IN LIEU	2,751	2,419	128	141	0	29	3	1	0	0	31	P-12
(3) DEPRECIATION	18,232	16,028	846	935	2	192	18	5	0	1	206	EXH 6D
(4) INTEREST NET OF AFUDC	10,328	9,107	480	500	1	103	10	3	0	0	124	P-19
(5) PREFERRED DIVIDENDS	588	519	27	28	0	6	1	0	0	0	7	P-19
(6) CORPORATE TAXES	4,166	3,673	194	202	0	41	4	1	0	0	50	P-19
NON-OPERATING REVENUE:												
(8) OTHER REVENUE	(611)	(541)	(29)	(26)	(0)	(5)	(1)	(0)	0	(0)	(8)	O-13
(9) RETURN (PROFIT/LOSS)	8,902	7,849	414	431	1	89	8	3	0	0	107	P-19
(10) TOTAL DISTRIBUTION	59,114	52,377	2,763	2,588	5	532	51	16	0	2	781	
RETAIL												
(11) METER READING & ELECTRIC INSPECT.	16,955	14,370	767	1,242	37	243	98	62	0	16	119	EXH 6A
(12) CUST. SERV. - H/O	5,402	4,878	265	125	0	24	2	0	0	0	106	C-7
(13) CALL CENTRE	20,979	16,888	891	2,097	70	410	183	118	0	30	291	C-3
(14) BILLING SERVICES	6,537	5,904	321	151	0	30	3	0	0	0	128	C-3
(15) ELECT. WIRING INSP. - H/O	471	425	23	11	0	2	0	0	0	0	9	C-7
(16) METER DATA SERVICES	832	45	44	104	134	104	104	194	0	104	0	O-16
(17) PAYMENT SERVICES	1,251	1,129	61	29	0	6	1	0	0	0	24	C-7
(18) CREDIT SERVICES	5,704	4,791	85	749	0	78	0	0	0	0	0	EXH 6C
(19) MARKETING & SALES	2,047	928	73	171	37	135	264	402	0	37	0	O-15
(20) COGS (NET OF SALES)	(432)	(390)	(21)	(10)	(0)	(2)	(0)	(0)	0	(0)	(8)	C-7
(22) GRANTS IN LIEU	0	0	0	0	0	0	0	0	0	0	0	N/A
(23) DEPRECIATION	0	0	0	0	0	0	0	0	0	0	0	N/A
(24) INTEREST NET OF AFUDC	0	0	0	0	0	0	0	0	0	0	0	N/A
(25) PREFERRED DIVIDENDS	0	0	0	0	0	0	0	0	0	0	0	N/A
(26) CORPORATE TAXES	0	0	0	0	0	0	0	0	0	0	0	N/A
NON-OPERATING REVENUE:												
(28) LATE PAYMENT CHARGE	(5,330)	(4,133)	(126)	(921)	0	(72)	(62)	0	0	0	(17)	EXH 7
(29) MISC. ELECTRIC	(2,003)	(1,859)	(113)	(13)	0	0	0	0	0	0	(17)	EXH 7
(30) OTHER REVENUE	(718)	(580)	(29)	(57)	(4)	(13)	(9)	(12)	0	(3)	(9)	O-14
(31) RETURN (PROFIT/LOSS)	0	0	0	0	0	0	0	0	0	0	0	N/A
(32) TOTAL RETAIL	51,695	42,398	2,243	3,677	275	945	584	765	0	183	625	
(33) TOTAL CUSTOMER	**110,809**	**94,774**	**5,006**	**6,265**	**280**	**1,476**	**635**	**781**	**0**	**185**	**1,407**	
(34) TOTAL NET EXPENSES	**$1,315,185**	**$693,650**	**$35,141**	**$313,082**	**$44,256**	**$32,825**	**$58,897**	**$91,415**	**$0**	**$21,929**	**$23,989**	
TOTAL REVENUE	**$1,315,185**	**$689,768**	**$36,687**	**$321,964**	**$43,662**	**$33,495**	**$57,293**	**$86,844**	**$0**	**$21,483**	**$23,989**	

EXHIBIT 6A

NOVA SCOTIA POWER INC.

ALLOCATION OF DISTRIBUTION OPERATING EXPENSES

FOR THE YEAR ENDING DECEMBER 31, 2014

(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
DEMAND												
(1) SUBSTATIONS	$306	$174	$10	$82	$11	$8	$14	$3	$0	$0	$4	P-5
(2) OVERHEAD LINES	25,192	14,944	843	6,909	685	670	823	0	0	0	319	P-1
(3) UNDERGROUND LINES	451	267	15	124	12	12	15	0	0	0	6	P-1
(4) LINE TRANSFORMERS	1,484	948	53	422	0	40	0	0	0	0	20	D-1
(5) METERS	0	0	0	0	0	0	0	0	0	0	0	---
(6) COMMUNICATIONS	8,882	5,119	289	2,402	330	236	397	0	0	0	109	D-2
(7) STREET LIGHTING	5,827	0	0	0	0	0	0	0	0	0	5,827	DIRECT
(8) CUSTOMER SERVICE	0	0	0	0	0	0	0	0	0	0	0	---
(9) TOTAL DEMAND	42,142	21,453	1,210	9,939	1,038	965	1,249	3	0	0	6,284	
CUSTOMER												
(10) SUBSTATIONS	0	0	0	0	0	0	0	0	0	0	0	--
(11) OVERHEAD LINES	13,565	12,290	648	305	0	60	3	0	0	0	258	P-2
(12) UNDERGROUND LINES	243	220	12	5	0	1	0	0	0	0	5	P-2
(13) LINE TRANSFORMERS	0	0	0	0	0	0	0	0	0	0	0	--
(14) METERS	948	813	43	66	1	17	7	2	0	0	0	P-6
(15) COMMUNICATIONS	0	0	0	0	0	0	0	0	0	0	0	--
(16) STREET LIGHTING	0	0	0	0	0	0	0	0	0	0	0	--
(17) CUSTOMER SERVICE	0	0	0	0	0	0	0	0	0	0	0	EXHIBIT 6B
(18) TOTAL CUSTOMER	14,756	13,323	703	377	1	78	10	3	0	0	263	
RETAIL												
(19) METERS	0	0	0	0	0	0	0	0	0	0	0	N/A
(20) CUSTOMER SERVICE	16,955	14,370	767	1,242	37	243	98	62	0	16	119	EXHIBIT 6B
(20) TOTAL RETAIL	16,955	14,370	767	1,242	37	243	98	62	0	16	119	
SUMMARY												
(21) SUBSTATIONS	306	174	10	82	11	8	14	3	0	0	4	P-3
(22) OVERHEAD LINES	38,758	27,235	1,491	7,215	685	729	826	0	0	0	577	P-1
(23) UNDERGROUND LINES	694	487	27	129	12	13	15	0	0	0	10	P-1
(24) LINE TRANSFORMERS	1,484	948	53	422	0	40	0	0	0	0	20	D-1
(25) METERS	17,904	15,183	810	1,307	38	260	105	65	0	16	119	P-6
(26) COMMUNICATIONS	8,882	5,119	289	2,402	330	236	397	0	0	0	109	D-2
(27) STREET LIGHTING	5,827	0	0	0	0	0	0	0	0	0	5,827	DIRECT
(28) CUSTOMER SERVICE	0	0	0	0	0	0	0	0	0	0	0	EXHIBIT 6B
(29) TOTAL DISTRIBUTION	$73,853	$49,146	$2,680	$11,557	$1,076	$1,286	$1,357	$69	$0	$16	$6,667	

EXHIBIT 6B

NOVA SCOTIA POWER INC.

ALLOCATION OF CUSTOMER SERVICE FIELD EXPENSES

FOR THE YEAR ENDING DECEMBER 31, 2014

(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) METER READING	(4) WIRING INSPECTION
(1) DOMESTIC	$14,370	$8,862	$5,508
(2) SMALL GENERAL	767	468	300
(3) GENERAL	1,242	1,100	141
(4) GENERAL LARGE	37	37	0
(5) SMALL INDUSTRIAL	243	215	28
(6) MEDIUM INDUSTRIAL	98	96	2
(7) LARGE INDUSTRIAL	62	62	0
(8) ELI 2P-RTP	0	0	0
(9) MUNICIPAL	16	16	0
(10) UNMETERED	119	0	119
(11) TOTAL	$16,955	$10,856	$6,099
ALLOCATION FACTOR		C-6	C-7

EXHIBIT 6C

NOVA SCOTIA POWER INC.

ALLOCATION OF CREDIT SERVICES EXPENSES

FOR THE YEAR ENDING DECEMBER 31, 2014

(IN THOUSANDS OF DOLLARS)

	(1)	(2)	(3)	(4)	(5)
	---------------BAD DEBT EXPENSE-----------------			CREDIT	
	DIRECT	TO BE ALLOC.	TOTAL	SERVICES	TOTAL
(1) DOMESTIC	$4,791	$0	$4,791	$0	$4,791
(2) SMALL GENERAL	0	85	85	0	85
(3) GENERAL	0	749	749	0	749
(4) GENERAL LARGE	0	0	0	0	0
(5) SMALL INDUSTRIAL	0	78	78	0	78
(6) MEDIUM INDUSTRIAL	0	0	0	0	0
(7) LARGE INDUSTRIAL	0	0	0	0	0
(8) ELI 2P-RTP	0	0	0	0	0
(9) MUNICIPAL	0	0	0	0	0
(10) UNMETERED	0	0	0	0	0
(11) TOTAL	$4,791	$913	$5,704	$0	$5,704
ALLOCATION FACTOR	DIRECT	R-1		C-7	

DOMESTIC - 84 %

NOVA SCOTIA POWER INC.

ALLOCATION OF DEPRECIATION EXPENSES

FOR THE YEAR ENDING DECEMBER 31, 2014

(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
DEMAND CLASSIFICATION												
GENERATION FUNCTION												
(1) STEAM PRODUCTION	$21,571	$12,258	$438	$4,974	$595	$433	$852	$1,328	$0	$442	$251	D-3A
(2) HYDRO PRODUCTION	4,313	2,451	87	995	119	87	170	266	0	88	50	D-3A
(3) WIND PRODUCTION	373	212	8	86	10	7	15	23	0	8	4	D-3A
(4) LM6000 PRODUCTION	902	512	18	208	25	18	36	56	0	18	10	D-3A
(5) GAS TURBINE PROD. - OTHER	1,199	681	24	276	33	24	47	74	0	25	14	D-3A
(6) GENERAL PROPERTY	8,306	4,720	168	1,915	229	167	328	512	0	170	97	P-7
(7) TOTAL GENERATION FUNCTION	36,664	20,834	744	8,454	1,011	736	1,449	2,258	0	751	427	
TRANSMISSION FUNCTION												
(8) TRANSMISSION PLANT < 138kV	2,325	1,321	47	536	64	47	92	143	0	48	27	D-3B
(9) GENERAL PROPERTY	604	343	12	139	17	12	24	37	0	12	7	P-8A
TOTAL < 138kV	2,930	1,665	59	676	81	59	116	180	0	60	34	
(10) TRANSMISSION PLANT > 69kV	7,611	4,325	154	1,755	210	153	301	469	0	156	89	D-3A
(11) GENERAL PROPERTY	1,978	1,124	40	456	55	40	78	122	0	41	23	P-8B
(12) TOTAL > 69kV	9,589	5,449	194	2,211	264	192	379	591	0	196	112	
(13) TOTAL TRANSMISSION FUNCTION	12,519	7,114	254	2,887	345	251	495	771	0	256	146	
DISTRIBUTION FUNCTION												
(14) DISTRIBUTION PLANT - Non Streetlig	32,178	19,584	1,104	8,935	565	856	687	27	0	2	418	P-9
(14) DISTRIBUTION PLANT - Streetlight	2,240	0	0	0	0	0	0	0	0	0	2,240	Direct
(15) GENERAL PROPERTY	5,622	3,422	193	1,561	99	150	120	5	0	0	73	P-9
(16) TOTAL DISTRIBUTION FUNCTION	40,041	23,006	1,297	10,496	664	1,006	807	32	0	2	2,731	
(17) TOTAL DEMAND	**89,223**	**50,954**	**2,295**	**21,837**	**2,020**	**1,992**	**2,751**	**3,061**	**0**	**1,010**	**3,303**	
ENERGY CLASSIFICATION												
GENERATION FUNCTION												
(18) STEAM PRODUCTION	43,650	20,346	1,092	11,296	1,796	1,203	2,362	4,209	0	876	470	E-1A
(19) HYDRO PRODUCTION	5,770	2,690	144	1,493	237	159	312	556	0	116	62	E-1A
(20) WIND PRODUCTION	7,794	3,633	195	2,017	321	215	422	752	0	156	84	E-1A
(21) LM6000 PRODUCTION	1,177	549	29	305	48	32	64	114	0	24	13	E-1A
(22) GAS TURBINE PROD. - OTHER	0	0	0	0	0	0	0	0	0	0	0	E-1A
(23) GENERAL PROPERTY	17,254	8,042	432	4,465	710	475	934	1,664	0	346	186	P-10
(24) TOTAL GENERATION FUNCTION	75,646	35,260	1,892	19,575	3,112	2,085	4,094	7,295	0	1,519	815	
TRANSMISSION FUNCTION												
(25) TRANSMISSION PLANT < 138kV	3,036	1,415	76	786	125	84	164	293	0	61	33	E-1B
(26) GENERAL PROPERTY	789	368	20	204	32	22	43	76	0	16	9	P-11A
(27) TOTAL < 138kV	3,825	1,783	96	990	157	105	207	369	0	77	41	
(28) TRANSMISSION PLANT > 69kV	9,938	4,632	249	2,572	409	274	538	958	0	199	107	E-1A
(29) GENERAL PROPERTY	2,583	1,204	65	668	106	71	140	249	0	52	28	P-11B
(30) TOTAL > 69kV	12,521	5,836	313	3,240	515	345	678	1,207	0	251	135	
(31) TOTAL TRANSMISSION FUNCTION	16,347	7,619	409	4,230	673	450	885	1,576	0	328	176	
(32) TOTAL ENERGY	**91,993**	**42,879**	**2,301**	**23,806**	**3,785**	**2,535**	**4,979**	**8,871**	**0**	**1,847**	**991**	

NOVA SCOTIA POWER INC.
ALLOCATION OF DEPRECIATION EXPENSES
FOR THE YEAR ENDING DECEMBER 31, 2014
(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
CUSTOMER CLASSIFICATION												
DISTRIBUTION FUNCTION												
(1) DISTRIBUTION PLANT	15,521	13,644	720	796	1	163	15	5	0	0	176	P-12
(2) GENERAL PROPERTY	2,712	2,384	126	139	0	29	3	1	0	0	31	P-12
(3) TOTAL DISTRIBUTION FUNCTION	18,232	16,028	846	935	2	192	18	5	0	1	206	
RETAIL FUNCTION												
(4) DISTRIBUTION PLANT	0	0	0	0	0	0	0	0	0	0	0	P-13
(5) GENERAL PROPERTY	0	0	0	0	0	0	0	0	0	0	0	P-13
(6) TOTAL RETAIL FUNCTION	0	0	0	0	0	0	0	0	0	0	0	
(7) TOTAL CUSTOMER	**18,232**	**16,028**	**846**	**935**	**2**	**192**	**18**	**5**	**0**	**1**	**206**	
(8) TOTAL DEPRECIATION	**$199,449**	**$109,862**	**$5,441**	**$46,578**	**$5,806**	**$4,720**	**$7,747**	**$11,937**	**$0**	**$2,857**	**$4,501**	

EXHIBIT 7

NOVA SCOTIA POWER INC.

REVENUE ANALYSIS

FOR THE YEAR ENDING DECEMBER 31, 2014
(IN THOUSANDS OF DOLLARS)

	(1) REVENUE	(2) EXPORT SALES	(3) LATE PAYMENT CHARGE	(4) MISC. CUSTOMER REVENUE
ELECTRIC REVENUE				
(1) DOMESTIC	$689,768	$906	$4,133	$1,859
(2) SMALL GENERAL	36,687	49	126	113
(3) GENERAL	321,964	503	921	13
(4) LARGE GENERAL	43,662	80	0	0
(5) SMALL INDUSTRIAL	33,495	54	72	0
(6) MEDIUM INDUSTRIAL	57,293	105	62	0
(7) LARGE INDUSTRIAL	86,844	187	0	0
(8) ELI 2P-RTP	0	0	0	0
(9) MUNICIPAL	21,483	39	0	0
(10) UNMETERED	23,989	21	17	17
(11) SUB-TOTAL	1,315,185	$1,943	$5,330	$2,003
(12) EXPORT SALES	1,943			
(13) TOTAL ELECTRIC REVENUE	1,317,128			
NON-RATE REVENUE				
(14) LATE PAYMENT CHARGE	5,330			
(15) MISC. CUST. REVENUE	2,003			
(16) OTHER	14,648			
(17) TOTAL	21,980			
DIRECT REVENUE				
(18) BOWATER BASIC BLOCK	9,782			
(19) BOWATER ADDITIONAL ENERGY	10,241			
(20) GEN.REPL./LOAD FOLL	1,072			
(21) LRT	21,856			
(22) REAL TIME PRICING	0			
(23) LED	4,341			
(24) TOTAL	47,292			
(25) TRANSFER FROM (TO) RETAINED EARNINGS	(124,745)			
(26) TOTAL REVENUE	**$1,261,656**			
ALLOCATION FACTOR		E-1	DIRECT	DIRECT

EXHIBIT 8A

NOVA SCOTIA POWER INC.

DEVELOPMENT OF ALLOCATION FACTORS

FOR THE YEAR ENDING DECEMBER 31, 2014

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
(1) N.C. DEMAND SEC.	1,719,617	1,098,733	61,954	489,526	0	45,965	0	0	0	0	23,440	
(2) % RESPONSIBILITY	100.00%	63.89%	3.60%	28.47%	0.00%	2.67%	0.00%	0.00%	0.00%	0.00%	1.36%	D-1
(3) N.C. DEMAND PRI.	2,009,264	1,158,064	65,299	543,365	74,713	53,306	89,812	0	0	0	24,706	
(4) % RESPONSIBILITY	100.00%	57.64%	3.25%	27.04%	3.72%	2.65%	4.47%	0.00%	0.00%	0.00%	1.23%	D-2
(5) 3 CP DEMAND	5,922,996	3,365,786	120,127	1,365,814	163,320	118,848	234,070	364,769	0	121,351	68,910	
(6) % RESPONSIBILITY	100.00%	56.83%	2.03%	23.06%	2.76%	2.01%	3.95%	6.16%	0.00%	2.05%	1.16%	D-3A
(7) 3 CP DEMAND - LESS ELIIR - 2	5,922,996	3,365,786	120,127	1,365,814	163,320	118,848	234,070	364,769	0	121,351	68,910	
(8) % RESPONSIBILITY	100.00%	56.83%	2.03%	23.06%	2.76%	2.01%	3.95%	6.16%	0.00%	2.05%	1.16%	D-3B
(9) 3 CP DMD. - LESS INT. & ELIIR - 2	5,653,248	3,365,786	120,127	1,365,814	163,320	118,848	234,070	95,022	0	121,351	68,910	
(10) % RESPONSIBILITY	100.00%	59.54%	2.12%	24.16%	2.89%	2.10%	4.14%	1.68%	0.00%	2.15%	1.22%	D-4
(11) MW.h GEN. & PURCH.	9,986,292	4,654,738	249,760	2,584,209	410,860	275,205	540,444	962,980	0	200,464	107,631	
(12) % RESPONSIBILITY	100.00%	46.61%	2.50%	25.88%	4.11%	2.76%	5.41%	9.64%	0.00%	2.01%	1.08%	E-1A
(13) MW.h GEN. & PURCH. Less EHV	9,986,292	4,654,738	249,760	2,584,209	410,860	275,205	540,444	962,980	0	200,464	107,631	
(14) % RESPONSIBILITY	100.00%	46.61%	2.50%	25.88%	4.11%	2.76%	5.41%	9.64%	0.00%	2.01%	1.08%	E-1B
(15) AVERAGE CUSTOMERS	504,531	456,991	24,109	11,349	19	2,221	198	32	0	8	9,604	
(16) % RESPONSIBILITY	100.00%	90.58%	4.78%	2.25%	0.00%	0.44%	0.04%	0.01%	0.00%	0.00%	1.90%	C-1
(17) SECONDARY CUSTOMERS	494,670	456,991	24,109	11,349	0	2,221	0	0	0	0	0	
(18) WEIGHTING FACTOR		1.00	1.00	5.00	100.00	5.00	25.00	100.00	100.00	100.00	0.82	
(19) WEIGHTED TOTAL	548,950	456,991	24,109	56,745	0	11,105	0	0	0	0	0	
(20) % RESPONSIBILITY	100.00%	83.25%	4.39%	10.34%	0.00%	2.02%	0.00%	0.00%	0.00%	0.00%	0.00%	C-2
(21) AVERAGE CUSTOMERS	504,531	456,991	24,109	11,349	19	2,221	198	32	0	8	9,604	
(22) WEIGHTING FACTOR		1.00	1.00	5.00	100.00	5.00	25.00	100.00	100.00	100.00	0.82	
(23) WEIGHTED TOTAL	567,675	456,991	24,109	56,745	1,900	11,105	4,950	3,200	0	800	7,875	
(24) % RESPONSIBILITY	100.00%	80.50%	4.25%	10.00%	0.33%	1.96%	0.87%	0.56%	0.00%	0.14%	1.39%	C-3
(25) CUSTOMER SECONDARY	504,274	456,991	24,109	11,349	0	2,221	0	0	0	0	9,604	
(26) % RESPONSIBILITY	100.00%	90.62%	4.78%	2.25%	0.00%	0.44%	0.00%	0.00%	0.00%	0.00%	1.90%	C-4
(27) CUSTOMER PRIMARY	504,531	456,991	24,109	11,349	19	2,221	198	32	0	8	9,604	
(28) % RESPONSIBILITY	100.00%	90.58%	4.78%	2.25%	0.00%	0.44%	0.04%	0.01%	0.00%	0.00%	1.90%	C-5
(29) AVG. CUST. - LESS UNMETERED	494,927	456,991	24,109	11,349	19	2,221	198	32	0	8	0	
(30) WEIGHTING FACTOR		1.00	1.00	5.00	100.00	5.00	25.00	100.00	100.00	100.00	0.82	
(31) WEIGHTED TOTAL	559,800	456,991	24,109	56,745	1,900	11,105	4,950	3,200	0	800	0	
(32) % RESPONSIBILITY	100.00%	81.63%	4.31%	10.14%	0.34%	1.98%	0.88%	0.57%	0.00%	0.14%	0.00%	C-6
(33) AVERAGE CUSTOMERS ADJ SEASONAL	490,561	443,021	24,109	11,349	19	2,221	198	32	0	8	9,604	
(34) % RESPONSIBILITY	100.00%	90.31%	4.91%	2.31%	0.00%	0.45%	0.04%	0.01%	0.00%	0.00%	1.96%	C-7

EXHIBIT 8B
PAGE 1 OF 2

NOVA SCOTIA POWER INC.
DEVELOPMENT OF ALLOCATION FACTORS
FOR THE YEAR ENDING DECEMBER 31, 2014

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
(1) POLE&WIRE INV.-DMD.	$197,824	$117,351	$6,617	$54,256	$5,375	$5,259	$6,462	$0	$0	$0	$2,504	
(2) % RESPONSIBILITY	100.00%	59.32%	3.34%	27.43%	2.72%	2.66%	3.27%	0.00%	0.00%	0.00%	1.27%	P-1
(3) POLE&WIRE INV.-CUST.	$106,520	$96,508	$5,091	$2,397	$2	$469	$21	$3	$0	$1	$2,028	
(4) % RESPONSIBILITY	100.00%	90.60%	4.78%	2.25%	0.00%	0.44%	0.02%	0.00%	0.00%	0.00%	1.90%	P-2
(5) SUB.,POLE&WIRE-DMD.	$227,936	$134,428	$7,580	$62,293	$6,477	$6,045	$7,884	$339	$0	$22	$2,868	
(6) % RESPONSIBILITY	100.00%	58.98%	3.33%	27.33%	2.84%	2.65%	3.46%	0.15%	0.00%	0.01%	1.26%	P-3
(7) SUB.,POLE&WIRE-CUST.	$106,520	$96,508	$5,091	$2,397	$2	$469	$21	$3	$0	$1	$2,028	
(8) % RESPONSIBILITY	100.00%	90.60%	4.78%	2.25%	0.00%	0.44%	0.02%	0.00%	0.00%	0.00%	1.90%	P-4
(9) SUBST. INVEST.-DMD.	$30,113	$17,077	$963	$8,037	$1,102	$786	$1,422	$339	$0	$22	$364	
(10) % RESPONSIBILITY	100.00%	56.71%	3.20%	26.69%	3.66%	2.61%	4.72%	1.13%	0.00%	0.07%	1.21%	P-5
(11) METER INVEST.-CUST	$25,072	$21,489	$1,134	$1,742	$17	$445	$180	$59	$0	$6	$0	
(12) % RESPONSIBILITY	100.00%	85.71%	4.52%	6.95%	0.07%	1.78%	0.72%	0.24%	0.00%	0.02%	0.00%	P-6
(13) DEMAND - GEN. PLANT	$650,206	$369,484	$13,187	$149,934	$17,929	$13,047	$25,695	$40,043	$0	$13,322	$7,565	
(14) % RESPONSIBILITY	100.00%	56.83%	2.03%	23.06%	2.76%	2.01%	3.95%	6.16%	0.00%	2.05%	1.16%	P-7
(15) DEMAND - TRANS. PLT. < 138kV	$47,308	$26,883	$959	$10,909	$1,304	$949	$1,870	$2,913	$0	$969	$550	
(16) % RESPONSIBILITY	100.00%	56.83%	2.03%	23.06%	2.76%	2.01%	3.95%	6.16%	0.00%	2.05%	1.16%	P-8A
(17) DEMAND - TRANS. PLT. > 69kV	$154,863	$88,002	$3,141	$35,711	$4,270	$3,107	$6,120	$9,537	$0	$3,173	$1,802	
(18) % RESPONSIBILITY	100.00%	56.83%	2.03%	23.06%	2.76%	2.01%	3.95%	6.16%	0.00%	2.05%	1.16%	P-8B
(19) DEMAND - DIST. PLANT	$429,856	$261,619	$14,752	$119,356	$7,548	$11,436	$9,178	$363	$0	$24	$5,581	
(20) % RESPONSIBILITY	100.00%	60.86%	3.43%	27.77%	1.76%	2.66%	2.14%	0.08%	0.00%	0.01%	1.30%	P-9
(19) DEMAND - DIST. PLANT	$10,251	$0	$0	$0	$0	$0	$0	$0	$0	$0	$10,251	
(20) % RESPONSIBILITY	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	P-9A
(23) ENERGY - GEN. PLANT	$1,350,698	$629,578	$33,781	$349,528	$55,571	$37,223	$73,098	$130,248	$0	$27,114	$14,558	
(24) % RESPONSIBILITY	100.00%	46.61%	2.50%	25.88%	4.11%	2.76%	5.41%	9.64%	0.00%	2.01%	1.08%	P-10
(25) ENERGY - TRANS. PLT. < 138kV	$61,772	$28,793	$1,545	$15,985	$2,541	$1,702	$3,343	$5,957	$0	$1,240	$666	
(26) % RESPONSIBILITY	100.00%	46.61%	2.50%	25.88%	4.11%	2.76%	5.41%	9.64%	0.00%	2.01%	1.08%	P-11A
(27) ENERGY - TRANS. PLT. > 69kV	$202,211	$94,253	$5,057	$52,327	$8,319	$5,573	$10,943	$19,499	$0	$4,059	$2,179	
(28) % RESPONSIBILITY	100.00%	46.61%	2.50%	25.88%	4.11%	2.76%	5.41%	9.64%	0.00%	2.01%	1.08%	P-11B
(29) CUSTOMER - DIST. PLANT	$212,277	$186,613	$9,845	$10,887	$20	$2,235	$205	$63	$0	$7	$2,403	
(30) % RESPONSIBILITY	100.00%	87.91%	4.64%	5.13%	0.01%	1.05%	0.10%	0.03%	0.00%	0.00%	1.13%	P-12
(31) CUSTOMER - RETAIL PLANT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
(32) % RESPONSIBILITY	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	P-13
(33) TOT.RATE BASE-DMD. (GEN.)	$707,163	$401,850	$14,342	$163,068	$19,499	$14,190	$27,946	$43,551	$0	$14,488	$8,227	
(34) % RESPONSIBILITY	100.00%	56.83%	2.03%	23.06%	2.76%	2.01%	3.95%	6.16%	0.00%	2.05%	1.16%	P-14
(35) TOT.RATE BASE-DMD. (TRANS. < 138kV)	$51,034	$29,001	$1,035	$11,768	$1,407	$1,024	$2,017	$3,143	$0	$1,046	$594	
(36) % RESPONSIBILITY	100.00%	56.83%	2.03%	23.06%	2.76%	2.01%	3.95%	6.16%	0.00%	2.05%	1.16%	P-15A
(37) TOT.RATE BASE-DMD. (TRANS. > 69kV)	$168,865	$95,959	$3,425	$38,939	$4,656	$3,388	$6,673	$10,400	$0	$3,460	$1,965	
(38) % RESPONSIBILITY	100.00%	56.83%	2.03%	23.06%	2.76%	2.01%	3.95%	6.16%	0.00%	2.05%	1.16%	P-15B
(39) TOT.RATE BASE-DMD. (DIST.) Non Streetli	$494,466	$299,291	$16,876	$136,603	$8,800	$13,093	$10,695	$405	$0	$26	$8,678	
(40) % RESPONSIBILITY	100.00%	60.53%	3.41%	27.63%	1.78%	2.65%	2.16%	0.08%	0.00%	0.01%	1.75%	P-16
(41) TOT.RATE BASE-DMD. (DIST.) Streetlight	$10,251	$0	$0	$0	$0	$0	$0	$0	$0	$0	$10,251	
(42) % RESPONSIBILITY	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	P-16B
(43) TOT.RATE BASE-ENG. (GEN.)	$1,581,279	$737,054	$39,548	$409,197	$65,058	$43,577	$85,577	$152,483	$0	$31,743	$17,043	
(44) % RESPONSIBILITY	100.00%	46.61%	2.50%	25.88%	4.11%	2.76%	5.41%	9.64%	0.00%	2.01%	1.08%	P-17
(45) TOT.RATE BASE-ENG. (TRANS. < 138kV)	$66,638	$31,061	$1,667	$17,244	$2,742	$1,836	$3,606	$6,426	$0	$1,338	$718	
(46) % RESPONSIBILITY	100.00%	46.61%	2.50%	25.88%	4.11%	2.76%	5.41%	9.64%	0.00%	2.01%	1.08%	P-18A
(47) TOT.RATE BASE-ENG. (TRANS. > 69kV)	$220,494	$102,775	$5,515	$57,058	$9,072	$6,076	$11,933	$21,262	$0	$4,426	$2,376	
(48) % RESPONSIBILITY	100.00%	46.61%	2.50%	25.88%	4.11%	2.76%	5.41%	9.64%	0.00%	2.01%	1.08%	P-18B

NOVA SCOTIA POWER INC.

DEVELOPMENT OF ALLOCATION FACTORS

FOR THE YEAR ENDING DECEMBER 31, 2014

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
(1) TOT. RATE BASE-CUST. (DIST.)	$264,927	$233,598	$12,324	$12,828	$24	$2,634	$246	$75	$0	$8	$3,191	
(2) % RESPONSIBILITY	100.00%	88.17%	4.65%	4.84%	0.01%	0.99%	0.09%	0.03%	0.00%	0.00%	1.20%	P-19
(3) TOT.RATE BASE-CUST.(RETAIL)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
(4) % RESPONSIBILITY	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	P-20
(5) DMD. - OPER.EXP. - GEN.	$29,991	$17,043	$608	$6,916	$827	$602	$1,185	$1,847	$0	$614	$349	
(6) % RESPONSIBILITY	100.00%	56.83%	2.03%	23.06%	2.76%	2.01%	3.95%	6.16%	0.00%	2.05%	1.16%	O-1
(7) DMD. - OPER.EXP. - TRANS. < 138kV	$2,728	$1,550	$55	$629	$75	$55	$108	$168	$0	$56	$32	
(8) % RESPONSIBILITY	100.00%	56.83%	2.03%	23.06%	2.76%	2.01%	3.95%	6.16%	0.00%	2.05%	1.16%	O-2A
(9) DMD. - OPER.EXP. - TRANS. > 69kV	$8,672	$4,928	$176	$2,000	$239	$174	$343	$534	$0	$178	$101	
(10) % RESPONSIBILITY	100.00%	56.83%	2.03%	23.06%	2.76%	2.01%	3.95%	6.16%	0.00%	2.05%	1.16%	O-2B
(11) DMD. - OPER.EXP. - DIST.	$42,142	$21,453	$1,210	$9,939	$1,038	$965	$1,249	$3	$0	$0	$6,284	
(12) % RESPONSIBILITY	100.00%	50.91%	2.87%	23.58%	2.46%	2.29%	2.96%	0.01%	0.00%	0.00%	14.91%	O-3
(13) ENG. - OPER.EXP. - GEN.	$79,881	$37,234	$1,998	$20,671	$3,287	$2,201	$4,323	$7,703	$0	$1,604	$861	
(14) % RESPONSIBILITY	100.00%	46.61%	2.50%	25.88%	4.11%	2.76%	5.41%	9.64%	0.00%	2.01%	1.08%	O-4
(15) ENG. - OPER.EXP. - TRANS. < 138kV	$3,562	$1,660	$89	$922	$147	$98	$193	$343	$0	$72	$38	
(16) % RESPONSIBILITY	100.00%	46.61%	2.50%	25.88%	4.11%	2.76%	5.41%	9.64%	0.00%	2.01%	1.08%	O-5A
(17) ENG. - OPER.EXP. - TRANS. > 69kV	$11,324	$5,278	$283	$2,930	$466	$312	$613	$1,092	$0	$227	$122	
(18) % RESPONSIBILITY	100.00%	46.61%	2.50%	25.88%	4.11%	2.76%	5.41%	9.64%	0.00%	2.01%	1.08%	O-5B
(19) CUST. - OPER. EXP. - DIST.	$14,756	$13,323	$703	$377	$1	$78	$10	$3	$0	$0	$263	
(20) % RESPONSIBILITY	100.00%	90.29%	4.76%	2.55%	0.01%	0.53%	0.06%	0.02%	0.00%	0.00%	1.78%	O-6
(21) CUST. - OPER. EXP. - RETAIL	$41,175	$34,061	$1,692	$3,266	$205	$654	$292	$313	$0	$133	$558	
(22) % RESPONSIBILITY	100.00%	82.72%	4.11%	7.93%	0.50%	1.59%	0.71%	0.76%	0.00%	0.32%	1.36%	O-7
(23) TOT. EXP. - DMD. (GEN.)	$140,374	$79,768	$2,847	$32,369	$3,871	$2,817	$5,547	$8,645	$0	$2,876	$1,633	
(24) % RESPONSIBILITY	100.00%	56.83%	2.03%	23.06%	2.76%	2.01%	3.95%	6.16%	0.00%	2.05%	1.16%	O-8
(25) TOT. EXP. - DMD. (TRANS. < 138kV)	$9,138	$5,193	$185	$2,107	$252	$183	$361	$563	$0	$187	$106	
(26) % RESPONSIBILITY	100.00%	56.83%	2.03%	23.06%	2.76%	2.01%	3.95%	6.16%	0.00%	2.05%	1.16%	O-9A
(27) TOT. EXP. - DMD. (TRANS. > 69kV)	$29,778	$16,921	$604	$6,867	$821	$597	$1,177	$1,834	$0	$610	$346	
(28) % RESPONSIBILITY	100.00%	56.83%	2.03%	23.06%	2.76%	2.01%	3.95%	6.16%	0.00%	2.05%	1.16%	O-9B
(29) TOT. EXP. - DMD. (DIST.)	$116,158	$64,623	$3,644	$29,638	$2,293	$2,853	$2,775	$63	$0	$4	$10,266	
(30) % RESPONSIBILITY	100.00%	55.63%	3.14%	25.51%	1.97%	2.46%	2.39%	0.05%	0.00%	0.00%	8.84%	O-10
(31) TOT. EXP. - ENG. (GEN.)	$759,365	$354,227	$19,005	$196,437	$31,209	$20,910	$41,036	$73,117	$0	$15,245	$8,180	
(32) % RESPONSIBILITY	100.00%	46.65%	2.50%	25.87%	4.11%	2.75%	5.40%	9.63%	0.00%	2.01%	1.08%	O-11
(33) TOT. EXP. - ENG. (TRANS. < 138 kV)	$11,932	$5,561	$298	$3,088	$491	$329	$646	$1,151	$0	$240	$129	
(34) % RESPONSIBILITY	100.00%	46.61%	2.50%	25.88%	4.11%	2.76%	5.41%	9.64%	0.00%	2.01%	1.08%	O-12A
(35) TOT. EXP. - ENG. (TRANS. > 69 kV)	$38,882	$18,123	$972	$10,062	$1,600	$1,072	$2,104	$3,749	$0	$781	$419	
(36) % RESPONSIBILITY	100.00%	46.61%	2.50%	25.88%	4.11%	2.76%	5.41%	9.64%	0.00%	2.01%	1.08%	O-12B
(37) TOT. EXP. -CUST. (DIST.)	$50,822	$45,069	$2,378	$2,183	$4	$449	$44	$13	$0	$1	$682	
(38) % RESPONSIBILITY	100.00%	88.68%	4.68%	4.30%	0.01%	0.88%	0.09%	0.03%	0.00%	0.00%	1.34%	O-13
(39) TOT. EXP. -CUST. (RETAIL)	$42,790	$34,599	$1,744	$3,427	$242	$787	$556	$715	$0	$170	$550	
(40) % RESPONSIBILITY	100.00%	80.86%	4.08%	8.01%	0.57%	1.84%	1.30%	1.67%	0.00%	0.40%	1.29%	O-14
(41) MARKETING & SALES	99.99%	45.33%	3.59%	8.37%	1.79%	6.58%	12.92%	19.62%	0.00%	1.79%	0.00%	O-15
(42) METER DATA SERVICES	100.02%	5.39%	5.27%	12.46%	16.17%	12.46%	12.46%	23.35%	0.00%	12.46%	0.00%	O-16
(43) SECONDARY CUST. REVENUE	$392,146	$0	$36,687	$321,964	$0	$33,495	$0	$0	$0	$0	$0	
(44) % RESPONSIBILITY	100.00%	0.00%	9.36%	82.10%	0.00%	8.54%	0.00%	0.00%	0.00%	0.00%	0.00%	R-1

EXHIBIT 9A

NOVA SCOTIA POWER INC.

SALES, GENERATION AND DEMAND ANALYSIS

FOR THE YEAR ENDING DECEMBER 31, 2014

	(1) MWH SALES	(2) ENERGY LINE LOSSES	(3) ENERGY REQUIREMENT	(4) CLASS NON-COINCIDENT DMD. (KW)	(5) SYSTEM COINCIDENT FACTOR	(6) SYSTEM COINCIDENT DMD. (KW)	(7) DEMAND LINE LOSSES	(8) SYSTEM COIN. PEAK DMD. (KW)	(9) SYSTEM COINCIDENT L/D FACTOR	(10) MW	(11) 3CP Contribution
(1) DOMESTIC	4,257,230	9.3%	4,654,738	1,036,540	100.0%	1,036,540	14.7%	1,188,498	44.71%	3,365,786	56.8%
(2) SMALL GENERAL	229,386	8.9%	249,760	58,447	61.5%	35,922	10.0%	39,526	72.13%	120,127	2.0%
(3) GENERAL	2,433,009	6.2%	2,584,209	487,817	82.8%	403,748	7.0%	432,030	68.28%	1,365,814	23.1%
(4) GENERAL LARGE	386,956	6.2%	410,860	70,885	70.0%	49,632	6.3%	52,776	88.87%	163,320	2.8%
(5) SMALL INDUSTRIAL	260,263	5.7%	275,205	47,973	78.3%	37,551	6.0%	39,786	78.96%	118,848	2.0%
(6) MEDIUM INDUSTRIAL	512,810	5.4%	540,444	87,602	82.3%	72,050	5.6%	76,073	81.10%	234,070	4.0%
(7) LARGE INDUSTRIAL	921,772	4.5%	962,980	138,738	81.5%	113,095	4.3%	117,949	93.20%	364,769	6.2%
(8) ELI 2P-RTP	0	N/A	0	0	N/A	0	N/A	0	N/A	-	0.0%
(9) MUNICIPAL	191,729	4.6%	200,464	40,907	97.8%	39,997	4.5%	41,806	54.74%	121,351	2.0%
(10) UNMETERED	97,813	10.0%	107,631	22,113	99.9%	22,088	10.8%	24,483	50.19%	68,910	1.2%
(11) SUB-TOTAL	9,290,967	7.5%	9,986,292	1,991,022	90.9%	1,810,625	11.2%	2,012,926	56.63%	5,922,996	100.0%
(12) BOWATER MERSEY	367,920	2.0%	375,389	42,000	100.0%	42,000	2.0%	42,857	99.99%	128,570	
(13) GEN.REPL./LOAD FOLL.	18,815	2.0%	19,199	23,900	0.2%	37	2.0%	38	N/A	315	
(14) REAL TIME PRICING	0	N/A	0	0	N/A	0	N/A	0	N/A	0	
(15) LRT	322,080	2.0%	328,618	38,000	96.8%	36,767	2.0%	37,517	99.99%	112,552	
(16) TOTAL	9,999,782	7.1%	10,709,498	2,094,922	90.2%	1,889,429	10.8%	2,093,337	58.40%	6,164,433	

EXHIBIT 9A

NOVA SCOTIA POWER INC.

SALES, GENERATION AND DEMAND ANALYSIS

FOR JANUARY 2011

	(1) MWH SALES	(2) ENERGY LINE LOSSES	(3) ENERGY REQUIREMENT	(4) CLASS NON-COINCIDENT DMD. (KW)	(5) SYSTEM COINCIDENT FACTOR	(6) SYSTEM COINCIDENT DMD. (KW)	(7) DEMAND LINE LOSSES	(8) SYSTEM COIN. PEAK DMD. (KW)	(9) SYSTEM COINCIDENT L/D FACTOR
(1) DOMESTIC	516,258	10.54%	570,685	1,013,128	97.1%	983,362	13.44%	1,115,541	68.76%
(2) SMALL GENERAL	25,143	9.71%	27,584	54,406	70.1%	38,108	9.83%	41,853	88.58%
(3) GENERAL	233,512	6.26%	248,124	487,817	93.2%	454,711	7.46%	488,643	68.25%
(4) GENERAL LARGE	32,543	6.58%	34,684	57,463	87.9%	50,514	6.74%	53,919	86.46%
(5) SMALL INDUSTRIAL	22,744	5.57%	24,010	44,936	88.7%	39,844	5.79%	42,151	76.56%
(6) MEDIUM INDUSTRIAL	44,133	5.05%	46,361	85,129	87.3%	74,312	5.31%	78,256	79.63%
(7) LARGE INDUSTRIAL	74,672	4.02%	77,673	121,617	86.6%	105,347	4.70%	110,293	94.66%
(8) ELI 2P-RTP	0	N/A	0	0	N/A	0	N/A	0	N/A
(9) MUNICIPAL	19,935	4.45%	20,821	39,114	99.2%	38,782	4.64%	40,581	68.96%
(10) UNMETERED	10,205	10.84%	11,311	22,108	78.3%	17,302	13.14%	19,576	77.66%
(11) SUB-TOTAL	979,144		1,061,252	1,925,716	93.6%	1,802,282	10.46%	1,990,813	71.65%
(12) BOWATER MERSEY	31,248	1.83%	31,821	42,000	100.0%	42,000	2.04%	42,857	99.80%
(13) GEN.REPL./LOAD FOLL.	990	2.04%	1,010	18,501	-0.6%	-117	2.04%	-119	-1137.38%
(14) REAL TIME PRICING	0	N/A	0	0	N/A	0	N/A	0	N/A
(15) EXPORT SALES	0	N/A	0	0	N/A	0	N/A	0	N/A
(16) LRT	27,355	2.03%	27,910	38,000	96.8%	36,767	2.04%	37,517	99.99%
(17) TOTAL	1,038,737	8.02%	1,121,994	2,024,217	92.9%	1,880,932	10.11%	2,071,068	72.82%

EXHIBIT 9A

NOVA SCOTIA POWER INC.

SALES, GENERATION AND DEMAND ANALYSIS

FOR FEBRUARY 2011

	(1) MWH SALES	(2) ENERGY LINE LOSSES	(3) ENERGY REQUIREMENT	(4) CLASS NON-COINCIDENT DMD. (KW)	(5) SYSTEM COINCIDENT FACTOR	(6) SYSTEM COINCIDENT DMD. (KW)	(7) DEMAND LINE LOSSES	(8) SYSTEM COIN. PEAK DMD. (KW)	(9) SYSTEM COINCIDENT L/D FACTOR
(1) DOMESTIC	447,869	10.84%	496,399	1,036,540	100.0%	1,036,540	14.66%	1,188,498	62.15%
(2) SMALL GENERAL	23,091	10.05%	25,412	57,717	62.2%	35,922	10.03%	39,526	95.67%
(3) GENERAL	219,011	6.41%	233,053	477,307	84.6%	403,748	7.00%	432,030	80.27%
(4) GENERAL LARGE	30,161	6.28%	32,054	58,667	84.6%	49,632	6.33%	52,776	90.38%
(5) SMALL INDUSTRIAL	21,804	5.87%	23,084	43,613	86.1%	37,551	5.95%	39,786	86.34%
(6) MEDIUM INDUSTRIAL	39,821	5.40%	41,970	77,859	92.5%	72,050	5.58%	76,073	82.10%
(7) LARGE INDUSTRIAL	70,292	4.25%	73,281	124,051	91.2%	113,095	4.29%	117,949	92.45%
(8) ELI 2P-RTP	0	N/A	0	0	N/A	0	N/A	0	N/A
(9) MUNICIPAL	18,948	4.39%	19,780	40,907	97.8%	39,997	4.52%	41,806	70.41%
(10) UNMETERED	8,648	10.56%	9,562	22,097	100.0%	22,088	10.84%	24,483	58.12%
(11) SUB-TOTAL	879,645		954,595	1,938,759	93.4%	1,810,625	11.17%	2,012,926	70.57%
(12) BOWATER MERSEY	28,224	2.03%	28,797	42,000	100.0%	42,000	2.04%	42,857	99.99%
(13) GEN.REPL./LOAD FOLL.	1,221	2.04%	1,246	19,501	0.2%	37	2.04%	38	4912.19%
(14) REAL TIME PRICING	0	N/A	0	0	N/A	0	N/A	0	N/A
(15) EXPORT SALES	0	N/A	0	0	N/A	0	N/A	0	N/A
(16) LRT	24,708	2.03%	25,209	38,000	96.8%	36,767	2.04%	37,517	99.99%
(17) TOTAL	933,798	8.14%	1,009,847	2,038,260	92.7%	1,889,429	10.79%	2,093,337	71.79%

EXHIBIT 9A

NOVA SCOTIA POWER INC.

SALES, GENERATION AND DEMAND ANALYSIS

FOR MARCH 2011

	(1) MWH SALES	(2) ENERGY LINE LOSSES	(3) ENERGY REQUIREMENT	(4) CLASS NON-COINCIDENT DMD. (KW)	(5) SYSTEM COINCIDENT FACTOR	(6) SYSTEM COINCIDENT DMD. (KW)	(7) DEMAND LINE LOSSES	(8) SYSTEM COIN. PEAK DMD. (KW)	(9) SYSTEM COINCIDENT L/D FACTOR
(1) DOMESTIC	448,408	10.15%	493,942	887,289	93.2%	826,992	12.35%	929,143	71.45%
(2) SMALL GENERAL	22,114	10.00%	24,326	50,502	76.6%	38,677	10.35%	42,679	76.61%
(3) GENERAL	225,239	6.80%	240,549	427,739	97.8%	418,481	7.76%	450,974	71.69%
(4) GENERAL LARGE	32,914	6.70%	35,118	58,108	92.1%	53,507	6.92%	57,210	82.51%
(5) SMALL INDUSTRIAL	21,869	6.43%	23,275	38,591	97.6%	37,673	6.63%	40,169	77.88%
(6) MEDIUM INDUSTRIAL	42,496	5.80%	44,961	72,921	89.3%	65,086	5.92%	68,937	87.66%
(7) LARGE INDUSTRIAL	75,457	4.60%	78,927	114,150	92.2%	105,208	4.62%	110,068	96.38%
(8) ELI 2P-RTP	0	N/A	0	0	N/A	0	N/A	0	N/A
(9) MUNICIPAL	18,941	4.99%	19,886	33,399	98.5%	32,913	5.10%	34,592	77.27%
(10) UNMETERED	8,555	9.93%	9,404	22,110	11.3%	2,497	7.66%	2,688	470.14%
(11) SUB-TOTAL	895,992		970,388	1,704,810	92.7%	1,581,034	9.83%	1,736,462	75.11%
(12) BOWATER MERSEY	31,248	2.03%	31,882	42,000	100.0%	42,000	2.04%	42,857	99.99%
(13) GEN.REPL./LOAD FOLL.	38	2.04%	39	1,842	-0.7%	-12	2.04%	-12	-428.70%
(14) REAL TIME PRICING	0	N/A	0	0	N/A	0	N/A	0	N/A
(15) EXPORT SALES	0	N/A	0	0	N/A	0	N/A	0	N/A
(16) LRT	27,276	2.01%	27,824	38,000	96.8%	36,767	2.04%	37,517	99.68%
(17) TOTAL	954,554	7.92%	1,030,133	1,786,652	92.9%	1,659,789	9.46%	1,816,824	76.21%

EXHIBIT 9A

NOVA SCOTIA POWER INC.

SALES, GENERATION AND DEMAND ANALYSIS

FOR APRIL 2011

	(1) MWH SALES	(2) ENERGY LINE LOSSES	(3) ENERGY REQUIREMENT	(4) CLASS NON-COINCIDENT DMD. (KW)	(5) SYSTEM COINCIDENT FACTOR	(6) SYSTEM COINCIDENT DMD. (KW)	(7) DEMAND LINE LOSSES	(8) SYSTEM COIN. PEAK DMD. (KW)	(9) SYSTEM COINCIDENT L/D FACTOR
(1) DOMESTIC	358,526	8.97%	390,670	787,516	95.8%	754,661	11.46%	841,129	64.51%
(2) SMALL GENERAL	18,756	9.09%	20,462	44,408	49.5%	21,980	8.71%	23,894	118.94%
(3) GENERAL	194,886	6.00%	206,572	383,448	87.6%	335,936	6.42%	357,497	80.25%
(4) GENERAL LARGE	30,042	6.11%	31,879	55,152	85.1%	46,953	6.16%	49,844	88.83%
(5) SMALL INDUSTRIAL	20,864	5.83%	22,080	39,767	81.9%	32,581	5.82%	34,478	88.94%
(6) MEDIUM INDUSTRIAL	42,349	5.43%	44,650	76,348	84.8%	64,715	5.44%	68,235	90.88%
(7) LARGE INDUSTRIAL	74,438	4.41%	77,718	121,813	88.4%	107,639	4.38%	112,351	96.08%
(8) ELI 2P-RTP	0	N/A	0	0	N/A	0	N/A	0	N/A
(9) MUNICIPAL	15,463	4.73%	16,194	29,110	93.0%	27,070	4.76%	28,358	79.31%
(10) UNMETERED	7,671	9.39%	8,391	22,110	12.3%	2,713	7.17%	2,908	400.83%
(11) SUB-TOTAL	762,995		818,616	1,559,671	89.4%	1,394,249	8.93%	1,518,694	74.86%
(12) BOWATER MERSEY	30,240	2.03%	30,854	42,000	100.0%	42,000	2.04%	42,857	99.99%
(13) GEN.REPL./LOAD FOLL.	1,462	2.04%	1,492	22,397	0.7%	157	2.04%	160	1293.35%
(14) REAL TIME PRICING	0	N/A	0	0	N/A	0	N/A	0	N/A
(15) EXPORT SALES	0	N/A	0	0	N/A	0	N/A	0	N/A
(16) LRT	26,472	2.03%	27,010	38,000	96.8%	36,767	2.04%	37,517	99.99%
(17) TOTAL	821,169	6.92%	877,972	1,662,068	88.6%	1,473,173	8.56%	1,599,229	76.25%

EXHIBIT 9A

NOVA SCOTIA POWER INC.

SALES, GENERATION AND DEMAND ANALYSIS

FOR MAY 2011

	(1) MWH SALES	(2) ENERGY LINE LOSSES	(3) ENERGY REQUIREMENT	(4) CLASS NON-COINCIDENT DMD. (KW)	(5) SYSTEM COINCIDENT FACTOR	(6) SYSTEM COINCIDENT DMD. (KW)	(7) DEMAND LINE LOSSES	(8) SYSTEM COIN. PEAK DMD. (KW)	(9) SYSTEM COINCIDENT L/D FACTOR
(1) DOMESTIC	321,861	8.99%	350,788	673,187	89.3%	600,903	10.55%	664,326	70.97%
(2) SMALL GENERAL	17,186	9.20%	18,767	39,719	79.2%	31,474	9.48%	34,459	73.20%
(3) GENERAL	183,713	6.40%	195,464	360,986	94.7%	341,706	7.11%	365,984	71.78%
(4) GENERAL LARGE	31,088	6.50%	33,109	59,127	92.9%	54,946	6.78%	58,670	75.85%
(5) SMALL INDUSTRIAL	21,028	6.19%	22,330	41,938	99.2%	41,617	6.44%	44,298	67.75%
(6) MEDIUM INDUSTRIAL	41,845	6.06%	44,382	77,834	89.9%	69,976	6.23%	74,332	80.25%
(7) LARGE INDUSTRIAL	74,730	5.06%	78,509	113,305	91.6%	103,834	5.03%	109,058	96.76%
(8) ELI 2P-RTP	0	N/A	0	0	N/A	0	N/A	0	N/A
(9) MUNICIPAL	13,868	4.81%	14,535	24,677	99.0%	24,430	4.85%	25,615	76.27%
(10) UNMETERED	6,995	10.56%	7,734	22,109	13.7%	3,020	5.43%	3,184	326.45%
(11) SUB-TOTAL	712,316		765,619	1,412,882	90.0%	1,271,905	8.49%	1,379,927	74.57%
(12) BOWATER MERSEY	31,248	2.03%	31,882	42,000	100.0%	42,000	2.04%	42,857	99.99%
(13) GEN.REPL./LOAD FOLL.	442	2.04%	451	3,189	22.5%	718	2.04%	733	82.68%
(14) REAL TIME PRICING	0	N/A	0	0	N/A	0	N/A	0	N/A
(15) EXPORT SALES	0	N/A	0	0	N/A	0	N/A	0	N/A
(16) LRT	27,355	2.03%	27,910	38,000	96.8%	36,767	2.04%	37,517	99.99%
(17) TOTAL	771,360	7.07%	825,862	1,496,072	90.3%	1,351,391	8.11%	1,461,033	75.98%

EXHIBIT 9A

NOVA SCOTIA POWER INC.

SALES, GENERATION AND DEMAND ANALYSIS

FOR JUNE 2011

	(1) MWH SALES	(2) ENERGY LINE LOSSES	(3) ENERGY REQUIREMENT	(4) CLASS NON-COINCIDENT DMD. (KW)	(5) SYSTEM COINCIDENT FACTOR	(6) SYSTEM COINCIDENT DMD. (KW)	(7) DEMAND LINE LOSSES	(8) SYSTEM COIN. PEAK DMD. (KW)	(9) SYSTEM COINCIDENT L/D FACTOR
(1) DOMESTIC	263,546	7.18%	282,475	665,640	94.6%	629,524	9.80%	691,192	56.76%
(2) SMALL GENERAL	16,366	7.18%	17,541	40,230	61.7%	24,808	8.07%	26,810	90.87%
(3) GENERAL	185,771	5.59%	196,155	387,816	77.6%	300,830	5.66%	317,844	85.71%
(4) GENERAL LARGE	30,922	5.21%	32,534	60,712	76.0%	46,157	5.45%	48,673	92.83%
(5) SMALL INDUSTRIAL	21,952	5.02%	23,055	45,324	72.8%	32,994	5.15%	34,693	92.30%
(6) MEDIUM INDUSTRIAL	43,808	4.93%	45,966	80,855	84.2%	68,050	5.12%	71,536	89.24%
(7) LARGE INDUSTRIAL	76,496	4.18%	79,690	124,550	92.8%	115,566	4.13%	120,335	91.98%
(8) ELI 2P-RTP	0	N/A	0	0	N/A	0	N/A	0	N/A
(9) MUNICIPAL	12,778	4.12%	13,304	24,358	100.0%	24,358	4.37%	25,422	72.68%
(10) UNMETERED	6,227	10.17%	6,861	22,109	11.6%	2,572	3.92%	2,673	356.47%
(11) SUB-TOTAL	657,866		697,578	1,451,595	85.8%	1,244,859	7.58%	1,339,179	72.35%
(12) BOWATER MERSEY	30,240	2.03%	30,854	42,000	100.0%	42,000	2.04%	42,857	99.99%
(13) GEN.REPL./LOAD FOLL.	577	2.04%	589	23,190	-0.1%	-29	2.04%	-30	-2762.43%
(14) REAL TIME PRICING	0	N/A	0	0	N/A	0	N/A	0	N/A
(15) EXPORT SALES	0	N/A	0	0	N/A	0	N/A	0	N/A
(16) LRT	26,472	2.03%	27,010	38,000	96.8%	36,767	2.04%	37,517	99.99%
(17) TOTAL	715,155	5.72%	756,030	1,554,785	85.1%	1,323,597	7.25%	1,419,523	73.97%

EXHIBIT 9A

NOVA SCOTIA POWER INC.

SALES, GENERATION AND DEMAND ANALYSIS

FOR JULY 2011

	(1) MWH SALES	(2) ENERGY LINE LOSSES	(3) ENERGY REQUIREMENT	(4) CLASS NON-COINCIDENT DMD. (KW)	(5) SYSTEM COINCIDENT FACTOR	(6) SYSTEM COINCIDENT DMD. (KW)	(7) DEMAND LINE LOSSES	(8) SYSTEM COIN. PEAK DMD. (KW)	(9) SYSTEM COINCIDENT L/D FACTOR
(1) DOMESTIC	264,900	7.22%	284,027	580,449	76.9%	446,200	7.89%	481,390	79.30%
(2) SMALL GENERAL	16,867	7.58%	18,145	38,796	92.9%	36,043	8.13%	38,974	62.58%
(3) GENERAL	200,920	5.82%	212,604	398,918	98.9%	394,684	6.76%	421,374	67.82%
(4) GENERAL LARGE	35,364	5.79%	37,410	64,855	98.1%	63,625	6.14%	67,534	74.46%
(5) SMALL INDUSTRIAL	22,315	4.97%	23,425	45,991	91.3%	41,966	5.16%	44,132	71.34%
(6) MEDIUM INDUSTRIAL	43,767	4.85%	45,890	82,658	92.8%	76,710	5.07%	80,598	76.53%
(7) LARGE INDUSTRIAL	79,763	4.16%	83,078	126,972	97.3%	123,570	4.25%	128,816	86.69%
(8) ELI 2P-RTP	0	N/A	0	0	N/A	0	N/A	0	N/A
(9) MUNICIPAL	14,080	4.10%	14,657	25,639	99.6%	25,539	4.11%	26,589	74.09%
(10) UNMETERED	6,490	10.32%	7,160	22,108	13.6%	3,002	5.03%	3,153	305.20%
(11) SUB-TOTAL	684,465		726,396	1,386,387	87.4%	1,211,340	6.71%	1,292,562	75.54%
(12) BOWATER MERSEY	31,248	2.03%	31,882	42,000	100.0%	42,000	2.04%	42,857	99.99%
(13) GEN.REPL./LOAD FOLL.	1,591	2.04%	1,624	23,449	10.4%	2,428	2.04%	2,478	88.09%
(14) REAL TIME PRICING	0	N/A	0	0	N/A	0	N/A	0	N/A
(15) EXPORT SALES	0	N/A	0	0	N/A	0	N/A	0	N/A
(16) LRT	27,355	2.03%	27,910	38,000	96.8%	36,767	2.04%	37,517	99.99%
(16) TOTAL	744,659	5.80%	787,812	1,489,835	86.8%	1,292,535	6.41%	1,375,413	76.99%

EXHIBIT 9A

NOVA SCOTIA POWER INC.

SALES, GENERATION AND DEMAND ANALYSIS

FOR AUGUST 2011

	(1) MWH SALES	(2) ENERGY LINE LOSSES	(3) ENERGY REQUIREMENT	(4) CLASS NON-COINCIDENT DMD. (KW)	(5) SYSTEM COINCIDENT FACTOR	(6) SYSTEM COINCIDENT DMD. (KW)	(7) DEMAND LINE LOSSES	(8) SYSTEM COIN. PEAK DMD. (KW)	(9) SYSTEM COINCIDENT L/D FACTOR
(1) DOMESTIC	259,435	8.21%	280,734	583,793	84.0%	490,139	9.44%	536,427	70.34%
(2) SMALL GENERAL	16,979	8.84%	18,481	41,234	82.1%	33,849	9.28%	36,992	67.15%
(3) GENERAL	195,364	6.42%	207,903	422,127	95.8%	404,390	7.52%	434,799	64.27%
(4) GENERAL LARGE	35,677	6.77%	38,093	69,711	95.0%	66,198	7.19%	70,955	72.16%
(5) SMALL INDUSTRIAL	22,273	5.73%	23,549	47,973	84.6%	40,562	5.89%	42,951	73.69%
(6) MEDIUM INDUSTRIAL	43,815	5.66%	46,294	81,056	89.6%	72,633	5.80%	76,849	80.97%
(7) LARGE INDUSTRIAL	85,523	5.01%	89,806	131,155	94.6%	124,091	5.03%	130,328	92.62%
(8) ELI 2P-RTP	0	N/A	0	0	N/A	0	N/A	0	N/A
(9) MUNICIPAL	13,883	4.81%	14,552	26,526	96.4%	25,562	4.82%	26,793	73.00%
(10) UNMETERED	7,048	10.57%	7,793	22,110	12.9%	2,859	5.47%	3,015	347.36%
(11) SUB-TOTAL	679,998		727,204	1,425,684	88.4%	1,260,282	7.84%	1,359,109	71.92%
(12) BOWATER MERSEY	31,248	2.03%	31,882	42,000	100.0%	42,000	2.04%	42,857	99.99%
(13) GEN.REPL./LOAD FOLL.	2,834	2.04%	2,892	23,447	75.9%	17,804	2.04%	18,167	21.39%
(14) REAL TIME PRICING	0	N/A	0	0	N/A	0	N/A	0	N/A
(15) EXPORT SALES	0	N/A	0	0	N/A	0	N/A	0	N/A
(16) LRT	27,355	2.03%	27,910	38,000	96.8%	36,767	2.04%	37,517	99.99%
(17) TOTAL	741,435	6.54%	789,888	1,529,131	88.7%	1,356,853	7.43%	1,457,650	72.83%

EXHIBIT 9A

NOVA SCOTIA POWER INC.

SALES, GENERATION AND DEMAND ANALYSIS

FOR SEPTEMBER 2011

	(1) MWH SALES	(2) ENERGY LINE LOSSES	(3) ENERGY REQUIREMENT	(4) CLASS NON-COINCIDENT DMD. (KW)	(5) SYSTEM COINCIDENT FACTOR	(6) SYSTEM COINCIDENT DMD. (KW)	(7) DEMAND LINE LOSSES	(8) SYSTEM COIN. PEAK DMD. (KW)	(9) SYSTEM COINCIDENT L/D FACTOR
(1) DOMESTIC	259,862	6.87%	277,712	552,662	90.0%	497,196	8.53%	539,626	71.48%
(2) SMALL GENERAL	15,373	7.35%	16,503	37,876	84.5%	31,986	7.66%	34,437	66.56%
(3) GENERAL	181,226	5.27%	190,777	434,599	95.0%	413,057	6.48%	439,809	60.25%
(4) GENERAL LARGE	33,303	4.86%	34,923	70,885	94.7%	67,104	5.24%	70,620	68.68%
(5) SMALL INDUSTRIAL	20,819	4.75%	21,808	45,821	84.0%	38,465	4.81%	40,315	75.13%
(6) MEDIUM INDUSTRIAL	42,676	4.67%	44,667	83,798	86.9%	72,776	4.73%	76,219	81.39%
(7) LARGE INDUSTRIAL	80,361	4.07%	83,630	138,738	89.9%	124,733	4.06%	129,794	89.49%
(8) ELI 2P-RTP	0	N/A	0	0	N/A	0	N/A	0	N/A
(9) MUNICIPAL	13,566	3.88%	14,092	27,312	96.7%	26,411	3.85%	27,426	71.36%
(10) UNMETERED	7,623	8.75%	8,289	22,110	12.2%	2,700	5.73%	2,855	403.24%
(11) SUB-TOTAL	654,808		692,401	1,413,801	90.1%	1,274,428	6.80%	1,361,102	70.65%
(12) BOWATER MERSEY	30,240	2.03%	30,854	42,000	100.0%	42,000	2.04%	42,857	99.99%
(13) GEN.REPL./LOAD FOLL.	6,682	2.04%	6,819	23,900	96.4%	23,047	2.04%	23,518	40.27%
(14) REAL TIME PRICING	0	N/A	0	0	N/A	0	N/A	0	N/A
(15) EXPORT SALES	0	N/A	0	0	N/A	0	N/A	0	N/A
(16) LRT	26,472	2.03%	27,010	38,000	96.8%	36,767	2.04%	37,517	99.99%
(17) TOTAL	718,203	5.41%	757,083	1,517,701	90.7%	1,376,242	6.45%	1,464,994	71.78%

EXHIBIT 9A

NOVA SCOTIA POWER INC.

SALES, GENERATION AND DEMAND ANALYSIS

FOR OCTOBER 2011

	(1) MWH SALES	(2) ENERGY LINE LOSSES	(3) ENERGY REQUIREMENT	(4) CLASS NON-COINCIDENT DMD. (KW)	(5) SYSTEM COINCIDENT FACTOR	(6) SYSTEM COINCIDENT DMD. (KW)	(7) DEMAND LINE LOSSES	(8) SYSTEM COIN. PEAK DMD. (KW)	(9) SYSTEM COINCIDENT L/D FACTOR
(1) DOMESTIC	299,381	8.32%	324,301	666,350	90.9%	605,415	10.17%	666,979	65.35%
(2) SMALL GENERAL	17,145	7.55%	18,440	38,805	72.5%	28,144	7.66%	30,301	81.80%
(3) GENERAL	189,540	6.01%	200,935	409,155	87.2%	356,584	6.80%	380,828	70.92%
(4) GENERAL LARGE	32,368	6.07%	34,333	67,431	79.4%	53,536	6.29%	56,903	81.10%
(5) SMALL INDUSTRIAL	19,175	5.67%	20,262	42,759	96.7%	41,333	5.99%	43,809	62.16%
(6) MEDIUM INDUSTRIAL	43,031	5.44%	45,372	78,875	93.1%	73,407	5.65%	77,553	78.63%
(7) LARGE INDUSTRIAL	78,588	4.61%	82,213	119,469	93.9%	112,118	4.61%	117,283	94.22%
(8) ELI 2P-RTP	0	N/A	0	0	N/A	0	N/A	0	N/A
(9) MUNICIPAL	14,607	4.51%	15,267	26,663	98.1%	26,156	4.55%	27,347	75.04%
(10) UNMETERED	8,211	8.43%	8,903	22,112	10.3%	2,285	6.42%	2,432	492.04%
(11) SUB-TOTAL	702,047		750,026	1,471,619	88.3%	1,298,978	8.04%	1,403,436	71.83%
(12) BOWATER MERSEY	31,248	2.03%	31,882	42,000	100.0%	42,000	2.04%	42,857	99.99%
(13) GEN.REPL./LOAD FOLL.	1,467	2.04%	1,497	7,533	19.7%	1,483	2.04%	1,513	132.94%
(14) REAL TIME PRICING	0	N/A	0	0	N/A	0	N/A	0	N/A
(15) EXPORT SALES	0	N/A	0	0	N/A	0	N/A	0	N/A
(16) LRT	27,355	2.03%	27,910	38,000	96.8%	36,767	2.04%	37,517	99.99%
(17) TOTAL	762,116	6.46%	811,315	1,559,151	88.5%	1,379,228	7.69%	1,485,323	73.42%

EXHIBIT 9A

NOVA SCOTIA POWER INC.

SALES, GENERATION AND DEMAND ANALYSIS

FOR NOVEMBER 2011

	(1) MWH SALES	(2) ENERGY LINE LOSSES	(3) ENERGY REQUIREMENT	(4) CLASS NON-COINCIDENT DMD. (KW)	(5) SYSTEM COINCIDENT FACTOR	(6) SYSTEM COINCIDENT DMD. (KW)	(7) DEMAND LINE LOSSES	(8) SYSTEM COIN. PEAK DMD. (KW)	(9) SYSTEM COINCIDENT L/D FACTOR
(1) DOMESTIC	350,596	8.97%	382,045	776,138	100.0%	776,138	11.76%	867,425	61.17%
(2) SMALL GENERAL	17,948	8.43%	19,461	45,312	66.1%	29,941	8.58%	32,510	83.14%
(3) GENERAL	198,025	5.73%	209,379	399,991	89.6%	358,203	6.34%	380,904	76.35%
(4) GENERAL LARGE	31,242	5.91%	33,088	58,137	89.6%	52,079	6.07%	55,239	83.19%
(5) SMALL INDUSTRIAL	21,031	5.68%	22,226	43,298	78.6%	34,022	5.72%	35,967	85.83%
(6) MEDIUM INDUSTRIAL	42,141	5.04%	44,263	78,808	91.4%	72,057	5.19%	75,800	81.10%
(7) LARGE INDUSTRIAL	78,531	4.04%	81,705	124,268	75.5%	93,876	3.79%	97,438	116.46%
(8) ELI 2P-RTP	0	N/A	0	0	N/A	0	N/A	0	N/A
(9) MUNICIPAL	16,324	4.03%	16,982	31,119	100.0%	31,119	4.06%	32,382	72.84%
(10) UNMETERED	9,592	9.25%	10,480	22,112	74.2%	16,412	8.48%	17,803	81.76%
(11) SUB-TOTAL	765,431		819,629	1,579,182	92.7%	1,463,845	8.99%	1,595,467	71.35%
(12) BOWATER MERSEY	30,240	2.03%	30,854	42,000	100.0%	42,000	2.04%	42,857	99.99%
(13) GEN.REPL./LOAD FOLL.	1,310	2.04%	1,337	21,278	92.6%	19,707	2.04%	20,109	9.23%
(14) REAL TIME PRICING	0	N/A	0	0	N/A	0	N/A	0	N/A
(15) EXPORT SALES	0	N/A	0	0	N/A	0	N/A	0	N/A
(16) LRT	26,551	2.05%	27,095	38,000	96.8%	36,767	2.04%	37,517	100.31%
(17) TOTAL	823,532	6.73%	878,915	1,680,460	93.0%	1,562,319	8.55%	1,695,951	71.98%

EXHIBIT 9A

NOVA SCOTIA POWER INC.

SALES, GENERATION AND DEMAND ANALYSIS

FOR DECEMBER 2011

	(1) MWH SALES	(2) ENERGY LINE LOSSES	(3) ENERGY REQUIREMENT	(4) CLASS NON-COINCIDENT DMD. (KW)	(5) SYSTEM COINCIDENT FACTOR	(6) SYSTEM COINCIDENT DMD. (KW)	(7) DEMAND LINE LOSSES	(8) SYSTEM COIN. PEAK DMD. (KW)	(9) SYSTEM COINCIDENT L/D FACTOR
(1) DOMESTIC	466,588	11.65%	520,959	965,934	96.0%	927,091	14.52%	1,061,747	65.95%
(2) SMALL GENERAL	22,417	9.92%	24,640	58,447	60.2%	35,197	10.09%	38,749	85.47%
(3) GENERAL	225,801	7.48%	242,695	451,524	90.9%	410,591	8.41%	445,141	73.28%
(4) GENERAL LARGE	31,331	7.36%	33,636	60,007	87.6%	52,591	7.67%	56,625	79.84%
(5) SMALL INDUSTRIAL	24,389	7.03%	26,103	47,271	72.9%	34,474	7.07%	36,910	95.06%
(6) MEDIUM INDUSTRIAL	42,928	6.38%	45,668	87,602	85.3%	74,747	6.68%	79,742	76.97%
(7) LARGE INDUSTRIAL	72,922	5.25%	76,748	130,016	99.5%	129,317	5.58%	136,527	75.56%
(8) ELI 2P-RTP	0	N/A	0	0	N/A	0	N/A	0	N/A
(9) MUNICIPAL	19,337	5.48%	20,395	36,870	100.0%	36,870	5.68%	38,964	70.36%
(10) UNMETERED	10,548	11.35%	11,745	22,113	100.0%	22,113	12.38%	24,851	63.52%
(11) SUB-TOTAL	916,260		1,002,588	1,859,785	92.6%	1,722,992	11.39%	1,919,257	70.21%
(12) BOWATER MERSEY	31,248	2.03%	31,882	42,000	100.0%	42,000	2.04%	42,857	99.99%
(13) GEN.REPL./LOAD FOLL.	200	2.04%	204	1,495	26.0%	389	2.04%	397	69.22%
(14) REAL TIME PRICING	0	N/A	0	0	N/A	0	N/A	0	N/A
(15) EXPORT SALES	0	N/A	0	0	N/A	0	N/A	0	N/A
(16) LRT	27,355	2.03%	27,910	38,000	96.8%	36,767	2.04%	37,517	99.99%
(17) TOTAL	975,063	8.98%	1,062,585	1,941,280	92.8%	1,802,148	10.98%	2,000,028	71.41%

EXHIBIT 9B

NOVA SCOTIA POWER INC.

DETERMINATION OF CLASS NON-COINCIDENT KW DEMAND BY VOLTAGE LEVEL

FOR THE YEAR ENDING DECEMBER 31, 2014

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED
(1) NON-COIN. KW SEC.	1,622,280	1,036,540	58,447	461,817	0	43,363	0	0	0	0	22,113
(2) LOSSES 6.00%	97,337	62,192	3,507	27,709	0	2,602	0	0	0	0	1,327
(3) SUB-TOTAL	1,719,617	1,098,733	61,954	489,526	0	45,965	0	0	0	0	23,440
(4) NON-COIN. KW PRI.	1,906,323	1,098,733	61,954	515,526	70,885	50,575	85,211	0	0	0	23,440
(5) LOSSES 5.40%	102,941	59,332	3,346	27,838	3,828	2,731	4,601	0	0	0	1,266
(6) SUB-TOTAL	2,009,264	1,158,064	65,299	543,365	74,713	53,306	89,812	0	0	0	24,706
(7) NON-COIN. KW TRANS.	2,191,301	1,158,064	65,299	543,365	74,713	53,306	92,204	138,738	0	40,907	24,706
(8) LOSSES 3.70%	81,078	42,848	2,416	20,104	2,764	1,972	3,412	5,133	0	1,514	914
(9) TOTAL	2,272,379	1,200,913	67,715	563,469	77,477	55,278	95,615	143,871	0	42,420	25,620

EXHIBIT 9C

NOVA SCOTIA POWER INC.

DETAIL OF MONTHLY CLASS SYSTEM COINCIDENT KW DEMAND

FOR THE YEAR ENDING DECEMBER 31, 2014

MONTH	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUST.	(7) MEDIUM INDUST.	(8) LARGE INDUST.	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED	(12) MERSEY SYSTEM	(13) GRLF	(14) REAL TIME PRICING	(15) LRT
(1) JANUARY	**2,033,551**	**1,115,541**	**41,853**	**488,643**	**53,919**	**42,151**	**78,256**	**110,293**	**0**	**40,581**	**19,576**	**42,857**	**(119)**	**0**	**37,517**
(2) FEBRUARY	**2,055,820**	**1,188,498**	**39,526**	**432,030**	**52,776**	**39,786**	**76,073**	**117,949**	**0**	**41,806**	**24,483**	**42,857**	**38**	**0**	**37,517**
(3) MARCH	1,779,307	929,143	42,679	450,974	57,210	40,169	68,937	110,068	0	34,592	2,688	42,857	(12)	0	37,517
(4) APRIL	1,561,711	841,129	23,894	357,497	49,844	34,478	68,235	112,351	0	28,358	2,908	42,857	160	0	37,517
(5) MAY	1,423,516	664,326	34,459	365,984	58,670	44,298	74,332	109,058	0	25,615	3,184	42,857	733	0	37,517
(6) JUNE	1,382,006	691,192	26,810	317,844	48,673	34,693	71,536	120,335	0	25,422	2,673	42,857	(30)	0	37,517
(7) JULY	1,337,896	481,390	38,974	421,374	67,534	44,132	80,598	128,816	0	26,589	3,153	42,857	2,478	0	37,517
(8) AUGUST	1,420,133	536,427	36,992	434,799	70,955	42,951	76,849	130,328	0	26,793	3,015	42,857	18,167	0	37,517
(9) SEPTEMBER	1,427,476	539,626	34,437	439,809	70,620	40,315	76,219	129,794	0	27,426	2,855	42,857	23,518	0	37,517
(10) OCTOBER	1,447,806	666,979	30,301	380,828	56,903	43,809	77,553	117,283	0	27,347	2,432	42,857	1,513	0	37,517
(11) NOVEMBER	1,658,433	867,425	32,510	380,904	55,239	35,967	75,800	97,438	0	32,382	17,803	42,857	20,109	0	37,517
(12) DECEMBER	**1,962,511**	**1,061,747**	**38,749**	**445,141**	**56,625**	**36,910**	**79,742**	**136,527**	**0**	**38,964**	**24,851**	**42,857**	**397**	**0**	**37,517**
(13) TOT. SUMMED DMD.	19,490,167	9,583,424	421,183	4,915,827	698,969	479,661	904,131	1,420,241	0	375,876	109,622	514,282	66,951	0	450,206
(14) 3 C/P DEMANDS	**6,051,882**	**3,365,786**	**120,127**	**1,365,814**	**163,320**	**118,848**	**234,070**	**364,769**	**0**	**121,351**	**68,910**	**128,570**	**315**	**0**	**112,552**
(15)					**3 C/P INTERRUPTIBLE RIDER DEMANDS**			**269,747**							
(16)					**NET 3 C/P LARGE INDUST. DEMANDS**			**95,022**							

NOVA SCOTIA POWER INC.

REVENUE TO EXPENSE COMPARISON

FOR THE YEAR ENDING DECEMBER 31, 2014
(IN THOUSANDS OF DOLLARS)

	(1) TOTAL DMD.RELATED EXPENSES	(2) TOTAL ENG.RELATED EXPENSES	(3) UNIT COST ENG.RELATED (C / kW.h)	(4) TOTAL CUST.RELATED EXPENSES	(5) TOTAL OPER. EXPENSES	(6) TOTAL RATE REVENUE	(7) % REVENUE TO EXPENSES
(1) DOMESTIC	$196,333	$402,543	9.46	$94,774	$693,650	$689,768	99.44
(2) SMALL GENERAL	8,537	21,598	9.42	5,006	35,141	36,687	104.40
(3) GENERAL	83,553	223,264	9.18	6,265	313,082	321,964	102.84
(4) LARGE GENERAL	8,502	35,474	9.17	280	44,256	43,662	98.66
(5) SMALL INDUSTRIAL	7,581	23,767	9.13	1,476	32,825	33,495	102.04
(6) MEDIUM INDUSTRIAL	11,615	46,647	9.10	635	58,897	57,293	97.28
(7) LARGE INDUSTRIAL	7,520	83,114	9.02	781	91,415	86,844	95.00
(8) ELI 2P-RTP	0	0	0.00	0	0	0	0.00
(9) MUNICIPAL	4,419	17,326	9.04	185	21,929	21,483	97.96
(10) UNMETERED	13,286	9,297	9.51	1,407	23,989	23,989	100.00
(11) SUB-TOTAL	$341,346	$863,030	9.29	$110,809	1,315,185	1,315,185	100.00
(12) DIRECT EXP./ REV					42,345	47,292	N/A
(13) RETURN ON DIRECT EXP.					4,948	0	N/A
(14) TOTAL					$1,362,477	$1,362,477	100.00

NOVA SCOTIA POWER INC.

REVENUE TO EXPENSE COMPARISON

FOR THE YEAR ENDING DECEMBER 31, 2014
(IN THOUSANDS OF DOLLARS)

	(1) TOTAL DMD.RELATED EXPENSES	(2) TOTAL ENG.RELATED EXPENSES	(3) UNIT COST ENG.RELATED (C / kW.h)	(4) TOTAL CUST.RELATED EXPENSES	(5) TOTAL OPER. EXPENSES	(6) TOTAL RATE REVENUE	(7) % REVENUE TO EXPENSES
(1) DOMESTIC	$180,890	$386,119	9.07	$90,556	$657,565	$654,440	99.52
(2) SMALL GENERAL	7,872	20,717	9.03	4,784	33,372	34,808	104.30
(3) GENERAL	77,007	214,146	8.80	6,029	297,183	305,474	102.79
(4) LARGE GENERAL	7,858	34,025	8.79	279	42,162	41,426	98.25
(5) SMALL INDUSTRIAL	6,990	22,796	8.76	1,428	31,213	31,779	101.81
(6) MEDIUM INDUSTRIAL	10,727	44,740	8.72	631	56,098	54,358	96.90
(7) LARGE INDUSTRIAL	6,436	79,717	8.65	780	86,932	82,372	94.76
(8) ELI 2P-RTP	0	0	0.00	0	0	0	0.00
(9) MUNICIPAL	4,060	16,618	8.67	184	20,863	20,382	97.70
(10) UNMETERED	12,467	8,917	9.12	1,348	22,733	23,081	101.53
(11) SUB-TOTAL	$314,307	$827,795	8.91	$106,020	1,248,122	1,248,122	100.00
(12) DIRECT EXP./ REV					42,384	47,212	N/A
(13) RETURN ON DIRECT EXP.					4,827	0	N/A
(14) TOTAL					$1,295,333	$1,295,333	100.00

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Request IR-83:

Please provide all workpapers supporting SR-01.

Response IR-83:

Please refer to the description of the Cost of Service Methodology included in SR-01 and Appendix O of the Application for the proposed Cost of Service Study (COSS) changes.

For methodological changes proposed by NS Power in the 2012 GRA, please refer to Attachment 1.

In general rate application submissions previous to 2012, NS Power provided information on proposed changes to the COSS methodology in its direct evidence and responses to information requests. For the background information regarding the original cost of service procedures that predate the 1995 COSS Decision,[1] please refer to Attachment 2, which is 2012 GRA CA IR-45.

[1] Generic Hearing respecting Cost of Service and Rate Design UARB Decision, NSPI864, September 22, 1995.

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Request IR-1:

With respect to SR-01:

(a) Please provide an Excel version of the 2012 Cost of Service.

(b) Please identify changes to the COSS model since the last COSS submission to the Board in the 2009 GRA Compliance Filing, particularly the changes with respect to Unmetered.

(c) There are two Exhibits marked Exhibit 10. Please identify which of these should be Exhibit 10A.

(d) Please explain why the total operating expenses (Column 5) differs between the two exhibits referenced in c).

Response IR-1:

(a) Please refer to Confidential Attachment 1, filed electronically.

(b) Please see table below for changes to the COSS model since the last COSS submission to the Board in the 2009 GRA Compliance Filing.

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#	Exhibits	Proposed Changes	Reasons for change
1	Input Data Tab	Increased precision in tracking of generation costs associated with environmental compliance and fuel conversion for the energy-only classification purposes.	In Compliance with the Board's Decision on Generic Hearing respecting COSS and Rate Design (NSPI864) in 1995, NSPI has been tracking the environmental assets separately. In previous GRA filings, the environmental projects incorporated into the COSS model were above $1 million. To the extent possible NSPI is tracking all environmental investments for the rate base classification purposes.
2	Input Data Tab	New direct streetlight-related depreciation cost input from NSPI's financial system.	Availability of this information makes the current indirect approach in allocation of these direct costs via the use of modified allocation factors redundant.
3	Input Data Tab	LED capital costs form an external input calculated in DE-03 – DE-04, Appendix G, Table 5A	Consistent with the way below-the-line categories are treated in COSS
4	Exhibit 2	Line (20) Street Lighting	LED-related rate base is directly assigned as it has been moved below-the-line.
5	Exhibit 2	Line (37) DEF. CR –ARO Wind	Added new category in the Asset Retirement Obligations to single out wind generation in accordance with financial systems.

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#	Exhibits	Proposed Changes	Reasons for change
6	Exhibit 2	Line (41) Contract Receivable	No longer deemed confidential.
7	Exhibit 2a	Line (23) Contract Receivable	No longer deemed confidential.
8	Exhibit 2b	Line (23) Contract Receivable	No longer deemed confidential.
9	Exhibit 3	Line (23) Contract Receivable	No longer deemed confidential.
10	Exhibit 3	Page 2, Lines (15) and (16) Distribution Plant	The distribution plant function is broken into streetlight and non-streetlight related components.
11	Exhibit 4	Lines (21) and (22)	Added two new categories in operating expenses to remain consistent with financial systems.
12	Exhibit 4	Lines (37) and (38)	The distribution plant function is broken into streetlight and non-streetlight related. The total streetlight distribution cost comes directly from NSPI's financial systems rather than being assigned indirectly via the use of allocators.
13	Exhibit 4 Detail		The distribution plant function is broken into streetlight and non-streetlight related components.
14	Exhibit 5	Page 3, Lines (14) through (20)	The distribution plant function is broken into streetlight and non-streetlight related.
15	Exhibit 6	Page 2, Lines (20) through (27)	The distribution plant function is broken into streetlight and non-streetlight related.

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#	Exhibits	Proposed Changes	Reasons for change
16	Exhibit 6	Line (11) in Retail Section	New category is introduced which is called Meter Reading and Electric Inspection replacing Operating and Maintenance category which was not used.
17	Exhibit 6A	Line (20)	New category is introduced which is called Customer Service.
18	Exhibit 6d	Lines (14) and (15)	The distribution plant function is broken into streetlight and non-streetlight related.
19	Exhibit 7	Line 22	LED capital costs are directly assigned.
20	Exhibit 8a	Lines (33) and (34)	Development of average customers allocation factor (C-7) adjusted for seasonal customers. Seasonal customers will only be taken into account during the months of active service and the COSS model averages this over twelve months. This impacts allocation of some customer-service related expenses such as – Head Office, Electric Wiring Inspection – Head Office, Payment Services, COGS.

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#	Exhibits	Proposed Changes	Reasons for change
21	Exhibit 8b	Lines (19) and (20)	Development of Demand – Dist. Plant (P – 9A). These allocation factors are used to appropriately allocate between streetlight and non-streetlight related expenses. This impacts operating expenses in Exhibit 6 that are streetlight and non-streetlight related.
22	Exhibit 8b	Lines (39) through (42)	Total Rate Base – demand (DIST) allocators, originally used for the allocation of streetlight- and non-streetlight-related capital costs combined (P-16), have been split into to two separate sets of allocators (P-16 and P-16B) to allocate these costs separately.
23	Exhibit 9	Columns (10) and (11)	Exhibit is enhanced with 3 coincident peak information as used for allocation of demand-related costs.

(c) The second exhibit should have been labeled as Exhibit 10A. Please refer to Confidential Attachment 1, filed electronically, which has these exhibits labeled appropriately.

(d) The total operating expenses in Exhibit 10A fall short of the total revenue requirement by the amount of the requested increase. The revenue deficiency, as reflected in Retained Earnings, is spread among all rate classes and set to match total operating expenses with total revenues priced at the current rates. This presentation of the cost information is consistent with past GRA filing practice.

Request IR-2:

With respect to DE-03 – DE-04, Appendix G, page 4:

(a) Please demonstrate how the "formula-based revenue allocation process" (Line 22) was used to develop the Street Light Rates approved by the Board in its Order NSUARB-NSPI-P-888, dated December 8, 2008.

(b) Please provide the derivation of the costs used to support the statements in Lines 26-29 that revenues associated with fixed maintenance services were set at costs but the revenue responsibilities for electric and fixture capital services were not.

Response IR-2:

(a) NSPI used the following formula-based revenue allocation process in the Streetlight Rates approved by the Board in its Order NSUARB-NSPI-P-888[1].

(i) Total revenue responsibility of the unmetered class was set at its cost of $25.2 million, as determined in the COSS model. At this point, only directly assigned costs of the streetlight maintenance service of $5.0 million, as shown in Exhibit 6A, are explicitly known. The balance of $20.2 million reflects combined electric service, inclusive of miscellaneous loads, and streetlight fixture capital costs. The costs of these categories are not explicitly stated in the COSS model.

(ii) In a parallel and independent unmetered pricing study, the revenue responsibility for the three service components is determined as follows.

[1] NSPI 2009 Rate Case, UARB Order, NSUARB-NSPI-P-888, December 8, 2008.

1. Streetlight related maintenance revenues are set at cost of $5.0 million as determined in the COSS model.

2. Fixture capital-related revenue of $8.1 million, are determined by multiplying individual fixture capital-related rates by forecasted number of fixtures in each category. The applied fixture rates are determined by direct application of the marginal cost of capital substitution formula.

3. Electric service-related revenue is set at a level commensurate with the variance between total costs from the COSS model and the sum of the two service components above.

(b) The costs of electric and fixture capital services can be calculated directly from COSS implementing these two steps.

(i) Streetlight capital-related costs can be separated from total capital-related costs by separating relevant allocators in Exhibit 8b between streetlight and non-streetlight rate base components. This is what NSPI proposed in its treatment of the Unmetered Class costs in the submitted COSS model in this application (Please refer to SR-01, Attachment 1).

(ii) Streetlight capital-related cost components and streetlight maintenance costs are subtracted from the total unmetered class costs to arrive at electric service costs.

Using the same approach to the 2009 CF COSS model, NSPI estimated these costs by the three types of services and compared them to the associated revenues.

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Step 1: Derivation of Streetlight Allocators

Allocator P-9 (8b line 20): depreciation and grants in lieu of taxes

Ratebase Category	Demand Dist Plant ($M)	Relative Share
Streetlight	26.2	7.4%
Other Unmetered Class	4.9	1.4%
Total Unmetered Class	31.1	8.8%
Other Distribution	321.2	91.2%
Total Distribution	352.3	100.0%

Allocator P-16 (8b line 38): Interest, Preferred Dividends, Corporate Taxes and Return

Ratebase Category	Total Ratebase - Demand (DIST) ($M)	Relative Share
Streetlight	26.2	6.2%
Other Unmetered Class	11.1	2.6%
Total Unmetered Class	37.3	8.9%
Other Distribution	384.0	91.1%
Total Distribution	421.4	100.0%

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Step 2: Separation of streetlight fixture capital-related costs from demand-related unmetered class costs

Allocation of Depreciation and Grants in Lieu of Taxes

Service Type	Allocator	Depreciation ($M)	Grants in lieu ($M)	Total ($M)
Streetlight	**7.4%**	**2.3**	**0.4**	**2.7**
Other Unmetered Class	1.4%	0.4	0.1	0.5
Total Unmetered Class	8.8%	2.7	0.5	3.2
COSS reference		Exh 6D, page 1, line 14	Exh 6, page 2, line 13	

Allocation of Interest, Preferred Dividends, Corporate Taxes and Return

Ratebase Category	Allocator	Interest ($M)	Preferred Dividends ($M)	Corporate Taxes ($M)	Return (Profit/Loss) ($M)	Total ($M)
Streetlight	**6.2%**	**1.0**	**0.1**	**0.8**	**0.8**	**2.7**
Other Unmetered Class	2.6%	0.4	0.1	0.3	0.3	1.2
Total Unmetered Class	8.9%	1.4	0.2	1.1	1.1	3.9
COSS reference		Exh 6, page 2, line 15	Exh 6, page 2, line 16	Exh 6, page 2, line 17	Exh 6, page 2, line 18	

Streetlight Capital-related Costs by Component

Capital Cost Component	**Amount ($M)**
Depreciation	**2.3**
Grants in lieu of taxes	**0.4**
Interest	**1.0**
Preferred Dividends	**0.1**
Corporate Taxes	**0.8**
Return (Profit/Loss)	**0.8**
Total	**5.4**

Step 3: Derivation of Electric Service Costs of the Unmetered Class

Unmetered Class Costs – Fixture Maintenance Cost – Fixture Capital Cost = Electric Service Cost

Total Unmetered Class Costs		$25.2 M
Less:		
Fixture Maintenance	5.0 M	
Fixture Capital	5.4 M	
Subtotal	10.4 M	(10.4 M)
Electric Service Costs of the Unmetered Class		**$14.8 M**

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Revenues and Costs of Unmetered Class Services Compared

	COSS-based Costs ($M)	Revenues ($M)	Variance $M	Variance %
Electric Service	14.8	12.1	(2.7)	-18.1%
Fixture Maintenance	5.0	5.0	0.0	0.0%
Fixture Capital	5.4	8.1	2.7	49.5%
Total	25.2	25.2	0.0	0.0%

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Request IR-3:

With respect to DE-03 – DE-04, Appendix G, please explain why the 2011 Current Rates shown in Schedule 11 are different from the rates approved by the Board in its Order NSUARB-NSPI-P-888, dated December 8, 2008.

Response IR-3:

Due to the Fuel Adjustment Mechanism processes, the Base Cost of Fuel is changed every two years or when a general rate application is filed. The 2011 current rates in Schedule 11 became effective on January 1, 2011 replacing the rates approved by the Board on December 8, 2008[1]. The current rates were approved by the Board in an order dated December 17, 2010[2], in the matter of a hearing into Nova Scotia Power Incorporated's Base Cost of Fuel Reset and Fuel Forecast Standardized Filing for 2011 Fuel Adjustment Mechanism.

[1] NSPI 2009 Rate Case, UARB Order, NSUARB-NSPI-P-888, December 8, 2008.
[2] NSPI 2011Base Cost of Fuel, UARB Order, NSUARB-P-887 (2), December 17, 2010.

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Request IR-4:

With respect to DE-03 – DE-04, Appendix G, page 5, Line 28, please reconcile the statement that depreciation and grants in lieu of taxes are allocated based on customer utilization of the entire distribution net plant, to the fact that in the COSS, these costs are allocated on the basis of rate base, and that over 80% of the rate base associated with street lighting is directly assigned.

Response IR-4:

While some rate base components are assigned directly to rate classes for the purpose of deriving class cost allocators, class responsibility for a given category of costs is determined by multiplying a single composite allocator, reflective of both direct and indirect rate base utilization components, by the total amount of shared costs. In this instance, the unmetered class allocator is predicated on the unmetered class utilization of the entire distribution plant with direct assignment of the streetlight fixture rate base component already factored in.

NSPI made this statement to provide context that the current methodology for the allocation of depreciation costs, which are a function of gross plant value, on the basis of a “pooled asset net plant value” will not always produce reasonable results. The statement is not intended to pass an unequivocal judgment on the outcome of the current methodology. It is to signal its potential shortcomings under specific circumstances.

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Request IR-5:

With respect to DE-03 – DE-04, Appendix G, page 6, Lines 18-22:

(a) Is the marginal cost of capital substitution formula used to directly set charges for capital service, or to develop allocators for the distribution of the capital related costs in the COSS?

(b) Are the actual costs of electric service and the actual costs of capital determined through the COSS or through the marginal cost of capital substitution?

Response IR-5:

(a) Under the current methodology, the marginal cost of capital substitution formula is used to set charges for capital service.

Under the proposed approach, the marginal cost of capital substitution formula is used to develop allocators for the distribution of the capital related costs in the COSS. The allocators are referred to as Revenue Correction Factors in DE-03 – DE-04, Appendix G Schedule 4. They are applied across-the-board to preliminary charges for capital service to generate revenues which match capital-related costs from the COSS.

(b) Under the current methodology the combined costs of electric service, inclusive of miscellaneous loads, and fixture capital services are determined through the COSS. They can be arrived at by subtracting the fixture maintenance-related costs from the total cost of the unmetered class. The marginal cost of capital substitution is a formulaic approach used to determine the price component of the fixture capital rate in the Streetlight rate calculations.

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Request IR-6:

With respect to DE-03 – DE-04, Appendix G, page 7, Line 31 to page 8 Line 2, please provide NSPI's calculations showing that the current methodology would produce electricity prices below zero in the second half of the LED's useful life.

Response IR-6:

Attachment 1, filed electronically with formulas intact, contains a long-term forecast of the unit costs and unit revenues associated with the three unmetered services: electricity, fixture maintenance and fixture capital. The forecast was produced by applying the current ratemaking methodology to the billing determinants from the 2009 Compliance Filing modified for the effect of a five year replacement of energy-intensive non-LED fixtures with the capital-intensive LED fixtures. To make the illustration of the pricing effects of the current methodology transparent, the analysis was simplified to account solely for the cost effects of the LED conversions through rising capital-related expenditures and declining consumption of electricity. All other factors, such as inflation in cost factors of electricity production, growth in the number of streetlights or miscellaneous load services, were held constant. To illustrate the pricing effect of a 25 year-long capital cycle of a five year rollout of LED assets, assumed to have a useful life of 20 years, the analysis was extended to 27 years. The last two years serve to illustrate the repetitive effect of the capital replacement cycle.

The five year LED rollout makes for a concentrated capital expenditure relative to the assets useful life of 20 years. Once the five year investment cycle comes to an end, the aggregate net plant value of LED fixtures starts declining steadily during the next 15 years. Parallel with this decline, the capital-related expenses, other than depreciation, such as taxes, earnings and interest, also decline. Under the simplifying assumptions made in this analysis the current ratemaking methodology produces a constant price level of LED fixture capital services and therefore constant revenue flow. Over the long-run, this leads to cyclical patterns in the over-recovery of

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fixture capital costs. The matching principle of rate class revenues with costs forces pricing of electricity below its costs. The pattern in the under-recovery of the electric costs mirrors that of the over-recovery of the fixture capital costs. Under the capital intensive LED technology the methodology would produce negative electric revenue (line 49) and negative price (line 61) by year 2029 or 17 years since the start of the LED rollout.

Simplifying Assumptions:

1. LED conversion takes place during the five year period commencing in 2012 at a fixed rate of 20 percent.
2. Total cost of service is predicated on net plant value of non-LED streetlight fixtures in service (this illustration does not reflect revenue flows associated with the proposed LED conversion fees).
3. The number of streetlights owned by NSPI and those by customers remain constant throughout the analysis.
4. Non-LED streetlights owned by NSPI and customers are converted at the same rate.
5. Miscellaneous Load remains constant throughout the analysis.
6. Inflation rate is 0 percent (no change in cost factors of production; i.e. unit cost of electricity and market LED fixture prices are held constant)
7. Unmetered rates are changed annually in reflection of changing costs as driven by LED conversion only.
8. Depreciation rate remains constant at 5 percent.
9. Tax Adjusted WACC at 11.59 percent remains constant (from 2009 Compliance Filing)
10. Assumed unit electric cost remains constant at $0.1273/kWh (simulated from 2009 Compliance Filing: $14.8 M / 115.6 GWh = $0.12803/kWh, please refer to NSPI's response to Multeese IR-2 for the derivation of the $14.8 million amount).
11. Electric service revenues (line 49) are priced to balance with total costs.

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Request IR-7:

With respect to DE-03 – DE-04, Appendix G, page 8, Lines 26-31, is it NSPI's intention in placing capital and depreciation of LED fixtures below-the-line that these charges and CCA credits and would be adjusted annually?

Response IR-7:

Placing these costs below-the-line is consistent with the incremental cost approach to the pricing of LED fixtures as opposed to the average cost approach on which the COSS methodology is based. Please refer to DE-03 – DE-04, Section 10.1.3, page 138, lines 5 - 13 and to Multeese IR-4. NSPI has proposed that these charges be set through GRA proceedings as is the case with the miscellaneous revenue charges which are also treated as a below-the-line category.

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Request IR-8:

With respect to DE-03 – DE-04, Appendix G, page 9, Lines 3-4, please explain how conversion fee revenues would be applied to all full service non-LED street light customers.

Response IR-8:

Please refer to DE-03 – DE-04, Appendix G, Page 17, lines 1 - 5 (Section 5.10).

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Request IR-9:

With respect to DE-03 – DE-04, Appendix G, page 9, Lines 10-12, please confirm that NSPI's financial systems contain (or will contain) depreciation related to LED and non-LED fixtures separately.

Response IR-9:

Confirmed.

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Request IR-10:

With respect to DE-03 – DE-04, Appendix G, Schedule 3, please provide the derivation of the $46,669,416.

Response IR-10:

The amount of $46,669,416 represents the average gross plant value (GPV) of non-LED fixtures in 2012. It has been calculated using these four steps.

1. 2011 Year End Gross Plant Value

2011 Beginning Balance	$52,179,534
Additions	2,326,168
Retirements	-
2011 Ending Balance	54,505,702
COSS Adjustment	466
Adjusted 2011 Gross Plant Value	$54,506,168

2. 2012 Year End Gross Plant Value

2012 Beginning Balance	$54,506,168
Additions	16,510,351
Retirements	(27,728)
Adjusted 2012 Ending Balance	$70,988,791

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3. 2012 Year End Gross Plant Value of non-LED fixtures in Service

Adjusted 2012 Ending Balance		$70,988,791
GPV of non-LED retirements		(14,476,088)
GPV of LED	16,510,351	
CWIP Associated with LED	1,169,689	
Total LED	$17,680,040	(17,680,040)
GPV of non-LED fixtures in service		$38,832,663

4. Arithmetic average of 2011 and 2012 is calculated.

($54,506,168 + $38,832,663) / 2 = $46,669,416

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Request IR-11:

With respect to DE-03 – DE-04, Appendix G, Schedule 4, please provide the development of the numbers used to calculate the revenue correction factors; i.e, for the non-LED, the development of the $8,603,338 and the $4,194,480; and for the LED the development of the $1,314,036 and the $1,314,415.

Response IR-11:

<u>Revenue correction factor for Non-LED Light Fixtures</u>

The revenue correction factor of 0.488 applied to non-LED fixtures is calculated by dividing the non-LED capital-related cost of $4,194,480, calculated as a total of cost items shown in lines 15 through 20 of page 3 of Exhibit 5 of the COSS model (Please refer to SR-01, Attachment 1, Page 39), by the preliminary non-LED fixture revenue of $8,603,338, as shown in the non-LED total in the column labeled "revenue" in the "2012 Forecast" section of Schedule 4 (Please refer to DE-03 – DE-04, Appendix G).

The COSS-based capital-related cost of $4,194,480 is determined by applying the relative shares of non-LED streetlights in the distribution net plant value to the demand-related portion of the distribution capital-related costs. For more explanation please refer to DE-03 – DE-04, Appendix G, Section 4.1, lines 8 through 15.

The preliminary revenue of $8,603,338 is calculated by multiplying the preliminary non-LED rates, as shown in the "Total Cost" column of the "Before Correction Factor" section, by the forecasted number of fixtures. For further details please refer to DE-03 – DE-04, Appendix G, Section 5.4.

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Revenue correction factor for LED Light Fixtures

The revenue correction factor of 1.003 applied to LED fixtures was calculated by dividing the LED capital-related cost of $1,314,415, as calculated in column labeled "LED" in DE-03 – DE04, Appendix G, Schedule 5A, by the preliminary LED fixture revenue of $1,314,037 as shown in the LED total at the bottom of the column labeled "revenue" in the "2012 Forecast" section of Schedule 4.

For details on how the cost of $1,314,415 is calculated please refer to DE-03 – DE-04, Appendix G, Section 5.5.

The preliminary revenue of $1,314,037 is calculated by multiplying the preliminary LED unit costs, as shown in the "Total Cost" column of the "Before Correction Factor" section, by the forecasted number of fixtures. For further details please refer to DE-03 – DE-04, Appendix G, Section 5.4.

In preparing this response NSPI realized that the revenue correction factor of 1.003 used for LED is incorrect. The factor is predicated on an incorrect LED cost amount of $1,314,415, which in turn is reflective of an incorrect Gross and Net Plant Value amounts of $17.68 million and $8.84 million as shown under column LED in Schedule 5A (Appendix G). The $17.68 million represents year-end results, as opposed to year-average results. The Net Plant Value of $8.84 million is predicated on the year-end value and does not reflect depreciation in this year. The figures should have been $8.84 million and $8.60 million, respectively. The resulting LED capital-related cost should have been $1,291,742, or $22,673 lower than submitted, and the revenue correction factor 0.9830.

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Request IR-12:

With respect to DE-03 – DE-04, Appendix G, Schedule 5:

(a) Please explain why grants in lieu should be included in WACC.

(b) Please explain why grants in lieu should be included in WACC for non-LED but not for LED.

Response IR-12:

(a) Grants and lieu are included with the WACC for the purposes of allocating the expense with the capital rate base investment in accordance with the COSS embedded cost approach as reflected in current rates.

(b) Grants in lieu are excluded in the calculation of the LED streetlights based on the proposed COSS below-the-line incremental cost approach. Grants in lieu are fixed costs that change with the annual CPI escalation and therefore are not an incremental cost to the new proposed LED fixture rate base addition.

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Request IR-13:

With respect to DE-03 – DE-04, Appendix G, Schedule 5A:

(a) Please provide the derivation of the Gross Plant Values and Net Plant Values for non-LED and LED.

(b) Please provide the derivation of the depreciation expenses of $2,189.4 and $682.9.

Response IR-13:

(a) Derivation of Gross Plant Values and Net Plant Values for non-LED

Please refer to Multeese IR-10 for the derivation of the non-LED gross plant value of $46.669 million.

The non-LED net plant value of $21.981 million represents a difference between the total net plant value of streetlights of $30.821 million and the LED net plant value of $8.840 million. The detailed calculation consists of these three steps.

1. 2011 non-LED Net Plant Value

2011 Gross Plant Value		$54,506,168
2010 Accumulated Depreciation	28,874,169	
2011 Depreciation	2,455,295	
2011 Accumulated Depreciation	31,329,464	(31,329,464)
2011 Net Plant Value (before CWIP)		23,176,704
2011 CWIP Adjustment		480,000
2011 Non-LED Net Plant Value		$23,656,704

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2. 2012 Non-LED Net Plant Value

2012 Gross Plant Value		$70,988,791
2011 Accumulated Depreciation	31,329,464	
2012 Depreciation	2,872,281	
2012 Retirements	(27,728)	
2012 Accumulated Depreciation and Retirements	34,174,017	(34,174,017)
2012 Net Plant Value (before CWIP)		36,814,774
2012 CWIP Adjustment		-
2012 LED Additions		(16,510,351)
2012 non-LED Net Plant Value		$20,304,423

3. Arithmetic average of 2011 and 2012 is calculated:

($23,656,704 + $20,304,423) ÷ 2 = $21,980,564

Derivation of Gross Plant Values and Net Plant Values for LED

The $17.68 million, which represents the LED gross plant value, is the budgeted capital spend in 2012 from our financial systems for the LED streetlight conversion. The figure represents a year-end gross plant value and as such is incorrectly displayed, as DE-03 – DE-04, Appendix G, Schedule 5 intends to show a year-average figure. The displayed figure should have been $8.84 million, half of the year-end value given its starting balance of $0 at the beginning of the year. The LED net plant value of $8.84 million represents half of its year-end gross plant value and as such is also incorrect. The figure should have been $8.604 million in reflection of the depreciation effect in that year. This figure is calculated using the following formula:

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$8.840 M * (1 – 5.33%/2) = $8.604 M

Please refer to Multeese IR-11 for the discussion of the implications of this adjustment on revenue responsibility allocation.

(b) The depreciation of LED streetlights is derived by multiplying the year-average gross plant value of $8.84 million by the depreciation rate of 5.33 percent.

Depreciation amount $8.840 M x 5.33% = $0.4712 M

This amount is then grossed up for tax purposes, by the corporate tax rate of 31 percent.

Gross up for tax purposes $0.4712 M / (1-31%) = $0.6829 M

The depreciation of non-LED streetlights is derived by taking the total depreciation forecasted for streetlights in 2012, from our financial systems, and subtracting the amount calculated for LED streetlights (thousands).

$2.8723 M - $0.6829 M = $2.1894 M

In preparing a response to this question, NSPI realized that it was not appropriate to deduct the grossed up amount of $0.6829 million from the total streetlight depreciation of $2.8723 million. Rather, the depreciation amount of $0.4712 million should have been subtracted as the $2.8723 million total does not include the grossed up tax amount.

$2.8723 M - $0.4712 M = $2.4011 M

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As a result the amount of depreciation expense allocated to non-LED streetlights, was under-estimated by $211,700. Please refer to Attachment 1 for the modified Schedule 5A.

The gross up amount of $211,700 should have been directly assigned and deducted from the corporate taxes for the cost allocation purposes to the COSS-based rate classes (line 42, SR-01 Attachment 1, Exhibit 4).

STREET / CROSSWALK LIGHTING STUDY

Tax-Adjusted Weighted Average Cost of Capital Amounts by Components
For 2012 Street Light Rates

Capital Cost Expenses (Net Plant Value)
For 2012 Street Light Rates

In thousands of dollars

Depreciation Rate	**5.33%**
Gross-up factor for tax purposes (LED only)	**31.00%**

	Non LED	LED	Non LED	LED
Gross Plant Value (YA)			$46,669	$17,680
Net Plant Value (YA)			$21,981	$8,840
a) Weighted Average Cost of Capital - Pretax				
ST Debt	0.21%	0.21%		$19.0
LT Debt	3.94%	3.94%		$348.6
Subtotal			*728*	*$367.5*
Preferred	0.22%	0.22%	$48.5	$19.1
Common	3.60%	3.60%	$767.7	$318.2
WACC - pretax cost	7.97%	7.97%	$1,543.8	$704.9
b) Additional income tax for common equity				
WACC - equity tax cost	1.62%	1.62%		$143.2
c) Large Corporations Tax				
WACC - Large Corporations Tax	0.03%	0.03%		$2.7
Subtotal			*$248.0*	*$145.9*
d) Grants in Lieu of Property Tax				
WACC - Grants in Lieu of Property Tax	1.09%		$213.3	$0.0
Subtotal Financing Expense	**10.71%**	**9.62%**	**$2,005.1**	**$850.8**
Depreciation Expense			**$2,401.1**	**$471.2**
Gross up for Tax Purposes			**N/A**	***$211.7***
Total Depreciation Expense including Gross Up for Tax Purposes			**N/A**	**$682.9**
CCA			**N/A**	**-$219.2**
TOTAL CAPITAL COST EXPENSE			**$4,406.2**	**$1,314.4**

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Request IR-14:

With respect to DE-03 – DE-04, Appendix G, please explain the purpose of Schedules 6 and 7, including a description of how the data provided in these schedules is used to develop proposed rates for 2012.

Response IR-14:

The purpose of Schedules 6 and 7 is to provide the Board with details behind how the material costs by street light type were developed. The total material costs illustrated in DE-03 – DE-04, Appendix G, Schedule 6 are used as inputs, where applicable, in Schedules 3 and 4.

To see how the material costs were calculated and then used to develop the proposed rates for 2012, please refer to DE-03 – DE-04, Appendix G, pages 13, 14 and 15 (Sections 5.3, 5.4 and 5.6).

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Request IR-15:

With respect to DE-03 – DE-04, Appendix G, Schedule 10, please provide the derivation of:

(a) Net Plant Value YE

(b) Net Plant Value of displaced non-LED (YE)

(c) Net Plant Value of displaced non-LED (YA)

Response IR-15:

For spreadsheet calculations, with formulas intact and numbered line references please refer to Attachment 1.

(a) The 2011 year-end net plant value of $23.1 million represents NSPI's forecast of non-LED streetlights before the commencement of a five-year LED rollout. Individual year balances, starting in 2012, decline from the 2011 benchmark by a cumulative rate of conversion shown in line 4.

(b) The net plant value of displaced non-LED Year End (YE) found in line 7, is calculated by subtracting the previous year Net Plant Value (YE) from the current year in line 6.

(c) The net plant value of displaced non-LED Year Average (YA) in line 8 is the average of the current and previous year net plant values of displaced non-LED (YE) in line 7.

Derivation of Net Plant Values

Line #		2011	2012	2013	2014	2015	2016	2017	Cumulative
(1)	**LED Conversions YE**		23,119	24,628	24,628	24,628	24,628		
(2)	**Fixture Inventory YE**	121,632	98,513	73,885	49,257	24,628	0		
(3)	**Annual Conversion Rate to LED**		19%	20%	20%	20%	20%	100%	
(4)	**Cumulative Annual Conversion Rate to LED**		19%	39%	60%	80%	100%		
(5)									
(6)	**Net Plant Value YE ***	$23.10	$18.71	$14.03	$9.35	$4.68	$0.00		
(7)	**Net Plant Value of displaced non-LED (YE) ***		($4.39)	($4.68)	($4.68)	($4.68)	($4.68)		($23.10)
(8)	**Net Plant Value of displaced non-LED (YA) ***		($2.20)	($4.53)	($4.68)	($4.68)	($4.68)	($2.34)	($23.10)

* In millions of dollars

(5) Intentionally left blank

Request IR-16:

With respect to DE-03 – DE-04, Appendix G, Schedule 10A, please provide the derivation of:

(a) The Stranded Asset values

(b) The Monthly LED Conversion Fee (5 Yrs)

(c) The Lump Sum LED Conversion Fee

Response IR-16:

For spreadsheet calculations, with formulas intact and numbered line references please refer to Attachment 1.

(a) The calculation of annual levelized costs of $5.78 million, which represents the sacrificed asset life value, is illustrated in DE-03 – DE-04, Appendix G, Schedule 10. The sacrificed asset values for each type of non-LED light fixture (Column F, lines 2 - 20) are calculated using the following steps:

(i) The fixture capital service monthly rate (Column B, labeled “Capital Cost/Month”, lines 2 - 20) is multiplied by the number of non-LED fixtures before conversion (Column C, lines 2 - 20) to calculate annual capital-related revenue by non-LED fixture type (Column D, lines 2 - 20).

(ii) The relative shares of annual capital-related revenues by non-LED fixture (Column E) are calculated by dividing the individual non-LED light fixture

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annual revenues (Column D, lines 2 - 20) by the total non-LED fixture annual revenue (Column D, line 21).

(iii) The levelized cost over the five year period of $5.78 million (Column F, line 21), is multiplied by the non-LED fixture relative shares (Column E) to calculate annual levelized costs in aggregate by individual fixture type.

The total lump sum amount of $23.1 million (Column H, line 21) is multiplied by the non-LED fixture relative shares (Column E) to calculate lump sum amounts in aggregate by individual fixture type.

(b) The monthly LED conversion fee (five-years) is calculated as follows:

(i) The assumed LED fixture equivalents of non-LED fixtures in Column A (lines 2 - 20) are shown in Column J (lines 2 - 20). The non-LED fixture counts (Column C, lines 2 - 20) and their sacrificed asset amounts (Column F, lines 2 - 20) are aggregated by the corresponding LED fixtures and displayed in Column B, lines 26 - 33, and Column C, lines 26 - 33.

(ii) The aggregate sacrificed asset values (Column C, labeled "Stranded Asset", lines 26 - 33) are divided by the aggregate number of fixtures (Column B, lines 26 - 33) and then divided by twelve to obtain the monthly LED conversion fees in Column D (lines 26 - 33). At the time of this filing, the salvage value cost was unknown. It will be included in the conversion fee at the time of the compliance filing.

(c) The lump sum conversion fee shown in Column H (lines 26 - 33) is calculated as follows:

(i) The lump sum LED conversion fee amounts, calculated in Column H (lines 2 - 20), are aggregated by the corresponding LED fixtures in column A (lines 26 -

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33) and shown in Column E (lines 26 - 33). The conversion fees in Column H (lines 26 - 33) are calculated by dividing values in Column E (lines 26 - 33) the aggregated fixture counts from column B (lines 26 - 33).

At the time of this filing, the salvage value cost was unknown. It will be included in the conversion fee at the time of the compliance filing.

Calculation of Conversion Fee (Per Fixture)

	A	B	C	D	E	F	G	H	I	J
	Formulas			**B x C**		**E x F (line 21)**	**F ÷ C ÷ 12**	**E x H (line 21)**	**H ÷ C**	
(1)	**Type of Non LED Light**	**Capital Cost/Month**	**# of Fix (brf conv. *)**	**Annual Revenue**	**Relative Share of Annual Revenue**	**Stranded Asset**	**Monthly LED conversion Fee (5 Years)**	**Lump Sum LED conversion Fee**	**Lump Sum LED conversion Fee**	**Type of LED Light**
(2)	100W MV	$3.07	272	$10,009	0.23%	$13,257	$4.06	$52,974.14	$194.76	Sat-48-44W
(3)	125W MV	$2.88	11222	$387,983	8.89%	$513,873	$3.82	$2,053,369.93	$182.98	Sat-48-55W
(4)	175W MV	$2.85	2684	$91,948	2.11%	$121,783	$3.78	$486,628.95	$181.31	Sat-48-87W
(5)	250W MV	$3.53	1033	$43,754	1.00%	$57,951	$4.68	$231,566.54	$224.17	Sat-96-88W
(6)	400W MV	$3.61	1413	$61,129	1.40%	$80,964	$4.77	$323,522.49	$228.96	Sat-96-173W
(7)				$0						
(8)	250W HPS	$3.08	5550	$205,298	4.70%	$271,912	$4.08	$1,086,523.05	$195.77	Sat-96-110W
(9)	400W HPS	$3.19	3664	$140,321	3.21%	$185,852	$4.23	$742,639.60	$202.69	Sat-96-173W
(10)	70W HPS	$2.90	40531	$1,411,232	32.33%	$1,869,141	$3.84	$7,468,842.81	$184.27	Sat-48-44W
(11)	100W HPS	$2.93	47219	$1,657,409	37.97%	$2,195,196	$3.87	$8,771,717.20	$185.77	Sat-72-65W
(12)	150W HPS	$3.09	5730	$212,466	4.87%	$281,406	$4.09	$1,124,459.82	$196.24	Sat-96-88W
(13)				$0						
(14)	135W LPS	$5.50	58	$3,829	0.09%	$5,071	$7.29	$20,262.28	$349.35	Sat-48-74W
(15)	180W LPS	$7.94	806	$76,792	1.76%	$101,709	$10.52	$406,416.63	$504.24	Sat-96-88W
(16)				$0						
(17)	400W MAL	$3.64	1315	$57,399	1.32%	$76,023	$4.82	$303,779.45	$231.01	Sat-96-173W
(18)	250W MAL	$3.58	109	$4,685	0.11%	$6,205	$4.74	$24,794.87	$227.48	Sat-96-110W
(19)	150W MAL	$3.58	4	$172	0.00%	$228		$909.90	$227.48	Sat-96-88W
(20)	100W MAL	$3.58	7	$301	0.01%	$398	$4.74	$1,592.33	$227.48	Sat-48-55W
(21)	**Total**		**121,617**	**$4,364,728**	**100.00%**	**$5,780,970.28**		**$23,100,000**		
(22)										
(23)										
(24)										

Transition of Non LED Fixtures to appropriate LED fixtures

(25)		**# of Fixtures**	**Stranded Asset**	**Monthly LED conversion Exit Fee (5**	**Lump Sum LED conversion Fee**	**Lump Sum LED conversion Fee (per fix.)**	**Salvage Value[1]**	**Total Lump Sum LED Conversion Fee**
(26)	LED Sat-48-44W	40,803	$1,882,398	$3.84	$7,521,817	$184.34	N/A	$184.34
(27)	LED Sat-48-55W	11,229	$514,272	$3.82	$2,054,962	$183.00	N/A	$183.00
(28)	LED Sat-48-74W	58	$5,071	$7.29	$20,262	$349.35	N/A	$349.35
(29)	LED Sat-48-87W	2,684	$121,783	$3.78	$486,629	$181.31	N/A	$181.31
(30)	LED Sat-72-65W	47,219	$2,195,196	$3.87	$8,771,717	$185.77	N/A	$185.77
(31)	LED Sat-96-88W	7,573	$441,294	$4.86	$1,763,353	$232.85	N/A	$232.85
(32)	LED Sat-96-110W	5,659	$278,117	$4.10	$1,111,318	$196.38	N/A	$196.38
(33)	LED Sat-96-173W	6,392	$342,839	$4.47	$1,369,942	$214.32	N/A	$214.32
(34)	**Total**	**121,617**	**$5,780,970**		**$23,100,000**			

1) At the time of filing, the salvage value was unknown. This will be made available at the time of the Compliance Filing

* brf conv. = before conversion

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Request IR-17:

With respect to DE-03-DE-04, page 51, Lines 7-31:

(a) Please explain how NSPI's proposed approach is different from the method approved by the Board in its December 21, 2010 letter, and demonstrate that difference using the numbers in the Board's letter.

(b) Please explain how NSPI's proposed approach is different from the approach it proposed in the May 2010 Point Tupper Wind Farm Hearing (NSUARB-NSPI-P-128.10)

Response IR-17:

(a) NSPIs proposed approach includes the OM&G, financing and depreciation costs being recovered through non-fuel rate components. As a result of this change, the project cost components that would remain in the FAM Structure include the Fuel Expense PPA (100 percent PPA) and the Sales and EcoEnergy Revenue (49 percent). The figures presented in the Board's letter of December 21, 2010, reflect the current impact to the FAM mechanism in 2010 and 2011 (columns 1 and 2). The proposed approach beginning in 2012 is presented in columns 3 and 4. Using the figures presented in the Board's letter, the Net FAM Impact under the proposed structure is as follows:

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NSPI Responses to Multeese Information Requests

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	Board Approved Accounting Methodology		**Proposed Approach**	
	2010 ($M)	**2011 ($M)**	**2010 ($M)**	**2011 ($M)**
Fuel Expense (100% PPA)	**2.6**	**6.3**	**2.6**	**6.3**
Non-Fuel Expenses				
Net Operating Income:				
Sales Revenue (49%)	(1.3)	(3.1)	(1.3)	(3.1)
EcoEnergy Revenue (49%)	(0.1)	(0.3)	(0.1)	(0.3)
Project O&MG (49%)	0.2	0.5	0.0	0.0
NSPI Internal O&MG (49%)	0.0	0.0	0.0	0.0
Capital Costs:				
Depreciation	0.6	1.4	0.0	0.0
Interest	0.7	1.1	0.0	0.0
Non-Fuel Recovery Component	**0.1**	**(0.5)**	**(1.4)**	**(3.4)**
Net FAM Impact	**2.7**	**5.8**	**1.2**	**2.9**

(b) The primary difference between this proposal and the reply submission filed for the Point Tupper Wind Project on May 13, 2010 is that NSPI is not seeking to remove the revenue streams of the project from the current FAM Mechanism. The 49 percent Sales and Eco Energy Revenue generated from the project will continue to offset the PPA expenses paid for the renewable generation. This approach is consistent with how NSPI recovers the operating costs of other NSPI owned wind projects.

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Request IR-18:

With respect to DE-03-DE-04, Section 10.1.2 (Large Industrial Rate):

(a) **Please provide a version of this tariff which highlights the specific changes being proposed.**

(b) **Please provide a list of customers currently on this rate, showing their total billing demand and their interruptible demand. (For the purposes of this response, customers can be identified as A, B, C, etc. rather than by name).**

(c) **Does NSPI intend that in future, the interruptible portion of the load of customers on this rate should be at least 2000KVA?**

(d) **If the answer to (c) is affirmative, why does NSPI propose limiting the interruptible portion to that minimum level, given that NSPI can accommodate interruptible loads of less than 2000KVA with its automated dialling system (Page 137, Lines 3-4) and NSPI relies on these loads (Page 137, Line 6)?**

(e) **Is the intent of the "grandfathering" (Page 137, Line 9) to allow existing customers whose interruptible load is less than 2000KVA to remain on the rate?**

(f) **What are the criteria that NSPI proposes to use to determine the regular billing demand which will "add value to the interruptible program" (Page 137, Line 15)?**

(g) **For each occasion in the last three years where NSPI has requested any customers on this rate to interrupt load, please specify the date of such interruption, the reason for the request, the customers who were requested to curtail load, the load reductions requested by customer, and the load actually curtailed by customer.**

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(h) As NSPI adds capacity to facilitate its transition to renewable energy, does it anticipate that the need for interruptible load will diminish? Why or why not?

Response IR-18:

(a) Please refer to Attachment 1.

(b) Please refer to Attachment 2 which shows non-coincident billing demands of Large Industrial Interruptible customers broken down by firm and non-firm service from the month of February, 2011.

(c) No.

(d) N/A.

(e) Yes. Some customers who previously qualified under the current criteria have reduced load through energy efficiency initiatives and should not be disqualified as a result of taking such measures. Secondly, many of the current customers have invested considerable time and funds to be able to respond when called to interrupt and many are experienced and reliable in executing load reductions when called.

(f) NSPI has not determined yet what these criteria will be. The current number of subscribed customers and subscribed load is manageable and well balanced to suit the demand response requirements, given the NSPI resources associated with this class of customers. A drop in individual customer billing demand does not pose a problem under the automated dialing system. For the interruption call purposes, customers are grouped into several teams representing comparable loads. To the extent a team's load gets out of line with the designed average the customer team mix can easily be rearranged.

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Most of the challenges revolve around the labor-intensive post interruption event analysis, customer on-site training, and process administration. Thus the challenges in the delivery of the interruptible service are concerned with the number of subscribed interruptible customers. This aspect of the service, however, is addressed under the two MVA threshold required for the Large Industrial Class membership.

NSPI would continue to monitor the effectiveness of proposed changes and would develop appropriate measures, as required and appropriate, to resolve new challenges.

(g) Please refer to Attachment 3.

(h) NSPI has not determined how increased non-dispatchable resources on the system will affect the requirement for interruptible load.

LARGE INDUSTRIAL TARIFF
(2 000 kVA or 1 800 kW, and Over)
Rate Code 23

DEMAND CHARGE

$10.573 per month per kilovolt ampere of maximum demand of the current month or the maximum actual demand of the previous December, January or February occurring in the previous eleven (11) months.

Deleted: 9.886

32 cents per kilovolt ampere reduction in demand charge where the transformer is owned by the customer.

ENERGY CHARGE

6.432 cents per kilowatt hour for firm sales

Deleted: 067

Deleted: 5.996 cents per kilowatt hour for interruptible sales ¶
¶
These energy charges reflect the "energy charge equalization" adjustments included in the 2009 Settlement Agreement and Approved by the UARB in its November 5, 2008 Decision.¶

DSM COST RECOVERY RIDER

The Demand Side Management Cost Recovery Charge (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Demand Side Management Cost Recovery Rider, shall apply, in addition to the energy charge.

FUEL ADJUSTMENT MECHANISM (FAM)

The FAM Actual Adjustment (AA) and Balance Adjustment (BA) charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the FAM Tariff, shall apply, in addition to the energy charge.

MINIMUM MONTHLY CHARGE

The minimum monthly charge shall be the greater of $12.65 or the demand charge.

AVAILABILITY:

This tariff is applicable to three phase electric power and energy supplied at the low voltage side of the bulk power transformer to any industrial customer having a regular billing demand of 2 000 kVA or 1 800 kW, and over.

SPECIAL CONDITIONS:

(1) At the option of the Company, supply may be at distribution voltage. Meter readings shall be increased by 1.75% for each transformation between the meter and the low

voltage side of the bulk power supply transformer to adjust for transformer losses. Also, meter readings shall be reduced when metering is at transmission voltage.

(2) Metering will normally be at the low voltage side of the transformer. Should the customer's requirements make it necessary for the Company to provide primary metering, then the customer will be required to make a capital contribution equal to the additional capital cost of primary metering as opposed to the cost of secondary metering.

(3) The Company will withdraw the availability of this tariff to any specific customer, if, on a consistent basis, the customer is not maintaining a regular demand of 2 000 kVA or 1,800 kW or, as a result of transferring to this tariff from the Medium Industrial category the customer would not see a reduction in his electric cost for the energy supplied. NSPI reserves the right to grandfather any customer enrolled in the interruptible service, who no longer meets the regular demand criteria, if in the opinion of the Company, the amount of load subscribed in the service is sufficient to continue to add value to the supply interruptible program.

(4) The Company reserves the right to have a separate service agreement, if in the opinion of the Company issues not specifically set out herein, must be addressed for the ongoing benefit of the Company and its customers.

(5) The customer will make all necessary arrangements to ensure that its load does not unduly deteriorate the integrity of the power supply system, either by its design and/or operation. These specific requirements shall be stipulated by way of a written operating agreement.

(6) In assessing issues which might unduly affect the integrity of the power supply system the following would be considered: reliability, harmonic voltage and current levels, voltage flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

INTERRUPTIBLE RIDER TO THE LARGE INDUSTRIAL TARIFF (Rate Code 25)

Customers who qualify for interruptible service will receive a $3.43 per month per kilovolt ampere reduction in demand charge for billed interruptible demand. The billed interruptible demand is defined as the difference between any contracted firm demand requirements and the total billing demand. Where the billing demand is less than the contracted firm demand, no interruptible credit shall apply. The billed interruptible demand will be the maximum interruptible demand of the current month or the maximum actual interruptible demand of the previous December, January or February occurring in the previous eleven (11) months.

AVAILABILITY:

This rider will be applicable to a minimum regular billing demand, as determined by NSPI to add value to the interruptible program, at 90% Power Factor, under the following terms and conditions:

Deleted: available

Deleted: of 2 000 kVA

(1) The customer has provided written notice of his desire to take service under this option, identifying that portion of the load that is to be firm and that portion that is to be interruptible.

(2) The customers will reduce their available interruptible system load by the amount requested by NSPI within ten (10) minutes of such request by the Company.

(3) Following interruption, service may only be restored by the customer with approval of the Company.

(4) Failure to comply in whole or in part with a request to interrupt load will result in penalty charges. The penalty will be comprised of two parts, a Threshold Penalty and a Performance Penalty.

The Threshold Penalty charge shall be the cost of the appropriate firm billing effective at that time for the consumption used in that billing period.

The Performance Penalty which is based on the customer's performance during the interruption event is calculated as per the formula below:

Performance Penalty = ($15/kVA x A) + ($30/kVA x B)

Where:

"A" is any residual customer demand (above that required by the interruption request) remaining in the third interval directly following two complete 5-minute intervals after the interruption call was delivered by telephone call.

"B" is the customer's average demand based on 5-minute interval data during the entire interruption event excluding the interval used to determine "A."

The total penalty will not exceed two times the cost of the appropriate firm billing effective at that time for the consumption used in that billing period.

(5) Should any customer under this rider desire to be served under any appropriate firm service rate, a five (5) year advance written notice must be given to the Company so as to ensure adequate capacity availability. Requests for conversion to firm service will be treated in the same manner as all other requests for firm service received by the Company. The Company may, however, permit an earlier conversion. In the event that the Customer desires to return to interruptible service in the future, the Customer may convert to interruptible service following two (2) years of service under the firm rate schedule. The Company may permit an earlier conversion from firm to interruptible service.

(6) Interruption is limited to 16 hours per day and 5 days per week to a maximum of 30% of the hours per month and 15% of the hours in a year.

SPECIAL CONDITIONS:

(1) The Company reserves the right to have a separate service agreement if in the opinion of the Company, issues not specifically set out herein must be addressed for the ongoing benefit of the Company and its customers.

(2) The customer will make all necessary arrangements to ensure that its load does not unduly deteriorate the integrity of the power supply system, either by its design and/or operation. Specific requirements shall be stipulated by way of a written operating agreement.

(3) In assessing issues which might unduly affect the integrity of the power supply system the following would be considered: reliability, harmonic voltage and current levels, voltage flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

(4) At the option of the Company, supply may be at distribution voltage. Meter readings shall be increased by 1.75% for each transformation between the meter and the low voltage side of the bulk power supply transformer to adjust for transformer losses. Also, meter readings shall be reduced when metering is at transmission voltage.

Current Large Industrial Interruptible Rider customer subscribed load showing firm subscription demand levels.

	Company	Feb-11 Demand kVA
Interruptible	Company A	2,247
Firm	Company A	250
Total	Company A	2,497
Interruptible	Company B	4,502
Interruptible	Company C	875
Interruptible	Company D	1,994
Interruptible	Company E	2,106
Interruptible	Company F	922
Interruptible	Company G	1,912
Interruptible	Company H	2,220
Interruptible	Company I	598
Interruptible	Company J	5,990
Interruptible	Company K	8,550
Interruptible	Company L	6,096
Interruptible	Company M	3,845
Interruptible	Company N	17,040
Firm	Company N	2,000
Total	Company N	19,040
Interruptible	Company O	23,664
Interruptible	Company P	10,536
Interruptible	Company R	10,893
Interruptible	Company S	2,032
Interruptible	Company T	1,692
Interruptible	Company U	2,110
Interruptible	Company V	384
Interruptible	Company W	4,234
Interruptible	Company X	2,435
Interruptible	Company Y	1,786
Interruptible	Company Z	2,797

Event	Reason	Customers	Load Requested	Load Reduced
January 26, 2009	Point Aconi off, Purchase cut by 90 MW, Capacity Shortage	A	0.8 MW	0.8 MW
		B	14 MW	14 MW
		C	1.8 MW	1.8 MW
		D	1.4 MW	1.4 MW
		E	0.9 MW	0.9 MW
		F	0.4 MW	0.4 MW
		G	0.4 MW	0.4 MW
		H	7.8 MW	7.8 MW
		I	3.3 MW	3.3 MW
		J	0.3 MW	0.3 MW
		K	0.2 MW	0.2 MW
		L	0.7 MW	0.7 MW
		M	15 MW	15 MW
		N	8.5 MW	8.5 MW
		O	18 MW	18 MW
		P	19.5 MW	0 MW
		Q	4.4 MW	4.4 MW
		R	3.5 MW	3.5 MW
		S	1.2 MW	1.2 MW
		T	0.6 MW	0.6 MW
		U	4.2 MW	4.2 MW
		V	1.6 MW	0 MW
		W	0.6 MW	0.6 MW
		X	0.5 MW	0.5 MW
		Y	1.9 MW	1.9 MW
		Z	5.2 MW	5.2 MW
		AA		
April 9, 2009	Tufts Cove 1 and 2 off, Lingan 1, 2 and 3 off, Wreck Cove 1 off, Capacity Shortage	A	0.6 MW	0.6 MW
		B	14 MW	14 MW
		C	1.6 MW	1.6 MW
		D	1.4 MW	1.4 MW
		E	0.8 MW	0.8 MW
		F	0.6 MW	0.6 MW
		G	0.7 MW	0 MW
		H	8.0 MW	8.0 MW
		I	3.0 MW	3.0 MW
		J	0.3 MW	0.3 MW
		K	0.2 MW	0.2 MW
		L	0.35 MW	0.35 MW
		M	11.0 MW	11.0 MW
		N	7.2 MW	7.2 MW
		O	5.0 MW	5.0 MW
		Q	1.2 MW	1.2 MW
		R	3.7 MW	3.7 MW
		S	1.0 MW	1.0 MW
		T	2.8 MW	2.8 MW
		U	2.5 MW	2.5 MW

		W X Y Z	0.6 MW 1.8 MW 1.6 MW 7.5 MW	0.6 MW 1.8 MW 1.6 MW 7.5 MW
December 1, 2009	Transmission lines L6010 and L6005 de-energized for highway shift, Metro Import Flow limit exceeded, Burnside 1 and 2 tripped off during peak load, interrupted 30MW of interruptible to maintain limits on transmission corridor (Flow into Metro) Tuft's Cove 1 off.	AB AC E G D N H	1.5 MW 6.0 MW 1.7 MW 1.4 MW 2.2 MW 8.5 MW 9.2 MW	1.5 MW 6.0 MW 1.7 MW 1.4 MW 2.2 MW 8.5 MW 9.2 MW
December 17, 2009	Tufts Cove 3 off, Capacity Deficiency	A B C D E F G H I J K L M N O Q R S T U W Y Z	0.7 MW 14 MW 1.7 MW 1.4 MW 0.7 MW 0.4 MW 0.8 MW 3.3 MW 2.7 MW 0.3 MW 0.2 MW 0.5 MW 13.2 MW 8.1 MW 18.7 MW 4.3 MW 3.8 MW 0.7 MW 3.0 MW 2.8 MW 0.6 MW 1.7 MW 2.7 MW	0.7 MW 14 MW 1.7 MW 1.4 MW 0.7 MW 0.4 MW 0.8 MW 3.3 MW 2.7 MW 0.3 MW 0.2 MW 0.5 MW 13.2 MW 8.1 MW 18.7 MW 4.3 MW 3.8 MW 0.7 MW 3.0 MW 2.8 MW 0.6 MW 1.7 MW 2.7 MW
February 1, 2010	Lingan 2 and 3 off, Capacity Deficiency	L Y R M K I C F	0.5 MW 1.8 MW 3.6 MW 15.0 MW 0.24 MW 2.5 MW 1.7 MW 0.3 MW	0.5 MW 1.8 MW 3.6 MW 15.0 MW 0.24 MW 2.5 MW 1.7 MW 0.3 MW
January 23, 2011	Tufts Cove 3 off, Lingan 2 off, Trenton 5 off, Purchase cut by	A C	0.4 MW 1.0 MW	0.4 MW 0 MW

	80MW; Capacity Shortage	D E F AB G H I J K L M N O Q R S U Y Z AA AC	0.6 MW 0.7 MW 0.3 MW 0.2 MW 0.4 MW 9.0 MW 2.5 MW 0.3 MW 0.2 MW 0.3 MW 14.5 MW 7.5 MW 17.0 MW 3.8 MW 4.3 MW 0.2 MW 1.8 MW 0.8 MW 4.6 MW 0.5 MW 2.0 MW	0.6 MW 0.7 MW 0 MW 0.2 MW 0.4 MW 9.0 MW 2.5 MW 0.3 MW 0.2 MW 0.3 MW 14.5 MW 7.5 MW 17.0 MW 3.8 MW 4.3 MW 0.2 MW 1.8 MW 0.8 MW 4.6 MW 0 MW 2.0 MW

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Request IR-19:

With respect to DE-03-DE-04, Appendix H. Provision is made on page 7 (Lines 2 - 5) for the development of a new nominal CBL between GRA's.

(a) Can a new CBL be set at any time?

(b) If a new CBL is set, will the SEC also be recalculated and submitted to the UARB for approval, or will this be done only through a GRA?

(c) If the SEC is to be reset between GRA's when a new nominal CBL is established, how will it be calculated and how will it receive UARB approval?

Response IR-19:

(a) Yes, subject to meeting the requirement, as specified in the Customer Baseline Load (CBL) section of the tariff, that "significant and permanent changes in customer consumption take place between GRA proceedings".

(b-c) NSPI does not propose any changes in this regard. Under the current arrangements, the Standard Energy Charge (SEC) is set only through a GRA.

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Request IR-20:

With respect to DE-03-DE-04, Appendix H, it is proposed on page 8, Line 22 that the credit floor should be lowered to "a credit equivalent to the fuel contribution portion of the SEC".

(a) Has the "fuel contribution portion of the SEC" been identified in NSPI's filing?

(b) Should the fuel and non-fuel portions of the SEC be specified in the tariff?

Response IR-20:

(a) Yes. Please refer to NPB IR-50.

(b) Yes, subject to UARB's approval of the proposed change to the floor in the credit mechanism.

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Request IR-21:

With respect to DE-03-DE-04, Appendix H, Appendix A, various colors are used to strikeout and add text. What is the significance of the various colors? Are all sections of Appendix A that are not struck out included in the proposed tariff?

Response IR-21:

There is no significance to various colors reflecting strikeout and add text. All sections of Appendix A that are not struck out are included in the proposed tariff.

Please refer to the Application, PR-01 for a clean version of the proposed tariff.

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Request IR-22:

With respect to DE-03-DE-04, Appendix H, it is noted on page 15 (1st paragraph) that "The provisional CBL_{op} level will be adjusted after the event based on the average energy taken during this period."

(a) Is there any maximum time during which a provisional CBL_{op} can remain in place?

(b) Is there any limit on the number of provisional CBL_{op}'s a customer may seek to put in place in a given year?

(c) If the provisional CBL_{op} is in effect for several billing periods, will all bills affected be adjusted after the fact? If so, please describe the adjustments that will need to be made.

Response IR-22:

(a) The provisional CBL_{op} can remain in place for as long as the underlying conditions, giving rise to the CBL reduction, are in effect and are deemed temporary. There is no maximum time limit proposed in this regard. However, should the underlying conditions be deemed permanent at some point during CBL_{op} implementation, the provisional CBL_{op}, subject to UARB's approval, would be considered a nominal CBL.

(b) There is no limit proposed on the number of provisional CBL_{op}'s a customer may seek to put in place in a given year.

(c) Yes, all affected bills are proposed to be adjusted after the fact.

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At the end of the duration of CBL_{op} event the average actual energy usage level of the customer for the period will be applied, as a CBL benchmark, to actual hourly consumption records to determine actual incremental and decremental energies which will then be priced using the hourly marginal cost Debit/Credit Mechanism.

The difference between the nominal CBL and the average actual consumption level will be priced at the avoided unit costs forecasted at the time of setting CBL_{op}. The difference between the re-estimated credits and debits, as described above, and the credits and debits actually billed will be addressed through a billing adjustment.

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Request IR-23:

With respect to DE-03-DE-04, Appendix H, it is noted on page 15 (1st paragraph) the customer will be compensated for fuel savings associated with the difference between the CBL and the CBL_{op} at the forecast average unit avoided cost associated with "this load reduction". Is "this load reduction" determined on the basis of the forecasted CBL_{op} or the CBL_{op} as determined after the fact? If the latter, will the avoided costs also be updated to be after the fact?

Response IR-23:

The customer will be compensated at the forecast average unit avoided cost, determined on the basis of the forecasted CBL_{op}, applied to the actual reduced CBL energy.

The difference between the forecast and actual (after the fact) average reduction is expected to be small. The tariff allows either party to request a review of the appropriateness of interim CBL arrangements if energy consumption differs significantly.

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Request IR-24:

With respect to SR-01 Attachment 1, Exhibit 2, why does the deferred credit ARO Wind on Line 37 not carry forward to Exhibits 2A, 2B and 3?

Response IR-24:

It is appropriate to carry the ARO Wind credit forward to Exhibits 2A, 2B and 3. NSPI is prepared to make the appropriate amendments to the cost of service study to address this item. The adjustment will not have a significant impact on the allocated costs to rate classes.

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Request IR-25:

With respect to SR-01 Attachment 1, Exhibit 2, please provide the derivation of the Street Lighting rate base on Line 20, and its assignment to Distribution and Direct Capital.

Response IR-25:

The Street Lighting rate base of $30.8 million, on Line 20, represents a total of non-LED rate base of $22.0 million and LED rate base of $8.8 million. For the derivation of these numbers please refer to Multeese IR-13 (a).

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Request IR-26:

With respect to SR-01 Attachment 1, Exhibit 3, page 2, why is the Total Company Distribution sub-total on Line 17 different from the Total Distribution classified as Demand in Exhibit 2B, page 3, Line 12?

Response IR-26:

Please refer to Multeese IR-24 and Multeese IR-27. Adjusting for these two items, results in the Total Company Distribution sub-total (Exhibit 3) equaling Total Distribution (Exhibit 2B).

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Request IR-27:

With respect to SR-01 Attachment 1, Exhibit 3B, why is the total plant ($26,205) different from the Substation plant shown on Line 13 of Exhibit 2?

Response IR-27:

The figures in Exhibit 3B do not reflect a CWIP value of $0.5 million associated with substation rate base which is appropriately accounted for in Exhibit 2. By incorporating the CWIP amounts into Exhibit 3B, the total plant allocations to each rate class would be:

Customer Class	**Total Plant – Submission**	**Total Plant - Revised**
(in thousands of $)		
Domestic	15,467	15,801
Small General	656	670
General	6,624	6,766
General Large	827	845
Small Industrial	681	696
Medium Industrial	1,155	1,177
Large Industrial	375	375
ELI 2P-RTP	42	42
Municipal	28	28
Unmetered	350	357
Total	**26,205**	**26,756**

NSPI is prepared to make the appropriate amendments to the cost of service study to address this item.

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Request IR-28:

With respect to SR-01 Attachment 1, page 53 of 69 (Exhibit 9A for the year 2012), please provide load research or other data to support the following changes relative to the 2009 Compliance Filing:

(a) A change of 9.9% in the Small General load factor, as calculated from sales data and non-co-incident demand before losses. (2009 LF = 40.3%; 2012 LF = 50.2%).

(b) An increase in the Small General co-incidence factor from 68.5% to 95.3%.

(c) An increase in the Unmetered co-incidence factor from 76.5% to 100%.

Response IR-28:

(a-b) The load profiles upon which these calculations are based change from year to year due to changes in customer behavior influenced by the economy and other factors. A substantial part of the change in the Small General load profile however, is due to a change in the energy threshold required for customer participation in the Small General rate which affected the properties of the class load profile.

Prior to 2004, the Small General rate class consisted of commercial customers consuming less than 12,000 kWh per year. In 2004, the customer requirement for participation in the rate class was changed from 12,000 kWh per year to the interim level of 22,000 kWh per year. The following year, the threshold was adjusted upwards again, to customers using less than 32,000 kWh per year.

The load profile used to calculate the 2009 compliance filing used an historical Small General load profile which did not yet reflect the complete effects of all the customer

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migration. The 2012 forecast is based on a load profile from 2008 when all the customer migration had been completed. The addition of more and larger customers to the Small General class was a major cause of the higher load factor and higher coincidence factor.

(c) The change in the Unmetered class co-incidence factor is due to updated load profiles used to create the load statistics.

In the 2009 Compliance Filing, the system peak occurred at the hour-ending 6:00PM. Based on January sunset times, this is considered an evening shoulder hour for the photocell operated equipment on the Unmetered rate such as street and area lighting. During this shoulder transition period from day to night, not all of this equipment would be turned on. In the updated load profiles, the system peak occurred at the hour-ending 7:00PM when all the photocell operated equipment is assumed to be turned on and the rate class would be at full load.

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Request IR-29:

With respect to SR-01 Attachment 1, Exhibit 4 (page 34 of 69), Line 21:

(a) What services are provided under Construction and Technical Services?

(b) How many people are employed in this group?

(c) What percentage of these costs is estimated to be contract costs?

Response IR-29:

(a) Please refer to Section 5.4.4, lines 9 to 12, page 92 of the Application.

(b) Please refer to Liberty IR-64 (a)

(c) Please refer to 2012 GRA DE-03 – DE-04 Appendix C page 20 for 2012 forecasted costs by account, including contracts.

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Request IR-30:

With respect to SR-01 Attachment 1, Exhibit 4 (page 34 of 69), Line 22:

(a) What services are provided under Sustainability?

(b) How many people are employed in this group?

(c) What percentage of these costs is estimated to be contract costs?

Response IR-30:

(a) Please refer to Liberty IR-50 (d).

(b) Please refer to Liberty IR-50 (b).

(c) Please refer to 2012 GRA DE-03 – DE-04 page 23 Appendix C for 2012 forecasted costs by account, including contracts.

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Request IR-31:

With respect to SR-01 Attachment 1, Exhibit 4 (page 34 of 69), Line 26, please explain why the total Distribution OM&G expense ($62,799) is 32.25% higher than it was in the 2009 Compliance Filing ($47,490).

Response IR-31:

The increase is caused by the functionalization of a newly created cost category "Technical and Construction Services", as distribution-related only.

The ensuing analysis, as prompted by this question, revealed that the cost category should have been functionalized among all areas of the Company using the following breakdown.

Category	Total ($)	Prod. Expenses ($)	Trans. Expenses ($)	Dist. Expenses ($)	Retail Expenses ($)	Direct Expenses ($)
T&C Services	13,524	3,167	1,656	3,913	4,788	0

The corrected functionalization reduces Total Distribution OM&G expense by $9.6 million and results in an increase of 12 percent over the 2009 Compliance Filing. NSPI is prepared to make the appropriate amendments to the cost of service study to address this item.

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Request IR-32:

With respect to SR-01 Attachment 1, Exhibit 4 (page 34 of 69), Lines 38, please provide the derivation of the portion that is directly assigned.

Response IR-32:

Please refer to Multeese IR-13 (b).

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Request IR-33:

With respect to SR-01 Attachment 1, Exhibit 4 – Detail (page 35 of 69), please confirm that the Distribution Street Lighting OM&G of $3,668 (no line number included in the exhibit) all relates to existing street lights.

Response IR-33:

Confirmed.

The $3.7 million represents Customer Operations-related costs before the final allocation of shared OM&G costs associated with the Distribution Functional Area is made in Exhibit 5 (page 3, line 14).

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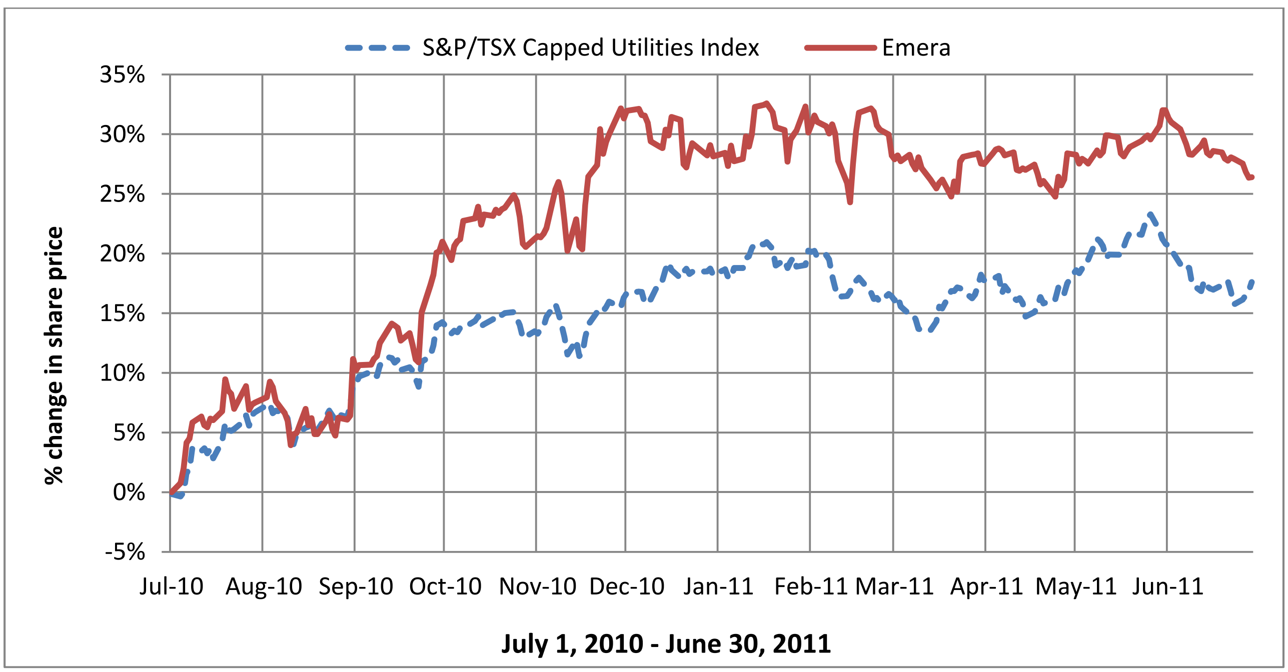
Request IR-34:

With respect to DE-03 - DE-04, 6.0 Capital Structure and Financing, please provide a chart outlining the performance of Emera Inc. ("EMA") versus the S&P/TSX Capped Utilities Index ("TTUT") over the past 12 months.

Response IR-34:

Please refer to the chart below.



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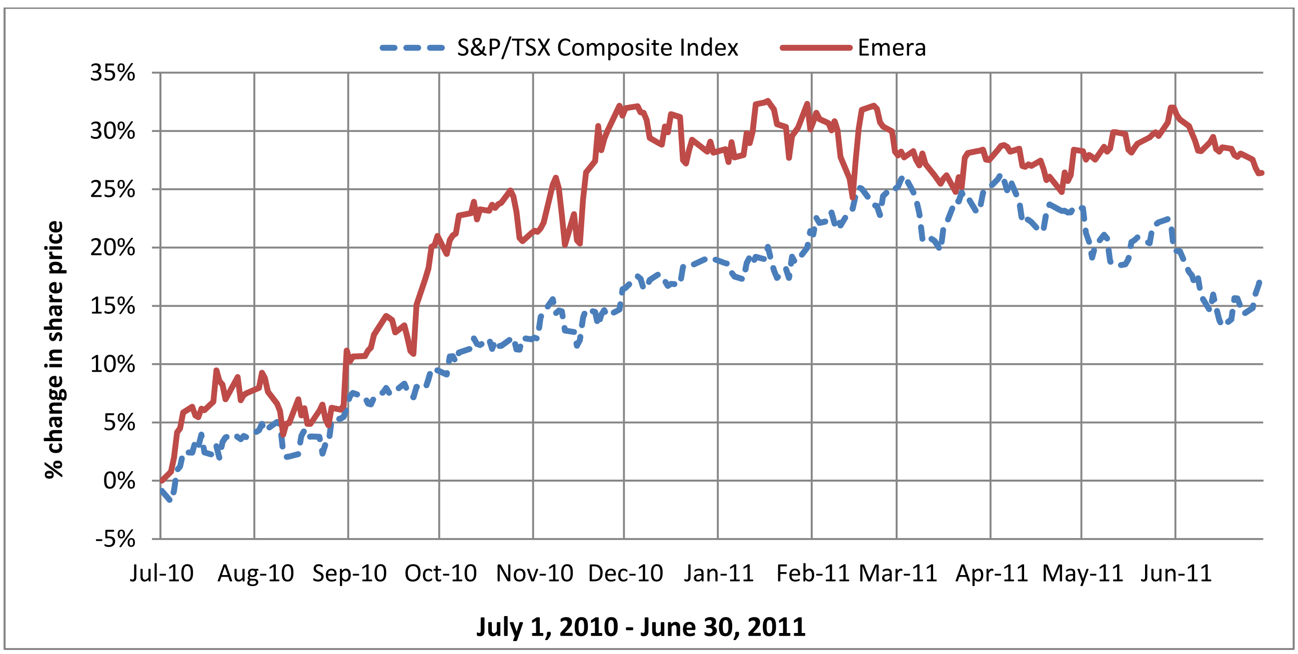
Request IR-35:

With respect to DE-03 - DE-04, 6.0 Capital Structure and Financing, please provide a chart outlining the performance of Emera Inc. ("EMA") versus the S&P/TSX Composite Index ("TSX") over the past 12 months.

Response IR-35:

Please refer to the chart below.



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Request IR-36:

With respect to DE-03 - DE-04, 5.0 OM&G, page 65 of 161, please provide any industry benchmarks for the OM&G/MWh and OM&G/customer results of NS Power.

Response IR-36:

Please refer to 2012 GRA DE-03 – DE-04 Appendix B.

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Request IR-37:

With respect to NSPI's response to Multeese IR-2(a):

(a) Please provide a copy of the "parallel and independent unmetered pricing study" referred to which resulted in the rates approved by the Board.

(b) If the study does not include the derivation of various street lighting rates, please provide the derivation of pricing for Rate Codes 121, 221 and 321 as approved by the Board in P-888.

Response IR-37:

(a–b) Please refer to Attachment 1.

Nova Scotia Power Incorporated

2009
UNMETERED CLASS
COST OF SERVICE AND PRICING STUDY REVIEW

Prepared in Support of 2009 Compliance Filing

SCHEDULE 1

STREET / CROSSWALK LIGHTING STUDY

Inventory Level as of JANUARY 2008

Rate Code	Description	Quantity			
		Full Charge	Energy & Maint	Energy Only	Total
001/003	Incandescent < 300 Watts	32	0	7	39
002	Incandescent > 300 Watts	2	0	0	2
		34	0	7	41
100	Mercury Vapour 100 Watts	276	0	0	276
101/201/301	Mercury Vapour 125 Watts	11,687	8	11	11,706
102/202/302	Mercury Vapour 175 Watts	2,932	22	152	3,106
103/203/303	Mercury Vapour 250 Watts	1,123	34	53	1,210
104/204/304	Mercury Vapour 400 Watts	1,445	9	15	1,469
105/205/305	Mercury Vapour 700 Watts	11	0	1	12
106/206/306	Mercury Vapour 1000 Watts	74	21	7	102
107	Mercury Vapour 250 Watt Cont. Oper.	5	0	0	5
		17,553	94	239	17,886
110	Fluorescent 2x24" 70 Watts	905	0	0	905
111	Fluorescent 2x48" 220 Watts	135	0	0	135
112	Fluorescent 2x72" 300 Watts	67	0	0	67
113/213	Fluorescent 4x72" 600 Watts	15	0	0	15
114/214	Fluorescent 1x96" 110 Watts	5	26	0	31
115/215	Fluorescent 1x72" 150 Watts	2	3	0	5
116	Fluorescent 4x48" 440 Watts	2	0	0	2
217	Fluorescent 1x48"	0	1	0	1
218	Fluorescent 2x48"	0	0	0	0
330	Fluorescent 4x35"	0	0	2	2
350	Fluorescent 4x96"	0	0	75	75
		1,131	30	77	1,238
117	Fluorescent Crosswalk Cont. 4x72"	0	0	1	1
118	Fluorescent Crosswalk Cont. 2x24"	0	0	16	16
119	Fluorescent Crosswalk Cont. 4x48"	0	0	21	21
120	Fluorescent Crosswalk Cont. 2x96"	0	0	32	32
150	Fluorescent Crosswalk Cont. 4x96"	0	0	21	21
		0	0	91	91
310	Fluorescent Crosswalk 2x24"	0	0	1	1
311	Fluorescent Crosswalk 4x48"	0	0	5	5
312	Fluorescent Crosswalk 2x72"	0	0	1	1
313	Fluorescent Crosswalk 4x72"	0	0	0	0
314	Fluorescent Crosswalk 1x96"	0	0	25	25
315	Fluorescent Crosswalk 1x72"	0	0	0	0
		0	0	32	32
121/221/321	High Pressure Sodium 250 Watts	5,346	141	1,691	7,178
122/326	High Pressure Sodium 400 Watts	3,752	0	87	3,839
123/222/322	High Pressure Sodium 70 Watts	39,004	248	6,322	45,574
124/223/323	High Pressure Sodium 100 Watts	46,746	109	2,540	49,395
125/224/324	High Pressure Sodium 150 Watts	5,420	229	1,310	6,959
126	HP Sodium 100 Watts - Cont. Oper.	10	0	0	10
327	High Pressure Sodium 500 Watts	0	0	3	3
328	High Pressure Sodium 1000 Watts	0	0	16	16
		100,278	727	11,969	112,974
130	Low Pressure Sodium 135 Watts	61	0	0	61
131/231/331	Low Pressure Sodium 180 Watts	876	43	37	956
132	Low Pressure Sodium 90 Watts	1	0	0	1
		938	43	37	1,018
140/342	Metallic Arc 400 Watts	1,286	0	156	1,442
141/341	Metallic Arc 1000 Watts	935	0	21	956
142/343	Metallic Arc 250 Watts	97	0	90	187
143	Metallic Arc 150 Watts	4	0	0	4
144	Metallic Arc 100 Watts	3	0	0	3
344	Metallic Arc 175 Watts	0	0	98	98
345	Metallic Arc 150 Watts	0	0	3	3
346	Metallic Arc 100 Watts	0	0	0	0
		2,325	0	368	2,693
	TOTAL	122,259	894	12,820	135,973

STREET / CROSSWALK LIGHTING STUDY
CALCULATION OF MAINTENANCE COSTS BY FIXTURE TYPE

(A) Code	(B) Lamp Type	(C) Service Life (Years)	(D) Maintenance Weighting Factors	(E) # of Full Chg & Eng.+Maint. Fixtures	(F) Weighting Total	(G) Cost Per Year	(H) Cost Per Month
A	Mercury Vapour	6.000	1.0000	5,952	5,952	$36.93	$3.08
B	Mercury Vapour - 125W	4.500	1.3333	11,695	15,593	$49.24	$4.10
C	Fluorescent	3.000	2.0000	1,161	2,322	$73.85	$6.15
D	High Pressure Sodium (Note1)	6.000	1.0000	101,005	101,005	$36.93	$3.08
E	Incandescent	0.625	9.6000	34	326	$354.50	$29.54
G	Metallic Arc 100W, 150W & 250W	2.500	2.4000	104	250	$88.63	$7.39
H	Metallic Arc 400W	3.750	1.6000	1,286	2,058	$59.08	$4.92
I	Metallic Arc 1000W	2.500	2.4000	935	2,244	$88.63	$7.39
J	Low Pressure Sodium	2.000	3.0000	981	2,943	$110.78	$9.23
				123,153	132,693		

Street Lighting Maint. Expenses
(from 2009 COSS, Exhibit 6A) **$4,900,000**

Annual Cost of High Pressure Sodium
(4,900,000 / 132,693 weighted fixtures) **$36.93**

Note 1: Maintenance weighting factors relative to High Pressure Sodium fixture, index = 1.0
Factor is: HPS service life / various fixture service lives

SCHEDULE 3

STREET / CROSSWALK LIGHTING STUDY

CAPITAL COST

Gross Plant Value (including installation costs) less Retirements of Street Lighting Equipment as of December 31, 2007 — **$47,751,749**

Description	Unit Cost Mar/1977	Unit Cost June 2007	# of Fixtures	Total Value	
Incandescent < 300 Watts	$51.36	$64.20	32	$2,054	
Incandescent > 300 Watts	$63.62	$79.53	2	159	
Mercury Vapour 100 Watts	$76.55	$228.81	276	63,151	
Mercury Vapour 125 Watts	$77.16	$204.16	11,687	2,385,989	
Mercury Vapour 175 Watts	$85.30	$200.64	2,932	588,264	
Mercury Vapour 250 Watts	$87.24	$292.72	1,123	328,728	
Mercury Vapour 400 Watts	$107.82	$302.69	1,445	437,388	
Mercury Vapour 700 Watts	$485.12	$451.03	11	4,961	
Mercury Vapour 1000 Watts	$492.29	$575.25	74	42,569	
Mercury Vapour 250 Watt Cont. Oper.	$87.24	$292.72	5	1,464	
Fluorescent 2x24" 70 Watts	$106.44	$133.05	905	120,410	
Fluorescent 2x48" 220 Watts	$131.91	$164.89	135	22,260	
Fluorescent 2x72" 300 Watts	$178.72	$223.40	67	14,968	
Fluorescent 4x72" 600 Watts	$293.72	$367.15	15	5,507	
Fluorescent 1x96" 110 Watts	$160.00	$200.00	5	1,000	
Fluorescent 1x72" 150 Watts	$121.22	$151.53	2	303	
Fluorescent 4x48" 440 Watts	$188.91	$236.14	2	472	
High Pressure Sodium 70 Watts	N/A	$200.01	39,004	7,801,190	
High Pressure Sodium 100 Watts	N/A	$192.16	46,756	8,984,502	
High Pressure Sodium 150 Watts	N/A	$195.20	5,420	1,057,997	
High Pressure Sodium 250 Watts	$156.49	$242.65	5,346	1,297,231	
High Pressure Sodium 400 Watts	$173.73	$254.90	3,752	956,373	
High Pressure Sodium 1000 Watts	N/A	$637.24	0	0	
Low Pressure Sodium 90 Watts	N/A	$597.79	1	598	
Low Pressure Sodium 135 Watts	$371.69	$597.79	61	36,465	
Low Pressure Sodium 180 Watts	$226.10	$557.01	876	487,938	
Metallic Additive 250 Watts	N/A	$298.80	101	30,179	
Metallic Additive 400 Watts	$358.84	$305.51	1,286	392,887	
Metallic Additive 1000 Watts	$560.49	$527.15	935	492,883	
Metallic Additive 100 Watts	N/A		3	0	25,557,890
			122,259		

Total Installation Costs (Labour) — $22,193,859

Installation Costs per Fixture — **$183.85**

Escalation Factor (Incandescent)	125%
Escalation Factor (Fluorescent)	125%

Note: 2007 costs are based on stores material inventory cost as of June 2007 with the exception of Incandescent and fluorescent which have been assumed at 130% of 1977 costs.

Sample Material Cost - 100 Watt High Intensity (Pressure) Sodium :
Inventory Prices as of June 2007

Fixture, Ballast & Photocell	$100.21
Bracket Assembly (Davit)	62.09
Wire	18.78
Miscellaneous Hardware	2.55
Lamp Replacement	8.53
TOTAL	**$192.16**

SCHEDULE 4

STREET / CROSSWALK LIGHTING STUDY

Capital Cost Rate Component Calculation

Depreciation Rate for 2009	4.67%
Tax Adjusted Weighted Average Cost of Capital	11.59%

	Material Cost June/2007	Labour Cost	Total	Depreciation Expense	Cost of Capital	Total Annual Cost	Total Monthly Cost
Incandescent < 300 Watts	$64.20	$183.85	$248.05	$11.58	$28.75	$40.33	$3.36
Incandescent > 300 Watts	79.53	183.85	263.37	12.30	30.52	42.82	3.57
Mercury Vapour 100 Watts	228.81	183.85	412.65	19.27	47.83	67.10	5.59
Mercury Vapour 125 Watts	204.16	183.85	388.00	18.12	44.97	63.09	5.26
Mercury Vapour 175 Watts	200.64	183.85	384.48	17.96	44.56	62.52	5.21
Mercury Vapour 250 Watts	292.72	183.85	476.57	22.26	55.23	77.49	6.46
Mercury Vapour 400 Watts	302.69	183.85	486.54	22.72	56.39	79.11	6.59
Mercury Vapour 700 Watts	451.03	183.85	634.87	29.65	73.58	103.23	8.60
Mercury Vapour 1000 Watts	575.25	183.85	759.10	35.45	87.98	123.43	10.29
Mercury Vapour 250 Watt Cont. Oper.	292.72	183.85	476.57	22.26	55.23	77.49	6.46
Fluorescent 2x24" 70 Watts	133.05	183.85	316.90	14.80	36.73	51.53	4.29
Fluorescent 2x48" 220 Watts	164.89	183.85	348.73	16.29	40.42	56.70	4.73
Fluorescent 2x72" 300 Watts	223.40	183.85	407.25	19.02	47.20	66.22	5.52
Fluorescent 4x72" 600 Watts	367.15	183.85	551.00	25.73	63.86	89.59	7.47
Fluorescent 1x96" 110 Watts	200.00	183.85	383.85	17.93	44.49	62.41	5.20
Fluorescent 1x72" 150 Watts	151.53	183.85	335.37	15.66	38.87	54.53	4.54
Fluorescent 4x48" 440 Watts	236.14	183.85	419.98	19.61	48.68	68.29	5.69
High Pressure Sodium 70 Watts	200.01	183.85	383.86	17.93	44.49	62.42	5.20
High Pressure Sodium 100 Watts	192.16	183.85	376.00	17.56	43.58	61.14	5.09
High Pressure Sodium 150 Watts	195.20	183.85	379.05	17.70	43.93	61.63	5.14
High Pressure Sodium 250 Watts	242.65	183.85	426.50	19.92	49.43	69.35	5.78
High Pressure Sodium 400 Watts	254.90	183.85	438.74	20.49	50.85	71.34	5.94
High Pressure Sodium 1000 Watts	637.24	183.85	821.09	38.34	95.16	133.51	11.13
Low Pressure Sodium 90 Watts	597.79	183.85	781.64	36.50	90.59	127.09	10.59
Low Pressure Sodium 135 Watts	597.79	183.85	781.64	36.50	90.59	127.09	10.59
Low Pressure Sodium 180 Watts	557.01	183.85	740.85	34.60	85.86	120.46	10.04
Metallic Arc 250 Watts	298.80	183.85	482.64	22.54	55.94	78.48	6.54
Metallic Arc 400 Watts	305.51	183.85	489.36	22.85	56.72	79.57	6.63
Metallic Arc 1000 Watts	$527.15	$183.85	$710.99	$33.20	$82.40	$115.61	$9.63

SCHEDULE 5

STREET / CROSSWALK LIGHTING STUDY

Tax-Adjusted Weighted Average Cost of Capital For 2009 Street Light Rates

a) Weighted Average Cost of Capital - Pretax

	Proportion	Cost	Extended
ST Debt	7.10%	6.17%	0.44%
LT Debt	46.40%	8.16%	3.79%
Preferred	9.00%	5.42%	0.49%
Common	37.50%	9.35%	3.51%
	100.00%		8.22%

WACC - pretax cost		8.22%
b) Additional income tax for common equity		
Extended equity cost	3.51%	
Effective tax rate (excluding surtax)	35.0%	
Income tax	1.89%	
WACC - equity tax cost		1.89%
c) Large Corporations Tax		
Provincial capital tax (2009)	0.175%	
Federal capital tax (2009)	0.000%	
Ave. NBV - Street Lighting	$25.914	
Ave. NBV - Assigned GP Plt.	1.863	
Ave. Deferred Chgs & W/C	3.410	
NPV - Total Street Lighting	$31.187	
Provincial capital tax	$0.055	
Federal capital tax	$0.000	
Total	$0.055	
Percentage of NBV	0.18%	
WACC - Large Corporations Tax		0.18%
d) Grants in Lieu of Property Tax		
Total 2009 Forecasted Expense	$34.800	
St. Lgts. % of Total Electric Plant	1.17%	
St. Lgts. Allocated Amount	$0.406	
Percentage of NBV	1.30%	
WACC - Grants in Lieu of Property Tax		1.30%
Total WACC - Interest / Carrying Cost		**11.59%**

STREET / CROSSWALK LIGHTING STUDY
AREA LIGHTING MATERIAL COST ANALYSIS
June 2007

Light Type Street Lights	Material Cost	Fixture	Lamp	Photocell	Davit	Wire	Connectors	Fasteners
Incandescent < 300 Watts	$51.36	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Incandescent > 300 Watts	$63.62	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Mercury Vapour 100 Watts	$228.81	**$122.41**	$15.99	$6.99	$62.09	$18.78	$0.94	$1.61
Mercury Vapour 125 Watts	$204.16	**$102.95**	$10.80	$6.99	$62.09	$18.78	$0.94	$1.61
Mercury Vapour 175 Watts	$200.64	**$102.95**	$7.28	$6.99	$62.09	$18.78	$0.94	$1.61
Mercury Vapour 250 Watts	$292.72	**$189.80**	$7.96	$6.99	$66.64	$18.78	$0.94	$1.61
Mercury Vapour 400 Watts	$302.69	**$198.75**	$8.98	$6.99	$66.64	$18.78	$0.94	$1.61
Mercury Vapour 700 Watts	$451.03	**$318.97**	$37.10	$6.99	$66.64	$18.78	$0.94	$1.61
Mercury Vapour 1000 Watts	$575.25	**$439.19**	$41.10	$6.99	$66.64	$18.78	$0.94	$1.61
Mercury Vapour 250 Watt Cont. Oper.	$292.72	**$189.80**	$7.96	$6.99	$66.64	$18.78	$0.94	$1.61
Fluorescent 2x24" 70 Watts	$106.44	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Fluorescent 2x48" 220 Watts	$131.91	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Fluorescent 2x72" 300 Watts	$178.72	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Fluorescent 4x72" 600 Watts	$293.72	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Fluorescent 1x96" 110 Watts	$160.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Fluorescent 1x72" 150 Watts	$121.22	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Fluorescent 4x48" 440 Watts	$188.91	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
High Pressure Sodium 70W	$200.01	$107.80	**$8.79**	$0.00	$62.09	$18.78	$0.94	$1.61
High Pressure Sodium 100W	$192.16	$100.21	**$8.53**	$0.00	$62.09	$18.78	$0.94	$1.61
High Pressure Sodium 150W	$195.20	$102.95	**$8.83**	$0.00	$62.09	$18.78	$0.94	$1.61
High Pressure Sodium 250 Watts	$242.65	$145.32	**$9.36**	$0.00	$66.64	$18.78	$0.94	$1.61
High Pressure Sodium 400 Watts	$254.90	$156.93	**$10.00**	$0.00	$66.64	$18.78	$0.94	$1.61
Low Pressure Sodium 90W	$597.79	$463.38	$44.00	$6.99	$62.09	$18.78	$0.94	$1.61
Low Pressure Sodium 135 Watts	$597.79	$463.38	$44.00	$6.99	$62.09	$18.78	$0.94	$1.61
Low Pressure Sodium 180 Watts	$557.01	$411.00	$55.60	$6.99	$62.09	$18.78	$0.94	$1.61
Metallic Additive 250W	$298.80	$191.62	**$19.21**	$0.00	$66.64	$18.78	$0.94	$1.61
Metallic Arc 400 Watts	$305.51	$202.61	**$14.93**	$0.00	$66.64	$18.78	$0.94	$1.61
Metallic Arc 1000 Watts	$527.15	$407.24	**$31.94**	$0.00	$66.64	$18.78	$0.94	$1.61

Light Type Flood Lights	Material Cost	Fixture	Lamp	Photocell	Davit	Wire	Connectors	Fasteners
Mercury Vapour 175 Watts	$69.84	$53.03	$7.28	$6.99	$0.00	$0.00	$0.94	$1.61
Mercury Vapour 250 Watts	$415.39	$397.90	$7.96	$6.99	$0.00	$0.00	$0.94	$1.61
Mercury Vapour 400 Watts	$299.68	$281.17	$8.98	$6.99	$0.00	$0.00	$0.94	$1.61
Mercury Vapour 1000 Watts	$489.82	$439.19	$41.10	$6.99	$0.00	$0.00	$0.94	$1.61
HIS 150W	$215.53	$180.76	$25.23	$6.99	$0.00	$0.00	$0.94	$1.61
High Intensity Sodium 250 Watts	$200.68	$181.78	$9.36	$6.99	$0.00	$0.00	$0.94	$1.61
High Intensity Sodium 400 Watts	$211.74	$192.21	$10.00	$6.99	$0.00	$0.00	$0.94	$1.61
Metallic Additive 250W	$220.36	$191.62	$19.21	$6.99	$0.00	$0.00	$0.94	$1.61
Metallic Arc 400 Watts	$227.08	$202.61	$14.93	$6.99	$0.00	$0.00	$0.94	$1.61
Metallic Arc 1000 Watts	$448.71	$407.24	$31.94	$6.99	$0.00	$0.00	$0.94	$1.61

Date: 7/6/2011

SCHEDULE 7

STREET / CROSSWALK LIGHTING STUDY

AREA LIGHTING MATERIAL COST ANALYSIS
June 2007

ITEM	DESCRIPTION	AVG COST	Location
0000386440	LAMP FLUORESCENT 40W 48	1.35	
0000386450	LAMP FLUORESCENT 40W 48	1.35	
0000386700	LAMP FLUORESCENT 75W 96	3.49	
0000386710	LAMP FLUORESCENT 205W	3.95	
0000387070	LAMP FLUORESCENT 35W 24	4.19	
0000387190	LAMP FLUORESCENT 60W 48	3.14	
0000387360	LAMP FLUORESCENT 85W 72	6.54	
0000388000	LAMP 100 WATT M.V.	15.99	
0000388180	LAMP 125 WATT M.V.	10.80	
0000388330	LAMP 175 WATT M.V.	7.28	
0000388500	LAMP 250 WATT M.V.	7.96	
0000388660	LAMP 400 WATT M.V.	8.98	
0000388770	LAMP 700 WATT M.V.	37.10	
0000388980	LAMP 1000 WATT MV	41.10	
0000388990	LAMP 70 WATT H.P.S.	8.79	
0000389000	LAMP 100 WATT H.P.S.	8.53	
0000389030	LAMP 135 WATT L.P.S.	44.00	
0000389040	LAMP 150 WATT HPS 100V	25.23	
0000389060	LAMP 150 WATT H.P.S.55V	8.83	
0000389090	LAMP 180 WATT L.P.S.	55.60	
0000389250	LAMP 250 WATT H.P.S.	9.36	
0000389400	LAMP 400 WATT H.P.S.	10.00	
0000389450	LAMP 1000W HPS	60.47	
0000389700	LAMP HALIDE 250W	19.21	
0000389770	LAMP HALIDE 400W	14.93	
0000389810	LAMP HALIDE 1000W	31.94	
0000389900	LAMP STREET LITE SIGNAL	2.21	
0002103270	CONDUIT FLEX BLK 1/2"	4.39	
0050091540	BOLT LAG 1/2"X 4" GALV	0.53	
0050103120	BOLT MACHINE 5/8" X 12"	1.08	
0054223510	CRIMPIT #2/0- #8 WR139	0.47	
0057151000	BRACKET 10'L	88.91	
0057152040	BRACKET 1 1/4"X4' FIXED	58.38	
0057152220	BRACKET 4'X 2' 16" TEN	27.46	
0057154060	BRACKET 1 1/4"X6' LOWER	62.09	
0057155060	BRACKET SWIVEL 1 1/4 X6	18.91	
0057155720	BRACKET TAPERED 6' X 2"	48.90	
0057155723	BRACKET TAPERED 8'	87.05	
0057155725	BRACKET TAPERED 2"X10'	106.44	
0057156020	BRACKET LOWER 2" X 6'	66.64	
0057156080	BRACKET FIXED 2" X 8'	87.48	
0057157010	BRACKET TAPERED 12'L	141.42	
0057158140	PLATE POLE ST LITE 1 1/	9.46	
0057158220	PLATE POLE ST LIGHT 2"	26.24	
0057350350	LUMINAIRE LPS 135W	463.38	

SCHEDULE 7

STREET / CROSSWALK LIGHTING STUDY

AREA LIGHTING MATERIAL COST ANALYSIS
June 2007

ITEM	DESCRIPTION	AVG COST	Location
0057350720	LUM LPS 180W 120/240/347 V	411.00	R04B
0057350750	LUMINAIRE LPS 180W 240V	493.30	XX
0057350800	LUMINAIRE LPS 180W 347V	495.00	XX
0057350830	LUMINAIRE HPS 70W POLY	73.33	XX
57350835	LUM. 70W POLY C/W LAMP	99.23	XX
0057350836	LUM 70W POLY ALUM.ALLOY	97.70	XX
0057350837	LUMINAIRE 70W HPS CWA ACRY	122.82	C01A
0057350850	LUMINAIRE HPS 70W GLASS	69.32	XX
0057350855	LUM. 70W GLASS C/W LAMP	97.68	C03A
0057350856	LUM 70W GLASS AL. ALLOY	99.37	M12D
0057350857	LUM. 70W GLASS CWI BAL.	120.32	M08A
0057350860	LUM 100W HPS POLY	75.00	XX
0057350865	LUM. 100W POLY C/W LAMP	100.21	XX
0057350866	LUMINAIRE 100W ACRYLIC HPS	124.85	C07A
0057350867	LUM 100W POLY AL. ALLOY	98.37	XX
0057350875	LUM. 100W GLASS C/WLAMP	98.76	XX
0057350877	LUM. 100W GLASS CWI BAL	135.75	XX
0057350880	LUMINAIRE HPS 150W GLAS	82.27	XX
0057350885	LUM. 150W GLASS C/WLAMP	100.95	XX
0057350886	LUMINAIRE 150W HPS CWI GLAS	145.97	M05A
0057350887	LUM. 150W HPS 240V GLAS	150.88	C09A
0057350890	LUMINAIRE HPS 150W POLY	79.24	XX
0057350895	LUM. 150W POLY C/W LAMP	102.95	XX
0057351315	LUMINAIRE 250W HPS CWI GLAS	145.32	C07A
0057351400	LUMINAIRE 250W HPS CWI 347V	160.36	C05A
0057351710	LUMINAIRE HPS 400W GLAS	109.60	XX
0057351715	LUMINAIRE 400W HPS CWI 120/2	156.93	M12A
0057351720	LUMINAIRE HPS 400W 240V	204.30	XX
0057351730	LUMINAIRE HPS 400W 347V	196.00	XX
0057351760	LUMINAIRE 400W 600V HPS CWI	169.81	M12A
0057353330	LUMINAIRE MTL-HLDE 400W	281.54	XX
0057353500	LUMINAIRE HALIDE 1000 W	300.00	XX
0057353550	LUMINAIRE HALIDE 1000 W	294.79	T01C
0057400920	AREA LIGHT MV 125 W	107.76	XX
0057401200	LUMINAIRES 70W H-P.S.	107.80	D14B
0057401205	DUSK-T-DAWN 70W HPS CWA	200.30	D08B
0057402020	AREA LIGHT MV 175 W	92.88	XX
0057402100	LUMINAIRES 100W H.P.S.	106.37	XX
0057402105	DUSK-T-DAWN 100W HPS CWA	140.50	C15A
0057402150	FLOODLIGHT 150W HPS CWI	180.76	C17A
0057402240	FLOODLIGHT M.V. 175W	53.03	
0057403330	FLOODLIGHT M V 250 W	397.90	XX
0057403500	FLOODLIGHT 250W HPS CWI	181.78	
0057404050	FLOODLIGHT M V 400 W	281.17	XX
0057404600	FLOODLIGHT 400W HPS CWI	192.21	C11A

SCHEDULE 7

STREET / CROSSWALK LIGHTING STUDY

AREA LIGHTING MATERIAL COST ANALYSIS
June 2007

ITEM	DESCRIPTION	AVG COST	Location
0057408250	FLOODLIGHT MTL HAL.250W	191.62	D05B
0057408500	FLOODLIGHT 400W MTL-HAL CV	202.61	D03A
0057409000	FLOODLIGHT 1000W MH CWI	407.24	
0057409380	FLOODLIGHT M V 1000 W	439.19	XX
0057600450	BRACKET & ADAPTORS	9.15	
0057601010	CAP SHORTING TWIST LOCK	4.80	
0057601200	CONTROL 120 V PHOTO	7.05	
0057601400	CONTROL ELECT 120V PHOTOC	6.99	
0057602000	PHOTO CONTROL 120V HD	19.90	
0057602400	CONTROL 240V ELECT PHOTOC	11.01	
0057602960	GUARD WIRE FOR ST-LITE	50.44	
0057603800	REFRACTOR GLASS	32.60	
0057603900	REFRACTORS POLYCARBON #	0.00	
0057604020	REFRACTOR POLY LU B2214	48.03	
0057604050	REFRACTOR POLY LU B2217	73.74	
0057604080	REFRACTOR POLYCARBON #9	21.07	
0057604170	REFRACTOR GLASS	66.37	
0057604200	REFRACTOR ACRYLIC VB15	40.70	
0057604210	REFRACTOR POLY LUM VB15	78.68	
0057604220	REFRACTOR AREA LIGHT	18.66	
0057604240	REFRACTOR GLASS OV15	16.00	
0057604250	REFRACTOR POLY LUM 0V15	24.00	
0057604255	REFRACTOR STREETLIGHT OV	17.85	
0057604270	REFRACTOR GLASS OV25	25.89	
0057604280	REFRACTOR POLY OV25	92.87	
0057604300	REFRACTOR GLASS OV50	17.50	
0057605800	REDUCER LAMPHOLDER,	6.25	
0057606100	REFRACTOR 125 W M V	34.36	
0057606500	REFRACTOR FOR SODIUM	71.31	
0057606550	REFRACTOR FOR SODIUM	88.62	
0057606700	REFRACTOR 250 W M V	38.69	
0057606950	REFRACTOR 400 W M V	33.01	
0057607300	RELAY 30 AMP 110 V MURC	33.89	
0057607330	RELAY 30 AMP 125 V	140.04	
0057607400	RELAY 60 AMP 115 V	215.37	
0057607440	RELAY 60 AMP 250 V	191.29	
0057608690	STARTERS HPS LUMINAIRES	31.63	
0057608700	STARTER FOR HPS 70-150W	40.95	
0057608703	STARTER FOR HPS 55V	41.17	
0057608710	STARTER FOR SODIUM	40.41	
0057608713	STARTER KIT HPS 55V 70/	31.75	
0057608720	STARTER FOR HPS 150-400	40.76	
0057608722	STARTER FOR HPS 100V	36.35	
0057608730	STARTER FOR SODIUM	48.16	
0065734220	CABLE CU ST-LITE 2C #12	1.20	

SCHEDULE 8

STREET / CROSSWALK LIGHTING STUDY
LAMP LIFE ANALYSIS
September 2005

Assumptions: Total annual photocell operating time is based on 4,000 hours per year or 333 hours per month.
All Average Rated Life Spans are as indicated in the IES Lighting Handbook, 1981 Edition
(IES = Illuminating Engineering Society)

Lamp Type	Average Life (Hrs)	Burning Hours per Year	Service Life (Years)	Life Relative to 100W HPS	Replacements Relative to 100W HPS
Incandescent	2500	4000	0.6	0.10	9.60
Flourescent (48 in., T12, Recess Base)	12000	4000	3.0	0.50	2.00
Mercury Vapour	24000	4000	6.0	1.00	1.00
Mercury Vapour 125W *See Note	18000	4000	4.5	0.75	1.33
Metal Halide 175W	7500	4000	1.9	0.31	3.20
Metal Halide 250W	10000	4000	2.5	0.42	2.40
Metal Halide 400W	15000	4000	3.8	0.63	1.60
Metal Halide 1000W	10000	4000	2.5	0.42	2.40
High Pressure Sodium 70W	24000	4000	6.0	1.00	1.00
High Pressure Sodium 100W	24000	4000	6.0	1.00	1.00
Low Pressure Sodium	8000	4000	2.0	0.33	3.00

*** No Average life data was available for this lamp size in the references listed above. 75% of the quoted life for all Mercury Lamps was used.**

STREET / CROSSWALK LIGHTING STUDY

ANALYSIS & COMPARISON OF PROPOSED VS CURRENT STREET LIGHTING RATES
EFFECTIVE JANUARY 1, 2009

Description	Rate Code	kW.h/Mo.	Power & Energy	Maintenance	Capital	2009 New Proposed Rates	2009 New Proposed Revenue	2007 Current Rates	Percent Change	Inv. Level at Jan. 2008 Units	Revenue Variance	Connected Load (kW)	Total Load (kW)	Continuous Load (kW)
Incandescent < 300 Watts - Note 1	001	97.00	$10.58	$3.08	$6.46	$20.12	$7,725	$19.50	3.2%	32	$237	0.291	9.312	
Incandescent > 300 Watts - Note 1	002	154.00	16.79	3.08	6.59	26.46	635	25.79	2.6%	2	16	0.462	0.924	
Incandescent < 300 Watts - Note 1	003	97.00	10.58	0.00	0.00	10.58	889	10.48	1.0%	7	8	0.291	2.037	
										41	261			
Mercury Vapour :														
Mercury Vapour 100 Watts	100	43.00	4.70	3.08	5.59	13.37	44,286	12.72	5.1%	276	2,158	0.129	35.604	
Mercury Vapour 125 Watts	101	52.00	5.66	4.10	5.26	15.02	2,106,109	14.27	5.2%	11,687	104,827	0.156	1,823.172	
Mercury Vapour 175 Watts	102	69.00	7.51	3.08	5.21	15.80	555,898	15.14	4.4%	2,932	23,212	0.207	606.924	
Mercury Vapour 250 Watts	103	97.00	10.58	3.08	6.46	20.12	271,104	19.50	3.2%	1,123	8,322	0.291	326.793	
Mercury Vapour 400 Watts	104	154.00	16.79	3.08	6.59	26.46	458,861	25.79	2.6%	1,445	11,663	0.462	667.590	
Mercury Vapour 700 Watts	105	260.00	28.36	3.08	8.60	40.04	5,286	39.28	1.9%	11	101	0.780	8.580	
Mercury Vapour 1000 Watts	106	363.00	39.60	3.08	10.29	52.97	47,034	52.13	1.6%	74	742	1.089	80.586	
Mercury Vapour 250 Watt Cont. Oper.	107	212.00	17.93	6.16	6.46	30.55	1,833	29.55	3.4%	5	60	0.291	1.455	1.455
Mercury Vapour 125 Watts	201	52.00	5.66	4.10	0.00	9.76	937	9.30	4.9%	8	44	0.156	1.248	
Mercury Vapour 175 Watts	202	69.00	7.51	3.08	0.00	10.59	2,796	10.22	3.6%	22	98	0.207	4.554	
Mercury Vapour 250 Watts	203	97.00	10.58	3.08	0.00	13.66	5,573	13.24	3.2%	34	171	0.291	9.894	
Mercury Vapour 400 Watts	204	154.00	16.79	3.08	0.00	19.87	2,146	19.39	2.5%	9	52	0.462	4.158	
Mercury Vapour 700 Watts	205	260.00	28.36	3.08	0.00	31.44	0	30.86	1.9%	0	0	0.780	0.000	
Mercury Vapour 1000 Watts	206	363.00	39.60	3.08	0.00	42.68	10,755	42.01	1.6%	21	169	1.089	22.869	
Mercury Vapour 125 Watts	301	52.00	5.66	0.00	0.00	5.66	747	5.62	0.7%	11	5	0.156	1.716	
Mercury Vapour 175 Watts	302	69.00	7.51	0.00	0.00	7.51	13,698	7.46	0.7%	152	91	0.207	31.464	
Mercury Vapour 250 Watts	303	97.00	10.58	0.00	0.00	10.58	6,729	10.48	1.0%	53	64	0.291	15.423	
Mercury Vapour 400 Watts	304	154.00	16.79	0.00	0.00	16.79	3,022	16.63	1.0%	15	29	0.462	6.930	
Mercury Vapour 700 Watts	305	260.00	28.36	0.00	0.00	28.36	340	28.10	0.9%	1	3	0.780	0.780	
Mercury Vapour 1000 Watts	306	363.00	39.60	0.00	0.00	39.60	3,326	39.25	0.9%	7	29	1.089	7.623	
										17,886	151,840			
Fluorescent :														
Fluorescent 2x24" 70 Watts	110	30.00	3.28	6.15	4.29	13.72	149,042	13.07	5.0%	905	7,102	0.091	82.355	
Fluorescent 2x48" 220 Watts	111	85.00	9.27	6.15	4.73	20.15	32,635	19.44	3.6%	135	1,143	0.254	34.290	
Fluorescent 2x72" 300 Watts	112	116.00	12.67	6.15	5.52	24.34	19,568	23.62	3.0%	67	577	0.348	23.316	
Fluorescent 4x72" 600 Watts	113	222.00	24.20	6.15	7.47	37.82	6,807	37.00	2.2%	15	147	0.665	9.975	
Fluorescent 1x96" 110 Watts	114	47.00	5.12	6.15	5.20	16.47	988	15.80	4.2%	5	40	0.141	0.705	
Fluorescent 1x72" 150 Watts	115	60.00	6.55	6.15	4.54	17.24	414	16.56	4.1%	2	16	0.180	0.360	
Fluorescent 4x48" 440 Watts	116	166.00	18.13	6.15	5.69	29.97	719	29.19	2.7%	2	19	0.499	0.998	
										1,131	9,044			
Fluorescent 4x72" 600 Watts	213	222.00	24.20	6.15	0.00	30.35	0	29.51	2.8%	0	0	0.665	0.000	
Fluorescent 1x96" 110 Watts	214	47.00	5.12	6.15	0.00	11.27	3,516	10.59	6.4%	26	212	0.141	3.666	
Fluorescent 1x72" 150 Watts	215	60.00	6.55	6.15	0.00	12.70	457	12.01	5.7%	3	25	0.180	0.540	
Fluorescent 4x48" 440 Watts	216	166.00	18.13	6.15	0.00	24.28	0	23.49	3.4%	0	0	0.499	0.000	
Fluorescent 1x48" 120 Watts	217	49.00	5.33	6.15	0.00	11.48	138	10.80	6.3%	1	8	0.146	0.146	
Fluorescent 2x48" 220 Watts	218	85.00	9.27	6.15	0.00	15.42	0	14.71	4.8%	0	0	0.254	0.000	
Fluorescent 4x35"	330	47.00	5.12	0.00	0.00	5.12	123	5.06	1.2%	2	1	0.140	0.280	
										32	246			

SCHEDULE 9
"REVISED"

STREET / CROSSWALK LIGHTING STUDY

ANALYSIS & COMPARISON OF PROPOSED VS CURRENT STREET LIGHTING RATES
EFFECTIVE JANUARY 1, 2009

Description	Rate Code	kW.h/Mo.	Power & Energy	Maintenance	Capital	2009 New Proposed Rates	2009 New Proposed Revenue	2007 Current Rates	Percent Change	Inv. Level at Jan. 2008 Units	Revenue Variance	Connected Load (kW)	Total Load (kW)	Continuous Load (kW)
Fluorescent Crosswalk - Continuous Burning - Customer Owned :														
Fluorescent 4x72" 600 Watts	117	486.00	41.09	0.00	0.00	41.09	493	40.73	0.9%	1	4	0.665	0.665	0.665
Fluorescent 2x24" 70 Watts	118	66.00	5.57	0.00	0.00	5.57	1,069	5.52	0.9%	16	10	0.091	1.456	1.456
Fluorescent 4x48" 440 Watts	119	364.00	30.79	0.00	0.00	30.79	7,759	30.53	0.9%	21	66	0.499	10.479	10.479
Fluorescent 2x96"	120	254.00	21.49	0.00	0.00	21.49	8,252	21.31	0.8%	32	69	0.348	11.136	11.136
Fluorescent 4x96"	150	613.00	51.84	0.00	0.00	51.84	13,064	51.38	0.9%	21	116	0.840	17.640	17.640
										91	265			
Fluorescent Crosswalk - Photocell Burning - Customer Owned :														
Fluorescent 2x24" 70 Watts	310	30.00	3.28	0.00	0.00	3.28	39	3.25	0.9%	1	0	0.091	0.091	
Fluorescent 4x48" 440 Watts	311	166.00	18.13	0.00	0.00	18.13	1,088	17.97	0.9%	5	10	0.499	2.495	
Fluorescent 2x72" 300 Watts	312	116.00	12.67	0.00	0.00	12.67	152	12.57	0.8%	1	1	0.348	0.348	
Fluorescent 4x72" 600 Watts	313	222.00	24.20	0.00	0.00	24.20	0	23.99	0.9%	0	0	0.665	0.000	
Fluorescent 1x96" 110 Watts	314	47.00	5.12	0.00	0.00	5.12	1,536	5.08	0.8%	25	12	0.142	3.550	
Fluorescent 1x72" 150 Watts	315	60.00	6.55	0.00	0.00	6.55	0	6.49	0.9%	0	0	0.180	0.000	
Fluorescent 4x96"	350	280.00	30.55	0.00	0.00	30.55	27,495	30.28	0.9%	75	243	0.841	63.075	
										107	266			
Low Pressure Sodium :														
Low Pressure Sodium 135 Watts	130	60.00	6.55	9.23	10.59	26.37	19,304	25.11	5.0%	61	923	0.180	10.980	
Low Pressure Sodium 180 Watts	131	80.00	8.73	9.23	10.04	28.00	294,321	28.77	-2.7%	876	(8,109)	0.240	210.240	
Low Pressure Sodium 90 Watts	132	45.00	4.90	9.23	10.59	24.72	297	23.49	5.2%	1	15	0.135	0.135	
Low Pressure Sodium 180 Watts E&M	231	80.00	8.73	9.23	0.00	17.96	9,267	16.93	6.1%	43	531	0.240	10.320	
Low Pressure Sodium 180 Watts E/O	331	80.00	8.73	0.00	0.00	8.73	3,876	8.65	0.9%	37	36	0.240	8.880	
										1,018	(6,604)			
High Pressure Sodium :														
High Pressure Sodium 250 Watts	121	100.00	10.91	3.08	5.78	19.77	1,268,227	19.11	3.4%	5,346	42,283	0.300	1,603.800	
High Pressure Sodium 400 Watts	122	150.00	16.36	3.08	5.94	25.38	1,142,933	24.70	2.8%	3,752	30,841	0.450	1,688.400	
High Pressure Sodium 70 Watts	123	32.00	3.48	3.08	5.20	11.76	5,504,837	11.11	5.9%	39,004	304,824	0.096	3,744.384	
High Pressure Sodium 100 Watts	124	45.00	4.90	3.08	5.09	13.07	7,334,369	12.42	5.3%	46,746	367,345	0.135	6,310.710	
High Pressure Sodium 150 Watts	125	65.00	7.09	3.08	5.14	15.31	995,510	14.62	4.7%	5,420	44,625	0.195	1,056.900	
HP Sodium 100 Watts - Cont. Oper.	126	99.00	8.35	6.16	5.09	19.60	2,353	18.60	5.4%	10	121	0.135	1.350	1.350
High Pressure Sodium 250 Watts	221	100.00	10.91	3.08	0.00	13.99	23,671	13.58	3.0%	141	694	0.300	42.300	
High Pressure Sodium 70 Watts	222	32.00	3.48	3.08	0.00	6.56	19,523	6.21	5.6%	248	1,042	0.096	23.808	
High Pressure Sodium 100 Watts	223	45.00	4.90	3.08	0.00	7.98	10,438	7.63	4.6%	109	458	0.135	14.715	
High Pressure Sodium 150 Watts	224	65.00	7.09	3.08	0.00	10.17	27,947	9.79	3.9%	229	1,044	0.195	44.655	
High Pressure Sodium 250 Watts	321	100.00	10.91	0.00	0.00	10.91	221,386	10.82	0.8%	1,691	1,826	0.300	507.300	
High Pressure Sodium 70 Watts	322	32.00	3.48	0.00	0.00	3.48	264,007	3.45	0.9%	6,322	2,276	0.096	606.912	
High Pressure Sodium 100 Watts	323	45.00	4.90	0.00	0.00	4.90	149,352	4.87	0.6%	2,540	914	0.135	342.900	
High Pressure Sodium 150 Watts	324	65.00	7.09	0.00	0.00	7.09	111,455	7.03	0.9%	1,310	943	0.195	255.450	
High Pressure Sodium 400 Watts	326	150.00	16.36	0.00	0.00	16.36	17,080	16.21	0.9%	87	157	0.450	39.150	
High Pressure Sodium 500 Watts	327	183.00	19.97	0.00	0.00	19.97	719	19.81	0.8%	3	6	0.550	1.650	
High Pressure Sodium 1000 Watts	328	363.00	39.61	0.00	0.00	39.61	7,605	39.26	0.9%	16	67	1.090	17.440	
High Pressure Sodium 1500 Watts	329	500.00	54.54	0.00	0.00	54.54	654		#DIV/0!	1	654	1.090	1.090	
										112,974	799,466			

SCHEDULE 9
"REVISED"

STREET / CROSSWALK LIGHTING STUDY

ANALYSIS & COMPARISON OF PROPOSED VS CURRENT STREET LIGHTING RATES
EFFECTIVE JANUARY 1, 2009

Description	Rate Code	kW.h/Mo.	Power & Energy	Maintenance	Capital	2009 New Proposed Rates	2009 New Proposed Revenue	2007 Current Rates	Percent Change	Inv. Level at Jan. 2008 Units	Revenue Variance	Connected Load (kW)	Total Load (kW)	Continuous Load (kW)
Metallic Additive :														
Metallic Arc 400 Watts	140	150.00	16.36	4.92	6.63	27.91	430,720	26.92	3.7%	1,286	15,290	0.450	578.700	
Metallic Arc 1000 Watts	141	360.00	39.27	7.39	9.63	56.29	631,618	55.22	1.9%	935	12,050	1.080	1,009.800	
Metallic Arc 250 Watts	142	100.00	10.91	7.39	6.54	24.84	28,914	25.65	-3.2%	97	(943)	0.300	29.100	
Metallic Arc 150 Watts	143	67.00	7.30	7.39	6.54	21.23	1,019	22.06	-3.8%	4	(40)	0.200	*0.800*	
Metallic Arc 100 Watts	144	50.00	5.45	7.39	6.54	19.38	698	20.23	-4.2%	3	(31)	0.150	0.450	
Metallic Arc 1000 Watts	341	360.00	39.27	0	0	39.27	9,896	38.92	0.9%	21	88	1.080	22.680	
Metallic Arc 400 Watts	342	150.00	16.36	0	0	16.36	30,626	16.21	0.9%	156	281	0.450	70.200	
Metallic Arc 250 Watts	343	100.00	10.91	0	0	10.91	11,783	10.82	0.8%	90	97	0.300	27.000	
Metallic Arc 175 Watts	344	75.00	8.18	0	0	8.18	9,620	8.11	0.9%	98	82	0.225	22.050	
Metallic Arc 150 Watts	345	67.00	7.30	0	0	7.30	263	7.23	1.0%	3	3	0.200	0.600	
Metallic Arc 100 Watts	346	50.00	5.45	0	0	5.45	0	5.40	0.9%	0	0	0.150	0.000	
										2,693	26,877			
TOTALS							$22,409,372.54			135,974	$981,988		22,242.051	44.181

Count = 83

Note 1 - Red highligted P&E charges relate to calculated rounding differences using Misc. Small Loads Tariff.
Note 2 - Incandescent rates were set at 250W and 400W Mercury Vapour

Calculation of Power & Energy Rate :			
Based on Misc. Small Loads Tariff Rate Components & 1kW lighting load			
Photocell Operation (4000 burning hours per year)			
Demand Charge $ 8.43/kW (annual)			$102.06
Energy Charge :			
1st Block : 1st 200 kW.h (annual)	2,400	0.09665	231.96
2nd Block : All additional (annual)	1,600	0.06396	102.34
			$436.36
Rate per kW.h	4,000		**$0.1090891**
Continuous Burning (8760 burning hours per year)			
Demand Charge $ 8.43/kW (annual)			$102.06
Energy Charge :			
1st Block : 1st 200 kW.h (annual)	2,400	0.09665	231.96
2nd Block : All additional (annual)	6,360	0.06396	406.79
			$740.81
Rate per kW.h	8,760		**$0.0845669**

Revenue Summary by Rate Component

	Power & Energy	Maintenance	Capital	Total
2009 Proposed Revenue (Using Actual Jan 2008 Inv. Level)				
Current Rates	$9,470,670	$4,329,764	$7,315,865	$21,116,299
Proposed Rates	9,704,758	4,892,737	7,811,878	22,409,373
Variance	234,088	562,973	496,013	1,293,074
Add. Forecasted S/L Revenue using 2009 Load Forecast	193,314	145,290	243,169	581,773
Adjusted 2009 Prop. S/L Revenue	9,898,072	5,038,027	8,055,047	22,991,146
Prop. Misc. Lighting Revenue	2,160,872			2,160,872
Add. Forecasted Misc. Revenue using 2009 Load Forecast	42,830			42,830
Total Prop. Unmetered Rev.	**$12,101,774**	**$5,038,027**	**$8,055,047**	**$25,194,848**

NON-CONFIDENTIAL

Request IR-38:

With respect to NSPI's response to Multeese IR-2(b), please provide the derivation of the Revenue numbers in the final table of that response.

Response IR-38:

Please refer to Multeese IR-37 Attachment 1 (Revenue Summary by Rate Component, page 15).

NON-CONFIDENTIAL

Request IR-39:

With respect to NSPI's response to Multeese IR-13, the last paragraph before the Revised Schedule 5A refers to adjustments to Line 42 of Exhibit 4 of the Cost of Service Study. For clarity, please provide a revised Line 42.

Response IR-39:

The revised Line 42 of Exhibit 4 in millions of dollars is shown below.

Category	Total Expenses ($M)	Prod. Expenses ($M)	Trans. Expenses ($M)	Dist. Expenses ($M)	Retail Expense ($M)	Direct Expenses ($M)
Corporate Taxes	40.70	27.68	4.85	8.04	0	0.14

NON-CONFIDENTIAL

Request IR-40:

With respect to NSPI's response to Multeese IR-13, the revised Schedule 5A LED Gross Plant Values and Net Plant Values do not appear to have been changed to reflect the response to this IR. Please provide Schedule 5A with those adjustments included.

Response IR-40:

Please refer to Attachment 1.

SCHEDULE 5A

STREET / CROSSWALK LIGHTING STUDY

Tax-Adjusted Weighted Average Cost of Capital Amounts by Components
For 2012 Street Light Rates

Capital Cost Expenses (Net Plant Value)
For 2012 Street Light Rates

Depreciation Rate	**5.33%**
Salvage Rate	**0.00%**
Salvage Incl. in Depreciation Rate	**0.00%**
Gross-up factor for tax purposes (LED only)	**0.00%**

	Non LED	LED	Non LED	LED
Gross Plant Value (YA)			$46,669	$8,840
Net Plant Value (YA)			$21,981	$8,604
a) Weighted Average Cost of Capital - Pretax				
ST Debt	0.21%	0.21%		$18.4
LT Debt	3.94%	3.94%		$339.3
Subtotal			*728*	*$357.8*
Preferred	0.22%	0.22%	$48.5	$18.6
Common	3.60%	3.60%	$767.7	$309.8
WACC - pretax cost	7.97%	7.97%	$1,543.8	$686.1
b) Additional income tax for common equity				
WACC - equity tax cost	1.62%	1.62%		$139.4
c) Large Corporations Tax				
WACC - Large Corporations Tax	0.03%	0.03%		$2.6
Subtotal			*$248.0*	*$142.0*
d) Grants in Lieu of Property Tax				
WACC - Grants in Lieu of Property Tax	1.09%		$213.3	$0.0
Subtotal Financing Expense	**10.71%**	**9.62%**	**$2,005.0**	**$828.1**
Depreciation Expense			**$2,401.1**	**$471.2**
Gross up for Tax Purposes			**N/A**	**$211.7**
Total Depreciation Expense Grossed Up for Tax Purposes			**N/A**	**$682.9**
CCA			**$0.0**	**-$219.2**
TOTAL CAPITAL COST EXPENSE			**$4,406.1**	**$1,291.8**

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Request IR-41:

With respect to RB-01, Attachment 1:

(a) Please identify any capital additions for 2011 and 2012 which were in the 2011 ACE Plan (including those proposed to be submitted for approval at a later date) but are not included in this Attachment, and explain why they were not included.

(b) Please identify any capital additions for 2011 and 2012 which are in this Attachment but were not included in the 2011 ACE Plan and explain why they were not in the ACE Plan.

(c) If any of the projects that were identified in the ACE Plan for later submission to the Board (as identified in Schedule C of the Board's June 23, 2011 Decision re the 2011 ACE Plan) are included in Attachment 1 but are no longer expected to be submitted before the end of 2012, please identify those projects and provide the reason for the delay.

(d) If any projects are identified in c), please provide an update of RB-01 Attachment 1 and RB-02, Attachment 1.

Response IR-41:

(a-b) Please refer to NPB IR-11. Differences between the RB-01 attachment and the ACE Plan reflect the fact that these documents were prepared on two different timelines (the background for the Application was prepared before the ACE Plan was finalized).

(c-d) Projects included in the 2011 ACE Plan for later submission are still being finalized. It is expected that all projects identified in that list will be brought forward to the UARB

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before the end of 2012 with the exception of Co-firing Biomass (CI 38947). This project is no longer being considered given the change in government policy. With only one change, NSPI has not prepared an updated version of the referenced attachments.

2012 General Rate Application (NSUARB P-892)
NSPI Responses to Multeese Information Requests

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Request IR-42:

With respect to NSPI's response to NPB IR-27, page 2, Lines 24-27, which note that the treatment of DSM in the COSS is different from the 2009 GRA and DSM proceedings, what plans does NSPI have to address this?

Response IR-42:

NSPI is prepared to make the appropriate amendments to the cost of service study regarding this item.

2012 General Rate Application (NSUARB P-892)
NSPI Responses to CA Information Requests

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Request IR-45:

Please provide the basis of the assumption that 30% of poles carry only primary lines, including all supporting data and analyses. (Exhibit 3B)

Response IR-45:

The Cost of Service Study is based on the methodology approved by the UARB in its Decision of September 22, 1995[1] in the matter of a Generic Hearing respecting Cost of Service and Rate Design for Nova Scotia Power Inc. The approved methodology has been applied consistently in NSPI filings since this Decision. NSPI has not attempted to retrieve and repeat the basis of this principle in this proceeding, which does not propose substantial revisions to the Cost of Service Study, other than in respect of the LED streetlights initiative.

Please refer to Attachments 1[2] and 2[3] for additional information concerning the allocation factors used in the Cost of Service Study submitted as evidence in the 1993 Hearing.

The 30 percent factor is discussed in Attachment 1, page 6 and Attachment 2, page 2.

[1] NSPI 1995 Cost of Service and Rate Design, UARB Decision NSUARB – NSPI – 864, September 22, 1995
[2] NSPI Hearing Relating to Cost of Service and Rate Design, NSUARB – NSPI – Direct Evidence (A.E. Dominie), February 15, 1993.
[3] NSPI Hearing Relating to Cost of Service and Rate Design, NSUARB – NSPI – Direct Evidence (A.E. Dominie), February 15, 1993.

ATTACHMENT 1

COST OF SERVICE PROCEDURES

1. Overview

The overall objective of a cost of service analysis is to identify any inter-class inequities which may be present with regards to over or under contribution to total allocated costs. This determination is based on a comparison of each class' revenue/cost ratio.

The first step in preparing a Cost of Service Study, once the test period is established, is to accumulate the financial and operating information pertaining to that period. In this case, the test period is the 12 months from January 1, 1993 to December 31, 1993. The data accumulated includes estimates for test period plant in service, reserve for depreciation, revenues, operating expenses, kilowatt hours sold, demand data and customer counts. After the data is reviewed, the study proceeds.

A Cost of Service Study consists of an allocation of all revenue requirement costs relative to the furnishing of electric utility service by the Company. This includes the appropriate assignment of operating and maintenance expenses, grants in lieu of taxes, depreciation and responsibility for interest and income taxes incurred on those elements of the electric utility plant in service necessary in whole or in part to provide electric service to the various classifications of utility customers, as well as any profit or loss incurred by the utility.

Where possible, costs are assigned directly to classes of service based upon details derived from the books and records of the Company or by special analyses and studies.

COST OF SERVICE PROCEDURES

Costs not directly assigned are analyzed by functional responsibility in groupings of accounts, such as production, transmission and distribution, and allocated to the various classes of service on the basis of the respective demands, energy use, number of customers, and/or revenue associated with the functional responsibility appropriate for each class of service. In general, the demand component of cost embraces those items which are incurred in order to obtain and maintain the ability to deliver electric energy to customers as called for by them, and are associated with meeting the maximum demands placed on the system. The energy use components of costs are those items which vary with the annual volume of energy supplied to the various classes of service provided by the Company. The customer components of cost are those items that vary with the number of customers served, and revenue related costs are those items which vary with the dollars of revenue received.

It is well established that large demands for electric energy require the use of large production units and transmission line facilities to meet these demands. Plant investment increases as such units and facilities are enlarged to meet these demands. Consequently, these costs are allocated in relationship to system maximum demand responsibility as measured by the allocation methodology. The distribution facilities are allocated on non-coincident demand to recognize diversity at that level. Class non-coincident demands are the demands which are imposed on the distribution system and, in general, are substantially larger than coincident demands. Consequently, the cost of service elements which increase with plant size and capacity are demand costs.

An example of energy costs which vary with the volume of electricity generated and supplied would be fuel costs. These costs increase as the quantity of fuel required to produce an enlarged energy output at generating stations is increased.

COST OF SERVICE PROCEDURES

A readily identifiable example of customer costs is customer accounting, including meter reading and collection expenses, and the fixed cost associated with the customer cost component of the distribution system.

Costs associated with miscellaneous revenue are not identified separately, but, rather, the miscellaneous revenue items are deducted from the overall cost assignment.

The first step in the cost analysis is the functionalization of plant and expenses into the functional groups of production, transmission and distribution. From the books and records of the Company, plant investment is readily identifiable for production, transmission and distribution functions. Likewise, expenses for operation and maintenance for production, transmission and distribution are also readily identifiable. However, there are several components of plant, depreciation and expenses which are not maintained on a production, transmission, or distribution basis. These items are functionalized prior to classification and allocation.

Following the functionalization step, production, transmission, and distribution plant and expense are classified. Classification is the process by which plant or costs are deemed to be demand, energy, or customer related.

The third step in conducting the cost study consists of the determination of those demand, energy or customer allocation factors which are necessary to allocate plant or expense to the various classes of service.

The fourth and final step is the allocation procedure. This step involves applying the allocation factors, determined in step 3, to the classified plant and expense from step 2, to determine the overall cost assigned to each class of service based upon the total plant and expenses for the test period.

COST OF SERVICE PROCEDURES

The full development of the results of the analysis are provided in Exhibits AED-2 through 9. The analysis was based on the budgeted test period January 1993 - December 1993. Exhibit 1 summarizes the results of the Cost of Service Studies prepared for Fiscals 1992 and Calendar 1993. Exhibits 2 and 3 detail the rate base analyses, and Exhibits 4 to 6 show the analyses of operating costs and depreciation expense. Exhibit 7 contains the revenue analysis and Exhibit 8 details the development of allocation factors. Exhibit 9 shows the analysis of sales and demand data. (Note that exhibits referenced hereafter are for AED).

2. Discussion

2.1 Methodology

The method of cost assignment presently utilized is the Average and Excess (A&E) method.

This method considers both the demand and energy requirements of the various customer classes in allocating generation and transmission responsibility. It respects both the maximum demand the class placed on the system as well as the extent to which the class used the facilities installed for service.

A portion of costs, equal to the system peak load factor percentage is considered energy related and allocated on the average demand (energy divided by hours in the period). The remaining costs are allocated based on the excess demand (class non-coincident peak demand minus average demand).

2.2 Rate Base

COST OF SERVICE PROCEDURES

Exhibit 2 contains the net investment in the various plant categories and working capital as provided by the budget for the calendar year ending December 31, 1993. The investment and working capital which is directly assigned is identified and removed from the total Company balances to arrive at the amounts to be allocated.

Exhibit 3 details the allocation of rate base to the various customer classes.

The first allocation factors to be developed are those related to the number of customers, demand, and energy sales. Exhibit 9A shows the projected energy sales for calendar year 1993 and the quantity generated and purchased before line losses. Given these figures by class and the forecasted coincident peak demands by sector, load factors based on the Fiscal 1992 actual results are applied to arrive at each class demand contribution. Exhibit 9B makes use of the class non-coincident demands and the load levels of those customers known to take power at the various usage levels, in order to arrive at the individual class responsibilities for non-coincident demand at the secondary and primary levels with losses included. These two exhibits provide the data necessary to calculate the demand and energy allocation factors in Exhibit 8. The calculation of these factors is simply the class amount divided by the total. The remaining allocation factors are developed throughout as needed.

With the demand, energy and customer factors developed, the allocation phase proceeds. Steam, and hydro production plant are allocated on the average and excess demand contribution and gas turbine plant is allocated based on the excess demand only.

Distribution plant is more complex in its cost causalities than are the other functions. Substations are allocated in accordance with Exhibit 3A. The

COST OF SERVICE PROCEDURES

amounts invested in facilities which are dedicated to a single customer's use were identified and directly allocated to the customer's respective class. The remaining allocable dollars are allocated on the basis of primary demand levels. The totals for each class are carried forward as the class allocations of substation investment as shown on Exhibit 3.

Pole and wire investment also require a more detailed analysis since the total is made up of both demand and customer components. Exhibit 3B details the first step of the analysis. Based on construction and engineering estimates, 30% of the poles were estimated to be primary while the remainder was split 50% primary and 50% secondary. The total was divided accordingly and then split between customer and demand responsibilities based on 50% demand and 50% customer. The total pole investment, broken down into primary demand and customer and secondary demand and customer, is allocated on Exhibit 3C, by the appropriate allocation factors.

The analysis and allocation of wire investment is similar to that of poles and is detailed in Exhibits 3D and 3E.

Underground facilities were allocated on the basis of the totals of pole and wire investment. Line transformers which are used in the secondary system were allocated on secondary class non-coincident demands. Services were spread on a weighted customer basis.

Meter costs are allocated on Exhibit 3F. The average unit cost of installing a meter for each class was determined. These costs when multiplied by the number of customers in each class provide the cost causation relationships required for developing the allocation.

COST OF SERVICE PROCEDURES

Land and Other were allocated on the basis of total substation, pole and wire investments.

The street lighting investment was assigned directly to the unmetered customers.

General and Intangible investment was allocated on the basis of all other plant investment. Finally, the working capital amounts were allocated in accordance with their cost causalities as defined by the allocation factors used.

At this point, all rate base items have been assigned to the various classes recognizing the cost causation and cost utilization relationships defined above.

2.3 Operating Expense

The analysis of operating costs begins in Exhibit 4 with functionalization. The costs are again grouped according to production, transmission, distribution, administrative and general and other. This phase is more complex than that of rate base because the books of the Company are kept on a divisional basis and divisional costs are sometimes caused by various functions. As a comparison, Thermal Division is all production related, while System Planning and Operations costs are functionalized as production, transmission, distribution and administrative and general. The reasons for the multiple functionalizations are fairly clear for all divisions.

Each function's costs are then listed and sub-grouped where necessary in order to classify them as demand, energy, customer, other and direct. This analysis is contained in Exhibit 5.

COST OF SERVICE PROCEDURES

The direct column contains those amounts which are not to be assigned to general customer classes. In production, fuel and purchased power is energy related, operating and maintenance are classified primarily as demand with a small percentage (16) being proportioned to energy during this step. Distribution costs are split between demand and customer. Administrative and general costs pertaining to the customer classification are so classified and the remainder or other portion is then allocated on the basis of all other operating and maintenance expenses, excluding fuel and purchased power, to the demand, energy and customer classifications. Grants in lieu of taxes, depreciation, interest, preferred dividends and taxes net will be allocated on the various rate base and the average and excess demand allocators and, therefore, classified as Other.

Exhibit 6 summarizes the next stage of the study which is allocation of operating costs. First, those costs classified as demand, (production operating and maintenance, and transmission) are allocated on the basis of the average and excess demand allocators.

The administrative and general costs which are demand related, were allocated on the basis of all other demand related operating costs. The analysis of distribution costs is more detailed.

Exhibit 6A contains the analysis of distribution costs in total and also the customer and demand breakdowns. Each of the component classifications are allocated using the same factors. Therefore, I will discuss the total section of the allocation only. The basic premise used throughout is that costs should be allocated in the same manner as their rate base counterparts. Land was allocated on the basis of substation, pole and wire investment. Substation costs are spread according to substation investment. Overhead and

COST OF SERVICE PROCEDURES

underground expenses were assigned in relation to the pole and wire and underground investments. Line transformers are secondary demand related. Services expense was allocated to secondary customers. Metering expenses were spread according to the meter investment per class. Communications is related to primary demand and street lighting was again assigned directly to the unmetered class. Exhibit 6B details the analysis of customer service expenses, for the distribution function, by class.

The second step requires the allocation of energy related costs such as fuel, purchased power, and operating and maintenance. These were allocated on the basis of energy generated and purchased.

Third, the customer related expenses are allocated. Again, the distribution costs are determined from Exhibit 6A. Billing and meter reading as well as customer services were assigned using total weighted customers. Exhibit 6C details the allocation of credit and collections expense. First, the bad debts expense is split between domestic and all other classes based on gross write off experience. The other class portion is assigned to each class based on the average number of customers served. The other portion is distributed on the basis of secondary customer revenue. Again, administrative and general costs which are customer related are allocated on the basis of all other customer related costs.

Finally, depreciation is allocated by function as shown on Exhibit 6D. Grants in lieu of taxes are allocated on the basis of total production, transmission and distribution plant. Interest, preferred dividends and taxes net expense is allocated based on the total rate base assignment from Exhibit 3. The total costs for each class are then determined and adjusted by non-rate revenue and the net income (loss) to arrive at the net cost by each customer class. The resultant total then becomes the input to rate design.

Using the total allocated costs for each class, a comparison is made with the revenues for each class to determine the percentage revenue to cost relationships. The results are shown on Exhibit 10.

3. Procedural Summary

3.1 Introduction

The rates charged by Nova Scotia Power to its customers for their consumption of electrical demand and energy, are developed through a systematic procedure of cost allocation (see Figure A-1 - Cost of Service Overview). This procedure attempts to charge to each existing (or proposed) rate class, the costs incurred by the Company in supplying the electrical requirements of that class.

While it is a primary concern that total system revenues cover the total cost of service, it is just as important that each sector of the public pay its individual fair share of the cost of providing electric service.

Cost allocation provides the best indication of how well this principle is being followed. While not an exact measurement, it is an accepted approximation and any differences are not considered sufficient to improperly influence conclusions drawn from the results.

COST OF SERVICE PROCEDURES

3.2 Procedure

Prior to preparing the actual study, the first task of the allocator is to secure and organize information pertaining to customer loads and consumption patterns, fixed asset detail, capital activity, operating data (both financial and system), as well as, system maps, one line diagrams, customer load studies, transmission, and distribution loss studies, particulars concerning dedicated facilities, etc.

The procedure can be subdivided into three major steps; Functionalization, Classification, and Allocation.

The following is a brief explanation of these steps as they are employed in transferring the Company's expenses and fixed assets, per the financial accounting responsibility system, to rate responsibility.

<u>Step 1 - Functionalize</u> (See Figure A-2)

- This is the procedure whereby expenses and fixed assets are re-grouped from the accounting system into functional cost groups. This activity is the most difficult and time consuming part of the cost allocation procedure, usually absorbing at least 60-70% of the total effort. It involves such activities as sub-dividing the transmission and distribution system components into the appropriate categories based on the different voltages at which service is rendered to the various customers and customer classifications. Also included is the sub-dividing of General Property, working capital provision, joint and common costs and plant, and the apportionment of contributed capital.

COST OF SERVICE PROCEDURES

Step 2 - Classify (See Figure A-3)

- This procedure effectively provides the total demand, energy, customer, and other costs. It separates each functionalized cost into its separate components and includes the selection of the appropriate methodologies based on sound utility criteria. Determination of the demand portion of the production costs can be based on any one of a number of acceptable criteria; coincident peak load factor, non-coincident peak load factor, or monthly average load factors for either peak. Distribution separation of customer and demand costs can be based on judgement, as well as, minimum customer or zero intercept methods. Any option chosen must be supportable and defensible based on the specific circumstances affecting the utility in the costing timeframe, as well as design, operating, and other functions as they may exist from time to time.

Step 3 - Allocate (See Figure A-4)

- In this step , all costs are assigned to the respective rate classes to arrive at the total cost attributable to that rate. For the sake of simplicity, only four classes are shown in the appendix and the non-rate revenues are deducted from the total costs allocated to each class. The result is further adjusted by the profit or loss provisions as appropriate. As well, individual cost components of major cost

  groupings are assigned based on factors developed from derivations of the major cost causation factor (e.g. various demand and energy factors are developed for individual distribution categories and losses at the various supply voltages). Various customer cost allocations are

COST OF SERVICE PROCEDURES

based on relative weights attached to the cost element (i.e. demand vs. straight energy meters). The key knowledge required for this step is a complete understanding of the various causation/utilization relationships that exist for all expenses so that they can be properly allocated to the various classes.

Where appropriate, all costs associated with the financing or operating of facilities (primarily Production and Transmission), dedicated or owned by one particular customer or class, are assigned directly to that customer or customer class.

Distribution demand costs are allocated based on the class non-coincident demand (the peak of the class, as a group, whenever it occurred, independent of system or individual customer peaks), and fuel on the kW.h generated for each class. Customer, Head Office and Other (Capital) costs are allocated based on the various factors which cause them to be incurred. It should be noted that where costs are referred to as Production, Transmission, Distribution, etc., that they are functional costs rather than divisional responsibility accounting costs.

For cost allocation purposes, the Transmission and Distribution functionalization split is taken at the 69 kV level. Everything below 69 kV is Distribution and all 69 kV and above is Transmission. In the case of substations where the incoming voltage is > or = to 69kV, and the outgoing voltage is < 69 kV, (Distribution Bulk Power) they are considered Distribution since their function is to supply a distribution voltage. Step-up stations at the generating plant are considered transmission for the same reason.

All in all, the entire procedure must be examined in a manner which reflects its use as an indicator, not a dictator. The cost allocator must ensure that all viable alternative approaches are examined and that the final position chosen will be acceptable and reasonable and produce the fairest and most equitable results.

3.3 Performance Measurements

After adjusting total cost allocation by the various non-rate revenue items and the net income (loss) to arrive at net costs attributable to rate recovery, the revenue from each class is measured against the assigned total net cost to determine the class performance; this is expressed as a percentage recovery and is commonly referred to as the Revenue/Cost Ratio.

COST OF SERVICE PROCEDURES

4. Terms and Definitions

Fixed Costs: those costs which do not vary materially with the volume of output or number of customers. They are generally related to the size and capacity of the plant installed to provide service. Costs such as interest, depreciation, operating labor and insurance are examples of fixed costs.

Variable Cost: those costs which vary substantially with plant output. They are a direct function of the length of time plant facilities are used to furnish service. Fuel is a prime example of a variable cost.

Customer Costs: those costs which relate to the number and size of customers and do not vary significantly with the volume of sales. They include such items as service and metering costs, customer accounting, and billing and collection costs.

Capacity Costs: those costs which are related to the electrical capacity of the total power system or to its various components. This term is sometimes used interchangeably with fixed costs.

COST OF SERVICE PROCEDURES

Demand Costs:	those costs which are to be allocated to customer classifications on the basis of their respective use of system capacity. This term is sometimes used interchangeably with capacity costs or fixed costs.
Energy & kW.h Costs:	those costs which are to be allocated to customer classifications on the basis of their respective kilowatt hour consumptions (terms are used interchangeably).
Direct Costs:	those costs which are assigned directly to a particular customer or customer classification such as a specific line, substation, services, meters and street lighting facilities.
Indirect Costs:	those costs which are not exclusively identifiable with a specific operation or facility of the system. Administrative and general expense is an example of indirect costs.
Common Costs:	those costs that are incurred in the provision of more than one product or service. One example would be the cost relating to boiler maintenance where the utility is engaged in the sale of both electricity and steam (sometimes used interchangeably with joint costs).

COST OF SERVICE PROCEDURES

Joint Costs: those costs which are incurred to serve more than one classification of service. A typical example is the cost related to the generation of electricity and the high voltage transmission lines which tie together the power sources and load centers (sometimes used interchangeably with common costs).

Cost Behavior: the causation of the particular cost with which we are concerned. The cost of property insurance is associated with gross investment in plant, and depreciation expense is based on gross depreciable plant.

Load Factor: the ratio of the average load in kilowatts during a specific time period to the maximum load occurring in such period.

$$\frac{\text{Average kW}}{\text{Maximum Load kW}} \times 100 = \text{Percent}$$

Diversity Factor: the ratio of the sum of the maximum non-coincident loads in kilowatts to the coincident demand of the combined loads. The diversity factor cannot be less than 1.0 or unity. Example:

$$\frac{\text{Max. Load (100 kW)} + \text{Max. Load (300 kW)}}{\text{Max. Coincident Demand (200 kW)}} = 2.0$$

COST OF SERVICE PROCEDURES

Coincidence Factor: the reciprocal of the diversity factor and always less than 1.0 or unity.

Example:

$$\frac{\text{Max. Coincident Demand (200 kW)}}{\text{Max. Load (100 kW) + Max. load (300 kW)}} = .5$$

Coincident Demand: the sum of two or more individual kilowatt demands which occur in the same demand interval.

Non-coincident Demand: the sum of two or more individual kilowatt demands which do not usually occur in the same demand interval, usually not to exceed one year.

Demand Interval: the period of time during which the flow of electricity is averaged such as one hour, thirty minutes, fifteen minutes, etc.

Peak Demand: the maximum demand imposed on a power system or component thereof within a particular demand interval.

Class Demand: the maximum coincident kilowatt demand of a class of customers within a particular demand interval.

ATTACHMENT 3

The following approaches are used in classifying individual distribution plant costs.

A. Land - The purpose of distribution land is to provide space to accommodate distribution assets. These common or indirect costs can best be related to the direct costs of distribution assets such as substation, pole and wire. Therefore, the method used to classify land is based on the average split of all three assets between demand and customer-related costs.

B. Easements-Line Right of Way -The purpose of having easements and Right of ways is so that the assets such as substations, pole and wire have a place to locate. These common or indirect costs can best be related to these assets. Therefore, the method used to classify Easements & Surveys is based on the average split of all three assets between demand and customer related costs.

C. Buildings Structures & Grounds-The purpose of these common costs can best be related to the direct costs associated with Substation, Poles & Overhead Wire investment. Therefore, these common costs are classified on that basis.

D. Substations-Distribution substations are classified demand and direct. Where a substation can be identified as serving only one customer the station costs are analyzed and directly assigned to the class of service which the station served. Substations are analyzed by the following functions:

- Distribution Bulk Power
- Distribution Dedicated Bulk Power
- Distribution General
- Distribution Dedicated General

E. Poles & Fixtures-In 1977, the average historical cost for various size poles was determined from the books and records of the company. Using the minimum size concepts, 30 and 35 foot poles were determined to be the minimum size required to physically connect all customers to the system.

The average weighted cost of 30 and 35 foot poles weighing 30 foot poles at 2 and 35 foot at 1 was $104.10. Total number of poles multiplied by this cost equated to 63% of the total investment in poles. This 63% of the pole investment was classified as customer cost and the remaining 37% as demand cost.

This separation then recognizes the minimum size required to provide service to all customers on the distribution system and the demand component is that cost which is over the base or that is required to serve the demands for electricity placed on the system.

Based upon engineering and construction estimates, 30% of the poles were then functionalized as primary only and the remaining 70% was functionalized 50% primary-50% secondary. These costs were then classified 63% customer-37% demand.

In 1982 we changed the relationship for that portion serving both the customer and demand classifications to a 50/50 split. The 50/50 relationship selected represented our best judgmental split based on data presented in previous hearings, general knowledge and assumptions, discussions with corporate engineering and distribution personnel and input from corporate consultants.

At the present time we see no reason why this relationship should be changed.

F. Overhead Lines-In 1977 an analysis was made for distribution wire investments using the same minimum size concepts used in the pole analysis. Number 1/0 copper and number 2/8 aluminum were deemed to be the minimum wire sizes required to provide the ability for the customers to take service from the distribution system. Based upon a sample review of the installed cost of this wire, 59% was deemed to be required for minimum size purposes. This was predicated on a weighted cost per foot weighing #6 wire twice and all other wire once. This equated to a cost of $131.38 per thousand feet. This cost, when multiplied by the total feet of wire provides for 59% of the total wire cost to be customer related. The remaining 41% is then demand related. This is done on the basis that cost above the base is there to meet the load or demand that the customer places on the system. As with poles, 30% of the wire was functionalized as primary and the remaining 70% was functionalized 50% primary and 50% secondary. These functions were then classified 59% customer related cost and 41% demand related cost..

In 1982 we changed the relationship for that portion serving both the customer and demand classification to a 50/50 split. The same criteria was used as outlined in the pole investment.

At the present time, we see no reason why this relationship should be changed.

G. Underground Lines-Underground facilities perform a similar function to Overhead lines. Therefore, the cost split is based on the same split used for Overhead line costs explained above.

H. Transformers-The purpose of line transformers is to control the demand on the secondary system. Line transformers are classified as demand-related costs.

I. Services-Services relate to the costs of providing service to a customer's premises and are therefore a customer-related cost.

J. Meters-Meter investment is assigned to each customer class based on a pre-determined meter cost for each class. The investments classified as customer-related.

K. Street Lighting-Street Lighting investment is classified as demand-related and assigned directly to the unmetered class.

As indicated above, the pole and wire accounts have been classified to both customer and demand-related costs based on a fixed percentage classification concept. This method is the simplest way of classifying these costs and is practised by several Canadian Utilities.

While the classification of the above account groupings are important, there are only a few commonly accepted methods for classifying distribution plant.

These methods include the Minimum Size and Minimum Intercept (zero–intercept) Methods.

The minimum system identifies the costs associated with providing the minimal service and, as such, does not vary with demand. These fixed costs are classified as customer-related.

The minimum size method uses costs associated with the minimal service based on current-day prices.

The minimum intercept method uses costs associated with various sizes of equipment using average installed book costs. The technique is to relate installed costs to current capacity or demand rating, create a curve for various sizes of the equipment using regression techniques and extend the curve to a no-load intercept. The cost related to the zero intercept load is the desired customer component. This method seeks to identify the portion of plant related to a hypothetical no-load or zero intercept situation.

This method requires considerably more data and calculation than does the minimum size method and although more accurate the difference between the two can be relatively small.

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Request IR-84:

Regarding Exhibit 3B of SR-01, please identify the specific dedicated substations that serve each of the following rate schedules, and specify the capacity of each such substation:

a) large industrial customers.
b) municipal customers.
c) general customers.
d) medium industrial customers.

Response IR-84:

(a-d) The applied Cost of Service Study (COSS) methodology in this Application, regarding the treatment of substation rate base for cost allocation purposes, is consistent with that used in all general rate application submissions following the Generic Cost of Service Hearing in 1995.[1] The methodology does not call for an update of foundational cost allocation coefficients which would require class- or customer-specific usage information by substation. The work to produce this information would require data research and analysis which cannot be completed in the time allotted for responding to information requests. The matter of allocation of substation costs, as raised in CA IR-84 to CA IR-94, has been examined by Consumer Advocate's consultant, Mr. Paul Chernick, in his information requests in the 2012 GRA. Please refer to Attachment 1 for NS Power's 2012 GRA responses to CA IR-39, IR-40, IR-170 and IR-172. The Board took note of the issues raised by Mr. Chernick in its 2012 GRA Decision[2] and ruled that they warranted a review in a separate COSS hearing to be held in 2013.[3]

[1] Generic Hearing respecting Cost of Service and Rate Design UARB Decision, NSPI864, September 22, 1995.
[2] NSPI 2012 General Rate Application, UARB Decision, NSUARB-NSPI-P-892, November 29, 2011, page 21, paragraph 46 and page 22, paragraph 48.
[3] NSPI 2012 General Rate Application, UARB Decision, NSUARB-NSPI-P-892, page 92, paragraph 270.

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Request IR-39:

Please explain whether any Large Industrial, ELI 2P-RTP, or Municipal customers are served from substations that also serve other classes, and if so, explain how that consideration is reflected in Exhibit 3B.

Response IR-39:

Please refer to CA IR-45.

Yes, there are large industrial and municipal customers who are served from substations that also serve other classes. This is currently not reflected in Exhibit 3B, as NSPI has not attempted to change the basis of this schedule in this proceeding. NSPI has not proposed revisions to the Cost of Service Study, other than in respect of the LED streetlight initiative.

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Request IR-40:

For each non-dedicated distribution substation,

(a) Please indicate whether the substation serves exclusively one class, and if so, which class.

(b) If the substation serves more than one class, please provide NSPI's estimate of the mix of class load on that substation.

Response IR-40:

(a-b) NSPI does not normally record the data as requested. We are unable to compile such information within the time prescribed to respond to this request. Please refer to CA IR-45.

NON-CONFIDENTIAL

Request IR-170:

Exhibit 3B to the COSS shows costs of dedicated substations that are direct-assigned to specific classes. CA IR-36 Attachment 1 states that "Dedicated customer transformers are not included" in that attachment. Both these sources thus indicate that NSPI can identify the dedicated substations. Yet CA IR-37 claims that NSPI does not know which substations are dedicated, or what classes they are dedicated to. Please reconcile these statements.

Response IR-170:

CA IR-36 references dedicated customer transformers, whereas CA IR-37 is referencing dedicated substations. These are two different components of NSPI's infrastructure. The exclusion of dedicated transformers from the substation list, included in the response to CA IR-36, does not imply that the list comes short of dedicated substations.

NSPI did not retrieve and repeat the basis of each of the elements of the Cost of Service Study for this proceeding, many of which were approved by the Board in its 1995 Decision and have since been used repeatedly in general rate applications and FAM processes. The work to produce a list of dedicated customer substations and transformers and to identify customers who use dedicated substations would require further data research and analysis which cannot be completed in the time allotted for responding to Information Requests. This effort may be of interest in a review of the Cost of Service Study in a separate proceeding, which has been routinely opposed by the Consumer Advocate.

NON-CONFIDENTIAL

Request IR-172:

The response to CA IR-38 says that "For the COSS purposes the rate base associated with the distribution substations has been split among the four categories …using the same proration approach since the last COSS hearing was held in 1995." Does this mean that the approach has been applied to the actual costs of the changing mix of dedicated and bulk distribution substations over time, that the same percentages have been used since 1995, or something else (and if so, what)?

Response IR-172:

The estimated percentages have changed as a result of applying the following approach:

The total distribution substation plant is segregated into the following six categories:

- A - Distribution Bulk Power
- B - Distribution Dedicated Bulk Power
- C - Distribution Customer Own Bulk Power
- D - Distribution General
- E - Distribution Dedicated General
- F - Distribution Customer Own General

NSPI has kept the gross plant values for categories B, C, E and F at constant dollar levels since 1996 and calculated their annual net plant values based on periodically updated depreciation

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rates. The annual net plant values of the two main categories A and D are modified to balance with the total net plant book value of all distribution substations. The modifications of A and D are put into effect by applying on an annual basis periodically updated depreciation rates to the estimates of gross plant values of A and D whose relative shares in the total gross plant value of all distribution substations, as simulated in these calculations, remain at approximately the same levels of 77 percent and 16 percent, respectively.

NON-CONFIDENTIAL

Request IR-85:

With regard to the $22,000 of bulk power substations dedicated to municipal customers, please identify the specific substation(s) and provide the investment and depreciation history that resulted in the substation(s) having a rate base of only $22,000.

Response IR-85:

Please refer to CA IR-84.

NON-CONFIDENTIAL

Request IR-86:

With regard to the $4,000 of general substations dedicated to medium industrial customers, please identify the specific substation(s) and provide the investment and depreciation history that resulted in the substation(s) having a rate base of only $4,000.

Response IR-86:

Please refer to CA IR-84.

NON-CONFIDENTIAL

Request IR-87:

Please explain whether the allocations in columns 2 and 4 of Exhibit 3B give the general and medium industrial customers any credit for the load served by the dedicated substations in columns 3 and 5.

Response IR-87:

Please refer to CA IR-84.

NON-CONFIDENTIAL

Request IR-88:

Please provide the number of large industrial customers that are served from non-dedicated substations, and the portion of class non-coincident peak represented by those customers.

Response IR-88:

Please refer to CA IR-84.

NON-CONFIDENTIAL

Request IR-89:

Please provide the number of municipal customers that are served from non-dedicated substations, and the portion of class non-coincident peak represented by those customers.

a) Please identify the non-dedicated substations that serve one municipal customers.

Response IR-89:

Please refer to CA IR-84.

NON-CONFIDENTIAL

Request IR-90:

Please provide a version of Exhibit 3B allocating appropriate shares of the non-dedicated substations to the large industrial and municipal classes.

Response IR-90:

Please refer to CA IR-84.

NON-CONFIDENTIAL

Request IR-91:

If NSPI cannot determine what portion of the large-industrial and municipal loads use non-dedicated substations, please explain why.

Response IR-91:

Please refer to CA IR-84.

NON-CONFIDENTIAL

Request IR-92:

Please state whether there are any non-dedicated substations that provide back-up service to any large industrial or municipal customers.

Response IR-92:

Please refer to CA IR-84.

CONFIDENTIAL (Attachment Only)

Request IR-93:

Please provide a list of NSPI's substations, and indicate for each substation:

a) Gross book value.
b) Accumulated depreciation.
c) Net book value.
d) The installation date of the substation.
e) The feeders for which the substation is the primary supply.
f) The feeders for which the substation is the secondary or backup supply.
g) The number of transformers in the substation.
h) The substation primary and secondary voltages.
i) The substation capacity (separated by voltage, if there is more than one secondary voltage).
j) The peak load on the substation, and the time and date of the peak.
k) Any available information on the mix of customer or rate-schedule loads served by the substation.
l) Which of the four categories in Exhibit 3B includes the substation.
m) If it is a dedicated substation, which class it serves.

Response IR-93:

(a-c) NS Power does not track the values of individual substations in the Asset Management Accounting System, nor are they depreciated separately as NS Power pools depreciation groups.

(d) Please refer to Confidential Attachment 1.

(e) Please refer to Attachment 2.

CONFIDENTIAL (Attachment Only)

(f) In urban locations, some substations have the capacity, through switching, to provide alternate or back-up supply when required. However, no substations are fully designated as secondary or backup supply.

(g-j) Please refer to Confidential Attachment 1.

(k) Please refer to Attachment 3.

(l-m) Please refer to CA IR-84.

Source Feeder	Comments
100C-421	
100C-422	
100C-423	
101H-411	
101H-412	
101H-413	
101H-421	
101H-422	
101H-423	
102W-311	
102W-312	
103C-311	
103C-313	
103C-314	
103H-431	
103H-432	
103H-433	
103H-434	
103W-311	
103W-312	
104H-411	
104H-412	
104H-413	
104H-421	
104H-422	
104H-423	
104H-431	
104H-432	
104H-433	
104H-441	
104H-442	
104S-311	
104S-312	
104S-313	
108H-411	
108H-412	
108H-413	
113H-431	
113H-432	
113H-433	
113H-434	
113H-441	
113H-442	
113H-443	
113H-444	
11S-301	

Source Feeder	Comments
11S-302	
11S-303	
11S-304	
11S-305	
11S-306	
11S-411	
11S-412	
11W-201	
11W-202	
11W-203	
124H-301	
124H-302	
126H-311	
126H-312	
126H-313	
127H-411	
127H-412	
127H-413	
129H-411	
129H-412	
129H-413	
12V-302	
12V-303	
12V-304	
131H-421	
131H-422	
131H-423	
131H-424	
137H-412	
137H-413	
137H-414	
139H-411	
139H-413	
139H-414	
13V-303	Hydro Station
14V-303	Hydro Station
15N-202	
15N-203	
15N-401	
15N-402	
15N-403	
15N-404	
15S-301	
15S-302	
15S-303	
16N-301	

Source Feeder	Comments
16N-302	
16V-314	
16V-315	
16W-301	
16W-302	
17N-201	
17N-202	
17N-203	
18V-411	
18V-412	
18V-413	
19C-203	
19W-311	
19W-312	
1C-411	
1C-412	
1H-403	
1H-405	
1H-415	
1H-419	
1H-424	
1H-427	
1H-429	
1H-431	
1N-402	
1N-403	
1N-404	
1N-405	
1N-421	
1V-443	
1W-411	Hydro Station
20H-301	
20H-302	
20H-303	
20H-304	
20H-305	
20H-306	
20N-201	
20N-203	
20N-204	
20V-311	
20W-311	
20W-312	
21W-311	
21W-312	
22C-402	

Source Feeder	Comments
22C-403	
22C-404	
22N-401	
22N-402	
22N-403	
22N-404	
22V-312	
22V-313	
22V-314	
22V-321	
22V-322	
22V-323	
22W-311	
22W-312	
22W-313	
23H-301	
23H-302	
23H-303	
23H-304	
23W-301	
23W-302	
24C-442	
24C-443	
25W-301	
25W-302	
25W-303	
2C-401	
2C-402	
2H-411	
2H-412	
2H-413	
30N-411	
30N-412	
36V-301	
36V-302	
36V-303	
36W-301	
36W-304	
37N-411	
37N-412	
37N-413	
37N-414	
37W-201	
37W-202	
37W-203	
3N-411	

Source Feeder	Comments
3S-301	
3S-302	
3S-303	
3S-307	
3S-308	
3S-309	
3S-403	
3S-405	
3W-201	Hydro Station
40H-302	
40H-303	
40H-304	
40H-305	
46W-301	
46W-303	
48H-301	
48H-302	
48H-303	
48H-304	
48W-201	
48W-203	
48W-204	
4C-424	
4C-430	
4C-432	
4C-441	
4C-442	
4N-311	
4N-312	
4N-313	
4S-321	
4S-322	
4S-323	
4S-324	
4S-331	
4S-332	
4S-333	
4S-334	
4W-211	Hydro Station
50N-311	
50N-410	
50N-411	
50N-412	
50N-415	
50V-401	
50V-402	

Source Feeder	Comments
50W-411	
50W-412	
51V-301	
54H-301	
54H-302	
54H-303	
54H-304	
55N-201	
55N-202	
55N-203	
55N-204	
55V-313	
55V-314	
55V-322	
55V-323	
56N-401	
56N-402	
56N-414	
57C-417	
57C-422	
57C-426	
57S-401	
57S-402	
57W-401	
57W-402	
58C-403	
58C-405	
58H-421	
58H-431	
59C-401	
59C-402	
59C-403	
62H-301	
62H-302	
62H-303	
62H-304	
62N-411	
62N-412	
62N-413	
62N-414	
62N-415	
62N-416	
63V-311	
63V-312	
63V-313	
64V-301	

Source Feeder	Comments
64V-302	
64V-303	
65V-301	
65V-302	
65V-303	
67C-411	
67C-412	
6N-301	
6N-302	
6S-221	
6S-223	
6S-224	
6S-225	
6W-201	Hydro Station
70V-311	
70V-312	
70W-203	
70W-204	
70W-311	
70W-312	
70W-313	
70W-314	
70W-321	
70W-322	
73W-411	
73W-412	
74N-411	
74N-412	
74V-301	
74V-302	
75N-251	
76V-301	
76W-201	
77V-301	
77V-302	
77V-303	
77V-401	
78W-301	
78W-302	
79V-401	
79V-402	
79V-403	
7N-211	
7N-301	
7N-302	
80W-301	

Source Feeder	Comments
80W-302	
80W-303	
81N-411	
81N-412	
81S-301	
81S-302	
81S-303	
81S-304	
81S-305	
81S-306	
81S-307	
82S-302	
82S-303	
82S-304	
82V-401	
82V-402	
82V-403	
82V-422	
82V-423	
83V-301	
83V-302	
83V-303	
84S-302	
84S-303	
84S-304	
84S-305	
84W-301	
84W-302	
85S-401	
85S-402	
87H-311	
87H-312	
87H-313	
87W-311	
87W-312	
88H-401	
88H-402	
88W-311	
88W-312	
88W-321	
88W-322	
88W-323	
89H-401	
89W-301	
89W-302	
89W-303	

Source Feeder	Comments
89W-304	
91W-411	
92H-331	
92H-332	
92H-333/L-3202	
92H-334	
92W-302	
93V-311	
93V-312	
93V-313	
95H-251	Hydro Station
96H-411	
96H-412	
99H-311	
99H-312	
9C-301	
9C-302	
9C-303	
9C-304	
L-4048	Supplied from 20V-Five Points
L-4049	Supplied from 3V Hell's Gate Hydro

FEEDER	TOTALCOUNT	RESIDENTIALCOUNT	RESIDENTIALPERCENT	COMMERCIALCOUNT	COMMERCIALPERCENT	INDUSTRIALCOUNT	INDUSTRIALPERCENT
100C-421	709	652	91.96	56	7.9	1	0.14
100C-422	471	416	88.32	46	9.77	9	1.91
100C-423	13		0	8	61.54	5	38.46
101H-411	2188	2146	98.08	41	1.87	1	0.05
101H-412	1739	1536	88.33	202	11.62	1	0.06
101H-413	3265	3055	93.57	208	6.37	2	0.06
101H-421	2742	2546	92.85	180	6.56	16	0.58
101H-422	838	616	73.51	217	25.89	5	0.6
101H-423	3152	2875	91.21	272	8.63	5	0.16
102H-211	1		0	1	100		0
102W-311	1116	1030	92.29	69	6.18	17	1.52
102W-312	1507	1422	94.36	81	5.37	4	0.27
103C-311	633	511	80.73	116	18.33	6	0.95
103C-313	311	286	91.96	23	7.4	2	0.64
103C-314	812	750	92.36	61	7.51	1	0.12
103H-431	876	698	79.68	167	19.06	11	1.26
103H-432	2768	2680	96.82	81	2.93	7	0.25
103H-433	1508	1247	82.69	255	16.91	6	0.4
103H-434	3030	2897	95.61	122	4.03	11	0.36
103W-311	1499	1419	94.66	75	5	5	0.33
103W-312	1426	1365	95.72	58	4.07	3	0.21
104H-411	1451	1368	94.28	83	5.72		0
104H-412	2180	1982	90.92	195	8.94	3	0.14
104H-413	2267	2094	92.37	171	7.54	2	0.09
104H-421	2873	2638	91.82	228	7.94	7	0.24
104H-422	1110	1057	95.23	52	4.68	1	0.09
104H-423	4534	4309	95.04	225	4.96		0
104H-431	2272	1846	81.25	420	18.49	6	0.26
104H-432	1395	1222	87.6	167	11.97	6	0.43
104H-433	763	562	73.66	196	25.69	5	0.66
104H-441	1975	1634	82.73	341	17.27		0
104H-442	1805	1657	91.8	144	7.98	4	0.22
104S-311	1171	973	83.09	193	16.48	5	0.43
104S-312	225	207	92	18	8		0
104S-313	511	455	89.04	55	10.76	1	0.2
108H-411	304	1	0.33	279	91.78	24	7.89
108H-412	436	2	0.46	413	94.72	21	4.82
108H-413	2640	2418	91.59	215	8.14	7	0.27
108W-101	1		0	1	100		0
10C-211	153	143	93.46	8	5.23	2	1.31
10C-212	298	259	86.91	36	12.08	3	1.01
10H-231	721	685	95.01	35	4.85	1	0.14
10H-232	894	847	94.74	47	5.26		0
10H-236	558	500	89.61	58	10.39		0
10H-237	57	54	94.74	3	5.26		0
10H-999	2		0	2	100		0
112C	1		0	1	100		0
113H-431	2070	1894	91.5	172	8.31	4	0.19
113H-432	2237	2189	97.85	45	2.01	3	0.13
113H-433	2527	2444	96.72	71	2.81	12	0.47

FEEDER	TOTALCOUNT	RESIDENTIALCOUNT	RESIDENTIALPERCENT	COMMERCIALCOUNT	COMMERCIALPERCENT	INDUSTRIALCOUNT	INDUSTRIALPERCENT
113H-434	3632	3506	96.53	123	3.39	3	0.08
113H-441	2849	2800	98.28	44	1.54	5	0.18
113H-442	2016	1937	96.08	78	3.87	1	0.05
113H-443	3417	3343	97.83	71	2.08	3	0.09
113H-444	639	627	98.12	10	1.56	2	0.31
114H-211	1		0		0	1	100
11C-301	231	211	91.34	20	8.66		0
11C-302	110	99	90	11	10		0
11N-200	1		0		0	1	100
11S-301	1538	1420	92.33	115	7.48	3	0.2
11S-302	1215	1165	95.88	47	3.87	3	0.25
11S-303	824	722	87.62	98	11.89	4	0.49
11S-304	1010	986	97.62	23	2.28	1	0.1
11S-305	1925	1815	94.29	107	5.56	3	0.16
11S-306	180	110	61.11	50	27.78	20	11.11
11S-411	2347	2205	93.95	125	5.33	17	0.72
11S-412	1348	1276	94.66	71	5.27	1	0.07
11W-201	203	45	22.17	157	77.34	1	0.49
11W-202	292	247	84.59	43	14.73	2	0.68
11W-203	506	465	91.9	41	8.1		0
124H-301	185	12	6.49	163	88.11	10	5.41
124H-302	202	5	2.48	179	88.61	18	8.91
126H-311	1227	1203	98.04	24	1.96		0
126H-312	1791	1695	94.64	93	5.19	3	0.17
126H-313	1644	1605	97.63	37	2.25	2	0.12
127H-411	2351	2229	94.81	115	4.89	7	0.3
127H-412	1		0		0	1	100
127H-413	102	3	2.94	89	87.25	10	9.8
129H-411	4135	4006	96.88	129	3.12		0
129H-412	4821	4593	95.27	226	4.69	2	0.04
129H-413	4025	3909	97.12	109	2.71	7	0.17
12V-302	1664	1497	89.96	146	8.77	21	1.26
12V-303	659	635	96.36	21	3.19	3	0.46
12V-304	975	869	89.13	97	9.95	9	0.92
131H-421	2162	2124	98.24	38	1.76		0
131H-422	3258	3119	95.73	118	3.62	21	0.64
131H-423	3358	3262	97.14	90	2.68	6	0.18
131H-424	3123	3004	96.19	114	3.65	5	0.16
136H	1		0	1	100		0
137H-412	97	96	98.97	1	1.03		0
137H-413	2677	2586	96.6	85	3.18	6	0.22
137H-414	1726	1512	87.6	194	11.24	20	1.16
139H-411	392	2	0.51	366	93.37	24	6.12
139H-413	178		0	176	98.88	2	1.12
139H-414	3422	3302	96.49	109	3.19	11	0.32
13N-211	108	63	58.33	45	41.67		0
13V-303	1508	1425	94.5	79	5.24	4	0.27
14C-211	435	417	95.86	12	2.76	6	1.38
14V	1		0	1	100		0
14V-303	12	11	91.67	1	8.33		0

FEEDER	TOTALCOUNT	RESIDENTIALCOUNT	RESIDENTIALPERCENT	COMMERCIALCOUNT	COMMERCIALPERCENT	INDUSTRIALCOUNT	INDUSTRIALPERCENT
15C-211	24	24	100		0		0
15N-202	717	629	87.73	88	12.27		0
15N-203	255	61	23.92	194	76.08		0
15N-401	4216	3962	93.98	237	5.62	17	0.4
15N-402	14		0	12	85.71	2	14.29
15N-403	1714	1493	87.11	197	11.49	24	1.4
15N-404	2651	2358	88.95	280	10.56	13	0.49
15S-301	1887	1791	94.91	93	4.93	3	0.16
15S-302	1385	1322	95.45	63	4.55		0
15S-303	1187	1144	96.38	41	3.45	2	0.17
16N-301	1780	1607	90.28	157	8.82	16	0.9
16N-302	678	655	96.61	18	2.65	5	0.74
16V-314	1368	1212	88.6	138	10.09	18	1.32
16V-315	858	810	94.41	44	5.13	4	0.47
16W-301	1848	1730	93.61	108	5.84	10	0.54
16W-302	1320	1276	96.67	39	2.95	5	0.38
17N-201	298	260	87.25	38	12.75		0
17N-202	317	287	90.54	30	9.46		0
17N-203	272	207	76.1	62	22.79	3	1.1
18V-411	371	365	98.38	5	1.35	1	0.27
18V-412	454	434	95.59	17	3.74	3	0.66
18V-413	1209	1159	95.86	46	3.8	4	0.33
19C-203	2	1	50		0	1	50
19H-201	2		0	1	50	1	50
19W-311	407	386	94.84	19	4.67	2	0.49
19W-312	1088	913	83.92	143	13.14	32	2.94
1C-411	762	539	70.73	212	27.82	11	1.44
1C-412	2		0	1	50	1	50
1H-403	771	511	66.28	259	33.59	1	0.13
1H-405	24	1	4.17	22	91.67	1	4.17
1H-415	79	59	74.68	19	24.05	1	1.27
1H-419	82	1	1.22	80	97.56	1	1.22
1H-424	450	411	91.33	39	8.67		0
1H-427	2338	2183	93.37	153	6.54	2	0.09
1H-429	1		0	1	100		0
1H-431	472	355	75.21	117	24.79		0
1N-402	2417	2149	88.91	248	10.26	20	0.83
1N-403	1413	1251	88.54	153	10.83	9	0.64
1N-404	242	235	97.11	6	2.48	1	0.41
1N-405	1650	1560	94.55	83	5.03	7	0.42
1N-421	2121	1927	90.85	193	9.1	1	0.05
1V-443	1590	1509	94.91	79	4.97	2	0.13
1W-411	7	6	85.71	1	14.29		0
20H-301	2122	2022	95.29	91	4.29	9	0.42
20H-302	1045	1023	97.89	21	2.01	1	0.1
20H-303	1271	1231	96.85	37	2.91	3	0.24
20H-304	2595	2445	94.22	143	5.51	7	0.27
20H-305	1651	1581	95.76	65	3.94	5	0.3
20H-306	2424	2247	92.7	175	7.22	2	0.08
20N-201	636	609	95.75	26	4.09	1	0.16

FEEDER	TOTALCOUNT	RESIDENTIALCOUNT	RESIDENTIALPERCENT	COMMERCIALCOUNT	COMMERCIALPERCENT	INDUSTRIALCOUNT	INDUSTRIALPERCENT
20N-203	39	36	92.31	3	7.69		0
20N-204	604	579	95.86	22	3.64	3	0.5
20V-311	1308	1234	94.34	70	5.35	4	0.31
20W-311	546	473	86.63	57	10.44	16	2.93
20W-312	154	135	87.66	12	7.79	7	4.55
21W-311	405	354	87.41	36	8.89	15	3.7
21W-312	280	224	80	29	10.36	27	9.64
22C-402	225	215	95.56	7	3.11	3	1.33
22C-403	602	564	93.69	29	4.82	9	1.5
22C-404	1352	1272	94.08	72	5.33	8	0.59
22N-401	2432	2180	89.64	240	9.87	12	0.49
22N-402	842	803	95.37	34	4.04	5	0.59
22N-403	889	839	94.38	44	4.95	6	0.67
22N-404	414	249	60.14	150	36.23	15	3.62
22V-312	1043	937	89.84	104	9.97	2	0.19
22V-313	543	407	74.95	119	21.92	17	3.13
22V-314	268	177	66.04	88	32.84	3	1.12
22V-321	1128	1038	92.02	82	7.27	8	0.71
22V-322	1800	1662	92.33	109	6.06	29	1.61
22V-323	2121	1998	94.2	121	5.7	2	0.09
22W-311	1136	1022	89.96	89	7.83	25	2.2
22W-312	1102	920	83.48	123	11.16	59	5.35
22W-313	1010	850	84.16	143	14.16	17	1.68
23H-301	1215	1147	94.4	68	5.6		0
23H-302	2034	1853	91.1	179	8.8	2	0.1
23H-303	3857	3729	96.68	128	3.32		0
23H-304	2449	2403	98.12	46	1.88		0
23W-301	214	206	96.26	8	3.74		0
23W-302	928	850	91.59	54	5.82	24	2.59
24C-442	726	685	94.35	39	5.37	2	0.28
24C-443	1092	967	88.55	121	11.08	4	0.37
24H	1		0	1	100		0
25C-211	18	13	72.22	5	27.78		0
25N-201	18	15	83.33	3	16.67		0
25W-301	890	834	93.71	52	5.84	4	0.45
25W-302	851	747	87.78	83	9.75	21	2.47
25W-303	1002	842	84.03	152	15.17	8	0.8
26C-202	95	93	97.89	2	2.11		0
26N-211	228	214	93.86	9	3.95	5	2.19
28N-201	15	15	100		0		0
2C-401	366	312	85.25	51	13.93	3	0.82
2C-402	1312	1221	93.06	85	6.48	6	0.46
2H-411	3179	3093	97.29	78	2.45	8	0.25
2H-412	1205	1000	82.99	205	17.01		0
2H-413	5584	5142	92.08	435	7.79	7	0.13
30N-411	539	505	93.69	34	6.31		0
30N-412	333	320	96.1	12	3.6	1	0.3
31C-311	95	95	100		0		0
32N-301	79	74	93.67	5	6.33		0
33N-201	12	12	100		0		0

FEEDER	TOTALCOUNT	RESIDENTIALCOUNT	RESIDENTIALPERCENT	COMMERCIALCOUNT	COMMERCIALPERCENT	INDUSTRIALCOUNT	INDUSTRIALPERCENT
34C-311	41	41	100		0		0
35C-211	11	11	100		0		0
35V-312	1134	1072	94.53	52	4.59	10	0.88
36C-211	73	68	93.15	5	6.85		0
36N-201	12	12	100		0		0
36V-301	345	303	87.83	18	5.22	24	6.96
36V-302	1581	1441	91.14	110	6.96	30	1.9
36V-303	1828	1724	94.31	75	4.1	29	1.59
36W-301	743	700	94.21	42	5.65	1	0.13
36W-304	437	415	94.97	21	4.81	1	0.23
37N-411	666	614	92.19	49	7.36	3	0.45
37N-412	285	275	96.49	10	3.51		0
37N-413	340	313	92.06	25	7.35	2	0.59
37N-414	466	435	93.35	28	6.01	3	0.64
37W-201	234	205	87.61	24	10.26	5	2.14
37W-202	215	163	75.81	43	20	9	4.19
37W-203	15	11	73.33	3	20	1	6.67
39H-211	4	1	25	2	50	1	25
3N-301	573	533	93.02	36	6.28	4	0.7
3N-303	1005	926	92.14	70	6.97	9	0.9
3N-411	20	12	60	6	30	2	10
3S-301	744	719	96.64	25	3.36		0
3S-302	1398	1360	97.28	37	2.65	1	0.07
3S-303	1656	1573	94.99	81	4.89	2	0.12
3S-307	1992	1854	93.07	135	6.78	3	0.15
3S-308	688	525	76.31	161	23.4	2	0.29
3S-309	1423	1362	95.71	58	4.08	3	0.21
3S-403	1401	1316	93.93	80	5.71	5	0.36
3S-405	22		0	17	77.27	5	22.73
3W-201	8	5	62.5	2	25	1	12.5
40H-302	2335	2185	93.58	147	6.3	3	0.13
40H-303	416	376	90.38	40	9.62		0
40H-304	1031	930	90.2	101	9.8		0
40H-305	965	961	99.59	3	0.31	1	0.1
45V-201	1		0		0	1	100
45V-202	482	453	93.98	29	6.02		0
46W-301	596	560	93.96	32	5.37	4	0.67
46W-303	524	474	90.46	50	9.54		0
47C-Dist	1		0		0	1	100
48H-301	2356	2252	95.59	104	4.41		0
48H-302	1439	1364	94.79	73	5.07	2	0.14
48H-303	383	307	80.16	66	17.23	10	2.61
48H-304	874	806	92.22	62	7.09	6	0.69
48W-201	324	291	89.81	32	9.88	1	0.31
48W-203	37	20	54.05	16	43.24	1	2.7
48W-204	645	602	93.33	41	6.36	2	0.31
49C-301	242	236	97.52	5	2.07	1	0.41
49N-332	1		0		0	1	100
4C-424	369	350	94.85	15	4.07	4	1.08
4C-430	1287	1206	93.71	75	5.83	6	0.47

FEEDER	TOTALCOUNT	RESIDENTIALCOUNT	RESIDENTIALPERCENT	COMMERCIALCOUNT	COMMERCIALPERCENT	INDUSTRIALCOUNT	INDUSTRIALPERCENT
4C-432	685	632	92.26	48	7.01	5	0.73
4C-441	2013	1865	92.65	133	6.61	15	0.75
4N-311	1079	1010	93.61	57	5.28	12	1.11
4N-312	2041	1942	95.15	91	4.46	8	0.39
4N-313	1107	1027	92.77	73	6.59	7	0.63
4S-321	1759	1655	94.09	103	5.86	1	0.06
4S-322	442	326	73.76	116	26.24		0
4S-323	754	460	61.01	289	38.33	5	0.66
4S-324	1114	1001	89.86	110	9.87	3	0.27
4S-331	832	656	78.85	176	21.15		0
4S-332	824	679	82.4	140	16.99	5	0.61
4S-333	804	717	89.18	85	10.57	2	0.25
4S-334	88	72	81.82	16	18.18		0
4W-211	4	4	100		0		0
500N-301	308	302	98.05	6	1.95		0
501H-301	184	175	95.11	9	4.89		0
501N-301	94	90	95.74	4	4.26		0
502H-301	70	69	98.57	1	1.43		0
503N-311	162	157	96.91	5	3.09		0
503N-321	92	91	98.91	1	1.09		0
503S-211	20	20	100		0		0
504H-301	62	61	98.39	1	1.61		0
504N-301	67	67	100		0		0
504S-211	7	7	100		0		0
505S-211	23	22	95.65	1	4.35		0
505V-201	92	69	75	21	22.83	2	2.17
506N-301	29	28	96.55	1	3.45		0
507H-311	120	119	99.17		0	1	0.83
507H-312	140	129	92.14	11	7.86		0
507N-301	44	44	100		0		0
507S-211	119	116	97.48	3	2.52		0
508S-201	83	79	95.18	4	4.82		0
509N-301	122	120	98.36	2	1.64		0
509V-301	637	539	84.62	91	14.29	7	1.1
50N-311	10		0	8	80	2	20
50N-410	1249	1175	94.08	67	5.36	7	0.56
50N-411	1261	1201	95.24	58	4.6	2	0.16
50N-412	747	696	93.17	40	5.35	11	1.47
50N-415	272	264	97.06	7	2.57	1	0.37
50V-401	838	746	89.02	87	10.38	5	0.6
50V-402	1709	1400	81.92	295	17.26	14	0.82
50W-411	1043	932	89.36	102	9.78	9	0.86
50W-412	1479	1374	92.9	97	6.56	8	0.54
510N-301	25	25	100		0		0
510W-211	133	128	96.24	5	3.76		0
511N-301	38	37	97.37	1	2.63		0
512C-311	266	250	93.98	16	6.02		0
512N-311	275	266	96.73	9	3.27		0
512N-321	212	210	99.06	2	0.94		0
512N-331	234	228	97.44	6	2.56		0

FEEDER	TOTALCOUNT	RESIDENTIALCOUNT	RESIDENTIALPERCENT	COMMERCIALCOUNT	COMMERCIALPERCENT	INDUSTRIALCOUNT	INDUSTRIALPERCENT
512V-311	35	31	88.57	4	11.43		0
512W-311	304	298	98.03	6	1.97		0
513N-301	197	192	97.46	5	2.54		0
513V-311	68	62	91.18	6	8.82		0
514C-301	327	314	96.02	13	3.98		0
514N-201	23	18	78.26	5	21.74		0
514S-311	65	58	89.23	7	10.77		0
514V-311	60	53	88.33	7	11.67		0
514W-211	33	33	100		0		0
515C-301	86	83	96.51	3	3.49		0
515S-311	204	201	98.53	3	1.47		0
515V-311	11	11	100		0		0
515W-211	314	272	86.62	41	13.06	1	0.32
516C-311	236	226	95.76	8	3.39	2	0.85
516N-311	226	220	97.35	6	2.65		0
516N-331	111	107	96.4	4	3.6		0
516V-311	20	18	90	2	10		0
516W-211	129	127	98.45	2	1.55		0
517C-301	231	211	91.34	20	8.66		0
517S-311	52	49	94.23	3	5.77		0
517V-311	6	6	100		0		0
517W-311	103	99	96.12	4	3.88		0
518N-311	50	48	96	2	4		0
518V-311	22	18	81.82	4	18.18		0
519N-201	663	613	92.46	48	7.24	2	0.3
519W-311	227	227	100		0		0
51V-301	1231	1126	91.47	100	8.12	5	0.41
521N-301	49	44	89.8	5	10.2		0
521S-211	1	1	100		0		0
522C-301	59	58	98.31	1	1.69		0
522S-211	1	1	100		0		0
522W-311	147	146	99.32	1	0.68		0
523C-301	48	46	95.83	2	4.17		0
524C-201	57	57	100		0		0
524N-311	27	26	96.3	1	3.7		0
524S-311	337	299	88.72	38	11.28		0
525S-311	168	161	95.83	7	4.17		0
525W-311	54	54	100		0		0
526S-211	31	28	90.32	3	9.68		0
527S-311	127	122	96.06	5	3.94		0
528C-301	75	73	97.33	2	2.67		0
528N-201	417	376	90.17	40	9.59	1	0.24
528N-202	362	338	93.37	24	6.63		0
528S-311	313	311	99.36	2	0.64		0
529C-201	56	53	94.64	3	5.36		0
529S-311	134	125	93.28	9	6.72		0
52C-211	45	42	93.33	3	6.67		0
52V-251	1		0		0	1	100
530N-201	41	39	95.12	2	4.88		0
530S-311	25	25	100		0		0

FEEDER	TOTALCOUNT	RESIDENTIALCOUNT	RESIDENTIALPERCENT	COMMERCIALCOUNT	COMMERCIALPERCENT	INDUSTRIALCOUNT	INDUSTRIALPERCENT
530W-201	120	103	85.83	13	10.83	4	3.33
531N-311	74	72	97.3	2	2.7		0
531S-311	4		0	4	100		0
531W-311	282	266	94.33	16	5.67		0
532N-201	495	473	95.56	22	4.44		0
532S-211	8	7	87.5	1	12.5		0
533N-311	147	142	96.6	5	3.4		0
533N-321	109	101	92.66	8	7.34		0
533S-211	121	112	92.56	9	7.44		0
534N-201	464	455	98.06	9	1.94		0
534S-212	50	38	76	10	20	2	4
535N-311	249	245	98.39	4	1.61		0
535N-321	215	211	98.14	4	1.86		0
535N-331	109	106	97.25	3	2.75		0
535N-341	309	302	97.73	3	0.97	4	1.29
535S-201	60	59	98.33	1	1.67		0
536N-201	107	105	98.13	2	1.87		0
538W-311	139	137	98.56	2	1.44		0
539N-201	70	69	98.57	1	1.43		0
539W-311	86	85	98.84	1	1.16		0
53N-Dist	1		0		0	1	100
540C-311	74	71	95.95	3	4.05		0
540C-312	77	57	74.03	20	25.97		0
540N-201	65	65	100		0		0
541C-311	132	125	94.7	6	4.55	1	0.76
542C-311	136	127	93.38	9	6.62		0
542W-311	559	548	98.03	11	1.97		0
543C-211	34	33	97.06	1	2.94		0
543W-311	149	144	96.64	5	3.36		0
544W-311	68	68	100		0		0
545C-211	79	76	96.2	3	3.8		0
545N-301	292	280	95.89	9	3.08	3	1.03
545W-311	260	255	98.08	5	1.92		0
546C-311	311	303	97.43	8	2.57		0
546W-311	171	169	98.83	2	1.17		0
546W-321	199	194	97.49	5	2.51		0
547C-311	46	44	95.65	2	4.35		0
547C-312	38	38	100		0		0
547N-411	6	6	100		0		0
548C-311	84	79	94.05	5	5.95		0
548W-311	447	428	95.75	16	3.58	3	0.67
549C-211	18	18	100		0		0
549N-201	26	26	100		0		0
54C-211	665	612	92.03	51	7.67	2	0.3
54C-213	368	333	90.49	34	9.24	1	0.27
54H-301	1561	1453	93.08	99	6.34	9	0.58
54H-302	1272	1222	96.07	50	3.93		0
54H-303	813	621	76.38	192	23.62		0
54H-304	1322	1211	91.6	109	8.25	2	0.15
550W-311	43	41	95.35	2	4.65		0

FEEDER	TOTALCOUNT	RESIDENTIALCOUNT	RESIDENTIALPERCENT	COMMERCIALCOUNT	COMMERCIALPERCENT	INDUSTRIALCOUNT	INDUSTRIALPERCENT
551C-301	47	46	97.87	1	2.13		0
552C-301	1	1	100		0		0
552W-311	54	53	98.15	1	1.85		0
553C-301	26	26	100		0		0
553W-211	80	72	90	6	7.5	2	2.5
554C-311	41	40	97.56	1	2.44		0
554W-311	1	1	100		0		0
555C-311	75	73	97.33	2	2.67		0
555W-311	143	142	99.3	1	0.7		0
556C-311	41	40	97.56	1	2.44		0
556W	7	7	100		0		0
556W-211	1	1	100		0		0
559C-311	150	139	92.67	11	7.33		0
55N-201	343	317	92.42	24	7	2	0.58
55N-202	305	198	64.92	103	33.77	4	1.31
55N-203	356	334	93.82	21	5.9	1	0.28
55N-204	544	524	96.32	17	3.13	3	0.55
55V-313	1658	1538	92.76	102	6.15	18	1.09
55V-314	1126	1033	91.74	77	6.84	16	1.42
55V-322	1223	1166	95.34	50	4.09	7	0.57
55V-323	1059	955	90.18	85	8.03	19	1.79
562C-311	40	40	100		0		0
564C-311	39	35	89.74	4	10.26		0
568C-311	294	273	92.86	21	7.14		0
56C-211	120	118	98.33	2	1.67		0
56N-401	617	505	81.85	109	17.67	3	0.49
56N-402	6	2	33.33	2	33.33	2	33.33
56N-414	1137	1062	93.4	71	6.24	4	0.35
570C-311	276	258	93.48	18	6.52		0
571C-311	36	36	100		0		0
572C-211	13	13	100		0		0
574C-311	30	30	100		0		0
578C-311	32	32	100		0		0
579C-211	6	6	100		0		0
57C-417	65	60	92.31	4	6.15	1	1.54
57C-422	510	490	96.08	19	3.73	1	0.2
57C-426	1475	1364	92.47	107	7.25	4	0.27
57S-401	1680	1576	93.81	100	5.95	4	0.24
57S-402	1585	1534	96.78	50	3.15	1	0.06
57W-401	670	636	94.93	31	4.63	3	0.45
57W-402	223	193	86.55	28	12.56	2	0.9
580C-311	39	37	94.87	2	5.13		0
580C-312	97	95	97.94	2	2.06		0
581C-311	351	328	93.45	22	6.27	1	0.28
581N-301	207	202	97.58	5	2.42		0
582C-311	243	228	93.83	9	3.7	6	2.47
582N-301	111	110	99.1	1	0.9		0
583C-211	58	56	96.55	2	3.45		0
584N-301	65	59	90.77	6	9.23		0
585C-311	435	419	96.32	16	3.68		0

FEEDER	TOTALCOUNT	RESIDENTIALCOUNT	RESIDENTIALPERCENT	COMMERCIALCOUNT	COMMERCIALPERCENT	INDUSTRIALCOUNT	INDUSTRIALPERCENT
586C-311	180	175	97.22	5	2.78		0
586N-311	1		0		0	1	100
587C-311	142	136	95.77	6	4.23		0
587N	1		0	1	100		0
587N-201	25	21	84	4	16		0
588C-311	220	211	95.91	9	4.09		0
58C-403	1042	946	90.79	92	8.83	4	0.38
58C-405	603	544	90.22	57	9.45	2	0.33
58H-421	1225	1175	95.92	48	3.92	2	0.16
58H-431	2066	1947	94.24	103	4.99	16	0.77
58H_111H-Dist	4		0	3	75	1	25
590C-311	304	298	98.03	6	1.97		0
591C-311	107	100	93.46	7	6.54		0
591N-311	47	47	100		0		0
592N-301	10	10	100		0		0
593N-301	39	39	100		0		0
594C-211	7	7	100		0		0
595C-311	20	19	95	1	5		0
595N-311	227	217	95.59	10	4.41		0
596C-311	10	10	100		0		0
598C-311	39	37	94.87	2	5.13		0
59C-401	402	386	96.02	16	3.98		0
59C-402	1129	1068	94.6	58	5.14	3	0.27
59C-403	523	455	87	63	12.05	5	0.96
5N-301	631	556	88.11	64	10.14	11	1.74
600C-311	11	11	100		0		0
605V-211	52	50	96.15	2	3.85		0
607N-301	498	460	92.37	35	7.03	3	0.6
608N-301	2	1	50	1	50		0
609N-301	182	172	94.51	10	5.49		0
609V-311	97	93	95.88	4	4.12		0
610N-301	62	60	96.77	2	3.23		0
611N-301	41	37	90.24	3	7.32	1	2.44
613N-301	5	5	100		0		0
613V-211	37	34	91.89	3	8.11		0
614N-301	22	20	90.91	2	9.09		0
616N-311	115	115	100		0		0
617N-311	54	53	98.15	1	1.85		0
618V-311	18	18	100		0		0
619N-301	655	628	95.88	25	3.82	2	0.31
619V-311	123	123	100		0		0
61C-311	64	60	93.75	4	6.25		0
61N-201	181	41	22.65	140	77.35		0
61N-202	346	274	79.19	70	20.23	2	0.58
61N-204	524	509	97.14	13	2.48	2	0.38
61N-205	607	573	94.4	32	5.27	2	0.33
61S-311	339	327	96.46	12	3.54		0
620H-201	2		0	2	100		0
620V-311	89	73	82.02	16	17.98		0
621V-311	81	78	96.3	3	3.7		0

FEEDER	TOTALCOUNT	RESIDENTIALCOUNT	RESIDENTIALPERCENT	COMMERCIALCOUNT	COMMERCIALPERCENT	INDUSTRIALCOUNT	INDUSTRIALPERCENT
622H-211	3		0	3	100		0
622V-211	138	101	73.19	37	26.81		0
624V-311	291	282	96.91	9	3.09		0
625V-311	168	157	93.45	11	6.55		0
626N-311	62	62	100		0		0
627H-211	1		0	1	100		0
627N-311	41	40	97.56	1	2.44		0
627V-311	299	287	95.99	12	4.01		0
629N-311	77	76	98.7	1	1.3		0
62H-301	599	579	96.66	19	3.17	1	0.17
62H-302	1399	1332	95.21	66	4.72	1	0.07
62H-303	583	539	92.45	44	7.55		0
62H-304	2464	2334	94.72	130	5.28		0
62N-411	729	557	76.41	168	23.05	4	0.55
62N-412	185	107	57.84	77	41.62	1	0.54
62N-413	2149	1952	90.83	186	8.66	11	0.51
62N-414	1478	1330	89.99	135	9.13	13	0.88
62N-415	814	762	93.61	46	5.65	6	0.74
62N-416	2049	1879	91.7	159	7.76	11	0.54
630N-311	84	82	97.62	2	2.38		0
630V-311	77	77	100		0		0
631N-311	122	121	99.18	1	0.82		0
632N-311	52	47	90.38	5	9.62		0
633N-311	18	18	100		0		0
633V-311	60	60	100		0		0
634V-311	243	234	96.3	9	3.7		0
636N-311	19	18	94.74	1	5.26		0
637H-311	138	137	99.28	1	0.72		0
637N-311	12	11	91.67	1	8.33		0
637V-311	26	24	92.31	2	7.69		0
639N-311	254	240	94.49	14	5.51		0
639N-321	183	177	96.72	6	3.28		0
639V-311	46	41	89.13	5	10.87		0
63C-311	143	141	98.6	2	1.4		0
63V-311	1203	1115	92.68	84	6.98	4	0.33
63V-312	1000	941	94.1	56	5.6	3	0.3
63V-313	1973	1856	94.07	102	5.17	15	0.76
640N-311	13	13	100		0		0
640V-311	168	162	96.43	6	3.57		0
641V-311	101	97	96.04	3	2.97	1	0.99
642H-311	8	1	12.5	7	87.5		0
642V-311	507	499	98.42	8	1.58		0
643N-211	4	4	100		0		0
643V-311	145	143	98.62	2	1.38		0
644N-311	81	78	96.3	3	3.7		0
644V-311	99	92	92.93	5	5.05	2	2.02
645V-311	72	69	95.83	3	4.17		0
646H-311	94	92	97.87	2	2.13		0
646V-311	3	3	100		0		0
647N-311	1328	1309	98.57	19	1.43		0

FEEDER	TOTALCOUNT	RESIDENTIALCOUNT	RESIDENTIALPERCENT	COMMERCIALCOUNT	COMMERCIALPERCENT	INDUSTRIALCOUNT	INDUSTRIALPERCENT
647N-312	890	884	99.33	6	0.67		0
648H-311	1		0	1	100		0
648V-311	27	3	11.11	22	81.48	2	7.41
649H-311	85	84	98.82	1	1.18		0
649N-311	133	131	98.5	2	1.5		0
64N-201	370	342	92.43	25	6.76	3	0.81
64V-301	938	900	95.95	34	3.62	4	0.43
64V-302	215	205	95.35	9	4.19	1	0.47
64V-303	221	217	98.19	4	1.81		0
650H-311	42	41	97.62	1	2.38		0
651N-311	55	53	96.36	2	3.64		0
651V-211	1		0	1	100		0
652N-311	73	71	97.26	2	2.74		0
652V-211	489	477	97.55	9	1.84	3	0.61
652V-212	505	415	82.18	88	17.43	2	0.4
654N-311	110	106	96.36	4	3.64		0
655N-311	36	36	100		0		0
655V-211	414	375	90.58	36	8.7	3	0.72
656N-311	39	36	92.31	1	2.56	2	5.13
656V-211	277	193	69.68	83	29.96	1	0.36
657V-211	57	57	100		0		0
658N-211	182	177	97.25	5	2.75		0
658V-211	89	88	98.88	1	1.12		0
65N-201	183	166	90.71	17	9.29		0
65S-211	1		0	1	100		0
65V-301	475	466	98.11	9	1.89		0
65V-302	2153	2068	96.05	77	3.58	8	0.37
65V-303	1062	898	84.56	154	14.5	10	0.94
660V-201	104	104	100		0		0
661N-311	58	58	100		0		0
662N-311	100	100	100		0		0
663N-311	60	58	96.67	2	3.33		0
663V-211	175	138	78.86	37	21.14		0
664N-211	208	207	99.52	1	0.48		0
665H-311	82	73	89.02	9	10.98		0
665N-311	150	145	96.67	5	3.33		0
665V-311	10	10	100		0		0
666H-311	16	16	100		0		0
666N-311	167	160	95.81	7	4.19		0
668N-411	70	67	95.71	3	4.29		0
669N-201	5		0	5	100		0
66V-201	335	287	85.67	45	13.43	3	0.9
670N-311	244	239	97.95	5	2.05		0
673N-311	22	22	100		0		0
675N-311	12	9	75	3	25		0
677H-211	1		0	1	100		0
677N-301	334	319	95.51	13	3.89	2	0.6
678H-211	8	7	87.5	1	12.5		0
678N-301	102	98	96.08	4	3.92		0
679H-311	261	259	99.23	1	0.38	1	0.38

FEEDER	TOTALCOUNT	RESIDENTIALCOUNT	RESIDENTIALPERCENT	COMMERCIALCOUNT	COMMERCIALPERCENT	INDUSTRIALCOUNT	INDUSTRIALPERCENT
67C-411	976	878	89.96	91	9.32	7	0.72
67C-412	1099	984	89.54	113	10.28	2	0.18
680N-211	1		0		0	1	100
681N-211	39	33	84.62	6	15.38		0
682N-211	494	423	85.63	71	14.37		0
686H-311	89	89	100		0		0
688H-211	1		0	1	100		0
689H-211	13		0	13	100		0
695H-311	73	73	100		0		0
697H-311	133	131	98.5	2	1.5		0
698H-311	10	10	100		0		0
699H-311	127	123	96.85	4	3.15		0
69C-311	105	100	95.24	5	4.76		0
69C-312	12	10	83.33	2	16.67		0
69V-211	477	405	84.91	68	14.26	4	0.84
6N-301	958	886	92.48	65	6.78	7	0.73
6N-302	212	204	96.23	7	3.3	1	0.47
6S-221	476	469	98.53	7	1.47		0
6S-223	562	559	99.47	3	0.53		0
6S-224	528	522	98.86	6	1.14		0
6S-225	937	898	95.84	39	4.16		0
6W-201	8	2	25	6	75		0
700H-311	114	112	98.25	2	1.75		0
701H-211	3		0	3	100		0
702H-311	91	91	100		0		0
703H-311	161	156	96.89	5	3.11		0
704H-311	229	213	93.01	12	5.24	4	1.75
705H-211	11	1	9.09	6	54.55	4	36.36
709H-221	408	395	96.81	12	2.94	1	0.25
70V-311	1460	1348	92.33	106	7.26	6	0.41
70V-312	912	873	95.72	29	3.18	10	1.1
70W-203	282	260	92.2	22	7.8		0
70W-204	267	236	88.39	30	11.24	1	0.37
70W-311	916	844	92.14	69	7.53	3	0.33
70W-312	826	780	94.43	44	5.33	2	0.24
70W-313	1833	1736	94.71	93	5.07	4	0.22
70W-314	462	331	71.65	130	28.14	1	0.22
70W-321	1546	1421	91.91	115	7.44	10	0.65
70W-322	933	826	88.53	106	11.36	1	0.11
73S-201	21	21	100		0		0
73W-411	4318	4183	96.87	128	2.96	7	0.16
73W-412	119	66	55.46	46	38.66	7	5.88
74N-411	893	827	92.61	60	6.72	6	0.67
74N-412	126	116	92.06	9	7.14	1	0.79
74S-211	4		0	4	100		0
74V-301	61	10	16.39	46	75.41	5	8.2
74V-302	8		0	6	75	2	25
74W-301	4		0	2	50	2	50
75N-251	1		0		0	1	100
76V-301	325	282	86.77	43	13.23		0

FEEDER	TOTALCOUNT	RESIDENTIALCOUNT	RESIDENTIALPERCENT	COMMERCIALCOUNT	COMMERCIALPERCENT	INDUSTRIALCOUNT	INDUSTRIALPERCENT
76W-201	4		0	3	75	1	25
77V-301	213	139	65.26	72	33.8	2	0.94
77V-302	1404	1304	92.88	98	6.98	2	0.14
77V-303	1114	981	88.06	110	9.87	23	2.06
77V-401	473	426	90.06	41	8.67	6	1.27
78C-311	91	88	96.7	3	3.3		0
78W-301	717	696	97.07	19	2.65	2	0.28
78W-302	437	407	93.14	23	5.26	7	1.6
79S-311	333	303	90.99	30	9.01		0
79V-401	1682	1555	92.45	116	6.9	11	0.65
79V-402	2113	1886	89.26	222	10.51	5	0.24
79V-403	634	594	93.69	33	5.21	7	1.1
7N-211	3		0	2	66.67	1	33.33
7N-301	1370	1265	92.34	97	7.08	8	0.58
7N-302	430	411	95.58	17	3.95	2	0.47
80W-301	639	617	96.56	22	3.44		0
80W-302	27	24	88.89	3	11.11		0
80W-303	3		0	2	66.67	1	33.33
81N-411	335	248	74.03	68	20.3	19	5.67
81N-412	1374	1260	91.7	101	7.35	13	0.95
81S-301	1188	1153	97.05	34	2.86	1	0.08
81S-302	1659	1585	95.54	71	4.28	3	0.18
81S-303	2141	2068	96.59	64	2.99	9	0.42
81S-304	960	894	93.13	66	6.88		0
81S-305	1693	1560	92.14	130	7.68	3	0.18
81S-306	1709	1622	94.91	84	4.92	3	0.18
81S-307	709	699	98.59	9	1.27	1	0.14
81W-Dist	2		0	1	50	1	50
82S-302	161	150	93.17	10	6.21	1	0.62
82S-303	1493	1402	93.9	89	5.96	2	0.13
82S-304	1189	1168	98.23	21	1.77		0
82V-401	2142	1986	92.72	135	6.3	21	0.98
82V-402	2118	2062	97.36	47	2.22	9	0.42
82V-403	684	651	95.18	26	3.8	7	1.02
82V-422	2129	1974	92.72	147	6.9	8	0.38
82V-423	2232	2036	91.22	184	8.24	12	0.54
82W-Dist	1		0		0	1	100
83N	1		0	1	100		0
83V-301	967	884	91.42	50	5.17	33	3.41
83V-302	1548	1326	85.66	214	13.82	8	0.52
83V-303	1026	967	94.25	54	5.26	5	0.49
84N	1		0	1	100		0
84S-302	248	176	70.97	70	28.23	2	0.81
84S-303	4		0	2	50	2	50
84S-304	1		0		0	1	100
84S-305	288	145	50.35	142	49.31	1	0.35
84W-301	1213	1064	87.72	129	10.63	20	1.65
84W-302	857	753	87.86	99	11.55	5	0.58
85N-101	1		0	1	100		0
85S-401	1548	1339	86.5	206	13.31	3	0.19

FEEDER	TOTALCOUNT	RESIDENTIALCOUNT	RESIDENTIALPERCENT	COMMERCIALCOUNT	COMMERCIALPERCENT	INDUSTRIALCOUNT	INDUSTRIALPERCENT
85S-402	253	221	87.35	32	12.65		0
86N	1		0	1	100		0
87C-311	350	329	94	20	5.71	1	0.29
87H-311	1111	1082	97.39	24	2.16	5	0.45
87H-312	1055	979	92.8	70	6.64	6	0.57
87H-313	1747	1674	95.82	70	4.01	3	0.17
87W-311	1682	1573	93.52	102	6.06	7	0.42
87W-312	1489	1408	94.56	71	4.77	10	0.67
88H-401	1245	1167	93.73	74	5.94	4	0.32
88H-402	662	630	95.17	30	4.53	2	0.3
88W-311	828	717	86.59	111	13.41		0
88W-312	1895	1729	91.24	146	7.7	20	1.06
88W-321	631	543	86.05	76	12.04	12	1.9
88W-322	379	272	71.77	104	27.44	3	0.79
88W-323	1245	1140	91.57	95	7.63	10	0.8
89H-401	93	89	95.7	4	4.3		0
89W-301	528	476	90.15	50	9.47	2	0.38
89W-302	990	934	94.34	47	4.75	9	0.91
89W-303	1218	1147	94.17	62	5.09	9	0.74
89W-304	318	259	81.45	56	17.61	3	0.94
8C-201	1		0		0	1	100
8H-211	371	336	90.57	34	9.16	1	0.27
8H-212	559	495	88.55	64	11.45		0
901H-411	1		0		0	1	100
91W-411	776	753	97.04	22	2.84	1	0.13
92H-331	2236	2129	95.21	105	4.7	2	0.09
92H-332	1130	1057	93.54	70	6.19	3	0.27
92H-333/L-3202	5		0	5	100		0
92H-334	1074	1038	96.65	35	3.26	1	0.09
92V-Dist	1		0		0	1	100
92W-302	824	804	97.57	18	2.18	2	0.24
93V-311	1137	990	87.07	131	11.52	16	1.41
93V-312	783	664	84.8	108	13.79	11	1.4
93V-313	1920	1783	92.86	127	6.61	10	0.52
95V-101	1		0	1	100		0
96H-411	1043	922	88.4	110	10.55	11	1.05
96H-412	810	777	95.93	31	3.83	2	0.25
99H-311	1972	1812	91.89	154	7.81	6	0.3
99H-312	825	671	81.33	147	17.82	7	0.85
9C-301	1		0		0	1	100
9C-302	8	7	87.5	1	12.5		0
9C-303	210	201	95.71	8	3.81	1	0.48
9C-304	62	60	96.77	2	3.23		0
9H-221	890	864	97.08	26	2.92		0
9H-222	3		0	3	100		0
9H-224	936	866	92.52	70	7.48		0
L-4048	2		0		0	2	100

NON-CONFIDENTIAL

Request IR-94:

Please provide the computation of share of medium industrial and general loads served from non-dedicated substations.

Response IR-94:

Please refer to CA IR-84.

NON-CONFIDENTIAL

Request IR-95:

Please provide the computation of the rate base for each category of substations in Exhibit 3B.

Response IR-95:

Please refer to Attachment 1 for the computation of the rate base for each category of substations in Exhibit 3B and to Attachment 2, which is 2012 GRA CA IR-172, for the description of the methodology.

NOVA SCOTIA POWER INCORPORATED
ANALYSIS OF DISTRIBUTION SUBSTATIONS
FOR THE YEAR ENDING DECEMBER 31, 2012

	TOTAL PLANT	DISTRIBUTION BULK POWER	DIST. DEDT. BULK POWER	DIST. CUST. OWN.BULK PWR.	DISTRIBUTION GENERAL	DIST. DEDT. GENERAL	DIST. CUST. OWN. GENERAL
GROSS PLANT VALUE	$77,158	$59,579	$2,926	$150	$12,961	$1,309	$233
ACC. DEPR. 2011/12/31	47,931	35,089	2,422	114	8,856	1,309	140
Depr. Exp. 2012	469	414	66	3	-19	0	5
ACC. DEPR. 2012/12/31	48,400	35,503	2,488	117	8,837	1,309	145
NET PLANT VALUE	28,758	24,076	438	33	4,124	0	88
CLASS DISTRIBUTION							
GENERAL	27		0	27		0	0
GENERAL LARGE	0		0	0		0	0
SMALL INDUSTRIAL	0		0	0		0	0
MEDIUM INDUSTRIAL	115		108	3		0	4
LARGE INDUSTRIAL	265		265	0		0	0
INTERRUPTIBLE	126		39	3		0	84
MUNICIPAL	26		26	0		0	0
TOTAL	$28,759	$24,076	$438	$33	$4,124	$0	$88

ANNUAL DEPRECIATION RATE = 1.28% plug

NOVA SCOTIA POWER INCORPORATED
ANALYSIS OF DISTRIBUTION SUBSTATIONS
FOR THE YEAR ENDING DECEMBER 31, 2013

	TOTAL PLANT	DISTRIBUTION BULK POWER	DIST. DEDT. BULK POWER	DIST. CUST. OWN.BULK PWR.	DISTRIBUTION GENERAL	DIST. DEDT. GENERAL	DIST. CUST. OWN. GENERAL
GROSS PLANT VALUE	$79,239	$61,179	$2,926	$150	$13,442	$1,309	$233
ACC. DEPR. 2012/12/31	48,400	35,503	2,488	117	8,837	1,309	145
Depr. Exp. 2013	2,674	1,535	66	3	1,065	0	5
ACC. DEPR. 2013/12/31	51,074	37,038	2,554	120	9,902	1,309	150
NET PLANT VALUE	28,165	24,141	372	30	3,540	0	83
CLASS DISTRIBUTION							
GENERAL	25		0	25		0	0
GENERAL LARGE	0		0	0		0	0
SMALL INDUSTRIAL	0		0	0		0	0
MEDIUM INDUSTRIAL	98		91	3		0	4
LARGE INDUSTRIAL	225		225	0		0	0
INTERRUPTIBLE	114		33	2		0	79
MUNICIPAL	22		22	0		0	0
TOTAL	$28,165	$24,141	$371	$30	$3,539.62	$0	$83

ANNUAL DEPRECIATION RATE = 1.28% plug

NOVA SCOTIA POWER INCORPORATED
ANALYSIS OF DISTRIBUTION SUBSTATIONS
FOR THE YEAR ENDING DECEMBER 31, 2014

	TOTAL PLANT	DISTRIBUTION BULK POWER	DIST. DEDT. BULK POWER	DIST. CUST. OWN.BULK PWR.	DISTRIBUTION GENERAL	DIST. DEDT. GENERAL	DIST. CUST. OWN. GENERAL
GROSS PLANT VALUE	$85,953	$66,349	$2,926	$150	$14,986	$1,309	$233
ACC. DEPR. 2013/12/31	48,400	35,503	2,488	117	8,837	1,309	145
Depr. Exp. 2014	5,493	3,538	66	3	1,881	0	5
ACC. DEPR. 2014/12/31	53,893	39,041	2,554	120	10,718	1,309	150
NET PLANT VALUE	32,060	27,308	372	30	4,268	0	83
CLASS DISTRIBUTION							
GENERAL	25		$0.00	$25.00		0	0
GENERAL LARGE	0		$0.00	$0.00		0	0
SMALL INDUSTRIAL	0		$0.00	$0.00		0	0
MEDIUM INDUSTRIAL	98		$91.00	$3.00		0	4
LARGE INDUSTRIAL	225		$225.00	$0.00		0	0
INTERRUPTIBLE	114		$33.00	$2.00		0	79
MUNICIPAL	22		$22.00	$0.00		0	0
TOTAL	$32,060	$27,308.03	$371.00	$30.00	$4,267.62	$0	$83

ANNUAL DEPRECIATION RATE = 1.28% plug

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Request IR-172:

The response to CA IR-38 says that "For the COSS purposes the rate base associated with the distribution substations has been split among the four categories …using the same proration approach since the last COSS hearing was held in 1995." Does this mean that the approach has been applied to the actual costs of the changing mix of dedicated and bulk distribution substations over time, that the same percentages have been used since 1995, or something else (and if so, what)?

Response IR-172:

The estimated percentages have changed as a result of applying the following approach:

The total distribution substation plant is segregated into the following six categories:

- A - Distribution Bulk Power
- B - Distribution Dedicated Bulk Power
- C - Distribution Customer Own Bulk Power
- D - Distribution General
- E - Distribution Dedicated General
- F - Distribution Customer Own General

NSPI has kept the gross plant values for categories B, C, E and F at constant dollar levels since 1996 and calculated their annual net plant values based on periodically updated depreciation

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rates. The annual net plant values of the two main categories A and D are modified to balance with the total net plant book value of all distribution substations. The modifications of A and D are put into effect by applying on an annual basis periodically updated depreciation rates to the estimates of gross plant values of A and D whose relative shares in the total gross plant value of all distribution substations, as simulated in these calculations, remain at approximately the same levels of 77 percent and 16 percent, respectively.

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Request IR-96:

Please provide the firm capacity value that NSPI assigns to each existing NSPI-owned or IPP wind farm, and each IPP wind project under contract, for the purpose of determining resource adequacy,

a) in the "10 Year System Outlook, 2012-2021 Report."

b) in the latest 18-month Load and Capacity Assessment.

Response IR-96:

(a) Please see the table below for the firm capacity value of wind assumed in the 2012 10-Year System Outlook.[1] The size of the province together with wind patterns result in limited diversity wind generation and hence it is generally treated in an aggregated manner. The assumed firm capacity value of wind reflects the firm capacity contribution based on a three-year average of actual capacity factors during peak hours and the annual forecasted value (as per the formula agreed on by NS Power and the Renewable Energy Industry Association of Nova Scotia and as employed in NS Power's 2009 Integrated Resource Plan (IRP) Update[2] modeling).

	Installed Wind Capacity (MW)	**Assumed Firm Contribution as a Percentage of Installed Wind Capacity (%)**	**Assumed Firm Capacity Contribution (MW)**
NSPI Owned Wind (as of 2012)	76	38%	29
Post-2001 Wind IP (as of 2012)	199	36%	71
Contracted Wind (assumed in-service 2013)	48	32%	15
Community Feed-in Tariff (assumed phased-in by 2018)	100	34%	34
Total	**424**	**35%**	**149**

[1] NSPI 10 Year System Outlook, 2012-2021 Report, NSUARB-NSPI-P-194, June 29, 2012.
[2] NSPI 2009 Integrated Resource Plan Update Final Report, NSUARB-NSPI-P-884, November 30, 2009.

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(b) For the purposes of operations planning, the 18-Month Forecast and Assessment assumes the wind has no firm capacity contribution. NS Power has used this assumption to provide certainty that sufficient capacity will be available in the short-term to meet firm load and operating reserve requirements. NS Power's experience to date has shown that we reach 35 percent of installed wind capacity less than half of the time (46 percent) using hourly average data. Please refer to PC IR-29 Attachment 1 for detailed information on wind performance data. In addition, approximately 10 percent of the time, less than 10 MW of wind is being generated on the system. The assumed capacity value for wind is being re-evaluated in the Renewables Integration Study presently underway. Short-term wind forecasting is improving and, as a result, NS Power is investigating increasing the capacity value assigned to wind for day-ahead planning purposes.

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Request IR-97:

Please provide any analyses, memos, studies or reports that addressed the decision to complete the Port Hawkesbury biomass plant, following the cessation of operation at the Port Hawkesbury mill and/or the bankruptcy of NewPage. Please include any documents describing the decision to assume and continue management of construction of the plant.

Response IR-97:

Please refer to CA IR-104.

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Request IR-98:

Please provide NSPI's current assessment of the completion date and capital cost of the Port Hawkesbury biomass plant.

Response IR-98:

NS Power is currently forecasting commercial operations in Q2, 2013. The capital cost of the Port Hawkesbury biomass plant is expected to be completed for the amount approved by the Board on October 14, 2010 of $183.2 million plus Allowance for Funds Used During Construction (AFUDC).

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Request IR-99:

Please provide NSPI's current assessment of the economic dispatch of the Port Hawkesbury biomass plant for each year 2013–2022, assuming

a) Non mill steam load

b) Full mill steam demand

Response IR-99:

(a-b) Compliance with the Renewable Electricity Standard (RES) will be the primary dispatch influence for the Port Hawkesbury biomass unit. Economic considerations will enter into dispatch decision for this facility if NS Power anticipates exceeding RES compliance targets in a given year. The output of the plant will depend upon the amount of RES energy procured through the Renewable Electricity Administrator, the Community Feed-In Tariff (COMFIT) program and current Community/Distribution connected project Power Purchase Agreement commitments in place.

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Request IR-100:

Please provide NSPI's current assessment of the cost of owning and operating the Port Hawkesbury biomass plant without the mill steam load, for each year NSPI has such a forecast, including

- **a) Fuel costs**
- **b) Non-fuel operating and maintenance costs**
- **c) Continuing capital investments**
- **d) Return, depreciation and taxes**

Response IR-100:

(a) Please refer to Page 8, Appendix B of the Application.

(b) Please refer to Page 36, Appendix E of the Application.

(c) NS Power has not included sustaining capital in the test year forecasts for this Application.

(d) Please refer to the figures below.

($M)	2013	2014
Return on Rate base	8.1	16.0
Depreciation	4.8	5.8
Capital Cost Allowance	(5.6)	(10.9)

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Request IR-101:

If the Port Hawkesbury mill steam load does not reappear, and NSPI has sufficient renewable energy to meet the RES without the biomass plant, does NSPI believe that the Port Hawkesbury biomass plant would be economic to operate, and if so, why and at what capacity factor?

Response IR-101:

The Port Hawkesbury Biomass plant is a Board approved project under development for NS Power to meet its obligations for renewable energy under the Renewable Electricity Standard (RES). This facility will be operational in 2013 and its energy production in that year will be determined by the in-service date and commissioning progress. The economics and capacity factor of the plant will depend upon the amount of RES energy procured through the Renewable Energy Administrator, the Community Feed-In Tariff (COMFIT) program and current Community/Distribution connected project Power Purchase Agreement commitments in place.

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Request IR-102:

Reference NSPI (Avon) IR-13(a-d)

a) **Was the "The cost for biomass … assumed in the Port Hawkesbury biomass capital application" premised on the mill providing a portion of the plant's fuel at cost, rather than market prices?**

b) **Please explain whether the biomass fuel price forecast in this case represents the average prices from the capital application, or the price for the portion of the biomass assumed in the capital application to be purchased at market prices from third-party suppliers.**

c) **Is it true that all fuel for the Port Hawkesbury biomass plant will now be obtained through competitive solicitation?**

d) **Please explain how NSPI could determine that completion of the Port Hawkesbury biomass was prudent without an estimate of the market price of biomass.**

Response IR-102:

(a) The cost of biomass in the Application was premised on supply from harvested private sources, and was extracted from the Port Hawkesbury Biomass project capital application.

(b) The biomass fuel price forecast in this Application represents the portion of the biomass assumed in the capital application to be purchased at market prices from third-party suppliers.

(c) No. In co-generation mode, Pacific West Commercial Corporation (PWCC) is to supply the portion of biomass fuel required to produce the amount of mill steam required. The procurement plan and competitive distribution process for the balance of the biomass fuel supply is under development, and may include a combination of agreements with PWCC

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and/or independent fuel sources. The detailed supply breakdown will depend on the biomass supply mix that is evaluated to produce the lowest cost of fuel energy to NS Power for the boiler for steam for electricity.

(d) NS Power contracted a 3rd party Agribusiness/Forest Sector Consultants (AGFOR) to review the PWCC biomass fuel supply sources and costs and the biomass fuel costs for stand-alone operation of the electricity plant.

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Request IR-103:

Regarding the economics of the Port Hawkesbury biomass plant under the arrangements for steam supply to the mill (and related payments) proposed in the current Load Retention Tariff proceeding

a) Please provide NSPI's current assessment of the net cost of owning and operating the Port Hawkesbury biomass plant with the mill steam load.

b) Under these arrangements, if NSPI does not need the renewable energy from the Port Hawkesbury biomass plant to meet the RES, would operation of the plant for electricity be cost-effective? If so, please explain why and estimate the capacity factor at which the plant would be dispatched.

Response IR-103:

(a) The project economics of operating the Port Hawkesbury biomass plant as a cogeneration facility were explored as part of the Port Hawkesbury Biomass Application.[1] The Board approved the project as being in the best interests of customers. Pacific West Commercial Corporation (PWCC) has not stepped into the biomass plant fuel supply terms negotiated with NewPage. PWCC is well positioned to provide that service but will need to compete for fuel supply to meet NS Power's requirement for a competitive process. The current arrangement provides a net O&M cost of $3 million annually (excluding station service power cost) for NS Power at the biomass plant. This is comparable to that expected under the previous contract with NewPage where NewPage was operating the plant.

(b) If NS Power does not need the renewable energy to meet the Renewable Electricity Standard (RES), steps will be taken to manage the costs and output of the plant

[1] NSPI 2010 Capital Work Order CI # 39029 Port Hawkesbury Biomass Plant, UARB Decision, NSUARB-NSPI-P-128.10, October 14, 2010.

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recognizing the relative cost of biomass to other fuel alternatives. Please refer to NSUARB IR-51 which shows the increased requirement for renewable energy by 2020.

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Request IR-104:

Please state when NSPI first became aware that the Renewable Energy Administrator intended to issue an RFP for 300 GWh of renewable energy for 2015.

a) Please explain how NSPI reassessed the economics of the Port Hawkesbury biomass plant in light of that addition of renewable energy to its supply.

b) If NSPI did not reassess the economics of the Port Hawkesbury biomass plant in light of the change in renewable energy supply, please explain why.

Response IR-104:

NS Power became aware of the Renewable Electricity Administrator's (REA) intention to issue a Request for Proproals (RFP) for 300 GWh of renewable energy for 2015 as a result of announcements and meetings during the August and September, 2011 time period.

(a-b) By September of 2011, NS Power had spent or committed roughly $154 million of the $183.2 million budgeted excluding Accumulated Funds Used During Construction (AFUDC). In NS Power's view, the per MWh total of fuel cost, other Operating and Maintenance (O&M) and the carrying cost of the capital necessary to complete the project at that time, make the project the lowest cost source of firm renewable energy available.

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Request IR-105:

Please provide NSPI's hourly import or export of electricity, for each hour of 2011, in MWh, with the price paid or received per MWh.

Response IR-105:

Please refer to Confidential Attachment 1 for imports and Confidential Attachment 2 for exports.

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Request IR-106:

Please clarify whether the 2013 value for "Post 2001 IPPs" includes a full year of output for the six wind projects shown as coming on line in July 2013. If not, please explain why the 2013 value is the same as the 2015 value.

Response IR-106:

As of December 31, 2011, NS Power's assumption was that all currently contracted wind Independent Power Producers (IPPs) would be commissioned throughout 2012 and be fully available for 2013. Since this date, NS Power has been made aware that some of these sites will not be fully available in 2013. An update to this assumption will be included in the fuel forecast update at the end of August with data updated as of June 30, 2012.

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Request IR-107:

Please provide a breakdown of the "Post 2001 IPPs" by project.

Response IR-107:

The following figure is a list of the current projects online as of June 2012 that makes up post 2001 Independent Power Producers (IPPs):

Contracting Party	Project Location
Pubnico Point LP	Pubnico
Glace Bay Lingan Wind Power Ltd.	Lingan
Glace Bay Lingan Wind Power Ltd.	Glace Bay 1B
Glace Bay Lingan Wind Power Ltd.	Port Caledonia (Donkin)
Confederation Power Inc.	Tiverton (Londonderry)
Confederation Power Inc.	Springhill
Confederation Power Inc.	Higgins Mountain
Renewable Energy Services Ltd.	Goodwood
Renewable Energy Services Ltd.	Brookfield (Lake Major)
Renewable Energy Services Ltd.	Point Tupper 1
Renewable Energy Services Ltd.	Digby
Renewable Energy Services Ltd.	Tatamagouche (Marshville/RJ)
Renewable Energy Services Ltd.	Point Tupper 3
Amherst Wind Power LP	Amherst
RMS Energy	Dalhousie Mountain
Shear Wind Inc.	Glen Dhu North
Shear Wind Inc.	Fitzpatrick Mountain
Maryvale Wind LP (Horizon Legacy)	Maryvale
Watts Wind Energy LP	Watts Section
Colchester-Cumberland Wind Field Inc.	Spiddle Hill
Halifax Renewable Energy Corp.	Sackville Landfill

Please refer to OP-08 Attachment 1 of the Application for capacity details of these projects.

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Request IR-108:

Please provide NSPI's current understanding of the amount of renewable energy the Renewable Energy Administrator intends to acquire through the pending RFP.

Response IR-108:

The Request for Proposals (RFP) issued by the Renewable Electricity Administrator (REA) states:

> **3.4.2 Selection of Award Group**
>
> The REA is charged with procuring a minimum of 300 GWh from IPPs. The determination of the size of the Award Group needs to consider the likely level of project attrition as well as the potential for Project's annual output to be overstated. Assuming a 13% project attrition level based on the Ontario Power Authority's Renewable Energy Supply III RFP, the 300 GWh minimum becomes approximately 339 GWh. Recognizing that projects are "lumpy" an additional 20% results in an upper limit to the Award Group of 407 GWh. A minimum of 339 GWh and maximum of 407 GWh represents the Award Group Target Size.[1]

[1] Nova Scotia Renewable Electricity Administrator Request for Proposals for 300 GWh of Renewable Energy from Independent Power Producers, June 15, 2012: http://nsrenewables.ca/sites/default/files/power_advisory_nova_scotia_rea_rfp_june_15.pdf

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Request IR-109:

Please provide a version of DE-03 - DE-04 Appendix C, including the renewable energy that the Renewable Energy Administrator intends to acquire.

Response IR-109:

Please refer to NSUARB IR-51 Attachment 1.

Request IR-110:

Please provide any information NSPI has available, concerning the costs and feasibility of wheeling renewable energy through New Brunswick to New England.

Response IR-110:

Transmission fees through New Brunswick are currently $6.07/MW hourly on-peak and $2.99/MW hourly off-peak. The New Brunswick System Operator's (NBSO) public site below lists on/off peak transmission prices for hourly/daily/weekly/monthly/yearly purchases:

https://www.nbso.ca/Public/en/docs-en/CompanyX%20-%20MP.PDF

NS Power also pays an ancillary service fee of $0.60 to the New England Independent System Operator (ISO).

In addition to the transmission fees line losses are currently 3.30 percent per MW. Please refer to the web link below:

https://www.nbso.ca/Public/en/pm/news/article.aspx?id=ef0d1dd8-20d4-4049-9b53-3995f33be9fa

NS Power also pays a negotiated scheduling fee to a licensed ISO New England market participant for sales into New England.

The ability of NS Power to sell Renewable Energy Credits (RECs) into New England is currently limited. There is very limited available firm transmission path through New Brunswick into New England and no indication that available firm transmission will be increased. This significantly limits the opportunity for sales.

REC legislation in the New England States was primarily aimed at the encouraging development of new merchant generation. A portfolio approach to selling RECs into New England is not permitted. Sales of RECs into New England require the creation of an e-tag from a qualified source to an ISO New England sink. As a result, no Canadian facility constructed to meet the Renewable Portfolio Standard needs of its own jurisdiction has been qualified as a source of RECs in the New England States. In addition to the above, NS Power will need to determine:

- Whether sale of renewable energy into other jurisdictions is consistent with government policy.

- The economic opportunity available once all tariffs and fees have been paid given contractual or actual costs for a qualified renewable facility(s).

- The ramifications for any load retention tariffs that might be in place at the time of the sale of the RECs.

This response is not comprehensive but is designed to highlight some of the uncertainty involved with REC sales into New England. NS Power will continue to review the market for RECs and opportunities to sell excess renewable energy into the New England market.

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Request IR-111:

Please provide any information NSPI has available, concerning the value of renewable energy credits in New England.

Response IR-111:

Market pricing for renewable energy credits (RECs) are available through ICAP. Each New England State, with the exception of Vermont, has adopted renewable energy standards and has created tradeable renewable credits that require the purchase of RECs. For example, in 2012 Connecticut requires that nine percent of their energy requirements be sourced from Class I RECs. The rules and requirements for each of these state programs differ widely. Once a facility is registered by a state(s), and credits created, then they can be sold at the then prevailing market price.

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Request IR-112:

Considering the excess of renewable energy that NSPI expects for 2013, please describe NSPI's efforts to sell the excess renewable energy credits to New England or other markets.

Response IR-112:

Please refer to CA IR-110.