
NON-CONFIDENTIAL

Request IR-1:

Please provide details of how ENSC plans to obtain the stakeholder views on program design and implementation that was formerly provided by the Program Development Working Group.

Response IR-1:

As part of its ongoing DSM administration, ENSC welcomes open and direct communication with stakeholders for input and views on program design, implementation and any other DSM related topic. The DSM Advisory Group will provide opportunity for input on program design and implementation similar to that previously offered by the PDWG.

NON-CONFIDENTIAL

Request IR-2:

Please describe the terms of reference for the DSM Advisory Group, including objectives, membership, meeting frequency, and potential agenda items.

Response IR-2:

The role of the DSM Advisory Group is to provide directional advice and stakeholder perspectives on emerging issues.

With ENSC as the chair and host, the invited membership of the DSM Advisory Group is as follows: Consumer Advocate, Ecology Action Centre, Extra-Large Industrial Sector, Halifax Regional Municipality, Large Industrial Sector, Municipal Electric Utilities, Nova Scotia Department of Energy, NSPI, Small Business Advocate and the UARB.

The DSM Advisory Group will meet quarterly, with additional meetings to be held as the Group deems necessary.

Potential agenda items include items arising from the Utility and Review Board Decision and Order on ENSC's DSM Plan, quarterly reports on DSM programs, and items identified by Advisory Group members.

NON-CONFIDENTIAL

Request IR-3:

Please provide a breakdown, including investment, targets, TRCs and PACS for each sub-program within each of the major program area such as the Green Heating Program and Low Income Program within the Existing Residential Program area.

Response IR-3:

The following figures provide a breakdown for 2013, 2014 and 2015, including investment, targets, TRCs and PACS for each sub-program areas within the Existing Residential Program.

The Existing Residential Program is broken out into five sub-program areas:

1. Low Income
2. Direct Install
3. Existing Homes
4. Green Heating Systems
5. MURB

For #3 above, Existing Homes, a portion of the projected participants receive a comprehensive home energy retrofit and also incorporate a Green Heating System. For #4 above, Green Heating Systems covers existing homes that do not receive a comprehensive home energy retrofit, however install a discrete green heating system (opportunity captured through direct channels); it does not cover the third component to the Green Heating Systems strategy, which has been allocated to the New Residential program area. The Existing Homes sub-program area of the Existing Residential program TRCs are below 1.0 for 2013 and 2014 due to slightly negative lifetime benefits projected for some measures.

The Green Heating Systems strategy is a comprehensive approach to addressing HVAC channels, and as such crosses the Existing Residential and New Residential program areas, as

ENSC 2013-2015 DSM Plan Filing (NSUAR-B-E-ENSC-R-12)
ENSC Responses to CA Information Requests

NON-CONFIDENTIAL

indicated in ENSC's Evidence, Appendix E. The values presented here represent only a part of the program. The TRC values for the program taken as a whole are presented in Appendix E, page 10. The Green Heating Systems sub-program area of the Existing Residential program TRCs are below 1.0 for each year due to the lifetime benefits projected for solar water heating.

2013	Investment (\$ million)	Lifetime Benefits (\$ million)^a	Incremental Annual Net Energy Savings at Generator (GWh)	Incremental Annual Net Demand Savings at Generator (MW)	Total Resource Cost Test (TRC)^b	Program Administrator Cost Test (PAC)^c
RESIDENTIAL SUB-PROGRAMS						
Low Income	4.5	4.8	6.4	1.5	1.1	1.1
Direct Install	0.2	0.3	0.7	0.2	1.5	1.7
Existing Homes	1.8	3.6	3.5	0.8	0.9	2.0
Green Heat	0.9	2.0	3.2	0.9	0.8	2.4
MURB	0.1	0.3	0.4	0.1	1.5	2.6
Total	7.4	11.0	14.3	3.5	1.0	1.5

Currency is expressed in 2013 dollars. Columns may not add correctly, due to rounding.

^a Lifetime benefits are expressed as the net present value of the avoided costs, including energy and capacity, over the life of the program measures.

^b TRC is a benefit/cost ratio comparing lifetime benefits to the sum of ENSC's and participants' costs.

^c PAC is a benefit/cost ratio comparing lifetime benefits to ENSC's costs.

2014	Investment (\$ million)	Lifetime Benefits (\$ million)^a	Incremental Annual Net Energy Savings at Generator (GWh)	Incremental Annual Net Demand Savings at Generator (MW)	Total Resource Cost Test (TRC)^b	Program Administrator Cost Test (PAC)^c
RESIDENTIAL SUB-PROGRAMS						
Low Income	4.4	5.2	6.4	1.5	1.2	1.2
Direct Install	0.2	0.3	0.7	0.2	1.7	1.9
Existing Homes	2.8	5.8	5.2	1.3	0.9	2.1
Green Heat	1.1	2.8	4.1	1.2	0.8	2.5
MURB	0.1	0.3	0.5	0.1	1.7	2.8
Total	8.6	14.5	16.9	4.2	1.0	1.7

Currency is expressed in 2013 dollars. Columns may not add correctly, due to rounding.

^a Lifetime benefits are expressed as the net present value of the avoided costs, including energy and capacity, over the life of the program measures.

^b TRC is a benefit/cost ratio comparing lifetime benefits to the sum of ENSC's and participants' costs.

^c PAC is a benefit/cost ratio comparing lifetime benefits to ENSC's costs.

ENSC 2013-2015 DSM Plan Filing (NSUAR-B-E-ENSC-R-12)
 ENSC Responses to CA Information Requests

NON-CONFIDENTIAL

1

2015	Investment (\$ million)	Lifetime Benefits (\$ million)^a	Incremental Annual Net Energy Savings at Generator (GWh)	Incremental Annual Net Demand Savings at Generator (MW)	Total Resource Cost Test (TRC)^b	Program Administrator Cost Test (PAC)^c
RESIDENTIAL SUB-PROGRAMS						
Low Income	4.4	5.4	6.2	1.4	1.2	1.2
Direct Install	0.2	0.4	0.7	0.2	1.8	2.0
Existing Homes	3.3	7.6	6.3	1.6	1.0	2.3
Green Heat	1.4	3.6	5.1	1.5	0.9	2.7
MURB	0.1	0.4	0.6	0.1	1.8	3.2
Total	9.4	17.5	18.9	4.8	1.1	1.9

Currency is expressed in 2013 dollars. Columns may not add correctly, due to rounding.

^a Lifetime benefits are expressed as the net present value of the avoided costs, including energy and capacity, over the life of the program measures.

^b TRC is a benefit/cost ratio comparing lifetime benefits to the sum of ENSC's and participants' costs.

^c PAC is a benefit/cost ratio comparing lifetime benefits to ENSC's costs.

NON-CONFIDENTIAL

Request IR-4:

Please provide specific examples of program design and delivery modifications that ENSC plans for 2013-15 that would not be possible under a series of one year programs.

Response IR-4:

Further to Dunsky's report on regulatory oversight, Appendix B of ENSC's filing, ENSC's rationale for multi-year plan approval is not based upon program design benefits but rather based upon its ability to contract efficiently, to build capacity within Nova Scotia, to effectively engage trade allies and large organizations, and to focus more organizational effort on DSM program delivery. One of the advantages, however, of a multi-year planning framework is the ability to respond rapidly to changing market dynamics, intelligence, or new information (program uptake, market shares, new technologies) that could not be anticipated in advance.

As a program design and delivery example, in 2009 a white paper was developed on fuel switching. In 2010 the UARB approved the launch of a fuel switching pilot aimed at the residential market (existing homes only). Later that year, ENSC designed the details of that fuel switching pilot, which was launched in 2011. In late 2011, with experience from the pilot in hand, ENSC decided to move to a more comprehensive Green Heating Systems strategy, currently submitted for approval. If approved, ENSC will replace the fuel switching pilot with a more comprehensive Green Heating Systems initiative in 2013. In the field of heating systems, then, it will have taken four years to move from a desire for a one-year pilot to implementation of the ensuing program.

Within a three-year approval cycle, it is likely that ENSC could have taken a more dynamic approach. While it is impossible to know exactly how that would have evolved, it is likely that implementation of the Green Heating Systems initiative could have started earlier. ENSC would therefore have had the opportunity to pursue deeper savings more rapidly, as a response to both

NON-CONFIDENTIAL

1 its evolving understanding of the market and recent innovations in ductless heat pump
2 technology.

3
4 ENSC believes that a multi-year approval horizon would minimize challenges, while providing
5 ample opportunity for the UARB and stakeholders to ensure oversight and accountability.

NON-CONFIDENTIAL

Request IR-5:

Please provide ENSC's views of the impact of a three year program versus a one year program on projected Total Resource Cost Test and Program Administration Cost Test numbers for 2013-15.

Response IR-5:

ENSC's view of the impact of a three year program versus a one year program on projected Total Resource Cost Test and Program Administration Cost Test numbers for 2013-15 is that certain costs are likely to be reduced for a three year program versus a one year program, and thus TRC test and PAC test ratios would correspondingly improve.

For example, ENSC DSM Plan regulatory review related costs should be lower for a three year program vs. a one year program, assuming the amount of time to address regulatory matters is lower for a three year program cycle. Assuming ENSC staff will be able to dedicate more time to program delivery and achieve more energy savings for Nova Scotians, TRC and PAC numbers for a three year versus a one year program should improve.

NON-CONFIDENTIAL

Request IR-6:

Please provide any recent load forecasts for the years 2013-2023, either ENSC's own or those of others, and a comparison with those in the 2007 IRP and 2009 IRP update.

Response IR-6:

The attached documents provide details of NS Power load forecasts. Please refer to:

- Attachment 1 - 2011 Load Forecast Report (latest available)
- Attachment 2 – 2009 Load Forecast Report (input to 2009 IRP Update)
- Attachment 3 – 2006 Load Forecaast Report (input to 2007 IRP)

The table below compares the total annual load of the base forecast. For equivalency, no adjustments are included for future DSM programs.

ENSC 2013-2015 DSM Plan Filing (NSUARB-E-ENSC-R-12)
 ENSC Responses to CA Information Requests

NON-CONFIDENTIAL

1

Annual GWh Year	IRP 2007 Fcst	IRP 2009 Fcst	2011 Load Fcst
	rev: 2006	rev: 2009	rev: 2011
	No DSM	No new DSM	No new DSM
2000	11,240	11,240	11,240
2001	11,303	11,303	11,303
2002	11,501	11,501	11,501
2003	12,009	12,009	12,009
2004	12,388	12,388	12,388
2005	12,338	12,338	12,338
2006	11,748	10,946	10,946
2007	12,981	12,639	12,639
2008	13,272	12,539	12,539
2009	13,545	12,478	12,073
2010	13,812	12,547	12,158
2011	14,064	12,615	12,803
2012	14,306	12,725	12,953
2013	14,542	12,821	13,077
2014	14,778	12,918	13,208
2015	15,028	13,008	13,334
2016	15,265	13,082	13,447
2017	15,506	13,156	13,547
2018	15,748	13,241	13,631
2019	15,995	13,326	13,730
2020	16,232	13,400	13,823
2021	16,470	13,468	13,909
2022	16,718	13,545	
2023	16,974	13,617	
2024	17,239	13,686	
2025	17,509	13,748	
2026	17,784	13,814	
2027	18,064	13,879	
2028	18,348	13,944	
2029	18,638	14,008	
2030		14,072	
2031		14,136	
2032		14,199	

2



2011 Load Forecast

Prepared

April 2011

Table of Contents

Executive Summary	1
Introduction	4
Forecast Models	4
Discussion of Major Inputs	5
Sector Model Inputs	6
Losses	7
Energy Forecast Details	7
Residential Sector Sales	8
Commercial Sector Sales	13
Industrial Sector Sales	15
Total Sales	18
System Losses and Unbilled Sales	18
Net System Requirement	19
Rate Class Sales	20
<i>Residential</i>	21
<i>Small General</i>	21
<i>General</i>	21
<i>Large General</i>	22
<i>Small Industrial</i>	22
<i>Medium Industrial</i>	22
<i>Large Industrial</i>	22
<i>Municipal</i>	23
<i>Unmetered Services</i>	23
<i>Generation Replacement and Load Following</i>	23
<i>Mersey System</i>	24
<i>Extra Large Industrial Two Part Real Time Pricing (ELI 2P-RTP)</i>	24
<i>One-Part Real Time Price (1P-RTP)</i>	24
System Losses and Unbilled Sales	25
Peak Demand	25
<i>Non-Firm Coincident Peak</i>	26
<i>Total Coincident Firm Peak</i>	26

List of Figures

Figure 1 Annual Net System Requirement	2
Figure 2 Annual Net System Peak (Winter-ending)	3
Figure 3 Forecast Variables	6
Figure 4 2010 NSPI Sector Sales.....	7
Figure 5 Persons per Residential Account	10
Figure 6 Annual NS Heating Degree-Days	11
Figure 7 Annual Energy – Residential Sector.....	12
Figure 8 Residential Sector Energy	13
Figure 9 Annual Energy – Commercial Sector.....	14
Figure 11 Annual Energy – Industrial Sector	16
Figure 12 Industrial Sector Energy	17
Figure 13 Total Energy Requirement	20

Appendices

Appendix A: 2010 NSPI Forecast

Appendix B: Figures

Appendix C: Forecast Sensitivity by Major Variable

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.

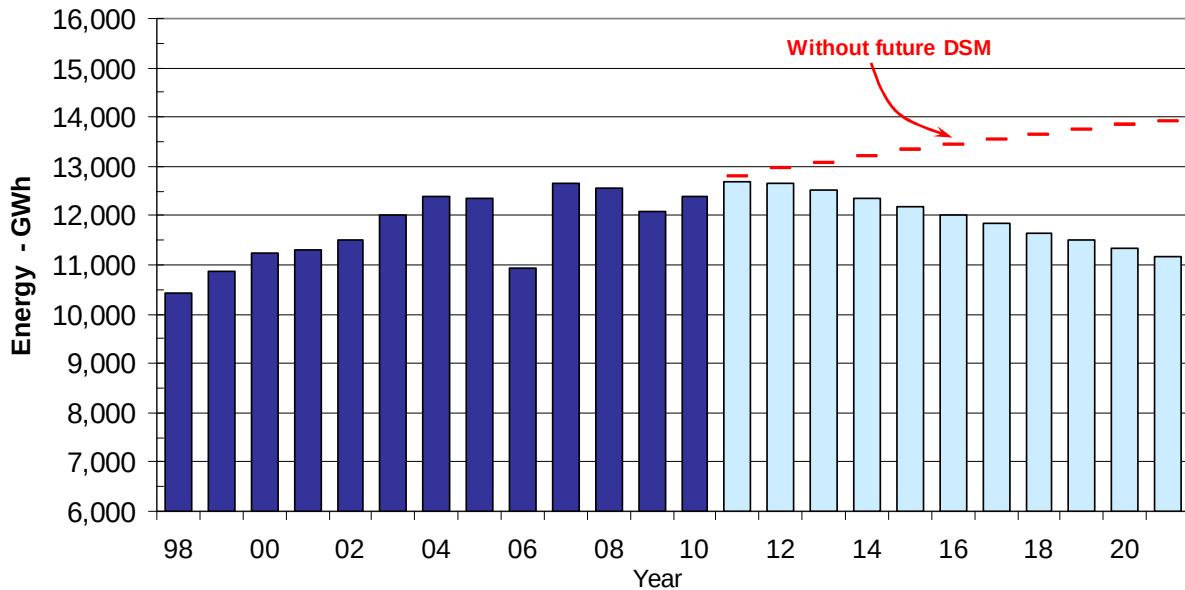
NSPI billed energy sales are initially modeled and forecast as three provincial customer sectors: residential, commercial and industrial. Input variables for each sector are updated and forecast sales are then calculated using the sector models. The sum of these in-province billed sales plus associated 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.

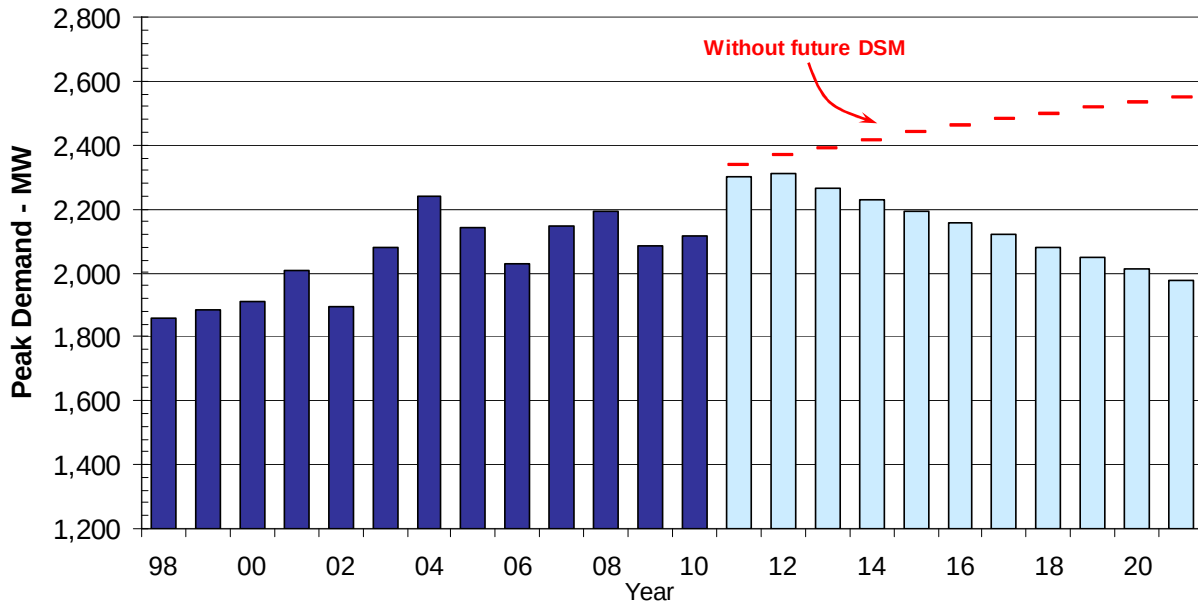
Figure 1 Annual Net System Requirement



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.

1 **Figure 2 Annual Net System Peak (Winter-ending)**



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

9 **New load forecasting methodology under development at NSPI**

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

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

1 **Introduction**

2
3 NSPI annually develops a forecast of energy sales and peak demand requirements to assess the
4 effects of customer, demographic and economic factors on the future provincial system load. It
5 is a fundamental input to the overall planning, budgeting and operating activities of the
6 Company. Produced in the winter of 2010-2011 and using information available at the time, this
7 forecast covers the period of 2011 - 2021. Unless otherwise noted, average growth rates stated
8 report the average annual rate calculated between 2011 and 2021.

10 **Forecast Models**

11
12 Nova Scotia electric energy sales are modeled and forecast as three provincial customer sectors:
13 residential, commercial and industrial. Energy forecasts for sector electricity sales are calculated
14 using econometric models in conjunction with forecasts for the independent variables used in
15 those models. Individual customer load forecast survey information is also used for large
16 customers in the Commercial and Industrial sectors.

17
18 The sector econometric models are multiple linear regression equations that are designed to
19 capture the relationships between electricity consumption and several independent variables. The
20 models then use these relationships to predict future energy loads. An examination of these
21 variables provides a meaningful explanation of the load growth in each sector. The individual
22 econometric model details are shown in the Appendices of this report.

23
24 The variables used in the preparation of the forecast include population, residential customer
25 growth, inflation, GDP, retail sales, oil and electricity prices, appliance saturation levels and
26 average energy use, water and space heat saturation levels and heating degree-days. The primary
27 source of economic and other provincial statistics used in the load forecast is the Conference
28 Board of Canada's *Economic Outlook*, which is released quarterly. This forecast provides a
29 provincial perspective and considers specific Nova Scotia projects and demographics.

1 **Discussion of Major Inputs**

2
3 The Gross Domestic Product (GDP) for Nova Scotia was estimated at \$27,536 million (in
4 constant 2002 dollars) in 2010, and is forecast to increase by 1.8 percent in 2011 and 1.9 percent
5 in 2012.

6
7 The provincial Consumer Price index (CPI) for 2010 was 2.2 percent annual growth, a rebound
8 from the negative 0.1 percent posted in 2009 due to the effects of the recession. It is forecast to
9 grow at 2.2 percent for 2011 and 2.1 percent in 2012, and remain in the 2 percent range for the
10 next several years as the Bank of Canada maintains watch on inflation targets.

11
12 Housing starts for NS were estimated at 3,438 units in 2009 (singles: 2,193), and were forecast
13 by the Conference Board of Canada (CBoC) to increase to 4,382 for 2010 (singles: 2,834). For
14 2011, total housing starts are forecast at 3,472, and 3,328 for the year 2012. The continued
15 urbanization and aging population trend is expected to drive a shift to more multi-unit housing
16 and condominiums.

17
18 Retail sales, with only 0.2 percent growth in 2009, rebounded with 3.1 percent growth in 2010.
19 For 2011, real growth is expected to slip by 0.2 percent but grow by 1.2 percent in 2012 as
20 consumer confidence improves.

21
22 Nova Scotia population in 2010 was estimated to be 942,217 with annual growth remaining
23 relatively flat in the past five years. There is little indication that the prevailing trends will be
24 altered soon. Further population growth in the forecast is marginal with the estimate for 2012 at
25 946,202 for an annual growth rate of 0.21 percent.

26
27 Figure 3 lists the annual growth rates of some of the major independent variables that affect the
28 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.

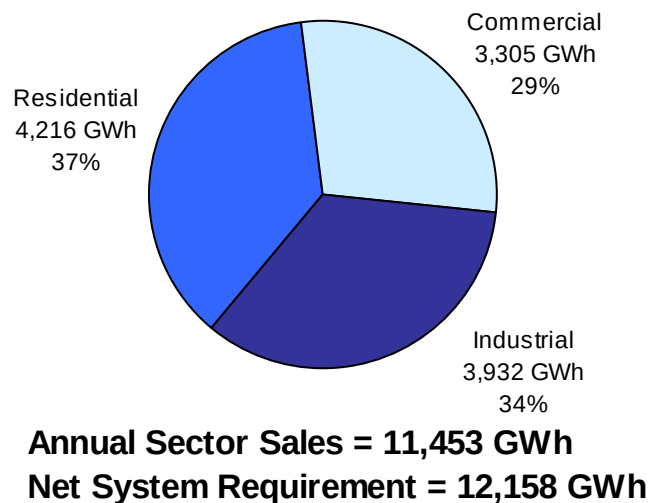
Losses

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.

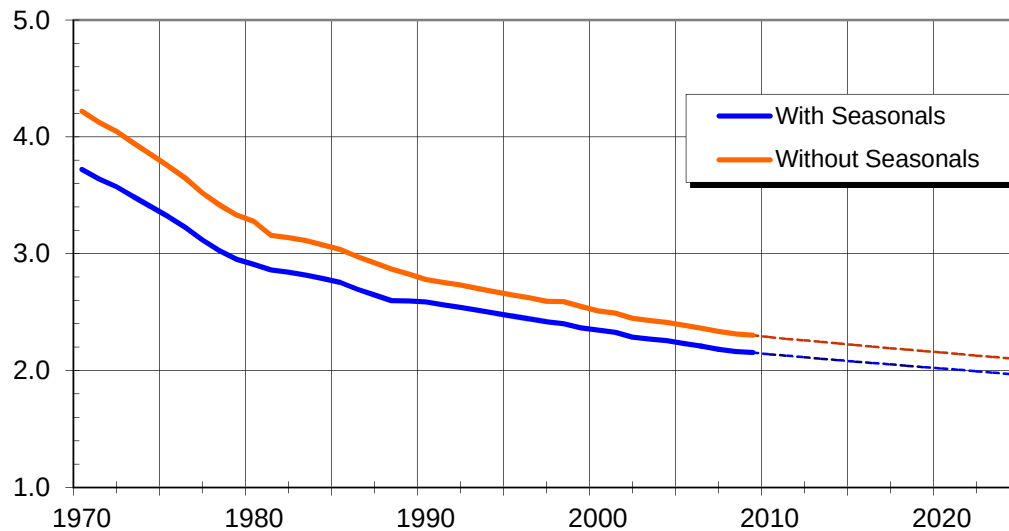
To capture the other sector growth trends, the residential electric load of the previous year is included in the model as a lagged dependent variable. It should be noted however, that the coefficients applied to this and the other variables are the result of estimates using data compiled over a 30-year 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.

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

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.

1 **Figure 5 Persons per Residential Account**



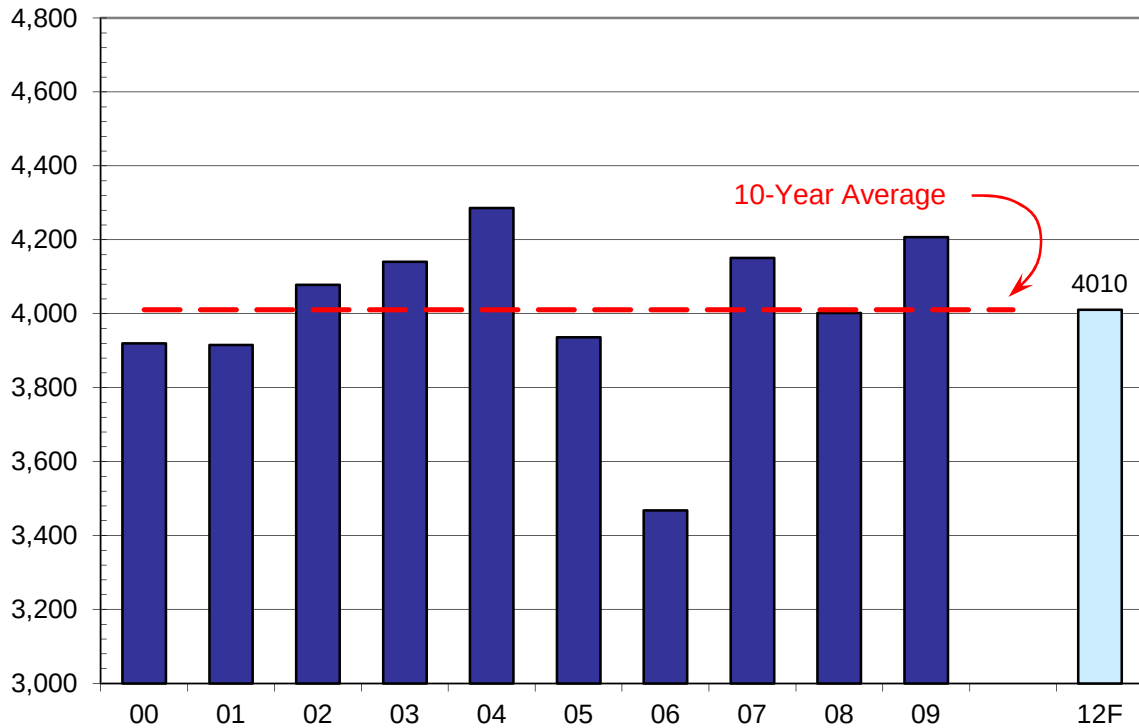
2
3
4 Within the residential sector forecast, large household appliances are modeled individually,
5 considering age, efficiency trends, and acquisition rates. Since these improvements apply only to
6 new appliances, the resulting effect on the overall system load is gradual as older appliances are
7 retired and replaced with more efficient models.

8
9 The saturation of electric space heat has been in the mid to high 20 percent range in recent years
10 and was estimated to be 29 percent in 2010. The saturation of electric water heating hovers
11 around 59 percent and is forecast to grow slowly over the forecast period.

12
13 The forecast for weather effects uses 10-year average temperatures, measured in heating degree-
14 days (HDD). Heating degree-days are a common measure of heating requirement, based on the
15 degree departure between the daily mean temperature and a given standard temperature. The
16 standard temperature of 18°C is used for these calculations and is assumed to be a comfortable
17 room temperature below which space heating is generally required. The forecast uses the
18 Environment Canada HDD data for Shearwater Airport for the years 2000-2009 which is 4,010
19 HDD.

20
21 Figure 6 shows the variation in the actual annual HDDs over the past ten years.

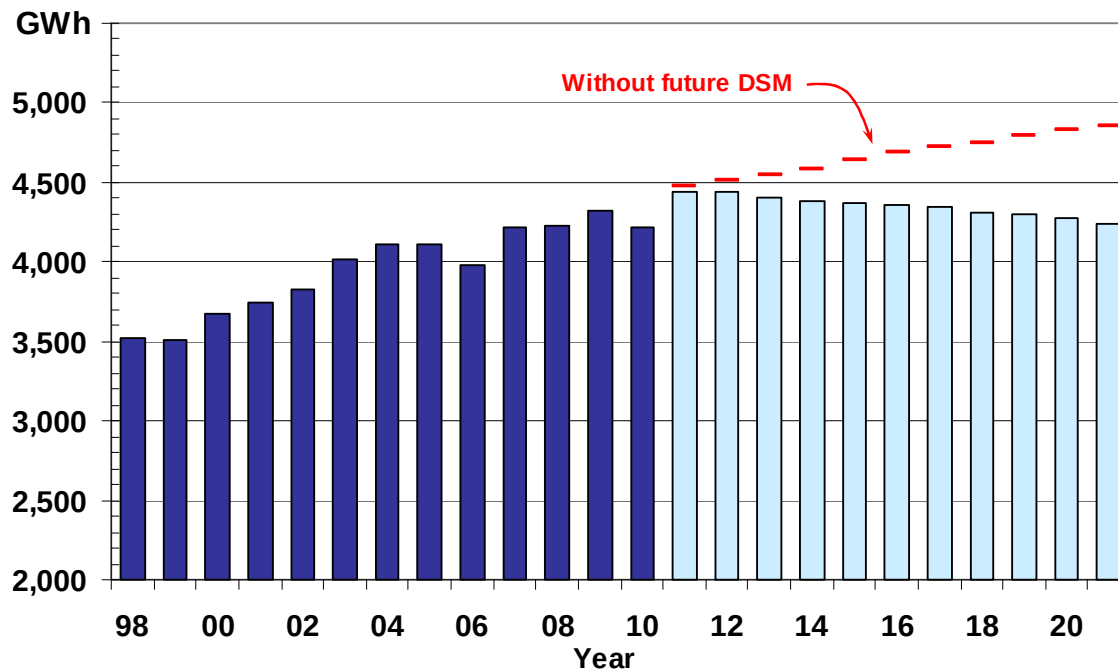
1 **Figure 6 Annual NS Heating Degree-Days**



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.

1 **Figure 7 Annual Energy – Residential Sector**



2
3
4 Growth in this sector is expected to be relatively low. The 2012 load forecast for this sector is
5 4,437 GWh representing a 1.3 percent annual increase over 2010 actual sales adjusted for
6 weather effects. Without the effects of DSM, 2012 sales are forecast at 4,514 GWh or 2.1
7 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

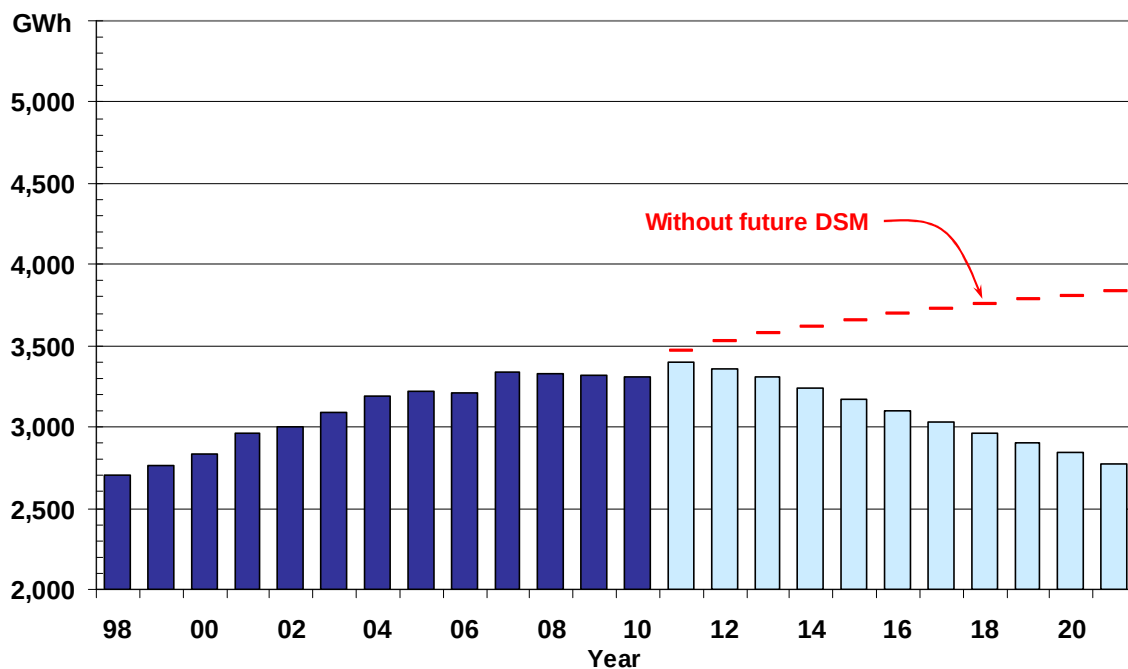
Real personal disposable income (RPDI) is also correlated to activity in the commercial sector and is included in the model.

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.

$$\text{Commercial} = 0.01906 \text{ RQTOS} + 0.01362 \text{ RPDI} + 0.2685 \text{ Residential} + 0.4245 \text{ Commercial load}_{t-1}$$

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

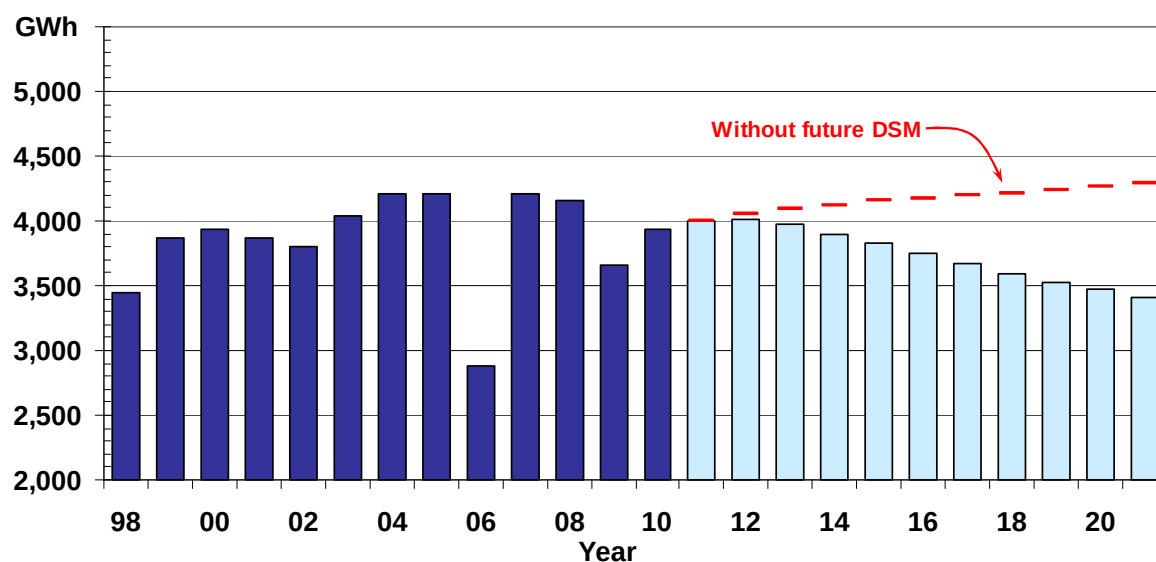
⁵ The actual results of 2009 include DSM effects estimated at 25.4 GWh

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 expected 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

1 reading and billing process, billed sales will vary somewhat from accrued sales. Energy
2 generated and sold but not yet billed, is referred to as “Unbilled” sales.

3
4 The difference between energy generated for use within provincial borders and the total NSPI
5 billed sales comprises transmission and distribution system losses as well as changes to the level
6 of unbilled sales. Losses of approximately 4 percent of sales within municipal utility service
7 areas are also included in this total Nova Scotia losses estimate.

8
9 Based on historical estimates, losses are forecast to range between 6.6 and 6.7 percent of the total
10 Nova Scotia energy requirement over the forecast period.

11 12 **Net System Requirement**

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

1 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

2
3 The NSR for the province has grown at an average of 0.9 percent per year in the five year period
4 from 2003-2008 and then declined by 3.7 percent in 2009 due to the recession. NSR is forecast
5 to decline by 1.3 percent over the next 10 years with the effects of DSM. Without DSM effects,
6 growth is forecast to average 1.1 percent annually.

8 Rate Class Sales

9
10 Forecast sales by sector are allocated into 13 rate classes for revenue forecasting purposes. The
11 following section describes these rate classes and their expected energy requirements for the
12 forecast period. In most cases, load growth trends by rate class are due to the same factors that
13 affect the sector to which they belong, however, migration of customers between rate classes in
14 the same sector can affect both historical and forecast energy requirements by class. Sales
15 requirements by class are computed using historical and forecast trends and customer migration
16 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.

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

6 7 ***Non-Firm Coincident Peak***

8
9 NSPI offers interruptible or “non-firm” service to industrial customers. Certain industrial
10 customers who meet specific criteria may utilize discounted rates in exchange for agreeing to
11 have their electricity supply interrupted on short notice in order to meet any necessary
12 emergency peak reductions required to maintain system stability. These rate classes are the
13 “Generation Replacement and Load Following” rate, the “Extra Large Industrial Two Part Real
14 Time Pricing” rate and the “Interruptible” rider of the Large Industrial rate. The combined
15 interruptible demand of these customers coincident with the monthly system peaks may at times
16 exceed 400 MW. At the January 2010 peak, there were 30 customers on these rates, representing
17 a combined coincident non-firm peak of 314 MW.

18
19 Non-firm coincident peak demand is forecast explicitly by customer for the near-term and an
20 allowance is made for unallocated or new customer growth in the longer term. Although one
21 customer departed from the non-firm rate in 2009, the remaining customers who currently take
22 non-firm service are expected to continue on the rate and therefore non-firm coincident peak is
23 forecast to grow only moderately from its current level assuming there are no major changes
24 made to the rate’s availability or requirements over the forecast period.

25 26 ***Total Coincident Firm Peak***

27
28 Total Coincident Firm Peak is the demand at the time of Nova Scotia Power’s system peak that
29 is attributable to all firm classes (e.g.: residential, small general, etc.), but excluding the non-firm
30 customer classes mentioned above.

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

6

1
2
3
4
5

Load Forecast

Appendices

1
2
3
4
5

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

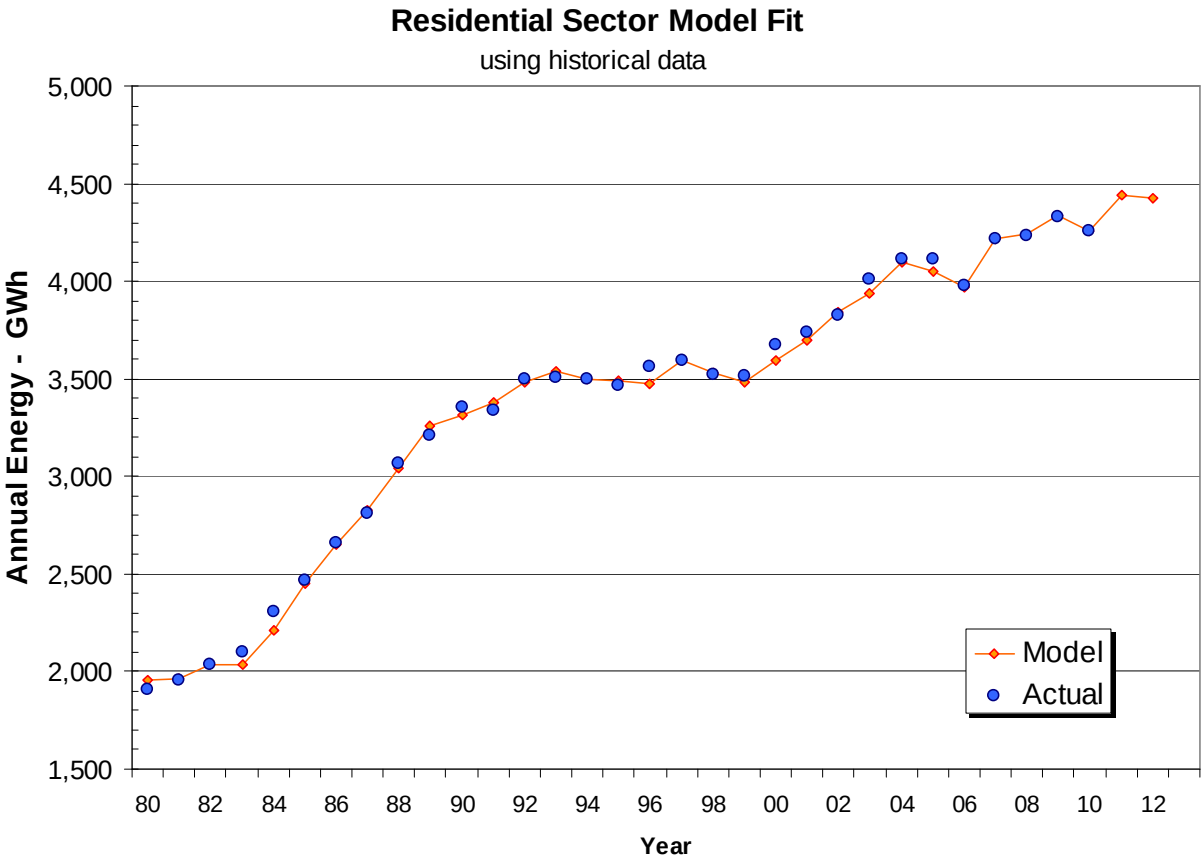
Sample size	25	No. parameters	5
Mean	3644.89	Std. deviation	446.59
Adj. R-square	0.99	Durbin-Watson	2.93
Ljung-Box(15)	24.3 P=0.94	Forecast error	34.55
BIC	42.64	MAPE	0.66%
MAD	23.63		

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.

1



2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25

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

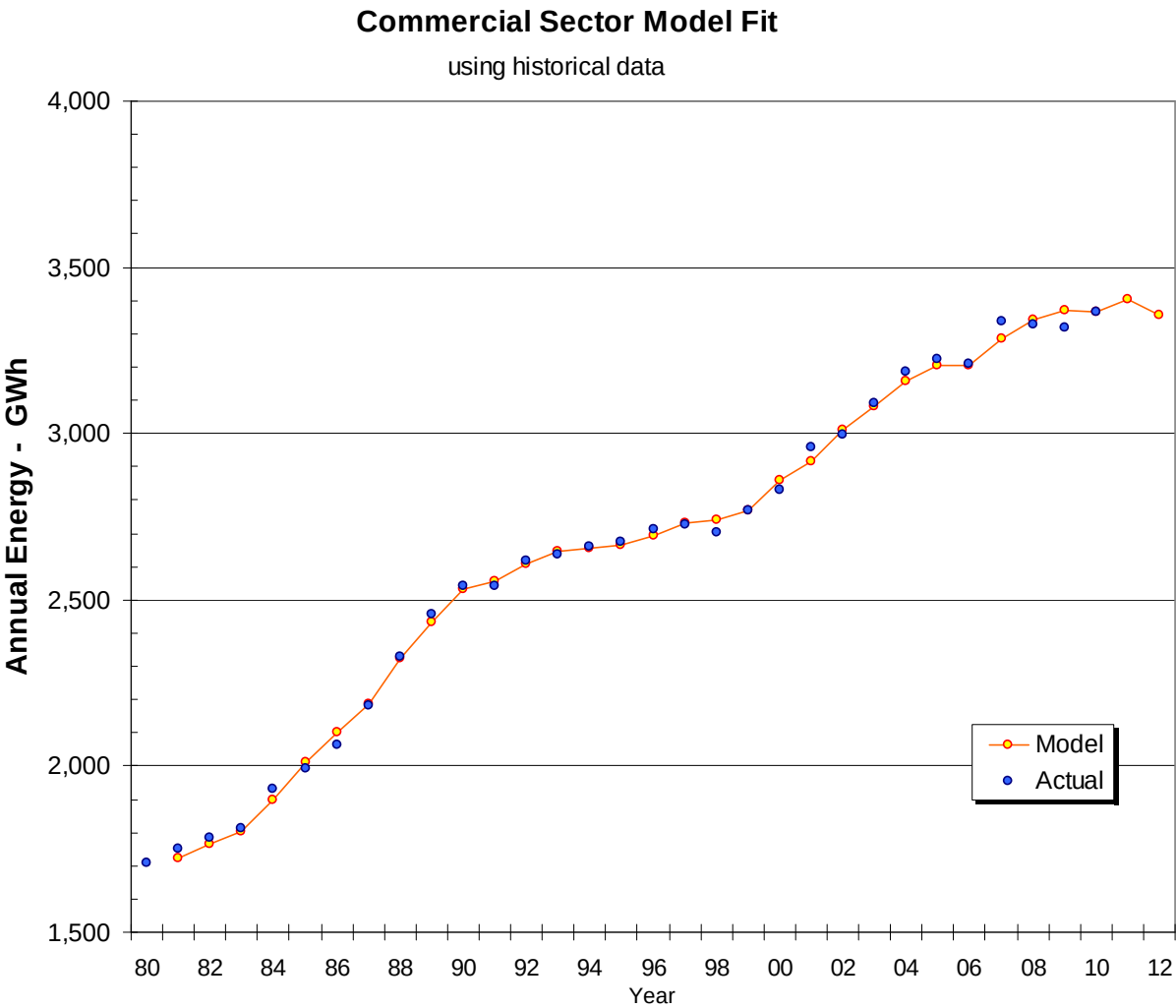
Within-Sample Statistics

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*	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



1
2
3
4
5
6
7
8
9
10
11
12
13

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

1 Medium Industrial
2

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

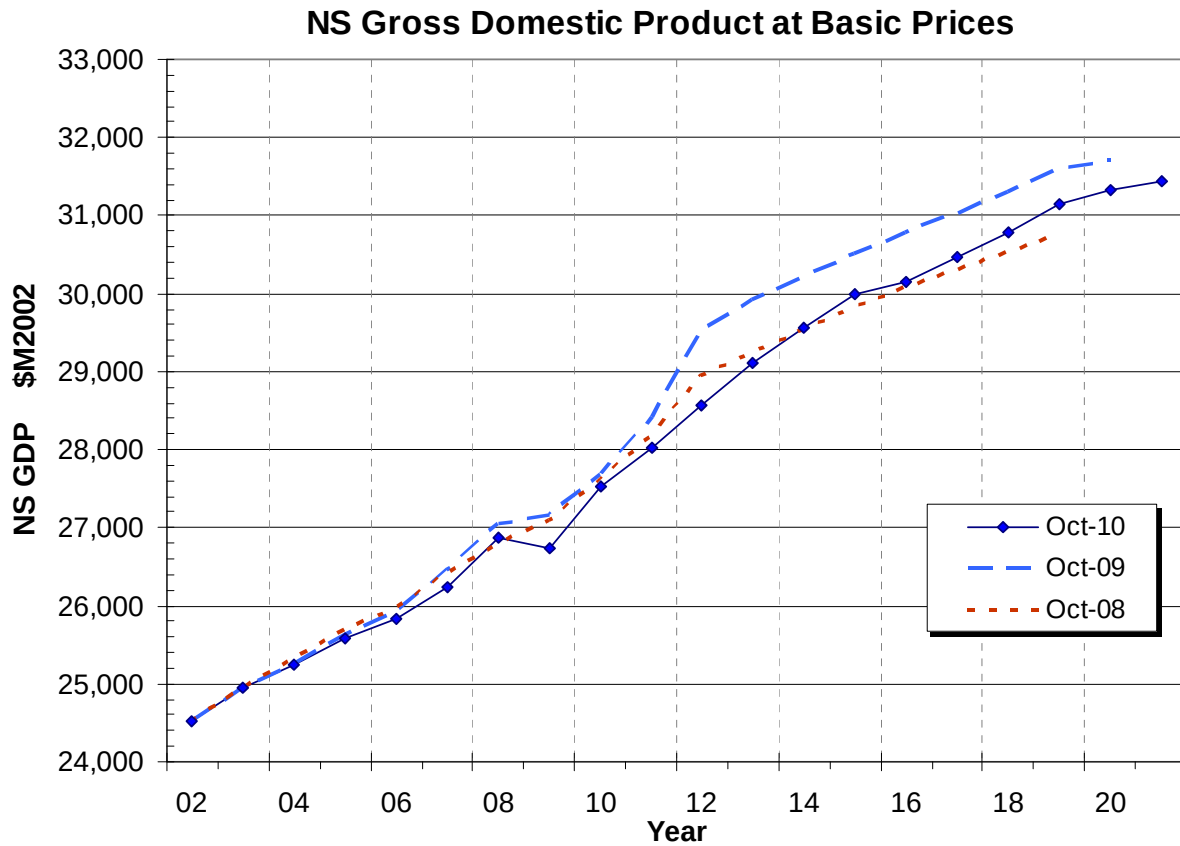
Rate Class Energy Sales
Without Future DSM Program Effects

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

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27

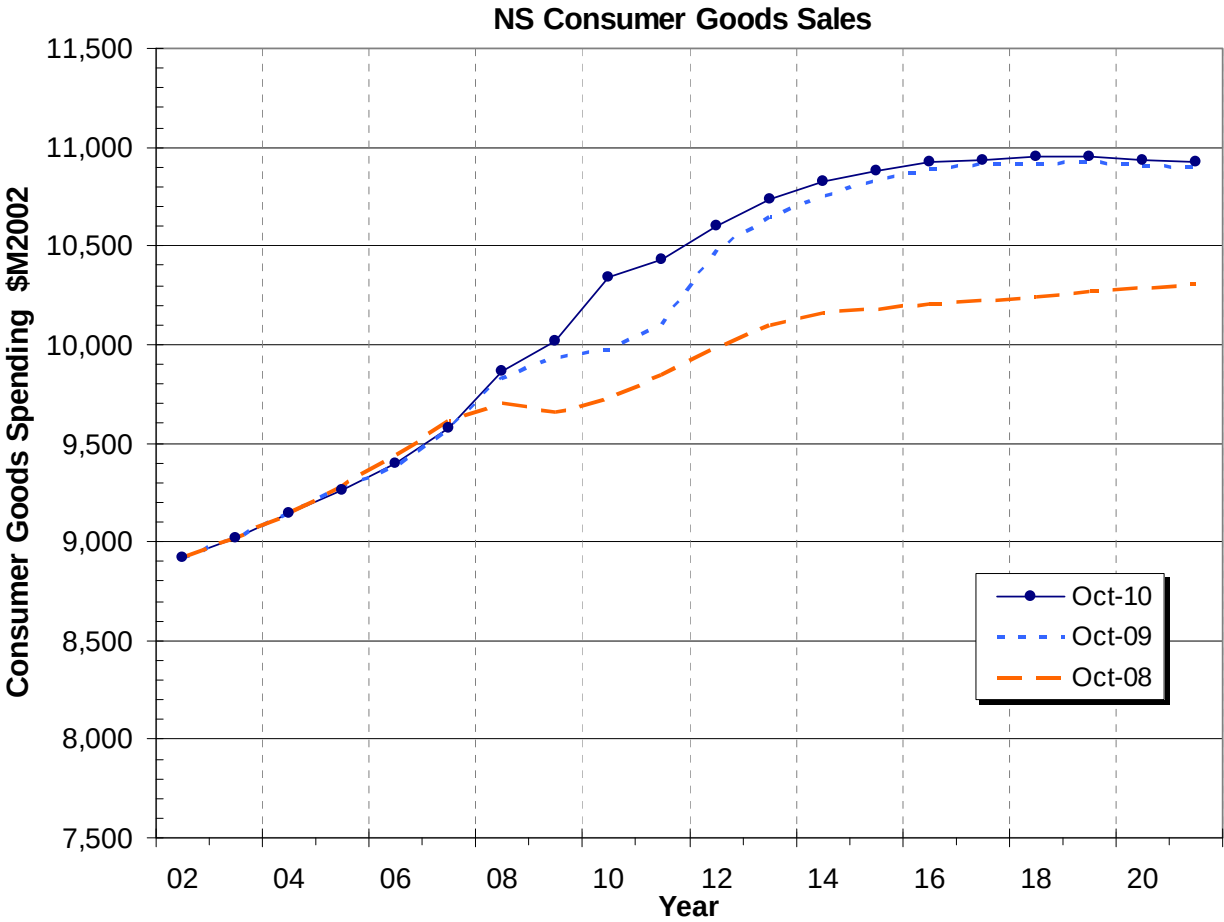
Appendix B

Figures

Figure B1: Nova Scotia Gross Domestic Product Basic Prices

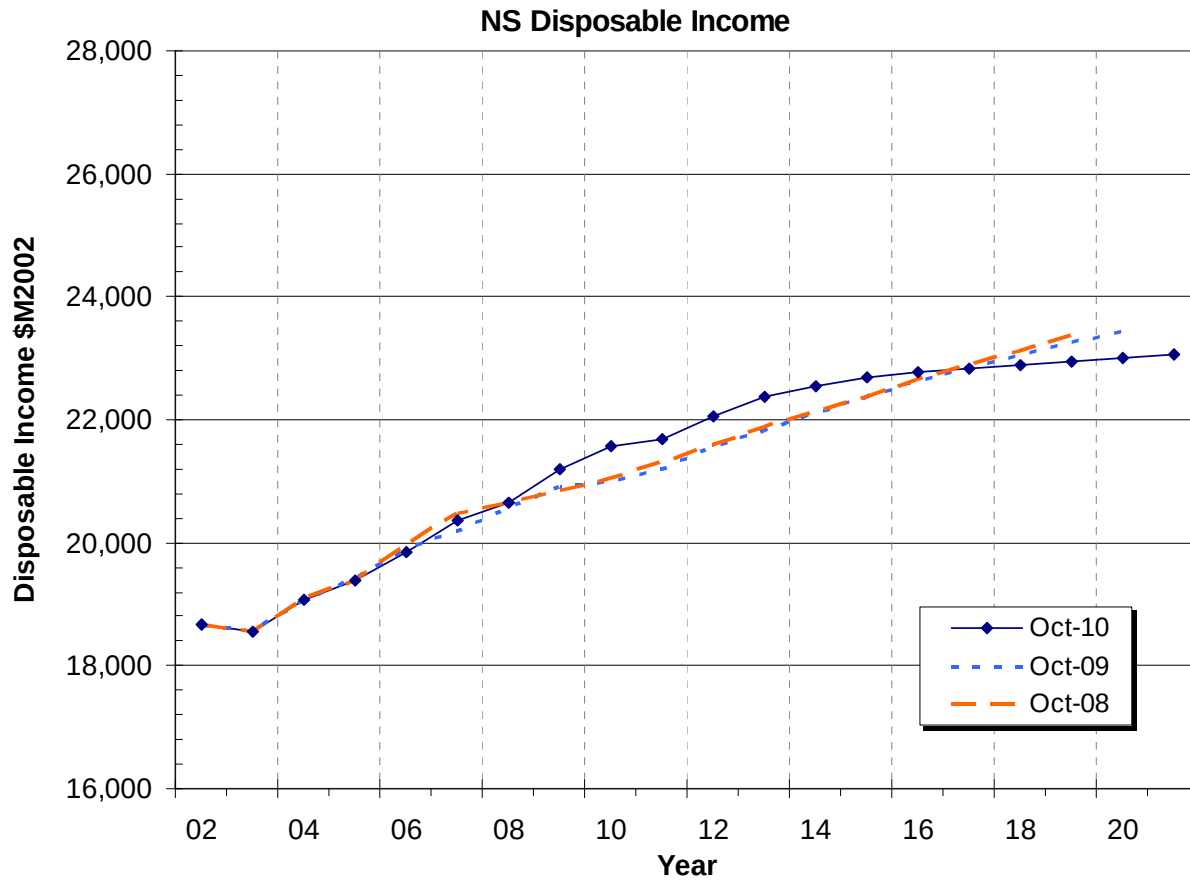
Note: Statistics Canada often re-estimates historical information to reconcile with changes in variable composition and to ensure historical consistency with forecasts. This is the case in the graph above.

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.

1 **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

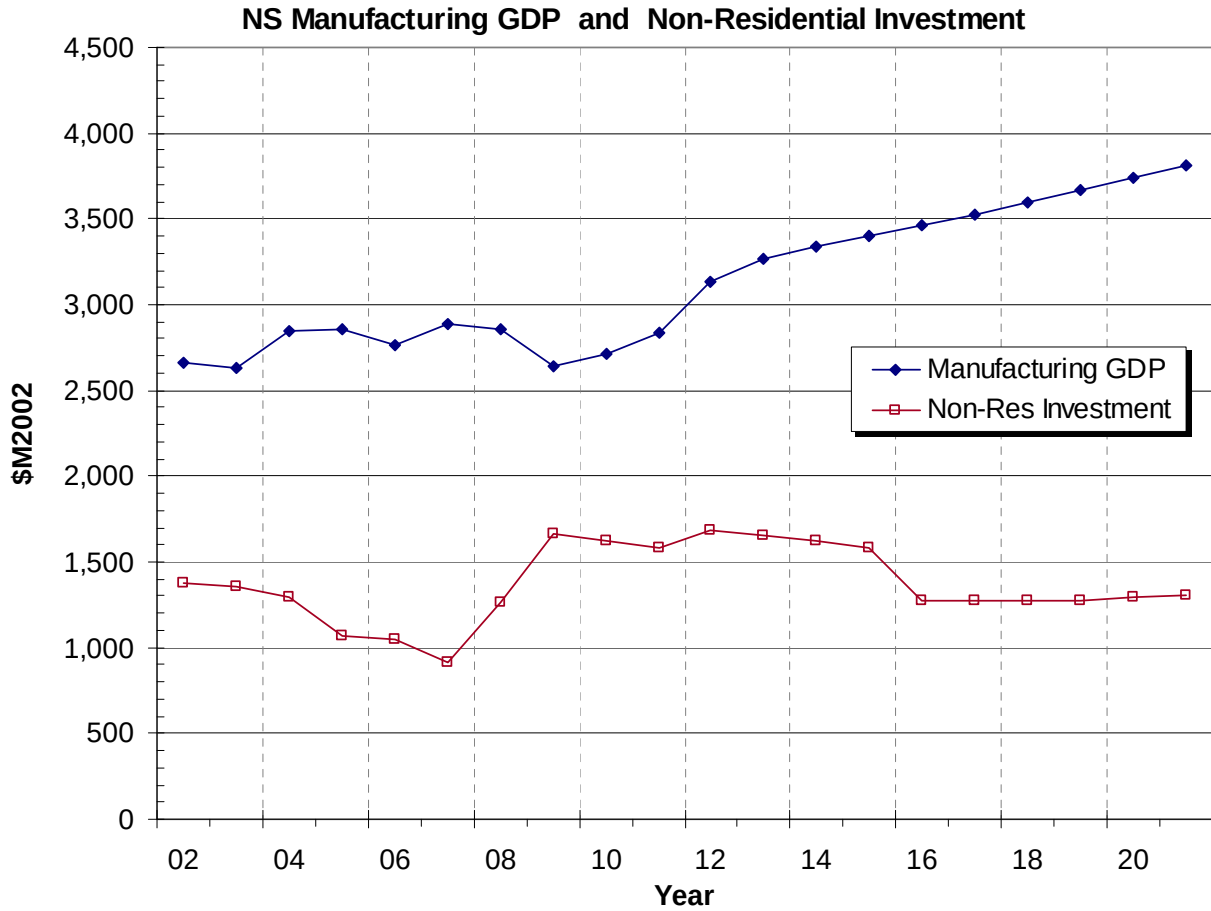


Figure B5: Nova Scotia Manufacturing Employment

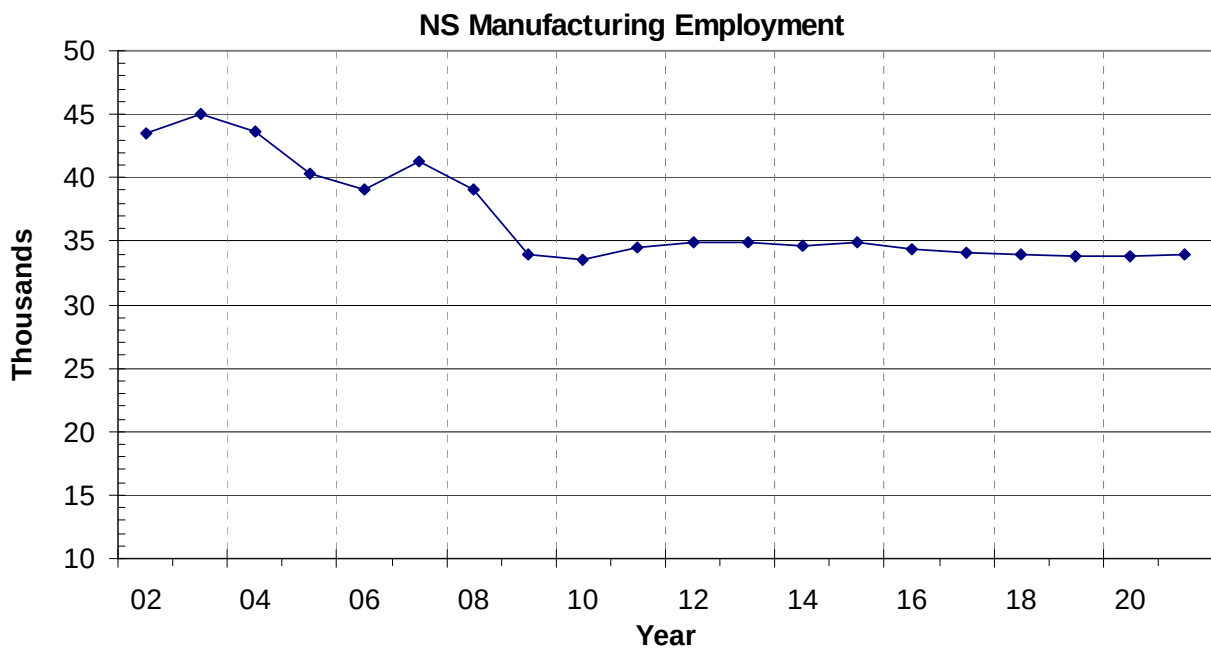


Figure B6: Nova Scotia Energy Sales

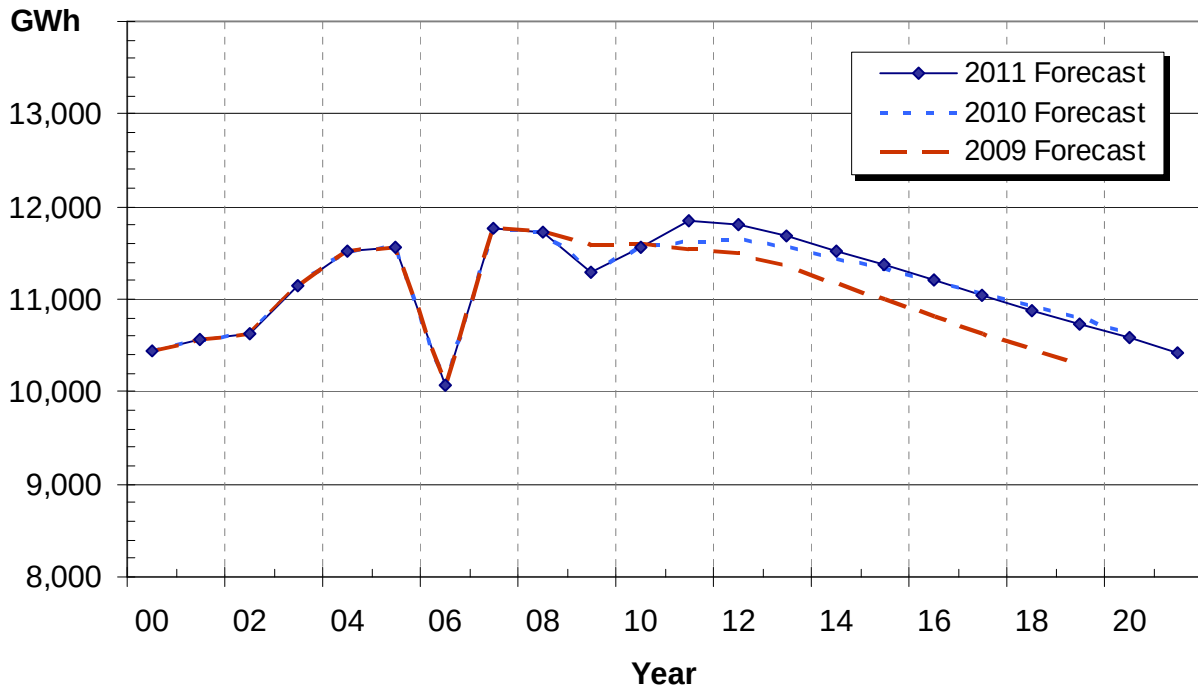


Figure B7: Total Nova Scotia Energy Losses

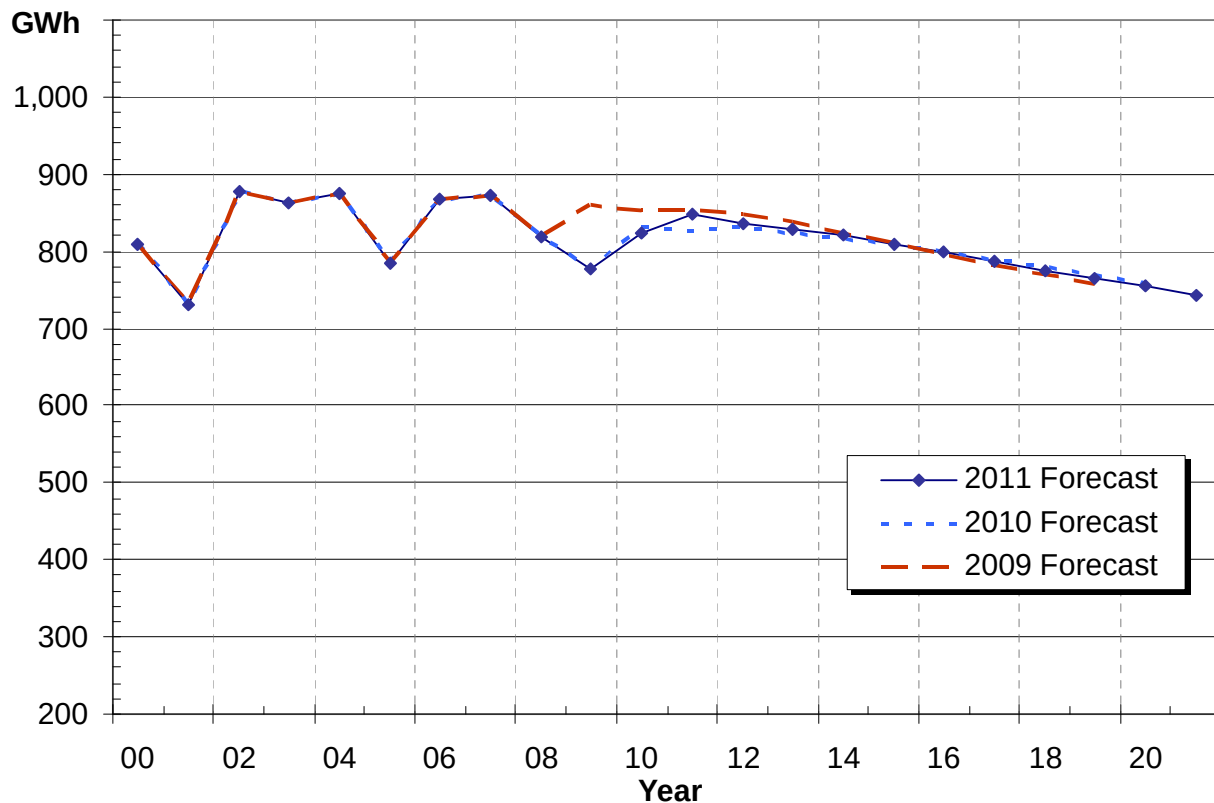


Figure B6: Total Nova Scotia Energy Requirement (NSR)

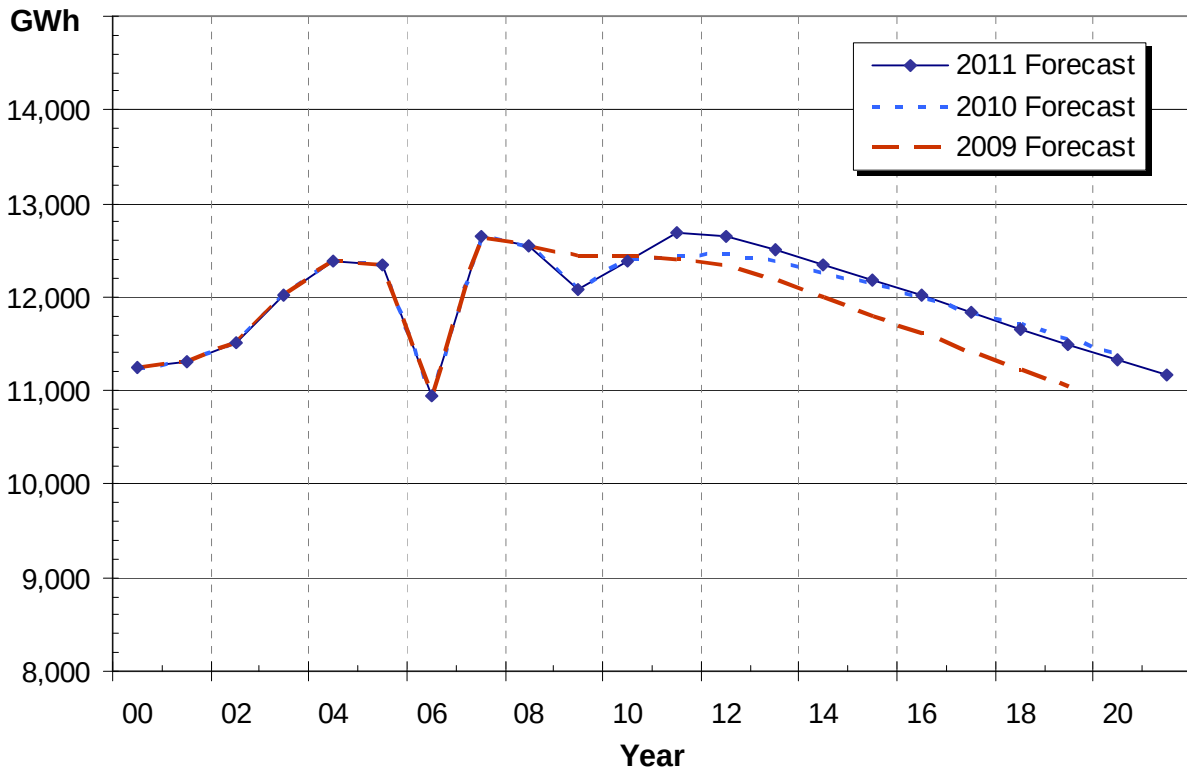
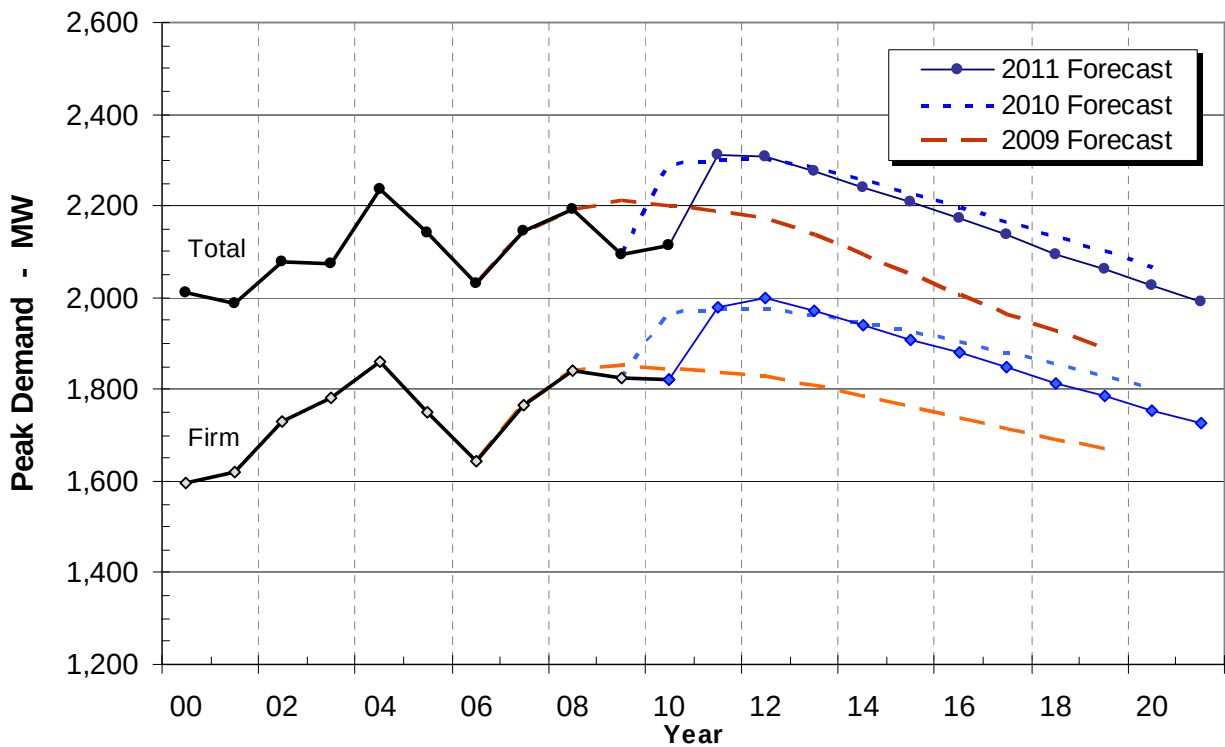


Figure B7: Net System Peak Demand and Firm Peak Demand



1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24

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 <i>2% growth on base year, 2010</i>	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.



2009 Load Forecast

Prepared

March 2009

Table of Contents

Executive Summary	1
Introduction.....	4
Forecast Models	4
Discussion of Major Inputs.....	5
Sector Model Inputs.....	7
Losses.....	8
Energy Forecast Details	8
Residential Sector Sales.....	8
Commercial Sector Sales	13
Industrial Sector Sales.....	16
Total Sales.....	18
System Losses and Unbilled Sales.....	18
Net System Requirement	19
Rate Class Sales	21
<i>Residential</i>	21
<i>Small General</i>	21
<i>General</i>	22
<i>Large General</i>	22
<i>Small Industrial</i>	22
<i>Medium Industrial</i>	22
<i>Large Industrial</i>	23
<i>Municipal</i>	23
<i>Unmetered Services</i>	24
<i>Generation Replacement and Load Following</i>	24
<i>Mersey System</i>	24
<i>Extra Large Industrial Two Part Real Time Pricing (ELI 2P-RTP)</i>	24
<i>One-Part Real Time Price (1P-RTP)</i>	25
System Losses and Unbilled Sales.....	25
Peak Demand	25
<i>Non Firm Coincident Peak</i>	26
<i>Total Coincident Firm Peak</i>	27

Appendix A.....	29
2008 NSPI Forecast	29
Appendix B.....	44
Figures.....	44
Appendix C.....	50
High and Low Forecast Scenarios	50
Appendix C: High and Low Forecast Scenarios.....	51
Appendix D.....	53
Forecast Sensitivity by Major Variable	53
Appendix D: Forecast Sensitivity by Major Variable.....	54

List of Figures

Figure 1	Annual Net System Requirement.....	2
Figure 2	Annual Net System Peak (Winter-ending)	3
Figure 4	2009 NSPI Sector Sales	8
Figure 5	Persons per Residential Account	10
Figure 6	Annual Energy – Residential Sector	12
Figure 8	Annual Energy – Commercial Sector	14
Figure 10	Annual Energy – Industrial Sector.....	16
Figure 3	Forecast Variables.....	6
Figure 7	Residential Sector Energy.....	13
Figure 9	Commercial Sector Energy	15
Figure 11	Industrial Sector Energy	17
Figure 12	Total Energy Requirement.....	20

Executive Summary

The Nova Scotia Power Inc. (NSPI) 2009 Load Forecast provides an outlook on the energy and peak demand requirements of in-province customers for 2009 to 2019. 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, economic indicators, customer surveys, technological and demographic changes in the market and the price and availability of other energy sources. Weather conditions, in particular temperature, affect electrical energy and peak demand. The forecast is based on the 10-year average temperatures measured in the Halifax area of the province.

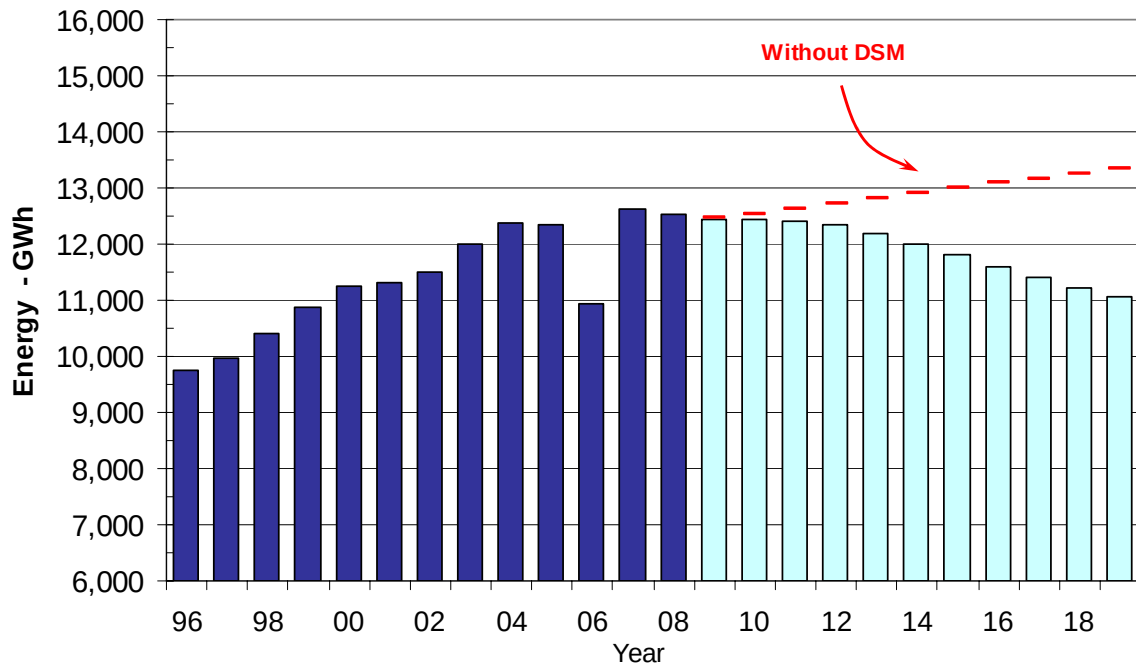
As with any forecast, there is a degree of uncertainty around actual future outcomes. In electricity forecasting, much of this uncertainty is due to the effects of variations in weather, the health of the economy, changes in large customer loads, the number of electric appliances and end-use equipment installed, as well as the manner and degree to which they are used. This forecast presents NSPI's "expected" or "most likely" case for rate-making purposes 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 calculated using the sector models. The sum of these in-province billed sales plus associated system losses and changes to unbilled sales is then determined. This is referred to as the Net System Requirement (NSR).

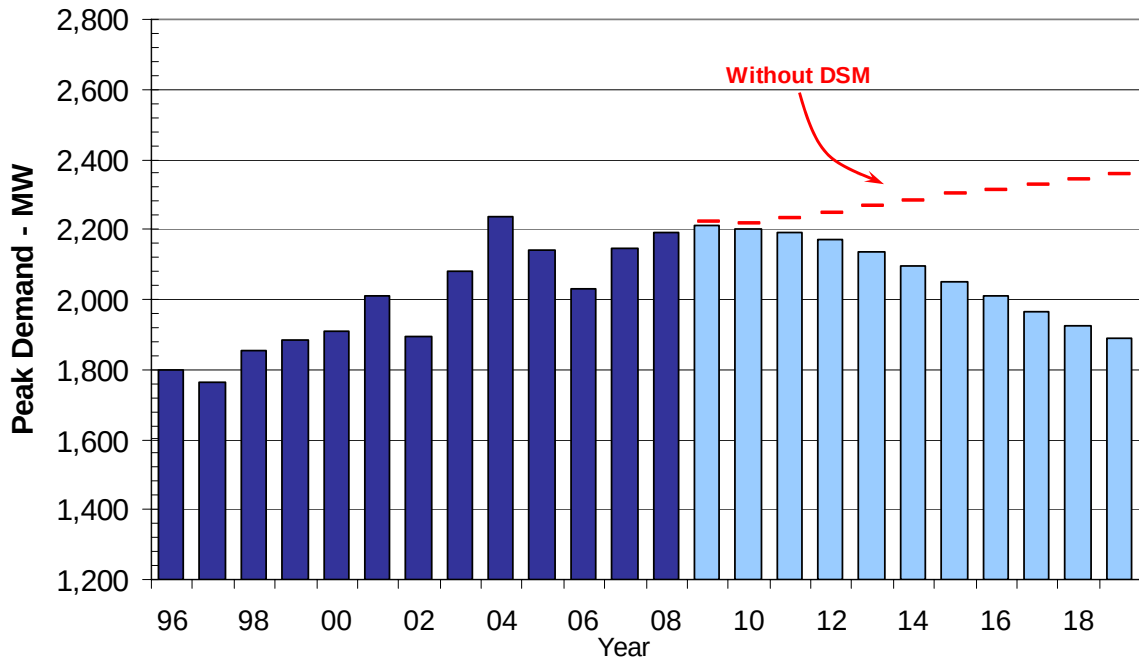
The NSR is forecast to decrease from 12,539 GWh in 2008 to 12,444 GWh in 2010, a decrease of 95 GWh primarily due to conservation measures and an economic downturn. For 2019, NSR is forecast to be 11,051 GWh, a load reduction over the ten year forecast period. The growth rates are generally lower than 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 growth rate, without the DSM effects is 0.6 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.

Figure 2**Annual Net System Peak (Winter-ending)**

Over the longer term, Net System Peak is forecast to decrease from 2,192 MW in winter 2007/08, to 1,888 MW in 2019, which represents an average annual decline of 1.2 percent. The declining growth rate is due to the anticipated effects of conservation and energy efficiency programs. Without the effects of the conservation and efficiency programs, the average growth rate is 0.6 percent.

The hourly peak demand in the year 2008 occurred in January and was 2,192 MW, 46 MW lower than the NSPI record peak demand experienced in 2004 (2,238 MW). This lower peak is attributed to reduced industrial load at that hour and temperatures approximately 4°C warmer than on the record setting day in 2004. (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 2009 is 2,214 MW, assuming typical winter temperatures.

1 **Introduction**

2
3 NSPI annually develops a forecast of energy sales and peak demand requirements to assess the
4 effects of customer, demographic and economic factors on the future provincial system load. It
5 is a fundamental input to the overall planning, budgeting and operating activities of the
6 Company. Produced in the winter of 2009 and using information available at the time, this
7 forecast covers the period of 2009 - 2019. Unless otherwise noted, average growth rates stated
8 report the average annual rate calculated between 2008 (the last year of actual data) and 2019.
9

10 **Forecast Models**

11
12 Nova Scotia electric energy sales are modeled and forecast as three provincial customer sectors:
13 residential, commercial and industrial. Energy forecasts for sector electricity sales are calculated
14 using econometric models in conjunction with forecasts for the independent variables used in
15 those models. Large customers in the Commercial and Industrial sectors are forecast
16 individually based on trends and information from the customers.
17

18 The sector econometric models are multiple linear regression equations that are designed to
19 capture the relationships between electricity consumption and several independent variables. The
20 models then use these relationships to predict future energy loads. An examination of these
21 variables provides a meaningful explanation of the load growth in each sector. The individual
22 econometric model details are shown in the Appendices of this report.
23

24 The variables used in the preparation of the forecast include population, residential customer
25 growth, inflation, GDP, retail sales, oil and electricity prices, appliance saturation levels and
26 average energy use, water and space heat saturation levels and heating degree-days. The primary
27 source of economic and other provincial statistics used in the load forecast is the Conference
28 Board of Canada's *Economic Outlook*, which is released quarterly. This forecast provides a
29 provincial perspective and considers specific Nova Scotia projects and demographics.
30
31
32
33

1 Discussion of Major Inputs

2
3 The Gross Domestic Product (GDP) for Nova Scotia was estimated at \$26,812 million (in
4 constant 2002 dollars) in 2008, and is forecast to increase by just 1.0 percent in 2009 and 2.0
5 percent in 2010. This low growth is attributed to the effects of the world-wide economic
6 downturn which will impose its challenges, particularly to the manufacturing and mining sector.

7
8 The lower Canadian dollar combined with lower fuel prices would provide some relief for Nova
9 Scotian manufacturers and exports, however, the sharp decline in demand for their products
10 south of the border will continue to limit their prospects. With the slump in the world-wide
11 economy, commodity prices have fallen sharply in recent months, which dramatically changes
12 the bottom line for both mining and recycling operations. Several of these businesses are
13 expected to curtail production or even close over the coming months. The troubled forest
14 products industry will continue to struggle in light of the US mortgage meltdown causing
15 housing starts to diminish there, in conjunction with slowing residential construction activity
16 here in Canada. With the news-generating hype of the US election over, and advertising down
17 due to the sagging economy, demand for pulp and paper products will remain weak, causing
18 continued difficulty for the province's producers. In the face of these depressed market
19 conditions, several NS lumber and paper mills have scheduled temporary production shutdowns.

20
21 Depressed prices and reduced landings will continue to affect the fishing communities around
22 the province. The combination of diminishing stocks in some areas combined with soft prices
23 may lead some fishers to keep their boats tied up at the wharf. Seafood exports were down 17%
24 over the first three quarters of 2008 and weak US household demand for the high-valued fish
25 products such as lobster is expected to persist.

26
27 Despite lower gasoline prices and a more favourable currency exchange rate, the economic
28 troubles south of the border will limit the number of US tourists visiting the province, and have a
29 negative effect on businesses catering to tourists. The loss of Zoom Airlines and reduced
30 capacity with Air Canada's regional carrier, Jazz, also suggests lower tourist traffic to the region.

31
32 In 2008, the provincial Consumer Price index (CPI) was estimated to grow 3.7 percent, up
33 substantially from 1.9% in 2007. It is forecast to grow at 2.1 percent for 2009 and 2010, and

remain at 1.9 percent or less for the next several years as the Bank of Canada maintains inflation below its 2 percent target.

Housing starts for NS were estimated at 4,750 units in 2007 (singles: 2887), and were forecast by the Conference Board of Canada (CBoC) to drop to 4,280 for 2008 (singles: 2,749). The pace of growth is expected to slow as economic conditions do not support an increase in starts. For 2009, total housing starts are forecast at 3,571, and 3,173 for the year 2010. Future housing demand is expected to become more aligned to the underlying demographics as prices and the aging population drive a shift to more semi-detached housing and condominiums.

Retail sales, with 4.2 percent growth in 2007, grew by 5.8 percent in 2008. Despite the slumping economy, some growth is forecast to be maintained at a rate of 3.8 percent in 2009 and 3.9 percent in 2010 as some consumer confidence remains intact.

Nova Scotia population in 2008 was estimated to be 938,310 with annual growth remaining relatively flat in the past five years. Further population growth in the forecast is marginal with the estimate for 2010 at 943,138 for an annual growth rate of 0.27 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	2008 Estimated Growth Rate	2009 Forecast Growth Rate	2010 Forecast Growth Rate
N.S. Population	0.1%	0.3%	0.3%
N.S. Consumer Price Index	3.7%	2.1%	2.1%
N.S. Personal Disposable Income	4.6%	3.1%	3.0%
N.S. GDP at basic prices	1.5%	1.0%	2.0%
N.S. Retail Sales	5.8%	3.8%	3.9%
N.S. Consumer Goods Sales	4.7%	1.6%	0.6%
Residential heating oil price	27.9%	-20.9%	5.5%

1 **Sector Model Inputs**

2
3 One factor influencing the residential forecast involves market effects including the price of
4 electricity versus other alternatives (e.g. fuel oil) and the effects of natural gas distribution. The
5 stock of electric appliances is estimated through maturities and conversion rates to and from
6 electric units as well as the electric heat penetration for new construction. Technology factors
7 are considered through increases in efficiency and the introduction of new equipment such as
8 Electric Thermal Storage (ETS) units.

9
10 The outlook for the retail price of furnace oil (#2 light) is based on futures pricing and, for the
11 long-term, escalated at rates consistent with other fuel price forecasts used by NSPI. The ratio of
12 oil prices to electricity prices is used in calculating the saturation of residential water and space
13 heating equipment. Furnace oil prices in NS are estimated to average 85.1¢ per litre in 2009 and
14 89.8¢ in 2010 as crude oil prices ease back from the highs of mid-2008.

15
16 Assumptions regarding the effects of natural gas distribution in the province are based on the
17 potential loss of electric space heating and water heating load, primarily in the residential sector.
18 The gas impact on this forecast is small however, due to a limited rollout plan in the growing
19 residential areas of Nova Scotia.

20
21 Electricity sales in the commercial sector are influenced by the level of business activity and as a
22 result, are closely related to the provincial GDP and consumer confidence. Electricity sales to
23 small and medium industrial customers are correlated to general economic growth in the
24 province. However, energy use in the industrial sector is also influenced by large industries such
25 as forestry and pulp & paper. Since changing economic conditions, exchange rates and trade
26 policies can create large fluctuations in sales as companies expand, contract or endure inventory
27 shutdowns; the large industrial forecast sometimes relies heavily on input from customers.

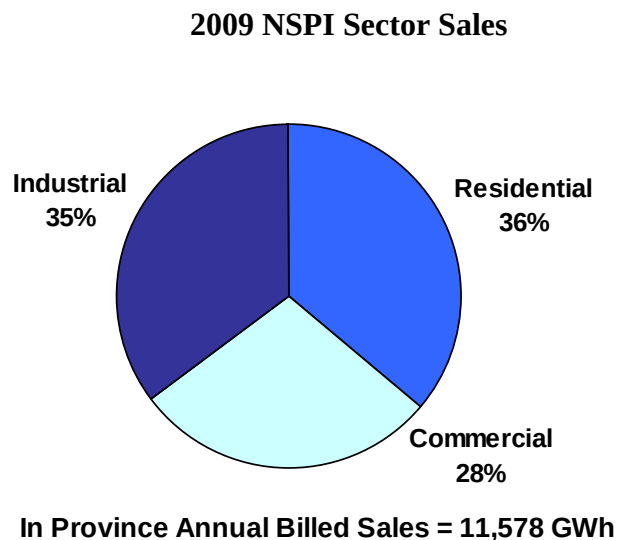
1 **Losses**

2
3 System losses have averaged 7.0 percent of NSR over the past five years and are expected to
4 remain in the 7 percent range over the 10 year forecast period.

6 **Energy Forecast Details**

7
8 For forecasting, modeling and sales reporting, Nova Scotia electric load is divided into three
9 sector requirements: residential, commercial and industrial. The relative sizes of sector sales are
10 shown in Figure 4.

12 **Figure 4**



24 **Residential Sector Sales**

26 In 2008, residential customers represented approximately 36 percent of total Nova Scotia energy
27 sales. In addition to direct domestic customers of the Company, the sector also includes
28 residential customers served by six municipal utilities. Seasonal residences comprised 6.5
29 percent of the residential base.

31 The residential sector offers an opportunity for more detailed modeling due to the relative
32 similarity of customer end-uses, compared to the wide variations in end-use by commercial and
33 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 Commercial Goods Sales (RCGOODS), as measured in current dollars.

To capture the overall 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

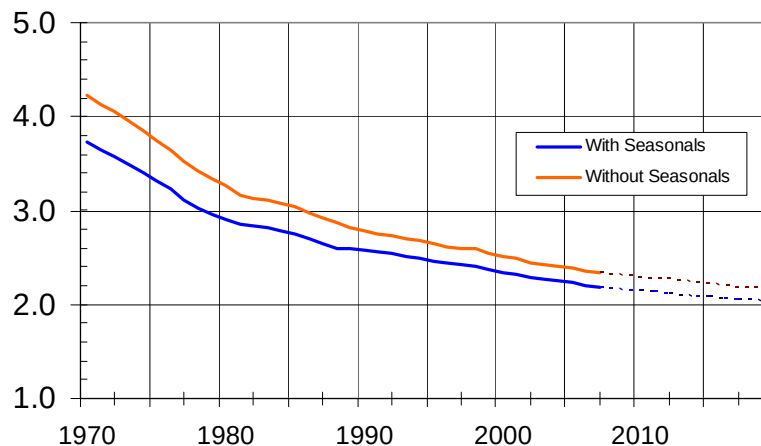
over a 30-year period, and are therefore reflective of longer term relationships and not just the prior year's results.

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

$$\text{Residential Load} = 323.8 \text{ AIDX} + 0.2502 \text{ CHDD} - 28.16 \text{ RREP} + 0.1077 \text{ RCGOODS} + 0.4423 \text{ Residential load}_{-1}$$

The forecast for new customers for 2009 is 3,703 diminishing to 2,830 by 2019. The number of additions has been decreasing steadily from more than 4,500 in 1997. Although the Nova Scotia 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**



With an ever-increasing array of new technology available, usage per customer continues to grow, despite efficiency improvements for many household appliances. Larger appliances are modeled individually considering the age, efficiency trends and acquisition rates. Efficiency improvements for televisions, dishwashers, clothes washers, and water heaters are forecast at 0.5 percent per year over the forecast period. Efficiency improvements in electric ranges are forecast at 1 percent per year. These improvements apply only to new appliances, and as a

1 result, the effect on the overall system load is very gradual as older appliances are retired and
2 replaced with more efficient models.

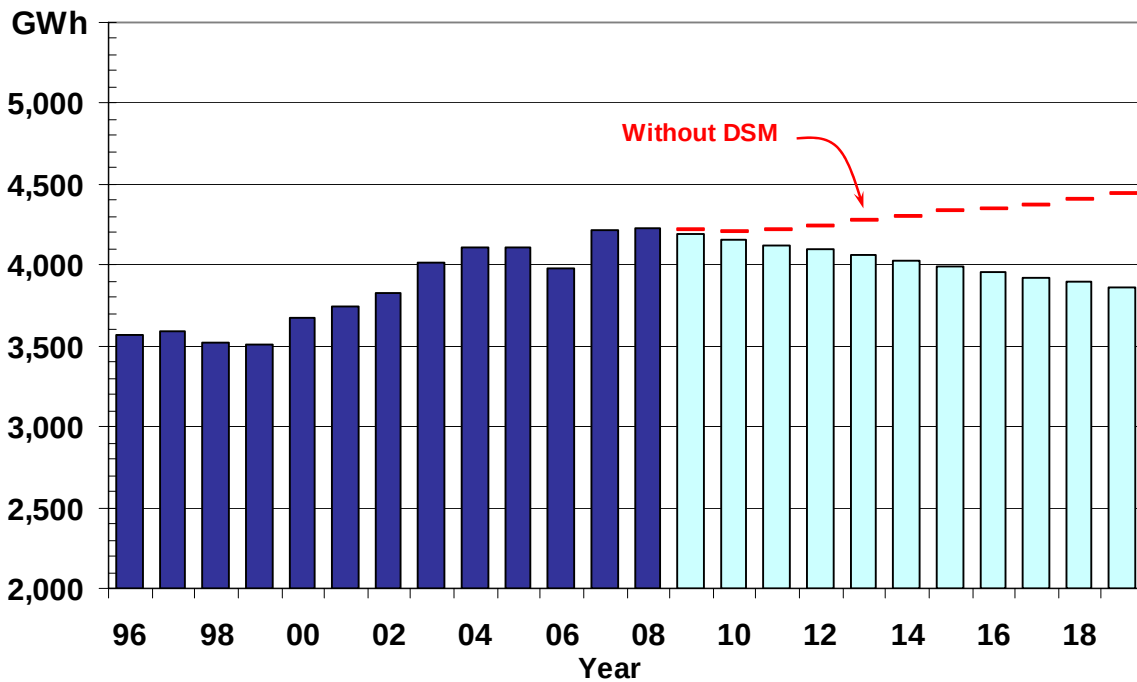
3
4 With the rapidly rising oil prices and increasing concerns over hazardous oil spills, the market
5 share of electric space heat has crept up slightly. The saturation of electric space heat has been
6 in the mid to high 20 percent range in recent years and was estimated to be 28 percent in 2008
7 with continuing customer additions. The saturation of electric water heating hovers around 57
8 percent and is forecast to grow slowly over the forecast period.

9
10 The forecast for weather effects uses 10-year average temperatures, measured in heating degree-
11 days (HDD). Heating degree-days are a common measure of heating requirement, based on the
12 degree departure between the daily mean temperature and a given standard temperature. The
13 standard temperature of 18°C is used for these calculations and is assumed to be a comfortable
14 room temperature below which space heating is generally required. The forecast uses the
15 Environment Canada HDD data for Shearwater Airport for the years 1998-2007 which averaged
16 3,932 HDD.

17
18 The residential sector load has grown at an average annual rate of 1.1 percent over the past five
19 years or 1.2 percent when adjusted for the effects of weather. Annual residential loads are shown
20 in Figure 6.

Figure 6

Annual Energy – Residential Sector



Growth in this sector is expected to be relatively low in the near term. The 2010 load forecast for this sector is 4,153 GWh or 0.9 percent decline over the forecast 2009 level. Without the effects of Conservation and DSM programs, 2010 sales are forecast at 4,205 GWh or 0.2 percent below 2009.

1 Figure 7 Residential Sector Energy

Year	Residential Sector <i>With DSM</i> GWh	Growth Rate %	Residential Sector <i>Without DSM</i> GWh	Growth Rate %
2001	3,741.2	1.9	3,741.2	1.9
2002	3,828.9	2.3	3,828.9	2.3
2003	4,010.5	4.7	4,010.5	4.7
2004	4,113.5	2.4	4,113.5	2.4
2005	4,114.3	0.0	4,114.3	0.0
2006	3,979.4	-3.3	3,979.4	-3.3
2007	4,218.2	6.0	4,218.2	6.0
2008	4,231.9	0.3	4,231.9	0.3
2009F	4,190.4	-1.0	4,211.8	-0.5
2010F	4,153.5	-0.9	4,205.4	-0.2
2011F	4,124.0	-0.7	4,213.8	0.2
2012F	4,095.3	-0.7	4,241.5	0.7
2013F	4,057.0	-0.9	4,269.4	0.7
2014F	4,027.3	-0.7	4,301.1	0.7
2015F	3,997.3	-0.7	4,329.5	0.7
2016F	3,957.8	-1.0	4,348.3	0.4
2017F	3,922.6	-0.9	4,371.6	0.5
2018F	3,895.2	-0.7	4,402.6	0.7
2019F	3,867.7	-0.7	4,433.6	0.7

2
3 Annual residential sector loads are shown in Figure 7. Over the 10 year forecast period, the
4 residential load is expected to decline an average 0.8 percent per year, or increase by 0.5 percent
5 per year when the effects of Conservation and DSM programs are removed.

7 **Commercial Sector Sales**

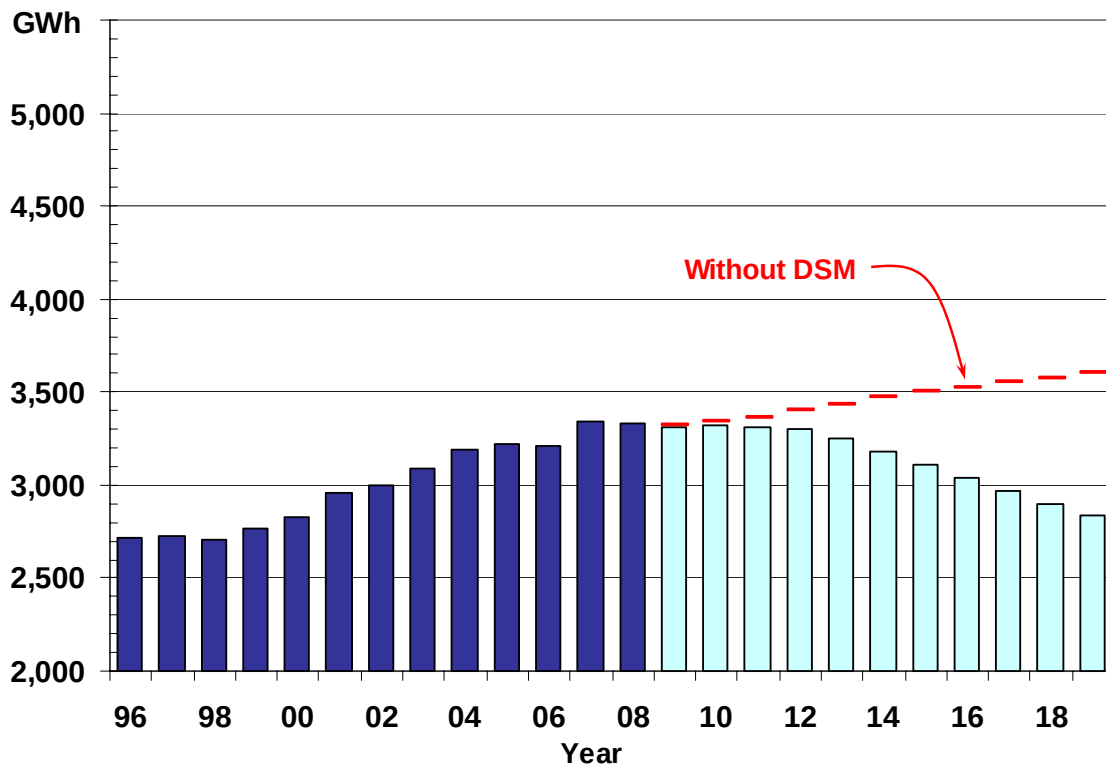
8
9 Energy sales to the commercial sector in 2008 represented 28 percent of Nova Scotia sales. This
10 customer group includes restaurants, hotels, offices, recreational facilities, stores warehouses
11 hospitals, schools and universities and street and traffic lights, as well as commercial customers
12 served by municipal utilities. The level of business activity in the province is a major factor in
13 determining the energy sales to this sector. The level of business activity is captured in GDP and
14 as a result, a strong correlation exists between commercial energy requirements and real GDP.
15 Real personal disposable income (RPDI) is also correlated to activity in the commercial sector
16 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.

$$\text{Commercial} = 0.02531 \text{ RQTOS} + 0.01268 \text{ RPDI} + 0.2806 \text{ Residential} + 0.3676 \text{ Commercial load}_{t-1}$$

This information is used in a reconciliation of the sector load by rate class. Annual commercial sector loads are indicated in Figure 8.

Figure 8 Annual Energy – Commercial Sector



Growth in this sector has averaged 1.5 percent over the past 5 years (1.5 percent when adjusted for weather). Driven by trends in wholesale trade, consumer confidence, reductions in sales tax, and growth in personal disposable income boosting retail trade activity, this sector is forecast to decline by 0.3 percent and grow by just 0.1 percent in 2009 and 2010, respectively. With the effects of the Conservation and DSM Programs, the annual load rate is expected to decline an

- 1 average 1.6 percent over the next 10 year period (or increase 0.8 percent without DSM effects).
 2 The annual commercial sector loads are shown in Figure 9.

3

4 **Figure 9 Commercial Sector Energy**

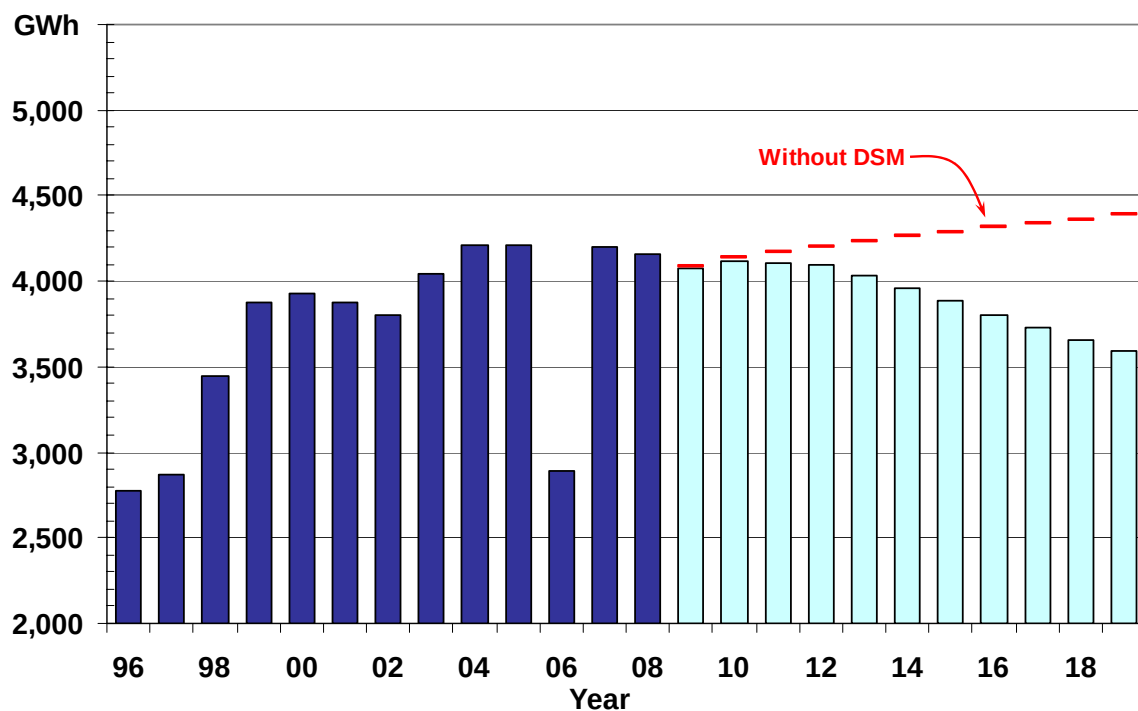
Year	Commercial Sector With DSM GWh	Growth Rate %	Commercial Sector Without DSM GWh	Growth Rate %
2001	2,959.3	4.6	2,959.3	4.6
2002	2,996.5	1.3	2,996.5	1.3
2003	3,090.6	3.1	3,090.6	3.1
2004	3,187.8	3.1	3,187.8	3.1
2005	3,223.2	1.1	3,223.2	1.1
2006	3,210.8	-0.4	3,210.8	-0.4
2007	3,342.9	4.1	3,342.9	4.1
2008	3,326.9	-0.5	3,326.9	-0.5
2009F	3,316.2	-0.3	3,321.4	-0.2
2010F	3,319.4	0.1	3,337.0	0.5
2011F	3,313.0	-0.2	3,362.3	0.8
2012F	3,302.5	-0.3	3,402.8	1.2
2013F	3,254.1	-1.5	3,436.5	1.0
2014F	3,181.9	-2.2	3,468.7	0.9
2015F	3,113.6	-2.1	3,498.6	0.9
2016F	3,041.3	-2.3	3,524.6	0.7
2017F	2,969.3	-2.4	3,549.7	0.7
2018F	2,901.2	-2.3	3,576.3	0.7
2019F	2,836.0	-2.3	3,603.4	0.7

Industrial Sector Sales

In 2008, the industrial sector represented 36 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 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 10.

Figure 10 Annual Energy – Industrial Sector



The load for this sector is forecast using a combination of econometric modeling and information from the large customers. To avoid the effects of customers migrating between the classes, the Small and Medium Industrial customer loads are combined and forecast together using an

1 econometric model. The economic factors that influence these customers are assumed to be the
 2 same regardless of the demand criterion that determines the customer's particular rate class. The
 3 growth rates calculated from the model are then used to forecast each class. This model relates
 4 industrial electricity consumption to GDP and load in the preceding year. In the early 1990s,
 5 significant load migrated from the Medium Industrial class to the new Interruptible Industrial
 6 Rate. A variable, MIGRATE, is used in the model to capture that effect.

7
 8 The Small and Medium Industrial econometric model equation is shown below. Complete fit
 9 statistics and model specifications are shown in the Appendix to this report.

$$SM_IND = 0.01501 RQTOS + 0.5259 SM_IND_{-1} - 35.51 MIGRATE$$

10
 11
 12
 13 Information from large customers is gathered regularly in order to develop their forecast monthly
 14 electricity requirements over the next three year period, given planned production levels and
 15 equipment changes. The information is used as input to prepare the large industrial load forecast
 16 by rate class. The annual industrial sector loads are shown in Figure 11.

17
 18 **Figure 11 Industrial Sector Energy**

Year	Industrial Sector With DSM GWh	Growth Rate %	Industrial Sector Without DSM GWh	Growth Rate %
2001	3,872.5	-1.5	3,872.5	-1.5
2002	3,798.6	-1.9	3,798.6	-1.9
2003	4,045.9	6.5	4,045.9	6.5
2004	4,212.1	4.1	4,212.1	4.1
2005	4,215.1	0.1	4,215.1	0.1
2006	2,887.7	-31.5	2,887.7	-31.5
2007	4,205.4	45.6	4,205.4	45.6
2008	4,161.5	-1.0	4,161.5	-1.0
2009F	4,071.6	-2.2	4,080.3	-2.0
2010F	4,117.5	1.1	4,142.3	1.5
2011F	4,111.0	-0.2	4,168.3	0.6
2012F	4,092.8	-0.4	4,202.5	0.8
2013F	4,036.9	-1.4	4,230.9	0.7
2014F	3,957.5	-2.0	4,258.7	0.7
2015F	3,882.7	-1.9	4,285.5	0.6
2016F	3,807.5	-1.9	4,312.2	0.6
2017F	3,731.1	-2.0	4,336.2	0.6
2018F	3,659.3	-1.9	4,360.8	0.6
2019F	3,590.8	-1.9	4,385.0	0.6

In the fall of 2004, one of NSPI's largest customers completed a sizeable process expansion, which substantially increased their load over 2003. At the end of 2005, that customer had a temporary shutdown and remained closed for nine months in 2006. For 2007, the plant returned to normal full load operations. With no new expansions or customer additions of large magnitude anticipated for 2009 or 2010, growth in the industrial sector will level off in the near-term. Conservation and DSM programs are 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 the major customer shutdown. For the five year period ending 2007, the average annual growth was 2.1 percent, encompassing the 2003 expansion at the largest paper mill. The forecast load for 2009 is 4,072 GWh with some customers operating below full load due to market conditions and DSM programs reducing load by 8.6 GWh. Between 2008-2019, industrial sales are expected to decline on average by 1.3 percent in this sector with DSM or grow at 0.5 percent in the absence of conservation programs.

Total Sales

Given the combined activities of each sector, including large industrial shutdowns, expansions, etc., total sales grew at an average annual rate of 1.9 percent over the last 10 years. Combining each of the sector sales forecasts, total Nova Scotia sales are expected to decline slightly, with an average annual growth rate of -1.1 percent over the next 10 years, due to the effects of energy conservation and DSM programs. Without DSM programs, growth is expected to average 0.5 percent per year. The billed sales are therefore expected to decline from 11,720 GWh in 2008 to 10,295 GWh by the year 2019.

System Losses and Unbilled Sales

The load forecast is developed using NSPI "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

1 billing process, billed sales will vary somewhat from accrued sales. Energy generated and sold
2 but not yet billed, is referred to as “Unbilled” sales.

3
4 The difference between energy generated for use within provincial borders and the total NSPI
5 billed sales comprises system losses as well as changes to the level of unbilled sales. Losses of
6 approximately 6 percent of sales within municipal utility service areas are also included in this
7 total Nova Scotia losses estimate.

8
9 Losses are estimated at both the transmission and distribution levels. Historical estimates for
10 transmission losses are obtained from NSPI’s Supervisory Control and Data Acquisition
11 (SCADA) system and are based upon an expected generation and transmission configuration. As
12 a result, transmission losses are forecast at 3.0 percent of the transmission energy requirement.
13 Based on historical estimates, distribution losses are forecast at approximately 6.0 percent of
14 distribution sales. As a result of forecast distribution and transmission losses, total system losses
15 average 6.9 percent of the total Nova Scotia energy requirement over the forecast period.

16 17 18 **Net System Requirement** 19

20 The Net System Requirement (NSR) is the energy required to supply the sum of residential,
21 commercial, and industrial electricity sales, plus the associated system losses within the province
22 of Nova Scotia. Loads served by industrial self-generation, exports, and transmission losses
23 associated with energy exports are not included. Annual NSR is shown in Figure 12.

Figure 12 Total Energy Requirement

Year	Net System Requirement With DSM GWh	Growth Rate %	Net System Requirement Without DSM GWh	Growth Rate %
2001	11,303.2	0.6	11,303.2	0.6
2002	11,501.0	1.8	11,501.0	1.8
2003	12,009.1	4.4	12,009.1	4.4
2004	12,387.6	3.2	12,387.6	3.2
2005	12,338.1	-0.4	12,338.1	-0.4
2006	10,946.2	-11.3	10,946.2	-11.3
2007	12,639.5	15.5	12,639.5	15.5
2008	12,538.9	-0.8	12,538.9	-0.8
2009F	12,439.0	-0.8	12,477.6	-0.5
2010F	12,444.4	0.0	12,547.2	0.6
2011F	12,401.9	-0.3	12,614.9	0.5
2012F	12,339.5	-0.5	12,724.9	0.9
2013F	12,185.1	-1.3	12,820.6	0.8
2014F	11,990.7	-1.6	12,918.2	0.8
2015F	11,804.2	-1.6	13,007.5	0.7
2016F	11,602.5	-1.7	13,081.6	0.6
2017F	11,404.9	-1.7	13,156.5	0.6
2018F	11,224.7	-1.6	13,241.5	0.6
2019F	11,051.1	-1.5	13,326.4	0.6

The Net System Requirement for the province has grown at an average of 0.9 percent per year in the five year period from 2003-2008 and is forecast to decline by 1.1 percent over the next 10 years with the effects of conservation and DSM programs. Without DSM effects, growth is forecast to average 0.6 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 35 percent of total NSPI sales in 2008. All-electric, non-all-electric and residential Time-of-Day (TOD) rate customers are included in this class. As of December 2008, there were approximately 435,840 domestic customers responsible for annual billed sales of 4,232 GWh, an average of 9,710 kWh/customer. Residential class sales grow for the reasons stated in the residential sector description, and are forecast to decline at an average of 0.8 percent per year over the forecast period with the effects of conservation and DSM programs. In the absence of DSM programs, the growth rate averages 0.5 percent.

Small General

Prior to 2004, this class comprised commercial sector customers whose annual energy consumption was less than 12,000 kWh. In January 2004, by UARB Order in the fall of 2002, this availability threshold increased to 22,000 kWh/yr, and was increased again to 32,000 kWh/yr in 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 2008, this class comprised approximately 22,920 customers. It represented 233 GWh in 2006, 246 GWh in 2007 and 239 GWh in 2008. It is forecast at 243 GWh in 2009, or 244 GWh in the absence of DSM programs.

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 in 2004 and 2005 causing a migration of customers from General to Small General. As of 2008, this class had approximately 11,570 customers accounting for the major portion of commercial sector energy and 21 percent of total NSPI sales for 2008. By 2009, energy sales for this class are anticipated to be 2,450 GWh and decline annually at an average of 1.6 percent over the forecast period, or grow by 0.7 percent in the absence of conservation and DSM programs.

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 2008, there were 18 customers in this class representing 3.6 percent of NSPI sales. Annual load growth over the entire forecast period is expected to average 0.2 percent or 1.0 percent in the absence of conservation and DSM programs.

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 2,260 customers as of December 2008, and had sales representing 2.2 percent of NSPI energy sales. Energy requirements in this class are forecast to decline at an average rate of 0.3 percent per year over the forecast period or grow at 1.2 percent in the absence of conservation and DSM programs.

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 2008, there were 196 customers in this class, representing about 4.6 percent of NSPI sales. Class sales are forecast to decline at an average of

7.3 percent over the next 10 years or grow at 1.2 percent in the absence of conservation and DSM programs.

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 in nature with the remaining load considered firm. Customers on the interruptible rider receive a reduction in demand charge. As of December 2008, there were 26 customers with the interruptible rider and four customers taking firm service only. The combined energy for the firm and interruptible customers was 996 GWh, and represented 8.5 percent of 2007 NSPI energy sales. The anticipated combined energy for firm and interruptible customers in 2009 is 956 GWh, or 8.2 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 NSPI's total Nova Scotia 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 6 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 2006, it has been possible for these municipalities to source their electricity from providers other than NSPI. This forecast assumes that NSPI continues to serve this load. In 2008, this class represented 1.7 percent of total NSPI sales. Municipal sales are forecast to decline by 1.1 percent over the next 10 years or grow at 0.6 percent in the absence of conservation and DSM programs.

Unmetered Services

This class is comprised of street and area lighting, as well as miscellaneous lighting and small loads. In 2008, unmetered sales represented approximately 1.0 percent of total NSPI sales. Energy sales in this class are forecast to decline at an average of 1.6 percent over the forecast period or grow at 0.8 percent in the absence of conservation and DSM programs.

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 2008, this class had three customers and represented about 0.1 percent of total NSPI sales. This class is also interruptible load and is currently forecast to remain near its 2008 level of approximately 11 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 2008 were 1,976 GWh or approximately 17 percent of NSPI sales. For 2009, 1,947 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 NSPI transmission losses, distribution losses and the year-over-year change in unbilled sales. The annual change in unbilled sales is currently in the order of 13 GWh, based on forecast growth in the accrued sales classes. 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 3.0 percent of the transmission system energy requirement. NSPI distribution losses are forecast at 6.0 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 6.9 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. For the winter of 2007/2008, the January peak reached of 2,192 MW at a

1 temperature of -14°C with the largest industrial customers operating near typical full load. This
 2 peak was 46 MW less than the highest peak that occurred four years earlier in January 2004,
 3 when the temperature was 4 degrees colder.

4
 5 With the exception of large customer classes, monthly and annual Net System Peaks are
 6 computed using forecast monthly energies and average historical coincident load factors for each
 7 of the rate classes. For large customers, individual demand contributions to system peak are
 8 assessed based on recent history or new customer information. Monthly peak loss percentages
 9 are applied to each monthly sales peak to produce losses by class and are then summed to
 10 produce the total peak demand forecast. This method produces forecast peaks that while not
 11 explicitly tied to a particular hourly temperature, recognize and average the actual peak and
 12 energy relationships from recent years.

13
 14 The system peak for 2009 is forecast at 2,214 MW. Over the longer term, Net System Peak is
 15 forecast to decrease from 2,192 MW in 2008 to 1,888 MW in 2019, which represents a decline of
 16 1.3% annual growth due to the effects of conservation and DSM. Without DSM, annual growth
 17 averages 0.7 percent.

18 19 ***Non Firm Coincident Peak***

20
 21 NSPI offers interruptible or “non-firm” service to industrial customers. Certain industrial
 22 customers who meet specific criteria may utilize discounted rates in exchange for agreeing to
 23 have their electricity supply interrupted on short notice in order to meet any necessary
 24 emergency peak reductions required to maintain system stability. These rate classes are the
 25 “Generation Replacement and Load Following” rate, the “Extra Large Industrial Two Part Real
 26 Time Pricing” rate and the “Interruptible” rider of the Large Industrial rate. As of the January
 27 2008 peak, there were 30 customers on these rates, representing a combined coincident non-firm
 28 peak of 352 MW.

29
 30 Non-firm coincident peak demand is forecast explicitly by customer for the near-term and an
 31 allowance is made for unallocated or new customer growth in the longer term. The customers
 32 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 NSPI'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.

While strictly speaking, the Firm Non-coincident Peak is generally referred to with respect to planning, NSPI typically uses Total Coincident Firm Peak as being representative of Total Non-Coincident Firm Peak, given that it is much more readily available each month (estimating non-coincident peak requires a full hourly load shape analysis, whereas coincident peak focuses on the peak hour only).

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.

1
2
3
4
5

Load Forecast

Appendices

1
2
3
4
5

Appendix A
2009 NSPI Forecast

Residential Sector Econometric Model Detail

$$DOMENG = 323.77 AIDX + 0.2502 CHDD - 28.16 RREP + 0.1077 RRCGOODS + 0.4422 DOMENG_{-1}$$

Forecast Model for DOMENG
Regression(5 regressors, 0 lagged errors)

Term	Coefficient	Std. Error	t-Statistic	Significance
AIDX	323.774438	53.421556	6.060745	0.999998
CUSTHDD	0.250221	0.038338	6.526670	0.999999
RRCGOODS	0.107744	0.014962	7.201080	1.000000
RREP	-28.163657	8.991179	-3.132365	0.995616
DOMENG1	0.442292	0.064302	6.878341	1.000000

Within-Sample Statistics

Sample size 30	Number of parameters 5
Mean 3238	Standard deviation 745.4
R-square 0.9973	Adjusted R-square 0.9969
Durbin-Watson 1.94	Ljung-Box(18)=26.97 P=0.9205
Forecast error 41.53	BIC 50.33
MAPE 0.01018	RMSE 37.91
MAD 29.57	

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	DSM	DomEng*	Actual	Growth
		GWh		GWh		GWh		GWh		GWh	GWh	GWh	GWh	GWh	%
1994	1.784	578	3,567	893	11.90	-335	7,556	814	3,506.9	1,551			3,500	3,498	-0.2%
1995	1.767	572	3,587	898	11.74	-331	7,483	806	3,498.3	1,547			3,492	3,463	-1.0%
1996	1.743	564	3,603	902	12.02	-338	7,552	814	3,462.9	1,532			3,473	3,565	2.9%
1997	1.753	568	3,735	935	11.73	-330	7,815	842	3,564.6	1,577			3,590	3,595	0.8%
1998	1.731	561	3,380	846	11.72	-330	8,061	869	3,594.8	1,590			3,535	3,524	-2.0%
1999	1.709	553	3,253	814	12.17	-343	8,442	910	3,524.4	1,559			3,493	3,512	-0.4%
2000	1.675	542	3,628	908	11.68	-329	8,647	932	3,512.0	1,553			3,606	3,672	4.6%
2001	1.673	542	3,739	935	11.42	-322	8,684	936	3,672.1	1,624			3,716	3,741	1.9%
2002	1.646	533	4,030	1008	11.11	-313	8,916	961	3,741.2	1,655			3,844	3,829	2.3%
2003	1.634	529	4,239	1061	11.01	-310	9,023	972	3,828.9	1,694			3,945	4,010	4.7%
2004	1.617	524	4,531	1134	10.78	-304	9,146	985	4,010.5	1,774			4,113	4,114	2.6%
2005	1.607	520	4,268	1068	11.21	-316	9,284	1,000	4,113.5	1,819			4,092	4,112	0.0%
2006	1.584	513	3,778	945	11.55	-325	9,431	1,016	4,112.4	1,819			3,968	3,979	-3.2%
2007	1.577	511	4,652	1164	10.98	-309	9,610	1,035	4,141.6	1,832			4,220	4,218	6.0%
2008	1.564	506	4,555	1140	10.89	-307	9,704	1,045	4,205.7	1,860			4,244	4,232	0.6%
2009	1.550	502	4,602	1152	11.79	-332	9,661	1,041	4,212.5	1,863	0.9	21	4,190		-1.3%
2010	1.537	498	4,673	1169	12.71	-358	9,719	1,047	4,211.8	1,863	1.1	52	4,153		-0.9%
2011	1.525	494	4,713	1179	13.00	-366	9,845	1,061	4,205.4	1,860	1.3	90	4,124		-0.7%
2012	1.514	490	4,736	1185	12.75	-359	9,983	1,076	4,213.8	1,864	1.5	146	4,095		-0.7%
2013	1.505	487	4,788	1198	12.97	-365	10,097	1,088	4,241.5	1,876	1.6	212	4,057		-0.9%
2014	1.497	485	4,827	1208	12.77	-360	10,158	1,094	4,269.4	1,888	1.7	274	4,027		-0.7%
2015	1.489	482	4,863	1217	12.56	-354	10,177	1,097	4,301.1	1,902	1.8	332	3,997		-0.7%
2016	1.483	480	4,911	1229	12.80	-360	10,203	1,099	4,329.5	1,915	1.8	391	3,958		-1.0%
2017	1.477	478	4,964	1242	12.76	-359	10,227	1,102	4,348.3	1,923	1.9	449	3,923		-0.9%
2018	1.473	477	5,020	1256	12.54	-353	10,244	1,104	4,371.6	1,934	1.9	507	3,895		-0.7%
2019	1.470	476	5,091	1274	12.61	-355	10,271	1,107	4,402.6	1,947	2.0	566	3,868		-0.7%

* - to align forecast to actuals in 2008, the modeled DomEng contains a launch adjustment of -12.7 GWh for 2009-2019



Commercial Sector Econometric Model Detail

$$COMENG = 0.02531 RQTOS + 0.01268 RPDI + 0.2806 DOMENG + 0.3676 COMENG_{-1}$$

Forecast Model for ComEng

Regression(4 regressors, 0 lagged errors)

Term	Coefficient	Std. Error	t-Statistic	Significance
-----	-----	-----	-----	-----
RQTOS	0.025315	0.004766	5.311397	0.999985
COMENG1	0.367606	0.067917	5.412594	0.999989
DOMENG	0.280641	0.036262	7.739354	1.000000
RPDI	0.012685	0.003946	3.214942	0.996528

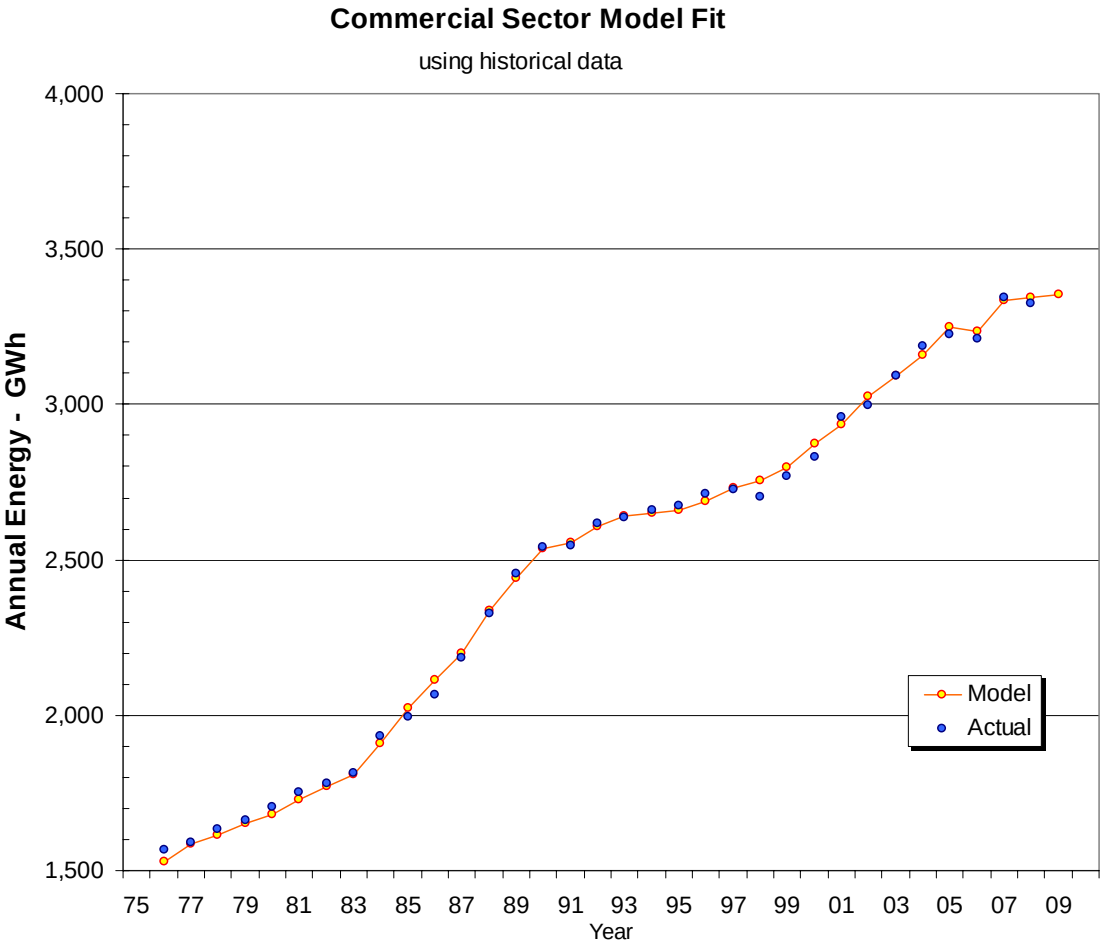
Within-Sample Statistics

Sample size 30	Number of parameters 4
Mean 2547	Standard deviation 519.4
R-square 0.9977	Adjusted R-square 0.9975
Durbin-Watson 2.041	Ljung-Box(18)=20.73 P=0.7067
Forecast error 26.08	BIC 30.46
MAPE 0.007559	RMSE 24.28
MAD 18.86	

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	DSM Effects GWh	ComEng*	Actual GWh	Growth %
1994	19,069	483	16,961	215	3,498	982	2,638	970		2,650	2,660	0.8%
1995	19,455	493	17,089	217	3,463	972	2,660	978		2,659	2,676	0.6%
1996	19,490	493	16,797	213	3,565	1,000	2,676	984		2,691	2,713	1.4%
1997	20,027	507	17,074	217	3,595	1,009	2,713	997		2,730	2,725	0.5%
1998	20,772	526	17,714	225	3,524	989	2,725	1,002		2,741	2,702	-0.8%
1999	21,971	556	18,263	232	3,512	986	2,702	993		2,767	2,767	2.4%
2000	22,729	575	18,382	233	3,672	1,031	2,767	1,017		2,856	2,829	2.3%
2001	23,531	596	18,663	237	3,741	1,050	2,829	1,040		2,922	2,959	4.6%
2002	24,509	620	18,673	237	3,829	1,075	2,959	1,088		3,020	2,996	1.3%
2003	24,955	632	18,566	236	4,010	1,126	2,996	1,102		3,094	3,091	3.1%
2004	25,337	641	19,094	242	4,114	1,154	3,091	1,136		3,174	3,188	3.1%
2005	25,706	651	19,381	246	4,112	1,154	3,240	1,191		3,242	3,225	1.2%
2006	25,959	657	19,969	253	3,979	1,117	3,157	1,161		3,188	3,211	-0.4%
2007	26,413	669	20,470	260	4,218	1,184	3,338	1,227		3,339	3,339	4.0%
2008	26,812	679	20,652	262	4,232	1,188	3,319	1,220		3,327	3,327	-0.4%
2009	27,092	686	20,845	264	4,212	1,182	3,318	1,220	5	3,316		-0.3%
2010	27,625	699	21,047	267	4,205	1,180	3,321	1,221	18	3,319		0.1%
2011	28,173	713	21,311	270	4,214	1,183	3,337	1,227	49	3,313		-0.2%
2012	28,955	733	21,602	274	4,241	1,190	3,362	1,236	100	3,303		-0.3%
2013	29,240	740	21,898	278	4,269	1,198	3,403	1,251	182	3,254		-1.5%
2014	29,540	748	22,154	281	4,301	1,207	3,437	1,263	287	3,182		-2.2%
2015	29,826	755	22,387	284	4,329	1,215	3,469	1,275	385	3,114		-2.1%
2016	30,077	761	22,647	287	4,348	1,220	3,499	1,286	483	3,041		-2.3%
2017	30,311	767	22,892	290	4,372	1,227	3,525	1,296	580	2,969		-2.4%
2018	30,538	773	23,125	293	4,403	1,236	3,550	1,305	675	2,901		-2.3%
2019	30,755	779	23,369	296	4,434	1,244	3,576	1,315	767	2,836		-2.2%

* - to align forecast to actuals in 2008, the modeled ComEng contains a launch adjustment of -30.5 GWh for 2009-2019



Industrial Econometric Model Details

Small and Medium Industrial Classes are summed and modeled together.

$$IND = 0.015016 RQTOS + 0.52599 IND_{-1} - 35.513 MIGRATE$$

Forecast Model for IND

Regression(3 regressors, 0 lagged errors)

Term	Coefficient	Std. Error	t-Statistic	Significance
RQTOS	0.015016	0.003164	4.745393	0.999813
IND[-1]	0.525994	0.105789	4.972091	0.999884
MIGRATE	-35.513079	7.074945	-5.019556	0.999895

Within-Sample Statistics

Sample size 20	Number of parameters 3
Mean 656.9	Standard deviation 122.4
R-square 0.9888	Adjusted R-square 0.9875
Durbin-Watson 1.007	Ljung-Box(12)=17.27 P=0.8604
Forecast error 13.68	BIC 15.79
MAPE 0.01476	RMSE 12.61
MAD 9.987	

Industrial Model Input Variables and Contributions

Year	RQTOS	RQTOS contrib GWh	MIGRATE	MIGRATE contrib GWh	Ind _[t-1]	Ind _[t-1] contrib GWh	DSM GWh	Ind*	Actual GWh	Growth %
1994	19,069	286	1	-36	518	272		523	528	2.0%
1995	19,455	292	1	-36	528	278		535	530	0.2%
1996	19,490	293	1	-36	530	279		536	531	0.3%
1997	20,027	301	0	0.0	531	279		580	569	7.2%
1998	20,772	312	0	0.0	569	299		611	607	6.6%
1999	21,971	330	0	0.0	607	319		649	670	10.5%
2000	22,729	341	0	0.0	670	352		694	703	5.0%
2001	23,531	353	0	0.0	703	370		723	740	5.2%
2002	24,509	368	0	0.0	740	389		757	766	3.4%
2003	24,955	375	0	0.0	766	403		777	796	4.0%
2004	25,337	380	0	0.0	796	419		799	807	1.3%
2005	25,706	386	0	0.0	807	424		810	798	-1.0%
2006	25,959	390	0	0.0	798	420		810	807	1.1%
2007	26,413	397	0	0.0	807	425		821	816	1.1%
2008	26,812	403	0	0.0	816	429		832	794	1.9%
2009	27,092	407	0	0.0	794	418	4	783		-6.0%
2010	27,625	415	0	0.0	782	411	11	786		0.5%
2011	28,173	423	0	0.0	786	413	28	796		1.3%
2012	28,955	435	0	0.0	796	419	54	813		2.2%
2013	29,240	439	0	0.0	813	428	96	827		1.6%
2014	29,540	444	0	0.0	827	435	149	838		1.4%
2015	29,826	448	0	0.0	838	441	199	848		1.2%
2016	30,077	452	0	0.0	848	446	249	858		1.1%
2017	30,311	455	0	0.0	858	451	298	866		1.0%
2018	30,538	459	0	0.0	866	456	345	874		0.9%
2019	30,755	462	0	0.0	874	460	390	881		0.8%

* - to align forecast to actuals in 2008, the modeled IND contains a launch adjustment of -40 GWh for 2009-2019

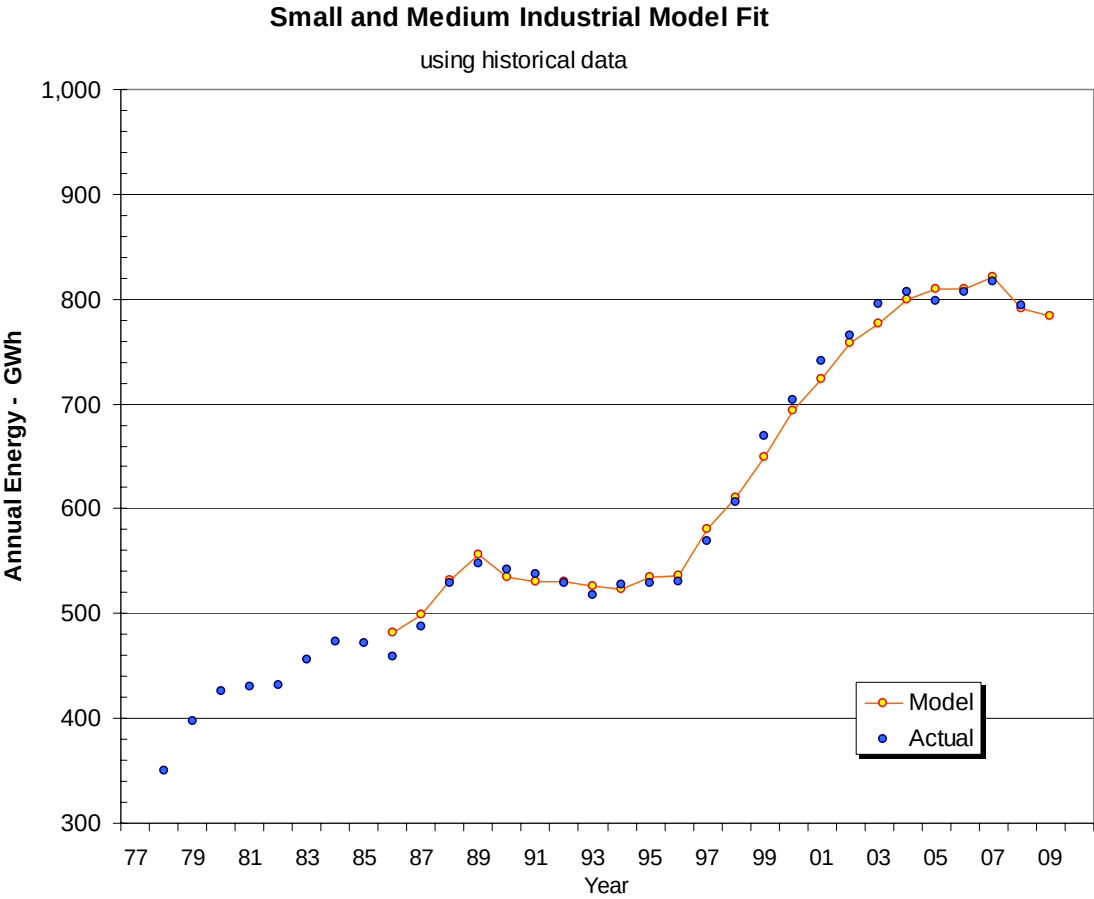


Table A1: Energy Requirement – 2009 NSPI Forecast**Energy Forecast with Conservation and DSM Program Effects**

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	4,190	-1.0	3,316	-0.3	4,072	-2.2	11,578	-1.2	861	12,439	-0.8
2010	4,153	-0.9	3,319	0.1	4,117	1.1	11,590	0.1	854	12,444	0.0
2011	4,124	-0.7	3,313	-0.2	4,111	-0.2	11,548	-0.4	854	12,402	-0.3
2012	4,095	-0.7	3,303	-0.3	4,093	-0.4	11,491	-0.5	849	12,339	-0.5
2013	4,057	-0.9	3,254	-1.5	4,037	-1.4	11,348	-1.2	837	12,185	-1.3
2014	4,027	-0.7	3,182	-2.2	3,958	-2.0	11,167	-1.6	824	11,991	-1.6
2015	3,997	-0.7	3,114	-2.1	3,883	-1.9	10,994	-1.5	811	11,804	-1.6
2016	3,958	-1.0	3,041	-2.3	3,808	-1.9	10,807	-1.7	796	11,602	-1.7
2017	3,923	-0.9	2,969	-2.4	3,731	-2.0	10,623	-1.7	782	11,405	-1.7
2018	3,895	-0.7	2,901	-2.3	3,659	-1.9	10,456	-1.6	769	11,225	-1.6
2019	3,868	-0.7	2,836	-2.2	3,591	-1.9	10,295	-1.5	757	11,051	-1.5

Table A2: Energy Requirement – 2009 NSPI Forecast

Energy Forecast without Conservation and 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	4,212	-0.5	3,321	-0.2	4,080	-2.0	11,614	-0.9	864	12,478	-0.5
2010	4,205	-0.2	3,337	0.5	4,142	1.5	11,685	0.6	863	12,547	0.6
2011	4,214	0.2	3,362	0.8	4,168	0.6	11,744	0.5	871	12,615	0.5
2012	4,241	0.7	3,403	1.2	4,202	0.8	11,847	0.9	878	12,725	0.9
2013	4,269	0.7	3,437	1.0	4,231	0.7	11,937	0.8	884	12,821	0.8
2014	4,301	0.7	3,469	0.9	4,259	0.7	12,029	0.8	890	12,918	0.8
2015	4,329	0.7	3,499	0.9	4,286	0.6	12,114	0.7	894	13,008	0.7
2016	4,348	0.4	3,525	0.7	4,312	0.6	12,185	0.6	896	13,082	0.6
2017	4,372	0.5	3,550	0.7	4,336	0.6	12,257	0.6	899	13,156	0.6
2018	4,403	0.7	3,576	0.7	4,361	0.6	12,340	0.7	902	13,241	0.6
2019	4,434	0.7	3,603	0.8	4,385	0.6	12,422	0.7	904	13,326	0.6

Table A3: Coincident Peak Demand - 2009 NSPI Forecast

Peak Forecast with Conservation and 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	-1.2	1,764	7.3
2008	2,192	2.2	352	-7.5	1,840	4.3
2009	2,214	1.0	360	2.1	1,854	0.8
2010	2,202	-0.5	359	-0.2	1,843	-0.6
2011	2,190	-0.6	352	-1.9	1,838	-0.3
2012	2,172	-0.8	344	-2.3	1,828	-0.5
2013	2,136	-1.6	329	-4.4	1,807	-1.1
2014	2,093	-2.0	309	-6.1	1,785	-1.3
2015	2,052	-2.0	290	-6.1	1,762	-1.2
2016	2,008	-2.2	271	-6.5	1,737	-1.4
2017	1,965	-2.1	252	-6.9	1,713	-1.4
2018	1,926	-2.0	235	-7.0	1,691	-1.3
2019	1,888	-2.0	218	-7.2	1,670	-1.2

Table A4: Coincident Peak Demand - 2009 NSPI Forecast

Peak Forecast without Conservation and 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	2,219	1.2	360	2.2	1,859	1.0
2010	2,219	0.0	360	0.1	1,858	0.0
2011	2,230	0.5	363	0.6	1,867	0.5
2012	2,249	0.9	366	0.8	1,883	0.9
2013	2,266	0.8	368	0.7	1,898	0.8
2014	2,284	0.8	371	0.7	1,913	0.8
2015	2,300	0.7	373	0.6	1,927	0.7
2016	2,313	0.6	375	0.6	1,938	0.6
2017	2,327	0.6	377	0.6	1,949	0.6
2018	2,343	0.7	379	0.6	1,963	0.7
2019	2,359	0.7	382	0.6	1,977	0.7

Table A3: Energy Sales by Rate Class - 2009 NSPI Forecast

Rate Class Energy Sales
With Conservation and DSM Program Effects

Class Sales (GWh)	2006 Actual	2007 Actual	2008 Actual	2009	2010	2011
Residential	3,907	4,142	4,156	4,115	4,078	4,049
Small General	233	246	239	243	245	244
General Demand	2,363	2,471	2,463	2,450	2,449	2,440
Large General	417	420	419	418	421	425
Unmetered	110	112	112	112	112	112
Small Industrial	240	248	254	251	252	252
Medium Industrial	567	568	539	528	524	516
Large Industrial	1,014	984	996	952	947	940
RTP	118	0	0	0	0	0
Mersey System	368	368	369	368	368	368
GR&LF	13	20	11	11	11	11
Municipal	187	197	197	196	195	194
ELII Rate	552	2,002	1,976	1,947	2,001	2009
Total Billed Sales	10,089	11,778	11,732	11,590	11,602	11,560
Losses & Unbilled	857	861	807	849	842	842
Net System Requirement	10,946	12,640	12,539	12,439	12,444	12,402

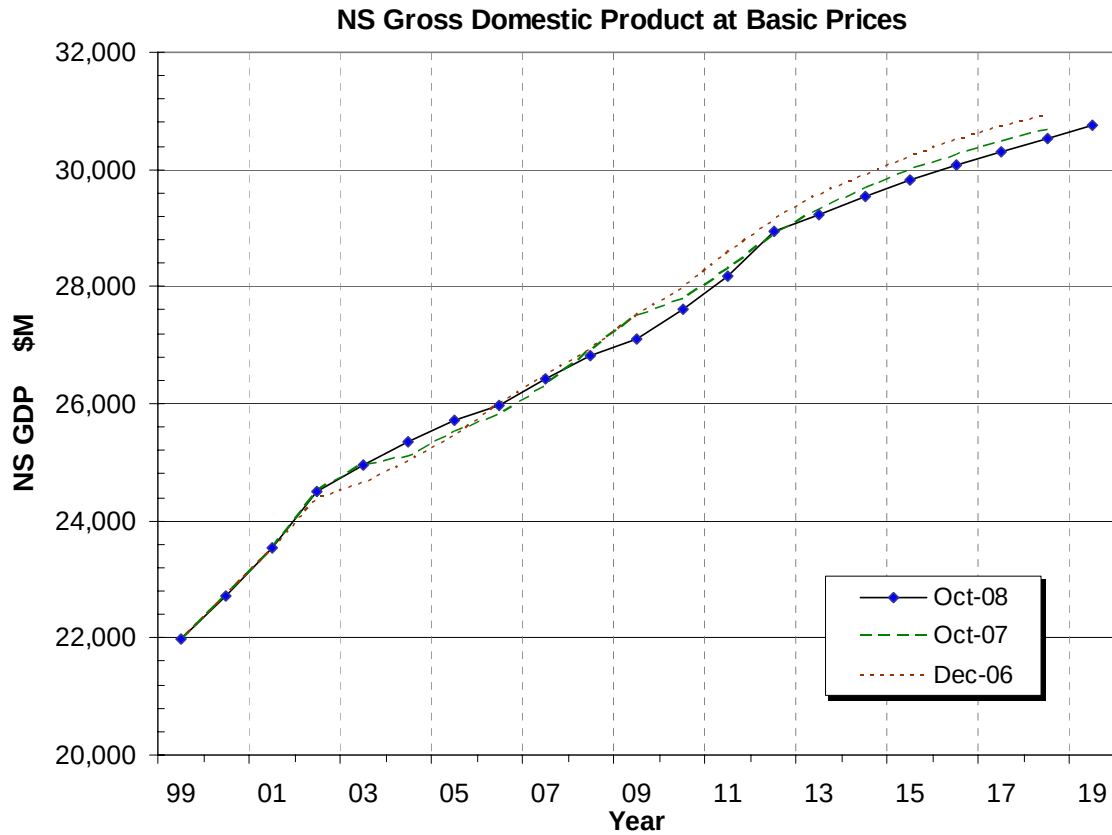
Rate Class Energy Sales
Without Conservation and DSM Program Effects

Class Sales (GWh)	2006 Actual	2007 Actual	2008 Actual	2009	2010	2011
Residential	3,907	4,142	4,156	4,136	4,129	4,138
Small General	233	246	239	244	249	254
General Demand	2,363	2,471	2,463	2,453	2,461	2,474
Large General	417	420	419	418	421	427
Unmetered	110	112	112	112	113	114
Small Industrial	240	248	254	251	252	255
Medium Industrial	567	568	539	532	534	541
Large Industrial	1,014	984	996	956	961	968
RTP	118	0	0	0	0	0
Mersey System	368	368	369	368	368	368
GR&LF	13	20	11	11	11	11
Municipal	187	197	197	197	197	198
ELII Rate	552	2,002	1,976	1,947	2,001	2009
Total Billed Sales	10,089	11,778	11,732	11,625	11,696	11,756
Losses & Unbilled	857	861	807	852	850	858
Net System Requirement	10,946	12,640	12,539	12,477	12,546	12,614

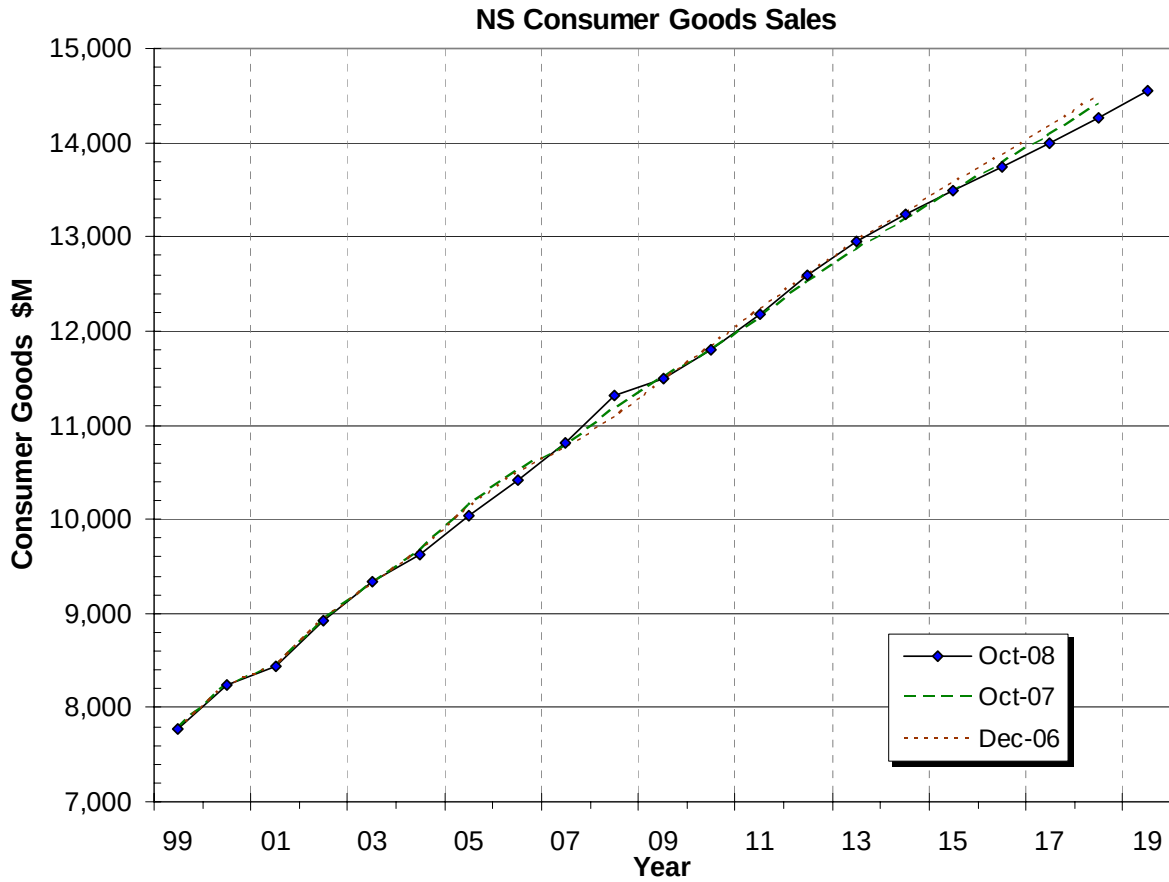
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27

Appendix B

Figures

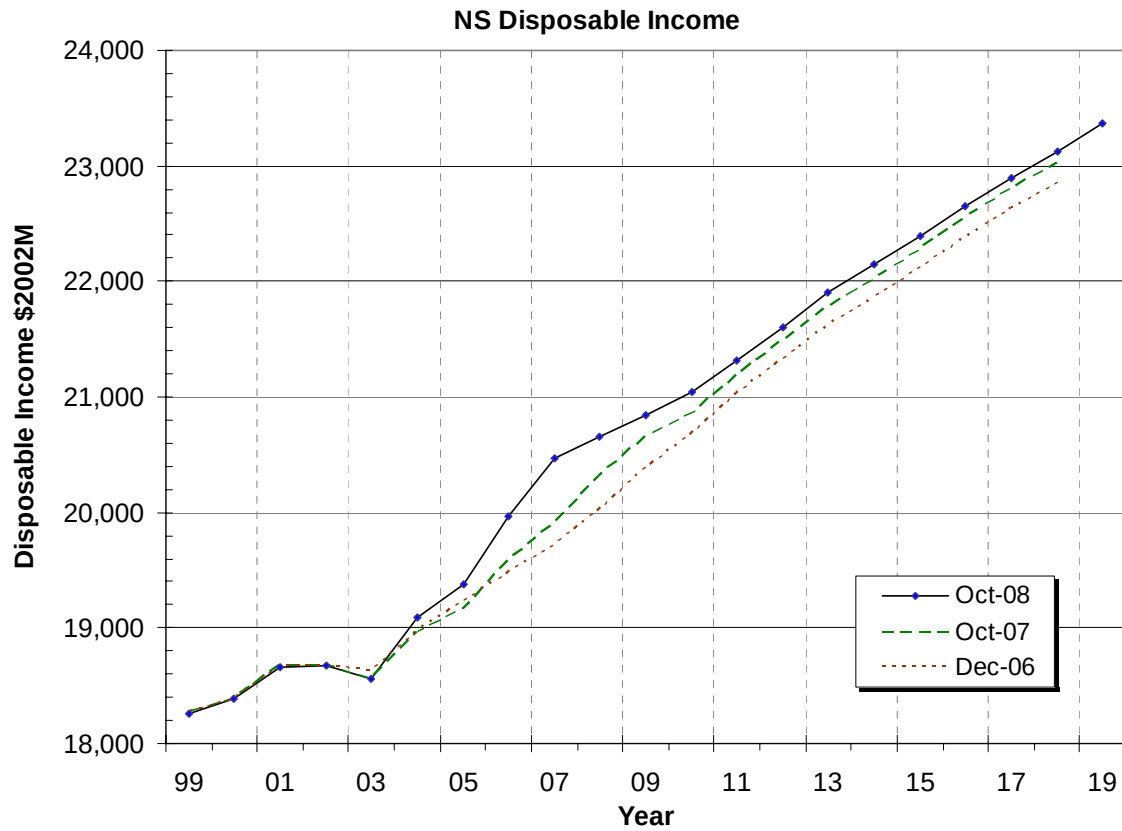
Figure B1: Nova Scotia Gross Domestic Product at Basic Prices

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.

1 **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 Energy Sales

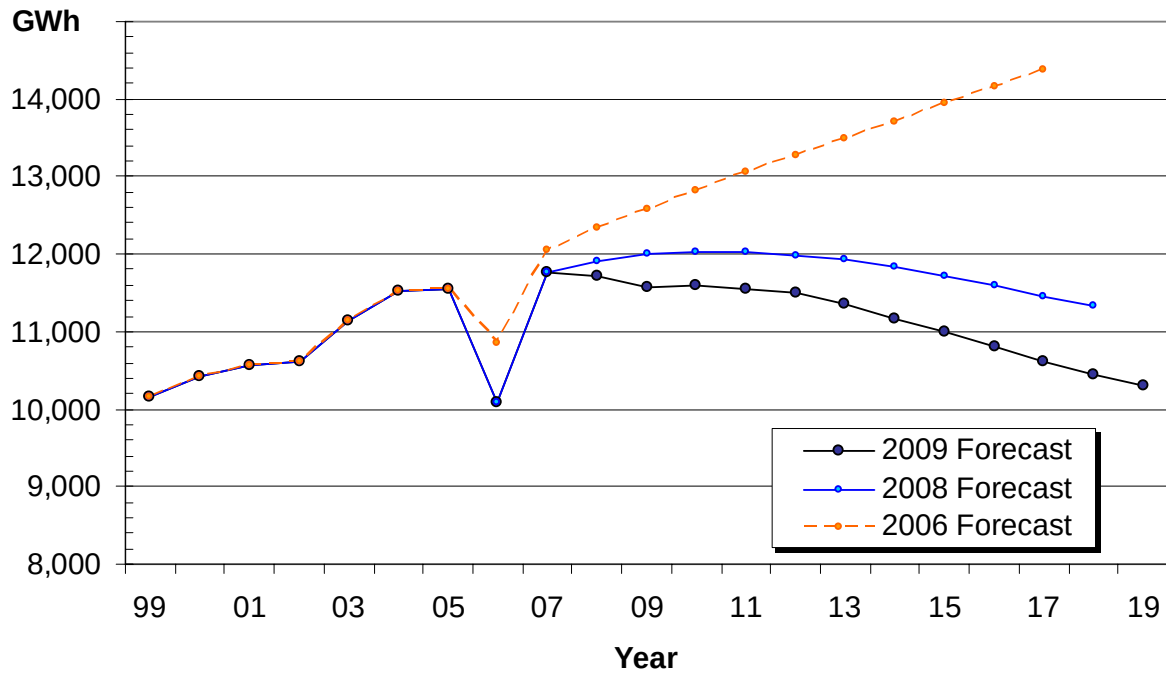


Figure B5: Total Nova Scotia Energy Losses

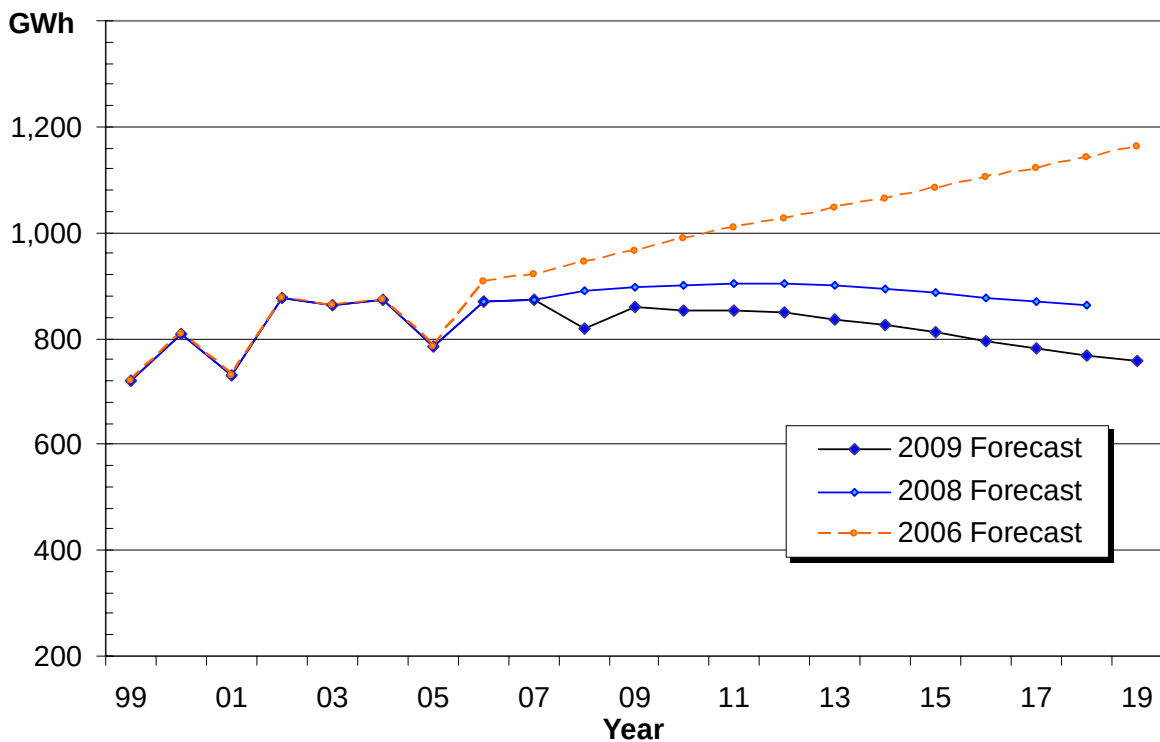


Figure B6: Total Nova Scotia Energy Requirement

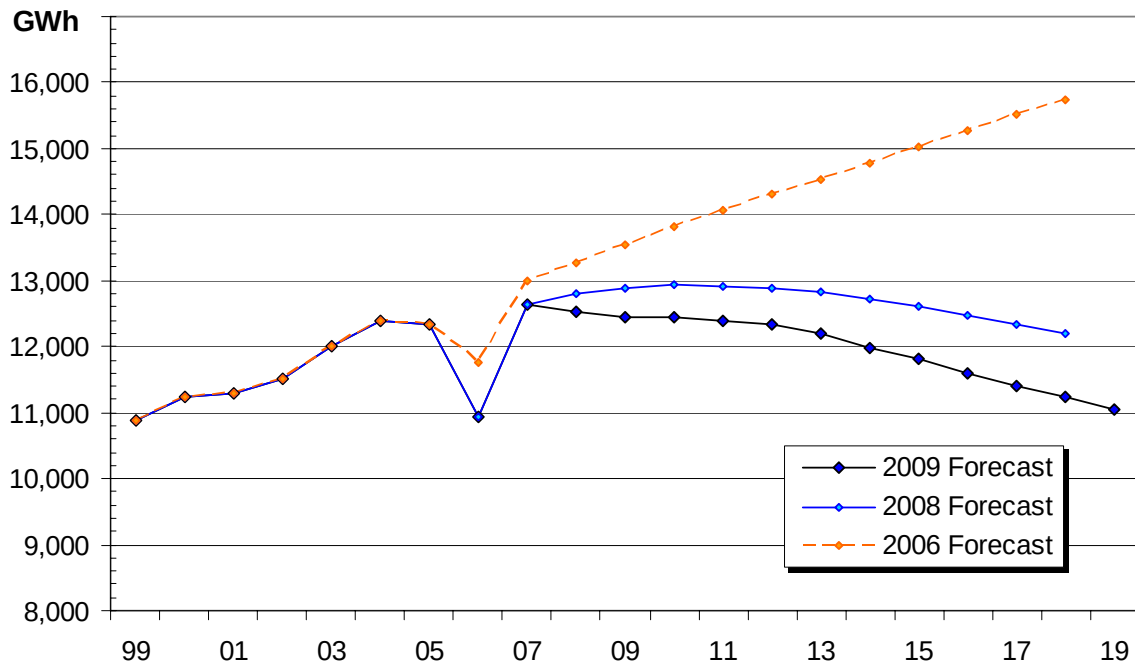
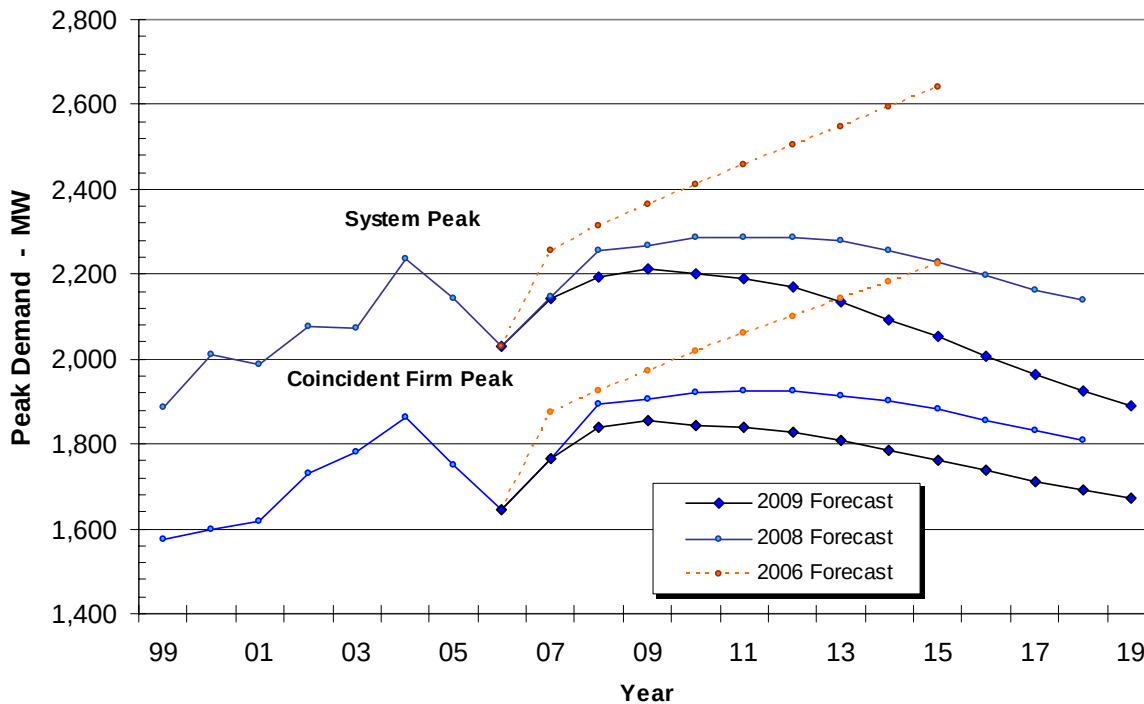


Figure B7: Net System Peak Demand and Firm Peak Demand



1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24

Appendix C

High and Low Forecast Scenarios

Appendix C: High and Low Forecast Scenarios

High and Low Forecast Scenarios

Low Forecast Scenario Assumptions

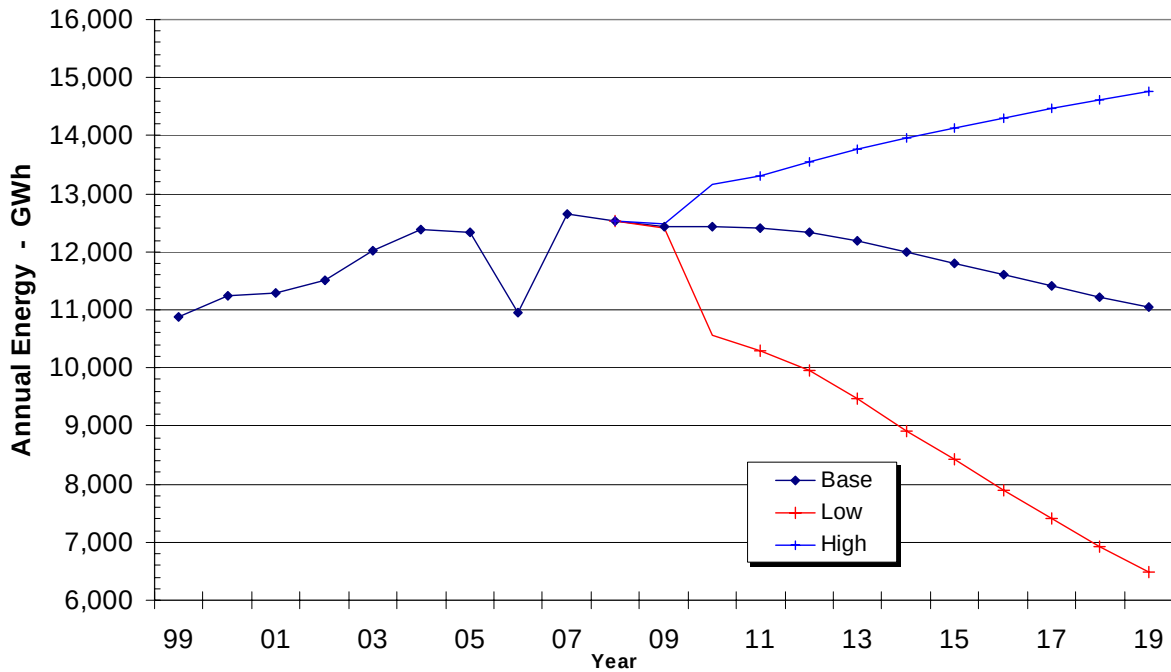
1	Major Paper Mill Closure (- 1,700 GWh /yr from 2010 onward)
2	Economic Growth Diminishes (Base case growth rate decreases by 50%)
3	30% reduction in home heating oil price 2010 on
4	Electricity Price Increase (10% above base case)
5	Residential customer additions (base case reduced by 250/yr)
6	DSM program effect 50% greater than forecast

High Forecast Scenario Assumptions

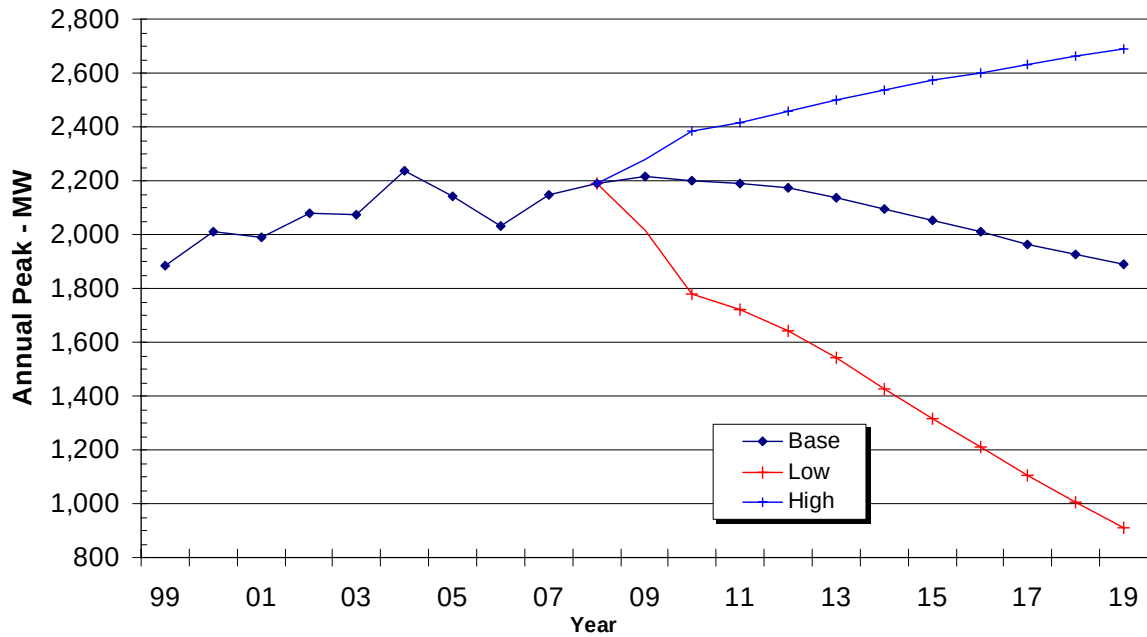
1	New industrial base load added, +500 GWh/year, beginning in 2010
2	Economic Growth Improves (Base case growth rate increases 50%)
3	125% increase in home heating oil price in 2010
4	Electricity Price decrease (10% below base case)
5	Residential customer additions (base case +250/yr)
6	No DSM program effect on load

Year	Low		Base		High	
	NSR GWh	Peak MW	NSR GWh	Peak MW	NSR GWh	Peak MW
2009	12,413	2,013	12,439	2,214	12,491	2,279
2010	10,559	1,780	12,444	2,202	13,151	2,384
2011	10,300	1,722	12,402	2,190	13,318	2,415
2012	9,948	1,644	12,339	2,172	13,549	2,459
2013	9,462	1,540	12,185	2,136	13,755	2,498
2014	8,924	1,426	11,991	2,093	13,956	2,536
2015	8,415	1,318	11,804	2,052	14,141	2,572
2016	7,900	1,209	11,602	2,008	14,304	2,602
2017	7,401	1,104	11,405	1,965	14,460	2,632
2018	6,932	1,005	11,225	1,926	14,619	2,662
2019	6,480	910	11,051	1,888	14,771	2,691

Annual Net System Requirement, High and Low Scenarios



Annual System Peak, High and Low Scenarios



1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25

Appendix D

Forecast Sensitivity by Major Variable

Appendix D: Forecast Sensitivity by Major Variable

Forecast Sensitivity by Major Variable

Based upon the 2009 load forecast models, the following table shows the relative sensitivity of the forecast to changes in various input assumptions.

Variable	Assumed Change	Effect on 2010 Load GWh	Effect on 2015 Load GWh
Lagged Dependent Variable <i>2% growth on base year, 2008</i>	Residential	13.4	0.2
	Commercial	3.5	0.0
	Industrial	4.8	0.2
	All	21.7	0.4
Consumer Goods Sales	+2%/yr (2010 on)	29.1	101.6
Gross Domestic Product	+2%/yr (2010 on)	23.8	248.0
Real Disposable Income	+2%/yr (2010 on)	5.8	54.7
Residential Electricity Price	+10% in 2010	-51.1	-302.5
Heating Degree-Days	+ 200 HDD/yr (2010 on)	83.2	171.7
Heating Oil Price	+10¢ per litre (2010 on)	1.1	158.1
DSM Program Effects	half of projected reduction	50.9	604.2
Residential Customer Additions	+2000/yr (2010 on)	16.9	163.2

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



2006 IRP Load Forecast

Prepared

September 2006

Table of Contents

Overview 1

Residential Sector Sales..... 2

Commercial Sector Sales 3

Industrial Sector Sales 4

Net System Requirement 5

Peak Demand 6

Assumptions for High and Low Scenarios 6

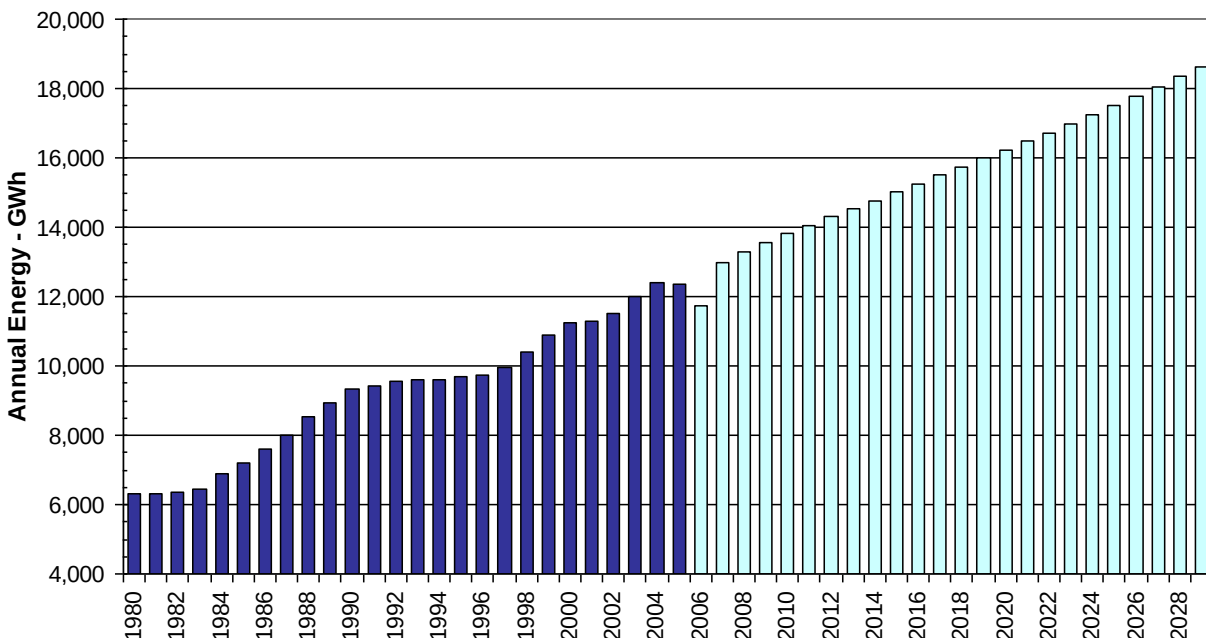
Overview

This report describes considerations, assumptions and methodology used in the preparation of the Nova Scotia Power Inc. (NSPI) IRP load forecast. It provides an outlook on the energy and peak demand requirements of in-province customers for 2006 to 2029. It is based on analyses of historical sales, weather, economic indicators, customer surveys, demographic and technological changes in the market, and the price and availability of other energy sources.

The base forecast methodology, assumptions and results are all consistent with the NSPI 2006 Load Forecast which covers the period 2006 to 2015 and is attached as an appendix to this report. This report describes the additional methodology and assumptions used to develop the forecast from 2016 to 2029. This IRP forecast is presented as the “base case” or most likely case for planning purposes, but also provides possible high and low scenarios for analysis.

The sum of in-province energy sales and associated system losses is referred to as Net System Requirement (NSR). The NSR for 2005 was 12,338 GWh (12,410 GWh weather-normalized) and is forecast to increase to 12,981 in 2007. The NSR for 2029 is forecast to be 18,638 GWh for an average annual increase of 1.7 percent over the forecast period. The historical and forecast NSR is shown in the graph in figure 1.

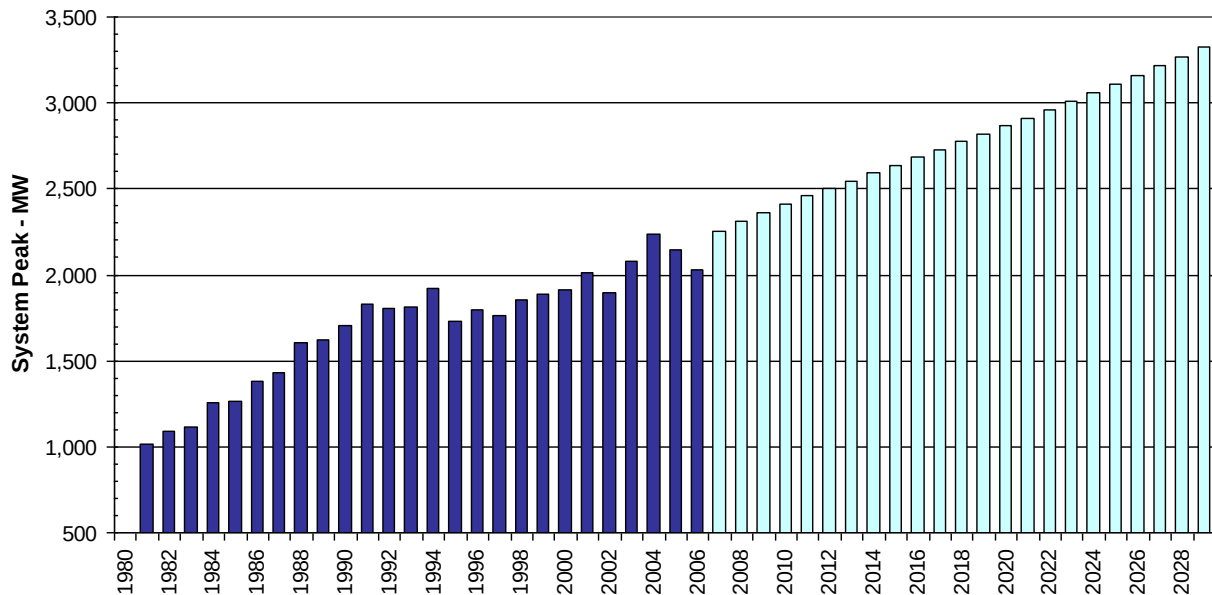
Figure 1: Annual Net System Requirement



The long-term outlook also forecast the peak hourly demand for future years. The process uses forecast energy requirements and expected load shapes (hourly consumption profiles) for the various customer sectors. Load shapes are developed from historical

analysis, adjusted for any expected changes. The net system peak in 2005 was 2143 MW and is forecast to be 2256 in 2007, growing to 3323 MW by 2029. The average annual growth rate over the forecast period to 2029 is 1.8 percent.

Figure 2 Net System Peak



Residential Sector Sales

Residential energy sales are forecast using the same models and assumptions as described in the 2006 NSPI Load Forecast report. For the IRP forecast period beyond 2015 shown in the Load Forecast Report, the following assumptions have been made to provide the extended forecast to 2029:

- The economic forecast from the Conference Board of Canada provides economic data to the year 2025 for use in the economic models.
- Long term home heating oil prices from PIRA Energy Group (oil price consultants) were available up to the year 2020, after which heating oil prices were escalated at an annual rate of 2.0% to the year 2025.
- An estimate of the long-term residential electricity price was developed, consistent with the latest Strategist (generation dispatch model) run. This data series extends to the year 2025.
- The current 30-year average (1976 to 2005) of annual heating degree-days (4150 HDD) was used for all the forecast years to 2025.
- The saturation of electric space heat is expected to continue to rise due to the forecast ratio of electricity to oil prices. Currently estimated to be approximately 30 percent, the proportion of residential customers using electric heating is estimated to grow to 43 percent by 2025.

- It is assumed that over the long term, natural gas distribution will continue to be limited. This forecast estimates 3.4 GWh of residential electric load migrated to natural gas by 2025.
- To provide the required forecast to the year 2029, residential loads were forecast to the year 2025 using the assumptions described above, and then the growth rate of 2025 (2.2 percent) was used to project the residential load for the subsequent years to 2029.

Table 1 lists the annual residential load forecast and growth rates to the year 2029.

Table 1: Residential Sector Sales

Year	GWh	Growth	Year	GWh	Growth
2000(actual)	3,672	4.6%	2015	5,240	2.3%
2001(actual)	3,741	1.9%	2016	5,347	2.0%
2002(actual)	3,829	2.3%	2017	5,460	2.1%
2003(actual)	4,010	4.7%	2018	5,574	2.1%
2004(actual)	4,114	2.6%	2019	5,692	2.1%
2005(actual)	4,114	0.0%	2020	5,805	2.0%
2006	4,204	2.2%	2021	5,919	2.0%
2007	4,327	2.9%	2022	6,042	2.1%
2008	4,466	3.2%	2023	6,172	2.2%
2009	4,588	2.7%	2024	6,307	2.2%
2010	4,706	2.6%	2025	6,446	2.2%
2011	4,814	2.3%	2026	6,587	2.2%
2012	4,918	2.2%	2027	6,732	2.2%
2013	5,018	2.0%	2028	6,880	2.2%
2014	5,123	2.1%	2029	7,031	2.2%

Commercial Sector Sales

Commercial energy sales are forecast using the same models and assumptions as described in the 2006 NSPI Load Forecast report. For the IRP forecast period beyond 2015 shown in the Load Forecast Report, the following assumptions have been made to provide the extended forecast to 2029:

- The economic forecast from the Conference Board of Canada provides economic data to the year 2025 for use in the economic models.
- To provide the required forecast to the year 2029, commercial loads were forecast to the year 2025 using the assumptions described above, and then the growth rate of 2025 (1.6 percent) was used to escalate the commercial load for the subsequent years to 2029.

Table 2 lists the annual commercial load forecast and growth rates to the year 2029.

Table 2: Annual Commercial Sector Sales

Year	GWh	Growth	Year	GWh	Growth
2000(actual)	2,829	2.3%	2015	3,933	1.8%
2001(actual)	2,959	4.6%	2016	3,999	1.7%
2002(actual)	2,996	1.3%	2017	4,066	1.7%
2003(actual)	3,091	3.1%	2018	4,132	1.6%
2004(actual)	3,188	3.1%	2019	4,198	1.6%
2005(actual)	3,223	1.1%	2020	4,262	1.5%
2006	3,275	1.6%	2021	4,326	1.5%
2007	3,345	2.1%	2022	4,392	1.5%
2008	3,423	2.3%	2023	4,459	1.5%
2009	3,503	2.3%	2024	4,529	1.6%
2010	3,581	2.2%	2025	4,600	1.6%
2011	3,657	2.1%	2026	4,672	1.6%
2012	3,728	2.0%	2027	4,745	1.6%
2013	3,798	1.9%	2028	4,819	1.6%
2014	3,864	1.8%	2029	4,894	1.6%

Industrial Sector Sales

Industrial energy sales are forecast using the same models and assumptions as described in the 2006 NSPI Load Forecast report. For the IRP forecast period beyond 2015 shown in the Load Forecast Report, the following assumptions have been made to provide the extended forecast to 2029:

- The economic forecast from the Conference Board of Canada provides economic data to the year 2025 for use in the economic models.
- To provide the required forecast to the year 2029, industrial loads were forecast to the year 2025 using the assumptions described above, and then the growth rate of 2025 (0.8 percent) was used to escalate the industrial load for the subsequent years to 2029.

Table 3 lists the annual industrial load forecast and growth rates to the year 2029.

Table 3: Annual Industrial Sector Sales

Year	GWh	Growth	Year	GWh	Growth
2000(actual)	3,930	1.5%	2015	4,771	1.0%
2001(actual)	3,873	-1.5%	2016	4,815	0.9%
2002(actual)	3,799	-1.9%	2017	4,858	0.9%
2003(actual)	4,046	6.5%	2018	4,901	0.9%
2004(actual)	4,212	4.1%	2019	4,943	0.9%
2005(actual)	4,215	0.1%	2020	4,984	0.8%
2006	3,362	-20.2%	2021	5,025	0.8%
2007	4,388	30.5%	2022	5,066	0.8%
2008	4,438	1.1%	2023	5,107	0.8%
2009	4,487	1.1%	2024	5,148	0.8%
2010	4,536	1.1%	2025	5,189	0.8%
2011	4,585	1.1%	2026	5,230	0.8%
2012	4,633	1.0%	2027	5,271	0.8%
2013	4,680	1.0%	2028	5,313	0.8%
2014	4,726	1.0%	2029	5,355	0.8%

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 transmission and distribution system losses within the province. The long-term NSR resulting from the model assumptions described in the previous sections is shown in Table 4.

Table 4: Annual Net System Requirement

Year	GWh	Growth	Year	GWh	Growth
2000(actual)	11,240	3.4%	2015	15,028	1.7%
2001(actual)	11,303	0.6%	2016	15,265	1.6%
2002(actual)	11,501	1.8%	2017	15,506	1.6%
2003(actual)	12,009	4.4%	2018	15,748	1.6%
2004(actual)	12,388	3.2%	2019	15,995	1.6%
2005(actual)	12,338	-0.4%	2020	16,232	1.5%
2006	11,748	-4.8%	2021	16,470	1.5%
2007	12,981	10.5%	2022	16,718	1.5%
2008	13,272	2.2%	2023	16,974	1.5%
2009	13,545	2.1%	2024	17,239	1.6%
2010	13,812	2.0%	2025	17,509	1.6%
2011	14,064	1.8%	2026	17,784	1.6%
2012	14,306	1.7%	2027	18,064	1.6%
2013	14,542	1.6%	2028	18,348	1.6%
2014	14,778	1.6%	2029	18,638	1.6%

Peak Demand

The 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 component of the load in Nova Scotia, the system peak occurs in the winter period from December through February. For this IRP forecast, the annual system peaks are calculated as in the 2006 NSPI Load Forecast, using forecast energies and average historical load factors. The long-term system peaks are shown in Table 5.

Table 5: Annual Net System Peak and Firm Peak

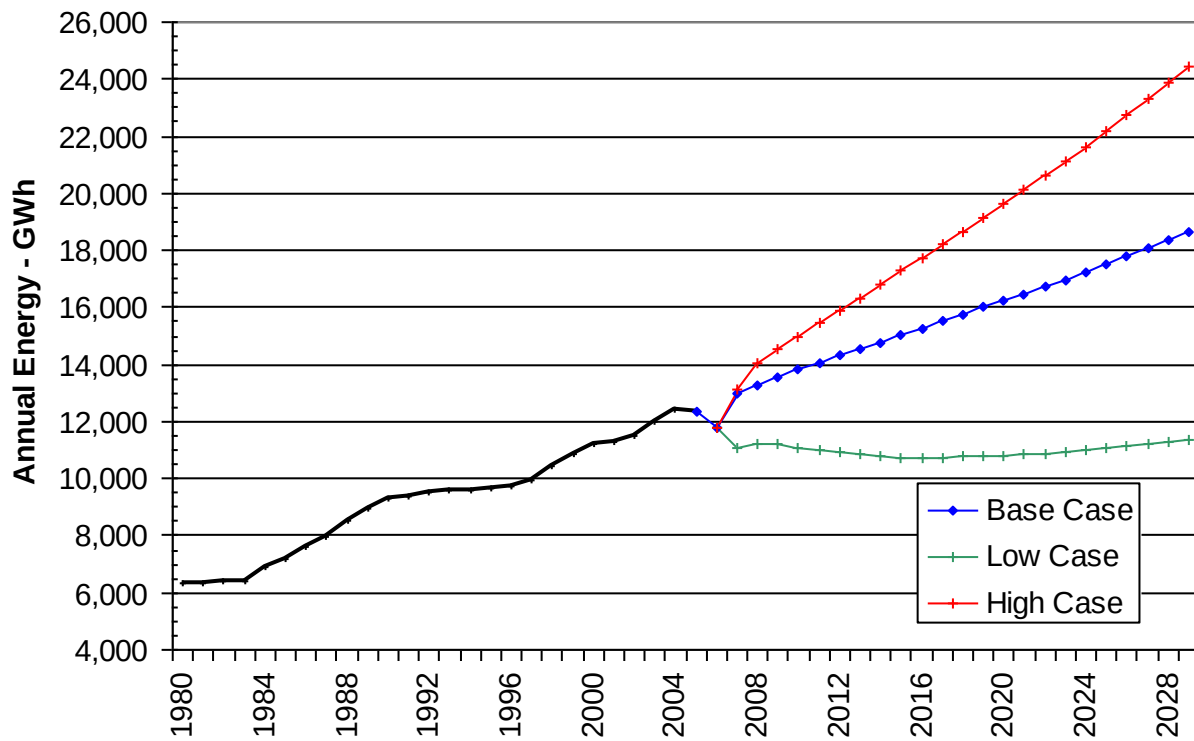
Year	Total Peak MW	Firm Peak MW	Non-firm Peak MW	Year	Total Peak MW	Firm Peak MW	Non-firm Peak MW
2000(actual)	2,009	1,597	412	2015	2,639	2,224	415
2001(actual)	1,988	1,619	369	2016	2,683	2,265	419
2002(actual)	2,078	1,730	348	2017	2,729	2,306	423
2003(actual)	2,074	1,783	291	2018	2,774	2,348	427
2004(actual)	2,238	1,861	377	2019	2,821	2,391	430
2005(actual)	2,143	1,751	392	2020	2,866	2,432	434
2006(actual)	2,029	1,644	386	2021	2,911	2,473	438
2007	2,256	1,875	381	2022	2,958	2,516	441
2008	2,312	1,927	385	2023	3,006	2,561	445
2009	2,363	1,973	390	2024	3,057	2,608	449
2010	2,413	2,019	394	2025	3,108	2,656	452
2011	2,460	2,061	399	2026	3,161	2,705	456
2012	2,504	2,102	403	2027	3,214	2,754	460
2013	2,548	2,141	407	2028	3,268	2,805	463
2014	2,592	2,181	411	2029	3,323	2,856	467

Assumptions for High and Low Scenarios

For system planning purposes, high and low cases have been developed in addition to the base case forecast. The low and high cases are the result of changing five major inputs to the forecast.

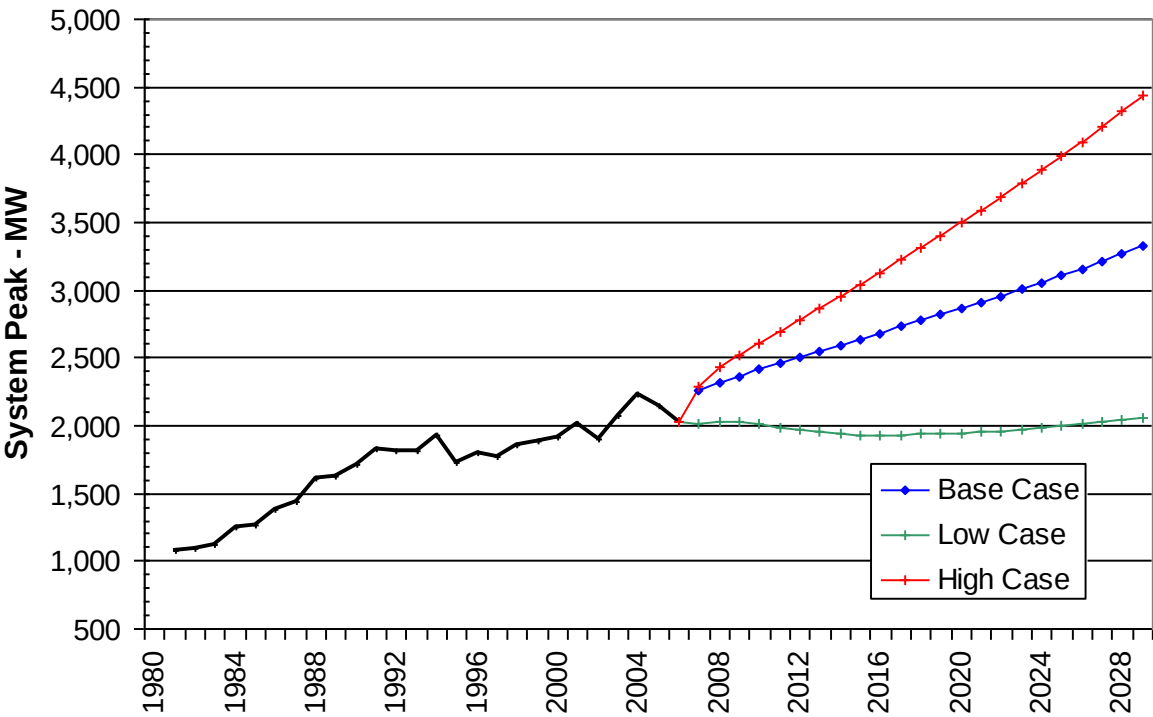
- Industrial load:
 - reduced by 1,700 GWh annually from 2007 onward for the low case, the equivalent to closing a major paper mill.
 - increased by 500 GWh annually from 2008 onward for the high case, the estimated load of a major industrial expansion or new industry moving to the province.
- Economic variables:
 - the annual growth rates of the major economic indicators used in the base forecast are reduced by 50 percent for the low case. This range was judged to be suitable and is within the variation observed in provincial GDP in recent years.
 - the annual growth rates of the economic indicators used in the base forecast are increased by 50 percent for the high case.
- Home heating oil prices
 - the low case price of heating oil was set 45 percent lower than the base case, using information from NSPI fuel price specialists as to possible low and high heating oil commodity prices.
 - for the high case, the price of heating oil was set 78 percent higher than the base case.
- Residential electricity price:
 - for the low case, the price was increased 10 percent above base case. The range of 10 percent was judged to be a suitable swing in electricity price for this analysis.
 - for the high case, the price was reduced 10 percent from base case.
- Residential customer additions:
 - for the low case, 250 customers were subtracted from the base case each year. This was judged to be a reasonable variation, roughly equal to a 10 percent change in anticipated customer additions.
 - for the high case, 250 additional customers were added to the base case each year of the forecast.

The combined results of these assumptions on the annual energy requirement are shown in figure 3.

Figure 3: Annual Energy Requirement, High and Low Cases

The growth in annual system peak for the high and low cases is shown in figure 4.

Figure 4: Annual Net System Peak



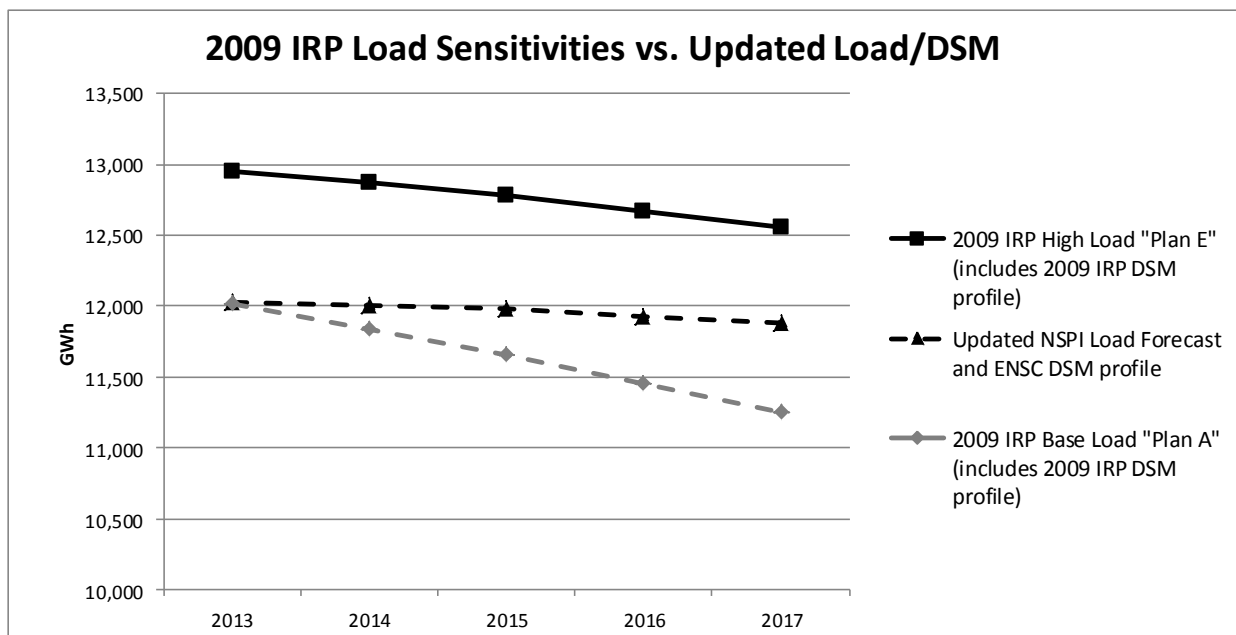
NON-CONFIDENTIAL

Request IR-7:

Please provide a copy of NSPI's preliminary review that confirms that ENSC's five-year DSM target projection is within range of the load sensitivities evaluated in the 2009 IRP.

Response IR-7:

Please refer to the chart below. The lower solid line represents the 2009 IRP Base Load sensitivity (Plan A) and the upper solid line represents the 2009 IRP High Load sensitivity (Plan E). These sensitivities include the effects of the DSM profile provided in the 2009 IRP Update Basic Assumptions. The dashed line represents NSPI's updated load forecast ("high bookend" case with Bowater and Port Hawkesbury Paper Mill PM2 load) and includes the effects of ENSC's current five year DSM target projection. The chart shows that the updated five-year projection of load and DSM savings is within the range of the Base and High load sensitivities evaluated in the 2009 IRP. Please also refer to Multeese IR-5c.



NON-CONFIDENTIAL

Request IR-8:

Please provide ENSC's views on whether experience with DSM in Nova Scotia since the 2007 indicates that the forecast level of savings in the 2007 IRP cannot be can be achieved at the projected costs in the 2007 IRP.

Response IR-8:

Please refer to Synapse IR-12.

NON-CONFIDENTIAL

Request IR-9:

Please provide ENSC's view on whether a review of the 2007 IRP is warranted before any increase in investment levels and targets over and above what has been proposed for 2013-2017.

Response IR-9:

ENSC's view is that an IRP update completed by the end of 2013 would be beneficial in informing DSM planning for years beyond 2015.

NON-CONFIDENTIAL

Request IR-10:

Please provide information on alternative levels of investment and savings for 2013-2015 that ENSC may have considered in preparing the 2013-15 DSM plan and reasons why any alternative levels of investment and savings targets were not requested.

Response IR-10:

Further to its discussion of the 2013-2015 DSM Plan development in section 1.1 of the Evidence, rather than preparing multiple plans with alternative levels of investment and savings, ENSC's approach was to build a multi-year plan that evolved through consultation with DSM consultants and stakeholders.

NON-CONFIDENTIAL

Request IR-11:

Please provide rationale for why solar domestic water heating was not considered within the Green Heating Program?

Response IR-11:

In the Green Heating System Initiative, Appendix E, solar domestic water heating is not specifically noted. This is clarified in Appendix A, page 11 lines 10 and 19 of the DSM filing where it refers to space and water heating systems. It was always the intention of ENSC to include solar domestic water heating in the definition of solar thermal.

NON-CONFIDENTIAL

Request IR-12:

Please provide ENSC's plan for ongoing tracking and evaluation of Energy Savings Actions and specifically the Home Energy Report

Response IR-12:

Prior to the launch of any Energy Savings Actions programs for which savings will be claimed, including the Home Energy Report, ENSC will work with its evaluator to develop a corresponding evaluation plan. All Energy Savings Actions programs for which ENSC claims savings will be subject to third-party evaluation.

The process for tracking savings from these initiatives will be designed prior to the program's implementation.

NON-CONFIDENTIAL

Request IR-13:

Please provide specific examples from each program area where recommendations made by Econoler have or will be implemented.

Response IR-13:

Program-specific examples are provided below. Please refer to CA IR-14 for ENSC's response regarding recommendations on evaluation plans and program manuals. Recommendation numbers refer to the numbers as listed in Appendix I of each evaluation report.

Efficient Products – Appliance Retirement	
ARet 5: Facilitate tracking of savings by using adjusted unitary savings values.	All tracking sheet recommendations have been implemented.
ARet 6: Determine the required fields and remove unnecessary ones.	
ARet 7: Standardize the entries and fix limitations.	
ARet 13: Conduct on-site metering for dehumidifiers and room air conditioners.	ENSC will conduct on-site metering for dehumidifiers and room air conditioners.
Efficient Products – Appliance Replacement	
The Appliance Replacement program is not being offered by ENSC during 2012.	
Efficient Products – Retail Markdown	
RMP 6: Monitor the energy savings in the tracking sheet.	All tracking sheet recommendations have been implemented.
RMP 7: Keep track of the manipulation made for calculating the number of units.	
RMP 8: Include technical information in the tracking sheet.	
RMP 9: Use relevant titles.	

ENSC 2013-2015 DSM Plan Filing (NSUAR-B-E-ENSC-R-12)
ENSC Responses to CA Information Requests

NON-CONFIDENTIAL

RMP 15: Support independent stores with their promotional displays.	ENSC will support independent stores with their promotional displays.
RMP 16: Improve visibility of discounted products.	ENSC is working to ensure the visibility of discounted products is increased during the 2012 campaigns.
RMP 22: Increase the number of retailer interviews.	ENSC will increase the number of retailer interviews.
Efficient Products – Low Income Renter The Low Income Renter program is being reconfigured in 2012. Relevant recommendations will be used to inform all residential direct install programs.	
LIR 5: Collect additional information on the products installed.	All tracking sheet recommendations will be implemented for residential direct install programs.
LIR 6: Ensure that all customer information is filled in systematically.	
LIR 11: Collect information on replaced wattage during the direct installation.	Information on replaced wattage will be collected in all residential direct install programs.
LIR 13: Collect information on air conditioning.	Information on air conditioning will be collected in all residential direct install programs.
Efficient Products – Multi-Unit Residential Renter The Multi-Unit Residential Renter program is being reconfigured into a Multi-Unit Residential Building program in 2012. Relevant recommendations will be used to inform the new program.	
MURR 5: Monitor the gross savings directly in the tracking sheet.	All tracking sheet recommendations will be implemented.
MURR 6: Establish a tracking sheet revision protocol.	
MURR 7: Collect all necessary information for determining the eligibility of each product installed.	
MURR 8: Collect information for establishing base cases.	
MURR 9: Collect information for establishing the line loss factor.	

ENSC 2013-2015 DSM Plan Filing (NSUARB-E-ENSC-R-12)
ENSC Responses to CA Information Requests

NON-CONFIDENTIAL

MURR 12: Increase the number of on-site visits.	ENSC plans to have its third-party evaluator conduct a sufficient number of on-site visits to obtain an acceptable precision level for estimating net savings.
Efficient Products – Direct Install	
EP-DI 5: Remove unnecessary fields.	All tracking sheet recommendations will be implemented.
EP-DI 6: Ensure that all fields are filled in systematically.	
EP-DI 7: Improve the labelling of the usage group field.	
EP-DI 13: Collect information on air conditioning.	ENSC will collect information on participants' use of air conditioning.
EP-DI 15: Collect information on the hot water tank volume.	ENSC will collect information on participants' hot water tank volume.
EP-DI 19: Increase the number of on-site visits conducted for the CFL category.	ENSC plans to have the third-party evaluator conduct a sufficient number of on-site visits to establish a reliable installation rate for CFLs.
Energuide for Existing Houses	
EEH 8: Create fields for building energy consumption data.	These tracking sheet recommendations will be implemented.
EEH 9: Ensure that all fields are systematically filled in.	
EEH 12: Create a list of pre-approved contractors.	ENSC is in the process of developing a pre-approved contractors list.
EEH 25: Conduct a more thorough billing analysis to evaluate the overestimation of energy consumption by HOT2000 with better precision.	ENSC will have its third-party evaluator develop a more comprehensive billing analysis to establish an adjustment ratio for HOT2000.
Fuel Substitution	
FS 5: Clearly define project status in the tracking sheet.	The tracking sheet has been adjusted to clearly define the project status.

ENSC 2013-2015 DSM Plan Filing (NSUARB-E-ENSC-R-12)
ENSC Responses to CA Information Requests

NON-CONFIDENTIAL

FS 11: Focus on energy bill savings in program communications.	Communications with participants now emphasize the opportunities to save on energy bills.
FS 13: Increase the number of participants who install natural gas systems.	ENSC is working with Heritage Gas to promote several systems that would be of interest to natural gas clients.
Low Income	
LI 7: Add complementary information.	The Low Income program is implementing changes to ENSC's Data Management System that will incorporate these recommendations.
LI 8: Standardize the entries.	
LI 9: Implement a verification protocol.	
LI 17: Assess the installation rate of certain prescriptive measures.	ENSC will have its third-party evaluator conduct a greater number of on-site visits to validate the installation rate of direct-install measures.
LI 19: Ensure the final audits are completed after the implementation of measures.	ENSC has worked with its service organizations to ensure final audits are completed within an acceptable period of time after work is completed.
Performance Plus	
PP 1: Determine the required fields and remove those that are unnecessary.	All program tracking sheet recommendations have been or will be implemented.
PP 2: Delete fields for individual measures savings for which energy savings are included in the EnerGuide rating.	
PP 3: Differentiate the applicant.	
PP 4: Create fields for building energy consumption data.	
PP 5: Ensure that all fields are systematically filled in.	

ENSC 2013-2015 DSM Plan Filing (NSUARB-E-ENSC-R-12)
ENSC Responses to CA Information Requests

NON-CONFIDENTIAL

PP 12: Collect the building energy consumption data for each house.	ENSC is in discussions with its service organizations to ensure that building energy consumption data is collected for each house or customer permission for ENSC to collect the required data from NSPI is obtained.
PP 15: Increase the number of in-depth interviews with home builders.	ENSC will have its third-party evaluator interview more home builders in 2012.
Business Energy Rebates	
BER 5: Break down the values used for savings calculations in different cells.	These tracking sheet recommendations will be addressed in 2012 when the BER program is transitioned to ENSC's Data Management System (DMS).
BER 6: Include measure sub-categories for categories with several measures.	
BER 7: Break down the address information.	
BER 8: Ensure that all fields are systematically filled in.	
BER 15: Provide information to participants on program portfolio.	BER cheque mail-outs will include brochures for other Business, Non-Profit, and Institutional (BNI) programs.
BER 17: Conduct on-site visits for compressed air or laundry measures.	ENSC will work with its evaluator to assess the costs and benefits of increasing the number of on-site visits for the categories listed.
BER 18: Increase the number of on-site visits for the lighting category.	
BER 19: Increase the number of on-site visits for the HVAC category.	
BER 20: Increase the number of on-site visits for the motors and drives category.	
BER 21: Increase the number of on-site visits for the occupancy sensors category.	
BER 22: Increase the number of on-site visits for the refrigeration category.	

NON-CONFIDENTIAL

Smart Lighting Choices	
SLC 4: Facilitate the tracking of products by requesting that distributors include the type of product purchased for each category.	Measure data is now tracked by type of lamp and/or ballast.
SLC 5: Investigate retrofit activities involving de-lamping.	ENSC is planning to collect information on de-lamping.
SLC 7: Collect information on heating source and on the use of air conditioning equipment during the C&I telephone survey campaigns.	ENSC is planning to collect information on heating sources and the use of air conditioning equipment during other BNI surveys.
C&I Custom	
C&IC 6: Develop a standardized nomenclature to name the electronic files.	All reporting functions are moving from the program tracking sheet to the DMS. These recommendations will be implemented through that process.
C&IC 7: Continue standardizing the entries and fix limitations.	
C&IC 8: Split the customer name field in two columns.	
C&IC 9: Add a new field for the savings at the consumer level.	
C&IC 10: Split the demand savings field in two different columns.	
C&IC 19: Continue to use contractors and design professionals to promote the program.	ENSC is using contractors and design professionals to promote the Custom program.

NON-CONFIDENTIAL

C&I New Construction	
CINC 6: Create automatic formulas for calculating data that are dependent on data of other fields.	All tracking sheet recommendations have been implemented through a migration of all projects to the DMS.
CINC 7: Standardize the entries and fix limitations.	
CINC 8: Add a peak demand savings field.	
CINC 9: Track the market type of each customer.	
CINC 10: Add customer contact details in the tracking sheet.	
CINC 11: Break down the address information.	
CINC 21: Define different energy savings indices (in kWh/m ²) depending on various factors.	ENSC is planning to define different energy savings indices depending on various factors.
CINC 25: Use the PDA savings figures for estimating NCWB project savings.	ENSC will use the PDA savings figures for estimating NCWB project savings.
Small Business Energy Solutions	
SBES 8: Present the detailed characteristics of each measure and the corresponding unitary savings to allow for savings calculation validation by the Evaluator.	ENSC is in the process of implementing or is planning to implement all tracking sheet recommendations.
SBES 9: Identify measures with lighting controls.	
SBES 10: Determine the required fields and remove the unnecessary ones.	
SBES 11: Make sure that all fields are systematically filled in.	
SBES 12: Set limitations for entries and develop a validation process.	

ENSC 2013-2015 DSM Plan Filing (NSUARB-E-ENSC-R-12)
ENSC Responses to CA Information Requests

NON-CONFIDENTIAL

SBES 20: Monitor satisfaction with specific aspects of program delivery.	ENSC will monitor participant satisfaction with specific aspects of program delivery, including the paperwork, procedures and project scheduling.
SBES 24: Increase the number of sites where data loggers are installed.	ENSC is increasing the number of sites where data loggers are installed.
SBES 25: Increase the number of on-site visits.	ENSC will have its third-party evaluator increase the number of on-site visits.

NON-CONFIDENTIAL

Request IR-14:

Please provide an update on the status of progress regarding development of evaluation plans and improvements to manuals as recommended by Econoler.

Response IR-14:

ENSC is in the process of completing evaluation plans for all existing programs. The expected completion date is May 31, 2012.

ENSC is incorporating Econoler's recommendations into each of its program manuals. Please refer to CA IR-13 for specific examples.

NON-CONFIDENTIAL

Request IR-15:

Please provide an estimate of free ridership for the Green Heating Program and what steps, if any, have been taken by ENSC to reduce free ridership levels from that reported with respect to the Fuel Substitution Pilot.

Response IR-15:

The anticipated free ridership levels for each system are presented in the table below, by technology and market.

Existing Residential	
Ductless Heat Pump	45.0%
Ground Source Heat Pump	0%
Pellet Furnace	0%
Wood Stove	42.0%
Pellet Stove	42.0%
Solar Domestic Hot Water	10.0%
New Construction	
Ductless Heat Pump	53.2%
Ground Source Heat Pump	5.0%
Air Source Heat Pump	60.0%
Pellet furnace	10.0%
Pellet Stove	42.0%
Solar Domestic Hot Water	10.0%

Strategies that ENSC has already taken to reduce free ridership in the 2012 Fuel Substitution program that could be applied to the Green Heating initiative include the following:

- focusing on mid-stream retailer advertising to make customers aware of rebates prior to their visits to retailers instead of advertising in areas in which customers are already looking for fuel substitution options

NON-CONFIDENTIAL

- eliminating or reducing options, such as mini-split heat pumps, for which there is already substantial demand, which leads to high free ridership

ENSC will limit free ridership for the Green Heating initiative by providing incentives for only the highest performing systems within each category (including establishing premium performance requirements where feasible).

NON-CONFIDENTIAL

Request IR-16:

Please provide a list of program changes ENSC plans to ensure the 2013-15 energy savings targets for business, non-profits and institutions are met given the significant underachievement in 2011 for these classes of customers.

Response IR-16:

Please refer to Avon IR-2.

NON-CONFIDENTIAL

1 **Request IR-17:**

2
3 **Please indicate whether ENSC is prepared to re-evaluate the Low Income Home target of**
4 **19 GWh for the three year period 2013-2015 in light of the fact that the 2011 evaluation**
5 **indicated savings of 12.4 GWh for one year.**

6
7 Response IR-17:

8
9 Yes, as part of ongoing mid-course corrections, ENSC would adjust program targets to
10 reflect experience gained in the previous year.

ENSC 2013-2015 DSM Plan Filing (NSUARB-E-ENSC-R-12)
ENSC Responses to CA Information Requests

NON-CONFIDENTIAL

Request IR-18:

Please provide ENSC's evaluation plan for Enabling Strategies.

Response IR-18:

ENSC is in the process of developing its Codes and Standards evaluation plan, which is the only Enabling Strategy for which energy savings will be claimed in 2012.

Prior to the launch of any additional Enabling Strategies for which savings will be claimed, ENSC will develop evaluation plans.

NON-CONFIDENTIAL

Request IR-19:

Is ENSC planning to include evaluation of Enabling Strategies in future third part program evaluations and, if not, why not?

Response IR-19:

ENSC plans to include third-party evaluation of Enabling Strategies for which it claims savings, such as with Codes and Standards. ENSC is not planning to include third-party evaluation of Enabling Strategies for which it is not claiming savings, as the purpose of Enabling Strategies is to encourage the adoption of energy-efficient behaviours and to increase participation in ENSC Residential and BNI programs, which are already part of existing third-party evaluations.

NON-CONFIDENTIAL

Request IR-20:

Please provide an update on the implementation Econoler's recommendation that evaluation plans be prepared for each program as part of program design phase.

Response IR-20:

ENSC will develop evaluation plans during the design phase of new programs. Please refer to CA IR-14 for an update on current programs.

NON-CONFIDENTIAL

Request IR-21:

Please explain whether ENSC has adopted and agrees with the cost-allocation recommendations Elenchus presents in Appendix C.

Response IR-21:

As noted on pages 31 and 32 of the Evidence, ENSC agrees with the two recommendations contained in Elenchus's report. Recommendation #1 was accepted in the 2009 Settlement Agreement, and therefore has already been adopted by ENSC; no change is proposed for the 2013-2015 period. Recommendation #2 would be adopted beginning in 2013.

NON-CONFIDENTIAL

Request IR-22:

Please provide as detailed and realistic as possible an example of the allocation of costs between taxpayer and ratepayer components, based on the proposed budget for 2013 or anticipated program activity.

a) Wherever possible, please identify the allocation method for each activity or expenditure category.

Response IR-22:

Three examples of expenditure categories are provided:

1. *Direct Program Cost and Joint Direct Program Cost*

The Low Income component of ENSC's Existing Residential service provides free energy audits and turnkey implementation of energy efficiency measures at no cost to participants. Any electric energy efficiency measures installed are charged 100% directly to ratepayers. The cost of non-electric energy efficiency measures installed are charged 100% directly to taxpayers.

2. *Administrative and Operational Overhead – common costs (staff/space)*

Rent on ENSC's office space is a cost that is "caused" by the number of staff. In accordance with the Cost Allocation Methodology, this cost is allocated to ratepayer and taxpayer programs on the basis of full-time equivalent staff associated with each program. Using the 2011 full-time direct program staff of 26.62 related to ratepayer programs, and 6.88 related to taxpayer programs as an approximation for 2013, monthly rent of \$38,000 would be allocated \$30,200 to ratepayer programs, and \$7,800 to taxpayer programs.

NON-CONFIDENTIAL

1
2 *3. General Program Administration*

3
4 ENSC's financial statement audit is a cost that is not "caused" by the number of staff or
5 space, but by the overall business activity. In accordance with the Cost Allocation
6 Methodology, this cost is allocated to ratepayer and taxpayer programs on the basis of total
7 directly allocated costs of each program. Using 2011 ratepayer direct program costs of \$31.7
8 million, and taxpayer direct program costs of \$5.3 million as an approximation for 2013, the
9 audit cost of \$23,000 would be allocated \$19,700 to ratepayers and \$3,300 to taxpayers.

NON-CONFIDENTIAL

1 **Request IR-23:**

2

3 **Please provide all available information on the planned allocation of the costs of enabling**
4 **strategies.**

5

6 Response IR-23:

7

8 Please refer to Avon IR-14.

NON-CONFIDENTIAL

1 **Request IR-24:**

2
3 **Please provide the attachments to Appendix C as Excel spreadsheets with all formulae**
4 **intact.**

5
6 Response IR-24:

7
8 As indentified in Avon IR-22, ENSC has revised its 2013-2015 Preliminary Cost Allocation
9 Tables and associated rate rider and bill impact tables. Please refer to the revised Preliminary
10 Cost Allocation Tables (Appendix C, Attachment 1) and the revised Preliminary Rate and Bill
11 Impact Tables (Appendix C, Attachments 2 and 3), filed concurrently with this IR Response,
12 March 30, 2012.

13
14 Please refer to Attachment 1 for the revised electronic version, filed electronically.

NON-CONFIDENTIAL

Request IR-25:

Please explain exactly how ENSC proposes to update the 3 CP kW Demand allocator and the MWh Energy Requirement in Attachment 1-1 of Appendix C in actual cost-recovery filings.

a) What sales values would be used in the adjustment in note 2?

b) What source or reference date will be used the MWh requirement?

Response IR-25:

ENSC will work with NSPI to ensure that it has the appropriate and most recent publicly available information on cost allocators as used for rate setting purposes. The process that ENSC will use in preparing the annual DCRR (DSM Cost Recovery Rider) will follow the approach used under NSPI's administration.

a) ENSC will ensure that it has NSPI's most recent publicly available sales data values appropriate for the adjustment in note 2.

b) ENSC will ensure that it has NSPI's most recent reference data that is publicly available to appropriately identify the MWh requirement.

NON-CONFIDENTIAL

Request IR-26:

Appendix C (p. 5) states that Elenchus supports “25% of costs being allocated on the basis of system benefits,” yet the allocation of this portion of costs is entirely on the generation plant portion of rate base (Attachment 1-1, note 1).

a) Please explain why this allocator does not reflect the system benefit of avoided fuel and variable O&M costs (including variable pollution-control costs).

b) Please provide Elenchus’s estimate of the fuel-related fraction of total system benefits, as reflected in the avoided costs used by ENSC in screening measures and programs.

c) Please provide Elenchus’s estimate of the fuel-related fraction of NSPI’s total generation costs.

Response IR-26:

a) A review of the makeup of system benefits was beyond the scope of Elenchus’ services to ENSC. The referenced statement is based on the fact that this methodology is approved by the UARB and that its continued use received broad acceptance at the stakeholder consultation sessions.

b) Please refer to part a.

c) Please refer to part a.

NON-CONFIDENTIAL

Request IR-27:

The bill-impact tables in Appendix C, Attachment 3, do not appear to reflect either the reduction in supply costs due to the energy-efficiency programs, or the reduction in the average usage by class due to the programs.

a) If either supply benefits or the change in usage is reflected in those tables, please explain how they are reflected.

b) Please provide the equivalent of these tables, reducing kWh and kW billing determinants as expected for the average class member (e.g., class savings ÷ customer number ÷ 12).

c) Please provide the equivalent of these tables, reducing rates by the costs avoided by the energy-efficiency programs.

Response IR-27:

a) NSPI has confirmed that DSM impacts are included in the load forecast. As a result, all tables are on the basis of DSM savings being realized.

b) Please refer to part a. All billing determinants already reflect savings from DSM.

c) The avoided costs provided by NSPI and used by ENSC in its DSM plan reflect costs that are avoided over NSPI's planning horizon. ENSC has not developed the requested tables since the effect of avoided cost on NSPI's rates is not part of the calculations for the bill impact resulting from the DSM rate rider.