Nova Scotia Utility and Review Board

NSPI
2009 Integrated Resource Plan Update Report

November 30, 2009

REDACTED

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EXECUTIVE SUMMARY

The 2009 Integrated Resource Plan (IRP) Update has incorporated new information to determine if changes are needed to the 2007 IRP Reference Plan.[1] The 2009 IRP Update Terms of Reference[2] (Appendix A) contains the following objective:

> To update Nova Scotia Power's 2007 Integrated Resource Plan based on current conditions and assumptions. The update should be meaningful, efficient and timely as per the UARB's order.

The 2009 IRP Update analysis has confirmed the direction set by the 2007 IRP. With updated modeling assumptions, in particular a lower load forecast and tighter emissions constraints, the 2009 IRP Update has resulted in a least cost Reference Plan consistent with 2007 findings that confirms the most cost effective approach is accomplished through significant investment in Demand Side Management (DSM) and new renewable generation, along with upgrades to Nova Scotia Power Inc.'s (NSPI's) existing generation fleet.

A key finding of the 2009 IRP Update is that the elements of the 2007 IRP Reference Plan remain appropriate for the first decade of the planning term with the Company meeting its emissions reduction obligations and provincial Renewable Energy Standard (RES) obligations. After 2018, a material investment is likely required in a renewable or low-emitting supply resource. A new generation source of this size will require a lead time of several years to plan, permit, engineer and construct.

The updated IRP Action Plan identifies the next steps to better understand evolving issues, while articulating a course to pursue resource planning options identified in the 2009 Reference Plan.

[1] NSPI's 2007 IRP Report can be accessed at http://www.nspower.ca/site-nsp/media/nspower/IRPReportVolume1July2007.pdf
[2] IRP Update Terms of Reference issued March 26, 2009, Nova Scotia Utility and Review Board.

The Action Plan addresses the following matters:

- NSPI will support pursuit of DSM programming consistent with the IRP and Board approved plans as interim Administrator and will support the new Administrator. The longer term level of DSM that is sustainable both economically and in terms of customer participation requires ongoing assessment and monitoring. This can be accomplished through a portfolio of energy efficiency solutions which will include targeted DSM program implementation with appropriate evaluation and verification. The new DSM Administrator, Efficiency Nova Scotia Corporation, is expected to be operational in time for execution of the 2011 program and presentation of the 2012 programming plan to the Nova Scotia Utility and Review Board (UARB, Board). A collaborative working group may be useful in supporting an efficient transition of DSM programming from NSPI to the new Administrator.

- NSPI will pursue wind generation, a key environmental compliance component of the recommended Reference Plan. Knowledge about the integration of wind generation onto NSPI's system will need to continue to build upon the work done since the 2007 IRP. The IRP process did not intend to address the day-to-day generation dispatch issues that are anticipated to arise as more intermittent energy sources are added, such as fast response back-up.

- NSPI will participate in the assessment of the sustainability and supply of biomass. As a renewable fuel resource in Nova Scotia, biomass creates options in various generation formats. A biomass Power Purchase Agreement (PPA) and biomass co-firing in NSPI's existing generating facilities are new supply options introduced in the 2009 IRP Update modeling exercise that have been selected as economic in the recommended Reference Plan. Biomass will require further study in terms of supply and sustainability as well as from a technical assessment perspective.

- NSPI will continue to apply to the Utility and Review Board for approval of capital investments to optimize the capacity and environmental performance of existing generation assets and will actively monitor technology developments with respect to low-impact generation and environmental retrofit technologies.

- NSPI will explore opportunities for a large non-emitting PPA as an option to respond to larger-scale needs in the second decade of the IRP planning period.

- NSPI will report annually to the UARB on the progress of the IRP Action Plan.

The 2009 IRP Update has achieved its objective. The ‘no regrets’[3] strategy of choosing a flexible approach that was pursued following the 2007 IRP has proven successful over the past two years. The Reference Plan is robust. The 2009 IRP Update has affirmed the need for significant investment in DSM, with incremental investment in renewables to meet RES and emissions requirements, together with incremental investments in NSPI’s hydroelectric facilities and solid-fuel generating facilities. The 2009 IRP Update also introduced new resources, such as biomass, which present a need for further investigation, and continue to support the direction set in 2007.

The 2009 IRP Update is a planning exercise. The 2009 IRP Update provides strategic direction, rather than prescriptive solutions. Tactics presented in the Action Plan, including pursuit of DSM and investment in utility assets, require formal application to the UARB, and subsequent UARB approval before implementation.

[3] A ‘no regrets’ strategy is one in which future decisions are unlikely to be negatively affected by earlier decisions made.

1.0 INTRODUCTION

In 2007, in collaboration with UARB staff and its consultants, and in consultation with stakeholders, NSPI developed a long-term Integrated Resource Plan. The recommended plan integrated supply and demand-side options to provide a strategic framework for meeting energy and demand requirements cost effectively and reliably, consistent with environmental legislation and regulations. The results revealed that this could be accomplished most cost-effectively through investment in DSM programs and renewable generation, as well as through upgrades to NSPI's existing generation fleet.

The 2007 IRP resulted in the following key findings:

- Based on experience in other jurisdictions and the limited DSM in place in Nova Scotia at the time, an increase in spending in this area appeared economically sound. The analysis showed that positive benefits accrue at levels of spending up to five percent of total revenue on an annual basis.

- Renewable generation appeared to be cost-effective compared to certain new fossil-based capacity. The technical and economic viability of achieving large amounts of intermittent renewable resources across Nova Scotia required further assessment in order to ultimately determine the amounts to pursue in Nova Scotia.

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

- The addition of a scrubber to the Lingan plant by 2020 appeared economic. In the interim, emissions were understood to be managed cost-effectively through utilization of lower-sulphur fuels.

- NSPI estimated that it had a two year window (2010 timeframe) before a decision needed 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, which was considered as an alternate World, significantly altered the results for the post 2020-period. The IRP resource plan for later years was likely to require revision if such constraints were adopted by government. The recommended resource plan for the early years would remain robust. [4]

On February 25, 2009[5], the UARB directed that the 2007 IRP be updated:

> The Board wishes to have a meaningful, efficient, and timely IRP update. The update process will follow the same collaborative approach used in developing the 2007 IRP, with Dr. Stutz taking a lead role with the initiative. The update should primarily focus on incorporating new information that is now available in order to determine what changes may be needed to the IRP reference plan. Demand-side options and supply-side options will again need to be considered during the update.

As directed, NSPI's 2009 IRP Update has focused on incorporating new information that is now available in order to determine the changes needed to the path set by the 2007 IRP Reference Plan.

[4] Nova Scotia Power Inc.'s Integrated Resource Plan (IRP) Report, July 2007, p. i-ii.
[5] UARB Correspondence to NSPI, February 25, 2009.

The Board indicated that the demand-side issues would include:

- Load Forecast
- DSM Programs
- Automated Metering Infrastructure (AMI)

The Board indicated that the supply-side issues would include:

- New Renewable Resources
- Existing Renewable Resources
- Environmental Considerations
- Long Term Fuel Forecast

NSPI, Board staff and the Board's consultants have worked jointly on the 2009 IRP Update. Stakeholder input was sought and incorporated throughout the process.

2.0 IRP UPDATE PROCESS OVERVIEW

Role of NSPI/UARB Staff and Consultants

NSPI's 2009 IRP Update has been developed as a joint effort between NSPI and UARB staff and its consultants. This collaboration has included all aspects of the project from establishing Terms of Reference, to identifying key assumptions, designing the analysis framework, selecting and assessing resource plans, analyzing model results, developing conclusions and compiling this report.

The IRP knowledge brought to this project by Board staff and consultants, Tellus Institute, Synapse Energy Economics, Inc., Multeese Consulting Inc., and The Liberty Consulting Group, along with NSPI technical and analytical expertise, has produced a comprehensive update of the 2007 IRP. The key outcomes confirm the direction indicated by the 2007 IRP and identify an action plan to enable NSPI to meet future customer needs and environmental obligations.

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

Stakeholder Consultation

In accordance with the 2009 IRP Update Terms of Reference, stakeholders were consulted throughout the process. Please refer to Appendix C for the list of 2009 IRP Update participants. Specific consultations included:

1. Three technical conferences covering Terms of Reference, the development of updated Basic Assumptions, and Analysis Results;
2. Participant input on the updated Basic Assumptions, Analysis Results and the Draft Report;

3. Access to a File Transfer Protocol (FTP) site for viewing of confidential documents by IRP Update participants who have signed confidentiality agreements;
4. Replies to queries issued by participants throughout the process concerning assumptions development, model design and Analysis Results.

The planning process has been enhanced by stakeholder participation and the foundation for the conclusions and the Action Plan have benefited from this significant stakeholder engagement.

Process Stages

The 2009 IRP Update included the following key stages:

- Updating of Basic Assumptions
- Determination of Plan Themes
- Worlds analysis
- Sensitivity analysis of resource plans
- Compilation of results
- Preparation of final report

Updating of Basic Assumptions

The updating of the Basic Assumptions phase took place over several months and involved NSPI staff working jointly with Board staff and consultants, as well as consultation with stakeholders. All assumptions from the 2007 IRP were updated to reflect more recent understanding, outlooks and developments. Per the scope described in the Terms of Reference, the assumptions update focused on the following:

- The emissions constraint assumptions, to reflect current government activity;
- The demand-side assumptions, to reflect NSPI experience since 2007;

- The supply-side alternatives, to reflect recent developments and focus on technologies expected to be commercially available before 2020;
- The load forecast and fuel forecast, using the methodologies employed in the 2007 IRP;
- The financial assumptions.

Emissions Constraints

At the conclusion of the 2007 IRP, the regulated emissions outlook remained uncertain from both provincial and federal perspectives. The 2009 IRP Update has benefited from increased clarity with respect to Provincial emissions targets for carbon dioxide (CO_2), sulphur dioxide (SO_2), nitrogen oxide (NO_x) and mercury (Hg), as suggested in the 2009 Energy Strategy and Climate Change Action Plan[6] released in January 2009**,** which were subsequently confirmed in the Air Quality Regulations[7] and new regulations respecting greenhouse gas emissions[8]. These regulations confirm Provincial requirements up until the year 2020. Of particular note, the 2009 IRP Update now reflects the Nova Scotia mandate that CO_2 requirements will be physical ("hard") caps between 2010 and 2020. Beyond 2020 uncertainty remains, though further physical reductions are expected and were assumed in the 2009 IRP Update assumptions.[9]

Federally, although guidance has been taken from the Government's most recent position in "Turning the Corner"[10], confirmation of specific regulation remains uncertain and pending.

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[6] *Toward a Greener Future, Nova Scotia's 2009 Nova Scotia Energy Strategy*, Nova Scotia Department of Energy, January 2009 and Toward *a Greener Future, Nova Scotia's 2009 Climate Change Action Plan*, Nova Scotia Department of Environment, January 2009.
[7] *Air Quality Regulations*, N.S. Reg. 28/2005, as amended by O.I.C. August 14, 2009, N.S. Reg. 261/2009.
[8] *Greenhouse Gas Regulations*, N.S. Reg. 260/2009.
[9] See Appendix D, Updated Basic Assumptions, pages 9-13.
[10] *Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas Emissions*, Government of Canada, March 2008.

Demand Side Management

In the 2007 IRP, alternative DSM spending levels were tested by extrapolating forecasts of energy and demand reduction levels of one percent and five percent of electric revenue, corresponding to lower and higher achievement of the economic DSM potential identified in NSPI's DSM consultant's report.[11] The model always picked the highest level of DSM savings offered because it was the lowest cost resource. For the 2009 IRP Update an energy reduction trajectory was assumed similar to the DSM profile from the 2007 IRP reference plan; that is, corresponding to five percent of annual revenue.

Renewables

Pursuant to the Provincial legislation, by 2011 NSPI is required to provide five percent of its energy from in-province renewable resources generated by independent power producers constructed after December 31, 2001. By 2013, the Company is required to provide an additional five percent; that is, 10 percent of its energy from in-province renewable resources constructed post-2001.[12]

In 2007, most of this renewable energy was assumed to come from wind. The 2009 IRP Update reflects the introduction of additional sources of renewable energy to the list of options. New renewable options (though not necessarily RES compliant in early years) made available to the model in the 2009 IRP Update included:

- Biomass PPA
- Biomass co-firing

[11] Summit Blue Consulting LLC., DSM Final Report prepared for Nova Scotia Power Inc., September 2006**.**

[12] On July 28, 2009, the Nova Scotia government announced that by 2015, 25% of Nova Scotia's electricity will be supplied by renewable energy. Regulations have not yet been proposed and it is not yet known what percentage of that amount might come from independent power producers and what percentage might come from NSPI. No modifications were made to the Basic Assumptions. The Company understands that the Government has initiated a process, led by Dr. David Wheeler, to determine how to best meet those targets.

On October 6, 2009, the Nova Scotia Government passed amendments to the RES (Renewable Energy Standard Regulations, N.S., as amended by O.I.C. 2009-437, Reg. 303/2009. The effect of the change was to move the 2010 compliance requirements to 2011. The 2009 IRP Update assumed that 2010 RES requirements would not be fully online until 2011. For the purposes of the 2009 IRP Update, this RES change therefore did not alter the plans.

- Tidal
- Large non-emitting PPA

Environmental Retrofits

Carbon Capture and Storage (CCS) is an emerging CO_2 emission mitigation technology, not offered in the 2007 IRP. Although this storage technology remains to be technically proven in Nova Scotia, for the 2009 IRP Update it was included as a supply option with an associated range of costs.

Other technologies included:

- Fluidized Gas Desulphurization (FGD) scrubbers (SO_2 /Hg)
- Activated Carbon injection (Hg)
- Baghouses (fly ash/Hg)
- Selective Catalytic Reduction (SCR) (NO_x)

Other Supply Side Options

Other supply side options that were modeled included Compressed Air Energy Storage (CAES) and Integrated Coal Gasification Combined Cycle (IGCC), Combined Cycle Gas and existing unit uprates.

Load

In 2007, the base load profile (pre-DSM) reflected growing load of on average approximately two percent annually over the year planning period.

NSPI's base load profile (pre-DSM) was updated to reflect NSPI's 2009 load forecast of approximately 0.5 percent average annual growth over the 25 year planning period. Combined with the effect of DSM (two percent of annual energy savings) this produces negative load growth, or an average decline, of approximately -1.5 percent annually. Over the 25 year planning period, this is a significant change.

In the 2009 IRP Update, the high load assumption also reflects a different growth profile than that forecast in 2007. In 2007, the high load forecast predicted growth above the two percent per year reflected in the 2007 base case. In the 2009 IRP Update, accounting for the impact of DSM, the high load profile reflects negative load growth of approximately -0.7 percent annually. This moderated outlook is closer to the 2007 base load forecast including DSM effects.

Fuel Prices

Fuel prices for natural gas, oil, coal, and petcoke were obtained from the same sources as 2007. For natural gas, heavy fuel oil (HFO) and light fuel oil (LFO) base case pricing, PIRA Energy Group's long-term forecasts were used. For high and low pricing of these commodities, PIRA Scenario Planning Service was used. For base, high and low case coal, Wood Mackenzie (formerly Hill & Associates) Coal Trade Service was used. For petcoke, Jacob's Consultancy Quarterly Petroleum Coke Price Forecasts were used. At the time of the establishment of the Basic Assumptions in June 2009, the forecasts used were prepared as of November 2008.

Although a natural gas forecast update was available from PIRA as of May 2009, an initial decision had been made to use the November 2008 forecasts for all fuels to ensure that pricing was taken from the same timeframe for consistency in the underlying macro-economic assumptions. Following receipt of stakeholder feedback on the Basic Assumptions, NSPI committed to review the updated forecasts for all fuels when received in June/July 2009.

Upon review of the updated forecasts, and in consultation with the UARB fuel consultant, the decision was made to widen the range for natural gas, specifically by lowering the low gas price assumption to be used in sensitivity testing. All other fuel pricing remained unchanged from the forecasts provided in the Basic Assumptions as it was determined the change in fuel pricing was not material from a long-term perspective.

Financial Assumptions

Financial assumptions, such as the inflation rate, short and long-term investment rates, income tax rates, and the foreign exchange rate forecast, were updated from the 2007 IRP to reflect current information.

See Appendix D for the Basic Assumptions and Appendix F for stakeholder comments on the Basic Assumptions.

<u>Determination of Plan Themes and Analysis Framework</u>

To fulfill the purpose of integrated planning, it is important that alternative resource plans be significantly different from each other. They must be viable plans that include a variety of options. In the 2007 IRP, following the setting of the Basic Assumptions, the plan themes that were established for the resource plans were: Coal, Natural Gas, DSM, and Renewables. For the 2009 IRP Update, the relevant area of focus has narrowed. In particular, a primarily coal-based theme was not studied. While coal generation is an element of all of the plans, in light of renewables targets and emissions constraints, these areas were the focal points of the 2009 IRP Update.

In 2007, DSM at varying levels was consistently chosen by the model and was a critical common element to all resource plans evaluated. As a result, an explicit DSM theme was not constructed for the 2009 IRP Update; rather two percent energy savings per year was assumed across all resource plans. Although not separate themes within the Worlds, plans with varying amounts of resources such as natural gas and renewables were evaluated. The Company, Board staff and consultants agreed on the following themes for the 2009 IRP Update:

- Base Load World
  - The typical starting point for IRP analysis is a set of plans produced when all assumptions, including load, are input at base settings.

- High Load World
  - Because load is a fundamental input assumption or constraint, understanding the effect on plans when it is varied, particularly when load is considered to be higher, is important to ensure an understanding of lead time and emission compliance variation risks.

- Kyoto World
  - Similar to the 2007 IRP there is ongoing interest in assessing how a more strictly constrained CO_2 World affects the selection of resources differently than using Base CO_2 constraints. For the 2009 IRP Update, a "Kyoto" type CO_2 trajectory was modeled to evaluate such plans.

The analysis framework for the 2009 IRP Update followed the framework established in the 2007 IRP. Because the intent was to provide an update to the 2007 analysis however, the scope of the 2009 work was more focused.

The resource plans identified for further study were selected on the basis of being low cost and/or providing distinct alternative resource plans for comparison while meeting the system reliability and environmental constraints. The following resource plans were developed and reviewed:

Base Load World:

- Plan A – Renewables - Additional biomass generation (Least Cost)
- Plan B – Renewables - Additional wind generation

- Plan C – Renewables - Additional natural-gas fired generation

High Load World:

- Plan D – Renewables and Carbon Capture and Storage
- Plan E – Renewables – Wind and Biomass
- Plan F – Renewables and large non-emitting PPA
- Plan G – Renewables and natural gas-fired generation

Kyoto World:

- Plan H – Capture and Storage
- Plan I – Renewables and natural gas-fired generation (one 280 MW combined cycle unit (CC))
- Plan J – Renewables with increased natural gas-fired generation (two 280 MW CC)
- Plan K – Large non-emitting PPA

Worlds Analysis

For the 2009 IRP Update, the Base Load World, High Load World and Kyoto World comprised the analysis plan themes. The intent was to reconsider NSPI's options and risks for meeting evolving requirements, taking into account developments over the past two years. As a result, Base Load and High Load optimizations were of primary focus.

In 2007, there was greater uncertainty around pending emissions constraints, and in particular, whether there would be physical carbon caps or carbon compliance credits available. Therefore, the 2007 Worlds analysis was conducted to evaluate resource planning under varying emission outlooks. Given the greater certainty around emissions constraints in 2009 versus 2007, for example with the recent release of the Nova Scotia Greenhouse Gas Regulations[13] and the amended Air Quality Regulations,[14] the known emission limits were input at their base assumptions in the High Load and Base Load Worlds. A Kyoto World was created at the outset of the 2009 IRP Update to consider

[13] *Greenhouse Gas Emissions Regulations*, N.S. Reg. 260/2009.
[14] *Air Quality Regulations*, N.S. Reg. 28/2005, as amended by O.I.C. August 14, 2009, N.S. Reg. 261/2009.

tighter CO_2 emission constraints and potential for credit trading to meet such carbon caps. It was not undertaken to study the variation with respect to other environmental constraints given the recent government direction in this regard.

Reality will not unfold exactly as anticipated in the model assumptions. Further analysis, such as sensitivity testing and evaluation of alternate Worlds, is therefore necessary. Given the uncertainty surrounding inputs such as load requirements, fuel prices, capital costs and environmental regulations, plans must be assessed for their robustness when such inputs are varied. Worlds analysis entails complete re-optimization to develop alternate resource plans that become low cost when a fundamental input changes (such as load). Worlds analysis is done to evaluate the alternate timing and/or type of resource(s) that would be called for under significantly different fundamental input assumptions. Sensitivity testing assesses the potential change in revenue requirement of plans when certain price or cost inputs are varied, while the resource mix in each plan is held constant.

The best IRP path is the one that not only meets the least cost measure but also is robust enough to withstand a variance in the base assumptions. For the purposes of this 2009 IRP Update, sensitivity tests, as well as Worlds analysis, were conducted to test the robustness of the plans. Short-term pricing changes and the value of flexibility to capture these opportunities (such as additional gas generation or fuel switching) are not evaluated in a long-term IRP sensitivity test.

Sensitivity Analysis

The purpose of Sensitivity analysis is to understand how the resource plans perform in terms of Net Present Value (NPV) when an input price assumption is varied. Different from model re-optimization completed in Worlds analysis, in Sensitivity testing each plan is held with its resources fixed but with a varying price input (high or low) value; the plan is re-dispatched in the model to produce a new study period NPV. This informs as to whether a change in input price assumptions would cause one of the resource plans to become more or less attractive (on a net present value of cost basis) relative to the other plans. For each resource plan, one input price assumption was varied at a time. All other assumptions were held constant for each test and the effect on the plan's total net present value was documented. The sensitivities analyzed in the 2009 IRP Update were:[15]

- Low and High Coal Price
- Low Gas Price
- High Biomass Price
- High Carbon Capture and Storage Capital Cost (transport feasibility and costs, and geology were not tested)

This set of sensitivity tests was conducted for each of the 11 plans across the three Worlds described in the previous section. The results of the sensitivity analysis are discussed in the next section.

See Appendix E for the detailed Analysis Results and Appendix F for the stakeholder comments on the analysis.

[15] If a resource was shown to be uneconomic (that is, not called for) in the base analysis, sensitivity pricing was not employed to determine what an even higher cost/price input would show. Similarly, if a resource was shown to be economic in the base plans, an even lower cost/price was not tested. For this reason, a high natural gas price was not tested nor was a low biomass price or low CCS cost.

3.0 ANALYSIS RESULTS AND CONCLUSIONS

Of the 11 plans selected, Plan A (Renewables – Additional Biomass Generation) was identified as the least cost plan overall. This means the plan's net present value of costs[16] over the study period is lower than any of the other plans. It is worthy of note that Plans B and E are similar to Plan A. Both call for incremental investments in wind and biomass co-firing, though timing and exact magnitude of investment varies by plan. Within the High Load World and the Kyoto World, the least cost plans were identified to be Plans D and H, respectively. In Plans D and H, Carbon Capture and Storage presents as a low cost resource option. As an emerging technology not yet tested in Nova Scotia, if Carbon Capture and Storage were to be pursued, further assessment would be required to evaluate in greater detail its suitability and risk in terms of cost, technical feasibility and timeframe of implementation. A component of this assessment is underway with research spearheaded by CCS Nova Scotia, a not-for-profit organization doing research on the geology of Nova Scotia to determine if carbon dioxide can be stored.

As was seen in the 2007 IRP, all plans include demand-side management, and renewable generation sufficient to meet the RES requirements modeled. All plans meet emissions constraints, planning reserve margin (which includes interruptible load) and other regulatory requirements.

Also consistent with 2007 findings, all plans include investment in certain existing NSPI generating stations to incrementally increase (or recover) the capacity of coal units and/or to economically comply with certain environmental emission constraints. The inclusion of these resources in the various base plans confirms they are economic across a broad range of alternative scenarios.

The table below summarizes the Resource Plans developed in the 2009 IRP Update and identifies the capacity[17] associated with each demand or supply option.

[16] Costs include utility costs (operating and capital related) as well as customer costs for DSM.
[17] For DSM capacity refers to reduction in demand.

2009 IRP UPDATE RESOURCE PLANS: SCHEDULE OF FIRM SUPPLY or DSM (Equivalent MW's)

	PLAN A (BASE)	PLAN B (BASE)	PLAN C (BASE)	PLAN D (HIGH LOAD)	PLAN E (HIGH LOAD)	PLAN F (HIGH LOAD)	PLAN G (HIGH LOAD)	PLAN H (KYOTO)	PLAN I (KYOTO)	PLAN J (KYOTO)	PLAN K (KYOTO)
New Resources 2010-2017											
DSM	290	290	290	290	290	290	290	290	290	290	290
TUC6	49	49	49	49	49	49	49	49	49	49	49
Hydro Uprates	4	4	4	7	7	7	7	7	7	7	7
Wind (Nets out 60 (26 firm) MW of existing 308 (100 firm) MW contracted already in service pre 2010; 2010-2017 = 248 (74 firm) MW per existing contracts plus added wind per Plans 2012-2017)	117	159	117	159	159	159	159	117	200	117	159
Biomass (PPAs only; excludes co-fire conversions since not new MW)	0	0	0	16	16	16	16	0	0	0	0
Coal Uprates	30	30	30	30	30	30	30	30	30	15	30
SUBTOTAL	**490**	**531**	**490**	**549**	**549**	**549**	**549**	**492**	**576**	**477**	**534**
New Resources 2018-2032											
DSM	552	552	552	552	552	552	552	552	552	552	552
Additional Wind	0	42	0	0	214	0	83	0	41	41	0
Additonal Biomass	16	16	16	0	55	55	55	16	71	0	16
Natural Gas	0	0	147	0	0	0	280	0	280	560	0
Large Non-Emitting Import PPA	0	0	0	0	0	300	0	0	0	0	300
Coal Retrofit Capacity Adjustments	-8	-8	0	-114	-8	-8	-8	-114	0	0	0
SUBTOTAL	**560**	**602**	**715**	**438**	**813**	**900**	**962**	**454**	**944**	**1153**	**868**
TOTAL ADDITIONAL FIRM SUPPLY & DEMAND MW's OVER PLANNING PERIOD	**1050**	**1134**	**1205**	**988**	**1363**	**1449**	**1512**	**946**	**1520**	**1631**	**1402**
Coal Emission Retrofit - Baghouse (# units)	2	0	0	3	2	1	2	2	0	0	0
Coal Emission Retrofit - FGD (Scrubber) (# units)	2	2	0	3	2	2	2	3	0	0	0
Coal Emission Retrofit - Carbon Capture Storage (CCS) (# units)	0	0	0	3	0	0	0	3	0	0	0

Note: Values in the table above represent firm MW, including deratings and DSM net of the interruptible industrial portion. The firm wind capacity numbers noted are based on average projected on-peak winter capacity factors which are slightly higher than the annual energy capacity factors modeled. (The annual energy from the wind block is still based on the annual capacity factor). As a result, the firm capacity contribution of the wind is higher than the annual capacity factor.

All existing generation facilities are assumed to continue in operation throughout the planning period.

The following three tables summarize the plans in Base, High Load and Kyoto Worlds, and resources called in for 2010 – 2032.

Resource Plans - 2009 IRP Update - Base Case Assumptions

Year	NSR (GWh)	Plan A	Plan B	Plan C
2010	12,398	TUC 6 (Nov) Activated CI (7 PC units) LS, Low BTU Coal Burn (Lin 1-4/Tup)	TUC 6 (Nov) Activated CI (7 PC units) LS, Low BTU Coal Burn (Lin 1-4/Tup)	TUC 6 (Nov) Activated CI (7 PC units) LS, Low BTU Coal Burn (Lin 1-4/Tup)
2011	12,320	Contract Wind 308MW (100MW Firm) *(Plus transmission and load following requirements)* Marshall Hydro (4.2MW)	Contract Wind 308MW (100MW Firm) *(Plus transmission and load following requirements)* Marshall Hydro (4.2MW)	Contract Wind 308MW (100MW Firm) *(Plus transmission and load following requirements)* Marshall Hydro (4.2MW)
2012	12,225	Biomass co-fire (4 units)	Wind (100MW nameplate, 40MW firm) *(Plus transmission and load following requirements)*	Biomass co-fire (4 units)
2013	12,016	Coal uprate +15MW (2 units) *(Plus transmission requirements)* Wind (100MW nameplate,40MW firm) (for RES) *(Plus transmission and load following requirements)*	Coal uprate +15MW (2 units) *(Plus transmission requirements)* Wind (100MW nameplate,40MW firm) (for RES) *(Plus transmission and load following requirements)*	Coal uprate +15MW (2 units) *(Plus transmission requirements)* Wind (100MW nameplate,40MW firm) (for RES) *(Plus transmission and load following requirements)*
2014	11,837			
2015	11,651			
2016	11,449			
2017	11,256		Biomass co-fire (2 coal units)	
2018	11,079	Biomass co-fire (1 unit) Baghouse (2 units) FGD (2 units)	Wind (100MW nameplate, 40MW firm) *(Plus transmission and load following requirements)* FGD (2 units)	Combined Cycle Gas 150 MW
2019	10,909	Biomass co-fire (1 unit)		Biomass co-fire (1 unit)
2020	10,734	Biomass co-fire (2 units)	Biomass co-fire (1 unit)	
2021	10,559			
2022	10,398			
2023	10,236		Biomass co-fire (1 unit)	
2024	10,077			Biomass co-fire (1 unit)
2025	9,913			
2026	9,759			
2027	9,607			
2028	9,457			
2029	9,310			
2030	9,165	Biomass PPA (15MW)	Biomass PPA (15MW)	Biomass PPA (15MW)
2031	9,023	*(Plus transmission requirements)*	*(Plus transmission requirements)*	*(Plus transmission requirements)*
2032	8,882			
NPV 2008-32 (M$)		**10,007**	**10,342**	**10,558**
Study Period (M$) (includes End Effects)		**13,335**	**13,710**	**14,100**

Note: NSR in the table above stands for Net System Requirement. The firm wind capacity numbers noted are based on average projected on-peak winter capacity factors which are slightly higher than the annual energy capacity factors modeled.

Resource Plans - 2009 IRP Update - High Load Forecast

Year	NSR (GWh)	Plan D	Plan E	Plan F	Plan G
2010	13,002	TUC 6 (Nov) Activated CI (7 PC units) LS, Low BTU Coal Burn (Lin 1-4/Tup)	TUC 6 (Nov) Activated CI (7 PC units) LS, Low BTU Coal Burn (Lin 1-4/Tup)	TUC 6 (Nov) Activated CI (7 PC units) LS, Low BTU Coal Burn (Lin 1-4/Tup)	TUC 6 (Nov) Activated CI (7 PC units) LS, Low BTU Coal Burn (Lin 1-4/Tup)
2011	13,023	Contract Wind 308MW (100MW Firm) *(Plus transmission and load following requirements)* Marshall Hydro (4.2MW) Nictaux Hydro (2.5 MW) Biomass co-fire (4 units)	Contract Wind 308MW (100MW Firm) *(Plus transmission and load following requirements)* Marshall Hydro (4.2MW) Nictaux Hydro (2.5 MW) Biomass co-fire (4 units)	Contract Wind 308MW (100MW Firm) *(Plus transmission and load following requirements)* Marshall Hydro (4.2MW) Nictaux Hydro (2.5 MW) Biomass co-fire (4 units)	Contract Wind 308MW (100MW Firm) *(Plus transmission and load following requirements)* Marshall Hydro (4.2MW) Nictaux Hydro (2.5 MW) Biomass co-fire (4 units)
2012	13,050	Biomass co-fire (1 unit) Biomass PPA (15MW) *(Plus transmission requirements)*	Biomass co-fire (1 unit) Biomass PPA (15MW) *(Plus transmission requirements)*	Biomass co-fire (1 unit) Biomass PPA (15MW) *(Plus transmission requirements)*	Biomass co-fire (1 unit) Biomass PPA (15MW) *(Plus transmission requirements)*
2013	12,950	Coal uprate +15MW (2 units) *(Plus transmission requirements)* Wind (100MW nameplate,40MW firm) (for RES) *(Plus transmission and load following requirements)*	Coal uprate +15MW (2 units) *(Plus transmission requirements)* Wind (100MW nameplate,40MW firm) (for RES) *(Plus transmission and load following requirements)*	Coal uprate +15MW (2 units) *(Plus transmission requirements)* Wind (100MW nameplate,40MW firm) (for RES) *(Plus transmission and load following requirements)*	Coal uprate +15MW (2 units) *(Plus transmission requirements)* Wind (100MW nameplate,40MW firm) (for RES) *(Plus transmission and load following requirements)*
2014	12,875	Biomass co-fire (1 unit)	Biomass co-fire (1 unit)	Biomass co-fire (1 unit)	Biomass co-fire (1 unit)
2015	12,784				
2016	12,671	Wind (100MW nameplate, 40MW firm) *(Plus transmission and load following requirements)*	Wind (100MW nameplate, 40MW firm) *(Plus transmission and load following requirements)*	Wind (100MW nameplate, 40MW firm) *(Plus transmission and load following requirements)*	Wind (100MW nameplate, 40MW firm) *(Plus transmission and load following requirements)*
2017	12,559	Biomass co-fire (2 units)	Biomass co-fire (2 units)	Biomass co-fire (2 units)	Biomass co-fire (2 units)
2018	12,457	CCS Retro-fit (1 unit) Baghouses (3 units)	Wind (100MW nameplate, 40MW firm) *(Plus transmission and load following requirements)* FGD (2 units) Baghouses (2 units)	Large PPA (300 MW) *(Plus transmission requirements)* FGD (2 units) Baghouse (1 unit)	Combined Cycle Gas (280MW) *(Plus transmission requirements)* FGD (2 units) Baghouses (2 units)
2019	12,354		Wind (100MW nameplate, 40MW firm) *(Plus transmission and load following requirements)*		2 x Wind (100MW nameplate,40MW firm) *(Plus transmission and load following requirements)*
2020	12,238				Biomass PPA (60MW) *(Plus transmission requirements)*
2021	12,121		Biomass PPA (60MW) *(Plus transmission requirements)*		
2022	12,018		Wind (100MW nameplate, 40MW firm) *(Plus transmission and load following requirements)*		
2023	11,917	CCS Retro-fit (1 unit)			
2024	11,821				
2025	11,724		Wind (100MW nameplate, 40MW firm) *(Plus transmission and load following requirements)*		
2026	11,631				
2027	11,544				
2028	11,460				
2029	11,381				
2030	11,305	CCS Retro-fit (1 unit)			
2031	11,234		Offshore Wind (100MW nameplate, 50MW firm) *(Plus transmission and load following requirements)*	Biomass PPA (60MW) *(Plus transmission requirements)*	
2032	11,165				
NPV 2008-32 (M$)		**11,828**	**12,050**	**12,150**	**12,253**
Study Period (M$) (includes End Effects)		**16,296**	**16,703**	**17,068**	**17,188**

Note: NSR in the table above stands for Net System Requirement. The firm wind capacity numbers noted are based on average projected on-peak winter capacity factors which are slightly higher than the annual energy capacity factors modeled.

Resource Plans - 2009 IRP Update - Kyoto Case

Year	NSR (GWh)	Plan H CCS	Plan I Renewables/Gas Combo	Plan J Mostly Gas	Plan K Large PPA
2010	12,398	TUC 6 (Nov) Activated CI (7 PC units) LS, Low BTU Coal Burn (Lin 1-4/Tup)	TUC 6 (Nov) Activated CI (7 PC units) LS, Low BTU Coal Burn (Lin 1-4/Tup)	TUC 6 (Nov) Activated CI (7 PC units) LS, Low BTU Coal Burn (Lin 1-4/Tup)	TUC 6 (Nov) Activated CI (7 PC units) LS, Low BTU Coal Burn (Lin 1-4/Tup)
2011	12,320	Contract Wind 308MW (100MW Firm) *(Plus transmission and load following requirements)* Marshall Hydro (4.2MW) Nictaux Hydro (2.5 MW)	Contract Wind 308MW (100MW Firm) *(Plus transmission and load following requirements)* Marshall Hydro (4.2MW) Nictaux Hydro (2.5 MW)	Contract Wind 308MW (100MW Firm) *(Plus transmission and load following requirements)* Marshall Hydro (4.2MW) Nictaux Hydro (2.5 MW)	Contract Wind 308MW (100MW Firm) *(Plus transmission and load following requirements)* Marshall Hydro (4.2MW) Nictaux Hydro (2.5 MW)
2012	12,225	Biomass co-fire (4 units)	Biomass co-fire (4 units)	Biomass co-fire (3 units)	Biomass co-fire (4 units)
2013	12,016	Coal uprate +15MW (2 units) *(Plus transmission requirements)* Wind (100MW nameplate,40MW firm) (for RES) *(Plus transmission and load following requirements)*	Coal uprate +15MW (2 units) *(Plus transmission requirements)* Wind (100MW nameplate,40MW firm) (for RES) *(Plus transmission and load following requirements)*	Coal uprate +15MW (1 unit) *(Plus transmission requirements)* Wind (100MW nameplate,40MW firm) (for RES) *(Plus transmission and load following requirements)*	Coal uprate +15MW (2 units) *(Plus transmission requirements)* Wind (100MW nameplate,40MW firm) (for RES) *(Plus transmission and load following requirements)*
2014	11,837				
2015	11,651				
2016	11,449		Wind (100MW nameplate, 40MW firm) *(Plus transmission and load following requirements)*		Wind (100MW nameplate, 40MW firm) *(Plus transmission and load following requirements)*
2017	11,256	Biomass PPA (15MW) *(Plus transmission requirements)*	Wind (100MW nameplate, 40MW firm) *(Plus transmission and load following requirements)* Biomass PPA (15MW) *(Plus transmission requirements)* Biomass PPA (60MW) *(Plus transmission requirements)*		
2018	11,079	Biomass co-fire (4 units) CCS retro-fit -3 units Baghouses (2 units)	Biomass co-fire (4 units) Wind (100MW nameplate, 40MW firm) *(Plus transmission and load following requirements)* Combined Cycle Gas (280MW) *(Plus transmission requirements)*	Combined Cycle Gas (2 x 280MW) *(Plus transmission requirements)*	Biomass co-fire (4 units) Biomass PPA (15MW) *(Plus transmission requirements)* Large non-emitting PPA (300 MW) *(Plus transmission requirements)*
2019	10,909			Wind (100MW nameplate, 40MW firm) *(Plus transmission and load following requirements)*	
2020	10,734				
2021	10,559				
2022	10,398				
2023	10,236				
2024	10,077				
2025	9,913				
2026	9,759				
2027	9,607				
2028	9,457				
2029	9,310				
2030	9,165				
2031	9,023				
2032	8,882				
NPV 2008-32 (M$)		**11,135**	**11,996**	**12,401**	**11,754**
Study Period (M$) (includes End Effects)		**14,665**	**16,034**	**16,902**	**15,879**

Note: NSR in the table above stands for Net System Requirement. The firm wind capacity numbers noted are based on average projected on-peak winter capacity factors which are slightly higher than the annual energy capacity factors modeled.

The net present worth of the cost of each plan is provided in the following table.

NPV of Costs – All Plans

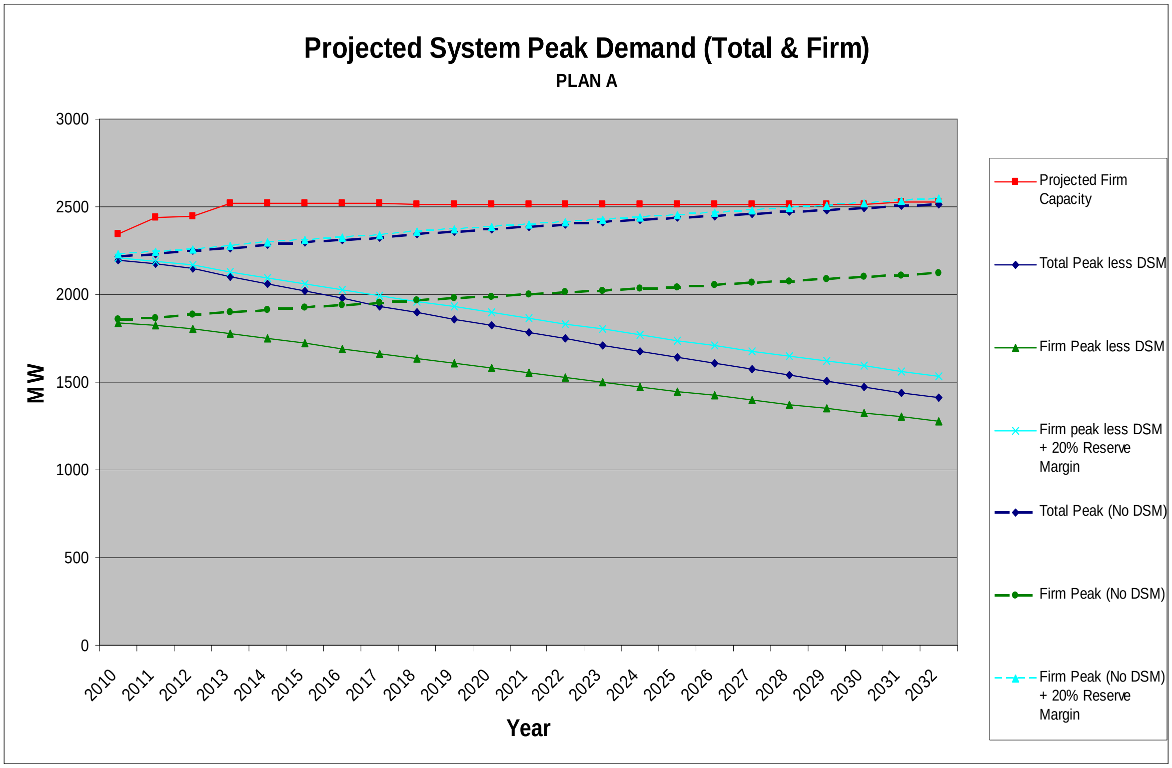
PLAN	NPV 2008-2032 (M$)	Study Period (M$) (includes End Effects)	% Increase Compared to Plan A (NPV 2008-2032)	% Increase Compared to Plan A (Study Period)	% Increase Compared to Least Cost Plan in Set (NPV 2008-2032)	% Increase Compared to Least Cost Plan in Set (Study Period)
PLAN A (Base Case/Load) Renewables Combo	$10,007	$13,335	-	-	-	-
PLAN B (Base Case/ Load) More Wind	$10,342	$13,710	3%	3%	-	-
PLAN C (Base Case/Load) More Gas	$10,558	$14,100	6%	6%	-	-
PLAN D (High Load World) CCS	$11,828	$16,296	-	-	(Compared to Plan D)	(Compared to Plan D)
PLAN E (High Load World) Renewables Combo	$12,050	$16,703	-	-	2%	2%
PLAN F (High Load World) Large Non-Emitting Import PPA	$12,150	$17,068	-	-	3%	5%
PLAN G (High Load World) More Gas	$12,253	$17,188	-	-	4%	5%
PLAN H (Kyoto World/Base Load) CCS	$11,135	$14,665	11%	10%	(Compared to Plan H)	(Compared to Plan H)
PLAN I (Kyoto World/Base Load) Renewables Combo	$11,996	$16,034	20%	20%	8%	9%
PLAN J (Kyoto World/Base Load) Renewables Combo More Gas	$12,401	$16,902	24%	27%	11%	15%
PLAN K (Kyoto World/Base Load) Large Non-Emitting Import PPA	$11,754	$15,879	17%	19%	6%	8%

Notes: In 2008 dollars with weighted average cost of capital of 6.81% after tax, as per the Basic Assumptions.
Costs include utility (operating and capital related) plus the customer cost of DSM.

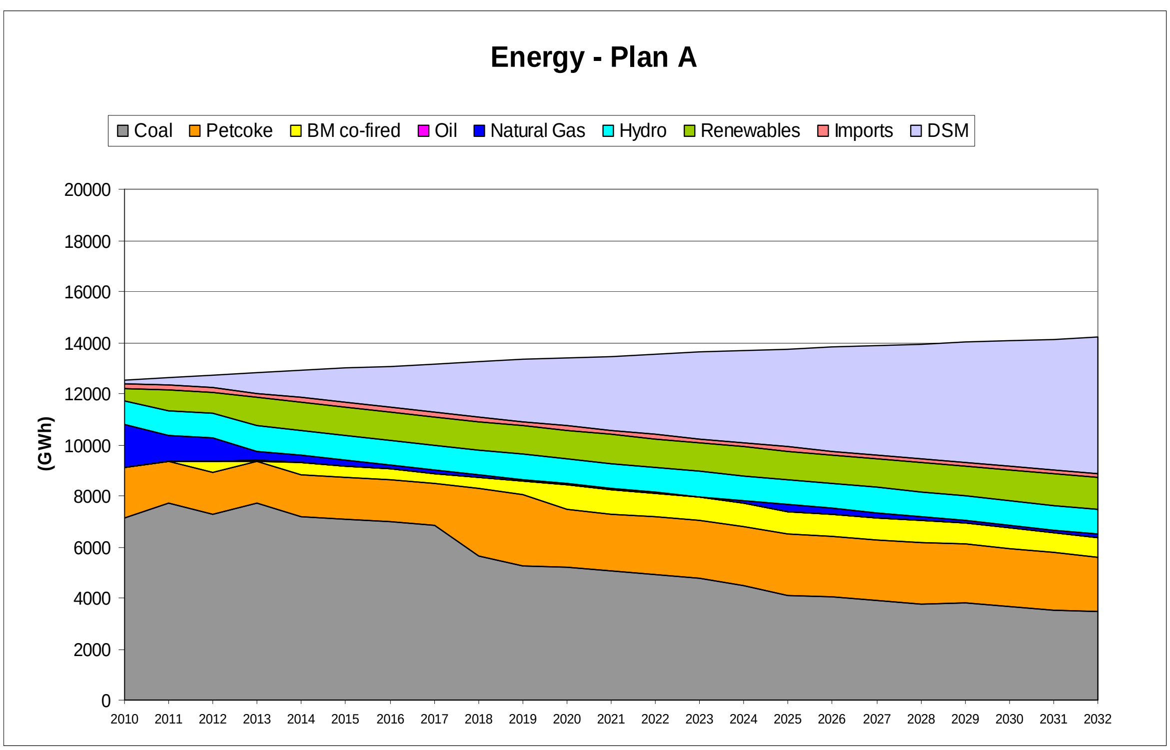
The range of costs among the plans is highlighted above. The plan differences in relation to the least cost plan in each set is provided for reference (Plan A for Base Load, Plan D for High Load and Plan H for Kyoto).

Consistent with the modeling assumptions, planning reserve margins (including interruptible load) are maintained throughout the planning period.

Investments required in the plans are being driven primarily by RES and emissions constraints rather than the traditional driver of having adequate capacity to meet peak demand. The graph below summarizes forecasted installed capacity and firm and total demand over the planning period.



The resource portfolio for the lowest cost plan, Plan A, is presented below.



The above graph reflects the following highlights about Plan A:

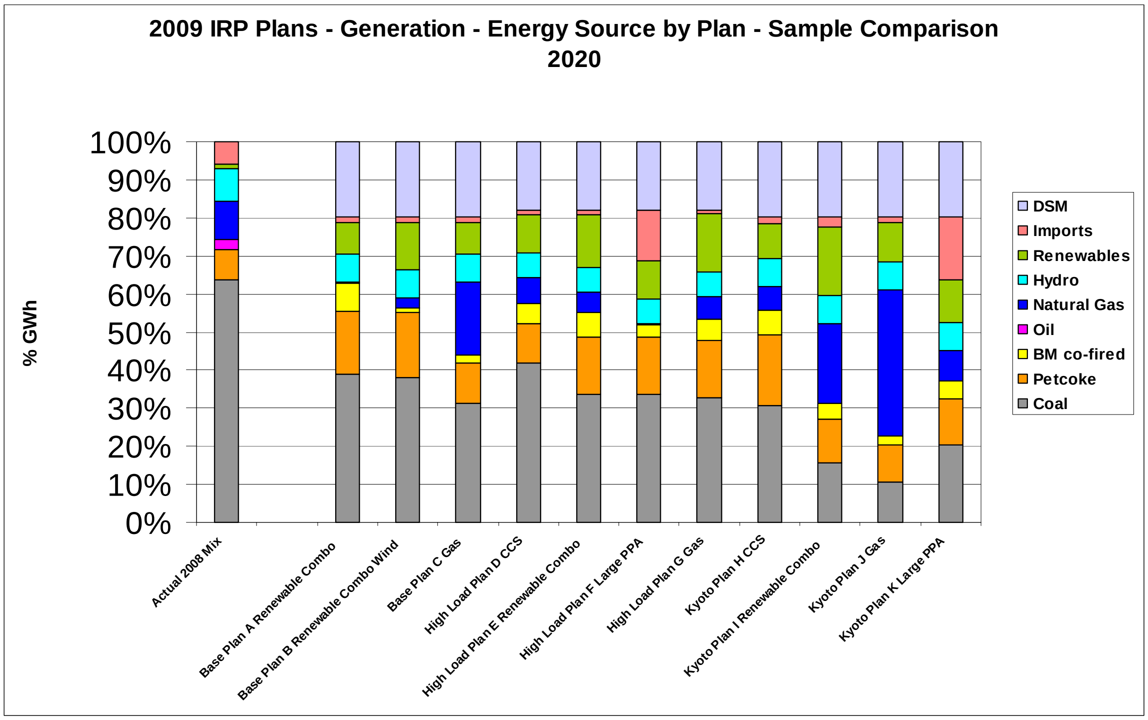
- Wind (308 MW nameplate, 100 MW firm) in 2011
- Wind (100 MW nameplate, 40 MW firm) in 2013 to meet RES 2013
- Biomass co-fired at 8 coal units phased in 2012 to 2020
- Biomass PPA (15 MW) in 2030
- Environmental equipment investments (baghouses and FGD/scrubber) required in 2018 to meet Hg/SO_2 reductions
- Upgrades to NSPI existing facilities

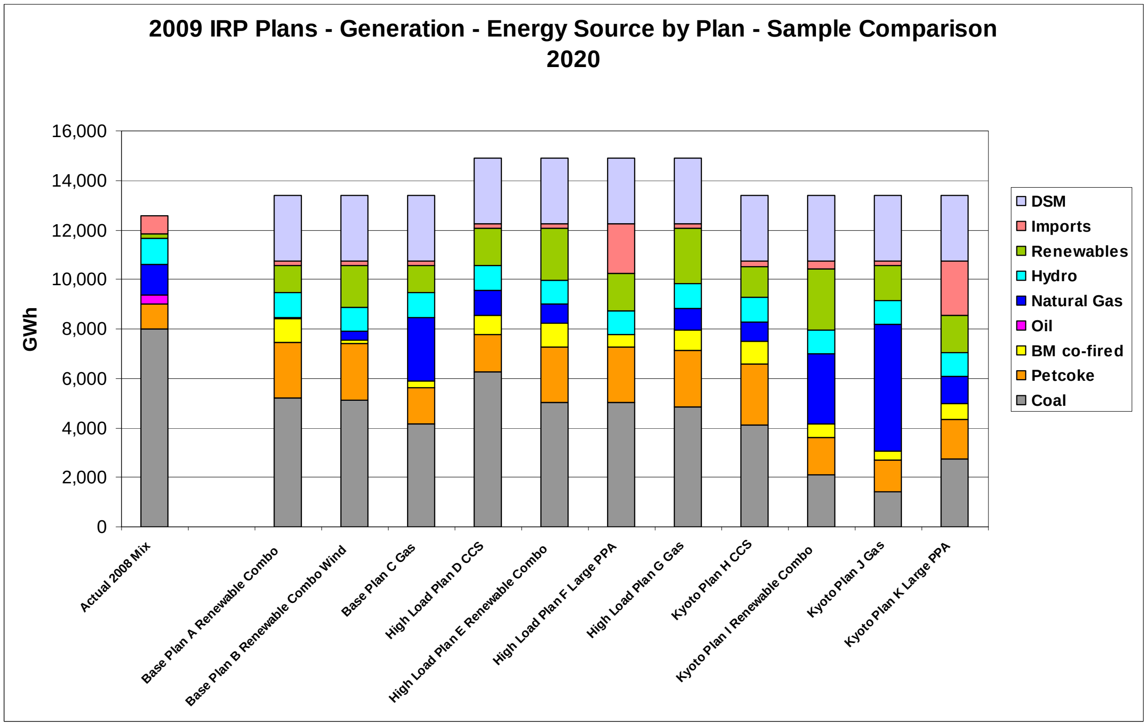
As the least-cost Base Load plan, Plan A has been selected as the Reference Plan, although other plans are similar to it. An IRP priority for the Company is to maintain planning flexibility. For this reason, plans such as Plan B in the Base Load World, and Plan E in the High Load World provide insight for the Company in considering the various drivers that will affect decision making over the planning period. In particular, should load grow faster than anticipated or co-benefits (that is, operating flexibility or RES compliance margin) be identified, the alternative resource plans could become the preferred plans or elements of these plans could be required. For example, it may be economic to pursue the Nictaux Falls hydro uprate which is not called for in Plan A, but which appears in the High Load World and is a relatively small capital investment. Gas generation, which is not independently selected in Plan A as stand-alone economic energy, becomes more economic when considered in combination with its load following (wind integration) capability. These are important considerations in maintaining a flexible ‘no regrets’ strategy.

Within Worlds, up until approximately 2018, the results do not vary substantially across the plans. Existing coal and pet-coke fired generating stations continue to provide base loaded generation. Renewables and DSM are also established as major components, driven by emissions constraints and project economics. After 2018, there is more divergence among plans with respect to resource options.

The commonality across plans in the near term is logical given the stricter emissions related requirements. Further analysis and study is required for the second planning decade. However, given that new generation sources have long lead times to plan, permit, and construct, decisions may have to be made over the next 3-6 years.

For comparison purposes, the energy mix for the other plans is provided below and shown as percent of GWh and total GWh respectively (2008 versus 2020 as comparison year). The reduction in coal fired generation reflects the shift to DSM, renewables and/or natural gas-fired generation, and highlights the importance of flexibility in planning.

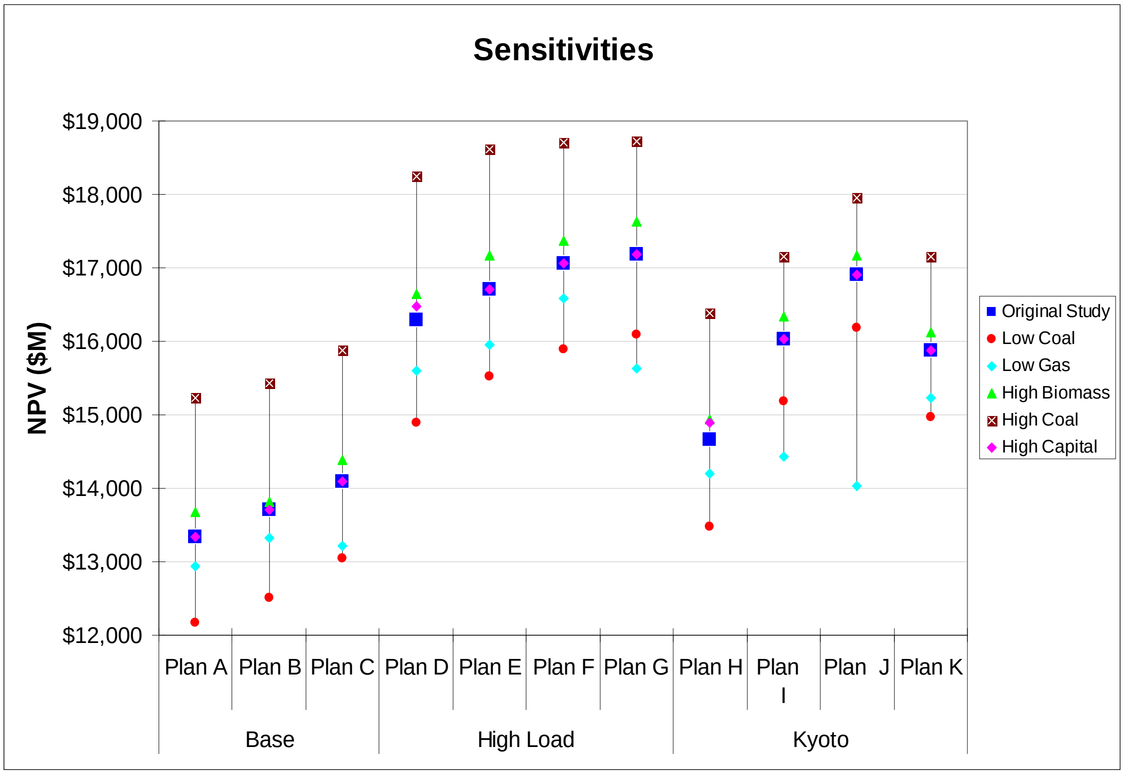




Sensitivity Analysis

The base assumptions analysis shows that Plan A is the least cost plan. In order to assess the robustness of the plan, Plan A and the other resource plans were assessed against changes to key assumptions.

The results across sensitivities for the resource plans are presented in the chart below.



The Sensitivity analysis provides the following insights:

- Change in coal prices did not change plans' rank orders.

- The low gas price was the only sensitivity run that resulted in a rank order change among certain plans. The plans which utilize more natural gas move closer to the lowest cost plan in the Base and High Load Worlds, and become the lowest cost plan in the Kyoto World.

- The high biomass price did not result in any changes in the plans' rank orders.

- The high Carbon Capture and Storage capital cost was only relevant in two plans within the High Load and Kyoto Worlds. There was no change in rank order as a result of this sensitivity run.

These insights indicate that the plans are robust. With respect to Plan A, the Sensitivity analysis reinforces the conclusions presented under the base assumptions. The marked effect of low gas prices highlights the need to monitor gas prices in relation to other key parameters, and to maintain a flexible approach as those relationships change.

Additional Analysis – Comment on a Lower Load World

The intent of the 2009 IRP Update was to reconsider NSPI's options and risks for meeting evolving emissions and RES requirements, taking into account developments over the past two years. As a result, Base Load and High Load optimizations were of primary focus.

A lower load optimization would indicate which resources might be avoided if load is lower. Fewer (or later installation of) supply-side resources would be required to meet energy demand and hence environmental constraints. If, for example, the load were significantly lower than the base load forecast, the level of investment required to precisely meet legislated targets would be less. To the extent that the resources called for in the early years of NSPI's IRP planning period are incremental (that is, there is no single large scale investment called for), this would be monitored and commented upon when approval for a specific level of investment is sought.

It is important to note, nonetheless, that if load materializes higher or actual renewable energy production is lower than forecast assumptions, the risk of non-compliance with renewable and environmental laws and the inability to serve load bear greater consequences than the risk associated with "over compliance" or "over building".

4.0 IMPLICATIONS FOR NSPI RESOURCE PLANNING

The 2009 IRP Update analysis supports Plan A as the Reference Plan because it was the least cost plan using base assumptions and it retained its least cost ranking under sensitivity testing.

The near term commonality across plans is to be expected. There are few options to address increasingly stringent emissions limits. As a result, all plans over the first decade have a significant renewables component and DSM investment. Over the second decade, DSM and renewables continue to compare favorably with other resource options.

Near term initiatives will focus on maintaining reliable and cost-effective service while meeting emissions constraints and renewable requirements, and monitoring DSM results and cost effectiveness. Over the longer term, more information will need to be gathered with respect to:

- load growth
- the impact of DSM and renewables on the system
- the timing and cost of transmission upgrades (depending on resources selected)
- the sustainability of biomass
- fuel prices and the value of flexibility
- the outlook for environmental regulation and legislation
- import energy opportunities
- the economic and technological feasibility of emerging technologies such as Tidal, Compressed Air Energy Storage and Carbon Capture and Storage.

Considerations for Planning for the First Decade

DSM

NSPI will support pursuit of DSM in the context of alignment with the IRP trajectory and Board approved plans through targeted program implementation with appropriate measurement and verification until the establishment and transition to the new DSM Administrator, Efficiency Nova Scotia Corporation. Following Efficiency Nova Scotia Corporation becoming operational, NSPI will continue to support the success of DSM programming in the context of IRP targets. The new DSM Administrator is expected to be operational in time to present the 2012 DSM Plan by February 2011. Success in DSM is critical to NSPI's Reference Plan and therefore will require ongoing assessment and monitoring to ensure that it is sustainable both economically and in terms of energy savings. This assessment will be ongoing over the near term and long term.

In addition to programs run by the Administrator, a number of other sources may contribute to the energy savings modeled in the IRP, including consumer behaviour, energy efficiency codes and standards and investments by other agencies and/or NSPI. The DSM benefits of NSPI's proposed Automated Metering Infrastructure (AMI) project for example, if approved by the Board, would contribute to the achievement of the potential that exists in Nova Scotia.

To better integrate and manage DSM, NSPI is upgrading its load forecasting model. Consistent with the Board's February 25, 2009 request, NSPI has recently applied to the Board for approval to enhance its end-use forecasting capability. The initiative includes software acquisition, set-up and training, as well as conducting customer surveys to gather Nova Scotia specific end-use data for the residential and commercial sectors. Over time it is expected the software will be incorporated within the Company's load forecasting methodology for the residential sector and then the commercial sector. In addition to providing enhanced forecasting capability, the model will provide a useful tool for monitoring ongoing DSM programs and guiding DSM program offerings.

As time progresses, updates will be made to the remaining achievable potential of DSM, and future DSM program investment levels and program designs will take this into account.

Renewables Integration

Biomass as a renewable fuel resource in Nova Scotia creates options in several generation formats. A biomass PPA and biomass co-firing require further study and investigation relative to sustainability and supply in Nova Scotia. Biomass will only be pursued through sustainable harvesting methods.

Additional Usage of Natural Gas

The parameter that has the potential to change the rank order among the plans is natural gas prices. NSPI will continue to examine the relationship of that parameter to others, and to monitor the behavior of gas prices in relation to the values of other parameters.

Other Considerations

There are areas that required further consideration following the 2007 IRP and will remain areas requiring attention following the 2009 IRP Update. As wind generation increases in volume, its impact on the transmission system will continue to require investigation. Back-up and Load Following is a required component of the wind generation for all plans. How that requirement will be met is not a part of the IRP modeling process although options could include fast-acting generation and added transmission interconnection to load following resources. Examples of fast-acting generation include hydro, natural gas, and air compression/ storage. Load control technology may also provide fast-acting load following capability as well as bring benefits in terms of demand savings.

Similarly, as new generation is built, different locations may have varying transmission cost implications. In addition to existing transmission outlook planning and reporting processes (for example, the annual 10 Year System Outlook submitted to the UARB), further engagement with the Board is anticipated on this matter, as is referenced in the Action Plan.

Considerations for Planning over the Second Decade

For the larger scale commitment(s) called for around 2018 in all plans, NSPI will continue to actively monitor import alternatives as well as other technology developments to capitalize on the economic and technologically feasible options to meet the next period's requirements. An in-stream tidal pilot project is underway, which could have long-term potential in terms of becoming an economic, larger-scale, renewable resource. NSPI personnel participate on Carbon Capture and Storage technical committees, are directly involved with CCS Nova Scotia and track the findings of various CCS pilot projects around the world. Opportunities for a large import power purchase will be reviewed in conjunction with neighbouring utilities and/or government plans for large-scale non emitting projects; for instance, understanding the potential timing and opportunity of the proposed Lower Churchill Falls project. While these resources are relevant to the latter phase of the planning period and commitments are not yet required, their long lead times support the work that is currently underway.

5.0 ACTION PLAN

The Analysis Results have identified considerations for demand and supply side planning for the near term (over the first decade) and for the longer term (over the second decade), as noted in Section 4.0 above. An Action Plan has been prepared to guide and inform planning over the near and long term. The Action Plan is expressed in three parts:

Part I – Focus on pre-2013 requirements.
Part II – Focus on post-2018 requirements.
Part III – Administrative/reporting actions.

Parts I and II are not segregated according to priority or chronology. Items in Part I are action items that address near term requirements. Items in Part II, although not required for near term planning, will require assessment in the near term because of lengthy study requirements or lead times for construction; for instance, the tidal pilot project which is underway. Where possible, NSPI has approximated time frames for the actions listed below. As time progresses, certain actions may require revision or may no longer be considered relevant. For this reason, the reporting obligations are set out in Part III to permit updating of the Action Plan where appropriate.

The steps of the IRP Action Plan are**:**

Part I

<u>Continue to develop the resources identified in the 2009 IRP Update plan pre 2013</u>

- Support pursuit of DSM consistent with the IRP trajectory and Board approved plans as interim Administrator until the new DSM Administrator, Efficiency Nova Scotia Corporation, is operational, which is expected to occur by February 2011 in time for the proposal of the 2012 DSM programming plan.

- Following establishment of Efficiency Nova Scotia Corporation, develop Terms of Reference for a collaborative working group that includes Efficiency Nova Scotia Corporation, NSPI and UARB staff and consultants to support efficient transition to the new Administrator and pursuit of DSM investments consistent with the IRP and Board approved plans. This group could consider matters such as:

    - Regulatory oversight of the new DSM Administrator by the UARB
    - Alignment of DSM to IRP trajectory
    - Integration of end-use modeling
    - Integration of AMI, if appropriate
    - Transition of programs, including measurement, evaluation and verification

  The Company anticipates this effort would be commenced during 2010.

- Continue to pursue wind generation opportunities including applicable backup/load following strategies and transmission upgrades, such as a second 345 kV intertie to New Brunswick. The Company anticipates that these ongoing pursuits will continue over the next several years.

- Provide a confidential technical briefing on the transmission system and transmission planning to Board staff and consultants during Q1 of 2010.

- Engage Board staff in advance of significant transmission-related capital applications.

- Participate with other stakeholders to assist in the evaluation of biomass supply and sustainability, and evaluation of technical constraints by government. The Company anticipates that this ongoing work will continue in 2010.

- Monitor the progress of the biomass mapping exercise (commissioned with the Nova Scotia Community College), to conduct a physical assessment (employing remote sensing, laser, and radar technology) and document the Nova Scotian biophysical landscape and resource level. The Company anticipates that this ongoing work will continue in 2010.

- Conduct an in-depth analysis of the biomass market in Nova Scotia, including an assessment of NSPI's effect on that market. (NSPI has recently awarded a contract to Gardner Pinfold with report expected in 2010.)

- Evaluate NSPI biomass co-firing (coal unit retrofit) opportunities. Continue with technical assessments (for example, test-burns, specification/costing of potential equipment retrofits, other design implications) to determine the feasibility of co-firing biomass. The Company anticipates that these ongoing pursuits will continue in 2010.

- Engage Department of Energy and Department of Environment to ensure appropriate test programs are established for verification of continued compliance with operating permit(s) for co-fired unit(s). The Company expects engagement to continue in 2010.

- Consider the recommendations arising out of the Nova Scotia government-led stakeholder process "N.S. Renewable Energy Consultations" (re: evolving renewable energy targets) and their effect on planning, if any. A Report is anticipated to be completed by Dr. David Wheeler in December 2009.

- Explore the implications of continued low natural gas prices for preferred resource plans.

- Pursue NSPI facility upgrades, including:
    - Precipitator upgrades to enable low sulphur, low-btu coal burning (Anticipated in 2010, 2011)
    - Marshall Falls Hydro (Anticipated in 2010, 2011)
    - Nictaux Hydro (To Be Determined)
    - Lingan Efficiency Uprate (To Be Determined)

Part II

<u>Prepare for post 2018 requirements</u>

- Execute tidal pilot project. Project has commenced and study will be ongoing.

- Actively monitor and participate in technology developments such as Carbon Capture and Storage. This work has commenced and will continue.

- Examine opportunities for large non-emitting PPA including associated transmission upgrades, such as opportunities with respect to the Lower Churchill Falls project and/or large-scale imports from New Brunswick.

- Evaluate the need for environmental retrofits to meet 2018 requirements.

- Incorporate pre-2013 results.

Part III

Report on progress

- As the Action Plan proceeds NSPI will provide the Board and interested parties with an annual report on the progress of the Action Plan. So as to incorporate year-end results, a report to the Board and interested parties on the status of the items listed in the Action Plan would be made by the end of Q1, on an annual basis commencing in 2011. Given that a number of items listed in the Action Plan call for activity in 2010, in addition to the annual reports to be filed by the end of Q1 each year starting in 2011, there will be an initial progress report filed in August of 2010. These progress reports will address each of the bulleted items listed in Parts I and II individually, describing what has been accomplished since the last report and cumulatively since the 2009 IRP Update. Looking ahead, they will indicate next steps to be undertaken and the associated timeline where applicable.

- In Q2 2012, consider, in conjunction with Board staff and interested parties, whether changing conditions would require an updated IRP.

6.0 CONCLUDING REMARKS

The 2009 IRP Update objectives have been met. The 2007 IRP has been updated to refresh the 2007 assumptions, account for new resources, and meet new environmental regulations. The 2009 IRP Update findings are directionally consistent with the 2007 findings, with some new resource options available under the low-cost plans.

The three key conclusions that emerged from the 2007 IRP process were:

1. Investment in demand-side management and renewable generation can provide savings to customers, though their long-term potential requires careful exploration and study.

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

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

Having completed the 2009 IRP Update, it is clear that these conclusions continue to apply. The 2009 IRP Update results confirm the key conclusions from the 2007 IRP process described above. The flexible, ‘no regrets’ strategy established in 2007 has been shown to be appropriate and will continue to be pursued as NSPI proceeds with its generation planning over the next decade.

NSPI Integrated Resource Plan
2009 Update

TERMS of REFERENCE

Objective

To update Nova Scotia Power's 2007 Integrated Resource Plan based on current conditions and assumptions. The update should be meaningful, efficient and timely as per the UARB's order.

Approach

In updating the IRP NSPI will:

1. Work jointly with Dr. Stutz and UARB staff and consultants;
2. Apply the 2007 IRP development framework;
3. Update assumptions, where needed, to reflect developments since 2007;
4. Consult with stakeholders;
5. Utilize publicly 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; and
6. Seek UARB approval for a temporary exemption from the application of OATT Standards of Conduct to permit limited sharing of non-public information between transmission function employees and other NSPI employees engaged in the IRP update process.

Scope

The IRP update will utilize a 25-year Planning Horizon.

Primary steps of the Integrated Resource Plan update are:

1. Review, and if appropriate, update the criteria for evaluation of the various plans.
2. Update :
   - The emissions constraint assumptions to reflect current activity
   - The supply-side alternatives to reflect recent developments and focus on technologies expected to be commercially available before 2020
   - The demand-side management assumptions to reflect NSPI experience since 2007
   - The load forecast and fuel forecast using methodologies employed in the 2007 IRP
   - The financial assumptions
3. Develop and 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 including DSM Total Resource Cost (TRC) and adjusted for end effects.
4. Perform analysis to test the robustness of the alternative resources plans.
5. Identify actions required over the next 3 to 5 years to meet load projections as well as regulatory and environmental requirements.
6. File the IRP Update Report with the UARB.

Stakeholder input will be sought with respect to:

- The OATT Standards of Conduct temporary exemption
- The model assumptions and plans
- The selection of a final IRP Reference Plan
- The IRP Update Report

IRP Process Timeline Summary

	Due No Later Than
1. Notice of Intention to Participate by Interested Parties	March 30
2. Stakeholder session to discuss the process for IRP update, review of approved Terms of Reference, and OATT Standards of Conduct temporary exemption	April 2
3. Feedback from stakeholders on OATT Standards of Conduct temporary exemption	April 6
4. Basic assumptions and plan themes issued to stakeholders	May 7
5. Technical Conference to discuss basic assumptions and plan themes	May 14
6. Stakeholder input on assumptions and plan themes	May 21
7. Final consolidated assumptions and plan themes issued	June 11
8. Preview of base scenarios for alternative plans and sensitivities communicated to stakeholders	June 29
9. Analysis results issued to stakeholders	September 1
10. Technical Conference to discuss analysis results	September 9
11. Stakeholder input on analysis results	September 16
12. Draft report provided to stakeholders for comment	October 8
13. Stakeholder comment on draft report	October 15
14. Final report filed with UARB	November 13

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August 14, 2009

Nancy McNeil
Clerk of the Board
Nova Scotia Utility and Review Board
1601 Lower Water Street, 3rd Floor
PO Box 1692, Unit "M"
Halifax, NS B3J 3S3

Re: Integrated Resource Plan (IRP) - P-884

Dear Ms. McNeil:

NSPI has been working jointly with Board staff and consultants and in consultation with stakeholders to update the 2007 IRP. Final basic assumptions were issued to stakeholders on June 11 and Base scenarios for alternative plans and sensitivities/worlds were identified on June 29, both as contemplated by the Terms of Reference.

Though the modelling work has been progressing well, the complexity of the effort and the need for careful review at all stages has led NSPI and the Board consultants to conclude that a schedule revision is required to meet the remaining milestones of the Terms of Reference. In order to accommodate the remaining work, the Terms of Reference timeline requires an extension of the date for filing the final report with the UARB from November 13 to November 30. The revised schedule has the support of Dr. Stutz and the other Board consultants. As such, NSPI requests that the Board approve the revised IRP Process Timeline as proposed.

A copy of the revised proposed IRP Process Timeline Summary is attached, and is provided to all IRP stakeholders by copy of this letter. Any questions the Board may have can be directed to the undersigned.

Yours truly,

Nicole Godbout
Regulatory Counsel

Attach.

c: All Parties

IRP Process Timeline Summary

	Original Date	Revised Date
1. Notice of Intention to Participate by Interested Parties	March 30	
2. Stakeholder session to discuss process for IRP update, review of approved Terms of Reference and OATT Standards of Conduct temporary exemption	March 31	
3. Feedback from stakeholders on OATT Standards of Conduct temporary exemption	April 6	
4. Basic assumptions and plan themes issued to stakeholders	May 7	
5. Technical Conference to discuss basic assumptions and plan themes	May 14	
6. Stakeholder input on assumptions and plan themes	May 21	
7. Final consolidated assumptions and plan themes issued	June 11	
8. Preview of base scenarios for alternative plans and sensitivities communicated to stakeholders	June 29	
9. Analysis results issued to stakeholders	September 1	September 22
10. Technical Conference to discuss analysis results	September 9	September 30
11. Stakeholder input on analysis results	September 16	October 8
12. Draft report provided to stakeholders for comment	October 8	October 29
13. Stakeholder comment on draft report	October 15	November 6
14. Final report filed with UARB	November 13	November 30

STATEMENT CONCERNING IRP UPDATE DEVELOPMENT, RESULTS AND RECOMMENDATIONS

Prepared by John Stutz
with input from UARB
Consultants and Staff

November 17, 2009

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—inclusion of demand- as well as supply-side resources, and consideration of a wide range of possibilities to address uncertainty. An IRP effort leads to the identification of a **Reference Plan** which describes the utility's strategy for meeting its resource needs over the planning period. Based on the IRP results, a short-run **Action Plan** sets tasks to be addressed between the completion of the IRP and its subsequent review and modification.

The IRP Update prepared by NSPI was governed by Terms of Reference (TOR) provided by the UARB. The TOR called for NSPI to work jointly with UARB Staff and Consultants and to consult with interested parties. A team of consultants led by Dr. John Stutz and assisted by Mr. Steve Pronko of Board Staff participated fully in the development of the Update. Interested parties were provided with NSPI's assumptions and plans for scenario analysis, modeling results, and draft report. Input was received during Technical Conferences and in written comments. Through this collaboration and consultation, the process requirements in the TOR were met.

The analysis performed for the IRP Update took into account three different views of the future. In addition to a Base Case the Update included a High Load Case and a Kyoto Case with tighter limits on CO_2 emissions. For each case a range of plans which met load and satisfied environmental constraints were developed. Sensitivity analyses were performed to see how the Net Present Value (NPV) of required revenues associated with the plans changed when fuel prices and capital costs were varied.

Plan A, the Reference Plan which emerged from the IRP Update, established a clear strategy for meeting the Company's future resource needs. The strategy calls for significant investment in DSM programs and new renewable generation as well as upgrades to NSPI's existing generation fleet. As NSPI noted in its report, the results from other plans, particularly B and E, support this strategy. The strategy is broadly the same as that identified in the 2007 IRP Report. The UARB Consultants support adoption of this strategy for meeting NSPI's future resource needs.

When considering the strategy developed in the Update there are a number of points which merit careful consideration:

- In the plans considered in the Update, DSM provided 80 percent of incremental resources in the Reference Plan and 50 percent or more in the others. In Nova Scotia experience in the development and implementation of DSM is still limited. Experience working with an independent DSM administrator to meet IRP objectives is non-existent.

- The renewable resources considered in Plans A, B, and E consist in large part of biomass co-firing and wind. The extent to which biomass can and should be utilized for electric generation is an open issue. There is limited experience with co-firing. Wind is a better-established technical option. However, because of its intermittent nature, the integration of large amounts of wind generation into a utility system creates challenges.

- As the introduction of "hard caps" for CO_2 emissions indicates, the environmental constraints under which NSPI needs to plan are subject to change. Meeting tighter constraints, such as those considered in the Kyoto case, could lead to the adoption of a new technology, Carbon Capture and Storage (CCS) at the coal units.

In response to these points and others NSPI has developed an Action Plan which identifies issues/areas to be addressed and activities to be undertaken. A rough indication of timing is also provided.

The UARB Consultants see the Action Plan proposed by NSPI as a continuation of the work begun in the IRP Update. This view is consistent with NSPI's comments in the final paragraph of the Executive Summary in its report:

> The IRP Update is a planning exercise. The Update provides strategic direction, rather than prescriptive solutions. Tactics presented in the Action Plan, including pursuit of increased investment in DSM and investment in utility assets, require formal application to the UARB, and subsequent UARB approval before implementation.

As this portion of NSPI's report indicates, the IRP establishes the strategy within which the tactical objectives addressed in the Action Plan are situated. As in the past, major capital expenditures will be individually submitted for Board approval, and will be addressed on their technical and economic merits. The activities covered by the Action Plan will provide an important part of the context within which formal applications by NSPI are evaluated.

In light of its important role, timely and thorough reporting on the Action Plan is essential. The reporting proposed in Part III of NSPI's Action Plan meets that need. The UARB Consultants support the Action Plan proposed by NSPI. The Consultants suggest that the Board direct NSPI to follow the plan, addressing all the issues/areas listed in Parts I and II and reporting as discussed in part III.

Integrated Resource Plan (IRP) Update - 2009

	Company	Participant	Email
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2009 IRP Update

Final Basic Assumptions

June 11, 2009

REDACTED

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IRP Update
Table of Contents

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IRP Update Overview

What is an IRP?

An Integrated Resource Plan (IRP) assesses various supply and demand scenarios to determine the best ways for NSPI to meet future requirements (including emission standards) in a cost-effective and reliable manner, while maintaining a minimum 20% capacity reserve margin above firm loads.

Background on 2007 IRP

NSPI conducted an IRP in 2007 which analyzed long-term supply and demand of electricity. The IRP produced near term plans that are economic and reliable, and reflected environmental and other requirements. The IRP was a collaborative planning process conducted by NSPI and staff and consultants of the UARB, in consultation with stakeholders. The IRP called for more renewable energy and a strong emphasis on energy conservation.

The 2007 IRP established three areas of focus:

- Increase Energy Efficiency and Conservation programs
- Add Renewable Energy sources
- Maintain existing generation fleet

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Why do an IRP Update in 2009?

NSPI has faced many changes since 2007:

- New government regulations relating to environmental performance
- Significant change in world financial markets
- Continued evolution of the company's approach to power production, as described below

NSPI is actively working to incorporate renewable energy into its generating mix, including 246 MW of wind power currently under contract and being constructed. The Company is exploring the option of operating its fossil-fuel based assets at reduced capacities and/or with new fuels, including biomass and natural gas, in order to reduce greenhouse gas emissions.

The IRP Update process will update the 2007 IRP based on new information about Nova Scotia’s greenhouse gas targets and renewable energy standard, new renewable projects, DSM experience and other changes since 2007.

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Progress on 2007 IRP Action Plan:

- DSM Programs
- Wind Integration Study
- Applied for approval of identified capital items
- Working to meet Renewable Energy Standard
- Actively monitored technology options (investments and emerging)
- Explored opportunities for clean power
- Participated in Federal Emissions Framework

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NSPI's IRP is:

- A strategic document
- A planning document that helps NSPI and governing bodies create long-term sustainable plans based on in-depth analysis
- A result of broad consultation with stakeholders
- A roadmap that outlines the primary demand and supply options to be used by NSPI to meet future electricity and emission requirements
- An analysis framework that integrates demand and supply options to meet future electricity requirements reliably and cost effectively in compliance with current and emerging operational and environmental constraints
- A reference against which to assess demand and supply-side applications
- A living document that will be updated as conditions change materially
- Developed using models that incorporate the best information available at the time of planning, as well as predictions about potential decisions that are subject to change as societal and technology priorities evolve.

NSPI’s IRP is not:

- An application for UARB approval of specific NSPI initiatives
- A commitment by NSPI to undertake specific initiatives
- A prohibition against specific third-party initiatives
- A review of regulatory or accounting treatment for NSPI assets or costs

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NSPI's IRP:

- Is based on current information about basic assumptions
- Sources include:
  - Recognized experts and consultants
  - UARB staff and UARB consultants
  - Proprietary information sources
  - Publicly available trends
  - Stakeholders / suppliers
  - NSPI's professional experience and judgment
- Has a 25-year planning horizon
- Provides ranges of realistic values based on current information

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CO_2 / Greenhouse Gases

Current Regulatory Requirements:

- Federal and North American level requirements remain pending and uncertain, although a general direction of a cap and trade approach appears to be forming
- Nova Scotia government has outlined hard cap targets for 2010 to 2020, with the intent to have further reductions post 2020, with limited compliance options
  - Use of offsets is not permitted under this approach
  - 3% of the cap could be achieved via specific pre-certified transmission investments up to 2019

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IRP Update
Basic Assumptions - Environmental

CO_2 / Greenhouse Gases

Regulatory Context:

Federal government's most recent position outlined in "Turning the Corner", calls for 20% reductions from 2006 by 2020 and 45-60% reductions by 2050

- While Intensity based approach was in the government plan, latest indications are shifting to a Cap & Trade approach with some relation to USA system
- Canadian system is likely to have a full range of compliance options
- President Obama has spoken of reductions of 20% from 2005 by 2020 with deeper cuts by 2050
- Waxman / Markey Congress Bill calls for 20% from 2005 in 2020 and 83% in 2050

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CO_2/Greenhouse Gases Emissions

Case	Emissions (Million tonnes)				
	2005	2010	2015	2020	2030
Low	10.6	10.0	10.0	7.5	6.3
Base	10.6	9.7	8.8	7.5	5.9
High	10.6	8.6	7.4	6.2	4.5

Assume pre-certified investment credit not available after 2019
1990 CO_2 emissions ~ 6.85 Mt
Current (2008/9) CO_2 emissions ~ 9.7 to 10 Mt/year

Pre-Certified Investment Rate (\$/tonne of CO_2)

Year	Pre-certified Investments Allowed (3%) of the Given Year's CO_2 Constraint in tonnes)	Rate (\$/tonne)
2010	290,000	15.00
2011	286,000	15.00
2012	280,000	25.00
2013	275,000	25.00
2014	269,000	40.00
2015	264,000	40.00
2016	256,000	40.00
2017	248,000	60.00
2018	241,000	60.00
2019	233,000	60.00
2020	0	-

Represents investments in transmission to enable renewables for RES and are assumed available

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CO_2 / Greenhouse Gases

Assumed Market Cost of Offsets (2008 $CDN / tonne CO_2)			
Year	**Low**	**Base**	**High**
2010	15.00	20.00	20.00
2015	19.00	29.00	37.00
2020	24.00	40.00	50.00
2025	31.00	44.00	62.00

NSPI will retain ownership of all GHG benefits resulting from PPAs and NSPI-customer-funded DSM.

Credits/offsets may be required and are available only for target scenarios that are more stringent than Base.

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SO_2

Current Regulatory Requirements:

As per existing and proposed NS Air Quality Regulations

- SO_2 - 108,750 tonnes/yr 2006 to 2009; 72,500 tonnes/yr in 2010 to 2014, 60,900 tonnes/yr 2015 to 2019, 36,200 2020 onward
- S in HFO – 2.0% annual average with 2.2% batch cap.

Regulatory Context:

- Consistent with Provincial Government Discussion Paper on Greenhouse Gas and Air Pollutant Emissions
- U.S. emission constraints poised to be tightened
- Reduction targets approximate possible federal reduction targets

SO_2

Case	Reduction
Low	20% reduction from 2010 cap by 2020 to 60,900 tonnes/yr
Base	50% reduction from 2010 cap by 2020 to 36,200 tonnes/yr (by 2015 reduced to 60,900 tonnes/yr)
High	50% reduction from 2010 cap by 2020 to 36,200 tonnes/yr (by 2015 reduced to 43,200 tonnes/yr); HFO max 1% S in 2015

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NO_x

Current Regulatory Requirements:

As per existing and proposed NS Air Quality Regulations

- NO_x cap of 21,365 t/yr. in 2009 to 2014, 19,200 t/yr. in 2015 to 2019, 14,960 t/yr. in 2020 and beyond

Regulatory Context:

- Consistent with existing Air Quality Regulations and NS's proposed targets in Air Pollutant Emissions Discussion Paper
- Consistent with trajectory of emission reductions proposed by federal government
- U.S. emission constraints poised to be tightened.

NO_x

Case	Reduction
Low	10% reduction from 2009 cap by 2020 (to 19,200 tonnes/yr)
Base	30% reduction from 2009 cap by 2020 (to 14,960 tonnes/yr)
High	60% reduction from 2009 cap by 2020 (to 9,000 tonnes/yr)

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Mercury

Current Regulatory Requirements:

- Cap of 168 kg/yr. until end of 2009 when cap reduces to 65 kg/yr. as per NS Air Quality Regulations.

Regulatory Context:

- Canada Wide Standards in force and implemented via provincial regulation, calling 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 in 2010 will be lower than the average Canadian & U.S. coal plants.

Mercury

Case	Reduction
Low	65 kg/yr. cap in 2010 50 kg/yr. cap in 2018 (70% reduction from 2005 cap)
Base	65 kg/yr. cap in 2010 34 kg/yr. cap in 2018 (80% reduction from 2005 cap)
High	65 kg/yr. cap in 2010 17 kg/yr. cap in 2020 (90% reduction from 2005 cap)

IRP Update
Basic Assumptions - Environmental

Renewable Portfolio Standard

Case	% New renewable (post 2001)
Low	2010 - 5% of energy 2013 - 10% of energy* 2016 - 10% of energy* 2019 - 10% of energy *
Base	2010 - 5% of energy 2013 - 10% of energy* 2016 - 12% of energy* 2019 - 14% of energy*
High	2010 - 5% of energy 2013 - 10% of energy* 2016 - 15% of energy* 2019 - 20% of energy*

"Energy" refers to in-province energy sales including effects of DSM

* *Renewable resource levels to achieve above targets will be assessed for contingency/robustness margin. As well, new capacity and/or regulation service may be required to ensure reliability of supply.*

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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	152	1973, coal conversion 1987	Coal/Coke/HFO
Lingan 1	153	1979	Coal/Coke/HFO
Lingan 2	153	1980	Coal/Coke/HFO
Lingan 3	158	1983	Coal/Coke/HFO
Lingan 4	153	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
Tufts Cove 6	48.6	November 2010	NG

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Summary of Existing Generation Plant (cont'd)

Hydro	Net Demonstrated Capacity (MW)
Wreck Cove	212
Annapolis Tidal	3.7
Avon	7.6
Black River	23
Nictaux	8.2
Lequille	12.5
Paradise	5.3
Mersey	42
Sissiboo	28
Bear River	11.5
Tusket	2.7
Roseway	1.6

Hydro	Net Demonstrated Capacity (MW)
St Margarets	10
Sheet Harbour	10
Dickie Brook	2.5
Fall River	0.5
Other	
NSPI Owner Wind	0.3
Renewable IPP (Pre-2001)	25.8
Renewable IPP (Post-2001)	25.7
Renewable IPP (Post-2001) (Contracted to be in-service by 2011)	73.7

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IRP Update
Basic Assumptions – Existing 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)	Activated Carbon Injection	n/a	n/a	65[2]	n/a
	Wet Scrubber (FGD) (with ACI) (2 units)	n/a	95	85[2]	n/a
	Dry Lime Scrubber (with ACI) (2 units)	n/a	95	85[2]	n/a
	Baghouse (+ Activated Carbon Injection) (2 units)	n/a	n/a	85[2]	n/a
	Carbon Capture (2 units)	n/a	95	85[2]	90
	Selective Catalytic Reduction (SCR)	50[1]	n/a	n/a	n/a
Pt. Tupper	Activated Carbon Injection	n/a	n/a	65[2]	n/a
	Carbon Capture	n/a	95	85[2]	90
	Selective Catalytic Reduction (SCR)	50[1]	n/a	n/a	n/a
Trenton 5	Low Nox Burners	50	n/a	n/a	n/a
	Baghouse (+ Activated Carbon Injection)	n/a	n/a	85[2]	n/a
	Carbon Capture	n/a	95	85[2]	90
	Selective Catalytic Reduction (SCR)	50[1]	n/a	n/a	n/a
Trenton 6	Activated Carbon Injection	n/a	n/a	65[2]	n/a
	Carbon Capture	n/a	95	85[2]	90
	Selective Catalytic Reduction (SCR)	50[1]	n/a	n/a	n/a

(1) SCR would allow 50% on top of that gained by Low NOx Burners.
(2) Hg collection depends on coal specification.

Activated Carbon Injection (ACI)

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IRP Update
Basic Assumptions – Future Supply Side

Additional Technology Alternatives Under Watch For Future Consideration

Alternative	Description	Assessment Summary
1	Nuclear	NSPI is prohibited from building nuclear by NS legislation
2	Landfill gas	Consideration to be based on preliminary screening analysis
3	Geothermal	Not available at utility scale
4	Solar (photovoltaic)	Consideration to be based on preliminary screening analysis
5	Fuel cells	Consideration to be based on preliminary screening analysis
6	Cogeneration	Consideration to be based on preliminary screening analysis
7	Distributed generation / micro turbines	Consideration to be based on preliminary screening analysis
8	Storage	Consideration to be based on preliminary screening analysis
9	Access to customers' generation	Net metering is in place; opportunities limited by economics

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Options to Increase Generation

Alternative	Technology	Net Capacity Increase (MW)	Fuel Type
TUC1 + 20 MW	Up rate	20	HFO/Gas
TUC2 + 8 MW	Up rate	8	HFO/Gas
Nictaux	Hydro	2.5	Water
Marshall Falls	Hydro	4.2	Water
Lingan 1-4	Uprate	4@15	Coal/Coke/HFO

Options to Add New Generation (for further study)

Alternative	Technology	Net Capacity Increase - MW	Fuel Type[1]
Off-Shore Wind	Assumes 38% Capacity Factor	100 (installed)	Wind
On-Shore Wind	Assume 32% Capacity Factor	100 (installed)	Wind
IGCC 400 with CO_2 Capture	Coal Gasification CC with CO shift and CO_2 Capture	400	Petcoke/Coal
PC 400 Supercritical with FGD, SCR and CO_2 Capture	Pulverized Coal with Amine Scrubber	400	Coal/Petcoke
CC150	2XLM6000, 50MW steam island	151	Gas
CC 280	New CT based Combined Cycle unit	280	Gas
IGCC 400 without CO_2 Capture	Coal gasification CC	400	Petcoke/Coal
LM6000	Simple cycle Combustion Turbine (CT) unit	49.4	Gas
PC 400 Supercritical with FGD, SCR	Supercritical PF Coal	400	Coal/Petcoke
CFB 400 Supercritical Boiler	Supercritical Circulating Fluidized Bed	400	Petcoke/Coal
CFB 265	Sub Critical CFB	265	Petcoke/Coal

Note: (1) Fuel as modeled, alternative blends including biomass would be considered an optimization.

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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 2008 $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.

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IRP Update
Basic Assumptions – Future Supply Side

Indicative Pricing Methodology: Examples

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% / -20%	Doesn't apply if more reliable information was available

Generally classified as ± 30% overnight pricing. Information from technical conferences and participation in industry expert groups. 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.

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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 (ACI) is used for Hg capture solutions for 2010 limits. It is understood that different types of activated carbon would be included.

Fuel is not included in the O&M cost estimates; fuel additives/sorbent are noted in the tables under O&M.

In the case of gas turbines, incremental O&M costs are added for blade life.

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Technology Assumptions - Biomass

When assessing biomass addition to the existing Pulverized coal Fired Units, we have assumed receiving biomass with a heat content of 7500 Btu/lb and approximately 27% moisture with a sizing of ¼ inch minus. This calls for some milling of fuel on site but not extensive fuel handling and storage facilities. The firing arrangement considered is based on current firing techniques for retrofit to existing units mainly demonstrated in the UK and Europe.

Biomass Fuel for Co-firing at Coal Plants*

[redacted]

* These are indicative prices for modeling purposes only.

Technology Assumptions -
Carbon Capture and Storage Retrofit

When looking at retrofitting carbon capture equipment to existing plants, a back end amine system has been considered. Current information is based on a 320 MW amine system. The Lingan retrofit model is being considered in a current EPRI Study that has recently been announced. Capital for the capture portion only is given. For modeling purposes, in addition to the capital noted for the capture, a price of $12 USD per tonne of CO2 is added for transport and sequestration. This is the total cost per tonne based on using an available aquifer. We are currently researching these costs and are assuming an aquifer or other suitable storage can be found.

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Technology Options to Control Emissions/Fuel Switch at Existing Plant - Costs

Plant/Unit	Technology	Capital Cost			O&M
		Low	Base	High	Total Annual Incremental O&M (includes estimate of fuel additive/sorbent)
		2008M$			2008K$/yr
Lingan 1-4	Activated Carbon Injection (ACI) Per Unit		3		2,392
	100% LS Low BTU Coal Burn Per Unit (gas flow and milling plant upgrades and sorbent to avoid capacity deration)		5		712
	2.5% S Wet Limestone (Two units)	179	210	240	6,585
	2.5% S Dry Lime (Two units)	126	168	211	13,763
	Baghouse (with ACI) (Two units)		60		3,340
	Selective Catalytic Reduction (SCR) Per Unit	21	24	32	1,128
	Carbon Capture (Two units)		433		11,940
	Biomass Firing Per unit (up to 10% of fuel blend per unit)		7		0

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Technology Options to Control Emissions/Fuel Switch at Existing Plant - Costs

Plant/Unit	Technology	Capital Cost			O&M
		Low	Base	High	Total Annual Incremental O&M (includes estimate of fuel additive/sorbent)
		2008M$			2008K$/yr
Pt. Tupper	Activated Carbon Injection (ACI)		3		1,686
	100% LS Low BTU Coal Burn (gas flow improvements to avoid capacity deration)		3		422
	Selective Catalytic Reduction	21	24	32	1,135
	Carbon Capture		259		5,970
	Biomass Firing (up to 10% of fuel blend)		7		0

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Technology Options to Control Emissions/Fuel Switch at Existing Plant - Costs

Plant/Unit	Technology	Capital Cost			O&M
		Low	Base	High	Total Annual Incremental O&M (includes estimate of fuel additive/sorbent)
		2008M$			2008K$/yr
Trenton 5					
	Activated Carbon Injection		3		841
	Selective Catalytic Reduction	22	25	32	1,099
	Carbon Capture		259		5,721
	Biomass Firing (up to 10% of fuel blend)		7		0

Technology Options to Control Emissions/Fuel Switch at Existing Plant - Costs

Plant/Unit	Technology	Capital Cost			O&M
		Low	Base	High	Total Annual Incremental O&M (includes estimate of fuel additive/sorbent)
		2008M$			2008K$/yr
Trenton 6	Activated Carbon Injection		3		1,660
	Selective Catalytic Reduction	23	26	34	1,155
	Carbon Capture		259		5,846
	Biomass Firing (up to 10% of fuel blend)		7		0
Point Aconi	Biomass Firing (up to 20% of fuel blend)		4		0
Burnside Gas	Gas Conversion	5	6	7	0

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Options to Increase Generation at Existing Plant - Costs

Alternative	Technology	Capital Cost			O&M
		Low	Base	High	Total Annual Plant (Unit) O&M
		2008M$			2008K$/yr
TUC1 +20MW	Increase Capacity	5	5	6	2,130
TUC2 +8MW	Increase Capacity	2	2	3	2,195
Nictaux	Hydro	5	6	8	37
Marshall Falls	Hydro	11	12	15	66
Lingan 1-4 (+15 MW; per Unit)	Increase Capacity	18	20	24	5,056

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IRP Update
Basic Assumptions – Future Supply Side

Options to Increase Generation - Costs

Alternative	Technology	Capital Cost			O&M
		Low	Base	High	Total Annual O&M
		2008M$			2008 K$/yr
On-Shore Wind	Assumes 32% Capacity Factor (+back-up and transmission costs)		260		6,447
Off-Shore Wind	Assumes 38% Capacity Factor (+back-up and transmission costs)		490		10,652
IGCC 400	Integrated Gasification CC with CO2 capture	2,282	3,260	4,239	11,844
PC 400	Super Critical with FGD, SCR, Mercury Capture and CO2 capture	1,795	2,246	2,919	11,448
CC150	New LM6000 based Combined Cycle	151	162	185	4,345
CC 280	Combined Cycle	251	258	288	8,840

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IRP Update
Basic Assumptions – Future Supply Side

Options to Increase Generation - Costs

Alternative	Technology	Capital Cost			O&M
		Low	Base	High	Total Annual O&M
		2008M$			2008K$/yr
IGCC 400	Integrated Gasification CC w/o CO2 capture	1,482	1,853	2,410	11,245
CC150	Phased-in Conversion LM1&LM2 Add HRSG	76	84	111	4,345
LM6000	Combustion Turbine	43	48	56	1,211
CFB 400	Circulating Fluidized Bed, Supercritical Boiler	1,359	1,700	2,210	10,747
PC 400	Ultra Super Critical with FGD, SCR, Mercury Capture	1,381	1,626	2,114	10,435
CFB 265	Sub Critical CFB	938	1,173	1,525	7,656

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Options to Increase Generation – Renewable PPA

Renewable PPA	Capacity Factor	[redacted]
TIDAL 75 MW x 5 blocks - available 2016-2020	~ 20%	
WIND 100 MW x 5 blocks (1 block available every 3 years starting 2013) (Assumed on Mainland NS) 100 MW x 2 blocks (Assumed on Cape Breton)	~ 32% ~ 38%	
BIOMASS 60 MW (400GWh/year); 15 MW (100 GWh/year) available starting 2012 Q3	~ 76%	
CAES - Compressed Air Energy Storage* 175 MW x 5 hours/day -> 320 GWh/year (available 2014) Energy to be dispatched on-peak Based on wind farm as pump storage: 60 MW x 16 hours/day -> 350 GWh/year **Above is indicative estimate for modeling purposes only; further study would be required on this technology in order to determine optimal design of capital, source of pump storage, compression configuration, etc.*	~ 21%	
OFFSHORE WIND 100 MW blocks (available 2014)	~ 38%	

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Options to add New Generation – Large Non-emitting PPA

Two Large Non-emitting PPAs will be considered. Both will be modeled with a capacity of 300MW and a capacity factor of approximately 70%.

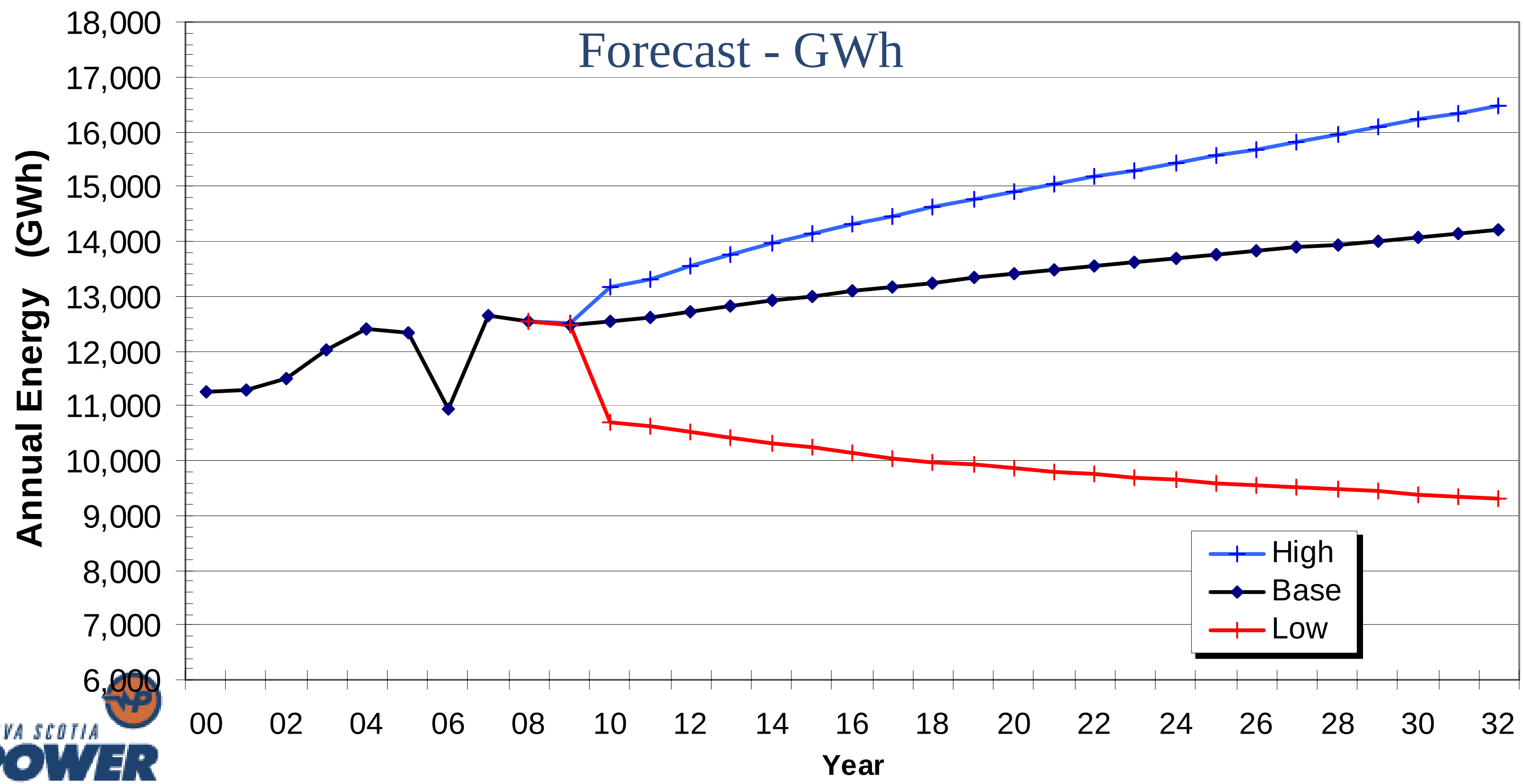
One option will be assumed to come from a westerly direction into Nova Scotia through New Brunswick. The second will come from the east into Nova Scotia.

Costing:

- Energy - both options will be based on a New England energy price
- Transmission tariff – the energy price will be adjusted for tariffs according to source and route relative to New England
- Transmission costs – transmission facility additions and upgrades as required

IRP Update
Basic Assumptions - Load Forecast

	Scenario Assumption	High	Low
1	Industrial	+ 500 GWh/yr base load, 2010 -	-1700 GWh closure, 2010 -
2	Economic Growth	Growth rate 50% higher than base	Growth rate 50% lower than base
3	Heating Oil Prices	125 % higher than base forecast	30% lower than base forecast
4	Electricity Price	10% lower than base case	10% above base case



NOTE: Does not include the effects of DSM

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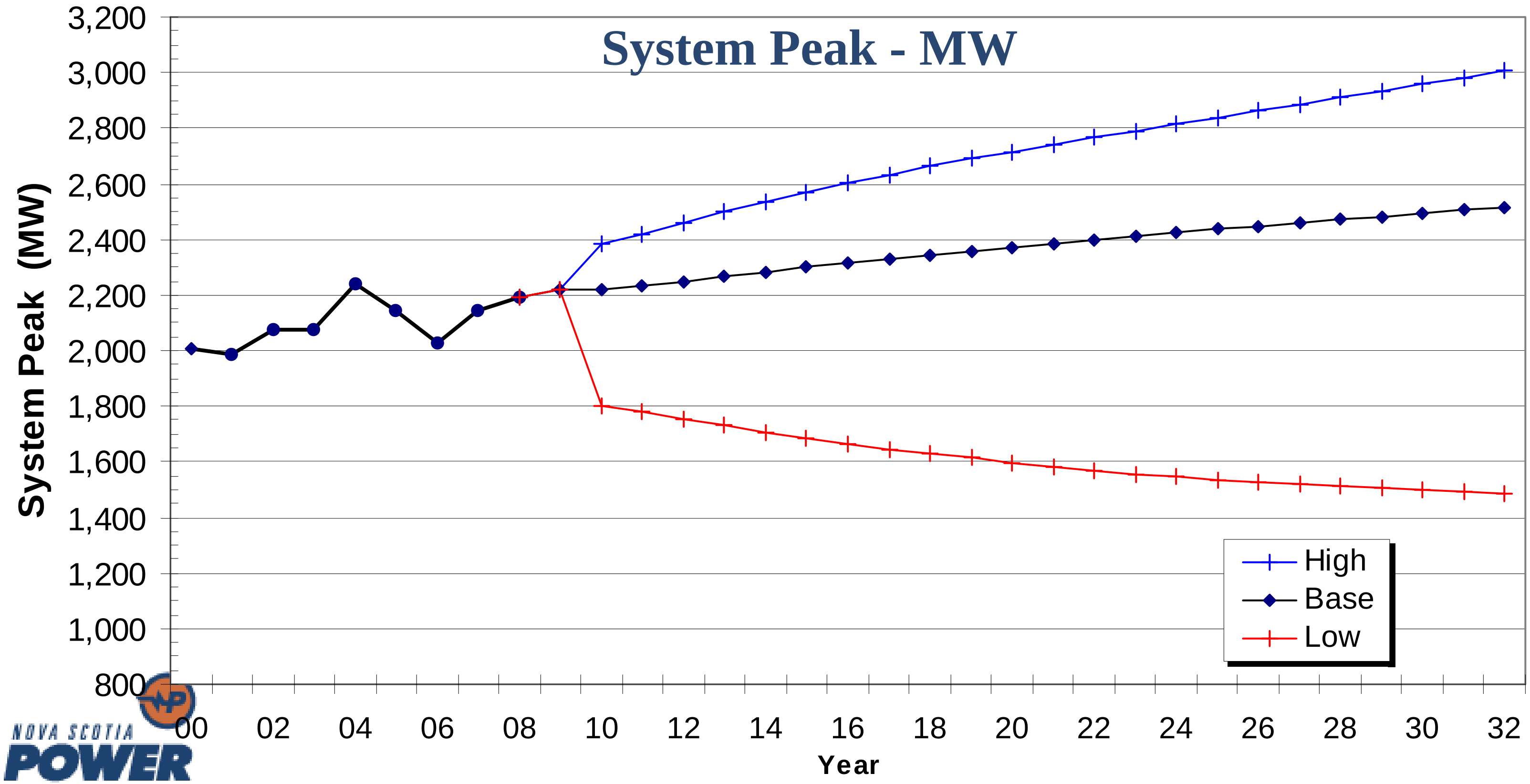
IRP Update
Basic Assumptions - Load Forecast

	Scenario Assumption	High	Low
1	Industrial	+ 500 GWh/yr base load, 2010 -	-1700 GWh closure, 2010 -
2	Economic Growth	Growth rate 50% higher than base	Growth rate 50% lower than base
3	Heating Oil Prices	125 % higher than base forecast	30% lower than base forecast
4	Electricity Price	10% lower than base case	10% above base case



NOTE: Does not include the effects of DSM

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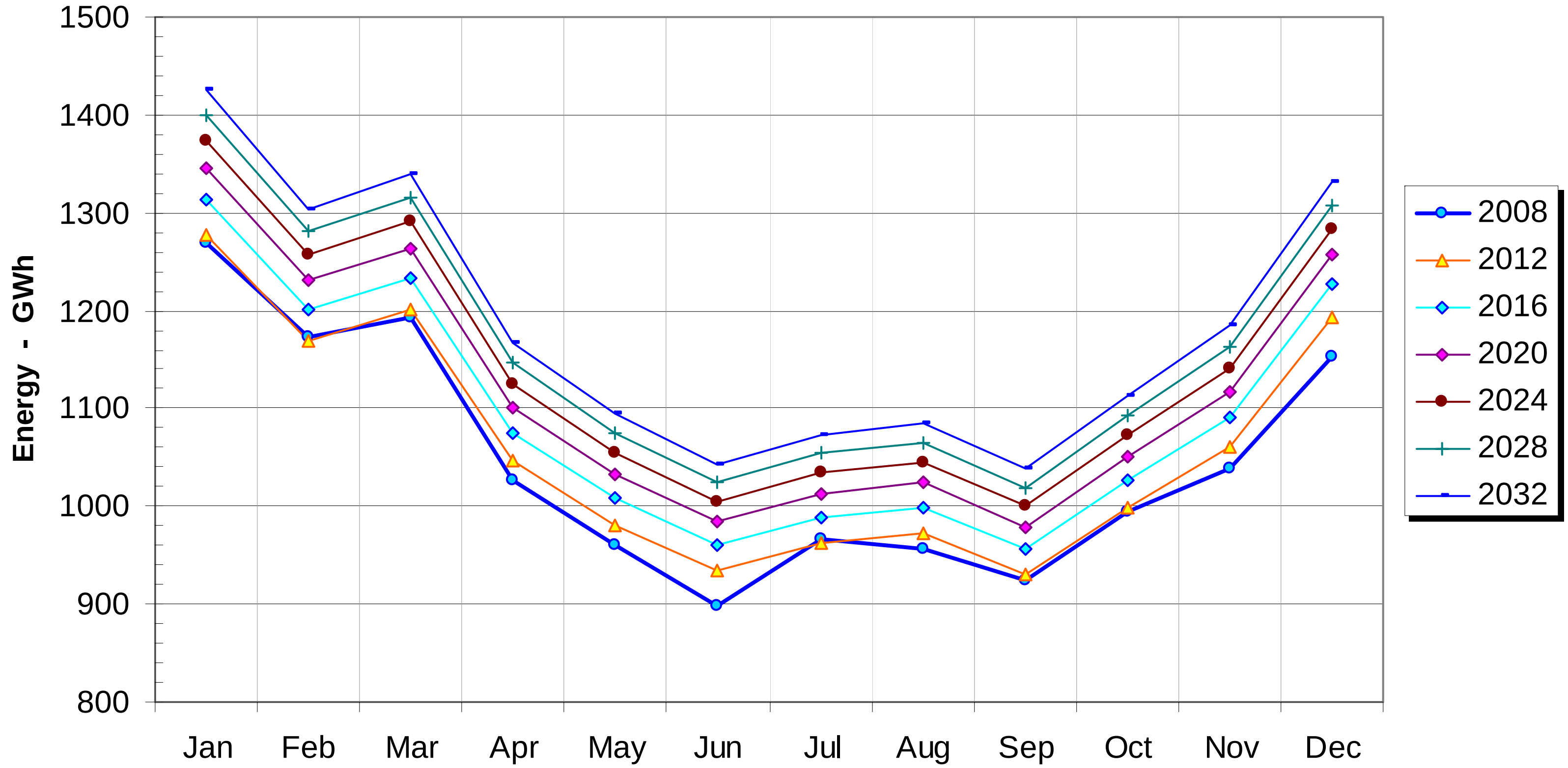
IRP Update
Basic Assumptions - Load Forecast

Monthly Energy Requirement
Base Case



[Year 2008 is actual load]

NOTE: Does not include the effects of DSM

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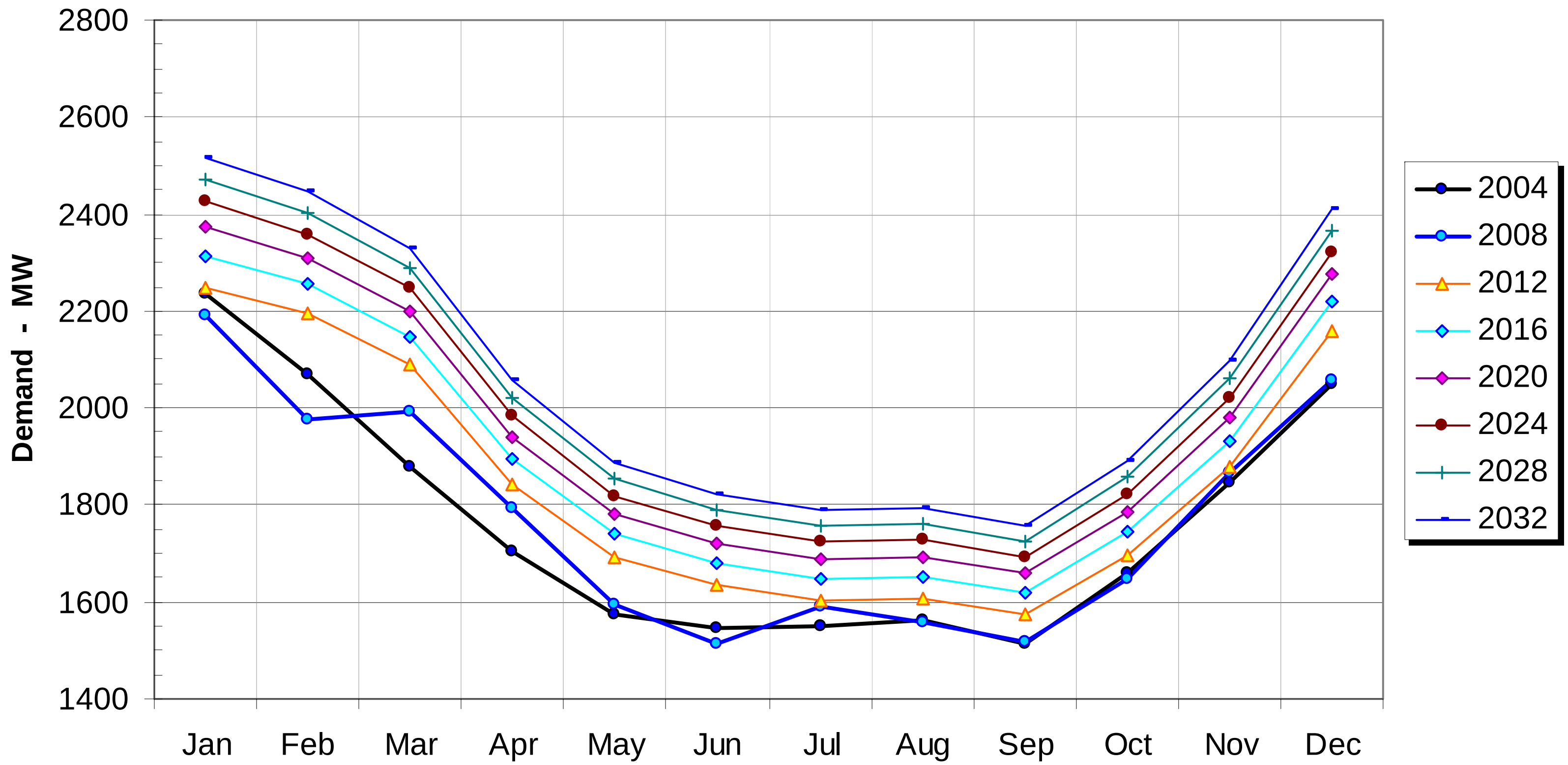
IRP Update
Basic Assumptions - Load Forecast

Monthly System Peak Demand
Base Case



[Years 2004 and 2008 are actual demand]

NOTE: Does not include the effects of DSM

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IRP Update
Basic Assumptions - Load Forecast
High & Low Scenarios (Net System Requirements)

	Low		Base		High	
Year	NSR GWh	Peak MW	NSR GWh	Peak MW	NSR GWh	Peak MW
2008	12,539	2,192	12,539	2,192	12,539	2,192
2009	12,470	2,218	12,478	2,219	12,491	2,221
2010	10,712	1,801	12,547	2,219	13,151	2,384
2011	10,618	1,779	12,615	2,230	13,318	2,415
2012	10,525	1,756	12,725	2,249	13,549	2,459
2013	10,416	1,730	12,821	2,266	13,755	2,498
2014	10,319	1,707	12,918	2,284	13,956	2,536
2015	10,228	1,686	13,008	2,300	14,141	2,572
2016	10,131	1,663	13,082	2,313	14,304	2,602
2017	10,045	1,643	13,156	2,327	14,460	2,632
2018	9,980	1,627	13,241	2,343	14,619	2,662
2019	9,922	1,613	13,326	2,359	14,771	2,691
2020	9,859	1,597	13,400	2,372	14,904	2,716
2021	9,796	1,582	13,468	2,385	15,030	2,739
2022	9,745	1,569	13,545	2,399	15,166	2,765
2023	9,694	1,556	13,617	2,412	15,297	2,789
2024	9,647	1,544	13,686	2,425	15,431	2,814
2025	9,600	1,532	13,748	2,436	15,558	2,838
2026	9,555	1,525	13,814	2,448	15,687	2,861
2027	9,512	1,518	13,879	2,460	15,816	2,885
2028	9,469	1,511	13,944	2,471	15,947	2,909
2029	9,428	1,504	14,008	2,482	16,079	2,933
2030	9,387	1,498	14,072	2,494	16,212	2,957
2031	9,348	1,492	14,136	2,505	16,347	2,981

NOTE: Does not include the effects of DSM

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IRP Update
Basic Assumptions - DSM

The basis for the profiles used in the 2007 IRP is as follows:

- The 2007 IRP DSM profile was based on the 8-year achievable potential identified in Summit Blue's 2006 DSM Potential Study
- Additional "High" (5% of revenues) and "Low" (1% of revenues) DSM profiles were established
- The "High" profile was established by multiplying the savings and total costs by 175%
- The "High" profile was in the IRP preferred plan

The result of the 2007 IRP demonstrates that a high level of DSM is economic to pursue. This is intuitively sound – since DSM is a relatively cost-effective option compared to supply side alternatives, the model will pick DSM over other alternatives on the list.

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IRP Update
Basic Assumptions - DSM

The profile from the 2007 IRP preferred plan, with some modifications to align for timing and cost of early DSM programs, will be used in the 2009 IRP update. It results in load reductions of approximately 2% per year over the study period and will be called the "2% Annual Savings" profile in this IRP.

This DSM profile projects that the 8-year economic potential identified in the 2006 study is reached before year 20 of the plan.

In comparison to the experience and plans of other jurisdictions, the profile is ambitious, one which would position Nova Scotia as a leader in energy conservation.

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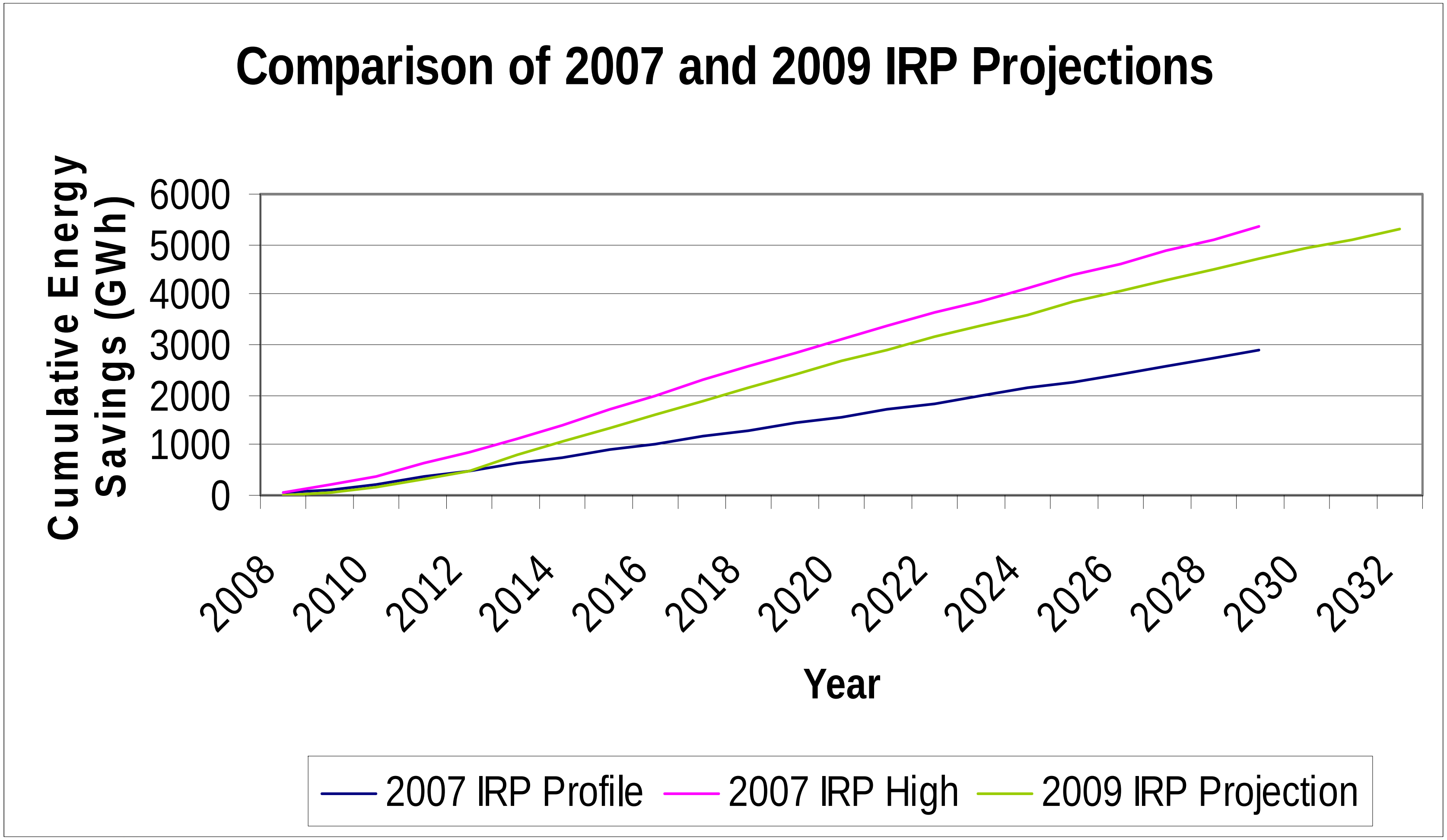
IRP Update
Basic Assumptions - DSM



IRP Update
Basic Assumptions - DSM

A summary of the 25 year horizon is included below. The approximate effect of this DSM profile is a 2% annual load decline which will offset the 0.5% annual growth resulting in a net 1.5% annual load decline over the time horizon.

TOTALS	25 Year Total	2008	2009	2010	2013	Year 10	Year 15	Year 20	Year 25
Savings									
Demand Savings (MW)		2.1	6.8	16.9	63.5	55.8	49.6	45.5	43.0
Cumulative (MW)	**1,106**	2.1	8.9	25.8	164.2	392.1	651.6	886.5	1105.7
Energy Savings (GWh)		16.1	50.3	82.7	305.3	268.4	238.2	217.4	204.0
Cumulative (GWh)	**5,317**	16.1	66.3	149.0	804.9	1900.7	3147.5	4272.8	5317.0
Incremental Costs									
Utility Costs ($Millions)*	**1,509**	3	10	23	82	75	67	64	63
Customer Costs ($Millions)*	**1011**	2	5	15	60	51	46	42	39
Total Costs ($Millions)*	**2520**	5	15	38	142	126	113	106	102

** Costs for 2008 and 2009 are expressed in 2008 dollars.*
Costs for 2010 and beyond are expressed in 2010 dollars.

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IRP Update
Basic Assumptions - DSM

All DSM is assumed to be included in the projection used in the 2009 IRP.

This encompasses conservation efforts and investments occurring both inside and outside of customer funded DSM programs, including:

- Consumer behaviour and investments
- Energy efficiency codes & standards
- Other agencies
- NSPI
- DSM Administrator

IRP Update
Basic Assumptions - DSM

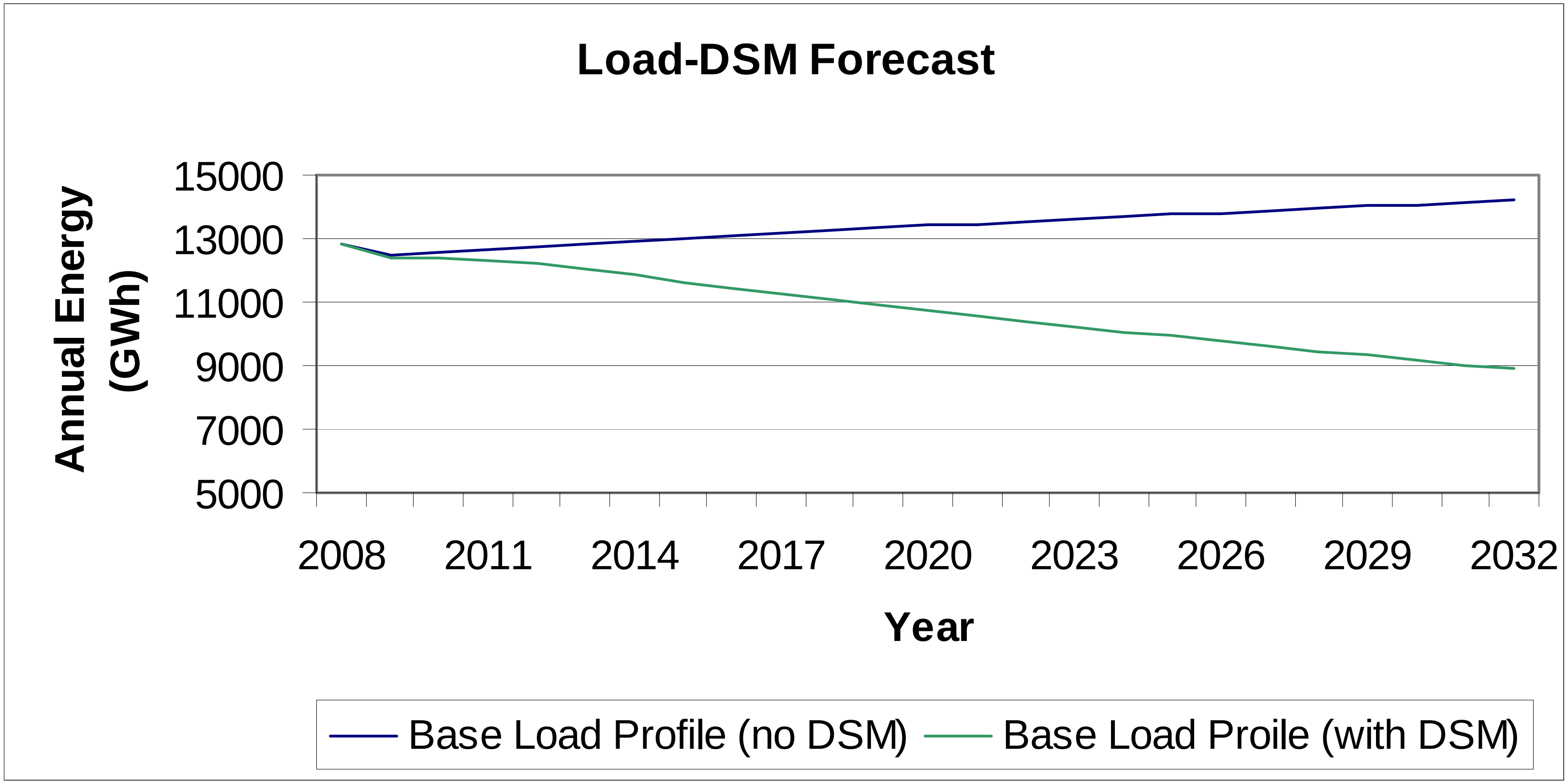
NSPI will continue to invest in energy conservation related to NSPI assets.

Examples could include:

- Upgrade to more energy efficient street-lighting technologies
- Automatic Metering Infrastructure

In addition, NSPI may pursue other DSM related measures such as rate design and direct load control.

IRP Update
Basic Assumptions - DSM



IRP Update
Basic Assumptions - Economic

	Low	Base Case	High
Rate of return on equity	8.50%	9.35%	11.00%
Maximum return on equity	8.75%	9.60%	11.25%
Minimum return on equity	8.25%	9.10%	10.75%
Discount Rate/WACC/Return on rate base - before tax	8.04%	8.33%	9.02%
Discount Rate/WACC/Return on rate base - after tax	6.71%	6.81%	7.57%
Inflation Rate 2008-2032	-	1.92%	-
Target capital structure:			
Debt	65.00%	62.50%	60.00%
Equity	35.00%	37.50%	40.00%
Short-term interest rates			
2008	-	3.53%	-
2009	-	2.26%	-
2010	-	3.06%	-
2011	-	4.86%	-
2012	-	5.64%	-
2013	-	5.71%	-
2014-2032	-	5.94%	-

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IRP Update
Basic Assumptions - Economic

	Low	Base Case	High
Short-term investment rates			
2008	-	2.79%	-
2009	-	0.00%	-
2010	-	0.65%	-
2011	-	2.55%	-
2012	-	3.42%	-
2013	-	3.52%	-
2014-2032	-	3.83%	-
Long-term interest rates			
2008	-	6.75%	-
2009	-	7.45%	-
2010	-	7.78%	-
2011	-	8.33%	-
2012	-	8.78%	-
2013	-	8.78%	-
2014-2032	-	8.68%	-
Income tax rate			
2008	-	35.50%	-
2009	-	35.00%	-
2010	-	34.00%	-
2011	-	32.50%	-
2012-2032	-	31.00%	-

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IRP Update
Basic Assumptions - Economic

	Low	Base Case	High
FX Exchange Rate Forecast			
2008	-	1.07	-
2009	-	1.24	-
2010	-	1.15	-
2011	-	1.10	-
2012	-	1.09	-
2013	-	1.10	-
2014-2032	-	1.08	-

Dashes indicate where high and low values were provided for the 2007 IRP. If determined to be key sensitivities, these can be estimated and included.

Natural Gas, HFO and LFO

NOTE: These values represent projections, developed solely for the IRP Update, and can and will vary significantly in the future.

[redacted]

All costs are nominal.

Coal

NOTE: These values represent projections, developed solely for the IRP Update, and can and will vary significantly in the future.

[redacted]

All costs are nominal.

Coal

NOTE: These values represent projections, developed solely for the IRP Update, and can and will vary significantly in the future.

[redacted]

All costs are nominal.

Petroleum Coke

NOTE: These values represent projections, developed solely for the IRP Update, and can and will vary significantly in the future.

[redacted]

All costs are nominal.

IRP Update
Basic Assumptions - Transmission Design Requirements

- System Reliability
  - System must be designed to comply with NPCC and NERC criteria
  - System must be designed to be dynamically balanced and remain stable for Defined Contingencies
  - Transmission Capacity must be maintained to deliver reserve for load fluctuations, real time capacity reserve for loss of generation, and meet reserve sharing agreements with NBSO
    - Spinning Reserve 36 MW (2009 levels)
    - 10 Minute Reserve 174 MW
- Lines must be operated within their Design Ratings
- Voltage and Frequency standards must be maintained

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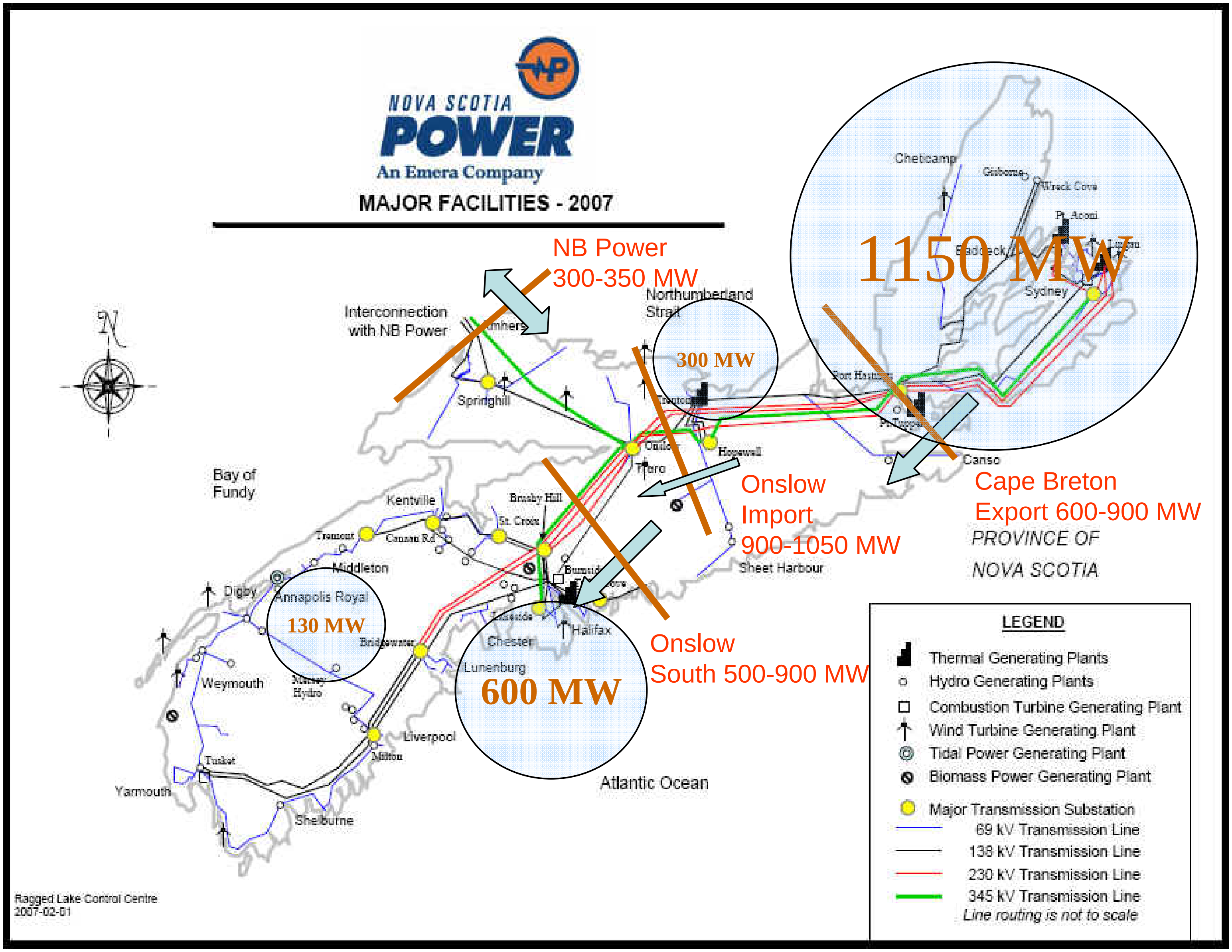
IRP Update

Basic Assumptions - Transmission

Current Transmission Interface Limits - with Existing Sources



- The existing transmission system has dynamic limitations and constraints.
- With current generation options and dispatch patterns interface limits are often reached with existing transmission facilities.
- Any additional generation in Cape Breton stresses the Cape Breton Export interface beyond criteria on single contingencies. Additional generation in both Cape Breton and Eastern Mainland stresses the Onslow South interface.
- Increasing east – west power flows necessitates reactive power compensation to meet voltage criteria in HRM.
- Additional generation in the West Mainland improves load flows and reduces system losses but the transmission system requires system upgrades to handle the additional capacity and contingencies.
- Increased usage of the NB intertie for imports, increases the risk of under-frequency load shedding of firm load for contingency loss of the 345kV tie plus reserve commitments must be able to be delivered at all times.

IRP Update
Basic Assumptions - Transmission - Common Transmission Facilities

Transmission Facility estimates were completed as if resource options were independent of each other. This table captures where transmission facilities are common between options.

Note 1: Back-up and Load Following for non-dispatchable renewables is assumed to be provided within NS and not included in Network Upgrades cost estimates. If back-up source is external to NS then second tie would be required.

Common Transmission Facilities	Additional 345kV NS/NB Tie Line	Brushy Hill Substation Additions	Onslow 345 Breaker Addition and Node Swap	345 Kv Line + 79N Bus Hopewell-Brushy Hill	New Spider Lake Substation additions	345kV Line 3C P.H. - Spider Lake	3C Port Hastings 345kV, substation	Canso 345Kv Crossing	Common Western /Valley Improvements
Large Generator 250MW-350MW									
Location									
HRM									
Pt. Tupper Area									
Eastern Shore									
Tidal (75MW x 5 blocks)									
block one Total 75MW									
block two --Total 150MW									
block three -- Total 225 MW									
block four and five -- Total 375MW									
Wind									
Mainland wind (100MW x 5 blocks)									
block one									
block two	Note 1								
block three	Note 1								
block four	Note 1								
block five	Note 1								
Cape Breton Wind (100MW x 2 blocks)									
block one	Note 1								
block two	Note 1								
Bio-mass									
60 MW bio-mass									
CAES Compressed Air Energy Storage									
175MW CAES site									
Offshore Wind 100MW									
NS on-land transmission									
Large Non-emitting 300MW Import									
Import through NB									
East into NS									
NS Transmission + Upgrades									

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IRP Update
Basic Assumptions - Transmission - Summary

- Network Upgrades, of some level, will be required for all incremental generation capacity
  - Network Upgrade Level varies with interconnection location
  - Network Upgrade Level varies with the size and sequencing of interconnections
  - Increased level of east to west flows causes greatest degrees of network upgrades

- Transmission Loss Factors increase as generation is interconnected further east of HRM and decrease as interconnected further west of HRM

- Increased capacity on the NS-NB intertie to allow more import, export, or load following capacity requires significant upgrades to the 345kV systems in both NS and southern NB

- System Impact Studies are needed to fully determine all Network Upgrade requirements

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IRP Update
Preview Analysis - Plan Themes

- Builds on the approach taken in the 2007 IRP, focusing on Key Themes
- Various Optimization Runs will be performed resulting in output plans
  - o "Least cost" optimizations and others
  - o Will be assessed for robustness in selecting a Preferred Plan and Next Steps

- Optimization Runs:
  - o "Base Case" or "Reference" least cost optimization run
    - Assumptions settings/alternatives set to their Base values
    - Likely to produce a "combo plan" (may be similar to the 2007 IRP in early years)
    - Will examine other plans from this run

  - o "High Load" optimization run
    - Most assumptions/alternatives set to their Base values, with Load forecast "High" case.
    - Will examine other plans from this run
    - May require more supply-side resources than the Base Load case
    - Could inform lead-time issues/risks

  - o "Deep Green" optimization run
    - Run CO_2 caps at deeper trajectory than NSPI's present 2009 outlook of future Low-Base-High ranges
    - Similar to the 2007 IRP Deep Green assumptions
    - Expected to require different supply-side resources than the Base CO_2 case
      - – For example, specific assessment of coal plant capacity factors/retirement perhaps more so than in other plans

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IRP Update
Preview Analysis – Plan Themes

- Other Plans
  - Large Non-Emitting PPA Plan
    - To the extent that this resource is or is not selected in one of the above runs, plans from the above optimization runs (e.g. Base Run) will be mined or a run will be done fixing it in, to inform the cost/economics of this alternative and its place in NSPI's long term plans.
  - Gas Plan
    - Similarly to the point above: To the extent that such resources are or are not selected in one of the above runs, plans from the above optimization runs (e.g. Base Run) will be mined or a run will be done fixing such resources in, to inform the cost/economics of gas alternatives and their place in NSPI's long term plans.

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IRP Update
Preview Analysis - Plan Themes

- Note on Sensitivities
  - Sensitivity tests (as opposed to re-optimization runs) will be conducted on the Base Case Run, other candidate plans, and as deemed sensible on the Worlds
  - Will “book end” results by varying key cost inputs to either their Low and/or High values, e.g. fuel prices
  - In the 2007 IRP, very few changes in rank order - no further optimizations were required
    - Depending on how the sensitivities affect the rank order, appropriate analyses will be done
  - By varying parameters, sensitivities will show which candidate plans continue to perform well to determine selection of candidate plans and preferred plan
- Business as Usual perspective
  - Time permitting a comparator case will be created to inform what a status quo World could look like. This will not be a candidate plan, but rather will be produced to illustrate how the Preferred Plan/reference Plan, as well as other Worlds, would compare to a status quo situation.

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IRP Update
Next Steps

- May 21 - Input received from stakeholders on assumptions, plans and themes
- June 11 - Final consolidated assumptions, plans and themes issued
- June 29 - Preview of base scenarios for alternative plans and sensitivities issued to stakeholders
- Sept 1 - Analysis results to stakeholders
- Sept 16 - Stakeholder input on analysis results
- Oct 5 - Draft report to stakeholders (changed from October 8 to allow more time for stakeholder review)
- Oct 15 - Input received from stakeholders on draft report
- Nov 13 - Final report filed with UARB

NOVA SCOTIA POWER
An Emera Company

Technology Assumptions - Biomass

When assessing biomass addition to the existing Pulverized coal Fired Units, we have assumed receiving biomass with a heat content of 7500 Btu/lb and approximately 27% moisture with a sizing of ¼ inch minus. This calls for some milling of fuel on site but not extensive fuel handling and storage facilities. The firing arrangement considered is based on current firing techniques for retrofit to existing units mainly demonstrated in the UK and Europe.

Biomass Fuel for Co-firing at Coal Plants*

[redacted]

* These are indicative prices for modeling purposes only.

Revision: Added biomass price
for High Case

IRP Update
Basic Assumptions
Revision to Slide 39

Options to Increase Generation – Renewable PPA

Renewable PPA	Capacity Factor	[redacted]
TIDAL 75 MW x 5 blocks - available 2016-2020	~ 20%	
WIND 100 MW x 5 blocks (1 block available every 3 years starting 2013) (Assumed on Mainland NS) 100 MW x 2 blocks (Assumed on Cape Breton)	~ 32% ~ 38%	
BIOMASS 60 MW (400GWh/year); 15 MW (100 GWh/year) available starting 2012 Q3	~ 76%	
CAES - Compressed Air Energy Storage* 175 MW x 5 hours/day -> 320 GWh/year (available 2014) Energy to be dispatched on-peak Based on wind farm as pump storage: 60 MW x 16 hours/day -> 350 GWh/year **Above is indicative estimate for modeling purposes only; further study would be required on this technology in order to determine optimal design of capital, source of pump storage, compression configuration, etc.*	~ 21%	
OFFSHORE WIND 100 MW blocks (available 2014)	~ 38%	

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Revision: Removed 'levelized' from biomass price

IRP Update
Basic Assumptions
Revision to Slide 56

Natural Gas, HFO and LFO

NOTE: These values represent projections, developed solely for the IRP Update, and can and will vary significantly in the future.

[redacted]

All costs are nominal.

Revision: Updated Natural Gas
Low Case

NATSOURCE

GREENHOUSE GAS EMISSIONS REDUCTION POLICY SCENARIOS FOR CANADA AND ASSOCIATED COMPLIANCE INSTRUMENT PRICING TO 2025

INCLUDING A SENSITIVITY ANALYSIS FOR A NOVA SCOTIA ONLY SCENARIO

REPORT FOR NOVA SCOTIA POWER INC.

NOVEMBER 7, 2008

Disclaimer

This report contains forward-looking statements that reflect Natsource's current beliefs with respect to future events and are based on information currently available to Natsource. Forward-looking statements inherently involve uncertainties and assumptions. Many factors could cause actual events and scenarios to differ materially from the events and scenarios discussed in the forward-looking statements. Although the forward-looking statements contained in this report are based upon what Natsource believes to be reasonable assumptions, Natsource cannot assure that actual events and scenarios will be consistent with these forward-looking statements. These forward-looking statements are made as of the date of this paper, and Natsource assumes no obligation to update or revise them to reflect new events or circumstances.

I. Introduction

This paper presents a set of policy scenarios for greenhouse gas (GHG) emissions reduction policy and associated pricing for compliance instruments that could occur in North America from now until 2025. The paper provides:

- A summary of recent policy, legislative and regulatory initiatives related to greenhouse gas (GHG) emissions reductions in Canada and the United States at the state/provincial, regional and federal level.
- A summary of economic model results relevant to major pieces of environmental policy/legislative/regulatory development.
- Three possible policy scenarios out to 2025. The scenarios are intended to bound the likely range of policy outcomes in Canada and the U.S. as policy evolves over the period from now to 2025. A most likely policy scenario is identified along with the rationale for choosing this scenario.
- A range of compliance instrument prices expressed in 2008 Canadian dollars associated with each of the policy scenarios in 2010, 2015, 2020 and 2025. A price sensitivity analysis is also provided for a scenario in which the Nova Scotia Government may decide to pursue a GHG emissions reduction program on its own with no links to other greenhouse gas markets.

II. Climate Policy and Legislation Update

The current state of GHG emissions reduction policy in North America is complex and in a state of flux, with a patchwork of federal, regional, provincial and state initiatives planned or implemented. In Canada, the Conservative minority government is pursuing a national regulatory program under the Canadian Environmental Protection Act, details of which are elaborated in Annex 1 to this report. The regulatory program will establish short-term emissions intensity targets for large industrial emitters for the period of 2010 to 2015, with firm emissions caps to be established by regulations in the medium to long term out to 2050.

In the October 2008 election campaign the Conservatives pledged to

> *"…implement our 'Turning the Corner' action plan to reduce Canada's greenhouse gas emissions in absolute terms by 20 per cent over 2006 levels by 2020. We will work with*

> *the provinces and territories and our NAFTA trading partners in the United States and Mexico, at both the national and state levels, to develop and implement a North America-wide cap and trade system for greenhouse gases and air pollution, with implementation to occur between 2012 and 2015."*

On November 5, 2008 the lead federal ministers for international climate change policy (Environment and Foreign Affairs) indicated their wish to launch discussions as soon as possible with the new Obama administration on a climate change pact that would include, among other mechanisms, a linked emissions trading system.[1]

At the provincial level, there is no agreement among provincial and territorial leaders on national measures to either regulate or tax GHG emissions. Nova Scotia has created a new Department of Environment in April 2008 and charged it with the development of a climate action plan to deliver on the provincial goal contained in the Environmental Goals and Sustainable Prosperity Act (2007) of reaching a 10% reduction of greenhouse gas emissions from 1990 levels by 2020 while continuing to see the economy of the province grow. The action plan is scheduled for release in late 2008. Alberta has regulations in place that require reductions in emissions intensity on the part of large industrial emitters in the province. British Columbia has introduced a broad-based carbon tax of $10 per tonne in 2008 rising to $30 per tonne by 2012. They have also introduced cap and trade legislation that will enable the province to implement regulations in 2009 to establish firm caps on large industrial emitters in the province in line with the expected targets under the Western Climate Initiative's (WCI) forthcoming cap and trade program. British Columbia, Manitoba, Quebec and Ontario are all members of the WCI and have signaled their intention to be part of the WCI cap and trade program.

In the U.S. at the federal level there have been a number of draft cap and trade bills in the Senate, notably the Lieberman-Warner bill that was debated in June 2008. In the House, Representatives Dingell and Boucher released a draft proposal in October 2008 that likely will frame climate debate in the House in 2009. Both the Democrat and Republican candidates for President are advocating a national cap and trade system as a key element of their climate change and energy policies. There are numerous state and regional initiatives that embrace some form of cap and trade system. These include the WCI, the Regional Greenhouse Gas Initiative (RGGI) of the northeast states, and the Midwest Greenhouse Gas Accord (MGA).

Highlights and the current status of significant North American GHG emissions reduction policy initiatives are provided in Table 1 and are further described in Annex 1 to this report.

[1] Globe and Mail November 6, 2008
http://www.theglobeandmail.com/servlet/story/RTGAM.20081105.wclimate1106/BNStory/National/home

Table 1 - Summary of Significant GHG Emissions Reduction Initiatives

Program/Province	Jurisdiction(s)	Regulated Entities	Target	Status
Canada Federal Draft Regulatory Framework	Canada	Sector-wide targets in the lime, pulp and paper, aluminum and cement sectors. Corporate targets in the electricity sector. Facility-specific targets in upstream oil and gas, oil sands, petroleum refining, natural gas pipelines, iron and steel, potash, fertilizer, base metal smelting, iron ore pelletizing and ilmetite sectors	Overall, an18% emissions intensity target from 2006 levels by 2010 with further 2% annual decreases in emissions intensity until 2015. Specific targets to be outlined in regulations under the CEPA	Elements of the offset system were published for comment in August 2008. Draft sectoral regulations are promised for late 2008 with implementation scheduled for 1 January 2010. Consultations are underway on the design of the Technology Fund and sectoral targets.
Nova Scotia	Nova Scotia	No regulations yet in place; observer status in the Regional Greenhouse Gas Initiative (RGGI)	Province wide target to reduce emissions of GHGs by 10% from 1990 levels by 2020	Newly created (April 2008) Department of Environment mandated to develop Climate Action Plan for release in late 2008

Alberta	Alberta	All facilities emitting direct GHG emissions equal or greater than 100,000 tonnes per year of CO_2e	Province wide target to stabilize emissions by 2020 and to achieve a 14% reduction from 2005 levels by 2050. Specified Gas Emitters Regulation requires covered entities to reduce their GHG emissions intensity by 12 percent from their baseline emissions intensity (averaged from 2003-2005)	First year of compliance ended March 2008. Report issued by government of Alberta shows 2.6 million of reductions achieved either by actions internal to corporate operations or by offsets projects in Alberta. $40 million contributed to the Alberta Climate Change and Emissions Management Fund. Separate $2 Billion CCS Fund announced July 2008
British Columbia	British Columbia	All sectors initially for the carbon tax. Cap and Trade program to be implemented later for large industrial emitters as part of the WCI cap and trade program	Province wide target of 33% below 2007 levels by 2020 and at least 80% below 2007 levels by 2050. Interim provincial targets for 2012 and 2016 to be released by the end of 2008. Carbon tax of $10 per tonne in 2008 increasing to $20 per tonne in 2012. No targets defined yet for large final emitters.	Carbon tax introduced to mixed public reaction in July 2008. Slow developments on the WCI front may delay release of sector specific targets.

US Federal Lieberman-Warner (S. 3036)	United States of America	Electric power generation, transportation, and heavy industry sectors and upstream coverage of petroleum and natural gas (~84% of total national GHG emissions)	2012: 4% below 2005 levels (5775 MMT) 2020: 18% below 2005 levels (4924 MMT) 2030: 36% below 2005 levels (3860 MMT) 2040: 53% below 2005 levels (2796 MMT) 2050: 71% below 2005 levels (1732 MMT)	Bill was introduced 20 May 2008 and cloture vote on motion to proceed passed 74-14 (needed 60 votes to pass). Bill was then considered by full Senate but failed to overcome filibuster and move forward with consideration of amendments by vote of 48-26 (needed 60 votes to pass).
US Federal Bingaman-Specter (S. 1766)	United States of America	Upstream coverage for petroleum, natural gas, and non CO2 GHGs and downstream coverage for coal facilities that use over 5,000 tons of coal per year (~86% of total national GHG emissions)	2012: 8% above 2005 levels (6652 MMT) 2020: ~2005 levels (6188 MMT) 2030: 22% below 2005 levels (4819 MMT) Cap remains at 4819 MMT from 2030 and beyond, although the President can set cap at 60% below 2006 levels (2475 MMT) contingent upon international participation	Bill was introduced 11 July 2007 and referred to Environmental and Public Works Committee on 2 August 2007, though never received committee consideration. On 9 July 2008, Bingaman released 4 strategies and 10 principles as guidance for Congress when drafting future climate legislation.

US Federal Dingell-Boucher Draft Legislation	United States of America	Power plants, sequestration sites, importers and producers of petroleum, fossil-based fuels, and other high GWP gases. Large industrial facilities will be included under the cap in 2014 and local natural gas distributors will be included in 2017.* Sources emitting less than 25,000 tons CO_2e annually will be subject to industry-specific emissions standards.	2012: ~5% above 2005 levels(4987 MMT)Phase-in coverage of l industrial facilities in 2014 and local natural gas distributors in 2017*2020: 6% below 2005 levels (5796 MMT)2030: 44% below 2005 levels (3436 MMT)2050: 80% below 2005 levels (1233 MMT)	Draft proposal was released on 7 October 2008 and is expected to frame debate in the House in 2009.
Regional Greenhouse Gas Initiative (RGGI)	Members (10): CT, DE, ME, MD, MA, NH, NJ, NY, RI, VT Observers (8): DC, PA Ontario, Quebec, NS, NB and Newfoundland	Power plants with generating capacity greater than 25 megawatts (MW) that have been operating on or after 1 January 2005	2009-2014: 188 million short tons 2015: cap declines 2.5% per year 2019: 10% below initial cap	Program officially begins 1 January 2009. First auction occurred on 25 September 2008 and witnessed clearing price of $3.07. The second is scheduled for 17 December 2008. Only 6 states expected to participate in September auction (CT, ME, MD, MA, RI, VT). Some analyses project RGGI may be overallocated in early years.

Western Climate Initiative (WCI)	Members (11): AZ, CA, MT, NM, UT, OR, WA BC, Manitoba, Quebec, Ontario Observers (13): AK, CO, ID, KS, NV, WY Saskatchewan Baja California, Chihuahua, Coahuila, Nuevo Leon, Sonora, Tamaulipas	1) Electricity combustion (first jurisdictional deliverer) 2) Industrial combustion (point of emission) 3) Industrial processes (point of emission) Starting in 2015 (upstream): 1) Residential, commercial, industrial fuel combustion 2) Transportation fuel	Aggregate target of 15% below 2005 levels by 2020. This regional target was calculated by aggregating each WCI participants differentiated reduction target.	The WCI formed five Working Subcommittees to develop key design elements of the program (Allocations; Data Reporting; Electricity; Offsets; Scope). On 23 July 2008 WCI released design draft for public comment. Final design document was released on 23 September 2008 and will be implemented over the next few years.
Midwestern Greenhouse Gas Accord (MGA)	Members (7): IL, IA, KS, MI, MN, WI, Manitoba Observers (4): ID, OH, SD Ontario	Electric power generation and industrial combustion sources will be regulated. Establishing thresholds and coverage of additional sectors is still under negotiation.	2020: 15%, 20%, or 25% below 2005 levels (TBD) 2050: 60-80% below 2005 levels	The MGGA was officially announced on 15 November 2007. The MGGA released draft recommendations on 15 September 2008. Final recommendations are scheduled to be completed in November 2008, but likely will be delayed until May 2009.

California	California	1)Electricity generation (including imports) 2) Industrial sources (> 25,000 CO_2e) Starting in 2015 (upstream): 1) Fuel combustion at facilities with <25,000 CO_2e 2) Residential and commercial fuel combustion (where enters market) 3) Transportation fuel (where enters market)	2010: 2000 levels 2020: 1990 levels 2050: 80% below 1990 levels	CARB has reviewed a number of recommendations from state regulatory agencies regarding the design and scope of a state-wide cap and trade program. On 15 October, CARB released its Final Scoping Plan outlining a number of regulatory initiatives including design elements for a cap and trade program to be implemented by 2012 and with provisions to be harmonized with the WCI.

III. Policy Scenarios and Relevant Economic Modeling

A. Considerations in Selecting Scenarios and Bounding the Analysis

The GHG policy scenarios in this analysis are constructed for the purpose of developing reasonable lower and upper bounds for estimates of the cost of GHG compliance instruments that Nova Scotia Power Inc. could face in the future. They are not a prediction of the future. They take into account a range of possible policy outcomes and the types of policy scenarios considered in GHG policy-related economic models, and focus on North American policy development and associated prices. To the extent that the scenarios envisage linkages to broader international GHG markets, the linkages take into account global pricing.

As a basis for a high-price scenario, the analysis considers a scenario with limited compliance flexibility. The amount of compliance flexibility assumed by economic models is a key determinant of prices. For example, a study by the U.S. Environmental Protection Agency (EPA)[2] finds that under the emissions trading program proposed by Senators Lieberman and McCain, prices in 2030 would increase by approximately 300% if no domestic or international offsets were allowed, relative to a scenario in which no restrictions were imposed on the use of international and domestic offsets. In light of this dynamic, and given the availability of economic models that consider limits on compliance flexibility, the high-price scenario in this analysis is one in which Canada and the U.S. allow no use of international offsets. From a political perspective, such a scenario could occur if the Canada and the U.S. seek to facilitate the turnover of old, emissions-intensive power plants as part of efforts to meet ambitious emission reduction targets. This turnover would be hastened and domestic abatement could be greatly increased if international offsets were to be excluded from the compliance regime. This scenario is referred to as the “Made in North America – Aggressive Targets” scenario discussed below.

As a basis for a low-price scenario, we consider the potential for a price cap or a carbon tax. Some segments of Canadian industry are advocating some form of price cap that would provide compliance cost certainty under the longer term targets that Canada will impose. The provinces of British Columbia and Quebec each have implemented a form of carbon tax within their jurisdictions. Both the BC and Quebec programs envisage eventually adopting a cap-and-trade system within the context of the Western Climate Initiative. Should cap and trade legislation in the U.S. not materialize, this “made in Canada” tax approach would imply that the Federal Government would impose a cap on the cost of compliance instruments and maintain it over time. This scenario is taken into account in the “Price Cap” scenario discussed below.

The mid-range price (and most likely) scenario is described below as “Linked Markets”.

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[2] EPA, *EPA Analysis of The Climate Stewardship and Innovation Act of 2007, S. 280 in 110th Congress*, July 16, 2007, http://www.epa.gov/climatechange/downloads/s280fullbrief.pdf

B. Policy Scenarios

Table 2 summarizes the key elements and assumptions of the three scenarios used for this paper. Detailed descriptions of each scenario follow. After the detailed descriptions, a discussion on the relative likelihood of each of the scenarios is provided.

Table 2 – Key Elements and Assumptions of Policy Scenarios

"Price Cap" Scenario	"Linked Markets" Scenario	"Made in North America – Aggressive Targets" Scenario
CANADA FEDERAL PROGRAM From 2010 • Intensity targets with price cap (technology fund contributions) • Access to price cap expanded and extended relative to current Federal Regulatory Framework for Air Emissions or comparable carbon t ax imposed • Price cap/carbon tax increases by 5% each year from $15 in 2010 to $25 in 2020 and $31 in 2025 • Domestic/international offsets allowed as envisioned in Federal Framework **U.S. FEDERAL PROGRAM** From 2012 • Bingaman bill with price cap • Domestic and international offsets allowed as per Bingaman bill **LINKAGES** Canada and U.S. do not link Canada and U.S. do not join an international regime Regional initiatives superseded by federal program	**CANADA FEDERAL PROGRAM** 2010-2015 • Intensity targets with price cap (technology fund contributions) • Access to price cap phased out as envisioned in Federal Framework • Domestic/international offsets allowed as envisioned in Federal Framework After 2015 • Target consistent with those in leading U.S. climate bills (e.g. McCain-Lieberman (55% below 1990 levels by 2050)[3] to Lieberman-Warner bill (67% below 1990 levels by 2050)[4] • No price cap • Limited or no constraints on domestic/international offsets **U.S. FEDERAL PROGRAM** From 2015 • Targets consistent those in leading U.S. climate bills (e.g. McCain-Lieberman (55% below 1990 levels by 2050) to Lieberman-Warner bill (67% below 1990 levels by 2050) • Limited or no constraints on domestic/international offsets **LINKAGES** Canada and U.S. link by 2020 Canada and U.S. join an international regime by 2020 Regional initiatives superseded by federal program in U.S. by beginning of 2015 and in Canada by the end of 2015	**CANADA FEDERAL PROGRAM** 2010-2014 • Intensity targets with price cap (technology fund contributions) From 2015 • Target consistent with those in more ambitious U.S. climate bills (e.g. Lieberman-Warner bill (67% below 1990 levels by 2050) • Domestic offsets allowed • No international offsets **U.S. FEDERAL PROGRAM** From 2015 • Target consistent with those in more ambitious U.S. climate bills (e.g. Lieberman-Warner bill (67% below 1990 levels by 2050) • Domestic offsets allowed • No international offsets **LINKAGES** Canada and U.S. link in 2015 Canada and U.S. do not join an international regime Regional initiatives superseded by federal program

[3] Based on the bill covering 76% of U.S. GHG emissions.
[4] Based on the bill covering 87% of U.S. GHG emissions.

1. Price Cap Scenario

In this scenario, Canada and the U.S. are outside of an international agreement and implement less ambitious but what appear to be politically feasible policies – e.g. the Bingaman-Specter climate bill (S. 1766) introduced in the U.S. Senate, which is the least stringent of current U.S. legislative proposals that may receive serious consideration, and which also incorporates a price cap. Reductions would be mandated in the U.S. beginning in 2015, based on the assumption that legislation may not be approved until 2010, and that time will be needed to develop regulations and provide regulated entities with some lead-time before requirements are implemented. Canada would implement its GHG intensity targets and allow for technology fund contributions for compliance starting in 2010. Some jurisdictions may impose a modest carbon tax, less than what has been proposed by the government of B.C. The technology fund payment provisions in the current Federal Regulatory Framework for Air Emissions are changed to eliminate the phase-out of access to the payments that occurs over 2010-17, and to increase the price cap over time.[5] For purposes of this analysis, we assume that the price cap would start at $15 in 2010 and would increase 5% per year to $24 in 2020 and $31 in 2025. These price levels reflect the need for Canada to increase the price over time in order to meet its emission reduction targets. They also were selected to be sufficiently low to provide a reasonable lower bound for pricing, insofar as they could be seen as a plausible approach at the Federal level to address emissions while simultaneously addressing industry's cost and competitiveness concerns. Also in keeping with this scenario serving as a lower bound for pricing, it is assumed that all provinces decide to conform to the Canadian Federal Plan and not to implement province-level targets or participate in the Western Climate Initiative. Regional initiatives and individual provincial and state initiatives (with the possible exception of California's) would be superseded by federal regulations or programs in both Canada and the U.S. Domestic offsets systems would be authorized for compliance with emissions targets in both the Canadian and U.S. systems. Given the price caps in Canada under this scenario, linkages with other carbon markets would be difficult.

This scenario would be possible if Canadian governments are willing (for economic competitiveness reasons) to accept that Large Final Emitters (LFEs) may make significant use of the price cap, which could jeopardize their ability to meet emission reduction targets; and if the U.S. Congress cannot reach consensus on a proposal more stringent than the Bingaman-Specter bill. (A discussion on the likelihood of the different scenarios is provided in subsection C below.) This situation could occur in the absence of a post-2012 international agreement that includes the world's largest emitters, including China, India and the U.S.

2. Linked Markets Scenario

In this scenario, Canada and the U.S. implement more ambitious reduction targets than in the price cap scenario (e.g. ranging from the 55% below 1990 target by 2050 in the McCain-Lieberman bill (S. 280) to the 67% below 1990 target by 2050 in the Lieberman-Warner proposal (S. 2191/S. 3036)). In this scenario, it is assumed that Canada and the U.S. join an international regime by 2020. For the U.S., joining an international regime requires that the Parties agree to

[5] The Framework Agreement sets the technology fund payment price at $15 in 2010 and increases it to $20 in 2013. In 2010, 70% of the compliance gap may be addressed through technology fund payments. The percentage decreases each year, reaching 10% in 2016.

the treaty and the U.S. Senate ratifies it by two-thirds majority and passes implementing legislation. It is highly unlikely that this would occur in the short term. We assume the U.S. passes a domestic GHG emission control program in the 2009-2010 timeframe and authorizes the use of domestic and international offsets. In this scenario, it is assumed that the U.S. trading program would begin by 2015. The U.S. would then join an international regime by 2020 while maintaining its targets.

Canada would maintain its current policy approach, including an intensity target with a technology fund compliance option, through the end of 2015. At that point, Canada would adopt more stringent absolute emissions targets comparable to those adopted by the U.S., and link its trading program to the U.S. trading program. It is assumed that limited constraints (e.g. the Lieberman-Warner bill's 30% offset limit) or no constraints would be imposed on international trading or domestic offsets. It is also assumed that the U.S. would allow Certified Emissions Reductions (CERs) under the successor regime to the Kyoto Protocol to be used for compliance starting in 2015 (even before joining an international regime) and Canada would maintain the provisions on CER use in the current Federal Framework through 2015 (i.e. CERs may be used for up to 10% of a firm's annual GHG emissions target)**.**

Regional initiatives and individual provincial and state initiatives would be superseded by the Federal program adopted in the U.S. by the beginning of 2015 (with the possible exception of California's), and by the new Federal program adopted in Canada by the end of 2015. Thus, provincial targets would be relevant through 2015 in Alberta, which allows for unlimited use of technology fund payments to meet emissions intensity targets. They would also be relevant in other Canadian provinces that have set GHG emissions targets, including participants in the Western Climate Initiative – British Columbia, Ontario, Quebec and Manitoba. It is difficult to say at the moment what targets may be applied to industry in Nova Scotia until such time as the 2008 Climate Action Plan is released.

This scenario would be possible if the Federal Government and state and provincial politicians agreed (by the beginning of 2015 for the U.S., by the end of 2015 for Canada) on the need for ambitious Federal programs.

3. Made in North America – Aggressive Targets Scenario

Canada and the U.S. adopt a trading program with ambitious targets (such as the 67% below 1990 by 2050 target in the Lieberman-Warner bill), but do not link to other programs or allow for international offsets. This scenario would be possible if negotiations on a successor agreement to the Kyoto treaty break down and/or a splinter group emerges (which could be formed based on North American Free Trade Agreement (NAFTA) countries or the Asia-Pacific Partnership for Clean Development and Climate). In this case, there could be differences among regional groups regarding eligibility of allowances and offsets from other regions, paving the way for restrictions on linking and the imposition of constraints on the use of international offsets for compliance in the U.S./Canada program. In Canada, it is assumed that a new federal government eliminates the technology fund based on uncertainties associated with its performance, but offers compliance flexibility through the use of domestic offsets and trading. It would be assumed that Canada would continue with a variation on its intensity and technology fund approach through 2014, at which point Canada would adopt targets comparable to those in the U.S. in 2015. Regional initiatives and individual provincial and state initiatives (with the possible exception of California's) would be superseded by federal regulations in both Canada and the U.S. in 2015.

This scenario could occur if the Canadian Federal Government decides that the climate change issue requires more ambitious action than the intensity-based approach. As noted above, it also could occur if Canada and the U.S. seek to facilitate the turnover of old, emissions-intensive power plants as part of efforts to meet ambitious GHG emission reduction targets.

C. Likelihood of the Different Scenarios

- **Linked Markets Scenario (Most Likely)**

In our view, the Linked Markets scenario is the most likely scenario at this time in light of current political trends in Canada and the U.S., pressures from Canadian business to avoid a regulatory "patchwork" for climate change, the ongoing effort by the international community to complete an international negotiation for a post-2012 climate framework agreement by the end of 2009, and economic considerations. A brief discussion on these dynamics follows.

In Canada, the October election has returned the Conservative government with a strengthened minority government. In the last week of the election campaign, the Conservative Party released its platform which contained a specific commitment to develop a cap and trade market to be linked with the US and Mexico and to be implemented in 2012-2015. This is a significant strengthening of the commitment in the March 2008 "Turning the Corner" climate policy that include a commitment to actively explore future linkages with US emissions trading systems. At the provincial level, a number of provincial governments are either implementing regulations (e.g. Alberta) or introducing legislation incorporating long-term targets for GHG emissions reductions (e.g. B.C., Ontario and Quebec), while the federal government continues to develop its regulatory program. This evolution in climate policy is one of the reasons that the Canadian business community, led by the Canadian Council of Chief Executives, has come out strongly in support of development of national as opposed to regional or provincial programs. Business is calling on the federal government to ensure that GHG reduction programs across all Canadian jurisdictions are harmonized and consistent. This call for harmonization also spills over to the U.S. and is consistent with the Linked Markets scenario.

In the U.S., both presidential candidates support the U.S. participating in an international climate agreement and adopting an economy-wide emission trading program with targets comparable to those assumed in the Linked Markets scenario. Over the past several years, Senator McCain has also co-sponsored the McCain-Lieberman emissions trading bill, which is considered in the Linked Markets scenario. Senator Obama supports legislation that would set targets at least as stringent as those included in the Lieberman-Warner proposal (which are even more stringent than those in the McCain-Lieberman bill). The Lieberman-Warner proposal was considered on the Senate floor in June 2008, but failed to overcome the 60-vote hurdle to proceed to a vote on the bill.

The conclusion of a post-2012 agreement now appears to be gaining momentum after Canada and the U.S. joined the rest of the world in adopting the "Bali roadmap," which sets a goal of finalizing international negotiations at a meeting to be held in December 2009. The Bali roadmap notes that "deep cuts in global emissions will be required to achieve the ultimate objective of the Convention," and references text in Working Group III's contribution to the Intergovernmental Panel on Climate Change's (IPCC) Fourth Assessment Report stating that

> "[u]nder most equity interpretations, developed countries as a group would need to reduce their emissions significantly by 2020 (10–40% below 1990 levels) and to still lower levels by 2050 (40–95% below 1990 levels) for low to medium stabilization levels (450–550ppm CO2-eq)."[6]

These reduction levels are broadly consistent with the emission reduction targets for Canada and the U.S. in the Linked Markets scenario.

With respect to economic considerations, Canada will have to choose between: 1) pursuing a cost minimization policy in relation to the rapidly expanding oil sands sector (i.e. a low price cap or delayed emission targets); and 2) pursuing a policy that imposes sufficient emission reduction requirements on carbon on oil, gas and electricity producers to avoid jeopardizing export markets that have signaled a willingness to impose trade restrictions on environmentally unfriendly products.

In the U.S., once the debate in Congress over different emissions trading proposals begins to receive closer attention as it moves through the legislative process, it is likely that members of Congress will place greater emphasis on reducing the costs of achieving GHG targets. This could result in legislation that authorizes the use of international offsets for compliance. In this context, we think it is likely that Congress will opt for international offsets provisions that more closely resemble those in the Linked Markets scenario than those in the Made in North America scenario, in which no international offset use is allowed. Moreover, it would be inconsistent with participating in an international climate agreement if the U.S. adopts an overly restrictive approach on offsets. It also would be economically inefficient. The use of international offsets will be critical for both Canada and the U.S. to achieve tough targets, particularly before carbon capture and storage technology is widely available.

Finally, we would expect that by 2020, the large majority of provincial/state and regional trading programs would be harmonized with federal programs. By that point, targets under federal programs are likely to be sufficiently stringent, and sub-national trading programs will have succeeded in helping to motivate the adoption of ambitious targets at the federal level. In addition, it likely would be difficult to maintain varying targets at the state/provincial/regional and federal levels for long, as it could have competitiveness impacts on companies with operations in several jurisdictions.

In summary, we believe that the Linked Markets scenario is the most likely of the three scenarios and that the pricing projections associated with the scenario represent our best estimate of prices in the period to 2025.

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[6] Contribution of Working Group III to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change, Technical Summary, page 90, http://www.ipcc.ch/pdf/assessment-report/ar4/wg3/ar4-wg3-ts.pdf

- **Made in North America – Aggressive Targets**

In our view, this scenario could occur if the Canadian Federal Government decides that the climate change issue requires more ambitious targets than the currently planned intensity-based targets. The scenario could also occur if Canada and the U.S. seek to facilitate the turnover of old, emissions-intensive power plants as part of efforts to meet ambitious GHG emission reduction targets. In addition, this scenario would also be consistent with the development of bilateral and regional trade blocs and agreements that have formed and been adopted over the past 15 years. These include the continued integration of the European Union, the North American Free Trade Agreement (NAFTA), the Association of Southeast Asian Nations (ASEAN), and U.S. bilateral trade agreements with Central and South American countries. It will continue to be challenging for the international community to reach consensus in negotiations to develop a successor agreement to the Kyoto Protocol. These negotiations will remain contentious over such issues as emission reduction targets, the use of markets for compliance, and the level of developing country participation, among others. In the event that an agreement is not reached, it is conceivable that Canada and the U.S. would link their trading programs, in light of NAFTA and how closely their economies are linked. It also is conceivable in this scenario that Canada and the U.S. would seek to meet their targets through domestic actions and bilateral trading in order to stimulate investment in the U.S. and Canada, and to forego the use of international offsets.

We believe that the likelihood of this scenario occurring is significantly less than the likelihood of the linked markets scenario, and approximately equal to that of the Price Cap scenario.

- **Price Cap Scenario**

In Canada, price caps in the form of contributions to a government-controlled technology fund have garnered significant support from industry. This is particularly true in Alberta where the provincial Technology Fund has emerged as the preferred option for industry to comply with provincial GHG regulatory controls. At the federal level, the government has indicated that it sees such contributions as being transitory, to be phased out in the longer term. What has not yet been tested, however, is the degree of accountability associated with each of these compliance options. At the federal level, legal opinions differ on whether a technology fund created under the existing Canadian Environmental Protection Act will need to deliver actual emissions reductions equal to the number of compliance units issued to industrial emitters in return for their contributions to the technology fund. This accountability issue may, in turn, move federal policy makers towards a carbon tax approach as opposed to a directed fund as currently envisaged. To date, carbon taxes in Canada have received mixed reviews in public opinion polling and were clearly rejected in the October 2008 election campaign.

In the U.S., price caps have appeared to have less support than other cost control options, perhaps because they could jeopardize the achievement of any emissions cap. A carbon tax also appears unlikely to garner sufficient support. Our view on this issue is shaped by events that occurred in the first Clinton Administration. In 1993, President Clinton proposed a small tax on the BTU content of energy sources. It met with extensive opposition in the Congress which was controlled by his own party, and it ended up as a 4.3 cent gasoline tax. A tax to limit GHG emissions would necessarily be much larger to have its intended effect. Nevertheless, it is still possible that concerns over costs, competitiveness and potential relocation of industry to countries that do not impose comparable targets could result in serious consideration of a price cap.

A price cap that is set at a low-to-moderate levels (such as the cap proposed in the Price Cap scenario) could receive some support because it would provide more compliance cost certainty to industry while having less likelihood (than a low price cap) of jeopardizing emissions caps. In addition, a price cap could be viewed more favorably by policy-makers if it was viewed as a transition mechanism and was not in place through the middle of the century. On the other hand, a price cap would still make it difficult or impossible to link to other trading schemes.

Overall, we believe the Price Cap scenario has a similar likelihood of occurring as the Made in North America scenario, and a much lower likelihood than the Linked Markets scenario..

D. Economic Model Estimates

The pricing forecasts in this report take into account a number of economic modeling studies that consider scenarios that are similar and relevant to the policy scenarios described in Section B. Table 3 summarizes the pricing estimates for these models.

Table 3: Summary of Economic Models

	2012	2015	2020	2025	2030	Comments
			CDN 2008 $			
LIEBERMAN-WARNER *						
EPA (IGEM)	n.a.	$ 12	$ 16	$ 20	$ 25	Linked Markets - Unlimited dom and intl credits
EPA (ADAGE)	n.a.	$ 31	$ 39	$ 51	$ 64	Linked Markets - Unlimited dom and intl credits
EPA (IGEM)	n.a.	$ 42	$ 54	$ 68	$ 87	Linked Markets - 15% dom 15% intl credits
Clean Air Task Force	$ 14	$ 17	$ 22	$ 33	$ 50	Linked Markets - 15% dom 15% intl credits
EIA	$ 17	$ 21	$ 21	$ 44	$ 62	Linked Markets - 15% dom 15% intl credits
ACCF/NAM	n.a.	$ 38	$ 64	$ 131	$ 269	Linked Markets - 15% dom 15% intl credits
MIT	n.a.	$ 50	$ 61	$ 75	$ 91	Made in North America - 15% dom offsets and no intl offsets
Charles River	n.a.	$ 50	$ 60	$ 73	$ 89	Made in North America - 15% dom offsets and no intl offsets
McCAIN-LIEBERMAN**						
EIA	$ 15	$ 17	$ 22	$ 25	$ 29	Linked Markets - Unlimited dom and intl credits
EIA	$ 15	$ 17	$ 25	$ 37	$ 54	Linked Markets - 30% dom and intl credits
EPA (IGEM)	n.a.	$ 11	$ 15	$ 19	$ 24	Linked Markets - Unlimited dom and intl credits
EPA (ADAGE)	n.a.	$ 17	$ 23	$ 29	$ 36	Linked Markets - 30% dom and intl credits
EPA (IGEM)	n.a.	$ 15	$ 18	$ 24	$ 31	Linked Markets - 30% dom and intl credits
EIA	$ 20	$ 24	$ 35	$ 48	$ 65	Made in North America - 30% domestic and no intl offsets
OTHER MODELS***						
Canadian Federal Model	$ 25	$ 40	$ 65	n.a.	n.a.	Federal Price Cap and 10% intl offsets
BC Climate Action Plan	n.a.	$ 27	$ 54	$ 108	$ 162	WCI Modeling by Jaccard

*
- U.S. EPA, Analysis of the Lieberman-Warner Climate Security Act, S. 2191 in 110th Congress, March 14, 2008, http://www.epa.gov/climatechange/downloads/s2191_EPA_Analysis.pdf
- Clean Air Task Force (CATF), The Lieberman-Warner Climate Security Act—S. 2191 Modeling Results from the National Energy Modeling System--Preliminary Results, February 2008, http://www.catf.us/publications/presentations/CATF_LWCSA_Short_Hill_Briefing_with_CAFE.pdf
- U.S. EIA, Energy Market and Economic Impacts of S. 2191, the Lieberman-Warner Climate Security Act of 2007, April 2008, http://www.eia.doe.gov/oiaf/servicerpt/s2191/pdf/sroiaf(2008)01.pdf
- The American Council for Capital Formation (ACCF) and the National Association of Manufacturers (NAM), Analysis of the Lieberman-Warner Climate Security Act (S.2191) Using the National Energy Modeling System (NEMS), March 2008, http://www.accf.org/pdf/NAM/fullstudy031208.pdf

- MIT, Appendix D: Analysis of the Cap and Trade Features of the Lieberman-Warner Climate Security Act (S.2191), February 2008, http://web.mit.edu/globalchange/www/MITJPSPGC_Rpt146_AppendixD.pdf (appendix to Paltsev et al. (2007): Assessment of U.S. Cap-and-Trade Proposals, MIT Joint Program on the Science and Policy of Global Change Report 146)
- Charles River Associates, Economic Analysis of the Lieberman-Warner Climate Security Act of 2007 Using CRA's MRN-NEEM Model: Summary of Findings, April 2008

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- U.S. EIA, Energy Market and Economic Impacts of S. 280, the Climate Stewardship and Innovation Act of 2007, July 2007, http://www.eia.doe.gov/oiaf/service_rpts.htm
- U.S. EPA, Analysis of Senate Bill S.280 in the 110th Congress, The Climate Stewardship and Innovation Act of 2007, July 2007, http://www.epa.gov/climatechange/economicanalyses.html#s280

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- Government of Canada, "Turning the Corner: Detailed Emissions and Economic Modeling," March 2008, p. 7, http://www.ec.gc.ca/doc/virage-corner/2008-03/pdf/571_eng.pdf
- BC Climate Action Plan, July 2008, Appendix I, http://www.livesmartbc.ca/attachments/climateaction_plan_web.pdf

The table is divided into three categories of models: 1) models that estimate prices under the McCain-Lieberman cap-and-trade bill (S. 280); 2) models that estimate prices under the more recent Lieberman-Warner bill (S. 2191/S. 3036); and 3) other models. We also include the Canadian Federal Government's March 2008 economic modeling of the Federal Regulatory Framework for Air Emissions.[7] As suggested by the table, to date there is significantly more modeling for U.S. cap-and-trade proposals than for the Canadian Federal Framework.

Models are further categorized according to the policy scenario to which they pertain. Models that assume limited or no constraints on the use of domestic and international offsets are relevant for the Linked Markets scenario. Those that assume access to domestic offsets but no access to international offsets are relevant for the Made in North America scenario. The "comments" column in the table includes brief descriptions of each model's assumptions regarding access to domestic and international offsets. No model pertains to the price cap scenario because price cap estimates were not derived based on modeling results.

To derive price estimates for any given scenario, we typically use the lowest and highest available economic modeling price estimates for relevant federal-level programs. (Price estimates for WCI are not considered because Nova Scotia is not participating in that program.) The price estimates in the section that follows take into account modeling estimates for the Canadian Federal Framework. In a linked U.S.-Canadian trading program, higher marginal costs of abatement in Canada could result in Canada becoming a net buyer of U.S. allowances. This would result in higher prices in the U.S. than those estimated in models of a U.S. trading program, which do not consider the impact of linking with Canada. To capture this effect, modeling estimates for the Canadian Federal Framework are used as the upper bound of a price range whenever they are higher than available estimates for U.S. programs for that scenario.

[7] For reference, WCI included a summary of economic modeling results in its September 2008 design recommendations. It was estimated that if domestic offsets can be used to meet 5% of the compliance obligation under the broad-coverage approach envisioned for the program, the allowance price in 2020 would be $24 (US$2007).

IV. Pricing Forecasts

This section provides GHG price estimates for compliance instruments in the three planning scenarios described in Section III B. The price estimates are largely based on relevant economic models, and are also informed by our understanding of and experience in GHG policy and carbon markets.

The prices contained in Table 4 correspond to the three planning scenarios. A discussion on the assumptions and methodologies for the price estimates in each of the scenarios follows.

Table 4: Price Estimates for Compliance Instruments in Three Planning Scenarios for Nova Scotia Power Inc. in Canada (CDN$2008 per tonne of CO_2e)

Year		2010	2015	2020	2025
Price Cap scenario		15	19	24	31
Linked Markets scenario	Price Range	15-25	17- 40	15 – 65	19 – 68
	Mid Point	20	29	40	44
Made in North America – Aggressive Targets scenario	Price Range	15-25	24 - 50	35 – 65	48 – 75
	Mid Point	20	37	50	62

Price Cap Scenario

- Prices presented in Table 4 are prices in Canada based on a federal price cap similar to the technology fund payment mechanism under the current proposed Federal Regulatory Framework. Prices would start at $15 per tonne of CO_2e in 2010 and would increase 5% each year, eventually reaching $31 per tonne of CO_2e in 2025. No economic models were used to estimate prices for this scenario.
- Only Canada's price cap is provided because it is assumed in this scenario that U.S. and Canada do not link, and that Nova Scotia Power Inc. would be affected mainly by Canadian policy.

Linked Markets Scenario

- In this scenario, Canada and U.S. join an international regime by 2020. Canada allows for technology fund payments (i.e. price cap) through the end of 2015, and then takes on more ambitious targets after 2015 and links with the U.S. by 2020. Both the U.S. and Canada would allow for the use of CERs for compliance (with no or limited restrictions) starting in 2015. Regional initiatives and individual provincial and state initiatives would be superseded by the Federal program adopted in the U.S. by 2015 (with the possible exception of California's), and the new Federal program adopted in Canada by the end of 2015.

- In the Canadian Federal program, prices reflect the federal government's economic model estimates for prices under the Federal Framework -- $25 per tonne of Co_2e in 2012, and $40 per tonne in 2015.[8] The price range for 2010 and 2015[9] reflects, on the low end, the costs of contributions to the Technology Fund, and on the high end, the economic model estimates for clearing prices in the domestic Canadian market. The maximum volume of Technology Fund contributions is phased down from 70% of the compliance gap in 2010 to 40% in 2015, 10% in 2016 and 2017, and 0% thereafter.
- Starting in 2020, price estimates in this scenario are based on prices for a linked U.S.-Canada trading program. For the Linked Markets scenario, it is assumed that limited constraints (e.g. the McCain-Lieberman and Lieberman-Warner proposals' 30% combined international and domestic offset limit) or no constraints are imposed on use of domestic and international offsets for compliance.
- In 2020, the low estimate ($15 per tonne) corresponds to U.S. EPA's IGEM model estimate of the McCain-Lieberman proposal with unlimited offsets.[10] The high estimate ($65 per tonne) corresponds to the Canadian Federal government's economic model estimates for prices under the Federal Framework in 2020. This high price was higher than any of the model estimates of U.S. prices under a similar scenario. It was included to reflect the possibility that the highest estimated price for a U.S. program would be lower than prices in a linked U.S.-Canada system, because Canada's higher marginal costs of abatement would pull prices in a linked system higher than in a U.S. system.
- In 2025, the low estimate ($19 per tonne) corresponds to U.S. EPA's IGEM model estimate of the McCain-Lieberman proposal with unlimited offsets.[11] The high estimate ($68) corresponds to U.S. EPA's IGEM model estimate of the Lieberman-Warner proposal with a 15% domestic and 15% international offset limit. (We excluded from consideration estimated prices from the ACCF/NAM model, which adopts a number of assumptions that result in far higher prices than any other model – i.e. $131 in 2025.)

Made in North America – Aggressive Targets Scenario

- In this scenario, Canada and U.S. implement ambitious targets (such as those in the Lieberman-Warner bill) that start in 2015, but do not link to a post-Kyoto international regime. Canada and the U.S.do not allow use of international offsets. Canada and the U.S. link their trading programs starting in 2015. The Canadian Federal Government eliminates the price cap/technology fund compliance option starting in 2012. Regional initiatives and individual provincial and state initiatives would be superseded by the Federal programs adopted in 2015. The price range includes models of the Lieberman-Warner proposal that assume no international offsets and global models of a U.S. trading program with similar targets through 2050 and that do not allow international offsets.
- In 2010 the regional and provincial programs still apply. Prices for the Federal Framework are the same as those in the Linked Markets scenario.

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[8] Government of Canada, "Turning the Corner: Detailed Emissions and Economic Modeling," March 2008, p. 7, http://www.ec.gc.ca/doc/virage-corner/2008-03/pdf/571_eng.pdf

[9] Price reflects $20 fee in 2013 dollars converted to 2008 dollars based on assumed GDP growth of 3% per year from 2008 to 2015.

[10] U.S. EPA, Analysis of Senate Bill S.280 in the 110th Congress, The Climate Stewardship and Innovation Act of 2007, July 2007, http://www.epa.gov/climatechange/economicanalyses.html#s280

[11] U.S. EPA, Analysis of Senate Bill S.280 in the 110th Congress, The Climate Stewardship and Innovation Act of 2007, July 2007, http://www.epa.gov/climatechange/economicanalyses.html#s280

- In 2015, the low price estimate ($24) corresponds to the U.S. Energy Information Administration's (EIA) economic model estimates for prices under the McCain-Lieberman proposal, assuming a 30% domestic offset limit and no international offsets. The high price estimate ($50) corresponds to Charles Rivers Associates' estimate of prices under the Lieberman-Warner proposal, assuming a 15% domestic offset limit and no international offsets.[12]
- In 2020, the low price estimate ($35) corresponds to EIA's economic model estimates for prices under the McCain-Lieberman proposal, assuming a 30% domestic offset limit and no international offsets. The high price estimate ($65) corresponds to the Canadian Federal government's economic model estimates for prices under the Federal Framework in 2020. This high price was higher than any of the model estimates of U.S. prices under a similar scenario. It was included to reflect the possibility that the highest estimated price for a U.S. program would be lower than prices in a linked U.S.-Canada program, because Canada's higher marginal costs of abatement would pull prices in a linked system higher than in a U.S. system.
- In 2025, the low price estimate ($48) corresponds to EIA's economic model estimates for prices under the McCain-Lieberman proposal, assuming a 30% domestic offset limit and no international offsets. The high price estimate ($75) corresponds to MIT's estimate of prices under a U.S. target similar to those in the Lieberman-Warner proposal, and assuming a 15% domestic offset limit and no international offsets.[13]

V. Sensitivity Analysis

A price sensitivity case was developed to capture a scenario in which the government of Nova Scotia implements a policy that is different from those being considered by the federal governments of both Canada and the U.S. A description of the sensitivity case is provided below.

The sensitivity case examines possible prices that could result if Nova Scotia decides to meet its provincial emission reduction target (10% below 1990 levels by 2020) and to set geographic restrictions on instruments (e.g. offsets) that could be used for compliance with the Nova Scotia program's emissions targets. In this "Nova Scotia compliance instruments only" case, Nova Scotia decides it will meet its target without using offsets or compliance instruments from outside the province.

The Canadian Federal Government would need to make a determination of the equivalency of the environmental results of the Nova Scotia GHG program vis-à-vis the federal GHG program under the Regulatory Framework. The Regulatory Framework indicates medium and long-term targets will be established with a goal of reducing absolute GHG emissions relative to 2006 levels by 20% by 2020 (approximately 1990 levels) for the country as a whole (additional detail is provided in Annex 1). If adopted by Nova Scotia, this goal would translate into an emissions

[12] Charles River Associates, Economic Analysis of the Lieberman-Warner Climate Security Act of 2007 Using CRA's MRN-NEEM Model: Summary of Findings, April 2008
[13] MIT, Appendix D: Analysis of the Cap and Trade Features of the Lieberman-Warner Climate Security Act (S.2191), February 2008, http://web.mit.edu/globalchange/www/MITJPSPGC_Rpt146_AppendixD.pdf

target of approximately 18.1 Mt by 2020.[14] Nova Scotia's current emissions target is 10% below 1990 levels by 2020, which translates into an absolute target of 17.6 Mt by 2020, slightly more stringent than the federal goal.[15] As a result, we assume that the Federal Government would determine that the Nova Scotia GHG program meets the equivalency test (i.e. that the emission reduction requirements of the Nova Scotia program are at least as stringent as those in the Federal Government's GHG program).

In this sensitivity case prices are considered through 2020, reflecting our view that Nova Scotia is unlikely to pursue a separate target beyond 2020 in any scenario. We assume that Nova Scotia participates in a broader federal program that corresponds to one of the three planning scenarios used in Table 4 after 2020. Table 5 presents the results. Prices in the table are prices that Nova Scotia would face under each sensitivity case.

Table 5: Price Estimates for Compliance Instruments in Sensitivity Analysis for Nova Scotia Power Inc. in Canada (CDN$2008 per tonne of CO_2e)

Year		2010	2015	2020
Nova Scotia Compliance Instruments Only				
As Applied to All Three Scenarios	Price	26	132	198

The "Nova Scotia compliance instruments only" case is unlikely in view of the high costs associated with meeting the Nova Scotia target while limiting eligible offsets to those generated in Nova Scotia ($26/tonne CO_2e in 2010, and $132/tonne CO_2e in 2015 and $198 in 2020). If Nova Scotia implemented a provincial emissions program, it is more likely that it will allow offsets from outside of Nova Scotia to be used for compliance. Allowing for offsets from other jurisdictions would significantly reduce compliance costs.

The "Nova Scotia compliance instruments only" sensitivity case was applied to each of the three policy scenarios as follows:

- In the Price Cap scenario, Nova Scotia pursues its target in the context of a modest Canadian Federal program with a price cap that is assumed to be extended to 2030. Nova Scotia does not have access to price cap payments under its program. The Canadian program is not linked to the U.S. federal program. Thus, Nova Scotia compliance buyers could theoretically need to compete against non-Nova Scotia Canadian buyers to purchase offsets from Nova Scotia. However, non-Nova Scotia Canadian buyers would not be willing to pay more than the Canadian Federal price cap.
- In the Linked Markets scenario, Nova Scotia pursues its target in the context of an ambitious Canadian federal program. However, the Canadian program allows for technology fund payments (i.e. price cap) through the end of 2015. Nova Scotia does not have access to price cap payments under its program. The U.S. and Canada link

[14] Based on the National Inventory Report, 1990-2005: Greenhouse Gas Sources and Sinks in Canada. Nova Scotia's target is estimated using 2005 (22.7 Mt) levels as proxy.
[15] Nova Scotia's 1990 GHG emissions were 19.5 Mt based on the National Inventory Report, 1990-2005: Greenhouse Gas Sources and Sinks in Canada, (http://www.ec.gc.ca/pdb/ghg/inventory_report/2005_report/ta11_6_eng.cfm),

their markets after 2015. Consequently, Nova Scotia compliance buyers could theoretically need to compete against non-Nova Scotia Canadian buyers (who have access to a price cap through 2015) immediately and U.S. buyers starting after 2015. U.S. and non-Nova Scotia Canadian buyers also have access to CERs.

- In the "Made in North America – Aggressive Targets" scenario, Nova Scotia pursues its target in the context of ambitious U.S. and Canadian federal programs which link starting in 2015 but do not allow for use of international offsets. The Canadian federal government eliminates the price cap/technology fund compliance option starting in 2015. Nova Scotia compliance buyers could theoretically need to compete against non-Nova Scotia Canadian buyers and U.S. buyers starting in 2015.

Based on estimated marginal costs in Nova Scotia, which are very high, we conclude that prices in this sensitivity case would be the same under all three of the scenarios, based on the following reasoning.

- Prices are based on the marginal cost of emission reductions in Nova Scotia and demand for Nova Scotia-based reductions in each scenario.
- The price estimate is based on marginal cost estimates in the Jaccard 2007 study. [16] That study is a marginal cost analysis focusing on domestic Canadian GHG abatement options. It provides a single GHG marginal abatement curve (MAC) for each province, and estimates volumes of GHG abatement in the Atlantic Provinces at different hypothetical GHG prices.[17] The study excludes landfills and sequestration in its cost curves. As a result, GHG prices in Nova Scotia could be lower than estimated in this report, based on the Jaccard 2007 study, if landfill and sequestration offset supply potential in Nova Scotia is taken into account.[18]
- In the Price Cap scenario, there would be no demand for Nova Scotia offsets from non-Nova Scotia Canadian buyers because – based on the Jaccard 2007 study -- marginal costs in Nova Scotia are far higher than the price cap. U.S. buyers would not be able to access Nova Scotia offsets because the U.S. program is not linked to Canada's. Therefore, we estimate prices for the sensitivity case based on the assumption that Nova Scotia buyers are the only source of demand for Nova Scotia-based reductions.[19]
- In the Linked Markets scenario and the Made in North America - Aggressive Targets scenario, targets in the U.S. and Canada are more stringent, and estimated prices are higher (see Table 4), than in the Price Cap scenario. This could mean that there theoretically could be demand for Nova Scotia offsets from outside of Nova Scotia. However, given that marginal costs in Nova Scotia are high relative to other Canadian provinces and relative to the U.S., we would expect there to be little or no demand from outside of Nova Scotia for Nova Scotia offsets. Therefore, for these scenarios we also estimate prices for the sensitivity case based on the assumption that Nova Scotia buyers are the only source of demand for Nova Scotia-based reductions.

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[16] MK Jaccard and Associates, Cost Curves for GHG Emission Reduction in Canada: The Kyoto Period and Beyond – Final Analysis Report (January 2007), http://www.greenparty.ca/files/JaccardFullReport.pdf.

[17] Disaggregated data of estimated marginal abatement costs for Nova Scotia only are not publicly available.

[18] To our knowledge, this type of data is not available.

[19] Demand in Nova Scotia is estimated based on the difference between Nova Scotia's emissions target (assuming it decreases linearly starting in 2010 through 2020) and Nova Scotia's projected emissions based on Canada's Energy Outlook: The Reference Case 2006 by Natural Resources Canada (http://www.nrcan-rncan.gc.ca/com/resoress/publications/peo/peo-eng.php)

Notwithstanding our statements regarding likelihood and timing of different scenarios provided in section III.C, at the request of Nova Scotia Power Inc., we applied the sensitivity analysis to all scenarios in Section III. In addition, we provided price estimates in the sensitivity cases for 2010, 2015 and 2020 in all three scenarios, despite the fact that the Linked Markets scenario assumes that local and regional programs are superseded after 2015, and the Price Cap scenario and Made in North America – Aggressive Targets scenario assumes that these programs are superseded starting in 2010. As might be expected, the sensitivity cases result in higher prices for Nova Scotia than in the scenarios considered without sensitivity cases. Thus, results for the sensitivity cases can be considered to represent alternative upper-bound estimates for each of the scenarios.

ANNEX 1 – NORTH AMERICAN GHG EMISSIONS REDUCTION POLICY INITIATIVES

Canada

Federal Government

Regulatory Framework for Air Emissions
On April 26, 2007 the Federal Government announced a framework to regulate GHG and other air emissions from major industrial sectors. On March 10, 2008 further details of the "Turning the Corner" plan were released including broad details of the Offset System Framework and the Credit for Early Action part of the plan. On June 29, 2008, Phase I of the application process for credit for early action was opened and on August 9, 2008 the Guideline for Protocol Developers under the Offset System was published. Draft regulations are expected to be published in the Canada gazette by the end of 2008 and the regulations will be finalized in 2009 and will come into force January 1, 2010. The regulations will require large industrial emitters in Canada to reduce their GHG emissions intensity by 6% per year from 2006 levels from 2007 to 2010 and by a further 2% each year until 2015. Following a period of consultation with industry, the Provinces and other stakeholders, medium and longer term targets will be established with a goal of reducing absolute GHG emissions relative to 2006 levels by 20% by 2020 (approximately 1990 levels) for the country as a whole.[20,21]

The GHG portion of the Regulatory Framework is to be implemented by way of regulations promulgated under the *Canadian Environmental Protection Act 1999* (CEPA 1999), eliminating the need to pass new legislation[22]. The Regulatory Framework sets a 2010 implementation date for the GHG emissions intensity reduction targets. The sectors that are covered include thermal electricity generation; oil and gas; forest products; smelting and refining; iron and steel; and cement, lime and chemicals. Facilities that are covered by the new regulations can comply in a number of ways including:

- Reducing their own emissions through internal actions;
- Contributing to a technology fund[23] consisting of two components: Deployment and Infrastructure, and Research and Development. Contribution rates to the two components of the fund will be at $15 (nominal) per tonne for each of 2010, 2011 and 2012, $20 (nominal) per tonne for 2013 and $20 (nominal) per tonne escalating with GDP for each of the years out to 2017;

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[20] Estimate based on 2005 emissions.
[21] National Inventory Report, 1990-2005: Greenhouse Gas Sources and Sinks in Canada. http://www.ec.gc.ca/pdb/ghg/inventory_report/2005_report/ta8_2_eng.cfm
[22] The establishment of the Technology Fund component of the Plan may require separate legislation if a legal ruling under CEPA requires the Fund to deliver one tonne of emissions reductions in return for each $15 contributed to the Fund during the period of 2010 to 2017.
[23] The proposed framework allows for contributions to either of two components of the Climate Change Technology Fund: 1. Deployment and Infrastructure Component: access as a percentage total target over 2010-2017 at a declining rate of 70% in 2010, 65% in 2011, 60% in 2012, 55% in 2013, 50% in 2014, 40% in 2015 and 10% in each of 2016 and 2017. 2. Research and Development Component: Access over 2010-2017 at 5 million tonnes per year.

- Receiving credit for certified project investments[24] (an option being considered, but rules not yet established)
- A one-time recognition of early action for firms that took verified action between 1992 and 2006 to reduce their GHG emissions[25];
- Inter-firm emissions trading;
- Purchasing domestic offsets;
- Potential linkages with regulatory-based emissions trading systems in the U.S.[26]; and,
- Purchasing Certified Emissions Reductions (CERs) under the Kyoto Protocol's Clean Development Mechanism (CDM)[27] up to an amount equal to 10% of a firm's total GHG emissions target.

Both CEPA 1999 and the Regulatory Framework include provisions to enter into "equivalency agreements" with Provinces that set GHG standards at least as stringent as the federal standards. Once signed, an equivalency agreement would lead to the suspension of the relevant CEPA 1999 GHG regulations, with only the Provincial regulations applying.[28]

In the October 2008 election campaign the Conservatives pledged to

> *"…implement our 'Turning the Corner' action plan to reduce Canada's greenhouse gas emissions in absolute terms by 20 per cent over 2006 levels by 2020. We will work with the provinces and territories and our NAFTA trading partners in the United States and Mexico, at both the national and state levels, to develop and implement a North*

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[24] A certified project investment would be pre-certified by the Government as being an investment in a transformative technology that would incrementally reduce future emissions to receive credits from the Government for that investment. These credits could then be used towards a facility's regulatory obligations. One of the key transformative technologies is carbon capture and storage, for which a 100% credit will be given for CCS investments.

[25] The submissions deadline for Phase I templates under the credit for early action scheme has been set for September 8, 2008. See http://www.ec.gc.ca/cmap-cea/default.asp?lang=En&n=B148443A-1 for details.

[26] The Regulatory Framework makes specific reference to the Western Regional Climate Action Initiative (later renamed WCI and described in detail later in report) and the Regional Greenhouse Gas Initiative (established in December 2005 by the governors of Connecticut, Delaware, Maine, New Hampshire, New Jersey, New York, and Vermont) in this regard.

[27] The Regulatory Framework makes no reference to the potential use of Emissions Reduction Units (ERUs) from the Joint Implementation provision of the Kyoto Protocol, and cabinet decisions in 2008 have clarified that ERUs will be excluded for eligible compliance instruments along with credits from forestry and agriculture CDM projects.

[28] Section 10 of CEPA 1999 allows the use of equivalency agreements where, by Cabinet decision, a regulation under CEPA 1999 is declared to no longer apply in a Province, a Territory or an area under the jurisdiction of an aboriginal government that has equivalent requirements. The equivalent regulation does not have to have the same wording as the CEPA 1999 regulation, but have the same effect. Equivalency agreements are possible for CEPA 1999 regulations dealing with, among other things, toxic substances, international air or international water pollution and environmental emergencies. CEPA 1999 requires that all proposed equivalency and administrative agreements undergo a 60-day public comment period. Agreements terminate five years after coming into force to ensure regular review and renewal as necessary. Agreements may be terminated at any time with three months notice. See http://www.ec.gc.ca/ceparegistry/the_act/guide04/s18.cfm#182

America-wide cap and trade system for greenhouse gases and air pollution, with implementation to occur between 2012 and 2015."

Provincial Plans, Programs and Policies

Canadian Council of the Federation

Premiers representing all provincial and territorial governments met July 16-18, 2008 in Quebec City to discuss, among other things, climate change. This meeting followed an unsuccessful attempt in 2007 to reach consensus on a common approach to dealing with greenhouse gas emissions reductions. At that time, Ontario, supported by BC, Quebec and Manitoba, proposed the creation of a national cap and trade system. The proposal was strongly opposed by Alberta, Saskatchewan and Newfoundland, who characterized it as a wealth transfer vehicle. In 2008, no attempt was made at reaching consensus on GHG emissions controls, and instead the meeting focused on new initiatives to increase energy efficiency with a goal of reaching a 20% increase in efficiency in each provincial and territorial jurisdiction by 2020. The Council also agreed to promote green technologies by convening a series of forums on specific technologies including carbon capture and storage (Alberta, Saskatchewan), large scale hydro (Newfoundland and Labrador), bioenergy (British Columbia) and next generation clean cars (Ontario).

The failure of the premiers to agree among themselves on a national approach to reducing emissions of greenhouse gases is not new, and highlights the difficulties that the federal government of Canada has in developing a national approach with firm caps and aggressive short to medium term targets. It further provides evidence that for the short term, likely to 2015 or so, both federal and provincial regulatory programs for greenhouse gas emissions reduction will co-exist in Canada.

Provincial Governments

Alberta

The Province of Alberta passed the *Climate Change and Emissions Management Act* (CCEMA) in 2003. It includes a goal to reduce emissions intensity to at least 50% of 1990 levels by 2020. The Specified Gas Emitters Regulation under CCEMA came into force on August 1, 2007 and requires established facilities[29] in Alberta emitting more than 100,000 tonnes of GHGs per year to reduce their GHG emissions intensity by 12 percent from their baseline emissions intensity[30] starting July 1, 2007. These reductions can be met by improving efficiency, buying offsets created in Alberta of 2002 and later vintage, or contributing to the Climate Change and Emissions Management Fund (the Management Fund).[31] The Management Fund was launched in April 2008 and to date has received contributions of approximately $40 million. The Fund grants

[29] For the purposes of the Specified Gas Emitters Regulation, an established facility is one that completed its first year of commercial operation before January 1, 2000 or has completed 8 years of commercial operation.

[30] The Baseline Emissions Intensity (BEI) for established emitters is the average emissions intensity over three years of operations during the period of 2003-2005.

[31] Draft Protocols that outline how to quantify and verify emissions reductions for different types of projects can be found here: http://www.climatechangecentral.com/default.asp?V_DOC_ID=2308.

unlimited access to all regulated entities to make compliance contributions at the rate of $15 per tonne of CO_2e. The first year of compliance ended in March 2008 and the Government of Alberta is reporting that some 2.6 million tonnes of CO_2e were reduced either through changes to internal operations or through reductions created and sold as offset in Alberta. The remainder of the compliance obligations was met through contributions to the Management Fund.

In March 2008, the Alberta government announced the Alberta Carbon Capture and Storage (CCS) Development Council, a partnership between governments, industry and scientific researchers, charged with developing a clear work plan for implementing carbon capture and storage in Alberta. The Council is expected to report back to government in the fall of 2008. In early July 2008, the Government of Alberta announced the creation of a $2 billion Carbon Capture and Storage Fund to assist the development of large scale CCS projects. At the same time the government issued an invitation for an expression of interest for CCS projects in the province with a deadline for submission by September 2, 2008.

British Columbia

On November 20, 2007 BC introduced Bill 44, which sets into law BC's GHG emissions target of at least 33 percent below 2007 levels by 2020, and at least 80 percent below 2007 levels by 2050.[32] It requires that interim GHG targets for 2012 and 2016 be set by the end of 2008. Bill 44 also requires that the Provincial Government and public sector organizations (including "provincial ministries and agencies, schools, colleges, universities, health authorities and Crown corporations") be carbon neutral in 2010 and thereafter, and pursue actions to minimize GHG emissions in 2008 and 2009.[33]

In June 2008, the Government released a comprehensive climate change plan[34] which includes:

- Effective July 1, 2008, a broad based revenue neutral carbon tax of $10 per tonne of CO_2 to be increased annually to reach $30 per tonne by 2012.
- Enabling legislation for a cap and trade system that will reflect the targets and design of the WCI cap and trade system[35].
- The establishment of a Pacific Carbon Trust to administer the commitment of making public sector organizations in the province carbon neutral through investment in BC-only offset projects.

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[32] British Columbia Bill Number 44 – 2007, Greenhouse Gas Reduction Targets Act, http://www.leg.bc.ca/38th3rd/1st_read/gov44-1.htm

[33] British Columbia Office of the Premier, News Release: " B.C. Introduces Climate Action Legislation," November 20, 2007, http://www2.news.gov.bc.ca/news_releases_2005-2009/2007OTP0181-001489.htm

[34] http://www.livesmartbc.ca/attachments/climateaction_plan_web.pdf

[35] Entities covered under the cap and trade system will be made exempt from the carbon tax once the cap and trade system is operational.

Other Provinces

On July 17, 2008 Ontario announced its decision to become a member of the WCI. In June 2007, Ontario announced its targets for GHG emissions as follows: 6% lower than 1990 levels by 2014, 15% lower than 1990 levels by 2020 and 80% lower than 1990 levels by 2050.[36]

In April 2008, Quebec joined the WCI. Quebec has embraced the targets in the Kyoto Protocol and has developed a program to achieve them, including the introduction on October 1, 2007 of Canada's first carbon tax designed to raise funding for implementing Quebec's climate policies.

In June 2007, Saskatchewan released its Saskatchewan Energy and Climate Change Plan with goals of stabilizing the level of GHG emissions by 2010, reducing emissions to 32% below current (2004) levels by 2020, and reducing emissions by 80% from current (2004) levels by 2050.[37]

On June 12, 2007, Manitoba became the second Canadian province to sign onto the WCI agreement. The WCI's reduction goal represents an aggregate regional target which encompasses the Manitoba Government's individual GHG reduction target of 6% below 1990 levels by 2012.[38,39]

Nov a Scotia has created a new Department of Environment in April 2008 and charged it with the development of a climate action plan to deliver on the provincial goal contained in the Environmental Goals and Sustainable Prosperity Act (2007) of reaching a 10% reduction of greenhouse gas emissions from 1990 levels by 2020 while continuing to see the economy of the province grow. The action plan is scheduled for release in late 2008. Nova Scotia is also an observer to the RGGI process in the NE USA.

United States

Federal Government

The political situation in which the U.S. Congress is debating GHG policy has dramatically shifted since the Democrats became the majority party in Congress, and since August 2006 when California adopted ambitious legislation requiring significant reductions in GHG emissions. To date, approximately 15 pieces of legislation have been introduced in the 110th Congress from both the Senate and House of Representatives that would establish a cap and trade program for GHGs. However, the complexity of GHG legislation suggests that a significant amount of debate may need to take place over the course of several years (as in the case of the *Clean Air Act*) before legislation can be passed. Federal preemption of state and regional programs, international competitiveness concerns, cost containment provisions, and incentives for coal and nuclear power are among some of the many issues expected to draw considerable attention in future debates. Nevertheless several factors have given new impetus for GHG legislation at the federal level. These include the change in control of the Congress, the proliferation of

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[36] http://www.premier.gov.on.ca/news/Product.asp?ProductID=1397
[37] *Saskatchewan Energy and Climate Change Plan*, 2007.
http://www.saskatchewan.ca/Default.aspx?DN=b92e42b6-6ab2-448a-a8d7-f698cad62eec
[38] Western Climate Initiative Statement of Regional Goal, August 22, 2007, p. 4.
http://www.westernclimateinitiative.org/ewebeditpro/items/O104F13006.pdf
[39] Manitoba also signed the Midwestern Greenhouse Gas Accord (see discussion in subsection c. below).

programs adopted at the state level, the Supreme Court decision finding that the U.S. Environmental Protection Agency (EPA) has the authority to regulate carbon dioxide (CO_2) and other GHG emissions, the recent Senate vote on the Lieberman-Warner bill, and others.[40] It is also noteworthy that the Bush administration – which has been accused of delaying meaningful U.S. participation in international negotiations for the past seven years – is now committed to engaging in international negotiations and has agreed to the Bali roadmap.[41] In addition, both U.S. Presidential candidates have previously cosponsored climate legislation as Senators and have publicly announced their support for a cap and trade program for GHGs in the U.S.

Senate
As the majority party, Democrats have controlled committees with jurisdiction over GHG legislation and have been actively moving legislation through the political process. In the Senate, the Environment and Public Works (EPW) Committee passed legislation that was revised and eventually brought to the Senate floor for debate on 2 June 2008. Debate on this legislation – the *Lieberman-Warner Climate Security Act* (S. 3036) – lasted for a week and consisted of a full reading of the bill, a number of floor speeches by the bill's proponents and opponents, and two procedural votes. Ultimately, the bill was pulled from the floor having failed to obtain the full sixty votes required to overcome a filibuster and move forward with consideration of amendments.[42] Despite its failure, S. 3036 represents the furthest any previous piece of climate legislation has reached in the U.S. Congress to date.

In addition to S. 3036, Senator Bingaman's and Senator Specter's *Low Carbon Economy Act* (S. 1766) also garnered attention, particularly from industry, which was attracted by the bill's less ambitious emissions caps and inclusion of a price cap. However, unlike the Lieberman-Warner bill, S. 1766 never received official committee consideration by vote.[43] Each of these bills incorporates differing approaches to a number of key design elements in a cap and trade program including auction/allocation schedules, limitations on the use and types of offsets, and overall environmental stringency, among others. Senator Bingaman also delivered a speech on 9 July 2008 highlighting four strategies and ten principles that should be considered by Congress when drafting climate legislation in the near future.[44] The provisions within each of these bills, and the principles laid out by Senator Bingaman, will likely be instrumental in shaping future debate of climate legislation in the Senate during the coming years.

[40] Supreme Court, *Commonwealth of Massachusetts v. EPA*, 05-1120, April 2007 http://www.supremecourtus.gov/opinions/06pdf/05-1120.pdf
[41] The administration also hosted a meeting of the major GHG-emitting countries in Washington, and plans to hold several more such meetings.
[42] On June 6, 2008 the bill was voted down 48 (yes) – 36 (no). Of the 16 Senators absent for the vote, 6 filed statements in favor of the legislation, although their votes are only counted when present.

[44] Senate Energy and Natural Resources Committee press release, "Finding the Path Forward on Climate Legislation," July 9, 2008.
http://energy.senate.gov/public/index.cfm?FuseAction=PressReleases.detail&PressRelease_id=7bd43a6f-f03a-453d-8f4f-1ed6cfc84056

House

In the House, a number of climate bills have been introduced throughout the 110th Congress. The most substantial piece of legislation to date is a draft proposal released in October 2008 by Representative John Dingell, chairman of the House Energy Committee, and Representative Rick Boucher, chairman of the Subcommittee on Energy and Air Quality. The draft proposal (see details above) represents the culmination of four "white papers" released by the two Congressmen over the past year. [45] The proposal likely will frame debate on climate legislation in the House in 2009.

The following table provides a side-by-side comparison of the Bingaman-Specter (S. 1766), the Lieberman-Warner (S. 3036), and the Dingell-Boucher (draft) legislative proposals:

Bill Number	S. 1766	S. 3036	Dingell-Boucher Draft Proposal
Sponsors	**Sen. Jeff Bingaman (D-NM)** **Sen. Arlen Specter (R-PA)**	**Sen. Joseph Lieberman (I-CT)** **Sen. John Warner (R-VA)**	Rep. John Dingell (D-MI) Rep. Rick Boucher (D-VA)
Date Introduced and Last Action	Introduced July 11, 2007; referred to EPW on August 2, 2007	Introduced May 20, 2008; cloture vote on motion to proceed 74-14; considered by Senate but failed to overcome filibuster and to move forward with consideration of amendments (48-26 vote)	Draft proposal released on October 7, 2008
GHG Emission Limits	> Cap set approximately 8% *above* 2005 levels in 2012 (6652 MMt) for covered sectors decreasing about 1% per year until reaching approximately 2005 levels by 2020 (6188 MMt) > Cap is set between 2021-2030 emissions and reduced to 22% below 2005 levels (4819 MMt) by 2030 for covered sectors > From 2030 and beyond caps remain at 4819 MMt for covered sectors (22% below 2005 levels) > President can set cap at 60% below 2006 levels (2475 MMt) contingent upon international participation	**>** Cap is set at approximately 4% *below* 2005 levels (5775 MMt) by 2012 and 18% below 2005 levels (4924 MMt) by 2020 for covered sectors **>** Cap is set at 36% below 2005 levels by 2030 (3860 MMt) and 53% below 2005 levels (2796 MMt) by 2040 for covered sectors **>** By 2050, cap will be 71% below 2005 levels (1732 MMt) for covered sectors	> Cap is set at approximately 5% above 2005 levels (4987 MMT) by 2012 and 6% below 2005 levels (5796 MMT) by 2020 for covered sectors > Cap Is set at approximately 44% below 2005 levels (3436 MMT) by 2030 and approximately 64% below 2005 levels (2335 MMT) by 2040 for covered sectors > By 2050, cap will be approximately 80% below 2005 levels (1233 MMT) for covered sectors
Regulated Industries	Upstream coverage for petroleum, natural gas, and non CO_2 GHGs and downstream coverage for coal facilities that use over 5,000 tons of coal per year (~86% of total national GHG emissions)	Electric power generation, transportation, and heavy industry sectors and upstream coverage of petroleum and natural gas (~84% of total national GHG emissions)	Upstream coverage for transportation fuels and natural gas (local distributors) and downstream coverage of electric power generation, large industrial facilities, sequestration sites, and other high GWP gas importers and producers (~87% of total national GHG emissions)*

[45] These white papers cover four different topics relating to a Federal cap and trade program: 1) scope; 2) competitiveness; 3) state government and preemption; and 4) cost containment. All four can be found here, http://energycommerce.house.gov/Climate_Change/index.shtml.

Offsets	Allows use of domestic offsets that meet broadly accepted standards. Up to 5% are set aside for agricultural sequestration. Also allows discounted credits for offsets not meeting approved standards. The President can also implement and international offset program, allowing not more than 10% of compliance obligation to be met in this manner.	Up to 15% of annual allowance cap can be met with domestic offsets. Unused portion can be carried over into the next year or met with international allowances and/or international forestry credits. An additional 15% of an annual allowance cap can be met with international offset credits, 5% of which can be project-based and 10% of which can be international forestry credits. Unused portion can be carried over into the next year or met with international allowances.	Allows up to 5% of an entities compliance obligation to be met with a combination of domestic/international offsets from 2012-2017 and up to 15% from 2018-2020. From 2021-2024, up to 15% of an entities compliance obligation can be met with domestic offsets and an additional 15% can be met with international offsets. From 2025 and beyond, domestic limits are increased to 20% while international limits remain at 15%.
Cost Control and Flexibility	A price ceiling, or "safety valve," on carbon set at $12 per ton, increasing 5% above inflation. Unlimited banking is also allowed.	Allows for unlimited banking and up to 15% of allowances per year can be borrowed at a default interest rate. Creates a Carbon Market Efficiency Board that is authorized to increase borrowing and domestic offset limits, lengthen borrowing repayment periods, and increase international allowance purchase limits. Also implements Cost-Containment Auctions in which allowances will be auctioned within a price range of $22-$30 beginning in 2012.	Allows for unlimited banking and allows up to 15% of a compliance obligation to be met using borrowing allowances at a default interest rate. Also allows for unlimited borrowing from the following year at no interest if reconciled within 5 years (otherwise 8% interest). Implements a cost-containment auction in which allowances will be borrowed from future years and auctioned within a range of $20-$30

State and Regional Emissions Trading Programs

In addition to developments at the Federal level, states and provinces throughout North America have undertaken a number of GHG legislative initiatives that seek to implement emissions trading programs. California has released a Final Scoping Plan for meeting its mandatory state GHG target which includes implementing a state-wide emissions trading program for its electricity sector, which is expected to work in conjunction with a Western Climate Initiative (WCI) regional trading program with broader sectoral coverage. The majority of other U.S. states and Canadian provinces that have taken action on GHG limits have passed, or are in the process of passing, legislation that will implement their respective regional emissions trading programs. For instance, in New England, ten states are participating in a carbon dioxide trading program known as the Regional Greenhouse Gas Initiative (RGGI) in which an emission cap will be set at current levels in 2009, and then reduced 10% by 2019.[46] In the West, seven states and the provinces of British Columbia, Manitoba, Ontario and Quebec are participating in the WCI, in which the aggregate emissions target, calculated based on individual states' separate GHG targets, is 15% below 2005 levels by 2020.[47] Another regional effort comprised of six states and Manitoba[48] known as the Midwestern Greenhouse Gas Accord (MGGA) was announced on November 15, 2007, although the program's targets will not be

[46] The Regional Greenhouse Gas Initiative was established in December 2005 by the governors of Connecticut, Delaware, Maine, New Hampshire, New Jersey, New York, and Vermont. Massachusetts, Rhode Island and Maryland have also joined RGGI. The District of Columbia, Pennsylvania, the Eastern Canadian Provinces and New Brunswick are participating as observers.

[47] The Western Climate Initiative (originally the Western Regional Climate Action Initiative) was established in August 2007 by the governors of Arizona, California, New Mexico, Oregon and Washington. Utah, British Columbia, Manitoba, and Montana have also joined the WCI. Alaska, Chihuahua, Coahuila, Colorado, Kansas, Nevada, Nuevo Leon, Ontario, Quebec, Saskatchewan, Sonora, Tamaulipas and Wyoming are participating as observers

[48] Manitoba is also participating in WCI.

finalized until July 2008.[49] Each of these programs will seek to establish a regional multi-sector cap-and-trade system within the next few years (except RGGI, which will begin in 2009). In addition, the large majority of these states and several others have already established individual state-wide GHG emission reduction targets. The following summarizes developments in California's proposed electricity sector trading program as well as the three emerging regional trading programs.

a) Regional Greenhouse Gas Initiative

On 20 December 2005, the governors of seven Northeastern states signed a memorandum of understanding (MoU) effectively creating the Regional Greenhouse Gas Initiative (RGGI) which establishes a multi-state CO_2 emissions trading program for power plants.[50] On 15 August 2006, RGGI states agreed on a Model Rule which contains final regulations on the establishment of the regional program.[51] Since the Model Rule was published, three additional states have joined RGGI and eight of the ten participating states have passed, or are in the process of passing, legislation to implement the program.[52] The program caps emissions from power plants at 188 million short tons for the 2009-2014 period (approximately 4% above annual average emissions in 2000-2004). From 2015, the cap declines by 2.5% per year in order to achieve a 10% reduction below the initial cap by 2019.[53] On 25 September 2008, RGGI held its first regional auction in which 12.6 million 2009 vintage RGAs were auctioned to participating members with a clearing price floor of $3.07 (a floor price was set at $1.86). The majority of RGGI states have opted to auction greater than 90 percent of their allotted RGAs, with the exception of Delaware which has chosen to auction only 60 percent and allocate the remaining 40 percent. A second auction is scheduled for 17 December 2008, just before RGGI officially commences on 1 January 2009.

b) Western Climate Initiative

The Western Climate Initiative (WCI) was launched on February 26, 2007 by the governors of Arizona, California, New Mexico, Oregon and Washington. Since its inception, British Columbia, Manitoba, Montana, Ontario, Quebec, and Utah have also signed onto the agreement.[54] On 22 August 2007 the WCI announced its emission target of 15 percent below 2005 levels by 2020.[55]

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[49] The Midwestern Greenhouse Gas Accord (MGGA) includes Illinois, Iowa, Kansas, Manitoba, Michigan, Minnesota and Wisconsin as participants. Indiana, Ohio, Ontario, and South Dakota are participating as observers.

[50] The governors of Connecticut, Delaware, Maine, New Hampshire, New Jersey, New York, Vermont and Massachusetts established RGGI in 2005, Rhode Island and Maryland have joined RGGI in 2007. The District of Columbia, Pennsylvania, the Eastern Canadian Provinces and New Brunswick are participating as observers.

[51] RGGI's model rule is available at http://www.rggi.org/docs/model_rule_8_15_06.pdf

[52] Rhode Island, Massachusetts and Maryland joined RGGI in 2007. Connecticut, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island and Vermont have passed or are in the process of passing legislation implementing the RGGI as of the date of this writing.

[53] Overview of RGGI CO2 Budget Trading Program, http://www.rggi.org/docs/program_summary_10_07.pdf

[54] Alaska, Chihuahua, Coahuila, Colorado, Kansas, Nevada, Nuevo Leon, Saskatchewan, Sonora, Tamaulipas and Wyoming are participating as observers according to the WCI website.

[55] Western Climate Initiative, Statement of Regional Goal, August 22, 2007 http://www.westernclimateinitiative.org/ewebeditpro/items/O104F13012.pdf

This regional goal was calculated by aggregating each WCI participant's differentiated GHG reduction target into a regional target. To achieve this target, WCI signatories formed five Working Subcommittees to facilitate the development of key design elements for a market-based multi-sector program.[56] On 23 September 2008, the WCI released its Final Design Document which outlines a number of core program principles.[57] Specifically, the program will cover approximately 70% of Canadian emission and 20% of U.S. emissions from: 1) electricity generation; 2) combustion at commercial and industrial sources; 3) industrial process emissions; 4) fuel combustion at source emitting less than 25,000 CO2e; and 5) combustion of transportation fuels (see table 1 for other details). With respect to cost-containment, the use of offset credits from projects in the U.S., Canada, Mexico, and CDM will be limited at 49% of total emission reductions from 2012-2020. The program will also allow for unlimited banking but no borrowing of allowances.

c) Midwestern Greenhouse Gas Accord

On 15 November 2007, Illinois, Iowa, Kansas, Michigan, Minnesota, Wisconsin and Manitoba announced the launch of the Midwestern Greenhouse Gas Reduction Accord (MGGA).[58,59] On 15 September 2008, the MGGA released draft recommendations addressing the following: 1) covered sectors and point of regulation; 2) regional targets; 3) potential linkages with other existing or future programs; 4) distribution of allowances; and 5) limitations on the use of offsets, among other recommendations.[60] No recommendations are expected to be established until the finalization of the program's Final Design Document in early 2009 (originally set for November 2008), and trading is expected to begin by summer of 2010, though this deadline likely will be pushed back until early 2011.

d) California

The *California Global Warming Solutions Act of 2006* (codified in the Health and Safety Code, Division 25.5, Section 38500) requires California to reduce economy-wide GHG emissions to 1990 levels by 2020 beginning in January 2012.[61] The *Act*, commonly known as AB 32, was signed into law by Governor Schwarzenegger in September 2006. The Governor's Executive Order S-3-05, which was issued in 2005, provides additional targets: 2000 levels by 2010, 1990 levels by 2020, and 80 percent below 1990 levels by 2050.[62] The focus of California's efforts appears to be on meeting the 2020 target established by law under AB32, and not on the more immediate 2010 target in the Executive Order. The agency responsible for deciding how California will achieve its GHG target under AB32, the California Air Resources Board (CARB), declared that a cap and trade program, integrated with direct regulation, will become part of

[56] The five Working Subcommittees include Allocations, Draft Reporting, Electricity, Offsets, and Scope.
[57] WCI website: http://westernclimateinitiative.org/WCI_Documents.cfm.
[58] Midwestern Greenhouse Gas Reduction Accord, http://www.midwesterngovernors.org/resolutions/GHGAccord.pdf
[59] Indiana, Ohio, Ontario, and South Dakota are participating as observers.
[60] Midwestern Greenhouse Gas Reduction Accord website: http://www.midwesternaccord.org/Meeting%20material%20pages/GHG-meeting-5_0908.html
[61] Health and Safety Code http://www.leginfo.ca.gov/cgi-bin/calawquery?codesection=hsc&codebody=&hits=20
[62] By January 1, 2008, the CARB must determine what the 1990 emissions levels were, which will effectively establish the cap. http://www.arb.ca.gov/ag/manuremgmt/ab32.pdf

California's reduction strategy.[63] On October 15, 2008, CARB released its Final Proposed Scoping Plan for implementing AB 32 which includes provisions for establishing a cap and trade program to work in conjunction with the WCI.[64] Specifically, the trading program would cover 85% of California's emissions from: 1) electricity generation; 2) large industrial facilities; 3) fuel combustion from sources emitting less than 25,000 CO_2e; 4) fuel combustion at residential and commercial sources; and 5) transportation fuel transportation..

[63] AB 32 directs CARB to adopt a plan by January 1, 2009 indicating how emission levels will be achieved from major GHG sources via regulations, market mechanisms, or other measures. The CARB has already adopted three early action regulations that impose a low carbon fuel standard, ban certain refrigerants used in cars, and require landfills to capture methane gas emitted by decomposing refuse. http://www.arb.ca.gov/cc/042307workshop/early_action_report.pdf

[64] California Air Resources Board website: http://www.arb.ca.gov/cc/cc.htm.

2009 IRP Projection

TOTAL	Incremental Achievable Potential Demand Savings (MW)	Cumulative Demand Savings (MW)	Incremental Achievable Potential Energy Savings (GWh)	Cumulative Energy Savings (GWh)	Incremental Program Costs Utility Cost ($M)	Cumulative Program Cost ($M)	Incremental Customer Costs ($M)	Cumulative Customer Costs ($M)	Incremental Total Costs ($M)	Cumulative Total Costs ($M)
2008*	2		16		3		2		5	
2009*	7	9	50	66	10	13	6	8	15	21
2010**	17	26	83	149	23	36	15	23	38	58
2011***	31	57	146	295	41	77	23	46	64	123
2012***	44	101	205	500	61	137	32	77	92	215
2013***	63	164	305	805	82	219	60	137	142	357
2014***	57	222	276	1,081	74	293	54	191	128	485
2015***	57	279	276	1,357	74	367	54	245	128	613
2016***	57	336	276	1,632	74	442	54	299	128	741
2017***	56	392	268	1,901	75	516	51	350	126	866
2018***	54	446	261	2,162	72	588	51	401	123	989
2019***	53	500	255	2,417	71	658	50	451	120	1,110
2020***	52	551	249	2,666	69	728	49	500	118	1,228
2021***	51	602	243	2,909	68	796	47	547	116	1,344
2022***	50	652	238	3,148	67	864	46	594	114	1,457
2023***	49	700	233	3,381	67	930	45	639	112	1,570
2024***	48	748	229	3,610	66	996	44	684	110	1,680
2025***	47	795	225	3,834	65	1,062	44	727	109	1,789
2026***	46	841	221	4,055	65	1,127	43	770	108	1,896
2027***	45	886	217	4,273	64	1,191	42	812	106	2,003
2028***	45	931	214	4,487	64	1,255	41	853	105	2,108
2029***	44	976	211	4,698	64	1,319	40	893	104	2,212
2030***	44	1,019	209	4,907	64	1,382	40	933	103	2,315
2031***	43	1,063	206	5,113	63	1,446	39	972	103	2,418
2032***	43	**1,106**	204	**5,317**	63	**1,509**	39	**1,011**	102	**2,520**

Notes:
The numbers in this table may not sum exactly due to rounding.
* Approved Programs (expressed in 2008 dollars)
** Proposed 2010 DSM Targets (expressed in 2010 dollars)
*** Potential DSM Investment in future years (expressed in 2010 dollars)

2009 IRP Update

Modeling /Analysis Results

September 22nd, 2009

NOVA SCOTIA POWER
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2009 IRP Update
Modeling / Analysis Results

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2009 IRP Update

UARB Letter of February 25, 2009

"The update should primarily focus on incorporating new information that is now available in order to determine what changes may be needed to the IRP reference plan."

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Summary of Findings

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Summary of Findings

– The key elements of NSPI's resource plan for the next 20 years are expected to be investment in DSM and renewables and upgrades to existing facilities
  - These elements are common to all resource plans examined over the first decade of the planning period
  - For the second decade, they continue to compare favourably with investments in alternative environmental technologies and forecast import costs
  - For most sensitivities examined, the renewables-based plans remain low cost throughout the planning period

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Summary of Findings

– Over the first decade the renewables-based resource plans are particularly robust

– Over the longer term more information is required with respect to:

- Load growth
- The impact of DSM and renewables on the power system
- Transmission upgrades – location, timing and cost
- The sustainability of biomass
- Fuel prices
- The outlook for environmental regulations/legislation
- Import opportunities, pricing, etc.
- The economic and technical feasibility of emerging technologies, in particular Carbon Capture and Storage

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Summary of Findings - Comparison to 2007 IRP Reference Plan

- The 2009 IRP Update Project findings are consistent with the 2007 IRP Reference Plan
  - Investments in renewables over the first decade are required
  - Success in DSM is a critical component
  - Maintaining and upgrading NSPI facilities is economic
  - Additional information is required to inform the long-term plan
- The IRP analysis has been improved and expanded through the inclusion of transmission cost information, updated emissions constraints and updated and expanded technology options
- As with the 2007 IRP, areas of uncertainty remain
  - Environmental, technological and economic developments will continue to be monitored to determine viable demand and supply alternatives over the long term

Modeling Approach

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2009 IRP Update
Modeling / Analysis Results

Modeling Approach

- Introduced resources systematically
  - Resource alternatives staged in the Strategist modeling
  - Emission constraints captured sequentially (assumptions as of June 2009)
  - Initial test runs performed to determine if the alternatives:
    - Could be fixed in the short term
    - Should remain as floating
    - Could be turned off in further runs
  - Thorough and comprehensive iteration and review of results informed the optimization process
    - Modeling assesses a wide range of resource combinations

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Analysis Framework

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Analysis Framework

- Strategist software is used to develop and compare alternative resource plans which satisfy model constraints
- Analysis focused on supply-side assessment
  - Consistent with the primary environmental drivers, supply sources focused on renewables, natural gas-fired generation and environmental equipment additions
- Consistent with ongoing DSM program development, DSM as modeled reduces energy requirements by 2% per year throughout planning period

Analysis Framework

- Low cost plans identified for further analysis
- Distinct alternative resource plans selected for comparison and further analysis
- Initial analysis employed Base World assumptions
- Quantitative analysis focused on net present value of revenue requirement for plans across the Planning Period, adjusted for End Effects

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Analysis Framework

- To broaden analysis scope and to test plan robustness, additional Worlds and Sensitivity analyses employed
  - Alternative Worlds developed to generate viable resource plans under materially different futures (Higher load and Kyoto-based carbon constraints)
  - Sensitivity Analysis employed within Worlds to test effects of changes to key assumptions on plan costs
    - Fuel cost (coal, natural gas and biomass)
    - Capital cost

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Analysis Framework (Upcoming)

- Determine recommended reference plan with consideration to qualitative as well as quantitative analysis
  - Commonality among plans
  - Flexibility
    - Change in constraints
    - Change in operating conditions
    - Lead times
  - Technology maturity

  Identify key information gaps for further investigation

- Develop Action Plan

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Analysis Results

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Analysis Results - Base World

- Resource Plans
  - Plan A-Renewables-Additional biomass generation (Least Cost)
  - Plan B-Renewables-Additional wind generation
  - Plan C-Renewables-Additional natural-gas fired generation

2009 IRP Update
Modeling / Analysis Results

Resource Plans - 2009 IRP Update - Base Case Assumptions

Year	NSR (GWh)	Plan A	Plan B	Plan C
2010	12,398	TUC 6 (Nov) Activated CI (7 PC units) LS, Low BTU Coal Burn (Lin 1-4/Tup)	TUC 6 (Nov) Activated CI (7 PC units) LS, Low BTU Coal Burn (Lin 1-4/Tup)	TUC 6 (Nov) Activated CI (7 PC units) LS, Low BTU Coal Burn (Lin 1-4/Tup)
2011	12,320	Contract Wind 308MW (100MW Firm) *(Plus transmission and load following requirements)* Marshall Hydro (4.2MW)	Contract Wind 308MW (100MW Firm) *(Plus transmission and load following requirements)* Marshall Hydro (4.2MW)	Contract Wind 308MW (100MW Firm) *(Plus transmission and load following requirements)* Marshall Hydro (4.2MW)
2012	12,225	Biomass co-fire (4 units)	Wind (100MW nameplate, 40MW firm) *(Plus transmission and load following requirements)*	Biomass co-fire (4 units)
2013	12,016	Coal uprate +15MW (2 units) *(Plus transmission requirements)* Wind (100MW nameplate,40MW firm) (for RES) *(Plus transmission and load following requirements)*	Coal uprate +15MW (2 units) *(Plus transmission requirements)* Wind (100MW nameplate,40MW firm) (for RES) *(Plus transmission and load following requirements)*	Coal uprate +15MW (2 units) *(Plus transmission requirements)* Wind (100MW nameplate,40MW firm) (for RES) *(Plus transmission and load following requirements)*
2014	11,837			
2015	11,651			
2016	11,449			
2017	11,256		Biomass co-fire (2 coal units)	
2018	11,079	Biomass co-fire (1 unit) Baghouse (2 units) FGD (2 units)	Wind (100MW nameplate, 40MW firm) *(Plus transmission and load following requirements)* FGD (2 units)	Combined Cycle Gas 150 MW
2019	10,909	Biomass co-fire (1 unit)		Biomass co-fire (1 unit)
2020	10,734	Biomass co-fire (2 units)	Biomass co-fire (1 unit)	
2021	10,559			
2022	10,398			
2023	10,236		Biomass co-fire (1 unit)	
2024	10,077			Biomass co-fire (1 unit)
2025	9,913			
2026	9,759			
2027	9,607			
2028	9,457			
2029	9,310			
2030	9,165	Biomass PPA (15MW)	Biomass PPA (15MW)	Biomass PPA (15MW)
2031	9,023	*(Plus transmission requirements)*	*(Plus transmission requirements)*	*(Plus transmission requirements)*
2032	8,882			
NPV 2008-32 (M$)		**$10,007**	**$10,342**	**$10,558**
Study Period (M$) (includes End Effects)		**$13,335**	**$13,710**	**$14,100**

Highlights of Plan A

– *Base World - Additional biomass generation (least cost)*

- Wind (100 MW nameplate) in 2013 to meet RES 2013
- Biomass co-fired at 8 coal units
- Biomass PPA (15 MW) in 2030
- Environmental equipment investment (baghouses and FGD/ scrubber) required in 2018 to meet Hg/SO2 reductions
- Upgrades to NSPI existing facilities
- Transmission investment and/or Back-up (load following) generation required
- Least cost plan

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Highlights of Plan B

– Base World - Additional wind generation

Changes compared to Plan A

- Additional wind (100 MW nameplate blocks) in 2012 and 2018
- Biomass co-fire at 4 coal units
- No baghouses in 2018
- Cost differential to Plan A approximately 3%, with and without End Effects

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Highlights of Plan C

– Base World - Additional natural gas-fired generation

Changes compared to Plan A

- 150 MW combined cycle gas unit added in 2018
- Biomass co-fired at 6 coal units
- No baghouse or FGD (scrubber) in 2018
- Cost differential to Plan A approximately 6%, with and without End Effects

General Highlights – Base World

- Negative Load Growth with Base Load + DSM (approximately -1.5% annually)
- Key resource elements are common to all plans over the first decade
  - Investment in DSM and renewables, upgrades to existing facilities
  - Wind to meet 2010-2012 RES
  - Investments and capacity recovery upgrades at coal units (~2010)
  - Marshall Falls Hydro Up-rate (~2011)
  - Additional investment in wind for 2013 RES plus investment in Co-firing Biomass
  - Efficiency improvement up-rates at existing facilities
  - Transmission investment and fast-acting back-up (load following) generation required to support wind
- For Plans A and B investment in 2018 required to meet Hg/SO2 reductions (e.g. FGD/scrubber and/or Baghouse)
- For Plan C combined cycle gas unit added in 2018
- Renewables - Additional Biomass Plan forecast to be the least cost

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Sensitivity Tests

- Keep the resources in each Plan constant and re-dispatch with price sensitivity
- All emission limits are met with each sensitivity run
- Tests robustness of Plan assuming a path is chosen but the future prices unfold differently

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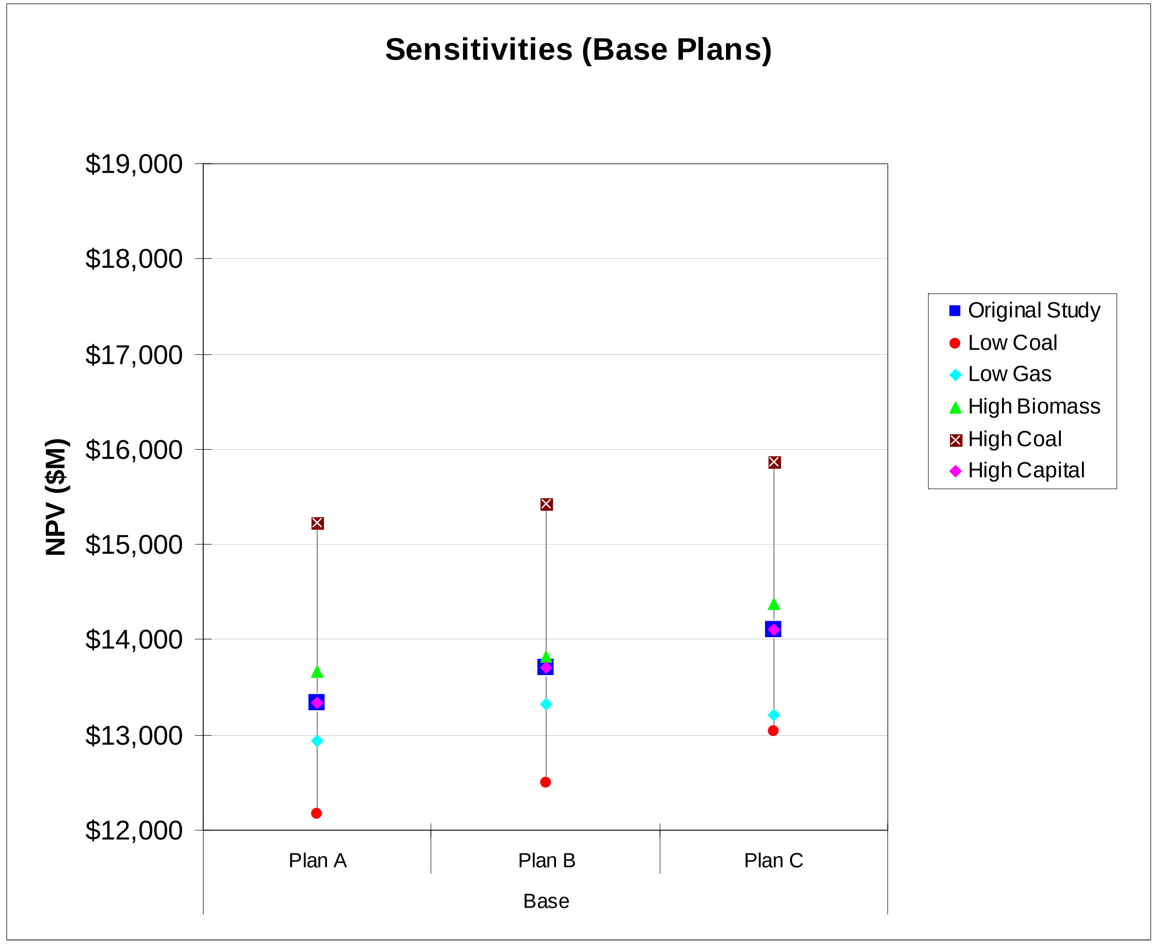
Sensitivity Tests

- Low and High Coal Price
- Low Gas Price
- High Biomass Price
- High Carbon Capture and Storage Capital Cost

2009 IRP Update
Modeling / Analysis Results

- For all Base World sensitivities, Plan A retains the least cost ranking

- Low gas prices change the relative positions of Plans B & C, and bring Plans A & C closer together



Analysis Results - High Load World

- Load Assumptions set to "high" (other assumptions set to "base")

Load + DSM = Flatter Load Growth (still negative Load Growth over the 25 years, -0.70% annually)

- Plan D – Renewables - Carbon Capture and Storage
- Plan E - Renewables
- Plan F – Renewables - Large non-emitting PPA
- Plan G - Renewables and natural gas-fired generation

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2009 IRP Update
Modeling / Analysis Results

Resource Plans - 2009 IRP Update - High Load Forecast

Year	NSR (GWh)	Plan D	Plan E	Plan F	Plan G
2010	13,002	TUC 6 (Nov) Activated CI (7 PC units) LS, Low BTU Coal Burn (Lin 1-4/Tup)	TUC 6 (Nov) Activated CI (7 PC units) LS, Low BTU Coal Burn (Lin 1-4/Tup)	TUC 6 (Nov) Activated CI (7 PC units) LS, Low BTU Coal Burn (Lin 1-4/Tup)	TUC 6 (Nov) Activated CI (7 PC units) LS, Low BTU Coal Burn (Lin 1-4/Tup)
2011	13,023	Contract Wind 308MW (100MW Firm) *(Plus transmission and load following requirements)* Marshall Hydro (4.2MW) Nictaux Hydro (2.5 MW) Biomass co-fire (4 units)	Contract Wind 308MW (100MW Firm) *(Plus transmission and load following requirements)* Marshall Hydro (4.2MW) Nictaux Hydro (2.5 MW) Biomass co-fire (4 units)	Contract Wind 308MW (100MW Firm) *(Plus transmission and load following requirements)* Marshall Hydro (4.2MW) Nictaux Hydro (2.5 MW) Biomass co-fire (4 units)	Contract Wind 308MW (100MW Firm) *(Plus transmission and load following requirements)* Marshall Hydro (4.2MW) Nictaux Hydro (2.5 MW) Biomass co-fire (4 units)
2012	13,050	Biomass co-fire (1 unit) Biomass PPA (15MW) *(Plus transmission requirements)*	Biomass co-fire (1 unit) Biomass PPA (15MW) *(Plus transmission requirements)*	Biomass co-fire (1 unit) Biomass PPA (15MW) *(Plus transmission requirements)*	Biomass co-fire (1 unit) Biomass PPA (15MW) *(Plus transmission requirements)*
2013	12,950	Coal uprate +15MW (2 units) *(Plus transmission requirements)* Wind (100MW nameplate,40MW firm) (for RES) *(Plus transmission and load following requirements)*	Coal uprate +15MW (2 units) *(Plus transmission requirements)* Wind (100MW nameplate,40MW firm) (for RES) *(Plus transmission and load following requirements)*	Coal uprate +15MW (2 units) *(Plus transmission requirements)* Wind (100MW nameplate,40MW firm) (for RES) *(Plus transmission and load following requirements)*	Coal uprate +15MW (2 units) *(Plus transmission requirements)* Wind (100MW nameplate,40MW firm) (for RES) *(Plus transmission and load following requirements)*
2014	12,875	Biomass co-fire (1 unit)	Biomass co-fire (1 unit)	Biomass co-fire (1 unit)	Biomass co-fire (1 unit)
2015	12,784				
2016	12,671	Wind (100MW nameplate, 40MW firm) *(Plus transmission and load following requirements)*	Wind (100MW nameplate, 40MW firm) *(Plus transmission and load following requirements)*	Wind (100MW nameplate, 40MW firm) *(Plus transmission and load following requirements)*	Wind (100MW nameplate, 40MW firm) *(Plus transmission and load following requirements)*
2017	12,559	Biomass co-fire (2 units)	Biomass co-fire (2 units)	Biomass co-fire (2 units)	Biomass co-fire (2 units)
2018	12,457	CCS Retro-fit (1 unit) Baghouses (3 units)	Wind (100MW nameplate, 40MW firm) *(Plus transmission and load following requirements)* FGD (2 units) Baghouses (2 units)	Large PPA (300 MW) *(Plus transmission requirements)* FGD (2 units) Baghouse (1 unit)	Combined Cycle Gas (280MW) *(Plus transmission requirements)* FGD (2 units) Baghouses (2 units)
2019	12,354		Wind (100MW nameplate, 40MW firm) *(Plus transmission and load following requirements)*		2 x Wind (100MW nameplate,40MW firm) *(Plus transmission and load following requirements)*
2020	12,238				Biomass PPA (60MW) *(Plus transmission requirements)*
2021	12,121		Biomass PPA (60MW) *(Plus transmission requirements)*		
2022	12,018		Wind (100MW nameplate, 40MW firm) *(Plus transmission and load following requirements)*		
2023	11,917	CCS Retro-fit (1 unit)			
2024	11,821				
2025	11,724		Wind (100MW nameplate, 40MW firm) *(Plus transmission and load following requirements)*		
2026	11,631				
2027	11,544				
2028	11,460				
2029	11,381				
2030	11,305	CCS Retro-fit (1 unit)			
2031	11,234		Offshore Wind (100MW nameplate, 50MW firm) *(Plus transmission and load following requirements)*	Biomass PPA (60MW) *(Plus transmission requirements)*	
2032	11,165				
NPV 2008-32 (M$)		**$11,828**	**$12,050**	**$12,150**	**$12,253**
Study Period (M$) (includes End Effects)		**$16,296**	**$16,703**	**$17,068**	**$17,188**

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Highlights of Plan D

- *High Load World - Renewables with Carbon Capture and Storage (CCS)*

- Wind (100 MW nameplate) in 2013 (to meet RES) and in 2016
- Biomass PPA (15 MW) in 2012
- Biomass co-fired at 8 coal units
- Upgrades to NSPI existing facilities
- Baghouses added in 2018
- Investment in Carbon Capture and Storage in 2018, 2023 and 2030
  - Uncertainties with cost, feasibility of transportation and long-term storage
  - CCS retrofits include FGD (scrubber)
- Transmission Investment and/or Back-up Generation required

- Low cost plan - relatively small savings compared to alternatives

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Highlights of Plan E

– High Load World - Renewables

Changes compared to Plan D

- Additional wind (100 MW nameplate blocks) in 2018, 2019, 2022, 2025
- Biomass PPA (60 MW) in 2021
- No Carbon Capture and Storage
- FGD (scrubber) in 2018
- Offshore wind in 2031
- Cost differential to Plan D approximately 2% with and without End Effects

Highlights of Plan F

– High Load World - Large non-emitting PPA (300MW)

Changes compared to Plan D

- Large non-emitting PPA (300 MW) in 2018
- No Carbon Capture and Storage
- FGD (scrubber) in 2018
- Biomass PPA (60MW) in 2031
- Cost differential to Plan D approximately 3% without End Effects and 5% with End Effects

Highlights of Plan G

– High Load World - 280MW CC natural gas-fired generation

Changes compared to Plan D

- Combined cycle gas unit 280 MW in 2018
- No Carbon Capture and Storage
- FGD (scrubber) in 2018
- Additional wind (2 x 100MW nameplate blocks) in 2019
- Biomass PPA (60MW) in 2020
- Cost differential to Plan D approximately 4% without End Effects and 5% with End Effects

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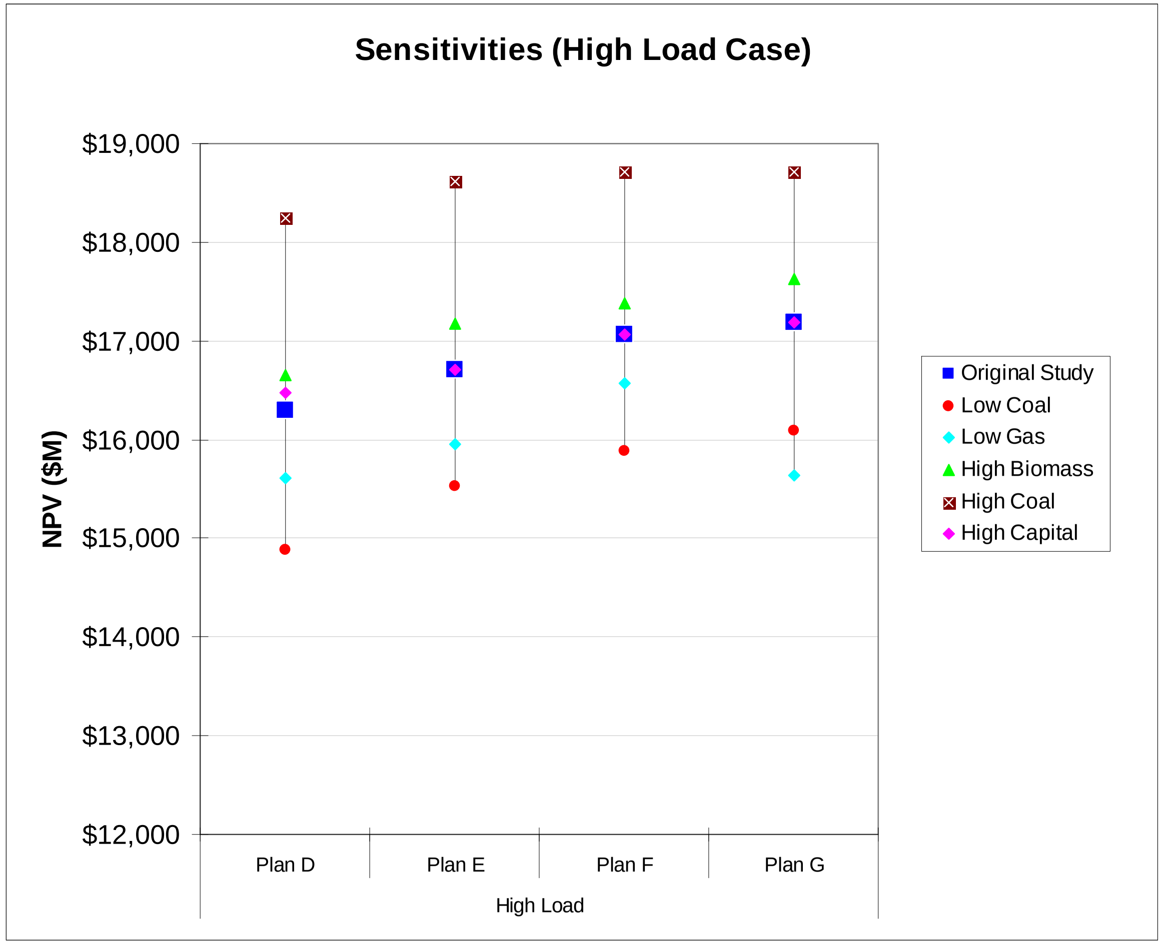
2009 IRP Update
Modeling / Analysis Results

-Plan D holds its low cost position across most sensitivities. Virtually the same as Plan G under low natural gas prices.

-Under Low Natural Gas price sensitivity Plans E, F and G change Rank Order.



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2009 IRP Update
Modeling / Analysis Results

General Highlights – High Load World

- Resources common to all Plans through first decade
- 2018 emissions limits met through Carbon Capture and Storage, Renewables, Large Non-emitting PPA and/or Natural Gas generation
- Cost differential between Low Cost CCS Plan and Renewables Plan small
- In general cost differential among all plans small relative to uncertainty regarding the technical and economic viability of options under consideration
- High load likely to require larger scale investment
- Reinforces importance of monitoring load growth and economic, technical and regulatory/legislative developments, and having a broad portfolio of prime energy sources
- Transmission investment and fast-acting back-up (load following) generation required to support wind

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Analysis Results - Kyoto World

CO2 reduced to 90% of 1990 levels

- 2010 – 6.4 Mt
- 2020 – 4.8 Mt
- 2030 – 4.1 Mt

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Analysis Results - Kyoto World

- 2010 - 2017
  - Base CO_2 hard cap limits will be met with physical reductions
  - The remainder of the reductions to Kyoto levels will be met with credits and/or further physical reductions

- 2018 – 2032
  - No CO_2 credits available
  - Kyoto hard caps will be met with physical reductions (2018 chosen as first year for Kyoto hard caps to align with Mercury reductions in 2018)

- Majority of CO_2 mitigation will be in place by 2018
  - 2018 cap ~5.1 Mt (50% reduction from current levels)
  - 2032 cap ~4.0 Mt (another 10% reduction from 2018)
  - Beyond 2020, the load drop each year outpaces the required CO_2 drop (Base load forecast → negative load growth)

Analysis Results - Kyoto World

Resource Plans

- Plan H - Carbon Capture and Storage
- Plan I - Renewables and natural gas-fired generation
- Plan J – Renewables with increased natural gas-fired generation
- Plan K - Large non-emitting PPA

2009 IRP Update
Modeling / Analysis Results

Resource Plans - 2009 IRP Update - Kyoto World

Year	NSR (GWh)	Plan H CCS	Plan I Renewables/Gas Combo	Plan J Mostly Gas	Plan K Large PPA
2010	12,398	TUC 6 (Nov) Activated CI (7 PC units) LS, Low BTU Coal Burn (Lin 1-4/Tup)	TUC 6 (Nov) Activated CI (7 PC units) LS, Low BTU Coal Burn (Lin 1-4/Tup)	TUC 6 (Nov) Activated CI (7 PC units) LS, Low BTU Coal Burn (Lin 1-4/Tup)	TUC 6 (Nov) Activated CI (7 PC units) LS, Low BTU Coal Burn (Lin 1-4/Tup)
2011	12,320	Contract Wind 308MW (100MW Firm) *(Plus transmission and load following requirements)* Marshall Hydro (4.2MW) Nictaux Hydro (2.5 MW)	Contract Wind 308MW (100MW Firm) *(Plus transmission and load following requirements)* Marshall Hydro (4.2MW) Nictaux Hydro (2.5 MW)	Contract Wind 308MW (100MW Firm) *(Plus transmission and load following requirements)* Marshall Hydro (4.2MW) Nictaux Hydro (2.5 MW)	Contract Wind 308MW (100MW Firm) *(Plus transmission and load following requirements)* Marshall Hydro (4.2MW) Nictaux Hydro (2.5 MW)
2012	12,225	Biomass co-fire (4 units)	Biomass co-fire (4 units)	Biomass co-fire (3 units)	Biomass co-fire (4 units)
2013	12,016	Coal uprate +15MW (2 units) *(Plus transmission requirements)* Wind (100MW nameplate,40MW firm) (for RES) *(Plus transmission and load following requirements)*	Coal uprate +15MW (2 units) *(Plus transmission requirements)* Wind (100MW nameplate,40MW firm) (for RES) *(Plus transmission and load following requirements)*	Coal uprate +15MW (1 unit) *(Plus transmission requirements)* Wind (100MW nameplate,40MW firm) (for RES) *(Plus transmission and load following requirements)*	Coal uprate +15MW (2 units) *(Plus transmission requirements)* Wind (100MW nameplate,40MW firm) (for RES) *(Plus transmission and load following requirements)*
2014	11,837				
2015	11,651				
2016	11,449		Wind (100MW nameplate, 40MW firm) *(Plus transmission and load following requirements)*		Wind (100MW nameplate, 40MW firm) *(Plus transmission and load following requirements)*
2017	11,256	Biomass PPA (15MW) *(Plus transmission requirements)*	Wind (100MW nameplate, 40MW firm) *(Plus transmission and load following requirements)* Biomass PPA (15MW) *(Plus transmission requirements)* Biomass PPA (60MW) *(Plus transmission requirements)*		
2018	11,079	Biomass co-fire (4 units) CCS retro-fit -3 units Baghouses (2 units)	Biomass co-fire (4 units) Wind (100MW nameplate, 40MW firm) *(Plus transmission and load following requirements)* Combined Cycle Gas (280MW) *(Plus transmission requirements)*	Combined Cycle Gas (2 x 280MW) *(Plus transmission requirements)*	Biomass co-fire (4 units) Biomass PPA (15MW) *(Plus transmission requirements)* Large non-emitting PPA (300 MW) *(Plus transmission requirements)*
2019	10,909			Wind (100MW nameplate, 40MW firm) *(Plus transmission and load following requirements)*	
2020	10,734				
2021	10,559				
2022	10,398				
2023	10,236				
2024	10,077				
2025	9,913				
2026	9,759				
2027	9,607				
2028	9,457				
2029	9,310				
2030	9,165				
2031	9,023				
2032	8,882				
NPV 2008-32 (M$)		$11,135	$11,996	$12,401	$11,754
Study Period (M$) (includes End Effects)		$14,665	$16,034	$16,902	$15,879

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Highlights of Plan H

- Kyoto World – Carbon Capture and Storage

- Wind (100 MW nameplate block) in 2013 to meet RES
- Biomass co-fire at 8 coal units; Biomass PPA (15 MW) in 2017
- Upgrades to NSPI existing facilities
- Investment in 3 Carbon Capture and Storage Retro-fit units (2018)
  - Uncertainties with cost, feasibility of transportation and long-term storage
  - CCS retrofits include FGD (scrubber)
- Baghouses added in 2018
- Transmission investment and/or back-up (load following) generation required
- Low cost plan within Kyoto World by large margin
  - Larger differentials between this plan and next lowest cost plan compared to other Worlds
  - Large differential between this plan and least cost plan in Base World

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Highlights of Plan I

- *Kyoto World - Renewables and natural gas-fired generation*

Comparison to Plan H

- No CCS, no baghouses
- Additional wind (100MW nameplate blocks) in 2016, 2017, 2018
- Additional Biomass PPA (15 MW and 60 MW) in 2017
- 280 MW combined cycle unit in 2018
- Higher cost than Plan H

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Highlights of Plan J

- *Kyoto World - Renewables with increased natural gas-fired generation*

Comparison to Plan H

- No CCS, no baghouses
- Biomass co-fire at 3 coal units
- No biomass PPA
- 2 x 280 MW combined cycle unit in 2018
- Additional wind (100MW nameplate block) in 2019
- Highest cost plan - Significant gap from Plan H

Highlights of Plan K

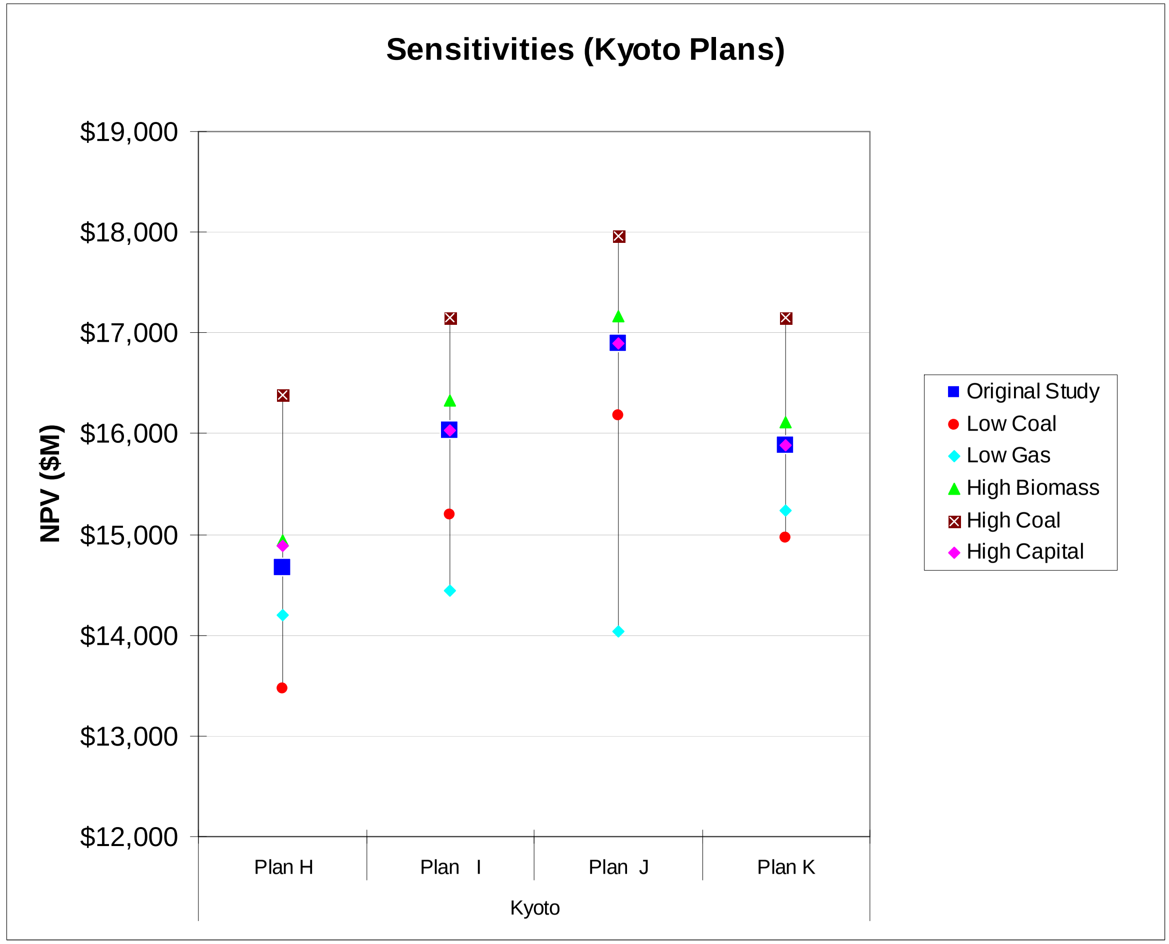
- *Kyoto World - Large Non-Emitting PPA*

Comparison to Plan H

- No CCS, no baghouses
- Additional wind (100 MW nameplate block) in 2016
- Large non-emitting PPA (300 MW) in 2018
- Second lowest cost plan within Kyoto World - Material gap from Plan H

2009 IRP Update
Modeling / Analysis Results

- Increased variability among plans
- Gas prices variations pronounced
- Rank Orders shift under Low Gas test



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2009 IRP Update
Modeling / Analysis Results

General Highlights – Kyoto World Plans

- Negative Load Growth with Base Load + DSM
- Greater than $1B more costly than similar plan in non-Kyoto World
- Reliance on carbon credits in short/mid-term
- Wind to meet 2010-2012 RES common to all plans
- Pre-2012 investments and capacity recovery upgrades at coal units common to all plans (~2010)
- Efficiency improvement up-rates at NSPI facilities common to plans
- Marshall Falls and Nictaux Hydro Up-rates common to plans (~2011)
- Additional investment in wind for 2013 RES plus investment in Co-firing Biomass
- Small Biomass PPA common except Plan J

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General Highlights -"Kyoto" World Plans

- In addition to Renewables, coal investment in 2018 to meet Hg/SO2 reductions (e.g. FGD/scrubber, Baghouse, CCS) or additional Gas or Large Non-Emitting PPA
- Carbon reductions will require large-scale investment
- Variability among plans more pronounced, as is uncertainty associated with solutions
- The technical and economic viability of key elements including CCS and Large PPA will need to be monitored
- Transmission investment and fast-acting back-up/load following generation required to support solutions

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Analysis Consolidation

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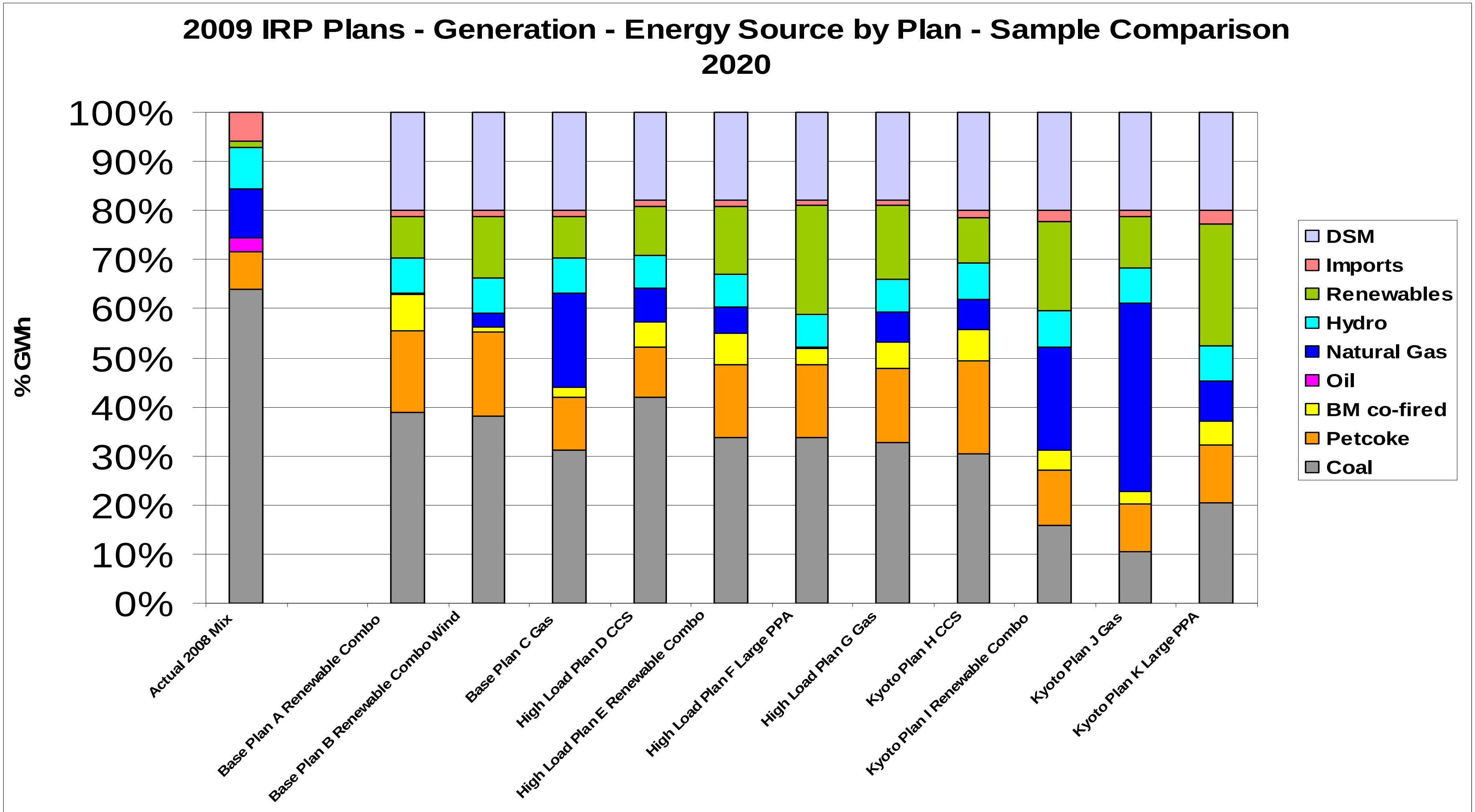
2009 IRP Update
Modeling / Analysis Results



Note: “Renewables” above includes Large Non Emitting PPA (as opposed to "Imports").

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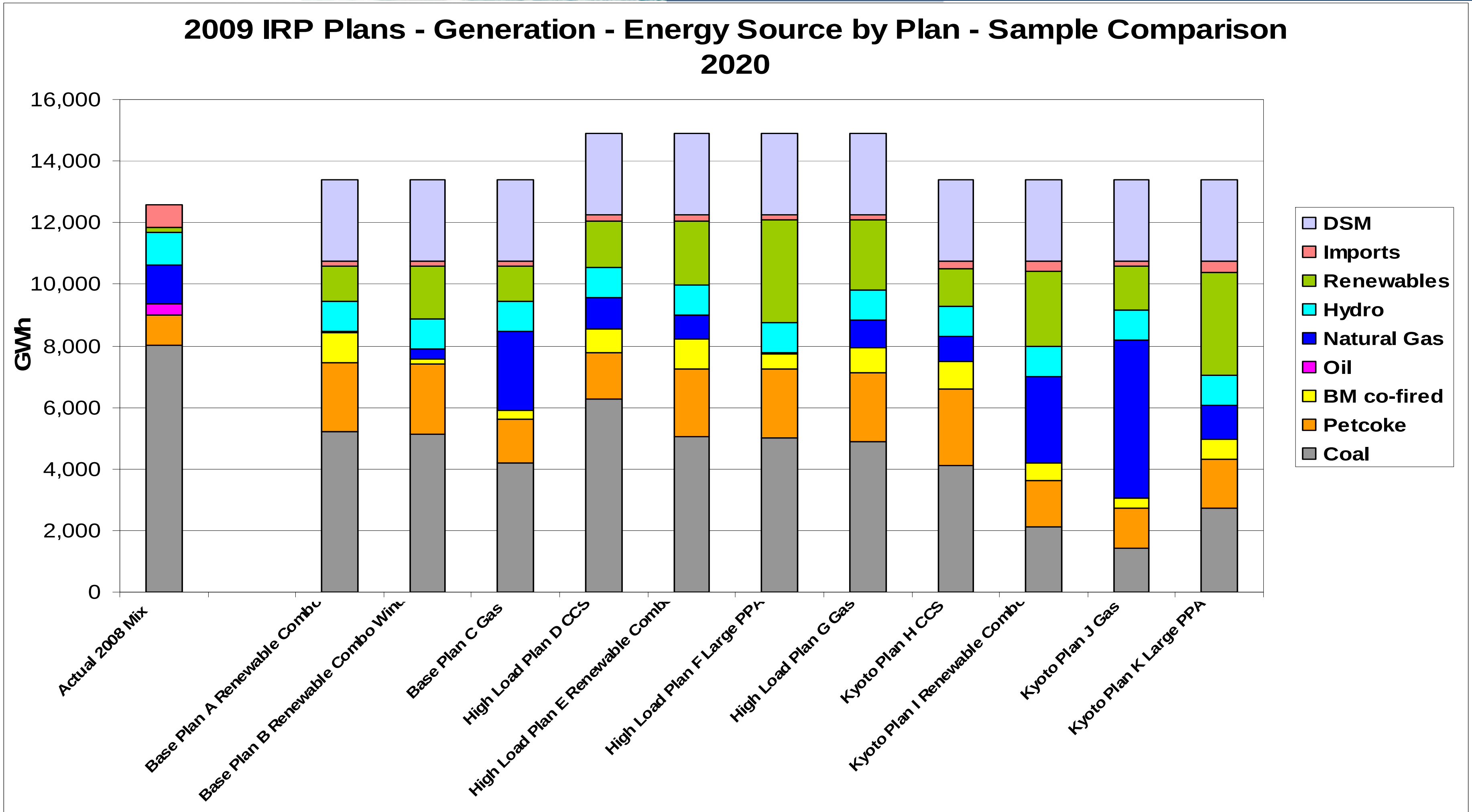
2009 IRP Update
Modeling / Analysis Results



Note: "Renewables" above includes Large Non Emitting PPA (as opposed to "Imports").

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Analysis Consolidation

- Reduction in coal-fired generation reflects shift to DSM, renewables and natural gas-fired generation over the next decade
- Flexibility will be key to minimize risks associated with volatile fuel prices, escalating capital costs, etc.
  - Near term resource options require modest planning/execution lead times (~3 years)
  - Longer term resource options require more extensive planning/execution lead times (~5 years)

Analysis Consolidation

- ***Forecast cost differentials within worlds are relatively small***

- In part, a function of plan commonality over first decade

- Over second decade plan costs diverge within Worlds

- Between Worlds, significant cost variations exist
  - For instance, at Base Load forecast, more than $1B in cost difference (increase) between Base and Kyoto Plans

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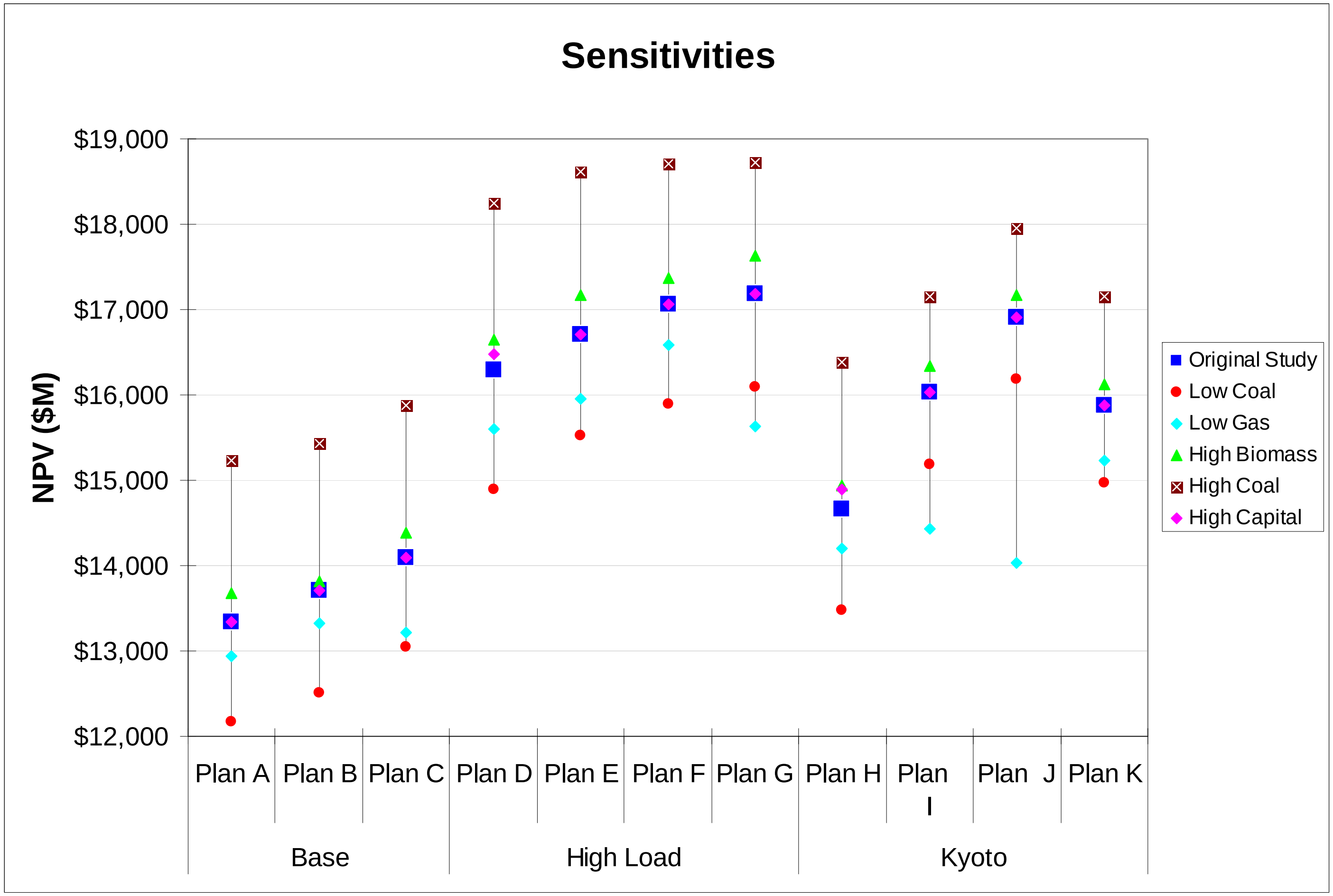
2009 IRP Update
Modeling / Analysis Results

Sensitivity Tests Conducted:

- Low and High Coal Price
- Low Gas Price
- High Biomass Price
- High Carbon Capture and Storage Capital Cost

- NOTE:
  Plans D to G supply more GWh (higher load) resulting in a higher revenue requirement



Sensitivity Results

Low and High Coal prices

- No changes in Plans' rank orders
  - NPVs over study period shift lower or higher

Low Gas price

- Only sensitivity test run that results in rank order change amongst certain Plans
- Plans with more natural gas get close to lowest cost in Base and High Load Worlds. Becomes lowest cost in Kyoto Plan J (mostly gas Kyoto plan)

High Biomass price

- No changes in Plans' rank orders

High Carbon Capture and Storage capital cost

- Only relevant in High Load and Kyoto World - two plans
- No change in rank order

Sensitivity Results

- Sensitivity Analysis suggests the Renewables Plans under Base and High Load World Assumptions are robust
  - It appears Biomass could play a cost-effective role in meeting Provincial renewables requirements in addition to wind and DSM

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2009 IRP Update
Modeling / Analysis Results

2009 IRP UPDATE RESOURCE PLANS: SCHEDULE OF FIRM SUPPLY or DSM (Equivalent MW's)

	PLAN A (BASE)	PLAN B (BASE)	PLAN C (BASE)	PLAN D (HIGH LOAD)	PLAN E (HIGH LOAD)	PLAN F (HIGH LOAD)	PLAN G (HIGH LOAD)	PLAN H (KYOTO)	PLAN I (KYOTO)	PLAN J (KYOTO)	PLAN K (KYOTO)
New Resources 2010-2017											
DSM	290	290	290	290	290	290	290	290	290	290	290
TUC6	49	49	49	49	49	49	49	49	49	49	49
Hydro Uprates	4	4	4	7	7	7	7	7	7	7	7
Wind (Nets out 60 (26 firm) MW of existing 308 (100 firm) MW contracted already in service pre 2010; 2010-2017 = 248 (74 firm) MW per existing contracts plus added wind per Plans 2012-2017)	117	159	117	159	159	159	159	117	200	117	159
Biomass (PPAs only; excludes co-fire conversions since not new MW)	0	0	0	16	16	16	16	0	0	0	0
Coal Uprates	30	30	30	30	30	30	30	30	30	15	30
SUBTOTAL	**490**	**531**	**490**	**549**	**549**	**549**	**549**	**492**	**576**	**477**	**534**
New Resources 2018-2032											
DSM	552	552	552	552	552	552	552	552	552	552	552
Additional Wind	0	42	0	0	214	0	83	0	41	41	0
Additonal Biomass	16	16	16	0	55	55	55	16	71	0	16
Natural Gas	0	0	147	0	0	0	280	0	280	560	0
Large Non-Emitting Import PPA	0	0	0	0	0	300	0	0	0	0	300
Coal Retrofit Capacity Adjustments	-8	-8	0	-114	-8	-8	-8	-114	0	0	0
SUBTOTAL	**560**	**602**	**715**	**438**	**813**	**900**	**962**	**454**	**944**	**1153**	**868**
TOTAL ADDITIONAL FIRM SUPPLY & DEMAND MW's OVER PLANNING PERIOD	**1050**	**1134**	**1205**	**988**	**1363**	**1449**	**1512**	**946**	**1520**	**1631**	**1402**
Coal Emission Retrofit - Baghouse (# units)	2	0	0	3	2	1	2	2	0	0	0
Coal Emission Retrofit - FGD (Scrubber) (# units)	2	2	0	3	2	2	2	3	0	0	0
Coal Emission Retrofit - Carbon Capture Storage (CCS) (# units)	0	0	0	3	0	0	0	3	0	0	0

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Resource Plans - Summary MW (Schedule of Supply or DSM MWs)

NOTE: Values in the table above represent firm MW, including derations and DSM net of the interruptible industrial portion

Analysis Consolidation

- Plan consistency over first decade is striking
  - Predominantly renewables and DSM-based
  - To be expected, given that constraints are environmental and that available tools to address them are limited

- Over longer term there appear to be viable options currently available to meet constraints and opportunities on the horizon
- The low cost Renewables Plans appear to be low risk and robust
- Developments inherent in the alternative Worlds and/or economic and technical opportunities represented by emerging technologies may ultimately require a shift from these plans. These developments will need to be monitored

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Conclusions

Conclusions

- The 2007 IRP Reference Plan and Action Plan have been affirmed through the Update process
  - In the near term
    - Investment in renewables and DSM continue to be required to meet environmental requirements
    - Upgrades to NSPI's existing assets are economically justified in all plans
  - Over the longer term
    - Renewables and DSM will continue to form the core of the resource plan
  - Precise levels and timing of resources shift between 2010 and 2018 but commonality remains amongst all plans
  - Other than the addition of Biomass, the Reference Plan has not changed materially

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2009 IRP Update
Modeling / Analysis Results

Conclusions

- As the least cost Base Plan, Plan A could serve as a viable reference plan
- Plan B has substantial commonality and comparable costs
- Plan E has similar attributes in High Load World
- Over the longer term, Plans A, B and E include technologies which are technically proven today
  - They provide flexibility to adjust to changing constraints and market conditions as the requirement for this is identified
- 2007 IRP “No regrets strategy” in the near term can be maintained
  - Flexibility to adjust to changing requirements is preserved

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Conclusions

- Changes to the Reference Plan will be required as NSPI moves through the first RES period and the Company continues to address new environmental challenges
  - In the near term this will require refinements to investment plans and operating programs to ensure the optimal investments are undertaken at the appropriate times, with consideration given to the variable production nature of renewables (e.g. hydro, wind) and the need for appropriate planning contingencies
  - Over the longer term, key market and environmental developments will need to be continuously monitored to ensure changes to the plans are anticipated in a timely manner. These include:
    - Load growth
    - The impact of DSM and renewables on the power system
    - Transmission upgrades – location, timing and cost
    - Back-up/load following generation – location, timing and cost
    - The sustainability of biomass
    - Fuel prices
    - The outlook for environmental regulations/legislation.
    - Import opportunities
    - The economic and technical feasibility of emerging technologies, in particular Carbon Capture and Storage

Next Steps

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Next Steps

- Technical Conference	Sept. 30
- Stakeholder comments on Analysis Results	Oct. 8
- Draft Report circulated	Oct. 29
- Stakeholder comments on Draft Report	Nov. 6
- Final Report issued	Nov. 30

APPENDIX A

Supply and Demand Side Matters for Consideration (UARB Correspondence February 25th, 2009)

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UARB Correspondence, February 25, 2009 – *Supply side issues should include*:

a. New Renewable Resources	- New renewable resources considered in options for new generation additions including; new wind, biomass, Compressed Air Energy Storage, large non-emitting PPA - Transmission cost assumptions were developed and incorporated within the analysis
b. Existing Renewable Resources	- Wind continues to be dominant in plans in the Update - Includes NSPI Hydro/Tidal resources - Transmission costs and back up generation are included in wind assumptions
c. Environmental Constraints	-Provincial regulations announced - Less uncertain compared to 2007 with Mercury, SO2, NOx, CO2 hard caps for 2010 to 2020 timeframe
d. Long term fuel forecast	New long term fuel forecasts were developed for Update - While volatility is shown in near term, long term forecasts are not significantly different from 2007 perspective (IRP modeling does not value shorter term flexibility such as fuel switching investments which may be valuable to customers in future)

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UARB Correspondence, February 25, 2009

Demand side issues should include:

a. Load Forecast	- Updated 25 year load forecast was developed using current information - End use modeling is in development but was determined to be premature for inclusion - Basic load forecast before DSM is lower than in 2007 IRP
b. DSM Programs	- In 2007, a significant level of DSM was found economic and to be pursued - Early experience has indicated positive results - For Update, DSM as modeled (similar trajectory as for 2007 IRP) would reduce energy requirements by 2% per year. (Investment of this size is believed to be achievable though these larger investment levels are as yet untested).
c. AMI	- Not assessed separately as part of this process - Anticipated to contribute to achieving DSM savings

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APPENDIX B

Summary of Results Across Plans

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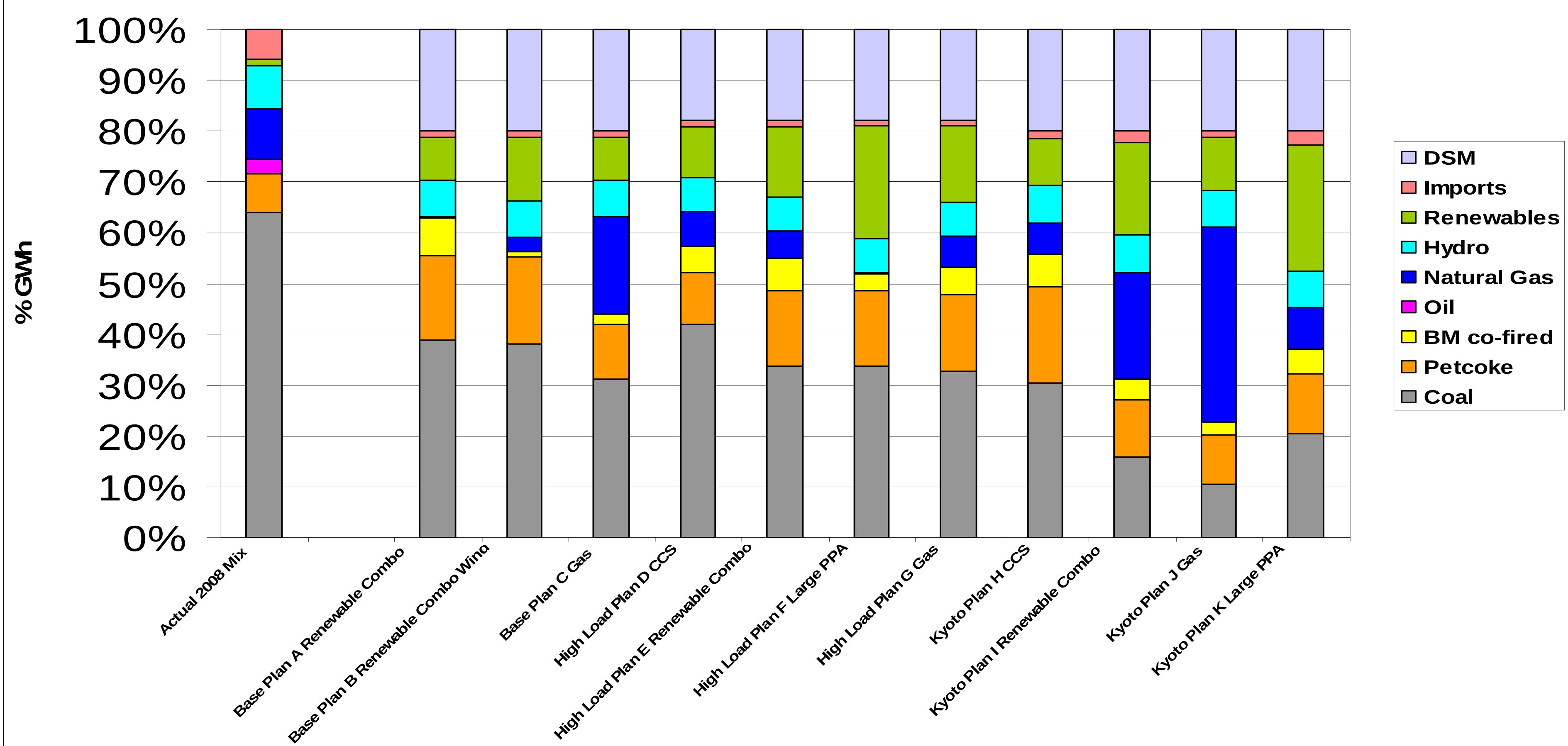
2009 IRP Update
Modeling / Analysis Results

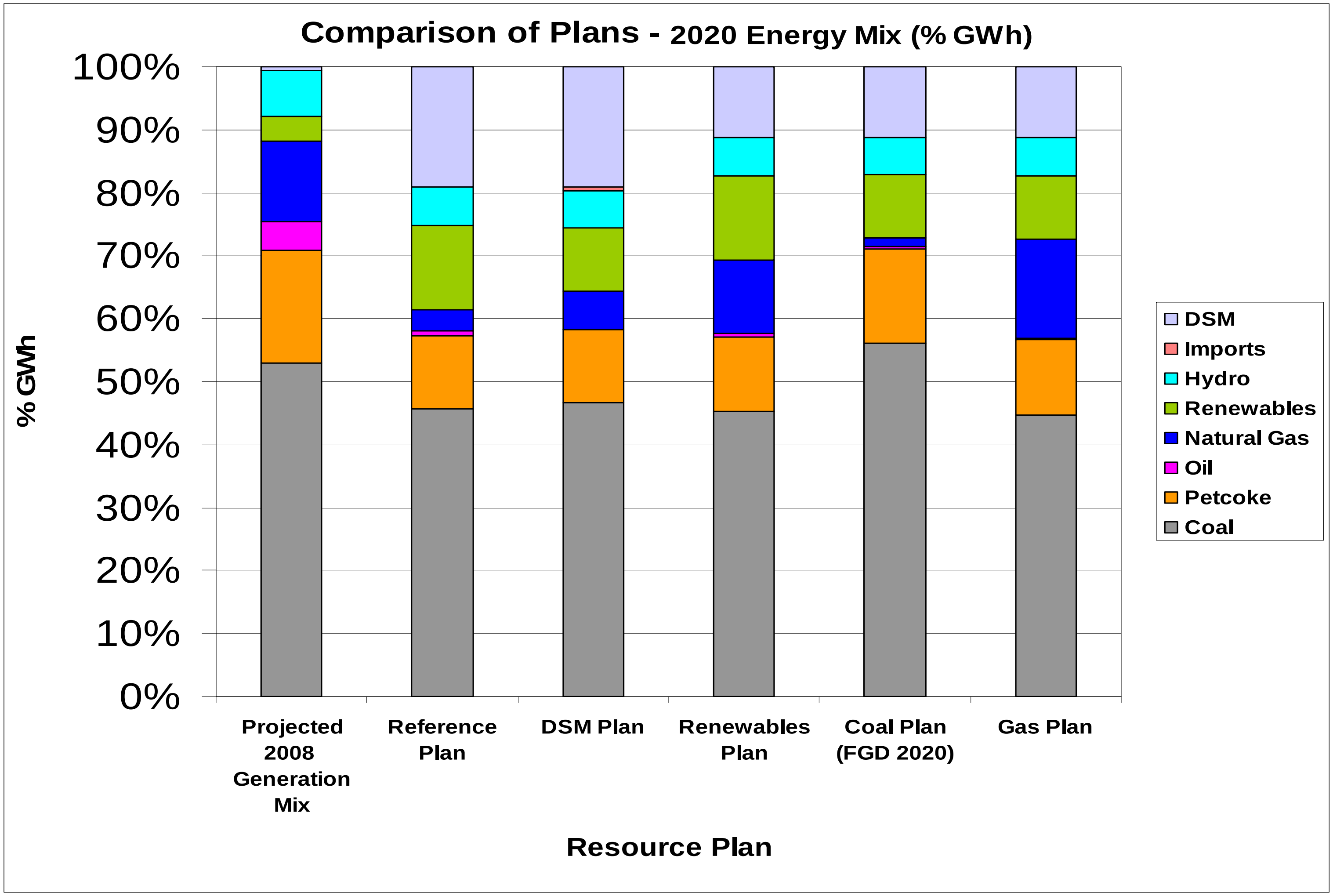
2009 IRP Plans - Generation - Energy Source by Plan - Sample Comparison 2020



Note: “Renewables” above includes Large Non Emitting PPA (as opposed to "Imports").

2009 IRP Update
Modeling / Analysis Results

Comparison: 2007 IRP Plans - Energy mix in Sample Year 2020



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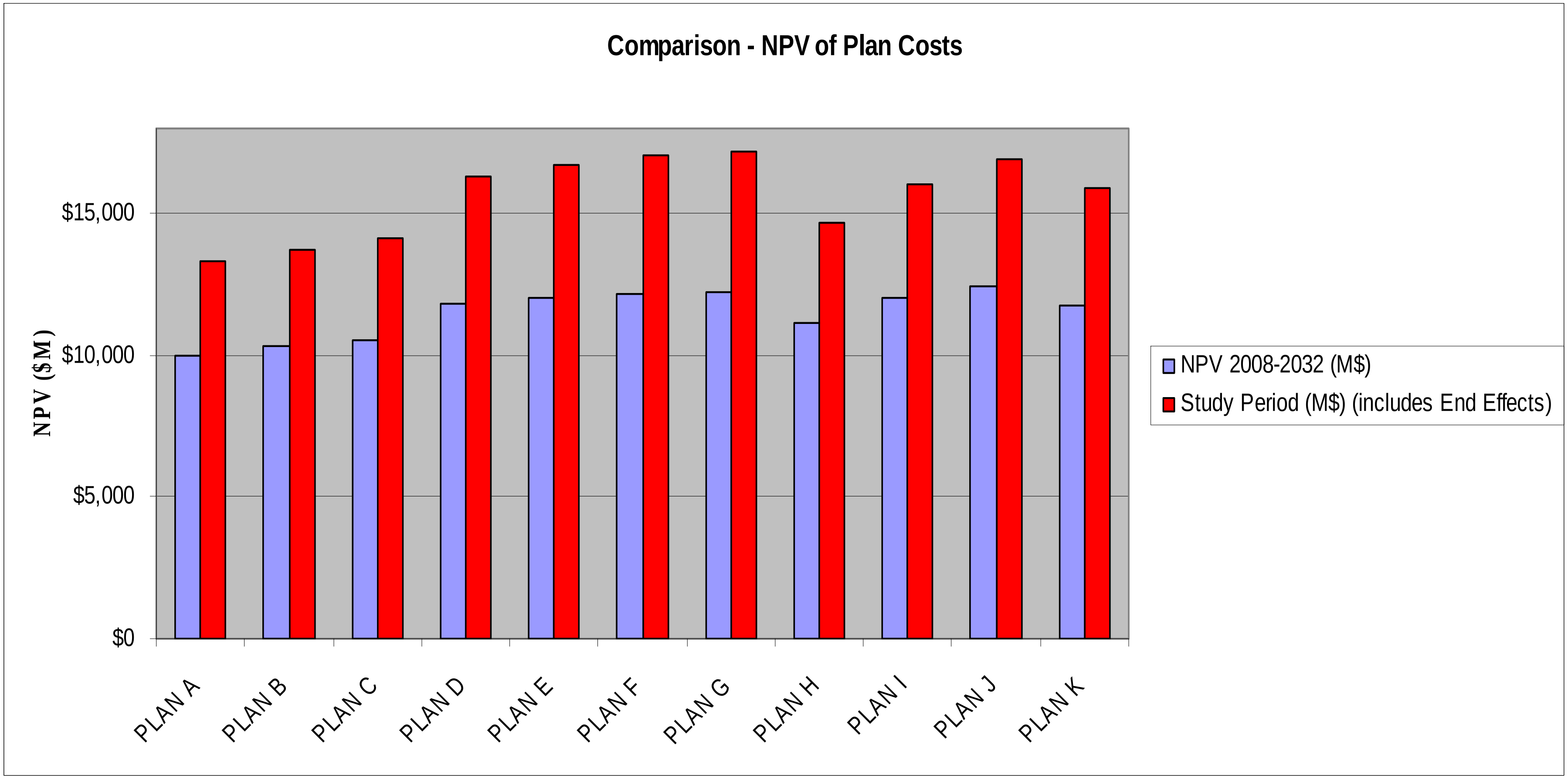

NPV of Costs - All Plans

PLAN	NPV 2008-2032 (M$)	Study Period (M$) (includes End Effects)	% Increase Compared to Plan A (NPV 2008-2032)	% Increase Compared to Plan A (Study Period)	% Increase Compared to Least Cost Plan in Set (NPV 2008-2032)	% Increase Compared to Least Cost Plan in Set (Study Period)
PLAN A (Base Case/Load) Renewables Combo	$10,007	$13,335	-	-	-	-
PLAN B (Base Case/ Load) More Wind	$10,342	$13,710	3%	3%	-	-
PLAN C (Base Case/Load) More Gas	$10,558	$14,100	6%	6%	-	-
PLAN D (High Load World) CCS	$11,828	$16,296	-	-	(Compared to Plan D)	(Compared to Plan D)
PLAN E (High Load World) Renewables Combo	$12,050	$16,703	-	-	2%	2%
PLAN F (High Load World) Large Non-Emitting Import PPA	$12,150	$17,068	-	-	3%	5%
PLAN G (High Load World) More Gas	$12,253	$17,188	-	-	4%	5%
PLAN H (Kyoto World/Base Load) CCS	$11,135	$14,665	11%	10%	(Compared to Plan H)	(Compared to Plan H)
PLAN I (Kyoto World/Base Load) Renewables Combo	$11,996	$16,034	20%	20%	8%	9%
PLAN J (Kyoto World/Base Load) Renewables Combo More Gas	$12,401	$16,902	24%	27%	11%	15%
PLAN K (Kyoto World/Base Load) Large Non-Emitting Import PPA	$11,754	$15,879	17%	19%	6%	8%

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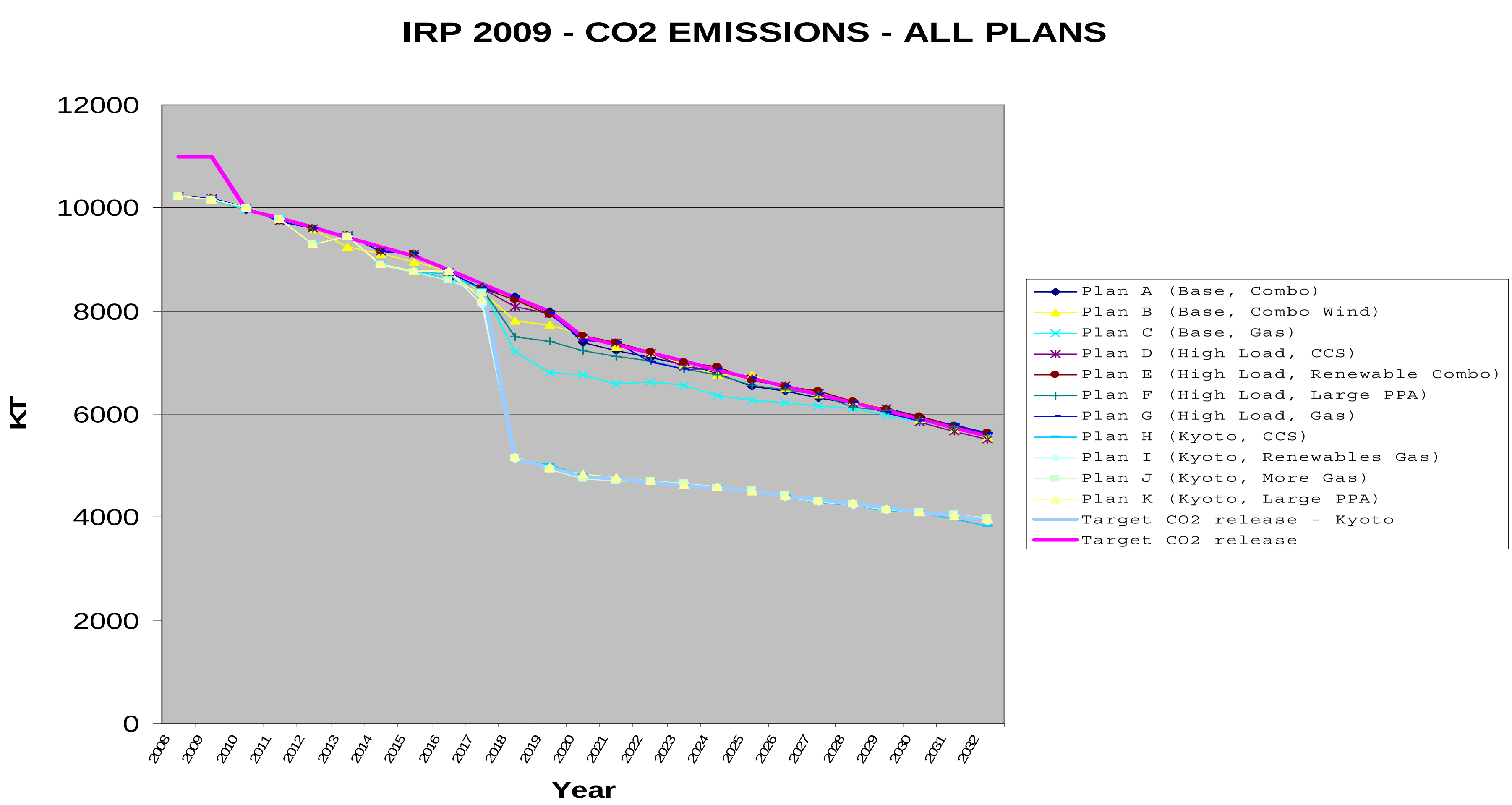

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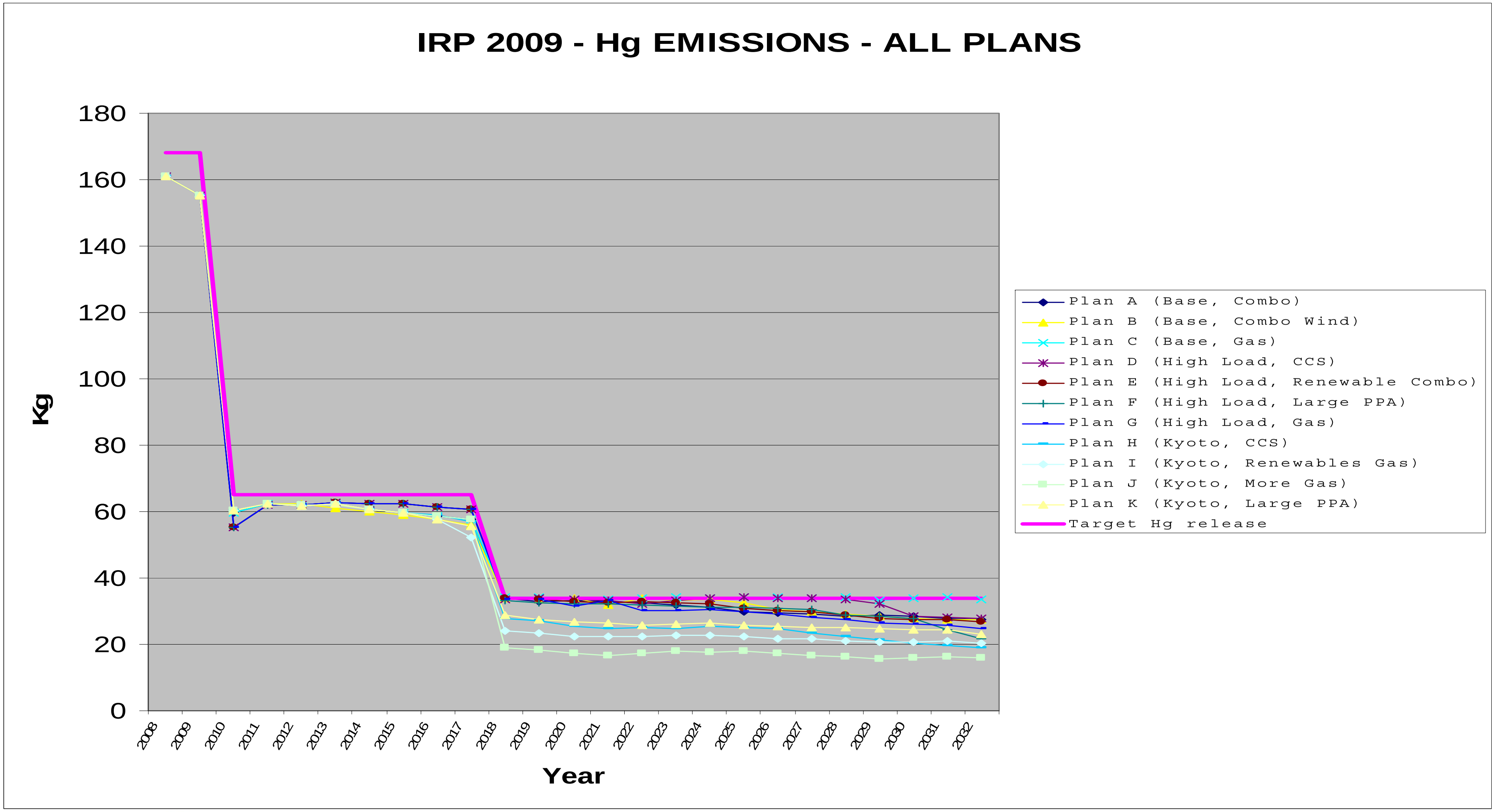
2009 IRP Update
Modeling / Analysis Results



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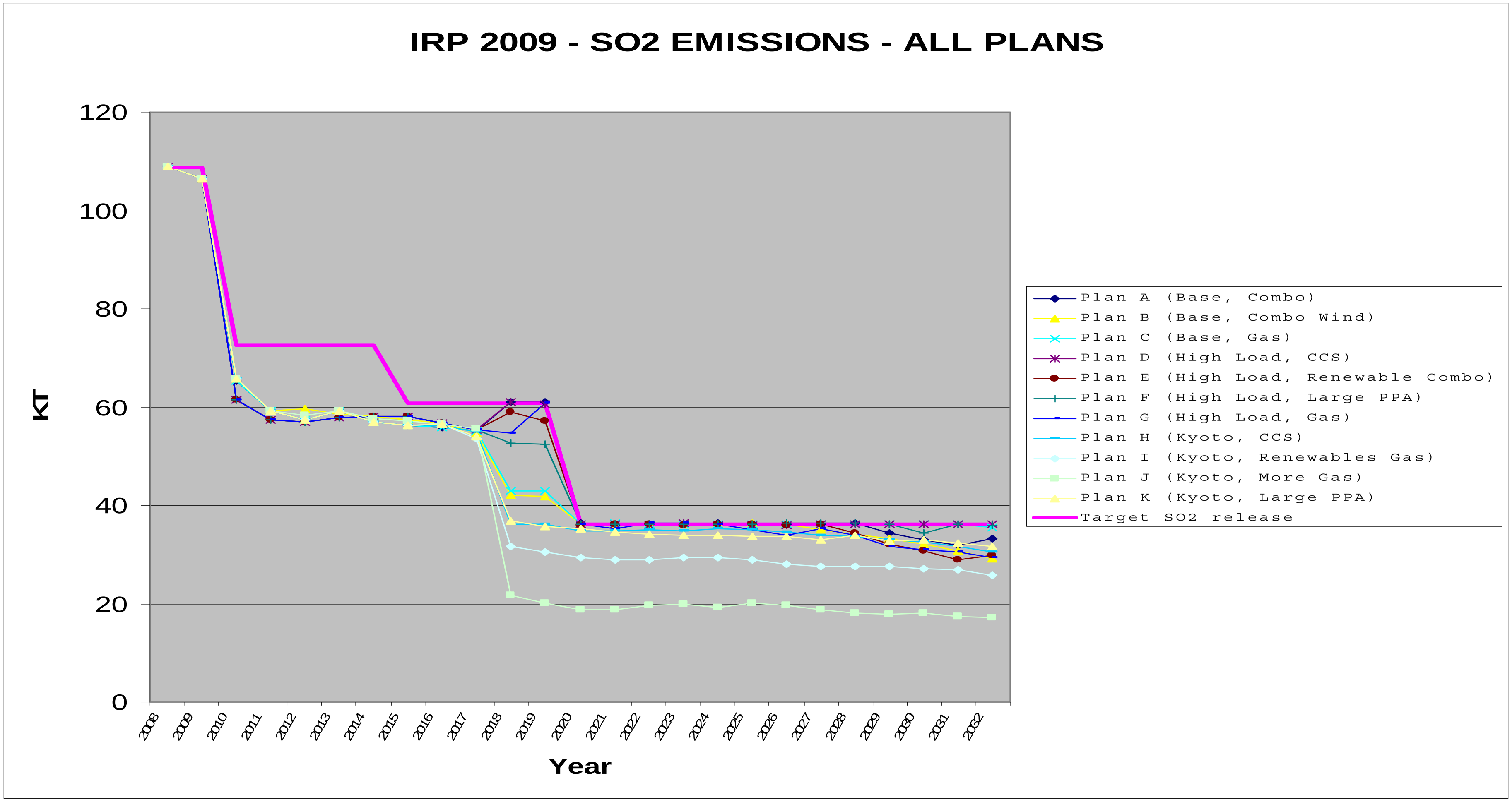
2009 IRP Update
Modeling / Analysis Results



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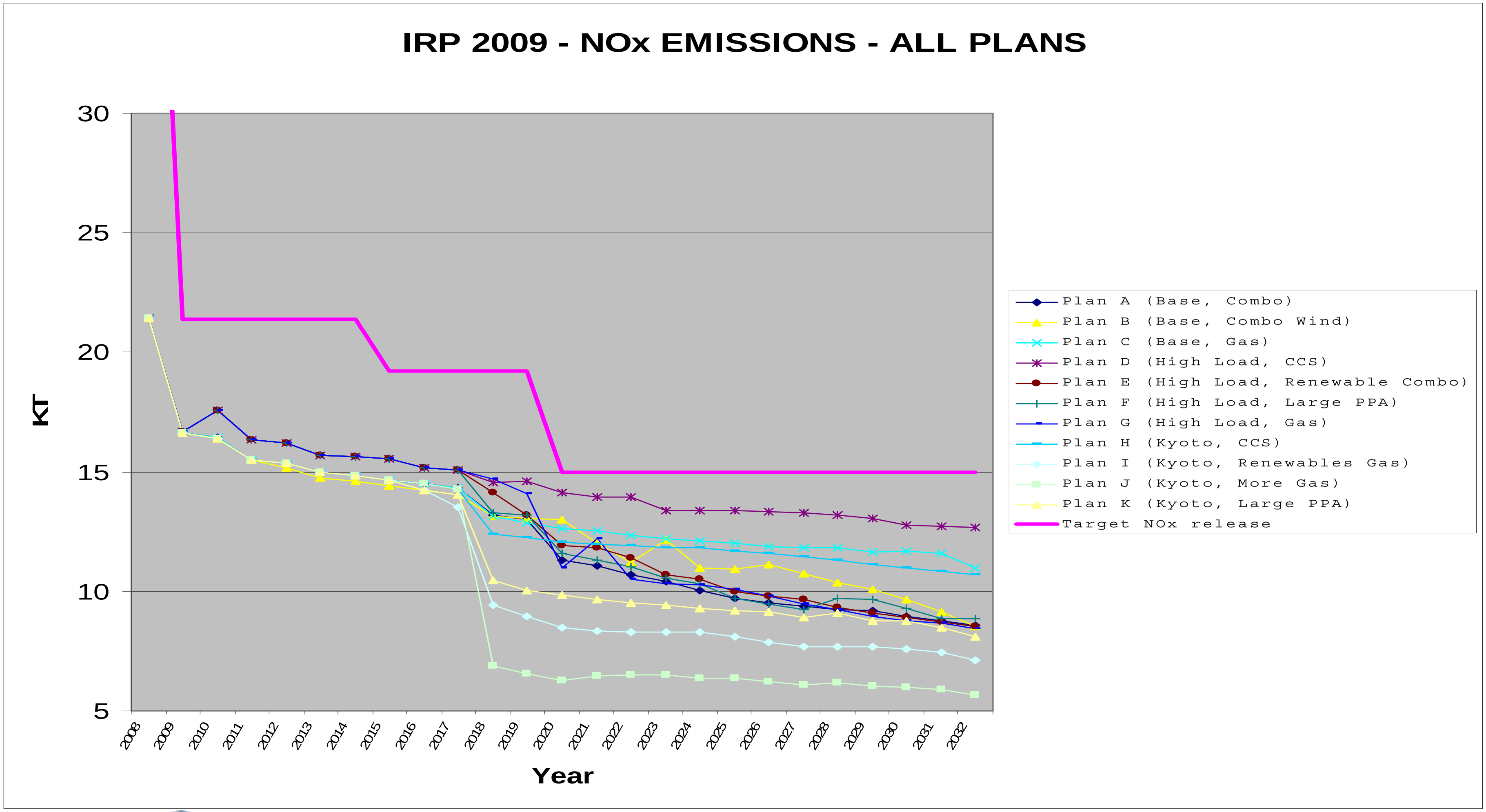
2009 IRP Update
Modeling / Analysis Results



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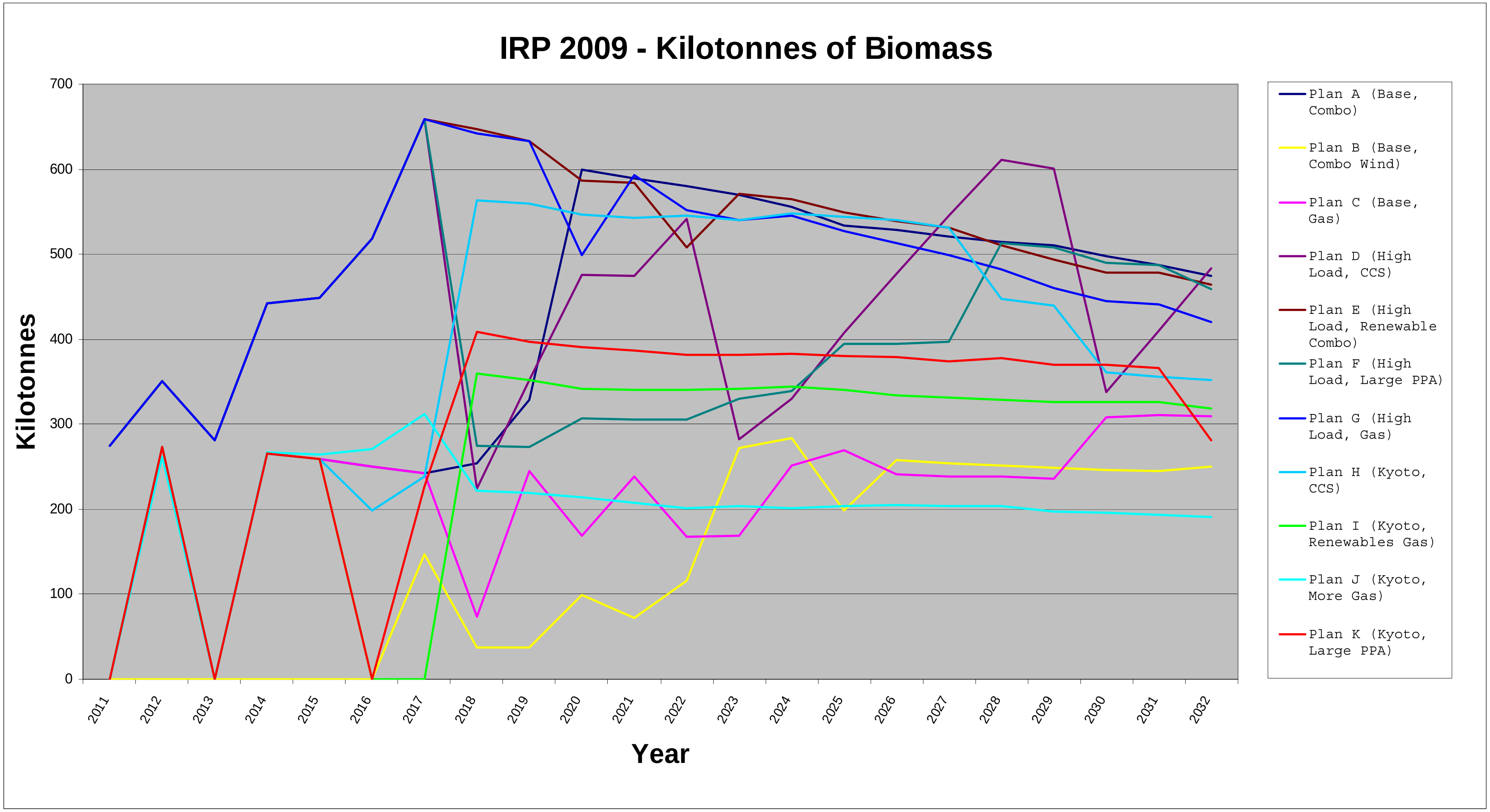
2009 IRP Update
Modeling / Analysis Results



(kilo-tonne = Dry kilo-tonne)

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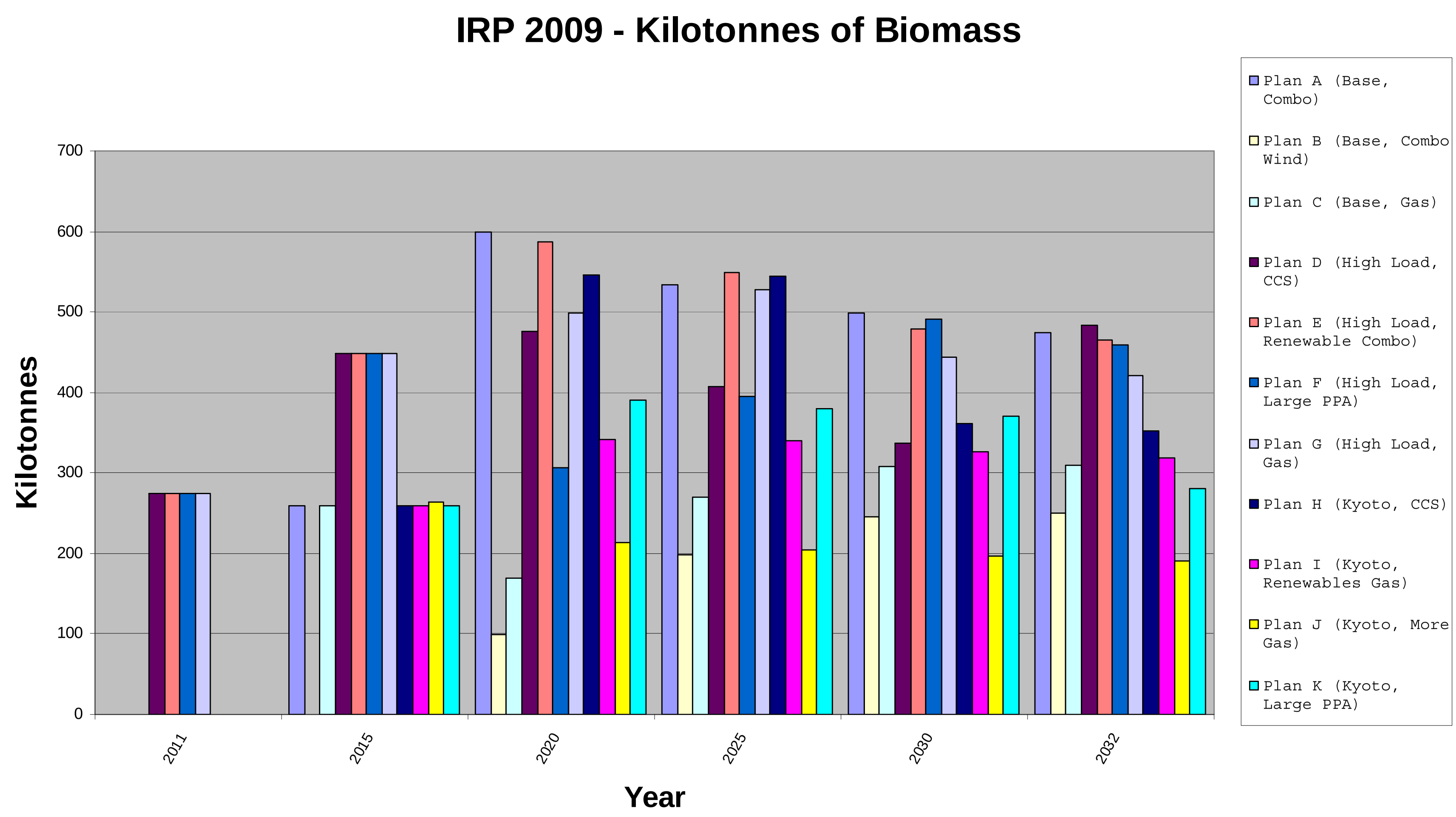
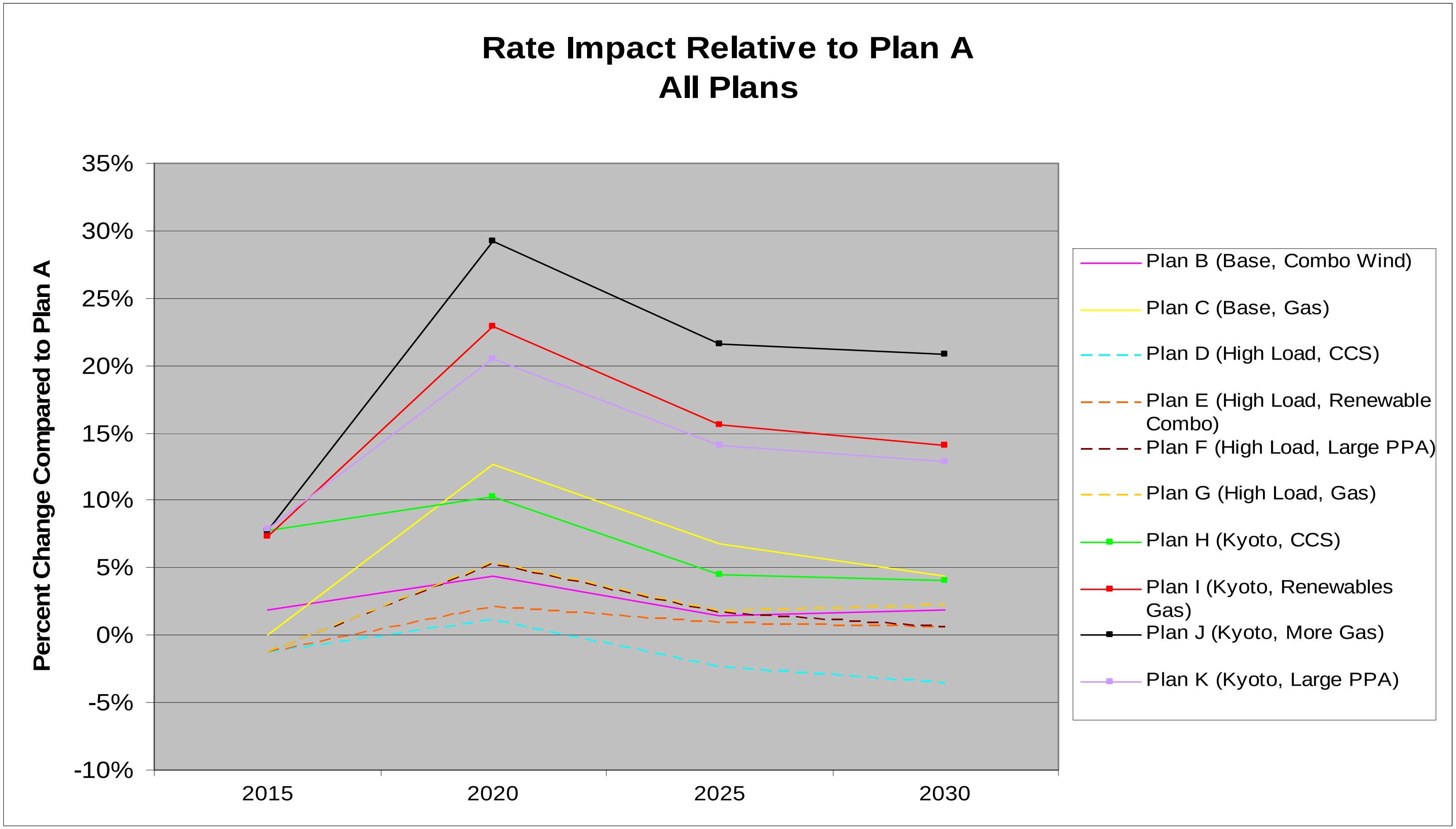
2009 IRP Update
Modeling / Analysis Results



(KT = Dry kilo-tonne)

2009 IRP Update
Modeling / Analysis Results



Rates are illustrative/relative/comparative only. Any future rates will be determined per Rate Application test year data.

APPENDIX C

Base Plan Results

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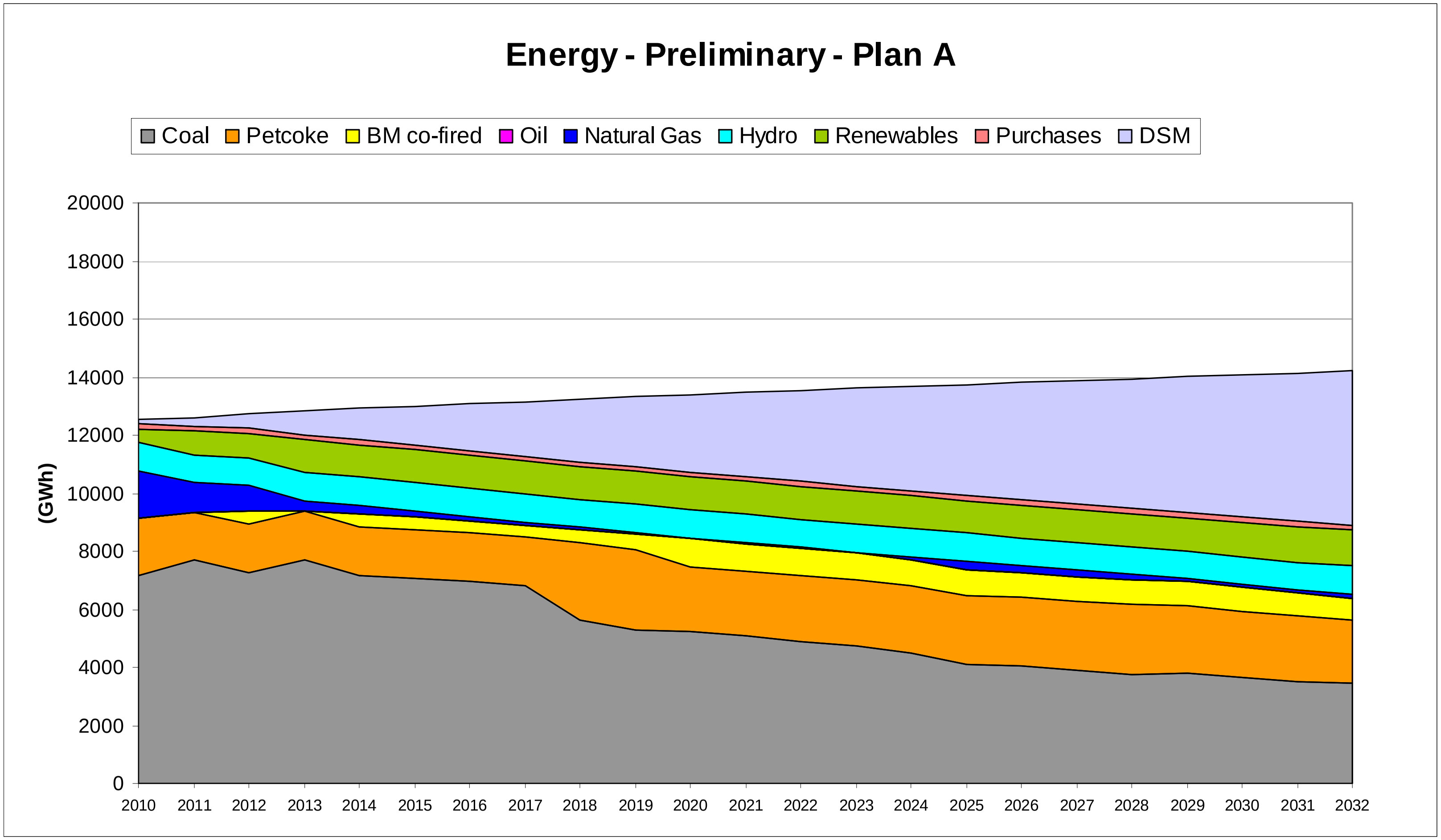
2009 IRP Update
Modeling / Analysis Results



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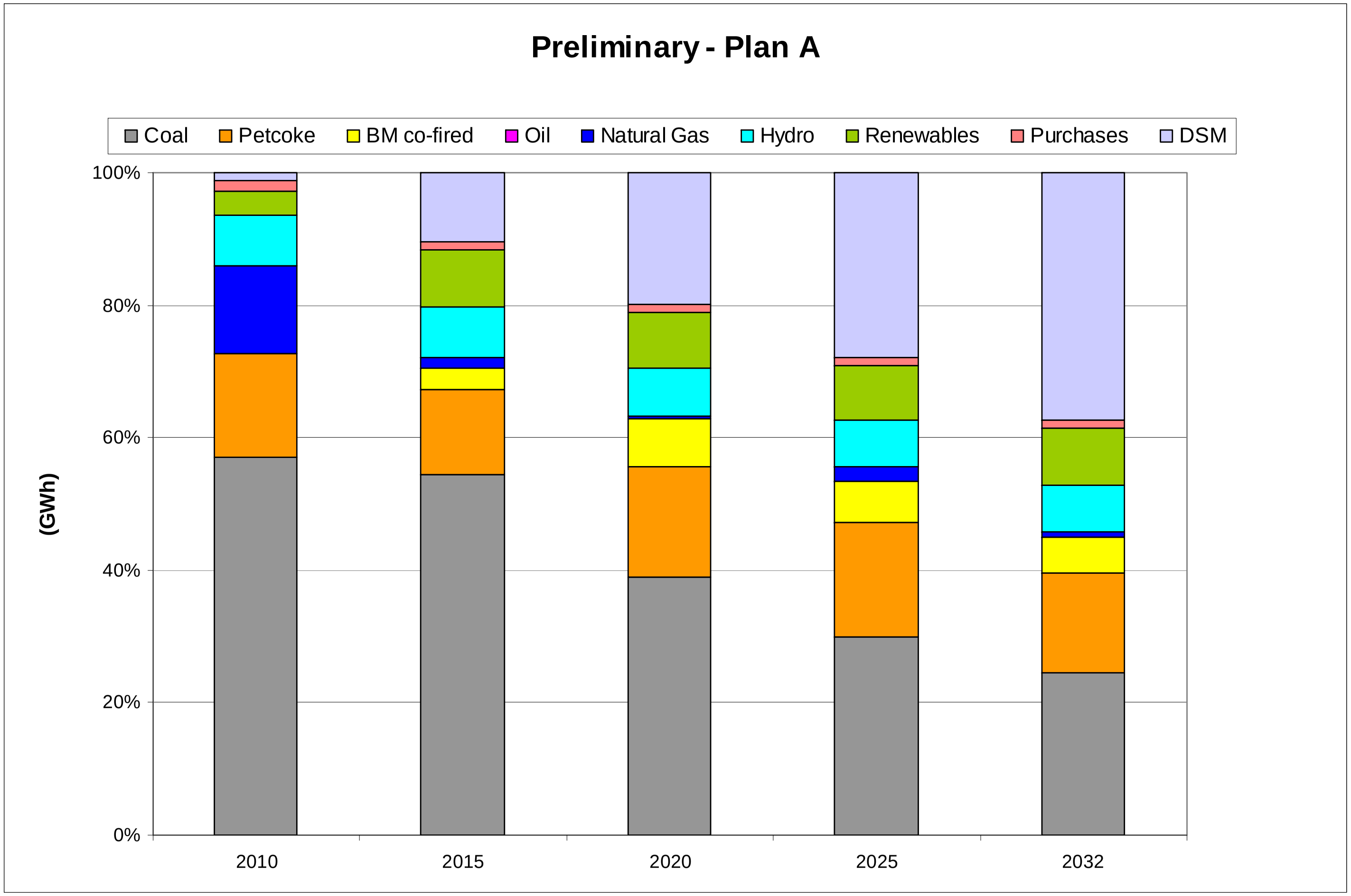
2009 IRP Update
Modeling / Analysis Results



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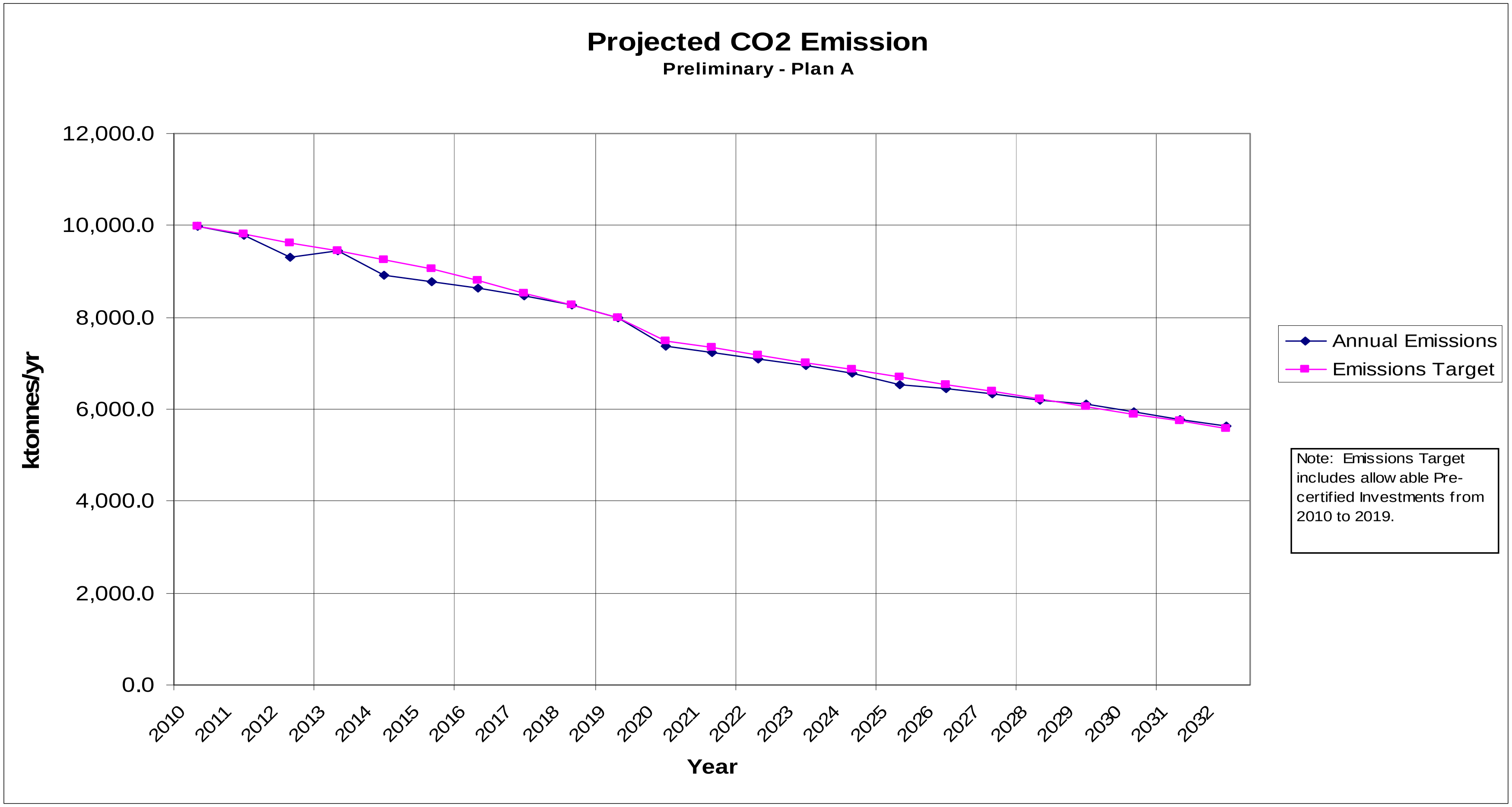
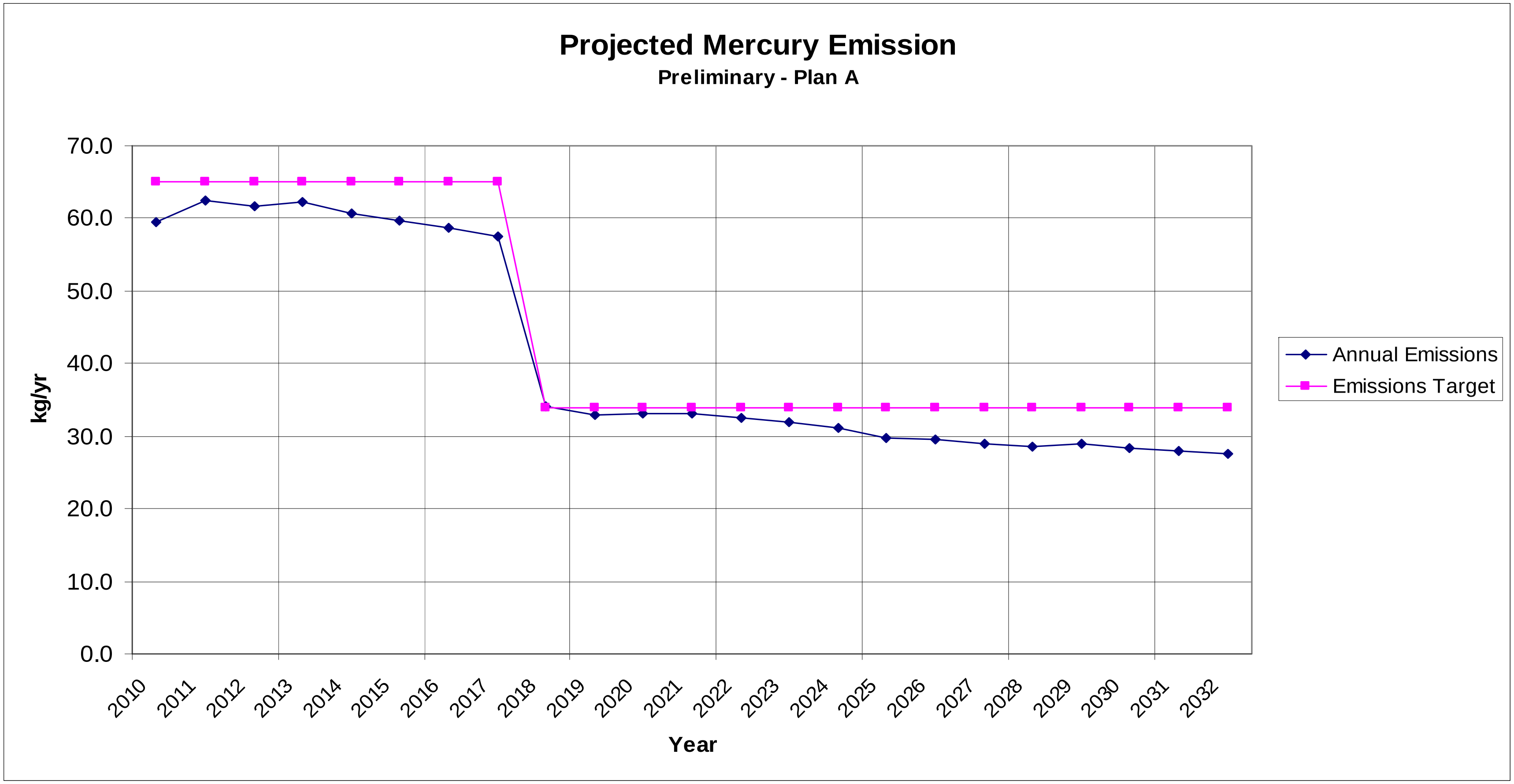
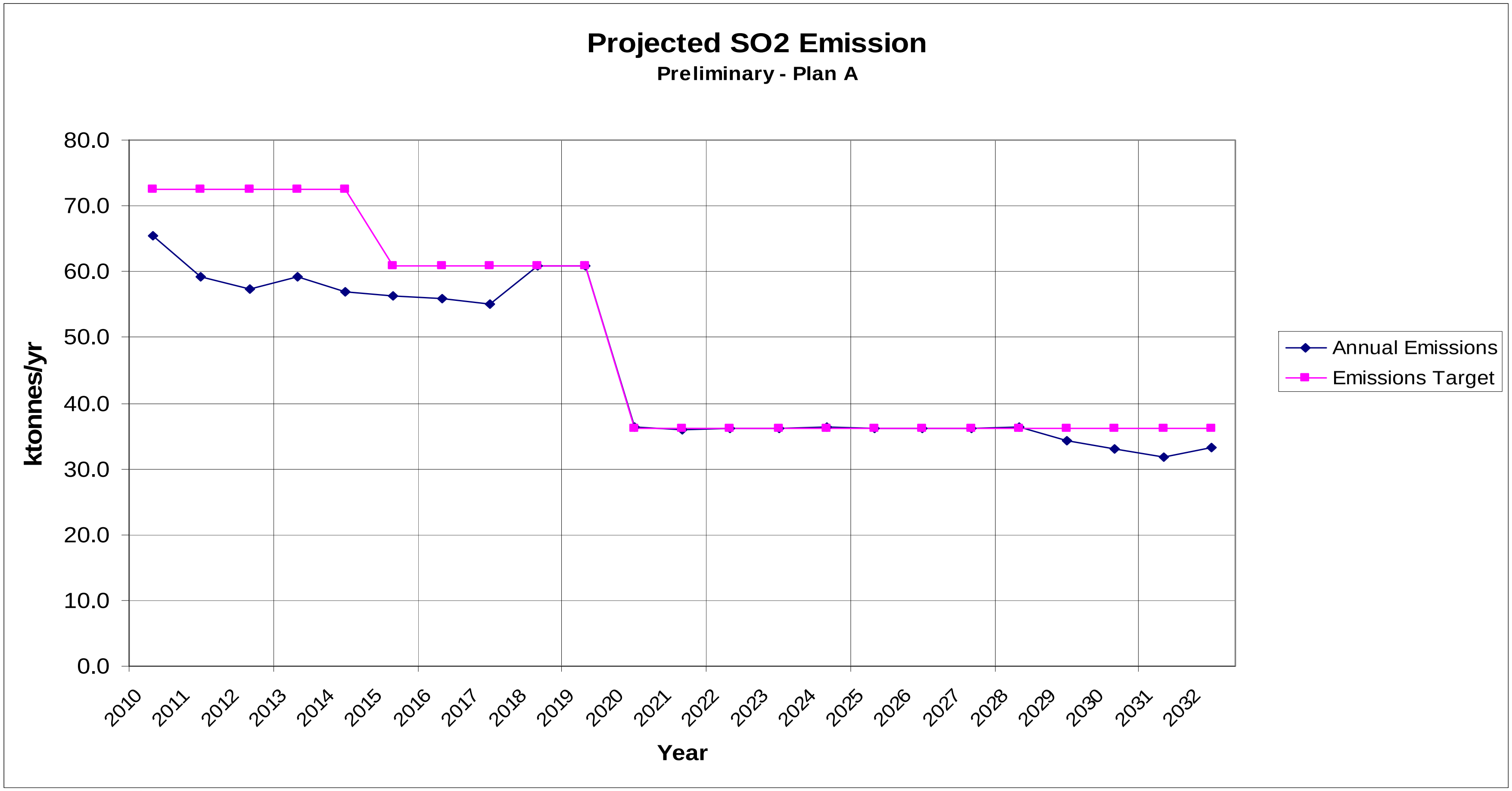
Emissions Graphs Plan A



Emissions Graphs Plan A

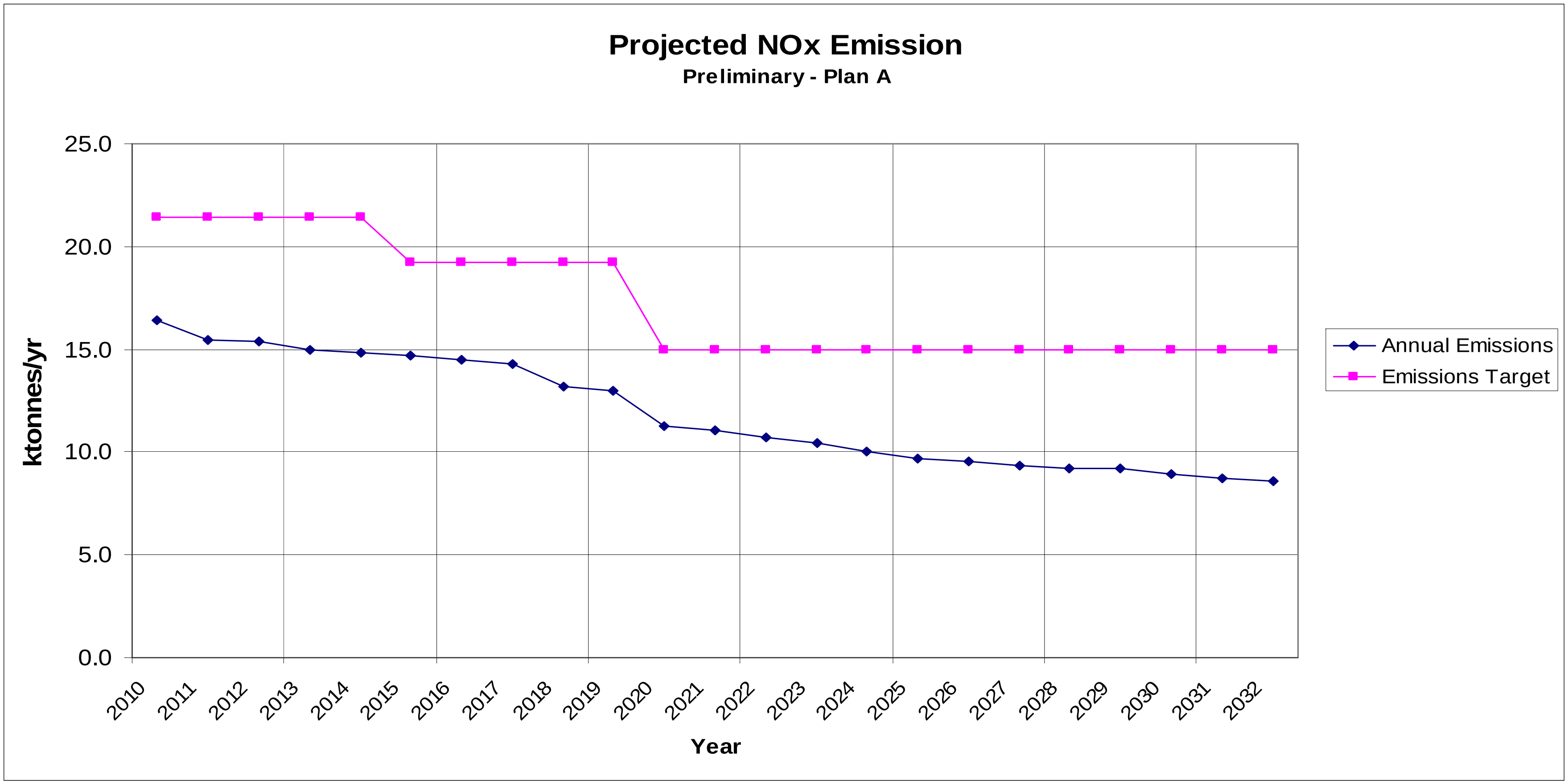


Emissions Graphs Plan A



2009 IRP Update
Modeling / Analysis Results

Emissions Graphs Plan A



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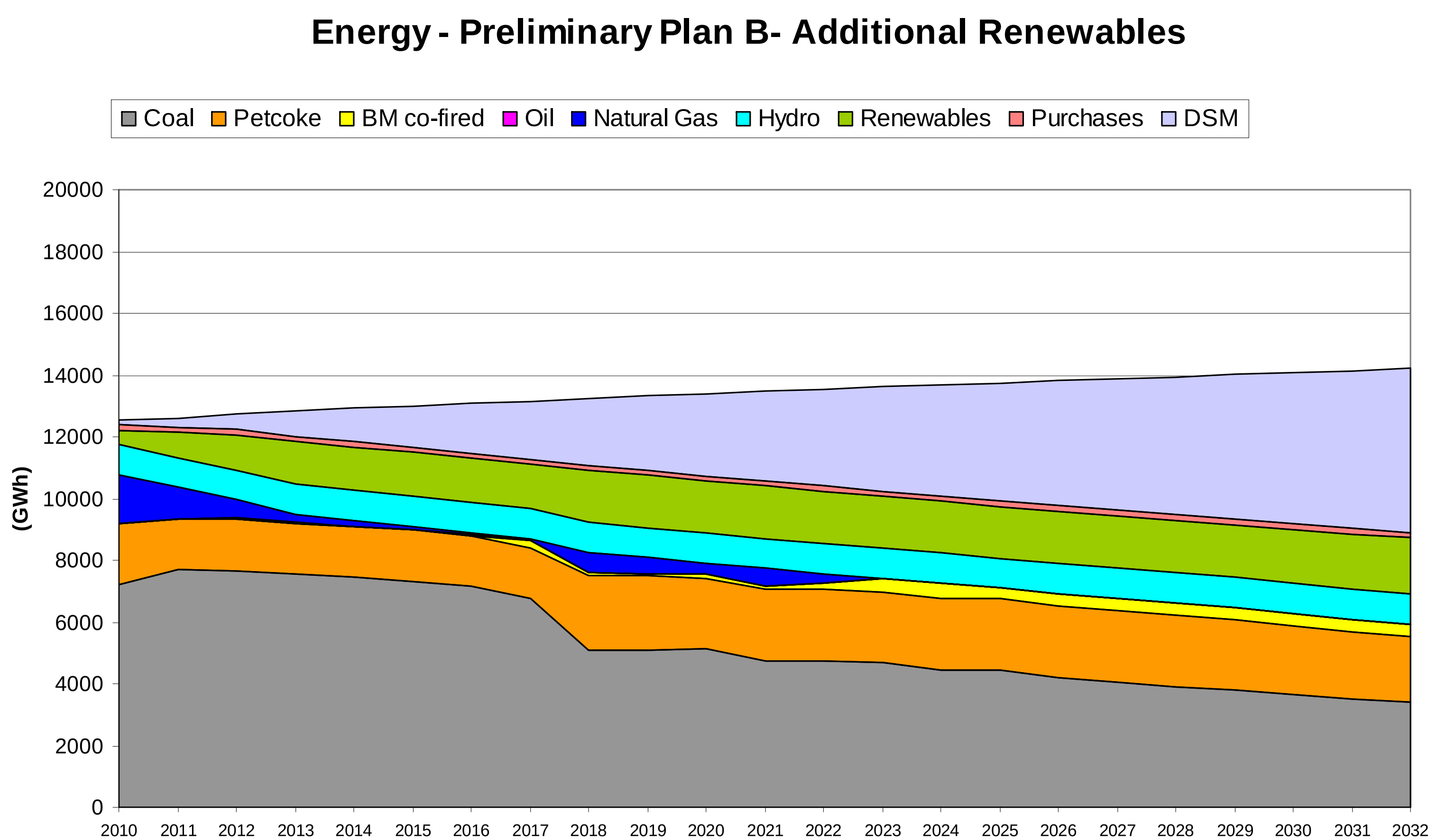
2009 IRP Update
Modeling / Analysis Results



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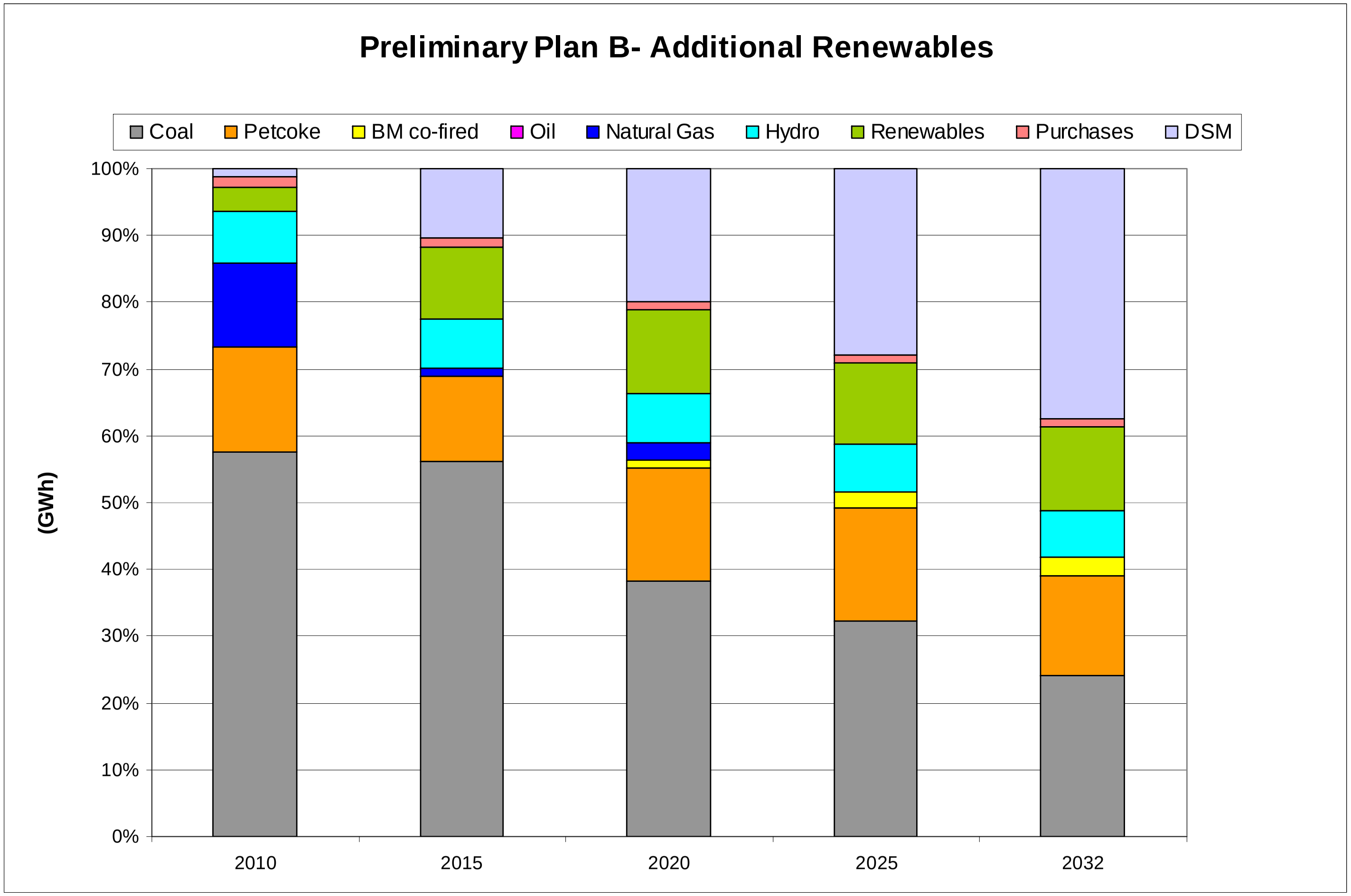
2009 IRP Update
Modeling / Analysis Results



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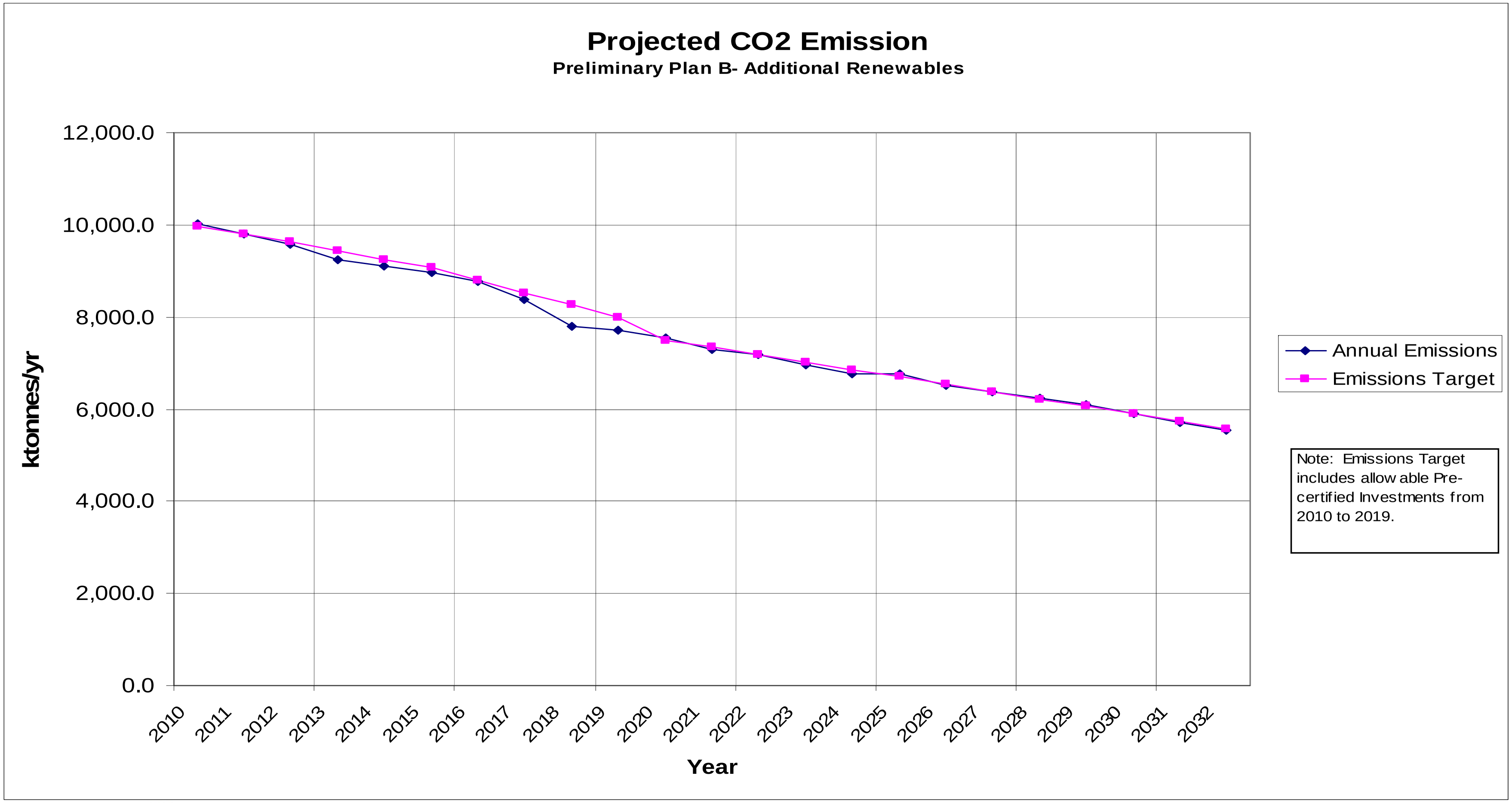
Emissions Graphs Plan B



NOVA SCOTIA POWER
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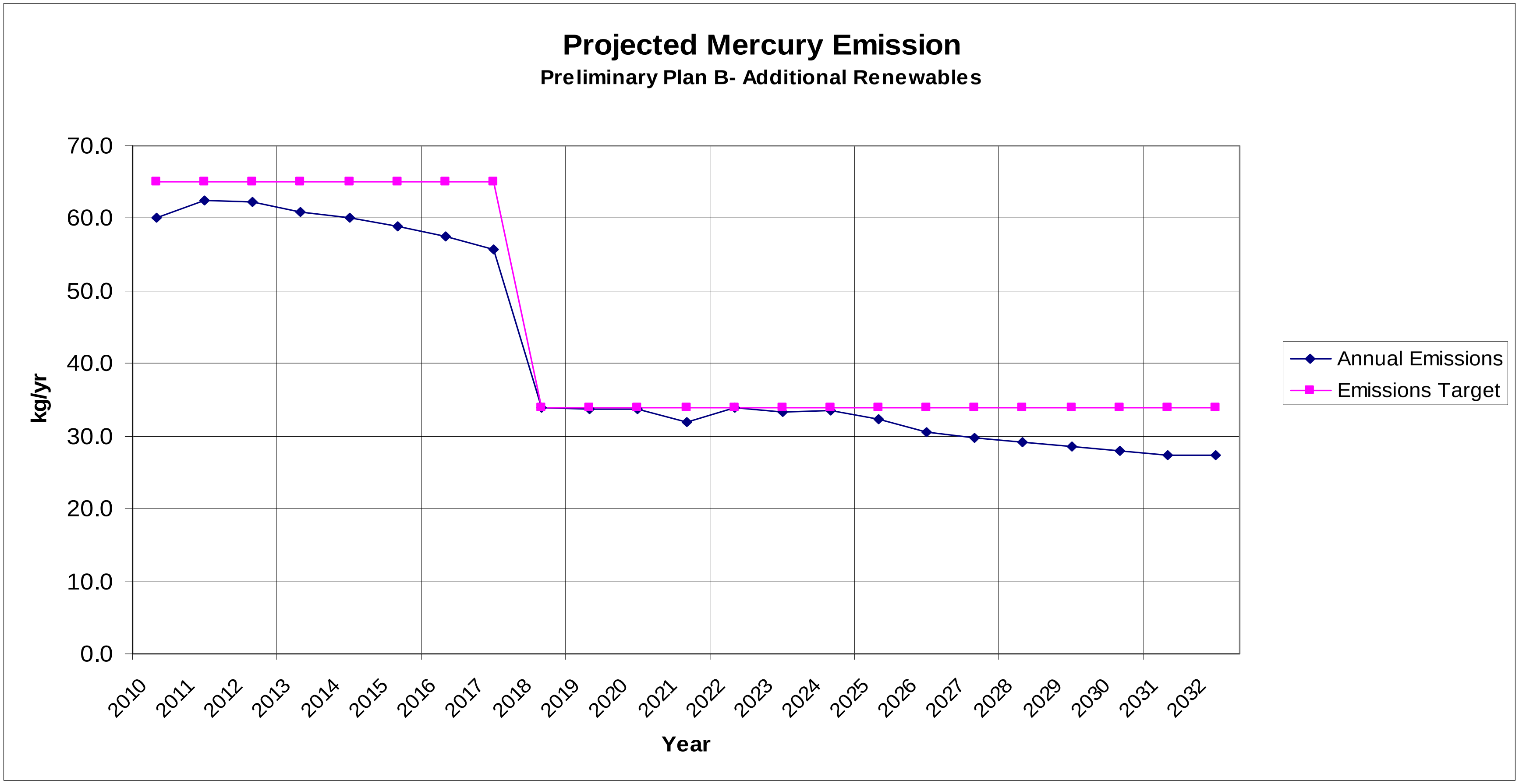
2009 IRP Update
Modeling / Analysis Results

Emissions Graphs Plan B



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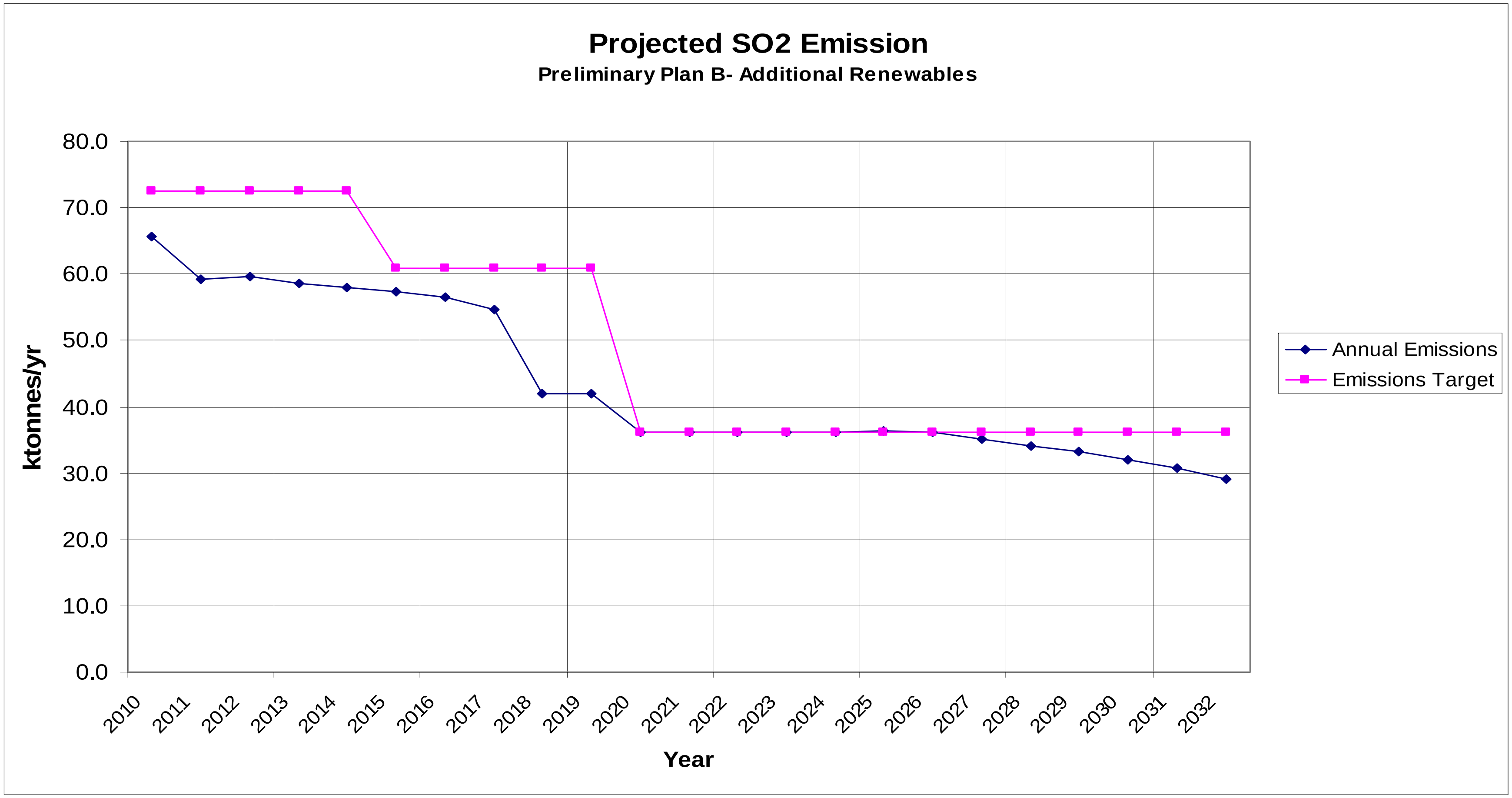
2009 IRP Update
Modeling / Analysis Results

Emissions Graphs Plan B



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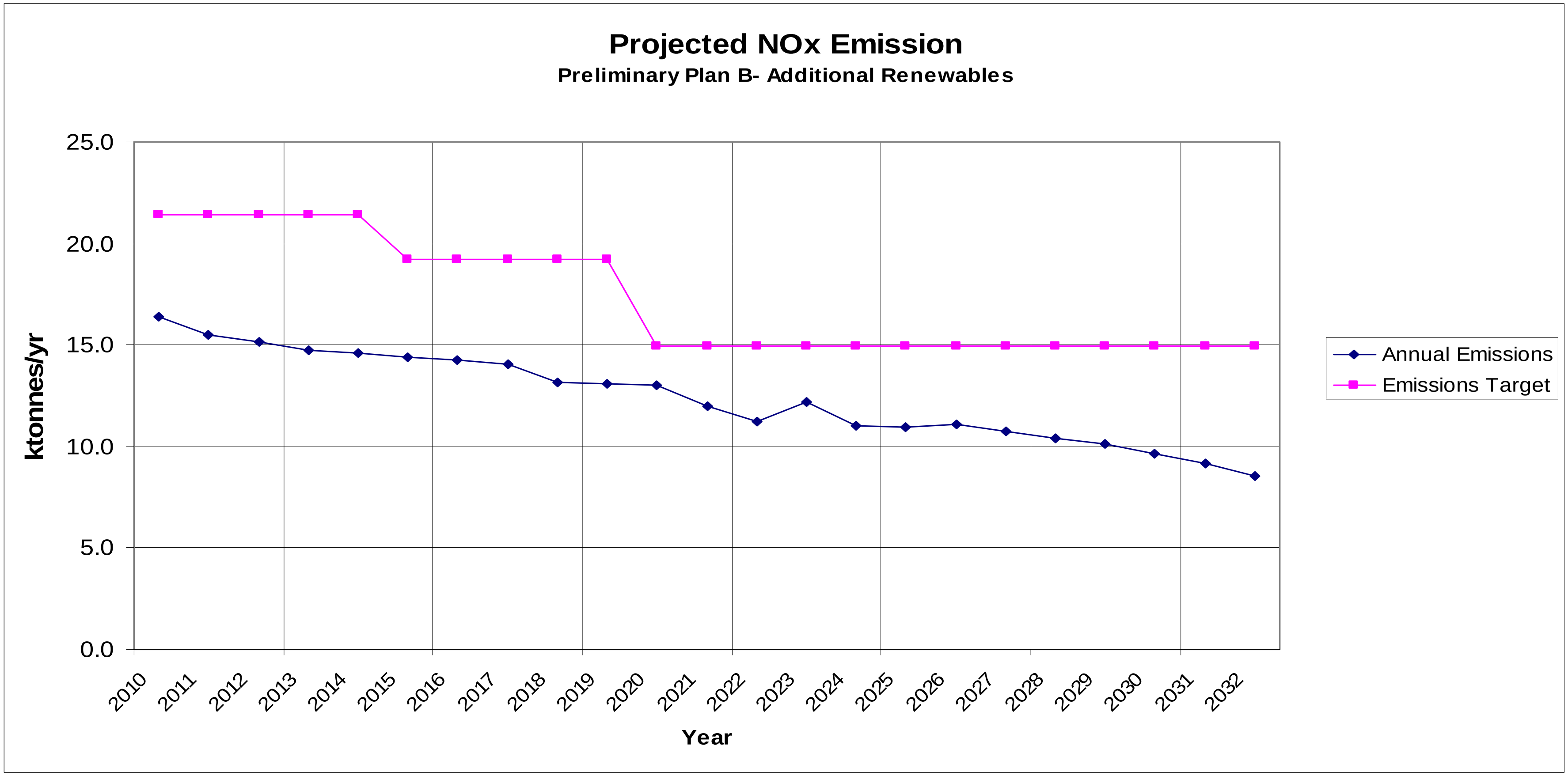
2009 IRP Update
Modeling / Analysis Results

Emissions Graphs Plan B



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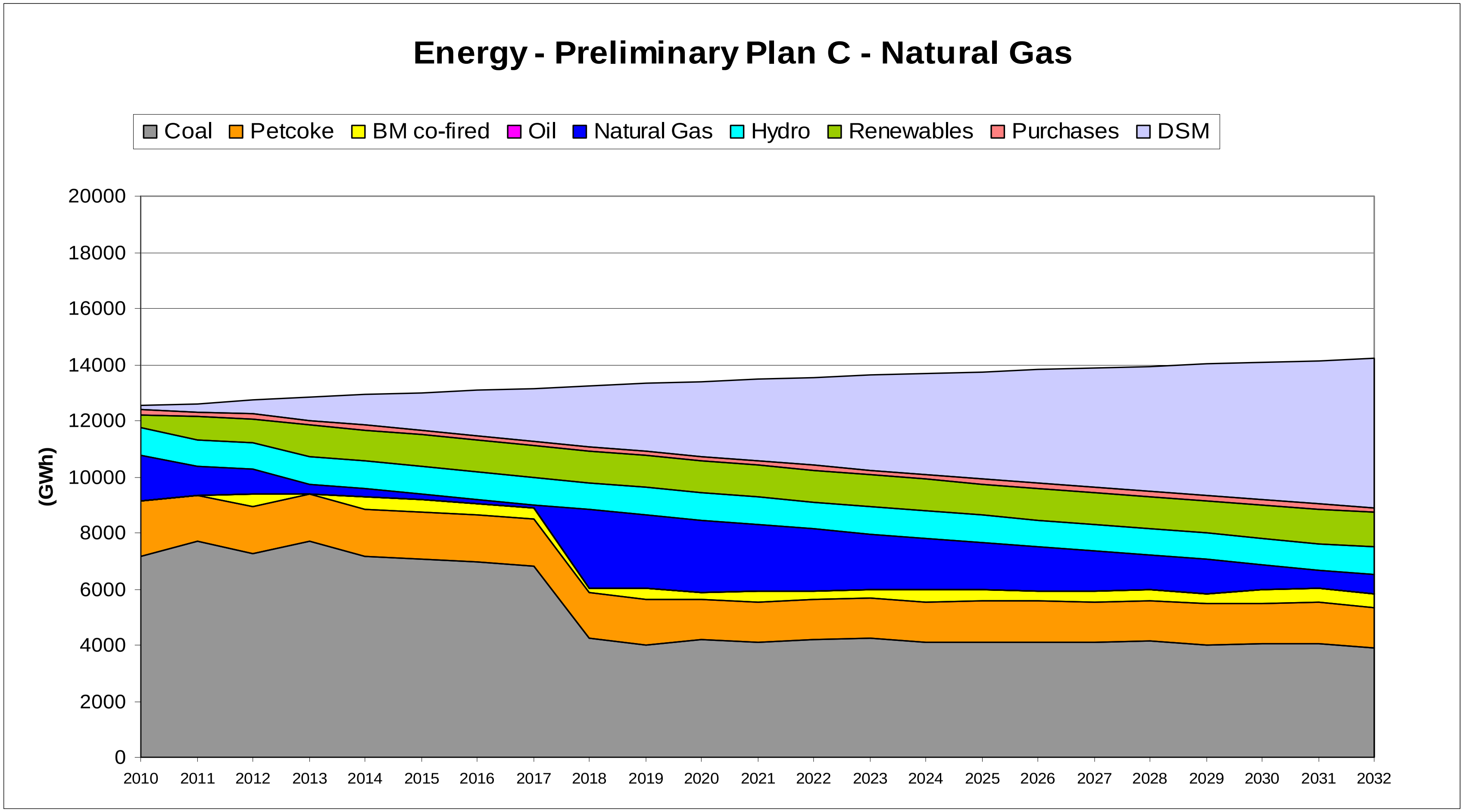
2009 IRP Update
Modeling / Analysis Results



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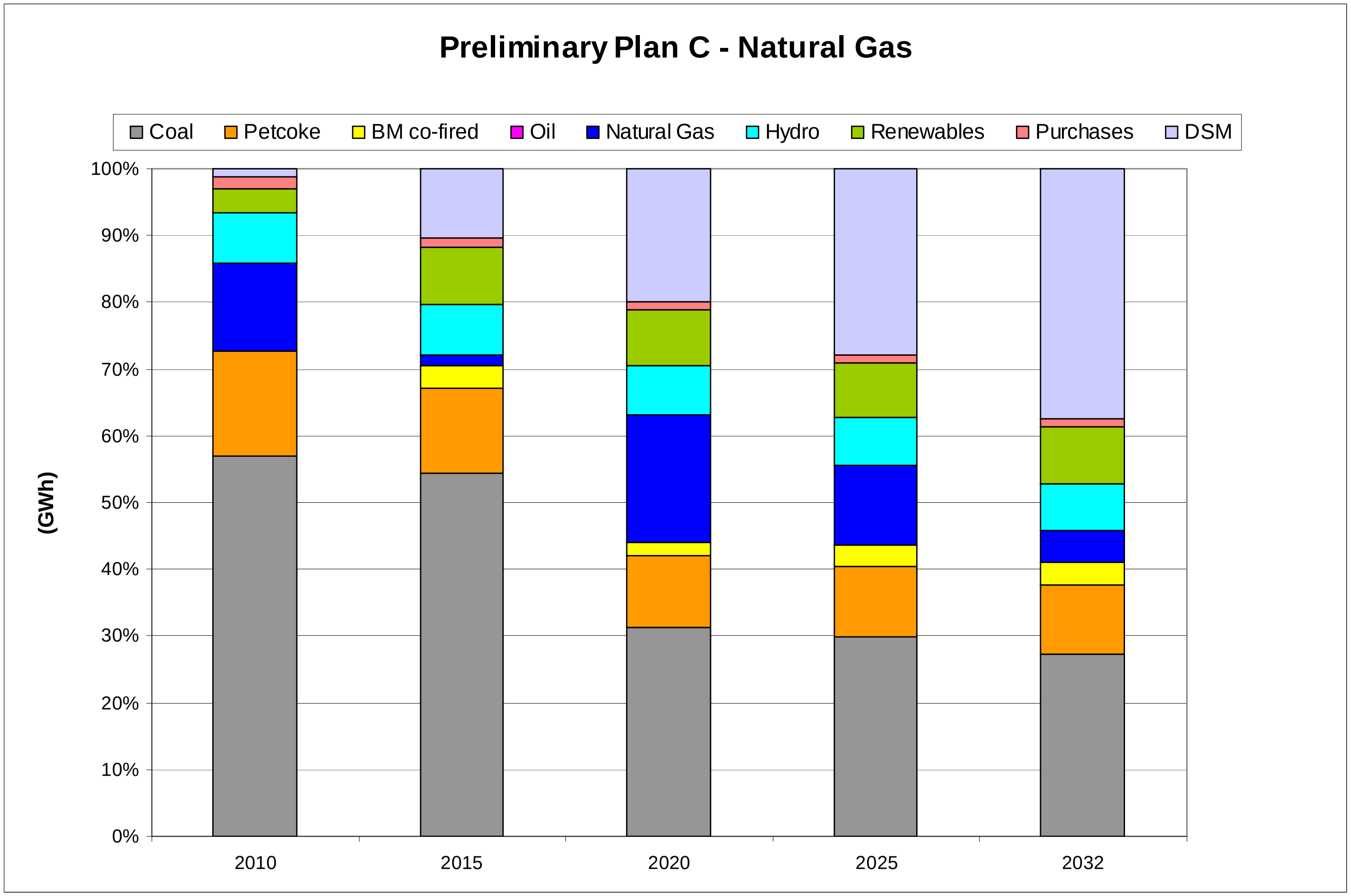
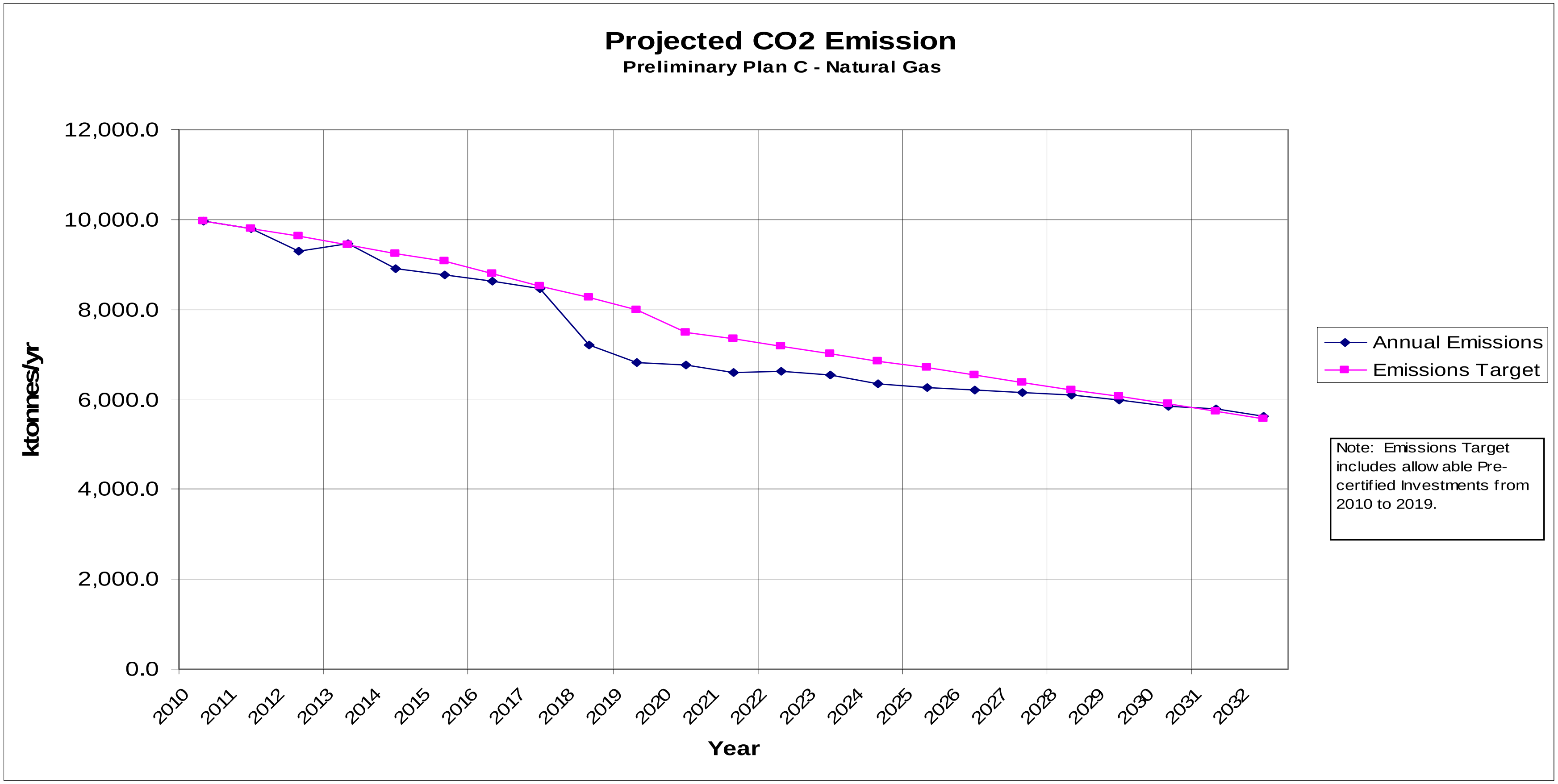
2009 IRP Update
Modeling / Analysis Results



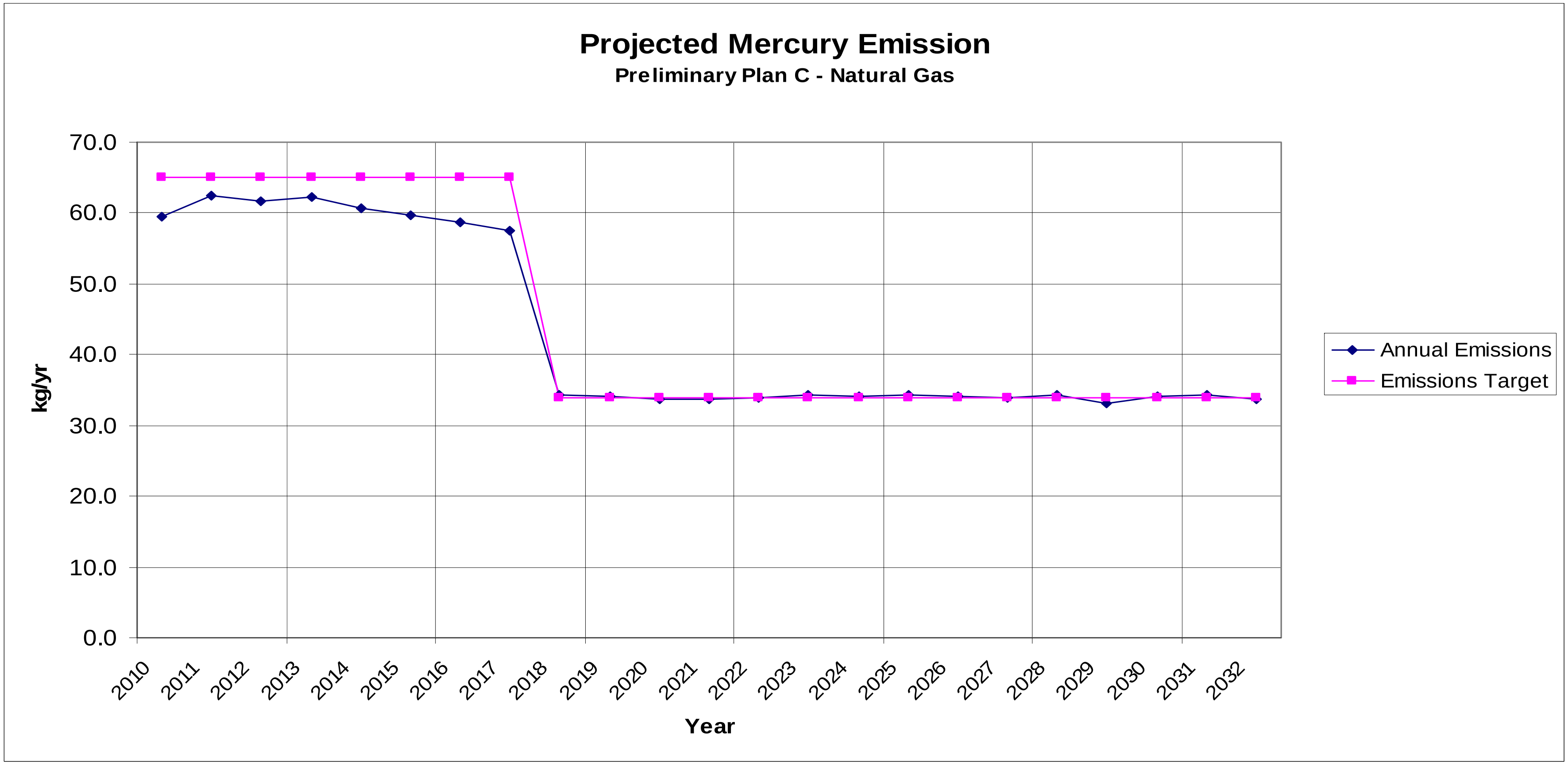
2009 IRP Update
Modeling / Analysis Results

Emissions Graphs Plan C



2009 IRP Update
Modeling / Analysis Results

Emissions Graphs Plan C



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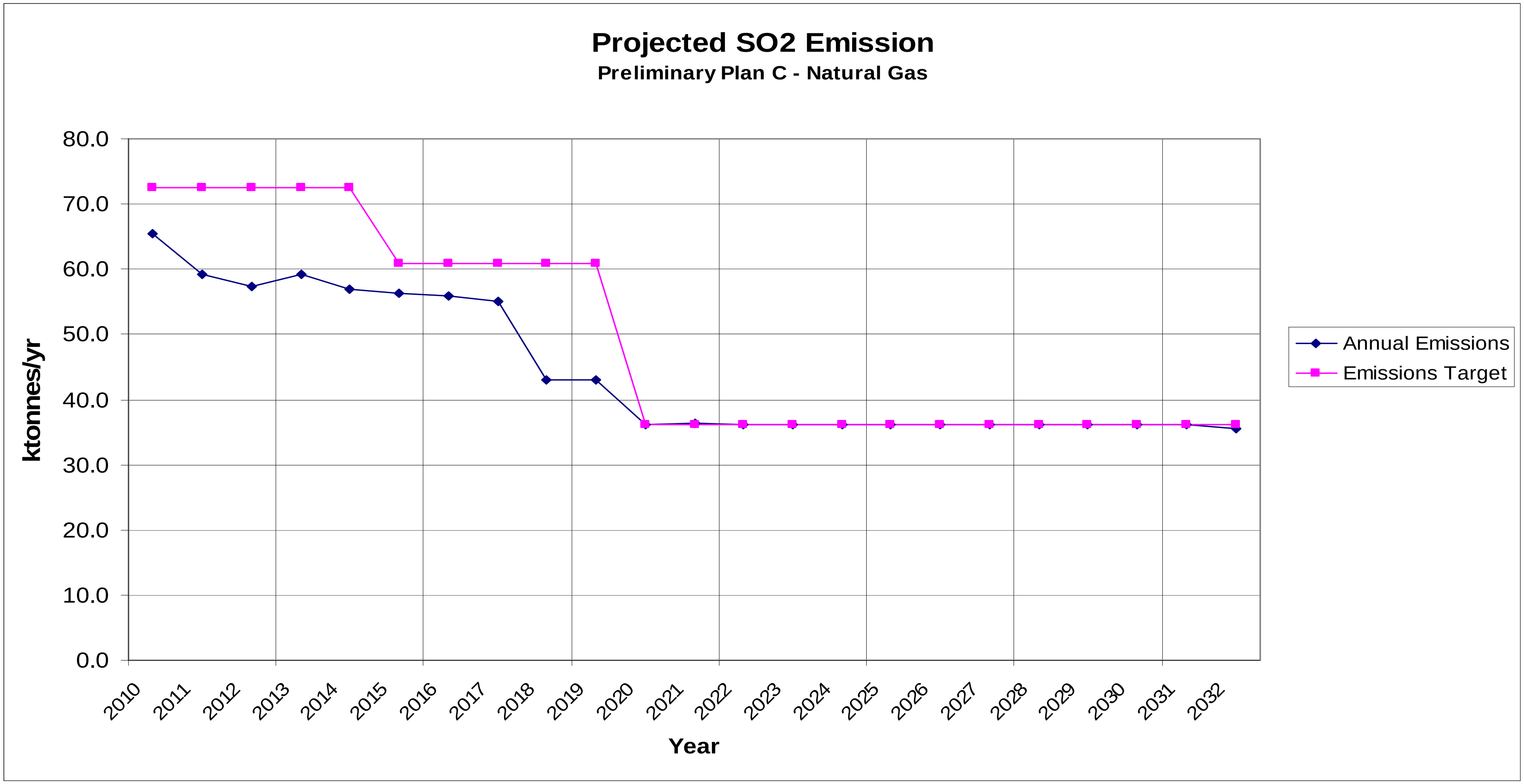
2009 IRP Update
Modeling / Analysis Results

Emissions Graphs Plan C



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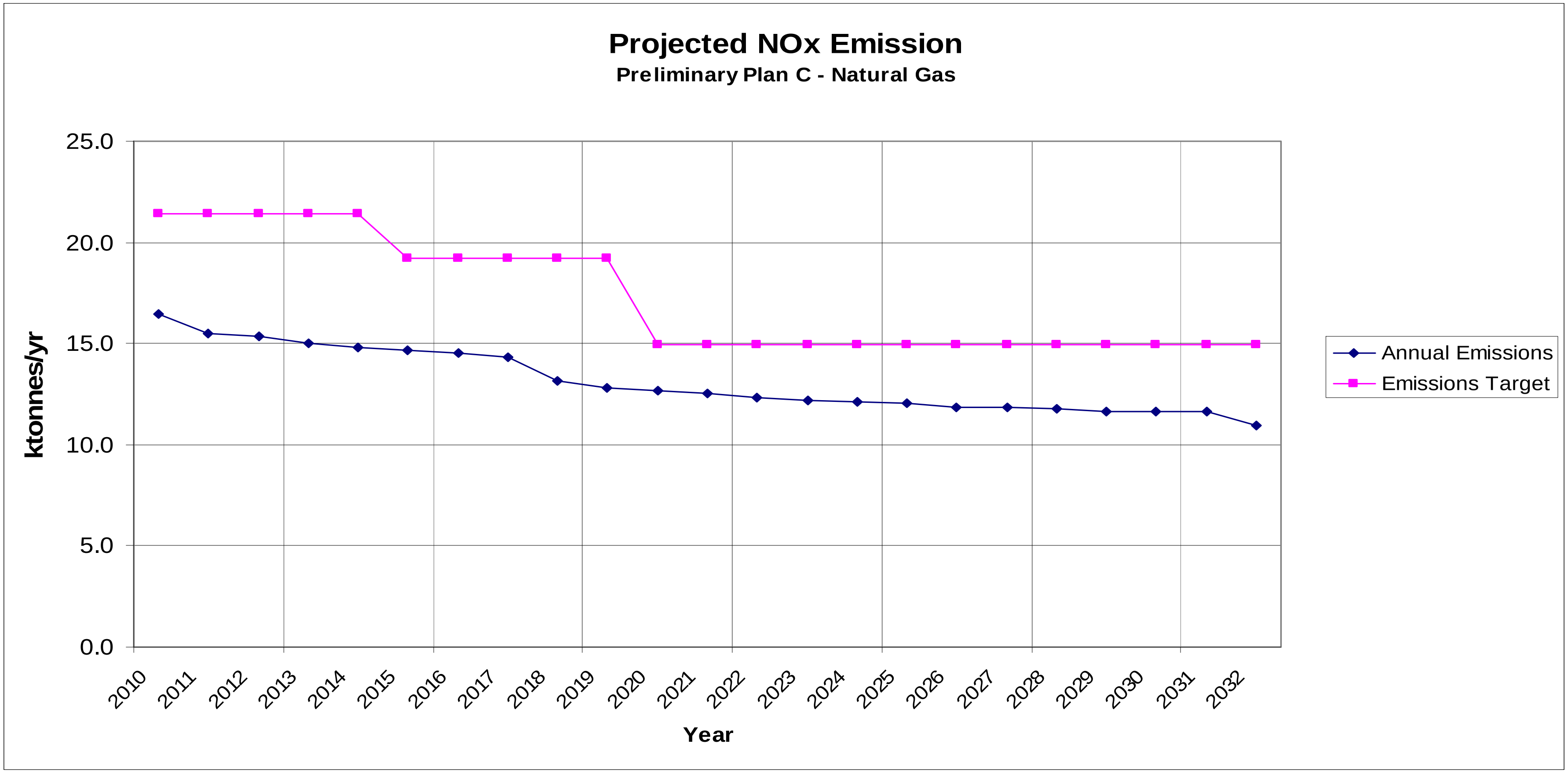
2009 IRP Update
Modeling / Analysis Results

Emissions Graphs Plan C



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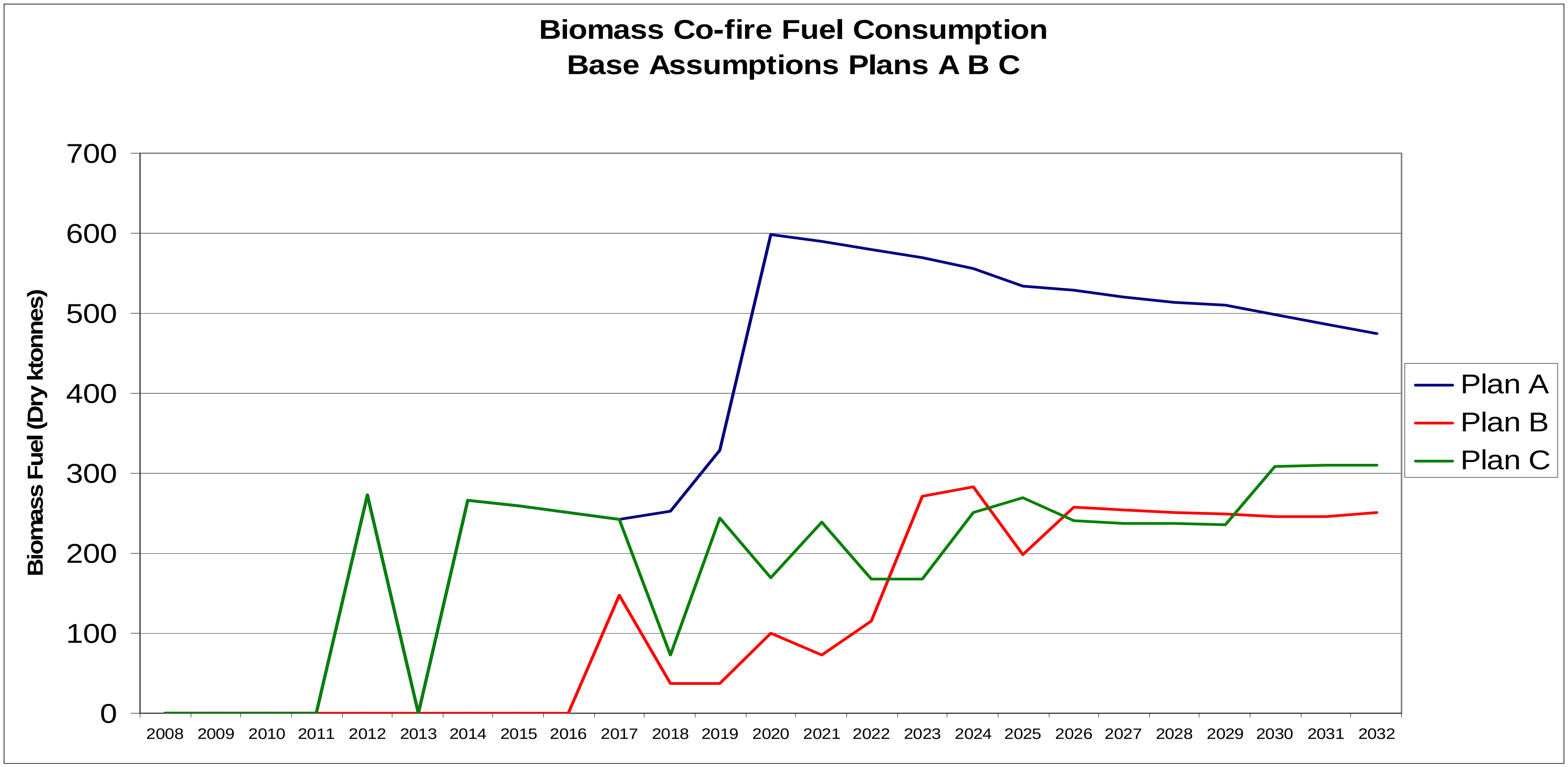
Tonnes Biomass Plans A, B, C



BASE PLANS – Estimate of Revenue Requirements

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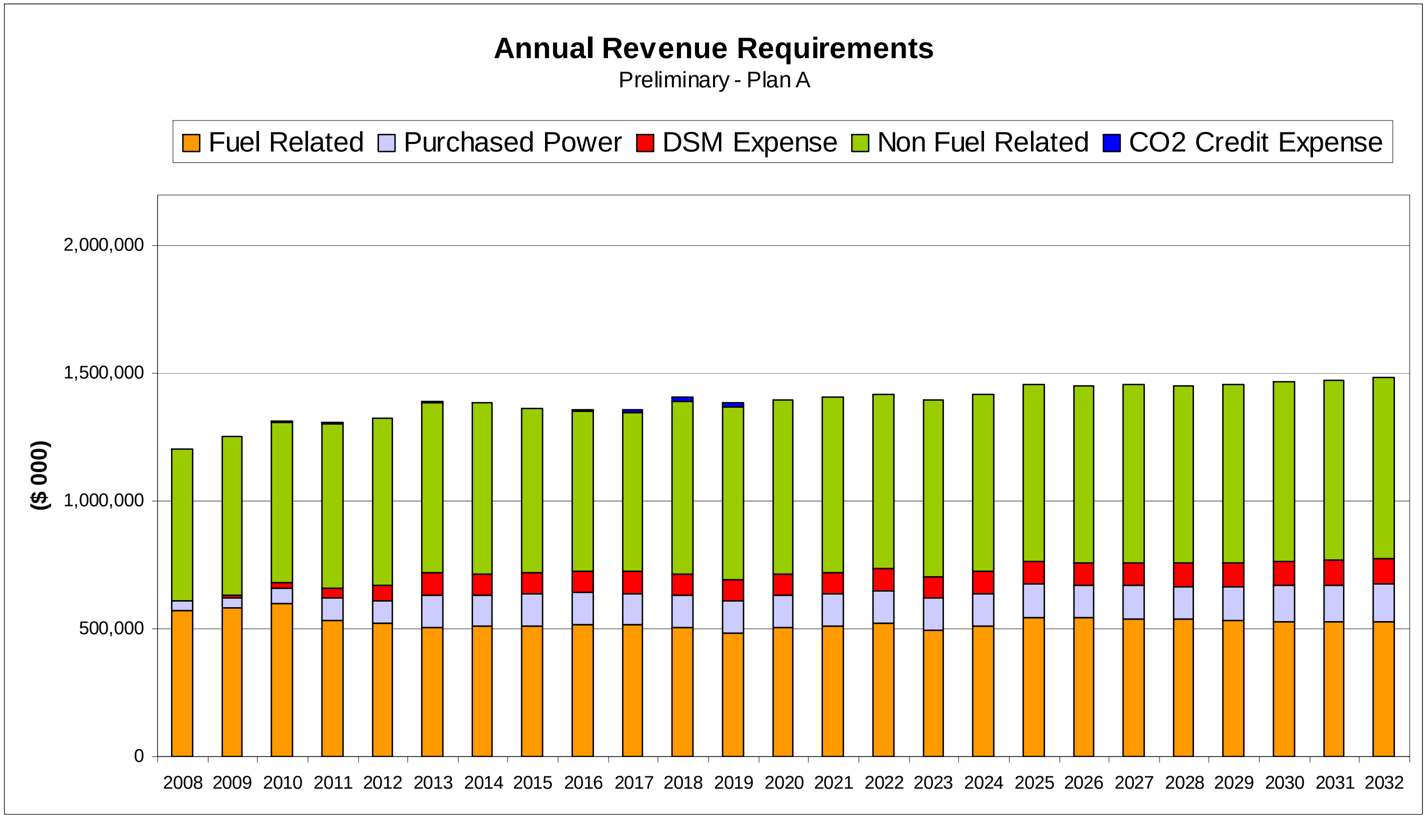
2009 IRP Update
Modeling / Analysis Results

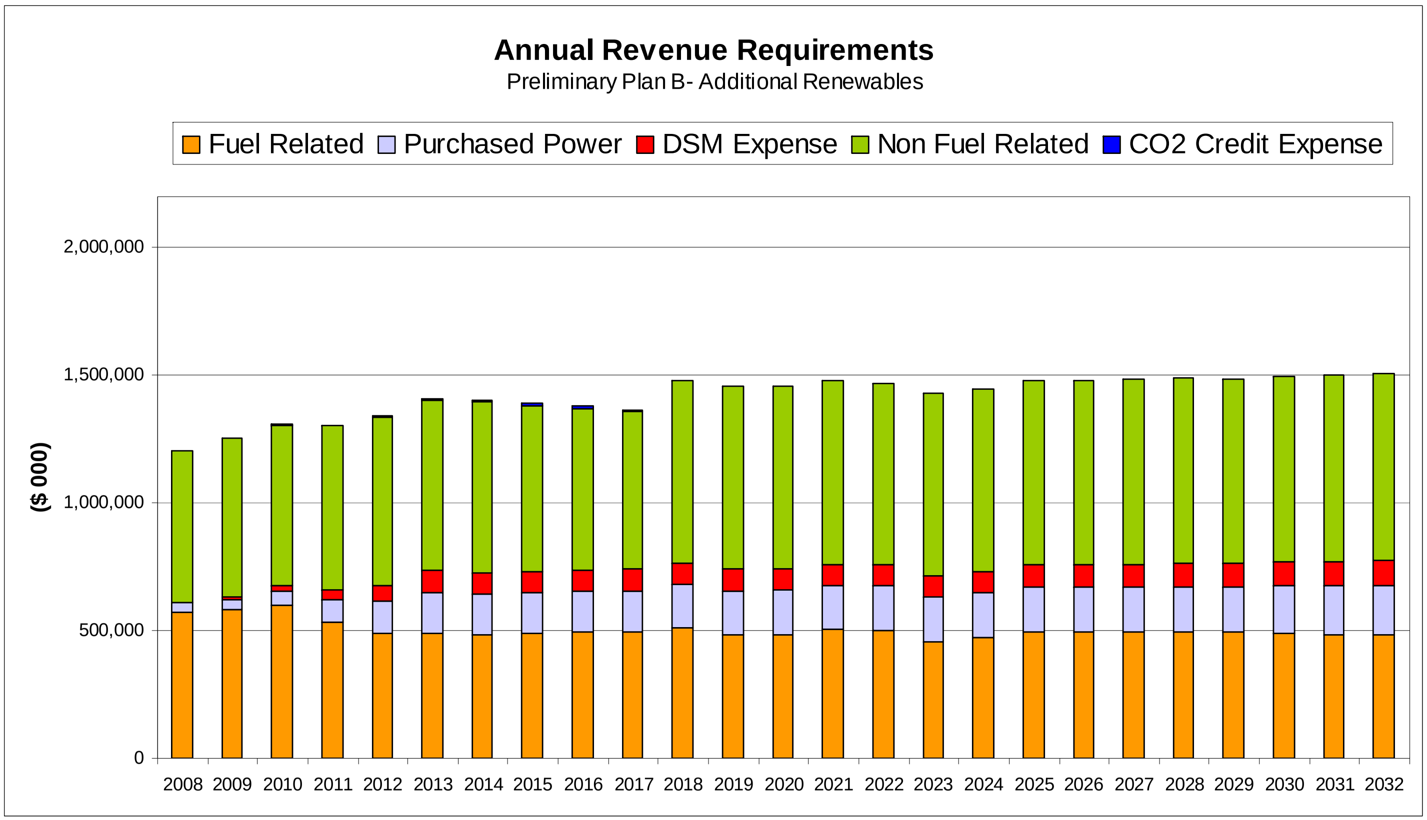
Revenue Requirements Base Plan A



Revenue requirements are illustrative/relative/comparative only. Actual future revenue requirement will be determined per Rate Application test year data.

2009 IRP Update
Modeling / Analysis Results

Revenue Requirements Base Plan B



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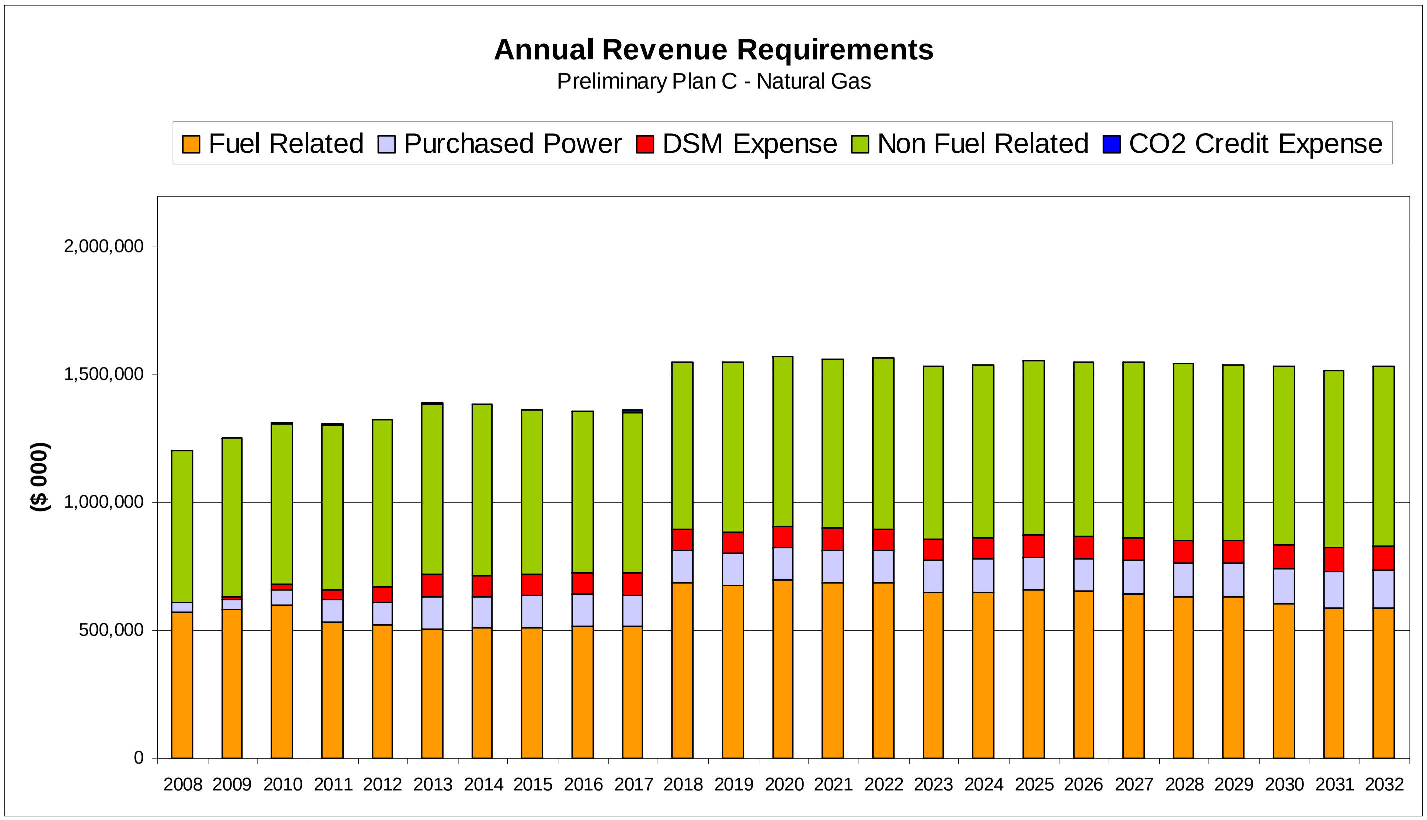
2009 IRP Update
Modeling / Analysis Results

Revenue Requirements Base Plan C



Revenue requirements are illustrative/relative/comparative only. Actual future revenue requirement will be determined per Rate Application test year data.

APPENDIX D

High Load World Plan Results

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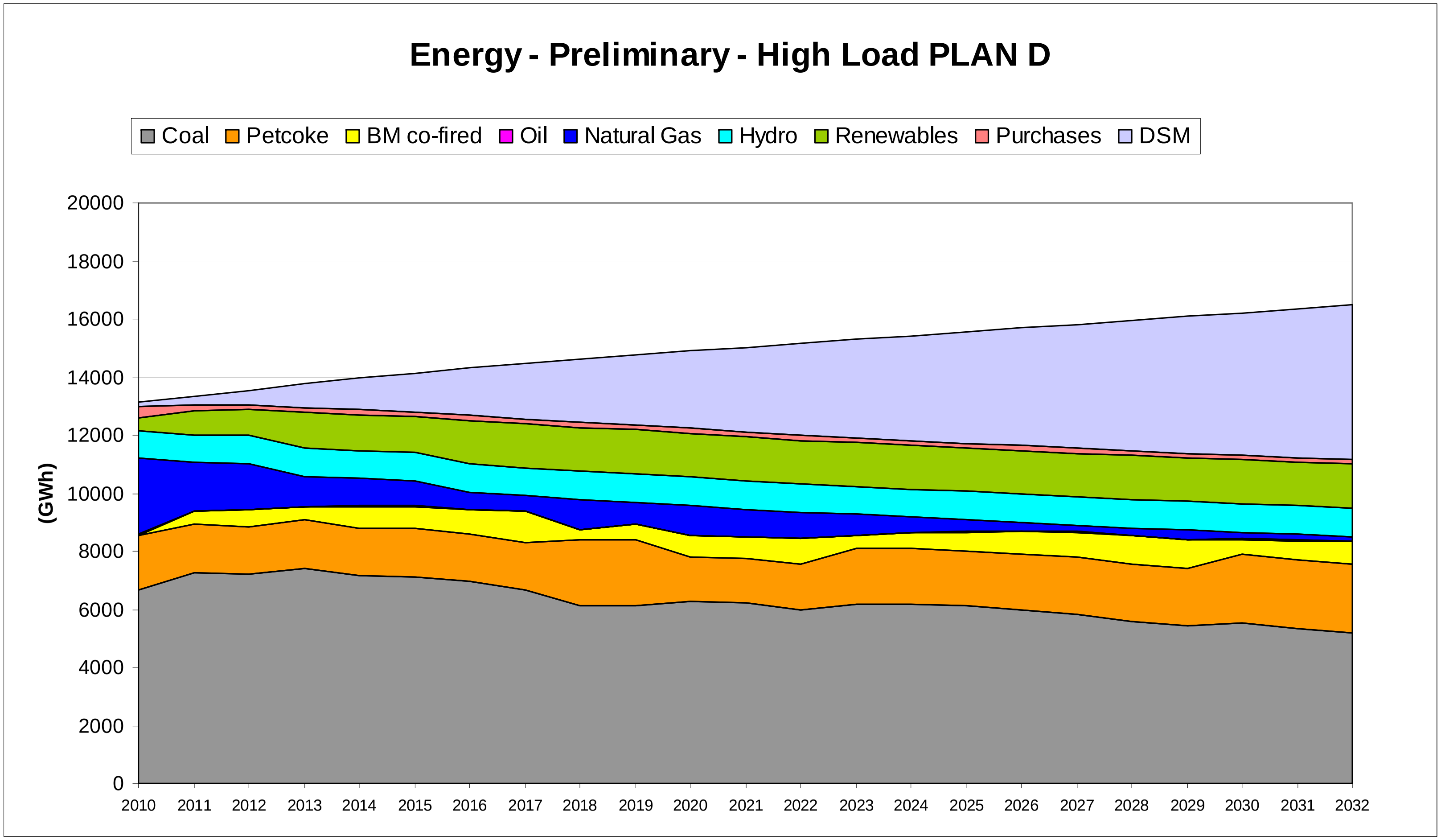
Modeling / Analysis Results



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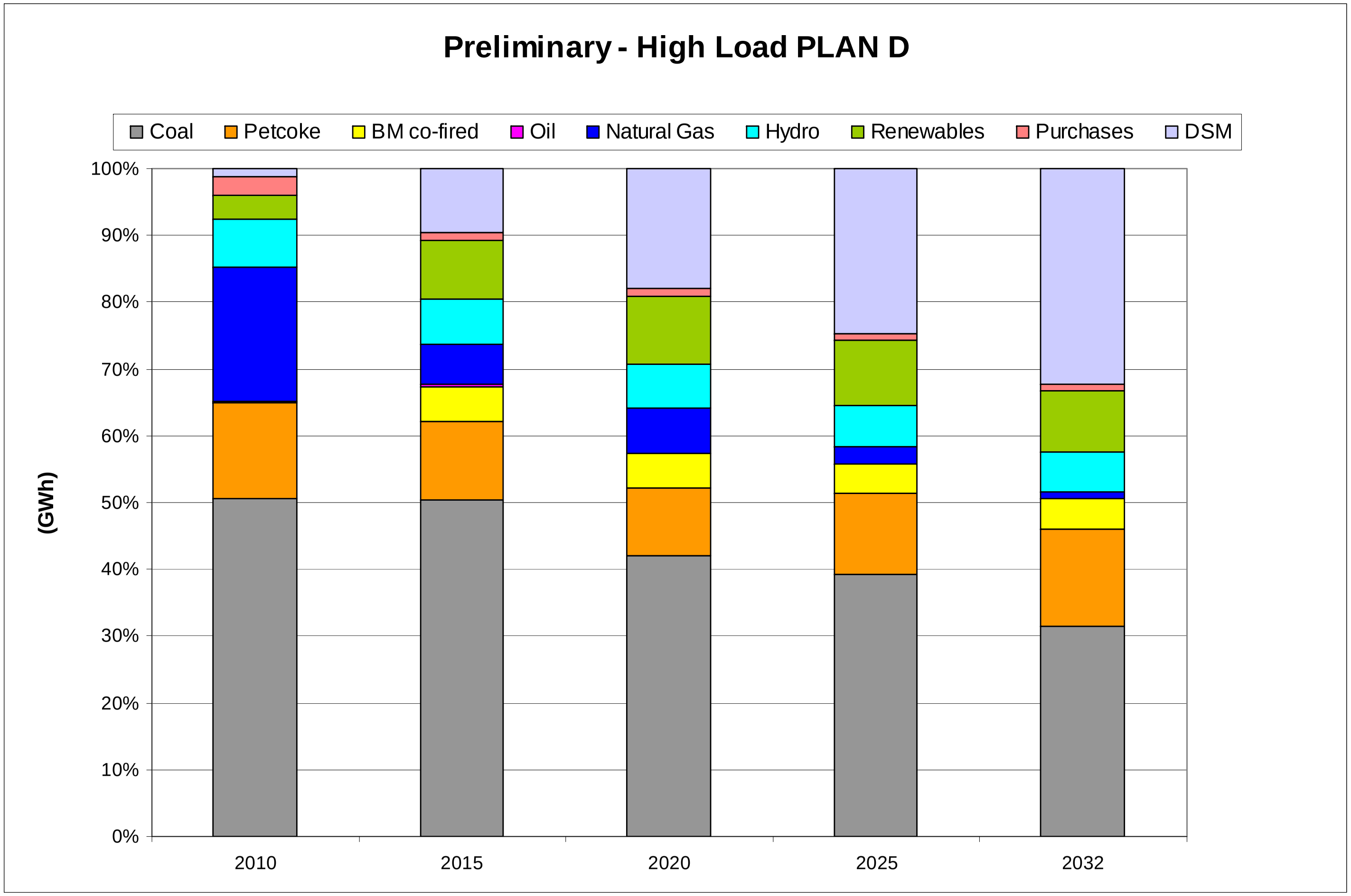

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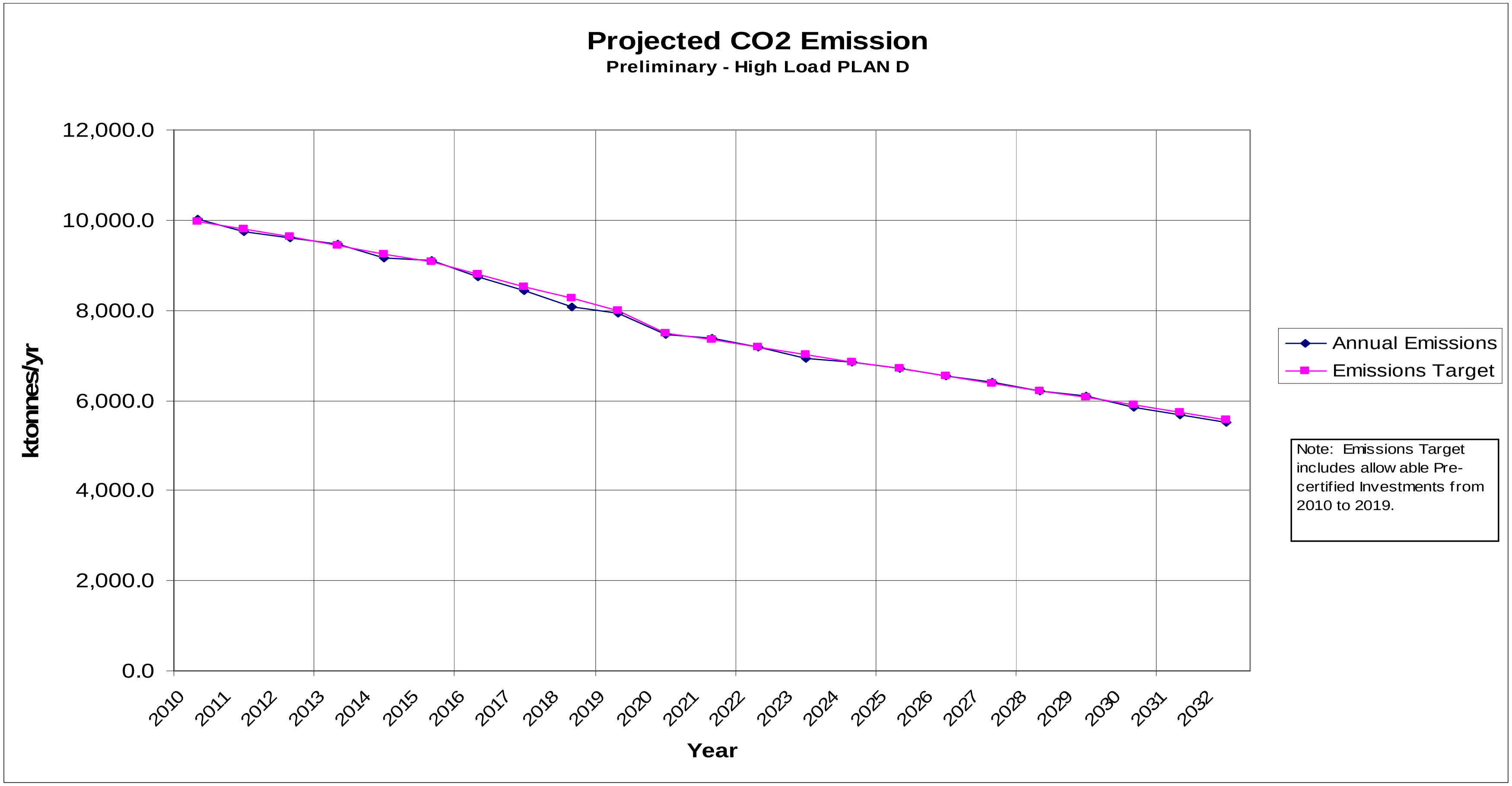
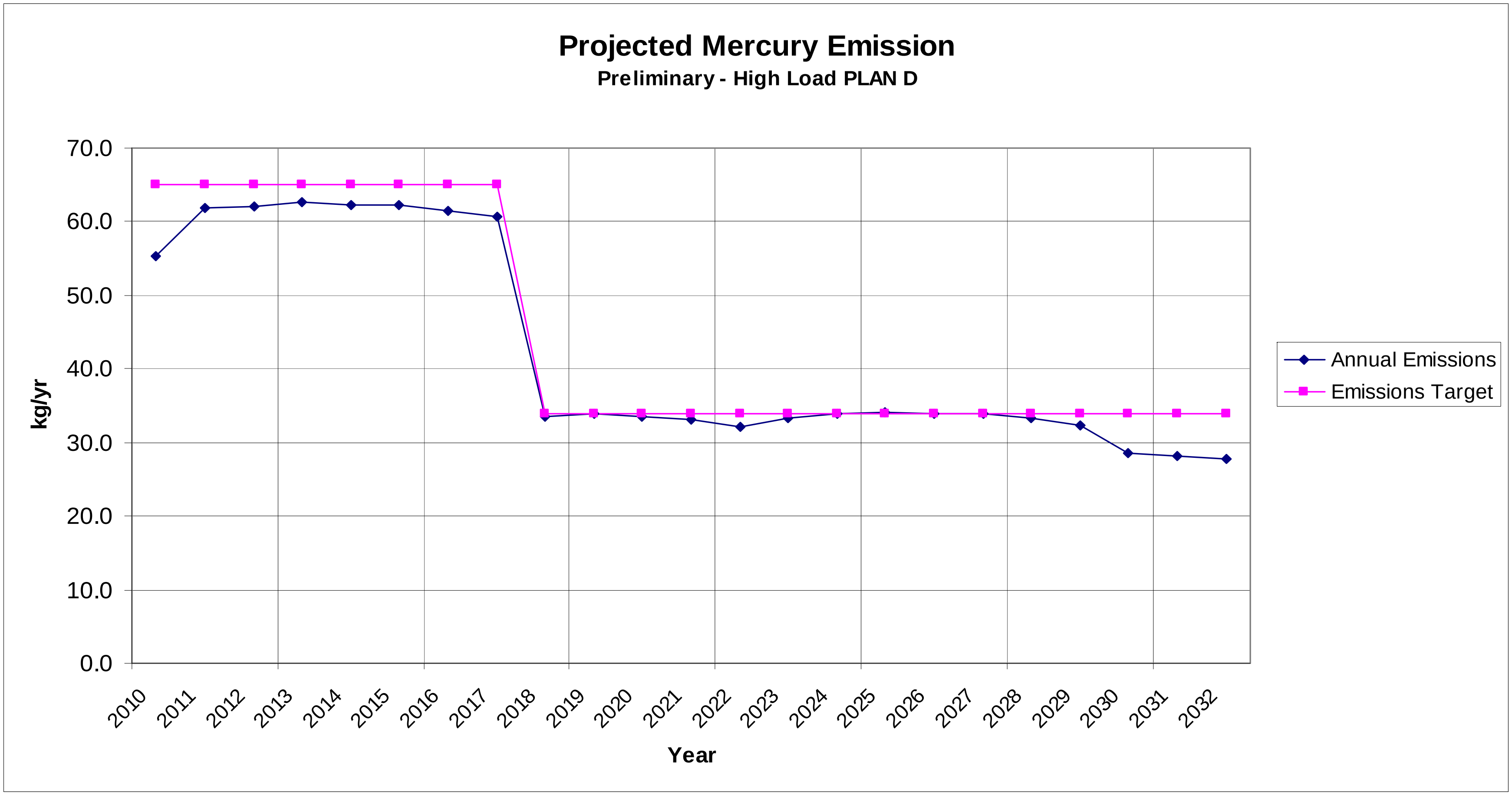
2009 IRP Update
Modeling / Analysis Results

Emissions Graphs Plan D

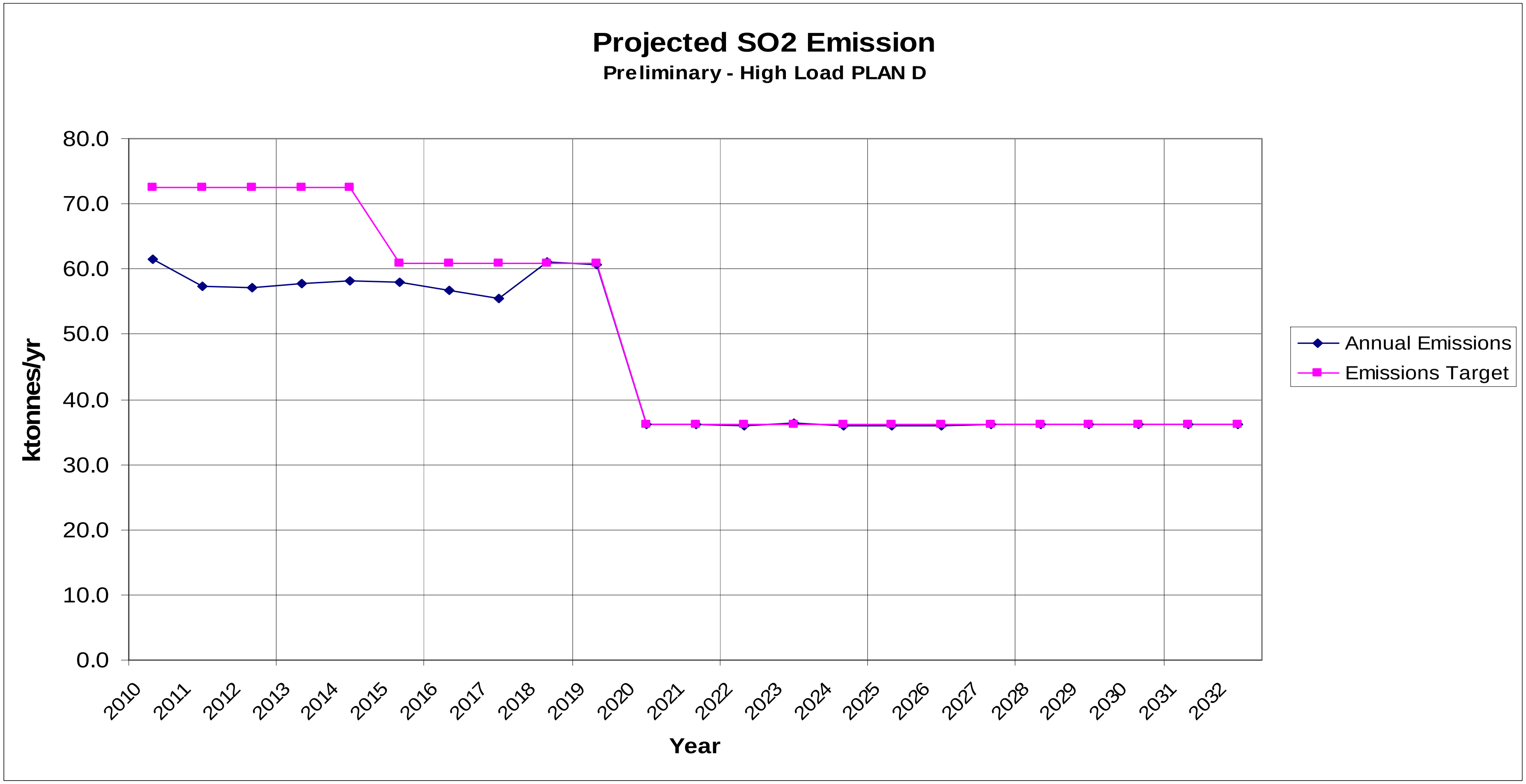


Emissions Graphs Plan D



2009 IRP Update
Modeling / Analysis Results

Emissions Graphs Plan D



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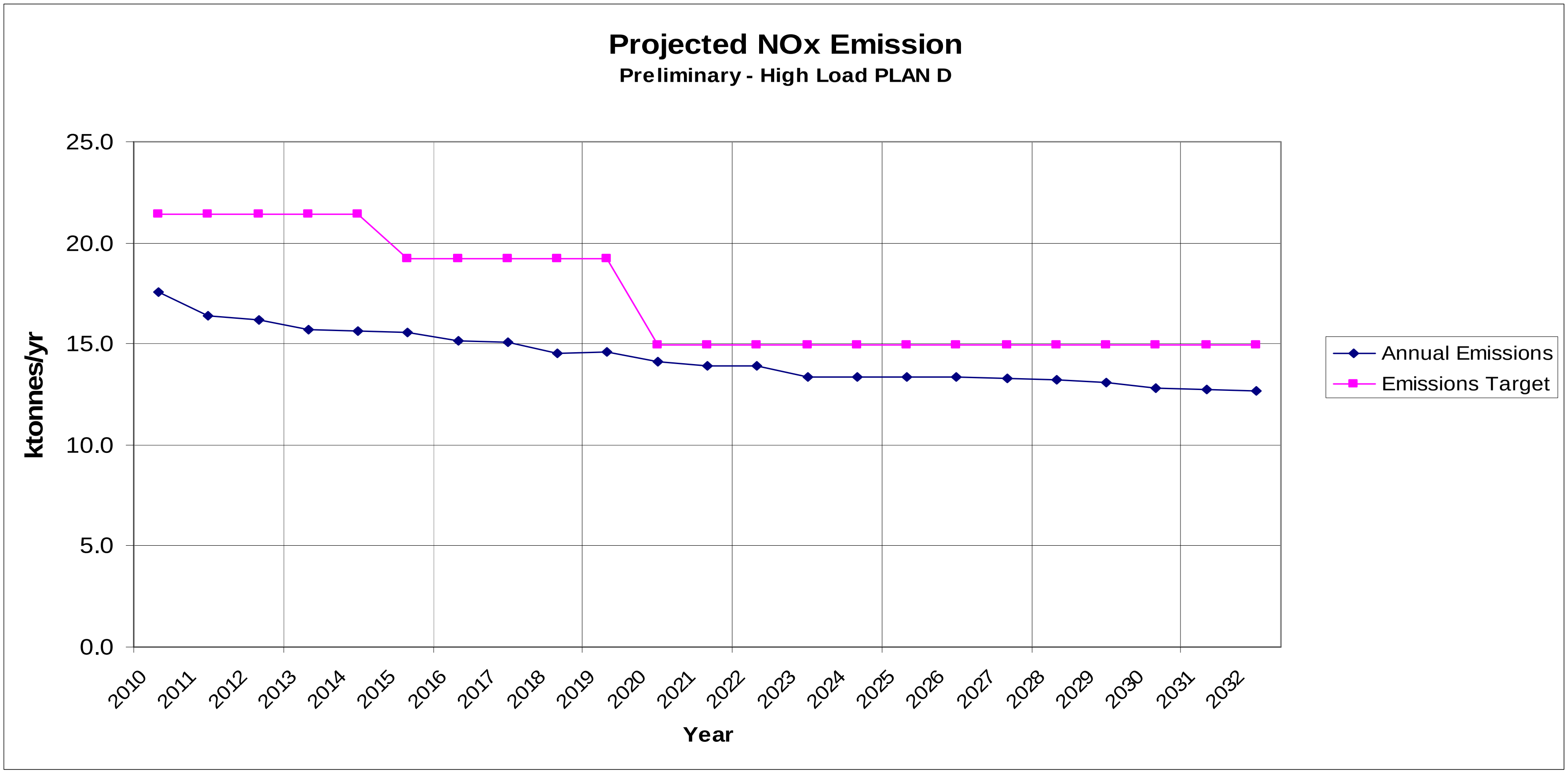
2009 IRP Update
Modeling / Analysis Results

Emissions Graphs Plan D



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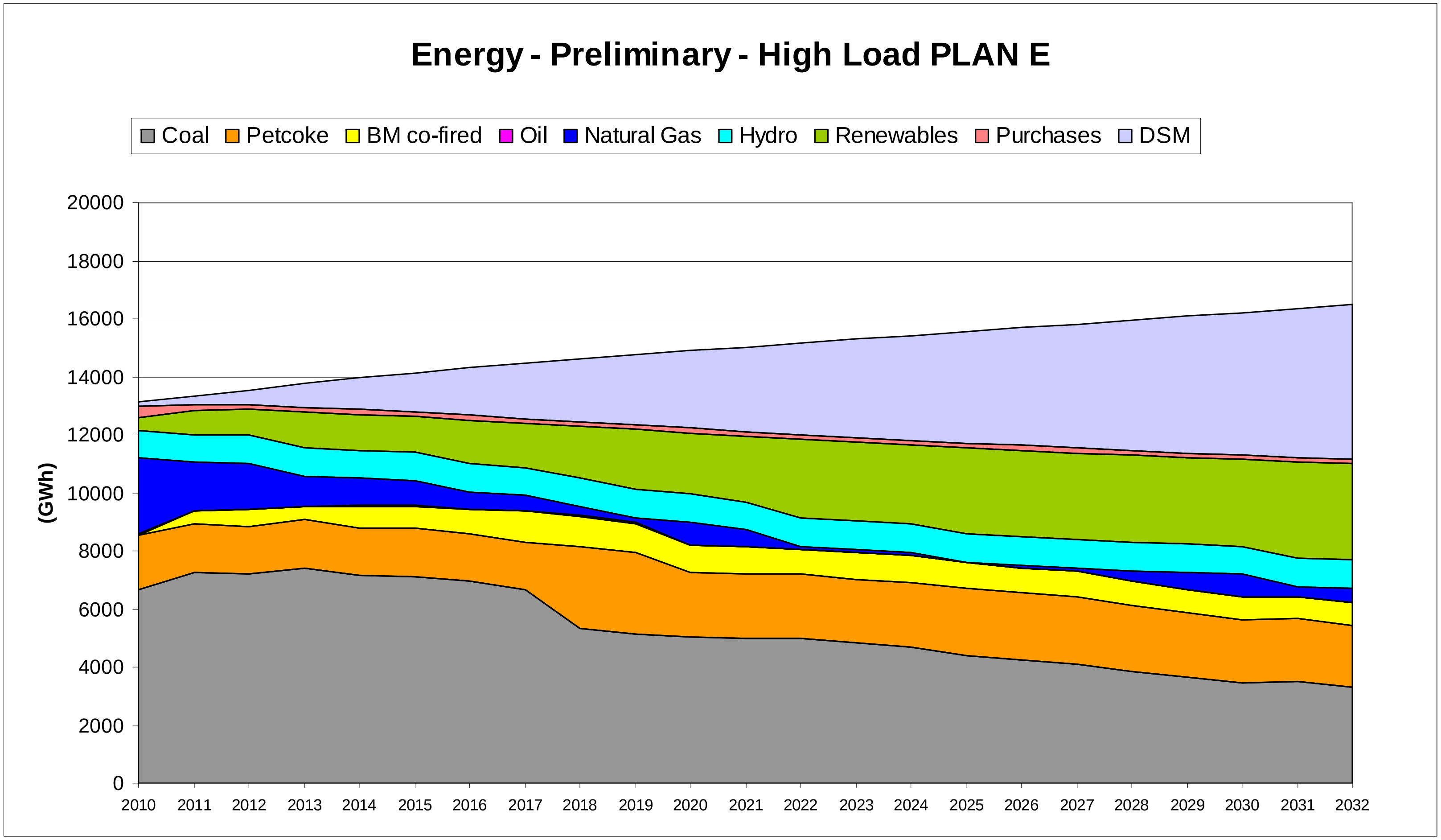
2009 IRP Update
Modeling / Analysis Results



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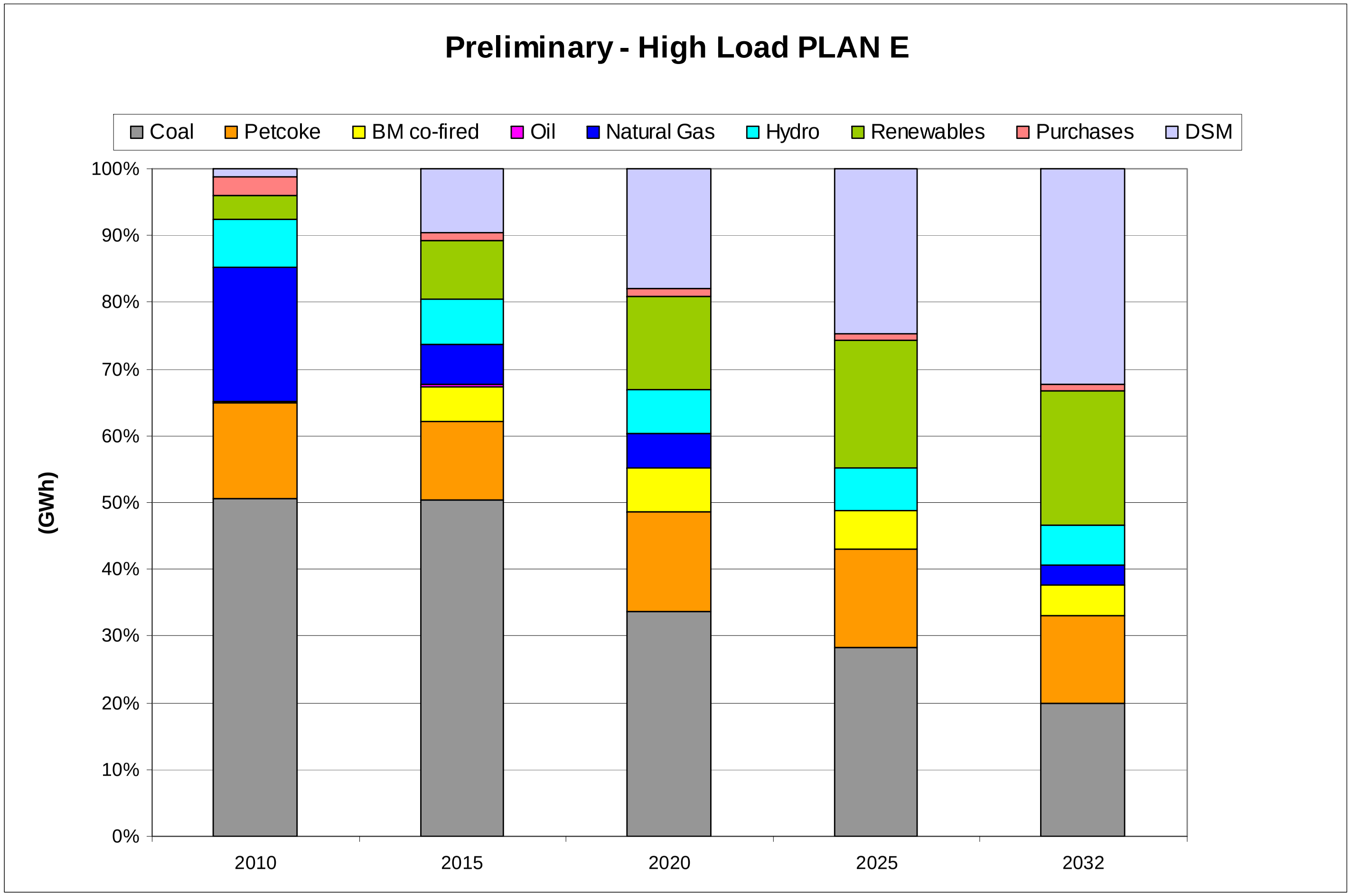
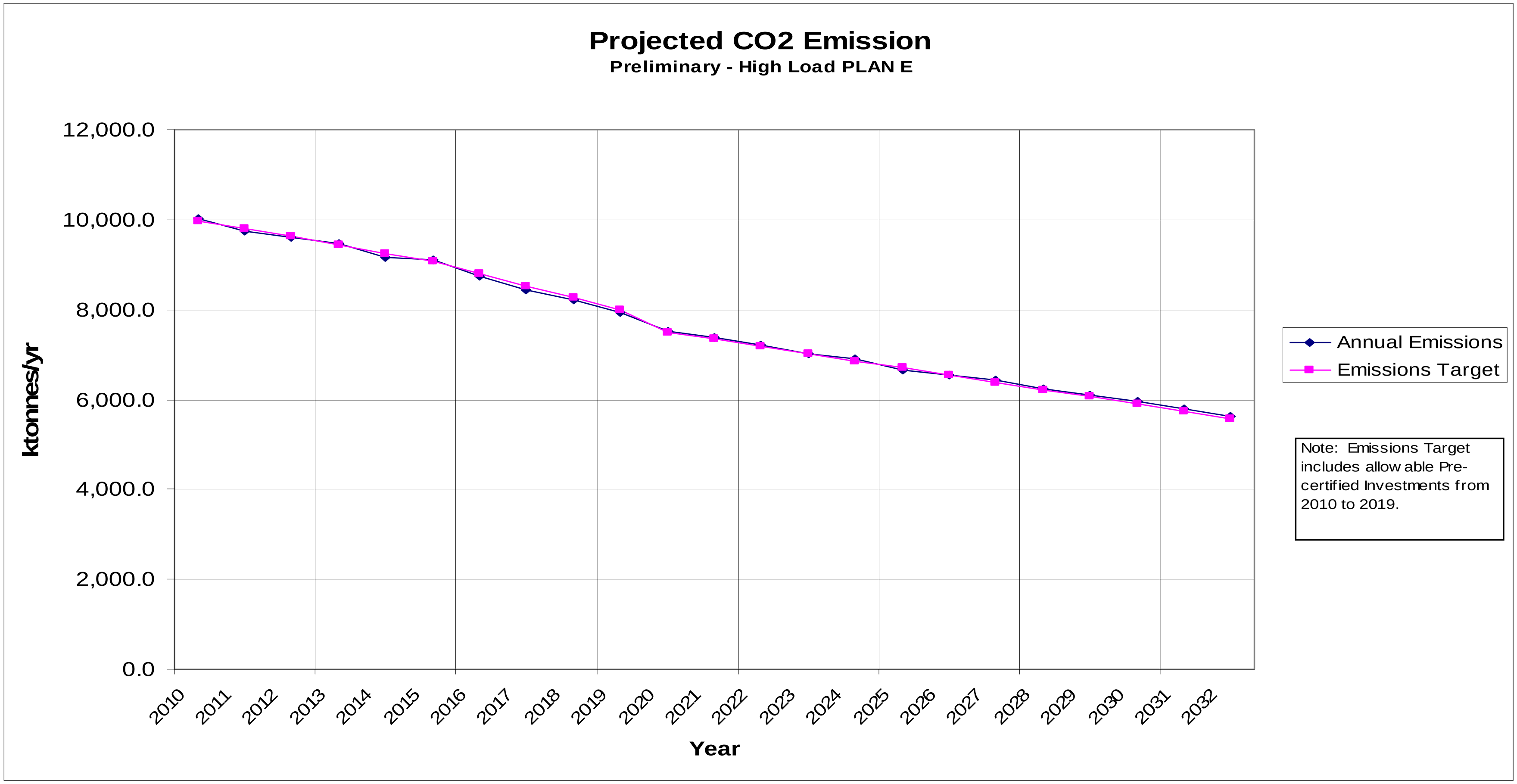
2009 IRP Update
Modeling / Analysis Results



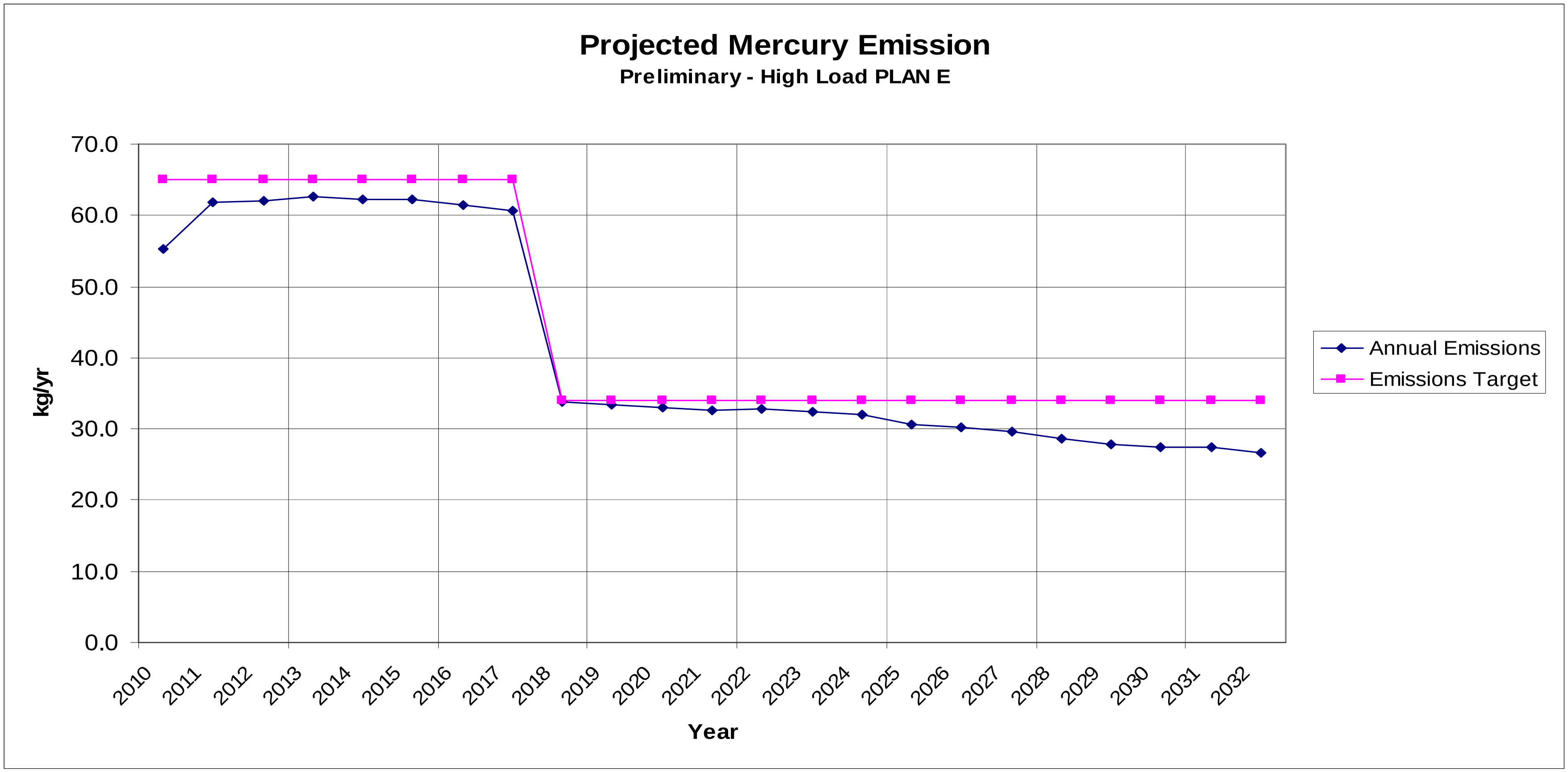
2009 IRP Update
Modeling / Analysis Results

Emissions Graphs Plan E



2009 IRP Update
Modeling / Analysis Results

Emissions Graphs Plan E



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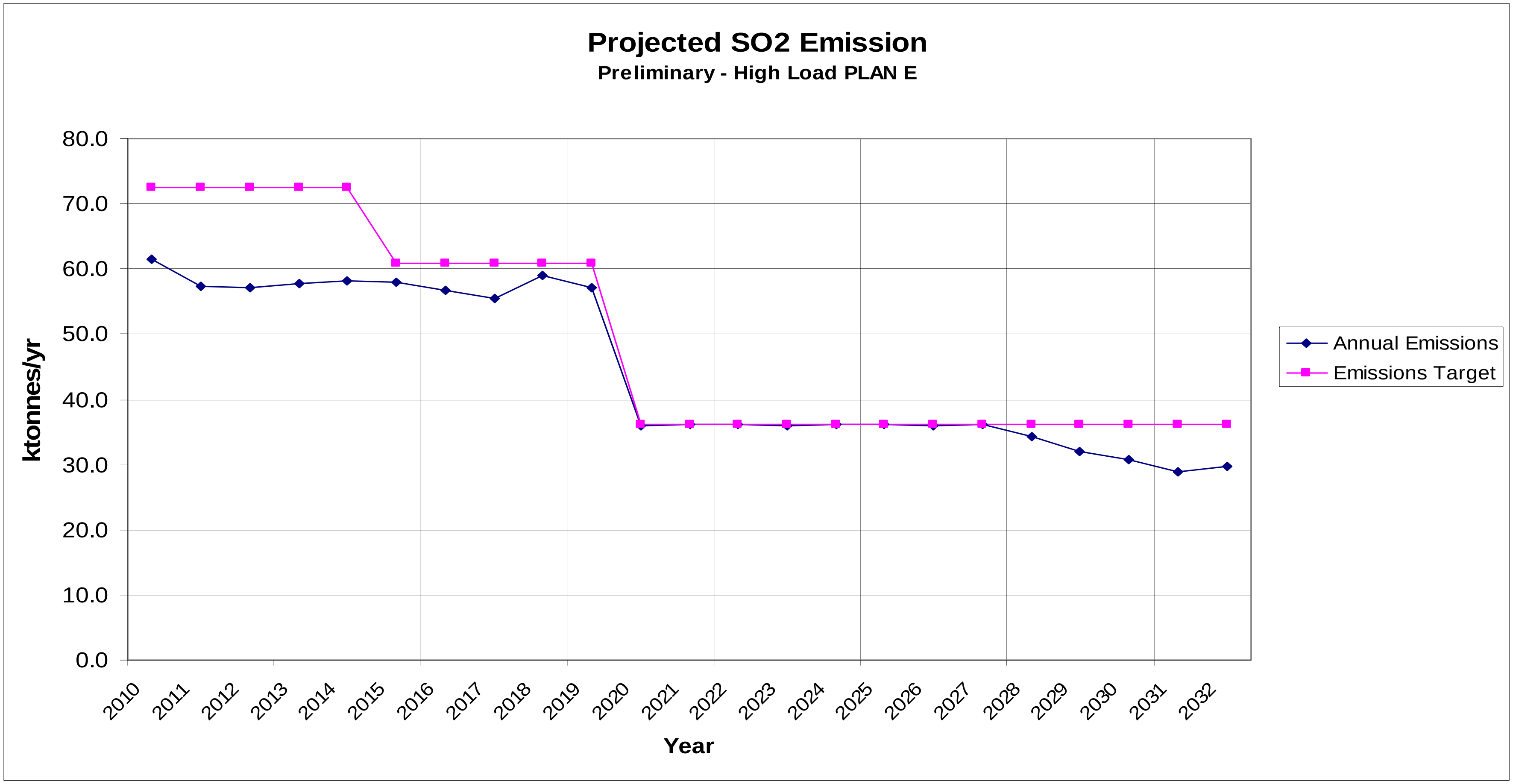
2009 IRP Update
Modeling / Analysis Results

Emissions Graphs Plan E



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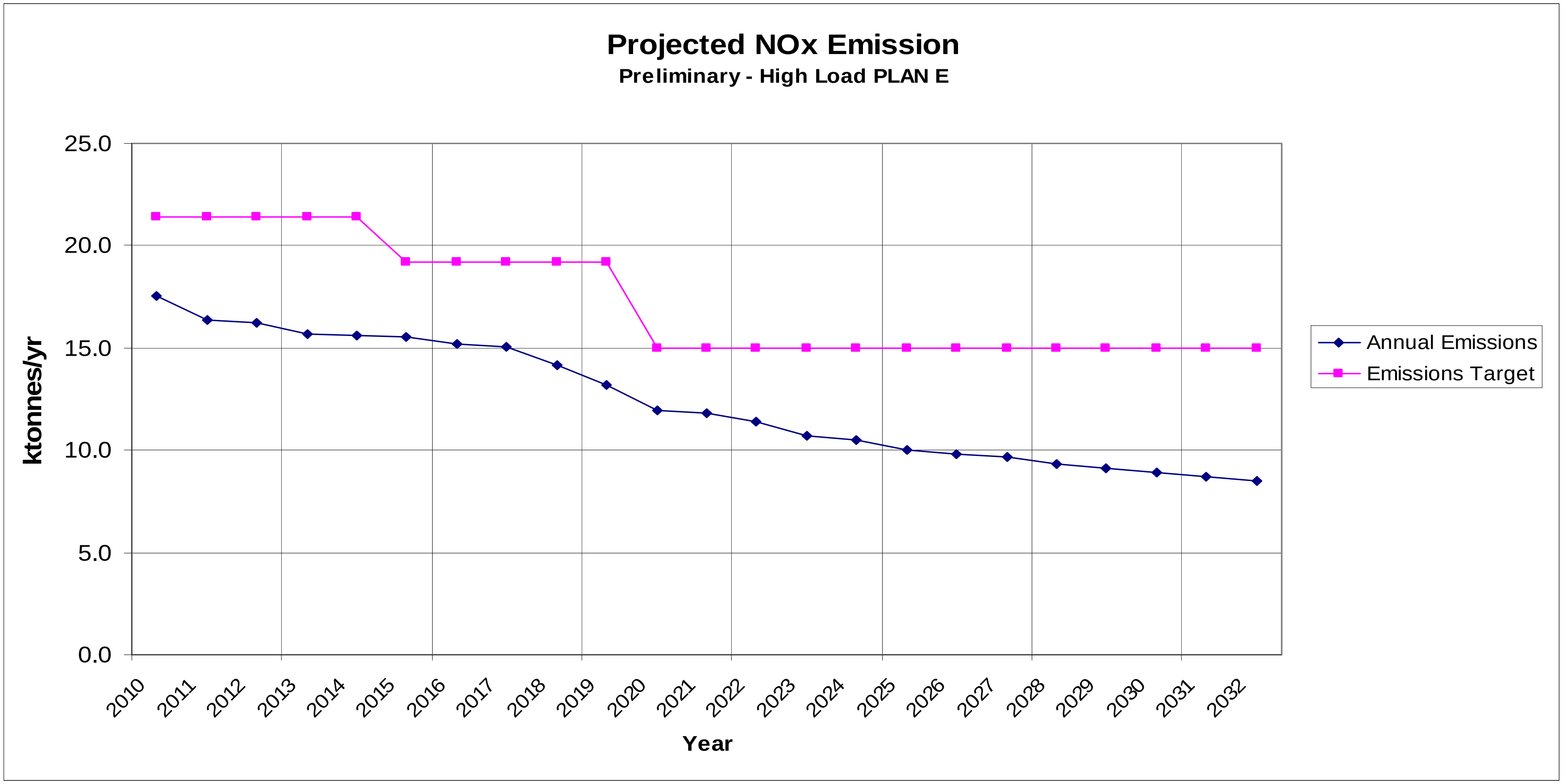
2009 IRP Update
Modeling / Analysis Results

Emissions Graphs Plan E



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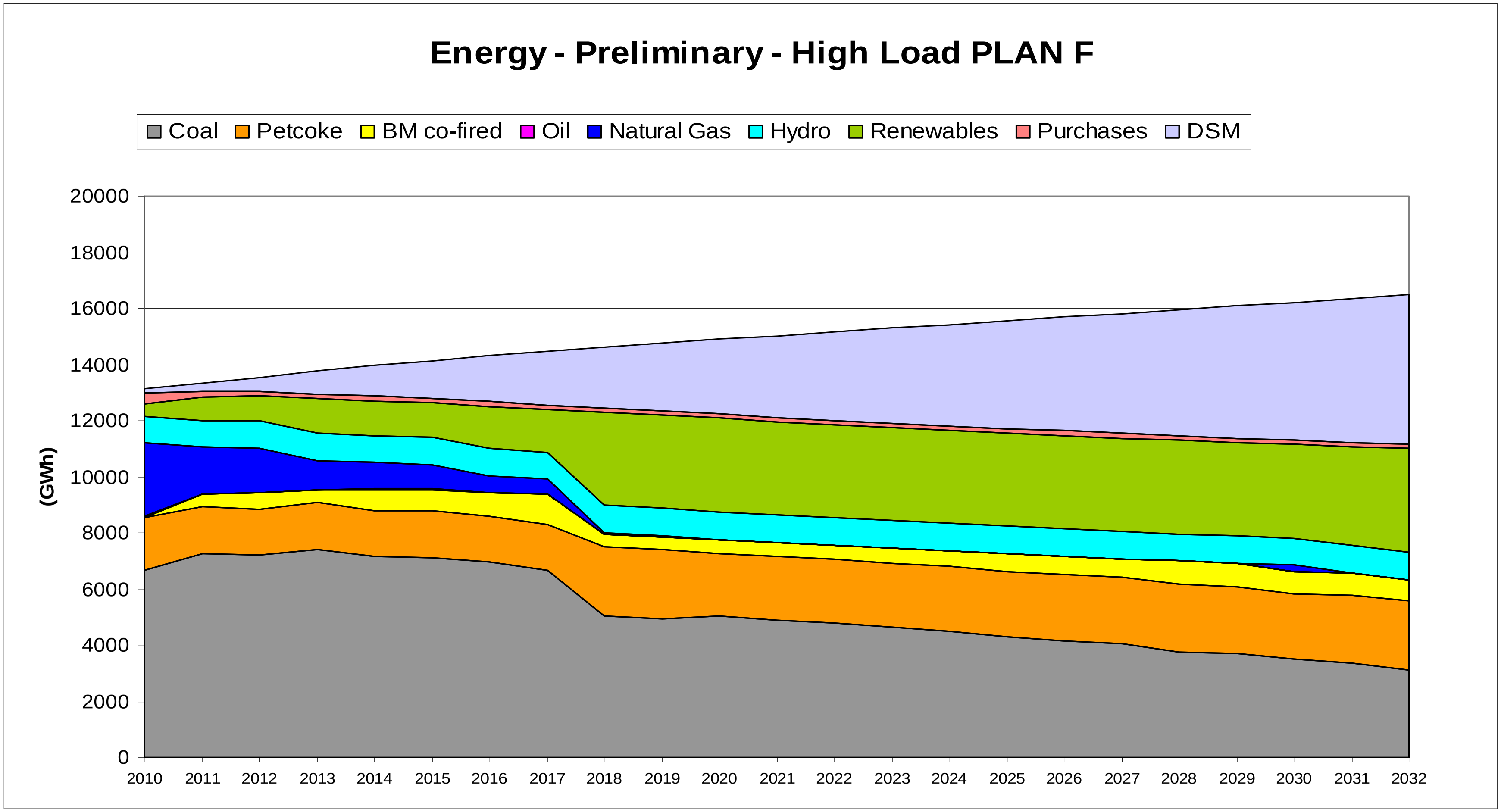
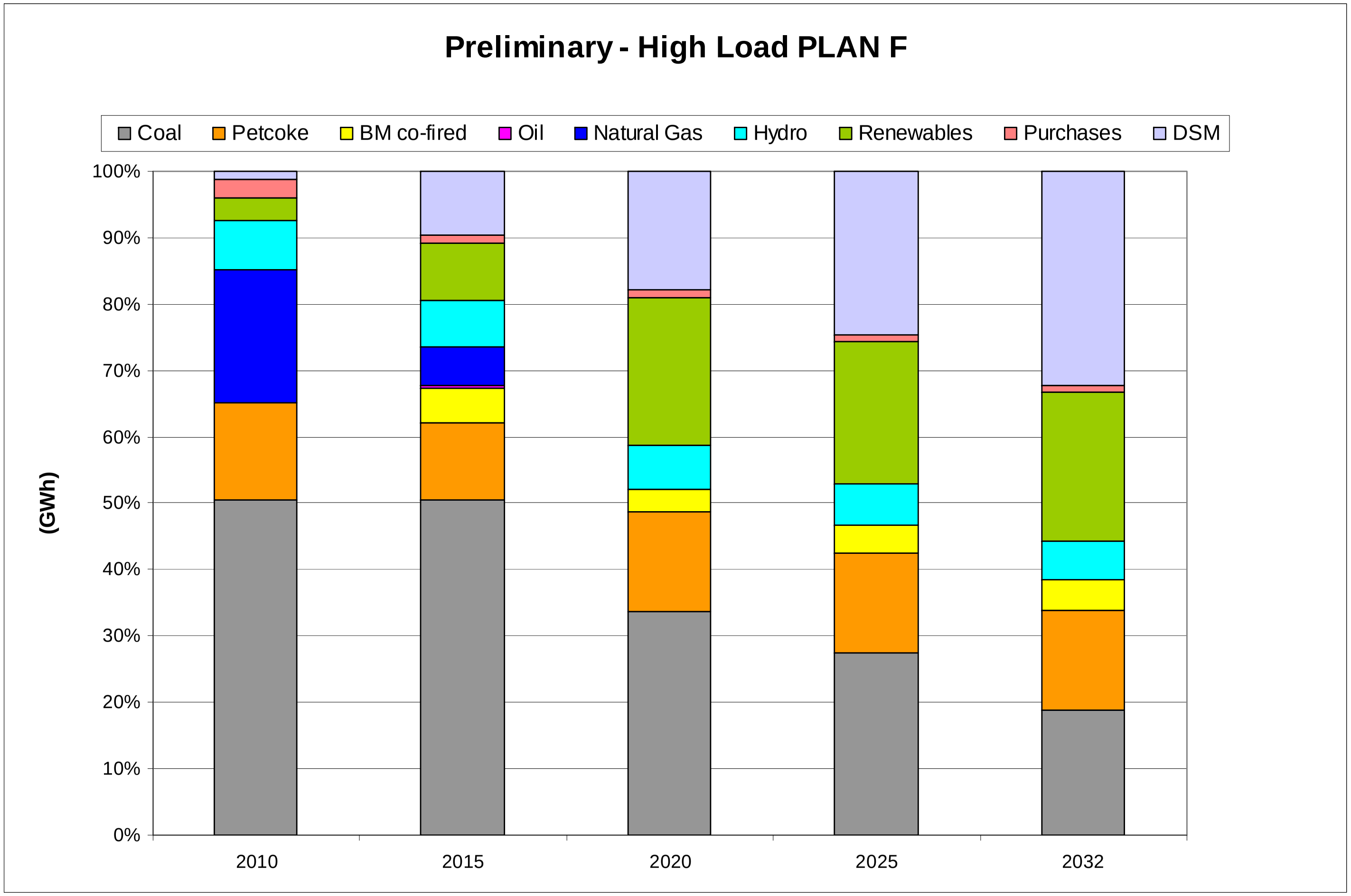
2009 IRP Update
Modeling / Analysis Results



Note: “Renewables” above includes Large Non Emitting PPA (as opposed to “Purchases").

2009 IRP Update
Modeling / Analysis Results



Note: "Renewables" above includes Large Non Emitting PPA (as opposed to "Purchases").

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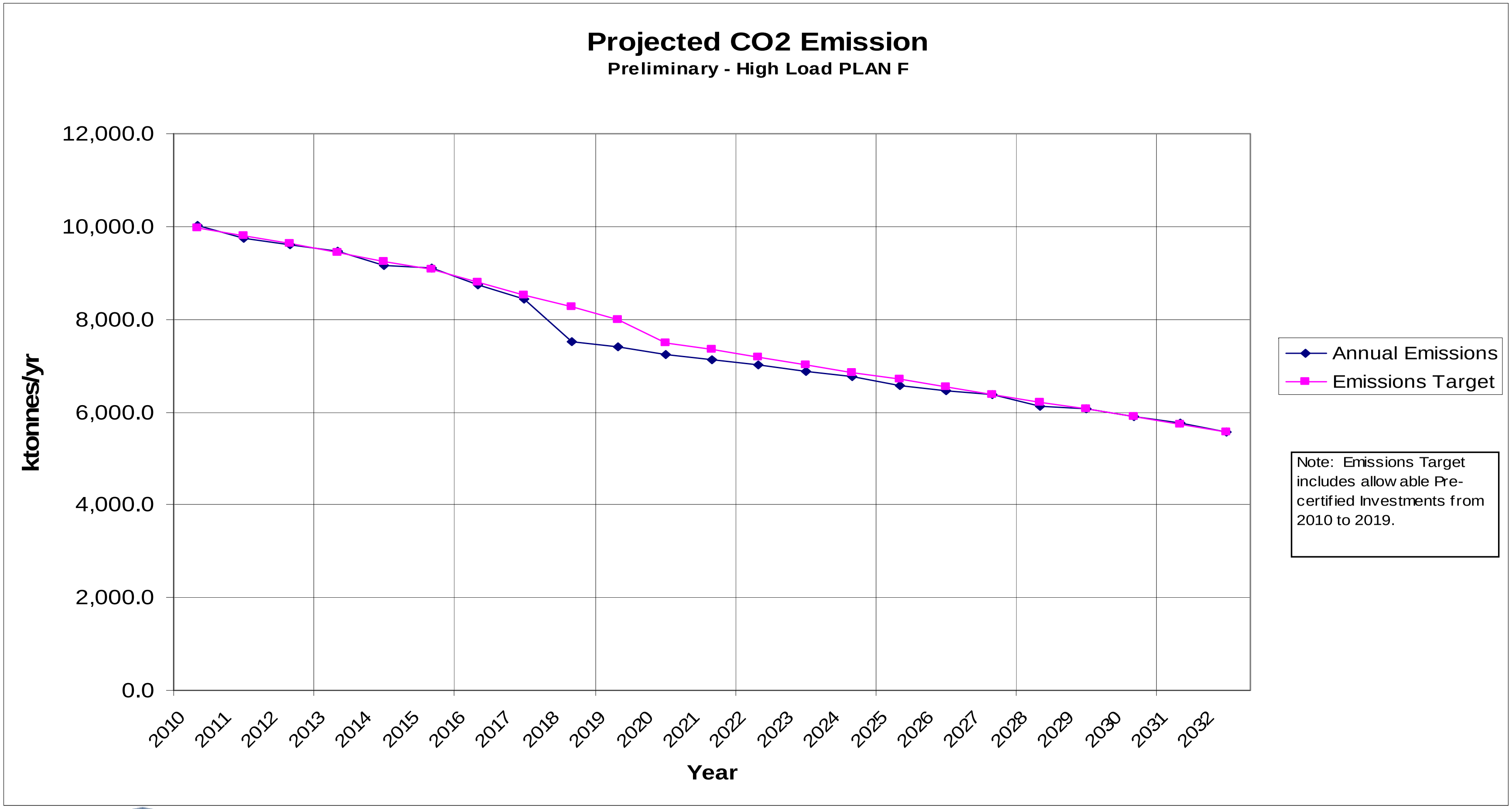
2009 IRP Update
Modeling / Analysis Results

Emissions Graphs Plan F



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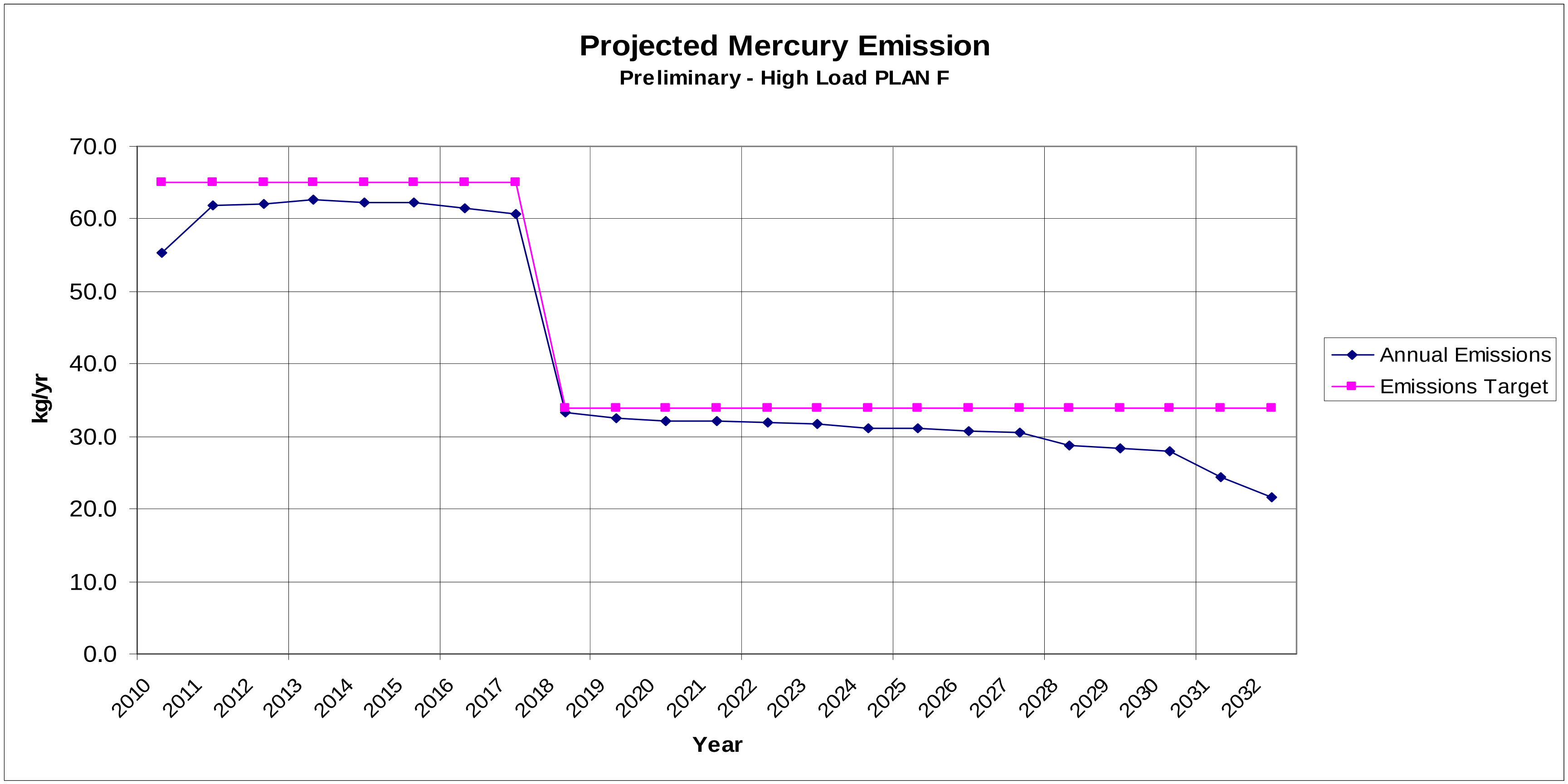
2009 IRP Update
Modeling / Analysis Results

Emissions Graphs Plan F



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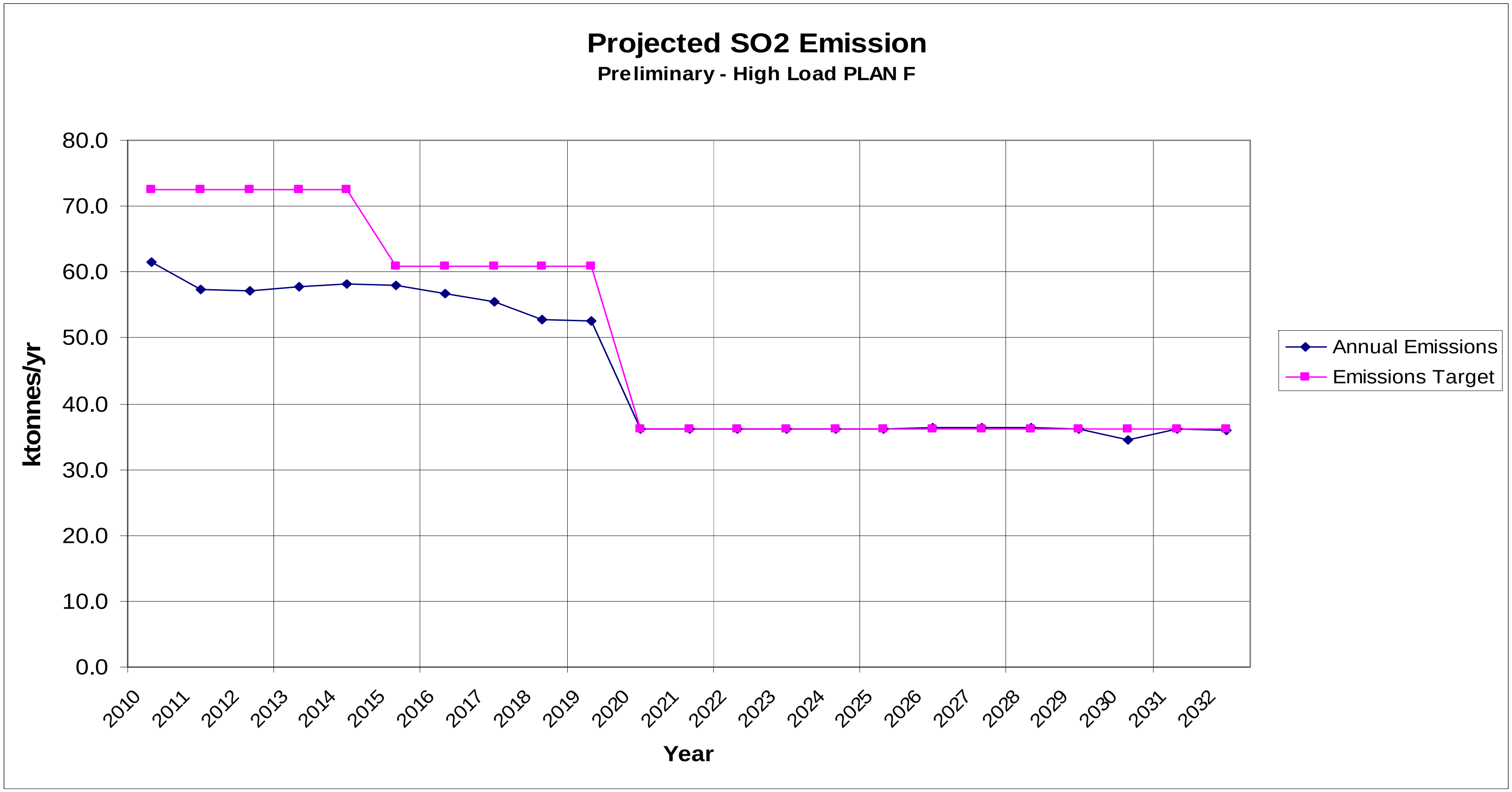
2009 IRP Update
Modeling / Analysis Results

Emissions Graphs Plan F



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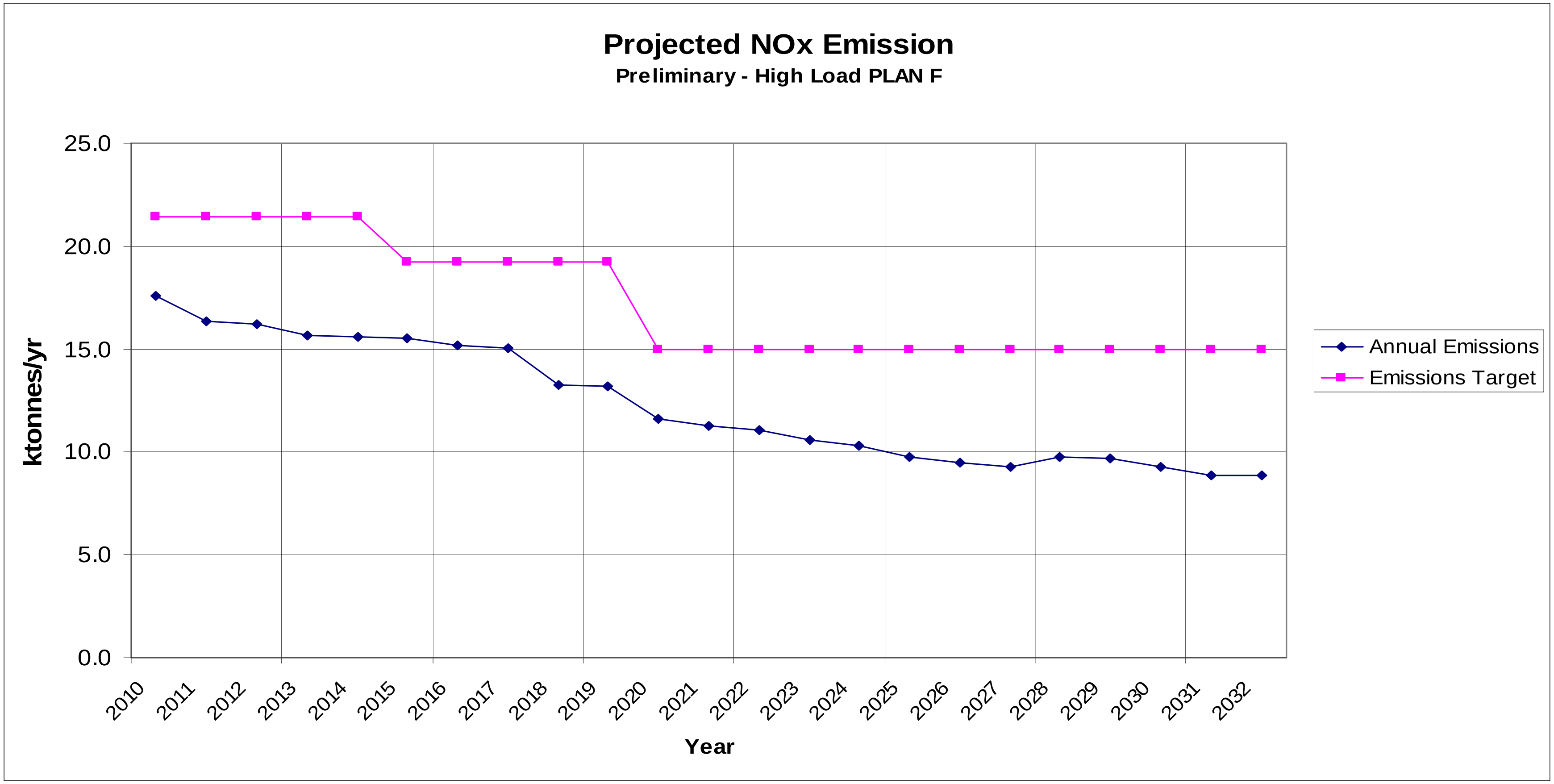
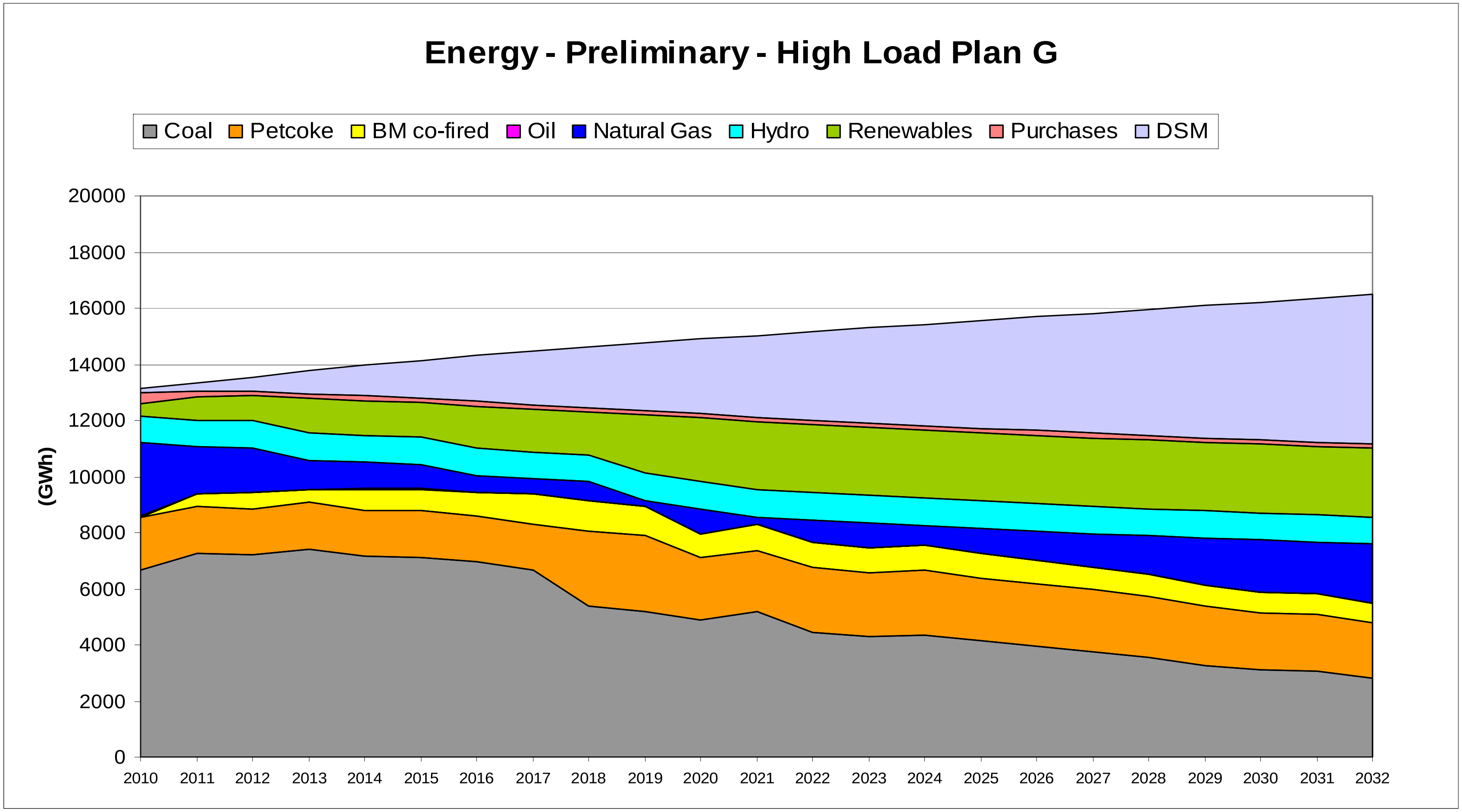
2009 IRP Update
Modeling / Analysis Results

Emissions Graphs Plan F



2009 IRP Update
Modeling / Analysis Results



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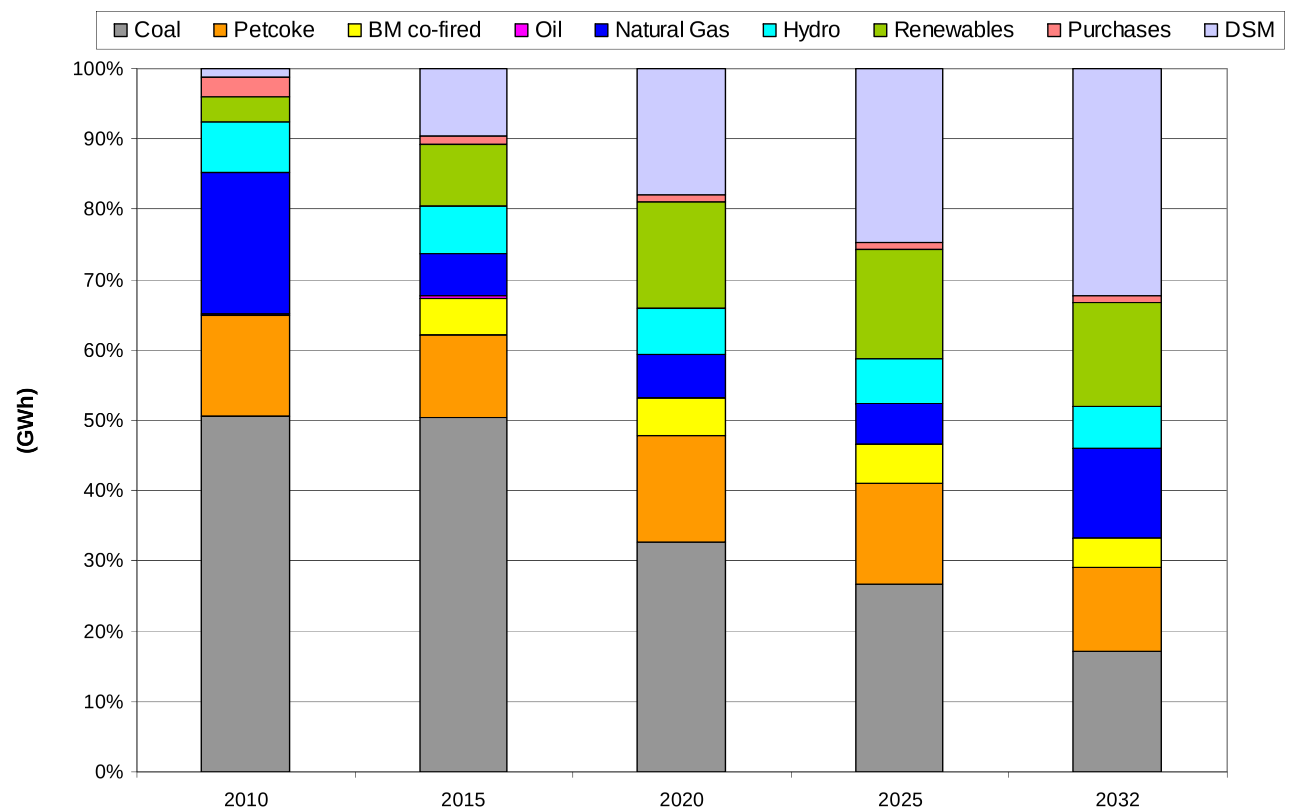
2009 IRP Update
Modeling / Analysis Results

Preliminary - High Load Plan G



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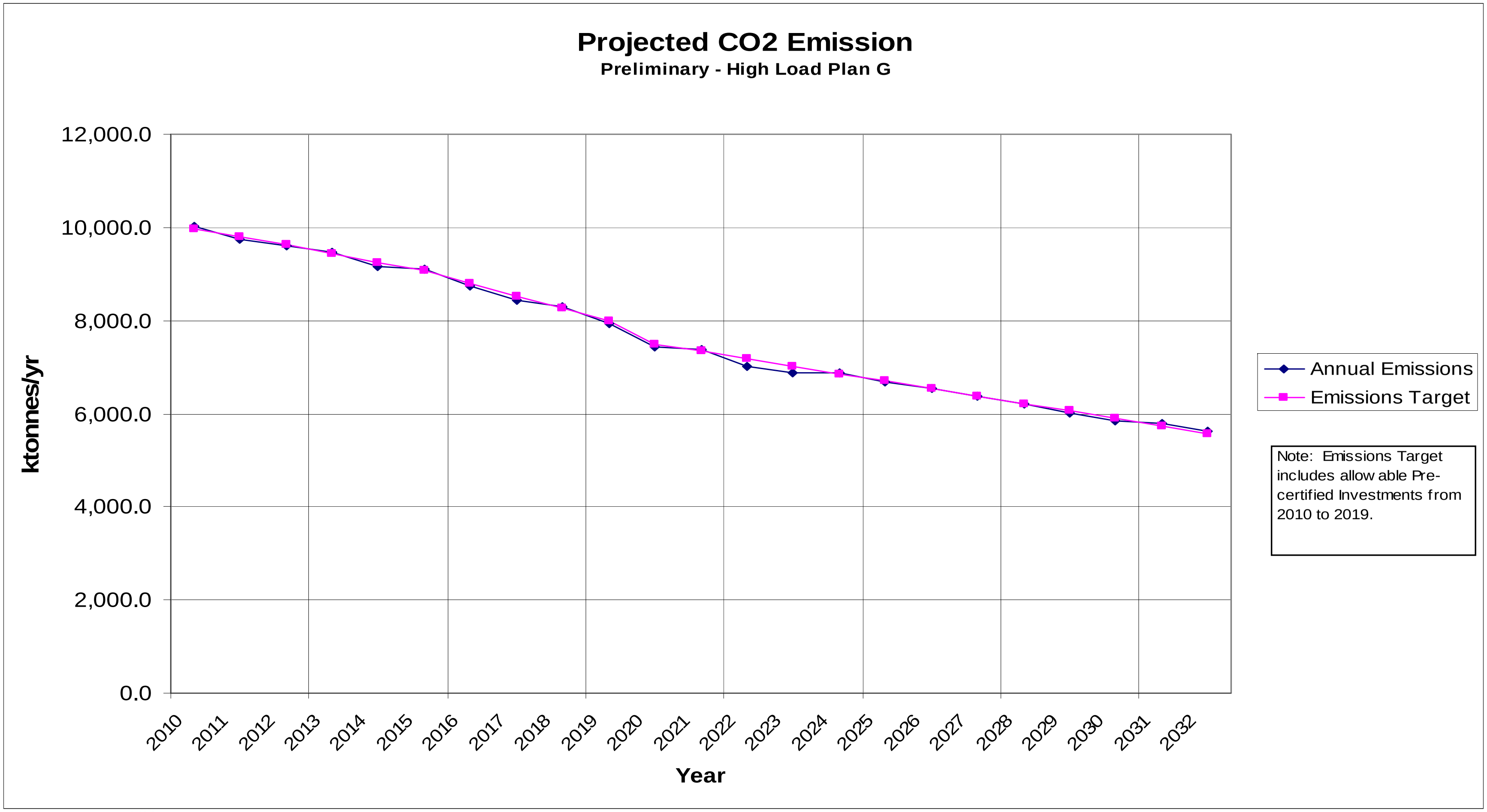
2009 IRP Update
Modeling / Analysis Results

Emissions Graphs Plan G



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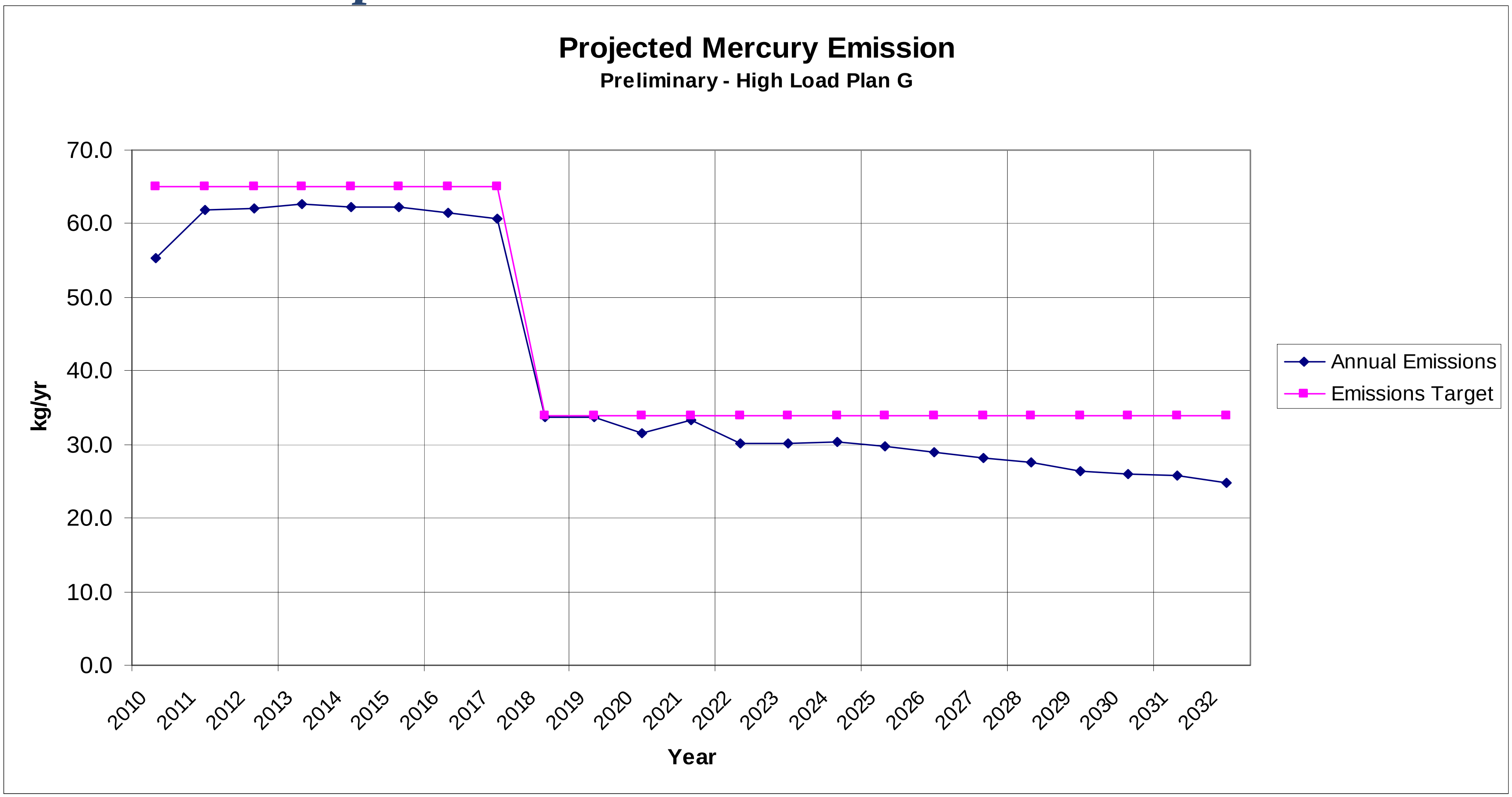
2009 IRP Update
Modeling / Analysis Results

Emissions Graphs Plan G



NOVA SCOTIA POWER
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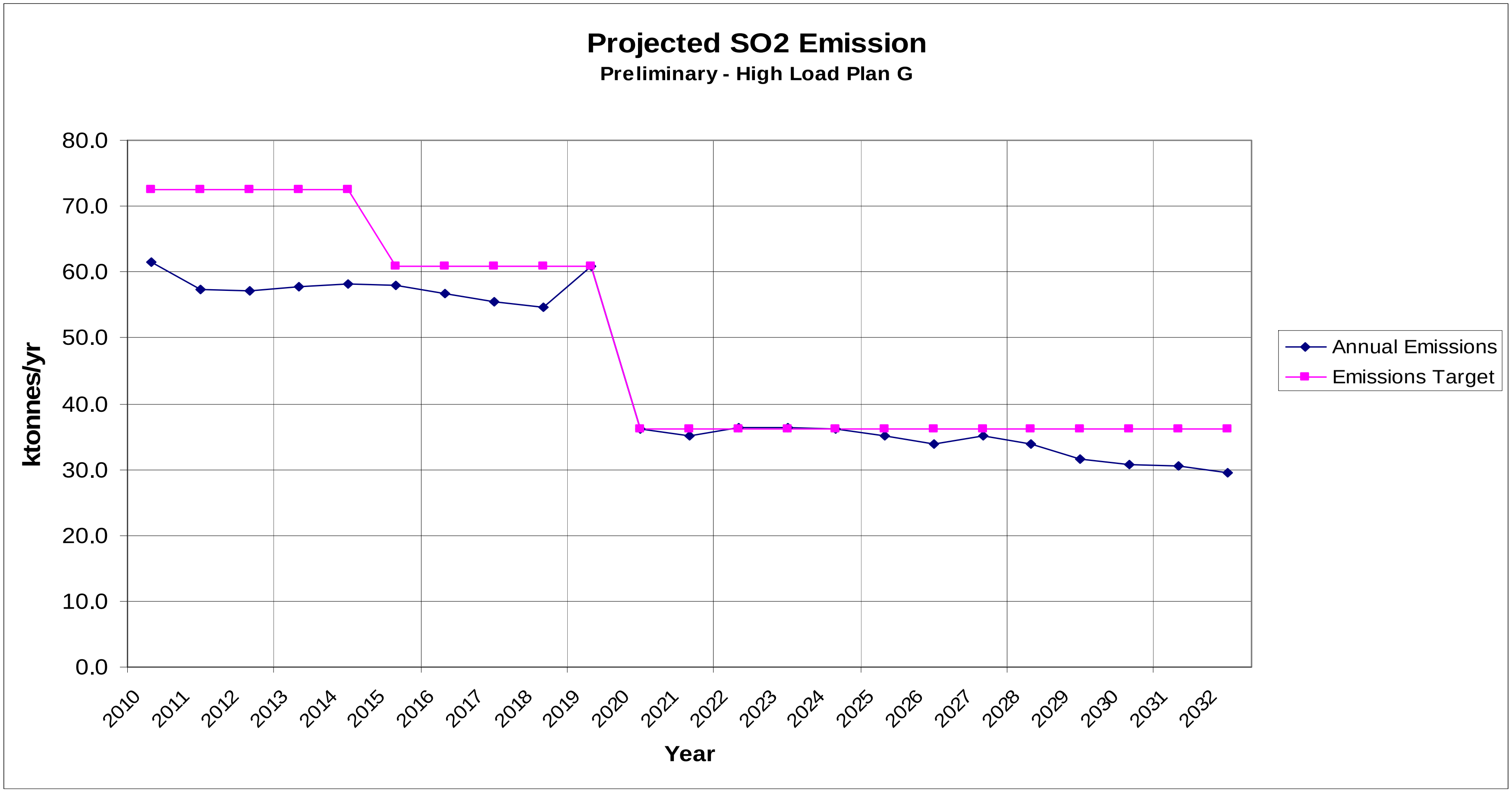
2009 IRP Update
Modeling / Analysis Results

Emissions Graphs Plan G



NOVA SCOTIA POWER
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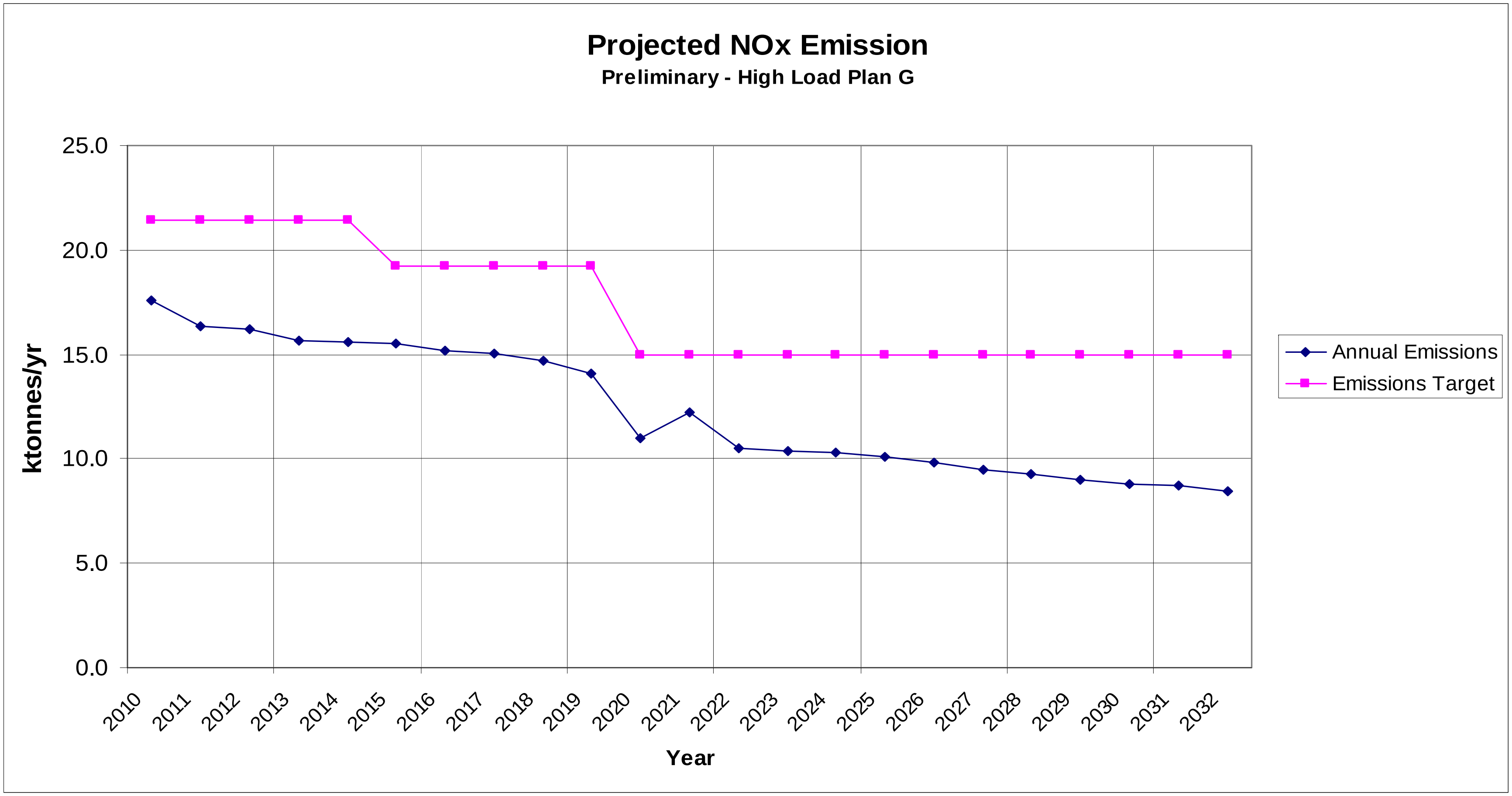
2009 IRP Update
Modeling / Analysis Results

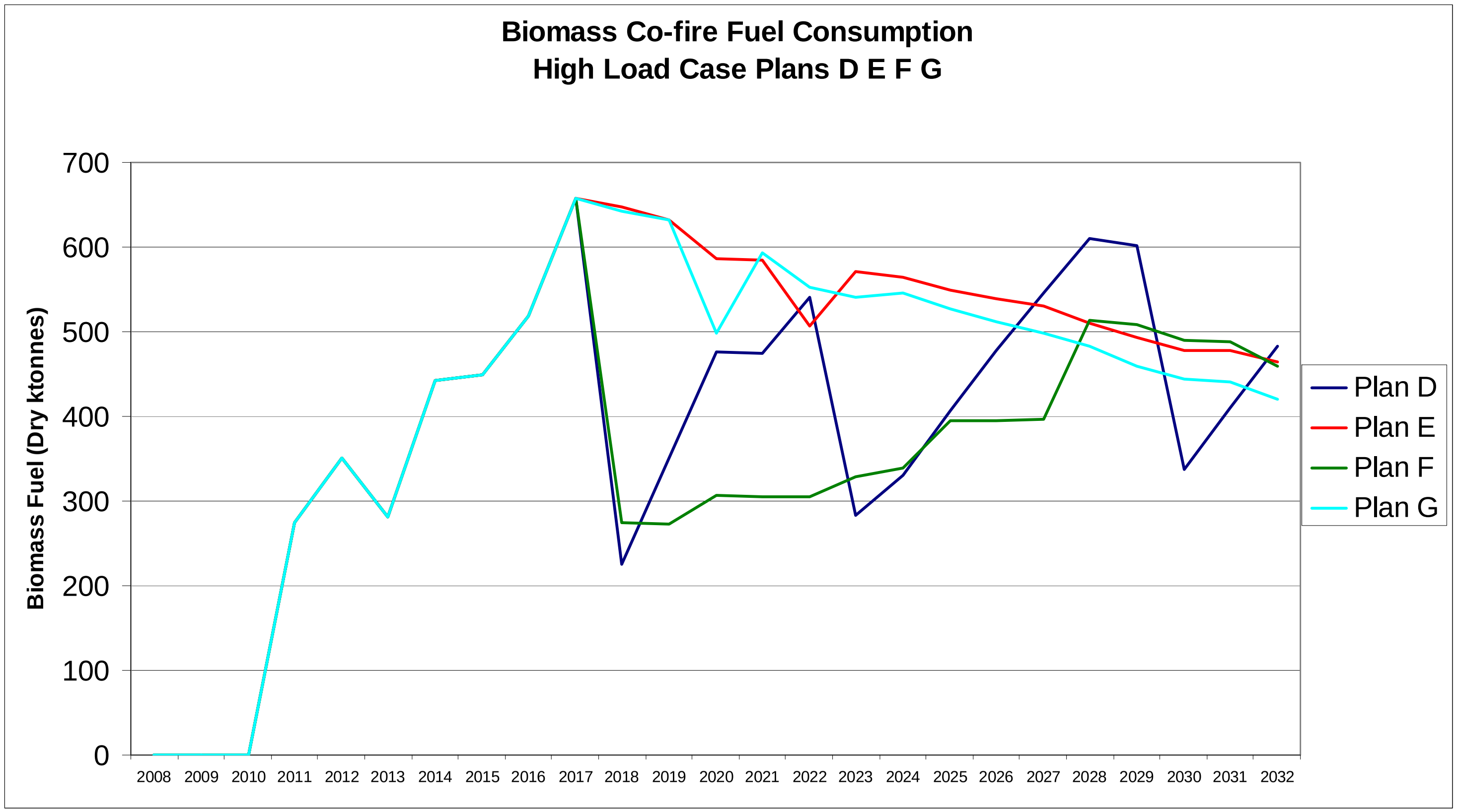
Emissions Graphs Plan G



NOVA SCOTIA POWER An Emera Company

2009 IRP Update
Modeling / Analysis Results

Tonnes Biomass Plan D, E, F, G



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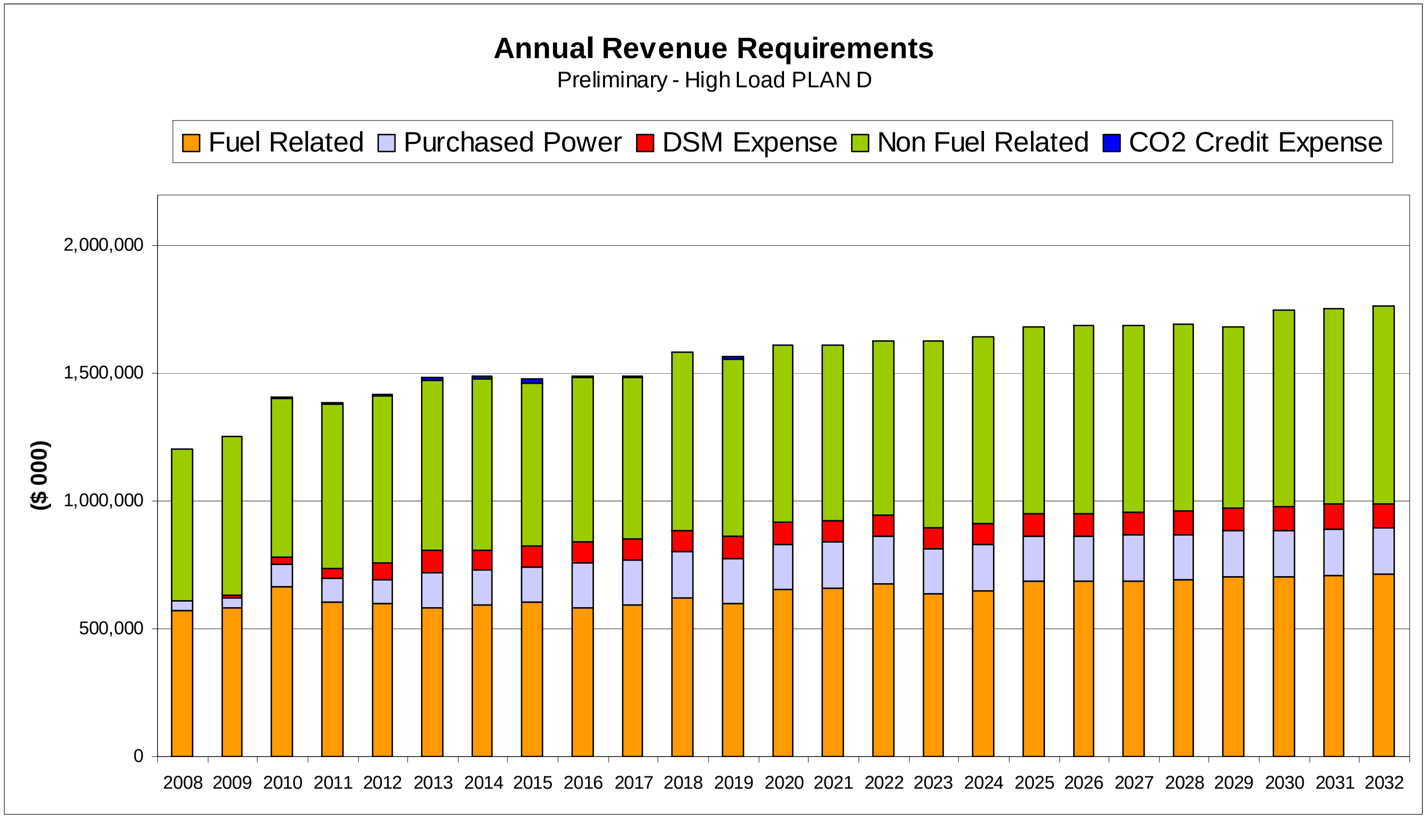
HIGH LOAD PLANS – Estimate of Revenue Requirements

NOVA SCOTIA POWER
An Emera Company

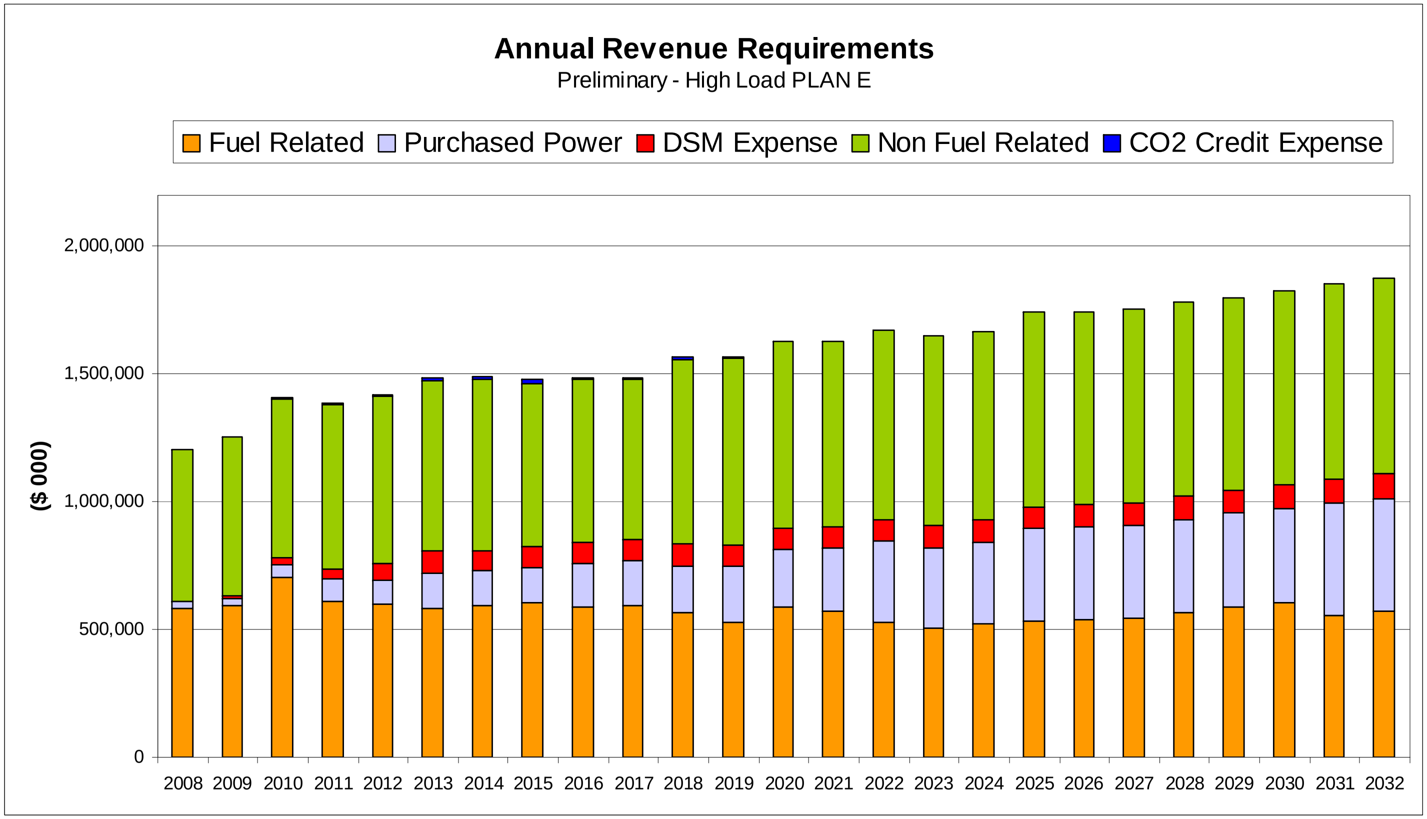
Revenue Requirements Base Plan D



Revenue requirements are illustrative/relative/comparative only. Actual future revenue requirement will be determined per Rate Application test year data.

2009 IRP Update
Modeling / Analysis Results

Revenue Requirements Base Plan E



Revenue requirements are illustrative/relative/comparative only. Actual future revenue requirement will be determined per Rate Application test year data.

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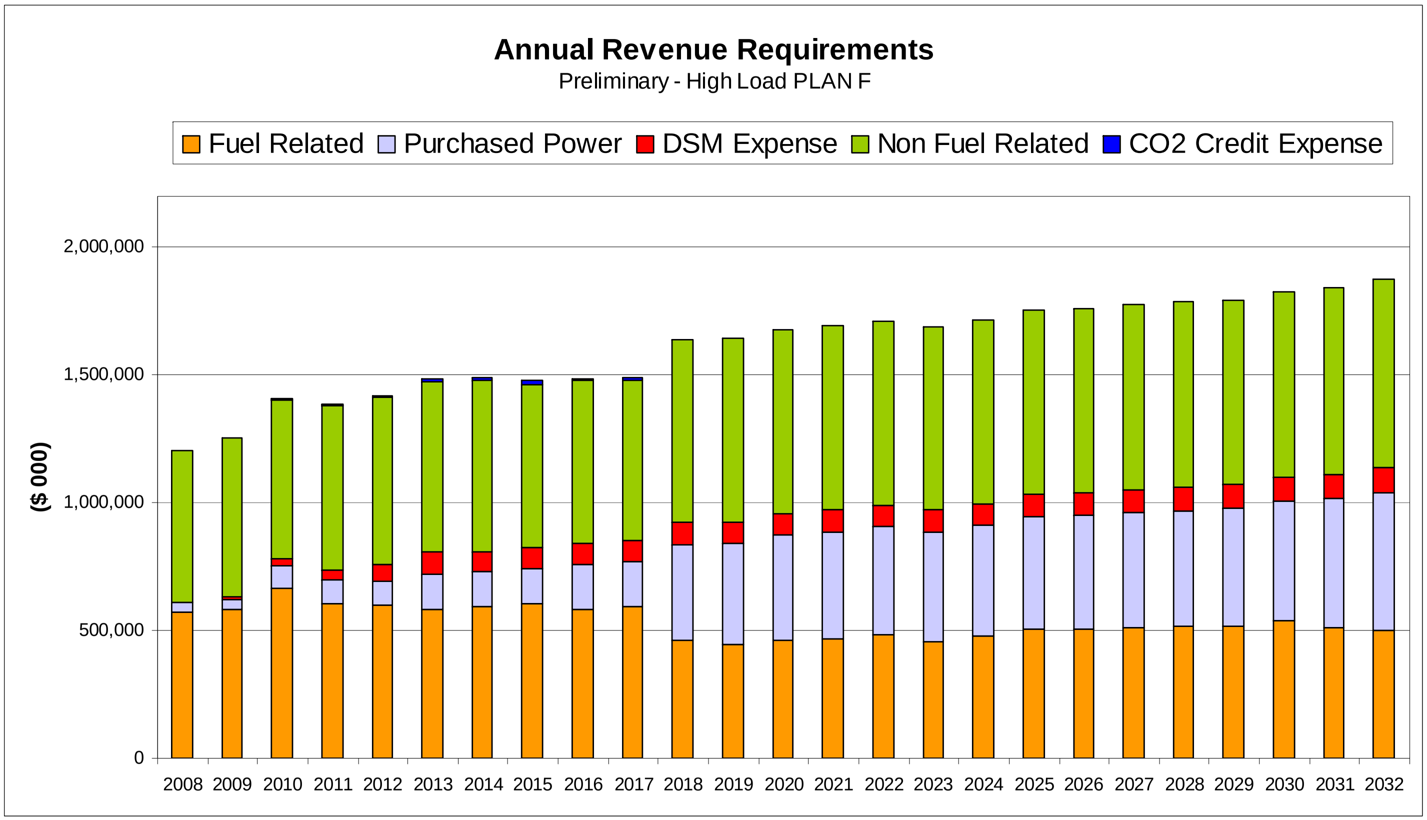
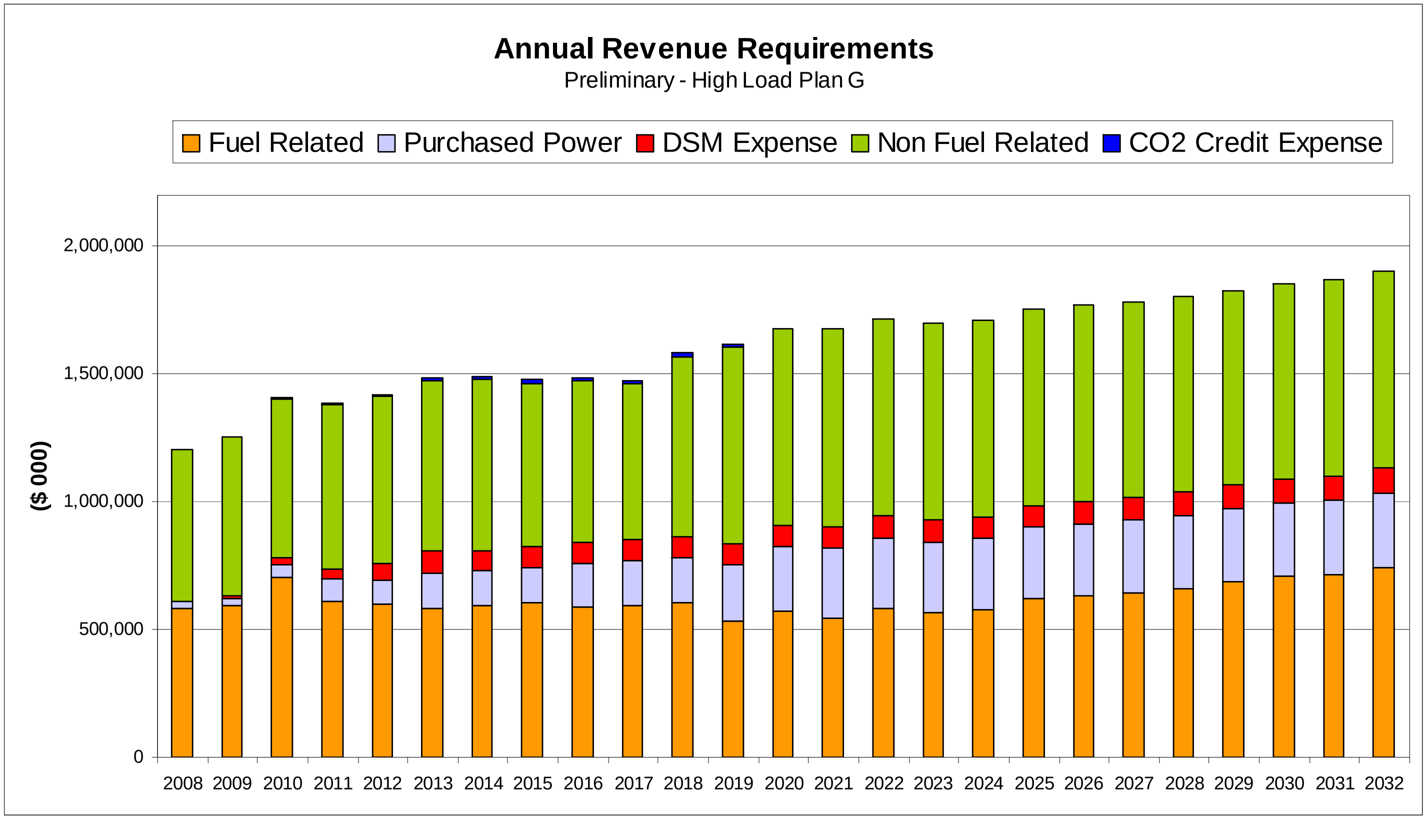
Revenue Requirements Base Plan F



Revenue requirements are illustrative/relative/comparative only. Actual future revenue requirement will be determined per Rate Application test year data.

2009 IRP Update
Modeling / Analysis Results

Revenue Requirements Base Plan G

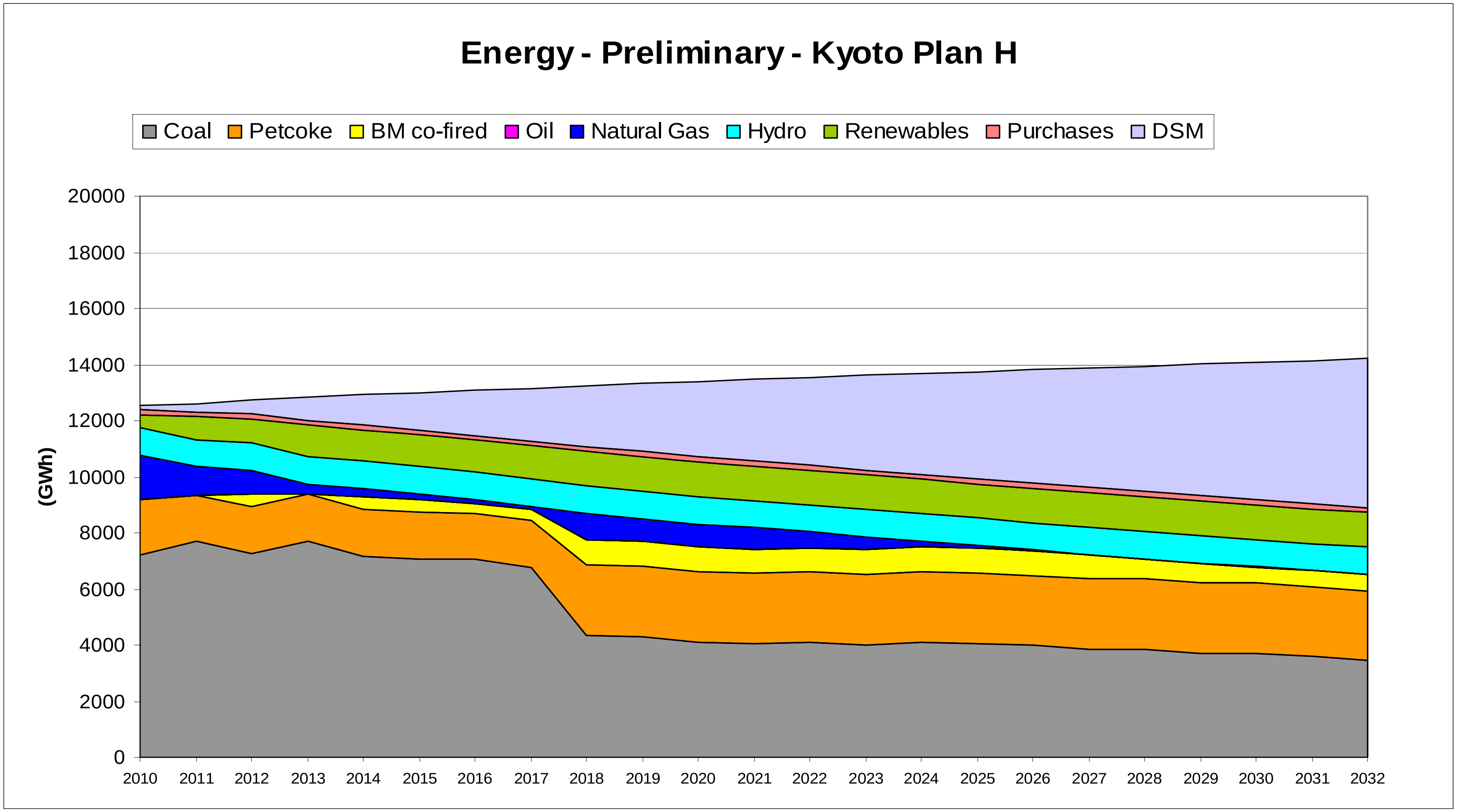


Revenue requirements are illustrative/relative/comparative only. Actual future revenue requirement will be determined per Rate Application test year data.

APPENDIX E

Kyoto World Plan Results

2009 IRP Update
Modeling / Analysis Results



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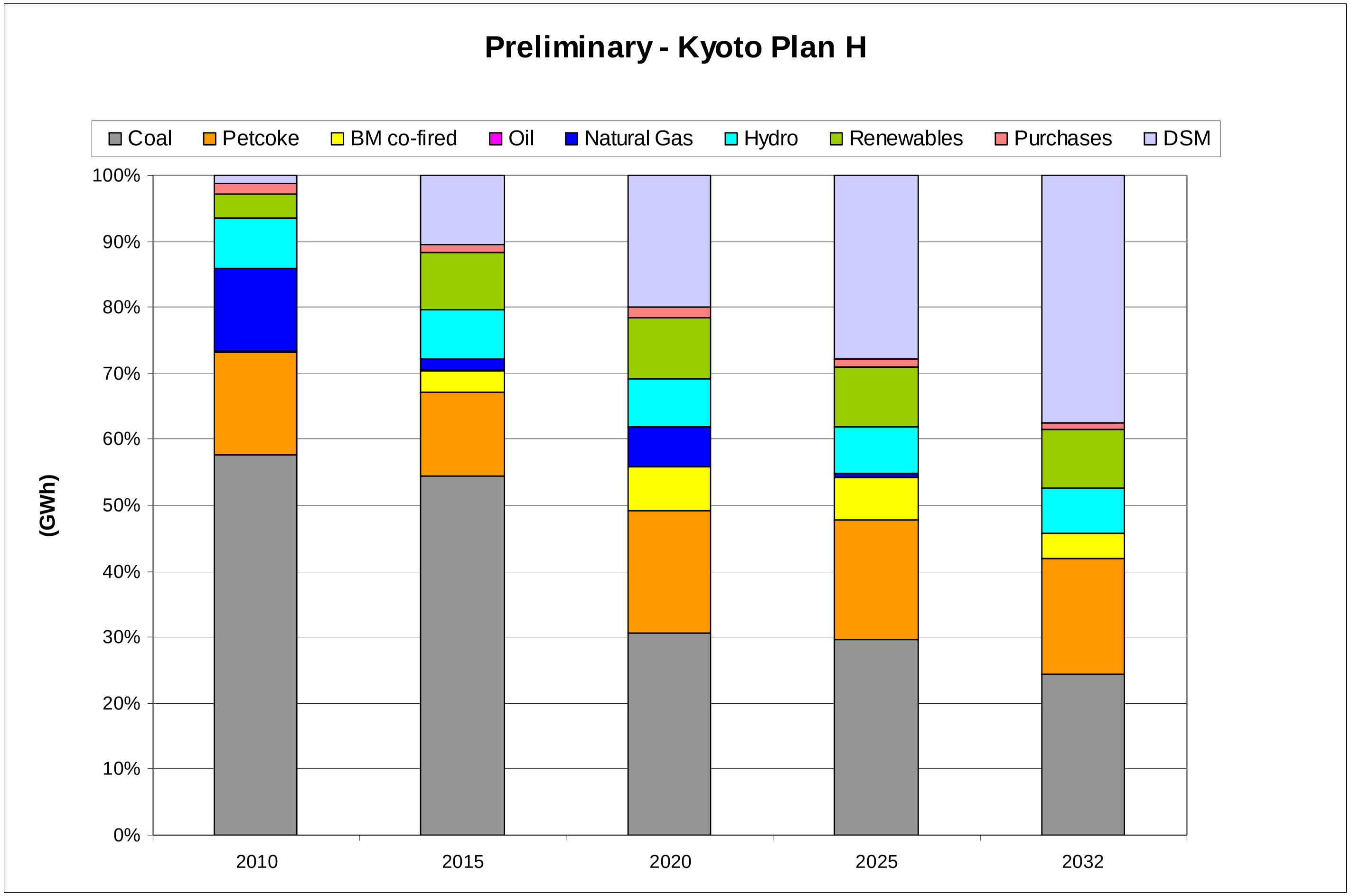
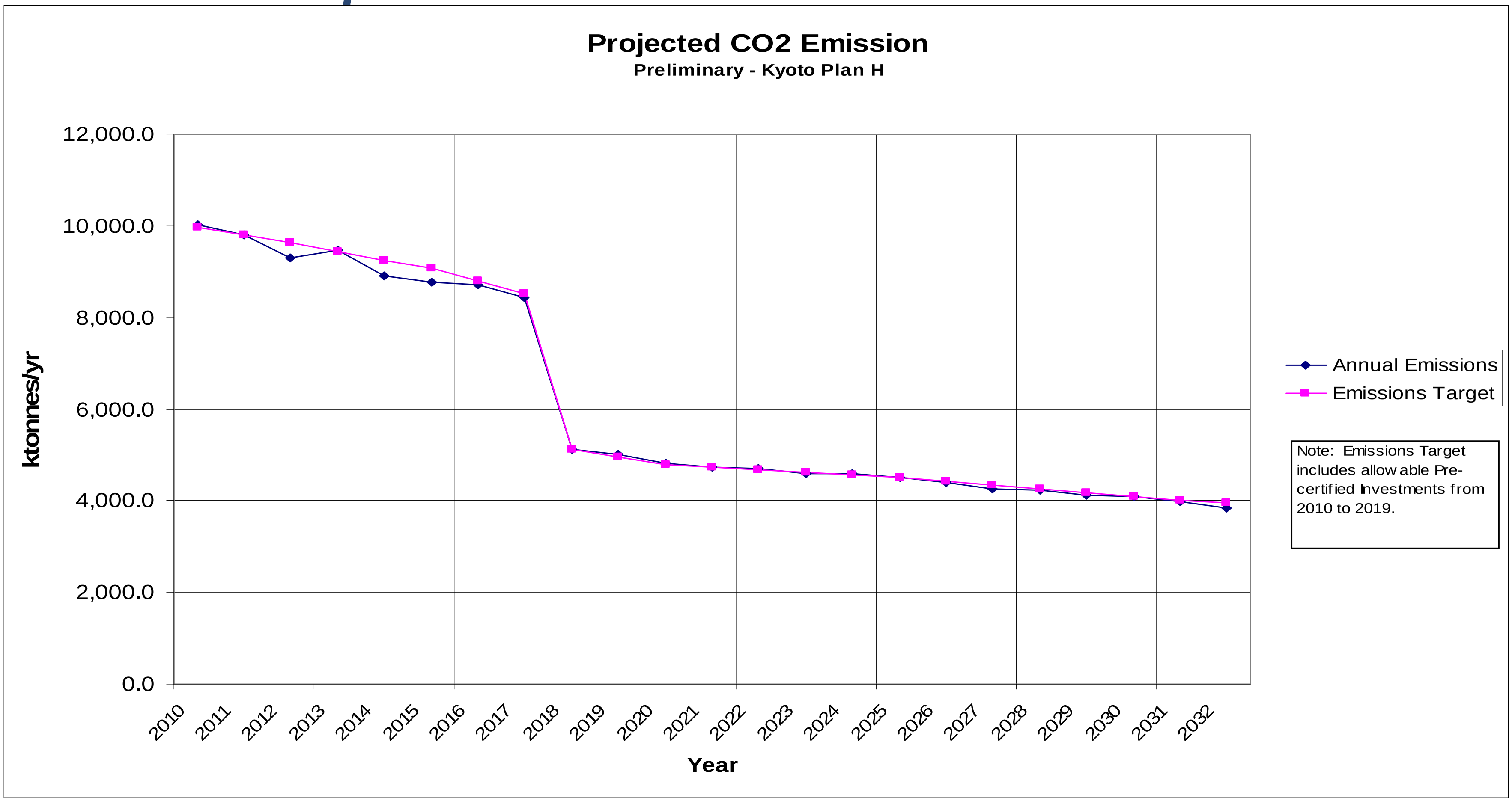
2009 IRP Update
Modeling / Analysis Results



2009 IRP Update
Modeling / Analysis Results

Emissions Graphs Plan H



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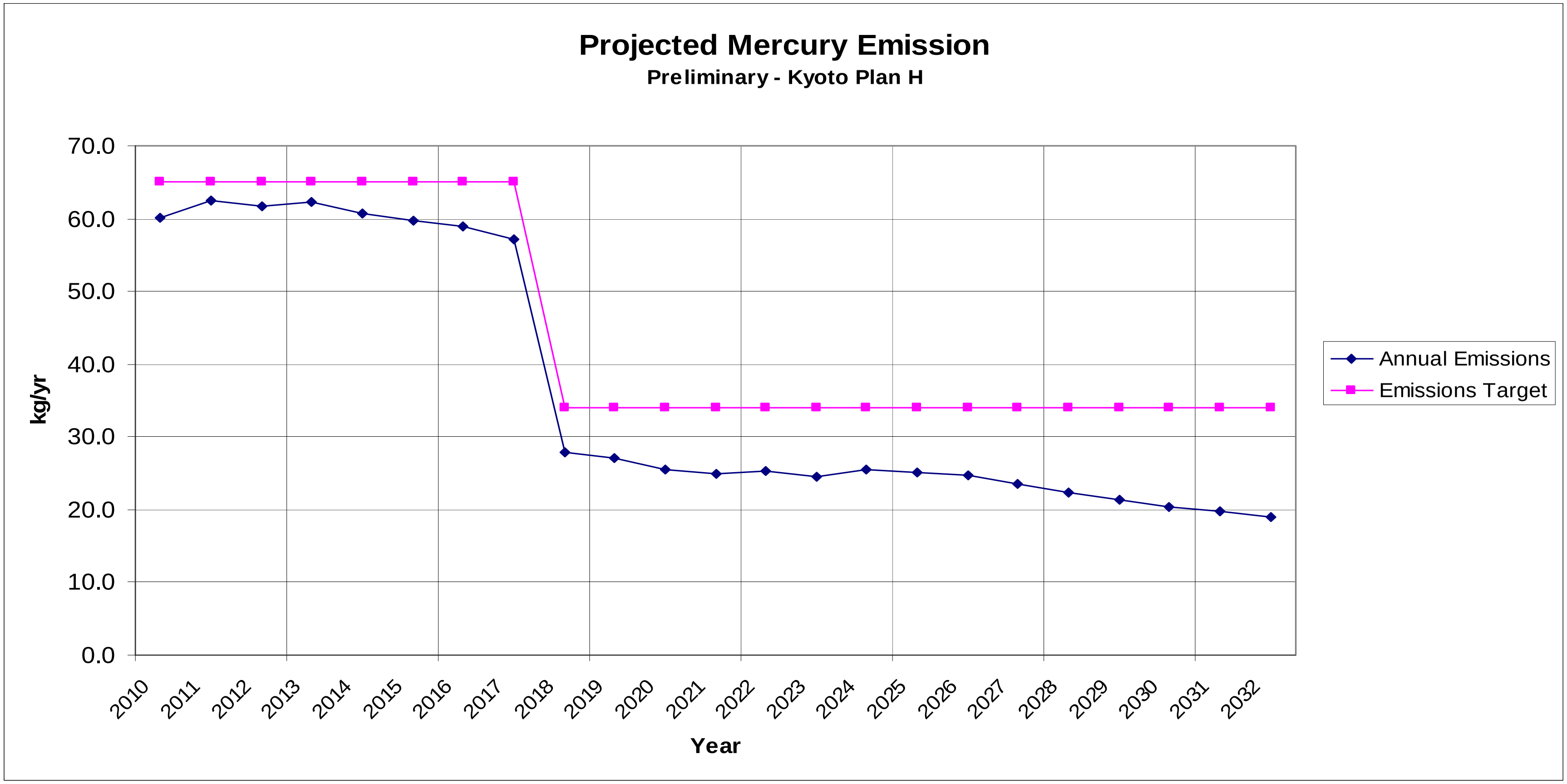
2009 IRP Update
Modeling / Analysis Results

Emissions Graphs Plan H



NOVA SCOTIA POWER
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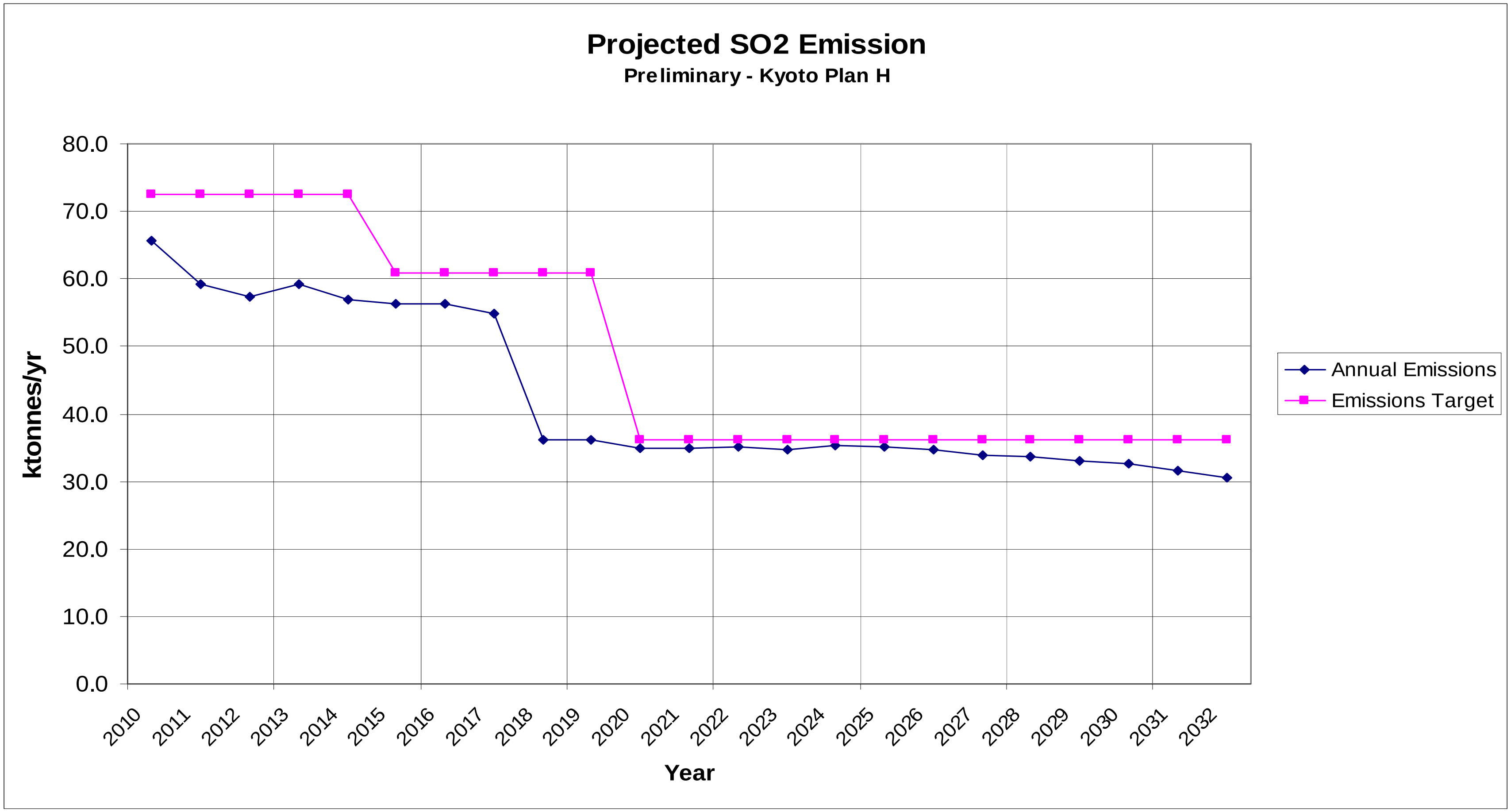
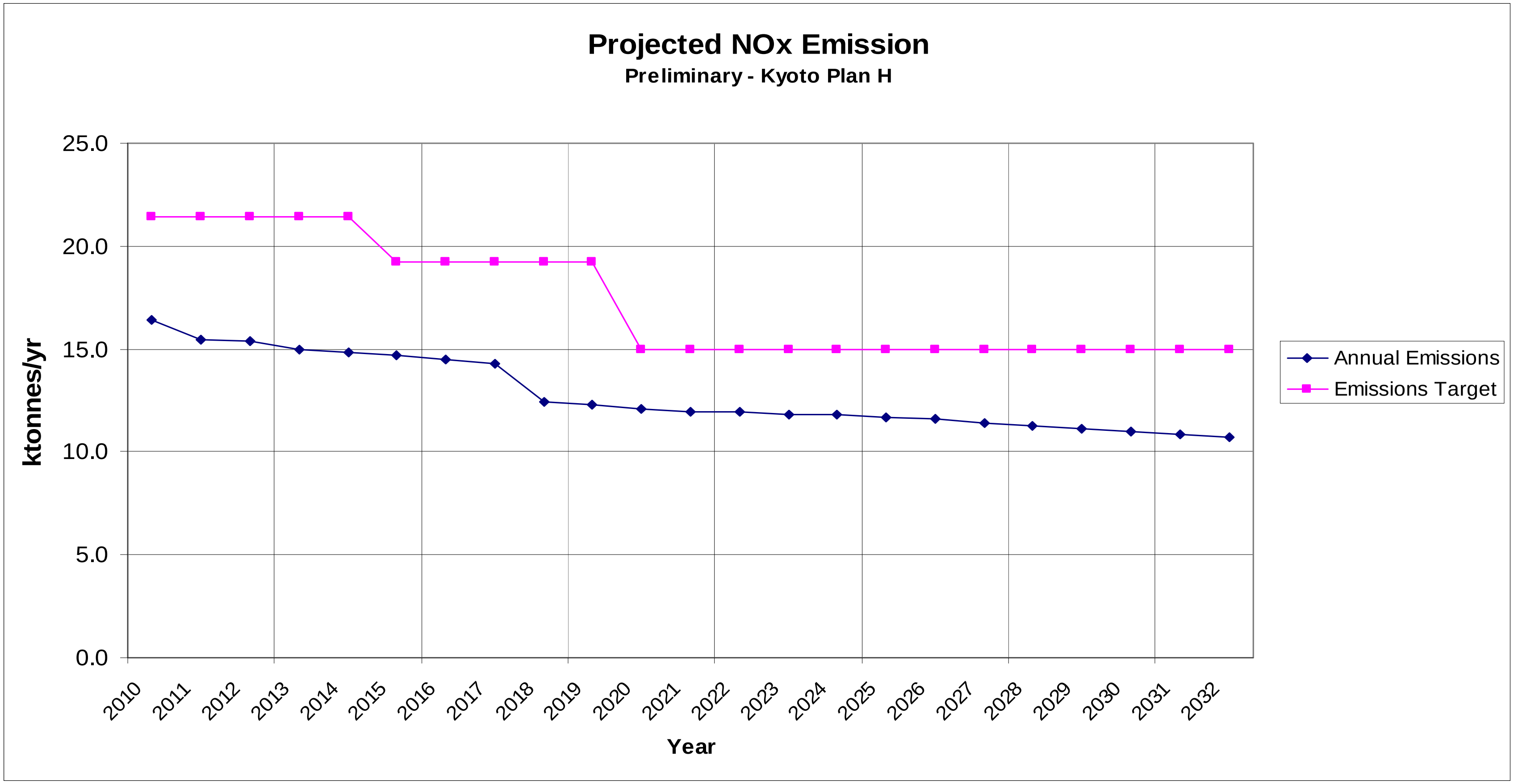
2009 IRP Update
Modeling / Analysis Results

Emissions Graphs Plan H

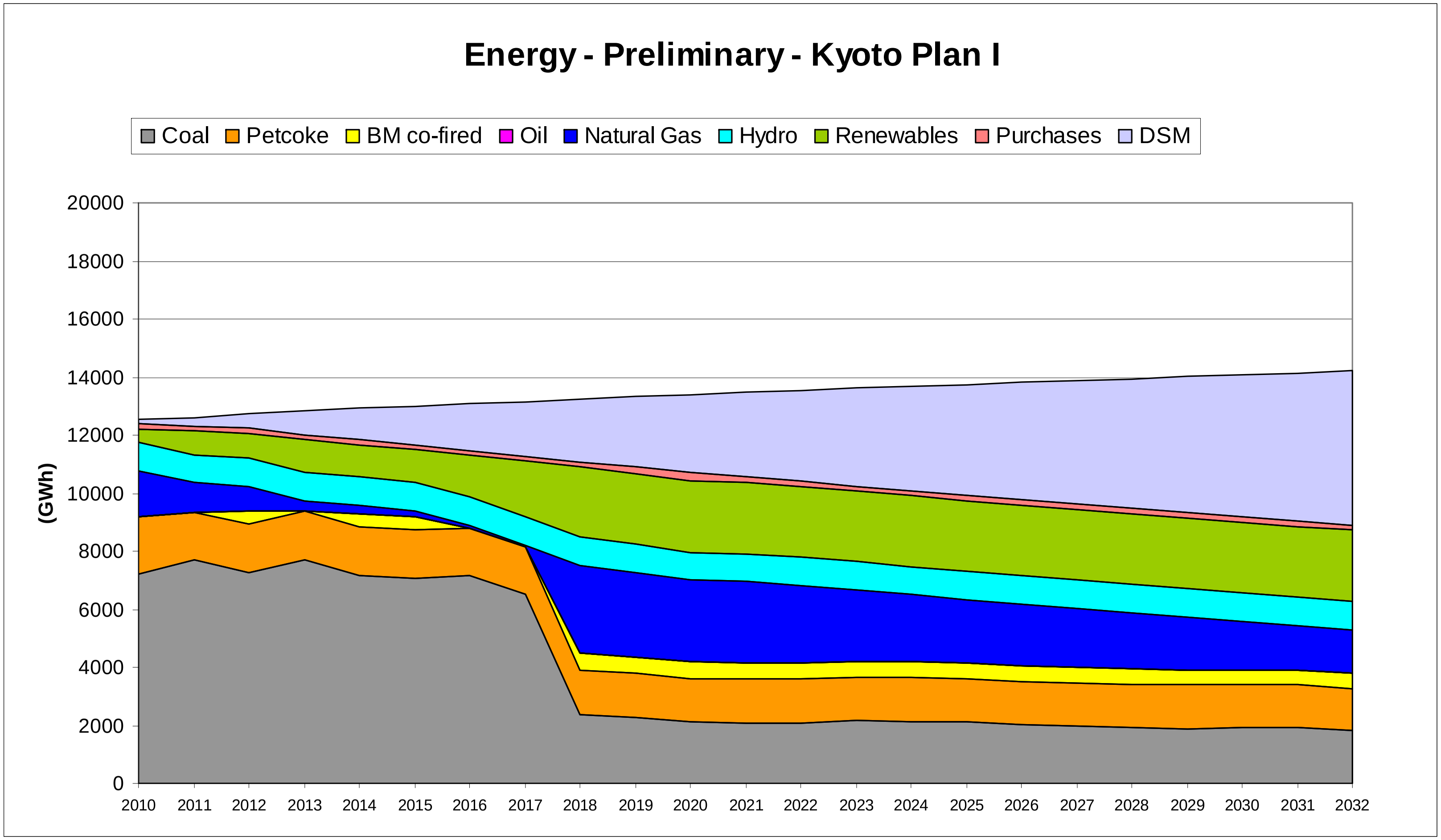


NOVA SCOTIA POWER
An Emera Company

Emissions Graphs Plan H



2009 IRP Update
Modeling / Analysis Results



NOVA SCOTIA POWER
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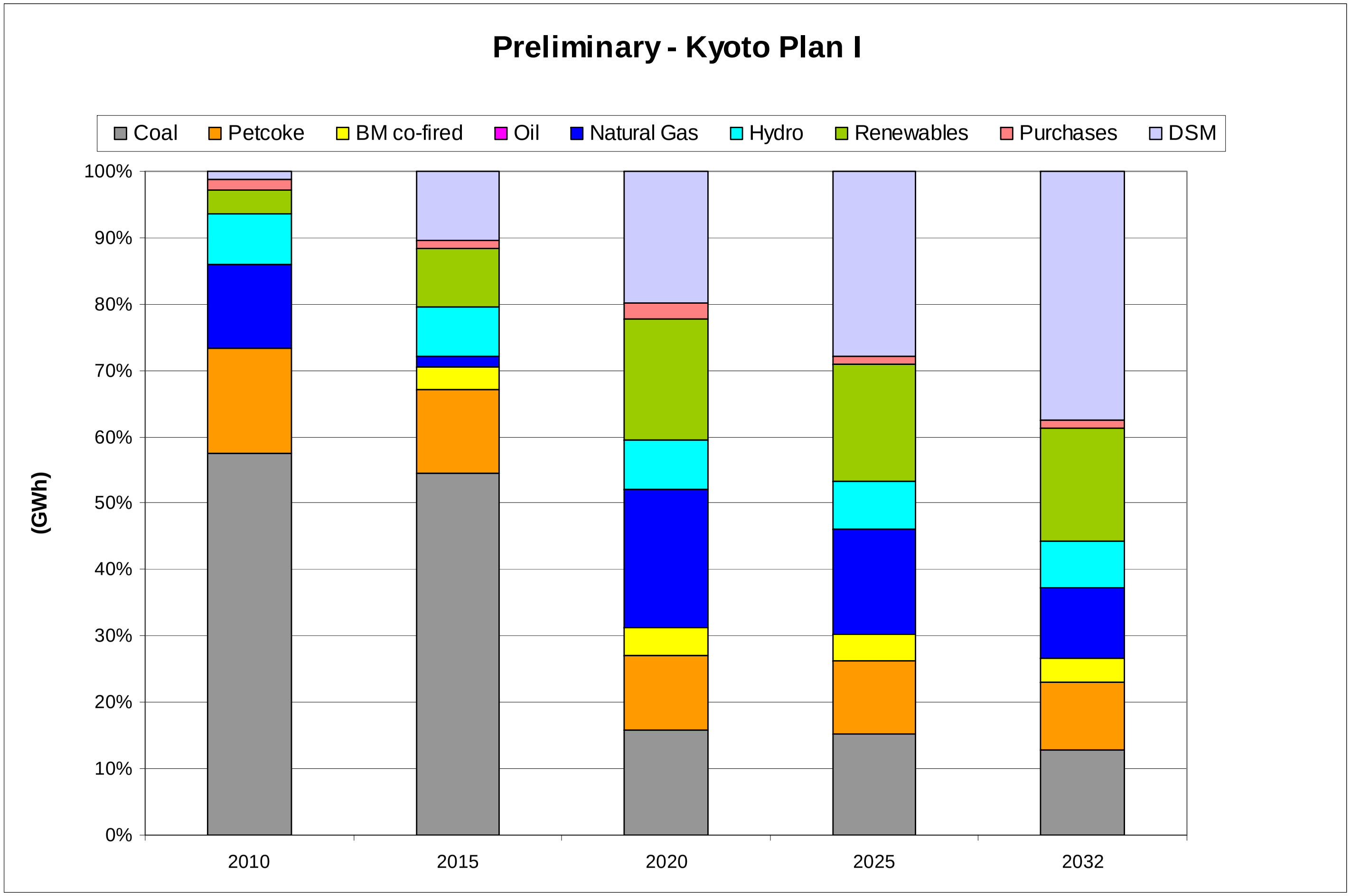
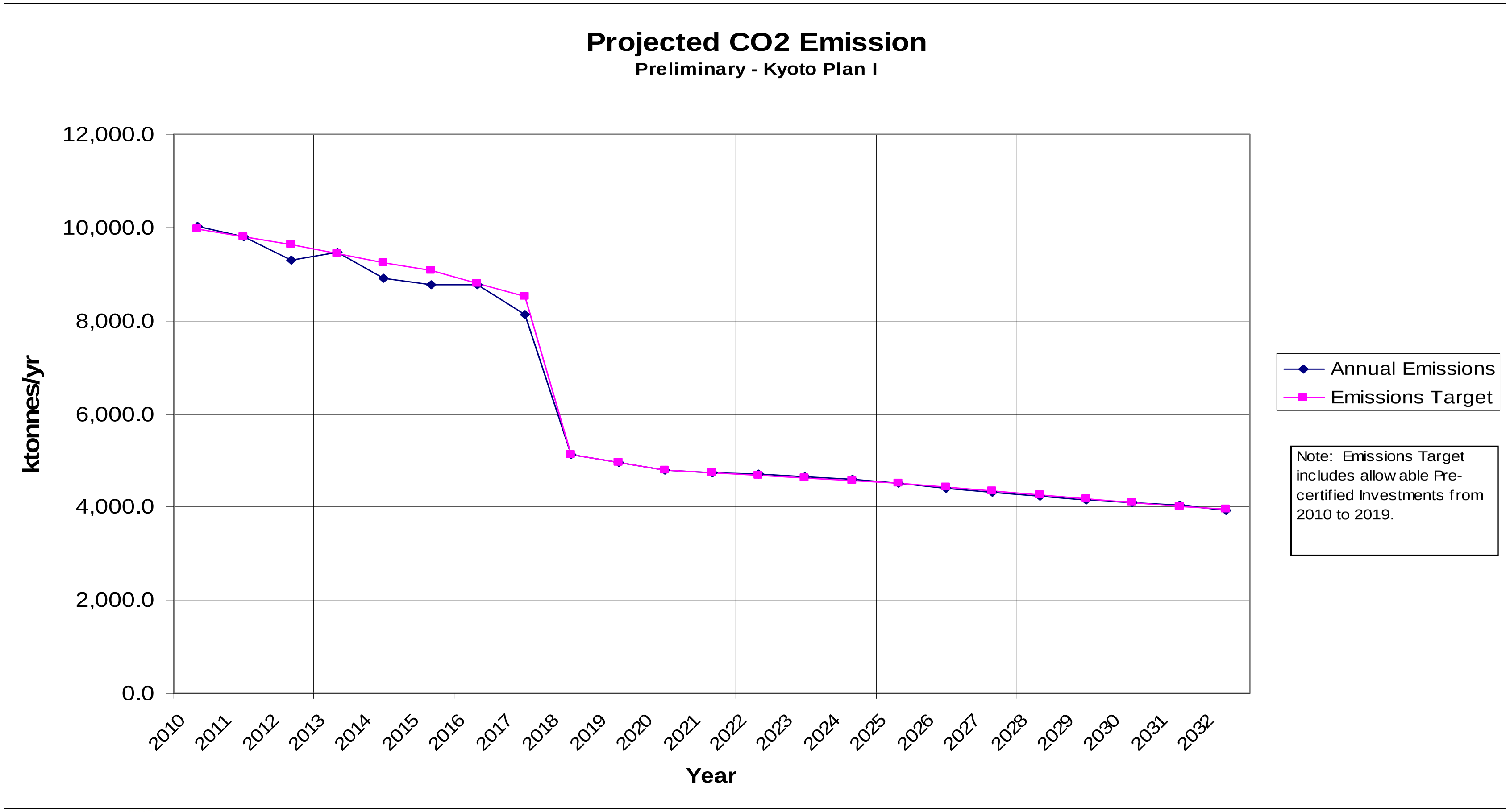
2009 IRP Update
Modeling / Analysis Results



NOVA SCOTIA POWER
An Emera Company

2009 IRP Update
Modeling / Analysis Results

Emissions Graphs Plan I



NOVA SCOTIA POWER
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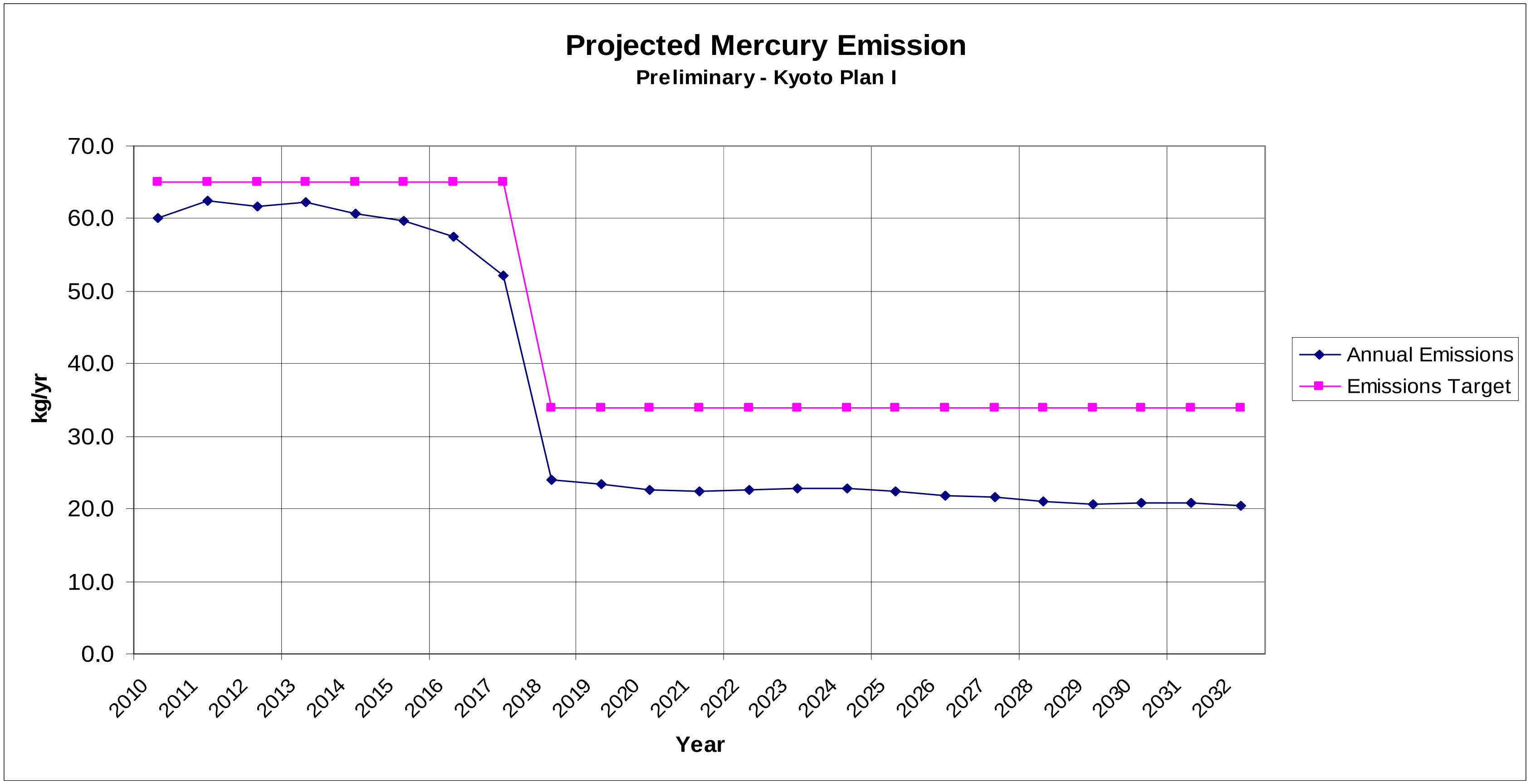
Emissions Graphs Plan I



NOVA SCOTIA POWER
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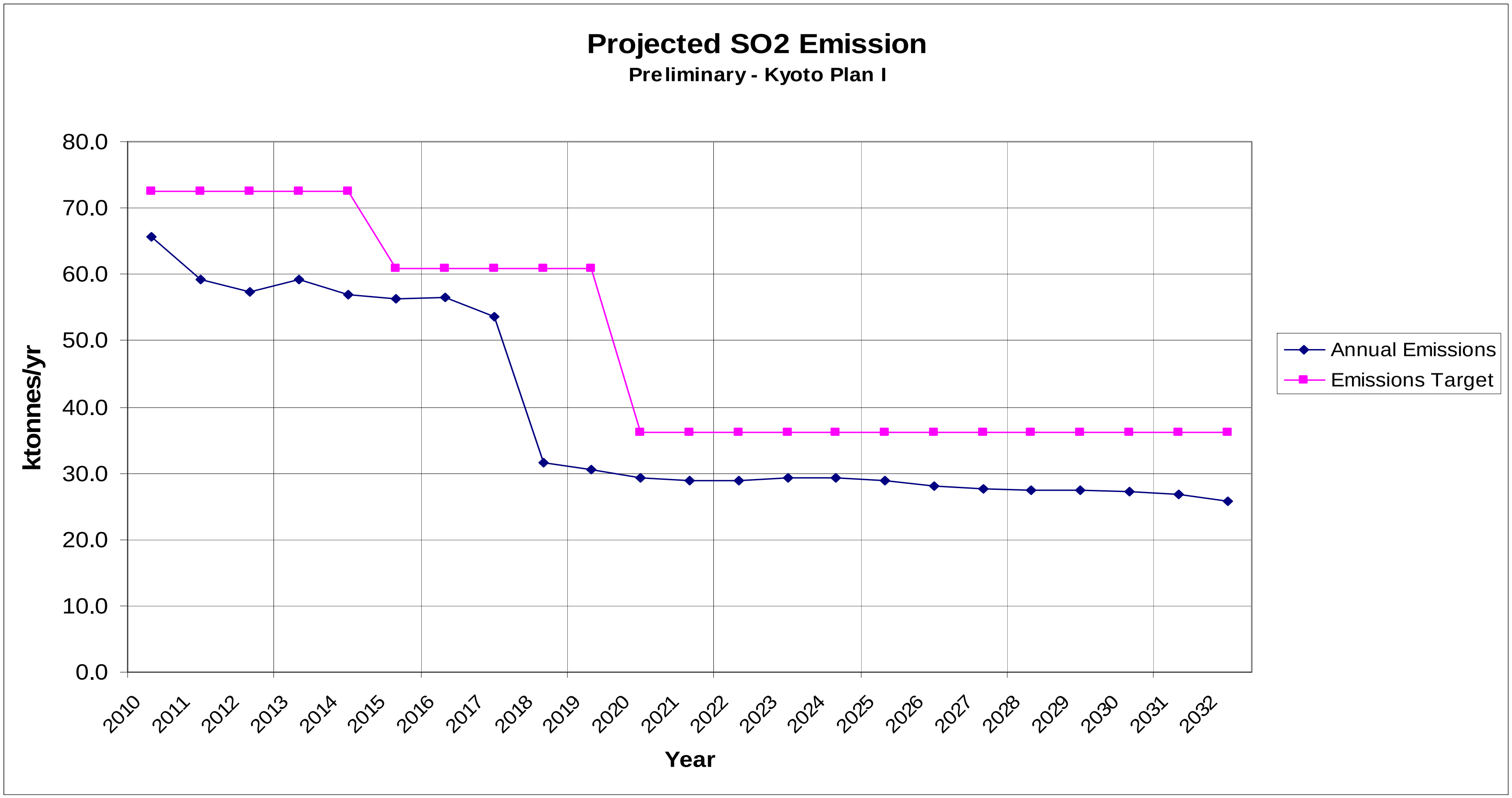
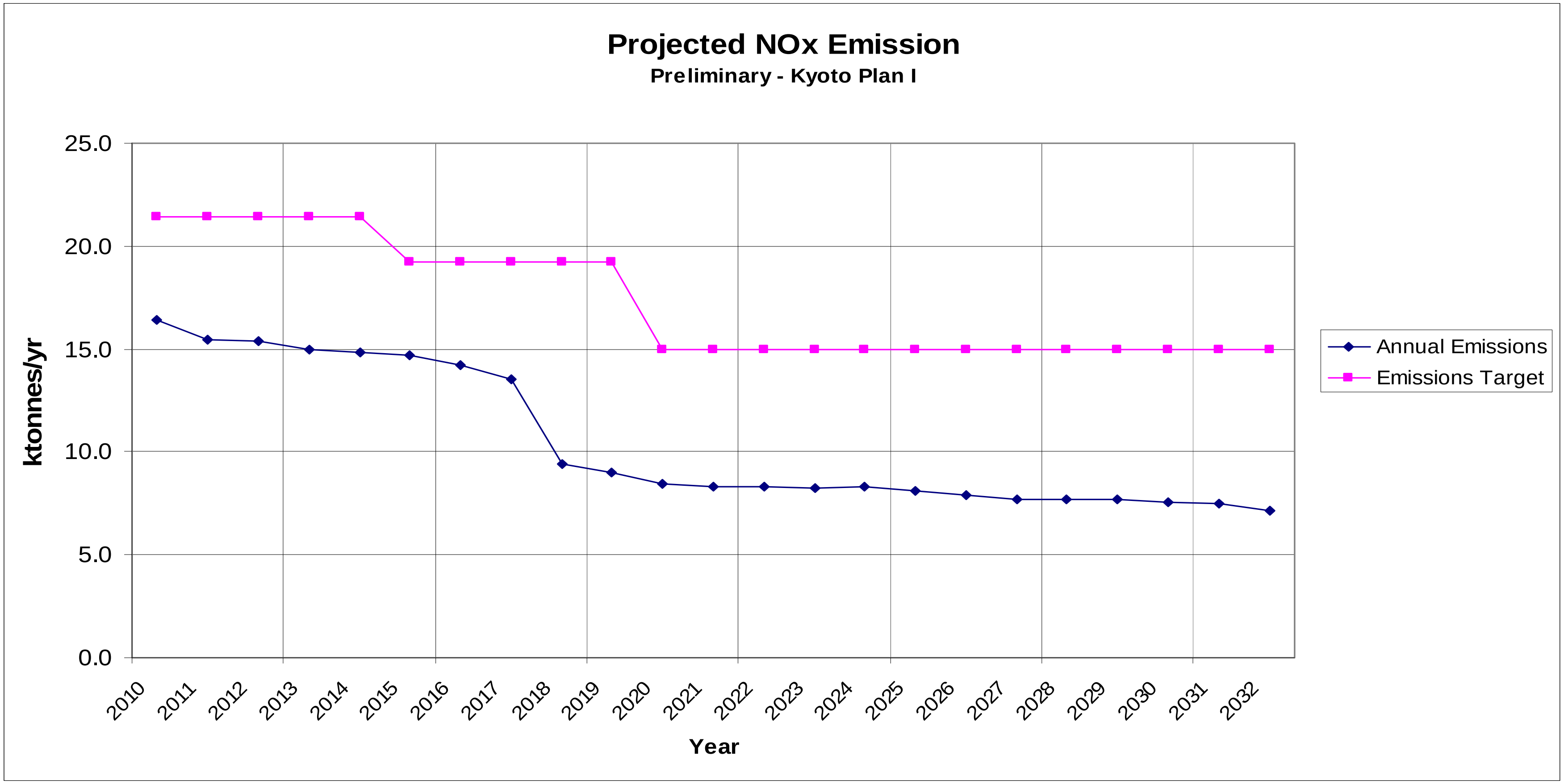
2009 IRP Update
Modeling / Analysis Results

Emissions Graphs Plan I



2009 IRP Update
Modeling / Analysis Results

Emissions Graphs Plan I



NOVA SCOTIA POWER
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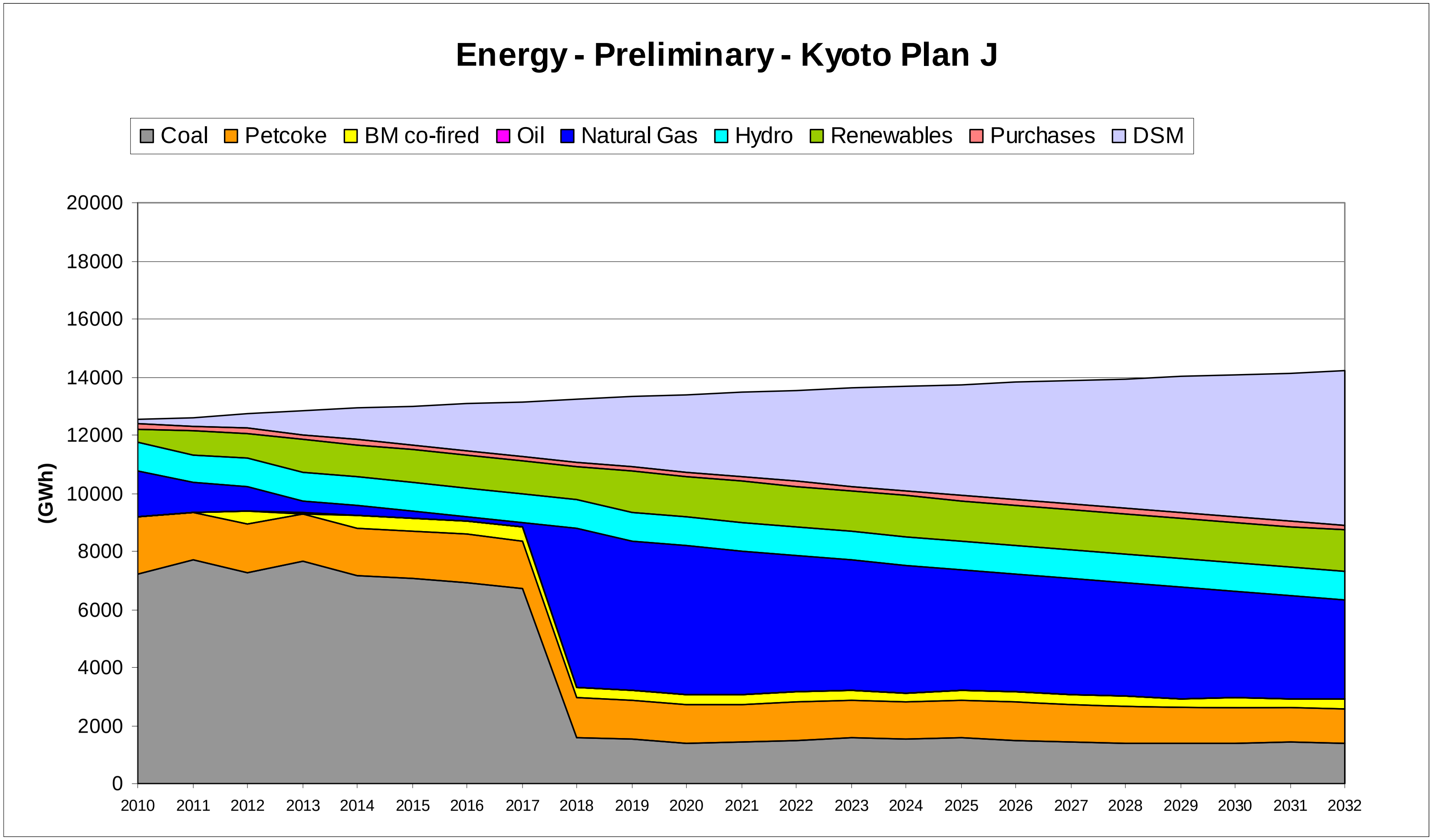
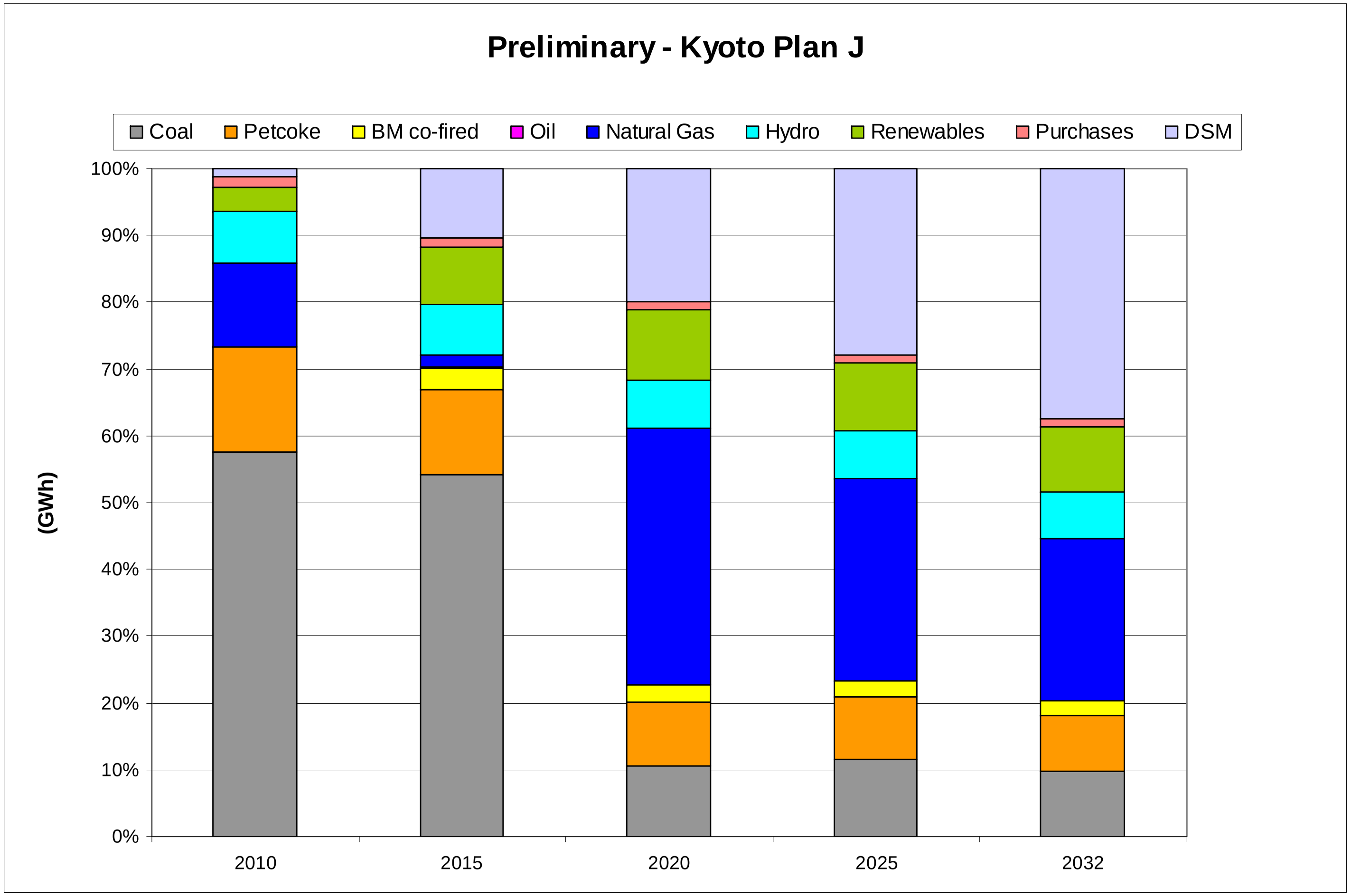
2009 IRP Update
Modeling / Analysis Results



2009 IRP Update
Modeling / Analysis Results



NOVA SCOTIA POWER
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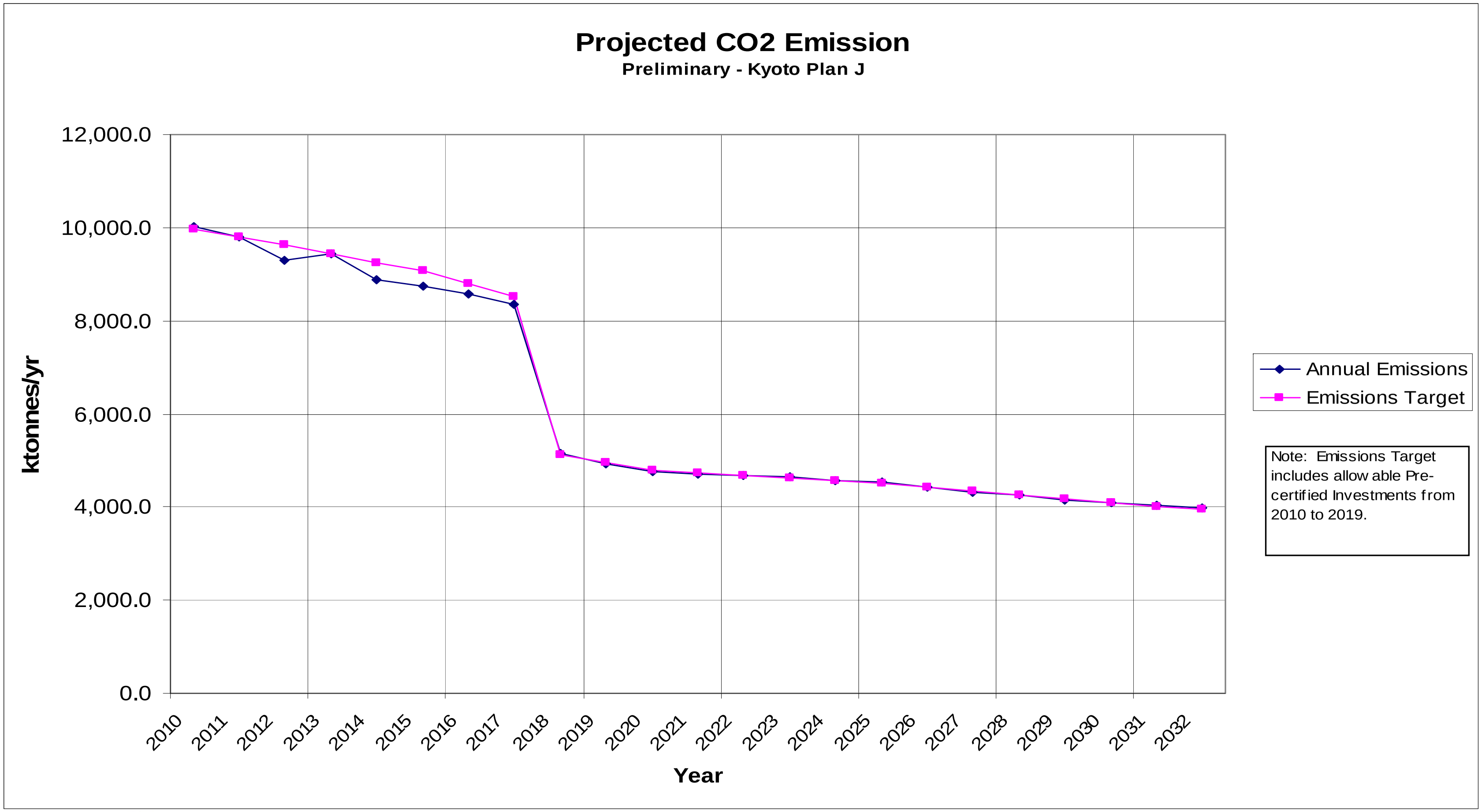
2009 IRP Update
Modeling / Analysis Results

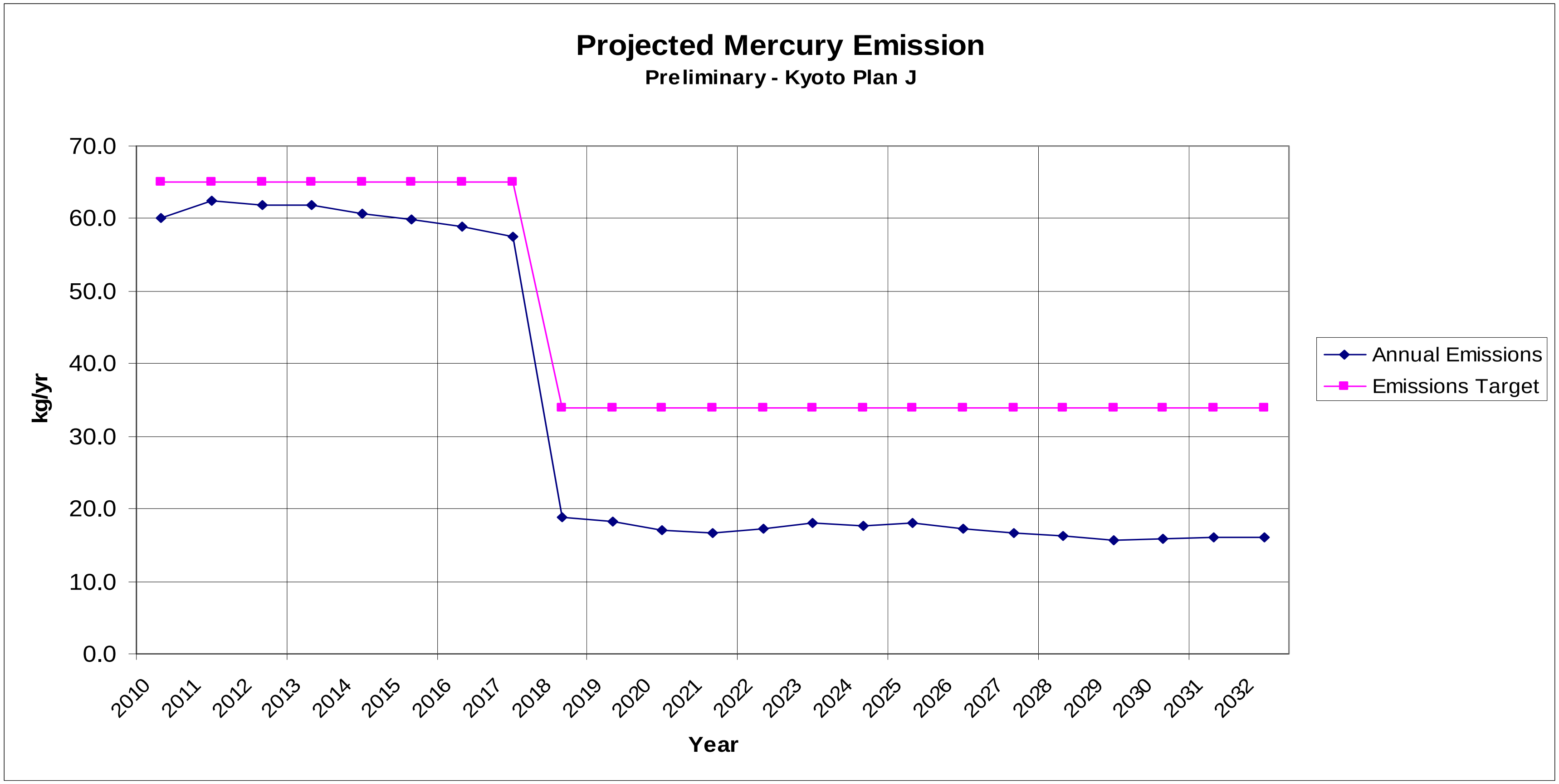
Emissions Graphs Plan J



NOVA SCOTIA POWER
An Emera Company

2009 IRP Update
Modeling / Analysis Results

Emissions Graphs Plan J



NOVA SCOTIA POWER
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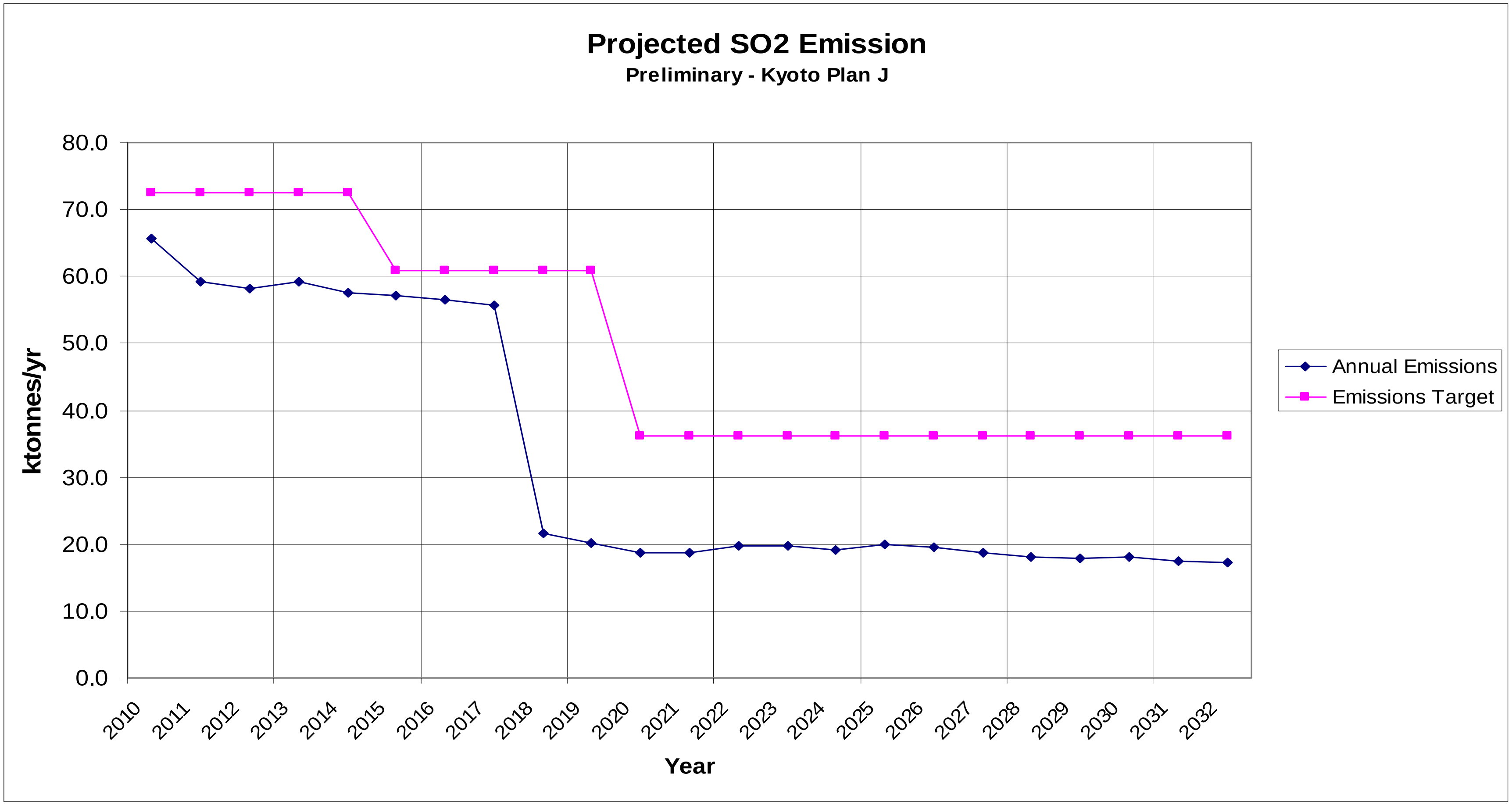
Emissions Graphs Plan J



NOVA SCOTIA POWER
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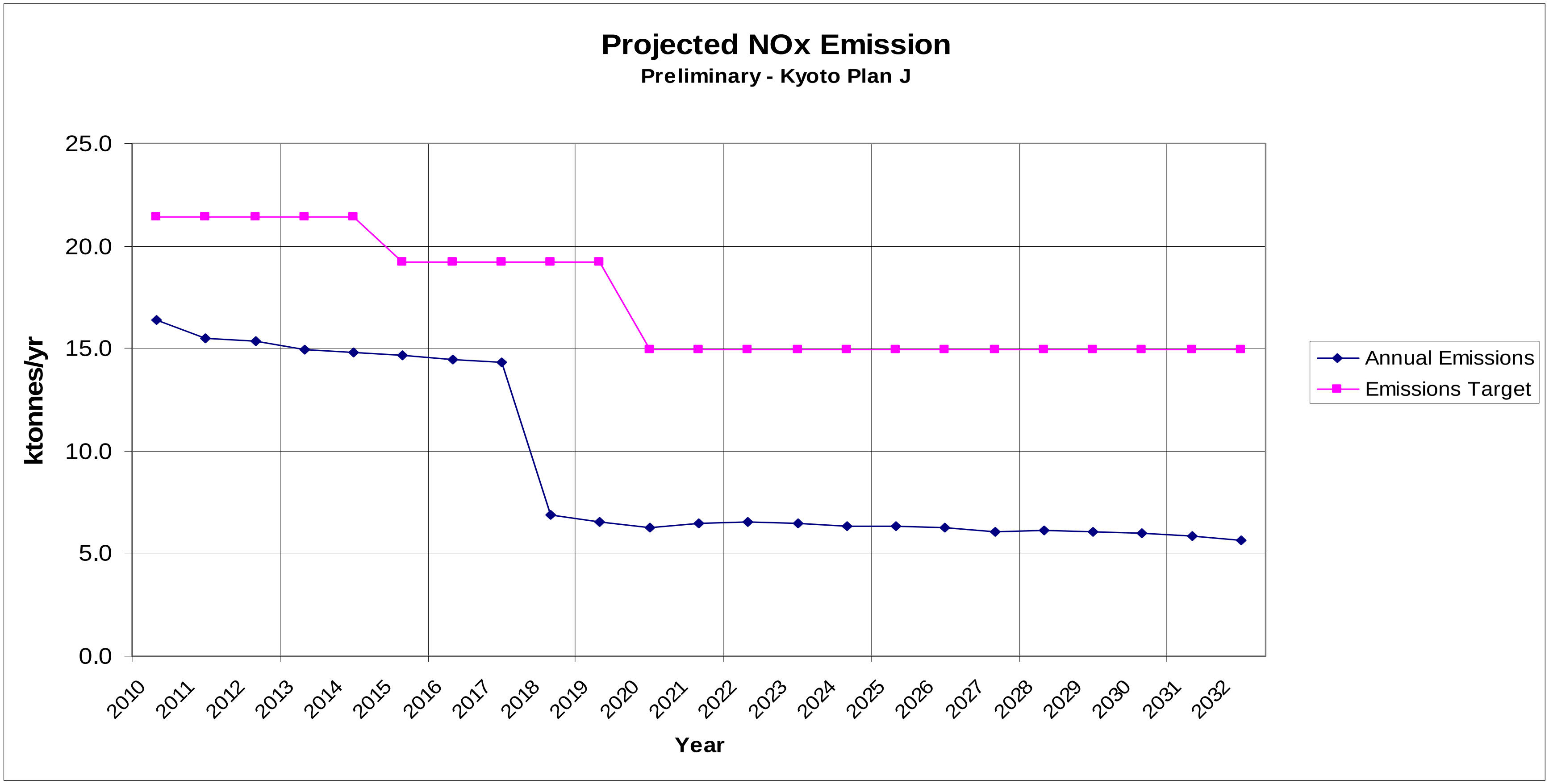
2009 IRP Update
Modeling / Analysis Results

Emissions Graphs Plan J



NOVA SCOTIA POWER
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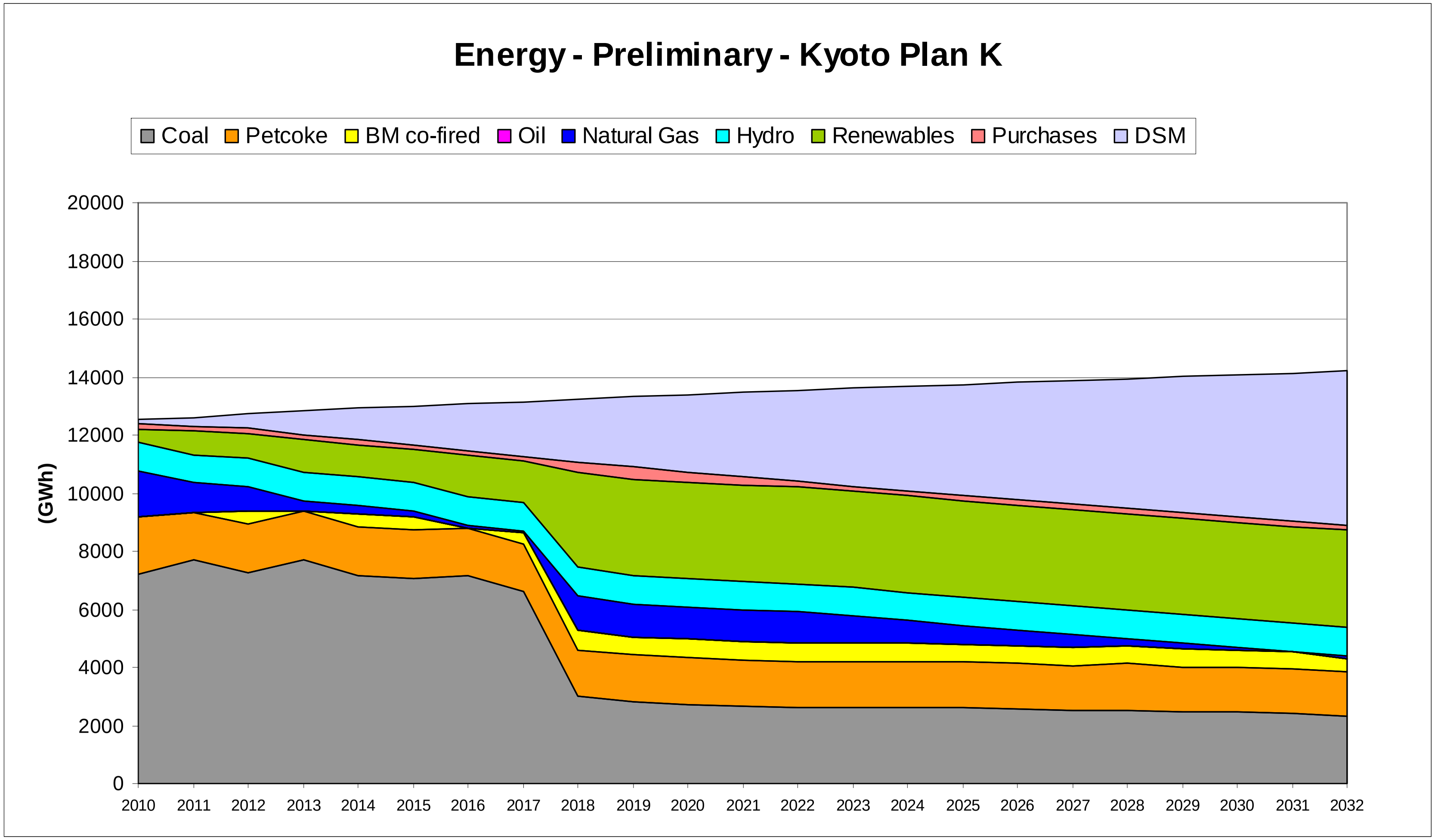
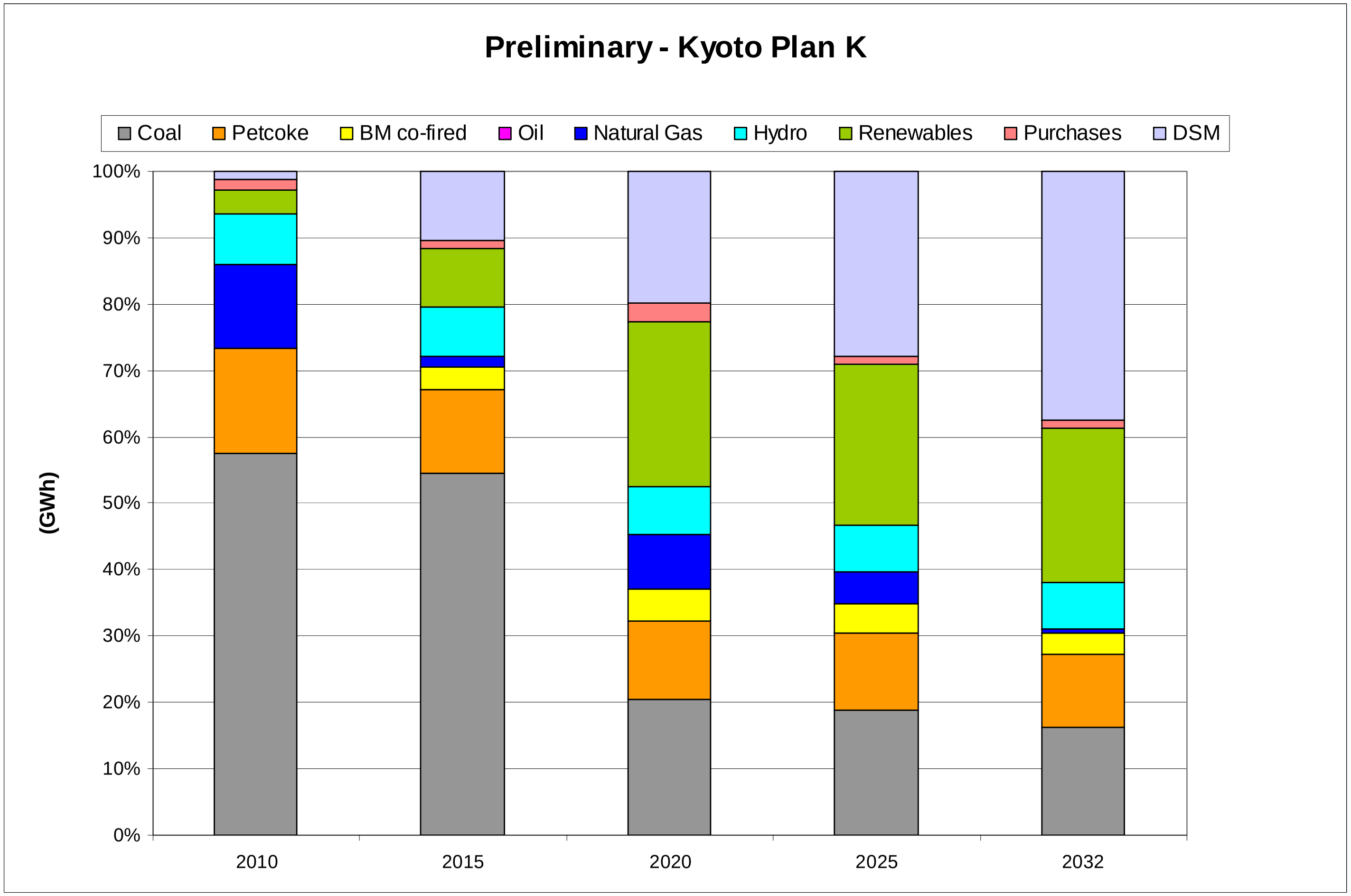
2009 IRP Update
Modeling / Analysis Results



Note: “Renewables” above includes Large Non Emitting PPA (as opposed to “Purchases").

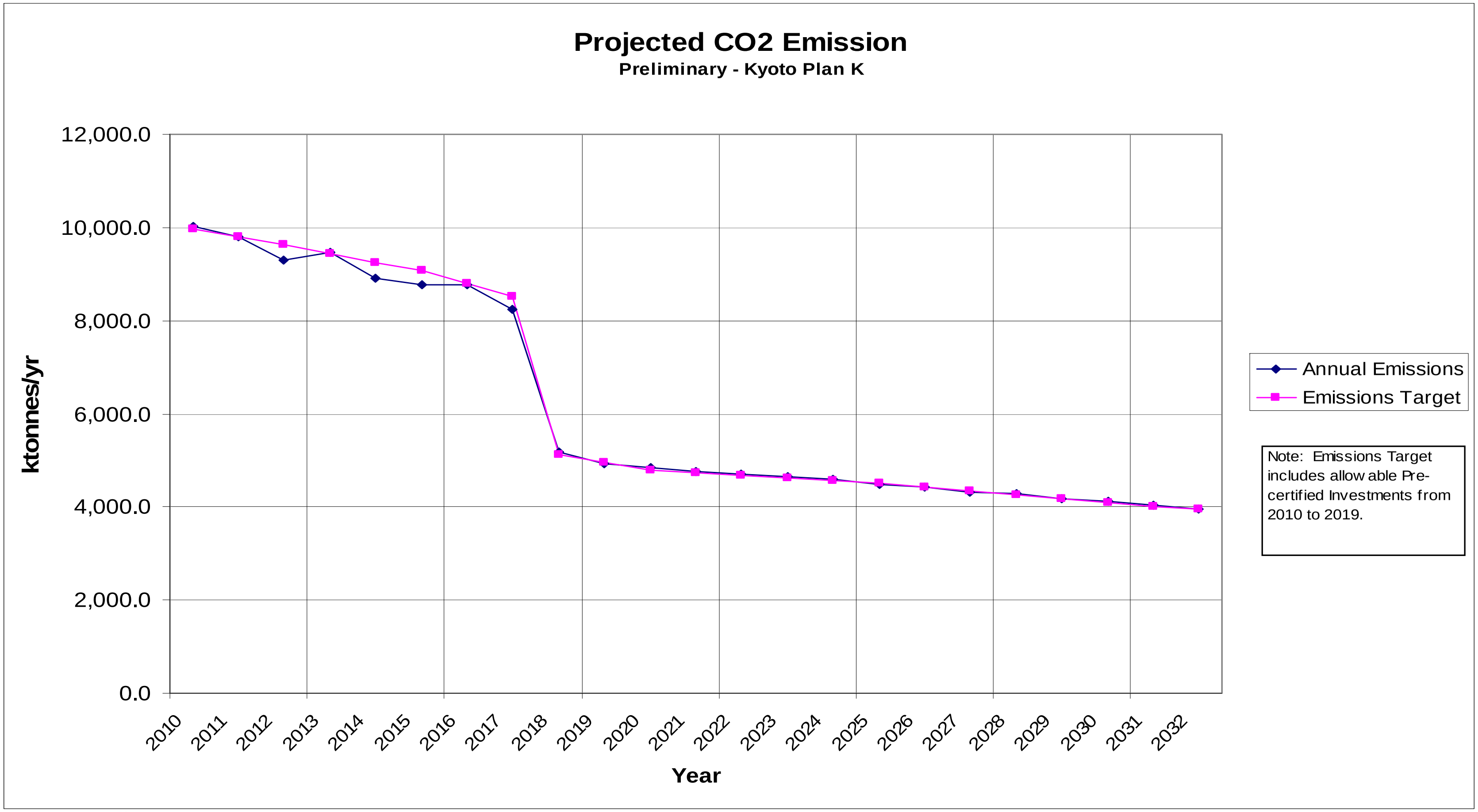
2009 IRP Update
Modeling / Analysis Results



Note: “Renewables” above includes Large Non Emitting PPA (as opposed to “Purchases").

2009 IRP Update
Modeling / Analysis Results

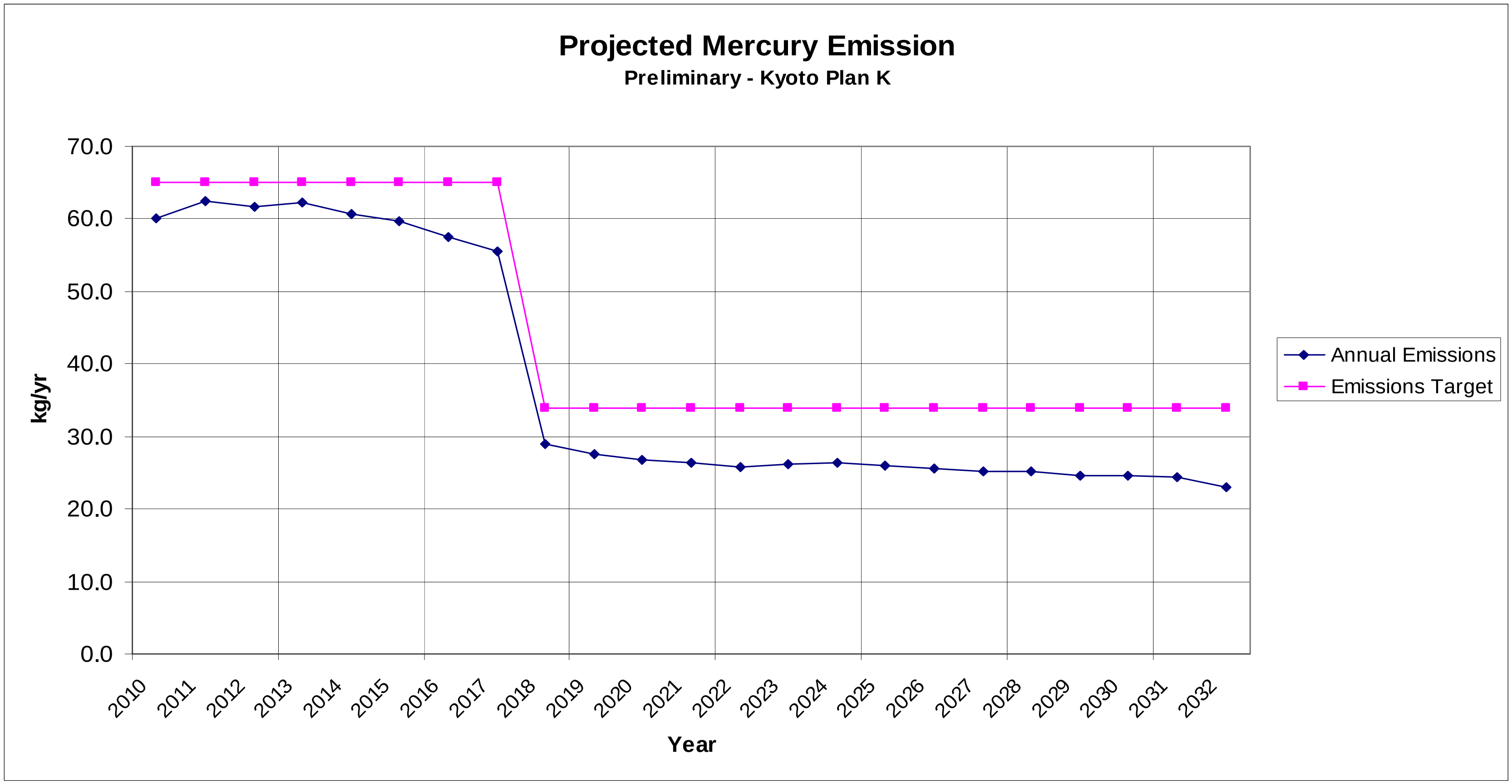
Emissions Graphs Plan K



NOVA SCOTIA POWER An Emera Company

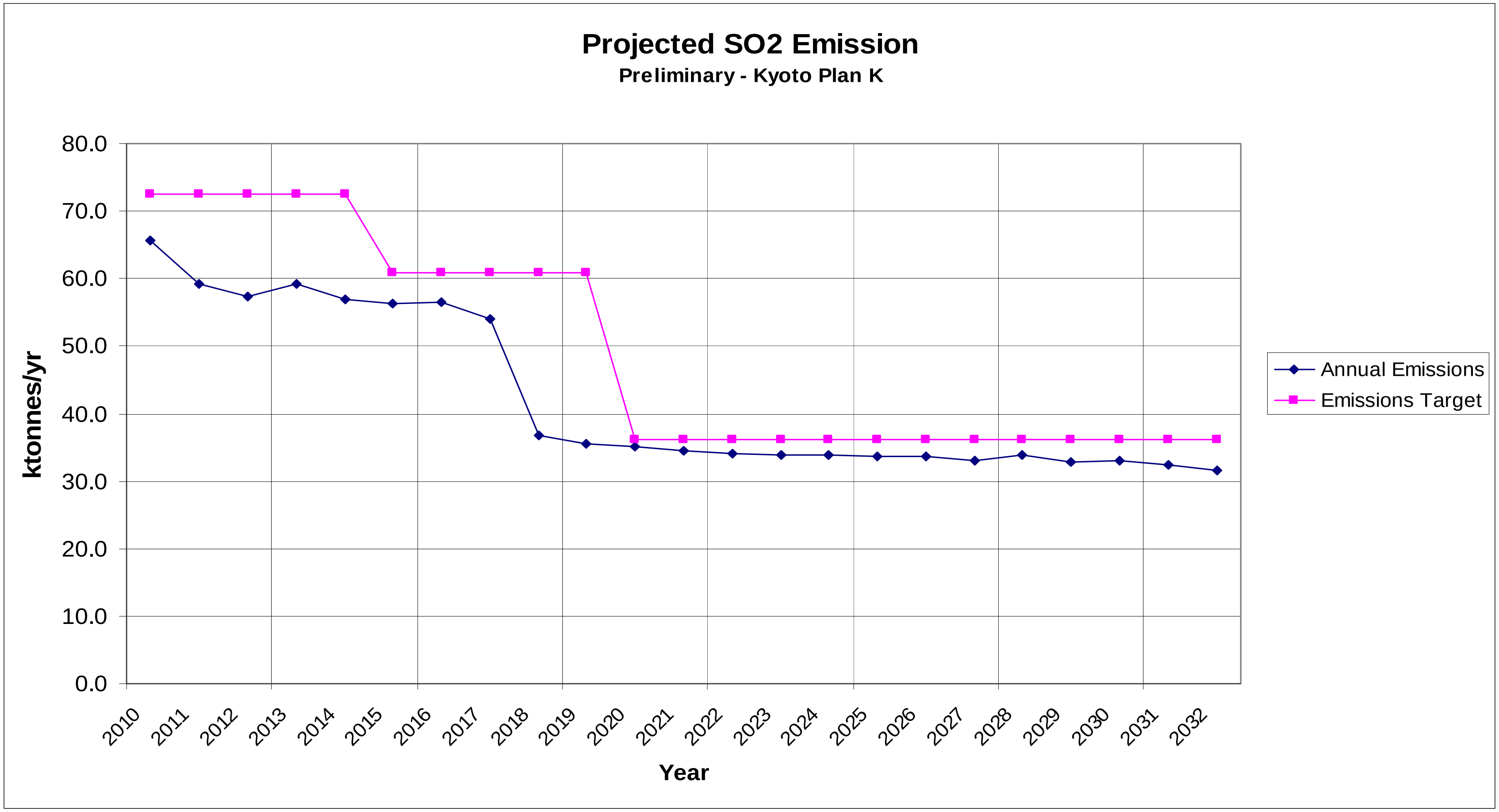
2009 IRP Update
Modeling / Analysis Results

Emissions Graphs Plan K



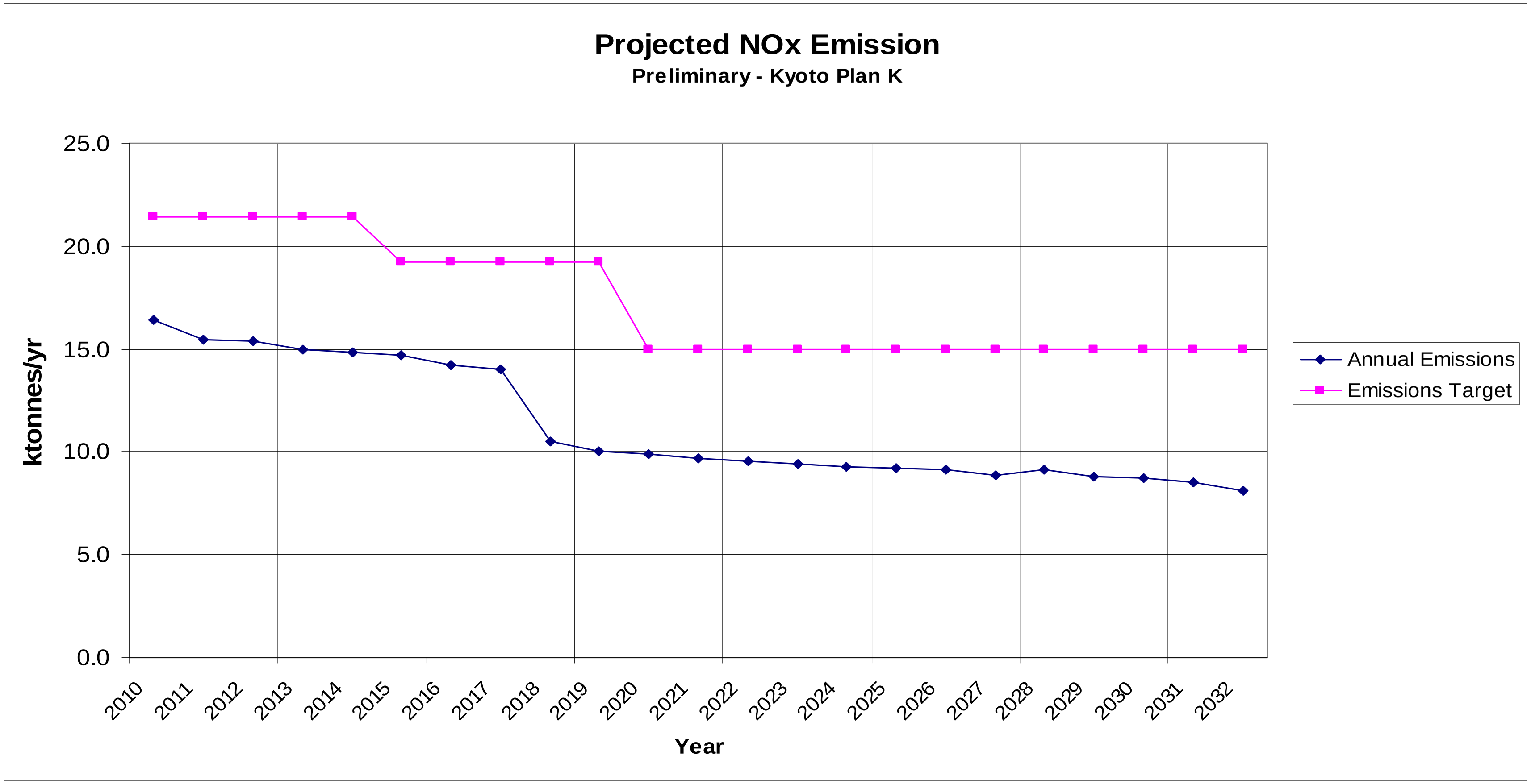
2009 IRP Update
Modeling / Analysis Results

Emissions Graphs Plan K

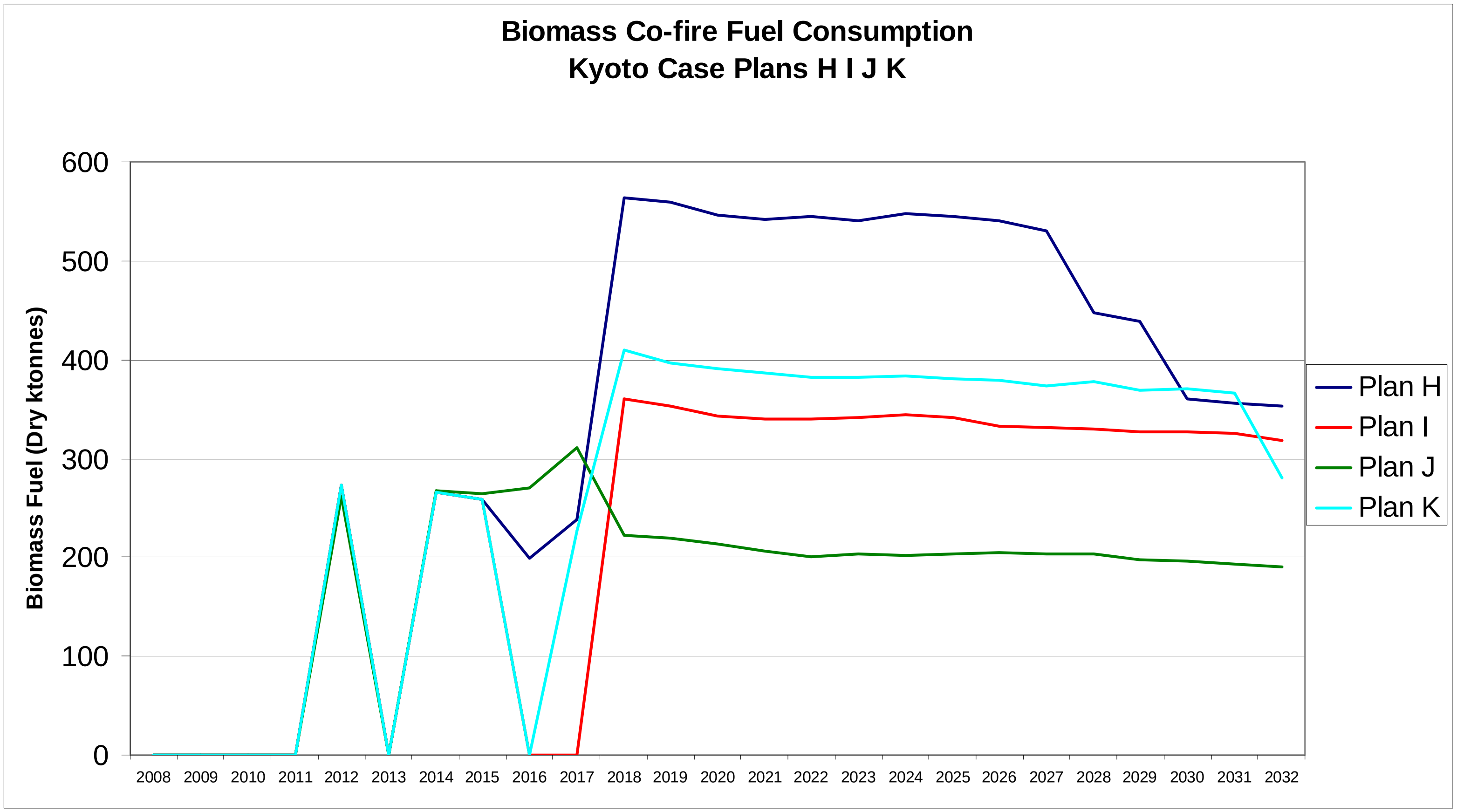


2009 IRP Update
Modeling / Analysis Results

Emissions Graphs Plan K



Tonnes Biomass Plan H, I, J, K



NOVA SCOTIA POWER
An Emera Company

KYOTO PLANS – Estimate of Revenue Requirements

NOVA SCOTIA POWER
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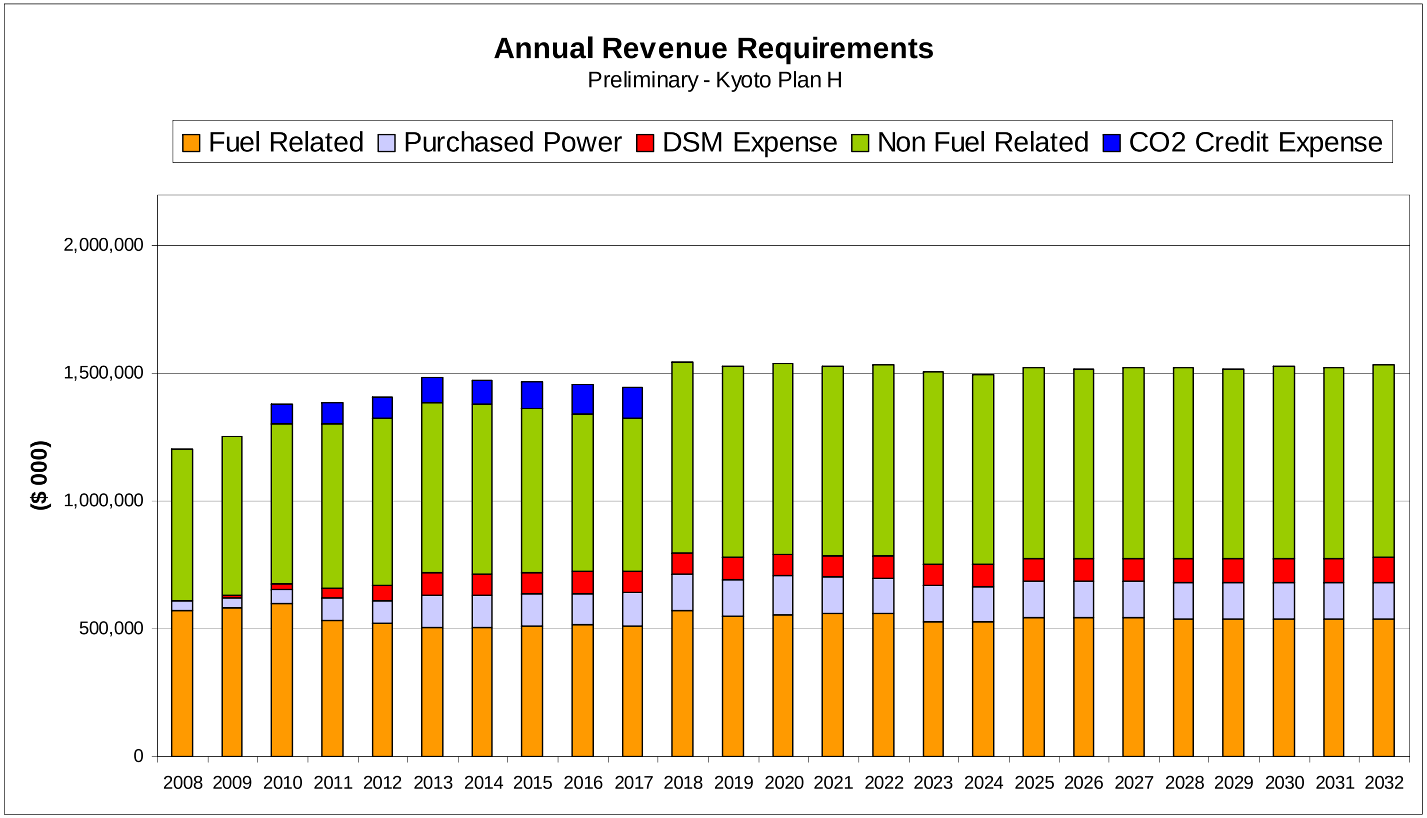
2009 IRP Update
Modeling / Analysis Results

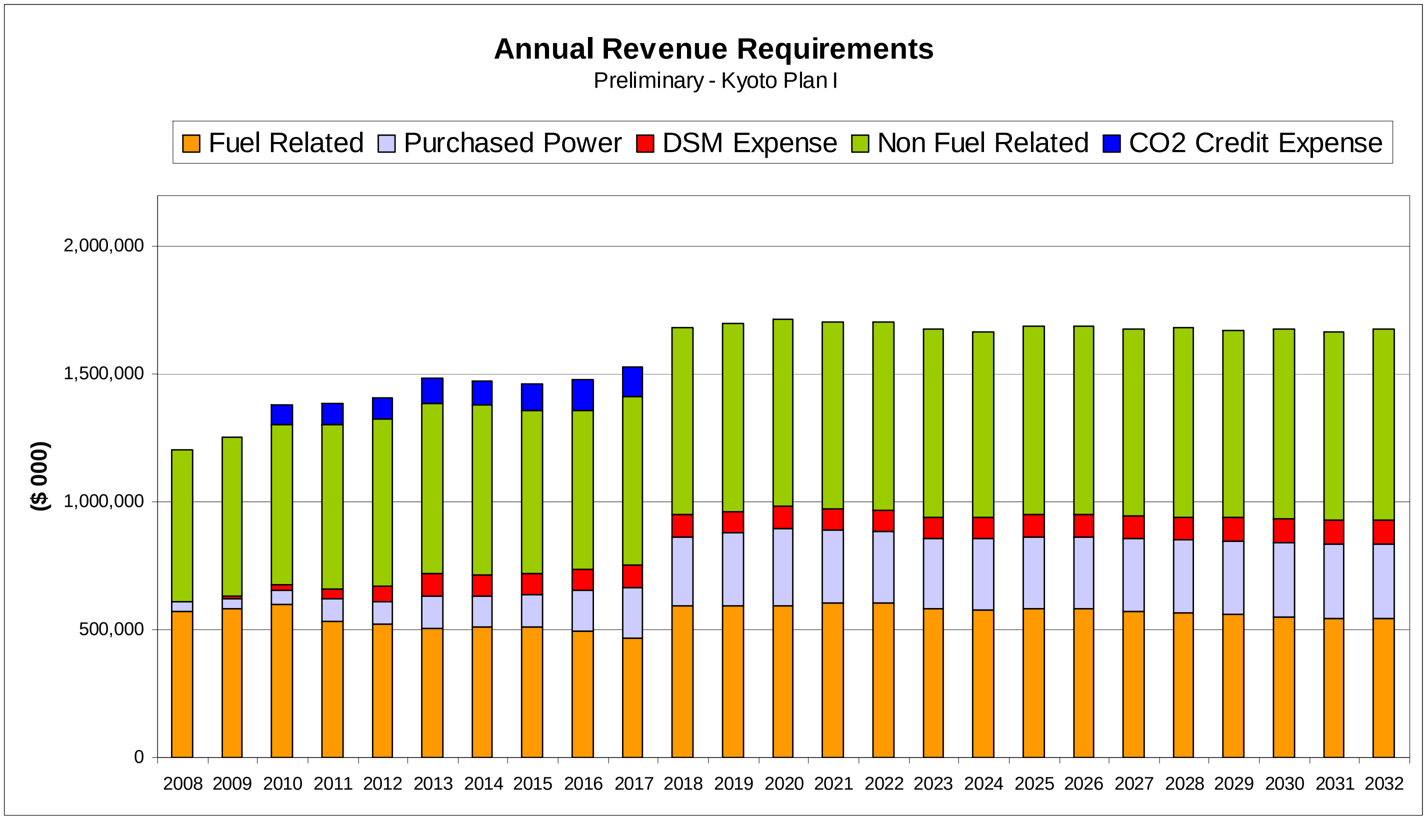
Revenue Requirements Base Plan H



Revenue requirements are illustrative/relative/comparative only. Actual future revenue requirement will be determined per Rate Application test year data.

2009 IRP Update
Modeling / Analysis Results

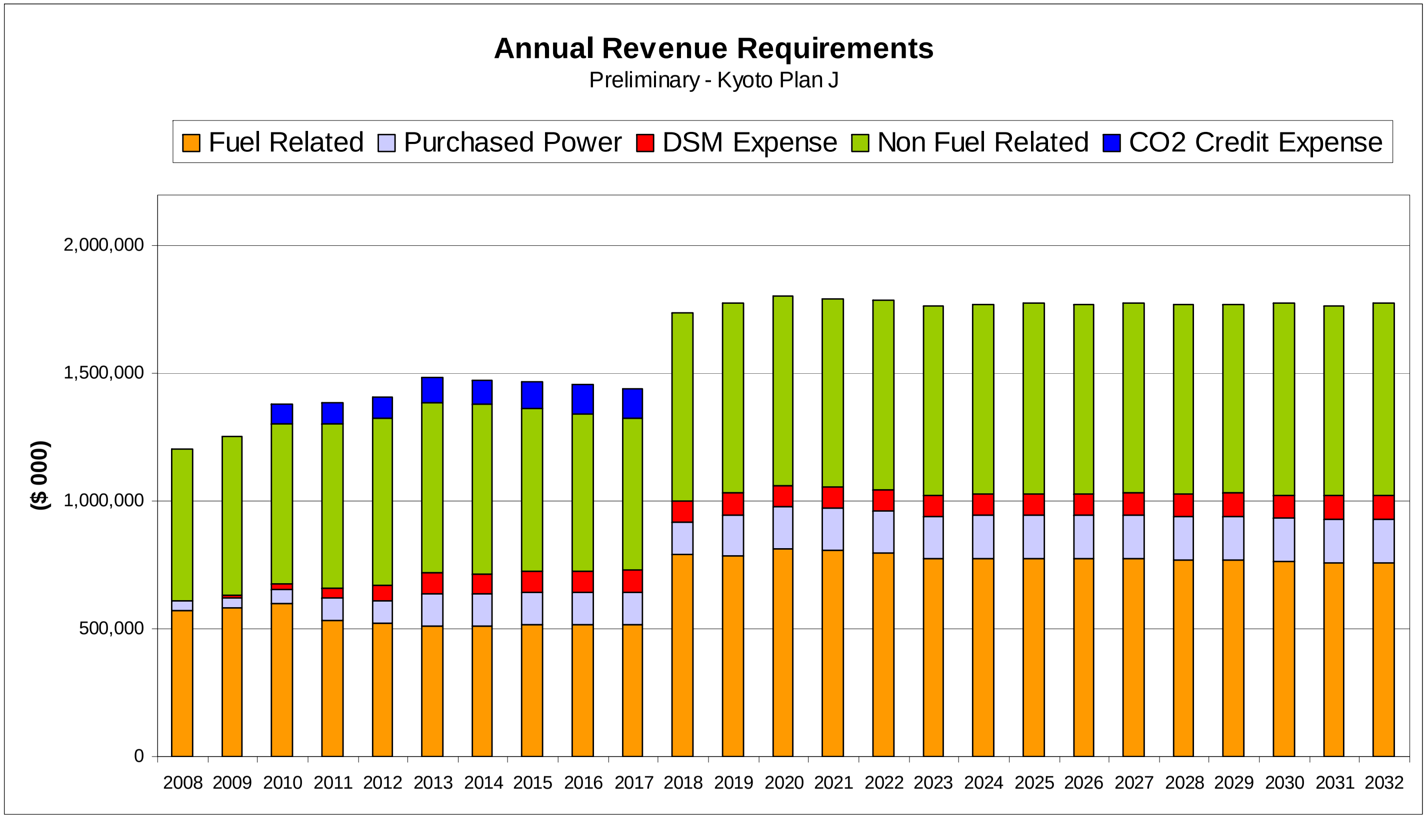
Revenue Requirements Base Plan I



Revenue requirements are illustrative/relative/comparative only. Actual future revenue requirement will be determined per Rate Application test year data.

2009 IRP Update
Modeling / Analysis Results

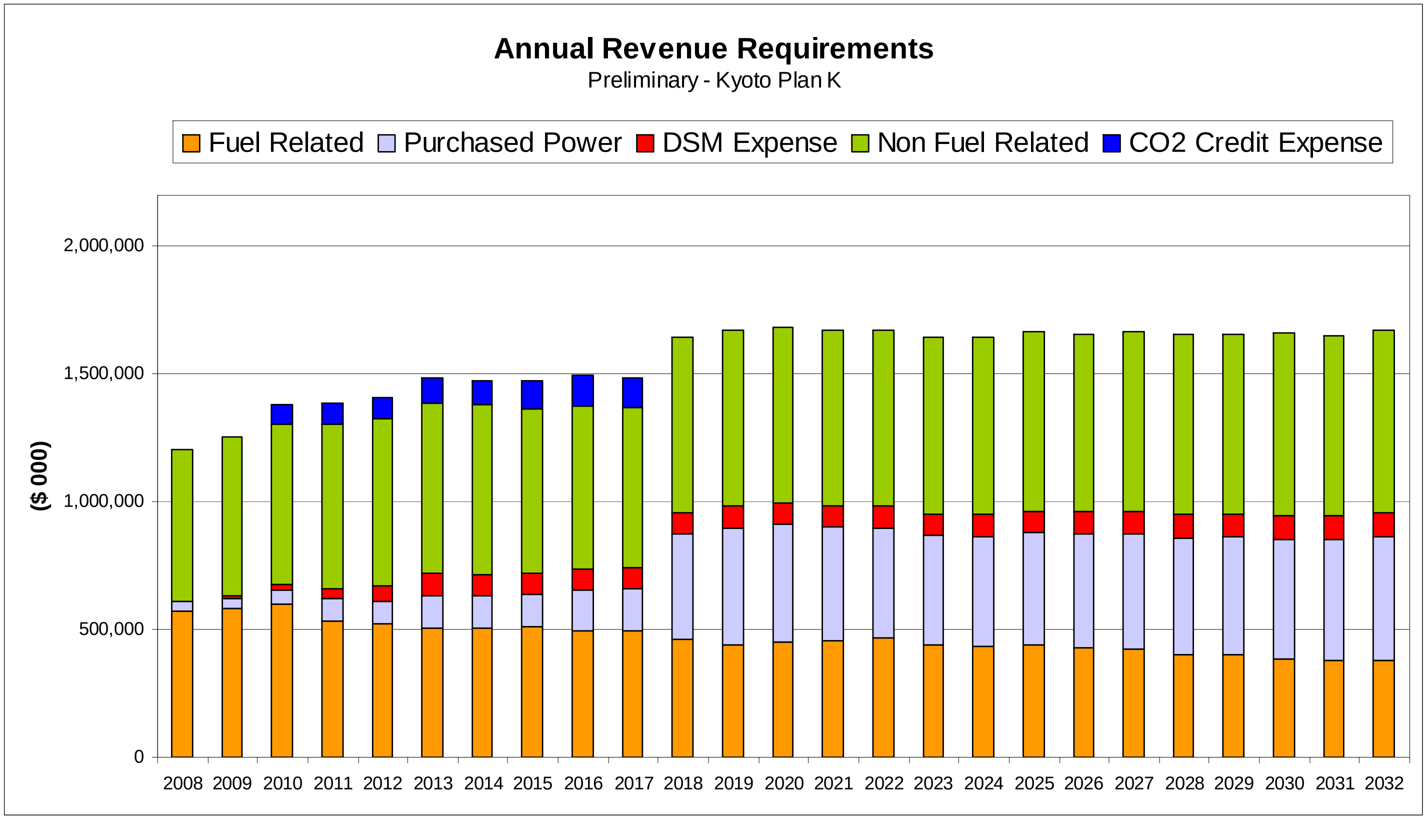
Revenue Requirements Base Plan J



Revenue requirements are illustrative/relative/comparative only. Actual future revenue requirement will be determined per Rate Application test year data.

2009 IRP Update
Modeling / Analysis Results

Revenue Requirements Base Plan K



Revenue requirements are illustrative/relative/comparative only. Actual future revenue requirement will be determined per Rate Application test year data.

APPENDIX F

Sensitivity Results

NOVA SCOTIA POWER
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Sensitivity Tests

- Low and High Coal Price
- Low Gas Price
- High Biomass Price
- High Carbon Capture and Storage Capital Cost

Low and High Coal Price

- No changes in Plans' rank orders
- NPVs over study period shift lower or higher

Low Coal		Original Study NPV (M$)	Rank	Low Coal Study NPV (M$)	Rank	Difference
Base	Plan A	$13,335	1	$12,171	1	-$1,163
	Plan B	$13,710	2	$12,504	2	-$1,206
	Plan C	$14,100	3	$13,040	3	-$1,060
High Load	Plan D	$16,296	1	$14,886	1	-$1,410
	Plan E	$16,703	2	$15,530	2	-$1,173
	Plan F	$17,068	3	$15,891	3	-$1,177
	Plan G	$17,188	4	$16,087	4	-$1,101
Kyoto	Plan H	$14,665	1	$13,469	1	-$1,195
	Plan I	$16,034	3	$15,192	3	-$843
	Plan J	$16,902	4	$16,186	4	-$715
	Plan K	$15,879	2	$14,968	2	-$911

High Coal		Original Study NPV (M$)	Rank	High Coal Study NPV (M$)	Rank	Difference
Base	Plan A	$13,335	1	$15,227	1	$1,892
Base	Plan B	$13,710	2	$15,432	2	$1,722
Base	Plan C	$14,100	3	$15,870	3	$1,770
High	Plan D	$16,296	1	$18,246	1	$1,950
High	Plan E	$16,703	2	$18,611	2	$1,908
High	Plan F	$17,068	3	$18,707	3	$1,639
High	Plan G	$17,188	4	$18,718	4	$1,530
Kyoto	Plan H	$14,665	1	$16,390	1	$1,726
Kyoto	Plan I	$16,034	3	$17,158	3	$1,123
Kyoto	Plan J	$16,902	4	$17,957	4	$1,055
Kyoto	Plan K	$15,879	2	$17,149	2	$1,269

Nova Scotia Power
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Low Gas Price

Plans with more natural gas get close to lowest cost in Base and High Load Worlds. Become lowest cost in Kyoto Plan J (mostly gas plan)

Low Gas		Original Study NPV (M$)	Rank	Low Gas Study NPV (M$)	Rank	Difference
Base	Plan A	$13,335	1	$12,945	1	-$390
Base	Plan B	$13,710	2	$13,325	3	-$385
Base	Plan C	$14,100	3	$13,208	2	-$892
High	Plan D	$16,296	1	$15,607	1	-$689
High	Plan E	$16,703	2	$15,948	3	-$755
High	Plan F	$17,068	3	$16,577	4	-$491
High	Plan G	$17,188	4	$15,634	2	-$1,554
Kyoto	Plan H	$14,665	1	$14,203	2	-$461
Kyoto	Plan I	$16,034	3	$14,438	3	-$1,597
Kyoto	Plan J	$16,902	4	$14,034	1	-$2,868
Kyoto	Plan K	$15,879	2	$15,236	4	-$644

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High Biomass Price

- No changes in Plans' rank orders

High Biomass		Original Study NPV (M$)	Rank	High Biomass Study NPV (M$)	Rank	Difference
Base	Plan A	$13,335	1	$13,670	1	$335
Base	Plan B	$13,710	2	$13,822	2	$112
Base	Plan C	$14,100	3	$14,382	3	$282
High	Plan D	$16,296	1	$16,650	1	$354
High	Plan E	$16,703	2	$17,175	2	$472
High	Plan F	$17,068	3	$17,374	3	$306
High	Plan G	$17,188	4	$17,633	4	$445
Kyoto	Plan H	$14,665	1	$14,943	1	$279
Kyoto	Plan I	$16,034	3	$16,333	3	$299
Kyoto	Plan J	$16,902	4	$17,172	4	$270
Kyoto	Plan K	$15,879	2	$16,116	2	$236

NOVA SCOTIA POWER
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2009 IRP Update
Modeling / Analysis Results

High Carbon Capture and Storage Capital Cost

- Only appears in High Load and Kyoto World - two plans with CCS Plan D and Plan H
- No change in rank order
- However, general uncertainty remains with this technology in terms of cost, feasibility of transportation and long-term storage

High Capital (CCS)		Original Study NPV (M$)	Rank	High Capital Study NPV (M$)	Rank	Difference
Base	Plan A	$13,335	1	$13,335	1	N/A
Base	Plan B	$13,710	2	$13,710	2	N/A
Base	Plan C	$14,100	3	$14,100	3	$0
High	**Plan D**	**$16,296**	**1**	**$16,473**	**1**	**$177**
High	Plan E	$16,703	2	$16,703	2	N/A
High	Plan F	$17,068	3	$17,068	3	$0
High	Plan G	$17,188	4	$17,188	4	N/A
Kyoto	**Plan H**	**$14,665**	**1**	**$14,890**	**1**	**$225**
Kyoto	Plan I	$16,034	3	$16,034	3	N/A
Kyoto	Plan J	$16,902	4	$16,902	4	N/A
Kyoto	Plan K	$15,879	2	$15,879	2	N/A

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Resource Plans - 2009 IRP Update - Kyoto World

Year	NSR (GWh)	Plan H CCS	Plan I Renewables/Gas Combo	Plan J Mostly Gas	Plan K Large PPA
2010	12,398	TUC 6 (Nov) Activated CI (7 PC units) LS, Low BTU Coal Burn (Lin 1-4/Tup)	TUC 6 (Nov) Activated CI (7 PC units) LS, Low BTU Coal Burn (Lin 1-4/Tup)	TUC 6 (Nov) Activated CI (7 PC units) LS, Low BTU Coal Burn (Lin 1-4/Tup)	TUC 6 (Nov) Activated CI (7 PC units) LS, Low BTU Coal Burn (Lin 1-4/Tup)
2011	12,320	Contract Wind 308MW (100MW Firm) *(Plus transmission and load following requirements)* Marshall Hydro (4.2MW) Nictaux Hydro (2.5 MW)	Contract Wind 308MW (100MW Firm) *(Plus transmission and load following requirements)* Marshall Hydro (4.2MW) Nictaux Hydro (2.5 MW)	Contract Wind 308MW (100MW Firm) *(Plus transmission and load following requirements)* Marshall Hydro (4.2MW) Nictaux Hydro (2.5 MW)	Contract Wind 308MW (100MW Firm) *(Plus transmission and load following requirements)* Marshall Hydro (4.2MW) Nictaux Hydro (2.5 MW)
2012	12,225	Biomass co-fire (4 units)	Biomass co-fire (4 units)	Biomass co-fire (3 units)	Biomass co-fire (4 units)
2013	12,016	Coal uprate +15MW (2 units) *(Plus transmission requirements)* Wind (100MW nameplate,40MW firm) (for RES) *(Plus transmission and load following requirements)*	Coal uprate +15MW (2 units) *(Plus transmission requirements)* Wind (100MW nameplate,40MW firm) (for RES) *(Plus transmission and load following requirements)*	Coal uprate +15MW (1 unit) *(Plus transmission requirements)* Wind (100MW nameplate,40MW firm) (for RES) *(Plus transmission and load following requirements)*	Coal uprate +15MW (2 units) *(Plus transmission requirements)* Wind (100MW nameplate,40MW firm) (for RES) *(Plus transmission and load following requirements)*
2014	11,837				
2015	11,651				
2016	11,449		Wind (100MW nameplate, 40MW firm) *(Plus transmission and load following requirements)*		Wind (100MW nameplate, 40MW firm) *(Plus transmission and load following requirements)*
2017	11,256	Biomass PPA (15MW) *(Plus transmission requirements)*	Wind (100MW nameplate, 40MW firm) *(Plus transmission and load following requirements)* Biomass PPA (15MW) *(Plus transmission requirements)* Biomass PPA (60MW) *(Plus transmission requirements)*		
2018	11,079	Biomass co-fire (4 units) CCS retro-fit -3 units Baghouses (2 units)	Biomass co-fire (4 units) Wind (100MW nameplate, 40MW firm) *(Plus transmission and load following requirements)* Combined Cycle Gas (280MW) *(Plus transmission requirements)*	Combined Cycle Gas (2 x 280MW) *(Plus transmission requirements)*	Biomass co-fire (4 units) Biomass PPA (15MW) *(Plus transmission requirements)* Large non-emitting PPA (300 MW) *(Plus transmission requirements)*
2019	10,909			Wind (100MW nameplate, 40MW firm) *(Plus transmission and load following requirements)*	
2020	10,734				
2021	10,559				
2022	10,398				
2023	10,236				
2024	10,077				
2025	9,913				
2026	9,759				
2027	9,607				
2028	9,457				
2029	9,310				
2030	9,165				
2031	9,023				
2032	8,882				
NPV 2008-32 (M$)		$11,135	$11,996	$12,401	$11,754
Study Period (M$) (includes End Effects)		$14,665	$16,034	$16,902	$15,879

Note: In each year from 2010 to 2018 between 2.8 and 3.6 Mt of CO_2 are abated with credits

Revision: Added note

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Analysis Results
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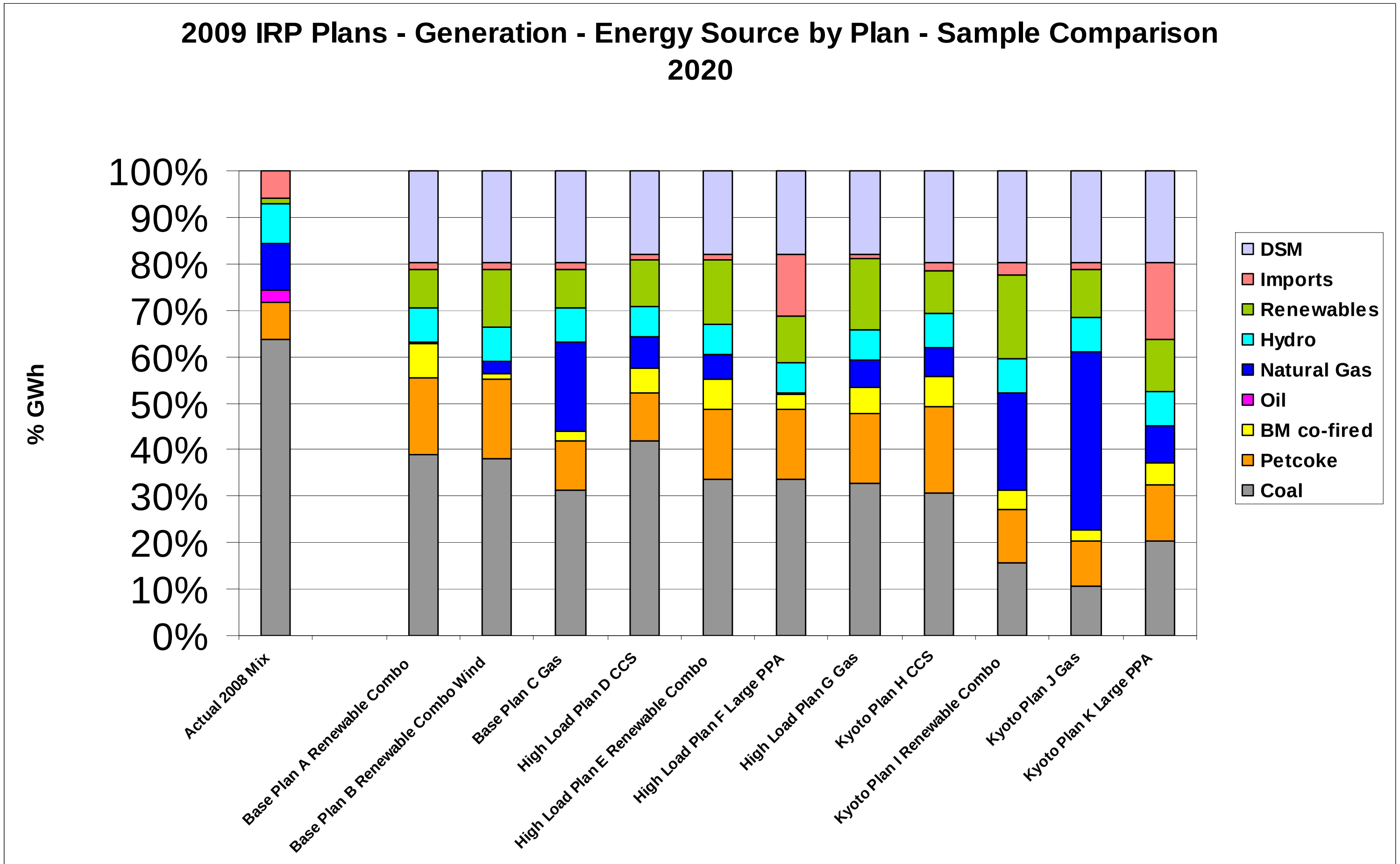

Revision: Moved Large Import from “Renewables” to “Imports”

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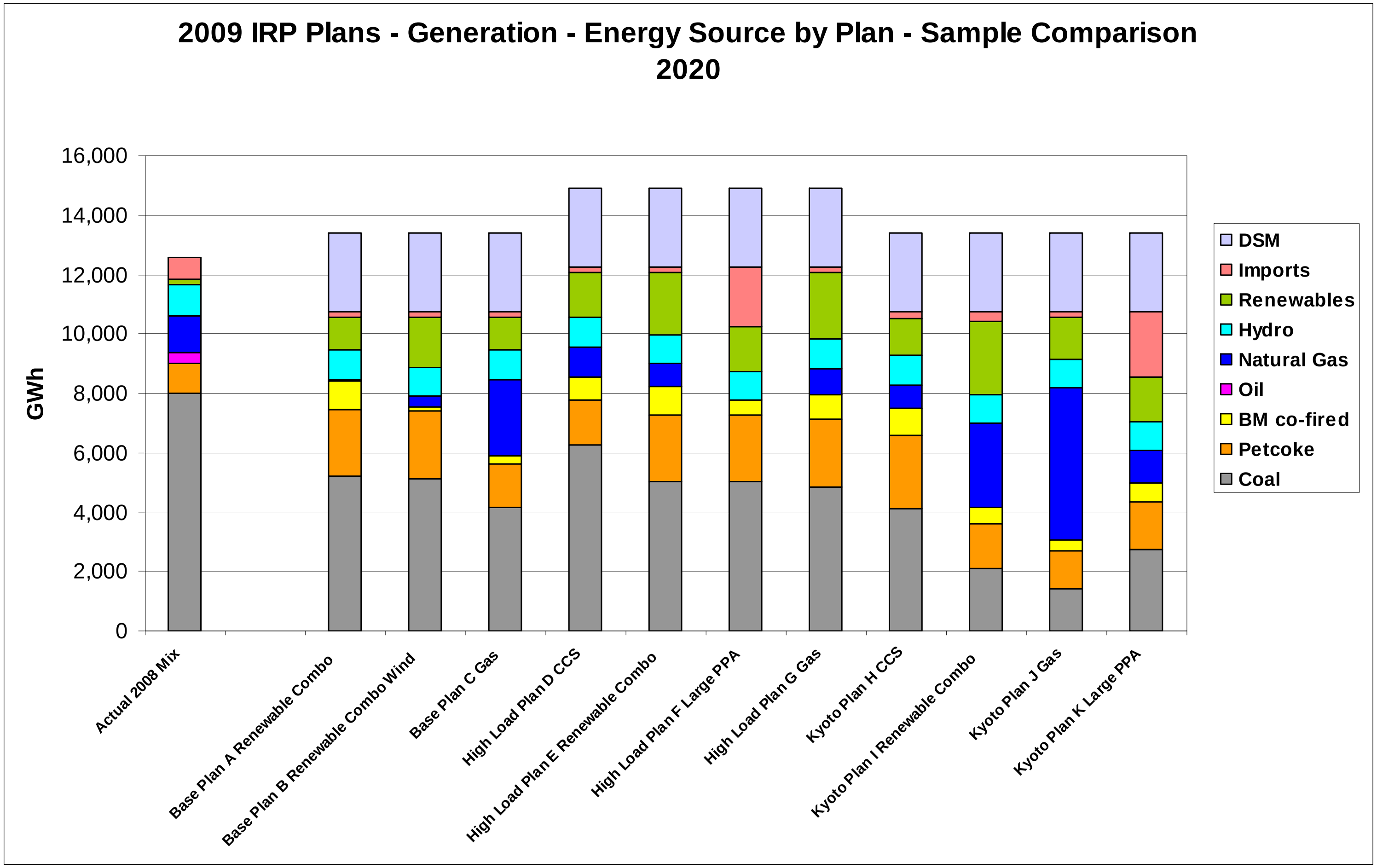
IRP Update
Analysis Results
Revision to Slide 47



Revision: Moved Large Import from “Renewables” to “Imports”

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Sensitivity Results

- Sensitivity Analysis suggests the Renewables Plans under Base and High Load World Assumptions are robust; also true in the Kyoto World
  - It appears Biomass could play a cost-effective role in meeting Provincial renewables requirements in addition to wind and DSM

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Revision: Added reference to Kyoto in first bullet

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Analysis Results
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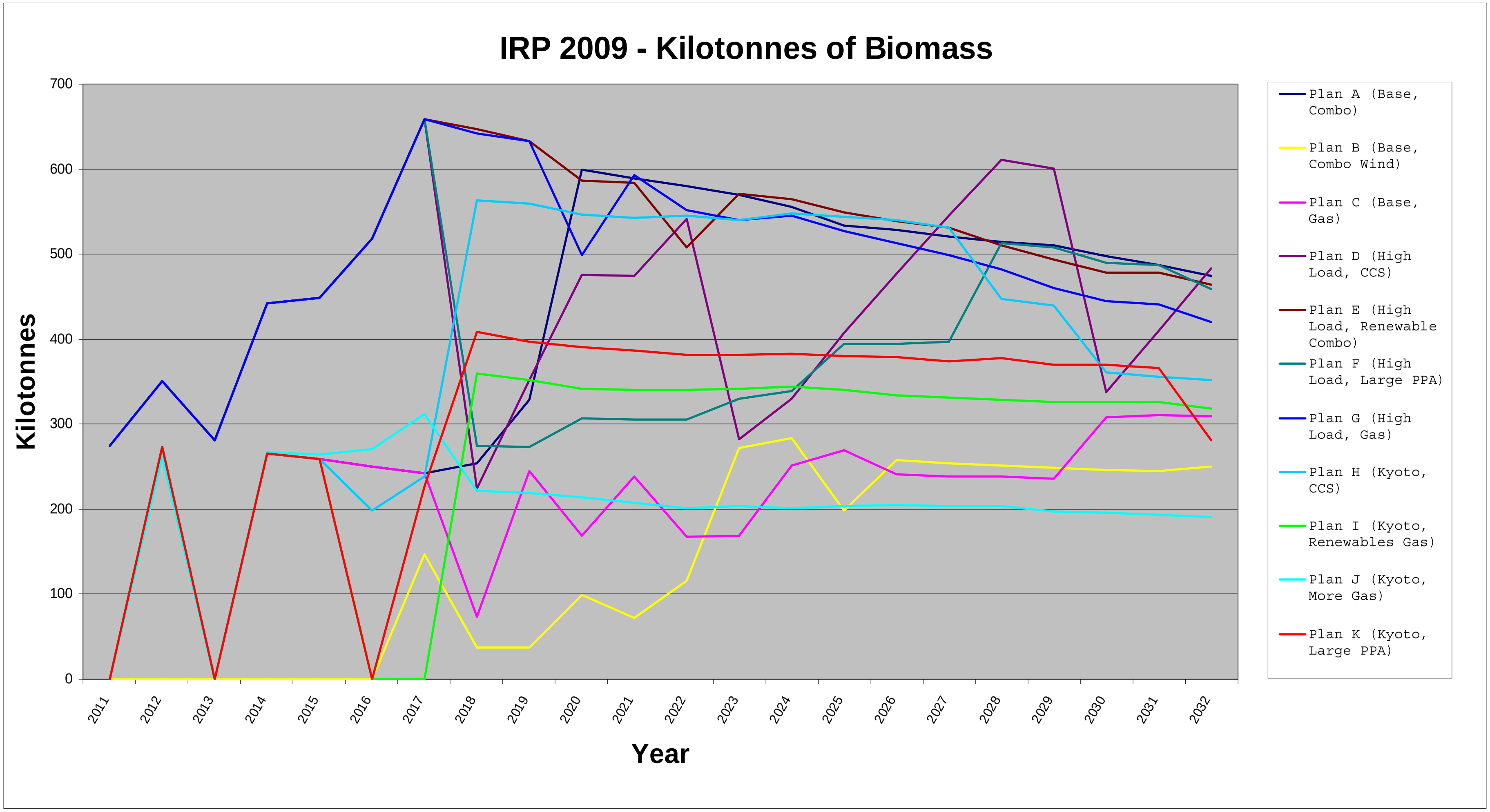

(kilo-tonne = Dry kilo-tonne)

Refers to NSPI co-fire retrofit biomass (biomass PPA not included)

Revision: Added clarification - biomass PPA not included

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Analysis Results
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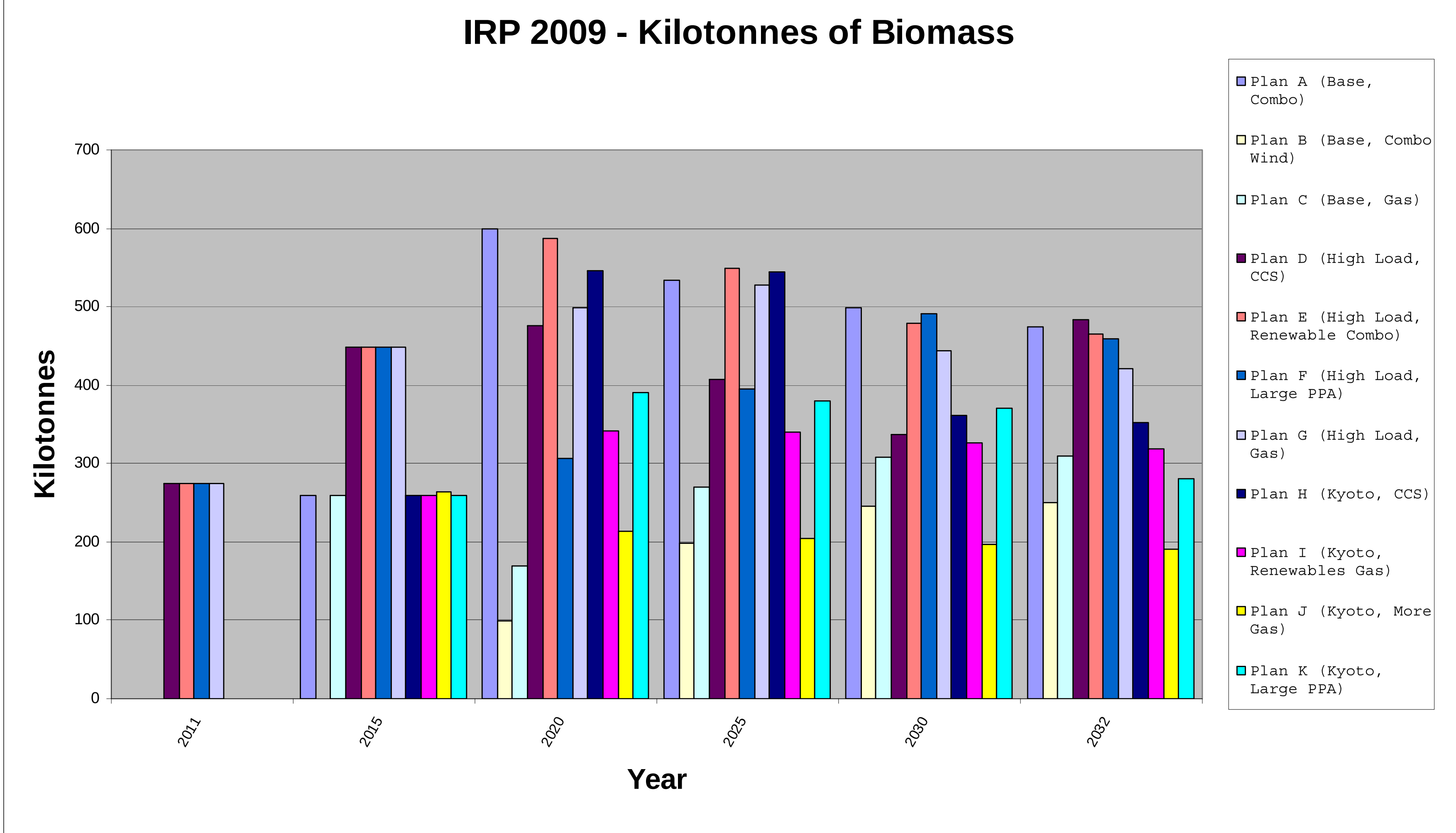

(kilo-tonne = Dry kilo-tonne)

Refers to NSPI co-fire retrofit biomass (biomass PPA not included)

Revision: Added clarification - biomass PPA not included

IRP Update
Analysis Results
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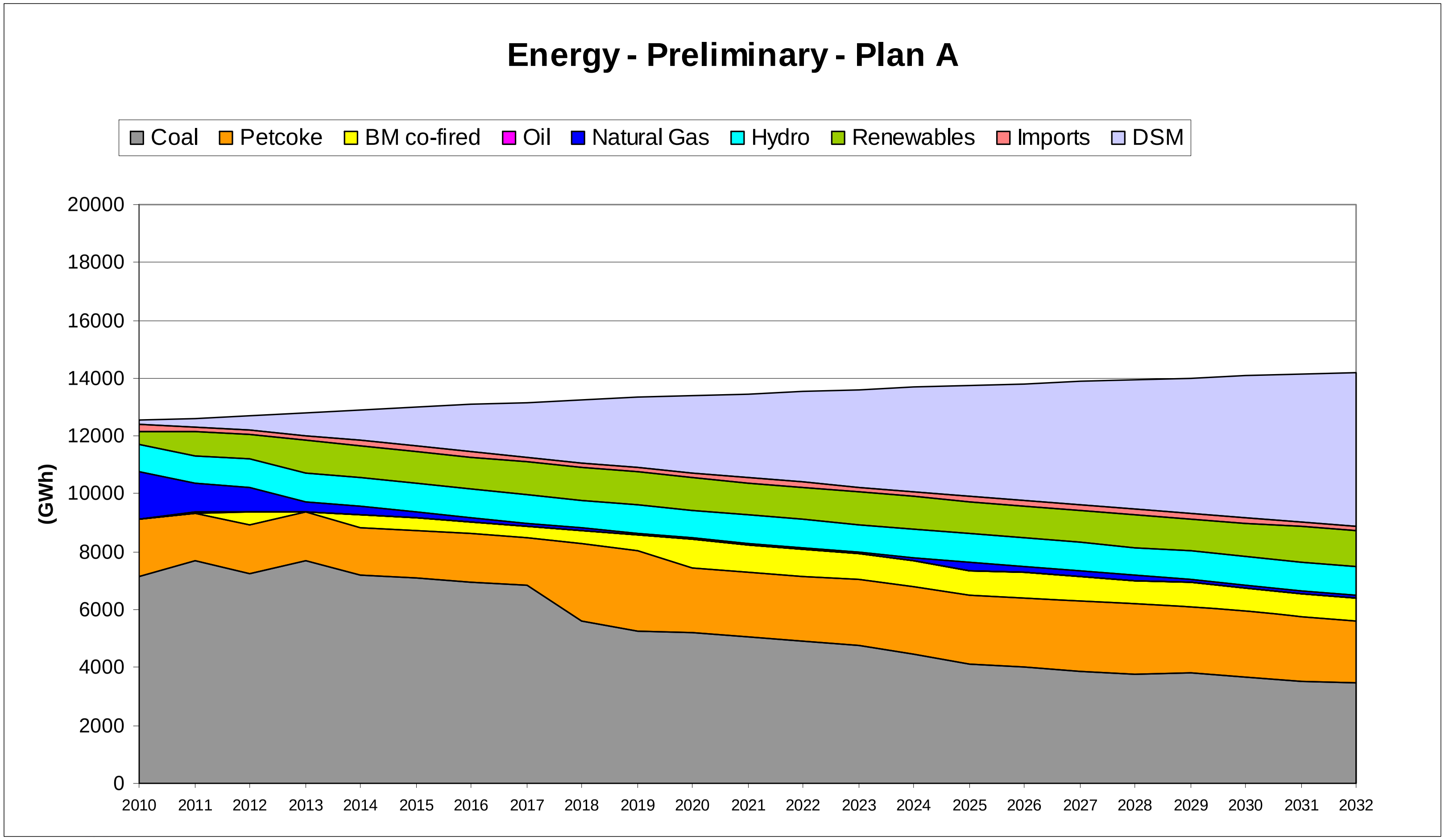

Revision: Changed Category from “Purchases” to “Imports”

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Analysis Results
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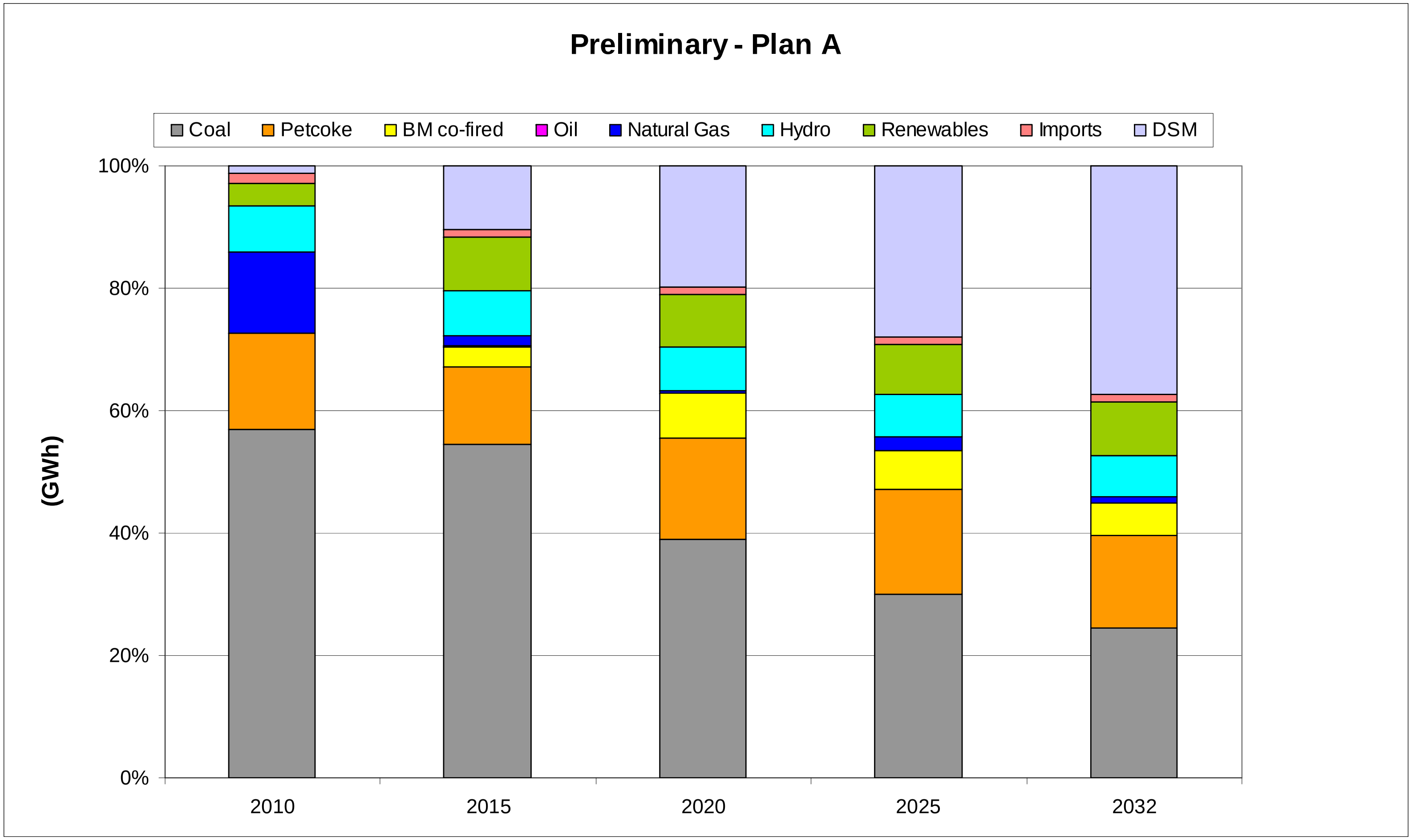

Revision: Changed Category from “Purchases” to “Imports”

NOVA SCOTIA POWER
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IRP Update
Analysis Results
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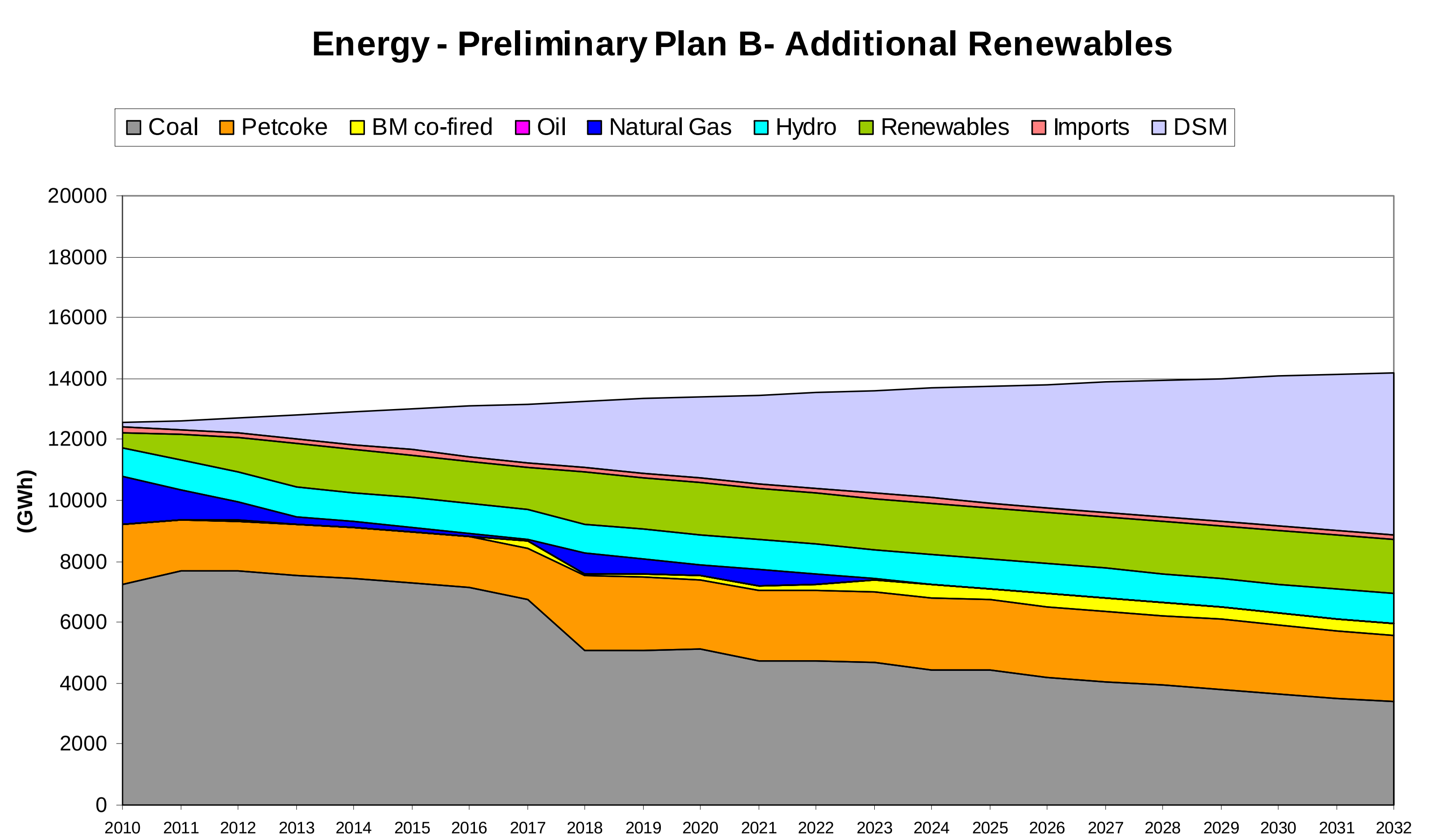
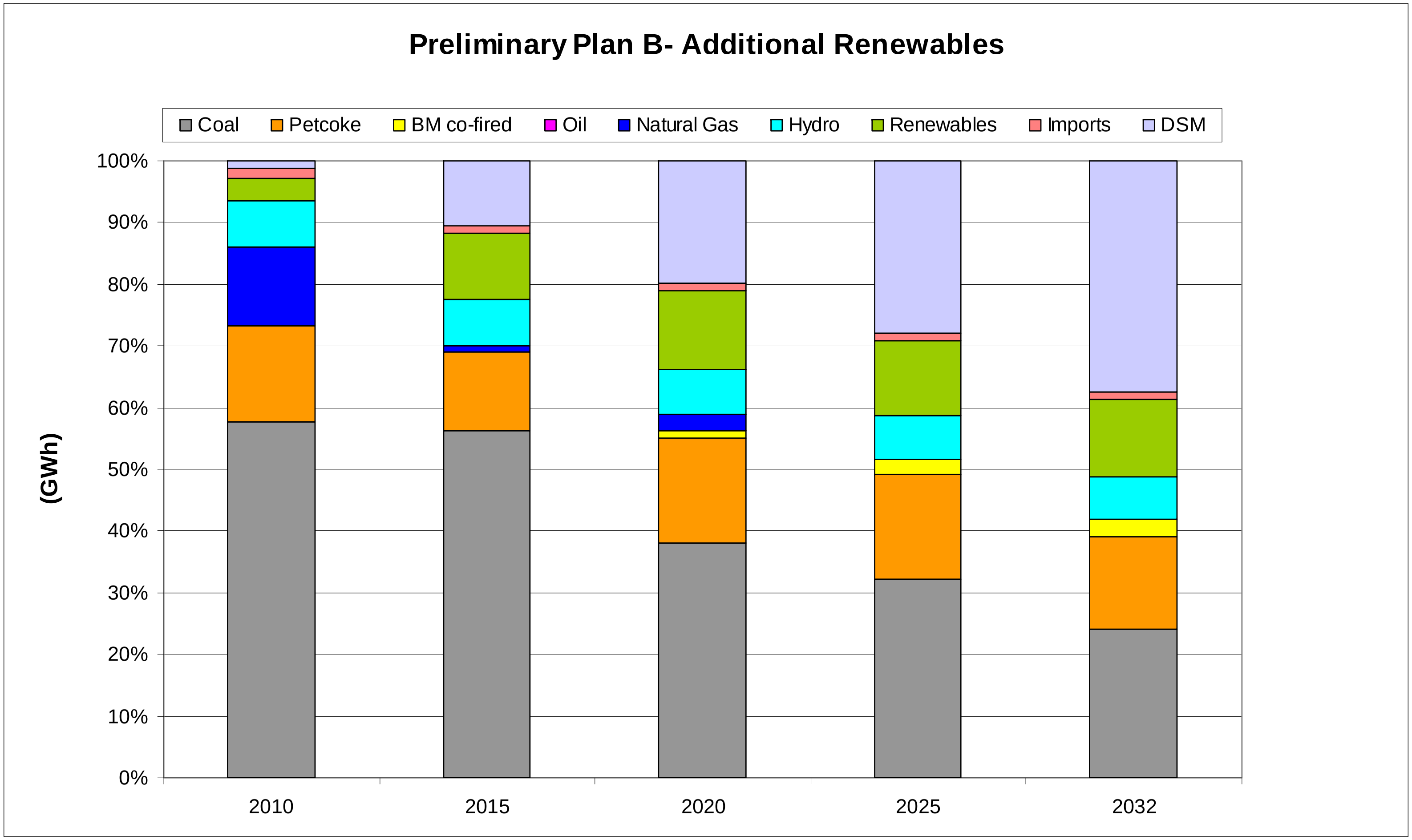


Revision: Changed Category from “Purchases” to “Imports”

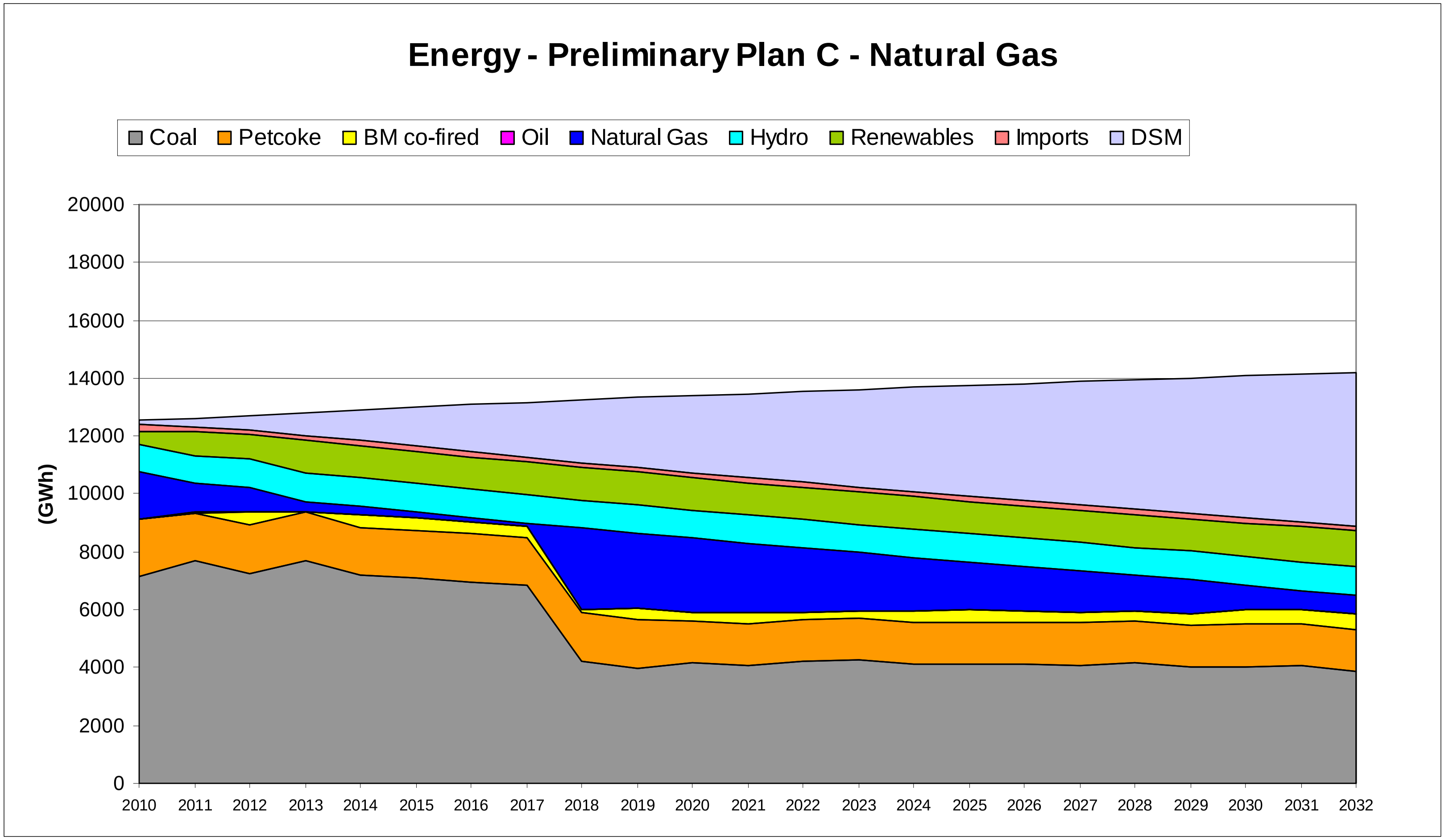
NOVA SCOTIA POWER An Emera Company

IRP Update
Analysis Results
Revisions to Slide 84



Revision: Changed Category from “Purchases” to “Imports”

IRP Update
Analysis Results
Revisions to Slide 89



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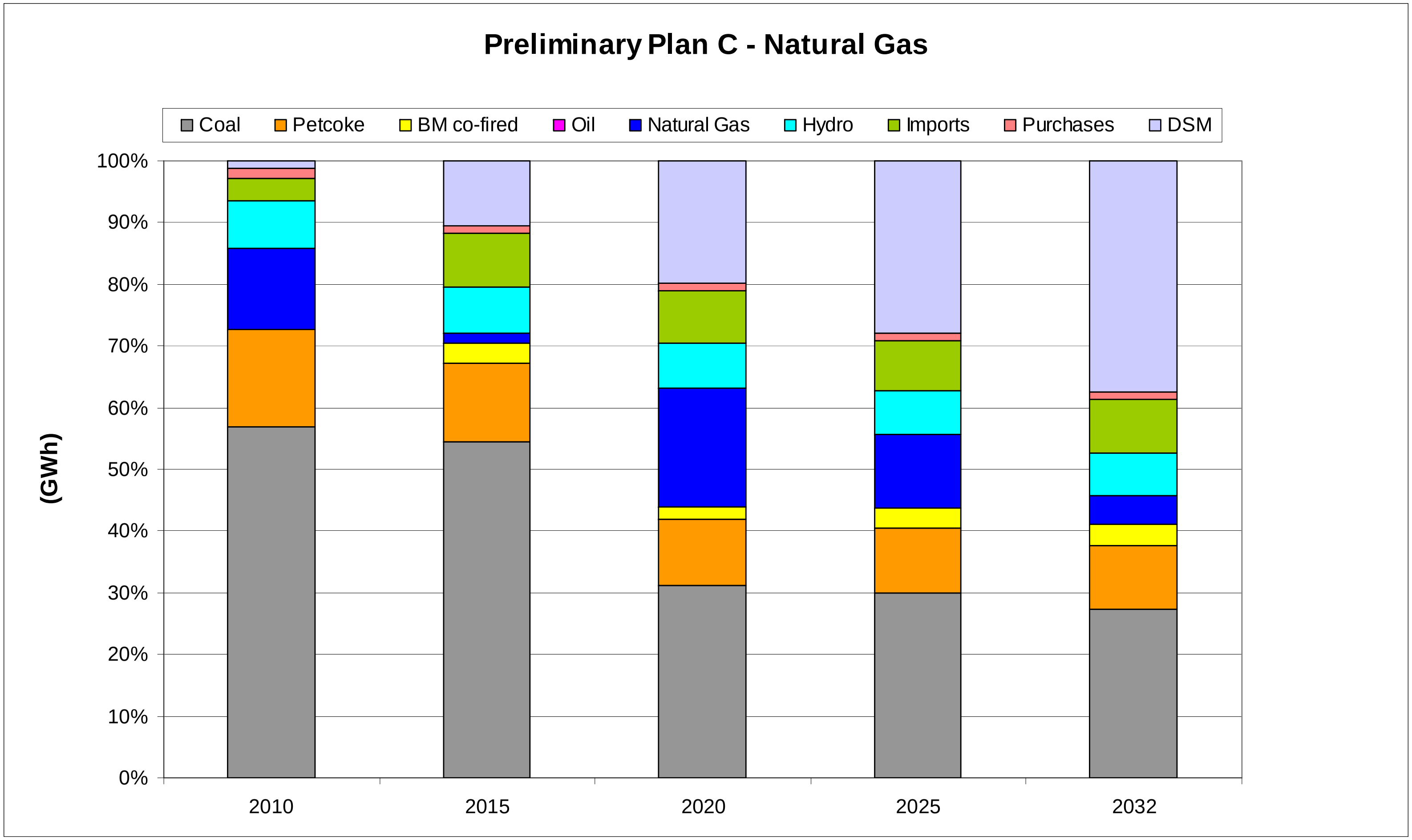
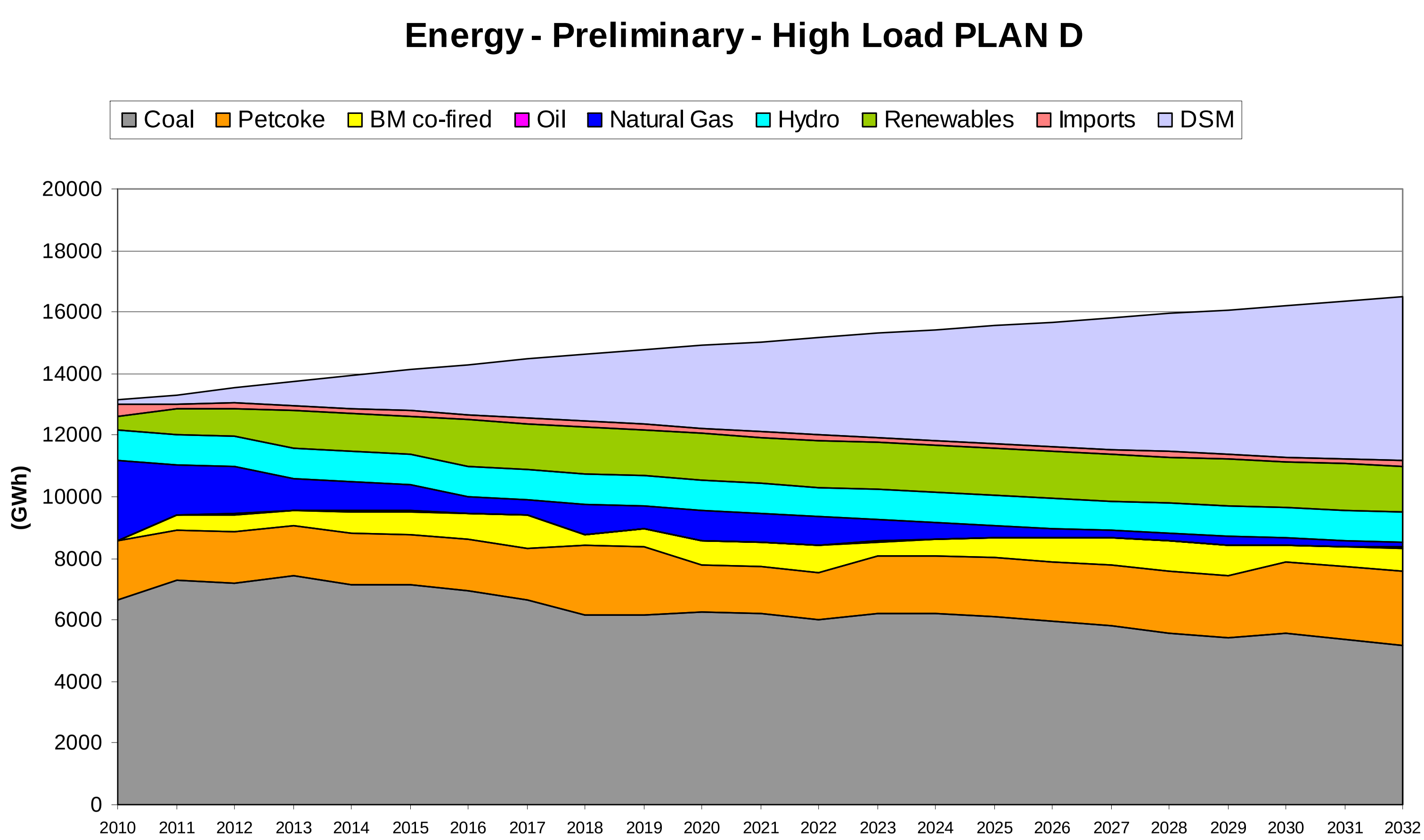
Revision: Changed Category from “Purchases” to “Imports”

IRP Update
Analysis Results
Revisions to Slide 90



Revision: Changed Category from “Purchases” to “Imports”

IRP Update
Analysis Results
Revisions to Slide 101



Revision: Changed Category from “Purchases” to “Imports”

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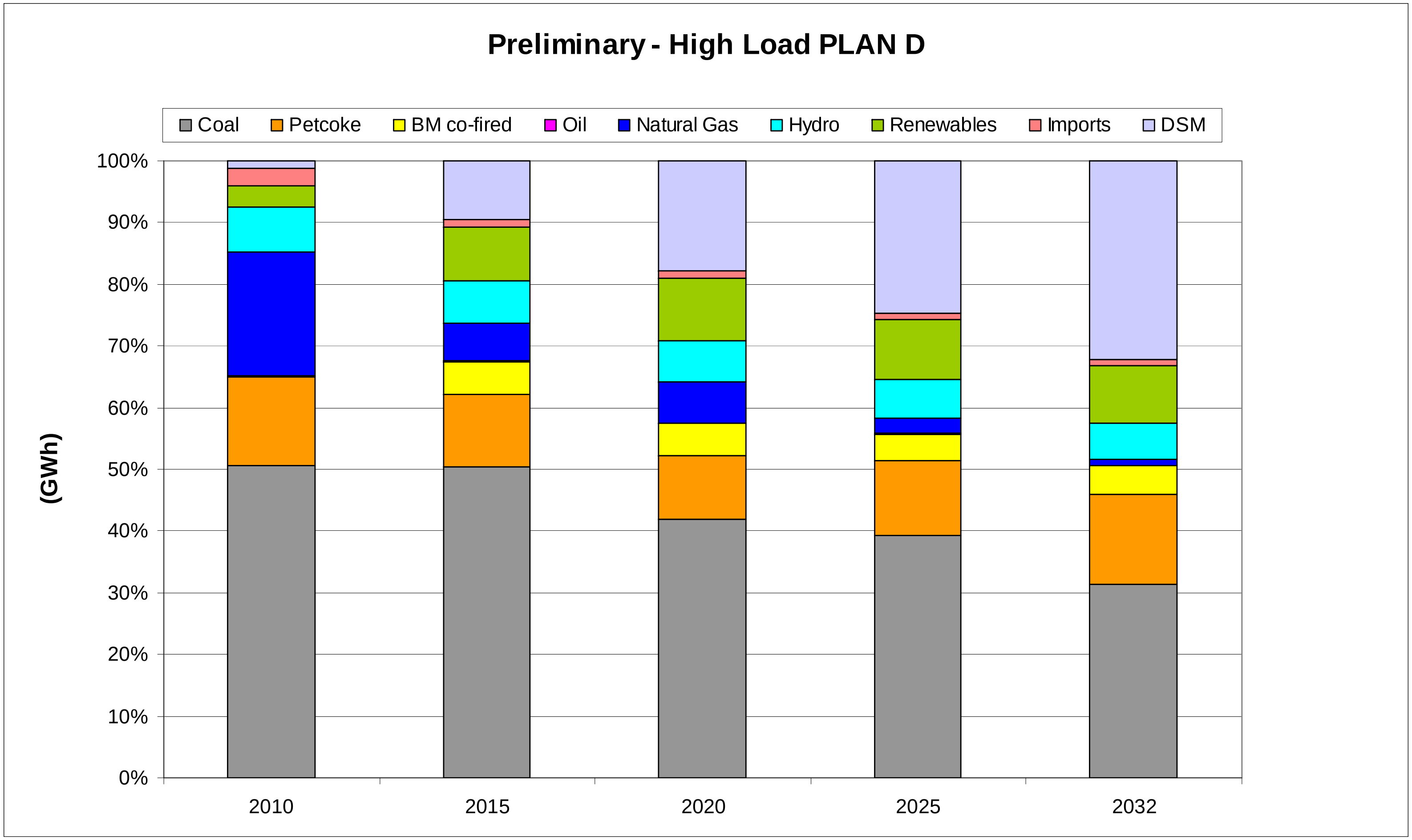
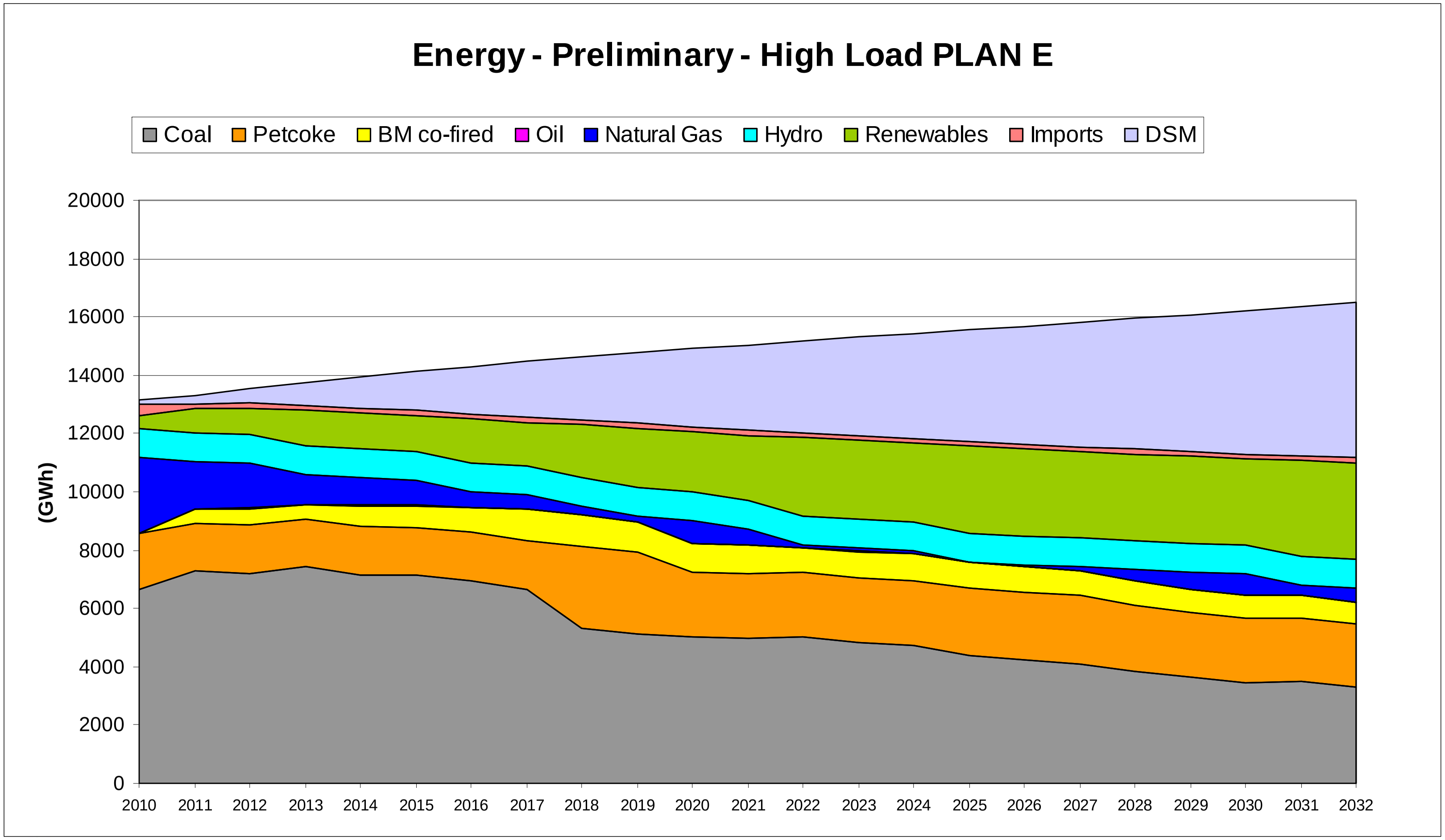
IRP Update
Analysis Results
Revisions to Slide 102



Revision: Changed Category from “Purchases” to “Imports”

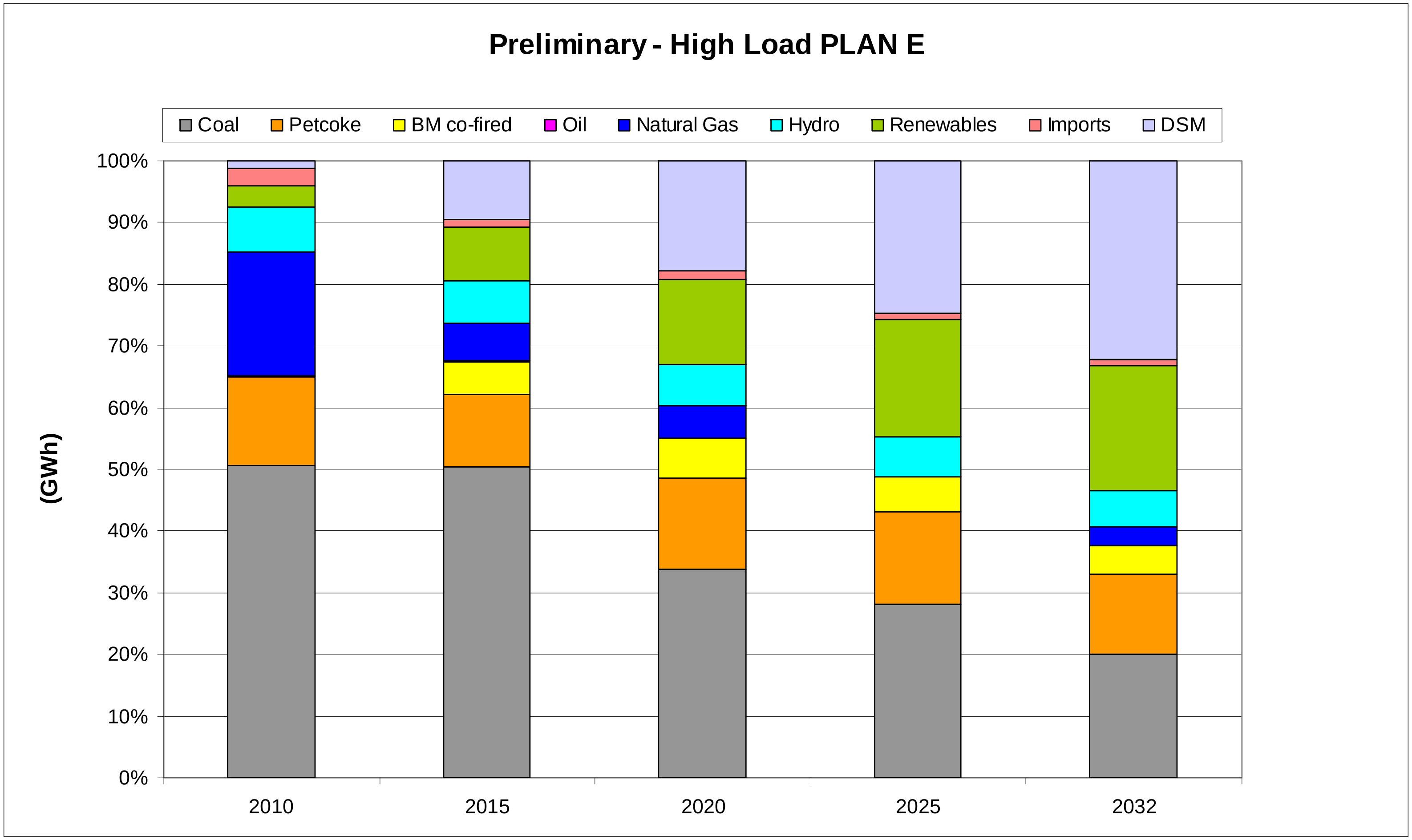
NOVA SCOTIA POWER
An Emera Company

IRP Update
Analysis Results
Revisions to Slide 107



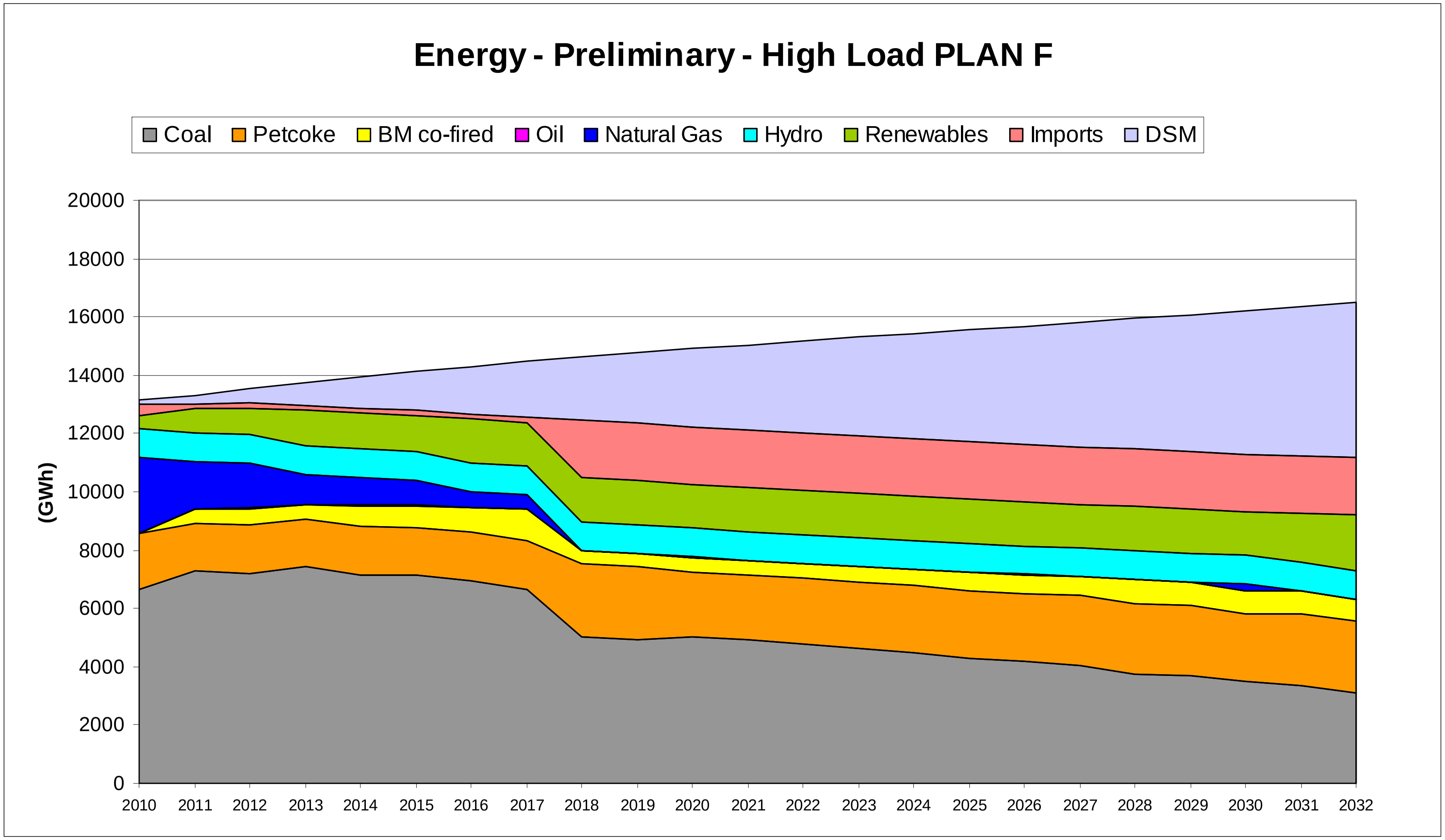
Revision: Changed Category from “Purchases” to “Imports”

IRP Update
Analysis Results
Revisions to Slide 108



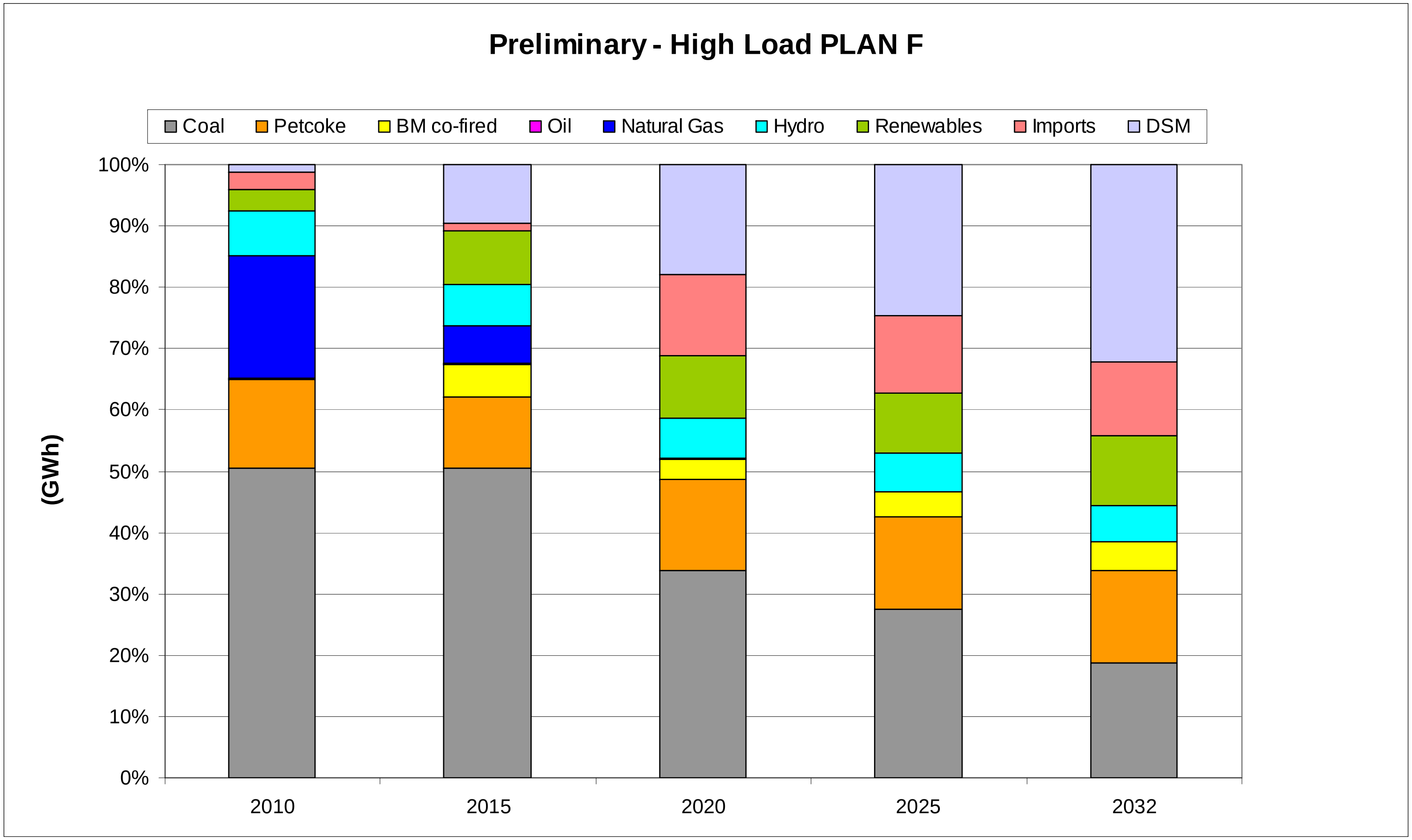
Revision: Changed Category from “Purchases” to “Imports”

IRP Update
Analysis Results
Revisions to Slide 113



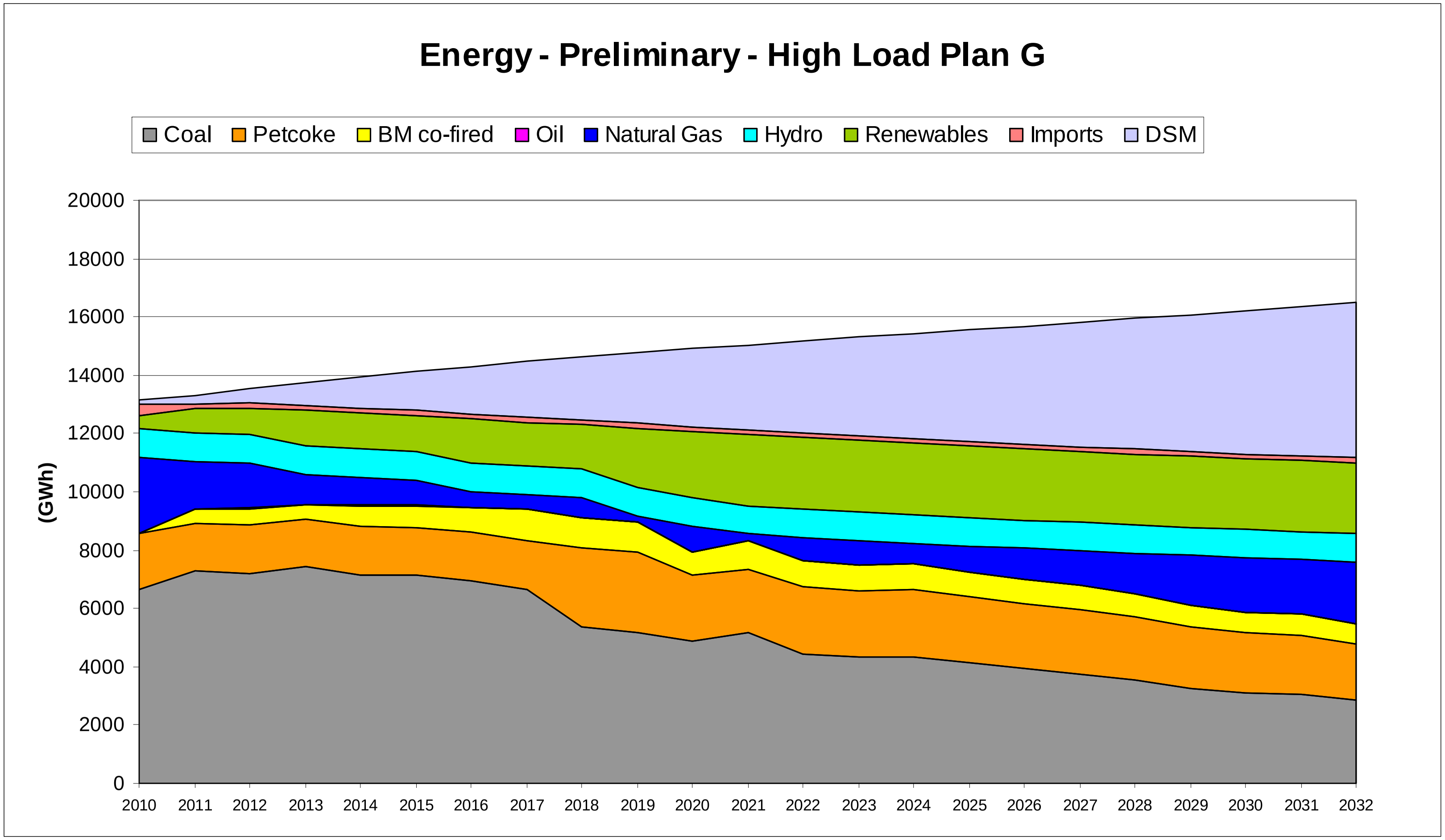
Revisions: Moved Large Import from “Renewables” to “Imports”
Changed Category from “Purchases” to “Imports”

IRP Update
Analysis Results
Revisions to Slide 114



Revisions: Moved Large Import from “Renewables” to “Imports”
Changed Category from “Purchases” to “Imports”

IRP Update
Analysis Results
Revisions to Slide 119



Revision: Changed Category from “Purchases” to “Imports”

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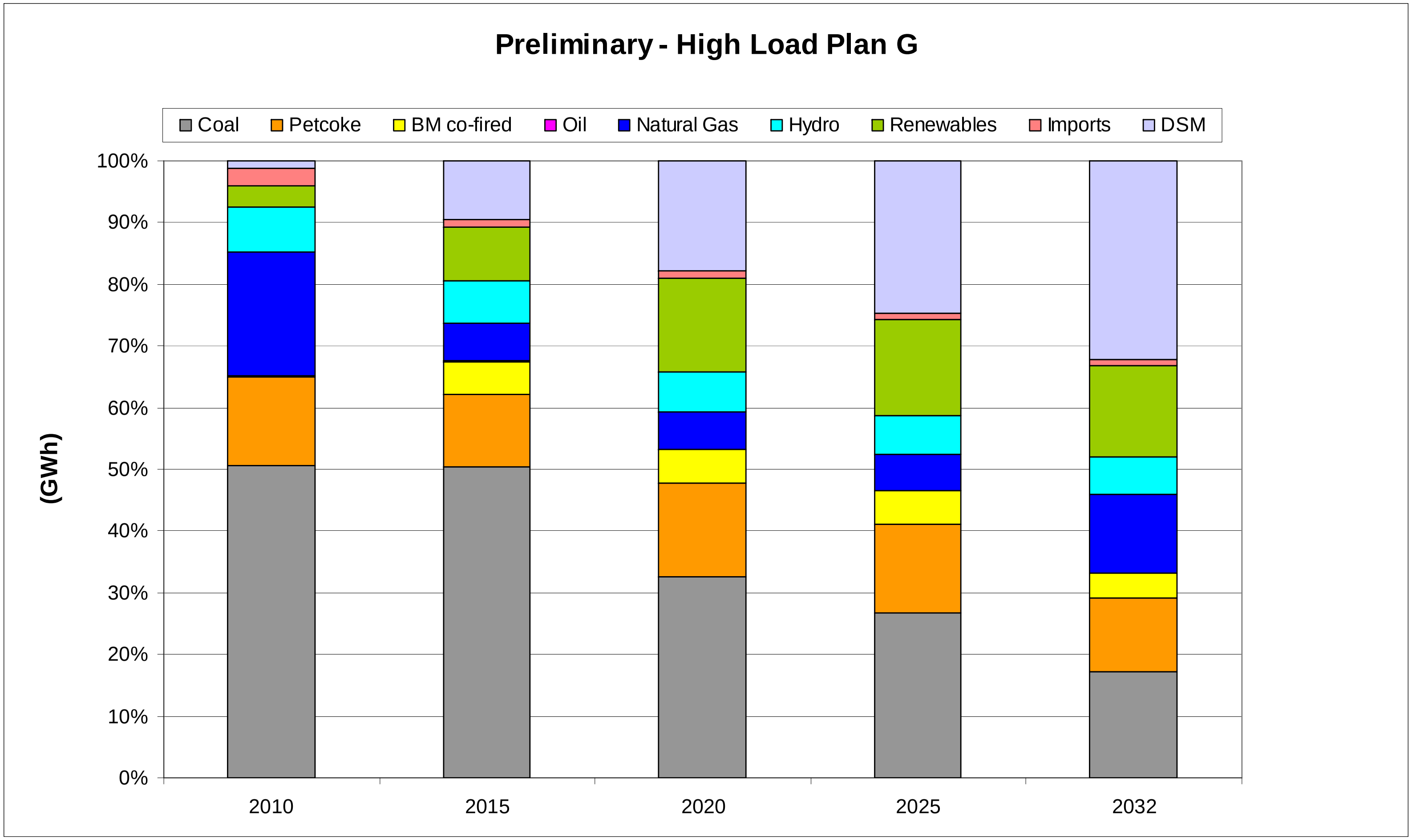
IRP Update
Analysis Results
Revisions to Slide 120



Revision: Changed Category from “Purchases” to “Imports”

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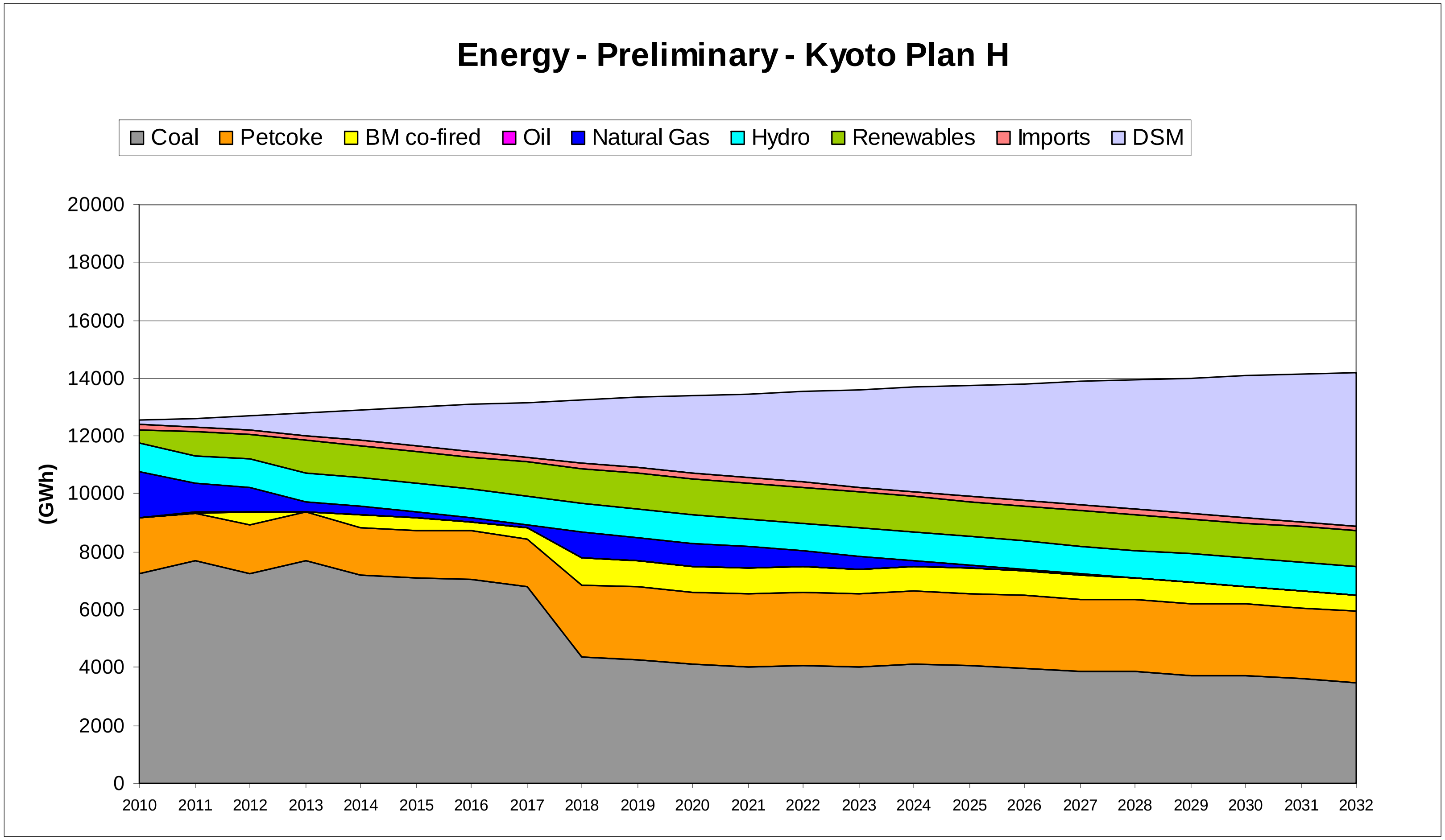
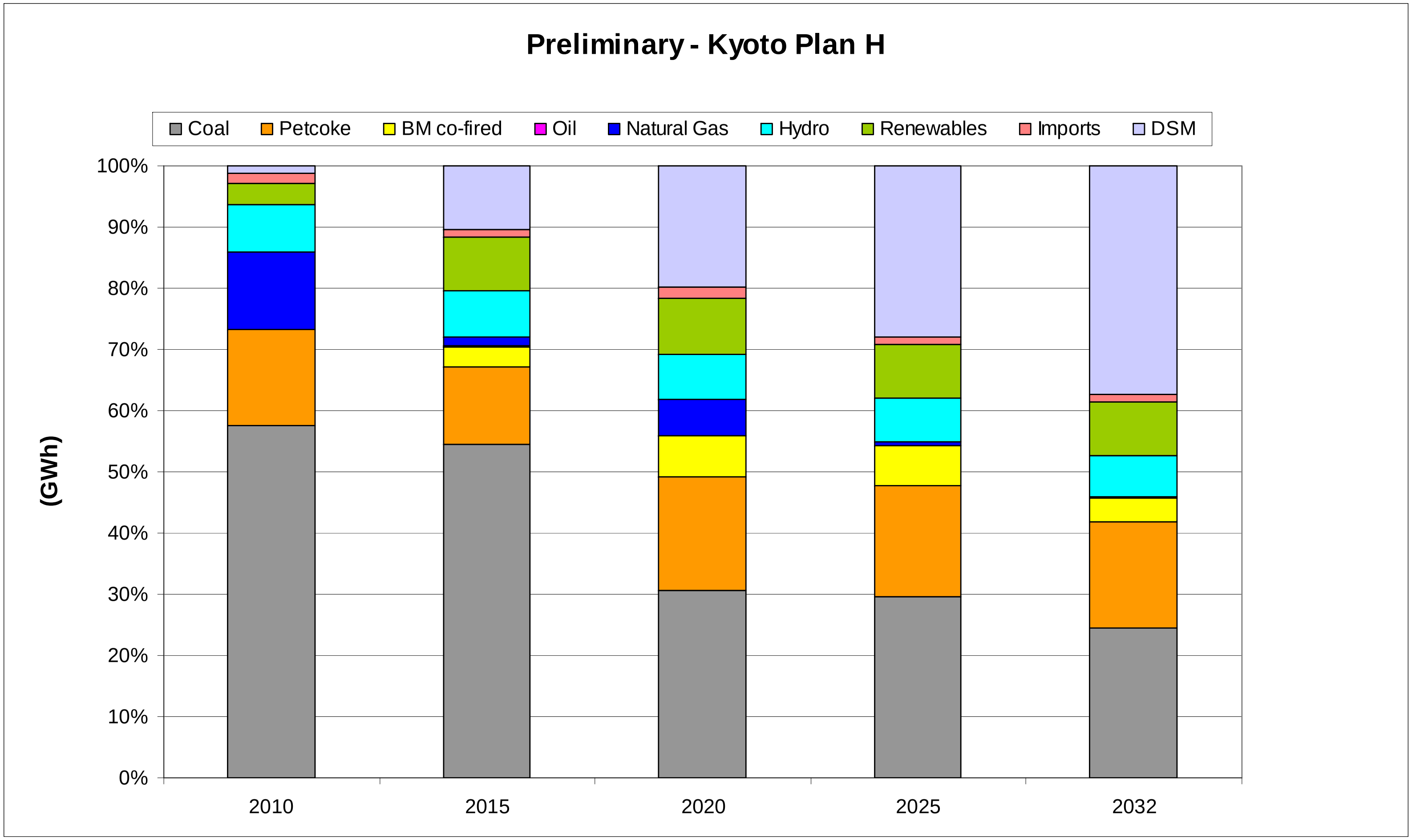
IRP Update
Analysis Results
Revisions to Slide 132



Revision: Changed Category from "Purchases" to "Imports"

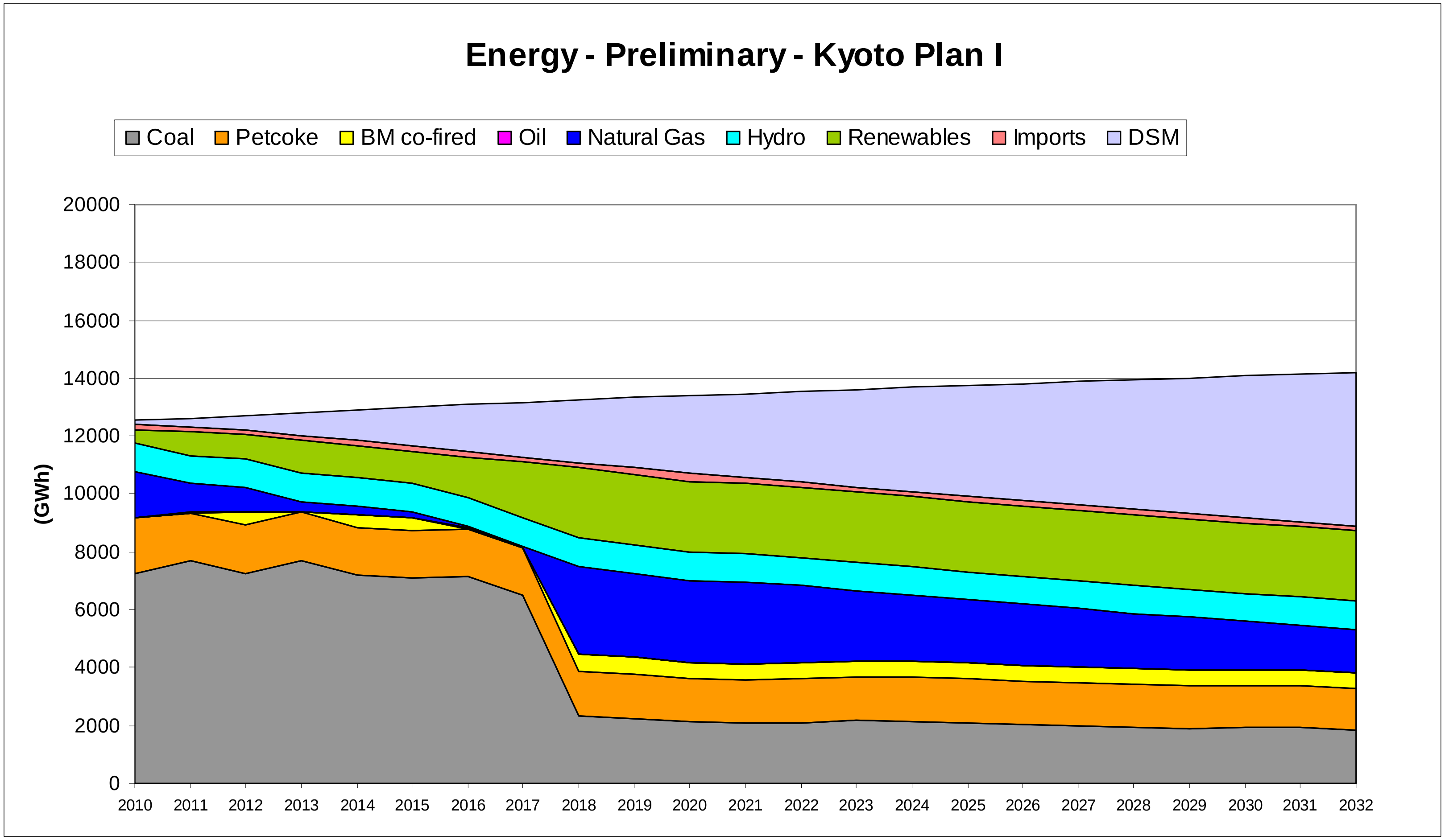
NOVA SCOTIA POWER An Emera Company

IRP Update
Analysis Results
Revisions to Slide 133



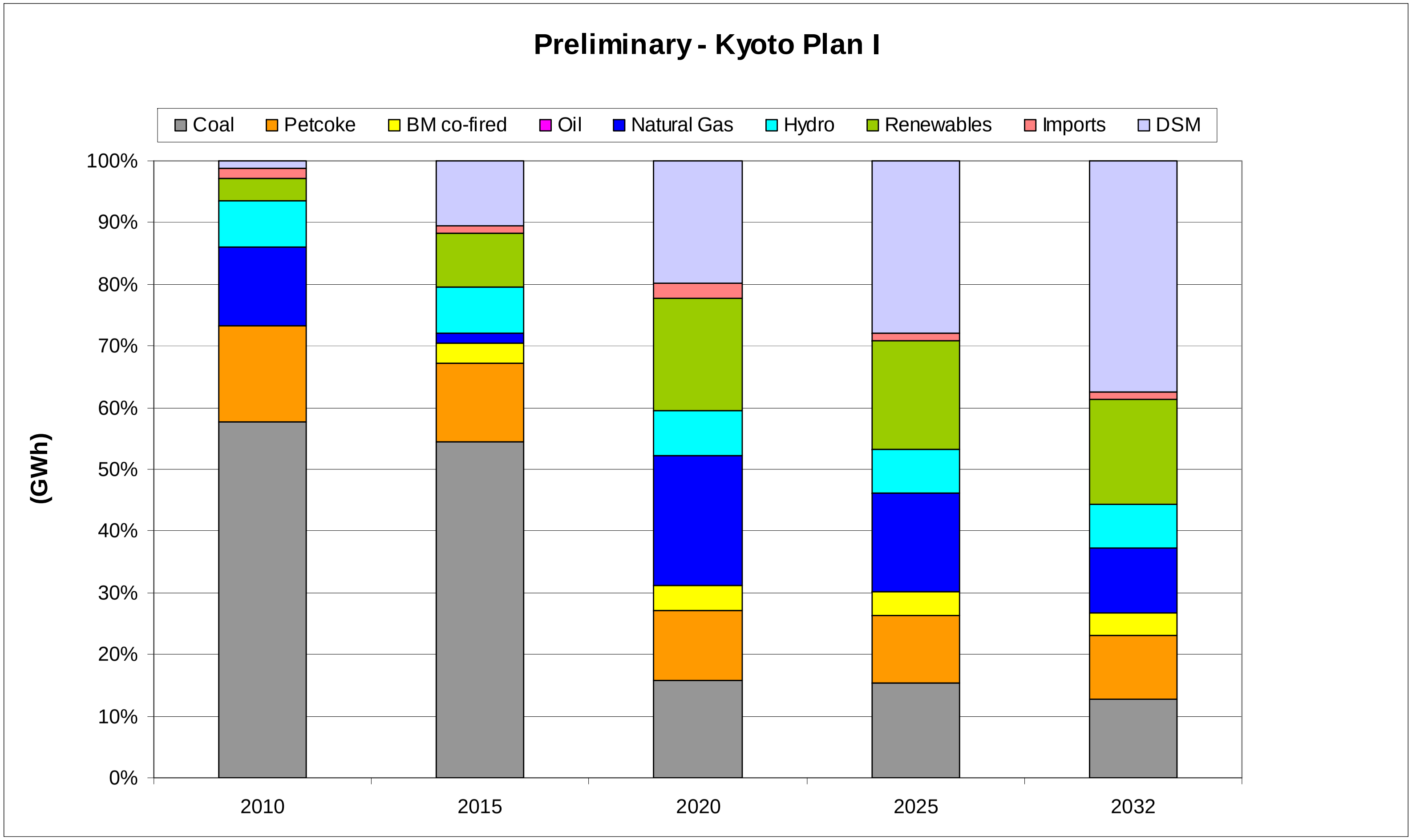
Revision: Changed Category from “Purchases” to “Imports”

IRP Update
Analysis Results
Revisions to Slide 138



Revision: Changed Category from “Purchases” to “Imports”

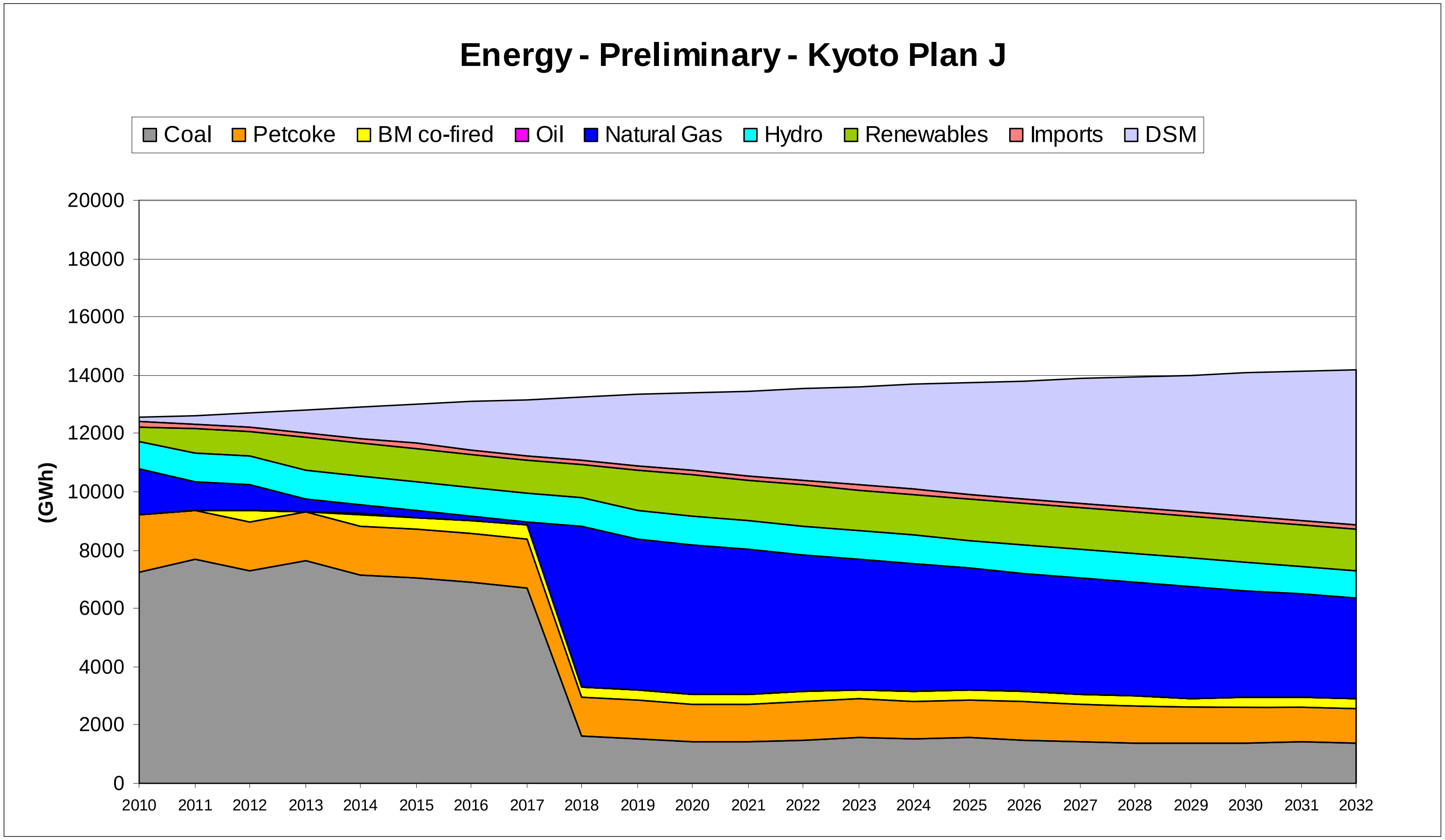
IRP Update
Analysis Results
Revisions to Slide 139



Revision: Changed Category from “Purchases” to “Imports”

NOVA SCOTIA POWER
An Emera Company

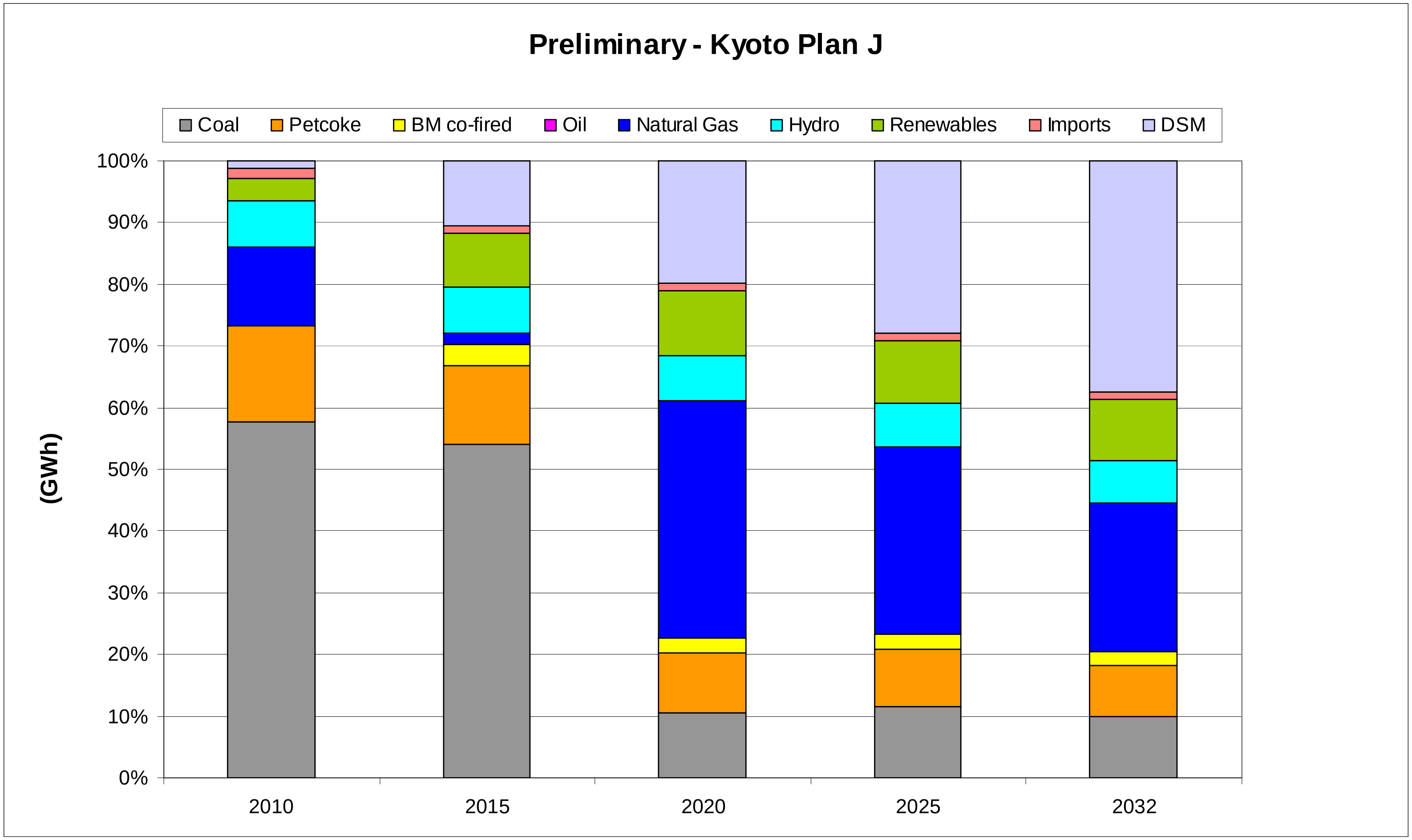
IRP Update
Analysis Results
Revisions to Slide 144



Revision: Changed Category from “Purchases” to “Imports”

NOVA SCOTIA POWER An Emera Company

IRP Update
Analysis Results
Revisions to Slide 145



Revision: Changed Category from “Purchases” to “Imports”

NOVA SCOTIA POWER
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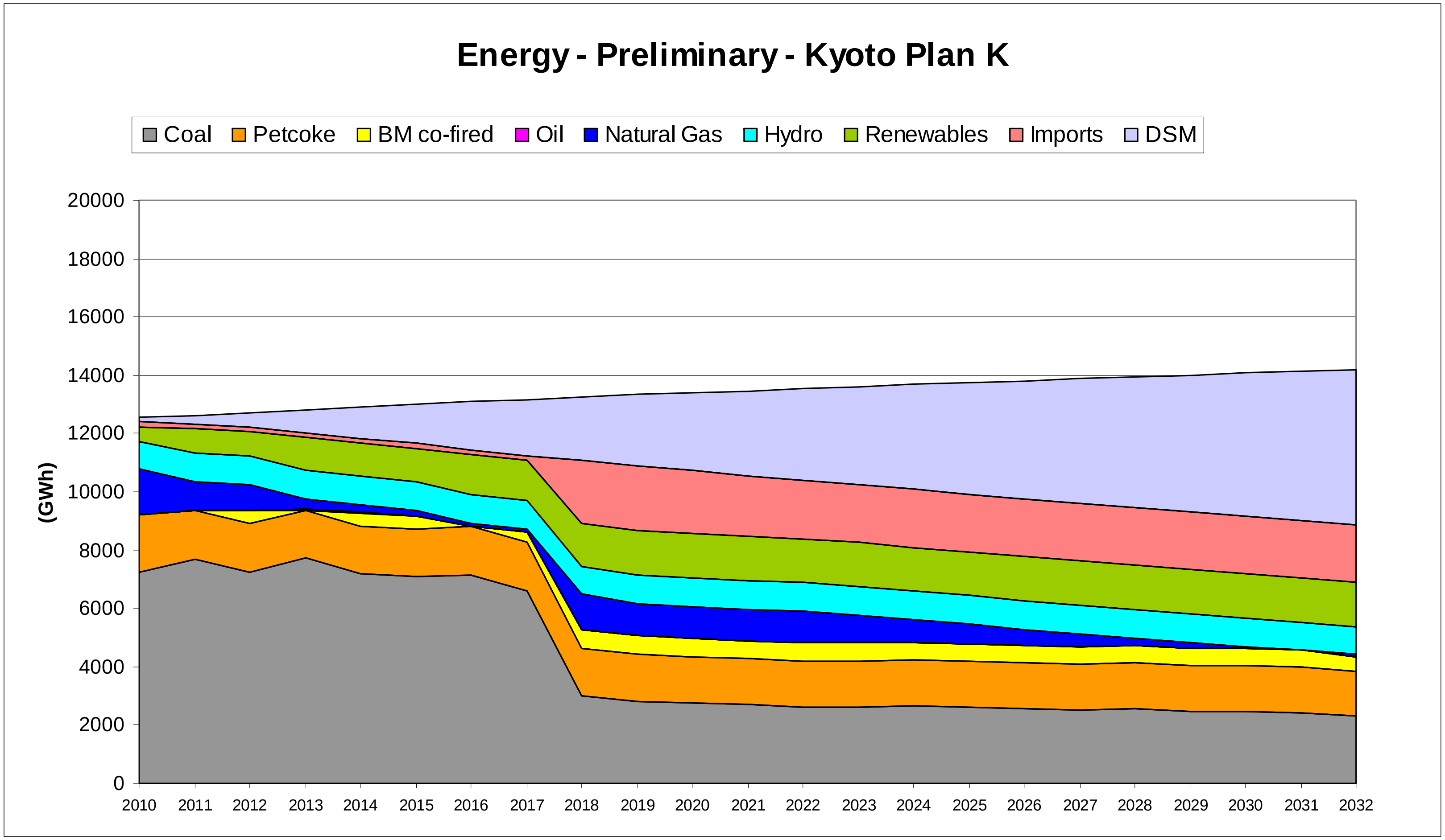
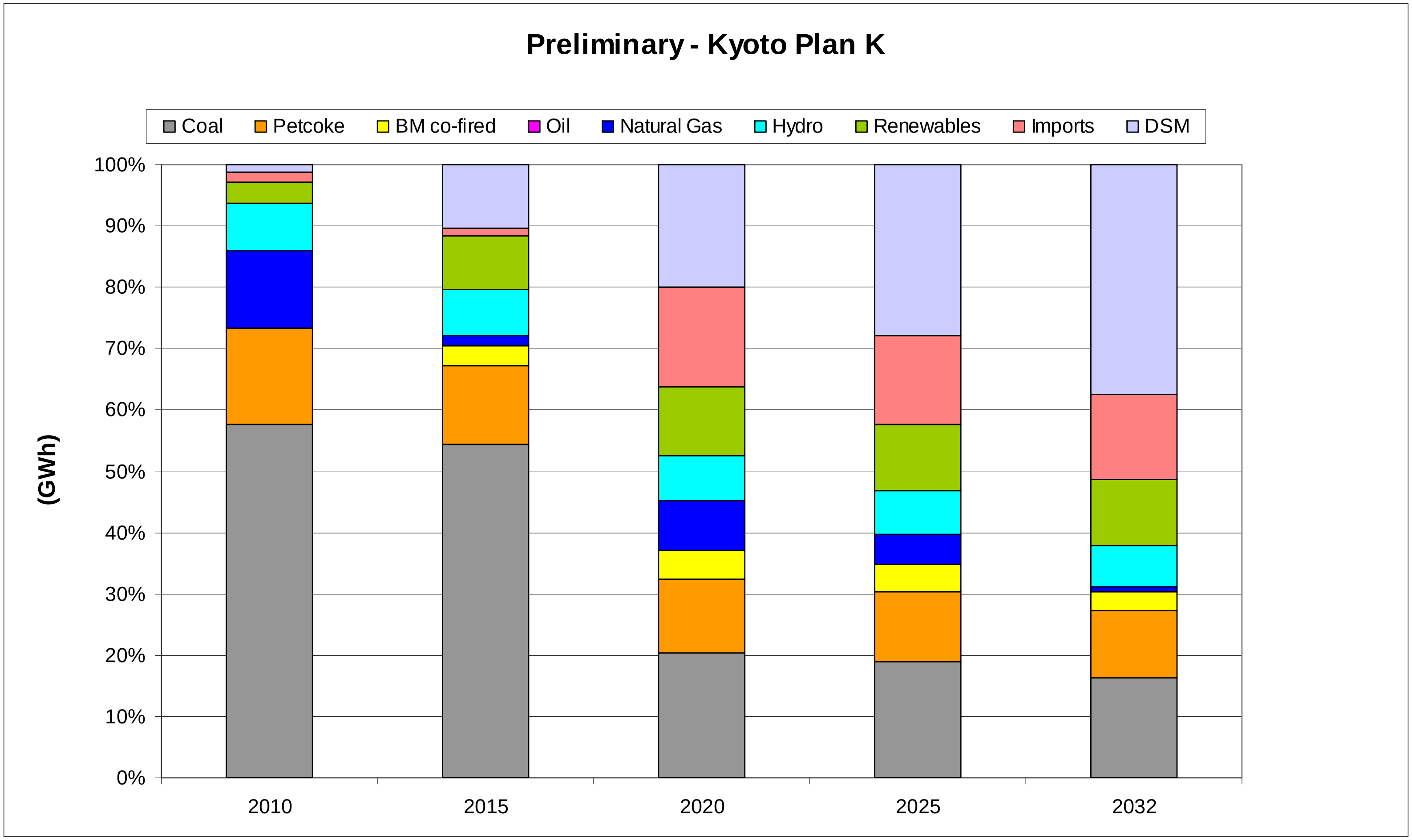
IRP Update
Analysis Results
Revisions to Slide 150



Revisions: Moved Large Import from “Renewables” to “Imports”
Changed Category from “Purchases” to “Imports”

Nova Scotia Power – An Emera Company

IRP Update
Analysis Results
Revisions to Slide 151



Revisions: Moved Large Import from “Renewables” to “Imports”
Changed Category from “Purchases” to “Imports”

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2009 IRP UPDATE
Responses to Stakeholder Input on Basic Assumptions
June 11, 2009

Introduction

On May 7, 2009, NSPI issued the initial draft of 2009 IRP Update Basic Assumptions which had been developed by NSPI jointly with Board staff and consultants (the "Working Group"), to IRP participants.

On May 14, 2009, NSPI facilitated a Technical Conference for participants at which the basic assumptions and plan themes contained in the May 7, 2009 initial draft were presented by NSPI and with support from members of the Working Group. Participants were provided an opportunity to comment and ask questions on the assumptions and plan themes.

Following the Technical Conference, on May 21, 2009, IRP participants submitted written comment for consideration with respect to the assumptions and plan themes. Comments were received from:

1. Alton Gas
2. The Avon Group
3. Ecology Action Centre
4. Minas Basin
5. NewPage Bowater
6. NS Department of Environment/NS Department of Energy

NSPI and the Working Group have reviewed and considered all input received and as a result NSPI has made several changes to the assumptions which will be modeled in the IRP update. NSPI has paraphrased the question or comment and provided a response in the summary table below.

Context for Responses

To provide context for some of the responses below, it may be helpful to provide additional insight into how the model works.

Strategist is a long term generation planning tool and as such uses load duration curves and probabilistic techniques to dispatch thermal units in order to reduce processing time when optimizing expansion plans. Operational issues such as load following, maintaining operational reserves, and tie line load control require an hourly dispatch model. This level of detail is not appropriate for directional long term planning purposes, and is not incorporated in the Strategist model. The IRP analysis will be reviewed with these types of synergies in mind and as appropriate, comments will be made in the Final Report, but the model will not optimize for them. Within the IRP context therefore:

a) Conclusions about storage and load following economics will not be made.

b) The back-up adder for wind will act as a placeholder for such costs in the IRP to acknowledge economically that there will be a cost to follow wind.

c) There will not be dynamic or hourly detailed load following modeling performed in the IRP to compare the detailed economics of buying load following services on the NS-NB tie, via back-up (capacity) adder, CAES (Compressed Air Energy Storage), or other specific projects that could support wind.

d) The CAES option will be evaluated on its ability to mitigate CO2 and as a dispatchable resource.

e) If an enabling project such as import/second tie to New Brunswick (for example, if part of a large non-emitting PPA resource) or gas generation is selected in the IRP Preferred Plan due to long term energy economics, robustness, and other factors, NSPI can in the future consider how such a characteristic would also enable load following services/wind integration. The specific justifications and business cases to compare options for their load following capability or other operational/reliability considerations, in terms of specific costs and benefits, would be done outside the scope of the IRP Update.

1	**Stakeholder**	Alton Gas
	Topic	Future Supply Side
	Suggestions/Comments	Use costs for CAES similar to LM 6000.
	Response	We have reviewed the additional information provided by Alton Gas as well as submissions made in 2006. The capital equipment associated with this installation includes: Gas Turbine, Turbo Expander, and Compressors and Caverns plus all related auxiliary equipment. Using Alton's data NSPI has confirmed the capital cost of this equipment for indicative modeling purposes. Further work would be required to vet the engineering details of the Alton project.
2	**Stakeholder**	Alton Gas
	Topic	PPA Renewables
	Suggestions/Comments	Use capacity factor for CAES similar to gas-fired combustion turbine.
	Response	Having reviewed the information provided by Alton Gas, costing appears to reflect an 8-hour storage volume and 77% efficiency, which may be either thermal or recovery efficiency. Eight hours equates to 33% capacity factor and is further reduced to 26% if adjusted for efficiency. Based on 85% reliability, the capacity factor would be adjusted to 22%. If the 77% efficiency is based on thermal, there would be an additional heat rate penalty of a 28% capacity factor. Given that this technology is new, it is NSPI's intention to offer the model a capacity factor of 21% and the $/MWh as referenced on slide 39 of the Basic Assumptions. NSPI will further investigate to better understand the referenced efficiency factor.
3	**Stakeholder**	Avon
	Topic	Plans
	Suggestions/Comments	Consider a scenario where carbon caps are met through trading or offsets.
	Response	A key focus of the 2009 IRP Update versus the 2007 IRP is how to meet reasonable physical carbon reduction, as opposed to a detailed analysis of the pros and cons of meeting CO2 hard caps versus compliance using offsets. The 2009 IRP Update Base Case run will be with CO2

		assumptions set as hard cap targets, as prescribed in the Nova Scotia Climate Change Action Plan (January 2009) and draft regulations (February 2009). In scenario runs with near and long term CO2 targets that are deeper than Base, offsets will be used up to 2020, at the CO2 credit prices outlined in the Basic Assumptions.
4	**Stakeholder**	Avon
	Topic	Plans
	Suggestions/Comments	Provide NPV and include cost analysis over 25 years
	Response	This can be provided with the Analysis/Final Report.
5	**Stakeholder**	Avon
	Topic	Plans
	Suggestions/Comments	Perform sensitivity of impacts of reduction of costs if implementation delayed
	Response	To the extent that technology is pulled into the plans to meet load and emissions constraints, an assessment will be made as to the appropriate sensitivities to perform in order to test the robustness of that technology's call into a plan. The high-low fuel and high-low capital cost assumptions may be selected as possible sensitivities against which NSPI would want to test. In terms of the specific request to test the sensitivity of plans to lower technology costs due to a delay in implementation, this could be thought of as being directionally covered by a low capital cost test.
6	**Stakeholder**	EAC
	Topic	DSM
	Suggestions/Comments	To more fully understand the DSM assumptions, provide an accounting of energy savings and program costs in each year.
	Response	The summary provided in the basic assumptions shows the DSM information at a number of intervals over the 25 year timeline. The additional requested information has been provided in Attachment 1.
7	**Stakeholder**	EAC

	Topic	DSM
	Suggestions/Comments	Resource savings such as water, oil and operations and maintenance are not currently taken into consideration. If the IRP only wishes to optimize with respect to the electric system, then the IRP should use a utility cost test rather than a TRC test which counts all resources.
	Response	When developing the DSM assumptions for the IRP, the analysis did not include such non-electric benefits and costs. This is consistent with the approach used in the 2007 IRP and in NSPI's recent DSM filings. As explained in the basic assumptions, since DSM is a cost-effective option compared to supply alternatives, the model will pick DSM over other alternatives. The suggestion to either enhance the benefits associated with DSM or to use to the utility costs instead of total costs would increase the attractiveness of DSM versus supply options. The DSM as projected will be in the Reference plan and increasing the economic attractiveness of DSM will not change that outcome. The total resource cost of DSM calculated using electric only benefits is appropriate for the IRP Update.
8	**Stakeholder**	EAC
	Topic	Plans
	Suggestions/Comments	Use Kyoto rather than Deep Green.
	Response	NSPI will develop a "Kyoto World" CO2 assumption set and model this world with 2010 - 2020 able to be met via offsets and 2020 onward as physical hard caps. The "Kyoto World" modeled in the 2007 IRP, was: 2010 6.4 Mtonnes 2015 5.6 Mtonnes 2020 4.8 Mtonnes 2025 4.5 Mtonnes 2030 4.1 Mtonnes
9	**Stakeholder**	EAC
	Topic	Future Supply Side
	Suggestions/Comments	Provide justification for CCS cost estimates.
	Response	The carbon capture cost estimates are based on detailed

		studies being carried out by the various organizations within CCPC (Canadian Clean Power Coalition) which includes a number of utilities, EPRI (Electric Power Research Institute), Natural Resources Canada and others. NSPI also participates in both the IEA (International Energy Agency) Clean Fossil Fuel Task Group and the IEA Green House Gas Task Group which provides insight into the status of the technology globally. The Pembina data was reviewed but, as it is several years old (2005), NSPI is comfortable that its cost information as presented for 2009 modeling purposes is appropriate. For clarification regarding the $12 USD per tonne for sequestration, this is specifically for "outside the fence sequestration costs" such as pipeline, well field/reservoir monitoring, etc. This is in addition to the capture capital costs; for example, retrofit to existing plants or inherent in costs of a new CCS plant.
10	**Stakeholder**	EAC
	Topic	Plans
	Suggestions/Comments	Include CCS sensitivity analysis with high/low estimates.
	Response	Upon review of the plans' outputs, it will be determined whether high or low or both sensitivity tests of CCS are warranted. For instance, if a plan calls for CCS, NSPI could run the plan with CCS cost set to its High, and see how the plan's rank order among the others (in terms of cost) changes.
11	**Stakeholder**	EAC
	Topic	Plans
	Suggestions/Comments	Include a "Renewable with energy storage" plan excluding CCS & large-scale interconnection/imports but including aggressive DSM, renewables, transmission upgrades, energy storage and demand control.
	Response	It is possible that from the base runs there will be plans without CCS and large-scale interconnection/imports – that is, with DSM, in-province renewables, some transmission upgrades to enable, etc. - without needing to create a separate scenario. If all plans among the least cost contenders rely on these resources, NSPI could run a

		plan without them and assess. Energy storage can be discussed qualitatively in terms of how it would augment/support wind/DSM/load control but it will not be modeled as an explicit feature of the IRP runs. Please also refer to the Context for Responses in the Introduction.
12	**Stakeholder**	Minas Basin
	Topic	Plans
	Suggestions/Comments	Model different choices for pricing of renewable energy (provided 3 options).
	Response	The purpose of an IRP is to identify the combination of supply and demand alternatives which most effectively meets long-term system load requirements across broad ranges of assumptions and constraints. Renewable resources are modeled within the IRP at the estimated cost to construct or purchase this generation. Renewables are selected for inclusion in the Reference Plan based on the comparison of the cost and attributes of this generation with other demand and supply options. The actual procurement of renewable resources, including the pricing and ownership of this generation, are matters determined when the procurement programs are executed.
13	**Stakeholder**	NPB
	Topic	Fuel
	Suggestions/Comments	Natural Gas Base Case should use NYMEX rather than PIRA.
	Response	Forward strips are not appropriate for long-term forecasting. Long-term supply/demand fundamental models are more appropriate to predict future fuel prices.
14	**Stakeholder**	NPB
	Topic	Fuel
	Suggestions/Comments	May 2009 PIRA is 10% less than Nov 2008. Reassess fuel once June PIRA, Wood MacKenzie and Jacob's updates are available.
	Response	Pricing for all fuels needs to be from a consistent timeframe to ensure consistency in underlying macro-

		economic assumptions. Decreases in prices from November to May are not material in the long-term perspective of the IRP. If the June reports show significant change, NSPI will review. For instance, the range (for example, low) to be used in sensitivity tests could be widened if appropriate.
15	**Stakeholder**	NPB
	Topic	Future Supply Side
	Suggestions/Comments	Use +30/-30% for capital costs except where current pricing available.
	Response	Upon reviewing cost assumptions for the large future additions in outer years, a -20% is to be used in most cases. Given that owner's costs were not included in NPB's numbers and this would account for approximately an additional 10%, NSPI is in the -30% range suggested. NSPI will, however, adjust the IGCC with capture, changing the low estimate from 2,608 to 2,282, since the Base value is relatively conservative. The other estimates have been reviewed and, using the known contract value for the PC 400MW as an anchor along with NSPI's own builds, they are considered reasonable for modeling purposes.
16	**Stakeholder**	NPB
	Topic	PPA – Renewables
	Suggestions/Comments	Use 28-30% for on-shore wind and reduce off-shore wind from 38%.
	Response	NSPI is satisfied that the on-shore wind capacity factor of 32% and the off-shore capacity factor of 38% are reasonable for use as indicative capacity factors for long-term planning purposes. For on-shore wind, it is supported by the actual performance of existing IPP projects as well as the use of 32% as the indicative capacity factor for wind in the Wholesale Tariffs recently approved by the Board.
17	**Stakeholder**	NPB
	Topic	Future Supply Side
	Suggestions/Comments	Clarify if effects of new technology capital additions on unit performance and energy replacement during retrofit

		are included in the model.
	Response	The Strategist model includes shutdown times for all units. Major capital additions are designed around installing equipment during a planned shutdown window. An example is the Trenton 5 Baghouse which will be linked into the planned shutdown period. This approach would be used for all the additions contemplated. Should additional considerations be identified, they would be addressed at the time a work order was advanced. New technology options do include material parasitic power penalties in terms of net output reductions, so the effect of recurring annual replacement energy due to parasitic power is captured in the model (for example, FGD, CCS, etc.).
18	**Stakeholder**	NPB
	Topic	Future Supply Side
	Suggestions/Comments	In the final report, make reference to capital costs for plants with nascent technology such as carbon capture are speculative, and construction of "first of kind" plants in near term is premised on significant capital costs.
	Response	NSPI costs on carbon capture study plants are based on advanced engineering studies that are projecting plants to be built in the 2015 time frame in other jurisdictions. These plants are all hoped to be part of the “20/20” solution advanced by the G8 developed economies – that is, an expressed desire to have 20 fully up and running carbon capture plants by the year 2020. At this level they would then be seen as fully commercial solutions. NSPI can discuss in the Final Report.
19	**Stakeholder**	NPB
	Topic	DSM
	Suggestions/Comments	Did not reduce DSM projection when Pulp & Paper removed.
	Response	This is correct. When NPB requested the DSM projection for Pulp & Paper be removed from the 2007 IRP projection, the energy saving was assumed to come from other classes within the Commercial & Industrial sector, which kept the 8-year achievable energy potential for those sectors at 23%. This level of achievable

potential is realistic.

20	**Stakeholder**	NPB
	Topic	DSM
	Suggestions/Comments	The modeling should not be locked in, but should allow for varying degrees of DSM effectiveness, which would allow for DSM to be available to be picked. An IRP conducted in this fashion provides little assistance in determining how much to actually spend on DSM in future, since such a determination would require an assessment of the achievable DSM and whether the benefits can be achieved for the costs assumed in the IRP.
	Response	The Basic Assumptions have noted that "DSM is a relatively cost effective option compared to supply side alternatives". Current estimates are that DSM costs would have to be significantly higher than projected in order to be displaced by a supply side option. While it will not be "locked in", as much DSM as is profiled will be included in the plans selected. The question with respect to DSM is not one of modeling, but rather one of achievability. A level of two percent annual energy savings will position Nova Scotia as a leader in DSM. This amount of energy savings is in line with other leading North American jurisdictions. (Other potential leaders include Illinois, Ohio, New York, Maryland and Vermont). The economic potential identified in the eight-year potential study is reached before Year 20 of the plan. Electric DSM programs in Nova Scotia are at an early stage. In the future, and at an appropriate time, a new potential study will be completed. This will incorporate the learning and experience since the 2006 DSM Potential Study and will produce a new projection of DSM potential and costs for use in a future IRP. As noted in the Technical Conference and in EAC's comments in this IRP Update, there is no consensus as to whether DSM costs will actually go up or down as programs expand: - As noted in Response #6, providing a lower cost stream associated with DSM is not expected to change the Reference plan. - Should DSM costs be significantly more expensive than

		projected, it is plausible that a supply side option would be chosen in lieu. A Higher Load World can approximate the scenario where DSM costs are significantly higher or where achievable amounts are lower. In a Higher Load World, additional supply side options are expected to be required versus the Base Load run in order to meet the higher demand requirement while maintaining environmental constraints. The output of a High Load World will be important to consider and understand in developing the Reference or Preferred plan and the 2009 IRP Final Report's Recommendations.
21	**Stakeholder**	NPB
	Topic	DSM
	Suggestions/Comments	"This profile is ambitious, one which would position Nova Scotia as a leader in energy conservation". This statement appears to be making a policy decision at the assumption level.
	Response	This is a policy decision, one that has been made based on insight from the 2007 IRP and with direction articulated in the NS Government's Energy Strategy: "This strategy lays a path for Nova Scotia… to become a leader in energy efficiency and conservation" (page 34) "After conservation and efficiency, renewable energy is Nova Scotia's best opportunity to meet our energy goals" (page 15) "This strategy makes a series of choices about how to deploy our limited resources. It begins with those that offer the greatest immediate impact: energy conservation and efficiency" (page 34) This statement is further supplemented by Nova Scotia's announced draft GHG regulations concerning hard caps and reductions. Successful DSM will be important in reaching the contemplated GHG hard cap targets.
22	**Stakeholder**	NPB
	Topic	DSM
	Suggestions/Comments	All DSM is assumed to be included in the projection used in the IRP. If no money is spent on customer-funded DSM programs, this form of DSM will still occur. It is unclear how customer costs will be

		appropriately modeled.
	Response	The IRP includes a projection of DSM achievable potential which is not reflected in the load forecast and can be attained through a variety of means including: -incentives through electric DSM programs -projects completely initiated and paid for by the customer -projects activated by electric utilities -mandates by government standards -incentives by government programs -various market forces In a potential DSM study, it is not possible to know how or when these various energy conservation alternatives will occur. Assumptions are made in the study which affect the estimates of utility and customer costs. As noted in the comment, some of this potential DSM may still occur without electric DSM programs. If so, this would simply change who pays the costs (whether the utility or the customer). For instance, if a standard is introduced, the costs which may have once been partially or wholly paid for under DSM programs may become entirely customer costs. Such changes do not affect the DSM economics or costs used in the IRP (total cost = customer + utility costs).
23	**Stakeholder**	NPB
	Topic	Transmission
	Suggestions/Comments	Provide more information about transmission costs.
	Response	The Standards of Conduct restrict the level of detail that can be provided. Qualitatively, network upgrade capital costs were developed by: - Preparing independent high-level feasibility assessments for each option - Using wind resource locations where wind resource options covered large geographic areas, such as mainland Nova Scotia - Assigning lowest identified network upgrade costs to the first block and so on for all blocks - Assuming Capacity Network Service for each resource option: o Network upgrades were based on the ability to deliver the full capacity of each option independently. Some transmission upgrades

may be common to more than one option as shown in the Common Facilities Table on slide 62 of the Basic Assumptions.

  - o Generation Interconnection Procedures (GIP) provide for interconnection applications for 'energy' service instead of capacity service. However, output capacity can be curtailed with this option.

- Assuming current resource economic dispatch patterns for each option:
  - o Flows on interfaces depend on the generation running to serve the load. As new generation resources were added, the highest cost generator, based on current economic dispatch, was curtailed. Changing the generator dispatch pattern away from the current economic model would affect the flows on interfaces and potentially the required network upgrades.

24	**Stakeholder**	NPB
	Topic	Load Forecast
	Suggestions/Comments	Bookend Base Case at a level between proposed low and base.
	Response	NSPI does not intend to have a Lower Load World run in the 2009 IRP Update. To the extent that this World is less likely to be the future direction, the priorities of the 2009 IRP Update are focussed on other key interest areas. A Lower Load optimization would provide a picture of the resources which may be required if inherent Load is lower; for example, fewer supply-side resources to meet energy demands than the Base or High Load case. Instead, the focus will be on meeting energy and environmental needs if Load is higher than anticipated for whatever reason.

25	**Stakeholder**	NPB
	Topic	PPA – Renewables
	Suggestions/Comments	What is the difference in assumed price for wind energy - XXX vs XXX?
	Response	The prices are different to represent thinking that over

		time the cost of wind will change.
26	**Stakeholder**	NPB
	Topic	PPA – Renewables
	Suggestions/Comments	How were off-shore wind, tidal and CAES prices derived?
	Response	These costs are based on a combination of indicative capital and O&M estimates, estimated capacity factors/performance, and NSPI's judgment in general as to how the pricing of each technology will develop over the next several years. The prices are indicative and considered suitable for directional, long term modeling purposes.
27	**Stakeholder**	NSDOE
	Topic	Emissions
	Suggestions/Comments	Lower CO2 base case for 2030 to 5.5M tonnes (difference between low and high).
	Response	The Federal Government has referred to a reduction of up to 65% from current levels by 2040 to 2050. Based on recent policy announcements by the US and discussions of harmonization of Canadian and US regulations, NSPI believes that a 65% reduction target is appropriate. A 65% reduction of 10Mt in 2045 would result in a Base target of 3.5Mt. Given a straight line trajectory from the 2020 Base target of 7.5Mt, to a 2045 Base target of 3.5Mt, the 2030 Base target would be 5.9Mt. As a result, we will revise the assumption to reflect a 2030 Base target of 5.9Mt.
28	**Stakeholder**	NSDOE
	Topic	Emissions
	Suggestions/Comments	Provide the number of offsets required to meet 8.6 in 2010 high case.
	Response	The base case calls for 9.7 million tonnes in 2010 with real reductions. A target instead of 8.6 would require 1.1 million tonnes to be offset.
29	**Stakeholder**	NSDOE

	Topic	Emissions
	Suggestions/Comments	Provide NatSource (Source of $/tonne offsets).
	Response	A copy has been provided to all stakeholders.
30	**Stakeholder**	NSDOE
	Topic	Emissions
	Suggestions/Comments	Reduce SO2 2015 high case to meet the Federal Government's proposed level (18,000 tonnes).
	Response	The 2020 target of 36,200 tonnes represents a significant reduction, likely beyond co-benefits of GHG abatement. The 2015 target represents a calculated middle ground.
31	**Stakeholder**	NSDOE
	Topic	Emissions
	Suggestions/Comments	25% of renewables by 2020 doesn't net out for DSM.
	Response	Adding pre-2001 renewables of 8.5% + 14% RES 2019, to get 22.5%, does not factor in the effect of forecast energy sales net of the DSM effect. With the effect of DSM included, the RES level at 2020 would be approximately 25% and hence the RES as proposed would achieve the goal of 25% in 2020. NSPI will continue to assess the level of renewables it must pursue to be comfortable that RES and other environmental requirements are able to be met.
32	**Stakeholder**	NSDOE
	Topic	Future Supply Side
	Suggestions/Comments	Capital costs should be based on typical years rather than focusing on a single year (ie. 2008 $Cdn).
	Response	2008 dollars/overnight indicative costs are used for the purpose of modeling, and escalation factors are built into the model. The research to derive the estimates is not just based on snapshot 2008 project costs but rather several recent years' studies. For modeling purposes 2008$ is the starting point and then escalation factors are applied to ensure economics and NPVs are on consistent terms.

33	**Stakeholder**	NSDOE
	Topic	Future Supply Side
	Suggestions/Comments	In comparing IGCC 400 (with and without CO2 capture), the Base delta of 1407M differs from the PC 400 delta (with and without capture) of 620M. Are the deltas correct and, if so, why the difference?
	Response	The deltas are correct. The difference, in part, is due to the advancement of gas turbine technology for the combustion of syngas ("synthetic gas", resulting from gasification process) versus a standard unit. As work is advanced on integration to increase reliability and system efficiency, prices have increased and are reflected in the costing. In the case of the PC unit, the addition of post combustion capture technology would be considered "bolt-on" and thus less capital intensive.
34	**Stakeholder**	NSDOE
	Topic	PPA - Renewables
	Suggestions/Comments	Give consideration to particulate emissions.
	Response	Particulate emissions are being addressed in NSPI's planned test program for biomass firing with the intent to develop a fuel and combustion technology that meets or improves upon all regulatory requirements.
35	**Stakeholder**	NSDOE
	Topic	PPA - Renewables
	Suggestions/Comments	27% moisture content is too high for biomass.
	Response	This number is derived from the actual "as fired" sample used at Point Aconi when NSPI burned a small amount of processed (size reduced) wood chips. Raw wood chips would be expected to have higher moisture content and wood pellets lower moisture content.
36	**Stakeholder**	NSDOE
	Topic	PPA – Renewables
	Suggestions/Comments	Use series of smaller blocks for biomass.
	Response	NSPI will offer the model another small block of biomass, ~15 MW or ~100 GWh, at the capacity factor and PPA price noted on slide 39 of the Basic Assumptions. The

		sizing is generic and not intended to pre-judge a maximum or minimum amount of biomass potentially of interest in the future. Given the other Biomass alternatives being considered in the model for the 2009 IRP Update, this level in addition to the options already presented is thought to be sufficient to test the directional economics of Biomass PPA options. The specific justification or business case details of any project would be tested at the time of application or submission within an RFP process.
37	**Stakeholder**	NSDOE
	Topic	PPA – Renewables
	Suggestions/Comments	Tidal capacity factor of 18% is too low.
	Response	NSPI is using a conservative figure as tidal energy is an emerging technology with expectations not yet well understood. NSPI will revise the number to reflect a capacity factor of 20% which has been provided by the Technology Provider, Open Hydro.
38	**Stakeholder**	NSDOE
	Topic	Load Forecast
	Suggestions/Comments	Why is there an increase in energy requirement in March?
	Response	Even though March may be a warmer month, the additional 2-3 days in March (vs. February) can result in an increased energy requirement.
39	**Stakeholder**	NSDOE
	Topic	DSM
	Suggestions/Comments	The utility costs jump from \$23M in 2010 to \$82M in 2013, and total costs jump from \$38M in 2010 to \$142M in 2013. Are these correct? - the 2007 IRP estimated \$50M annually.
	Response	The costs are correct; the profile for this IRP update is the high case from 2007 and adjusted with current information. The first 5 years (2008-2013) reflect the energy savings and costs shown in NSPI's 2010 DSM filing. Time value of money adjustments were also made to put costs in the right terms (the 2007 IRP data was in 2006 dollars)

40	**Stakeholder**	NSDOE
	Topic	DSM
	Suggestions/Comments	Include Smart Grid Technology.
	Response	The IRP will not explicitly model this technology. The IRP contains a DSM roadmap that can be met through a variety of technologies and programs and does not preclude any.
41	**Stakeholder**	NSDOE
	Topic	Plans
	Suggestions/Comments	Integrate highly constrained CO2 and pollutants by optimizing Deep Green run on C02 first, then fix C02 and optimize air pollutants
	Response	In the Deep Green (Kyoto) run NSPI will optimize CO2 to its Kyoto settings and the other air emissions to their Base and then assess for co-benefits of the deeper CO2 track with the other air emissions. (While possible to do as suggested, the intention of the Kyoto World has been to isolate CO2 as the more strict factor to assess how the supply side must react to comply; and as such what the co-benefits with the other emissions would look like – for example, such that SO2 or NOx or Hg removal technologies would not be advanced ahead of what a Kyoto track could take each to a few years later, for instance 2015 versus 2020 timing.)

2009 IRP Update

Response to Stakeholder Comments on Analysis Results

Introduction

On September 22, 2009, NSPI issued the Analysis Results to stakeholders. On September 30, NSPI facilitated a Technical Conference for participants at which the Analysis Results were presented. Participants were provided an opportunity to comment and ask questions on the Analysis Results, and were given an opportunity to submit written comments for consideration. On October 13, 2009, comments were received from the Departments of Energy and Environment.

NSPI has paraphrased the questions and comments and provided responses in the table below.

1	**Stakeholder**	Departments of Energy and Environment
	Suggestions/Comments	If biomass is selected for future electricity generation, it should be subject to testing and verification of outcomes, with approval by government.
	Response	Agreed. NSPI will engage Department of Energy and Department of Environment to ensure appropriate test programs are established for verification of continued compliance to operating permit(s) for co-fired unit(s)
2	**Stakeholder**	Departments of Energy and Environment
	Suggestions/Comments	Would a large PPA of 300 MW be large hydro, nuclear or tidal?
	Response	The Basic Assumptions identified the large non emitting PPA contemplated in the 2009 IRP Update analysis to be out of province hydro. However, it could be from any non-emitting resource.
3	**Stakeholder**	Departments of Energy and Environment
	Suggestions/Comments	The required lead time for a large PPA such as nuclear, large hydro or tidal would be 5-10 years.
	Response	Agreed.

2009 IRP UPDATE
Responses to Stakeholder Input on draft IRP Update Report
November 30, 2009

Introduction

On October 29, 2009, NSPI issued the draft 2009 IRP Update Report which had been developed by NSPI jointly with Board staff and consultants (the Working Group), to IRP participants. Participants were given the opportunity to submit written comment for consideration in the final Report. Comments were received from:

1. Nova Scotia Department of Environment
2. New Page Port Hawkesbury Corp. and Bowater Mersey Paper Company Ltd. (NPB)

NSPI and the Working Group have reviewed and considered all input received and as a result NSPI has made several changes to the report. NSPI has paraphrased the question or comment and provided a response in the summary table below.

1	**Stakeholder**	Nova Scotia Department of Environment
	Topic	Biomass co-firing
	Suggestions/Comments	Relative to the fourth bullet on page 36, it should be anticipated that biomass co-firing testing processes may extend beyond "verification of continued compliance with operating permit(s) for co-fired unit(s)" to identifying new technical and emission issues and options not existing currently in operating approvals.
	Response	NSPI acknowledges this point.
2	**Stakeholder**	NPB
	Topic	Appendix B: Board Staff & Consultants Statement
	Suggestions/Comments	It would be important information for interested parties if the Board staff and consultants have different views than NSPI with respect to the IRP Update results. The final

		comments should be provided to interested parties well in advance of the issuance of the Final Report, so that interested parties can have the benefit of those views and provide further comments on the Draft IPR Update if warranted.
	Response	The final comments of Board staff and consultants were sent to stakeholders on November 24.
3	**Stakeholder**	NPB
	Topic	Action Plan
	Suggestions/Comments	Add second bullet on page 34 under the Action Plan heading "continue to Develop the Resources Identified in the 2009 IRP Update Plan Pre-2013", which would read as follows: "Monitor the impact of DSM to determine whether the assumed energy savings levels are being achieved. Provide annual reports to the Board and staff and interested parties on the energy savings level achieved by DSM in the prior 12-month period."
	Response	NSPI agrees with this statement. This action will be addressed as part of DSM Evaluation, Verification and Measurement processes.
4	**Stakeholder**	NPB
	Topic	Action Plan
	Suggestions/Comments	Add another bulleted item to the list of bullets in Part I of the Action Plan which starts on page 34 as follows: "Provide an updated load forecast to Board staff and interested parties on an annual basis."
	Response	NSPI provides a 10 Year System Outlook (updated annually), an 18 Month Forecast (weekly data updated in April and October) and a 10 Year Load and Resource Assessment (monthly data updated annually) and these documents are available publicly at: http://oasis.nspower.ca/en/home/oasis/forecastsandassessments.aspx

5	**Stakeholder**	NPB
	Topic	Action Plan
	Suggestions/Comments	Add the following words at the end of the final bullet on page 36 that references the exploring of implications of continued low natural gas prices for preferred resource plans: ", and monitor the behaviour of natural gas prices in relation to the values of other parameters and provide an annual report in this regard to the Board and interested parties."
	Response	NSPI provides forecasts containing updated price strips that are available on an ongoing basis in the FAM Confidential Data Room. NSPI has also added the following additional bullet to the Action Plan at page 38 which confirms that the annual progress reports will report on each action item individually: "These progress reports will address each of the bulleted items listed in Parts I and II individually, describing what has been accomplished since the last report and cumulatively since the 2009 IRP Update. Looking ahead, they will indicate next steps to be undertaken and the associated timeline where applicable."
6	**Stakeholder**	NPB
	Topic	Action Plan
	Suggestions/Comments	In the last paragraph on page 32 relative to regular progress reports, insert the words "and interested parties" after the word "Board" in the two places where the word "Board" occurs in that paragraph.
	Response	Agreed. NSPI has incorporated these changes in the Final Report.
7	**Stakeholder**	NPB
	Topic	Action Plan
	Suggestions/Comments	In the first bullet on page 35 relative to the establishment of a collaborative DSM working group to support transition to a new Administrator, add the words "and representatives of each of the industrial, residential and municipal customer classes" after the word "consultants".

	Response	Pursuant to section 40, of the Efficiency Nova Scotia Act, Bill 49, 1st Sess., 61st General Assembly, NS 2009 (assented to 5 November 2009, c. 3), NSPI and the Administrator are required to enter into a transition plan which pursuant to section 42 must be approved by the UARB. It is appropriate that the collaboration contemplated by the first bullet on page 35 be the parties who will be involved in the process of transition of the functional responsibilities associated with DSM administration.
8	**Stakeholder**	NPB
	Topic	Action Plan
	Suggestions/Comments	In the second and third last bullets on page 35 relative to transmission (providing a confidential technical briefing and engaging Board staff in advance of significant transmission-related capital applications), add the words "and interested parties" after the word "Board Staff".
	Response	With respect to the third last bullet, as required by the Market Rules, NSPI annually files a 10 Year System Outlook which contains transmission planning information. It is available on the following site: http://oasis.nspower.ca/en/home/oasis/forecastsandassessments.aspx. The briefing included in the Action Plan is intended to be an informal discussion between NSPI and the Board about confidential transmission infrastructure issues and emerging industry developments. With respect to the second last bullet, Technical Conferences will be held to share information about significant transmission-related capital applications.
9	**Stakeholder**	NPB
	Topic	Action Plan
	Suggestions/Comments	In the first bullet on page 38 relative to the annual progress report, add the words "and interested parties" after the word "Board" in each of the two places in which it occurs.
	Response	Agreed. NSPI has incorporated these changes in the Final Report.

10	**Stakeholder**	NPB
	Topic	Action Plan
	Suggestions/Comments	In the final bullet on page 38 relative to consideration for an updated IRP in 2012, add the words "in conjunction with Board staff and interested parties" after the word "consider".
	Response	Agreed. NSPI has incorporated these changes in the Final Report.