Electricity Price, Energy Production and Emissions Impact

Evaluating proposed GHG Emission Reduction Frameworks for the Alberta Electricity Industry

Updated Reference Case & Sensitivity Results prepared for CASA EPT GHG Sub-group

Final Report Issued:
June 24, 2004

Submitted to:

CASA Electricity Project Team - GHG Sub-Group

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Table of Contents

List of Figures

List of Tables

Chapter 1 Executive Summary

In its efforts to recommend environmental policy regarding greenhouse gas (GHG) and other airborne emissions in respect of the electric power sector in Alberta, the CASA Electricity Project Team (EPT) GHG Subgroup retained EDC Associates Ltd. to provide an independent study. This study quantifies the potential impact to Alberta generators energy production, airborne emissions and the *wholesale* market price of electricity resulting from several GHG policy scenarios that include a proactive policy framework relative to what might have occurred assuming a 'Business as Usual' environment. In addition, the impact associated with a generation development scenario that includes large-scale coal development over the next 22 years was considered in the context of the "Business as Usual' environment as well as an environment with GHG reduction targets in place.

In all, 6 cases are quantitatively evaluated and presented in this report: an updated Reference Case and five sensitivities. The new Reference Case or new 'Business as Usual' has been updated where it now assumes and incorporates several of the key recommendations made by the CASA EPT in its November 2003 report to the Alberta government regarding environmental policy frame work in Alberta. However, it is not assumed that any other jurisdiction in Canada or elsewhere has adopted a similar formal change to policy as yet. This key change to the Reference Case forecast means that certain environmental costs (relating to NO_x, SO_x, Hg and particulate matter – excluding GHG), generation retirement assumptions and renewable power development occur within the Business as Usual scenario. Another key element of this analysis that differs from previous phases of the CASA EPT project is that all the sensitivities use the same fundamental assumptions for electricity demand and natural gas prices.

Three of the five sensitivities attempt to evaluate the impact of several key assumptions relating to progressive GHG reduction levels and costs related to meeting GHG requirements. The two remaining sensitivities assume an "all-coal" future electricity supply sequence both with and without GHG emission reduction costs. This contrasts with the current business as usual generation supply sequence that is strongly weighted toward natural gas fired generation. Each of the sensitivities is presented relative to the Reference Case.

Reference Case Results

The Reference Case assumes a status quo environment where demand growth in electricity continues on its presently apparent course that is largely driven by economic activity, particularly in the oil and gas segment of the economy. While demand continues to grow positively, this scenario includes some naturally occurring efficiency gains that improve electric energy demand relative to economic growth. This results in an 'economic' efficiency gain of approximately 1% per year.

In the Reference Case, natural gas generation is forecast to form the majority of capacity additions over the forecast horizon. EPCOR's Genesee expansion (GP3) is assumed to proceed under this scenario; however it is recognized that two additional coal projects have been announced for development, TransAlta's Keephills expansion called Centennial and Fording Coal's Brooks Greenfield coal mine and generation plant development. As noted above, while circumstances may change as market conditions evolve, these two projects have been assigned a low probability with respect to development. This fact represents a risk to the analysis presented in this report, and this risk is explicitly modeled in the coal generation sensitivities.

It should be noted that natural gas fired cogeneration is expected to be developed in Alberta, particularly associated with robust oilsands development and commensurate with northern transmission capabilities. However once again this represents a forecast risk in that coal or coke could also be utilized as a primary fuel source for oilsands or insitu bitumen steam requirements. This would obviously have an implication on the emission forecast since the GHG forecast assumes that cogeneration facilities are fired by natural gas, and other fuels would likely create higher GHG emissions. On the other hand, oilsands projects could potentially purchase electricity for their operations from the wholesale market and not build cogeneration capacity. This would have a potential impact on the price forecast primarily because it would represent a reduction in assumed supply and an increase in demand.

Renewable energy resource additions (largely wind based) continue to be added to the supply mix based on the renewable energy policy outlined in the CASA EPT Report to stakeholders in late 2003. In this policy, 3.5% of energy traded through the AESO must come from incremental 'green' sources by 2008. Furthermore, this target is sustained throughout the forecast time period, which amounts to 3.5% of energy growth after 2008 being met by renewable sources. Within the context of the analysis, wind power is assumed to meet the renewable capacity requirements.

Another key assumption that natural gas, a primary source of energy, falls in price relative to the levels currently seen in the near-term market. The front end (2004) of the forecast is based on the forward market, and natural gas prices are expected to average $6.10/GJ in 2004. Prices are expected to fall in 2005 and 2006, and 2007 and slowly increase afterwards; this is consistent with many firm's forecasts. Overall, natural gas prices are assumed to average $5.10/GJ in the first 10 years of the forecast (2004 to 2013) and average $5.72/GJ from 2014 to 2025.

The Reference Case is supported by a total Alberta electric energy demand forecast that starts out at 65,100 GWh in 2004 and by 2025 growth in load reaches 105,300 GWh. Note that these forecasts represent total Alberta internal load and therefore include energy produced by onsite generation at industrial facilities. The makeup of energy production by fuel type to satisfy this demand is currently led by coal and natural gas facilities, 64% and 31% respectively in 2004. By 2025 this mix changes to 34% and 61%, respectively. This reversal is largely due to coal plant retirements and very little new coal plant additions.

Electricity prices are forecast to decline between 2004 and 2006, and remain relatively low in 2007 and 2008. As such, the average price from 2004 through 2008 is forecast at $49/MWh. However, electricity prices are forecast to recover in 2009 as supply and demand approach a more sustainable balance due to demand growth and capacity retirements. From 2009 through 2025, electricity prices range from $59/MWh and $83/MWh, and average $70/MWh. Overall, the Reference Case electricity price forecast calls for an average price of $65/MWh between 2004 and 2025.

The market heat rates over the same forecast range from 8.8 GJ/MWh in 2006 to 14.4 GJ/MWh in 2020, with an overall average market heat rate of 11.9 GJ/MWh between 2004 and 2025. Market heat rates in the first 5 years of the forecast are all below 10 GJ/MWh on an annual basis due to a very large reserve margin forecast for the province. From 2009 through 2025, the market has an average heat rate of 12.7 GJ/MWh, which is generally consistent with the long-run 'all in' costs of new combined cycle natural gas generation.

GHG emissions are the final element presented in this report, and the Reference Case calls for GHG emissions of 52 Mt in 2004 and a peak of 60 Mt of GHG emissions in 2025. This implies a growth rate of 0.7% per year in GHG emissions in the Reference Case. This result is driven by the assumption that Genesee 3 is the last coal plant built in the forecast, and several existing coal plants are retired and replaced with natural gas generation.

Sensitivity Results

There are two main sets of sensitivity results: three of the five sensitivities use identical assumptions as the Reference Case except a GHG policy is put in place that levies varying levels of costs on coal and natural gas generators. These costs are created because generators that are impacted by the given

GHG policy are required to buy emission offsets, and these offsets form a variable for generators. The other two sensitivities utilize identical assumptions as the Reference Case as well, with one exception. Coal-fired generation is assumed to make up the majority of capacity additions in these sensitivities, and as a result 3200 MW of coal capacity is added after Genesee 3 is completed. One of the 'Coal' sensitivities operates under the assumption that no GHG policy is in place, while the second sensitivity examines the most stringent GHG policy from the set of policies in the earlier sensitivities.

Vintage Policy Sensitivity Results

The three GHG policies are identified as Vintage One, Vintage Two and Vintage Three. In general, Vintage One forms the base upon which Vintage Two and Vintage Three are defined. Vintage One has several key features: new coal plants must purchase GHG offsets to reduce their net emissions to 0.418 t/MWh, and coal plants that are more than 40 years old and not covered by a PPA must meet this same standard. Natural gas plants greater than 30 years old as well as new natural gas plants are required to offset their emissions to 0.375 t/MWh.

Vintage Two has the exact same provisions as Vintage One, with the additional requirement that any plant that is not impacted by the Vintage One policy must reduce its GHG emissions by 5% from its baseline intensity. Vintage Three uses the same criteria, except the emission reduction is 15%. It should be noted that there is a floor to the required offsets in that no unit is required to offset to below its vintage intensity limit. For example, a natural gas generator with an emission intensity of 0.4 t/MWh is not required to reduce its emissions below 0.375 t/MWh, even though a 15% reduction would imply a reduction below this level.

Vintage One Sensitivity Results

The Vintage One sensitivity did not create a substantial impact on the electricity price forecast, relative to the Reference Case, as electricity prices rose by an average of $1.10 /MWh from 2008 onwards, which is the year the policy is enacted. The cost impact is lower from 2008 through 2020 due to the fact that the Vintage One policy creates the majority of its costs from 2021 onwards. The conclusion is drawn that since the vast majority of natural gas units face very few, if any, costs under this policy, and these units are forecast to set the price the majority of the time, the Vintage One policy does not create a large impact on the wholesale electricity price.

In terms of GHG emissions, the Vintage One policy reduces emissions slightly relative to the Reference Case from 2008 onwards. GHG emissions are 2% to 3% lower than in the Reference Case between 2008 and 2020, as Genesee 3 is required to offset its emissions to 0.418 t/MWh under the Vintage One policy. However, the impact of the Vintage One policy grows quite substantially from 2020 to 2021, as several units that are more than 40 years old see their PPA contracts expire. Once this GHG policy exemption expires, these units are required to offset their emissions to 0.418 t/MWh as well. As a result, GHG emissions fall by 13% in the Vintage One sensitivity relative to the Reference Case in 2021, and this figure grows to 22% by 2025 as several more units reach 40 years of age and are required to offset their emissions.

Vintage Two Sensitivity Results

The Vintage Two policy creates somewhat larger GHG emission costs for most generators than the Vintage One policy, and these costs appear to flow through into the electricity price forecast. On an overall average basis from 2008 onwards, electricity prices are $1.60/MWh higher than the Reference Case in Vintage Two. This result, relative to the Reference One results, represents about $0.50/MWh increase, which is perhaps marginally higher than might be expected. In terms of the split in market impact between 2008 and 2020 versus 2021 through 2025, Vintage Two sees a $0.90/MWh impact in the early years versus a $3.50/MWh impact in the later years. The cost impact from 2021 onwards appears to be higher than might be expected[1] given the fact that coal generation is rarely on the margin, but it is not surprising that the price impact increases after 2020 when the PPA's expire.

GHG emissions under the Vintage Two policy realize a noticeable drop from 2008 onwards, as the majority of GHG emitters are required to reduce their reductions by 5% under the general reduction requirement. Genesee 3 is still required to meet its reduction requirement as per Vintage One, but all the other coal plants are also required to reduce their emissions by 5%. Further, some natural gas generators (those with a GHG intensity greater than 0.375 t/MWh) are also required to reduce their emissions by 5%. As a result, GHG emissions fall by 7% in 2008 relative to the Reference Case. In 2020, this reduction falls to 6% as several coal plants retire and are replaced by natural gas units that are not required to reduce their emissions in either the Reference Case or the Vintage Two sensitivity. From 2021 onwards, the Vintage portion of the policy once again creates large emission reduction requirements for several coal plants, and GHG emissions fall by 15% and 23% in 2021 and 2025 respectively.

Vintage Three Sensitivity Results

The Vintage Three policy creates the largest GHG emission costs for the electricity industry, but once again these costs are centered on coal generators and relatively inefficient natural gas generators. Given that there is a floor emission requirement of 0.375 t/MWh on natural gas generators, the majority of cogeneration and combined cycle plants do not face the full potential of costs under the 15% reduction requirement. As such, the higher cost of the policy does not all flow through to consumers, as the electricity price increases by $2/MWh between 2008 and 2025 relative to the Reference Case. Once again, the larger price increase is seen from 2021 onwards, as electricity prices increase by $4.30/MWh in these years. From 2008 through 2020, the policy creates a $1.15/MWh price increase relative to the Reference Case.

GHG emissions under the Vintage Three policy realize a distinct drop from 2008 onwards, as the majority of GHG emitters are required to reduce their reductions by 15% under the general reduction requirement. Genesee 3 is still required to meet its reduction requirement as per Vintage One, but all the other coal plants are also required to reduce their emissions by 15%, as per the Vintage Two policy. Further, some natural gas generators (those with a GHG intensity greater than 0.375 t/MWh) are also required to reduce their emissions by as much as 15%—it is important to recognize that no natural gas generators are required to reduce their reductions below the 'floor' value. As a result, GHG emissions fall by 15% in 2008 relative to the Reference Case. In 2020, this reduction falls to 12% as several coal plants retire and are replaced by natural gas units that are not required to reduce their emissions in either the Reference Case or any of the Vintage sensitivities. From 2021 onwards, the Vintage portion of the policy once again creates large emission reduction requirements for several coal plants, and GHG emissions fall by 19% and 26% in 2021 and 2025 respectively.

Coal Generation Sensitivity Results

The purpose of the coal generation sensitivity forecasts is to determine how sensitive the price and emission forecasts are to the type of generation that is added to the supply mix over time. In the Reference Case, combined cycle natural gas generation and cogeneration form the large majority of generation additions, and very little coal generation after Genesee 3 is forecast to be built. The coal generation sensitivities counter this assumption, as the combined cycle generation in the Reference forecast is large replaced with coal generation. Note that the cogeneration assumptions are unchanged since these projects are only partially driven by the electricity market.

[1] Since natural gas generation is on the margin in the large majority of hours, it was expected that price increases would reflect the cost increases for these units. Natural gas generation GHG costs are generally less than $1.50/MWh at the highest, so the $3.50/MWh appears to reflect a larger amount of coal generation costs being passed onto the market than was expected.

Coal Generation with no GHG Policy Sensitivity Results

The first obvious result from the coal generation sensitivities is that energy production from coal generation is dramatically higher than in the Reference Case. In the Reference Case, coal generation declines from a peak of 45 TWh in 2007 to 36 TWh in 2025 due to unit retirements. However, in the coal generation sensitivities, coal generation peaks in 2025 at 62 TWh. As a result, coal maintains a much flatter market share in terms of energy production than in the Reference Case, ranging from 64% in 2004 to as low as 50% in 2016. In the Reference Case, coal energy falls to 34% of the total energy production in 2025.

Average electricity prices in the coal generation sensitivity are roughly $1.30/MWh lower than the Reference Case, but the more noticeable feature between the two forecasts is that the coal forecast has a much ‘lumpier’ profile. This occurs because coal generation is assumed to develop in very large blocks of 400 MW or more, and each addition causes a noticeable impact on the market. Furthermore, the longer lead time required for a coal facility increases the likelihood that a generator will come online either earlier or later than required to balance supply and demand. For example, the coal sensitivity has much higher prices than the Reference Case in 2011, which is when the first coal plant beyond Genesee 3 is forecast to be built. In 2012, the 450 MW plant built in 2011 causes prices to fall below the Reference Case—see Figure 26 on page 49 for details.

Since the coal facilities built under this sensitivity are assumed to use traditional coal generation technology, the emission intensity of the generators is much higher than the combined cycle natural gas plants they replace in the supply stack. In this sensitivity, there is no GHG policy, so the new coal plants are not required to buy emission offsets to reach emission intensity levels of 0.418 t/MWh as per the Vintage sensitivities. Actual GHG emissions in the coal sensitivity are roughly equivalent to the Reference Case emissions until 2012, when the first coal plant after Genesee 3 is in service for an entire year. By 2025, GHG emissions are 26% higher than the Reference Case, and the electricity is forecast to produce 75.4 Mt of GHG as opposed to 59.8 Mt in the Reference Case.

Coal Generation with Vintage Three GHG Policy Sensitivity Results

The coal generation with Vintage Three GHG policy assumes the same generation development as the previous scenario, except the Vintage Three policy is implemented. In this sensitivity the Vintage portion of the policy makes a large impact on net GHG emissions because all the new coal plants are required to offset their emissions to 0.418 t/MWh. Note that this emission intensity is not much higher than the 0.375 t/MWh typical intensity of the combined cycle natural gas generation that is replaced.

Since the GHG offset costs are applied to a much larger amount of generation in this sensitivity than in the Vintage Three sensitivity, it might be expected that the policy would have a greater impact on electricity price. However, the results once again suggest that the price impact of the policy is minimal, as electricity prices only increase by $0.90/MWh relative to the coal sensitivity with no GHG policy between 2008 and 2025. If the 2008 through 2020 and 2021 through 2025 periods are used for comparison once again, the price differences show a large impact from 2021 through 2025 ($2.50/MWh), and a small increase of $0.25/MWh from 2008 through 2025.

In terms of GHG emissions, the Vintage Three policy creates substantial reductions relative to the previous coal generation sensitivity. GHG emissions are between 11% and 15% below the Reference Case from 2008 through 2020 in this sensitivity, whereas in the previous coal sensitivity they ranged from equivalent to 16% higher than the Reference Case. In fact, the coal generation with Vintage Three policy is very similar to the Vintage Three policy with Reference Case natural gas generation in terms of emissions because the policy makes coal generators look very similar to combined cycle generators from a GHG emissions perspective. From 2021 onwards, GHG emissions in this sensitivity fall by 18% to 23% relative to the Reference Case, which is again quite similar to the Vintage Three sensitivity results.

Key Assumptions and Results

Key Assumptions

In the previous stages of this project, several different natural gas and demand forecasts were put together under different 'Scenarios' that envisioned alternative views of the world going forward. Under the 'Business as Usual' scenarios, natural gas prices were lower and electricity demand was higher, while under the 'Emissions management' scenarios, the assumption was that economy wide adjustments would take place that would lead to higher natural gas prices and lower electricity demand. Within this report, there is only ONE set of natural gas price and electricity demand assumptions. All of the changes are restricted to either GHG policy options in three of the sensitivities, and generation development in the other two sensitivities.

Cogeneration development assumptions are key in this analysis, as the report specifically examines what might occur if coal generation replaces combined cycle natural gas generation. As such, it is important to recognize that Reference Case and all five sensitivities include 1000 MW of cogeneration (net to grid) between 2004 and 2025. In addition to this 1000 MW, the forecast estimates that roughly 1800 MW of generation will be developed to meet onsite load requirements, and the majority of this generation is forecast to come from cogeneration. Overall, the forecast call for 2800 MW of natural gas fired cogeneration to be developed over the 22 year forecast period.

Variation around the cogeneration assumptions could occur in two key ways. First, cogeneration capacity might be fired by a fuel other than natural gas, such as coke or Syngas. The use of an alternative fuel would likely increase emissions from cogeneration facilities relative to the natural gas assumption, but there would be very little impact on the electricity price forecast. Second, oilsand developments may choose to buy electricity from the wholesale market rather than produce it with cogeneration. This would change the forecast supply / demand balance by reducing supply from cogeneration capacity and increasing demand in the oilsand sector. In this case, the deviation from forecast generation additions would likely cause a price impact rather than an emission impact.

Forecast Results

Table 1 presents the overall results discussed in the previous section, and illustrates average electricity price forecast for various timeframes. The overall average forecast price includes the years between 2004 and 2007, when there is very little difference between any of the sensitivities. Since the GHG policy is implemented in 2008 and the coal generation in the coal sensitivities does not impact the market until 2011, the first three years of the forecast are basically identical across all the sensitivities and Reference Case.

Table 1 - Overall Forecast Results (Real 2004 Dollars)

	Overall Average (2004 - 2025)	Policy Years Average (2008-2025)	PPA Years Average (2008-2020)	Post PPA Years Average (2021-2025)
Reference Case	$ 52.78	$ 53.12	$ 53.61	$ 51.86
Vintage 1 Sensitivity	$ 53.28	$ 53.90	$ 53.92	$ 53.84
Vintage 2 Sensitivity	$ 53.52	$ 54.30	$ 54.32	$ 54.26
Vintage 3 Sensitivity	$ 53.79	$ 54.62	$ 54.54	$ 54.83
Coal Generation with No GHG Policy Sensitivity	$ 51.96	$ 52.23	$ 54.30	$ 46.84
Coal Generation with Vintage Three Sensitivity	$ 52.54	$ 52.81	$ 54.44	$ 48.57

Overall, the results indicate a small, but consistent impact associated with the GHG policy. The size of the increase in the years 2008 through 2025 ranges from $0.80/MWh to $1.50/MWh, but the majority of this impact is seen from 2021 onwards when units that are covered by PPA contracts are exposed to the GHG policy requirements. In the earlier years (2008 through 2020), the price impact ranges from $0.30/MWh to $0.93/MWh.

Costs to Generators

The analysis has indicated that the impact of the GHG policies on the market price for electricity will be rather small. However, the impact to the electricity price only represents part of the story—electricity generators will face significant costs in order to realize the emission reduction targets contained in the various policy options. Table 2 and Table 3 present various ways of tabulating the total GHG offset costs that coal and natural gas generators will face under the proposed policies.

Table 2 - Total Coal Generator GHG Emission Costs

	Vintage One	Vintage Two	Vintage Three	Coal No GHG	Coal & Vintage Three	Reference Case
Cumulative GHG Emission Costs ($000)	$1,132,534	$1,475,243	$2,177,817	-	$3,502,407	-
Present Value of GHG Emission Costs ($000)*	$260,458	$382,204	$630,007	-	$883,172	-
Present Value of Total Coal Energy (GWh)**	429,150	429,150	429,150	462,780	462,780	429,150
Levelized GHG Emission Costs per MWh***	$0.61	$0.90	$1.48	-	$1.86	-

* Assumes 10% Discount Rate
** Energy only includes coal fired plants
*** Assumes inflation rate of 2.0% and term of 21 years (2005-2025), starting in 2005

Since the timing and size of emission reductions varies across each policy, the nominal costs presented in the first row tell only a portion of the story. For example, in the Vintage One sensitivity, the majority of emission reductions take place beyond 2021, and this results in a large difference between the nominal costs and the present value of those same costs. In the Vintage One sensitivity, the present value is less than 1/4 of the nominal value, while in the Vintage Three sensitivity the present value is just under 1/3 of the nominal value. This difference occurs because the Vintage Three policy creates costs (and emission reductions) much sooner than the Vintage One policy.

The third row of the table simply calculates the present value of all energy produced by coal facilities between 2005 and 2025. This amount is used to calculate a levelized $/MWh tariff discounted back to 2005 dollars in order to quantify the emission costs on a more meaningful basis. The $0.90/MWh tariff for the Vintage Two sensitivity can be interpreted as: if each coal MWh was charged $0.90/MWh from 2005 through 2025, and this $0.90/MWh was increased by 2% each year, this charge would be financially equivalent, in present value terms, to the impact of the Vintage Two policy. However, it is very important to recognize that this is not how the policy is actually implemented—some coal units will pay a much larger portion of the total emission costs than others. The levelized number simply represents the cost of the GHG policy spread across the entire coal generation sector and spread across time from 2005 through 2025.

In the coal generation sensitivity with Vintage Three GHG costs, the emission costs are by far the highest of any sensitivity. This result occurs because the new coal facilities built are required to offset their emissions to 0.418 t/MWh, while the combined cycle natural gas plants they replaced did not face any GHG costs. In total nominal costs, the coal sensitivity with Vintage Three GHG policy results in about 50% more GHG costs than the Vintage Three sensitivity under the Reference Case supply assumptions. However, in present value terms, the cost increase only amounts to about a 40% cost increase because many of the incremental coal costs occur late in the forecast period. Furthermore, since there is much more coal energy in the coal sensitivity, the $/MWh levelized cost for coal generators is only 27% higher in the coal sensitivity than in the Vintage Three Sensitivity.

Although natural gas facilities do not face the same level of emission charges as the coal facilities because their baseline GHG intensity is much lower, there are still GHG charges for several natural gas generators. This section presents a brief summary of these costs—each row is interpreted in the same manner as the table for the coal plants above.

Table 3 - Total Natural Gas Generator GHG Emission Costs

	Vintage One	Vintage Two	Vintage Three	Coal No GHG	Coal & Vintage Three	Reference Case
Cumulative GHG Emission Costs ($000)	$665	$59,920	$79,260	-	$67,482	-
Present Value of GHG Emission Costs ($000)*	$127	$16,245	$22,182	-	$20,448	-
Present Value of NG Energy (GWh)**	367,617	367,617	367,617	316,961	316,961	367,617
Levelized GHG Emission Costs per MWh***	$0.00	$0.04	$0.06	-	$0.06	-

* Assumes 10% Discount Rate
** Energy only includes natural gas fired plants
*** Assumes inflation rate of 2.0% and term of 21 years (2005-2025), starting in 2005

In the Vintage One sensitivity, natural gas plants face almost no GHG costs because the plants that would be subject to costs almost all retire before the offset costs would be triggered under the Reference Case assumptions.

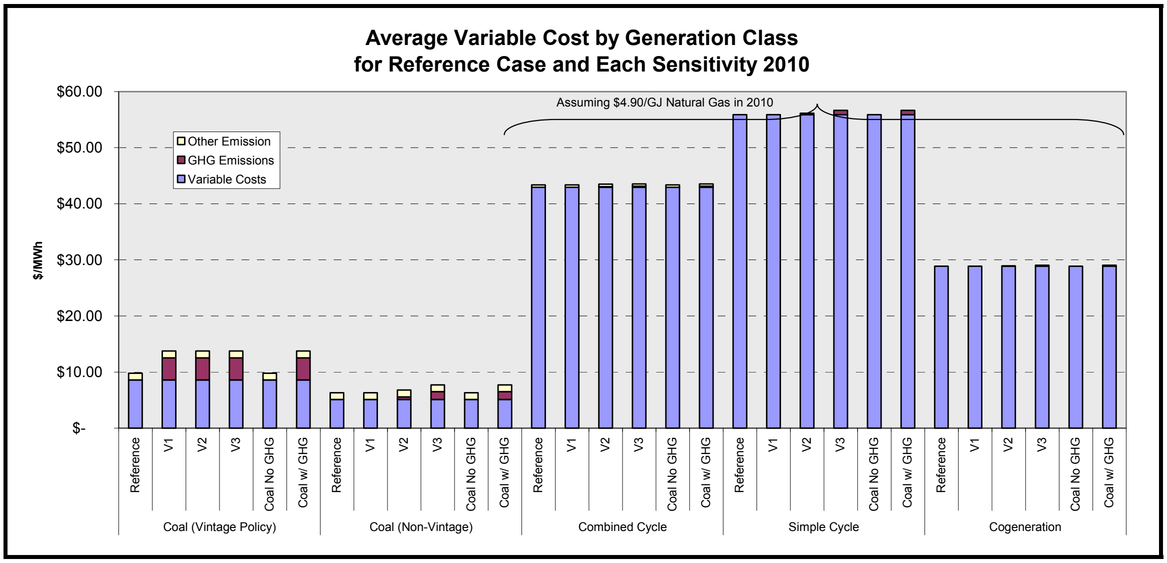
As with the coal GHG costs, each successive Vintage policy results in higher costs for generators. However, the scale of the costs is roughly 95% lower than the coal costs because a large portion of the natural gas generation fleet does not face any costs for GHG offsets under the various policies, and even the most GHG intense existing natural gas generator faces costs of perhaps $1.25/MWh in the latter part of the forecast. A new simple cycle natural gas generator could face GHG offset costs around $3/MWh. Since the most GHG intense natural gas generators tend to be peaking generators that run at very low capacity factors relative to cogeneration and combined cycle generators, the average impact is very small across the total natural gas generation fleet.

Although the tables above present a summary of the total cost to industry associated with the policy options, they do not give a good indication of what the impact on operating costs will be for specific class of generator. Figure 1 and Figure 2 look at the impact on operating costs for various types of generation units in 2010 and 2025 for each policy. It is important to recognize that the costs presented in these tables are for *representative* units and do not reflect the specific costs to a given generator. Furthermore, the costs are purely an estimate of the variable cost per MWh for electricity from each unit, and do not include any returns on capital, PPA payments or any other costs that are not directly related to energy production. In effect, the costs outlined reflect the impact on the energy market's merit order if units purely bid their variable cost.

Figure 1 and Figure 2 represent the same information, but at two different points in time. Five categories of generators are considered in the figures—two types of coal generators and three types of natural gas generators. The two types of coal generators are those that are subject to the Vintage One policy, i.e. new generators and generators that have reached the end of their design/PPA life. In 2010, the only generator in the Vintage Policy category is a new generator, such as Genesee 3. However, in 2025, this category includes Sundance 3 through 6, Keephills 1 and 2 and Battle River 5 as well as any new coal generators. On the other hand, the coal non-vintage category includes basically all of the existing coal generators in 2010, but only includes Sheerness 1 and 2 and Genesee 1 and 2 in 2025.

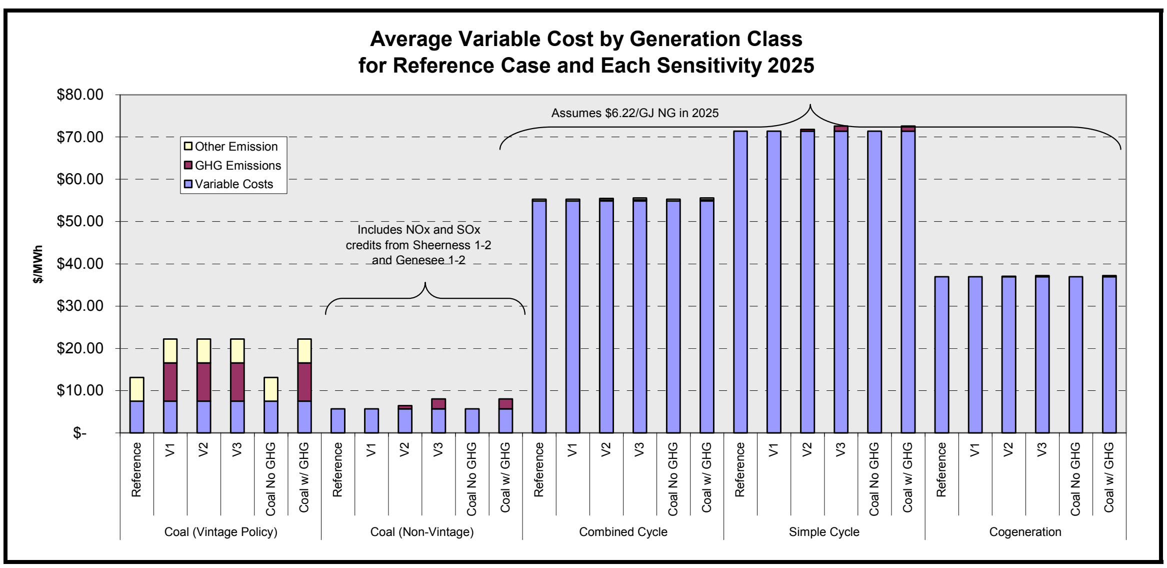
Natural gas units are categorized according to the type of technology they incorporate. The vast majority of the natural gas facilities included in the figures is modern natural gas generation built in 1998 or later. Older facilities such as Clover Bar, Rossdale and the older on-site generators are not included in these figures because they do not represent a 'typical' natural gas generator in Alberta, and these types of technology are extremely unlikely to be built in the future. One important caveat that results from this is that some natural gas units will face much higher costs than those indicated in the figure, but the costs in the figure are believed to be indicative of most capacity in the province for the years 2010 and 2025.

Figure 1 - Marginal Cost Impact by Generator Class – 2010



In the 2010 Reference Case, coal plants face emission costs associated with mercury whether they fall into the Vintage category or not. GHG costs of $4/MWh show up for coal plants in the Vintage Category for all three Vintage sensitivities, but for the non-Vintage coal plants the costs are smaller and only appear in Vintage Two and Three. Combined cycle natural gas plants face well under $1/MWh in emission costs in all the sensitivities, and even simple cycle plants face less than $1/MWh in variable emission costs. Cogeneration costs are also very near $0/MWh, and overall Figure 31 shows that coal plants face much higher variable cost increases from the GHG policies.

Figure 2 - Marginal Cost Impact by Generator Class – 2025



In 2025 the results are quite similar, although the graph suggests that a typical 'Vintage' coal plant faces environmental costs that account for roughly 2/3 of its total operating costs under all the GHG policy scenarios. However, note that these costs only apply to coal plants that are over 40 years old or plants that have not yet been completed. Coal plants that are not covered by the 'Vintage' policy face a maximum of $2.30/MWh for GHG under the assumptions given for the Vintage Three policy. Natural gas plants face up to $1.28/MWh in emission costs for simple cycle plants in Vintage Three, but this amounts to around 1% of their total operating costs.

Overall, the results in this report can be summarized in several key points. First, the GHG policy options examined create a small but consistent impact on electricity prices, and this impact appears to fall somewhere between $1/MWh and $2/MWh. Second, natural gas generators do not appear to face detrimental impacts from this policy, as these generators recover all or slightly more than all, of the costs levied on them from the increase in market price. Coal generators see their margins decline because their cost increases exceed the increase in market price, especially units that are subject to the Vintage portion of the GHG policy. Third, GHG emissions are reduced in all of the policy options, and the key difference in the various options appears to relate to emission reduction timing. The more stringent policy options create emission reductions from 2008 onwards, while the Vintage One option does not create large emission reductions until after 2021 when the PPA contracts expire. Fourth, the coal sensitivities reveal that electricity prices will not be dramatically different if coal generation replaces natural gas generation in the forecast. However, GHG emissions in the absence of any GHG policy are dramatically higher when coal generation is the primary development option. If a GHG policy such as the Vintage Three policy is implemented, GHG emissions are brought down to similar levels whether coal or natural gas generation is the dominant electricity provider. Finally, the results indicate that there are significant costs required in order to meet the emission policy standards, and these costs are primarily borne by coal generators. The policies do not create a large cost for natural gas generators, and this is the fundamental reason the forecast price is not impacted by more than $2/MWh in the various GHG policies.

Chapter 2 Introduction

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.

Project Background

The CASA Electricity Project Team (EPT) is evaluating proposed management scenarios for reducing air emissions of 5 priority substances from electricity generation facilities in Alberta. As a result of prior stages of this project, emission policy has been put in place for mercury, particulate matter, SO_x and NO_x. However, an emission policy for GHG was not put forth, although a renewable energy target of 3.5% was accepted. This stage of the project evaluates several GHG policy options under two separate generation development pathways.

The Objectives of the Study are:

1. Energy Price: To estimate the incremental impact on the annual average wholesale Alberta electricity price for each year from 2004 to 2025 from implementing a proposed GHG emissions framework, including consideration of various options for the timing and scale of emission reductions.
2. Energy Production: To estimate the impact on the supply stacking order, that is generation energy production by fuel type for each year from 2004 to 2025 from implementing a proposed GHG framework.
3. Emissions: To determine the EPG sector's aggregate GHG emissions profile by fuel type expressed as an average emission for each year from 2004 to 2025 as a result of implementing the proposed emissions management framework.
4. Generation development: To evaluate the impact on the results of a sensitivity in which coal generation development is extensive. Since coal generation has low variable costs but higher emissions than natural gas fired generation, the amount of coal capacity in the province is an important variable that must be considered when evaluating the impact of proposed GHG policy options.
5. Costs: To calculate the estimated financial impact of the GHG policy on fossil fuel generators in Alberta.

Project Scope

Phase 1

Based on the project background, as noted above, and discussions with project proponents, EDC was requested to provide a proposal to complete the following scope of work: a written report and presentation that assessed the relative impact of the project objectives[2]. This formed Phase 1 of the project, and served as a preliminary investigation into the impact of the emission management framework.

Two scenarios were modeled to meet the above objectives and a number of sensitivities tested certain variables and 16 sensitivities were defined to test the quantitative assessment impact on price and supply stacking order from a change in key variables.

Phase 2

As a follow-up to the results from Phase 1 of this project, Phase 2 was initiated with several revised assumptions, policies and inputs. Phase 2 uses the results from Phase 1 in order to evaluate a much narrower range of policy options. Once again, two main scenarios were evaluated along with a number of sensitivities.

At the conclusion of Phase 2 of the project, the CASA EPT reached a consensus and put forth recommendations to the province that covered mercury, particulate matter, SO_2 and NO_x emissions as well as a target for renewable energy production. These recommendations were accepted by the provincial government in early 2004, and are now part of the 'business as usual' projections for the Alberta electricity industry.

Phase 3

Phase 3 of the project examines the impact of GHG policy under the revised business environment created by the adoption of the CASA EPT's recommendations. One basic scenario that includes the costs and generation unit retirement implications from the Phase 2 recommendations is tested under several sensitivities. The Reference Case is developed on the assumption that no GHG policy is implemented—emission policy for the other four substances is already part of this Reference Case, so this scenario can be described as 'Business as Usual'. Three sensitivities are built off of this Reference Case that examine the impact of three GHG policies. Each of these sensitivities is identical to the Reference Case with the exception of GHG offset costs levied against natural gas and coal generators.

Two additional sensitivities are examined that test the results if coal based generation forms the majority of new investment from 2010 onwards. In the first sensitivity, there is no GHG policy—in effect, this sensitivity is the same as the Reference Case except coal generation forms the majority of capacity additions. In the second sensitivity, the most stringent GHG policy from the first sensitivities is used in conjunction with the coal generation assumption.

Reference Case Scenario

The new Reference Case now incorporates the following assumptions that have been implemented as a result of recommendations in the CASA EPT's November 2003 Report to Stakeholders.

1. A policy that 3.5% of energy comes from new renewable sources by 2008 is put in place. New renewable sources are defined as renewable generation built after December 31st, 2001.
2. The planning reserve margin is targeted at 16.5%. This assumption is changed from the 13% reserve margin in the previous Reference Case in order to accommodate 800 MW of wind capacity and its intermittent energy production.
3. Mercury and particulate matter emission reduction capital is to be installed by 2009. Five coal plants are exempted: HR Milner, Battle River 3 and 4, and Sundance 1 and 2.

[2] Please see *Emission Price, Energy Production and Emissions Impact* report issued July 30th, 2003.

4. Employ emissions trading systems for NO_x and SO_2.

In the Reference Case (as well as all sensitivities to follow), NO_x and SO_2 baselines were established for existing facilities based on their historic emissions intensities. Baselines for new units were set based on the Best Available Technology Economically Achievable (BATEA) level, as defined by the 2003 federal guidelines for thermal facilities. Existing units are allowed to operate at their approved baseline intensity until the end of their design life[3], at which time they can physically upgrade to meet the BATEA levels of the day, shut down or purchase offset credits. Once they reach the end of their maximum operating life[4], they must either physically upgrade to the BATEA levels of the day or shut down.

All other assumptions with respect to supply, demand and natural gas prices are developed under the assumption that the economy will proceed under a 'business as usual' type environment.

GHG Policy Sensitivities

In addition to the Reference Case, five sensitivities were developed. Three of the sensitivities change one assumption relative to the specific GHG reduction level whereas the other two assume an all coal based generation development sequence. One key difference in Phase 3 of the project relative to Phases 1 and 2 is that electricity demand and natural gas prices are not impacted by GHG policy. In other words, the basic fundamental forecasts of electricity demand and natural gas prices are the same in the GHG policy sensitivities as they are in the Reference Case. In Phases 1 and 2, it was assumed that demand and natural gas prices would be different under an emissions policy framework. The five sensitivities are as follows:

1. Vintage One GHG Sensitivity

   The Vintage One GHG sensitivity models a GHG policy that applies to coal and natural gas generators at the end of their design life. Coal plants must offset their GHG emissions to 0.418 t/MWh once they reach the end of their design life while natural gas units must offset their GHG emissions to 0.375 t/MWh at the end of their design life. New natural gas plants must also offset their emissions to the 0.375 t/MWh target if they are above this level, although the is unlikely to be an issue except for peaking units. Natural gas units with emissions below 0.375 t/MWh do not earn credits, but they are not required to offset GHG emissions. New coal plants are required to meet the 0.418 t/MWh immediately.

2. Vintage Two GHG Sensitivity

   The Vintage Two sensitivity includes all the aspects of the Vintage One policy, but all units not impacted by the Vintage One policy (coal and natural gas units prior to the end of their design life) are required to offset their emissions by 5%. Note that natural gas units with emissions below 0.375 t/MWh are not impacted by the Vintage One policy, so they are not required to offset their emissions by 5% in the Vintage Two policy.

3. Vintage Three GHG Sensitivity

   Vintage Three is the same as Vintage Two, except the offset requirement for plants not impacted by Vintage One is 15%.

4. All Coal Generation Development Sensitivity without GHG costs

[3] The end of Design Life is defined as the date of expiry of the PPA term or 40 years from the date of commissioning, whichever is greater, for coal-fired units, the date of expiry of the PPA term or 30 years from the date of commissioning, whichever is greater for non-peaking gas-fired units and the date of expiry of the PPA term or 60 years from the date of commissioning, whichever is greater for peaking gas-fired units.

[4] Maximum operating life is defined as 50 years for coal, 40 years for non-peaking gas units and 60 years for peaking gas units.

This sensitivity represents a second take on the 'business as usual' environment modeled in the Reference Case. However, coal generation takes the place of natural gas generation, which results in a much different overall supply situation.

5. All Coal Generation Development Sensitivity with Vintage Three GHG costs

   This sensitivity takes the coal generation sensitivity from above and adds the GHG costs from the Vintage Three policy.

Chapter 3 Demand and Supply Forecasts

This chapter presents the basic fundamental assumptions for energy demand and generation supply for all of the cases presented in this report.

Demand Forecast

The analysis started by modeling and forecasting the economic activity in the province from the bottom up. Economic activity was forecast using EDC's in-house macroeconomic model. This model forecast Alberta gross domestic product (GDP), personal consumption, natural population plus net migration, labour force, households and unemployment rates, by using information on capital investments, oil and gas prices and production, exports and other industrial sector's information. These resultant forecasts were then used to derive total electrical energy requirements, by sector, for the whole province. The next section outlines the demand forecasts for the Reference Case. Finally, note that the Reference Case demand is used for all of the sensitivities that follow, i.e. there is no sensitivity that contemplates energy efficiency increases in the Alberta economy that result in lower electricity demand.

Macroeconomic Forecast

This section provides a summary of the economic outlook for Alberta, Canada and the United States. Each of these economies plays an important role in defining GDP within Alberta, and there is a clear and strong link between economic growth and electricity consumption. Residential, commercial and industrial growth rates all depend on the overall health of the economy. As such, it is important to place the electric energy growth forecasts presented later in this document within the context of the overall macroeconomic environment.

Canadian growth has outpaced US growth over the last several years, but it looks as though that trend has changed. Starting with the extremely hot third Quarter of 2003, the US has turned in very strong growth in the last 6 months and it appears as though the long assumed economic recovery has finally arrived for real. Canada, on the other hand, is experiencing some difficulties and actually turned in an outright decline in GDP during January 2004, although most analysts expect the Canadian economy will still deliver moderate growth in 2004.

United States

Economic recovery in the United States appears to have finally been confirmed, as data released throughout April has been surprisingly strong. Although GDP growth has been through the roof for the last two quarters, jobs have not been forthcoming, as productivity gains have apparently absorbed the GDP growth. However, the most recent employment report was positive with 308,000 net jobs created, and many analysts appear to believe that the recovery is firmly in place.

With the Federal Funds interest rate still set at the historically low level of 1% and the economy picking up steam, Alan Greenspan has indicated that the Fed will begin to raise interest rates in order to fend off inflationary pressures. However, any interest rate increase is likely to be at least six months off, and some analysts speculate that the Fed will keep interest rates steady until 2005 because there are no real signs of inflation in the US. Wage growth, considered a key inflationary indicator, has remained weak throughout this recovery as the economy still has excess labor capacity to absorb.

GDP growth in the US is expected to remain strong throughout 2004, and the majority of forecasters peg annual growth around 4.9% in 2004 and slow to a more sustainable 3.5% in 2005. American growth appears to be supported by tax breaks, as retail sales have been strong with a large tax refund and business investment is being encouraged by accelerated depreciation on machinery investments. Since the impacts of these cuts are temporary, it appears as though analysts believe a fundamental recovery is in place based on their strong forecasts over the next two years.

Canada

Ralph Goodale, Canada's newest Finance Minister, released his first budget in late March, but there was very little in the budget that should be expected to impact the Canadian economy. The budget is once again balanced and shows a small contingency reserve of approximately $2 billion. In terms of the energy sector, the only substantive news is that the Government is planning to sell its stake in Petro-Canada, which is expected to net about $2 billion in revenue during this fiscal year.

One long-term goal that is notable in the budget is that the government intends to reduce the debt to 25% of GDP within 10 years. This is not a dramatic accomplishment since the debt currently stands at about 40% of GDP, but it does represent a dramatic improvement over the last decade. In 1994, debt stood at approximately 70% of GDP and debt-servicing costs accounted for roughly 40% of all spending. Lower interest rates, balanced budgets and modest debt repayment and relatively strong growth over the previous 10 years have allowed the government to improve its fiscal position quite substantially.

The Canadian economy has been much weaker than the US economy in recent months, as GDP actually fell by 0.1% in January. Furthermore, employment numbers were quite weak in February and March, and the Bank of Canada responded by lowering its overnight rate to 2%. The Bank has indicated that it will not ease monetary policy any further, meaning that the Canadian economy will not likely receive any further stimulus this year.

Despite the rough start to 2004, most analysts see a relatively healthy Canadian economy in 2004 and 2005. GDP growth is pegged at between 2% and 3% in 2004, and this is forecast to increase to over 3% in 2005. While these numbers are relatively tame compared to the results expected for the United States, they do represent healthy growth that will allow the Bank of Canada to gradually raise interest rates over the next 18 months.

One of the continuing challenges for the Canadian economy will be the strength of the Canadian dollar. The Canadian dollar is expected to appreciate over the next 2 years and reach perhaps $0.77 cents US. Since the Canadian economy is heavily export dependant, this places a drag on the growth rate. However, if energy and other commodity prices remain as strong as they have been in recent months, even a high Canadian dollar may not put too much of a drag on the economy.

Given the modest growth prospects for the economy, unemployment is not expected to decline substantially over the next two years. In a similar vein, inflation will likely remain in check because there is still excess capacity in the economy and the Bank of Canada will have plenty of latitude to raise interest rates if inflation starts to show up.

In the long-run, the Canadian economy is expected to continue to grow at its long-term sustainable path of 3% per year, the inflation rate is expected to be around the Bank of Canada's target of 2% and the unemployment rate is expected to converge to 6.8%.

Alberta

In its 2004 budget, the Government of Alberta defines 2003 as a year of surprises and challenges. Two factors proved to be challenging in 2003: the 22% Canadian dollar appreciation together with a sluggish US economy in the first ¾ of the year and the shut-down of Alberta's cattle and beef exports due to the discovery of two cases of BSE with linkages to Alberta. The BSE cases affected an industry valued at $2.3 billion and the increase in the value of the Canadian currency was responsible for a 5.1% decline in Alberta's international exports excluding energy and agricultural products.

On the other hand and according to the Alberta Government, growth from a variety of sources helped push the provincial 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.

The Alberta Government once again delivered a balanced budget with spending hikes and moderate tax cuts. Total program spending was up nearly 3% to $22.6 billion, while forecast revenue is pegged at just under $23 billion. The small surplus forecast is based on conservative oil and natural gas prices, and the government will quite likely realize larger resource revenues than the $4.8 billion forecast in the budget document. As a result, it is quite possible the provinces $3.7 billion dollar debt could be eliminated at the end of the current budget year.

In terms of spending increases, the two biggest expense items also received the largest increases: health and education. Together, these two items account for nearly 60% of total expenditures. Furthermore, when the budget is broken down by function rather than ministry, health and education account for over 65% of total expenditure.

Economic activity in the province of Alberta is forecast using EDC's macroeconomic model. The model uses historical data series from Statistics Canada and from the government of Alberta. Moreover, EDC has, from time to time, contracted sector research and analysis specialist with respect to forward outlooks for other major commodity sectors in the province, such as petrochemical and forestry products. The macroeconomic forecast was performed to the year 2020 using EDC's model. From 2021 onwards average growth rates were applied under the assumption that the macroeconomic variables would grow at rates similar to growth in the 2016 to 2020 period.

In 2004, strong energy prices and an improving US economy are expected to buoy the Alberta economy, which is expected to attain a 3.6% growth rate. Strong job creation is expected to reduce the unemployment rate, which is forecast to fall from 5.1% in 2003 to 4.9% in 2004. Economic growth in the province is expected to vary from year to year according to investment decisions. Around 2008 to 2010, the economy is expected to expand at higher growth rates than in other years due to the expected completion of major oil and gas projects.

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

It is important to note once again that this forecast assumes that emission management proposals do not impact the Alberta economy.

Oil and Natural Gas Forecast

Another set of important economic variables in this forecast pertains to natural gas and crude oil price projections. Both commodities are important economic drivers within Alberta, and crude oil prices have a potential to impact the electricity industry profoundly. Heavy oil and bitumen projects generally consume large amounts of electricity, and the price of crude oil is the key variable in determining how many heavy oil or bitumen projects proceed. Additionally, many of these projects may choose to invest in cogeneration equipment, which can turn a large electricity consumer into a net electricity producer, and the projects often have low variable costs for electricity production. As a result, both the electricity demand forecast and generation supply forecast are heavily influenced by the forward view of world crude oil prices.

As noted, natural gas prices are an important fundamental input in any electricity price forecast for Alberta, partially as a result of its role in demand growth. However, the larger impact created by natural gas prices comes about because natural gas is the fuel source for a growing portion of the generating fleet in Alberta. Natural gas prices therefore are reflected in the marginal production costs of generation, and this creates a direct linkage between natural gas prices and electricity prices, at least in the short-term. In the long-term, natural gas prices will tend to play a role in generation investment choices—higher natural gas prices sustained over time will break down the linkage between natural gas prices and electricity prices because alternatively fueled generation such as coal, wind and hydro could become more economically attractive.

Oil Price Forecast

The WTI oil price averaged around $35US/bbl in January and February while it averaged close to $37US/bbl in March. As of April 13th WTI crude oil prices rose from approximately $34US/bbl to $38US/bbl. Oil futures traded at levels not seen since the run-up to the first Gulf War in October of 1990. Among other things, a factor that fueled higher oil prices was OPEC's announcement and later implementation (at least notionally) [5] of reduced export quotas as of April 1st. OPEC agreed to cut production quotas by 1 million barrels per day amid concerns that oil prices would fall once the northern hemisphere's winter ends and world demand declines. Terrorism fears, political unrest in Venezuela, the potential for worker union activism in Nigeria and rising demand for oil in China have also been impacting oil prices. The nervousness of the market was tested when oil futures rose after the Madrid bombings were attributed to extremists linked to the al-Qaeda terrorist network. In addition, potential price spikes remain a danger given the uncertainty surrounding the recovery of output from Iraq. According to the Ross Smith Energy Group's (RSEG) April forecast, the market will still remain in fairly bullish territory through the rest of the year due to rising global political tensions and the exuberant bullishness of speculators. The RSEG is anticipating WTI oil prices to average $29.50US/bbl in 2004. [6]

Supplies of crude in the US are tight partly because demand for energy has steadily increased as the economy has improved. Oil demand in the US is seen to have surged by over 2% in the final quarter of 2003 compared to the previous year. Commercial US crude oil inventories fell by 2.1 million barrels during the first week of April, which left stocks 6.7% below the 5-year average at this time of the year. Also below their 5-year levels are US motor gasoline inventories and distillated fuel inventories. Total commercial petroleum inventories are 44.1 million barrels less than the 5-year average at this time (April 2004) of the year according to the Energy Information Administration (EIA). Motor gasoline and distillate fuel demand has recently been up relative to last year, although kerosene-type jet fuel demand has been down. Overall, total product supplied has been recently up in the US compared to last year. In early April, well before the peak driving season, the average retail regular gasoline price reached an all time record of $1.78US per gallon in the US. [7]

World oil demand rose by 2% in 2003 and it is expected to grow at a 2.2% growth rate in 2004 and 2005 according to the EIA. According to the National Energy Board (NEB), the Canadian energy industry accounted for 16% of Canadian exports in 2003. The boost was mainly attributed to record level commodity prices. Energy exports reached $62 billion in 2003 or 27% more than the previous year. US imports from Canada increased in 2003 and made up 16% of all crude oil imports going into the US. According to some, the amount of US imports from Canada is likely to increase to protect the US from a possible disruption in supply. [8] Last year, the oil sands played a greater role as they accounted for 34% of total Canadian crude oil output and they are slated to continue to increase their

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[5] Among the countries that have not started to implement (as of April 15th) the April 1st production cut is Kuwait. High oil prices have given little incentive to OPEC members to cut supply from March levels. Many forecasts are not assuming full compliance by OPEC members.

[6] Ross Smith Energy Group Ltd. *Energy Update, The RSEG Oil Report, March 2004 – April Forecast*.

[7] Preliminary data from the EIA shows that first quarter 2004 gasoline demand reached and all-time record of 8.8 million barrels per day in the US. The early end of a severe winter in many parts of the US contributed to the increase in demand.

[8] Ross Smith Energy Group Ltd. *Industry Fundamentals, Energy Update*, March 2004.

share as new projects begin production. The EIA expects oil sands to add 2.5 million barrels per day by 2025.

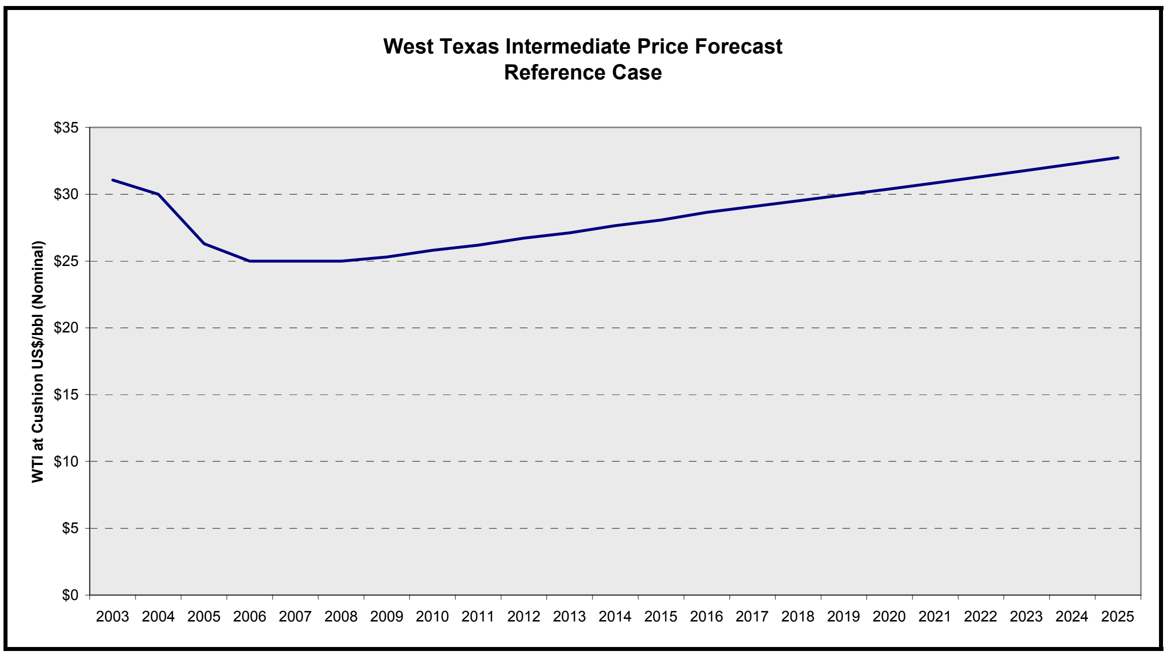
Looking at the back end of the forecast, the EIA projects the average lower 48 crude oil price to be $23.61US/bbl (2002 constant dollars) in 2010 and $26.72US/bbl ($51US/bbl in nominal dollars) in 2025 in its reference case forecast. Given this assumption, the gap between domestic US supply and demand is expected to widen. Net imports of petroleum into the US are expected to increase from 53% of domestic petroleum consumption to 70% in 2025.

As of April 13th the NYMEX crude oil forward curve was averaging $29.10US/bbl from 2006 to 2010 with little discrepancy among the individual years. The WTI forecast (short-term and long-term) was derived from a consensus of sources that include the NYMEX WTI forward curve as of April 13th, the most recent Chenery Dobson Management's Survey of Hydrocarbon Price Forecasts (January 2004), CERI's short-term forecast and other organizations' forecasts (Global Insight, Goldman Sachs, Peters & Co. etc) as shown in the Alberta Government's 2004 Budget.

Given the current international market conditions, WTI crude oil prices are expected to average $30US/bbl in 2004. As OECD inventories recover and Iraq's output increases, oil prices are anticipated to fall to $26.30/bbl in 2005. It should be noted that the consensus among forecasters of higher oil prices is partly due to the depreciation of the US dollar against other major currencies. Some analysts argue that OPEC has non-officially increased its price band due to the US dollar depreciation.

Figure 3 shows the oil price assumption for each year of the forecast. Oil prices are anticipated to average $26.24US/bbl from 2004 to 2013 (next ten years) and to average $30.19US/MWh from 2014 to 2025.

Figure 3 - World Crude Oil Price Forecast



Natural Gas Price Forecast

AECO-C natural gas prices averaged $6.74/GJ in January, $5.76/GJ in February, $5.88/GJ in March and as of April 19th AECO-C month to date prices have averaged $6.28/GJ. Cold weather in the US Northwest and Midwest regions contributed to the run-up in natural gas spot and future prices in March and a spring chill in the US Northeast underpinned high prices in early April. As temperatures have recently moderated, marking the end of the heating season, spot prices have eased in most North American market locations. For example, April AECO-C spot prices reached a high of $6.81/GJ on April 4th and as of April 19th AECO-C prices have fallen to just above $6/GJ. However, in the US, the onset of spring maintenance at many nuclear power plants has helped support natural gas prices. But perhaps more importantly, increasing oil prices have been playing a significant role in keeping natural gas prices buoyant as some consumers have fuel switching capabilities.

The EIA is expecting natural gas demand to rise by 2.4% in 2004 in the US due to economic growth, weather related factors and an overall increase in fuel oil prices relative to natural gas prices. The agency is forecasting natural gas spot prices at $5.31US/mmBTU for 2004 and about $5.21/mmBtu for 2005. Prices are not expected to ease significantly during the 2004 storage refill months.[9] On the other hand, the Ross Smith Energy Group (RSEG) is projecting a softening in prices through the summer based on natural gas market fundamentals. The RSEG is anticipating demand to be constrained by high prices and expects US natural gas demand to grow in the range of 1.4% to 1.5% annually in 2004 and 2005. Closer to home, Canadian natural gas demand is anticipated to increase by 1.8% in each of 2004 and 2005. According to the RSEG, working gas in underground storage in the US will bottom out at a familiar comfort level of 1 Tcf and the storage build will be healthy throughout the refill season. Currently, total working gas in the US is considered to be within the 5-year historical range. The only main factor currently underpinning strong natural gas prices are high oil prices according to the RSEG.[10]

On the supply side, the Ross Smith Energy Group is of the view that natural gas production will increase by 1% to 1.5% for 2004 in the Western Canadian Sedimentary Basin. Production in the lower 48 US States is expected to increase by 1.5% annually in 2004 and 2005. Although these numbers are on the aggressive end of the range, the RSEG expects strong energy prices, good cash flows and aggressive upstream activity to drive the growth.[11] The EIA expects natural gas production to rise slightly through 2005 although an exact figure was not available.[12]

According to the EIA's Annual Energy Outlook with Projections to 2025, US natural gas production from unconventional sources is projected to increase more rapidly than conventional production. Non-conventional sources include tight sands, shale, and coal bed methane. Alaska is projected to start transporting natural gas to the lower 48 States through the North Slope Alaska pipeline by 2018. Net imports to the US are expected to account for 43% of total growth in supply from 2002 to 2025. Of all sources, LNG will account for most of the increase in net imports. Imports from Canada are projected to peak in 2010 and then decline gradually. The EIA projects, in its base case, that a Mackenzie Delta natural gas pipeline will begin sending supplies to the US by 2009. However, the EIA expresses considerable uncertainty regarding the economic viability and timing of coal bed methane in Western Canada. Also prospects of significant increases in offshore production in Eastern Canada have diminished over the past few years.[13]

According to the EIA's reference case forecast, natural gas demand growth is expected to be led by electric generation. Demand from electricity generators is expected to increase from 27% of total end use in 2002 to 29% of total use in 2025. Regarding total US domestic consumption, total growth is expected to range from 29% to 51% from 2002 to 2025. In the long-run, the EIA expects natural gas prices delivered to end users to increase at a slower rate than wellhead prices because there is a projected decline in average transmission and distribution margins.

As of April 13th the NGX AECO-C forward curve was averaging $6.63/GJ from May to December. If the forward curve is averaged with year-to-date actual prices, the 2004 average price would be around $6.47/GJ, $0.14/GJ above the 2003 average price. The AECO-C forecast presented in this section is derived from a consensus of sources that include the NGX and NYMEX forward curves as of April 13th, the most recent Chenery Dobson Management's Survey of Hydrocarbon Price Forecasts (January

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[9] Energy Information Administration, *Short-Term Energy Outlook – April 2004*.

[10] Ross Smith Energy Group Ltd., *Energy Update, The Natural Edge*, *March 2004 – April Forecast*.

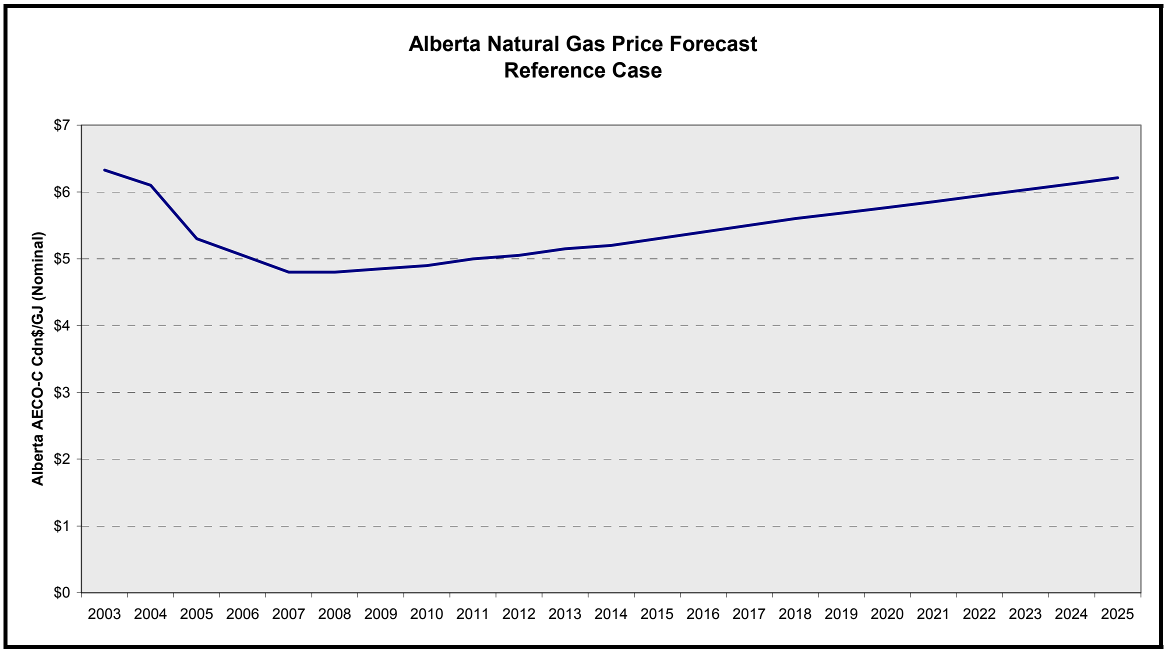
[11] Ross Smith Energy Group Ltd., *Energy Update, The Natural Edge*, *March 2004 – April Forecast*.

[12] Energy Information Administration, *Short-Term Energy Outlook – April 2004*.

[13] Energy Information Administration, *Annual Energy Outlook 2004 with Projections to 2025.*

2004), CERI's forecast and other organizations' forecasts (Gilbert Lausten Jung Associates, Peters & Co. Limited) as shown in the Alberta Government's 2004 Budget. The front end (2004) of the forecast was more heavily weighted towards the market forward curve than toward the institutional forecasts. Natural gas prices are expected to average $6.10/GJ in 2004 and $5.30/GJ in 2005. Natural gas prices are assumed to bottom out in 2007 and slowly increase afterwards; this is consistent with many firm's forecasts. As Figure 4 depicts, natural gas prices are assumed to average $5.10/GJ in the first 10 years of the forecast (2004 to 2013) and average $5.72/GJ from 2014 to 2025.

Figure 4 - Alberta Natural Gas Price Forecast



Alberta's natural gas production levels are expected to decline throughout the forecast period as conventional reserves dry up. By the end of the forecast period, US deliveries from Alberta production are forecast to disappear. This is not to say that the pipelines will not be filled, rather, the source of the production is not forecast to originate in Alberta. In should be mentioned that this forecast does not call for significant amount of production from coal bed methane projects in Alberta.

Electric Energy Demand Forecast

The energy and demand forecast was performed for the 2003 to 2020 period using EDC's in-house model. The model uses regression analysis, historical data from the Power Pool of Alberta, energy statistics from the Alberta Energy and Utilities Board, as well as EDC's inputs and results from EDC's oil and gas and macroeconomic forecasting models. EDC also uses information regarding specific industrial projects that are expected to come on-stream and increase load in the future, examples of these are heavy oil upgraders, refinery expansions, pipelines, oil and gas processing facilities, coal mines, etc. It should be noted that many publicly announced projects in reality never come into fruition or are delayed according to their original schedule. To account for this reality, EDC assigns a probability to all major industrial projects and uses a probability-weighted approach to derive the final energy and demand forecast.

The farther into the future that one goes the less information there is available regarding specific projects and related forecast. For the 2021 to 2025 period, demand is assumed to follow the trend that it is expected to followed during the 2016 to 2020 period. The average compounded growth rate of the 2016 to 2020 forecast period was applied to the 2021 to 2025 energy sales forecast.

The first quarter of 2004 has seen important growth in demand. Compared to last year, Alberta internal consumption has grown by 5.1%. The largest jump in demand was in January's peak demand, which rose by 6.3% relative to January of last year and 2.1% relative to December 2003. Alberta internal demand reached an all time record of 8,967 MW during a January cold snap (January 26th). On average, January was 1.8 degrees Celsius colder than normal and the month had 6.4% more heating degree-days than normal. On the other hand, February and March were warmer than normal months. February and March were 3 and 3.3 degrees Celsius warmer than normal, respectively. However, both months nonetheless posted important increases in energy consumption. February registered the highest growth (6.5%) in internal energy consumption compared to February 2003 due mainly to the extra day that the 2004 leap year has.[14] Notwithstanding the extra day in 2004, strong demand growth is the result of a healthy Alberta economy. The Alberta economy grew almost twice as fast as the overall Canadian economy in 2003 according to the Alberta government and the expectations for 2004 are even more robust.

Regarding the amount of domestic energy that trades notionally through the Alberta Electric System Operator (AESO), energy sales have increased at a lower rate.[15] AIES domestic energy sales rose by 3.8% in the first quarter of 2004 with February registering the highest growth rate (4.8%). At 7,720 MW, January's AIES peak demand (during the cold snap) was 5.2% above the January 2003 peak demand and 104 MW (1.4%) above the December 2003 peak demand. The difference between domestic AIES demand and Alberta internal demand is mainly behind the fence load that does not trade in the Alberta electricity market; most of this energy is produced and consumed onsite by industrial facilities. The greater growth in Alberta internal demand relative to AIES demand attests to the current dynamism in the industrial sector with behind the fence load. Industries with onsite load include oil and gas and the chemical sectors among others.

Exports are additional to domestic AIES sales, and add to the energy that is traded through the market. Low prices in Alberta, especially during off-peak hours have contributed to growing exports. Compared to Q1 2003, AIES exports (including exports to City of Medicine Hat) grew by 23% in the first quarter of the year. Electricity prices in the US Northwest have been increasing due to strong gas prices and concerns regarding hydro generation. Prices are expected to go up further during the summer when the market is more sensitive to hydro generation. The latest forecast from the Northwest River Forecast Center predicts flows from April to September at the Dalles Dam on the Washington-Oregon border to be 77% of normal. As a result, electricity traders are expecting prices to increase significantly in the US Northwest. In addition, US Northwest prices are influenced by prices in California. The US Southwest has typically very hot summers and demand usually increases significantly during that time of the year. Due to the current market expectations, AIES exports are forecast to grow from 1,296 GWh in 2003 to 1,575 GWh in 2004.

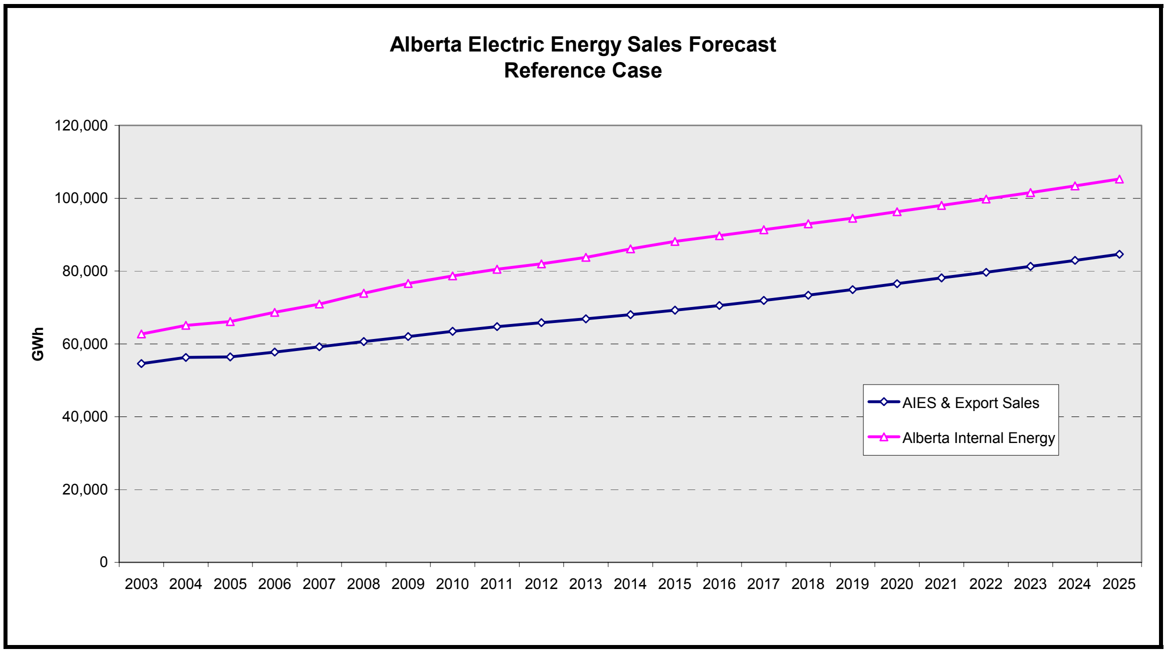
Domestic AIES energy sales are forecast to grow by approximately 2.6% in 2004. However, AIES sales plus exports (total energy notionally traded through the AESO) are forecast to grow in the range of 3% to 3.3%. It should be noted that this is the energy and demand forecast that is used to derive the price forecast in this report. Total internal consumption (which includes behind the fence load but excludes exports) is forecast to grow by approximately 3.8% in 2004. Growth in domestic consumption is expected to be mainly fueled by energy sales to the oil and gas and commercial sectors.

Figure 5 depicts the AIES (plus exports) and internal energy forecasts. AIES sales and exports in 2004 are expected to be robust due to strong expected domestic consumption supported by solid economic growth; however most of the difference in energy sales growth is due to increased export sales. Over the entire (22-year) forecast period, AIES energy sales (plus exports) are forecast to grow at an annualized rate of 2%. However, sales are forecast to grow slightly faster during the first 10 years of the forecast at 2.1%.

[14] In fact, average internal demand grew by only 2.8% in February 2004 relative to February 2003.

[15] AIES domestic energy sales refer to energy traded through the AESO excluding exports.

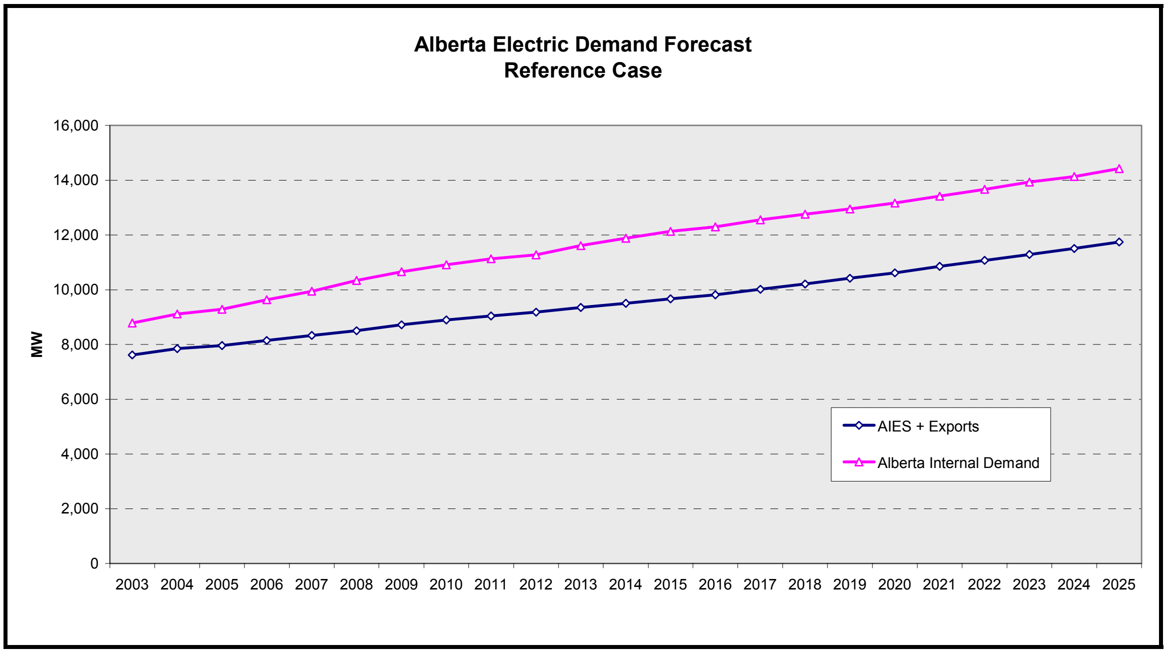
Figure 5 - Electric Energy Sales Forecast



Over the entire forecast horizon (2004 to 2022) Alberta internal consumption is anticipated to grow at an annual compounded growth rate of 2.4% (see Figure 5). However, there is a substantial difference between the growth expected in the first 10 years of the forecast and the remaining 12 years. In the first 10 years (2004 to 2013) significant development in the oil sands industry is expected to boost internal consumption to a 2.9% annualized growth rate. As development slows down during the 2014 to 2025 period, internal consumption is expected to moderate to an annualize growth rate of 2%.

Figure 6 depicts the current AIES and internal peak demand forecasts. In general, the peak demand forecasts follow the same trend that energy sales have and it is discussed above. Also, in general, Alberta Internal Load is expected to have a higher load factor compared to AIES energy sales due to the greater amount of industrial load that internal demand has. Regarding AIES and export demand that trades through the AESO, it is important to recognize that exports are not expected to contribute to the peak AIES demand as most AIES exports occur during off-peak hours while most imports occur during on-peak hours. This pattern is expected to persist during the entire forecast period. This forecast assumes that there will not be a significant increase in the province's export capability.

Figure 6 - Alberta Peak Demand Forecast



One of the risks inherent in this forecast is related to cogeneration development. Due to the efficiency gains of cogeneration, many have built and are expected to build onsite generation. However, if the expected amount of cogeneration does not materialize there will be less capacity available and a greater amount of energy will be bought from the grid than what it is forecast. This would mean a higher AIES demand in the future in need of supply. Visually, this would mean that AIES and exports energy and demand would be closer to Alberta Internal consumption and demand in Figure 5 and Figure 6.

Finally, the Alberta internal energy and demand historical data and forecast, shown in Figure 5 and Figure 6, corresponds to internal load as reported by the AESO and as such it does not include behind the fence load that it is not currently being reported by the AESO. However, most behind the fence load is being metered and reported since it is necessary for system control purposes. Also, over time, the AESO has been adding sites that were not previously being included in the internal demand estimates. Behind the fence load at Celanese in Edmonton is an example. Some behind the fence load from this site was added to internal demand estimates in late March of 2004. In the AESO's estimates of internal demand, the inclusion of this load looks like an increase in demand when in reality internal demand did not grow since the load has been there for many years.[16]

[16] The increase in internal demand estimates due to Celanese is related to the addition of Celanese's generation to the AESO's Current Supply & Demand Report.

AIES Energy Sales and Alberta Internal Load

Energy and Peak Demand Forecast Reference Case				
Year	AIES + Export Energy Sales (GWh)	AIES Peak Demand (MW)	Alberta Internal Load (GWh)	Internal Peak Demand (MW)
2003	54,599	7,616	62,714	8,786
2004	56,263	7,848	65,099	9,115
2005	56,457	7,959	66,136	9,286
2006	57,759	8,146	68,680	9,633
2007	59,208	8,331	70,950	9,945
2008	60,667	8,503	73,920	10,342
2009	62,041	8,715	76,609	10,653
2010	63,454	8,894	78,661	10,910
2011	64,733	9,044	80,504	11,127
2012	65,827	9,179	81,976	11,278
2013	66,890	9,348	83,796	11,614
2014	68,037	9,504	86,128	11,882
2015	69,264	9,668	88,136	12,130
2016	70,562	9,813	89,751	12,294
2017	71,956	10,018	91,370	12,552
2018	73,380	10,210	92,979	12,756
2019	74,918	10,417	94,536	12,947
2020	76,566	10,619	96,297	13,164
2021	78,111	10,852	98,030	13,414
2022	79,688	11,069	99,795	13,669
2023	81,296	11,290	101,592	13,929
2024	82,937	11,504	103,420	14,133
2025	84,611	11,745	105,282	14,422

Generation Supply Forecast

This section presents the key assumptions that underlie the other generation supply side of the market. As noted in the introduction, there are two distinct sets of supply assumptions for various sensitivities in this analysis. This section outlines the two sets of supply assumptions and highlights the similarities and differences between the two.

Reference Case Scenario Supply Assumptions

The supply assumptions outlined for the Reference Case also apply to the Vintage One, Vintage Two and Vintage Three sensitivities. These forecasts are based on the premise that natural gas fired cogeneration and combined cycle generators will form the majority of generation capacity investment over the next 22 years. Wind generation forms an important part of the supply picture, especially between 2004 and 2008, because Alberta has adopted a renewable energy target of 3.5%, but under the Reference Case assumptions, very little coal generation is developed in Alberta after Genesee 3.

In the near-term, between 2004 and 2008, the majority of the generation additions come from projects that have already been announced, such as Genesee 3. Several other large generation projects such as Hunt Energy, AES, and Centennial are included in the forecast, but the capacity of these projects has been discounted to reflect uncertainty over whether the projects will actually proceed as announced. A list detailing the assumptions for the announced projects is contained in the Appendix.

In the mid and later portions of the forecast, the supply additions come from three sources. First, small wind projects are developed that maintain the 3.5% renewable energy target over time. In effect, 3.5% of demand growth from 2008 onwards is met by wind energy. Second, cogeneration projects are projected to occur at oilsands and heavy oil sites as this industry expands. Finally, combined cycle natural gas plants are forecast to 'fill-in' the remainder of the capacity needs over the forecast horizon. These generic capacity additions are forecast to be built in the south in order to take advantage of transmission loss credits. Two basic criteria are used to determine how much combined cycle generation is built in the long-term: a planned reserve margin of 15% to 18% and electricity prices that are roughly consistent with the 'all-in' cost of combined cycle generation. There is no specific attempt to manage the forecast price on a year-to-year basis, but the general assumption is that long-term average electricity prices should generate a reasonable return for entrants.

Figure 7 - Reference Case Supply Additions by Fuel and Technology Type

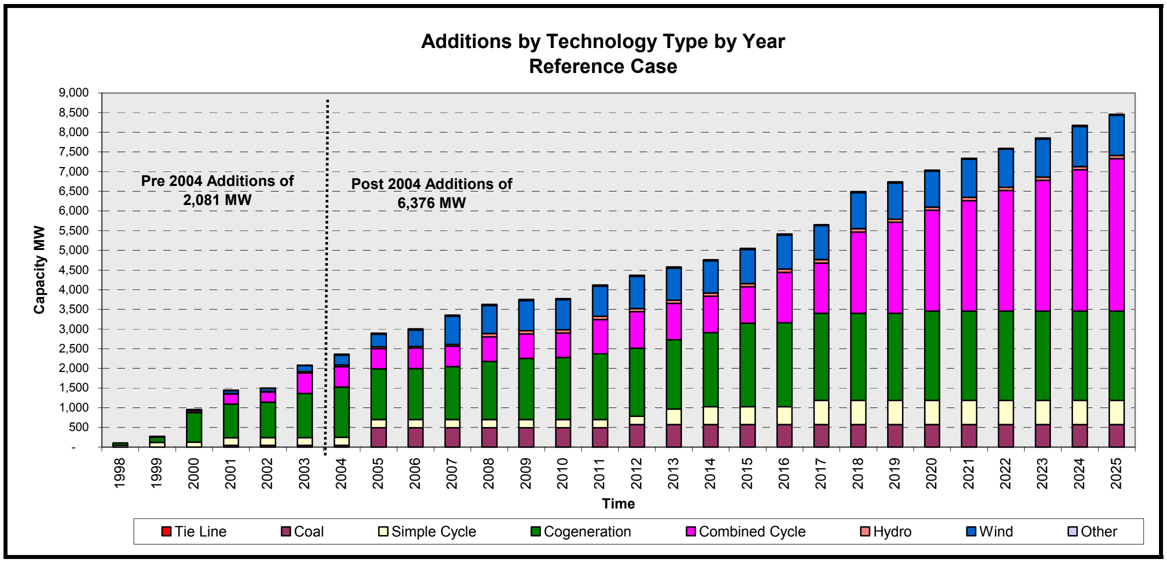


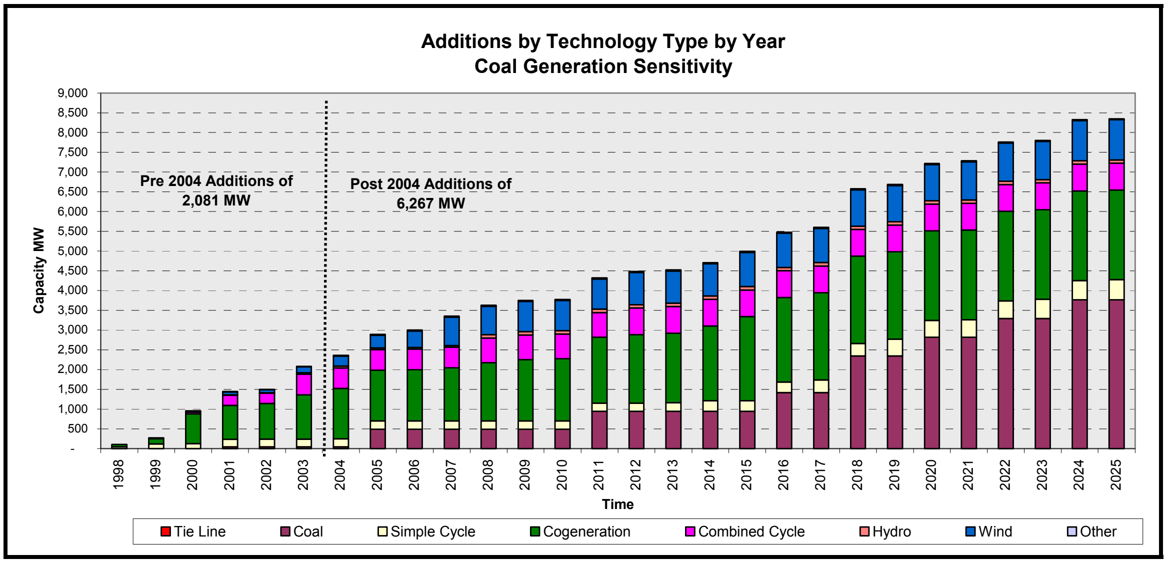
Figure 7 illustrates the capacity additions in the Reference Case on an annual basis. Note that these capacity additions are net to grid and do not reflect generation that is developed solely to meet onsite load. This generation amounts to approximately 1800 MW of natural gas fired generation additions between 2004 and 2025. There is an implicit assumption that all load met with onsite generation will be powered with natural gas capacity with the exception of Opti/Nexen which is forecast to use Syngas. It is quite possible that other units will use a fuel such as Syngas to power the onsite generation in oilsands applications.

With respect to the net to grid generation pictured in the graph, the majority of the generation additions in the next 5 years are either coal or wind generation. Several cogeneration projects are also forecast to develop, but cogeneration does not form a large part of the generation picture between 2004 and 2008. From 2009 onwards, combined cycle generation and cogeneration make up almost all the generation development in Alberta.

Coal Generation Sensitivity Supply Assumptions

The coal generation sensitivities differ from the Reference Case supply assumptions in one key way: coal fired generation replaces the majority of combined cycle gas generation that is forecast to develop between 2009 and 2025. Figure 8 details the generation additions on an annual basis.

Figure 8 - Reference Case Supply Additions by Fuel and Technology Type



Cogeneration projects are not altered in this sensitivity, as these projects are assumed to develop for reasons that are only partly driven by the electricity market. As a result of this altered assumption, roughly 3200 MW of extra coal powered generation is forecast to be built. The first coal plant developed that does not appear in the Reference Case appears in 2011, and additional plants are built in 2016, 2018 (2 plants), 2020, 2022 and 2024. Very little combined cycle and simple cycle generation is developed in this sensitivity, as illustrated by the yellow and pink portions of the bars in the graph.

Retirements

The underlying assumption in this analysis is that coal plants have an economic life of 50 years and natural gas fired units have an economic life of 40 years[17]. However, several retirements are assumed to take place during the forecast period that are contrary to this basic assumption. The following units have been retired at the noted time in all the Cases and Scenarios presented in this document:

1. HR Milner, January 1st 2009
2. Clover Bar 1-4, January 1st 2006
3. Rossdale 8-10, January 1st 2006
4. Sturgeon 1-2, January 1st 2006
5. Rainbow 1-4, January 1st, 2006
6. Wabamun 4, January 1st, 2011
7. Battle River 3 and 4, January 1st, 2016
8. Sundance 1 and 2, January 1st, 2018

The decision to retire HR Milner is based on its operating costs and fuel supply options. Specifically, the recent sales agreement for HR Milner outlined that the new owners procured coal supply for the facility for 2004 through 2008. Since the facility is only marginally economic over the course of the next several years, it is 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 implemented in early 2004.

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

Chapter 4 Reference Case

This chapter presents the results for the Reference Case, which includes the recommendations contained in the CASA EPT's November 2003 report to stakeholders. As such, the Base Case assumes that the recommendations in the report are implemented on the schedule outlined in the report. The specific recommendations that are now included in the Base Case include:

1. NO_x and SO_x emission standards and the associated costs are included for all the relevant generation units.
2. Mercury standards and the estimated costs of meeting the standards for existing coal units are implemented in 2009 with the exception of Wabamun 4, Battle River 3 and 4 and Sundance 1 and 2. These units retire at the end of 2010, 2015 and 2017 respectively. HR Milner is forecast to retire in 2009 and therefore does not install the capital necessary to meet the mercury standards, but HR Milner is also exempt under the policy as long as it retires at the end of 2012. New coal units must also meet the standard by 2009, which means that any coal plants built after 2009 must meet the standard upon completion.
3. The 3.5% green energy target by 2008 is adhered to in this analysis. As a result of this target, roughly 800 MW of wind generation is built between 2001 and 2008, and an average of 17 MW of wind capacity is built per year after 2008 in order to maintain the target.

Given the time frame of the forecast (2004 to 2025), and the number of generating units in Alberta whose end of book life occurs, particularly in the later period of the forecast, one key assumption has been made with respect to the operating life of all generating plants. Based on input from the CASA EPT and generation owners, it has been assumed that all natural gas and coal plants have operating lives of 40 and 50 years, respectively. However, it should be noted that incremental capital and downtime has been assumed to be needed in year 40 to life extend the coal units beyond the typical design life of 40 years.

The Reference Case is best described as a 'Business as Usual' scenario where business as usual already includes emission policy around the substances described above.

Energy Production Forecast

One important factor to keep in mind about the energy production forecast is that the figures and numbers quoted in this section refer to total Alberta internal generation plus imports. In other words, electricity consumed on-site at large industrial cogeneration facilities is included in the numbers. One key result of this convention is that the 3.5% green energy target referred to in the section above looks as though it falls short of being met. However, since the green target is applied to AESO traded energy only, the target is met because internal load includes a large amount of generation that is consumed on-site.

Figure 9 - Energy Production by Fuel Type (Reference Case)

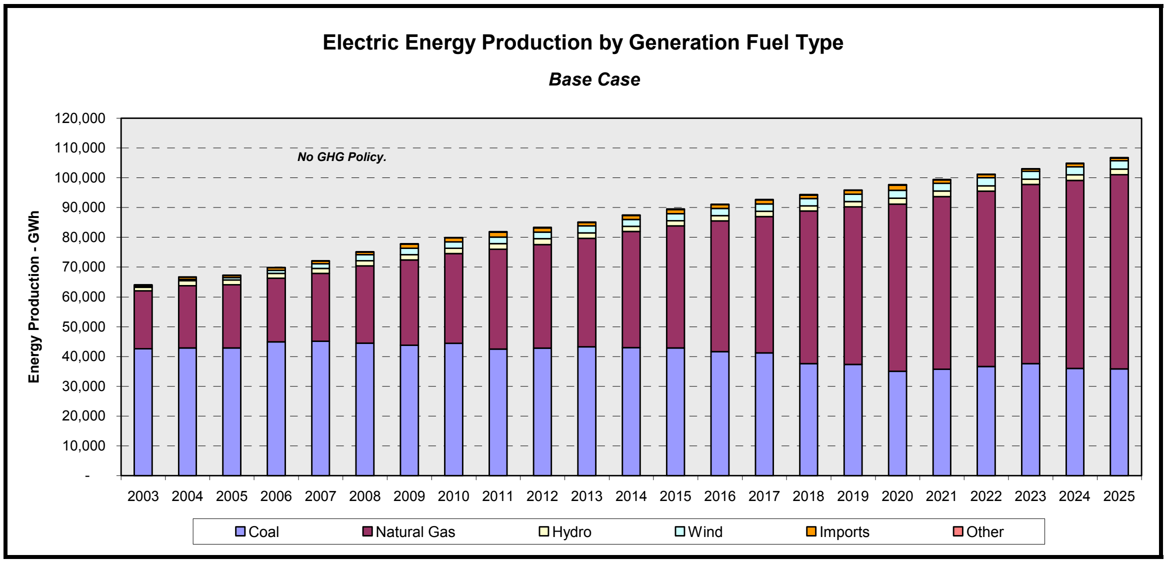


Figure 9 illustrates that coal energy production generally declines over the 22 year forecast, although total coal energy production does peak in 2006. Since there are no notable coal additions forecast after Genesee 3 in 2005, the gradual retirements of the existing regulated fleet lead to a gradual decline in coal energy. Natural gas generation meets the majority of the energy needs that arise due to demand growth and coal retirements. Finally, the figure illustrates the impact the renewable energy target has on energy production in the province, as wind energy develops rapidly between 2004 and 2008 and shows up as a noticeable fuel source from 2008 onwards.

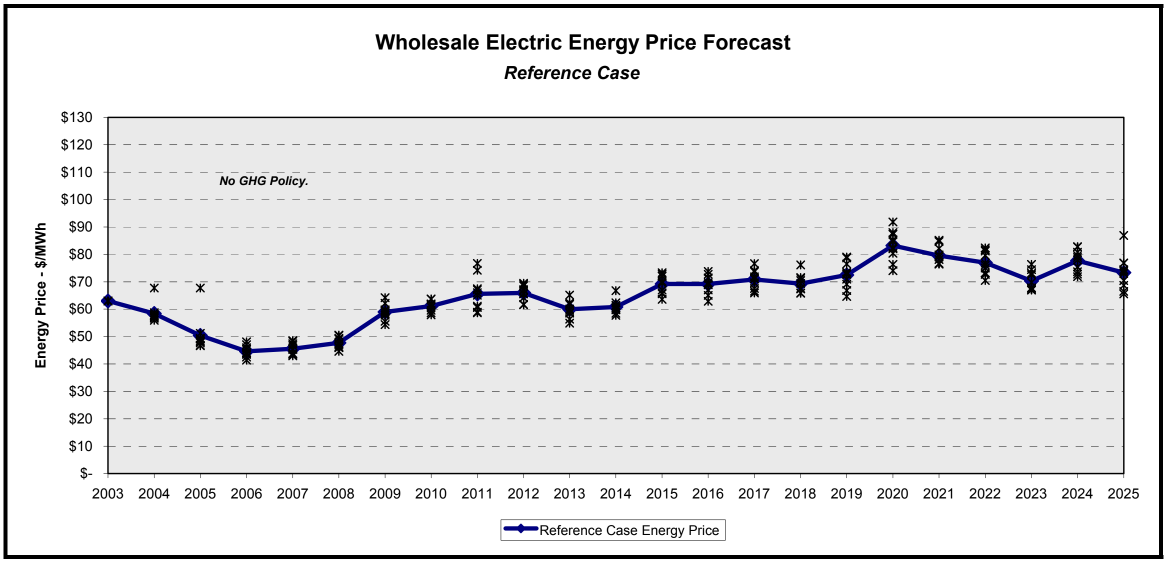
Electricity Price Forecast

This section summarizes the pool price forecast results for the 22-year period from 2004 until 2025. Stochastic details for each year can be found in the Appendix of this report.

Power prices have been high to this point in 2004, but this has largely been due to very high natural gas prices in the first quarter. Prices are expected to decline in 2005 and 2006 as a result of unit additions combined with slightly lower natural gas prices. Electricity prices are expected to remain relatively flat in 2007 and 2008 as new wind generation and several cogeneration projects are developed. Prices increase substantially from 2009 onwards due to unit retirements (HR Milner) and a gradual move towards a more sustainable balance between supply and demand in the market.

It is important to note that the price forecast from 2009 through 2015 is strongly dependent on the assumptions for the Centennial and Fording coal plants. If these plants are built *as announced by the developers*, it is likely prices will not begin to increase until much later than 2009. However, economic review based on this price forecast suggests that neither Centennial nor Brooks are attractive investments in 2008. In fact, the coal sensitivities examined in this report (see page 49 for the start of this section) suggest that it will take until 2011 until the first of these coal plants could be economically completed.

Figure 10 - Electric Energy Price (Reference Case)

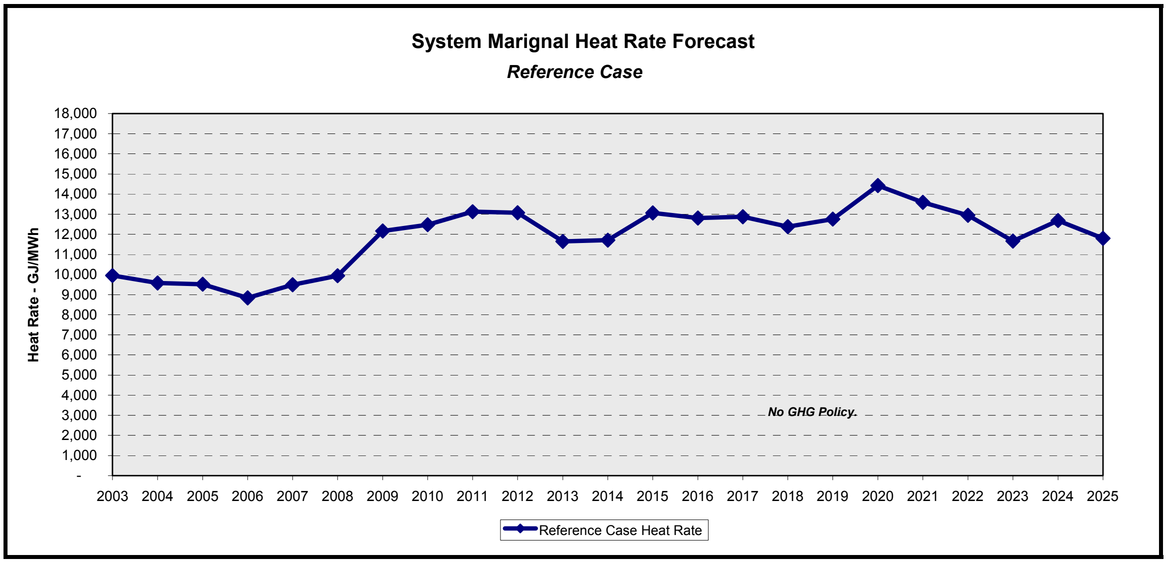


As Figure 10 illustrates, electricity prices trend upwards between 2006 and 2020. There are numerous years where prices move above the general trend line, primarily due to a number of longer than average scheduled outages occurring in that specific year. For example, prices in 2020 are the highest annual prices of the forecast period because Sundance 3 and 4 are offline for extended periods in order to install life extension capital. Prices are generally quite high in several years between 2020 and 2024 as several of the current coal plants reach 40 years of age during this period and are taken offline in order to install life extension capital. However, since these high prices are likely to be transitory in nature, it is not anticipated that a greater amount of generation would come online in response to these events. Nonetheless, it is an important point to note that the aging coal fleet has the potential to impact market prices due to requirements for capital replacements and upgrades upon PPA expiration.

Average prices over the forecast in the Reference Case are $65.05/MWh, but the initial years of the forecast drive this value down. From 2009 onwards (which is the point the market is forecast to approach its long-term balance) prices average $69.67/MWh.

Since natural gas fired generation is an investment option readily available to many potential generation developers, an electricity price forecast presented as a system marginal heat rate is a useful way of depicting the results. Figure 11 illustrates forecast electricity price relative to the cost of natural gas, which is a rough measure for the potential economic viability of new gas fired generation in the market.

Figure 11 - System Marginal Heat Rate (Reference Case)



Since the natural gas price forecast moves steadily upward in the long-run, the system marginal heat rate graph shows an almost identical shape to the electricity price graph. Heat rates are forecast to remain below 10 GJ/MWh until 2009. The increase in 2009 is due to a large number of outages at the existing coal facilities that are required to meet the mercury emission standards. Average forecast heat rates are basically cyclical between 11 GJ/MWh and 13 GJ/MWh between 2009 and 2019. As noted previously, coal outages associated with an aging coal fleet are seen between 2020 and 2025, and the annual average heat rates are periodically quite high during this period as a result.

In terms of overall averages, the Reference Case has an average heat rate of 11.9 GJ/MWh between 2004 and 2025. However, since electricity prices, and therefore heat rates, are quite low between 2004 and 2008, the average heat rate is somewhat biased downwards over the entire forecast term. For example, from 2010 through 2025 (when the vast majority of combined cycle generators are added), the average heat rate is 12.7 GJ/MWh. Typical combined cycle generation, which is the default generation source in the Reference Case, is estimated to be financially viable in this type of environment. In effect, the long-term price of electricity creates reasonable economic returns for the most readily available investment alternative, combined cycle natural gas plants.

GHG Emissions Forecast

As with energy production, GHG emissions are based on total Alberta internal generation and therefore include electricity consumed on industrial cogeneration sites as well as the City of Medicine Hat. In order to calculate GHG emissions, individual plants' emission factors (as provided by the CASA EPT GHG subgroup) are multiplied by their forecast energy production. This information is aggregated into GHG emissions by fuel type, which effectively means that coal and natural gas account for all the GHG emissions in Alberta[18]. It should be noted that biomass generation actually creates GHG emissions, but under the Environment Canada guidelines, these emissions are included in the land-use change and forestry sector.

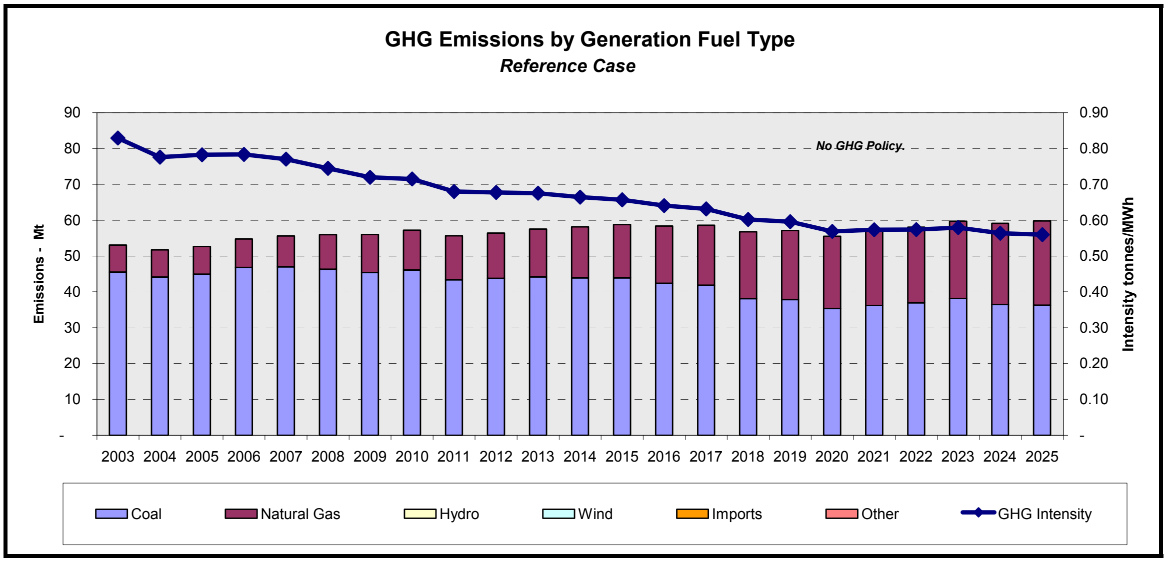
Figure 12 presents two types of information. The first, the GHG emission intensity index, can be interpreted as the average number of tonnes of CO_2 in each MWh of electricity produced in Alberta. This measurement is presented as the line in the figure and is presented along the right hand scale.

[18] The CASA EPT GHG subgroup report includes a GHG credit for wind generation of 0.21 t/MWh. As such, it includes GHG emissions for wind generation that are not reflected in this analysis.

The second measure is bar graph outlining the total GHG emissions measured in millions of tonnes (Mt) and this information is presented using the left hand scale.

As the Figure illustrates, the emission intensity is forecast to fall over time in the Reference Case, largely because natural gas generation meets the load growth in the province. GHG emissions are forecast to decline from 0.81 t/MWh in 2004 to 0.56 t/MWh in 2025. The largest annual declines are seen in 2011 and 2018 as a result of coal plant retirements. Note that from 2020 through 2025 the emission intensity index is more or less flat—the decline rate falls because no coal is retired and the natural gas developed in these years has emissions that are only about 20% less intense than the system average. In effect, the natural rate of decline in the emission intensity dramatically slows from approximately 2020 onwards even if no new coal facilities are built.

Figure 12 - GHG Emissions by Fuel Type (Reference Scenario)



In terms of total emissions, as depicted by the vertical bars, GHG emissions generally increase throughout the forecast, albeit at a very slow rate. In fact, total GHG emissions increase by roughly 12% from 2004 through 2025, which works out to an average annual compound growth rate of 0.5% over the 22 year forecast. This slow growth rate develops because coal generation emissions actually fall by 20% over the forecast as a result of coal facility retirements. The growth in total emissions would be much faster if the retiring coal plants are replaced with new coal plants rather than combined cycle natural gas facilities. This is specifically examined in the sensitivities with coal generation investment in this report.

Chapter 5 GHG Policy Sensitivities

There are three GHG policies that are examined relative to the Reference Case in this section. All the fundamental assumptions from the Reference Case are retained in these sensitivities, but each sensitivity includes a GHG emission policy that reduces GHG emissions via offsets. However, since GHG offsets enter into the variable cost structure of coal and natural gas generators under the policies, there is an expectation that the electricity market price may be impacted. This chapter evaluates this potential impact.

Vintage One GHG Policy

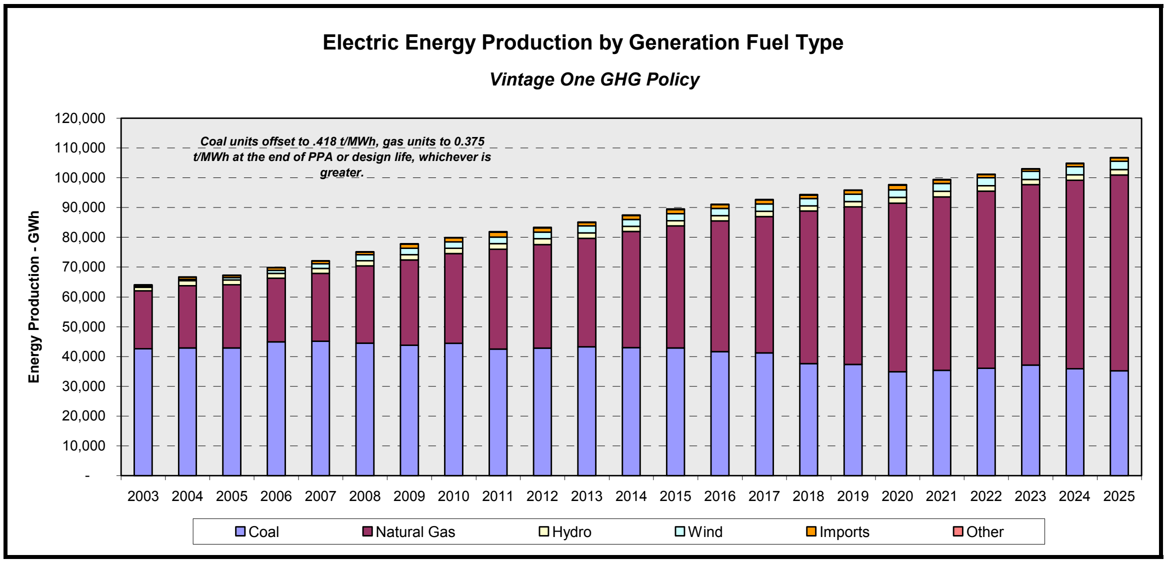
The Vintage One policy is the least stringent GHG policy of the three contemplated in this report, and the majority of its emission reductions are not seen until 2021. The basic aspects that impact the electricity price forecast are as follows:

1. Coal generation that is new or post design life offsets its GHG emissions to 0.418t/MWh.
2. Natural gas generation that is new or post design life offsets its GHG emissions to 0.375 t/MWh.
3. Natural gas generation with GHG intensity below 0.375 t/MWh does not offset GHG emissions or earn GHG credits and no unit must offset its emissions below its vintage intensity limit.
4. Design life for coal generation is the greater of 40 years or PPA term with the exception of Wabamun 4, whose design life is 2010.
5. Design life for natural gas generation is 30 years.

Energy Production Forecast

One of the questions an emissions framework brings up is whether or not the 'supply stack' will be altered such that coal generation's share of total energy production falls when GHG costs are imposed on electricity generators. Although natural gas generation also faces some GHG charges under the Vintage One policy, the majority of the costs are faced by coal facilities at the end of the design life, i.e. 40 years. Figure 13illustrates the energy production by fuel source under the Vintage One GHG policy assumptions.

Figure 13 - Energy Production by Fuel Type (Vintage One GHG Policy)



Coal based generation again peaks in 2006 in the Vintage One sensitivity, as was the case in the Reference Case. However, since the majority of the GHG costs 'kick in' after 2020 in this policy, it is more appropriate to look at energy production from this timeframe. For example, in 2025, coal production in the Vintage One sensitivity totals 35.2 GWh, which very similar to the 35.8 GWh seen in the Reference Case. It seems to be the case that energy production is not significantly altered by the Vintage One sensitivity.

Electricity Price Forecast

The electricity price forecast for the Vintage One GHG policy is somewhat higher than the Reference Case from 2008 onwards, when the GHG policy is implemented. The Vintage One forecast has an average price of $65.83/MWh over the 22 year term, which is about $0.80/MWh higher than the Reference Case. This can be considered statistically significant because despite the fact that any one year can vary by several $/MWh randomly due to the stochastic nature of the forecast. For example, Figure 14 illustrates that the Reference Case has a higher price forecast for 2011, but this is due to random factors such as forced outages that vary from forecast to forecast.[19] However, a difference in a 22 year average of nearly $1/MWh potentially represents a result consistent with some GHG costs being passed onto the market.

[19] EDC uses a stochastic model based on a Monte Carlo type simulation that allows impacts such as random generation outages to be modeled. This process creates random impacts that may be larger than the policy impact in any one year. However, over the course of several years, the likelihood of the random impacts being larger than the policy diminishes.

Figure 14 - Electric Energy Price Forecast Comparison (Vintage One versus Reference)

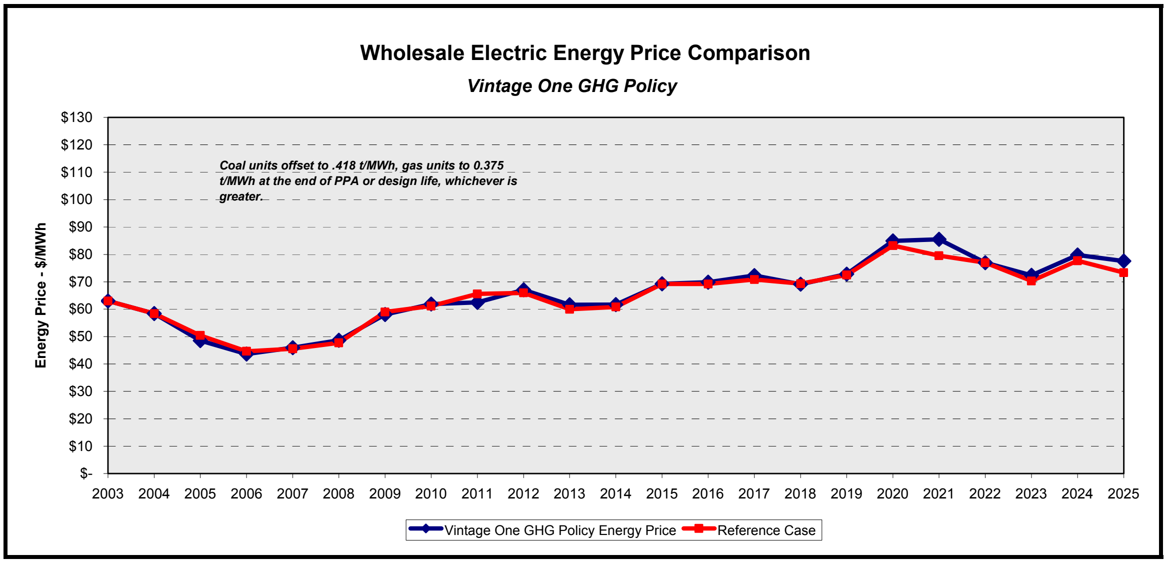
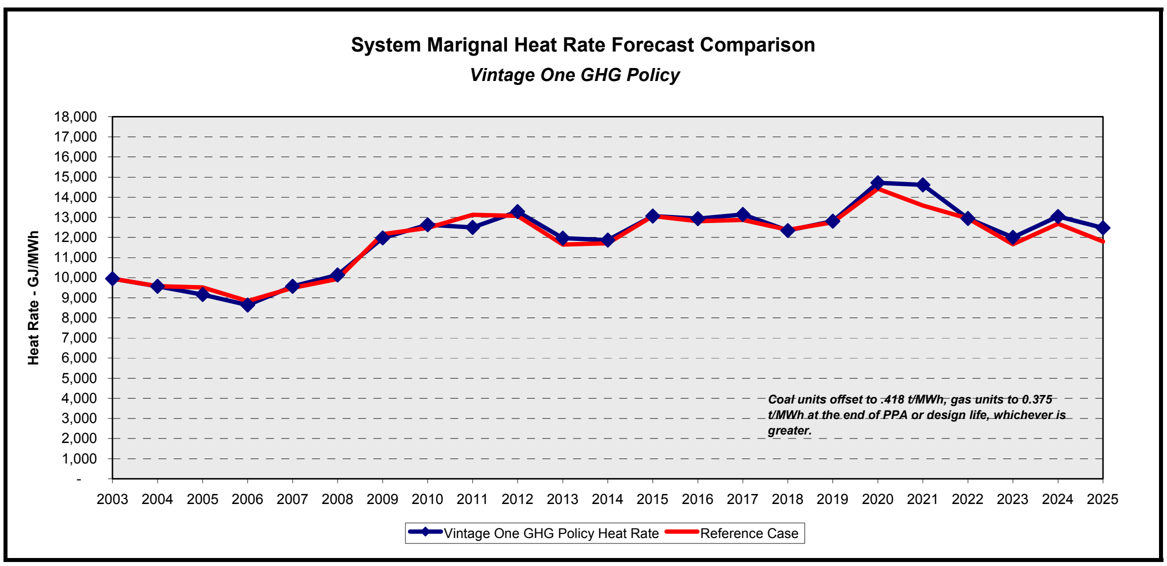


Figure 14 should also be examined at several intervals given the nature of the Vintage One policy. Since the majority of units do not face GHG offset costs until 2021 given the PPA terms, one might expect that the price difference between the Vintage One sensitivity and the Reference Case would be greater from 2021 through 2025 than from 2008 through 2020. The results bear out this belief, as the early years of the policy show an average price increase of $0.40/MWh while the later years show an impact of $2.90/MWh.

Figure 15 - System Marginal Heat Rate Forecast Comparison (Vintage One versus Reference)

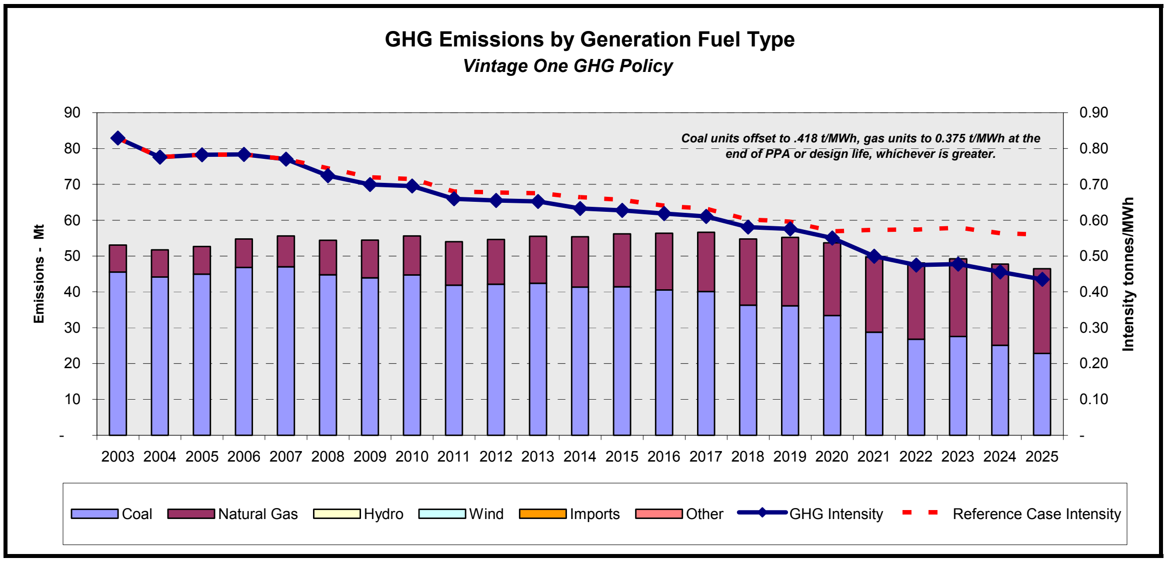


The heat rate figure suggests much the same result as the price forecast above because natural gas price assumptions are identical between the two forecasts. In this instance, the heat rate graph reveals exactly the same information relative to the price graph in that forecast heat rates are very marginally higher in the Vintage One sensitivity than in the Reference Case. It is important to recognize that the heat rate figures presented in this section as well as any following sections are simply another way of looking at the price forecast. Since there are incremental costs for some natural gas generators under the various Vintage sensitivities, heat rate comparisons such as the one in Figure 15 are valuable only as a measure of how electricity prices relate to natural gas prices.

Emissions Forecast

In order to present emissions in a meaningful manner, the Reference Case emissions are presented for comparison. As in the Reference Case, emissions are presented both in terms of an intensity index (right hand scale, lines on the graph) as well as total emissions (left hand scale, bars on the graph). Note that the Reference Case results are only presented in terms of the emission intensity—emission volumes are only presented for the Vintage One sensitivity.

Figure 16 - GHG Emission Forecast Comparison (Vintage One versus Reference)



The first reduction in the Vintage One sensitivity relative to the Reference Case appears in 2008 when the policy is first initiated. Genesee 3 accounts for nearly all of the reductions in the first years of the forecast because it is the only substantial unit impacted by the forecast. As a new coal plant, Genesee 3 is required to offset its emissions to the level of a new combined cycle plant under this sensitivity, which was not true in the Reference Case. This is an important distinction—even though current provincial policy calls for Genesee 3 to offset its emissions, the Reference Case is based on no GHG standards.

Although emissions in the Vintage One sensitivity are somewhat below the Reference Case between 2008 and 2019, the real difference is seen from 2021 onwards when several of the coal units must buy offsets because their PPA's expire. The intensity index drops sharply at this time, as several coal units are exposed to the policy at the same time. Prior to 2021, basically all the coal units were exempted from the Vintage One standards because they were covered by PPA's, and the Vintage One policy is not binding while this is true.

In order to get a preliminary sense of the costs that are involved with the Vintage One GHG policy, it is useful to look at offset costs in 2025. If GHG offsets are priced at $15/tonne, as is assumed in this analysis, the Vintage One policy is forecast to cost approximately $200 million nominally in 2025 for the entire industry. Please note that the cost impact of the various GHG policies will be examined more thoroughly in the conclusion of this report.

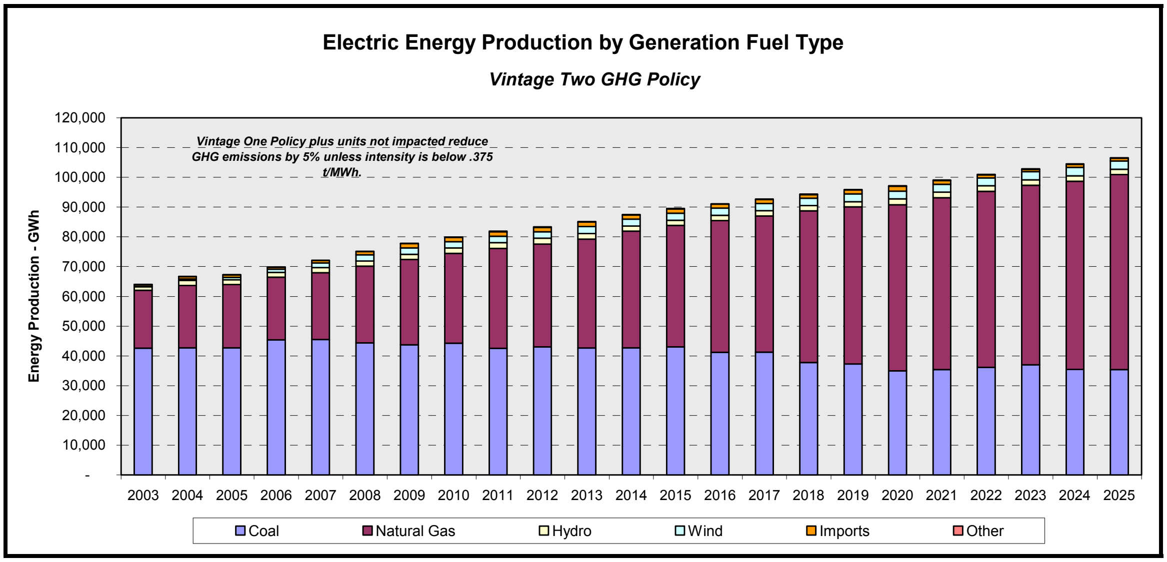
Vintage Two GHG Policy

The Vintage Two GHG policy is basically the Vintage One policy combined with a general offset requirement of 5% for most generators. Each unit that is not impacted by the Vintage One policy parameters is required to offset 5% of its GHG emissions based on its baseline emission intensity. Units with emission intensities below 0.375 t/MWh are exempted from this policy, which means that the majority of new natural gas generation forecast to be built will not be subject to GHG emission charges.

Energy Production Forecast

Figure 17 illustrates the energy production by fuel type, which is unchanged from the Vintage One sensitivity. Since the incremental emission reductions typically amount for cost increases well below $1/MWh for even the most GHG intense coal units, there is not a material impact in any way on the merit order. Once again, there are small annual differences in energy production that arise due to random generation outages, but there is not a statistically significant change in the merit order.

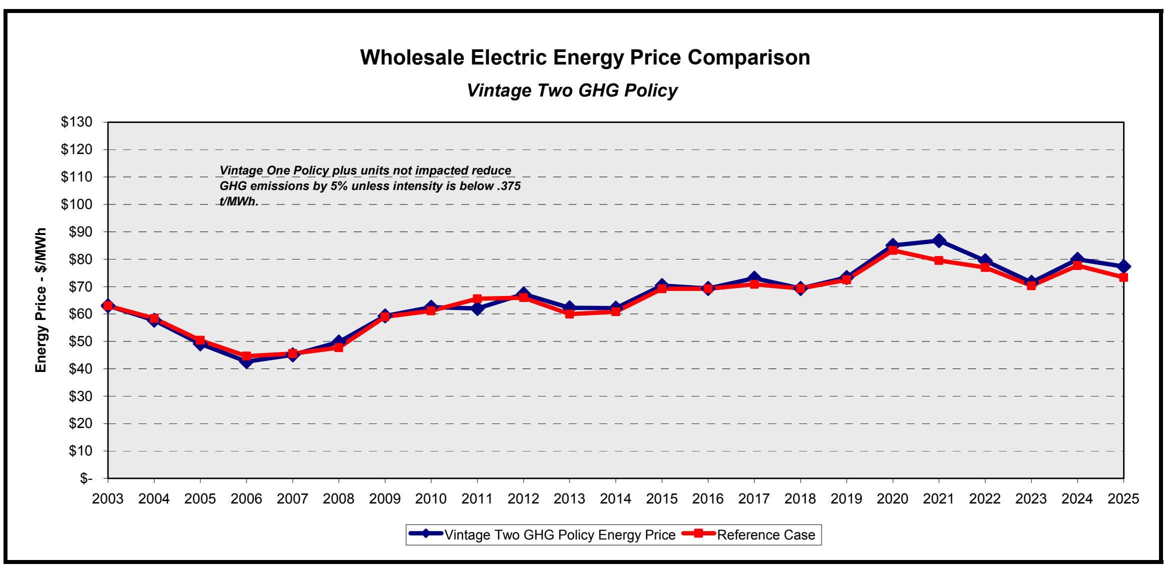
Figure 17 - Energy Production by Fuel Type (Vintage Two GHG Policy)



Electricity Price Forecast

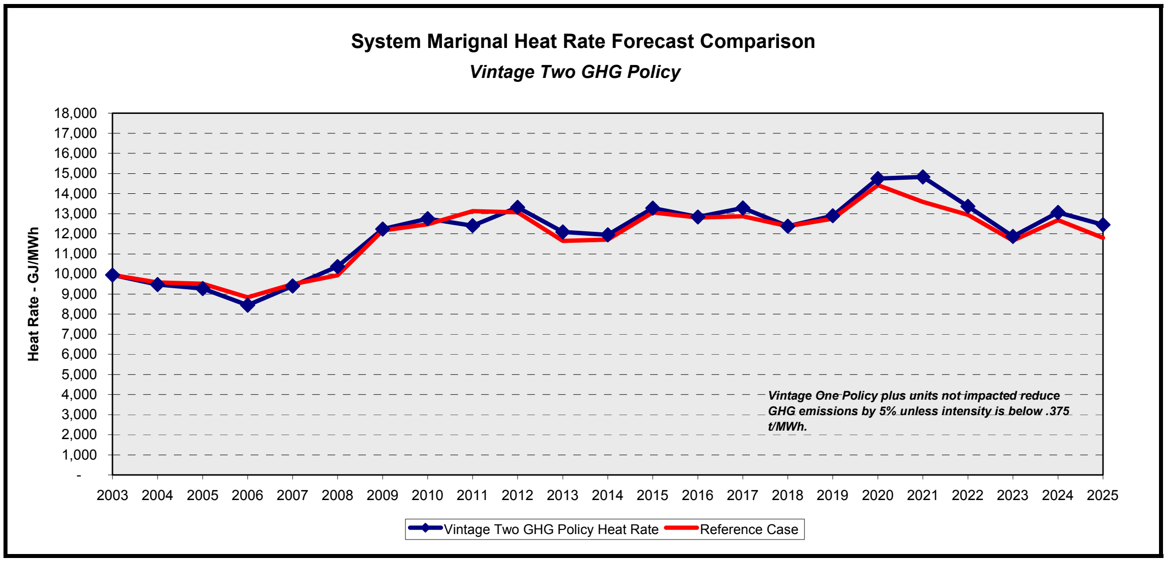
Electricity prices are also very similar in Vintage Two as compared to the Reference Case. Once again, the general pattern of annual prices is very nearly identical, but there does seem to be a marginal increase in Vintage Two relative to the Reference Case.

Figure 18 - Electric Energy Price Forecast Comparison (Vintage Two versus Reference)



From 2008 through 2025 (the years the policy is in place), electricity prices are $1.60/MWh higher than in the Reference Case—a $0.50/MWh larger increase than seen in the Vintage One sensitivity. This reflects the incremental costs that are created in this sensitivity being passed on to the market price. However, as before, it is useful to look at prices between 2008 and 2020 since 2021 represents a large increase in costs for many coal generators under the policy. In this forecast, there is an $0.85/MWh price increase from 2008 through 2020, which is $0.47/MWh higher than the Vintage One impact. From 2021 through 2025, the price increase is $3.50/MWh, which $0.60/MWh larger than the Vintage One Impact. The conclusion from the price forecast is that some further costs relative to Vintage One appear to be passed onto the market, and the total impact probably amounts to around $1.60/MWh relative to the Reference Case.

Figure 19 - System Marginal Heat Rate Forecast Comparison (Vintage Two versus Reference)

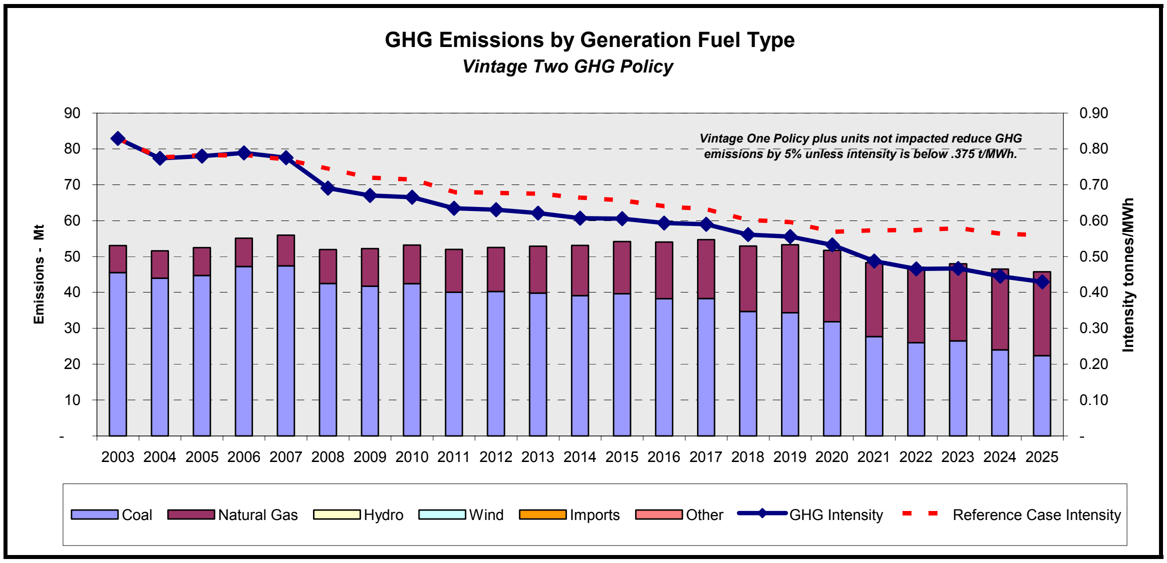


Once again, since the natural gas price assumptions are the same between Vintage Two and the Reference Case, the heat rate graph yields the same basic information as the price comparison above. Again, this information presents another way of looking at the price forecast and does not include the fact that generators face more costs under the Vintage Policies than in the Reference Case.

Emissions Forecast

Since the Vintage Two policy is really the Vintage One policy plus an additional 5% GHG intensity reduction for most units, the results are quite predictable. From 2008 through 2020, the Vintage Two intensity falls further below the Reference Case than the Vintage One intensity index. From 2021 onwards, the difference between the Vintage One and Vintage Two policies decreases because units are removed from their PPA exemption. Although there is a slight difference between Vintage One and Vintage Two in these years, the more obvious change is from 2008 through 2020.

Figure 20 - SO_2 Emission Volumes and Intensity Index (Vintage Two GHG Policy)



The key point to note is that in 2008 when the GHG policy is enacted, the Vintage Two intensity line drops more sharply than it did in the Vintage One example previously. For example, the emission intensity in 2008 drops from 0.72 t/MWh in the Vintage One sensitivity to 0.69 t/MWh in the Vintage Two sensitivity—note that in the Reference Case, the intensity in 2008 is 0.74 t/MWh.

In total cost terms, once again using 2025 as a basis for comparison, the Vintage Two policy is forecast to cost the electricity industry $210 million, which is $10 million more than in the Vintage One sensitivity. However, since the Vintage Two policy creates a 5% reduction cost for most generators from 2008 onwards, the total cost over the 22 year forecast is significantly greater under the Vintage Two policy, as will be shown in the conclusions of this report.

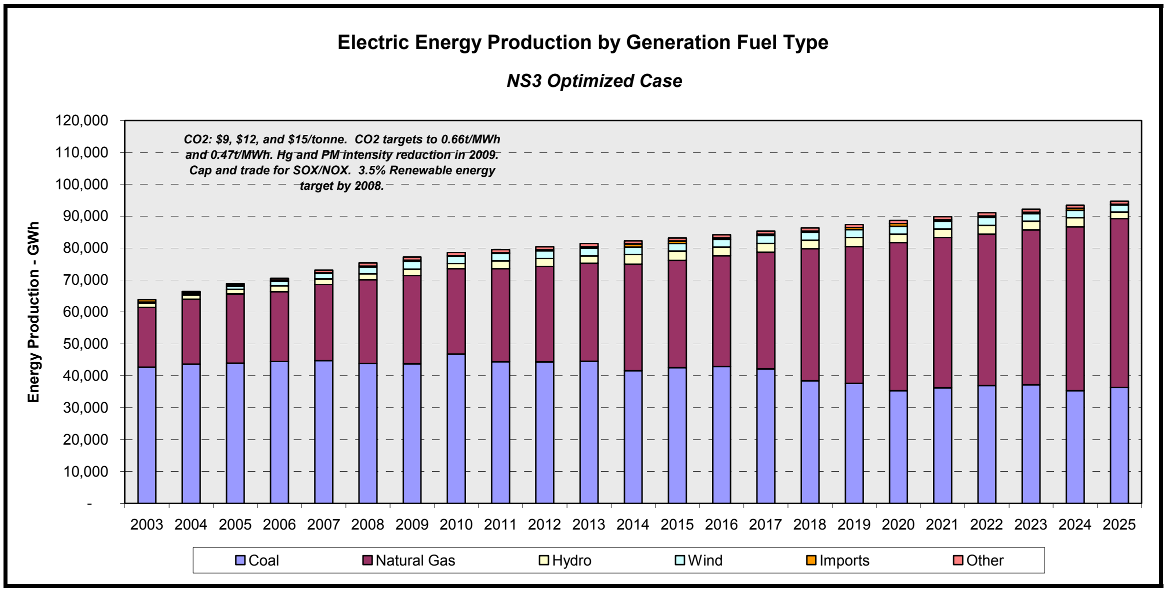
Vintage Three GHG Policy

The Vintage Three GHG policy is basically the Vintage One policy combined with a general offset requirement of 15% for most generators, as opposed to the 5% requirement in the Vintage Two policy. Each unit that is not impacted by the Vintage One policy parameters is required to offset 15% of its GHG emissions based on its baseline emission intensity. Units with emission intensities below 0.375 t/MWh are also exempted from the Vintage Three policy, which means that the majority of new natural gas generation forecast to be built will again not be subject to GHG emission charges.

Energy Production Forecast

As has been the case in the two previous sensitivities, there is not a significant change in energy production in the Vintage Three policy relative to the Reference Case. Although the GHG costs associated with the 15% intensity reduction requirement can amount to $3/MWh for the most GHG intense coal generators, this is not enough to disrupt the merit order.

Figure 21 - Energy Production by Fuel Type (Vintage Three GHG Policy)



As noted in the previous Vintage sensitivities, there is once again no statistically significant impact shown to total energy production by fuel source under the Vintage Three policy.

Energy Price Forecast

Figure 22 - Electric Energy Price Forecast Comparison (Vintage Three versus Reference)

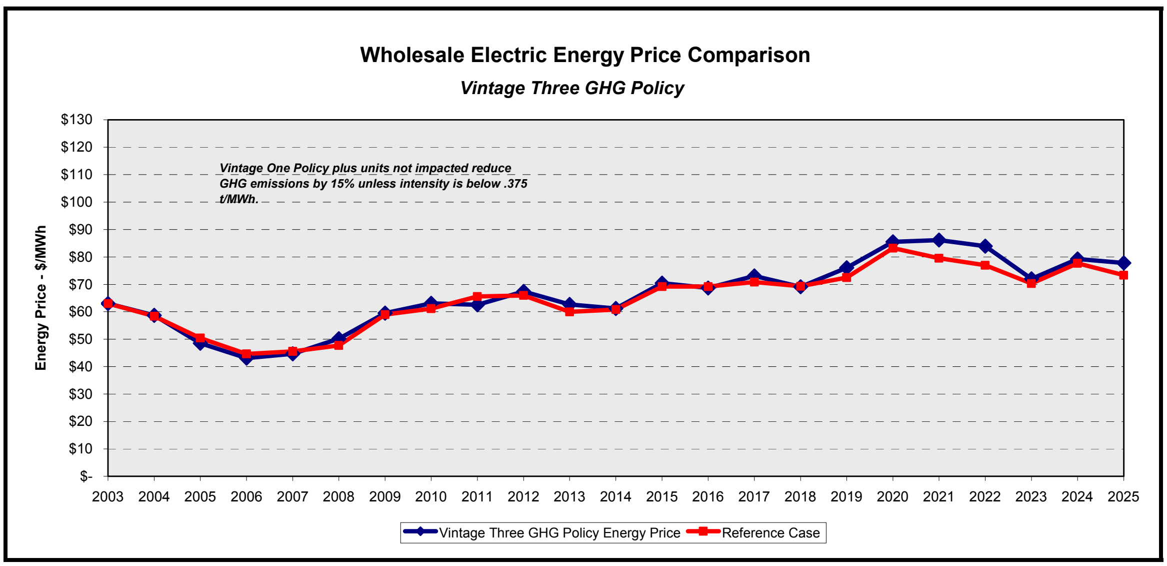
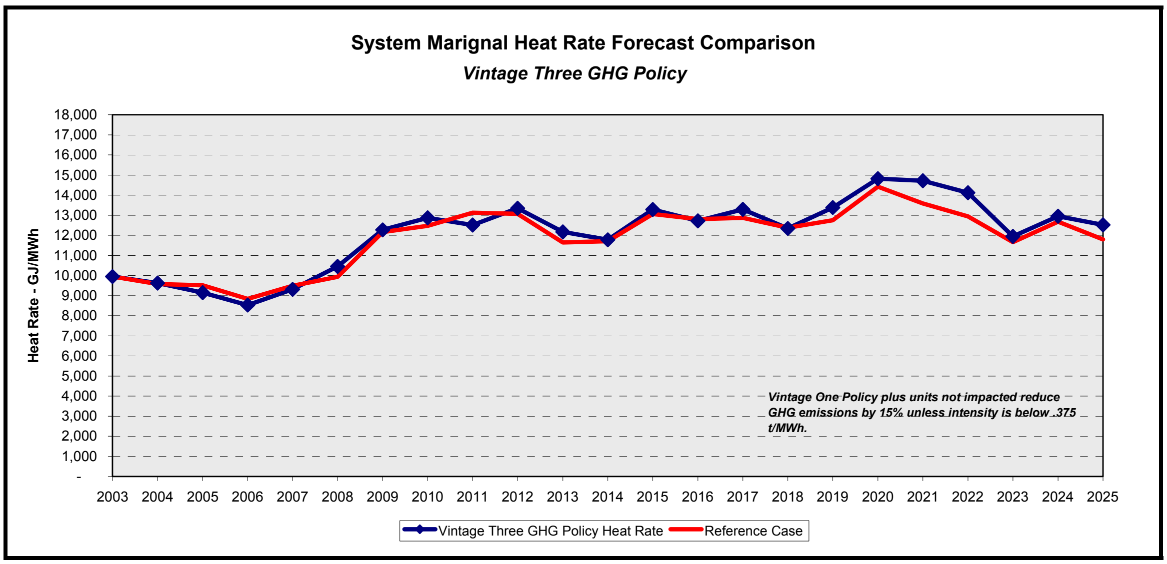


Figure 22 tells a similar story to the pattern seen in the two previous sensitivities relative to the Reference Case—the GHG policy appears to create a minor price increase. In the Vintage Three sensitivity graph above, the impact is generally more apparent in the later years of the forecast as the early portion of the forecast does not show a substantial price increase. In terms of averages, Vintage Three has the highest overall price of the three GHG sensitivities at $66.52/MWh, which is about $1.50/MWh higher than the Reference Case. From 2021 onwards, the Vintage Three Sensitivity also has the highest average price of $79.84/MWh, which is $4.30/MWh higher than the Reference Case. This impact seems relatively large and appears to be largely driven by the 2021 and 2022 forecasts. As noted earlier in the report, random impacts associated with generation outage timing varies in a

Monte Carlo type process between forecasts, and this can potentially inflate the impact of the policy, particularly when measured over small timeframes. From 2008 through 2020, the 15% 'haircut' for units not impacted by the Vintage policy has a $1.15/MWh impact on the forecast price, and this result does not seem to be unduly impacted by any one year.

One key factor to recognize in this result is that the majority of natural gas units do not face any cost from the GHG policy because there is a 0.375 t/MWh 'floor' that excludes many units from the policy. The majority of new natural gas facilities have GHG intensities between 0.32 t/MWh and 0.42 t/MWh. Given the floor level, a unit at the 0.42 t/MWh high end of the range would have GHG offset costs of $0.68/MWh when offsets are priced at $15/tonne. Furthermore, many units would not face any costs at all since new combined cycle plants and the large majority of cogeneration plants will operate below the floor level. Further, 'peaking' natural gas units that actually face higher costs under the Vintage Three policy typically do not bid based on short-term variable costs in the modeling process because these units must recover their capital costs in a very small number of hours. For example, a peaking natural gas plant might have variable costs of $80/MWh, but its offer into the market might be $200/MWh for the small number of hours it operates. As such, increasing marginal costs for a given unit from $80/MWh to $81/MWh does not really impact the market price when the unit offers its energy at a much higher price.

Figure 23 - System Marginal Heat Rate Forecast Comparison (Vintage Three versus Reference)

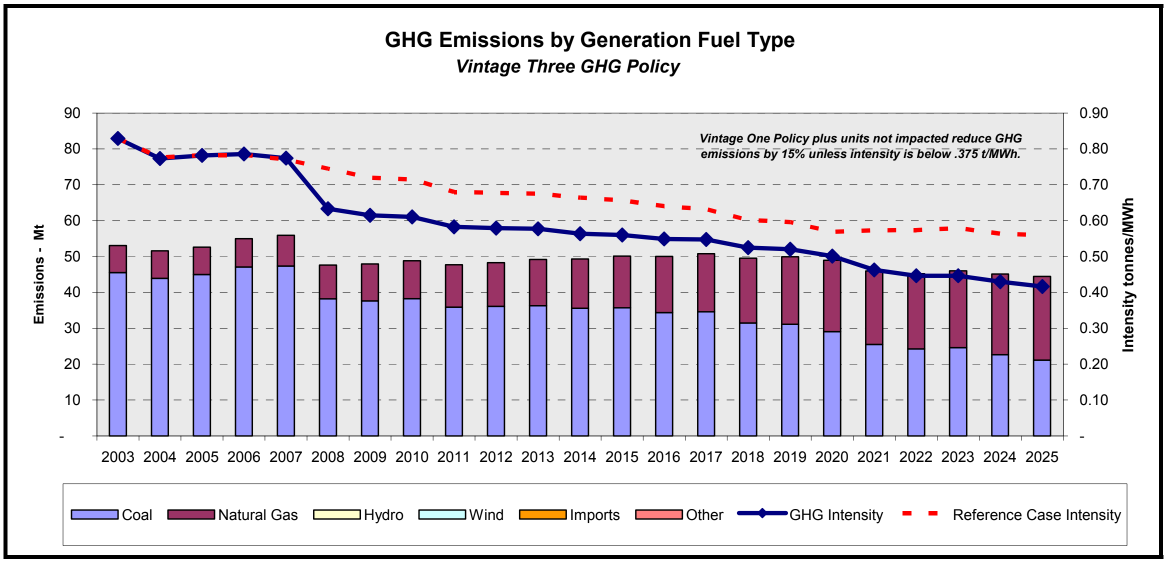


Once again, since the natural gas price forecast is identical between the Reference Case and the Vintage Three sensitivity, the heat rate graph in Figure 23 reveals the same information as the price graph. The impact of the Vintage Three GHG policy is generally quite small, and the price / heat rate impact appears to occur mainly after 2020.

GHG Emissions Forecast

The Vintage Three policy creates a substantial reduction in emissions from 2008 onwards as all units with GHG intensities above 0.375 t/MWh are required to offset their emissions by 15%. As a result, overall GHG emissions fall by nearly 15% in 2008. By 2020, the impact of the Vintage Three policy relative to the Reference Case is reduced to a 12% reduction in GHG emissions because several coal facilities retire and are replaced with new combined cycle generators. These new units have identical emissions in both the Reference Case and the Vintage Three sensitivity because their emissions are below the 0.375 t/MWh 'floor'.

Figure 24 - GHG Emissions Forecast Comparison (Vintage Three versus Reference)



From 2021 onwards, the Vintage Three policy looks very similar to the Vintage One and Two policies as the majority of the emission reductions occur because several coal units are required to buy down to combined cycle emission level in 2021. As a result, there is only an 8% reduction in emissions from Vintage One to Vintage Three in 2021, as compared to the nearly 15% reduction seen in 2008. When compared to the Reference Case, the Vintage Three policy yields a 20% reduction in GHG emissions in 2021.

Overall Sensitivity Results

There are several main results apparent from the sensitivity results seen in this chapter. First, the evidence from energy production suggests that the merit order is not appreciably impacted by the various policy options. Since energy production by fuel type is relatively stable between the Reference Case and the various sensitivities, the results suggest that coal generation is not displaced in the merit order by natural gas generation as a result of the relatively higher GHG costs it will face. In essence, although the operating margins for coal units will be impacted by the offset costs of up to $11/MWh from 2021 onwards, the costs are not sufficient to result in higher variable costs than seen in the most efficient natural gas units.

Second, electricity prices are forecast to be slightly higher under the GHG sensitivities, but the impact generally appears to be $2/MWh or less, depending on the sensitivity. Random elements within the forecast result in price differences between several of the sensitivities that are seem to be driven by one or two years. There does appear to be some evidence that the price impact of the GHG policies is greater from 2021 onwards, and the size of this price impact in the later years may be as large as $4/MWh, although this large number appears to be driven by outliers in the forecast. If outliers are ignored, the impact in the latter portion of the forecast appears to fall between $2.50/MWh and $3/MWh.

Finally, the results show that the GHG policy sensitivities create reductions in GHG emissions via offset purchase requirements. The timing and size of the reductions varies across each sensitivity, as the Vintage One sensitivity creates very minor reductions from 2008 through 2020, while the Vintage Three sensitivity results in reductions of at least 12% in every year from 2008 through 2025. Reductions are largest in all of the sensitivities from 2021 onwards when several existing coal units are required to reduce their emissions to combined cycle levels.

Chapter 6 Coal Generation Sensitivity Results

In order to test the sensitivity of the basic results presented in the two previous chapters, two additional forecasts were tested. These additional sensitivities are akin to the Reference Case and Vintage Policy Three, respectively, except the generation supply assumptions underlying the forecasts are different. In these forecasts, coal generation forms the backbone of the supply additions, and combined cycle natural gas generation is displaced as a result.

In the coal generation sensitivities, 7 additional coal plants are added beyond Genesee 3 and these coal plants total 3200 MW of capacity. These plants are assumed to include the proposed Centennial plants, Genesee 4 and various Brooks plants. Note that current coal proposals amount to 5 coal plants, so there is an implicit assumption within this analysis that the Brooks site is expanded beyond the two plants currently proposed.

The new coal plants are brought online gradually between 2011 and 2024, roughly corresponding to the pace at which combined cycle natural gas plants are brought online in the Reference Case. However, one feature of the coal generation scenario is that the capacity additions come in larger increments, which results in much 'lumpier' capacity additions that the Reference Case. Note that this implies an assumption that large-scale coal plants will continue to have a cost advantage over smaller scale coal facilities and technology will not make coal facilities viable on smaller scales, as has occurred with natural gas plants.

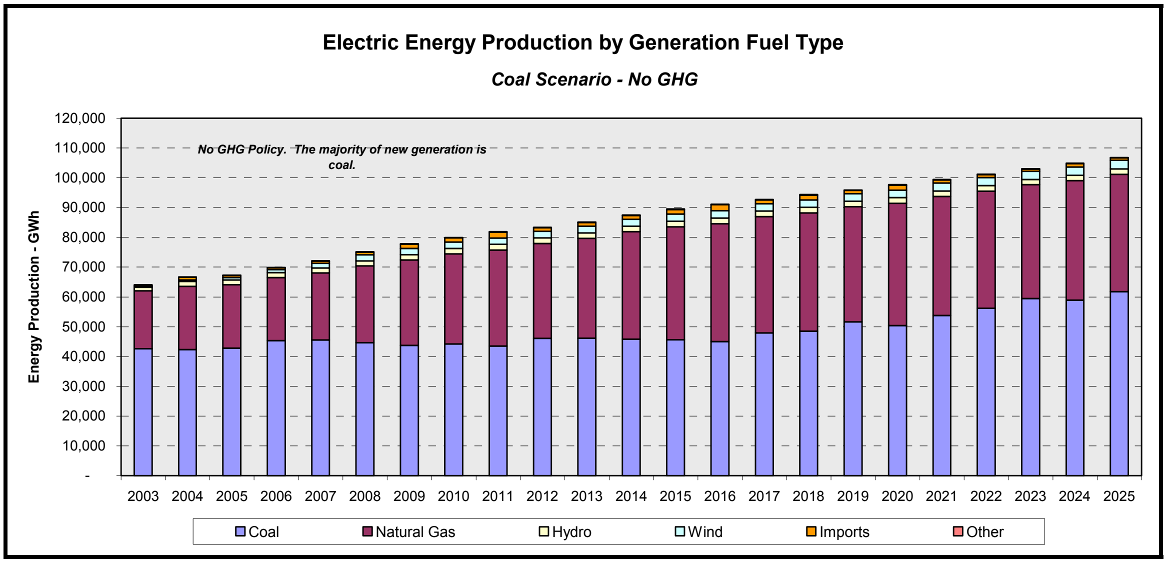
Coal Generation with no GHG Policy

This sensitivity is perhaps best represented as an alternative take on the Reference Case because it is developed under the same set of emission policies as the Reference Case. However, in this sensitivity, the generation development assumptions are dramatically different, as outlined above. Once again, it should be noted that all assumptions other than generation development are identical to the Reference Case, i.e. policies such as the 3.5% renewable energy target are still in place in this sensitivity.

Another assumption that should be highlighted is that the total amount of generation developed in the coal generation sensitivities is very similar to the Reference Case. However, the timing and fuel source for new projects is altered to accommodate the assumption that the majority of new projects will be coal fired.

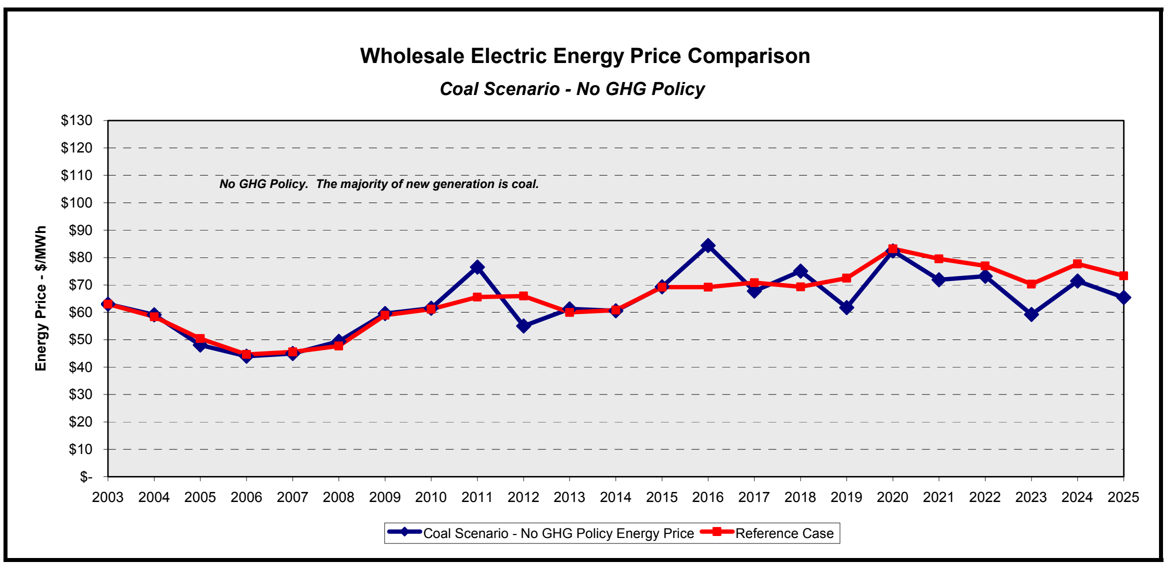
Figure 25 shows the energy production by fuel type for this sensitivity, as well as for the coal sensitivity with GHG costs that follows in the next section. Since energy production was not impacted in these sensitivities with the imposition of the Vintage Three policy, Figure 25 applies for both this sensitivity as well as the coal sensitivity with Vintage Three policy costs sensitivity that follows.

Figure 25 - Energy Production by Fuel Type (Coal Generation Sensitivity)



The figure shows the impact of adding 3200 MW of coal generation over the 22 year forecast quite clearly. Contrary to the Reference Case and associated sensitivities, coal generation increases over time in this sensitivity and peaks in 2025, rather than 2006 as per the Reference Case. Natural gas generation does increase as well due to cogeneration projects and new natural gas merchant generation required for peaking and reserve purposes. In total, 26,000 GWh of natural gas generation from the Reference Case is converted to coal generation in the coal sensitivities for the year 2025.

Figure 26 - Forecast Price Comparison



As Figure 26 illustrates, the price results under the coal generation sensitivity are similar to those in the Reference Case. In fact, from 2004 through 2010, the forecasts are basically identical. However, the first difference appears in 2011 as the 'lumpy' nature of coal additions is seen. Prices are higher in 2011 in the coal sensitivity because the large coal plant is brought online in late 2011 and displaces potential natural gas generation. On the other hand, electricity prices are lower in 2012 as the new coal unit is brought online for the entire year and its large capacity combined with lower variable costs results in relatively lower prices. A similar pattern can be seen throughout the forecast as the coal sensitivity results in much more annual price movement than in the Reference Case. The overall average price in the coal sensitivity is $63.71/MWh, which is $1.34/MWh lower than the Reference Case.

GHG emissions are the third relevant piece of the analysis in this sensitivity. As might be expected based on the energy production graph, there is a significant increase in GHG emissions relative to the Reference Case in this sensitivity because coal based generation, under current technology assumptions, results in much higher per unit GHG emissions than natural gas fired generation.

Figure 27 - Forecast GHG Emission Comparison

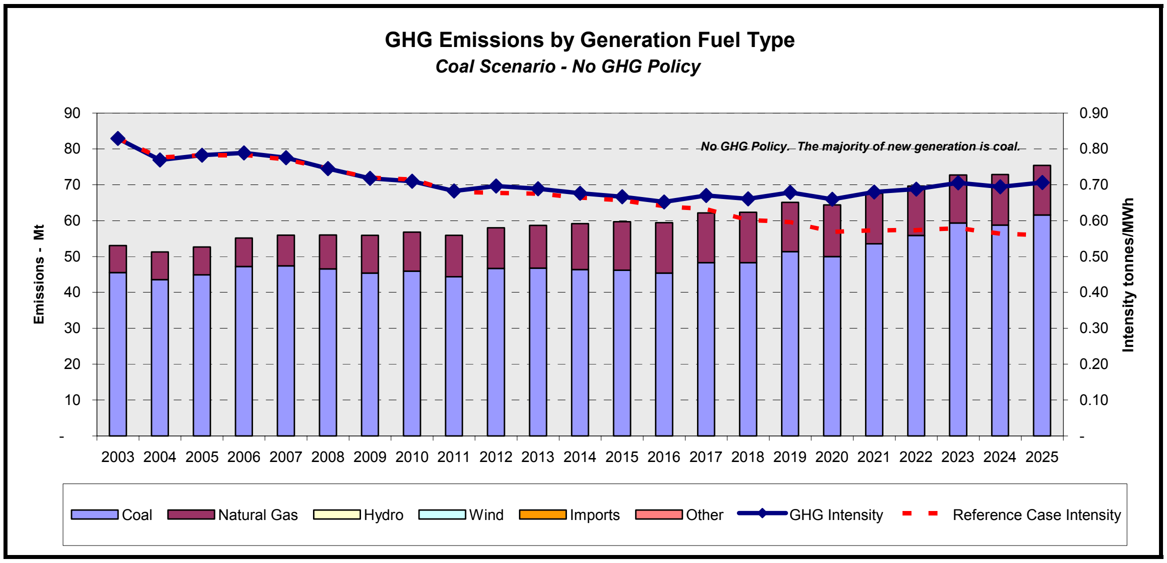
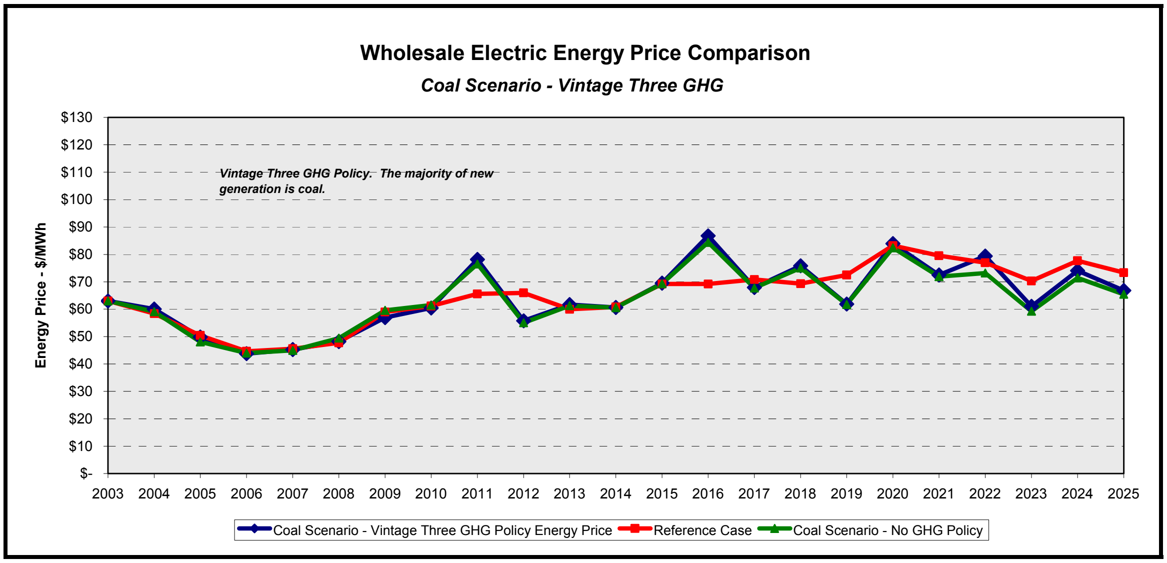


Figure 27 illustrates that the coal generation sensitivity results in substantially higher emissions than in the Reference Case. For example, in 2025, the emission intensity under the coal sensitivity is about 25% higher than the Reference Case. Total emissions in 2025 are approximately 75 Mt, which compares to 60 Mt in the Reference Case. The addition of 3200 MW of coal capacity, at emission intensities between 0.86 t/MWh to 1.0 t/MWh, leads to an additional 15 Mt of GHG emissions relative to the Reference Case. This quantifies the size of the risk represented by the generation mix—if coal generation forms nearly all of the capacity additions beyond cogeneration over the next 22 years, the Reference Case understates emissions by about 25%. Note that if cogeneration projects fail to materialize and even more coal plants are developed, the size of the gap would increase further.

Coal Sensitivity with Vintage Three GHG Policy

This sensitivity is performed under the same assumptions as the previous coal generation sensitivity, except the GHG emission costs associated with the Vintage Three policy are levied against generators. Once again, Figure 28 presents the results of the sensitivity relative to the Reference Case as well as the coal sensitivity with no GHG charges. The results show that the GHG charges result in a modest price increase that increases in size from 2021 onwards when units formerly exempted by PPA contracts are exposed to the Vintage portion of the policy.

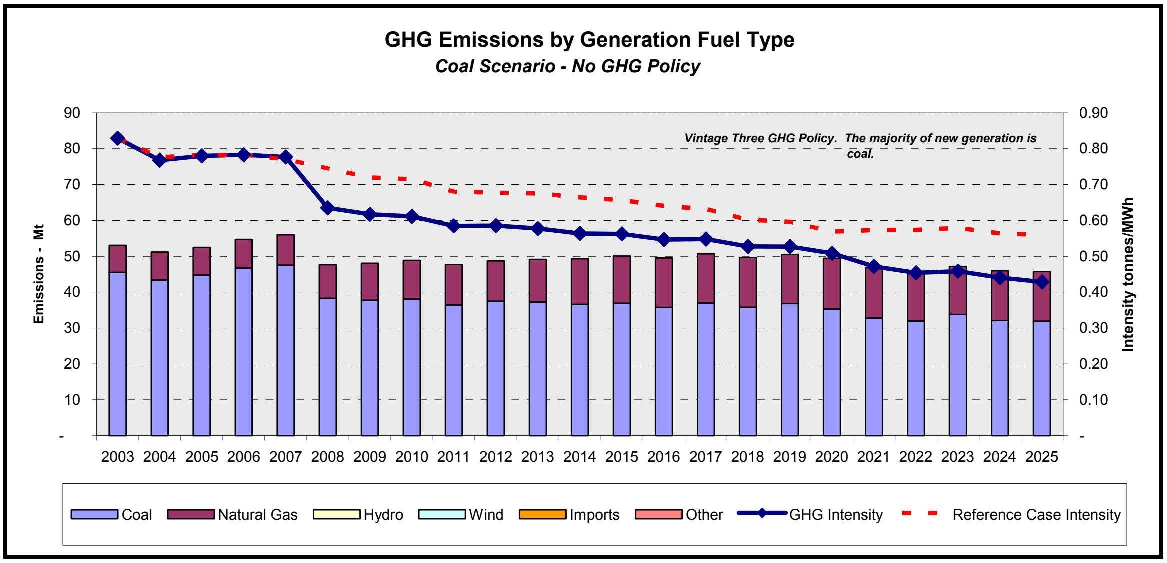
Figure 28 - Forecast Price Comparison



In terms of average prices, the coal sensitivity with the Vintage Three GHG policy has an average price of $64.55/MWh between 2004 and 2025. Note that this is $0.85/MWh higher than the coal sensitivity with no GHG costs. However, as the figure illustrates, the majority of the impact is concentrated from the 2021 through 2025 timeframe. Over these 5 years, the coal sensitivity with GHG policy in place averages $70.74/MWh, while the non-GHG sensitivity averages $68.22/MWh. This difference of $2.50/MWh can be considered a significant difference, especially when it represents a 5-year average price. On the other hand, between 2008 and 2020, the difference between the two forecasts is only $1.20/MWh.

On the GHG emissions side of the analysis, the Vintage Three policy serves to bring emissions below the Reference Case because effectively all plants are required to buy emission offsets amounting to 15% of their GHG emissions. Further, since all new coal plants are required to offset their GHG emissions to 0.418 t/MWh, the impact of new coal plants' GHG emissions does not show up. In effect, the requirement for new coal plants to look very much like new combined cycle natural gas plants dramatically reduces the *net* GHG emissions. It is important to recognize that the electricity industry will still physically emit the 75 Mt in 2025 of GHG emissions as shown in Figure 27, but the Vintage Three policy requires roughly 30 Mt of offsets to be purchased. At $15/tonne, this amounts to $450 million worth of GHG offsets (nominal dollars) for the electricity sector in 2025 alone.

Figure 29 - Forecast GHG Emission Comparison



It is also interesting to compare Figure 29 to Figure 24, which represents the GHG emissions from the Vintage Three policy sensitivity. The difference between these figures is that Figure 29 represents a sensitivity with significant coal generation development while Figure 24 represents the Reference Case natural gas dominated supply scenario. Due to the parameters of the policy, the emission graphs are almost identical because new coal plants are required to offset their emissions to a level very similar to combined cycle natural gas plants. In effect, Figure 29 implies that it does not really matter what type of generation is built, the Vintage Three policy results in very similar GHG emissions. However, it must be made clear that the cost to the electricity industry is much higher under a coal generation sensitivity because more offsets must be purchased to meet the policy parameters. For example, the $450 million for 2025 quoted above is reduced to roughly $225 million in 2025 if natural gas generation forms the majority of new generation additions as per the Reference Case.

Chapter 7 Key Assumptions and Results

This final chapter presents a review of some key elements of the analysis. There are two main sections in this chapter. The first section presents key assumptions that have the potential to sway the forecast and may be subject to considerable risk. The second section contains results from the electricity price forecasts and draws out key results and conclusions. Results and conclusions are focused on electricity prices and the overall cost impact of environmental policies on the electric generation industry.

Key Assumptions

There are several assumptions that should be highlighted once again in order to properly frame this forecast exercise. Each assumption outlined in this section has the potential to have a large impact on both the results and the various stakeholders, and as such, it is important to make these assumptions clear.

Forecast Methodology and Implications

The forecasts presented in this report represent a fundamental approach that reflects the short and long-term costs of producing electricity. Individual generators are expected to behave rationally in the spot market and long-term investment is forecast to proceed in a manner that provides economic returns for new generation. Although the model does reflect generator behaviours that result in short-term economic profits under ‘tight’ market conditions, potential new behaviours resulting from a GHG policy are not captured. This section explores potential impacts from the policy both in the short and long-term that are not reflected in the forecast results contained in this report.

Potential Short-Term Behaviours

Any change in the market has the potential to result in new generator offer strategies that either inflate or reduce the impact that would be expected from fundamental analysis. This section explores some potential outcomes from the GHG policy from a behavioral perspective rather than from a purely fundamental perspective.

For historical context on the impact a policy change can have on the electricity market, it is useful to look back on the transmission tariff. The transmission tariff change in June 2000 resulted in increased marginal costs for generators of several dollars per MWh because generators faced a direct variable charge for transmission. As with the GHG policy costs, it was expected that this cost would be passed on to consumers via the electricity price to the extent that the marginal generator faced new costs. However, the onset of this policy change coincided with events such as the California power crisis, high natural gas costs and the Wabamun 4 generation outage. As a result, it is impossible to discern whether historical prices show the cost being passed onto the market at an inflated or deflated rate. When this cost disappears in 2006 as per the provincial government’s latest transmission directive, it will be interesting to see whether or not electricity prices fall by the amount of the cost reduction.

One factor that may influence generator behaviour is the fact that many companies own interests in multiple generators. For example, some generators have both coal and natural gas generation assets—some participants may be able to develop an offer strategy that allows the higher GHG costs associated with coal units to be passed into the market via the natural gas generation units that face much lower GHG costs. In effect, the participants may try to recover the high costs coal units face by changing the way their natural gas units bid into the market, even though the natural gas generator does not face significant costs itself. This would result in a larger impact on the electricity price forecast than estimated in a purely fundamental model approach.

It is also important to recognize that with a 'commodity' as nebulous as GHG offsets combined with a credit market that is not yet established, it is very difficult to discern the behaviours that will occur in the offset and electricity markets. Given that the offset market will be a market only in the sense that policy and rules create the market and the commodity it trades, it is certainly probable that unpredictable behaviours and strategies will result in the interaction between the two markets. One simple example relates to the time interval over which emission factors and credit requirements will be measured. It is easy to see a situation where a combined cycle natural gas unit will operate both above and below the intensity threshold in the policy for portions of the year based on market conditions as well as ambient weather conditions. If the emission policy is applied over short intervals, this unit would face emission costs but if the time interval is annual, it is possible its annual average emissions would fall below the threshold. Nonetheless, in the periods the unit operates above the threshold, it may very well decide to include a GHG cost in its offer given the uncertainties in how the year will develop, and this potential is not reflected in this report.

Potential Long-Term Behaviours

Long-term behaviours in the electricity market will primarily be reflected in the investment decisions market entrants make over time. A GHG policy alters the relative cost structures of potential generators and may shape the investment decisions in the long-run. For example, given a target of 0.375 t/MWh for natural gas generation, it is likely that new natural gas generators will meet this target in order to avoid the risk of being required to purchase GHG offsets. Further, the choice between natural gas and coal generation additions is substantially altered in the presence of GHG standards.

A typical new coal generator will see its 'all in' costs increase by as much as $9/MWh as a result of the GHG policy. In terms of the investment decision between coal and combined cycle natural gas capacity, this is roughly equivalent to a $1.25/GJ increase in the long-term average price of natural gas.[20] In other words, the Vintage GHG policy shifts the relative attractiveness of new generation capacity from coal towards natural gas capacity.

Another result of the Vintage Policy is that the relative attractiveness of emission free technology is increased. Wind, hydro and solar power, for example, do not create emissions and were assumed to be granted an emission credit of 0.21 t/MWh. This amounts to roughly a $2 - $3/MWh incentive for these technologies, combined with the fact that overall electricity prices are expected to increase by $1 to $2/MWh due to the GHG policy. It is possible that wind technology improvements, for example, will allow wind generation to become cost competitive with coal and/or natural gas generation partially as a result of the GHG policy. In this event, the electricity system will have to come to terms with the impact large-scale wind generation has on system reliability and reserve requirements as wind technology could become the best investment choice on a cost basis.

Constant Market Design

With the wholesale market review currently underway, it is important to note that the analysis in this report assumes the current 'energy only' market design continues in the future. Small changes in this market design such as a day-ahead market would not likely have a substantial impact on the forecast results, but a dramatic change such as a capacity market would alter the results. Without knowing the details of a capacity market, it is not possible to determine exactly how different the results would be, but some basic premises can be stated.

In the current market design, coal capacity can not generate economic returns unless natural gas generators set the price, i.e. coal generators have marginal costs well below their average costs. In a

[20] EDC generally assumes that a long-term natural gas price of $5/GJ in real terms results in combined cycle generation costs that are similar to coal costs on an 'all in' basis. The GHG policies examined in this report appear to move this break-even point to over $6/GJ.

competitive market dominated by coal capacity, energy prices would gravitate towards the marginal cost of coal generation. Clearly, this is not attractive for coal capacity because it does not allow the units to recover their large capital costs. In essence, coal generators need natural gas generators to set the price for a large amount of the year in order to create a return on capital.

Since a capacity market implies that generators will be compensated for their capital costs outside of the energy market, there will no longer be a legitimate reason for generators to submit offers above their marginal costs into the energy market.[21] If this is the case, coal generators may very well set the price in many hours and still generate fair returns. However, since coal generators face much higher GHG offset costs than natural gas generators under the proposed policies, the impact of the policy would be much greater. In effect, the cost of GHG offsets would be more likely to flow through into the energy price with a capacity market.

There are other potential impacts that could arise from a capacity market design, but the detailed analysis falls outside the scope of this document. For example, it is not clear how a capacity market would change the incentives for fuel efficiency, i.e. lower heat rates. The current market design rewards efficient generators because they are more likely to be in merit and they earn an economic profit in the hours a less efficient generator sets the price. Clearly, this reward for efficiency will be enhanced with GHG offset costs added into the picture for natural gas units that fall below the threshold efficiency as well as all coal units. In addition, it is unlikely that intermittent capacity such as wind would be eligible in a capacity market since it does not contribute to reliability, and this is the purpose of the capacity market. As such, a capacity market without specific 'green energy' targets would not likely create an incentive to develop capacity such as wind or solar power, although hydro capacity may fit within the capacity market. However, without details in how a capacity market would be implemented, it is not possible to determine whether this same type of incentive would exist.

Case Definition

In the previous stages of this project, several different natural gas and demand forecasts were put together under different 'Scenarios' that envisioned alternative views of the world going forward. Under the 'Business as Usual' scenarios, natural gas prices were lower and electricity demand was higher, while under the 'Emissions management' scenarios, the assumption was that economy wide adjustments would take place that would lead to higher natural gas prices and lower electricity demand. Within this stage of the analysis, there is only ONE set of natural gas price and electricity demand assumptions.

In this phase of the analysis, the difference between the sensitivities comes down to two elements. The first set of sensitivities varies the GHG policy that results in a range of variable costs for fossil-fired generation. Since these sensitivities are all developed on the assumption that natural gas based generation will form the majority of capacity additions over the next 22 years, there is a potential cost risk that arises if a large amount of coal is developed instead. The second set of sensitivities address this issue. In these two sensitivities, GHG policies taken from the first set of forecast are used, but the generation assumptions are altered. In effect, these forecasts test the cost magnitude of the GHG policies on the industry given a much greater amount of GHG emissions from increased coal generation.

Valuation of PPA Units and Retirement Decisions

Once again, analysis was performed that determined whether the policies under consideration create sufficient costs for existing coal units that would lead them to retire prematurely. As was the case in the previous analysis, it is important to stress that the economic tests on existing coal generation was done upon the assets themselves and not upon the PPA contracts. The analysis was framed from the perspective of a third party bidder who was not concerned about the price originally paid for the PPA contracts or the hedging decisions made as a result of the PPA purchase. The PPA holders paid a

[21] In the current market design, there is an implicit assumption that marginal generators recover their capital costs during times of shortage when the electricity prices rise well above marginal costs. If a capacity market exists, it will presumably allow generators to recover their capital costs in the secondary market and the energy market should simply reflect production costs.

price for the PPA contracts and likely sold portions or all of the power forward from the underlying PPA assets. As this information is confidential, only the PPA holders themselves could undertake this analysis. The results of such an analysis would suggest to the PPA holders if there was any value appreciation/degradation in their contracts. This would signal whether or not the PPA holder would be inclined to write-down or, in the worst case scenario, walk away from their PPA contracts.

The actual analysis undertaken by EDC attempted to value what the underlying assets would be worth to a new bidder given the operating costs of each facility. It was assumed that power was sold into the spot market assuming EDC's energy forecast (i.e. no hedging). This type of valuation would signal whether there was still any market value in the underlying generating facilities. A signal implying no market value (negative acquisition price), would be the basis for the asset's retirement and omission from the Alberta dispatch queue. Since it is the retirements that matter for the energy forecast (dispatch), the acquisition valuation methodology is more meaningful than a valuation of the PPA from the PPA holders' perspective. Asset write-downs or voided contracts are not commensurate with asset retirements.

As was the case in the previous cost analysis for the PPA units, it is once again estimated that no existing coal units will be forced to retire early for purely economic reasons as a result of the GHG policy. Although the incremental costs associated with these policies clearly erodes the value of the units, the magnitude of the costs is not nearly sufficient to induce early retirements. Operating margins for coal units are sufficiently large enough to absorb the incremental costs and still remain profitable. Furthermore, the returns generated by the coal units within the forecast environment are strong enough to suggest that there is substantial room for forecast deviations before any units will be forced from the market.

Cogeneration Development

One of the largest risks inherent in this forecast exercise is that the generation development sequence will not progress as forecast. For example, the Reference Case and its associated sensitivities assume one new 450 MW coal facility (Genesee 3) over the forecast horizon. If generation development unfolds in a different manner, there is a large risk that prices and emission levels will differ substantially from those presented in this study. Since this is largely addressed via the coal sensitivities, the main un-examined risk in terms of generation development comes from the cogeneration sector of the industry.

As Figure 7 and Figure 8 show in the generation assumptions section (page 31), the industry is assumed to develop 1000 MW of cogeneration (net to grid) between 2004 and 2025. In addition to this 1000 MW, the forecast estimates that roughly 1800 MW of generation will be developed to meet onsite load requirements, and the majority of this generation is forecast to come from cogeneration. Overall, the forecast call for 2800 MW of natural gas fired cogeneration to be developed over the 22 year forecast period.

In order to somewhat quantify the risk inherent in this assumption, it is useful to look at oil sand industry estimates for cogeneration capacity as taken from the RIWG Report.[22] Based on the survey results in this report, the industry believes it will add between 1000 MW and 2500 MW of cogeneration capacity by 2012. On a discounted basis, as presented in the RIWG Report, the range of capacity additions is forecast between 600 MW and 1700 MW, again by 2012. Clearly, even within individual companies in the oilsands industry, there is a large range of potential cogeneration development over the next 10 years, never mind the next 22 years. The forecast in this report falls in the lower middle range of cogeneration additions by 2012, but there are definitely risks on both ends of the cogeneration development spectrum in this report.

As noted previously in the report, there are two different risks inherent in the cogeneration assumptions. First, it natural gas does not fuel the new cogeneration capacity, it is likely that GHG emissions will be higher than forecast because the alternative fuels are likely to be more GHG intense. Second, it is

[22] Cogeneration / Transmission Sub-Committee Oil Sands Cogeneration Potential Survey Results. Athabasca Regional Issues Working Group. May 2003.

possible that cogeneration will not develop in the oilsands and the projects will purchase electricity from the wholesale market. This represents an increase in market demand combined with a decrease in supply, which is quite likely to have an impact on the wholesale electricity price.

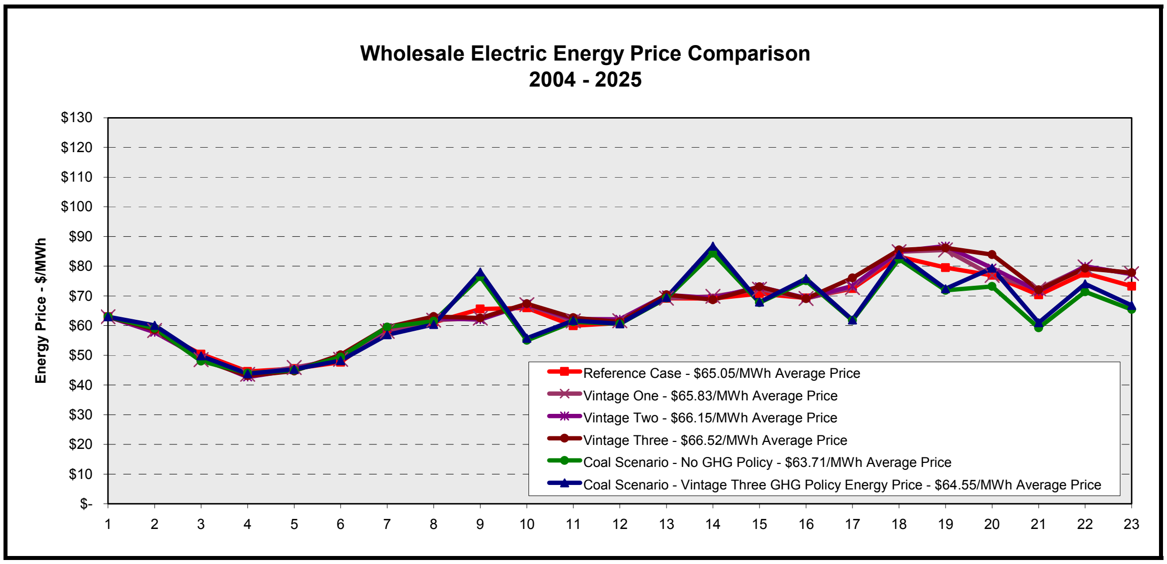
Results

This section concentrates on results that relate to the various price forecasts and the implications of the price forecasts. Although the price results are presented in detail in Chapters 4, 5 and 6, this section brings the results together for comparison.

Price Forecast Results

Chapters 4, 5 and 6 present the forecast results for the Reference Case, Vintage GHG policy sensitivities and the coal development sensitivities, while this section looks at the forecasts as a group. In addition, the differences between each of the forecasts are broken down by cause—in this case, the only differences are GHG policy costs and generation development.

Figure 30 - Overall Price Forecast Results



As noted throughout the document, the Reference Case (red line) is generally quite similar to the three Vintage sensitivities, while the two coal sensitivities have a much more jagged profile due to the size of typical coal facilities.

The impact of the GHG policies is rather small, although the average price is higher in all of the GHG sensitivities relative to the Reference Case. In overall average terms, the electricity price impact from the policies seems to fall between $0.80/MWh and $1.50/MWh.

In the coal sensitivities, the impact of the Vintage Three GHG policy is similar at $0.85/MWh on average. However, one important caveat in all the sensitivities is that the impact of the policy appears to grow from 2021 onwards when more generators are exposed to the Vintage aspect of the policy.

GHG Policy Costs

The analysis to this point has indicated that the impact of the GHG policies on the market price for electricity will be rather small. This section examines the costs coal and natural gas generators will face in order to reduce GHG emissions. The costs developed are calculated using forecast production numbers for each generating facility existing and forecast to be built in the province combined with the specific reduction targets outlined in each specific GHG policy. GHG offsets are priced at $9/tonne between 2008 and 2012, $12/tonne between 2013 and 2017 and $15/tonne from 2018 onwards.

Coal Units

Table 4 - Total Coal Generator GHG Emission Costs

	Vintage One	Vintage Two	Vintage Three	Coal No GHG	Coal & Vintage Three	Reference Case
Cumulative GHG Emission Costs ($000)	$1,132,534	$1,475,243	$2,177,817	-	$3,502,407	-
Present Value of GHG Emission Costs ($000)*	$260,458	$382,204	$630,007	-	$883,172	-
Present Value of Total Coal Energy (GWh)**	429,150	429,150	429,150	462,780	462,780	429,150
Levelized GHG Emission Costs per MWh***	$0.61	$0.90	$1.48	-	$1.86	-

* Assumes 10% Discount Rate
** Energy only includes coal fired plants
*** Assumes inflation rate of 2.0% and term of 21 years (2005-2025), starting in 2005

Table 4 presents the total cost of the various GHG emission policies under the two different generation development scenarios. The first row in the table presents the cumulative, nominal dollar costs of each policy levied against energy produced by coal facilities. Note that this includes existing coal facilities plus forecast coal developments such as Genesee 3. In the coal generation sensitivity, there are an additional 3200 MW of coal capacity built by 2025, as noted earlier in the report.

Since the timing and size of emission reductions varies across each policy, the nominal costs presented in the first row tell only a portion of the story. For example, in the Vintage One sensitivity, the majority of emission reductions take place beyond 2021, and this results in a large difference between the nominal costs and the present value of those same costs. In the Vintage One sensitivity, the present value is less than 1/4 of the nominal value, while in the Vintage Three sensitivity the present value is just under 1/3 of the nominal value. This difference occurs because the Vintage Three policy creates costs (and emission reductions) much sooner than the Vintage One policy.

The third row of the table simply calculates the present value of all energy produced by coal facilities between 2005 and 2025. This amount is used to calculate a levelized $/MWh tariff discounted back to 2005 dollars in order to quantify the emission costs on a more meaningful basis. [23] The $0.90/MWh tariff for the Vintage Two sensitivity can be interpreted as: if each coal MWh was charged $0.90/MWh from 2005 through 2025, and this $0.90/MWh was increased by 2% each year, this charge would be financially equivalent on a present value basis to the impact of the Vintage Two policy. However, it is very important to recognize that this is not how the policy is actually implemented—some coal units will pay a much larger portion of the total emission costs than others. The levelized number simply represents the cost of the GHG policy spread across the entire coal generation sector and spread across time from 2005 through 2025.

In the coal generation sensitivity with Vintage Three GHG costs, the emission costs are by far the highest of any sensitivity. This result occurs because the new coal facilities built are required to offset their emissions to 0.418 t/MWh, while the combined cycle natural gas plants they replaced did not face any GHG costs. In total nominal costs, the coal sensitivity with Vintage Three GHG policy results in about 50% more GHG costs than the Vintage Three sensitivity under the Reference Case supply assumptions. However, in present value terms, the cost increase only amounts to about a 40% cost increase because many of the incremental coal costs occur late in the forecast period. Furthermore, since there is much more coal energy in the coal sensitivity, the $/MWh levelized cost for coal generators is only 27% higher in the coal sensitivity than in the Vintage Three Sensitivity.

[23] The nominal costs from 2005-2025 are present-valued at a nominal discount rate of 10%. The energy associated with these nominal costs is discounted with a real discount rate i.e. assuming 2% inflation, the real discount rate = (1+.10)/(1+.02) - 1. The present value of the nominal costs is then divided by the present value of real energy producing a $/MWh real levelized tariff. As a check on this calculation, the real tariff is then multiplied by the energy in each year and the 2% escalation index. The resulting nominal dollar costs which are produced will equal the original nominal dollar costs at the beginning of the calculation on a present value basis across the two cost streams.

Natural Gas Units

Although natural gas facilities do not face the same level of emission charges as the coal facilities because their baseline GHG intensity is much lower, there are still GHG charges for several natural gas generators. This section presents a brief summary of these costs—each row is interpreted in the same manner as the table for the coal plants above.

Table 5 - Total Natural Gas Generator GHG Emission Costs

	Vintage One	Vintage Two	Vintage Three	Coal No GHG	Coal & Vintage Three	Reference Case
Cumulative GHG Emission Costs ($000)	$665	$59,920	$79,260	-	$67,482	-
Present Value of GHG Emission Costs ($000)*	$127	$16,245	$22,182	-	$20,448	-
Present Value of NG Energy (GWh)**	367,617	367,617	367,617	316,961	316,961	367,617
Levelized GHG Emission Costs per MWh***	$0.00	$0.04	$0.06	-	$0.06	-

* Assumes 10% Discount Rate
** Energy only includes natural gas fired plants
*** Assumes inflation rate of 2.0% and term of 21 years (2005-2025), starting in 2005

In the Vintage One sensitivity, natural gas plants face almost no GHG costs because the plants that would be subject to costs almost all retire before the offset costs would be triggered under the Reference Case assumptions. One note for this scenario is that since 'behind the fence' generation is not modeled on a unit-by-unit basis, emission costs for these units are not captured with respect to the 30 year design life trigger. As such, the estimates in Table 5 do not fully reflect emission costs for units such as older Medicine Hat generators and older onsite generation at Suncor, Syncrude and Dow, for example.

As with the coal GHG costs, each successive Vintage policy results in higher costs for generators. However, the scale of the costs is roughly 95% lower than the coal costs because a large portion of the natural gas generation fleet does not face any costs for GHG offsets under the various policies, and even the most GHG intense existing natural gas generator faces costs of perhaps $1.25/MWh in the latter part of the forecast. Since the most GHG intense natural gas generators tend to be peaking generators that run at very low capacity factors relative to cogeneration and combined cycle generators, the average impact is very small across the total natural gas generation fleet.

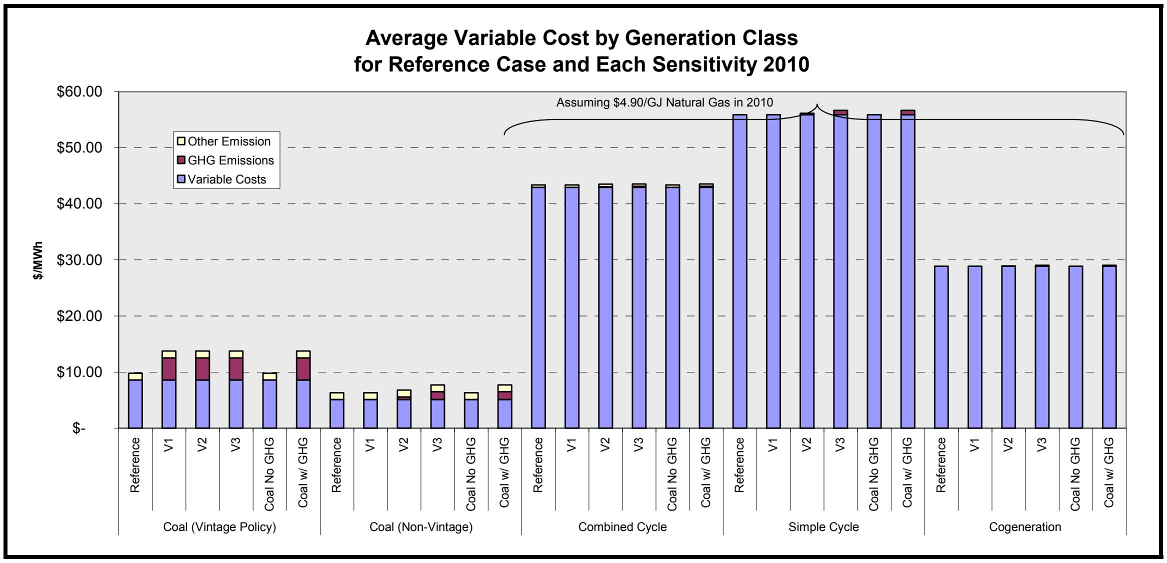
Marginal Cost Impact

The tables in the previous section detail the overall impact on the electricity industry in terms of total costs, but they do not relate information around operating costs to specific generators. This section looks at the impact on operating costs for various types of generation units in 2010 and 2025 for the various policies. It is important to recognize that the costs presented in these tables are for *representative* units and do not reflect the specific costs to a given generator. Furthermore, the costs are purely an estimate of the variable cost per MWh for electricity from each unit, and do not include any returns on capital, PPA payments or any other costs that are not directly related to energy production. In effect, the costs outlined reflect the impact on the energy market's merit order if units purely bid their variable cost.

Figure 31 and Figure 32 represent the same information, but at two different points in time. Five categories of generators are considered in the figures—two types of coal generators and three types of natural gas generators. The two types of coal generators are those that are subject to the Vintage One policy, i.e. new generators and generators that have reached the end of their design/PPA life. In 2010, the only generator in the Vintage Policy category is a new generator, such as Genesee 3. However, in 2025, this category includes Sundance 3 through 6, Keephills 1 and 2 and Battle River 5 as well as any new coal generators. On the other hand, the coal non-vintage category includes basically all of the existing coal generators in 2010, but only includes Sheerness 1 and 2 and Genesee 1 and 2 in 2025.

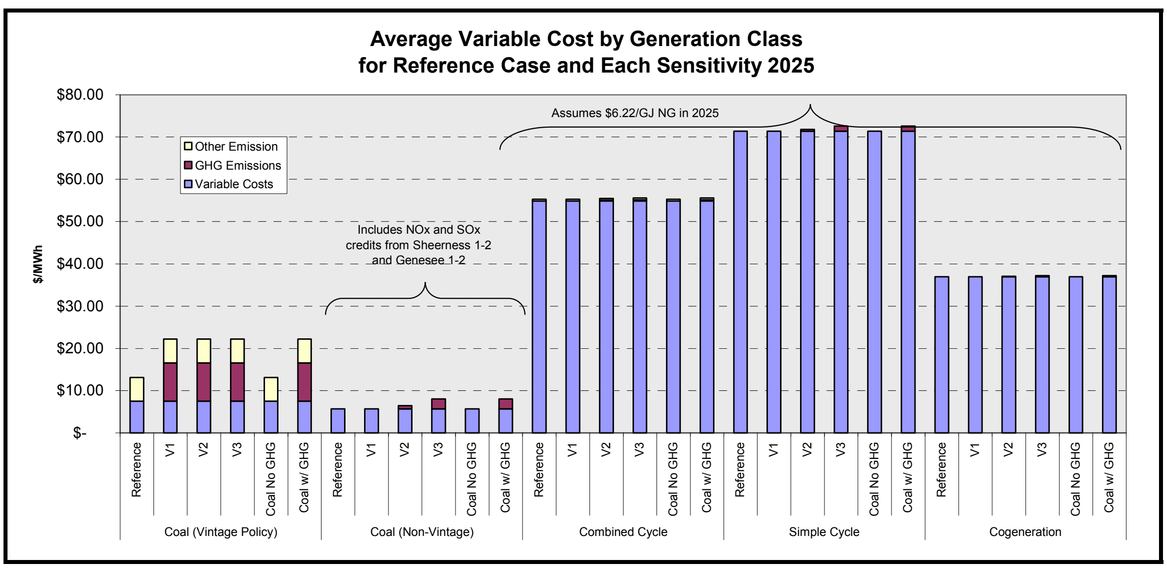
Natural gas units are categorized according to the type of technology they incorporate. The vast majority of the natural gas facilities included in the figures is modern natural gas generation built in 1998 or later. Older facilities such as Clover Bar, Rossdale and the older on-site generators are not included in these figures because they do not represent a 'typical' natural gas generator in Alberta, and these types of technology are extremely unlikely to be built in the future. One important caveat that results from this is that some natural gas units will face much higher costs than those indicated in the figure, but the costs in the figure are believed to be indicative of most capacity in the province for the years 2010 and 2025.

Figure 31 - Marginal Cost Impact by Generator Class – 2010



In the 2010 Reference Case, coal plants face emission costs associated with mercury whether they fall into the Vintage category or not. GHG costs of $4/MWh show up for coal plants in the Vintage Category for all three Vintage sensitivities, but for the non-Vintage coal plants the costs are smaller and only appear in Vintage Two and Three. Combined cycle natural gas plants face well under $1/MWh in emission costs in all the sensitivities, and even simple cycle plants face less than $1/MWh in variable emission costs. Cogeneration costs are also very near $0/MWh, and overall Figure 31 shows that coal plants face much higher variable cost increases from the GHG policies.

Figure 32 - Marginal Cost Impact by Generator Class – 2025



In 2025 the results are quite similar, although the graph suggests that a typical 'Vintage' coal plant faces environmental costs that account for roughly 2/3 of its total operating costs under all the GHG policy scenarios. However, note that these costs only apply to coal plants that are over 40 years old or plants that have not yet been completed. Coal plants that are not covered by the 'Vintage' policy face a maximum of $2.30/MWh for GHG under the assumptions given for the Vintage Three policy. Natural gas plants face up to $1.28/MWh in emission costs for simple cycle plants in Vintage Three, but this amounts to around 1% of their total operating costs. It should be noted that new simple cycle plants are not reflected in the figure, but these plants would face GHG offset costs of as much as $3/MWh because they are required to offset to 0.375 t/MWh in all of the Vintage sensitivities. Based on the estimates that the forecast price increases by around $3/MWh after 2021 in the various Vintage sensitivities, it appears that many of the GHG costs on marginal natural gas plants are passed on to the market electricity price.

Overall, the figures for the marginal cost impact of the GHG policy options illustrate that natural gas plants are able to pass on all or slightly more than their total costs into the market price for electricity. However, the higher costs allocated to coal generators are not fully passed onto the market because these units are base loaded and do not have as much influence on the electricity price. The un-recovered costs can be substantial, but the majority of the costs appear after a plant passes its 40 year design life and is subject to the 'Vintage' policy.

Chapter 8 Appendices

Fundamental Assumptions

Macroeconomic Input Assumptions and Forecasts

Table 6 - Economic Assumptions (Reference Case)

EDC - Forecast Assumptions - Reference Case																									Nominal dollars unless indicated otherwise
Assumption	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
WTI Price(1) (US$/bbl - $97 Real)	23.80	23.60	27.33	26.04	22.45	20.92	20.49	20.09	19.91	19.91	19.79	19.79	19.68	19.68	19.58	19.58	19.49	19.39	19.30	19.20	19.11	19.01	18.92	18.83	18.73
Heavy Differential (Cdn$/bbl - $97 Real)	10.24	6.02	9.75	7.81	6.49	6.19	5.90	5.71	5.67	5.63	5.52	5.48	5.44	5.41	5.37	5.33	5.30	5.26	5.23	5.21	5.20	5.20	5.20	5.20	5.20
Crude Oil (WTI US$/bbl - Nominal)	25.75	26.11	31.08	30.00	26.30	25.00	25.00	25.00	25.30	25.81	26.19	26.72	27.12	27.66	28.07	28.64	29.07	29.50	29.94	30.39	30.85	31.31	31.78	32.26	32.74
Cdn Par Light Oil @ Edmonton ($Cdn/bbl)	38.81	40.13	43.62	38.84	33.51	31.81	31.80	31.78	32.16	32.80	33.29	33.96	34.46	35.15	35.67	36.39	36.93	37.48	38.04	38.60	39.18	39.76	40.35	40.95	41.56
Bow River @ Hardisty ($Cdn/bbl)	27.73	33.46	32.53	29.84	25.91	24.41	24.60	24.68	24.96	25.50	25.99	26.56	26.96	27.55	27.97	28.59	29.03	29.48	29.92	30.36	30.78	31.20	31.62	32.04	32.47
Natural Gas Price Cdn$/GJ ($97 Real)	4.78	3.51	5.56	5.30	4.52	4.23	3.93	3.86	3.82	3.78	3.78	3.74	3.74	3.70	3.70	3.69	3.69	3.68	3.66	3.64	3.63	3.61	3.59	3.57	3.56
Alberta AECO-C Cdn$/GJ (Nominal)	5.17	3.88	6.33	6.10	5.30	5.05	4.80	4.80	4.85	4.90	5.00	5.05	5.15	5.20	5.30	5.40	5.50	5.60	5.68	5.77	5.86	5.94	6.03	6.12	6.22
Canadian CPI (1997=100)	1.082	1.107	1.137	1.152	1.172	1.195	1.220	1.244	1.271	1.296	1.323	1.350	1.378	1.406	1.434	1.462	1.492	1.521	1.552	1.583	1.615	1.647	1.680	1.713	1.748
Canadian Exchange Rate ($Cdn/$US)	0.65	0.64	0.71	0.76	0.77	0.77	0.77	0.77	0.77	0.77	0.77	0.77	0.77	0.77	0.77	0.77	0.77	0.77	0.77	0.77	0.77	0.77	0.77	0.77	0.77
Canadian Interest Rate (90 T-Bill Rate %)	3.8	2.5	2.9	2.3	3.0	4.1	4.4	4.6	5.0	5.3	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5
Canadian RGDP Growth (%)	1.5	3.3	1.7	2.8	3.3	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Canadian Unemployment Rate (%)	7.2	7.6	7.6	7.6	7.4	7.2	7.1	7.0	6.9	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8

Table 7 - Population, Household & Employment Statistics for Alberta (Reference Case)

EDC - Forecast Assumptions - Reference Case

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
2001	3,057	763	392	1,983	1,014	311	37,197	17,590	34.0	1,103	1,711	1,632	4.6	29.2	1,132
2002	3,114	765	393	2,032	1,040	318	37,843	17,907	35.0	1,135	1,768	1,674	5.3	38.8	1,169
2003	3,154	761	391	2,068	1,059	325	38,163	18,732	23.9	1,161	1,815	1,722	5.1	36.2	1,204
2004	3,202	763	392	2,103	1,078	336	38,650	18,182	40.9	1,185	1,850	1,759	4.9	33.5	1,235
2005	3,254	767	394	2,139	1,098	348	39,150	18,497	42.9	1,208	1,886	1,790	5.1	31.7	1,265
2006	3,305	771	396	2,174	1,118	360	39,771	18,862	42.2	1,230	1,921	1,821	5.2	30.2	1,294
2007	3,357	775	398	2,209	1,137	372	40,377	19,188	42.1	1,253	1,956	1,852	5.3	29.5	1,321
2008	3,409	780	400	2,244	1,156	386	40,973	19,525	42.9	1,277	1,991	1,888	5.2	28.9	1,348
2009	3,465	785	403	2,280	1,176	399	41,356	19,749	45.0	1,302	2,028	1,927	5.0	28.8	1,375
2010	3,522	791	406	2,317	1,196	414	41,973	20,087	46.5	1,327	2,066	1,965	4.9	28.8	1,402
2011	3,580	797	409	2,354	1,216	429	42,601	20,434	46.5	1,353	2,102	1,997	5.0	29.0	1,428
2012	3,640	804	412	2,391	1,237	444	43,224	20,772	48.7	1,380	2,140	2,036	4.9	29.5	1,456
2013	3,701	811	416	2,429	1,258	461	43,868	21,120	49.0	1,407	2,178	2,070	4.9	30.0	1,484
2014	3,764	819	420	2,467	1,279	477	44,513	21,464	49.9	1,435	2,216	2,106	4.9	30.3	1,512
2015	3,828	827	424	2,506	1,300	495	45,163	21,832	51.4	1,464	2,255	2,144	4.9	30.9	1,540
2016	3,894	836	428	2,546	1,322	513	45,827	22,208	52.9	1,494	2,295	2,183	4.9	31.6	1,570
2017	3,963	845	433	2,586	1,344	532	46,505	22,593	54.7	1,525	2,336	2,224	4.8	32.4	1,600
2018	4,034	855	438	2,628	1,367	551	47,202	22,991	56.1	1,557	2,378	2,265	4.8	33.2	1,630
2019	4,106	865	443	2,670	1,390	571	47,912	23,400	57.3	1,590	2,420	2,306	4.7	34.0	1,662
2020	4,180	876	448	2,713	1,414	592	48,634	23,820	58.7	1,623	2,463	2,349	4.6	34.9	1,694
Avg Annual Compound Growth 2004 to 2020	**1.7%**	**0.8%**	**0.8%**	**1.6%**	**1.7%**	**3.6%**	**1.4%**	**1.4%**	**5.4%**	**2.0%**	**1.8%**	**1.8%**	**4.9**	**31.0**	**2.0%**

Table 8 - Alberta Major Economic Variables (Reference Case)

EDC - Forecast Assumptions - Reference Case										Alberta Economic Accounts Forecast ($000s)		
Forecast Year	GDP Mkt Price	Personal Consumption	Government Consumption	Government Investment	Business Investment	Large Proj. Investment	Net Exports	Imports	Exports	NOMINAL GDP GROWTH	GDP At Market Price	REAL GDP GROWTH
	$M	$M	$M	$M	$M	$M	$M	$M	$M	%	1992 $	%
2001	151,655	67,850	19,731	3,320	39,668		21,086	(75,345)	96,431	4.7%	112,075	2.8%
2002	150,817	72,108	20,923	3,547	40,865		13,374	(76,718)	90,092	-0.6%	114,706	2.3%
2003	174,337	78,205	23,010	3,600	39,526	4,090	25,906	(82,257)	108,163	15.6%	118,102	3.0%
2004	178,529	83,495	24,128	3,775	40,648	3,960	22,523	(85,926)	108,449	2.4%	122,303	3.6%
2005	179,113	87,583	24,878	3,893	40,116	5,487	17,157	(88,693)	105,850	0.3%	125,954	3.0%
2006	185,111	91,672	25,674	4,017	38,676	9,199	15,873	(92,500)	108,373	3.3%	130,237	3.4%
2007	192,385	95,912	26,528	4,151	41,060	9,358	15,376	(96,619)	111,995	3.9%	134,591	3.3%
2008	201,634	100,493	27,503	4,303	43,906	9,212	16,217	(101,115)	117,332	4.8%	139,479	3.6%
2009	212,361	105,515	28,598	4,475	50,448	5,755	17,571	(106,184)	123,755	5.3%	144,836	3.8%
2010	223,121	110,763	29,767	4,658	55,751	3,539	18,644	(111,389)	130,033	5.1%	150,035	3.6%
2011	233,353	116,031	30,941	4,841	59,938	2,356	19,244	(116,516)	135,761	4.6%	154,498	3.0%
2012	245,068	121,809	32,162	5,032	64,083	1,563	20,420	(122,175)	142,595	5.0%	159,853	3.5%
2013	256,484	127,761	33,450	5,234	67,221	1,852	20,966	(127,984)	148,949	4.7%	164,654	3.0%
2014	268,352	133,954	34,769	5,440	71,289	1,375	21,524	(134,030)	155,554	4.6%	169,652	3.0%
2015	281,041	140,519	36,148	5,656	74,922	1,578	22,218	(140,459)	162,677	4.7%	174,948	3.1%
2016	294,471	147,454	37,609	5,885	79,389	1,194	22,940	(147,282)	170,222	4.8%	180,359	3.1%
2017	308,546	154,830	39,140	6,124	83,468	1,444	23,539	(154,522)	178,061	4.8%	186,033	3.1%
2018	323,149	162,447	40,766	6,379	87,935	740	24,883	(161,519)	186,403	4.7%	191,730	3.1%
2019	338,362	170,347	42,442	6,641	91,484	740	26,709	(168,521)	195,230	4.7%	197,546	3.0%
2020	354,458	178,665	44,180	6,913	95,872	73	28,755	(175,877)	204,632	4.8%	203,597	3.1%
Avg Annual Compound Growth 2004 to 2020	**4.3%**	**5.0%**	**3.9%**	**3.9%**	**5.4%**	**N/A**	**0.6%**	**4.6%**	**3.8%**	**4.3%**	**3.3%**	**3.3%**

Energy Demand Forecast

Table 9 - Alberta Electric Energy and Demand Forecast (Reference Case)

ALBERTA ELECTRICITY FORECAST (AIES & AIL)

Reference Case

Reference Case:	TOTAL ENERGY SALES (GWh)										
ENERGY (GWh)	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2010**	**2015**	**2020**	**2025**	**Gwth % 2004 to 2025**
Residential	6,933	7,226	7,342	7,551	7,680	7,802	8,323	9,056	9,899	10,819	1.8%
Commercial	10,510	11,190	11,446	11,912	12,292	12,690	14,235	16,175	18,200	20,478	2.7%
Farms & Irrigation	1,772	1,703	1,791	1,829	1,829	1,836	1,866	1,906	1,948	1,990	0.5%
Oil & Gas	16,527	16,738	15,811	16,298	16,286	16,802	19,350	21,490	24,826	28,375	2.7%
Other Industrial	12,707	12,619	12,696	12,751	12,882	13,027	13,652	14,338	15,090	15,882	1.0%
SUB-TOTAL	**48,449**	**49,476**	**49,086**	**50,341**	**50,969**	**52,157**	**57,427**	**62,966**	**69,962**	**77,543**	2.1%
Exports	2,294	617	1,296	1,575	1,163	1,206	1,327	1,379	1,382	1,526	0.7%
T&D Losses	5,081	5,091	5,078	5,225	5,228	5,311	5,671	5,968	6,351	6,760	1.3%
TOTAL ENERGY SALES	**55,824**	**55,184**	**55,459**	**57,142**	**57,360**	**58,674**	**64,426**	**70,312**	**77,696**	**85,829**	2.0%
Isolated	159	128	127	129	130	131	138	144	152	161	1.1%
CMH System Load	747	730	733	750	761	771	834	904	978	1,058	1.7%
AIES+ EXPORTS ENERGY SALES	**54,918**	**54,326**	**54,599**	**56,263**	**56,469**	**57,771**	**63,454**	**69,264**	**76,566**	**84,611**	2.0%
Internal Load Adjustment	-453	5,107	8,114	8,836	9,668	10,909	15,206	18,872	19,731	20,672	4.3%
AB INTERNAL LOAD[1]	**54,465**	**59,433**	**62,714**	**65,099**	**66,137**	**68,680**	**78,661**	**88,136**	**96,297**	**105,282**	2.4%
TOTAL PEAK DEMAND (MW) - Recorded Actual & Normalized Forecast											
AB PEAK DEMAND	**7,744**	**7,692**	**7,758**	**7,995**	**8,111**	**8,297**	**9,055**	**9,841**	**10,806**	**11,946**	2.0%
Load Factor	82.3%	81.9%	81.6%	81.4%	80.7%	80.7%	81.2%	81.6%	81.9%	82.0%	
Isolated Peak	30	24	24	25	25	25	26	27	29	31	1.1%
CMH System Load	108	110	117	122	124	125	135	146	158	170	1.7%
AIES PEAK DEMAND	**7,606**	**7,558**	**7,616**	**7,848**	**7,962**	**8,146**	**8,894**	**9,668**	**10,619**	**11,745**	2.0%
Load Factor	82.4%	82.1%	81.8%	81.6%	81.0%	81.0%	81.4%	81.8%	82.1%	82.2%	
Internal Load Adjustment[2]	328	1,012	1,170	1,267	1,324	1,487	2,016	2,462	2,545	2,677	3.8%
AB INTERNAL PEAK DEMAND[1]	**7,934**	**8,570**	**8,786**	**9,115**	**9,286**	**9,633**	**10,910**	**12,130**	**13,164**	**14,422**	2.3%
Load Factor	78.4%	79.2%	81.5%	81.3%	81.3%	81.4%	82.3%	82.9%	83.3%	83.3%	

Notes: 1. Figures in this Table correspond to Alberta Internal Load as reported by the Alberta Electric System Operator (AESO). A certain amount of behind the fence load may not be reported.
2. Figures in this Table correspond to actual and expected AIES and internal demand. The AIES peak demand and the internal peak demand are not necessarily coincident.
The difference between AIES demand and internal demand shown here is at the time internal demand peaks.

Reference Case Data Tables

Energy Production Forecast

Table 10 - Energy Production by Fuel Type (Reference Case)

Reference Case

Energy by Type

	Annual Energy (GWh)						
	2003	**2004**	**2005**	**2010**	**2015**	**2020**	**2025**
Coal	42,563	42,901	42,912	44,378	42,874	34,995	35,812
Natural Gas	19,440	20,870	21,167	30,171	40,940	56,184	65,251
Hydro	1,253	1,625	1,646	1,787	1,766	1,977	1,831
Wind	189	506	778	2,158	2,376	2,625	2,823
Imports	533	718	646	1,342	1,399	1,734	925
Other	31	55	149	152	160	164	167
Total	**64,010**	**66,674**	**67,299**	**79,988**	**89,514**	**97,679**	**106,809**
Reference Case Energy	64,010	66,674	67,299	79,988	89,514	97,679	106,809

Electric Energy Price Forecast

Table 11 - Electric Energy Price and Seed Data (Reference Case)

Reference Case

	GJ/MWH						
Market Heat Rates	**2003**	**2004**	**2005**	**2010**	**2015**	**2020**	**2025**
Reference Case Heat Rate	9,943	9,575	9,513	12,476	13,057	14,425	11,794
Reference Case Heat Rate	9,943	9,575	9,513	12,476	13,057	14,425	11,794

Stochastic Seeds	$/MWh						
Reference Case Energy Price	$ 62.98	$ 58.41	$ 50.42	$ 61.13	$ 69.20	$ 83.22	$ 73.30
Reference Case Energy Price	**$ 62.98**	**$ 58.41**	**$ 50.42**	**$ 61.13**	**$ 69.20**	**$ 83.22**	**$ 73.30**
Seed 1	*$ 62.98*	*$ 67.73*	*$ 67.73*	*$ 57.90*	*$ 72.01*	*$ 91.81*	*$ 66.48*
Seed 2	*$ 62.98*	*$ 57.68*	*$ 49.15*	*$ 63.74*	*$ 65.60*	*$ 87.91*	*$ 74.44*
Seed 3	*$ 62.98*	*$ 57.55*	*$ 49.40*	*$ 61.95*	*$ 63.59*	*$ 84.66*	*$ 70.43*
Seed 4	*$ 62.98*	*$ 58.72*	*$ 48.11*	*$ 61.72*	*$ 72.14*	*$ 82.39*	*$ 76.84*
Seed 5	*$ 62.98*	*$ 57.79*	*$ 49.13*	*$ 61.76*	*$ 73.31*	*$ 80.34*	*$ 65.53*
Seed 6	*$ 62.98*	*$ 56.85*	*$ 46.77*	*$ 60.74*	*$ 66.95*	*$ 82.02*	*$ 86.86*
Seed 7	*$ 62.98*	*$ 55.92*	*$ 51.20*	*$ 58.66*	*$ 70.13*	*$ 76.33*	*$ 76.91*
Seed 8	*$ 62.98*	*$ 57.98*	*$ 46.64*	*$ 63.68*	*$ 65.94*	*$ 85.30*	*$ 68.70*
Seed 9	*$ 62.98*	*$ 56.65*	*$ 47.69*	*$ 59.63*	*$ 72.78*	*$ 74.08*	*$ 73.09*
Seed 10	*$ 62.98*	*$ 57.22*	*$ 48.38*	*$ 61.57*	*$ 69.56*	*$ 87.37*	*$ 73.69*
Max	*$ 62.98*	*$ 67.73*	*$ 67.73*	*$ 63.74*	*$ 73.31*	*$ 91.81*	*$ 86.86*
Min	*$ 62.98*	*$ 55.92*	*$ 46.64*	*$ 57.90*	*$ 63.59*	*$ 74.08*	*$ 65.53*

Emissions Forecasts

Table 12 - Emission Volumes and Indices (Reference Case)

Reference Case

	2003	2004	2005	2010	2015	2020	2025
Mercury	**Annual Mercury Emissions (kg/year) and Annual Mercury Index (mg/MWh)**						
Mercury Volume	711	720	709	343	305	193	203
Mercury Intensity	11	11	11	4	3	2	2
Reference Case Volume	711	720	709	343	305	192	198
Reference Case Index	11	11	11	4	3	2	2
SOx	**Annual SOx Emissions (tonnes/year) and Annual SOx Index (kg/MWh)**						
SOx Volume	113,687	114,703	112,234	112,395	104,465	84,185	61,277
SOx Intensity	1.8	1.7	1.7	1.4	1.2	0.9	0.6
Reference Case Volume	113,687	114,703	112,234	112,395	104,465	83,984	59,922
Reference Case Index	1.8	1.7	1.7	1.4	1.2	0.9	0.6
NOx	**Annual NOx Emissions (tonnes/year) and Annual NOx Index (kg/MWh)**						
Coal	73,756	74,857	73,891	75,910	69,727	56,365	42,297
Natural Gas	16,964	15,834	15,649	18,345	15,650	20,292	21,245
Other	22	38	105	106	112	115	117
NOx Volume	**90,741**	**90,729**	**89,644**	**94,361**	**85,489**	**76,772**	**63,659**
NOx Intensity	1.4	1.4	1.3	1.2	1.0	0.8	0.6
Reference Case Volume	90,766	90,761	89,669	94,431	85,569	76,879	62,862
Reference Case Index	1.4	1.4	1.3	1.2	1.0	0.8	0.6
PM	**Annual PM Emissions (tonnes/year) and Annual PM Index (kg/MWh)**						
PM Volume	6,741	6,702	6,749	4,545	4,347	3,219	3,296
PM Intensity	0.11	0.10	0.10	0.06	0.05	0.03	0.03
Reference Case Volume	6,741	6,702	6,749	4,545	4,347	3,203	3,235
Reference Case Index	0.11	0.10	0.10	0.06	0.05	0.03	0.03
GHG	**Annual GHG Emissions (tonnes/year) and Annual GHG Index (tonnes/MWh)**						
Coal	45,519,337	44,151,033	44,971,265	46,104,862	43,874,468	35,359,512	36,316,531
Natural Gas	7,539,757	7,588,414	7,672,403	11,092,625	14,897,275	20,167,913	23,441,052
GHG Volume	**53,059,094**	**51,739,446**	**52,643,668**	**57,197,487**	**58,771,744**	**55,527,425**	**59,757,583**
	0.83	0.78	0.78	0.72	0.66	0.57	0.56
Reference Case Volume	53,059,094	51,739,446	52,643,668	57,197,487	58,771,744	55,527,425	59,757,583
Reference Case Index	0.83	0.78	0.78	0.72	0.66	0.57	0.56

Table 13 - Emission Volumes by Fuel Type (Reference Case)

Reference Case

Mercury (HG)

	Annual Mercury Emissions by Fuel Type (kg/year)						
	2003	2004	2005	2010	2015	2020	2025
Coal	711	720	709	343	305	193	203
Natural Gas	-	-	-	-	-	-	-
Hydro	-	-	-	-	-	-	-
Wind	-	-	-	-	-	-	-
Imports	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-
Total	711	720	709	343	305	193	203

GHG

	Annual GHG Emissions by Fuel Type (tonnes/year)						
Coal	45,519,337	44,151,033	44,971,265	46,104,862	43,874,468	35,359,512	36,316,531
Natural Gas	7,539,757	7,588,414	7,672,403	11,092,625	14,897,275	20,167,913	23,441,052
Hydro	-	-	-	-	-	-	-
Wind	-	-	-	-	-	-	-
Imports	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-
Total	53,059,094	51,739,446	52,643,668	57,197,487	58,771,744	55,527,425	59,757,583

SOx

	Annual SOx Emissions by Fuel Type (tonnes/year)						
Coal	113,687	114,703	112,234	112,395	104,465	84,185	61,277
Natural Gas	-	-	-	-	-	-	-
Hydro	-	-	-	-	-	-	-
Wind	-	-	-	-	-	-	-
Imports	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-
Total	113,687	114,703	112,234	112,395	104,465	84,185	61,277

NOx

	Annual NOx Emissions by Fuel Type (tonnes/year)						
Coal	73,756	74,857	73,891	75,910	69,727	56,365	42,297
Natural Gas	16,964	15,834	15,649	18,345	15,650	20,292	21,245
Hydro	-	-	-	-	-	-	-
Wind	-	-	-	-	-	-	-
Imports	25	32	24	69	81	105	53
Other	22	38	105	106	112	115	117
Total	90,766	90,761	89,669	94,431	85,569	76,877	63,712

PM

	Annual PM Emissions by Fuel Type (tonnes/year)						
Coal	6,741	6,702	6,749	4,545	4,347	3,219	3,296
Natural Gas	-	-	-	-	-	-	-
Hydro	-	-	-	-	-	-	-
Wind	-	-	-	-	-	-	-
Imports	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-
Total	6,741	6,702	6,749	4,545	4,347	3,219	3,296

Vintage One GHG Policy Data Tables

Energy Production Forecast

Table 14 - Energy Production by Fuel Type (Vintage One Sensitivity)

Vintage One GHG Policy

Energy by Type

	Annual Energy (GWh)						
	2003	**2004**	**2005**	**2010**	**2015**	**2020**	**2025**
Coal	42,563	42,901	42,912	44,378	42,874	34,840	35,168
Natural Gas	19,440	20,870	21,167	30,171	40,940	56,643	65,767
Hydro	1,253	1,625	1,646	1,787	1,766	1,900	1,863
Wind	189	506	778	2,158	2,376	2,568	2,784
Imports	533	718	646	1,342	1,399	1,565	1,067
Other	31	55	149	152	160	165	159
Total	**64,010**	**66,674**	**67,299**	**79,988**	**89,514**	**97,679**	**106,809**
Base Case Energy	64,010	66,674	67,299	79,988	89,514	97,679	106,809

Electric Energy Price Forecast

Table 15 - Electric Energy Price and Seed Data Type (Vintage One Sensitivity)

Vintage One GHG Policy

Market Heat Rates	GJ/MWH						
	2003	**2004**	**2005**	**2010**	**2015**	**2020**	**2025**
Reference Case Heat Rate	9,943	9,575	9,513	12,476	13,057	14,425	11,794
Vintage One GHG Policy Heat Rate	9,943	9,568	9,156	12,624	13,062	14,716	12,473

Stochastic Seeds	$/MWh						
Reference Case Energy Price	$ 62.98	$ 58.41	$ 50.42	$ 61.13	$ 69.20	$ 83.22	$ 73.30
Vintage One GHG Policy Energy Price	**$ 62.98**	**$ 58.37**	**$ 48.53**	**$ 61.86**	**$ 69.23**	**$ 84.90**	**$ 77.52**
Seed 1	*$ 62.98*	*$ 68.99*	*$ 47.78*	*$ 56.22*	*$ 65.80*	*$ 79.09*	*$ 78.83*
Seed 2	*$ 62.98*	*$ 59.12*	*$ 47.47*	*$ 56.02*	*$ 70.85*	*$ 83.18*	*$ 78.09*
Seed 3	*$ 62.98*	*$ 57.90*	*$ 47.61*	*$ 65.26*	*$ 70.65*	*$ 90.16*	*$ 78.55*
Seed 4	*$ 62.98*	*$ 56.85*	*$ 49.54*	*$ 60.79*	*$ 68.48*	*$ 89.63*	*$ 77.13*
Seed 5	*$ 62.98*	*$ 56.77*	*$ 48.08*	*$ 65.75*	*$ 72.57*	*$ 86.25*	*$ 74.13*
Seed 6	*$ 62.98*	*$ 55.51*	*$ 48.87*	*$ 60.53*	*$ 72.15*	*$ 81.14*	*$ 75.30*
Seed 7	*$ 62.98*	*$ 57.81*	*$ 48.68*	*$ 57.32*	*$ 68.71*	*$ 86.08*	*$ 76.26*
Seed 8	*$ 62.98*	*$ 57.46*	*$ 48.49*	*$ 62.74*	*$ 66.71*	*$ 83.02*	*$ 80.08*
Seed 9	*$ 62.98*	*$ 55.92*	*$ 50.04*	*$ 67.94*	*$ 68.13*	*$ 82.21*	*$ 79.56*
Seed 10	*$ 62.98*	*$ 57.33*	*$ 48.73*	*$ 66.02*	*$ 68.23*	*$ 88.23*	*$ 77.27*
Max	*$ 62.98*	*$ 68.99*	*$ 50.04*	*$ 67.94*	*$ 72.57*	*$ 90.16*	*$ 80.08*
Min	*$ 62.98*	*$ 55.51*	*$ 47.47*	*$ 56.02*	*$ 65.80*	*$ 79.09*	*$ 74.13*

Emissions Forecasts

Table 16 - Emission Volumes and Indices Type (Vintage One Sensitivity)

Vintage One GHG Policy

Mercury	Annual Mercury Emissions (kg/year) and Annual Mercury Index (mg/MWh)						
	2003	**2004**	**2005**	**2010**	**2015**	**2020**	**2025**
Mercury Volume	711	720	709	343	305	192	198
Mercury Intensity	11	11	11	4	3	2	2
Reference Case Volume	711	720	709	343	305	192	198
Reference Case Index	11	11	11	4	3	2	2
SOx	**Annual SOx Emissions (tonnes/year) and Annual SOx Index (kg/MWh)**						
SOx Volume	113,687	114,703	112,234	112,395	104,465	83,984	59,922
SOx Intensity	1.8	1.7	1.7	1.4	1.2	0.9	0.6
Reference Case Volume	113,687	114,703	112,234	112,395	104,465	83,984	59,922
Reference Case Index	1.8	1.7	1.7	1.4	1.2	0.9	0.6
NOx	**Annual NOx Emissions (tonnes/year) and Annual NOx Index (kg/MWh)**						
Coal	73,756	74,857	73,891	75,910	69,727	56,231	41,301
Natural Gas	16,964	15,834	15,649	18,345	15,650	20,437	21,389
Other	47	71	129	175	193	211	173
NOx Volume	**90,766**	**90,761**	**89,669**	**94,431**	**85,569**	**76,879**	**62,862**
NOx Intensity	1.4	1.4	1.3	1.2	1.0	0.8	0.6
Reference Case Volume	90,766	90,761	89,669	94,431	85,569	76,879	62,862
Reference Case Index	1.4	1.4	1.3	1.2	1.0	0.8	0.6
PM	**Annual PM Emissions (tonnes/year) and Annual PM Index (kg/MWh)**						
PM Volume	6,741	6,702	6,749	4,545	4,347	3,203	3,235
PM Intensity	0.11	0.10	0.10	0.06	0.05	0.03	0.03
Reference Case Volume	6,741	6,702	6,749	4,545	4,347	3,203	3,235
Reference Case Index	0.11	0.10	0.10	0.06	0.05	0.03	0.03
GHG	**Annual GHG Emissions (tonnes/year) and Annual GHG Index (tonnes/MWh)**						
Coal	45,519,337	44,151,033	44,971,265	44,709,353	41,426,444	33,380,002	22,836,571
Natural Gas	7,539,757	7,588,414	7,672,403	10,913,537	14,726,735	20,331,065	23,635,116
GHG Volume	**53,059,094**	**51,739,446**	**52,643,668**	**55,622,890**	**56,153,179**	**53,711,067**	**46,471,687**
	0.83	0.78	0.78	0.70	0.63	0.55	0.44
Reference Case Volume	53,059,094	51,739,446	52,643,668	57,197,487	58,771,744	55,527,425	59,757,583
Reference Case Index	0.83	0.78	0.78	0.72	0.66	0.57	0.56

Table 17 - Emission Volumes by Fuel Type (Vintage One Sensitivity)

Vintage One GHG Policy

Mercury (HG)

Annual Mercury Emissions by Fuel Type (kg/year)	2003	2004	2005	2010	2015	2020	2025
Coal	711	720	709	343	305	192	198
Natural Gas	-	-	-	-	-	-	-
Hydro	-	-	-	-	-	-	-
Wind	-	-	-	-	-	-	-
Imports	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-
Total	711	720	709	343	305	192	198

GHG

Annual GHG Emissions by Fuel Type (tonnes/year)	2003	2004	2005	2010	2015	2020	2025
Coal	45,519,337	44,151,033	44,971,265	44,709,353	41,426,444	33,380,002	22,836,571
Natural Gas	7,539,757	7,588,414	7,672,403	10,913,537	14,726,735	20,331,065	23,635,116
Hydro	-	-	-	-	-	-	-
Wind	-	-	-	-	-	-	-
Imports	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-
Total	53,059,094	51,739,446	52,643,668	55,622,890	56,153,179	53,711,067	46,471,687

SOx

Annual SOx Emissions by Fuel Type (tonnes/year)	2003	2004	2005	2010	2015	2020	2025
Coal	113,687	114,703	112,234	112,395	104,465	83,984	59,922
Natural Gas	-	-	-	-	-	-	-
Hydro	-	-	-	-	-	-	-
Wind	-	-	-	-	-	-	-
Imports	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-
Total	113,687	114,703	112,234	112,395	104,465	83,984	59,922

NOx

Annual NOx Emissions by Fuel Type (tonnes/year)	2003	2004	2005	2010	2015	2020	2025
Coal	73,756	74,857	73,891	75,910	69,727	56,231	41,301
Natural Gas	16,964	15,834	15,649	18,345	15,650	20,437	21,389
Hydro	-	-	-	-	-	-	-
Wind	-	-	-	-	-	-	-
Imports	25	32	24	69	81	95	62
Other	22	38	105	106	112	116	111
Total	90,766	90,761	89,669	94,431	85,569	76,879	62,862

PM

Annual PM Emissions by Fuel Type (tonnes/year)	2003	2004	2005	2010	2015	2020	2025
Coal	6,741	6,702	6,749	4,545	4,347	3,203	3,235
Natural Gas	-	-	-	-	-	-	-
Hydro	-	-	-	-	-	-	-
Wind	-	-	-	-	-	-	-
Imports	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-
Total	6,741	6,702	6,749	4,545	4,347	3,203	3,235

Vintage Two GHG Policy Data Tables

Energy Production Forecast

Table 18 - Energy Production by Fuel Type (Vintage Two Sensitivity)

Vintage Two GHG Policy

Energy by Type

Energy by Type	Annual Energy (GWh)						
	2003	**2004**	**2005**	**2010**	**2015**	**2020**	**2025**
Coal	42,563	42,679	42,680	44,261	43,018	34,928	35,404
Natural Gas	19,440	20,999	21,306	30,180	40,795	56,368	65,719
Hydro	1,253	1,659	1,647	1,815	1,791	1,981	1,812
Wind	189	509	767	2,125	2,339	2,589	2,793
Imports	533	774	748	1,454	1,410	1,649	917
Other	31	54	151	153	161	165	164
Total	**64,010**	**66,674**	**67,299**	**79,988**	**89,514**	**97,679**	**106,809**
Base Case Energy	64,010	66,674	67,299	79,988	89,514	97,679	106,809

Electric Energy Price Forecast

Table 19 - Electric Energy Price and Seed Data (Vintage Two Sensitivity)

Vintage Two GHG Policy

Market Heat Rates

GJ/MWH	2003	2004	2005	2010	2015	2020	2025
Reference Case Heat Rate	9,943	9,575	9,513	12,476	13,057	14,425	11,794
Vintage Two GHG Policy Heat Rate	9,943	9,467	9,271	12,752	13,272	14,742	12,448

Stochastic Seeds

$/MWh	2003	2004	2005	2010	2015	2020	2025
Reference Case Energy Price	$ 62.98	$ 58.41	$ 50.42	$ 61.13	$ 69.20	$ 83.22	$ 73.30
Vintage Two GHG Policy Energy Price	**$ 62.98**	**$ 57.75**	**$ 49.14**	**$ 62.48**	**$ 70.34**	**$ 85.05**	**$ 77.36**
Seed 1	*$ 62.98*	*$ 67.06*	*$ 49.27*	*$ 64.11*	*$ 78.03*	*$ 85.30*	*$ 83.84*
Seed 2	*$ 62.98*	*$ 55.38*	*$ 47.01*	*$ 62.63*	*$ 67.22*	*$ 87.40*	*$ 78.48*
Seed 3	*$ 62.98*	*$ 56.51*	*$ 49.09*	*$ 61.50*	*$ 69.81*	*$ 84.42*	*$ 80.11*
Seed 4	*$ 62.98*	*$ 55.78*	*$ 49.44*	*$ 57.47*	*$ 65.46*	*$ 90.90*	*$ 72.57*
Seed 5	*$ 62.98*	*$ 56.18*	*$ 49.61*	*$ 58.61*	*$ 69.30*	*$ 84.09*	*$ 75.44*
Seed 6	*$ 62.98*	*$ 57.34*	*$ 48.64*	*$ 58.31*	*$ 72.03*	*$ 80.55*	*$ 73.75*
Seed 7	*$ 62.98*	*$ 57.74*	*$ 49.15*	*$ 64.13*	*$ 68.59*	*$ 88.62*	*$ 79.80*
Seed 8	*$ 62.98*	*$ 57.69*	*$ 48.84*	*$ 72.30*	*$ 75.12*	*$ 84.62*	*$ 76.96*
Seed 9	*$ 62.98*	*$ 56.75*	*$ 50.15*	*$ 59.96*	*$ 66.27*	*$ 80.10*	*$ 77.72*
Seed 10	*$ 62.98*	*$ 57.06*	*$ 50.17*	*$ 65.82*	*$ 71.57*	*$ 84.48*	*$ 74.97*
Max	*$ 62.98*	*$ 67.06*	*$ 50.17*	*$ 72.30*	*$ 78.03*	*$ 90.90*	*$ 83.84*
Min	*$ 62.98*	*$ 55.38*	*$ 47.01*	*$ 57.47*	*$ 65.46*	*$ 80.10*	*$ 72.57*

Emissions Forecasts

Table 20 - Emission Volumes and Indices (Vintage Two Sensitivity)

Vintage Two GHG Policy

Mercury	Annual Mercury Emissions (kg/year) and Annual Mercury Index (mg/MWh)						
	2003	**2004**	**2005**	**2010**	**2015**	**2020**	**2025**
Mercury Volume	711	718	706	341	308	193	200
Mercury Intensity	11	11	10	4	3	2	2
Reference Case Volume	711	720	709	343	305	192	198
Reference Case Index	11	11	11	4	3	2	2
SOx	**Annual SOx Emissions (tonnes/year) and Annual SOx Index (kg/MWh)**						
SOx Volume	113,687	114,198	111,556	112,254	105,012	84,216	60,319
SOx Intensity	1.8	1.7	1.7	1.4	1.2	0.9	0.6
Reference Case Volume	113,687	114,703	112,234	112,395	104,465	83,984	59,922
Reference Case Index	1.8	1.7	1.7	1.4	1.2	0.9	0.6
NOx	**Annual NOx Emissions (tonnes/year) and Annual NOx Index (kg/MWh)**						
Coal	73,756	74,513	73,485	75,735	70,066	56,160	41,613
Natural Gas	16,964	15,872	15,807	18,330	15,601	20,364	21,375
Other	47	71	136	180	194	219	165
NOx Volume	**90,766**	**90,455**	**89,428**	**94,246**	**85,861**	**76,743**	**63,154**
NOx Intensity	1.4	1.4	1.3	1.2	1.0	0.8	0.6
Reference Case Volume	90,766	90,761	89,669	94,431	85,569	76,879	62,862
Reference Case Index	1.4	1.4	1.3	1.2	1.0	0.8	0.6
PM	**Annual PM Emissions (tonnes/year) and Annual PM Index (kg/MWh)**						
PM Volume	6,741	6,657	6,674	4,543	4,367	3,213	3,257
PM Intensity	0.11	0.10	0.10	0.06	0.05	0.03	0.03
Reference Case Volume	6,741	6,702	6,749	4,545	4,347	3,203	3,235
Reference Case Index	0.11	0.10	0.10	0.06	0.05	0.03	0.03
GHG	**Annual GHG Emissions (tonnes/year) and Annual GHG Index (tonnes/MWh)**						
Coal	45,519,337	43,926,916	44,717,349	42,434,647	39,637,985	31,850,714	22,369,998
Natural Gas	7,539,757	7,677,573	7,751,724	10,781,952	14,530,014	20,077,017	23,462,165
GHG Volume	**53,059,094**	**51,604,489**	**52,469,073**	**53,216,599**	**54,167,999**	**51,927,731**	**45,832,162**
	0.83	0.77	0.78	0.67	0.61	0.53	0.43
Reference Case Volume	53,059,094	51,739,446	52,643,668	57,197,487	58,771,744	55,527,425	59,757,583
Reference Case Index	0.83	0.78	0.78	0.72	0.66	0.57	0.56

Table 21 - Emission Volumes by Fuel Type (Vintage Two Sensitivity)

Vintage Two GHG Policy

Mercury (HG) — Annual Mercury Emissions by Fuel Type (kg/year)

	2003	2004	2005	2010	2015	2020	2025
Coal	711	718	706	341	308	193	200
Natural Gas	-	-	-	-	-	-	-
Hydro	-	-	-	-	-	-	-
Wind	-	-	-	-	-	-	-
Imports	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-
Total	711	718	706	341	308	193	200

GHG — Annual GHG Emissions by Fuel Type (tonnes/year)

	2003	2004	2005	2010	2015	2020	2025
Coal	45,519,337	43,926,916	44,717,349	42,434,647	39,637,985	31,850,714	22,369,998
Natural Gas	7,539,757	7,677,573	7,751,724	10,781,952	14,530,014	20,077,017	23,462,165
Hydro	-	-	-	-	-	-	-
Wind	-	-	-	-	-	-	-
Imports	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-
Total	53,059,094	51,604,489	52,469,073	53,216,599	54,167,999	51,927,731	45,832,162

SOx — Annual SOx Emissions by Fuel Type (tonnes/year)

	2003	2004	2005	2010	2015	2020	2025
Coal	113,687	114,198	111,556	112,254	105,012	84,216	60,319
Natural Gas	-	-	-	-	-	-	-
Hydro	-	-	-	-	-	-	-
Wind	-	-	-	-	-	-	-
Imports	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-
Total	113,687	114,198	111,556	112,254	105,012	84,216	60,319

NOx — Annual NOx Emissions by Fuel Type (tonnes/year)

	2003	2004	2005	2010	2015	2020	2025
Coal	73,756	74,513	73,485	75,735	70,066	56,160	41,613
Natural Gas	16,964	15,872	15,807	18,330	15,601	20,364	21,375
Hydro	-	-	-	-	-	-	-
Wind	-	-	-	-	-	-	-
Imports	25	33	30	73	81	104	50
Other	22	38	106	107	113	115	115
Total	90,766	90,455	89,428	94,246	85,861	76,743	63,154

PM — Annual PM Emissions by Fuel Type (tonnes/year)

	2003	2004	2005	2010	2015	2020	2025
Coal	6,741	6,657	6,674	4,543	4,367	3,213	3,257
Natural Gas	-	-	-	-	-	-	-
Hydro	-	-	-	-	-	-	-
Wind	-	-	-	-	-	-	-
Imports	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-
Total	6,741	6,657	6,674	4,543	4,367	3,213	3,257

Vintage Three GHG Policy Data Tables

Energy Production Forecast

Table 22 - Energy Production by Fuel Type (Vintage Three Sensitivity)

Vintage Three GHG Policy

Energy by Type	Annual Energy (GWh)						
	2003	**2004**	**2005**	**2010**	**2015**	**2020**	**2025**
Coal	42,563	42,670	42,889	44,401	42,907	35,244	35,348
Natural Gas	19,440	21,066	21,086	30,037	40,995	56,257	65,813
Hydro	1,253	1,651	1,639	1,831	1,771	1,918	1,801
Wind	189	504	806	2,124	2,345	2,584	2,887
Imports	533	726	734	1,440	1,334	1,514	792
Other	31	56	145	155	162	162	167
Total	**64,010**	**66,674**	**67,299**	**79,988**	**89,514**	**97,679**	**106,809**
Base Case Energy	64,010	66,674	67,299	79,988	89,514	97,679	106,809

Electric Energy Price Forecast

Table 23 - Electric Energy Price and Seed Data (Vintage Three Sensitivity)

Vintage Three GHG Policy

Market Heat Rates	GJ/MWH						
	2003	**2004**	**2005**	**2010**	**2015**	**2020**	**2025**
Reference Case Heat Rate	9,943	9,575	9,513	12,476	13,057	14,425	11,794
Vintage Three GHG Policy Heat Rate	9,943	9,621	9,152	12,868	13,285	14,819	12,521

Stochastic Seeds	$/MWh						
Reference Case Energy Price	$ 62.98	$ 58.41	$ 50.42	$ 61.13	$ 69.20	$ 83.22	$ 73.30
Vintage Three GHG Policy Energy Price	**$ 62.98**	**$ 58.69**	**$ 48.50**	**$ 63.05**	**$ 70.41**	**$ 85.49**	**$ 77.82**
Seed 1	*$ 62.98*	*$ 69.42*	*$ 48.93*	*$ 65.98*	*$ 69.14*	*$ 88.64*	*$ 71.24*
Seed 2	*$ 62.98*	*$ 58.53*	*$ 49.17*	*$ 64.15*	*$ 70.93*	*$ 81.77*	*$ 78.07*
Seed 3	*$ 62.98*	*$ 58.60*	*$ 49.03*	*$ 59.84*	*$ 67.55*	*$ 90.68*	*$ 76.09*
Seed 4	*$ 62.98*	*$ 58.30*	*$ 49.31*	*$ 59.96*	*$ 70.33*	*$ 82.89*	*$ 78.69*
Seed 5	*$ 62.98*	*$ 59.22*	*$ 48.02*	*$ 59.82*	*$ 71.64*	*$ 86.10*	*$ 85.74*
Seed 6	*$ 62.98*	*$ 57.56*	*$ 48.54*	*$ 60.22*	*$ 71.13*	*$ 83.77*	*$ 79.40*
Seed 7	*$ 62.98*	*$ 56.18*	*$ 49.32*	*$ 63.41*	*$ 72.49*	*$ 79.76*	*$ 74.83*
Seed 8	*$ 62.98*	*$ 57.34*	*$ 47.08*	*$ 66.51*	*$ 72.10*	*$ 92.72*	*$ 79.21*
Seed 9	*$ 62.98*	*$ 56.62*	*$ 47.43*	*$ 62.34*	*$ 71.14*	*$ 80.07*	*$ 80.20*
Seed 10	*$ 62.98*	*$ 55.15*	*$ 48.20*	*$ 68.30*	*$ 67.64*	*$ 88.52*	*$ 74.70*
Max	*$ 62.98*	*$ 69.42*	*$ 49.32*	*$ 68.30*	*$ 72.49*	*$ 92.72*	*$ 85.74*
Min	*$ 62.98*	*$ 55.15*	*$ 47.08*	*$ 59.82*	*$ 67.55*	*$ 79.76*	*$ 71.24*

Emissions Forecasts

Table 24 - Emission Volumes and Indices (Vintage Three Sensitivity)

Vintage Three GHG Policy

Mercury	**Annual Mercury Emissions (kg/year) and Annual Mercury Index (mg/MWh)**						
	2003	**2004**	**2005**	**2010**	**2015**	**2020**	**2025**
Mercury Volume	711	717	710	343	306	195	199
Mercury Intensity	11	11	11	4	3	2	2
Reference Case Volume	711	720	709	343	305	192	198
Reference Case Index	11	11	11	4	3	2	2
SOx	**Annual SOx Emissions (tonnes/year) and Annual SOx Index (kg/MWh)**						
SOx Volume	113,687	114,356	112,477	112,169	104,863	84,631	60,426
SOx Intensity	1.8	1.7	1.7	1.4	1.2	0.9	0.6
Reference Case Volume	113,687	114,703	112,234	112,395	104,465	83,984	59,922
Reference Case Index	1.8	1.7	1.7	1.4	1.2	0.9	0.6
NOx	**Annual NOx Emissions (tonnes/year) and Annual NOx Index (kg/MWh)**						
Coal	73,756	74,427	73,989	75,937	69,891	56,723	41,466
Natural Gas	16,964	15,906	15,621	18,248	15,679	20,317	21,391
Other	47	67	129	189	191	208	158
NOx Volume	**90,766**	**90,400**	**89,739**	**94,373**	**85,761**	**77,248**	**63,014**
NOx Intensity	1.4	1.4	1.3	1.2	1.0	0.8	0.6
Reference Case Volume	90,766	90,761	89,669	94,431	85,569	76,879	62,862
Reference Case Index	1.4	1.4	1.3	1.2	1.0	0.8	0.6
PM	**Annual PM Emissions (tonnes/year) and Annual PM Index (kg/MWh)**						
PM Volume	6,741	6,636	6,744	4,541	4,356	3,242	3,256
PM Intensity	0.11	0.10	0.10	0.06	0.05	0.03	0.03
Reference Case Volume	6,741	6,702	6,749	4,545	4,347	3,203	3,235
Reference Case Index	0.11	0.10	0.10	0.06	0.05	0.03	0.03
GHG	**Annual GHG Emissions (tonnes/year) and Annual GHG Index (tonnes/MWh)**						
Coal	45,519,337	43,913,981	44,979,128	38,246,202	35,697,228	29,075,767	21,102,714
Natural Gas	7,539,757	7,649,866	7,630,993	10,594,097	14,449,251	19,890,699	23,345,036
GHG Volume	**53,059,094**	**51,563,848**	**52,610,122**	**48,840,299**	**50,146,479**	**48,966,465**	**44,447,750**
	0.83	0.77	0.78	0.61	0.56	0.50	0.42
Reference Case Volume	53,059,094	51,739,446	52,643,668	57,197,487	58,771,744	55,527,425	59,757,583
Reference Case Index	0.83	0.78	0.78	0.72	0.66	0.57	0.56

Table 25 - Emission's Volumes by Fuel Type (Vintage Three Sensitivity)

Vintage Three GHG Policy

Mercury (HG)	Annual Mercury Emissions by Fuel Type (kg/year)						
	2003	2004	2005	2010	2015	2020	2025
Coal	711	717	710	343	306	195	199
Natural Gas	-	-	-	-	-	-	-
Hydro	-	-	-	-	-	-	-
Wind	-	-	-	-	-	-	-
Imports	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-
Total	711	717	710	343	306	195	199

GHG	Annual GHG Emissions by Fuel Type (tonnes/year)						
Coal	45,519,337	43,913,981	44,979,128	38,246,202	35,697,228	29,075,767	21,102,714
Natural Gas	7,539,757	7,649,866	7,630,993	10,594,097	14,449,251	19,890,699	23,345,036
Hydro	-	-	-	-	-	-	-
Wind	-	-	-	-	-	-	-
Imports	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-
Total	53,059,094	51,563,848	52,610,122	48,840,299	50,146,479	48,966,465	44,447,750

SOx	Annual SOx Emissions by Fuel Type (tonnes/year)						
Coal	113,687	114,356	112,477	112,169	104,863	84,631	60,426
Natural Gas	-	-	-	-	-	-	-
Hydro	-	-	-	-	-	-	-
Wind	-	-	-	-	-	-	-
Imports	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-
Total	113,687	114,356	112,477	112,169	104,863	84,631	60,426

NOx	Annual NOx Emissions by Fuel Type (tonnes/year)						
Coal	73,756	74,427	73,989	75,937	69,891	56,723	41,466
Natural Gas	16,964	15,906	15,621	18,248	15,679	20,317	21,391
Hydro	-	-	-	-	-	-	-
Wind	-	-	-	-	-	-	-
Imports	25	28	27	80	77	95	41
Other	22	40	102	108	114	113	117
Total	90,766	90,400	89,739	94,373	85,761	77,248	63,014

PM	Annual PM Emissions by Fuel Type (tonnes/year)						
Coal	6,741	6,636	6,744	4,541	4,356	3,242	3,256
Natural Gas	-	-	-	-	-	-	-
Hydro	-	-	-	-	-	-	-
Wind	-	-	-	-	-	-	-
Imports	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-
Total	6,741	6,636	6,744	4,541	4,356	3,242	3,256

Coal Generation With No GHG Policy Data Tables

Energy Production Forecast

Table 26 - Energy Production by Fuel Type (Coal Generation with no GHG Policy Sensitivity)

Coal Scenario - No GHG Policy

Energy by Type	Annual Energy (GWh)						
	2003	**2004**	**2005**	**2010**	**2015**	**2020**	**2025**
Coal	42,563	42,338	42,833	44,237	45,585	50,427	61,776
Natural Gas	19,440	21,236	21,248	30,213	37,937	40,993	39,406
Hydro	1,253	1,653	1,618	1,810	1,905	1,923	1,799
Wind	189	517	810	2,183	2,424	2,473	2,899
Imports	533	877	645	1,395	1,499	1,699	767
Other	31	53	145	150	164	163	162
Total	**64,010**	**66,674**	**67,299**	**79,988**	**89,514**	**97,679**	**106,809**
Base Case Energy	64,010	66,674	67,299	79,988	89,514	97,679	106,809

Table 27 - Electric Energy Price and Seed Data (Coal Generation with no GHG Policy Sensitivity)

Coal Scenario - No GHG Policy

Market Heat Rates

	GJ/MWH						
	2003	2004	2005	2010	2015	2020	2025
Reference Case Heat Rate	9,943	9,575	9,513	12,476	13,057	14,425	11,794
Coal Scenario - No GHG Policy Heat Rate	9,943	9,685	9,064	12,550	13,073	14,282	10,528

Stochastic Seeds

	$/MWh						
Reference Case Energy Price	$ 62.98	$ 58.41	$ 50.42	$ 61.13	$ 69.20	$ 83.22	$ 73.30
Coal Scenario - No GHG Policy Energy Price	**$ 62.98**	**$ 59.08**	**$ 48.04**	**$ 61.50**	**$ 69.29**	**$ 82.40**	**$ 65.43**
Seed 1	*$ 62.98*	*$ 67.73*	*$ 48.37*	*$ 55.75*	*$ 67.90*	*$ 74.18*	*$ 62.36*
Seed 2	*$ 62.98*	*$ 57.68*	*$ 46.48*	*$ 65.28*	*$ 71.01*	*$ 79.98*	*$ 62.43*
Seed 3	*$ 62.98*	*$ 58.30*	*$ 47.69*	*$ 70.01*	*$ 66.87*	*$ 88.00*	*$ 64.77*
Seed 4	*$ 62.98*	*$ 57.96*	*$ 47.90*	*$ 58.08*	*$ 75.47*	*$ 85.64*	*$ 62.27*
Seed 5	*$ 62.98*	*$ 57.37*	*$ 47.56*	*$ 69.20*	*$ 70.36*	*$ 85.11*	*$ 65.10*
Seed 6	*$ 62.98*	*$ 59.16*	*$ 47.48*	*$ 59.05*	*$ 65.93*	*$ 83.91*	*$ 68.10*
Seed 7	*$ 62.98*	*$ 59.42*	*$ 48.73*	*$ 63.83*	*$ 66.45*	*$ 86.14*	*$ 74.39*
Seed 8	*$ 62.98*	*$ 57.05*	*$ 50.01*	*$ 58.95*	*$ 63.72*	*$ 82.18*	*$ 64.97*
Seed 9	*$ 62.98*	*$ 57.84*	*$ 48.16*	*$ 54.25*	*$ 72.41*	*$ 78.38*	*$ 67.80*
Seed 10	*$ 62.98*	*$ 58.31*	*$ 48.04*	*$ 60.57*	*$ 72.75*	*$ 80.46*	*$ 62.11*
Max	*$ 62.98*	*$ 67.73*	*$ 50.01*	*$ 70.01*	*$ 75.47*	*$ 88.00*	*$ 74.39*
Min	*$ 62.98*	*$ 57.05*	*$ 46.48*	*$ 54.25*	*$ 63.72*	*$ 74.18*	*$ 62.11*

Emissions Forecasts

Table 28 - Emission Volumes and Indices (Coal Generation with no GHG Policy Sensitivity)

Coal Scenario - No GHG Policy

Mercury	**Annual Mercury Emissions (kg/year) and Annual Mercury Index (mg/MWh)**						
	2003	**2004**	**2005**	**2010**	**2015**	**2020**	**2025**
Mercury Volume	711	713	708	341	326	272	314
Mercury Intensity	11	11	11	4	4	3	3
Reference Case Volume	711	720	709	343	305	192	198
Reference Case Index	11	11	11	4	3	2	2
SOx	**Annual SOx Emissions (tonnes/year) and Annual SOx Index (kg/MWh)**						
SOx Volume	113,687	113,251	112,359	111,803	106,173	96,256	81,686
SOx Intensity	1.8	1.7	1.7	1.4	1.2	1.0	0.8
Reference Case Volume	113,687	114,703	112,234	112,395	104,465	83,984	59,922
Reference Case Index	1.8	1.7	1.7	1.4	1.2	0.9	0.6
NOx	**Annual NOx Emissions (tonnes/year) and Annual NOx Index (kg/MWh)**						
Coal	73,756	73,897	73,821	75,658	71,328	66,987	59,971
Natural Gas	16,964	16,117	15,692	18,285	14,729	15,717	13,545
Other	47	75	125	183	200	218	151
NOx Volume	**90,766**	**90,089**	**89,638**	**94,126**	**86,257**	**82,922**	**73,668**
NOx Intensity	1.4	1.4	1.3	1.2	1.0	0.8	0.7
Reference Case Volume	90,766	90,761	89,669	94,431	85,569	76,879	62,862
Reference Case Index	1.4	1.4	1.3	1.2	1.0	0.8	0.6
PM	**Annual PM Emissions (tonnes/year) and Annual PM Index (kg/MWh)**						
PM Volume	6,741	6,552	6,729	4,532	4,609	4,684	5,765
PM Intensity	0.11	0.10	0.10	0.06	0.05	0.05	0.05
Reference Case Volume	6,741	6,702	6,749	4,545	4,347	3,203	3,235
Reference Case Index	0.11	0.10	0.10	0.06	0.05	0.03	0.03
GHG	**Annual GHG Emissions (tonnes/year) and Annual GHG Index (tonnes/MWh)**						
Coal	45,519,337	43,539,307	44,898,453	45,919,127	46,195,483	49,990,190	61,607,391
Natural Gas	7,539,757	7,740,827	7,743,928	10,878,090	13,463,414	14,435,999	13,827,515
GHG Volume	**53,059,094**	**51,280,134**	**52,642,382**	**56,797,218**	**59,658,897**	**64,426,188**	**75,434,906**
	0.83	0.77	0.78	0.71	0.67	0.66	0.71
Reference Case Volume	53,059,094	51,739,446	52,643,668	57,197,487	58,771,744	55,527,425	59,757,583
Reference Case Index	0.83	0.78	0.78	0.72	0.66	0.57	0.56

Table 29 - Emission Volumes by Fuel Type (Coal Generation with no GHG Policy Sensitivity)

Coal Scenario - No GHG Policy

Mercury (HG)	Annual Mercury Emissions by Fuel Type (kg/year)						
	2003	2004	2005	2010	2015	2020	2025
Coal	711	713	708	341	326	272	314
Natural Gas	-	-	-	-	-	-	-
Hydro	-	-	-	-	-	-	-
Wind	-	-	-	-	-	-	-
Imports	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-
Total	711	713	708	341	326	272	314

GHG	Annual GHG Emissions by Fuel Type (tonnes/year)						
Coal	45,519,337	43,539,307	44,898,453	45,919,127	46,195,483	49,990,190	61,607,391
Natural Gas	7,539,757	7,740,827	7,743,928	10,878,090	13,463,414	14,435,999	13,827,515
Hydro	-	-	-	-	-	-	-
Wind	-	-	-	-	-	-	-
Imports	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-
Total	53,059,094	51,280,134	52,642,382	56,797,218	59,658,897	64,426,188	75,434,906

SOx	Annual SOx Emissions by Fuel Type (tonnes/year)						
Coal	113,687	113,251	112,359	111,803	106,173	96,256	81,686
Natural Gas	-	-	-	-	-	-	-
Hydro	-	-	-	-	-	-	-
Wind	-	-	-	-	-	-	-
Imports	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-
Total	113,687	113,251	112,359	111,803	106,173	96,256	81,686

NOx	Annual NOx Emissions by Fuel Type (tonnes/year)						
Coal	73,756	73,897	73,821	75,658	71,328	66,987	59,971
Natural Gas	16,964	16,117	15,692	18,285	14,729	15,717	13,545
Hydro	-	-	-	-	-	-	-
Wind	-	-	-	-	-	-	-
Imports	25	38	23	78	85	104	37
Other	22	37	102	105	115	114	113
Total	90,766	90,089	89,638	94,126	86,257	82,922	73,668

PM	Annual PM Emissions by Fuel Type (tonnes/year)						
Coal	6,741	6,552	6,729	4,532	4,609	4,684	5,765
Natural Gas	-	-	-	-	-	-	-
Hydro	-	-	-	-	-	-	-
Wind	-	-	-	-	-	-	-
Imports	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-
Total	6,741	6,552	6,729	4,532	4,609	4,684	5,765

Coal Generation with Vintage Three GHG Policy Data Tables

Energy Production Forecast

Table 30 - Energy Production by Fuel Type (Coal Generation with Vintage Three Sensitivity)

Coal Scenario - Vintage Three GHG Policy

Energy by Type	Annual Energy (GWh)						
	2003	**2004**	**2005**	**2010**	**2015**	**2020**	**2025**
Coal	42,563	42,246	42,715	44,224	45,914	50,370	61,460
Natural Gas	19,440	21,252	21,265	30,333	37,926	41,075	39,843
Hydro	1,253	1,660	1,625	1,799	1,880	1,928	1,807
Wind	189	514	781	2,090	2,331	2,522	2,787
Imports	533	948	771	1,389	1,296	1,620	754
Other	31	53	143	153	167	164	158
Total	**64,010**	**66,674**	**67,299**	**79,988**	**89,514**	**97,679**	**106,809**
Base Case Energy	64,010	66,674	67,299	79,988	89,514	97,679	106,809

Electric Energy Price Forecast

Table 31 - Electric Energy Price and Seed Data (Coal Generation with Vintage Three Sensitivity)

Coal Scenario - Vintage Three GHG Policy

	GJ/MWH						
Market Heat Rates	**2003**	**2004**	**2005**	**2010**	**2015**	**2020**	**2025**
Reference Case Heat Rate	9,943	9,575	9,513	12,476	13,057	14,425	11,794
Coal Scenario - Vintage Three GHG Policy Heat Rate	9,943	9,844	9,397	12,328	13,110	14,546	10,753

Stochastic Seeds	$/MWh						
Reference Case Energy Price	$ 62.98	$ 58.41	$ 50.42	$ 61.13	$ 69.20	$ 83.22	$ 73.30
Coal Scenario - Vintage Three GHG Policy Energy Price	**$ 62.98**	**$ 60.05**	**$ 49.80**	**$ 60.41**	**$ 69.48**	**$ 83.92**	**$ 66.83**
Seed 1	*$ 62.98*	*$ 69.02*	*$ 47.80*	*$ 62.99*	*$ 63.93*	*$ 78.08*	*$ 67.60*
Seed 2	*$ 62.98*	*$ 58.18*	*$ 48.60*	*$ 63.88*	*$ 71.84*	*$ 82.64*	*$ 67.51*
Seed 3	*$ 62.98*	*$ 60.00*	*$ 49.84*	*$ 63.11*	*$ 73.06*	*$ 91.60*	*$ 66.69*
Seed 4	*$ 62.98*	*$ 58.85*	*$ 49.29*	*$ 58.15*	*$ 73.89*	*$ 87.64*	*$ 74.13*
Seed 5	*$ 62.98*	*$ 57.04*	*$ 49.16*	*$ 55.84*	*$ 64.32*	*$ 84.93*	*$ 60.17*
Seed 6	*$ 62.98*	*$ 56.63*	*$ 54.96*	*$ 63.04*	*$ 68.28*	*$ 82.76*	*$ 63.09*
Seed 7	*$ 62.98*	*$ 59.58*	*$ 50.12*	*$ 59.09*	*$ 70.66*	*$ 81.21*	*$ 66.31*
Seed 8	*$ 62.98*	*$ 65.00*	*$ 47.80*	*$ 51.99*	*$ 62.93*	*$ 77.08*	*$ 66.60*
Seed 9	*$ 62.98*	*$ 57.18*	*$ 49.60*	*$ 63.88*	*$ 72.84*	*$ 81.64*	*$ 68.51*
Seed 10	*$ 62.98*	*$ 59.00*	*$ 50.84*	*$ 62.11*	*$ 73.06*	*$ 91.60*	*$ 67.69*
Max	*$ 62.98*	*$ 69.02*	*$ 54.96*	*$ 63.88*	*$ 73.89*	*$ 91.60*	*$ 74.13*
Min	*$ 62.98*	*$ 56.63*	*$ 47.80*	*$ 51.99*	*$ 62.93*	*$ 77.08*	*$ 60.17*

Emissions Forecasts

Table 32 - Emission Volumes and Indices (Coal Generation with Vintage Three Sensitivity)

Coal Scenario - Vintage Three GHG Policy

	2003	2004	2005	2010	2015	2020	2025
Mercury	**Annual Mercury Emissions (kg/year) and Annual Mercury Index (mg/MWh)**						
Mercury Volume	711	711	705	342	328	271	312
Mercury Intensity	11	11	10	4	4	3	3
Reference Case Volume	711	720	709	343	305	192	198
Reference Case Index	11	11	11	4	3	2	2
SOx	**Annual SOx Emissions (tonnes/year) and Annual SOx Index (kg/MWh)**						
SOx Volume	113,687	112,700	111,188	112,066	107,093	96,553	81,280
SOx Intensity	1.8	1.7	1.7	1.4	1.2	1.0	0.8
Reference Case Volume	113,687	114,703	112,234	112,395	104,465	83,984	59,922
Reference Case Index	1.8	1.7	1.7	1.4	1.2	0.9	0.6
NOx	**Annual NOx Emissions (tonnes/year) and Annual NOx Index (kg/MWh)**						
Coal	73,756	73,778	73,471	75,606	72,069	67,012	59,565
Natural Gas	16,964	16,160	15,746	18,325	14,783	15,795	13,660
Other	47	77	138	184	192	208	149
NOx Volume	**90,766**	**90,015**	**89,355**	**94,116**	**87,044**	**83,015**	**73,374**
NOx Intensity	1.4	1.4	1.3	1.2	1.0	0.8	0.7
Reference Case Volume	90,766	90,761	89,669	94,431	85,569	76,879	62,862
Reference Case Index	1.4	1.4	1.3	1.2	1.0	0.8	0.6
PM	**Annual PM Emissions (tonnes/year) and Annual PM Index (kg/MWh)**						
PM Volume	6,741	6,560	6,697	4,530	4,647	4,686	5,740
PM Intensity	0.11	0.10	0.10	0.06	0.05	0.05	0.05
Reference Case Volume	6,741	6,702	6,749	4,545	4,347	3,203	3,235
Reference Case Index	0.11	0.10	0.10	0.06	0.05	0.03	0.03
GHG	**Annual GHG Emissions (tonnes/year) and Annual GHG Index (tonnes/MWh)**						
Coal	45,519,337	43,454,686	44,746,629	38,125,205	36,927,904	35,272,668	31,925,889
Natural Gas	7,539,757	7,750,720	7,743,869	10,763,625	13,291,311	14,292,870	13,837,149
GHG Volume	**53,059,094**	**51,205,406**	**52,490,498**	**48,888,830**	**50,219,215**	**49,565,539**	**45,763,039**
	0.83	0.77	0.78	0.61	0.56	0.51	0.43
Reference Case Volume	53,059,094	51,739,446	52,643,668	57,197,487	58,771,744	55,527,425	59,757,583
Reference Case Index	0.83	0.78	0.78	0.72	0.66	0.57	0.56

Table 33 - Emission Volumes by Fuel Type (Coal Generation with Vintage Three Sensitivity)

Coal Scenario - Vintage Three GHG Policy

Mercury (HG)	Annual Mercury Emissions by Fuel Type (kg/year)						
	2003	2004	2005	2010	2015	2020	2025
Coal	711	711	705	342	328	271	312
Natural Gas	-	-	-	-	-	-	-
Hydro	-	-	-	-	-	-	-
Wind	-	-	-	-	-	-	-
Imports	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-
Total	711	711	705	342	328	271	312

GHG	Annual GHG Emissions by Fuel Type (tonnes/year)						
Coal	45,519,337	43,454,686	44,746,629	38,125,205	36,927,904	35,272,668	31,925,889
Natural Gas	7,539,757	7,750,720	7,743,869	10,763,625	13,291,311	14,292,870	13,837,149
Hydro	-	-	-	-	-	-	-
Wind	-	-	-	-	-	-	-
Imports	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-
Total	53,059,094	51,205,406	52,490,498	48,888,830	50,219,215	49,565,539	45,763,039

SOx	Annual SOx Emissions by Fuel Type (tonnes/year)						
Coal	113,687	112,700	111,188	112,066	107,093	96,553	81,280
Natural Gas	-	-	-	-	-	-	-
Hydro	-	-	-	-	-	-	-
Wind	-	-	-	-	-	-	-
Imports	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-
Total	113,687	112,700	111,188	112,066	107,093	96,553	81,280

NOx	Annual NOx Emissions by Fuel Type (tonnes/year)						
Coal	73,756	73,778	73,471	75,606	72,069	67,012	59,565
Natural Gas	16,964	16,160	15,746	18,325	14,783	15,795	13,660
Hydro	-	-	-	-	-	-	-
Wind	-	-	-	-	-	-	-
Imports	25	40	37	77	75	93	38
Other	22	37	100	107	117	115	111
Total	90,766	90,015	89,355	94,116	87,044	83,015	73,374

PM	Annual PM Emissions by Fuel Type (tonnes/year)						
Coal	6,741	6,560	6,697	4,530	4,647	4,686	5,740
Natural Gas	-	-	-	-	-	-	-
Hydro	-	-	-	-	-	-	-
Wind	-	-	-	-	-	-	-
Imports	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-
Total	6,741	6,560	6,697	4,530	4,647	4,686	5,740