Electricity Framework
5 Year Review

—Generation & Emissions Forecasts —

Report prepared for:

Clean Air Strategic Alliance (CASA)

Submitted to:

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Executive Summary

The Clean Air Strategic Alliance (CASA) is currently reviewing elements of the Emissions Management Framework for the Alberta Electricity Sector developed by the Electricity Project Team (EPT) in 2003. This 5-year review is in accordance with Recommendation 29 from the CASA EPT Emissions Management Framework, November 2003. The EPT 5 year Review Project Team has directed a working group to update the emission forecast undertaken in 2003. This report presents the results from the 2008 Alberta electricity sector emissions forecast and outlines the key assumptions and provides a comparison of the results with the NS1 case presented in the 2003 analysis, dated November 6, 2003.

The outcome of the analysis in 2008 is, in general, a positive one as forecast emission output expectations have changed, the primary driver of which is commodity prices and CO_2 emissions mitigation policy as it relates to the economy and changes in future resource additions. As discussed in later sections, oil prices are substantially above those levels expected in 2003. The effect of this is an increase in behind-the-fence load as oil sands production facilities ramp up productive capacity to take advantage of higher oil prices. Thus, more on-site generation is required, primarily in the form of cogeneration. The higher natural gas price since 2003 has changed the investment decisions of generators leading to less natural gas-fired generation in the latter years of the forecast. The lack of future extra natural gas-fired capacity necessitates increased production from other forms of energy production, the bulk of which is expected to be served by coal-fired units.

The expectation of higher costs in the future reflects significant changes to government policy regarding such things as CO_2 emissions. While not formerly a part of the scope of this document, the effects of environmental legislation are now being felt through changing assumptions regarding the future development of the electric industry, and more specifically supply resource additions. Greater concerns over CO_2 emissions from large final emitters, such as the thermal electric generators and oil sands facilities, are likely to be met with some measure of conservation, if not outright carbon capture, in addition to a migration to those technologies with a much smaller carbon footprint.

The result of the new supply mix alters both absolute emissions and emission intensity levels over the various stages of the forecast when compared with the 2003 results. The 2008 Electricity framework review has higher aggregate coal-fired generation levels than the 2003 analysis but a lower market share of energy production. In this forecast the production from coal units remains relatively flat throughout the 22 year term whereas previously, production from coal was declining post 2010. While gas-fired electricity generation continues to increase, its absolute market share is also less than in the 2003 forecast. Growth in other projects, such as wind and biomass facilities contribute to the reduction in the market share of both coal and gas-fired facilities having the effect of driving the emission intensity levels down. The general result is that while the absolute emission level increases the emission intensity for each of the four substances declines.

Overall, absolute mercury emissions levels have not changed significantly from the 2003 report with the exception of a shift of the regulation implementation date from 2009 to 2011. In 2010 and 2014 there are nominal changes to the absolute emission levels as a result of new retirement date assumptions for Wabamun 4, retiring 9 months earlier, and HR Milner which is assumed to stay in service for an additional 5 years. Mercury emission intensity has declined post 2011 when compared to the 2003 report as a result of renewable energy additions capturing generation market share, most notably of which, are wind and hydro.

Absolute particulate matter emissions follow a similar trend as in the 2003 forecast but are considerably higher throughout the 2008 forecast. This is principally the result of the switch in technology from bag houses to activated carbon for the capture of mercury. Activated carbon and the electrostatic precipitators alone do not provide the associated benefit of particulate matter capture. As well, increased coal-fired generation levels over those in the 2003 report add to the absolute emission level of the current forecast. Particulate matter intensity levels across the forecast have remained relatively flat when compared to the 2003 forecast as higher absolute levels are offset by an overall reduction in generation market share of coal-fired generation shifting to renewable energy technology.

Absolute SO_2 emissions in both cases are relatively constant. However in the 2008 update, post 2022 absolute emissions are considerably higher than were previously forecast as a result of higher output from coal plants to serve the higher load forecast. Intensity levels are appreciably below the 2003 case until 2022. This result is expected and is attributable to the higher level of coal-fired energy production during that period.

The NO_x emission level analysis presents an interesting story which supports some of the conclusions drawn above. The proportion of natural gas NO_x emissions is visibly lower in the 2003 to 2022 period and higher thereafter. NO_x emitted from coal generation is roughly on par with the 2003 report until 2020 where the data shows a considerable appreciation over the 2003 results. Emission intensity, as in the previous emission cases, is well below the 2003 projection as a result of lower overall coal production as a percentage of the total generation.

An important caveat to this forecast update relates to the uncertainty regarding the potential impact of the new Federal Greenhouse Gas Policy, as outlined in the "Turning the Corner" document release March 10, 2008, which is designed to encourage control of greenhouse gas (GHG) emissions beginning January 1, 2010 and that ultimately anticipates full carbon-capture and storage or sequestration by the year 2018. In addition, on July 8, 2008 the Alberta government announced a considerable cash grant of $2 Billion dollars to encourage construction of Alberta's first large scale CCS project. Thus far there is no commercial scale operation of this technology and the monies will be allocated across a number of associated projects including electricity generation, oil sands and upgrading projects. While the forecast updated presented herein accounts for the introduction of additional GHG emission costs, the full extent of carbon capture and storage is not yet fully understood, nor is it ratified into law, and therefore the forecast does not yet incorporate this outcome. The important point is that policy seemingly is moving in this direction despite the lack of technological solutions at hand, which represents a risk to any "business as usual" forecast.

The cost associated with Carbon Capture and Storage (CCS) technologies are still not well-defined; however current projects estimates illustrate that future costs may be as much as $40 to $50 MWh above current conventional facility costs. The introduction of these costs through new technology implementation undoubtedly will affect the bidding strategy and margin of existing plants, influence the decision on the retirement dates of aging plants and will affect the choice of technology. Depending on the final GHG legislation, life extensions to existing plants may be of significant value and if pursued by the owners could result in a negative impact on emission levels forecast in the future. However, the current understanding of CCS technology suggests there may be also be some positive implications on other emissions while reducing GHG emission levels. In any event, the potential for the federal GHG emissions policy to fundamentally alter the generation supply mix and wholesale price levels in the Alberta electricity market suggests that this policy be noted as a potential forecast risk.

Background & Scope of Work

Background

The Clean Air Strategic Alliance (CASA) was established in March 1994 as a forum to manage air quality issues in Alberta. CASA is a non-profit association composed of diverse stakeholders from government, industry, and non-governmental organizations. Representatives from each of these sectors are committed to developing and applying a comprehensive air quality management system for the people of Alberta.

In 2003 the CASA Electricity Project Team (EPT) evaluated several proposed scenarios for reducing air emissions of 5 priority substances from electricity generation facilities in Alberta. To assist this evaluation process, CASA required modeling of these various scenarios to estimate costs (i.e. impact to wholesale electricity price) as well as electric energy production and emissions. As a result, CASA completed a quantitative assessment of the impact on the electric sector under several distinct scenarios and sensitivities thereto resulting from a variation in certain key assumptions.

The key objectives of the previous study work was: to estimate the incremental impact on the annual average wholesale Alberta electricity price, to estimate the impact on the supply stacking order, that is generation energy production by fuel type, and to determine the electric power generation sector's aggregate emissions profile by fuel type (or by technology type) expressed as an average emission for each year.

Now in 2008, CASA is currently reviewing elements of the Emissions Management Framework for the Alberta Electricity Sector developed by the Electricity Project Team (EPT) in 2003. This 5-year review is in accordance with Recommendation 29 from the CASA EPT Emissions Management Framework, November 2003. The EPT 5 year Review Project Team has directed a working group to update the emission forecast undertaken in 2003.

Scope of Work Required

EDC Associates Ltd. will provide the CASA Electricity Framework 5-year Review Project Team sub-group the Control Technologies and Reductions Strategies, with an update to emissions forecasts for the four parameters of NOx, SO_2, Particulate Matter (PM), and Mercury (Hg).

The purpose of this work is to provide the sub-group, with an assessment of the effects that possible changes in the forecast amount and type of generation may have on emissions forecasts as compared to the original forecast analysis conducted in 2003.

EDC Associates Ltd. will provide an update of the 2003 emission forecast for the four parameters: NOx, SO_2, Particulate Matter (PM), and Mercury (Hg)

The primary focus is the emission forecast for the 5 year period from 2008-2013, however the sub-group is also interested in a forecast for the next 25 years (or at least until 2030), as it is recognized that the majority of emission reduction actions will be taken within that timeframe.

All materials used to prepare the forecast (i.e. technical reports) should be identified and either listed or included in appropriate appendices.

Input data (emission intensities for existing units, on a unit-by-unit basis) will be supplied by the working group.

While not explicit in the scope of work as outlined above, the following assumptions have been made with respect to the submission of this proposal:

- Where a single deterministic base case forecast is required for comparison to the 2003 forecasts, and
- The base case is to be based on the assumption that all emissions reductions are met through physical reductions resulting from incremental capital investment and operating costs associated with retrofits or enhancements made to each unit where possible—rather than by a cap and trade mechanism.

Work Plan and Milestones

EDC's proposes to complete the following high level tasks identified as part of the overall work plan:

1) Identify all information and data necessary to calculate the desired quantitative emissions metrics and review previous forecast assumptions, results and conclusions,
2) Develop:
   a) Draft report, and
   b) Database for data and metric calculations and populate with forecast data already in possession, review for accuracy and deficiency,
3) Update and extend all forecast models and vet assumptions to 2030,
   a) Milestone: Assess assumption data set for deficiencies and communicate status and or remedial action taken,
4) Generate forecasts for the desired quantitative emissions metrics (for all four substances: NOx, SO_2, PM and Hg)—review for accuracy and reasonableness,
5) Compare and contrast current forecast results with 2003 forecasts,
   a) Milestone: Issue draft forecast data for review and comment
6) Complete draft report and circulate for review and comment,
   a) Milestone: Issue draft report for review and comment
7) Finalize report material.

Review of NS1 Case Forecast (2003)

In reviewing the analysis completed as part of the Emissions Management Framework for the electricity sector in 2003, it is apparent that circumstances have changed that have resulted in slightly different outcomes than expected. While, the previous analysis correctly identified many issues that could have a material effect on the outcome of the forecasts, some of which have come to fruition as expected and other outcomes which were the result of different or unexpected circumstances. It is clear that in the past five years, the landscape surrounding the Alberta electric industry has changed dramatically in response to underlying fundamentals and some unforeseen policy changes.

Five years ago, while the economy in Alberta was expected to be strong with real GDP growth forecast at 3 to 4 percent from 2004 to 2008 (averaging 3.4 percent), very few predicted the "boom" that propelled real GDP growth to a level almost twice that expected—ranging from 3 to 7 percent (averaging 5.4 percent). This very high economic growth has largely resulted from the secondary and tertiary economic effects of a substantial increase in the price of crude oil and natural gas that has spurred an unprecedented level of drilling for natural gas and the development of northern Alberta's oil sands. While higher oil and natural gas commodity prices were expected, the levels actually reached have surpassed even the high case scenarios and sensitivities envisioned at the time. Many of the events and circumstances underpinning higher commodity prices worldwide have largely resulted from events and circumstances outside the control of Canada or the United States, much less Alberta.

Consequently, the high level of direct oil and gas activities reached has spawned growth across almost every sector of Alberta's economy over the last five years actually bringing the economy close to the limits of its potential. The limits of economic growth potential have been tested by all of the unintended outcomes related to the shortages experienced of almost everything, from labour to housing and materials, which has limited growth through higher costs and delays.

In addition, the expectation of higher costs in the future has also resulted from significant changes to government policy particularly regarding such things as emissions related to carbon dioxide. While not formerly a part of the scope of this document, the effects of environmental legislation are now being felt through changing assumptions regarding the future development of the electric industry, and more specifically supply resource additions. Greater concerns over CO_2 emissions from large final emitters, such as the thermal electric generators and oil sands facilities, are likely to be met with some measure of conservation, if not outright carbon capture, in addition to a migration to those technologies with a much smaller carbon footprint.

The latter has already started to occur with a significant increase in the development of wind power as its technology has made tremendous advancements in terms of unit cost reductions resulting from increased utilization rates and onsite construction cost optimization. While CO_2 emission reductions are now part of the landscape, complete carbon capture is still a ways off, having only been introduced by the Canadian Federal government in early 2008 and not yet ratified into law. However by early 2009 this could be ratified for implementation by as early as 2018.

All of these issues combined, have meant that business as usual is quite a bit different today than it was only five years ago. This is not to say that these events were not contemplated, as many of them were tested using scenario and sensitivity analysis, but many of the issues were excluded from the business as usual case. That said, the following sections outline the "thinking of the day" with respect to the many key underlying assumptions of the business as usual case from the 2003 report.

2003 Electricity Demand and Supply Forecast

This section presents a review of the forecast of macroeconomic conditions and the related electricity supply and demand assumptions that formed the inputs to the 2003 NS1 Case.

Macroeconomic Forecast

The Canadian, American and Albertan macroeconomic forecasts form an important element in the electric energy demand forecast. Residential, commercial and industrial growth rates all depend on the overall health of the economy. This section presents the macroeconomic environment assumptions employed in the 2003 NS1 Case forecast that underpinned the energy demand forecast presented in the next section.

United States

At the time of the original report consensus implied that the United States was recovering from an economic downturn. Interest rates were at historic lows and GDP growth had been exponential over the previous two quarters as a result. Employment reports were positive with 308,000 net jobs created. GDP growth in the US was expected to remain strong throughout the following year and the majority of forecasts pegged annual growth at around 4.9% in 2004 moving to a more sustainable 3.5% in 2005. American retail growth was strong supported by tax breaks and business investment was encouraged by accelerated depreciation on machinery investments. The strong forecasts for the next two years suggested that many analysts believed in a continuation of a fundamental recovery in the US.

Canada

In 2003, the Canadian economy was expected to continue to grow at its long-term sustainable path of 3% per year, the inflation rate was forecast to fluctuate around the Bank of Canada's target of 2% and the unemployment rate was expected to level off at 6.8% over the long run. The Canadian dollar was expected to appreciate through the next few years to a target of $0.77 cents US. Recognizing that the Canadian economy was heavily export dependant, the domestic growth rate was expected to drag as a direct result of the strength in the dollar. However, there was the thought that the continued strength in energy and other commodity prices may offset the impact of a high Canadian dollar on the economy.

Despite the rough start to 2004, most analysts foresaw a relatively healthy Canadian economy in 2004 and 2005. GDP growth was pegged between 2% and 3% in 2004, and was forecast to propel to over 3% in 2005. As the real GDP numbers came in the Bank of Canada expectedly increased the interest rate through successive periods peaking at 4.75% in July of 2007. The Canadian economy has proven to be quite resilient to the US economy during the recent downturn south of the border, a marked change from the 2004 timeframe when Canada's economy tracked the US economy closely.

Alberta

Growth from a variety of sources helped push the Alberta real GDP growth rate to 3.1% in 2003, exceeding the national GDP growth rate by 1.4 percentage points. According to the Alberta government, growth in 2003 was spurred by a sharp increase in conventional energy sector investment (fueled by high energy prices) and a robust household sector. Alberta's retail sales remained the highest in Canada, housing starts continued at near record levels and Alberta led the country in job creation, growing by 2.9%. Also, Alberta's manufacturing sector recorded a very strong performance, growing by 5% for the year, compared to a decline of 1% nationally.

Over the 2004 to 2020 forecast period the Alberta economy was forecast to grow at an annualized rate of 3.3% the unemployment rate was forecast to average 4.9%, as migration from other provinces was expected to prevent it from falling further. Across the 2004-2020 forecast period, the number of net migrants was forecast to average 48,700 persons per year. This level of net migration was expected to have a direct impact on economic activity and energy consumption. Finally, housing starts were projected to decline from 2003 levels but were forecast to remain high by historical standards.

Electric Energy and Demand Forecast (AIES and AIL)

This section presents a summary review of the demand and supply output from the 2003 NS1 Case to provide the basis for comparison to the 2008 Forecast update. While there have been considerable changes to the forecasting model over the past 5 years the rationale and logic employed in 2003 continues to be employed today thus allowing for a direct comparison between the two analyses. The macroeconomic forecast under the 2003 NS1 Case explored the likely impacts of the Kyoto Protocol on the overall economic climate in Alberta.

These background assumptions were important drivers of the energy demand forecast, which is presented in Table 6 in Appendix 2 for reference.

AIES energy sales were and continue to be substantially lower than Alberta's Internal Load by definition. The difference is related to behind the fence load and exports. AIES energy sales were forecast to grow at 1.6% annually in the 2003 report generating total sales of 77 TWh by the year 2025. AIL energy sales posted a forecast growth rate of 2% annually yielding energy sales of just under 94 TWh in 2025. This suggested that exports and behind the fence load growth were a considerable component of AIL energy growth with the latter being of greater significance. Internal load peak demand was also forecast to grow faster than the AIES peak demand as the measurement closely tracks the energy demand forecast. The difference was forecast to reach near 2,100 MW by 2025, which is a substantial increase from the 1,230 MW difference forecast in 2003.

From an emissions perspective, the energy attributable to onsite load that is not included in AIES energy is very important. Although the vast majority of this load is met with very efficient gas-fired cogeneration technology, there is still a significant amount of GHG and NO_x emissions associated with this type of generation. If an emissions forecast is presented without this energy, it significantly understates total emissions from the electricity sector. Over the forecast period the economy as a whole was expected to become more efficient as new and more efficient technologies become economic. In addition, the implementation of energy efficiency measures in all sectors was forecast to be most significant in the residential and commercial sectors.

Supply Resource Capacity Additions and Retirements

Capacity Additions

Generation is added to the dispatch model over time in two ways. First, publicly announced projects are assigned a probability and a completion date based on their level of development and an assessment of their economic viability. Second, when necessary, generic capacity is added to supply when the reserve margin reaches a critical level that necessitates new projects in order to maintain system stability and reliability. The model produced large forecast reserve margins from 2003 to 2009 due to near term project announcements combined with the 3.5% renewable energy target in place for 2008.

The supply additions for the NS1 Case were based on:

1. Publicly announced projects from 2003-2009
2. Generic combined-cycle and simple-cycle backfilling from 2009 onward to meet a reserve margin of 13%.

In the previous forecast there was roughly 1,000 MW of additional wind power installed by 2008. This volume of wind capacity necessitated an increased reserve margin of 15% to reflect the intermittent and energy constrained nature of the additional wind power.

Retirements

The underlying assumption in the analysis was that coal plants have an economic life of 50 years and natural gas-fired units have an economic life of 40 years[1]. However, contrary to this basic assumption, several retirements were assumed to take place during the forecast period as a result of contractual obligations and physical operating characteristics. Table 1 shows the units and retirement schedule utilized in the 2003 NS1 scenario referenced in this document.

[1] Some behind the fence natural gas generators are assumed to upgrade to meet emission requirements for NO_x and continue operation beyond 40 years.

Table 1 – 2003 NS1 Case Generation Unit Retirement Schedule

EDC - 2003 NS1 Case Retirments					
Generator Unit	Company Name	Fuel Type	Gross MCR	Net to Grid MCR	Retirement Date
Clover Bar 1-4	EPCOR	Natural Gas	628	628	Jan-06
Rossdale 8-10	EPCOR	Natural Gas	209	209	Jan-06
Sturgeon 1-2	ATCO	Natural Gas	18	18	Jan-06
Rainbow 1-3	ATCO	Natural Gas	87	87	Jan-06
HR Milner	ATCO	Coal	143	143	Jan-09
Wabamun 4	TransAlta	Coal	279	279	Jan-11
Battle River 3 and 4	ATCO	Coal	296	296	Jan-16
Sundance 1 and 2	TransAlta	Coal	560	560	Jan-18

The decision to retire HR Milner was based on its operating costs and fuel supply options. The 2002 sales agreement for the plant highlighted that the new owners procured coal supply for the facility for 2004 through 2008 although alternative options were being pursued. Since the facility was only marginally economic over the course of the next several years, it was assumed that it will not be extended beyond this coal supply agreement. The Battle River and Sundance retirements occur as a result of the mercury emission policy requirements coinciding with the expiration of their PPA.

Review of Key Assumptions

There were a number of assumptions that impacted the forecast, both in terms of emissions and prices, and thus presented the risk of forecast error. The NS1 case had the embedded expectation that natural gas prices would increase as a result of specific continent wide policies to reduce GHG emissions which had very little to do with any specific policy measures enacted by the Alberta electricity industry. Natural gas price risk was identified as being the number one risk in a price forecast for the Alberta electricity industry as it had and still has the propensity to play a role in the type of generation development that takes place and the related impact on emissions. Building on the risk mentioned above, the type of generation was considerably prone to forecast error.

Transmission policy development was undergoing change during the course of conducting this analysis. The underlying transmission assumption in the report was that transmission investment requirements would influence generation development. Changes to the congestion management aspect of the transmission policy would increase the likelihood of the Keephills expansion being built. However, the analysis in 2003 assumed that cogeneration projects in northern Alberta prevailed over incremental coal plants based on the assumption that most projects were slated to occur in conjunction with heavy oil and oil sands developments. It was forecast that 1,300 MW of cogeneration (net-to-grid) was to be developed between 2004 and 2025.

While this was a valid assumption at the time, the low realized power prices experienced in late 2004 and 2005 combined with the high natural gas prices limited the willingness of oilsands developers to develop surplus capacity for sale to the grid. As well, cost overruns on many of the large oilsands projects have further caused these developers to scale back their cogeneration capacity to more-or-less meet their onsite load. Consequently, there is less cogeneration and more coal capacity today versus the assumptions in 2003. This is an important consideration because it highlights the responsiveness of developers to changing market dynamics in Alberta and the associated risk of forecast error.

The 3.5% renewable source requirement also contained elements of forecast risk. The NS1 price curve was not high enough to ensure full cost recovery for the wind generator so the required subsidies were estimated. It was calculated that the wind units had a levelized cost of $68/MWh and $60/MWh assuming 15% and 10% levered equity returns, which was higher than the forecast revenue throughout most of forecast term. The need for incentives was forecast to be neutralized at a capital cost of $1000/KW which dropped the all-in costs for wind capacity below the average price in the forecast. As well, embedded in the cost numbers quoted for wind generation was the Wind Power Producers Incentive (WPPI), and the required subsidies were in incremental to the WPPI.

Offsetting the expiration of the WPPI in today's market is the lower capital cost of wind generators and the higher pool price forecast. Combined these factors have reduced the need for subsidies as wind units are now an attractive investment on a standalone basis. The potential for credits/offsets under an emerging Federal plan further incents developers to bring wind generation online.

Analysis suggested that no coal plants will be forced to retire for purely economic reasons as a result of the potential environmental policy frameworks examined in the original document. However, this did not suggest that there were not large cost implications for the existing generation fleet. For example, the average increase to a coal-fired generator was $1.80 per MWh, but with a total cost of $2.7MM for the entire fleet. The NS1 Optimized Case put the least cost on generators and resulted in no coal unit retirements from the existing coal fleet but there were large aggregate cost associated with coal plant emissions by 2030.

5-Year Emissions Forecast Update (2008)

2008 Electricity Demand and Supply Forecast

Over the past 5 years, while many things have remained the same—others have changed dramatically. The current outlook for growth in the electric industry is more robust than previously anticipated from a base case point of view. The forecast for demand has accelerated to higher levels on the back of increased oil and natural gas developments that has spurred much higher levels of economic activity. Resource development has also changed course with greater concerns over GHG emissions driving some investment choices as well as rising capital and operating costs of most all thermal generation technologies. The combined effects of these changes to the supply and demand forecasts have generally pushed up on future expected power prices along with creating more near term volatility and long term uncertainly. The following sections outline the current set of assumptions that provide the basis of the current electricity forecast update and the subsequent outlook for absolute emissions and emission intensity.

Macroeconomic Forecast

This section reviews the major macroeconomic variables in the 2008 forecast which influence Alberta's future GDP growth. Since GDP and electricity consumption are closely correlated, they help provide a solid context for the energy demand forecast. Table 3 in Appendix on page 30 outlines the major economic assumptions employed in the forecast.

United States

In the US, what had started as a subprime lending issue has led to a nationwide credit crisis. Weakness in financial markets and low real GDP growth has resulted in the US Federal Reserve Chairman, Ben Bernanke, informing Congress that a recession is possible. Recessions are generally characterized by negative economic activity, associated with high unemployment and negative real GDP growth, lasting for two consecutive quarters. The capability of the country to weather this financial storm is now further complicated by liquidity and consumer spending issues, domestic employment degradation and increasing food and fuel prices.

Job losses have started to become an issue and are expected to grow through the remainder of 2008 and into 2009. TD Bank expects the unemployment rate to reach 5.3% compared to 4.6% recorded in 2007. High unemployment will depress personal income which will, in turn, reduce domestic consumption. Throughout this financial crisis the US economy has been supported by strong consumer spending in spite of dropping personal disposable income since the final quarter of 2007. As the impacts filter through the economy we see less available credit, a continued decline in housing prices and financial market losses which have eroded personal net worth have now began to moderate consumer spending. During the first quarter of 2008, Congress passed a fiscal stimulus package aimed at boosting consumer spending. The Economic Stimulus Act of 2008 will send cheques of up to $600 per person out in May and June of this year. Most analysts expect that over half of the money will be saved and the remainder spent. While this should contribute to GDP growth, most analysts expect that its influence will be temporary.

Canada

The condition of the US economy directly impacts Canada through its export sales. RBC says the combination of tighter credit conditions and weaker US demand for Canadian goods is a good indication of modest economic growth for the Canadian market. While low unemployment and average wage growth have allowed for modest gains in the domestic economy, levelizing real GDP growth this year suggests that the risk of declining future growth is a real possibility although this is not currently forecast in the 2008 analysis. The Bank of Canada (BOC) has lowered the overnight rate 3% in attempts to thwart the cross border effects of a longer and more pronounced US economic slowdown.

The BOC noted that the domestic economy is expected to remain strong despite tightening credit conditions and slowing business and consumer spending. The percentage point decrease in GST this January as well as increased competition from imports through the higher exchange rate has lead to lower prices for retail domestic goods. As a result, inflation this year has hovered near the BOC's target rate of 2%, with gasoline prices and mortgage costs being the main contributing factors. Near the end of the year, there is the potential for inflation to rise as the BOC rate cuts further impact the market.

The Loonie peaked in October 2007 at 1.10US$/C$ and has since fell to parity with the American dollar where it has remained throughout much of 2008, averaging, at the time of writing, 0.99 US¢/C$. Historical analysis shows that the Canadian currency is positively correlated with the price of oil and the recent oil price escalation is support the stronger Loonie. Nonetheless, in the second half of the year, most forecasts expect that the Loonie will depreciate so as to average 0.96 US¢/C$ over the full year, dropping to 0.95 US¢/C$ by 2009.

Canadian real GDP growth is forecast to average 1.6% in 2008, rising to 2.3% in 2009. This forecast reflects the risk of declining economic activity mainly in those areas impacted by the US. This slow real GDP growth is despite a strong domestic economy supported by retail sales, low unemployment and hourly wage growth. As the rate cuts made by the BOC make their way to the consumer and the US economy begins to rebound, real GDP growth in Canada should rise.

Alberta

The economic climate in Alberta continues to depend to a great extent on the levels of energy exports. Fears that Alberta's economy would be impacted by high oil prices and a weak US have eased over the past quarter as energy related exports have soared, unemployment remains tight, and real GDP growth is forecast to be almost twice Canada's average. Alberta continues to increase oil production and exports by supplementing its declining conventional oil production with larger increases in non-conventional production. Industries other than oil and gas (e.g. manufacturing) have also been growing over the past few years, although the rapid growth in the oil and gas sector has technically kept the economy from full diversification.

The recent high prices for natural gas, crude oil, and coal have led to significant increases in energy related exports. The value of exports leaving Alberta in March reached $8.5 billion, around 22% higher than exports from March 2007 and the highest monthly figure in history. During the first quarter, exports totaled almost $5 billion above the same period in 2007, suggesting Alberta is well on its way to its sixth consecutive year of record annual exports. Around 88% of Alberta's exports are destined for the US, mostly energy related. However, Alberta also exports some agricultural, industrial goods, and manufactured products which should see increases in demand as the American economy recovers.

Over the past five years Alberta's population has grown by 2.2% with inter-provincial immigration accounting for the majority of increases. According to the most recent Alberta Population Report from Alberta Finance, the last two quarters of 2007 recorded negative net inter-provincial migration as the combination of more affordable housing costs and demand for skilled workers in Saskatchewan entice Albertans to leave. Still, Alberta is expected to grow to over 3.5 million people by the end of this year.

Building permits for Alberta totaled $3.7 billion over the first quarter of this year, down about 4% from the last quarter of 2007. This decline was mostly the result of poor numbers in March as the first two months of 2008 registered construction projects at a record setting pace. Permits in March amounted to about $997 million, ending thirteen straight months of building permits valued at greater than $1 billion. Compared to the peak set during Q2-2007, building permits in March were about 19% lower with declines in both residential and non-residential construction. Some of this difference can be explained by some of the huge one-off projects that were issued building permits in 2007, such as the $1.1 billion Bow Tower in Calgary. There have been legitimate declines in the residential construction sector influenced by lower net migration and high inventories.

Reaching a high of 7.0% real GDP growth in 2006, the Albertan economy has cooled with this forecast calling for real GDP growth of 3.7% and 3.8% in 2008 and 09, respectively. Most of this growth can be attributed to oil and gas related investment. As oil prices surpass all-time highs and natural gas prices rise to near double-digits, making even the more capital intensive projects economical. It is important to note that this forecast reflects slower GDP growth associated with higher costs of living and a tight labour market. Over the forecast period, real GDP growth is expected to average 4.0% as real GDP growth is expected to rise in the later years of the forecast period. Table 4 and Table 5 in the Appendix outline the economic assumptions for the Alberta economy.

Oil and Natural Gas Price Forecasts

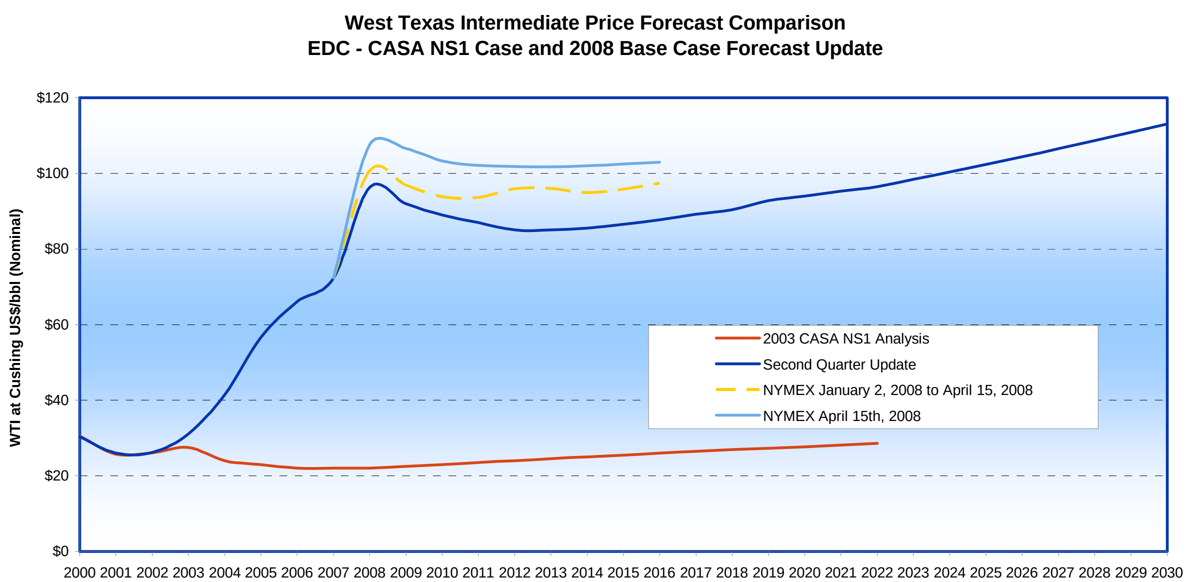
Natural gas and crude oil prices are important economic drivers within Alberta and crude oil prices have the potential to impact the electricity industry profoundly. In the model both the electricity demand forecast and generation supply forecast are heavily influenced by the forward view of world crude oil prices. As discussed previously, natural gas prices are an important fundamental input in an electricity price forecast for Alberta. The most significant impact created by natural gas prices comes about because natural gas is the fuel source of a growing portion of the generation fleet in Alberta. Further, emission regulations could mean that capacity, and more specifically peaking capacity, will tend to be provided by natural gas-fired units. This section compares the oil and natural gas price assumptions utilized in the 2003 NS1 Case with the 2008 Base Case analysis.

Oil Price Forecast

In 2003 the price for WTI had hovered around the US$35/bbl range following the resolution of a number of world political events. The NYMEX futures markets were backwardated valuing crude between US$25/bbl and US$28/bbl. The forecast had prices remaining relatively flat in real terms escalating at the inflation rate over the long term. In 2008 the price of WTI has escalated dramatically to US$126/bbl. Short term forward prices are in contango peaking at US$140/bbl with some analysts calling for US$150/bbl as we enter the "peak oil" era .

The short-term and long-term WTI price forecast in this study was derived from a consensus of sources that include the NYMEX WTI forward curves several fundamental forecasting consultants, the EIA's Short Term Energy Outlook and the RSEG Oil Report. Figure 1 depicts the current forecast plotted against the 2003 forecast and the average NYMEX forward curve. Between 2008 and 2013, the WTI average price is forecast to average US$89.04/bbl reaching US$113.07/bbl by 2030. Most fundamental forecasts have recently raised their price estimates as the forward market seems to indicate that there is no end in sight to $100/bbl plus WTI prices. Compared to the 2003 report, the current forecast anticipates higher prices through the entire forecast period with a continuation of the bullish market activity seen over the past two quarters. This oil price forecast is significantly higher than the 2003 report and has generated considerable differences in the electricity market forecast including forecast load growth and behind the fence generation projections. The average increase in the crude oil price is approximately US$60/bbl.

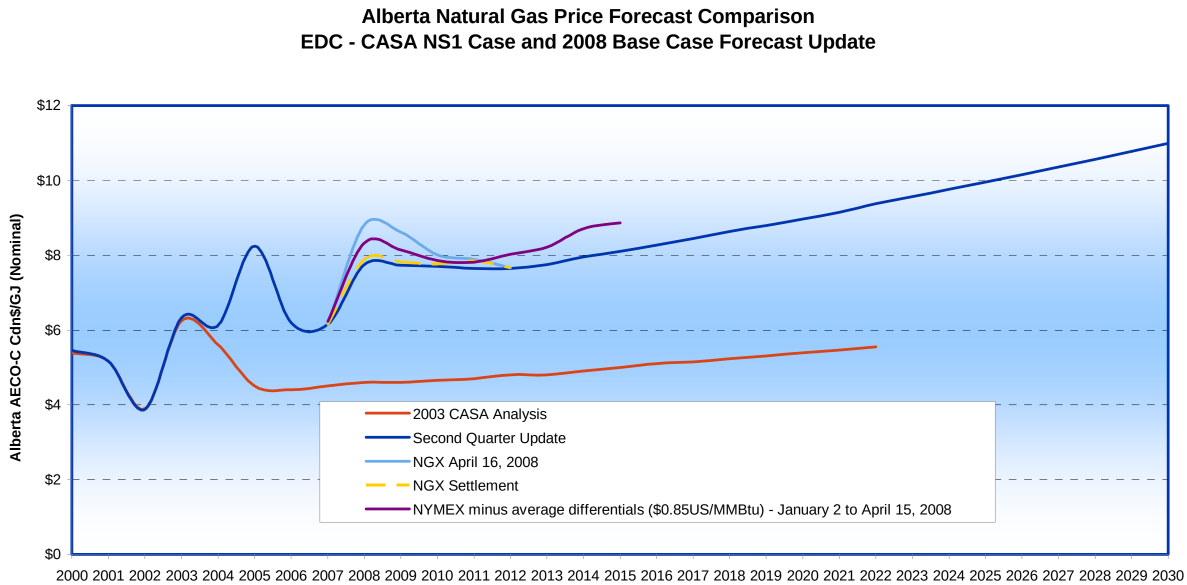
Figure 1 – US Crude Oil Price Forecast Comparison



Natural Gas Price Forecast

In 2003, natural gas prices were on a turbulent path with AECO-C spot prices ranging from C$5.42/GJ and C$15.29/GJ. Forward markets were relatively flat with seasonal fluctuations averaging 10%. Thus far in 2008 natural gas prices have averaged C$8.23/GJ which marks an increase of 34% from the average price in 2007. The low prices received in 2007 precipitated slower rig activity in 2007 resulting in significantly lower WCSB production. The reduction in production has provided support to higher prices and upticks in the forward natural gas market price which are expected to encourage activity in the WCSB.

Figure 2 – Alberta Natural Gas Price Forecast Comparison



The AECO-C forecast presented in Figure 2 is derived from a consensus of sources that include the NGX forward curve, the NGX average settlement price, and the NYMEX forward curve average settlement price. In addition, natural gas price forecasts from several fundamental forecasting consultants were used.

The current forecast shows Alberta natural gas prices averaging $7.91/GJ between 2008 and 2013 and $8.96/Gj over the entire forecast period 2008 to 2030. The difference between the 2003 and 2008 Natural gas price forecasts is considerable at ~$3/GJ higher on average. Currently, on a BTU for BTU basis natural gas is cheaper than heating oil for switchable customers. In fact, at a 6:1 ratio natural gas prices could theoretically rise above US$20/Gj before switching takes place. This scenario is likely not sustainable as other market factors will adjust the prices.

Electric Energy and Demand Forecast (AIES and AIL)

Year-to-date electric energy consumption has recovered from the sluggish pace set in 2007 with most of the increases stemming from higher domestic AIES energy sales. First quarter domestic AIES energy sales, or energy traded through the AESO and consumed in province, increased 2.2% over domestic AIES energy sales from Q1-2007 as a result of a number of severe cold weather periods. During 2007 the lower level of activity in the natural gas sector and the slowdown in sectors of the economy that are sensitive to the exchange rate and economic activity in the US caused some deceleration in energy demand over the year. As commodity prices rise and economic activity recovers there it is expected that these sectors will return to more normal levels and energy demand will follow. Table 7 in the Appendix on page 20 presents the demand forecast output from the 2008 model run.

Year-to-date (January to March) AIL, which includes domestic AIES energy sales, City of Medicine Hat load, and behind the fence load, has seen cumulative growth of 1.9%. Increases in domestic AIES energy sales are responsible for the majority of the growth with declines in year-over-year behind the fence load persisting. Declines in behind the fence load from disruptions in behind the fence operations, mostly in oil sands and related sectors, caused projects to be derated or completely off-line for unscheduled maintenance. It is expected that these disruptions are temporary issues and historical growth trends should resume.

AIES energy sales (including exports) are expected to grow by 3.5% annually between 2008 and 2013 compared to a 1.5% annual average growth rate (AAGR) in the 2003 forecast; a 133% increase. Over the entire forecast period, 2008 to 2030, a 2.5% average annual growth rate is forecast whereas 1.6% was used for the same period in the 2003 forecast. In this forecast AIL load growth is expected to grow annually by 4.9% between 2008 and 2013 while over the longer term to 2030 the average annual growth rate is 3%. It is interesting to contrast these growth rates with the 1.8% and 2% used for the same periods in the 2003 AIL forecast.

The main driver in the difference between AIES and AIL is demand from the behind the fence load of the oil and gas sector which is forecast to see increased production as a result of the higher commodity price environment. AIL load growth is based on the assumption that several major oil sands projects will be completed within this time frame adding additional behind the fence load. Of course, any delays in the commissioning of these projects will have an effect on AIL growth.

Figure 3 compares the 2008 energy forecast to the 2003 NS1 Case in GWhs. Post 2010 the current AIES forecast is substantially higher than it was in the 2003 analysis. The divergence between the two forecasts after 2010 reflects the increases in behind the fence load associated mostly with developments in the oil sands sector. Given the higher crude price forecast and the expectation that prices could remain elevated for some time, it is expected that oil sands producers will be eager to bring their projects on-line and reap the benefits of these higher prices. Overall the 2008 long-term demand forecast is consistent with the expectation that production of bitumen and synthetic oil will more than triple by 2030.

Figure 3 – AIES and AIL Energy Forecast Comparison

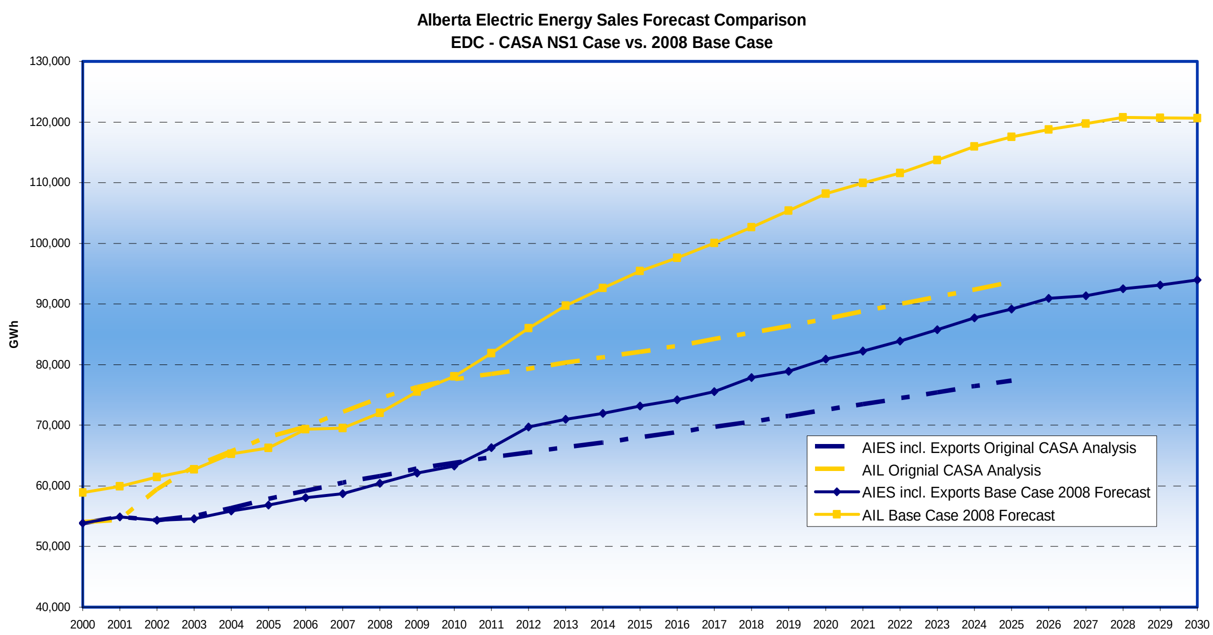
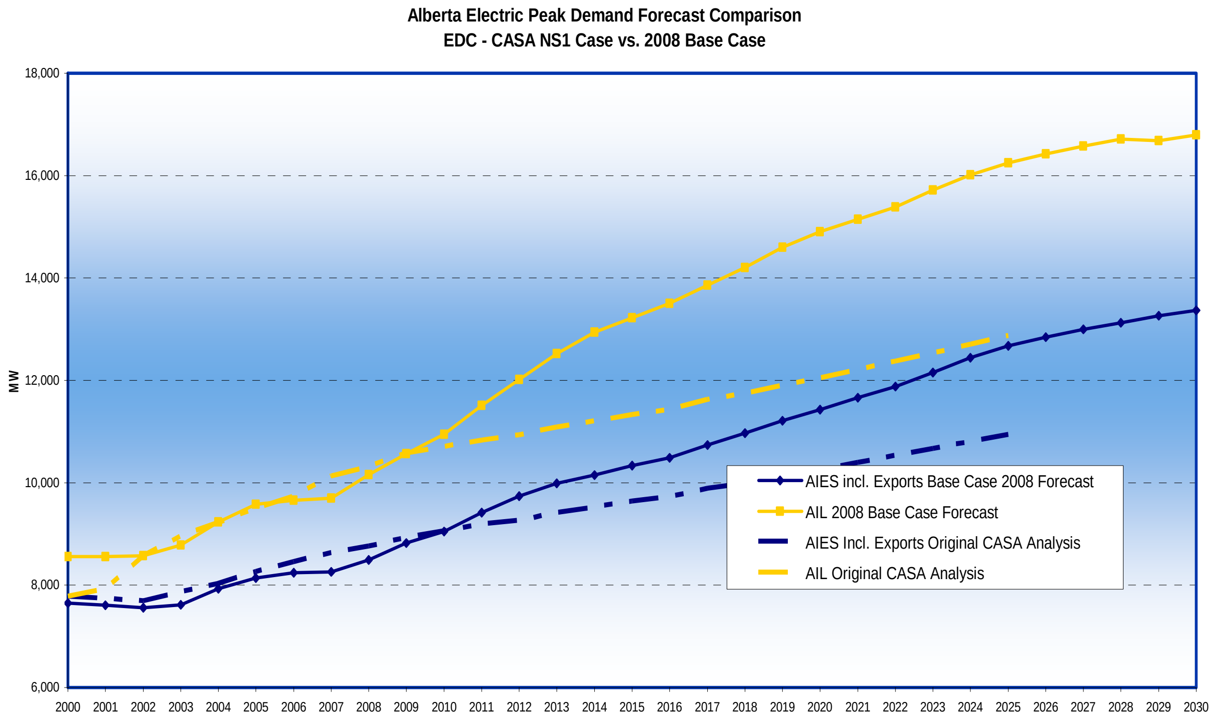


Figure 4 shows peak demand in MWs which follows roughly the same trend as energy growth. However, it should be noted that the long-term load factor forecasts are subject to uncertainties that affect the peak demand forecast exclusively. Pool prices and advances in technology may also affect the way customers respond to pool price (load responsiveness or direct load control), potentially impacting load at the time the system peaks.

Figure 4 – Alberta Energy Peak Demand Comparison



Electricity Supply Forecast

The following sections outline the key assumptions regarding future resource development in response to the demands of future load and subject to development constraints and changing generation technology and its cost structure.

Supply Capacity Additions and Retirements

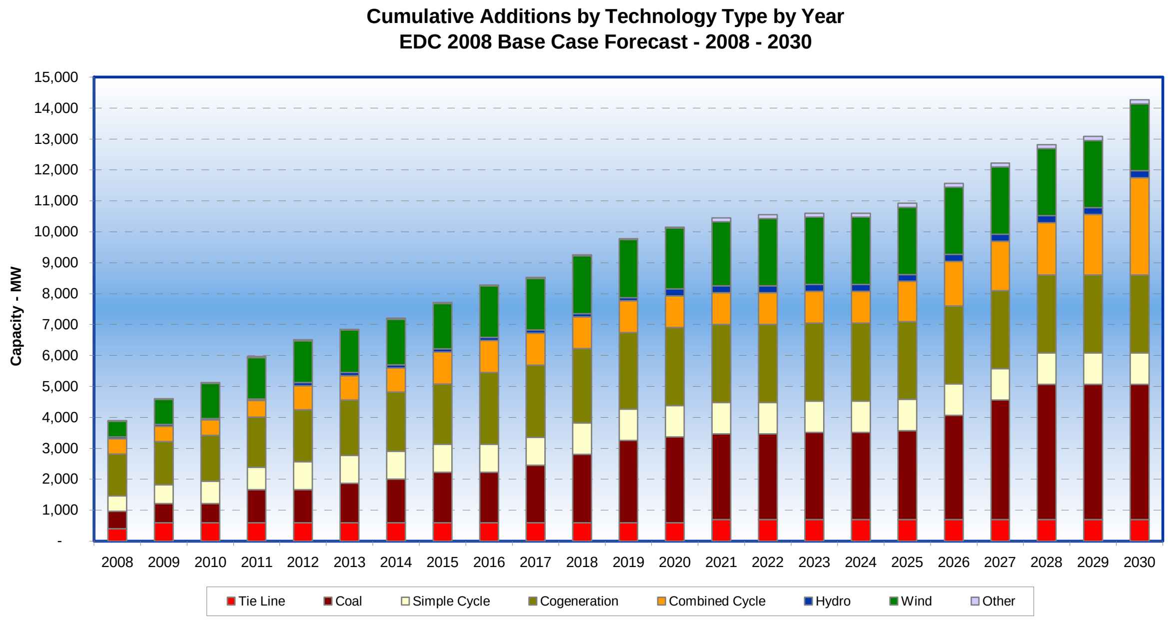
Total supply resource additions are largely made up from know or announced generation project along with other speculated or generic projects that are required to meet incremental demand and future capacity retirements.

Generation Projects Publicly Announced

In the 2003 NS1 Case over 6,000 MW of capacity was added to the forecast, the bulk of which was combined-cycle natural gas-fired capacity. The thinking of the day was that northern Alberta industrial loads would build incremental capacity over their on-site load needs. Natural gas was preferred over coal for fuel because of its low forecast cost and clean burning attributes. The subsequent increase in natural gas prices, the development of emissions control technology and the realization of some certainty in the emissions regulation arena has brought coal–fired generation back into favour. As well, in the 2003 forecast there only 800 MW of wind capacity added over the entire forecast. At the time, wind generation facilities required subsidies to operate at a profit whereas today technological costs have come down and power prices have increased. Additionally, the potential opportunity to utilize wind power as an offset to company-wide GHG emissions makes the projects even more attractive to developers. In 2008 there is in excess of 2,000 MW of wind capacity added over the duration of the forecast.

Figure 5 shows the cumulative generation additions by technology until 2030 from the 2008 forecast. New capacity is expected to be met from announced projects, future projects that may have been identified but not yet announced, plus speculative projects. The projects noted below form a large portion of the capacity additions forecast between 2008 and 2021 following which generic projects are added as needed. Coal, wind and cogeneration projects dominate this list, but gas-fired simple-cycle project announcements have become more prominent over the past couple of years. There are also two combined-cycle plants that will potentially run on synthetic gas from coal gasification. EPCOR's Dodds-Roundhill project will use synthetic gas from a gasification plant being proposed by Sheritt and recently, Enmax has announced that a portion of its proposed 1,000 MW Sheppard Energy Centre may be powered by gasifying coal, however very few details are available on the Enmax project.

Figure 5 – Cumulative Supply Additions by Technology



The forecast also includes over 3,000 MW of net-to-grid generation capacity between 2008 and 2013 with the large majority (though not all) of the generation based in northern Alberta. The uncertainty over which projects will actually proceed combined with uncertainty around the amount of net electricity available leads to low probabilities for some of the projects. Additionally, some cogeneration projects are not expected to come on-line according to the developer's original schedule but according to an expected date of completion for oil sands projects that is driven by the oil sands forecast in this analyses. Oil sands projects are expected to be completed according to the current oil production forecast, where production of raw bitumen and synthetic oil is anticipated to triple over the forecast horizon. In total there is over 14,000 MW of capacity installed in the province between 2008 and 2030.

Within the federal GHG emissions framework it is stated that carbon capture and storage (CCS) will be a viable option for reducing emissions with targets based on CCS for coal units effective by 2018. Some analysis of the increased costs that would result from including CCS with the main generation types in Alberta suggests that with carbon capture, the average pulverized coal unit's bid into the market could rise by 70%. This analysis implies that coal generation, historically the cheaper alternative of electricity production, would need cost recovery from the market equivalent to that of a nuclear generator, if and when CCS becomes mandatory. This increase in costs is compounded by the fact that technology associated with CCS is new to Alberta with no physical CCS currently in existence in the province. History has shown the new technological projects are prone to cost over-runs and delays. This simple example of the effects of GHG emissions policy shows the extent to which future generation is likely to be impacted. The province is expected to face higher base-load generation costs as existing coal units comply with environmental policy. Meanwhile, nuclear and hydro facilities will become more economically viable albeit logistically more difficult, which can already be seen by the announcements of Bruce Power Nuclear units and the Slave River hydro project.

In regards to the significant numbers of wind projects included in the generation forecast several projects have suffered delays as a result of delays with the upgrade to the southwest transmission system. The AESO has said that there are as many as 9,000 MW of wind projects on the books but at other presentations it has mentioned that only 1,400 MW can be accommodated with approved transmission upgrades. Given the current state of the transmission system and upgrades being built in the next few years our province will not be able to accommodate the announced amount of wind. It is very difficult to determine what projects will get built first and it is also hard to determine exactly when the projects will actually get built for a variety of reasons. Like the probabilities for coal projects, a component of the probabilities assigned to wind projects should be considered from a strictly analytical perspective and not so much from a development perspective. The forecast concerns itself with what is perceived as a reasonably possible amount of overall wind added in a given year rather than which projects comprise that amount.

Generation Retirement Assumptions

Generation unit retirements are an important element of the resource adequacy picture, as there are several older coal and natural gas facilities that could retire in the near future at the end of their physical and useful life. In aggregate the model has 626 MW of gross capacity and 591 MW of net-to-grid capacity retiring between 2008 and 2013. Of the later amount, approximately 313 MW is natural gas-fired and 279 MW is coal-fired. Plant retirement assumptions over the next 5 years are outlined in Table 2.

The majority of the plants listed in Table 2 are being retired because they are reaching the end of their reasonable operating life, although some plants like Sundance 1 and 2 and Battle River 3 and 4 are assumed to retire specifically as the result of environmental policy (CASA recommendations for mercury standards). With federal legislation potentially coming into effect by 2012 it is possible some older plants may retire around this time rather than upgrade. However, with the potential to trade emission credits for NO_x and SO_x, new environmental standards may not trigger any retirements not already contemplated.

TransAlta has announced that it may consider extending the life of Wabamun 4 as regulatory uncertainty, uncertainty around transmission development and environmental rules may potentially delay decisions to build new power plants. Within the forecast, Wabamun 4 is assumed to retire in March 2010, but there is some degree of risk around this assumption. Some might argue that Wabamun 4 may not retire until Keephills 3 gets built, particularly if a supply crunch has a significant likelihood to occur around 2011 which represents a risk in the forecast.

Table 2 – 2008 Base Case Generation Retirement Schedule

Retirement Assumptions _ EDC 2008 Base Case Forecast - 2008 - 2013					
Generator Unit	Company Name	Fuel Type	Gross MCR	Net to Grid MCR	Retirement Date
Rossdale #10	EPCOR	Gas	71	71	Jul-09
Rossdale #8	EPCOR	Gas	67	67	Jul-09
Rossdale #9	EPCOR	Gas	71	71	Jul-09
Sturgeon #1	ATCO	Gas	10	10	Jan-10
Sturgeon #2	ATCO	Gas	8	8	Jan-10
Wabamun #4	TransAlta	Coal	279	279	Mar-10
Rainbow #1	ATCO	Gas	26	26	Jan-11
Rainbow #2	ATCO	Gas	40	40	Jan-11
Rainbow #3	ATCO	Gas	21	21	Jan-11
Weyerhaeuser	Weyerhaeuser	Biomass	35	0	Jan-13

The current retirement assumptions have varied from the assumptions made in the 2003 report in both the specific units and the timing. The Clover Bar facility has been retired by EPCOR and the Rainbow and Rossdale units are being kept online for TMR services, at the request of the AESO. It is assumed that these units will retire when the upgrade to the transmission system in northwest Alberta is complete, and at this time January 2010 has been assumed as the retirement date. The HR Milner facility is currently forecast to remain online until 2015 as per the fuel supply agreement and the Wabamun 4 unit is retiring during 2010 due to mercury emission requirements.

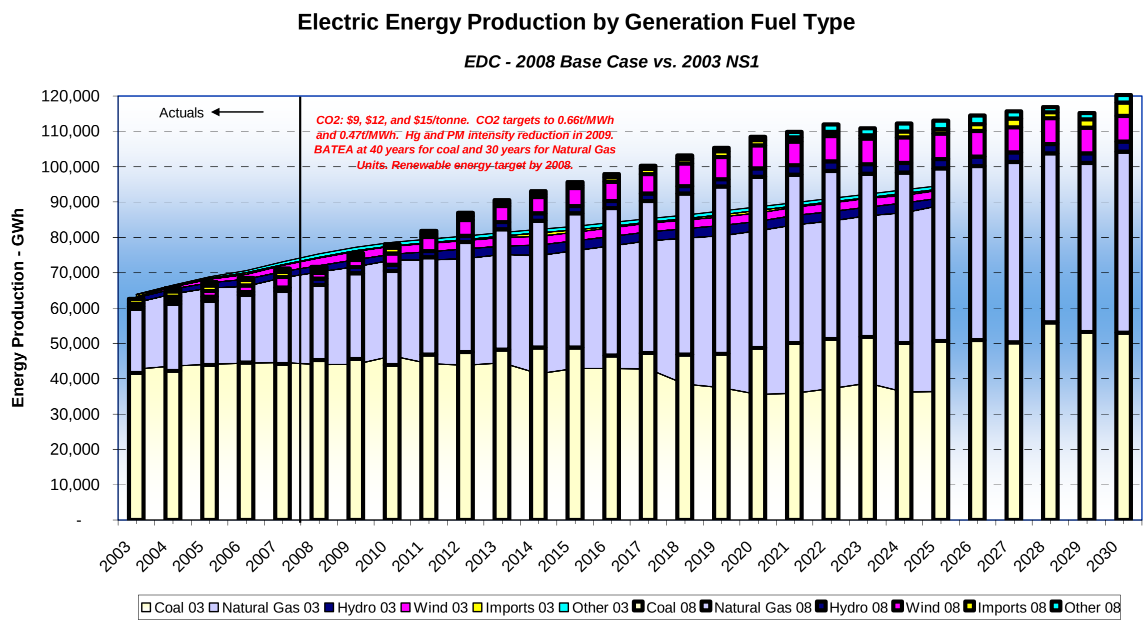
Energy Production and Electricity Price Forecasts

Future supply resources are independently dispatched through a production simulation model to arrive at total energy production to meet energy requirements on an hour-by-hour basis, subject to many conditions and constraints, which also yields the marginal wholesale market price.

Energy Production by Technology

Figure 6 shows the change in energy production by fuel type over time; results from the most recent analysis are represented by the bars in the foreground while the outcomes from the 2003 analysis are represented by the area graph in the background. Compared to the 2003 analysis coal maintains a relatively constant market share over the duration of the forecast. This is likely a function of the higher baseload demand growth and stronger prices in the forecast. As well coal-fired generators are better able to absorb the higher environmental costs under this higher pool price regime relative to the 2003 forecast.

Figure 6 – Energy Production for AIES Sales by Fuel Type



Coal is expected to continue to be the dominant source of energy in Alberta throughout the forecast period, although its market share generally declines over time as additional fuel types are added to the supply portfolio. Between 2008 and 2013, 285 TWh of electrical energy come from coal-fired units. Over the total forecast period 2008 to 2030 coal generates in excess of 1,100 TWh of electrical energy. On an annual basis coal production is expected to generate around 50 TWh from 2014 through 2030, with production peaking at 56 TWh in 2028. This constant forecast production profile occurs because the coal additions that are forecast to happen after 2013 primarily serve the purpose of replacing retirements of existing facilities rather than new additions that would add to net capacity.

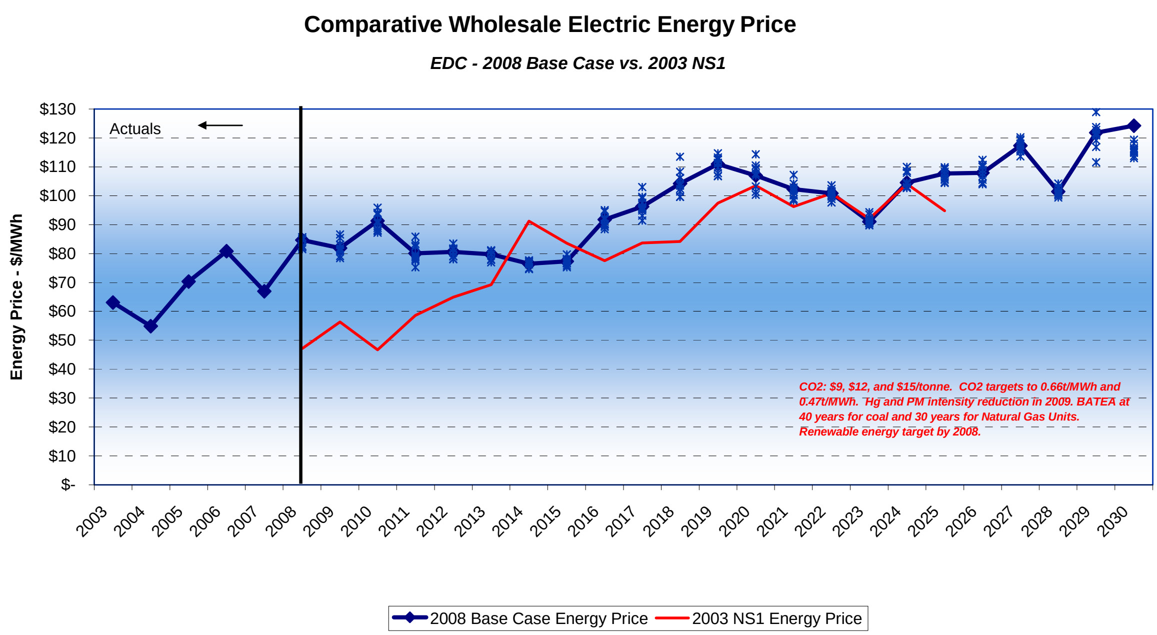
Natural gas-fired generation grows but a relatively slower pace than in the 2003 analysis and throughout the forecast they hold a relatively lower market share. Natural gas-fired energy production in Alberta can be separated into the three key technology types: cogeneration, combined-cycle and simple-cycle. Natural gas-fired generation grows from over 20 TWh in 2008 to over 48 TWh in 2030 representing the bulk of the energy growth during this period. Over the period 2008-2013 cogeneration produces 108 GWhs of energy, this value increase to 627 GWh when the entire forecast to 2030 is examined. This represents an annual production value of 34 GWh of energy by 2030. As a result of the large scale combined-cycle plants discussed above this technology is expected to have higher growth rates while simple-cycle plants, being smaller in scale are forecast to grow at a slightly lower rate.

Annual combined-cycle production grows over the course of the forecast from 1,600 GWh in 2007 to 7,300 GWh by 2030. From 2015 to 2019, there is a higher market heat rate and thus a higher capacity factor for these units. Furthermore, there have been several combined-cycle project announcements since the 2003 study, including the Enmax Shepard Energy Centre which is currently adding 250 MW each year, on a probability weighted basis, in 2012 and 2015. Simple-cycle generation roughly triples from its 2008 level to its highest level, seen in the high heat rate years of 2018 and 2019. The majority of the simple-cycle units are added in the very near term, and these units are expected to see cyclical usage levels based on the overall market supply-demand conditions.

Wind and hydro generation are the two main forms of 'renewable' energy produced in Alberta, and they might be expected to gain in prominence with more environmental regulation. Wind certainly exhibits this pattern, as wind production is forecast to increase from the 2008 level of 1,625 GWh to 7,462 GWh in 2030. Hydro increases slightly relative to current generation levels over the 22 year forecast, largely as the result of additional hydro capacity (such as the proposed development by TransCanada/ATCO at Slave River) being added in northern Alberta.

Wholesale Electricity Prices

Figure 7 – Alberta Electricity Spot Market Forecast (2008 – 2030)



Electricity prices average $97.44/MWh over the forecast, with on-peak prices averaging $117.83/MWh and off-peak prices averaging $78.02/MWh. This forecast is up considerably from the 2003 NS1 analysis in the 2008 – 2013 periods where prices previously averaged $57.14/MWh. It is worth noting that the price drivers of this increase are related more to the higher commodity price environment and the resulting supply and demand mix and less to environmental legislation impacts in the near term, 2008 to 2015. However, further out 2015 to 2025, much of the price increase is expected to be related to environmental compliance costs. As Figure 7 illustrates, electricity prices are forecast to remain above $75/MWh nominally on an annual basis from 2008 through 2013, with 2014 marking the low point across the entire forecast due to some large scale capacity additions post 2010. Generally, forecast prices are trending upward from 2008 through 2010, as generation development, particularly baseload capacity, fails to keep pace with load growth and generation retirements. Of significance is the dramatic change in prices in 2010 between the two forecasts. The price spike occurs as a result of losing the base load capacity from Wabamun 4 in March of 2010 whereas in the 2003 analysis, the unit remained online throughout the year.

Prices are expected to decline between 2011 through 2015 from the $90/MWh to just under $80/MWh, which coincidentally marks the low point of the forecast. This occurs as several large baseload plants are brought online in response the high prices in prior years. Keephills 3 is assumed to come online in 2011, as per its current construction schedule. The Enmax Sheppard combined-cycle plant Phase 1 is scheduled to come online in 2012, adding several hundred more MW to the grid von a probability weighted basis. In 2013, prices are expected to drop once again from the completion of the EPCOR Dodds – Roundhill coal gasification plant, in addition to upgrades at existing plants, boosting baseload capacity by at least another 200 MW.

In both forecasts' prices exhibit similar trends between 2016 and 2020 increasing from a low of $90/MWh to a high of $110/MWh. while the two forecast look similar this outcome is the result of different assumptions in the model. The retirement assumptions for Battle River and Sundance units have not changed between the forecasts but the type and cost of replacement capacity is substantially higher. Coal-fired capacity replaces much of the retired energy and it is priced at a higher cost as a result of emissions control technology. In the 2003 NS1 case the majority of the replacement capacity was cogeneration units which, with the low natural gas prices of the day, yielded low cost energy production.

The ultimate driver of the price forecast is the cost of the installed capacity. Several peaking capacity projects, scheduled for the 2008 through 2010 timeframe, should keep Alberta power prices well below the lofty levels experienced in the 2000/2001 price cycle, but near term prices are still expected to reach relatively high levels. Given the sheer number of peaking capacity plants that are planned for the next few years, there is some risk that a large amount of peaking capacity could come online and depress spot prices relative to the forecast. Alternatively, there is also the risk that some large scale capacity additions will be delayed as a result of uncertainty over federal environmental regulation and transmission infrastructure developments in Alberta. If the latter were to occur there is the risk that prices will be higher than anticipated well beyond the 2014 time period.

A third set of coal plants is expected to come online in the 2017 through 2020 timeframe, when about 1,350 MW in total coal capacity is added to the market. About 40% of this capacity will be absorbed by retirements, as Sundance 1 and 2 are expected to retire in 2018. Despite the assumption that significant coal capacity will be developed in 2017 to 2020, prices rise significantly in part due to increases in environmental costs, as well as increased future uncertainty of environmental legislation regarding carbon emissions. This legislation will drive the marginal costs for baseload (coal) generated electricity up, and is a major driver in the increase of power prices beginning in 2016. This added cost and uncertainty will likely linger in the forecast until legislation on this matter becomes clearer, at which point the costs can be better estimated. This uncertainty is also expected to lead to some delays in the construction of coal-fired baseload generation. For instance, given the current legislation, we do not expect Genesee 4 to begin producing power until 2020, which is another contributor to the run up in power prices from 2016 to 2019 and then the forecasted drop in prices come 2020. Prices trough at 2023 and subsequently rise peaking at $124.25/MWh in 2030.

Review and Comparison of Emissions Forecasts

The charts below present the absolute emissions and emission intensity forecast from the current model and compare them to the 2003 NS1 forecast results. Absolute emissions from the 2008 analyses are represented by the bars in the foreground while the results from the 2003 analysis are denoted by the area graph in the background; tabular output for the current and NS1 case is presented in Table 9 in the Appendix on page 36. Note that Table 9 shows Absolute Emission levels and the resulting Emission Intensity level by fuel type. Energy output values from the 2003 NS1 case and the 2008 analysis are presented in tabular form in Table 8 in the Appendix on page 35 and the resulting intensity levels for the 2003 and 2008 analysis are represented by the red and blue line graphs respectively in the graphs below. Emission intensity levels are calculated by dividing the absolute emission levels by the AIL energy output which includes behind-the-fence load. The absolute emission forecast includes behind-the-fence generation and, as such, the use of behind-the-fence load is required to calculate the true emissions intensity factor.

Pre 2008 data is based on actual results where the data is available; in general electricity demand, supply levels and prices are actual data while absolute emission levels have been used where available. A clear trend for emission intensities emerges between the 2003 forecast and the 2008 forecast for the 5 year period to 2008. Intensity levels are higher in almost cases as a result of lower load growth levels than forecast in 2003 and lower natural gas-fired energy production yielding a higher percentage for the coal-fired units' energy production. NOx intensity is the exception and exhibits a lower intensity pre 2008. This is related to lower energy production from gas-fired units such as the Clover Bar facility. The 2003 to 2008 period has provided a good look back test of the modeling capabilities and demonstrates that the model produces results commensurate with expectations.

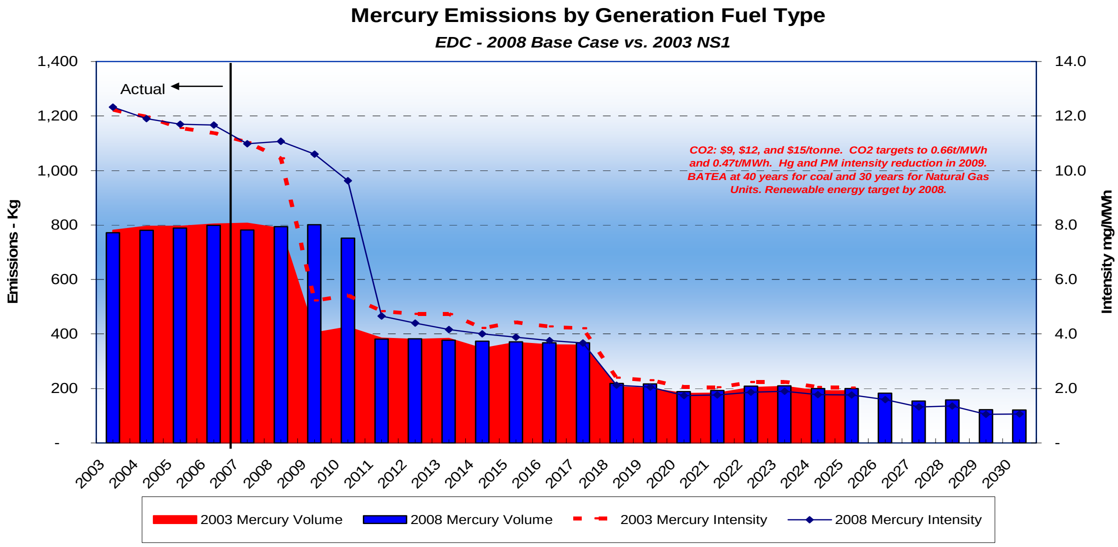
The federal government has announced plans to encourage control of greenhouse gas (GHG) emissions. The "Turning the Corner" emissions policy dictates an initial intensity reduction target of 18% in 2012, increasing by 2% annually until 2020. Contributions into a technological fund would begin in 2010 at $15 per tonne, rising to $20 per tonne in 2013 and increasing by inflation plus real GDP growth each year thereafter. Emitters will have the option of meeting the federal targets through actual improvements, contributions to a fund, and/or domestic offsets. Over time, the percentage an emitter can contribute to a fund will decrease until 2018 when paying into the fund will no longer be an option. This is meant to encourage physical emissions reduction while providing additional capital for R&D on lower emitting and more fuel efficient technologies.

Emissions costs will affect the bidding strategy and margin of existing plants, influence the decision on retirement dates of aging plants and affect the choice of technology, timing and profitability of new generation. Federal policy states that in any province where environmental policy is of equal standing with national regulations the two plans will be complimentary; such that, whatever an emitter pays to one level of plan will be credited to the other. Since the federal plan requires a larger reduction, in this study it will provide the envelope of costs after 2010 with provincial policy dictating emissions regulation before then. Subsequent forecasts will likely involve alternative assumptions as more is learned about the legislation, the available technologies and the market price of Carbon.

Mercury (Hg) Emissions

Absolute mercury emissions exhibit much the same trend in the 2008 forecast as they did in the 2003 forecast. The most significant change between the two forecasts occurs in the 2009 to 2011 period as a result of adjusted input assumptions. In the previous analysis it was expected that mercury emissions legislation would be in place for 2009. The 2008 update adjusts this assumption to the 2011 period to match current expected policy implementation dates. Higher absolute emission levels between 2003 and 2008 forecasts are the result of increased coal-fired generation relative to the 2003 assumptions. As discussed earlier, there has been less cogeneration capacity installed in the province as a result of higher natural gas price expectations along with capital cost constraints at oil sands facilities with the result being an increase in coal-fired output over the forecast period.

Figure 8 – Mercury Emission Volumes and Intensity Index



Looking forward, the retirement of Wabamun 4 in 2010 contributes to a reduction in absolute Hg emission levels as this unit's replacement with cleaner burning generation reduces the mercury intensity below the 2003 forecast. The existing HR Milner unit retirement date has been extended to 2015 in this forecast but has no effect on mercury emission levels as the unit has a bag house and fully captures mercury emissions. As per the 2003 forecast the removal of Sundance 1 and 2 in 2018 produces a second step change in both absolute emission and intensity levels of mercury. In the latter years of the forecast, mercury emissions continue to decline as legacy coal plants are phased out of the electricity generation portfolio.

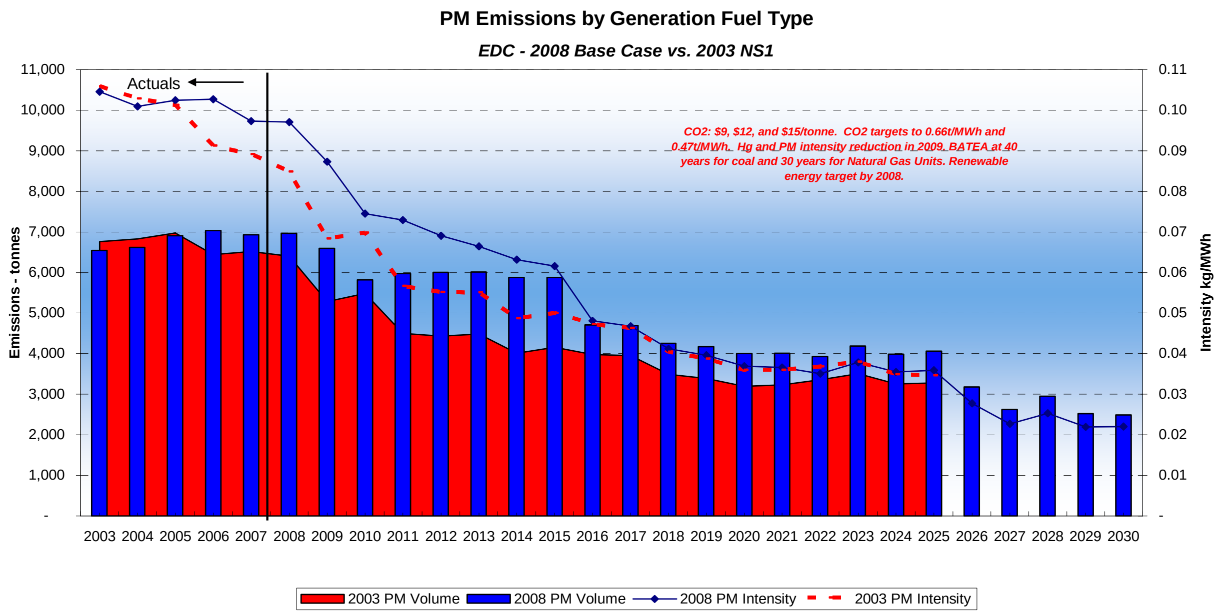
Particulate Matter (PM) Emissions

The target emission level for PM is 0.095 Kg/MWh. The technology to be employed for mercury reduction is activated carbon and is no longer a bag house technology due to lower capital and operational costs as well as a higher capture rate on the activated carbon process. This change has a direct effect on PM emissions which no longer decline in step with mercury reduction. Absolute particulate matter emission reduction occurs solely as a result of the retirement of the legacy coal plants.

The notable difference between the 2003 and 2008 forecasts is that the actual aggregate coal-fired generation is higher in the 2008 forecast relative to the 2003 forecast which relates to the lower-than-expected actual natural gas generation development over the forecast period. Across the forecast period absolute PM emissions are higher than in the 2003 forecast due to the use of activated carbon and electrostatic precipitators to control mercury reductions in place of bag houses. Activated carbon provides no residual benefit to the capture of PM emissions. As well, the higher aggregate coal-fired generation resulting from less gas-fired generation being installed in the 2008 forecast also contributes to this outcome. Higher PM emissions in the post 2020 time frame are related to a higher level of coal-fired generation levels relative to the 2003 analysis. Again, absolute particulate matter emissions posts 2022 are higher than in the 2003 forecast levels as a result of the technology shift away from bag houses. While PM intensity levels are higher in the first half of the 2008 forecast relative to the 2003 forecast, the PM intensity levels post 2009 are well below the target level of 0.095 KG/MWh. This result is a product of the fact that coal-fired energy production holds a smaller percentage share of the total market production

The overall PM emission intensity is on par with than those reported in the 2003 report in the post 2016 period as a result of the lower relative percentage of energy produced from coal-fired units due to the expectation of higher energy production from competing technologies despite the Mercury reduction technology change.

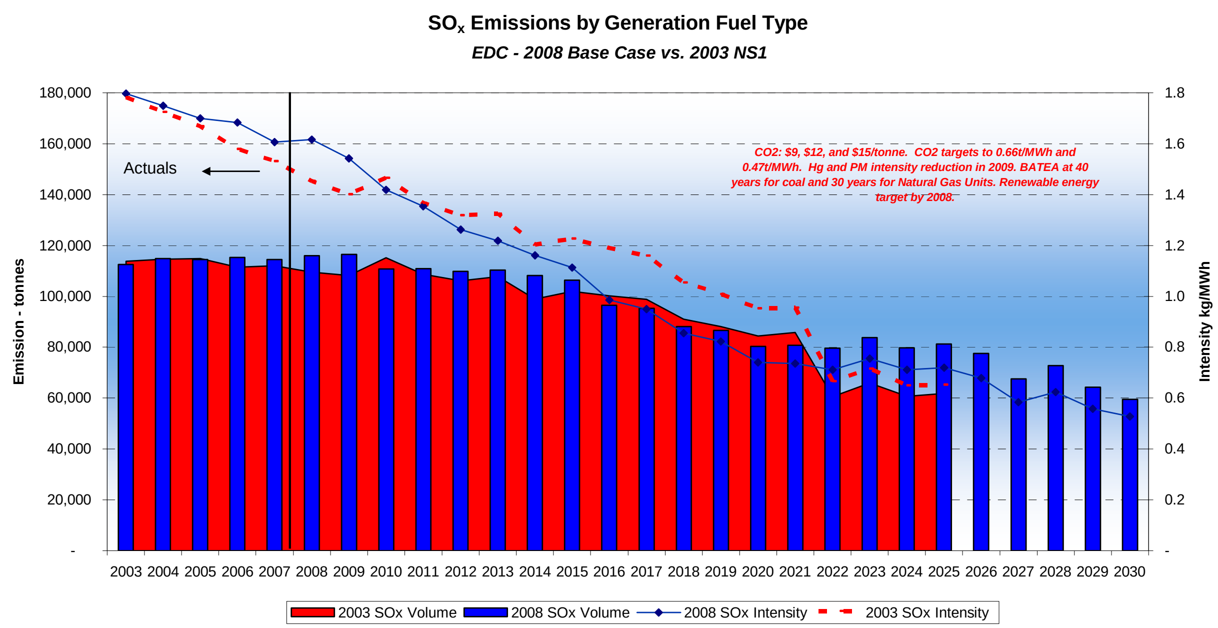
Figure 9 – Particulate Matter Emission Volumes and Intensity Index



SO_2 Emissions

The absolute levels of SO_2 remain relatively unchanged in this update until 2016 when the Sundance units 1 and 2 are expected to be retired. However, from 2022 onward absolute SO_2 emissions are higher because aggregate coal-fired generation is higher. In 2022 there is a noticeable increase in SO_2 intensity levels in the 2008 analysis. This is the result of the higher output of coal-fired energy production in the 2008 forecast.

Figure 10 – SO_2 Emission Volumes and Intensity Index



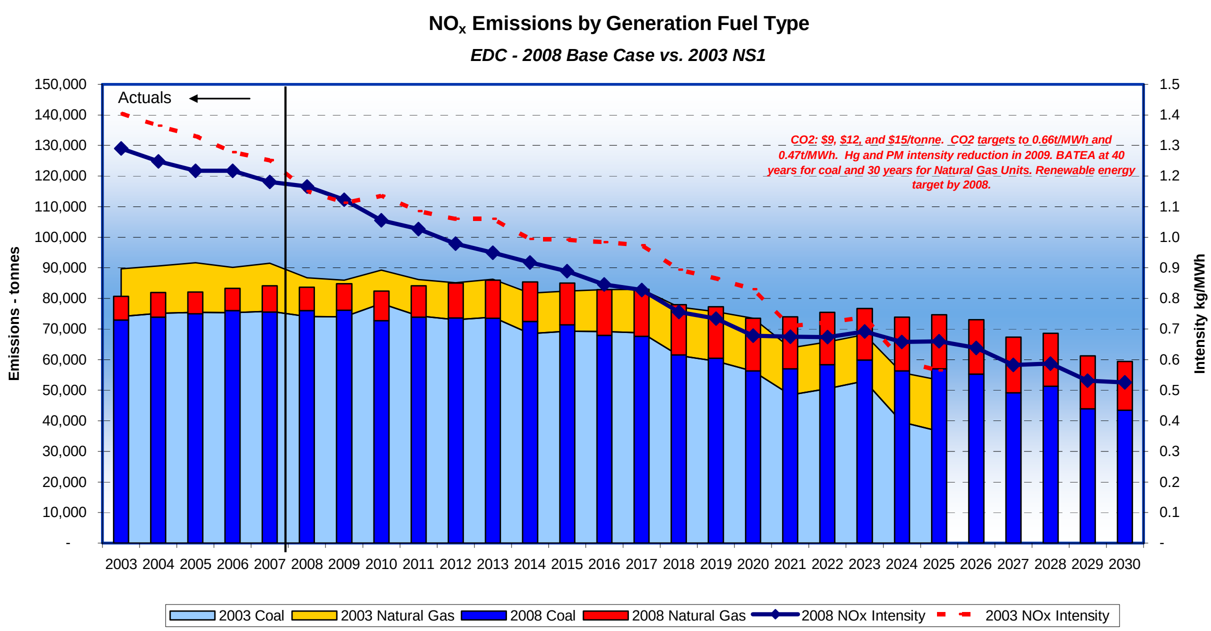
In 2003 it was assumed that natural gas-fired capacity would be considerably higher, in 2008 the natural gas price forecast tends to impede the willingness of natural gas- fired electricity producers to install surplus capacity when developing behind-the-fence generation. Intensity levels fell below the 2003 levels post 2010 again as a result of the increased load being served natural gas and renewable facilities.

NO_X Emissions

Compared to the 2003 forecast NOx absolute emission levels from natural gas are relatively lower until 2012 as a result of the higher volume of coal-fired generation accounting for a larger share of electricity production. As in the SOx case above, post 2020 absolute emission levels are higher as a result of higher load levels being served by this increase of coal-fired energy production. Natural gas Nox emissions are relatively constant post 2019 as a result of consistent generation levels.

NOx intensities fell below the 2003 report for most of the forecast as a result of the lower relative percentage of energy produced from coal-fired units and the higher production levels from other technologies. Exceptions are observed in 2024 and 2025 which arises as a result of relatively constant coal-fired generation levels post 2020.

Figure 11 – NOx Emission Volumes and Intensity Index

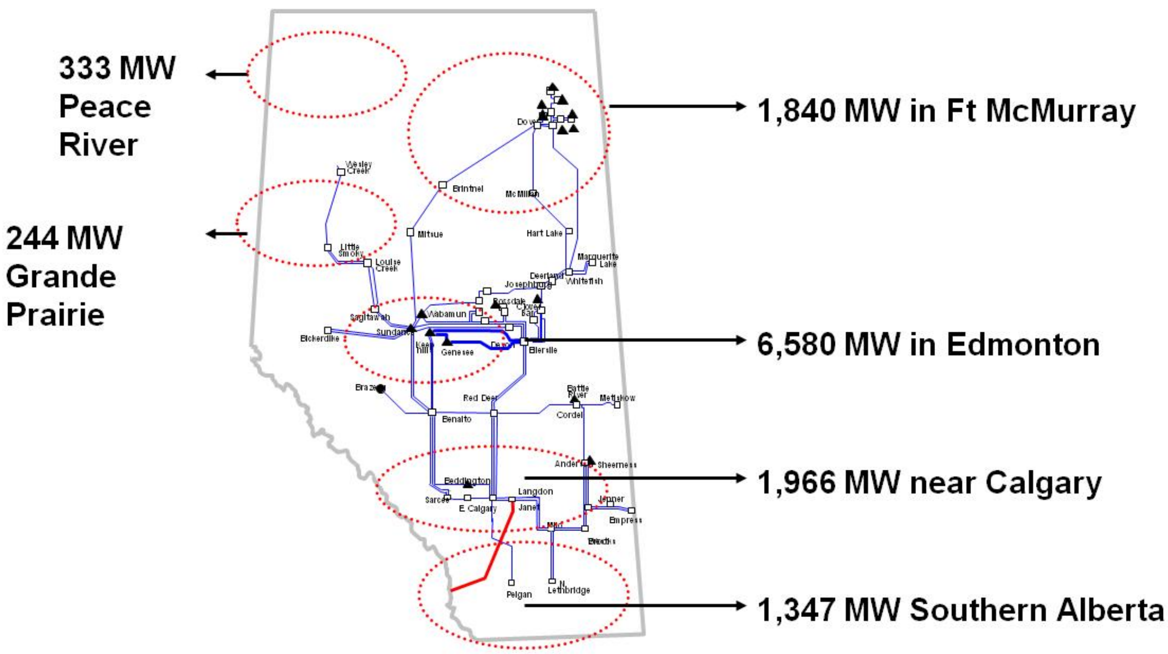


Alberta Generation Development

EDC monitors the development of new generation projects and likely technology developments as an ongoing part of producing electricity price forecasts. Figure 12 presents current generation capacity installations by region relative to major centers in the Alberta market.

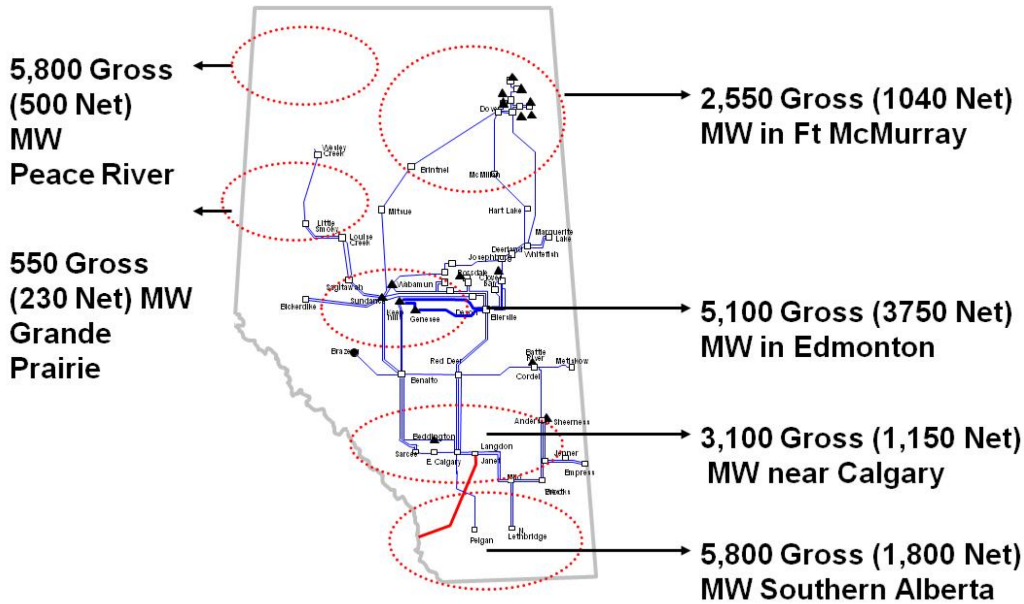
There are three clearly identifiable areas of concentrated generation development; the Wabamun, Calgary and Ft. Mac Murray areas are areas of significant generation clustering. The Wabamun area includes the Edmonton and surrounding region and has in excess of 6,500 MW of installed generating capacity, the majority of which is coal-fired. The Calgary area includes the City of Calgary and surrounding areas and has roughly 2,000 MW of installed capacity, the bulk of which is natural gas-fired. Finally, the Ft McMurray area which includes the Cold Lake region has just less than 2,000 MW of installed capacity consisting mainly of natural gas-fired cogeneration units.

Figure 12 – Existing Alberta Generation (2007)



As discussed earlier in this report the Alberta electricity demand is expected to experience considerable growth levels over the forecast period. The corresponding level of generation capacity additions slated to meet this level of growth is also considerable. While some of the expected projects are planned for regions already identified as regional "development areas" there are a number of proposals which would see generation development occur in less congested areas of the province. Figure 13 illustrates the areas of proposed generation additions, showing both gross MW capacities as well as expected net or probability weighted additions from 2008 to 2030 that are assumed as part of the forecasts presented herein.

Figure 13 – Future Alberta Generation (2008-2030)



During the forecast period the Peace River area is expected to add 5,800 MW of new generation capacity. However 70% or the forecast 4,000 MW of this capacity is designated as nuclear, 1,200 MW are expected to come from hydro additions (in the Slave River area) and the remaining 600 MW are forecast to be gas-fired capacity. The net, or probability weighted, value is 500 MW because the nuclear and hydro capacity additions have a very low probability weighting at present.

The Ft. McMurray region is expected to host an incremental 2,550 MW of capacity the vast majority of which is expected to be natural gas-fired cogeneration. This area has the potential to become a significant regional generation development area in Alberta. However, the current net capacity additions to the area are 1,040 MW due to uncertainty associated with some oil sands projects in the area.

The Grande Prairie region is expected to host an additional 500 MW of generation with an expected net value of 230 MW on a probability weighted basis. The largest component of the increase is expected from a coal-fired expansion at an existing site with the balance coming from simple-cycle gas-fired units.

The Edmonton area which, in this analysis, includes the Wabamun region has the potential to see an incremental addition of 5,000 MW of coal-fired capacity on a gross basis where 3,750 MW is assumed on a net probability weighted basis. It is expected that over the next 22 years there will be some retirements from the existing coal fleet however there is still the likelihood that the area could see an excess of 10,000 MW of total installed coal-fired capacity—albeit the technology deployed remains uncertain.

The Calgary and surrounding area could potentially see an additional 3,100 MW or 1,150 MW on a net risk weighted basis. The Brooks Bow City coal-fired unit is expected to add 900 MW, but is considerably reduced on a probability weighted basis, and numerous smaller projects are forecast to be natural gas-fired units.

The forecast suggests that Southern Alberta could add an incremental 5,800 MW, the vast majority of which will be wind projects and there could also be 675 MW natural gas-fired generation capacity added in the area. The net probability weighted incremental capacity installed in the area is expected to be 1,800 MW.

Appendix 1 – Macroeconomic Assumptions

Table 3 – Economic Assumptions

EDC - CASA Electricity Framework 5 Year Review (2008-2030) Assumptions										
Assumption	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2015**	**2020**	**2025**	**2030**
WTI Price(1) (US$/bbl - $97 Real)	73.04	68.44	64.91	62.21	59.59	58.42	57.14	56.24	55.50	55.50
Heavy Differential (Cdn$/bbl - $97 Real)	20.40	20.31	19.40	18.33	17.73	17.24	16.67	16.38	16.26	16.26
Crude Oil (WTI US$/bbl - Nominal)	96.25	92.00	89.00	87.00	85.00	85.00	86.50	94.00	102.41	113.07
Cdn Par Light Oil @ Edmonton ($Cdn/bbl)	99.67	96.24	94.07	92.92	91.75	93.79	95.43	103.69	112.96	124.72
Bow River @ Hardisty ($Cdn/bbl)	74.03	70.20	68.67	68.42	67.56	69.80	71.29	77.51	84.26	93.03
Natural Gas Price Cdn$/GJ ($97 Real)	6.17	6.03	5.88	5.72	5.61	5.57	5.59	5.61	5.64	5.64
Alberta AECO-C Cdn$/GJ (Nominal)	7.75	7.73	7.70	7.65	7.65	7.75	8.10	8.97	9.95	10.99
Canadian CPI (1997=100)	1.257	1.282	1.309	1.336	1.364	1.392	1.448	1.599	1.765	1.949
Canadian Exchange Rate ($Cdn/$US)	0.96	0.95	0.94	0.93	0.92	0.90	0.90	0.90	0.90	0.90
Canadian Interest Rate (90 T-Bill Rate %)	2.8	3.5	4.0	4.0	4.1	4.2	4.4	4.8	4.8	4.8
Canadian RGDP Growth (%)	2.0	2.3	2.5	2.6	2.8	3.0	3.0	3.0	3.0	3.0
Canadian Unemployment Rate (%)	6.0	6.2	6.3	6.4	6.5	6.6	6.6	6.6	6.6	6.6

Table 4 – Population, Housing & Employment Statistics for Alberta

EDC - 2008 Forecast Update (2008 - 2030)										Population, Household and Employment Statistics Alberta (000's)					
	Alberta	Age 0 - 17		Age 18 - 64		Age 65+	Mortality		Net		Labor Force & Employment			Household Formation	
Forecast	Population	M & F	Male	M & F	Male	M & F	Births	Deaths	Migration	Households	Labor Force	Employment	Unempl Rate	Starts	Total Stock
Year	000s	000s	000s	000s	000s	000s			000s	000s	000s	000s	%	000s	000s
2000	3,005	764	392	1,939	991	302	37,836	17,050	29.9	1050	1,667	1,584	5.0	26.3	1,105
2001	3,057	763	392	1,983	1,014	311	37,197	17,590	34.0	1104	1,710	1,631	4.6	29.2	1,172
2002	3,116	764	393	2,034	1,041	318	37,602	17,937	28.3	1135	1,764	1,671	5.3	38.8	1,205
2003	3,161	763	392	2,073	1,061	326	39,450	18,098	24.2	1165	1,809	1,717	5.1	36.2	1,240
2004	3,208	762	391	2,112	1,081	334	40,635	18,775	33.4	1195	1,842	1,758	4.6	36.3	1,277
2005	3,281	769	395	2,169	1,110	342	41,345	19,004	63.2	1226	1,858	1,784	3.9	40.8	1,315
2006	3,371	780	400	2,239	1,148	352	42,875	19,757	81.5	1256	1,938	1,871	3.4	49.0	1,336
2007	3,474	792	407	2,320	1,194	362	44,661	20,581	43.2	1,295	2,031	1,959	3.5	48.3	1,382
2008	3,542	800	411	2,365	1,218	376	45,511	21,103	42.7	1,326	2,078	2,005	3.5	44.6	1,425
2009	3,610	809	415	2,410	1,242	391	46,350	21,633	42.9	1,363	2,124	2,046	3.7	43.1	1,466
2010	3,673	817	419	2,450	1,264	405	47,189	22,138	37.4	1,398	2,167	2,081	4.0	41.9	1,505
2011	3,741	826	424	2,491	1,285	424	47,956	22,681	42.7	1,436	2,209	2,125	3.8	41.5	1,544
2012	3,816	837	429	2,535	1,309	443	48,713	23,266	48.3	1,468	2,251	2,171	3.6	38.9	1,581
2013	3,895	849	435	2,583	1,335	463	49,542	23,889	53.3	1,501	2,296	2,219	3.4	37.8	1,616
2014	3,975	862	441	2,631	1,361	482	50,433	24,522	53.7	1,535	2,343	2,264	3.3	37.2	1,651
2015	4,055	874	448	2,679	1,387	502	51,330	25,160	53.1	1,569	2,389	2,308	3.4	36.8	1,686
2016	4,136	887	454	2,723	1,411	526	52,220	25,809	53.6	1,604	2,434	2,352	3.4	36.7	1,720
2017	4,218	900	461	2,768	1,435	551	53,033	26,476	55.3	1,639	2,479	2,398	3.3	37.0	1,754
2018	4,302	913	467	2,814	1,460	575	53,863	27,159	56.4	1,675	2,523	2,442	3.2	37.3	1,789
2019	4,388	927	474	2,860	1,485	600	54,708	27,857	57.7	1,712	2,569	2,488	3.1	37.8	1,824
2020	4,474	941	481	2,907	1,510	626	55,569	28,569	58.5	1,749	2,615	2,533	3.1	38.4	1,860
2021	4,560	955	489	2,954	1,535	651	56,440	29,291	58.8	1,786	2,661	2,579	3.1	39.0	1,896
2022	4,647	969	496	3,001	1,561	677	57,316	30,020	58.6	1,824	2,707	2,623	3.1	39.4	1,932
2023	4,734	983	503	3,048	1,586	702	58,190	30,581	58.6	1,862	2,753	2,668	3.1	39.8	1,969
2024	4,821	997	510	3,095	1,611	728	59,063	31,146	59.0	1,900	2,799	2,713	3.1	40.2	2,007
2025	4,909	1,012	517	3,143	1,636	755	59,942	31,714	59.2	1,938	2,846	2,759	3.1	40.6	2,044
2026	4,998	1,026	525	3,190	1,662	782	60,825	32,285	59.3	1,977	2,892	2,804	3.1	41.0	2,082
2027	5,086	1,040	532	3,237	1,687	809	61,710	32,858	59.2	2,016	2,939	2,849	3.1	41.4	2,120
2028	5,175	1,055	539	3,284	1,712	836	62,594	33,431	59.0	2,056	2,986	2,894	3.1	41.7	2,159
2029	5,264	1,069	546	3,331	1,737	863	63,477	34,005	58.7	2,095	3,032	2,938	3.1	42.0	2,198
2030	5,353	1,083	554	3,378	1,762	891	64,357	34,578	58.4	2,135	3,078	2,982	3.1	42.2	2,237
Compound Growth 2008 to 2030													**3.6**		

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Table 5 – Alberta Gross Domestic Product

EDC - 2008 Forecast Update (2008 - 2030) Assumptions - Mid Case						Alberta Economic Accounts Forecast ($000s)					
Forecast Year	GDP Mkt Price $M	Personal Consumption $M	Government Consumption $M	Government Investment $M	Business Investment $M	Net Exports $M	Imports $M	Exports $M	NOMINAL GDP GROWTH %	GDP At Constant Price 1997 $	REAL GDP GROWTH %
2000	144,789	63,274	19,531	2,564	37,221	22,192	(73,958)	96,150	23.7%	121,871	6.4%
2001	151,274	66,815	20,988	3,222	38,650	21,621	(78,103)	99,724	4.5%	125,167	2.7%
2002	150,594	71,241	22,621	3,498	38,489	14,854	(79,142)	93,996	-0.4%	128,117	2.4%
2003	170,113	75,172	24,353	3,022	43,736	23,795	(81,895)	105,690	13.0%	132,463	3.4%
2004	189,521	79,719	25,738	3,613	47,621	32,924	(87,052)	119,976	11.4%	140,598	6.1%
2005	222,159	86,705	27,818	4,574	62,379	40,690	(97,072)	137,762	17.2%	149,474	6.3%
2006	240,025	95,649	30,258	5,875	71,538	36,866	(103,989)	140,855	8.0%	159,956	7.0%
2007	251,240	102,502	30,984	5,637	71,835	40,283	(109,024)	149,307	4.7%	165,663	3.6%
2008	282,723	109,609	32,279	5,689	77,425	57,721	(116,694)	174,415	12.5%	171,788	3.7%
2009	294,933	116,772	33,869	5,941	83,979	54,372	(126,096)	180,467	4.3%	178,319	3.8%
2010	308,935	124,035	35,684	6,334	89,050	53,832	(134,412)	188,244	4.7%	185,557	4.1%
2011	326,981	131,512	37,724	6,714	94,752	56,279	(143,460)	199,740	5.8%	194,375	4.8%
2012	347,553	139,261	40,006	7,090	100,651	60,546	(152,902)	213,448	6.3%	203,973	4.9%
2013	370,749	147,282	42,845	7,484	107,240	65,897	(163,785)	229,683	6.7%	213,821	4.8%
2014	392,916	155,647	45,762	7,860	113,655	69,991	(173,493)	243,484	6.0%	223,255	4.4%
2015	415,339	164,314	48,773	8,213	120,230	73,809	(183,514)	257,323	5.7%	232,497	4.1%
2016	436,492	173,237	51,851	8,525	127,243	75,637	(194,062)	269,698	5.1%	241,204	3.7%
2017	460,137	182,447	55,060	8,821	134,562	79,247	(205,040)	284,287	5.4%	250,550	3.9%
2018	484,429	191,938	58,402	9,100	142,076	82,914	(216,350)	299,263	5.3%	260,064	3.8%
2019	511,129	201,743	61,929	9,380	150,115	87,961	(228,292)	316,253	5.5%	269,750	3.7%
2020	537,740	211,900	65,608	9,653	158,251	92,327	(240,519)	332,846	5.2%	279,644	3.7%
2021	565,235	222,380	69,831	9,913	166,678	96,432	(253,182)	349,614	5.1%	289,647	3.6%
2022	593,279	233,131	73,943	10,162	175,330	100,713	(266,201)	366,914	5.0%	299,703	3.5%
2023	623,563	244,144	78,485	10,412	184,336	106,186	(279,683)	385,869	5.1%	309,737	3.3%
2024	654,419	255,419	82,882	10,661	193,648	111,810	(293,588)	405,398	4.9%	319,739	3.2%
2025	685,791	266,943	87,220	10,904	203,148	117,576	(307,808)	425,383	4.8%	329,898	3.2%
2026	716,713	278,675	91,515	11,132	212,872	122,520	(322,354)	444,874	4.5%	339,847	3.0%
2027	748,309	290,585	95,797	11,343	222,815	127,769	(337,207)	464,976	4.4%	349,749	2.9%
2028	780,618	302,652	100,082	11,540	232,968	133,377	(352,349)	485,727	4.3%	359,606	2.8%
2029	813,741	314,858	104,381	11,723	243,330	139,449	(367,772)	507,221	4.2%	369,426	2.7%
2030	847,719	327,193	108,703	11,895	253,904	146,023	(383,473)	529,497	4.2%	379,216	2.7%
Compound Growth 2008 to 2030									6.7%		3.9%

Appendix 2 – Energy and Demand Forecasts

Table 6 – Alberta Electric Energy and Demand Forecast by Year – 2003 NS1 Case

ALBERTA ELECTRICITY
EDC - 2003 NS1 Case

ENERGY (GWh)	2003	2008	2009	2010	2011	2012	2013	2014	2015	2020	2025	Gwth % 2008-2013	Gwth % 2008 - 2025
Residential	7,530	8,191	8,314	8,404	8,505	8,605	8,712	8,802	8,901	9,627	9,619	1.2%	0.9%
Commercial	11,539	13,616	13,946	14,260	14,557	14,839	15,220	15,595	15,966	17,737	17,732	2.3%	1.5%
Farms & Irrigation	1,755	1,798	1,803	1,801	1,800	1,799	1,799	1,795	1,792	1,811	1,808	0.0%	0.0%
Oil & Gas	17,360	19,285	19,733	20,080	20,402	20,651	20,896	21,148	21,411	22,958	22,944	1.6%	1.0%
Other Industrial	12,090	13,412	13,642	13,785	13,901	14,009	14,120	14,220	14,316	14,716	14,703	1.0%	0.5%
SUB-TOTAL	**50,273**	**56,301**	**57,437**	**58,330**	**59,165**	**59,903**	**60,747**	**61,559**	**62,386**	**66,850**	**66,808**	1.5%	1.0%
Yr Over Yr % Increase	1.2%	1.8%	2.0%	1.6%	1.4%	1.2%	1.4%	1.3%	1.3%	1.5%	-0.1%		
Exports	679	931	963	1,015	1,066	1,069	1,066	1,066	1,066	1,069	1,070	2.8%	0.8%
T&D Losses	4,973	5,378	5,445	5,490	5,528	5,549	5,578	5,603	5,628	5,769	5,770	0.7%	0.4%
TOTAL ENERGY SALES	**55,925**	**62,610**	**63,845**	**64,835**	**65,759**	**66,522**	**67,391**	**68,229**	**69,081**	**73,688**	**73,648**	1.5%	0.9%
Isolated	162	172	174	175	176	177	178	180	181	187	187	0.8%	0.5%
CMH System Load	733	789	810	825	839	844	858	872	877	949	950	1.7%	1.0%
AIES ENERGY SALES	**55,031**	**61,650**	**62,862**	**63,835**	**64,744**	**65,500**	**66,354**	**67,177**	**68,023**	**72,552**	**77,389**	1.5%	1.3%
Yr Over Yr % Increase	1.3%	1.8%	2.0%	1.5%	1.4%	1.2%	1.3%	1.2%	1.3%	1.4%	1.2%		
Internal Load Adjustment	8,157	12,797	13,395	13,738	13,695	13,834	13,967	14,029	14,077	15,054	16,245	1.8%	1.3%
AB INTERNAL LOAD	**63,188**	**74,447**	**76,257**	**77,572**	**78,439**	**79,333**	**80,321**	**81,207**	**82,099**	**87,605**	**93,634**	1.5%	1.3%
Yr Over Yr % Increase	6.3%	3.1%	2.4%	1.7%	1.1%	1.1%	1.2%	1.1%	1.1%	1.5%	1.4%		
TOTAL PEAK DEMAND (MW) - Recorded Actual & Normalized Forecast													
AB PEAK DEMAND	**7,875**	**8,764**	**8,936**	**9,065**	**9,191**	**9,268**	**9,419**	**9,530**	**9,644**	**10,253**	**10,936**	1.5%	1.2%
Load Factor	81.1%	81.3%	81.6%	81.6%	81.7%	81.7%	81.7%	81.7%	81.8%	81.8%	76.9%		
Isolated Peak	31	33	33	33	33	34	34	34	34	36	36	0.8%	0.5%
CMH System Load	117	129	131	133	136	137	139	141	143	155	155	1.6%	1.0%
AIES PEAK DEMAND	**7,727**	**8,603**	**8,771**	**8,898**	**9,021**	**9,097**	**9,246**	**9,355**	**9,466**	**10,063**	**10,745**	1.5%	1.2%
Load Factor	81.3%	81.6%	81.8%	81.9%	81.9%	82.0%	81.9%	82.0%	82.0%	82.1%	82.2%		
	1,229	1,716	1,809	1,812	1,814	1,841	1,849	1,856	1,862	1,989	2,135	1.5%	1.2%
AB INTERNAL PEAK DEMAND	**8,957**	**10,318**	**10,581**	**10,710**	**10,835**	**10,938**	**11,095**	**11,210**	**11,329**	**12,051**	**12,880**	1.5%	1.2%
Load Factor	80.5%	82.1%	82.3%	82.7%	82.6%	82.6%	82.6%	82.7%	82.7%	82.8%	83.0%	**0.1%**	**0.1%**

Table 7 – Alberta Electric Energy and Demand Forecast by Year – 2008 Base Case

ALBERTA ELECTRICITY FORECAST (AIES & AIL)
EDC - 2008 Base Case (2008 - 2030)

TOTAL ENERGY SALES (GWh)

ENERGY (GWh)	2003	2008	2009	2010	2011	2012	2013	2014	2015	2020	2025	2030	Gwth % 2008-2013	Gwth % 2008-2030
Residential	7,581	8,538	8,796	8,977	9,137	9,337	9,531	9,729	9,903	10,951	11,702	14,091	2.3%	3.0%
Commercial	11,118	13,020	13,482	13,905	14,260	14,743	15,203	15,672	16,109	18,542	19,923	22,570	3.4%	3.3%
Farms & Irrigation	1,776	1,803	1,847	1,872	1,890	1,914	1,935	1,953	1,966	2,035	1,918	1,635	1.5%	-0.4%
Oil & Gas	17,367	19,876	21,179	21,692	22,843	24,215	25,092	25,578	25,778	28,057	29,039	28,332	5.2%	1.9%
Other Industrial	11,512	11,487	11,851	12,124	12,390	12,773	13,049	13,332	13,600	15,126	15,883	17,812	2.7%	2.5%
SUB-TOTAL	**49,354**	**54,724**	**57,155**	**58,572**	**60,519**	**62,981**	**64,810**	**66,264**	**67,356**	**74,711**	**78,465**	**84,440**	**3.7%**	**2.5%**
Yr Over Yr % Increase	-0.3%	10.9%	4.4%	2.5%	3.3%	4.1%	2.9%	2.2%	1.6%	2.4%	1.1%	3.8%		
T&D Losses	4,838	4,661	4,815	4,880	5,108	5,430	5,263	4,976	5,029	5,551	5,769	6,248	2.6%	1.5%
ENERGY SALES	**54,191**	**59,385**	**61,970**	**63,452**	**65,628**	**68,412**	**70,072**	**71,240**	**72,385**	**80,262**	**84,234**	**90,687**	**3.6%**	**2.4%**
Exports	1,296	994	659	294	771	1,610	1,250	1,102	1,057	1,018	702	1,076	5.1%	0.4%
TOTAL ENERGY SALES	**55,487**	**60,379**	**62,629**	**63,745**	**66,399**	**70,021**	**71,323**	**72,342**	**73,441**	**81,280**	**84,936**	**91,763**	**3.6%**	**2.4%**
Isolated	126	127	129	130	132	133	135	136	136	141	146	147	1.1%	0.7%
CMH System Load	763	843	876	893	894	926	947	962	1,006	1,136	1,276	1,437	2.5%	3.2%
AIES ENERGY SALES	**54,598**	**59,409**	**61,624**	**62,722**	**65,373**	**68,962**	**70,241**	**71,245**	**72,298**	**80,002**	**83,515**	**90,179**	**3.6%**	**2.4%**
Yr Over Yr % Increase	0.5%	8.8%	3.7%	1.8%	4.2%	5.5%	1.9%	1.4%	1.5%	2.7%	0.8%	4.0%		
Internal Load Adjustment	8,116	12,272	13,829	15,067	16,433	17,967	20,251	21,879	23,302	28,416	29,509	30,225	13.0%	6.7%
AB INTERNAL LOAD	**62,714**	**71,681**	**75,453**	**77,789**	**81,806**	**86,929**	**90,492**	**93,124**	**95,600**	**108,419**	**113,024**	**120,404**	**5.2%**	**3.1%**
Yr Over Yr % Increase	2.1%	14.3%	5.3%	3.1%	5.2%	6.3%	4.1%	2.9%	2.7%	3.0%	0.7%	4.5%		
TOTAL PEAK DEMAND (MW) - Recorded Actual & Normalized Forecast														
AB PEAK DEMAND	**7,754**	**8,528**	**8,902**	**9,123**	**9,451**	**9,813**	**10,065**	**10,262**	**10,445**	**11,515**	**12,237**	**13,194**	**3.6%**	**2.5%**
Load Factor	81.7%	80.6%	80.3%	79.8%	80.2%	81.2%	80.9%	80.5%	80.3%	80.4%	79.2%	79.4%		
Isolated Peak	24	24	25	25	25	25	26	26	26	27	28	28	1.7%	0.8%
CMH System Load	114	120	122	124	125	127	130	132	138	152	168	183	1.7%	2.4%
AIES PEAK DEMAND	**7,616**	**8,384**	**8,755**	**8,974**	**9,301**	**9,660**	**9,910**	**10,104**	**10,281**	**11,336**	**12,041**	**12,983**	**3.6%**	**2.5%**
Load Factor	81.8%	80.7%	80.4%	79.8%	80.2%	81.3%	80.9%	80.5%	80.3%	80.3%	79.2%	79.3%		
Internal Load Adjustment	1,170	1,657	1,738	1,884	2,007	2,089	2,350	2,526	2,666	3,234	3,488	3,390	8.4%	4.8%
AB INTERNAL PEAK DEMAND	**8,786**	**10,041**	**10,493**	**10,858**	**11,307**	**11,749**	**12,259**	**12,630**	**12,947**	**14,571**	**15,529**	**16,373**	**4.4%**	**2.9%**
Load Factor	81.5%	81.3%	82.1%	81.8%	82.6%	84.2%	84.3%	84.2%	84.3%	84.7%	83.1%	83.9%	0.7%	0.1%

Appendix 3 – Emission Forecasts and Emission Intensities

Table 8 – 2008 Base Case vs. 2003 NS1 Annual AIL Energy Production by Fuel type Comparison

2008 Base Case

Energy by Type	Annual Energy (GWh)										
	2008	2009	2010	2011	2012	2013	2014	2015	2020	2025	2030
Coal	45,256	45,523	43,885	46,879	47,494	48,210	48,824	48,827	48,739	50,654	53,081
Natural Gas	21,276	24,288	26,620	27,470	31,199	34,019	35,877	37,954	48,336	48,806	51,151
Hydro	1,786	1,763	1,797	1,765	1,808	2,066	2,024	2,040	2,386	2,707	2,831
Wind	1,625	1,856	2,865	3,855	4,444	4,515	4,717	5,126	6,499	7,178	7,462
Imports	937	1,181	1,682	963	1,045	817	758	751	1,557	1,286	3,785
Other	801	842	940	874	939	864	925	902	901	2,393	2,094
Total	**71,681**	**75,453**	**77,790**	**81,806**	**86,929**	**90,492**	**93,124**	**95,600**	**108,419**	**113,024**	**120,404**

2003 NS1 Case

Energy by Type	Annual Energy (GWh)									
	2008	2009	2010	2011	2012	2013	2014	2015	2020	2025
Coal	43,968	44,038	46,418	44,283	43,788	44,472	41,443	42,889	35,450	36,386
Natural Gas	26,193	27,631	27,129	29,295	30,141	30,692	33,359	33,290	46,424	52,649
Hydro	1,861	1,952	1,667	2,366	2,741	2,336	3,037	2,770	2,651	2,089
Wind	2,111	2,360	2,297	2,348	2,364	2,435	2,409	2,449	2,371	2,279
Imports	262	267	95	194	368	458	1,036	769	780	302
Other	983	972	980	1,018	1,000	994	989	999	997	1,003
Total	**75,378**	**77,220**	**78,587**	**79,505**	**80,402**	**81,388**	**82,273**	**83,165**	**88,674**	**94,708**

Table 9 – Annual Emission Values Comparison

Table 9 shows the associated intensity of the each examined emission in the respective units.

EDC - 2008 Base Case vs. 2003 NS1

Mercury	Annual Mercury Emissions (kg/year) and Annual Mercury Index (mg/MWh)										
	2008	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2020**	**2025**	**2030**
2008 Mercury Volume	794	801	752	382	382	377	373	372	189	199	121
2008 Mercury Intensity	11.1	10.6	9.6	4.7	4.4	4.2	4.0	3.9	1.7	1.8	1.1
2003 Mercury Volume	787	404	425	385	380	384	347	369	182	192	-
2003 Mercury Intensity	10.4	5.2	5.4	4.8	4.7	4.7	4.2	4.4	2.0	2.0	-
SOx	**Annual SOx Emissions (tonnes/year) and Annual SOx Index (kg/MWh)**										
2008 SOx Volume	115,940	116,567	110,713	110,867	109,809	110,313	108,154	106,413	80,335	81,288	59,537
2008 SOx Intensity	1.6	1.5	1.4	1.4	1.3	1.2	1.2	1.1	0.7	0.7	0.5
2003 SOx Volume	109,491	108,153	115,187	108,681	106,078	107,795	98,993	102,058	84,435	61,794	-
2003 SOx Intensity	1.5	1.4	1.5	1.4	1.3	1.3	1.2	1.2	1.0	0.7	-
NOx	**Annual NOx Emissions (tonnes/year) and Annual NOx Index (kg/MWh)**										
2008 Coal	76,012	76,193	72,683	73,879	73,641	73,536	72,444	71,359	56,302	57,031	43,464
2008 Natural Gas	7,661	8,631	9,720	10,193	11,438	12,353	12,956	13,665	17,259	17,580	15,896
2008 NOx Volume	**83,674**	**84,824**	**82,403**	**84,072**	**85,079**	**85,889**	**85,400**	**85,024**	**73,561**	**74,611**	**59,360**
2008 NOx Intensity	1.2	1.1	1.1	1.0	1.0	0.9	0.9	0.9	0.7	0.7	0.5
2003 Coal	74,136	73,985	78,289	74,305	73,020	73,879	68,519	69,315	56,225	36,578	-
2003 Natural Gas	12,570	11,909	10,941	11,922	12,175	12,349	13,256	13,113	17,319	16,808	-
2003 NOx Volume	86,706	85,893	89,230	86,227	85,195	86,227	81,774	82,429	73,544	53,386	-
2003 NOx Intensity	1.150	1.112	1.135	1.1	1.1	1.1	1.0	1.0	0.8	0.6	-
PM	**Annual PM Emissions (tonnes/year) and Annual PM Index (kg/MWh)**										
2008 PM Volume	6,962	6,597	5,819	5,967	6,002	6,015	5,881	5,881	4,007	4,061	2,487
2008 PM Intensity	0.10	0.09	0.07	0.07	0.07	0.07	0.06	0.06	0.04	0.04	0.02
2003 PM Volume	6,398	5,283	5,485	4,503	4,435	4,484	4,008	4,159	3,194	3,278	-
2003 PM Intensity	0.08	0.07	0.07	0.06	0.06	0.06	0.05	0.05	0.04	0.03	-

Appendix 4 – Corrected 2008 Forecast Results

Several adjustments were made to the 2008 forecast results that were necessary to incorporate new information as well as correct for some formulaic errors that existed in the original 2008 emission level and intensity forecast results. These adjustments had a material effect on both historical and forecast emission levels and intensity calculations. CASA requested EDC attach an Appendix to the Electricity Framework 5 Year Review document dated September 2008 summarizing the corrections and showing the corrected 2008 data relative to the 2003 NS1 Case.

The first revision was a correction to a formulaic error made during the 5 Year Review process that resulted in a higher calculation of the total energy supply from 2003 to 2007. Due to the double counting of a natural gas-fired generating unit, historical energy production was slightly inflated and correspondingly reduced the emission intensity. Over these years, the corrected total energy supply is an average of 3% (almost 2,000 GWh) lower than the total energy supply reported along with the original 2008 results. The corrected 2008 emission intensity forecast results show slightly higher historical emission intensities for all air pollutants. A second adjustment was made to the historical energy production from some wind generators which had also been double counted creating some slight differences in total energy supply in those years.

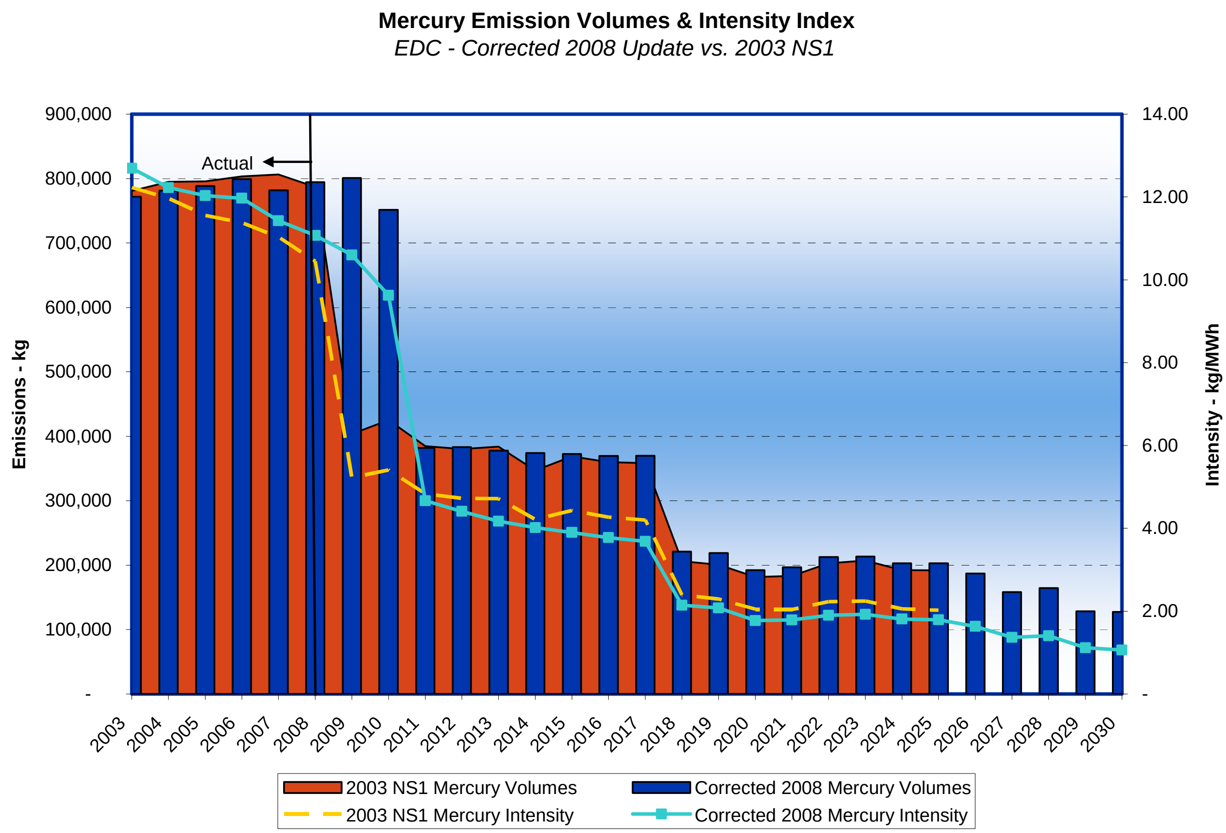
The third revision related to the omission of formulas of several coal-fired generation additions scheduled to come on-line over the forecast period. These units had been inadvertently omitted from the emission forecast totals. Starting with Keephills 3, scheduled to come on-line in 2011, these coal-fired generators represent a noticeable portion of future supply as some older coal generation retires and Alberta's electricity demand continues to grow. For the most part, the inclusion of the emissions associated with these facilities resulted in higher absolute forecast emissions and a higher expected emission intensities in the corrected 2008 forecast results.

Finally, a fourth revision was made to incorporate new information pertaining to the NO_X emission intensity of a few generators that was provided by CASA to be incorporated along with all other changes. The majority of this adjustment impacted natural gas-fired facilities; with their relatively low NO_X emission intensity this had a rather minor impact on the overall NO_X forecast.

Mercury (Hg) Emissions

As a result of including mercury emissions from those previously omitted future coal-fired generators, corrected mercury emissions from those units accumulated to 6,577 kg by 2030. On a base of 127,544 kg in 2030, this represents a 5% increase in mercury emissions. This understated the mercury emission intensity in 2030 by 0.05 kg/MWh. On a base of 1.06 kg/MWh, this also represents an increase of 5%. The corrected 2008 mercury emissions forecast is shown in Figure 14 along with the mercury emissions level and emission intensity forecast from the 2003 NS1 case.

Figure 14 – Mercury Emission Volumes & Intensity Index (Corrected 2008 vs. 2003 NS1 Case)

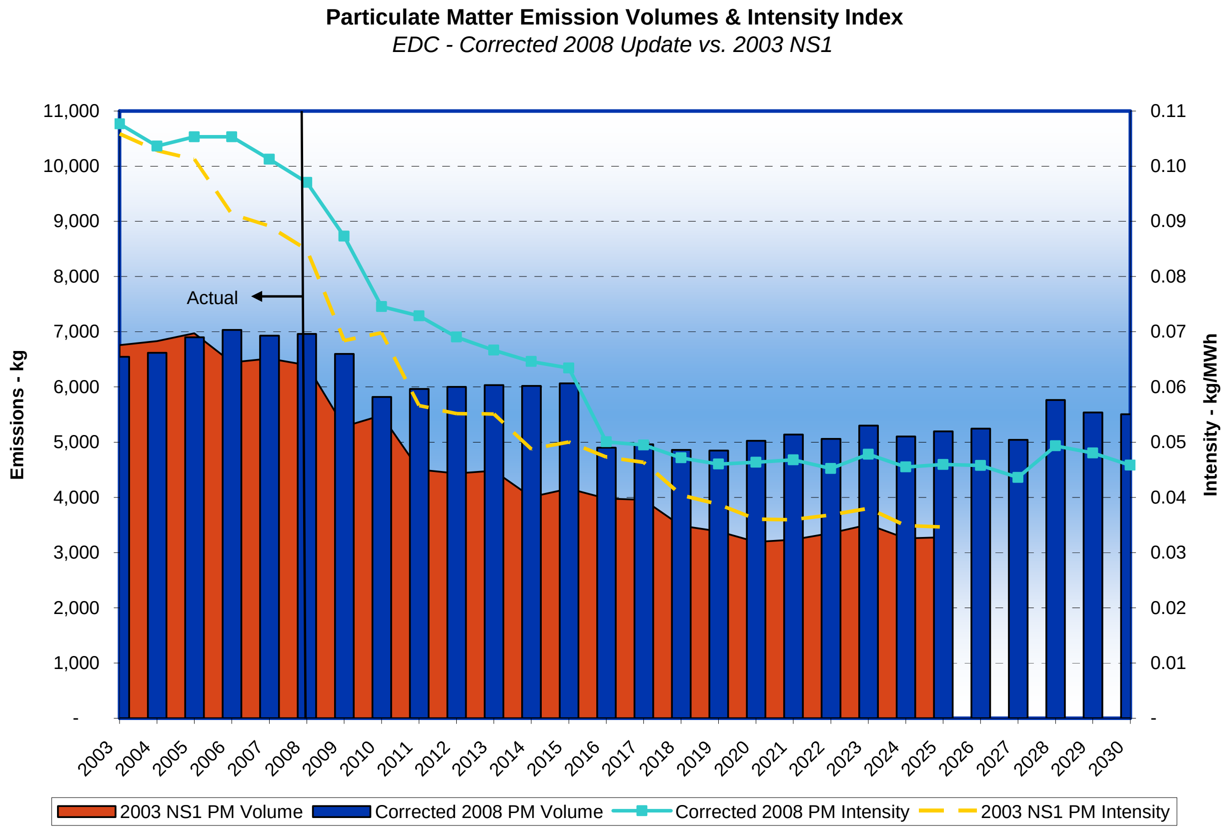


Total corrected mercury emissions are expected to reach 127,544 kg by 2030, representing an average decrease of 30,611 kg (or 4%) in each year from 2009 to 2030. By 2030, the mercury emission intensity is forecast to amount to 1.06 kg/MWh, from an average decline of 0.43 kg/MWh (or 4%) each year of the forecast.

Particulate Matter (PM) Emissions

A similar formulaic error to that which omitted the emissions of future coal-fired generation also omitted the emissions from three existing coal-fired units over the last 5 years of the forecast period. As a result of including PM emissions from those previously omitted coal-fired generators, corrected PM emissions accumulated to 3,019 kg by 2030. On a base of 5,506 kg in 2030, this represents a 121% increase in PM emissions. This understated the PM emission intensity in 2030 by 0.025 kg/MWh. On a base of 0.046 kg/MWh, this also represents an increase of 121%. The corrected 2008 PM emissions forecast is shown in Figure 15 along with the PM emissions level and emission intensity forecast from the 2003 NS1 case.

Figure 15 – Particulate Matter Emissions Volumes & Intensity Index (Corrected 2008 vs. 2003 NS1 Case)

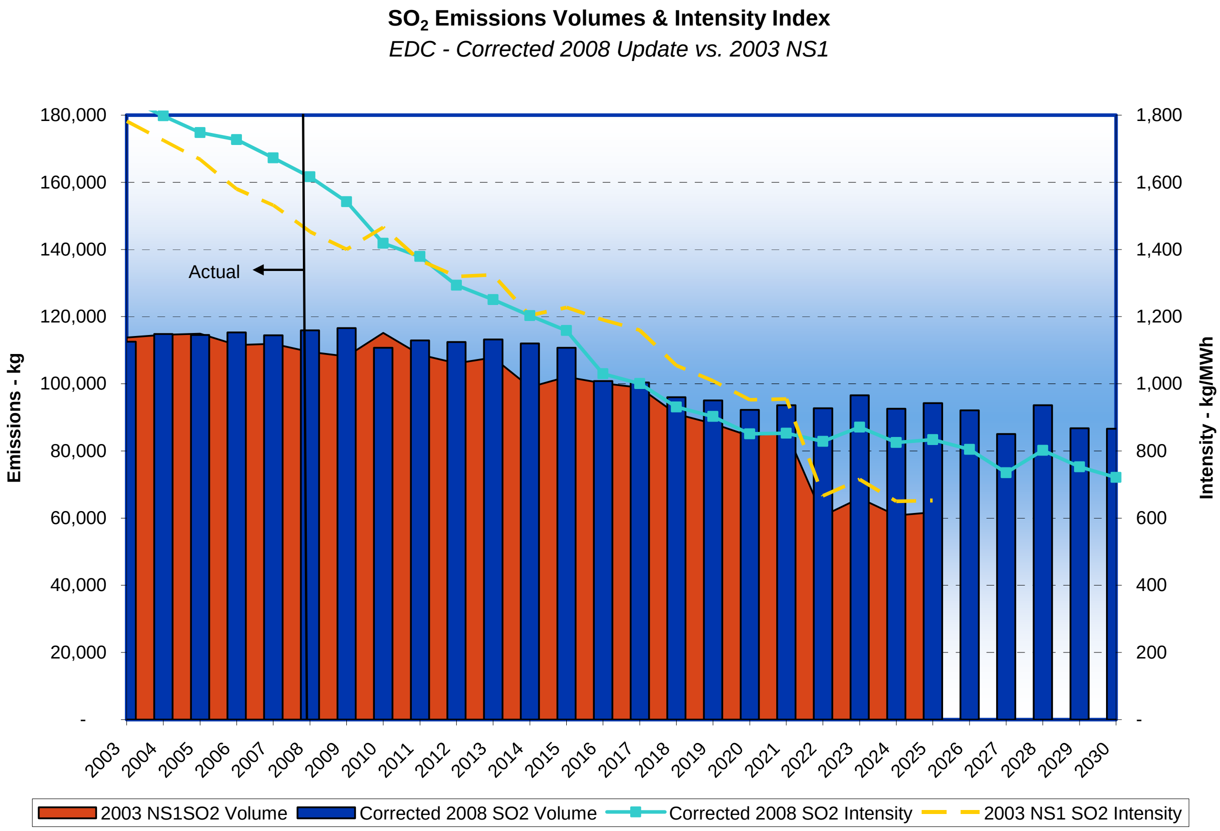


Total corrected PM emissions are expected to reach 5,506 kg by 2030, representing an average decrease of 50 kg (or 1%) in each year from 2009 to 2030. By 2030, the PM emission intensity is forecast to amount to 0.046 kg/MWh, from an average decline of 0.002 kg/MWh (or 2%) each year of the forecast.

SO_2 Emissions

As a result of including SO_2 emissions from those previously omitted future coal-fired generators, corrected SO_2 emissions accumulated to 27,077 kg by 2030. On a base of 86,614 kg in 2030, this represents a 45% increase in SO_2 emissions. This understated the SO_2 emission intensity in 2030 by 225 kg/MWh. On a base of 721 kg/MWh, this also represents an increase of 45%. The corrected 2008 SO_2 emissions forecast is shown in Figure 16 along with the SO_2 emissions level and emission intensity forecast from the 2003 NS1 case.

Figure 16 – SO_2 Emission Volumes & Intensity Index (Corrected 2008 vs. 2003 NS1 Case)



Total corrected SO_2 emissions are expected to reach 86,614 kg by 2030, representing an average decrease of 1,362 kg (or 1%) in each year from 2009 to 2030. By 2030, the SO_2 emission intensity is forecast to amount to 721 kg/MWh, from an average decline of 37 kg/MWh (or 2%) each year of the forecast.

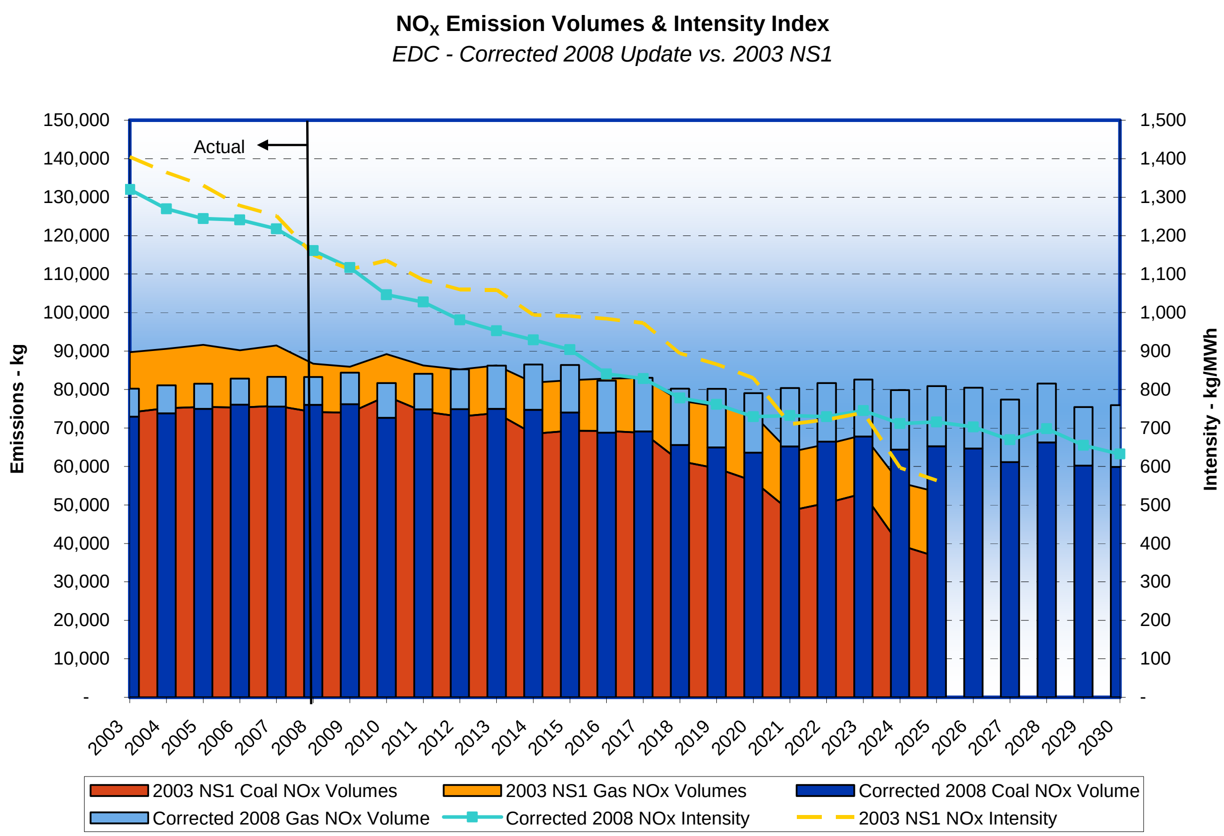
NO_X Emissions

As a result of including the previously omitted future coal-fired generators, corrected coal-fired NO_X emissions increased by 16,467 kg by 2030. On the other hand, the correction to the NO_X emission intensity of a couple coal-fired generators decreased NO_X emissions by 37 kg by 2030. This resulted in a net increase of 16,429 kg in coal-fired NO_X emissions by 2030. On the total NO_X emissions base of 75,928 kg in 2030, this represents a 28% increase in NO_X emissions.

The adjustments to the emission intensity of gas-fired generation led to higher natural gas-fired NO_X emissions. By 2030, corrected natural gas NO_X emissions from these units increased by 139 kg. On a total NO_X emissions base of 75,928 kg in 2030, this represents a 0.2% increase in NO_X emissions. Note that in every year over the forecast period, with the exception of 2030, there are less natural gas-fired NO_X emissions as a result of excluding those emissions previously assigned to forecast wind generation.

The additional corrected emissions from coal generation were far greater than the correction to natural gas emissions resulting in the original forecast understating the NO_X absolute emissions level and intensity forecast. By 2030, the corrected NO_X emission intensity is forecast to be 632 kg/MWh, which represents an increase of 138 kg/MWh or 28% on the original forecast. The corrected 2008 NO_X emissions forecast is shown in Figure 17 along with the NO_X emissions level and emission intensity forecast from the 2003 NS1 case.

Figure 17 – NO_X Emission Volumes & Intensity Index (Corrected 2008 vs. 2003 NS1 Case)



In summary, coal NO_X emissions are expected to reach 59,893 kg by 2030, representing an average decrease of 741 kg (or 1%) in each year from 2009 to 2030. While natural gas NO_X emissions are expected to reach 16,035 kg by 2030, representing an average increase of 355 kg (or 4%) in each year from 2009 to 2030. As a result, total NO_X emissions are expected to reach 75,928 kg by 2030, representing an average decrease of 386 kg (or 0.5%)

in each year from 2009 to 2030. By 2030, the corrected aggregate NO_X emission intensity is forecast to amount to 632 kg/MWh, from an average decline of 22 kg/MWh (or 2%) per year.

Table 10 summarizes the corrected 2008 emissions level and emission intensity forecast results alongside the results from the 2003 NS1 case.

Table 10 – Corrected 2008 and 2003 NS1 Emission Volumes and Intensity Summary

Corrected 2008 Update vs. 2003 NS1 Case

Mercury	Annual Mercury Emission (tonnes/year) and Annual Mercury Index (Mg/MWh)									
	2008	2009	2010	2011	2012	2013	2014	2015	2020	2025	2030
Corrected 2008 Update - Mercury Volume	794	801	752	382	383	378	374	373	192	203	128
Corrected 2008 Update - Mercury Intensit	11	11	10	5	4	4	4	4	2	2	1
2003 NS1 Case - Mercury Volume	787	404	425	385	380	384	347	369	182	192	-
2003 NS1 Case - Mercury Intensity	10	5	5	5	5	5	4	4	2	2	-

SO_X	Annual SO_X Emission (kg/year) and Annual SO_X Index (kg/MWh)										
	2008	2009	2010	2011	2012	2013	2014	2015	2020	2025	2030
Corrected 2008 Update - SO_X Volume	115,940	116,567	110,713	112,927	112,477	113,191	112,000	110,720	92,228	94,236	86,614
Corrected 2008 Update - SO_X Intensity	1,616	1,542	1,418	1,379	1,294	1,251	1,203	1,158	851	834	721
2003 NS1 Case - SO_X Volume	109,491	108,153	115,187	108,681	106,078	107,795	98,993	102,058	84,435	61,794	-
2003 NS1 Case - SO_X Intensity	1,453	1,401	1,466	1,367	1,319	1,324	1,203	1,227	952	652	-

NO_X	Annual NO_X Emission (kg/year) and Annual NO_X Index (kg/MWh)										
	2008	2009	2010	2011	2012	2013	2014	2015	2020	2025	2030
Corrected 2008 Update - NO_X Coal Volum	76,012	76,193	72,683	74,883	74,942	74,997	74,745	74,046	63,552	65,247	59,893
Corrected 2008 Update - NO_X Gas Volum	7,248	8,233	8,986	9,223	10,325	11,210	11,744	12,328	15,522	15,634	16,035
Corrected 2008 Update - NO_X Volume	83,261	84,425	81,668	84,106	85,266	86,207	86,489	86,374	79,074	80,881	75,928
Corrected 2008 Update - NO_X Intensity	1,161	1,117	1,046	1,027	981	953	929	903	729	716	632
2003 NS1 Case - NO_X Coal Volume	74,136	73,985	78,289	74,305	73,020	73,879	68,519	69,315	56,225	36,578	-
2003 NS1 Case - NO_X Gas Volume	12,570	11,909	10,941	11,922	12,175	12,349	13,256	13,113	17,319	16,808	-
2003 NS1 Case - NO_X Volume	86,706	85,893	89,230	86,227	85,195	86,227	81,774	82,429	73,544	53,386	-
2003 NS1 Case - NO_X Intensity	1,150	1,112	1,135	1,085	1,060	1,059	994	991	829	564	-

PM	Annual PM Emission (kg/year) and Annual PM Index (kg/MWh)										
	2008	2009	2010	2011	2012	2013	2014	2015	2020	2025	2030
Corrected 2008 Update - PM Volume	6,962	6,597	5,819	5,967	6,002	6,033	6,016	6,067	5,026	5,196	5,506
Corrected 2008 Update - PM Intensity	0.10	0.09	0.07	0.07	0.07	0.07	0.06	0.06	0.05	0.05	0.05
2003 NS1 Case - PM Volume	6,398	5,283	5,485	4,503	4,435	4,484	4,008	4,159	3,194	3,278	-
2003 NS1 Case - PM Intensity	0.08	0.07	0.07	0.06	0.06	0.06	0.05	0.05	0.04	0.03	-