Requirement:

Cost of Service Study.

Submission:

Please refer to Attachment 1.

SR-01

Cost of Service Study

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1. Cost of Service Study Methodology

1.1 Overview

From a cost-of-service methodology perspective, NSPI's customers fall into two broad categories, Below-the-line (BTL) and Above-the-line (ATL). The Cost of service methodology subject to discussion in this section is concerned with the cost allocation to ATL classes only. Before costs are allocated to ATL classes, the total cost responsibility of this group must be determined by subtracting costs associated with serving BTL classes from the total revenue requirement of the company.

The overall objective of a cost of service study is to determine the costs associated with serving each customer class, and to identify any inter-class inequities that may be present with regard to over or under contribution to total allocated costs. This determination is based on a comparison of revenue/cost (R/C) ratios.

The first step in preparing a Cost of Service Study (COSS), once the test period is established, is to collect the detailed financial and operating information pertaining to that period. The data accumulated includes estimates for: plant-in-service, construction work in progress (CWIP), reserve for depreciation, working capital allowances, deferred charges, deferred credits, contract receivables, revenues, operating expenses, energy sales and demand statistics and customer counts.

The Cost of Service Study allocates the costs (therefore the revenue requirement) of providing electric service by the Company. This includes the appropriate assignment of operating and maintenance expenses, grants in lieu of taxes, depreciation and the responsibility for interest and corporate taxes incurred on those elements of the electric utility plant in service that are necessary in whole, or in part, to provide electric service to the various classifications of utility customers, as well as an approved return on investment.

Where possible, costs are assigned directly to classes of service based upon information acquired from the financial books and records of the Company or through additional analyses or studies.

Costs not directly assigned are analyzed by functional responsibility in groupings of accounts, such as production, transmission, distribution and retail. These groupings are then allocated to the various classes of service on the basis of the respective demands, energy use, number of customers, and/or revenue associated with the functional responsibility appropriate for each class of service. In general, the demand component of cost comprises those items that are incurred in order to produce and deliver electric energy to customers as called for by them. Sufficient infrastructure must be installed to supply peak demand as required, while maintaining a required reserve margin.

Plant investment increases as units and facilities grow to meet demand. Consequently, these costs are allocated based on contributions to system coincident demand. Distribution facilities are allocated based on non-coincident demand to recognize that this infrastructure must be sized to provide that capacity. Class non-coincident demands are the demands that are imposed on the distribution system and, in general, are substantially larger than coincident demands. Consequently, the cost of service elements that increase with plant size and capacity are classified as demand costs.

Energy related costs are those items that vary with the annual volume of energy supplied to the various classes of service provided by the Company. The prime example of energy costs that vary with the volume of electricity generated and supplied is fuel costs. These costs increase as the quantity of fuel required to produce energy from generating units is increased.

The customer related costs are those items that vary with the number of customers served, and revenue related costs are those items that vary with the dollars of revenue received. An example of customer costs is customer service field expenses, including meter reading and electric wiring inspection expenses.

Costs associated with services related to miscellaneous revenues are not identified separately, rather these items are deducted from the overall cost assignment process.

Functionalization

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

Classification

Following the functionalization step, production, transmission, distribution and retail plant and operating expenses are **classified**. Classification is the process by which plant and operating costs are determined to be demand, energy, or customer related.

Allocation Factors

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

Allocation

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

Exhibit 1 summarizes the results of the Cost of Service Study under present and proposed rates for the test period. The full analysis is provided in the various other Exhibits.

- Exhibits 2 and 3 detail the rate base analyses,
- Exhibits 4 to 6 show the analyses of operating costs and depreciation expense.
- Exhibit 7 contains the revenue analysis
- Exhibit 8 details the development of allocation factors.
- Exhibit 9 shows the analysis of sales and demand data.
- Exhibit 10 details the demand, energy and customer costs along with the revenue by class and the resulting Revenue/Cost Ratios for the test period under proposed rates.
- Exhibit 10A details the demand, energy and customer costs along with the revenue by class and the resulting Revenue/Cost Ratios under current rates for the test period.

1.2 Methodology

The method of cost assignment utilized is the Load Factor/3 Coincident Peak (LF/3 CP) method, as approved by the UARB in its September 29, 1995 Order NSPI-864.

This method considers both the demand and energy requirements of the various customer classes in allocating generation and transmission responsibility. It respects both the maximum demands the class places on the system, as well as the extent to which the class uses the facilities on an ongoing basis.

A percentage of costs, equal to the system peak load factor percentage is considered energy related and allocated on the kWh at generation. The remaining costs are considered demand-related and are allocated based on the sum of three coincident peak demands at generation for December, January and February (the peak winter period). Environmental and fuel conversion assets in the rate base are extracted up front and classified 100% as energy-related.

1.2.1 Rate Base

Exhibits 2, 2A and 2B

Exhibit 2 contains the net plant investment in the various asset categories, with allowance for working capital and allowance for materials and supplies.

In keeping with the Board's decision from the 2005 Rate Application, dated March 31, 2005, changes were made in this exhibit and subsequent rate base exhibits (2A, 2B and 3) to include construction work in progress (CWIP), deferred charges, deferred credits and contract receivables.

The net plant investment, allowance for working capital, allowance for materials and supplies, deferred charges, deferred credits and contract receivables that are directly assigned are identified as the "Direct Capital" column in exhibit 2. Direct capital is subtracted from the total company rate base to arrive at the amounts to be allocated among COSS-based rate classes. Starting with the 2012 test year, the rate base associated with the forthcoming LED streetlight investment is proposed to be treated as direct capital. This is consistent with the proposed ratemaking treatment of the LED services as a BTL category to be priced using an incremental cost approach.

Exhibits 3, 3A, 3B, 3C, 3D, 3E, 3F, 3G

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

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

With the demand, energy and customer factors developed, the allocation phase proceeds. Steam, Hydro and LM6000 assets are allocated on the load factor and 3CP demand contribution, other gas turbine assets are allocated based on the 3CP demand only and wind assets are assigned 30% to 3CP demand and the remaining plant to energy.
Transmission plant is initially segregated between > 69 kV and < 138 kV voltage using a 76.6%/23.4% ratio. Both portions of these assets are classified on load factor and allocated on 3CP demand contribution to customer classes based on their required service voltage.

Distribution plant is more complex in its cost causalities than are the other functions. Substations are allocated in accordance with Exhibit 3B. The amounts invested in facilities that are dedicated to a single customer's use were identified and directly allocated to the customer's respective class. The remaining substation investment is allocated on the basis of primary demand levels. The totals for each class are carried forward as class allocations of substation investment, as shown in Exhibit 3.

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

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

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

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

The "Land" and "Other" assets, listed in Exhibit 3A, were allocated on the basis of total substation, pole and wire investments. The "non LED Street Lighting" investment was assigned directly to the unmetered customers.

The "General Property Plant" investment listed in Exhibit 3, was allocated on the basis of all other plant investment. Finally, allowance for working capital, allowance for materials and supplies, deferred charges, deferred credits and contract receivables were allocated in accordance with their cost causalities as defined by the allocation factors used.

To provide more transparency in the allocation of streetlight fixture-related costs, the distribution-related rate base information in exhibit 3 has been separated between the streetlight-related versus non-streetlight related categories.

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

1.2.2 Operating Expense

The analysis of operating costs begins in Exhibit 4 with functionalization. In this step total operating costs are grouped according to production, transmission, distribution, retail and direct assignment. The "Direct Expenses" column contains those costs that are not to be assigned to ATL customer classes as they represent costs incurred by BTL customers. Starting with the 2012 test year, the "Direct Expense" column also reflects the capital-related costs associated with the BTL category of LED streetlight fixtures. The "Corporate Groups" operating expenses have been assigned to each function based on their overall responsibility to each primary business operation within the Company. "Cost of Goods Sold" (Net of Retail Sales), "Grants in Lieu of Taxes", "Depreciation" (by function), "Interest" (net of AFUDC), "Preferred Dividends" and "Corporate Taxes" are assigned to each function based on various rate base functionalizations. As approved by the Board in the 2009 General Rate Application, Demand Side Management expenses incurred in 2008 and 2009 are included in the COSS. These amortized costs are allocated in the same way as fixed generation costs and are expected to be fully recovered by 2015[1].

In Exhibit 5, the functionalized expenses from Exhibit 4 are listed and sub-grouped, where necessary, in order to classify them as demand, energy and customer. To provide more clarity in the treatment of streetlight fixture-related costs they have been separated from all the other distribution-related costs to form a separate sub-group of the "Distribution Function".

Exhibit 6 summarizes the next stage of the study, which is the allocation of operating costs. First, those costs which are classified as "Demand" (generation, transmission and distribution) are allocated on the basis of the 3CP demand allocators. Consistent with the treatment of the streetlight fixture-related costs in exhibit 5, these costs are shown separately in exhibit 6.

Exhibit 6A contains the analysis of total distribution operating expenses broken down by demand-, customer-, and retail-related categories. The basic allocation premise used is that costs should be allocated in the same manner as their rate base counterparts. Substation costs are allocated according to substation investment.

[1] DSM amortized costs are reflected in the Financial tables under the "regulatory amortization" component.

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

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

Third, the customer related expenses are allocated. Again, the distribution costs are determined from Exhibit 6A. In Exhibit 6, the "Call Centre" was assigned using total weighted customers. "Customer Service – H/O" and "Billing Services" were assigned using average customers, adjusted for seasonality. "Quality Assurance and Communication", "Electrical Wiring Inspection" (head office) and "Payment Services" costs were assigned using average customers. "Marketing and Sales" and "Meter Data Services" costs were allocated on the basis of defined responsibility commitments to each customer class. Exhibit 6C details the allocation of credit services expenses. First, the "Bad Debt Expense" is split between domestic and all other classes based on gross write-off experience. The other portion of bad debt expense is assigned to each class based on secondary customer revenue. The other operating portion is distributed on the basis of average number of customers.

Depreciation is allocated by function as shown on Exhibit 6D. Consistent with the treatment of streetlight fixture related costs in exhibits 5 and 6, they are shown as separate sub-components under the Distribution Function category. With the streetlight fixture depreciation cost information being directly available from the company's accounting information system for some time now, NSPI proposes to use this information directly for the direct cost assignment purposes in COSS going forward. NSPI deems this approach to be more accurate and transparent than the current method predicated on rate base allocators.

In Exhibit 6, grants in lieu of taxes are allocated on the basis of total production, transmission, distribution and retail net plant. Interest (net of AFUDC) preferred dividends and corporate taxes expense are allocated on the basis of total rate base assignment from Exhibit 3. The total costs for each class are then determined and adjusted by non-rate revenue and the return (profit/loss) to arrive at the net cost to each customer class. The resultant total then becomes the input to rate design.

Exhibit 7 serves the purpose of verifying the accuracy of the cost allocation analysis. The ATL revenues are shown against revenues of other categories, determined outside of the COSS, and retained earnings from the financial tables. Consistent with the treatment of the BTL categories, the LED fixture-related revenue component is placed under "Direct Revenue".

Using the total allocated costs for each class, a comparison is made with the revenues for each class to determine the percentage revenue to cost relationships. The results are shown on Exhibit 10, under proposed rates for the test year. Exhibit 10A has been provided to show the equivalent information under present rates.

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

EXHIBIT 1

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

	2011	
CUSTOMER CLASS	**PRESENT**	**PROPOSED**
(1) DOMESTIC	98.91	99.15
(2) SMALL GENERAL	102.32	105.00
(3) GENERAL	107.17	105.00
(4) LARGE GENERAL	98.69	100.61
(5) SMALL INDUSTRIAL	102.00	100.64
(6) MEDIUM INDUSTRIAL	100.79	97.23
(7) LARGE INDUSTRIAL	97.54	97.53
(8) ELI 2P-RTP	90.99	95.00
(9) MUNICIPAL	99.84	97.87
(10) UNMETERED	100.00	100.00
(11) TOTAL	100.00	100.00

EXHIBIT 2

NOVA SCOTIA POWER INC.
FUNCTIONALIZATION OF AVERAGE RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2012
(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) GENERATION	(3) TRANSMISSION	(4) DISTRIBUTION	(5) RETAIL	(6) DIRECT CAPITAL
PRODUCTION PLANT						
(1) STEAM	$1,471,480	$1,471,480	$0	$0	$0	$0
(2) HYDRO	336,959	318,828	0	0	0	18,131
(3) WIND	249,265	249,265	0	0	0	0
(4) LM6000	62,909	62,909	0	0	0	0
(5) GAS TURBINE - OTHER	11,102	11,102	0	0	0	0
(6) TOTAL PROD. PLANT	2,131,715	2,113,584	0	0	0	18,131
(7) Transmission < 138kV	90,235	0	90,235	0	0	0
(8) Transmission > 69kV	295,386	0	295,386	0	0	0
(9) TRANSMISSION PLANT	385,621	0	385,621	0	0	0
DISTRIBUTION PLANT						
(10) LAND	4,579	0	0	4,579	0	0
(11) EASEMENTS & SURVEY	14,479	0	0	14,479	0	0
(12) OTHER	1,818	0	0	1,818	0	0
(13) SUBSTATIONS	26,756	0	0	26,756	0	0
(14) POLES & FIXTURES	158,187	0	0	158,187	0	0
(15) O.H. LINES	106,788	0	0	106,788	0	0
(16) U.G. LINES	33,114	0	0	33,114	0	0
(17) LINE TRANSFORMERS	141,297	0	0	141,297	0	0
(18) SERVICES	57,592	0	0	57,592	0	0
(19) METERS	23,330	0	0	23,330	0	0
(20) STREET LIGHTING	30,821	0	0	21,981	0	8,840
(21) TOTAL DIST. PLANT	598,761	0	0	589,921	0	8,840
(22) SUB-TOTAL	3,116,097	2,113,584	385,621	589,921	0	26,971
(23) GEN. PROPERTY PLANT	236,684	161,939	29,546	45,199	0	0
(24) TOT. PLT.IN SERVICE	3,352,781	2,275,523	415,167	635,120	0	26,971
Working Capital & Deferred Charges/Credits						
(25) CASH - FUEL	0	0	0	0	0	0
(26) CASH - OTHER	59,050	27,308	6,255	25,283	0	204
(27) MAT. & SUP. - FUEL	95,300	95,300	0	0	0	0
(28) MAT. & SUP. - OTHER	27,250	18,644	3,402	5,204	0	0
(29) DEF. CHG. - Financing	87,950	60,176	10,979	16,796	0	0
(30) DEF. CHG. - Tax	40,600	27,779	5,068	7,753	0	0
(31) DEF. CHG. - Pension	58,150	26,985	6,181	24,984	0	0
(32) DEF. CHG. - Steam Assets	0	0	0	0	0	0
(33) DEF. CHG. - Fuel Deferral	48,050	48,050	0	0	0	0
(34) DEF. CHG. - Other	6,650	4,550	830	1,270	0	0
(35) DEF. CR. - ARO Steam	(91,688)	(91,688)	0	0	0	0
(36) DEF. CR. - ARO Hydro	(17,124)	(17,124)	0	0	0	0
(37) DEF. CR. - ARO Wind	(16,950)	(16,950)	0	0	0	0
(38) DEF. CR. - ARO CT	(7,270)	(7,270)	0	0	0	0
(39) DEF. CR. - ARO Trans	(16,180)	0	(16,180)	0	0	0
(40) DEF. CR. - Other	(2,150)	(2,150)	0	0	0	0
(41) CONTRACT RECEIVABLE	0	0	0	0	0	0
(42) TOT.WORKING CAPITAL	271,638	173,610	16,535	81,289	0	204
(43) TOTAL AVE. RATE BASE	$3,624,419	$2,449,133	$431,702	$716,409	$0	$27,175

NOVA SCOTIA POWER INC.

CLASSIFICATION OF AVERAGE RATE BASE

FOR THE YEAR ENDING DECEMBER 31, 2012

(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	$1,471,480	$1,228,735	$242,745	$0
(2) HYDRO PLANT	318,828	312,833	5,995	0
(3) WIND PLANT	249,265	133,647	115,618	0
(4) LM6000 PLANT	62,909	62,909	0	0
(5) GAS TURBINE PLANT - OTHER	11,102	11,102	0	0
(6) TOTAL GENERATION PLANT	2,113,584	1,749,226	364,358	0
(7) GENERAL PROPERTY PLANT	161,939	134,023	27,917	0
(8) TOTAL PLANT IN SERVICE	2,275,523	1,883,249	392,275	0
Working Capital & Deferred Charges/Credits:				
(9) CASH - FUEL	0	0	0	0
(10) CASH - OTHER	27,308	7,406	19,902	0
(11) MAT. & SUPPLIES - FUEL	95,300	0	95,300	0
(12) MAT. & SUPPLIES - OTHER	18,644	15,430	3,214	0
(13) DEF. CHG. - Financing	60,176	49,802	10,374	0
(14) DEF. CHG. - Tax	27,779	22,990	4,789	0
(15) DEF. CHG. - Pension	26,985	7,318	19,667	0
(16) DEF. CHG. - Steam Assets	0	0	0	0
(17) DEF. CHG. - Fuel Deferral	48,050	0	48,050	0
(18) DEF. CHG. - Other	4,550	3,766	784	0
(19) DEF. CR. - ARO Steam	(91,688)	(76,563)	(15,125)	0
(20) DEF. CR. - ARO Hydro	(17,124)	(16,802)	(322)	0
(21) DEF. CR. - ARO CT	(7,270)	(7,270)	0	0
(22) DEF. CR. - Other	(2,150)	(1,795)	(355)	0
(23) CONTRACT RECEIVABLE	0	0	0	0
(24) SUB-TOTAL	190,560	4,282	186,278	0
(25) TOTAL GENERATION FUNCTION	**2,466,083**	**1,887,531**	**578,552**	**0**
TRANSMISSION FUNCTION				
(26) TRANSMISSION PLANT < 138kV	90,235	90,235	0	0
(27) GENERAL PROPERTY PLANT	6,914	6,914	0	0
(28) TOTAL PLANT IN SERVICE	97,149	97,149	0	0
Working Capital & Deferred Charges/Credits:				
(29) CASH - FUEL	0	0	0	0
(30) CASH - OTHER	1,498	576	922	0
(31) MAT. & SUPPLIES - FUEL	0	0	0	0
(32) MAT. & SUPPLIES - OTHER	796	796	0	0
(33) DEF. CHG. - Financing	2,569	2,569	0	0
(34) DEF. CHG. - Tax	1,186	1,186	0	0
(35) DEF. CHG. - Pension	1,480	569	911	0
(36) DEF. CHG. - Other	194	194	0	0
(37) DEF. CHG. - ARO Trans.	(3,786)	(3,786)	0	0
(38) SUB-TOTAL	3,937	2,104	1,833	0
(39) TOTAL TRANS. < 138kV	101,086	99,253	1,833	0

NOVA SCOTIA POWER INC.

CLASSIFICATION OF AVERAGE RATE BASE

FOR THE YEAR ENDING DECEMBER 31, 2012

(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	295,386	295,386	0	0
(2) GENERAL PROPERTY PLANT	22,632	22,632	0	0
(3) TOTAL PLANT IN SERVICE	318,018	318,018	0	0
Working Capital & Deferred Charges/Credits:				
(4) CASH - FUEL	0	0	0	0
(5) CASH - OTHER	4,757	1,829	2,929	0
(6) MAT. & SUPPLIES - FUEL	0	0	0	0
(7) MAT. & SUPPLIES - OTHER	2,606	2,606	0	0
(8) DEF. CHG. - Financing	8,410	8,410	0	0
(9) DEF. CHG. - Tax	3,882	3,882	0	0
(10) DEF. CHG. - Pension	4,701	1,807	2,894	0
(11) DEF. CHG. - Other	636	636	0	0
(12) DEF. CHG. - ARO Trans	(12,394)	(12,394)	0	0
(13) SUB-TOTAL	12,598	6,776	5,823	0
(14) TOTAL TRANS. > 69kV	330,616	324,793	5,823	0
(15) TOTAL TRANSMISSION FUNCTION	**$431,702**	**$424,046**	**$7,656**	**$0**

DISTRIBUTION FUNCTION

DISTRIBUTION PLANT:				
(16) LAND	4,579	3,121	0	1,458
(17) EASEMENTS & SURVEY	14,479	9,867	0	4,612
(18) OTHER	1,818	1,239	0	579
(19) SUBSTATIONS	26,756	26,756	0	0
(20) POLES & FIXTURES	158,187	102,822	0	55,365
(21) O.H. LINES	106,788	69,412	0	37,376
(22) U.G. LINES	33,114	21,524	0	11,590
(23) LINE TRANSFORMERS	141,297	141,297	0	0
(24) SERVICES	57,592	0	0	57,592
(25) METERS	23,330	0	0	23,330
(26) STREET LIGHTING	21,981	21,981	0	0
(27) TOTAL DISTRIBUTION PLANT	589,921	398,019	0	191,902
(28) GENERAL PROPERTY PLANT	45,199	30,496	0	14,703
(29) TOTAL PLANT IN SERVICE	635,120	428,514	0	206,605
Working Capital & Deferred Charges/Credits:				
(30) CASH - FUEL	0	0	0	0
(31) CASH - OTHER	25,283	11,171	0	14,112
(32) MAT. & SUPPLIES - FUEL	0	0	0	0
(33) MAT. & SUPPLIES - OTHER	5,204	3,511	0	1,693
(34) DEF. CHG. - Financing	16,796	11,332	0	5,464
(35) DEF. CHG. - Tax	7,753	5,231	0	2,522
(36) DEF. CHG. - Pension	24,984	11,039	0	13,945
(37) DEF. CHG. - Other	1,270	857	0	413
(38) SUB-TOTAL	81,289	43,140	0	38,149
(39) TOTAL DISTRIBUTION FUNCTION	**716,409**	**471,654**	**0**	**244,754**

NOVA SCOTIA POWER INC.

CLASSIFICATION OF RATE BASE

FOR THE YEAR ENDING DECEMBER 31, 2012

(IN THOUSANDS OF DOLLARS)

	(1)	(2)	(3)	(4)
		INITIAL CLASSIFICATION		
	TOTAL COMPANY	DEMAND RELATED PLANT	ENERGY RELATED PLANT	CUSTOMER RELATED PLANT
RETAIL FUNCTION				
DISTRIBUTION PLANT:				
(1) SERVICES	0	0	0	0
(2) METERS	0	0	0	0
(3) TOTAL RETAIL PLANT	0	0	0	0
(4) GENERAL PROPERTY PLANT	0	0	0	0
(5) TOTAL PLANT IN SERVICE	0	0	0	0
Working Capital & Deferred Charges/Credits:				
(6) CASH - FUEL	0	0	0	0
(7) CASH - OTHER	0	0	0	0
(8) MAT. & SUPPLIES - FUEL	0	0	0	0
(9) MAT. & SUPPLIES - OTHER	0	0	0	0
(10) DEF. CHG. - Financing	0	0	0	0
(11) DEF. CHG. - Tax	0	0	0	0
(12) DEF. CHG. - Pension	0	0	0	0
(13) DEF. CHG. - Other	0	0	0	0
(14) SUB-TOTAL	0	0	0	0
(15) TOTAL RETAIL FUNCTION	**0**	**0**	**0**	**0**
(16) TOTAL AVE. RATE BASE	**$3,614,194**	**$2,783,232**	**$586,208**	**$244,754**

NOVA SCOTIA POWER INC.

CLASSIFICATION OF AVERAGE RATE BASE

FOR THE YEAR ENDING DECEMBER 31, 2012
(IN THOUSANDS OF DOLLARS)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	INITIAL R/B CLASSIFICATION			FURTHER CLASSIFICATION			FULLY CLASSIFIED RATE BASE		
	DEMAND PLANT	ENERGY PLANT	CUSTOMER PLANT	DEMAND PLANT	ENERGY PLANT	CUSTOMER PLANT	DEMAND PLANT	ENERGY PLANT	CUSTOMER PLANT
GENERATION FUNCTION									
(1) STEAM PLANT	$1,228,735	$242,745	$0	($756,409)	$756,409	$0	$472,326	$999,154	$0
(2) HYDRO PLANT	312,833	5,995	0	(192,580)	192,580	0	120,253	198,575	0
(3) WIND PLANT	133,647	115,618	0	(93,553)	93,553	0	40,094	209,171	0
(4) LM6000 PLANT	62,909	0	0	(38,727)	38,727	0	24,182	38,727	0
(5) GAS TURBINE PLANT - OTHER	11,102	0	0	0	0	0	11,102	0	0
(6) TOTAL GENERATION PLANT	1,749,226	364,358	0	(1,081,269)	1,081,269	0	667,957	1,445,627	0
(7) GENERAL PROPERTY PLANT	134,023	27,917	0	(82,845)	82,845	0	51,178	110,762	0
(8) TOTAL PLANT IN SERVICE	1,883,249	392,275	0	(1,164,114)	1,164,114	0	719,135	1,556,389	0
Working Capital & Deferred Charges/Credits:									
(9) CASH - FUEL	0	0	0	0	0	0	0	0	0
(10) CASH - OTHER	7,406	19,902	0	0	0	0	7,406	19,902	0
(11) MAT. & SUPPLIES - FUEL	0	95,300	0	0	0	0	0	95,300	0
(12) MAT. & SUPPLIES - OTHER	15,430	3,214	0	(9,538)	9,538	0	5,892	12,752	0
(13) DEF. CHG. - Financing	49,802	10,374	0	(30,785)	30,785	0	19,017	41,158	0
(14) DEF. CHG. - Tax	22,990	4,789	0	(14,211)	14,211	0	8,779	19,000	0
(15) DEF. CHG. - Pension	7,318	19,667	0	0	0	0	7,318	19,667	0
(16) DEF. CHG. - Steam Assets	0	0	0	0	0	0	0	0	0
(17) DEF. CHG. - Fuel Deferral	0	48,050	0	0	0	0	0	48,050	0
(18) DEF. CHG. - Other	3,766	784	0	(2,328)	2,328	0	1,438	3,112	0
(19) DEF. CR. - ARO Steam	(76,563)	(15,125)	0	47,132	(47,132)	0	(29,431)	(62,257)	0
(20) DEF. CR. - ARO Hydro	(16,802)	(322)	0	10,343	(10,343)	0	(6,459)	(10,665)	0
(21) DEF. CR. - ARO CT	(7,270)	0	0	0	0	0	(7,270)	0	0
(22) DEF. CR. - Other	(1,795)	(355)	0	1,105	(1,105)	0	(690)	(1,460)	0
(23) CONTRACT RECEIVABLE	0	0	0	0	0	0	0	0	0
(24) SUB-TOTAL	4,282	186,278	0	1,719	(1,719)	0	6,001	184,559	0
							0	0	0
(25) TOTAL GENERATION FUNCTION	1,887,531	578,552	0	(1,162,395)	1,162,395	0	725,136	1,740,947	0
TRANSMISSION FUNCTION									
(26) TRANSMISSION PLANT < 138kV	90,235	0	0	(55,549)	55,549	0	34,686	55,549	0
(27) GENERAL PROPERTY PLANT	6,914	0	0	(4,256)	4,256	0	2,658	4,256	0
(28) TOTAL PLANT IN SERVICE	97,149	0	0	(59,805)	59,805	0	37,344	59,805	0
Working Capital & Deferred Charges/Credits:									
(29) CASH - FUEL	0	0	0	0	0	0	0	0	0
(30) CASH - OTHER	576	922	0	0	0	0	576	922	0
(31) MAT. & SUPPLIES - FUEL	0	0	0	0	0	0	0	0	0
(32) MAT. & SUPPLIES - OTHER	796	0	0	(490)	490	0	306	490	0
(33) DEF. CHG. - Financing	2,569	0	0	(1,582)	1,582	0	988	1,582	0
(34) DEF. CHG. - Tax	1,186	0	0	(730)	730	0	456	730	0
(35) DEF. CHG. - Pension	569	911	0	0	0	0	569	911	0
(36) DEF. CHG. - Other	194	0	0	(120)	120	0	75	120	0
(37) DEF. CR. - ARO Trans.	(3,786)	0	0	2,331	(2,331)	0	(1,455)	(2,331)	0
(38) SUB-TOTAL	2,104	1,833	0	(590)	590	0	1,513	2,424	0
(39) TOTAL TRANS. < 138kV	99,253	1,833	0	(60,395)	60,395	0	38,857	62,228	0

NOVA SCOTIA POWER INC.

CLASSIFICATION OF AVERAGE RATE BASE

FOR THE YEAR ENDING DECEMBER 31, 2012

(IN THOUSANDS OF DOLLARS)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	INITIAL R/B CLASSIFICATION			**FURTHER CLASSIFICATION**			**FULLY CLASSIFIED RATE BASE**		
	DEMAND PLANT	**ENERGY PLANT**	**CUSTOMER PLANT**	**DEMAND PLANT**	**ENERGY PLANT**	**CUSTOMER PLANT**	**DEMAND PLANT**	**ENERGY PLANT**	**CUSTOMER PLANT**
(1) TRANSMISSION PLANT > 69kV	295,386	0	0	(181,839)	181,839	0	113,546	181,839	0
(2) GENERAL PROPERTY PLANT	22,632	0	0	(13,932)	13,932	0	8,700	13,932	0
(3) TOTAL PLANT IN SERVICE	318,018	0	0	(195,772)	195,772	0	122,246	195,772	0
Working Capital & Deferred Charges/Credits:									
(4) CASH - FUEL	0	0	0	0	0	0	0	0	0
(5) CASH - OTHER	1,829	2,929	0	0	0	0	1,829	2,929	0
(6) MAT. & SUPPLIES - FUEL	0	0	0	0	0	0	0	0	0
(7) MAT. & SUPPLIES - OTHER	2,606	0	0	(1,604)	1,604	0	1,002	1,604	0
(8) DEF. CHG. - Financing	8,410	0	0	(5,177)	5,177	0	3,233	5,177	0
(9) DEF. CHG. - Tax	3,882	0	0	(2,390)	2,390	0	1,492	2,390	0
(10) DEF. CHG. - Pension	1,807	2,894	0	0	0	0	1,807	2,894	0
(11) DEF. CHG. - Other	636	0	0	(391)	391	0	244	391	0
(12) DEF. CR. - ARO Trans	(12,394)	0	0	7,630	(7,630)	0	(4,764)	(7,630)	0
(13) SUB-TOTAL	6,776	5,823	0	(1,933)	1,933	0	4,843	7,756	0
(14) TOTAL TRANS. > 69kV	324,793	5,823	0	(197,705)	197,705	0	127,089	203,527	0
(15) TOTAL TRANSMISSION FUNCTION	$424,046	$7,656	$0	($258,100)	$258,100	$0	$165,946	$265,756	$0

NOVA SCOTIA POWER INC.

CLASSIFICATION OF AVERAGE RATE BASE

FOR THE YEAR ENDING DECEMBER 31, 2012

(IN THOUSANDS OF DOLLARS)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	INITIAL R/B CLASSIFICATION			FURTHER CLASSIFICATION			FULLY CLASSIFIED RATE BASE		
	DEMAND PLANT	ENERGY PLANT	CUSTOMER PLANT	DEMAND PLANT	ENERGY PLANT	CUSTOMER PLANT	DEMAND PLANT	ENERGY PLANT	CUSTOMER PLANT
DISTRIBUTION FUNCTION									
DISTRIBUTION PLANT:									
(1) LAND	$3,121	$0	$1,458	$0	$0	$0	$3,121	$0	$1,458
(2) EASEMENTS & SURVEY	9,867	0	4,612	0	0	0	9,867	0	4,612
(3) OTHER	1,239	0	579	0	0	0	1,239	0	579
(4) SUBSTATIONS	26,756	0	0	0	0	0	26,756	0	0
(5) POLES & FIXTURES	102,822	0	55,365	0	0	0	102,822	0	55,365
(6) O.H. LINES	69,412	0	37,376	0	0	0	69,412	0	37,376
(7) U.G. LINES	21,524	0	11,590	0	0	0	21,524	0	11,590
(8) LINE TRANSFORMERS	141,297	0	0	0	0	0	141,297	0	0
(9) SERVICES	0	0	57,592	0	0	0	0	0	57,592
(10) METERS	0	0	23,330	0	0	0	0	0	23,330
(11) STREET LIGHTING	21,981	0	0	0	0	0	21,981	0	0
(12) TOTAL DISTRIBUTION PLANT	398,019	0	191,902	0	0	0	398,019	0	191,902
(13) GENERAL PROPERTY PLANT	30,496	0	14,703	0	0	0	30,496	0	14,703
(14) TOTAL PLANT IN SERVICE	428,514	0	206,605	0	0	0	428,514	0	206,605
Working Capital & Deferred Charges/Credits:									
(15) CASH - FUEL	0	0	0	0	0	0	0	0	0
(16) CASH - OTHER	11,171	0	14,112	0	0	0	11,171	0	14,112
(17) MAT. & SUPPLIES - FUEL	0	0	0	0	0	0	0	0	0
(18) MAT. & SUPPLIES - OTHER	3,511	0	1,693	0	0	0	3,511	0	1,693
(19) DEF. CHG. - Financing	11,332	0	5,464	0	0	0	11,332	0	5,464
(20) DEF. CHG. - Tax	5,231	0	2,522	0	0	0	5,231	0	2,522
(21) DEF. CHG. - Pension	11,039	0	13,945	0	0	0	11,039	0	13,945
(22) DEF. CHG. - Other	857	0	413	0	0	0	857	0	413
(23) SUB-TOTAL	43,140	0	38,149	0	0	0	43,140	0	38,149
(24) TOTAL DISTRIBUTION FUNCTION	$471,654	$0	$244,754	$0	$0	$0	$471,654	$0	$244,754
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	**$2,783,232**	**$586,208**	**$244,754**	**($1,420,495)**	**$1,420,495**	**$0**	**$1,362,737**	**$2,006,703**	**$244,754**

NOVA SCOTIA POWER INC.
ALLOCATION OF AVERAGE RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2012
(IN THOUSANDS OF DOLLARS)

DEMAND CLASSIFICATION

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
GENERATION FUNCTION												
(1) STEAM PLANT	$472,326	$248,497	$11,011	$97,210	$11,497	$7,602	$14,826	$22,890	$44,766	$8,876	$5,150	D-3A
(2) HYDRO PLANT	120,253	63,267	2,803	24,749	2,927	1,936	3,775	5,828	11,397	2,260	1,311	D-3A
(3) WIND PLANT	40,094	21,094	935	8,252	976	645	1,259	1,943	3,800	753	437	D-3A
(4) LM6000 PLANT	24,182	12,723	564	4,977	589	389	759	1,172	2,292	454	264	D-3A
(5) GAS TURBINE PLANT - OTHER	11,102	5,841	259	2,285	270	179	348	538	1,052	209	121	D-3A
(6) TOTAL GENERATION PLANT	667,957	351,421	15,571	137,473	16,260	10,751	20,967	32,371	63,307	12,553	7,283	
(7) GEN. PROPERTY PLANT	51,178	26,925	1,193	10,533	1,246	824	1,606	2,480	4,851	962	558	P-7
(8) TOTAL PLANT IN SERVICE	719,135	378,347	16,764	148,006	17,505	11,575	22,574	34,851	68,158	13,514	7,841	
Working Capital & Deferred Charges/Credits:												
(9) CASH - FUEL	0	0	0	0	0	0	0	0	0	0	0	D-3A
(10) CASH - OTHER	7,406	3,896	173	1,524	180	119	232	359	702	139	81	O-1
(11) MAT. & SUPPLIES - FUEL	0	0	0	0	0	0	0	0	0	0	0	D-3A
(12) MAT. & SUPPLIES - OTHER	5,892	3,100	137	1,213	143	95	185	286	558	111	64	P-7
(13) DEF. CHG. - Financing	19,017	10,005	443	3,914	463	306	597	922	1,802	357	207	P-7
(14) DEF. CHG. - Tax	8,779	4,619	205	1,807	214	141	276	425	832	165	96	P-7
(15) DEF. CHG. - Pension	7,318	3,850	171	1,506	178	118	230	355	694	138	80	O-1
(16) DEF. CHG. - Steam Assets	0	0	0	0	0	0	0	0	0	0	0	D-3A
(17) DEF. CHG. - Fuel Deferral	0	0	0	0	0	0	0	0	0	0	0	D-3A
(18) DEF. CHG. - Other	1,438	757	34	296	35	23	45	70	136	27	16	P-7
(19) DEF. CR. - ARO Steam	(29,431)	(15,484)	(686)	(6,057)	(716)	(474)	(924)	(1,426)	(2,789)	(553)	(321)	D-3A
(20) DEF. CR. - ARO Hydro	(6,459)	(3,398)	(151)	(1,329)	(157)	(104)	(203)	(313)	(612)	(121)	(70)	D-3A
(21) DEF. CR. - ARO CT	(7,270)	(3,825)	(169)	(1,496)	(177)	(117)	(228)	(352)	(689)	(137)	(79)	D-3A
(22) DEF. CR. - Other	(690)	(363)	(16)	(142)	(17)	(11)	(22)	(33)	(65)	(13)	(8)	D-3A
(23) CONTRACT RECEIVABLE	0	0	0	0	0	0	0	0	0	0	0	D-3A
(24) SUB-TOTAL	6,001	3,157	140	1,235	146	97	188	291	569	113	65	
(25) TOTAL GEN. FUNCTION	725,136	381,504	16,904	149,241	17,651	11,672	22,762	35,142	68,727	13,627	7,906	
TRANSMISSION FUNCTION												
(26) TRANSMISSION PLANT < 138kV	34,686	20,160	893	7,886	933	617	1,203	1,857	0	720	418	D-3B
(26) GEN. PROPERTY PLANT	2,658	1,545	68	604	71	47	92	142	0	55	32	P-8A
(28) TOTAL PLANT IN SERVICE	37,344	21,704	962	8,491	1,004	664	1,295	1,999	0	775	450	
Working Capital & Deferred Charges/Credits:												
(29) CASH - FUEL	0	0	0	0	0	0	0	0	0	0	0	D-3B
(30) CASH - OTHER	576	335	15	131	15	10	20	31	0	12	7	O-2A
(31) MAT. & SUPPLIES - FUEL	0	0	0	0	0	0	0	0	0	0	0	D-3B
(32) MAT. & SUPPLIES - OTHER	306	178	8	70	8	5	11	16	0	6	4	P-8A
(33) DEF. CHG. - Financing	988	574	25	225	27	18	34	53	0	21	12	P-8A
(34) DEF. CHG. - Tax	456	265	12	104	12	8	16	24	0	9	5	P-8A
(35) DEF. CHG. - Pension	569	331	15	129	15	10	20	30	0	12	7	O-2A
(36) DEF. CHG. - Other	75	43	2	17	2	1	3	4	0	2	1	P-8A
(37) DEF. CR. - ARO Trans.	(1,455)	(846)	(37)	(331)	(39)	(26)	(50)	(78)	0	(30)	(18)	D-3B
(38) SUB-TOTAL	1,513	880	39	344	41	27	52	81	0	31	18	
(39) TOTAL TRANS. < 138kV	38,857	22,584	1,001	8,835	1,045	691	1,347	2,080	0	807	468	

NOVA SCOTIA POWER INC.

ALLOCATION OF AVERAGE RATE BASE

FOR THE YEAR ENDING DECEMBER 31, 2012
(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
(1) TRANSMISSION PLANT > 69kV	113,546	59,738	2,647	23,369	2,764	1,828	3,564	5,503	10,762	2,134	1,238	D-3A
(2) GENERAL PROPERTY PLANT	8,700	4,577	203	1,790	212	140	273	422	825	163	95	P-8B
(3) TOTAL PLANT IN SERVICE	122,246	64,315	2,850	25,160	2,976	1,968	3,837	5,924	11,586	2,297	1,333	
Working Capital & Deferred Charges/Credits:												
(4) CASH - FUEL	0	0	0	0	0	0	0	0	0	0	0	D-3A
(5) CASH - OTHER	1,829	962	43	376	45	29	57	89	173	34	20	O-2B
(6) MAT. & SUPPLIES - FUEL	0	0	0	0	0	0	0	0	0	0	0	D-3A
(7) MAT. & SUPPLIES - OTHER	1,002	527	23	206	24	16	31	49	95	19	11	P-8B
(8) DEF. CHG. - Financing	3,233	1,701	75	665	79	52	101	157	306	61	35	P-8B
(9) DEF. CHG. - Tax	1,492	785	35	307	36	24	47	72	141	28	16	P-8B
(10) DEF. CHG. - Pension	1,807	951	42	372	44	29	57	88	171	34	20	O-2B
(11) DEF. CHG. - Other	244	129	6	50	6	4	8	12	23	5	3	P-8B
(12) DEF. CR. - ARO Trans	(4,764)	(2,507)	(111)	(981)	(116)	(77)	(150)	(231)	(452)	(90)	(52)	D-3A
(13) SUB-TOTAL	4,843	2,548	113	997	118	78	152	235	459	91	53	
(14) TOTAL TRANS. > 69kV	127,089	66,863	2,963	26,156	3,094	2,046	3,989	6,159	12,045	2,388	1,386	
(14) TOTAL TRANS. FUNCTION	165,946	89,447	3,963	34,991	4,139	2,737	5,337	8,239	12,045	3,195	1,854	
DISTRIBUTION FUNCTION												
(15) DISTRIBUTION PLANT - Non Street	375,487	237,879	10,086	98,665	5,752	9,950	7,302	402	45	30	5,376	EXH. 3A
(16) DISTRIBUTION PLANT - Streetlight	21,981	0	0	0	0	0	0	0	0	0	21,981	EXH. 3A
	0	0	0	0	0	0	0	0	0	0	0	
(17) SUB-TOTAL	397,468	237,879	10,086	98,665	5,752	9,950	7,302	402	45	30	27,357	
(18) GEN. PROPERTY PLANT	30,496	19,320	819	8,013	467	808	593	33	4	2	437	P-9
	427,963	257,199	10,905	106,678	6,219	10,758	7,895	435	49	32	27,794	
Working Capital & Deferred Charges/Credits:												
(19) CASH - FUEL	0	0	0	0	0	0	0	0	0	0	0	P-9
(20) CASH - OTHER	11,171	5,922	251	2,493	237	255	297	8	1	1	1,706	O-3
(21) MAT. & SUPPLIES - FUEL	0	0	0	0	0	0	0	0	0	0	0	P-9
(22) MAT. & SUPPLIES - OTHER	3,511	2,224	94	923	54	93	68	4	0	0	50	P-9
(23) DEF. CHG. - Financing	11,332	7,179	304	2,978	174	300	220	12	1	1	162	P-9
(24) DEF. CHG. - Tax	5,231	3,314	141	1,375	80	139	102	6	1	0	75	P-9
(25) DEF. CHG. - Pension	11,039	5,852	248	2,464	234	252	294	8	1	1	1,686	O-3
(26) DEF. CHG. - Other	857	543	23	225	13	23	17	1	0	0	12	P-9
(27) SUB-TOTAL	43,140	25,033	1,061	10,457	791	1,061	998	38	4	3	3,692	
(28) TOTAL DIST. FUNCTION	471,103	282,232	11,967	117,135	7,010	11,819	8,893	473	53	35	31,486	
(29) TOTAL DEMAND	**$1,362,186**	**$753,183**	**$32,834**	**$301,366**	**$28,800**	**$26,228**	**$36,992**	**$43,855**	**$80,825**	**$16,857**	**$41,246**	

NOVA SCOTIA POWER INC.
ALLOCATION OF AVERAGE RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2012
(IN THOUSANDS OF DOLLARS)

ENERGY CLASSIFICATION

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) INDUSTRIAL LARGE	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
GENERATION FUNCTION												
(1) STEAM PLANT	$999,154	$395,376	$19,754	$222,104	$34,549	$22,844	$44,592	$80,280	$152,118	$17,015	$10,522	E-1A
(2) HYDRO PLANT	198,575	78,578	3,926	44,142	6,866	4,540	8,862	15,955	30,232	3,382	2,091	E-1A
(3) WIND PLANT	209,171	82,771	4,136	46,497	7,233	4,782	9,335	16,806	31,846	3,562	2,203	E-1A
(4) LM6000 PLANT	38,727	15,325	766	8,609	1,339	885	1,728	3,112	5,896	660	408	E-1A
(5) GAS TURBINE PLANT - OTHER	0	0	0	0	0	0	0	0	0	0	0	E-1A
(6) TOTAL GENERATION PLANT	1,445,627	572,050	28,581	321,352	49,987	33,051	64,519	116,153	220,092	24,619	15,223	
(7) GENERAL PROPERTY PLANT	110,762	43,830	2,190	24,621	3,830	2,532	4,943	8,899	16,863	1,886	1,166	P-10
(8) TOTAL PLANT IN SERVICE	1,556,389	615,879	30,771	345,973	53,817	35,583	69,462	125,053	236,956	26,505	16,390	
Working Capital & Deferred Charges/Credits:												
(9) CASH - FUEL	0	0	0	0	0	0	0	0	0	0	0	E-1A
(10) CASH - OTHER	19,902	7,876	393	4,424	688	455	888	1,599	3,030	339	210	O-4
(11) MAT. & SUPPLIES - FUEL	95,300	37,711	1,884	21,184	3,295	2,179	4,253	7,657	14,509	1,623	1,004	E-1A
(12) MAT. & SUPPLIES - OTHER	12,752	5,046	252	2,835	441	292	569	1,025	1,941	217	134	P-10
(13) DEF. CHG. - Financing	41,158	16,287	814	9,149	1,423	941	1,837	3,307	6,266	701	433	P-10
(14) DEF. CHG. - Tax	19,000	7,518	376	4,223	657	434	848	1,527	2,893	324	200	P-10
(15) DEF. CHG. - Pension	19,667	7,782	389	4,372	680	450	878	1,580	2,994	335	207	O-4
(16) DEF. CHG. - Steam Assets	0	0	0	0	0	0	0	0	0	0	0	E-1A
(17) DEF. CHG. - Fuel Deferral	48,050	19,014	950	10,681	1,661	1,099	2,144	3,861	7,315	818	506	E-1A
(18) DEF. CHG. - Other	3,112	1,231	62	692	108	71	139	250	474	53	33	P-10
(19) DEF. CR. - ARO Steam	(62,257)	(24,636)	(1,231)	(13,839)	(2,153)	(1,423)	(2,779)	(5,002)	(9,479)	(1,060)	(656)	E-1A
(20) DEF. CR. - ARO Hydro	(10,665)	(4,220)	(211)	(2,371)	(369)	(244)	(476)	(857)	(1,624)	(182)	(112)	E-1A
(21) DEF. CR. - ARO CT	0	0	0	0	0	0	0	0	0	0	0	E-1A
(22) DEF. CR. - Other	(1,460)	(578)	(29)	(325)	(50)	(33)	(65)	(117)	(222)	(25)	(15)	E-1A
(23) CONTRACT RECEIVABLE	0	0	0	0	0	0	0	0	0	0	0	E-1A
(24) SUB-TOTAL	184,559	73,032	3,649	41,026	6,382	4,220	8,237	14,829	28,099	3,143	1,944	
(24) TOTAL GEN. FUNCTION	1,740,947	688,911	34,420	386,999	60,198	39,803	77,699	139,882	265,054	29,648	18,333	
TRANSMISSION FUNCTION												
(26) TRANSMISSION PLANT < 138kV	55,549	25,929	1,295	14,566	2,266	1,498	2,924	5,265	0	1,116	690	E-1B
(27) GENERAL PROPERTY PLANT	4,256	1,987	99	1,116	174	115	224	403	0	85	53	P-11A
(28) TOTAL PLANT IN SERVICE	59,805	27,915	1,395	15,682	2,439	1,613	3,148	5,668	0	1,201	743	
Working Capital & Deferred Charges/Credits:												
(29) CASH - FUEL	0	0	0	0	0	0	0	0	0	0	0	E-1B
(30) CASH - OTHER	922	430	22	242	38	25	49	87	0	19	11	O-5A
(31) MAT. & SUPPLIES - FUEL	0	0	0	0	0	0	0	0	0	0	0	E-1B
(32) MAT. & SUPPLIES - OTHER	490	229	11	128	20	13	26	46	0	10	6	P-11A
(33) DEF. CHG. - Financing	1,582	738	37	415	65	43	83	150	0	32	20	P-11A
(34) DEF. CHG. - Tax	730	341	17	191	30	20	38	69	0	15	9	P-11A
(35) DEF. CHG. - Pension	911	425	21	239	37	25	48	86	0	18	11	O-5A
(36) DEF. CHG. - Other	120	56	3	31	5	3	6	11	0	2	1	P-11A
(37) DEF. CR. - ARO Trans.	(2,331)	(1,088)	(54)	(611)	(95)	(63)	(123)	(221)	0	(47)	(29)	E-1B
(38) SUB-TOTAL	2,424	1,131	57	635	99	65	128	230	0	49	30	
(39) TOTAL TRANS. < 138kV	62,228	29,047	1,451	16,317	2,538	1,678	3,276	5,898	0	1,250	773	

NOVA SCOTIA POWER INC.

ALLOCATION OF AVERAGE RATE BASE

FOR THE YEAR ENDING DECEMBER 31, 2012

(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) INDUSTRIAL LARGE	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
(1) TRANSMISSION PLANT > 69kV	181,839	71,956	3,595	40,421	6,288	4,157	8,116	14,610	27,685	3,097	1,915	E-1A
(2) GENERAL PROPERTY PLANT	13,932	5,513	275	3,097	482	319	622	1,119	2,121	237	147	P-11B
(3) TOTAL PLANT IN SERVICE	195,772	77,469	3,871	43,519	6,769	4,476	8,737	15,730	29,806	3,334	2,062	
Working Capital & Deferred Charges/Credits:												
(4) CASH - FUEL	0	0	0	0	0	0	0	0	0	0	0	E-1A
(5) CASH - OTHER	2,929	1,159	58	651	101	67	131	235	446	50	31	O-5B
(6) MAT. & SUPPLIES - FUEL	0	0	0	0	0	0	0	0	0	0	0	E-1A
(7) MAT. & SUPPLIES - OTHER	1,604	635	32	357	55	37	72	129	244	27	17	P-11B
(8) DEF. CHG. - Financing	5,177	2,049	102	1,151	179	118	231	416	788	88	55	P-11B
(9) DEF. CHG. - Tax	2,390	946	47	531	83	55	107	192	364	41	25	P-11B
(10) DEF. CHG. - Pension	2,894	1,145	57	643	100	66	129	233	441	49	30	O-5B
(11) DEF. CHG. - Other	391	155	8	87	14	9	17	31	60	7	4	P-11B
(12) DEF. CR. - ARO Trans	(7,630)	(3,019)	(151)	(1,696)	(264)	(174)	(341)	(613)	(1,162)	(130)	(80)	E-1A
(13) SUB-TOTAL	7,756	3,069	153	1,724	268	177	346	623	1,181	132	82	
(14) TOTAL TRANS. > 69kV	203,527	80,538	4,024	45,243	7,038	4,653	9,083	16,353	30,986	3,466	2,143	
(15) TOTAL TRANS. FUNCTION	265,756	109,585	5,475	61,560	9,576	6,331	12,359	22,251	30,986	4,716	2,916	
(16) TOTAL ENERGY	**$2,006,703**	**$798,495**	**$39,895**	**$448,559**	**$69,774**	**$46,134**	**$90,058**	**$162,132**	**$296,041**	**$34,364**	**$21,250**	

NOVA SCOTIA POWER INC.
ALLOCATION OF AVERAGE RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2012
(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) INDUSTRIAL LARGE	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
CUST. CLASSIFICATION												
DISTRIBUTION FUNCTION												
(1) DISTRIBUTION PLANT	$191,899	$168,130	$8,816	$10,436	$17	$2,139	$185	$62	$3	$6	$2,105	EXH. 3A
(2) GEN. PROPERTY PLANT	14,703	12,882	675	800	1	164	14	5	0	0	161	P-12
(3) TOTAL PLANT IN SERVICE	206,603	181,012	9,491	11,236	18	2,303	199	67	3	6	2,266	
WORKING CAPITAL:												
(4) CASH - FUEL	0	0	0	0	0	0	0	0	0	0	0	P-12
(5) CASH - OTHER	14,112	12,747	668	358	1	72	7	2	0	0	257	O-6
(6) MAT. & SUPPLIES - FUEL	0	0	0	0	0	0	0	0	0	0	0	P-12
(7) MAT. & SUPPLIES - OTHER	1,693	1,483	78	92	0	19	2	1	0	0	19	P-12
(8) DEF. CHG. - Financing	5,464	4,787	251	297	0	61	5	2	0	0	60	P-12
(9) DEF. CHG. - Tax	2,522	2,210	116	137	0	28	2	1	0	0	28	P-12
(10) DEF. CHG. - Pension	13,945	12,596	660	354	1	72	7	2	0	0	254	O-6
(11) DEF. CHG. - Other	413	362	19	22	0	5	0	0	0	0	5	P-12
(12) SUB-TOTAL	38,149	34,185	1,792	1,260	2	256	23	7	0	1	621	
(13) TOTAL DIST. FUNCTION	244,751	215,197	11,283	12,496	20	2,560	222	74	4	7	2,887	
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	**244,751**	**215,197**	**11,283**	**12,496**	**20**	**2,560**	**222**	**74**	**4**	**7**	**2,887**	
(28) TOTAL AVE. RATE BASE	**$3,613,640**	**$1,766,876**	**$84,013**	**$762,421**	**$98,594**	**$74,922**	**$127,272**	**$206,061**	**$376,869**	**$51,228**	**$65,383**	

EXHIBIT 3A

NOVA SCOTIA POWER INC.

ALLOCATION OF AVERAGE DISTRIBUTION RATE BASE

FOR THE YEAR ENDING DECEMBER 31, 2012

(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
DEMAND												
(1) LAND	$3,121	$1,922	$81	$810	$77	$83	$98	$6	$1	$0	$43	P-3
(2) EASEMENTS & SURVEY	9,867	6,076	258	2,560	243	261	309	19	2	1	137	P-3
(3) OTHER	1,239	763	32	321	31	33	39	2	0	0	17	P-3
(4) SUBSTATIONS	26,205	15,467	656	6,624	827	681	1,155	375	42	28	350	EXH 3B
(5) POLES & FIXTURES	102,822	63,719	2,702	26,777	2,427	2,732	3,025	0	0	0	1,440	EXH 3D
(6) O.H. LINES	69,412	43,015	1,824	18,076	1,639	1,844	2,042	0	0	0	972	EXH 3F
(7) U.G. LINES	21,524	13,339	566	5,605	508	572	633	0	0	0	301	P-1
(8) LINE TRANSFORMERS	141,297	93,579	3,968	37,891	0	3,745	0	0	0	0	2,115	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	21,981	0	0	0	0	0	0	0	0	0	21,981	DIRECT
(12) TOTAL DEMAND	397,468	237,879	10,086	98,665	5,752	9,950	7,302	402	45	30	27,357	
CUSTOMER												
(13) LAND	1,458	1,320	69	34	0	7	0	0	0	0	28	P-4
(14) EASEMENTS & SURVEY	4,612	4,175	219	108	0	21	1	0	0	0	87	P-4
(15) OTHER	579	524	27	14	0	3	0	0	0	0	11	P-4
(16) SUBSTATIONS	0	0	0	0	0	0	0	0	0	0	0	---
(17) POLES & FIXTURES	55,365	50,126	2,628	1,294	1	253	11	2	0	0	1,050	EXH 3D
(18) O.H. LINES	37,376	33,839	1,774	874	1	171	7	1	0	0	709	EXH 3F
(19) U.G. LINES	11,589	10,493	550	271	0	53	2	0	0	0	220	P-2
(20) LINE TRANSFORMERS	0	0	0	0	0	0	0	0	0	0	0	---
(21) SERVICES	57,592	47,725	2,502	6,161	0	1,204	0	0	0	0	0	C-2
(22) METERS	23,328	19,928	1,045	1,680	15	429	164	59	3	5	0	EXH 3G
(23) STREET LIGHTING	0	0	0	0	0	0	0	0	0	0	0	---
(24) TOTAL CUSTOMER	$191,899	$168,130	$8,816	$10,436	$17	$2,139	$185	$62	$3	$6	$2,105	
RETAIL												
(25) SERVICES	0	0	0	0	0	0	0	0	0	0	0	---
(26) METERS	0	0	0	0	0	0	0	0	0	0	0	---
(27) TOTAL RETAIL	0	0	0	0	0	0	0	0	0	0	0	
SUMMARY												
(28) LAND	4,579	3,242	151	844	77	89	98	6	1	0	71	P-3 & 4
(29) EASEMENTS & SURVEY	14,479	10,252	477	2,668	243	282	310	19	2	1	225	P-3 & 4
(30) OTHER	1,818	1,287	60	335	31	35	39	2	0	0	28	P-3 & 4
(31) SUBSTATIONS	26,205	15,467	656	6,624	827	681	1,155	375	42	28	350	EXH 3B
(32) POLES & FIXTURES	158,187	113,845	5,330	28,071	2,428	2,985	3,036	2	0	0	2,490	EXH 3D
(33) O.H. LINES	106,788	76,854	3,598	18,950	1,639	2,015	2,049	1	0	0	1,681	EXH 3F
(34) U.G. LINES	33,113	23,832	1,116	5,876	508	625	635	0	0	0	521	P-1 & 2
(35) LINE TRANSFORMERS	141,297	93,579	3,968	37,891	0	3,745	0	0	0	0	2,115	D-1
(36) SERVICES	57,592	47,725	2,502	6,161	0	1,204	0	0	0	0	0	C-2
(37) METERS	23,328	19,928	1,045	1,680	15	429	164	59	3	5	0	EXH 3G
(38) STREET LIGHTING	21,981	0	0	0	0	0	0	0	0	0	21,981	DIRECT
(39) TOTAL AVE. RATE BASE	**$589,367**	**$406,009**	**$18,902**	**$109,100**	**$5,769**	**$12,090**	**$7,487**	**$464**	**$48**	**$36**	**$29,462**	

EXHIBIT 3B

NOVA SCOTIA POWER INC.

ANALYSIS OF AVERAGE DISTRIBUTION SUBSTATION RATE BASE

FOR THE YEAR ENDING DECEMBER 31, 2012

(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	$26,205	$21,392	$506	$4,215	$92
ALLOCATION					
(2) DOMESTIC	15,467	12,921	0	2,546	0
(3) SMALL GENERAL	656	548	0	108	0
(4) GENERAL	6,624	5,510	29	1,086	0
(5) GENERAL LARGE	827	691	0	136	0
(6) SMALL INDUSTRIAL	681	569	0	112	0
(7) MEDIUM INDUSTRIAL	1,155	861	119	170	5
(8) LARGE INDUSTRIAL	375	0	288	0	87
(9) ELI 2P-RTP	42	0	42	0	0
(10) MUNICIPAL	28	0	28	0	0
(11) UNMETERED	350	292	0	58	0
(12) TOTAL	$26,205	$21,392	$506	$4,215	$92
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, 2012

(IN THOUSANDS OF DOLLARS)

	(1) TOTAL PLANT	(2) PRIMARY DEMAND	(3) PRIMARY CUSTOMER	(4) SECONDARY DEMAND	(5) SECONDARY CUSTOMER
(1) TOTAL NET POLE COST	$158,187				
(2) PRIMARY ONLY (30%)	47,456	$47,456	$0	$0	$0
(3) 50% JOINT - PRI. (1)	55,365	27,683	27,683	0	0
(4) 50% JOINT - SEC. (1)	55,365	0	0	27,683	27,683
(5) TOTAL	$158,187	$75,139	$27,683	$27,683	$27,683

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

EXHIBIT 3D

NOVA SCOTIA POWER INC.

ALLOCATION OF AVERAGE POLE INVESTMENT

FOR THE YEAR ENDING DECEMBER 31, 2012

(IN THOUSANDS OF DOLLARS)

	(1) TOTAL PLANT	(2) PRIMARY DEMAND	(3) PRIMARY CUSTOMER	(4) SECONDARY DEMAND	(5) SECONDARY CUSTOMER
(1) DOMESTIC	$113,845	$45,385	$25,057	$18,334	$25,069
(2) SMALL GENERAL	5,330	1,924	1,314	777	1,314
(3) GENERAL	28,071	19,353	647	7,424	647
(4) GENERAL LARGE	2,428	2,427	1	0	0
(5) SMALL INDUSTRIAL	2,985	1,998	126	734	126
(6) MEDIUM INDUSTRIAL	3,036	3,025	11	0	0
(7) LARGE INDUSTRIAL	2	0	2	0	0
(8) ELI 2P-RTP	0	0	0	0	0
(9) MUNICIPAL	0	0	0	0	0
(10) UNMETERED	2,490	1,026	525	414	525
(11) TOTAL	$158,187	$75,139	$27,683	$27,683	$27,683
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, 2012

(IN THOUSANDS OF DOLLARS)

	(1) TOTAL PLANT	(2) PRIMARY DEMAND	(3) PRIMARY CUSTOMER	(4) SECONDARY DEMAND	(5) SECONDARY CUSTOMER
(1) TOTAL NET WIRE COST	$106,788				
(2) PRIMARY ONLY (30%)	32,036	$32,036	$0	$0	$0
(3) 50% JOINT - PRI. (1)	37,376	18,688	18,688	0	0
(4) 50% JOINT - SEC. (1)	37,376	0	0	18,688	18,688
(5) TOTAL	$106,788	$50,724	$18,688	$18,688	$18,688

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

EXHIBIT 3G

NOVA SCOTIA POWER INC.

ANALYSIS OF AVERAGE METER INVESTMENT

FOR THE YEAR ENDING DECEMBER 31, 2012

	(1) TOTAL CUSTOMERS	(2) UNIT METER COST	(3) TOTAL COST	(4) PERCENT	(5) METER COST ($000)
(1) DOMESTIC	449,674	$34.00	$15,288,916	85.42	$19,928
(2) SMALL GENERAL	23,578	34.00	801,652	4.48	1,045
(3) GENERAL	11,611	111.00	1,288,821	7.20	1,680
(4) GENERAL LARGE	18	657.00	11,826	0.07	15
(5) SMALL INDUSTRIAL	2,268	145.00	328,860	1.84	429
(6) MEDIUM INDUSTRIAL	192	657.00	126,144	0.70	164
(7) LARGE INDUSTRIAL	34	1,338.00	45,492	0.25	59
(8) ELI 2P-RTP	2	1,338.00	2,676	0.01	3
(9) MUNICIPAL	8	520.00	4,160	0.02	5
(10) UNMETERED	9,419	N/A	0	0.00	0
(11) TOTAL	496,804		$17,898,547	100.00	$23,328

EXHIBIT 3F

NOVA SCOTIA POWER INC.

ALLOCATION OF AVERAGE WIRE INVESTMENT

FOR THE YEAR ENDING DECEMBER 31, 2012

(IN THOUSANDS OF DOLLARS)

	(1) TOTAL PLANT	(2) PRIMARY DEMAND	(3) PRIMARY CUSTOMER	(4) SECONDARY DEMAND	(5) SECONDARY CUSTOMER
(1) DOMESTIC	$76,854	$30,638	$16,915	$12,377	$16,924
(2) SMALL GENERAL	3,598	1,299	887	525	887
(3) GENERAL	18,950	13,065	437	5,011	437
(4) GENERAL LARGE	1,639	1,639	1	0	0
(5) SMALL INDUSTRIAL	2,015	1,349	85	495	85
(6) MEDIUM INDUSTRIAL	2,049	2,042	7	0	0
(7) LARGE INDUSTRIAL	1	0	1	0	0
(8) ELI 2P-RTP	0	0	0	0	0
(9) MUNICIPAL	0	0	0	0	0
(10) UNMETERED	1,681	692	354	280	354
(11) TOTAL	$106,788	$50,724	$18,688	$18,688	$18,688
ALLOCATION FACTOR		D-2	C-5	D-1	C-4

EXHIBIT 4

NOVA SCOTIA POWER INC.

FUNCTIONALIZATION OF OPERATING EXPENSES

FOR THE YEAR ENDING DECEMBER 31, 2012

(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	$475,459	$458,893	$0	$0	$0	$16,566
PURCHASED POWER:						
(2) REGULAR	52,232	52,232	0	0	0	0
(3) WIND	46,190	46,190	0	0	0	0
(4) THERMAL - OPERATING & MAINT.	82,693	82,007	0	0	0	686
(5) HYDRO - OPERATING & MAINT.	5,215	3,729	0	0	0	1,486
(6) WIND - OPERATING & MAINT.	5,244	5,244	0	0	0	0
(7) LM6000 - OPERATING & MAINT.	397	397	0	0	0	0
(8) COMBUSTION TURBINE - OPER. & MAINT.	921	921	0	0	0	0
(9) ENERGY, FUELS & RISK MGMT.	3,825	3,825	0	0	0	0
(10) GENERATION DEVELOPMENT	0	0	0	0	0	0
(11) TOTAL PRODUCTION OPER. & MAINT.	98,296	96,124	0	0	0	2,172
CUSTOMER OPERATIONS:						
(12) TRANSMISSION & DISTRIBUTION	51,377	0	16,133	34,869	0	375
CUST. SERV. / MARKETING & SALES:						
(13) Qty. Ass., Comm., Call Ctr. & Rev. Ops.	32,459	0	0	374	32,085	0
OTHER OPERATING						
CORPORATE GROUPS:						
(14) EXECUTIVE MANAGEMENT	1,254	451	138	326	339	0
(15) CORP. SECRETARY & LEGAL SERVICES	8,485	3,055	933	2,206	2,291	0
(16) EXTERNAL RELATIONS & ENVIRONMENT	2,211	796	243	575	597	0
(17) REGULATORY AFFAIRS	5,859	2,109	645	1,523	1,582	0
(18) FINANCE GROUP	5,959	2,145	656	1,549	1,609	0
(19) ENTERPRISE SERVICES	19,475	5,063	5,258	7,011	2,142	0
(20) HUMAN RESOURCES	5,216	1,408	1,878	574	1,356	0
(21) TECHNICAL & CONSTRUCTION SERVICES	13,524	0	0	13,524	0	0
(22) SUSTAINABILITY	1,974	1,974	0	0	0	0
(23) SUB-TOTAL	63,958	17,003	9,751	27,289	9,916	0
(24) OTHER EXPENSES	2,378	856	262	618	642	0
(25) DIRECT ADMIN. & GEN. EXPENSE	0	(485)	(148)	(350)	(364)	1,347
(26) TOTAL OM&G EXPENSES	**248,468**	**113,497**	**25,997**	**62,799**	**42,279**	**3,894**
(27) COGS (NET OF SALES)	(620)	0	0	0	(620)	0
(28) DSM AMORTIZATION	0	0	0	0	0	0
(29) GRANTS IN LIEU OF TAXES	36,400	24,905	4,544	6,951	0	0
DEPRECIATION:						
(30) STEAM	58,243	58,243	0	0	0	0
(31) HYDRO	9,539	8,823	0	0	0	716
(32) WIND	8,223	8,223	0	0	0	0
(33) LM6000	2,001	2,001	0	0	0	0
(34) OTHER GAS TURBINE	1,197	1,197	0	0	0	0
(35) TRANSMISSION < 138kV	4,428	0	4,428	0	0	0
(36) TRANSMISSION > 69kV	14,497	0	14,497	0	0	0
(37) DISTRIBUTION - Non Streetlight Related	44,551	0	0	44,551	0	0
(38) DISTRIBUTION - Streetlight Related	2,872	0	0	2,189	0	683
(39) GENERAL PROPERTY	32,443	22,198	4,050	6,196	0	0
(40) INTEREST NET	121,500	81,622	14,288	23,712	0	1,878
(41) PREFERRED DIVIDENDS	8,000	5,446	953	1,582	0	19
(42) CORPORATE TAXES	40,700	27,821	4,870	8,082	0	(73)
(43) TOTAL EXPENSES	**$1,206,323**	**$911,291**	**$73,628**	**$156,062**	**$41,659**	**$23,683**
(44) NON-OPERATING REVENUE:						
(45) EXPORT SALES	(961)	(961)	0	0	0	0
(46) LATE PAYMENT CHARGE	(4,933)	0	0	0	(4,933)	0
(47) MISC. ELECTRIC	(1,758)	0	0	0	(1,758)	0
(48) OTHER REVENUE	(7,098)	(5,469)	(442)	(937)	(250)	0
(49) NET INCOME	130,457	85,542	15,078	25,022	0	4,814
(50) TOTAL NET EXPENSES	**$1,322,031**	**$990,403**	**$88,264**	**$180,148**	**$34,719**	**$28,497**

NOVA SCOTIA POWER INC.
FUNCTIONALIZATION OF OPERATING EXPENSES
FOR THE YEAR ENDING DECEMBER 31, 2012
(IN THOUSANDS OF DOLLARS)

	(1) TOTAL EXPENSES	(2) PROD. EXPENSES	(3) TRANS. EXPENSES	(4) DIST. EXPENSES	(6) RETAIL EXPENSES	(8) DIRECT EXPENSES
(1) FUEL	$475,459	$458,893	$0	$0	$0	$16,566
PURCHASED POWER:						
(3) REGULAR	52,232	52,232	0	0	0	0
(4) WIND	46,190	46,190	0	0	0	0
(3) TOTAL	573,882	557,315	0	0	0	16,566
POWER PRODUCTION						
(4) THERMAL OPERATING & MAINT.	82,693	82,007	0	0	0	686
(5) HYDRO OPERATING & MAINT.	5,215	3,729	0	0	0	1,486
(6) WIND - OPERATING & MAINT.	5,244	5,244	0	0	0	0
(6) LM6000 OPERATING & MAINT.	397	397	0	0	0	0
(7) COMBUSTION TURBINE - OPER. & MAINT.	921	921	0	0	0	0
(8) FUEL PROCUREMENT	3,825	3,825	0	0	0	0
(9) GENERATION DEVELOPMENT	0	0	0	0	0	0
TOTAL POWER PRODUCTION	98,296	96,124	0	0	0	2,172
SUSTAINABILITY	1,974	1,974	0	0	0	0
CORPORATE GROUPS						
EXECUTIVE MANAGEMENT	1,254	451	138	326	339	0
CORP. SECRETARY	7,414	2,669	816	1,928	2,002	0
LEGAL SERVICES	1,071	386	118	278	289	0
EXTERNAL RELATIONS	2,211	796	243	575	597	0
ENVIRONMENTAL POLICIES & PROGRAMS	0	0	0	0	0	0
	11,950	4,302	1,315	3,107	3,227	0
CUSTOMER OPERATIONS						
TRANSMISSION & DISTRIBUTION:						
TRANSMISSION:						
< 138kV	3,863	0	3,863	0	0	0
> 69kV	12,645	0	12,270	0	0	375
DISTRIBUTION:						
SUBSTATIONS	1,307	0	0	1,307	0	0
OVERHEAD LINES	24,067	0	0	24,067	0	0
UNDERGROUND LINES	1,116	0	0	1,116	0	0
LINE TRANSFORMERS	870	0	0	870	0	0
METERS (Meter Shop Only)	0	0	0	0	0	0
COMMUNICATIONS	3,841	0	0	3,841	0	0
STREET LIGHTING	3,668	0	0	3,668	0	0
TOTAL DISTRIBUTION	34,869	0	0	34,869	0	0
TOTAL CUSTOMER OPERATIONS - T & D	51,377	0	16,133	34,869	0	375
TECHNICAL & CONSTRUCTION SERVICES	13,524	0	0	13,524	0	0
CUST. SERV. / MARKETING & SALES						
ADMINISTRATION:						
CUSTOMER SERVICE - ADMIN.	1,259	0	0	0	1,259	0
ENERGY EFFICIENCY	420	0	0	0	420	0
CUST. COMM. & QTY ASSURANCE	1,468	0	0	0	1,468	0
CUSTOMER SOLUTIONS	477	0	0	0	477	0
CALL CENTRE:						
(a) CALL CENTRE - CSR's	5,948	0	0	0	5,948	0
(b) CALL CENTRE OPERATIONS	0	0	0	0	0	0
(c) CALL CENTRE - HALIFAX	0	0	0	0	0	0
(d) CALL NETWORK (COLLECTIONS)	596	0	0	0	596	0
(e) ELECTRICAL WIRING INSPECTION	3,953	0	0	0	3,953	0
REVENUE OPERATIONS:						
(a) BILLING SERVICES	3,541	0	0	0	3,541	0
(b) METER DATA SERVICES	610	0	0	0	610	0
(c) METER SERVICES - METER SHOP	374	0	0	374	0	0
(d) METER SERVICES - FIELD	5,965	0	0	0	5,965	0
(e) ELECTRICAL WIRING INSPECTION - FIELD	2,376	0	0	0	2,376	0
(f) PAYMENT SERVICES	475	0	0	0	475	0
(g) CREDIT SERVICES	0	0	0	0	0	0
(h) BAD DEBT EXPENSE	3,504	0	0	0	3,504	0
(i) MARKETING & SALES	1,275	0	0	0	1,275	0
(j) ELECTRICAL WIRING INSPECTION - H/O	219	0	0	0	219	0
TOTAL CUST. SERV. / MARKETING & SALES	32,459	0	0	374	32,085	0

NOVA SCOTIA POWER INC.
FUNCTIONALIZATION OF OPERATING EXPENSES
FOR THE YEAR ENDING DECEMBER 31, 2012
(IN THOUSANDS OF DOLLARS)

	(1) TOTAL EXPENSES	(2) PROD. EXPENSES	(3) TRANS. EXPENSES	(4) DIST. EXPENSES	(6) RETAIL EXPENSES	(8) DIRECT EXPENSES
REGULATORY AFFAIRS	$5,859	$2,109	$645	$1,523	$1,582	$0
FINANCE GROUP						
INTERNAL AUDIT	1,451	522	160	377	392	0
INVESTOR RELATIONS	275	99	30	72	74	0
DIRECTOR FINANCE	508	183	56	132	137	0
TREASURER	1,010	364	111	263	273	0
CORPORATE TAX	463	167	51	120	125	0
GM FINANCE	0	0	0	0	0	0
CORPORATE CONTROLLER	2,252	811	248	586	608	0
CORP. PERFORMANCE & BACK OFFICE	0	0	0	0	0	0
TOTAL FINANCE	5,959	2,145	656	1,549	1,609	0
ENTERPRISE SERVICES						
PROCUREMENT & FACILITIES	8,965	2,331	2,420	3,227	986	0
INFORMATION TECHNOLOGY	10,510	2,733	2,838	3,784	1,156	0
TOTAL ENTERPRISE SERVICES	19,475	5,063	5,258	7,011	2,142	0
HUMAN RESOURCES						
--HUMAN RESOURCES	5,216	1,408	1,878	574	1,356	0
OTHER EXPENSES	2,378	856	262	618	642	0
DIRECT ADM. & GEN. EXPENSE	0	(485)	(148)	(350)	(364)	1,347
TOTAL DIVISIONAL EXPENSES	**248,468**	**113,497**	**25,997**	**62,799**	**42,279**	**3,894**
COGS (NET OF RETAIL SALES)	**(620)**	**0**	**0**	**0**	**(620)**	**0**
DSM EXPENSES	**0**	**0**	**0**	**0**	**0**	**0**
OTHER EXPENSES	**0**	**0**	**0**	**0**	**0**	**0**
CAPITAL RELATED EXPENSES						
GRANTS IN LIEU OF TAXES	36,400	24,905	4,544	6,951	0	0
DEPRECIATION :						
STEAM	58,243	58,243	0	0	0	0
HYDRO	9,539	8,823	0	0	0	716
WIND	8,223	8,223	0	0	0	0
LM6000	2,001	2,001	0	0	0	0
GAS TURBINE - OTHER	1,197	1,197	0	0	0	0
TRANSMISSION < 138kV	4,428	0	4,428	0	0	0
TRANSMISSION > 69kV	14,497	0	14,497	0	0	0
DISTRIBUTION - Non Streetlight Related	44,551	0	0	44,551	0	0
DISTRIBUTION - Streetlight Related	2,872	0	0	2,189	0	683
GENERAL PROPERTY	32,443	22,198	4,050	6,196	0	0
GLACE BAY WRITE-OFF	0	0	0	0	0	0
INTEREST NET	121,500	81,622	14,288	23,712	0	1,878
PREFERRED DIVIDENDS	8,000	5,446	953	1,582	0	19
CORPORATE TAXES	40,700	27,821	4,870	8,082	0	(73)
TOTAL OPERATING EXPENSES	**1,206,323**	**911,291**	**73,628**	**156,062**	**41,659**	**23,683**
NON-OPERATING REVENUE:						
GREEN POWER SURCHARGE	0	0	0	0	0	0
EXPORT SALES	(961)	(961)	0	0	0	0
LATE PAYMENT CHARGE	(4,933)	0	0	0	(4,933)	0
MISC. ELECTRIC	(1,758)	0	0	0	(1,758)	0
OTHER REVENUE	(7,098)	(5,469)	(442)	(937)	(250)	0
PROFIT/LOSS	130,457	85,542	15,078	25,022	0	4,814
TOTAL NET EXPENSES	**$1,322,031**	**$990,403**	**$88,264**	**$180,148**	**$34,719**	**$28,497**

NOVA SCOTIA POWER INC.

CLASSIFICATION OF OPERATING EXPENSES

FOR THE YEAR ENDING DECEMBER 31, 2012
(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DEMAND EXPENSES	(3) ENERGY EXPENSES	(4) CUSTOMER EXPENSES
GENERATION FUNCTION				
(1) FUEL	$458,893	$0	$458,893	$0
(2) PURCHASED PWR REG - FIXED	23,505	7,428	16,076	0
(3) PURCHASED PWR REG - VAR.	28,728	0	28,728	0
(4) PURCHASED PWR WIND - FIXED	13,857	4,157	9,700	0
(5) PURCHASED PWR WIND - VAR.	32,333	0	32,333	0
(6) OPER. & MAINT. - STEAM	100,842	26,770	74,072	0
(7) OPER. & MAINT. - HYDRO	11,034	2,929	8,105	0
(8) OPER. & MAINT. - LM6000	489	130	359	0
(9) OPER. & MAINT. - OTHER CT's	1,133	951	181	0
(10) DSM AMORTIZATION	0	0	0	0
(11) GRANTS IN LIEU OF TAXES	24,905	7,871	17,034	0
DEPRECIATION:				
(12) STEAM	58,243	18,695	39,548	0
(13) HYDRO	8,823	3,328	5,495	0
(14) WIND	8,223	1,323	6,900	0
(15) LM6000	2,001	769	1,232	0
(16) GAS TURBINE - OTHER	1,197	1,197	0	0
(17) GENERAL PROPERTY	22,198	7,015	15,182	0
(18) INTEREST NET OF AFUDC	81,622	24,000	57,622	0
(19) PREFERRED DIVIDENDS	5,446	1,601	3,844	0
(20) CORPORATE TAXES	27,821	8,181	19,640	0
NON-OPERATING REVENUE:				
(21) EXPORT SALES	(961)	0	(961)	0
(22) OTHER REVENUE	(5,469)	(698)	(4,771)	0
(23) RETURN (PROFIT/LOSS)	85,542	25,153	60,389	0
(24) TOTAL GENERATION	**990,403**	**140,800**	**849,602**	**0**
	990,403			
TRANSMISSION FUNCTION				
Transmission < 138kV:				
(25) O&M < 138kV	6,225	2,393	3,832	0
(26) GRANTS IN LIEU OF TAXES	1,064	409	655	0
DEPRECIATION:				
(27) TRANSMISSION	4,428	1,702	2,726	0
(28) GENERAL PROPERTY	948	364	583	0
(29) INTEREST NET OF AFUDC	3,346	1,286	2,060	0
(30) PREFERRED DIVIDENDS	223	86	137	0
(31) CORPORATE TAXES	1,140	438	702	0
NON-OPERATING REVENUE:				
(32) OTHER REVENUE	(103)	(40)	(64)	0
(33) RETURN (PROFIT/LOSS)	3,531	1,357	2,173	0
(34) TOTAL < 138kV	**20,801**	**7,996**	**12,805**	**0**

EXHIBIT 5
Page 2 of 3

NOVA SCOTIA POWER INC.

CLASSIFICATION OF OPERATING EXPENSES

FOR THE YEAR ENDING DECEMBER 31, 2012
(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DEMAND EXPENSES	(3) ENERGY EXPENSES	(4) CUSTOMER EXPENSES
Transmission > 69kV:				
(1) O&M > 69kV	19,773	7,601	12,172	0
(2) GRANTS IN LIEU OF TAXES	3,480	1,338	2,142	0
DEPRECIATION:				
(3) TRANSMISSION	14,497	5,573	8,924	0
(4) GENERAL PROPERTY	3,102	1,192	1,910	0
(5) INTEREST NET OF AFUDC	10,943	4,206	6,736	0
(6) PREFERRED DIVIDENDS	730	281	449	0
(7) CORPORATE TAXES	3,730	1,434	2,296	0
NON-OPERATING REVENUE:				
(8) OTHER REVENUE	(338)	(130)	(208)	0
(9) RETURN (PROFIT/LOSS)	11,548	4,439	7,109	0
(10) TOTAL > 69kV	**67,463**	**25,933**	**41,530**	**0**
(11) TOTAL TRANSMISSION	**$88,264**	**$33,929**	**$54,336**	**$0**

88,264

EXHIBIT 5
Page 3 of 3

NOVA SCOTIA POWER INC.
CLASSIFICATION OF OPERATING EXPENSES
FOR THE YEAR ENDING DECEMBER 31, 2012
(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DEMAND EXPENSES	(3) ENERGY EXPENSES	(4) CUSTOMER EXPENSES
DISTRIBUTION FUNCTION				
BEFORE STREETLIGHTS				
(1) SUBSTATIONS	$2,329	$2,329	$0	$0
(2) OVERHEAD LINES	42,885	27,875	0	15,010
(3) UNDERGROUND LINES	1,989	1,293	0	696
(4) LINE TRANSFORMERS	1,550	1,550	0	0
(5) METERS	667	0	0	667
(6) COMMUNICATIONS	6,845	6,845	0	0
(7) GRANTS IN LIEU OF TAXES	6,738	4,363	0	2,375
DEPRECIATION:				
(8) DISTRIBUTION	44,551	30,058	0	14,492
(9) GENERAL PROPERTY	6,196	4,180	0	2,015
(10) INTEREST NET OF AFUDC	22,984	14,883	0	8,101
(11) PREFERRED DIVIDENDS	1,533	993	0	540
(12) CORPORATE TAXES	7,834	5,073	0	2,761
(13) RETURN (PROFIT/LOSS)	24,255	15,706	0	8,549
STREETLIGHTS				
non-LED				
(14) MAINTENACE	6,536	6,536	0	0
(15) GRANTS IN LIEU OF TAXES	213	213	0	0
(16) DEPRECIATION	2,189	2,189	0	0
(17) INTEREST NET OF AFUDC	728	728	0	0
(18) PREFERRED DIVIDENDS	49	49	0	0
(19) CORPORATE TAXES	248	248	0	0
(20) RETURN (PROFIT/LOSS)	768	768	0	0
Subtotal	10,730	10,730	0	0
(21) OTHER REVENUE	(937)	(657)	0	(280)
(22) TOTAL DISTRIBUTION	**180,148**	**125,222**	**0**	**54,926**
RETAIL FUNCTION				
(23) QTY. ASSURANCE. & COMM.	4,917	0	0	4,917
(24) CALL CENTRE	14,241	0	0	14,241
(25) BILLING SERVICES	4,804	0	0	4,804
(26) ELECT. WIRING INSPECT. - H/O	297	0	0	297
(27) METER DATA SERVICES	827	0	0	827
(28) METER READING - FIELD	8,092	0	0	8,092
(29) ELECT. WIRING INSPECT. - FIELD	3,224	0	0	3,224
(30) PAYMENT SERVICES	644	0	0	644
(31) CREDIT SERVICES	0	0	0	0
(32) BAD DEBT EXPENSE	3,504	0	0	3,504
(33) MARKETING & SALES	1,730	0	0	1,730
(34) COGS (NET OF RETAIL SALES)	(620)	0	0	(620)
(35) GRANTS IN LIEU OF TAXES	0	0	0	0
(36) DEPRECIATION:				
(37) DISTRIBUTION	0	0	0	0
(38) GENERAL PROPERTY	0	0	0	0
(39) INTEREST NET OF AFUDC	0	0	0	0
(40) PREFERRED DIVIDENDS	0	0	0	0
(41) CORPORATE TAXES	0	0	0	0
NON-OPERATING REVENUE:				
(42) LATE PAYMENT CHARGE	(4,933)	0	0	(4,933)
(43) MISC. ELECTRIC	(1,758)	0	0	(1,758)
(44) OTHER REVENUE	(250)	0	0	(250)
(45) RETURN (PROFIT/LOSS)	0	0	0	0
(46) TOTAL RETAIL	**34,719**	**0**	**0**	**34,719**
(47) TOTAL NET EXPENSES	**$1,293,534**	**$299,951**	**$903,938**	**$89,645**

NOVA SCOTIA POWER INC.

ALLOCATION OF OPERATING EXPENSES

FOR THE YEAR ENDING DECEMBER 31, 2012

(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
DEMAND CLASSIFICATION												
	13,857											
GENERATION												
(1) FUEL	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	D-3A
(2) PURCH. POWER REG - FIXED	7,428	3,908	173	1,529	181	120	233	360	704	140	81	D-3A
(3) PURCH. POWER WIND - FIXED	4,157	2,187	97	856	101	67	130	201	394	78	45	D-3A
(4) OPER. & MAINT. - STEAM	26,770	14,084	624	5,510	652	431	840	1,297	2,537	503	292	D-3A
(5) OPER. & MAINT. - HYDRO	2,929	1,541	68	603	71	47	92	142	278	55	32	D-3A
(6) OPER. & MAINT. - LM6000	130	68	3	27	3	2	4	6	12	2	1	D-3A
(7) OPER. & MAINT. - OTHER CT's	951	500	22	196	23	15	30	46	90	18	10	D-3A
(8) DSM AMORTIZATION	0	0	0	0	0	0	0	0	0	0	0	D-3A
(7) GRANTS IN LIEU	7,871	4,141	183	1,620	192	127	247	381	746	148	86	P-7
(8) DEPRECIATION	32,327	17,008	754	6,653	787	520	1,015	1,567	3,064	608	352	EXH 6D
(9) INTEREST NET OF AFUDC	24,000	12,627	559	4,940	584	386	753	1,163	2,275	451	262	P-14
(10) PREFERRED DIVIDENDS	1,601	842	37	330	39	26	50	78	152	30	17	P-14
(11) CORPORATE TAXES	8,181	4,304	191	1,684	199	132	257	396	775	154	89	P-14
NON-OPERATING REVENUE:												
(13) OTHER REVENUE	(698)	(367)	(16)	(144)	(17)	(11)	(22)	(34)	(66)	(13)	(8)	O-8
(14) RETURN (PROFIT/LOSS)	25,153	13,233	586	5,177	612	405	790	1,219	2,384	473	274	P-14
(15) INTERR. RIDER DMD ADJ.	(4,590)	0	0	0	0	0	0	(4,590)	0	0	0	DIRECT
(16) ALLOC. OF INTERR. DMD. ADJ.	4,590	2,773	123	1,085	128	85	165	75	0	99	57	D-4
(17) ELI 2P-RTP DEMAND ADJ.	(13,278)	0	0	0	0	0	0	0	(13,278)	0	0	DIRECT
(18) ALLOC. OF ELI 2P-RTP DMD. ADJ.	13,278	8,021	355	3,138	371	245	479	216	0	287	166	D-4
(19) ELI 2P-RTP PRIORITY DMD ADJ.	(1,992)	0	0	0	0	0	0	0	(1,992)	0	0	DIRECT
(20) ALLOC. OF ELI 2P-RTP PRI. DMD. ADJ.	1,992	1,158	51	453	54	35	69	107	0	41	24	D-3B
(21) TOTAL GENERATION	140,800	86,028	3,812	33,653	3,980	2,632	5,133	2,631	(1,925)	3,073	1,783	
TRANSMISSION												
Transmission < 138kV												
(22) OPERATING & MAINT.	2,393	1,391	62	544	64	43	83	128	0	50	29	D-3B
(23) GRANTS IN LIEU	409	238	11	93	11	7	14	22	0	8	5	P-8A
(24) DEPRECIATION	2,066	1,201	53	470	56	37	72	111	0	43	25	EXH 6D
(25) INTEREST NET OF AFUDC	1,286	747	33	292	35	23	45	69	0	27	15	P-15A
(26) PREFERRED DIVIDENDS	86	50	2	20	2	2	3	5	0	2	1	P-15A
(27) CORPORATE TAXES	438	255	11	100	12	8	15	23	0	9	5	P-15A
NON-OPERATING REVENUE:												
(27) OTHER REVENUE	(40)	(23)	(1)	(9)	(1)	(1)	(1)	(2)	0	(1)	(0)	O-9A
(28) RETURN (PROFIT/LOSS)	1,357	789	35	309	36	24	47	73	0	28	16	P-15A
(29) TOTAL < 138kV	$7,996	$4,647	$206	$1,818	$215	$142	$277	$428	$0	$166	$96	

NOVA SCOTIA POWER INC.

ALLOCATION OF OPERATING EXPENSES

FOR THE YEAR ENDING DECEMBER 31, 2012
(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) ELI 2P-RTP	(9) MUNICIPAL	(10) UNMETERED	(11) ALLOCATION FACTOR
Transmission > 69kV												
(1) OPERATING & MAINT.	7,601	3,999	177	1,564	185	122	239	368	720	143	83	D-3A
(2) GRANTS IN LIEU	1,338	704	31	275	33	22	42	65	127	25	15	P-8B
(3) DEPRECIATION	6,765	3,559	158	1,392	165	109	212	328	641	127	74	EXH 6D
(4) INTEREST NET OF AFUDC	4,206	2,213	98	866	102	68	132	204	399	79	46	P-15B
(5) PREFERRED DIVIDENDS	281	148	7	58	7	5	9	14	27	5	3	P-15B
(6) CORPORATE TAXES	1,434	754	33	295	35	23	45	69	136	27	16	P-15B
NON-OPERATING REVENUE:												
(8) OTHER REVENUE	(130)	(68)	(3)	(27)	(3)	(2)	(4)	(6)	(12)	(2)	(1)	O-9B
(9) RETURN (PROFIT/LOSS)	4,439	2,335	103	914	108	71	139	215	421	83	48	P-15B
(10) TOTAL > 69kV	25,933	13,644	605	5,337	631	417	814	1,257	2,458	487	283	
(11) TOTAL TRANSMISSION	33,929	18,291	810	7,155	846	560	1,091	1,685	2,458	653	379	
DISTRIBUTION												
Non SL												
(12) OPERATING & MAINT.	39,892	24,611	1,044	10,363	983	1,059	1,236	33	4	2	556	EXH 6A
(13) GRANTS IN LIEU	4,363	2,764	117	1,146	67	116	85	5	1	0	62	P-9
(14) DEPRECIATION	34,238	21,691	920	8,997	524	907	666	37	4	3	490	EXH 6D
(15) INTEREST NET OF AFUDC	14,883	9,353	397	3,882	232	392	295	16	2	1	315	P-16
(16) PREFERRED DIVIDENDS	993	624	26	259	15	26	20	1	0	0	21	P-16
(17) CORPORATE TAXES	5,073	3,188	135	1,323	79	134	100	5	1	0	107	P-16
NON-OPERATING REVENUE:												
(18) OTHER REVENUE	(657)	(373)	(16)	(156)	(11)	(16)	(14)	(1)	(0)	(0)	(69)	O-10
(19) RETURN (PROFIT/LOSS)	15,706	9,870	418	4,096	245	413	311	17	2	1	332	P-16
SL												
non-LED												
(20) OPERATING & MAINT.	6,536	0	0	0	0	0	0	0	0	0	6,536	EXH 6A
(21) GRANTS IN LIEU OF TAXES	213	0	0	0	0	0	0	0	0	0	213	P-9A
(22) Depreciation	2,189	0	0	0	0	0	0	0	0	0	2,189	EXH 6D
(23) INTEREST NET OF AFUDC	728	0	0	0	0	0	0	0	0	0	728	P-16B
(23) PREFERRED DIVIDENDS	49	0	0	0	0	0	0	0	0	0	49	P-16B
(25) CORPORATE TAXES	248	0	0	0	0	0	0	0	0	0	248	P-16B
(26) OTHER REVENUE												
(27) RETURN (PROFIT/LOSS)	768	0	0	0	0	0	0	0	0	0	768	P-16B
Subtotal	10,730	0	0	0	0	0	0	0	0	0	10,730	
(28) TOTAL DISTRIBUTION	125,222	71,727	3,041	29,910	2,135	3,030	2,698	113	13	8	12,546	
(29) TOTAL DEMAND	**$299,951**	**$176,046**	**$7,664**	**$70,719**	**$6,962**	**$6,222**	**$8,922**	**$4,429**	**$545**	**$3,735**	**$14,708**	

NOVA SCOTIA POWER INC.

ALLOCATION OF OPERATING EXPENSES

FOR THE YEAR ENDING DECEMBER 31, 2012

(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
ENERGY CLASSIFICATION												
GENERATION												
(1) FUEL	$458,893	$182,348	$9,095	$101,991	$15,821	$10,460	$20,380	$36,648	$69,517	$7,827	$4,807	DIRECT
(3) PURCH. POWER REG - FIXED	16,076	6,362	318	3,574	556	368	717	1,292	2,448	274	169	E-1A
(4) PURCH. POWER REG - VAR.	28,728	11,368	568	6,386	993	657	1,282	2,308	4,374	489	303	E-1A
(5) PURCH. POWER WIND - FIXED	9,700	3,838	192	2,156	335	222	433	779	1,477	165	102	E-1A
(6) PURCH. POWER WIND - VAR.	32,333	12,794	639	7,187	1,118	739	1,443	2,598	4,923	551	340	E-1A
(7) OPER. & MAINT. - STEAM	74,072	29,311	1,464	16,466	2,561	1,694	3,306	5,952	11,277	1,261	780	E-1A
(8) OPER. & MAINT. - HYDRO	8,105	3,207	160	1,802	280	185	362	651	1,234	138	85	E-1A
(9) OPER. & MAINT. - LM6000	359	142	7	80	12	8	16	29	55	6	4	E-1A
(10) OPER. & MAINT. - OTHER CT's	181	72	4	40	6	4	8	15	28	3	2	E-1A
(11) DSM AMORTIZATION	0	0	0	0	0	0	0	0	0	0	0	E-1A
(8) GRANTS IN LIEU	17,034	6,741	337	3,787	589	389	760	1,369	2,593	290	179	P-10
(9) DEPRECIATION	68,358	27,050	1,351	15,195	2,364	1,563	3,051	5,492	10,407	1,164	720	EXH 6D
(10) INTEREST NET OF AFUDC	57,622	22,801	1,139	12,809	1,992	1,317	2,572	4,630	8,773	981	607	P-17
(11) PREFERRED DIVIDENDS	3,844	1,521	76	855	133	88	172	309	585	65	40	P-17
(12) CORPORATE TAXES	19,640	7,772	388	4,366	679	449	877	1,578	2,990	334	207	P-17
NON-OPERATING REVENUE:												
(14) EXPORT SALES	(961)	(380)	(19)	(214)	(33)	(22)	(43)	(77)	(146)	(16)	(10)	EXH 7
(15) OTHER REVENUE	(4,771)	(1,892)	(94)	(1,060)	(165)	(109)	(212)	(382)	(724)	(81)	(50)	O-11
(16) RETURN (PROFIT/LOSS)	60,389	23,897	1,194	13,424	2,088	1,381	2,695	4,852	9,194	1,028	636	P-17
(17) TOTAL GENERATION	849,602	336,951	16,820	188,843	29,331	19,393	37,818	68,042	129,003	14,480	8,922	
TRANSMISSION												
Transmission < 138kV												
(18) OPERATING & MAINT.	3,832	1,789	89	1,005	156	103	202	363	0	77	48	E-1B
(19) GRANTS IN LIEU	655	306	15	172	27	18	34	62	0	13	8	P-11A
(20) DEPRECIATION	3,309	1,545	77	868	135	89	174	314	0	66	41	EXH 6D
(21) INTEREST NET	2,060	961	48	540	84	56	108	195	0	41	26	P-18A
(22) PREFERRED DIVIDENDS	137	64	3	36	6	4	7	13	0	3	2	P-18A
(23) CORPORATE TAXES	702	328	16	184	29	19	37	67	0	14	9	P-18A
NON-OPERATING REVENUE:												
(25) OTHER REVENUE	(64)	(30)	(1)	(17)	(3)	(2)	(3)	(6)	0	(1)	(1)	O-12A
(26) RETURN (PROFIT/LOSS)	2,173	1,015	51	570	89	59	114	206	0	44	27	P-18A
(27) TOTAL < 138kV	12,805	5,977	299	3,358	522	345	674	1,214	0	257	159	
Transmission > 69kV												
(28) OPERATING & MAINT.	12,172	4,817	241	2,706	421	278	543	978	1,853	207	128	E-1A
(29) GRANTS IN LIEU	2,142	848	42	476	74	49	96	172	326	36	23	P-11B
(30) DEPRECIATION	10,834	4,287	214	2,408	375	248	484	870	1,649	185	114	EXH 6D
(31) INTEREST NET	6,736	2,666	133	1,497	233	154	301	541	1,026	115	71	P-18B
(32) PREFERRED DIVIDENDS	449	178	9	100	16	10	20	36	68	8	5	P-18B
(33) CORPORATE TAXES	2,296	909	45	510	79	52	102	184	350	39	24	P-18B
NON-OPERATING REVENUE:												
(35) OTHER REVENUE	(208)	(82)	(4)	(46)	(7)	(5)	(9)	(17)	(32)	(4)	(2)	O-12B
(36) RETURN (PROFIT/LOSS)	7,109	2,813	141	1,580	246	163	317	571	1,082	121	75	P-18B
(37) TOTAL > 69kV	41,530	16,434	821	9,232	1,436	950	1,854	3,337	6,323	707	437	
(38) TOTAL TRANSMISSION	54,336	22,411	1,120	12,590	1,958	1,295	2,528	4,551	6,323	964	596	
(39) TOTAL ENERGY	**$903,938**	**$359,362**	**$17,939**	**$201,432**	**$31,289**	**$20,688**	**$40,345**	**$72,593**	**$135,326**	**$15,445**	**$9,518**	

NOVA SCOTIA POWER INC.
ALLOCATION OF OPERATING EXPENSES
FOR THE YEAR ENDING DECEMBER 31, 2012
(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
CUST. CLASSIFICATION												
DISTRIBUTION												
(1) OPERATING & MAINT.	$16,372	$14,789	$775	$415	$1	$84	$8	$2	$0	$0	$298	EXH 6A
(2) GRANTS IN LIEU	2,375	2,081	109	129	0	26	2	1	0	0	26	P-12
(3) DEPRECIATION	16,508	14,463	758	898	1	184	16	5	0	0	181	EXH 6D
(4) INTEREST NET OF AFUDC	8,101	7,123	373	414	1	85	7	2	0	0	96	P-19
(5) PREFERRED DIVIDENDS	540	475	25	28	0	6	0	0	0	0	6	P-19
(6) CORPORATE TAXES	2,761	2,428	127	141	0	29	3	1	0	0	33	P-19
NON-OPERATING REVENUE:												
(8) OTHER REVENUE	(280)	(248)	(13)	(12)	(0)	(2)	(0)	(0)	(0)	(0)	(4)	O-13
(9) RETURN (PROFIT/LOSS)	8,549	7,516	394	436	1	89	8	3	0	0	101	P-19
(10) TOTAL DISTRIBUTION	54,926	48,627	2,550	2,449	4	501	44	14	1	1	736	
RETAIL												
(11) METER READING & ELECTRIC INSPEC	11,316	9,482	502	926	26	181	71	50	3	12	63	EXH 6A
(12) CUST. SERV. - H/O	4,917	4,437	240	118	0	23	2	0	0	0	96	C-7
(13) CALL CENTRE	14,241	11,407	598	1,473	46	288	122	86	5	20	196	C-3
(14) BILLING SERVICES	4,804	4,335	235	116	0	23	2	0	0	0	94	C-3
(15) ELECT. WIRING INSP. - H/O	297	268	14	7	0	1	0	0	0	0	6	C-7
(16) METER DATA SERVICES	827	37	36	86	112	86	86	161	136	86	0	O-16
(17) PAYMENT SERVICES	644	581	31	16	0	3	0	0	0	0	13	C-7
(18) CREDIT SERVICES	3,504	2,944	50	466	0	45	0	0	0	0	0	EXH 6C
(19) MARKETING & SALES	1,730	656	52	121	26	95	187	284	284	26	0	O-15
(20) COGS (NET OF SALES)	(620)	(560)	(30)	(15)	(0)	(3)	(0)	(0)	(0)	(0)	(12)	C-7
(22) GRANTS IN LIEU	0	0	0	0	0	0	0	0	0	0	0	N/A
(23) DEPRECIATION	0	0	0	0	0	0	0	0	0	0	0	N/A
(24) INTEREST NET OF AFUDC	0	0	0	0	0	0	0	0	0	0	0	N/A
(25) PREFERRED DIVIDENDS	0	0	0	0	0	0	0	0	0	0	0	N/A
(26) CORPORATE TAXES	0	0	0	0	0	0	0	0	0	0	0	N/A
NON-OPERATING REVENUE:												
(28) LATE PAYMENT CHARGE	(4,933)	(3,825)	(117)	(852)	0	(66)	(57)	0	0	0	(16)	EXH 7
(29) MISC. ELECTRIC	(1,758)	(1,631)	(99)	(11)	0	0	0	0	0	0	(15)	EXH 7
(30) OTHER REVENUE	(250)	(199)	(10)	(20)	(2)	(5)	(3)	(4)	(4)	(1)	(3)	O-14
(31) RETURN (PROFIT/LOSS)	0	0	0	0	0	0	0	0	0	0	0	N/A
(32) TOTAL RETAIL	34,719	27,931	1,503	2,430	209	671	410	577	425	143	420	
(33) TOTAL CUSTOMER	89,645	76,558	4,052	4,878	213	1,172	453	592	425	144	1,157	
(34) TOTAL NET EXPENSES	$1,293,534	$611,966	$29,655	$277,030	$38,463	$28,082	$49,721	$77,613	$136,297	$19,324	$25,382	

EXHIBIT 6A

NOVA SCOTIA POWER INC.

ALLOCATION OF DISTRIBUTION OPERATING EXPENSES

FOR THE YEAR ENDING DECEMBER 31, 2012

(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
DEMAND												
(1) SUBSTATIONS	$2,329	$1,375	$58	$589	$74	$61	$103	$33	$4	$2	$31	P-5
(2) OVERHEAD LINES	27,875	17,274	732	7,259	658	741	820	0	0	0	390	P-1
(3) UNDERGROUND LINES	1,293	801	34	337	31	34	38	0	0	0	18	P-1
(4) LINE TRANSFORMERS	1,550	1,027	44	416	0	41	0	0	0	0	23	D-1
(5) METERS	0	0	0	0	0	0	0	0	0	0	0	---
(6) COMMUNICATIONS	6,845	4,134	175	1,763	221	182	276	0	0	0	93	D-2
(7) STREET LIGHTING	6,536	0	0	0	0	0	0	0	0	0	6,536	DIRECT
(8) CUSTOMER SERVICE	0	0	0	0	0	0	0	0	0	0	0	---
(9) TOTAL DEMAND	46,427	24,611	1,044	10,363	983	1,059	1,236	33	4	2	7,092	
CUSTOMER												
(10) SUBSTATIONS	0	0	0	0	0	0	0	0	0	0	0	--
(11) OVERHEAD LINES	15,010	13,589	713	351	0	69	3	1	0	0	285	P-2
(12) UNDERGROUND LINES	696	630	33	16	0	3	0	0	0	0	13	P-2
(13) LINE TRANSFORMERS	0	0	0	0	0	0	0	0	0	0	0	--
(14) METERS	667	569	30	48	0	12	5	2	0	0	0	P-6
(15) COMMUNICATIONS	0	0	0	0	0	0	0	0	0	0	0	--
(16) STREET LIGHTING	0	0	0	0	0	0	0	0	0	0	0	--
(17) CUSTOMER SERVICE	0	0	0	0	0	0	0	0	0	0	0	EXHIBIT 6B
(18) TOTAL CUSTOMER	16,372	14,789	775	415	1	84	8	2	0	0	298	
RETAIL												
(19) METERS	0	0	0	0	0	0	0	0	0	0	0	N/A
(20) CUSTOMER SERVICE	11,316	9,482	502	926	26	181	71	50	3	12	63	EXHIBIT 6B
(20) TOTAL RETAIL	11,316	9,482	502	926	26	181	71	50	3	12	63	
SUMMARY												
(21) SUBSTATIONS	2,329	1,375	58	589	74	61	103	33	4	2	31	P-3
(22) OVERHEAD LINES	42,885	30,864	1,445	7,610	658	809	823	1	0	0	675	P-1
(23) UNDERGROUND LINES	1,989	1,431	67	353	31	38	38	0	0	0	31	P-1
(24) LINE TRANSFORMERS	1,550	1,027	44	416	0	41	0	0	0	0	23	D-1
(25) METERS	11,983	10,051	532	974	27	193	76	52	3	12	63	P-6
(26) COMMUNICATIONS	6,845	4,134	175	1,763	221	182	276	0	0	0	93	D-2
(27) STREET LIGHTING	6,536	0	0	0	0	0	0	0	0	0	6,536	DIRECT
(28) CUSTOMER SERVICE	0	0	0	0	0	0	0	0	0	0	0	EXHIBIT 6B
(29) TOTAL DISTRIBUTION	$74,115	$48,881	$2,321	$11,704	$1,010	$1,323	$1,315	$85	$7	$15	$7,453	

EXHIBIT 6B

NOVA SCOTIA POWER INC.

ALLOCATION OF CUSTOMER SERVICE FIELD EXPENSES

FOR THE YEAR ENDING DECEMBER 31, 2012

(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) METER READING	(4) WIRING INSPECTION
(1) DOMESTIC	$9,482	$6,572	$2,909
(2) SMALL GENERAL	502	345	158
(3) GENERAL	926	849	78
(4) GENERAL LARGE	26	26	0
(5) SMALL INDUSTRIAL	181	166	15
(6) MEDIUM INDUSTRIAL	71	70	1
(7) LARGE INDUSTRIAL	50	50	0
(8) ELI 2P-RTP	3	3	0
(9) MUNICIPAL	12	12	0
(10) UNMETERED	63	0	63
(11) TOTAL	$11,316	$8,092	$3,224
ALLOCATION FACTOR		C-6	C-7

EXHIBIT 6C

NOVA SCOTIA POWER INC.

ALLOCATION OF CREDIT SERVICES EXPENSES

FOR THE YEAR ENDING DECEMBER 31, 2012

(IN THOUSANDS OF DOLLARS)

	(1)	(2)	(3)	(4)	(5)
	---------------BAD DEBT EXPENSE-----------------			CREDIT	
	DIRECT	TO BE ALLOC.	TOTAL	SERVICES	TOTAL
(1) DOMESTIC	$2,944	$0	$2,944	$0	$2,944
(2) SMALL GENERAL	0	50	50	0	50
(3) GENERAL	0	466	466	0	466
(4) GENERAL LARGE	0	0	0	0	0
(5) SMALL INDUSTRIAL	0	45	45	0	45
(6) MEDIUM INDUSTRIAL	0	0	0	0	0
(7) LARGE INDUSTRIAL	0	0	0	0	0
(8) ELI 2P-RTP	0	0	0	0	0
(9) MUNICIPAL	0	0	0	0	0
(10) UNMETERED	0	0	0	0	0
(11) TOTAL	$2,944	$561	$3,504	$0	$3,504
ALLOCATION FACTOR	DIRECT	R-1		C-7	

DOMESTIC - 84 %

NOVA SCOTIA POWER INC.
ALLOCATION OF DEPRECIATION EXPENSES
FOR THE YEAR ENDING DECEMBER 31, 2012
(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
DEMAND CLASSIFICATION												
GENERATION FUNCTION												
(1) STEAM PRODUCTION	$18,695	$9,836	$436	$3,848	$455	$301	$587	$906	$1,772	$351	$204	D-3A
(2) HYDRO PRODUCTION	3,328	1,751	78	685	81	54	104	161	315	63	36	D-3A
(3) WIND PRODUCTION	1,323	696	31	272	32	21	42	64	125	25	14	D-3A
(4) LM6000 PRODUCTION	769	405	18	158	19	12	24	37	73	14	8	D-3A
(5) GAS TURBINE PROD. - OTHER	1,197	630	28	246	29	19	38	58	113	22	13	D-3A
(6) GENERAL PROPERTY	7,015	3,691	164	1,444	171	113	220	340	665	132	76	P-7
(7) TOTAL GENERATION FUNCTION	32,327	17,008	754	6,653	787	520	1,015	1,567	3,064	608	352	
TRANSMISSION FUNCTION												
(8) TRANSMISSION PLANT < 138kV	1,702	989	44	387	46	30	59	91	0	35	21	D-3B
(9) GENERAL PROPERTY	364	212	9	83	10	6	13	20	0	8	4	P-8A
TOTAL < 138kV	2,066	1,201	53	470	56	37	72	111	0	43	25	
(10) TRANSMISSION PLANT > 69kV	5,573	2,932	130	1,147	136	90	175	270	528	105	61	D-3A
(11) GENERAL PROPERTY	1,192	627	28	245	29	19	37	58	113	22	13	P-8B
(12) TOTAL > 69kV	6,765	3,559	158	1,392	165	109	212	328	641	127	74	
(13) TOTAL TRANSMISSION FUNCTION	8,832	4,760	211	1,862	220	146	284	438	641	170	99	
DISTRIBUTION FUNCTION												
(14) DISTRIBUTION PLANT - Non Streetligl	30,058	19,043	807	7,898	460	797	584	32	4	2	430	P-9
(14) DISTRIBUTION PLANT - Streetlight	2,189	0	0	0	0	0	0	0	0	0	2,189	Direct
(15) GENERAL PROPERTY	4,180	2,648	112	1,098	64	111	81	4	1	0	60	P-9
(16) TOTAL DISTRIBUTION FUNCTION	36,428	21,691	920	8,997	524	907	666	37	4	3	2,680	
(17) TOTAL DEMAND	**77,586**	**43,459**	**1,884**	**17,512**	**1,532**	**1,573**	**1,965**	**2,042**	**3,709**	**780**	**3,131**	
ENERGY CLASSIFICATION												
GENERATION FUNCTION												
(18) STEAM PRODUCTION	39,548	15,649	782	8,791	1,367	904	1,765	3,178	6,021	673	416	E-1A
(19) HYDRO PRODUCTION	5,495	2,175	109	1,222	190	126	245	442	837	94	58	E-1A
(20) WIND PRODUCTION	6,900	2,731	136	1,534	239	158	308	554	1,051	118	73	E-1A
(21) LM6000 PRODUCTION	1,232	487	24	274	43	28	55	99	188	21	13	E-1A
(22) GAS TURBINE PROD. - OTHER	0	0	0	0	0	0	0	0	0	0	0	E-1A
(23) GENERAL PROPERTY	15,182	6,008	300	3,375	525	347	678	1,220	2,311	259	160	P-10
(24) TOTAL GENERATION FUNCTION	68,358	27,050	1,351	15,195	2,364	1,563	3,051	5,492	10,407	1,164	720	
TRANSMISSION FUNCTION												
(25) TRANSMISSION PLANT < 138kV	2,726	1,272	64	715	111	74	144	258	0	55	34	E-1B
(26) GENERAL PROPERTY	583	272	14	153	24	16	31	55	0	12	7	P-11A
(27) TOTAL < 138kV	3,309	1,545	77	868	135	89	174	314	0	66	41	
(28) TRANSMISSION PLANT > 69kV	8,924	3,531	176	1,984	309	204	398	717	1,359	152	94	E-1A
(29) GENERAL PROPERTY	1,910	756	38	425	66	44	85	153	291	33	20	P-11B
(30) TOTAL > 69kV	10,834	4,287	214	2,408	375	248	484	870	1,649	185	114	
(31) TOTAL TRANSMISSION FUNCTION	14,143	5,832	291	3,276	510	337	658	1,184	1,649	251	155	
(32) TOTAL ENERGY	**82,501**	**32,882**	**1,643**	**18,471**	**2,873**	**1,900**	**3,709**	**6,677**	**12,057**	**1,415**	**875**	

NOVA SCOTIA POWER INC.

ALLOCATION OF DEPRECIATION EXPENSES

FOR THE YEAR ENDING DECEMBER 31, 2012

(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
CUSTOMER CLASSIFICATION												
DISTRIBUTION FUNCTION												
(1) DISTRIBUTION PLANT	14,492	12,697	666	788	1	162	14	5	0	0	159	P-12
(2) GENERAL PROPERTY	2,015	1,766	93	110	0	22	2	1	0	0	22	P-12
(3) TOTAL DISTRIBUTION FUNCTION	16,508	14,463	758	898	1	184	16	5	0	0	181	
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	**16,508**	**14,463**	**758**	**898**	**1**	**184**	**16**	**5**	**0**	**0**	**181**	
(8) TOTAL DEPRECIATION	**$176,595**	**$90,804**	**$4,285**	**$36,881**	**$4,406**	**$3,657**	**$5,689**	**$8,724**	**$15,766**	**$2,196**	**$4,187**	

EXHIBIT 7

NOVA SCOTIA POWER INC.

REVENUE ANALYSIS

FOR THE YEAR ENDING DECEMBER 31, 2012
(IN THOUSANDS OF DOLLARS)

	(1) REVENUE	(2) EXPORT SALES	(3) LATE PAYMENT CHARGE	(4) MISC. CUSTOMER REVENUE
ELECTRIC REVENUE				
(1) DOMESTIC	$606,735	$380	$3,825	$1,631
(2) SMALL GENERAL	31,138	19	117	99
(3) GENERAL	290,881	214	852	11
(4) LARGE GENERAL	38,699	33	0	0
(5) SMALL INDUSTRIAL	28,262	22	66	0
(6) MEDIUM INDUSTRIAL	48,346	43	57	0
(7) LARGE INDUSTRIAL	75,696	77	0	0
(8) ELI 2P-RTP	129,482	146	0	0
(9) MUNICIPAL	18,912	16	0	0
(10) UNMETERED	25,382	10	16	15
(11) SUB-TOTAL	1,293,534	$961	$4,933	$1,758
(12) EXPORT SALES	961			
(13) TOTAL ELECTRIC REVENUE	1,294,495			
NON-RATE REVENUE				
(14) LATE PAYMENT CHARGE	4,933			
(15) MISC. CUST. REVENUE	1,758			
(16) OTHER	7,098			
(17) TOTAL	13,788			
DIRECT REVENUE				
(18) BOWATER BASIC BLOCK	9,280			
(19) BOWATER ADDITIONAL ENERGY	11,177			
(20) GEN.REPL./LOAD FOLL	6,726			
(21) REAL TIME PRICING	0			
(22) LED	1,314			
(23) TOTAL	28,497			
(24) TRANSFER FROM (TO) RETAINED EARNINGS	(130,457)			
(25) TOTAL REVENUE	**$1,206,323**			
ALLOCATION FACTOR		E-1	DIRECT	DIRECT

EXHIBIT 8A

NOVA SCOTIA POWER INC.

DEVELOPMENT OF ALLOCATION FACTORS

FOR THE YEAR ENDING DECEMBER 31, 2012

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
(1) N.C. DEMAND SEC.	1,884,602	1,248,139	52,921	505,388	0	49,944	0	0	0	0	28,210	
(2) % RESPONSIBILITY	100.00%	66.23%	2.81%	26.82%	0.00%	2.65%	0.00%	0.00%	0.00%	0.00%	1.50%	D-1
(3) N.C. DEMAND PRI.	2,177,982	1,315,539	55,779	560,971	70,354	57,920	87,685	0	0	0	29,733	
(4) % RESPONSIBILITY	100.00%	60.40%	2.56%	25.76%	3.23%	2.66%	4.03%	0.00%	0.00%	0.00%	1.37%	D-2
(5) 3 CP DEMAND	6,671,256	3,509,838	155,518	1,373,015	162,393	107,379	209,410	323,310	632,285	125,369	72,739	
(6) % RESPONSIBILITY	100.00%	52.61%	2.33%	20.58%	2.43%	1.61%	3.14%	4.85%	9.48%	1.88%	1.09%	D-3A
(7) 3 CP DEMAND - LESS ELIIR - 2	6,038,971	3,509,838	155,518	1,373,015	162,393	107,379	209,410	323,310	0	125,369	72,739	
(8) % RESPONSIBILITY	100.00%	58.12%	2.58%	22.74%	2.69%	1.78%	3.47%	5.35%	0.00%	2.08%	1.20%	D-3B
(9) 3 CP DMD. - LESS INT. & ELIIR - 2	5,810,298	3,509,838	155,518	1,373,015	162,393	107,379	209,410	94,636	0	125,369	72,739	
(10) % RESPONSIBILITY	100.00%	60.41%	2.68%	23.63%	2.79%	1.85%	3.60%	1.63%	0.00%	2.16%	1.25%	D-4
(11) MW.h GEN. & PURCH.	12,160,035	4,811,852	240,416	2,703,080	420,469	278,013	542,704	977,034	1,851,330	207,083	128,053	
(12) % RESPONSIBILITY	100.00%	39.57%	1.98%	22.23%	3.46%	2.29%	4.46%	8.03%	15.22%	1.70%	1.05%	E-1A
(13) MW.h GEN. & PURCH. Less EHV	10,308,705	4,811,852	240,416	2,703,080	420,469	278,013	542,704	977,034	0	207,083	128,053	
(14) % RESPONSIBILITY	100.00%	46.68%	2.33%	26.22%	4.08%	2.70%	5.26%	9.48%	0.00%	2.01%	1.24%	E-1B
(15) AVERAGE CUSTOMERS	496,804	449,674	23,578	11,611	18	2,268	192	34	2	8	9,419	
(16) % RESPONSIBILITY	100.00%	90.51%	4.75%	2.34%	0.00%	0.46%	0.04%	0.01%	0.00%	0.00%	1.90%	C-1
(17) SECONDARY CUSTOMERS	487,131	449,674	23,578	11,611	0	2,268	0	0	0	0	0	
(18) WEIGHTING FACTOR		1.00	1.00	5.00	100.00	5.00	25.00	100.00	100.00	100.00	0.82	
(19) WEIGHTED TOTAL	542,647	449,674	23,578	58,055	0	11,340	0	0	0	0	0	
(20) % RESPONSIBILITY	100.00%	82.87%	4.34%	10.70%	0.00%	2.09%	0.00%	0.00%	0.00%	0.00%	0.00%	C-2
(21) AVERAGE CUSTOMERS	496,804	449,674	23,578	11,611	18	2,268	192	34	2	8	9,419	
(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	561,371	449,674	23,578	58,055	1,800	11,340	4,800	3,400	200	800	7,724	
(24) % RESPONSIBILITY	100.00%	80.10%	4.20%	10.34%	0.32%	2.02%	0.86%	0.61%	0.04%	0.14%	1.38%	C-3
(25) CUSTOMER SECONDARY	496,550	449,674	23,578	11,611	0	2,268	0	0	0	0	9,419	
(26) % RESPONSIBILITY	100.00%	90.56%	4.75%	2.34%	0.00%	0.46%	0.00%	0.00%	0.00%	0.00%	1.90%	C-4
(27) CUSTOMER PRIMARY	496,804	449,674	23,578	11,611	18	2,268	192	34	2	8	9,419	
(28) % RESPONSIBILITY	100.00%	90.51%	4.75%	2.34%	0.00%	0.46%	0.04%	0.01%	0.00%	0.00%	1.90%	C-5
(29) AVG. CUST. - LESS UNMETERED	487,385	449,674	23,578	11,611	18	2,268	192	34	2	8	0	
(30) WEIGHTING FACTOR		1.00	1.00	5.00	100.00	5.00	25.00	100.00	100.00	100.00	0.82	
(31) WEIGHTED TOTAL	553,647	449,674	23,578	58,055	1,800	11,340	4,800	3,400	200	800	0	
(32) % RESPONSIBILITY	100.00%	81.22%	4.26%	10.49%	0.33%	2.05%	0.87%	0.61%	0.04%	0.14%	0.00%	C-6
(33) AVERAGE CUSTOMERS ADJ SEASONAL	482,613	435,483	23,578	11,611	18	2,268	192	34	2	8	9,419	
(34) % RESPONSIBILITY	100.00%	90.23%	4.89%	2.41%	0.00%	0.47%	0.04%	0.01%	0.00%	0.00%	1.95%	C-7

NOVA SCOTIA POWER INC.
DEVELOPMENT OF ALLOCATION FACTORS
FOR THE YEAR ENDING DECEMBER 31, 2012

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
(1) POLE&WIRE INV.-DMD.	$172,234	$106,734	$4,526	$44,853	$4,066	$4,576	$5,067	$0	$0	$0	$2,412	
(2) % RESPONSIBILITY	100.00%	61.97%	2.63%	26.04%	2.36%	2.66%	2.94%	0.00%	0.00%	0.00%	1.40%	P-1
(3) POLE&WIRE INV.-CUST.	$92,741	$83,965	$4,403	$2,168	$2	$423	$18	$3	$0	$1	$1,759	
(4) % RESPONSIBILITY	100.00%	90.54%	4.75%	2.34%	0.00%	0.46%	0.02%	0.00%	0.00%	0.00%	1.90%	P-2
(5) SUB.,POLE&WIRE-DMD.	$198,439	$122,201	$5,181	$51,477	$4,893	$5,257	$6,222	$375	$42	$28	$2,762	
(6) % RESPONSIBILITY	100.00%	61.58%	2.61%	25.94%	2.47%	2.65%	3.14%	0.19%	0.02%	0.01%	1.39%	P-3
(7) SUB.,POLE&WIRE-CUST.	$92,741	$83,965	$4,403	$2,168	$2	$423	$18	$3	$0	$1	$1,759	
(8) % RESPONSIBILITY	100.00%	90.54%	4.75%	2.34%	0.00%	0.46%	0.02%	0.00%	0.00%	0.00%	1.90%	P-4
(9) SUBST. INVEST.-DMD.	$26,205	$15,467	$656	$6,624	$827	$681	$1,155	$375	$42	$28	$350	
(10) % RESPONSIBILITY	100.00%	59.02%	2.50%	25.28%	3.16%	2.60%	4.41%	1.43%	0.16%	0.11%	1.33%	P-5
(11) METER INVEST.-CUST	$23,328	$19,928	$1,045	$1,680	$15	$429	$164	$59	$3	$5	$0	
(12) % RESPONSIBILITY	100.00%	85.43%	4.48%	7.20%	0.06%	1.84%	0.70%	0.25%	0.01%	0.02%	0.00%	P-6
(13) DEMAND - GEN. PLANT	$667,957	$351,421	$15,571	$137,473	$16,260	$10,751	$20,967	$32,371	$63,307	$12,553	$7,283	
(14) % RESPONSIBILITY	100.00%	52.61%	2.33%	20.58%	2.43%	1.61%	3.14%	4.85%	9.48%	1.88%	1.09%	P-7
(15) DEMAND - TRANS. PLT. < 138kV	$34,686	$20,160	$893	$7,886	$933	$617	$1,203	$1,857	$0	$720	$418	
(16) % RESPONSIBILITY	100.00%	58.12%	2.58%	22.74%	2.69%	1.78%	3.47%	5.35%	0.00%	2.08%	1.20%	P-8A
(17) DEMAND - TRANS. PLT. > 69kV	$113,546	$59,738	$2,647	$23,369	$2,764	$1,828	$3,564	$5,503	$10,762	$2,134	$1,238	
(18) % RESPONSIBILITY	100.00%	52.61%	2.33%	20.58%	2.43%	1.61%	3.14%	4.85%	9.48%	1.88%	1.09%	P-8B
(19) DEMAND - DIST. PLANT	$375,487	$237,879	$10,086	$98,665	$5,752	$9,950	$7,302	$402	$45	$30	$5,376	
(20) % RESPONSIBILITY	100.00%	63.35%	2.69%	26.28%	1.53%	2.65%	1.94%	0.11%	0.01%	0.01%	1.43%	P-9
(19) DEMAND - DIST. PLANT	$21,981	$0	$0	$0	$0	$0	$0	$0	$0	$0	$21,981	
(20) % RESPONSIBILITY	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	P-9A
(23) ENERGY - GEN. PLANT	$1,445,627	$572,050	$28,581	$321,352	$49,987	$33,051	$64,519	$116,153	$220,092	$24,619	$15,223	
(24) % RESPONSIBILITY	100.00%	39.57%	1.98%	22.23%	3.46%	2.29%	4.46%	8.03%	15.22%	1.70%	1.05%	P-10
(25) ENERGY - TRANS. PLT. < 138kV	$55,549	$25,929	$1,295	$14,566	$2,266	$1,498	$2,924	$5,265	$0	$1,116	$690	
(26) % RESPONSIBILITY	100.00%	46.68%	2.33%	26.22%	4.08%	2.70%	5.26%	9.48%	0.00%	2.01%	1.24%	P-11A
(27) ENERGY - TRANS. PLT. > 69kV	$181,839	$71,956	$3,595	$40,421	$6,288	$4,157	$8,116	$14,610	$27,685	$3,097	$1,915	
(28) % RESPONSIBILITY	100.00%	39.57%	1.98%	22.23%	3.46%	2.29%	4.46%	8.03%	15.22%	1.70%	1.05%	P-11B
(29) CUSTOMER - DIST. PLANT	$191,899	$168,130	$8,816	$10,436	$17	$2,139	$185	$62	$3	$6	$2,105	
(30) % RESPONSIBILITY	100.00%	87.61%	4.59%	5.44%	0.01%	1.11%	0.10%	0.03%	0.00%	0.00%	1.10%	P-12
(31) CUSTOMER - RETAIL PLANT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
(32) % RESPONSIBILITY	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	P-13
(33) TOT.RATE BASE-DMD. (GEN.)	$725,136	$381,504	$16,904	$149,241	$17,651	$11,672	$22,762	$35,142	$68,727	$13,627	$7,906	
(34) % RESPONSIBILITY	100.00%	52.61%	2.33%	20.58%	2.43%	1.61%	3.14%	4.85%	9.48%	1.88%	1.09%	P-14
(35) TOT.RATE BASE-DMD. (TRANS. < 138kV)	$38,857	$22,584	$1,001	$8,835	$1,045	$691	$1,347	$2,080	$0	$807	$468	
(36) % RESPONSIBILITY	100.00%	58.12%	2.58%	22.74%	2.69%	1.78%	3.47%	5.35%	0.00%	2.08%	1.20%	P-15A
(37) TOT.RATE BASE-DMD. (TRANS. > 69kV)	$127,089	$66,863	$2,963	$26,156	$3,094	$2,046	$3,989	$6,159	$12,045	$2,388	$1,386	
(38) % RESPONSIBILITY	100.00%	52.61%	2.33%	20.58%	2.43%	1.61%	3.14%	4.85%	9.48%	1.88%	1.09%	P-15B
(39) TOT.RATE BASE-DMD. (DIST.) Non Streetl	$449,122	$282,232	$11,967	$117,135	$7,010	$11,819	$8,893	$473	$53	$35	$9,505	
(40) % RESPONSIBILITY	100.00%	62.84%	2.66%	26.08%	1.56%	2.63%	1.98%	0.11%	0.01%	0.01%	2.12%	P-16
(41) TOT.RATE BASE-DMD. (DIST.) Streetlight	$21,981	$0	$0	$0	$0	$0	$0	$0	$0	$0	$21,981	
(42) % RESPONSIBILITY	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	P-16B
(43) TOT.RATE BASE-ENG. (GEN.)	$1,740,947	$688,911	$34,420	$386,999	$60,198	$39,803	$77,699	$139,882	$265,054	$29,648	$18,333	
(44) % RESPONSIBILITY	100.00%	39.57%	1.98%	22.23%	3.46%	2.29%	4.46%	8.03%	15.22%	1.70%	1.05%	P-17
(45) TOT.RATE BASE-ENG. (TRANS. < 138kV)	$62,228	$29,047	$1,451	$16,317	$2,538	$1,678	$3,276	$5,898	$0	$1,250	$773	
(46) % RESPONSIBILITY	100.00%	46.68%	2.33%	26.22%	4.08%	2.70%	5.26%	9.48%	0.00%	2.01%	1.24%	P-18A
(47) TOT.RATE BASE-ENG. (TRANS. > 69kV)	$203,527	$80,538	$4,024	$45,243	$7,038	$4,653	$9,083	$16,353	$30,986	$3,466	$2,143	
(48) % RESPONSIBILITY	100.00%	39.57%	1.98%	22.23%	3.46%	2.29%	4.46%	8.03%	15.22%	1.70%	1.05%	P-18B

NOVA SCOTIA POWER INC.

DEVELOPMENT OF ALLOCATION FACTORS

FOR THE YEAR ENDING DECEMBER 31, 2012

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
(1) TOT. RATE BASE-CUST. (DIST.)	$244,751	$215,197	$11,283	$12,496	$20	$2,560	$222	$74	$4	$7	$2,887	
(2) % RESPONSIBILITY	100.00%	87.92%	4.61%	5.11%	0.01%	1.05%	0.09%	0.03%	0.00%	0.00%	1.18%	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.	$26,770	$14,084	$624	$5,510	$652	$431	$840	$1,297	$2,537	$503	$292	
(6) % RESPONSIBILITY	100.00%	52.61%	2.33%	20.58%	2.43%	1.61%	3.14%	4.85%	9.48%	1.88%	1.09%	O-1
(7) DMD. - OPER.EXP. - TRANS. < 138kV	$2,393	$1,391	$62	$544	$64	$43	$83	$128	$0	$50	$29	
(8) % RESPONSIBILITY	100.00%	58.12%	2.58%	22.74%	2.69%	1.78%	3.47%	5.35%	0.00%	2.08%	1.20%	O-2A
(9) DMD. - OPER.EXP. - TRANS. > 69kV	$7,601	$3,999	$177	$1,564	$185	$122	$239	$368	$720	$143	$83	
(10) % RESPONSIBILITY	100.00%	52.61%	2.33%	20.58%	2.43%	1.61%	3.14%	4.85%	9.48%	1.88%	1.09%	O-2B
(11) DMD. - OPER.EXP. - DIST.	$46,427	$24,611	$1,044	$10,363	$983	$1,059	$1,236	$33	$4	$2	$7,092	
(12) % RESPONSIBILITY	100.00%	53.01%	2.25%	22.32%	2.12%	2.28%	2.66%	0.07%	0.01%	0.01%	15.28%	O-3
(13) ENG. - OPER.EXP. - GEN.	$74,072	$29,311	$1,464	$16,466	$2,561	$1,694	$3,306	$5,952	$11,277	$1,261	$780	
(14) % RESPONSIBILITY	100.00%	39.57%	1.98%	22.23%	3.46%	2.29%	4.46%	8.03%	15.22%	1.70%	1.05%	O-4
(15) ENG. - OPER.EXP. - TRANS. < 138kV	$3,832	$1,789	$89	$1,005	$156	$103	$202	$363	$0	$77	$48	
(16) % RESPONSIBILITY	100.00%	46.68%	2.33%	26.22%	4.08%	2.70%	5.26%	9.48%	0.00%	2.01%	1.24%	O-5A
(17) ENG. - OPER.EXP. - TRANS. > 69kV	$12,172	$4,817	$241	$2,706	$421	$278	$543	$978	$1,853	$207	$128	
(18) % RESPONSIBILITY	100.00%	39.57%	1.98%	22.23%	3.46%	2.29%	4.46%	8.03%	15.22%	1.70%	1.05%	O-5B
(19) CUST. - OPER. EXP. - DIST.	$16,372	$14,789	$775	$415	$1	$84	$8	$2	$0	$0	$298	
(20) % RESPONSIBILITY	100.00%	90.33%	4.74%	2.54%	0.00%	0.51%	0.05%	0.01%	0.00%	0.00%	1.82%	O-6
(21) CUST. - OPER. EXP. - RETAIL	$29,234	$24,008	$1,205	$2,281	$158	$469	$212	$248	$142	$106	$404	
(22) % RESPONSIBILITY	100.00%	82.13%	4.12%	7.80%	0.54%	1.60%	0.73%	0.85%	0.48%	0.36%	1.38%	O-7
(23) TOT. EXP. - DMD. (GEN.)	$116,346	$61,211	$2,712	$23,945	$2,832	$1,873	$3,652	$5,638	$11,027	$2,186	$1,269	
(24) % RESPONSIBILITY	100.00%	52.61%	2.33%	20.58%	2.43%	1.61%	3.14%	4.85%	9.48%	1.88%	1.09%	O-8
(25) TOT. EXP. - DMD. (TRANS. < 138kV)	$6,678	$3,882	$172	$1,518	$180	$119	$232	$358	$0	$139	$80	
(26) % RESPONSIBILITY	100.00%	58.12%	2.58%	22.74%	2.69%	1.78%	3.47%	5.35%	0.00%	2.08%	1.20%	O-9A
(27) TOT. EXP. - DMD. (TRANS. > 69kV)	$21,624	$11,377	$504	$4,450	$526	$348	$679	$1,048	$2,049	$406	$236	
(28) % RESPONSIBILITY	100.00%	52.61%	2.33%	20.58%	2.43%	1.61%	3.14%	4.85%	9.48%	1.88%	1.09%	O-9B
(29) TOT. EXP. - DMD. (DIST.)	$109,405	$62,231	$2,639	$25,970	$1,901	$2,633	$2,402	$97	$11	$7	$11,515	
(30) % RESPONSIBILITY	100.00%	56.88%	2.41%	23.74%	1.74%	2.41%	2.20%	0.09%	0.01%	0.01%	10.52%	O-10
(31) TOT. EXP. - ENG. (GEN.)	$794,945	$315,327	$15,739	$176,693	$27,441	$18,143	$35,378	$63,649	$120,680	$13,549	$8,346	
(32) % RESPONSIBILITY	100.00%	39.67%	1.98%	22.23%	3.45%	2.28%	4.45%	8.01%	15.18%	1.70%	1.05%	O-11
(33) TOT. EXP. - ENG. (TRANS. < 138 kV)	$10,695	$4,992	$249	$2,804	$436	$288	$563	$1,014	$0	$215	$133	
(34) % RESPONSIBILITY	100.00%	46.68%	2.33%	26.22%	4.08%	2.70%	5.26%	9.48%	0.00%	2.01%	1.24%	O-12A
(35) TOT. EXP. - ENG. (TRANS. > 69 kV)	$34,630	$13,703	$685	$7,698	$1,197	$792	$1,546	$2,782	$5,272	$590	$365	
(36) % RESPONSIBILITY	100.00%	39.57%	1.98%	22.23%	3.46%	2.29%	4.46%	8.03%	15.22%	1.70%	1.05%	O-12B
(37) TOT. EXP. -CUST. (DIST.)	$46,658	$41,358	$2,169	$2,024	$3	$414	$36	$12	$1	$1	$639	
(38) % RESPONSIBILITY	100.00%	88.64%	4.65%	4.34%	0.01%	0.89%	0.08%	0.03%	0.00%	0.00%	1.37%	O-13
(39) TOT. EXP. -CUST. (RETAIL)	$30,343	$24,104	$1,227	$2,387	$184	$561	$399	$532	$425	$132	$392	
(40) % RESPONSIBILITY	100.00%	79.44%	4.04%	7.87%	0.61%	1.85%	1.31%	1.75%	1.40%	0.44%	1.29%	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	$350,281	$0	$31,138	$290,881	$0	$28,262	$0	$0	$0	$0	$0	
(44) % RESPONSIBILITY	100.00%	0.00%	8.89%	83.04%	0.00%	8.07%	0.00%	0.00%	0.00%	0.00%	0.00%	R-1

EXHIBIT 9A

NOVA SCOTIA POWER INC.

SALES, GENERATION AND DEMAND ANALYSIS

FOR THE YEAR ENDING DECEMBER 31, 2012

	(1) MWH SALES	(2) ENERGY LINE LOSSES	(3) ENERGY REQUIREMENT	(4) CLASS NON-COINCIDENT DMD. (KW)	(5) SYSTEM COINCIDENT FACTOR	(6) SYSTEM COINCIDENT DMD. (KW)	(7) DEMAND LINE LOSSES	(8) SYSTEM COIN. PEAK DMD. (KW)	(9) SYSTEM COINCIDENT L/D FACTOR	(10) MW	(11) 3CP Contribution
(1) DOMESTIC	4,372,538	10.05%	4,811,852	1,177,490	91.0%	1,071,487	15.24%	1,234,772	44.49%	3,509,838	52.6%
(2) SMALL GENERAL	219,487	9.54%	240,416	49,926	95.3%	47,557	11.26%	52,912	51.87%	155,518	2.3%
(3) GENERAL	2,534,007	6.67%	2,703,080	503,624	76.9%	387,416	7.69%	417,217	73.96%	1,373,015	20.6%
(4) GENERAL LARGE	394,351	6.62%	420,469	66,749	76.6%	51,094	7.12%	54,734	87.69%	162,393	2.4%
(5) SMALL INDUSTRIAL	261,850	6.17%	278,013	52,126	64.6%	33,659	5.90%	35,646	89.03%	107,379	1.6%
(6) MEDIUM INDUSTRIAL	512,944	5.80%	542,704	85,528	78.5%	67,116	5.57%	70,855	87.44%	209,410	3.1%
(7) LARGE INDUSTRIAL	932,644	4.76%	977,034	136,644	73.7%	100,725	4.24%	104,997	106.23%	323,310	4.8%
(8) ELI 2P-RTP	1,814,318	2.04%	1,851,330	206,548	100.0%	206,548	2.04%	210,762	100.27%	632,285	9.5%
(9) MUNICIPAL	197,368	4.92%	207,083	40,574	100.0%	40,574	4.83%	42,532	55.58%	125,369	1.9%
(10) UNMETERED	115,740	10.64%	128,053	26,613	100.0%	26,607	14.91%	30,575	47.81%	72,739	1.1%
(11) SUB-TOTAL	11,355,248		12,160,035	2,345,821	86.7%	2,032,783	10.93%	2,255,001	61.56%	6,671,256	100.0%
(12) BOWATER MERSEY	368,928	2.04%	376,454	42,000	100.0%	42,000	2.04%	42,857	100.27%	128,570	
(13) GEN.REPL./LOAD FOLL.	108,411	2.04%	110,623	34,100	30.5%	10,390	2.04%	10,602	119.11%	31,940	
(14) REAL TIME PRICING	0	N/A	0	0	N/A	0	N/A	0	N/A	0	
(16) TOTAL	11,832,587	6.88%	12,647,112	2,421,921	86.1%	2,085,173	10.71%	2,308,459	62.54%	6,831,767	

EXHIBIT 9A

NOVA SCOTIA POWER INC.

SALES, GENERATION AND DEMAND ANALYSIS

FOR JANUARY 2011

	(1) MWH SALES	(2) ENERGY LINE LOSSES	(3) ENERGY REQUIREMENT	(4) CLASS NON-COINCIDENT DMD. (KW)	(5) SYSTEM COINCIDENT FACTOR	(6) SYSTEM COINCIDENT DMD. (KW)	(7) DEMAND LINE LOSSES	(8) SYSTEM COIN. PEAK DMD. (KW)	(9) SYSTEM COINCIDENT L/D FACTOR
(1) DOMESTIC	529,956	11.51%	590,948	1,177,490	91.0%	1,071,487	15.24%	1,234,772	64.33%
(2) SMALL GENERAL	24,058	10.27%	26,529	49,926	95.3%	47,557	11.26%	52,912	67.39%
(3) GENERAL	243,206	7.13%	260,537	463,307	83.6%	387,416	7.69%	417,217	83.93%
(4) GENERAL LARGE	33,626	6.91%	35,948	60,580	84.3%	51,094	7.12%	54,734	88.28%
(5) SMALL INDUSTRIAL	22,882	5.85%	24,222	45,953	73.3%	33,659	5.90%	35,646	91.33%
(6) MEDIUM INDUSTRIAL	44,144	5.45%	46,550	76,331	87.9%	67,116	5.57%	70,855	88.30%
(7) LARGE INDUSTRIAL	75,703	4.22%	78,896	114,042	88.3%	100,725	4.24%	104,997	101.00%
(8) ELI 2P-RTP	153,672	2.04%	156,807	206,548	100.0%	206,548	2.04%	210,762	100.00%
(9) MUNICIPAL	20,909	4.50%	21,850	40,574	100.0%	40,574	4.83%	42,532	69.05%
(10) UNMETERED	9,721	11.80%	10,869	26,607	100.0%	26,607	14.91%	30,575	47.78%
(11) SUB-TOTAL	1,157,877		1,253,156	2,261,357	89.9%	2,032,783	10.93%	2,255,001	74.69%
(12) BOWATER MERSEY	31,248	1.91%	31,844	42,000	100.0%	42,000	2.04%	42,857	99.87%
(13) GEN.REPL./LOAD FOLL.	8,579	2.04%	8,754	28,701	36.2%	10,390	2.04%	10,602	110.98%
(14) REAL TIME PRICING	0	N/A	0	0	N/A	0	N/A	0	N/A
(15) EXPORT SALES	0	N/A	0	0	N/A	0	N/A	0	N/A
(16) TOTAL	1,197,704	8.02%	1,293,754	2,332,058	89.4%	2,085,173	10.71%	2,308,459	75.33%

EXHIBIT 9A

NOVA SCOTIA POWER INC.

SALES, GENERATION AND DEMAND ANALYSIS

FOR FEBRUARY 2011

	(1) MWH SALES	(2) ENERGY LINE LOSSES	(3) ENERGY REQUIREMENT	(4) CLASS NON-COINCIDENT DMD. (KW)	(5) SYSTEM COINCIDENT FACTOR	(6) SYSTEM COINCIDENT DMD. (KW)	(7) DEMAND LINE LOSSES	(8) SYSTEM COIN. PEAK DMD. (KW)	(9) SYSTEM COINCIDENT L/D FACTOR
(1) DOMESTIC	459,800	11.66%	513,395	1,115,975	90.3%	1,008,039	15.42%	1,163,436	65.67%
(2) SMALL GENERAL	22,095	10.39%	24,391	49,477	100.0%	49,477	11.22%	55,029	65.96%
(3) GENERAL	228,102	7.51%	245,230	503,624	89.6%	451,231	8.76%	490,772	74.36%
(4) GENERAL LARGE	30,827	7.01%	32,989	56,425	88.1%	49,712	7.19%	53,285	92.13%
(5) SMALL INDUSTRIAL	21,937	6.19%	23,295	47,284	73.3%	34,633	6.24%	36,794	94.21%
(6) MEDIUM INDUSTRIAL	39,832	5.79%	42,137	72,080	88.9%	64,099	5.90%	67,882	92.37%
(7) LARGE INDUSTRIAL	68,601	4.50%	71,689	109,802	93.9%	103,089	4.56%	107,792	98.97%
(8) ELI 2P-RTP	143,757	2.04%	146,690	206,548	100.0%	206,548	2.04%	210,762	103.57%
(9) MUNICIPAL	19,129	4.76%	20,040	39,636	97.7%	38,728	5.08%	40,696	73.28%
(10) UNMETERED	9,258	12.59%	10,423	26,609	39.4%	10,494	9.45%	11,486	135.04%
(11) SUB-TOTAL	1,043,338		1,130,280	2,227,459	90.5%	2,016,050	11.01%	2,237,935	75.16%
(12) BOWATER MERSEY	29,232	2.04%	29,828	42,000	100.0%	42,000	2.04%	42,857	103.57%
(13) GEN.REPL./LOAD FOLL.	8,321	2.04%	8,490	29,730	34.4%	10,216	2.04%	10,424	121.20%
(14) REAL TIME PRICING	0	N/A	0	0	N/A	0	N/A	0	N/A
(15) EXPORT SALES	0	N/A	0	0	N/A	0	N/A	0	N/A
(16) TOTAL	1,080,890	8.11%	1,168,598	2,299,189	90.0%	2,068,266	10.78%	2,291,217	75.90%

EXHIBIT 9A

NOVA SCOTIA POWER INC.

SALES, GENERATION AND DEMAND ANALYSIS

FOR MARCH 2011

	(1) MWH SALES	(2) ENERGY LINE LOSSES	(3) ENERGY REQUIREMENT	(4) CLASS NON-COINCIDENT DMD. (KW)	(5) SYSTEM COINCIDENT FACTOR	(6) SYSTEM COINCIDENT DMD. (KW)	(7) DEMAND LINE LOSSES	(8) SYSTEM COIN. PEAK DMD. (KW)	(9) SYSTEM COINCIDENT L/D FACTOR
(1) DOMESTIC	460,387	10.84%	510,283	922,134	89.1%	821,964	12.95%	928,377	73.88%
(2) SMALL GENERAL	21,160	10.77%	23,439	44,369	68.4%	30,363	10.80%	33,641	93.65%
(3) GENERAL	234,589	7.91%	253,143	465,033	94.8%	440,761	9.17%	481,185	70.71%
(4) GENERAL LARGE	33,284	7.20%	35,681	60,367	94.8%	57,240	7.54%	61,557	77.91%
(5) SMALL INDUSTRIAL	22,002	6.75%	23,487	45,814	90.0%	41,229	6.95%	44,093	71.59%
(6) MEDIUM INDUSTRIAL	42,507	6.19%	45,137	75,465	98.6%	74,417	6.46%	79,227	76.58%
(7) LARGE INDUSTRIAL	75,839	4.88%	79,544	120,677	79.9%	96,439	4.84%	101,104	105.75%
(8) ELI 2P-RTP	153,672	2.04%	156,807	206,548	100.0%	206,548	2.04%	210,762	100.00%
(9) MUNICIPAL	18,620	5.28%	19,603	35,465	100.0%	35,448	5.57%	37,421	70.41%
(10) UNMETERED	9,705	12.93%	10,961	26,609	9.8%	2,598	7.10%	2,782	529.52%
(11) SUB-TOTAL	1,071,766		1,158,084	2,002,480	90.2%	1,807,007	9.58%	1,980,148	78.61%
(12) BOWATER MERSEY	31,248	2.04%	31,885	42,000	100.0%	42,000	2.04%	42,857	100.00%
(13) GEN.REPL./LOAD FOLL.	7,627	2.04%	7,783	12,042	84.3%	10,152	2.04%	10,359	100.98%
(14) REAL TIME PRICING	0	N/A	0	0	N/A	0	N/A	0	N/A
(15) EXPORT SALES	0	N/A	0	0	N/A	0	N/A	0	N/A
(16) TOTAL	1,110,641	7.84%	1,197,752	2,056,522	90.4%	1,859,159	9.37%	2,033,364	79.17%

EXHIBIT 9A

NOVA SCOTIA POWER INC.

SALES, GENERATION AND DEMAND ANALYSIS

FOR APRIL 2011

	(1) MWH SALES	(2) ENERGY LINE LOSSES	(3) ENERGY REQUIREMENT	(4) CLASS NON-COINCIDENT DMD. (KW)	(5) SYSTEM COINCIDENT FACTOR	(6) SYSTEM COINCIDENT DMD. (KW)	(7) DEMAND LINE LOSSES	(8) SYSTEM COIN. PEAK DMD. (KW)	(9) SYSTEM COINCIDENT L/D FACTOR
(1) DOMESTIC	368,084	9.59%	403,398	862,681	84.7%	730,896	11.81%	817,235	68.56%
(2) SMALL GENERAL	17,946	9.62%	19,673	42,772	67.0%	28,671	9.72%	31,459	86.85%
(3) GENERAL	202,976	6.67%	216,506	414,263	91.4%	378,693	7.49%	407,052	73.87%
(4) GENERAL LARGE	30,577	6.54%	32,577	55,657	94.8%	52,758	6.78%	56,338	80.31%
(5) SMALL INDUSTRIAL	20,991	6.05%	22,261	46,014	95.8%	44,076	6.28%	46,846	66.00%
(6) MEDIUM INDUSTRIAL	42,360	5.61%	44,735	78,185	96.8%	75,667	5.81%	80,064	77.60%
(7) LARGE INDUSTRIAL	74,998	4.52%	78,387	125,703	77.4%	97,275	4.52%	101,676	107.08%
(8) ELI 2P-RTP	148,715	2.04%	151,748	206,548	100.0%	206,548	2.04%	210,762	100.00%
(9) MUNICIPAL	15,454	4.92%	16,214	31,199	98.7%	30,787	5.17%	32,378	69.55%
(10) UNMETERED	9,363	10.74%	10,369	26,608	9.8%	2,599	5.18%	2,733	526.92%
(11) SUB-TOTAL	931,465		995,868	1,889,630	87.2%	1,647,970	8.41%	1,786,541	77.42%
(12) BOWATER MERSEY	30,240	2.04%	30,857	42,000	100.0%	42,000	2.04%	42,857	100.00%
(13) GEN.REPL./LOAD FOLL.	8,806	2.04%	8,986	32,597	31.1%	10,128	2.04%	10,335	120.76%
(14) REAL TIME PRICING	0	N/A	0	0	N/A	0	N/A	0	N/A
(15) EXPORT SALES	0	N/A	0	0	N/A	0	N/A	0	N/A
(16) TOTAL	970,511	6.72%	1,035,710	1,964,227	86.6%	1,700,098	8.21%	1,839,732	78.19%

EXHIBIT 9A

NOVA SCOTIA POWER INC.

SALES, GENERATION AND DEMAND ANALYSIS

FOR MAY 2011

	(1) MWH SALES	(2) ENERGY LINE LOSSES	(3) ENERGY REQUIREMENT	(4) CLASS NON-COINCIDENT DMD. (KW)	(5) SYSTEM COINCIDENT FACTOR	(6) SYSTEM COINCIDENT DMD. (KW)	(7) DEMAND LINE LOSSES	(8) SYSTEM COIN. PEAK DMD. (KW)	(9) SYSTEM COINCIDENT L/D FACTOR
(1) DOMESTIC	330,636	9.44%	361,864	774,913	79.6%	616,605	10.91%	683,849	71.12%
(2) SMALL GENERAL	16,445	9.75%	18,048	37,972	62.3%	23,650	9.71%	25,947	93.49%
(3) GENERAL	191,340	6.90%	204,533	386,872	85.2%	329,654	7.33%	353,829	77.70%
(4) GENERAL LARGE	30,580	6.85%	32,674	55,622	90.0%	50,040	6.95%	53,516	82.06%
(5) SMALL INDUSTRIAL	21,157	6.80%	22,595	43,867	82.9%	36,345	6.87%	38,843	78.19%
(6) MEDIUM INDUSTRIAL	41,856	6.64%	44,634	79,461	76.8%	61,053	6.62%	65,096	92.16%
(7) LARGE INDUSTRIAL	77,472	5.51%	81,742	127,644	84.8%	108,267	5.50%	114,227	96.18%
(8) ELI 2P-RTP	153,672	2.04%	156,807	206,548	100.0%	206,548	2.04%	210,762	100.00%
(9) MUNICIPAL	14,137	5.77%	14,952	25,669	99.0%	25,423	5.96%	26,939	74.60%
(10) UNMETERED	9,921	12.19%	11,130	26,609	11.8%	3,142	6.43%	3,344	447.42%
(11) SUB-TOTAL	887,215		948,980	1,765,177	82.8%	1,460,726	7.92%	1,576,351	80.92%
(12) BOWATER MERSEY	31,248	2.04%	31,885	42,000	100.0%	42,000	2.04%	42,857	100.00%
(13) GEN.REPL./LOAD FOLL.	8,031	2.04%	8,194	13,389	80.0%	10,706	2.04%	10,925	100.82%
(14) REAL TIME PRICING	0	N/A	0	0	N/A	0	N/A	0	N/A
(15) EXPORT SALES	0	N/A	0	0	N/A	0	N/A	0	N/A
(16) TOTAL	926,493	6.75%	989,059	1,820,566	83.1%	1,513,432	7.71%	1,630,133	81.55%

EXHIBIT 9A

NOVA SCOTIA POWER INC.

SALES, GENERATION AND DEMAND ANALYSIS

FOR JUNE 2011

	(1) MWH SALES	(2) ENERGY LINE LOSSES	(3) ENERGY REQUIREMENT	(4) CLASS NON-COINCIDENT DMD. (KW)	(5) SYSTEM COINCIDENT FACTOR	(6) SYSTEM COINCIDENT DMD. (KW)	(7) DEMAND LINE LOSSES	(8) SYSTEM COIN. PEAK DMD. (KW)	(9) SYSTEM COINCIDENT L/D FACTOR
(1) DOMESTIC	270,920	7.72%	291,832	613,972	65.1%	399,492	7.69%	430,232	94.21%
(2) SMALL GENERAL	15,660	7.27%	16,799	35,635	93.2%	33,209	7.47%	35,690	65.37%
(3) GENERAL	193,483	5.41%	203,947	436,796	97.3%	425,098	6.19%	451,418	62.75%
(4) GENERAL LARGE	32,044	5.25%	33,727	63,261	95.1%	60,135	5.36%	63,360	73.93%
(5) SMALL INDUSTRIAL	22,086	5.65%	23,335	47,064	89.7%	42,216	5.79%	44,658	72.57%
(6) MEDIUM INDUSTRIAL	43,819	5.30%	46,140	81,513	88.8%	72,386	5.35%	76,256	84.04%
(7) LARGE INDUSTRIAL	76,702	4.44%	80,109	122,148	83.1%	101,543	4.34%	105,950	105.01%
(8) ELI 2P-RTP	148,715	2.04%	151,748	206,548	100.0%	206,548	2.04%	210,762	100.00%
(9) MUNICIPAL	13,401	4.63%	14,021	25,390	98.0%	24,873	4.78%	26,062	74.72%
(10) UNMETERED	9,443	9.07%	10,299	26,607	12.5%	3,334	4.74%	3,492	409.67%
(11) SUB-TOTAL	826,272		871,957	1,658,935	82.5%	1,368,834	5.77%	1,447,878	83.64%
(12) BOWATER MERSEY	30,240	2.04%	30,857	42,000	100.0%	42,000	2.04%	42,857	100.00%
(13) GEN.REPL./LOAD FOLL.	7,921	2.04%	8,082	33,390	31.7%	10,597	2.04%	10,813	103.81%
(14) REAL TIME PRICING	0	N/A	0	0	N/A	0	N/A	0	N/A
(15) EXPORT SALES	0	N/A	0	0	N/A	0	N/A	0	N/A
(16) TOTAL	864,433	5.38%	910,897	1,734,325	82.0%	1,421,431	5.64%	1,501,548	84.26%

EXHIBIT 9A

NOVA SCOTIA POWER INC.

SALES, GENERATION AND DEMAND ANALYSIS

FOR JULY 2011

	(1) MWH SALES	(2) ENERGY LINE LOSSES	(3) ENERGY REQUIREMENT	(4) CLASS NON-COINCIDENT DMD. (KW)	(5) SYSTEM COINCIDENT FACTOR	(6) SYSTEM COINCIDENT DMD. (KW)	(7) DEMAND LINE LOSSES	(8) SYSTEM COIN. PEAK DMD. (KW)	(9) SYSTEM COINCIDENT L/D FACTOR
(1) DOMESTIC	272,403	7.75%	293,525	549,365	82.4%	452,631	8.35%	490,413	80.45%
(2) SMALL GENERAL	16,139	8.04%	17,437	34,943	98.0%	34,235	8.43%	37,122	63.13%
(3) GENERAL	209,260	5.70%	221,193	433,895	100.0%	433,895	6.46%	461,944	64.36%
(4) GENERAL LARGE	36,864	6.15%	39,131	66,014	98.3%	64,901	6.36%	69,029	76.19%
(5) SMALL INDUSTRIAL	22,451	5.57%	23,702	47,928	90.2%	43,209	5.73%	45,683	69.74%
(6) MEDIUM INDUSTRIAL	43,779	5.20%	46,053	79,683	89.5%	71,307	5.25%	75,052	82.47%
(7) LARGE INDUSTRIAL	78,206	4.37%	81,620	118,174	91.8%	108,474	4.37%	113,212	96.90%
(8) ELI 2P-RTP	153,672	2.04%	156,807	206,548	100.0%	206,548	2.04%	210,762	100.00%
(9) MUNICIPAL	14,719	4.60%	15,395	26,709	95.0%	25,378	4.73%	26,578	77.85%
(10) UNMETERED	9,282	9.23%	10,139	26,609	11.7%	3,123	4.69%	3,269	416.88%
(11) SUB-TOTAL	856,774		905,001	1,589,868	90.8%	1,443,700	6.19%	1,533,063	79.34%
(12) BOWATER MERSEY	31,248	2.04%	31,885	42,000	100.0%	42,000	2.04%	42,857	100.00%
(13) GEN.REPL./LOAD FOLL.	9,180	2.04%	9,367	33,649	42.9%	14,419	2.04%	14,713	85.57%
(14) REAL TIME PRICING	0	N/A	0	0	N/A	0	N/A	0	N/A
(15) EXPORT SALES	0	N/A	0	0	N/A	0	N/A	0	N/A
(16) TOTAL	897,202	5.47%	946,254	1,665,517	90.1%	1,500,119	6.03%	1,590,633	79.96%

EXHIBIT 9A

NOVA SCOTIA POWER INC.

SALES, GENERATION AND DEMAND ANALYSIS

FOR AUGUST 2011

	(1) MWH SALES	(2) ENERGY LINE LOSSES	(3) ENERGY REQUIREMENT	(4) CLASS NON-COINCIDENT DMD. (KW)	(5) SYSTEM COINCIDENT FACTOR	(6) SYSTEM COINCIDENT DMD. (KW)	(7) DEMAND LINE LOSSES	(8) SYSTEM COIN. PEAK DMD. (KW)	(9) SYSTEM COINCIDENT L/D FACTOR
(1) DOMESTIC	266,811	8.81%	290,322	522,712	96.1%	502,474	9.95%	552,488	70.63%
(2) SMALL GENERAL	16,247	9.57%	17,802	33,522	73.7%	24,689	9.60%	27,058	88.43%
(3) GENERAL	203,474	6.49%	216,685	426,258	87.9%	374,528	7.00%	400,738	72.68%
(4) GENERAL LARGE	36,370	7.24%	39,002	66,749	85.5%	57,036	7.32%	61,210	85.64%
(5) SMALL INDUSTRIAL	22,409	6.37%	23,837	48,722	72.9%	35,501	6.37%	37,764	84.84%
(6) MEDIUM INDUSTRIAL	43,826	6.20%	46,545	80,574	83.0%	66,866	6.22%	71,022	88.09%
(7) LARGE INDUSTRIAL	87,481	5.24%	92,068	136,644	88.3%	120,714	5.18%	126,972	97.46%
(8) ELI 2P-RTP	153,672	2.04%	156,807	206,548	100.0%	206,548	2.04%	210,762	100.00%
(9) MUNICIPAL	14,520	5.27%	15,285	26,776	85.6%	22,916	5.35%	24,142	85.10%
(10) UNMETERED	9,624	9.92%	10,579	26,610	11.2%	2,974	5.46%	3,136	453.35%
(11) SUB-TOTAL	854,434		908,931	1,575,114	89.8%	1,414,245	7.14%	1,515,292	80.62%
(12) BOWATER MERSEY	31,248	2.04%	31,885	42,000	100.0%	42,000	2.04%	42,857	100.00%
(13) GEN.REPL./LOAD FOLL.	10,423	2.04%	10,635	33,647	78.7%	26,482	2.04%	27,022	52.90%
(14) REAL TIME PRICING	0	N/A	0	0	N/A	0	N/A	0	N/A
(15) EXPORT SALES	0	N/A	0	0	N/A	0	N/A	0	N/A
(16) TOTAL	896,105	6.18%	951,452	1,650,761	89.8%	1,482,727	6.91%	1,585,171	80.67%

EXHIBIT 9A

NOVA SCOTIA POWER INC.

SALES, GENERATION AND DEMAND ANALYSIS

FOR SEPTEMBER 2011

	(1) MWH SALES	(2) ENERGY LINE LOSSES	(3) ENERGY REQUIREMENT	(4) CLASS NON-COINCIDENT DMD. (KW)	(5) SYSTEM COINCIDENT FACTOR	(6) SYSTEM COINCIDENT DMD. (KW)	(7) DEMAND LINE LOSSES	(8) SYSTEM COIN. PEAK DMD. (KW)	(9) SYSTEM COINCIDENT L/D FACTOR
(1) DOMESTIC	267,191	7.22%	286,474	614,153	90.0%	553,004	8.72%	601,209	66.18%
(2) SMALL GENERAL	14,709	7.63%	15,832	32,173	77.2%	24,845	7.71%	26,760	82.17%
(3) GENERAL	188,749	5.18%	198,520	406,619	68.7%	279,283	5.13%	293,614	93.91%
(4) GENERAL LARGE	33,809	5.49%	35,664	65,935	67.7%	44,602	5.30%	46,968	105.46%
(5) SMALL INDUSTRIAL	20,946	5.20%	22,037	47,924	61.5%	29,489	5.11%	30,995	98.75%
(6) MEDIUM INDUSTRIAL	42,687	5.01%	44,827	81,783	82.4%	67,409	5.03%	70,798	87.94%
(7) LARGE INDUSTRIAL	81,358	4.39%	84,931	130,401	88.6%	115,562	4.34%	120,583	97.82%
(8) ELI 2P-RTP	148,715	2.04%	151,748	206,548	100.0%	206,548	2.04%	210,762	100.00%
(9) MUNICIPAL	14,198	4.27%	14,805	25,528	89.6%	22,878	4.36%	23,875	86.12%
(10) UNMETERED	9,721	7.69%	10,469	26,612	65.5%	17,431	6.51%	18,565	78.32%
(11) SUB-TOTAL	822,084		865,307	1,637,676	83.1%	1,361,052	6.10%	1,444,129	83.22%
(12) BOWATER MERSEY	30,240	2.04%	30,857	42,000	100.0%	42,000	2.04%	42,857	100.00%
(13) GEN.REPL./LOAD FOLL.	14,026	2.04%	14,312	34,100	31.5%	10,755	2.04%	10,975	181.13%
(14) REAL TIME PRICING	0	N/A	0	0	N/A	0	N/A	0	N/A
(15) EXPORT SALES	0	N/A	0	0	N/A	0	N/A	0	N/A
(16) TOTAL	866,350	5.09%	910,476	1,713,775	82.5%	1,413,808	5.95%	1,497,961	84.42%

EXHIBIT 9A

NOVA SCOTIA POWER INC.

SALES, GENERATION AND DEMAND ANALYSIS

FOR OCTOBER 2011

	(1) MWH SALES	(2) ENERGY LINE LOSSES	(3) ENERGY REQUIREMENT	(4) CLASS NON-COINCIDENT DMD. (KW)	(5) SYSTEM COINCIDENT FACTOR	(6) SYSTEM COINCIDENT DMD. (KW)	(7) DEMAND LINE LOSSES	(8) SYSTEM COIN. PEAK DMD. (KW)	(9) SYSTEM COINCIDENT L/D FACTOR
(1) DOMESTIC	307,678	8.72%	334,512	749,948	87.0%	652,222	10.75%	722,329	62.24%
(2) SMALL GENERAL	16,406	8.47%	17,795	33,713	79.9%	26,921	8.65%	29,250	81.77%
(3) GENERAL	197,408	6.29%	209,823	389,071	78.0%	303,340	6.43%	322,836	87.36%
(4) GENERAL LARGE	32,196	6.58%	34,314	58,495	78.4%	45,863	6.55%	48,866	94.38%
(5) SMALL INDUSTRIAL	19,292	6.22%	20,492	40,921	65.1%	26,630	6.13%	28,264	97.45%
(6) MEDIUM INDUSTRIAL	43,042	5.88%	45,572	81,578	81.3%	66,341	5.90%	70,254	87.19%
(7) LARGE INDUSTRIAL	81,777	5.11%	85,953	126,478	87.6%	110,851	5.04%	116,435	99.22%
(8) ELI 2P-RTP	153,672	2.04%	156,807	206,548	100.0%	206,548	2.04%	210,762	100.00%
(9) MUNICIPAL	15,252	4.91%	16,001	27,768	96.8%	26,876	5.08%	28,242	76.15%
(10) UNMETERED	9,489	9.27%	10,368	26,611	48.2%	12,836	7.47%	13,794	101.02%
(11) SUB-TOTAL	876,211		931,637	1,741,132	84.9%	1,478,427	7.62%	1,591,032	78.70%
(12) BOWATER MERSEY	31,248	2.04%	31,885	42,000	100.0%	42,000	2.04%	42,857	100.00%
(13) GEN.REPL./LOAD FOLL.	9,056	2.04%	9,240	17,733	61.4%	10,888	2.04%	11,110	111.79%
(14) REAL TIME PRICING	0	N/A	0	0	N/A	0	N/A	0	N/A
(15) EXPORT SALES	0	N/A	0	0	N/A	0	N/A	0	N/A
(16) TOTAL	916,514	6.14%	972,763	1,800,864	85.0%	1,531,315	7.42%	1,644,999	79.48%

EXHIBIT 9A

NOVA SCOTIA POWER INC.

SALES, GENERATION AND DEMAND ANALYSIS

FOR NOVEMBER 2011

	(1) MWH SALES	(2) ENERGY LINE LOSSES	(3) ENERGY REQUIREMENT	(4) CLASS NON-COINCIDENT DMD. (KW)	(5) SYSTEM COINCIDENT FACTOR	(6) SYSTEM COINCIDENT DMD. (KW)	(7) DEMAND LINE LOSSES	(8) SYSTEM COIN. PEAK DMD. (KW)	(9) SYSTEM COINCIDENT L/D FACTOR
(1) DOMESTIC	360,026	9.63%	394,682	928,580	93.4%	867,571	12.93%	979,732	55.95%
(2) SMALL GENERAL	17,173	9.32%	18,773	38,696	65.4%	25,312	9.29%	27,664	94.25%
(3) GENERAL	206,245	6.18%	218,990	409,379	71.2%	291,505	6.09%	309,270	98.35%
(4) GENERAL LARGE	31,820	6.19%	33,789	57,323	74.1%	42,457	6.08%	45,039	104.20%
(5) SMALL INDUSTRIAL	21,159	5.99%	22,427	49,904	50.0%	24,952	5.82%	26,404	117.97%
(6) MEDIUM INDUSTRIAL	42,152	5.53%	44,483	83,580	54.9%	45,921	5.19%	48,304	127.90%
(7) LARGE INDUSTRIAL	79,203	4.29%	82,601	129,586	95.3%	123,539	4.38%	128,948	88.97%
(8) ELI 2P-RTP	148,715	2.04%	151,748	206,548	100.0%	206,548	2.04%	210,762	100.00%
(9) MUNICIPAL	16,990	4.33%	17,726	33,671	92.6%	31,176	4.52%	32,586	75.55%
(10) UNMETERED	10,075	8.84%	10,966	26,610	66.1%	17,578	7.99%	18,983	80.23%
(11) SUB-TOTAL	933,559		996,185	1,963,879	85.4%	1,676,560	9.01%	1,827,690	75.70%
(12) BOWATER MERSEY	30,240	2.04%	30,857	42,000	100.0%	42,000	2.04%	42,857	100.00%
(13) GEN.REPL./LOAD FOLL.	8,654	2.04%	8,830	31,478	30.9%	9,732	2.04%	9,931	123.50%
(14) REAL TIME PRICING	0	N/A	0	0	N/A	0	N/A	0	N/A
(15) EXPORT SALES	0	N/A	0	0	N/A	0	N/A	0	N/A
(16) TOTAL	972,453	6.52%	1,035,873	2,037,357	84.8%	1,728,292	8.81%	1,880,477	76.51%

EXHIBIT 9A

NOVA SCOTIA POWER INC.

SALES, GENERATION AND DEMAND ANALYSIS

FOR DECEMBER 2011

	(1) MWH SALES	(2) ENERGY LINE LOSSES	(3) ENERGY REQUIREMENT	(4) CLASS NON-COINCIDENT DMD. (KW)	(5) SYSTEM COINCIDENT FACTOR	(6) SYSTEM COINCIDENT DMD. (KW)	(7) DEMAND LINE LOSSES	(8) SYSTEM COIN. PEAK DMD. (KW)	(9) SYSTEM COINCIDENT L/D FACTOR
(1) DOMESTIC	478,645	12.95%	540,616	1,115,294	85.8%	956,638	16.20%	1,111,630	65.37%
(2) SMALL GENERAL	21,449	11.42%	23,898	46,772	90.6%	42,381	12.26%	47,577	67.51%
(3) GENERAL	235,174	7.99%	253,974	457,932	93.2%	426,595	9.01%	465,026	73.41%
(4) GENERAL LARGE	32,355	8.09%	34,974	56,864	88.3%	50,207	8.30%	54,374	86.45%
(5) SMALL INDUSTRIAL	24,538	7.28%	26,324	52,126	62.5%	32,579	7.24%	34,939	101.27%
(6) MEDIUM INDUSTRIAL	42,939	6.87%	45,890	85,528	77.3%	66,071	6.96%	70,672	87.28%
(7) LARGE INDUSTRIAL	75,303	5.57%	79,494	131,719	79.5%	104,716	5.54%	110,521	96.68%
(8) ELI 2P-RTP	153,672	2.04%	156,807	206,548	100.0%	206,548	2.04%	210,762	100.00%
(9) MUNICIPAL	20,039	5.75%	21,190	39,713	100.0%	39,713	6.11%	42,141	67.59%
(10) UNMETERED	10,138	13.26%	11,483	26,613	100.0%	26,613	15.28%	30,679	50.31%
(11) SUB-TOTAL	1,094,254		1,194,649	2,219,108	88.0%	1,952,060	11.59%	2,178,320	73.71%
(12) BOWATER MERSEY	31,248	2.04%	31,885	42,000	100.0%	42,000	2.04%	42,857	100.00%
(13) GEN.REPL./LOAD FOLL.	7,789	2.04%	7,948	11,695	91.5%	10,696	2.04%	10,914	97.88%
(14) REAL TIME PRICING	0	N/A	0	0	N/A	0	N/A	0	N/A
(15) EXPORT SALES	0	N/A	0	0	N/A	0	N/A	0	N/A
(16) TOTAL	1,133,291	8.93%	1,234,482	2,272,803	88.2%	2,004,755	11.34%	2,232,091	74.34%

EXHIBIT 9B

NOVA SCOTIA POWER INC.

DETERMINATION OF CLASS NON-COINCIDENT KW DEMAND BY VOLTAGE LEVEL

FOR THE YEAR ENDING DECEMBER 31, 2012

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED
(1) NON-COIN. KW SEC.	1,777,927	1,177,490	49,926	476,781	0	47,117	0	0	0	0	26,613
(2) LOSSES 6.00%	106,676	70,649	2,996	28,607	0	2,827	0	0	0	0	1,597
(3) SUB-TOTAL	1,884,602	1,248,139	52,921	505,388	0	49,944	0	0	0	0	28,210
(4) NON-COIN. KW PRI.	2,066,397	1,248,139	52,921	532,231	66,749	54,953	83,193	0	0	0	28,210
(5) LOSSES 5.40%	111,585	67,400	2,858	28,740	3,604	2,967	4,492	0	0	0	1,523
(6) SUB-TOTAL	2,177,982	1,315,539	55,779	560,971	70,354	57,920	87,685	0	0	0	29,733
(7) NON-COIN. KW TRANS.	2,564,083	1,315,539	55,779	560,971	70,354	57,920	90,020	136,644	206,548	40,574	29,733
(8) LOSSES 3.70%	94,871	48,675	2,064	20,756	2,603	2,143	3,331	5,056	7,642	1,501	1,100
(9) TOTAL	2,658,954	1,364,214	57,843	581,727	72,957	60,063	93,351	141,699	214,190	42,075	30,833

EXHIBIT 9C

NOVA SCOTIA POWER INC.

DETAIL OF MONTHLY CLASS SYSTEM COINCIDENT KW DEMAND

FOR THE YEAR ENDING DECEMBER 31, 2012

MONTH	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUST.	(7) MEDIUM INDUST.	(8) LARGE INDUST.	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED	(12) MERSEY SYSTEM	(13) GRLF	(14) REAL TIME PRICING
(1) JANUARY	**2,308,459**	**1,234,772**	**52,912**	**417,217**	**54,734**	**35,646**	**70,855**	**104,997**	**210,762**	**42,532**	**30,575**	**42,857**	**10,602**	**0**
(2) FEBRUARY	**2,291,217**	**1,163,436**	**55,029**	**490,772**	**53,285**	**36,794**	**67,882**	**107,792**	**210,762**	**40,696**	**11,486**	**42,857**	**10,424**	**0**
(3) MARCH	2,033,364	928,377	33,641	481,185	61,557	44,093	79,227	101,104	210,762	37,421	2,782	42,857	10,359	0
(4) APRIL	1,839,732	817,235	31,459	407,052	56,338	46,846	80,064	101,676	210,762	32,378	2,733	42,857	10,335	0
(5) MAY	1,630,133	683,849	25,947	353,829	53,516	38,843	65,096	114,227	210,762	26,939	3,344	42,857	10,925	0
(6) JUNE	1,501,548	430,232	35,690	451,418	63,360	44,658	76,256	105,950	210,762	26,062	3,492	42,857	10,813	0
(7) JULY	1,590,633	490,413	37,122	461,944	69,029	45,683	75,052	113,212	210,762	26,578	3,269	42,857	14,713	0
(8) AUGUST	1,585,171	552,488	27,058	400,738	61,210	37,764	71,022	126,972	210,762	24,142	3,136	42,857	27,022	0
(9) SEPTEMBER	1,497,961	601,209	26,760	293,614	46,968	30,995	70,798	120,583	210,762	23,875	18,565	42,857	10,975	0
(10) OCTOBER	1,644,999	722,329	29,250	322,836	48,866	28,264	70,254	116,435	210,762	28,242	13,794	42,857	11,110	0
(11) NOVEMBER	1,880,477	979,732	27,664	309,270	45,039	26,404	48,304	128,948	210,762	32,586	18,983	42,857	9,931	0
(12) DECEMBER	**2,232,091**	**1,111,630**	**47,577**	**465,026**	**54,374**	**34,939**	**70,672**	**110,521**	**210,762**	**42,141**	**30,679**	**42,857**	**10,914**	**0**
(13) TOT. SUMMED DMD.	22,035,785	9,715,701	430,108	4,854,902	668,275	450,929	845,483	1,352,416	2,529,139	383,592	142,837	514,282	148,123	0
(14) 3 C/P DEMANDS	**6,831,767**	**3,509,838**	**155,518**	**1,373,015**	**162,393**	**107,379**	**209,410**	**323,310**	**632,285**	**125,369**	**72,739**	**128,570**	**31,940**	**0**
(15)					**3 C/P INTERRUPTIBLE RIDER DEMANDS**			**228,673**						
(16)					**NET 3 C/P LARGE INDUST. DEMANDS**			**94,636**						

EXHIBIT 10

NOVA SCOTIA POWER INC.

REVENUE TO EXPENSE COMPARISON

FOR THE YEAR ENDING DECEMBER 31, 2012
(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	$176,046	$359,362	8.22	$76,558	$611,966	$606,735	99.15
(2) SMALL GENERAL	7,664	17,939	8.17	4,052	29,655	31,138	105.00
(3) GENERAL	70,719	201,432	7.95	4,878	277,030	290,881	105.00
(4) LARGE GENERAL	6,962	31,289	7.93	213	38,463	38,699	100.61
(5) SMALL INDUSTRIAL	6,222	20,688	7.90	1,172	28,082	28,262	100.64
(6) MEDIUM INDUSTRIAL	8,922	40,345	7.87	453	49,721	48,346	97.23
(7) LARGE INDUSTRIAL	4,429	72,593	7.78	592	77,613	75,696	97.53
(8) ELI 2P-RTP	545	135,326	7.46	425	136,297	129,482	95.00
(9) MUNICIPAL	3,735	15,445	7.83	144	19,324	18,912	97.87
(10) UNMETERED	14,708	9,518	8.22	1,157	25,382	25,382	100.00
(11) SUB-TOTAL	$299,951	$903,938	7.96	$89,645	1,293,534	1,293,534	100.00
(12) DIRECT EXP./ REV					23,683	28,497	N/A
(13) RETURN ON DIRECT EXP.					4,814	0	N/A
(14) TOTAL					$1,322,030	$1,322,031	100.00

EXHIBIT 10

NOVA SCOTIA POWER INC.

REVENUE TO EXPENSE COMPARISON

FOR THE YEAR ENDING DECEMBER 31, 2012

(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	$156,647	$338,860	7.75	$71,191	$566,699	$564,213	99.56
(2) SMALL GENERAL	6,818	16,915	7.71	3,772	27,505	29,391	106.85
(3) GENERAL	62,957	189,915	7.49	4,559	257,430	273,212	106.13
(4) LARGE GENERAL	6,221	29,498	7.48	212	35,931	35,987	100.16
(5) SMALL INDUSTRIAL	5,546	19,504	7.45	1,106	26,155	26,281	100.48
(6) MEDIUM INDUSTRIAL	7,971	38,033	7.41	448	46,452	44,958	96.78
(7) LARGE INDUSTRIAL	3,301	68,430	7.34	590	72,321	70,391	97.33
(8) ELI 2P-RTP	(1,532)	127,726	7.04	425	126,619	113,493	89.63
(9) MUNICIPAL	3,301	14,562	7.38	144	18,008	17,587	97.66
(10) UNMETERED	13,636	8,972	7.75	1,085	23,693	25,302	106.79
(11) SUB-TOTAL	$264,867	$852,414	7.51	$83,532	1,200,813	1,200,813	100.00
(12) DIRECT EXP./ REV					23,667	27,182	N/A
(13) RETURN ON DIRECT EXP.					3,515	0	N/A
(14) TOTAL					$1,227,996	$1,227,996	100.00

Requirement:

Load Forecast Report.

Submission:

Please refer to Attachment 1.

NOVA SCOTIA POWER
An Emera Company

2011 Load Forecast

Prepared

April 2011

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Appendices

Executive Summary

The Nova Scotia Power Inc. (NSPI) 2011 Load Forecast provides an outlook on the energy and peak demand requirements of in-province customers for 2011 to 2021. As well, it describes the considerations, assumptions and methodology used in the preparation of the forecast. The NSPI Forecast provides the basis for the financial planning and overall operating activities of the Company.

The forecast is based on analyses of sales history, weather, economic indicators, customer surveys, technological and demographic changes in the market and the price and availability of other energy sources.

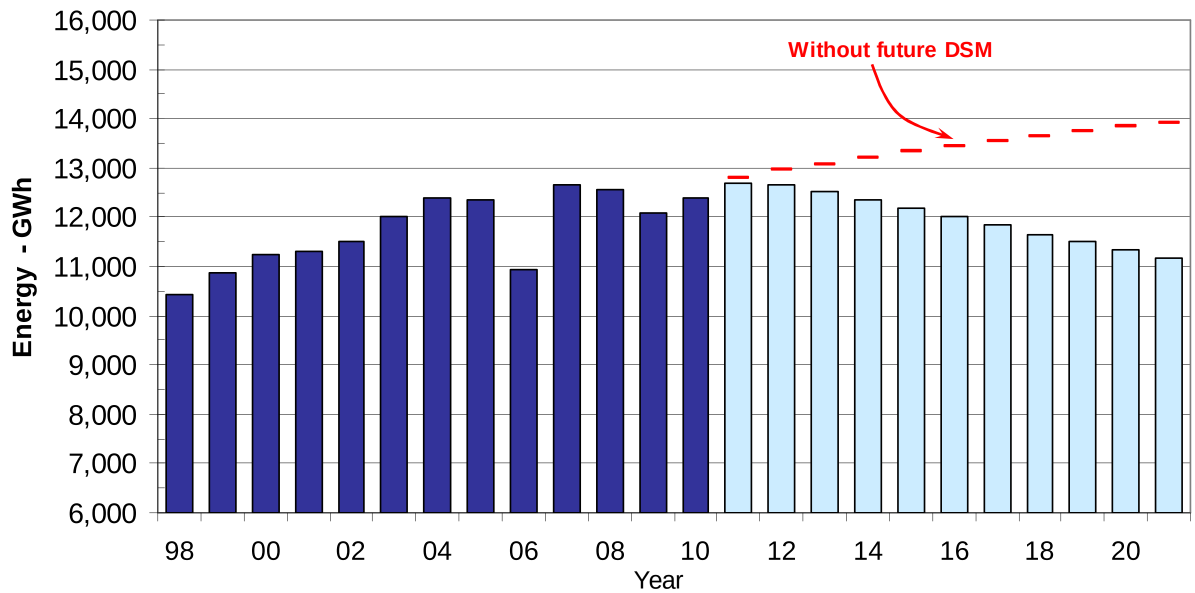
As with any forecast, there is a degree of uncertainty around actual future outcomes. In electricity forecasting, much of this uncertainty is due to the impact of variations in weather, the health of the economy, changes in large customer loads, the number of electric appliances and end-use equipment installed, as well as the manner and degree to which they are used. This forecast presents NSPI's "expected" or "most likely" case and also provides less probable, but possible high and low scenarios for longer term planning purposes.

NSPI billed energy sales are initially modeled and forecast as three provincial customer sectors: residential, commercial and industrial. Input variables for each sector are updated and forecast sales are then calculated using the sector models. The sum of these in-province billed sales plus associated system transmission and distribution losses and changes to unbilled sales are then determined. This is referred to as the Net System Requirement (NSR).

The NSR grew at an average annual rate of 0.9 percent over the previous five years but dropped by 3.7 percent in 2009 due to the economic recession that affected sales, primarily in the industrial sector. Load growth rebounded by 2.5 percent in 2010 and is expected to grow similarly in 2011.

For 2021, NSR is forecast to be 11,173 GWh, an average annual load reduction of 1.3 percent over the ten year forecast period. The growth rates are generally lower than those observed in the recent past, due to the anticipated effects of conservation and energy efficiency programs (demand side management or DSM) planned for the coming years. The underlying 10-year annual growth rate, without the DSM effects is 0.8 percent. The growth in annual net system requirement is shown in Figure 1.

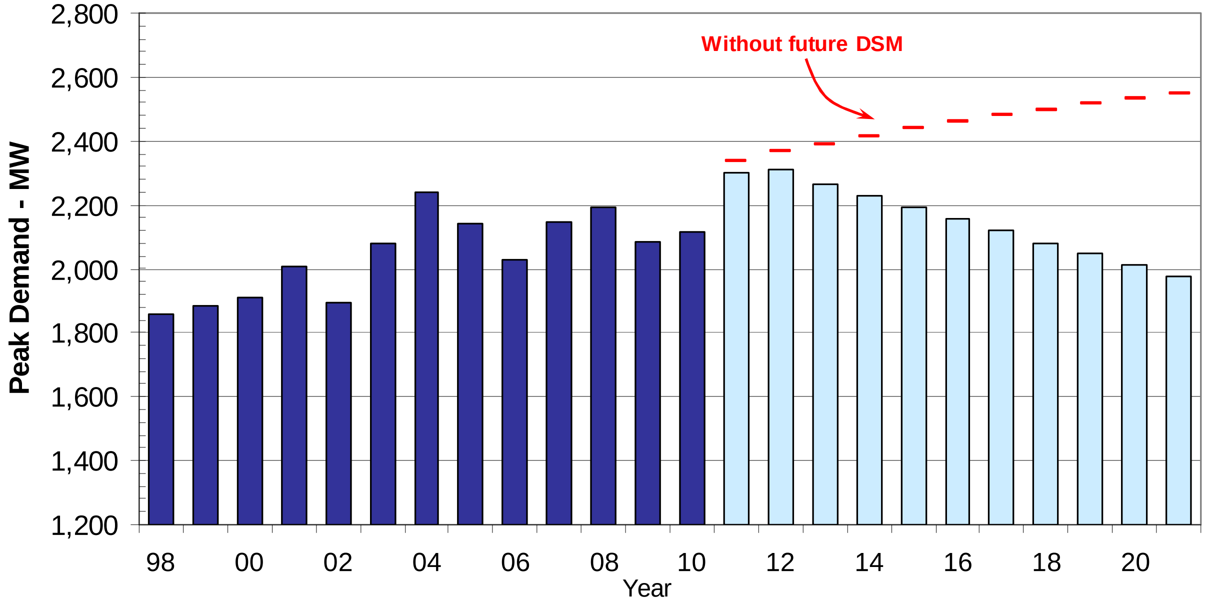
Figure 1 Annual Net System Requirement



In addition to annual energy requirements, NSPI also forecasts the peak hourly demand for future years. The forecast methodology uses forecast energy requirements and expected load shapes (hourly consumption profiles) for the various customer classes. Load shapes are derived from historical analysis, adjusted for any expected changes (e.g. customer plans to add major equipment). Growth in annual net system peak is shown in Figure 2.

Over the longer term, Net System Peak is forecast to decrease from 2,114 MW in winter 2009/10, to 1,991 MW in 2021. The average growth over the forecast period is an annual decline of 1.5 percent. The negative growth rate is due to the anticipated effects of DSM programs. Without the effects of DSM, the average growth rate is 1.0 percent.

Figure 2 Annual Net System Peak (Winter-ending)



The hourly peak demand in the year 2010 occurred in February and was 2,114 MW with temperatures of approximately -13°C (Winter peaks are typically set when cold temperatures drive residential and commercial electric space heating load, on weekdays with temperatures in the range of -15°C or colder). The forecast peak for 2012 is 2,301 MW, assuming typical winter temperatures.

New load forecasting methodology under development at NSPI

A review of NSPI's load forecasting methodology in 2008 recognized that load forecasting could be enhanced with better integration of DSM savings by adopting an end-use model framework.

NSPI is currently reviewing methods of updating its load forecasting methodology to employ Statistically-Adjusted End-use (SAE) modeling. This structure allows the retention some of the economic inputs of the prior model, but also allows for more detailed modeling of end-use types and efficiency trends of those end-use appliances. It is expected that this will allow for improved analysis and integration of DSM effects in the load forecast.

Introduction

NSPI annually develops a forecast of energy sales and peak demand requirements to assess the effects of customer, demographic and economic factors on the future provincial system load. It is a fundamental input to the overall planning, budgeting and operating activities of the Company. Produced in the winter of 2010-2011 and using information available at the time, this forecast covers the period of 2011 - 2021. Unless otherwise noted, average growth rates stated report the average annual rate calculated between 2011 and 2021.

Forecast Models

Nova Scotia electric energy sales are modeled and forecast as three provincial customer sectors: residential, commercial and industrial. Energy forecasts for sector electricity sales are calculated using econometric models in conjunction with forecasts for the independent variables used in those models. Individual customer load forecast survey information is also used for large customers in the Commercial and Industrial sectors.

The sector econometric models are multiple linear regression equations that are designed to capture the relationships between electricity consumption and several independent variables. The models then use these relationships to predict future energy loads. An examination of these variables provides a meaningful explanation of the load growth in each sector. The individual econometric model details are shown in the Appendices of this report.

The variables used in the preparation of the forecast include population, residential customer growth, inflation, GDP, retail sales, oil and electricity prices, appliance saturation levels and average energy use, water and space heat saturation levels and heating degree-days. The primary source of economic and other provincial statistics used in the load forecast is the Conference Board of Canada's *Economic Outlook*, which is released quarterly. This forecast provides a provincial perspective and considers specific Nova Scotia projects and demographics.

Discussion of Major Inputs

The Gross Domestic Product (GDP) for Nova Scotia was estimated at $27,536 million (in constant 2002 dollars) in 2010, and is forecast to increase by 1.8 percent in 2011 and 1.9 percent in 2012.

The provincial Consumer Price index (CPI) for 2010 was 2.2 percent annual growth, a rebound from the negative 0.1 percent posted in 2009 due to the effects of the recession. It is forecast to grow at 2.2 percent for 2011 and 2.1 percent in 2012, and remain in the 2 percent range for the next several years as the Bank of Canada maintains watch on inflation targets.

Housing starts for NS were estimated at 3,438 units in 2009 (singles: 2,193), and were forecast by the Conference Board of Canada (CBoC) to increase to 4,382 for 2010 (singles: 2,834). For 2011, total housing starts are forecast at 3,472, and 3,328 for the year 2012. The continued urbanization and aging population trend is expected to drive a shift to more multi-unit housing and condominiums.

Retail sales, with only 0.2 percent growth in 2009, rebounded with 3.1 percent growth in 2010. For 2011, real growth is expected to slip by 0.2 percent but grow by 1.2 percent in 2012 as consumer confidence improves.

Nova Scotia population in 2010 was estimated to be 942,217 with annual growth remaining relatively flat in the past five years. There is little indication that the prevailing trends will be altered soon. Further population growth in the forecast is marginal with the estimate for 2012 at 946,202 for an annual growth rate of 0.21 percent.

Figure 3 lists the annual growth rates of some of the major independent variables that affect the load forecast.

Figure 3 Forecast Variables

Forecast Variables	2010 Actual Growth Rate	2011 Forecast Growth Rate	2012 Forecast Growth Rate
N.S. Population	0.3%	0.2%	0.2%
N.S. Consumer Price Index	2.2%	2.2%	2.1%
N.S. Personal Disposable Income	1.9%	0.4%	1.8%
N.S. GDP	3.0%	1.8%	1.9%
N.S. Retail Sales	3.1%	-0.2%	1.2%
N.S. Consumer Goods Sales	3.3%	0.8%	1.6%
Home heating oil price	0.0%	5.5%	1.6%

Sector Model Inputs

One factor influencing the residential forecast involves market effects including the price of electricity versus other alternatives (e.g. fuel oil) and the effects of natural gas distribution. The stock of electric appliances is estimated through maturities and conversion rates to and from electric units as well as the electric heat penetration for new construction. Technology factors are considered through increases in efficiency and the introduction of new equipment.

The outlook for the retail price of furnace oil (#2 light) is based on futures pricing and, for the long-term, escalated at rates consistent with other fuel price forecasts used by NSPI. The ratio of oil prices to electricity prices is used in calculating the saturation of residential water and space heating equipment. Furnace oil prices in NS are estimated to average 90 ¢ per litre in 2011 and 92 ¢ in 2012.

Assumptions regarding the effects of natural gas distribution in the province are based on the potential loss of electric space heating and water heating load, primarily in the residential sector. The gas impact on this forecast is projected to remain small however, due to a limited rollout in the growing residential areas of Nova Scotia and limited uptake observed to date in the residential sector.

Electricity sales in the commercial sector are influenced by the level of business activity and as a result, are closely related to the provincial GDP and consumer confidence. Electricity sales to small and medium industrial customers are correlated to general economic growth in the province. However, energy use in the industrial sector is also influenced by large industries such as forestry and pulp & paper. Since changing economic conditions, exchange rates and trade policies can create large fluctuations in sales as companies expand, contract or endure inventory shutdowns; the large industrial forecast relies heavily on input from customer surveys.

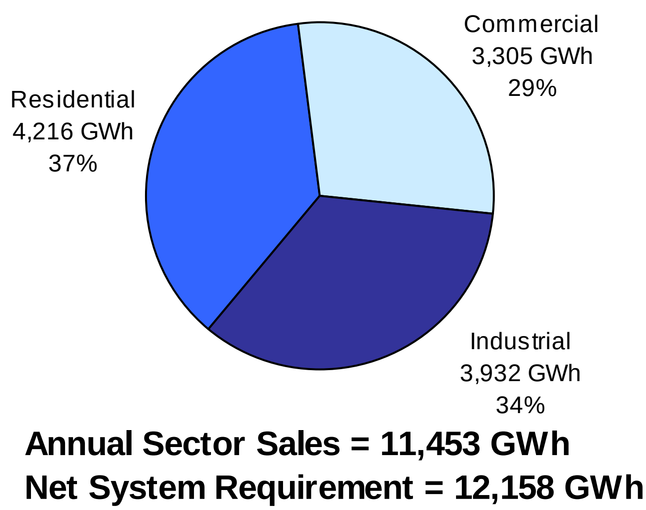
Losses

System losses have averaged 6.7 percent of NSR over the past five years and are expected to remain in the 6.6 to 6.7 percent range over the 10 year forecast period.

Energy Forecast Details

For forecasting, modeling and sales reporting, Nova Scotia electric load is divided into three sector requirements: residential, commercial and industrial. The relative sizes of sector sales are shown in Figure 4.

Figure 4 2010 NSPI Sector Sales



Residential Sector Sales

In 2010, residential customers represented approximately 37 percent of total Nova Scotia energy sales. In addition to direct domestic customers of the Company, the sector also includes residential customers served by six municipal utilities. Seasonal residences comprised 6.5 percent of the residential base.

The residential sector offers an opportunity for more detailed modeling due to the relative similarity of customer end-uses, compared to the wide variations in end-use by commercial and industrial customers. The residential sector forecast is prepared using an econometric model that uses forecast retail sales, an overall end-use appliance index, a variable representing electric heating load, residential electricity cost per kWh and residential electric load from the previous year. A series of end-use models are used to calculate the appliance index and space heating variable forecasts.

A population forecast is used in conjunction with customer formation trends to produce a residential customer count forecast. Sector average electricity costs per kWh and forecast furnace oil prices are used in a market share model to estimate the annual electric space and water heat penetration rates. A composite variable (CHDD) is calculated for use in the residential model that takes into account the annual number of all-electric customers and the forecast heating degree-days.

Household appliance load is modeled using non-linear regression methods that forecast the annual saturation rates of major appliances. Efficiency improvements for new units are accounted for in the stock vintage models that calculate the overall system average use for each appliance type given the age and efficiency mix of the total stock. This appliance saturation and average use information is used to create a composite variable (AIDX), which is used in the residential sector econometric model.

The real cost of electricity is another factor that may affect residential electricity consumption. Consumers may respond to increases in energy prices by reducing consumption or delaying the acquisition of a major appliance, however the price elasticity of this sector appears to be small in the near-term. The econometric model uses the average sector customer price per kWh after tax measured in constant dollars (RREP).

Provincial economic trends are represented in the residential sector model through the forecast of Consumer Goods Spending (RCGOODS), as measured in current dollars. This variable is combined with the forecast of the NS consumer price index to recalculate it in constant dollars for long-term modeling purposes.

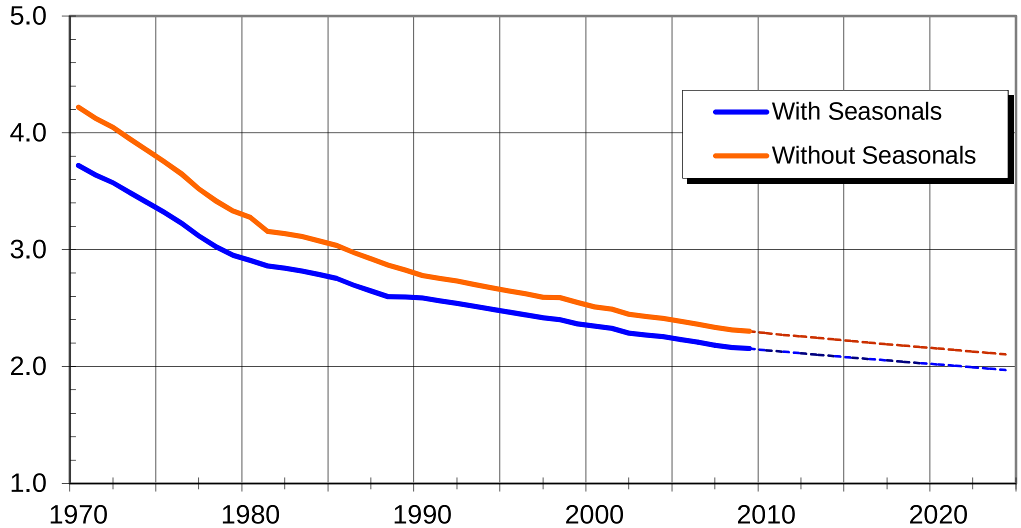
To capture the other sector growth trends, the residential electric load of the previous year is included in the model as a lagged dependent variable. It should be noted however, that the coefficients applied to this and the other variables are the result of estimates using data compiled over a 30-year period, and are therefore reflective of longer term relationships and not just the prior year's results.

The residential econometric model is shown below. Complete residential sector model fit statistics and model specifications are provided in the Appendix of this report.

$$\textit{Residential Load} = 302.4\ \textit{AIDX} + 0.2540\ \textit{CHDD} - 28.25\ \textit{RREP} + 0.1095\ \textit{RCGOODS} + 0.4458\ \textit{Residential load}_{-1}$$

The forecast for new customers for 2011 is 3,676 diminishing to 2,734 by 2021. The number of additions has been decreasing steadily from more than 4,500 in 1997. Although the provincial population is expected to grow at a very low rate, Nova Scotians are becoming more urbanized and increasingly choosing to live in smaller households. This trend is indicated in Figure 5. The result is an increase in the overall number of households, which in turn boosts the total number of electric customers for a given population.

Figure 5 Persons per Residential Account



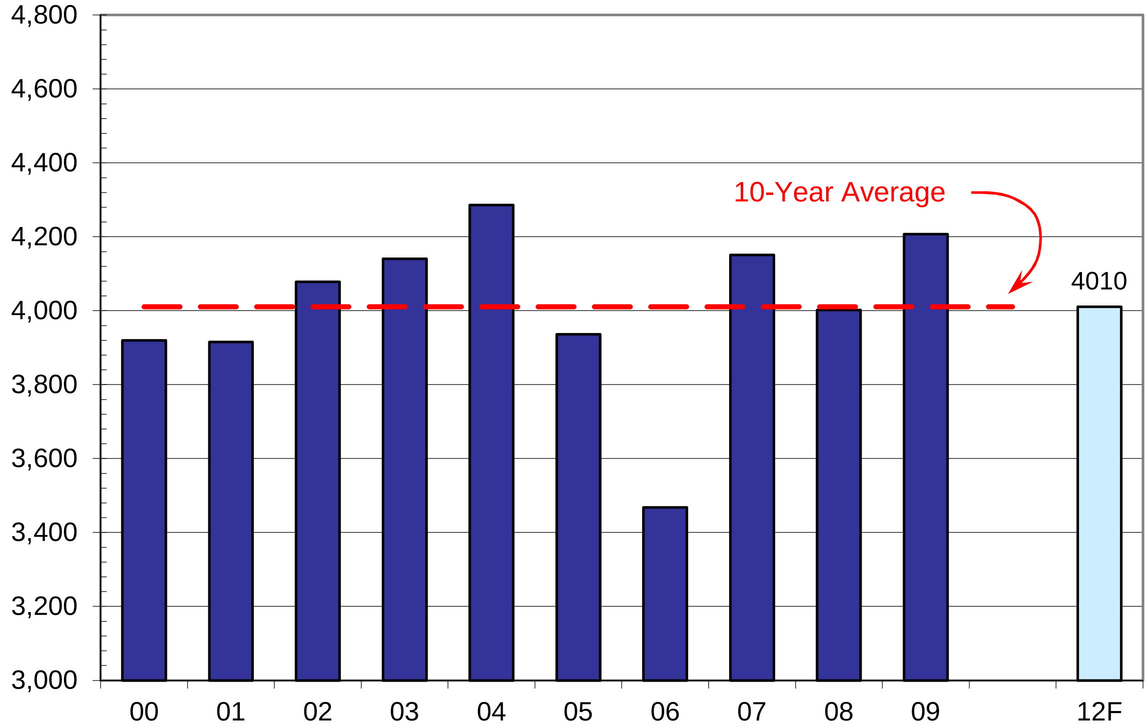
Within the residential sector forecast, large household appliances are modeled individually, considering age, efficiency trends, and acquisition rates. Since these improvements apply only to new appliances, the resulting effect on the overall system load is gradual as older appliances are retired and replaced with more efficient models.

The saturation of electric space heat has been in the mid to high 20 percent range in recent years and was estimated to be 29 percent in 2010. The saturation of electric water heating hovers around 59 percent and is forecast to grow slowly over the forecast period.

The forecast for weather effects uses 10-year average temperatures, measured in heating degree-days (HDD). Heating degree-days are a common measure of heating requirement, based on the degree departure between the daily mean temperature and a given standard temperature. The standard temperature of 18°C is used for these calculations and is assumed to be a comfortable room temperature below which space heating is generally required. The forecast uses the Environment Canada HDD data for Shearwater Airport for the years 2000-2009 which is 4,010 HDD.

Figure 6 shows the variation in the actual annual HDDs over the past ten years.

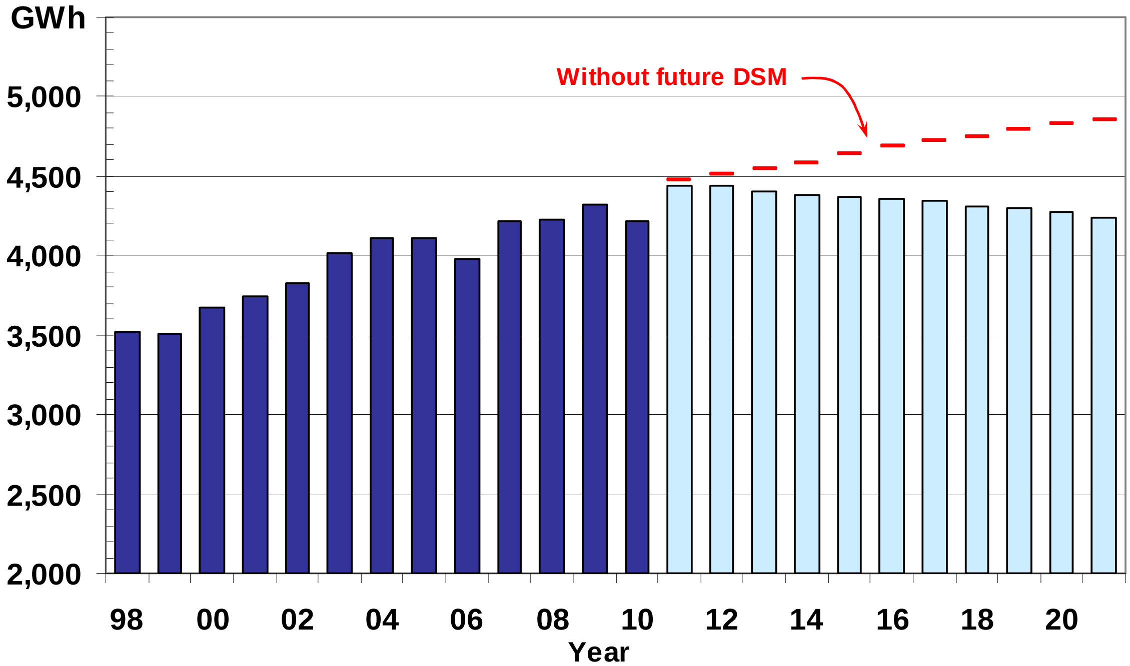
1 **Figure 6 Annual NS Heating Degree-Days**



2
3

4 The residential sector load has grown at an average annual rate of 0.5 percent over the past five
5 years (0.8 percent when adjusted for the effects of weather). Annual residential loads are shown
6 in Figure 7.

Figure 7 Annual Energy – Residential Sector



Growth in this sector is expected to be relatively low. The 2012 load forecast for this sector is 4,437 GWh representing a 1.3 percent annual increase over 2010 actual sales adjusted for weather effects. Without the effects of DSM, 2012 sales are forecast at 4,514 GWh or 2.1 percent annual increase on 2010.

Figure 8 Residential Sector Energy

Year	Residential Sector GWh	Growth Rate %	Without future DSM Residential GWh	Growth Rate %
2001	3,741	1.9	3,741	1.9
2002	3,829	2.3	3,829	2.3
2003	4,011	4.7	4,011	4.7
2004	4,114	2.4	4,114	2.4
2005	4,114	0.0	4,114	0.0
2006	3,979	-3.3	3,979	-3.3
2007	4,218	6.0	4,218	6.0
2008[1]	4,232	0.3	4,232	0.3
2009[2]	4,318	2.0	4,318	2.0
2010[3]	4,216	-2.4	4,216	-2.4
2011F	4,444	5.4	4,475	6.1
2012F	4,437	-0.2	4,514	0.9
2013F	4,399	-0.9	4,542	0.6
2014F	4,381	-0.4	4,586	1.0
2015F	4,372	-0.2	4,634	1.1
2016F	4,361	-0.2	4,682	1.0
2017F	4,343	-0.4	4,722	0.9
2018F	4,312	-0.7	4,750	0.6
2019F	4,293	-0.5	4,789	0.8
2020F	4,269	-0.6	4,824	0.7
2021F	4,243	-0.6	4,857	0.7

Annual residential sector loads are shown in Figure 8. Over the 10 year forecast period, the residential load growth is expected decrease by 0.5 percent annually. Without the effects of DSM, residential sector loads would increase by 0.8 percent per year.

Commercial Sector Sales

Energy sales to the commercial sector in 2010 represented 29 percent of Nova Scotia sales. This customer group includes restaurants, hotels, offices, recreational facilities, stores warehouses hospitals, schools and universities and street and traffic lights, as well as commercial customers served by municipal utilities. The level of business activity in the province is a major factor in determining the energy sales to this sector. The level of business activity is captured in GDP and as a result, a strong correlation exists between commercial energy requirements and real GDP.

[1] The actual results of 2008 include the effects of DSM estimated at 0.9 GWh
[2] The actual results of 2009 include the effects of DSM estimated at 8.0 GWh
[3] The actual results of 2010 include the effects of DSM estimated at 22.4 GWh

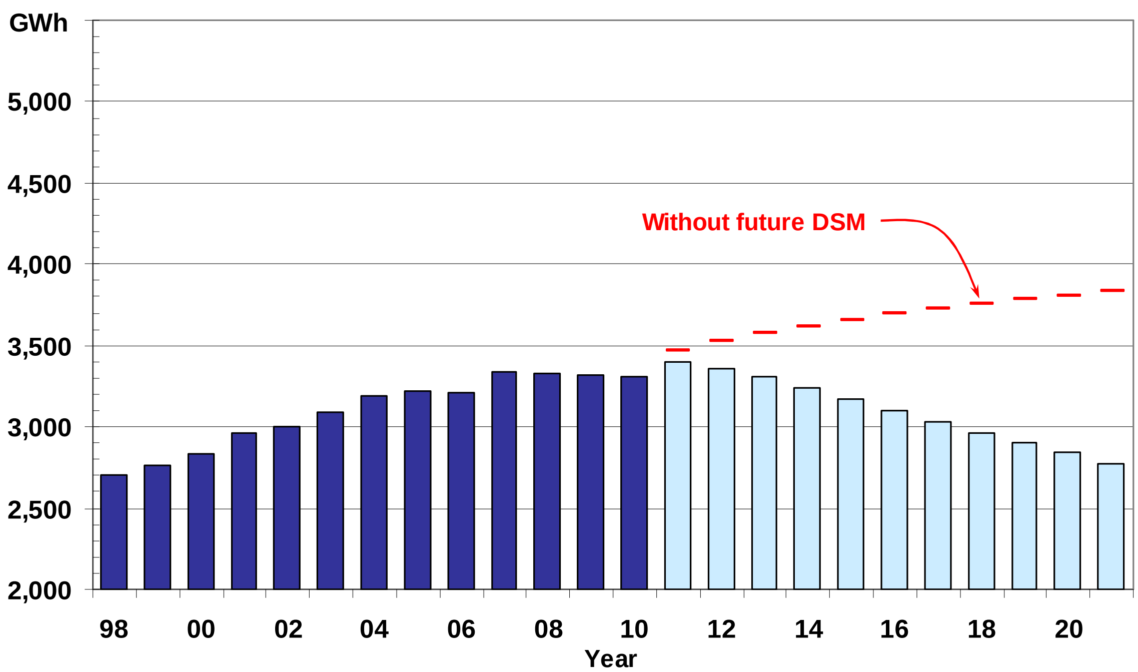
Real personal disposable income (RPDI) is also correlated to activity in the commercial sector and is included in the model.

The commercial sector forecast is produced using an econometric model using real GDP, RPDI, residential electricity sales and the commercial electricity sales from the previous year. The equation is shown below. Complete details of the commercial sector model are presented in the Appendix of this report.

$$Commercial = 0.01906\ RQTOS + 0.01362\ RPDI + 0.2685\ Residential + 0.4245\ Commercial\ load_{-1}$$

Additionally, the largest commercial customers are surveyed to obtain their forecasts of any foreseen load changes. This information is used in a reconciliation of the sector load by rate class. Annual commercial sector loads are indicated in Figure 9.

Figure 9 Annual Energy – Commercial Sector



Growth in this sector has averaged 0.5 percent over the past 5 years (also 0.6 percent when adjusted for weather). Driven by trends in wholesale trade, consumer confidence, and growth in personal disposable income boosting retail trade activity, this sector is forecast to grow to 3,355

GWh by 2012. With the effects of DSM, the annual load rate is expected to decline an average 2.0 percent over the next 10 year period (or increase 1.0 percent without conservation effects). The annual commercial sector loads are shown in Figure 10.

Figure 10 Commercial Sector Energy

Year	Commercial With future DSM GWh	Growth Rate %	Commercial Without future DSM GWh	Growth Rate %
2001	2,959	4.6	2,959	4.6
2002	2,997	1.3	2,997	1.3
2003	3,091	3.1	3,091	3.1
2004	3,188	3.1	3,188	3.1
2005	3,223	1.1	3,223	1.1
2006	3,211	-0.4	3,211	-0.4
2007	3,343	4.1	3,343	4.1
2008[4]	3,327	-0.5	3,327	-0.5
2009[5]	3,320	-0.2	3,320	-0.2
2010[6]	3,305	-0.5	3,305	-0.5
2011F	3,401	2.9	3,467	4.9
2012F	3,355	-1.3	3,527	1.7
2013F	3,309	-1.4	3,574	1.3
2014F	3,240	-2.1	3,617	1.2
2015F	3,173	-2.0	3,658	1.1
2016F	3,101	-2.3	3,693	0.9
2017F	3,031	-2.2	3,725	0.9
2018F	2,965	-2.2	3,753	0.8
2019F	2,903	-2.1	3,783	0.8
2020F	2,839	-2.2	3,809	0.7
2021F	2,774	-2.3	3,832	0.6

Industrial Sector Sales

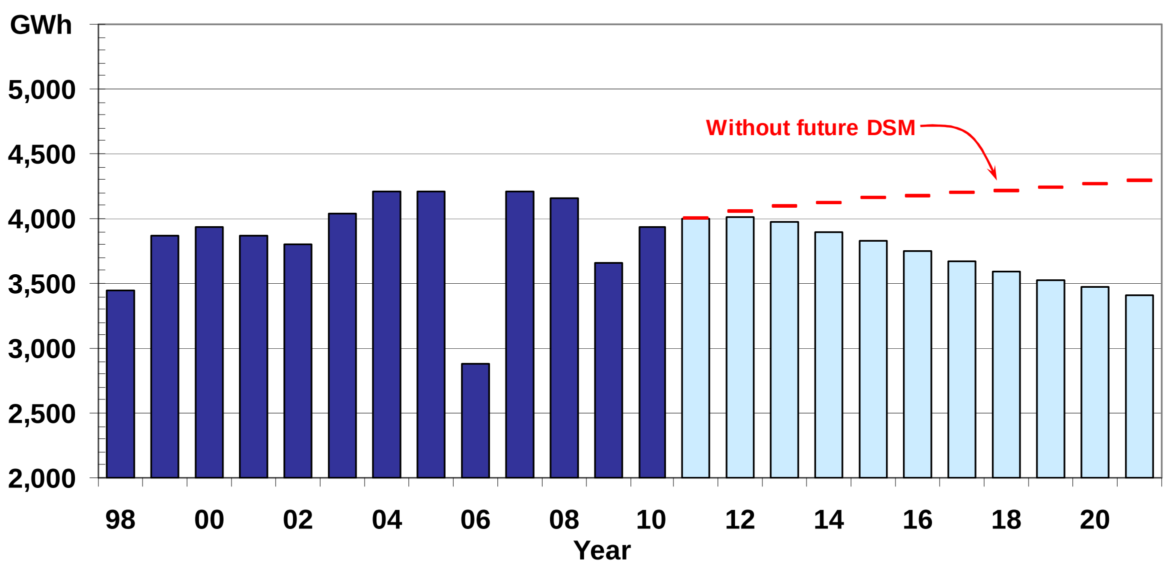
In 2010, the industrial sector represented 34 percent of Nova Scotia total electricity sales. This group is comprised of customers who process raw materials or manufacture finished goods. It includes both primary resource industries such as mining and forestry as well as secondary industries such as manufacturing and food processing. While this sector is made up of over

[4] The actual results of 2008 include DSM effects estimated at 2.5 GWh
[5] The actual results of 2009 include DSM effects estimated at 25.4 GWh
[6] The actual results of 2010 include DSM effects estimated at 40.2 GWh

2,000 customers, a few large customers represent most of the energy consumption. For instance, the five largest customers use two-thirds of the energy in this sector and one-quarter of in-province energy sales. With relatively few customers representing a large proportion of the load in this sector, changes in production levels, equipment and technology changes, expansion or downsizing can have a significant impact on the load.

The demand for manufactured and processed goods is driven by exports as well as the health of the provincial economy. Annual industrial sector loads are shown in Figure 11. The 12 percent drop in 2009 sales was the result of the economic downturn which directly affected the markets for many industrial customers.

Figure 11 Annual Energy – Industrial Sector



The load for this sector is forecast using a combination of econometric modeling and large customer surveys. The Small Industrial customer class model uses NS Manufacturing GDP and Non-Residential Investment as economic inputs and the Medium Industrial customer class model uses NS Manufacturing GDP and Employment in Manufacturing as the economic drivers. Both models use the previous year's sales as a lagged dependent variable.

The Small Industrial econometric model equation is shown below. Complete fit statistics and model specifications are shown in the Appendix to this report.

$$SM\_IND = 0.01885\ GDP\_Man + 0.01278\ NonRes\_Inv + 0.7220\ SM\_IND_{-1}$$

The Medium Industrial econometric model equation is shown below.

$$MED\_IND = 0.06218\ GDP\_Man + 1.168\ Man\_Emp + 0.5911\ MED\_IND_{-1}$$

Large customers forecasts are based on trends and customer input. Customers are surveyed regularly in order to gather their forecast monthly electricity requirements over the next three year period, given planned production levels and equipment changes. The information is used as input to prepare the large industrial load forecast by rate class. The annual industrial sector loads are shown in Figure 12.

Figure 12 Industrial Sector Energy

Year	With future DSM Industrial GWh	Growth Rate %	Without future DSM Industrial GWh	Growth Rate %
2001	3,873	-1.5	3,873	-1.5
2002	3,799	-1.9	3,799	-1.9
2003	4,046	6.5	4,046	6.5
2004	4,212	4.1	4,212	4.1
2005	4,215	0.1	4,215	0.1
2006	2,888	-31.5	2,888	-31.5
2007	4,205	45.6	4,205	45.6
2008[7]	4,161	-1.0	4,161	-1.0
2009[8]	3,658	-12.1	3,658	-12.1
2010[9]	3,932	7.5	3,932	7.5
2011F	3,995	1.6	4,004	1.8
2012F	4,018	0.6	4,053	1.2
2013F	3,971	-1.2	4,091	0.9
2014F	3,898	-1.8	4,123	0.8
2015F	3,826	-1.8	4,152	0.7
2016F	3,748	-2.0	4,174	0.5
2017F	3,670	-2.1	4,193	0.5
2018F	3,598	-1.9	4,215	0.5
2019F	3,532	-1.9	4,238	0.5
2020F	3,471	-1.7	4,263	0.6
2021F	3,412	-1.7	4,285	0.5

[7] The actual results of 2008 include DSM effects estimated at 0.9 GWh
[8] The actual results of 2009 include DSM effects estimated at 4.8 GWh
[9] The actual results of 2010 include DSM effects estimated at 19.9 GWh

With no new expansions or customer additions of large magnitude anticipated for 2011 or 2012, combined with slow recovery from the economic recession, growth in the industrial sector is expect to remain low. DSM is expected to diminish overall growth in this sector.

Industrial sector load growth averaged 1.4 percent per year from 2000-2005, but dipped by 20 percent in 2006 due to a major customer shutdown. For the five year period ending 2008, the average annual growth was 0.6 percent, encompassing the 2003 expansion at the largest paper mill. The industrial load for 2009 dropped 12 percent with many customers operating below full load due to market conditions during the recession. In 2010, the industrial sector began a recovery from the recession, posting a growth rate of 7.5 percent and will continue to grow by 1.6 percent in 2011. Between 2011-2021, industrial sales are expected to decline on average by 1.6 percent in this sector with energy conservation, or grow at 0.7 percent in the absence of DSM.

Total Sales

Given the combined activities of each sector, including large industrial shutdowns, expansions, etc., total sales grew at an average annual rate of 1.0 percent over the 5 years ending 2008, but then had a 3.6 percent drop in 2009 due to the economic slowdown. Combining each of the sector sales forecasts, total Nova Scotia sales are expected to decline with an average annual growth rate of 1.3 percent over the 10 year forecast period due to the effects of energy conservation. Without conservation programs, growth is expected to average 0.8 percent per year. The billed sales are therefore expected to decline from 11,840 GWh in 2011 to 10,430 GWh by the year 2021.

System Losses and Unbilled Sales

The load forecast is developed using Nova Scotia Power “billed” sales rather than “accrued” sales to provide a longer historical time series upon which to base the models. Billed sales refers to the amount of energy billed to customers in a given time period such as a calendar month or a year, whereas accrued sales recognizes the amount of energy actually generated and consumed during that specific time period. Due to the periodic nature and delays inherent in any meter reading and billing process, billed sales will vary somewhat from accrued sales. Energy generated and sold but not yet billed, is referred to as "Unbilled" sales.

The difference between energy generated for use within provincial borders and the total NSPI billed sales comprises transmission and distribution system losses as well as changes to the level of unbilled sales. Losses of approximately 4 percent of sales within municipal utility service areas are also included in this total Nova Scotia losses estimate.

Based on historical estimates, losses are forecast to range between 6.6 and 6.7 percent of the total Nova Scotia energy requirement over the forecast period.

Net System Requirement

The Net System Requirement (NSR) is the energy required to supply the sum of residential, commercial, and industrial electricity sales, plus the associated system losses within the province of Nova Scotia. Loads served by industrial self-generation, exports, and transmission losses associated with energy exports are not included. Annual NSR is shown in Figure 13.

Figure 13 Total Energy Requirement

Year	With future DSM Net System Requirement GWh	Growth Rate %	Without future DSM Net System Requirement GWh	Growth Rate %
2001	11,303	0.6	11,303	11.5
2002	11,501	1.8	11,501	1.8
2003	12,009	4.4	12,009	4.4
2004	12,388	3.2	12,388	3.2
2005	12,338	-0.4	12,338	-0.4
2006	10,946	-11.3	10,946	-11.3
2007	12,640	15.5	12,640	15.5
2008	12,539	-0.8	12,539	-0.8
2009	12,073	-3.7	12,073	-3.7
2010	12,158	0.7	12,158	0.7
2011F	12,688	4.4	12,803	5.3
2012F	12,647	-0.3	12,953	1.2
2013F	12,507	-1.1	13,077	1.0
2014F	12,339	-1.3	13,208	1.0
2015F	12,180	-1.3	13,334	1.0
2016F	12,008	-1.4	13,447	0.8
2017F	11,832	-1.5	13,547	0.7
2018F	11,651	-1.5	13,631	0.6
2019F	11,492	-1.4	13,730	0.7
2020F	11,333	-1.4	13,823	0.7
2021F	11,173	-1.4	13,909	0.6

The NSR for the province has grown at an average of 0.9 percent per year in the five year period from 2003-2008 and then declined by 3.7 percent in 2009 due to the recession. NSR is forecast to decline by 1.3 percent over the next 10 years with the effects of DSM. Without DSM effects, growth is forecast to average 1.1 percent annually.

Rate Class Sales

Forecast sales by sector are allocated into 13 rate classes for revenue forecasting purposes. The following section describes these rate classes and their expected energy requirements for the forecast period. In most cases, load growth trends by rate class are due to the same factors that affect the sector to which they belong, however, migration of customers between rate classes in the same sector can affect both historical and forecast energy requirements by class. Sales requirements by class are computed using historical and forecast trends and customer migration between classes.

Residential

This class includes residential sector customers served directly by NSPI and represented 38 percent of total NSPI sales in 2010. All-electric, non-all-electric and residential Time-of-Day (TOD) rate customers are included in this class. As of December 2010, there were 442,816 domestic customers responsible for annual billed sales of 4,144 GWh, an average of 9,359 kWh/customer. Residential class sales grow for the reasons stated in the residential sector description, and are forecast to diminish by 0.5 percent over the forecast period with the effects of DSM.

Small General

Prior to 2004, this class comprised commercial sector customers whose annual energy consumption was less than 12,000 kWh. This threshold was changed to 32,000 kWh/yr by January 2005. This moved some customers previously billed under the General (medium commercial) rate to Small General, thereby decreasing the load in the General class and increasing the Small General load. At the end of 2010, this class comprised 23,436 customers that consumed 235 GWh in 2010. It is forecast at 219 GWh in 2012.

General

Prior to 2004, this class comprised commercial sector customers whose annual energy consumption was greater than 12,000 KWh and for whom no other class was applicable. As discussed in the Small General class section, this threshold was changed, causing a migration of customers from General to Small General. As of 2010, this class had approximately 11,410 customers accounting for the major portion of commercial sector energy and 21 percent of total NSPI sales for 2010. By 2012, energy sales for this class are anticipated to be 2,531 GWh and decline annually at an average of 2.0 percent over the forecast period.

Large General

This class comprises large commercial sector customers (malls, universities, hospitals, etc) whose regular maximum demand is 2,000 kVA or more. As of December 2010, there were 17 customers in this class representing 3.6 percent of NSPI sales.

Small Industrial

This class comprises small industrial, farming and processing customers whose regular demand is less than 250 kVA. This class was made up of 2,251 customers as of December 2010, and had sales representing 2.1 percent of NSPI energy sales.

Medium Industrial

This class is applicable to any industrial customer having a regular demand of at least 250 kVA, but less than 2,000 kVA. As of December 2010, there were 196 customers in this class, representing about 3.6 percent of NSPI sales.

Large Industrial

This class is available to larger industrial customers having a regular demand of 2,000 KVA or more. Customers in this class may choose to have all or a portion of their load served as interruptible with the remaining load considered firm. Customers on the interruptible rider receive a reduction in demand charge. As of December 2010, there were 25 customers with the interruptible rider and four customers taking firm service only. The combined energy for the firm and interruptible customers was 929 GWh, and represented 8.1 percent of 2010 Nova Scotia Power energy sales. The anticipated combined energy for firm and interruptible customers in 2012 is 933 GWh, or 7.9 percent of energy sales.

Municipal

This class comprises municipal utilities that purchase wholesale electricity from NSPI and distribute it within their own service territories. The six municipalities are: Antigonish, Berwick, Canso, Lunenburg, Mahone Bay and Riverport. Loads within these municipalities include customers in residential, commercial and industrial sectors, and have been included in Nova Scotia Power's total sector sales estimates. Energy in this class also includes the losses incurred by the municipal utility in delivering the electricity requirements. These losses are estimated to average approximately 4 percent of sales.

An Open Access Transmission Tariff (OATT), which supports the opening of the electricity market in Nova Scotia, is now available to the six municipal utilities. Beginning in 2007, it has been possible for these municipalities to source their electricity from providers other than NSPI. While this forecast currently assumes that Nova Scotia Power continues to serve this load, adjustments will have to be made if or when the volume becomes significant in terms of long-term forecasting. In 2010, the municipal class represented 1.7 percent of total Nova Scotia Power sales. The anticipated energy sales in 2012 are 197 GWh including the effects of energy conservation programs.

Unmetered Services

This class is comprised of street and area lighting, as well as miscellaneous lighting and small loads. In 2010, unmetered sales represented approximately 1.0 percent of total Nova Scotia Power sales. The anticipated energy sales in 2012 are 116 GWh including the effects of a street light relamping project. An estimated 4 GWh is projected to be saved in the first year of the project to replace most of the street lights in Nova Scotia with light-emitting diode (LED) technology. The project is expected to span a five year period beginning in 2012 and result in total annual savings of 44 GWh.

Generation Replacement and Load Following

This class is available to customers who have their own generation capacity of no less than 2,000 kW. As of December 2010, this class had three customers and represented about 0.1 percent of total Nova Scotia Power sales. This class is also interruptible load and is currently forecast to remain near its 2010 level of approximately 20 GWh annually.

Mersey System

This class involves specific contract energy to one customer, Bowater Mersey Paper Company, in accordance with the Mersey System Agreement.

Extra Large Industrial Two Part Real Time Pricing (ELI 2P-RTP)

This rate operates with a standard energy rate and credits/charges for actual loads below/above the customer's pre-determined baseline load level (CBL). It is optionally available to, and currently in use by, two large industrial customers that are served at 138KV. This rate was designed to create a mechanism enabling customers to gain benefits equal to the benefit created by altering load usage in accordance with hourly price signals. The customer pays a standard energy charge with credits based on decremental energy below the CBL and costs added for incremental energy taken above the CBL. In addition, it is priority interruptible in nature from a supply perspective. Sales under this rate in 2010 were 1,857 GWh or approximately 16 percent of NSPI sales. For 2012, 1,904 GWh are forecast on this rate.

One-Part Real Time Price (1P-RTP)

This is an energy-only rate based on NSPI's 20 minute-ahead forecast hourly marginal energy costs plus differing fixed cost adders for on-peak and off-peak usage. It is available to customers served at transmission or distribution voltages with loads of 2,000 kVA or more. The fixed cost adders are calculated annually in advance and are based on NSPI's budgeted costs. Potentially lower prices in off-peak periods can provide an incentive to customers to shift energy consumption from weekdays to nights and weekends, off the NSPI system peak. This rate was used significantly in 2001 and 2002, but became unattractive to customers in 2003 as off-peak marginal costs rose.

System Losses and Unbilled Sales

This category includes Nova Scotia Power transmission losses, distribution losses and the year-over-year change in unbilled sales. Losses on sales within the service area of municipal utilities are not included in this class, but are included in the municipal rate class to which they belong. Transmission losses are forecast at approximately 3 percent of the transmission system energy requirement. NSPI distribution losses are forecast at approximately 5.5 percent of distribution level sales. Residential and commercial classes tend to have higher losses due to the lower voltages at which they are served. The overall mix of sales to each sector results in total NSPI losses which are forecast to average 6.6 percent of NSR over the forecast period.

Peak Demand

The total system peak is defined as the highest single hourly average demand experienced in a year. It includes both firm and interruptible loads and due to the weather-sensitive load component in Nova Scotia, the total system peak occurs in the period from December through February.

Peak demands are measured on an individual hour-by-hour basis and are not directly related to monthly heating degree days, but rather to the daily or hourly temperatures which drive space heating load. On some cold weather occasions, load does not reach the anticipated peak due to NSPI requests for interruption or the ELI-2P-RTP customers responding to price signals. For the winter of 2009/2010, the January peak reached 2,114 MW at a temperature of -13°C with the largest industrial customers operating below full load. This peak was 124 MW less than the highest peak that occurred six years earlier in January 2004, when the temperature was 5° C colder.

With the exception of large customer classes, monthly and annual net system peaks are computed using forecast monthly energy and average historical coincident load factors for each of the rate classes. Monthly peak loss percentages are applied to each monthly sales peak to produce losses by class and are then summed to produce the total peak demand forecast. This method produces forecast peaks that while not explicitly tied to a particular hourly temperature, recognize and average the actual peak and energy relationships from recent years.

The system peak for 2012 is forecast at 2,308 MW. Over the longer term, net system peak is forecast to decrease to 1,991 MW in 2021, which represents decline of 1.5 percent annual growth rate due to the effects of conservation and DSM programs. Without these programs, annual growth averages 1.0 percent.

Non-Firm Coincident Peak

NSPI offers interruptible or “non-firm” service to industrial customers. Certain industrial customers who meet specific criteria may utilize discounted rates in exchange for agreeing to have their electricity supply interrupted on short notice in order to meet any necessary emergency peak reductions required to maintain system stability. These rate classes are the “Generation Replacement and Load Following” rate, the “Extra Large Industrial Two Part Real Time Pricing” rate and the “Interruptible” rider of the Large Industrial rate. The combined interruptible demand of these customers coincident with the monthly system peaks may at times exceed 400 MW. At the January 2010 peak, there were 30 customers on these rates, representing a combined coincident non-firm peak of 314 MW.

Non-firm coincident peak demand is forecast explicitly by customer for the near-term and an allowance is made for unallocated or new customer growth in the longer term. Although one customer departed from the non-firm rate in 2009, the remaining customers who currently take non-firm service are expected to continue on the rate and therefore non-firm coincident peak is forecast to grow only moderately from its current level assuming there are no major changes made to the rate’s availability or requirements over the forecast period.

Total Coincident Firm Peak

Total Coincident Firm Peak is the demand at the time of Nova Scotia Power’s system peak that is attributable to all firm classes (e.g.: residential, small general, etc.), but excluding the non-firm customer classes mentioned above.

Total Non-coincident Firm Peak is defined as the highest peak demand for the combined firm classes, which may or may not be coincident with the time of NSPI's total system peak, depending upon non-firm customer demand fluctuations. Load shape statistics indicate that especially during winter months, the non-coincident firm peak and the coincident firm peak are usually close, due to the peak often being driven by cold temperatures.

Load Forecast

Appendices

Appendix A

2010 NSPI Forecast

Residential Sector Econometric Model Detail

$DOMENG = 302.4\ AIDX + 0.2540\ CHDD - 28.25\ RREP + 0.1095\ RRCGOODS + 0.4458\ DOMENG_{-1}$

```
Forecast Model for DOMENG

Dynamic regression
 Regression(5 regressors, 0 lagged errors)

Term        Coefficient   Std. Error  t-Statistic  Percentile
 AIDX         302.4        51.28         5.897      1.000
 CUSTHDD      0.2540       0.02916       8.711      1.000
 RRCGOODS     0.1095       0.01211       9.040      1.000
 RREP        -28.25        12.02        -2.351      0.9709
 DomEng1      0.4458       0.05200       8.572      1.000


 Sample size  25                 No. parameters  5
 Mean  3644.89                   Std. deviation  446.59
 Adj. R-square  0.99             Durbin-Watson  2.93
 Ljung-Box(15)  24.3 P=0.94      Forecast error  34.55
 BIC  42.64                      MAPE  0.66%
 MAD  23.63
```

Residential Model Input Variables and Contributions

Year	AIDX	AIDX Contrib.	CHDD	CHDD Contrib.	Electric Price	Electric Price Contrib.	Consumer Goods Sales	Consumer Goods Contrib.	DomEng$_{[-1]}$	DomEng$_{[-1]}$ Contrib.	Nat. Gas Effect	Future DSM	DomEng*	Actual	Growth
		GWh		GWh		GWh		GWh		GWh	GWh	GWh	GWh	GWh	%
1994	1.784	539	3,567	906	11.90	-336	7,556	827	3,506.9	1,563			**3,500**	**3,498**	-0.2%
1995	1.768	535	3,587	911	11.74	-332	7,483	819	3,498.3	1,560			**3,493**	**3,463**	-1.0%
1996	1.751	529	3,603	915	12.02	-340	7,552	827	3,462.9	1,544			**3,476**	**3,565**	2.9%
1997	1.748	529	3,735	949	11.73	-331	7,815	856	3,564.6	1,589			**3,591**	**3,595**	0.8%
1998	1.728	522	3,357	853	11.72	-331	8,061	883	3,594.8	1,603			**3,529**	**3,524**	-2.0%
1999	1.694	512	3,229	820	12.17	-344	8,442	924	3,524.4	1,571			**3,484**	**3,512**	-0.4%
2000	1.676	507	3,562	905	11.68	-330	8,647	947	3,512.0	1,566			**3,594**	**3,672**	4.6%
2001	1.664	503	3,671	933	11.42	-323	8,684	951	3,672.1	1,637			**3,701**	**3,741**	1.9%
2002	1.647	498	3,980	1011	11.11	-314	8,916	976	3,741.2	1,668			**3,839**	**3,829**	2.3%
2003	1.636	495	4,163	1057	11.01	-311	9,023	988	3,828.9	1,707			**3,936**	**4,010**	4.7%
2004	1.613	488	4,416	1122	10.78	-305	9,148	1,002	4,010.5	1,788			**4,094**	**4,114**	2.6%
2005	1.595	482	4,159	1056	11.21	-317	9,265	1,015	4,060.1	1,810			**4,046**	**4,112**	0.0%
2006	1.578	477	3,719	945	11.55	-326	9,400	1,029	4,133.5	1,843			**3,967**	**3,979**	-3.2%
2007	1.556	471	4,630	1176	10.98	-310	9,579	1,049	4,108.4	1,832			**4,222**	**4,218**	6.1%
2008	1.512	457	4,570	1161	11.20	-316	9,868	1,081	4,175.3	1,861			**4,260**	**4,231.9**	0.9%
2009	1.514	458	4,921	1250	12.42	-351	10,014	1,097	4,221.8	1,882			**4,340**	**4,327.8**	1.9%
2010	1.492	451	4,287	1089	11.59	-327	10,342	1,132	4,282.0	1,909			**4,259**	**4,258.3**	-1.9%
2011	1.471	445	4,968	1262	11.99	-339	10,428	1,142	4,398.3	1,961	0.8	31	**4,444**		4.3%
2012	1.452	439	5,086	1292	13.30	-376	10,599	1,161	4,444.1	1,981	1.0	77	**4,424**		-0.5%
2013	1.434	434	5,189	1318	14.19	-401	10,734	1,175	4,423.7	1,972	1.1	143	**4,359**		-1.5%
2014	1.418	429	5,273	1339	14.05	-397	10,829	1,186	4,358.9	1,943	1.2	204	**4,300**		-1.4%
2015	1.404	425	5,351	1359	13.74	-388	10,877	1,191	4,299.6	1,917	1.3	263	**4,244**		-1.3%
2016	1.391	421	5,435	1381	13.61	-385	10,922	1,196	4,244.4	1,892	1.4	321	**4,187**		-1.3%
2017	1.380	417	5,524	1403	13.68	-386	10,936	1,198	4,187.2	1,867	1.4	379	**4,122**		-1.6%
2018	1.371	415	5,613	1426	14.08	-398	10,949	1,199	4,122.2	1,838	1.4	438	**4,045**		-1.9%
2019	1.363	412	5,699	1447	13.82	-390	10,947	1,199	4,044.6	1,803	1.5	496	**3,978**		-1.6%
2020	1.357	410	5,786	1470	13.87	-392	10,935	1,197	3,978.2	1,773	1.5	555	**3,907**		-1.8%
2021	1.352	409	5,874	1492	13.91	-393	10,921	1,196	3,907.2	1,742	1.5	614	**3,834**		-1.9%

* - to align forecast to actuals in 2010, the modeled DomEng contains a launch adjustment of 4.9 GWh for 2010-2020.


Residential Sector Model Fit
using historical data
5,000
4,500
4,000
3,500
3,000
2,500
2,000
1,500
Annual Energy - GWh
80
82
84
86
88
90
92
94
96
98
00
02
04
06
08
10
12
Year
Model
Actual

Commercial Sector Econometric Model Detail

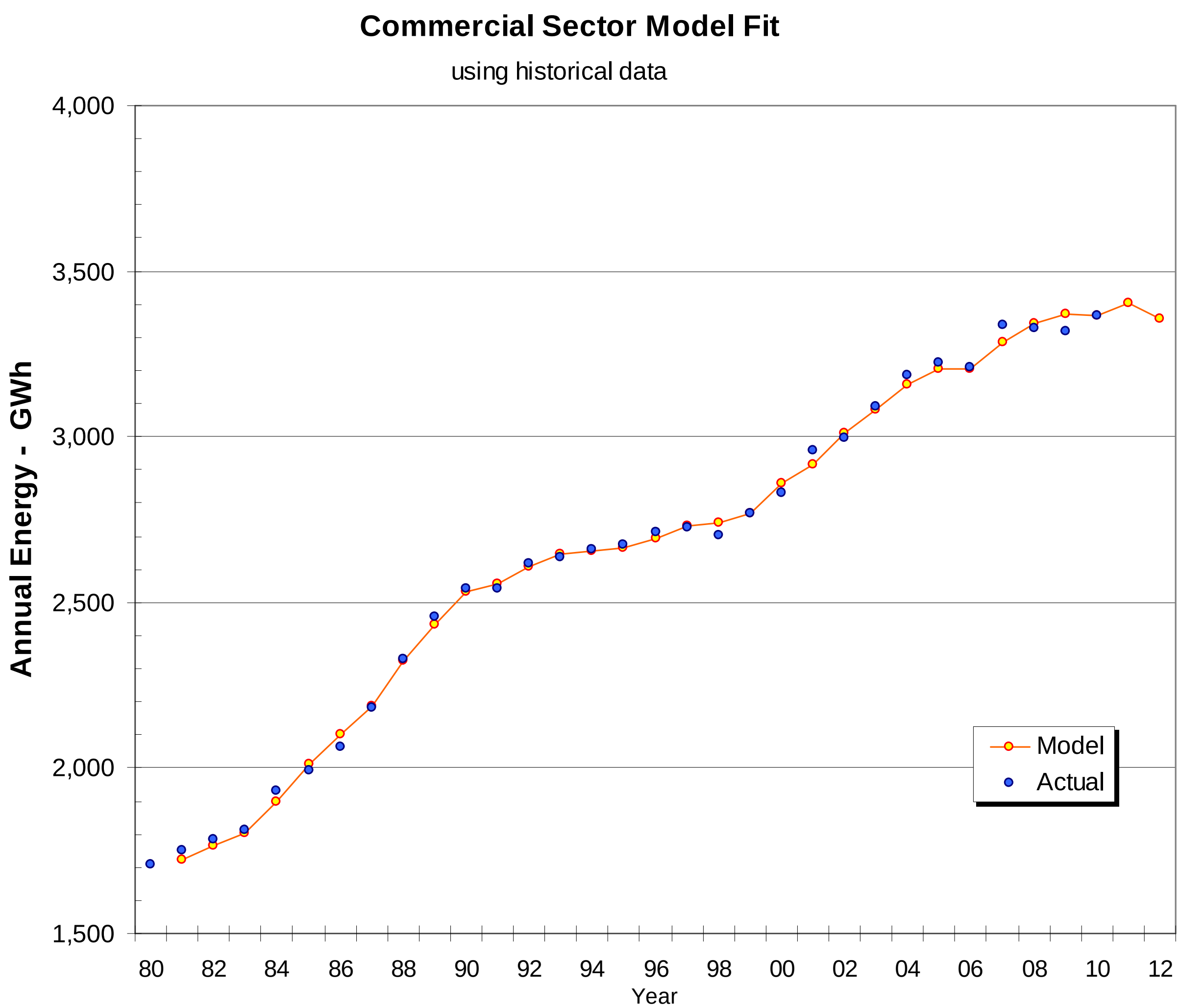
$$COMENG = 0.01906\ RQTOS + 0.01362\ RPDI + 0.2685\ DOMENG + 0.4245\ COMENG_{-1}$$

```
Forecast Model for ComEng
Regression(4 regressors, 0 lagged errors)

 Term       Coefficient  Std. Error  t-Statistic  Percentile
  RQTOS       0.01906      0.005582    3.414      0.9979
  ComEngWA1   0.4245       0.08265     5.136      1.000
  DomEng      0.2685       0.04757     5.644      1.000
  RPDI        0.01362      0.004529    3.009      0.9942


Within-Sample Statistics

  Sample size  30             No. parameters  4
  Mean  2656.21               Std. deviation  502.23
  Adj. R-square  1.00         Durbin-Watson  2.03
  Ljung-Box(18)  13.7 P=0.25  Forecast error  29.91
  BIC  34.94                  MAPE  0.76%
  MAD  20.48
```

Commercial Model Input Variables and Contributions

Year	RQTOS	RQTOS contrib GWh	RPDI	RPDI contrib GWh	DomEng	DomEng contrib GWh	$ComEng_{[-1]}$	$ComEng_{[-1]}$ contrib GWh	Future DSM Effects GWh	ComEng* GWh	Actual GWh	Growth %
1994	19,069	363	16,959	231	3,498	939	2,638	1,120		**2,654**	2,660	0.8%
1995	19,455	371	17,085	233	3,463	930	2,660	1,129		**2,663**	2,676	0.6%
1996	19,490	371	16,796	229	3,565	957	2,676	1,136		**2,693**	2,713	1.4%
1997	20,027	382	17,070	232	3,595	965	2,713	1,152		**2,731**	2,725	0.5%
1998	20,772	396	17,707	241	3,524	946	2,725	1,157		**2,740**	2,702	-0.8%
1999	21,971	419	18,250	249	3,512	943	2,725	1,157		**2,767**	2,767	2.4%
2000	22,729	433	18,374	250	3,672	986	2,797	1,187		**2,857**	2,829	2.3%
2001	23,531	448	18,652	254	3,741	1,005	2,847	1,208		**2,915**	2,959	4.6%
2002	24,509	467	18,668	254	3,829	1,028	2,971	1,261		**3,011**	2,996	1.3%
2003	24,955	476	18,562	253	4,010	1,077	3,004	1,275		**3,081**	3,091	3.1%
2004	25,250	481	19,074	260	4,114	1,104	3,088	1,311		**3,156**	3,188	3.1%
2005	25,593	488	19,385	264	4,112	1,104	3,177	1,349		**3,205**	3,225	1.2%
2006	25,837	492	19,833	270	3,979	1,068	3,240	1,375		**3,206**	3,211	-0.4%
2007	26,231	500	20,376	278	4,218	1,133	3,244	1,377		**3,287**	3,343	4.1%
2008	26,865	512	20,663	281	4,232	1,136	3,332	1,414		**3,351**	3,327	0.2%
2009	26,741	510	21,187	289	4,318	1,159	3,327	1,412		**3,368**	3,320	0.5%
2010	27,536	525	21,581	294	4,258	1,143	3,311	1,406		**3,365**	3,365	-0.1%
2011	28,034	534	21,677	295	4,475	1,201	3,388	1,438	66	**3,401**		1.0%
2012	28,575	545	22,069	301	4,514	1,212	3,467	1,472	171	**3,355**		-1.3%
2013	29,116	555	22,361	305	4,542	1,220	3,527	1,497	265	**3,309**		-1.4%
2014	29,574	564	22,558	307	4,586	1,231	3,574	1,517	378	**3,240**		-2.1%
2015	29,984	571	22,691	309	4,634	1,244	3,617	1,535	485	**3,173**		-2.0%
2016	30,154	575	22,763	310	4,682	1,257	3,658	1,553	592	**3,101**		-2.3%
2017	30,473	581	22,820	311	4,722	1,268	3,693	1,568	693	**3,031**		-2.2%
2018	30,795	587	22,884	312	4,750	1,275	3,725	1,581	788	**2,965**		-2.2%
2019	31,136	593	22,951	313	4,789	1,286	3,753	1,593	880	**2,903**		-2.1%
2020	31,325	597	23,007	313	4,824	1,295	3,783	1,606	970	**2,839**		-2.2%
2021	31,436	599	23,068	314	4,857	1,304	3,809	1,617	1058	**2,774**		-4.4%

* - to align forecast to actuals in 2010, the modeled ComEng contains a launch adjustment of -2.2 GWh for 2010-2020


Commercial Sector Model Fit
using historical data
Annual Energy - GWh
4,000
3,500
3,000
2,500
2,000
1,500
80
82
84
86
88
90
92
94
96
98
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02
04
06
08
10
12
Year
Model
Actual

Industrial Econometric Model Details

Small and Medium Industrial class models are shown below.

$$SM\_IND = 0.01885\ GDP\_Man + 0.01278\ NonRes\_Inv + 0.7220\ SM\_IND_{-1}$$

$$MED\_IND = 0.06218\ GDP\_Man + 1.168\ Man\_Emp + 0.5911\ MED\_IND_{-1}$$

Dynamic regression
Regression(3 regressors, 0 lagged errors)

Term	Coefficient	Std. Error	t-Statistic	Percentile
GDP_Man	0.01885	0.006059	3.165	0.9943
SM_IND[-1]	0.72200	0.07601	9.535	1.000
NonRes_Inv	0.01278	0.003134	3.893	0.9988

Within-Sample Statistics

```
Sample size  25        No. parameters  3
Mean  203.80           Std. deviation  45.69
Adj. R-square  0.98    Durbin-Watson  0.93
Ljung-Box(12)  11.8    P=0.53  Forecast error  5.74
BIC  6.62              MAPE  2.28%
MAD  4.12
```

Dynamic regression
Regression(3 regressors, 0 lagged errors)

Term	Coefficient	Std. Error	t-Statistic	Percentile
GDP_Man	0.06218	0.02548	2.441	0.9768
MED_IND[-1]	0.5911	0.1372	4.309	0.9997
Man_Emp	1.168	0.4372	2.673	0.9861

Within-Sample Statistics

```
Sample size  25        No. parameters  3
Mean  455.58           Std. deviation  76.49
Adj. R-square  0.95    Durbin-Watson  1.00
Ljung-Box(17)  25.9    P=0.92  Forecast error  17.40
BIC  19.81             MAPE  3.00%
MAD  13.49
```

Industrial Model Input Variables and Contributions

Small Industrial

Year	GDP_Man $M2002	NonRes_Inv $M2002	GDP_Man contrib GWh	NonRes_Inv contrib GWh	Sm_Ind[-1]	Sm_Ind[-1] contrib GWh	Sm_Ind Model GWh	Sm_Ind Actual GWh	Growth %
1994	1,877	486	35	6	136.5	98.5	140.1	139.3	2.0%
1995	2,020	577	38	7	139.3	100.6	146.0	147.5	5.9%
1996	2,015	631	38	8	147.5	106.5	152.5	153.0	3.7%
1997	2,154	636	41	8	153.0	110.5	159.2	168.4	10.0%
1998	2,216	1,812	42	23	168.4	121.6	186.5	192.5	14.3%
1999	2,412	2,398	45	31	192.5	139.0	215.1	216.1	12.3%
2000	2,408	1,429	45	18	216.1	156.1	219.7	213.9	-1.0%
2001	2,421	1,509	46	19	213.9	154.4	219.3	222.4	4.0%
2002	2,662	1,379	50	18	222.4	160.5	228.4	234.1	5.3%
2003	2,629	1,357	50	17	234.1	169.0	235.9	238.3	1.8%
2004	2,848	1,298	54	17	238.3	172.1	242.4	239.2	0.4%
2005	2,856	1,070	54	14	239.2	172.7	240.2	241.1	0.8%
2006	2,761	1,049	52	13	241.1	174.1	239.5	239.9	-0.5%
2007	2,883	914	54	12	239.9	173.2	239.3	248.1	3.4%
2008	2,861	1,259	54	16	248.1	179.1	249.1	254.5	2.6%
2009	2,640	1,664	50	21	254.5	183.7	254.8	252.6	-0.7%
2010	2,714	1,621	51	21	252.6	182.4	254.3	253.7	0.5%
2011	2,837	1,582	53	20	253.7	183.2	256.4		1.0%
2012	3,135	1,688	59	22	256.4	185.1	265.3		3.5%
2013	3,270	1,655	62	21	265.3	191.5	273.8		3.2%
2014	3,337	1,625	63	21	273.8	197.7	280.8		2.6%
2015	3,397	1,586	64	20	280.8	202.8	286.6		2.0%
2016	3,458	1,278	65	16	286.6	206.9	287.9		0.5%
2017	3,519	1,277	66	16	287.9	207.9	290.0		0.7%
2018	3,596	1,276	68	16	290.0	209.4	293.0		1.0%
2019	3,670	1,274	69	16	293.0	211.5	296.5		1.2%
2020	3,743	1,299	71	17	296.5	214.1	300.7		1.4%
2021	3,810	1,307	72	17	300.7	217.1	305.1		1.5%

* - to align forecast to actuals in 2010, the model contains a launch adjustment of -0.5 GWh for 2010-2021

Medium Industrial

Year	GDP_Man $M2002	Man_Emp 000's	GDP_Man contrib GWh	Man_Emp contrib GWh	Med_Ind[-1]	Med_Ind[-1] contrib GWh	Med_Ind Model GWh	Med_Ind Actual GWh	Growth %
1994	1,877	486	116.7	42.1	381	225	384	389	2.0%
1995	2,020	577	125.6	47.1	389	230	403	382	-1.8%
1996	2,015	631	125.3	43.4	382	226	395	378	-1.1%
1997	2,154	636	133.9	43.8	378	223	401	401	6.1%
1998	2,216	1,812	137.8	47.9	401	237	423	414	3.3%
1999	2,412	2,398	150.0	51.3	414	245	446	454	9.6%
2000	2,408	1,429	149.7	49.1	454	268	467	490	7.9%
2001	2,421	1,509	150.5	49.2	490	289	489	518	5.8%
2002	2,662	1,379	165.5	50.7	518	306	522	531	2.6%
2003	2,629	1,357	163.5	52.6	531	314	530	558	4.9%
2004	2,848	1,298	177.1	51.0	558	330	558	567	1.8%
2005	2,856	1,070	177.6	47.1	567	335	560	557	-1.8%
2006	2,761	1,049	171.7	45.7	557	329	547	567	1.8%
2007	2,883	914	179.3	48.2	567	335	563	568	0.1%
2008	2,861	1,259	177.9	45.7	568	336	559	539	-5.0%
2009	2,640	1,664	164.2	39.7	539	319	523	492	-8.8%
2010	2,714	1,621	168.8	39.2	492	291	493	493	0.2%
2011	2,837	1,582	176.4	40.4	493	291	502		1.9%
2012	3,135	1,688	194.9	40.8	502	297	526		4.9%
2013	3,270	1,655	203.3	40.8	526	311	549		4.3%
2014	3,337	1,625	207.5	40.4	549	325	567		3.1%
2015	3,397	1,586	211.2	40.7	567	335	581		2.5%
2016	3,458	1,278	215.0	40.1	581	343	592		2.0%
2017	3,519	1,277	218.8	39.9	592	350	603		1.8%
2018	3,596	1,276	223.6	39.7	603	356	614		1.8%
2019	3,670	1,274	228.2	39.5	614	363	624		1.8%
2020	3,743	1,299	232.7	39.5	624	369	635		1.7%
2021	3,810	1,307	236.9	39.6	635	376	646		1.7%

* - to align forecast to actuals in 2010, the model contains a launch adjustment of -6.0 GWh for 2010-2021

Table A1: Energy Requirement – 2011 NSPI Forecast

Energy Forecast with Future DSM Program Effects

Year	Residential Sector GWh	Growth %	Commercial Sector GWh	Growth %	Industrial Sector GWh	Growth %	Total Sales GWh	Growth %	Losses GWh	Total Energy GWh	Growth %
1994	3,498	0.4	2,660	1.0	2,756	0.3	8,914	0.5	679	9,593	0.0
1995	3,463	-1.0	2,676	0.6	2,864	3.9	9,003	1.0	671	9,674	0.8
1996	3,565	2.9	2,713	1.4	2,774	-3.1	9,052	0.5	701	9,753	0.8
1997	3,595	0.8	2,725	0.5	2,867	3.3	9,187	1.5	778	9,965	2.2
1998	3,524	-2.0	2,702	-0.8	3,442	20.1	9,668	5.2	743	10,412	4.5
1999	3,512	-0.4	2,767	2.4	3,872	12.5	10,150	5.0	720	10,870	4.4
2000	3,672	4.6	2,829	2.3	3,930	1.5	10,431	2.8	809	11,240	3.4
2001	3,741	1.9	2,959	4.6	3,873	-1.5	10,573	1.4	730	11,303	0.6
2002	3,829	2.3	2,996	1.3	3,799	-1.9	10,624	0.5	877	11,501	1.8
2003	4,010	4.7	3,091	3.1	4,046	6.5	11,147	4.9	862	12,009	4.4
2004	4,114	2.6	3,188	3.1	4,212	4.1	11,513	3.3	874	12,388	3.2
2005	4,114	0.0	3,223	1.1	4,215	0.1	11,553	0.3	786	12,338	-0.4
2006	3,979	-3.3	3,211	-0.4	2,888	-31.5	10,078	-12.8	868	10,946	-11.3
2007	4,218	6.0	3,343	4.1	4,205	45.6	11,767	16.8	873	12,639	15.5
2008	4,232	0.3	3,327	-0.5	4,161	-1.0	11,720	-0.4	819	12,539	-0.8
2009	4,318	2.0	3,320	-0.2	3,658	-12.1	11,297	-3.6	777	12,073	-3.7
2010	4,216	-2.4	3,305	-0.5	3,932	7.5	11,453	1.4	704	12,158	0.7
2011	4,444	5.4	3,401	2.9	3,995	1.6	11,840	3.4	848	12,688	4.4
2012	4,437	-0.2	3,355	-1.3	4,018	0.6	11,811	-0.2	836	12,647	-0.3
2013	4,399	-0.9	3,309	-1.4	3,971	-1.2	11,679	-1.1	828	12,507	-1.1
2014	4,381	-0.4	3,240	-2.1	3,898	-1.8	11,519	-1.4	820	12,339	-1.3
2015	4,372	-0.2	3,173	-2.0	3,826	-1.8	11,371	-1.3	809	12,180	-1.3
2016	4,361	-0.2	3,101	-2.3	3,748	-2.0	11,209	-1.4	799	12,008	-1.4
2017	4,343	-0.4	3,031	-2.2	3,670	-2.1	11,044	-1.5	788	11,832	-1.5
2018	4,312	-0.7	2,965	-2.2	3,598	-1.9	10,876	-1.5	775	11,651	-1.5
2019	4,293	-0.5	2,903	-2.1	3,532	-1.9	10,727	-1.4	765	11,492	-1.4
2020	4,269	-0.6	2,839	-2.2	3,471	-1.7	10,579	-1.4	754	11,333	-1.4
2021	4,243	-1.2	2,774	-4.4	3,412	-3.4	10,430	-2.8	743	11,173	-2.8

Table A2: Energy Requirement – 2011 NSPI Forecast

Energy Forecast without Future DSM Program Effects

Year	Residential Sector GWh	Growth %	Commercial Sector GWh	Growth %	Industrial Sector GWh	Growth %	Total Sales GWh	Growth %	Losses GWh	Total Energy GWh	Growth %
1994	3,498	0.4	2,660	1.0	2,756	0.3	8,914	0.5	679	9,593	0.0
1995	3,463	-1.0	2,676	0.6	2,864	3.9	9,003	1.0	671	9,674	0.8
1996	3,565	2.9	2,713	1.4	2,774	-3.1	9,052	0.5	701	9,753	0.8
1997	3,595	0.8	2,725	0.5	2,867	3.3	9,187	1.5	778	9,965	2.2
1998	3,524	-2.0	2,702	-0.8	3,442	20.1	9,668	5.2	743	10,412	4.5
1999	3,512	-0.4	2,767	2.4	3,872	12.5	10,150	5.0	720	10,870	4.4
2000	3,672	4.6	2,829	2.3	3,930	1.5	10,431	2.8	809	11,240	3.4
2001	3,741	1.9	2,959	4.6	3,873	-1.5	10,573	1.4	730	11,303	0.6
2002	3,829	2.3	2,996	1.3	3,799	-1.9	10,624	0.5	877	11,501	1.8
2003	4,010	4.7	3,091	3.1	4,046	6.5	11,147	4.9	862	12,009	4.4
2004	4,114	2.6	3,188	3.1	4,212	4.1	11,513	3.3	874	12,388	3.2
2005	4,114	0.0	3,223	1.1	4,215	0.1	11,553	0.3	785	12,338	-0.4
2006	3,979	-3.3	3,211	-0.4	2,888	-31.5	10,078	-12.8	868	10,946	-11.3
2007	4,218	6.0	3,343	4.1	4,205	45.6	11,767	16.8	873	12,639	15.5
2008	4,232	0.3	3,327	-0.5	4,161	-1.0	11,720	-0.4	819	12,539	-0.8
2009	4,318	2.0	3,320	-0.2	3,658	-12.1	11,297	-3.6	777	12,073	-3.7
2010	4,216	-2.4	3,305	-0.5	3,932	7.5	11,453	1.4	704	12,158	0.7
2011	4,475	0.8	3,467	1.2	4,004	2.1	11,946	1.4	857	12,803	1.3
2012	4,514	1.9	3,527	2.1	4,053	0.7	12,094	1.6	859	12,953	1.6
2013	4,542	1.7	3,574	1.7	4,091	0.5	12,208	1.3	869	13,077	1.3
2014	4,586	1.6	3,617	1.5	4,123	0.5	12,326	1.2	882	13,208	1.3
2015	4,634	1.6	3,658	1.4	4,152	0.6	12,444	1.2	890	13,334	1.2
2016	4,682	1.1	3,693	1.2	4,174	0.6	12,548	1.0	899	13,447	1.0
2017	4,722	1.1	3,725	1.1	4,193	0.6	12,641	0.9	907	13,547	0.9
2018	4,750	1.1	3,753	1.0	4,215	0.6	12,718	0.9	913	13,631	0.9
2019	4,789	0.9	3,783	1.0	4,238	0.6	12,810	0.8	921	13,730	0.8
2020	4,824	0.9	3,809	1.0	4,263	0.6	12,895	0.8	928	13,823	0.8
2021	4,857	0.6	3,832	0.7	4,285	0.6	12,975	0.6	934	13,909	0.6

Table A3: Coincident Peak Demand - 2011 NSPI Forecast

Peak Forecast with Future DSM Program Effects

Year	Net System Peak MW	Growth %	Non-Firm Peak MW	Growth %	Firm Peak MW	Growth %
2000	2,009	6.6	412	33.3	1,597	1.3
2001	1,988	-1	369	-10.4	1,619	1.4
2002	2,078	4.5	348	-5.7	1,730	6.9
2003	2,074	-0.2	291	-16.4	1,783	3.1
2004	2,238	7.9	377	29.6	1,861	4.4
2005	2,143	-4.2	392	4.0	1,751	-5.9
2006	2,029	-5.3	386	-1.5	1,644	-6.1
2007	2,145	5.7	381	-1.3	1,764	7.3
2008	2,192	2.2	352	-7.5	1,840	4.3
2009	2,092	-4.5	268	-23.9	1,824	-0.8
2010	2,114	1.0	295	10.0	1,820	-0.3
2011	2,310	9.3	316	7.3	1,994	9.6
2012	2,308	-0.1	309	-2.4	2,000	0.3
2013	2,277	-1.4	308	-0.3	1,970	-1.5
2014	2,242	-1.6	304	-1.3	1,938	-1.6
2015	2,208	-1.5	298	-1.9	1,910	-1.4
2016	2,173	-1.6	292	-1.9	1,880	-1.5
2017	2,135	-1.7	287	-2.0	1,849	-1.7
2018	2,096	-1.9	281	-1.9	1,815	-1.8
2019	2,061	-1.7	276	-1.8	1,785	-1.6
2020	2,026	-1.7	271	-1.7	1,755	-1.7
2021.	1,991	-1.7	267	-1.7	1,725	-1.7

Table A4: Coincident Peak Demand - 2010 NSPI Forecast

Peak Forecast without Future DSM Program Effects

Year	Net System Peak MW	Growth %	Non-Firm Peak MW	Growth %	Firm Peak MW	Growth %
2000	2,009	6.6	412	33.3	1,597	1.3
2001	1,988	-1	369	-10.4	1,619	1.4
2002	2,078	4.5	348	-5.7	1,730	6.9
2003	2,074	-0.2	291	-16.4	1,783	3.1
2004	2,238	7.9	377	29.6	1,861	4.4
2005	2,143	-4.2	392	4.0	1,751	-5.9
2006	2,029	-5.3	386	-1.5	1,644	-6.1
2007	2,145	5.7	381	-1.3	1,764	7.3
2008	2,192	2.2	352	-7.5	1,840	4.3
2009	2,092	-4.5	268	-23.9	1,824	-0.8
2010	2,114	1.0	295	10.0	1,820	-0.3
2011	2,344	10.9	317	7.7	2,026	11.4
2012	2,369	1.1	311	-2.0	2,058	1.5
2013	2,390	0.9	314	0.9	2,076	0.9
2014	2,415	1.0	316	0.8	2,099	1.1
2015	2,439	1.0	318	0.7	2,120	1.0
2016	2,461	0.9	320	0.5	2,141	1.0
2017	2,480	0.8	322	0.5	2,159	0.8
2018	2,496	0.6	323	0.5	2,172	0.6
2019	2,515	0.8	325	0.5	2,190	0.8
2020	2,532	0.7	327	0.6	2,205	0.7
2021	2,548	1.3	329	1.1	2,220	1.4

Table A3: Energy Sales by Rate Class - 2010 NSPI Forecast

Rate Class Energy Sales
With Future DSM Program Effects

Class Billed Sales (GWh)	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011	2012
Residential	4,142	4,156	4,244	4,144	4,370	4,364
Small General	246	239	237	235	231	219
General Demand	2,471	2,463	2,458	2,447	2,547	2,531
Large General	420	419	417	416	408	394
Unmetered	112	112	112	113	118	116
Small Industrial	248	254	253	254	255	262
Medium Industrial	568	539	492	495	496	512
Large Industrial	984	996	901	929	933	933
RTP	0	0	0	0	0	0
Mersey System	368	369	291	356	368	369
GR&LF	20	11	6	20	19	19
Municipal	197	197	198	193	199	197
ELI Rate	2,002	1,976	1,695	1,857	1899	1904
Total Billed Sales	11,778	11,732	11,304	11,461	11,843	11,819
Losses & ΔUnbilled	861	807	769	697	840	828
Net System Requirement	12,640	12,539	12,073	12,158	12,683	12,647

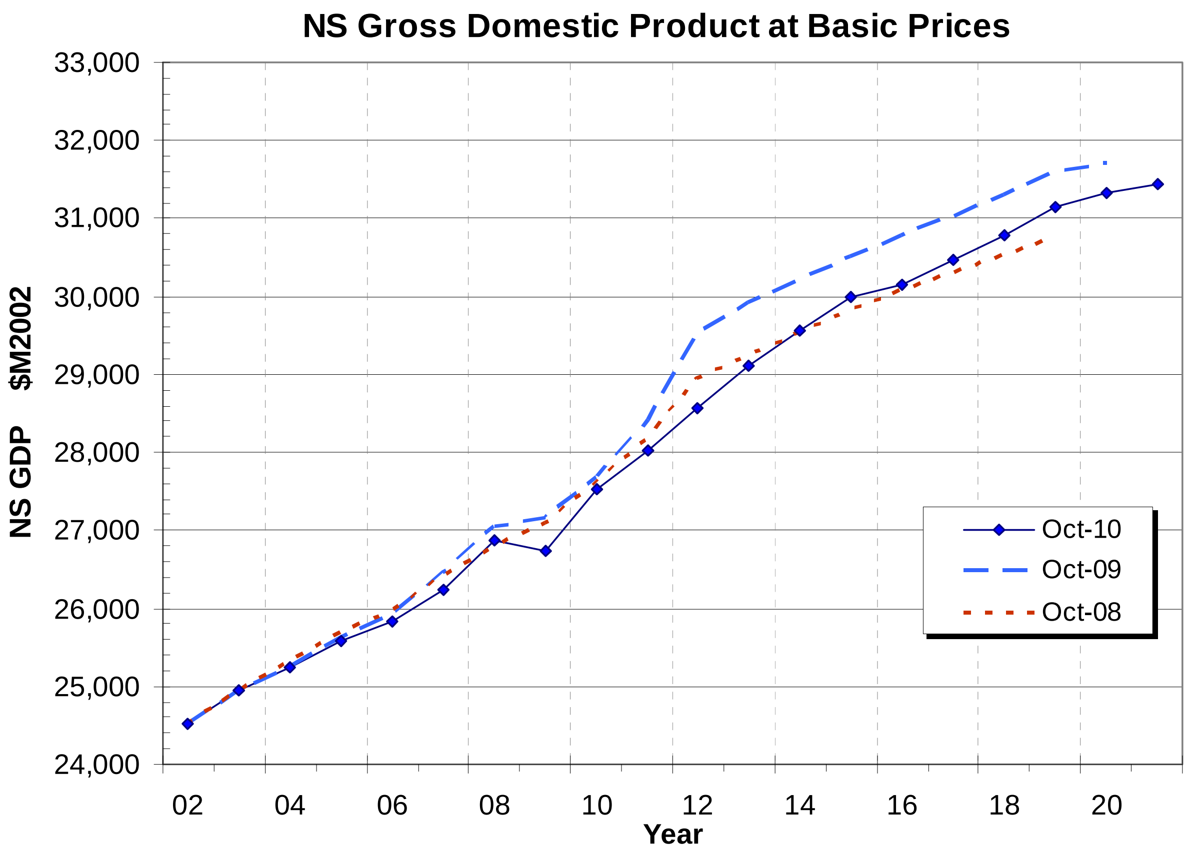
Rate Class Energy Sales
Without Future DSM Program Effects

Class Billed Sales (GWh)	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011	2012
Residential	4,142	4,156	4,244	4,144	4,399	4,438
Small General	246	239	237	235	240	242
General Demand	2,471	2,463	2,458	2,447	2,593	2,648
Large General	420	419	417	416	418	418
Unmetered	112	112	112	113	118	120
Small Industrial	248	254	253	254	256	265
Medium Industrial	568	539	492	495	502	526
Large Industrial	984	996	901	929	939	948
RTP	0	0	0	0	0	0
Mersey System	368	369	291	356	368	369
GR&LF	20	11	6	20	19	19
Municipal	197	197	198	193	202	204
ELI Rate	2,002	1,976	1,695	1,857	1899	1904
Total Billed Sales	11,778	11,732	11,304	11,461	11,954	12,102
Losses & ΔUnbilled	861	807	769	697	849	851
Net System Requirement	12,640	12,539	12,073	12,158	12,803	12,953

Appendix B

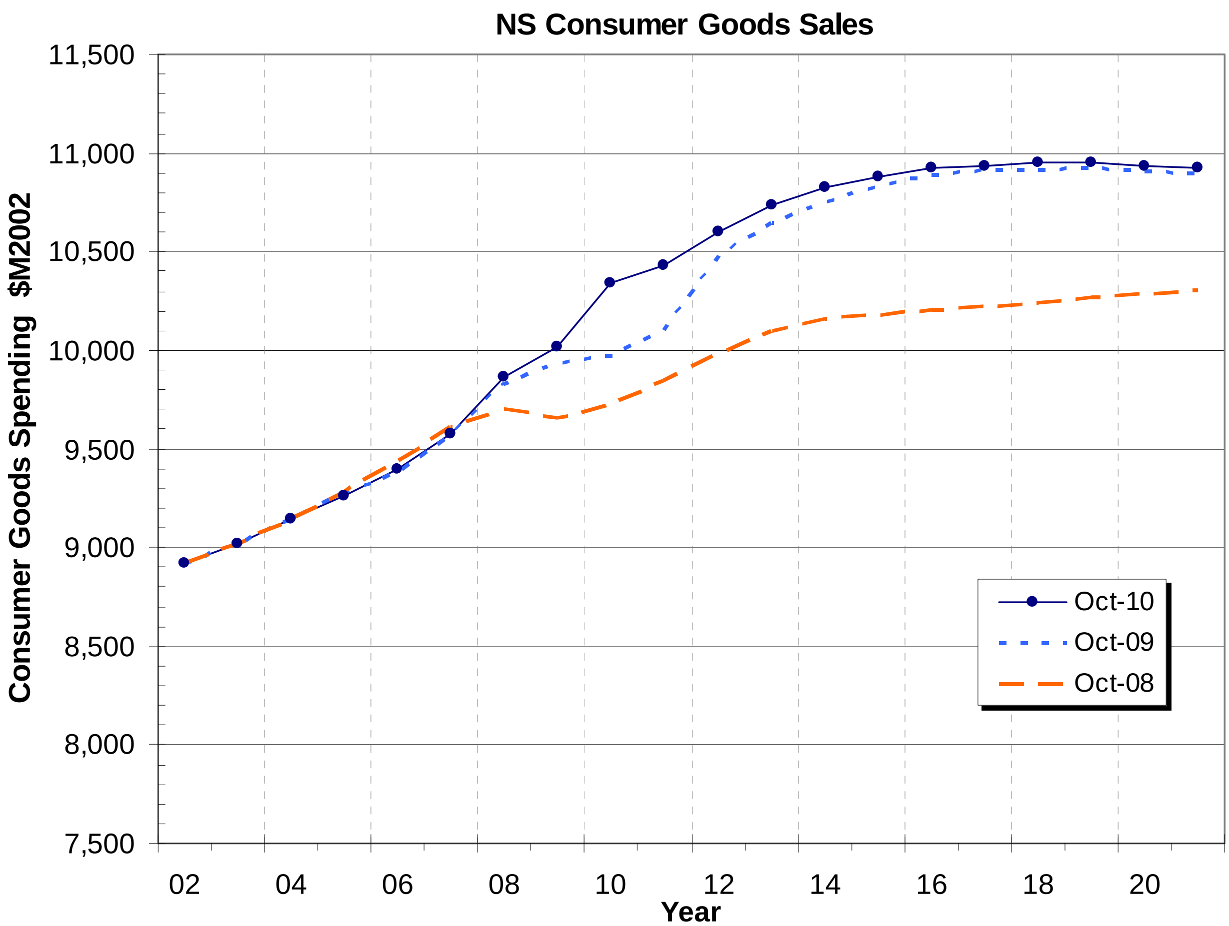
Figures

Figure B1: Nova Scotia Gross Domestic Product Basic Prices



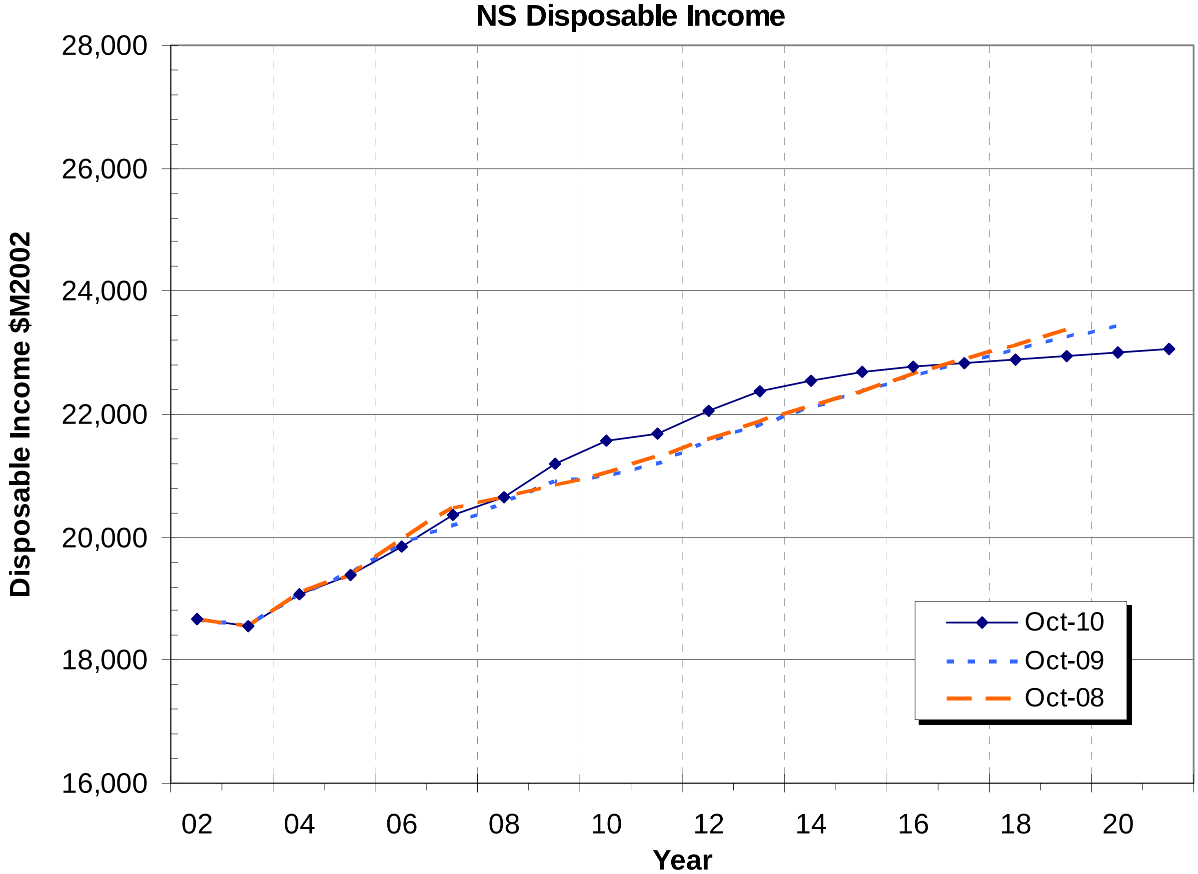
Note: Statistics Canada often re-estimates historical information to reconcile with changes in variable composition and to ensure historical consistency with forecasts. This is the case in the graph above.

Figure B2: Nova Scotia Consumer Goods Sales



Note: Statistics Canada often re-estimates historical information to reconcile with changes in variable composition and to ensure historical consistency with forecasts. This is the case in the graph above.

Figure B3: Nova Scotia Real Disposable Income



Note: Statistics Canada often re-estimates historical information to reconcile with changes in variable composition and to ensure historical consistency with forecasts. This is the case in the graph above.

Figure B4: Nova Scotia Manufacturing GDP and Non-Residential Investment

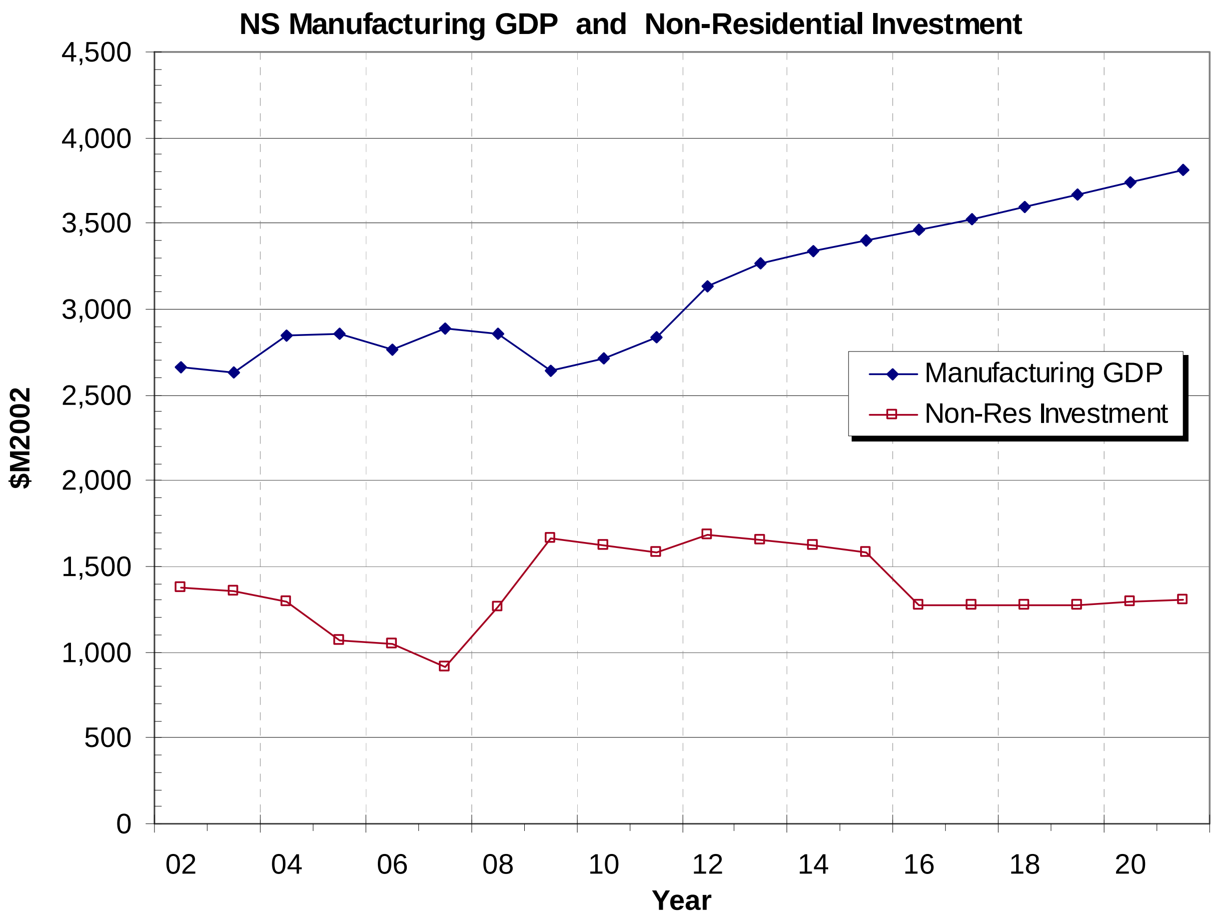


Figure B5: Nova Scotia Manufacturing Employment

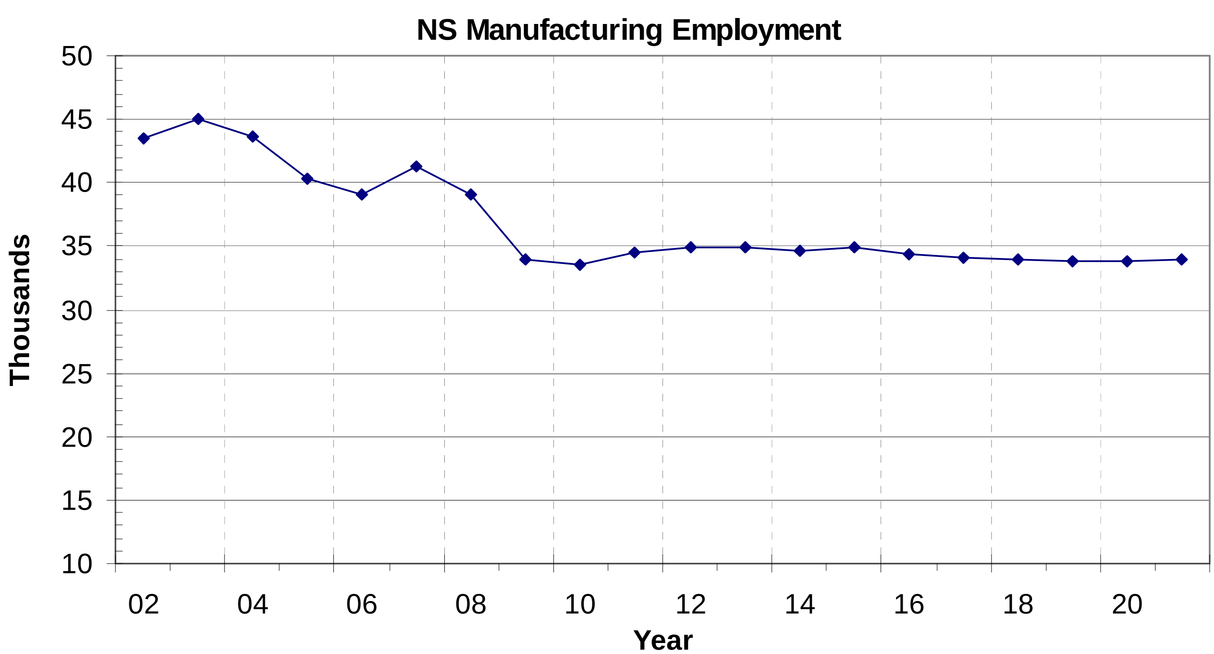


Figure B6: Nova Scotia Energy Sales

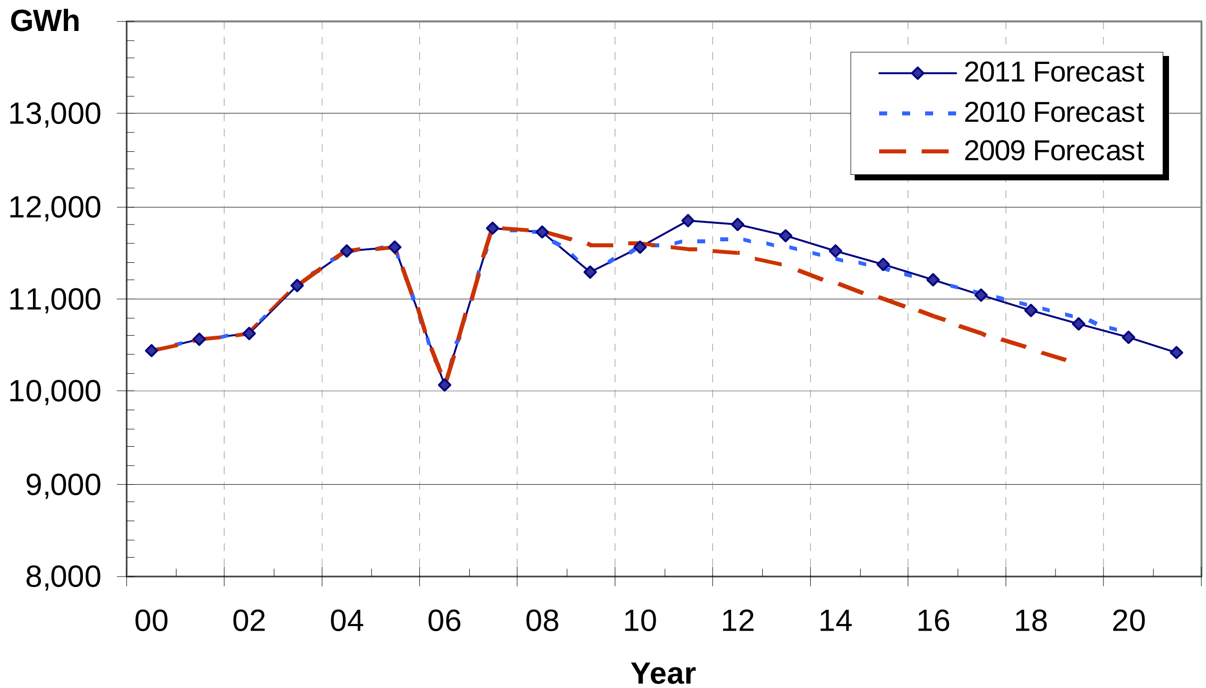


Figure B7: Total Nova Scotia Energy Losses

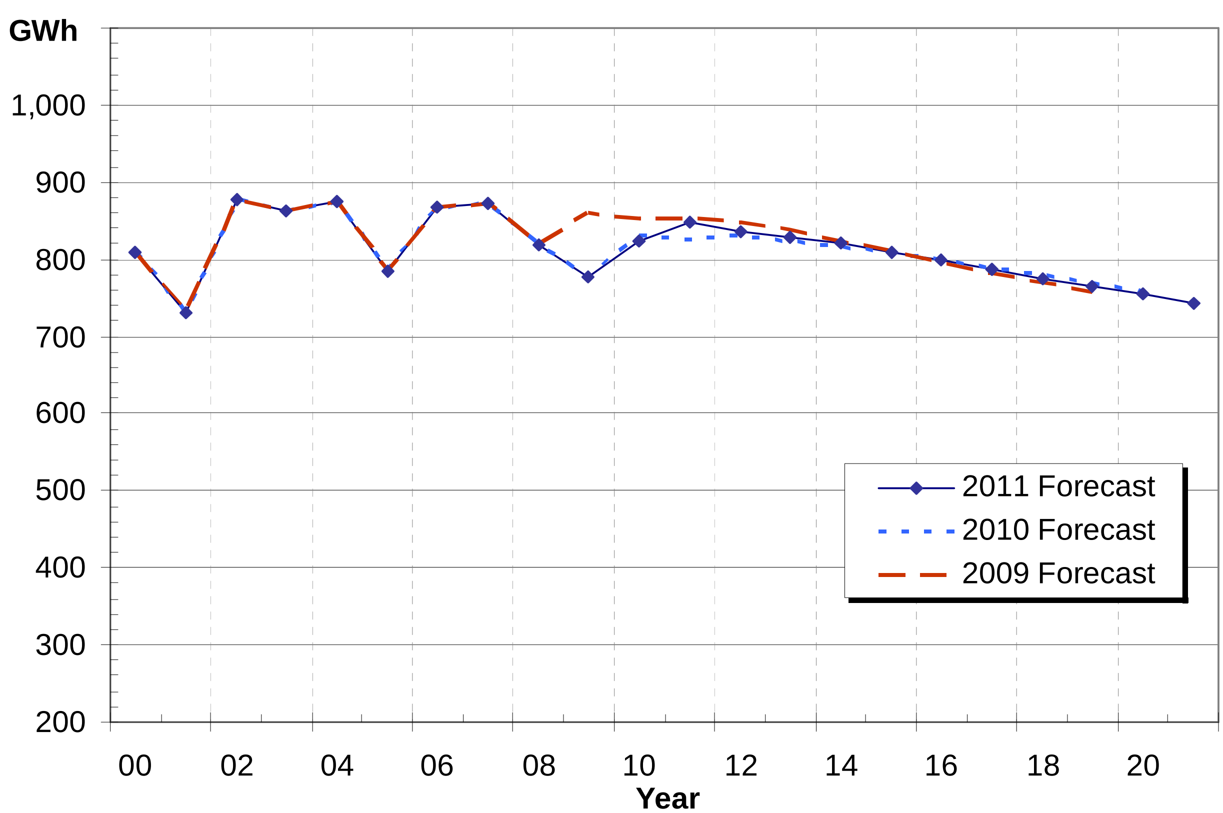


Figure B6: Total Nova Scotia Energy Requirement (NSR)

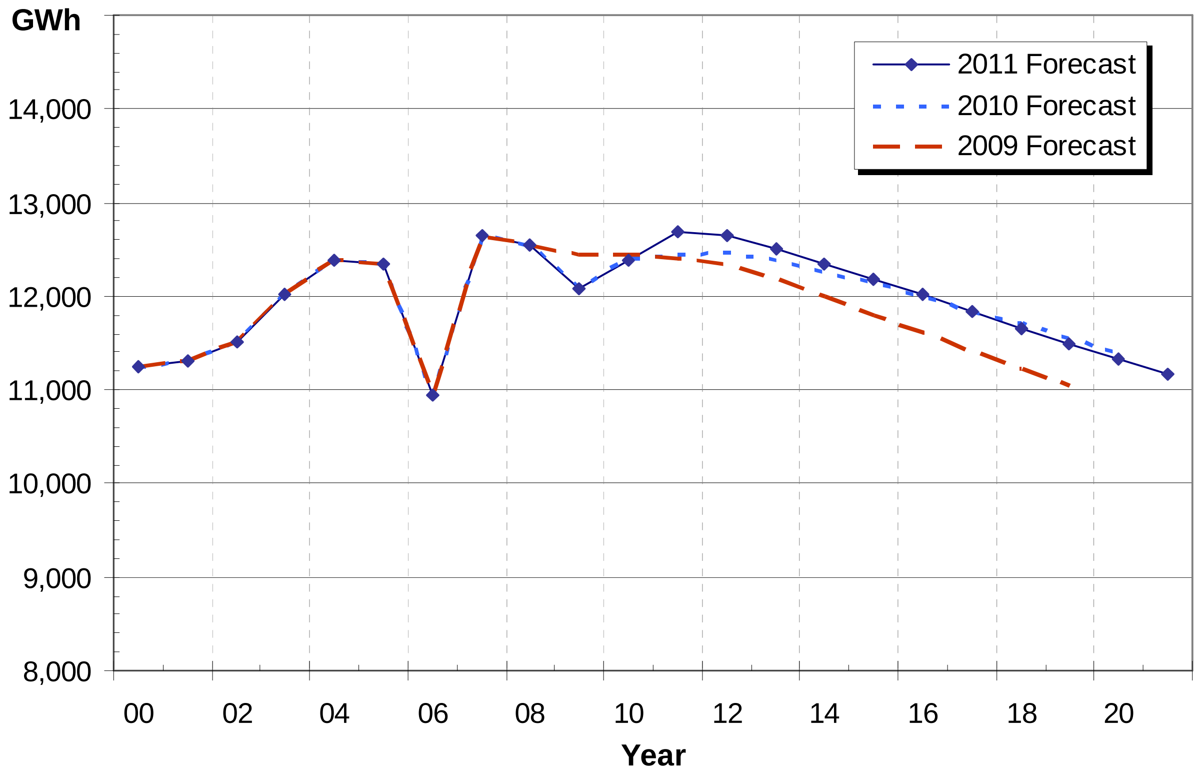
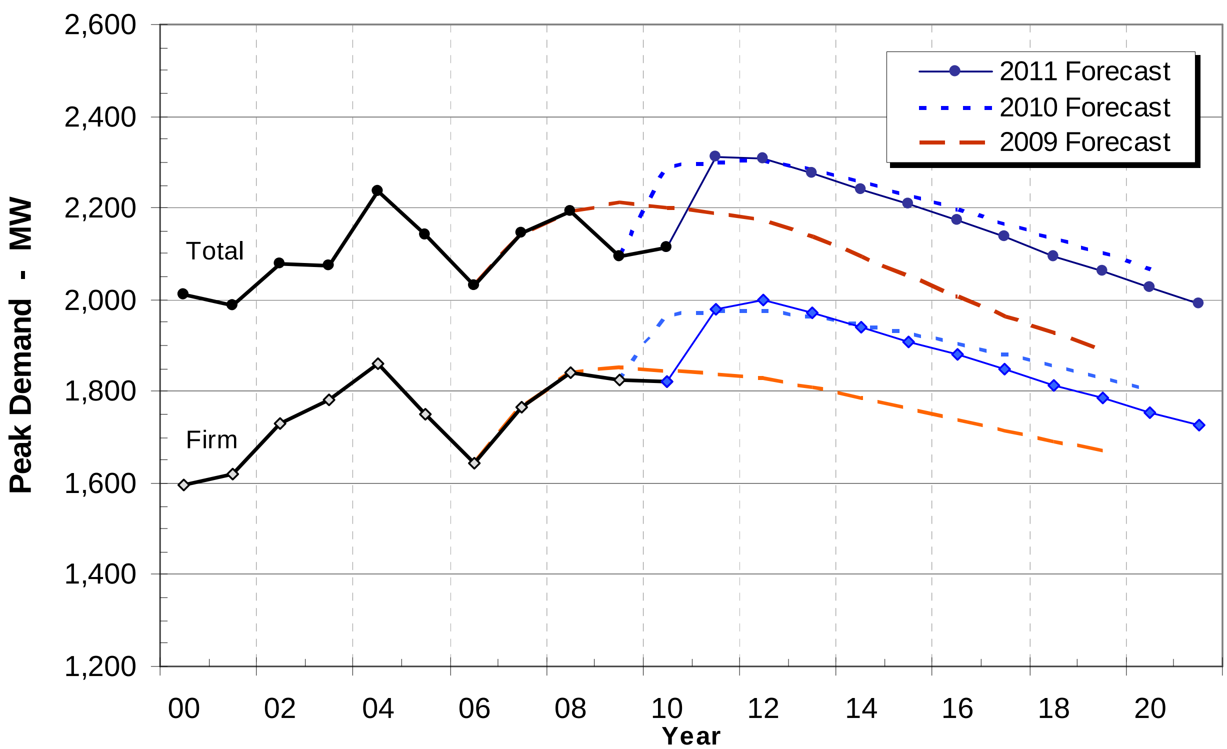


Figure B7: Net System Peak Demand and Firm Peak Demand



Appendix C

Forecast Sensitivity by Major Variable

Appendix C: Forecast Sensitivity by Major Variable

Forecast Sensitivity by Major Variable

Based upon the 2011 load forecast models, the following table shows the relative sensitivity of the forecast to changes in various input assumptions.

Variable	Assumed Change	Effect on 2011 Load GWh	Effect on 2016 Load GWh
Lagged Dependent Variable *2% growth on base year, 2010*	Residential	28.1	0.7
	Commercial	12.9	0.1
	Industrial	10.3	1.2
	All	51.4	2.1
Consumer Goods Sales	+2%/yr (2011 on)	62.6	427.1
Gross Domestic Product (GDP)	+2%/yr (2011 on)	11.4	117.3
GDP - Manufacturing	+2%/yr (2011 on)	4.8	70.4
Real Disposable Income	+2%/yr (2011 on)	6.4	63.8
Investment – Non-Residential	+2%/yr (2011 on)	0.4	5.7
Employment – Manufacturing Sector	+2%/yr (2011 on)	0.9	10.2
Residential Electricity Price	+10% in 2011	-46.8	-156.1
Heating Degree-Days	+ 200 HDD/yr (2011 on)	86.9	192.4
Heating Oil Price	+10¢ per litre (2011 on)	0.0	43.5
DSM Program Effects	half of projected reduction	59.9	699.4
Residential Customer Additions	+2000/yr (2011 on)	21.8	223.6

Note: This table portrays changes to individual variables only. In many cases, there are interdependencies that would require scenario development for more complete evaluation.

Requirement:

Fuel Price Forecasts (industry forecasts used to indicate future trends in gas, oil, and coal prices).

Submission:

The following industry information has been used to develop the fuel forecast used in NSPI's 2012 General Rate Application:

- Price strip for natural gas from NYMEX, basis [redacted] quote
- Price strip for Heavy Fuel Oil, broker quotes
- Price strip for Light Fuel oil, broker quotes
- McCloskey's FAX: International Coal Market Update
- Wood MacKenzie Quarterly Price Forecast
- Indicative Offers

This information has been purchased from various industry associations and is copyrighted. NSPI cannot therefore reproduce these reports for distribution to other parties. This information is available for viewing at NSPI offices.

Requirement:

Lead-Lag Study.

Submission:

Please refer to Attachment 1.

JTBrowne
Consulting

Nova Scotia Power Inc.

Lead-Lag Study
For Determining
Cash Working Capital

March 30, 2011

Costing &
Regulatory Consulting

TABLE OF CONTENTS

Exhibits:

JTBC-1: Resume – John T. Browne

INTRODUCTION

Nova Scotia Power Inc. ("NSPI") is an integrated electric utility. Its rates are regulated by the Nova Scotia Utility and Review Board ("NSUARB") using a return on rate base methodology. This methodology allows NSPI an opportunity to recover through its regulated rates a fair return on its rate base. To support the amount of cash working capital included in its 2012 rate base, the utility has conducted a lead-lag study.

Based on its lead-lag study which reflects its estimates as of March 25, 2011, NSPI has estimated its cash working capital requirement for the 2012 test year to be $66.6 million. The calculation of this amount is set out in Table 1 which replicates Table 12 in the "Summary of Results" section.

Table 1 presents:

- the major categories of cash operating expenses;
- the revenue lag ("Rev Lag") for each expense category which is discussed in a later section and which is the same for each expense category except for Cost of Goods Sold;
- the expense lag ("Exp Lag") for each expense category which are discussed in a later section;
- the net lag for each expense category which is equal to the revenue lag less the expense lag;
- the cash working capital percentage ("CWC %") for each expense category which is equal to the net lag divided by 366[1];
- the cash working capital for each expense category which is equal to the cash operating expense multiplied by the cash working capital percentage;
- the total of the cash working capital for each of the cash operating expense categories;
- the cash working capital associated with the harmonized sales tax ("HST") the goods and services tax ("GST") and demand side management ("DSM") which are discussed in a later section; and
- the total cash working capital that should be included in NSPI's 2012 rate base.

---

[1] The net lag is divided by the number of days in the year. Normally this is 365, but 2012 will be a leap year with 366 days.

Table 1

Nova Scotia Power Inc.
Cash Working Capital
2012[2]

	2012 ($ mm)	Rev Lag	Exp Lag	Net Lag	CWC %	Working Capital ($ mm)
Fuels	612.2	51.86	27.13	24.73	6.8	41.4
Cost of Goods Sold	1.5	0	38.89	-38.89	-10.6	-0.2
OM&G - Labour	127.0	51.86	23.37	28.49	7.8	9.9
OM&G - Excl'd Labour	125.8	51.86	26.48	25.38	6.9	8.7
Grants in lieu of Taxes	36.4	51.86	-136.66	188.52	51.5	18.8
Income Taxes	33.6	51.86	210.04	-158.18	-43.2	-14.5
						64.1
HST-Collected	213.9			-12.07	-3.3	-7.1
HST / GST - Paid	67.3			29.02	7.9	5.3
DSM	43.7			35.80	9.8	4.3
						66.6

[2] The numbers in the tables may not add, or multiply across, due to rounding.

In Table 1, there is no revenue lag for Cost of Goods Sold. Many customers pay at the time of purchase (or shortly thereafter), and the amounts are immaterial. Therefore, to be conservative, NSPI assumed a zero revenue lag for this expense.

NSPI asked me as a chartered accountant and economist with experience in addressing regulatory issues[3] to:

- Advise on the methodology for its lead-lag study.
- Review its lead-lag study to determine whether the methodology is reasonable and adequately supports the determination of the net cash working capital that is to be included in NSPI's rate base for the 2012 test year.

Based on my understanding of NSPI's methodology as set out in the "Opinion" section, the methodology that NSPI used in its lead-lag study is a reasonable application of the traditional approach used by regulated utilities to establish their cash working capital requirement, and therefore, for purposes of establishing its 2012 rate base, the methodology adequately supports the determination of NSPI's cash working capital requirement. As discussed in the "Opinion" section, my opinion deals solely with the methodology employed by NSPI.

The next five sections of this report sets out my understanding of NSPI's lead-lag study. The next section presents the basic methodology used in the study. This is followed by sections that discuss the revenue lag; the expense lags for each of the cash operating expense categories; the impact of the HST / GST and DSM on NSPI's cash working capital; and the summary of the study results.

The last section presents my opinion on the methodology used in NSPI's lead-lag study.

[3] A copy of my resume has been attached as Exhibit JTBC-1.

METHODOLOGY

NSPI has completed a lead-lag study to support the cash working capital that will be included in its rate base for the 2012 test year.

CASH WORKING CAPITAL

In carrying out its operations, a utility incurs costs that are recovered through its revenues. However, there is usually a lag from the time that a utility pays for the costs to provide service and the time it collects the revenues to recover those costs. Cash working capital represents the investment required to fund cash operating expenses until they are recovered through the collection of revenues.

NSPI is regulated under a return on rate base methodology whereby a return is included in the revenue requirement that it is allowed to recover through rates. The return is expected to compensate the utility for the cost of its investment in regulated operations and is calculated by multiplying the utility's average rate base by its weighted average cost of capital. This rate base should equal its investment required for regulated operations, including the amount required to fund cash working capital.

SCOPE

NSPI has employed the definition of cash working capital traditionally used by regulated utilities. This traditional definition defines cash working capital as the investment required to finance cash operating expenses from the time they are paid until the time they are recovered from customers.

In determining cash working capital, the traditional definition considers payables associated with cash operating expenses and receivables associated with the revenues intended to recover these costs.

Cash working capital based on the traditional definition is what the NSUARB approved in the last decision in which it specifically dealt with this issue[4].

LEAD-LAG STUDY

NSPI has used a lead-lag study to determine its cash working capital. This method of estimating the amount of cash working capital is the one most commonly used by major Canadian utilities.

4 Nova Scotia Utilities and Review Board: NSUARB-NSPI-P-882; March 10, 2006.

With a lead-lag study, a utility determines the average time from payment of cash operating expenses to the time those costs are recovered from customers. This establishes the average amount of cash working capital required per dollar of cash operating expenses. The result is applied to the estimated amount of cash operating expenses to determine the cash working capital that should be included in the utility's rate base. A lead-lag study tends to reflect the most accurate measure of the cash working capital required by a utility.

The measurement of the time between payment and recovery of cash operating expenses is usually broken into two steps: the time between the provision of service and the time of recovery; and the time between the provision of service and payment. The net lag (or lead) is determined by subtracting the second period of time from the first.

A lead-lag study involves the following steps:

- Determine the average net lag from the time of sale to the time that the revenues are collected from customers (i.e., revenue lag).
- Determine the average net lag from the time of sale to the time of payment for each major category of cash operating expense (i.e., expense lag).
- Calculate the average net lag for each category of cash operating expense by subtracting the average expense lag for that category from the average revenue lag.
- Calculate the net cash working capital associated with each category of cash operating expense (i.e., expense * net lag / number of days in the year)
- Calculate the total of the working capital associated with each cash operating expense.
- Add the net impact of the collection and payment of sales taxes and similar items (i.e., HST / GST and DSM) on working capital.

DATA

In completing its lead-lag study, NSPI used data from 2009. At the time the study was undertaken, this was the most recent year for which a complete year of data was available.

With regards to the revenues and expenses used in the study, NSPI started with the amounts from its 2009 regulated statements. NSPI then removed the amounts listed in Table 2 from its expenses because they were not cash operating expenses.

Table 2

Lead - Lag Study Exclusions From 2009 Expenses	
	$mm
Depreciation Expense	140.2
Accretion Expense	3.3
Regulatory Amortization	27.2
Fuel Adjustment Mechanism	13.5
Future Income Taxes	-5.2
Bad Debt Expense	4.6
Interest	111.5
Preferred Dividends	9.5
AFUDC	-6.5
	298.1

HEDGES

NSPI enters into hedging arrangements for foreign exchange and commodity prices to help manage the risk associated with its fuel purchases. These hedges may affect the timing of the cash flows associated with its purchases, and therefore affect the related net expense lag.

The impact of the hedges on NSPI's cash working capital requirements is difficult to estimate, and over time, it is expected the impacts will tend to average out to zero. As a result, in establishing individual expense lags, the impact of hedges was not included in the calculations.

This is consistent with how hedges were treated in NSPI's previous lead-lag study

ADJUSTMENTS FOR 2012

Once the study was completed using data from 2009, the results were adjusted for estimated changes between 2009 and 2012. These changes are set out in the "Summary of Results" section and are based on NSPI's estimates as of March 25, 2011.

NET LAG - REVENUES

The net revenue lag represents the average number of days between the provision of service and the date that the revenue from the service is collected from customers. It is comprised of three lags:

- service lag - the number of days between the provision of service and the end of the service period;
- billing lag - the number of days between the end of the service period and the date that an invoice is issued; and
- collection lag – the number of days between the date that an invoice is issued and the date the money is collected from customers.

NSPI calculated a weighted average revenue lag of 51.56 days. As set out in Table 3, this is a weighted average of the lags for each of the following revenue categories:

- Bi-monthly Customers
- Monthly Customers
- Large Customers
- Grid Sales
- Ecoenergy Rebates
- Natural Gas Sales

BI-MONTHLY AND MONTHLY CUSTOMERS

Domestic (i.e. residential), commercial and industrial customers other than large customers (discussed below) are billed either bi-monthly or monthly with billing dates spread throughout the month. Standard payment terms are 30 days for bi-monthly customers and 20 days for monthly customers.

The average service lag was 29.92 days for bi-monthly customers and 14.71 days for monthly customers. The billing lag for both types of customers was 2 days.

The average collection lag was determined by dividing the average accounts receivable by the average daily billings (i.e., total billings divided by 365). Prior to this calculation, the allowance for doubtful accounts was removed from accounts receivable and the bad debt expense was removed from the total billings. Except for a specific allowance related to large customers, it was assumed that both the allowance for doubtful accounts and the bad debts expense applied only to the bi-monthly and monthly customers.

Table 3

Revenue Net Lag 2009						
	2009 Revenues		Lag			
	$, 000	%	Service	Billing & Collection	Net	Weighted Average
Bi-monthly Customers	635,983	50.59	29.92	35.21	65.13	32.95
Monthly Customers	328,985	26.17	14.71	24.31	39.02	10.21
Large Customers	247,943	19.72	14.71	20.37	35.08	6.92
Grid Sales	895	0.07	14.81	20.18	34.99	0.02
Natural Gas Sales	42,643	3.39	14.66	25.48	40.14	1.36
Ecoenergy Rebates	735	0.06	45.13	124.63	169.75	0.10
	1,257,183					51.56

After removing the amount related to large customers, the remainder of the allowance for doubtful accounts was allocated to the bi-monthly and monthly customer classes on the basis of their average accounts receivable balances. The bad debt expense was then allocated on the same basis as the allowance for doubtful accounts.

The average accounts receivable was calculated as the average of the weekly balances. Only 46 weeks of data were available. For the other six weeks, the average for the previous and subsequent weeks was used.

The above calculations produced a weighted average collection lag of 33.21 days for bi-monthly customers and 22.31 days for monthly customers. With the billing lag of two days, the total billing and collection lags were 35.21 days and 24.31 days.

LARGE CUSTOMERS

In 2009, 65 customers fell in the category of Large Customers. They are billed monthly on the first business day following the month that service is provided. However, the invoices are dated the last day of the month for which service was provided. The standard payment terms are 20 days.

Since Large Customers are billed monthly, the average service lag was 14.71 days; and since the invoices are dated the last day of the month for which service was provided, the billing lag was zero days.

To determine the average collection period, NSPI conducted a detailed review of all billings to Large Customers in 2009. NSPI identified the invoice date and the payment date for each bill and calculated a weighted average collection lag of 20.37 days.

GRID SALES

Grid sales are power sales to customers outside of Nova Scotia. Sales for each month are invoiced in the following month with settlement in the latter part of that month. It was assumed that any sales are made evenly throughout each month resulting in a service lag ranging from 13.5 to 15 days.

NSPI reviewed each of the invoices covering its grid sales in 2009 to identify the service, billing and collection lags. NSPI then calculated the total net lag for each invoice and the weighted average net lag for all invoices.

NATURAL GAS SALES

Where it has excess gas, NSPI resells its natural gas. Sales for each month are invoiced in the following month with settlement towards the end of that month. It was assumed that sales are made evenly throughout each month resulting in a service lag ranging from 13.5 to 15 days.

NSPI reviewed each of the invoices covering its natural gas sales in 2009 to identify the service, billing and collection lags. It then calculated the total net lag for each invoice and the weighted average net lag for all invoices.

ECOENERGY REBATES

Ecoenergy rebates are amounts received through the Federal Government's Ecoenergy program. The rebates offset the cost of renewable power.

At the end of each quarter, a claim is made to the Federal Government for the rebates.

In 2009, the claims were made by an IPP that sold power to NSPI. The IPP then passed on to NSPI its share of the rebates. NSPI reviewed each of the four payments covering the rebates to identify the service, billing and collections lags. It then calculated the total net lag for each payment and the weighted average net lag for all of the payments.

In 2012, it is expected that NSPI will continue to receive rebates indirectly through IPPs but will also make claims directly for renewable energy that it produces. This is not expected to have a material impact on NSPI's net revenue lag.

NET LAG - CASH OPERATING EXPENSES

The expense lag represents the time from the provision of service by NSPI to the time the related cash operating expenses are paid. It can comprise three lags:

- service lag – where a supplier provides a service over a period of time, the average number of days between the provision of service by the supplier and the end of the service period;
- billing lag - the number of days between the end of the service period, or the date goods are acquired, and the date that an invoice is issued; and
- payment lag – the number of days between the date that an invoice is issued and the date the amount is paid to the supplier.

NSPI divided its cash operating expenses into the following categories and calculated a net expense lag for each category:

- Fuels
- Cost of Goods Sold
- OM&G – Labour
- OM&G – Other
- Grants in Lieu of Taxes
- Income Taxes

FUELS

Fuels includes fuel for generation, additives used in the production of power, solid fuel handling costs and purchased power.

The expense lag is usually determined in relation to the point in time the related services are provided to NSPI's customers. However, in some cases, fuel is placed in inventory and the average amount of inventory is included in NSPI's rate base. In these cases, the net expense lead should be calculated as:

- the average time in inventory; less
- the average time between the fuel being inventoried and paid.

Since the time in inventory is recognized by including the average inventory in rate base, the time between the fuel being inventoried and the supplier being paid should be recognized as a reduction in cash working capital. Therefore, where the cost of the fuel is inventoried, the expense lag is determined by the average time between the fuel being added to inventory and the time payment is made to the suppliers.

Table 4 sets out the calculation of the weighted average expense lag for fuels.

Table 4

Fuels Net Lag 2009				
	2009 ($,000)	%	Net Lag	Weighted Net Lag
Natural Gas	180,914.1	33.05	39.06	12.91
Heavy Fuel Oil	0.0	0.00	15.52	0.00
Light Fuel Oil	2,158.8	0.39	37.28	0.15
Diesel	3,151.3	0.58	34.45	0.20
Solid Fuel	289,017.2	52.79	22.88	12.08
Solid Fuel Handling Costs	4,139.8	0.76	37.96	0.29
Additives - 2009	4,964.0	0.91	35.01	0.32
Additives - Mercury Sorbents	452.0	0.08	38.74	0.03
Purchased Power	37,440.9	6.84	34.19	2.34
IPPs	25,199.5	4.60	24.36	1.12
TOTAL	547,437.6			29.43

Natural Gas

Natural gas is acquired and either burned or re-sold throughout the month resulting in a service lag of between 13.5 and 15 days. To determine the service, billing and payment lags for natural gas, NSPI reviewed all of the purchases for 2009. After calculating the net lag for each purchase as the sum of the service, billing and payment lags, the weighted average of the net lags was calculated.

Heavy Fuel Oil, Light Fuel Oil, Diesel and Solid Fuel (Coal and Petcoke)

To determine the average time between the date heavy fuel oil, light fuel oil, diesel and solid fuel were recorded in inventory[5] and the date the suppliers were paid, NSPI considered all of the purchases for 2009. After determining the net lag for each purchase, the weighted average of the net lags was calculated for each type of fuel.

In 2009, NSPI faced the unusual situation of having a negative expense for heavy fuel oil. This was the result of low consumption combined with favourable hedges. As a result, for purposes of calculating the weighted net lag for fuel in 2009, the heavy fuel oil expense was deemed to be zero. In arriving at the weighted net lag for 2012, the estimated heavy fuel oil expense for 2012 was used.

Solid Fuel Handling Costs

Solid fuel handling costs are expensed as incurred and not inventoried

The net expense lags for each of the expense categories in solid fuel handling costs were taken from the net expense lags for similar types of OM&G expenses. A weighted average of these net lags was then calculated.

Additives

Additives - 2009

Excluding mercury sorbents, there are three categories of additives: limestone, fireshield and targeted in-furnace injection (“TIFI”).

To determine the average time between the date the additives were recorded in inventory, or expensed, and the date the suppliers were paid, NSPI reviewed all purchases in 2009. After determining the net lag for each purchase, the weighted average of the net lags was calculated.

Additives – Mercury Sorbents

Mercury sorbents were not used in full production during 2009. Therefore purchases from June 2010 were used to estimate the expense lag associated with these additives.

To determine the average time between the date the additives were recorded in inventory, or expensed, and the date the suppliers were paid, NSPI reviewed all purchases in June

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5 A small portion of the total purchases related to services provided or environment fees associated with fuel, and these purchases were expensed. In the case of these purchases, the net lag was calculated from the time the services were provided until the supplier was paid.

2010. After determining the net lag for each purchase, the weighted average of the net lags was calculated.

Purchased Power & IPPs

NSPI is billed monthly for purchased power and power purchased from in-province independent power producers (“IPPs”), and it was assumed that this power is acquired throughout the month. As a result the service lag varied from 13.5 to 15 days. To determine the service, billing lag and payment lags, NSPI reviewed all of the purchased power acquired in 2009. After calculating the net lag for each purchase as the sum of the service, billing and payment lags, the weighted average of the net lags was calculated for each type of purchased power.

COST OF GOODS SOLD

Cost of goods sold refers to the cost of electro thermal storage (“ETS”) units and their installation.

The net lag was calculated as the weighted average of the net lag on the cost of the ETS units and the net lag on the cost of installation.

- To estimate the net lag on the cost of the ETS units, invoices from 2009 equal to 94% of the estimated purchases in 2009 were reviewed. Information from these invoices was used to establish the lag from the time the units were placed in inventory till the time the suppliers were paid.

- To estimate the net lag on the cost of installation, invoices representing 38% of the installation costs expensed in 2009 were reviewed to establish the net lag from the date of installation to the date the suppliers were paid.

OM&G – LABOUR

As a result of labour costs, payments are made to employees, the government for taxes and other parties for employee benefits. To estimate the weighted average expense lag associated with these costs, NSPI reviewed the majority of the payments related to its OM&G labour expense in 2009.

Table 5 sets out the weighted average expense lag for labour.

Net Pay to Employees

The payments to employees are net of deductions for income taxes, the employees’ share of other government payments (e.g., EI and CPP) and employee benefits.

Table 5

OMG - Labour Net Lag 2009				
	2009 ($,000)	%	Net Lag	Weighted Net Lag
Bi- Weekly				
Net Pay	78,890.5	52.2	14.42	7.53
Government Payments	44,448.9	29.4	21.54	6.34
Benefit Supplier Payments	7,346.3	4.9	109.05	5.30
Other Payments – Payroll Dates	12,812.1	8.5	14.42	1.22
Other Payments – Non-payroll Dates	3,487.8	2.3	39.63	0.91
Incentive				
Net Pay	1,900.3	1.3	232.00	2.92
Government Payments	1,909.1	1.3	237.00	3.00
Other Payments – Payroll Dates	54.7	.00	239.00	0.09
Other Payments – Non-payroll Dates	206.6	0.1	231.00	0.32
TOTAL	151,056.5			27.63

NSPI employees are paid bi-weekly. They are paid for the two weeks ending each second Thursday, with payments deposited in their bank accounts on the following Friday, except where there is a holiday in which case they are paid on the preceding day.

The payments are funded by NSPI on the day of deposit. This results in a service lag of 6.5 days and an average payment lag of slightly less than 8 days, for a total average net lag of 14.42 days.

An incentive payment or bonus is paid to employees in February of the following year. Since only half the payment is recognized as an expense for regulatory purposes, only half the payment was considered in the lead-lag study. The service period covers the entire year resulting in an average service period of 182 days. The payments for 2009 were deposited in employee accounts on February 19, 2010, resulting in a payment lag of 50 days. Combining the service and payment lags resulted in a total net lag of 232 days.

Government Payments

Government payments include the employees' income tax deductions, the employee and employer share of Employment Insurance ("EI") and Canada Pension Plan ("CPP") payments, and the employer's Workman's Compensation Benefits ("WCB") payments.

NSPI reviewed the actual payments made to the government associated with each pay period and the incentive payment to establish the average payment lag for both the bi-weekly payroll and the incentive pay. The service periods were the same as with the net pay to employees.

The review found a weighted average payment lag of 15.04 days for the government payments associated with the bi-weekly payroll, and 55 days for the government payment associated with the incentive payment. Combined with the service lags, this produced a net lag of 21.54 days for the bi-weekly payroll and 237 days for the incentive payroll.

Benefit Supplier Payments

The benefit supplier payments are the employee and employer shares of the payments for long term disability, life, dental and health insurance. These payments only relate to the bi-weekly pay payroll and not the incentive pay.

NSPI reviewed the actual payments made to its benefit supplier for each pay period to establish the average payment lag. The review found a weighted average payment lag of 102.55 days. Combined with the service lag, which was the same as with the net pay to employees, this resulted in net lag of 109.05 days.

In 2012, NSPI will be using a new benefit supplier. Under terms agreed to with the new supplier, payments related to any payroll paid in the month are to be paid on the last day of the month.

Other Payments – Payroll Dates and Non-payroll Dates

Other payments refer to amounts deducted from employees' pay and paid to other parties for pensions, Canada savings bonds, etc. It also includes the employer portion of these payments other than the pension payments included in "OM&G - Excluding Labour" as

"Employee Benefits". These latter payments are the employer pension payments in excess of those that match the employee pension payments.

The payments were divided into two categories: those paid on the same day employees are paid and those paid on other dates. In both cases the service periods were the same as with the net pay to employees

In the case of the payments paid on the same date as the payroll, the payment lag and net lag for the bi-weekly pay were the same as for the associated net pay. For the incentive pay, the payment was made on the date of the next regular payroll which was seven days after the incentive payment was made to employees. This added seven days to the payment lag and net lag compared to the incentive net pay.

In the case of payments made on other dates and related to the biweekly payroll, NSPI reviewed 78% of the payments and used the resulting weighted average payment lag of 33.13 days for all of the payments. Combined with the service lag, this resulted in net lag of 39.63 days

In the case of the payment made on another date related to the incentive pay, NSPI reviewed the payment to determine that the payment lag was 49 days. Combined with the service lag, this resulted in a net lag of 231 days.

OM&G – EXCLUDING LABOUR

Table 6 sets out the weighted average expense lag for OM&G – Excluding Labour (hereafter referred to as OM&G).

To estimate the weighted average expense lag for OM&G, NSPI first estimated a net expense lag for 11 of the 12 largest categories of OM&G expense, representing $98.1 million or 81.9% of the gross OM&G expense. The rent category was excluded since about 95% of the amount in this category related to rent for the Barrington Tower. With NSPI's relocation in 2011, these rental payments will not be relevant in 2012.

The weighted average of the 11 estimated net lags was 35.64 days and this amount was used as the net expense lag for all OM&G.

To estimate the expense lags for each of the 11 categories, NSPI reviewed purchases that related to 2009 and were paid in 2009. In total, NSPI reviewed 186 invoices plus the bi-weekly invoice details from Canada Post. In aggregate, it reviewed purchases totalling $34.7 million. This was equal to 35.3% of the total expenses for the 11 categories in 2009 and 28.9% of the gross OM&G expenses in 2009.

For the individual categories, the amounts reviewed as a percent of 2009 expense ranged from 11.1 % to 99.9%. In all cases where the percentage was below 50%, at least 15 invoices were reviewed.

Table 6

OM&G - Excluding Labour Net Lag 2009				
	2009 ($,000)	%	Net Lag	Weighted Net Lag
Materials	12,654.9	12.9	50.62	6.53
Contracts	46,345.1	47.2	42.19	19.93
Freight, Post. & Del.	2,424.4	2.5	32.98	0.81
Telephones	1,749.3	1.8	53.69	0.96
Consulting	8,335.8	8.5	82.04	6.97
Fleet Fuel	2,984.8	3.0	51.73	1.57
Rental & Maint.	3,131.9	3.2	45.27	1.44
Legal & Audit	6,373.2	6.5	59.93	3.89
Employee Benefits	8,724.2	8.9	7.85	0.70
Insurance	3,676.5	3.7	-120.33	-4.51
Data Communications	1,721.5	1.8	-151.66	-2.66
	98,121.7			35.64
Other OM&G Expenses	21,702.5			
	119,824.2			

For each category, NSPI determined the net lag for each purchase reviewed and then calculated the weighted average of the individual net lags. These weighted average net lags were used as the estimated net lags for the categories.

In 2012, the estimated weighted average net lag is estimated to decrease from 35.64 days to 26.48 days. This decrease is due primarily to the expected increase in the "Employee Benefits" category from $8.7 million in 2009 to $34.7 million in 2012 and the resulting greater weight given to its net lag of 7.85 days.

GRANTS IN LIEU OF TAXES

NSPI does not pay municipal taxes other than deed transfer tax. Instead it pays grants in lieu of taxes to the Provincial Government. The amounts are paid in two instalments each year:

- January 31 – covering the period January 1 through December 31 of the current year
- June 1 – covering the period from April 1 of the current year through March 31 of the following year.

Table 7 sets out the weighted average expense lag for "Grants in Lieu of Taxes".

Table 7

Grants In Lieu of Taxes
Net Lag
2009

Payment	2009 Expense ($,000)	%	Service Lag	Payment Lead	Net Lead	Weighted Net Lead
June 2008	4,324.6	12.4	44.5	302.0	257.5	31.91
January 2009	17,298.2	49.6	182.0	335.0	153.0	75.85
June 2009	13,272.0	38.0	137.0	213.0	76.0	28.91
	34,894.8					136.66

INCOME TAXES

NSPI makes instalments on its federal and provincial income taxes, provincial capital tax ("PCT") and Part VI.I tax at the end of each month. All of these taxes are combined under the heading Income Taxes. Where the actual tax expense exceeds the amount of the instalments, there is a final true-up at the end of February of the following year. Where the actual tax expense is less than the amount of the instalments, a refund is received after NSPI files its tax return.

The Income Tax payments for 2009 had characteristics that are not expected to be repeated in 2012. Therefore the net lag was calculated using the expected instalments and true-up for 2012.

In 2012, it is expected that NSPI will be making monthly instalments based on its taxes payable for 2011. As NSPI's taxes payable for 2012 are expected to be significantly higher than in 2011, NSPI's 2012 monthly instalments are expected to cover a small portion of NSPI's 2012 taxes, resulting in the majority of the 2012 taxes being paid at the end of February 2013. As a result, NSPI has estimated the weighted average expense lag for Income Taxes to be 210.04 days.

HST / GST & DSM

The harmonized sales tax ("HST"), the goods and services tax ("GST") and demand side management ("DSM") are not part of NSPI expenses. They are amounts that NSPI is required to collect and then remits to a third party; or in the case of the HST credit, is required to pay and then receives a refund from the government. Although not an expense, NSPI is required to make the associated payments, and the difference between the time of payment and the related recovery affects NSPI's financing requirements.

The impact of the HST and GST on NSPI cash working capital in 2009 is set out in Table 8. The impact of DSM is not included on the table since it did not apply in 2009.

Table 8

HST / GST
Impact on Working Capital
2009

	($ mm)	Net Lag	CWC %	Working Capital ($ mm)
HST Collected	157.5	-15.98	-4.4	-6.9
HST / GST Paid	58.7	27.15	7.4	4.4
				-2.5

HST COLLECTED

NSPI collects HST from its customers which it then remits to the government. NSPI has the use of the HST it collects from the time it is collected from customers until the time it remits the funds on to the government. This reduces NSPI's net financing requirements.

NSPI collects HST on most of its in-province sales although there are some exceptions, such as sales to first nations customers. NSPI does not collect HST on sales to customers outside of Canada or to affiliates: many of its grid sales and most of its natural gas sales are to such customers.

The amounts collected are usually paid to the government at the end of the month following the month in which the customer's invoice is dated. In the case of some customers that fall into the Large Customer category, the amounts collected are paid to the government at the end of the second month following the month in which the customer's invoice is dated

In 2009, there was a provincial rebate program under which the Province of Nova Scotia provided rebates to NSPI equal to the provincial portion of the HST on a portion of domestic residential sales. NSPI remitted HST to the Federal Government as if the rebates did not exist, but credited customers for the amount of the rebates at the time the customer invoices were generated. The Provincial Government than provided the rebates to NSPI. In 2012, the rebates are expected to cover the entire provincial portion of the HST on domestic residential sales.

NSPI estimated the HST collected by category of sale. It also estimated the average net lead for each category. This net lead represented the time from when the HST was collected from customers, or the Province, to when NSPI remitted the HST. Except for Grid Sales and Natural Gas Sales, this net lead was calculated as the difference between:

- the number of days between the date an invoice was issued and the date the HST related to the invoice (including the portion covered by the provincial rebate) was paid to the government; and

- the number of days between the date an invoice was issued and the date HST included in the invoice was collected from customers or the rebate related to the invoice was collected from the Province.

In the case of Regular Customers – Rebates (i.e., regular customers that qualify for the provincial rebate) the net lead was a weighted average of:

- The net lead for HST recoverable from customers; and

- The net lead for HST covered by the rebate.

In the case of Grid Sales and Natural Gas Sales, the time between the collection of HST and the date the related amounts were refunded was calculated directly

For each category of sale, the estimated amount of HST was multiplied by the net lead. The weighted average of the net leads was then calculated. Table 9 sets out the net leads associated with each of the customer categories and the weighted average net lead.

HST/GST PAID

NSPI pays HST as part of the cost of many of its goods and services and pays the goods and services tax (“GST”) to the government on imports. NSPI then receives a refund from the government for the HST and GST paid. NSPI must fund the HST and GST payments from the time it pays them until the time it receives a refund from the government. This increases NSPI’s net financing requirements.

Table 9

Impact of HST Collected on Working Capital 2009				
	HST			
	$, 000	%	Net Lead	Weighted Net Lead
Regular Customers - Rebates	69,060	43.9	5.19	2.27
Regular Customers - Other	54,598	34.7	23.04	7.99
Large Customers	32,143	20.4	26.18	5.34
Grid Sales	63	0.0	40.91	0.02
Natural Gas Sales	1,616	1.0	34.87	0.36
	157,480			15.98

For purposes of the lead-lag study, only HST and GST related to cash operating expenses were considered.

NSPI pays the HST when it pays the invoices bearing the HST. The refund for HST paid is netted against the payment to the government for HST collected at the end of the month following the month that the invoice is dated. Invoices not processed before the end of the month are included with the invoices in the following month, or possibly even later, thereby delaying the refund of HST. NSPI has not considered this possibility in the calculation of its net cash working capital and this tends to reduce its estimated cash working capital requirement.

NSPI estimated the HST paid by category of expense. It also estimated the average lag for each category from the time HST is paid until the time it is refunded as the difference between:

- the number of days between the date an invoice was issued and the date the HST included in the invoice was refunded; and
- the number of days between the date an invoice was issued and the date HST included in the invoice was paid to suppliers.

NSPI assumed invoices are issued throughout the month resulting in an average time from the issuing of an invoice to receiving a refund of 45.63 days. The time from the issuing of an invoice to the payment date is the payment lag which was determined in establishing the expense lags for each category.

In the case of the GST, the amounts are paid to the government at the end of the month and refunded at the end of the next month resulting in a net lag of 30.42 days.

Table 10 sets out the net lags associated with each of the major expense categories and the weighted average net lag.

Table 10

Impact of HST/GST Paid on Working Capital 2009

	HST / GST		Invoice Date to			
	$, 000	%	Refund	Paid	Net	Weighted Net Lag
OM&G	13,295	22.65	45.63	36.69	8.94	2.02
Fuels	36,271	61.79	45.63	12.62	33.01	20.40
Total HST	49,566					
GST	9,134	15.56			30.42	4.73
	58,700					27.15

DSM

In 2009, NSPI was responsible for DSM programs. However, beginning in 2010, an independent administrator, Efficiency Nova Scotia Corporation ("ENSC"), has been established to administer the DSM programs for the province of Nova Scotia.

In 2012, NSPI will collect a DSM Cost Recovery Rider Charge ("DCRR") on behalf of ENSC. The DCRR will be a separate charge included on most customer bills and collected when customers pay their bills.

Each month, NSPI will make a payment to ENSC that reflects the DCRR included in forecast revenues for the previous month, even if those revenues are not billed until after the month end. The payment will be made on the first scheduled wire transfer date in each month.

For 2012, the net lag will be calculated as the difference between:

- the number of days between the date service associated with the DCCR is provided and date the DCCR is paid to ENSC; and

- the number of days between the date service is provided and the date the associated revenues are collected from customers.

The first amount will assume that revenue is earned evenly throughout the month. The latter amount will reflect the relevant lags determined in arriving at the net revenue lag.

SUMMARY OF RESULTS

Table 11 summarizes NSPI's cash working capital based primarily on 2009 data. It reflects what has been discussed in previous sections.

Table 11

Nova Scotia Power Inc. Cash Working Capital 2009						
	2009 ($ mm)	Rev Lag	Exp Lag	Net Lag	CWC %	Working Capital ($ mm)
Fuels	543.7	51.56	29.43	22.13	6.1	33.0
Cost of Goods Sold	1.7		38.89	-38.89	-10.7	-0.2
OM&G - Labour	109.4	51.56	27.63	23.93	6.6	7.2
OM&G - Excl'd Labour	103.4	51.56	35.64	15.92	4.4	4.5
Grants in lieu of Taxes	34.9	51.56	-136.66	188.22	51.6	18.0
Income Taxes	54.4	51.56	210.04	-158.48	-43.4	-23.6
						38.8
HST-Collected	157.5			-15.98	-4.4	-6.9
HST-Paid	58.7			27.15	7.4	4.4
						36.3

To estimate its cash working capital for 2012, NSPI started with its results for 2009 and then, to reflect changes expected between 2009 and 2012, made a number of adjustments based on NSPI's estimates as of March 25, 2011. These adjustments include the following:

- replaced the 2009 amounts for each major category of cash operating expense with the estimates for 2012;
- changed the revenue lag to reflect changes in the mix of revenues by customer type;
- changed the expense lag for fuels to reflect changes in the expected mix of fuels;
- changed the expense lag for labour to reflect the expected payment terms for the supplier of long term disability, life, dental and health insurance;
- changed the expense lag for OM&G to reflect changes in the mix of OM&G expenses;
- changed the impact of HST/GST on cash working capital to reflect the increase in HST by two percentage points to 15%, the expansion of the provincial rebate program, estimated changes in the amounts to which HST/GST will be applied, and changes in the mix of revenues and expenses to which the HST/ GST will be applied; and
- added the impact of DSM on cash working capital.

With the above changes, NSPI's estimated its cash working capital for 2012 to be $66.6 million as calculated in Table 12.

Table 12

Nova Scotia Power Inc. Cash Working Capital 2012						
	2012 ($ mm)	Rev Lag	Exp Lag	Net Lag	CWC %	Working Capital ($ mm)
Fuels	612.2	51.86	27.13	24.73	6.8	41.4
Cost of Goods Sold	1.5	0	38.89	-38.89	-10.6	-0.2
OM&G - Labour	127.0	51.86	23.37	28.49	7.8	9.9
OM&G - Excl'd Labour	125.8	51.86	26.48	25.38	6.9	8.7
Grants in lieu of Taxes	36.4	51.86	-136.66	188. 52	51.5	18.8
Income Tax	33.6	51.86	210.04	-158.18	-43.2	-14.5
						64.1
HST-Collected	213.9			-12.07	-3.3	-7.1
HST-Paid	67.3			29.02	7.9	5.3
DSM	43.7			35.80	9.8	4.3
						66.6

OPINION

I have reviewed the NSPI lead-lag study that is to be used to support the cash working capital requirement that will be included in NSPI's rate base for the 2012 test year.

The lead-lag study was completed by NSPI, although I advised NSPI on the methodology used in the study, including the application of the basic methodology to the major categories of NSPI's revenues and expenses.

NSPI's study was conducted using data from 2009. 2009 was chosen because it was the most recent year for which a complete year of data was available at the time the study was undertaken. The initial results were then updated for estimated differences between 2009 and 2012. Based on the estimates as of March 25, 2011, NSPI's cash working capital requirement for 2012 is $66.6 million.

The lead-lag study used various financial data and other information as inputs. For example, NSPI collected information on the time between the date of various invoices and the date those invoices were paid, and it provided information on its operations that affected the estimation of its cash working capital. I did not perform verification procedures on these inputs or the calculations provided by NSPI.

The focus of my opinion, and the review to support it, was the reasonableness and adequacy of the methodology employed in NSPI's lead-lag study. This methodology included the application of the basic methodology to the major categories of NSPI's revenues and expenses.

My understanding of the methodology used by NSPI has been summarized in the previous sections of this report. This understanding is based on my review which included the following:

- I reviewed documentation on NSPI's methodology that had been prepared by the utility.
- I reviewed the schedules used in NSPI's lead-lag study[6] to assist in understanding the methodology employed by the utility.
- I had a number of discussions with NSPI employees.

Based on my understanding of NSPI's methodology as set out above, the methodology that NSPI used in its lead-lag study is a reasonable application of the traditional approach

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6 Other than changes that were discussed with me and which are reflected in the previous sections, NSPI has stated that it did not make any material changes to the schedules from the time I reviewed them until March 25, 2011.

used by regulated utilities to establish their cash working capital requirement, and therefore, for purposes of establishing its 2012 rate base, the methodology adequately supports the determination of NSPI’s cash working capital requirement.

RESUME - JOHN T. BROWNE

Summary:

John Browne has been assisting clients in applying regulatory principles and resolving financial, accounting and costing issues related to rate regulation for over 25 years. Prior to establishing his own practice 11 years ago, he was a consultant with Deloitte and Touche LLP, the last seven years as a partner.

He has directed and worked on a wide range of studies for rate-regulated entities that have dealt with accounting and cost allocation principles, the determination of rate base, cost of service determination, product costing/pricing, rate of return, capital structure, and methods of regulation.

He has appeared as an expert witness on accounting, costing and financial issues before following regulatory tribunals: Canadian Radio-television and Telecommunications Commission, Canadian Transport Commission, the Alberta Public Utilities Board / the Alberta Energy and Utilities Board, the Manitoba Public Utilities Board, Newfoundland and Labrador Board of Commissioners of Public Utilities and the Nova Scotia Board of Commissioners of Public Utilities.

Education / Professional Qualifications:

- Bachelor of Commerce - Queen's University
- Master of Arts (Economics) - Queen's University
- Chartered Accountant

Committees/ Publications

Mr. Browne was Chairman of the Canadian Institute of Chartered Accountants (“CICA”) Study Group that produced the CICA research report “Financial Reporting By Rate Regulated Enterprises”.

He authored or co-authored the CA Magazine articles “A Matter Of Principles - Part I” “A Matter Of Principles - Part II” and "Regulatory Assets". These articles dealt with accounting by rate-regulated enterprises.

He co-authored the Deloitte & Touche publication “Basics of Canadian Rate Regulation” and authored the Deloitte & Touche monograph “The Contractual Pitfalls of Relying on GAAP”. He has also authored a number of papers for distribution to clients and potential clients such as “Fundamentals of Rate Regulation” (an update of “Basics of Canadian Rate Regulation”).

Key Clients: Mr. Browne's major clients have included: Newfoundland Power Inc., Nova Scotia Power Inc., New Brunswick Power Corporation, Hydro Quebec, Ontario Hydro, Manitoba Hydro, SaskPower, Edmonton Power, Ottawa Hydro, Canadian Electricity Association, Ontario Energy Board, Atco Gas, Enbridge, Newfoundland Telephone Company Ltd., Bell Canada, Manitoba Telephone System, Saskatchewan Telecommunications, AGT/TELUS, Teleglobe, Telesat Canada, Southwestern Bell Telephone Company, New York Telephone, The Telecommunication Authority of Singapore and Dhiraagu (Maldives).

Selected Assignments:

- Completed a survey of Canadian regulators to determine what they viewed as their objectives and how they interpreted those objectives.

- Researched and analysed the methodology for calculating working capital for Edmonton Power. Prepared evidence on the issue and appeared as an expert witness.

- Assisted a telecommunications company in developing and supporting a position on working capital for a regulatory hearing.

- Advised Nova Scotia Power on the methodology for a lead-lag study and reviewed the methodology employed to determine whether it was reasonable and adequately supported the utility’s net cash working capital. The opinion was included in the utility’s rate submission (issue was resolved as part of negotiated settlement).

- Advised Newfoundland Power on issues related to the calculation of cash working capital, reviewed the methodology it used to establish its cash working capital, and provided an opinion as to whether the methodology was consistent with established regulatory practice and appropriate in the context of the utility. The opinion was included in the utility’s rate submission (issue was resolved as part of negotiated settlement).

- Assisted Hydro-Québec by researching issues related to the determination of rate base for a first time rate application and preparing a report that recommended how the utility’s rate base should be established at its initial rate hearing.

- Assisted Newfoundland Power by providing an opinion on regulatory accounting policies including: relationship of regulatory accounting policies to GAAP, the use of the accrual vs. billed method for recognizing revenue, the treatment of unrecognized unbilled revenue and policies related to the utility's transition to an asset rate base methodology. The opinion was submitted to the utility's regulator and expert testimony was provided.

- Prepared a report for Hydro-Québec TransÉnergie that addressed regulatory issues related to the transfer of assets into the utility's regulated rate base.

- Reviewed various regulatory issues as part of the due diligence for Altalink's purchase of TransAlta's transmission assets in Alberta.

- Provided a written opinion for Nova Scotia Power on its regulatory treatment of amounts related to an income tax dispute. The report dealt with past taxes that had not been recovered in allowed rates and future taxes that may not be payable.

- Prepared a report for SaskPower, an integrated electric utility, that addressed the issues related to including or excluding non-core operations from the scope of rate regulation and the regulatory implications for any dealings between these types of operations and its core regulated operations.

- Provided a one-day workshop on regulatory issues to an electric utility with both distribution and transmission operations. The key focus was on performance-based regulation and affiliate transactions.

- Provided a written opinion for Newfoundland Light & Power on accounting and regulatory issues related to future employee benefits and the company's hydro production equalization reserve. The opinion was included in the company's rate submission.

- Completed a study for New Brunswick Power that identified and evaluated the options for restructuring the electric power industry in New Brunswick and privatizing all or part of the Company. As part of the assignment, reviewed the developments occurring throughout the world with a focus on North America.

- Provided a written opinion for Nova Scotia Power that addressed whether its proposal to change from market value to market related value in determining its pension expense was consistent with generally accepted accounting principles and established regulatory principles.

- Assisted a diversified energy company by reviewing its transfer prices to and from regulated operations and recommending changes.

- Researched and analysed the issue of a deferral plan for the introduction of a new plant into rate base. Prepared evidence on the issue for Nova Scotia Power and appeared as an expert witness. Subsequently prepared evidence and appeared as an expert witness on changes to the deferral of the costs on the plant due to changes in circumstances.

- Prepared a report that dealt with the corporate charges from a parent company to a regulated gas utility. The report evaluated the consistency of the charges with the past decisions of the OEB and its Affiliate Relationships Code for Gas Distributors. The report was submitted to the OEB.

- Assisted Ontario Hydro Services Company (now Hydro One), in understanding its regulatory options by researching and providing advice on a number of regulatory issues related to transfer pricing, structural organization, accounting for income taxes, relationships with affiliated companies, performance-based regulation, etc.

- Researched and evaluated options for the regulation of Nova Scotia Power. A recommendation was submitted to the utility's regulator and expert testimony provided.

- Advised New Brunswick Power Distribution and Customer Service Corporation on regulatory issues related to a proposed fuel deferral account.

- Analysed the issue of the appropriate accounting and regulatory treatment of Nova Scotia Power's defeasance program. Prepared evidence and appeared as an expert witness on the issue.

- Researched and evaluated the appropriateness of Newfoundland Power Inc.'s inter-corporate charges. A recommendation with support was submitted to the Newfoundland and Labrador Board of Commissioners of Public Utilities.

- Completed a study and recommended a cost of equity rate for Edmonton Power for each of the years 1985, 1986, 1987, 1988, 1989, 1993 and 1996. The reports for 1985, 1986 and 1996 were included in the Company's rate submissions to the Public Utilities Board of Alberta / Alberta Electric and Utility Board and expert testimony was provided at a public hearing.

- Assisted New Brunswick Electric Power in addressing various accounting issues related to its first rate hearing.

- Completed a study to establish an appropriate capital structure for Edmonton Power and prepared a report recommending an appropriate capital structure for regulatory purposes that formed part of the utility's 1996 submission to the Alberta Energy and Utility Board.

- Advised Manitoba Hydro on the development of appropriate financial targets and prepared evidence on the issue for submission to the utility's regulator. The assignment required researching and analysing the issue of appropriate financial targets for a government owned utility.

- Researched, analysed and prepared a recommendation on the issue of whether Nova Scotia Power should recover a purchase premium paid by the utility on the purchase of a distribution utility.

- Prepared and delivered a half day seminar on accounting for the effects of rate regulation for a Canadian electric utility.

- Participated in the in the OEB consultation process dealing with the transition to IFRS. As part of this participation, made a presentation on proposed principles to guide the development and maintenance of regulatory accounting policies (RAP) and a framework for evaluating proposed changes in RAP.

- Advised the business unit of a major telecommunications company on the appropriate basis for establishing the transfer prices to be charged to other business units within the company.

- Evaluated the ability of a telecommunications company's existing costing systems to meet CRTC Phase III costing requirements and provided an opinion on whether the methodology would be defensible.