ORIGINAL

Nova Scotia Utility and Review Board

NSUARB-NSPI-P-886

IN THE MATTER OF *The Public Utilities Act*, R.S.N.S. 1989, c. 380, as amended

- and -

IN THE MATTER OF an Application by Nova Scotia Power Incorporated for Approval of Certain Revisions to its Rates, Charges and Regulations

REDACTED

Compliance Filing
2007 Rate Application
Nova Scotia Power Inc.

RECEIVED
FEB 15 2007
Nova Scotia
Utility and Review Board

February 15, 2007

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1.0 INTRODUCTION

On October 10, 2006 Nova Scotia Power Inc. ("NSPI") filed an application with the Nova Scotia Utility and Review Board ("UARB", "Board") for approval of its 2007 test year revenue requirement and associated rates.

The application process proceeded with two rounds of Information Requests from Intervenors and Board staff to NSPI, Intervenor Evidence being filed, and Information Requests to Intervenors. In addition, in response to a Board directive, NSPI filed an updated fuel cost forecast and an OM&G report on January 8, 2007. NSPI responded to information requests regarding the OM&G report.

On January 22, 2007 NSPI informed the Board that a Settlement Agreement ("SA") had been reached with most of the Confidential Intervenors. Non-confidential Intervenors were apprised of the details of the proposed settlement that morning. On January 23, 2007, SEB also agreed to the settlement based on an ELI 2P-RTP rate provided at that time. CME also subsequently agreed to the settlement. The Minutes of Settlement are reproduced in Appendix 1.[1]

The process allowed all Intervenors and the Board to review and consider the evidence and IR responses that are typically presented in support of a rate application. The Board held an evening session on Wednesday, January 24, 2007 to hear and consider submissions from informal intervenors.

On February 5, 2007 the Board issued its Decision approving the SA and NSPI's corresponding revenue requirement. The Board directed NSPI to submit a Compliance Filing to reflect the SA by February 15, 2007.

[1] The second page of the Minutes of Settlement contains the signatures of those in agreement. Not all signatures appear on a single document. The second page has been reproduced several times in Appendix 1 to capture all signatures.

A summary of the manner in which each point of the SA has been included is provided in section 1.1. A number of appendices are included with this document, as follows:

Appendix 1: Minutes of Settlement
Appendix 2: Financial Tables
Appendix 3: Cost of Service Study
Appendix 4: Revenue Allocation
Appendix 5: Rate Components
Appendix 6: Proof of Revenue
Appendix 7: Compliance Tariffs
Appendix 8: Regulation Changes

1.1 Confirmation of Settlement Agreement Items

1. NSPI's 2007 test year revenue requirement is set at $1,159.5 million, with new rates effective April 1, 2007.

This is confirmed as shown in Appendix 2, Table 1, and at the bottom of Figures 9.1 through 9.4 (revenue allocation) of Appendix 4. Appendix 6 shows that the amount designed to be collected from electric rates is $1,140.3 million. This amount, plus approximately $8.5 million in exports and $10.6 million in Miscellaneous Revenue equals the $1,159.5 million revenue requirement.

2. NSPI's 2007 forecasted fuel expense is set at $470 million, with the natural gas margin set at $47 million. In the event NSPI's actual natural gas margin does not achieve a level of $47 million, NSPI may defer for later recovery in rates any difference, down to $39 million, for a maximum deferral of $8 million.

This is confirmed by the sum of fuel and purchased power costs shown on lines 1 and 2, column 1, of Exhibit 4 of the Cost of Service Study (COSS) included as Appendix 3. Recovery of a deferral of up to $8 million will be requested in a future proceeding if actual 2007 gas margin is less than $47 million.

3. **The third year of the phase in of depreciation rates is deferred for recovery in the next general rate application.**

This reduces 2007 depreciation expense by $6 million. This can be confirmed by comparing the sum of the figures shown in rows 26 through 34 of column 1, Exhibit 4 of the attached COSS, with the sum from the same exhibit filed with NSPI's October 10, 2006 Application.

4. **All parties agree in principle that the UARB should adopt a Fuel Adjustment Mechanism ("FAM"). The parties request the UARB to establish a process that commences as soon as possible to establish a FAM. The parties will work constructively on the content or elements of a FAM. A FAM hearing will begin no later than July 15, 2007.**

This item is not addressed in this Compliance Filing.

5. **NSPI shall file with the UARB and the parties (subject to the usual undertakings regarding confidentiality), on or before October 31, 2007, an updated forecast for fuel and purchased power and other significant projected cost changes for 2008. Any of the parties may ask the UARB to consider whether there should be a proceeding to adjust rates for 2008.**

This item has no effect on 2007 revenue requirement or rates.

6. **Excess earnings by NSPI, if any, in 2007 and 2008 will be applied to the S21 unamortized balance.**

This item has no effect on 2007 revenue requirement or rates.

7. **NSPI's request for a deferral of first quarter 2007 fuel costs is withdrawn.**

This item has no effect on 2007 revenue requirement or rates.

8. There are no further changes to NSPI's Application including: rate base and return on rate base, return on equity, OM&G, regulatory amortizations and income taxes.

The financial effect of the SA is summarized on Table 1 of Appendix 2.

9. NSPI's request for a true-up for the 2P-RTP is deferred to the December 1 annual review of the ELI 2P-RTP rate.

No true up is requested in this Compliance Filing.

10. The UARB directive from the 2006 Rate Case regarding the study of NSPI's OM&G is not deemed to be completed by this Agreement.

This item has no effect on 2007 revenue requirement or rates.

11. The Revenue to Cost ratio methodology as described by Dr. Stutz at pages 15 and 16 of his December 20, 2006 Evidence will be adopted, except for modifications to incorporate a change to the unmetered rate class, for which the combined C3 weighting factor will be .82 for billing services and call centres.

The revenue allocation procedure is shown in Appendix 4. Other than the General class, the Unmetered class, and the ELI 2P-RTP class, all other class revenue responsibilities have been increased by the same percentage.

The General class increase is lower because its R/C ratio remains higher than other classes. As directed, it has been reduced to 107% from approximately 109%, half of the reduction necessary to bring it to 105%.

The Unmetered class increase results from the street light maintenance and capital expenses from the cost study conducted in 2006, the use of 0.82 as the weighting factor (see Exhibit 8A, line 22, column 11, of COSS) applied to the C3 allocation

factor, and setting the class at a R/C ratio of 100%.

The ELI 2P-RTP increase has been determined setting the R/C ratio at 95%. Other classes receive an increase of equal percentage to provide the remaining revenue requirement.

On January 23, 2007, NSPI filed Exhibit N-49. This Exhibit has been revised to reflect the final calculation of the COSS. The updated exhibit appears as Table 9.4 in Appendix 4.

The first revision is with respect to the Unmetered Class weighting factor used with the C-3 allocator. The COSS used to prepare Exhibit N-49 inadvertently did not reflect the factor of 0.82 as stated in the SA. Correcting this reduced the costs assigned to the Unmetered class in accordance with the SA.

The second revision is with respect to the amount of depreciation expense allocated to the ELI 2P-RTP class. The amount of transmission-related depreciation expense allocated to this class understated the costs of serving the class, resulting in the increase shown in Exhibit N-49.

Prior to this revision, the anticipated ELI 2P-RTP rate had already been communicated as $56.55/MWh in a public session before the Board. The rate should have been $57.33/MWh at a 95% R/C ratio. NSPI will honor the stated $56.55 ELI 2P-RTP rate. Other customer classes will be charged the revised rates in accordance with the SA. As a result of these COSS revisions, the rate increases for other customers will be lower than those indicated in Exhibit N-49, because the removal of the over-allocated amount of transmission-related depreciation expense from other customer classes outweighs the effect of applying the weighting factor of 0.82 in respect of the Unmetered Class. The corrected final revenue increases are found on Table 9.4 of Appendix 4.

12. Subject to paragraph 4, above, this agreement does not preclude NSPI or any of the parties from taking any positions in future regulatory proceedings.

This item has no effect on 2007 revenue requirement or rates.

2.0 COST OF SERVICE

The revised COSS is shown in Appendix 3. Cost data is input into the Cost of Service Study in Exhibits 2 and 4 only. All other exhibits that deal with classification and allocation of costs are derived from Exhibits 2 and 4.

The revisions to rate base which result from the Board's decision are input to the Cost of Service in Exhibit 2.

The revisions to operating cost that result from the Board's decision are input to the Cost of Service in Exhibit 4.

In addition to cost data, the Cost of Service also includes a revenue analysis. This is shown in Exhibit 7.

Exhibit 1 summarizes the costs, revenues and R/C ratios by class under the compliance rates. As shown in that exhibit, all R/C ratios except the General class are within the 0.95 – 1.05 range specified by the Board. The General class continues to be outside the range and as a result, this class experiences the lowest overall increase of all the above-the-line classes.

3.0 RATE DESIGN

As shown in Table 1 of Appendix 2, the total revenue approved by the Board as a result of its February 5, 2007 decision is $1,159.5 million. Of this, $10.6 million will result from the provision of miscellaneous services such as pole attachment fees, wiring inspections, and connection charges, as discussed further in Section 5.5. An additional $8.5 million is expected to come from export sales. The balance, $1,140.4 million, will be provided through

the sale of electricity to customers in Nova Scotia.

Per the Settlement Agreement and the Board's decision, revenue allocation was calculated using the approach recommended by Dr. Stutz in his December 20, 2006 Evidence. The revenue allocation steps are shown in Appendix 4.

The derivation of Below-the-Line (BTL) rates and the revenues they are expected to produce in 2007 are discussed in Section 3.1. Although the ELI 2P-RTP rate is a BTL rate for purposes of operational reviews, its cost of service is based on the COSS and the rate level changes as if it was an Above-the-Line (ATL) rate. It has been included with the ATL classes in this filing.

The derivation of Above-the-Line rates and the revenues they are expected to produce in 2007 are discussed in Section 3.2.

Figure 3.1 summarizes the expected sources of revenues, comparing the Compliance Filing with NSPI's October 10, 2006 filing.

Figure 3.1

Test Year Revenue Forecast for 2007 (in millions of $)

Category	October, 2006 Submission	February 2007, Compliance Filing	Variance	% Variance
Above-the-line	$1,158.7	$1,121.2	-$37.5	-3.2%
Below-the-line	$19.5	$19.2	-$0.3	-1.8%
Total in Province	$1,178.2	$1,140.4	-$37.9	-3.2%
Export Revenues	$8.5	$8.5	$0.0	0.0%
Electric Revenue	$1,186.8	$1,148.9	-$37.9	-3.2%
Miscellaneous Revenues	$10.8	$10.6	-$0.2	-1.7%
Total Revenue	$1,197.6	$1,159.5	-$38.1	-3.2%

3.1 Below-the-Line Rates

The BTL rates that are annually adjusted rates ("AARs") are normally approved in a process that is separate and distinct from ATL rates. Due to the introduction of the new operating parameters regarding the ELI 2P-RTP rate, the Board approved NSPI's November 1, 2006 request to delay filing the 2007 AARs, namely the Load Following rate and 1P-RTP adders. No customers currently use the 1P-RTP rate.

In order to accurately forecast the expected marginal costs used as the basis of the Load Following rate, it is important that the forecast system load shape reflects the load expected given the rates in effect. The new ELI 2P-RTP rate, which took effect in December, 2006, assumes that the loadshape for ELI 2P-RTP customers is a flat Customer Baseline Loadshape (CBL). It is this loadshape that therefore must be used in calculating the average marginal costs for 2007 for the purposes of the Load Following rate.

The SA stipulates a 2007 test year revenue requirement of $1,159.5 million. The Load Following rate forecast at the time of NSPI's October 10, 2006 Rate filing was projected to be approximately $108/MWh, resulting in anticipated revenue of $1.2 million. This is the figure that was used in the revenue allocation procedures associated with the SA and which forms the basis for the average 3.8% ATL increase of this Compliance Filing.

The proposed 2007 AARs have not yet been formally reviewed by the Board. Now that the 2007 ELI 2P-RTP CBLs are known, NSPI will calculate the 2007 average marginal costs using these CBLs in the system load shape and will submit, in a separate application for the Board's approval, the proposed 2007 AARs which will be applied retroactively to January 1, 2007. The AAR tariffs are not included in this Compliance Filing.

3.2 Above-the-Line Revenues and Rate Design

Given the total revenues of $ 1,159.5 million and the expected revenues from miscellaneous sources, export sales and BTL sales, the residual revenue from ATL sales can be calculated.

As shown in Figure 3.1, this revenue is $1,121.2 million. This is equivalent to an average increase of 3.8% for all above-the-line classes, as shown in Table 11, Appendix 2.

The resulting revenues by class, based on the Board's directed approach, are shown in Appendix 4.

3.3 Proposed Rates

NSPI developed new rates by applying the class revenue percent increases to both energy and demand charges within each rate class. No customer charges were changed. There are no changes to the interruptible credit for the Large Industrial Class and no changes to the transformer ownership credit. The compliance rates are included as Figure 9.5 in Appendix 5.

The Compliance Tariffs are shown in Appendix 7. The Unmetered Services section has been expanded to include a more complete list of street lighting types in general use. These include full charge (operating, maintenance and capital), operating and maintenance only, and operating-only rates.

On February 12, 2007 NSPI requested a revision to the wording of the "CBL Base Cost" section of the ELI 2P-RTP tariff. The requested revision is operational in nature, has the support of SEB, and does not affect other customer classes. The ELI 2P-RTP tariff included in this Compliance filing reflects the proposed wording change.

3.4 Proof of Electric Revenue

To demonstrate that the proposed new rates will provide electric revenue of $1,148.9 million ($ 1,159.5 million in in-province and export sales minus $10.6 million of miscellaneous revenue), the new rates were applied to expected billing determinants in 2007. The results are shown in Appendix 6.

3.5 Miscellaneous Revenues

As directed by the Board, NSPI has increased certain miscellaneous charges by the average percent increase for above-the-line classes. That increase is 3.8%. Only a portion of miscellaneous rates are subject to the increase, and as a result, total miscellaneous revenues increased by 1.8% to $10.6 million.

APPENDIX 1

MINUTES OF SETTLEMENT

2006 NOVA SCOTIA UTILITY AND REVIEW BOARD P-886

IN THE MATTER OF: *The Public Utilities Act*, R.S.N.S. 1989, c.380 as amended

- and -

IN THE MATTER OF: An Application by Nova Scotia Power Incorporated for Approval of Certain Revisions to its Rates, Charges and Regulations

MINUTES OF SETTLEMENT

WHEREAS the Applicant, Nova Scotia Power Inc. ("NSPI"), the undersigned Intervenors (Avon Valley et al, the Consumer Advocate, the Halifax Regional Municipality, and the Municipal Electric Utilities Co-operative of Nova Scotia), and the staff of the Nova Scotia Utility and Review Board, have reached agreement on the matters in issue in this Application;

AND WHEREAS this Agreement is subject to review and approval by the Nova Scotia Utility and Review Board;

THE UNDERSIGNED PARTIES ("the parties") HEREBY AGREE and respectfully request the Utility and Review Board ("UARB") to approve:

1. NSPI's 2007 test year revenue requirement is set at $1,159.5 million, with new rates effective April 1, 2007.

2. NSPI's 2007 forecasted fuel expense is set at $470 million, with the natural gas margin set at $47 million. In the event NSPI's actual natural gas margin does not achieve a level of $47 million, NSPI may defer for later recovery in rates any difference, down to $39 million, for a maximum deferral of $8 million.

3. The third year of the phase in of depreciation rates is deferred for recovery in the next general rate application.

4. All parties agree in principle that the UARB should adopt a Fuel Adjustment Mechanism ("FAM"). The parties request the UARB to establish a process that commences as soon as possible to establish a FAM. The parties will work constructively on the content or elements of a FAM. A FAM hearing will begin no later than July 15, 2007.

5. NSPI shall file with the UARB and the parties (subject to the usual undertakings regarding confidentiality), on or before October 31, 2007, an updated forecast for fuel and purchased power and other significant projected cost changes for 2008.

Any of the parties may ask the UARB to consider whether there should be a proceeding to adjust rates for 2008.

6. Excess earnings by NSPI, if any, in 2007 and 2008 will be applied to the S21 unamortized balance.

7. NSPI's request for a deferral of first quarter 2007 fuel costs is withdrawn.

8. There are no further changes to NSPI's Application including: rate base and return on rate base, return on equity, OM&G, regulatory amortizations and income taxes.

9. NSPI's request for a true-up for the 2P-RTP is deferred to the December 1 annual review of the ELI 2P-RTP rate.

10. The UARB directive from the 2006 Rate Case regarding the study of NSPI's OM&G is not deemed to be completed by this Agreement.

11. The Revenue to Cost ratio methodology as described by Dr. Stutz at pages 15 and 16 of his December 20, 2006 Evidence will be adopted, except for modifications to incorporate a change to the unmetered rate class, for which the combined C3 weighting factor will be .82 for billing services and call centres.

12. Subject to paragraph 4, above, this agreement does not preclude NSPI or any of the parties from taking any positions in future regulatory proceedings.

AGREED, and signed by legal Counsel or other authorized representative, THIS 21st DAY OF JANUARY, 2007.

Nova Scotia Power Inc.

Per: Rene Gallant

Avon Valley et al

Per: Robert G. Grant, Q.C.

Consumer Advocate

Per: John Merrick, Q.C.

Halifax Regional Municipality

Per: Martin C. Ward, Q.C.

Municipal Electric Utilities Co-operative Of Nova Scotia

Per: Don Regan

UARB Staff

Per: Bruce Outhouse, Q.C.

Any of the parties may ask the UARB to consider whether there should be a proceeding to adjust rates for 2008.

6. Excess earnings by NSPI, if any, in 2007 and 2008 will be applied to the S21 unamortized balance.

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8. There are no further changes to NSPI's Application including: rate base and return on rate base, return on equity, OM&G, regulatory amortizations and income taxes.

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Per: Robert G. Grant, Q.C.

Consumer Advocate

Per: John Merrick, Q.C.

Halifax Regional Municipality

Per: Martin C. Ward, Q.C.

Municipal Electric Utilities Co-operative Of Nova Scotia

Per: Don Regan

UARB Staff

Per: Bruce Outhouse, Q.C.

Any of the parties may ask the UARB to consider whether there should be a proceeding to adjust rates for 2008.

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AGREED, and signed by legal Counsel or other authorized representative, THIS 21st DAY OF JANUARY, 2007,

Nova Scotia Power Inc.

Per: Rene Gallant

Avon Valley et al

Per: Robert G. Grant, Q.C.

Consumer Advocate

Per: John Merrick, Q.C.

Halifax Regional Municipality

Per: Martin C. Ward, Q.C.

Municipal Electric Utilities Co-operative Of Nova Scotia

Per: Don Regan

UARB Staff

Per: Bruce Outhouse, Q.C.

Any of the parties may ask the UARB to consider whether there should be a proceeding to adjust rates for 2008.

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7. NSPI's request for a deferral of first quarter 2007 fuel costs is withdrawn.

8. There are no further changes to NSPI's Application including: rate base and return on equity, OM&G, regulatory amortizations and income taxes.

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12. Subject to paragraph 4, above, this agreement does not preclude NSPI or any of the parties from taking any positions in future regulatory proceedings.

AGREED, and signed by legal Counsel or other authorized representative, THIS 21st DAY OF JANUARY, 2007,

Nova Scotia Power Inc.

Per: Rene Gallant

Avon Valley et al

Per: Robert Grant, Q.C.

Consumer Advocate

Per: John Merrick, Q.C.

Halifax Regional Municipality

Per: Mary Ellen Donovan

Municipal Electric Utilities Co-operative Of Nova Scotia

Per: Don Regan

UARB Staff

Per: Bruce Outhouse, Q.C.

Stora Enso and Bowater (SEB)

Per: George Cooper, Q.C.

Canadian Manufacturers and Exporters (CME)

Per: Robert Patzelt, Q.C.

Any of the parties may ask the UARB to consider whether there should be a proceeding to adjust rates for 2008.

6. Excess earnings by NSPI, if any, in 2007 and 2008 will be applied to the S21 unamortized balance.

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12. Subject to paragraph 4, above, this agreement does not preclude NSPI or any of the parties from taking any positions in future regulatory proceedings.

AGREED, and signed by legal Counsel or other authorized representative, THIS 2nd DAY OF ~~JANUARY~~ FEBRUARY, 2007,

Nova Scotia Power Inc.	**Avon Valley et al**
Per: Rene Gallant	Per: Robert Grant, Q.C.
Consumer Advocate	**Halifax Regional Municipality**
Per: John Merrick, Q.C.	Per: Mary Ellen Donovan
Municipal Electric Utilities Co-operative Of Nova Scotia	**UARB Staff**
Per: Don Regan	Per: Bruce Outhouse, Q.C.
Stora Enso and Bowater (SEB)	**Canadian Manufacturers and Exporters (CME)**
Per: George Cooper, Q.C.	Per: Robert Patzelt, Q.C.

APPENDIX 2

FINANCIAL TABLES

Nova Scotia Power Inc. **Table 1**

Revenue Requirement
Years Ended December 31st
Millions of Dollars

Compliance Filing - 2007 Rate Case

	(1)	(2)	(3)
	Proposed Rates Test Year Forecast 2007	**Compliance Rates Test Year Forecast 2007**	**Change**
Net Regulated Plant in Service	2,328.4	2,334.4	$ 6.0
Plus: Construction work in progress	33.9	33.9	-
Net Utility Fixed Assets	2,362.3	2,368.3	6.0
Add:			
Deferred Charges & Credits			
Financing Charges	140.8	140.8	-
Tax Charges	147.7	147.7	-
Pension Charges	34.2	34.2	-
Steam Plant Charges	0.5	0.5	-
Other General Charges	0.5	0.5	-
Asset Retirement Obligation	(79.2)	(79.2)	-
Other Deferred Credits	(3.5)	(3.5)	-
[redacted]	9.3	11.5	2.2
Allowance for materials and supplies	77.5	77.5	-
Allowance for working capital	25.1	25.1	-
Total additions	353.0	355.1	2.2
Regulated Rate Base	$2,715.3	$2,723.4	8.2
Average Regulated Rate Base	**2,772.2**	**2,776.3**	4.1
Weighted average cost of capital	8.25%	8.25%	-
Cost of capital	228.8	229.0	0.3
Less: AFUDC	(2.3)	(2.3)	-
Operating costs	740.8	712.1	(28.7)
Depreciation and amortization	152.3	146.3	(6.0)
Income taxes	81.0	77.3	(3.7)
Total Revenue Requirement	**$1,200.5**	**$1,162.4**	**(38.1)**
Less: Securitization fees, included in Other revenue	(2.9)	(2.9)	-
Net Revenue per Statement of Earnings	**$1,197.6**	**$1,159.5**	**(38.1)**

Notes:
1) Figures presented reflect whole numbers which may cause $0.1M in rounding differences on some line items.

Nova Scotia Power Inc. **Table 2**

Regulated Statement of Earnings
Years Ended December 31st
Millions of Dollars

Compliance Filing - 2007 Rate Case

		(1) Proposed Rates Test Year Forecast 2007	(2) Compliance Rates Test Year Forecast 2007	(3) Change
3	**Revenue**			
4	Electric	$1,186.8	$1,148.8	($38.0)
5	Other	10.8	10.7	(0.1)
6	Total	1,197.6	1,159.5	**(38.1)**
7				
8	**Cost of Operations**			
9	Fuel and purchased power	498.7	470.0	(28.7)
10	Cost of goods sold	1.1	1.1	-
11	Operating maintenance and general	200.9	200.9	-
12	Grants in lieu of property taxes	33.4	33.4	-
13	Provincial large corporation tax	6.6	6.6	-
14	Depreciation	136.1	130.1	(6.0)
15	Total Cost of Operations	876.9	842.2	(34.7)
16				
17	**Earnings From Operations**	320.7	317.3	(3.4)
18				
19	Regulatory amortization	(16.2)	(16.2)	-
20	Allowance for funds used during construction	2.3	2.3	-
21				
22	**Earnings Before Interest and Tax**	306.9	303.5	(3.4)
23				
24	Other income	-	-	
25	Interest	112.3	112.6	0.3
26				
27	**Earnings Before Income Tax**	194.6	190.9	(3.8)
28				
29	Federal large corporations tax	-	-	-
30	Corporate income tax	81.0	77.3	(3.7)
31				
32	**Net Earnings Before Dividends**	113.5	113.6	0.1
33				
34	Preferred dividends	14.1	14.1	-
35				
36	**Net Earnings Applicable to Common Shares**	$99.4	$99.5	0.1
37				
38	**Notes:**			
39	1) Figures presented reflect whole numbers which may cause $0.1M in rounding differences on some line items.			
40	2) Part VI.I tax reclassified from preferred dividends to corporate income tax.			

Nova Scotia Power Inc. **Table 3**

Regulated Balance Sheet
Years Ended December 31st
Millions of Dollars

Compliance Filing - 2007 Rate Case

	(1) Proposed Rates Test Year Forecast 2007	(2) Compliance Rates Test Year Forecast 2007	(3) Change
Assets			
Fixed assets (net)	$2,328.4	$2,334.4	$6.0
Construction work in progress	33.9	33.9	-
	2,362.3	2,368.3	6.0
Current assets			
Cash	-	-	-
Restricted cash	-	-	-
Accounts receivable	181.1	178.0	(3.1)
Income taxes receivable	4.9	4.9	-
Materials inventory	26.8	26.8	-
Fuel inventory	51.7	51.7	-
Prepaid expenses	5.2	5.2	-
Due from associated companies	22.8	21.2	(1.6)
	292.5	287.8	(4.7)
Deferred charges	323.7	323.7	-
[redacted]	9.3	11.5	2.2
Total Assets	**$2,987.8**	**$2,991.4**	**3.6**
Equity and Liabilities			
Shareholder's Equity			
Common shares	$830.6	$830.6	-
Preferred shares	260.0	260.0	-
Retained earnings	187.6	190.6	3.0
Long term debt	1,233.8	1,233.8	-
Deferred credits	82.7	82.7	-
Current Liabilities			
Current portion of long term debt	115.0	115.0	-
Bank indebtedness	88.3	93.6	5.3
Accounts payable	161.4	156.7	(4.7)
Dividends payable	3.2	3.2	-
Income taxes payable	-	-	-
Accrued interest	25.2	25.2	-
	393.2	393.7	0.5
Total Liabilities and Equity	**$2,987.8**	**$2,991.4**	**3.6**

Notes:
1) Figures presented reflect whole numbers which may cause $0.1M in rounding differences on some line items.

Nova Scotia Power Inc. **Table 4**

Regulated Statement of Retained Earnings
Years Ended December 31st
Millions of Dollars

Compliance Filing - 2007 Rate Case

	(1) Proposed Rates Test Year Forecast 2007	(2) Compliance Rates Test Year Forecast 2007	(3) Change
Regulated Retained Earnings at Beginning of Year	$233.6	$233.6	$0.0
Net earnings applicable to common shares	99.4	99.5	$0.1
	333.0	333.1	$0.1
Common dividends	(145.4)	(142.5)	$2.9
Regulated Retained Earnings at End of Year	$187.6	$190.6	$3.0

Notes:
1) Figures presented reflect whole numbers which may cause $0.1M in rounding differences on some line items.
2) All dividends are paid to the extent required to maintain the capital structure approved by the UARB.

Nova Scotia Power Inc. **Table 5**

Regulated Statement of Cash Flows
Years Ended December 31st
Millions of Dollars

Compliance Filing - 2007 Rate Case

	(1) Proposed Rates Test Year Forecast 2007	(2) Compliance Rates Test Year Forecast 2007	(3) Change
Operating Activities			
Net earnings applicable to common	$99.4	$99.5	$0.1
Non cash items:			
Depreciation	136.1	130.1	(6.0)
Regulatory amortization	16.2	16.2	-
Less AFUDC	(2.3)	(2.3)	-
Deferred charges, net	23.3	23.3	-
Cash flow from operations	272.7	266.8	(5.9)
Change in operating working capital	74.5	72.2	(2.3)
Net Cash From Operations	347.2	339.0	(8.2)
Financing Activities			
Dividends paid on common shares	(145.4)	(142.5)	2.9
Proceeds from (repayment of) long term debt	(0.8)	(0.8)	-
Increase in (repayment of) short term debt	(67.1)	(61.8)	5.3
Other	-	-	-
Net Cash From Financing	(213.3)	(205.1)	8.2
Investing Activities			
Property plant and equipment, net	(133.9)	(133.9)	-
Net Cash Used in Investing	(133.9)	(133.9)	-
Change in Cash Position	-	-	-
Cash Position Beginning	-	-	-
Cash Position Ending	-	-	-

Notes:
1) Figures presented reflect whole numbers which may cause $0.1M in rounding differences on some line items.
2) All dividends are paid to the extent required to maintain the capital structure approved by the UARB.

Nova Scotia Power Inc. **Table 6**

Detail of Electric Revenue
Years Ended December 31st
Millions of Dollars

Compliance Filing - 2007 Rate Case

	(1) Proposed Rates Test Year Forecast 2007	(2) Compliance Rates Test Year Forecast 2007	(3) Change
Residential	**$524.8**	**$504.2**	**($20.6)**
General			
Small general	30.2	29.4	(0.7)
General	252.8	249.3	(3.5)
Large general	35.8	34.4	(1.4)
Total General	**318.8**	**313.1**	**(5.6)**
Industrial			
Small industrial	24.7	24.1	(0.6)
Medium industrial	50.2	49.0	(1.2)
Large industrial	74.5	72.2	(2.4)
GRLF	1.2	1.2	-
Mersey Basic Block	7.3	7.3	-
Mersey Additional Energy	11.1	10.7	(0.3)
Extra large industrial interruptible	-		-
Real time pricing	-	-	-
Extra large industrial interruptible - 2	124.9	119.5	(5.4)
Total Industrial	**293.9**	**283.9**	**(9.9)**
Other			
Municipal	16.6	15.7	(0.9)
Unmetered	24.2	23.3	(0.8)
Total Other	**40.7**	**39.0**	**(1.7)**
Total In Province Electric Revenue	**1,178.2**	**1,140.4**	**(37.9)**
Export Sales	**8.5**	**8.5**	-
Total Electric Revenue	**$1,186.8**	**$1,148.8**	**(38.0)**

Notes:
1) Figures presented reflect whole numbers which may cause $0.1M in rounding differences on some line items.

Nova Scotia Power Inc. **Table 7**

Gwh Production and Sales

Years Ended December 31st

Compliance Filing - 2007 Rate Case

	(1) Proposed Rates Test Year Forecast 2007	(2) Compliance Rates Test Year Forecast 2007	(3) Change
Residential	**4,257.5**	**4,257.5**	-
General			
Small general	241.8	241.8	-
General	2,478.6	2,478.6	-
Large general	421.4	421.4	-
Total General	**3,141.7**	**3,141.7**	-
Industrial			
Small industrial	253.3	253.3	-
Medium industrial	585.2	585.2	-
Large industrial	1,079.3	1,079.3	-
GRLF	11.8	11.8	-
Mersey Basic Block	189.0	189.0	-
Mersey Additional Energy	178.9	178.9	-
Extra large industrial interruptible	-	-	-
Real time pricing	-	-	-
Extra large industrial interruptible - 2	2,076.1	2,076.1	-
Total Industrial	**4,373.5**	**4,373.5**	-
Other			
Municipal	196.3	196.3	-
Unmetered	112.4	112.4	-
Total Other	**308.7**	**308.7**	-
Total In Province Electric Sales	**12,081.4**	**12,081.4**	-
Export	**76.2**	**76.2**	-
Total Electric Sales	**12,157.6**	**12,157.6**	-
Losses			
In-province sales	899.2	899.2	-
Export sales	2.4	2.4	-
Total Losses	**901.6**	**901.6**	-
Total System Requirements	**13,059.2**	**13,059.2**	-
Net System Requirements	**12,980.6**	**12,980.6**	-

Notes:

1) Figures presented reflect whole numbers which may cause $0.1M in rounding differences on some line items.

Nova Scotia Power Inc. **Table 8**

Detail of Fuel and Purchased Power
Years Ended December 31st
Millions of Dollars

Compliance Filing - 2007 Rate Case

	(1) Proposed Rates Test Year Forecast 2007	(2) Compliance Rates Test Year Forecast 2007	(3) Change
Fuel By Type			
Solid Fuel	$276.8	$275.8	($1.0)
Natural gas	98.0	94.8	($3.2)
Bunker C	97.0	86.8	($10.2)
Furnace	2.3	1.3	($1.1)
Diesel	14.5	14.2	($0.3)
Additives	3.2	3.2	-
Total Fuel For Generation	**491.8**	**476.1**	(15.8)
Purchased Power			
Imports	5.0	5.0	-
Independent power producers	27.1	27.1	-
Total Purchased Power	**32.1**	**32.1**	-
Fuel and Purchased Power	**523.9**	**508.2**	(15.8)
Fuel For Resale			
Costs	98.3	75.2	(23.1)
Recoveries	(131.9)	(101.2)	30.7
Additional Margin as per settlement agreement	-	(20.6)	(20.6)
Net Cost (Benefit)	**(33.6)**	**(46.6)**	(13.0)
Export Sales	**7.6**	**7.6**	-
Water Royalties	**0.8**	**0.8**	-
MTM on HFO and Natural Gas	**-**	**-**	-
Total Fuel and Purchased Power	**$498.7**	**$470.0**	**(28.7)**
Total System Requirements (GWH)	**13,059.2**	**13,059.2**	
Total Fuel Cost / MWH	**$38.19**	**$35.99**	

Notes:
1) Figures presented reflect whole numbers which may cause $0.1M in rounding differences on some line items.

Nova Scotia Power Inc. **Table 9**

Operating, Maintenance and General
Years Ended December 31st
Millions of Dollars

Compliance Filing - 2007 Rate Case

	(1) Proposed Rates Test Year Forecast 2007	(2) Compliance Rates Test Year Forecast 2007	(3) Change
Corporate Groups	$35.1	$35.1	$0.0
Power Production	75.8	75.8	-
Customer Operations	52.3	52.3	-
Customer Services	25.0	25.0	-
Corporate Adjustments	12.7	12.7	-
Total Operating, Maintenance & General	**$200.9**	**$200.9**	**$0.0**

Notes:
1) Figures presented reflect whole numbers which may cause $0.1M in rounding differences on some line items.

Nova Scotia Power Inc. **Table 10**

Detail of Interest Charges
Years Ended December 31st
Millions of Dollars

Compliance Filing - 2007 Rate Case

	(1) Proposed Rates Test Year Forecast 2007	(2) Compliance Rates Test Year Forecast 2007	(3) Change
Interest on long-term debt	$92.3	$92.3	$0.0
Interest on short-term borrowings	4.2	4.4	$0.3
Other financing charges & adjustments	1.5	1.5	-
Amortization of deferred financing charges	14.4	14.4	-
Net Interest Expense	**$112.3**	**$112.6**	$0.3
Securitization fees, included in Other revenue	2.9	2.9	-
Total Regulated Financing Cost	**$115.3**	**$115.6**	$0.3

Notes:
1) Figures presented reflect whole numbers which may cause $0.1M in rounding differences on some line items.

Nova Scotia Power Inc. **Table 11**

Revenue Requirement and Rate Increase
Years Ended December 31st
Millions of Dollars

Compliance Filing - 2007 Rate Case

		(1) Proposed Rates Test Year Forecast 2007		(2) Compliance Rates Test Year Forecast 2007	
Forecast Net Earnings at Proposed Rates (Full Year)		**$99.4**		**$ 99.5**	
Less:					
	Net earnings at present rates	48.3		85.3	
	Incremental other revenue increase	0.4		0.2	
	Mersey Additional Energy revenue increase	0.8		0.5	
Add:					
	Net increase in income tax	31.5		27.8	
	Incremental interest expense	(0.1)		0.2	
Electric Revenue Rate Requirement			**$81.3**		**$41.5**
Electric Revenue Present Rates		$1,104.6		$1,107.0	$2.4
Less:	Annually adjusted rate class revenue	18.7		18.7	
	Export sales	8.5		8.5	
Electric Rate Revenue Present Rates for general application customers			$1,077.4		$1,079.8
Percent Increase on Present Rates for general application customers			**7.55%**		**3.8%**

Notes:
1) Figures presented reflect whole numbers which may cause $0.1M in rounding differences on some line items.

Nova Scotia Power Inc.

Capital Structure and Ratios **Table 12**

Years Ended December 31st

Millions of Dollars

Compliance Filing - 2007 Rate Case

	(1) Proposed Rates Test Year Forecast 2007	(2) Compliance Rates Test Year Forecast 2007	(3) Change
Capitalization:			
Debt %	52.9%	53.0%	0.1%
Preferred %	9.6%	9.5%	-0.1%
Common %	37.5%	37.5%	0.0%
Total Regulated Capitalization $:	$2,715.3	$2,723.5	$8.2
Ratios:			
Return on average common equity (%)	9.55%	9.55%	0.0%
Average common equity ($M)	$1,041.2	$1,042.8	$1.6
FFO Interest Coverage (times)	3.8x	3.7x	-0.1x
FFO to Adjusted Debt (%)	22%	21%	-1%

Notes:

1) FFO defined as: (Cash flows from operations + Interest expense - Amortization of deferred financing costs) / Net Interest expense

2) Figures presented reflect whole numbers which may cause $0.1M in rounding differences on some line items.

3) Adjusted debt reflects debt and preferred shares

Nova Scotia Power Inc. **Table 13**

Estimated Average Capital and Cost of Capital
Years Ended December 31st
Millions of Dollars

Compliance Filing - 2007 Rate Case

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Opening	Closing	Average Capital	Capital Ratio	Cost Pre-tax Factor	Cost After-tax Factor	Weighted Pre-tax Cost	Weighted After-tax Cost
Estimated Cost of Capital								
Short-term debt	$155.4	$93.6	$124.5	4.5%	5.91%	3.65%	0.26%	0.16%
Long-term debt	1,349.6	1,348.8	1,349.2	48.6%	8.02%	5.00%	3.90%	2.43%
Total debt	$1,505.0	$1,442.4	$1,473.7	53.1%	13.92%	8.66%	4.16%	2.60%
Preferred shares	260.0	260.0	260.0	9.4%	5.42%	5.11%	0.51%	0.48%
Common equity	1,064.2	1,021.2	1,042.7	37.6%	9.55%	9.55%	3.59%	3.59%
Total	**$2,829.2**	**$2,723.5**	**$2,776.3**	**100.0%**			**8.25%**	**6.66%**

Notes:
1) Figures presented reflect whole numbers which may cause $0.1M in rounding differences on some line items.
2) Calculation based on **2007 Test Year Compliance Rates Forecast.**
3) Short-term debt cost factor includes account receivable securization fees accounted for in Other Revenue.
4) Pre-tax equity cost excludes the income tax gross-up factor
5) Average capital reflects average of year-end balances

Nova Scotia Power Inc. **Table 14**

Average Rate Base
Supporting Schedule - Capital Assets
Years Ended December 31st
Millions of dollars

Compliance Filing - 2007 Rate Case

		(1) Compliance Forecast	(2) Compliance Rates	(3)	(4)
1					
2		2006	Test Year Forecast 2007	Average 2007	Reference
3	**Net Regulated Plant in Service**				
4	Net Regulated Plant in Service, beginning balance	[redacted]	$2,340.0		Table 3, line 4
5	Add: Asset additions		120.5		
6	Less:				
7	Depreciation, net		(127.1)		Table 14, line 25
8	[redacted]		-		
9	Less: ARO adjustment to liability		1.0		
10					
11	Net Regulated Plant in Service, ending balance		2,334.4	2,337.2	Table 3, line 4
12					
13	**Construction work in progress**				
14	Construction work in progress, beginning balance		18.3		Table 3, line 5
15	Add: Capital spending including AFUDC		136.2		Table 5, lines 11& 30
16	Less: Asset additions (per above)		(120.5)		
17					
18	Construction work in progress, ending balance		33.9	26.1	Table 3, line 5
19					
20	**Depreciation expense**				
21	Depreciation, regulated expense		130.1		Table 2, line 14
22	Less:				
23	Asset retirement obligation		(3.0)		
24			-		
25	Depreciation, net (per above)		127.1		Table 14, Line 7

14 **Notes:**
15 1) Figures presented reflect whole numbers which may cause $0.1M in rounding differences on some line items.

Nova Scotia Power Inc. **Table 15**

Average Rate Base

Supporting Schedule - Deferred Charges & Credits

Years Ended December 31st

Millions of dollars

Compliance Filing - 2007 Rate Case

		(1) Compliance Forecast	(2) Compliance Rates	(3)	(4)
1					
2		2006	Test Year Forecast 2007	Average 2007	Reference
3	**Deferred Charges - Financing**				
4	**Defeasance**				
5	Beginning balance		$143.8		
6	Less: Amortization		(12.7)		
7	Ending balance		131.1	137.5	
8	**Financing Issue Costs**				
9	Beginning balance		11.4		
10	Add: New debt issue costs		-		
11	Less: Amortization		(1.7)		
12	Ending balance		9.7	10.6	
13					
14	**Total Deferred Charges - Financing Ending Balance**		140.8	148.0	Table 1, line 8
15					
16	**Total Amortization**		(14.4)		Table 10, line 6
17					
18	**Deferred Charges - Tax**				
19	Beginning balance		163.8		
20	Add: Additions / Adjustments		-		
21	Less: Amortizations		(16.2)		
22	Ending balance		147.7	155.7	Table 1, line 9
23					
24	**Deferred Charges - Pension**				
25	Beginning balance		43.5		
26	Add: Pension funding		23.7		
27	Less: Pension expense		(33.0)		
28	Ending balance		34.2	38.8	Table 1, line 10
29					
30	**Deferred Charges - Steam Plant**				
31	Beginning balance		0.5		
32	Amortization/Addition of fuel hedge premiums		-		
33	Less: Amortization of coal transporation assets		-		
34	Ending balance		0.5	0.5	Table 1, line 11
35					
36	**Deferred Charges - Other General**				
37	Beginning balance		0.7		
38	Add: General additions		-		
39	Less: Amortization		(0.2)		
40	Ending balance		0.5	0.6	Table 1, line 12
41					
42	**Asset retirement Obligation**				
43	Beginning balance		75.2		
44	Add: True up to ARO liability		1.0		
45	Add: Asset retirement obligation expense		3.0		Table 14, line 23
46	Ending balance		79.2	77.2	Table 1, line 13
47					
48	**Other Deferred Credits**				
49	Beginning balance		4.0		
50	Less: Amortization		(0.6)		
51	Ending balance		3.5	3.8	Table 1, line 14
52					
53	**Long term receivable**				
54	Beginning balance		85.7		
55	Add: Gas contract price difference		42.9		
56	Less: Shell Payment		(117.1)		
57	Ending balance		11.5	48.6	Table 1, line 15

14 **Notes:**

15 1) Figures presented reflect whole numbers which may cause $0.1M in rounding differences on some line items.

Forecasts are compiled for purposes of this rate application and are not intended to be relied upon for other purposes.

Nova Scotia Power Inc. **Table 16**

Average Rate Base
Supporting Schedule - Allowance for Materials & Supplies
Years Ended December 31st
Millions of dollars

Compliance Filing - 2007 Rate Case

	(1) Compliance Forecast	(2) Compliance Rates Test Year	(3)	(4)
	2006	Forecast 2007	Average 2007	Reference
Fuel Inventory				
January		$47.8		
February		45.8		
March		47.7		
April		49.4		
May		47.9		
June		50.2		
July		48.5		
August		51.2		
September		52.1		
October		57.5		
November		59.3		
December		51.7		Table 3, line 14
Average		50.8	51.4	
Materials Inventory				
January		26.8		
February		26.8		
March		26.8		
April		26.8		
May		26.8		
June		26.8		
July		26.8		
August		26.8		
September		26.8		
October		26.8		
November		26.8		
December		26.8		Table 3, line 13
Average		26.8	26.6	
Allowance for materials and supplies				
Fuel		50.8	51.4	
Materials		26.8	26.6	
Sub-total		$77.5	$78.0	Table 1, line 16

Notes:
1) Figures presented reflect whole numbers which may cause $0.1M in rounding differences on some line items.

Nova Scotia Power Inc. **Table 17**

Average Rate Base
Supporting Schedule - Allowance for Working Capital
Years Ended December 31st
Millions of dollars

Compliance Filing - 2007 Rate Case

1	**2007 Proposed Rates Test Year - Cash Working Capital Requirement**					
2	**Category**	**Lag Days (a)**	**Net Lag Days (b) [42.1 days - (a)]**	**% of Year (c) [(b) / 365]**	**Annual Cost (d)**	**CWC [(c) x (d)]**
3						
4	Revenue Lag	42.1				
5	Labour	21	21.1	5.8%	$ 112.3	6.5
6	Non-Labour Operating	50	(7.9)	(2.2)	88.6	(1.9)
7	Fuel & Purchased Power	29.4	12.7	3.5	630.6	21.9
8	Grants In Lieu of Taxes	(91)	133.1	36.5	33.4	12.2
9	Income Taxes	53	(10.9)	(3.0)	87.6	(2.6)
10	HST					(4.0)
11						
12	**TOTAL**					**32.1**
13	Less Consumer Deposits					(7.0)
14	**CWC Requirement - 2007**	Table 1, Line 17				**25.1**
15						
16	**2007 Compliance Rates Test Year - Cash Working Capital Requirement**					
17	**Category**	**Lag Days (a)**	**Net Lag Days (b) [42.1 days - (a)]**	**% of Year (c) [(b) / 365]**	**Annual Cost (d)**	**CWC [(c) x (d)]**
18						
19	Revenue Lag	42.1				
20	Labour	21	21.1	5.8%	$ 112.3	6.5
21	Non-Labour Operating	50	(7.9)	(2.2)	$ 88.6	(1.9)
22	Fuel & Purchased Power	29.4	12.7	3.5	$ 630.6	21.9
23	Grants In Lieu of Taxes	(91)	133.1	36.5	$ 33.4	12.2
24	Income Taxes	53	(10.9)	(3.0)	$ 87.6	(2.6)
25	HST					(4.0)
26						
27	**TOTAL**					**32.1**
28	Less Consumer Deposits					(7.0)
29	**CWC Requirement - 2007**	Table 1, Line 17				**25.1**

30 **Notes:**
31 1) Figures presented reflect whole numbers which may cause $0.1M in rounding differences on some line items.

Forecasts are compliled for purposes of this rate application and are not intended to be relied upon for other purposes.

APPENDIX 3

COST OF SERVICE STUDY

NOVA SCOTIA POWER INC.
COST OF SERVICE STUDY ANALYSIS
REFERENCE GUIDE

"REDACTED"

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EXHIBIT 1

NOVA SCOTIA POWER INC.

REVENUE TO EXPENSE COMPARISON

FOR THE YEAR ENDING DECEMBER 31, 2007

(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	$152,159	$291,692	6.85	$71,251	$515,103	$504,229	97.89
(2) SMALL GENERAL	8,708	16,478	6.81	3,898	29,085	29,425	101.17
(3) GENERAL	64,839	162,739	6.57	5,266	232,844	249,316	107.07
(4) LARGE GENERAL	7,231	27,380	6.50	226	34,836	34,404	98.76
(5) SMALL INDUSTRIAL	5,735	16,529	6.53	1,292	23,556	24,073	102.20
(6) MEDIUM INDUSTRIAL	9,748	38,030	6.50	573	48,351	48,992	101.32
(7) LARGE INDUSTRIAL	2,787	68,726	6.37	625	72,137	72,185	100.07
(8) EXTRA LI INTERR. - 2	(1,752)	127,101	6.12	463	125,813	119,522	95.00
(9) MUNICIPAL	3,373	12,628	6.43	144	16,144	15,724	97.39
(10) UNMETERED	14,627	7,644	6.80	1,049	23,321	23,321	100.00
(11) SUB-TOTAL	$267,456	$768,948	6.57	$84,787	1,121,190	1,121,190	100.00
(12) DIRECT EXP./ REV					15,737	19,165	N/A
(13) RETURN ON DIRECT EXP.					3,428	0	N/A
(14) TOTAL					$1,140,355	$1,140,355	100.00

EXHIBIT 2

NOVA SCOTIA POWER INC.

FUNCTIONALIZATION OF AVERAGE RATE BASE

FOR THE YEAR ENDING DECEMBER 31, 2007

(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) GENERATION	(3) TRANSMISSION	(4) DISTRIBUTION	(5) RETAIL	(6) DIRECT CAPITAL
PRODUCTION PLANT						
(1) STEAM	$1,053,843	$1,053,843	$0	$0	$0	$0
(2) HYDRO	258,490	240,574	0	0	0	17,916
(3) WIND	3,025	3,025	0	0	0	0
(4) LM6000	62,547	62,547	0	0	0	0
(5) GAS TURBINE - OTHER	10,672	10,672	0	0	0	0
(6) TOTAL PROD. PLANT	1,388,577	1,370,661	0	0	0	17,916
(7) Transmission < 138kV	66,019	0	66,019	0	0	0
(8) Transmission > 69kV	216,112	0	216,112	0	0	0
(9) TRANSMISSION PLANT	282,131	0	282,131	0	0	0
DISTRIBUTION PLANT						
(10) LAND	2,715	0	0	2,715	0	0
(11) EASEMENTS & SURVEY	11,042	0	0	11,042	0	0
(12) OTHER	996	0	0	996	0	0
(13) SUBSTATIONS	29,400	0	0	29,400	0	0
(14) POLES & FIXTURES	134,742	0	0	134,742	0	0
(15) O.H. LINES	92,037	0	0	92,037	0	0
(16) U.G. LINES	25,000	0	0	25,000	0	0
(17) LINE TRANSFORMERS	123,171	0	0	123,171	0	0
(18) SERVICES	55,160	0	0	55,160	0	0
(19) METERS	21,744	0	0	21,744	0	0
(20) STREET LIGHTING	26,122	0	0	26,122	0	0
(21) TOTAL DIST. PLANT	522,129	0	0	522,129	0	0
(22) SUB-TOTAL	2,192,837	1,370,661	282,131	522,129	0	17,916
(23) GEN. PROPERTY PLANT	170,472	107,433	22,114	40,925	0	0
(24) TOT. PLT.IN SERVICE	2,363,309	1,478,094	304,245	563,054	0	17,916
Working Capital & Deferred Charges/Credits						
(25) CASH - FUEL	16,541	16,541	0	0	0	0
(26) CASH - OTHER	7,083	3,316	871	2,766	0	130
(27) MAT. & SUP. - FUEL	51,361	51,361	0	0	0	0
(28) MAT. & SUP. - OTHER	26,648	16,794	3,457	6,397	0	0
(29) DEF. CHG. - Financing	148,005	93,275	19,199	35,531	0	0
(30) DEF. CHG. - Tax	155,755	98,159	20,205	37,392	0	0
(31) DEF. CHG. - Pension	38,834	18,521	4,862	15,450	0	0
(32) DEF. CHG. - Steam Assets	506	506	0	0	0	0
(33) DEF. CHG. - Other	622	392	81	149	0	0
(34) DEF. CR. - ARO Steam	(67,950)	(67,950)	0	0	0	0
(35) DEF. CR. - ARO Hydro	(6,570)	(6,570)	0	0	0	0
(36) DEF. CR. - ARO CT	(2,677)	(2,677)	0	0	0	0
(37) DEF. CR. - Other	(3,754)	(3,754)	0	0	0	0
[redacted]	48,627	48,627	0	0	0	0
(39) TOT.WORKING CAPITAL	413,031	266,540	48,674	97,686	0	130
(40) TOTAL AVE. RATE BASE	$2,776,340	$1,744,635	$352,919	$660,740	$0	$18,046

EXHIBIT 2A
Page 1 of 3

NOVA SCOTIA POWER INC.

CLASSIFICATION OF AVERAGE RATE BASE

FOR THE YEAR ENDING DECEMBER 31, 2007
(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	$1,053,843	$940,589	$113,254	$0
(2) HYDRO PLANT	240,574	240,574	0	0
(3) WIND PLANT	3,025	3,025	0	0
(4) LM6000 PLANT	62,547	62,547	0	0
(5) GAS TURBINE PLANT - OTHER	10,672	10,672	0	0
(6) TOTAL GENERATION PLANT	1,370,661	1,257,407	113,254	0
(7) GENERAL PROPERTY PLANT	107,433	98,557	8,877	0
(8) TOTAL PLANT IN SERVICE	1,478,094	1,355,964	122,131	0
Working Capital & Deferred Charges/Credits:				
(9) CASH - FUEL	16,541	0	16,541	0
(10) CASH - OTHER	3,316	930	2,386	0
(11) MAT. & SUPPLIES - FUEL	51,361	0	51,361	0
(12) MAT. & SUPPLIES - OTHER	16,794	15,406	1,388	0
(13) DEF. CHG. - Financing	93,275	85,567	7,707	0
(14) DEF. CHG. - Tax	98,159	90,048	8,111	0
(15) DEF. CHG. - Pension	18,521	5,194	13,327	0
(16) DEF. CHG. - Steam Assets	506	452	54	0
(17) DEF. CHG. - Other	392	360	32	0
(18) DEF. CR. - ARO Steam	(67,950)	(60,648)	(7,302)	0
(19) DEF. CR. - ARO Hydro	(6,570)	(6,570)	0	0
(20) DEF. CR. - ARO CT	(2,677)	(2,677)	0	0
(21) DEF. CR. - Other	(3,754)	(3,351)	(403)	0
[redacted]	48,627	0	48,627	0
(23) SUB-TOTAL	266,540	124,712	141,828	0
(24) TOTAL GENERATION FUNCTION	**1,744,635**	**1,480,676**	**263,959**	**0**
TRANSMISSION FUNCTION				
(25) TRANSMISSION PLANT < 138kV	66,019	66,019	0	0
(26) GENERAL PROPERTY PLANT	5,175	5,175	0	0
(27) TOTAL PLANT IN SERVICE	71,193	71,193	0	0
Working Capital & Deferred Charges/Credits:				
(28) CASH - FUEL	0	0	0	0
(29) CASH - OTHER	211	74	137	0
(30) MAT. & SUPPLIES - FUEL	0	0	0	0
(31) MAT. & SUPPLIES - OTHER	809	809	0	0
(32) DEF. CHG. - Financing	4,493	4,493	0	0
(33) DEF. CHG. - Tax	4,728	4,728	0	0
(34) DEF. CHG. - Pension	1,181	413	767	0
(35) DEF. CHG. - Other	19	19	0	0
(36) SUB-TOTAL	11,440	10,536	904	0
(37) TOTAL TRANS. < 138kV	**82,633**	**81,729**	**904**	**0**

NOVA SCOTIA POWER INC.

CLASSIFICATION OF AVERAGE RATE BASE

FOR THE YEAR ENDING DECEMBER 31, 2007
(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	216,112	216,112	0	0
(2) GENERAL PROPERTY PLANT	16,939	16,939	0	0
(3) TOTAL PLANT IN SERVICE	233,051	233,051	0	0
Working Capital & Deferred Charges/Credits:				
(4) CASH - FUEL	0	0	0	0
(5) CASH - OTHER	659	231	428	0
(6) MAT. & SUPPLIES - FUEL	0	0	0	0
(7) MAT. & SUPPLIES - OTHER	2,648	2,648	0	0
(8) DEF. CHG. - Financing	14,707	14,707	0	0
(9) DEF. CHG. - Tax	15,477	15,477	0	0
(10) DEF. CHG. - Pension	3,682	1,289	2,393	0
(11) DEF. CHG. - Other	62	62	0	0
(12) SUB-TOTAL	37,234	34,413	2,821	0
(13) TOTAL TRANS. > 69kV	**270,286**	**267,465**	**2,821**	**0**
(14) TOTAL TRANSMISSION FUNCTION	**$352,919**	**$349,194**	**$3,725**	**$0**
DISTRIBUTION FUNCTION				
DISTRIBUTION PLANT:				
(15) LAND	2,715	1,874	0	841
(16) EASEMENTS & SURVEY	11,042	7,621	0	3,421
(17) OTHER	996	687	0	309
(18) SUBSTATIONS	29,400	29,400	0	0
(19) POLES & FIXTURES	134,742	87,582	0	47,160
(20) O.H. LINES	92,037	59,824	0	32,213
(21) U.G. LINES	25,000	16,250	0	8,750
(22) LINE TRANSFORMERS	123,171	123,171	0	0
(23) SERVICES	55,160	0	0	55,160
(24) METERS	21,744	0	0	21,744
(25) STREET LIGHTING	26,122	26,122	0	0
(26) TOTAL DISTRIBUTION PLANT	522,129	352,531	0	169,598
(27) GENERAL PROPERTY PLANT	40,925	27,632	0	13,293
(28) TOTAL PLANT IN SERVICE	563,054	380,163	0	182,891
Working Capital & Deferred Charges/Credits:				
(29) CASH - FUEL	0	0	0	0
(30) CASH - OTHER	2,766	1,067	0	1,700
(31) MAT. & SUPPLIES - FUEL	0	0	0	0
(32) MAT. & SUPPLIES - OTHER	6,397	4,319	0	2,078
(33) DEF. CHG. - Financing	35,531	23,990	0	11,541
(34) DEF. CHG. - Tax	37,392	25,246	0	12,146
(35) DEF. CHG. - Pension	15,450	5,957	0	9,493
(36) DEF. CHG. - Other	149	101	0	49
(37) SUB-TOTAL	97,686	60,681	0	37,006
(38) TOTAL DISTRIBUTION FUNCTION	**660,740**	**440,844**	**0**	**219,896**

NOVA SCOTIA POWER INC.

CLASSIFICATION OF RATE BASE

FOR THE YEAR ENDING DECEMBER 31, 2007
(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	**$2,758,294**	**$2,270,713**	**$267,684**	**$219,896**

NOVA SCOTIA POWER INC.

CLASSIFICATION OF AVERAGE RATE BASE

FOR THE YEAR ENDING DECEMBER 31, 2007

(IN THOUSANDS OF DOLLARS)

	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	$940,589	$113,254	$0	($611,195)	$611,195	$0	$329,394	$724,449	$0
(2) HYDRO PLANT	240,574	0	0	(156,325)	156,325	0	84,249	156,325	0
(3) WIND PLANT	3,025	0	0	(2,118)	2,118	0	908	2,118	0
(4) LM6000 PLANT	62,547	0	0	(40,643)	40,643	0	21,904	40,643	0
(5) GAS TURBINE PLANT - OTHER	10,672	0	0	0	0	0	10,672	0	0
(6) TOTAL GENERATION PLANT	1,257,407	113,254	0	(810,280)	810,280	0	447,127	923,534	0
(7) GENERAL PROPERTY PLANT	98,557	8,877	0	(63,510)	63,510	0	35,046	72,387	0
(8) TOTAL PLANT IN SERVICE	1,355,964	122,131	0	(873,791)	873,791	0	482,173	995,922	0
Working Capital & Deferred Charges/Credits:									
(9) CASH - FUEL	0	16,541	0	0	0	0	0	16,541	0
(10) CASH - OTHER	930	2,386	0	0	0	0	930	2,386	0
(11) MAT. & SUPPLIES - FUEL	0	51,361	0	0	0	0	0	51,361	0
(12) MAT. & SUPPLIES - OTHER	15,406	1,388	0	(9,928)	9,928	0	5,478	11,316	0
(13) DEF. CHG. - Financing	85,567	7,707	0	(55,140)	55,140	0	30,427	62,847	0
(14) DEF. CHG. - Tax	90,048	8,111	0	(58,027)	58,027	0	32,021	66,138	0
(15) DEF. CHG. - Pension	5,194	13,327	0	0	0	0	5,194	13,327	0
(16) DEF. CHG. - Steam Assets	452	54	0	(293)	293	0	158	348	0
(17) DEF. CHG. - Other	360	32	0	(232)	232	0	128	264	0
(18) DEF. CR. - ARO Steam	(60,648)	(7,302)	0	39,409	(39,409)	0	(21,239)	(46,711)	0
(19) DEF. CR. - ARO Hydro	(6,570)	0	0	4,269	(4,269)	0	(2,301)	(4,269)	0
(20) DEF. CR. - ARO CT	(2,677)	0	0	0	0	0	(2,677)	0	0
(21) DEF. CR. - Other	(3,351)	(403)	0	2,177	(2,177)	0	(1,173)	(2,581)	0
[redacted]	0	48,627	0	0	0	0	0	48,627	0
(23) SUB-TOTAL	124,712	141,828	0	(77,766)	77,766	0	46,947	219,594	0
							0	0	0
(24) TOTAL GENERATION FUNCTION	1,480,676	263,959	0	(951,556)	951,556	0	529,120	1,215,515	0
TRANSMISSION FUNCTION									
(25) TRANSMISSION PLANT < 138kV	66,019	0	0	(42,899)	42,899	0	23,120	42,899	0
(26) GENERAL PROPERTY PLANT	5,175	0	0	(3,362)	3,362	0	1,812	3,362	0
(27) TOTAL PLANT IN SERVICE	71,193	0	0	(46,261)	46,261	0	24,932	46,261	0
Working Capital & Deferred Charges/Credits:									
(28) CASH - FUEL	0	0	0	0	0	0	0	0	0
(29) CASH - OTHER	74	137	0	0	0	0	74	137	0
(30) MAT. & SUPPLIES - FUEL	0	0	0	0	0	0	0	0	0
(31) MAT. & SUPPLIES - OTHER	809	0	0	(526)	526	0	283	526	0
(32) DEF. CHG. - Financing	4,493	0	0	(2,919)	2,919	0	1,573	2,919	0
(33) DEF. CHG. - Tax	4,728	0	0	(3,072)	3,072	0	1,656	3,072	0
(34) DEF. CHG. - Pension	413	767	0	0	0	0	413	767	0
(35) DEF. CHG. - Other	19	0	0	(12)	12	0	7	12	0
(36) SUB-TOTAL	10,536	904	0	(6,529)	6,529	0	4,006	7,434	0
(37) TOTAL TRANS. < 138kV	81,729	904	0	(52,791)	52,791	0	28,938	53,695	0

REDACTED Appendix 3 Page 7 of 41

NOVA SCOTIA POWER INC.

CLASSIFICATION OF AVERAGE RATE BASE

FOR THE YEAR ENDING DECEMBER 31, 2007

(IN THOUSANDS OF DOLLARS)

	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	216,112	0	0	(140,430)	140,430	0	75,683	140,430	0
(2) GENERAL PROPERTY PLANT	16,939	0	0	(11,007)	11,007	0	5,932	11,007	0
(3) TOTAL PLANT IN SERVICE	233,051	0	0	(151,437)	151,437	0	81,615	151,437	0
Working Capital & Deferred Charges/Credits:									
(4) CASH - FUEL	0	0	0	0	0	0	0	0	0
(5) CASH - OTHER	231	428	0	0	0	0	231	428	0
(6) MAT. & SUPPLIES - FUEL	0	0	0	0	0	0	0	0	0
(7) MAT. & SUPPLIES - OTHER	2,648	0	0	(1,721)	1,721	0	927	1,721	0
(8) DEF. CHG. - Financing	14,707	0	0	(9,556)	9,556	0	5,150	9,556	0
(9) DEF. CHG. - Tax	15,477	0	0	(10,057)	10,057	0	5,420	10,057	0
(10) DEF. CHG. - Pension	1,289	2,393	0	0	0	0	1,289	2,393	0
(11) DEF. CHG. - Other	62	0	0	(40)	40	0	22	40	0
(12) SUB-TOTAL	34,413	2,821	0	(21,374)	21,374	0	13,039	24,195	0
(13) TOTAL TRANS. > 69kV	267,465	2,821	0	(172,811)	172,811	0	94,654	175,632	0
(14) TOTAL TRANSMISSION FUNCTION	$349,194	$3,725	$0	($225,601)	$225,601	$0	$123,592	$229,327	$0

NOVA SCOTIA POWER INC.

CLASSIFICATION OF AVERAGE RATE BASE

FOR THE YEAR ENDING DECEMBER 31, 2007

(IN THOUSANDS OF DOLLARS)

	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	$1,874	$0	$841	$0	$0	$0	$1,874	$0	$841
(2) EASEMENTS & SURVEY	7,621	0	3,421	0	0	0	7,621	0	3,421
(3) OTHER	687	0	309	0	0	0	687	0	309
(4) SUBSTATIONS	29,400	0	0	0	0	0	29,400	0	0
(5) POLES & FIXTURES	87,582	0	47,160	0	0	0	87,582	0	47,160
(6) O.H. LINES	59,824	0	32,213	0	0	0	59,824	0	32,213
(7) U.G. LINES	16,250	0	8,750	0	0	0	16,250	0	8,750
(8) LINE TRANSFORMERS	123,171	0	0	0	0	0	123,171	0	0
(9) SERVICES	0	0	55,160	0	0	0	0	0	55,160
(10) METERS	0	0	21,744	0	0	0	0	0	21,744
(11) STREET LIGHTING	26,122	0	0	0	0	0	26,122	0	0
(12) TOTAL DISTRIBUTION PLANT	352,531	0	169,598	0	0	0	352,531	0	169,598
(13) GENERAL PROPERTY PLANT	27,632	0	13,293	0	0	0	27,632	0	13,293
(14) TOTAL PLANT IN SERVICE	380,163	0	182,891	0	0	0	380,163	0	182,891
Working Capital & Deferred Charges/Credits:									
(15) CASH - FUEL	0	0	0	0	0	0	0	0	0
(16) CASH - OTHER	1,067	0	1,700	0	0	0	1,067	0	1,700
(17) MAT. & SUPPLIES - FUEL	0	0	0	0	0	0	0	0	0
(18) MAT. & SUPPLIES - OTHER	4,319	0	2,078	0	0	0	4,319	0	2,078
(19) DEF. CHG. - Financing	23,990	0	11,541	0	0	0	23,990	0	11,541
(20) DEF. CHG. - Tax	25,246	0	12,146	0	0	0	25,246	0	12,146
(21) DEF. CHG. - Pension	5,957	0	9,493	0	0	0	5,957	0	9,493
(22) DEF. CHG. - Other	101	0	49	0	0	0	101	0	49
(23) SUB-TOTAL	60,681	0	37,006	0	0	0	60,681	0	37,006
(24) TOTAL DISTRIBUTION FUNCTION	$440,844	$0	$219,896	$0	$0	$0	$440,844	$0	$219,896
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	**$2,270,713**	**$267,684**	**$219,896**	**($1,177,158)**	**$1,177,158**	**$0**	**$1,093,556**	**$1,444,842**	**$219,896**

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NOVA SCOTIA POWER INC.

ALLOCATION OF AVERAGE RATE BASE

FOR THE YEAR ENDING DECEMBER 31, 2007
(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) EXTRA LI INTERR. - 2	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
DEMAND CLASSIFICATION												
GENERATION FUNCTION												
(1) STEAM PLANT	$329,394	$158,134	$8,033	$65,498	$9,186	$5,234	$12,471	$19,916	$41,070	$6,041	$3,811	D-3A
(2) HYDRO PLANT	84,249	40,446	2,055	16,752	2,349	1,339	3,190	5,094	10,505	1,545	975	D-3A
(3) WIND PLANT	908	436	22	180	25	14	34	55	113	17	10	D-3A
(4) LM6000 PLANT	21,904	10,516	534	4,355	611	348	829	1,324	2,731	402	253	D-3A
(5) GAS TURBINE PLANT - OTHER	10,672	5,123	260	2,122	298	170	404	645	1,331	196	123	D-3A
(6) TOTAL GENERATION PLANT	447,127	214,654	10,904	88,909	12,469	7,104	16,929	27,035	55,750	8,200	5,173	
(7) GEN. PROPERTY PLANT	35,046	16,825	855	6,969	977	557	1,327	2,119	4,370	643	405	P-7
(8) TOTAL PLANT IN SERVICE	482,173	231,479	11,758	95,877	13,447	7,661	18,256	29,154	60,119	8,843	5,579	
Working Capital & Deferred Charges/Credits:												
(9) CASH - FUEL	0	0	0	0	0	0	0	0	0	0	0	D-3A
(10) CASH - OTHER	930	446	23	185	26	15	35	56	116	17	11	O-1
(11) MAT. & SUPPLIES - FUEL	0	0	0	0	0	0	0	0	0	0	0	D-3A
(12) MAT. & SUPPLIES - OTHER	5,478	2,630	134	1,089	153	87	207	331	683	100	63	P-7
(13) DEF. CHG. - Financing	30,427	14,607	742	6,050	849	483	1,152	1,840	3,794	558	352	P-7
(14) DEF. CHG. - Tax	32,021	15,372	781	6,367	893	509	1,212	1,936	3,992	587	370	P-7
(15) DEF. CHG. - Pension	5,194	2,494	127	1,033	145	83	197	314	648	95	60	O-1
(16) DEF. CHG. - Steam Assets	158	76	4	31	4	3	6	10	20	3	2	D-3A
(17) DEF. CHG. - Other	128	61	3	25	4	2	5	8	16	2	1	P-7
(18) DEF. CR. - ARO Steam	(21,239)	(10,196)	(518)	(4,223)	(592)	(337)	(804)	(1,284)	(2,648)	(390)	(246)	D-3A
(19) DEF. CR. - ARO Hydro	(2,301)	(1,105)	(56)	(458)	(64)	(37)	(87)	(139)	(287)	(42)	(27)	D-3A
(20) DEF. CR. - ARO CT	(2,677)	(1,285)	(65)	(532)	(75)	(43)	(101)	(162)	(334)	(49)	(31)	D-3A
(21) DEF. CR. - Other	(1,173)	(563)	(29)	(233)	(33)	(19)	(44)	(71)	(146)	(22)	(14)	D-3A
[redacted]	0	0	0	0	0	0	0	0	0	0	0	D-3A
(23) SUB-TOTAL	46,947	22,538	1,145	9,335	1,309	746	1,777	2,839	5,854	861	543	
(24) TOTAL GEN. FUNCTION	529,120	254,017	12,903	105,213	14,756	8,407	20,033	31,992	65,973	9,704	6,122	
TRANSMISSION FUNCTION												
(25) TRANSMISSION PLANT < 138kV	23,120	12,680	644	5,252	737	420	1,000	1,597	0	484	306	D-3B
(26) GEN. PROPERTY PLANT	1,812	994	50	412	58	33	78	125	0	38	24	P-8A
(27) TOTAL PLANT IN SERVICE	24,932	13,674	695	5,664	794	453	1,078	1,722	0	522	330	
Working Capital & Deferred Charges/Credits:												
(28) CASH - FUEL	0	0	0	0	0	0	0	0	0	0	0	D-3B
(29) CASH - OTHER	74	41	2	17	2	1	3	5	0	2	1	O-2A
(30) MAT. & SUPPLIES - FUEL	0	0	0	0	0	0	0	0	0	0	0	D-3B
(31) MAT. & SUPPLIES - OTHER	283	155	8	64	9	5	12	20	0	6	4	P-8A
(32) DEF. CHG. - Financing	1,573	863	44	357	50	29	68	109	0	33	21	P-8A
(33) DEF. CHG. - Tax	1,656	908	46	376	53	30	72	114	0	35	22	P-8A
(34) DEF. CHG. - Pension	413	227	12	94	13	8	18	29	0	9	5	O-2A
(35) DEF. CHG. - Other	7	4	0	2	0	0	0	0	0	0	0	P-8A
(36) SUB-TOTAL	4,006	2,197	112	910	128	73	173	277	0	84	53	
(37) TOTAL TRANS. < 138kV	28,938	15,871	806	6,574	922	525	1,252	1,999	0	606	382	

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NOVA SCOTIA POWER INC.

ALLOCATION OF AVERAGE RATE BASE

FOR THE YEAR ENDING DECEMBER 31, 2007
(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) EXTRA LI INTERR. - 2	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
(1) TRANSMISSION PLANT > 69kV	75,683	36,333	1,846	15,049	2,111	1,202	2,865	4,576	9,436	1,388	876	D-3A
(2) GENERAL PROPERTY PLANT	5,932	2,848	145	1,180	165	94	225	359	740	109	69	P-8B
(3) TOTAL PLANT IN SERVICE	81,615	39,181	1,990	16,229	2,276	1,297	3,090	4,935	10,176	1,497	944	
Working Capital & Deferred Charges/Credits:												
(4) CASH - FUEL	0	0	0	0	0	0	0	0	0	0	0	D-3A
(5) CASH - OTHER	231	111	6	46	6	4	9	14	29	4	3	O-2B
(6) MAT. & SUPPLIES - FUEL	0	0	0	0	0	0	0	0	0	0	0	D-3A
(7) MAT. & SUPPLIES - OTHER	927	445	23	184	26	15	35	56	116	17	11	P-8B
(8) DEF. CHG. - Financing	5,150	2,473	126	1,024	144	82	195	311	642	94	60	P-8B
(9) DEF. CHG. - Tax	5,420	2,602	132	1,078	151	86	205	328	676	99	63	P-8B
(10) DEF. CHG. - Pension	1,289	619	31	256	36	20	49	78	161	24	15	O-2B
(11) DEF. CHG. - Other	22	10	1	4	1	0	1	1	3	0	0	P-8B
(12) SUB-TOTAL	13,039	6,260	318	2,593	364	207	494	788	1,626	239	151	
(13) TOTAL TRANS. > 69kV	94,654	45,441	2,308	18,821	2,640	1,504	3,584	5,723	11,802	1,736	1,095	
(14) TOTAL TRANS. FUNCTION	123,592	61,312	3,114	25,395	3,562	2,029	4,835	7,722	11,802	2,342	1,478	
DISTRIBUTION FUNCTION												
(15) DISTRIBUTION PLANT	352,531	197,872	13,058	87,303	5,858	8,656	7,813	705	0	66	31,201	EXH. 3A
(16) GEN. PROPERTY PLANT	27,632	15,509	1,023	6,843	459	678	612	55	0	5	2,446	P-9
	380,163	213,381	14,081	94,146	6,318	9,334	8,425	761	0	71	33,646	
Working Capital & Deferred Charges/Credits:												
(17) CASH - FUEL	0	0	0	0	0	0	0	0	0	0	0	P-9
(18) CASH - OTHER	1,067	542	36	242	24	24	31	1	0	0	167	O-3
(19) MAT. & SUPPLIES - FUEL	0	0	0	0	0	0	0	0	0	0	0	P-9
(20) MAT. & SUPPLIES - OTHER	4,319	2,424	160	1,070	72	106	96	9	0	1	382	P-9
(21) DEF. CHG. - Financing	23,990	13,465	889	5,941	399	589	532	48	0	4	2,123	P-9
(22) DEF. CHG. - Tax	25,246	14,170	935	6,252	420	620	560	51	0	5	2,234	P-9
(23) DEF. CHG. - Pension	5,957	3,027	200	1,350	133	135	174	5	0	0	933	O-3
(24) DEF. CHG. - Other	101	57	4	25	2	2	2	0	0	0	9	P-9
(25) SUB-TOTAL	60,681	33,685	2,223	14,880	1,048	1,477	1,394	113	0	11	5,849	
(26) TOTAL DIST. FUNCTION	440,844	247,066	16,304	109,026	7,366	10,811	9,820	874	0	81	39,495	
(27) TOTAL DEMAND	**$1,093,556**	**$562,395**	**$32,322**	**$239,634**	**$25,684**	**$21,247**	**$34,688**	**$40,588**	**$77,775**	**$12,128**	**$47,095**	

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NOVA SCOTIA POWER INC.

ALLOCATION OF AVERAGE RATE BASE

FOR THE YEAR ENDING DECEMBER 31, 2007
(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) EXTRA LI INTERR. - 2	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
ENERGY CLASSIFICATION												
GENERATION FUNCTION												
(1) STEAM PLANT	$724,449	$273,857	$15,472	$152,728	$25,703	$15,510	$35,706	$64,551	$121,878	$11,859	$7,186	E-1A
(2) HYDRO PLANT	156,325	59,094	3,339	32,956	5,546	3,347	7,705	13,929	26,299	2,559	1,551	E-1A
(3) WIND PLANT	2,118	800	45	446	75	45	104	189	356	35	21	E-1A
(4) LM6000 PLANT	40,643	15,364	868	8,568	1,442	870	2,003	3,621	6,838	665	403	E-1A
(5) GAS TURBINE PLANT - OTHER	0	0	0	0	0	0	0	0	0	0	0	E-1A
(6) TOTAL GENERATION PLANT	923,534	349,116	19,723	194,699	32,767	19,773	45,518	82,290	155,371	15,117	9,161	
(7) GENERAL PROPERTY PLANT	72,387	27,364	1,546	15,261	2,568	1,550	3,568	6,450	12,178	1,185	718	P-10
(8) TOTAL PLANT IN SERVICE	995,922	376,479	21,269	209,960	35,335	21,322	49,086	88,740	167,549	16,302	9,879	
Working Capital & Deferred Charges/Credits:												
(9) CASH - FUEL	16,541	6,253	353	3,487	587	354	815	1,474	2,783	271	164	E-1A
(10) CASH - OTHER	2,386	902	51	503	85	51	118	213	401	39	24	O-4
(11) MAT. & SUPPLIES - FUEL	51,361	19,416	1,097	10,828	1,822	1,100	2,531	4,576	8,641	841	509	E-1A
(12) MAT. & SUPPLIES - OTHER	11,316	4,278	242	2,386	401	242	558	1,008	1,904	185	112	P-10
(13) DEF. CHG. - Financing	62,847	23,758	1,342	13,249	2,230	1,346	3,098	5,600	10,573	1,029	623	P-10
(14) DEF. CHG. - Tax	66,138	25,002	1,412	13,943	2,347	1,416	3,260	5,893	11,127	1,083	656	P-10
(15) DEF. CHG. - Pension	13,327	5,038	285	2,810	473	285	657	1,187	2,242	218	132	O-4
(16) DEF. CHG. - Steam Assets	348	131	7	73	12	7	17	31	59	6	3	E-1A
(17) DEF. CHG. - Other	264	100	6	56	9	6	13	24	44	4	3	P-10
(18) DEF. CR. - ARO Steam	(46,711)	(17,658)	(998)	(9,848)	(1,657)	(1,000)	(2,302)	(4,162)	(7,858)	(765)	(463)	E-1A
(19) DEF. CR. - ARO Hydro	(4,269)	(1,614)	(91)	(900)	(151)	(91)	(210)	(380)	(718)	(70)	(42)	E-1A
(20) DEF. CR. - ARO CT	0	0	0	0	0	0	0	0	0	0	0	E-1A
(21) DEF. CR. - Other	(2,581)	(976)	(55)	(544)	(92)	(55)	(127)	(230)	(434)	(42)	(26)	E-1A
[redacted]	48,627	18,382	1,039	10,252	1,725	1,041	2,397	4,333	8,181	796	482	E-1A
(23) SUB-TOTAL	219,594	83,011	4,690	46,295	7,791	4,701	10,823	19,567	36,943	3,595	2,178	
(24) TOTAL GEN. FUNCTION	1,215,515	459,491	25,959	256,254	43,126	26,024	59,909	108,306	204,493	19,897	12,057	
TRANSMISSION FUNCTION												
(25) TRANSMISSION PLANT < 138kV	42,899	19,497	1,101	10,873	1,830	1,104	2,542	4,596	0	844	512	E-1B
(26) GENERAL PROPERTY PLANT	3,362	1,528	86	852	143	87	199	360	0	66	40	P-11A
(27) TOTAL PLANT IN SERVICE	46,261	21,025	1,188	11,725	1,973	1,191	2,741	4,956	0	910	552	
Working Capital & Deferred Charges/Credits:												
(28) CASH - FUEL	0	0	0	0	0	0	0	0	0	0	0	E-1B
(29) CASH - OTHER	137	62	4	35	6	4	8	15	0	3	2	O-5A
(30) MAT. & SUPPLIES - FUEL	0	0	0	0	0	0	0	0	0	0	0	E-1B
(31) MAT. & SUPPLIES - OTHER	526	239	13	133	22	14	31	56	0	10	6	P-11A
(32) DEF. CHG. - Financing	2,919	1,327	75	740	125	75	173	313	0	57	35	P-11A
(33) DEF. CHG. - Tax	3,072	1,396	79	779	131	79	182	329	0	60	37	P-11A
(34) DEF. CHG. - Pension	767	349	20	194	33	20	45	82	0	15	9	O-5A
(35) DEF. CHG. - Other	12	6	0	3	1	0	1	1	0	0	0	P-11A
(36) SUB-TOTAL	7,434	3,379	191	1,884	317	191	440	796	0	146	89	
(37) TOTAL TRANS. < 138kV	53,695	24,403	1,379	13,610	2,290	1,382	3,182	5,752	0	1,057	640	

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NOVA SCOTIA POWER INC.

ALLOCATION OF AVERAGE RATE BASE

FOR THE YEAR ENDING DECEMBER 31, 2007
(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) EXTRA LI INTERR. - 2	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
(1) TRANSMISSION PLANT > 69kV	140,430	53,085	2,999	29,605	4,982	3,007	6,921	12,513	23,625	2,299	1,393	E-1A
(2) GENERAL PROPERTY PLANT	11,007	4,161	235	2,320	391	236	542	981	1,852	180	109	P-11B
(3) TOTAL PLANT IN SERVICE	151,437	57,246	3,234	31,926	5,373	3,242	7,464	13,494	25,477	2,479	1,502	
Working Capital & Deferred Charges/Credits:												
(4) CASH - FUEL	0	0	0	0	0	0	0	0	0	0	0	E-1A
(5) CASH - OTHER	428	162	9	90	15	9	21	38	72	7	4	O-5B
(6) MAT. & SUPPLIES - FUEL	0	0	0	0	0	0	0	0	0	0	0	E-1A
(7) MAT. & SUPPLIES - OTHER	1,721	650	37	363	61	37	85	153	289	28	17	P-11B
(8) DEF. CHG. - Financing	9,556	3,613	204	2,015	339	205	471	852	1,608	156	95	P-11B
(9) DEF. CHG. - Tax	10,057	3,802	215	2,120	357	215	496	896	1,692	165	100	P-11B
(10) DEF. CHG. - Pension	2,393	904	51	504	85	51	118	213	403	39	24	O-5B
(11) DEF. CHG. - Other	40	15	1	8	1	1	2	4	7	1	0	P-11B
(12) SUB-TOTAL	24,195	9,146	517	5,101	858	518	1,192	2,156	4,070	396	240	
(13) TOTAL TRANS. > 69kV	175,632	66,392	3,751	37,027	6,231	3,760	8,656	15,649	29,547	2,875	1,742	
(14) TOTAL TRANS. FUNCTION	229,327	90,796	5,130	50,636	8,522	5,142	11,838	21,401	29,547	3,932	2,382	
(15) TOTAL ENERGY	**$1,444,842**	**$550,286**	**$31,089**	**$306,891**	**$51,648**	**$31,166**	**$71,747**	**$129,708**	**$234,040**	**$23,829**	**$14,439**	

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NOVA SCOTIA POWER INC.

ALLOCATION OF AVERAGE RATE BASE

FOR THE YEAR ENDING DECEMBER 31, 2007
(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) EXTRA LI INTERR. - 2	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
CUST. CLASSIFICATION												
DISTRIBUTION FUNCTION												
(1) DISTRIBUTION PLANT	$169,597	$147,622	$8,029	$9,704	$17	$2,078	$219	$54	$3	$5	$1,866	EXH. 3A
(2) GEN. PROPERTY PLANT	13,293	11,571	629	761	1	163	17	4	0	0	146	P-12
(3) TOTAL PLANT IN SERVICE	182,890	159,193	8,658	10,464	18	2,241	236	58	3	5	2,013	
WORKING CAPITAL:												
(4) CASH - FUEL	0	0	0	0	0	0	0	0	0	0	0	P-12
(5) CASH - OTHER	1,700	1,475	80	91	2	19	7	3	0	1	22	O-6
(6) MAT. & SUPPLIES - FUEL	0	0	0	0	0	0	0	0	0	0	0	P-12
(7) MAT. & SUPPLIES - OTHER	2,078	1,809	98	119	0	25	3	1	0	0	23	P-12
(8) DEF. CHG. - Financing	11,541	10,046	546	660	1	141	15	4	0	0	127	P-12
(9) DEF. CHG. - Tax	12,146	10,572	575	695	1	149	16	4	0	0	134	P-12
(10) DEF. CHG. - Pension	9,493	8,237	448	506	12	104	40	20	1	4	121	O-6
(11) DEF. CHG. - Other	49	42	2	3	0	1	0	0	0	0	1	P-12
(12) SUB-TOTAL	37,006	32,181	1,750	2,074	16	439	81	31	2	5	426	
(13) TOTAL DIST. FUNCTION	219,895	191,374	10,409	12,538	34	2,680	317	89	5	10	2,439	
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	**219,895**	**191,374**	**10,409**	**12,538**	**34**	**2,680**	**317**	**89**	**5**	**10**	**2,439**	
(28) TOTAL AVE. RATE BASE	**$2,758,293**	**$1,304,056**	**$73,819**	**$559,063**	**$77,365**	**$55,093**	**$106,752**	**$170,385**	**$311,820**	**$35,967**	**$63,973**	

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EXHIBIT 3A

NOVA SCOTIA POWER INC.

ALLOCATION OF AVERAGE DISTRIBUTION RATE BASE

FOR THE YEAR ENDING DECEMBER 31, 2007

(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) EXTRA LI INTERR. - 2	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
DEMAND												
(1) LAND	$1,874	$1,097	$72	$492	$54	$49	$73	$7	$0	$1	$28	P-3
(2) EASEMENTS & SURVEY	7,621	4,463	295	2,001	221	201	295	29	0	3	115	P-3
(3) OTHER	687	403	27	180	20	18	27	3	0	0	10	P-3
(4) SUBSTATIONS	29,400	16,314	1,077	7,443	1,070	751	1,598	667	0	62	419	EXH 3B
(5) POLES & FIXTURES	87,582	51,829	3,420	23,160	2,405	2,323	3,115	0	0	0	1,330	EXH 3D
(6) O.H. LINES	59,824	35,402	2,336	15,819	1,643	1,587	2,128	0	0	0	909	EXH 3F
(7) U.G. LINES	16,250	9,616	635	4,297	446	431	578	0	0	0	247	P-1
(8) LINE TRANSFORMERS	123,171	78,747	5,197	33,911	0	3,295	0	0	0	0	2,021	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	26,122	0	0	0	0	0	0	0	0	0	26,122	DIRECT
(12) TOTAL DEMAND	352,531	197,872	13,058	87,303	5,858	8,656	7,813	705	0	66	31,201	
CUSTOMER												
(13) LAND	841	759	41	20	0	4	0	0	0	0	17	P-4
(14) EASEMENTS & SURVEY	3,421	3,086	168	81	0	16	1	0	0	0	69	P-4
(15) OTHER	309	278	15	7	0	1	0	0	0	0	6	P-4
(16) SUBSTATIONS	0	0	0	0	0	0	0	0	0	0	0	---
(17) POLES & FIXTURES	47,160	42,544	2,314	1,111	1	227	12	1	0	0	950	EXH 3D
(18) O.H. LINES	32,213	29,060	1,581	759	1	155	8	1	0	0	649	EXH 3F
(19) U.G. LINES	8,749	7,894	429	206	0	42	2	0	0	0	176	P-2
(20) LINE TRANSFORMERS	0	0	0	0	0	0	0	0	0	0	0	---
(21) SERVICES	55,160	45,526	2,476	5,945	0	1,213	0	0	0	0	0	C-2
(22) METERS	21,744	18,475	1,005	1,575	15	420	196	51	3	4	0	EXH 3G
(23) STREET LIGHTING	0	0	0	0	0	0	0	0	0	0	0	---
(24) TOTAL CUSTOMER	$169,597	$147,622	$8,029	$9,704	$17	$2,078	$219	$54	$3	$5	$1,866	
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	2,715	1,856	114	512	54	53	73	7	0	1	45	P-3 & 4
(29) EASEMENTS & SURVEY	11,042	7,549	462	2,082	221	217	296	29	0	3	183	P-3 & 4
(30) OTHER	996	681	42	188	20	20	27	3	0	0	17	P-3 & 4
(31) SUBSTATIONS	29,400	16,314	1,077	7,443	1,070	751	1,598	667	0	62	419	EXH 3B
(32) POLES & FIXTURES	134,742	94,372	5,734	24,271	2,406	2,550	3,127	1	0	0	2,280	EXH 3D
(33) O.H. LINES	92,037	64,462	3,917	16,578	1,643	1,742	2,136	1	0	0	1,557	EXH 3F
(34) U.G. LINES	24,999	17,510	1,064	4,503	446	473	580	0	0	0	423	P-1 & 2
(35) LINE TRANSFORMERS	123,171	78,747	5,197	33,911	0	3,295	0	0	0	0	2,021	D-1
(36) SERVICES	55,160	45,526	2,476	5,945	0	1,213	0	0	0	0	0	C-2
(37) METERS	21,744	18,475	1,005	1,575	15	420	196	51	3	4	0	EXH 3G
(38) STREET LIGHTING	26,122	0	0	0	0	0	0	0	0	0	26,122	DIRECT
(39) TOTAL AVE. RATE BASE	**$522,128**	**$345,494**	**$21,087**	**$97,007**	**$5,875**	**$10,734**	**$8,032**	**$759**	**$3**	**$70**	**$33,067**	

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EXHIBIT 3B

NOVA SCOTIA POWER INC.

ANALYSIS OF AVERAGE DISTRIBUTION SUBSTATION RATE BASE

FOR THE YEAR ENDING DECEMBER 31, 2007

(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	$29,400	$26,439	$847	$1,971	$143
ALLOCATION					
(2) DOMESTIC	16,314	15,183	0	1,132	0
(3) SMALL GENERAL	1,077	1,002	0	75	0
(4) GENERAL	7,443	6,885	40	513	4
(5) GENERAL LARGE	1,070	994	0	74	2
(6) SMALL INDUSTRIAL	751	699	0	52	0
(7) MEDIUM INDUSTRIAL	1,598	1,287	201	96	14
(8) INDUSTRIAL LARGE	667	0	558	0	109
(9) EXTRA LI INTERR. - 2	0	0	0	0	0
(10) MUNICIPAL	62	0	48	0	14
(11) UNMETERED	419	390	0	29	0
(12) TOTAL	$29,400	$26,439	$847	$1,971	$143
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, 2007

(IN THOUSANDS OF DOLLARS)

	(1) TOTAL PLANT	(2) PRIMARY DEMAND	(3) PRIMARY CUSTOMER	(4) SECONDARY DEMAND	(5) SECONDARY CUSTOMER
(1) TOTAL NET POLE COST	$134,742				
(2) PRIMARY ONLY (30%)	40,423	$40,423	$0	$0	$0
(3) 50% JOINT - PRI. (1)	47,160	23,580	23,580	0	0
(4) 50% JOINT - SEC. (1)	47,160	0	0	23,580	23,580
(5) TOTAL	$134,742	$64,002	$23,580	$23,580	$23,580

DEMAND COST - 50% }
} (1)
CUST. COST - 50% }

EXHIBIT 3D

NOVA SCOTIA POWER INC.

ALLOCATION OF AVERAGE POLE INVESTMENT

FOR THE YEAR ENDING DECEMBER 31, 2007

(IN THOUSANDS OF DOLLARS)

	(1) TOTAL PLANT	(2) PRIMARY DEMAND	(3) PRIMARY CUSTOMER	(4) SECONDARY DEMAND	(5) SECONDARY CUSTOMER
(1) DOMESTIC	$94,372	$36,753	$21,265	$15,075	$21,278
(2) SMALL GENERAL	5,734	2,425	1,157	995	1,157
(3) GENERAL	24,271	16,668	555	6,492	556
(4) GENERAL LARGE	2,406	2,405	1	0	0
(5) SMALL INDUSTRIAL	2,550	1,692	113	631	113
(6) MEDIUM INDUSTRIAL	3,127	3,115	12	0	0
(7) INDUSTRIAL LARGE	1	0	1	0	0
(8) EXTRA LI INTERR. - 2	0	0	0	0	0
(9) MUNICIPAL	0	0	0	0	0
(10) UNMETERED	2,280	943	475	387	475
(11) TOTAL	$134,742	$64,002	$23,580	$23,580	$23,580
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, 2007

(IN THOUSANDS OF DOLLARS)

	(1) TOTAL PLANT	(2) PRIMARY DEMAND	(3) PRIMARY CUSTOMER	(4) SECONDARY DEMAND	(5) SECONDARY CUSTOMER
(1) TOTAL NET WIRE COST	$92,037				
(2) PRIMARY ONLY (30%)	27,611	$27,611	$0	$0	$0
(3) 50% JOINT - PRI. (1)	32,213	16,106	16,106	0	0
(4) 50% JOINT - SEC. (1)	32,213	0	0	16,106	16,106
(5) TOTAL	$92,037	$43,718	$16,106	$16,106	$16,106

DEMAND COST - 50% }
} (1)
CUST. COST - 50% }

EXHIBIT 3F

NOVA SCOTIA POWER INC.

ALLOCATION OF AVERAGE WIRE INVESTMENT

FOR THE YEAR ENDING DECEMBER 31, 2007

(IN THOUSANDS OF DOLLARS)

	(1) TOTAL PLANT	(2) PRIMARY DEMAND	(3) PRIMARY CUSTOMER	(4) SECONDARY DEMAND	(5) SECONDARY CUSTOMER
(1) DOMESTIC	$64,462	$25,105	$14,526	$10,297	$14,534
(2) SMALL GENERAL	3,917	1,657	790	680	791
(3) GENERAL	16,578	11,385	379	4,434	380
(4) GENERAL LARGE	1,643	1,643	1	0	0
(5) SMALL INDUSTRIAL	1,742	1,156	77	431	77
(6) MEDIUM INDUSTRIAL	2,136	2,128	8	0	0
(7) INDUSTRIAL LARGE	1	0	1	0	0
(8) EXTRA LI INTERR. - 2	0	0	0	0	0
(9) MUNICIPAL	0	0	0	0	0
(10) UNMETERED	1,557	644	324	264	324
(11) TOTAL	$92,037	$43,718	$16,106	$16,106	$16,106
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, 2007

	(1) TOTAL CUSTOMERS	(2) UNIT METER COST	(3) TOTAL COST	(4) PERCENT	(5) METER COST ($000)
(1) DOMESTIC	430,332	$34.00	$14,631,288	84.97	$18,475
(2) SMALL GENERAL	23,406	34.00	795,804	4.62	1,005
(3) GENERAL	11,239	111.00	1,247,529	7.24	1,575
(4) GENERAL LARGE	18	657.00	11,826	0.07	15
(5) SMALL INDUSTRIAL	2,293	145.00	332,485	1.93	420
(6) MEDIUM INDUSTRIAL	236	657.00	155,052	0.90	196
(7) INDUSTRIAL LARGE	30	1,338.00	40,140	0.23	51
(8) EXTRA LI INTERR. - 2	2	1,338.00	2,676	0.02	3
(9) MUNICIPAL	6	520.00	3,120	0.02	4
(10) UNMETERED	9,606	N/A	0	0.00	0
(11) TOTAL	477,168		$17,219,920	100.00	$21,744

EXHIBIT 4

NOVA SCOTIA POWER INC.

FUNCTIONALIZATION OF OPERATING EXPENSES

FOR THE YEAR ENDING DECEMBER 31, 2007

(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	$437,925	$431,429	$0	$0	$0	$6,496
(2) PURCHASED POWER	32,099	31,777	0	0	0	322
(3) THERMAL - OPERATING & MAINT.	65,756	64,844	0	0	0	912
(4) HYDRO - OPERATING & MAINT.	7,975	6,464	0	0	0	1,511
(5) WIND - OPERATING & MAINT.	34	34	0	0	0	0
(6) LM6000 - OPERATING & MAINT.	285	285	0	0	0	0
(7) COMBUSTION TURBINE - OPER. & MAINT.	824	824	0	0	0	0
(8) ENERGY, FUELS & RISK MGMT.	3,625	3,625	0	0	0	0
(9) GENERATION DEVELOPMENT	5,878	5,878	0	0	0	0
(10) TOTAL PRODUCTION OPER. & MAINT.	84,377	81,954	0	0	0	2,423
CUSTOMER OPERATIONS:						
(11) TRANSMISSION & DISTRIBUTION	48,698	0	17,318	30,718	0	661
CUST. SERV. / MARKETING & SALES:						
(12) Qty. Ass., Comm., Call Ctr. & Rev. Ops.	28,978	0	0	186	28,792	0
OTHER OPERATING						
CORPORATE GROUPS:						
(13) EXECUTIVE MANAGEMENT	2,086	751	229	542	563	0
(14) CORP. SECRETARY & LEGAL SERVICES	6,105	2,198	672	1,587	1,648	0
(15) EXTERNAL RELATIONS & ENVIRONMENT	1,654	596	182	430	447	0
(16) REGULATORY AFFAIRS	5,473	1,970	602	1,423	1,478	0
(17) FINANCE GROUP	5,175	1,863	569	1,346	1,397	0
(18) ENTERPRISE SERVICES	12,963	3,370	3,500	4,667	1,426	0
(19) HUMAN RESOURCES	4,363	1,178	1,571	480	1,134	0
(20) SUB-TOTAL	37,819	11,926	7,325	10,475	8,093	0
(21) OTHER EXPENSES	1,014	365	111	264	274	0
(22) DIRECT ADMIN. & GEN. EXPENSE	0	(288)	(88)	(208)	(216)	799
(23) TOTAL OM&G EXPENSES	**200,884**	**93,957**	**24,667**	**41,434**	**36,943**	**3,884**
(24) COGS (NET OF SALES)	(391)	0	0	0	(391)	0
(25) GRANTS IN LIEU OF TAXES	33,437	20,903	4,303	7,963	0	269
DEPRECIATION:						
(26) STEAM	42,954	42,954	0	0	0	0
(27) HYDRO	5,831	5,265	0	0	0	566
(28) WIND	94	94	0	0	0	0
(29) LM6000	2,277	2,277	0	0	0	0
(30) OTHER GAS TURBINE	867	867	0	0	0	0
(31) TRANSMISSION > 69kV	3,386	0	3,386	0	0	0
(32) TRANSMISSION < 138kV	11,082	0	10,169	0	0	913
(33) DISTRIBUTION	41,597	0	0	41,597	0	0
(34) GENERAL PROPERTY	22,025	13,880	2,857	5,287	0	0
(35) INTEREST NET	126,445	78,427	15,865	29,703	0	2,450
(36) PREFERRED DIVIDENDS	14,100	8,844	1,789	3,349	0	118
(37) CORPORATE TAXES	83,921	52,625	10,645	19,931	0	720
(38) TOTAL EXPENSES	**$1,058,533**	**$783,299**	**$73,681**	**$149,263**	**$36,553**	**$15,737**

NOVA SCOTIA POWER INC.

CLASSIFICATION OF OPERATING EXPENSES

FOR THE YEAR ENDING DECEMBER 31, 2007
(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DEMAND EXPENSES	(3) ENERGY EXPENSES	(4) CUSTOMER EXPENSES
GENERATION FUNCTION				
(1) FUEL	$431,429	$0	$431,429	$0
(2) PURCHASED POWER - FIXED	14,267	4,654	9,613	0
(3) PURCHASED POWER - VAR.	17,509	0	17,509	0
(4) OPER. & MAINT. - STEAM	84,091	23,043	61,049	0
(5) OPER. & MAINT. - HYDRO	8,427	2,309	6,118	0
(6) OPER. & MAINT. - LM6000	369	101	268	0
(7) OPER. & MAINT. - OTHER CT's	1,069	898	171	0
(8) GRANTS IN LIEU OF TAXES	20,903	6,819	14,084	0
DEPRECIATION:				
(9) STEAM	42,954	13,426	29,528	0
(10) HYDRO	5,265	1,844	3,421	0
(11) WIND	94	28	66	0
(12) LM6000	2,277	797	1,480	0
(13) GAS TURBINE - OTHER	867	867	0	0
(14) GENERAL PROPERTY	13,880	4,528	9,352	0
(15) INTEREST NET OF AFUDC	78,427	23,786	54,642	0
(16) PREFERRED DIVIDENDS	8,844	2,682	6,161	0
(17) CORPORATE TAXES	52,625	15,960	36,665	0
NON-OPERATING REVENUE:				
(18) EXPORT SALES	(8,548)	0	(8,548)	0
(19) OTHER REVENUE	(2,430)	(316)	(2,114)	0
(20) RETURN (PROFIT/LOSS)	60,763	18,428	42,335	0
(21) TOTAL GENERATION	**833,084**	**119,855**	**713,229**	**0**
TRANSMISSION FUNCTION				
Transmission < 138kV:				
(22) O&M < 138kV	5,989	2,097	3,892	0
(23) GRANTS IN LIEU OF TAXES	1,007	353	655	0
DEPRECIATION:				
(24) TRANSMISSION	3,386	1,186	2,200	0
(25) GENERAL PROPERTY	669	234	434	0
(26) INTEREST NET OF AFUDC	3,715	1,301	2,414	0
(27) PREFERRED DIVIDENDS	419	147	272	0
(28) CORPORATE TAXES	2,493	873	1,620	0
NON-OPERATING REVENUE:				
(29) OTHER REVENUE	(53)	(19)	(35)	0
(30) RETURN (PROFIT/LOSS)	2,878	1,008	1,870	0
(31) TOTAL < 138kV	**20,502**	**7,180**	**13,322**	**0**

NOVA SCOTIA POWER INC.

CLASSIFICATION OF OPERATING EXPENSES

FOR THE YEAR ENDING DECEMBER 31, 2007
(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DEMAND EXPENSES	(3) ENERGY EXPENSES	(4) CUSTOMER EXPENSES
Transmission > 69kV:				
(1) O&M > 69kV	18,678	6,541	12,137	0
(2) GRANTS IN LIEU OF TAXES	3,295	1,154	2,141	0
DEPRECIATION:				
(3) TRANSMISSION	10,169	3,561	6,608	0
(4) GENERAL PROPERTY	2,189	766	1,422	0
(5) INTEREST NET OF AFUDC	12,150	4,255	7,895	0
(6) PREFERRED DIVIDENDS	1,370	480	890	0
(7) CORPORATE TAXES	8,153	2,855	5,298	0
NON-OPERATING REVENUE:				
(8) OTHER REVENUE	(175)	(61)	(114)	0
(9) RETURN (PROFIT/LOSS)	9,414	3,297	6,117	0
(10) TOTAL > 69kV	**65,243**	**22,848**	**42,395**	**0**
(11) TOTAL TRANSMISSION	**$85,744**	**$30,028**	**$55,716**	**$0**

NOVA SCOTIA POWER INC.

CLASSIFICATION OF OPERATING EXPENSES

FOR THE YEAR ENDING DECEMBER 31, 2007
(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DEMAND EXPENSES	(3) ENERGY EXPENSES	(4) CUSTOMER EXPENSES
DISTRIBUTION FUNCTION				
(1) SUBSTATIONS	$1,156	$1,156	$0	$0
(2) OVERHEAD LINES	30,488	19,817	0	10,671
(3) UNDERGROUND LINES	836	543	0	293
(4) LINE TRANSFORMERS	2,409	2,409	0	0
(5) METERS	249	0	0	249
(6) COMMUNICATIONS	1,958	1,958	0	0
(7) STREET LIGHTING	4,338	4,338	0	0
(8) GRANTS IN LIEU OF TAXES	7,963	5,313	0	2,650
DEPRECIATION:				
(9) DISTRIBUTION	41,597	28,085	0	13,512
(10) GENERAL PROPERTY	5,287	3,570	0	1,717
(11) INTEREST NET OF AFUDC	29,703	19,817	0	9,885
(12) PREFERRED DIVIDENDS	3,349	2,235	0	1,115
(13) CORPORATE TAXES	19,931	13,298	0	6,633
NON-OPERATING REVENUE:				
(14) OTHER REVENUE	(463)	(318)	0	(145)
(15) RETURN (PROFIT/LOSS)	23,013	15,354	0	7,659
(16) TOTAL DISTRIBUTION	**171,813**	**117,575**	**0**	**54,238**
RETAIL FUNCTION				
(17) QTY. ASSURANCE. & COMM.	4,321	0	0	4,321
(18) CALL CENTRE	11,523	0	0	11,523
(19) BILLING SERVICES	4,243	0	0	4,243
(20) ELECT. WIRING INSPECT. - H/O	263	0	0	263
(21) METER DATA SERVICES	845	0	0	845
(22) METER READING - FIELD	7,400	0	0	7,400
(23) ELECT. WIRING INSPECT. - FIELD	2,145	0	0	2,145
(24) PAYMENT SERVICES	1,100	0	0	1,100
(25) CREDIT SERVICES	296	0	0	296
(26) BAD DEBT EXPENSE	2,880	0	0	2,880
(27) MARKETING & SALES	1,929	0	0	1,929
(28) COGS (NET OF RETAIL SALES)	(391)	0	0	(391)
(29) GRANTS IN LIEU OF TAXES	0	0	0	0
(30) DEPRECIATION:				
(31) DISTRIBUTION	0	0	0	0
(32) GENERAL PROPERTY	0	0	0	0
(33) INTEREST NET OF AFUDC	0	0	0	0
(34) PREFERRED DIVIDENDS	0	0	0	0
(35) CORPORATE TAXES	0	0	0	0
NON-OPERATING REVENUE:				
(36) LATE PAYMENT CHARGE	(3,743)	0	0	(3,743)
(37) MISC. ELECTRIC	(2,147)	0	0	(2,147)
(38) OTHER REVENUE	(113)	0	0	(113)
(39) RETURN (PROFIT/LOSS)	0	0	0	0
(40) TOTAL RETAIL	**30,549**	**0**	**0**	**30,549**
(41) TOTAL NET EXPENSES	**$1,121,190**	**$267,458**	**$768,945**	**$84,787**

NOVA SCOTIA POWER INC.

ALLOCATION OF OPERATING EXPENSES

FOR THE YEAR ENDING DECEMBER 31, 2007
(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) EXTRA LI INTERR. - 2	(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- FIXED	4,654	2,234	113	925	130	74	176	281	580	85	54	D-3A
(3) OPER. & MAINT. - STEAM	23,043	11,062	562	4,582	643	366	872	1,393	2,873	423	267	D-3A
(4) OPER. & MAINT. - HYDRO	2,309	1,109	56	459	64	37	87	140	288	42	27	D-3A
(5) OPER. & MAINT. - LM6000	101	49	2	20	3	2	4	6	13	2	1	D-3A
(6) OPER. & MAINT. - OTHER CT's	898	431	22	179	25	14	34	54	112	16	10	D-3A
(7) GRANTS IN LIEU	6,819	3,274	166	1,356	190	108	258	412	850	125	79	P-7
(8) DEPRECIATION	21,490	10,317	524	4,273	599	341	814	1,299	2,680	394	249	EXH 6D
(9) INTEREST NET OF AFUDC	23,786	11,419	580	4,730	663	378	901	1,438	2,966	436	275	P-14
(10) PREFERRED DIVIDENDS	2,682	1,288	65	533	75	43	102	162	334	49	31	P-14
(11) CORPORATE TAXES	15,960	7,662	389	3,174	445	254	604	965	1,990	293	185	P-14
NON-OPERATING REVENUE:												
(12) OTHER REVENUE	(316)	(152)	(8)	(63)	(9)	(5)	(12)	(19)	(39)	(6)	(4)	O-8
(13) RETURN (PROFIT/LOSS)	18,428	8,847	449	3,664	514	293	698	1,114	2,298	338	213	P-14
(14) INTERR. RIDER DMD ADJ.	(6,928)	0	0	0	0	0	0	(6,928)	0	0	0	DIRECT
(15) ALLOC. OF INTERR. DMD. ADJ.	6,928	4,045	205	1,675	235	134	319	62	0	155	97	D-4
(16) ELIIR-2 INTERR. DMD. ADJ.	(16,996)	0	0	0	0	0	0	0	(16,996)	0	0	DIRECT
(17) ALLOC. OF ELIIR-2 INT. DMD. ADJ.	16,996	9,923	504	4,110	576	328	783	153	0	379	239	D-4
(18) ELIIR-2 PRIORITY INT. DMD ADJ.	(2,549)	0	0	0	0	0	0	0	(2,549)	0	0	DIRECT
(19) ALLOC. OF ELIIR-2 PRI. INT. DMD. ADJ.	2,549	1,398	71	579	81	46	110	176	0	53	34	D-3B
(20) TOTAL GENERATION	119,855	72,905	3,703	30,197	4,235	2,413	5,750	711	(4,601)	2,785	1,757	
TRANSMISSION												
Transmission < 138kV												
(21) OPERATING & MAINT.	2,097	1,150	58	476	67	38	91	145	0	44	28	D-3B
(22) GRANTS IN LIEU	353	193	10	80	11	6	15	24	0	7	5	P-8A
(23) DEPRECIATION	1,420	779	40	323	45	26	61	98	0	30	19	EXH 6D
(24) INTEREST NET OF AFUDC	1,301	713	36	296	41	24	56	90	0	27	17	P-15A
(25) PREFERRED DIVIDENDS	147	80	4	33	5	3	6	10	0	3	2	P-15A
(26) CORPORATE TAXES	873	479	24	198	28	16	38	60	0	18	12	P-15A
NON-OPERATING REVENUE:												
(27) OTHER REVENUE	(19)	(10)	(1)	(4)	(1)	(0)	(1)	(1)	0	(0)	(0)	O-9A
(28) RETURN (PROFIT/LOSS)	1,008	553	28	229	32	18	44	70	0	21	13	P-15A
(29) TOTAL < 138kV	$7,180	$3,938	$200	$1,631	$229	$130	$311	$496	$0	$150	$95	

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NOVA SCOTIA POWER INC.

ALLOCATION OF OPERATING EXPENSES

FOR THE YEAR ENDING DECEMBER 31, 2007
(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) EXTRA LI INTERR. - 2	(9) MUNICIPAL	(10) UNMETERED	(11) ALLOCATION FACTOR
Transmission > 69kV												
(1) OPERATING & MAINT.	6,541	3,140	160	1,301	182	104	248	395	816	120	76	D-3A
(2) GRANTS IN LIEU	1,154	554	28	229	32	18	44	70	144	21	13	P-8B
(3) DEPRECIATION	4,328	2,078	106	861	121	69	164	262	540	79	50	EXH 6D
(4) INTEREST NET OF AFUDC	4,255	2,043	104	846	119	68	161	257	531	78	49	P-15B
(5) PREFERRED DIVIDENDS	480	230	12	95	13	8	18	29	60	9	6	P-15B
(6) CORPORATE TAXES	2,855	1,371	70	568	80	45	108	173	356	52	33	P-15B
NON-OPERATING REVENUE:												
(7) OTHER REVENUE	(61)	(29)	(1)	(12)	(2)	(1)	(2)	(4)	(8)	(1)	(1)	O-9B
(8) RETURN (PROFIT/LOSS)	3,297	1,583	80	656	92	52	125	199	411	60	38	P-15B
(9) TOTAL > 69kV	22,848	10,969	557	4,543	637	363	865	1,381	2,849	419	264	
(10) TOTAL TRANSMISSION	30,028	14,906	757	6,174	866	493	1,176	1,877	2,849	569	359	
DISTRIBUTION												
(11) OPERATING & MAINT.	30,222	15,355	1,013	6,850	675	686	882	26	0	2	4,732	EXH 6A
(12) GRANTS IN LIEU	5,313	2,982	197	1,316	88	130	118	11	0	1	470	P-9
(13) DEPRECIATION	31,656	17,768	1,173	7,839	526	777	702	63	0	6	2,802	EXH 6D
(14) INTEREST NET OF AFUDC	19,816	11,106	733	4,901	331	486	441	39	0	4	1,775	P-16
(15) PREFERRED DIVIDENDS	2,234	1,252	83	553	37	55	50	4	0	0	200	P-16
(16) CORPORATE TAXES	13,297	7,453	492	3,289	222	326	296	26	0	2	1,191	P-16
NON-OPERATING REVENUE:												
(17) OTHER REVENUE	(319)	(173)	(11)	(77)	(6)	(8)	(8)	(1)	0	0	(35)	O-10
(18) RETURN (PROFIT/LOSS)	15,355	8,605	568	3,797	257	377	342	30	0	3	1,376	P-16
(19) TOTAL DISTRIBUTION	117,573	64,348	4,248	28,468	2,130	2,829	2,823	199	0	18	12,511	
(20) TOTAL DEMAND	$267,456	$152,159	$8,708	$64,839	$7,231	$5,735	$9,748	$2,787	($1,752)	$3,373	$14,627	

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NOVA SCOTIA POWER INC.

ALLOCATION OF OPERATING EXPENSES

FOR THE YEAR ENDING DECEMBER 31, 2007
(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) EXTRA LI INTERR. - 2	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
ENERGY CLASSIFICATION												
GENERATION												
(1) FUEL	$431,431	$163,085	$9,212	$91,016	$15,309	$9,245	$21,263	$38,412	$72,560	$7,059	$4,270	DIRECT
(2) PURCH. POWER- FIXED	9,613	3,634	205	2,027	341	206	474	857	1,617	157	95	E-1
(3) PURCH. POWER- VAR.	17,509	6,619	374	3,691	621	375	863	1,560	2,946	287	174	E-1
(4) OPER. & MAINT. - STEAM	61,049	23,078	1,304	12,870	2,166	1,307	3,009	5,440	10,271	999	606	E-1
(5) OPER. & MAINT. - HYDRO	6,118	2,313	131	1,290	217	131	302	545	1,029	100	61	E-1
(6) OPER. & MAINT. - LM6000	268	101	6	57	10	6	13	24	45	4	3	E-1
(7) OPER. & MAINT. - OTHER CT's	171	65	4	36	6	4	8	15	29	3	2	E-1
(8) GRANTS IN LIEU	14,084	5,324	301	2,969	500	302	694	1,255	2,369	231	140	P-10
(9) DEPRECIATION	43,847	16,575	936	9,244	1,556	939	2,161	3,907	7,377	718	435	EXH 6D
(10) INTEREST NET OF AFUDC	54,642	20,656	1,167	11,520	1,939	1,170	2,693	4,869	9,193	894	542	P-17
(11) PREFERRED DIVIDENDS	6,161	2,329	132	1,299	219	132	304	549	1,037	101	61	P-17
(12) CORPORATE TAXES	36,665	13,860	783	7,730	1,301	785	1,807	3,267	6,168	600	364	P-17
NON-OPERATING REVENUE:												
(13) EXPORT SALES	(8,548)	(3,231)	(183)	(1,802)	(303)	(183)	(421)	(762)	(1,438)	(140)	(85)	EXH 7
(14) OTHER REVENUE	(2,114)	(799)	(45)	(446)	(75)	(45)	(104)	(188)	(356)	(35)	(21)	O-11
(15) RETURN (PROFIT/LOSS)	42,335	16,003	904	8,925	1,502	906	2,087	3,772	7,122	693	420	P-17
(16) TOTAL GENERATION	713,231	269,612	15,231	150,425	25,307	15,278	35,152	63,521	119,969	11,671	7,065	
TRANSMISSION												
Transmission < 138kV												
(17) OPERATING & MAINT.	3,892	1,769	100	986	166	100	231	417	0	77	46	E-1B
(18) GRANTS IN LIEU	655	298	17	166	28	17	39	70	0	13	8	P-11A
(19) DEPRECIATION	2,635	1,197	68	668	112	68	156	282	0	52	31	EXH 6D
(20) INTEREST NET	2,414	1,097	62	612	103	62	143	259	0	48	29	P-18A
(21) PREFERRED DIVIDENDS	272	124	7	69	12	7	16	29	0	5	3	P-18A
(22) CORPORATE TAXES	1,620	736	42	411	69	42	96	174	0	32	19	P-18A
NON-OPERATING REVENUE:												
(23) OTHER REVENUE	(35)	(16)	(1)	(9)	(1)	(1)	(2)	(4)	0	(1)	(0)	O-12A
(24) RETURN (PROFIT/LOSS)	1,870	850	48	474	80	48	111	200	0	37	22	P-18A
(25) TOTAL < 138kV	13,322	6,055	342	3,377	568	343	789	1,427	0	262	159	
Transmission > 69kV												
(26) OPERATING & MAINT.	12,137	4,588	259	2,559	431	260	598	1,081	2,042	199	120	E-1A
(27) GRANTS IN LIEU	2,141	809	46	451	76	46	106	191	360	35	21	P-11B
(28) DEPRECIATION	8,030	3,035	171	1,693	285	172	396	715	1,351	131	80	EXH 6D
(29) INTEREST NET	7,895	2,985	169	1,664	280	169	389	703	1,328	129	78	P-18B
(30) PREFERRED DIVIDENDS	890	337	19	188	32	19	44	79	150	15	9	P-18B
(31) CORPORATE TAXES	5,298	2,003	113	1,117	188	113	261	472	891	87	53	P-18B
NON-OPERATING REVENUE:												
(32) OTHER REVENUE	(114)	(43)	(2)	(24)	(4)	(2)	(6)	(10)	(19)	(2)	(1)	O-12B
(33) RETURN (PROFIT/LOSS)	6,117	2,312	131	1,290	217	131	301	545	1,029	100	61	P-18B
(34) TOTAL > 69kV	42,395	16,026	905	8,938	1,504	908	2,089	3,777	7,132	694	421	
(35) TOTAL TRANSMISSION	55,716	22,081	1,247	12,314	2,072	1,251	2,879	5,205	7,132	956	579	
(36) TOTAL ENERGY	**$768,948**	**$291,692**	**$16,478**	**$162,739**	**$27,380**	**$16,529**	**$38,030**	**$68,726**	**$127,101**	**$12,628**	**$7,644**	

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NOVA SCOTIA POWER INC.

ALLOCATION OF OPERATING EXPENSES

FOR THE YEAR ENDING DECEMBER 31, 2007
(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) EXTRA LI INTERR. - 2	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
CUST. CLASSIFICATION												
DISTRIBUTION												
(1) OPERATING & MAINT.	$20,757	$18,012	$980	$1,107	$25	$227	$88	$43	$3	$8	$264	EXH 6A
(2) GRANTS IN LIEU	2,650	2,307	125	152	0	32	3	1	0	0	29	P-12
(3) DEPRECIATION	15,229	13,256	721	871	1	187	20	5	0	0	168	EXH 6D
(4) INTEREST NET OF AFUDC	9,885	8,603	468	564	2	120	14	4	0	0	110	P-19
(5) PREFERRED DIVIDENDS	1,115	970	53	64	0	14	2	0	0	0	12	P-19
(6) CORPORATE TAXES	6,633	5,773	314	378	1	81	10	3	0	0	74	P-19
NON-OPERATING REVENUE:												
(7) OTHER REVENUE	(145)	(126)	(7)	(8)	(0)	(2)	(0)	(0)	(0)	(0)	(2)	O-13
(8) RETURN (PROFIT/LOSS)	7,659	6,665	363	437	1	93	11	3	0	0	85	P-19
(9) TOTAL DISTRIBUTION	63,782	55,459	3,016	3,564	31	753	147	58	4	10	740	
RETAIL												
(10) OPERATING & MAINT.	0	0	0	0	0	0	0	0	0	0	0	EXH 6A
(11) CUST. SERV. - H/O	4,321	3,897	212	102	0	21	2	0	0	0	87	C-1
(12) CALL CENTRE	11,523	9,169	499	1,197	38	244	126	64	4	13	168	C-3
(13) BILLING SERVICES	4,243	3,376	184	441	14	90	46	24	2	5	62	C-3
(14) ELECT. WIRING INSP. - H/O	263	237	13	6	0	1	0	0	0	0	5	C-1
(15) METER DATA SERVICES	845	38	37	88	114	88	88	165	139	88	0	O-16
(15) PAYMENT SERVICES	1,100	992	54	26	0	5	1	0	0	0	22	C-1
(16) CREDIT SERVICES	3,176	2,686	59	386	0	38	0	0	0	0	6	EXH 6C
(17) MARKETING & SALES	1,929	731	58	135	29	106	208	316	316	29	0	O-15
(18) COGS (NET OF SALES)	(391)	(352)	(19)	(9)	(0)	(2)	(0)	(0)	(0)	(0)	(8)	C-1
(19) GRANTS IN LIEU	0	0	0	0	0	0	0	0	0	0	0	N/A
(20) DEPRECIATION	0	0	0	0	0	0	0	0	0	0	0	N/A
(21) INTEREST NET OF AFUDC	0	0	0	0	0	0	0	0	0	0	0	N/A
(22) PREFERRED DIVIDENDS	0	0	0	0	0	0	0	0	0	0	0	N/A
(23) CORPORATE TAXES	0	0	0	0	0	0	0	0	0	0	0	N/A
NON-OPERATING REVENUE:												
(24) LATE PAYMENT CHARGE	(3,743)	(2,902)	(88)	(647)	0	(50)	(43)	0	0	0	(12)	EXH 7
(25) MISC. ELECTRIC	(2,147)	(1,993)	(122)	(14)	0	0	0	0	0	0	(19)	EXH 7
(26) OTHER REVENUE	(113)	(87)	(5)	(10)	(1)	(2)	(2)	(2)	(2)	(1)	(1)	O-14
(27) RETURN (PROFIT/LOSS)	0	0	0	0	0	0	0	0	0	0	0	N/A
(28) TOTAL RETAIL	21,004	15,792	882	1,702	195	539	426	566	460	134	310	
(29) TOTAL CUSTOMER	**84,787**	**71,251**	**3,898**	**5,266**	**226**	**1,292**	**573**	**625**	**463**	**144**	**1,049**	
(30) TOTAL NET EXPENSES	**$1,121,190**	**$515,103**	**$29,085**	**$232,844**	**$34,836**	**$23,556**	**$48,351**	**$72,137**	**$125,813**	**$16,144**	**$23,321**	

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EXHIBIT 6A

NOVA SCOTIA POWER INC.

ALLOCATION OF DISTRIBUTION OPERATING EXPENSES

FOR THE YEAR ENDING DECEMBER 31, 2007

(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) EXTRA LI INTERR. - 2	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
DEMAND												
(1) SUBSTATIONS	$1,156	$642	$42	$293	$42	$30	$63	$26	$0	$2	$16	P-5
(2) OVERHEAD LINES	19,817	11,727	774	5,240	544	526	705	0	0	0	301	P-1
(3) UNDERGROUND LINES	543	322	21	144	15	14	19	0	0	0	8	P-1
(4) LINE TRANSFORMERS	2,409	1,540	102	663	0	64	0	0	0	0	40	D-1
(5) METERS	0	0	0	0	0	0	0	0	0	0	0	---
(6) COMMUNICATIONS	1,958	1,124	74	510	74	52	95	0	0	0	29	D-2
(7) STREET LIGHTING	4,338	0	0	0	0	0	0	0	0	0	4,338	DIRECT
(8) CUSTOMER SERVICE	0	0	0	0	0	0	0	0	0	0	0	---
(9) TOTAL DEMAND	30,222	15,355	1,013	6,850	675	686	882	26	0	2	4,732	
CUSTOMER												
(10) SUBSTATIONS	0	0	0	0	0	0	0	0	0	0	0	--
(11) OVERHEAD LINES	10,671	9,626	524	251	0	51	3	0	0	0	215	P-2
(12) UNDERGROUND LINES	293	264	14	7	0	1	0	0	0	0	6	P-2
(13) LINE TRANSFORMERS	0	0	0	0	0	0	0	0	0	0	0	--
(14) METERS	249	211	11	18	0	5	2	1	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	9,545	7,910	430	831	25	170	83	42	3	8	43	EXHIBIT 6B
(18) TOTAL CUSTOMER	20,757	18,012	980	1,107	25	227	88	43	3	8	264	
RETAIL												
(19) METERS	0	0	0	0	0	0	0	0	0	0	0	N/A
(20) TOTAL RETAIL	0	0	0	0	0	0	0	0	0	0	0	
SUMMARY												
(21) SUBSTATIONS	1,156	642	42	293	42	30	63	26	0	2	16	P-3
(22) OVERHEAD LINES	30,488	21,353	1,297	5,492	544	577	708	0	0	0	516	P-1
(23) UNDERGROUND LINES	836	586	36	151	15	16	19	0	0	0	14	P-1
(24) LINE TRANSFORMERS	2,409	1,540	102	663	0	64	0	0	0	0	40	D-1
(25) METERS	249	211	11	18	0	5	2	1	0	0	0	P-6
(26) COMMUNICATIONS	1,958	1,124	74	510	74	52	95	0	0	0	29	D-2
(27) STREET LIGHTING	4,338	0	0	0	0	0	0	0	0	0	4,338	DIRECT
(28) CUSTOMER SERVICE	9,545	7,910	430	831	25	170	83	42	3	8	43	EXHIBIT 6B
(29) TOTAL DISTRIBUTION	**$50,978**	**$33,366**	**$1,993**	**$7,957**	**$700**	**$913**	**$970**	**$69**	**$3**	**$11**	**$4,996**	

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EXHIBIT 6B

NOVA SCOTIA POWER INC.

ALLOCATION OF CUSTOMER SERVICE FIELD EXPENSES

FOR THE YEAR ENDING DECEMBER 31, 2007

(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) METER READING	(4) WIRING INSPECTION
(1) DOMESTIC	$7,910	$5,976	$1,934
(2) SMALL GENERAL	430	325	105
(3) GENERAL	831	780	51
(4) GENERAL LARGE	25	25	0
(5) SMALL INDUSTRIAL	170	159	10
(6) MEDIUM INDUSTRIAL	83	82	1
(7) INDUSTRIAL LARGE	42	42	0
(8) EXTRA LI INTERR. - 2	3	3	0
(9) MUNICIPAL	8	8	0
(10) UNMETERED	43	0	43
(11) TOTAL	$9,545	$7,400	$2,145
ALLOCATION FACTOR		C-6	C-1

EXHIBIT 6C

NOVA SCOTIA POWER INC.

ALLOCATION OF CREDIT SERVICES EXPENSES

FOR THE YEAR ENDING DECEMBER 31, 2007

(IN THOUSANDS OF DOLLARS)

	(1)	(2)	(3)	(4)	(5)
	----------BAD DEBT EXPENSE----------				
	DIRECT	TO BE ALLOC.	TOTAL	CREDIT SERVICES	TOTAL
(1) DOMESTIC	$2,419	$0	$2,419	$267	$2,686
(2) SMALL GENERAL	0	45	45	15	59
(3) GENERAL	0	379	379	7	386
(4) GENERAL LARGE	0	0	0	0	0
(5) SMALL INDUSTRIAL	0	37	37	1	38
(6) MEDIUM INDUSTRIAL	0	0	0	0	0
(7) INDUSTRIAL LARGE	0	0	0	0	0
(8) EXTRA LI INTERR. - 2	0	0	0	0	0
(9) MUNICIPAL	0	0	0	0	0
(10) UNMETERED	0	0	0	6	6
(11) TOTAL	$2,419	$461	$2,880	$296	$3,176
ALLOCATION FACTOR	DIRECT	R-1		C-1	

DOMESTIC - 84 %

NOVA SCOTIA POWER INC.

ALLOCATION OF DEPRECIATION EXPENSES

FOR THE YEAR ENDING DECEMBER 31, 2007

(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) EXTRA LI INTERR. - 2	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
DEMAND CLASSIFICATION												
GENERATION FUNCTION												
(1) STEAM PRODUCTION	$13,426	$6,445	$327	$2,670	$374	$213	$508	$812	$1,674	$246	$155	D-3A
(2) HYDRO PRODUCTION	1,844	885	45	367	51	29	70	111	230	34	21	D-3A
(3) WIND PRODUCTION	28	14	1	6	1	0	1	2	4	1	0	D-3A
(4) LM6000 PRODUCTION	797	383	19	159	22	13	30	48	99	15	9	D-3A
(5) GAS TURBINE PROD. - OTHER	867	416	21	172	24	14	33	52	108	16	10	D-3A
(6) GENERAL PROPERTY	4,528	2,174	110	900	126	72	171	274	565	83	52	P-7
(7) TOTAL GENERATION FUNCTION	21,490	10,317	524	4,273	599	341	814	1,299	2,680	394	249	
TRANSMISSION FUNCTION												
(8) TRANSMISSION PLANT < 138kV	1,186	650	33	269	38	22	51	82	0	25	16	D-3B
(9) GENERAL PROPERTY	234	128	7	53	7	4	10	16	0	5	3	P-8A
TOTAL < 138kV	1,420	779	40	323	45	26	61	98	0	30	19	
(10) TRANSMISSION PLANT > 69kV	3,561	1,710	87	708	99	57	135	215	444	65	41	D-3A
(11) GENERAL PROPERTY	766	368	19	152	21	12	29	46	96	14	9	P-8B
(12) TOTAL > 69kV	4,328	2,078	106	861	121	69	164	262	540	79	50	
(13) TOTAL TRANSMISSION FUNCTION	5,748	2,856	145	1,183	166	95	225	360	540	109	69	
DISTRIBUTION FUNCTION												
(14) DISTRIBUTION PLANT	28,085	15,764	1,040	6,955	467	690	622	56	0	5	2,486	P-9
(15) GENERAL PROPERTY	3,570	2,004	132	884	59	88	79	7	0	1	316	P-9
(16) TOTAL DISTRIBUTION FUNCTION	31,656	17,768	1,173	7,839	526	777	702	63	0	6	2,802	
(17) TOTAL DEMAND	**58,893**	**30,941**	**1,842**	**13,296**	**1,291**	**1,213**	**1,741**	**1,722**	**3,219**	**509**	**3,119**	
ENERGY CLASSIFICATION												
GENERATION FUNCTION												
(18) STEAM PRODUCTION	29,528	11,162	631	6,225	1,048	632	1,455	2,631	4,968	483	293	E-1A
(19) HYDRO PRODUCTION	3,421	1,293	73	721	121	73	169	305	576	56	34	E-1A
(20) WIND PRODUCTION	66	25	1	14	2	1	3	6	11	1	1	E-1A
(21) LM6000 PRODUCTION	1,480	559	32	312	52	32	73	132	249	24	15	E-1A
(22) GAS TURBINE PROD. - OTHER	0	0	0	0	0	0	0	0	0	0	0	E-1A
(23) GENERAL PROPERTY	9,352	3,535	200	1,972	332	200	461	833	1,573	153	93	P-10
(24) TOTAL GENERATION FUNCTION	43,847	16,575	936	9,244	1,556	939	2,161	3,907	7,377	718	435	
TRANSMISSION FUNCTION												
(25) TRANSMISSION PLANT < 138kV	2,200	1,000	56	558	94	57	130	236	0	43	26	E-1B
(26) GENERAL PROPERTY	434	197	11	110	19	11	26	47	0	9	5	P-11A
(27) TOTAL < 138kV	2,635	1,197	68	668	112	68	156	282	0	52	31	
(28) TRANSMISSION PLANT > 69kV	6,608	2,498	141	1,393	234	141	326	589	1,112	108	66	E-1A
(29) GENERAL PROPERTY	1,422	538	30	300	50	30	70	127	239	23	14	P-11B
(30) TOTAL > 69kV	8,030	3,035	171	1,693	285	172	396	715	1,351	131	80	
(31) TOTAL TRANSMISSION FUNCTION	10,665	4,233	239	2,361	397	240	552	998	1,351	183	111	
(32) TOTAL ENERGY	**54,512**	**20,808**	**1,176**	**11,605**	**1,953**	**1,178**	**2,713**	**4,905**	**8,728**	**901**	**546**	

REDACTED Appendix 3 Page 33 of 41

NOVA SCOTIA POWER INC.

ALLOCATION OF DEPRECIATION EXPENSES

FOR THE YEAR ENDING DECEMBER 31, 2007

(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) EXTRA LI INTERR. - 2	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
CUSTOMER CLASSIFICATION												
DISTRIBUTION FUNCTION												
(1) DISTRIBUTION PLANT	13,512	11,761	640	773	1	166	17	4	0	0	149	P-12
(2) GENERAL PROPERTY	1,717	1,495	81	98	0	21	2	1	0	0	19	P-12
(3) TOTAL DISTRIBUTION FUNCTION	15,229	13,256	721	871	1	187	20	5	0	0	168	
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	**15,229**	**13,256**	**721**	**871**	**1**	**187**	**20**	**5**	**0**	**0**	**168**	
(8) TOTAL DEPRECIATION	**$128,634**	**$65,005**	**$3,738**	**$25,772**	**$3,246**	**$2,578**	**$4,473**	**$6,632**	**$11,947**	**$1,411**	**$3,833**	

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EXHIBIT 7

NOVA SCOTIA POWER INC.

REVENUE ANALYSIS

FOR THE YEAR ENDING DECEMBER 31, 2007
(IN THOUSANDS OF DOLLARS)

	(1) REVENUE	(2) EXPORT SALES	(3) LATE PAYMENT CHARGE	(4) MISC. CUSTOMER REVENUE
ELECTRIC REVENUE				
(1) DOMESTIC	$504,229	$3,231	$2,902	$1,993
(2) SMALL GENERAL	29,425	183	88	122
(3) GENERAL	249,316	1,802	647	14
(4) LARGE GENERAL	34,404	303	0	0
(5) SMALL INDUSTRIAL	24,073	183	50	0
(6) MEDIUM INDUSTRIAL	48,992	421	43	0
(7) LARGE INDUSTRIAL	72,185	762	0	0
(8) EXTRA LI INTERR. - 2	119,522	1,438	0	0
(9) MUNICIPAL	15,724	140	0	0
(10) UNMETERED	23,321	85	12	19
(11) SUB-TOTAL	1,121,190	$8,548	$3,743	$2,147
(12) EXPORT SALES	8,548			
(13) TOTAL ELECTRIC REVENUE	1,129,739			
NON-RATE REVENUE				
(14) LATE PAYMENT CHARGE	3,743			
(15) MISC. CUST. REVENUE	2,147			
(16) OTHER	3,235			
(17) TOTAL	9,125			
DIRECT REVENUE				
(18) BOWATER BASIC BLOCK	7,258			
(19) BOWATER ADDITIONAL ENERGY	10,741			
(20) GEN.REPL./LOAD FOLL	1,166			
(21) REAL TIME PRICING	0			
(22) EXTRA LI INTERRUPTIBLE	0			
(23) TOTAL	19,165			
(24) TRANSFER FROM (TO) RETAINED EARNINGS	(99,495)			
(25) TOTAL REVENUE	**$1,058,533**			
ALLOCATION FACTOR		E-1	DIRECT	DIRECT

EXHIBIT 8A

NOVA SCOTIA POWER INC.

DEVELOPMENT OF ALLOCATION FACTORS

FOR THE YEAR ENDING DECEMBER 31, 2007

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) EXTRA LI INTERR. - 2	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
(1) N.C. DEMAND SEC.	1,761,940	1,126,463	74,337	485,090	0	47,137	0	0	0	0	28,914	
(2) % RESPONSIBILITY	100.00%	63.93%	4.22%	27.53%	0.00%	2.68%	0.00%	0.00%	0.00%	0.00%	1.64%	D-1
(3) N.C. DEMAND PRI.	2,067,557	1,187,292	78,351	538,441	77,695	54,666	100,638	0	0	0	30,475	
(4) % RESPONSIBILITY	100.00%	57.42%	3.79%	26.04%	3.76%	2.64%	4.87%	0.00%	0.00%	0.00%	1.47%	D-2
(5) 3 CP DEMAND	6,490,207	3,115,781	158,272	1,290,542	180,995	103,120	245,729	392,418	809,227	119,033	75,090	
(6) % RESPONSIBILITY	100.00%	48.01%	2.44%	19.88%	2.79%	1.59%	3.79%	6.05%	12.47%	1.83%	1.16%	D-3A
(7) 3 CP DEMAND - LESS ELIIR - 2	5,680,980	3,115,781	158,272	1,290,542	180,995	103,120	245,729	392,418	0	119,033	75,090	
(8) % RESPONSIBILITY	100.00%	54.85%	2.79%	22.72%	3.19%	1.82%	4.33%	6.91%	0.00%	2.10%	1.32%	D-3B
(9) 3 CP DMD. - LESS INT. & ELIIR - 2	5,336,667	3,115,781	158,272	1,290,542	180,995	103,120	245,729	48,105	0	119,033	75,090	
(10) % RESPONSIBILITY	100.00%	58.38%	2.97%	24.18%	3.39%	1.93%	4.60%	0.90%	0.00%	2.23%	1.41%	D-4
(11) MW.h GEN. & PURCH.	12,592,175	4,760,109	268,925	2,654,677	446,765	269,594	620,625	1,122,003	2,118,450	206,123	124,904	
(12) % RESPONSIBILITY	100.00%	37.80%	2.14%	21.08%	3.55%	2.14%	4.93%	8.91%	16.82%	1.64%	0.99%	E-1A
(13) MW.h GEN. & PURCH. Less EHV	10,473,725	4,760,109	268,925	2,654,677	446,765	269,594	620,625	1,122,003	0	206,123	124,904	
(14) % RESPONSIBILITY	100.00%	45.45%	2.57%	25.35%	4.27%	2.57%	5.93%	10.71%	0.00%	1.97%	1.19%	E-1B
(15) AVERAGE CUSTOMERS	477,168	430,332	23,406	11,239	18	2,293	236	30	2	6	9,606	
(16) % RESPONSIBILITY	100.00%	90.18%	4.91%	2.36%	0.00%	0.48%	0.05%	0.01%	0.00%	0.00%	2.01%	C-1
(17) SECONDARY CUSTOMERS	467,270	430,332	23,406	11,239	0	2,293	0	0	0	0	0	
(18) WEIGHTING FACTOR		1.00	1.00	5.00	100.00	5.00	50.00	100.00	100.00	100.00	0.82	
(19) WEIGHTED TOTAL	521,398	430,332	23,406	56,195	0	11,465	0	0	0	0	0	
(20) % RESPONSIBILITY	100.00%	82.53%	4.49%	10.78%	0.00%	2.20%	0.00%	0.00%	0.00%	0.00%	0.00%	C-2
(21) AVERAGE CUSTOMERS	477,168	430,332	23,406	11,239	18	2,293	236	30	2	6	9,606	
(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	540,775	430,332	23,406	56,195	1,800	11,465	5,900	3,000	200	600	7,877	
(24) % RESPONSIBILITY	100.00%	79.58%	4.33%	10.39%	0.33%	2.12%	1.09%	0.55%	0.04%	0.11%	1.46%	C-3
(25) CUSTOMER SECONDARY	476,876	430,332	23,406	11,239	0	2,293	0	0	0	0	9,606	
(26) % RESPONSIBILITY	100.00%	90.24%	4.91%	2.36%	0.00%	0.48%	0.00%	0.00%	0.00%	0.00%	2.01%	C-4
(27) CUSTOMER PRIMARY	477,168	430,332	23,406	11,239	18	2,293	236	30	2	6	9,606	
(28) % RESPONSIBILITY	100.00%	90.18%	4.91%	2.36%	0.00%	0.48%	0.05%	0.01%	0.00%	0.00%	2.01%	C-5
(29) AVG. CUST. - LESS UNMETERED	467,562	430,332	23,406	11,239	18	2,293	236	30	2	6	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	532,898	430,332	23,406	56,195	1,800	11,465	5,900	3,000	200	600	0	
(32) % RESPONSIBILITY	100.00%	80.75%	4.39%	10.55%	0.34%	2.15%	1.11%	0.56%	0.04%	0.11%	0.00%	C-6

NOVA SCOTIA POWER INC.

DEVELOPMENT OF ALLOCATION FACTORS

FOR THE YEAR ENDING DECEMBER 31, 2007

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) EXTRA LI INTERR. - 2	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
(1) POLE&WIRE INV.-DMD.	$147,406	$87,231	$5,756	$38,979	$4,048	$3,910	$5,243	$0	$0	$0	$2,239	
(2) % RESPONSIBILITY	100.00%	59.18%	3.91%	26.44%	2.75%	2.65%	3.56%	0.00%	0.00%	0.00%	1.52%	P-1
(3) POLE&WIRE INV.-CUST.	$79,373	$71,604	$3,895	$1,870	$1	$382	$20	$2	$0	$0	$1,598	
(4) % RESPONSIBILITY	100.00%	90.21%	4.91%	2.36%	0.00%	0.48%	0.02%	0.00%	0.00%	0.00%	2.01%	P-2
(5) SUB.,POLE&WIRE-DMD.	$176,806	$103,545	$6,833	$46,422	$5,117	$4,661	$6,841	$667	$0	$62	$2,658	
(6) % RESPONSIBILITY	100.00%	58.56%	3.86%	26.26%	2.89%	2.64%	3.87%	0.38%	0.00%	0.04%	1.50%	P-3
(7) SUB.,POLE&WIRE-CUST.	$79,373	$71,604	$3,895	$1,870	$1	$382	$20	$2	$0	$0	$1,598	
(8) % RESPONSIBILITY	100.00%	90.21%	4.91%	2.36%	0.00%	0.48%	0.02%	0.00%	0.00%	0.00%	2.01%	P-4
(9) SUBST. INVEST.-DMD.	$29,400	$16,314	$1,077	$7,443	$1,070	$751	$1,598	$667	$0	$62	$419	
(10) % RESPONSIBILITY	100.00%	55.49%	3.66%	25.32%	3.64%	2.55%	5.43%	2.27%	0.00%	0.21%	1.42%	P-5
(11) METER INVEST.-CUST	$21,744	$18,475	$1,005	$1,575	$15	$420	$196	$51	$3	$4	$0	
(12) % RESPONSIBILITY	100.00%	84.97%	4.62%	7.24%	0.07%	1.93%	0.90%	0.23%	0.01%	0.02%	0.00%	P-6
(13) DEMAND - GEN. PLANT	$447,127	$214,654	$10,904	$88,909	$12,469	$7,104	$16,929	$27,035	$55,750	$8,200	$5,173	
(14) % RESPONSIBILITY	100.00%	48.01%	2.44%	19.88%	2.79%	1.59%	3.79%	6.05%	12.47%	1.83%	1.16%	P-7
(15) DEMAND - TRANS. PLT. < 138kV	$23,120	$12,680	$644	$5,252	$737	$420	$1,000	$1,597	$0	$484	$306	
(16) % RESPONSIBILITY	100.00%	54.85%	2.79%	22.72%	3.19%	1.82%	4.33%	6.91%	0.00%	2.10%	1.32%	P-8A
(17) DEMAND - TRANS. PLT. > 69kV	$75,683	$36,333	$1,846	$15,049	$2,111	$1,202	$2,865	$4,576	$9,436	$1,388	$876	
(18) % RESPONSIBILITY	100.00%	48.01%	2.44%	19.88%	2.79%	1.59%	3.79%	6.05%	12.47%	1.83%	1.16%	P-8B
(19) DEMAND - DIST. PLANT	$352,531	$197,872	$13,058	$87,303	$5,858	$8,656	$7,813	$705	$0	$66	$31,201	
(20) % RESPONSIBILITY	100.00%	56.13%	3.70%	24.76%	1.66%	2.46%	2.22%	0.20%	0.00%	0.02%	8.85%	P-9
(21) ENERGY - GEN. PLANT	$923,534	$349,116	$19,723	$194,699	$32,767	$19,773	$45,518	$82,290	$155,371	$15,117	$9,161	
(22) % RESPONSIBILITY	100.00%	37.80%	2.14%	21.08%	3.55%	2.14%	4.93%	8.91%	16.82%	1.64%	0.99%	P-10
(23) ENERGY - TRANS. PLT. < 138kV	$42,899	$19,497	$1,101	$10,873	$1,830	$1,104	$2,542	$4,596	$0	$844	$512	
(24) % RESPONSIBILITY	100.00%	45.45%	2.57%	25.35%	4.27%	2.57%	5.93%	10.71%	0.00%	1.97%	1.19%	P-11A
(25) ENERGY - TRANS. PLT. > 69kV	$140,430	$53,085	$2,999	$29,605	$4,982	$3,007	$6,921	$12,513	$23,625	$2,299	$1,393	
(26) % RESPONSIBILITY	100.00%	37.80%	2.14%	21.08%	3.55%	2.14%	4.93%	8.91%	16.82%	1.64%	0.99%	P-11B
(27) CUSTOMER - DIST. PLANT	$169,597	$147,622	$8,029	$9,704	$17	$2,078	$219	$54	$3	$5	$1,866	
(28) % RESPONSIBILITY	100.00%	87.04%	4.73%	5.72%	0.01%	1.23%	0.13%	0.03%	0.00%	0.00%	1.10%	P-12
(29) CUSTOMER - RETAIL PLANT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
(30) % 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
(31) TOT.RATE BASE-DMD. (GEN.)	$529,120	$254,017	$12,903	$105,213	$14,756	$8,407	$20,033	$31,992	$65,973	$9,704	$6,122	
(32) % RESPONSIBILITY	100.00%	48.01%	2.44%	19.88%	2.79%	1.59%	3.79%	6.05%	12.47%	1.83%	1.16%	P-14
(33) TOT.RATE BASE-DMD. (TRANS. < 138kV)	$28,938	$15,871	$806	$6,574	$922	$525	$1,252	$1,999	$0	$606	$382	
(34) % RESPONSIBILITY	100.00%	54.85%	2.79%	22.72%	3.19%	1.82%	4.33%	6.91%	0.00%	2.10%	1.32%	P-15A
(35) TOT.RATE BASE-DMD. (TRANS. > 69kV)	$94,654	$45,441	$2,308	$18,821	$2,640	$1,504	$3,584	$5,723	$11,802	$1,736	$1,095	
(36) % RESPONSIBILITY	100.00%	48.01%	2.44%	19.88%	2.79%	1.59%	3.79%	6.05%	12.47%	1.83%	1.16%	P-15B
(37) TOT.RATE BASE-DMD. (DIST.)	$440,844	$247,066	$16,304	$109,026	$7,366	$10,811	$9,820	$874	$0	$81	$39,495	
(38) % RESPONSIBILITY	100.00%	56.04%	3.70%	24.73%	1.67%	2.45%	2.23%	0.20%	0.00%	0.02%	8.96%	P-16
(39) TOT.RATE BASE-ENG. (GEN.)	$1,215,515	$459,491	$25,959	$256,254	$43,126	$26,024	$59,909	$108,306	$204,493	$19,897	$12,057	
(40) % RESPONSIBILITY	100.00%	37.80%	2.14%	21.08%	3.55%	2.14%	4.93%	8.91%	16.82%	1.64%	0.99%	P-17
(41) TOT.RATE BASE-ENG. (TRANS. < 138kV)	$53,695	$24,403	$1,379	$13,610	$2,290	$1,382	$3,182	$5,752	$0	$1,057	$640	
(42) % RESPONSIBILITY	100.00%	45.45%	2.57%	25.35%	4.27%	2.57%	5.93%	10.71%	0.00%	1.97%	1.19%	P-18A
(43) TOT.RATE BASE-ENG. (TRANS. > 69kV)	$175,632	$66,392	$3,751	$37,027	$6,231	$3,760	$8,656	$15,649	$29,547	$2,875	$1,742	
(44) % RESPONSIBILITY	100.00%	37.80%	2.14%	21.08%	3.55%	2.14%	4.93%	8.91%	16.82%	1.64%	0.99%	P-18B

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NOVA SCOTIA POWER INC.

DEVELOPMENT OF ALLOCATION FACTORS

FOR THE YEAR ENDING DECEMBER 31, 2007

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) EHV INDUSTRIAL	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
(1) TOT. RATE BASE-CUST. (DIST.)	$219,895	$191,374	$10,409	$12,538	$34	$2,680	$317	$89	$5	$10	$2,439	
(2) % RESPONSIBILITY	100.00%	87.03%	4.73%	5.70%	0.02%	1.22%	0.14%	0.04%	0.00%	0.00%	1.11%	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.	$23,043	$11,062	$562	$4,582	$643	$366	$872	$1,393	$2,873	$423	$267	
(6) % RESPONSIBILITY	100.00%	48.01%	2.44%	19.88%	2.79%	1.59%	3.79%	6.05%	12.47%	1.83%	1.16%	O-1
(7) DMD. - OPER.EXP. - TRANS. < 138kV	$2,097	$1,150	$58	$476	$67	$38	$91	$145	$0	$44	$28	
(8) % RESPONSIBILITY	100.00%	54.85%	2.79%	22.72%	3.19%	1.82%	4.33%	6.91%	0.00%	2.10%	1.32%	O-2A
(9) DMD. - OPER.EXP. - TRANS. > 69kV	$6,541	$3,140	$160	$1,301	$182	$104	$248	$395	$816	$120	$76	
(10) % RESPONSIBILITY	100.00%	48.01%	2.44%	19.88%	2.79%	1.59%	3.79%	6.05%	12.47%	1.83%	1.16%	O-2B
(11) DMD. - OPER.EXP. - DIST.	$30,222	$15,355	$1,013	$6,850	$675	$686	$882	$26	$0	$2	$4,732	
(12) % RESPONSIBILITY	100.00%	50.81%	3.35%	22.67%	2.23%	2.27%	2.92%	0.09%	0.00%	0.01%	15.66%	O-3
(13) ENG. - OPER.EXP. - GEN.	$61,049	$23,078	$1,304	$12,870	$2,166	$1,307	$3,009	$5,440	$10,271	$999	$606	
(14) % RESPONSIBILITY	100.00%	37.80%	2.14%	21.08%	3.55%	2.14%	4.93%	8.91%	16.82%	1.64%	0.99%	O-4
(15) ENG. - OPER.EXP. - TRANS. < 138kV	$3,892	$1,769	$100	$986	$166	$100	$231	$417	$0	$77	$46	
(16) % RESPONSIBILITY	100.00%	45.45%	2.57%	25.35%	4.27%	2.57%	5.93%	10.71%	0.00%	1.97%	1.19%	O-5A
(17) ENG. - OPER.EXP. - TRANS. > 69kV	$12,137	$4,588	$259	$2,559	$431	$260	$598	$1,081	$2,042	$199	$120	
(18) % RESPONSIBILITY	100.00%	37.80%	2.14%	21.08%	3.55%	2.14%	4.93%	8.91%	16.82%	1.64%	0.99%	O-5B
(19) CUST. - OPER. EXP. - DIST.	$20,757	$18,012	$980	$1,107	$25	$227	$88	$43	$3	$8	$264	
(20) % RESPONSIBILITY	100.00%	86.77%	4.72%	5.33%	0.12%	1.09%	0.42%	0.21%	0.01%	0.04%	1.27%	O-6
(21) CUST. - OPER. EXP. - RETAIL	$25,470	$20,396	$1,058	$2,246	$167	$487	$263	$253	$145	$105	$350	
(22) % RESPONSIBILITY	100.00%	80.08%	4.15%	8.82%	0.65%	1.91%	1.03%	0.99%	0.57%	0.41%	1.37%	O-7
(23) TOT. EXP. - DMD. (GEN.)	$101,742	$48,844	$2,481	$20,231	$2,837	$1,617	$3,852	$6,152	$12,686	$1,866	$1,177	
(24) % RESPONSIBILITY	100.00%	48.01%	2.44%	19.88%	2.79%	1.59%	3.79%	6.05%	12.47%	1.83%	1.16%	O-8
(25) TOT. EXP. - DMD. (TRANS. < 138kV)	$6,190	$3,395	$172	$1,406	$197	$112	$268	$428	$0	$130	$82	
(26) % RESPONSIBILITY	100.00%	54.85%	2.79%	22.72%	3.19%	1.82%	4.33%	6.91%	0.00%	2.10%	1.32%	O-9A
(27) TOT. EXP. - DMD. (TRANS. > 69kV)	$19,613	$9,415	$478	$3,900	$547	$312	$743	$1,186	$2,445	$360	$227	
(28) % RESPONSIBILITY	100.00%	48.01%	2.44%	19.88%	2.79%	1.59%	3.79%	6.05%	12.47%	1.83%	1.16%	O-9B
(29) TOT. EXP. - DMD. (DIST.)	$102,537	$55,916	$3,691	$24,748	$1,879	$2,460	$2,489	$170	$0	$15	$11,170	
(30) % RESPONSIBILITY	100.00%	54.53%	3.60%	24.14%	1.83%	2.40%	2.43%	0.17%	0.00%	0.01%	10.89%	O-10
(31) TOT. EXP. - ENG. (GEN.)	$681,559	$257,639	$14,554	$143,748	$24,184	$14,600	$33,591	$60,699	$114,641	$11,153	$6,751	
(32) % RESPONSIBILITY	100.00%	37.80%	2.14%	21.09%	3.55%	2.14%	4.93%	8.91%	16.82%	1.64%	0.99%	O-11
(33) TOT. EXP. - ENG. (TRANS. < 138 kV)	$11,487	$5,220	$295	$2,911	$490	$296	$681	$1,230	$0	$226	$137	
(34) % RESPONSIBILITY	100.00%	45.45%	2.57%	25.35%	4.27%	2.57%	5.93%	10.71%	0.00%	1.97%	1.19%	O-12A
(35) TOT. EXP. - ENG. (TRANS. > 69 kV)	$36,391	$13,757	$777	$7,672	$1,291	$779	$1,794	$3,243	$6,122	$596	$361	
(36) % RESPONSIBILITY	100.00%	37.80%	2.14%	21.08%	3.55%	2.14%	4.93%	8.91%	16.82%	1.64%	0.99%	O-12B
(37) TOT. EXP. -CUST. (DIST.)	$56,269	$48,920	$2,661	$3,136	$30	$661	$136	$56	$4	$10	$656	
(38) % RESPONSIBILITY	100.00%	86.94%	4.73%	5.57%	0.05%	1.17%	0.24%	0.10%	0.01%	0.02%	1.17%	O-13
(39) TOT. EXP. -CUST. (RETAIL)	$27,008	$20,774	$1,096	$2,372	$196	$592	$471	$569	$462	$134	$342	
(40) % RESPONSIBILITY	100.00%	76.92%	4.06%	8.78%	0.72%	2.19%	1.74%	2.11%	1.71%	0.50%	1.27%	O-14
(41) MARKETING & SALES	100.00%	37.90%	3.00%	7.00%	1.50%	5.50%	10.80%	16.40%	16.40%	1.50%	0.00%	O-15
(42) METER DATA SERVICES	100.00%	4.50%	4.40%	10.40%	13.50%	10.40%	10.40%	19.50%	16.50%	10.40%	0.00%	O-16
(43) SECONDARY CUST. REVENUE	$302,814	$0	$29,425	$249,316	$0	$24,073	$0	$0	$0	$0	$0	
(44) % RESPONSIBILITY	100.00%	0.00%	9.72%	82.33%	0.00%	7.95%	0.00%	0.00%	0.00%	0.00%	0.00%	R-1

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EXHIBIT 9A

NOVA SCOTIA POWER INC.

SALES, GENERATION AND DEMAND ANALYSIS

FOR THE YEAR ENDING DECEMBER 31, 2007

	(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	4,257,452	11.81%	4,760,109	1,062,701	85.8%	911,910	17.51%	1,071,630	50.71%
(2) SMALL GENERAL	241,815	11.21%	268,925	70,129	80.5%	56,449	15.11%	64,981	47.24%
(3) GENERAL	2,478,553	7.11%	2,654,677	483,397	85.1%	411,339	8.52%	446,398	67.89%
(4) GENERAL LARGE	421,375	6.03%	446,765	73,714	76.3%	56,261	7.09%	60,248	84.65%
(5) SMALL INDUSTRIAL	253,266	6.45%	269,594	49,197	61.1%	30,052	7.60%	32,336	95.17%
(6) MEDIUM INDUSTRIAL	585,153	6.06%	620,625	98,162	73.9%	72,577	7.50%	78,023	90.80%
(7) INDUSTRIAL LARGE	1,079,311	3.96%	1,122,003	157,883	78.2%	123,442	3.17%	127,353	100.57%
(8) EXTRA LI INTERR. - 2	2,076,080	2.04%	2,118,450	312,692	84.6%	264,400	2.03%	269,774	89.64%
(9) MUNICIPAL	196,279	5.02%	206,123	39,557	99.3%	39,289	5.33%	41,384	56.86%
(10) UNMETERED	112,382	11.14%	124,904	27,277	62.3%	16,979	18.74%	20,161	70.72%
(11) SUB-TOTAL	11,701,666		12,592,175	2,374,709	83.5%	1,982,698	11.58%	2,212,288	64.98%
(12) BOWATER MERSEY	367,920	2.30%	376,385	42,000	100.0%	42,000	2.07%	42,868	100.23%
(13) GEN.REPL./LOAD FOLL.	11,789	2.25%	12,054	23,802	4.5%	1,079	2.04%	1,101	124.98%
(14) REAL TIME PRICING	0	N/A	0	0	N/A	0	N/A	0	N/A
(15) EXTRA LI INTERR.	0	N/A	0	0	N/A	0	N/A	0	N/A
(16) EXPORT SALES	76,225	3.09%	78,583	0	N/A	0	N/A	0	N/A
(17) TOTAL	12,157,600	7.42%	13,059,197	2,440,511	83.0%	2,025,777	11.38%	2,256,257	66.07%

EXHIBIT 9B

NOVA SCOTIA POWER INC.

DETERMINATION OF CLASS NON-COINCIDENT KW DEMAND BY VOLTAGE LEVEL

FOR THE YEAR ENDING DECEMBER 31, 2007

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) EXTRA LI INTERR. - 2	(10) MUNICIPAL	(11) UNMETERED
(1) NON-COIN. KW SEC.	1,662,208	1,062,701	70,129	457,632	0	44,469	0	0	0	0	27,277
(2) LOSSES 6.00%	99,732	63,762	4,208	27,458	0	2,668	0	0	0	0	1,637
(3) SUB-TOTAL	1,761,940	1,126,463	74,337	485,090	0	47,137	0	0	0	0	28,914
(4) NON-COIN. KW PRI.	1,464,879	1,126,463	74,337	510,855	73,714	51,865	95,482	0	0	0	28,914
(5) LOSSES 5.40%	58,595	60,829	4,014	27,586	3,981	2,801	5,156	0	0	0	1,561
(6) SUB-TOTAL	2,067,557	1,187,292	78,351	538,441	77,695	54,666	100,638	0	0	0	30,475
(7) NON-COIN. KW TRANS.	1,811,927	1,187,292	78,351	538,441	77,695	54,666	103,318	157,883	312,692	39,557	30,475
(8) LOSSES 3.70%	67,042	43,930	2,899	19,922	2,875	2,023	3,823	5,842	11,570	1,464	1,128
(9) TOTAL	2,675,843	1,231,222	81,250	558,363	80,569	56,688	107,141	163,725	324,262	41,021	31,603

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EXHIBIT 9C

NOVA SCOTIA POWER INC.

DETAIL OF MONTHLY CLASS COINCIDENT KW DEMAND

FOR THE YEAR ENDING DECEMBER 31, 2007

MONTH	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUST.	(7) MEDIUM INDUST.	(8) LARGE INDUST.	(9) EXTRA LI INTERR. - 2	(10) MUNICIPAL	(11) UNMETERED	(12) MERSEY SYSTEM	(13) GRLF	(14) REAL TIME PRICING	(15) EXTRA LI INTERR.
(1) JANUARY	**2,256,257**	**1,071,630**	**64,981**	**446,398**	**60,248**	**32,336**	**78,023**	**127,353**	**269,774**	**41,384**	**20,161**	**42,868**	**1,101**	**0**	**0**
(2) FEBRUARY	**2,168,675**	**1,031,017**	**56,438**	**417,803**	**57,225**	**32,110**	**70,696**	**122,699**	**269,569**	**40,933**	**26,220**	**42,868**	**1,097**	**0**	**0**
(3) MARCH	2,029,501	832,704	39,556	470,971	67,750	41,869	88,614	132,898	269,813	38,206	2,712	42,868	1,540	0	0
(4) APRIL	1,840,946	779,761	50,585	350,836	51,940	34,986	73,488	128,117	269,903	31,148	26,021	42,868	1,293	0	0
(5) MAY	1,664,343	649,309	24,714	323,344	57,558	40,648	84,106	140,651	269,791	26,847	2,866	42,868	1,641	0	0
(6) JUNE	1,559,228	494,249	42,411	328,816	70,445	48,097	87,104	144,823	269,791	26,046	2,869	42,868	1,709	0	0
(7) JULY	1,586,387	443,301	52,215	393,191	72,430	45,274	91,959	144,509	269,917	26,563	2,802	42,868	1,358	0	0
(8) AUGUST	1,609,314	437,511	44,165	429,728	75,212	43,415	87,657	146,263	269,860	27,963	2,688	42,868	1,984	0	0
(9) SEPTEMBER	1,589,884	546,076	40,498	313,675	57,187	33,477	84,401	150,072	269,770	26,195	24,529	42,868	1,136	0	0
(10) OCTOBER	1,720,242	730,673	32,949	287,661	49,627	28,822	76,812	142,925	269,865	28,251	28,251	42,868	1,538	0	0
(11) NOVEMBER	1,925,106	803,961	53,739	382,502	58,354	34,151	79,993	141,993	269,504	33,026	23,657	42,868	1,358	0	0
(12) DECEMBER	**2,194,956**	**1,013,134**	**36,853**	**426,341**	**63,522**	**38,674**	**97,010**	**142,366**	**269,884**	**36,716**	**28,709**	**28,578**	**13,169**	**0**	**0**
(13) TOT. SUMMED DMD.	22,144,839	8,833,326	539,104	4,571,266	741,498	453,859	999,863	1,664,669	3,237,441	383,278	191,485	500,126	28,924	0	0
(14) 3 C/P DEMANDS	**6,619,888**	**3,115,781**	**158,272**	**1,290,542**	**180,995**	**103,120**	**245,729**	**392,418**	**809,227**	**119,033**	**75,090**	**114,314**	**15,367**	**0**	**0**
(15)						3 C/P INTERRUPTIBLE RIDER DEMAND		344,313							
(16)						NET 3 C/P LARGE INDUST. DEMANDS		48,105							

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APPENDIX 4
REVENUE ALLOCATION

Figure 9.1	R/C Ratio	% Revenue Increase	Current Revenue
ABOVE-THE-LINE CLASSES			
Residential	93.5%	0.0%	$481.6
Commercial			
Small General	96.6%	0.0%	$28.1
General	104.9%	0.0%	$244.3
Large General	94.3%	0.0%	$32.9
Total Commercial	**102.9%**	**0.0%**	**$305.3**
Industrial			
Small Industrial	97.6%	0.0%	$23.0
Medium Industrial	96.8%	0.0%	$46.8
Large Industrial	95.6%	0.0%	$68.9
ELI 2P-RTP	91.3%	0.0%	$114.8
Total Industrial	**94.0%**	**0.0%**	**$253.5**
Other			
Municipal	93.0%	0.0%	$15.0
Unmetered	104.5%	0.0%	$24.4
Total Other	**99.8%**	**0.0%**	**$39.4**
Total Above-the-line classes	**96.3%**	**0.0%**	**$1,079.8**
Below-the-line		**0.0%**	**$18.7**
Exports		**0.0%**	**$8.5**
Miscellaneous		**0.0%**	**$10.5**
Total Revenue		**0.0%**	**$1,117.5**
Revenue Requirement		**0.0%**	**$1,159.5**
Revenue Shortfall			**-$42.1**

With no rate increase, there is a shortfall of $42.1 million.

Figure 9.2	R/C Ratio	% Revenue Increase	Proposed Revenue
ABOVE-THE-LINE CLASSES			
Residential	**97.2%**	**4.0%**	**$500.9**
Commercial			
Small General	100.5%	4.0%	$29.2
General	109.1%	4.0%	$254.2
Large General	98.1%	4.0%	$34.2
Total Commercial	**107.0%**	**4.0%**	**$317.6**
Industrial			
Small Industrial	101.5%	4.0%	$23.9
Medium Industrial	100.7%	4.0%	$48.7
Large Industrial	99.4%	4.0%	$71.7
ELI 2P-RTP	95.0%	4.1%	$119.5
Total Industrial	**97.8%**	**4.1%**	**$263.8**
Other			
Municipal	96.7%	4.0%	$15.6
Unmetered	100.0%	-4.3%	$23.3
Total Other	**98.7%**	**-1.1%**	**$38.9**
Total Above-the-line classes	**100.0%**	**3.8%**	**$1,121.3**
Below-the-line		**2.1%**	**$19.1**
Exports		**0.0%**	**$8.5**
Miscellaneous		**1.8%**	**$10.6**
Total Revenue		**3.8%**	**$1,159.5**
Revenue Requirement		**0.0%**	**$1,159.5**
Revenue Shortfall			**$0.0**

An average increase of 3.8% is required to recover the shortfall. When applied to the miscellaneous charges that are to increase, this results in a 1.8% increase in Miscellaneous revenue.

Using the 2006 Unmetered COSS and setting the R/C ratio at 100%, and setting the ELI 2P-RTP R/C ratio at 95% results in an average increase of 4.0% to other ATL classes.

This however, produces a R/C ratio of 109.1% for the General Class, exceeding the 105% maximum of the 95-105 band.

Figure 9.3	R/C Ratio	% Revenue Increase	Proposed Revenue
ABOVE-THE-LINE CLASSES			
Residential	**97.2%**	**4.0%**	**$500.9**
Commercial			
Small General	100.5%	4.0%	$29.2
General	107.1%	2.0%	$249.3
Large General	98.1%	4.0%	$34.2
Total Commercial	**105.4%**	**2.4%**	**$312.7**
Industrial			
Small Industrial	101.5%	4.0%	$23.9
Medium Industrial	100.7%	4.0%	$48.7
Large Industrial	99.4%	4.0%	$71.7
ELI 2P-RTP	95.0%	4.1%	$119.5
Total Industrial	**97.8%**	**4.1%**	**$263.8**
Other			
Municipal	96.7%	4.0%	$15.6
Unmetered	100.0%	-4.3%	$23.3
Total Other	**98.7%**	**-1.1%**	**$38.9**
Total Above-the-line classes	**99.6%**	**3.4%**	**$1,116.4**
Below-the-line		**2.1%**	**$19.1**
Exports		**0.0%**	**$8.5**
Miscellaneous		**1.8%**	**$10.6**
Total Revenue		**3.3%**	**$1,154.7**
Revenue Requirement		**0.0%**	**$1,159.5**
Revenue Shortfall			**-$4.8**

Reducing the R/C ratio for General so that it is halfway between the 109.1% and 105% sets it at 107.1%. This results in a revenue increase of 2.0% to the General Class and produces a revenue shortfall of $4.8 million.

Figure 9.4	R/C Ratio	% Revenue Increase	Proposed Revenue
ABOVE-THE-LINE CLASSES			
Residential	**97.9%**	**4.7%**	**$504.2**
Commercial			
Small General	101.2%	4.7%	$29.4
General	107.1%	2.0%	$249.3
Large General	98.8%	4.7%	$34.4
Total Commercial	**105.5%**	**2.6%**	**$313.1**
Industrial			
Small Industrial	102.2%	4.7%	$24.1
Medium Industrial	101.3%	4.7%	$49.0
Large Industrial	100.1%	4.7%	$72.2
ELI 2P-RTP	95.0%	4.1%	$119.5
Total Industrial	**98.1%**	**4.4%**	**$264.8**
Other			
Municipal	97.4%	4.7%	$15.7
Unmetered	100.0%	-4.3%	$23.3
Total Other	**98.9%**	**-0.9%**	**$39.0**
Total Above-the-line classes	**100.0%**	**3.8%**	**$1,121.2**
Below-the-line		**2.4%**	**$19.2**
Exports		**0.0%**	**$8.5**
Miscellaneous		**1.8%**	**$10.6**
Total Revenue		**3.8%**	**$1,159.5**
Revenue Requirement		**0.0%**	**$1,159.5**
Revenue Shortfall			**$0.0**

When this $4.8 million is reallocated to the other ATL classes (with the exception of Unmetered and ELI 2P-RTP) the average revenue increase is 4.7%.

APPENDIX 5

RATE COMPONENTS

Figure 9.5 PROPOSED INCREASES BY RATE COMPONENT

RESIDENTIAL TARIFFS

Domestic Service Rate		units	Current Rate	Proposed Rate	% change
Customer Charge		$/mo	10.83	10.83	0.0%
Energy Charge		¢/kWh	10.13	10.67	5.3%
Domestic Service TOD Rate					
Customer Charge		$/mo	18.82	18.82	0.0%
December, January & Feb: energy charge					
	on-peak	¢/kWh	14.560	15.32	5.2%
	shoulder	¢/kWh	10.130	10.67	5.3%
	off-peak	¢/kWh	5.065	5.335	5.3%
Other months: energy charge					
	on-peak	¢/kWh	10.13	10.670	5.3%
	off-peak	¢/kWh	5.065	5.335	5.3%

COMMERCIAL TARIFFS

Small General Rate	units	Current Rate	Proposed Rate	% change
Customer Charge	$/mo	12.65	12.65	0.0%
Energy Charge, block 1 (first 200 kWhs)	¢/kWh	11.21	11.81	5.4%
Energy Charge, block 2	¢/kWh	9.86	10.39	5.4%
General Rate				
Demand Charge	$/kW	8.10	8.26	2.0%
Energy Charge, block 1 (first 200kWh * demand)	¢/kWh	8.60	8.78	2.1%
Energy Charge, block 2	¢/kWh	6.08	6.20	2.0%
Transformer Ownership Credit	¢/kVA	32.00	32.00	0.0%
Large General Rate				
Demand Charge (Ratcheted)	$/kVA	9.61	10.06	4.7%
Energy Charge	¢/kWh	5.71	5.98	4.7%
Transformer Ownership Credit	¢/kVA	32.00	32.00	0.0%

INDUSTRIAL TARIFFS

Small Industrial Rate	units	Current Rate	Proposed Rate	% change
Demand Charge	$/kVA	5.63	5.89	4.6%
Energy Charge, block 1 (first 200 kWhs * demand)	¢/kWh	7.33	7.67	4.6%
Energy Charge, block 2	¢/kWh	5.59	5.85	4.7%
Transformer Ownership Credit	¢/kVA	32.00	32.00	0.0%
Medium Industrial Rate				
Demand Charge	$/kVA	9.05	9.48	4.8%
Energy Charge	¢/kWh	5.21	5.46	4.8%
Transformer Ownership Credit	¢/kVA	32.00	32.00	0.0%
Large Industrial Rate				
Demand Charge (Ratcheted)	$/kVA	8.74	9.11	4.2%
Energy Charge	¢/kWh	5.25	5.47	4.2%
Transformer Ownership Credit	¢/kVA	(32.00)	(32.00)	0.0%
Interruptible Credit	$/kVA	(3.43)	(3.43)	0.0%
Extra Large Industrial 2P-RTP Rate				
Customer Charge	$/mo	20,700.00	20,700.00	0.0%
Demand Charge (Ratcheted)	$/kVA	-	-	NA
Energy Charge	¢/kWh	5.506	5.733*	4.1%
Interruptible Credit	$/kVA	-	-	NA

MUNICIPAL TARIFFS

Municipal Rate	units	Current Rate	Proposed Rate	% change
Demand Charge (Ratcheted)	$/kVA	8.96	9.38	4.7%
Energy Charge	¢/kWh	5.38	5.63	4.6%
Transformer Ownership Credit	$/kVA	32.00	32.00	0.0%

* Note: Actual energy charge will be 5.655¢/kWh per Exhibit N-49.

APPENDIX 6

PROOF OF REVENUE

Proposed Tariffs	First KWh Block			Second KWh Block			Third KWh Block			Total KWHs		Demand			Base Charge			PROPOSED
Above-the-line Classes	Energy in GWh	Per KWh Charge	Revenue	Energy in GWh	Per KWh Charge	Revenue	Energy in GWh	Per KWh Charge	Revenue	GWHS	Revenue	GWS or GVAS	Charge per KW or KVA	Revenue	Billmonths (in millions)	Base Charge	Revenue	RATES FORECAST 2007
Residential Sector																		
Domestic Service	4,141.1	$ 0.1067	$ 441.7							4,141.1	$ 441.7				4.9	$ 10.83	$ 53.34	$ 495.1
Domestic Service Time of Day	9.0	$ 0.1532	$ 1.4	22.1	$ 0.1066	$ 2.4	85.3	0.0533	$ 4.5	116.3	$ 8.3				0.05	$ 18.82	$ 0.9	$ 9.1
Total	**4,150.1**		**$ 443.1**	**22.1**		**$ 2.35**	**85.3**		**$ 4.54**	**4,257.5**	**$ 450.0**				**5.0**		**$ 54.21**	**$ 504.2**
Commercial Sector																		
Small General	54.1	$ 0.1181	$ 6.4	187.7	$ 0.1039	$ 19.5				241.8	$ 25.9				0.28	$ 12.65	$ 3.5	$ 29.4
General	1,399.8	$ 0.0878	$ 122.8	$ 1,078.7	$ 0.0620	$ 66.9				2,478.6	$ 189.8	7.2	$ 8.26	$ 59.6				$ 249.3
Large General																		
Without Trans. Own.	237.4	$ 0.0598	$ 14.2							237.4	$ 14.2	0.5	$ 10.06	$ 5.3				$ 19.5
With Trans. Own.	184.0	$ 0.0598	$ 11.0							184.0	$ 11.0	0.4	$ 9.74	$ 3.9				$ 14.9
Sub-total	421.4		$ 25.2							421.4	$ 25.2	0.9		$ 9.2				$ 34.4
Total	**1,875.3**		**$ 154.4**	**1,266.5**		**$ 86.4**				**3,141.7**	**$ 240.8**	**8.1**		**$ 68.8**	**0.3**		**$ 3.5**	**$ 313.1**
Industrial Sector																		
Small Industrial	172.8	$ 0.0767	$ 13.3	80.5	$ 0.0585	$ 4.7				253.3	$ 18.0	1.0	$ 5.89	$ 6.1				$ 24.1
Medium Industrial	585.2	$ 0.0546	$ 31.9							585.2	$ 31.9	1.8	$ 9.48	$ 17.1				$ 49.0
Large Industrial Firm																		
Without Trans. Own.	99.9	$ 0.0547	$ 5.5							99.9	$ 5.5	0.177	$ 9.1126	$ 1.6				$ 7.08
With Trans. Own.	281.7	$ 0.0547	$ 15.4							281.7	$ 15.4	0.086	$ 8.7926	$ 0.8				$ 16.18
Sub-total	381.6		$ 20.9							381.6	$ 20.9	0.26		$ 2.4				$ 23.26
Large Industrial Interruptible																		
Without Trans. Own.	251.7	$ 0.0547	$ 13.8							251.7	$ 13.8	0.7	$ 5.68	$ 3.9				$ 17.7
With Trans. Own.	446.0	$ 0.0547	$ 24.4							446.0	$ 24.4	1.3	$ 5.36	$ 6.8				$ 31.2
Sub-total	697.7		$ 38.2							697.7	$ 38.2	2.0		$ 10.7				$ 48.9
Total Large Industrial	**1,079.3**		**$ 59.1**							**1,079.3**	**$ 59.1**	**2.22**		**$ 13.1**				**$ 72.2**
Extra Large Industrial Interruptible	**2,076.1**	**$ 0.05733**	**$ 119.0**							**2,076.1**	**$ 119.0**	**3.81**	**$ -**	**$ -**	**0.000**	**$ 20,700**	**$ 0.497**	**$ 119.5**
Total Industrial	**3,913.3**		**$ 223.3**	**80.48**		**$ 4.7**				**3,993.8**	**$ 228.0**	**8.87**		**$ 36.3**	**0.000**		**$0.497**	**$ 264.8**
Other																		
Municipal																		
Without Trans. Own.	121.3	$ 0.0563	$ 6.8							121.3	$ 6.8	0.3	$ 9.38	$ 3.0				$ 9.8
With Trans. Own.	75.0	$ 0.0563	$ 4.2							75.0	$ 4.2	0.2	$ 9.06	$ 1.7				$ 5.9
Sub-total	196.3		$ 11.1							196.3	$ 11.1	0.5		$ 4.7				$ 15.7
Unmetered	112.4	$ 0.2075	$ 23.3							112.4	$ 23.3							$ 23.3
Total	**308.7**		**$ 34.4**							**308.7**	**$ 34.4**	**0.5**		**$ 4.7**				**$ 39.0**
Total Above-the-line	**10,247.4**		**$ 855.2**	**1,369.01**		**$ 93.5**	**85.26**		**$ 4.5**	**11,701.7**	**$ 953.2**	**17.50**		**$ 109.7**	**5.25**		**$ 58.2**	**$ 1,121.2**
Below-the-line Classes																		
GRLF and Mersey Contract	379.7	$ 0.0505	$ 19.2							379.7	$ 19.2							$ 19.2
Total	**379.7**		**$ 19.2**							**379.7**	**$ 19.2**							**$ 19.2**
Total In-Province	**10,627.1**		**$ 874.4**	**1,369.0**		**$ 93.5**	**85.3**		**$ 4.5**	**12,081.4**	**$ 972.4**	**17.5**		**$ 109.7**	**5.3**		**$ 58.2**	**$ 1,140.3**
Exports	**83.6**	**$ 0.1023**	**$ 8.5**							**83.6**	**$ 8.5**							**$ 8.5**
Total Electric Revenue	**10,710.7**		**$ 882.9**	**1,369.0**		**$ 93.5**	**85.3**		**$ 4.5**	**12,164.9**	**$ 981.0**	**17.5**		**$ 109.7**	**5.3**		**$ 58.2**	**$ 1,148.9**

Note: All calculations for above-the-line classes are done using electric tariffs before rounding.

APPENDIX 7

COMPLIANCE TARIFFS

PROPOSED TARIFFS

NOVA SCOTIA POWER INCORPORATED

DOMESTIC SERVICE TARIFF
Rate Codes 02, 03, 04

CUSTOMER CHARGE

$10.83 per month

ENERGY CHARGE

10.67 cents per kilowatt hour

MINIMUM MONTHLY CHARGE

The minimum monthly charge shall be $10.83.

AVAILABILITY:

This tariff is applicable to electric energy used by any customer in a private residence for the customer's own domestic or household use, including lighting, cooking, heating, or refrigeration purposes. Upon application to the Company the domestic tariff shall be available to any other customer within the provisions of Section 73 of the Public Utilities Act, R.S.N.S. 1989, c. 380, as amended.

Any outbuilding located on residential property adjacent to a domestic dwelling and supplied electrically through a separate meter shall have rates applied in accordance with actual use of the building.

If the building is used principally for the owner's personal pursuits and hobbies, the Domestic tariff shall be applied.

If the building is used principally for commercial purposes the appropriate General or Industrial tariff shall be applied.

Optional Green Power Rider

Customers taking service under this rider may choose to support NSPI's Green Power program by purchasing "blocks" of Green Power. For every block purchased, NSPI will provide 125 kW.h per month from green energy sources, thereby displacing energy from fossil fuels. Blocks may be purchased at a cost of $5 per month. This charge shall be over and above the customer's normal bill for service taken under the Domestic Service rate.

PROPOSED TARIFFS

NOVA SCOTIA POWER INCORPORATED

DOMESTIC SERVICE TARIFF
Rate Codes 02, 03, 04

Special Terms and Provisions

1. Green Power, as defined for the purposes of this rider includes energy produced from renewable resources that have minimal impact on the environment, and could be independently certified by third party environmental organizations.

2. Service under this rider may be limited at the discretion of the Company, based on the expected level of green energy available.

PROPOSED TARIFFS

NOVA SCOTIA POWER INCORPORATED

DOMESTIC SERVICE TIME-OF-DAY TARIFF (OPTIONAL)
Rate Code 06

CUSTOMER CHARGE

$18.82 per month

ENERGY CHARGE

December, January and February

07:00 am to 12:00 pm	15.320 cents per kilowatt hour
12:00 pm to 04:00 pm	10.670 cents per kilowatt hour
04:00 pm to 11:00 pm	15.320 cents per kilowatt hour
11:00 pm to 07:00 am	5.335 cents per kilowatt hour

The above rates apply weekdays (Monday to Friday inclusive), excluding statutory holidays. For Saturdays, Sundays and statutory holidays, all consumption will be billed at the rate of 5.335 cents per kilowatt hour.

March to November

07:00 am to 11:00 pm	10.670 cents per kilowatt hour
11:00 pm to 07:00 am	5.335 cents per kilowatt hour

The above rates apply weekdays (Monday through Friday inclusive), excluding statutory holidays. For Saturdays, Sundays and statutory holidays, all consumption will be billed at the rate of 5.335 cents per kilowatt hour.

MINIMUM MONTHLY CHARGE

The minimum monthly charge shall be $18.82.

AVAILABILITY:

This tariff is only available to customers employing electric-based heating systems utilizing Electric Thermal Storage (ETS) equipment, and electric in-floor radiant heating systems utilizing thermal storage and appropriate timing and controls approved by the Company.

This tariff is applicable to electric energy used by any customer in a private residence for the customer's own domestic or household use, including lighting, cooking, heating, or refrigeration purposes. This tariff is not available to any other customer within the provisions of Section 73 of the Public Utilities Act, R.S.N.S. 1989, c. 380, as amended.

PROPOSED TARIFFS

NOVA SCOTIA POWER INCORPORATED

DOMESTIC SERVICE TIME-OF-DAY TARIFF (OPTIONAL)
Rate Code 06

Any outbuilding located on residential property adjacent to a domestic dwelling and supplied electrically through a separate meter shall have rates applied in accordance with actual use of the building.

If the building is used principally for the owner's personal pursuits and hobbies, the Domestic tariff shall be applied.

If the building is used principally for commercial purposes the appropriate General or Industrial tariff shall be applied.

PROPOSED TARIFFS

NOVA SCOTIA POWER INCORPORATED

SMALL GENERAL TARIFF
Rate Code 10

CUSTOMER CHARGE

$12.65 per month

ENERGY CHARGE

11.81 cents per kilowatt hour for the first 200 kilowatt hours per month

10.39 cents per kilowatt hour for all additional kilowatt hours

MINIMUM MONTHLY CHARGE

The minimum monthly charge shall be $12.65.

AVAILABILITY:

This tariff is applicable to electric energy for use where the annual consumption is less than 32 000 kW.h per year and for which no other rates are applicable.

PROPOSED TARIFFS

NOVA SCOTIA POWER INCORPORATED

GENERAL TARIFF
Rate Code 11

DEMAND CHARGE

$8.26 per month per kilowatt of maximum demand.

32 cents per kilowatt reduction in demand charge where the transformer was owned by the customer prior to February 1, 1974, or under Special Condition (2) as set out below.

ENERGY CHARGE

8.78 cents per kilowatt hour for the first 200 kilowatt hours per month per kilowatt of maximum demand.

6.20 cents per kilowatt hour for all additional kilowatt hours.

MAXIMUM PER KW.H CHARGE/MINIMUM BILL

The maximum charge per kW.h will be that for a billing load factor of 10% except that the minimum monthly bill shall not be less than $12.65.

AVAILABILITY:

This tariff is applicable to electric power and energy where the annual consumption is 32 000 kW.h, or greater and for which no other rates are applicable.

SPECIAL CONDITIONS:

(1) Metering will normally be at the low voltage side of the substation. 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. Adjustment to the metered kW.h usage will be made when metering is on the high voltage side. Meter readings shall then be reduced by 1.75%.

(2) When the customer requires non-standard service provisions, the Company may require the customer to own any transformer normally provided by the Company.

PROPOSED TARIFFS

NOVA SCOTIA POWER INCORPORATED

LARGE GENERAL TARIFF
(2 000 kV.A or 1 800 kW, and Over)
Rate Code 12

DEMAND CHARGE

$10.06 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.

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

ENERGY CHARGE

5.98 cents per kilowatt hour.

MINIMUM MONTHLY CHARGE

The minimum monthly charge shall be $12.65.

AVAILABILITY:

This tariff is applicable to electric power and energy for any use except industrial, where the regular billing demand is 2 000 kV.A or 1 800 kW, and over.

SPECIAL CONDITIONS:

(1) Metering will normally be at the low voltage side of the substation.

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. Adjustments to the metered kW.h usage will be made under the following conditions:

(a) If the substation high voltage side is 69 kV or higher, and metering is on the high voltage side, meter readings shall be reduced by 1.75%.

(b) If the substation high voltage side is lower than 69 kV, and metering is on the low voltage side, meter readings shall be increased by 1.75%.

NOVA SCOTIA POWER INCORPORATED

LARGE GENERAL TARIFF
(2 000 kV.A or 1 800 kW, and Over)
Rate Code 12

(2) The Company will withdraw the availability of this tariff to any specific customer, if, on a consistent basis, the customer is not maintaining a billing demand of 2 000 kV.A or 1 800 kW.

(3) The Company reserves the right to have a separate service and/or operating 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.

PROPOSED TARIFFS

NOVA SCOTIA POWER INCORPORATED

SMALL INDUSTRIAL TARIFF
(Up to 249 kV.A. or 224 kW)
Rate Code 21

DEMAND CHARGE

$5.89 per month per kilovolt ampere of maximum demand.

32 cents per kilovolt ampere reduction in demand charge where the transformer was owned by the customer prior to February 1, 1974, or under Special Condition (2) as set out below.

ENERGY CHARGE

7.67 cents per kilowatt hour for the first 200 kilowatt hours per month per kilovolt ampere of maximum demand.

5.85 cents per kilowatt hour for all additional kilowatt hours.

MAXIMUM PER KW.H CHARGE/MINIMUM BILL

The maximum charge per kW.h will be that for a billing load factor of 10% except that the minimum monthly bill shall not be less than $12.65.

AVAILABILITY:

This tariff is applicable to electric power and energy supplied to any customer, for industrial use, including farming and processing, where the regular billing demand is less than 250 kV.A or 225 kW.

SPECIAL CONDITIONS:

(1) Metering will normally be at the low voltage side of the substation. 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 cost of primary metering as opposed to the cost of secondary metering.

Adjustment to the metered kW.h usage will be made when metering is on the high voltage side. Meter readings shall then be reduced by 1.75%.

(2) When the customer requires non-standard service provisions, the Company may require the customer to own any transformer normally provided by the Company.

PROPOSED TARIFFS

NOVA SCOTIA POWER INCORPORATED

MEDIUM INDUSTRIAL TARIFF
(250 kV.A or 225 kW - 1 999 kV.A or 1 799 kW)
Rate Code 22

DEMAND CHARGE

$9.48 per month per kilovolt ampere of maximum demand.

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

ENERGY CHARGE

5.46 cents per kilowatt hour.

MINIMUM MONTHLY CHARGE

The minimum monthly charge shall be $12.65.

AVAILABILITY:

This tariff is applicable to electric power and energy supplied to any industrial customer having a regular billing demand of 250 kV.A (225 kW) and over, and for which no other rates are applicable.

SPECIAL CONDITIONS:

(1) Metering will normally be at the low voltage side of the substation. 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. Adjustment to the metered kW.h usage will be made when metering is on the high voltage side. Meter readings shall then be reduced by 1.75%.

(2) The Company may withdraw the availability of this tariff to any specific customer, if, in the opinion of the Company, the customer is not maintaining a billing demand of 250 kV.A (225 KW).

PROPOSED TARIFFS

NOVA SCOTIA POWER INCORPORATED

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

DEMAND CHARGE

$9.11 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.

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

ENERGY CHARGE

5.47 cents per kilowatt hour.

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 kV.A 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 kV.A 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.

NOVA SCOTIA POWER INCORPORATED

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

(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.

PROPOSED TARIFFS

NOVA SCOTIA POWER INCORPORATED

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

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 available to a minimum regular billing demand of 2 000 kV.A at 90% Power Factor, under the following terms and conditions:

(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 charge shall be twice 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.

NOVA SCOTIA POWER INCORPORATED

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

(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.

PROPOSED TARIFFS

NOVA SCOTIA POWER INCORPORATED

MUNICIPAL TARIFF

DEMAND CHARGE

$9.38 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.

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

ENERGY CHARGE

5.63 cents per kilowatt hour.

AVAILABILITY:

This tariff is applicable to three phase electric power and energy, supplied at the low voltage side of the bulk power transformer, to municipal electric utilities. 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 transformation losses. Also, meter readings shall be reduced when metering is at transmission voltage.

PROPOSED TARIFFS

NOVA SCOTIA POWER INCORPORATED

EXTRA LARGE INDUSTRIAL TWO PART REAL TIME PRICING TARIFF (ELI 2P-RTP)

AVAILABILITY:

1. This tariff is available to customer load formerly served under the Extra Large Industrial Interruptible Rate (ELIIR) and 2P-RTP tariffs, specifically that of StoraEnso Port Hawkesbury Ltd (StoraEnso), and Bowater Mersey Paper Company Ltd (Bowater) other than load served based on the Mersey Agreement.

2. The service voltage shall not be less than 138kV, line to line, at each delivery point. Service is provided at the supply side of the customer's transformation equipment. The customer must own the transformation facilities and no transformer ownership credit is applicable.

3. Customers served under this tariff must accept priority supply interruption, meaning that customers on this tariff are interrupted after GRLF rate customers, and in advance of Interruptible Rider customers.

4. This tariff, as well as the ELIIR-2 tariff, is an alternative replacement tariff for the former ELIIR rate. Once having selected this tariff, the customer is no longer eligible for the ELIIR-2 tariff. Once on this tariff, the customer must commit to taking service under this rate for a minimum of twelve months.

5. This tariff cannot be taken in conjunction with the 1P-RTP rate.

CHARGES:

Customer Charge

The monthly customer charge under this tariff is $20,700.00 per month, per customer.

Standard Energy Charge

The standard energy charge, before accounting for shifting credits or additional charges, is 5.655 cents per kWh. This charge will apply to all Customer Baseline Load (CBL) energy, regardless of actual consumption.

The energy charge is calculated using NSPI's approved Cost of Service Study (COSS) for the load forecast to be served under the ELIIR-2 and ELI 2P-RTP tariffs combined.

PROPOSED TARIFFS

NOVA SCOTIA POWER INCORPORATED

EXTRA LARGE INDUSTRIAL TWO PART REAL TIME PRICING TARIFF (ELI 2P-RTP)

Changes to Rate Components

The customer charge and standard energy charge of this tariff shall be subject to change as approved by the UARB following general rate applications by the Company. For operational purposes, the annual CBL for each customer is reset for each calendar year.

RATE MECHANISM:

The intent of this rate is to create a mechanism enabling customers to gain benefit equal to the benefit created by altering load usage in accordance to hourly pricing signals.

The customer will be billed based on a pre-determined CBL at the Standard Energy Charge, regardless of energy actually taken during a billing period, with credits based on decremental energy taken below the CBL and costs added for energy taken above the CBL.

Incremental and Decremental energy deviations from the CBL will be billed/credited based on the 20-minute ahead marginal cost, as posted on NSPI's RTP website, adjusted according to the schedule stipulated in the Decremental Rebate section of this tariff.

Order in which Rates are Applied

Customers may elect to utilize other rates below the ELI 2P-RTP. In such case, the customer will make written request to the Company, specifying the MW level above which ELI 2P-RTP is to apply. Such changes will only be applied to the next full calendar year of billing.

With respect to the "stacking order" under which customers taking multiple rates are billed, no other rate may be taken above this rate.

DEFINITIONS:

Pricing Period

Each hour of the day is a distinct pricing period, the day starting at the 00:00:01, the first hour ending at 01:00:00. The applicable 20 minute ahead marginal price as posted on the RTP website will apply for each such period.

PROPOSED TARIFFS

NOVA SCOTIA POWER INCORPORATED

EXTRA LARGE INDUSTRIAL TWO PART REAL TIME PRICING TARIFF (ELI 2P-RTP)

Customer Baseline Load (CBL)

This is a flat line load shape used for the operational purpose of calculating hourly Incremental Load (IL) and Decremental Load (DL). The CBL level (in MW) is to be calculated as the average hourly demand of the customer's annual forecast total energy requirement (excluding system losses) from the Company. The CBL level will be in effect from January 1st to December 31st of each year, and calculated according to the following formula:

$$\frac{\text{Forecast total energy requirement from the Company}}{\text{(Total number of hours in rate year)} - \text{(Total hours of major scheduled maintenance*)}}$$

*major scheduled maintenance as defined within this tariff

Forecast Total Energy Requirement

Forecast total energy requirement from the Company is determined using the customer's total actual annual energy requirement (excluding system losses) from the Company for the previous 12 month period ending October 31st of each year, subject to any correction for anomalies, as agreed between the Company and the customer. The Company shall provide the customer, on or before the 3rd normal working day of November each year, their previous 12 month energy consumption. On or before the 15th day of November each year, the customer shall provide the Company, in writing, the proposed CBL for the subsequent calendar year. This submission shall include justification for the proposed CBL, including the anticipated dates and durations of the major scheduled maintenance periods.

The parties will diligently, and in good faith, attempt to reach agreement. NSPI will have two weeks in which to accept or reject the proposal in writing, with stated reasons for its rejection. In the event of disagreement, either party may refer the matter to the UARB for resolution, with the request for an expedited decision on the issues between the parties.

Major Scheduled Maintenance Periods

Prior to the start of each calendar year, the customer will provide the Company with information on the timing and duration and magnitude of its anticipated periods of major scheduled maintenance. If the customer and the Company are unable to agree on periods of major scheduled maintenance, the matter will be referred to the UARB.

The customer will also provide the Company with three (3) weeks notice in advance of commencing each scheduled maintenance period, clearly indicating the date and time of the commencement and termination of the maintenance period.

NOVA SCOTIA POWER INCORPORATED

EXTRA LARGE INDUSTRIAL TWO PART REAL TIME PRICING TARIFF (ELI 2P-RTP)

During periods of major scheduled maintenance, the CBL will be reduced accordingly to match the operating conditions of the plant. Such events will be treated as cutouts and will not affect the CBL for the subsequent year.

Marginal Cost (MC)

The MC will be the 20-minute ahead forecast of hourly marginal fuel and variable O&M cost in any hour, excluding any impacts of electricity exports, but including imports when they impact marginal costs. The MC forecast for each hour will be calculated by NSPI based on in-province load requirements. The load level(s) assumed for customers on the ELI 2P-RTP tariff will be the CBL value.

Projections of the anticipated hourly energy price (week ahead and day ahead) will be provided to the customer according to the following schedule:

- By midnight each day, hourly price forecasts for each hour of the next seven days shall be provided to the customer.
- Major changes to the hourly price forecasts will be provided to the customer as soon as possible after they occur.

The actual price used for billing purposes will be the MC, adjusted as stipulated in the Decremental Rebate section of this tariff.

Decremental Load (DL)

This is the hourly energy calculated as the difference between the CBL and the actual demand when actual demand is less than the CBL. When other tariffs are used below ELI 2P-RTP, DL in any hour is limited to the amount available between the lower ELI 2P-RTP threshold and the CBL.

Decremental Rebate (DR)

The Decremental Load (DL) each hour, is multiplied by the MC, or a fraction of the MC as defined below, adjusted for losses, in that hour, and summed to produce the Decremental Rebate (DR).

PROPOSED TARIFFS

NOVA SCOTIA POWER INCORPORATED

EXTRA LARGE INDUSTRIAL TWO PART REAL TIME PRICING TARIFF (ELI 2P-RTP)

DL will be credited according to the following schedule:

- The credit for decrements, up to 30 MW for Bowater, and 75 MW for StoraEnso will be at MC as defined by this tariff.
- For the next 10MW for Bowater, and 30 MW for StoraEnso, the credits for decrements will be the greater of:
  - 80% of the MC; and
  - the ELI 2P-RTP Standard Energy Charge
- For further decrements in excess of the above amounts the credit will be the greater of:
  - 60% of MC; and
  - the ELI 2P-RTP Standard Energy Charge

Decremental Load eligible for DR is limited to 20% of the customer's annual CBL energy for the operating year. Once this limit is reached for the year, no further shifting rebates will be applied. Incremental load taken above the CBL will continue to be charged using incremental charges.

Incremental Load (IL)

This is the hourly energy calculated as the difference between the actual load and the CBL whenever the actual load exceeds the CBL.

Incremental Charges (IC)

The Incremental Load (IL) each hour, multiplied by the MC, adjusted for losses, in that hour, and summed to produce the Incremental Charge (IC).

Losses Adjustment:

A 2% adjustment to metered energy will be applied to determine requirement including system losses. This Loss adjustment will be applied in determining the IL and the DL.

Incremental Export Benefit Credit

Customers who take service under this rate will be given an Incremental Export Benefit Credit (IEBC) defined as follows:

IEBC = (Lesser of Customer's Monthly DL or NSPI's Actual Exports calculated monthly) x NSPI's Average Export Margin in the month

However, in no case shall the total annual IEBC exceed 15% of NSPI's total actual annual export margin.

NOVA SCOTIA POWER INCORPORATED

EXTRA LARGE INDUSTRIAL TWO PART REAL TIME PRICING TARIFF (ELI 2P-RTP)

CBL Base Cost (CBL_{bc})

The monthly CBL_{bc} is calculated by multiplying the actual ELI 2P-RTP energy under the CBL level in each hour of the billing period by the applicable Standard Energy Charge.

Bill Calculation:

At the end of each month:

Total Bill = CBL_{bc} + Incremental Charges – Decremental Rebates - Incremental Export Benefit Credit

Applicable Energy Charges, rebates, penalties, and adjustments will be calculated by the Company and indicated on the customer's monthly bill.

SPECIAL CONDITIONS:

Modification of Existing CBL

If an existing ELI 2P-RTP customer undertakes significant physical plant modification, (as signified by a specific capital expenditure above and beyond normal annual capital spending) or other material change (such as a change in product line) the Company or the customer may propose suitable adjustments to the CBL.

In the event of significant load reductions that have not been reflected in the CBL (such as plant shut downs, labour issues or any other reason), the CBL will be lowered accordingly or by agreement the rate may be suspended altogether until the customer returns to normal operations.

If the customer and NSPI cannot agree on any of the above modifications to the CBL the matter will be submitted to the UARB for adjudication.

Use of Self-Generation

Unless existing customer-owned generation is to be retired, for purposes of determining forecast CBL energy, the continued use of such generation is to be appropriately accounted for in the customer's CBL energy requirement. Such self-generation shall continue to be used in a normal fashion. Beyond this, it is expected that customers will use their own existing generation in whatever fashion they see as appropriate.

PROPOSED TARIFFS

NOVA SCOTIA POWER INCORPORATED

EXTRA LARGE INDUSTRIAL TWO PART REAL TIME PRICING TARIFF (ELI 2P-RTP)

Supply Interruption:

This tariff is interruptible for supply reasons. The customer will reduce its available interruptible system load by the amount requested by NSPI within ten (10) minutes of such request by the Company. Following interruption, service may only be restored by the customer with the approval of the Company.

The customer will make available suitable contact telephone numbers of a person or persons who are able to reduce the required load within ten minutes.

Supply Interruption calls will be made to all customers taking energy under this tariff and the ELIIR-2 tariff, on an equitable and transparent basis.

Customers are expected to comply with all calls for interruption. Failure to comply in whole or in part with a request to interrupt load will result in penalty charges. The penalty charge for each failure shall be twice the cost of the appropriate billing as per this rate, for the total load subscribed under this rate. Should the customer fail to respond during subsequent calls within the same month, the same penalties will apply for each failure to interrupt.

Supply interruptions will be 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 per year.

Conversion of Interruptible Load to Firm

Should a customer under this rate desire to be served under any applicable 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 a 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 service under the firm rate schedule. The Company may permit an earlier conversion from firm to interruptible service.

Order of Supply Interruption:

In the event of an interruption required in order to avoid shortfalls in electricity supply, rate classes will be called upon to provide capacity to NSPI in the following order:

1. Generation Replacement and Load Following (GRLF) Rate;
2. Extra Large Industrial Interruptible Rate-2, and ELI 2P-RTP Rate
3. Interruptible Rider to the Large Industrial Rate.

PROPOSED TARIFFS

NOVA SCOTIA POWER INCORPORATED

EXTRA LARGE INDUSTRIAL TWO PART REAL TIME PRICING TARIFF (ELI 2P-RTP)

In recognition that this tariff will receive interruption calls in advance of Interruptible Rider customers, the ELI 2P-RTP tariff will receive an interruptible credit (as determined in NSPI's COSS) that is 15% higher than the credit provided to Interruptible Rider customers for supply interruptibility.

Suspension of 2P-RTP Billing Mechanism

The Rate will be suspended during any period in which the customer's load is reduced due to a disruption in the supply of electricity to the customer because of an interruption call or NSPI system conditions. The suspension shall apply until such time as the customer has received permission from the Company to resume operations.

The energy lost under the CBL will be estimated by the customer for the specific period from the start of the disruption to the time that NSPI notifies the customer that it can resume operation. An amount equivalent to the estimated lost energy, taken above the CBL immediately following the disruption, will be charged at the Standard Energy Charge rather than at IC.

If the customer and NSPI cannot agree on the amount of energy lost, the matter will be submitted to the UARB for adjudication.

Separate Service Agreement

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.

Maintain System Integrity

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 separate operating agreement.

In assessing issues that 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.

Sole Supplier

NSPI reserves the right to be the sole supplier of all external power requirements (i.e. excluding self-generation) for customers taking service under this tariff.

PROPOSED TARIFFS

NOVA SCOTIA POWER INCORPORATED

EXTRA LARGE INDUSTRIAL TWO PART REAL TIME PRICING TARIFF (ELI 2P-RTP)

Power Factor Correction

Under normal operating conditions, an average power factor over the entire billing period, calculated for kWh consumed and lagging kVAR-h, as recorded, of not less than 90% lagging for the total customer load (under all rates) shall be maintained, or the following adjustment factors (Constant) will be applied to the Energy Charge in effect:

Power Factor	Constant	Power Factor	Constant
90-100%	1.0000	65-70%	1.1255
80-90%	1.0230	60-65%	1.1785
75-80%	1.0500	55-60%	1.2455
70-75%	1.0835	50-55%	1.3335

Metering Costs

Metering will normally be at the low side of the transformer and, for billing purposes, meter readings will be increased by 1.75%. Should the customer's requirements make it necessary for the Company to provide primary metering, the customer will be required to make a capital contribution equal to the additional cost of primary metering as opposed to the cost of secondary metering. The costs of any special metering or communication systems required by the customer to take service under this tariff shall be paid for by the customer as a capital contribution.

Special Consideration for Customer Purchasing Own Fuel

At the customer's option, the customer and NSPI shall use best efforts to enter into physical and/or financial purchases or hedges, the settlement of which shall be credited or charged to the customer's account. It is understood that the execution and settlement of these arrangements shall, under no circumstances, affect the rates or revenue requirements charged to the Company's other customers.

PROPOSED TARIFFS

NOVA SCOTIA POWER INCORPORATED

OUTDOOR RECREATIONAL LIGHTING TARIFF
Rate Code 41

ENERGY CHARGE

10.99 cents per kilowatt hour for all metered kilowatt hours per month.

AVAILABILITY

This rate is available to all outdoor recreational lighting for the period May through October only.

PROPOSED TARIFFS

NOVA SCOTIA POWER INCORPORATED

UNMETERED SERVICE RATES

(A) STREET AND AREA LIGHTING

AVAILABILITY:

These rates shall be applicable to the supply, operation and maintenance, or where indicated, operation and maintenance only, of street and area lighting. Except where otherwise indicated, the rates apply to fixtures operating for approximately 4000 hours per year. Maintenance does not include globe washing, cleaning, repair, or replacement of parts or bulbs necessitated by vandalism. Such costs will be charged to the customer.

RATES

(1) INCANDESCENT

Rate Code	Watts	kW.h/Mo.	$/Mo.	Other
a) Operating, Maintenance and Capital (Full Charge)				
001	300 and less	97	$19.50	
002	Greater than 300	154	25.79	
b) Operating Only				
003	300 and Less	97	10.48	

(2) MERCURY VAPOUR

a) Operating, Maintenance and Capital (Full Charge)				
100	100	43	$12.72	
101	125	52	14.27	
102	175	69	15.14	
103	250	97	19.50	
104	400	154	25.79	
105	700	260	39.28	
106	1000	363	52.13	
107	250	212	29.55	Continuous Operation

PROPOSED TARIFFS

NOVA SCOTIA POWER INCORPORATED

UNMETERED SERVICE RATES

(2) **MERCURY VAPOUR** (cont'd)

Rate Code	Watts	kW.h/Mo.	$/Mo.	Other
b) Operating and Maintenance Only				
201	125	52	9.30	
202	175	69	10.22	
203	250	97	13.24	
204	400	154	19.39	
205	700	260	30.86	
206	1000	363	42.01	
c) Operating Only				
301	125	52	5.62	
302	175	69	7.46	
303	250	97	10.48	
304	400	154	16.63	
305	700	260	28.10	
306	1000	363	39.25	

(3) **FLUORESCENT**

Rate Code	Bulb Length	Number of Bulbs/Unit	kW.h/Mo.	$/Mo.	Other
a) Operating, Maintenance and Capital (Full Charge)					
110	24	2	30	$13.07	
111	48	2	85	19.44	
112	72	2	116	23.62	
113	72	4	222	37.00	
114	96	1	47	15.80	
115	72	1	60	16.56	
116	48	4	166	29.19	

PROPOSED TARIFFS

NOVA SCOTIA POWER INCORPORATED

UNMETERED SERVICE RATES

(3) **FLUORESCENT** (cont'd)

Rate Code	Bulb Length	Number of Bulbs/Unit	kW.h/Mo.	$/Mo.	Other
b) Operating and Maintenance Only					
213	72	4	222	29.51	
214	96	1	47	10.59	
215	72	1	60	12.01	
216	48	4	166	23.49	
217	48	1	49	10.80	
218	48	2	85	14.71	
c) Operating Only					
330	35	4	47	5.06	

(4) **FLUORESCENT CROSSWALK**

a) Continuous Burning - Operating Only					
117	72	4	486	40.73	
118	24	2	66	5.52	
119	48	4	364	30.53	
120	96	2	254	21.31	
150	96	4	613	51.38	
b) Photocell Operation - Operating Only					
310	24	2	30	$ 3.25	
311	48	4	166	17.97	
312	72	2	116	12.57	
313	72	4	222	23.99	
314	96	1	47	5.08	
315	72	1	60	6.49	
350	96	4	280	30.28	

PROPOSED TARIFFS

NOVA SCOTIA POWER INCORPORATED

UNMETERED SERVICE RATES

(5) **LOW PRESSURE SODIUM**

Rate Code	Watts	kW.h/Mo.	$/Mo.	Other
a) Operating, Maintenance and Capital (Full Charge)				
130	135	60	25.11	
131	180	80	28.77	
132	90	45	23.49	
b) Operating and Maintenance Only				
231	180	80	16.93	
c) Operating Only				
331	180	80	8.65	

6) **HIGH PRESSURE SODIUM**

a) Operating, Maintenance and Capital (Full Charge)				
121	250	100	19.11	
122	400	150	24.70	
123	70	32	11.11	
124	100	45	12.42	
125	150	65	14.62	
126	100	99	18.60	Continuous Operation

PROPOSED TARIFFS

NOVA SCOTIA POWER INCORPORATED

UNMETERED SERVICE RATES

(6) **HIGH PRESSURE SODIUM** (cont'd)

Rate Code	Watts	kW.h/Mo.	$/Mo.	Other
b) Operating and Maintenance Only				
221	250	100	13.58	
222	70	32	6.21	
223	100	45	7.63	
224	150	65	9.79	
c) Operating Only				
321	250	100	10.82	
322	70	32	3.45	
323	100	45	4.87	
324	150	65	7.03	
326	400	150	16.21	
327	500	183	19.81	

(7) **METALLIC ADDITIVE**

a) Operating, Maintenance and Capital (Full Charge)				
140	400	150	26.92	
141	1000	360	55.22	
142	250	100	25.65	
143	150	67	22.06	
144	100	50	20.23	
b) Operating Only				
341	1000	360	38.92	
342	400	150	16.21	
343	250	100	10.82	
344	175	75	8.11	
345	150	67	7.23	
346	100	50	5.40	

PROPOSED TARIFFS

NOVA SCOTIA POWER INCORPORATED

UNMETERED SERVICE RATES

(8) LIGHT EMITTING DIODE (LED) LESS THAN 30 WATTS FOR TRAFFIC CONTROL SIGNALS ONLY

Rate Code	$/Mo.	Other
530	$0.27	Non – Continuous
531	$0.44	Continuous

PROPOSED TARIFFS

NOVA SCOTIA POWER INCORPORATED

UNMETERED SERVICE RATES

(B) MISCELLANEOUS LIGHTING

DEMAND CHARGE

$8.43 per month per kilowatt of connected load.

ENERGY CHARGE

9.58 cents per kilowatt hour for the first 200 kilowatt hours per month per kilowatt of connected load.

6.34 cents per kilowatt hour for all additional kilowatt hours.

MAXIMUM PER KW.H CHARGE/MINIMUM BILL

The maximum charge per kW.h will be that for a billing load factor of 10% except that the minimum monthly bill for the electric power and energy portion of the Miscellaneous Lighting Rate shall be $12.65 per month if such unmetered service is billed separately from any metered account.

CAPITAL CHARGE: (if applicable)

Depreciation based on a 25 year life, and interest at the Company's long term rate shall be used to determine the monthly capital charge.

MAINTENANCE CHARGE: (if applicable)

Cost of normal fixture maintenance and bulb replacement on the basis of current cost levels shall be used to calculate the monthly maintenance charge.

This portion of the rate does not include any provision for globe washing or cleaning. Repair or replacement of parts or bulbs necessitated by vandalism will be charged to the customer.

AVAILABILITY:

This rate shall be applicable to the supply, operation and maintenance of lighting units not provided for under the Street and Area Lighting rate.

PROPOSED TARIFFS

NOVA SCOTIA POWER INCORPORATED

UNMETERED SERVICE RATES

(C) MISCELLANEOUS SMALL LOADS

DEMAND CHARGE

$8.43 per month per kilowatt of connected load.

ENERGY CHARGE

9.58 cents per kilowatt hour for the first 200 kilowatt hours per month per kilowatt of connected load.

6.34 cents per kilowatt hour for all additional kilowatt hours.

The flat rate calculation (using a 30 day month) will be based on the specific information of each service using the above rate. The charge will be expressed in cents per kW.h per month and will be rounded to hundredths of a cent in its application.

MAXIMUM PER KW.H CHARGE/MINIMUM BILL

The maximum charge per kW.h will be that for a billing load factor of 10% except that the minimum monthly bill shall be $12.65 per month if such unmetered service is billed separately from any metered account.

AVAILABILITY:

A flat rate shall be calculated for any service requiring the supply of power and energy only, with a predeterminable usage, and where metering is considered to be impractical, such as: Telephone Booths, Cable Vision Power Supplies, Traffic Control Lights, Police Telephones, Railway Signals, etc.

APPENDIX 8

REGULATION CHANGES

PROPOSED REGULATION

NOVA SCOTIA POWER INCORPORATED

7.1 SCHEDULE OF CHARGES

The following charges shall apply:

(a)	Connection or reconnection of electric service, whether metered or unmetered, to any premises during the Company's normal working hours.	$22.00 standard charge
(b)	Connection or reconnection of electric service, whether metered or unmetered, to any premises after the Company's normal working hours, if requested by the Customer and is not a reconnection for non payment.	$22.00 standard charge plus $59.00 charge for additional costs.
(c)	Reconnection of electric service, whether metered or unmetered, to any premises after the Company's normal working hours, if requested by the Customer and is a reconnection associated with non payment.	$22.00 standard charge plus $59.00 charge for additional costs.
(d)	Connection or reconnection of electric service to any premises serviced by temporary service in accordance with these Regulations.	$22.00 standard charge plus all other costs incurred by the Company in connecting or reconnecting service
(e)	Collection Charge: • With Disconnection Notice • With Registered Mail Notification	$16.00 standard charge $8.00 standard charge
(f)	Disconnection-Seasonal Electric Service	$25.00 standard charge
(g)	Returned Cheque Charge	$18.00

PROPOSED REGULATION

NOVA SCOTIA POWER INCORPORATED

7.1 SCHEDULE OF CHARGES

(h)	Interest on Overdue Accounts	1.5% per month or part thereof, or a maximum of 19.56% per annum
(i)	Interest on Deposits	Interest Rate based on Royal Bank prime rate minus 1%; set January 1st of each year
(j)	Dispute Test Fee re satisfactory meter	$29.00
(k)	Standard Contribution for three-phase service 15 kW and under	$952.00
(l)	Charge for installation of Recording Equipment	
	• 240 volt single phase voltage recorder	$25.00
	• all other recording equipment	Actual Costs incurred by the Company
(m)	Service Charge for any miscellaneous requests.	Actual Costs incurred by the Company
(n)	All pole attachments for telecommunication common carriers, or broadcasters, exclusive of those under joint use agreements.	$14.15 per pole per year
(o)	Access to NSPI Mobile Radio Network	Monthly Charge
	- Basic Dispatch Service	$26.00
	- Individual/Group Call Feature	$21.00
	- Networking Features	$11.00
	- Interconnect Facility (PSTN) Access	$41.00

PROPOSED REGULATION

NOVA SCOTIA POWER INCORPORATED

7.2 SCHEDULE OF WIRING INSPECTION FEES

7.2.1 Permits and Inspections

Permits and inspections will normally be of three types:

a) Regular Permits and Inspections
b) Annual Permits and Inspections
c) Special Permits and Inspections

a) Regular Permits and Inspections

All persons, firms or corporations within Nova Scotia Power's inspection authority who are eligible to install electrical installations for the use of electrical energy shall, before commencing or doing any electrical installation of new equipment, or repairs, or altering or adding to any electrical installation or equipment already installed, submit and obtain approval in a manner prescribed by the inspection authority.

Individual permits shall be required for temporary and individual miscellaneous services and each dwelling unit of a single, duplex or row type housing, etc., whether supplied via an individual or multi-position metering devices.

Apartment type buildings, multi-tenant industrial and commercial installations shall be performed under one permit.

Permits are not transferable.

Permits shall be issued only to the firm or persons performing the work described on the Permit and in compliance with Section 4, "Permit" of the regulations made by the Fire Marshall pursuant to the Electrical Installation and Inspection Act.

Permit holders shall immediately notify the Electrical Inspection Authority upon the completion of an electrical installation requesting a FINAL inspection.

The fee for a Regular Permit and Inspection will be based on the Installed Value, including labour, material and sundries of the electrical installation, alteration, upgrade, repair or extension.

PROPOSED REGULATION

NOVA SCOTIA POWER INCORPORATED

7.2 SCHEDULE OF WIRING INSPECTION FEES

When a dispute arises regarding the cost of an electrical installation the permit applicant may be required, at the Inspection Authority discretion, to supply a letter from the owner indicating the value of the contract and/or a bill of materials for the project.

The fees for a Regular Permit and Inspection, including the number of Inspection Visits, shall be based on the Installed Value of the installation as shown in the Inspection Fee Schedule.

b) **Annual Permits and Inspections**

An annual maintenance permit shall be issued for an establishment to cover all minor repairs as required under sections 4(a) (B), (2) and (3) of the regulations made by the Fire Marshal pursuant to the Electrical Installation Act.

Such a permit does not entitle the holder to effect major electrical alterations or additions.

The number of inspection visits shall be at the discretion of the Inspection Authority. Notwithstanding the above, at least one inspection visit shall be made in the year for which the permit is issued.

c) **Special Permits and Inspections**

Where the fee for a Regular Permit and Inspection are inappropriate the special permit and inspection fee shall apply. (Ex. carnivals and travelling shows).

7.2.2 Late Application Fee

Where an electrical contractor fails to obtain an electrical wiring permit prior to commencing the electrical work, an additional fee shall be payable in the amount of fifty (50) percent of the regular fee, up to a maximum additional fee of $100.00.

PROPOSED REGULATION

NOVA SCOTIA POWER INCORPORATED

7.2 SCHEDULE OF WIRING INSPECTION FEES

7.2.3 Payment of Fees

Fees for permits and inspections shall be paid at the time of requesting the permit unless otherwise indicated by the inspection authority. Permits having fees in arrears in excess of 120 days shall be subject to cancellation and at the discretion of the inspection authority, no additional permits shall be issued to the holder of the unpaid permits until such time the outstanding fees have been adequately dealt with.

7.2.4 Refund of Fees

The holder of a permit may apply to the inspection authority for a refund less a $10.00 non-refundable portion of the permit fee with respect to a cancelled or unused permit. No refund shall be issued for a permit where an inspection call has been made at the request of the permit holder.

7.2.5 Expiry of Permits

A permit for electrical work is valid for 12 months from the date of issue in respect of residential and 24 months in respect of all others unless otherwise noted on the permit. Upon expiry, a renewal fee to a maximum of 50% of the cost of the original permit shall be charged.

7.2.6 Review of Plans and Specifications

The Inspection Authority may, prior to issuing a permit, request the submission of plans and specifications for any proposed electrical installation. Plans shall be submitted for all commercial, industrial institutional installations exceeding 250 volts or 250 amperes.

PROPOSED REGULATION

NOVA SCOTIA POWER INCORPORATED

7.2 SCHEDULE OF WIRING INSPECTION FEES

7.2.7 Inspection Fee Schedule

a) **Regular Permits and Inspection**

The fee for a regular permit and the maximum number of inspection visits, with respect to an installation will be calculated, as follows.

b) **Annual Permit and Inspection**

The fee for an annual permit and inspection for any one establishment shall be the appropriate hourly rate.

c) **Special Permit and Inspection**

The fee for a special permit and inspection for any one project shall be the appropriate hourly rate.

d) **Plans Examination**

The fees for the examination of electrical plans and specifications shall be per review:

0 – 1,000 amps	$ 89.00
Greater than 1,000 amps	$ 89.00

e) **Primary Services**

The fees for the inspection of a primary service (padmount, vault, etc.) shall be per installation.	$113.00

f) **Letter of Acceptance**

The fees for a Letter of Acceptance shall be	$ 29.00

PROPOSED REGULATION

NOVA SCOTIA POWER INCORPORATED

7.2 SCHEDULE OF WIRING INSPECTION FEES

INSPECTION FEE SCHEDULE

INSTALLED VALUE OF ELECTRICAL INSTALLATION	INSPECTION VISITS	PERMIT FEE
$ 0,000 to $ 2,000	1	$ 53.00
$ 2,001 to $ 4,000	2	$ 107.00
$ 4,001 to $ 6,000	2	$ 179.00
$ 6,001 to $ 8,000	2	$ 225.00
$ 8,001 to $ 10,000	2	$ 273.00
$ 10,001 to $ 15,000	3	$ 357.00
$ 15,001 to $ 25,000	3	$ 453.00
$ 25,001 to $ 50,000	3	$ 655.00
$ 50,001 to $ 100,000	3	$1,011.00
$100,001 to $ 300,000	4	$1,546.00
$300,001 to $ 500,000	5	$2,022.00
$500,001 to $750,000	6	$2,617.00
$750,001 to $1,000,000	8	$3,092.00
+ $1,000,000	10	$3,569.00 + 0.15% of cost in excess of $1,000,000

New Installations are subject to the following minimum inspection fees:

RESIDENTIAL-ALL INSTALLATIONS	$107.00
COMMERCIAL/INDUSTRIAL INSTITUTIONAL	
Up to 100 AMPS	$107.00
Over 100 to 400 AMPS	$273.00
Over 400 to 800 AMPS	$357.00
Over 800 to 1000 AMPS	$453.00
Over 1000 AMPS	$655.00

APPROVED: NOVA SCOTIA UTILITY AND REVIEW BOARD

EFFECTIVE: APRIL 1, 2007

PROPOSED REGULATION

NOVA SCOTIA POWER INCORPORATED

7.2 SCHEDULE OF WIRING INSPECTION FEES

g) **Hourly Rate Inspections**

Note: All fees are per inspection visit.

Normal Working Hours:

i)	For the first hour or fraction thereof	$ 52.00
ii)	.....For each additional half-hour or fraction thereof	$ 22.00

Outside Normal Working Hours:

Extension of a regular work day (before or after)

i)	For the first hour or fraction thereof.....	$ 70.00
ii)	.....For each additional half-hour or fraction thereof	$ 30.00

Weekends and Statutory Holidays:

Scheduled inspections on weekends (Saturday, Sunday) and statutory holidays:

i)	For the first hour or fraction thereof.....	$116.00
ii)	.....For each additional half-hour or fraction thereof	$ 42.00

h) **Inspections in Excess of Maximum Number of Visits**

For an inspection visit, in excess of the maximum number of visits permitted under the Regular Permit and Inspection Fee the Special Permit and Inspection Fee shall apply.

PROPOSED REGULATION

NOVA SCOTIA POWER INCORPORATED

7.3 SCHEDULE OF LOAD RESEARCH MONITORING, REPORTING AND ANALYTICAL CHARGES

The following schedule of charges shall apply to customers requesting Load Research information. **(Note: Customers must provide access to a shared phone line for data collection via automatic meter reading equipment):**

a) **Recovery of the Capital Cost of Installed Equipment** will be the actual costs incurred by the Company.

b) **Setup for Load Research** will be the actual cost incurred by Company plus a 25% markup.

c) **Analysis and Reporting Charges** will be the actual costs incurred by the Company plus at 25% markup.

d) **Specialized Customer Analysis** will be the actual costs incurred by the Company plus at 25% markup.

SCHEDULE OF LOAD RESEARCH CHARGES

		ONE-TIME	BI-MONTHLY	MONTHLY
1.0	**Recovery of Capital Cost of Meter Equipment**			
	Single or Three Phase	301.00	11.15	5.47
2.0	**Recovery of Installation Charges**			
	Single Phase Service Self-Contained	56.00		
	Single Phase Service, Transformer Rated and Three Phase Service	224.00		
3.0	**Load Research Setup**	40.00		

PROPOSED REGULATION

NOVA SCOTIA POWER INCORPORATED

7.3 SCHEDULE OF LOAD RESEARCH MONITORING, REPORTING AND ANALYTICAL CHARGES

4.0	**Analysis and Reporting**	**See Charge per Billing Period**
	Base Package	
	Load profile for peak day billing period plus times and magnitude of six highest peaks	33.00
	Options	
	Data File	33.00
	Load profile for each day for each billing period	33.00
	Power factor for plot for peak day (kVA billed cust. only)	33.00
	Power factor plot for each day (kVA billed cust. only)	11.00
	Reports of billing period average load profile for each day of the week	33.00
	Report of billing period average load profile for an specific day of the week	11.00
	Daily summary	11.00
	Monthly summary	11.00
	Weekly or monthly detail	11.00
	Daily comparison: Any two customers specified days	11.00
	Load duration plot	11.00
	Daily consumption plot	11.00
	Complete package (all of the above options)	180.00
5.0	**Specialized Analysis**	
	Hourly Rate	91.00