Integrated Resource Plan (IRP) Report

Volume 1

Nova Scotia Power Inc.

July 2007

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Executive Summary

In collaboration with Nova Scotia Utility and Review Board ("UARB", "Board") staff and its consultants, and with Integrated Resource Plan ("IRP") process stakeholders, Nova Scotia Power Inc. (NSPI) has developed a long-term resource plan for the Board's consideration. The recommended plan integrates supply and demand-side options to provide a strategic framework for meeting environmental legislation and regulations, cost effectively and reliably.

The current context for integrated resource planning in Nova Scotia centers on the need to concurrently meet the growing requirements for electricity, while accomplishing significant near term and longer term reductions in emissions of key air pollutants. Actions are needed to meet established 2010 emissions regulations. Significant additional actions will also be needed to meet the expected, but as yet unspecified, longer term air-emissions goals. Today's rapidly evolving air-emissions regulatory policy requires a thoughtful, flexible approach.

The central theme of the recommended IRP is achieving reductions in NSPI air-emissions and meeting forecast increases in NSPI customer load. It appears this can be accomplished most cost-effectively through investment in demand-side management ("DSM") programs and renewable generation as well as through upgrades to NSPI's existing generation fleet.

To address specific issues raised during the IRP process, the analysis concludes the following:

- Based on experience in other jurisdictions and the limited DSM currently in place in Nova Scotia, an increase in spending in this area appears economically sound. The IRP analysis suggests positive benefits accrue at levels of spending up to five percent of total revenue.

- Renewable generation appears to be cost-effective compared to certain new fossil-based capacity. The technical and economic viability of achieving large amounts of intermittent resource across Nova Scotia requires further work in order to ultimately determine the amounts to pursue in Nova Scotia.

- Generation from existing NSPI base load fossil-fuel plants remains low cost compared to alternatives, even with added investments needed for emissions control. Continued operation of the fossil fuel fleet at high capacity factors appears economic. Incremental investment to increase the capacity and environmental performance of these units is cost-effective.

- The addition of a scrubber to the Lingan plant by 2020 appears economic. In the interim, emissions can be managed cost-effectively through utilization of lower-sulphur fuels. Emerging Federal Government sulphur dioxide emissions regulations, as previewed in the April 26th "Regulatory Framework for Air Emissions" could change this outcome. This development will continue to be monitored.

- NSPI likely has a two year window (2010 timeframe) before a decision needs to be made with respect to the need for a large-scale generation capacity addition.

- The implementation of "hard carbon caps" with limited availability of offsets significantly alters the IRP analysis in the post 2020-period. If aggressive changes in this regard are introduced, the IRP resource plan for later years will likely need to be revised. The early years' recommended resource plan would remain robust.

The IRP process identified three key areas where additional information, not available today, is required:

- How fast can DSM effectively and economically ramp up in Nova Scotia?

- How much intermittent capacity can be placed reliably and economically on the electrical system in Nova Scotia?

- What will be the requirements arising from pending emissions regulation being contemplated or put forth by the Governments of Canada and Nova Scotia?

There is much to be done by 2010. An Action Plan has been developed which is designed to: assess the opportunity for DSM and renewables in our Province; optimize existing generation assets; and monitor ongoing developments with respect to emissions regulation and emerging technologies. The Action Plan contains the following components:

- NSPI should undertake to design a comprehensive DSM program, considering earlier work and the IRP. The program will, in the initial years, need to reflect the status of DSM development in Nova Scotia. A primary initial objective will be to assess the longer term level of DSM that is sustainable both economically and in terms of stakeholder acceptance. This can be accurately assessed through targeted DSM program activation coupled with appropriate measurement and verification.

- NSPI will continue to support work to complete a Wind Integration Study. This work will inform the potential of large-scale intermittent generation in Nova Scotia.

- NSPI will apply to the UARB for the approval of capital investments to optimize the capacity and environmental performance of existing generation assets.

- NSPI will continue to actively monitor technology developments both with respect to low impact generation technologies and environmental retrofit technologies.

- NSPI will continue to explore opportunities to obtain additional clean power sources from within and outside the province.

- NSPI will continue to participate in the development of the Federal Regulatory Framework for Air Emissions as well as provincial developments to the benefit of Nova Scotia.

- NSPI will update the IRP as more specific information on DSM and renewables is available. A report to the UARB on the status of items included in the Action Plan will be filed in approximately two years.

The IRP process has achieved its objective. The recommended reference plan is robust and provides a clear direction for addressing electric energy and environmental needs in the coming years.

The IRP process has served to highlight the complexity and dynamic nature of utility planning today. The resultant Action Plan sets forth a direction which will enable NSPI and customers to seize current opportunities and manage effectively through an uncertain future.

1.0 INTRODUCTION

The IRP Terms of Reference (Appendix 1) as approved by the Nova Scotia Utility and Review Board contains the following objective:

> "To develop a resource plan which utilizes supply-side and demand-side options, to enable NSPI to meet future emissions and other requirements in a cost-effective and reliable manner."[1]

NSPI, Board staff and the Board's consultants have collaborated to develop the resource plan referenced in the IRP objective. This process, and the analysis and recommendations flowing from it, are the subject of this report.

To provide a complete record of the IRP development this report is presented in three volumes. Volume 1 provides a description of the IRP process, analysis results and recommendations, with a focus on presenting the recommended action plan. Volume 2 is a compilation of material issued to Intervenors throughout this process. Volume 3 provides copies of Intervenor comment on the IRP results and final report.

The IRP development is a strategic exercise. The IRP provides important strategic direction, as opposed to proscriptive solutions. Tactics presented in the Action Plan, including increased investment in Demand-Side Management and investment in utility plant, require formal application to the Utility and Review Board by NSPI. These filings will require UARB approval to fund the initiatives as part of customer rates.

[1] IRP Terms of Reference, approved by UARB on July 24, 2006.

2.0 NSPI RESOURCE PLANNING CONTEXT

NSPI Overview

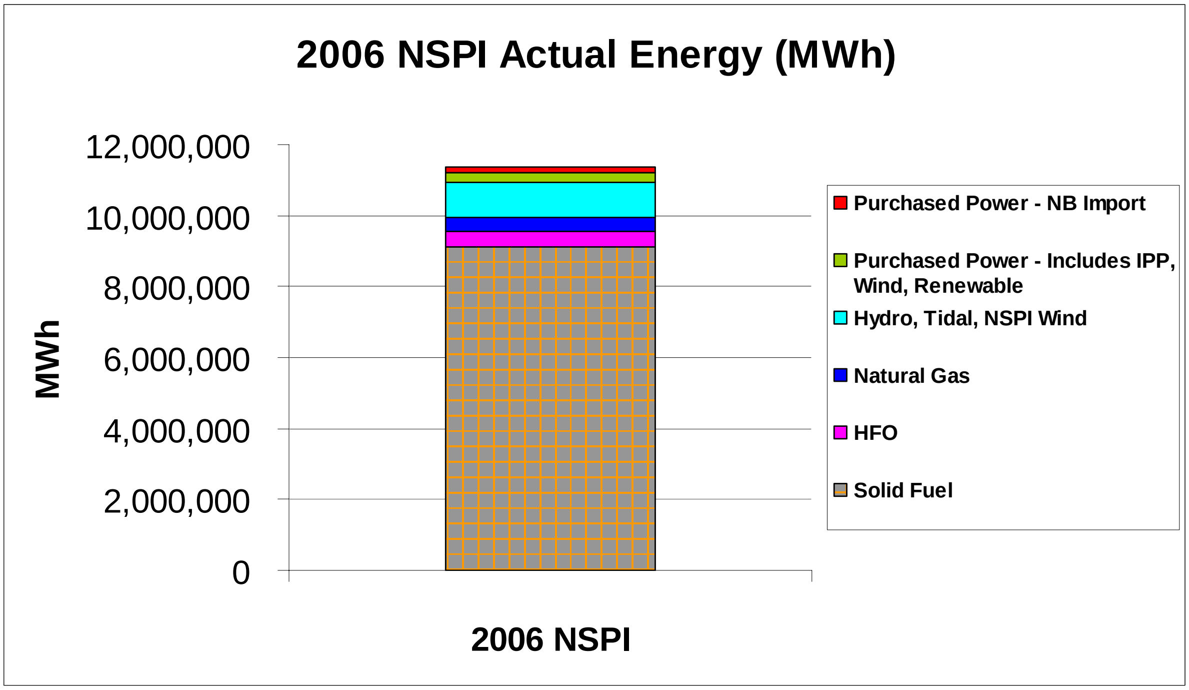
NSPI is a vertically integrated electric utility, regulated by the Nova Scotia Utility and Review Board. The Company serves 470,000 residential, commercial, industrial and municipal customers across Nova Scotia. In 2006, peak load was 2,085 megawatts. Total energy produced was 11,352 gigawatt hours.[2]

A diagram of the Company's power system is provided in Appendix 2. The NSPI transmission system spans the Province and is interconnected with the New Brunswick power system across a 345 kilovolt inter-tie. The inter-tie can allow for sharing of reserves and economic exchange of energy. The maximum capacity of the inter-tie is 300 megawatts import, 350 megawatts export.

The table and chart below summarize the resource mix of NSPI's generation fleet. The Company's generation portfolio is primarily fossil fuel based, the majority of which is low-cost coal and petroleum coke.

As of IRP Basic Assumptions	
Generation Type	**Capacity (Firm MW)**
Hydro & Tidal	397
Natural Gas	98
LFO	222
HFO & Natural Gas	321
Coal & Petcoke	1252
SUB TOTAL NSPI Installed	**2290**
Contract IPP pre 2001	26
New Renewables post 2001 contracted firm capacity on peak (mostly wind)	18
SUB TOTAL Contracted Firm	**44**
TOTAL	**2334**

[2] For 2006 a major customer was off-line for a portion of the year.



Over the past decade all NSPI generation additions have been either natural gas fired or renewable. NSPI has reduced emissions of sulphur dioxide by 25 percent since 2005. It has also recently initiated a program to install Low NO_x Combustion Firing Systems on its solid fuel units. This technology can reduce NO_x emissions by 40 percent or more. The installation at Lingan 3 is complete. Lingan Units 2 and 4 installations are under construction, with applications to the UARB anticipated for Pt. Tupper, Trenton and Lingan. In addition, NSPI has filed applications with the UARB to install a baghouse and replace the generator for Trenton 5.

Air Emissions Legislation and Regulation

Fossil fuel plants emit sulphur dioxide, nitrogen oxides, mercury and carbon dioxide (a greenhouse gas). All are the subject of increasingly stringent legislation and regulations, both at the provincial and federal government levels.

NSPI reported the following emissions for 2005 and 2006[3]:

	2005	2006
Sulphur dioxide	103,772 tonnes	106,617 tonnes
Nitrogen oxides	32,305 tonnes	28,040 tonnes
Mercury	105 kilograms	162 kilograms
Carbon dioxide (equivalent)[4]	10,648,422 tonnes	9,745,204 tonnes

The Nova Scotia Air Quality Regulations[5] specify the following maximum emission levels for nitrogen oxides and sulphur dioxide:

- 2009 Nitrogen oxides 21,365 tonnes
- 2010 Sulphur dioxide 72,500 tonnes

The recently released Federal Government's Regulatory Framework for Air Emissions proposes the following additional reductions for the electricity sector from 2006 emission levels (specific limits for NSPI have not been developed and could be different than the sectoral averages listed below):

- 2012-2015 Sulphur dioxide 60% reduction
- 2012-2015 Nitrogen oxides 59% reduction
- 2012-2015 Mercury 48% reduction
- 2010 Greenhouse gases intensity 18% reduction (CO_2e)
- 2015 Greenhouse gases intensity 28% reduction (CO_2e)
- 2020 Greenhouse gases intensity 38% reduction (CO_2e)

In addition to the above, legislation has been enacted within Nova Scotia which requires NSPI to increase the proportion of total energy generated from renewable sources constructed after December 31, 2001 to 5 percent of sales by 2010 and 10 percent of sales

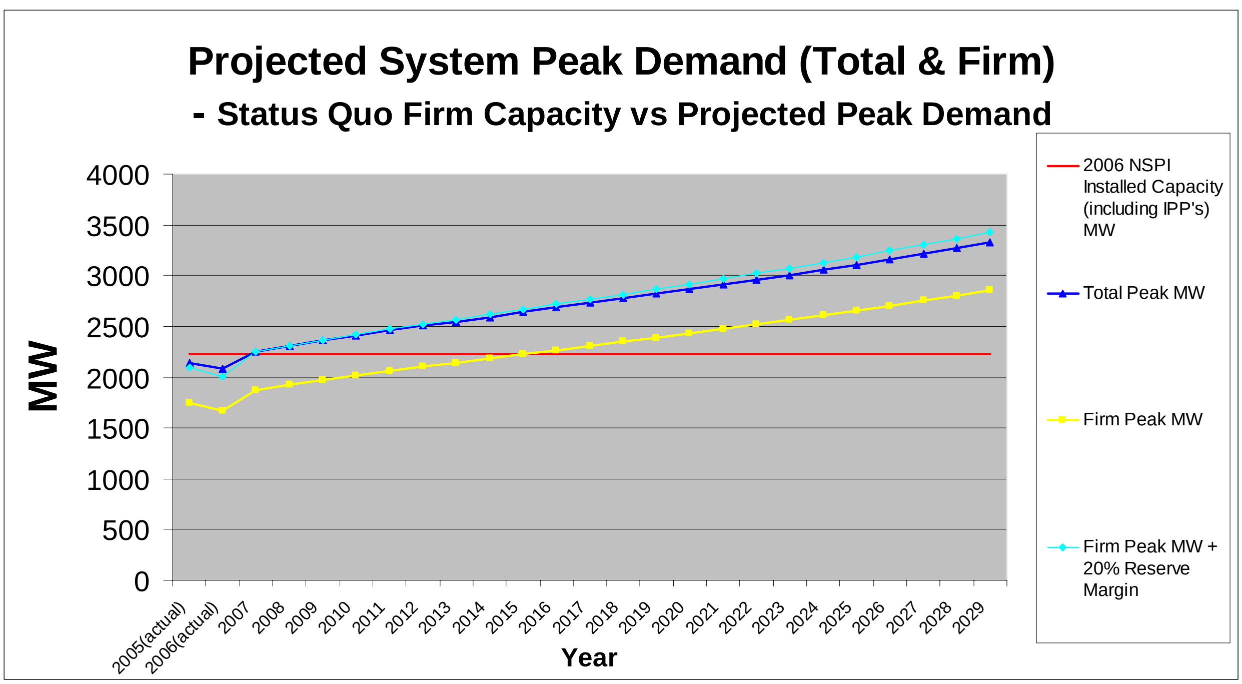
[3] 2005 emissions reduction regulations came into effect March 1, 2005. Emission levels for 2006 are not fully representative since a major customer was off-line for a significant portion of the year.
[4] Carbon dioxide (equivalent) includes CO2 and other greenhouse gases.
[5] Air Quality Regulations made under Section 112 of the Environment Act, effective March 1, 2005.

in 2013. Currently, renewable generation constructed after December 31, 2001 accounts for 2.8 percent of NSPI's net system peak and approximately 1.4 percent of energy.

Nova Scotia's Environmental Goals and Sustainable Prosperity Act provides additional guidance to potential future emissions regulations. The legislation established a goal for Nova Scotia to reduce greenhouse gas emissions to 10 percent below 1990 levels by the year 2020. It is unclear how this provincial goal might be translated into limits for NSPI, the transportation sector and other significant sources of greenhouse gases (such as home heating).

NSPI Load Growth and Planning

Nova Scotia's electric load has been growing to meet customer demand for electric energy. The chart below provides NSPI's forecast annual total and firm peak demands and compares this to the Company's current installed capacity (chart reflects pre-IRP DSM).



NSPI planning criteria requires a 20 percent reserve margin (i.e. NSPI must maintain installed capacity which exceeds forecast firm load by 20 percent). Firm load refers to NSPI customers other than those who are on interruptible rates. Customers on interruptible rates receive a rate credit for agreeing to have their service interrupted in the event of a supply shortfall.

As is evident from the chart, as demand grows, reserve margins decline. Reduced reserve margins constrain the operating flexibility of the utility system and ultimately can reduce reliability of service to our customers. As well, increasing load without additions to capacity increases the cost of serving customers as more expensive generation must be dispatched during peak periods.

A utility has three options to address these circumstances. It can take measures to reduce customer load or it can add generation capacity, or it can do both. The first is referred to as Demand-side Management; the second is a supply-side response. The resource planning exercise which seeks to optimize the two alternatives is referred to as Integrated Resource Planning (IRP).

3.0 ISSUES TO BE ADDRESSED

In addition to the development and presentation of a Preferred Resource Plan for NSPI, the IRP analysis was conducted to provide strategic insight into planning issues. These include:

1. The potential to invest in scrubber technology versus switching to lower sulphur fuels, in order to meet sulphur dioxide limits;
2. The amount of demand-side management spending which is economically sound and acceptable to stakeholders in Nova Scotia;
3. The amount of renewable generation, beyond current targets that may be economically and technically viable in Nova Scotia;
4. The timing of the next major generation addition;
5. Identification of near-term supply and environmental additions;
6. The use of carbon offsets/credits versus the requirement for physical reductions in carbon emissions.

4.0 IRP PROCESS OVERVIEW

NSPI/UARB Staff and Consultant Collaboration

NSPI's IRP has been developed as a collaborative effort between NSPI and UARB staff and its consultants. This collaboration has included all aspects of the IRP from designing key assumptions, to design of the analysis framework, selection and assessment of resource plans, analysis of model results, development of conclusions and ultimately the compilation of this report.

The IRP expertise brought to this project by Board staff, the Tellus Institute and Synapse Energy Economics, Inc. along with NSPI technical and analytical expertise and that of its consultants, including DSM consultant Summit Blue, and IRP consultant, La Capra Associates, has produced a comprehensive IRP for Nova Scotia. The key outcomes are a resource plan and an action plan which defines a direction to enable NSPI to meet customer needs and environmental obligations during a period of substantial uncertainty.

The views of the Board's consultants on this project are presented in Appendix 3.

Stakeholder Consultation

In accordance with the IRP Terms of Reference, stakeholders were consulted throughout the IRP process (see Appendix 4 for the list of formal intervenors). Specific consultations included:

1. Stakeholder input on the IRP Terms of Reference;
2. Three technical conferences covering IRP processes, IRP assumptions development and analysis results;
3. Development of a File Transfer Protocol (FTP) site for Intervenors which provided IRP Intervenor access to support documentation;
4. Replies to queries issued by Intervenors throughout the process concerning assumptions development, model design and analysis results;

5. Incorporation within the IRP analysis of requests for sensitivities and consideration of alternative modeling scenarios (e.g. the “Deep Green World”);
6. Stakeholder input on IRP conclusions;
7. Stakeholder input on IRP final report;
8. Informal contact between NSPI and individual stakeholders during the IRP process;
9. Direct engagement by stakeholders with UARB’s representatives.

The foundation for the IRP conclusions and the Action Plan have benefited from this significant stakeholder engagement. The plan has been enhanced by the participation of these stakeholders.

Analysis Process

NSPI’s IRP included the following key stages:

- Development of Basic Assumptions
- Analysis of Basic Assumptions to create resource plans
- Sensitivity analysis of resource plans
- Worlds analysis of resource plans
- Compilation of results

These stages are illustrated in the flowchart provided in Appendix 5.

The development of the Basic Assumptions took place over several months and involved collaboration with Board staff and consultants, as well as consultation with stakeholders. Each of the basic assumptions included a most likely or base assumption as well as a range of high and low values. The basic assumptions included:

- Load forecast – energy and peak load;

- Fuel forecasts for coal, petcoke, natural gas and heavy fuel oil;
- Future environmental emissions constraints for sulphur dioxide, nitrogen oxides, mercury, and carbon dioxide. (In addition to constraints on carbon, cost of carbon credits was also included);
- Future supply side and environmental control options which included a range of capital costs;
- Demand side management options which included alternative levels of spending to achieve different energy and demand savings;
- Financial assumptions including discount rate and foreign exchange.

Once the Basic Assumptions were agreed on these were used to create the resource plans. To fulfill the purpose of integrated planning it is important that alternative resource plans be significantly different. They must be reasonable plans that include a variety of options. At the same time each alternative needs to meet criteria including system reliability and environmental constraints. The Company, Board Staff and consultants agreed on the following themes for the base resource plans:

- Coal
- Natural Gas
- DSM
- Renewables

Several hundred candidate plans were created, by the modeling software, for each theme. Ultimately the resource plans that were selected for further study were those plans that met the criteria referenced above and were the least cost plans among each theme's set of candidate plans. This led to the following six base resource plans:

2% DSM[6] + Coal Plan (FGD 2020) – referred to as the Coal Plan

2% DSM + Coal Plan (FGD 2012) – referred to as the Coal Plan (FGD 2012)

2% DSM + Natural Gas Plan – referred to as the Gas Plan

[6] 2 percent and 5 percent DSM refer to annual DSM spending as a percentage of electric revenue.

2% DSM + Renewables beyond the RPS- referred to as the Renewables Plan

5% DSM – referred to as the DSM Plan

5% DSM + Renewables beyond the RPS- referred to as the Reference Plan.

Of these six plans, the 5 percent DSM Plan + Renewables beyond the RPS was identified as the least cost plan overall. This means the plan's net present value of costs[7] over the study period is lower than any of the other plans under the "most likely" (i.e. Base) assumptions. Said another way, over the course of time, this plan if completed based on IRP assumptions, would be the least expensive way to meet electric energy demand and environmental requirements.

If there were certainty that the World described in the Basic Assumptions ("most likely" scenario) would unfold as is, then we would not need to do further analysis. However, there is considerable uncertainty in all of the basic assumptions including how load will change, or how fuel prices will change or how environmental regulations may develop. This is the reason the basic assumptions include a range of values and not simply a single view of an assumption.

This uncertainty requires analysis of each of the six resource plans to ensure the best outcome. The best path is the one that not only meets the least cost measure and other criteria but also is robust enough to withstand changes to the basic assumptions.

This analysis was conducted in two ways: sensitivity analysis and world analysis.

The purpose of the sensitivity analysis was to understand which of the six resource plans was most price sensitive and to determine if an assumption change would cause one of the resource plans to become more attractive (on a net present value of cost basis). Specifically, for each resource plan one assumption was varied at a time. All others were held constant and the effect on the plan's total net present value documented. The sensitivities analyzed were:

[7] Costs include utility costs as well as customer costs for DSM.

1. Capital costs
2. Carbon dioxide (CO_2) credit costs
3. Coal costs
4. Gas prices
5. Discount rates
6. Heavy Fuel Oil (HFO) costs
7. DSM program costs

For each of the six plans, each of the high and low values of the above sensitivities was analyzed. With six plans, seven variables, and high and low cases, the total number of sensitivities amount to 84 model runs. By changing one of the above assumptions, the cost of the plan increased or decreased. Under this approach, resource plans are fixed (i.e. no addition or removal of resources). Sensitivity analysis shows how the specific plan reacts to a change in a price based assumption. For example, increasing the cost of coal had a greater price effect on the two coal plans than it did on any other plans.

The results of the sensitivity analysis are discussed later in the report.

The world analysis broadens the sensitivity analysis. In this analysis, assumptions change to reflect different futures such that the resource plan itself is altered. The world analysis assesses which plans are most flexible to changing conditions. In order to respond to these changing conditions, we allow the model[8] freedom, unlike above, to add or remove resources so that an optimal solution to the new world is created. For example, in examining a future where load is higher than in the most likely case the scenario cannot be solved without adding more resources to a plan. The model must have freedom to add resources to serve the new load otherwise it is not able to solve the problem. The results of the world analysis show how consistent certain resource additions are over a variety of worlds.

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[8] The model used in the IRP was New Energy Strategist version 4.06-Strategic Corporate Planning System.

The worlds that were examined were the following:

- High and low load scenarios;
- Highest (most stringent) and lowest (least stringent) emissions constraints;
- Several variations to the costs and benefits of DSM;
- Hard carbon caps with and without credit constraints.

The results of the world analysis are presented later in this report.

The combination of the analyses included in the above sensitivities and worlds means that almost all possible variations to the Base, Low and High assumptions have been analyzed. How plans react to these changes informs as to how robust the plans are.

Assumptions

NSPI developed initial assumptions in a variety of relevant areas. With input from stakeholders, NSPI and the Board consultants developed a collaborative consensus about the Basic Assumptions. Comment on key aspects of the modeling assumptions follows.

Demand-Side Management Modeling

Over the past decade NSPI has worked successfully with customers to establish demand response programs. The programs have been primarily rate design-driven and today include interruptible pricing for large industrials, time of day pricing for residential customers with systems to shift heating loads, and the Extra Large Industrial Two Part Real Time Pricing rate for NSPI's two largest customers. NSPI also provides customers educational materials regarding energy efficiency and conservation and supports a variety of small scale initiatives across Nova Scotia each year.

As part of its 2006 Rate Application, NSPI proposed to invest an incremental $5 million in conservation and energy efficiency programs. NSPI submitted a proposed 2006

Conservation and Energy Efficiency Plan. In its March 10, 2006 Decision, the UARB concluded that the plan would benefit from additional design work. The Board directed NSPI "to retain an outside consultant and to complete the Plan's design and development"[9].

On September 8, 2006, NSPI filed its Direct Evidence on DSM including its Revised DSM Plan (Proposed General DSM Programming) and Summit Blue's DSM report (Consultant's DSM Report). On September 28, 2006 the Board advised NSPI that it would reserve its decision on whether or not to hold a hearing with respect to NSPI's revised DSM Plan filing until the IRP process was completed.

For the purpose of modeling DSM within an IRP, DSM program cost and energy and capacity savings information was required, ideally across the various customer segments. NSPI relied on the work of consultants, Summit Blue Consulting, LLC for this information. In its DSM report Summit Blue recommended spending on DSM programs by NSPI equal to 2 percent of electric revenue. The consultant also provided a forecast of energy and demand savings at this level of spending. To test alternative DSM spending levels in the IRP the consultant extrapolated these energy and demand savings to spending levels of 1 percent and 5 percent of electric revenue, corresponding to lower/higher achievement of the economic DSM potential identified in its September 2006 DSM report.

The tables below present the annual DSM information as developed by Summit Blue at a 2 percent and 5 percent spending level. The third table below illustrates spending levels for 1 percent, 2 percent and 5 percent DSM through the planning period.

[9] Decision, Nova Scotia Utility and Review Board, March 10, 2006, page 306.

2 percent of Revenue Program Spend (costs in 2006 dollars)

TOTALS	22 Year Total	Year 1	Year 2	Year 3	Year 5	Year 10	Year 15	Year 20	Year 22
Demand Savings (MW)		6.5	10.4	17.5	26.4	34.2	36.4	41.0	43.4
Cumulative (MW)	**705.1**	6.5	16.9	34.4	84.0	248.4	424.8	619.5	705.1
Energy Savings (GWh)		44.5	71.2	106.8	142.4	166.8	169.8	183.9	192.6
Cumulative (GWh)	**3419.4**	44.5	115.6	222.4	489.3	1313.3	2151.6	3038.7	3419.4
Utility Costs ($Millions)	**589.1**	6.6	10.5	16.5	23.3	28.7	29.8	32.9	34.6

5 percent of Revenue Program Spend (costs in 2006 dollars)

TOTALS	22 Year Total	Year 1	Year 2	Year 3	Year 5	Year 10	Year 15	Year 20	Year 22
Demand Savings (MW)		11.4	18.2	30.6	46.2	57.9	56.2	57.0	60.0
Cumulative (MW)	**1113**	11.4	29.6	60.2	147.0	431.9	715.0	997.5	1113.0
Energy Savings (GWh)		77.8	124.5	186.8	249.2	282.1	258.2	245.8	243.4
Cumulative (GWh)	**5354.9**	77.8	202.4	389.2	872.0	2283.7	3617.1	4867.1	5354.9
Utility Costs ($Millions)	**1372.8**	16.4	26.3	41.3	58.3	70.1	68.4	70.1	71.5

Summary: DSM 1, 2, 5 percent Revenue Spend Program Projections (costs in 2006 dollars)[10]

DSM Spending as % of Annual Revenue		Residential	Commercial	Industrial
~ 2%	Utility Cost ($Millions)	290.0	118.4	180.7
	Customer Cost ($Millions)	205.1	234.4	431.8
	Total Resource Cost ($Millions)	495.1	352.7	612.6
	Demand Savings (MW)	226.4	170.3	308.5
	Energy Savings (GWh)	886.4	763.7	1769.3
~ 1%	Utility Cost ($Millions)	145.0	59.2	90.4
	Customer Cost ($Millions)	102.5	117.2	215.9
	Total Resource Cost ($Millions)	247.5	176.4	306.3
	Demand Savings (MW)	113.2	85.1	154.2
	Energy Savings (GWh)	443.2	381.8	884.7
~ 5%	Utility Cost ($Millions)	725.0	295.9	351.9
	Customer Cost ($Millions)	141.4	321.4	487.6
	Total Resource Cost ($Millions)	866.4	617.3	839.5
	Demand Savings (MW)	396.1	298.0	418.9
	Energy Savings (GWh)	1551.2	1336.4	2467.3

[10] Utility costs are those DSM costs recovered in electric customer rates. Customer costs are direct customer costs to implement DSM initiatives.

Modeling of Renewables

Provincial legislation requires NSPI, by 2010, to produce 5 percent of its energy from renewable resources constructed after December 31, 2001. NSPI forecasts this to equal approximately 690 Gigawatt-hours (GWh) in 2010. By 2013 when the RPS increases to 10 percent, post 2001 renewable generation will account for approximately 1,450 GWh.

The current state of renewable technology suggests that most of this energy is expected to be provided by wind generation. Wind generation depends on weather conditions. It is intermittent and cannot be dispatched. It is modeled accordingly.

For the purposes of the IRP it is assumed incremental renewable generation will come mostly from wind and will provide a "capacity equivalent" of 32 percent of generator nameplate (manufacturer's suggested maximum capacity). The resource is modeled at a contract price of $.085/kWh for the 2010 RPS, $.08/kWh for 2013. Beyond the amount required to comply with the RPS, additional renewable generation is driven by economics at a price of $.092/kWh[11]. Renewable generation beyond the RPS is added in the Renewable Plan, the Reference Plan and in some of the Worlds analysis.

Environmental Assumptions

Annual limits for sulphur dioxide and nitrogen oxide have been established and modeled as fixed constraints. Modeling of carbon dioxide is more complex and involves significantly more uncertainty.

For carbon dioxide, the fixed constraints have been calculated according to "intensity-based targets". It is expected the Federal Government, as an alternative to specific CO_2 limits, will require that over time generation from older plants meet tighter emissions levels. Based on this approach the IRP forecasts carbon constraints which will be in place over the planning period for NSPI's established generators.

[11] This consists of a renewable energy charge and backup cost (given the variable nature of the wind resource). The actual cost of backup will be informed, in part, through the Wind Integration Study.

In addition, it is expected that future compliance with CO_2 caps may be attained, at least in part, through an emissions trading system or technology funds. Such a trading system is assumed to be the source of the allowances that are applied in the model with a range of carbon credit costs assumed. NSPI also modeled the implementation of carbon dioxide caps (i.e. physical limits).

The influence of carbon on the IRP analysis and the acknowledged uncertainty of this assumption required broad IRP modeling in this area. Additional cases in which the use of carbon credits is constrained are explored in the Worlds analysis.

5.0 RESULTS AND IRP CONCLUSIONS

The table below summarizes the Resource Plans developed in the IRP and identifies the capacity[12] associated with each demand or supply option included in each.

All six Resource Plans contain investment in demand-side management, and renewable generation sufficient to meet the RPS requirements. All plans meet emissions constraints, reserve margin and other regulatory requirements.

In addition, all plans include investment in existing NSPI plants to increase the capacity of these units (i.e. uprates, waste heat utilization and Hydro improvements). Five of the plans include Tufts Cove Waste Heat Recovery project which represents the capacity added by using the waste heat energy from the two existing Tufts Cove single-cycle gas turbines (Tufts Cove 6). The inclusion of these resources in the various base plans confirms they are economic across a broad range of alternative scenarios.

2007 IRP RESOURCE PLANS: SCHEDULE OF FIRM SUPPLY or DSM MW's

		Reference Plan	DSM Plan	Renewables Plan	Coal Plan	Coal Plan (FGD in 2012)	Gas Plan
New Resources 2008-2014							
	DSM	256	256	146	146	146	146
	TUC 6	50	50	0	50	50	50
	LM 6000						
	Uprates	20	20	20	20	20	20
	Hydro	4.3	4.3	4.3	4.3	4.3	4.3
	RPS	166	166	166	166	166	166
	Additional Wind	16		16			
	SUBTOTAL	512.3	496.3	352.3	386.3	386.3	386.3
New Resources 2015-2029							
	Additional Wind	144		144			
	Pulverized Coal*				400	400	
	LM 6000						
	Combined Cycle			280			560
	DSM	857	857	559	559	559	559
	SUBTOTAL	1001	857	983	959	959	1119
	TOTAL FIRM SUPPLY & DEMAND MW's OVER PLANNING PERIOD	1513.3	1353.3	1335.3	1345.3	1345.3	1505.3

[12] For DSM capacity refers to reduction in demand.

The net present worth of the cost of each plan is provided in the following table. The accumulation of costs over the planning period is shown in the chart which follows. The table confirms that under the Base Assumptions, the 5 percent DSM plus Renewables Beyond the RPS Plan is the least-cost plan (the Reference Plan).

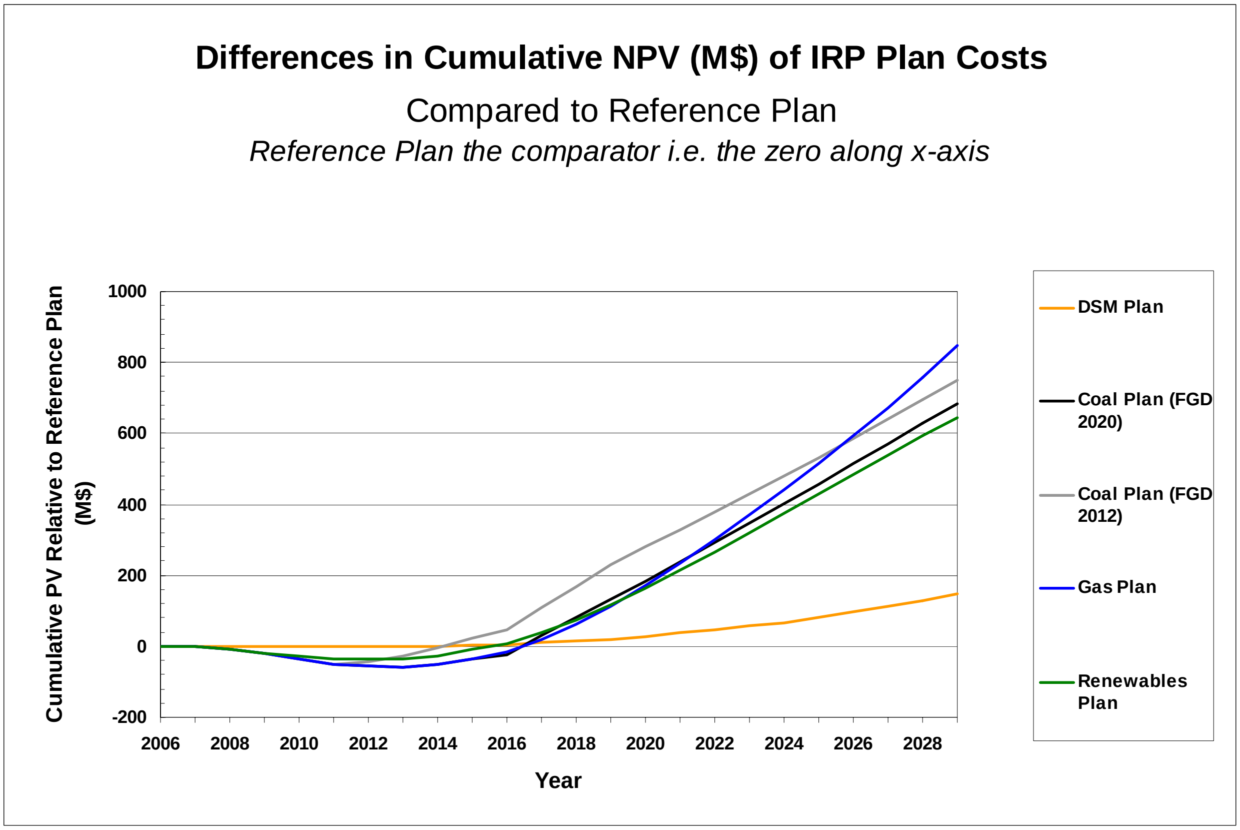
Resource Plan Cumulative Present Worths (millions of dollars).

Plan	Study Period[13] NPV	Increase from Reference Case
Reference Plan	**$14,479.9**	
DSM Plan	$14,747.7	$267.8
Coal Plan (FGD 2020)	$15,503.7	$1,023.8
Coal Plan (FGD 2012)	$15,551.4	$1,071.5
Gas Plan	$15,925.4	$1,445.5
Renewables Plan	$15,435.2	$955.3

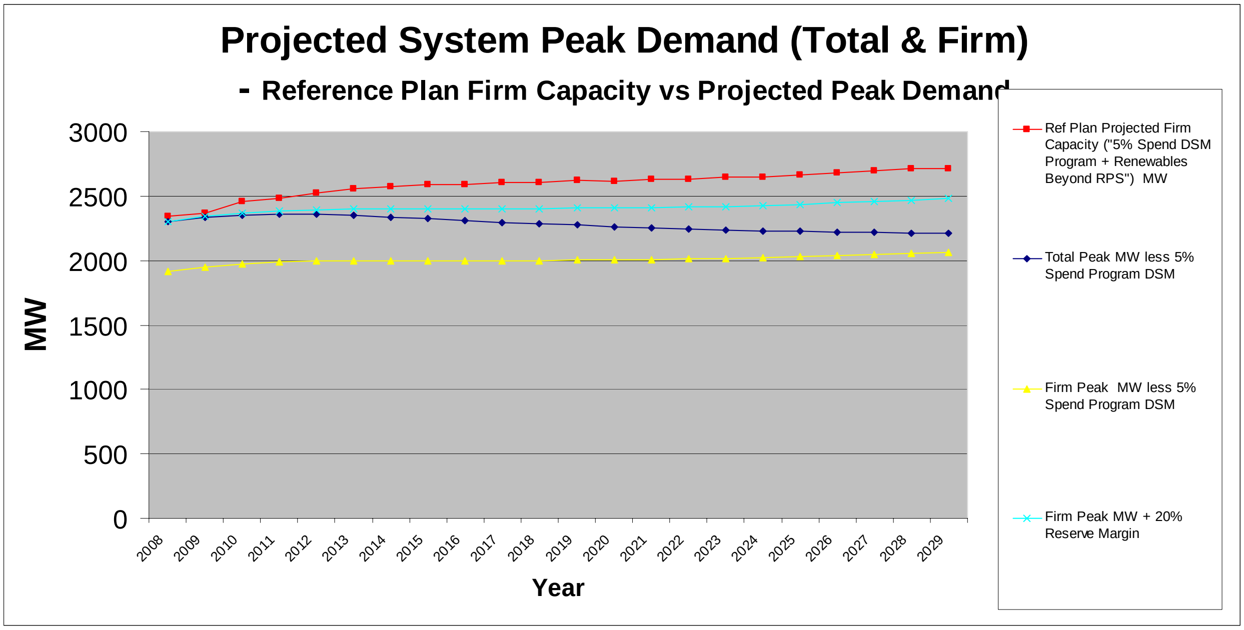
Most striking about this information is the difference between the two lowest cost plans and the fossil based plans. The key components of the Reference Plan and the DSM Plan are the same; spending on DSM programs at 5 percent of electric revenue and high penetration of renewables.

The profile presented below shows the present values of the plans over the planning period compared to the Reference Plan, which is represented by the X axis. While the fossil-based plans are forecast to be lower cost by a small margin in the early years, this is overcome by the plans with 5 percent of annual revenue spending on DSM assuming the forecast savings available from these plans emerge.

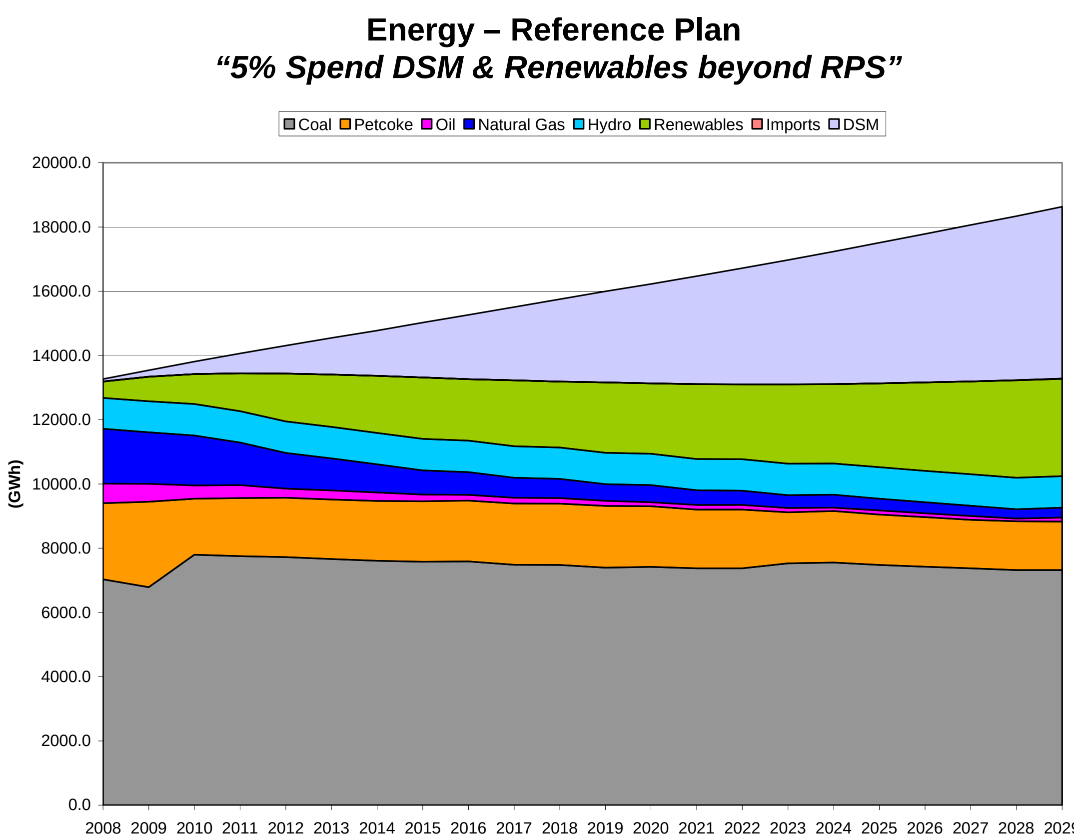
[13] Study Period represents cost over the Planning Period plus end-effects. End-effects calculations are used to account for the cost of replacing the resources and for differences in operating costs beyond the Planning Period. The Planning Period is the range of years (in the IRP 2007-2029) over which all feasible combinations of resources are analyzed.



Consistent with the modeling assumptions, reserve margins are maintained throughout the planning period. In the Reference Plan, this is achieved through demand-side management and the addition of renewable generation. The chart below summarizes forecast installed capacity and firm and total demand over the planning period.



The resource portfolio for the lowest cost Reference Plan under the Base Assumptions is presented below.



The above graphic depicts the following:

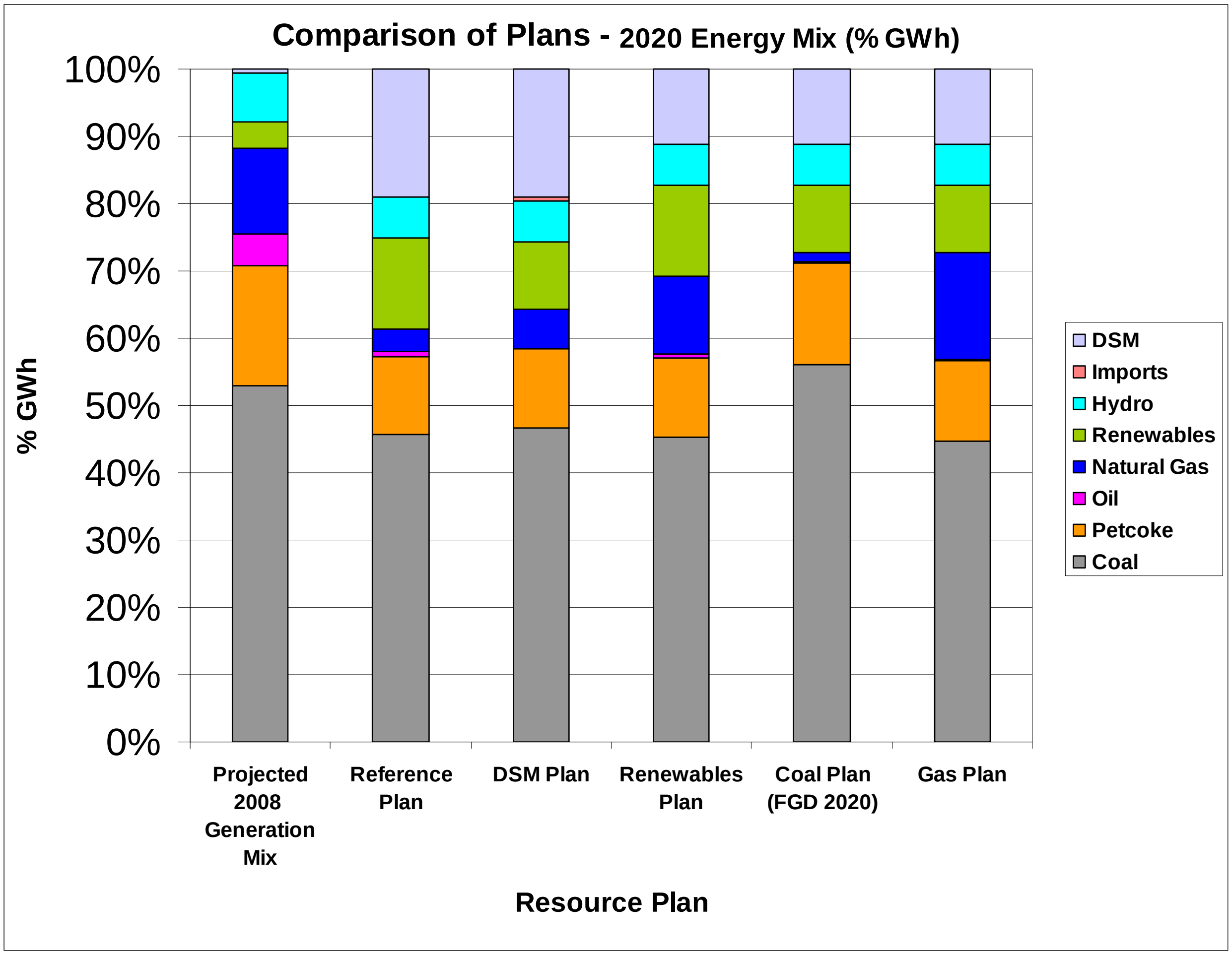
- Under this plan, DSM energy and demand savings are forecast to offset load growth over the planning period;
- Generation from oil and natural gas is expected to decline, replaced by renewable generation;
- Coal and petroleum coke (petcoke) generation remains essentially unchanged over the planning period.

This fuel mix outcome is related to the relative cost relationship among fossil fuels, which is forecast to be largely unchanged over the planning period. Petcoke and coal are expected to remain low-cost compared to oil and natural gas even when allowance for carbon cost is included. Therefore generation from the existing solid fuel facilities remains economic, so long as the emissions constraints can be met through fuel switching, purchase of carbon offsets and other means at these plants, together with the emissions displacement associated with the addition of renewable generation and DSM.

With respect to new generation, half the contribution from renewables has been defined through Provincial legislation. In addition to meeting the requirement of the RPS, this renewable energy acts to reduce emissions.

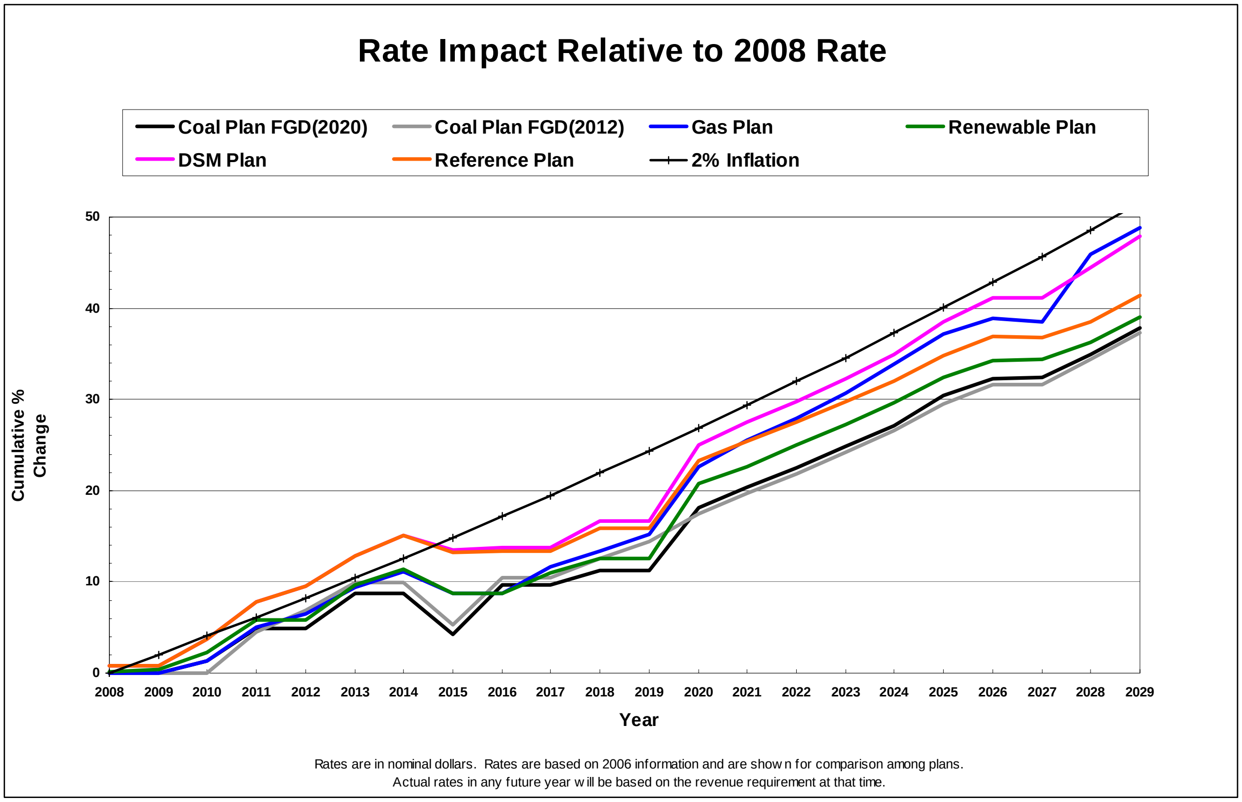
The addition of renewable energy, investment in DSM and investment in environmental controls allow NSPI to meet its emissions constraints under this plan, while continuing to generate from low cost fossil units. Under the Base Assumptions, this is the low cost plan.

For comparison purposes, the energy mixes of the Resource Plans under the Base Assumptions are provided below (2020 used as comparison year). The results do not vary substantially across the plans. Existing coal and pet-coke fired generating stations continue to provide base load generation. Renewables and DSM are also established as major components, driven by emissions constraints and project economics compared to competing higher cost gas-fired generation and new solid fuel generation.

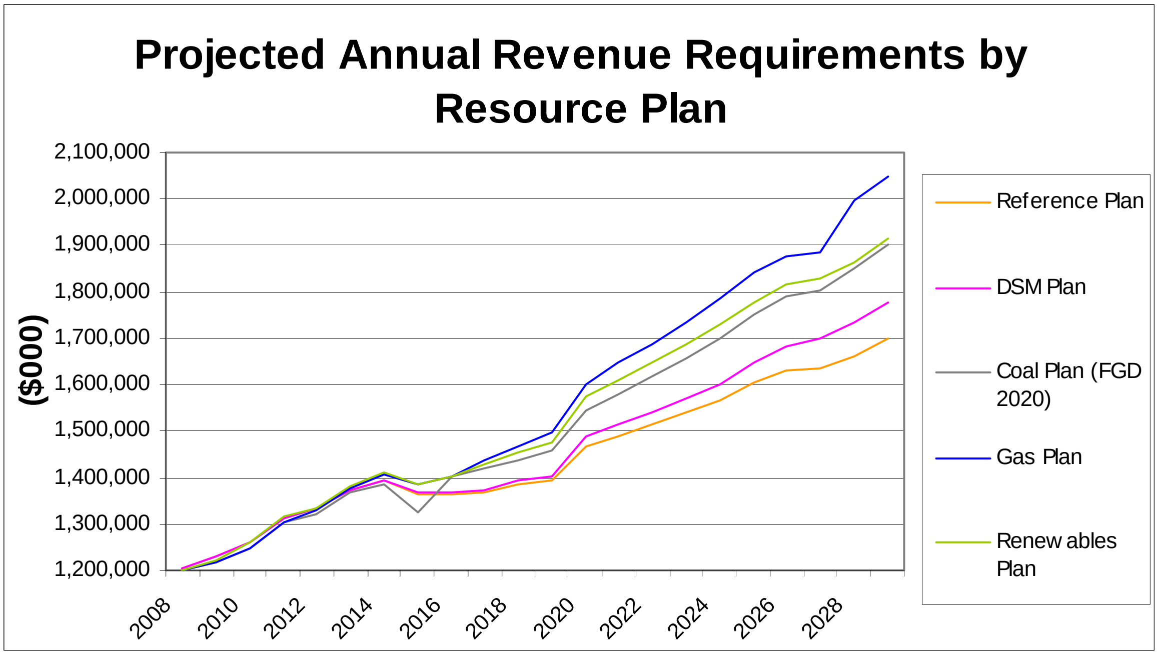


The relative effect of the resource plans on customer electric rates over the planning period is estimated in the chart below. The plans track closely over the planning period. The coal-based plans are shown to provide the lowest cost per kilowatt hour. This is to be expected because the DSM-based plans, while lower in total resource cost, result in a reduction in customer sales. The result is an increase on a per unit basis (i.e. under 5 percent spend DSM plans, rates are forecast to increase, but due to reduced energy usage, total customer cost will be less than for alternative plans).

The rate projections assume power purchases and DSM are expensed. Plant additions are capitalized. The chart shows that over the planning period, rates track inflation. It is important to note that the rates forecast are based on the 2006 Basic Assumptions over the planning period. Actual customer rates in future years are dependent on the revenue requirement at that time. This chart compares alternative resource plans under consistent assumptions. It is not intended to predict future electricity rates.



The chart above depicts a percent rate increase comparison among the various resource plans. The chart below compares the annual revenue requirement in thousands of dollars for each resource plan. The annual revenue requirement chart shows that the plans track closely for the first six years and separate post 2014 once the plans' resource additions diverge**.**



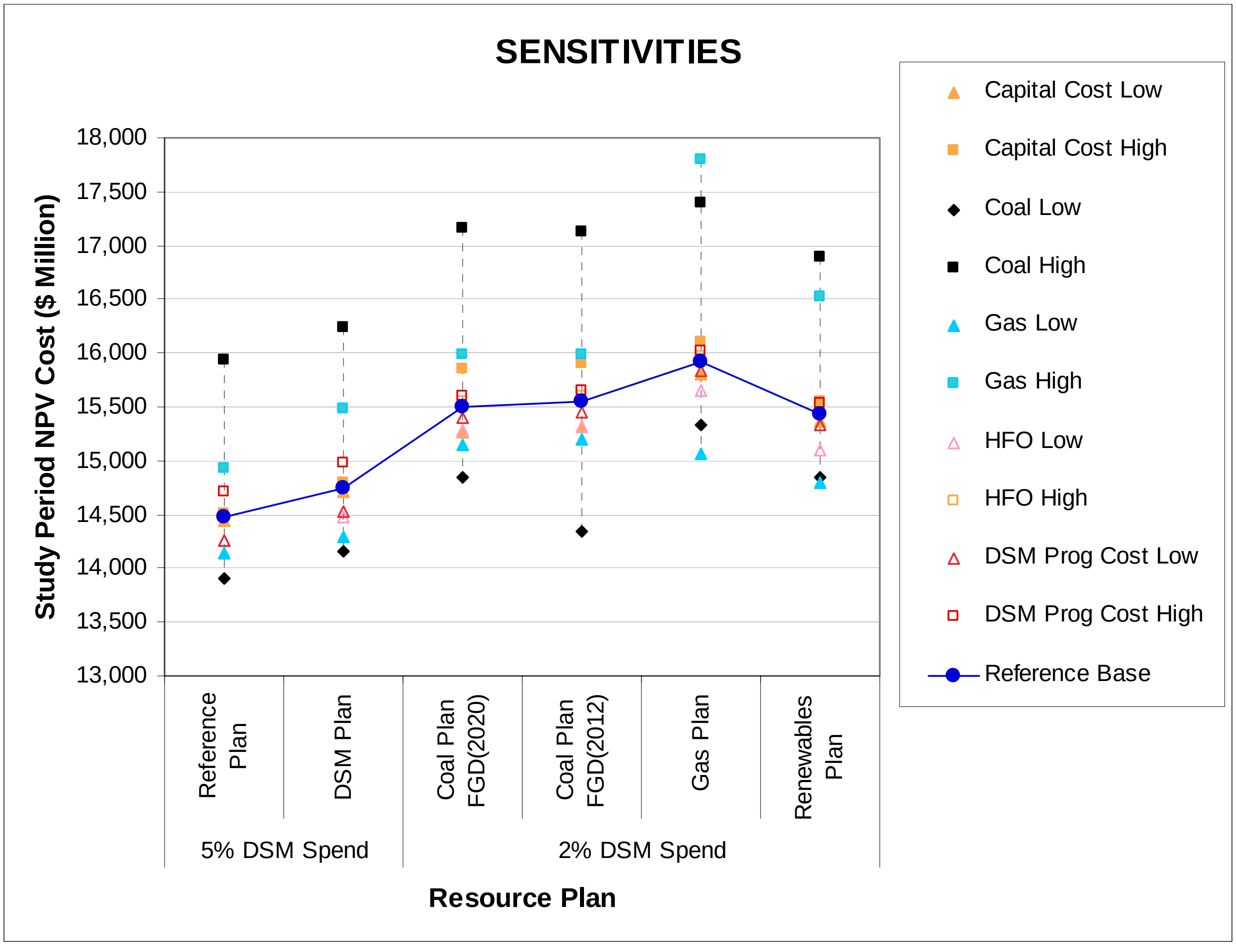
Variance in the trends between the Rates and Revenue Requirement charts is due to reduced customer load resulting from DSM, i.e. the difference between per unit and absolute revenue requirement.

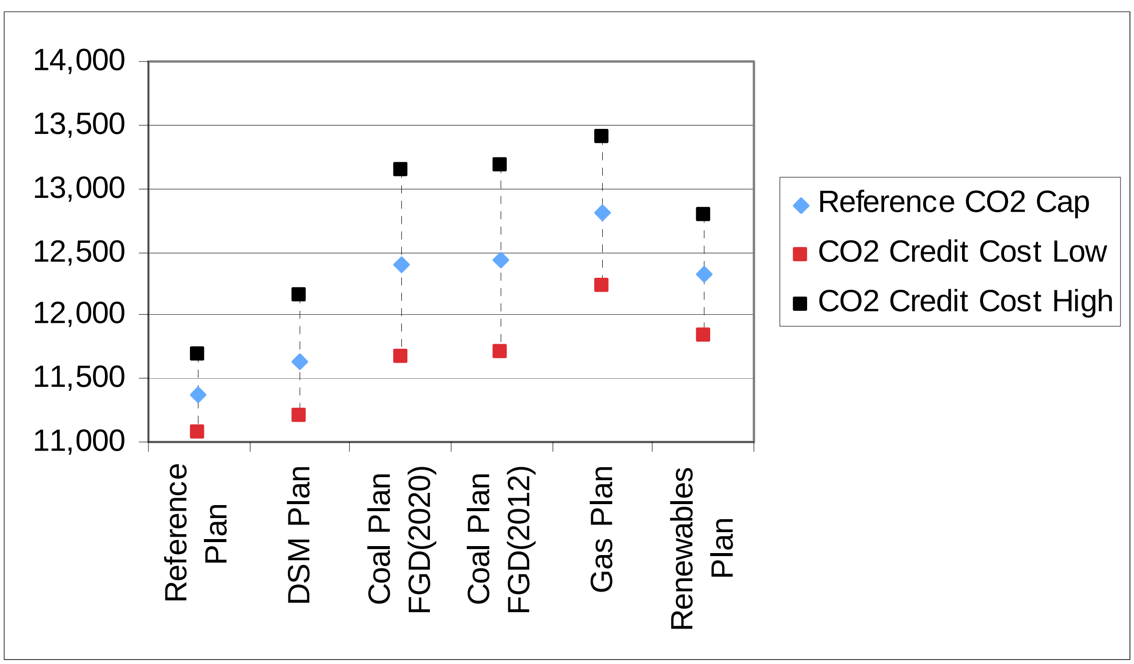
Sensitivity Analysis

The base assumptions analysis shows the Reference Plan is the most economic. In order to assess the robustness of the plan, it and the other resource plans were assessed against changes to key assumptions.

The results across sensitivities for the six resource plans are presented in the charts below.[14] Due to the magnitude of the cost, the results are presented in two charts. In the non carbon dioxide sensitivities, plans all include the cost of purchasing credits from zero emissions to the carbon dioxide level produced in each plan. The carbon dioxide credit cost sensitivity is presented in a separate graph as only the cost of purchasing required credits (i.e. to buy down to a cap as opposed to zero) is included. This separate presentation does not affect the ranking of the plans.

[14] Discount rate sensitivity was not included in the chart as results were similar across all plans.


SENSITIVITIES
Study Period NPV Cost ($ Million)
18,000
17,500
17,000
16,500
16,000
15,500
15,000
14,500
14,000
13,500
13,000
Reference Plan
DSM Plan
Coal Plan FGD(2020)
Coal Plan FGD(2012)
Gas Plan
Renewables Plan
5% DSM Spend
2% DSM Spend
Resource Plan
Capital Cost Low
Capital Cost High
Coal Low
Coal High
Gas Low
Gas High
HFO Low
HFO High
DSM Prog Cost Low
DSM Prog Cost High
Reference Base


14,000
13,500
13,000
12,500
12,000
11,500
11,000
Reference Plan
DSM Plan
Coal Plan FGD(2020)
Coal Plan FGD(2012)
Gas Plan
Renewables Plan
Reference CO2 Cap
CO2 Credit Cost Low
CO2 Credit Cost High

The Sensitivity Analysis provides the following insights:

In all cases the Reference Plan and the DSM Plan are ranked as the lowest and second lowest cost plans respectively:

- The largest changes in resource plan present worth of costs are driven by changes to fuel prices and CO_2 credit prices;

- The overall ranking of plans by net present value is unaffected by most sensitivities. Exceptions included the following:

  - Under the low capital cost sensitivity, low CO_2 credit prices or low coal price assumptions, the Coal Plans are lower cost than the Renewables Plan;

  - Under low gas price assumptions the Gas Plan is lower cost than the Coal plans;

  - Under high gas price assumptions the Coal Plans are lower cost than the Renewables Plan.

The above suggests the plans that include 5 percent (of revenue) DSM spending are robust and the least cost overall. Among the fossil fuel-based plans, cost is largely a function of fuel prices.

With respect to the preferred plan, the Sensitivity Analysis reinforces the conclusions presented under the Base Assumptions.

Worlds Analysis

Through the development of alternative modeling "worlds", the IRP was able to examine the effect of differing assumptions on the various resource plans. Where the Sensitivity Analysis identified the cost effect of changing assumptions against a fixed plan, the Worlds analysis sought to identify where changing assumptions would change the selected supply/demand configurations and the cost of these configurations.

Worlds were created to examine the following:

1. A high load future
2. A low load future
3. Differing DSM program profiles
4. High and low environmental constraints
5. The implementation of "hard-cap carbon" worlds.

1. A High Load Future

For this world the plan with 5 percent DSM plus Renewables beyond the RPS was applied. The additional load requirement is met through the addition of two gas turbines in 2008 and 2009; two 150 MW gas units in 2013 and 2014 (one converted gas turbine) and two 400 MW coal units in 2016 and 2020.

The analysis illustrates the substantial change in cost that can arise if load growth should escalate substantially. It also serves to provide insight to the rapid advancement of capacity requirements which can arise should actual load growth exceed the forecast by a significant margin over an extended period. Based on the lead times necessary to construct new large-scale capacity, this needs to be carefully monitored.

2. A low load future

For this world, load was considerably lower than the base assumptions resulting from the departure of a large industrial customer from the NS system and from decreased load in the residential and commercial sectors. Because of the magnitude of decreased load, the model was offered 0, 1 or 2 percent spending on DSM. This resulted in the 2 percent spend on DSM being the economic solution. As the reserve margin in this scenario was well above the normal range, additional DSM was not considered as it would have increased reserve margins to 100 percent.

With 2 percent DSM and the RPS included, the low load world requires little additional generation. The analysis indicates that a reduction in costs can result if a significant amount of load does not materialize.

3. Differing DSM program profiles (timing of program start and magnitude of benefits)

To test the effect of delays in initiating the DSM program or the achievement of lower than forecast DSM benefits, world runs were created which assumed a two year lag in the program (lag in costs and benefits); 20 percent lower than expected energy and capacity savings (costs are the same and benefits are 20 percent less); and the exclusion of the pulp and paper sector from the DSM program (exclusion of costs and benefits).

In all cases, despite the reduced DSM benefits, high investment in DSM is confirmed as the key element of the low cost strategy. The gap between the high DSM plans and the competing plans continues to be wide. The substantial gap between the cost of the Worlds plans and the plans as developed under base assumptions reinforces the potential value of DSM and the additional cost which may be incurred should these programs be delayed. The additional cost arises from having to place additional supply side resources on the system to meet load requirements.

4. High and Low Environmental Constraints

Worlds analysis, both more stringent ("high") and less stringent ("low") than the base environmental assumptions, were prepared to determine the effect on investment in environmental additions.

While the costs of the plans differ substantially over the planning period, the investment in available environmental technologies in the period prior to 2019 does not. The addition of Low NO_x technologies at Lingan, Pt. Tupper and Trenton and the addition of the baghouse at Trenton 5 are economically attractive.

The addition of the FGD at Lingan by 2020 and the addition of Low NO_x technology at Trenton 6 is less clear. These options are not selected by all resource plans.

5. The implementation of "hard-cap carbon" worlds requiring physical carbon reductions in 2020 (vs. the opportunity to purchase offsetting carbon credits).

All of the plans and analyses discussed above rely to varying degrees upon the purchase of "credits" to meet carbon dioxide emission reduction goals.

In order to explore the sensitivity of the IRP to the possibility that physical carbon dioxide emissions reductions might be required, the Worlds analysis was utilized to assess the effect of firm carbon caps at different levels, with carbon credit availability constrained in 2020.

The CO_2 emissions reduction levels were analyzed at three levels with credits constrained from 2020 and beyond for each:

Case	Approximate CO_2 Emissions (Million tonnes)				
	2010	2015	2020	2025	2030
Base	10.0	9.5	9.1	7.7	6.4
Kyoto	6.4	5.6	4.8	4.5	4.1
Deep Green World	6.44	4.93	3.43	2.95	2.53

In order to solve for some of these scenarios, it was necessary to add new options to the model (e.g. carbon sequestration, offshore wind) beyond those contemplated in the Basic Assumptions. These are summarized in the table below. Costing and availability of these options entail more uncertainty than is inherent in the IRP Basic Assumptions in general.

Option	Comment	Cost
Purchase Power Agreement – from non-emitting source	300 MW firm	Energy $108/MWh (esc 2% annually). Capital = $300M for tie-line upgrade.
Carbon Sequestration – New	400MW	Capital = $1,378.8M. Incremental O&M: $13.78M (esc 2% annually).
Carbon Sequestration – Retro Fit	300MW* - Lingan (2 units)	Capital cost = $333M (to capture & sequester CO2). Incremental O&M = $ 9.2M (esc 2% annually).
Additional Gas	280CC	Consistent with IRP Assumptions
Offshore Wind	100 MW blocks, 35 MW firm	Energy $150/MWh (includes wind back-up @ $12/MWh, no escalation)
Biomass	20MW Unit, 85% CF	Capital cost = $48M. Annual O&M $2.7M (esc 2% annually). Fuel $4.80/mmbtu (esc 2%).

* A station service power penalty of 30 percent is reflected in the modeling of this option.

It is important to note that some of these new low carbon dioxide emitting options are beyond the control of NSPI or the Province (e.g. the zero emission power purchase) or are not commercially available today (e.g. carbon capture and sequestration from pulverized or Integrated Gasification Combined Cycle (IGCC) coal generation). Although these options are not available today, they were modeled in order to allow the model to solve for the carbon hard cap/credit constrained Worlds. Therefore the results of these Worlds over the longer-term must be critically considered; the feasibility, performance, and costs of these options require further study. In the short-term, all of the carbon-constrained worlds rely on investment in DSM to meet load**.**

The results of the Worlds analysis are summarized in the attached table. The table presents the cost of each of the plans under the various Worlds. The left-most column in the table identifies the World analyzed. The two middle columns identify the plans assessed and the characteristics of the plans. The right-most column identifies the change in cost under the worlds compared to the Reference Plan previously identified as the least cost plan under the Base Assumptions. In order to manage the volume of analysis, judgment was applied in order to limit this analysis to the most viable plans (i.e. not all plans are presented for all Worlds).

Resource Plan	Plan Type	Comments	Study Period NPV	Delta to Reference Case
Base Plans	**Reference Plan**		**$14,479.9**	
	DSM Plan		$14,747.7	$267.8
	Coal Plan (FDG 2020)		$15,503.7	$1,023.8
	Coal Plan (FGD 2012)		$15,551.4	$1,071.5
	Gas Plan		$15,925.4	$1,445.5
	Renewables Plan		$15,435.2	$955.3
Low Load	2%Spend DSM		$9,621.1	-$4,858.8
High Load	Reference Plan	RPS advanced 1 year + additional generation	$19,029.0	$4,549.1
Low Air Emissions	DSM Plan	Low air emission limits and CO2 credit costs	$11,921.7	-$2,558.2
High Air Emissions	Coal Plan	No FGD	$17,694.8	$3,214.9
(High air emission limits	Reference Plan		$17,336.5	$2,856.6
and CO2 credit costs)	Gas Plan		$17,791.4	$3,311.5
	Gas Plan	Option to retire exisitng units	$17,901.8	$3,421.9
Base CO2 Limits	Reference Plan	Existing Options	$14,981.8	$501.9
(CO2 Credit Constrained	Reference Plan	Existing Options & New CO2 Mitigation Options	$14,645.6	$165.7
starting in 2020)	DSM Plan	Existing Options & New CO2 Mitigation Options	$14,857.6	$377.7
Kyoto Case CO2 Limits	Reference Plan	Existing Options & New CO2 Mitigation Options	$14,714.0	$234.1
(CO2 Credit Constrained starting in 2020)	DSM Plan	Existing Options & New CO2 Mitigation Options	$15,002.0	$522.1
Deep Green Case CO2 Limits	Reference Plan	Existing Options & New CO2 Mitigation Options	$14,976.1	$496.2
(CO2 Credit Constrained starting in 2020)	DSM Plan	Existing Options & New CO2 Mitigation Options	$15,298.2	$818.3
DSM Delayed 2 Years	DSM Plan		$15,129.8	$649.9
	Coal Plan (FGD 2020)		$15,771.5	$1,291.6
	Renewables Plan	TUC 6	$15,719.3	$1,239.4
DSM -20% Benefits	DSM Plan		$15,418.6	$938.7
	Coal Plan (FGD 2020)		$15,956.6	$1,476.7
	Renewables Plan	TUC 6	$15,907.5	$1,427.6
Remove P& P Portion of DSM	DSM Plan		$15,138.1	$658.2
	Coal Plan (FGD 2020)		$15,765.0	$1,285.1
	Renewables Plan	TUC 6	$15,749.3	$1,269.4

High Air Emissions Worlds include high CO_2 credit costs. Low Air Emissions World includes low CO_2 credit costs. All other worlds include base CO_2 credit costs. This difference contributes to the difference in the NPV values. Each solution to reduce CO_2 to more stringent levels (Kyoto and Deep Green Worlds) requires additional investigation before costs, timing and feasibility could be confirmed.

The analysis confirms that for all Worlds:

1. The high DSM investment continues to be selected in the low cost solutions;
2. Investment in renewables is pursued to meet the requirements of the RPS;
3. Investment in Low NO_x technologies and the Trenton 5 baghouse reduce the overall cost to customers.

These are all elements included in the Reference Plan. The findings of the Worlds analysis reinforce the Sensitivity Analysis findings and the analysis results under the Base Assumptions. The Reference Plan is a robust plan (certain near-term investments are common to it and most other resource Plans and Worlds), and it remains the low cost plan under a broad range of assumptions.

6.0 SUMMARY

The IRP analysis provides support that the Reference Plan, 5 percent DSM Plan with Renewables beyond the RPS should be the Preferred Plan. In addition, to being the low cost plan the Preferred Plan also meets the other criteria set out in the UARB approved Terms of Reference.

1. System reliability requires that all resource plans at a minimum must meet reserve margin requirements. The Preferred Plan meets these criteria for the lowest cost.

2. Plan robustness is the ability of a plan to withstand realistic potential changes to key assumptions. The sensitivity analyses tested plan robustness. The analyses showed that across all sensitivities the Preferred Plan and the DSM Plan retained their first and second place rank respectively.

3. Cash flow measures the timing and magnitude of benefits relative to the timing and magnitude of required expenditures. While the Coal Plans, Gas Plan and Renewables Plan are slightly less expensive in the early years, the increased cost of those four plans beyond 2014 outpaces the cost of the Preferred Plan and the DSM plan. This indicates that the Preferred Plan and DSM plan are more favourable than alternative resource plans.

4. Flexibility is the absence of constraints on future decisions arising from the selection of a particular plan. The Preferred Plan is the most flexible of all resource plans. Unlike the Coal Plans, Gas Plan or Renewables Plan, the Preferred Plan would not require NSPI to commit to large scale generation in the next several years. It allows a two year window for additional, necessary information and experience to be collected. There is time to assess the potential and cost for additional renewable wind energy in Nova Scotia through the Wind Integration Study. It also allows time for

DSM to be implemented, monitored and evaluated. If the Wind Integration Study shows that the even higher levels of renewables contemplated in the Preferred Plan cannot economically be accommodated on the system, there is flexibility to reflect this in an IRP update. Similarly, if DSM experience in Nova Scotia indicates a level of savings less than that projected in the Plan, alternative plans can be considered during these two years.

5. Future regulatory emissions outlook requires that all plans must meet current and future emissions requirements. The Preferred Plan is the low cost method of meeting those requirements.

In addition to the above resource questions, the IRP analysis provides insight to the specific resource planning issues raised earlier. Each is summarized below with comment.

1. The requirement to invest in a scrubber in order to meet sulphur dioxide limits versus switching to lower sulphur fuels;

   The Lingan scrubber addition by 2020 appears economic. Prior to this, sulphur dioxide emissions can be managed cost-effectively through utilization of fuel switching to lower-sulphur fuels. Should Federal Government regulations introduce more stringent sulphur regulations than are currently in place in Nova Scotia, the FGD may be required sooner.

2. The amount of demand-side management spending which is economically viable in Nova Scotia;

   Based on DSM achievements in other jurisdictions, and assuming an extrapolation of the costs and benefits, to higher levels, the IRP analysis provides direction as to the potential benefits for NSPI customers of large-scale investment in DSM. Whether the forecast level of savings can be achieved at the projected cost in Nova Scotia will not be known until specific initiatives are undertaken and the foundation for a comprehensive DSM program is established and monitored.

Under this extrapolation, total spending equivalent to 5 percent of revenue was shown to be economically sound within the IRP. Because of the implications of DSM implementation on near-term capacity reserve margins, it is essential that a further assessment of DSM's potential be completed within the next two years.

3. The amount of renewable generation beyond the provincially legislated Renewable Portfolio Standard (RPS) which is economically viable in Nova Scotia;

The potential of additional renewable energy is encouraging. The analysis completed to date is narrow in scope, amounting to a comparison of the all-in cost of renewable supply additions to the alternative DSM or fossil-based opportunities.

This analysis needs further work to consider the effect of variable, intermittent generation, on operating costs (i.e., backup supply) and the stability of the power system.

The capacity additions required by the RPS will result in a total installed capacity of approximately 240 MW (10 percent of total system peak) by 2010 and approximately 510 MW (20 percent of total system peak) by 2013. This means that by 2013 there could be many hours in the year where 40 percent of the load is being served by a variable source. This has significant technical, reliability and cost implications.

The Preferred Plan includes additional wind beyond 2013. It is expected the recently undertaken wind integration study will inform this decision.

NSPI is actively engaged with the Provincial Government in this process. Once the study is complete, the potential for renewables in Nova Scotia can be more precisely assessed.

4. The timing of the next major generation addition;

The Preferred Plan does not include a major generation addition before 2029. This is a result of all load growth being accommodated by aggressive DSM, renewable generation and uprates to existing facilities.

Should the projected penetration of DSM and/or renewable generation prove unachievable in Nova Scotia, the plan will change and a generation addition may be required. In this regard, it is important to note that the Coal Plan, which also has allowance for 2 percent DSM, identifies the addition of 400 MW of new capacity in 2016 to economically meet system requirements. (The Coal Plan calls for this addition in 2016 because it would be economic though not yet required for capacity in that year. 2018 is the year in which the addition would be required for capacity.) To meet this plan, an eight year lead time for permitting and construction of such plants suggests work would need to begin in 2010. This suggests NSPI has a window to make this assessment.

5. Identification of near-term supply and environmental additions;

The Preferred Plan primarily relies on DSM and Renewables additions to meet load growth.

The absence of investment in new (large) generating capacity, combined with the uncertainty with DSM and expansion of the renewables portfolio, means the reliability of existing NSPI generation becomes increasingly significant and economic opportunities to maintain and increase the capacity of existing units should be pursued.

Consistent with this, the IRP results have confirmed that the capacity uprates to existing units and the Waste Heat Recovery Project at Tufts Cove are cost effective. As well the IRP Preferred Plan includes the addition of Low NO_x equipment to Lingan, Pt. Tupper and Trenton.

6. The effect of carbon offsets/credits versus the requirement for physical reductions in carbon emissions.

The IRP analysis examined the effect of hard caps and credit constraints as part of reducing carbon dioxide emissions. In order to achieve this result, additional supply and (unproven) technologies were added. These were at least, in part, speculative solutions as the options were not all commercially available.

If aggressive hard caps are implemented and credits are constrained, the later years of the overall resource plan will need to be reevaluated.

7.0 STAKEHOLDER COMMENT ON IRP

Since the initiation of the IRP in July 2006, stakeholders in the IRP have been consulted and provided input on the IRP analysis framework, assumptions, conclusions, action plan and content for this final report. Intervenor views have been diverse, reflecting a variety of interests, concerns and experience with the matters considered by the IRP.

A complete copy of Intervenor comments on the draft report is provided in Volume 3. NSPI respects that there are many perspectives about the matters raised by the IRP.

In general, stakeholder comments fall into three categories:

- The extent to which Intervenor comments have been considered in the IRP process;
- DSM investment levels and implementation issues; and
- Matters that will be addressed in subsequent NSPI applications.

For the first category, NSPI, with UARB Staff and consultants, has sought to address these through the implementation of a broad IRP analysis framework. In addition the IRP analysis incorporated specific input from stakeholders. Examples include:

- The addition of the DSM Worlds with Pulp and Paper sector benefits removed as recommended by Stora Enso Port Hawkesbury Limited and Bowater Mersey Paper Company Limited;
- The creation of the Deep Green World as recommended by Ecology Action Centre; and
- The addition of an action item to explore clean energy import opportunities as recommended by Dr. Larry Hughes.

As noted by several Intervenors, the resultant analysis involves uncertainty, in particular DSM, intermittent generation and future environmental regulation. NSPI acknowledges this and has sought to address this in the development of the action plan presented in this report. Intervenors appear to agree with NSPI that more work needs to be done in these key areas.

With respect to the second category, the analysis selected DSM as the economic choice over supply side alternatives because the levelized cost of DSM is lower than the next best alternative. This underscores the importance of testing energy and demand savings projected in the IRP, as the DSM program advances. This is reflected in the Action Plan. Matters of DSM implementation will be addressed in a separate DSM process. NSPI welcomes stakeholder input in this process.

The third category raises future generation issues that will be addressed upon specific applications being filed with the UARB. This includes capital work order submissions. The UARB retains oversight of the process for each future application. NSPI views the IRP as consistent with the UARB practice with respect to approval of applications as it has been previously established.

The IRP can serve as a helpful guide and reference plan for all stakeholders, the Company and the UARB as future applications are considered. Ultimately NSPI investments, approved by the UARB, can affect the prices our customers pay. With this in mind the Company welcomes stakeholder input on major capital investment associated with the IRP.

8.0 ACTION PLAN

Three key conclusions have emerged from the IRP process:

1. Investment in demand-side management and renewable generation can provide savings to customers, though the long-term potential for these two resource options requires more careful exploration and study;

2. The existing fossil fuel fleet will continue to play a central role in meeting NSPI customer requirements and

3. The context for resource planning beyond 2010 remains dynamic, due to the potential for significant changes in environmental or other requirements.

There is a window, during which NSPI can act on these conclusions and which provides time before a firm decision needs to be made with respect to investment in a new major capacity addition. The IRP analysis suggests this window is two years.

An action plan is required to achieve the potential benefits presented in the Preferred Plan while controlling our customers' exposure to costs associated with uncertainty with the longer-term effects of demand-side management and expansion of renewables generation. A flexible approach is required, in essence a "no regrets" strategy.

The steps of the IRP Action Plan are:

1. NSPI will initiate the development of a comprehensive DSM program, aimed at realizing the potential indicated in the IRP analysis. The ramp-up proposed in the IRP analysis can serve as a benchmark for the plan. The program is expected to include reporting mechanisms to track expenditures and assess changes in electricity demand and energy across the various customer segments to capture the effect of significant 'ramp up'.

2. NSPI will continue to work with the stakeholders to complete the Wind Integration Study. Once this is complete, the potential for the penetration of intermittent generation across our Province can be more precisely addressed.

3. NSPI will apply to the UARB for approval to commence with economic capital programs necessary to optimize the capacity and environmental performance of its existing generation fleet. These investments may include:

    a. Addition of Low NO_x combustion firing equipment to Lingan, Pt. Tupper and Trenton;

    b. Capacity upgrades to Lingan Units 1-4;

    c. Incremental hydro additions and

    d. Conversion of Tufts Cove 4 and 5 to waste heat recovery operation.

4. NSPI will continue to actively monitor technology developments both with respect to low impact generation technologies and environmental retrofit technologies.

5. NSPI will continue to explore opportunities to obtain additional clean power sources from within and outside the province.

6. NSPI will continue to participate in the development of the Federal Emissions framework.

NSPI plans to update the IRP analysis once information from DSM implementation and the wind integration study is available and further clarity on the emissions framework is obtained. A report to the UARB on the status of the items included in the Action Plan will be filed in approximately two years.

APPENDIX 1

NSPI Integrated Resource Plan-2006

Terms of Reference

Objective

To develop a resource plan which utilizes supply-side and demand-side options, to enable NSPI to meet future emissions and other requirements in a cost-effective and reliable manner.

Approach

In developing the IRP NSPI will:

- Collaborate with Dr. Stutz;
- Use the IRP framework as described in the Scope below;
- Maintain compliance with the UARB regulatory framework;
- Maintain compliance with the environmental regulatory framework;
- Employ assumptions, where needed, to plan for environmental compliance;
- Consult with stakeholders; and
- Utilize available information whenever it is possible and appropriate to do so. Provide the UARB and stakeholders (and their respective advisors) who sign applicable confidentiality undertakings with designated confidential information as necessary to support the planning process.

Scope

The IRP will consider a 23-year Planning Horizon (2007-2029).
Primary steps of the Integrated Resource Planning process are:

1. Develop a set of criteria for evaluation of various plans.
2. Develop a load forecast of future supply requirements.

3. Develop realistic supply-side and demand-side alternatives to meet future emissions and other requirements.
4. Perform a screening analysis to determine which alternatives are to be evaluated further in the IRP process and which can be removed from further consideration.
5. Evaluate alternative plans in order to determine the best option. The objective function is the cumulative present worth of the annual revenue requirements over the planning period adjusted for end effects.
6. Perform sensitivity analysis to determine the effect of realistic variations in input assumptions.
7. Develop a recommended emissions control plan based upon the above analysis.
8. Identify actions required over the next 3 to 5 years to meet load projections as well as regulatory and environmental requirements.

IRP Framework

<u>Process</u>

The objective will be the minimization of the cumulative present worth of annual revenue requirements, adjusted for end effects, and subject to a number of considerations, including:

- System reliability requirements;
- Plan robustness - the ability of a plan to withstand realistic potential changes to key assumptions;
- Cash flow - the timing and magnitude of benefits relative to the timing and magnitude of required expenditures;
- Flexibility - the absence of constraints on future decisions arising from the selection of a particular plan; and
- Future regulatory emissions outlook.

Modeling assumptions will include financial analysis assumptions, emissions constraints, load forecast, supply-side options and demand-side options. Where appropriate, NSPI will address contrasting views about reasonable assumptions through sensitivity analyses.

NSPI will consider technically and economically viable supply-side technologies including operating characteristics, capital and operating costs and operational assumptions.

The potential role of demand-side management in a resource plan will be carefully assessed. Estimated DSM costs and load effects will be included in the IRP analysis.

NSPI's strategic planning model, Strategist, will be employed to evaluate alternative plans and complete the integration of supply and demand-side options. Once specific, realistic plans are identified, they will be assessed against the objective and the final criteria.

IRP Deliverables

1. Load Forecast

NSPI develops econometric load forecasts which provide annual energy consumption by customer sector and annual peak system demand.

Twenty-year demand and energy projections are provided as inputs to Strategist. Beyond this period an average annual growth rate is applied to the remaining planning horizon.

The distribution of energy and demand is profiled within Strategist through the application of the total energy and demand figures to the NSPI load curves. The load curves are developed based on data acquired through NSPI's load research sampling.

2. Supply-side Options

NSPI will provide a summary of viable supply-side options, including emissions abatement technologies. The summary will identify the cost and operating characteristics of the various technologies and discuss the opportunity and limitations of these within the NSPI power system.

A screening of the technologies will be completed, focusing on:

- System stability;
- Cost;
- Flexibility;
- Available, commercialized technology;
- Fuel considerations;
- Regulatory emissions outlook;
- Ability to obtain regulatory approval.

Included in the supply-side assessment will be:

- Optimization of existing generation;
- Conventional solid fuel generation;
- Gas-fired generation;
- Emissions management options including abatement technologies, fuel choice and other options;
- Renewables;
- Distributed Generation;
- Emerging technologies, particularly those expected to be commercially available by 2010;
- Enhanced interconnection and power purchasing.

3. Demand-side Options

This process will identify a viable role and approach to demand-side management initiatives that could be implemented in Nova Scotia in the coming years. NSPI will consider DSM initiatives and load forecasting.

NSPI will develop a preliminary assessment of the potential for DSM including cost, load, and usage effects and utilize this for the purpose of IRP development. While the analysis of DSM will be more detailed for the period through 2010, the cost and potential impact of DSM will be considered for the entire period through 2029.

4. Basic Assumptions

NSPI will file a Basic Modeling Assumptions document containing a consolidation of all modeling assumptions.

5. Plan Integration

Plan scenarios will be developed based on combinations of supply-side and demand-side options per items 1 through 3 above. The alternative plans will be assessed using the Strategist Tool. Strategist will rank the plans according to net present worth of the revenue requirements.

6. Sensitivity Analysis

The IRP process involves adoption of a variety of assumptions, some of which may involve significant uncertainty. Views on these assumptions may vary significantly.

Reflecting this, sensitivities will be identified against which to assess the various competing resource plans. Ultimately the test of the soundness of the recommended plan is its ability to withstand changes to assumptions, across a reasonable range.

7. Final IRP Report with Recommendation

The IRP will culminate in a written report to the UARB which will address the following areas:

1. Background/Process Overview.
2. Criteria for evaluation of the various plans.
3. Load forecast of future supply requirements.

4. Sets of alternative supply-side and DSM alternatives to meet future emissions and other requirements.
5. Screening analysis to determine which alternatives are to be evaluated further as Plans in the IRP process.
6. Evaluation of alternative plans in order to determine the least cost plan.
7. Sensitivity analysis on the least cost plan and other selected plans to determine the robustness of the plans to variations in input assumptions.
8. Selection of recommended plan to meet future emission requirements.
9. Actions required over the next 3 to 5 years to meet load projections and other regulatory and environmental requirements.

Stakeholder Engagement

The IRP framework and the resultant plan will form the foundation for the Company's future investment decisions. Stakeholder input will be an integral part of the process.

While the IRP process will provide increased structure and enable direct stakeholder input to NSPI's planning process, it is important to acknowledge that uncertainty will continue to exist in key areas. Despite this uncertainty, decisions will need to be made.

The integrated resource planning process is technical in nature and time-consuming. NSPI will consult with stakeholders at appropriate points in the planning process and in a manner which delivers value to the planning process.

Confidentiality

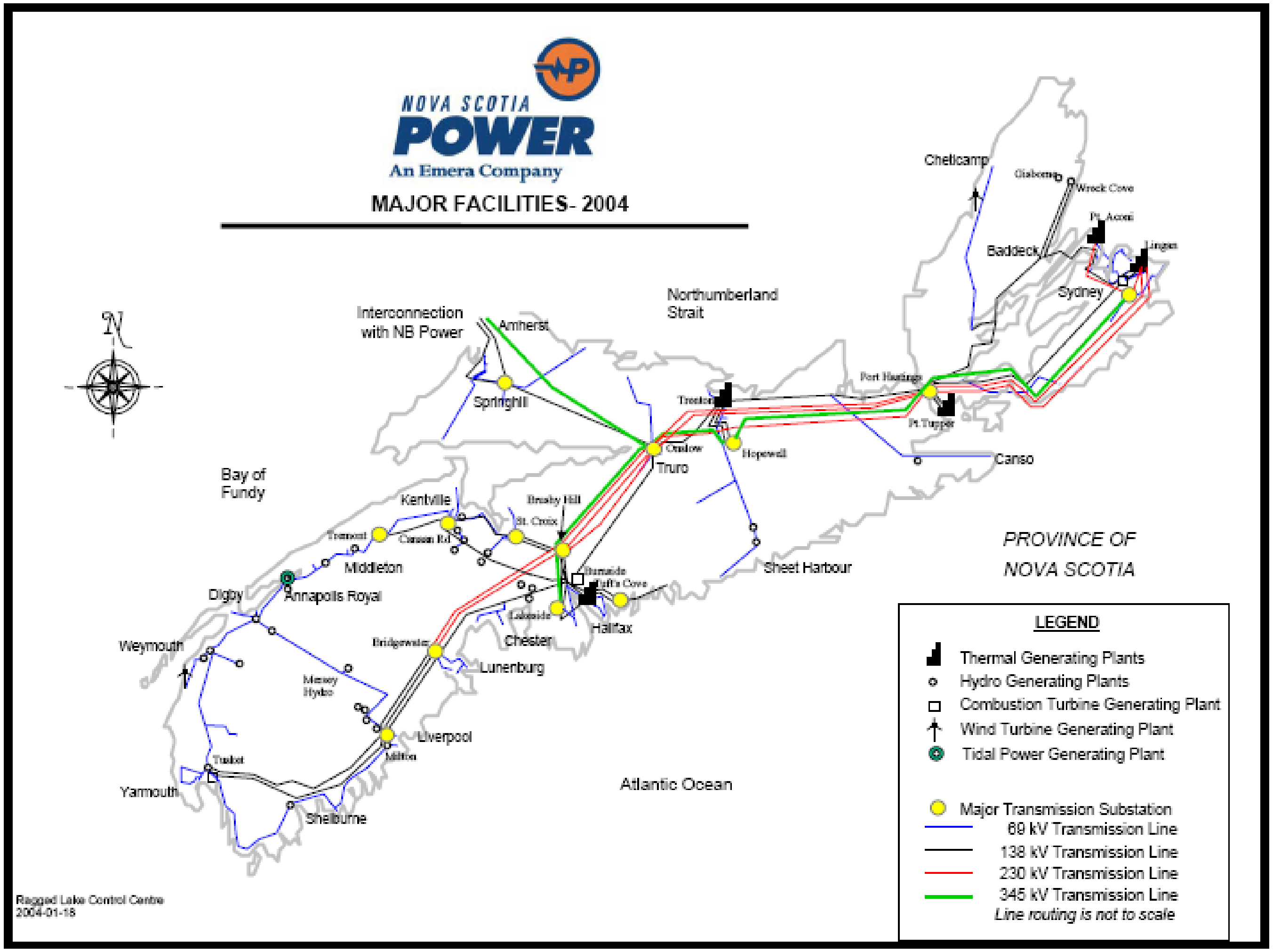
The IRP process involves the compilation of confidential data concerning NSPI's existing and anticipated operating environments. Components include actual operating characteristics of our assets and power system as well as strategic initiatives the Company may undertake. It is important to recognize this planning process takes place in an environment of future competitive generation, according to current government policy.

To the extent reasonable, without threatening NSPI's long-term competitive or financial position, information will be presented in a fashion designed to engage all stakeholders. Certain confidential information, such as detailed data from modeling software, may be limited to the Board. Summary reports will be more widely available.

IRP Process Timeline Summary

1.	Terms of Reference submitted to UARB for approval	July 4, 2006
2.	UARB approval of Terms of Reference	July 21, 2006
3.	Public advertising	Dates to be determined by the Board
4.	Notice of Intention to Participate by Interested Parties	September 1, 2006
5.	Basic assumptions including load forecast, supply and demand side options compiled and issued to stakeholders along with modeling assumptions	September 15, 2006
6.	Technical Conference to discuss basic assumptions	September 22, 2006
7.	Stakeholder input on key deliverables and modeling assumptions	October 6, 2006
8.	Final consolidated modeling assumptions issued	January 19, 2007
9.	Base scenarios for alternative Plans established and sensitivities identified	March 2, 2007
10.	Results of Technical Analysis (i.e. scenarios)	May 11, 2007
11.	Technical Conference on analysis results	May 23, 2007
12.	Stakeholder input on analysis results	June 13, 2007
13.	Draft report to stakeholders for comment	July 4, 2007
14.	Stakeholder comments on draft report	July 11, 2007
15.	Final report filed with UARB	July 25, 2007

APPENDIX 2


NOVA SCOTIA
POWER
An Emera Company
MAJOR FACILITIES- 2004
Interconnection with NB Power
Amherst
Springhill
Northumberland Strait
Cheticamp
Wreck Cove
Baddeck
Sydney
Port Hastings
Trenton
Pt.Tupper
Onslow
Truro
Hopewell
Canso
Bay of Fundy
Kentville
Brushy Hill
St. Croix
Canaan Rd
Middleton
Digby
Annapolis Royal
Weymouth
Burnside
Tufts Cove
Lakeside
Halifax
Chester
Bridgewater
Lunenburg
Mersey Hydro
Liverpool
Milton
Yarmouth
Shelburne
Sheet Harbour
Atlantic Ocean
PROVINCE OF NOVA SCOTIA
LEGEND
Thermal Generating Plants
Hydro Generating Plants
Combustion Turbine Generating Plant
Wind Turbine Generating Plant
Tidal Power Generating Plant
Major Transmission Substation
69 kV Transmission Line
138 kV Transmission Line
230 kV Transmission Line
345 kV Transmission Line
Line routing is not to scale
Ragged Lake Control Centre
2004-01-18

APPENDIX 3

TELLUS INSTITUTE
for a Great Transition

STATEMENT CONCERNING IRP DEVELOPMENT, RESULTS AND RECOMMENDATIONS

John Stutz and Bruce Biewald

July 16, 2007

Integrated Resource Planning (IRP) is a process used to develop resource plans for electric utilities. It differs from older planning approaches in two key respects—consideration of demand as well as supply-side resources, and use of a wide range of analyses to address uncertainty. An IRP effort usually leads to the identification of a **Preferred Resource Plan** which describes the utility's strategy for meeting its resource needs over the planning period. Based on the Preferred Plan, a short-run **Action Plan** is developed. This plan sets the tasks to be accomplished between the completion of the current IRP and its subsequent review in two or three years.

The IRP developed by NSPI was governed by the Terms of Reference (TOR) provided by the UARB. These TOR called for collaboration with UARB Staff and Consultants, and consultation with other interested parties. A team of consultants supervised by Dr. Stutz, led by Mr. Biewald, and assisted by Mr. Ross Young of Board Staff participated fully in all aspects of the IRP process. Other parties were provided with IRP work products including assumptions, plans for scenario analysis, modeling results, and proposed action plans. Based on discussion at Technical Conferences and written comments, significant modifications were made. As a result, it is our view that the process requirements set in the TOR have been fully met.

Selection of the Preferred Plan was made through a three-stage procedure. First, based on the most likely planning assumptions, a large number of resource plans were developed by, in effect, offering the Company's computer planning model (Strategist) different sets of resource options for meeting future needs and constraints. Based on this effort, a Reference Case—the plan that minimized the Net Present Value of costs—along with five other Base Resource Plans were identified. Second, in the Sensitivity Analysis, the six Base Resource Plans were rerun using a wide range of assumptions, not just those judged most likely. Third, in the Worlds Analysis, Base Resource Plans were modified to reflect worlds which, in various respects, differ from the future assumed in the modeling leading to the selection of the six Base Resource Plans.

Throughout all of this analysis the Reference Case proved to be quite robust. It was the "least-cost choice" throughout the Sensitivity Analysis and, with suitable additions, it generally provided a least-cost choice in the Worlds Analysis. (We say "generally" only because, in the Worlds Analysis, the Reference Case was, for technical reasons, sometimes replaced by a similar plan with somewhat less renewable resources.) Based on these results, the Reference Case was selected as the Preferred Plan.

The Preferred Plan which emerged from NSPI's IRP effort has established a clear strategy for meeting the Company's future resource needs:

- Anticipated growth in energy consumption and peak demand is offset by an aggressive Demand-Side Management (DSM) program that quickly ramps up to expenditures of roughly 5% of Company revenues (5% DSM).

- Renewable resource additions meet and then substantially exceed the requirements of the Renewable Portfolio Standard (RPS), provide all of the new generating capacity.

- Upgrades to a number of existing generating facilities, to boost output and address environmental concerns, are required.

We strongly support adoption of the Preferred Plan—referred to in the IRP report as "5% DSM + Renewables"—as the strategy for meeting NSPI's future resource needs. That being said, there are a number of uncertainties which need to be acknowledged:

- The level of savings in the 5% DSM spending is a very aggressive target. NSPI has little experience in the development and implementation of DSM. It is unclear at present whether we can ramp up successfully to achieve the savings projected for this case.

- The renewable resources considered in the IRP consist largely of wind. Because of its intermittent nature, the integration of wind in large amounts into a utility system creates technical challenges.

- The environmental constraints under which NSPI needs to plan depend on Federal and Provincial regulations, some of which are currently in flux. Some of the results obtained in the IRP analysis—such as the possibility of economic delay in investment in Flue Gas Desulfurization (FGD) until 2020—could be affected by changes in these regulations.

Over the next two years the results of the IRP indicate that there is a "window of opportunity" during which these and perhaps other uncertainties can be addressed. How to do this while also making substantial progress in resource planning and acquisition is addressed in the Action Plan

In light of the uncertainty discussed above, it is appropriate to defer consideration of a hearing or other formal review of the IRP results for about 2 years. During that period the uncertainties can be addressed—by gaining experience with DSM, through required studies of integration of renewables and, hopefully, by the evolution and clarification of the regulation framework. To preserve options the actions taken over the next 2 years should meet a “no regrets standard.” In particular, while DSM activity should be sufficiently vigorous to test our ability to meet the 5% target, it should be compatible with meeting lesser targets as well. Moving quickly and vigorously on DSM is particularly important since, as the IRP results show clearly, any significant delay in DSM development is likely to be accompanied by significant increases in costs. To move work along on DSM we suggest continuation of the process which has served us well in developing the IRP—collaboration and consultation under the general direction of Dr. Stutz.

APPENDIX 4

NOVA SCOTIA POWER INC.

INTEGRATED RESOURCE PLAN

P-884

CONTACTS FOR NSPI
BOARD COUNSEL CONSULTANT
FORMAL INTERVENORS

Contacts for NSPI:

Mr. Rene Gallant
Regulatory Counsel
Emera Inc.
14th Floor, Barrington Tower
1894 Barrington Street
P. O. Box 910, Halifax, NS B3J 2W5

Tel: (902) 428-6408
Fax: (902) 428-6542
email: rene.gallant@emera.com

Mr. Eric Ferguson
Manager, Regulatory Affairs
Nova Scotia Power Inc.
14^{th} Floor, Barrington Tower, Scotia Square
P. O. Box 910
Halifax , NS B3J 2W5

Te1: (902) 428-6078
Fax: (902) 428-6542
email: eric.ferguson@nspower.ca

Board Counsel:

Mr. S. Bruce Outhouse, Q.C.
Blois Nickerson & Bryson
500 - 1568 Hollis Street
P.O. Box 2147
Halifax, NS B3J 3B7

Tel: (902) 425-6000
Fax: (902) 429-7347
email: bouthouse@bloisnickerson.com

Board Counsel Consultants:

Dr. John Stutz
Tellus Institute
11 Arlington Street
Boston, MASS 02116-3411

Tel: (617) 266-5400
Fax: (617) 266-8303
email: jstutz@tellus.org

and

Bruce Biewald
President
Synapse Energy Economics, Inc.
22 Pearle Street
Cambridge, MA 02139

Tel: (617) 661-3248, ext. 222
Fax: (617) 661-0599
email: bbiewald@synapse-energy.com

Consumer Advocate:

Mr. John Merrick, Q.C.
Merrick, Jamieson, Sterns, Washington & Mahody
Suite 503, 5475 Spring Garden Road
Halifax, NS B3J 3T2

Tel: (902) 429-3123
Fax: (902) 429-3522
email: jmerrick@mjswm.com

and

William Mahody

email: bill@mjswm.com

and

Nancy Brockway

Nbrockway@aol.com

Formal Intervenors:

Adsum for Women and Children
c/o Sheri Lecker

Tel: (902) 425-3466
Fax: (902) 423-9336
email: adsumexecdir@hfx.eastlink.ca

Affordable Energy Coalition
c/o Megan Leslie
Community Legal Worker
Dalhousie Legal Aid
2209 Gottingen Street
Halifax, NS B3K 3B5

Tel: (902) 423-8105
Fax: (902) 422-8067
email: maleslie@dal.ca

and

Claire McNeil
Staff Lawyer

Tel: (902) 423-8105
Fax: (902) 422-8067
email: cmcneil@dal.ca

Antigonish Regional Development Authority
c/o Alisha Grant, Development Officer
188 Main Street, Suite 201
Antigonish, NS B2G 2B9

Tel: (902) 863-3330
Fax: (902) 863-4095
email: ardaenviro@antigonishrda.ns.ca

Atlantic Chapter of the Canada Green Building Council
c/o John Crace
Vice President, WHW Architects
1640 Market Street
Halifax, NS B3J 2C8

Tel: (902) 429-5490, ext. 105
Fax: (902) 429-2632
email: jcrace@whwarchitects.com

Avon Valley et al.
(Avon Valley Greenhouses Ltd.)
(Canadian Salt Company Limited)
(CKF Inc.)
(Crown Fibre Tube Inc.)
(Halifax Grain Elevator Limited)
(High Liner Foods Incorporated)
(Imperial Oil Limited)
(Intertape Polymer Inc.
(J. D. Irving Ltd., Saw Mills Division)
(Maritime Paper Products Ltd.)
(Michelin North America (Canada) Inc.)
(Minas Basin Pulp & Power Company Ltd.)
(Oxford Frozen Foods Limited)
(Statia Terminals Canada)
(Trentonworks Limited)

c/o Robert G. Grant, Q.C.
Stewart McKelvey
Suite 900 - Purdy=s Tower One
1959 Upper Water Street
P. O. Box 997
Halifax, NS B3J 2X2

Tel: (902) 420-3328
Fax: (902) 420-1417
email: rgrant@smss.com

and

Nancy G. Rubin
Stewart McKelvey

Tel: (902) 420-3337
Fax: (902) 420-1417
email: nrubin@smss.com

and

Mark Freeman

Tel: (902) 444-1707
Fax: (902) 420-1417
email: mfreeman@smss.com

and

Dave Wright

email: dwright@smss.com

Berwick Electric Commission
c/o Don Regan, Superintendent
Berwick Electric Commission
236 Commercial Street, P. O. Box 130
Berwick, NS B0P 1E0

Tel: (902) 538-4744
Fax: (902) 538-4779
email: dregan@town.berwick.ns.ca

Black River Wind Limited
c/o Neal Livingston
President
Box 55
Mabou, NS B0E 1X0

Tel: (902) 258-3354
Cell: 456-2004
SEND INFO BY MAIL ONLY

Canadian Manufacturers & Exporters
c/o Ms. Ann E. Janega
Vice-President, Nova Scotia Division
1869 Upper Water Street
Collins= Bank Bldg., 3rd Floor
Halifax, NS B3J 1S9

Tel: (902) 422-4477
Fax: (902) 422-9563
email: ann.janega@cme-mec.ca

and

Robert Patzelt
Vice-President, Risk Management &
General Counsel
Scotia Investments Limited
3 Bedford Hills Road
Bedford, NS B4A 1J5

Tel: (902) 832-2512
Fax: (902) 835-8151
email: rpatzelt@scotiainvestments.ca

and

Kristin Harris
Scotia Investments Limited
3 Bedford Hills Road
Bedford, NS B4A 1J5

Tel: (902) 832-6610
Fax: (902) 835-8062
email: kharris@scotiainvestments.ca

Cape Breton Regional Municipality
c/o John Whalley
Economic Development Manager
320 Esplanade
Sydney, NS B1P 7B9

Tel: (902) 563-5220
Fax: (902) 564-0481
email: jawhalley@cbrm.ns.ca

Ecology Action Centre
c/o Mr. Brendan Haley
Energy Coordinator
2705 Fern Lane
Halifax, NS B3K 4L3
Tel: (902) 442-0199
Fax: (902) 405-3716
email: energy@ecologyaction.ca

and

G. Ternan
gternan@ns.sympatico.ca

and

Steve Zubalik
Zubalik@hotmail.com

and

Glenn Reed, Consultant
Vermont Energy Investment Corporation
5 Water Street
Arlington, MA 02476
Tel: (781) 646-1505, ex. 203
Fax: (781) 646-1506
email: greed@veic.org

and

Blair Hamilton, Consultant
Vermont Energy Investment Corporation
255 South Champlain Street
Burlington, VT 05401
(802) 860-4095, ex. 1024
Fax: (802) 658-1643
Mobile: (802) 999-2687
email: bhamilton@veic.org

and

Kaitlyn Mitchell
email: kaitlynmitchell@dal.ca

GasWorks Energy Corp.
c/o Dwight Jeans
President
P. O. Box 31313
Halifax, NS B3L 1Y5
email: dwightjeans@ns.sympatico.ca

and

John Reynolds
Vice President, Regulatory Affairs
email: jonelr@ns.sympatico.ca

Genuine Progress Index (GPI) Atlantic
c/o Clare Levin
Tel: (902) 489-2524
email: clevin@gpiatlantic.org

Guysborough County Regional Development Authority
c/o Karen McNulty
Petroleum/Energy Office
46 Main Street
Guysborough, NS B0H 1N0
email: kmcnulty@gcrda.ns.ca

Halifax Regional Municipality
c/o M.E. Donovan
Senior Solicitor
HRM-Legal Services
P.O. Box 1749
5251 Duke Street, 3rd Floor
Scotia Square
Halifax, NS B3J 3A5
Tel. 902-490-4226
Fax: 902-490-4232
email: donovad@halifax.ca

and

Julian Boyle
HRM-Capital Projects
40 Alderney Drive, 6th Floor
P. O. Box 1749
Halifax, NS B3J 3A5
Tel: (902)-490-7115
Fax: (902)-490-4727
email: boylej@halifax.ca

and

Stephen King
HRM - Environmental Management
40 Alderney Drive, 2nd Floor
P. O. Box 1749
Halifax, NS B3J 3A5
Tel: (902) 490-6188
Fax: (902) 490-5862
email: kings@halifax.ca

and

Angus Doyle
Tel: 902-490-5019
email: doylean@halifax.ca

Dr. Larry Hughes, PhD
Professor, Energy Research Group
Department of Electrical and Computer Engineering
Dalhousie University
Room C367, 1360 Barrington Street
P. O. Box 1000
Halifax, NS B3J 2X4

Tel: (902) 494-3950
Fax: (902) 422-7535
email: larry.hughes@dal.ca

and

Ms. Mandeep Dhaliwal — email: mandeep.dhaliwal@dal.ca
Mr. Keshab Gajurel — email: keshab@dal.ca
Mr. Aaron Long — email: aklong@dal.ca
Ms. Niki Sheth — email: shethnikita198@gmail.com
Mr. Tylor Wood — email: ty877323@dal.ca
Mr. Alain Joseph — email: aajoseph@dal.ca

Liberal Caucus Office
c/o Ryan Grant
Researcher
5151 George Street, Suite 1402
P. O. Box 741
Halifax, NS B3J 2T3

Tel: 902-424-6181
Fax: 902-424-0539
email: grantrd@gov.ns.ca

New Democratic Party Caucus Office (NDP)
c/o Lorraine Glendenning
Researcher
Centennial Building, Suite 1001
1660 Hollis Street
Halifax, NS B3J 1V7

Tel: (902) 424-2646
Fax: (902) 424-0504
email: glendele@gov.ns.ca

Nova Scotia Association of Health Organizations (NSAHO)
c/o Peter Nestman
Coordinator of Member Relations
2 Dartmouth Road
Bedford, NS B4A 2K7

Tel: (902) 832-8500, ext. 306
Fax: (902) 832-8505
email: petern@nsaho.ns.ca

Province of Nova Scotia - Department of Energy
c/o Stephen T. McGrath, Solicitor
Department of Justice
P. O. Box 7, 400 - 5151 Terminal Road
Halifax, NS B3J 2L6
Tel: (902) 424-6288
Fax: (902) 424-1730
email: mcgratst@gov.ns.ca

and

Allan L. Crandlemire
Nova Scotia Department of Energy
Suite 400, Bank of Montreal Bldg.
5151 George Street, P. O. Box 2664
Halifax, NS B3J 3P7
Tel: (902) 424-6829
Fax: (902) 424-0528
email: crandlal@gov.ns.ca

and

Scott McCoombs
Nova Scotia Department of Energy
Tel: (902) 424-7305
Fax: (902) 424-0528
email: srmccoom@gov.ns.ca

and

Richard Penny
Nova Scotia Department of Energy
Tel: (902) 424-4162
Fax: (902) 424-0528
email: pennyrn@gov.ns.ca

and

George Foote
Nova Scotia Department of Energy
email: gffoote@gov.ns.ca

and

Howlan Mullally
Nova Scotia Department of Energy
email: mullalh@gov.ns.ca

Nova Scotia Department of Environment and Labour
c/o Andrew Murphy
Manager, Air Quality Branch
5151 Terminal Road, 5th Floor
P. O. Box 697
Halifax, NS B3J 2T8
Tel: (902) 424-2177
Fax: (902) 424-0503
email: murphyaj@gov.ns.ca

and

Johnny McPherson
Air Quality Branch, NSDOE
email: mcpherjp@gov.ns.ca

and

Sharon Vervaet
Air Quality Branch, NSDOE
email: vervaess@gov.ns.ca

The Sierra Club of Canada
c/o Bruno Marcocchio
65 Leonard Street
Sydney, NS B1S 2T7
email: brunom@eastlink.ca
Fax: (902) 539-3957

Stora Enso Port Hawkesbury Limited
and
Bowater Mersey Paper Company Limited
(AStora/Bowater@)
c/o George T. H. Cooper, Q.C.
McInnes Cooper
1300 - 1969 Upper Water Street
Purdy=s Wharf Tower II
P. O. Box 730
Halifax, NS B3J 2V1
Tel: (902) 444-8527 & 425-6500
Fax: (902) 425-6350
email: george.cooper@mcinnescooper.com
peggy.merrill@mcinnescooper.com

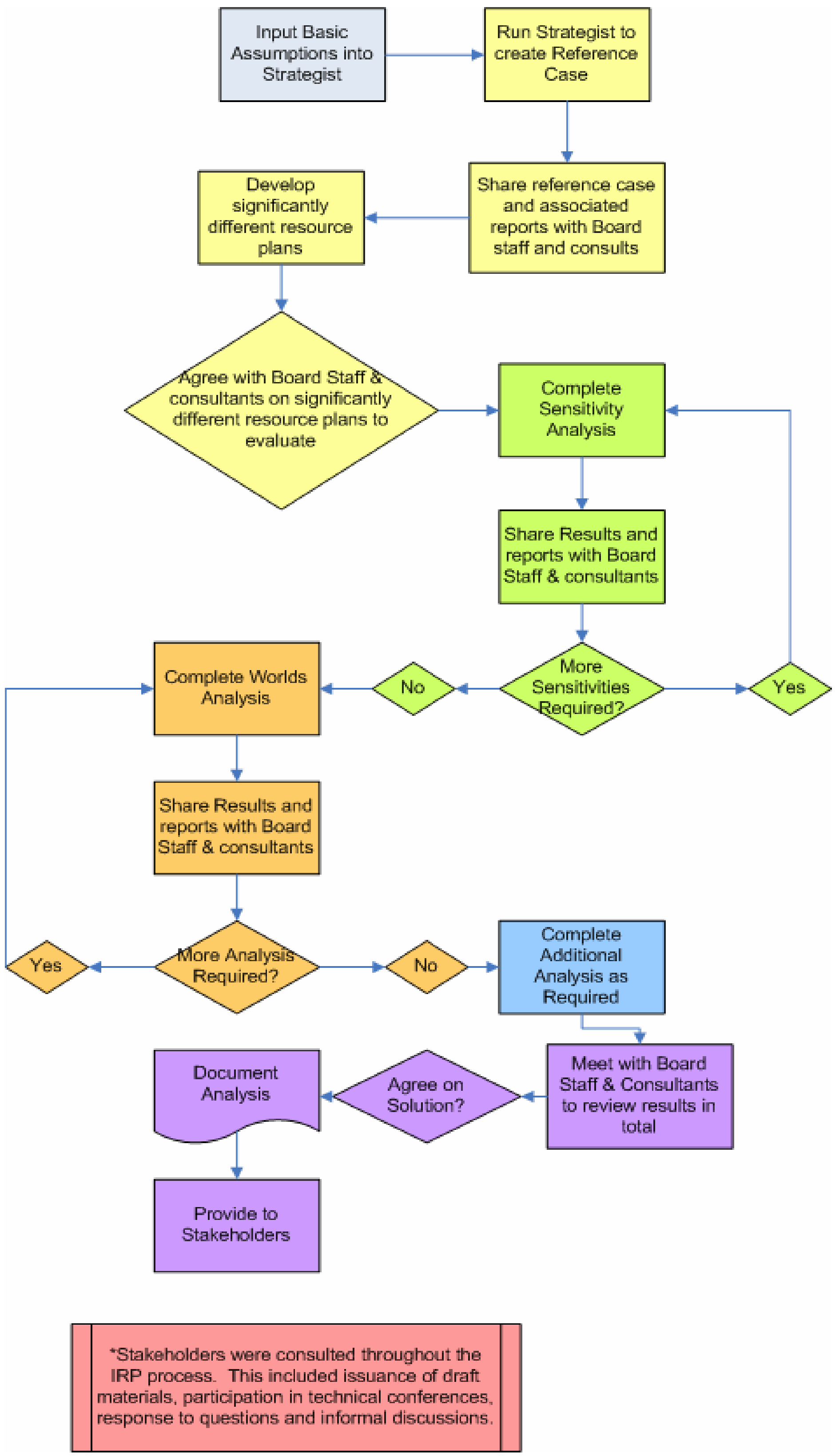
and

David S. MacDougall
Tel: (902) 444-8461 & 425-6500
Fax: (902) 425-6350
email:
david.macdougall@mcinnescooper.com

Xstrata Coal Donkin Management Limited
c/o Darren Nicholls
Project Manager
Ste. 201, Senator=s Place
633 Main Street
Glace Bay, NS B1A 6J3
Tel: (902) 849-9235
email: dnicholls@xstratacoal.com

APPENDIX 5

NSPI's IRP Analysis Flowchart



Integrated Resource Plan (IRP) Report

Volume 2

(Redacted)

Draft Report for Stakeholder Comment

Nova Scotia Power Inc.

July 26, 2007

REFERENCE DOCUMENTS

1. IRP Load Forecast:

1.1 IRP load forecast detail tech conf response.pdf

2. Demand Side Management:

2.1 NSPI DSM Evidence 9-8-06.pdf
2.2 Appendix A Revised DSM Plan - Proposed General DSM Programming 9-27-06.pdf
2.3 Appendix B Consultant's DSM Report 9-27-06.pdf

3. Slide Decks and Related Material:

3.1 N McNeil Re Integrated Resource Plan (IRP) Assumptions October 13 2006.pdf
3.2 IRP Basic Assumptions CONFIDENTIAL - October 13 2006.pdf
3.3 Attachment 1 IRP Basic Assumptions CONFIDENTIAL Feb 9 2007 FINAL.pdf
3.4 IRP Basic Assumptions (Confidential).htm
3.5 Attachment 2 Listing of Changes to IRP Basic Assumptions _since Oct 13__Feb9th_FINAL.pdf
3.6 Attachment 3 Next Stages.pdf
3.7 IRP Basic Assumptions questions & comments for Feb 22, 2007.pdf
3.8 IRP Feb 22 2007 Technical Conference.pdf
3.9 May 11 2007 Letter IRP Intervenors.pdf
3.10 IRP Results_Final_Colour.pdf

4. Other Documentation from Intervenor FTP site:

4.1 Attachment 4 IRP Basic Assumptions FTP site Index FINAL.pdf

2006 IRP
Load Forecast

Prepared

September 2006

Table of Contents

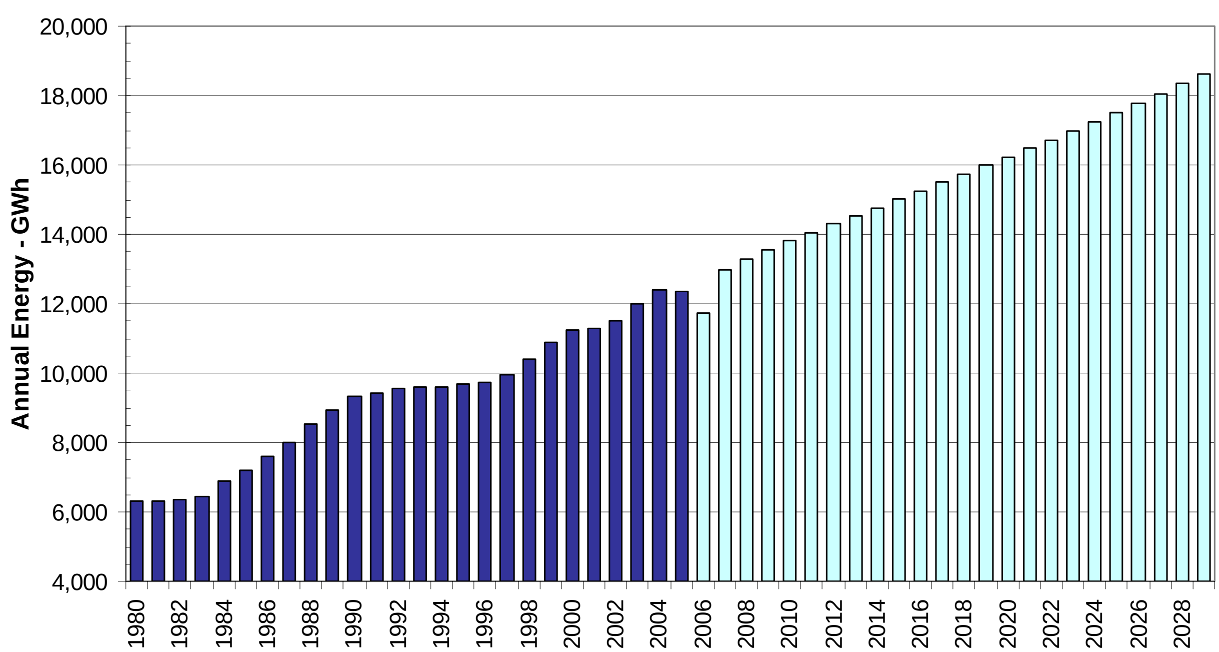
Overview

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 Appendix A 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.

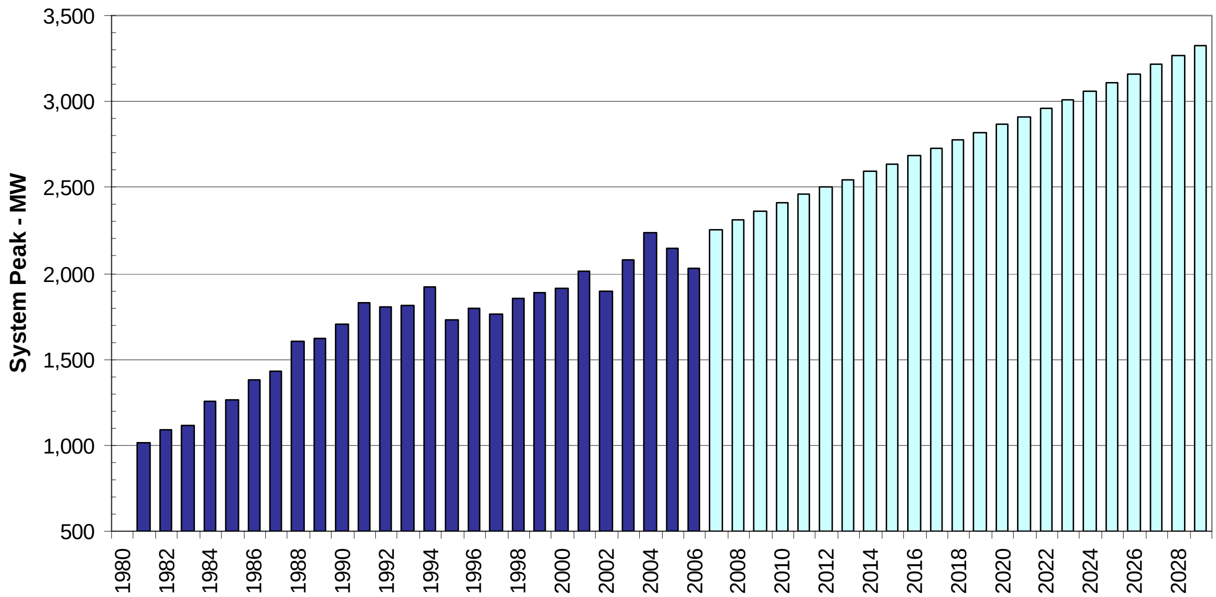
The sum of in-province energy sales and associated system losses is referred to as Net System Requirement (NSR). The NSR for 2005 was 12,338 GWh (12,410 GWh weather-normalized) and is forecast to increase to 12,981 in 2007. The NSR for 2029 is forecast to be 18,638 GWh for an average annual increase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

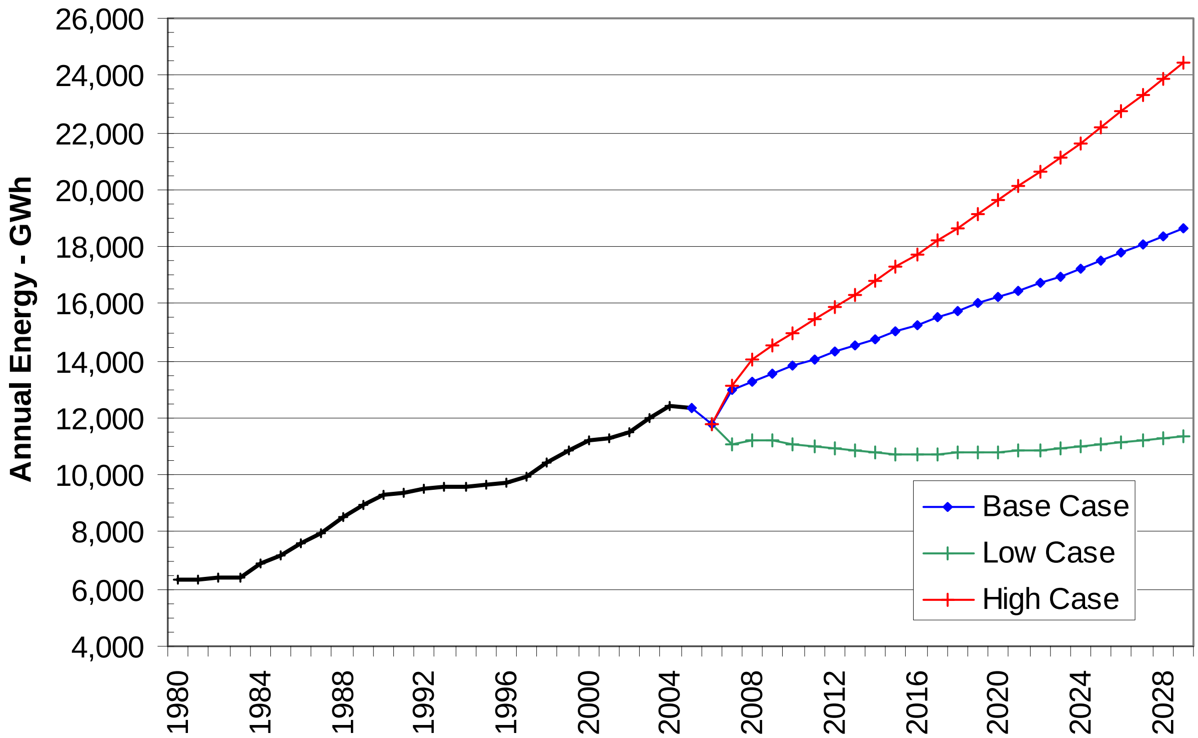
Assumptions for High and Low Scenarios

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.

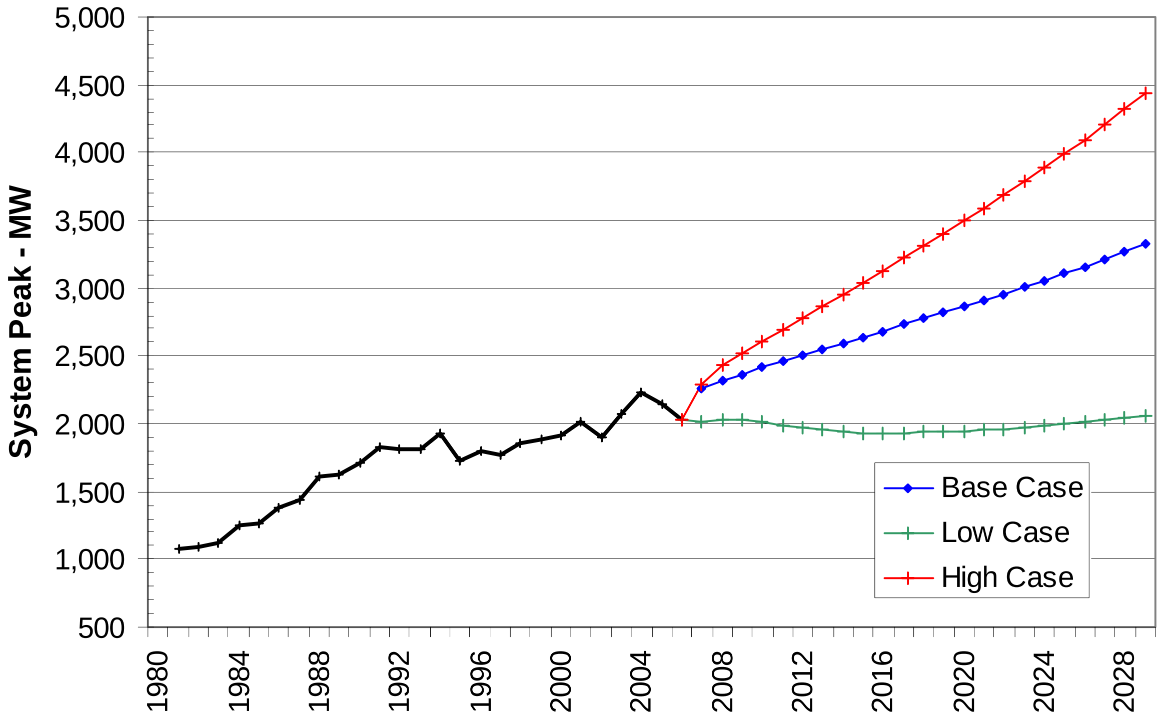
The combined results of these assumptions on the annual energy requirement are shown in figure 3.

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



Figures 5, 6 and 7 show the monthly variation in system peak over a series of years for the base case, high case and low case, respectively.

Figure 5: Monthly System Peak - Base Case

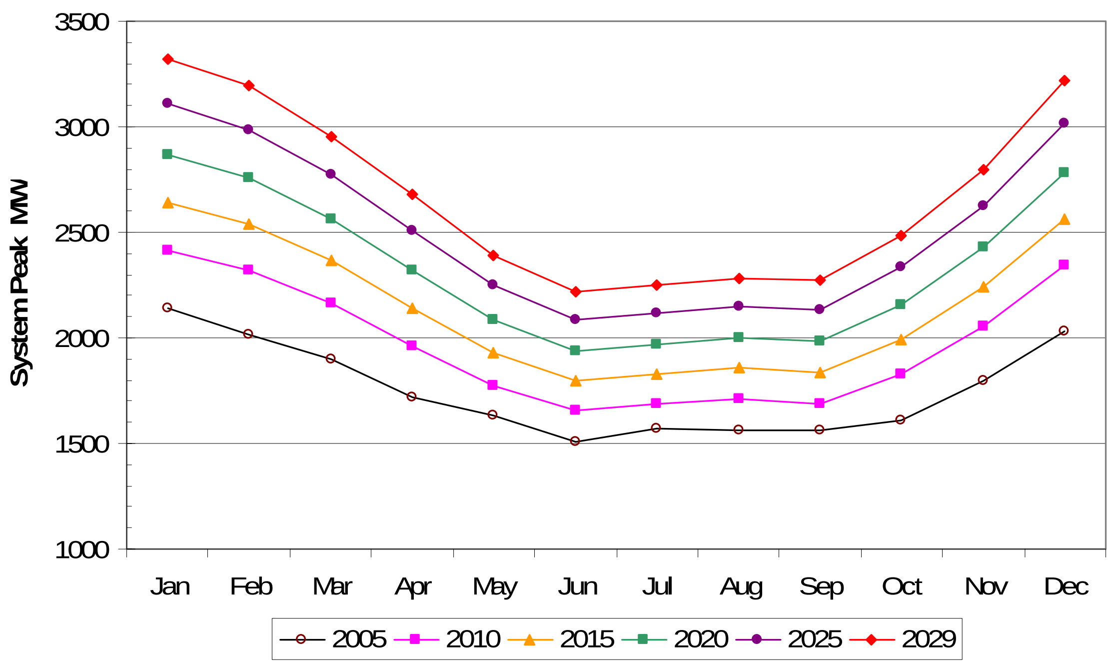


Figure 6: Monthly System Peak - High Case

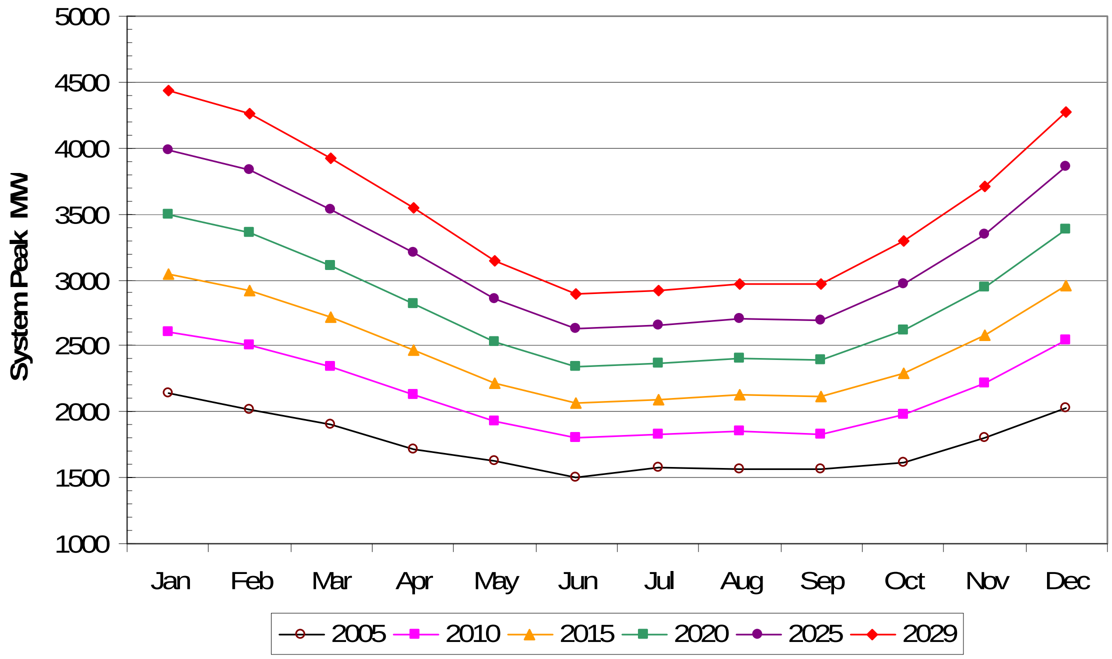
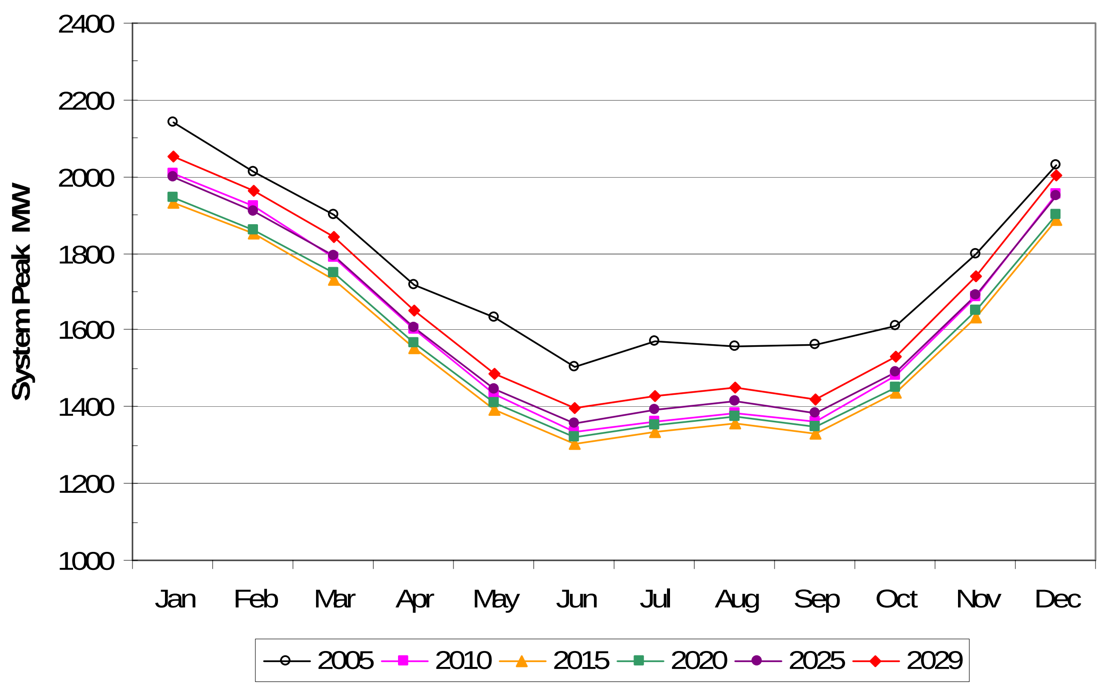


Figure 7: Monthly System Peak - Low Case



Appendix A

2006 Load Forecast

Prepared

September 2006

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Executive Summary

The Nova Scotia Power Inc. (NSPI) 2006 Load Forecast provides an outlook on the energy and peak demand requirements of in-province customers for 2006 to 2015. 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.

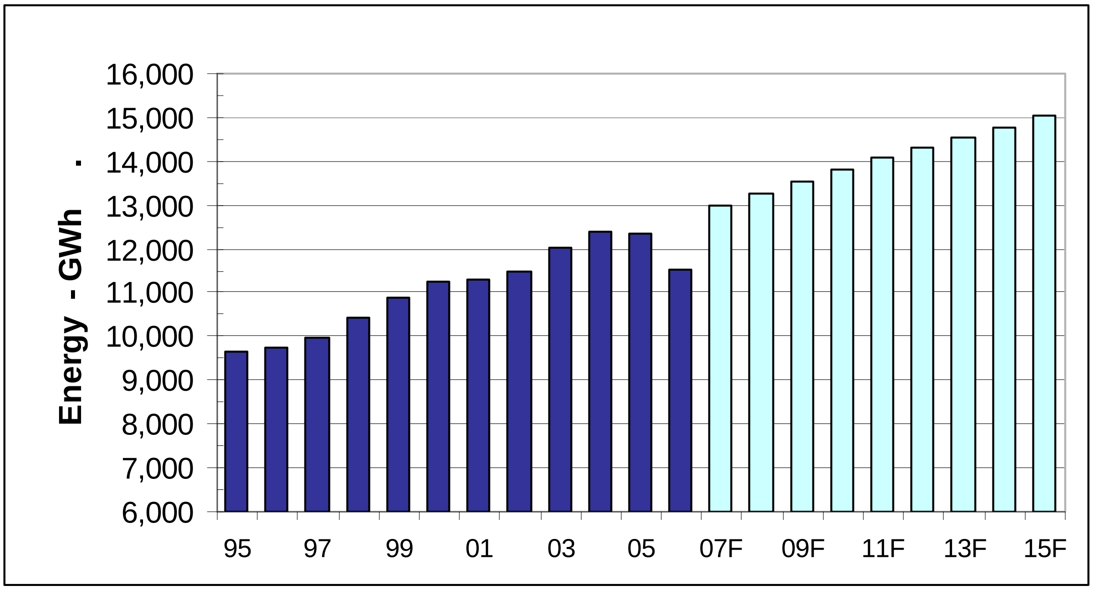
The forecast is based on analyses of sales history, economic indicators, customer surveys, technological and demographic changes in the market and the price and availability of other energy sources. Weather conditions, in particular temperature, affect electrical energy and peak demand. The forecast is based on the 30-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 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 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).

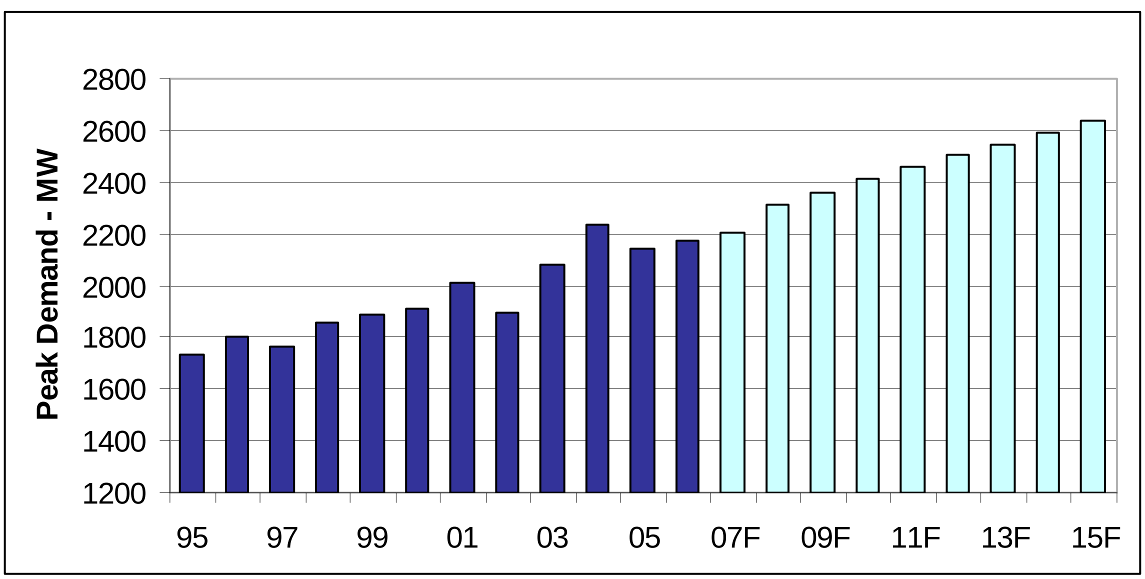
The NSR is forecast to increase from 12,338 GWh in 2005 to 12,981 in 2007, an average increase of 2.6 percent per year. In 2015, NSR is forecast to increase to 15,028, representing an average increase of 2.0 percent per year over the ten year forecast period. Growth in annual net system requirement is 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 process 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 increase from 2143 MW in 2005, to 2639 MW in 2015, which represents an annual growth rate of 2.1 percent.

The actual hourly peak demand to date in 2006 occurred in February and was 1854 MW, 384 MW lower than the record experienced in 2004 (2238 MW). This lower peak was caused by two factors: first, a large industrial customer shutdown, reducing demand by approximately 215 MW; second, the province experienced a mild winter where temperatures did not go below -10°C around the time of the peak demand (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 2007 is 2256 MW, assuming a return to normal (30 year average) temperatures. No load reductions or changes in demand profiles due to Demand Side Management (DSM) or conservation programs are assumed in this forecast.

Introduction

NSPI annually develops a forecast of energy sales and peak demand requirements to assess the impact of customer, demographic and economic factors on the future provincial system load. It is a fundamental input to the overall planning, budgeting and operating activities of the Company. Produced in the spring of 2006 and using information available at the time, this forecast covers the 10-year period of 2006 - 2015. Unless otherwise noted, average growth rates stated report the average annual rate calculated between 2005 (the last year of actual data) and 2015.

Forecast Models

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

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

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

While there may be some reduction in energy consumption as a result of increasing electricity prices, the elasticity has generally been quite small. This forecast is required in advance of, and used as part of the input to determining what, if any increase might be required and therefore this potential but small impact has not been explicitly modeled in this forecast.

Discussion of Major Inputs

The Gross Domestic Product (GDP) for Nova Scotia was $23,528 million (in constant 1997 dollars) in 2005, and is forecast to increase by 2.2 percent in 2006 and 2.5 percent in 2007. This growth continues to be fuelled by a broad base of economic gains. The last federal budget contained increased expenditures for the military, a major contributor to the Halifax area economy. Other budget items such as the reduction in the GST should offer some gains in disposable income and provide for further growth in the retail sector. Housing starts and sales have remained strong, but are expected to soften slightly with possibility of increased mortgage rates. Major commercial investments include the $270 million development at Dartmouth Crossing, the new development centre for Research In Motion and the start-up of the $400 million Sydney Tar Ponds clean-up project. Container traffic through the Port of Halifax is expected to continue to grow as more ships get routed to North America through the Suez Canal. While the elevated Canadian dollar will squeeze the margins of many provincial manufacturers, it could also provide these same manufacturers with opportunities to invest in foreign-sourced equipment (now relatively cost-effective), thereby boosting future productivity. Tourism will continue to be challenged in the face of high gasoline prices and the high dollar.

In 2004, the provincial Consumer Price index (CPI) slowed to 1.8 percent growth from 3.4 percent in 2003. In 2005, CPI growth rose to 2.8 percent and it is forecast to grow at 2.2 percent for 2006, 1.7 percent in 2007, 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.

Single housing starts were approximately 3180 in 2005, and are forecast by the Conference Board of Canada (CBoC) to be 3223 for 2006. For 2007, single starts are forecast at 2460. The housing market is expected to weaken with the satisfaction of pent-up demand. Meanwhile, future demand is expected to become more aligned to the underlying demographics. Additionally, there has been some deterioration in affordability in urban areas. Multi-unit starts were approximately 1590 in 2005 and are forecast to decrease to approximately 720 in 2006 and 540 in 2007.

Retail sales, with 2.8 percent growth in 2004, grew by 3.5 percent in 2005. Strong growth is forecast to be maintained at a rate of 3.8 percent in 2006 and 3.7 percent in 2006 and 2007, as consumer confidence remains positive.

Nova Scotia population in 2005 was estimated to be 937,818 with an average annual growth rate of just 0.07 percent in the past 5 years. Despite the continuing focus on immigration, there is little indication that the prevailing trends will be altered soon, particularly as migration to the bustling economies of the western provinces seems to be picking up. Further population growth is not anticipated in the forecast with the estimate for 2010 at 935,215 for an annual growth rate of -0.06 percent.

Table 1 lists the annual growth rates of some of the major independent variables that affect the forecast.

Table 1 **Forecast Variables**

Forecast Variables	2005 Actual Growth Rate	2006 Forecast Growth Rate	2007 Forecast Growth Rate
N.S. Population	0.02%	-0.11%	-0.04%
N.S. Consumer Price Index	2.8%	2.2%	1.7%
N.S. Real Personal Disposable Income	1.7%	2.2%	2.0%
N.S. Real GDP at basic prices	2.4%	2.2%	2.5%
N.S. Retail Sales	3.5%	3.8%	3.7%
Real residential heating oil price change	19.5%	6.3%	4.3%

Sector Model Inputs

A 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 such as Electric Thermal Storage (ETS) units

The outlook for the retail price of furnace oil (#2 light) is consistent with other fuel prices 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 are estimated to average 91¢ per litre in 2006 and 97¢ in 2007.

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. The gas impact on this forecast is small however, due to a limited rollout plan. Continued high prices for natural gas are also expected be a deterrent to switching to gas from electric where gas is available.

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 highly 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.

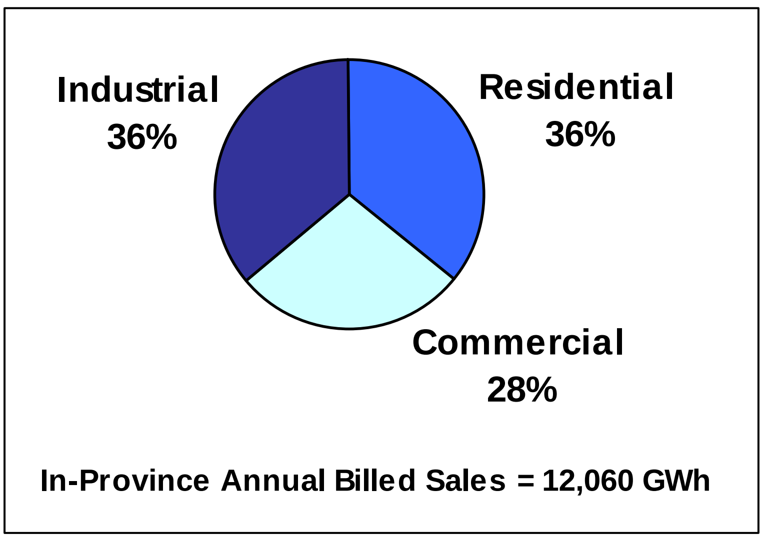
Losses

System losses have averaged 7.0 percent of NSR over the past five years and are expected to remain in the 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 3.

Figure 3 **2007 NSPI Sector Sales**



Residential Sector Sales

In 2005, residential customers represented approximately 36 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 quite 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 Retail Sales, as measured in current dollars.

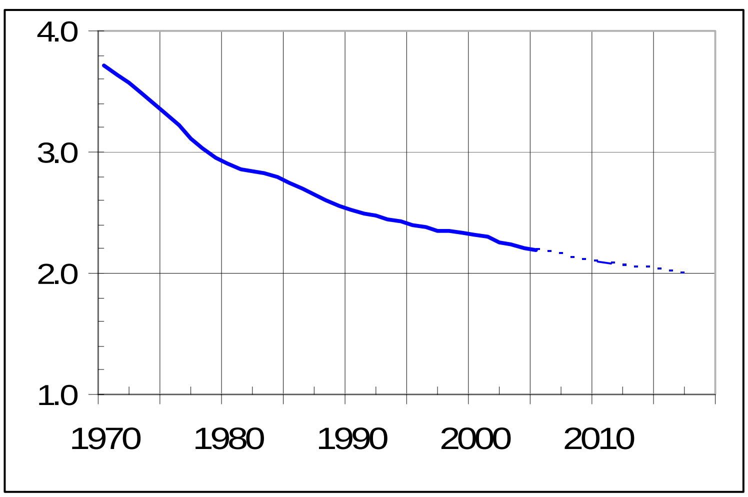
To capture the overall sector growth trends, the residential electric load of the previous year is included in the model as a lagged dependent variable. It should be noted however, that the coefficients applied to this and the other variables are the result of estimates using data compiled over a 30-year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

$$\textit{Residential Load} = 683.4\ \textit{AIDX} + 0.1257\ \textit{CHDD} - 31.79\ \textit{RREP} + 0.07878\ \textit{RRTS} + 0.4599\ \textit{Residential load}_{-1}$$

The forecast for new customers for 2006 is 3921 including seasonal, diminishing to 2405 by 2015. The number of additions has been decreasing steadily from more than 4500 in 1997. Although the Nova Scotia population is expected to grow at a very low rate or even decrease, Nova Scotians are increasingly choosing to live in smaller households. This trend is indicated in Figure 4. The result is an increase in the overall number of households, which in turn boosts total electric customers for a given population.

Figure 4 **Persons per Residential Account**

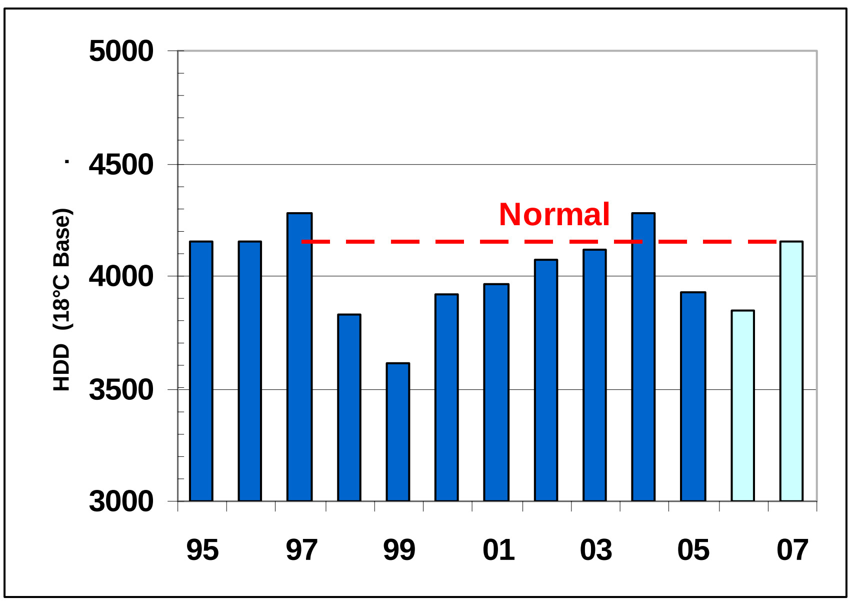


With an ever-increasing array of new technology available, usage per customer continues to grow, despite efficiency improvements for many household appliances. Larger appliances are modeled individually considering the age, efficiency trends and acquisition rates. Efficiency improvements for televisions, 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 result, the effect on the overall system load is very gradual as older appliances are retired and replaced with more efficient models.

With the rapidly rising oil prices and increasing concerns over hazardous oil spills, the market share of electric space heat has crept up slightly. The saturation of electric space heat has been in the mid to high 20 percent range in recent years and was estimated to be 30 percent in 2005 with continuing customer additions. The saturation of electric water heating hovers around 55 percent and is forecast to grow slowly over the forecast period.

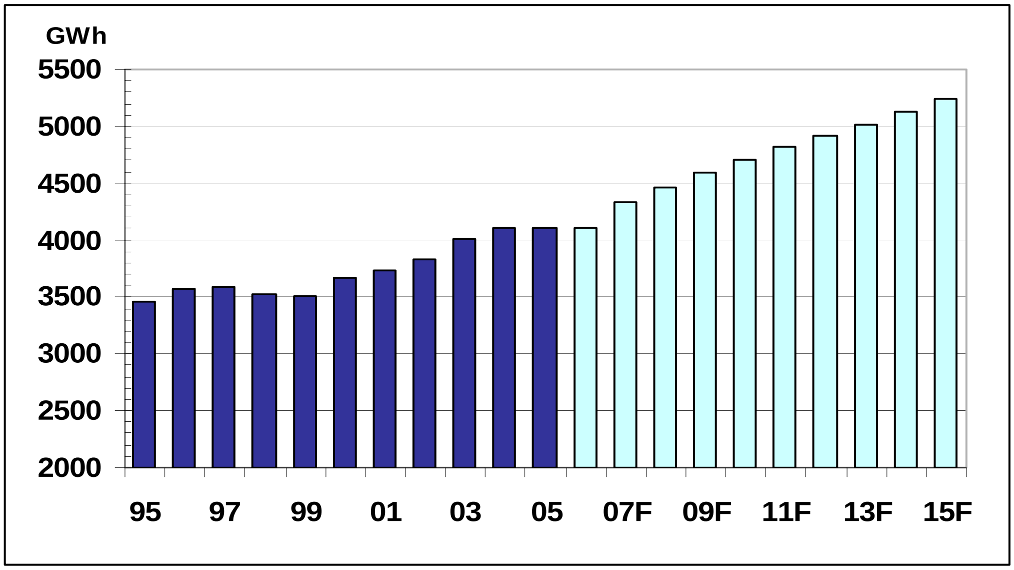
The forecast for weather effects uses 30-year average temperatures, measured in heating degree-days (HDD). Heating degree-days are a common measure of heating requirement, based on the degree departure between the daily mean temperature and a given standard temperature. The standard temperature of 18°C is used for these calculations and is assumed to be a comfortable room temperature below which space heating is generally required. The 30-year average is commonly used as the standard benchmark. The forecast uses the Environment Canada HDD data for Shearwater Airport for the years 1976-2005 and is 4150.1. Figure 5 shows the variation in annual HDDs over the past ten years as well as the forecast for 2006 and 2007.

Figure 5 **Annual NS Heating Degree-Days**



The residential sector load has grown at an average annual rate of 2.3 percent over the past five years or 1.8 percent when adjusted for the effects of weather. Annual residential loads are shown in Figure 6.

Figure 6 **Annual Energy – Residential Sector**



The 2007 load forecast for this sector is 4,327 GWh, or 2.9 percent over the forecast 2006 level.

Table 2 **Residential Sector Energy**

Year	Residential Sector GWh	Growth Rate %
2000	3,672.1	4.6
2001	3,741.2	1.9
2002	3,828.9	2.3
2003	4,010.5	4.7
2004	4,113.5	2.4
2005	4,114.3	0.0
2006F	4,203.6	2.2
2007F	4,326.9	2.9
2008F	4,466.2	3.2
2009F	4,588.4	2.7
2010F	4,706.4	2.6
2011F	4,813.9	2.3
2012F	4,917.5	2.2
2013F	5,018.0	2.0
2014F	5,122.7	2.1
2015F	5,240.2	2.3

Over the 10 year forecast period the residential load is expected to average 2.4 percent per year, reflecting the trend toward more electric heating customers as furnace oil prices are assumed to remain relatively high. Natural gas distribution is not expected to significantly impact the residential sector load in the near term due to limited distribution and expected high gas prices.

Commercial Sector Sales

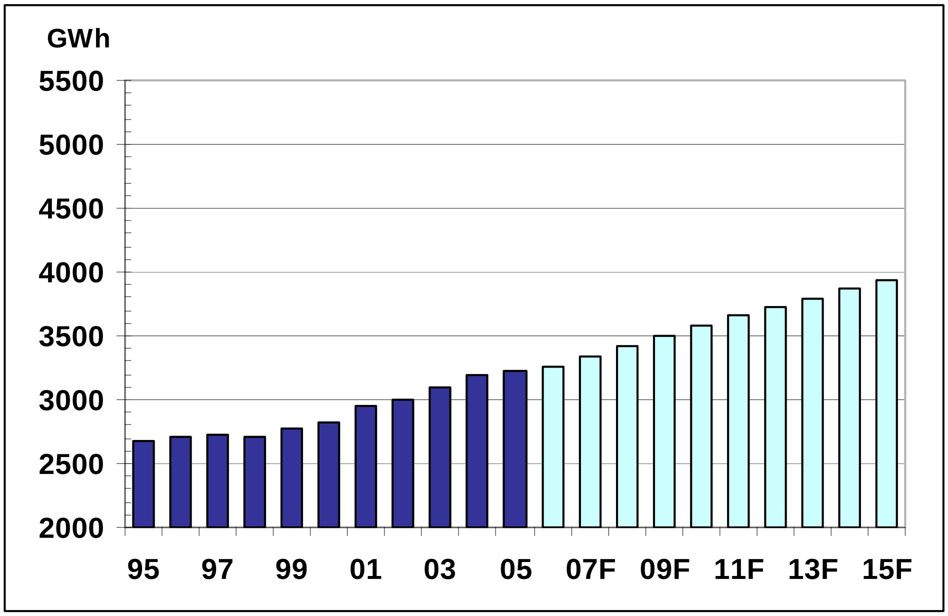
Energy sales to the commercial sector in 2005 represented 28 percent of Nova Scotia sales. This customer group includes restaurants, hotels, offices, recreational facilities, stores warehouses hospitals, schools and universities and street and traffic lights, as well as commercial customers served by 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. Real personal disposable income (RPDI) is also correlated to activity in the commercial sector and is included in the model.

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

$$Commercial = 0.01838\ RQTOS + 0.01969\ RPDI + 0.2015\ Residential + 0.5146\ Commercial\ load_{-1}$$

Additionally, the largest commercial customers are surveyed to obtain their forecasts of any foreseen load changes. This information is used in a reconciliation of the sector load by rate class. Annual commercial sector loads are indicated in Figure 7.

Figure 7 **Annual Energy – Commercial Sector**



Growth in this sector has averaged 2.6 percent over the past 5 years (2.4 percent when adjusted for weather). Driven by strong wholesale trade, consumer confidence and growth in personal disposable income boosting retail trade activity, this sector is forecast to grow by 1.6 percent and 2.1 percent in 2006 and 2007, respectively. The annual growth rate is expected to average 2.0 percent over the next 10 year period. The annual commercial sector loads are shown in Table 3.

Table 3 **Commercial Sector Energy**

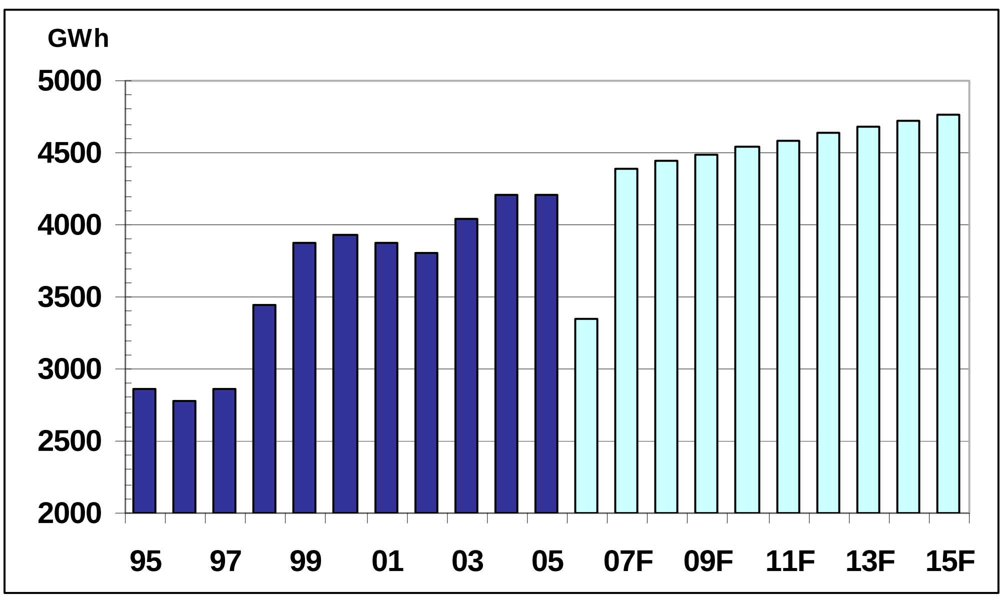
Year	Commercial Sector GWh	Growth Rate %
2000	2,829.4	2.3
2001	2,959.3	4.6
2002	2,996.5	1.3
2003	3,090.6	3.1
2004	3,187.8	3.1
2005	3,223.2	1.1
2006F	3,275.4	1.6
2007F	3,344.6	2.1
2008F	3,423.2	2.3
2009F	3,502.8	2.3
2010F	3,581.4	2.2
2011F	3,656.7	2.1
2012F	3,728.2	2.0
2013F	3,797.7	1.9
2014F	3,864.5	1.8
2015F	3,932.7	1.8

Industrial Sector Sales

In 2005, the industrial sector represented 36 percent of Nova Scotia total electricity sales. This group comprises 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. 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 8.

Figure 8 **Annual Energy – Industrial Sector**



The load for this sector is forecast using a combination of econometric modeling and large customer surveys. To avoid the effects of customers migrating between the classes, the Small and Medium Industrial customer loads are combined and forecast together using an econometric model. The economic factors that influence these customers are assumed to be the same regardless of the demand criterion that determines the customer's particular rate class. The growth rates calculated from the model are then used to forecast each class. This model relates industrial electricity consumption to GDP and load in the preceding year. In the early 1990s, significant load migrated from the Medium Industrial class to the new Interruptible Industrial Rate. A dummy variable, MIGRATE, is used in the model to capture that effect.

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

$$SM\_IND = 0.009305\ RQTOS + 0.7441\ SM\_IND_{-1} - 28.70\ MIGRATE$$

Large customers are surveyed each year 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 Table 4.

Table 4 **Industrial Sector Energy**

Year	Industrial Sector GWh	Growth Rate %
2000	3,930.0	1.5
2001	3,872.5	-1.5
2002	3,798.6	-1.9
2003	4,045.9	6.5
2004	4,212.1	4.1
2005	4,215.1	0.1
2006F	3,362.4	-20.2
2007F	4,388.4	30.5
2008F	4,438.0	1.1
2009F	4,487.2	1.1
2010F	4,536.4	1.1
2011F	4,585.0	1.1
2012F	4,632.8	1.0
2013F	4,680.0	1.0
2014F	4,725.8	1.0
2015F	4,770.7	1.0

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 is expected to remain closed for much of 2006. The forecast for 2007 assumes the plant will be at normal full load. With no new expansions or customer additions of large magnitude anticipated for 2006 or 2007, growth in the industrial sector will level off in the near-term.

Industrial sector load growth averaged 1.4 percent per year from 2000-2005, but dips by 20 percent in 2006 due to the major customer shutdown. The forecast load for 2007 is 4,388 GWh with major customers assumed at normal full load. Between 2005-2015, growth is expected to average 1.2 percent in this sector.

Total Sales

Given the combined activities of each sector, including large industrial shutdowns, expansions, etc., total sales grew at an average annual rate of 2.5 percent over the last 10 years. As a result of each of the sector sales forecasts, total Nova Scotia sales are expected to grow at an average annual rate 1.9 percent over the next 10 years. The billed sales are therefore expected to grow from 11,553 GWh in 2005 to 13,944 GWh by the year 2015.

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 billing process, billed sales will vary somewhat from accrued sales. The difference in the energy generated and sold but not yet billed, is referred to as “Unbilled” sales.

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

Losses are estimated at both the transmission and distribution levels. Historical estimates for transmission losses are obtained from NSPI's Supervisory Control and Data Acquisition (SCADA) system and are based upon an expected generation and transmission configuration. As a result, transmission losses are forecast at 3.0 percent of the transmission energy requirement. Based on historical estimates, distribution losses are forecast at approximately 6.2 percent of distribution sales. As a result of forecast distribution and transmission losses, total system losses average 6.9 percent of NSR over the forecast period.

Net System Requirement

The Net System Requirement (NSR) is the energy required to supply the sum of residential, commercial, and industrial electricity sales, plus the associated system losses within the province of Nova Scotia. Loads served by industrial self-generation, exports, and transmission losses associated with energy exports are not included. Annual NSR is shown in Table 5.

Table 5 **Total Energy Requirement**

Year	Net System Requirement GWh	Growth Rate %
2000	11,240.1	3.4
2001	11,303.2	0.6
2002	11,501.0	1.8
2003	12,009.1	4.4
2004	12,387.6	3.2
2005	12,338.1	-0.4
2006F	11,784.1	-4.8
2007F	12,980.6	10.5
2008F	13,272.1	2.2
2009F	13,544.7	2.1
2010F	13,812.0	2.0
2011F	14,063.6	1.8
2012F	14,305.8	1.7
2013F	14,541.6	1.6
2014F	14,777.7	1.6
2015F	15,028.4	1.7

The Net System Requirement for the province has grown at an average of 1.9 percent per year from 2000-2005 and is forecast to average 2.0 percent over the next 10 years.

Rate Class Sales

Forecast sales by sector are allocated into 14 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 2005. All-electric, non-all-electric and residential Time-of-Day (TOD) rate customers are included in this class. As of December 2005, there were approximately 423,500 domestic customers responsible for annual billed sales of 4,039 GWh, an average of 9,537 kWh/customer. Residential class sales grow for the reasons stated in the residential sector description, and are forecast to grow at an average of 2.4 percent per year over the forecast period.

Small General

In the past, this class has 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 2005, this class was comprised of approximately 22,000 customers. It represented 109 GWh in sales in 2003, 165 GWh in 2004 and 232 GWh in 2005. With the rate migration completed, it is forecast at 242 GWh in 2007 and a return to approximately 2 percent per year growth.

General

In the past, 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 2005, this class had approximately 11,200 customers accounting for the major portion of commercial sector energy and 21 percent of total NSPI sales for 2005. By 2007, energy sales for this class are anticipated to be 2,476 GWh and grow annually at an average of 2.1 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 2005, 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 1.6 percent.

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 2,212 customers as of December 2005, and had energy sales representing 2.1 percent of NSPI total sales. Energy requirements in this class are forecast to grow at an average rate of 2.0 percent per year over the forecast period.

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 2005, there were 225 customers in this class, representing about 4.8 percent of total NSPI sales. Class sales are forecast to grow at an average of 2.0 percent over the next 10 years.

Large Industrial

This class is available to larger industrial customers having a regular demand of 2,000 KVA or more. As of December 2005, there were six customers in the "firm load" category. 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, In 1996, the Interruptible rate class was eliminated and the rate was attached to the Large Industrial class as a rider, available to those customers who have contracted to reduce their system load by a specified demand within 10 minutes of a request by NSPI. Customers on the rider receive a reduction in demand charge for billed interruptible kVA. As of December 2005, there were 25 customers on the Large Industrial Interruptible Rider. The combined energy for the firm and interruptible customers represented 997 GWh, or 8.6 percent of total 2005 NSPI energy sales. The anticipated combined energy for firm and interruptible customers in 2007 is 1,079 GWh, or 8.9 percent of total 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.

The UARB recently approved the Open Access Transmission Tariff (OATT), which supports the opening of the electricity market in Nova Scotia to power producers and the six municipal utilities. Beginning in 2006, it will be possible for these municipalities to source their electricity from providers other than NSPI. In 2005, this class represented 1.7 percent of total NSPI sales. Municipal sales are forecast to grow at an average annual rate of 2.1 percent over the next 10 years.

Unmetered Services

This class comprises street and area lighting, as well as miscellaneous lighting and small loads. In 2005, unmetered sales represented approximately 0.9 percent of total NSPI sales. Energy sales in this class are forecast to grow at an average of 2.0 percent over the forecast period.

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 2005, this class comprised 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 2005 level of approximately 12 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 Interruptible Rate (ELIIR)

This rate is calculated annually in advance and based on NSPI's budgeted base load costs. It is optionally available to, and currently in use by, two large industrial customers who commit blocks of more than 20 MW of load and are served at 138KV or more. This rate was designed to reward high monthly load factors and contains an economic interruptibilty provision. In addition, it is priority interruptible in nature from a supply perspective. Sales under this rate in 2005 were 1791 GWh or approximately 16 percent of NSPI sales. The ELIIR rate remains in place for 2006, but will be replaced in 2007 with a newly developed 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.

Two-Part Real Time Price (2P-RTP)

By its September 28, 2006 Decision in the matter of replacing the ELIIR rate, the UARB directed NSPI to modify the formerly approved 2P-RTP to incorporate aspects contained in that Decision. NSPI, as directed, will file the revised rate on October 16, 2006. Until that time, specific details of the rate and associated load remain uncertain.

Extra Large Industrial Interruptible Rate – 2 (ELIIR-2)

By its September 28, 2006 Decision in the matter of replacing the ELIIR rate, the UARB directed NSPI to modify the existing ELIIR rate to incorporate aspects contained in that Decision. NSPI, as directed, will file the revised rate on October 16, 2006. Until that time, specific details of the rate and associated load remain uncertain.

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 14 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 6.2 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.

Although peak demands are measured on an individual hour-by hour-basis and are not directly related to monthly heating degree days, January 2006 did not have particularly cold weather. The monthly peak of 1798 MW occurred at a temperature of just -6°C and a largest industrial customers were operating approximately 225 MW below typical load.

The February 2006 peak was only slightly higher at 1854 MW, with termperature of -10°C and the largest industrial customers were again approximately 225 MW below typical loads.

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

The system peak for 2007 is forecast at 2256 MW. Over the longer term, Net System Peak is forecast to increase from 2143 MW in 2005 to 2702 MW in 2015, which represents an average annual growth rate of 2.1 percent.

Non Firm Coincident Peak

NSPI offers interruptible, or “non-firm” service to industrial customers who meet certain criteria and contract to have their electricity supply interrupted on short notice in order to meet any necessary emergency peak reductions. These rate classes are the “Generation Replacement and Load Following” rate, the “Extra Large Industrial Interruptible” rate and the “Interruptible” rider of the Large Industrial rate. As of the January 2005 peak, there were 30 customers on these rates, representing a combined coincident non-firm peak of 392 MW.

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

Total Coincident Firm Peak

Total Coincident Firm Peak is the demand at the time of 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.

Load Forecast
Appendices

Appendix A

2006 NSPI Forecast

Residential Sector Econometric Model Detail

DOMENG = 683.4 AIDX + 0.1257 CHDD – 31.79 RREP + 0.07877 RRTS + 0.4599 DOMENG $_{-1}$

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

Term	Coefficient	Std. Error	t-Statistic	Significance
EFFIDX	683.420493	74.620566	9.158608	1.000000
CUSTHDD	0.125711	0.035709	3.520432	0.998811
RREP	-31.791492	5.282988	-6.017710	0.999999
RRTS	0.078778	0.012295	6.407588	1.000000
DOMENG[-1]	0.459957	0.075438	6.097196	0.999999

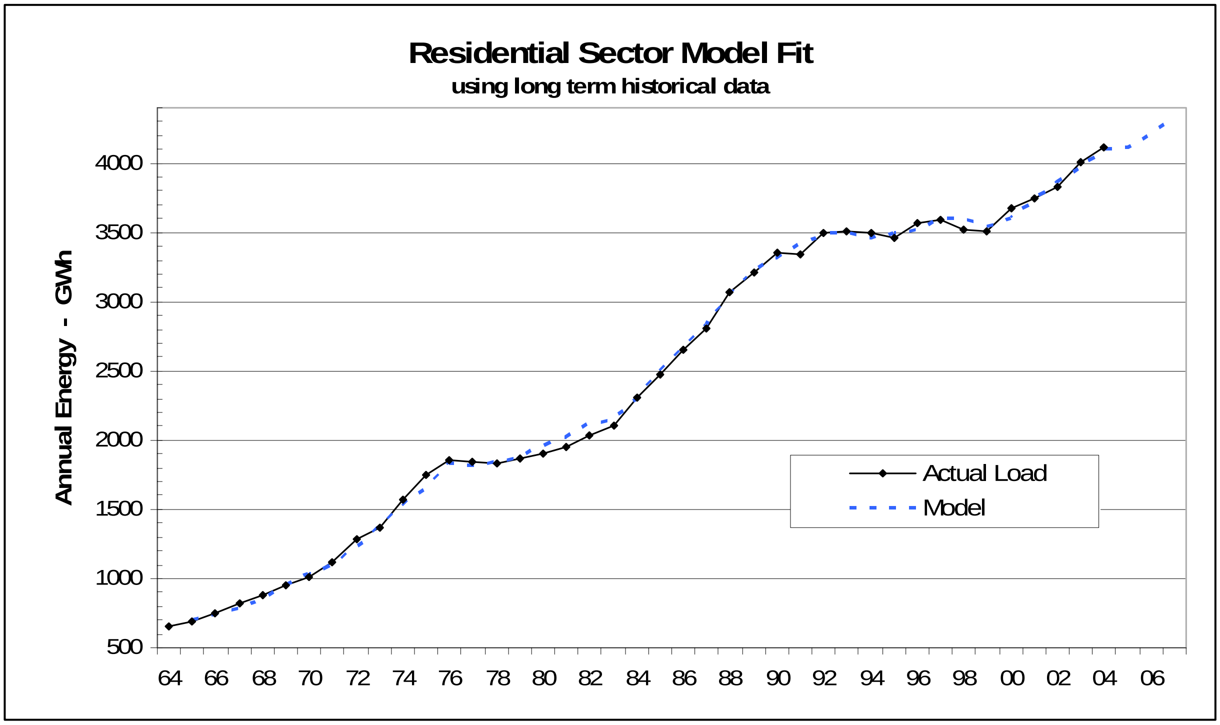
Within-Sample Statistics

Sample size 41	Number of parameters 5
Mean 2499	Standard deviation 1096
R-square 0.9984	Adjusted R-square 0.9982
Durbin-Watson 1.523	Ljung-Box(18)=18.36 P=0.5681
Forecast error 46.15	BIC 54.23
MAPE 0.01681	RMSE 43.24
MAD 34.81	

Residential Model Input Variables and Contributions

Year	AIDX	AIDX Contrib.	CHDD	CHDD Contrib.	Electric Price	Electric Price Contrib.	Retail Sales	Retail Sales Contrib.	$DomEng_{[-1]}$	$DomEng_{[-1]}$ Contrib.	Nat. Gas Effect	DomEng*	Actual	Growth
		GWh		GWh		GWh		GWh		GWh	GWh	GWh	GWh	%
1994	1.79	1221.2	3,192	401.2	9.94	-316.0	6,859	540.3	3,506.9	1,613.0	0	**3459.8**	**3498.3**	-0.2%
1995	1.77	1209.8	3,574	449.2	9.80	-311.7	6,795	535.3	3,498.3	1,609.1	0	**3491.8**	**3462.9**	-1.0%
1996	1.75	1193.3	3,714	466.9	10.03	-319.0	7,455	587.3	3,462.9	1,592.8	0	**3521.3**	**3564.6**	2.9%
1997	1.74	1189.6	3,798	477.5	9.79	-311.3	7,762	611.5	3,564.6	1,639.6	0	**3606.9**	**3594.8**	0.8%
1998	1.73	1182.2	3,460	435.0	9.79	-311.1	8,103	638.4	3,594.8	1,653.5	0	**3597.9**	**3524.4**	-2.0%
1999	1.71	1165.8	3,223	405.1	10.16	-323.0	8,615	678.7	3,524.4	1,621.1	0	**3547.6**	**3512**	-0.4%
2000	1.67	1144.7	3,529	443.7	9.75	-310.0	8,956	705.5	3,512.0	1,615.4	0	**3599.2**	**3672.1**	4.6%
2001	1.68	1144.9	3,727	468.5	9.53	-303.0	9,278	730.9	3,672.1	1,689.0	0	**3730.3**	**3741.2**	1.9%
2002	1.66	1132.2	4,213	529.6	9.28	-294.9	9,840	775.1	3,741.2	1,720.8	0	**3862.9**	**3828.9**	2.3%
2003	1.67	1137.9	4,463	561.0	9.19	-292.1	10,015	789.0	3,828.9	1,761.1	0	**3956.9**	**4010.5**	4.7%
2004	1.64	1118.7	4,871	612.3	9.00	-286.2	10,297	811.1	4,010.5	1,844.7	0	**4100.7**	**4113.5**	2.6%
2005	1.63	1115.2	4,634	582.6	9.36	-297.6	10,655	839.4	4,113.5	1,892.0	0	**4114.3**	**4114.3**	0.0%
2006	1.63	1112.5	5,282	664.1	9.97	-317.1	11,055	870.9	4,113.2	1,891.9	-0.3	**4203.6**		2.2%
2007	1.63	1110.7	5,653	710.6	9.81	-311.9	11,460	902.8	4,203.6	1,933.5	-0.4	**4326.9**		2.9%
2008	1.62	1108.3	5930	745.4	9.27	-294.7	11,882	936.1	4326.9	1,990.2	-0.7	**4466.2**		3.2%
2009	1.62	1106.2	6101	767.0	9.17	-291.5	12,340	972.1	4466.2	2,054.2	-1.3	**4588.4**		2.7%
2010	1.62	1104.2	6235	783.8	8.79	-279.5	12,792	1007.7	4588.4	2,110.5	-1.7	**4706.4**		2.6%
2011	1.62	1102.4	6367	800.4	8.82	-280.4	13,293	1047.2	4706.4	2,164.8	-2.1	**4813.9**		2.3%
2012	1.61	1101.2	6503	817.5	8.85	-281.3	13,794	1086.7	4813.9	2,214.2	-2.4	**4917.5**		2.2%
2013	1.61	1100.1	6645	835.3	8.96	-285.0	14,302	1126.7	4917.5	2,261.8	-2.6	**5018.0**		2.0%
2014	1.61	1099.2	6785	852.9	8.88	-282.2	14,799	1165.8	5018.0	2,308.1	-2.8	**5122.7**		2.1%
2015	1.61	1098.7	6923	870.3	8.48	-269.6	15,307	1205.9	5122.7	2,356.2	-2.9	**5240.2**		2.3%

* - to align forecast to actuals in 2005, the modeled DomEng contains a launch adjustment of 18.4 GWh for 2005-2015


Residential Sector Model Fit
using long term historical data
Annual Energy - GWh
4000
3500
3000
2500
2000
1500
1000
500
64
66
68
70
72
74
76
78
80
82
84
86
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06
Actual Load
Model

Commercial Sector Econometric Model Detail

$$COMENG = 0.01838\ RQTOS + 0.01968\ RPDI + 0.2015\ DOMENG + 0.5145\ COMENG_{-1}$$

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

Term	Coefficient	Std. Error	t-Statistic	Significance
RQTOS	0.018387	0.003946	4.660185	0.999960
RPDI	0.019686	0.006249	3.150433	0.996777
DOMENG	0.201502	0.043502	4.631997	0.999956
COMENG[-1]	0.514591	0.075251	6.838373	1.000000

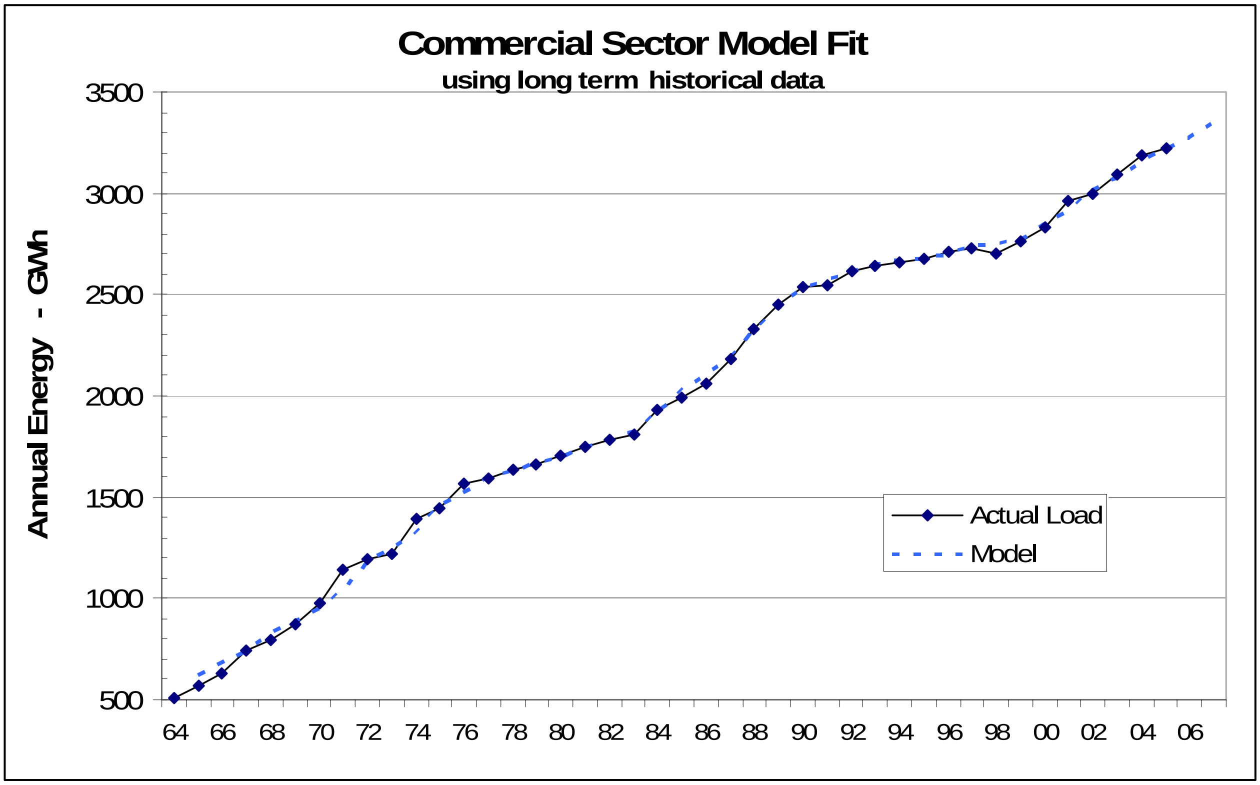
Within-Sample Statistics

Sample size 41	Number of parameters 4
Mean 2008	Standard deviation 778.1
R-square 0.9983	Adjusted R-square 0.9982
Durbin-Watson 1.89	Ljung-Box(18)=8.424 P=0.02837
Forecast error 32.91	BIC 37.47
MAPE 0.01641	RMSE 31.26
MAD 22.82	

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	ComEng* GWh	Actual GWh	Growth %
1994	17,535	322.4	14,168	278.9	3,498.3	704.9	2,638.3	1,357.6	**2,663.9**	2,660.2	0.8
1995	17,888	328.9	14,273	281.0	3,462.9	697.8	2,660.2	1,368.9	**2,676.6**	2,676.0	0.6
1996	17,922	329.5	14,027	276.1	3,564.6	718.3	2,676.0	1,377.0	**2,701.0**	2,712.9	1.4
1997	18,379	337.9	14,258	280.7	3,594.8	724.4	2,712.9	1,396.0	**2,739.0**	2,725.3	0.5
1998	19,063	350.5	14,796	291.3	3,524.4	710.2	2,725.3	1,402.4	**2,754.4**	2,702.4	-0.8
1999	20,169	370.8	15,254	300.3	3,512.0	707.7	2,702.4	1,390.6	**2,769.5**	2,766.8	2.4
2000	20,867	383.7	15,354	302.3	3,672.1	739.9	2,766.8	1,423.8	**2,849.7**	2,829.4	2.3
2001	21,607	397.3	15,593	307.0	3,741.2	753.9	2,829.4	1,456.0	**2,914.1**	2,959.3	4.6
2002	22,415	412.1	15,619	307.5	3,828.9	771.5	2,959.3	1,522.8	**3,014.0**	2,996.5	1.3
2003	22,630	416.1	15,540	305.9	4,010.5	808.1	2,996.5	1,542.0	**3,072.1**	3,090.6	3.1
2004	22,981	422.5	15,697	309.0	4,113.5	828.9	3,090.6	1,590.4	**3,150.8**	3,187.8	3.1
2005	23,528	432.6	15,958	314.1	4,113.1	828.8	3,187.8	1,640.4	**3,215.9**	3,223.2	1.1
2006	24,035	441.9	16,304	321.0	4,203.5	847.0	3223.0	1,658.5	**3,275.4**		1.6
2007	24,624	452.8	16,634	327.5	4,326.8	871.9	3275.4	1,685.5	**3,344.6**		2.1
2008	25,097	461.5	16,947	333.6	4,466.2	899.9	3344.6	1,721.1	**3,423.2**		2.3
2009	25,582	470.4	17,238	339.3	4,588.4	924.6	3423.2	1,761.5	**3,502.8**		2.3
2010	26,103	480.0	17,450	343.5	4,706.4	948.4	3502.8	1,802.5	**3,581.4**		2.2
2011	26,554	488.2	17,700	348.4	4,813.9	970.0	3581.4	1,842.9	**3,656.6**		2.1
2012	26,963	495.8	17,926	352.9	4,917.5	990.9	3656.7	1,881.7	**3,728.3**		2.0
2013	27,371	503.3	18,173	357.7	5,018.0	1,011.1	3728.2	1,918.5	**3,797.7**		1.9
2014	27,678	508.9	18,393	362.1	5,122.7	1,032.2	3797.7	1,954.2	**3,864.5**		1.8
2015	27,993	514.7	18,616	366.5	5,240.2	1,055.9	3864.5	1,988.6	**3,932.7**		1.8

* - to align forecast to actuals in 2005, the modeled ComEng contains a launch adjustment of 7.0 GWh for 2005-2015


Commercial Sector Model Fit
using long term historical data
Annual Energy - GWh
3500
3000
2500
2000
1500
1000
500
64
66
68
70
72
74
76
78
80
82
84
86
88
90
92
94
96
98
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02
04
06
Actual Load
Model

Industrial Econometric Model Details

Small and Medium Industrial Classes are summed and modeled together.

$$SM\_IND = 0.009305\ RQTOS + 0.7441\ SM\_IND_{-1} - 28.69\ MIGRATE$$

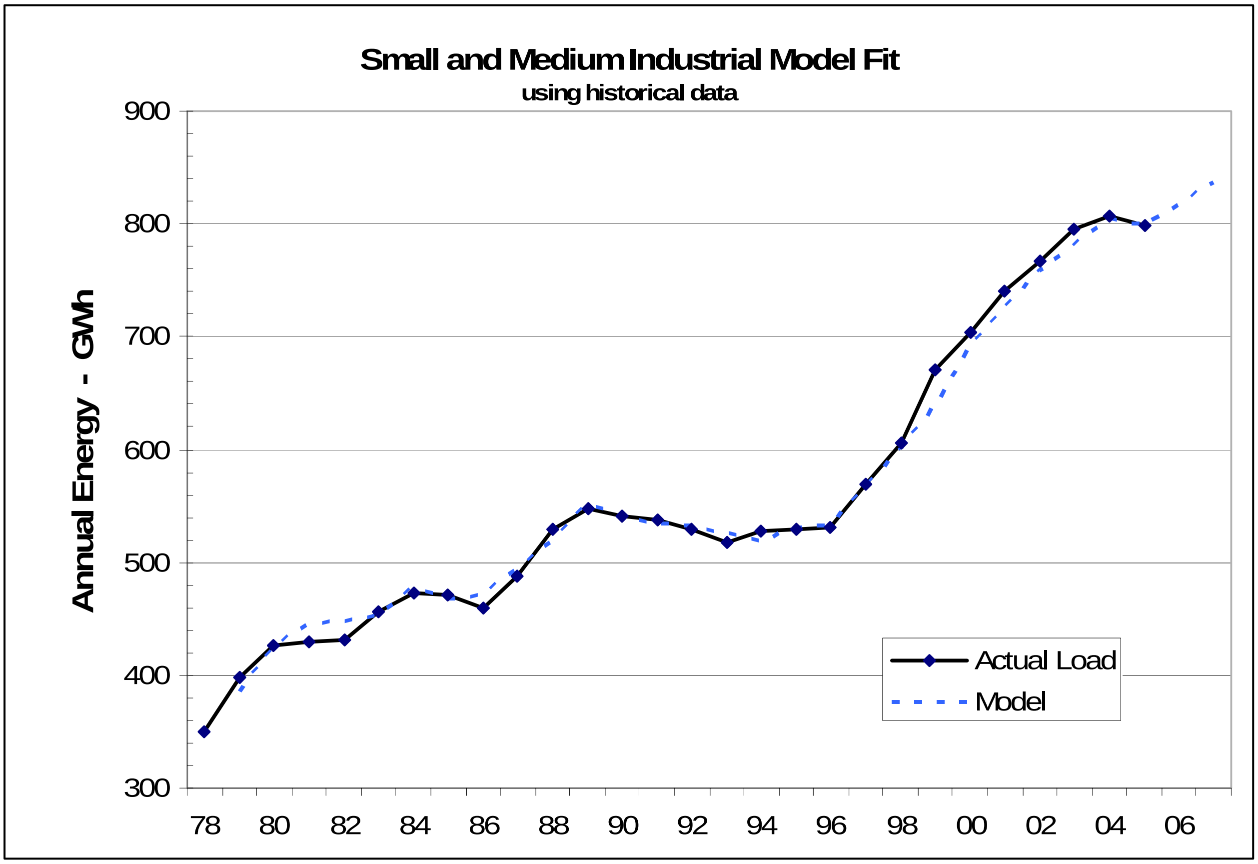
```
Forecast Model for SM_IND
Regression(3 regressors, 0 lagged errors)

Term               Coefficient  Std. Error  t-Statistic  Significance
----------------------------------------------------------------------
MIGRATE             -28.699063    6.694597    -4.286899     0.999745
RQTOS                 0.009305    0.002628     3.540010     0.998331
SM_IND[-1]            0.744101    0.083565     8.904460     1.000000

Within-Sample Statistics
---------------------------------------------------------------
Sample size 27                   Number of parameters 3
Mean 566                         Standard deviation 125.4
R-square 0.9866                  Adjusted R-square 0.9855
Durbin-Watson 1.022              * Ljung-Box(18)=33.36 P=0.9849
Forecast error 15.11             BIC 17.1
MAPE 0.01931                     RMSE 14.24
MAD 10.42
```

Industrial Model Input Variables and Contributions

Year	RQTOS	RQTOS contrib GWh	MIGRATE	MIGRATE contrib GWh	$SM\_Ind_{[-1]}$	$SM\_Ind_{[-1]}$ contrib GWh	SM_Ind* GWh	Actual GWh	Growth %
1994	17,535	163.2	1	-28.7	517.8	385.3	**519.7**	528.3	2.0
1995	17,888	166.4	1	-28.7	528.3	393.1	**530.9**	529.6	0.2
1996	17,922	166.8	1	-28.7	529.6	394.1	**532.1**	530.9	0.3
1997	18,379	171.0	0	0.0	530.9	395.1	**566.1**	569.2	7.2
1998	19,063	177.4	0	0.0	569.2	423.5	**600.9**	606.6	6.6
1999	20,169	187.7	0	0.0	606.6	451.3	**639.0**	670.0	10.5
2000	20,867	194.2	0	0.0	670.0	498.6	**692.7**	703.5	5.0
2001	21,607	201.0	0	0.0	703.5	523.5	**724.5**	740.3	5.2
2002	22,415	208.6	0	0.0	740.3	550.8	**759.4**	766.8	3.6
2003	22,630	210.6	0	0.0	766.8	570.6	**781.1**	795.9	3.8
2004	22,981	213.8	0	0.0	795.9	592.2	**806.1**	806.6	1.3
2005	23,528	218.9	0	0.0	806.6	600.2	**798.2**	798.2	-1.0
2006	24,035	223.6	0	0.0	798.1	593.9	**817.5**		2.4
2007	24,624	229.1	0	0.0	817.5	608.4	**837.4**		2.4
2008	25,097	233.5	0	0.0	837.5	623.2	856.8		2.3
2009	25,582	238.0	0	0.0	856.8	637.5	875.6		2.2
2010	26,103	242.9	0	0.0	875.6	651.6	894.5		2.2
2011	26,554	247.1	0	0.0	894.5	665.6	912.7		2.0
2012	26,963	250.9	0	0.0	912.7	679.2	930.1		1.9
2013	27,371	254.7	0	0.0	930.1	692.1	946.9		1.8
2014	27,678	257.5	0	0.0	946.9	704.6	962.2		1.6
2015	27,993	260.5	0	0.0	962.2	715.9	976.5		1.5


Small and Medium Industrial Model Fit
using historical data
Annual Energy - GWh
900
800
700
600
500
400
300
78
80
82
84
86
88
90
92
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06
Actual Load
Model

Table A1: Energy Requirement – 2006 NSPI Forecast

Energy Forecast

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	4,204	2.2	3,275	1.6	3,362	-20.2	10,841	-6.2	907	11,748	-4.8
2007	4,327	2.9	3,345	2.1	4,388	30.9	12,060	11.2	921	12,981	10.5
2008	4,466	3.2	3,423	2.3	4,438	1.1	12,327	2.2	945	13,272	2.2
2009	4,588	2.7	3,503	2.3	4,487	1.1	12,578	2.0	966	13,545	2.1
2010	4,706	2.6	3,581	2.2	4,536	1.1	12,824	2.0	988	13,812	2.0
2011	4,814	2.3	3,657	2.1	4,585	1.1	13,056	1.8	1008	14,064	1.8
2012	4,918	2.2	3,728	2.0	4,633	1.0	13,279	1.7	1027	14,306	1.7
2013	5,018	2.0	3,798	1.9	4,680	1.0	13,496	1.6	1046	14,542	1.6
2014	5,123	2.1	3,864	1.8	4,726	1.0	13,713	1.6	1065	14,778	1.6
2015	5,240	2.3	3,933	1.8	4,771	1.0	13,944	1.7	1085	15,028	1.7

Table A2: Coincident Peak Demand - 2006 NSPI Forecast

Peak Forecast

Year	Net System Peak MW	Growth %	Non-Firm Peak MW	Growth %	Firm Peak MW	Growth %
2000	2009	6.6	412	33.3	1597	1.3
2001	1988	-1	369	-10.4	1619	1.4
2002	2078	4.5	348	-5.7	1730	6.9
2003	2074	-0.2	291	-16.4	1783	3.1
2004	2238	7.9	377	29.6	1861	4.4
2005	2143	-4.2	392	4.0	1751	-5.9
2006	2029	-5.3	386	-1.5	1644	-6.1
2007	2256	11.2	381	-1.3	1876	14.1
2008	2312	2.4	385	1.2	1927	2.7
2009	2363	2.2	390	1.1	1973	2.4
2010	2413	2.1	394	1.1	2019	2.3
2011	2460	1.9	399	1.1	2061	2.1
2012	2504	1.8	403	1.1	2102	2.0
2013	2548	1.7	407	1.0	2141	1.9
2014	2592	1.7	411	1.0	2181	1.9
2015	2639	1.8	415	1.0	2224	2.0

Table A3: Energy Sales by Rate Class - 2005 NSPI Forecast

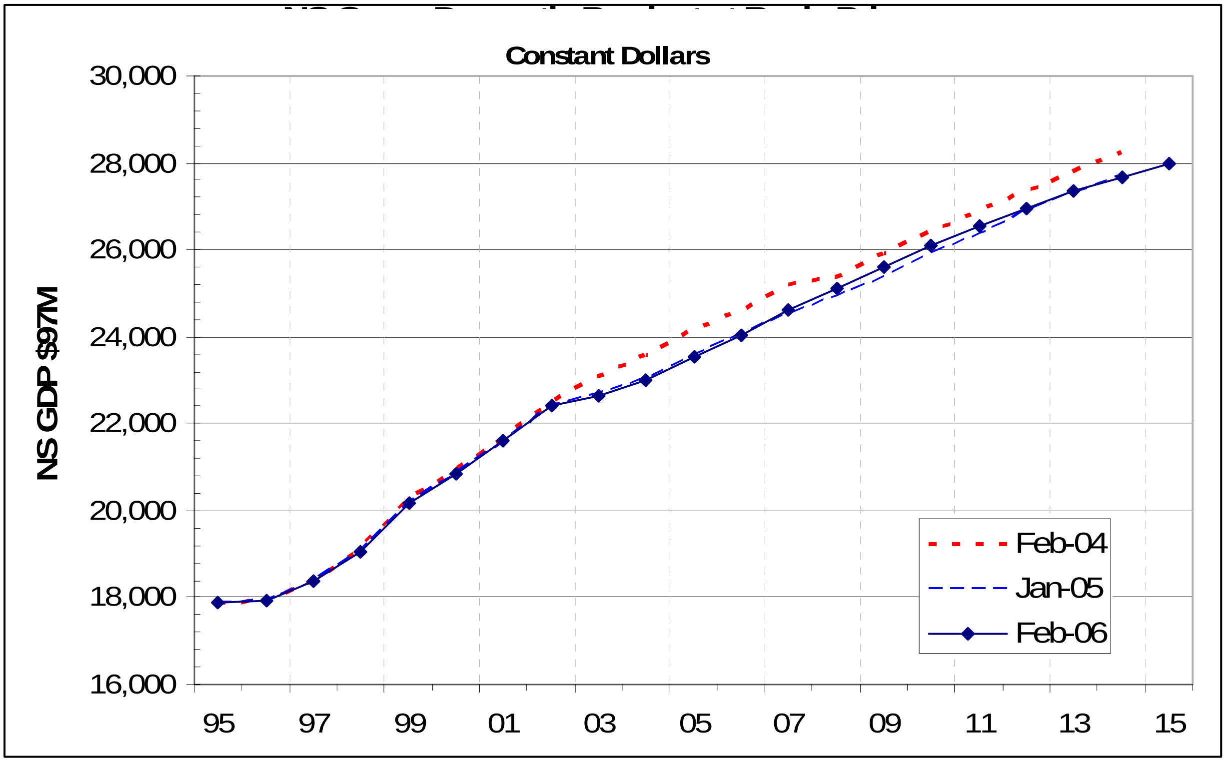
Rate Class Energy Sales

Class Sales (GWh)	2002 Actual	2003 Actual	2004 Actual	2005 Actual	2006	2007
Residential	3,760	3,940	4,040	4039	4130	4251
Small General	104	109	165	232	237	242
General Demand	2,350	2,417	2,426	2381	2424	2476
Large General	358	375	401	413	413	421
Unmetered	100	102	105	108	110	112
Small Industrial	235	238	239	241	247	253
Medium Industrial	531	558	567	557	571	585
Large Industrial	292	330	135	143	135	137
RTP	85	26	49	234	161	218
L.I. Interruptible	1,038	1,147	924	853	924	942
Mersey System	190	190	190	190	189	189
Mersey Additional Energy					179	179
GR&LF	444	385	223	190	12	12
Municipal	178	184	190	191	192	196
Ind. Expansion Rate	968	1,158	0	0	0	0
ELII Rate	0	0	1,870	1791	930	1858
Total Billed Sales	10,635	11,158	11,525	11,564	10,853	12,072
Losses & Unbilled	866	851	863	774	895	909
Net System Requirement	11,501	12,009	12,388	12,338	11,748	12,981

Appendix B

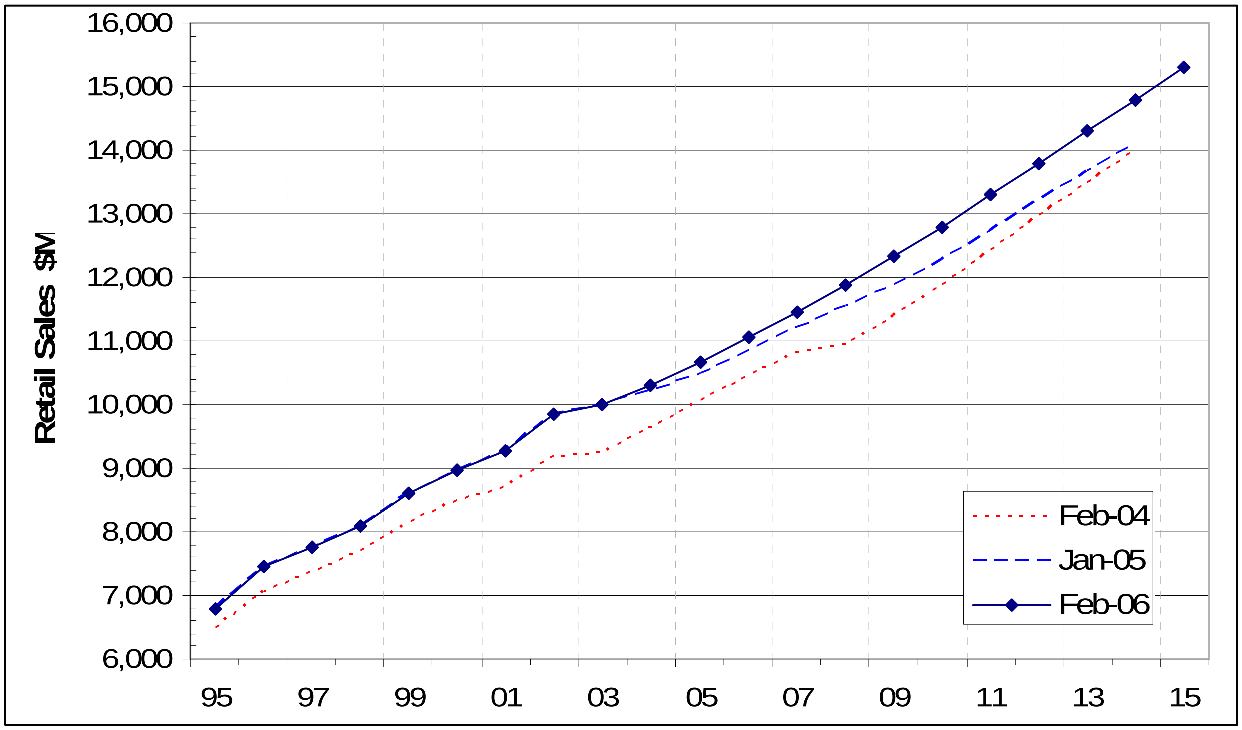
Figures

Figure B1: NS Gross Domestic Product Basic Prices



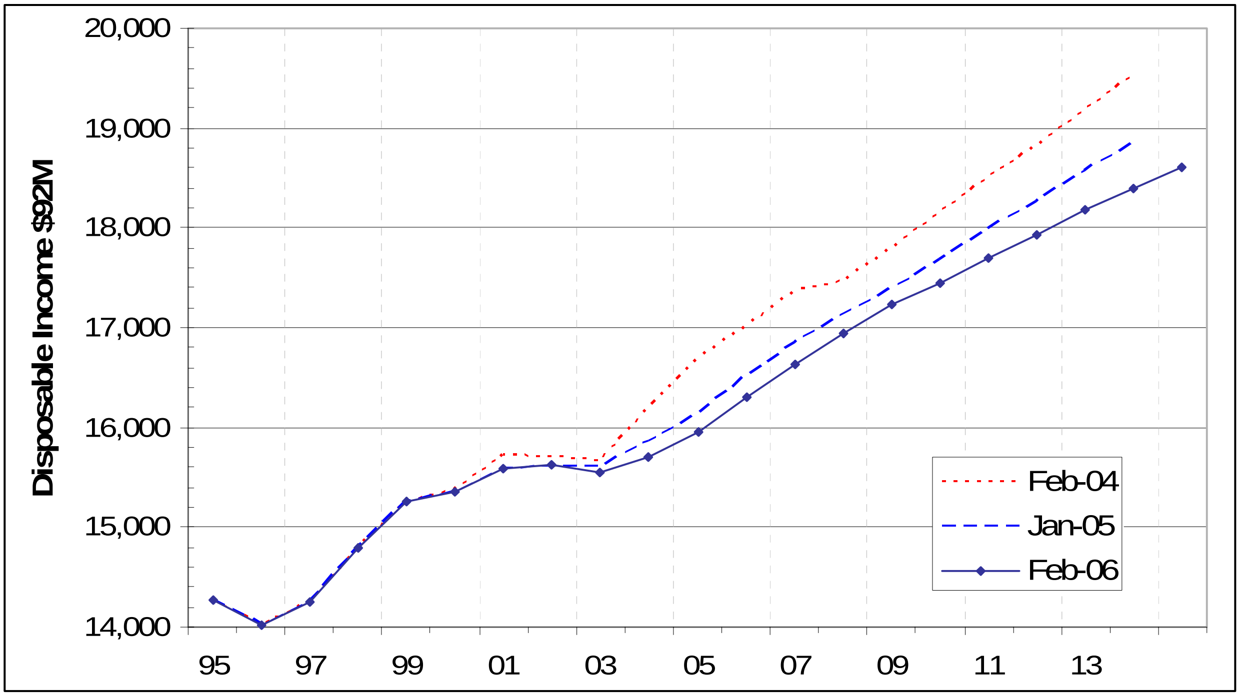
Note: Statistics Canada often re-estimates historical information to reconcile with changes in variable composition and to ensure historical consistency with forecasts. This is the case in the graph above.

Figure B2: NS Retail Sales



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

Figure B3: NS 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: NS Energy Sales

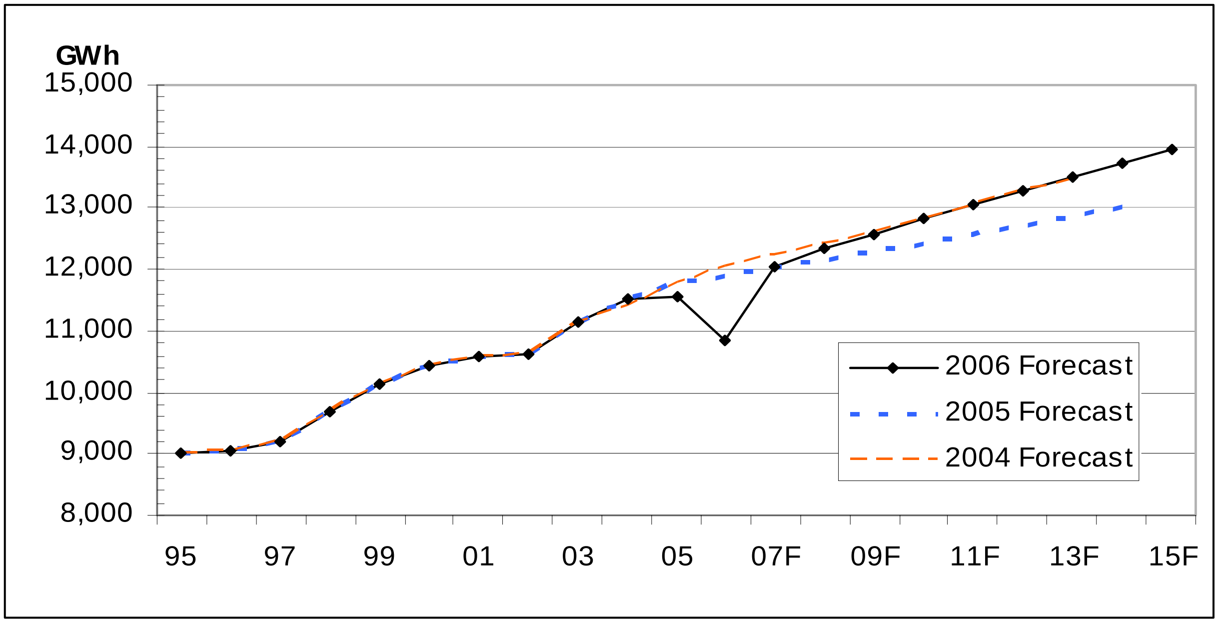


Figure B5: Total NS Energy Losses

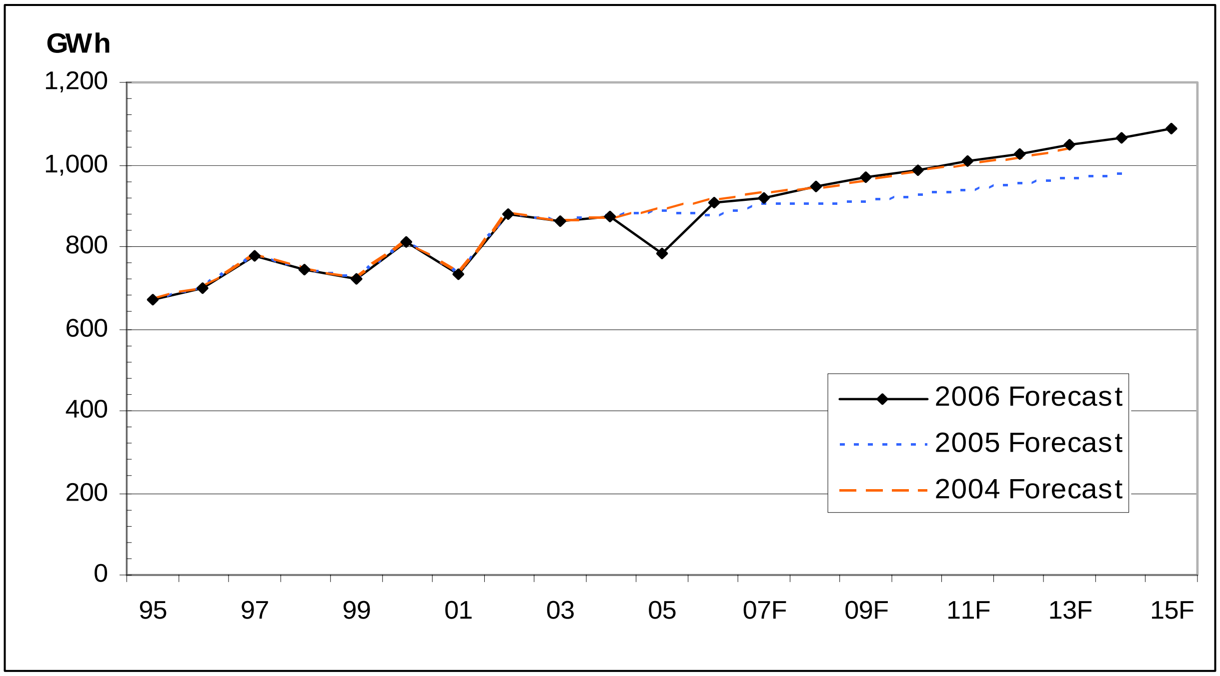


Figure B6: Total NS Energy Requirement

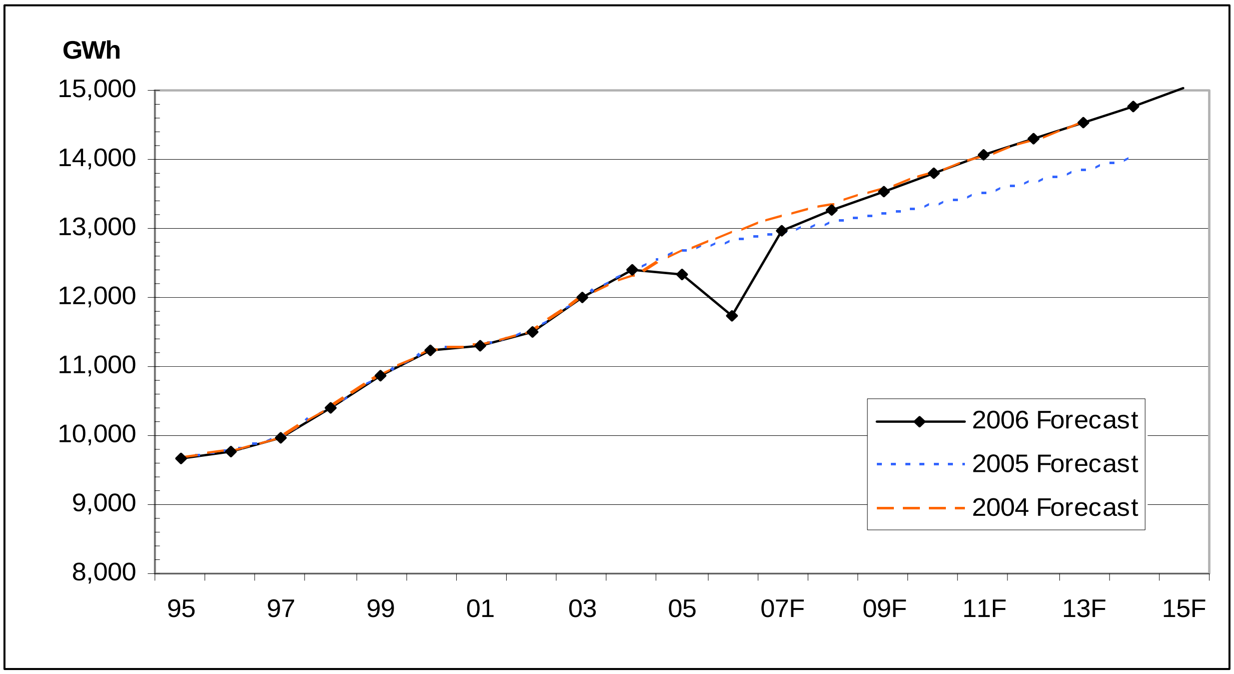
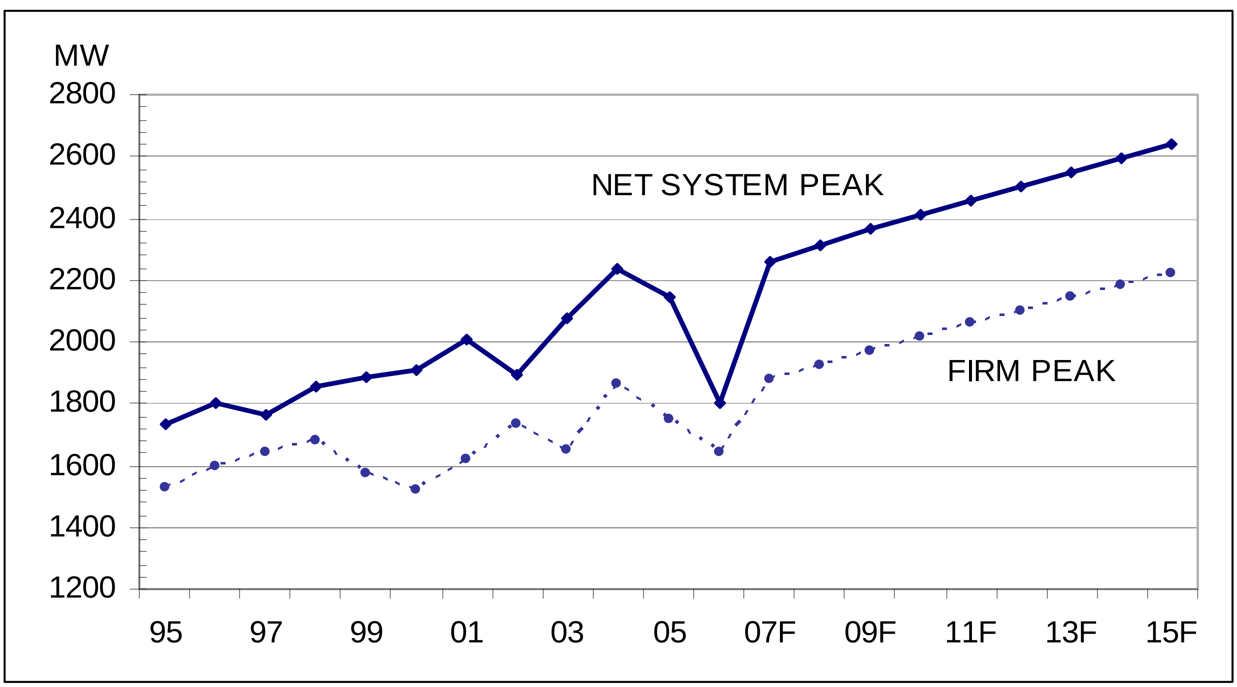


Figure B7: Net System Peak Demand and Firm Peak Demand



Appendix C

High and Low Forecast Scenarios

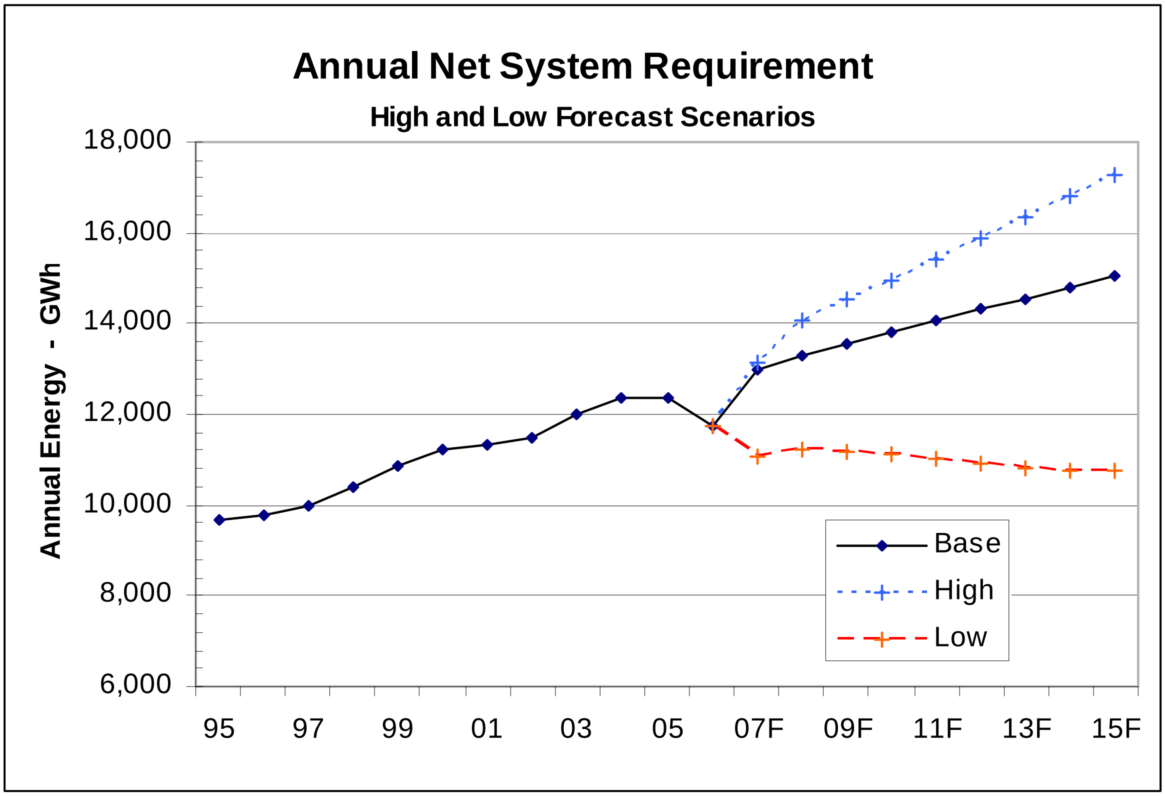
Appendix C: High and Low Forecast Scenarios

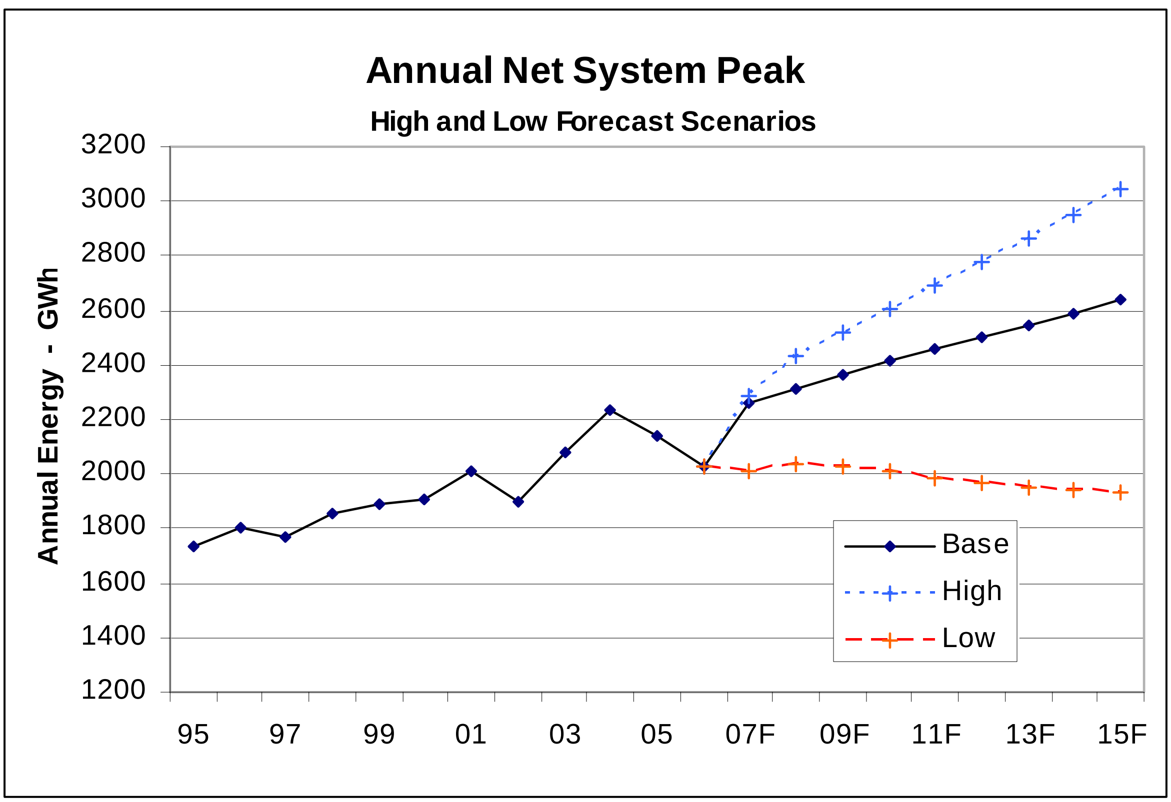
High and Low Forecast Scenarios

Low Forecast Scenario Assumptions	
1	*Major Paper Mill Closure (- 1,700 GWh /yr from 2007 onward)*
2	*Economic Growth Diminishes (Base case growth rate decreases by 50%)*
3	*45% reduction in home heating oil price in 2007*
4	*Electricity Price Increase (10% above base case)*
5	*Residential customer additions (base case reduced by 250/yr)*

High Forecast Scenario Assumptions	
1	New industrial load base added, +500 GWh/year, beginning in 2008
2	Economic Growth Improves (Base case growth rate increases 50%)
3	78% increase in home heating oil price in 2007
4	*Electricity Price decrease (10% below base case)*
5	Residential customer additions (base case +250/yr)

	Low		**Base**		**High**	
Year	NSR GWh	Peak MW	NSR GWh	Peak MW	NSR GWh	Peak MW
2007	11,084	2228	12,981	2,257	13,125	2,285
2008	11,210	2254	13,272	2,312	14,071	2,433
2009	11,184	2247	13,545	2,363	14,513	2,517
2010	11,100	2229	13,812	2,413	14,971	2,604
2011	10,998	2207	14,064	2,460	15,430	2,691
2012	10,904	2187	14,306	2,504	15,887	2,778
2013	10,828	2171	14,542	2,548	16,344	2,864
2014	10,772	2159	14,778	2,592	16,801	2,952
2015	10,752	2154	15,028	2,639	17,273	3,042


Annual Net System Requirement
High and Low Forecast Scenarios
Annual Energy - GWh
18,000
16,000
14,000
12,000
10,000
8,000
6,000
95
97
99
01
03
05
07F
09F
11F
13F
15F
Base
High
Low


Annual Net System Peak
High and Low Forecast Scenarios
Annual Energy - GWh
3200
3000
2800
2600
2400
2200
2000
1800
1600
1400
1200
95
97
99
01
03
05
07F
09F
11F
13F
15F
Base
High
Low

Appendix D

Forecast Sensitivity by Major Variable

Appendix D: Forecast Sensitivity by Major Variable

Forecast Sensitivity by Major Variable

Based upon the 2006 load forecast models, the following table shows the relative sensitivity of the forecast to changes in various input assumptions.

Variable	Assumed Change	Effect on 2007 Load GWh	Effect on 2011 Load GWh
Lagged Dependent Variable 2% growth on base year, 2005	Residential	27.2	2.2
	Commercial	18.7	1.3
	Industrial	9.7	3.0
	All	55.5	6.5
Retail Sales	+2%/yr (2006 on)	58.3	286.7
Gross Domestic Product	+2%/yr (2006 on)	55.3	273.3
Real Disposable Income	+2%/yr (2006 on)	17.8	79.8
Residential Electricity Price	+10% in 2006	-66.0	-97.1
Heating Degree-Days	+ 200 HDD/yr (2006 on)	68.0	112.9
Heating Oil Price	+10¢ per litre (2006 on)	10.0	69.7
Residential Customer Additions	+2000/yr (2006 on)	26.0	113.4

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

Nova Scotia Utility and Review Board

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

- and -

IN THE MATTER OF An Application of Nova Scotia Power Incorporated for Approval of NSPI's Revised DSM Plan (Proposed General DSM Programming)

Nova Scotia Power Inc.

DIRECT EVIDENCE

DATED: September 8th, 2006

NOVA SCOTIA UTILITY AND REVIEW BOARD

IN THE MATTER OF: **The *PUBLIC UTILITIES ACT*, R.S.N.S. 1989, c.380 as amended**

- and -

IN THE MATTER OF: **An Application of Nova Scotia Power Incorporated for Approval of NSPI's Revised DSM Plan (Proposed General DSM Programming)**

NOTICE OF APPLICATION

TO: The Nova Scotia Utility and Review Board.

1. Nova Scotia Power Incorporated ("NSPI") is a public utility incorporated pursuant to the Companies Act, and conducts its business in Nova Scotia and is engaged in the production and supply of electric energy.

2. The most recent rate application for a general rate increase was submitted by NSPI on July 5, 2005 (the 2006 Application). The Nova Scotia Utility and Review Board (UARB, Board) issued a Decision in this matter on March 10, 2006.

3. Included in the Board's Decision was a directive for NSPI to file, no later than June 30, 2006, a revised DSM plan.

4. On May 2, 2006, the UARB revised the date of this filing to September 8, 2006.

5. In its March 10, 2006 Order, the UARB indicated that a separate hearing would be held in the second half of 2006.

6. The Company therefore makes this Application for Approval of NSPI's Revised DSM Plan (Proposed General DSM Programming).

7. In support of this Application is filed the Direct Evidence of NSPI.

8. NSPI seeks Direction from the Board providing for:

    a) Pre-hearing procedures
    b) Setting the date for the hearing
    c) Such other matters as the Board deems fit.

Dated at Halifax, Halifax Regional Municipality, Province of Nova Scotia this 8th day of September, 2006.

NOVA SCOTIA POWER INCORPORATED

Per: C M'Carthy
for Ralph R. Tedesco
Chief Executive Officer

Names and Addresses for Service:

J. Rene Gallant,
Regulatory Counsel,
Nova Scotia Power Incorporated

Address:	14th Floor, Barrington Tower 1894 Barrington Street
Mail:	P.O. Box 910 Halifax, NS B3J 2W5
Telephone:	902-428-6408
Fax:	902-428-6542
E-mail:	rene.gallant@nspower.ca

Alan Richardson,
General Manager, Customer Service,
Nova Scotia Power Incorporated

Address:	16th Floor, Barrington Tower 1894 Barrington Street
Mail:	P.O. Box 910 Halifax, NS B3J 2W5
Telephone:	902-428-6228
Fax:	902-428-6990
E-mail:	alan.richardson@nspower.ca

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1.0 FORWARD

NSPI and Summit Blue would like to thank the following individuals / organizations for participating in the process of developing this revised plan:

- Judy McMullen, Clean Nova Scotia
- Brendan Haley, Ecology Action Centre
- Marcus Goodick, Ecology Action Centre
- Hudson Shotwell, Ecology Action Centre
- Jeff Brown, Ecology Action Centre
- Stephen King, Halifax Regional Municipality
- Julian Boyle, Halifax Regional Municipality
- John Merrick, Consumer Advocate
- Nancy Brockway, Nbrockway and Associates (Consultant to Consumer Advocate)
- Heather Foley-Melvin, Conserve Nova Scotia
- Peg MacInnis, Consultant to Conserve Nova Scotia
- Jena Cole, NDP Caucus
- Stephen McGrath, Nova Scotia Department of Justice
- Brian Hayes, Nova Scotia Department of Energy
- Richard Penny, Nova Scotia Department of Energy
- Howlan Mullally, Nova Scotia Department of Energy
- Nancy Rondeau, Nova Scotia Department of Energy
- Megan Leslie, Dalhousie Legal Aid Service/Affordable Energy Coalition
- Sheema Hosain, Dalhousie Legal Aid Service/Affordable Energy Coalition
- Robert Patzelt, Scotia Investments Ltd./CME
- David Henry, Canadian Salt, Pugwash
- Ross Young, NSUARB
- George Smith, NSUARB

- John Stutz, Tellus Institute (Consultant to the Board)
- Carmen Dunn, ACAP Cape Breton
- Bruce Young, ACAP Cape Breton
- Larry Hughes, Dalhousie University
- Mandeep Dhaliwal, Dalhousie University
- Niki Sheth, Dalhousie University
- Aaron Long, Dalhousie University
- Al Joseph, Dalhousie University
- John Woods, ECANS
- Sunday Miller, Adsum House
- David MacDougall, McInnes Cooper
- Adam Garrett, McInnes Cooper
- Terry Gerhardt, Minas Basin Pulp & Paper
- Ross Giffin, Minas Basin Pulp & Paper
- Paul Pettipas, Nova Scotia Home Builders' Association
- Don Regan, Berwick Electric
- Jim Retallack, Consultant to Berwick Electric
- John H. Reynolds, P.Eng., Consultant
- Nancy Rubin, Stewart McKelvey

The willingness of these individuals to share their views has improved the quality of the plan, and bodes well for an effective review as part of forthcoming formal hearings.

While views on specific points may differ, the goal of greater conservation and energy efficiency is clearly a shared objective of all.

2.0 INTRODUCTION

In this filing, NSPI is providing a Demand Side Management (DSM) Plan, which has been revised from the version filed with the Board in 2005. The revisions are based in large part on recommendations NSPI received from its consultant Summit Blue, an expert in the field of utility DSM, hired to assist NSPI in finalizing the plan. The engagement of an external DSM expert and the filing of the revised plan were directed by the UARB in its March 10th, 2006 Decision.

NSPI's revised DSM Plan (Proposed General DSM Programming) is attached as APPENDIX A and includes general conservation, energy efficiency, and demand management programs for all customer segments, for a two year period.

The consultant's DSM Report is attached as APPENDIX B.

2.1 Background/Timelines

As part of its 2006 Rate Application, NSPI proposed to invest an incremental $5 million in conservation and energy efficiency programs. Prior to the hearing, NSPI submitted its proposed 2006 Conservation and Energy Efficiency Plan.

In its March 10, 2006 Decision, the UARB commended NSPI's efforts in preparing this DSM plan. It also concluded that the plan needed additional design work and resources. The Board directed NSPI to retain an outside consultant to complete the Plan's design and development. In the Decision, the Board set April 15, 2006 as the filing date for the terms of reference for hiring the consultant, and also set June 30, 2006 as the date for NSPI to file the revised Demand Side Management Plan. The Board also advised that it would monitor the process of retaining and selecting the consultant.

On April 13, 2006, NSPI filed its draft terms of reference for hiring a DSM consultant. On May 2, 2006, the Board revised the date for filing the completed DSM Plan to September 8th, 2006. On May 12, 2006 NSPI issued the Board approved Request for Proposal (RFP) for DSM Consulting Services. The closing date for proposal submissions was May 26, 2006 and on June 23, 2006, after receiving Board approval, NSPI awarded the DSM contract for consulting services to Summit Blue.

On July 14, 2006 NSPI held its first DSM Stakeholder Session during which Summit Blue discussed their approach and solicited views and comments from the group. Throughout the course of Summit Blue's work, the DSM Stakeholders were encouraged to provide input, views, and feedback for the consultant's consideration, and this was shared via email and as maintained on a website where DSM Stakeholders had read-only as well as download access.

On August 15, 2006, Summit Blue submitted the first draft of their DSM Report and on August 18, 2006 a second DSM Stakeholder session was held during which Summit Blue presented highlights of the report and provided opportunity for group discussion. Over the following week, DSM Stakeholders were asked to submit feedback for Summit Blue to take into consideration as they finalized the DSM Report.

On September 1st, 2006, Summit Blue submitted the final DSM Report along with recommended General DSM Programming.

3.0 CUSTOMER FOCUS

NSPI's customers have expressed strong interest in Conservation and Energy Efficiency. The expectations that NSPI should do more to advance energy efficiency and conservation were clear in our November 2004 research conducted with customers to gather their views on how Nova Scotia should meet future supply needs. Addition of renewable generation, particularly wind, was our customers' first choice. Second was for NSPI to pursue more demand side management, particularly energy efficiency and conservation. NSPI's second Customer Energy forum in 2005, and its associated customer survey, provided further supporting information on our customers' expectations in the area of Conservation and Energy Efficiency.

4.0 NSPI'S ASSESSMENT OF CONSULTANT RECOMMENDATIONS

4.1 Nova Scotia Power's Role

The consultant was asked to specifically address whether the objectives of DSM may conflict with the Utility's business of generating and selling electricity including pursuing its shareholders' interests, and whether NSPI should be implementing the DSM plan.

Consultant's Recommendations:

- NSPI should administer DSM programs, leveraging the work being done by Natural Resources Canada and the provincial government, while outsourcing much of the program delivery to local agencies. NSPI should position these programs as customer service programs and use them to help promote the NSPI brand.

- NSPI should implement the programs using both in-house staff and outsourcing the delivery of services (for example weatherization services) to local community groups.

NSPI fully supports these recommendations.

4.2 Level of Investment

The consultant was asked to discuss and recommend a reasonable level of DSM spending for NSPI.

Consultant's Recommendation:

- The spending on DSM programs should start at 0.7% of in-province electric revenues and ramp up to 2% by 2010.

NSPI believes that the consultant's recommendation offers a reasonable range of suggested spending years 1 and 2. NSPI believes that levels beyond year 2 should be evaluated further, and should as well be re-evaluated after year 1 results vs. targets are known.

4.3 DSM Programming

The consultant was asked in general to provide discussion and recommendations on NSPI's overall approach to DSM. Other specific items for the consultant to address included: an assessment of public education and youth education as DSM program elements; and a suggested non-discriminatory means for reaching low income families with NSPI's DSM plan. Additionally, the consultant was asked to discuss the appropriateness of the methodology NSPI used for economic evaluation of programs.

Consultant's Recommendations:

- Calculate the Total Resource Cost (TRC) test to determine the program cost-effectiveness, and also calculate Rate Impact Test (RIM) to determine the impact of the DSM programs on customer rates and the Utility Cost Test (UCT) to determine the utility benefits.

- NSPI should promote and leverage Natural Resources Canada, including program delivery where possible.

- Funds for additional demand response program development and pilot programs should be included in the DSM portfolio.

- The DSM programs should provide rebates & incentives to overcome the high first cost market barrier.

- The NSPI DSM programs should only provide incentives for electricity savings measures.

- The DSM plan should include programs for all sectors: residential, low-income, commercial, and industrial. Low-income program spending should be up to 10% of the overall residential budget.

- Overcome the split incentive for low-income renters by working with the multi-family building owners to install DSM measures.

- NSPI should expand their education and outreach efforts, not only as a means to increase awareness and knowledge, but to direct consumers to one of their programs.

- The energy/demand savings from education and outreach should not be included in the overall portfolio impacts.

In general, NSPI is supportive of the above recommendations. Of note, the following are NSPI's more specific comments:

Industrials

In its DSM Report and proposed DSM Programming, the consultant suggested an increased level of DSM activity for the Industrial customer sector. NSPI is supportive of this as it aligns with the Canadian Electricity Association (CEA)'s national DSM Potential study *"Demand Side Management Potential in Canada"* conducted by Marbek Resource Consultants Ltd., as well as another recent DSM potential study for Industrial customers in New Brunswick entitled *"Energy Performance Benchmarking & Best Practices in the New Brunswick Industrial and Manufacturing Sector"* conducted by the Canadian Manufacturers and Exporters Association in association with Neill and Gunter Ltd. and Marbek Resource Consultants Ltd.

Low Income

Nova Scotia Power recognizes that customers with low income can be particularly affected by rising energy costs. This group was identified during last year's planning work with stakeholders as an important sub-group of residential customers. The consultant's DSM Report and proposed DSM Programming suggest ways of reaching this important sub-group. NSPI is prepared to adopt Summit Blue's recommendation should the Board conclude that such a program is permitted under regulation.

4.4 Recovery in Rates

The consultant was asked to assess and make recommendations on the methodology for allocation of DSM costs among rate classes.

Consultant's Recommendations:

- Costs of the DSM programs should be allocated across the entire rate base.

- Lost margins due to lower sales of electricity should be addressed through a reconciliation procedure (annual rate case or lost revenue recovery) or a decoupling of revenues by tying them to the number of customers and weather adjusted sales, so that it is not a disincentive to utility investment in DSM.

- The regulators should offer additional incentives for meeting or exceeding DSM targets.

NSPI can support these measures, should the Board determine they should be included in our DSM plan.

4.5 Tracking and Reporting of Results

The consultant was asked to comment on program evaluation methodology.

Consultant's Recommendations:

- Detailed evaluation plans should be developed for each of the programs. These plans should include the use of integrated data collection as part of the program administration, to help reduce the costs and uncertainty in future evaluation data collection.

- A robust program data tracking system should be developed as part of the final DSM program development to ensure that the data needed for evaluation purposes is being collected.

- Review level of DSM spending every two years.

- A more extensive avoided cost study than was used for this assignment should be considered in the next 2-3 years to better account for the total benefits of DSM measures. The deployment of these recommendations should proceed in the meantime.

- In the next 1-2 years a more detailed DSM potential study should be performed, to better understand where the potential for savings in Nova Scotia exists. The potential study completed as part of this project provides a sufficient foundation from which to launch the initial DSM programs in Nova Scotia. A more detailed study will help focus these programs further.

NSPI's is supportive of these recommendations.

5.0 CLOSING

NSPI's revised DSM Plan (Proposed General DSM Programming) is attached as APPENDIX A and includes general conservation, energy efficiency, and demand management programs for all customer segments, for a two year period.

The consultant's DSM Report is attached as APPENDIX B.

APPENDIX A

Revised DSM Plan

(Proposed General DSM Programming)

(September 8, 2006)

NOVA SCOTIA POWER INCORPORATED

Proposed General DSM Programming

September 8, 2006

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1.0 GENERAL PROGRAM DESCRIPTIONS - SUMMARY

The following section discusses the programs included in NSPI's DSM plan and the key attributes of each these programs. These are general program descriptions with key program highlights and are not meant to be full program implementation plans. It will require several months after receiving regulator approval before the DSM programs will be ready to be rolled out. The program development process has just been started in this general plan and will take additional planning.

Table 1 presents a summary of the portfolio of DSM programs. The overall benefit cost ratio using the TRC test is 3.84, which includes the cost of the Education and Outreach program. These numbers are approximate and may change up or down depending on final program design.

Table 1: Program Portfolio Summary

Program	Year 1 Coin. Peak Demand Savings (kW)	Year 1 First Year Energy Savings (MWh)	Year 1 Total Program Costs ($000)	Year 2 Coin. Peak Demand Savings (kW)	Year 2 First Year Energy Savings (MWh)	Year 2 Total Program Costs ($000)	TRC
Residential New Construction	246	1,197	$326	393	1,915	$520	2.4
Residential Existing	988	5,397	$1,375	1,581	8,636	$2,199	3.2
Residential Products	1,552	6,795	$1,800	2,483	10,872	$2,880	3.2
C&I Existing	3,332	27,696	$2,516	5,331	44,314	$4,024	4.3
C&I New Construction	386	3,394	$308	618	5,430	$493	5.1
Education			$223			$416	
Future Programs			$100			$100	
Portfolio Totals	**6,504**	**44,479**	**$6,548**	**10,406**	**71,167**	**$10,532**	**3.8**

2.0 RESIDENTIAL PROGRAMS AND INITIATIVES

2.1 New Construction "EnerGuide for New Houses" (or equivalent)

Target Market

Purchasers, developers and builders of new houses that use either a Heat Pump or Electric Thermal Storage being constructed in Nova Scotia Power's service area.

Objectives

The primary objective of the program is to stimulate the installation of energy-efficient products in new home construction. Since the federal government discontinued EnerGuide programs for houses in May of 2006, we will refer to it as EnerGuide (or equivalent) in our discussion. By equivalent, we are making an assumption that the infrastructure of such a program will exist at a government level and NSPI will have an opportunity to build on it as described below. Secondary objectives are to achieve new minimum energy-efficiency legislation for windows, and mandatory energy performance labeling and levels for new houses.

Specifically, the program's deliverables are to:

- Encourage homebuilders to utilize the EnerGuide for New Houses (EGNH) (or equivalent) labeling tool to build a more energy-efficient home, leading to mandatory labeling for new homes.
- Encourage homebuilders to install ENERGY STAR labeled windows, leading to a new minimum energy-efficiency standard for windows in NS.
- Encourage homebuilders to include energy-efficient products that are not captured within the EGNH (or equivalent).
- Educate customers about the benefits of having energy-efficient technologies in their homes and influence their buying decisions.

Technology

- EnerGuide for New Houses was a federal government program that has been offered to existing residential customers for nearly two years. The program is delivered by an agent that collects data on a home's planned building envelope and heating system and then uses software to model the homes expected energy consumption. Suggested improvements are given to the builder and built into the home's design to improve its expected energy performance. The home is then rated on a scale of 0-100 based on its modeled energy performance. Labeling the home provides homebuyers with a benchmark of how energy-efficient a home is relative to other homes. The federal government target was for all new homes to be rated as an EGNH 80 by 2010.
- ENERGY STAR labeled windows are designed and tested to perform better than standard new windows, thereby reducing heat loss from a home. Performance is normally improved through the use of a low-emissivity (low-e) coating, advanced frame design, improved spacer bars and inert gases.
- There are numerous electricity consuming devices that are installed in a new home by a builder outside of heating systems and the building envelope. Packages of energy-efficient products can target specific end-use devices and encourage builders to install ENERGY STAR labeled products.

ENERGY STAR labeled products that could qualify for incentives include:

- Lighting
- Appliances
- Ventilation
- Heating

Market Barriers

- Capital cost difference between standard products and energy-efficient models, which customers are not willing to pay for, and as a result developers are not willing to install.
- Low builder and residential customer awareness of energy-efficiency options in new construction.

Program Description

Each year, approximately 3,000 new homes are built in Nova Scotia Power's service area, creating new load for the utility. Within these new homes exist numerous untapped opportunities to implement energy-efficiency measures. These opportunities are in the areas of space heating, building envelope, lighting, ventilation, and appliances.

Participating customers who have builders upgrade the design of their new home utilizing the EnerGuide for New Houses (or equivalent) software to achieve an EnerGuide rating of 77 or better, install ENERGY STAR labeled windows or packages of ENERGY STAR products will qualify for incentives based on what they have installed or achieved. Builders will receive documentation to assist them in informing customers about the energy-efficient components of their homes and to drive customer demand for ENERGY STAR products. Advertising in targeted media to builders and new home buyers is critical for generating interest, understanding, and ultimately market pull. Program management and field staff work with developers to help enhance their knowledge and gain their support for the program.

The incentives will be offered for new houses that use either a Heat Pump or Electric Thermal Storage, and participate in the EnerGuide for New Houses program, and upgrade to achieve an EnerGuide rating of 77 or higher.

NSPI plans to work with both federal and provincial governments as well as program and service delivery agencies to develop the implementation of this program.

Another objective of the program is to achieve Provincial legislation for minimum window efficiency standards and energy labeling of new homes. Nova Scotia Power's involvement in the new home construction market can help gain customer, builder and manufacturer participation in these initiatives.

Customer Benefits

- Builders and developers may increase use of energy-efficient features in their home construction.
- Customers reduce energy usage.
- Customers with low-e glass in their house can expect a more comfortable home in the summer as a result of reduced solar gain.

Approximate Budget: Year 1 and Year 2

Program Costs	Year 1	Year 2
Delivery/Admin	$81,000	$130,000
Marketing	$72,000	$115,000
Incentives	$63,000	$100,000
Technical Assistance	$97,000	$155,000
Monitoring & Evaluation	$13,000	$20,000
Total	**$326,000**	**$520,000**

Approximate Expected Results: Year 1 and Year 2

	Year 1	Year 2
Energy (MWh)	1,196	1,915
Demand (kW)	246	393
Participants	247	396
TRC Ratios	2.4	2.4

2.2 EnerGuide for Existing Houses (or equivalent)

Target Market

Owners of existing electrically heated houses in Nova Scotia Power's service area, along with their renovators and contractors.

Objectives

The primary objective of the program is to stimulate the installation of energy-efficient measures in existing houses.

Specifically, the program's deliverables are to:

- Encourage homeowners to improve the overall efficiency of the building envelope of their house.
- Encourage homeowners to install ENERGY STAR labeled windows, HVAC equipment and appliances as appropriate when renovating their house.
- Educate customers about the benefits of having energy-efficient technologies in their homes and influence their buying decisions.

Technology

Although each house is unique, some general statements can still be made about retrofit opportunities.

- Virtually all houses will benefit from air-leakage control. Weather-stripping and sealants will stop drafts, save money, improve comfort and protect the structure. Moisture control and ventilation may help reduce condensation problems.
- Insulate a poorly insulated attic.
- Insulate an empty frame wall. If there is no insulation in a frame wall, insulation should be added to fill the cavity.
- Insulate the basement. Basements are areas of significant heat loss in most houses.
- Make the most of repair and renovation work. Almost all repairs and renovations around the house can have an energy-efficient component piggybacked onto the work.

Market Barriers

- Capital cost difference between standard products and energy-efficient models, which customers are not willing to pay for, and as a result renovators and contractors are not willing to install.
- Low builder and residential customer awareness of energy-efficiency options in equipment replacement markets.
- Low builder and residential customer awareness of building envelope measures such as air sealing.

Program Description

Although the EnerGuide for Existing Houses program was discontinued by the federal government in May of 2006, we are making an assumption that the infrastructure of such a program will continue to exist at a government level. NSPI would work with both federal and provincial governments to help provide a similar program within the province. The program will focus on making real efficiency gains while ensuring homeowners receive the full benefits. NSPI will leverage the program and is willing to work with both federal and provincial governments as well as program and service delivery agencies on the implementation plan and delivery of the program. NSPI was anticipating between 4,500 and 6,000 homes taking advantage of this program in Nova Scotia in 2006 before it was discontinued.

NSPI will supplement the program by adding an element of educational information on the behavioral aspects of conservation and energy efficiency. This may take the form of written material as well as direction to NSPI's web-based information on conservation and energy efficiency. Customers will then be able to combine information on house efficiency with that of simple and practical behavioral tips to maximize their potential energy savings.

NSPI will limit the participation in this program to electrically heated houses, since the funding is provided by electric ratepayers. NSPI will use a simple billing data regression tool to determine if the home uses electricity as their primary source of heat. Similar to the previous federal funding criteria, NSPI would offer financial incentives for eligible homeowners that implement recommendations of the initial assessment causing improvements in the EnerGuide rating of their house.

Low-Income Component

NSPI recognizes that low income households form an important population segment where the potential benefits of energy efficiency may go unrealized in the absence of specific DSM programming responsive to the needs of these customers. NSPI is prepared to include a low income component of this program with Board concurrence that it is permitted under regulation. This low-income component would be developed by modeling it similar to the previous EnerGuide for Low-Income Households program.

The low-income component of this program will have the following characteristics:

- Participation in this program is limited to electrically heated houses
- Participation in the low-income component will not require participant spending.
- The program will partner with existing, credible, recognized community agencies to deliver services to the low-income population.
- The program will incorporate education and outreach components to help customers understand the actual costs of using energy for everyday tasks, such as drying clothes.
- The program will seek partnerships with enough contractors to be able to serve the demand for services by the low-income community.
- Up to 10% of the total Existing Houses budget would be allocated to the low-income component of this program.

Customer Benefits

- Customers reduce energy usage.
- Customers have a more comfortable home.
- The energy-efficient improvements may improve resale value of the home.

Approximate Budget: Year 1 and Year 2

Program Costs	Year 1	Year 2
Delivery/Admin	$291,000	$465,000
Marketing	$198,000	$317,000
Incentives	$542,000	$867,000
Technical Assistance	$291,000	$465,000
Monitoring & Evaluation	$53,000	$85,000
Total	**$1,375,000**	**$2,199,000**

Approximate Expected Results: Year 1 and Year 2

	Year 1	Year 2
Energy (MWh)	5,397	8,635
Demand (kW)	988	1,581
Participants	1,350	2,160
TRC Ratios	3.2	3.2

2.3 ENERGY STAR Retail Products

Target Market

The target market is all 420,000 NSPI residential customers. This includes owners and renters living in all housing types, from single family to multi-family dwellings.

Goals and Objectives

The objective of the ENERGY STAR Products program is to promote ENERGY STAR lighting and appliances which will increase the use of energy-efficient lighting and products in the consumer market and help consumers save money and energy.

Technology

On average lighting accounts for approximately 13% of a household's energy bill, and is one of the easiest areas in a residential household to achieve sustainable savings. The average household has upwards of 30 light bulbs, thereby offering significant market potential.

Compact fluorescent lamps (CFLs) can use up to 75% less energy and last up to eight times longer than standard incandescent bulbs, and also provide peak demand savings especially in winter.

ENERGY STAR refrigerators also save significant energy. A refrigerator built in 1990 uses twice as much energy as a current ENERGY STAR Refrigerator.

Market Barriers

- *Customer awareness:* related to both the existence of the technology and of its benefits and applications. This is mostly a barrier for ENERGY STAR refrigerators.
- *Higher prices* of CFLs relative to standard incandescent bulbs. Higher prices of ENERGY STAR refrigerators compared to standard refrigerators.
- *Quality of technology:* past perceptions of CFL technology may be poor.

Program Description

The program will use two components to sell compact fluorescent lights: direct sale coupons and promotion of the Natural Resources Canada Switch and Save campaign. The program will also offer mail rebates to promote the purchase of ENERGY STAR Refrigerators

NSPI will participate in the national ENERGY STAR Switch and Save promotion. NSPI will leverage the national ENERGY STAR campaign to promote a consistent nationwide message and cut promotion costs.

The direct sales component would sell a wide variety of compact fluorescent bulbs through third party vendors at competitive prices. The actual sale and fulfillment of the bulbs are handled through the lighting vendor who manages and owns the entire lighting inventory. An instant rebate would be offered on selected CFLs and fixtures that meet the ENERGY STAR qualifications.

NPSI will promote ENERGY STAR Lighting using the following:

- Use in-house staff to establish personal contact and work closely with the retailers on the promotion aspects of the lighting incentives (coupon placement, point of purchase displays, implementing buy-downs, etc.). The NSPI representatives will also be the single point of contact for the retailers' participation in the C&I programs.
- Allow multiple bulb purchases per coupon. Instead of requiring the participant to fill out one coupon per bulb, provide space on the coupon for multiple bulbs.
- Don't limit retail CFL purchases to only residential customers. Allow commercial customers to also use the coupons at retailer locations. There should be business and residential check boxes on the coupon so that CFLs being used in commercial applications can be credited with the higher energy savings resulting from the longer hours of use.
- Use short-term community based events to increase awareness. NSPI could enlist the help of local leaders and issue a challenge to the community to meet CFL installation goals over a few months.

CFLs could be offered to the community at a reduced price for the term of the challenge.

Customer Benefits

- Customers reduce energy usage.
- The energy-efficient improvements may improve resale value of the home.

Approximate Budget: Year 1 and Year 2

Program Costs	Year 1	Year 2
Delivery/Admin	$294,000	$471,000
Marketing	$415,000	$665,000
Incentives	$935,000	$1,495,000
Technical Assistance	$87,000	$138,000
Monitoring & Evaluation	$69,000	$111,000
Total	**$1,800,000**	**$2,880,000**

Approximate Expected Results: Year 1 and Year 2

	Year 1	Year 2
Energy (MWh)	6,794	10,871
Demand (kW)	1,552	2,483
Participants	10,219	16,351
TRC Ratios	3.2	3.2

2.0 COMMERCIAL AND INDUSTRIAL PROGRAMS

2.1 Existing Buildings

Target Market

Commercial, institutional, and industrial building owners in Nova Scotia Power's service area.

Objectives

The objective of the program is to encourage customers to integrate energy efficiency into their ongoing business practices.

Technology

The current potential study estimates reveal that there is significant achievable energy savings in lighting, motors and processes. In particular the Existing Buildings program will focus on the following energy savings opportunities:

- Efficient lighting system retrofits, such as converting incandescent light bulbs to compact fluorescent lamps (CFLs), converting T12 lighting systems to T8 lighting systems, natural day lighting, and converting to LED exit signs.
- Efficient HVAC and control systems, such as efficient heating and air conditioning systems, programmable thermostats for local zone temperature control, installing energy management systems to optimize the control of the HVAC systems, building envelope measures such as improved insulation, and other measures.
- Efficient refrigeration measures, such as efficient refrigeration compressors.
- Industrial specific measures should include:
    - Variable speed drives on motors

- Replacement of old air compressor systems with high-efficiency air compressors. All leaks in the systems should be repaired during the upgrade process.
- When replacing old motors, high-efficiency motors should be used.
- Custom rebates for non-prescriptive DSM measures, including industrial process efficiency improvements. Custom measures can apply to commercial customers as well.

Market Barriers

- *Financial:* Energy-efficiency projects compete with other capital projects for budget; therefore, return on investment must be attractive for these projects to receive funding. Pay back periods of greater than 2 years may be a barrier due to the frequent turnover of properties within the property management and developers sub-sector.
- *Resources:* Many customers do not have resources dedicated to energy efficiency; and for some personnel, energy efficiency may be only one of their many areas of responsibility. Without a dedicated internal energy champion, or access to external energy consultants, many energy-efficiency projects never get initiated and others go uncompleted.
- *Strategic Importance:* Many Commercial/Industrial customers identify customer comfort, an appropriate ambience, and selling their product as being a greater priority for them than energy efficiency.
- *External Barriers:* There are key market barriers that cannot be influenced by NSPI programs, but impact customer participation and the ability to achieve targets. The key external barrier in the

Commercial/Industrial sector is global and North American economic conditions/climates.

- *Awareness & Understanding:* Many Commercial/Industrial customers are not fully aware of the benefits of energy efficiency, alternative energy-efficient technologies available on the market, and energy-efficiency programs available to help them. There also may be a disconnect between what motivates property developers and the tenants that will occupy the space.

Program Description

Almost 90% of the achievable energy savings is expected to come from the existing commercial and industrial (C&I) facilities in the NSPI service territory. NPSI will offer a service that helps C&I customers analyze their facilities' energy use and recommends energy efficiency improvements. NSPI will offer both prescriptive and custom incentives for these energy-efficient upgrades to encourage the installation of these measures. Custom incentives will help encourage industrial customers to improve their processes and encourage commercial customers to potentially adopt newer proven technologies.

NSPI will offer an on-site energy assessment either through contracted auditors or through in-house staff. The audit will provide detailed cost and payback information for specific conservation opportunities to help prioritize improvements. Participants will also receive a report containing an energy end-use profile and rate analysis. The customers may either receive a partial rebate or be charged a subsidized fee for the assessment.

NSPI representatives will work with the facilities and production staff of large commercial and industrial organizations to determine if the facility is considering any capital improvements, changes to production, and opportunities to save energy. The representatives will be the single point of contact for these facilities for participating in any of NSPI programs. Other agencies and utilities have found that having multiple programs calling on industrial customers does not garner much attention from the facility staff. Having one point of contact provides a higher level of service for these customers and allows the representative to determine the best approach for helping the facility install energy improvements.

Customer Benefits

- Access to resources (financial and human) to assist in assessing energy-savings opportunities and implementing energy-efficiency projects.
- Reduced electrical consumption.
- Maintenance savings resulting from energy-efficient technologies.
- Improved employee comfort and productivity.

Approximate Budget: Year 1 and Year 2

Program Costs	Year 1	Year 2
Delivery/Admin	$339,000	$542,000
Marketing	$363,000	$580,000
Incentives	$1,233,000	$1,973,000
Technical Assistance	$484,000	$774,000
Monitoring & Evaluation	$97,000	$155,000
Total	**$2,516,000**	**$4,024,000**

Approximate Expected Results: Year 1 and Year 2

	Year 1	Year 2
Energy (MWh)	27,696	44,314
Demand (kW)	3,332	5,331
Participants	710	1,137
TRC Ratios	4.3	4.3

3.2 New Construction

Target Market

All new Commercial and Industrial construction including high-rise, multi-unit residential facilities in Nova Scotia. However, most program participants will likely be larger commercial facilities such as office buildings, schools, and health care facilities. This program will also be available for new commercial or industrial expansion projects.

Objective

A comprehensive energy acquisition and market transformation program to improve the energy efficiency of all new Commercial and Industrial construction by influencing owners, developers, architects, engineers, energy consultants and contractors to adopt energy efficiency into their design objectives and to apply whole building integrated design as a standard industry practice.

This program also supports the adoption of higher efficiency energy codes for buildings.

Technology

The typical projects/technologies include:

- Adoption of integrated design process, which incorporates a systematic application of energy-efficiency measures, to all end uses in a building at the early design stage.
- The primary systems will include lighting, windows, building envelope, HVAC and refrigeration systems.

Market Barriers

- *Awareness & Understanding*: For developers/owners and design team members, there is a perception that integrated design will result in higher capital and design costs and lengthy project time delays. For owners/end users, there is a lack of understanding of the financial, health and productivity benefits that can be achieved.

- *Strategic Importance*: For owners/end users, there can be a lack of understanding of the direct and indirect benefits of high performance buildings including: tenant comfort, productivity gains, and increased marketability of the building. For design teams, there may be a lack of understanding of the competitive advantage that this approach will bring to their business.
- *Return & Affordability:* There are perceived and actual incremental costs for both the integrated design process and capital costs to implement the efficiency measures.
- *Internal Constraints:* There is a lack of trained and experienced consultants to conduct energy simulation modeling which is essential to high performance building design. Lacking industry experience in high performance building design and construction results in higher design and construction costs for these buildings.

Program Description

NSPI plans to offer a design assistance program to influence building owners, architects, and engineers to include energy-efficient systems and equipment in their design for new construction, e.g., new malls, and/or major renovation projects. This program will focus on reviewing various building systems, such as HVAC, lighting, window glazing, and controls, to determine their interactive effects on energy use and winter peak kW savings.

Building owners will benefit from a no-cost, professional energy consultation and comprehensive, whole-building energy analysis to provide information on costs, savings, and paybacks to aid in initial decision making for their building's future energy use. NSPI will also provide rebates to building owners for implementation of energy-efficient system strategies.

Architects and engineers will benefit from an additional whole-building energy analysis that aids them in helping their clients achieve energy saving results. Building design professionals will be compensated for their time spent in meetings, data analysis, and additional design review.

Electric rebates to building owners may range from \$170 to \$275 per kW saved based on percent of peak kW saved. The baseline for rebate calculations is the estimated peak kW the building would have used if built to according to the current practices. A baseline study should be conducted for this market to determine current building practices. If a model Building Energy Code were adopted, then the minimum requirements of this Building Energy Code would be the baseline for rebate calculations. (Note: there are no current required building energy codes in Nova Scotia.)

Since NSPI serves building owners in different areas and size, the program may offer two levels of service to serve many of these buildings:

- *Custom Consulting:* a custom consulting service would target new construction and major renovation projects over 50,000 square feet that are early in the design process. The program could provide design teams (including the building owner, architect, and engineer) with customized information for their building so that design teams can make informed tradeoff decisions between cost, energy savings, and technologies. A custom consulting service could offer a system model of anticipated energy performance with hourly, whole-building computer simulations (utilizing the U.S. Department of Energy's DOE2e modeling system). Multiple combinations of different energy system strategies are modeled independently, providing the design team with a choice of solutions.

Financial incentives would be provided to building owners for implementing the comprehensive energy conservation strategies. All custom consulting projects would also include measurement and verification to ensure that the selected strategies were installed and operating as intended.

- *Plan Review:* a plan review service would target new construction and major renovation projects between 15,000 and 50,000 square feet that are in the early to mid stages of design. Focusing on the needs of smaller building owners, a plan review service would provide a professional review of existing construction documents and specifications within a two-week period. This review would allow the program to fit into the design-build model and can be completed before major equipment goes out to bid. Like a custom consulting service, a plan review service makes recommendations for energy-efficient upgrades and promotes their adoption during the design phase of new construction projects. Financial incentives would be provided to building owners for implemented equipment over code. NSPI would also complete a verification of the installed equipment.

Changes to the federal and local energy codes will impact a design assistance program by increasing minimum efficiency requirements and new equipment standards. Working with the intent of the energy code changes, a design assistance program offers customers a unique opportunity to test the savings potential of new and innovative technologies.

The new construction services would focus on the following energy savings opportunities:

- Efficient lighting systems, such as installing T5 lighting systems instead of T12 or T8 systems, installing compact fluorescent lamps

- (CFLs) instead of incandescent lamps, installing T8 lighting systems instead of T12 systems in industrial facilities, designers should look for opportunities to use natural day lighting where possible, and the use of LED exit signs instead of incandescent exit signs
- Efficient HVAC and building envelope measures that improve the overall efficiency of the HVAC systems and thermal envelope of the building. A more comprehensive approach is emphasized instead of the installation of simple measures such as programmable thermostats.
- Install energy management systems to optimize the control of the HVAC system.
- Efficient refrigeration systems.

Customer Benefits

- Improved energy efficiency and lower operating and maintenance expenses.
- Increased occupant comfort and health.
- Increased building valuation.
- Increased productivity and learning of employees/students.

Approximate Budget: Year 1 and Year 2

Program Costs	Year 1	Year 2
Delivery/Admin	$44,000	$71,000
Marketing	$56,000	$90,000
Incentives	$131,000	$209,000
Technical Assistance	$65,000	$104,000
Monitoring & Evaluation	$12,000	$19,000
Total	**$308,000**	**$493,000**

Approximate Expected Results: Year 1 and Year 2

	Year 1	Year 2
Energy (MWh)	3,394	5,430
Demand (kW)	386	618
Participants	74	118
TRC Ratios	5.1	5.1

3.0 EDUCATION AND OUTREACH PROGRAM

Target Market

The target market is all NSPI customers. This includes owners and renters living in all housing types, from single family to multi-family dwellings, as well as commercial and industrial customers.

Goals and Objectives

The goal of Education and Outreach Program is to increase awareness of energy efficiency. The success of this program will lead to more participation in one of NSPI's conservation and energy efficiency programs.

Market Barriers

- *Low customer awareness:* related to both the existence of the technology and of its benefits and applications.
- *Limited market availability and accessibility:* the selection and quantity of some high-efficiency technology available to the Nova Scotia market is limited.
- *Higher prices* of high-efficiency technology relative to standard efficiency technology.
- *Quality of technology:* past perceptions of high-efficiency technology may be poor.

Technology

All electrical energy efficiency technologies will be promoted, including but not limited to:

- CFL lighting technologies
- High-efficiency HVAC equipment
- High-efficiency refrigerators
- Horizontal axis clothes washers
- Building envelope measures, (i.e. insulation and air sealing)

Education material will be developed for the residential and C&I sectors separately since the applications of the energy-efficiency technology will vary by sector.

Program Description

NSPI will offer a consumer education program that provides an indirect impact service that creates awareness and provides residential consumers with information on energy conservation. The goal is to encourage consumers to incorporate conservation habits into their everyday lives. To reach and impact the diverse residential market, energy conservation education needs to address different lifestyles, learning preferences, and areas of interest. To appeal to this broad market, the program should provide a wide array of educational programs and products including, but not limited to:

- Low-income workshops
- Reference material publications
- A bi-monthly newsletter insert to all consumers
- Seminars and conference sponsorships for appropriate educational topics

- School-based science education curriculum on energy and energy efficiency, including in home applications of simple energy conservation measures such as CFLs and weatherization.

Approximate Budget: Year 1 and Year 2

Program Costs	Year 1	Year 2
Delivery/Admin	$223,000	$416,000
Marketing		
Incentives		
Technical Assistance		
Monitoring & Evaluation		
Total	**$223,000**	**$416,000**

Savings resulting from the Education and Outreach program will be captured via participation in the other NSPI programs.

Approximate Expected Results: Year 1 and Year 2

	Year 1	Year 2
Energy (MWh)	N/A	N/A
Demand (kW)	N/A	N/A
Participants	N/A	N/A
TRC Ratios	N/A	N/A

4.0 FUTURE DSM PROGRAMMING

NSPI will explore and evaluate opportunities for future DSM programming including pricing design as well as use of emerging technologies in areas of lighting, smart metering, load monitoring and load control. This includes activities such as studies, evaluations, piloting and program design.

Approximate Budget: Year 1 and Year 2

Program Costs	Year 1	Year 2
Delivery/Admin	$100,000	$100,000
Marketing		
Incentives		
Technical Assistance		
Monitoring & Evaluation		
Total	**$100,000**	**$100,000**

Approximate Expected Results: Year 1 and Year 2

	Year 1	Year 2
Energy (MWh)	N/A	N/A
Demand (kW)	N/A	N/A
Participants	N/A	N/A
TRC Ratios	N/A	N/A

APPENDIX B

Consultant's DSM Report

(September 8, 2006)

NOVA SCOTIA POWER INC.:
DSM REPORT
SUMMER 2006

FINAL REPORT

Prepared for:

John Aguinaga
Manager, Conservation & Energy Efficiency
Nova Scotia Power Inc
P.O. Box 910
Halifax, NS B3J 2W5
902-428-6364

Prepared by:

Summit Blue Consulting, LLC
1722 14th St., Ste. 230
Boulder, CO 80302
720-564-1130

Contacts:

Summit Blue Consulting

Randy Gunn
rgunn@summitblue.com
312-938-4242

Summit Blue Canada

Gay Cook
gcook@summitblue.com
416-604-9393

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1. EXECUTIVE SUMMARY

1.1 Introduction and Overall Methodology

Nova Scotia Power Inc. (NSPI) hired Summit Blue Consulting in late June 2006 to conduct a review of its proposed 2006 Conservation and Energy Efficiency Plan, and to make appropriate recommendations to revise and complete the plan. NSPI was asked by its regulatory agency, the Utility and Review Board of Nova Scotia (UARB) to hire a consultant with DSM expertise to complete its plan's design and development.

Summit Blue conducted a five step process to complete Phase 1 of this assignment:

1. Conduct project initiation and stakeholder meetings, and assess the status of DSM in Nova Scotia. As part of this task, Summit Blue met separately with NSPI staff and a group of provincial stakeholders that had either contributed to NSPI's initial DSM plan or had submitted comments on the plan as part of the regulatory review process. Summit Blue also collected applicable data on NSPI's customers and energy conservation programs that are currently active in the province, such as those conducted by Natural Resources Canada.

2. Estimate DSM potentials for Nova Scotia. This task included:

    a. Developing approximate baseline profiles for NSPI's residential, commercial, and industrial customers.

    b. Characterizing DSM measures that are appropriate for NSPI's service area. Characterizing measures includes estimating per unit energy and demand savings, incremental costs compared to standard efficiency measures, and measure lifetimes. Energy and demand savings for climate dependent measures such as insulation are estimated by building simulation models: Energy 10 for residential customers and eQUEST for commercial customers.

    c. Estimate DSM potentials for the 2007-2014 period for residential, commercial, and industrial customers separately. Calibrate the estimates to the results of the benchmarking analysis conducted as part of the next task on reviewing NSPI's 2006 DSM plan.

3. Conduct a comprehensive review and analysis of NSPI's 2006 DSM plans. This task primarily involved comparing NSPI's 2006 DSM plan to actual DSM program results or planned DSM programs from eight somewhat similar Canadian and American utilities. The objectives of this analysis are to compare NSPI's proposed DSM goals to other utilities' DSM goals and budgets by customer class and end use where available, and also to compare DSM "institutional arrangements" in the other jurisdictions compared to NSPI's proposals for Nova Scotia.

4. Develop recommendations for revising NSPI's DSM plan, using the results of the previous two project tasks.

5. Prepare a project report that summarizes the analysis conducted and the results obtained.

Although this project is not primarily focused on DSM policy, Summit Blue addressed several DSM policy matters that we believe are important to setting up a successful portfolio of DSM programs. These include ensuring that NSPI is not financially harmed from conducting DSM programs, to various more technical matters such as DSM program evaluation approaches. The reviewers of Summit Blue's draft project report encouraged a broader discussion of DSM policy, such as whether DSM is really a waste of money, particularly for large industrial customers, to whether it is critical to conduct DSM benefit-cost analysis using the societal test as the primary cost effectiveness test instead of the TRC test, whether oil heating is preferable to electric heating, and so on. Summit Blue addresses DSM policy issues in the context of this assignment: what is most important to developing a successful portfolio of DSM programs, and industry "best practices" regarding these issues. Summit Blue does not intend that its comments in these regards should be interpreted as the final and authoritative findings on these issues. It is entirely appropriate for NSPI and Nova Scotia decision makers to make the ultimate decisions on these matters, factoring in perhaps a broader range of considerations than those addressed by Summit Blue.

1.2 Review of NSPI's 2006 DSM Plan

In this task Summit Blue assessed NSPI's 2006 DSM plan against tried and proven DSM programs delivered by similar utilities and agencies in North America. This included collecting and analyzing benchmark data from selected jurisdictions, comparing these results to NSPI's DSM plan, and describing areas of similarities and differences to aid in identifying areas for improvements and/or modifications.

A brief summary of the similarities and differences between NSPI's proposed plan and the results and plans of the utilities and agencies reviewed include:

1.2.1 Similarities Between NSPI's DSM Plan and Other DSM Results/Plans Reviewed

1. NSPI's plan focuses on the resource acquisition strategy for DSM, in which the utility focuses on working with customers to achieve concrete and somewhat easily measured DSM program savings.

2. NSPI proposes to implement the DSM programs itself, while contracting out certain functions to be determined. This is similar to the other utility DSM program administration approaches.

3. Residential and commercial lighting conservation programs are considerable focuses of NSPI's DSM program portfolio, and such programs often account for significant shares of total conservation impacts by many utilities and agencies.

4. NSPI does not propose any fuel switching programs as part of its DSM portfolio, which is almost always the case amongst the organizations reviewed.

5. Education and outreach programs and efforts are a considerable focus for NSPI and many of the organizations reviewed.

6. NSPI's emphasis on energy conservation, compared to demand savings, is similar to other Canadian utilities and US non-utility organizations, but different than the demand reduction DSM focus of many American utilities.

7. NSPI focused on the results of the total resource cost (TRC) test to evaluate its DSM programs economically. The TRC test is often the primary test used to judge DSM programs' cost-effectiveness, particularly in Canada.

1.2.2 Differences Between NSPI's DSM Plan and Other DSM Results/Plans Reviewed

1. NSPI's proposed DSM spending as a percentage of total utility spending is lower than for the other organizations reviewed. However, almost all the other organizations reviewed have been conducting DSM programs for some time, and have had time to get past the program "ramp-up" phase, while NSPI's plan was only for the first year of a multi-year DSM effort.

2. NSPI expected to achieve most of its DSM savings from residential customers, while almost all of the other organizations reviewed achieve most of their DSM savings from commercial and industrial customers. In addition, NSP's proposed residential energy savings were greater as a percentage of residential sales than any of the other organizations reviewed.

3. NSPI expected to achieve DSM savings at generally lower costs of conserved energy than the other organizations reviewed.

4. Most jurisdictions recover DSM program costs through fixed rate or percentage "adders" to customers' bills, similar to how fuel clause adjustments often are structured. However, NSPI proposed to allocate DSM program costs just to the customer sectors for which the program costs were spent.

5. Investor-owned utilities are often compensated in some manner for the "lost margins" caused by their DSM programs. This arrangement helps to diminish the "throughput disincentive" that may cause utilities to not conduct DSM programs. Without such arrangements, utilities typically lose money from DSM programs, unless they are in jurisdictions that require annual rate cases.

6. NSPI did not include its existing load management programs, nor expansion of load management programs, as part of its DSM portfolio, as many utilities do.

7. Many utilities and agencies offer DSM programs targeted towards new residential and commercial construction, in order to minimize the "lost opportunities" for energy conservation that occur once a building is built. NSPI proposed a residential new construction program, but not a similar commercial program.

8. NSPI estimated energy and demand savings from various types of educational programs. Estimating savings from such programs is generally not done in the DSM "industry".

1.3 DSM Potential Methodology and Results

This section provides a summary of the methodology and results for the DSM potential aspect of the project.

1.3.1 Methodology

Summit Blue used a methodology to develop DSM potential estimates for Nova Scotia Power that we had previously used in DSM potential study projects for Missouri River Energy Services, Arizona Public Service Company, and the International Energy Agency. The steps that Summit Blue used to conduct this DSM potential analysis were:

1. Collect and use existing data to characterize the Nova Scotia market. No individual customer data was available or used to estimate DSM potentials for Nova Scotia. However, NSPI provided a lot of very useful data on their overall customer base, including:

    a. Numbers of customers, electricity sales, and estimated peak demands for each of the residential, commercial, and industrial sectors.

    b. Estimates for the electric heating and water heating saturations for their residential customers, from a combination of their internal data and Statistics Canada information that NSPI uses for forecasting purposes.

    c. The market research study that NSPI commissioned on its residential and commercial customers' attitudes towards energy efficiency and efficient lighting products.

    d. Summaries of results from NSPI's 2004 and 2005 customer energy forums.

    e. Copies of Natural Resources Canada reports on residential and commercial customers' energy use and energy equipment.

    f. Contacts with Canadian national and provincial government officials, who provided information on model building energy codes, as well as energy efficiency programs such as EnerGuide for Houses.

    g. Very recent DSM potential studies that had been done for all of Canada.

2. Develop an inventory of common DSM measures that Summit Blue had analyzed for previous projects, as well as several additional DSM measures that NSPI recommended, such as LED holiday lights.

3. Estimate each DSM measure's per unit energy and demand savings, costs, and lifetimes. Summit Blue developed the energy and demand savings estimates using the Energy 10 building simulation software for residential HVAC and building envelope measures such as insulation, and used the eQUEST building simulation model for the same purpose for corresponding commercial and industrial DSM measures. For DSM measures whose savings are not very climate dependent, such as efficient refrigerators, Summit Blue used engineering estimates and published sources for the savings estimates, such as the California Database of Energy Efficiency Resources (DEER), as well as the Canadian and U.S. ENERGY STAR websites. Similar published sources were used for the DSM measure lifetime and costs estimates. Some DSM measure costs were estimated from Canadian Sears and Home Depot websites.

4. Estimate the current saturations for the DSM measures using the data collected in the first step above, estimates from previous Summit Blue projects with utilities that are new to DSM, and NSPI staff estimates for current practices in areas such as common residential insulation levels.

5. Estimate the technical DSM potential using a spreadsheet that Summit Blue developed for that purpose. The technical potential for a given DSM measure is estimated to be: 1- the current DSM measure saturation per customer * typical numbers of energy using equipment per home or building * the number of customers per sector (residential, etc.) * the per unit energy and demand savings per measure.

6. Estimate the economic potential for the DSM measures using the same spreadsheet as is used to estimate technical potential. For a given DSM measure, economic potential is either the same as technical potential, or it is zero if the measure does not pass the total resource cost (TRC) test. Economic potential is therefore an estimate of all of the DSM technical potential that is "cost-effective," as defined by the TRC test.

7. Estimate achievable or market DSM potential using the DSM program and portfolio benchmarking. **The benchmarking results are the most important considerations in Summit Blue's process to develop achievable DSM potential estimates.** This is because uncalibrated computer models do not produce reliable forecasts. Computer model estimates must be calibrated to actual results of some type in order to produce realistic estimates. Summit Blue calibrated the C&I potential estimates to the common total energy savings performance of 1.0% of current C&I sales saved per year from the four top-performing C&I DSM program portfolios. Similarly, Summit Blue used a calibration target of 0.8% of residential sales, larger than all but the top two total residential energy savings achievements, to calibrate the total residential potential estimates.

1.3.2 Achievable Potential Results and Cost Effectiveness

In total, the achievable DSM potential from 2007-2014 is estimated to be about 167 MW of coincident peak demand reduction and 890 GWh of first-year energy savings. This represents about 9% of NSPI's forecast 2006 coincident peak demand of 1,963 MW, and 7% of NSPI's forecast 2006 energy use of 11,996 GWh. The total estimated lifetime energy savings are about 14 TWh. The estimated cost to realize this achievable potential is approximately $127 million, or an average of about $16 million per year, which represents approximately 1.7% of NSPI's 2005 revenues of $955 million.

So the cost of conserved energy over the lifetime of the DSM measures installed as part of this DSM program portfolio is about 0.9 cents/kWh, while the cost of conserved demand is about $763/kW. This cost of conserved energy is very consistent with the lower cost DSM program portfolios reviewed, such as Xcel Energy's Minnesota DSM programs, whose 2005 program results had a lifetime cost of conserved energy of 1.1 cents/kWh[1]. The cost of conserved energy for NSPI's estimated DSM potential ranges from lows of 0.5 and 0.6 cents/kWh (lifetime) for industrial and commercial programs respectively, to a high of 2.0 cents/kWh for residential programs. The residential, commercial, and industrial DSM program portfolios are each very cost effective, with TRC ratios of 3.1-4.5.

Residential programs typically have higher costs of conserved energy than C&I programs due to residential measures' higher per unit relative costs and shorter annual hours of operation than commercial and industrial DSM measures. The benchmarking results discussed in section three present such results in some detail. Virtually all jurisdictions in North America that are conducting large-scale DSM programs include significant residential DSM program components, even though it would be more cost effective to just conduct DSM programs for commercial and industrial customers. This is generally done for equity and political reasons.

The residential, commercial, and industrial customer sectors each have similar estimated amounts of achievable potential, with the residential sector having the largest estimated amount of potential peak demand savings, while the industrial sector has the largest estimated amount of energy savings potential. Residential programs are expected to account for over half of the entire DSM program budget, as residential DSM measures generally have higher costs of conserved energy due to their smaller sizes and

[1] Xcel Energy Corporation, "2005 Status Report and Associated Compliance Filings, Minnesota Natural Gas and Electric Conservation Improvement Program" (Xcel Energy Corporation, Minneapolis, MN, April 2006) p. 29.

lower annual hours of operation than commercial and industrial measures. Table 1-1 shows the achievable potential estimates by customer sector.

Table 1-1. NSPI Achievable DSM Potential Summary, Years 1-8

Residential End Uses	Years 1-8 Coin. Peak Demand Savings (MW)	Years 1-8 First Year Energy Savings (GWh)	Years 1-8 Lifetime Energy Savings (GWh)	Years 1-8 Total Program Costs (Million$)
Lighting	31.1	129.5	808.3	$31.1
HVAC	13.8	58.9	1,450.3	$21.8
Water Heating	8.7	61.5	1,028.3	$8.7
Load Management	10.8	0.2	2.5	$3.8
Refrigeration	2.0	17.8	205.2	$5.7
Subtotal	66.6	268.0	3,494.7	$71.1

Commercial End Uses	Years 1-8 Coin. Peak Demand Savings (MW)	Years 1-8 First Year Energy Savings (GWh)	Years 1-8 Lifetime Energy Savings (GWh)	Years 1-8 Total Program Costs (Million $)
Lighting	15.1	183.6	2,995.0	$5.3
HVAC	11.7	33.5	509.9	$13.7
Refrigeration	0.4	4.6	44.8	$0.3
Motors/Compressors	1.0	7.4	110.8	$0.8
Load Management	10.0	0.0	0.2	$0.7
Subtotal	38.1	229.2	3,660.6	$20.7

Industrial End Uses	Years 1-8 Coin. Peak Demand Savings (MW)	Years 1-8 First Year Energy Savings (GWh)	Years 1-8 Lifetime Energy Savings (GWh)	Years 1-8 Total Program Costs (Million $)
Lighting	9.4	82.5	1,268.6	$3.3
HVAC	0.2	0.8	12.9	$0.2
Motors	14.0	112.5	1,687.6	$10.9
Air Compressors	0.4	23.0	345.3	$0.2
Process	22.2	173.8	3,476.3	$19.7
Load Management	16.3	0.1	1.6	$0.1
Subtotal	62.5	392.7	6,792.4	$34.4

Totals	**167.2**	**889.9**	**13,947.7**	**$126.2**

1.4 DSM Plan Recommendations Overview

This section provides the recommendations for revising the current NSPI DSM plan and providing the groundwork for future programs. These recommendations for revising the current plan are based upon the benchmarking work and the DSM potential analysis from the previous sections, as well as the interveners' comments and the critique of the current plan from the previous sections. The goal of this revised DSM plan is to provide NSPI with a comprehensive, equitable, and defensible DSM plan upon which NSPI can build successful future DSM programs and services.

Many jurisdictions in North America have successfully implemented DSM programs over the past several years. NSPI can build on the knowledge from these other jurisdictions and avoid some of the mistakes made by the early programs. This DSM plan uses the lessons learned combined with the demographics of the NSPI territory to develop a comprehensive DSM plan that is best suited for NSPI's customers.

The main goal of this study is to develop the foundation on which NSPI can build their DSM programs. This revised plan will focus on the first two years of the NSPI DSM programs. After the first two years NSPI should evaluate the programs and determine what is working well and what aspects of the programs need to be changed. After the first two years of the program it will be important to determine how well the programs are doing at overcoming the market barriers and whether there are other market barriers that the programs should be addressing. These program evaluations should include a process evaluation, to make sure the programs are operating efficiency; an impact evaluation, to determine if the expected savings are being achieved; and a market assessment to make sure that the programs are having the expected effect on the markets. Further discussion on the recommended evaluation activities is included below.

Below we address many of the issues associated with the development of DSM program plans. Based upon our experience, the benchmarking analysis, and DSM best practices, we developed a list of recommendations for a successful DSM plan. These recommendations include:

1. NSPI should administer DSM programs, leveraging the work being done by Natural Resources Canada and the provincial government, while outsourcing much of the program delivery to local agencies. NSPI should position these programs as customer service programs and use them to help promote the NSPI brand.

2. Lost margins due to lower sales of electricity should be addressed through a reconciliation procedure (annual rate case or lost revenue recovery) or a decoupling of revenues by tying them to the number of customers and weather adjusted sales, so that it is not a disincentive to utility investment in DSM.

3. The regulators should offer additional incentives for meeting or exceeding DSM targets.

4. The spending on DSM programs should start at 0.7% of in-province electric revenues and ramp up to 2% by 2010.

5. Review level of DSM spending every two years.

6. The DSM programs should provide rebates & incentives to overcome the high first cost market barrier.

7. The DSM plan should include programs for all sectors: residential, low-income, commercial, and industrial. Low-income program spending should be up to 10% of the overall residential budget.

8. The NSPI DSM programs should only provide incentives for electricity savings measures.

9. Costs of the DSM programs should be allocated across the entire rate base.

10. Overcome the split incentive for low-income renters by working with the multifamily building owners to install DSM measures.

11. NSPI should expand their education and outreach efforts, not only as a means to increase awareness and knowledge, but to direct consumers to one of their programs.

12. The energy/demand savings from education and outreach should not be included in the overall portfolio impacts.

13. Funds for additional demand response program development and pilot programs should be included in the DSM portfolio.

14. Calculate the Total Resource Cost (TRC) test to determine the program cost-effectiveness, and also calculate Rate Impact Test (RIM) to determine the impact of the DSM programs on customer rates and the Utility Cost Test (UCT) to determine the utility benefits.

15. A more extensive avoided cost study than was used for this assignment should be considered in the next 2-3 years to better account for the total benefits of DSM measures. The deployment of these recommendations should proceed in the meantime.

16. In the next 1-2 years a more detailed DSM potential study should be performed, to better understand where the potential for savings in Nova Scotia exists. The potential study completed as part of this project provides a sufficient foundation from which to launch the initial DSM programs in Nova Scotia. A more detailed study will help focus these programs further.

17. NSPI should implement the programs using both in-house staff and outsourcing the delivery of services (for example weatherization services) to local community groups.

18. NSPI should promote and leverage Natural Resources Canada programs, including program delivery where possible.

19. Detailed evaluation plans should be developed for each of the programs. These plans should include the use of integrated data collection as part of the program administration, to help reduce the costs and uncertainty in future evaluation data collection.

20. A robust program data tracking system should be developed as part of the final DSM program development to ensure that the data needed for evaluation purposes is being collected.

1.5 Suggested Year 1-Year 2 DSM Program Goals and Budgets

Table 1-2 below shows the DSM potential results for program years one and two, which we suggest as the program goals for those years. As discussed in the DSM potential section of the report, Summit Blue believes that a two-year "ramp-up" period will be required before NSPI will be able to achieve the average annual DSM potential estimates for the eight year forecast period. This is consistent with the other utility experiences from the benchmarked organizations.

Table 1-2. NSPI Proposed DSM Goals and Budgets Years 1-2

Residential End Uses	Year 1 Coin. Peak Demand Savings (MW)	Year 1 First Year Energy Savings (GWh)	Year 1 Total Program Costs (Million$)	Year 2 Coin. Peak Demand Savings (MW)	Year 2 First Year Energy Savings (GWh)	Year 2 Total Program Costs (Million$)
Lighting	1.6	6.5	$1.6	2.5	10.4	$2.5
HVAC	0.7	2.9	$1.1	1.1	4.7	$1.7
Water Heating	0.4	3.1	$0.4	0.7	4.9	$0.7
Load Management	0.0	0.0	$0.0	0.0	0.0	$0.0
Refrigeration	0.1	0.9	$0.3	0.2	1.4	$0.5
Subtotal	2.8	13.4	$3.4	4.5	21.4	$5.4

Commercial End Uses	Year 1 Coin. Peak Demand Savings (MW)	Year 1 First Year Energy Savings (GWh)	Year 1 Total Program Costs (Million$)	Year 2 Coin. Peak Demand Savings (MW)	Year 2 First Year Energy Savings (GWh)	Year 2 Total Program Costs (Million$)
Lighting	0.8	9.2	$0.3	1.2	14.7	$0.4
HVAC	0.6	1.7	$0.7	0.9	2.7	$1.1
Refrigeration	0.0	0.2	$0.0	0.0	0.4	$0.0
Motors/Compressors	0.1	0.4	$0.0	0.1	0.6	$0.1
Load Management	0.0	0.0	$0.0	0.0	0.0	$0.0
Subtotal	1.4	11.5	$1.0	2.3	18.3	$1.6

Industrial End Uses	Year 1 Coin. Peak Demand Savings (MW)	Year 1 First Year Energy Savings (GWh)	Year 1 Total Program Costs (Million$)	Year 2 Coin. Peak Demand Savings (MW)	Year 2 First Year Energy Savings (GWh)	Year 2 Total Program Costs (Million$)
Lighting	0.5	4.1	$0.2	0.8	6.6	$0.3
HVAC	0.0	0.0	$0.0	0.0	0.1	$0.0
Motors	0.7	5.6	$0.5	1.1	9.0	$0.9
Air Compressors	0.0	1.2	$0.0	0.0	1.8	$0.0
Process	1.1	8.7	$1.0	1.8	13.9	$1.6
Load Management	0.0	0.0	$0.0	0.0	0.0	$0.0
Subtotal	2.3	19.6	$1.7	3.7	31.4	$2.7

Subtotals	**6.5**	**44.5**	**$6.1**	**10.4**	**71.2**	**$9.7**
Education, Research, Evaluation	0	0	**$0.5**	0	0	**$0.8**
Totals	**6.5**	**44.5**	**6.6**	**10.4**	**71.2**	**10.5**

2. INTRODUCTION

This report was prepared for Nova Scotia Power Inc. (NSPI) to meet the requirements of a Utility and Review Board March 10, 2006 decision. This decision directed NSPI to hire a DSM consultant to review and modify its Demand Side Management (DSM) plan. This section outlines the state of DSM in Nova Scotia, provides a brief overview of NSPI customer and load statistics and load management initiatives, and describes high level findings about the current state of DSM in Nova Scotia compared to other jurisdictions in North America.

Section 3 of the report provides a comprehensive review of NSPI's DSM plan in comparison to selected utilities and agencies in North America. Section 4, building on this benchmark information, provides an analysis of the achievable potential in major customer sectors and the range of cost-effective options to pursue this potential. Section 5 identifies areas for improvements/modifications to the plan and recommends how best to modify the plan.

2.1 Background

Nova Scotia does currently have some DSM programs for consumers, as do the provincial government and other entities. In addition, the Nova Scotia government is in the process of setting up Conserve Nova Scotia, a Crown Corp. to address Conservation and Energy Efficiency for all energy forms. NSPI wants to coordinate and leverage its DSM efforts with these other organizations. The notes below describe some of the current initiatives.

- *The Atlantic Coastal Action Program (ACAP) - Cape Breton is a non-profit charitable community organization.* Established in 1992, the original mission was to develop a comprehensive ecosystem management plan for the watershed area of industrial Cape Breton Island, Nova Scotia. ACAP-Cape Breton has grown into a dynamic group that integrates environmental, social, and economic factors into projects focusing on action, education and ecosystem planning. They also provide Home Energy Assessments under the federal EnerGuide Program.

- *Clean Nova Scotia is a non-profit, non-government environmental organization established in 1988.* The organization delivers environmental programs province-wide including Home Energy Evaluations, and provides information to all Nova Scotians. Clean Nova Scotia, funded by the Nova Scotia Dept. of Energy, provides a toll free EnerInfo Line to answer questions about improving home heating, energy efficiency, lighting, insulation, and hot water heaters. Clean Nova Scotia can connect customers with Home Energy Evaluation providers and provide information on energy efficiency grants. However, as of May 13, 2006, the federal EnerGuide for Houses Retrofit Incentive program has been cancelled, and no new initial audits will be done.

- *Sustainable Housing & Education Consultants (Sustainable Housing)established in 1991 is an organization committed to assisting builders and homeowners to create energy efficient and healthy homes, while respecting and helping the environment.* Sustainable Housing provides Home Energy Evaluations across Nova Scotia under the federal EnerGuide Program for Existing Homes as well as the EnerGuide for New Houses & R2000 program. In conjunction with a number of organizations, including Federal and Provincial governments, they manage and conduct energy efficiency educational events, workshops and new home demonstrations such as the CHBA EnviroHome.

- *The Eco-Efficiency Centre, opened in 1998, is a not for profit, arms-length agency that promotes the message to small and medium sized businesses (SMEs) that there can be both ecological and economical advantages to making the right environmental choices.* Initiated as a partnership between Dalhousie University (School for Resource and Environmental Studies) and NSPI, the Centre provides information in an integrated fashion on eco-efficiency/pollution prevention, resource conservation, and economic efficiency. While the Centre's work has largely been focused on Burnside Industrial Park, its scope now extends to the broader business community of Halifax Regional Municipality and, as resources allow, to SMEs throughout Nova Scotia. One service that they offer is preliminary environmental reviews of company facilities to identify source control, energy, and water conservation opportunities.

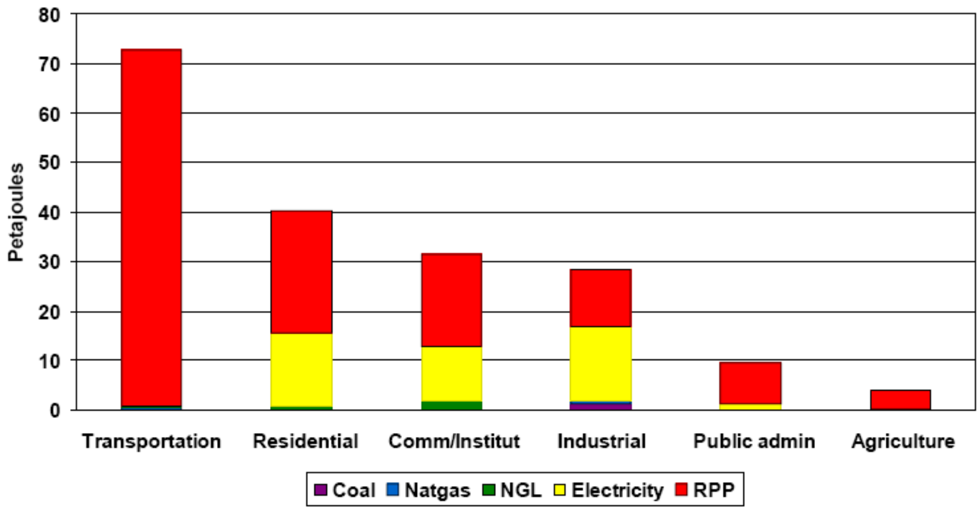
- *The Ecology Action Centre (EAC), a Nova Scotia environmental organization that has been around for 35 years and has over 900 members and 250 volunteers and staff.* Most EAC projects related to energy efficiency are for the Transportation sector; the energy issues committee has only recently started to develop energy efficiency and renewable energy related projects. The EAC recently completed the first demonstration of a green renovation site in Nova Scotia. A 100 year old site in Halifax's North End was renovated to improve efficiency, including passive solar features, in-floor radiant heating, and a solar hot water system. The retrofit was done for about half the normal costs through volunteer labour, recycling of local materials, use of local materials (e.g., mud-walls), and in-kind donations. EAC received an Environment Canada grant to conduct tours with descriptive and interactive displays, providing energy-efficient items. EAC is currently conducting an inventory of solar installations in Nova Scotia and is developing an initiative for targeted solar hot water installations.

- *In 2005 the Nova Scotia Department of Energy launched a $10 million multi-year Smart Energy Choices program to promote energy efficiency in Nova Scotia.* The program has major initiatives focused on housing, transportation, lighting/electricity, public education, and government house-in-order. The program includes energy savings kits which include CFLs, low-flow showerheads and information, rebates for efficient wood heating appliances and oil-fire heating systems, and incentives linked to the federal EnerGuide for Houses initiative.

- *The Nova Scotia Home Builder's Association (NSHBA) is committed to raising awareness of the benefits that energy efficient housing provides homeowners*. Programs such as the R-2000 and EnerGuide for New Houses allow homeowners to achieve lower energy costs, reduce greenhouse gas emissions and provide a more comfortable home for their family. NSHBA is committed to educating consumers through home shows, seminars, websites and workshops.

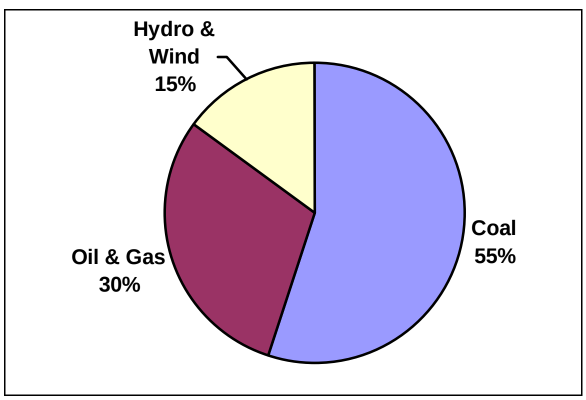
- *Conserve Nova Scotia, a concept proposed by the recently elected premier, Rodney MacDonald, is a Crown Corporation to encourage Nova Scotians to use less energy from all sources.* In June 2006, the premier appointed a chief administration officer and plans to introduce legislation to create Conserve Nova Scotia in the fall. The new corporation will have a four-year budget of $5 million to look at energy efficiency in all fuels across all sectors—not just electricity. Figure 2.1 below shows the breakdown of energy end use by sector and fuel for 2004.

Figure 2-1. Energy End Use by Sector (2004)[2]



Electricity is produced mainly from imported fossil fuels. With electricity in Nova Scotia produced mainly from fossil fuels (see Figure 2-2), the province is a high per capita emitter of all common air pollutants, mercury, and greenhouse gases. And virtually all of the fossil fuels used for generation are imported. Beginning in 2005 and continuing through the end of the decade, Air Quality Regulations under the Nova Scotia Environment Act require reductions of sulphur dioxide, oxide of nitrogen, and mercury emitted from NSPI facilities. Plans developed to achieve the objectives of NSPI's Air Emission Strategy include energy conservation and efficiency measures aimed at customers. [3]

Figure 2-2. Current NSPI Generation Capacity Mix (Total = 2,293 MW)



Energy use is balanced among customer classes but a few customers account for a large proportion of energy used. 37% of the energy is used in the industrial sector mainly for pulp and paper, in fact two customers—Stora and Bowater—account for 20% of total energy sales or (43%) of industrial sales. And about 60 large commercial and industrial customers account for 30% (3,400 MWh) of the total annual energy consumption. Table 2-1 below shows the breakdown of electricity energy and demand by

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[2] Nova Scotia's energy mix: is it sustainable? Is it secure? Presentation to Conserve Nova Scotia by L. Hughes, Energy Research Group, Dalhousie University, 2006..

[3] Emera 2005 Annual Financial Report.

customer sector for 2005. The residential and industrial sectors use about the same amount of electricity, but account for more of the demand and the revenue for NSPI.

Table 2-1. NSPI Electricity Data by Customer Sector (2005)

Customer Sector	Customers	Energy (GWh)	Demand (MW)[4]	Revenue ($m)	% Energy	% Demand	% Revenue
Residential	420,462	4,000	1,056	411.4	35	43	42
Commercial	33,564	3,000	624	263.9	26	25	28
Industrial	2,470	4,200	734	235.1	36	29	25
Other[5]	8,848	300	66	44.9	3	3	5
TOTAL	**465,344**	**11,500**	**2,480**	**955.3**	**100**	**100**	**100**

Electricity demand has been increasingly for space and water heating in Nova Scotia. Statistics Canada data shows that in 2003, 52% of existing homes were oil heated but 62% of new home heating systems are electric and over 70% of new water heating is going to electric. Although wood is estimated to be used to heat about 100,000 homes, it is usually not the primary fuel as it is not a dependable source due to access and availability.

NSPI does offer its customers some load management options as outlined below:

- *NSPI provides two interruptible rate tariffs for its industrial customers.* Most of NSPI's large customers are on the Interruptible Rider to Large Industrial Tariff providing 134 MW of interruptible load. Customers must reduce available interruptible system load by the amount requested by NSPI within 10 minutes; failure to comply will result in penalty charges. The Extra Large Industrial Interruptible Rate (ELIIR) provides is a further 270 MW of interruptible load; much of it economically interruptible. The ELIIR is under redesign for 2007. Customers must provide a 5 year notice to go off the interruptible rate.

- *NSPI, as directed by the regulator, has provided time-of-day rates for residential customers who have equipment that enables them to shift electrical heating to off peak periods.* Initially, this only applied to Electric Thermal Storage (ETS) equipment, but in-floor radiant heating was included starting in 2001 and central systems in 2004. ETS has only recently been developed for commercial facilities.

2.2 Review of Demand-Side Management in Nova Scotia

Summit Blue's first project task was to conduct meetings with Nova Scotia Power and the Provincial DSM stakeholder group regarding the project, and to conduct a review of DSM in Nova Scotia. The goals of the latter review are to thoroughly understand the current status and recent history of DSM in the province, and how Nova Scotia and its DSM opportunities and plans compare to other jurisdictions.

2.2.1 DSM Review Methodology

Summit Blue performed the following work to complete this task:

- Reviewed NSPI's 2005 DSM Plan and supporting documents, including intervenors' comments on plans, and regulatory decisions.

[4] Non-coincident demand for 2005.

[5] Unmetered and municipal utilities.

- Reviewed reports and data on Customer Energy Forums held by NSPI in 2004 and 2005.
- Met with NSPI departments to gather information about current and historical DSM, rates, load forecasts, etc.
- Reviewed CEA/NRCAN reports on residential, commercial, and industrial customers' energy use and DSM potential estimates.
- Contacted the Nova Scotia Dept. of Energy for information about energy codes & standards.
- Held a technical conference with provincial stakeholders to solicit input on their DSM issues and background information.
- Collected and reviewed information on previous, current, and proposed DSM programs in Nova Scotia and in other Atlantic provinces.

In addition to the specific data collection and analysis conducted for this project task, Summit Blue reviewed the results of its similar previous work for other clients and jurisdictions. These previous project results include the report on DSM spending that Summit Blue conducted for CAMPUT. [6]

2.2.2 High-Level Comparison of Nova Scotia to Other Jurisdictions Regarding DSM

Rather than present a summary of the public record regarding NSPI's 2005 DSM Plan, which the provincial stakeholders are already well aware of, this section will summarize the similarities and differences between Nova Scotia/NSPI and other jurisdictions that Summit Blue is familiar with from past projects. This section will start with similarities between Nova Scotia and other jurisdictions, and then discuss corresponding significant differences.

Similarities Between Nova Scotia and Other Jurisdictions

For purposes of brevity, Summit Blue will present this information in a series of bullets, without extensive footnotes or references.

- The key drivers for re-consideration of DSM in Nova Scotia are NSPI's growing electric system demand, and the interests of customers and stakeholders. Many jurisdictions across North America are responding to electric system expansion needs and high energy prices by expanding DSM program efforts, including Hydro Quebec, Ontario, several American Midwestern states, and southern American states such as Florida.
- Nova Scotia has energy efficiency regulations for appliances as do most other jurisdictions.
- Other Atlantic provinces are also just beginning DSM planning and programs.
- In many North American jurisdictions, multiple organizations implement DSM programs or provide services for DSM program sponsors. Utilities are often required to implement DSM programs by provincial or state laws or regulations, while government energy agencies also often implement some types of DSM programs. The organizations sponsoring DSM programs often meet regularly to make sure they are not duplicating efforts. Both utilities and government energy agencies often subcontract technical DSM services such as energy audits, building simulation modeling, and program evaluations.

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[6] D. Violette, Summit Blue Consulting, "Demand Side Management: Determining Appropriate Spending Levels and Cost-effectiveness Testing". Prepared for the Canadian Association of Members of Public Utility Tribunals (CAMPUT), January 30, 2006.

- NSPI has a considerable amount of industrial load on interruptible rates and provides time-of-day rates to certain customer classes. Many American utilities have offered demand response or load management programs for longer periods of time and more actively than is the case for energy efficiency programs.
- NSPI's proposed 2005 DSM portfolio relied on lighting DSM programs to account for a large share of their energy conservation savings. Lighting DSM programs have often been one of the main areas where DSM program funds have been targeted in many organizations' DSM portfolios.
- Several parties raised the issue of NSPI's motivations and financial incentives regarding DSM in comments on NSPI's proposed DSM portfolio. The question "why does a company want to encourage its customers to use less of its product" is common in North American DSM proceedings.

Differences Between Nova Scotia and Other Jurisdictions

- NSPI is Nova Scotia's dominant vertically integrated electric supplier, serving over 90% of the province's customers. This situation is similar to some other Canadian provinces such as British Columbia, Manitoba, and Quebec. However, the situation in Nova Scotia is different than in most American states, where a dominant electric supplier that serves over half of the residents in a state may exist, but most states also have many smaller electric utilities, such as municipal utilities and cooperatives, that each serve relatively small numbers of customers.

- There is very little natural gas service available in Nova Scotia, unlike most other jurisdictions in North America.

- There is little air-conditioning load in Nova Scotia in the residential sector. Almost no customers own central air conditioners, and less than 10% own room air conditioners. This is the lowest saturation of any provincial grouping reported on in Natural Resource Canada's 2003 Survey of Household Energy Use, and much lower than even northern American states.

- Nova Scotia has does not have energy building codes whereas most jurisdictions with active DSM programs also have significant energy code requirements, as were recently passed in Ontario.

- NSPI's proposed DSM portfolio was focused on the residential sector in terms of program funding and expected savings. Many other jurisdictions have seen more energy and demand savings from the commercial & industrial sector than the residential sector.

- NSPI proposed a generally larger role for public education programs regarding DSM than many other leading DSM program sponsors. However, energy conservation information programs are common elements in many DSM program portfolios. California started a practice of not trying to quantify the energy and demand savings impacts from energy information programs that many jurisdictions have followed.

- NSPI's proposed DSM spending level for 2005 of 0.5% of revenues was somewhat low by industry standards. DSM spending as a percent of revenues typically ranges from 1% to 3% for the utilities and agencies reviewed for this project, as well as for the CAMPUT report. However, NSPI's proposal was for the first year of a multi-year program, so the comparisons between NSPI and other organizations that have been doing DSM for a long time are somewhat misleading.

3. Review of Nova Scotia Power Inc.'s Conservation and Energy Efficiency Plan 2006

In this task Summit Blue assessed NSPI's 2006 DSM plan against tried and proven DSM programs delivered by similar utilities and agencies in North America. This included collecting and analyzing benchmark data from selected jurisdictions, comparing these results to NSPI's DSM plan, and describing areas of similarities and differences to aid in identifying areas for improvements and/or modifications. Section 5 of this report builds on both the technical potential and comparison of NSPI DSM plan to industry practices to recommend modifications and improvements to Nova Scotia Power's Conservation and Energy Efficiency Plan to achieve the maximum cost-effective electricity DSM potential in the province.

3.1 Methodology

This section covers the methodology to collect and analyze benchmark programs and compare overall levels of DSM costs and costs of savings in major customer segments, and addresses the similarities and differences between utility-delivered and agency-delivered DSM portfolios.

This task involved comparing NSPI's proposed DSM program portfolio to other North American DSM program portfolios, highlighting significant similarities and differences. Programs selected included both utilities that are somewhat new to DSM, such as Hydro Quebec, as well as utilities and agencies that have conducted DSM programs for a long time such as British Columbia and Efficiency Vermont. The analysis of the DSM program portfolios' normalized program results, and NSPI's 2006 program plans, for utility size, sales to major customer weather, currency, and stage in the DSM program "life cycle".

The benchmarking data for these utilities and agencies was prepared as follows:

- For selected utilities and other organizations offering DSM programs, compiled 2005 reported program results or planned results if no results were available—program descriptions, energy and demand savings, customer participation, and costs.

- Categorized actual DSM program results by major customer sector—residential and commercial & industrial (C&I)— and calculated percentages from each category.

- Normalized results by utility or state overall sales and peak demands to produce estimates of savings as percentages of overall sales and peak demand (where appropriate).

- Converted program spending to Canadian dollars where needed, and divided spending by the DSM program energy and demand savings to determine each utility's cost of conserved energy and demand in terms of $/MWh and $/kW.

- Calculated energy education and information spending as a percentage of total DSM budgets.

- Collected benefit-cost ratios for each program, where available, and described the main tests that the utilities or agencies use to assess the programs' cost-effectiveness.

Data and information on DSM programs for eight jurisdictions were collected, including actual results for 2005 where available. BC Hydro, Hydro Quebec, and Manitoba Hydro are included in the benchmarking task since these utilities are similar to Nova Scotia Power, that is, vertically integrated electric utilities that serve most of the provincial electricity needs, with similar climates and customer bases. Efficiency Vermont, New Jersey Office of Clean Energy, and the New York State Energy Research and Development Authority (NYSERDA) were included as they have similar climates to Nova Scotia, as well as two Minnesota utilities—Xcel Energy and Otter Tail Power. Only planned results were available for Hydro Quebec Distribution (HQD); a separate analysis was done for HQD and NSPI, as there can be a big difference between planned vs. actual results and costs for DSM programs.

3.2 Benchmark Results

This section shows energy and demand savings results and other statistics overall and by major customer sectors—residential and commercial and industrial (C&I). Table 3-1 shows the results for utilities and agencies that provided actual results and costs for 2005. Table 3-2 shows the costs and expected savings for planned programs for Hydro Quebec and Nova Scotia Power by major customer sector. Table 3-3 and Table 3-3 present the statistics calculated for jurisdictions.

Table 3-1. 2005 Actual DSM Results

	DSM Results								
Utility/Agency	**GWh**	**MW**	**TRC B/C**	**Costs ($M)**	**Customers**	**Annual GWh**	**Peak MW**	**Revenue ($M)**	**Heating DDays**
Residential									
BC Hydro	192	N/A	2.1	21	1,484,339	15,814	N/A	1,016	
Manitoba Hydro	10	2	1.4/3.1	3	443,000	6,370		386	
MN - Xcel Energy	10	32.0	0.4-5.5	15	1,062,137	8,289	2,331	808	
MN - Otter Tail	3	0.5	1.66	1	46,324	502	142	42	
Efficiency Vermont	28	4.7	0.6-1.3	7	296,182	2,109	N/A	330	
NJ Clean Energy Program	90	37.1	N/A	70	3,354,455	49,498	N/A	3,792	
NYSERDA	74	7.6	N/A	6	7,178,953	28,452	N/A	8,304	
Commercial & Industrial									
BC Hydro	257	N/A	1.6	53	190,716	35,391	N/A	1,688	
Manitoba Hydro	55	162	1.5-32	17	62,826	13,411	N/A	553	
MN - Xcel Energy	253	80	34.9	33	128,815	22,103	3,970	1,477	
MN - Otter Tail	14	2	2.2	1	11,745	1,382	212	94	
Efficiency Vermont	27	4	1.5	8	46,978	3,554	N/A	425	
NJ Clean Energy Program	288	36	N/A	30	472,641	66,695	N/A	5,786	
NYSERDA	1,295	280	N/A	218	1,083,954	131,969	N/A	12,874	
Total									
BC Hydro	449	N/A	1.7	55	1,675,055	51,205	N/A	2,704	3,139
Manitoba Hydro	65	164	2.5	20	505,826	19,781	4,169	939	6,014
MN - Xcel Energy	263	112	2.1	48	1,190,952	30,392	6,301	2,284	4,416
MN - Otter Tail	17	3	3.8	1	58,069	1,884	354	137	4,426
Efficiency Vermont	56	9	1.2	15	343,160	5,664	N/A	755	4,299
NJ Clean Energy Program	378	73	N/A	100	3,827,096	116,193	N/A	9,578	2,698
NYSERDA	1,369	288	N/A	224	8,262,907	160,421	N/A	21,179	2,710

Table 3-2. Planned DSM Results

Utility/Agency	DSM Results GWh	MW	TRC B/C	Costs ($M)	Customers	Annual GWh	Peak MW	Revenue ($M)	Heating DDays
Residential									
Hydro Quebec	243	N/A	N/A	54	3,450,455	57,024	N/A	3,675	
Nova Scotia Power	60	14	3.9	4	420,462	4,000	1056	441	
Commercial & Industrial									
Hydro Quebec	181	N/A	N/A	55	302,055	112,153	N/A	5,446	
Nova Scotia Power	12	2	3.1-3.2	1	44,882	7,500	1,424	554	
Total									
Hydro Quebec	424	N/A		109	3,752,510	169,177	N/A	9,121	4,585
Nova Scotia Power	72	16		5	465,344	11,500	2,480	995	4,501

Table 3-3. Statistics for Actual Results

Utility/Agency	Spending as % of Revenue	Energy Savings as % of Sales	Demand Savings as % of Peak Demand	Cost of Savings $/kWh	$/kW
Residential					
BC Hydro	2.1%	1.2%	N/A	$0.11	N/A
Manitoba Hydro	0.8%	0.2%	N/A	$0.30	$1,494
MN - Xcel Energy	1.9%	0.1%	1.4%	$1.58	$476
MN - Otter Tail	1.6%	0.5%	0.4%	$0.25	$1,331
Efficiency Vermont	2.1%	1.3%	N/A	$0.25	$1,503
NJ Clean Energy Program	1.8%	0.2%	N/A	$0.77	$1,886
NYSERDA	0.1%	0.3%	N/A	$0.09	$841
Commercial & Industrial					
BC Hydro	3.1%	0.7%	N/A	$0.21	N/A
Manitoba Hydro	3.1%	0.4%	N/A	$0.31	$105
MN - Xcel Energy	2.2%	1.1%	2.0%	$0.13	$413
MN - Otter Tail	1.3%	1.0%	1.0%	$0.09	$582
Efficiency Vermont	1.9%	0.7%	N/A	$0.30	$2,057
NJ Clean Energy Program	0.5%	0.4%	N/A	$0.10	$813
NYSERDA	1.7%	1.0%	N/A	$0.17	$791
Total					
BC Hydro	2.7%	0.9%	N/A	$0.16	N/A
Manitoba Hydro	2.1%	0.3%	4.0%	$0.31	$122
MN - Xcel Energy	2.1%	0.9%	1.8%	$0.18	$431
MN - Otter Tail	1.4%	0.9%	0.7%	$0.11	$725
Efficiency Vermont	2.0%	1.0%	N/A	$0.27	$1,757
NJ Clean Energy Program	1.0%	0.3%	N/A	$0.26	$1,355
NYSERDA	1.1%	0.9%	N/A	$0.17	$792

Table 3-4. Statistics for Planned Programs

Utility/Agency	Spending as % of Revenue	Energy Savings as % of Sales	Demand Savings as % of Peak Demand	Cost of Savings	
				$/kWh	$/kW
Residential					
Hydro Quebec	1.5%	0.4%	N/A	$0.22	N/A
Nova Scotia Power	0.9%	1.5%	1.3%	$0.07	$286
Commercial & Industrial					
Hydro Quebec	1.0%	0.2%	N/A	$0.30	N/A
Nova Scotia Power	0.2%	0.2%	0.1%	$0.12	$500
Total					
Hydro Quebec	1.2%	0.3%	N/A	$0.26	N/A
Nova Scotia Power	0.5%	0.6%	0.6%	$0.07	$312

Savings as a percent of energy sales varied quite widely across jurisdictions reporting actual results. As shown in Figure 3-1, residential savings from actual results are less than 0.6% of total sales with two exceptions. Actual savings for the C&I customer sectors are about 1% of sales but much lower for planned DSM programs (Figure 3-2). NSPI's proposed savings as a percent of sales is at the top end for residential but at the low end for C&I customers.

Figure 3-1. Actual Savings as % of Sales

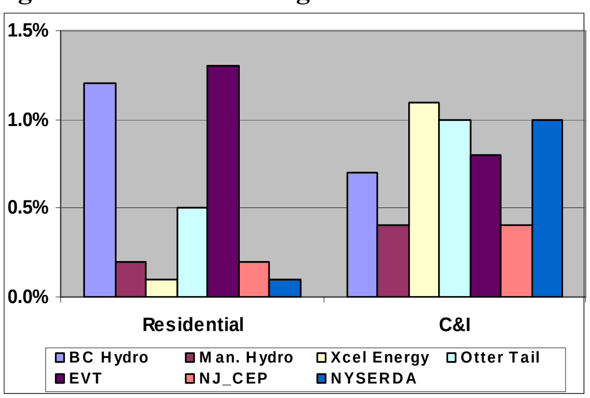
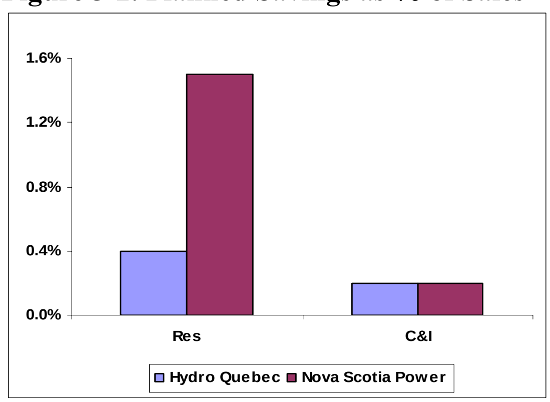
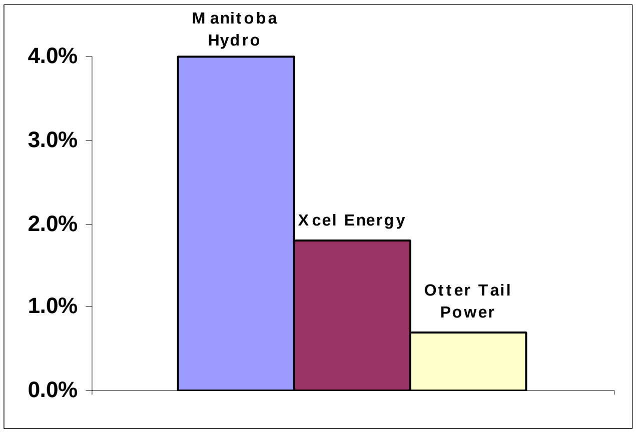


Figure 3-2. Planned Savings as % of Sales



Demand savings as a percent of peak demand range from less than 0.5 % to 4%. Calculations of actual demand savings as a percentage of sales were only possible for the two Minnesota utilities; BC Hydro does not track demand savings and baseline peak demand estimates were not available for Vermont, New Jersey, or New York. Xcel Energy has seen substantial peak savings in both major sectors (1.5% in the residential and 2.0% in the C&I sector), unlike with energy savings where residential savings were less than 0.2% of sales. These savings were achieved with interruptible rates and direct load control. Manitoba Hydro saved 4% of peak demand, mostly through interruptible rates; customers are interrupted for both economic and emergency reasons. BC Hydro does not offer interruptible rates currently; there was minimal interest in these rates when the utility previously offered them.

Figure 3-3. Actual Demand Savings as % of Peak Demand



Level of Spending & Cost of Savings

DSM spending as a percent of revenue is fairly consistent for residential but varies more widely in the C&I sector (see Figure 3-4 and Figure 3-5 below). Spending on DSM in the residential sector as a percent of revenue ranges from about 1% to 2%, except for NYSERDA; Nova Scotia's plan falls at the low end of residential spending and at the bottom of the range for C&I spending, second only to New Jersey's less than 0.5%. In contrast, Manitoba Hydro and BC Hydro spent 3.1% of annual C&I revenues on DSM programs.

Figure 3-4. Actual DSM Spending as % of Revenue by Major Customer Sector

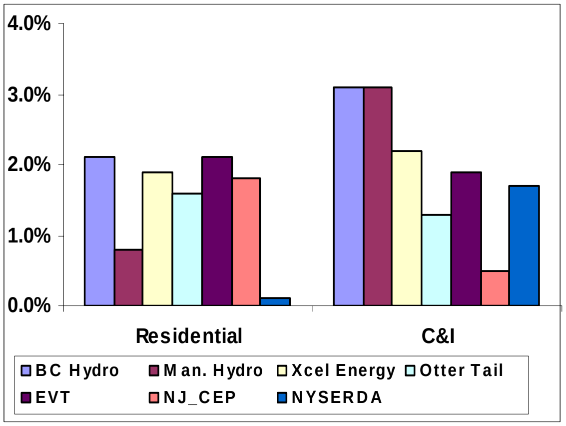
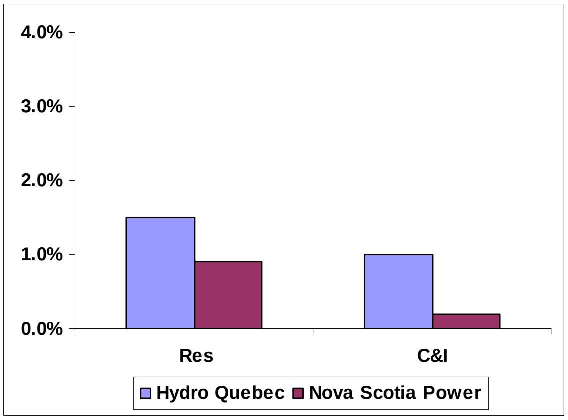


Figure 3-5. Planned DSM Spending as % of Revenue by Major Customer Sector



Reported results show that residential savings results can cost significantly more than C&I savings while planned results expect the opposite. Residential energy costs range from a low of $0.09/kWh for NYSERDA to a high of $1.60 per kWh for Xcel Energy. Savings costs for C&I programs were all under $0.50/kWh. NSPI expects its program costs to be low in both customer sectors— $0.07/kWh for residential and $0.12/kWh for C&I. Figure 3-6 and Figure 3-7 show graphical comparisons of costs for energy saved by major customer sector for actual program results and planned DSM activities.

Figure 3-6. Actual Costs of Energy Savings ($/kWh)

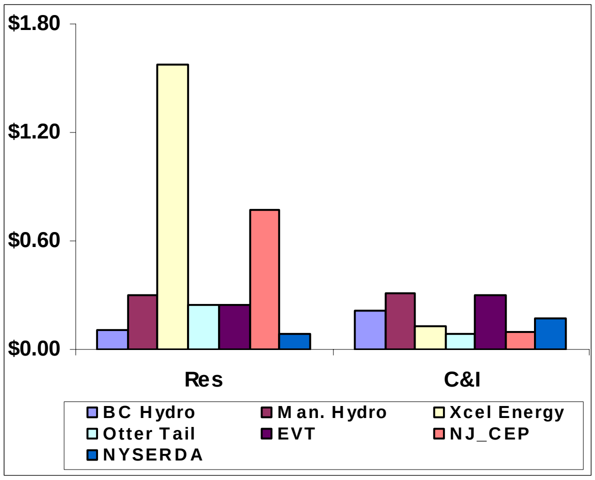
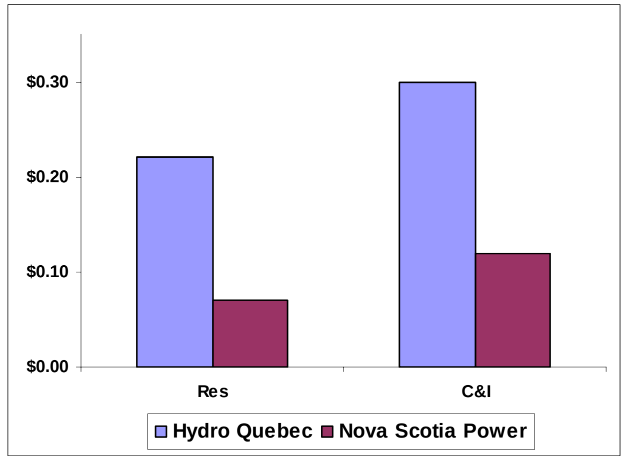
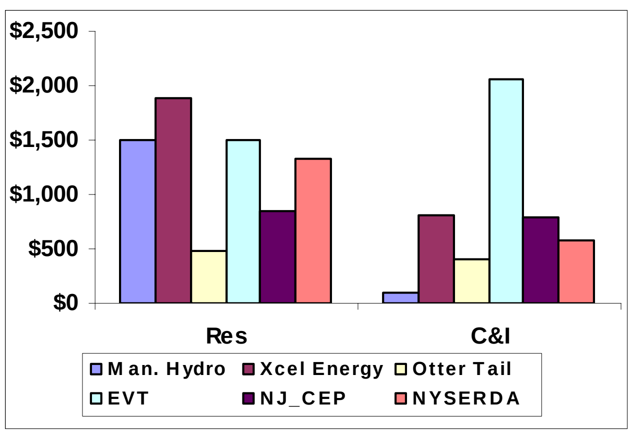


Figure 3-7. Expected Costs of Energy Savings ($/kWh)



Costs for demand savings are often higher in the residential sector than in the C&I sector. As shown in Figure 3-8, costs to save demand in the residential sector range from $500 to $2,000 per peak kW. C&I costs for peak demand are usually $1,000/kW or lower; Manitoba Hydro achieved C&I demand savings at a cost of $105/kW but residential demand savings cost about $1,500/kW; most demand savings in the C&I sector are from interruptible rates. NSPI plans expect to achieve demand savings in all sectors at low costs compared to other locations and they have not included interruptible load in their savings forecast.

Figure 3-8. Actual Costs of Demand Savings



Cost-Effectiveness

Most of the actual DSM programs reviewed were cost-effective in terms of the Total Resource Cost Test. As shown in Table 3.1, most of the program portfolios had TRC benefit-cost ratios greater than one, with the exceptions of Xcel Energy with a ratio of 0.4 for low-income programs and Efficiency Vermont with a ratio of 0.6 for existing buildings which include low-income initiatives. Manitoba Hydro recorded the highest benefit-cost ratio for its Agricultural Heat Pads Program, followed by Xcel Energy's benefit-cost ratio of 25 for its interruptible rates program.

DSM Spending and Results Over Several Years

This section uses BC Hydro to illustrate how DSM program results and costs can change over time. This is to help address the reasonableness of NSPI spending on DSM in a first year of a long-term strategy. BC Hydro provided results (2003 to 2005) and forecasts (2006-2012) for cumulative costs and results as shown in Figure 3-9 and Figure 3-10. Savings in the industrial sector are expected to continue to increase over the longer term while savings in other sectors level off after about four years.

Figure 3-9. BC Hydro Cumulative GWh Savings (2003- 2012)

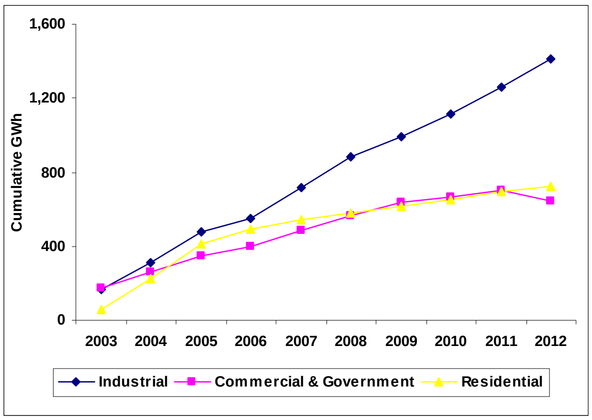
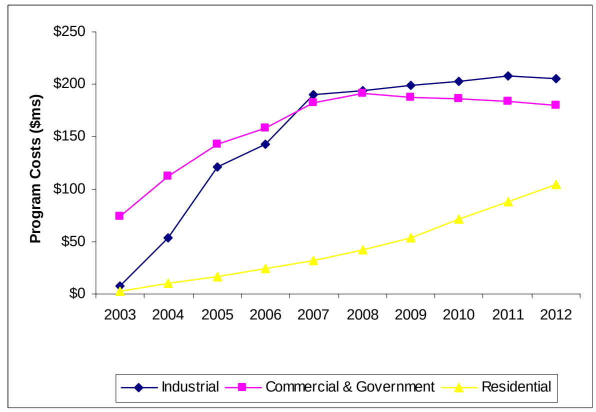


Figure 3-10. BC Hydro Cumulative Total Program Costs (2003-2012)



Actual savings and costs vary from year to year as program mixes change; some programs ramp up, some come to an end, and others are introduced. The following figures illustrate five year program results and costs for two of BC Hydro's programs. Costs are generally higher in early program years compared to savings achieved as programs are introduced to the market, then level off. Savings can be short term or more consistent over the longer term (Figure 3-12). Jurisdictions planning and delivering DSM programs consider the lifecycle of the program; some are short-term (Figure 3-11) while others can continue to deliver savings for many years (Figure 3-12).

Figure 3-11. BCH PS Partners Program

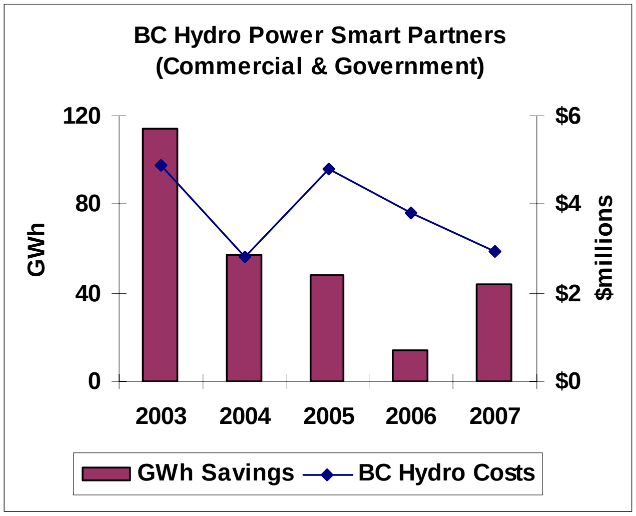
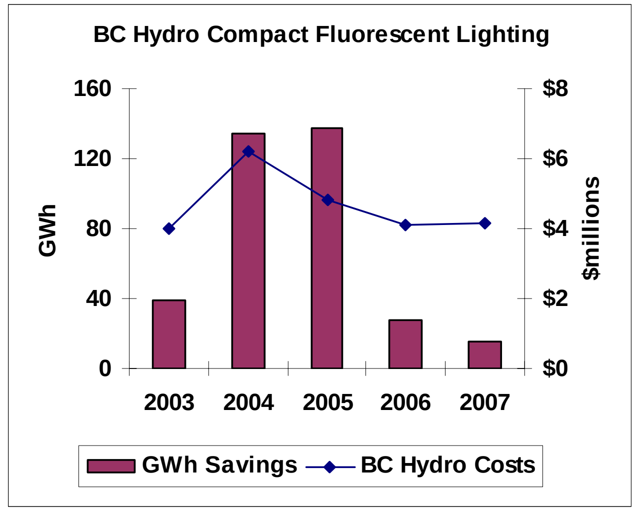


Figure 3-12. BCH CFL Program



Approaches to DSM

Tenure

Three of the organizations reviewed are relatively new in their DSM offerings, starting in the late 1990s or more recently. One organization went through a restructuring-induced hiatus whereby DSM programs were discontinued after an initial period prior to market restructuring, then restarted recently. The other four organizations have offered programs starting as far back as the 1930s (in particular load management). These entities began offering contemporary types of energy efficiency programs in the 1980s, though in one case the entity administering the programs has changed as a consequence of electricity market restructuring.

It took the various organizations anywhere from one to almost ten years to develop their respective DSM organizations and portfolios as they currently stand, though most organizations were set up and became operational to at least a modest extent within two years of being authorized. In almost every case, underlying near-term electricity resource needs existed such that the programs were charged with having almost an immediate impact.

Market Approach

In terms of the basic approach to influencing the marketplace, two organizations emphasize a market transformation strategy in their portfolios, attempting to influence "upstream" service and equipment provider market channels and what they offer end customers, along with educating and informing end customers directly. The emphasis is on influencing market channels and key market actors other than end customers. The other organizations take a primarily resource acquisition approach where end customers are the primary target of program offerings (e.g., using rebates to influence customers' purchases of end use equipment). For these organizations, market transformation is a consequential objective of the resource acquisition strategy – also important but with an end customer focused program strategy.

Administrative Approach

The administrative approach to programs also varies, but appears to be associated with whether the underlying strategy for going to market is resource acquisition or market transformation.[7]

Three of the organizations reviewed use non-utility third parties – either a state agency or a private sector agent under contract to a state agency – to develop and administer the DSM portfolio, though utilities are involved with promoting programs in all those situations. The remaining organizations have utility-administered portfolios. Though they often utilize various other market actors to help deliver the programs and have varying degrees of market transformation involved, utility portfolios tend to be much more resource acquisition oriented.

Economic Screening

The economic screening of programs' cost-effectiveness typically uses the Total Resource Cost test or its externality-enhanced corollary the Societal Cost test, though other tests – particularly the Utility Cost Test – also are employed to provide additional perspective. In cases where multiple tests are employed, minimum thresholds are typically utilized to optimize the overall economic picture – for example, requiring a 1.0 or greater TRC result *and* a Rate Impact test result of >0.8.

DSM Programs

Four of the organizations reviewed offer demand response and/or load management programs; the others focus primarily on energy efficiency programs. There does not appear to be a strong pattern of these program types related to the underlying generation mix. For example, one would think that hydro-dominated situations, with energy storage and average-demand concerns, would tend to have only energy efficiency programs, whereas a more fossil-fuel oriented supply mix would have a strong load management or demand response component. While two of three organizations with a heavy base of hydro capacity only offer energy efficiency programs, the third also offers curtailable rates to industrial customers. Among organizations with a heavily fossil fuel-based supply mix, two offer only energy efficiency programs; both are non-utility agencies emphasizing market transformation. Load management and demand response programs require close involvement and coordination with utility system operations, so there is a natural affinity for such programs as part of utility (retail distribution companies and wholesale system operator) DSM portfolios; non-utility agencies, for the same reason, generally do not offer them.[8]

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[7] *Market transformation* is a strategic approach to influencing markets that relies more upon interactions with market actors upstream of end consumers – i.e., to transform in a more top-down way what manufacturers make, distributors distribute, retailers retail, and service agents maintain and repair. The effects of a market transformation approach are generally more widespread than the counterpart strategy of resource acquisition. *Resource acquisition* is a strategy that also influences markets, but primarily from the end consumer upward by emphasizing direct influences on consumers' equipment efficiencies (buying higher efficiency equipment and maintaining it as such) and their various energy-use affecting behaviours and general lifestyle. Both strategies deploy similar types of marketing and sales tactics, such as providing financial incentives to offset high-efficiency equipment higher costs, but the tactics are aimed at different audiences. Certainly, there is overlap between the strategies; some would assert they are complementary.

[8] There is at least one demand response program offered by a non-utility agent: the Energy-Smart Pricing Plan, a real-time pricing program offered by the Chicago Community Energy Cooperative. This program is offered in conjunction with the Cooperative's purchase of electricity blocks from Commonwealth Edison and is triggered by the spot prices for that electricity; essentially, Cooperative members save money two ways: by assuming the price risk for the purchased electricity, as well as reducing their usage in response to price volatilities.

Programs offered address major end uses: air conditioning and refrigeration, lighting, process and HVAC equipment, motors and compressors, and building thermal envelopes. In some cases where electric space or water heating is significantly saturated, programs for heating equipment including thermal storage and geothermal systems are likely to be available as well, including fuel switching in one organization's case.

- ENERGY STAR. There is widespread use of the U.S. ENERGY STAR program to promote energy-efficient equipment purchases, particularly for residential markets though some organizations also use its commercial and industrial components. The program has been used for both market transformation and resource acquisition. It addresses a broad spectrum of market channels and virtually the entire supply chain from manufacturer to end customer.
- Low-income. All organizations reviewed, except for BC Hydro and Manitoba Hydro, specifically target low-income residential markets in order to meet social policy objectives associated with those markets. BC Hydro addresses low-income customers by providing residential programs that allow these customers to participate, for example, giving out free CFLs as well as coupons. Manitoba Hydro is in the process of developing programs specific to the low-income consumers. Results that were reviewed for low-income programs show that the TRC ratios are usually not cost-effective even with a target TRC ratio of 0.8.
- New Construction. Programs targeting new construction are increasingly in evidence, including components of the ENERGY STAR program but also more customized approaches such as for new commercial buildings through design and engineering technical support and associated incentives for adopting certain designs and equipment configurations.
- Fuel Switching. Only one organization (a hydro-electric based utility) promotes fuel switching in its DSM portfolio. This may be due to the fact that fuel switching programs historically have proved problematic and overly complex from a regulatory oversight perspective, because of issues concerning cross-form energy accounting (e.g., how to account for electric impacts when an electric water heater is switched to natural gas), organizational accountability (not all the organizations are multi-fuel), and concerns about possible gaming simply to achieve whatever financial incentives may be available. Probably for similar reasons, combined heat and power programs are scarce among the organizations reviewed; only one organization offers such a program and that organization is a state agency.
- Load Management/Demand Response. Most of the utilities reviewed, having integrated system operations situations that enable monitoring and control, offer load management programs. These include both direct load control and customer-driven load response programs. Hydro-based utilities are less likely to have such programs, however. Demand response programs involving customer-driven (vs. utility-controlled) demand reduction/shifting actions are on the rise, though utilities continue to use direct load control programs. The two programs address complementary market needs in terms of customer preferences for managing their loads during high peak periods. In restructured electricity markets and in relation to agency organizations reviewed, load management programs are developed and managed at the wholesale level by regional system operating organizations, and so do not appear in the review of the DSM organizations here.
- Behavioural Programs. Programs that depend on potentially volatile customer behaviour, particularly "smart thermostat" and energy management system programs, are not popular because of the impact uncertainties involved.
- Information and Education. Information and education programs are universal among organizations reviewed, developed, and managed to maximize what may be termed "direct-impact" programs such as lighting. Energy and demand impacts of information and education programs tend not to be directly estimated because of the difficulty of measuring effects and uncertainty over time of impacts to attribute to such programs, though some organizations have

and continue to attempt to measure the direct impacts of such programs, especially for measures not covered by direct-impact types of programs. These programs often are viewed in the context of the overall portfolio, e.g., percentage of the total portfolio expenditures for such programs, and to the extent the overall portfolio's cost-effectiveness is managed when such programs' expenditures are included.

- Rebates and Incentives. All organizations reviewed offer rebates and incentives to end-use customers, and sometimes to upstream trade allies, to encourage the purchase and adoption of energy efficiency and demand response measures.
- Upstream and Community Markets. Upstream market programs, including bulk purchase programs, trade programs, and community-level efficiency promotion programs, are offered by some of the organizations reviewed. These often are information-based programs, though incentives – usually directed at energy-service trades – may be part of the program.
- Financing. Some organizations provide financing programs as an alternative or complement to direct incentives, to help improve cash flow for efficiency investments.
- R&D. Little in the way of research and development programs was seen in reviewing the various organizations' situations. In some cases R&D is embedded in the program, so is not readily apparent from the review information, but generally the organizations reviewed appear to rely on external R&D to develop technologies, products, and services.

Lighting and other energy-efficient products (including refrigeration) provide the most residential savings across the jurisdictions. Table 3-5 below shows which programs in the residential sector produced energy savings (adjusted for total sector energy sales). The agencies in Vermont, New Jersey, and New York now categorize programs by new construction, efficient products, and low-income (with some exceptions), so results by program are not directly comparable to utilities. For the agencies, efficient products, which include lighting, provide the most savings.

Table 3-5. Actual 2005 Energy Savings for Residential Programs as % of Sales

Program/Measures	BCHydro	Man. Hydro	Xcel Energy	Otter Tail	EVT	NJ_CEP	NYSERDA
Lighting	0.940%	0.127%	0.044%	0.312%			
HVAC			0.049%	0.106%		0.030%	
Refrigeration	0.220%						
Water Heating				0.035%			
Efficient Products					1.142%	0.128%	0.030%
Envelope/Misc.		0.027%					0.025%
Low-income			0.017%	0.075%		0.011%	0.001%
New Construction	0.030%	0.002%			0.041%	0.012%	0.001%
Education/Advertising							
Energy Audits							
Fuel Substitution	0.010%						
Existing Buildings	0.010%				0.167%		
Direct Load Control			0.006%	0.003%			
Total Savings (MWh)	**192,000**	**9,900**	**9,668**	**2,670**	**28,466**	**90,289**	**73,793**
Annual Energy Sales (MWh)	**15,814,000**	**6,370,000**	**8,289,361**	**502,139**	**2,109,494**	**28,452,659**	**49,497,852**
Savings as a % of Sales	**1.21%**	**0.16%**	**0.12%**	**0.53%**	**1.35%**	**0.32%**	**0.15%**

Table 3-6. Actual 2005 Energy Savings for Commercial & Industrial Programs as % of Sales

Program/Measures	BCHydro	Man. Hydro	Xcel Energy	Otter Tail	EVT	NJ_CEP	NYSERDA
Lighting	0.010%	0.122%	0.279%	0.023%			0.006%
HVAC			0.046%	0.012%			
Refrigeration			0.030%	0.028%			
Motors and Drives			0.131%	0.063%			
Compressed Air			0.100%				
Custom/Cooking	0.690%	0.195%	0.200%	0.882%			
New Construction	0.010%	0.051%	0.304%	0.038%	0.295%	0.031%	0.233%
Existing Buildings		0.022%	0.042%		0.778%	0.400%	0.682%
Product Incentive	0.020%	0.019%					
Energy Audits							0.060%
Interruptible Rates			0.008%				
Direct Load Control			0.004%				
Total Savings (MWh)	**257,000**	**54,800**	**252,890**	**14,466**	**27,394**	**287,671**	**1,295,345**
Annual Energy Sales (MWh)	**35,391,000**	**13,411,000**	**22,103,072**	**1,381,881**	**2,554,278**	**66,695,467**	**131,968,977**
Savings as a % of Sales	**0.73%**	**0.41%**	**1.14%**	**1.05%**	**1.07%**	**0.43%**	**0.98%**

Custom projects provide the highest savings for utility C&I sectors; existing buildings provide the most savings for the agencies reviewed. As shown in Table 3-6 below, the agencies aggregate savings from programs into existing buildings and new construction, sometimes also targeting a specific sub-segment, such as schools, for both new construction and existing buildings opportunities. Lighting, motors and drives, compressed air, and refrigeration—where identified separately—also contribute to energy savings.

Load management options such as interruptible rates and direct load control do not contribute significantly to energy savings. However, these options do provide significant demand savings as a percentage of peak demand, e.g., Xcel Energy's interruptible rates and direct load control programs reduce peak demand by 1% in the residential sector and by 0.8% in the C&I sector.

Costs of energy savings are generally lower for C&I programs but residential lighting and energy efficient product savings are also achieved at reasonably low costs.. Table 3-7 and Table 3-8 show the costs of energy savings for individual DSM programs in the residential and C&I sectors. Costs to achieve energy savings range from a low of nine cents per kWh for the New Jersey Clean Energy Program's Efficient Products initiative (which includes lighting) to a high of $11/kWh for Xcel Energy's direct load control programs. Xcel Energy's cost of energy savings is skewed by the cost to achieve residential direct load control which is a very low cost way to achieve demand savings, as shown in Tables 3.9 and 3.10. Interruptible rates in the C&I sector have achieved demand savings at costs below $40/kW.

Table 3-7 Costs of Residential Energy Savings by Type of Program

Program/Measures	BCHydro	ManHydro	Xcel Energy	Otter Tail	EVT	NJ	NYSERDA
Lighting	$0.06	$0.14	$0.13	$0.06			
Cooling/Heat pumps			$1.27	$0.15		$0.87	
Refrigeration	$0.26						
Water Heating				$0.29			
Efficient Products					$0.08	$0.09	$0.12
Envelope/Misc.	$1.96	$0.71					
Low Income			$0.88	$0.56		$2.74	$0.71
New Construction	$0.55	$8.19			$1.84	$3.80	
Education/Advertising							
Energy Audits							
Fuel Substitution	$0.36						
Existing Buildings					$0.64		
Direct Load Control			$11.09	$6.75			
Total Savings (MWh)	**192,000**	**9,900**	**9,668**	**2,670**	**28,466**	**90,289**	**73,793**
Total Costs ($000)	**$21,172**	**$3,182**	**$15,246**	**$666**	**$7,066**	**$69,962**	**$6,389**
Costs of Savings ($/kWh)	**$0.11**	**$0.32**	**$1.58**	**$0.25**	**$0.25**	**$0.77**	**$0.09**

Table 3-8 Costs of C&I Energy Savings by Type of Program

Program/Measures	BCHydro	Man. Hydro	Xcel Energy	Otter Tail	EVT	NJ	NYSERDA
Lighting	$1.38	$0.31	$0.18	$0.33			$0.17
Cooling/Roofing/HPs			$0.20	$0.08			
Refrigeration			$0.07	$0.10			
Motors and Drives			$0.07	$0.10			
Compressed Air			$0.05				
Custom/Cooking	$0.16	$0.06	$0.08	$0.05			
New Construction		$0.20	$0.11	$0.05	$0.43	$0.32	$0.29
Existing Buildings		$0.91	$0.09		$0.25	$0.09	$0.14
Product Incentive	$0.20	$0.12					
Energy Audits							$0.05
Interruptible Rates			$0.39				
Direct Load Control			$2.26				
Total Savings (MWh)	**257,000**	**54,800**	**252,890**	**14,466**	**27,394**	**287,671**	**1,295,345**
Total Costs ($000)	**$53,337**	**$16,875**	**$33,204**	**$1,239**	**$8,172**	**$29,569**	**$217,711**
Costs of Savings ($/kWh)	**$0.21**	**$0.31**	**$0.13**	**$0.09**	**$0.30**	**$0.10**	**$0.17**

Table 3-9 Costs of Residential Demand Savings by Type of Program

Program/Measures	ManHydro	Xcel Energy	Otter Tail	EVT	NJ	NYSERDA
Lighting	$723	$3,272	$467			
Cooling/Heat pumps		$724	$4,272		$1,030	
Refrigeration						
Water Heating			$1,527			
Efficient Products				$471	$1,223	$884
Envelope/Misc.	$1,507					
Low Income		$5,881	$3,633		$27,183	$288
New Construction				$12,913	$1,231	
Education/Advertising						
Energy Audits						
Fuel Substitution						
Existing Buildings				$6,485		
Direct Load Control		$227	$905			
Total Savings (kW)	**2,400**	**32,118**	**450**	**4,697**	**37,079**	**7,604**
Total Costs ($000)	**$3,182**	**$15,246**	**$666**	**$7,066**	**$69,962**	**$6,389**
Costs of Savings ($/kW)	**$1,326**	**$475**	**$1,480**	**$1,504**	**$1,887**	**$840**

Table 3-10 Costs of C&I Demand Savings by Type of Program

Program/Measures	Man. Hydro	Xcel Energy	Otter Tail	EVT	NJ	NYSERDA
Lighting	$2,057	$899	$333			$627
Cooling/Roofing/HPs		$289	$1,633			
Refrigeration		$771	$261			
Motors and Drives		$587	$797			
Compressed Air		$380				
Custom/Cooking	$417	$751	$407			
New Construction	$1,934	$464	$450	$2,292	$1,143	$1,243
Existing Buildings	$5,288	$1,502		$1,926	$838	$646
Product Incentive						
Energy Audits						$257
Interruptible Rates	$38	$30				
Direct Load Control		$184				
Total Savings (kW)	**161,500**	**80,465**	**2,189**	**3,972**	**33,204**	**279,921**
Total Costs ($000)	**$16,875**	**$33,204**	**$1,239**	**$8,172**	**$29,569**	**$217,711**
Costs of Savings ($/kW)	**$104**	**$413**	**$566**	**$2,057**	**$891**	**$778**

Cost Recovery/Customer Class Allocation & Financial Incentives

Utilities recover program costs through base rates or rate surcharges such as a resource adjustment, whereas agencies fund via separately itemized charges collected from customers via bills; but the effect on customer bills is the same. Typically, though not always, the cost recovery charge is one fixed rate applied to all "eligible" customers.[9] One non-utility organization reviewed does split its cost recovery by major customer class, but again such a split is an exception to typical practice. DSM is considered a resource, similar to a power plant, and therefore costs are generally recovered from the entire rate base rather than only from customers that participated in the programs. Another basic premise underlying a single fixed rate surcharge to fund DSM is that customers have an opportunity to participate in programs in relation to their energy consumption levels, with smaller customers who have smaller DSM potential paying less than customers with greater consumption levels. Also, cost recovery charges tend to be treated in the same manner as fuel adjustment clauses and such clauses typically are uniform across customer classes.[10] Certainly, actual program budgets tend to allocate funds by other factors such as social or customer service objectives, so in practice some types of customers may receive a disproportionately higher (or lower) level of DSM services than what they are funding. This can become a political issue in the course of regulatory oversight, but typically does not result in altering the basic cost recovery paradigm of a single fixed funding rate.

Program costs are recovered through customer bills in all the situations reviewed (as opposed, say, to funding via an external tax), though itemization and terminology of cost recovery differ. Some

[9] In some jurisdictions industrial customers may opt out of DSM programs and pay no surcharge to fund DSM; however, they are generally required to operate self funded DSM efforts to substitute for utility DSM programs..

[10] Indeed, one jurisdiction has redefined "fuel adjustment" as "resource adjustment" because the rate rider is used for a variety of resource-related true-ups including both supply and demand resources.

organizations simply expense the costs, but most have some sort of deferred accounting process that enables a true-up of actual costs to projected costs as implied by the charges applied to customers' bills, and the amounts actually collected relative to customers' usage. In some cases the costs accrued through the deferred accounting are capitalized and embedded in base rates at some point in the course of future rate cases.

Financial incentives for programs are provided in several jurisdictions, and may include either recovery of lost revenues or estimated margins on revenues, provision of a "profit" on expenditures (usually with a minimum performance threshold and capped to avoid windfalls), or both. In some restructured jurisdictions no incentives are in place because utilities no longer have vertically integrated systems for which they are accountable and for which historically they had at least some need for incentives to offset the loss of traditional business and the loss of profits to that business. BC Hydro, a vertically integrated Crown corporation which exports electricity, on the other hand has considered DSM to be its most cost-effective resource to meet demand.

Program Administration – Utility/Agency Comparisons

This section provides the results of an analysis of how the utility DSM portfolios compare to other agencies' DSM portfolios, including types of and approaches to DSM, and whether the utilities' DSM program savings tend to be larger or smaller as percentages of the relevant baseline customer sales than other agencies' DSM program results in relation to those agencies' baselines. In addition, utilities' (BC Hydro, Xcel Energy, Otter Tail) DSM costs of conserved energy were compared to agencies' (NYSERDA, NJ CEP, & EVT) costs of conserved energy.

- <u>Organization Types.</u> Of the eight organizations reviewed, five are utilities that directly offer and administer DSM programs to end customers. The other three are public agencies in the U.S. operating under statewide jurisdictions and with the agency either directly administering the program portfolio or with third party service entities (equipment contractors, energy service companies, and in some cases end customers themselves) administering the programs. As discussed below, these two basic organizational approaches to DSM efforts can result in different market channeling of the same DSM measures, as well as different consideration of underlying DSM economics.

- <u>Size.</u> Five of the eight organizations reviewed comprise at least one million customers; two of the three smaller entities comprise roughly a half million customers each and the other about 50,000. All entities reflect a customer mix of roughly one-third of kWh being sold to residential customers and two-thirds of kWh sold going to commercial, institutional, and industrial customers. This similar mix of kWh sales distribution across all the entities reviewed means that all have substantial customer service commitments, and associated DSM needs, across very different end user markets.

- <u>Revenues.</u> Annual electricity revenues associated with the six large organizations range from $2 billion to $18 billion; the three smaller organizations have annual electricity sales revenues ranging from just over $100 million to about $1.5 billion. Thus, the market and economic scale of most situations reviewed is substantially greater than NSPI's situation. This generally means the scale of resources available for DSM portfolios is also substantially greater, which can affect the DSM portfolio strategy. Otter Tail Power, which is much smaller than NSPI, has implemented some very cost-effective programs over the years, however, so size is not necessarily the key factor in program effectiveness – rather, the overall size of the effort is just not as large as big organizations' portfolios.

- Peak Demand & Capacity. The organizations' electric peaks[11] range from a modest 350 MW to nearly 38,000 MW, with annual kWh sales ranging from 1.9 TWh to over 290 TWh. The organizations reviewed reflect a variety of underlying electric generation resources that present varying avoided cost situations. Three organizations' supply resource mixes are dominated by hydro-electric supply, three others have substantial nuclear capacity in the mix – at least 30% nuclear capacity – with equal or greater percentages of fossil fuel-fired capacity (coal and/or natural gas) comprising the bulk of remaining supply resources. To at least some extent, this variety of underlying supply resource mixes tends to drive DSM program strategies in different directions because of the underlying supply resource economics.

The primary differences in DSM portfolios and their administration between utilities and agencies concern program strategies and regulatory treatment of program funding and cost recovery. As to program strategies, utilities take more of a resource acquisition approach while agencies emphasize market transformation. From an independent viewpoint the emphasis on strategy means less than the impacts that are achieved, which in turn tends to be the result of good planning, sufficient budget and staffing (in particular having skilled people and staff continuity), and disciplined execution of program tactics. Both resource acquisition and market transformation strategies have been shown to be effective when these factors are adequately addressed – as the saying goes, "the devil is in the details."

Utilities' DSM portfolios are developed internally and reviewed and approved through regulatory oversight processes, with utility staff generally administering programs directly. Agencies' portfolios are developed either by the agency or through solicitation processes, with administration either by the agency or a contracted administrative agent. Agency programs may or may not be offered through utilities, depending on retail service restrictions set forth in restructuring (e.g., New Jersey). Where utilities are prohibited from directly offering programs[12], the agency and/or contracted third party administrators and energy efficiency service providers perform all functions of taking programs to market and administering them. The key strength of a utility-administered program is its tie to the utility value proposition, the depth of utilities' tenure and credibility serving customers over long periods of time, and the associated identity of utilities as an expert advisor on managing energy use. The key strength of a third-party-administered program is that it consolidates what otherwise often is a plethora of similar, yet in various ways different programs within a given geographic jurisdiction (i.e., state or province), such that customers with facilities in different utility territories need not participate in multiple programs.

There is no discernable advantage for either utility or agency in terms of savings or costs. Figure 3-13 shows energy savings as a percent of sales range from under 0.5% to about 1%. Figure 3-14 shows utility costs to achieve savings varied more widely than equivalent agency costs. A study done by the American Council for an Energy-Efficient Economy (ACEEE) in 2005 showed that, in the top five states ranked by 2003 DSM savings as a percentage of electricity sales, it was utilities that delivered the programs.[13]

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[11] Or total generating capacity where annual peak demands were not readily available.

[12] Including New Jersey and Texas, for example; note that New York's utilities are one of several conduits for NYSERDA's programs. For example the Long Island Power Authority (LIPA) directly promotes NYSERDA's programs to its customers and currently is initiating a comprehensive evaluation of those programs as LIPA offers them.

[13] ACEEE's 3rd National Scorecard on Utility and Public Benefits Energy Efficiency Programs: A National Review and Update of State Level Activity, York, D. & Kushler, M., 2005.

Figure 3-13. Actual Energy Savings as a % of Sales (Comparing Utilities and Agencies)

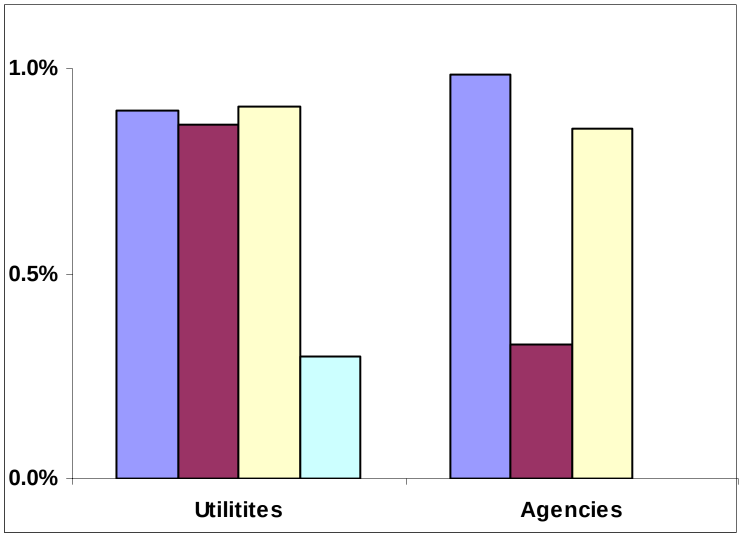
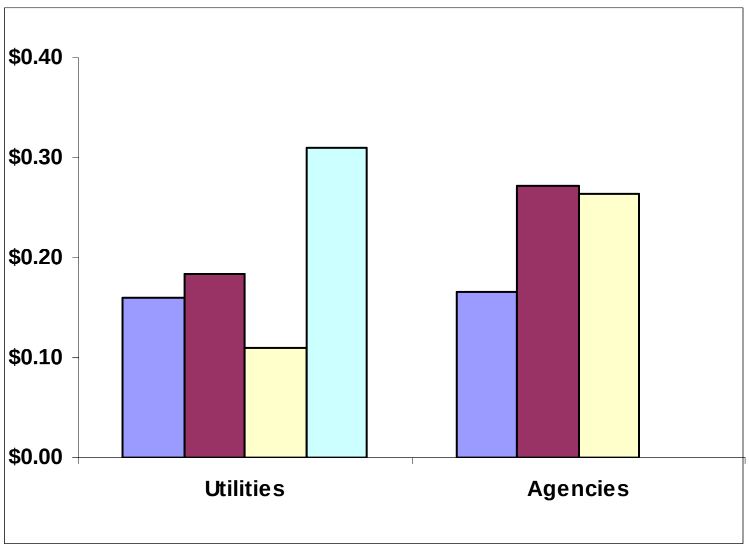


Figure 3-14. Actual Costs of Energy Savings ($/kWh) for Utilities Compared to Agencies



Program Evaluation

Program evaluation requirements vary widely among the organizations reviewed. All have some level of periodic review as part of regulatory oversight, though such reviews may not entail formal evaluations but rather a check on administrative reporting. Some require annual evaluations of major programs – one utility, for example, conducts a formal impact evaluation of load management programs each year, historically using internal load research resources.

Most organizations undertake formal program impact and/or process evaluations "as needed" in relation to program performance and the relative importance of the program in the overall portfolio, when underlying program conditions change significantly or other issues that drive a need or a milestone to conduct the evaluation. Normally, evaluations are conducted by independent research consultants via an evaluation project bid process. In some cases, explicit evaluation protocols, in particular the International Performance Measurement and Verification Protocol (IPMVP), are utilized to establish and guide impact and process evaluations so that the evaluation is appropriately tailored to the program budget and impact scale, its unit impact measurements, and the desired rigor in relation to various issues in play for the program. Regulatory oversight is normally applied to results and to address disagreements over the evaluation findings.

Certain “custom efficiency” types of programs have a real-time evaluation component in that the end customer efficiency improvement projects brought to the organization are evaluated to some level of rigor prior to being approved for inclusion in the program and becoming eligible for program incentives. In such cases, post-installation verifications are often done on at least a spot basis to ensure accurate impact reporting. In some but by no means all cases, evaluations are underlain by periodic market potential studies that are utilized to set strategic program goals. Evaluations may be used to help track programs’ market saturation in relation to the program’s potential as well as address timely issues affecting program performance and why it is or is not tracking well toward achieving its potential.

3.3 Similarities and Differences with NSPI’s DSM Plan

This section outlines the similarities and differences between NSPI’s 2006 DSM Plan and results and portfolios in the other jurisdictions that were reviewed. Table 3-11 below briefly describes how Nova Scotia’s DSM plan compares to the other jurisdictions reviewed.

Table 3-11. NSPI Plan and Benchmark Locations: Similarities and Differences

	Similarities	Differences
Approach to DSM	• NSPI's plan focuses on resource acquisition as do most of the utilities reviewed. • NSPI plans to implement the DSM programs; this is the same administrative approach as other utilities focusing on resource acquisition.	• NSPI proposes to provide minimal rebates and incentives to either end-use customers or trade allies unlike the other jurisdictions reviewed.
DSM Spending & Costs	• NSPI's expected costs to attain C&I program savings are similar to those in the other jurisdictions.	• NSPI's proposed spending as a percent of revenue is lower, particularly in the C&I sector. • Overall, NSPI expects to achieve energy and demand savings for lower costs than is generally noted.
Cost Recovery & Incentives		• Most jurisdictions recover costs through fixed rates applied to all customers; NSPI proposes to allocate the program costs to the customer sector in which it is spent. • Investor-owned utilities are generally compensated for lost margins and sometimes provided incentives.
Types of Programs	• Lighting programs are offered in most jurisdictions and the NSPI plan has a strong lighting component. • NSPI, as in most jurisdictions, does not include fuel switching in its proposed DSM portfolio. • Education and outreach programs are an important component of the NSPI plan which is comparable to other DSM program portfolios reviewed.	• NSPI does not offer programs for new construction in the C&I sector. • NSPI, which does offer a load management program, available to residential customers only, has not included this activity in its portfolio. • NSPI has about 400 MW of load under interruptible rates, however, unlike other utilities with these types of rates, NSPI has not included the impacts in its DSM program mix.
Energy & Demand Savings	• NSPI's emphasis on energy savings is similar to other Canadian utilities and U.S. non-utility organizations.	• NSPI expects much lower C&I savings than do other utilities and agencies. • The NSPI plan forecasts higher residential savings as a percent of revenue than has generally been seen in actual results. • NSPI, unlike other jurisdictions, allocates energy and demand savings to information and education programs.

4. DSM POTENTIAL METHODOLOGY AND RESULTS

This section presents a summary of the methodology and results for the DSM potential aspect of the project. The methodology for calculating the TRC test results for DSM measures and programs is also presented in this section.

4.1 Methodology

This section describes the DSM potential analysis approach and methods. There are three primary aspects to the DSM potential analysis conducted: characterizing residential and commercial/industrial customers, characterizing applicable DSM measures for each customer sector, and estimating DSM potentials from those two sets of inputs and the results of the benchmarking analysis. The approach for the residential sector will be discussed first, then for the commercial and industrial sectors. Summit Blue did not analyze data on individual NSPI customers as part of this DSM potential analysis, since customer information beyond electricity billing histories was not readily available, and due to customer data confidentiality concerns.

4.1.1 Residential Analysis

The residential customer and DSM measure characterizations will be discussed in this section.

Residential Customer Characterization

Summit Blue primarily used NSPI customer statistics and previously conducted market research, a Natural Resources Canada report on residential energy use and equipment[14], and information from the Nova Scotia Statistical Review[15] to characterize NSPI's customer base. Useful information from these sources included:

- The average home's heated area in the Atlantic region of Canada was 1,245 sq.ft. in 2003.[16]
- In 2003, approximately 27% of Nova Scotia residents heated their homes principally with electricity, only 7% of residents own room air conditioners, and almost no residents own central air conditioners.[17]
- In 2003, about 19% of Atlantic Canada's residents had a second refrigerator in their household, and about 69% of Atlantic Canada's residents had a freezer in their household.[18]
- In 2003, about 71% of Atlantic Canada's residents used electricity for water heating.[19] This estimate is similar to NSPI's internal estimate of 60% electric water heating for their customers, which is the statistic that Summit Blue used to estimate water heating DSM potentials.

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[14] Natural Resources Canada, "Survey of Household Energy Use" (Natural Resources Canada, Ottawa, ON, December 2005.)

[15] Nova Scotia Department of Finance, "Nova Scotia Statistical Review" (Nova Scotia Department of Finance, Halifax, NS, October 2005.)

[16] Natural Resources Canada: 2005, *op.cit.*, p.9.

[17] Nova Scotia Department of Finance: 2005, *op.cit.*, p. 40-41.

[18] Natural Resources Canada: 2005, *op.cit.*, p.22.

- The average Canadian household owns about 26 light bulbs in 2003, of which 75% are incandescent lamps, or about 20 per household.[20]

- The average NSPI customer has installed about five compact fluorescent lamps as of late 2005.[21]

Characterizing Residential DSM Measures

Characterizing DSM measures requires 1) determining the list of DSM measures to evaluate, 2) estimating the incremental savings from each measure - improving from the baseline to the new technology, and 3) estimating the measure costs and lifetimes. In addition, the baselines must consider that different classes of homes have different penetrations of technologies, such as existing homes compared to new construction.

The Summit Blue project team first drew up a list of prospective measures from past experience and added to and subtracted from that list as necessary for the project. Additions included new technologies or improvements to existing technologies, while subtractions primarily involved central air conditioner measures, which have almost zero saturation in Nova Scotia's residential market. The goal was a comprehensive list of DSM measures applied in different segments of the residential market: new construction versus existing construction.

Once identified, the project team determined which measures would have a significant climate-dependent savings component. Those measures that were determined to be climate-*independent* (lighting, appliances, and domestic hot water) were characterized using engineering calculations and assumptions for energy savings. Climate-dependent measures (HVAC equipment, insulation, air-sealing, etc.) were simulated with a computer model (Energy 10) to estimate savings.

Climate-independent DSM measures are described in many resources, including: the ENERGY STAR website[22], the California Database of Energy-efficient Resources[23], various utility online audit services, and manufacturer data. These resources were particularly useful for appliances. Other end-uses were analyzed using engineering principles such as steady-state heat loss, rated power, and hours of operation. For climate-independent measures, savings were permitted to vary according to construction type, e.g., new homes versus existing construction.

Climate-*dependent* DSM measures were modeled using Energy-10 software, an hourly simulation tool designed specifically for small commercial and residential structures. The project team made two baseline models reflecting typical constructions of two building types: new single family homes and existing single family homes, for the Halifax climate zone.

Model input parameters, such as building size, installed equipment type and age, and insulation levels, were based on the sources previously discussed and model building code (new construction) information.

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[19] *Ibid.* p.26.

[20] *Ibid, p.28.*

[21] Corporate Research Associates, "Nova Scotia Power Energy Conservation Study Customer Research Highlights" (Corporate Research Associates, November 2005) p. 47. The five CFLs per household estimate was calculated from the percentages of customers reporting having installed various numbers of CFLs.

[22] http://www.energystar.gov/

[23] http://www.energy.ca.gov/deer/

The models were then calibrated to produce energy consumption that corresponded to NSPI's residential customer electricity consumption data.

Variations in DSM measure costs exist for certain higher cost measures such as HVAC equipment and insulation where labor costs factor in more heavily. Measure cost estimates for these measures were weighted by factors contained in industry sources such as the RS Means Mechanical Cost Data.

The project team estimated measure lifetimes from a combination of resources including: manufacturer data, typical economic depreciation assumptions, the California DEER database, and various studies reviewed for this report.

4.1.2 Commercial/Industrial Analysis

The commercial/industrial customer and DSM measure characterizations will be discussed in this section.

Commercial and Industrial Customer Characterization

Summit Blue primarily used NSPI customer statistics and previously conducted market research, a Natural Resources Canada report on commercial energy use[24], an ACEEE study on the energy conservation potential for pulp and paper mills[25], and information from two recently completed Canadian DSM potential studies to characterize NSPI's customer base. Useful information from these sources included:

- Paper mills account for about 40% of NSPI's industrial sales, while food processing and fisheries account for about 13% of their industrial sales.
- ACEEE estimated that the electric energy conservation potential for pulp and paper plants is approximately 18% for a new plant in 2000 compared to a 1980 vintage plant.[26]
- The average commercial and institutional facility in Atlantic Canada is about 2,400 square meters in size, or about 25,500 sq.ft.[27]
- The average NSPI commercial and industrial customer has installed about six CFLs in their facilities as of late 2005.[28]
- NSPI staff believe that there is relatively little electric heating in the C&I sectors, in contrast to the residential sector.

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[24] Natural Resources Canada, "Commercial and Institutional Consumption of Energy Survey" (Natural Resources Canada, Ottawa, ON, December 2005.)

[25] American Council for an Energy-efficient Economy, "Energy Efficiency and the Pulp and Paper Industry" (ACEEE, Washington, D.C., 1996.)

[26] ACEEE: 1996, *op.cit*, p.32.

[27] Natural Resources Canada: 2005, *op.cit*, p.7.

[28] Corporate Research Associates: 2005, *op.cit*, p.48. The six CFL per business estimate was calculated from the percentages of customers reporting having installed various numbers of CFLs.

Summit Blue assumed that the saturation rates for most energy conservation measures (ECMs) are modest in the commercial and industrial sectors, 20% or less for almost all measures, except for common measures such as roof insulation. This assumption is based on previous Summit Blue studies for utilities that are somewhat new to DSM, and the limited historical availability of commercial and industrial energy conservation programs in NSPI's service area to assist customers with installing ECMs.

Characterizing Commercial/Industrial DSM Measures

Summit Blue started the commercial/industrial DSM measure characterization process by developing a list of DSM measures from previous Summit Blue projects and NSPI staff recommendations. After the individual measures were assigned to a primary end use category (i.e., lighting, heating, etc.), the project team estimated the following parameters for each measure:

- Per-unit energy and coincident peak demand savings
- Typical operating hours
- Measure lifetimes
- Measure costs

To do this, the project team first separated the measures into two categories: weather-dependent measures and weather-independent measures. Much of the research and analysis for the weather-independent measures had been conducted by Summit Blue in 2005-2006 for separate studies, and this data was mostly reused with slight modifications, such as for Halifax costs, for NSPI's service territory. The research consisted of Internet searches and phone calls for manufacturer data concerning end-use demand and energy consumption, and Internet searches and phone calls for retailer data concerning equipment costs. Other research included reviewing estimates of measure lifetimes, operating hours, and coincidence factors for a variety of end-uses and market sectors and from a number of different sources. All of this data was then compiled into a spreadsheet with outputs for per-unit energy and demand savings, incremental cost, payback periods, and benefit-cost ratios. These measure spreadsheets were used as the basis for the values required by the NSPI DSM Potential Study.

These DSM measure spreadsheets were also used as the starting point for the analysis of the weather-dependent measures, such as insulation, windows, etc. Some of the values, such as measure lifetimes, were reused for this potential study. Because of their inherent sensitivity to climate, however, the per-unit energy and demand savings were re-calculated by creating a simulation model using the DOE-2 powered eQuest software package. Summit Blue chose Halifax as the center of NSPI's service territory. Based on the billing data provided by NSPI, the project team modeled the energy consumption with a 2-story, 25,000 sq.ft. office building with slightly longer operating hours to reflect the higher energy consumption in the retail, college, and health care sectors, which are NSPI's largest commercial building segments. For each measure, a baseline case and an energy-efficient case were modeled separately, and the difference in peak demand and energy consumption per unit was calculated and entered into the measure characterization spreadsheet.

4.1.3 Estimate Technical, Economic, and Market DSM Potential, and TRC Test Explanation

The general approach for estimating DSM resource potentials consisted of three steps: (1) estimate technical and economic DSM potential, (2) estimate preliminary market penetrations and the resulting achievable potential for each measure, and (3) calibrate the achievable DSM potential estimates using the benchmarking information described in the previous section. **This third step is the most important step in Summit Blue's DSM potential estimation process.** For this benchmarking analysis, the average annual DSM potential values for each end use and sector were compared to actual program results for corresponding top performing programs and portfolios.

Technical DSM potential means the amount of DSM savings that could be achieved not considering economic and market barriers to customers installing DSM measures. Technical potential is calculated as the product of the DSM measures' savings per unit, the quantity of applicable equipment in each facility, the number of facilities in NSPI's service area, and 100% - the measure's current market saturation. Technical potential estimates include DSM measures that are not cost effective, nor does technical potential consider market barriers such as customers' lack of awareness of DSM measures. So technical DSM potential estimates do not provide a realistic basis for setting DSM program goals.

Economic DSM potential means the amount of technical DSM potential that is "cost-effective", as defined by the results of the total resource cost (TRC) test. This test also does not consider economic or market barriers to customers installing DSM measures. Some confusion existed about the TRC test amongst the NSPI stakeholder group that met on August 18th to discuss Summit Blue's draft project report. So the benefits and costs for the TRC test are described below, including selected factors that are not included in the TRC test.

The DSM program benefits for the TRC test are the avoided costs of building generation, transmission, and distribution capacity, as well as the avoided fuel and power purchase costs caused by the savings from DSM programs. The DSM costs for the TRC test are the full incremental cost of the applicable DSM measure(s), plus the DSM program administration costs. All costs and benefits are specified as net present values. The costs of rebates or financial incentives are not included in the TRC test calculation, as those costs are considered transfer payments from non-participants to participants, and so net out to zero for a utility's entire customer base. Environmental externalities are also not a factor considered in the TRC test, but are included as part of the societal test.

Summit Blue did not factor in "intuitive" considerations about whether a particular DSM program or programs are warranted in its potential estimates, as several reviewers of Summit Blue's draft report suggested in one manner or another. If a given DSM program passed the TRC test, and is being successfully implemented by more than one of the utilities or agencies reviewed, Summit Blue considers such programs as viable for inclusion in the DSM potential analysis and program development.

Due to time and information availability constraints, Summit Blue used a simplified approach to calculating the DSM avoided cost benefits for the TRC test. NSPI supplied Summit Blue with annual and "levelized" estimates of avoided generation capacity costs and fuel/power purchase costs from 2007-2025. These values were developed in 2005 using the Company's version of the Strategist model, and were used in a Provincial regulatory proceeding. (Levelized costs are essentially a constant annuity value for a time series of costs that produces an equivalent net present value.) However, NSPI did not have transmission and distribution avoided cost estimates from DSM readily available, as estimating these avoided costs is generally somewhat complex and time consuming. To somewhat compensate for those unavailable T&D avoided cost estimates, Summit Blue used NSPI's "levelized" generation avoided cost estimates to calculate DSM's avoided cost benefits. This simplified approach over-estimates the net present value of avoided costs for measures with lifetimes less than the 19 year period for which the levelized costs were calculated. This is particularly the case for compact fluorescent lamps, which have estimated lifetimes of five to ten years for residential applications, depending on the annual hours of use.

Another simplifying assumption that Summit Blue made in the TRC test calculations was ignoring the avoided cost benefits from fuels other than electricity. Summit Blue used this simplifying assumption to expedite the analysis process, and because we did not believe that ignoring this factor would overlook a significant source of DSM benefits. For confirmation of this assessment, we note that Xcel Energy's

2007-2009 Minnesota DSM filing does include the avoided cost benefits of conserved natural gas from electric DSM program as part of its benefit-cost analysis. Xcel Energy's result for its overall 2007 conservation programs is that there is a $1 per kW avoided cost benefit from natural gas conservation from its electric DSM programs, out of a total of $3,209 per kW in avoided cost benefits, or about 0.03% of the total avoided cost benefits[29].

Achievable potential is an estimate of the amount of DSM potential that could be captured by realistic DSM programs over the eight year forecast period (2007-2014) covered by this DSM potential analysis. The key parameter that must be estimated to forecast achievable DSM potential is the market penetration for each DSM measure at the end of the forecast period in 2014. Summit Blue estimated this parameter for each DSM measure based on our previous DSM potential projects, as well as NSPI staff expectations regarding what would be reasonable to expect in their service area over the forecast period. For most non-lighting measures, a maximum market penetration of 50% over the forecast period was assumed, while lighting DSM measure saturations were generally assumed to reach 70%-90% saturation by 2014, as that range of DSM measure saturations have already been achieved in some utility service areas that have been conducting DSM programs for a long time. However, it is important to emphasize that Summit Blue's assumptions regarding end of period DSM measure saturation estimates were calculated so as to produce DSM potential estimates for each sector and end use that are consistent with the utility and agency DSM program benchmarking results discussed in the previous section.

4.2 DSM Potential Results

This section provides the DSM potential results separately for the residential, commercial, and industrial sectors.

4.2.1 Residential Achievable DSM Potential Results

The annual and total residential achievable DSM potential results are shown in Table 4-1 below. The energy values shown below are for the DSM measures' first-year energy savings, the demand savings are the peak coincident demand savings, and the program costs are the total estimated DSM program budgets for a given year, including rebate or other customer incentive costs, as well as administrative, implementation, and evaluation costs. So the annual values in the table below are in the same format as the DSM goals that most utilities and agencies propose or report on through their DSM regulatory filings.

[29] Xcel Energy Corporation, "2007/2008/2009 Triennial Plan, Minnesota Natural Gas and Electric Conservation Improvement Program", p.73.

Table 4-1. Total Annual Residential Achievable Potential Estimates, Years 1-8

Residential Total	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8
Lighting									
Achievable Potential Demand Savings (MW)	31.1	1.6	2.5	3.7	4.7	4.7	4.7	4.7	4.7
Achievable Potential Energy Savings (GWh)	129.5	6.5	10.4	15.5	19.4	19.4	19.4	19.4	19.4
Program Costs (Million $)	$31.1	$1.6	$2.5	$3.7	$4.7	$4.7	$4.7	$4.7	$4.7
Heating/HVAC									
Achievable Potential Demand Savings (MW)	13.8	0.7	1.1	1.7	2.1	2.1	2.1	2.1	2.1
Achievable Potential Energy Savings (GWh)	58.9	2.9	4.7	7.1	8.8	8.8	8.8	8.8	8.8
Program Costs (Million $)	$21.8	$1.1	$1.7	$2.6	$3.3	$3.3	$3.3	$3.3	$3.3
Water Heating									
Achievable Potential Demand Savings (MW)	8.7	0.4	0.7	1.0	1.3	1.3	1.3	1.3	1.3
Achievable Potential Energy Savings (GWh)	61.5	3.1	4.9	7.4	9.2	9.2	9.2	9.2	9.2
Program Costs (Million $)	$8.7	$0.4	$0.7	$1.0	$1.3	$1.3	$1.3	$1.3	$1.3
Load Management/DLC									
Achievable Potential Demand Savings (MW)	10.8	0.5	0.9	1.3	1.6	1.6	1.6	1.6	1.6
Achievable Potential Energy Savings (GWh)	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Program Costs (Million $)	$3.8	$0.2	$0.3	$0.5	$0.6	$0.6	$0.6	$0.6	$0.6
Refrigeration and Miscellaneous									
Achievable Potential Demand Savings (MW)	2.0	0.1	0.2	0.2	0.3	0.3	0.3	0.3	0.3
Achievable Potential Energy Savings (GWh)	17.8	0.9	1.4	2.1	2.7	2.7	2.7	2.7	2.7
Program Costs (Million $)	$5.7	$0.3	$0.5	$0.7	$0.9	$0.9	$0.9	$0.9	$0.9
Residential Total									
Achievable Potential Demand Savings (MW)	66.6	3.3	5.3	8.0	10.0	10.0	10.0	10.0	10.0
Achievable Potential Energy Savings (GWh)	268.0	13.4	21.4	32.2	40.2	40.2	40.2	40.2	40.2
Program Costs (Million $)	$71.1	3.6	5.7	8.5	10.7	10.7	10.7	10.7	10.7

The total estimated residential energy conservation potential, 268 GWh, amounts to approximately 6.4% of NSPI's forecast 2006 residential energy consumption of about 4,200 GWh. This is equal to annual average energy savings of about 33.5 of GWh, or 0.8% of NSPI's forecast 2006 residential sales. The calibration target for residential energy conservation potential from the benchmarking analysis that we used to estimate NSPI's DSM potential is savings towards the top of the residential DSM portfolios reviewed, and was set at 0.8% of residential sales. This is slightly lower than the two top-performing residential DSM program portfolios, but the wide range of residential energy savings achieved (0.1%-1.3% of residential sales) by the utility and agencies reviewed indicated that some caution is in order when considering trying to reach the top-performing residential portfolios in a relatively short period of time. Many of the organizations reviewed have been conducting DSM program for considerable periods of time, but have only achieved modest success from an energy savings standpoint in the residential sector.

Approximately 90% of the energy and demand savings impacts are expected to be realized from existing homes, as compared to new construction. However, this statistic is not cited to suggest that residential new construction programs, or new construction programs more generally, are not important. In fact, Summit Blue and most of the DSM "industry" believe that new construction programs are quite important. This is mainly due to the widespread recognition that it is much easier and less expensive to build a home or building right the first time from an energy efficiency perspective than it is to try to go back to the home or building after it is built, and "fix" its energy efficiency.

Summit Blue's estimated average total residential DSM potential is only approximately half of NSPI's proposed 2006 residential energy savings goal of 60 GWh, or 1.4% of forecast 2006 residential sales. Given that NSPI's proposed 2006 residential savings goal is higher than all the actual benchmark DSM program results reviewed, from organizations that have all been conducting DSM programs for some time, we believe that NSPI's proposed residential DSM goal was a somewhat over-optimistic performance expectation for the first year of a DSM program portfolio.

Generally, over-achieving a realistic yet stretching goal is a more positive experience for all concerned than failing to meet a very high performance expectation set for the first year of a new endeavor. Accordingly, based on the histories of the benchmark utilities and energy agencies, Summit Blue estimates that a two-year ramp-up period will be required before NSPI's DSM results hit the annual average impacts for the eight year forecast period. We have estimated the annual achievements of the total DSM potential will follow an s-shaped curve, with impacts of 5% of the total DSM potential in the first year, 8% in the second year, 12% (the eight year average) in the third year, and 15% in each of the last five years of the forecast period.

Residential Energy Efficiency Results by End Use

Residential lighting measures, CFLs in high-use, medium-use, and low-use fixtures, account for almost half of the total estimated residential energy and demand reduction potential, a total of about 31 MW of coincident peak demand reduction and 130 GWh of first year energy savings over the eight year forecast period. This amounts to an average of about 3.9 peak MW and 16 GWh per year. The average energy savings amount to about 0.4% of NSPI's forecast 2006 residential energy sales, which is similar to the top-performing residential lighting program for which specific results were reported for 2005.

The market penetration rates for CFLs in residences across North America are likely to considerably increase over the medium term, due to increasing numbers of residential lighting DSM programs across the continent, as well as the considerable cost reductions that manufacturers of CFLs have realized over the past few years, and will likely continue to realize in the future. One can now purchase a six pack of CFLs at Home Depot for only about $10 in total, which used to be the typical price of a single CFL as recently as about five years ago. This expectation that the prices of CFLs will continue to decrease is largely responsible for the estimate that the achievable potential for residential lighting programs is the highest percentage of "economic" potential, discussed at the end of this section, than the results for any other end use in any sector.

Space heating and water heating DSM measures are estimated to have similar total energy savings impacts of about 60 GWh for heating and 61 GWh for water heating. Both space and water heating have about 10 applicable DSM measures that were included in the DSM potential analysis. The largest space heating measure in terms of energy conservation potential is ENERGY STAR heat pumps, while the largest corresponding water heating measure is drain water heat recovery.

Refrigeration DSM measures have the smallest energy conservation potential of the four end uses evaluated, at about 18 GWh in total. This is primarily due to the fact that government minimum energy efficiency standards have already caused most of the energy conservation potential for more efficient refrigerators to be realized. The largest refrigeration DSM measure is removing a secondary refrigerator from homes with such units.

Residential Demand Response Results

NSPI currently offers its residential customers a time-of-day rate for customers that install electric thermal storage heating systems. Currently about 1% of NSPI's residential customer base are participating in this program.

Other North American utilities also offer residential customers a variety of additional demand response programs, including direct load control of major electricity using equipment such as water heaters, heating systems, and central air conditioners. The latter type of equipment is not found in significant numbers in NSPI's service area.

In addition, several utilities offer additional types of demand response rates such as real-time-pricing (RTP) and critical-peak pricing. However, NSPI's industrial RTP rate is currently under review since the differences between on-peak and off-peak costs to supply electricity have recently narrowed significantly. So Summit Blue did not try to estimate the DSM potential for these types of rates, because these types of rates need meaningful electric price differences throughout the day in order to be effective at reducing peak demands.

Summit Blue estimated the potential for direct load control of electric water heaters and NSPI's current TOU rate and storage heating systems. In total, these demand response measures are estimated to have a demand reduction potential of about 11 MW over the forecast period. Cycling electric water heaters during peak demand periods is estimated to have the largest achievable potential during this period. However, a water heater cycling only DLC program would be somewhat rare in North America. Most utility DLC programs have central air conditioners as the main appliance being controlled. The program cost estimates developed were adapted from other utility DLC programs, so should be further reviewed by NSPI as part of a detailed program development process before this program will be ready for full-scale implementation.

NSPI has somewhat less potential for residential demand response programs than other utilities for which Summit Blue has done comparable DSM potential estimates. This is primarily due to the almost complete absence of central air conditioners in its residential customer base, and the somewhat high cost of electric thermal storage systems, which significantly limit their market penetration.

For purposes of comparison, Summit Blue reviewed the results from our demand response potential assessment for the International Energy Agency's demand response resources project. [30] As part of that project, Summit Blue surveyed 40 North American utilities on their demand response programs in late 2004. We found that the top-performing residential direct load control programs had achieved impacts that amounted to 10% or more of the utilities' residential peak demands. However, the large majorities of the impacts from these utilities' demand response programs were from direct load control of central air conditioners during summer peak demand periods.

4.2.2 Commercial Achievable DSM Potential Results

The annual and total commercial sector DSM potential results are summarized in Table 4-2. The energy values shown below are for the DSM measures' first-year energy savings, the demand savings are the peak coincident demand savings, and the program costs are the total estimated DSM program budgets for a given year, including rebate or other customer incentive costs, as well as administrative, implementation, and evaluation costs. So the annual values in the table below are in the same format as the DSM goals that most utilities and agencies propose or report on through their DSM regulatory filings.

[30] Limited results from this study are publicly available at www.demandresponseresources.com.

Table 4-2. Total Annual Commercial Achievable DSM Potential Estimates, Years 1-8

Total Commercial	Total	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8
Lighting									
Achievable Potential Demand Savings (MW)	15.1	0.8	1.2	1.8	2.3	2.3	2.3	2.3	2.3
Achievable Potential Energy Savings (GWh)	183.6	9.2	14.7	22.0	27.5	27.5	27.5	27.5	27.5
Program Costs (Million $)	$5.3	$0.3	$0.4	$0.6	$0.8	$0.8	$0.8	$0.8	$0.8
Heating/Cooling									
Achievable Potential Demand Savings (MW)	11.7	0.6	0.9	1.4	1.8	1.8	1.8	1.8	1.8
Achievable Potential Energy Savings (GWh)	33.5	1.7	2.7	4.0	5.0	5.0	5.0	5.0	5.0
Program Costs (Million $)	$13.7	$0.7	$1.1	$1.6	$2.0	$2.0	$2.0	$2.0	$2.0
Refrigeration									
Achievable Potential Demand Savings (MW)	0.4	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1
Achievable Potential Energy Savings (GWh)	4.6	0.2	0.4	0.6	0.7	0.7	0.7	0.7	0.7
Program Costs (Million $)	$0.3	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Motors/Compressed Air									
Achievable Potential Demand Savings (MW)	1.0	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2
Achievable Potential Energy Savings (GWh)	7.4	0.4	0.6	0.9	1.1	1.1	1.1	1.1	1.1
Program Costs (Million $)	$0.8	$0.0	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1
Load Control									
Achievable Potential Demand Savings (MW)	10.0	0.5	0.8	1.2	1.5	1.5	1.5	1.5	1.5
Achievable Potential Energy Savings (GWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Program Costs (Million $)	$0.7	$0.0	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1
Total									
Achievable Potential Demand Savings (MW)	38.1	1.9	3.1	4.6	5.7	5.7	5.7	5.7	5.7
Achievable Potential Energy Savings (GWh)	229.2	11.5	18.3	27.5	34.4	34.4	34.4	34.4	34.4
Program Costs (Million $)	$20.7	$1.0	$1.7	$2.5	$3.1	$3.1	$3.1	$3.1	$3.1

The total estimated commercial energy conservation potential, 232 GWh, amounts to approximately 7.4% of NSPI’s forecast 2006 commercial energy consumption of about 3,100 GWh. This is equal to annual average energy savings of about 30 of GWh, or about 0.9% of NSPI’s forecast 2006 commercial sales. The calibration target for commercial and industrial energy conservation potential from the benchmarking analysis that we used to estimate NSPI’s DSM potential is savings of about 1% of commercial and industrial sales. This level of commercial and industrial savings was achieved in 2005 by several of the utilities and agencies reviewed. So the total NSPI commercial DSM potential estimate is slightly less this calibration target, while the industrial DSM potential estimates are slightly greater than this target, as will be discussed in the following section.

Approximately 85%-90% of the energy and demand savings impacts are expected to be realized from existing buildings, compared to new construction. However, this statistic is not cited to suggest that commercial new construction programs, or new construction programs more generally, are not important. In fact, Summit Blue and most of the DSM “industry” believe that new construction programs are quite important. This is mainly due to the widespread recognition that it is much easier and less expensive to build a building right the first time from an energy efficiency perspective than it is to try to go back to the building after it is built, and “fix” its energy efficiency.

Summit Blue’s estimated total commercial DSM potential is considerably larger than NSPI’s proposed 2006 commercial energy savings goal of 8.3 GWh, or 0.3% of forecast 2006 commercial sales. However, since several of the benchmark utilities and agencies achieved commercial DSM energy savings of about 1% of commercial and industrial sales, Summit Blue is optimistic that this level of savings is achievable from a full-scale DSM portfolio. However, as with the residential DSM programs, Summit Blue estimates that a two-year ramp-up period will be required before NSPI’s commercial DSM results hit the annual average impacts for the eight year forecast period. We have estimated the annual achievements of the total DSM potential will follow an s-shaped curve, with impacts of 5% of the total DSM potential in the first year, 8% in the second year, 12% (the eight year average) in the third year, and 15% in each of the last five years of the forecast period.

Commercial Energy Efficiency Results

The large majority of commercial energy conservation potential, about 79% of the total estimated energy savings, is expected to come from lighting measures, primarily CFLs, T8 tubular fluorescent systems with electronic ballasts, and LED exit lights. The total estimated commercial lighting energy and demand reduction potential is about 15 MW of coincident peak demand reduction and 189 GWh of first year energy reduction over the eight year forecast period. This amounts to an average of about 1.9 peak MW and 24 GWh per year. This average annual energy savings amount to about 0.7% of NSPI's forecast 2006 commercial energy sales, which is more than twice as large as the top-performing commercial and industrial lighting program for which specific results were reported for 2005. Most of the benchmark utilities and agencies have been conducting DSM programs for some time, and have already achieved a significant share of the commercial lighting DSM potential in their service areas. So their remaining lighting potential is smaller than for a utility such as NSPI that is newer to DSM.

Efficient HVAC and building envelope measures, efficient motors and air compressors, and efficient refrigeration systems account for the remaining 23% of commercial DSM potential, or about 0.2% of NSPI's forecast 2006 commercial energy sales. This result is consistent with the limited information on the energy savings from these types of programs obtained from the benchmarking data. Impacts from these latter types of programs are often limited in the first several years of an organization's DSM efforts, as customers typically just replace this type of equipment when it fails and cannot be inexpensively repaired.

Commercial Demand Response Results

Currently NSPI offers two interruptible rates to its large industrial customers (those with demands of two megawatts or more), an Interruptible Rider to the Large Industrial Tariff, and the Extra Large Industrial Interruptible Tariff Rider (ELIIR). The Interruptible Rider provides large industrial customers with rate discounts to reduce their loads during emergency conditions, while the ELIIR provides large industrial customers with rate discounts to reduce their loads during high-priced electric periods as well as emergency conditions.

Several utilities in North America also offer interruptible rates to medium and large commercial customers in addition to large industrial customers. These types of interruptible rates are generally structured rather simply, along the lines of NSPI's Interruptible Rider, which offers a flat demand charge discount per kilowatt of load reduced. Several utilities, such as Xcel Energy in Minnesota, make interruptible rates available to commercial and industrial customers who commit to reducing their loads by as little as 50 kW during a peak demand period.

Summit Blue estimated the DSM potential for commercial interruptible rates, direct load control of central air conditioners and electric water heaters, and a commercial version of its residential TOU rate and electric storage heating system. In total, the commercial demand response potential is estimated to be about 10 MW over the forecast period, or about two percent of NSPI's commercial peak demand of about 520 MW. About two-thirds of the demand response or load management potential is forecast to be achieved from interruptible rates, while the other third of the demand response potential is approximately evenly divided between 1) direct load control (DLC) of air conditioners/water heaters and 2) TOU rates and storage heating systems. Implementing commercial DR programs in Nova Scotia may require approval of rate discounts offered through such programs through separate rate case related regulatory processes, so may require more time to implement than energy efficiency programs.

These demand response potential estimates are based in part on the results from Summit Blue's demand response potential assessment for the International Energy Agency's Demand Response Resources project.[31] As part of that project, Summit Blue surveyed 40 North American utilities on their demand response programs. We found that the top-performing C&I interruptible rate programs had achieved impacts that amounted to 10% or more of the utilities' C&I peak demands, but no data was available on just the commercial program impacts. However, several utilities surveyed explicitly stated that they achieved most of their interruptible rate impacts from industrial customers compared to commercial customers, so the top-performing commercial interruptible rate program impacts are expected to be smaller than the combined C&I totals. Also, almost all the utilities that Summit Blue surveyed for this project achieved larger C&I impacts from interruptible rate programs than they achieved from direct load control or storage heating programs for this customer class.

4.2.3 Industrial Achievable DSM Potential Results

The annual and total industrial sector DSM potential results are summarized in Table 4-3. The energy values shown below are for the DSM measures' first-year energy savings, the demand savings are the peak coincident demand savings, and the program costs are the total estimated DSM program budgets for a given year, including rebate or other customer incentive costs, as well as administrative, implementation, and evaluation costs. So the annual values in the table below are in the same format as the DSM goals that most utilities and agencies propose or report on through their DSM regulatory filings.

Table 4-3. Total Annual Industrial Achievable DSM Potential Estimates, Years 1-8

Total Industrial	8 Year Total	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8
Lighting									
Achievable Potential Demand Savings (MW)	9.4	0.5	0.8	1.1	1.4	1.4	1.4	1.4	1.4
Achievable Potential Energy Savings (GWh)	82.5	4.1	6.6	9.9	12.4	12.4	12.4	12.4	12.4
Program Costs (Million $)	$3.3	$0.2	$0.3	$0.4	$0.5	$0.5	$0.5	$0.5	$0.5
Heating/Cooling									
Achievable Potential Demand Savings (MW)	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Achievable Potential Energy Savings (GWh)	0.8	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Program Costs (Million $)	$0.2	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Motors									
Achievable Potential Demand Savings (MW)	14.0	0.7	1.1	1.7	2.1	2.1	2.1	2.1	2.1
Achievable Potential Energy Savings (GWh)	112.5	5.6	9.0	13.5	16.9	16.9	16.9	16.9	16.9
Program Costs (Million $)	$10.9	$0.5	$0.9	$1.3	$1.6	$1.6	$1.6	$1.6	$1.6
Air Compressors									
Achievable Potential Demand Savings (MW)	0.4	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1
Achievable Potential Energy Savings (GWh)	23.0	1.2	1.8	2.8	3.5	3.5	3.5	3.5	3.5
Program Costs (Million $)	$0.2	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Pulp and Paper Mills									
Achievable Potential Demand Savings (MW)	22.2	1.1	1.8	2.7	3.3	3.3	3.3	3.3	3.3
Achievable Potential Energy Savings (GWh)	173.8	8.7	13.9	20.9	26.1	26.1	26.1	26.1	26.1
Program Costs (Million $)	$19.7	$1.0	$1.6	$2.4	$3.0	$3.0	$3.0	$3.0	$3.0
Load Control									
Achievable Potential Demand Savings (MW)	16.3	0.8	1.3	2.0	2.4	2.4	2.4	2.4	2.4
Achievable Potential Energy Savings (GWh)	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Program Costs (Million $)	$0.1	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Total									
Achievable Potential Demand Savings (MW)	62.5	3.1	5.0	7.5	9.4	9.4	9.4	9.4	9.4
Achievable Potential Energy Savings (GWh)	392.7	19.6	31.4	47.1	58.9	58.9	58.9	58.9	58.9
Program Costs (Million $)	$34.4	$1.7	$2.8	$4.1	$5.2	$5.2	$5.2	$5.2	$5.2

Approximately 90% of the energy and demand savings impacts are expected to be realized from existing buildings, compared to new construction. The total estimated industrial energy conservation potential, 399 GWh of first-year energy savings, amounts to approximately 9.2% of NSPI's forecast 2006 industrial energy consumption of about 4,300 GWh. This is equal to annual average energy savings of about 50 GWh, or about 1.1% of NSPI's forecast 2006 industrial sales. The calibration target for commercial and industrial energy conservation potential from the benchmarking analysis that we used to estimate NSPI's DSM potential is savings of about 1% of commercial and industrial sales. This level of commercial and industrial savings was achieved in 2005 by several of the utilities and agencies reviewed. So the total NSPI industrial DSM potential estimate is slightly larger than this calibration target, while the

[31] R. Gunn, "North American Utility Demand Response Survey Results" (Association of Energy Services Professionals, February 6, 2006, San Diego, CA).

commercial DSM potential results were slightly less than this calibration target, as discussed in the previous section.

Summit Blue's estimated total industrial DSM potential is considerably larger than NSPI's proposed 2006 industrial energy savings goal of 0.9 GWh, or 0.02% of forecast 2006 industrial sales. However, since several of the benchmark utilities and agencies achieved commercial DSM energy savings of about 1% of C&I sales, Summit Blue is optimistic that this level of savings is achievable from a full-scale DSM portfolio. However, as with the residential and commercial DSM programs, Summit Blue estimates that a two-year ramp-up period will be required before NSPI's industrial DSM results hit the annual average impacts for the eight year forecast period. We have estimated the annual achievements of the total DSM potential will follow an s-shaped curve, with impacts of 5% of the total DSM potential in the first year, 8% in the second year, 12% (the eight year average) in the third year, and 15% in each of the last five years of the forecast period.

Industrial Energy Efficiency Results

The large majority of estimated industrial energy conservation potential comes from industrial process efficiency improvements from pulp and paper plants and energy-efficient motor measures. These two types of industrial DSM measures account for about 72% of the total estimated industrial energy savings, totaling about 36 MW of coincident peak demand reduction and 287 GWh of first year energy conservation potential over the eight year forecast period. This amounts to an average of about 4.5 peak MW and 36 GWh of savings per year. The average process and motor energy savings amount to about 0.8% of NSPI's forecast 2006 industrial energy sales. This result is similar to the results from the top performing utility's (Otter Tail Power's) Custom program, which covers industrial process measures, as well as adjustable speed drives.

Efficient lighting and air compressor measures also have significant DSM potential in the industrial sector, accounting for a total of about 100 GWh of first year energy conservation potential, or about 0.2% of NSPI's forecast 2006 industrial energy sales. Efficient HVAC DSM measures have relatively low conservation potential in the industrial sector, as many industrial facilities only use small amounts of energy for this end use.

Industrial Demand Response Results

Currently NSPI offers two interruptible rates to its large industrial customers (those with demands of two megawatts or more), an Interruptible Rider to the Large Industrial Tariff, and the Extra Large Industrial Interruptible Tariff Rider (ELIIR). The Interruptible Rider provides large industrial customers with rate discounts to reduce their loads during conditions, while the ELIIR provides large industrial customers with rate discounts to reduce their loads during high-priced electric periods as well as emergency conditions.

NSPI's customers subscribing to the ELIIR provide NSPI with about 264 MW of potential demand reduction during expensive electric periods, while the Interruptible Rider customers are capable of reducing their demands by a total of about 136 MW during emergency conditions. In total, NSPI's existing industrial demand response potential accounts for about 77% of the total industrial load. This percentage of demand responsive load is far larger than any of the utilities than Summit Blue surveyed as part of its study for the International Energy Agency. As part of that project Summit Blue concluded that 10% of C&I load participating in an interruptible rate program was best practice performance. [32]

[32] R. Gunn: 2006, *op.cit.* p. 11.

However, several utilities in North America also offer interruptible rates to medium sized industrial customers in addition to large industrial customers. These types of interruptible rates are generally structured rather simply, along the lines of NSPI's Interruptible Rider, which offers a flat demand charge discount per kilowatt of load reduced. Several utilities, such as Xcel Energy in Minnesota, make interruptible rates available to commercial and industrial customers who commit to reducing their loads by as little as 50 kW during a peak demand period. However, expanding industrial DR programs to smaller customers in Nova Scotia may require approval of rate discounts offered through such programs through separate rate case related regulatory processes, and so may require more time to implement than energy efficiency programs.

Summit Blue estimated the DSM potential for industrial interruptible rates and direct load control of central air conditioners and electric water heaters. In total, the industrial demand response potential is estimated to be about 16 MW of coincident peak demand reduction over the forecast period, or about three percent of NSPI's commercial peak demand of about 520 MW. The large majority of demand response or load management potential is forecast to be achieved from interruptible rates, while only a small amount of potential is estimated to come from direct load control (DLC) of air conditioners and water heaters, primarily due to the small magnitude of those loads in the industrial sector.

4.2.4 Economic DSM Potential Results

As discussed previously, economic potential is the amount of technical DSM potential that is "cost-effective" as defined by the TRC test. However, economic potential does not consider market barriers, such as customers' lack of awareness of DSM measures, nor economic barriers, such as customers requiring DSM measures to have much faster "paybacks" than simply meeting the utility discount rate, as estimated by the TRC test.

Economic potential is therefore more analogous to a "thought experiment" than a realistic benchmark for specific DSM programs or portfolios. It helps to imagine how economic potential would be achieved in practice to illustrate the limitations of the concept. Implementing economic DSM potential would require hiring DSM measure installers who would drive throughout a utility's service area with truckloads of DSM measures. The installers would visit homes and businesses with computers to calculate the TRC test ratios for each measure in the home or business. The measures that pass the TRC test for a given home or business would be installed, regardless of whether the homeowner or business owner wants the DSM measure or not. This is obviously not a feasible manner in which to operate an actual DSM program.

The economic potential concept has further limitations when considered in the context of demand response programs in addition to energy efficiency programs. In theory, almost all loads in homes and businesses could be shut down for several hours during a peak demand period or emergency situation. If the homeowner or business owner is provided with a rate discount for reducing their loads during such peak or emergency periods, shutting down loads would be considered very cost-effective from the perspective of the TRC test. However, most homeowners and business owners do not care to be inconvenienced in this manner during normal circumstances, and the large majority will not elect to participate in interruptible rate style programs. This is often not the case for the largest businesses, for whom the cost of electricity is often one of their largest operating costs, and such businesses are often very interested in reducing a large operating cost, and are often willing to be inconvenienced to do so.

The economic potential estimates and ranges of TRC results for each class of DSM measure are shown in Table 4-4 below. The load management results duplicate the energy efficiency results in many cases, as the same kilowatt that is conserved cannot then be reduced through a load management or demand response program.

Table 4-4. NSPI Economic DSM Potential Summary 2007-2014, Years 1-8

Residential End Uses	Years 1-8 Coin. Peak Demand Savings (MW)	Years 1-8 First Year Energy Savings (GWh)	Range of All TRC Measure Results
Lighting	54.7	164.6	1.6-12.1
HVAC	125.1	579.3	0.1-6.6
Water Heating	77.1	545.9	0.4-9.3
Load Management	90.6	1.4	0.8-2.8
Refrigeration	17.3	151.3	0.4-3.8
Subtotal	364.8	1,442.5	

Commercial End Uses	Years 1-8 Coin. Peak Demand Savings (MW)	Years 1-8 First Year Energy Savings (GWh)	Range of All TRC Measure Results
Lighting	36.3	457.2	0.7-11.2
HVAC	41.1	107.4	0.5-2.4
Refrigeration	1.8	18.9	0.1-3.4
Motors/Compressors	9.0	65.2	1.6-2.9
Load Management	532.0	0.2	1.0-2.9
Subtotal	620.2	648.9	

Industrial End Uses	Years 1-8 Coin. Peak Demand Savings (MW)	Years 1-8 First Year Energy Savings (GWh)	Range of All TRC Measure Results
Lighting	19.9	206.1	4.1-12.6
HVAC	1.0	3.8	0.9-2.6
Motors	123.7	992.7	3.0-6.5
Air Compressors	1.8	107.9	3.0-6.5
Process	67.9	532.0	1.0-2.9
Load Management	108.5	0.6	4.6-5.0
Subtotal	322.7	1,843.0	

Totals	**1,307.7**	**3,934.5**	

The largest amount of economic peak demand reduction potential is found in the commercial sector, mostly from demand response measures that are currently not offered to this customer class. The industrial sector has the lowest amount of economic demand reduction potential since a large share of the load in this sector is already participating in interruptible rate programs.

Overall, the total achievable demand reduction potential is estimated to be about 13% of the corresponding economic potential. The ratio of achievable potential to economic potential is low for demand reduction potential due to the large economic potential for demand response measures, as previously discussed. The ratio of overall achievable energy reduction potential to the corresponding economic potential is estimated to be about 23%, much higher than the corresponding demand reduction ratio, due to the smaller impact of demand response measures for energy conservation purposes.

The TRC test results range widely from ratios of 0.1 to 12.6. The TRC test results that are less than one are shown for illustrative purposes only, but these measures were not included in the economic potential estimates. The main factors influencing the magnitude of the TRC test results are the incremental costs of the DSM measures, as well as the measures' per unit energy and demand savings.

5. DSM PLAN RECOMMENDATIONS

5.1 Overview

This section provides the recommendations for revising the current NSPI DSM plan and providing the groundwork for future programs. These recommendations for revising the current plan are based upon the benchmarking work and the DSM potential analysis from the previous sections, as well as the interveners' comments and the critique of the current plan from the previous sections. The goal of this revised DSM plan is to provide NSPI with a comprehensive, equitable, and defensible DSM plan upon which NSPI can build successful future DSM programs and services.

Many jurisdictions in North America have successfully implemented DSM programs over the past several years. NSPI can build on the knowledge from these other jurisdictions and avoid some of the mistakes made by the early programs. This DSM plan uses the lessons learned combined with the demographics of the NSPI territory to develop a comprehensive DSM plan that is best suited for NSPI's customers.

The main goal of this study is to develop the foundation on which NSPI can build their DSM programs. This revised plan will focus on the first two years of the NSPI DSM programs. After the first two years NSPI should evaluate the programs and determine what is working well and what aspects of the programs need to be changed. After the first two years of the program it will be important to determine how well the programs are doing at overcoming the market barriers and if there are other market barriers that the programs should be addressing. These program evaluations should include a process evaluation, to make sure the programs are operating efficiently; an impact evaluation, to determine if the expected savings are being achieved; and a market assessment to make sure that the programs are having the expected effect on the markets. Further discussion on the recommended evaluation activities is included below.

5.2 Discussion of Key Issues

The section discusses the general issues associated with the development of a DSM plan for NSPI. These issues are concerned with the funding, the operation, and the management of the programs that are recommended in the DSM plan. Most of these general issues will need to be addressed and resolved before the proposed DSM plan can be successfully implemented. These general issues include:

- Program administration
- Assessing the "Throughput Incentive" barrier
- Reasonable levels of spending
- Rate Class allocation of DSM costs
- Conservation based pricing design
- Financing as DSM program element
- Implementation of programs
- Reaching low-income customers
- Public education and youth education DSM program elements
- Program evaluation activities
- Economic evaluation of DSM programs

Many of these issues were addressed in a report titled "Demand-Side Management: Determining Appropriate Spending Levels and Cost-Effectiveness Testing" prepared by Summit Blue and the Regulatory Assistance Project for Canadian Association of Members of Public Utility Tribunals (CAMPUT). Where appropriate this work will be referenced.

5.2.1 Discussion of Program Administration

The administration of the DSM programs has been strongly debated during the past several years. The question is who can best administer DSM programs, the utilities or other entities. The debate centers on the motivations and capabilities of the utilities versus other entities. Do the utilities, with revenues tied directly to retail sales, have the motivation to successfully manage DSM programs? Do other entities, without a relationship to the customer base, have enough access to the customers? Often this debate ignores one of the fundamental goals of DSM programs, to create a long-term DSM services infrastructure.

As discussed in the benchmarking section, DSM program administration has been handled differently by different jurisdictions. The level of success of the DSM programs does not seem to be a function of how the programs are administered. A recent study for the Center for the Study of Energy Markets concluded that none of the different methods for DSM program administration is superior to the other methods.

> *We observe that no single administrative structure for energy efficiency programs has yet emerged in the US that is clearly superior to all of the other alternatives. We conclude that this is not likely to happen soon for three reasons. First, policy environments differ significantly among the states. Second, the structure and regulation of the electric utility industry differs among the regions of the US. Third, market transformation and resource acquisition, two program strategies that were once seen as alternatives, are increasingly coming to be seen as complements. Energy efficiency programs going forward are likely to include elements of both strategies. But, the administrative arrangements that are best suited to support market transformation may be different from the arrangements that are best for resource acquisition.*[33]

In the U.S. the issue of DSM program administration was largely a result of the restructuring of the electricity industry. Utilities feared that in a restructured market the DSM program costs would put them at a disadvantage to the new market competitors. Prior to restructuring, the administration, design, and delivery of ratepayer funded energy efficiency program activities was largely the responsibility of utilities, operating within the context of an Integrated Resource Planning process that was overseen and governed by state regulators. In restructured markets the administration of DSM programs was re-evaluated to find the structures that were best suited to a deregulated environment. These alternative structures to utility administration included administration by non-utility entities, such as existing state governmental agencies, or non-profit corporations with boards of directors.

In assessing the relative merits of administrative structures, policymakers and regulators must evaluate the trade-offs involved with working with each of these types of entities: utilities, existing state governmental agencies, or non-profit corporations.

Utilities

Generally the electric utility has a single purpose to provide reliable, efficient delivery of electric power to end users. Regulators recognize that utilities often have financial disincentives to promote customer load reductions, given that electricity sales are the main source of their revenues and profits. However, some utilities view energy efficiency programs as a core part of their customer services activities. Utilities have a trusted position with customers and market actors and often have economies of scale and scope

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[33] Carl Blumstein, Charles Goldman, and Galen Barbose, "Who Should Administer Energy efficiency Programs?" (August 1, 2003). Center for the Study of Energy Markets. Paper CSEMWP-115. page 1. http://repositories.cdlib.org/ucei/csem/CSEMWP-115

that can facilitate the management of DSM programs. Problems may arise if there are multiple utilities operating in the market; having DSM programs administered by multiple utilities may lead to unnecessary administrative expenses, as was the case in Vermont.

State Agencies

When considering state agencies as candidates to administer a public-purpose energy efficiency program, policymakers must weigh the potential benefits of an administrator without perceived conflicts of interest against the potential problems of state government administration. For examples, agencies may have difficulties in focusing on a new mission, constraints imposed by staffing limitations or bureaucratic procurement requirements, challenges of providing effective incentives for state agencies, and the potential for suboptimal allocation of funds or mix of programs due to political pressures.

The security of funds for DSM programs collected by state agencies has become an issue in the U.S. States where the DSM monies are mixed with other revenue streams have seen these funds raided by legislators to help balance the state budgets. Some states have protected DSM funds by completely separating the funds from the state budgets.

Non-profit Corporations

Non-profit energy efficiency corporations with boards of directors are typically single purpose organizations whose sole mission is delivery of energy efficiency programs and often have to be created. Policymakers must take into consideration the balance between the objectives/mission and the challenges of creating a successful incentive mechanism for the nonprofit. These organizations have the advantages of being single purpose and are often considered unbiased. A newly created organization will take time to become an established, well respected, trusted program administrator.

The choice of DSM program administrator often depends on the primary objective of the programs, resource acquisition or market transformation. Studies have shown that when resource acquisition is the primary objective, utilities are strong candidates to administer DSM programs.[34] This is particularly the case if the utility is large and covers most of the jurisdiction. Utilities have easy access to customers and are often trusted by their customers. The effectiveness of resource acquisition programs is relatively easy to measure, so incentives can be tied to performance. In market transformation programs, direct access to customers is not as important. Market transformation programs affect the way the market actors behave so that they help change the customer buying habits. Program successes are more difficult to measure. Performance incentives for these activities, if offered, may be based on both subjective measures such as stakeholders' opinions about the value of the administrator's efforts and objective measures such as changes in market share. However, objective measures such as changes in market share may be difficult or costly to obtain given available market data.

Some jurisdictions have both resource acquisition and market transformation goals. This situation is becoming more common as program designers balance the need for short-term and long-term successes. This may lead to a hybrid approach for DSM program administration. For example, in the Pacific Northwest a regional agency administers market transformation programs and utilities or non-utility entities (either state agencies or non-profit corporations) administer resource acquisition programs.

The primary differences in DSM portfolios and their administration between utilities and agencies concern program strategies and regulatory treatment of program funding and cost recovery. As to

[34] Ibid. Page 17.

program strategies, utilities take more of a resource acquisition approach while agencies emphasize market transformation. From an independent viewpoint the emphasis on strategy means less than the impacts that are achieved, which in turn tends to be the result of good planning, sufficient budget and staffing (in particular having skilled people and staff continuity), and disciplined execution of program tactics. Both resource acquisition and market transformation strategies have been shown to be effective when these factors are adequately addressed – as the saying goes, “the devil is in the details.”

Utilities tended to achieve higher energy savings at lower costs than did agencies. A study done by the American Council for an Energy-Efficient Economy (ACEEE) showed that, in the top five states in terms of 2003 DSM savings as a percentage of electricity sales, it was utilities that delivered the programs.[35]

Recommendation:

- *NSPI should administer DSM programs, leveraging the work being done by Natural Resources Canada and the provincial government, while outsourcing much of the program delivery to local agencies. NSPI should position these programs as customer service programs and use them to help promote the NSPI brand.*

5.2.2 Discussion of Overcoming “Throughput Incentives” To Selling Electricity

As was found in the CAMPUT report most jurisdictions with successful energy efficiency efforts recognize the tension of the throughput incentive, the link between sales and net income (profits) that is an inevitable outcome of traditional regulation.[36] Even though utilities do not earn “profit” from these programs the utilities must pay attention to debt coverage and are concerned (along with their bondholders and lenders) that revenue erosion from reduced sales can hinder debt repayment. In addition, a reduction in sales means that the fixed costs are spread over a smaller rate base and may result in an increase in rates. The throughput incentive, where it exists, is identified universally as a barrier, and maybe the key barrier, to effective energy efficiency deployment. Yet, as the long-standing method of regulation that is well understood by participants, there can be considerable reluctance from utility and regulatory staff to change.

Some jurisdictions return lost margins to utilities, sometimes as a result of a regulatory proceeding that produces a precise accounting based on evaluation of program accomplishments in terms of saved kWh. Regulatory proceedings to calculate lost revenue adjustments can be time consuming and contentious, often due to debates over the accuracy of the evaluation of saved kWh, unless there is a clear process that is easily implemented.

Some states (e.g., Oregon, Maryland, and California) have changed the way some utilities make money, decoupling sales from profits, by keying utility revenues to something other than sales, such as number of customers. This approach is effective, and has the advantage of opening the utility to consider all cost-effective measures that might lead to reduced sales (efficiency, demand response, customer-owned generation) without concern for eroded profits. A revenue cap approach can also explicitly build in ways to share risks between consumers and utilities—risks such as unseasonably hot or cold weather, volatile commodity prices, or economic downturns. In this approach, there is no reason to change the customer

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[35] ACEEE’s 3rd National Scorecard on Utility and Public Benefits Energy Efficiency Programs: A National Review and Update of State Level Activity, York, D. & Kushler, M., 2005.

[36] A more detailed discussion of this issue of incentives and disincentives in the delivery of DSM can be found in the Regulatory Assistance Project Newsletter, “Regulatory Reform: Removing Disincentives to Utility Investment in Energy Efficiency,” September, 2005. (Available at www.raponline.org.)

rate design, at least not for the purpose of changing utility incentives. Regulators may wish to change rate design to influence consumption patterns.

Some industry advocates suggest a different form of decoupling. The idea is that rate design is shifted such that more money is collected via the fixed portion of the rate, and less is collected in the variable portion. The rationale is that utilities will be more open to energy efficiency if they do not have so much revenue dependent on the commodity charge. As we have just discussed, a better way to avoid commodity charge dependence is to connect revenues with numbers of customers, and this way also preserves the long run marginal cost pricing signal to customers that maintain the message to conserve.

There are a number of states that offer positive incentives for attaining the DSM goals in terms of sharing the benefits of DSM between customers and rate-payers. For example, at least six jurisdictions (Minnesota, Ontario, Vermont, Rhode Island, Connecticut and New Hampshire) offer performance incentives for meeting or exceeding specified efficiency targets. Performance goals and incentives can be used independent of the throughput issue. Goals can be an organizing focus for energy efficiency staff, and linking achieving these goals with some financial reward allows a connection to employee bonuses and a shareholder benefit. In addition to the program incentives just mentioned, there are other financial ways regulators can signal to utilities that energy efficiency is a priority.

One way is to assure that investments in energy efficiency appear on the utility books in a way equivalent to an investment in a power generator or a transmission line. A drawback to this approach is the difference in control that the utility has between the owned, tangible asset of a generator and a “regulatory asset” represented by the capital spent, but not by a hard asset. As long as the investment community is comforted that rates will be set to recover the costs of these investments, there should be no substantive difference, but utilities are likely to want to limit the amount of regulatory assets on their books.

A more simple way to reward a utility for a job well done on energy efficiency is to add basis points to the cost of capital used to set rates. Investor owned companies can allocate some of these funds directly to shareholders. In the case of a publicly owned utility or an IOU, this revenue from customers can be used for performance incentive pay for employees involved in the successful programs.

Where additional incentives for meeting or exceeding DSM targets have been used, the impact on the utility and its rate-payers appears to be positive. The incentive now provided to Massachusetts distribution companies, for example, is not overly large, but it does capture the attention of management and helps create best efforts for cost-effective DSM.

Lost revenues and potential disincentives to utility investment in DSM has been a contentious issue in a number of jurisdictions, even though it is undoubtedly true. If the utility or distribution company sees sales decline over what would have been the case, then they must not be earning the same level of revenues and profits. Nevertheless, this disincentive is real and should be addressed either through an adjustment clause that tracks and makes the utility whole (or mostly whole) for lost margins due to lower revenues, or through a decoupling option to eliminate this disincentive. NSPI should not lose revenue as a result of the DSM programs.

Recommendations:

- Lost margins due to lower sales of electricity should be addressed through a reconciliation procedure (annual rate case or lost revenue recovery) or a decoupling of revenues by tying them to the number of customers and weather adjusted sales, so that it is not a disincentive to utility investment in DSM.
- The regulator should offer additional incentives for meeting or exceeding DSM targets.

5.2.3 Discussion of Reasonable Level of DSM Spending

Determining the appropriate level of DSM is a challenging task for any utility, jurisdictional, or regional organization. There is no single or predominant approach but in many cases results are similar in terms of rough size of targeted savings and dollars allocated, sometimes as a percent of total revenues. The CAMPUT study interviewed several program managers and regulators to determine the methods used for setting the level of DSM spending.

There are several considerations viewed as important in setting targets. First, targets should cover a period of time that allows for ramp-up of DSM programs and development of the appropriate infrastructure for resource acquisition and market transformation programs. Second, a minimum level of expenditure can be established such that the amount dedicated to energy efficiency is sufficient to build and maintain a critical mass of infrastructure within markets' program capacity; and, over time, the amount should never go so low that critical capacity (i.e., qualified contractors, trained employees) is eliminated. In Vermont, when Efficiency Vermont was created, this minimum amount was thought to be roughly a 1.5% surcharge on rates. Program budgets were ramped up from there after the first year (2000) to the current level of roughly 3.0% of rates in 2005.

There are a number of ways to set the final amount. It can be set administratively, as in many restructured states. This would typically be a rough round number approximating what policymakers felt consumers could afford, informed by how much was spent on energy efficiency in the past. This is simple, and in jurisdictions where energy efficiency stirred some of the more contentious regulatory disputes (owing to the throughput incentive), the relief from fighting is just as welcome as the secured commitment. But this approach has a long term problem—energy efficiency is disconnected from other resources that are serving customers. There is no assessment as to whether all cost-effective energy efficiency is being achieved. The program becomes like a government program, in which managers get a budget and do their best to manage within it, without necessarily considering fundamental questions about the size and purpose of the program.

In most states and provinces where energy efficiency programs exist, at one time or another a resource-driven process was used to set energy efficiency budgets. In some states, spending has not returned to the nominal levels of the early 1990s (i.e., not accounting for inflation) despite higher avoided costs today. To really know the appropriate spending level for energy efficiency, some regulatory process in which energy efficiency and other resources are evaluated together is necessary, e.g., an Integrated Resource Plan.

A key issue in each jurisdiction, not always explicit, is resolving the conflict between wanting to procure all cost-effective energy efficiency and concern about the resulting immediate effect on rates. In many jurisdictions, it is evident some compromise was struck, allowing for a significant yet limited rate impact to support a meaningful suite of programs. Budgets based solely on findings from an IRP or from a benefit-cost assessment would come down squarely on the side of accepting whatever rate effects are necessary to secure a long term overall resource plan—energy efficiency might enable fewer kWh to meet the region's energy needs but at a somewhat higher price for each kWh.

Our analysis shows an expenditure of 0.7% of annual electric revenues might be appropriate with a ramping up to a level near 2% of annual electric revenue. These figures are irrespective of whether a jurisdiction has adopted retail electric competition or imposed generation divestiture, though regulatory oversight details may be quite different in either case. Our benchmarking study found that there was no correlation to spending levels and the impact achieved. We recommend that NSPI base their DSM plan on the best practice programs, which should deliver the savings more efficiently. We note that some jurisdictions have recently raised their DSM spending levels, but encourage NSPI to focus not on overall spending, but on the overall cost of conserved energy.

Spending a higher percentage of revenue on DSM may be warranted if there is expected to be rapid growth in electric demand or an increasing gap between demand and supply due to such things as plant retirements or siting limitations. Even those states with 3% of annual revenues as an expenditure target have found that there have typically been more cost-effective DSM opportunities than could be met by the 3% funding. Caution should be used so that any increase in spending is still being spent efficiently, such that the cost of conserved energy remains at a reasonable level.

It is important to review the level of DSM spending periodically. California calls for a review of DSM spending every three years, Texas requests annual DSM forecast and filings to ensure the 10% of growth is being obtained by the DSM programs offered, and Idaho and British Columbia conduct an IRP update every two years. It is important to update avoided costs used as the benchmark for determining cost-effective DSM, and to incorporate any unforecasted events (e.g., the recent rise in the price of natural gas) that might change the economics of DSM versus other resources. The review should take into account the importance of maintaining a critical mass of basic capacity within markets for implementing energy efficiency programs, such as contractors, craftsmen, and trade ally relationships.

Recommendations:

- Consider conducting a more thorough avoided cost study than was used in this assignment in the next 2-3 years to better account for the total benefits of DSM measures. The deployment of these recommendations should proceed in the meantime.

- In the next 1-2 years a more detailed DSM potential study should be performed, to better understand where the potential for savings in Nova Scotia exists. The potential study completed as part of this project provides a sufficient foundation from which to launch the initial DSM programs in Nova Scotia. A more detailed study will help focus these programs further.
- Spending on DSM program should start at 0.7% of in-province electric revenues, and ramp up to 2% by 2010.
- Review level of DSM spending every two years.

5.2.4 Discussion of Allocation of DSM Costs Among Rate Classes

Through our benchmarking analysis we found that almost all jurisdictions charge customers the same rate or percentage to recover DSM costs. When examining this finding it is important to remember that DSM costs are a small part of customers' overall bills, even in the most aggressive DSM states, 2%-3%, which contributes to regulators not wanting to get too complicated about cost recovery formulas.

Utilities recover program costs through base rates or rate surcharges such as a resource adjustment, whereas agencies fund via separately itemized charges collected from customers via bills; the effects on customer bills are equivalent. Typically, though not always, the cost recovery charge is one fixed rate applied to all “eligible” customers.[37] Including the industrial customers in this cost recovery charge maintains the cost equity for system savings that will benefit all customers. Many industrial customers have a long standing practice of energy-efficiency and conservation; however as technologies improve

[37] In some jurisdictions industrial customers may opt out of DSM programs and pay no surcharge to fund DSM; however, they are generally required to operate self funded DSM efforts to substitute for utility DSM programs.

there will be additional energy-efficiency opportunities at these facilities. One non-utility organization reviewed does split its cost recovery by major customer class, but again such a split is an exception to typical practice. DSM is considered a resource, similar to a power plant, and therefore costs are generally recovered from the entire rate base rather than only from customers that participated in the programs. Another basic premise underlying a single fixed rate surcharge to fund DSM is that customers have an opportunity to participate in programs in relation to their energy consumption levels, with smaller customers who have smaller DSM potential paying less than customers with greater consumption levels. Also, cost recovery charges tend to be treated in the same manner as fuel adjustment clauses and such clauses typically are uniform across customer classes.[38] Certainly, actual program budgets tend to allocate funds by other factors such as social or customer service objectives, so in practice some types of customers may receive a disproportionately higher (or lower) level of DSM services than what they are funding. This can become a political issue in the course of regulatory oversight, but typically does not result in altering the basic cost recovery paradigm of a single fixed funding rate.

Program costs are recovered through customer bills in all the situations reviewed (as opposed, say, to funding via an external tax), though itemization and terminology of cost recovery differ. Some organizations simply expense the costs, but most have some sort of deferred accounting process that enables a true-up of actual costs to projected costs as implied by the charges applied to customers' bills, and the amounts actually collected relative to customers' usage. In some cases the costs accrued through the deferred accounting are capitalized and embedded in base rates at some point in the course of future rate cases.

Recommendation:

- Costs of the DSM programs should be allocated across the entire rate base.

5.2.5 Discussion of Conservation Based Pricing Design

As previously discussed, Nova Scotia Power has a considerable amount of load currently on interruptible rates, about 400 MW or almost 20% of the Company's peak demand. NSPI also has residential time-of day rates available for residential customers that install storage heating systems. Several utilities in North America offer interruptible rates to commercial customers and medium sized industrial customers. While Summit Blue believes that additional DSM potential exists for expansions to NSPI's current demand response programs, the specifics of such programs require further research, and may require separate regulatory approvals for the rate discounts typically offered through such programs.

Based on the premise that: 1) consumers will respond to price signals by altering their patterns of energy usage; and 2) that even the small reductions in system demand provided by residential customers can result in substantial benefits to the system during critical periods, residential time-differentiated pricing schemes are gaining traction across the United States, with at least 67 utilities offering such pricing options.[39] Past pricing programs have shown that:

[38] Indeed, one jurisdiction has redefined "fuel adjustment" as "resource adjustment" because the rate rider is used for a variety of resource-related true-ups including both supply and demand resources.

[39] A nationwide survey of residential time-differentiated pricing programs recently conducted by Summit Blue identified 67 U.S. utilities offering residential Time-of-Use (TOU), Critical Peak Pricing (CPP), or Real-Time Pricing (RTP) rates, either as permanent offerings or pilot/experimental programs.

- While initially reluctant to participate, consumers expressed satisfaction with the rates and many chose to remain on the pricing structure at the end of the pilot period, even in the absence of incentives.

- Critical peak pricing programs can trigger a reduction in peak period residential demand of over 13 percent. This impact was greatest in hotter climate zones.

- Impacts are greater when automated demand response technologies are used.

- In the absence of price incentives, calls for load reduction on critical days failed to result in sustainable demand response.

- High relative levels of responsiveness were associated with college education, high annual income, and presence of central A/C.

Summit Blue has conducted a series of evaluations of a residential real-time pricing (RTP) program called the Energy-Smart Pricing Plan^{SM} (ESPP) offered in the ComEd service territory of Illinois in collaboration with the Community Energy Cooperative. This program was introduced in 2003 and was the first large-scale residential RTP program in the United States. Some findings of relevance to this project include:

- Over half of all participants showed significant response to price notification, with the rest of participants showing some response.

- Residential customers responded to hourly prices with a price elasticity of -4.2%, which can result in significant changes in electricity demand.

- Participants expressed great satisfaction with the demand reduction tips, reminders, and other assistance provided by the program staff.

- Interestingly, and in contrast to the findings of the California Statewide Pricing Pilot, lower-income households were more likely to be "high responders." Such participants who owned central air conditioning units reduced their electric usage compared to their baseline by almost 30% overall during high priced periods.

- The actions taken by customers who had the largest reductions in their electric use during periods of high prices include turning up the temperature of their air conditioning systems and turning off lights. A large portion of participants also shifted their clothes washing to nighttime to avoid high price periods.

Electric utilities across North America are conducting some or all of six types of demand response programs for commercial and/or industrial customers:

1. **Interruptible rates (IRs):** Through these programs, utilities offer customers generally fixed price discounts for reducing their loads to certain levels during peak demand periods. Customers are usually given one to two hours notice before the start of a control period to reduce their loads to the agreed upon levels. Utilities often require multi-year contracts with customers as a condition of program participation, and usually penalize customers if they fail to reduce their loads to the levels specified in their contracts.

2. **Demand "Bidding" or "Buy-back" (DBB):** These programs are similar to interruptible rate programs, but are newer vintage programs that are designed to be more flexible and give customers more options. The rate discounts offered to customers are usually linked to spot market electric prices in some manner. Customer participation and the amount they reduce their loads during peak periods are usually optional.

3. **Direct load control (DLC)**: Through these programs, customers allow their utility to directly control their central air conditioner, water heater, or other types of major electrical equipment. Utilities cycle this equipment on and off during peak demand periods, usually in alternating 15 minute cycles. Utilities usually offer customers some type of rate discount as a participation incentive.

4. **Time-of-use (TOU) rates:** The most common type of TOU rates are "two-part" rates that charge customers a higher "on-peak" price than the standard "flat" utility rate during daytime hours, and a lower "off-peak" price during nighttime hours and weekends. Some utilities offer a "three-part" TOU rate, in which both the on-peak and off-peak periods are shorter than the typical two-part TOU rate periods. In addition, the three-part TOU rate includes a "shoulder" period between the on-peak and off-peak hours, during which time prices are between the on-peak and off-peak prices.

5. **Critical peak pricing (CPP) rates:** These are similar to TOU rates, but add a "critical peak" period and rate. The "critical peak" period is usually 1% or fewer hours throughout the year, during which time the utilities' production or power purchase costs are highest. Electric prices during this period are higher than the regular TOU on-peak prices.

6. **Real-time pricing (RTP):** Prices offered through these programs are tied to some type of hourly pricing benchmark, such as the PJM RTP rate, or are based on the utilities' internally calculated short-term marginal costs.

Almost 90% of the utilities surveyed are conducting at least one type of DR program for C/I customers. The most common C/I DR programs, each offered by about half of the utilities surveyed, are interruptible rates, two-part TOU rates, and DBB programs. The next most common types of C/I DR programs, each offered by about one-fourth of the utilities surveyed, are DLC and RTP programs.[40]

It is interesting to note that approximately two-thirds of the utilities surveyed are conducting at least one type of DR program for residential customers. The most prevalent residential DR programs are two-part TOU rates and DLC programs, each conducted by about one-third of the utilities surveyed.[41]

Recommendation:

- Funds for additional demand response program development and pilot programs should be included in the DSM program portfolio.

[40] R. Gunn, "North American Utility Demand Response Survey Results", (Association of Energy Services Professionals, February 6, 2006, San Diego, CA.)

[41] Ibid.

5.2.6 Discussion of Customer Financial Incentives

There are number of methods used by DSM programs to overcome the fact that high efficiency technology typically costs more than standard efficiency equipment. The most common means of helping consumers overcome the high first cost of high efficiency equipment is to provide a cash rebate. Rebates are typically about 25%-50% of the incremental cost of the high-efficiency equipment, but may be higher if there are other market barriers to the technology. The rebates can be instant rebates, taken at the cash register, or mail-in rebates where the customer receives a rebate check in the mail. For most lighting DSM programs, instant rebates are used, due to the low rebate amounts; however, for appliance programs the rebates are typically higher and mail-in rebates are used.

Financing of energy efficiency measures through bank loans is another method to overcome the higher first cost of high efficiency equipment. The program administers work with a local institute to arrange financing for consumers installing energy efficiency measures. The program may have to provide funds to the lending institution to "buy-down" the interest rate offered to consumers and may also have to guarantee that the institution will receive a certain volume of these loans. The loans typically have a 15 year term and cannot exceed the useful life of the loan-funded equipment. Financing as an incentive has met with limited success. Often when consumer is presented with the attractiveness of the financial investment they may use internal funds. Some corporate policies don't allow for the taking on of debt for capital improvements.

In addition to these direct financial incentives, some programs make use of indirect incentives such as sales spiffs or manufacturer buy-downs. Sales spiffs are incentives paid to the sales staff at a equipment supplier or retailer for the promotion and sales of high efficiency equipment. Since the sales spiffs are not paid directly to the consumer, they are used by only a few programs and only to complement the direct incentives. Manufacturer buy-downs occur when DSM programs work with retailers and manufacturers to provide high efficiency equipment to consumers at a discount. The DSM program agrees to "buy-down" the price of the energy savings equipment by a specific amount on a fixed number of units. The manufacturers, often along with a retail partner, brings these products to market, provides documentation of the products, and invoices the DSM program for the agreed upon price. The customers receive the products at discount, but may not be aware of how the DSM program actually paid for this discount. This type of incentive is less hassle for the consumer, but may not help to promote the program.

Another method of overcoming the first cost market barrier is to use an on-bill payment system such as the Pay As You Save (PAYS®) system. PAYS enables building owners or tenants to obtain and install money-saving resource efficiency products with no up-front payment and no debt obligation. Those who benefit from the savings pay for these products through a tariff charged on their utility bill, but only for as long as they occupy the location where the products were installed. The monthly charge is always lower than the product's estimated savings and it remains on the bill for that location until all costs are recovered. Like a loan, PAYS allows for payment over time, but unlike a loan the PAYS obligation ends when occupancy ends or the product fails.[42] One of the main hurdles with the PAYS system is receiving approval from the utilities commission for the addition of the monthly payment to the customer bill.

Recommendations:

- The DSM programs should provide rebates & incentives to overcome the high first cost market barrier.
- The NSPI DSM programs should only provide incentives for electricity savings measures.

[42] http://www.paysamerica.org/What_is_PAYSr__/what_is_paysr__.html

5.2.7 Discussion of Implementation of Programs

The implementation of the DSM programs has followed several models that span the range from program implementation by in-house staff to outsourcing of all program implementation. Efficiency Vermont implements virtually all program activity by in-house staff and outsources very little of the program implementation. This model requires a relatively large staff, but provides direct control over programs, which allows for immediate changes to the programs. On of the potential downsides to this model is that large staff may lead to programs running longer or in an inefficient manner in order to keep staff employed. To date this has not been the case with the Efficiency Vermont programs.

On the other end of the spectrum, Efficiency Maine completely outsources the implementation of their DSM programs. Efficiency Maine, part of the Maine Public Utilities Commission, has a limited staff that performs the program design and planning. The implementation of the programs is outsourced to third-parties through a bidding process. While this model allows for a more streamlined administrative staff, the programs may be slower to react to program changes. Also this type of program implementation may not build strong relations in the market, particularly if the program implementers are changed every couple of years.

There are some advantages to using in-house staff. Using in-house staff to market and sell the DSM services will help build the NSPI brand and create better customer service ties. In particular, Efficiency Vermont has found that using in-house staff to manage key accounts (medium to large retailers and medium to large industrial customers) has led to more energy savings opportunities, increased customer trust, and improved program awareness.

Natural Resources Canada has programs been offering programs in Nova Scotia. Nova Scotia should consider leveraging on Natural Resources Canada program delivery where possible. This would also help leverage program dollars and prevent confusion in the market place.

Recommendations:

- NSPI should implement the programs using both in-house staff and outsourcing the delivery of services (for example weatherization services) to local community groups.
- NSPI should promote and leverage Natural Resources Canada programs, including program delivery where possible.

5.2.8 Discussion of Non-discriminatory Means To Reach Low-Income Customers

The nation's low-income population pays, on average, more on energy than the median-income household pays as a percentage of income. Many utilities have helped to address this burden by providing energy efficiency programs for their low-income customers. Often these programs were in response to regulatory mandates and may not have been cost-effective. Due to additional societal benefits of these low-income programs some regulators have decided that a benefit cost ratio of 0.8 is sufficient to justify these programs. Some utilities, however, have proven that these programs can operate cost-effectively.

In addition to helping relieve the relatively high energy burden shouldered by low-income customers, low-income DSM programs have other benefits. Typically low-income homes and buildings are older and not well maintained buildings, and therefore have more savings opportunities than the average residential building. Reducing the low-income energy burden may also reduce arrearages, disconnect/reconnect costs, working capital needs, and create customer goodwill. Helping customers reduce their energy burden is also believed to help the local economy, because the money they save is typically spent on other local services.

There are several ways to reach low-income customers that are non-discriminatory. The best approach is to work with existing low-income programs, either government programs and/or community agencies. These low-income programs can promote the utility programs to consumers when the consumer applies for services. The low-income program may choose to offer these agencies a referral fee and thus help to put funds into the referring services. The program administrator may also form partnerships with affordable-housing developers, banks, first-time home ownership programs, local housing financing agencies, state and local land trusts, and community development financial institutions. These partnerships may provide effective cost savings by centralizing participant recruitment, sharing of trained energy efficiency professionals, and development of joint delivery. It may be possible to use these partnerships to deliver the energy efficiency programs

Other methods to reach low-income customers include mass mailings and canvassing low-income areas. Utility bill stuffers or mailings that describe all the DSM programs being offered in the jurisdiction and the requirements for participation in each of the programs can help recruit participants for all program types including low-income programs. However, the response rate from such mailings is typically around 1%. Canvassing low-income areas using door tags may be another way to recruit participants for the low-income programs. The door hangers typically announce that program installation contractors will be in the area within a couple of weeks and that the homeowner should call and schedule an appointment. Customers can then be screened for eligibility when they call to schedule an appointment.

To help make low-income programs more cost-effective, it is important to target low-income customers with high-energy use. These customers tend to use energy the most inefficiently and therefore have the highest potential to save energy both through efficiency measures and by becoming more aware and involved in conserving energy. Often these high-use, low-income customers tend to have higher arrears. Targeting customers with higher arrears will help identify these high-use, low-income customers, but will also help the utility reduce bad debt and the administrative cost of collections.

Another effective means to reaching the low-income population is to identify low-income multi-family housing. In the multi-family housing situation, the low-income families are renters and have no incentive to make major energy savings improvements to their apartments. Likewise the owners of the buildings have little financial incentive to make energy savings improvements to the building, because the renters typically pay for the utilities. A successful low-income program will identify and work with the building owners to implement energy savings measures. Incentives will need to be offered to help reduce the cost of the measures.

Recommendations:

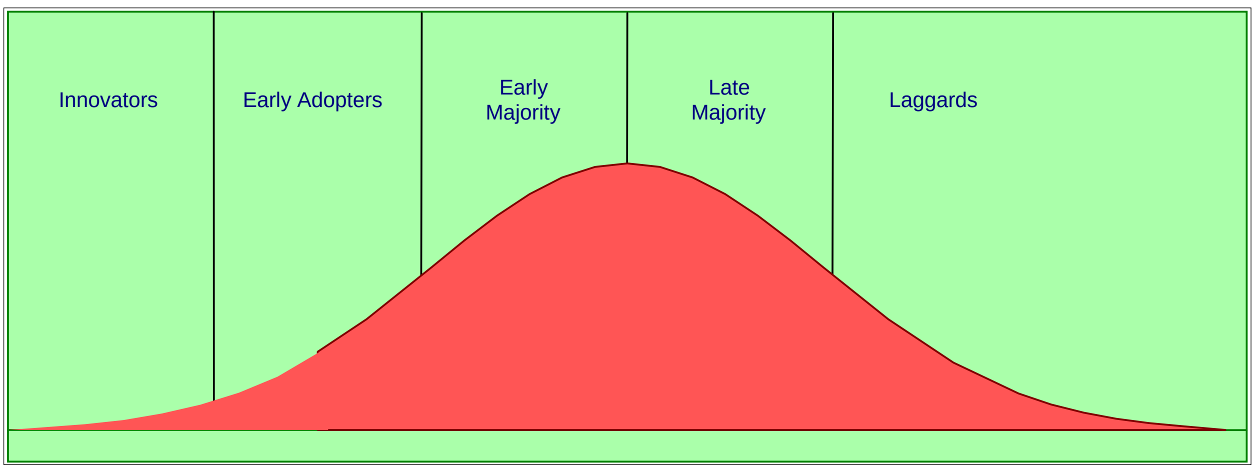
- The DSM plan should include programs for all sectors: residential, low-income, commercial, and industrial. Low-income program spending should be up to 10% of the overall residential budget.
- Overcome the split incentive for low-income renters by working with the multifamily building owners to install DSM measures.

5.2.9 Discussion of Education & Outreach

Education has proven to be a valuable component of energy efficiency programs, not just education of the customer, but also education of the service providers and program sponsors. Experience has shown that energy efficiency programs increase energy savings and enhance the persistence of savings by providing customer education and providing training to maintenance staff. Education helps the customer feel more committed to the program and gives the customer some control over their energy usage and savings.

Building awareness and interest in energy efficiency is the goal of education and outreach programs. Generally, when energy efficiency is discussed, the value is placed on the later stages along the 'purchasing decision' continuum (awareness –> knowledge -> preference -> action), the *preference* and *action* components. Customer action in response to DSM program offerings results in energy and demand savings. If we look at the goals of the outreach and awareness programs, it is the *awareness* and *knowledge* the programs are mostly seeking to build. If the ultimate goal is to get enough participants to purchase high efficiency equipment or use DSM services, one way to look at the effect of outreach and education is to consider energy efficiency as a new product entering a market. The technology adoption or diffusion curve principle used in product develop is an effective way to demonstrate the effects of *awareness* on *action*. Figure 5-1 below shows a traditional adoption curve. Energy efficiency in Nova Scotia may still be in the innovators and early adopters phase of this curve. *Basically, you can't move up the adoption curve to action unless you increase awareness and interest.*

Figure 5-1. Product Adoption Curve



Use of a technology adoption curve is well accepted among proponents of EE market transformation programs, where many of the 'progress indicators' used to measure the success of market transformation efforts are awareness and interest criteria. Actual energy savings attributable to the increases in awareness and interest may not occur until years later and not typically counted in the current year.

Education and outreach programs can occur through one or more *outreach channels: direct contact, trade*, or *government channel.* In *direct contact channels* a program representative or designee meets with a customer at their place of business or home. In *trade channels* the program communicates their messaging through a trade intermediary or at a trade show-styled function. In the *government channel*, cities and quasi-governmental entities become the conduits though which information is released.

These education and outreach activities need to be creative and attention grabbing. Trade associations and utility field representatives alike believe that brochures and print materials need to use less text and more images. Since most small and medium businesses and residential customers (essentially anyone for whom energy management is not a professional responsibility) often will not take the time to read energy-related literature, some consumers recommended that materials should be geared simply toward grabbing the audience's attention and directing them to further resources. Consumers have found that materials including testimonials from businesses within the target community that have succeeded in and benefited from implementing energy efficiency projects are effective education pieces. Perhaps even more effective is to use the outreach and awareness channels as a means of linking consumers with actual one-stopshopping type services and actionable programs. Such a shift would address the inability of current information-only programs to "close the sale."

Often it is difficult to quantify the savings associated with an education program. Participants in an education program may immediately change their behavior to reduce their energy use; however these changes may not last. Also it is often hard to determine the causality of action following participation in an education program and to determine how much impact the education program had on the participant's decision to make energy efficiency improvements. Evaluating the effects and impacts of an education program can be expensive as a result of these issues. Due to these difficulties and expense of evaluation savings are not typically claimed for education programs.

Recommendations:

- NSPI should continue and perhaps expand their education and outreach efforts, not only as a means to increase awareness and knowledge, but to direct consumers to one of their programs.
- The energy/demand savings from education and outreach should not be included in the overall portfolio impacts.

By directing the consumers to the DSM programs, the consumer will be provided with more detailed information and may be more likely to take the desired action, installing an energy efficiency measure or participating in a DSM program.

5.2.10 Discussion of Program Evaluation Activities

As with any new program or progress it is essential to conduct an evaluation of the program or process to ensure that the objectives are being achieved. The results of the evaluation can be used to revise the program and improve the process. This cycle of planning, implementing, evaluating, and revising the programs should happen continuously throughout the life of the program to ensure its success.

The California Evaluation Framework defines impact evaluations as the estimation of gross and net effects from the implementation of one or more energy efficiency programs. Most program impact **projections** contain ex-ante estimates of savings. These estimates are what the program is expected to save as a result of its implementation efforts and are often used for program planning and contracting purposes and for prioritizing program funding choices. In contrast the impact evaluation focuses on identifying and estimating the amount of energy and demand the program **actually provides**. Estimates of actual savings are ex-post savings: program savings that can be documented after the program has made the changes that are to produce the savings. Savings induced by the program are called "net" savings, as they are beyond or in addition to what would have occurred without the program. Ex-post net savings are the savings estimates as measured/verified as being achieved by the program.

The process evaluation, according to the California Framework, is a systematic assessment of an energy efficiency program for the purposes of documenting program operations at the time of the examination and identifying improvements that can be made to increase the program's efficiency or effectiveness for acquiring energy resources. In addition, a process evaluation can also help increase the effectiveness of other programs by providing other program planners and administrators with the evaluation results. These planners can then review the process evaluation results to determine if their programs can benefit from the evaluation's findings and recommendations.

The market characterization evaluations focus on the evaluation of program-induced market effects when the program being evaluated has a goal of making longer-term lasting changes in the way a market operates. These evaluations examine changes within a market that are caused, at least in part, by the energy efficiency programs attempting to change that market. These evaluations are challenging, as markets are constantly in a state of change as new and competing technologies are offered or as other non-program market transformation efforts compete with the program's efforts.

Impact evaluations: Impact evaluations are given highest priority among implementers due to the importance of truing up savings estimates and the desire to focus spending on program implementation. Net energy savings are usually determined on an annual basis, but evaluations can be run every two to three years (and applied until a subsequent evaluation). Impact evaluations are normally conducted through engineering analysis, billing analysis, metering, or a combination of these approaches. The International Performance Measurement and Verification Protocols (IPMVP) includes recommended approaches for determining energy savings from efficiency programs.[43] The IPMVP guidelines have become the de facto standards for California and other regions throughout the United States.

Process evaluations: Process evaluations are critical to ensuring effective, efficient implementation. Process evaluations are typically conducted within a year of implementation of new programs or following substantial changes to programs.

Market characterization studies: Some regions also conduct periodic market characterization (or market research) studies. These are typically conducted less frequently (usually on an "as needed' basis), and are often custom studies designed to assist with potential analysis, program development, or baseline assessment. Other administrators, however, like to conduct regular market characterization studies, although usually less frequently (e.g., every two to five years) than impact or process evaluations.

Allocating the evaluation budget: Prioritization should be given based on a number of factors, including the implementation budgets, expected savings, and market sector (so all are given some attention). Another important consideration is the risk factor: programs with a history of evaluation, with proven measures and good secondary data, should be considered less risky than programs that institute newer, less proven measures (i.e., newer measures should be given evaluation priority).

Calculation of market effects: Market effects, or attribution analysis, includes the examination of freeridership and spillover. Traditional resource acquisition programs that offer incentives and little training/education are the best candidates for freeridership and spillover analysis. Market transformation programs that emphasize education, training, and long-term market effects need to look at incremental impacts of market indicators (e.g., penetration levels, awareness levels, etc.) to assess program impacts. This should be done by the use of comparison states and market share data, where available.

Evaluation budgets and staffing: Evaluation budgets for other implementers throughout the U.S. are typically in the 2% to 4% of annual program budgets, and this seems to be sufficient. Note this usually does not include full-time evaluation staff, whose salaries and benefits are typically allocated to organizational overhead or program implementation. At least one full-time equivalent (FTE) should initially be assigned to manage evaluation activities, expanding as the need increases. Evaluation staff should be able to manage approximately 4-6 programs year.

Outsourcing evaluations: An attempt should be made to outsource as much research as possible to maximize objectivity and avoid any potential conflict of interest.

Primary data collection: Evaluation staff should work with program implementation staff at the early stages of implementation to ensure that the necessary data are being collected for evaluation. Sufficient

[43] The guidelines can be downloaded at www.ipmvp.org.

budgets should be allocated for database design, which should be outsourced to a qualified firm or conducted by third party implementation contractors. The data tracking systems should be the backbone of the program delivery and should be kept up to date by the program staff or program implementers. If possible the programs should use an integrated data collection approach so that evaluation data is collected at the optimal points of contact during the project implementation. For example, a survey of participants prior to participation in the program will provide valuable data for future impact evaluation. Reports on program activity should be produced quarterly, at a minimum, to validate the progress of program activities and ensure that high level metrics (e.g., number of participants, incentive levels, etc.) are available for evaluation.

Recommendations:

- Detailed evaluation plans should be developed for each of the programs. These plans should include the use of integrated data collection as part of the program administration, to help reduce the costs and uncertainty in future evaluation data collection.
- A robust program data tracking system should be developed as part of the final DSM program development to ensure that the data needed for evaluation purposes is being collected.

5.2.11 Discussion of Economic Evaluation of DSM programs

There are a couple of main DSM Program cost-effectiveness tests used through the U.S. and Canada. Table 5-1 identifies and defines the types of cost-effectiveness tests currently in use in the U.S. As this table shows, the tests range from narrowly focused to widely inclusive with respect to the number and type of benefits and costs included. Table 5-2 presents a summary of the inputs for each of these tests.

Table 5-1. General Description of Types of Cost-Effectiveness Tests

Test Name(s)	Measurement Approach	General Costs Included	General Benefits Included
Utility Test[1,2]	Measures net costs taking perspective of utility. Excludes participant costs.	Utility costs	Avoided supply, T&D, generation and capacity costs during load reduction periods.
Program Administrator Cost Test[2]	Measures net costs based on administrative costs only.	Program administrative costs; incentives; increased supply costs during periods of increased load.	Net avoided supply costs; marginal cost of reduction in T&D, generation, and capacity during load reduction periods.
Participant Test[1,2]	Measures quantifiable costs and benefits taking customer perspective.	Expenses incurred by customers, increase in customer utility bills, value of customer time spent arranging program participation.	Reduction in customer utility bills, incentive paid, tax credits, gross energy savings.
Ratepayer Impact Measure (RIM), a.k.a. Non-Participant Test[1,2]	Measures program impacts on customer bills or rates.	Initial & annual program costs incurred by administrator and any other parties, incentives paid, decreased revenue from load reduction periods, increased supply costs from load increase periods	Savings from avoided supply costs, including T&D and generation; capacity costs reduction during load reduction periods; increased revenue during load increase periods.
Total resource Cost Test (TRC)[1,2]	Measures net costs taking perspective of utility, but includes participant and non-participant costs. Applied at program and/or measure level.	Program costs paid by utility and participants; increase in supply costs during load increase periods; spillover	Avoided supply costs; reduction in T&D, generation and capacity costs; tax credits.
Societal Test[1,2,3]	Based on TRC, but takes perspective of society. Applied at program and/or measure level. May use higher marginal costs than TRC; should use societal discount rate; excludes tax credits & interest.	All costs included in TRC, plus: externalities, some non-energy costs (including costs to participants and society).	All benefits included in TRC, plus: externalities (avoided environmental damage, increased system reliability, fuel diversity), some non-energy benefits (including benefits to participants and society).
Public Purpose Test (PPT)[1,2,3]	Based on Societal Test; takes societal perspective; takes long-term view. Applied at portfolio level.	Same as Societal, but takes into account market effects & broader array of externalities	Same as Societal, but takes into account market effects & broader array of externalities, non-energy benefits; spillover.

[1] Sebold, Frederick D, Alan Fields, Lisa Skumatz, Shel Feldman, Miriam Goldberg, Kenneth Keating and Jane Peters. 2001. A Framework for Planning and Assessing Publicly Funded Energy Efficiency. March 1. Study PG&E-SW040. San Francisco: Pacific Gas & Electric.

[2] California State Governor's Office. 2001. Standard Practice Manual: Economic Analysis of Demand-Side Management Programs. October 2001.

[3] TecMarket Works Framework Team. 2004. The California Evaluation Framework. May. Project Number K2033910. Rosemead Calif.: Southern California Edison.

Table 5-2. Summary of the Various Benefits and Costs Considered by B/C Tests

Inputs	Total Resource Cost Test	Ratepayer Impact Measure	Utility Cost Test	Participant Cost Test	Societal Test	Public Purpose Test
Benefits						
Avoided Power Supply Costs	√	√	√		√	√
Avoided T&D Costs	√	√	√		√	√
Bill Reductions				√		
Conservation "Adder" (Environmental)					√	√
Costs						
Direct Utility Costs	√	√	√		√	√
Direct Customer Costs	√			√	√	√
Utility Program Administration	√	√	√		√	√
Lost Revenues		√				

As discussed in the CAMPUT study, a jurisdiction reveals its view on the purpose of energy efficiency by the benefit – cost tests it uses to evaluate programs and measures. Use of the Ratepayer Impact Test (RIM) indicates a strong interest in the satisfaction of individual consumers, but ignores the resource and societal values that flow to all along with the obvious value to the program participant. Many widely used energy efficiency programs do not pass the RIM Test.

Use of the Total Resource Cost (TRC) test instead of a Societal test values the economics of energy efficiency compared with other sources, but values at zero other advantages to society that, though perhaps hard to quantify, are worth more than zero, but may not be substantial. These other advantages may flow from avoided air pollution, water use, or reduced risk from avoided capital construction of generation and transmission, for example. Use of the societal test to evaluate energy efficiency programs represents a view that all effects of energy efficiency programs are important. Precision in the societal test is elusive, and jurisdictions that use it sometimes apply a rough "adder" or "multiplier" to handicap other sources in comparison with efficiency.

Accurate valuation of energy efficiency requires reasonable assessments of system avoided costs. Such assessments must be updated from time to time, and provide a valuable benchmark for managing energy efficiency activities. A valuable element to this process comes from gaining knowledge about the shape of the utility's hourly load curve. Programs that produce savings in particularly valuable hours have more value to consumers.

With increasingly regional electricity markets, stakeholders in New England and, separately, in California are collaborating on an avoided cost analysis framework that many will share. As a practical matter, the avoided cost assessment matters most if energy efficiency budgets are actively managed and are set based on this assessment. If a set amount of dollars is allocated to efficiency, the challenge becomes how best to use those funds, so avoided cost still remains important for program evaluation.

Further study of energy efficiency value is underway in several states. Utilities are considering the ability of EE (and other distributed resources) to avoid or delay load growth that would otherwise lead to investments in upgraded transmission and distribution, in addition to new generation already captured in most avoided cost calculations.

Another facet of benefit-cost is the prevalence of “potential studies.” A potential study provides useful intelligence, telling a decision-maker how much energy efficiency is available from among the regularly occurring “opportunities” and the accumulated “retrofits.” Recent studies in the Northeast U.S. indicate the potential of such quantities that annual energy use could be reduced year after year with a modest increase in spending from current levels. The only downside of a potential study is the expense – $250,000 to $500,000 or more for a comprehensive regional study. However, DSM potential studies can be designed to meet multiple objectives. Information from a DSM potential study is often used as the first step in design of programs since such studies can document current practice and establish energy use baselines. This information can also be used to design an appropriate program for a region and help establish initial customer/trade ally incentives and marketing messages.

Assessing and evaluating DSM accomplishments is important on a prospective basis to develop a cost-effective mix of DSM programs, and on a retrospective basis to discern whether the expected benefits were actually obtained. These retrospective studies also can be used to develop a more cost-effective mix of DSM activities and provide suggestions on how to make a specific program more effective. The use of benefit-cost tests reflects the importance that regulators in a jurisdiction place on different factors. This is one reason why there are five tests incorporated into the methodology in common use today—the California Standard Practice Manual tests.

- The primary test commonly used is the Total Resource Cost Test applied to a portfolio of programs, with program specific tests used to address appropriate program design and the mix of programs in the portfolio. For retrospective analyses, it is important to understand that delivering a DSM program is like introducing a new product into a market. Some programs will likely work better than expected, while others will encounter problems that need to be rectified. As a result, it may be unreasonable to expect all programs to pass the TRC test, but the portfolio as a whole should pass the TRC test.

- The Participant Test is commonly used to ensure that customers that participate in the program do benefit, but it should not have a significant role in setting overall DSM expenditure levels. Rather, it is useful in the design of specific programs to ensure that the customer perspective in represented.

- The other tests commonly calculated can be used to provide different perspectives. If there is a large discrepancy between a ranking of DSM activities based on the TRC Test and one based on the RIM or Societal Test, then the planning process should be flexible enough to make adjustments. Also, if one program drops substantially in its ranking relative to other programs, it may pose some equity problems across customers that could be corrected by making adjustments in the program. The TRC Test is generally used as the guide, with the other tests used to check for extreme differences, which allows some flexibility in the design of a DSM program or the mix of DSM activities. The benefit-cost tests include not only avoided costs of generation (i.e., the commodity cost), but also avoided transmission and distribution (T&D) costs. Progress is being made on determining avoided T&D costs in various states that have started to focus on this issue. The Societal Cost Test could be considered, to provide a more complete picture of the programs’ benefits to society. However, in at least one jurisdiction, Minnesota, that Summit Blue is very familiar with, the societal DSM benefit-cost test results are only marginally better than the TRC test results[44]. In addition, externality hearings are generally contentious and time consuming, so may not be the best use of limited Provincial resources.

Recommendations:

- Calculate the Total Resource Cost (TRC) test to determine the program cost-effectiveness, and also calculate Rate Impact Test (RIM) to determine the impact of the DSM programs on customer rates and the Utility Cost Test (UCT) to determine the utility benefits.

5.3 Market Barriers Discussion

5.3.1 Importance to Program Design

Understanding and overcoming the market barriers to the installation of energy efficiency technologies and service is essential to success of any DSM program. Based on our preliminary analysis, the market barriers in Nova Scotia do not appear to be different than in other jurisdictions. However, if the programs are not achieving the expected participation rates, it may be necessary to conduct an evaluation of the barriers to energy efficiency technologies and services in Nova Scotia.

5.3.2 General Market Barriers

Understanding the reasons that more consumers do not adopt energy efficiency technologies and services is one of the fundamental issues in designing DSM programs. These reasons have been thoroughly studied over the past 20 years. The most cited of these studies was done for the California market.[45] This section will summarize the market barriers to energy efficiency identified in this study. It should be understood that not all these barriers apply to all energy efficiency technologies and services and that some of the barriers to certain technologies may be stronger than others.

When discussing market barriers to energy efficiency technology, first cost, or the incremental cost of the energy efficiency technology, is often cited as the main market barrier. For example, it is much less expensive to buy a 66¢ incandescent light bulb than to purchase a $3-$4 compact fluorescent lamp. In this discussion first cost is not included as a specific market barrier, but broken down into a number of distinct market barriers that can be addressed by strategies including lowering the first costs through incentives.

The first three market barriers are closely related to and stem from the fact that information is not perfect and is expensive. This includes knowledge of current and future prices, technology options and development, and all other factors that might influence the economies of a particular investment.

1. Lack of information and ability to use information - This barrier reflects the fact that sellers of energy-efficient products or services typically have more and better information about their offerings than do consumers. It also reflects the incentive that sellers have to provide misleading information. This market barrier is closely related to high information costs and performance uncertainties because obtaining the information required to assess claims adequately may be costly or impossible. This barrier is different from high information costs however, in that appropriate use of the information may require

[44] For Xcel Energy's 2005 program results, the overall societal test result was 8.51, compared to 8.13 for the TRC test result. So the societal test results are only 5% better than the TRC test results.

[45] "A Scoping Study on Energy efficiency Market Transformation by California Utility DSM Programs" by Joseph Eto, Ralph Prahl and Jeff Schlegel.

specialized knowledge held only by the vendor; thus, opportunism on the part of those with the specialized knowledge is a special concern.

2. Information or search costs - the costs (time and money) of identifying energy-efficient products or services or of learning about energy-efficient practices. Search costs can be thought of as costs of acquiring information.

3. Performance uncertainties - the difficulties consumers face in evaluating claims about future benefits, which are made for many energy efficiency investments and activities. In some cases it may be impossible to obtain the relevant information; one may not be able to generalize from existing information but instead must "experience" the energy performance as it is affected by one's own unique operating conditions, practices, or preferences.

4. Hassle or transaction costs - the indirect costs of acquiring energy efficiency and are also closely related to information or search costs. These costs include the time, materials, and labor involved in obtaining or contracting for an energy-efficient product or service. For example, the extra time and effort required to bring a contractor unfamiliar with a new technology up to speed.

5. Hidden costs - unexpected costs associated with reliance on or operation of energy-efficient products or services. These costs could include additional operating and maintenance costs associated with energy-efficient equipment or additional staff costs associated with monitoring or servicing transactions (e.g., contractor supervision). They might also include additional costs resulting from the quality of installation. Many of these unplanned costs are incurred after the acquisition of an energy-efficient product or service. They may also be thought of as performance uncertainties.

6. Access to bank financing - a result of the lending industry's inability to account for the unique features of loans for energy savings projects (i.e., that future reductions in utility bills increase the borrower's ability repay a loan) as distinct from the other factors affecting the evaluation of a borrower's credit-worthiness. This market barrier can be analyzed as reflecting lenders' uncertainty regarding the reliability of future savings and reflecting the additional costs associated with formally recognizing this feature of energy savings projects.

7. Individual practices (aka bounded rationality) - Everyone relies on “rules of thumb" to varying degrees. Rules of thumb serve to limit the focus or scope of considerations for a given decision. This barrier refers to the way in which individuals process and act (not necessarily logically) on whatever information they may have. This barrier is distinct from high search costs, performance uncertainties, and asymmetric information because more or better information alone may be insufficient to change behavior. This barrier is often evidenced by the phrase, “That’s how I have always done it.”

8. Organization practices or custom - organizational behavior or systems of practice that discourage or inhibit cost-effective energy efficiency decisions. This barrier is also closely related to hassle costs or subsequent hidden costs, which in this case might be faced by individuals acting within organizations. For example, institutional procurement rules, policies, and practices that make it difficult for organizations to act on energy efficiency decisions based on economic merit.

9. Misplaced or split incentives - institutional relationships which mean that the incentives of an agent charged with purchasing energy efficiency are not aligned with those of the persons who would benefit from the purchase. A common example of this barrier is renter versus building owner. The renter pays the utility bills, but the owner is responsible for upgrades to the building. The owner doesn’t want to pay for energy savings measures, because they won’t see the benefits and the renter doesn’t want to pay for the upgrades because they don’t own the building.

10. Product or service unavailability - Unavailability is a market barrier created by the manufacturers and distributors of products or service providers that inhibits consumer access to the product. Lack of supply and high consumer demand may result in higher prices. Distributors may face high search and acquisition costs in order to accurately anticipate demand or they may react according to their “rules of thumb” to predict future demand. As a result, they may limit shelf space for or not stock energy-efficient products. In addition, inefficient products may get periodically “dumped” in a market as the industry moves to new standards, which also creates a lack of availability of products.

11. Externalities – costs associated with transactions that are not included in the price paid in the transaction. For example, environmental costs associated with the generation of electricity by fossil fuel. For a market to operate efficiently, transactions must include the full costs, which include these externalities.

12. Lack of utility rates signals (i.e., nonexternality mispricing) – consumer rate (based on the average costs of generation and not the marginal costs) may not offer the consumer a price signal for investing in energy efficiency. For example, time of use rates encourage consumers to use energy during the off-peak period.

13. Inseparability of product features – inability to acquire desired energy efficiency features in products without also acquiring additional features. These additional features may be undesirable and increase the cost of the product beyond what the consumer is willing to pay for the energy efficiency features. For example, ENERGY STAR Refrigerators almost always include high-end features that lead to a retail price that is hundreds of dollars more than the incremental cost of making the refrigerator.

14. Irreversibility – It is often difficult to reverse the installation of energy-efficient products or services due to future information (lower fuel prices, better technology). This barrier is very difficult to overcome with conventional program interactions, but basic manufacturer research and development to change the characteristics of the product or services may overcome this barrier.

5.4 Summary of Findings and Recommendations

Based upon our experience, the benchmarking analysis, and DSM best practices, we developed a list of findings recommendations for a successful DSM plan. These findings and recommendations include:

1. NSPI should administer DSM programs, leveraging the work being done by Natural Resources Canada and the provincial government, while outsourcing much of the program delivery to local agencies. NSPI should position these programs as customer service programs and use them to help promote the NSPI brand.

2. Lost margins due to lower sales of electricity should be addressed through a reconciliation procedure (annual rate case or lost revenue recovery) or a decoupling of revenues by tying them to the number of customers and weather adjusted sales, so that it is not a disincentive to utility investment in DSM.

3. The regulators should offer additional incentives for meeting or exceeding DSM targets.

4. The spending on DSM programs should start at 0.7% of in-province electric revenues, and ramp up to 2% by 2010.

5. Review level of DSM spending every two years.

6. The DSM programs should provide rebates & incentives to overcome the high first cost market barrier.
7. The DSM plan should include programs for all sectors: residential, low-income, commercial, and industrial. Low-income program spending should be up to 10% of the overall residential program budget.
8. The NSPI DSM programs should only provide incentives for electricity savings measures.
9. Costs of the DSM programs should be allocated across the entire rate base.
10. Overcome the split incentive for low-income renters by working with the multifamily building owners to install DSM measures.
11. NSPI should expand their education and outreach efforts, not only as a means to increase awareness and knowledge, but to direct consumers to one of their programs.
12. The energy/demand savings from education and outreach should not be included in the overall portfolio impacts.
13. Funds for additional demand response program development and pilot programs should be included in the DSM portfolio.
14. Calculate the Total Resource Cost (TRC) test to determine the program cost-effectiveness, and also calculate Rate Impact Test (RIM) to determine the impact of the DSM programs on customer rates and the Utility Cost Test (UCT) to determine the utility benefits.
15. A more extensive avoided cost study than was used for this assignment should be considered in the next 2-3 years to better account for the total benefits of DSM measures. The deployment of these recommendations should proceed in the meantime.
16. In the next 1-2 years a more detailed DSM potential study should be performed, to better understand where the potential for savings in Nova Scotia exists. The potential study completed as part of this project provides a sufficient foundation from which to launch the initial DSM programs in Nova Scotia. A more detailed study will help focus these programs further.
17. NSPI should implement the programs using both in-house staff and outsourcing the delivery of services (for example weatherization services) to local community groups.
18. NSPI should promote and leverage Natural Resources Canada programs, including program delivery where possible.
19. Detailed evaluation plans should be developed for each of the programs. These plans should include the use of integrated data collection as part of the program administration, to help reduce the costs and uncertainty in future evaluation data collection.
20. A robust program data tracking system should be developed as part of the final DSM program development to ensure that the data needed for evaluation purposes is being collected.

APPENDIX A: SUMMARIES OF BENCHMARKED DSM PROGRAM PORTFOLIOS

Appendix A.1: BC Hydro

CHARACTERISTICS	
Type of Entity (e.g. investor-owned utility):	Integrated electric utility / Crown Corporation
Size (e.g. # of customers):	1.7 million
Generation Mix (%):	90 % hydro; 10 fossil-fuel (?)
Total MW capacity:	11,000 MW
Peak one-hour demand integrated system (MW)	9,437
Annual GWh Sale (includes trade)s:	51,205
Annual Revenue (year end Mar 31):	$3,725 m (2005) $4,311 (2006)
Sales to Major Customer Sectors (%):	32% Residential, 35% Light Industrial & Commercial, 32% Large Industrial, 4 % Other)
Industrial Intensities:	Lots of pulp & paper, not a heavy manufacturing centre
DSM BACKGROUND	
Approach, e.g. resource acquisition, market transformation, conservation culture: (Note any change in approach over time)	Mainly resource acquisition. Resource Expenditure & Acquisition Plan done every two years. BC Hydro assumes that by reducing barriers to EE, DSM programs can lead to market transformation, i.e. permanent changes in structure & functioning of markets including more EE behavior among customer and higher market penetration of EE products. Selected programs in residential and commercial/government sectors are assumed to trigger market transformation, and associated electricity savings are attributed to the program No market transformation assumed in industrial sector.
Type of Programs (e.g. EE, DR, LM, etc.)	Energy efficiency and fuel switching
Year Programs Started:	2003
Time to Set up Infrastructure:	Already had infrastructure in place from previous DSM activities.
When Significant Savings were Noted:	2003
DSM EVALUATION	
Evaluation Practices:	BC Hydro determines the impact of DSM programs as follows: A complete evaluation plan is prepared. The actual evaluations are conducted at major milestones or at program completion. Process, market, and impact evaluations are conducted, and are overseen by a BC Hydro cross-functional DSM Evaluation Oversight Team. In addition, for programs that include larger individual projects (i.e., > 0.3 GWh/year), technical & financial reviews are conducted before an incentive is offered to provide assurance the technology is feasible, the estimated electricity savings are reasonable, and the cost-effectiveness is acceptable. A complete plan is also put in place for measurement & verification (M&V) of savings to assure that a baseline is established and that M&V of actual savings is practical. Post completion inspections are conducted for all significant

	projects and a sample of smaller projects.
Cost-effectiveness Tests:	TRC benefits must be > total costs, RIM must be > 0.8, calculate UCT
COST RECOVERY & INCENTIVES	
Methods & Mechanisms:	BC Hydro capitalizes virtually all of its costs with all DSM costs are included in customer rates. No performance incentives are provided.
Customer Class Allocation:	Fixed
Performance Incentives for utilities/agencies:	None. DSM is considered the most cost-effective resource in the integrated plan process.
DSM PROGRAM DESCRIPTIONS	
Residential:	New Home Program stimulates EE product installations in new homes through builder rebates to install Power Smart Packages, customer education, & maintaining energy building code standards. Renovation Rebate educates homeowners of electric heated homes who are considering renovations about the areas of greatest heat loss from the average home and how this heat loss can be reduced. Variable Speed Motors (VSMs) partners with NRCAN to offer rebates to increase penetration of high-efficiency VSMs into gas furnace market, and partners with Terasen Gas to deliver the program. Fuel Substitution focuses on builders in areas of low gas penetration to encourage installation of gas furnaces in new homes and promotes gas water heaters and stoves to existing homeowners. Refrigerator Buy-Back offers an incentive and free pick up and environmental disposal of inefficient second refrigerators Seasonal LED promotes LED lighting by initially offering free samples and now providing consumer rebates and educational advertising; program staff work directly with manufacturers & retailers. CFL Lighting was initially promoted with giveaway events & coupons and advertising but emphasis is now focused on coupons and advertising; program staff work directly with manufacturers & retailers. Enabling Initiatives – Residential support programs in achieving energy acquisition and market transformation goals and include a Retail Initiative (coupons) and a Home Energy Profile.
Commercial:	Power Smart Partners – Commercial & Government, a direct energy acquisition program based on partnering with top customers, provides financial support and help to identify and electricity savings. Schools, Universities, Colleges and Hospitals is same as PS Partners but fully funded by BC Hydro. Power Smart Product Incentive Program offers incentives to install select products that save energy and can easily replace existing, less efficient products. Lighting Redesign offers incentives for lighting redesign studies and installing energy-saving lighting and education and skills training for the design industry and partners. Small Business CFL Lighting involves distribution coupons and educational material to small business customers to encourage the adoption of CFL bulbs and to inform customers of their benefits. High Performance Buildings, an energy acquisition/market transformation program to accelerate demand and production of new C&I energy-efficient buildings & plants, provides tools & financial incentives, education and training, and promotional campaigns. Enabling Initiatives – Industrial, Commercial & Government, support programs in achieving goals and include Power Smart Alliance, e.Catalog, Information Gateway, and Standards.
Institutional:	Covered under Commercial
Industrial:	Power Smart Partners – Industrial, a direct energy acquisition program based on partnering with top industrial customers, provides financial support and help to identify and implement electricity savings. High Performance Buildings – covered under Commercial.
Other	Public Awareness & Communications includes: 1) Power Smart Outreach; 2) Public education & advertising; 3) Primary & secondary school education; 4) Sponsorships & events; 5) public relations; 6) Internet; 7) Key customer recognition; and 8) Power Smart Information telephone line

Appendix A.2: Hydro Quebec

CHARACTERISTICS	
Type of Entity (e.g. investor-owned utility):	Vertically integrated electric utility - Crown Corp.
Size (e.g. # of customers):	3,753 million
Generation Mix (%):	95 % hydro, 5% fossil
Total MW capacity:	34,571
Average Peak MW Demand:	N/A
Annual GWh Sales:	169,200,000 (15.3 TWh Exported)
Annual Revenue:	$4,480 million (HQ Distribution)
Sales to Major Customer Sectors (%):	34% Residential & farm, 20 % General & Institutional, 43 % Industrial, 3 % Other.
Industrial Intensities:	Aluminum, mines, P&P, manufacturing

DSM BACKGROUND	
Approach, e.g. resource acquisition, market transformation, conservation culture: *(Note any change in approach over time)*	Generally resource acquisition. Have been increasing targets on a regular basis.
Type of Programs (e.g. EE, DR, LM, etc.)	Energy efficiency
Year Programs Started:	2003
Time to Set up Infrastructure:	1.5 years
When Significant Savings were Noted:	2004
Other:	

DSM EVALUATION	
Evaluation Practices:	Evaluations are done by third parties – US experts hired to transfer knowledge to Quebec players.
Cost-effectiveness Tests:	Not used.
Other Results (measure saturations, customer satisfaction, etc.)	Now tracking customer satisfaction, participation, & penetration rates.

COST RECOVERY & INCENTIVES	
Methods & Mechanisms:	Recovered through rates.
Customer Class Allocation:	n/a
Performance Incentives for utilities/agencies:	n/a

DSM PROGRAM DESCRIPTIONS	
Residential:	Energy Wise Home Diagnostic – diagnosis of home energy use and potential savings either by mail or online. New Home – Novoclimat provides subsidies for new single family electrically heated homes built to Novaclimat standards as established by Québec's Agence de l'efficacité énergétique. EnerGuide for Homes – provides grants for audits of existing homes; grants were previously provided by NRCan. Low-income Program – started in 1999, the program provides free installation of energy savings equipment & measures for low-income consumers, e.g. caulking. Retrofit Social & Community Housing facilitates implementing basic energy efficiency measures and other systems as part of renovations of social & community housing, e.g. building envelope, electromechanical systems, conditioning common spaces & utility rooms. Energy Star Products – informational advertising about Energy Star Products.
Commercial:	Business Empower Program provides financial incentives to incorporate energy-efficient designs and equipment in new buildings and major retrofits (includes HQ buildings). Efficient Products – provides financial incentives for energy-efficient equipment such as motors, lighting & traffic signals. Industry Empower Program – provides financial incentives to small and medium sized industries to energy-efficient measures and systems.
Institutional:	Covered under Commercial.
Industrial:	Covered under Commercial
Large Companies:	Financing – loans and other financing options for energy-efficient projects. Research & Demonstrations – provides financial assistance for feasibility studies (50% of costs up to $25,000) and to demonstrate new energy savings technologies or systems. Chain Accounts customized energy saving program

Appendix A.3: Manitoba Hydro

CHARACTERISTICS	
Type of Entity (e.g. investor-owned utility):	Crown Corporation
Size (e.g. # of customers):	443,000 residential customers
Generation Mix (%):	95% hydro, 5% other
Total MW capacity:	5,480
Average Peak MW Demand:	4,146
Annual GWh Sales:	19,781 retail
Annual Electric Revenue:	$1.5 billion
Sales to Major Customer Sectors (%):	68% of sales to C&I customers, 32% to residential customers
Industrial Intensities:	NA

DSM BACKGROUND	
Approach, e.g. resource acquisition, market transformation, conservation culture: *(Note any change in approach over time)*	Resource acquisition and market transformation
Type of Programs (e.g. EE, DR, LM, etc.)	EE, DR, LM
Year Programs Started:	1989
Time to Set up Infrastructure:	Gradually between 1989 and 1991
When Significant Savings were Noted:	1991
Other:	

DSM EVALUATION	
Evaluation Practices:	Conduct regular but not annual process, impact and market evaluations.
Cost-effectiveness Tests:	Primarily use and report on TRC and RIM tests.
Other Results (measure saturations, customer satisfaction, etc.)	NA

COST RECOVERY & INCENTIVES	
Methods & Mechanisms:	NA
Customer Class Allocation:	NA
Performance Incentives for utilities/agencies:	NA

Electric DSM PROGRAM DESCRIPTIONS	
Residential:	Insulation Rebate Program—offers customers information and rebates for installing insulation that covers 90%-100% of the material cost. New Construction Program—provides prescriptive Power Smart standards and incentives to install EE measures in new homes. CFL Lighting Program—promote CFLs through a buy one, get two free promotion. Refrigerator Buy-Back (new program)—information, incentives, and disposal services to help customers remove older and secondary refrigerators. Thermostat Program (new program)—provide information and incentives that will cover 50%-80% of the cost of an electronic thermostat and 25%-50% of the cost of a line voltage thermostat. Energy Star Appliances (new program)—covers clothes washers, refrigerators, freezers, and dishwashers. Provides information on Energy Star and incentives aimed at offsetting sales taxes on units. Water and Energy Saver Package Program (new program)—provide a free package of low cost water and energy conservation measures, including low-flow showerheads, pipe insulation, heat traps, and faucet aerators. ECM Furnace Motors (new program)—information and rebates to promote EE furnace motors. Geothermal Earth Power (new program)—provides information and rebates for ground source HP units to customers. Also a focus on increasing the number of contractors that carry the product. Power Smart Residential Home Comfort Program (new program)—provides loans for the purchase of EE products. MH also offers the following customer service related EE programs that are not described further in their filing: • EnergyGuide for Houses In Home Energy Evaluation Program (existing homes) • EnerGuide for Houses New Home Energy Evaluation Program • Power Smart Do-It-Yourself Home Assessments (Online and Mail-in) • WISE (Wisdom In Saving Energy) Program • Power Smart R 2000 Program • New Homes Energy Workshops • Existing Homes Energy Workshops • Consumer Information Services • Power Smart "Energy Expert"
Commercial:	Commercial Parking Lot Lighting—information and incentives to promote parking lot control sensors. Commercial Lighting Program—provide information and rebates that cover 75%-84% of incremental costs to install EE lighting systems. Internal Retrofit Program—information and incentives to MH building to upgrade the efficiency of their energy using equipment. Commercial Custom—information and rebates for non-prescriptive DSM measures. Offers incentive of 24 cents/kWh, which covers about 69% of incremental costs. Commercial Chillers—education and rebates that cover about 100% of incremental costs for EE chillers. Commercial Air Conditioners-- education and rebates that cover about 100% of incremental costs for EE rooftop AC units. Commercial Recommissioning and Audit Program—energy audits are the first step of the

	program. Recommissioning analyses also offered to qualified customers. Commercial Air Barrier Activities—educates designers and customers about the importance of air barriers for electric heated new construction, and provides incentives that cover about 35% of the incremental costs. Agricultural Heat Pads—provides information and rebates to encourage the installation of efficient heat pads instead of less efficient heat lamps. Commercial Windows—education and rebates that cover 100% of incremental costs for EE windows installed in new construction and renovation projects. Commercial Vending Machine Sensor Program—information and rebates to promote vending machine sensors. Geothermal Heat Pumps—provides rebates for EE units. MH also provides the following “cost recovery” program which are not further described in their filing: • Power Smart Energy Manager • Government Services Financing Program • Religious Building Initiative MH also provides the following EE related customer service programs: • Recreation Facility Mail-In Energy Assessment • Customer Information Sheets • Engineering Expertise
Institutional:	Same as commercial.
Industrial:	Quality Motors Repair Program—information and rebates that cover 100% of incremental costs to improve the quality and EE of motor repairs. Performance Optimization—provides information and incentives for four initiatives: • Custom Engineered Solutions: custom rebate program for air compressors, pumps, fans, and process systems. • Eco-efficiency Audits and Feasibility Studies. • Energy management systems. • Waste stream thermal recovery. Curtailable Rates Program—interruptible rates program for large industrial customers with 5 MW of more of load, who can reduce their load during peak periods with five minutes or one hour’s notice. Industrial and Commercial Generated Power Service Program—offers qualified customers a monthly credit for load displacement caused by customer-owned generators that can be dispatched by MH. Studying TOU and inverted rates for possible implementation in the future. MH also provides the following EE related customer service programs: • Customer Information Sheets • Industrial Technology Workshops • Engineering Expertise: building envelope and infrastructure, process and motive power systems, on-site generation and heat recovery, power quality analysis.

Appendix A.4: Efficiency Vermont

CHARACTERISTICS	
Type of Entity (e.g. investor-owned utility):	Third party administrator – Non-profit
Size (e.g. # of customers):	343,160 *(Source: EIA 2004)*
Generation Mix (%):	Nuclear 70%; Hydro 22%; Other renewable 8% *(Source: EIA 2004)*
Total MW capacity:	1,997 *(Source: EIA 2004)*
Average Peak MW Demand:	n/a
Annual GWh Sales:	11,327 *(Source: EIA 2004)*
Annual Revenue:	$624,332,000 *(Source: EIA 2004)*
Sales to Major Customer Sectors (%):	37% Res; 35% Com. 28% Ind *(Source: EIA 2004)*
Industrial Intensities:	n/a

DSM BACKGROUND	
Approach, e.g. resource acquisition, market transformation, conservation culture: *(Note any change in approach over time)*	Market-based approach to market transformation
Type of Programs (e.g. EE, DR, LM, etc.)	EE
Year Programs Started:	2000
Time to Set up Infrastructure:	1
When Significant Savings were Noted:	67% increase in savings during the second year of the program than 12% average increase in savings over the next 5 years.
Other:	

DSM EVALUATION	
Evaluation Practices:	DPS evaluates EVT savings claims and makes a recommendation to the Contract Administrator, a private contractor that resolves any disputes surrounding the claims and makes recommendations to the Board. The Board makes the final determination about EVT's performance and awards incentives accordingly. Incentives are given for other performance categories (e.g., equity and pipeline projects) in which the same verification process is followed, but performance is evaluated every three years. Savings and cost-effectiveness claims are verified every three years by an independent auditor. DPS conducts process and market assessments as necessary.
Cost-effectiveness Tests:	Societal Cost Test
Other Results (measure saturations, customer satisfaction, etc.)	

COST RECOVERY & INCENTIVES	
Methods & Mechanisms:	DSM costs by EVT are expensed. Utilities collect the money as a percentage charge on electric bills. Funds are transferred

	to a manager, where they are drawn for appropriate purposes by EVT and for EVT support activities. For efficiency that is conducted as part of DUP, there is a lost revenue recovery mechanism called Account Correcting for Efficiency, or ACE. This mechanism removes the disincentive for the utility to pursue energy efficiency.
Customer Class Allocation:	20% of Savings from Industrial Customers 50% of Non-residential project at small businesses
Performance Incentives for utilities/agencies:	EVT receives performance incentives based on its performance in categories such as total electricity savings, total resource benefits, peak summer savings, geographic equity, etc. (see below). Incentive awards are scaled. EVT must meet minimum targets in order to receive any award. Meeting 100% of the target results in receiving 100% of the award for that category. Targets are designed to be "stretch targets" to encourage EVT to pursue ambitious goals. Higher performance in a given category can result in higher levels of incentives, but the total incentive is capped at pre-determined levels ($1.25 million in 2004). 2006-2008 program cycle: 204,000 MWh savings; 30 MW peak demand reductions; 81,600 peak summer MWh savings; 10,600 annual MWh of committed projects; $111 million net social benefits to VT; $1.70 of value for each dollar committed by each county; 3 community-based projects with over 50% community participation; 40,000 MWh savings from industrial customers; 50% of non-res projects completed by small businesses; 40 large grocery stores to stock and promote sale of CFLs; $1.20 in avoided costs for each dollar spent by the state toward the EEC; at least 15% spending on low-income projects.

2004 Performance Indicators	% of Total Incentive	Up to (millons)
Annual Energy	35%	$0.44
TRB	35%	$0.44
Under Dev. Projects	5%	$0.06
Summer Peak kW	5%	$0.06
Residential Service	5%	$0.06
Business Services	10%	$0.13
Geographic Equity	5%	$0.06
Total	100%	$1.25

DSM PROGRAM DESCRIPTIONS	
Residential:	**Residential New Construction** works with builders and buyers of new homes to encourage the incorporation of approaches that improve building performance and energy efficiency. Provides technical assistance, plan reviews, on-site inspections, performance testing, energy ratings and ENERGY STAR labeling for qualified homes. Integrated energy code and code support into these services to this market to help sustain code and beyond-code practices in outreach to builders. **Residential Existing** focuses on the acquisition of cost-effective energy savings and supporting market transformation. Offer services to all Vermont households, with targeted activities serving low-income single family homes and households with high electric usage. Supports retailers, contractors and renovators to give Vermont households access to an increasingly knowledgeable network of trades people and professionals who provide products, guidance and services that make Vermont homes more energy-efficient. **Efficient Products** promotes ENERGY STAR qualified products and to strengthen relationships with retailers, wholesale vendors and manufacturers of energy-efficient products, provides financial incentives for ENERGY STAR qualified compact fluorescent light bulbs, lighting fixtures, ceiling fans with lights, clothes washers, room air conditioners, freezers and refrigerators.
Commercial:	**Business New Construction** offers customized comprehensive design assistance to support the vision of designers and owners while integrating optimal energy-efficient approaches; review of architectural and engineering plans and contractor designs coupled with consultation on energy efficiency opportunities; energy analysis of buildings and measures; financial incentives for cost-effective energy-efficient approaches; outreach to businesses with new construction projects listed weekly on Works in Progress and in the Act 250 process; and informational resources that aid design professionals and design-build contractors in their hands-on work and that communicate the benefits of high performance design concepts to their prospective and current customers. **Business Existing Building** offers businesses a simple, easy-to-use prescriptive application process and standardized financial incentives to businesses engaging in qualifying equipment upgrades, as well as a customized services including detailed technical analysis and partnering with third parties to procure technical design assistance as well as cash flow analysis with financing options to help meet the unique investment criteria of each business.
Institutional:	Part of Commercial programs
Industrial:	Part of Commercial programs

Appendix A.5: New Jersey Office of Clean Energy

CHARACTERISTICS	
Type of Entity (e.g. investor-owned utility):	Run by 7 electric and gas utilities
Size (e.g. # of customers):	3,775,980 *(Source: EIA 2004)*
Generation Mix (%):	Nuclear 48.46%; Natural Gas 28.61%; Coal 18.47%; Petroleum 2.49%; Other Renewables 2.33% *(Source: EIA 2004)*
Total MW capacity:	18,165 *(Source: EIA 2004)*
Average Peak MW Demand:	N/A
Annual GWh Sales:	95,148 *(Source: EIA 2004)*
Annual Revenue:	$7,984,416,000 *(Source: EIA 2004)*
Sales to Major Customer Sectors (%):	Res 36%, Com 49%, Ind 14% *(Source: EIA 2004)*
Industrial Intensities:	
DSM BACKGROUND	
Approach, e.g. resource acquisition, market transformation, conservation culture: *(Note any change in approach over time)*	The NJ approach placed more emphasis on market transformation over the past 4 years. In 2003 the NJ BPU decided to have third-parties manage the portfolio of programs. As of this writing this transition is still in progress.
Type of Programs (e.g. EE, DR, LM, etc.)	Energy efficiency, renewable energy and
Year Programs Started:	Early 1980's
Time to Set up Infrastructure:	2 years
When Significant Savings were Noted:	n/a
DSM EVALUATION	
Evaluation Practices:	The New Jersey Office of Clean Energy has engaged Rutgers University's Center for Energy, Economic and Environmental Policy (CEEEP) to manage evaluation and related research activities. CEEEP develops evaluation and related research plans, with input on the plans from the OCE, the Clean Energy Council, program managers and others. Once plans are approved by the OCE, CEEEP either perform the evaluation and research activities or engages third-party contractors through RFPs. The approved 2005 Evaluation and Related Research Plan includes: • Market Assessment: The market assessment planned for 2005 gathered information regarding the state of the energy efficiency marketplace in New Jersey to help inform program designs and incentive levels. • Impact Evaluation: Protocols are used to estimate the savings from energy efficiency measures and generation from renewable energy facilities. An impact evaluation contractor has been engaged to measure actual savings or generation which will be used to update protocols.
Cost-effectiveness Tests:	Total Resource Cost Test
Other Results (measure saturations, customer satisfaction, etc.)	

COST RECOVERY & INCENTIVES	
Methods & Mechanisms:	Costs are recovered through a systems benefit charge collected through a fuel adjustment clause. Costs are expensed and deferred accounting with pass through is to be used until 2006.
Customer Class Allocation:	n/a
Performance Incentives for utilities/agencies:	New Jersey currently has no incentives for utilities to participate in DSM. The electric power industry in New Jersey has been restructured such that the utilities now are wires companies only and no longer build, own or operate electric generation. The Board is transferring responsibility for program administration to the OCE and will hire program mangers to deliver most of the programs. It is anticipated that the entities engaged to serve as program managers will be provided with financial incentives to deliver certain levels of energy savings.

DSM PROGRAM DESCRIPTIONS	
Residential:	**Residential HVAC electric/gas** This program combines the previous COOLAdvantage and WARMAdvantage Programs. The goal of this program is to improve the energy efficiency of new electric central air conditioners and heat pumps. The Program promotes both the sale of qualifying energy-efficient equipment and improvements in proper system sizing and installation "best practices" that affect operating efficiency. To this end, the Program provides rebates towards the purchase and installation of energy-efficient electric central air conditioners or heat pumps. This Program also is designed to promote the purchase of high efficiency natural gas home heating systems and/or water heaters. To this end, the Program also provides rebates towards the purchase of qualifying high-efficiency natural gas equipment. **New Jersey ENERGY STAR Homes Program** A New Jersey ENERGY STAR Home is certified by the Environmental Protection Agency (EPA) to be at least 30% more energy-efficient than a standard home. The New Jersey ENERGY STAR Homes program is part of the larger EPA ENERGY STAR program developed to promote energy-wise products and programs that help consumers save money while protecting the environment. Incentives are provide to the builder to promote this high level of energy efficiency. **ENERGY STAR Products** This program offers incentives for the purchase of high efficiency, ENERGY STAR qualified, lighting and appliances. The incentives may be in the form of manufacturer buy downs (lighting) and/or rebates. The program currently promotes: lighting, room air conditioners, refrigerators, clothes washers and clothes dryers. **Residential Low-income** This Program is designed to improve energy affordability for income eligible households. This objective is accomplished through the direct installation of energy efficiency measures, personalized customer energy education and counseling. Participants are asked to partner with the program to develop and carry out a household energy savings Action Plan.
Commercial:	**C/I Construction** New Jersey's Clean Energy Programs offer commercial and industrial customers design support, technical support and incentives to improve construction, renovation and equipment upgrade projects. This includes both new construction and retrofit projects. The program also focus on new construction and renovation projects in schools. **Combined Heat and Power** Provides financial incentives for Combined Heat & Power (CHP) installations to enhance energy efficiency. This program also offers qualifying customers, contractors and energy service companies financial incentives to buy and install various Combined Heat & Power units.
Institutional:	*Included in commercial*
Industrial:	*Included in commercial*

Appendix A.6: New York State Energy & Research Development Agency (NYSERDA)

CHARACTERISTICS	
Type of Entity (e.g. investor-owned utility):	public benefit corporation created in 1975 by the New York State Legislature.
Size (e.g. # of customers):	7,786,682 *(Source: EIA 2004 Data)*
Generation Mix (%):	Nuclear 29.46%; Natural Gas 19.81%; Hydro 17.39%; Coal 16.57%; Petroleum 15.34%; Other Renewables 2.04% *(Source: EIA 2004 Data)*
Total MW capacity:	37,843 *(Source: EIA 2004 Data)*
Average Peak MW Demand:	N/A
Annual GWh Sales:	290,163 *(Source: EIA 2004 Data)*
Annual Revenue:	$18,209,096,000 *(Source: EIA 2004 Data)*
Sales to Major Customer Sectors (%):	Res. 33%, Com. 51%, Ind. 14% *(Source: EIA 2004 Data)*
Industrial Intensities:	
DSM BACKGROUND	
Approach, e.g. resource acquisition, market transformation, conservation culture: *(Note any change in approach over time)*	Programs are integrated on many levels by sharing customers, addressing common barriers, and seeking to accomplish common program objectives. Moreover, individual markets might be influenced by several NYSERDA programs. Programs have both resource acquisition and market transformation goals.
Type of Programs (e.g. EE, DR, LM, etc.)	Energy efficiency and demand response
Year Programs Started:	1998
Time to Set up Infrastructure:	2 years
When Significant Savings were Noted:	Within first year.
DSM EVALUATION	
Evaluation Practices:	NYSERDA's evaluation function is conducted primarily by a team of independent evaluation contractors. All contractors were selected through competitive solicitation with a member of the Advisory Group and DPS staff serving on each review panel. The Advisory Group and DPS staff help allocate the evaluation budget, identify evaluation activities to be conducted, and establish timelines for evaluation activities. These evaluation activities include process evaluations, impact evaluation, attribution evaluation, market assessments and measurement and verification.
Cost-effectiveness Tests:	In the recent evaluation of programs the NYSERDA evaluation team utilized eight scenarios to calculate benefit-cost tests, because there is not universal agreement on the most appropriate method to calculate benefit-cost ratios for energy efficiency programs.

COST RECOVERY & INCENTIVES	
Methods & Mechanisms:	Costs are recovered through a system benefits charge and expensed. Utilities collect the funds from customers through rates and remit them to NYSERDA. Sometimes utilities keep some of the funds, for example, Rochester G&E had a lot of ESCO contract obligations so the utility keeps some of the funds to pay for these. Least cost planning can be used in specific rate cases, e.g. Con Ed - targeted DSM program for MW relief- system wide program that can be funded with incremental dollars to the SBC charge - 25% of power to come from renewable resources (now at about 18 % from water).
Customer Class Allocation:	n/a
Performance Incentives for utilities/agencies:	n/a

DSM PROGRAM DESCRIPTIONS	
Residential:	**ENERGY STAR® Products & Residential ENERGY STAR® Marketing Programs**. These two programs work in tandem to increase awareness, understanding, stocking, promotion, and sales of ENERGY STAR® Products. These programs target the following 16 appliances and lighting products: refrigerators, dishwashers, clothes washers, room air conditioners and through-the-wall (TTW) units, compact fluorescent light bulbs (CFLs), suspended lighting fixtures, portable fixtures, ceiling-mounted fixtures, wall-mounted fixtures, recessed fixtures, exterior fixtures, cabinet integrated fixtures, ceiling fans, dehumidifiers, and freezers. **Keep Cool Program.** This program encourages the replacement of old, working air conditioners with ENERGY STAR®- labeled room air conditioners and TTW units. Turned-in units are permanently removed from service and are de-manufactured and recycled. This program is coupled with a multi-media marketing campaign encouraging consumers to follow three specific energy tips during the summer months: (1) buy ENERGY STAR® products, (2) shift appliance use to non-peak periods, and (3) use timers or programmable thermostats on air conditioners. Due to the success of the program, the bounty program ceased after 2003. The marketing component was continued in 2004 and the program was renamed Stay Cool!. **New York ENERGY STAR® Labeled Homes (NYESLH) Program**. This program is an enhanced version of the EPA's ENERGY STAR® Labeled Homes Program, providing technical assistance and financial incentives to one- to four-family home builders and Home Energy Rating System (HERS) raters. The program encourages the adoption of energy-efficient design features and the selection and installation of more energy-efficient equipment in new construction and substantial renovation projects. **Home Performance with ENERGY STAR® (HPwES) Program**. This program is designed to enhance the capacity for delivering energy efficiency services to existing one-to four-family residences. Energy efficiency improvements supported by the program include building shell measures; electric measures, such as refrigerators and lighting fixtures; heating and cooling measures, such as boilers and central air conditioning; and renewable energy technologies, such as photovoltaics. **ENERGY STAR® Products Bulk Purchase Program.** This program provides purchase assistance for early replacement of inefficient appliances through education, bulk procurement, and incentives in order to influence market transformation in the multifamily sector. Bulk purchase activities were originally part of the Appliances and Lighting Program, but became a separate program in 2002. Incentives were discontinued in 2003. **Residential Comprehensive Energy Management Program**. This program promotes the acquisition and installation of sophisticated energy management and advanced metering systems. This program helps position residential customers to take advantage of retail competition, while enabling program implementers access to customers' energy-use data.

	Residential Technical Assistance Program. This program improves the operation of multifamily housing by identifying and encouraging the implementation of cost-effective energy efficiency measures that also enhance health, safety, and comfort. Activities supported include: feasibility studies, computer-assisted building modeling; energy efficiency technical training, and commissioning. **Energy $mart Communities Program**. The program was developed to complement the Department of Energy **Rebuild America** Program. Energy $mart Communities targets regional needs by bringing together organizations and agencies that contribute to local "model" projects demonstrating how energy efficiency and energy resource approaches can be used to create economic, social and environmental benefits. To transfer the success of these model projects to the rest of the region, this program provides information and support at the local level to individuals and organizations interested in energy efficiency and **New York Energy $martSM** programs. **Residential Special Promotions Program.** The program seeks to increase the availability, promotion, and sale of energy-efficient products and services by implementing promotions in markets not currently addressed through other marketing activities. This program is designed to influence the behavior of up-stream and mid-stream market participants, as well as residential Specific Low-income programs include: **Assisted Multifamily Program.** This program is designed to improve energy efficiency in eligible multifamily buildings, reduce energy bills for tenants and owners, and provide increased health and safety benefits to building occupants. **Assisted Home Performance with ENERGY STAR®.** This program is designed to reduce the energy burden on low-income New York residents by bringing a "building performance" approach to home improvement. The program follows a market transformation model first introduced by the Home Performance with ENERGY STAR® Program. **Low-Income Direct Installation.** This program, now closed, was designed to improve energy efficiency for low-income households by installing electric reduction measures in homes receiving shell and heating system improvements through the federal Weatherization Assistance Program at a time when electric reduction measures were ineligible. **Weatherization Network Initiative.** This program is built on the lessons learned in the Low-Income Direct Installation Program. It returns to previously weatherized homes to implement electric measures in one- to four-family homes that did not receive electric reduction measures through the Weatherization Assistance Program and are currently ineligible for additional services. **Low-Income Oil Buying Strategies.** This program is designed to improve energy affordability for low-income customers through the bulk purchase of home heating fuel and other procurements that reduce the price of fuel oil. **Low-Income Energy Awareness.** This program is designed to implement a public awareness campaign to result in measurable improvements in the enrollment of low-income residents in energy efficiency and energy management programs. **Low-Income Aggregation.** This program is designed to improve energy affordability for low-income customers by grouping them together and increasing their buying power, to take advantage of reduced commodity prices through the bulk purchase of energy. **Low-Income Forum on Energy (LIFE).** This program provides one of the largest and most comprehensive public forums dedicated to discussing the issues facing the low-income population in the changing energy environment.
Commercial:	**New Construction Program** encourages energy-efficient design and building practices among architects and engineers, and urges them to inform building owners about the long-term advantages of building to higher energy standards. **Commercial/Industrial Performance Program** provides incentives to energy service companies (ESCOs) and other contractors to install energy efficiency capital improvements. **Peak-Load Reduction Program** provides incentives to identify and implement measures to reduce electric load during periods of peak electric demand. Incentives are available for four

	categories of measures: 1) permanent demand reduction, 2) load curtailment and shifting, 3) dispatchable emergency generation, and 4) interval meters. **Enabling Technology Program** supports innovative technologies that enhance the capabilities of load serving entities, curtailment service providers and New York Independent System Operator (NYISO) direct customers to reduce electricity load in response to emergency and/or market-based price signals. The projects in the program, funded as R&D demonstration projects, have provided significant contributions to the amount of curtailable load available. **Technical Assistance Program, including the FlexTech and Energy Audit Programs,** funds detailed energy studies by customer-selected or NYSERDA-contracted consultants. It includes energy feasibility studies, energy operations management, and rate analysis and aggregation. These three program components, which were once managed separately, are now offered as one solicitation. **Smart Equipment Choices Program** is an expansion of the pre-qualified equipment component offered under the New Construction Program, and was designed to encourage the installation of high-efficiency measures through incentives at the time of retrofit or replacement to improve the energy efficiency of existing electrical loads. **New York Energy $mart^{SM} Loan Fund** provides reduced-interest financing for energy efficiency measures and related facility improvements
Institutional:	*Included in Commercial*
Industrial:	*Included in Commercial*
Other:	*Included in Commercial*

Appendix A.7: Xcel Energy (Minnesota)

CHARACTERISTICS	
Type of Entity (e.g. investor-owned utility):	IOU
Size (e.g. # of customers):	1.06 million residential customers
Generation Mix (%):	Approx 50% coal, 40% nuclear, 10% other
Total MW capacity:	NA
Average Peak MW Demand:	6,300
Annual GWh Sales:	30.4 TWh retail
Annual Revenue:	$1.89 billion
Sales to Major Customer Sectors (%):	73% of sales to C&I customers, 27% to residential customers
Industrial Intensities:	Somewhat light industrial
DSM BACKGROUND	
Approach, e.g. resource acquisition, market transformation, conservation culture: *(Note any change in approach over time)*	Resource acquisition
Type of Programs (e.g. EE, DR, LM, etc.)	EE, DR, LM
Year Programs Started:	LM in 1967, electric EE in 1982
Time to Set up Infrastructure:	Gradually between 1982 and 1990
When Significant Savings were Noted:	About 1990, but that was due to increased state DSM requirements.
Other:	Have to file IRPs every two years and DSM plans every three years with state regulators.
DSM EVALUATION	
Evaluation Practices:	Conduct regular but not annual process and impact evaluations. Conduct market evaluations/DSM potential studies about every 5-10 years.
Cost-effectiveness Tests:	Use all 5 standard CA stakeholder tests.
Other Results (measure saturations, customer satisfaction, etc.)	Estimate measure saturations as part of DSM potential studies.
COST RECOVERY & INCENTIVES	
Methods & Mechanisms:	DSM costs recovered through deferred accounts. Program cost recovery mechanism is flat addition to the Company's fuel adjustment mechanism.
Customer Class Allocation:	DSM cost recovery charge the same for all rate classes.
Performance Incentives for utilities/agencies:	Performance incentive of up to 30% of direct DSM program costs possible, generally for achieving about 150% of overall approved DSM goal. Used to recover "lost margins" due to DSM, up to 1999.

Electric DSM PROGRAM DESCRIPTIONS	
Residential:	Central Air Conditioner (and ground source heat pump) Quality Installation Program—rebates for customers purchasing an EE unit that is installed by a qualifying contractor. Consumer Education about EE—home shows, publications, and online resources. Home Efficiency new construction EE program—rebates for customers installing a package of electric measures. Home Energy Audit—online, on-site, and infrared analysis audit options offered. Home Lighting—promotion of CFLs through a catalog and rebates. Home Performance Rebates (with Energy Star)—Rebates for implementing a package of EE measures in existing homes. Saver's Switch direct load control program—offers a 15% summer bill discount for cycling customers' air conditioners on peak days, plus a 2% monthly electric bill discount for customers who allow their electric water heaters to be cycled. Low-income Energy Services—free weatherization, appliance replacement, and other measures for qualified low-income customers.
Commercial:	Compressed Air Efficiency—Rebates for studies and upgrades for compressor systems. Computer Efficiency (New Program)—rebates for computers with efficient power supplies, Cooling Efficiency—Rebates and engineering analysis for efficient cooling equipment. Custom Efficiency—engineering assistance and rebates for non-prescriptive EE measures. Energy Analysis—online, on-site, and Energy Star buildings analysis/audit options offered. Energy Design Assistance—design assistance and rebates for EE measures for new buildings that are larger than 50,000 sq.ft. Energy Management Systems--engineering analysis and rebates for installing EMS systems. Lighting Efficiency—lighting redesign studies and rebates to install EE lighting systems. Motor Efficiency—rebates for EE motors and variable frequency drives. Recommissioning—engineering analysis and rebates for recommissioning projects. Electric Rate Savings—interruptible rates program for customers who can reduce their loads by at least 50 kW on peak days. Saver's Switch—Commercial version of similar residential program, but limited to central air conditioners.
Institutional:	Same as commercial.
Industrial:	Same as commercial, plus: Industrial Efficiency (new program)—Process efficiency energy analysis, plus a bidding process for customers to request specific assistance and incentives to implement EE measures.
Other:	Planning and Research—DSM training, regulatory compliance, product development, and market research/evaluations.

Appendix A.8: Otter Tail Power, Minnesota

CHARACTERISTICS	
Type of Entity (e.g. investor-owned utility):	IOU
Size (e.g. # of customers):	46 thousand residential customers
Generation Mix (%):	75% coal, 15% purchases, 7% hydro, 3% other
Total MW capacity:	NA
Average Peak MW Demand:	354
Annual GWh Sales:	1.9 TWh retail
Annual Revenue:	$112 million
Sales to Major Customer Sectors (%):	74% of sales to C&I customers, 26% to residential customers
Industrial Intensities:	Somewhat light industrial
DSM BACKGROUND	
Approach, e.g. resource acquisition, market transformation, conservation culture: *(Note any change in approach over time)*	Resource acquisition
Type of Programs (e.g. EE, DR, LM, etc.)	EE, DR, LM
Year Programs Started:	LM in 1930s, electric EE in 1982
Time to Set up Infrastructure:	Gradually between 1982 and 1990
When Significant Savings were Noted:	About 1990, but that was due to increased state DSM requirements.
Other:	Have to file IRPs every two years and DSM plans every three years with state regulators.
DSM EVALUATION	
Evaluation Practices:	Conduct regular but not annual process and impact evaluations. Conduct market evaluations/DSM potential studies about every 10 years.
Cost-effectiveness Tests:	Use all 5 standard CA stakeholder tests.
Other Results (measure saturations, customer satisfaction, etc.)	Estimate measure saturations as part of DSM potential studies.
COST RECOVERY & INCENTIVES	
Methods & Mechanisms:	DSM costs recovered through deferred accounts. Program cost recovery mechanism is flat addition to the Company's fuel adjustment mechanism.
Customer Class Allocation:	DSM cost recovery charge the same for all rate classes.
Performance Incentives for utilities/agencies:	Performance incentive of up to 30% of direct DSM program costs possible, generally for achieving about 150% of overall approved DSM goal. Used to recover "lost margins" due to DSM, up to 1999.

Electric DSM PROGRAM DESCRIPTIONS	
Residential:	Hot Packs—provides customers with free packets of low-cost energy saving hot water measures. Residential Demand Control—load management program for water heaters, dryers, and electric space heaters. Air Conditioning Control program—offers a $5 monthly summer bill credit for cycling customers' air conditioners on peak days. Air Source Heat Pumps—provides rebates for EE units. Geothermal Heat Pumps—provides rebates for EE units. Financing—provides low-interest loans for EE measures qualified for other Otter Tail DSM programs. Advertising and Education (about EE)—television and radio promotions, publications, and online resources. Implementation and Training—training on DSM technologies for Otter Tail staff and customers. Change-A-Light, Change-the-World—promote CFLs through coordinated marketing and incentives with manufacturers and retailers. House Therapy Low-income program—provide free energy audits, weatherization and appliance replacement services to low-income customers.
Commercial:	Lighting—provide rebates to install EE lighting systems. Cooking—provides rebates for the installation of EE systems. Refrigeration—provides rebates for the installation of EE systems. Motors--rebates for EE motors. Grants—custom rebate program for non-prescriptive DSM measures. Energy Analysis and Recommissioning—compressed air audits and recommissioning analyses offered. Financing—provides low-interest loans for EE measures qualified for other Otter Tail DSM programs. Air Source Heat Pumps—provides rebates for EE units. Geothermal Heat Pumps—provides rebates for EE units. Implementation and Training—training on DSM technologies for Otter Tail staff and customers. Plan Review—design assistance and rebates for EE measures for new commercial buildings.
Institutional:	Same as commercial.
Industrial:	Same as commercial.
Other:	Technical Research—General market research and technical research, the latter primarily for industrial customers. Program development—funding for Otter Tail to develop new DSM programs. Regulatory Assessments and Carrying charges—accounting charges for DSM programs.

APPENDIX B: NSPI BRIEF DSM MEASURE DESCRIPTIONS

Lighting Measures

Most of the lighting measures discussed below are only used for DSM potential estimates for the commercial and industrial sector. CFLs and LED night lights also apply to the residential sector, while LED holiday lights only apply to the residential sector.

<u>T8 Lamps and Electronic Ballasts</u>

T8 lamps and electronic ballasts are the most common alternative for standard T12 lamp and magnetic ballast tubular fluorescent lighting systems. T8 fluorescent lamps are one inch in diameter, and are thinner than T12 lamps, which are 1.5 inches in diameter. T8 systems are approximately 30% more efficient than standard T12 systems.

<u>T5 Lamps and Electronic Ballasts</u>

T5 lamps and electronic ballasts are a newer alternative tubular fluorescent lighting system. T5 fluorescent lamps are 5/8 of an inch in diameter, thinner than both T8 lamps and T12 lamps. T5 lighting systems are primarily used in new construction, and are not appropriate for most retrofit situations, as the lamps are only available in metric lengths.

<u>Compact Fluorescent Lamps</u>

Compact fluorescent lamps (CFLs) are the most common alternatives to standard incandescent lamps. CFLs are generally about four times as efficient as incandescent lamps, and last about 10 times as long. The newer "spiral" CFLs are also generally about the same size as incandescent lamps of similar light output.

<u>Occupancy Sensors</u>

Occupancy sensors automatically turn off the lights in a room or an area when the area is unoccupied. Occupancy sensors are an alternative to standard wall mounted on/off lighting switches.

<u>Pulse Start Metal Halide</u>

Pulse start metal halide lamps are a newer type of metal halide systems that use formed body arc tubes and require an ignitor to start the lamps. Pulse start metal halide lamps are more efficient than standard metal halide systems, and also provide better light output maintenance over the lifetime of the lamp, as well as a longer lamp lifetime.

<u>Delamping</u>

The definition of delamping used for this project is replacing a four lamp, four foot fluorescent lighting fixture with a similar two lamp or three lamp fixture. This measure is intended for areas that are currently over-lit. Lighting reflectors are often used as part of delamping projects.

Efficient Street Lights

Efficient street lights generally use more efficient high intensity discharge lighting systems than mercury vapor systems. Usually either high-pressure sodium systems or pulse start metal halide systems are used. HPS systems produce a yellow-orange color of light, while pulse start metal halide systems produce "white" light comparable to mercury vapor systems.

LED Exit Signs

LED exit signs are one of the most efficient types of exit signs on the market. They generally only draw about two to three watts of power, compared to 10 watts or more for CFLs, or 20 watts or more for incandescent exit signs.

LED Traffic Lights

LED Traffic lights use LED lamps instead of incandescent lamps for each of the three lights in the traffic signal.

LED Night Lights

LED night lights use LED lamps instead of incandescent lamps.

LED Holiday Lights

LED holiday lights use LED lamps instead of incandescent lamps.

HVAC Measures

Efficient Packaged Commercial Air Conditioning Systems

Standard efficiency units are specified as units with EER ratings of 8.9-9.8, depending on unit size and type. Efficient units are specified as units with EER ratings of 10.4-11.5, depending on the sizes and efficiencies. These specifications are based on the California DEER database.

Efficient Chiller Systems

Chiller efficiency varies by compressor type (centrifugal, reciprocating or screw), condenser type (water-cooled or air-cooled) and vintage (age). Newer, water-cooled centrifugal machines tend to be the most efficient[46]. Chillers are not generally covered by government efficiency standards, so efficient units are usually defined relative to a utility or state-specific baseline. For purposes of this project, Summit Blue defined standard efficiency air cooled chillers as having kW/ton ratings of 1.3-1.4, and efficient units to have efficiencies of 0.95-1.25 kW/ton. For water cooled chillers, standard efficiency units were defined as those with efficiency ratings of 0.65 kW/ton, while efficient units were defines as units with efficiencies of 0.47- 0.61 kW/ton, depending upon the unit size and type. These specifications are also based on the California DEER database.

[46] Itron, Inc. "Database for Energy Efficiency Resources (DEER) Update Study" (Itron Inc., Vancouver, WA, December 2005), p. 7-26. Available at www.energy.ca.gov/deer.

Energy Management Systems

Energy management systems are automated control systems that customers use to control the energy systems in their facilities. EMS systems most commonly control HVAC systems and lighting systems. They save energy by shutting energy using equipment off at pre-set times, by monitoring and controlling HVAC system operation so that the equipment is operated as efficiently as possible, and by cycling equipment so that energy usage is reduced during peak periods.

Energy Star Residential Room Air Conditioners

Energy Star room air conditioners must be at least 10% more efficient than standard Canadian models, which are defined as units with a minimum EER rating of 9.4-10.8 depending upon the size and type of the unit[47]. Canadian 2003 minimum efficiency standards for room air conditioners range from 8.5 EER to 9.8 EER depending on the unit size and type.

Energy Star Residential Air Source Heat Pumps

Energy Star air source heat pumps are units with minimum ratings of 14 SEER, EER ratings of 11.0-11.5, and heating system performance factors of 7.0-7.1 or higher[48]. Canadian 2006 minimum efficiency standards for heat pumps are 13 SEER and 6.7 HSPF.

HVAC Diagnostic Repair, Testing, and Maintenance

Many residential and commercial HVAC systems are not operating as efficiently as possible due to inadequate maintenance. This package of services includes ensuring proper refrigerant charge, lubrication, cleanliness and fan operation.

HVAC Duct Sealing, Operations and Maintenance

Many HVAC ducts are not sealed well and leak conditioned air into unconditioned spaces such as basements and attics. Duct sealing reduces such heat loss.

HVAC Duct Insulation

Uninsulated HVAC ducts that run through uninsulated spaces like basements or attics transfer some of the heated or cooled air into those spaces rather than the conditioned zones. The amount of this heat loss is reduced with duct insulation.

Building Envelope Measures

Ceiling Insulation

Ceiling insulation includes both insulating uninsulated roof areas and adding insulation to under-insulated roof areas. In Nova Scotia, the general rule of thumb is that the proper amount of ceiling insulation is an R-value of about 40.

[47] See Canadian Energy Star web site: http://oee.nrcan.gc.ca/energystar.

[48] Ibid.

Wall Insulation

Wall insulation is most cost-effective when insulating un-insulated wall areas. In Nova Scotia, the general rule of thumb is that the proper amount of wall insulation is an R-value of about 20.

Floor Insulation

Many residential basement floors are uninsulated, which results in heat loss to the ground underneath the home. Floor insulation reduces this heat loss.

Efficient Windows

Efficient windows are generally considered to be either triple paned windows, windows with a radiant barrier to reflect heat back into the conditioned space, or windows with low “shading coefficients”. Reducing the shading coefficients of glass will reduce the amount of solar heat gain into the building. This reduced solar gain will decrease the cooling load for the building, but may increase the heating load[49].

Comprehensive Shell Air Sealing

This measure includes caulking, weather stripping, and sealing other visible cracks and penetrations in the building shell.

Commercial and Industrial Refrigeration Measures

The following measures are most applicable to grocery stores. Secondary markets include restaurants or cafeterias in office buildings.

High Efficiency Evaporative Fan Motors

This measure involves replacing shade-pole evaporator fan motors with either permanent split-capacitor (PSC) or electrically commutated (EC) motors. According to the California DEER database, the incremental cost for these measures is small[50].

Efficient Ice Makers

Energy-efficient ice-makers come as either air-cooled or water-cooled units and are rated based on the pounds of ice produced in a 24-hour period. Energy-efficient ice-makers are defined by the use of high-efficiency compressors, high-efficiency fan motors, and thicker insulation. Energy savings vary by type and capacity and range from 18-28% in most cases.[51]

[49] Itron: 2005, *op.cit.*, p. 7-17.

[50] Itron: 2005, *op.cit.*, p. 7-72.

[51] “Packaged Commercial Refrigeration Equipment”, ACEEE, December 2002

Strip Curtains and Night Covers

The majority of heat loss from an open display fixture is through infiltration. Covering open fixtures with plastic curtains during low traffic periods and at night can reduce convection by 50% or more when they are applied, thereby reducing refrigeration loads[52].

Efficient Refrigeration Compressors

This measure involves the use of high-efficiency compressors in the place of standard compressors in the refrigeration cycle. Energy-savings potential is in the range of 6-16%.[53]

High Efficiency Multiplex Rack Compressor System

A multiplex-compressor system consists of multiple compressors drawing from a common suction header (suction-group), and serving any number of display fixtures. The suction group is controlled to satisfy the lowest temperature required by any of the attached display fixtures. For this reason the display fixtures served by a given suction group usually have similar temperature requirements; separate suction-groups are typically used for low-temperature and medium-temperature demands[54].

Residential Refrigeration and Appliance Measures

Energy Star Refrigerators and Freezers

Energy Star refrigerators must exceed Canadian minimum energy efficiency standards by at least 15% for full-size units, and 20% for compact size units[55]. Energy Star freezers must exceed Canadian minimum energy efficiency standards by at least 10% for full-sized units and 20% for compact units.

Remove Secondary Refrigerators and Freezers

Second refrigerators and freezers that customers own are often older and less efficient appliances. For example, the most common refrigerator sold in 1990 used between 60-70 kWh per cubic foot, compared to 2003, when the most common refrigerator sold used less than 30 kWh per cubic foot[56]. According to Natural Resources Canada's 2003 household energy survey, 19% of households in the Atlantic region have more than one refrigerator[57].

Convection Ovens

Convection ovens are similar to traditional ovens except they have circulating fans to increase heat transfer to the food. Food cooks faster and at a slightly lower temperature in a convection oven.

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[52] Itron: 2005, *op.cit.*, p. 7-74.

[53] http://www.aps.com/images/pdf/Refrigeration.pdf

[54] Itron: 2005, *op.cit.*, p. 7-67.

[55] See Canadian Energy Star web site: http://oee.nrcan.gc.ca/energystar.

[56] Natural Resources Canada, "Energy Consumption of Major Household Appliances Shipped in Canada, Trends for 1990-2003 ", (NRCAN, Gatineau, QC, December 2005) p.8.

[57] Natural Resources Canada, "2003 Survey of Household Energy Use, Summary Report", (NRCAN, Ottawa, ON, December 2005) p.22.

Power Strips with Occupancy Sensors

Power strips with occupancy sensors have several inputs that are controlled by an associated occupancy sensor and some that are not controlled. In an office environment, a computer could be plugged into an uncontrolled input and a monitor and task lamp could be plugged into the sensor controlled inputs.

Commercial and Industrial Process Measures

Compressed Air Leak Maintenance/Detection

Compressed air leak maintenance or detection includes helping customers identify and repair leaks in their air compressor systems. Utility DSM programs often offer this type of service using an ultrasonic inspection device.

Efficient Air Compressors

Efficient compressors come in a variety of system types. There are three primary factors determining a compressor’s overall efficiency: the compressor type, partial loading controls, and the efficiency of the motor. Incentives for efficient compressors can be most effective as part of evaluating an entire air compressor system, and not just considering the compressor in isolation.

Custom Measures

For purposes of this assignment, Summit Blue has defined “custom” measures as other energy efficiency measures beyond those specifically defined in this section. Generally, “custom” measures are somewhat unique or have application-specific components that make developing generic savings or cost estimates difficult, or subject to considerable judgment. Utilities’ definitions of “custom” measures vary, as do their engineering analysis or assistance offers and requirements to screen and evaluate potential custom measures. For example, Otter Tail Power includes adjustable speed drives (ASDs) in its C&I Grants (custom) program, while Xcel Energy includes ASDs in its Motor Efficiency program, with qualification requirements.

Energy-efficient Motors

NEMA has defined “Premium” efficiency motors, which many utilities, such as Otter Tail Power Company and Xcel Energy, use for their Motor DSM programs. Xcel Energy included the NEMA definitions in its 2005/2006 Biennial CIP Filing[58].

Variable Frequency Drives (VFDs)

Variable frequency drives or adjustable speed drives (ASDs) vary the speed of motors so that their speeds are proportionate to the loads the motors are serving. This saves energy because motor energy use varies with the cube of the speed for applications such as HVAC fans. So if a motor is running at half speed and is controlled by a VFD, it will only use one-eighth of its full speed energy use (as one-half cubed equals one-eighth). Without a VFD, the motor running at half load will use about one-half of its full load energy use.

[58] Xcel Energy: 2004, *op.cit.*, p. 38.

Energy Information Assistance

Providing energy information to customers can be done in various ways. One of the most common ways for utilities to do so is through energy audits, which utilities often subsidize with DSM program funding.

Demand Response or Load Management Measures

Direct load control measures apply to both residential and commercial/industrial customers. Interruptible rates are just for C&I customers. Real-time-pricing programs are most commonly offered to C&I customers.

Direct Load Control (DLC)

DLC programs involve cycling or shutting off customers' air conditioners, water heaters, pool pumps, electric heating systems, or other electrical equipment during utilities' peak demand periods.

Interruptible Rates

Interruptible rate programs generally offer customers electric price discounts for reducing their loads during peak demand periods. The terms of the electric price discounts vary widely, from discounts that are constant throughout the year, to those that are only in effect during utilities' peak demand season, such as the summer, to discounts that are only offered during periods in which customers actually have to reduce their loads. The Company has a lot of experience with these types of programs, and has developed a significant demand response resource through these programs.

Real-Time-Pricing (RTP)

Through RTP programs, utilities offer customers rates that vary by the hour, instead of the typical flat rates that are fixed throughout the year. These rates encourage customers to develop abilities to vary their system operations during periods of high electric prices. The Company has offered these rates to its largest customers for several years, and has two current participants.

Water Heating Measures

Most of the water heater measures discussed below are just included as part of the residential DSM potential estimates. Only efficient water heaters were included in the C&I DSM potential estimates.

Efficient Water Heaters

Traditional electric water heaters have an overall efficiency of about 90% including standby and distribution losses. High efficiency units achieve 95% efficiency with improved insulation and heat traps that minimize convection into under insulated distribution pipes.

Heat Pump Water Heaters

Heat pump water heaters use compressed refrigerants to extract heat from ambient air (or water) and move that heat to stored hot water. During warm weather these machines can move 4 units of heat for every one comparable unit of input energy, thus achieving a coefficient of performance (COP) up to 4.0. COP decreases as ambient air temperature decreases. At about 10-20°F, heat pumps become ineffective. At cold ambient temperatures traditional electric resistance heating elements back-up the heat pump compressor

Tankless Water Heaters

Tankless water heaters are more efficient than standard water heaters since they avoid the energy lost from the hot water that is stored in conventional tanks. Tankless water heaters have “energy factors” of about 98%.

Low Flow Showerheads

Low flow showerheads use an orifice plate inside the fixture to restrict the water flow to a maximum 2.5 gallons per minute versus a 3.5 gallon per minute permitted with standard new showerheads. Water flow from older showerheads typically exceed 5.0 gallons per minute.

Faucet Aerators

Faucet aerators introduce air into the water as it leaves the faucet. The result is perceived full flow at a much reduced actual flow rate. We estimated that a faucet aerator reduces flow from 2 gallons per minute to 1 gallon per minute.

Hot Water Pipe Insulation

Pre-formed segments of foam insulation are placed around hot water distribution pipes to minimize heat loss. While useful for the entire length of hot water piping, it is most cost-effective in the first 5-10 feet of pipe extending from the hot water heater.

Hot Water Set-back Thermostat

Similar to a HVAC set-back thermostat, a water heater setback thermostat reduces the temperature setpoint of the water tank during periods when full service is not required. Savings accrue from reduced stand-by and distribution system losses.

Drain Water Heat Recovery

These systems recover some of the heat from drain pipe hot water.

Energy Star Clothes Washers

Energy Star clothes washers must exceed Canadian minimum energy efficiency standards by at least 36% in 2004 and have a modified energy factor of 40.21, and effective January 1, 2007, the minimum efficiency requirement for Energy Star status increases to 48.45 L/kWh/cycle, or 1.72 cu.ft./kWh/cycle[59].

Energy Star Dishwashers

Energy Star dishwashers must exceed Canadian minimum energy efficiency standards by at least 25%[60]. The Canadian and American minimum efficiency standards for this appliance are the same.

[59] See Canadian Energy Star web site: http://oee.nrcan.gc.ca/energystar.

[60] See Canadian Energy Star web site: http://oee.nrcan.gc.ca/energystar.

APPENDIX C: GLOSSARY OF TERMS

Achievable (Market) Potential – An achievable or market potential analysis evaluates the amount of savings that would occur in response to specific program funding and measure incentive levels.

Economic Potential – An economic potential analysis goes a step farther to include an examination of measure cost-effectiveness.

Impact Evaluation - Impact evaluations are the estimation of gross and net effects from the implementation of one or more energy efficiency programs. Most program impact projections contain ex-ante estimates of savings. These estimates are what the program is expected to save as a result of its implementation efforts and are often used for program planning and contracting purposes and for prioritizing program funding choices. In contrast the impact evaluation focuses on identifying and estimating the amount of energy and demand the program actually provides.

Integrated Data Collection – An approach in which surveys of key market actors and end-use customers (EUCs) are conducted in "real time" as close to the key intervention points as possible; usually integrated as part of the standard program implementation or other program paperwork process.

Market Characterization – The market characterization evaluations focus on the evaluation of program-induced market effects when the program being evaluated has a goal of making longer-term lasting changes in the way a market operates. These evaluations examine changes within a market that are caused, at least in part, by the energy efficiency programs attempting to change that market.

Market Transformation – an approach in which a program attempts to influence "upstream" service and equipment provider market channels and what they offer end customers, along with educating and informing end customers directly. The emphasis is on influencing market channels and key market actors other than end customers.

Process Evaluation - The process evaluation is a systematic assessment of an energy efficiency program for the purposes of documenting program operations at the time of the examination and identifying improvements that can be made to increase the program's efficiency or effectiveness for acquiring energy resources.

Ratepayer Impact Measure - The Ratepayer Impact Test measures what happens to customer bills or rates due to changes in utility revenues and operating costs caused by the program … This test indicates the direction and magnitude of the expected change in customer bills or rate levels. (from Standard Practice Manual)

Resource Acquisition – an approach in which end customers are the primary target of program offerings (e.g., using rebates to influence customers' purchases of end use equipment).

Societal Cost Test - The Societal Test, a modified version of the TRC, adopts a societal rather a utility service area perspective. The primary difference between the Societal and TRC test is that the Societal Test accounts for externalities… excludes tax credit benefits, and uses a societal discount rate. (from Standard Practice Manual)

Technical Potential – A technical potential analysis evaluates how much energy can be saved from a technical perspective without considering measure economics.

Total Resource Cost Test - The Total Resource Cost Test measures the net costs of a demand-side management program as a resource option based on the total costs of the program, including both the participants' and the utility's costs. (from Standard Practice Manual)

Utility Cost Test - The Utility Cost Test measures the net costs of a demand-side management program as a resource option based on the costs incurred by the utility … and excluding any net costs incurred by the participant. The benefits are similar to TRC benefits. Costs are defined more narrowly. (from Standard Practice Manual)

NOVA SCOTIA
POWER
An Emera Company

October 13, 2006

Nancy McNeil
Regulatory Affairs Officer
Nova Scotia Utility and Review Board
1601 Lower Water Street, 3rd Floor
PO Box 1692 – Unit M
Halifax, NS B3J 3S3

Dear Ms. McNeil,

Re: Nova Scotia Power Inc. Integrated Resource Plan (IRP) Assumptions

On September 15th, NSPI issued a document to IRP stakeholders which identified assumptions to be used in the development of the Integrated Resource Plan. On September 22nd, a technical conference was held to review this information with stakeholders. Since that date NSPI has provided additional information in support of the proposed assumptions and a number of the intervenors have provided NSPI with written comment regarding the IRP assumptions and process, as well as broader policy-related matters.

Based on intervenor feedback, a number of changes to the IRP assumptions have been made. These changes have been incorporated within the attached revised Basic Assumptions document and are summarized in the attached listing of changes.

NSPI intends to utilize these assumptions in the next stage of IRP development – the development of base scenarios and sensitivities. This stage will involve the development of alternative planning scenarios based on the grouping of like assumptions (e.g. a suite of the more aggressive environmental assumptions will be compiled to be used in the development of the least cost long-term plan which satisfies these assumptions). As well, sensitivities significant to these plans will be proposed.

This filing is not necessarily the "final word" on IRP assumptions. Thus far consensus has not been reached on aspects of some key assumptions. As well, additional information has been requested of NSPI in some areas, and in others stakeholders continue to assess the assumptions proposed.

NSPI has developed a reasonable set of assumptions to move the IRP process forward. Timely resolution of these matters is needed to begin to undertake analysis and meet the IRP schedule. This is a key objective of the issuance of IRP base scenarios for alternative plans and proposed sensitivities. This information will be issued to stakeholders by October 27.

Going forward NSPI will continue to communicate with IRP stakeholders to ensure participants remain well-apprised of the IRP development. We will shortly be in contact with stakeholders to provide feedback with respect to the matters raised in the submissions but not explicitly addressed in the revised Assumptions Document. Should further changes to the assumptions prove necessary these can be incorporated in the IRP analysis, either directly through revisions to the Base Assumptions or indirectly through inclusion in the IRP sensitivity analysis.

Should the Board have questions or comment concerning this material, please contact the undersigned or direct Board staff to contact NSPI Manager, Regulatory Affairs, Eric Ferguson.

Yours truly,

Tammy Bucknam

Rene Gallant
For Regulatory Counsel

Cc:	Ralph Tedesco	By Email
	Graeme MacKenzie	By Email
	Eric Ferguson	By Email
	Bill Hattie	By Email

Integrated Resource Plan
Basic Assumptions

REDACTED

October 13, 2006

NOVA SCOTIA
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IRP Basic Assumptions Overview

Objective of the IRP, as stated in the Terms of Reference:

"*To develop a resource plan which utilizes supply-side and demand-side options, to enable NSPI to meet future emissions and other requirements in a cost-effective and reliable manner*."

IRP Basic Assumptions Overview

Following are the basic assumptions for the IRP development, analysis and selection of the most suitable options to meet future emissions and other requirements in a cost-effective and reliable manner, while maintaining a minimum 20% capacity reserve margin above firm loads as set forth in the NS – NB Interconnection Agreement.

These assumptions are based on NSPI's present best understanding. Recognized experts and consultants, proprietary information sources, publicly available trends, and NSPI's professional experience and judgment are among the sources used to derive these assumptions.

The IRP covers the period from 2007 to 2029, and therefore considers solutions with a long-term view. Those solutions with better near-term benefits will be viewed more favourably.

IRP Basic Assumptions Overview

Assumptions for key areas, for example fuel costs, financial or load assumptions, are highly volatile and may change over time, and are therefore impossible to predict accurately. These assumptions or forecasts may change in the future, perhaps substantially.

Therefore, deviations from the assumptions will happen over time. NSPI has used best efforts to provide ranges of realistic values as appropriate, based on current information.

IRP Basic Assumptions Overview

This IRP process was initiated to address increasingly strict emissions requirements, particularly SO_2.

These emissions reductions come into effect in 2009-2010. The timelines required to develop and implement the strategy require that we determine the solutions promptly so that they can be implemented in a timely, cost-effective manner. Delays to this process may result in increased costs to NSPI's customers.

To meet future required SO_2 reductions, NSPI must do one or more of the following:

- Reduce load (eg DSM)
- Replace existing fossil fueled generation with lower-emitting sources.
- Consume cleaner fuel in its existing fossil fueled generation, while upgrading existing plant to allow this.
- Provide SO_2 capturing technology to existing fossil fueled generation.

IRP Basic Assumptions Overview

The most significant assumptions, as identified in NSPI's Air Emissions Strategy, are:

- Future emission limits with respect to SO_2.
- Future emission limits with respect to CO_2.
- Future cost differential between high sulphur and low sulphur fuel.

IRP Basic Assumptions
Environmental

SO_2

Current Regulatory Requirements:

As per NS Air Quality Regulations

- SO_2 - 108,750 t/yr 2006 to 2009; 72,500 t/yr in 2010
- S in HFO – 2.0% annual with 2.2% cap.

Regulatory Context:

Additional reductions considered likely.

U.S. emission constraints poised to be tightened

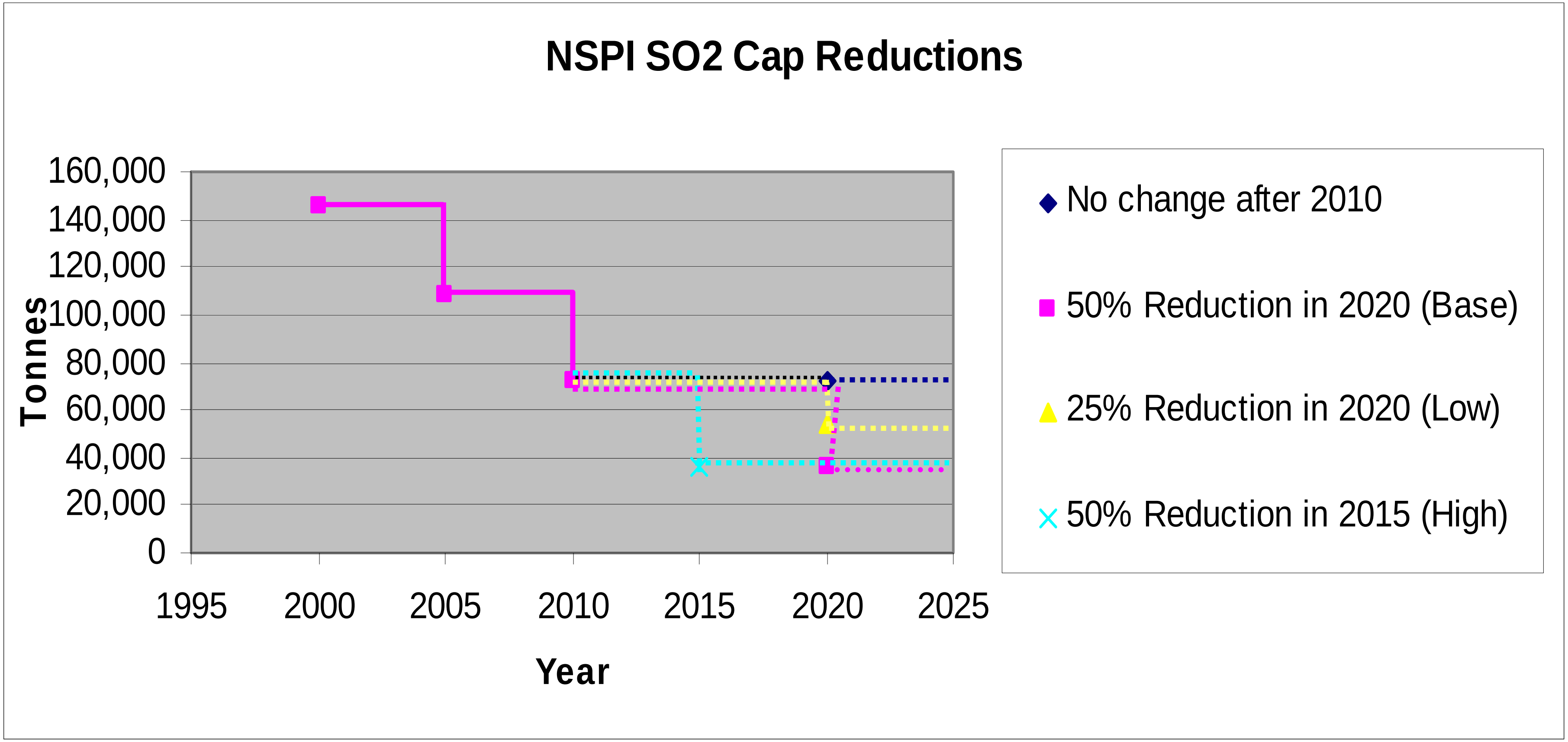
Achieving new source performance in Nova Scotia would require a 50% reduction from the 2010 cap.

IRP Basic Assumptions Environmental

SO_2

Case	Reduction
Base	50% reduction from 2010 cap by 2020 (to 36,200 t/yr)
	Consistent with new source performance and the 1st phase of U.S. rules ~10 yrs. after rules are implemented.
Low	25% reduction from 2010 cap by 2020 (to 54,400 t/yr)
	Places NSPI at average U.S. and Canadian performance in 2002.
High	50% reduction from 2010 cap by 2015 (to 36,200 t/yr); HFO max 1% S in 2015; then constant for remainder of planning period.
	Consistent with new source performance, and 1st phase of U.S. rules ~5 yrs. after rules are implemented.

IRP Basic Assumptions Environmental



IRP Basic Assumptions
Environmental

CO_2 / Greenhouse Gases

Current Regulatory Requirements:

Pending and uncertain

Regulatory Context:

Canada remains in Kyoto but is currently developing a “Made in Canada” approach possibly starting in 2010

- Probable focus is having older equipment meet the emissions levels of newer, less GHG intensive equipment for the electricity sector
- Domestic offsets system likely, with possible tie to US offsets and credits

NEG/ECP agreed to reduce regional GHG intensity for the electricity sector by 20% by 2025

UNFCC recommends long-term reduction target of 75-85%

IRP Basic Assumptions
Environmental

CO_2 / Greenhouse Gases

Case	Reductions (Million t)			
	2010	**2015**	**2020**	**2029**
Base	0.7	1.5	3.1	4.3
Low	0.0	0.0	0.1	0.3
High	1.7	3.1	4.3	5.7
*Kyoto sensitivity**	*6.4*	*5.6*	*4.8***	*4.1*

**Kyoto numbers are total emissions, not reductions*
*** assume credits no longer available or too expensive*
1990 CO_2 emissions – 6.85M t
Current CO_2 emissions ~ 10M t / year

IRP Basic Assumptions
Environmental

CO_2 / Greenhouse Gases

Assumed Cost of Offsets (2006$US / tonne CO_2)			
Year	**Base**	**Low**	**High**
2010	11.50	3.00	17.50
2015	18.50	4.50	32.50
2020	23.50	6.50	41.50
2025	30.00	8.50	53.00

IRP Basic Assumptions Environmental

CO_2 / Greenhouse Gases

Generating Unit Anniversary Date Assumption			
Case	**Year**	**Emission Constraint**	**Basis for Constraint**
Base	2010	418 tonnes / GWh	Equivalent Performance Emission Standard (EPES) approach beginning in 2010. Parameters are after 40 years of service the specific unit benchmark standard will become 418 t / GWh. (equivalent to Alberta's requirements).
Low	2010	880 tonnes / GWh	Similar to Most Likely use an EPES approach beginning in 2010 with a 43 year life and a more lenient unit benchmark standard of 880 t / GWh (equivalent to the original Large Final Emitters (LFE) program).
High	2010	418 tonnes / GWh	Similar to Most Likely use an (EPES) approach beginning in 2010. Parameters are after 35 years of service the specific unit benchmark standard will become 418 t /GWh. (equivalent to Alberta's requirements).

IRP Basic Assumptions
Environmental

NO_x

Current Regulatory Requirements:

- As per NS Air Quality Regulations
  - NOx cap of 21,365 t/yr. in 2009

Regulatory Context:

- Additional reductions considered likely.
- Historically actions to address NOx in Canada have not been as stringent as for SO_2.
- U.S. emission constraints poised to be tightened.
- NSPI emissions are better positioned against other plants in North America but intensity is about 25 - 30% higher. (Based on a simple average; 45-50% higher if production weighted.)

IRP Basic Assumptions
Environmental

NO_x

Case	Reduction
Base	30% reduction from 2009 cap by 2020 (to 14,700 t/yr)
Low	10% reduction from 2009 cap by 2020 (to 19,000 t/yr)
High	60% reduction from 2009 cap by 2020 (to 9,000 t/yr)

IRP Basic Assumptions Environmental

Mercury

Current Regulatory Requirements:

Cap of 168 kg/yr. as per NS Air Quality Regulations.

Regulatory Context:

Canada Wide Standards are pending and call for:

- a cap of 65 kg for NSPI in 2010.
- new source performance standards for new coal-fired plants.
- a review of the standards in 2012 to explore an 80% reduction from the 2005 cap.

NEG/ECP Action Plan calls for 75% capture by 2010.

The U.S. is adopting up to 70% capture by 2018.

NSPI emissions are currently lower than the average Canadian & U.S. coal plants.

IRP Basic Assumptions
Environmental

Mercury

Case	Reduction
Base	- 65 kg/yr. cap in 2010 - 34 kg/yr. cap in 2020 (80% reduction from 2005 cap)
Low	- 65 kg/yr. cap in 2012 - 34 kg/yr. cap in 2020 (80% reduction from 2005 cap)
High	- 65 kg/yr. cap in 2010 - 17 kg/yr. cap in 2020 (90% reduction from 2005 cap)

IRP Basic Assumptions
Environmental

Renewable Portfolio Standard

Case	% New renewable (post 2001)
Base	- 2010 - 5% of energy - 2013 - 10% of energy*
Low	- 2010 - 5% of energy - 2013 – 10% of energy*
High	- 2010 - 5% of energy - 2013 -10% of energy* - 2020 - 15% of energy*

NOTE: It is assumed that NSPI will have fulfilled its 2.5% of electricity from renewable sources voluntary commitment between 2003 and 2007.

* New capacity back-up or other guarantees required to ensure reliability of supply.

IRP Basic Assumptions
Supply Side

Summary of Existing Generation Plant

Thermal Unit	Net Demonstrated Capacity (MW)	In Service	Fuel
Tufts Cove 1	81	1965	NG / HFO
Tufts Cove 2	93	1972	NG / HFO
Tufts Cove 3	147	1976	NG / HFO
Trenton 5	150	1969	Coal/Coke/HFO
Trenton 6	157	1991	Coal/Coke/HFO
Pt Tupper	154	1973, coal conversion 1987	Coal/Coke/HFO
Lingan 1	155	1979	Coal/Coke/HFO
Lingan 2	155	1980	Coal/Coke/HFO
Lingan 3	155	1983	Coal/Coke/HFO
Lingan 4	155	1984	Coal/Coke/HFO
Pt Aconi	171	1994	Coal/Coke & limestone sorbent (CFB)
Combustion Turbines			
Tusket 1*	24		LFO
Burnside 1 – 4*	4 @ 33		LFO
Victoria Junction 1 – 2*	2 @ 33		LFO
Tufts Cove 4 – 5*	2 @ 49		NG

* winter ratings

Summary of Existing Generation Plant (cont'd)

Hydro	Net Demonstrated Capacity (MW)
Wreck Cove	230
Annapolis Tidal	3.7
Avon	6.8
Black River	22.5
Nictaux	8.3
Lequille	11.2
Paradise	4.7
Mersey	42.5
Sissiboo	24.0
Bear River	13.4
Tusket	2.4
Roseway	1.8

Hydro	Net Demonstrated Capacity (MW)
St Margarets	10.8
Sheet Harbour	10.8
Dickie Brook	3.8
Fall River	0.5
Other	
New Renewables (firm capacity on peak)	18.3
Contract IPP	25.6

IRP Basic Assumptions
Supply Side

Technology Options to Control Emissions at Existing Plant

Alternative	Description	Site Considerations
1	Scrubber in Lingan	Best available site
2	Scrubber in Trenton	Space limitations
3	Scrubber in Pt Aconi	CFB technology used
4	Scrubber in Pt Tupper	Possible but single unit plant
5	Baghouse in Lingan	Not required to meet emissions regulations
6	Baghouse in Trenton	Not required to meet emissions regulations / Best available site
7	Baghouse in Pt Aconi	Already has a baghouse
8	Baghouse in Pt Tupper	Not required to meet emissions regulations
9	LNCFS in Lingan	Unit 3 in progress, best available site for more LNCFS
10	LNCFS in Trenton	Unit 5 being considered; Unit 6 has low NOx technology
11	LNCFS in Pt Aconi	CFB technology used
12	LNCFS in Pt Tupper	Being considered, if needed to meet emissions regulations
13	SCR / SNSC in Lingan	Not needed until emissions requirements reduce further, most economic site will then be determined
14	SCR / SNCR in Trenton	Not needed until emissions requirements reduce further, most economic site will then be determined
15	SCR / SNCR in Pt Aconi	CFB technology used
16	SCR / SNCR in Pt Tupper	Not needed until emissions requirements reduce further, most economic site will then be determined
17	Carbon Injection in Lingan	Not required if a scrubber is provided
18	Carbon Injection in Trenton	Unit 5 would be considered when baghouse added
19	Carbon Injection in Pt Aconi	Could be added to existing baghouse if emissions requirements reduce further
20	Carbon Injection in Pt Tupper	Least likely site
21	Sorbent injection	Not economical with intended fuels
22	Ozone	Not commercially proven
23	Plasma technology	Not commercially proven
24	CO_2 sequestration	Not commercially proven

IRP Basic Assumptions
Supply Side

Technology Options to Control Emissions at Existing Plant (for further study)

Plant/Unit	Technology	Emission Impact (% Removal)			
		NOx	SO_2	Hg	CO_2
Lingan (1-4)	Low NOx Burners	45	N/A	N/A	low
	Wet Scrubber (FGD) (320MW)	N/A	95	45[2]	high
	Selective Catalytic Reduction (SCR)	50[1]	N/A	N/A	low
	Seawater Scrubber	N/A	95%$_{MAX}$ @ 1.7%S	45	high
	Dry Lime Scrubber	N/A	95%max	45	moderate
	Baghouse + Carbon Injection			85[2]	moderate
Pt. Tupper	Low NOx Burners	45	N/A	N/A	low
	Selective Catalytic Reduction	50[1]	N/A	N/A	low
	Baghouse + Carbon Injection			85[2]	moderate
Trenton 5	Low NOx Burners	50	N/A	N/A	low
	Dry Lime Scrubber	N/A	95% max	40[2]	moderate
	Selective Catalytic Reduction	50[1]	N/A	N/A	low
	Baghouse + Carbon Injection			85[2]	moderate
Trenton 6	Low NOx Burners	50	N/A	N/A	low
	Dry Lime Scrubber	N/A	95% max	40[2]	moderate
	Selective Catalytic Reduction	50[1]	N/A	N/A	low
	Baghouse + Carbon Injection			85[2]	moderate

Notes: (1) SCR would allow 50% on top of that gained by Low NO_x Burners.
(2) Hg collection depends on coal specification.

IRP Basic Assumptions
Supply Side

Technology Alternatives to Meet Future Generation Requirements

Alternative	Description	Assessment Summary
1	Nuclear	Prohibited by NS legislation
2	Wind	Desired by NSPI if economical (in addition to RPS requirements)
3	Biomass	Desired by NSPI if economical (in addition to RPS requirements)
4	Landfill gas	Desired by NSPI if economical (in addition to RPS requirements)
5	Geothermal	Not available at utility scale
6	Solar	Currently not economically available
7	Fuel cells	Not commercially available yet
8	Cogeneration	Opportunities assessed to date not economical
9	Tidal	Stream tidal under review, but not commercially available by 2010
10	Distributed generation / micro turbines	Very limited economical applications (remote locations)
11	Pumped storage	No available sites in NS
12	Access to customers' generation	Net metering is in place; opportunities limited by economics
13	Shared with neighbouring utilities	Opportunities for joint development with 3rd parties are regularly investigated. This alternative will likely require transmission investment.

A 250 GWH allowance for potential co-gen / distributed generation in 2012 will be modeled as a sensitivity.

IRP Basic Assumptions
Supply Side

Options to Increase Generation / Fuel Switch at Existing Plant (for further study)

Alternative	Technology	Net Capacity Increase - MW	Fuel Type
Burnside Gas	Gas Conversion	0	Gas
TUC1 + 15	Uprate	15	HFO/Gas
Nictaux	Hydro	2.5	Water
Marshall Falls	Hydro	1.8	Water
TUC 2 + 6	Uprate	6	Oil/Gas
Lingan 1-4	Uprate	4 X 20	Coal/Coke/HFO
Lingan 1-4	Uprate	4 X 5	Coal/Coke/HFO
TUC 6 C-C	Convert TUC 4 & 5 to C-C with duct firing.	52.5	Gas

IRP Basic Assumptions Supply Side

Options to Add New Generation (for further study)

Alternative	Technology	Net Capacity Increase - MW	Fuel Type[1]
LM6000	Simple cycle Combustion Turbine (CT) unit	49.4	Gas
CC150	2XLM6000, 50MW steam island	151	Gas
CC 280	New CT based Combined Cycle unit	280	Gas
CFB 400 Supercritical Boiler	Circulating Fluidized Bed	400	Coke/Coal 80/20
PC 400 Supercritical with FGD, SCR and CO_2 Capture	Pulverized Coal with Amine Scrubber	400	Coal/Coke 85/15
PC 400 Supercritical with FGD, SCR	Supercritical PF Coal	400	Coal/Coke 85/15
CFB 265	Sub Critical CFB	265	Coke/Coal 80/20
IGCC 400 without CO_2 Capture	Coal gasification CC	400	Coke/Coal 80/20
IGCC 400 with CO_2 Capture	Coal Gasification CC with CO shift and CO_2 Capture	400	Coke/Coal 80/20
Renewables (including capacity back-up)	Wind turbines, biomass, landfill gas	Incremental	various

Note: (1) Fuel as modeled, alternative blends including biomass would be considered an optimization.

IRP Basic Assumptions
Supply Side

Capital Cost Assumptions – Indicative Pricing

In evaluating the capital for both technology options to control emissions at existing plants and for future supply side options, indicative pricing was developed using ranges based on previous work and our current level of understanding. Actual pricing can vary based on market conditions.

All prices are current costs. In the case of larger units or components of significant dollar value, pricing is based on industry selected United States Gulf Coast, modified to Nova Scotia market conditions. (Current practice for industry feasibility studies.)

This costing approach is typical of methods used in most other jurisdictions for long-term planning purposes.

IRP Basic Assumptions
Supply Side

Indicative Pricing methodology: Examples

NOx Burners	± 10 %	First unit is now under construction
Burnside Gas / TUC Mods	+ 15% / -10%	Studies done and engineering review done. No construction.
Lingan Upgrades		
Baghouse/Carbon Injection	+ 20% / - 10%	Budget Estimates from suppliers. No detailed engineering.
Future Additions	+ 30% / -10%	

Generally classified as ± 30% overnight pricing. Information from technical conferences and participation in industry expert groups. Modified to +30% / -10% to reflect current market outlook on labour and supply. Pricing may vary based on market conditions.

IRP Basic Assumptions
Supply Side

Technology assumptions:

Where dry scrubbers are used on units, the cost of a baghouse must also be included. The Trenton 5 Baghouse is an appropriate proxy value.

Activated Carbon Injection is used for Hg capture solutions. It is understood that different types of activated carbon would be included.

Fuel is not included in the O&M cost estimates.

In the case of gas turbines, incremental O&M costs are added for blade life.

IRP Basic Assumptions Supply Side

Technology Options to Control Emissions at Existing Plant - Costs

Plant/Unit	Technology	Capital Cost Low	Base	High	O&M (2006$) Total Annual O&M
		2006M$			K$ / yr
Lingan 1-4	Low NOx Burners	4.2	4.6	5.1	0
	2.5% S Wet Limestone (320MW)	156	183	210	6,341
	2.5% S Dry Lime (320MW)*	110	146	183	12,940
	1.7% S Wet Limestone (320MW)	149	175	201	5,624
	1.7% S Dry Lime (320MW)*	105	140	175	9,657
	1.7% S Seawater(320MW)	149	199	249	6,289
	Selective Catalytic Reduction (SCR)	19	21.1	27.4	1,060
Pt. Tupper	Low NOx Burners	4.2	4.6	5.1	0
	Selective Catalytic Reduction	19	21.1	27.4	1,060
Trenton 5	Low NOx Burners	4.2	4.6	5.1	0
	Carbon Injection(1.5M$) /Baghouse(29 M$)	27.5	30.5	36.6	1,262
	Selective Catalytic Reduction	22	24.5	31.9	1,060
Trenton 6	Low NOx Burners	4.2	4.6	5.1	0
	Selective Catalytic Reduction	23.4	26	33.8	1,124

***Note: Lime receiving and storage costs not included to date**

IRP Basic Assumptions
Supply Side

Options to Increase Generation / Fuel Switch at Existing Plant - Costs

Alternative	Technology	Capital Cost			O&M (2006)
		Low	Base	High	Total Annual O&M
		2006M$			K$/yr
BSD Gas	Gas Conversion	4.6	5.1	5.8	0
TUC1 +15	Increase Capacity	3.6	4.0	4.6	0
Nictaux	Hydro	3.3	3.7	4.8	minimal
Marshall Falls	Hydro	3.2	3.5	4.6	minimal
TUC2 +6	Increase Capacity	1.8	2.0	2.3	0
Lingan 1-4	Increase Capacity	4.5	5.0	6.0	0
Lingan 1-4	Increase Capacity	18	20.0	24.0	0
TUC6	Combined Cycle Convert TUC 4&5 Add HRSG	51	56	62	1,150

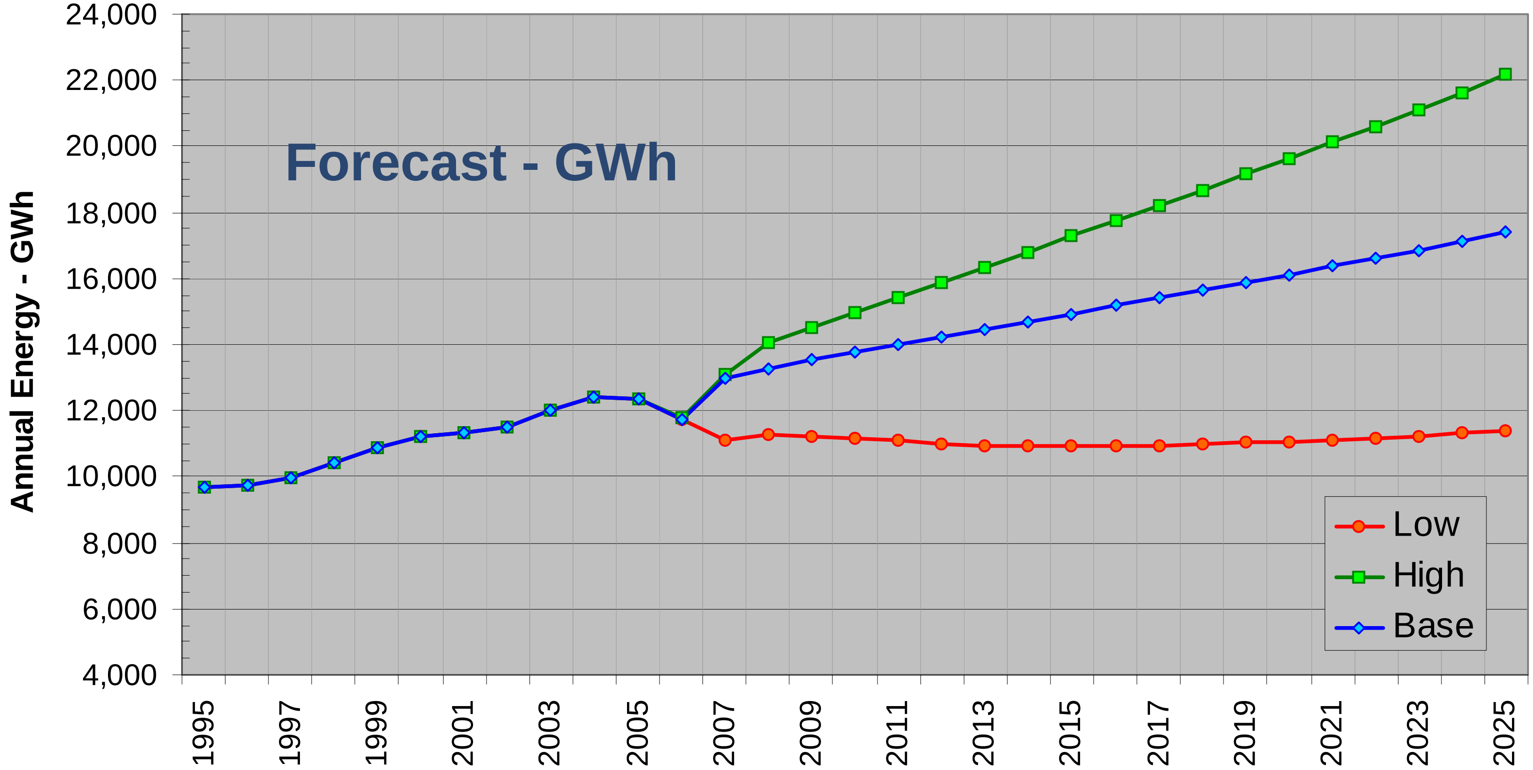
IRP Basic Assumptions
Supply Side

Options to Add New Generation - Costs

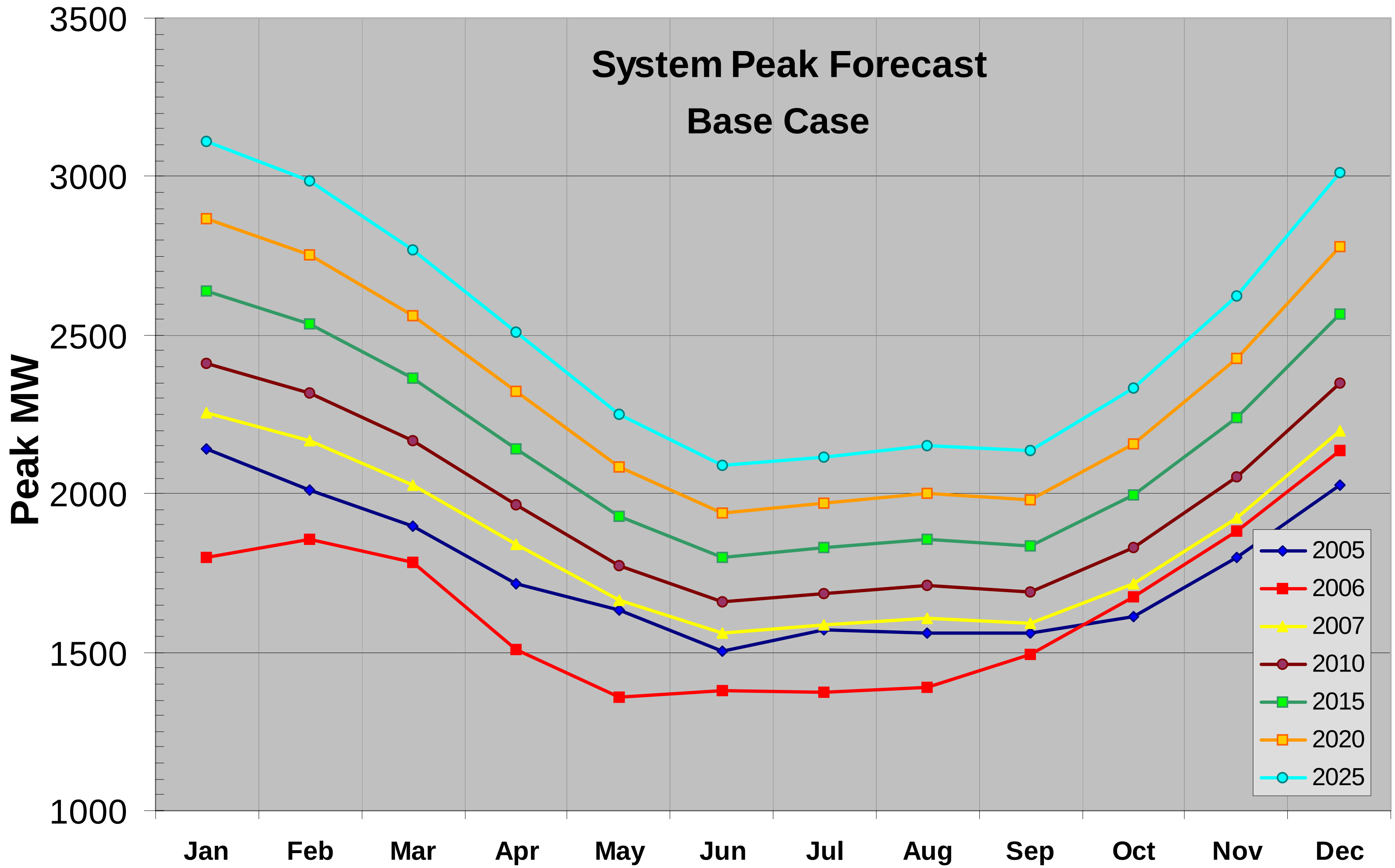
Alternative	Technology	Capital Cost			O&M (2006)
		Low	Base	High	Total Annual O&M
		2006M$			K$/yr
LM6000	Combustion Turbine	37.8	42	46.2	1,627
CC150	New LM6000 based Combined Cycle	109	121	160	4,226
CC 280	Combined Cycle	172	215	275	8,641
CFB 400	Circulating Fluidized Bed , Supercritical Boiler	802	1003	1304	10,522
PC 400	Super Critical with FGD,SCR, Mercury Capture and CO2 capture	1088	1361	1769	11,208
PC 400	Ultra Super Critical with FGD, SCR, Mercury Capture	846	996	1295	10,217
CFB 265	Sub Critical CFB	575.2	719	935	7,493
IGCC 400	Integrated Gasification CC w/o CO2 capture	908	1135	1476	11,016
IGCC 400	Integrated Gasification CC with CO2 capture	1092	1365	1775	11,602
Renewables	Wind Turbines Biomass Landfill Gas	Currently considered as transactions under Power Purchase Agreement			

IRP Basic Assumptions
Load Forecast

Scenario Assumption		High	Low
1	Industrial	+ 500 GWh/yr base load, 2008 -	-1700 GWh/Yr closure, 2007-
2	Economic Growth	Growth rate 50% higher than base.	Growth rate 50% lower than base.
3	Heating Oil Prices	78 % higher than base forecast	45% lower than base forecast
4	Electricity Price	10% lower than base case, 2007 -	10% above base case, 2007 -
5	Residential Customers	Base case + 250/yr	Base case - 250/yr



IRP Basic Assumptions
Load Forecast



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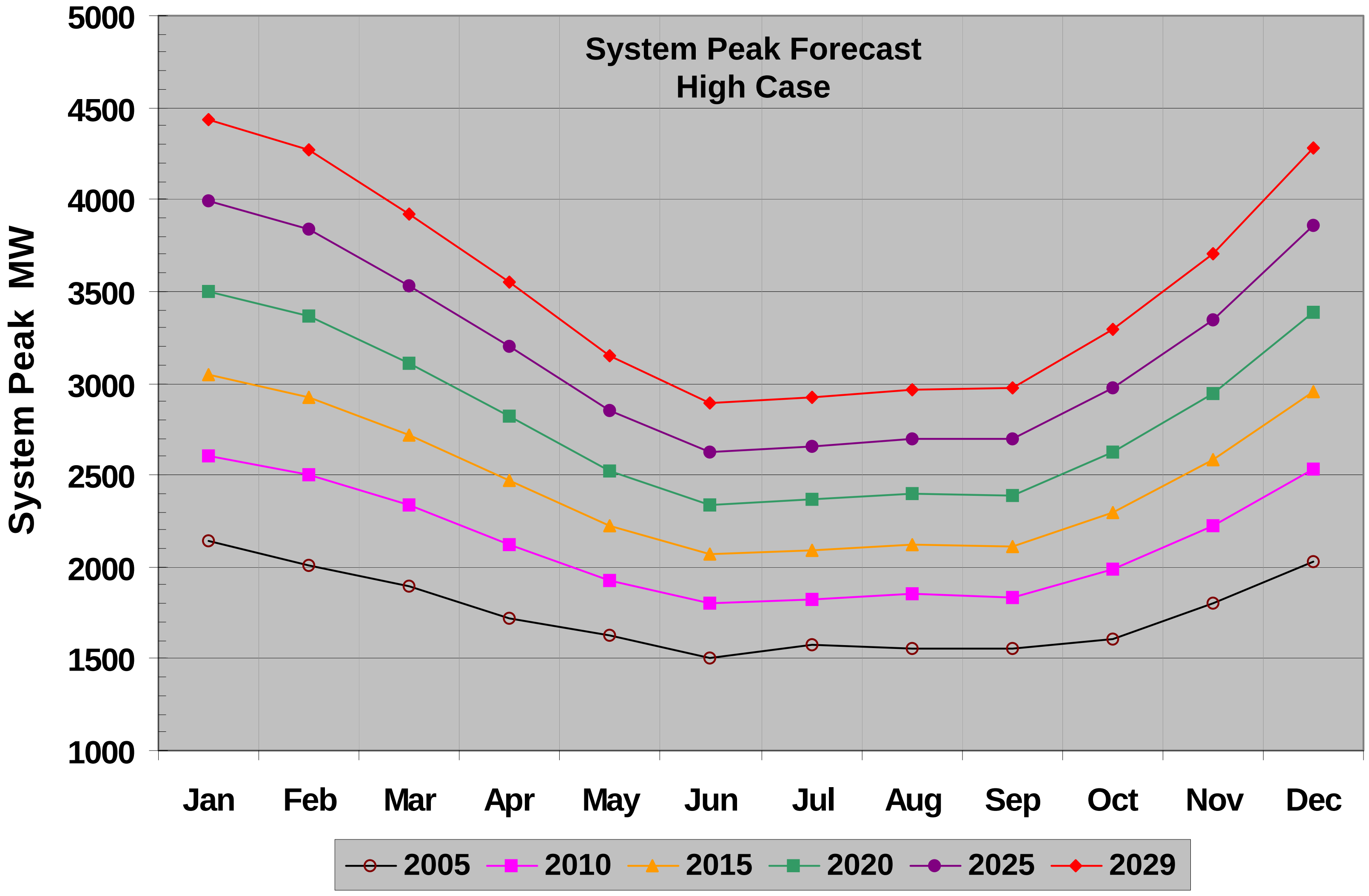
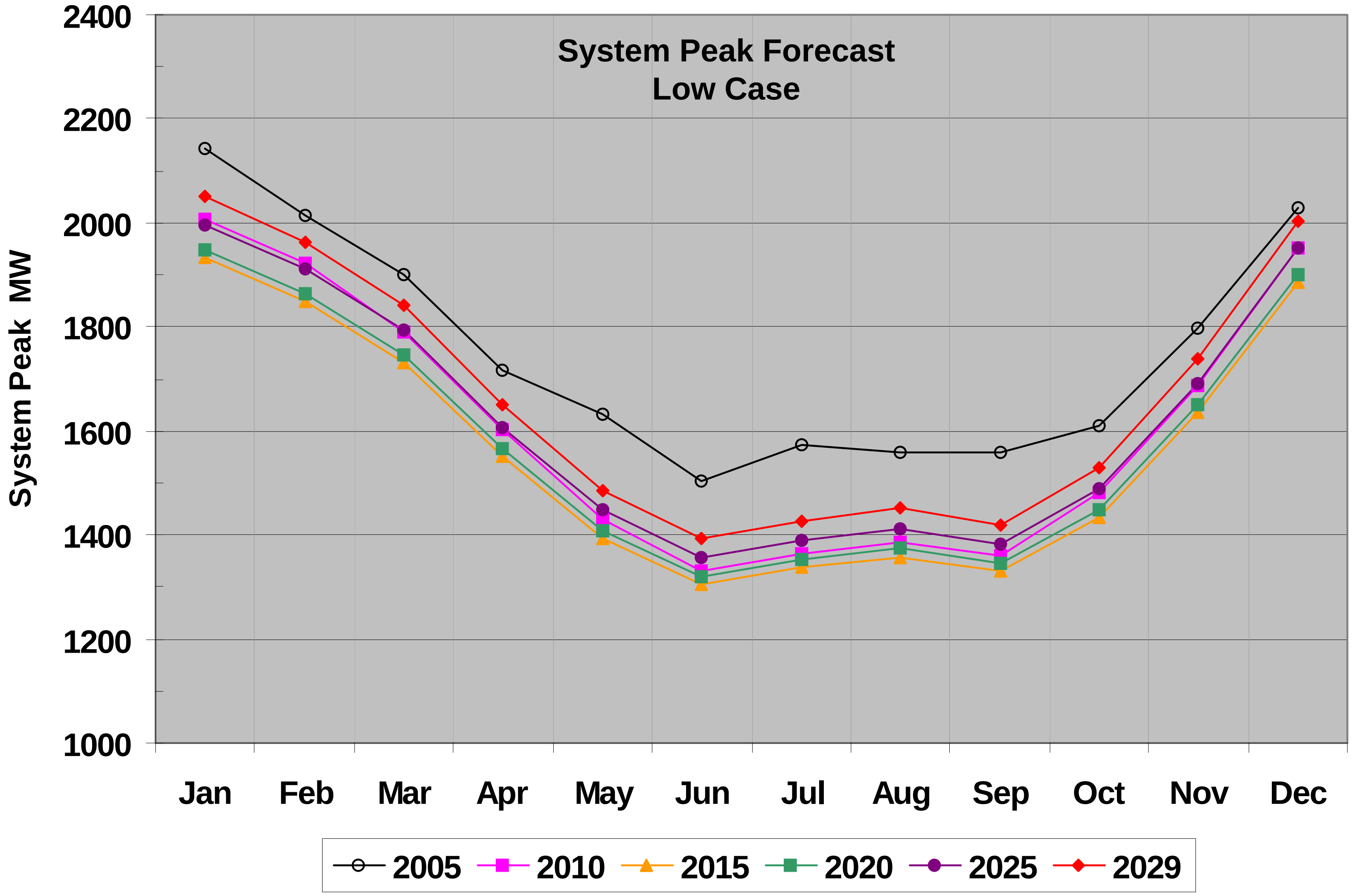
Load Forecast



IRP Basic Assumptions
Load Forecast



IRP Basic Assumptions
Load Forecast

System Peak Forecast (MW)

Year	Low Case MW	Low Case %	Base Case MW	Base Case %	High Case MW	High Case %
2007	2,008	-6.1%	2,256	5.6%	2,285	6.9%
2008	2,033	1.3%	2,312	2.5%	2,433	6.4%
2009	2,027	-0.3%	2,363	2.2%	2,517	3.5%
2010	2,008	-0.9%	2,413	2.1%	2,604	3.5%
2011	1,986	-1.1%	2,460	1.9%	2,691	3.3%
2012	1,966	-1.0%	2,504	1.8%	2,778	3.2%
2013	1,950	-0.8%	2,548	1.7%	2,864	3.1%
2014	1,938	-0.6%	2,592	1.7%	2,952	3.0%
2015	1,934	-0.2%	2,639	1.8%	3,042	3.1%
2016	1,931	-0.1%	2,683	1.7%	3,130	2.9%
2017	1,932	0.0%	2,729	1.7%	3,220	2.9%
2018	1,935	0.2%	2,774	1.7%	3,311	2.8%
2019	1,942	0.3%	2,821	1.7%	3,404	2.8%
2020	1,947	0.3%	2,866	1.6%	3,496	2.7%
2021	1,954	0.3%	2,911	1.6%	3,588	2.7%
2022	1,962	0.4%	2,958	1.6%	3,684	2.7%
2023	1,972	0.5%	3,006	1.6%	3,783	2.7%
2024	1,984	0.6%	3,057	1.7%	3,884	2.7%
2025	1,997	0.7%	3,108	1.7%	3,989	2.7%
2026	2,011	0.7%	3,161	1.7%	4,096	2.7%
2027	2,024	0.7%	3,214	1.7%	4,206	2.7%
2028	2,038	0.7%	3,268	1.7%	4,319	2.7%
2029	2,051	0.7%	3,323	1.7%	4,435	2.7%

IRP Basic Assumptions
Demand Side

DSM will be modeled as a Transaction for Strategist to evaluate. It will reflect the Summit Blue recommended DSM hourly profile (broken down to Residential, Commercial and Industrial) out to year 2029. A summary of the 22 year DSM program as identified by Summit Blue is included below. Year 1 is assumed to be 2008.

TOTALS	22 Year Total	Year 1	Year 2	Year 3	Year 5	Year 10	Year 15	Year 20	Year 22
Demand Savings (MW)		6.5	10.4	15.6	19.5	19.4	20.3	22.9	24.4
Cumulative (MW)	**424.3**	6.5	16.9	32.5	71.5	168.8	267.6	376.3	424.3
Energy Savings (GWh)		44.5	71.2	106.8	133.4	133.0	139.7	156.8	166.5
Cumulative (GWh)		44.5	115.6	222.4	489.3	1155.6	1856.6	2582.4	2910.4
Program Costs $ (Millions)	**448.7**	6.6	10.5	15.8	19.7	19.9	21.8	25.5	27.5

For Strategist, alternate DSM scenarios will be created to reflect lower and higher levels of spend along with the associated demand and energy savings. This selects the most cost effective DSM level versus other supply options over the study period.

IRP Basic Assumptions
Economic

	Base Assumption	High	Low
Rate of Return on Equity (ROE)	9.55%	11.00%	9.30%
Maximum Return on Equity	9.80%		
Minimum Return on Equity	9.30%		
(Actual return on equity can vary outside these ranges based on			
actual market conditions including risk and cost of capital.)			
Return on Rate Base	8.21%	11.09%	8.21%
Discount Rate/Weighted Average Cost of Capital			
•Before Tax	8.21%	11.09%	8.21%
•After Tax	6.61%		6.61%
Inflation Rate 2007-2029	2.00%	3.00%	1.00%
Target Capital Structure			
•Debt	62.50%	60%	65%
•Equity	37.50%	40%	35%
Short Term Debt Interest Rate			
2006	4.60%	6.11%	2.08%
2007	4.40%		
2008-2029	4.50%		
Short Term Investment Rate			
2006	4.23%	5.92%	1.99%
2007-2029	4.00%		

IRP Basic Assumptions
Economic

	Base Assumption		High	Low
Long Term Debt Interest Rate				
Capitalized Interest Debt Rate				
Auto Debt Interest Rate				
2006		5.93%	9.80%	5.42%
2007		5.70%		
2008-2029		7.50%		
Federal Income Tax Rate – May 2006 Federal Budget				
2006 – 2007		38.12%	N/A	N/A
2008		36.50%		
2009		36.00%		
2010 – 2029		35.00%		
FX Exchange Rate Forecast				
2007	$	1.13	1.30	1.00
2008	$	1.16	1.30	1.00
2009	$	1.17	1.50	1.00
2010	$	1.21	1.50	1.00
2011	$	1.23	1.62	1.00
2012	$	1.25	1.62	1.00
2013	$	1.28	1.62	1.00
2014	$	1.30	1.62	1.00
2015	$	1.28	1.62	1.00
2016 - 2029	$	1.25	1.62	1.00

IRP Basic Assumptions
Fuel

Natural Gas, HFO and LFO

NOTE: These values represent projections, developed solely for the IRP, and can and will vary significantly in the future.

	CDN$/mmbtu Tuft's Cove Delivered Cost			CDN$/mmbtu Tuft's Cove Delivered Cost			CDN$/mmbtu Tuft's Cove Delivered Cost			CDN $/mmbtu Burnside Delivered Cost		
	Base Case Natural Gas	Low Case Natural Gas	High Case Natural Gas	Base Case 2.2% HFO	Low Case 2.2% HFO	High Case 2.2% HFO	Base Case 1% HFO	Low Case 1% HFO	High Case 1% HFO	Base Case LS LFO	Low Case LS LFO	High Case LS LFO
2008	[redacted]											
2009												
2010												
2011												
2012												
2013												
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2015												
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2025												
2026												
2027												
2028												
2029												

Fuel cost assumptions are considered highly confidential, and have been provided to the UARB for their review for reasonableness.
At the September 22 Technical Conference, NSPI will discuss the methodology used to produce fuel cost assumptions and general trends and predictions in fuel costs.

All costs are nominal.

IRP Basic Assumptions
Fuel

Coal

NOTE: These values represent projections, developed solely for the IRP, and can and will vary significantly in the future.

	CDN$/mmbtu Lingan			CDN$/mmbtu Pt. Aconi			CDN$/mmbtu Pt. Tupper			CDN$/mmbtu Trenton		
	Base Case LS Colombian	Low Case LS Colombian	High Case LS Colombian	Base Case LS Colombian	Low Case LS Colombian	High Case LS Colombian	Base Case LS Colombian	Low Case LS Colombian	High Case LS Colombian	Base Case LS Colombian	Low Case LS Colombian	High Case LS Colombian
2008	[redacted]											
2009												
2010												
2011												
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2028												
2029												

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All costs are nominal.

IRP Basic Assumptions
Fuel

Coal

NOTE: These values represent projections, developed solely for the IRP, and can and will vary significantly in the future.

	CDN$/mmbtu Lingan			CDN$/mmbtu Pt. Aconi			CDN$/mmbtu Pt. Tupper			CDN$/mmbtu Trenton		
	Base Case LS Colombian	Low Case LS Colombian	High Case LS Colombian	Base Case LS Colombian	Low Case LS Colombian	High Case LS Colombian	Base Case LS Colombian	Low Case LS Colombian	High Case LS Colombian	Base Case LS Colombian	Low Case LS Colombian	High Case LS Colombian
2008	[redacted]											
2009	[redacted]											
2010	[redacted]											
2011	[redacted]											
2012	[redacted]											
2013	[redacted]											
2014	[redacted]											
2015	[redacted]											
2016	[redacted]											
2017	[redacted]											
2018	[redacted]											
2019	[redacted]											
2020	[redacted]											
2021	[redacted]											
2022	[redacted]											
2023	[redacted]											
2024	[redacted]											
2025	[redacted]											
2026	[redacted]											
2027	[redacted]											
2028	[redacted]											
2029	[redacted]											

Fuel cost assumptions are considered highly confidential, and have been provided to the UARB for their review for reasonableness.
At the September 22 Technical Conference, NSPI will discuss the methodology used to produce fuel cost assumptions and general trends and predictions in fuel costs.

All costs are nominal.

IRP Basic Assumptions
Fuel

Petroleum Coke

NOTE: These values represent projections, developed solely for the IRP, and can and will vary significantly in the future.

	CDN$ / mmbtu			CDN$ / mmbtu			CDN$ / mmbtu			CDN$ / mmbtu		
	Lingan			Pt. Aconi			Pt. Tupper			Trenton		
	Base Case 6% Petcoke	Low Case 6% Petcoke	High Case 6% Petcoke	Base Case 6% Petcoke	Low Case 6% Petcoke	High Case 6% Petcoke	Base Case 6% Petcoke	Low Case 6% Petcoke	High Case 6% Petcoke	Base Case 6% Petcoke	Low Case 6% Petcoke	High Case 6% Petcoke
2008	[redacted]											
2009	[redacted]											
2010	[redacted]											
2011	[redacted]											
2012	[redacted]											
2013	[redacted]											
2014	[redacted]											
2015	[redacted]											
2016	[redacted]											
2017	[redacted]											
2018	[redacted]											
2019	[redacted]											
2020	[redacted]											
2021	[redacted]											
2022	[redacted]											
2023	[redacted]											
2024	[redacted]											
2025	[redacted]											
2026	[redacted]											
2027	[redacted]											
2028	[redacted]											
2029	[redacted]											

Fuel cost assumptions are considered highly confidential, and have been provided to the UARB for their review for reasonableness.
At the September 22 Technical Conference, NSPI will discuss the methodology used to produce fuel cost assumptions and general trends and predictions in fuel costs.

All costs are nominal.

IRP Basic Assumptions
Transmission

RELIABILITY: NSPI's current spinning reserve requirement per the NS – NB Interconnection Agreement = 32 MW. With the addition of a large generating unit (> 300 MW), spinning reserve = 47 MW.

NSPI IMPORT LEVEL: Import level across the NB Power inter-tie is set at 22% of NSPI's load to a max of 300 MW. With a new 250 – 350 MW unit, the import level would reduce to 100 MW, and with a new unit > 350 MW, the limit would reduce to 0.

To increase the capacity of the NB Power inter-tie to allow more import, significant upgrades to 345kV transmission systems in NB and NS would be required. Historically, the cost differential between in-province generation and imports has not justified the cost of upgrading the inter-tie. Inter-tie upgrades would be part of a future business case to compare importing more energy vs equivalent sourcing within NS.

IRP Basic Assumptions
Transmission

Transmission costs (2006$M) (large unit):

	HRM	Pt Tupper	Eastern Shore
Base	25	154	147
Low	22	120	100
High	60	300	300

Generator location – impact on System Losses:

Location	Losses (% of gen. capacity)
HRM	Neutral
Pt Tupper	4.6%
Eastern Shore	1.8%

IRP Basic Assumptions
NSPI's Planning Process

Generation planning overview - Strategist model:

•Computer software system developed by, and fully supported by, the technical and consulting services of New Energy Associates.

•Supports electric utilities in decision analysis and corporate strategic planning.

•Strategist's broad range of applications includes:

- resource screening and alternative analysis
- generation and fuel modeling
- environmental analysis
- marketing program analysis
- finance and rates planning capabilities and
- network economy interchange

•A flexible control system ties the Strategist application modules together and automates data transfer from one module to another.

IRP Basic Assumptions Conclusion

Planning, by its nature, involves uncertainty, and with long-term planning such as the IRP, uncertainties are magnified. This set of basic assumptions represents a view of the future world in which NSPI and stakeholders must arrive at a decision.

Integrated Resource Plan Basic Assumptions

REDACTED

February 9th, 2007 *(Attachment 1)*

NOVA SCOTIA POWER
An Emera Company

IRP Basic Assumptions Overview

Objective of the IRP, as stated in the Terms of Reference:

"*To develop a resource plan which utilizes supply-side and demand-side options, to enable NSPI to meet future emissions and other requirements in a cost-effective and reliable manner*."

IRP Basic Assumptions
Overview

Following are the basic assumptions for the IRP development, analysis and selection of the most suitable options to meet future emissions and other requirements in a cost-effective and reliable manner, while maintaining a minimum 20% capacity reserve margin above firm loads.

These assumptions are based on NSPI's present best understanding. Recognized experts and consultants, proprietary information sources, publicly available trends, and NSPI's professional experience and judgment are among the sources used to derive these assumptions. NSPI collaborated with UARB staff and UARB consultants in finalizing these assumptions.

The IRP covers the period from 2007 to 2029, and therefore considers solutions with a long-term view. Those solutions with better near-term benefits will be viewed more favourably.

IRP Basic Assumptions Overview

Assumptions for key areas, for example fuel costs, financial or load assumptions, are highly volatile and may change over time, and are therefore impossible to predict accurately. These assumptions or forecasts may change in the future, perhaps substantially.

Therefore, deviations from the assumptions will happen over time. NSPI has used best efforts to provide ranges of realistic values as appropriate, based on current information.

IRP Basic Assumptions
Environmental

SO_2

Current Regulatory Requirements:

As per NS Air Quality Regulations

- SO_2 - 108,750 t/yr 2006 to 2009; 72,500 t/yr in 2010
- S in HFO – 2.0% annual with 2.2% cap.

Regulatory Context:

> Additional reductions considered likely.

> U.S. emission constraints poised to be tightened

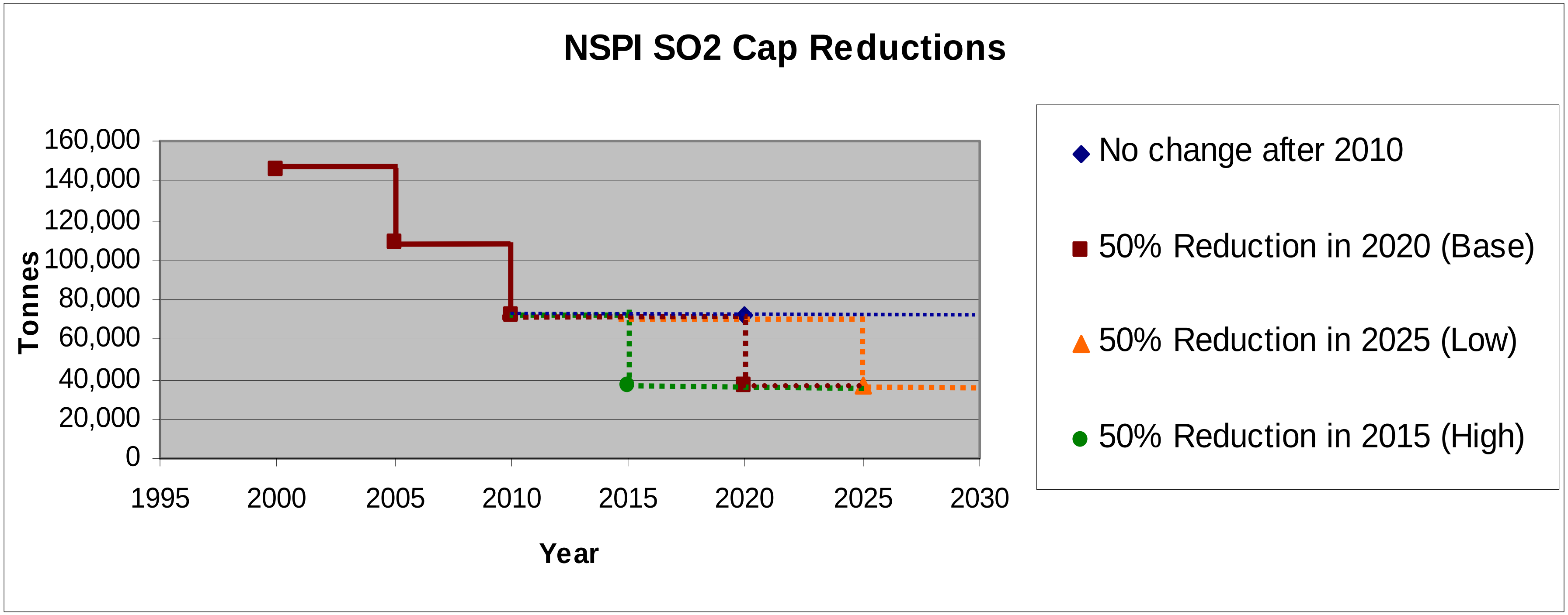
> Achieving new source performance in Nova Scotia would require a 50% reduction from the 2010 cap (Canadian New Source Emission Guideline).

IRP Basic Assumptions
Environmental

SO_2

Case	Reduction
Base	50% reduction from 2010 cap by 2020 (to 36,200 t/yr)
Low	50% reduction from 2010 cap by 2025 (to 36,200 t/yr)
High	50% reduction from 2010 cap by 2015 (to 36,200 t/yr); HFO max 1% S in 2015.

IRP Basic Assumptions
Environmental



IRP Basic Assumptions
Environmental

CO_2 / Greenhouse Gases

Current Regulatory Requirements:

Pending and uncertain

Regulatory Context:

> Canada remains in Kyoto and has developed Bill C30 – Clean Air Act and its Notice of Intent to regulate

- Long term reductions of 45 to 65% with short term intensity based reduction targets

> Capital stock turnover framework proposed by main emitters from the electricity sector.

> Domestic offsets system likely, with possible tie to US offsets and credits

> NEG/ECP* agreed to reduce regional GHG intensity for the electricity sector by 20% by 2025

> UNFCCC* recommends long-term reduction target of 75-85%

*NEG, New England Governors; ECP, Eastern Canadian Premiers

*UNFCCC, United Nations Framework Convention on Climate Change

IRP Basic Assumptions
Environmental

CO_2 / Greenhouse Gases

Case	Year	Emission Constraint	Basis for Constraint
Base	2010	418 tonnes / GWh	Equivalent Performance Emission Standard (EPES) approach beginning in 2010. Parameters are after 45 years of service the specific unit benchmark standard will become 418 t/GWh. Standard reduces over time (350 t/GWh in 2020 then 300 t/GWh in 2030)
Low	2010	880 tonnes / GWh	Similar to Base, use an EPES approach beginning in 2010 with a 50 year life and a standard of 880 t/GWh.
High	2010	418 tonnes / GWh	Similar to Base, use an EPES approach beginning in 2010. Parameters are after 35 years of service the specific unit benchmark standard will become 418 t/GWh (and reduce over time). In addition, apply a 10% "haircut" (i.e. short term, arbitrary) in 2010 to emissions intensity.

Estimated CO_2/Greenhouse Gases Emissions

Case	Approximate Emissions (Million tonnes)				
	2010	2015	2020	2025	2030
Low	10.0	10.1	11.5	11.7	12.6
Base	10.0	9.5	9.1	7.7	6.4
High	7.9	7.6	6.3	6.3	4.5
Kyoto (sensitivity)	6.4	5.6	4.8*	4.5	4.1

**Assume credits no longer available*
1990 CO_2 emissions ~ 6.85M t
Current (2006) CO_2 emissions ~ 10M t / year

IRP Basic Assumptions
Environmental

CO_2 / Greenhouse Gases

Assumed Cost of Offsets (2006$US / tonne CO_2)			
Year	**Base**	**Low**	**High**
2010	11.50	3.00	17.50
2015	18.50	4.50	32.50
2020	23.50	6.50	41.50
2025	30.00	8.50	53.00

IRP Basic Assumptions Environmental

NO_x

Current Regulatory Requirements:

As per NS Air Quality Regulations

NOx cap of 21,365 t/yr. in 2009

Regulatory Context:

> Additional reductions considered likely.

> Historically actions to address NOx in Canada have not been as stringent as for SO_2.

> U.S. emission constraints poised to be tightened.

IRP Basic Assumptions
Environmental

NO_x

Case	Reduction
Base	30% reduction from 2009 cap by 2020 (to 14,700 t/yr)
Low	10% reduction from 2009 cap by 2020 (to 19,000 t/yr)
High	60% reduction from 2009 cap by 2020 (to 9,000 t/yr)

IRP Basic Assumptions
Environmental

Mercury

Current Regulatory Requirements:

Cap of 168 kg/yr. as per NS Air Quality Regulations.

Regulatory Context:

Canada Wide Standards are pending and call for:

- a cap of 65 kg for NSPI in 2010.
- new source performance standards for new coal-fired plants.
- a review of the standards in 2012 to explore an 80% reduction from the 2005 cap.

NEG/ECP Action Plan calls for 75% capture by 2010.

The U.S. is adopting up to 70% capture by 2018.

NSPI emissions are currently lower than the average Canadian & U.S. coal plants.

IRP Basic Assumptions
Environmental

Mercury

Case	Reduction
Base	- 65 kg/yr. cap in 2010 - 34 kg/yr. cap in 2020 (80% reduction from 2005 cap)
Low	- 65 kg/yr. cap in 2012 - 34 kg/yr. cap in 2020 (80% reduction from 2005 cap)
High	- 65 kg/yr. cap in 2010 - 17 kg/yr. cap in 2020 (90% reduction from 2005 cap)

IRP Basic Assumptions
Environmental

Renewable Portfolio Standard

Case	% New renewable (post 2001)
Base	- 2010 - 5% of energy - 2013 - 10% of energy*
Low	- 2010 - 5% of energy - 2013 – 10% of energy*
High	- 2010 - 5% of energy - 2013 -10% of energy* - 2020 - 15% of energy*

NOTE: It is assumed that NSPI will have fulfilled its voluntary commitment that 2.5% of electricity be from renewable sources between 2003 and 2007.

* New capacity and regulation service required to ensure reliability of supply.

IRP Basic Assumptions
Supply Side

Summary of Existing Generation Plant

Thermal Unit	Net Demonstrated Capacity (MW)	In Service	Fuel
Tufts Cove 1	81	1965	NG / HFO
Tufts Cove 2	93	1972	NG / HFO
Tufts Cove 3	147	1976	NG / HFO
Trenton 5	150	1969	Coal/Coke/HFO
Trenton 6	157	1991	Coal/Coke/HFO
Pt Tupper	154	1973, coal conversion 1987	Coal/Coke/HFO
Lingan 1	155	1979	Coal/Coke/HFO
Lingan 2	155	1980	Coal/Coke/HFO
Lingan 3	155	1983	Coal/Coke/HFO
Lingan 4	155	1984	Coal/Coke/HFO
Pt Aconi	171	1994	Coal/Coke & limestone sorbent (CFB)
Combustion Turbines			
Tusket 1*	24		LFO
Burnside 1 – 4*	4 @ 33		LFO
Victoria Junction 1 – 2*	2 @ 33		LFO
Tufts Cove 4 – 5*	2 @ 49		NG

* winter ratings

IRP Basic Assumptions
Supply Side

Summary of Existing Generation Plant (cont'd)

Hydro	Net Demonstrated Capacity (MW)
Wreck Cove	230
Annapolis Tidal	3.7
Avon	6.8
Black River	22.5
Nictaux	8.3
Lequille	11.2
Paradise	4.7
Mersey	42.5
Sissiboo	24.0
Bear River	13.4
Tusket	2.4
Roseway	1.8

Hydro	Net Demonstrated Capacity (MW)
St Margarets	10.8
Sheet Harbour	10.8
Dickie Brook	3.8
Fall River	0.5
Other	
New Renewables (firm capacity on peak)	18.3
Contract IPP	25.6

IRP Basic Assumptions
Supply Side

Technology Options to Control Emissions at Existing Plant

Alternative	Description	Site Considerations
1	Scrubber in Lingan	Best available site
2	Scrubber in Trenton	Space limitations
3	Scrubber in Pt Aconi	CFB technology used provides SO2 reduction
4	Scrubber in Pt Tupper	Possible but single unit plant
5	Baghouse in Lingan	Not required to meet emissions regulations
6	Baghouse in Trenton	Not required to meet emissions regulations / Best application of technology
7	Baghouse in Pt Aconi	Already has a baghouse
8	Baghouse in Pt Tupper	Not required to meet emissions regulations
9	LNCFS in Lingan	Best available site for more LNCFS (e.g. Unit 3 completed, Units 2&4 2007)
10	LNCFS in Trenton	Unit 5 being considered; Unit 6 has low NOx technology
11	LNCFS in Pt Aconi	CFB technology used
12	LNCFS in Pt Tupper	Being considered, if needed to meet emissions regulations
13	SCR / SNSC in Lingan	Not needed until emissions requirements reduce further, most economic site will then be determined
14	SCR / SNCR in Trenton	Not needed until emissions requirements reduce further, most economic site will then be determined
15	SCR / SNCR in Pt Aconi	CFB technology used provides NOx reduction
16	SCR / SNCR in Pt Tupper	Not needed until emissions requirements reduce further, most economic site will then be determined
17	Carbon Injection in Lingan	Not required if a scrubber is provided
18	Carbon Injection in Trenton	Unit 5 would be considered when baghouse added
19	Carbon Injection in Pt Aconi	Could be added to existing baghouse if emissions requirements reduce further
20	Carbon Injection in Pt Tupper	Least likely site
21	Sorbent injection	Not economical with intended fuels
22	Ozone	Not commercially proven
23	Plasma technology	Not commercially proven
24	CO_2 sequestration	Not commercially proven, geology unknown

Technology Options to Control Emissions at Existing Plant (for further study)

Plant/Unit	Technology	Emission Impact (% Removal)			
		NOx	SO_2	Hg	CO_2
Lingan (1-4)	Low NOx Burners	50	N/A	N/A	low
	Selective Catalytic Reduction (SCR)	50[1]	N/A	N/A	low
	Wet Scrubber (FGD) (2 units)	N/A	95	45[2]	high
	Seawater Scrubber (2 units)	N/A	$95\%_{MAX}$ @ 1.7%S	45	high
	Dry Lime Scrubber (2 units)	N/A	95%max	45	moderate
	Baghouse + Carbon Injection			85[2]	moderate
Pt. Tupper	Low NOx Burners	50	N/A	N/A	low
	Selective Catalytic Reduction	50[1]	N/A	N/A	low
	Baghouse + Carbon Injection			85[2]	moderate
Trenton 5	Low NOx Burners	50	N/A	N/A	low
	Dry Lime Scrubber	N/A	95% max	40[2]	moderate
	Selective Catalytic Reduction	50[1]	N/A	N/A	low
	Baghouse + Carbon Injection			85[2]	moderate
Trenton 6	Low NOx Burners	45	N/A	N/A	low
	Dry Lime Scrubber	N/A	95% max	40[2]	moderate
	Selective Catalytic Reduction	50[1]	N/A	N/A	low
	Baghouse + Carbon Injection			85[2]	moderate

Notes:
(1) SCR would allow 50% on top of that gained by Low NO_x Burners.
(2) Hg collection depends on coal specification.
(3) Early retirement of Trenton Unit 5 will also be evaluated as a control option during Strategist runs.

IRP Basic Assumptions
Supply Side

Technology Alternatives to Meet Future Generation Requirements

Alternative	Description	Assessment Summary
1	Nuclear	NSPI is prohibited from building nuclear by NS legislation
2	Wind	Desired by NSPI if economical (in addition to RPS requirements). Integration issues to be assessed/addressed.
3	Biomass	Desired by NSPI if economical (in addition to RPS requirements)
4	Landfill gas	Desired by NSPI if economical (in addition to RPS requirements)
5	Geothermal	Not available at utility scale
6	Solar (photovoltaic)	Consideration to be based on preliminary screening analysis
7	Fuel cells	Consideration to be based on preliminary screening analysis
8	Cogeneration	Consideration to be based on preliminary screening analysis
9	Tidal	Consideration to be based on preliminary screening analysis
10	Distributed generation / micro turbines	Consideration to be based on preliminary screening analysis
11	Pumped storage	No available sites in NS
12	Access to customers' generation	Net metering is in place; opportunities limited by economics
13	Shared with neighbouring utilities	Opportunities for joint development with 3rd parties are regularly investigated

A 250 GWh allowance for potential co-gen / distributed generation in 2012 will be modeled as a sensitivity.

IRP Basic Assumptions
Supply Side

Options to Increase Generation / Fuel Switch at Existing Plant (for further study)

Alternative	Technology	Net Capacity Increase - MW	Fuel Type
Burnside Gas	Gas Conversion	0	Gas
TUC1 +15MW	Uprate	15	HFO/Gas
Nictaux	Hydro	2.5	Water
Marshall Falls	Hydro	1.8	Water
TUC 2 +6MW	Uprate	6	Oil/Gas
Lingan 1-4 +5MW	Uprate	4 X 5	Coal/Coke/HFO
Lingan 1-4 +20MW	Uprate	4 X 20	Coal/Coke/HFO
TUC 6 C-C	Convert TUC 4 & 5 to C-C with duct firing.	52.5	Gas

IRP Basic Assumptions
Supply Side

Options to Add New Generation (for further study)

Alternative	Technology	Net Capacity Increase - MW	Fuel Type[1]
LM6000	Simple cycle Combustion Turbine (CT) unit	49.4	Gas
CC150	2XLM6000, 50MW steam island	151	Gas
CC 280	New CT based Combined Cycle unit	280	Gas
CFB 400 Supercritical Boiler	Circulating Fluidized Bed	400	Coke/Coal 80/20
PC 400 Supercritical with FGD, SCR and CO_2 Capture	Pulverized Coal with Amine Scrubber	400	Coal/Coke 85/15
PC 400 Supercritical with FGD, SCR	Supercritical PF Coal	400	Coal/Coke 85/15
CFB 265	Sub Critical CFB	265	Coke/Coal 80/20
IGCC 400 without CO_2 Capture	Coal gasification CC	400	Coke/Coal 80/20
IGCC 400 with CO_2 Capture	Coal Gasification CC with CO shift and CO_2 Capture	400	Coke/Coal 80/20
Renewables (including capacity back-up when required*)	Wind turbines*, biomass, landfill gas	Incremental	various

Note: (1) Fuel as modeled, alternative blends including biomass would be considered an optimization.

IRP Basic Assumptions
Supply Side

Capital Cost Assumptions – Indicative Pricing

In evaluating the capital for both technology options to control emissions at existing plants and for future supply side options, indicative pricing was developed using ranges based on previous work and our current level of understanding. Actual pricing can vary based on market conditions.

All prices are 2006 $Can. In the case of larger units or components of significant dollar value, pricing is based on industry selected United States Gulf Coast, modified to Nova Scotia market conditions. (Current practice for industry feasibility studies.)

This costing approach is typical of methods used in most other jurisdictions for long-term planning purposes.

IRP Basic Assumptions
Supply Side

Indicative Pricing methodology: Examples

NOx Burners	± 10 %	First unit is now under construction
Burnside Gas / TUC Mods	+ 15% / -10%	Studies done and engineering review done. No construction.
Lingan Upgrades		
Baghouse/Carbon Injection	+ 20% / - 10%	Budget Estimates from suppliers. No detailed engineering.
Future Additions	+ 30% / -10%	

Generally classified as ± 30% overnight pricing. Information from technical conferences and participation in industry expert groups. Modified to +30% / -10% to reflect current market outlook on labour and supply. Pricing may vary based on market conditions. The individual cost estimates on the following slides reflect the degree of uncertainty associated with the cost of those technologies.

IRP Basic Assumptions
Supply Side

Technology assumptions:

Where dry scrubbers are used on units, the cost of a baghouse must also be included. The Trenton 5 Baghouse is an appropriate proxy value.

Activated Carbon Injection is used for Hg capture solutions. It is understood that different types of activated carbon would be included.

Fuel is not included in the O&M cost estimates.

In the case of gas turbines, incremental O&M costs are added for blade life.

IRP Basic Assumptions
Supply Side

Technology Options to Control Emissions at Existing Plant - Costs

Plant/Unit	Technology	Capital Cost			O&M (2006$)
		Low	Base	High	Total Annual O&M
		2006M$			K$ / yr
Lingan 1-4	Low NOx Burners	4.2	4.6	5.1	0
	2.5% S Wet Limestone (2 units)	156	183	210	6,341
	2.5% S Dry Lime(2 units)*	110	146	183	12,940
	1.7% S Wet Limestone (2 units)	149	175	201	5,624
	1.7% S Dry Lime (2 units)*	105	140	175	9,657
	1.7% S Seawater(2 units)	149	199	249	6,289
	Selective Catalytic Reduction (SCR)	19	21.1	27.4	1,060
Pt. Tupper	Low NOx Burners	4.2	4.6	5.1	0
	Selective Catalytic Reduction	19	21.1	27.4	1,060
Trenton 5	Low NOx Burners	4.2	4.6	5.1	0
	Carbon Injection(1.5M$) /Baghouse(29 M$)	27.5	30.5	36.6	1,262
	Selective Catalytic Reduction	22	24.5	31.9	1,060
Trenton 6	Low NOx Burners	4.2	4.6	5.1	0
	Selective Catalytic Reduction	23.4	26	33.8	1,124

***Note: Lime receiving and storage costs not included to date**

IRP Basic Assumptions
Supply Side

Options to Increase Generation / Fuel Switch at Existing Plant - Costs

Alternative	Technology	Capital Cost			O&M (2006)
		Low	Base	High	Total Annual O&M
		2006M$			K$/yr
BSD Gas	Gas Conversion	4.6	5.1	5.8	0
TUC1 +15MW	Increase Capacity	3.6	4.0	4.6	0
Nictaux	Hydro	3.3	3.7	4.8	minimal
Marshall Falls	Hydro	3.2	3.5	4.6	minimal
TUC2 +6MW	Increase Capacity	1.8	2.0	2.3	0
Lingan 1-4 +5MW	Increase Capacity	4.5	5.0	6.0	0
Lingan 1-4 +20MW	Increase Capacity	18	20.0	24.0	0
TUC6	Combined Cycle Convert TUC 4&5 Add HRSG	51	56	62	1,150

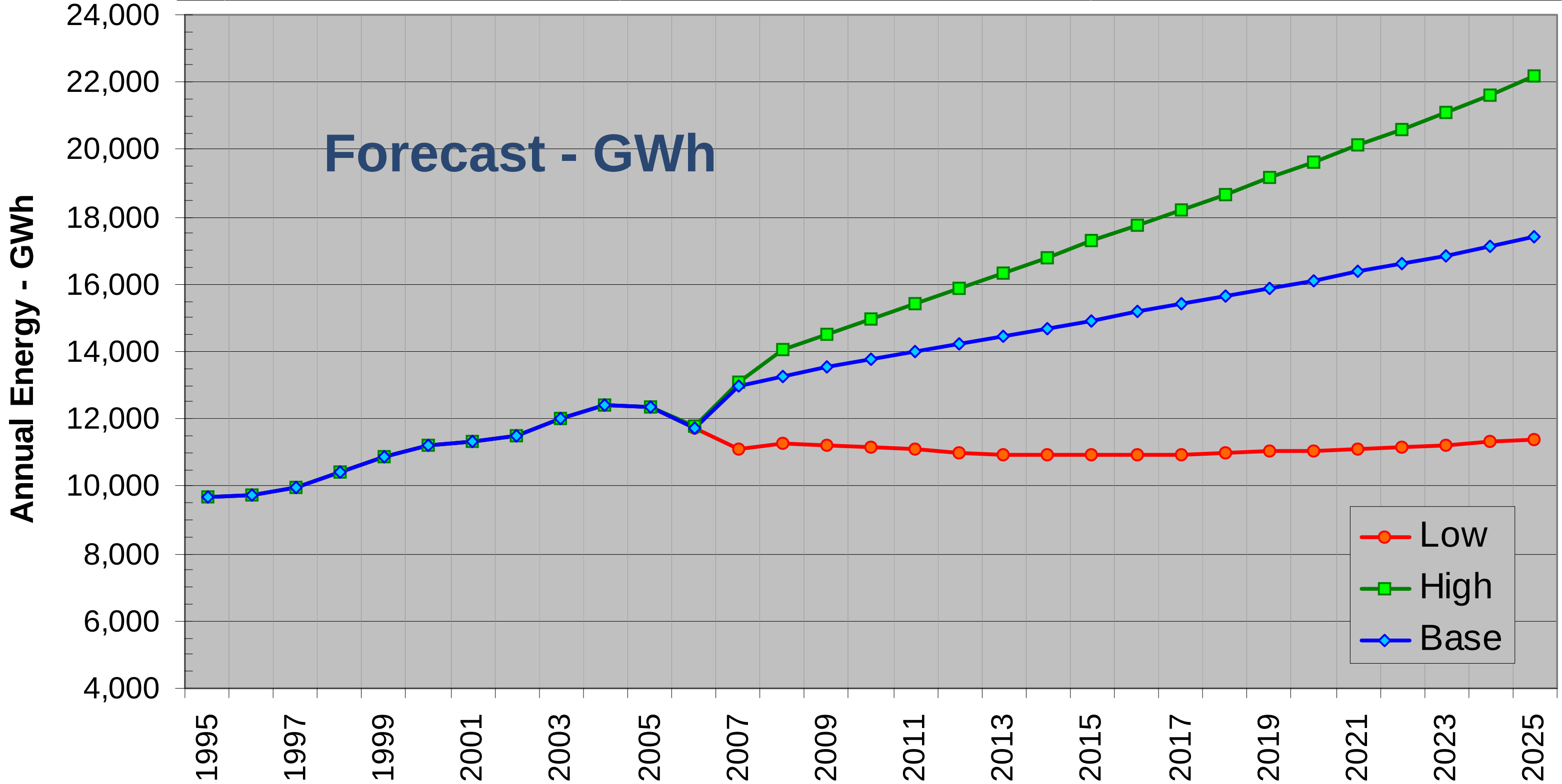
IRP Basic Assumptions
Supply Side

Options to Add New Generation - Costs

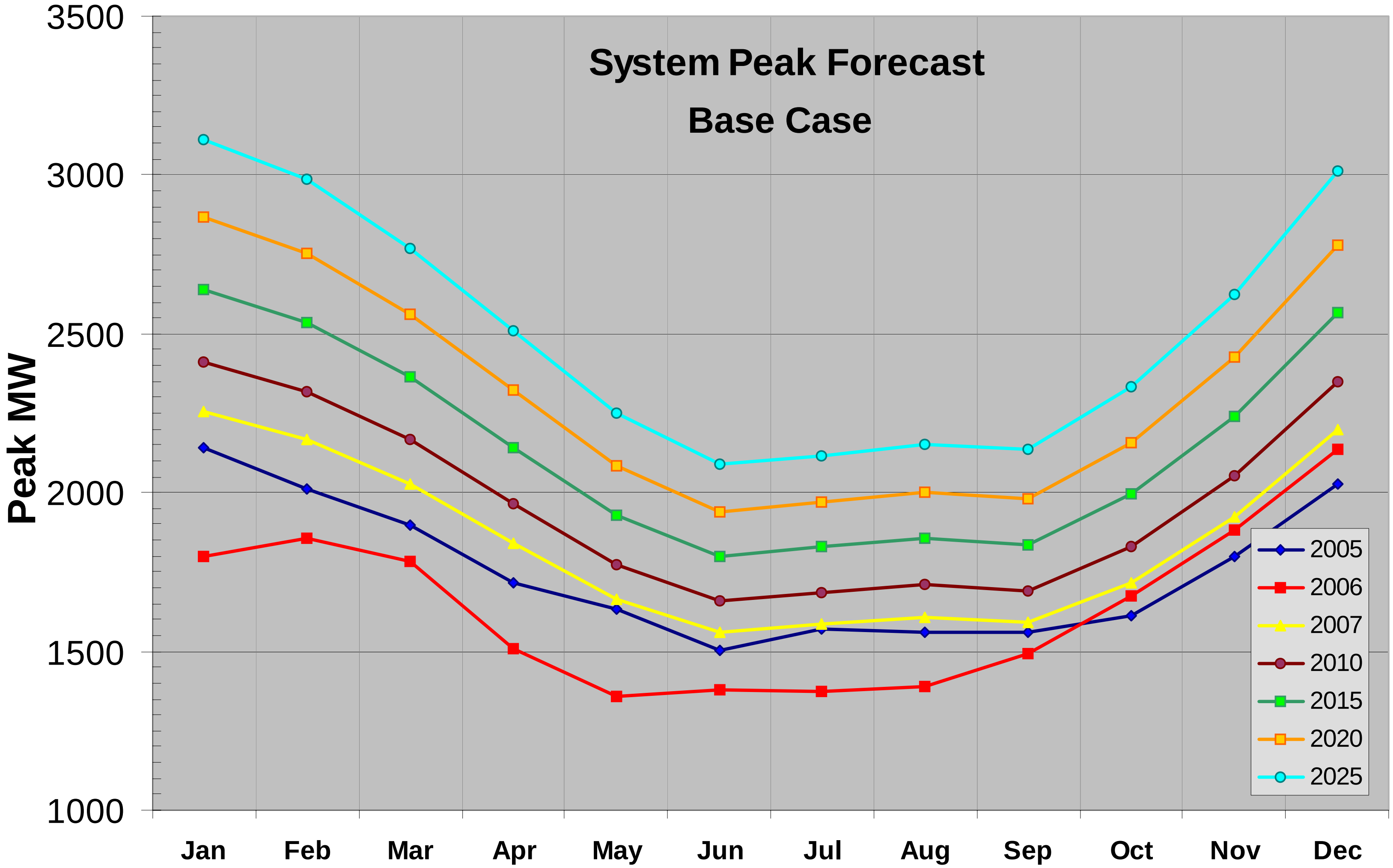
Alternative	Technology	Capital Cost			O&M (2006)
		Low	Base	High	Total Annual O&M
		2006M$			K$/yr
LM6000	Combustion Turbine	37.8	42	46.2	1,627
CC150	New LM6000 based Combined Cycle	109	121	160	4,226
CC 280	Combined Cycle	172	215	275	8,641
CFB 400	Circulating Fluidized Bed , Supercritical Boiler	802	1003	1304	10,522
PC 400	Super Critical with FGD,SCR, Mercury Capture and CO2 capture	1088	1361	1769	11,208
PC 400	Ultra Super Critical with FGD, SCR, Mercury Capture	846	996	1295	10,217
CFB 265	Sub Critical CFB	575.2	719	935	7,493
IGCC 400	Integrated Gasification CC w/o CO2 capture	908	1135	1476	11,016
IGCC 400	Integrated Gasification CC with CO2 capture	1092	1365	1775	11,602
Renewables	Wind Turbines Biomass Landfill Gas	> Considered as transactions under Power Purchase Agreement, $85/MWh RPS 2010, $80/MWh RPS 2013; > System integration cost proxy applied to wind $10 USD/MWh (~ 0.3 : 1 back-up capacity/regulation per unit of wind generation)			

IRP Basic Assumptions
Load Forecast

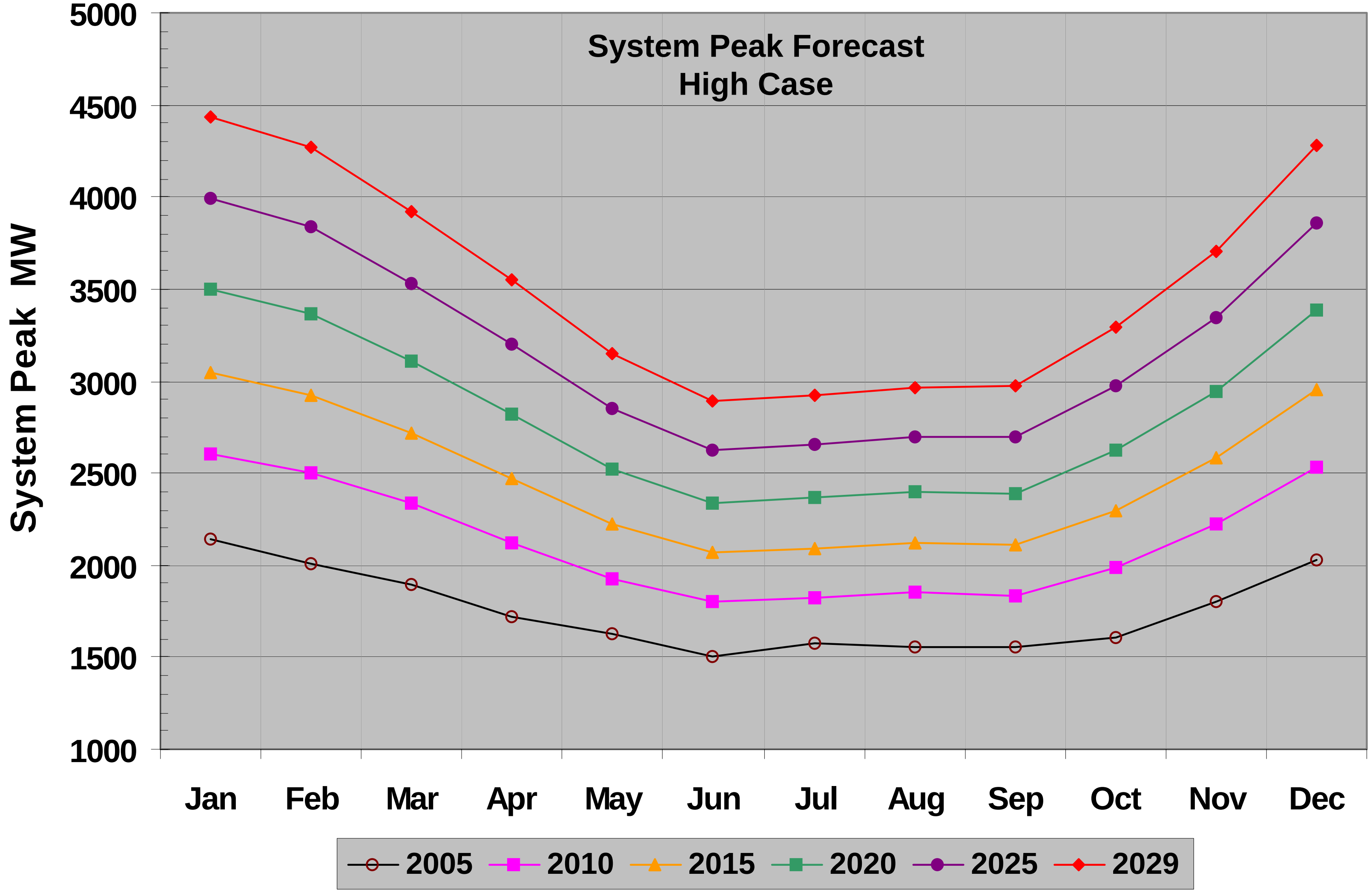
Scenario Assumption		High	Low
1	Industrial	+ 500 GWh/yr base load, 2008 -	-1700 GWh closure, 2007 -
2	Economic Growth	Growth rate 50% higher than base.	Growth rate 50% lower than base.
3	Heating Oil Prices	78 % higher than base forecast	45% lower than base forecast
4	Electricity Price	10% lower than base case, 2007 -	10% above base case, 2007 -
5	Residential Customers	Base case + 250/yr	Base case - 250/yr



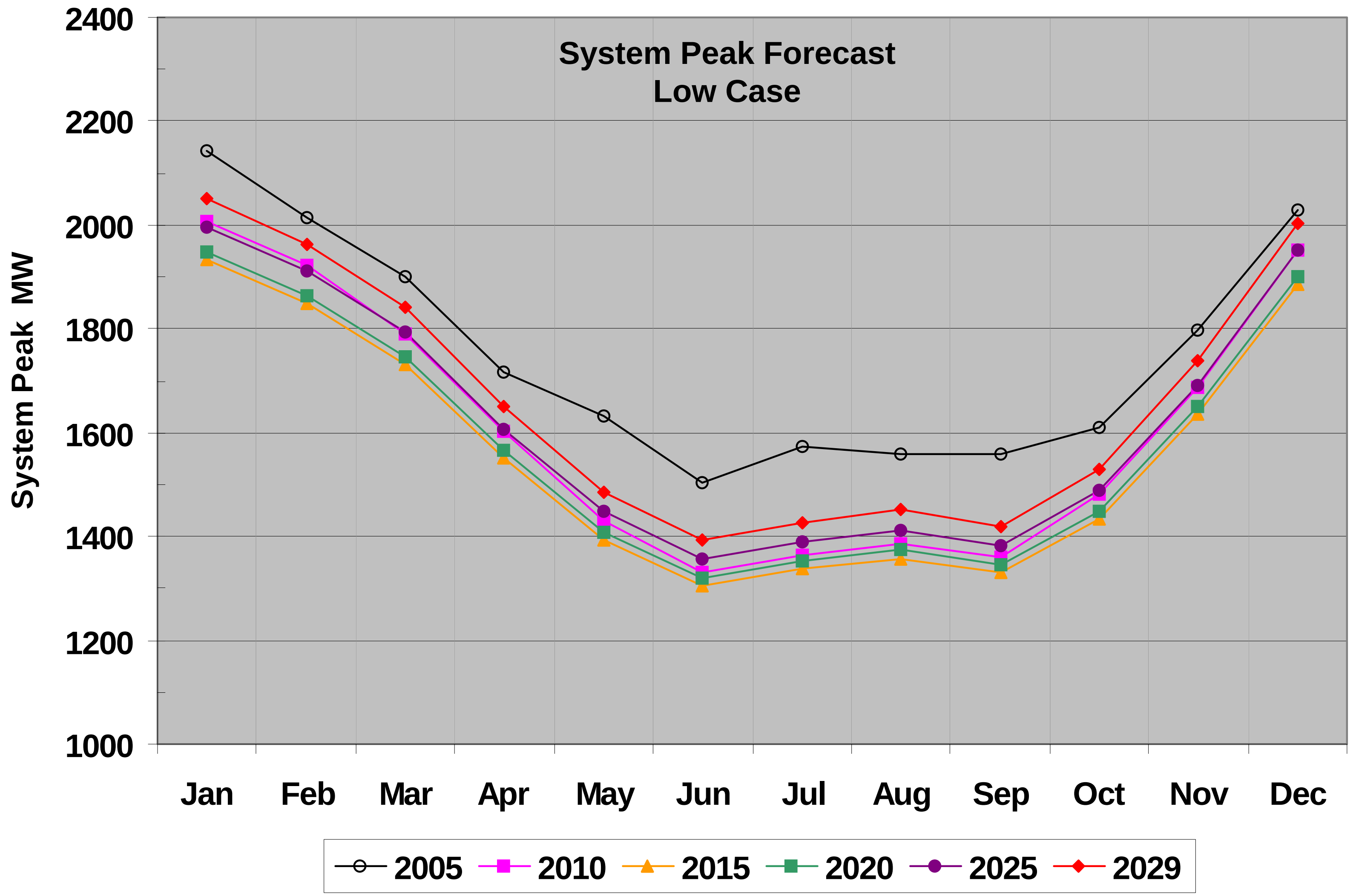
IRP Basic Assumptions
Load Forecast



IRP Basic Assumptions
Load Forecast



IRP Basic Assumptions
Load Forecast



IRP Basic Assumptions
Load Forecast

System Peak Forecast (MW)

Year	Low Case MW	Low Case %	Base Case MW	Base Case %	High Case MW	High Case %
2007	2,008	-6.1%	2,256	5.6%	2,285	6.9%
2008	2,033	1.3%	2,312	2.5%	2,433	6.4%
2009	2,027	-0.3%	2,363	2.2%	2,517	3.5%
2010	2,008	-0.9%	2,413	2.1%	2,604	3.5%
2011	1,986	-1.1%	2,460	1.9%	2,691	3.3%
2012	1,966	-1.0%	2,504	1.8%	2,778	3.2%
2013	1,950	-0.8%	2,548	1.7%	2,864	3.1%
2014	1,938	-0.6%	2,592	1.7%	2,952	3.0%
2015	1,934	-0.2%	2,639	1.8%	3,042	3.1%
2016	1,931	-0.1%	2,683	1.7%	3,130	2.9%
2017	1,932	0.0%	2,729	1.7%	3,220	2.9%
2018	1,935	0.2%	2,774	1.7%	3,311	2.8%
2019	1,942	0.3%	2,821	1.7%	3,404	2.8%
2020	1,947	0.3%	2,866	1.6%	3,496	2.7%
2021	1,954	0.3%	2,911	1.6%	3,588	2.7%
2022	1,962	0.4%	2,958	1.6%	3,684	2.7%
2023	1,972	0.5%	3,006	1.6%	3,783	2.7%
2024	1,984	0.6%	3,057	1.7%	3,884	2.7%
2025	1,997	0.7%	3,108	1.7%	3,989	2.7%
2026	2,011	0.7%	3,161	1.7%	4,096	2.7%
2027	2,024	0.7%	3,214	1.7%	4,206	2.7%
2028	2,038	0.7%	3,268	1.7%	4,319	2.7%
2029	2,051	0.7%	3,323	1.7%	4,435	2.7%

IRP Basic Assumptions
Demand Side Management

DSM will be modeled as Load Groups for Strategist to evaluate. It will reflect the Summit Blue recommended DSM hourly profile (broken down to Residential, Commercial and Industrial) out to year 2029. A summary of the 22 year horizon, with DSM spending level at approximately 2% of annual revenue, is included below. Year 1 is assumed to be 2008.

TOTALS	22 Year Total	Year 1	Year 2	Year 3	Year 5	Year 10	Year 15	Year 20	Year 22
Demand Savings (MW)		6.5	10.4	17.5	26.4	34.2	36.4	41.0	43.4
Cumulative (MW)	**705.1**	6.5	16.9	34.4	84.0	248.4	424.8	619.5	705.1
Energy Savings (GWh)		44.5	71.2	106.8	142.4	166.8	169.8	183.9	192.6
Cumulative (GWh)	**3419.4**	44.5	115.6	222.4	489.3	1313.3	2151.6	3038.7	3419.4
Utility Costs ($Millions)	**589.1**	6.6	10.5	16.5	23.3	28.7	29.8	32.9	34.6

- **Costs are expressed in 2006 dollars.**

IRP Basic Assumptions
Demand Side Management

For Strategist, three levels of DSM effort were created to reflect various levels of DSM spending along with the associated demand and energy savings. These were developed for each of the three Customer Sectors (Residential, Commercial, and Industrial). These three levels were established at approximately 1%, 2% and 5% of annual revenue.

Sensitivity analysis will consider the uncertainty of DSM costs, ranging from 75% to 125% of the Total Resource Cost to accomplish the same levels of demand and energy savings.

The next Slide shows the three levels of effort for each of the three Customer Sectors as Totals over the 22 year horizon.

IRP Basic Assumptions
DSM – Three Levels of Benefits and Costs

- **The numbers presented below reflect Totals over the 22 year horizon**.
- **Costs are expressed in 2006 dollars.**

DSM Spending as % of Annual Revenue		Residential	Commercial	Industrial
~ 2%	Utility Cost ($Millions)	290.0	118.4	180.7
	Customer Cost ($Millions)	205.1	234.4	431.8
	Total Resource Cost ($Millions)	495.1	352.7	612.6
	Demand Savings (MW)	226.4	170.3	308.5
	Energy Savings (GWh)	886.4	763.7	1769.3
~ 1%	Utility Cost ($Millions)	145.0	59.2	90.4
	Customer Cost ($Millions)	102.5	117.2	215.9
	Total Resource Cost ($Millions)	247.5	176.4	306.3
	Demand Savings (MW)	113.2	85.1	154.2
	Energy Savings (GWh)	443.2	381.8	884.7
~ 5%	Utility Cost ($Millions)	725.0	295.9	351.9
	Customer Cost ($Millions)	141.4	321.4	487.6
	Total Resource Cost ($Millions)	866.4	617.3	839.5
	Demand Savings (MW)	396.1	298.0	418.9
	Energy Savings (GWh)	1551.2	1336.4	2467.3

IRP Basic Assumptions
Economic

	Base Case	High	Low	
Rate of return on equity	9.55%	11.00%	9.30%	
Maximum return on equity	9.80%	11.25%	9.55%	
Minimum return on equity	9.30%	10.75%	9.05%	
Discount Rate/WACC/Return on rate base - before tax	8.21%	10.89%	5.79%	
Discount Rate/WACC/Return on rate base - after tax	6.62%	8.00%	5.08%	
Inflation Rate 2007-2029	2.00%	3.00%	1.00%	
Target capital structure:				
Debt	62.50%	60.00%	65.00%	
Equity	37.50%	40.00%	35.00%	
Short-term interest rates				
2006	4.60%	6.11%	2.08%	
2007	4.40%	6.50%	2.00%	
2008-2029	4.50%	10.00%	2.00%	
Short-term investment rate				
2006	4.23%	5.92%	1.99%	
2007-2029	4.00%	9.00%	2.00%	

IRP Basic Assumptions
Economic

	Base Case	High	Low	
Long-term interest rates				
2006	5.90%	9.00%	4.20%	
2007	5.70%	9.00%	4.20%	
2008-2029	7.50%	12.00%	4.00%	
Income tax rate				
2006-2007	38.12%	-	-	
2008	36.50%	-	-	
2009	36.00%	-	-	
2010-2029	35.00%	-	-	
FX Exchange Rate Forecast				
2007	$ 1.13	$ 1.30	$ 1.00	
2008	$ 1.16	$ 1.30	$ 1.00	
2009	$ 1.17	$ 1.50	$ 1.00	
2010	$ 1.21	$ 1.50	$ 1.00	
2011	$ 1.23	$ 1.62	$ 1.00	
2012	$ 1.25	$ 1.62	$ 1.00	
2013	$ 1.28	$ 1.62	$ 1.00	
2014	$ 1.30	$ 1.62	$ 1.00	
2015	$ 1.28	$ 1.62	$ 1.00	
2016-2029	$ 1.25	$ 1.62	$ 1.00	

Natural Gas, HFO and LFO

NOTE: These values represent projections, developed solely for the IRP, and can and will vary significantly in the future.

	CDN$ / mmbtu Tuft's Cove Delivered Cost			CDN$ / mmbtu Tuft's Cove Delivered Cost			CDN$ / mmbtu Tuft's Cove Delivered Cost			CDN$ / mmbtu Burnside Delivered Cost		
	Base Case Natural Gas	Low Case Natural Gas	High Case Natural Gas	Base Case 2.2% HFO	Low Case 2.2% HFO	High Case 2.2% HFO	Base Case 1% HFO	Low Case 1% HFO	High Case 1% HFO	Base Case LS LFO	Low Case LS LFO	High Case LS LFO
[redacted]												

All costs are nominal.

Coal

NOTE: These values represent projections, developed solely for the IRP, and can and will vary significantly in the future.

	------------------CDN$ / mmbtu ------------------			------------------CDN$ / mmbtu ------------------			------------------CDN$ / mmbtu ------------------			------------------CDN$ / mmbtu ------------------		
	------------------ Lingan ------------------			------------------ Pt. Aconi ------------------			------------------ Pt. Tupper ------------------			------------------ Trenton ------------------		
	Base Case LS Colombian	Low Case LS Colombian	High Case LS Colombian	Base Case LS Colombian	Low Case LS Colombian	High Case LS Colombian	Base Case LS Colombian	Low Case LS Colombian	High Case LS Colombian	Base Case LS Colombian	Low Case LS Colombian	High Case LS Colombian

[redacted]

All costs are nominal.

Coal

NOTE: These values represent projections, developed solely for the IRP, and can and will vary significantly in the future.

	CDN$ / mmbtu			CDN$ / mmbtu			CDN$ / mmbtu			CDN$ / mmbtu		
	Lingan			Pt. Aconi			Pt. Tupper			Trenton		
	Base Case US MS	Low Case US MS	High Case US MS	Base Case US MS	Low Case US MS	High Case US MS	Base Case US MS	Low Case US MS	High Case US MS	Base Case US MS	Low Case US MS	High Case US MS
[redacted]												

All costs are nominal.

IRP Basic Assumptions
Fuel

Petroleum Coke

NOTE: These values represent projections, developed solely for the IRP, and can and will vary significantly in the future.

	------------------CDN$ / mmbtu ------------------			------------------CDN$ / mmbtu ------------------			------------------CDN$ / mmbtu ------------------			------------------CDN$ / mmbtu ------------------		
	------------------ Lingan ------------------			------------------ Pt. Aconi ------------------			------------------ Pt. Tupper ------------------			------------------ Trenton ------------------		
	Base Case 6% Petcoke	Low Case 6% Petcoke	High Case 6% Petcoke	Base Case 6% Petcoke	Low Case 6% Petcoke	High Case 6% Petcoke	Base Case 6% Petcoke	Low Case 6% Petcoke	High Case 6% Petcoke	Base Case 6% Petcoke	Low Case 6% Petcoke	High Case 6% Petcoke
[redacted]												

All costs are nominal.

IRP Basic Assumptions Transmission

RELIABILITY: NSPI's current spinning reserve requirement per the NS – NB Interconnection Agreement = 32 MW. With the addition of a large generating unit (> 300 MW), spinning reserve = 47 MW.

NSPI IMPORT LEVEL: Import level across the NB Power inter-tie is set at 22% of NSPI's load to a max of 300 MW. With a new 250 – 350 MW unit, the import level would reduce to 100 MW, and with a new unit > 350 MW, the limit would reduce to 0 (i.e. tie acts as "spare generator" in case of loss of largest unit).

To increase the capacity of the NB Power inter-tie to allow more import, significant upgrades to 345kV transmission systems in NB and NS would be required. Historically, the cost differential between in-province generation and imports has not justified the cost of upgrading the inter-tie. Inter-tie upgrades would be part of a future business case to compare importing more energy vs. equivalent sourcing within NS.

IRP Basic Assumptions
Transmission

Transmission costs (2006$M) (large unit):

	HRM	Pt Tupper	Eastern Shore
Base	25	154	147
Low	22	120	100
High	60	300	300

Generator location – impact on System Losses:

Location	Losses (% of gen. capacity)
HRM	Neutral
Pt Tupper	4.6%
Eastern Shore	1.8%

IRP Basic Assumptions
NSPI's Planning Process

Generation planning overview - Strategist model:

•Computer software system developed by, and fully supported by, the technical and consulting services of New Energy Associates.

•Supports electric utilities in decision analysis and corporate strategic planning.

•Strategist's broad range of applications includes:

- resource screening and alternative analysis
- generation and fuel modeling
- environmental analysis
- marketing program analysis
- finance and rates planning capabilities and
- network economy interchange

•A flexible control system ties the Strategist application modules together and automates data transfer from one module to another.

IRP Basic Assumptions Conclusion

Planning, by its nature, involves uncertainty, and with long-term planning such as the IRP, uncertainties are magnified. This set of basic assumptions represents a view of the future world in which NSPI and stakeholders must arrive at a decision.

From: GARGAN, MARLENE
Sent: Friday, February 09, 2007 4:58 PM
To: Aaron Long; Alain Joseph; Andrew Murphy; Branko Zatezabo; Brendan Haley; Bruce Biewald; Bruce Outhouse; Bruno Marcocchio; David MacDougall; Don Regan; G Ternan; George Cooper; George Foote; Howlan Mullally; John Stutz; Johnny McPherson; Julian Boyle; Keshab Gajurel; Larry Hughes; Mandeep Dhaliwal; ME Donovan; Nancy Rubin; Niki Sheth; Richard Penny; Robert Grant; Robert Patzelt; Ross Young; Scott McCoombs; Tylor Wood; William Mahody
Cc: uarb.nmcneil@gov.ns.ca; GALLANT, Rene; FERGUSON, ERIC; MACKENZIE, GRAEME; MACDONALD, LIA; AGUINAGA, JOHN; CANTWELL, KELLY; HATTIE, BILL; DONNELLY, ALLISON
Subject: IRP Basic Assumptions

Attachments: Attachment 1 IRP Basic Assumptions CONFIDENTIAL Feb 9 2007 FINAL.pdf; Attachment 2 Listing of Changes to IRP Basic Assumptions _since Oct 13__Feb9th_FINAL.pdf; Attachment 3 Next Stages.pdf; Attachment 4 IRP Basic Assumptions FTP site Index FINAL.pdf

Over the past several months, NSPI, Board staff and the Board's consultants have collaborated on the development of the modeling assumptions to be employed in the development of NSPI's Integrated Resource Plan. The outcome of this effort is summarized in Attachment 1. Changes from the most recent assumptions document presented to IRP stakeholders on October 13, 2006 are summarized in Attachment 2. Comment on the next stages of the IRP process is provided in Attachment 3.

NSPI will host a Technical Conference February 22nd to receive stakeholder comment on the revised IRP assumptions. The conference is scheduled for 9:00 am to 3:00 pm. The location is yet to be determined.

In addition to the attached information, NSPI has provided other related documentation on a FTP site which is available for viewing by all stakeholders at the following address (a listing of files posted to this site is provided in Attachment 4):

ftp://ext-ftp.emera.com/
Username: nspgp04
Password: nsp0125

Responses to questions raised by Intervenors previously concerning the IRP assumptions, to which NSPI has yet to reply, will be issued by February 20th. With this issuance, further information concerning the IRP modelling process will also be provided.

NSPI looks forward to receiving stakeholder input on the attached assumptions. Information as to the location and agenda for the February 22nd technical conference will be issued shortly.

Yours truly,

Rene Gallant
Regulatory Counsel
Regulatory Affairs

ATTACHMENT 2

SLIDE # (Issue Oct 13, 2006)	**SLIDE # (Issue Feb 9, 2007)**	**CHANGE to Basic Assumption**
OVERVIEW		
5, 6	N/A	- Slides deleted
ENVIRONMENTAL		
SO2		
8	6	- Table updated with revised Low Case assumption as per collaboration between NSPI and UARB Consultants
9	7	- Graph trajectory updated with revised Low Case assumption as per collaboration between NSPI and UARB Consultants
CO2		
10	8	- Preamble updated as per latest Canadian regulatory context for CO2 regulation
11,12	10,11	- Table updated to reflect latest Canadian regulatory and industry outlook for Equivalent Performance Emission Standard (EPES)/capital stock turn over framework. - Carbon prices to be modeled directly in Strategist for plan optimization.
13	9	- Base/Low/High rationale revised to reflect latest Canadian context/outlook re. application of EPES
SUPPLY SIDE		
22	20	- Changed Lingan, Pt Tupper & Trenton 6 Low NOx % reduction - Added note 3 regarding Trenton 5
27	25	- Added last sentence.
Renewables - Wind		
31	29	- Added Purchase Power Agreement cost assumption for renewable generation options, and delta system integration cost to be applied to wind generation (capacity, regulation support).
DSM		
37	35-37	- Slides added to present estimated costs and savings for each of three levels of assumed DSM effort.
ECONOMIC		
38	38	- Completed High & Low values for Max & Min Return on Equity - Revised Return on Rate Base / Discount / WAAC values - Completed High & Low values for Short-term interest rates - Completed High & Low values for Short-term investment rate
39	39	- Completed High & Low values for Long-term interest rates

ATTACHMENT 3

IRP-Next Stages

The next two stages of the IRP, with the associated dates as approved by the Board, are as follows:

- Base Scenarios and Sensitivities — March 2, 2007
- Results of Technical (i.e., Scenarios) Analysis — May 11, 2007

The Base Scenarios and Sensitivities stage will identify the suite of resource plans to be evaluated. Along with the Base Plan (i.e. initial least cost plan), competing plans will be identified which reflect specific attributes (e.g. a renewables plan, a coal plan, a gas plan, a DSM plan).

The sensitivities against which these plans will be assessed will include changes to a single variable (e.g. natural gas prices) and changes to related sets of variables (e.g. a more highly constrained emissions regime). The purpose of the sensitivities is to test for plan robustness (i.e. does the attractiveness of a plan change unduly in response to a change in assumptions).

The Results of the Technical Analysis will be compiled by NSPI and Board staff and consultants for presentation to stakeholders. The results will be summarized according to the effect on revenue requirement as well as other qualitative measures.

Once these stages of the IRP development have been completed, the results of the analysis will be presented to stakeholders. Additional stakeholder consultation will be undertaken in accordance with the original schedule approved by the Board, prior to the filing of the IRP Final Report.

The IRP process provides the relevant information with respect to cost and operating issues associated with specific demand and supply-related technologies.

The outcome of the process will be the identification of a resource plan that:

1. Integrates demand-side and supply-side options and emissions reduction technologies to comply with forecast operating and environmental constraints; and
2. Balances the minimization of revenue requirement over the planning horizon, with system reliability, plan robustness, cash flow, flexibility and future regulatory emissions outlook.

Ultimately the approved plan will provide a guide for the evaluation of future utility applications. The Plan will not commit NSPI or other parties to specific investments, nor will it be prescriptive with respect to the design or execution of demand-side programs or supply-related initiatives. These are generally matters for future UARB applications.

NOVA SCOTIA POWER
Integrated Resource Plan

Responses to Intervenor Comments re Basic Assumptions Fall 2006

NOTE: Slide numbers in the "Issues" column are per document issued October 13th, 2006. References in the "Response" are per Basic Assumptions issued February 9th, 2007.

Issue number	Intervenor	Issue (as of October 13th, 2006 filing)	Response (as of February 9th, 2007 filing)
1	Halifax Regional Municipality Oct 2, 2006	Recommendation # 1: Recommends a flowchart of the current decision making process be supplied to outline the process, inputs and outputs to the IRP.	Please refer to the accompanying document (issued Feb. 20th, 2007), section "IRP Analysis Plan.ppt", for an outline of the modeling, scenario and sensitivity process.
2		Recommendation # 2: Recommends full cost benefit analysis be conducted by UARB/NS Dept of Energy of moving the Systems Operator oversight function out of NSP.	Outside scope of IRP.
3		Recommendation # 3: Recommends a detailed approach and assumptions to identify NSPI's current CO_2/greenhouse gas baseline be provided.	Please see revised slides 8-13 (per Basic Assumptions filing Feb. 9th) and supporting documentation in folder "2 Enviro Emissions" on the NSPI IRP FTP site.
4		Recommendation # 4: Recommends a list of current generation retirement dates be provided with detailed life cycle costing	IRP assumes that all plants remain available for life of planning period. The model will dispatch according to economics while maintaining compliance with operating constraints.
5		Recommendation # 5: Recommends a list of non-NSPIU generation alternative be incorporated in the IRP process with a list of constraints	The Strategist model optimizes system resources. In doing so it evaluates all demand and supply-side options available to meet system requirements while complying with system constraints. The resultant plan does not specify the party who builds the assets.

			With respect to distributed generation and cogeneration, these are not explicitly included as supply options. The reason for this is that these installations are typically unique, reflecting site specific conditions. Consideration of such alternatives for input to modeling will be based on preliminary screening analysis. Excluding these items from the IRP analysis in no way limits their opportunity for development. If they are economically viable with willing investors, they will be pursued regardless of whether they are explicitly included in the IRP assessment.
6		Recommendation # 6: Recommends more involvement in NSPSO function in oversight of load forecasting and generation expansion planning to bring greater transparency to the process and minimize potential conflicts of interest.	Representatives from the NSPSO are involved with the IRP process as necessary for Transmission and other system discussion/input. It is NSPI's expectation that the 2007 IRP will serve as the initial NSPSO filing.
7	NS Environment & Labour Oct 6, 2006	Slide 3: Clarification on how short-term solutions will be favoured	The comment on slide 3 was intended to convey that all else being equal if a plan has lower near-term costs or higher near-term benefits it will be judged favourably.
8		Clarification that the IRP stay with original intent to utilize long term planning	Confirmed.
9		Slide 11: The "low" case scenario of zero emission abatement does not seem likely, and more significant targets should be used for the "high" case scenario	Please see response to item #3. Note that on revised assumptions distributed Oct. 13th and retained in Feb. 9th filing (slide 10), added "Kyoto" per EAC's suggestion to show likely emission limits under Kyoto for incorporation within sensitivity analysis. Please refer to item #1.

10		Slide 22: Qualifiers of “low’, “moderate”, and “high” be changed to quantitative metrics that show the percent increase or decrease of CO2 equivalents with each technology	NSPI’s intention on this slide was to flag the relative or directional impact (i.e. increase) in CO2 emissions associated with each technology. Strategist recognizes emissions associated with parasitic power.
11		Slide 22: Consideration must be given to the effects and costs of storage, handling and management of residuals.	Confirmed.
12		Slide 24: Define the term “Uprate” and detail the technical and fiscal aspects of “uprating” to be provided.	“Uprate” means the provision of technology to an existing generating unit to increase its capacity. Cost details are provided in slide 28 (Feb 9th).
13		Slide 24: Recommend that options to improve existing infrastructure and early retirement of higher emission generation be appropriately weighted as a favourable solution.	Please see response to item #4. Note that early retirement of Trenton Unit 5 will be evaluated as an emissions control option during Strategist runs (per slide 22 in the Feb. 9th).
14		Slide 25: Difference in gross capacity should be made explicit when comparing technologies to arrive at same net capacity	Please refer to the accompanying document (issued Feb. 20th, 2007) “Options to Add New Generation (2).doc” for explicit notation of Gross and Net MW capacity assumed for each new generation option, as well as for estimated lead times for construction (to be updated on Feb. 9th slide 23).
15		Slide 25: Present additional information on the relative cost of producing electricity between different technologies.	Cost details are provided in slides 28 and 29 (Feb. 9th).
16		Slide 25: Include options for IPP, distributed generation and/or co-generation	Please see response to item #5
17		Slide 38:	Please see revised slides 38 and 39 (Feb. 9th) for base, high

		Essential that "high" and "low" discount rates and different planning horizons be applied to determine the sensitivity of present values of all permutations of the assumptions	and low financial assumptions.
18		Externalities: Provide for each suite of preferable options, dispersions and deposition modeling for emissions and comparison with the current state of generation; valuation of those impacts and inclusion of those vales in the IRP process.	Outside scope of IRP. Please refer to the Terms of Reference. IRP examines units in an abstract fashion as opposed to site-specific details. Upon determining the appropriate site for new generation, such matters are for consideration in other permitting approval processes.
19	Ecology Action Centre Oct 6, 2006	Greenhouse Gas Emission	Please see response to item #3. Note that on revised assumptions distributed Oct. 13th and retained in Feb. 9th filing (slide 10), added "Kyoto" per EAC's suggestion to show likely emission limits under Kyoto for incorporation within sensitivity analysis. Please refer to item #1.
20		Local Air Quality	Outside scope of IRP. All NSPI power plants will continue to be in compliance (meet regulations) as established by their environmental operating permits.
21		Plant Retirement Dates	Please refer to item #4.
22		Demand Side Management	Please see revised slides 35-37 (Feb. 9th) and supporting documentation in folder "5 DSM" on the NSPI IRP FTP site. The IRP process will assess the viability of DSM with various spending levels compared to supply alternatives. It will not design the underlying DSM programs or determine who administers them.

23	Barrington Wind Energy Oct 6, 2006	The IRP is a System process, and the differences between NSPI requirements and System requirements need to be clearly noted.	The IRP will address system requirements. Please see response to item #6.
24		The absence of the NSPSO clearly speaks to the need for an ISO.	Please see response to item #23.
25		The absence of underlying information, deemed confidential, invalidates many parties from effective participation.	Information has been made fully available to UARB Staff and Consultants. The IRP FTP site as referenced in the Feb. 9th covering letter provides relevant background for all intervenors to review.
26		There is a presumption that impending emissions reductions requirements are driving the process, rather than providing a system view of the future from all perspectives.	Please see response to item #23.
27		There is a presumption that the inputs and outputs from this process are functional only for the IRP process. Our understanding of an IRP would be that this is the roadmap from which future decisions will be made.	Please refer to the Feb. 9th covering letter: *"Ultimately the approved plan will provide a guide for the evaluation of future utility applications. The Plan will not commit NSPI or other parties to specific investments, nor will it be prescriptive with respect to the design or execution of demand-side programs or supply-related initiatives. These are generally matters for future UARB applications."*
28		The document relating to the determination of the base case of load growth was to have been sent to Stakeholders.	This documentation was provided to Intervenors on Oct 6, 2006. It is also provided on the IRP FTP site referenced in the Feb. 9th covering letter.
29		Slide 11: The Low scenario for CO2 reduction does not even assume that NSPI is implementing the RPS.	NSPI does intend to model Base RPS as indicated on slide 16 (Feb. 9th).
30		Slide 11: Does this assume any increase in total generating capacity by NSPI?	Yes. Slide 10 (Feb. 9th) assumes increased generation to meet load. Please see NSPI's response to request # 9 (by Barrington Wind) from the Sept 22 Technical Conference, contained in the information package issued by NSPI to

			Intervenors on Sept 29.
31		Slide 12: How did NSPI arrive at the "Assumed Cost of Offsets" as the current price is US $10 per ton CO2 o Does this mean that NPSI's "Low" scenario assume that the price of coal will fall over the period to 2010	The assumptions are based on input from industry experts in the field. The cost of offsets is not related to the price of coal. UARB Staff and Consultants have reviewed and are in agreement with NSPI's assessment and conclusion as to appropriate CO2 credit assumptions.
32	Ross Young – UARB Oct 2, 2006	Are values in the tables in current dollars or constant year dollars? If constant dollars, what year?	Values are in 2006 dollars.
33		The numbers in the tables are in Canadian dollars. Were the forecasts derived in US$ and then converted to Canadian dollars using the base case exchange rate shown on slide 39?	For basis of the capital cost assumptions on slides 27-29 (Feb. 9th) see leading slides 24-26 (Feb. 9th). Fuel cost assumptions were derived in US dollars and converted to Canadian using the base case exchange rate. See also items #60-#79 below.
34	Berwick Electric Commission Oct 6, 2006	1: It is implicit, but not explicit, that the outcome from this IRP is to be the basis of decision making and the backbone of information to all Stakeholders beyond the immediate requirement for emission abatement. A clear stipulation in the Final Report that notes this, and stipulates that this document, with (annual) updates, will form the basis of future system planning should be included.	Please see response to item #27
35		2: While several new generation options are suggested, how are the uncertainties around future operations costs going to be a) applied and b) provided to stakeholders during the process.	Please refer to slides 24-29 (Feb. 9th) for cost assumption details.
36		3: At least two IPP renewable projects totaling at least 50-75MW have been proposed and both developers have	Please see response to item #5.

		attempted to work with NSPI to facilitate their development. NSPI to date has been unwilling to engage the developers…	
37		4: Slide 11 applies a low case scenario of 0 GHG reduction by 2015, and a mere 0.1 Mt by 2020. Please note that we do not believe this to be a reasonable reduction, even for the low case and even accepting the current uncertainties in how GHG reductions are going to be achieved.	Please see response to item #3.
38		5: Slide 12 provides a range of costs for CO_2 Offsets. The Low case provides for anticipated purchases from low-cost countries to meet offset requirements. Given that there is anticipated to be a RPS in effect in Nova Scotia very shortly, and that the RPS will accommodate only new renewables (unlike Maine) would it not be more realistic to utilized RPS costs experienced in the RPS states rather than offshore purchases for at least a portion of this cost assumption?	Meeting the provincial RPS will reduce the growth of CO2 emissions but additional offsets may be required. Also, please refer to information presented on the IRP FTP site and the response to item #31.
39		6: Slide 18 applies the scenarios for the implications of a RPS in Nova Scotia… Is it reasonable to assume that only the minimum obligation will be built in Nova Scotia through the next decade.	Please see response to items #5, #29 and #1. Although the base assumptions for IRP contemplate RPS level, the IRP modeling and analysis will assess higher levels of renewables as well.
40		7: Slides 19 and 20 provide current system information. NSPI officials on September 22nd stated there are no assets expected to be retired within the present planning horizon. Various retirement dates for generation assets were evidenced in the Depreciation Hearing in 2004. Please re-file those retirement dates in this proceeding.	Please see response to item #4.
41		8: Slide 23 speaks of options to add new generation, but does	Please see response to item #5.

		not incorporate the Terms of Reference requirement to evaluate Distributed Generation.	
42		9: Slide 37 shows a cumulative (MW) reduction of 424.3MW demand... Can you clarify the 424.3 assertion?	Please see response to item #22.
43		10: NSPI has asserted that fuel information is confidential and cannot be provided to stakeholders...	Please see methodology in IRP FTP site folder "7 Fuel". The underlying data has been reviewed with UARB Staff and Consultants.
44		11: Slide 44 provides a bit of information on the implications of the construction of new generation, but does not provide enough information for parties to assess various options. For example, would the construction of 10 units, each of 30 MW have the same reliability issues, spinning reserve issues, and inter-tie constraint issues as the single 300MW unit would cause?	Please see response to item #5.
45		12: Slide 45 provides a range of transmission costs (we assume capital costs) that would be incurred with the construction of a single large unit in three regions. The cost spread between the Low, Base, and High Cases is huge. Should not these costs be able to be more narrowly defined given that new transmission costs are quite clearly able to be budgeted?	More narrow definition of capital costs would be determined upon system impact study by NSPSO.
46		13: Can more detail as to the derivation of the assumptions be provided?	NSPI has provided additional documentation as to how assumptions were derived on the IRP FTP site as per the Feb. 9th covering letter.
47		14: The lack of fuel data will make all of the outputs invalid from the perspective of the Stakeholders.	Please see response to item #43.

48		15: Please clarify how a long-term system study can be undertaken without the independent validation and participation of the NSPSO.	Please see response to item #6.
49		16: Given that the operating experience of TC5 has been so fundamentally different than what was modeled in the application for that facility, both in terms of need and operating costs, how can the continued emphasis on variable operating cost units, ie fossil fuel units, continue to form the backbone of future planning?	Tuft's Cove 5 has operated as per its business case. 2006 load requirements have been significantly affected by a single customer being offline hence has obviously affected the need for the marginal units, like TC5. Base, reliable generation is required along with other forms of energy.
50	Berwick Electric Commission Oct 10, 2006	…This all important planning function should be the responsibility of the Nova Scotia Power System Operator.	Please see response to item #6.
51		We are particularly interested to know how NSPI will integrate renewables into the IRP, and how NSPI will facilitate and incent development of renewables…	Please see response to item #5 and slides 16, 21, 23, and 29 (Feb. 9th).
52	SEB Oct 6, 2006 Non Conf	2: No cost data is given with respect to these technologies, or any of the other technologies listed on slide 22	Cost information is provided in slide 27 (Feb. 9th).
53		3: Provide cost information for generation / fuel switch options on slides 24 and 25.	Cost information is provided in slides 28 and 29 (Feb. 9th).
54		5a: The high end inflation rate over the entire planning period of 5.6% appears high.	See revised values in slide 38 (Feb. 9th).
55		5b: As risks related to fuel pricing appear more volatile than for capital or other operating expenses, and considering the importance of the fuel price differentials for the analysis,	Analysis will test sensitivities of discount rates on resources plans but will not differentiate between capital and operating or among technologies.

		consideration should be given to a different discount rate for fuel costs than for other capital/operating costs.	
56		5c: It is unclear from slide 39 whether the high and low numbers for the foreign exchange rate of $1.00 and $1.62 are the highs and lows for each year of the planning period or just the first year. This should be clarified.	Please see revised values in slide 39 (Feb. 9th).
57		6: With respect to wind power, NSPI should specifically indicate what value it anticipates may be available to it for the sale of any Renewable Energy Credits ("RECs") for wind power developed by NSPI or acquired by NSPI together with any associated RECs. The underlying assumptions for this value over the planning period should be identified.	REC's or Emission reduction credits (ERC's) have a value in the market place if they are in excess of what is needed in the province. NSPI anticipates to need/use all the REC's from renewable energy in NS to help meet reduction targets in the future, hence are not indicating further value anticipated for resale of such credits.
58		7: As the Board indicated on September 28, 2006 that NSPI's DSM filing will be part of the IRP process, it is important that the assumptions underlying NSPI's proposed DSM plan be thoroughly vetted…	Please see response to item #22.
59		8: SEB requests that NSPI identify which co-generation opportunities have been assessed to date and why NSPI has determined that they are not economical, and that NSPI identify which opportunities for development with neighbouring third parties have been investigated in the past two years, and provide NSPI's views with respect to those opportunities.	Please see response to item #5.
60	SEB Oct 6, 2006 Conf	Coal 1: SEB requests that NSPI provide these costs broken down by FOB coal prices, sea freight and internal inland transportation costs.	Please see methodology in IRP FTP site folder "7 Fuel". The underlying data has been reviewed with UARB Staff and Consultants.

61		Coal 2: It is not clearly stated whether the figures quoted are real or nominal.	Figures are nominal.
62		Coal 3: SEB requests that NSPI provide an explanation of the underlying assumptions on which the figures are based.	Coal commodity pricing is from the Hill and Associates International Coal Trade: Supply, Demand and Prices to 2015 (strictly confidential). At the Sept 22 Technical Conference, NSPI provided a verbal explanation of how the fuel cost assumptions were developed. Also, please see response to items #46 and #60 above.
63		Coal 4: Please clarify whether in the low, base and high cases, NSPI is using the same Canadian/US dollar exchange rate, or whether it is using its low, base and high values for the exchange rate.	The Base case Canadian/US dollar exchange rate was used for all cases.
64		Coal 5: Nowhere in the documentation are price assumptions provided for medium sulphur U.S. sourced coal.	This information has been added in slide 42. Note the typo in issue Oct. 13th did not include MS heading, see corrected slide 42 (Feb. 9th).
65		Coal 6: Please specifically identify why no other sources of coal which are currently being burned by NSPI (mid-sulphur Pittsburgh seam, Venezuelan, etc.) are identified.	Both MS and Venezuelan coals will be modeled.
66		Coal 7: NSPI has not provided any assumptions with respect to ultra-low sulphur fuel from, for example, Russia or Indonesia.	It is assumed on a long-term average basis that these fuels will be priced equivalent to Colombian Imports.
67		Pet Coke 1: A breakdown of petroleum coke pricing between freight and FOB price assumptions is necessary.	Please see item # 60 above.

68		Pet Coke 2: Please clarify whether in the low, base and high cases, NSPI is using the same Canadian/US dollar exchange rate, or whether it is using its low, base and high values for the exchange rate.	Please see item # 63 above.
69		Pet Coke 3: A specific explanation is requested with respect to the jump in pet coke prices in the years 2013-2015, particularly 2014.	Petcoke commodity pricing is from the Jacobs Consultancy Petroleum Price Forecast (strictly confidential). Please see response to item # 60.
70		Pet Coke 4: There are no assumptions provided for anything other than 6% sulphur pet coke. An explanation is required as to why, for example, an analysis of 4% sulphur pet coke is not appropriate.	6% is the more widely available fuel and is appropriate for long term planning; 4% Petcoke is an opportunity fuel.
71		Pet Coke 5: Please provide the key underlying assumptions on which the pet coke forecast was based.	Please see item # 69 above.
72		Natural gas, HFO & LFO 1: Slide 40 shows Burnside Delivered Cost for LFO. Is NSPI assuming that Burnside will not be converted to natural gas at any time during the planning period? If so, please indicate the basis for NSPI's assumption. If not, please provide the assumed natural gas pricing for Burnside for the applicable years.	Please refer to slide 22 (as issued Feb. 9th).
73		Natural gas, HFO & LFO 2: Please identify the relationship between the low, base and high values and the low, base and high exchange rates for each of natural gas, HFO and LFO.	Please see item # 63 above.
74		Natural gas, HFO & LFO 3: Please indicate whether the prices in the forecast are based on	The prices in the forecast are based on the general gas market. Forecast and dispatch are based on the general gas

		the general gas market or whether they take into account the specific terms of the existing contract.	market.
75		Natural gas, HFO & LFO 4: The natural gas forecast assumes escalation of 23%, 29% and 14% for the base, low and high cases, respectively, for the year 2011. Please provide a detailed assumption of the basis for this significant increase. Please also explain why the low case escalator is higher than either the base or high case escalators, and why the base case escalation is so much higher than the high case escalation for 2011.	Natural Gas, HFO and LFO Commodity pricing is from the PIRA Oil, Henry Hub and Gas Basis Forecasts, and the PIRA Oil and Gas Scenario Planning Service (strictly confidential). Please see response to item #60.
76		Natural gas, HFO & LFO 5: In 2014 the natural gas forecast assumes escalation of 6%, 15% and 11% for the base, low and high cases, respectively, and again these figures appear disproportional. SEB requests that NSPI provide a specific explanation.	Please see item #75.
77		Natural gas, HFO & LFO 6: NSPI has provided values only, with no underlying assumptions. Please provide the primary underlying assumptions which are driving each of the forecasts.	Please see item #75.
78		Natural gas, HFO & LFO 7: With respect to 2.2% HFO, on the assumption that gas and oil fluctuate in tandem, at least from a long-term view (although obviously there will be short-term disparities), the ratios of 2.2% HFO to gas for the years 2008, 2009 and 2010 respectively of 1.11, 1.16 and 1.2 for the base case, 0.9, 1.05 and 1.17 for the low case, and 1.13, 1.09 and 1.15 for the high case appear questionable, particularly for the larger ratios greater than 1.1. SEB requests that NSPI provide its views on this point.	Please see item #75.
79		Natural gas, HFO & LFO 8: With respect to 1% HFO for 2009 through 2010 (all cases), it	Please see item # 75.

		appears unusually high in relation to gas. Again, SEB requests that NSPI comment on this point.	
80	GPI Atlantic Oct 6, 2006	Would like to submit their report “The Energy Accounts for the NS Genuine Progress Index” as part of the process.	NSPI acknowledges receipt of this document.
81	NDP Oct 6, 2006	1: It would be in the interest of NSPI’s customers and indeed the company’s shareholders, to incorporate a more realistic assumption now, rather than having to do so in the future when political leadership is finally shown in Canada and Nova Scotia, with regard to climate change.	Please see response to item #3. NSPI believes that these are realistic assumptions for CO_2 reductions.
81		2: The targets being discussed by Nova Scotia Power Incorporated are based on the adoption of intensity targets for CO_2 emissions, rather than the capping of, or reduction in emissions. This methodology of measuring and managing CO_2 emissions is the subject of intense debate in the international scientific community as to its usefulness. The NDP is therefore concerned that NSPI is placing too much emphasis on the usefulness of this methodology in the absence of an international consensus on the subject.	Please see response to item #3. (NSPI has converted the intensity approach to actual emission reductions.)
82		3: The NDP is surprised to see that the issue of local air quality has not been raised in this process.	Outside scope of IRP. All NSPI power plants will continue to be in compliance (meet regulations) as established by their environmental operating permits.
83	NS Department of Energy Oct 5, 2006	1: Please clarify how imports and co-generation will be modeled by NSP in the IRP process in order to meet required emission reductions.	Please see response to item #5.

84		1: Please provide a table that shows NSPI's base, low and high forecasts of firm demand and capacity indicating the year when % reserve is below the 20% requirement and new capacity is required for each scenario?	The information requested is an output of the Strategist model and therefore not available until after analysis of plans has been completed.
85		2: Slide 10 - Assumptions should indicate development of global carbon market likely within 2029 time frame rather than just tie-in to US market.	Please see response to item #3.
86		3: Slide 10 - We recommend low case should be the base case	Please see response to item #3.
87		3: It might be useful to have a blended base case, as only one scenario is being used at present - a vintage based approach to plant replacement. Another scenario involving absolute reductions or based on intensity could be blended with the vintage scenario for the base case - especially for the 2015 and 2020 time frames.	Please see response to item #3. NSPI may consider a case or sensitivity to address this scenario. Please refer to the accompanying document (issued Feb. 20th, 2007) "IRP Analysis Plan.ppt" for an outline of the modeling, scenario and sensitivity process.
88		3: Slide 11 - Please provide the basis for the 10Mt/year value for current C02 emissions. What year is this based on and how is it calculated? Please provide the specific CO2 caps in Mt and the year that is modeled in Strategist for the IRP process for base, low and high cases.	10 Mt/year is the rounded value of our 2005 emission of CO2 and our projection for 2006. Note that in the revised Basic Assumptions issued Feb. 9th, the table on slide 10 represents total estimated CO2 not reductions.
89		4: Slide 12 - Please clarify NSPI's GHG cost of offsets assumptions.	Please see response to item #31 and #38.
90		5:	Please see response to item #29.

		Slide 19 – Please justify the low case renewable scenario post 2010. Is it reasonable to assume there would be no new renewable requirement on the base case post 2013?	
91		6: Slides 19 & 20 - Please confirm that net capacity for each existing unit modeled in the IRP process is equal to the capacity modeled in current reliability studies. Please explain any de-ratings or discrepancies.	Confirmed, though net capacities are revised yearly based on actual performance of units.
92		6: Please provide a table indicating all existing NSPI unit retirement dates within the IRP study period to 2029.	Please see response to item #4.
93		7: Slides 22, 24, 25 - Please supply life cycle costs for all emission technology options, generation plant upgrade options, and new generation options modeled in the IRP process.	Please see revised slides 27, 28, 29 (Feb. 9th).
94		7: Please clarify the net capacity increases indicated on slide 24.	The net capacity increases listed on slide 22 (Feb. 9th) are the additional megawatts available after some investment is made on a unit. In the case of Lingan Units 1 through 4, the net capacity increase could be 4 units at 5 MW each for a total increase of 20 MW or 4 units at 20 MW each for a total increase of 80 MW.
95		8: Slide 25 - Please explain why there is no co-generation potential identified as Halifax Community Energy project is in the works. Are micro-turbines in the mix over the longer term? Are other forms of de-centralized generation being considered?	Please see response to item #5.
96		9:	Please see response to item #28.

		Slide 32 – Please provide the base growth rate as well as other growth rates on an annual basis.	
97		10: Slide 37 – Please clarify how Summit Blue DMS programs be able to be selected in the IRP process? Will it be on an individual basis or blocks and can those inputs be made available.	Please see response to item #22 and the accompanying document (issued Feb. 20th, 2007) "IRP Analysis Plan.ppt" for an outline of the modeling, scenario and sensitivity process. The underlying data has been reviewed with UARB Staff and Consultants.
98		10: Slide 37 - Additional analysis on Summit Blue packages is requested in order to verify DSM inputs to Strategist.	Please see response to item #97 above.
99		11: Slide 38 – Inflation appears too high on high case as annual average.	Please see response to item #54.
100		12: Please explain how the IRP process will model end effects beyond 2029 and how it impacts the present worth value of the scenarios	*End Effects Analysis (Dynamic Programming)* The end effects calculations are used to analyze differences between alternatives after the planning period's horizon. They are significant in determining the economic optimal rankings when addressing the question of what plans make sense from a long run economic standpoint. Differences between alternatives are due to different operating characteristics and lives. Without end effects analysis, the results may be biased against commissioning capital intensive units in the latter years of the planning period (2007-2029). The planning period is the range of years over which all feasible combinations of resources are analyzed. The end effects analysis results in one objective function value, representing the entire end effects and planning period for each feasible state in the last year of the planning period. Note that each feasible state represents the end point of a unique expansion plan. Also the objective function value for

			each state is the value for the entire planning horizon. Therefore, the end effects result is used to augment the planning period result to account for the cost of replacing the resources and for differences in operating cost after the planning period. *Final Rankings* In order to determine the economic optimal plan and rank order of the suboptimal plans, the final objective function values are used. Final results (after end effects) are reported in the Integrated Plan Report. The Total Utility Cost (PV) is the total cost (excluding customer costs and externalities) for the individual plan. It represents the present value of a utility's revenue requirement from both the planning and end effects periods. If minimization of utility costs has been selected, this value is used to rank the plans and select the economic "optimal plan". Note: Instead of a finite end effects period, such as 30 years, we use an infinite end effects period as it reduces computation time and provides the same conclusion (same least cost plan) as the 30 year end effect period.
101		13: Explain how the IRP process will model the high and low case assumptions. Will they be modeled on an individual basis as sensitivities on the base case scenarios or will specific scenarios be developed for high and low assumptions.	Please refer to the accompanying document (issued Feb. 20th, 2007) "IRP Analysis Plan.ppt" for an outline of the modeling, scenario and sensitivity process.
102	John Merrick, Consumer Advocate,	In reference to the slides on environmental emissions assumptions, it is noted that accuracy of regulatory and other environmental standards is key. Implies that if IRP does not	NSPI's assumptions are based on input from several subject matter experts and direct conversations with regulators. With respect to future SO2, NOx and

	October 16th, 2006.	accurately estimate these, "sudden and significant rate impact" will ensue later.	Mercury please refer to the submission by NSDOEL stating support for NSPI assumptions. NSDOEL are responsible for the regulations. For greenhouse gas emission, please refer to revised slides 8-11 (Feb. 9th). NSPI has reviewed the input from several sources and has included a more stringent set of assumptions which will be used in our analysis: The "Kyoto" line in our Basic Assumptions documentation (revision issued Oct. 13th/Feb. 9th) will be incorporated into sensitivity analysis (although the reductions noted therein actually go beyond what was contemplated in the first Kyoto compliance period).
103		Can we assume indefinitely that credits will be allowed to be vehicle of compliance?	Both the previous and current federal governments include a cap and trade system as part of the overall framework for reducing greenhouse gas emissions. This is consistent with the European Union and now many states in the USA. Note that there will be generation plans analyzed which reduce emissions of greenhouse gases in Nova Scotia with a much lower reliance on purchasing offset credits.
104		Questioning ranges for CO2 credit prices - perhaps need more sensitivities given infancy of markets had to base things on.	Please see response to item #31 and #103.
106		Asking NSPI to provide assessment as to the impact on consumers of the various scenarios being considered?	The assessment criteria for plans/scenarios are included in the Terms of Reference. In addition please refer to the accompanying document (issued Feb. 20th, 2007) "IRP Analysis Plan.ppt" for an outline of the modeling, scenario and sensitivity process. Further questions can be addressed at the Technical Conference Feb. 22nd.

Integrated Resource Plan Technical Conference

February 22, 2007

NOVA SCOTIA POWER
An Emera Company

IRP Technical Conference - Agenda

Time	Item	Panelists
8:45 – 9:00	•Arrival, coffee	
9:00 – 9:30	•Welcome •Introductions •Housekeeping •Update activities since Sept 22, 2006 Technical Conference	Rene Gallant / John Stutz
9:30 – 10:45	Modeling / Analysis Plan	Kelly Cantwell / Dan Peaco / Bruce Biewald
10:45 – 11:00	Break	
11:00 – 11:30	DSM Panel	John Aguinaga / Tim Woolf
11:30 – 12:00	Emissions Panel	Terry Toner / Bruce Biewald
12:00 – 12:30	Lunch	
12:30 – 1:00	Supply Side Panel	Doug Campbell / Graeme MacKenzie / Bruce Biewald
1:00 – 1:30	Load Forecast / Fuel Panel	Ron MacDougall / Allison Donnelly / Rick Hornby
1:30 – 2:00	Summary of comments Next steps Adjourn	Rene Gallant / John Stutz

IRP – Schedule of Remaining Activities

Activity	Date
Results of technical analysis	May 11 07
Technical Conference on analysis results	May 23 07
Stakeholder input on analysis results	June 13 07
Draft report to Stakeholders for comment	July 4 07
Stakeholder comments on draft report	July 11 07
Final report filed with UARB	July 25 07

IRP – Analysis Plan

IRP Analysis Presentation Panel

1. **NSPI** — **Kelly Cantwell**
   - Mgr Generation Planning, NSPI

2. **La Capra Associates** — **Dan Peaco**
   - IRP Advisor to NSPI

3. **Synapse Energy Economics** — **Bruce Biewald**
   - IRP Advisor to UARB

Analysis Plan Developed in Collaboration with UARB

IRP – Analysis Plan

Objectives:

1. Introduction to IRP Analysis
2. Overview of NSPI's IRP Analysis Plan
3. Description of Resource Plans, Worlds and Sensitivities
4. Overview of the IRP Model – STRATEGIST
5. Analysis Results to be Delivered on May 11

IRP – Analysis Plan

Key Elements of an IRP Analysis

“Basic Assumptions”

1. Develop Requirements and Cost Inputs
2. Identify and Describe Resource Options (Supply & DSM)

“IRP Analysis”

3. Analysis to Determine the Least Cost Plan to Meet Needs
4. Sensitivity & Worlds Analysis for a Robust Plan

IRP – Analysis Plan

Elements of Least Cost Determination

1. Analysis of Total Cost Over the Planning Horizon

2. Overall Objective of Lowest Net Present Value of Costs
   - Including all System and DSM participant costs (total resource cost)

IRP – Analysis Plan

Need For Sensitivities and Alternative Worlds Analysis

1. **Key Inputs Have Significant Uncertainty**
    - Fuel Costs
    - Demand and Energy Requirements
    - Resource Availability
    - Environmental Requirements

2. **Key Inputs Are a Matter of Policy**
    - Renewable Content
    - Environmental Requirements

3. **Investments Are Long Term**

IRP – Analysis Plan

Overview of the Plan:

- **Resource Plans**
  - an alternative plan with a distinct set of characteristics

- **Sensitivities**
  - response of the plan outputs to variation in a single or related set of input assumptions, e.g. natural gas price

- **Alternative Worlds Analysis**
  - response of the resource plans to significantly different futures, e.g. green world

The purpose of worlds and sensitivities is to test for robustness of the resource plans

IRP – Analysis Plan

Overview of the Analysis Plan

1. Create “Basic Assumptions” Database in the Model
2. Develop a “Reference Case” Plan (Most likely assumptions)
3. Develop Significantly Different Alternative Plans
4. Conduct Sensitivity Analysis on the Plans
5. Conduct Alternatives Worlds Analysis on the Plans
6. Conduct Additional Analysis as Required
7. Comparative Analysis to Select Most Robust Plan
8. Develop Action Plan

IRP – Analysis Plan

Alternative Resource Plan Themes:

- Reference Case
- DSM plan
- Coal Plan(s)
- Natural Gas Plan
- Renewables Plan

IRP – Analysis Plan

Sensitivities:

- Capital costs
- CO_2 credit costs
- Coal costs
- Gas prices
- Discount rates
- HFO costs
- DSM program costs

IRP – Analysis Plan

Worlds Analysis:

- Green World + Kyoto
- Light Green World
- High Load
- Low Load

IRP – Analysis Plan

The IRP Planning Model - STRATEGIST:

- NSPI uses STRATEGIST, a resource plan analysis model
  - Evaluates many alternative resource plans (supply or demand) to meet future needs (load, environmental)
  - Evaluates cost, performance and emissions of each alternative plan
  - Determines the optimal plan to meet the need for the given inputs
  - Evaluates resource plans on NPV of Total Resource Costs (TRC)

- Strategist Outputs Include
  - All fixed and variable costs of the resource plans over time
  - Operation of generating units
  - Levels of Air Emissions of Key Pollutants over time

IRP – Analysis Plan

IRP Planning Results To Be Delivered:

- Comparison for Alternative Resource Plans
  - Listing of Resources Added Over the Planning Period
  - Cost Results
  - Emissions Results

- Robustness Measures
  - Comparison of Plans on Response to Key Uncertainties
  - Comparison of Plans under Different Worlds

- Key Observations
  - Commonalities Across Plans
  - Action steps

IRP – Analysis Plan

Next Steps

- Stakeholders receive analysis package with key observations
- Technical conference May 23 to consult on results
- Draft Report
- Final Report

IRP Basic Assumptions Environmental

SO_2

Current Regulatory Requirements:

As per NS Air Quality Regulations

- SO_2 - 108,750 t/yr 2006 to 2009; 72,500 t/yr in 2010
- S in HFO – 2.0% annual with 2.2% cap.

Regulatory Context:

> Additional reductions considered likely.

> U.S. emission constraints poised to be tightened

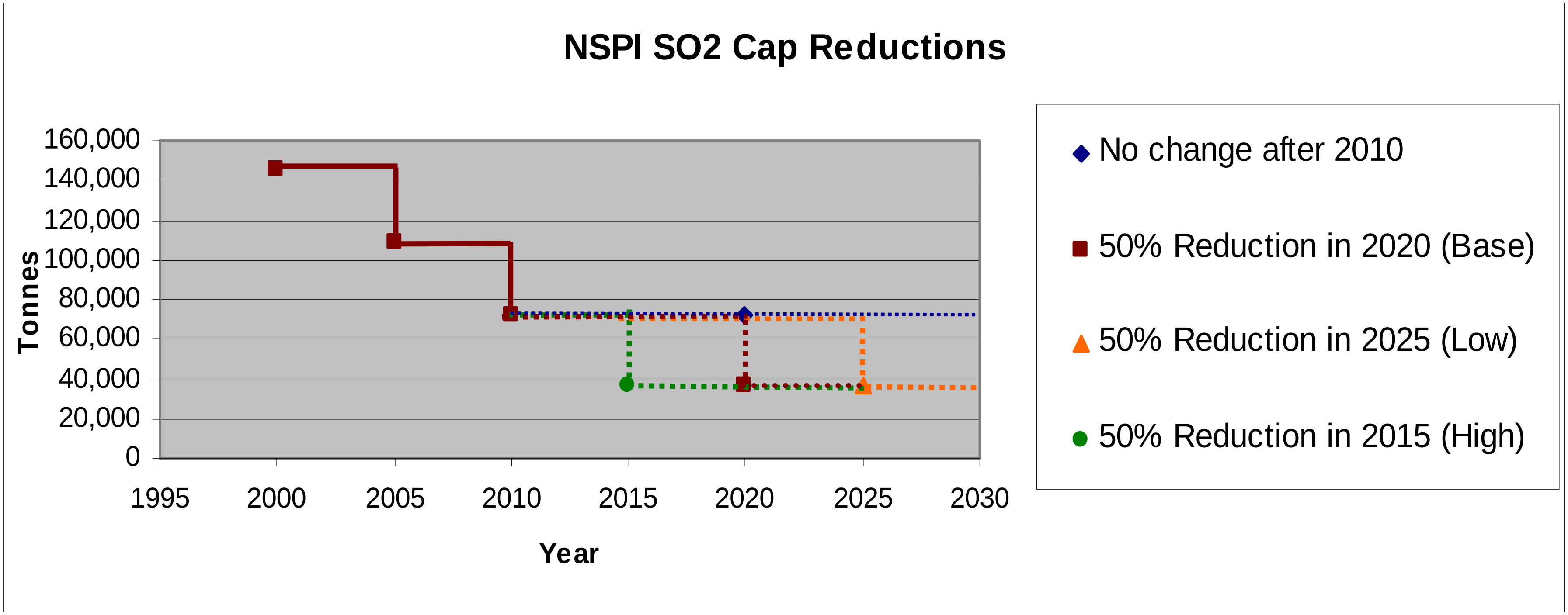
> Achieving new source performance in Nova Scotia would require a 50% reduction from the 2010 cap (Canadian New Source Emission Guideline).

IRP Basic Assumptions Environmental

SO_2

Case	Reduction
Base	50% reduction from 2010 cap by 2020 (to 36,200 t/yr)
Low	50% reduction from 2010 cap by 2025 (to 36,200 t/yr)
High	50% reduction from 2010 cap by 2015 (to 36,200 t/yr); HFO max 1% S in 2015.

IRP Basic Assumptions
Environmental



IRP Basic Assumptions
Environmental

CO_2 / Greenhouse Gases

Current Regulatory Requirements:

Pending and uncertain

Regulatory Context:

> Canada remains in Kyoto and has developed Bill C30 – Clean Air Act and its Notice of Intent to regulate
- Long term reductions of 45 to 65% with short term intensity based reduction targets

> Capital stock turnover framework proposed by main emitters from the electricity sector.

> Domestic offsets system likely, with possible tie to US offsets and credits

> NEG/ECP* agreed to reduce regional GHG intensity for the electricity sector by 20% by 2025

> UNFCCC* recommends long-term reduction target of 75-85%

*NEG, New England Governors; ECP, Eastern Canadian Premiers

*UNFCCC, United Nations Framework Convention on Climate Change

IRP Basic Assumptions
Environmental

CO_2 / Greenhouse Gases

Case	Year	Emission Constraint	Basis for Constraint
Base	2010	418 tonnes / GWh	Equivalent Performance Emission Standard (EPES) approach beginning in 2010. Parameters are after 45 years of service the specific unit benchmark standard will become 418 t/GWh. Standard reduces over time (350 t/GWh in 2020 then 300 t/GWh in 2030)
Low	2010	880 tonnes / GWh	Similar to Base, use an EPES approach beginning in 2010 with a 50 year life and a standard of 880 t/GWh.
High	2010	418 tonnes / GWh	Similar to Base, use an EPES approach beginning in 2010. Parameters are after 35 years of service the specific unit benchmark standard will become 418 t/GWh (and reduce over time). In addition, apply a 10% “haircut” (i.e. short term, arbitrary) in 2010 to emissions intensity.

Estimated CO_2/Greenhouse Gases Emissions

Case	Approximate Emissions (Million tonnes)				
	2010	2015	2020	2025	2030
Low	10.0	10.1	11.5	11.7	12.6
Base	10.0	9.5	9.1	7.7	6.4
High	7.9	7.6	6.3	6.3	4.5
Kyoto (sensitivity)	6.4	5.6	4.8*	4.5	4.1

**Assume credits no longer available*
1990 CO_2 emissions ~ 6.85M t
Current (2006) CO_2 emissions ~ 10M t / year

IRP Basic Assumptions
Environmental

CO_2 / Greenhouse Gases

Assumed Cost of Offsets (2006$US / tonne CO_2)			
Year	**Base**	**Low**	**High**
2010	11.50	3.00	17.50
2015	18.50	4.50	32.50
2020	23.50	6.50	41.50
2025	30.00	8.50	53.00

IRP Basic Assumptions
Gross MW, Lead Times

Alternative	Technology	Gross Capacity MW	Net Capacity Increase - MW	Fuel Type[1]	Lead Time - Years
LM6000	Simple cycle Combustion Turbine (CT) unit	51.4	49.4	Gas	4
CC150	2XLM6000, 50MW steam island	156	151	Gas	6
CC 280	New CT based Combined Cycle unit	292	280	Gas	6
CFB 400 Supercritical Boiler	Circulating Fluidized Bed	440	400	Coke/Coal 80/20	8
PC 400 Supercritical with FGD, SCR and CO2 Capture	Pulverized Coal with Amine Scrubber	570	400	Coal/Coke 85/15	9
PC 400 Supercritical with FGD, SCR	Supercritical PF Coal	430	400	Coal/Coke 85/15	8
CFB 265	Sub Critical CFB	290	265	Coke/Coal 80/20	8
IGCC 400 without CO2 Capture	Coal gasification CC	459	400	Coke/Coal 80/20	9
IGCC 400 with CO2 Capture	Coal Gasification CC with CO shift and CO2 Capture	515	400	Coke/Coal 80/20	9
Renewables (including capacity back-up when required*)	Wind turbines*, biomass, landfill gas		Incremental	various	

IRP Basic Assumptions
Source Data Selection

	Base Case	High & Low Case
Natural Gas, HFO & LFO	PIRA Long Term Forecasts	PIRA Scenario Planning Service
Coal	Hill & Associates International Coal Trade	Hill & Associates NSPI Report
Petcoke	Jacob's Consultancy NSPI Report	Jacob's Consultancy NSPI Report
Gearless Ocean Freight	Clarkson's NSPI Report	

NOVA SCOTIA
POWER
An Emera Company

May 11, 2007

To: Integrated Resource Plan (IRP) Intervenors

Re: Integrated Resource Plan

The attached slides show preliminary results of the technical analysis conducted as part of the Integrated Resource Plan (IRP). These results will be presented to stakeholders at a technical conference on May 23. A detailed agenda for the conference will follow.

Background

The IRP is a collaborative planning process conducted by Nova Scotia Power and staff of the Nova Scotia Utility and Review Board, in consultation with stakeholders. It was initiated in early 2006 following an application by NSPI for approval of flue gas desulphurization equipment at the Lingan generating station.

The purpose of the IRP has been to analyze through computer modeling the many uncertainties about the long-term future of supply and demand of electricity, and to use this analysis to produce near term plans that will meet the electricity needs of customers in the most economic and reliable way, reflecting environmental and other requirements.

More than ever, uncertainty about our energy future abounds.

Since the start of the IRP process itself significant shifts in the public policy discussion have occurred and continue to occur. Through sets of assumptions, the IRP anticipates most of the range of possibilities but not all, and this is the nature of the process.

For example, the recently announced federal limits on sulphur dioxide, nitrogen oxides and particulate matter have not yet been fully analyzed but will be in the coming months.

Despite the uncertainty, the IRP does point to certain preliminary high level conclusions.

More Conservation and Renewable Energy

In any foreseeable electricity future for Nova Scotia, the highest near term priorities should be to increase energy conservation and renewable generation.

PO Box 910, Halifax, Nova Scotia, Canada B3J 2W5
Customer Service 1-800-428-6230 (428-6230 in Metro Halifax) **Power Outage Line** 1-877-428-6004 (428-6004 in Metro Halifax)
www.nspower.ca

The IRP points to significant benefits from increased efforts in demand side management (DSM). In purely economic terms, the modeling suggests it may make sense to devote as much as five percent of electricity system revenues to demand side management.

The IRP indicates the need to design programs consistent with this result, and to phase in the programs and monitor the outcomes. These expenditures on DSM would affect electricity rates and would require approval by the Utility and Review Board.

Renewable energy should be added consistent with, or beyond the levels contained in the provincial government's Renewable Energy Standard subject to a technical analysis of the integration of variable power generation into the electricity grid. The provincial government has committed to such a study.

The above measures should allow the utility to delay making large capital expenditures in new generation facilities until there is greater clarity about the future of environmental rules, and about the technologies and other measures that could be deployed to meet them.

Embedded in the IRP are plans for certain incremental capital additions to improve the efficiency, output and environmental performance of Nova Scotia Power's existing thermal and hydro facilities. The work orders for these expenditures are also subject to the normal approval process.

Reduced Reliance on Carbon-Intensive Fuels

The IRP analysis contemplates futures where coal and other carbon intensive fossil fuels serve a significantly smaller share of projected future electricity energy demand in Nova Scotia.

The modeling contemplates long term scenarios where carbon-intensive fuels (coal, oil and petroleum coke) serve less than 50 percent of projected demand, compared to 75 percent today. The difference would be made up of a variety of alternatives including demand side management, renewable energy, clean imported energy or natural gas.

At the same time, the IRP shows that NSPI's thermal power plants remain economic to operate under a wide range of assumptions about the future, though capacity factors may be lower than today's levels.

These scenarios involve many different assumptions about commodity prices, constraints on emissions, and a range of compliance measures including import power, financial instruments and new technologies such as carbon capture and storage, which may or may not be commercially available.

These uncertainties are the reasons that low risk strategies in the near term are priority action items for the IRP. These actions items are closely aligned with current provincial energy policy.

It is possible that the future will unfold differently than contemplated by the IRP, but the analysis today says that coal plants can operate in a world where significant reductions take place in emissions of greenhouse gases and other emissions. Consistent with this analysis, NSPI will continue to seek approval for capital expenditures to improve operating performance and reduce emissions at the Trenton generating station, as recently requested.

Scrubbers at Lingan and Next Steps

With respect to flue gas desulphurization, the IRP analysis suggests this capital decision will be needed, but a decision can be delayed in the near term. The uncertainty of the timing stems from recent federal regulations on sulphur dioxide and other emissions. Additional analysis will be required.

There are things that the IRP cannot tell us. For example, the IRP does not try to accurately predict the future cost increases associated power generation. Rather, it uses sensitivities to compare and test future scenarios for the relative merits of different approaches. e.g. an emphasis on renewable energy, demand side management, natural gas, or coal-fired generation.

The information in the IRP does suggest that certain actions be taken, and these are summarized in more detail in the slides. Following the technical conference on May 23, a draft report will be circulated, followed by a final report and action plan expected to be filed with the UARB in July.

NSPI and the UARB staff thank participants for their continued cooperation and interest in the IRP. We look forward to seeing you at the workshop.

Yours truly,

Rene Gallant
Regulatory Counsel
Nova Scotia Power

IRP Modeling Results
May 11th, 2007
Deliverable to Stakeholders

Table of Contents

Overview

Recall IRP Terms of Reference

- The objective will be the minimization of the cumulative present worth of annual revenue requirements*, adjusted for end effects, and subject to a number of considerations, including:
  - System reliability requirements;
  - Plan robustness - the ability of a plan to withstand realistic potential changes to key assumptions;
  - Cash flow - the timing and magnitude of benefits relative to the timing and magnitude of required expenditures;
  - Flexibility - the absence of constraints on future decisions arising from the selection of a particular plan; and
  - Future regulatory emissions outlook.

*Note that the original terms of reference referenced annual revenue requirements based on total utility costs. As a result of including the analysis of DSM in the IRP, it was agreed with stakeholders that the IRP would evaluate total resource costs in the net present value analysis.

Collaborative Process

- Analysis was a collaborative process between the Company, Board Staff and their consultants, informed by consultation with stakeholders.
- The process included:
  - Using the basic assumptions to develop significantly different resource plans
  - Conduct sensitivity analysis on resource plans
  - Complete worlds analysis on resource plans
  - Agreement on analysis results
  - Documentation of analysis results
- Synopsis of the work done to date:
  - Started February completed May
  - 6 Base Plans
  - 96 Sensitivity runs
  - 9 World Runs
  - Additional analysis/troubleshooting
- Process also included screening of supply side options. This information is provided in Appendix A.

Confirm Basic Assumptions & Action to other Stakeholder Feedback

- As of February 22nd Technical Conference, no further changes were made to the Basic Assumptions
- An additional "World" was added to the modeling analysis plan, per Ecology Action Center (EAC). To allow the model to solve in these worlds additional options had to be added to the assumptions. These are explained later in the document
- Carbon Hard-cap to "Deep Green" trajectory:

Case	Approximate Emissions (Million tonnes)				
	2010	2015	2020	2025	2030
"Deep Green" World (per EAC)	6.44	4.93	3.43*	2.95	2.53

- Additional DSM "World" was added to the modeling analysis plan, per SEB request that potential MW/MWh contribution from Pulp & Paper be minimized due to upgrades already completed by this industrial sector

Review Key Issues of IRP

- Scrubber Timing versus Fuel Switching
- Amount of DSM
- Amount of Renewables Beyond RPS
- Next Major Generation Addition
- Near Term Supply & Environmental Additions
- Carbon Offsets/Credits versus Physical Reductions

High Level Conclusions

Results

- FGD appears to be needed and economic by 2020. May be required earlier depending on new regulations.
- 5% annual spending on DSM appears to be economic versus alternatives
- Renewables beyond RPS appear to be economically attractive.
- In almost all resource plans, certain near term supply and environmental additions are economic and provide for risk mitigation to meet constraints.
- Next major generation addition may be deferred indefinitely if DSM and renewables are successful
- New technology, import power, financial instruments may also be needed to meet near and longer term carbon regulation

Actions

- Complete further analysis of new federal emissions framework.
- Ramp up DSM effort to target savings for 5% spending case, monitor results
- Conduct wind integration study to assess feasibility and system costs
- Prepare related work orders.
- Monitor DSM results and integration study.
- Understand feasibility and timing of technology solutions in Nova Scotia.

Resource Plans

Description	**Plan Name**
5% Spend DSM + Renewables beyond Renewable Portfolio Standard (RPS)	Reference Plan
5% Spend DSM	DSM Plan
2% Spend DSM + Renewables beyond RPS	Renewables Plan
2% Spend DSM + New 400 MW Pulverized Coal Plant (LIN FGD 2020	Coal Plan (FGD 2020)
2% Spend DSM + New 400 MW Pulverized Coal Plant (LIN FGD 2012)	Coal Plan (FGD 2012)
2% Spend DSM + New 280 MW CC Natural Gas Plant	Gas Plan

Detailed description of each plan is available in Appendix B. 5% spend on DSM equates to spending 5% of electric revenue on DSM

6 Base Resource Plans

Summary MW

2007 IRP REFERENCE PLANS: SCHEDULE OF SUPPLY OR DSM MWs

		"Reference" 5% Spend DSM + Renewables > RPS	5% Spend DSM	2% Spend DSM + Renewables > RPS	2% Spend DSM Coal Plant (FGD in 2020)	2% Spend DSM Coal Plan (FGD in 2012)	2% Spend DSM Natural Gas
New Resources 2008-2014							
	DSM	256	256	146	146	146	146
	TUC 6	50	50	0	50	50	50
	LM 6000						
	Uprates	20	20	20	20	20	20
	Hydro	4.3	4.3	4.3	4.3	4.3	4.3
	RPS	166	166	166	166	166	166
	Additional Wind	16		16			
		512.3	496.3	352.3	386.3	386.3	386.3
New Resources 2015-2029							
	Additional Wind	144		144			
	Pulverized Coal				400	400	
	LM 6000						
	Combined Cycle			280			560
	DSM	857	857	559	559	559	559
	SUBTOTAL	1001	857	983	959	959	1119
TOTAL SUPPLY AND DSM MWs OVER PLANNING PERIOD		1513.3	1353.3	1335.3	1345.3	1345.3	1505.3

Additional detail provided in Appendix C

Reference Case

Least cost plan using base assumptions

(5% DSM Spend + Renewables beyond RPS)

Reference Plan

5% DSM + Renewables

- Least cost plan under the “base assumptions”
    - Lowest long term cost as measured by the net present value of revenue requirements and total resource costs
    - It does not mean that it is the plan with the lowest rate impact or the plan that is the most robust
  - 5% of annual revenue spent on DSM programs with ramp up beginning in 2008
  - Ten 50 MW (16MW firm) blocks of wind added over the period 2013 to 2029 (beyond the RPS)

Note: Resource plan NPVs are shown in Appendix B

Loads & Resources – Reference Case

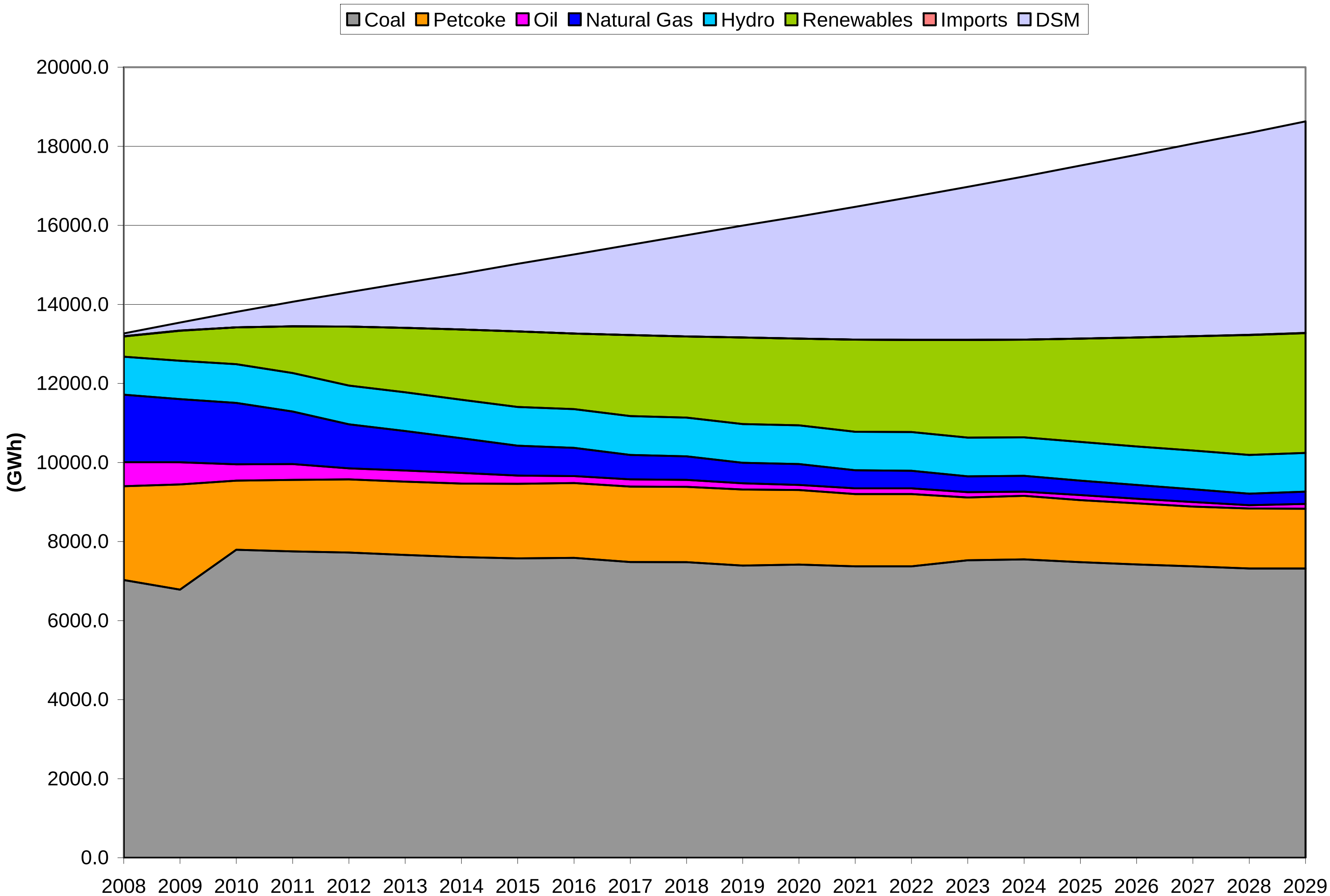
5% Spend DSM & Renewables beyond RPS

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2029
Peak Firm Load (MW)	1,927	1,973	2,019	2,061	2,101	2,141	2,181	2,224	2,264	2,306	2,856
Peak Firm Less DSM	1,919	1,951	1,975	1,988	1,995	1,999	1,998	1,999	1,998	1,999	2,066
DSM Firm	8	22	44	73	106	142	183	225	266	307	790
RM Required (MW)	460	468	474	477	479	480	480	480	479	480	496
Required MWs	2,302	2,342	2,371	2,386	2,395	2,399	2,398	2,399	2,397	2,399	2,479
Existing MWs	2334	2334	2334	2334	2334	2334	2334	2334	2334	2334	2334
Additions MWs											
TUC6			51.9								
LIN 1 Uprate					5						
LIN 2 Uprate			5								
LIN 3 Uprate				5							
LIN 4 Uprate			5								
Hydros			4.3								
RPS	4.7	28.8	27.8	19.2	28.8	38.7					
Additional Wind							16	16		16	
FGD											
Total Annual Additions	4.7	28.8	94	24.2	33.8	38.7	16	16	0	16	0
Total Cumulative Additions	4.7	33.5	127.5	151.7	185.5	224.2	240.2	256.2	256.2	272.2	376.2
Total Firm Capacity (MW)	2338.7	2367.5	2461.5	2485.7	2519.5	2558.2	2574.2	2590.2	2590.2	2606.2	2710.2
Surplus (Deficit) MWs above RM	36	26	91	100	125	160	176	191	193	208	232
Reserve Margin %	22%	21%	25%	25%	26%	28%	29%	30%	30%	30%	31%

Note: All years are shown in Appendix D. Reserve Margin (RM)

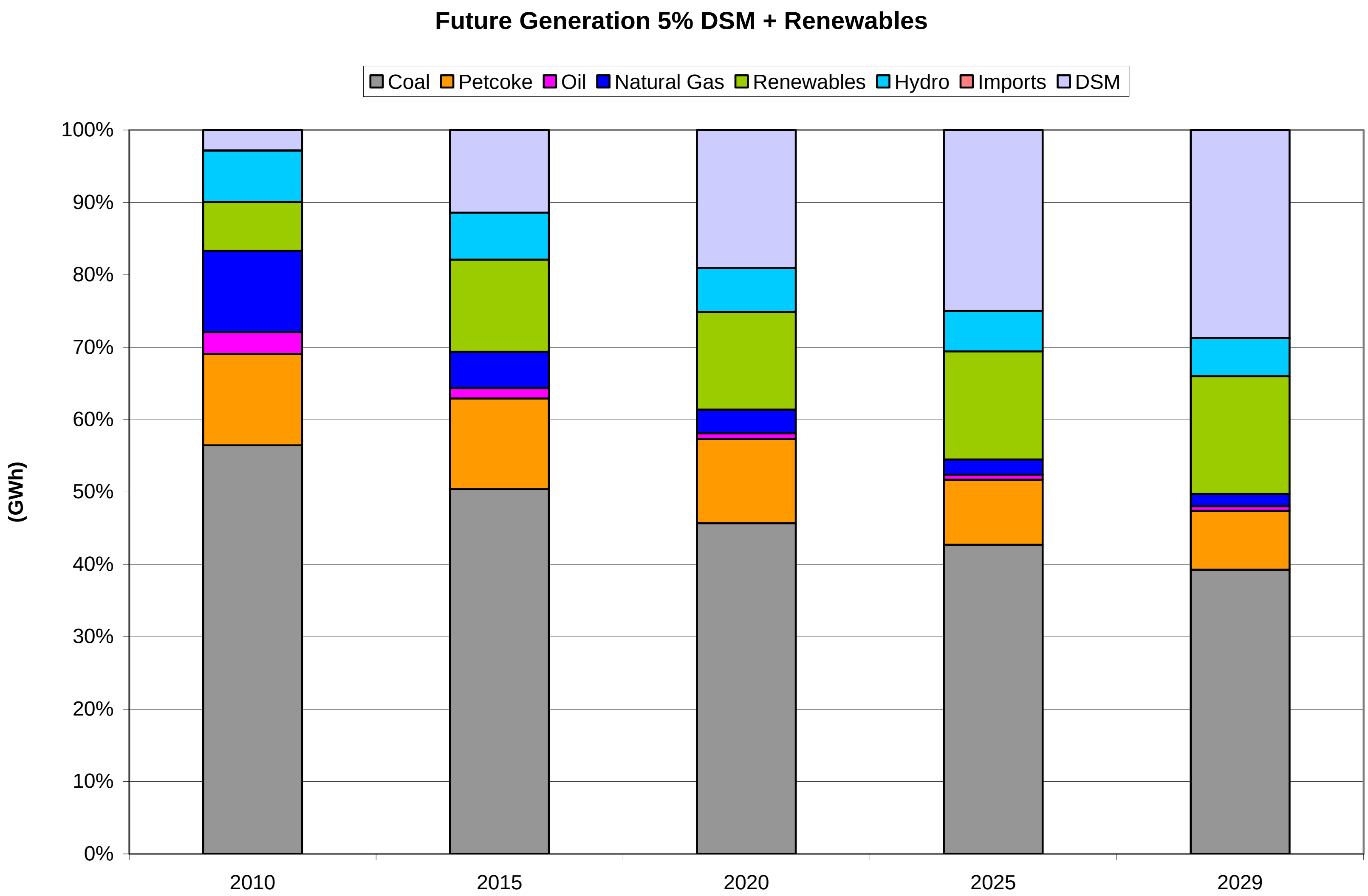
Energy – Reference Case

"5% Spend DSM & Renewables beyond RPS"



Energy – Reference Case

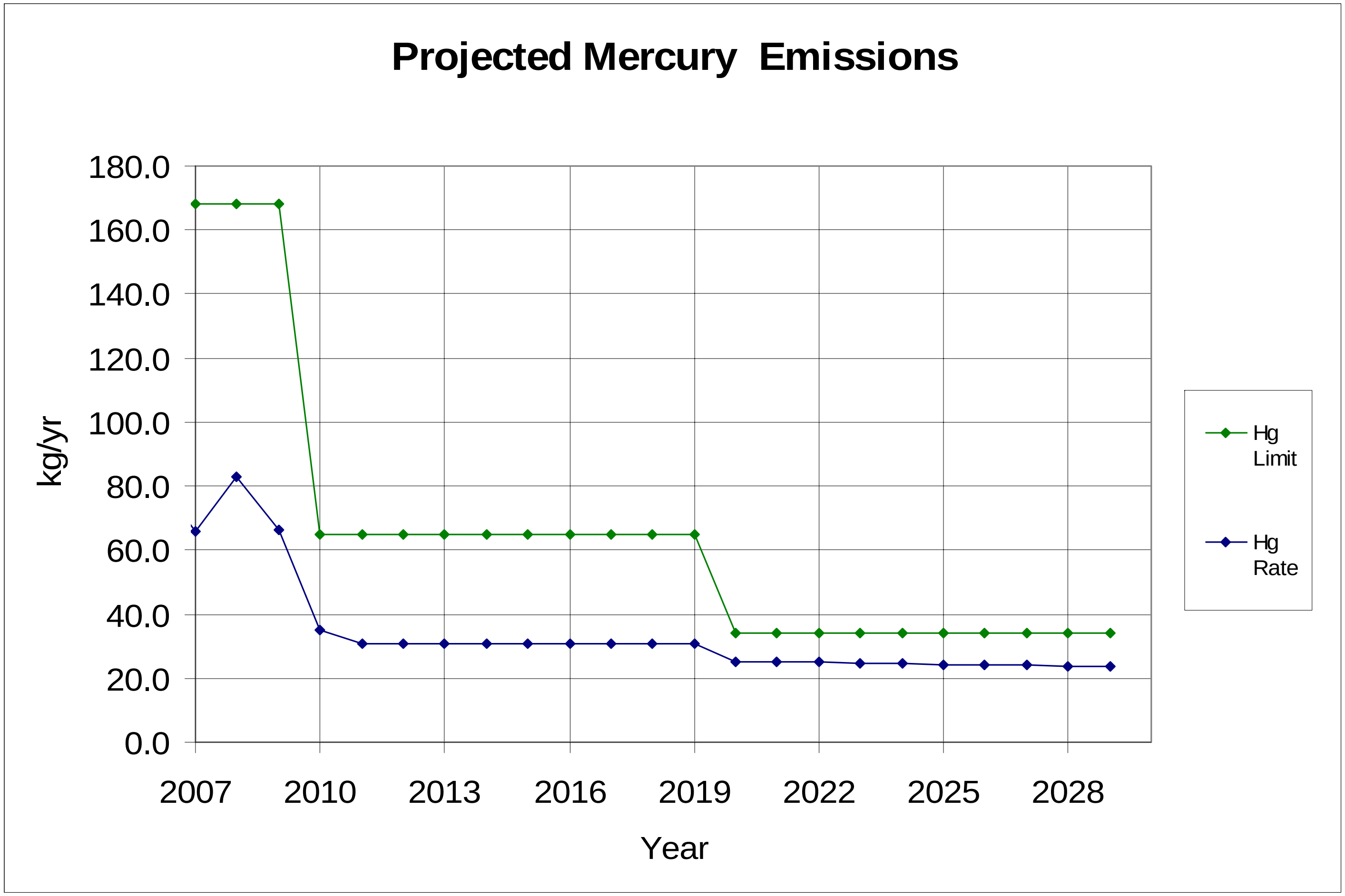
5% Spend DSM & Renewables beyond RPS



Emissions Trajectories: – Reference Case

5% Spend DSM & Renewables beyond RPS

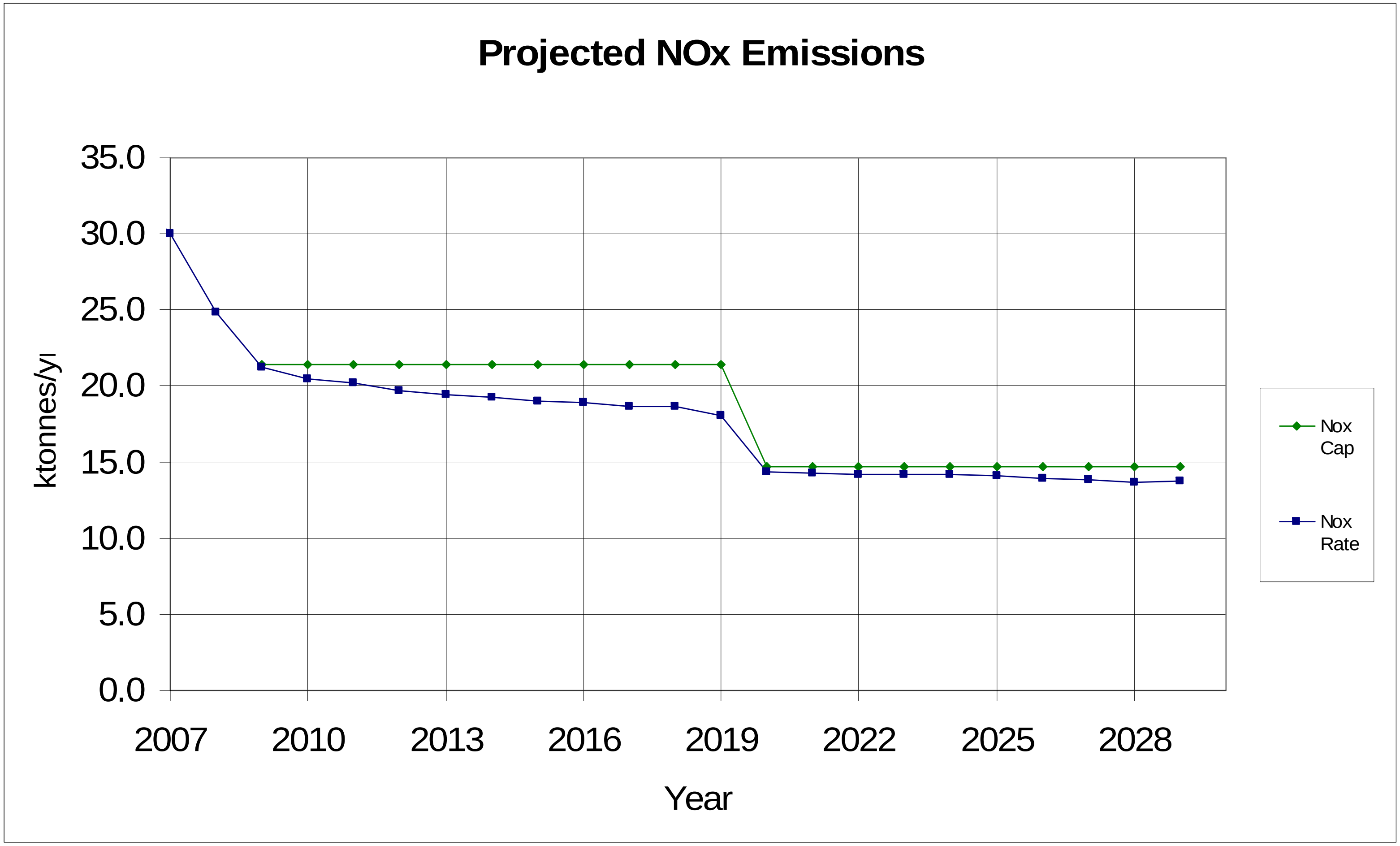
Hg



Emissions Trajectories: – Reference Case

5% Spend DSM & Renewables beyond RPS

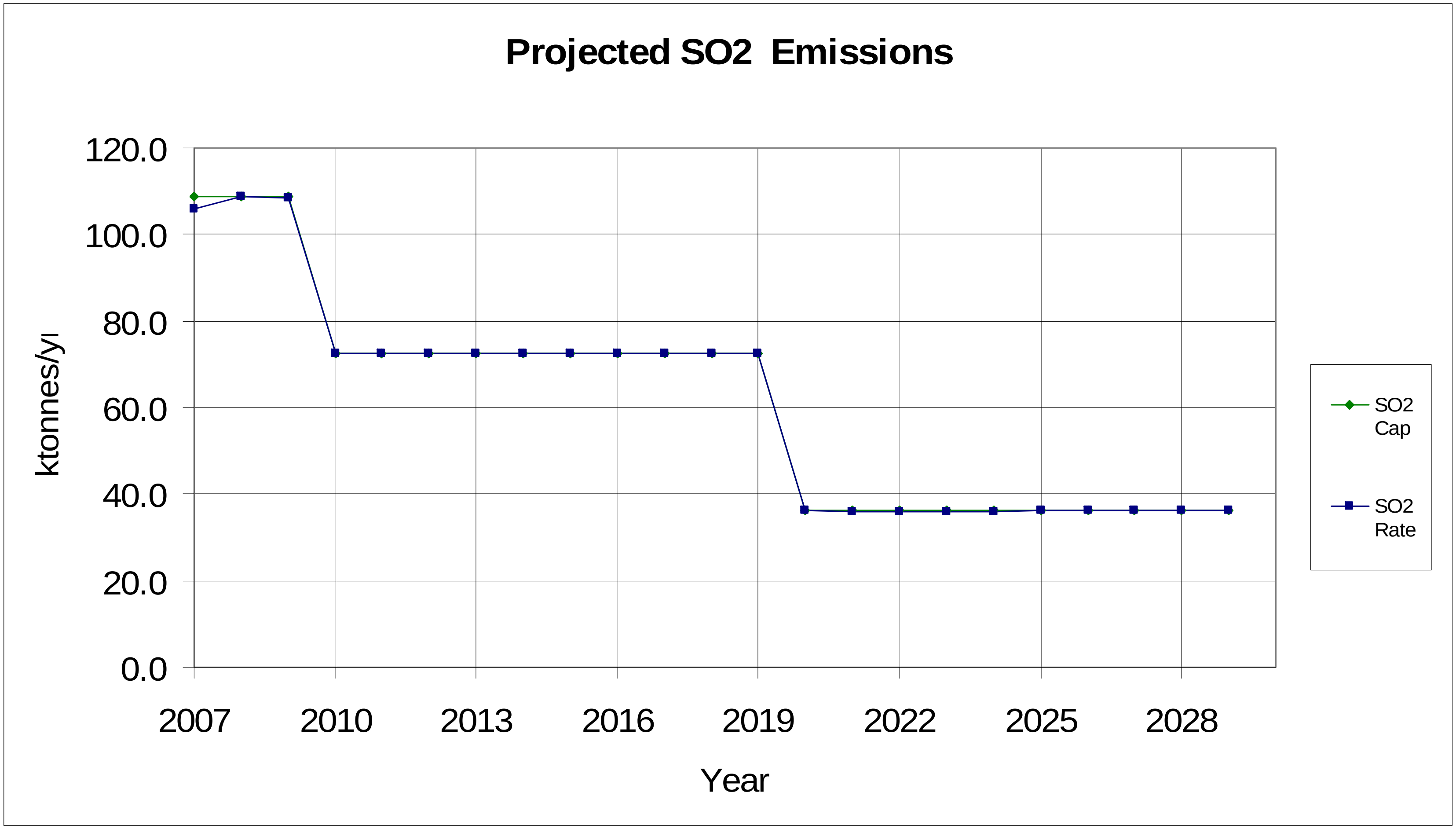
NOx



Emissions Trajectories: – Reference Case

5% Spend DSM & Renewables beyond RPS

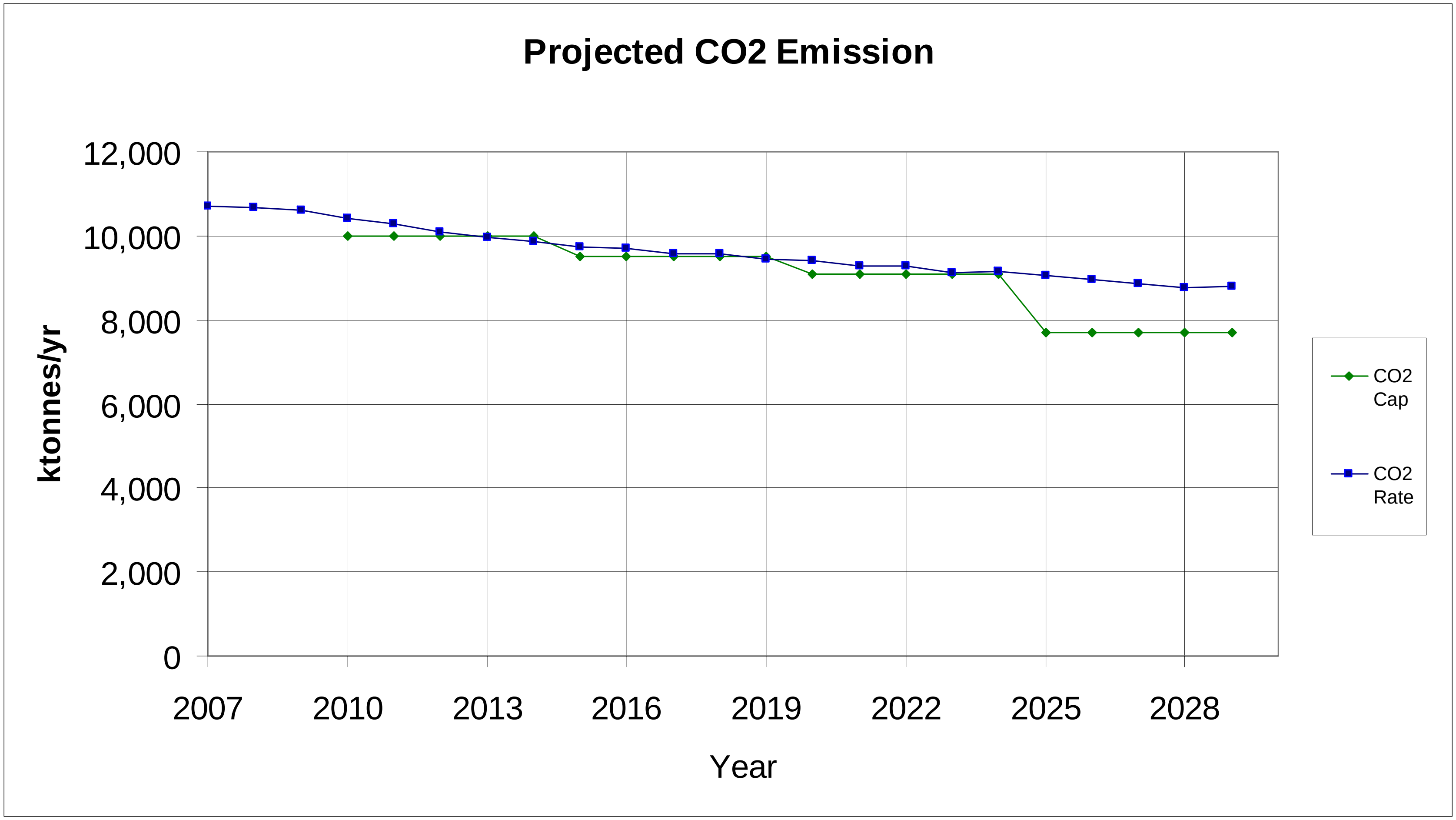
SO2



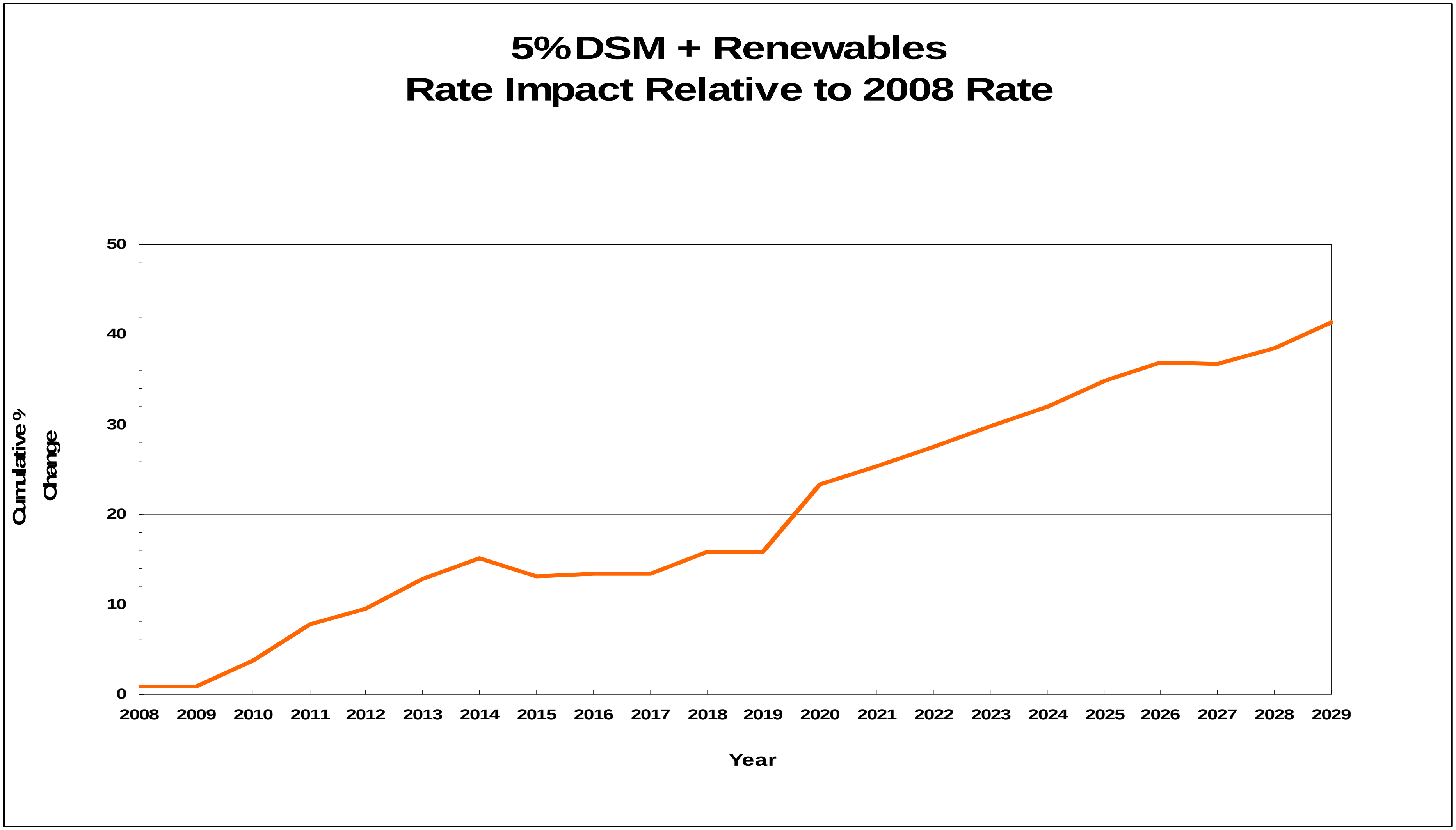
Emissions Trajectories: – Reference Case

5% Spend DSM & Renewables beyond RPS

CO2



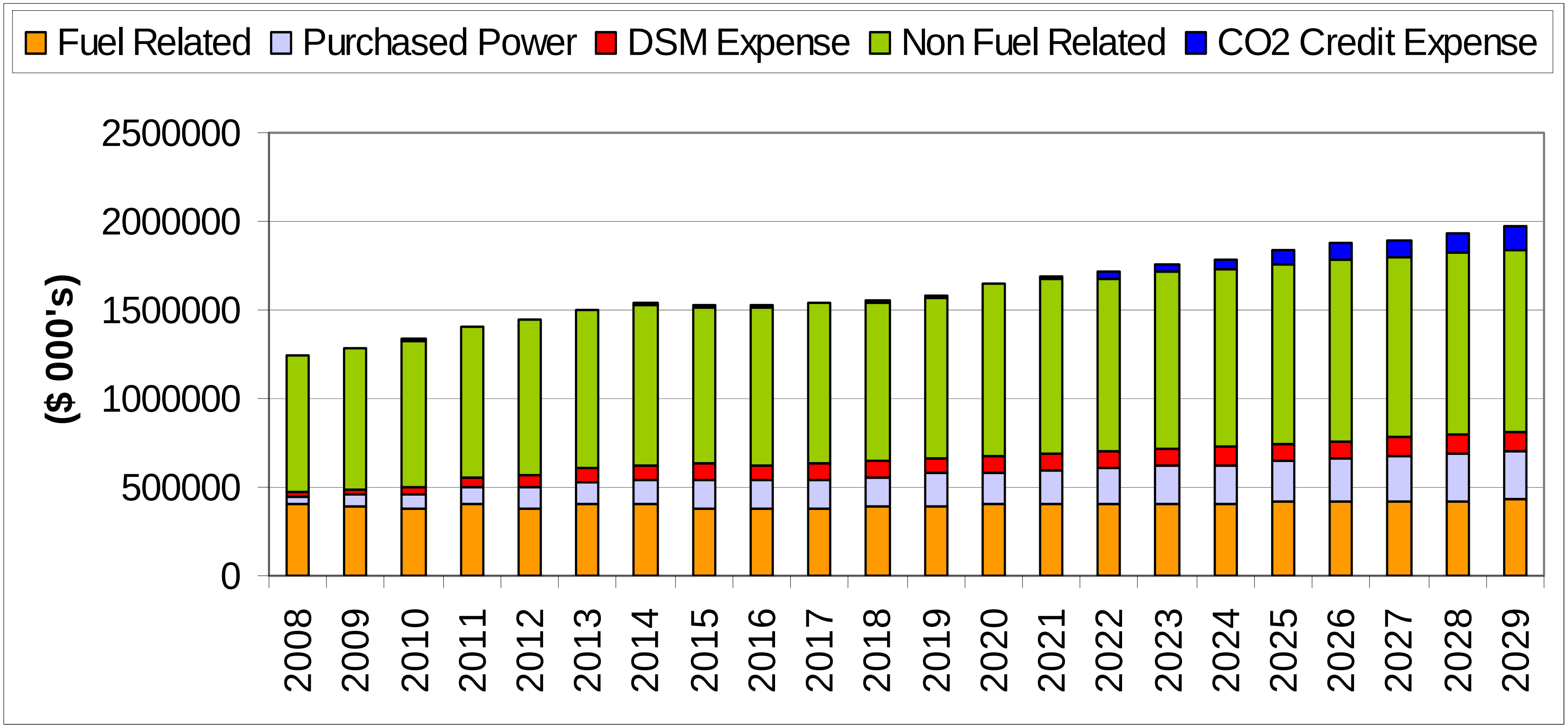
Cumulative Rate Effect



Rates are in nominal dollars. Rates are based on 2006 information and are shown for comparison between plans. Actual rates in any future year will be based on the revenue requirement at that time.

Annual Revenue Requirements

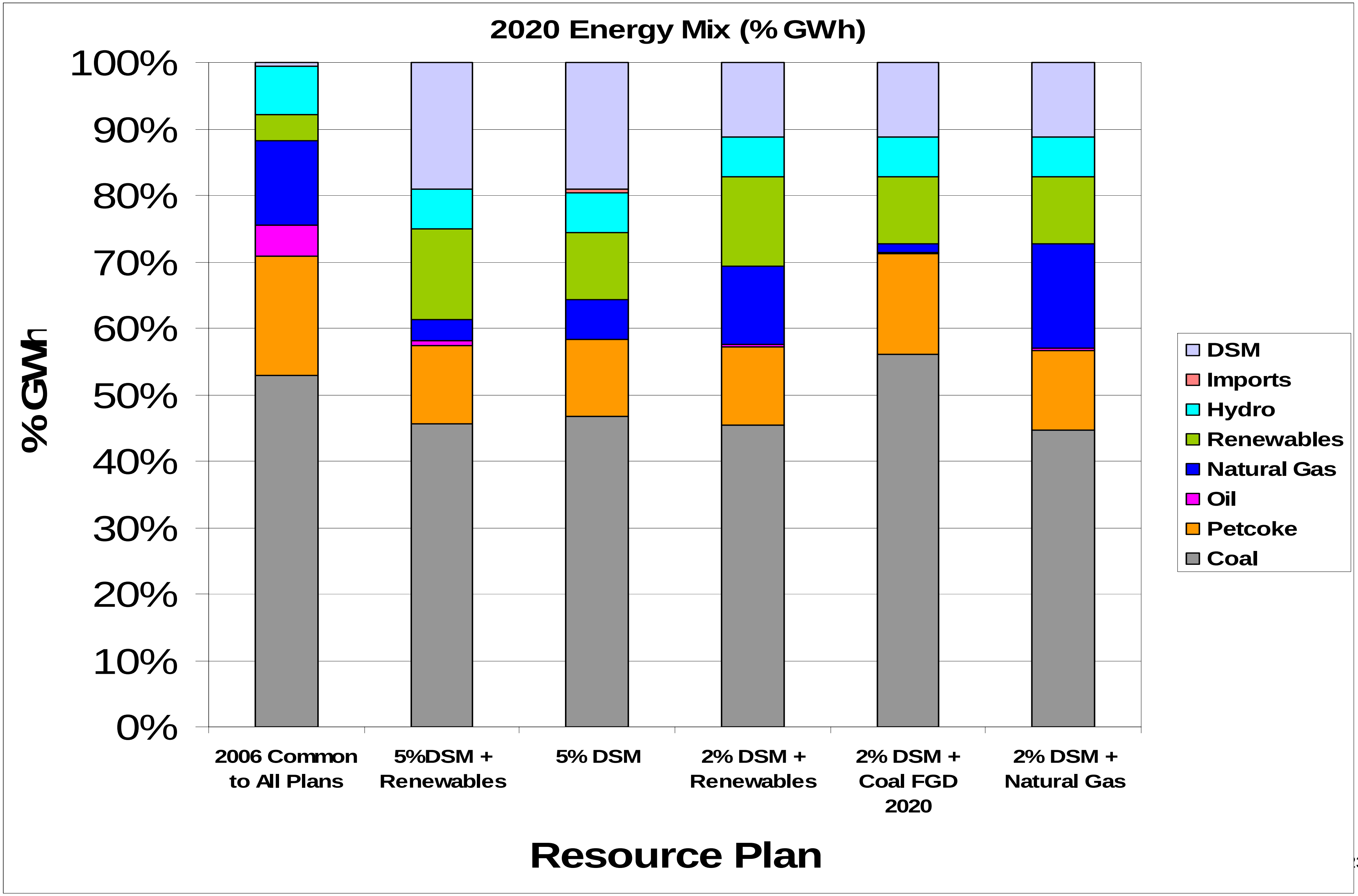
5% DSM + Renewables



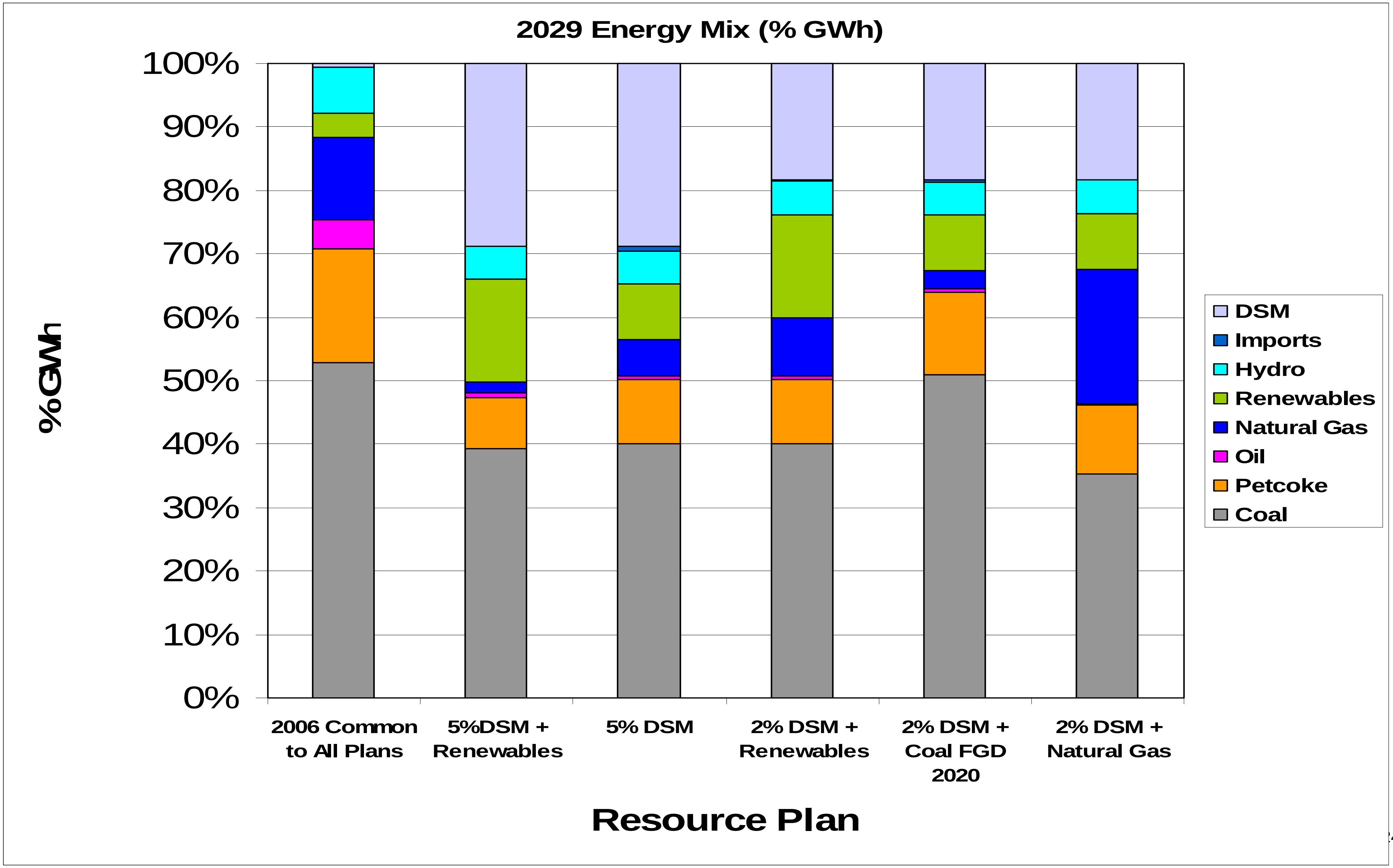
Note: Nominal dollars

Comparison of Candidate Plans to Reference Case

Comparison of Plans – Energy Mix @ 2020

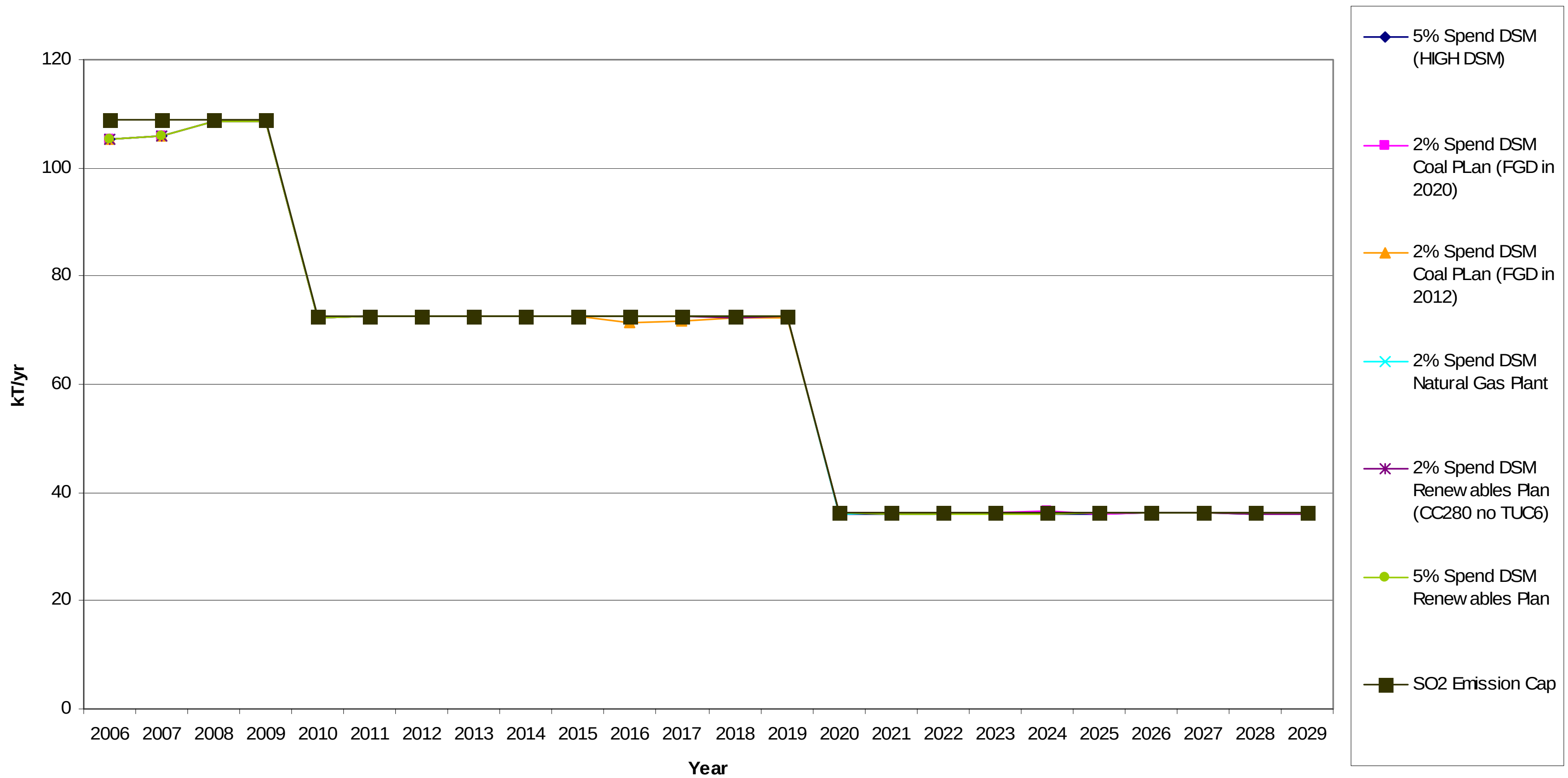


Comparison of Plans – Energy Mix @ 2029



Plan Comparison

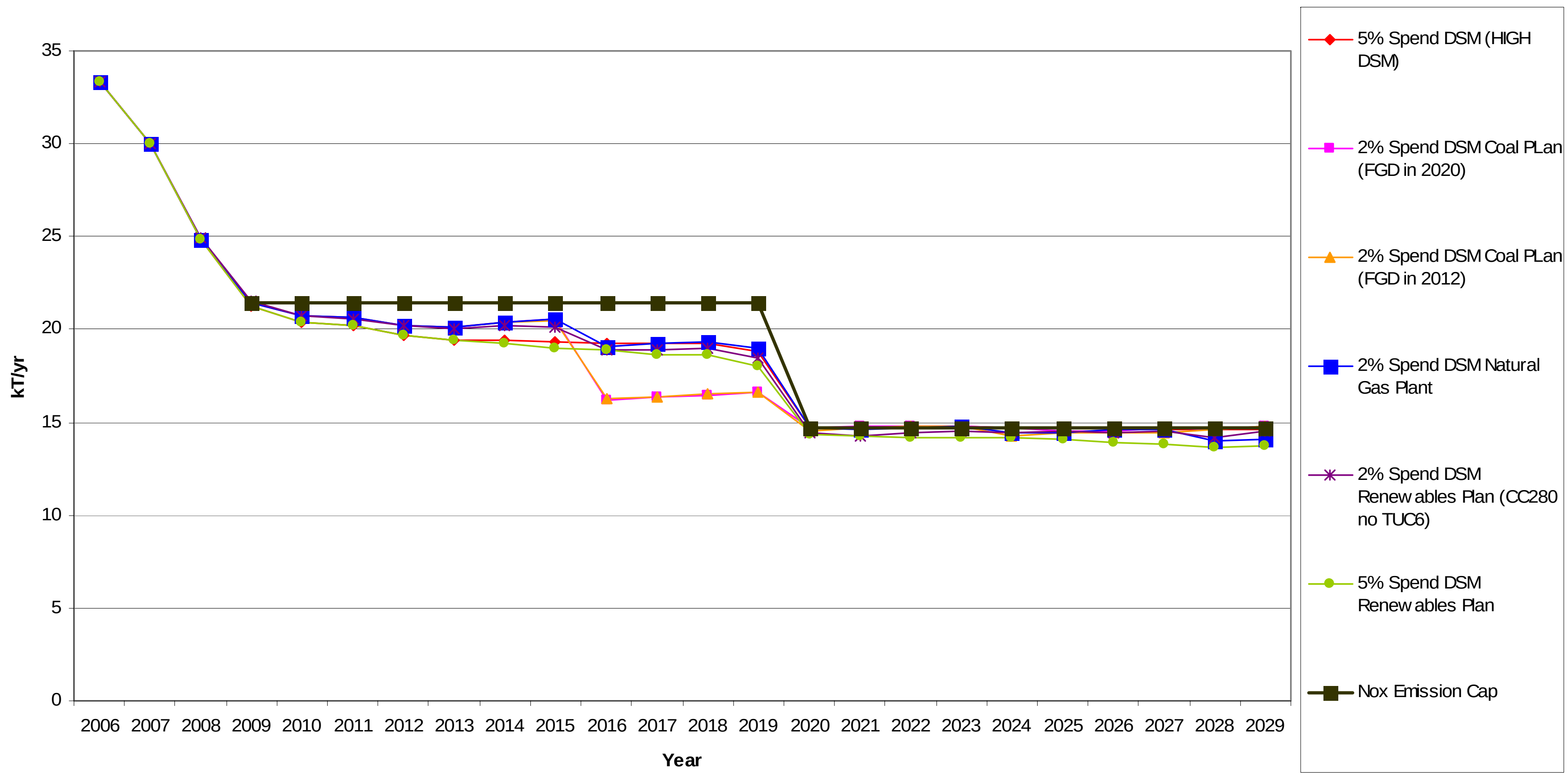
SO2 Emissions



Note: All plans are meeting the SO2 cap.

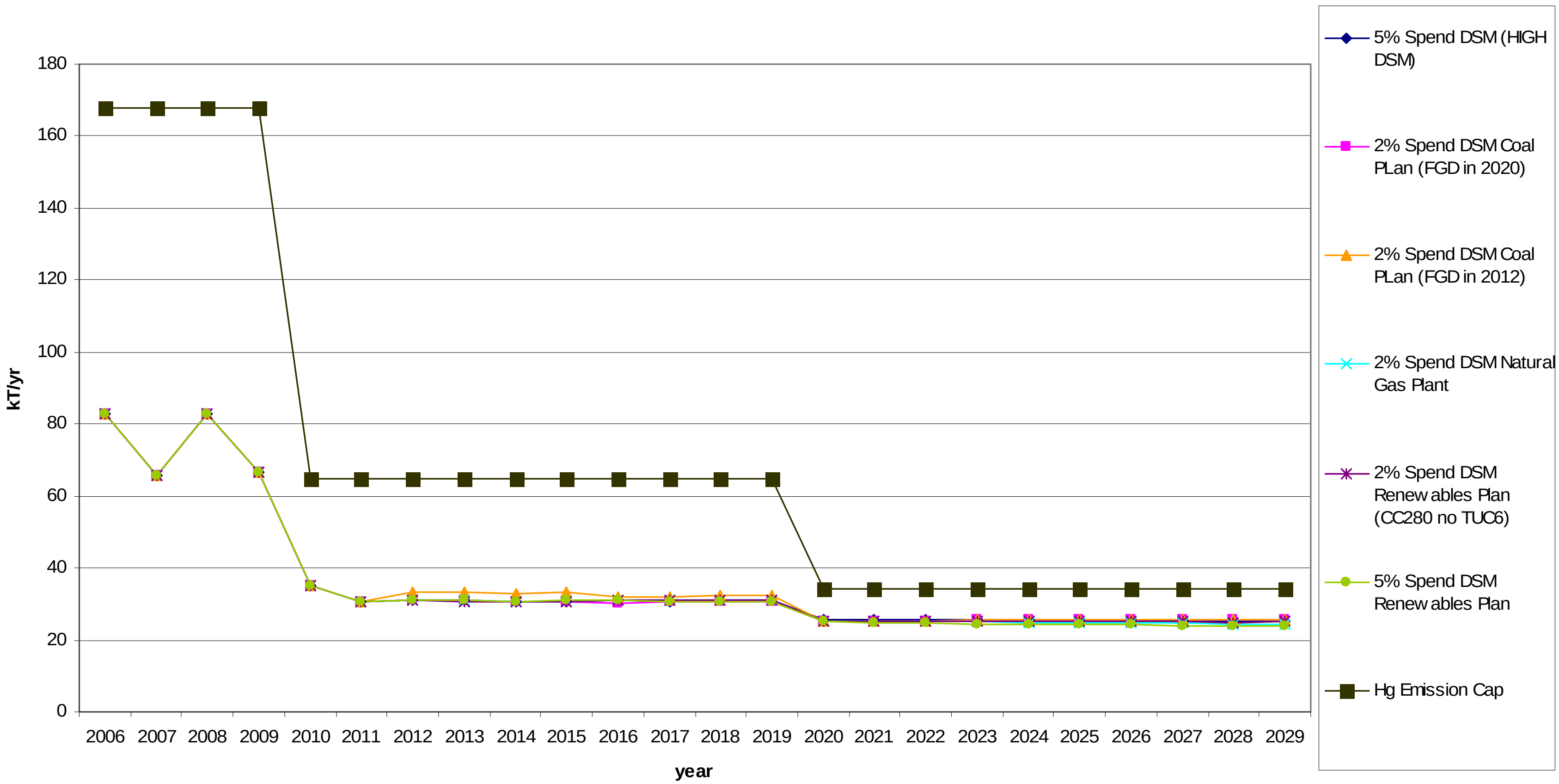
Plan Comparison

Nox Emissions



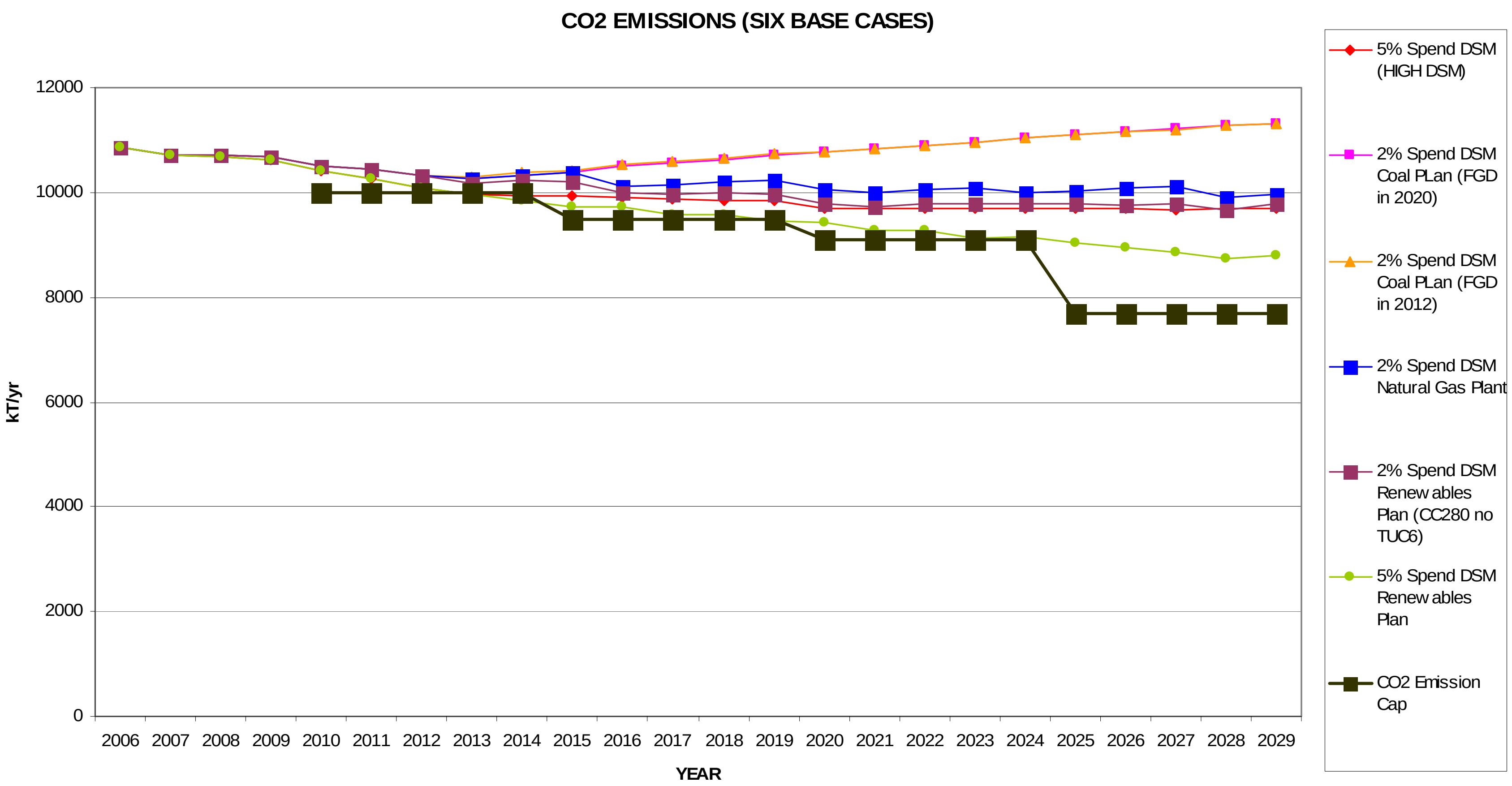
Plan Comparison

Hg Emissions

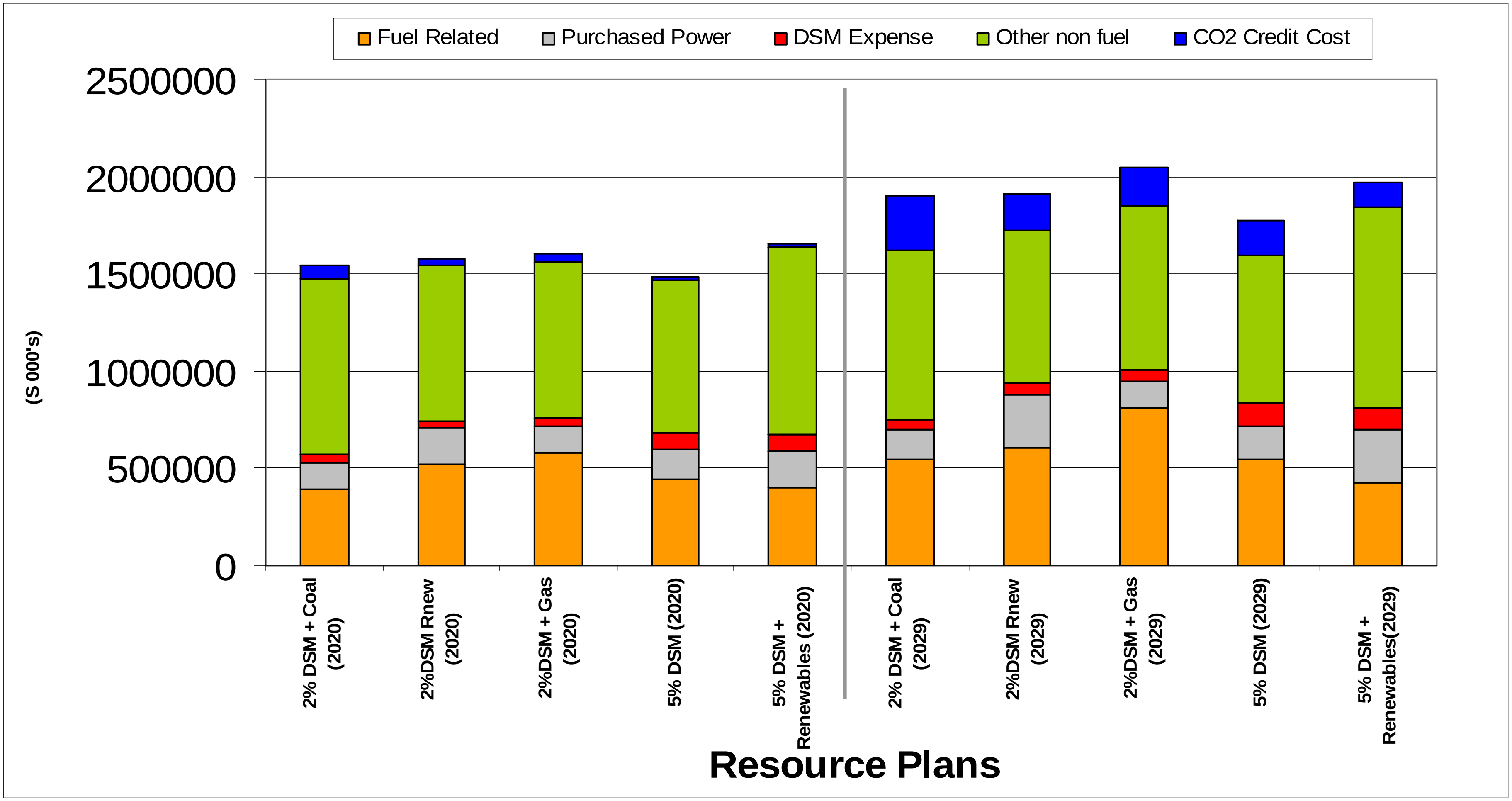


Plan Comparison

CO2 Emissions

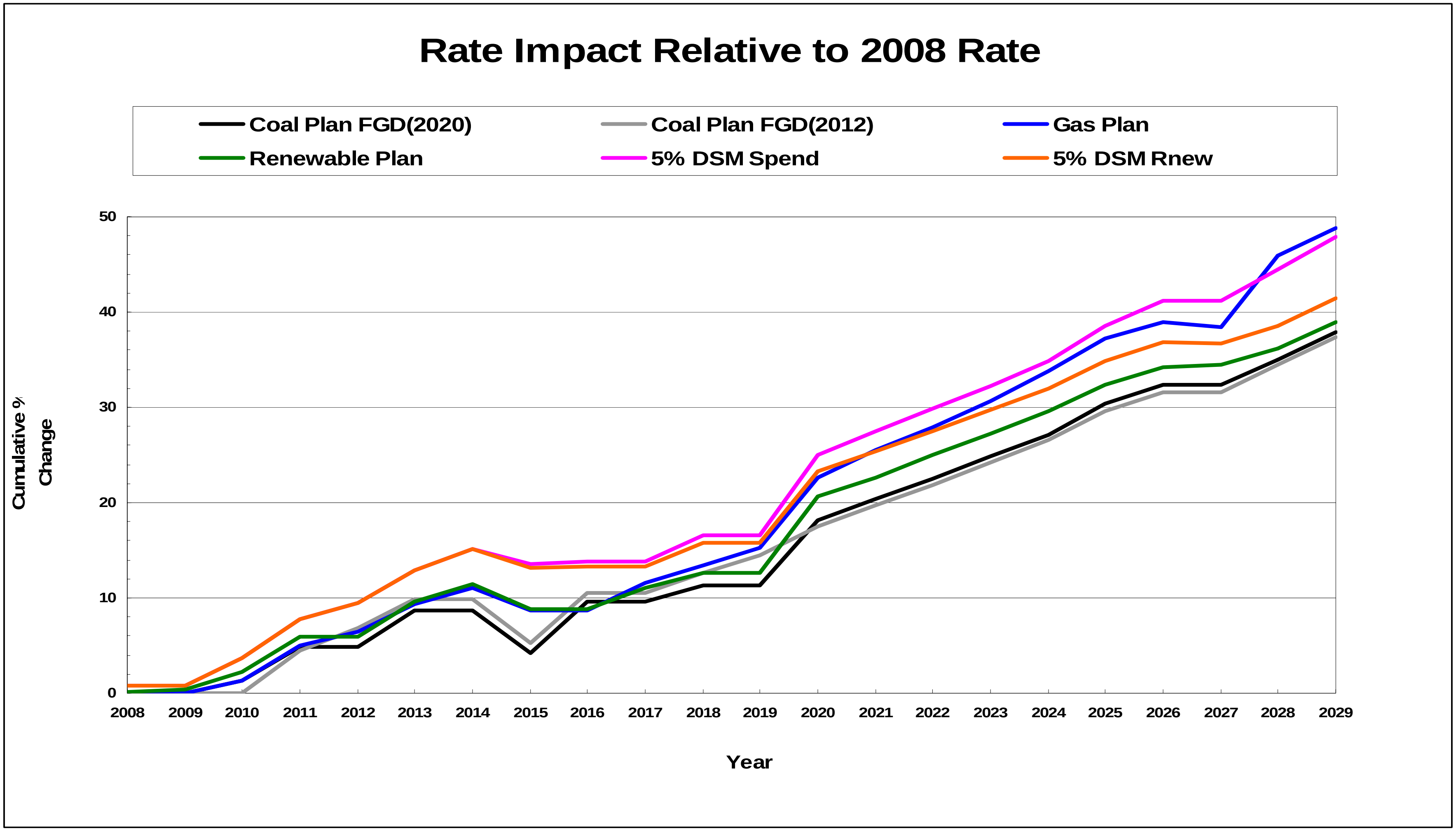


Annual Revenue Requirement Comparison 2020 & 2029



Note: Annual revenue requirements shown in nominal dollars. For detailed charts for each resource plan, see Appendix F

Rate Comparison



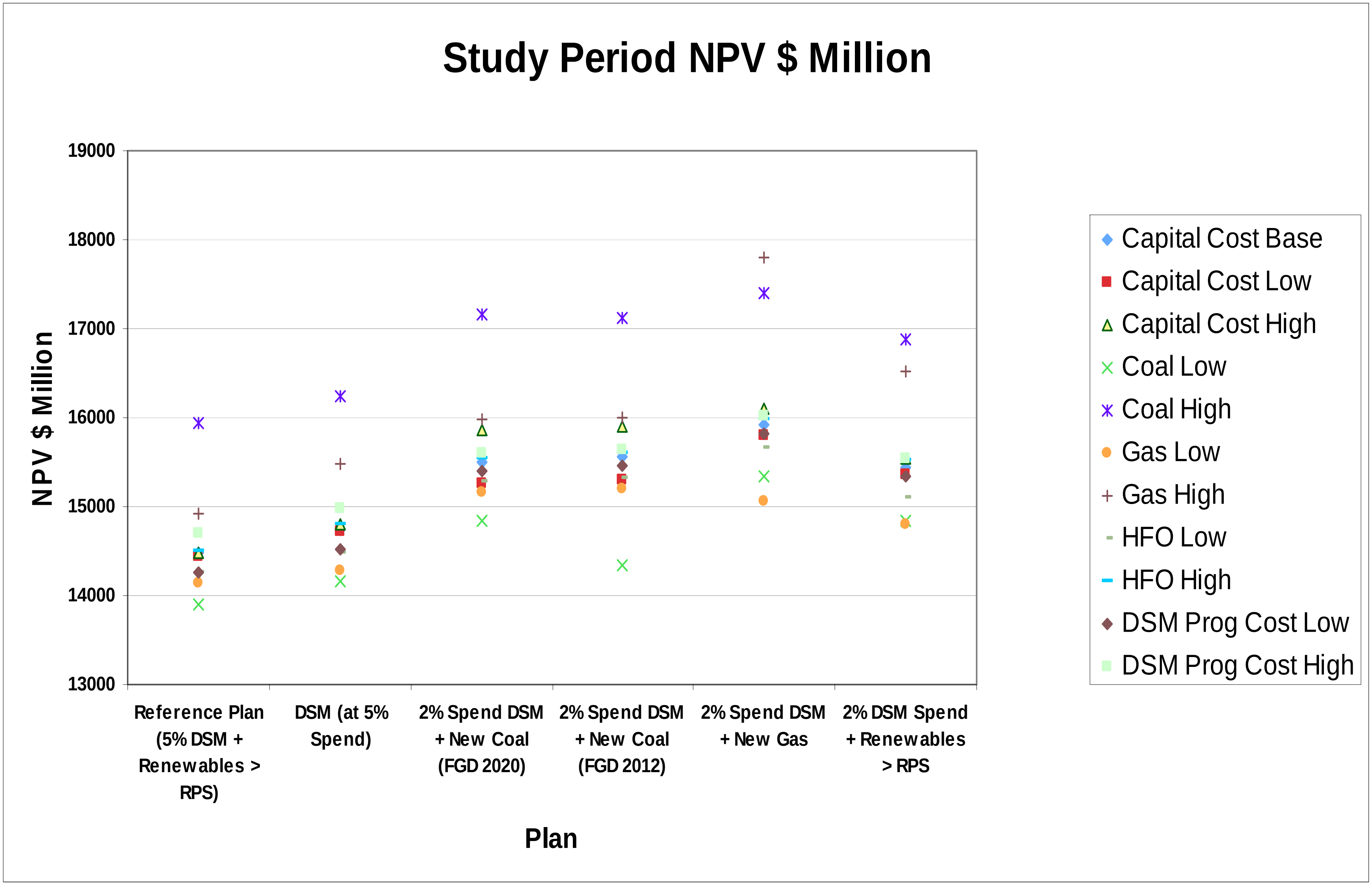
Rates are in nominal dollars. Rates are based on 2006 information and are shown for comparison among plans. Actual rates in any future year will be based on the revenue requirement at that time.

Sensitivities

SENSITIVITIES

- See Appendix G for tornado results
- Key Points:
  - All base plans most sensitive to fuel prices, CO_2 credit prices
  - Rank order of plans' NPV cost does not change with most sensitivities
    - In all cases the 5% DSM Spend + Renewables ("Reference") and 5% Spend DSM (second rank) retain their order (#1, #2)
    - Other exceptions:
      - Under low capital cost, CO2 credit prices or coal price assumptions the Coal Plans outrank the Renewables Plan
      - Under low gas price assumptions the Natural Gas Plan outranks the Coal Plans
      - Under high gas price assumptions the Coal Plans outrank the Renewables Plan

SENSITIVITIES



Worlds

Worlds

- Load- assessed the effect of the high load assumption on the resource plans.
- DSM- assessed DSM by varying timing of program start and magnitude of benefits.
- Environment- assessed low and high environmental constraints effect on resource plans
- Carbon- assessed a number of hard cap carbon worlds in addition to the environmental worlds listed above.

Results – Load Variation World

- High load and low load worlds were included in the list of items for analysis.
- Due to time constraints only one load variation world could be completed. High load was evaluated.
- Results build on the 5% DSM + Renewables plan by adding:
  - Two LM6000 in 2008 & 2009
  - Two 150 MW gas units (1 conversion of LMs) in 2013 & 2014
  - Two 400 MW coal units in 2016 & 2020

Environment

- SO2, NOx, Hg
- Highly constrained environmental assumptions are shown in Appendix H
- Worlds analysis investigated the effect of a range of constraints on either side of the most likely assumptions. Considering, how to meet the caps using:

Description of World	**Plan Name**
Large capacity additions and no renewables beyond the RPS	High Air Emissions (AE), Coal High AE, Gas
Renewables beyond the RPS and no large capacity additions	High AE, Renewables
Retirement of 1 or more coal units	High AE, Retire

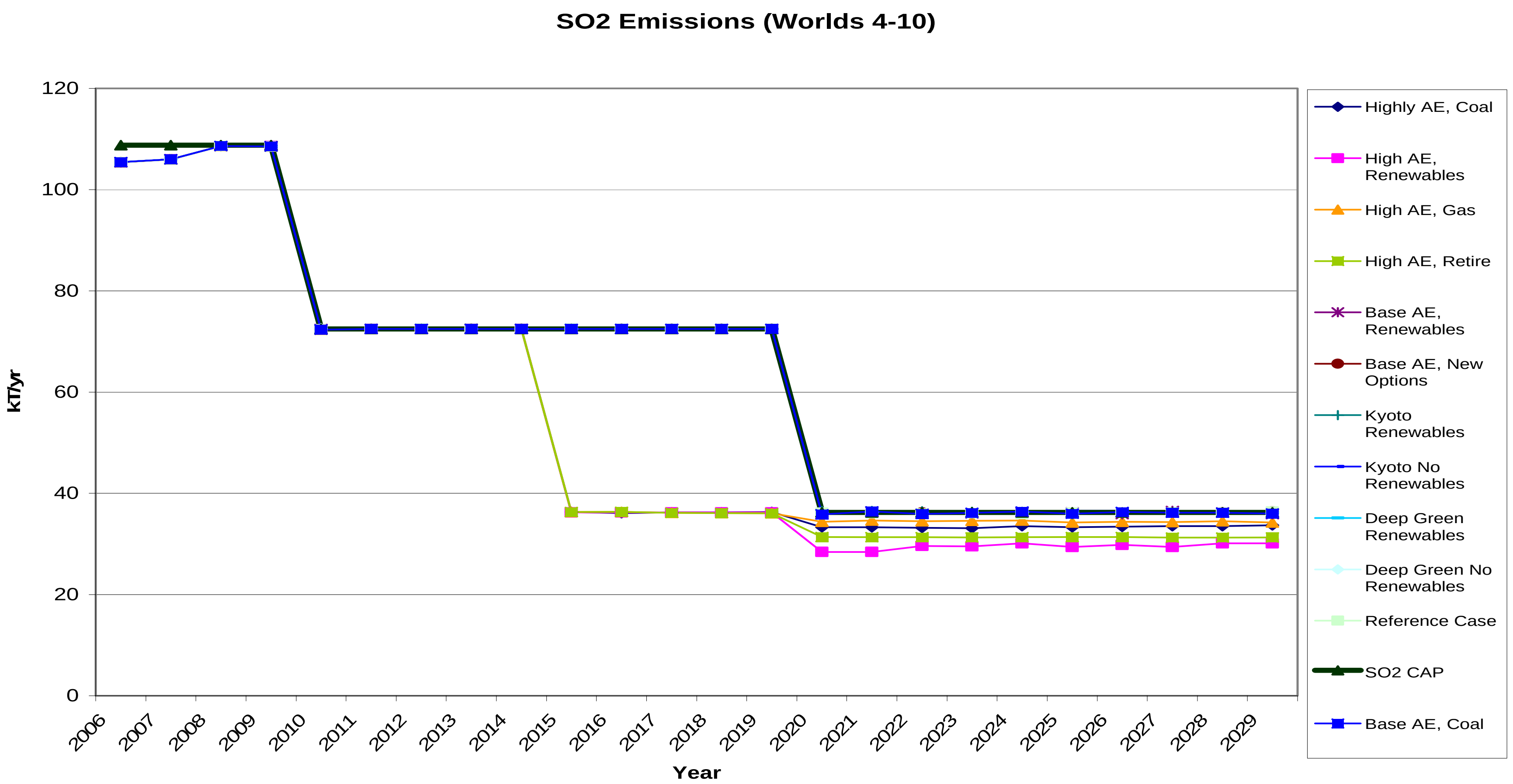
Environmental Additions

Under High Environmental Constraints

	Base Run # 20	**Green P90**	**Green P90**	**Green P90**	**Green P90**
	5% Spend DSM Renewables Plan	**5% Spend DSM High AE, Coal**	**5% Spend DSM High AE, Renewables**	**5% Spend DSM High AE, Gas**	**5% Spend DSM High AE, Retire**
2006	Lingan 3 LN (Jul)	Lingan 3 LN (Jul)	Lingan 3 LN (Jul)	Lingan 3 LN (Jul)	Lingan 3 LN (Jul)
2007	Lingan 2 LN (Jul) Lingan 4 LN (Jul)	Lingan 2 LN (Jul) Lingan 4 LN (Jul)	Lingan 2 LN (Jul) Lingan 4 LN (Jul)	Lingan 2 LN (Jul) Lingan 4 LN (Jul)	Lingan 2 LN (Jul) Lingan 4 LN (Jul)
2008	Pt Tupper LN (Jul) Trenton 5LN (Nov) Lingan 1 LN (Jul)	Pt Tupper LN (Jul) Trenton 5LN (Nov) Lingan 1 LN (Jul)	Pt Tupper LN (Jul) Trenton 5LN (Nov) Lingan 1 LN (Jul)	Pt Tupper LN (Jul) Trenton 5LN (Nov) Lingan 1 LN (Jul)	Pt Tupper LN (Jul) Trenton 5LN (Nov) Lingan 1 LN (Jul)
2009	Trenton 5 Baghouse (Jul)	Trenton 5 Baghouse (Jul)	Trenton 5 Baghouse (Jul)	Trenton 5 Baghouse (Jul)	Trenton 5 Baghouse (Jul)
2015			**L3/L4 FGD**		
2019	**Trenton 6 LN (Oct)**	**Trenton 6 LN (Oct)**	**Trenton 6 LN (Oct)**	**Trenton 6 LN (Oct)**	**Trenton 6 LN (Oct)**
2020	**L1/L2 SCR, L1/L2 FGD**	**L1/L2 SCR, L3/L4 SCR**	**L1/L2 SCR/FGD, L3/L4 SCR**	**L1/L2 SCR, L3/L4 SCR PTSR,T6SR**	**L3/L4 SCR, PTSR,T6SR L1/L2 Retired**
NPV 2006-29 (M$)	**$12,497.0**	**$15,051.5**	**$14,794.5**	**$15,066.5**	**$15,142.6**
Study Period (M$) (includes End Effects)	**$14,479.9**	**$17,694.8**	**$17,336.5**	**$17,791.4**	**$17,901.8**

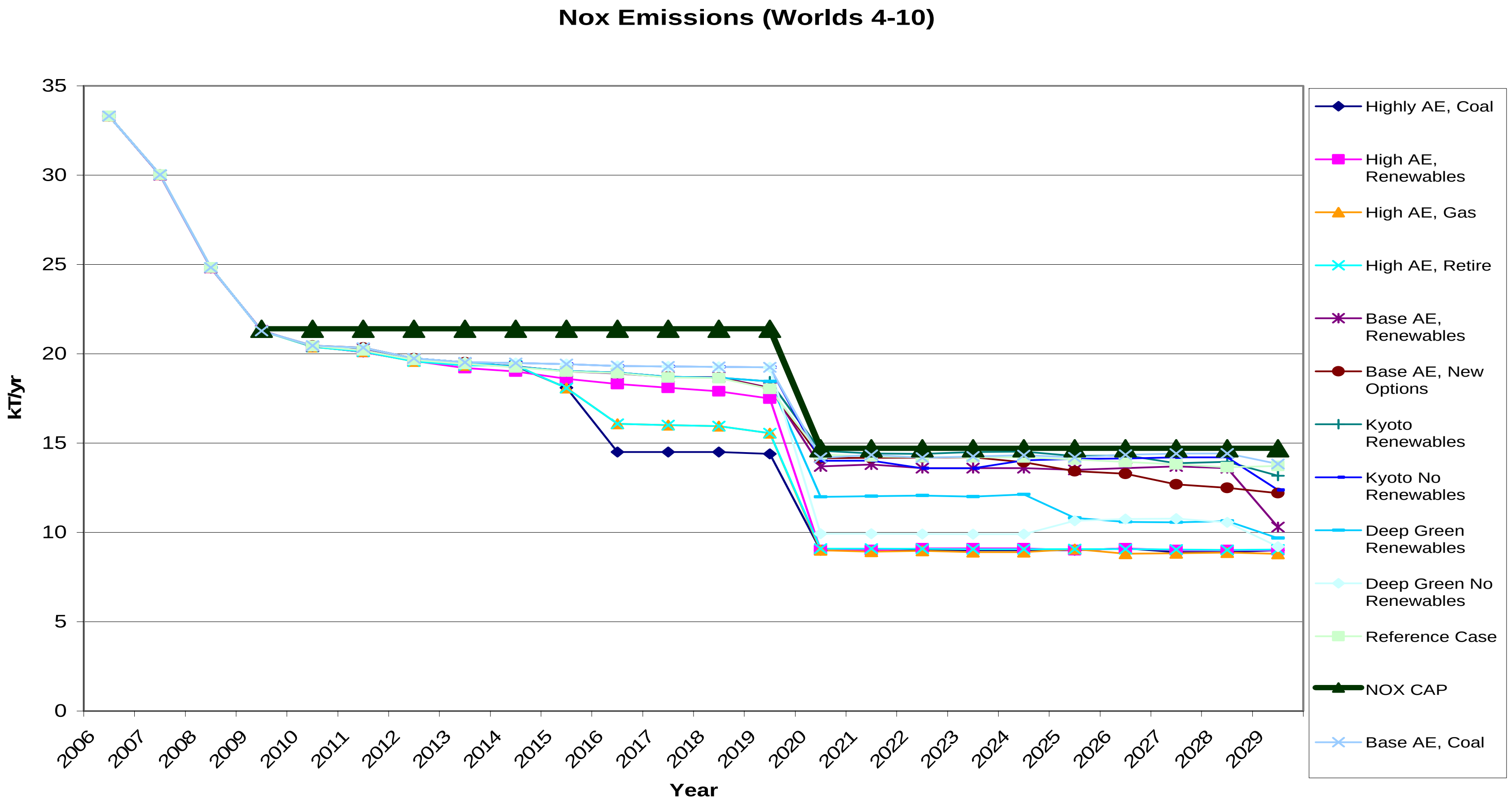
Comparison of Plans under Highly Constrained Emissions

SO2 Emissions



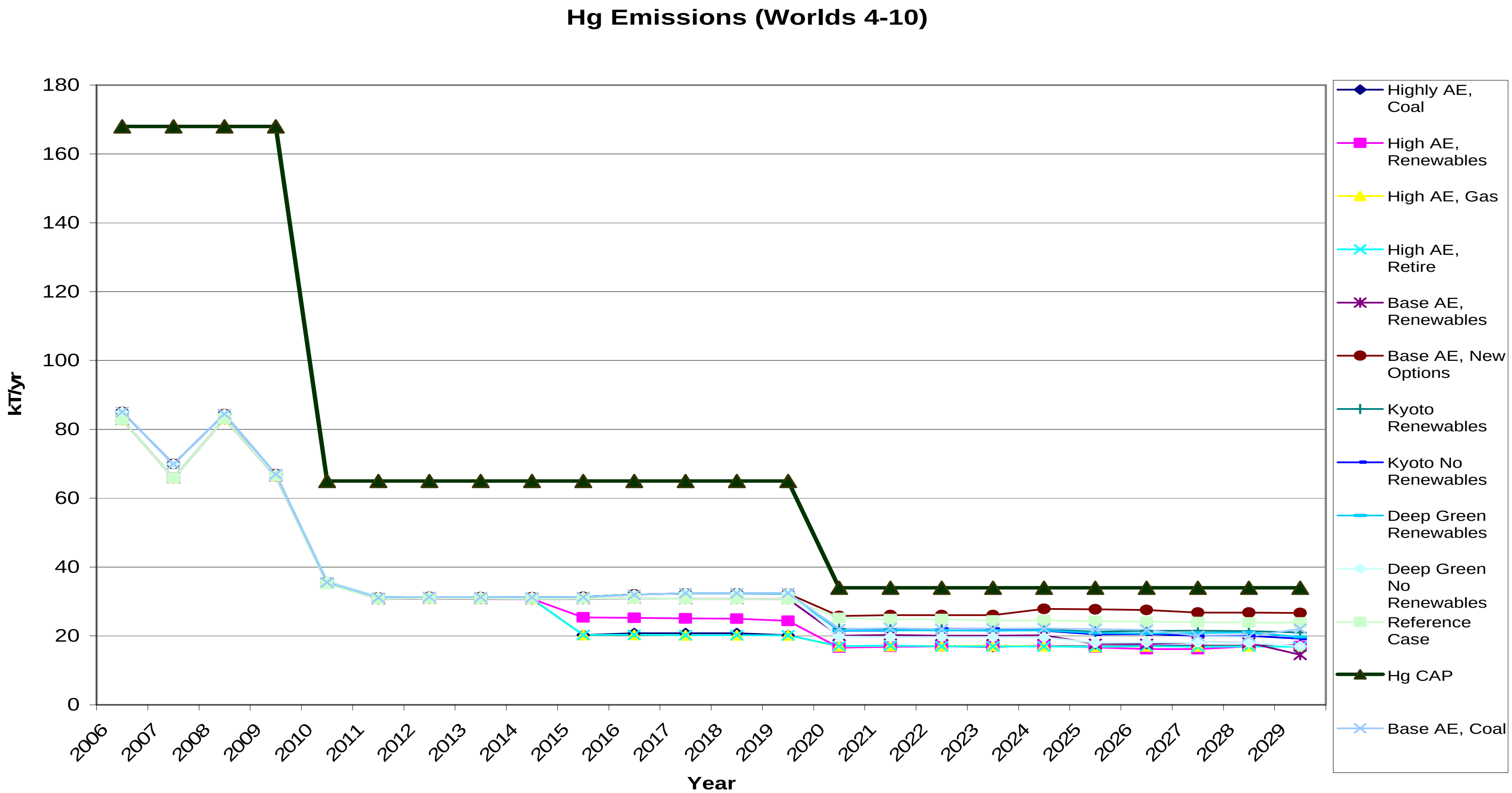
Comparison of Plans under Highly Constrained Emissions

NOx Emissions

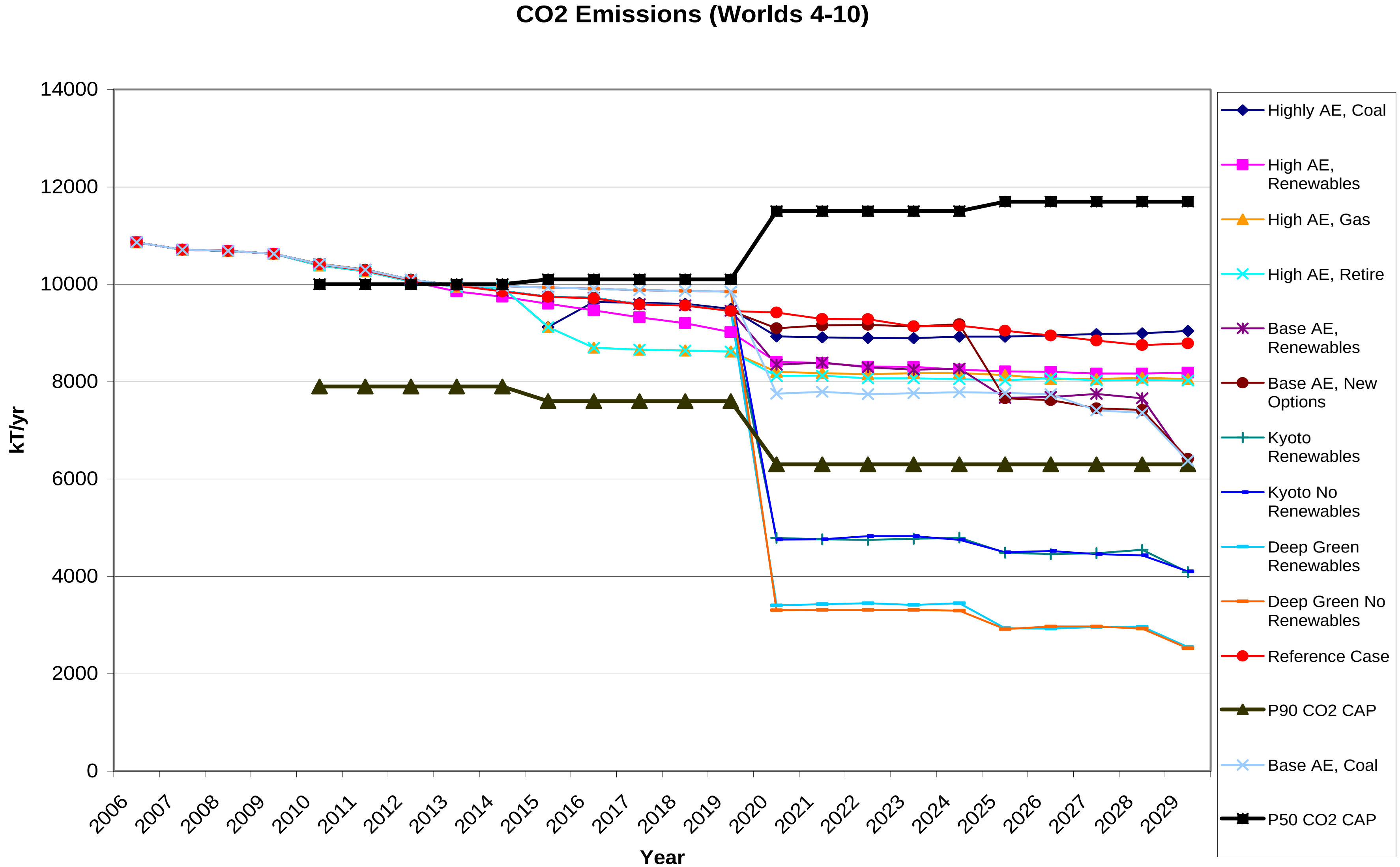


Comparison of Plans under Highly Constrained Emissions

Hg Emissions



Comparison of Plans under Highly Constrained Emissions



Note: Chart shows the effect of no restrictions on credits available

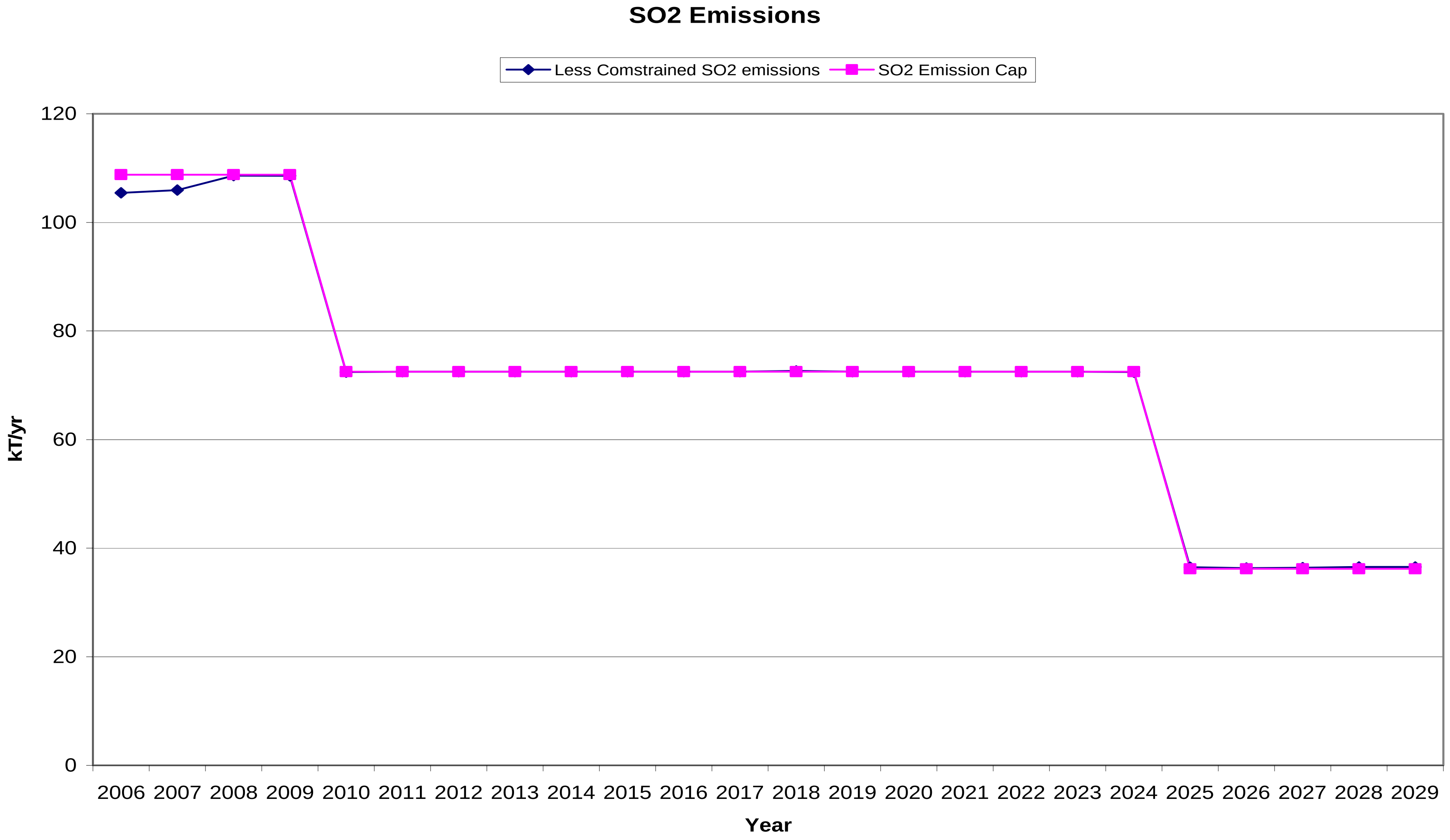
Environmental Additions

Under Less Constrained Environmental Emissions

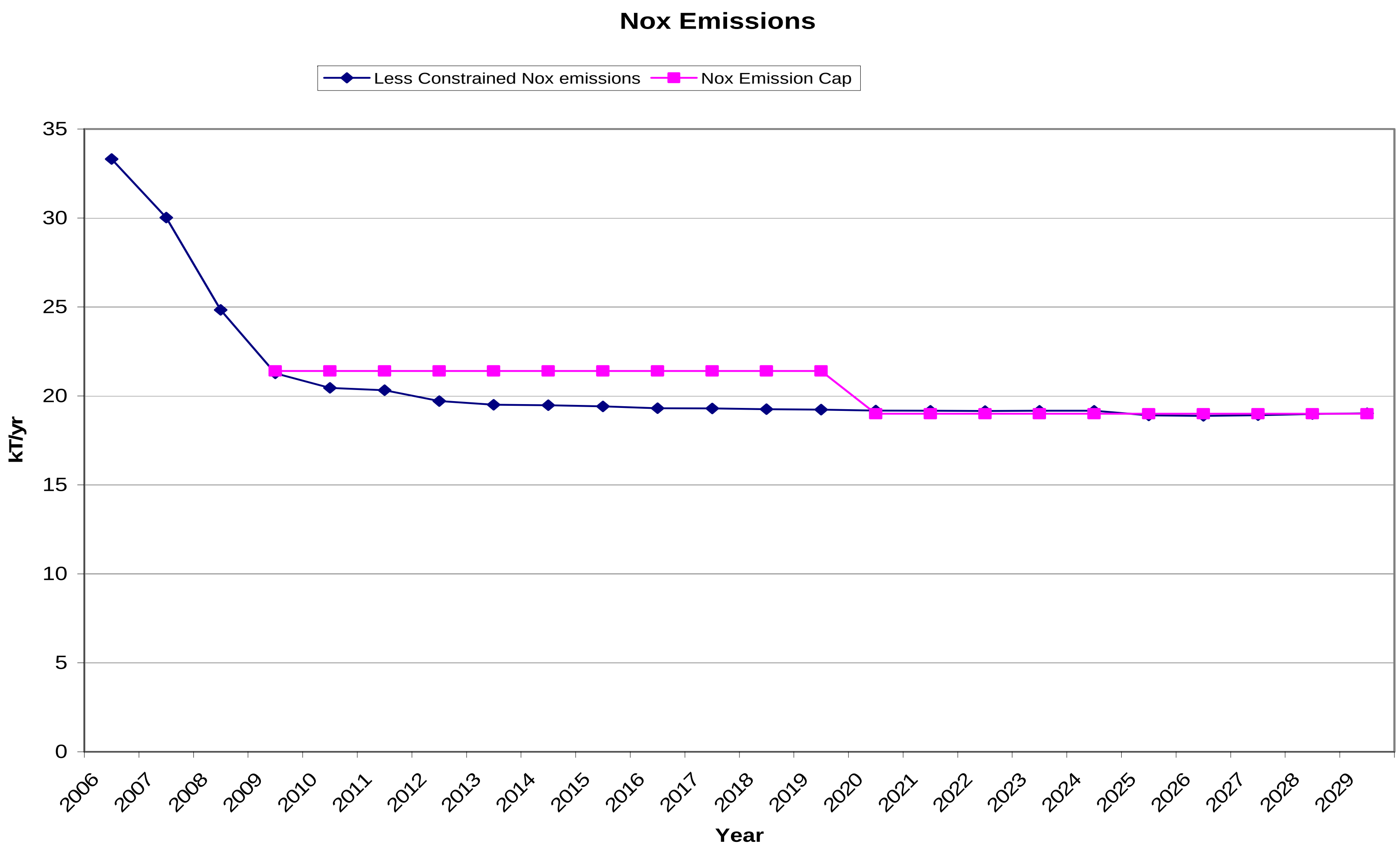
- See Less Constrained Environmental Emissions in Appendix H (note they are less than the base assumptions, not less constrained than current constraints)
- The model was free to pick the optimal way to meet the new environmental caps.
- All additions up to 2019 are consistent with base assumption conclusions
- If less stringent environmental restrictions were effected, the choices in the next decade would still hold. Later years would require different choices.

The plan summary for the less constrained environmental emissions is also shown in Appendix H

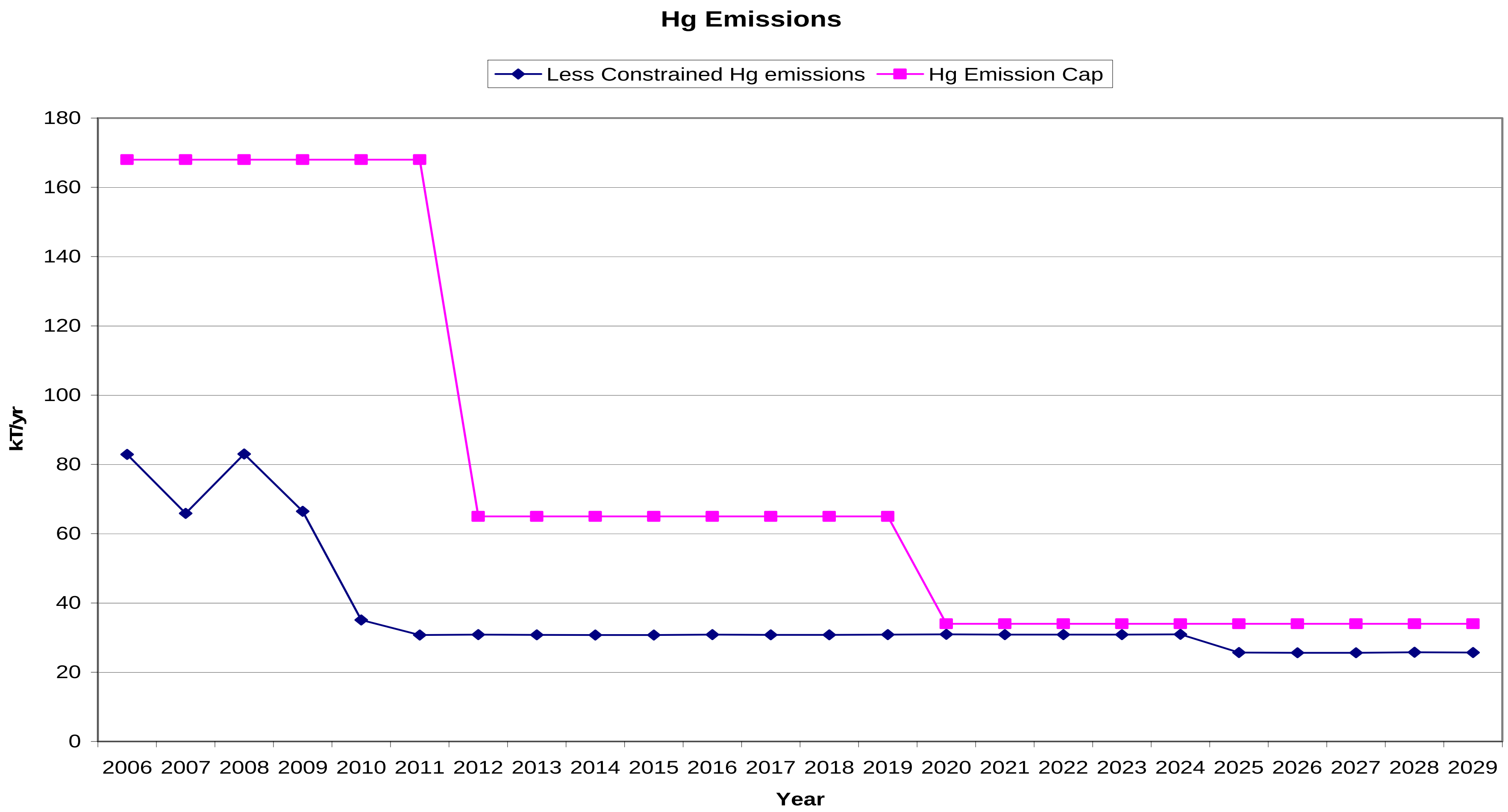
Plan Under Less Constrained Environmental Emissions



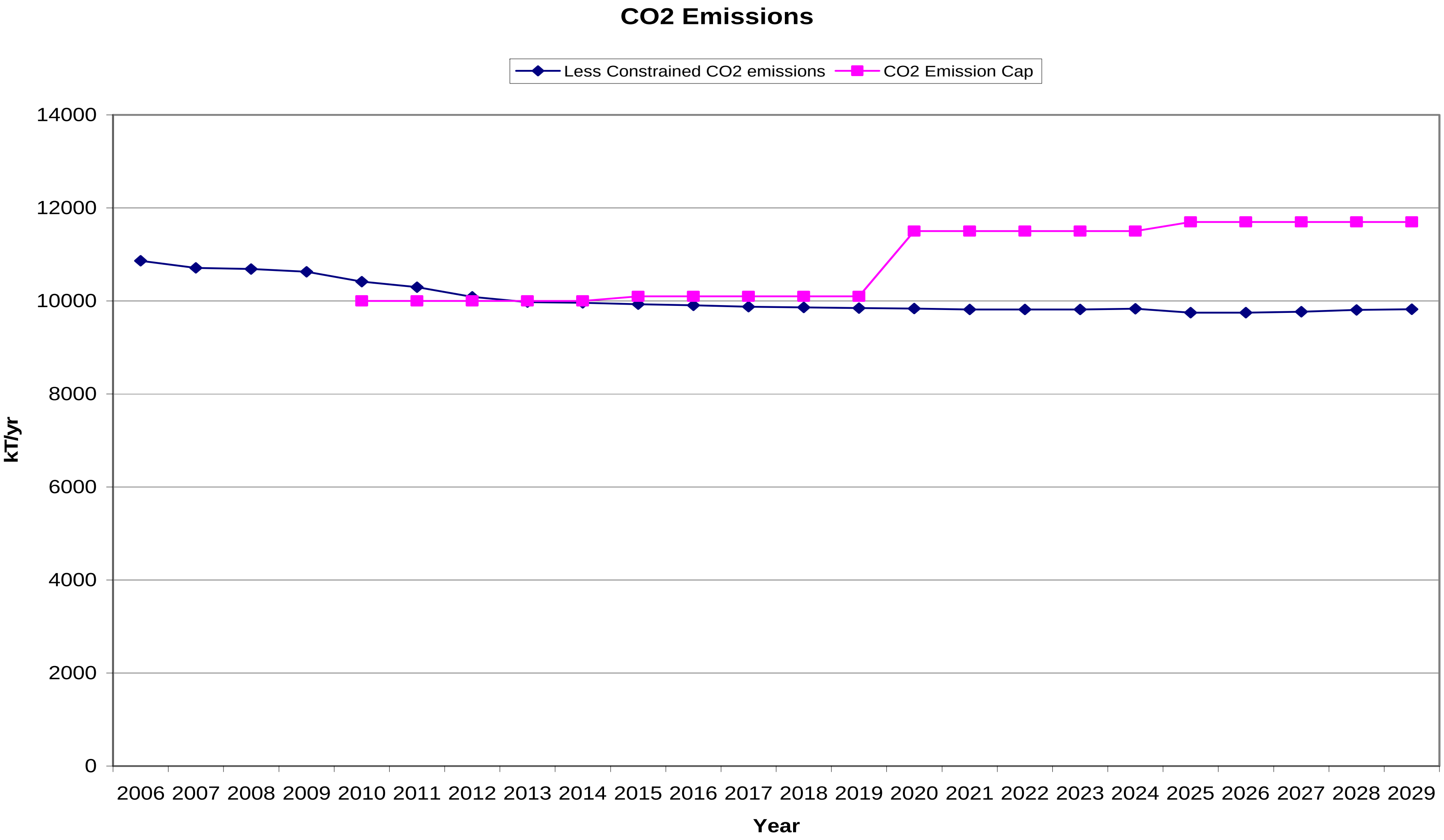
Plan Under Less Constrained Environmental Emissions



Plan Under Less Constrained Environmental Emissions



Plan Under Less Constrained Environmental Emissions



Results – Environmental/Air Emission Constraints Variation Worlds

2007 IRP P10 and P90 Air Emission Constraints Worlds: SCHEDULE OF SUPPLY OR DSM MW's

		5% Spend DSM, Less Constrained Enviro Emissions	5% Spend DSM,High AE, Coal	5% Spend DSM, High AE, Renewables	5% Spend DSM,High AE, Gas	5% Spend DSM,High AE, Retire
New Resources 2008-2014						
	DSM	256	256	256	256	256
	TUC 6	50	50	50	50	50
	LM 6000	0	0	0	0	0
	Uprates	20	20	20	20	20
	Hydro	4.3	4.3	4.3	4.3	4.3
	RPS	166	166	166	166	166
	Additional Wind	0	0	32	0	0
Subtotal		496.3	496.3	528.3	496.3	496.3
New Resources 2015-2029						
	Additional Wind	0	0	160	0	0
	Pulverized Coal	0	400	0	0	0
	LM 6000	0	0	0	0	0
	Combined Cycle	0	0	0	280	280
	Retire Units	0	0	0	0	-300
	DSM	857	857	857	857	857
Subtotal		857	1257	1017	1137	837
Total Supply or DSM MW's over planning period		1353.3	1753.3	1545.3	1633.3	1333.3

Conclusions from Environmental Worlds Analysis

- Common across all plans:
  - Point Tupper Low Nox 2008
  - Trenton 5 Low Nox 2008
  - Lingan 1 Low Nox 2008
  - Trenton 5 baghouse 2009
- Differences among plans
  - Lingan FGD timing
  - Trenton 6 Low Nox 2019 or not at all

Carbon Hard Cap Worlds:

- Three carbon constrained worlds examined
  - Base Assumptions with carbon credits constrained in 2020 and beyond
  - Kyoto carbon assumptions with all other assumptions at base level. Credits constrained in 2020
  - Deep green carbon assumptions with all other assumptions at base level. Credits constrained in 2020.

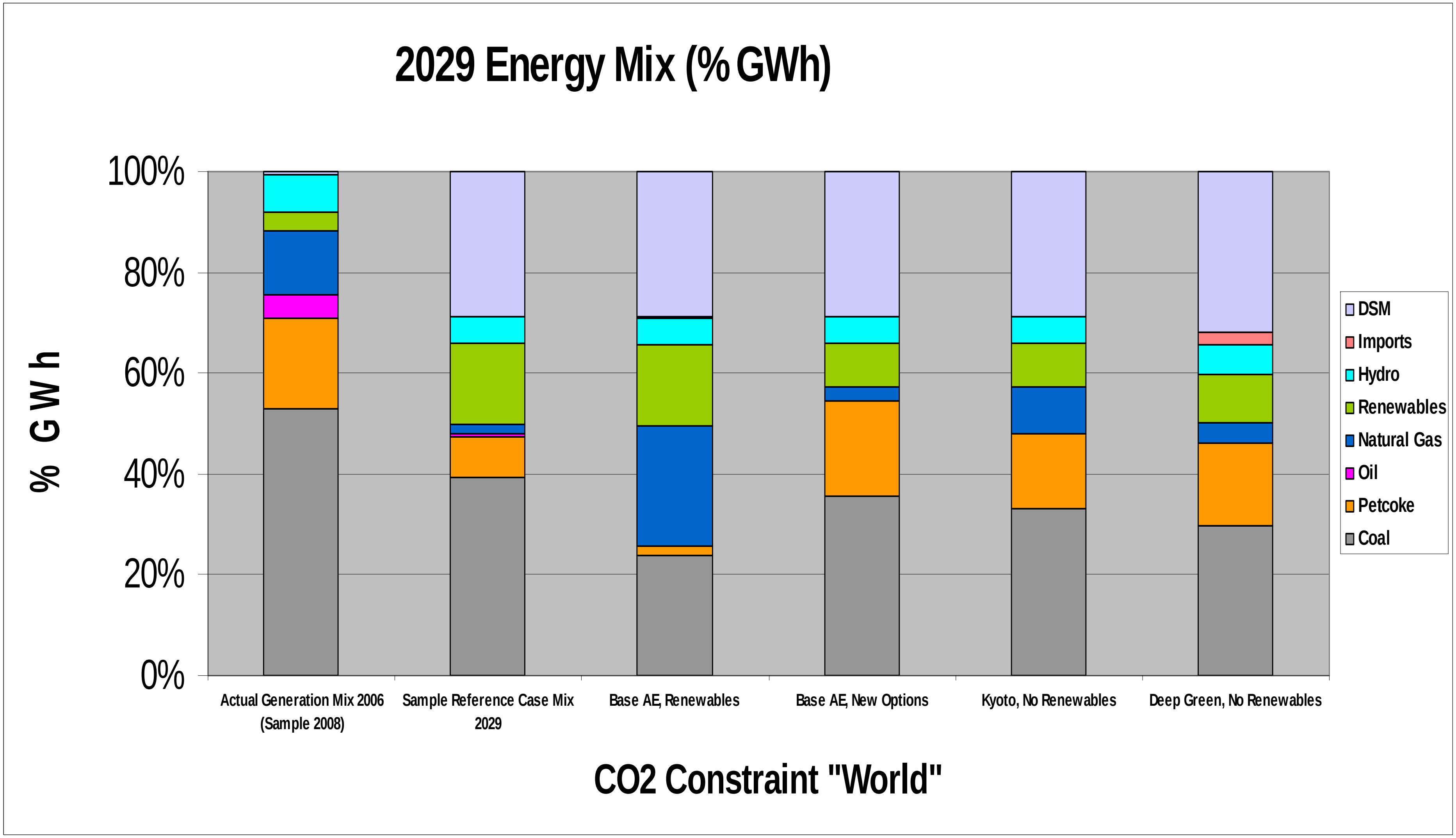
Case	Approximate Emissions (Million tonnes)				
	2010	2015	2020	2025	2030
Base	10.0	9.5	9.1	7.7	6.4
Kyoto	6.4	5.6	4.8	4.5	4.1
Deep Green World	6.44	4.93	3.43	2.95	2.53

New Options for Hard Caps

- To solve for Kyoto and Deep Green model required additional options. We added:
- All options carry significant uncertainty. Each requires additional investigation before costs, timing and feasibility could be confirmed.

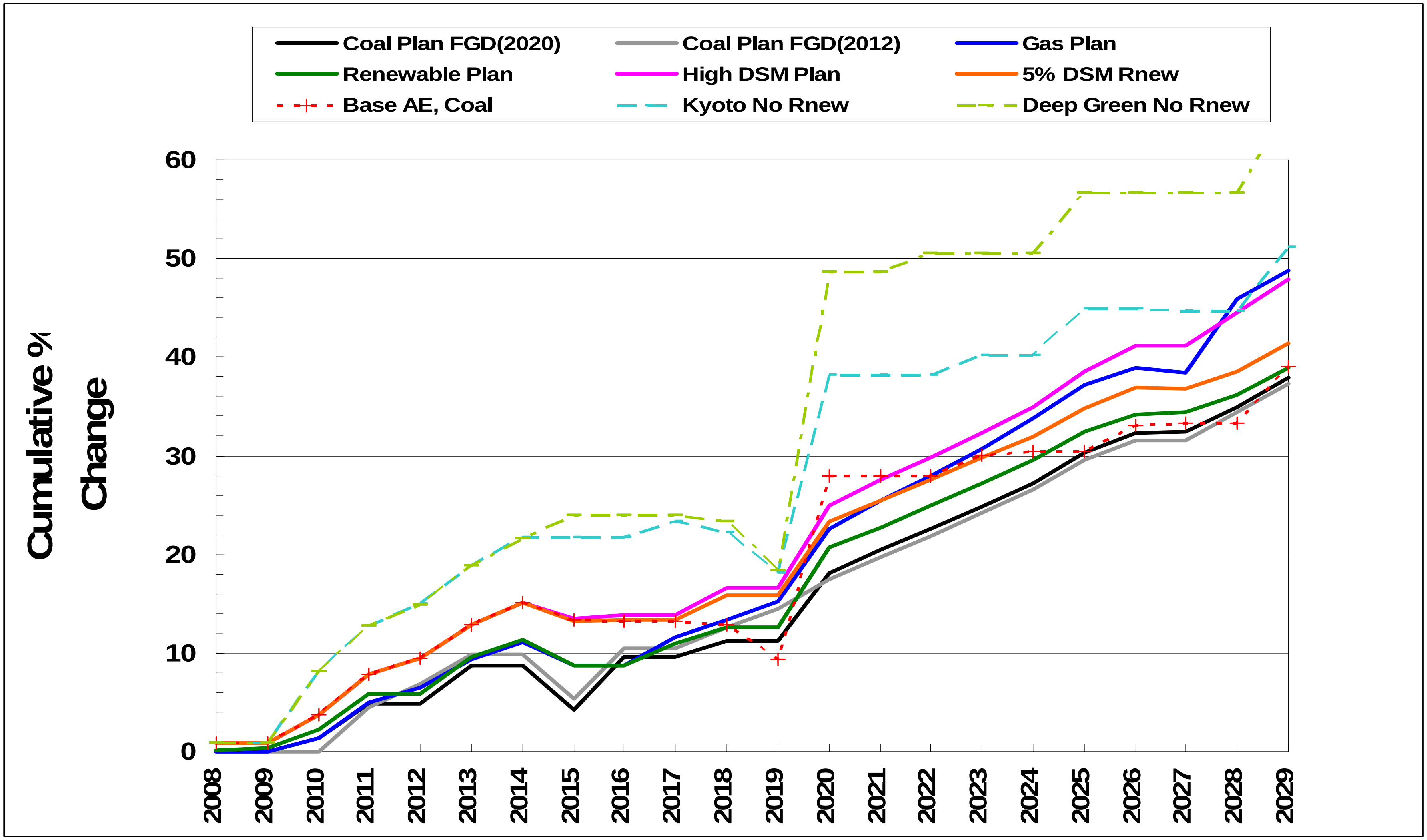
Option	Comment	Cost
Purchase Power Agreement	300 MW firm	energy $108/MW (esc 2%annually); capital = $300M for tie-line upgrade
Carbon Sequestration – New	400MW	Capital $1,378.8 M Incremental O&M: $13.78M (esc 2% annually);
Carbon Sequestration – Retro Fit	300MW- Lingan (2 units)	capital cost =$333M (to capture & sequester CO2) Incremental O&M = $ 9.2 M (esc 2%annually)
Additional Gas	280CC	Consistent with IRP Assumptions
Offshore Wind	100 MW blocks, 35 MW firm	energy $150/MWh - includes wind back-up @$12/MWh (no escalation)
Biomass	20MW Unit, 85% CF	capital cost $48 M annual O&M $2.7M (esc 2%annually) fuel $4.80/mmbtu (esc 2%)

Comparison of CO2 Hard Cap Worlds – Energy Mix @ 2029



Detailed Energy Mix charts for each CO2 constraint world are available in Appendix I. Additional detail is provided in Appendix J

Rate Comparison
Carbon Worlds vs. Base Plans



Kyoto No Rnew and Deep Green No Rnew refer to the fact that no renewables beyond the RPS are included.

DSM Worlds

- Varied amount of DSM three ways:
  - Achieve program trajectory, but 2-year lag in costs & benefits realized
  - Achieve program trajectory, but -20% of benefits realized
  - Achieve program trajectory, with exception that Industrial pulp & paper contribution be minimized assuming associated upgrades have already been implemented at these plants

Results – DSM Variation Worlds

2007 IRP DSM Benefits Variation Worlds: SCHEDULE OF SUPPLY OR DSM MW's

		5% Spend DSM delay 2 years	2% Spend DSM Coal Plant (FGD in 2020) delay 2 years	2% Spend DSM + Renewables > RPS delay 2 years	5% Spend DSM -20% benefits	2% Spend DSM Coal Plant (FGD in 2020) -20% benefits	2% Spend DSM + Renewables > RPS -20% benefits	5% Spend DSM P&P DSM Out	2% Spend DSM Coal Plant (FGD in 2020) P&P DSM Out	2% Spend DSM + Renewables > RPS P&P DSM Out
New Resources 2008-2014										
	DSM	147	84	84	205	117	117	221	126	126
	TUC 6	50	50	50	0	50	50	0	50	50
	LM 6000	0	49	0	0	0	0	0	0	0
	Uprates	20	20	20	20	20	20	20	20	20
	Hydro	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3
	RPS	166	166	166	166	166	166	166	166	166
	Additional Wind			16			16			16
Subtotal		387.3	373.3	340.3	395.3	357.3	373.3	411.3	366.3	206.3
New Resources 2015-2029										
	Additional Wind	0	0	144	0	0	144	0	0	144
	Pulverized Coal	400	400	0	400	400	0	400	400	0
	LM 6000	0	0	0	0	49	0	0	0	0
	Combined Cycle	0	0	280	0	0	280	0	0	280
	DSM	851	536	536	686	447	447	746	472	472
Subtotal		1251	936	960	1086	896	871	1146	872	896
Total SUPPLY OR DSM MW's over planning period		1638.3	1309.3	1300.3	1481.3	1253.3	1244.3	1557.3	1238.3	1102.3

Note: Additional detail is provided in Appendix K

Conclusions from DSM Analysis

- Amount of DSM:
  - Implement DSM program quickly and monitor progress as to benefits achieved
  - Refine MW/MWh to be expected from programs for future modeling update exercises
  - Common near-term investments across all cases:
    - Continued operation of Trenton 5 appears economic
    - Lingan Up-rates
    - Small Hydro additions
    - TUC6 required in most plans
      - Three cases (one base plan, two DSM Worlds) where this requirement varies:
        - » "2% DSM + Renewables beyond RPS" base plan, but varying DSM benefit for this plan requires TUC6
        - » Conversely, in the "5% DSM -20% Benefits" and "5% DSM, no pulp & paper contribution" worlds, TUC6 falls out due to these plans' dispatch of subsequent larger generation

OTHER ANALYSIS

- FGD 2012 versus 2020: Key issue that drove initial IRP process
  - P50 fuel assumption favours FGD in 2020 versus 2012
    - I.e. Fuel switch to meet scheduled 2010 SO2 reduction
  - P90 low sulphur coal with P50 or P10 pet coke, favours FGD 2012
  - P90 air emissions assumption favours FGD in 2015
  - April 26th Federal Regulatory Framework for Air Emissions contemplate alternative emissions caps and timing for SO2. This has not been analyzed as part of the IRP. Additional analysis is required once the regulations are understood.

A comparison of NPVs is provided in Appendix L

Preliminary Conclusions & Actions

DSM

- Conclusion:
- Spending 5% of annual electric revenue appears to be economic.
- Actions Required:
  - Complete program design to maximize energy resource cost savings from investing 5% of annual electric revenue
    - Collect end-use market data to inform design and implementation
  - Seek recovery of costs
  - Implement programs and monitor results
  - Report in two years

Preliminary Conclusions & Actions

Renewables

- Conclusions:
  - Additional wind beyond the RPS appears to be economic

- Actions Required:
  - Conduct wind integration study to assess feasibility and costs of wind in Nova Scotia

Preliminary Conclusions & Actions

Supply Side

- Conclusions:
  - Most incremental near term supply and environmental additions appear economic and/or provide for risk mitigation to meet constraints
  - 5% spending of annual electric revenues on DSM may forego the need for additional large scale generation

- Actions:
- Near Term
  - File work orders supporting the appropriate additions

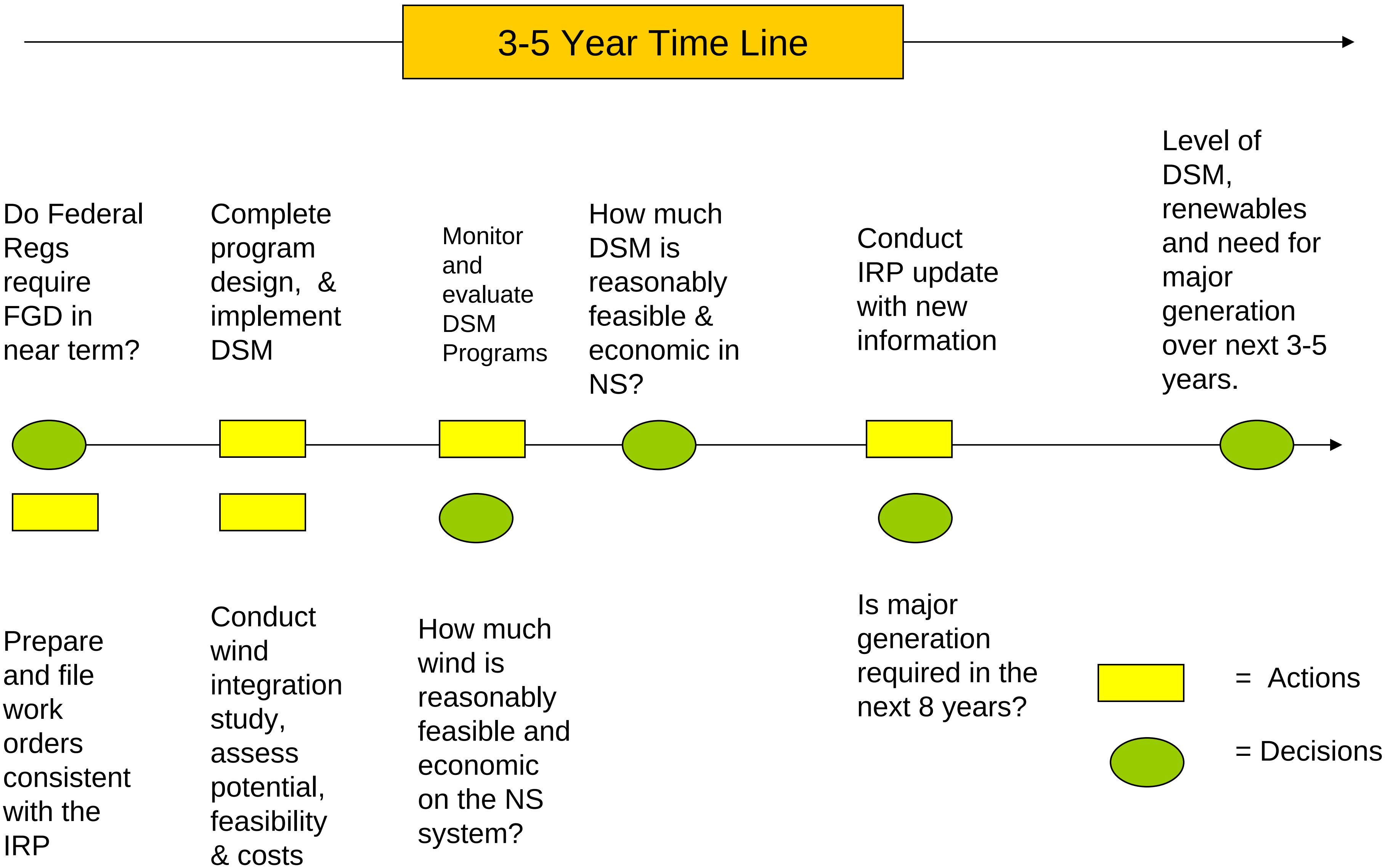
- Longer Term
  - Re-evaluate the need for major generation, once DSM programs have been in place and monitored for two years.

Preliminary Conclusions & Actions

Carbon Credits vs Physical Reductions

- Conclusions:
  - In the 2020 timeframe, physical reductions appear to be on par with the cost of purchasing credits.
  - Whether physical reductions or financial instruments are used to meet caps in 2020, neither affects the decisions required in the next 3-5 years.
- Actions Required:
  - There is considerable uncertainty surrounding the availability and feasibility of physical reductions technologies. The next 3-5 years should focus on gaining more certainty.
  - Purchase financial instruments if required to meet caps before technologies are available

Decision Tree



Early Observations on an Action Plan

- Complete program design to maximize energy resource cost savings from investing 5% of annual electric revenue, apply to recover costs
- Implement DSM and monitor and record results for two years.
- Conduct wind integration study in NS to determine wind integration issues and costs of wind in NS.
- Refresh IRP assumptions in two years to reflect results of DSM programs and wind integration study. Determine at that time if a large generation unit is required in NS
- File work orders in support of short term environmental additions.
- File work orders in support of short term incremental supply options.
- Understand the federal regulations and their effect on NS electricity

NEXT STEPS

Technical Conference	May 23
Stakeholder Input on Results	June 13
Draft Report to Stakeholders	July 4
Stakeholder Comment on Report	July 11
Final Report Filed with UARB	July 25

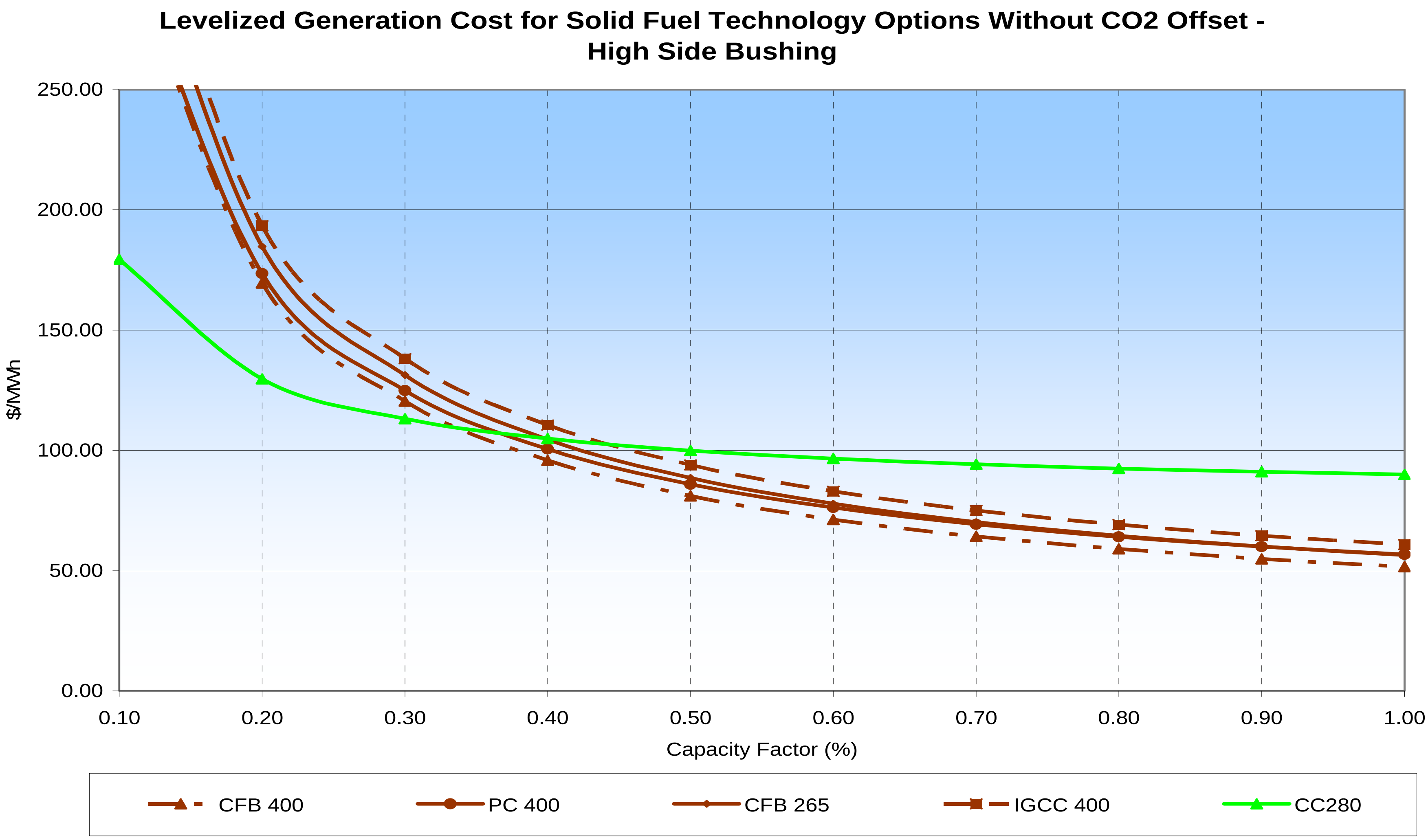
Appendix

Appendix A
Screening Curves

- Generation Option Capital and Operating Costs - information from IRP basic assumptions, in 2006 dollars
- Fuel cost information - information from IRP basic assumptions fuel cost forecast, with fuel forecast levelized for the period used (ie. 40 years).
  – Where fuel cost information was needed beyond 2029, costs were adjusted using 2% inflation. Fuel blend is consistent with Strategist modeling.
- The **before tax** cost of capital was used. The before tax cost of capital rate used is 8.21%, the "most likely" from the IRP basic assumptions.
- The resulting net levelized $/MWhr cost estimated is the **actual cost of production**, before application of tax effects, etc. As noted in the spreadsheet references, the calculation formulas and practices were taken from the book "Least-Cost Electric Utility Planning", by Harry G. Stoll.
- \- For CO2 offset costs, the "most likely" cost curve from the IRP basic assumptions was used for the period 2010 to 2029. After 2029, the offset costs are escalated at 2% inflation.
- Screening curves are shown on the following pages.

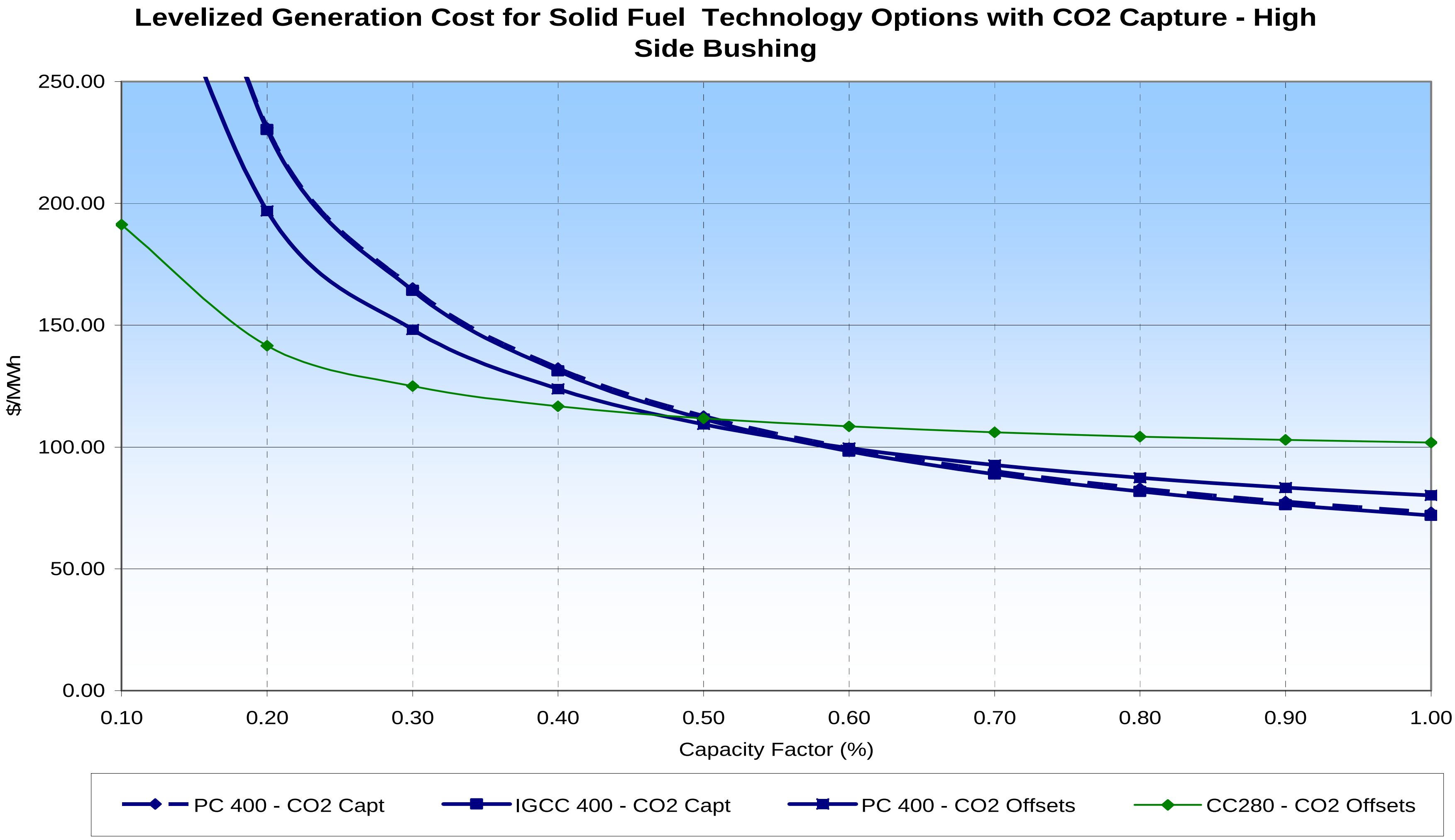
Appendix A

Screening Curves



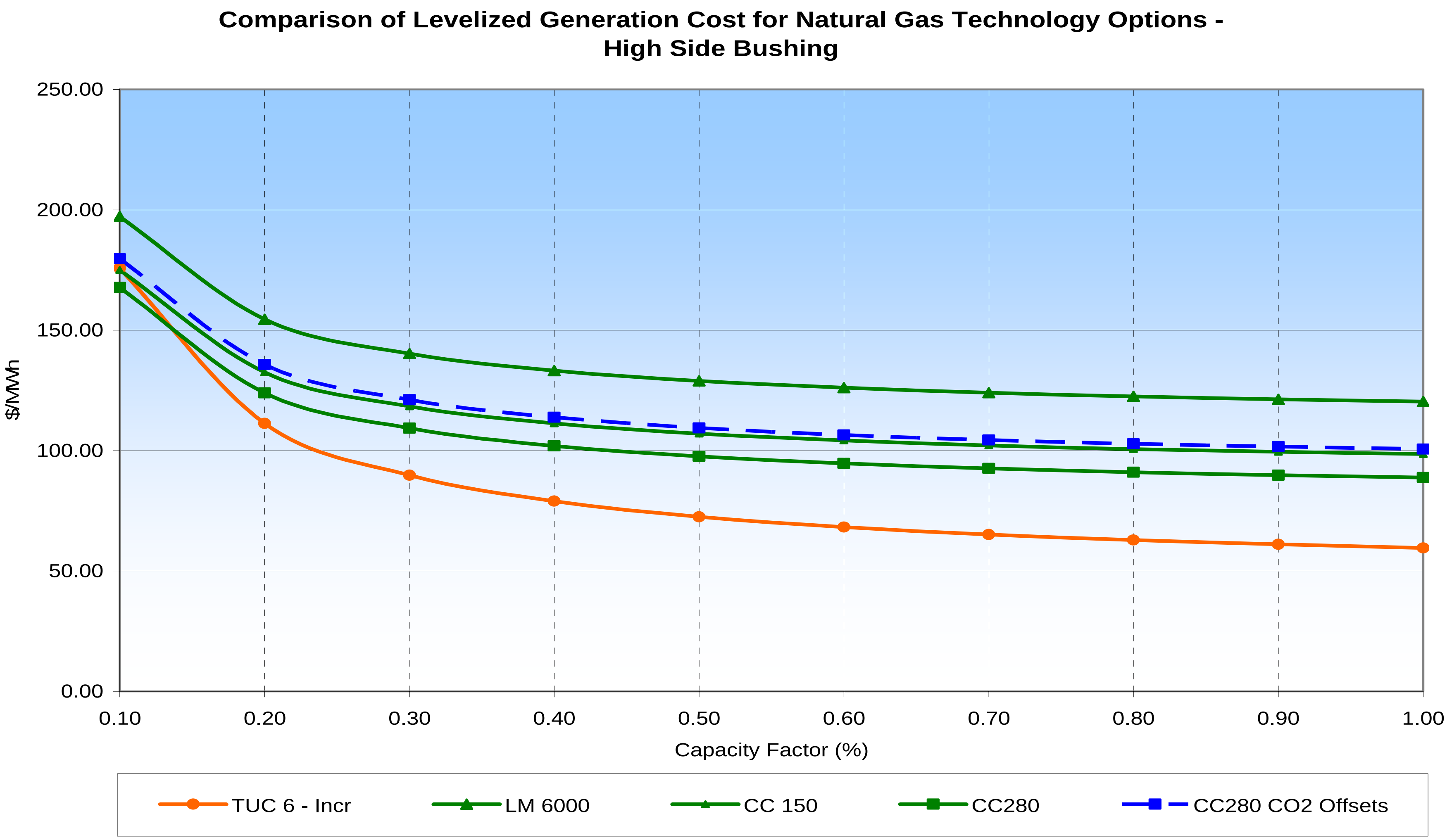
Appendix A

Screening Curves



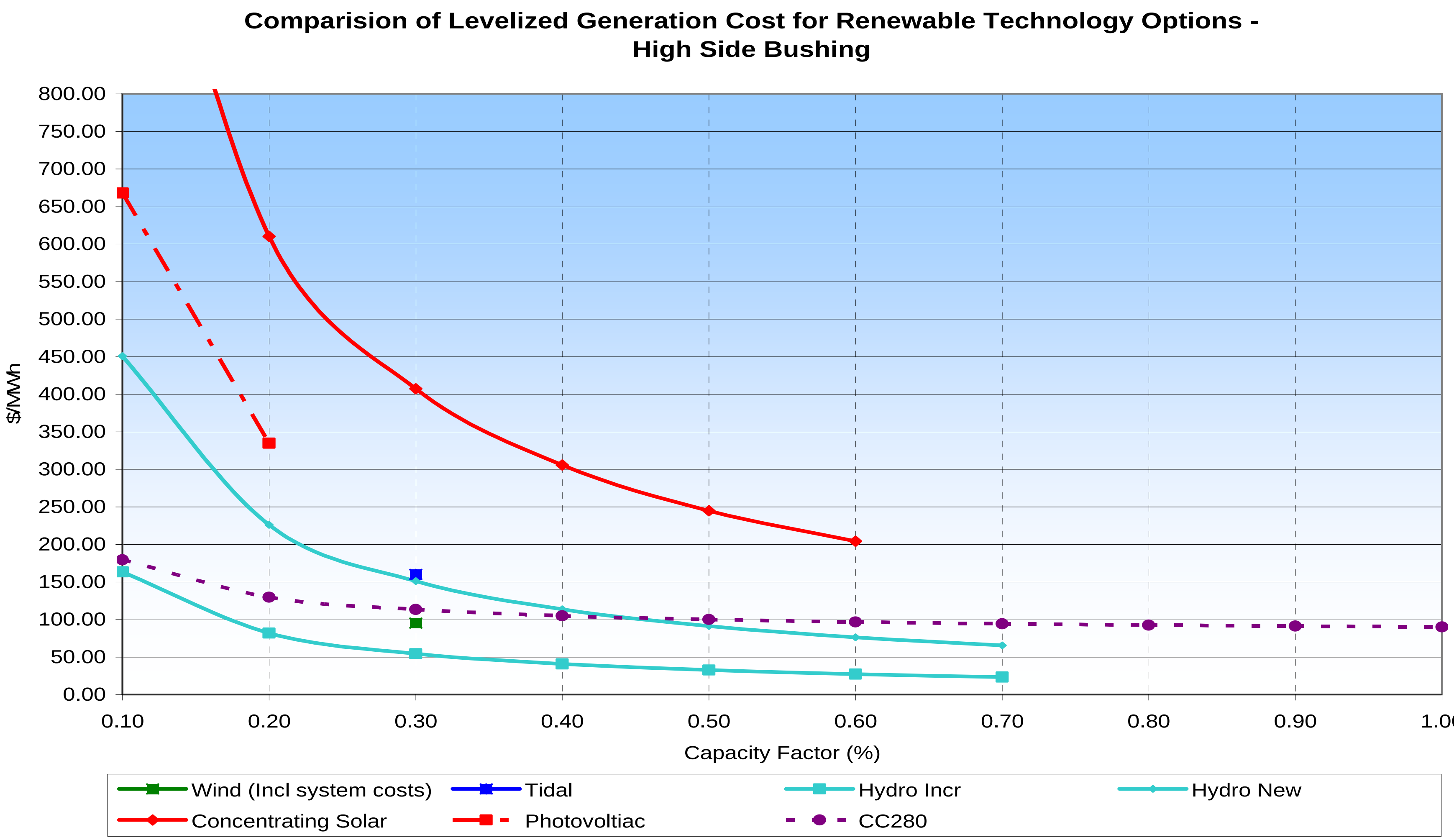
Appendix A

Screening Curves



Appendix A

Screening Curves



Appendix B

6 Base Resource Plans: Summary

IRP Resource Plans (CO2 Credit Costs are included in the Unit Dispatch Costs)

Year	5% Spend DSM Renewables Plan	5% Spend DSM	2% Spend DSM Renewables Plan	2% Spend DSM Coal Plan (FGD in 2020)	2% Spend DSM Coal Plan (FGD in 2012)	2% Spend DSM Natural Gas Plan
2006	Lingan 3 LN (Jul)	Lingan 3 LN (Jul)	Lingan 3 LN (Jul)	Lingan 3 LN (Jul)	Lingan 3 LN (Jul)	Lingan 3 LN (Jul)
2007	Lingan 2 LN (Jul)	Lingan 2 LN (Jul)	Lingan 2 LN (Jul)	Lingan 2 LN (Jul)	Lingan 2 LN (Jul)	Lingan 2 LN (Jul)
	Lingan 4 LN (Jul)	Lingan 4 LN (Jul)	Lingan 4 LN (Jul)	Lingan 4 LN (Jul)	Lingan 4 LN (Jul)	Lingan 4 LN (Jul)
	Burnside 1 (33 MW) (Jan)	Burnside 1 (33 MW) (Jan)	Burnside 1 (33 MW) (Jan)	Burnside 1 (33 MW) (Jan)	Burnside 1 (33 MW) (Jan)	Burnside 1 (33 MW) (Jan)
2008	Pt Tupper LN (Jul)	Pt Tupper LN (Jul)	Pt Tupper LN (Jul)	Pt Tupper LN (Jul)	Pt Tupper LN (Jul)	Pt Tupper LN (Jul)
	Trenton 5LN (Nov)	Trenton 5LN (Nov)	Trenton 5LN (Nov)	Trenton 5LN (Nov)	Trenton 5LN (Nov)	Trenton 5LN (Nov)
	Lingan 1 LN (Jul)	Lingan 1 LN (Jul)	Lingan 1 LN (Jul)	Lingan 1 LN (Jul)	Lingan 1 LN (Jul)	Lingan 1 LN (Jul)
	DSM_Res 5%	DSM_Res 5%	DSM_Res 2%	DSM_Res 2%	DSM_Res 2%	DSM_Res 2%
	DSM_Com 5%	DSM_Com 5%	DSM_Com 2%	DSM_Com 2%	DSM_Com 2%	DSM_Com 2%
	DSM_Ind 5%	DSM_Ind 5%	DSM_Ind 2%	DSM_Ind 2%	DSM_Ind 2%	DSM_Ind 2%
2009	Trenton 5 Baghouse (Jul)	Trenton 5 Baghouse (Jul)	Trenton 5 Baghouse (Jul)	Trenton 5 Baghouse (Jul)	Trenton 5 Baghouse (Jul)	Trenton 5 Baghouse (Jul)
	TUC 6 (Dec)	TUC 6 (Dec)		TUC 6 (Dec)	TUC 6 (Dec)	TUC 6 (Dec)
	Lingan 2 +5MW (Jul)	Lingan 2 +5MW (Jul)	Lingan 2 +5MW (Jul)	Lingan 2 +5MW (Jul)	Lingan 2 +5MW (Jul)	Lingan 2 +5MW (Jul)
	Lingan 4 +5MW (Jul)	Lingan 4 +5MW (Jul)	Lingan 4 +5MW (Jul)	Lingan 4 +5MW (Jul)	Lingan 4 +5MW (Jul)	Lingan 4 +5MW (Jul)
	Nictaux (2.5 MW) (Oct)	Nictaux (2.5 MW) (Oct)	Nictaux (2.5 MW) (Oct)	Nictaux (2.5 MW) (Oct)	Nictaux (2.5 MW) (Oct)	Nictaux (2.5 MW) (Oct)
	Marsh F. (1.8 MW) (Oct)	Marsh F. (1.8 MW) (Oct)	Marsh F. (1.8 MW) (Oct)	Marsh F. (1.8 MW) (Oct)	Marsh F. (1.8 MW) (Oct)	Marsh F. (1.8 MW) (Oct)
2010	Lingan 3 +5MW (Jul)	Lingan 3 +5MW (Jul)	Lingan 3 +5MW (Jul)	Lingan 3 +5MW (Jul)	Lingan 3 +5MW (Jul)	Lingan 3 +5MW (Jul)
			Lingan 1 +5MW (Jul)	Lingan 1 +5MW (Jul)	Lingan 1 +5MW (Jul)	Lingan 1 +5MW (Jul)
	RPS (79 MW Firm total)	RPS (79 MW Firm total)	RPS (79 MW Firm total)	RPS (79 MW Firm total)	RPS (79 MW Firm total)	RPS (79 MW Firm total)
2011	Lingan 1 +5MW (Jul)	Lingan 1 +5MW (Jul)				
2012					**Lingan 3/4 FGD**	
2013	RPS (166MW Firm total)	RPS (166MW Firm total)	RPS (166MW Firm total)	RPS (166MW Firm total)	RPS (166MW Firm total)	RPS (166MW Firm total)
			Rnew 50 MW (16 MW firm)			
2014	Rnew 50 MW (16 MW firm)					
2015	Rnew 50 MW (16 MW firm)		Rnew 50 MW (16 MW firm)			
2016			**CC (280MW)**	**PC 400MW (FGD,SCR,Tox)**	**PC 400MW (FGD,SCR,Tox)**	**CC (280MW)**
2017	Rnew 50 MW (16 MW firm)		Rnew 50 MW (16 MW firm)			
2018						
2019	**Trenton 6 LN (Oct)**	**Trenton 6 LN (Oct)**	**Trenton 6 LN (Oct)**			**Trenton 6 LN (Oct)**
	Rnew 50 MW (16 MW firm)		Rnew 50 MW (16 MW firm)			
2020	L1/L2 SCR, L1/L2 FGD	L1/L2 SCR, L1/L2 FGD	L3/L4 SCR, L3/L4 FGD	L3/L4 SCR, L3/L4 FGD	Lingan 3/4 SCR	L3/L4 SCR, L3/L4 FGD
2021	Rnew 50 MW (16 MW firm)		Rnew 50 MW (16 MW firm)			
2022						
2023	Rnew 50 MW (16 MW firm)		Rnew 50 MW (16 MW firm)			
2024						
2025	Rnew 50 MW (16 MW firm)		Rnew 50 MW (16 MW firm)			
2026	Rnew 50 MW (16 MW firm)		Rnew 50 MW (16 MW firm)			
2027	Rnew 50 MW (16 MW firm)		Rnew 50 MW (16 MW firm)			
2028	Rnew 50 MW (16 MW firm)		Rnew 50 MW (16 MW firm)			**CC (280MW)**
2029						
Study Period (M$) (includes End Effects)	**$14,479.9**	**$14,747.7**	**$15,435.2**	**$15,503.7**	**$15,551.4**	**$15,925.4**

Appendix C

6 Base Resource Plans

Summary MW

2007 IRP REFERENCE PLANS: SCHEDULE OF SUPPLY OR DSM MW's

		Comments: Why each is selected	Levelized Cost of the Incremental kWh	"Reference" 5% Spend DSM + Renewables > RPS	5% Spend DSM	2% Spend DSM + Renewables > RPS	2% Spend DSM Coal Plant (FGD in 2020)	2% Spend DSM Coal Plan (FGD in 2012)	2% Spend DSM Natural Gas
New Resources 2008-2014									
	DSM	Cheapest alternative	~$0.061-0.063/kWh	256	256	146	146	146	146
	TUC 6	Improved heat rate, additional capacity	~$0.065/kWh	50	50	0	50	50	50
	LM 6000	N/A	~$0.125/kWh						
	Uprates	Affordable capital, minimal incremental OM&G/fuel	~ $0.014/kWh	20	20	20	20	20	20
	Hydro	Affordable capital, minimal incremental OM&G/fuel	~ $0.035/kWh	4.3	4.3	4.3	4.3	4.3	4.3
	RPS	Fixed	~$0.09/kWh	166	166	166	166	166	166
	Additional Wind	Economic energy	~$0.09/kWh	16		16			
			SUBTOTAL	512.3	496.3	352.3	386.3	386.3	386.3
New Resources 2015-2029									
	Additional Wind	Economic energy	~$0.09/kWh	144		144			
	Pulverized Coal	Economic energy	~$0.064/kWh				400	400	
	LM 6000	N/A	~$0.125/kWh						
	Combined Cycle	Economic energy	~$0.093/kWh			280			560
	DSM	Cheapest alternative	~$0.061-0.063/kWh	857	857	559	559	559	559
			SUBTOTAL	1001	857	983	959	959	1119
			TOTAL SUPPLY OR DSM MW's OVER PLANNING PERIOD	1513.3	1353.3	1335.3	1345.3	1345.3	1505.3

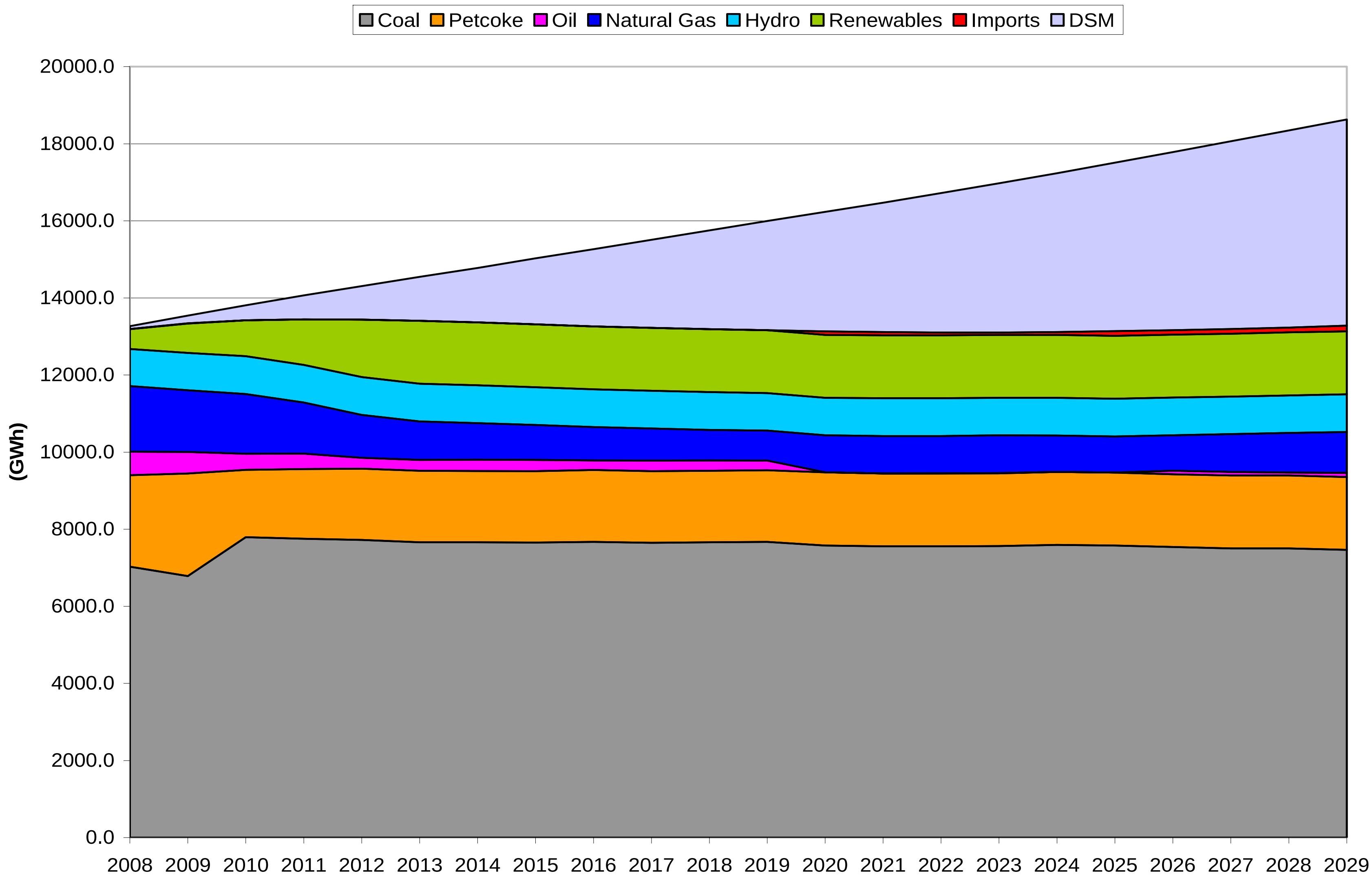
Appendix D

Loads & Resources – Reference Case
“5% Spend DSM & Renewables beyond RPS”

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Peak Firm Load	1,927	1,973	2,019	2,061	2,101	2,141	2,181	2,224	2,264	2,306	2,347	2,391	2,432	2,473	2,517	2,561	2,608	2,656	2,705	2,754	2,805	2,856
Peak Firm Less DSM	1,916	1,943	1,959	1,960	1,954	1,942	1,925	1,909	1,890	1,874	1,858	1,845	1,829	1,814	1,802	1,790	1,781	1,772	1,764	1,756	1,750	1,743
DSM	11	30	60	101	147	199	256	315	374	432	489	546	603	659	715	771	827	884	941	998	1,055	1,113
RM Required	460	466	470	470	469	466	462	458	454	450	446	443	439	435	432	430	427	425	423	422	420	418
Required MWs	2,299	2,332	2,351	2,352	2,345	2,331	2,310	2,290	2,268	2,249	2,229	2,214	2,195	2,177	2,162	2,148	2,137	2,127	2,117	2,108	2,100	2,092
Existing MWs	2334	2334	2334	2334	2334	2334	2334	2334	2334	2334	2334	2334	2334	2334	2334	2334	2334	2334	2334	2334	2334	2334
Additions MWs																						
TUC6		51.9																				
LIN 1 Uprate				5																		
LIN 2 Uprate		5																				
LIN 3 Uprate			5																			
LIN 4 Uprate		5																				
Hydros		4.3																				
RPS	4.7	28.8	27.8	19.2	28.8	38.7																
Additional Wind							16	16		16		16		16		16		16	16	16	16	
FGD													-8									
Total Annual Additions	4.7	95	32.8	24.2	28.8	38.7	16	16	0	16	0	16	-8	16	0	16	0	16	16	16	16	0
Total Cumulative Additions	4.7	99.7	132.5	156.7	185.5	224.2	240.2	256.2	256.2	272.2	272.2	288.2	280.2	296.2	296.2	312.2	312.2	328.2	344.2	360.2	376.2	376.2
Total Firm Capacity	2338.7	2433.7	2466.5	2490.7	2519.5	2558.2	2574.2	2590.2	2590.2	2606.2	2606.2	2622.2	2614.2	2630.2	2630.2	2646.2	2646.2	2662.2	2678.2	2694.2	2710.2	2710.2
Surplus (Deficit) MWs above RM	40	102	116	138	175	227	264	300	322	357	377	408	419	453	468	498	509	536	561	586	610	619
Reserve Margin %	22%	25%	26%	27%	29%	32%	34%	36%	37%	39%	40%	42%	43%	45%	46%	48%	49%	50%	52%	53%	55%	55%

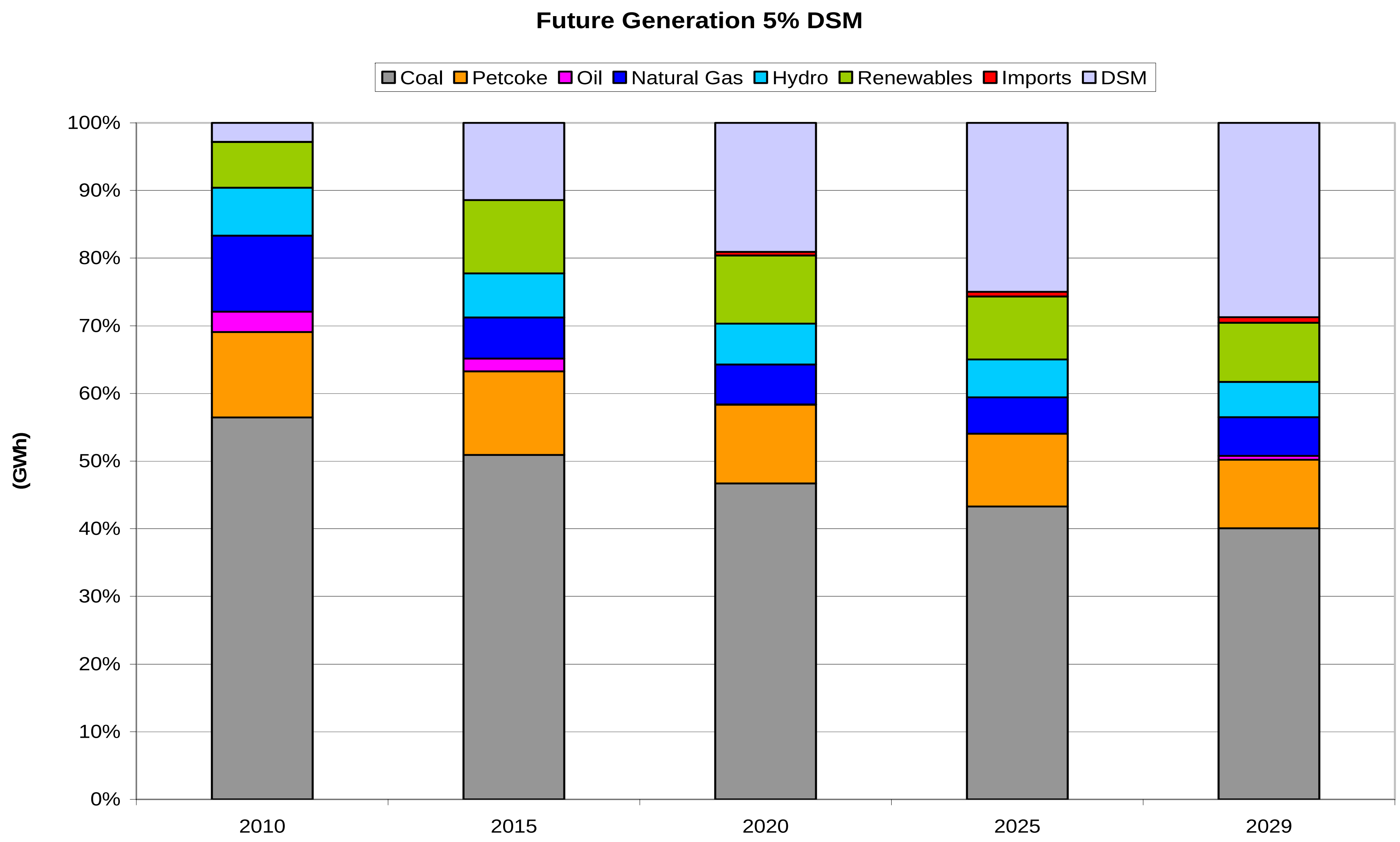
Appendix E

Energy *5% Spend DSM*



Appendix E

Energy *5% Spend DSM*



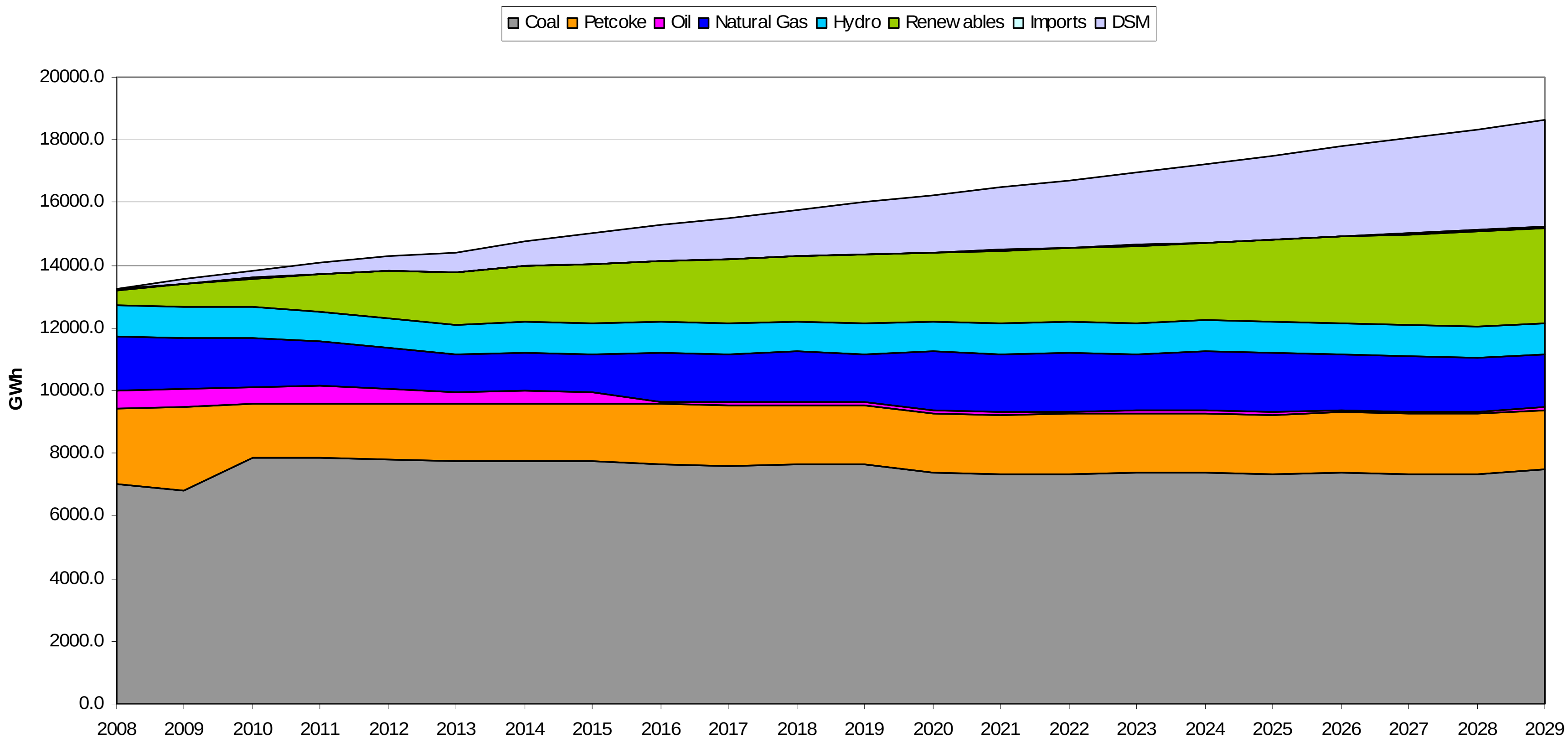
Loads & Resources

5% DSM

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Peak Firm Load (MW)	1,927	1,973	2,019	2,061	2,101	2,141	2,181	2,224	2,264	2,306	2,347	2,391	2,432	2,473	2,517	2,561	2,608	2,656	2,705	2,754	2,805	2,856
Peak Firm Less DSM	1,919	1,951	1,975	1,988	1,995	1,999	1,998	1,999	1,998	1,999	2,000	2,004	2,005	2,006	2,011	2,015	2,022	2,030	2,039	2,047	2,056	2,066
DSM Firm	8	22	44	73	106	142	183	225	266	307	347	387	427	467	506	546	586	626	666	707	749	790
RM Required (MW)	460	468	474	477	479	480	480	480	479	480	480	481	481	481	483	484	485	487	489	491	494	496
Required MWs	2,302	2,342	2,371	2,386	2,395	2,399	2,398	2,399	2,397	2,399	2,399	2,404	2,406	2,407	2,413	2,418	2,427	2,436	2,446	2,456	2,468	2,479
Existing MWs	2334	2334	2334	2334	2334	2334	2334	2334	2334	2334	2334	2334	2334	2334	2334	2334	2334	2334	2334	2334	2334	2334
Additions MWs																						
TUC6			51.9																			
LIN 1 Uprate					5																	
LIN 2 Uprate			5																			
LIN 3 Uprate				5																		
LIN 4 Uprate			5																			
Hydros			4.3																			
RPS	4.7	28.8	27.8	19.2	28.8	38.7																
Additional Wind																						
FGD													-8									
Total Annual Additions	4.7	28.8	94	24.2	33.8	38.7	0	0	0	0	0	0	-8	0	0	0	0	0	0	0	0	0
Total Cumulative Additions	4.7	33.5	127.5	151.7	185.5	224.2	224.2	224.2	224.2	224.2	224.2	224.2	216.2	216.2	216.2	216.2	216.2	216.2	216.2	216.2	216.2	216.2
Total Firm Capacity (MW)	2338.7	2367.5	2461.5	2485.7	2519.5	2558.2	2558.2	2558.2	2558.2	2558.2	2558.2	2558.2	2550.2	2550.2	2550.2	2550.2	2550.2	2550.2	2550.2	2550.2	2550.2	2550.2
Surplus (Deficit) MWs above RM	36	26	91	100	125	160	160	159	161	160	159	154	144	143	138	132	124	114	104	94	82	72
Reserve Margin %	22%	21%	25%	25%	26%	28%	28%	28%	28%	28%	28%	28%	27%	27%	27%	27%	26%	26%	25%	25%	24%	23%

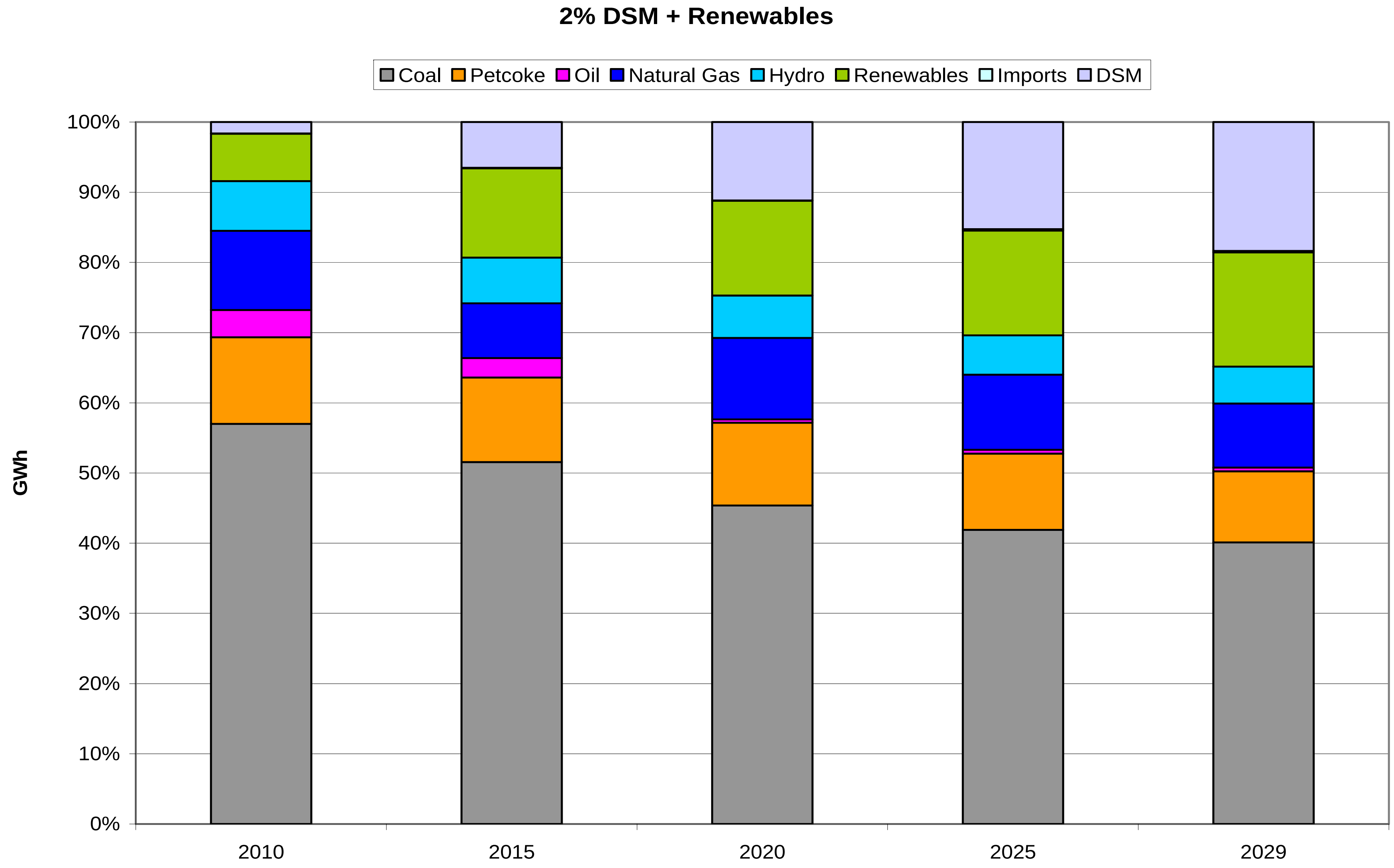
Appendix E

Energy *2% DSM + Renewables*



Appendix E

Energy *2% DSM + Renewables*



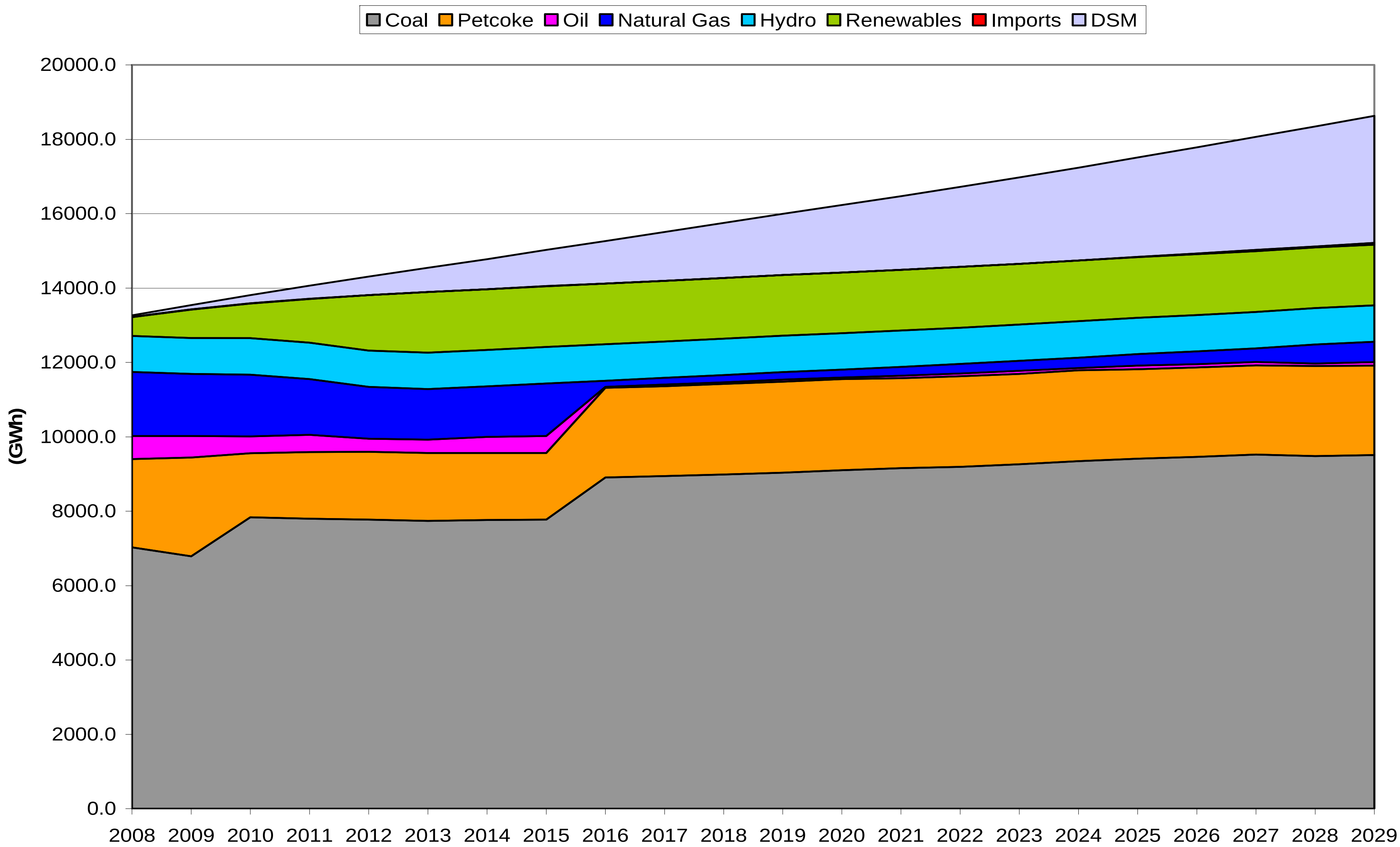
Loads & Resources

2% DSM + Renewables

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Peak Firm Load (MW)	1,927	1,973	2,019	2,061	2,101	2,141	2,181	2,224	2,264	2,306	2,347	2,391	2,432	2,473	2,517	2,561	2,608	2,656	2,705	2,754	2,805	2,856
Peak Firm Less DSM	1,922	1,961	1,994	2,020	2,041	2,060	2,077	2,095	2,112	2,130	2,148	2,168	2,186	2,203	2,224	2,244	2,267	2,291	2,315	2,338	2,364	2,388
DSM Firm	4.7	12.3	24.9	41.5	60.3	81.3	104.4	128.5	152.3	175.9	199.3	222.7	246.1	269.5	293.1	316.9	341.0	365.5	390.3	415.5	441.3	467.6
RM Required (MW)	461	471	479	485	490	494	498	503	507	511	515	520	525	529	534	539	544	550	556	561	567	573
Required MWs	2,307	2,353	2,393	2,423	2,449	2,472	2,492	2,515	2,534	2,556	2,577	2,602	2,623	2,644	2,669	2,693	2,720	2,749	2,778	2,806	2,836	2,866
Existing MWs	2334	2334	2334	2334	2334	2334	2334	2334	2334	2334	2334	2334	2334	2334	2334	2334	2334	2334	2334	2334	2334	2334
Additions MWs																						
TUC6																						
LIN 1 Uprate				5																		
LIN 2 Uprate			5																			
LIN 3 Uprate				5																		
LIN 4 Uprate			5																			
Hydros			4.3																			
RPS	4.7	28.8	27.8	19.2	28.8	38.7																
Additional Wind						16		16		16		16		16		16		16	16	16	16	
Combined Cycle									280													
FGD													-8									
Total Annual Additions	4.7	28.8	42.1	29.2	28.8	54.7	0	16	280	16	0	16	-8	16	0	16	0	16	16	16	16	0
Total Cumulative Additions	4.7	33.5	75.6	104.8	133.6	188.3	188.3	204.3	484.3	500.3	500.3	516.3	508.3	524.3	524.3	540.3	540.3	556.3	572.3	588.3	604.3	604.3
Total Firm Capacity (MW)	2338.7	2367.5	2409.6	2438.8	2467.6	2522.3	2522.3	2538.3	2818.3	2834.3	2834.3	2850.3	2842.3	2858.3	2858.3	2874.3	2874.3	2890.3	2906.3	2922.3	2938.3	2938.3
Surplus (Deficit) MWs above RM	32	15	17	15	19	51	30	24	284	278	257	248	219	214	190	181	154	142	129	116	102	72
Reserve Margin %	22%	21%	21%	21%	21%	22%	21%	21%	33%	33%	32%	31%	30%	30%	29%	28%	27%	26%	26%	25%	24%	23%

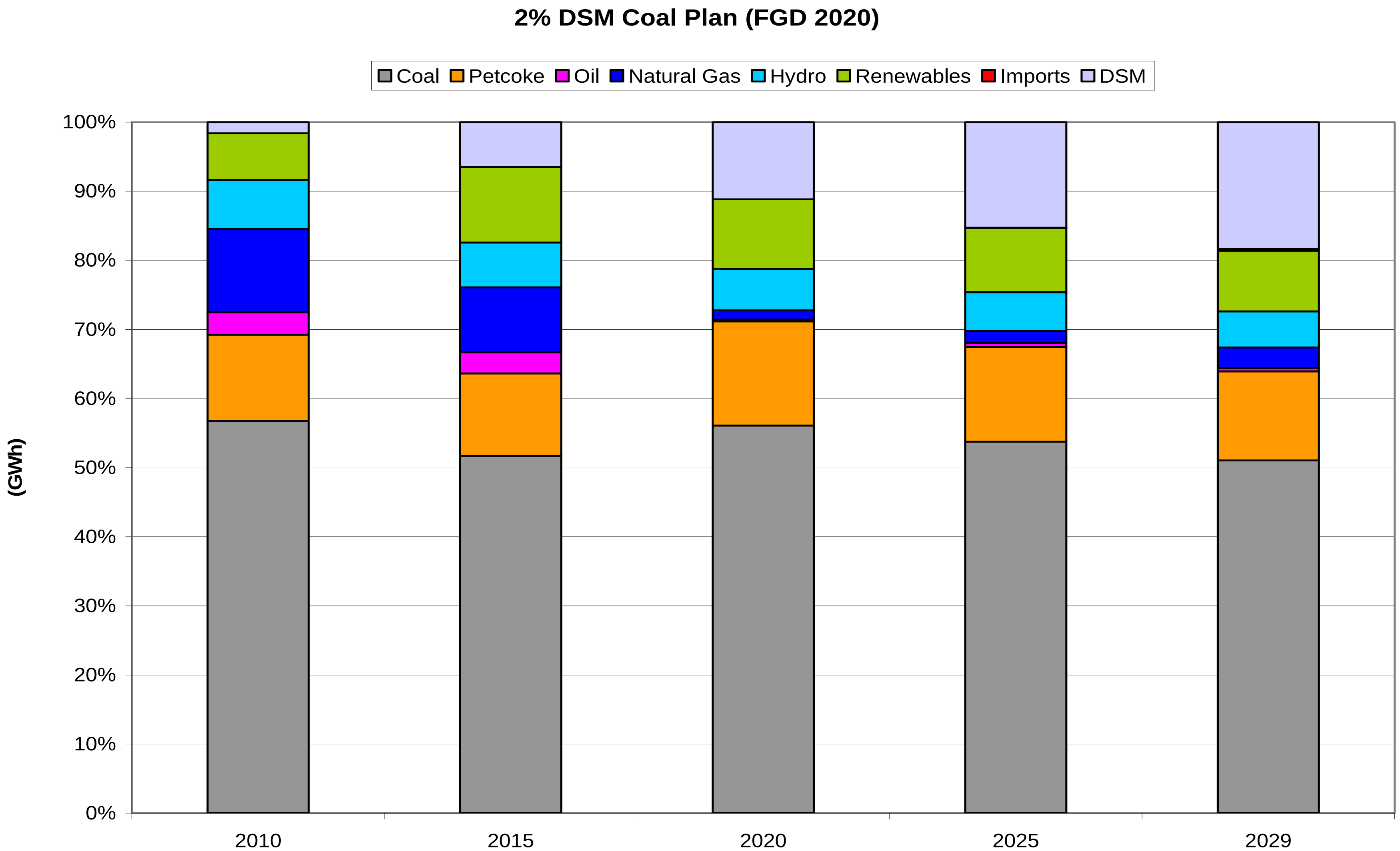
Appendix E

Energy *2% DSM + Coal*



Appendix E

Energy *2% DSM + Coal*



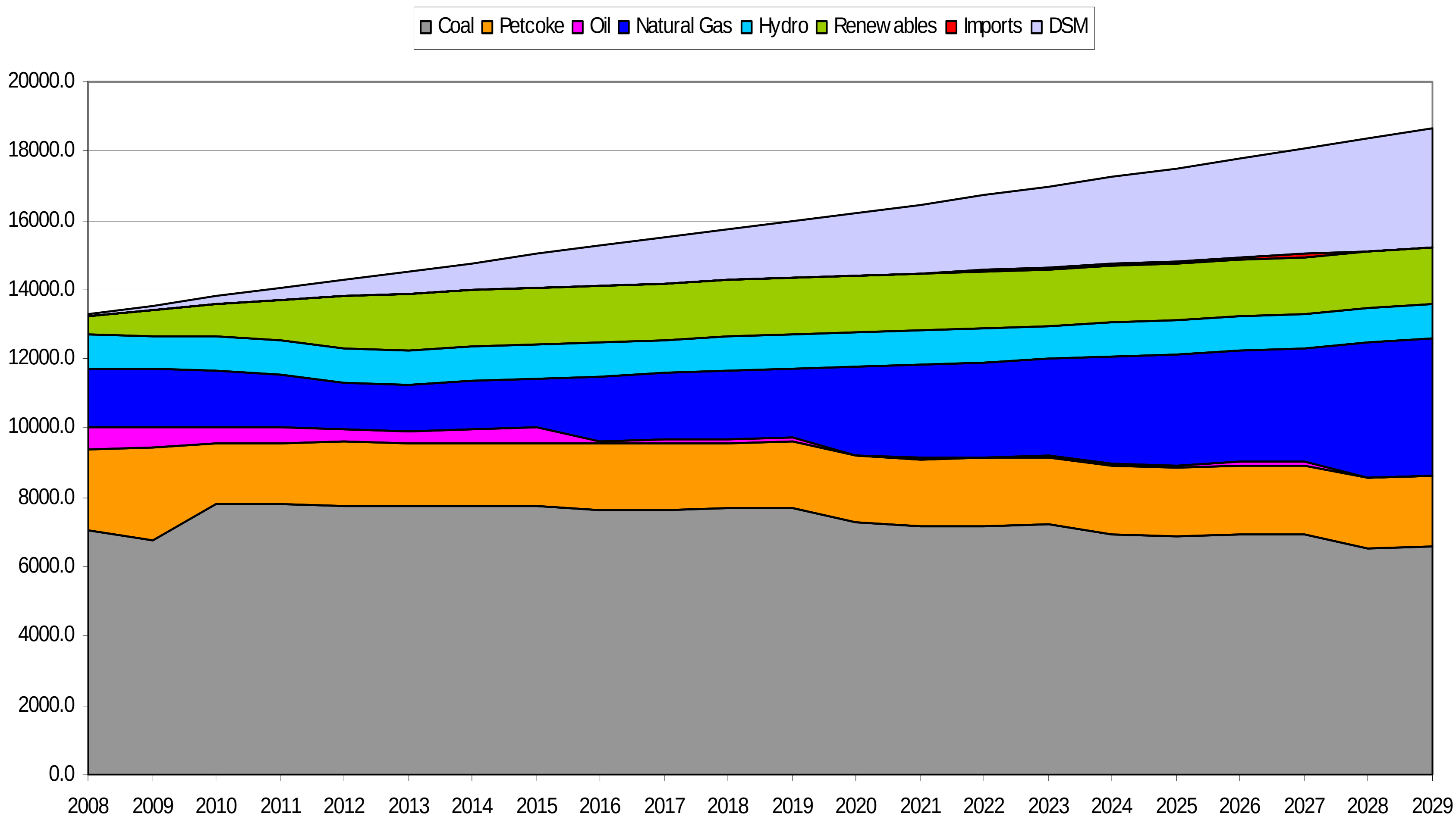
Loads & Resources

2% DSM + Coal

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Peak Firm Load (MW)	1,927	1,973	2,019	2,061	2,101	2,141	2,181	2,224	2,264	2,306	2,347	2,391	2,432	2,473	2,517	2,561	2,608	2,656	2,705	2,754	2,805	2,856
Peak Firm Less DSM	1,922	1,961	1,994	2,020	2,041	2,060	2,077	2,095	2,112	2,130	2,148	2,168	2,186	2,203	2,224	2,244	2,267	2,291	2,315	2,338	2,364	2,388
DSM Firm	4.7	12.3	24.9	41.5	60.3	81.3	104.4	128.5	152.3	175.9	199.3	222.7	246.1	269.5	293.1	316.9	341.0	365.5	390.3	415.5	441.3	467.6
RM Required (MW)	461	471	479	485	490	494	498	503	507	511	515	520	525	529	534	539	544	550	556	561	567	573
Required MWs	2,307	2,353	2,393	2,423	2,449	2,472	2,492	2,515	2,534	2,556	2,577	2,602	2,623	2,644	2,669	2,693	2,720	2,749	2,778	2,806	2,836	2,866
Existing MWs	2334	2334	2334	2334	2334	2334	2334	2334	2334	2334	2334	2334	2334	2334	2334	2334	2334	2334	2334	2334	2334	2334
Additions MWs																						
TUC6			51.9																			
LIN 1 Uprate				5																		
LIN 2 Uprate			5																			
LIN 3 Uprate				5																		
LIN 4 Uprate			5																			
Hydros			4.3																			
RPS	4.7	28.8	27.8	19.2	28.8	38.7																
PC Coal									400													
FGD													-8									
Total Annual Additions	4.7	28.8	94	29.2	28.8	38.7	0	0	400	0	0	0	-8	0	0	0	0	0	0	0	0	0
Total Cumulative Additions	4.7	33.5	127.5	156.7	185.5	224.2	224.2	224.2	624.2	624.2	624.2	624.2	616.2	616.2	616.2	616.2	616.2	616.2	616.2	616.2	616.2	616.2
Total Firm Capacity (MW)	2338.7	2367.5	2461.5	2490.7	2519.5	2558.2	2558.2	2558.2	2958.2	2958.2	2958.2	2958.2	2950.2	2950.2	2950.2	2950.2	2950.2	2950.2	2950.2	2950.2	2950.2	2950.2
Surplus (Deficit) MWs above RM	32	15	69	67	71	87	66	44	424	402	381	356	327	306	282	257	230	202	173	144	114	84
Reserve Margin %	22%	21%	23%	23%	23%	24%	23%	22%	40%	39%	38%	36%	35%	34%	33%	31%	30%	29%	27%	26%	25%	24%

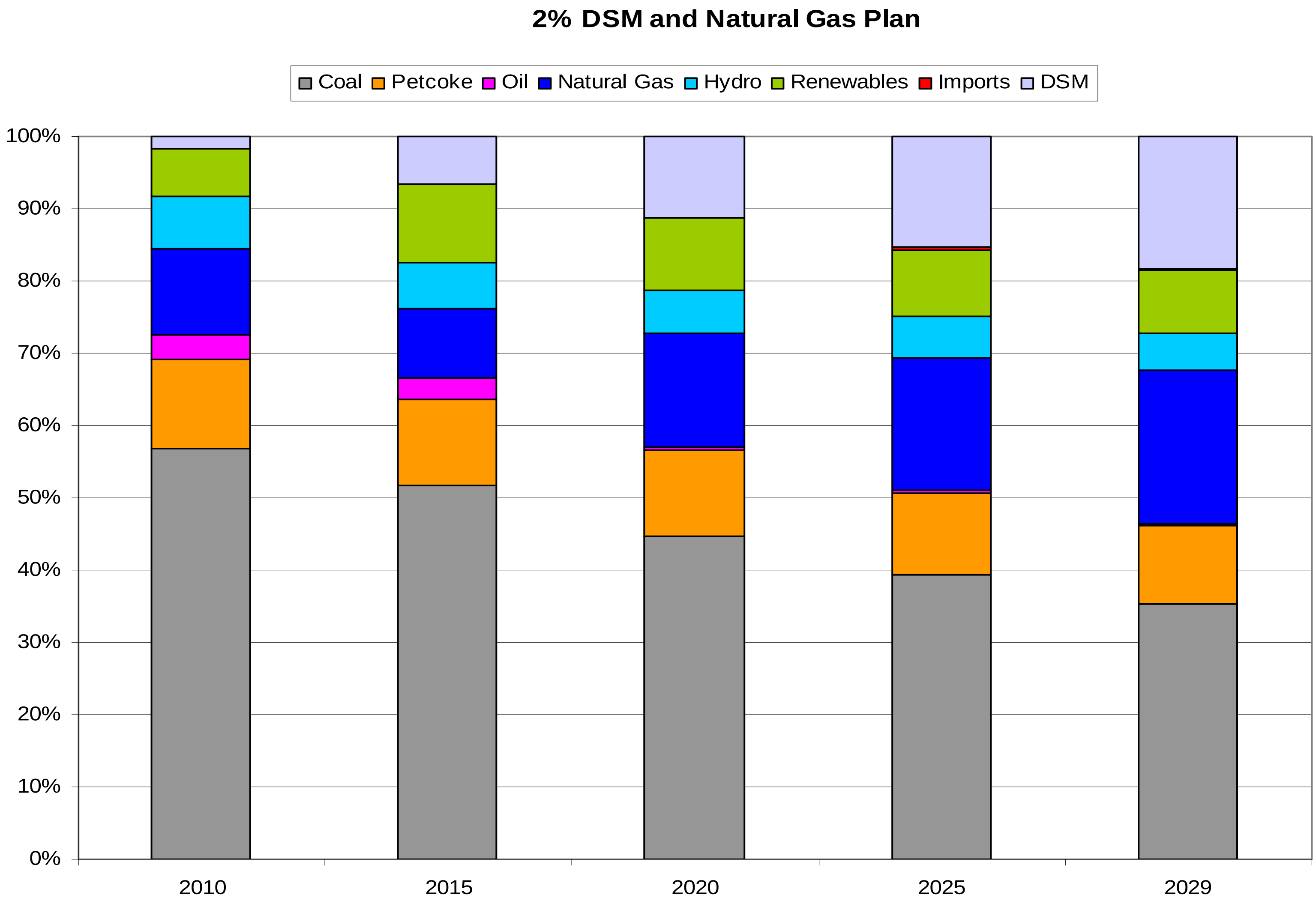
Appendix E

Energy *2% DSM + Natural Gas*



Appendix E

Energy *2% DSM + Natural Gas*



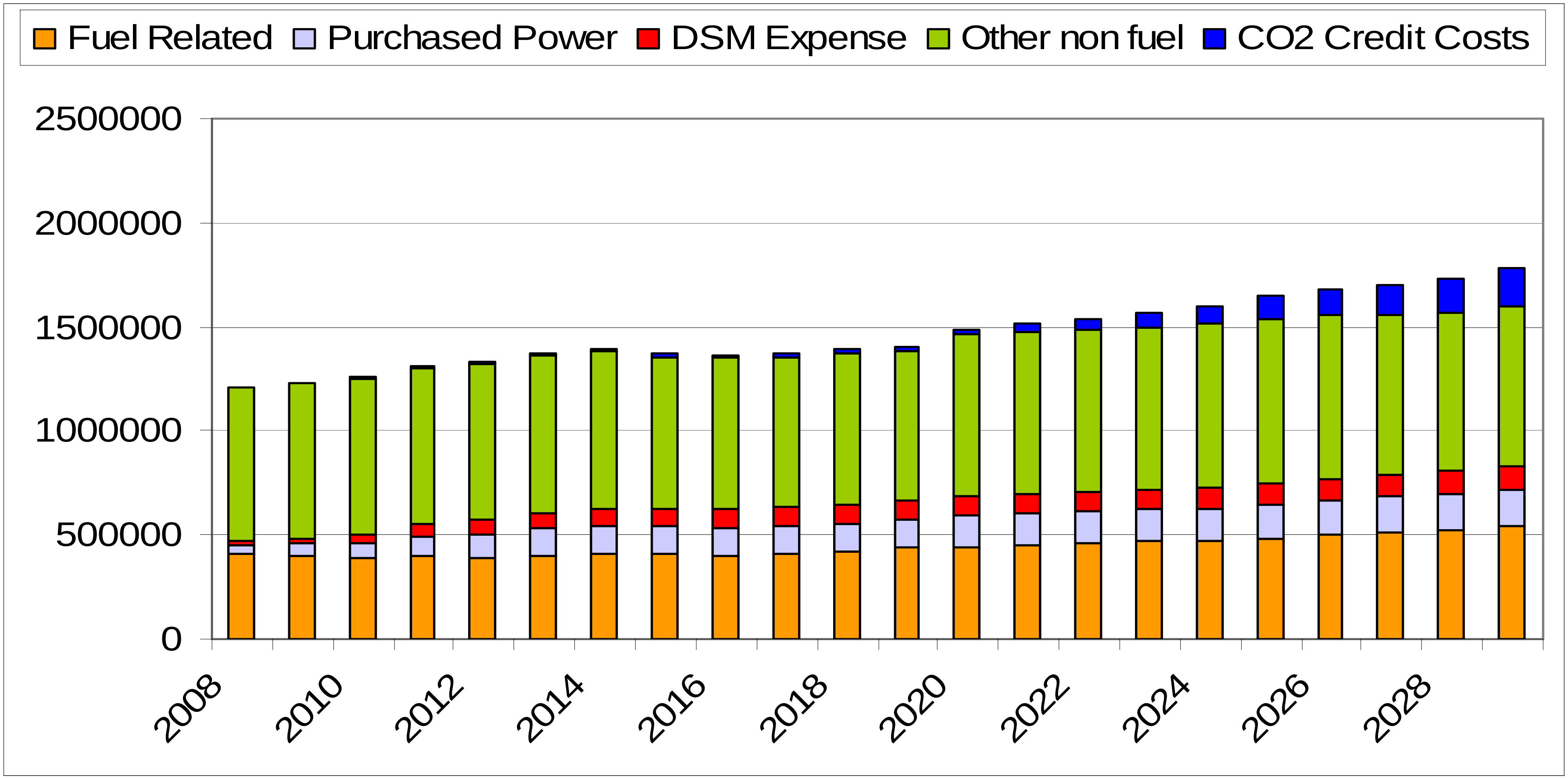
Loads & Resources

2% DSM + Natural Gas

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Peak Firm Load (MW)	1,927	1,973	2,019	2,061	2,101	2,141	2,181	2,224	2,264	2,306	2,347	2,391	2,432	2,473	2,517	2,561	2,608	2,656	2,705	2,754	2,805	2,856
Peak Firm Less DSM	1,922	1,961	1,994	2,020	2,041	2,060	2,077	2,095	2,112	2,130	2,148	2,168	2,186	2,203	2,224	2,244	2,267	2,291	2,315	2,338	2,364	2,388
DSM Firm	4.7	12.3	24.9	41.5	60.3	81.3	104.4	128.5	152.3	175.9	199.3	222.7	246.1	269.5	293.1	316.9	341.0	365.5	390.3	415.5	441.3	467.6
RM Required (MW)	461	471	479	485	490	494	498	503	507	511	515	520	525	529	534	539	544	550	556	561	567	573
Required MWs	2,307	2,353	2,393	2,423	2,449	2,472	2,492	2,515	2,534	2,556	2,577	2,602	2,623	2,644	2,669	2,693	2,720	2,749	2,778	2,806	2,836	2,866
Existing MWs	2334	2334	2334	2334	2334	2334	2334	2334	2334	2334	2334	2334	2334	2334	2334	2334	2334	2334	2334	2334	2334	2334
Additions MWs																						
TUC6			51.9																			
LIN 1 Uprate				5																		
LIN 2 Uprate			5																			
LIN 3 Uprate				5																		
LIN 4 Uprate			5																			
Hydros			4.3																			
RPS	4.7	28.8	27.8	19.2	28.8	38.7																
Additional Wind																						
Combined Cycle									280												280	
FGD													-8									
Total Annual Additions	4.7	28.8	94	29.2	28.8	38.7	0	0	280	0	0	0	-8	0	0	0	0	0	0	0	280	0
Total Cumulative Additions	4.7	33.5	127.5	156.7	185.5	224.2	224.2	224.2	504.2	504.2	504.2	504.2	496.2	496.2	496.2	496.2	496.2	496.2	496.2	496.2	776.2	776.2
Total Firm Capacity (MW)	2338.7	2367.5	2461.5	2490.7	2519.5	2558.2	2558.2	2558.2	2838.2	2838.2	2838.2	2838.2	2830.2	2830.2	2830.2	2830.2	2830.2	2830.2	2830.2	2830.2	3110.2	3110.2
Surplus (Deficit) MWs above RM	32	15	69	67	71	87	66	44	304	282	261	236	207	186	162	137	110	82	53	24	274	244
Reserve Margin %	22%	21%	23%	23%	23%	24%	23%	22%	34%	33%	32%	31%	29%	28%	27%	26%	25%	24%	22%	21%	32%	30%

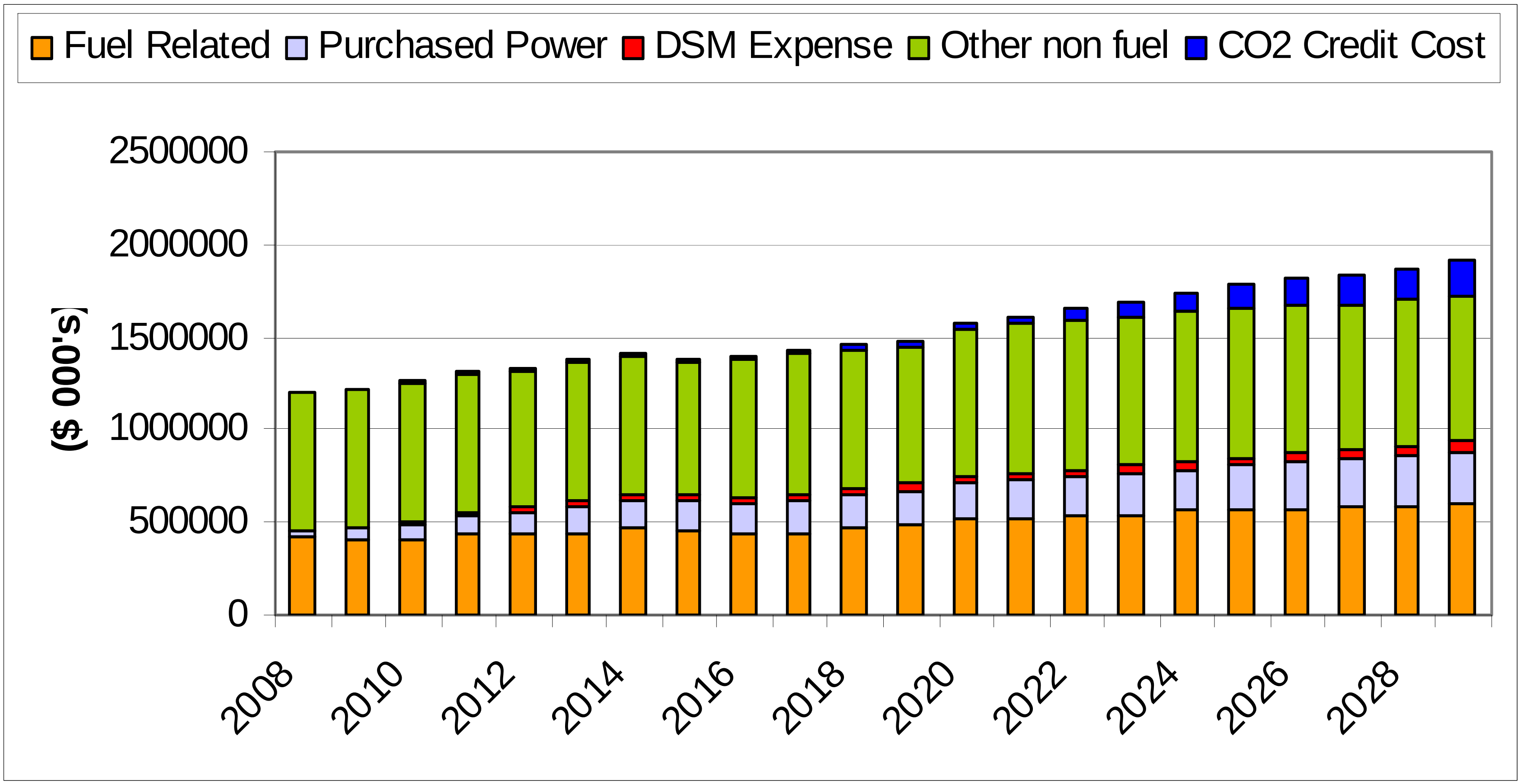
Appendix F

Annual Revenue Requirements 5*% DSM*



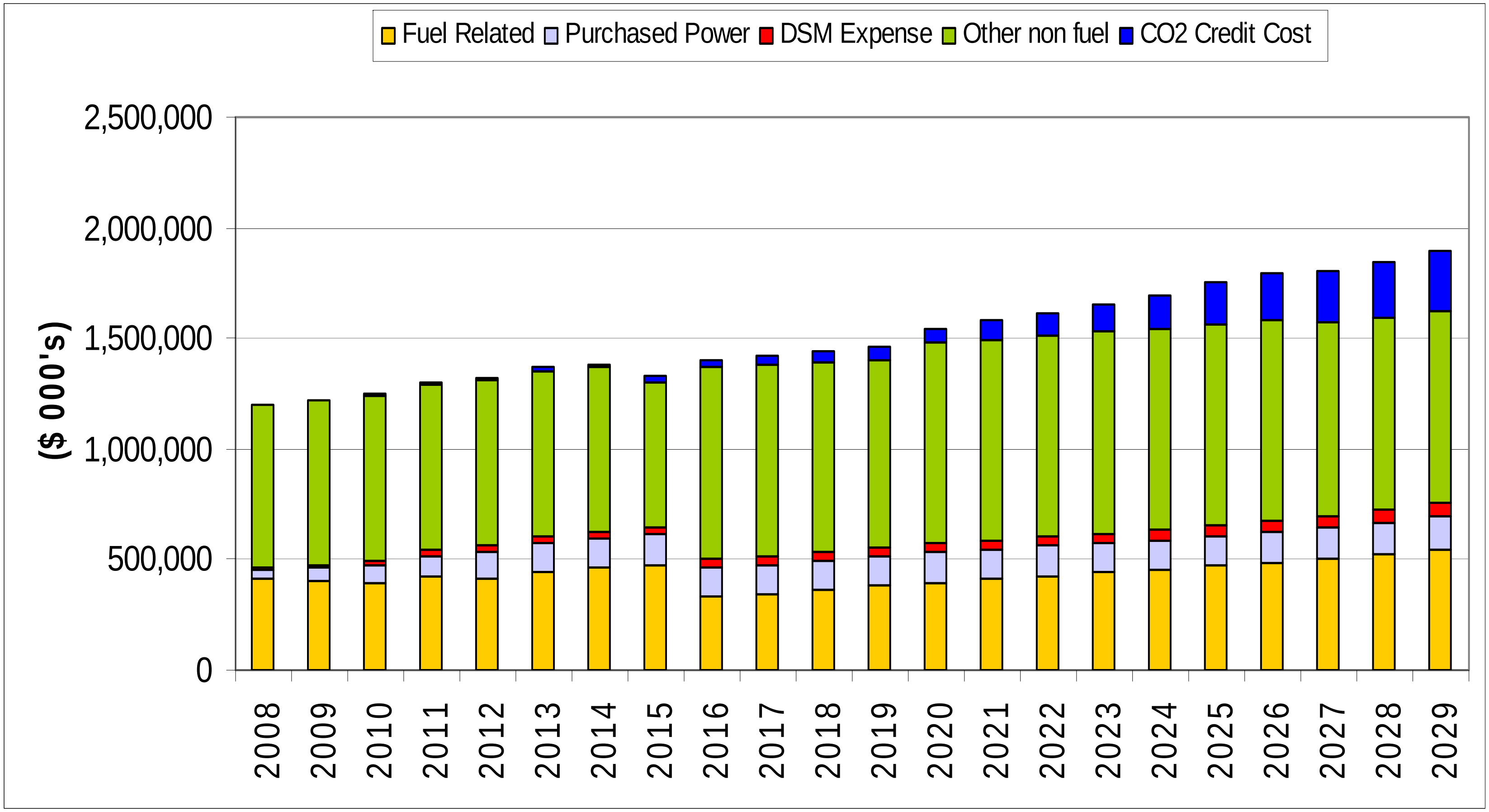
Appendix F

Annual Revenue Requirements *2% DSM + Renewable*



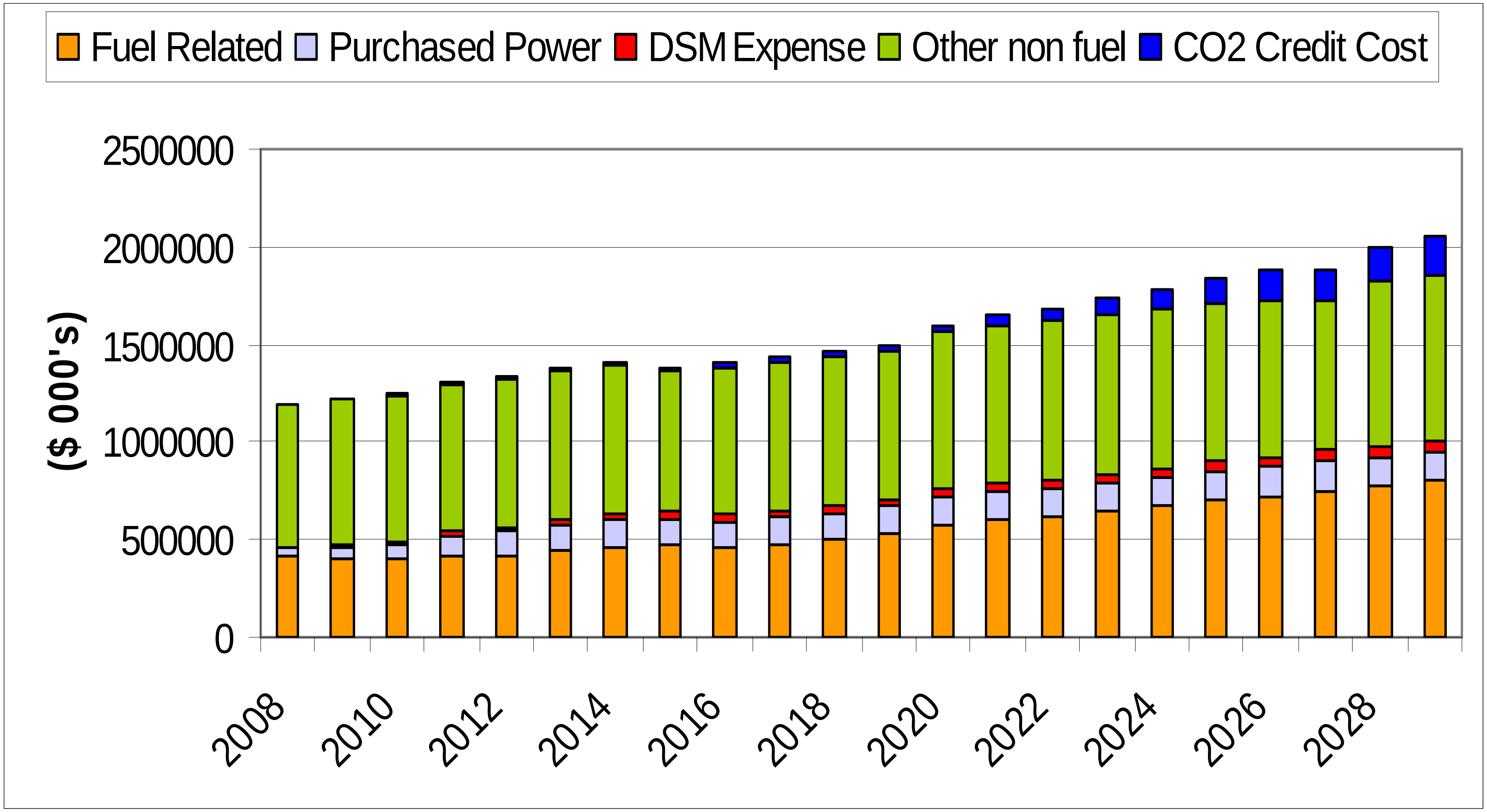
Appendix F

Annual Revenue Requirements *2% DSM + Coal*

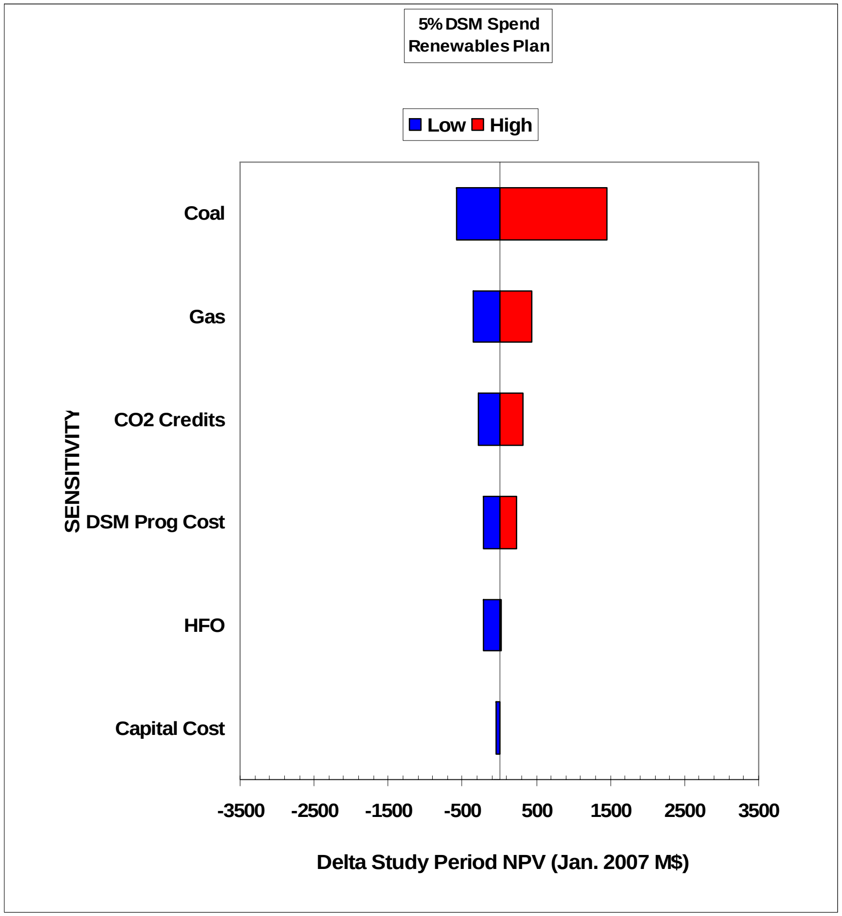


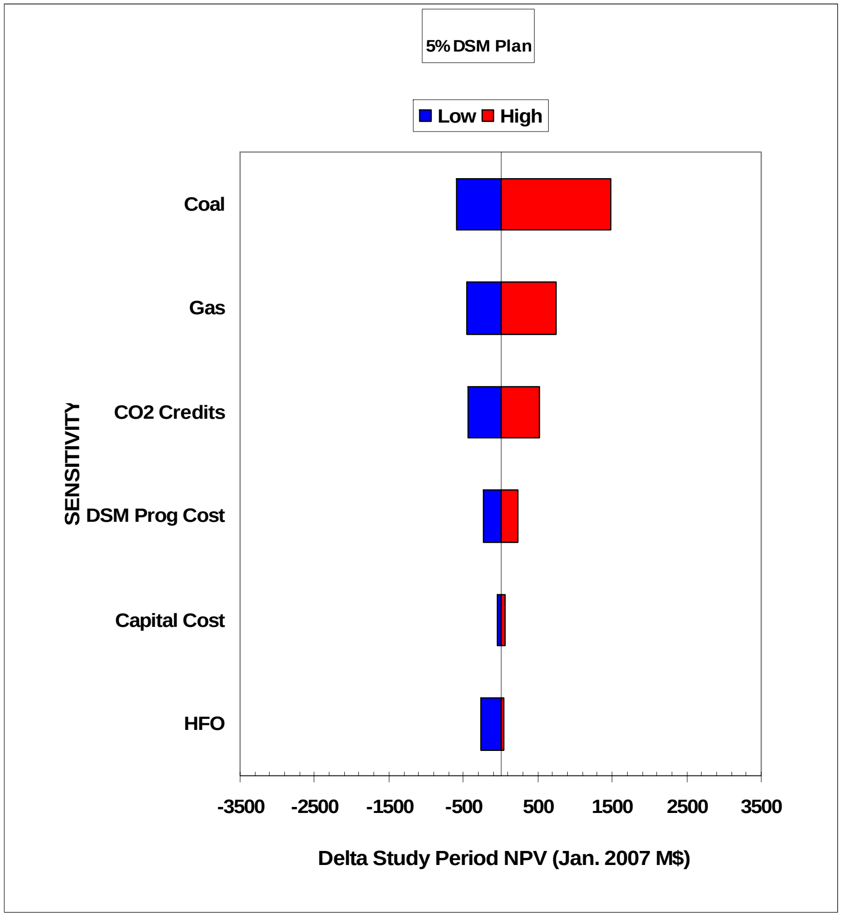
Appendix F

Annual Revenue Requirements *2% DSM Gas Plan*

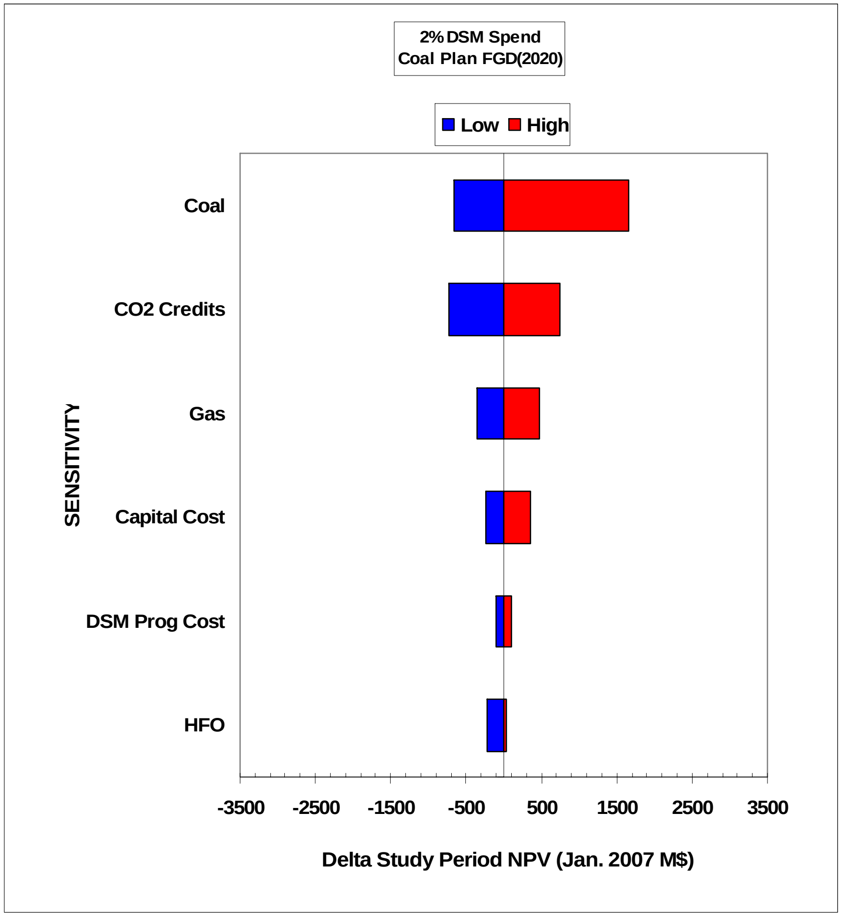


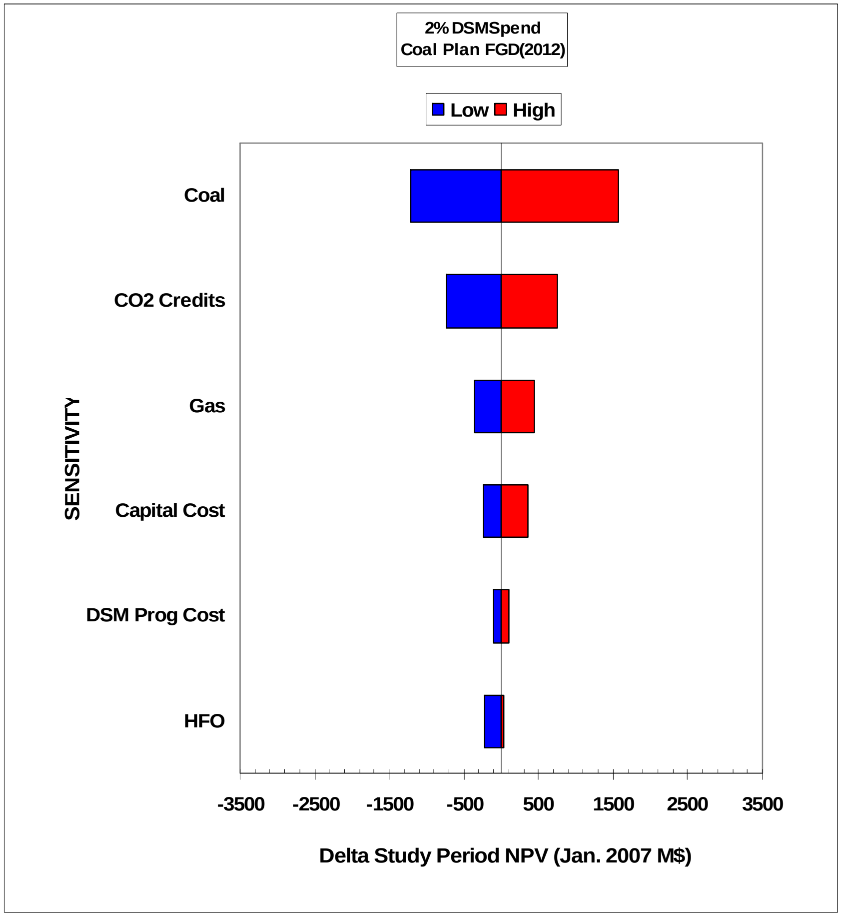
Appendix G
Sensitivities



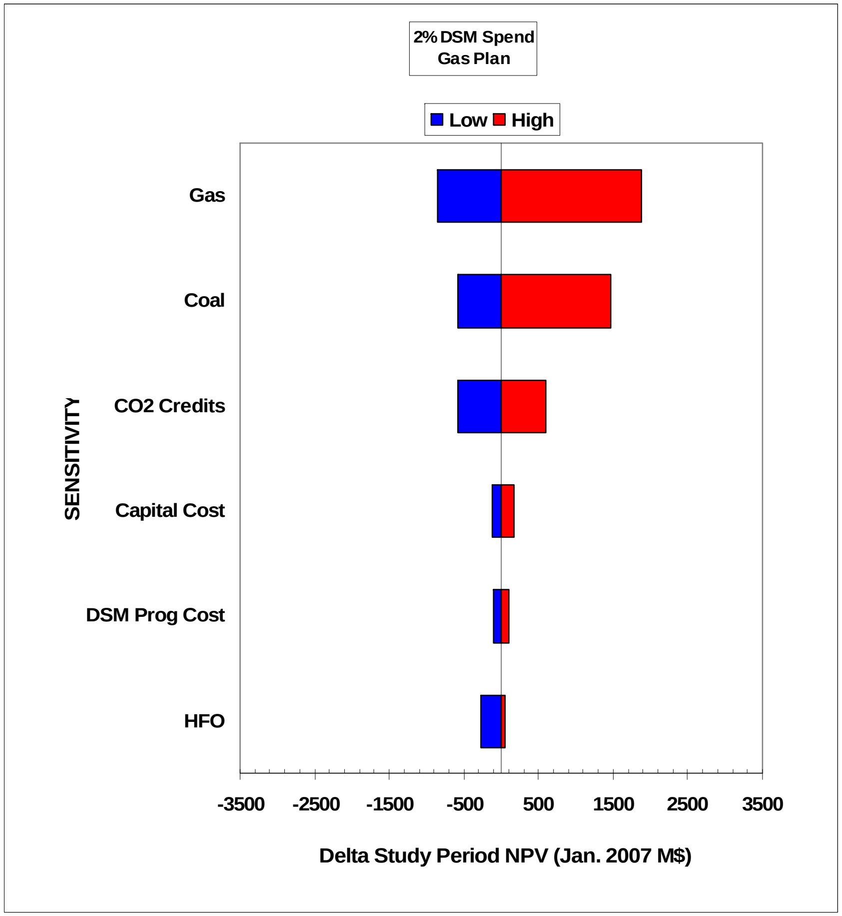


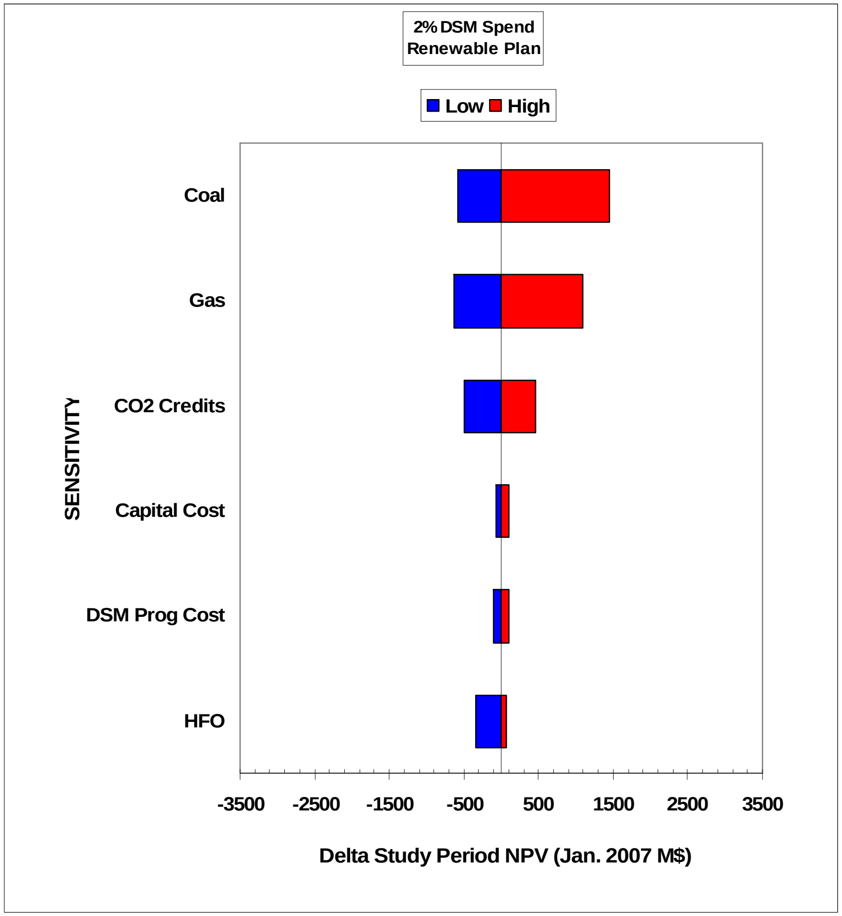
Appendix G
Sensitivities





Appendix G
Sensitivities





Appendix G

SENSITIVITIES

BASE PLAN CASE =>		5% DSM Spend Reference Plan ("Reference")	5% DSM Spend DSM Plan	2% DSM Spend Renewable Plan	2% DSM Spend Coal Plan FGD(2020)	2% DSM Spend Coal Plan FGD(2012)	2% DSM Spend Gas Plan
SENSITIVITY =>		Study Period NPV (M$)	Study Period NPV (M$)	Study Period NPV (M$)	Study Period NPV (M$)	Study Period NPV (M$)	Study Period NPV (M$)
Reference	**Base**	**14480**	**14748**	**15435**	**15504**	**15551**	**15925**
Capital Cost	**Low**	14442	14710	15362	15269	15308	15809
	High	14490	14801	15544	15853	15910	16097
CO2 Credits [1] **(with CO2 Cap)**	**Low**	11082	11199	11830	11662	11705	12228
	High	11683	12155	12784	13137	13181	13404
Coal	**Low**	13899	14153	14848	14847	14342	15338
	High	15938	16234	16888	17161	17119	17394
Gas	**Low**	14133	14287	14799	15151	15192	15066
	High	14924	15486	16526	15981	15991	17803
HFO	**Low**	14259	14478	15100	15283	15322	15657
	High	14509	14797	15511	15544	15593	15974
Disc Rate	**Low**	12418	12624	13161	13208	13257	13208
	High	17425	17786	18696	18801	18844	19397
DSM Prog Cost	**Low**	14260	14521	15337	15405	15454	15828
	High	14707	14975	15533	15602	15649	16023

Note:

(1) CO2 Credits Sensitivity Cases include a Base CO2 cap (allowance) starting in 2010 while all other Reference and Sensitivities do not include a CO2 cap. In all other cases, the model includes the cost of purchasing credits from 0.

Appendix H

IRP Basic Assumptions
Environmental

SO_2

Case	Reduction
Base	50% reduction from 2010 cap by 2020 (to 36,200 t/yr)
Low	50% reduction from 2010 cap by 2025 (to 36,200 t/yr)
High	50% reduction from 2010 cap by 2015 (to 36,200 t/yr); HFO max 1% S in 2015.

Appendix H

IRP Basic Assumptions

Environmental

NO_x

Case	Reduction
Base	30% reduction from 2009 cap by 2020 (to 14,700 t/yr)
Low	10% reduction from 2009 cap by 2020 (to 19,000 t/yr)
High	60% reduction from 2009 cap by 2020 (to 9,000 t/yr)

Appendix H

IRP Basic Assumptions
Environmental

Mercury

Case	Reduction
Base	- 65 kg/yr. cap in 2010 - 34 kg/yr. cap in 2020 (80% reduction from 2005 cap)
Low	- 65 kg/yr. cap in 2012 - 34 kg/yr. cap in 2020 (80% reduction from 2005 cap)
High	- 65 kg/yr. cap in 2010 - 17 kg/yr. cap in 2020 (90% reduction from 2005 cap)

Appendix H

IRP Basic Assumptions
Environmental

Estimated CO_2/Greenhouse Gases Emissions

Case	Approximate Emissions (Million tonnes)				
	2010	2015	2020	2025	2030
Low	10.0	10.1	11.5	11.7	12.6
Base	10.0	9.5	9.1	7.7	6.4
High	7.9	7.6	6.3	6.3	4.5
Kyoto (sensitivity)	6.4	5.6	4.8*	4.5	4.1
Deep Green	6.4	4.9	3.4*	2.9	2.5

**Assume credits no longer available*
1990 CO_2 emissions ~ 6.85M t
Current (2006) CO_2 emissions ~ 10M t / year

Appendix H

IRP Basic Assumptions

Environmental

CO_2 / Greenhouse Gases

Assumed Cost of Offsets (2006$US / tonne CO_2)			
Year	**Base**	**Low**	**High**
2010	11.50	3.00	17.50
2015	18.50	4.50	32.50
2020	23.50	6.50	41.50
2025	30.00	8.50	53.00

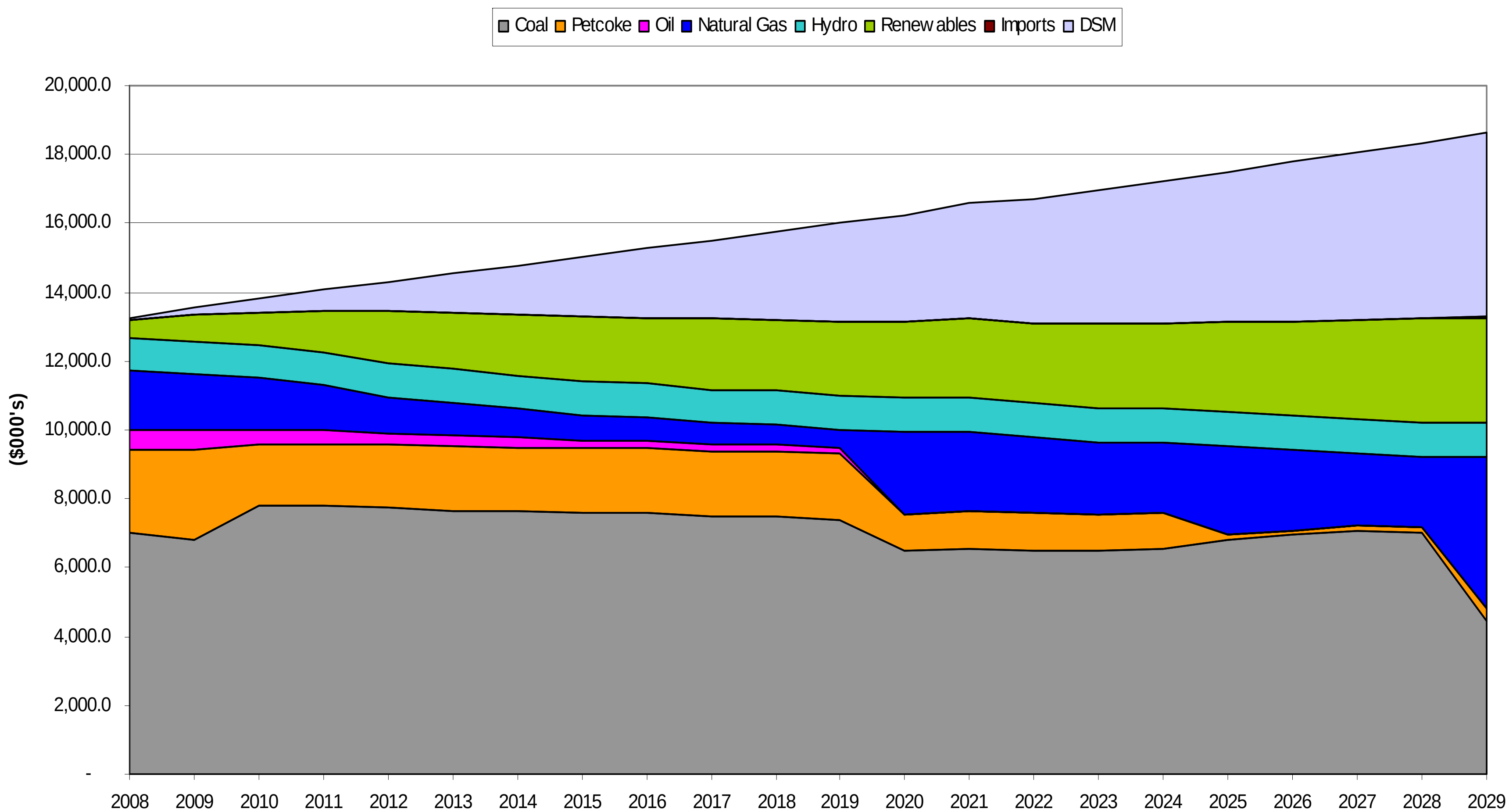
Appendix H

Summary Plan Comparison *Least Constrained Emissions*

Year	World #3 5% Spend DSM Low Air Emissions	Run #20 5% Spend DSM
2006	Lingan 3 LN (Jul)	Lingan 3 LN (Jul)
2007	Lingan 2 LN (Jul) Lingan 4 LN (Jul) Burnside 1 (33 MW) (Jan)	Lingan 2 LN (Jul) Lingan 4 LN (Jul) Burnside 1 (33 MW) (Jan)
2008	Pt Tupper LN (Jul) Trenton 5LN (Nov) Lingan 1 LN (Jul) DSM_Res 5% DSM_Com 5% DSM_Ind 5%	Pt Tupper LN (Jul) Trenton 5LN (Nov) Lingan 1 LN (Jul) DSM_Res 5% DSM_Com 5% DSM_Ind 5%
2009	Trenton 5 Baghouse (Jul) TUC 6 (Dec) Lingan 2 +5MW (Jul) Lingan 4 +5MW (Jul) Nictaux (2.5 MW) (Oct) Marsh F. (1.8 MW) (Oct)	Trenton 5 Baghouse (Jul) TUC 6 (Dec) Lingan 2 +5MW (Jul) Lingan 4 +5MW (Jul) Nictaux (2.5 MW) (Oct) Marsh F. (1.8 MW) (Oct)
2010	Lingan 3 +5MW (Jul) RPS (79 MW Firm total)	Lingan 3 +5MW (Jul) RPS (79 MW Firm total)
2011 2012	Lingan 1 +5MW (Jul)	Lingan 1 +5MW (Jul)
2013	RPS (166MW Firm total)	RPS (166MW Firm total)
2014 2015 2016 2017 2018		
2019		**Trenton 6 LN (Oct)**
2020 2021 2022 2023 2024 2025 2026	 **L3/L4 FGD**	L1/L2 SCR, L1/L2 FGD
2027		
2028 2029		
NPV 2006-29 (M$)	**$10,352.3**	**$12,643.8**
Study Period (M$) (includes End Effects)	**$11,921.7**	**$14,747.7**

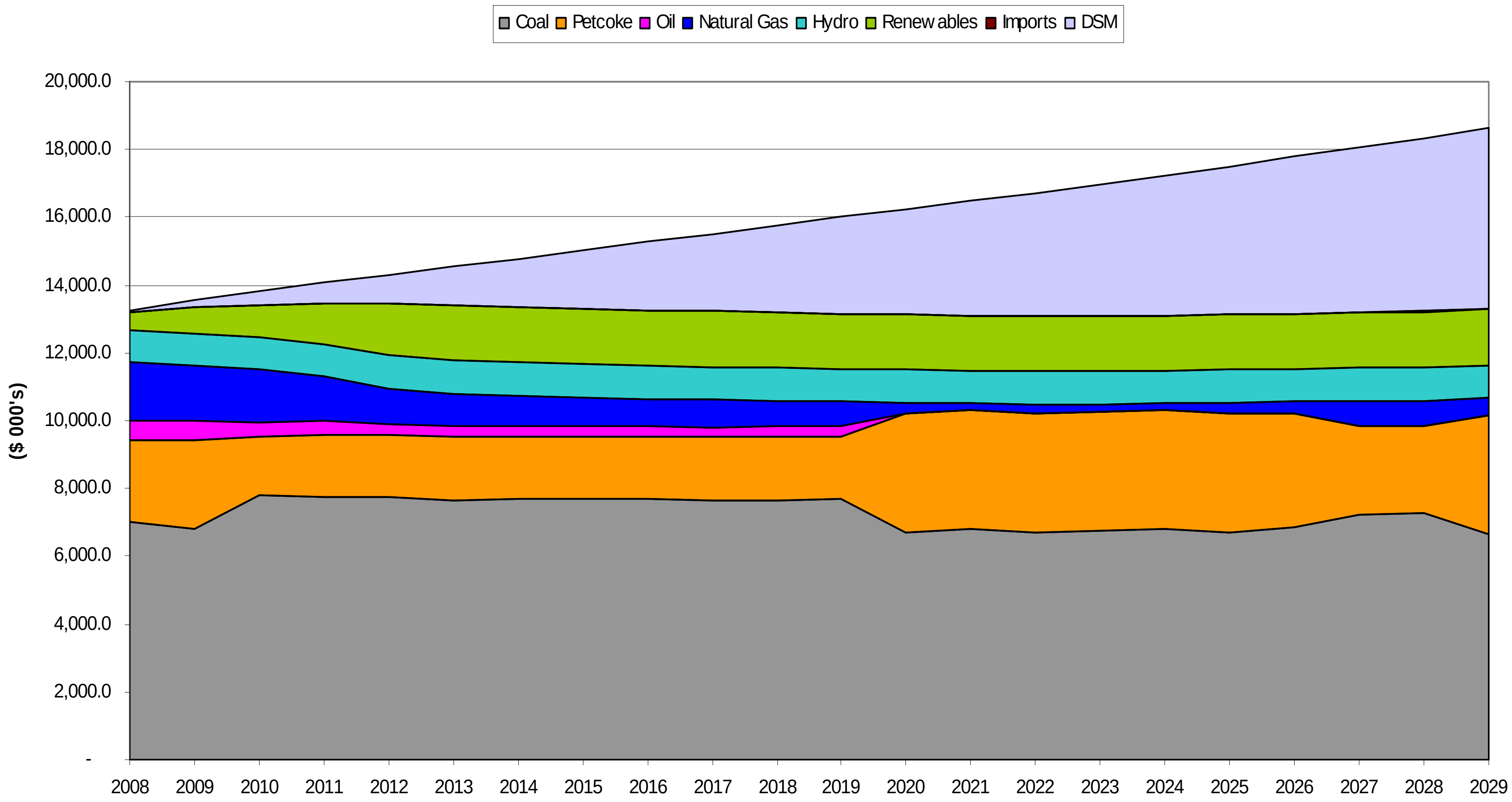
Appendix I

Energy: Base Assumptions (existing options) Credits Constrained 2020



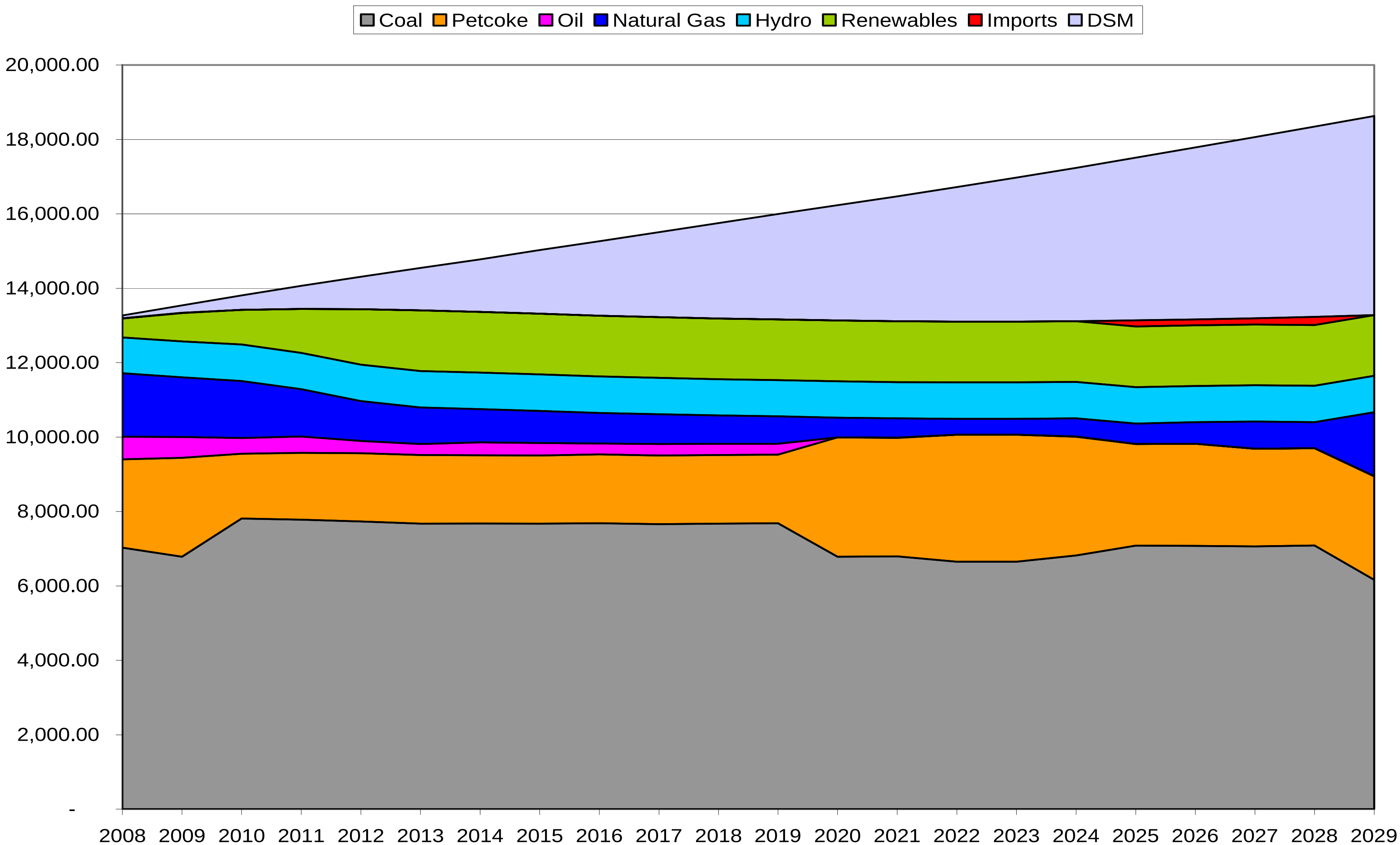
Appendix I

Energy: Base Assumptions (new options- non renew) Credits Constrained 2020



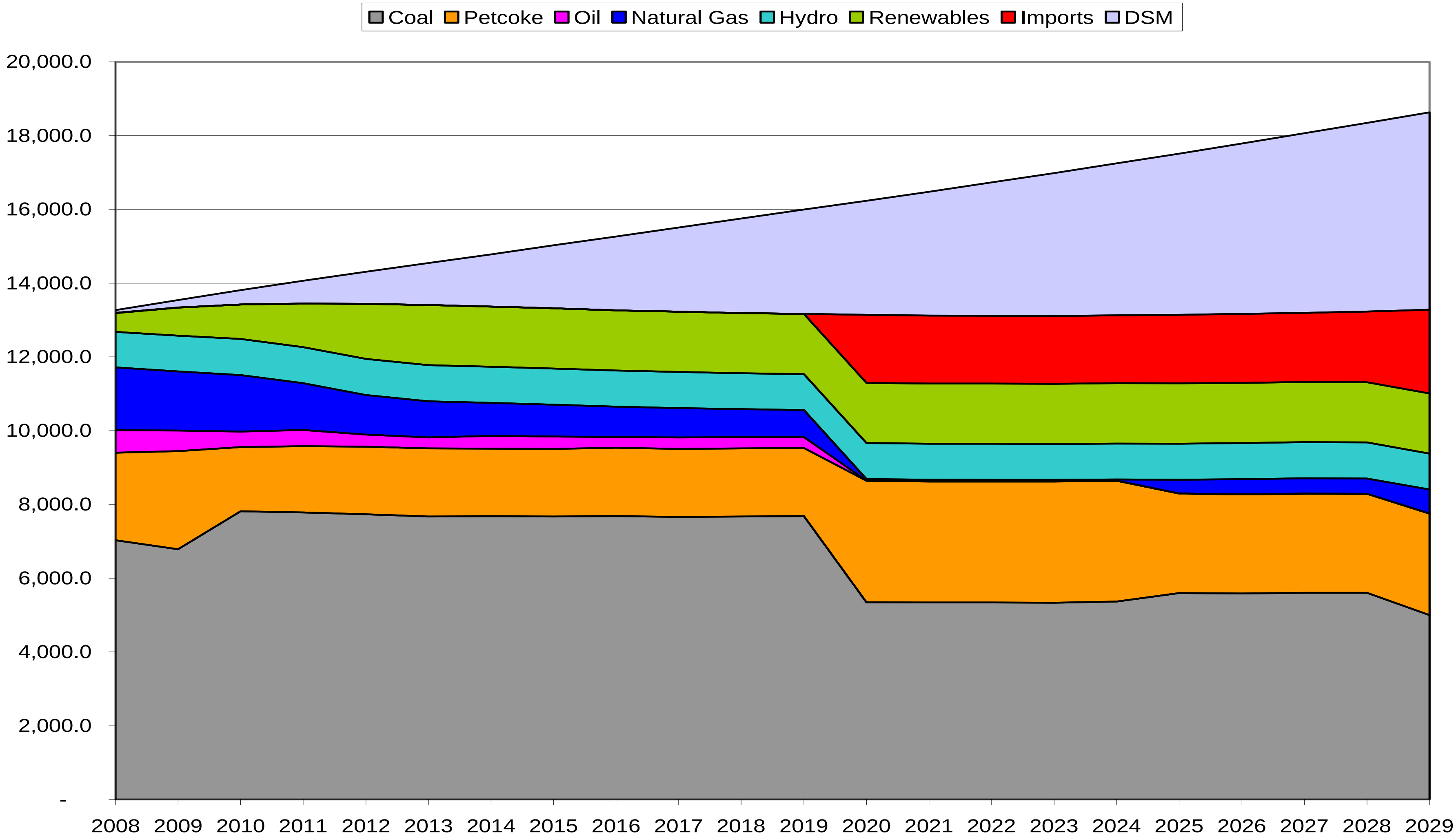
Appendix I

Energy: Kyoto Scenario – Credits constrained in 2020



Appendix I

Energy: Deep Green Scenario – Credits constrained in 2020



Appendix J

Carbon Hard Cap Worlds

	Run #20	Run #7	Run #8	Run #8A	without Renewables beyond RPS	
	5% Spend DSM	**5% Spend DSM**	**5% Spend DSM**	**5% Spend DSM**	**World #9A**	**World #10A**
Year	**Renewables Plan**	**Base CO2 Existing Options**	**Base CO2 New & Existing Options Renewables Beyond RPS**	**Base CO2 New & Existing Options NO Renewables Beyond RPS**	**5% Spend DSM Kyoto Case CO2 Credit Constrain 2020**	**5% Spend DSM Deep Green Case CO2 Credit Constrain 2020**
2006	Lingan 3 LN (Jul)	Lingan 3 LN (Jul)	Lingan 3 LN (Jul)	Lingan 3 LN (Jul)	Lingan 3 LN (Jul)	Lingan 3 LN (Jul)
2007	Lingan 2 LN (Jul) Lingan 4 LN (Jul) Burnside 1 (33 MW) (Jan)	Lingan 2 LN (Jul) Lingan 4 LN (Jul) Burnside 1 (33 MW) (Jan)	Lingan 2 LN (Jul) Lingan 4 LN (Jul) Burnside 1 (33 MW) (Jan)	Lingan 2 LN (Jul) Lingan 4 LN (Jul) Burnside 1 (33 MW) (Jan)	Lingan 2 LN (Jul) Lingan 4 LN (Jul) Burnside 1 (33 MW) (Jan)	Lingan 2 LN (Jul) Lingan 4 LN (Jul) Burnside 1 (33 MW) (Jan)
2008	Pt Tupper LN (Jul) Trenton 5LN (Nov) Lingan 1 LN (Jul) DSM_Res 5% DSM_Com 5% DSM_Ind 5%	Pt Tupper LN (Jul) Trenton 5LN (Nov) Lingan 1 LN (Jul) DSM_Res 5% DSM_Com 5% DSM_Ind 5%	Pt Tupper LN (Jul) Trenton 5LN (Nov) Lingan 1 LN (Jul) DSM_Res 5% DSM_Com 5% DSM_Ind 5%	Pt Tupper LN (Jul) Trenton 5LN (Nov) Lingan 1 LN (Jul) DSM_Res 5% DSM_Com 5% DSM_Ind 5%	Pt Tupper LN (Jul) Trenton 5LN (Nov) Lingan 1 LN (Jul) DSM_Res 5% DSM_Com 5% DSM_Ind 5%	Pt Tupper LN (Jul) Trenton 5LN (Nov) Lingan 1 LN (Jul) DSM_Res 5% DSM_Com 5% DSM_Ind 5%
2009	Trenton 5 Baghouse (Jul) TUC 6 (Dec) Lingan 2 +5MW (Jul) Lingan 4 +5MW (Jul) Nictaux (2.5 MW) (Oct) Marsh F. (1.8 MW) (Oct)	Trenton 5 Baghouse (Jul) TUC 6 (Dec) Lingan 2 +5MW (Jul) Lingan 4 +5MW (Jul) Nictaux (2.5 MW) (Oct) Marsh F. (1.8 MW) (Oct)	Trenton 5 Baghouse (Jul) TUC 6 (Dec) Lingan 2 +5MW (Jul) Lingan 4 +5MW (Jul) Nictaux (2.5 MW) (Oct) Marsh F. (1.8 MW) (Oct)	Trenton 5 Baghouse (Jul) TUC 6 (Dec) Lingan 2 +5MW (Jul) Lingan 4 +5MW (Jul) Nictaux (2.5 MW) (Oct) Marsh F. (1.8 MW) (Oct)	Trenton 5 Baghouse (Jul) TUC 6 (Dec) Lingan 2 +5MW (Jul) Lingan 4 +5MW (Jul) Nictaux (2.5 MW) (Oct) Marsh F. (1.8 MW) (Oct)	Trenton 5 Baghouse (Jul) TUC 6 (Dec) Lingan 2 +5MW (Jul) Lingan 4 +5MW (Jul) Nictaux (2.5 MW) (Oct) Marsh F. (1.8 MW) (Oct)
2010	Lingan 3 +5MW (Jul) RPS (79 MW Firm total)	Lingan 3 +5MW (Jul) RPS (79 MW Firm total)	Lingan 3 +5MW (Jul) RPS (79 MW Firm total)	Lingan 3 +5MW (Jul) RPS (79 MW Firm total)	Lingan 3 +5MW (Jul) Lingan 1 +5MW (Jul) RPS (79 MW Firm total)	Lingan 3 +5MW (Jul) Lingan 1 +5MW (Jul) RPS (79 MW Firm total)
2011	Lingan 1 +5MW (Jul)	Lingan 1 +5MW (Jul)	Lingan 1 +5MW (Jul)	Lingan 1 +5MW (Jul)		
2012						
2013	RPS (166MW Firm total)	RPS (166MW Firm total)	RPS (166MW Firm total)	RPS (166MW Firm total)	RPS (166MW Firm total)	RPS (166MW Firm total)
2014	Rnew 50 MW (16 MW firm)	Rnew 50 MW (16 MW firm)	Rnew 50 MW (16 MW firm)			
2015	Rnew 50 MW (16 MW firm)	Rnew 50 MW (16 MW firm)	Rnew 50 MW (16 MW firm)			
2016						
2017	Rnew 50 MW (16 MW firm)	Rnew 50 MW (16 MW firm)	Rnew 50 MW (16 MW firm)			
2018						
2019	**Trenton 6 LN (Oct)** Rnew 50 MW (16 MW firm)	**Trenton 6 LN (Oct)** Rnew 50 MW (16 MW firm)	**Trenton 6 LN (Oct)** Rnew 50 MW (16 MW firm)			
2020	L1/L2 SCR, L1/L2 FGD	**CC (280MW)**	**L1/L2 SCR, L1/L2 FGD**	**IGCY 400MW**	**L1/L2 CC, L3/L4 CC IGCY 400MW**	**L1/L2 CC, L3/L4 CC IGCY 400MW, PPA 300MW**
2021	Rnew 50 MW (16 MW firm)		Rnew 50 MW (16 MW firm)			
2022		Rnew 50 MW (16 MW firm)				
2023	Rnew 50 MW (16 MW firm)	Rnew 50 MW (16 MW firm)	Rnew 50 MW (16 MW firm)			
2024			**Biomass (20MW)**			
2025	Rnew 50 MW (16 MW firm)	Rnew 50 MW (16 MW firm)	Rnew 50 MW (16 MW firm) **L3/L4 CC (carbon capture)**			
2026	Rnew 50 MW (16 MW firm)	Rnew 50 MW (16 MW firm)	Rnew 50 MW (16 MW firm)			
2027	Rnew 50 MW (16 MW firm)	Rnew 50 MW (16 MW firm)	Rnew 50 MW (16 MW firm) **R100 100 MW (35 MW firm)**			
2028	Rnew 50 MW (16 MW firm)	Rnew 50 MW (16 MW firm)	Rnew 50 MW (16 MW firm)			
2029		**CC (280MW)**	**R100 100 MW (35 MW firm)**	**L3/L4 CC (carbon capture)**	**CC (280MW)**	
NPV 2006-29 (M$)	**$12,497.0**	**$12,643.7**	**$12,579.0**	**$12,680.4**	**$12,763.9**	**$12,992.9**
(includes End Effects)	**$14,479.9**	**$14,981.8**	**$14,645.6**	**$14,857.6**	**$15,002.0**	**$15,298.2**

Appendix J

Results – Carbon Constraint Worlds

2007 IRP CO2 Credit Constrained Worlds: SCHEDULE OF SUPPLY OR DSM MW's

		5% Spend DSM Plan, Base CO2 Credit Constrained @ 2020 run with "existing" options	5% Spend DSM Plan, Base CO2 Credit Constrained @ 2020 run with "new" options	5% Spend DSM Plan No Renewables > RPS, Base CO2 Credit Constrained @ 2020 run with "new" options	5% Spend DSM Pan, Kyoto Level Cap CO2 Credit Constrained @ 2020 A	5% Spend DSM Pan, Kyoto Level Cap CO2 Credit Constrained @ 2020 B	5% Spend DSM Pan, Kyoto Level Cap CO2 Credit Constrained @ 2020 C	5% Spend DSM Pan, Kyoto Level Cap CO2 Credit Constrained @ 2020 D	5% Spend DSM Pan, No Renewables >RPS, Kyoto Level Cap CO2 Credit Constrained @ 2020 E	5% Spend DSM Pan, Deep Green Level Cao CO2 Credit Constrained @ 2020 A	5% Spend DSM Pan, Deep Green Level Cao CO2 Credit Constrained @ 2020 B	5% Spend DSM Pan, Deep Green Level Cao CO2 Credit Constrained @ 2020 C	5% Spend DSM Pan No Renewables > RPS, Deep Green Level Cao CO2 Credit Constrained @ 2020 D
New Resources 2008-2014													
	DSM	256	256	256	256	256	256	256	256	256	256	256	256
	TUC 6	50	50	50	50	50	50	50	50	50	50	50	50
	LM 6000	0	0	0	0	0	0	0	0	0	0	0	0
	Uprates	20	20	20	20	20	20	20	20	20	20	20	20
	Hydro	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3
	RPS	166	166	166	166	166	166	166	166	166	166	166	166
	Additional Wind	16	16	0	16	16	16	16	0	16	16	16	0
Subtotal		512.3	512.3	496.3	512.3	512.3	512.3	512.3	496.3	512.3	512.3	512.3	496.3
New Resources 2015-2029													
	Additional Wind	144	144	0	144	144	144	144	0	144	144	144	0
	Offshore Wind	0	64	0	32	96	32	0	0	64	96	128	0
	Pulverized Coal	0	0	0	0	0	0	400	0	0	0	0	0
	LM 6000	0	0	0	0	0	0	0	0	0	0	0	0
	Biomass	0	20	0	0	20	0	0	0	20	0	0	0
	PPA + 300 MW Tie-line	0	0	0	300	0	0	0	0	0	0	300	300
	IGCC	0	0	400	0	0	400	0	400	400	400	0	400
	Combined Cycle	560	0	0	0	280	0	0	280	0	280	280	0
	DSM	857	857	857	857	857	857	857	857	857	857	857	857
Subtotal		1561	1085	1257	1333	1397	1433	1401	1537	1485	1777	1709	1557
Total New & Avoided MW's over planning period		2073.3	1597.3	1753.3	1845.3	1909.3	1945.3	1913.3	2033.3	1997.3	2289.3	2221.3	2053.3

Appendix K: DSM Variation Worlds

Year	5% DSM Delay 2 Years	2% DSM Delay 2 Years Coal Plan (FGD in 2020)	2% DSM - Delay 2 Years Renewables Plan	5% DSM -20% Benefits	2% DSM -20% Benefits Coal Plan (FGD in 2020)	2% DSM -20% Benefits Renewables Plan	5% DSM Stora Portion of DSM Removed from Ind. Sector	2% DSM - Coal (FGD 2020) Stora Portion of DSM Removed from Ind. Sector	2% DSM - Renewables Plan Stora Portion of DSM Removed from Ind. Sector
2006	Lingan 3 LN (Jul)	Lingan 3 LN (Jul)	Lingan 3 LN (Jul)	Lingan 3 LN (Jul)	Lingan 3 LN (Jul)	Lingan 3 LN (Jul)	Lingan 3 LN (Jul)	Lingan 3 LN (Jul)	Lingan 3 LN (Jul)
2007	Lingan 2 LN (Jul) Lingan 4 LN (Jul) Burnside 1 (33 MW) (Jan)	Lingan 2 LN (Jul) Lingan 4 LN (Jul) Burnside 1 (33 MW) (Jan)	Lingan 2 LN (Jul) Lingan 4 LN (Jul) Burnside 1 (33 MW) (Jan)	Lingan 2 LN (Jul) Lingan 4 LN (Jul) Burnside 1 (33 MW) (Jan)	Lingan 2 LN (Jul) Lingan 4 LN (Jul) Burnside 1 (33 MW) (Jan)	Lingan 2 LN (Jul) Lingan 4 LN (Jul) Burnside 1 (33 MW) (Jan)	Lingan 2 LN (Jul) Lingan 4 LN (Jul) Burnside 1 (33 MW) (Jan)	Lingan 2 LN (Jul) Lingan 4 LN (Jul) Burnside 1 (33 MW) (Jan)	Lingan 2 LN (Jul) Lingan 4 LN (Jul) Burnside 1 (33 MW) (Jan)
2008	Pt Tupper LN (Jul) Trenton 5LN (Nov) Lingan 1 LN (Jul)	Pt Tupper LN (Jul) Trenton 5LN (Nov) Lingan 1 LN (Jul)	Pt Tupper LN (Jul) Trenton 5LN (Nov) Lingan 1 LN (Jul)	Pt Tupper LN (Jul) Trenton 5LN (Nov) Lingan 1 LN (Jul) **DSM_Res 5% (-20%)** **DSM_Com 5% (-20%)** **DSM_Ind 5% (-20%)**	Pt Tupper LN (Jul) Trenton 5LN (Nov) Lingan 1 LN (Jul) **DSM_Res 2% (-20%)** **DSM_Com 2% (-20%)** **DSM_Ind 2% (-20%)**	Pt Tupper LN (Jul) Trenton 5LN (Nov) Lingan 1 LN (Jul) **DSM_Res 2% (-20%)** **DSM_Com 2% (-20%)** **DSM_Ind 2% (-20%)**	Pt Tupper LN (Jul) Trenton 5LN (Nov) Lingan 1 LN (Jul) DSM_Res 5% DSM_Com 5% **DSM_Ind 5% (Stora Out)**	Pt Tupper LN (Jul) Trenton 5LN (Nov) Lingan 1 LN (Jul) DSM_Res 2% DSM_Com 2% **DSM_Ind 2% (Stora Out)**	Pt Tupper LN (Jul) Trenton 5LN (Nov) Lingan 1 LN (Jul) DSM_Res 2% DSM_Com 2% **DSM_Ind 2% (Stora Out)**
2009	Trenton 5 Baghouse (Jul) TUC 6 (Dec) Lingan 2 +5MW (Jul) Lingan 4 +5MW (Jul) Nictaux (2.5 MW) (Oct) Marsh F. (1.8 MW) (Oct)	Trenton 5 Baghouse (Jul) TUC 6 (Dec) Lingan 2 +5MW (Jul) Lingan 4 +5MW (Jul) Nictaux (2.5 MW) (Oct) Marsh F. (1.8 MW) (Oct)	Trenton 5 Baghouse (Jul) **TUC 6 (Dec)** Lingan 2 +5MW (Jul) Lingan 4 +5MW (Jul) Nictaux (2.5 MW) (Oct) Marsh F. (1.8 MW) (Oct)	Trenton 5 Baghouse (Jul) Lingan 2 +5MW (Jul) Lingan 4 +5MW (Jul) Nictaux (2.5 MW) (Oct) Marsh F. (1.8 MW) (Oct)	Trenton 5 Baghouse (Jul) TUC 6 (Dec) Lingan 2 +5MW (Jul) Lingan 4 +5MW (Jul) Nictaux (2.5 MW) (Oct) Marsh F. (1.8 MW) (Oct)	Trenton 5 Baghouse (Jul) **TUC 6 (Dec)** Lingan 2 +5MW (Jul) Lingan 4 +5MW (Jul) Nictaux (2.5 MW) (Oct) Marsh F. (1.8 MW) (Oct)	Trenton 5 Baghouse (Jul) Lingan 2 +5MW (Jul) Lingan 4 +5MW (Jul) Nictaux (2.5 MW) (Oct) Marsh F. (1.8 MW) (Oct)	Trenton 5 Baghouse (Jul) TUC 6 (Dec) Lingan 2 +5MW (Jul) Lingan 4 +5MW (Jul) Nictaux (2.5 MW) (Oct) Marsh F. (1.8 MW) (Oct)	Trenton 5 Baghouse (Jul) **TUC 6 (Dec)** Lingan 2 +5MW (Jul) Lingan 4 +5MW (Jul) Nictaux (2.5 MW) (Oct) Marsh F. (1.8 MW) (Oct)
2010	Lingan 3 +5MW (Jul) **DSM_Res 5%** **DSM_Com 5%** **DSM_Ind 5%** RPS (79 MW Firm total)	Lingan 3 +5MW (Jul) Lingan 1 +5MW (Jul) **DSM_Res 2%** **DSM_Com 2%** **DSM_Ind 2%** RPS (79 MW Firm total)	Lingan 3 +5MW (Jul) Lingan 1 +5MW (Jul) **DSM_Res 2%** **DSM_Com 2%** **DSM_Ind 2%** RPS (79 MW Firm total)	Lingan 3 +5MW (Jul) RPS (79 MW Firm total)	Lingan 3 +5MW (Jul) Lingan 1 +5MW (Jul) RPS (79 MW Firm total)	Lingan 3 +5MW (Jul) Lingan 1 +5MW (Jul) RPS (79 MW Firm total)	Lingan 3 +5MW (Jul) RPS (79 MW Firm total)	Lingan 3 +5MW (Jul) Lingan 1 +5MW (Jul) RPS (79 MW Firm total)	Lingan 3 +5MW (Jul) Lingan 1 +5MW (Jul) RPS (79 MW Firm total)
2011 2012	Lingan 1 +5MW (Jul)			Lingan 1 +5MW (Jul)			Lingan 1 +5MW (Jul)		
2013	RPS (166MW Firm total)	RPS (166MW Firm total) **LM6000 (49MW)**	RPS (166MW Firm total) Rnew 50 MW (16 MW firm)	RPS (166MW Firm total)	RPS (166MW Firm total)	RPS (166MW Firm total) Rnew 50 MW (16 MW firm)	RPS (166MW Firm total)	RPS (166MW Firm total)	RPS (166MW Firm total) Rnew 50 MW (16 MW firm)
2014 2015 2016 2017 2018	**PC 400MW (FGD,SCR,Tox)**	**PC 400MW (FGD,SCR,Tox)**	Rnew 50 MW (16 MW firm) **CC (280MW)** Rnew 50 MW (16 MW firm)	**PC 400MW (FGD,SCR,Tox)**	**PC 400MW (FGD,SCR,Tox)**	Rnew 50 MW (16 MW firm) **CC (280MW)** Rnew 50 MW (16 MW firm)	**PC 400MW (FGD,SCR,Tox)**	**PC 400MW (FGD,SCR,Tox)**	Rnew 50 MW (16 MW firm) **CC (280MW)** Rnew 50 MW (16 MW firm)
2019		**Trenton 6 LN (Oct)**	**Trenton 6 LN (Oct)** Rnew 50 MW (16 MW firm)	**Trenton 6 LN (Oct)**	**Trenton 6 LN (Oct)**	**Trenton 6 LN (Oct)** Rnew 50 MW (16 MW firm)	**Trenton 6 LN (Oct)**	**Trenton 6 LN (Oct)**	**Trenton 6 LN (Oct)** Rnew 50 MW (16 MW firm)
2020 2021 2022 2023 2024 2025 2026		L3/L4 SCR, L3/L4 FGD	L3/L4 SCR, L3/L4 FGD Rnew 50 MW (16 MW firm) Rnew 50 MW (16 MW firm) Rnew 50 MW (16 MW firm) Rnew 50 MW (16 MW firm)	L3/L4 FGD	L3/L4 SCR, L3/L4 FGD	L3/L4 SCR, L3/L4 FGD Rnew 50 MW (16 MW firm) Rnew 50 MW (16 MW firm) Rnew 50 MW (16 MW firm) Rnew 50 MW (16 MW firm)	L3/L4 FGD	L3/L4 SCR, L3/L4 FGD	L3/L4 SCR, L3/L4 FGD Rnew 50 MW (16 MW firm) Rnew 50 MW (16 MW firm) Rnew 50 MW (16 MW firm) Rnew 50 MW (16 MW firm)
2027			Rnew 50 MW (16 MW firm)			Rnew 50 MW (16 MW firm)			Rnew 50 MW (16 MW firm)
2028 2029			Rnew 50 MW (16 MW firm)		**LM6000 (49MW)**	Rnew 50 MW (16 MW firm)			Rnew 50 MW (16 MW firm)
Study Period (M$) (includes End Effects)	**$15,129.8**	**$15,771.5**	**$15,719.3**	**$15,418.6**	**$15,956.6**	**$15,907.5**	**$15,138.0**	**$15,765.0**	**$15,749.3**

Appendix L

Synopsis of all Plan's and World's NPVs

Resource Plan	World's Analysis	DSM Spending Level	Plan Type	Comments	Study Period NPV	Delta to Reference Case
Base Plans	**Run #20**	**5% Spend DSM**	**Renewables beyond RPS**	**Reference Case**	**$14,479.9**	
		5% Spend DSM			$14,747.7	$267.8
		2% Spend DSM	Coal Plan	FGD in 2020	$15,503.7	$1,023.8
		2% Spend DSM	Coal Plan	FGD in 2012	$15,551.4	$1,071.5
		2% Spend DSM	Natural Gas Plan		$15,925.4	$1,445.5
		2% Spend DSM	Renewables beyond RPS	CC280, No TUC 6	$15,435.2	$955.3
High Load	Run #2	5% Spend DSM	Renewables beyond RPS	RPS advanced 1 year	$19,029.0	$4,549.1
Low Air Emissions	Run #3	5% Spend DSM		Low air emission limits and CO2 credit costs	$11,921.7	-$2,558.2
High Air Emissions	Run #4	5% Spend DSM	Coal Plan	No FGD	$17,694.8	$3,214.9
(High air emission limits	Run #5	5% Spend DSM	Renewables beyond RPS		$17,336.5	$2,856.6
and CO2 credit costs)	Run #6A	5% Spend DSM	Natural Gas Plan		$17,791.4	$3,311.5
	Run #6B	5% Spend DSM	Natural Gas Plan	Option to retire exisitng units	$17,901.8	$3,421.9
Base CO2 Limits	Run #7	5% Spend DSM	Renewables beyond RPS	Existing Options	$14,981.8	$501.9
(CO2 Credit Constrained	Run #8	5% Spend DSM	Renewables beyond RPS	Existing Options & New CO2 Mitigation Options	$14,645.6	$165.7
starting in 2020)	Run #8A	5% Spend DSM		Existing Options & New CO2 Mitigation Options	$14,857.6	$377.7
Kyoto Case CO2 Limits	Run #9	5% Spend DSM	Renewables beyond RPS	Existing Options & New CO2 Mitigation Options	$14,714.0	$234.1
(CO2 Credit Constrained starting in 2020)	Run #9A	5% Spend DSM		Existing Options & New CO2 Mitigation Options	$15,002.0	$522.1
Deep Green Case CO2 Limits	Run #10	5% Spend DSM	Renewables beyond RPS	Existing Options & New CO2 Mitigation Options	$14,976.1	$496.2
(CO2 Credit Constrained starting in 2020)	Run #10A	5% Spend DSM		Existing Options & New CO2 Mitigation Options	$15,298.2	$818.3
DSM Delayed 2 Years	Run #11	5% Spend DSM			$15,129.8	$649.9
	Run #12	2% Spend DSM	Coal Plan		$15,771.5	$1,291.6
	Run #13	2% Spend DSM	Renewables beyond RPS	TUC 6	$15,719.3	$1,239.4
DSM -20% Benefits	Run #14	5% Spend DSM			$15,418.6	$938.7
	Run #15	2% Spend DSM	Coal Plan		$15,956.6	$1,476.7
	Run #16	2% Spend DSM	Renewables beyond RPS	TUC 6	$15,907.5	$1,427.6
Remove Stora Portion of DSM	Run #17	5% Spend DSM			$15,138.1	$658.2
	Run #18	2% Spend DSM	Coal Plan		$15,765.0	$1,285.1
	Run #19	2% Spend DSM	Renewables beyond RPS	TUC 6	$15,749.3	$1,269.4

Note: Runs 4-6b include high CO2 credit costs. Run 3 includes low CO2 credit costs. All other worlds include base CO2 credit costs. This differences contribute significantly to the difference in the NPV values.

ATTACHMENT 4

IRP Assumptions Background Data Book - FTP Site Index

1. General

1-IRP Technical Conference – Sept. 22, 2006
2-Sept. 22 Tech Conf. Actions
3-IRP Basic Assumptions REDACTED – Oct. 13, 2006
4-Listing of Changes to Basic Assumptions, Oct. 13, 2006

2. Enviro Emissions

0-Enviro Assump. Document Index for IRP Background

<u>Tab 1</u>
-NS Air Quality Regulations
-Web Link for Air Quality Regulations

<u>Tab 2</u>
-Acid Rain Strategy Post 2000

<u>Tab 3</u>
-2004 Acid Deposition Science Assessment

<u>Tab 4</u>
-PM and Ozone Canada Wide Standards

<u>Tab 5</u>
-CAIR Basic Information
-Web Link for Basic Information for the CAIR

<u>Tab 6</u>
-New Source Emission Guidelines for Thermal Electricity Gener.
-Web Link for new Source Emission Guidelines

<u>Tab 7</u>
-Moving forward on climate change

<u>Tab 8</u>
-NEG-ECP Resolutions Overview 1973-2002
-News NEG-ECP Climate Change Action Plan (July 2001)

<u>Tab 9</u>
-United Nations Framework Convention on Climate Change

Tab 10
-Transition Principles Backgrounder

Tab 11
-Mercury Canada Wide Standard

Tab 12
-NEG-ECP Resolutions Overview 1973-2002
News NEG-ECP Mercury Action Plan (1998)

Tab 13
-Clean Air Mercury Rule Basic Information
-Web Link to U.S. Clean Air Mercury Rule Info.

Tab 14
-Emission Constraints remise Expert Interview List

-CO2 Credit Prices Background

-Hydro System Optimize for Wind NSPI IRP Action Items Dec. 12, 2006

-Trading Report E

3a. Supply Side Emission Cntrl

1-Emission Technology Alternatives
2-Emission Technology & Generation Cost Assumptions
3-IRP Scrubber Cost Assumptions Calc.
4-Alstom Technical Study FGD 120806
5-P + EA Nova Scotia FGD Report 30-Jan-2006

3b. Supply Side New Generation

1-New Generation Alternatives
2-Gneration Cost & emission Tech Assumptions

4. Load

-IRP Load Forecast Detail Tech Conf. Response
-IRP Load Forecast Performance
-Memo IRP Load Forecast Performance

5. DSM
DSM Evidence

1-NSPI DSM Evidence 9-8-06
2-Appendix A Revised DSM Plan –Proposal General DSM Programming 9-27-06
3-Appendix B Consultants DSM Report Plan Filed Sept. 8, 2006
4-Corrections to NSPI's Revised DSM Plan Filed Sept. 8, 2006

6. Financial

-Bank of Canada CAD-UDS FX High Low 1980-2006
-Bank of Canada T-bill High Low 1996-2006
-Bank of Canada Overnight Money Market Financing High Low 1996-2006
-Bank of Canada High Low Long Term Bond Yields 1996-2006
-Financial Assumption Sources for IRP
-FX Forecasts per Chartered Banks Summer 2006
-FX Rate High and Low over the last 26 years
-Responses re Economic Assumptions Post Tech Conf.
-Stats Canada CPI 1987-2006

7. Fuel

-NSPI Long Term Fuel Price Forecast Assumptions IRP Planning

8. Transmission

-Tx Loss Factors in Strategist Revised Dec. 19, 2006

Integrated Resource Plan (IRP) Report

Volume 3

Intervenor Comment on IRP Results and Draft Final Report

Nova Scotia Power Inc.

July 2007

STAKEHOLDER COMMENTS REGARDING IRP RESULTS (JUNE 13, 2007)

Affordable Energy Coalition (AEC)
Atlantic Chapter of the Canada Green Building Council (CGBC)
Canadian Manufacturers and Exporters (CME)
Consumer Advocate (CA)
Dr. Larry Hughes
Ecology Action Centre (EAC)
GPI Atlantic (GPI)
Halifax Regional Municipality (HRM)
Municipal Electric Utilities of Nova Scotia Co-operative (MEUNSC)
Stora Enso Port Hawkesbury (SEB)
The Sierra Club of Canada

STAKEHOLDER COMMENTS REGARDING IRP REPORT (JULY 11, 2007)

Atlantic Chapter of the Canada Green Building Council
Avon et al.
Canadian Manufacturers and Exporters
Common Input
Dr. Larry Hughes
Ecology Action Centre
Halifax Regional Municipality
Municipal Electric Utilities of Nova Scotia Co-operative
Province of Nova Scotia
Stora Enso Port Hawkesbury