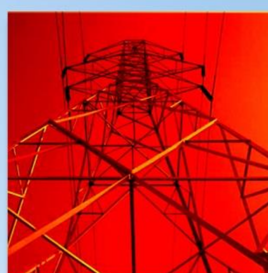
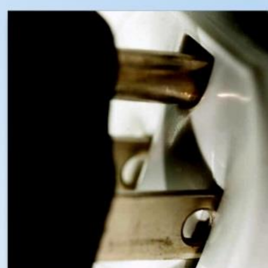
Electricity Framework
5 Year Review

—Generation & Emissions Forecasts —



Report prepared for:

Clean Air Strategic Alliance (CASA)



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Report Issued:
October 29, 2014

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Table of Contents

List of Tables

List of Figures

Background Scope of Work

Background

Incorporated in 1992, EDC Associates Ltd. (EDCA) is an independent energy-consulting firm based in Calgary, Alberta, Canada that provides consulting services with respect to electric energy pricing, generation economic development, energy procurement, regulatory and legal issues, and electric industry training (see Appendix 4).

On April 15, 2014, the Clean Air Strategic Alliance (CASA; the "Client") engaged EDC Associates Ltd. (EDCA) to quantify the progress of electricity industry emissions reduction for 4 pollutants, Mercury (Hg), Particulate Matter (PM), Sulphur Dioxides (SOx) and Nitrogen Oxides (NOx). CASA is currently reviewing elements of the Emissions Management Framework for the Alberta Electricity Sector (Alberta Framework) developed by the Electricity Project Team in 2003 and 2009. This is the second Five-Year Review and is in accordance with Recommendation 29 from the Alberta Framework.

The Electricity Framework Review Project Team has directed a working group to:

- Develop a base case for the emissions profile expected under the Alberta Framework
- Update the emission forecast undertaken in 2003 and 2009

Scope

This report is the second phase of the two phase project.

The report for Phase 1, dated April 8, 2014, provided the CASA task group with a detailed comparison of the assumptions used to carry out the previous 2003 and 2009 forecasts, versus those used in EDCA's Q4-2013 Quarterly Forecast Update. The Q4-2013 Update served as the basis for the Phase I report, but the more current Q3-2014 was used for the final 2014 forecast. Because the 2 reports were cast about 9 months apart, there are some differences in forecast assumptions (e.g., different natural gas and demand forecasts). However, the main drivers impacting the CASA-specific emissions forecasts (coal-fired retirement dates and combined-cycle being the forecast source of base-load power) remain the same, so the findings in the first phase report are still valid.

This report, Phase 2, entailed producing an emissions forecast from 2014 to 2030, and a comparison to the 2003 and 2009 forecasts.

Report Layout

The report is presented in three sections. The first discusses EDCA's modeling methodology and the underlying assumptions (e.g., design life, capital costs, etc.) that impact the emissions forecast. The second section recaps the changing forward view of electricity demand and generation fleet make-up from the changing perspective of the successive 5 year review dates. The final section compares the 2014 forecast of emissions and emission intensities to the two previous forecasts for each pollutant (Hg, PM, SOx, NOx), by year, from 2006 to 2030.

Throughout the report, graphs assign the green line to 2003 values, red to 2009 and blue to 2014. The 2003 and 2009 values are one-for-one as previously reported, with 2003 representing what was termed the "NS-1" Scenario, and 2009 representing the last report EDCA has on file (Generation and Emission Forecast Amended July 2009). The 2014 values represent a combination of actuals (2006-2013) and forecasts (2014-2030).

On May 21, 2014, EDCA issued an initial draft forecast for discussion with the CASA team. Following significant debate, EDCA negotiated several changes to model parameters.

Detailed data is available in a companion Excel file.

Executive Summary

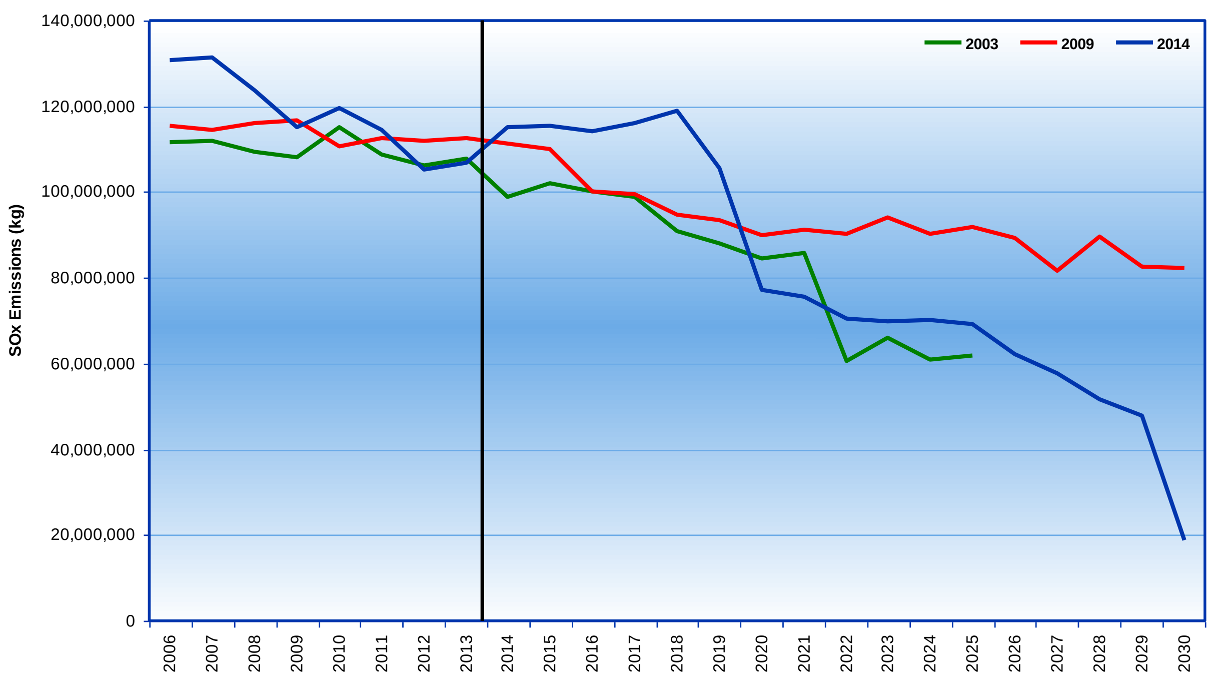
This report details the significant reductions in four pollutants across the forecast period, as well as provides comparisons to the two previous forecasts. The level of coal production is the main determinant of the emission level of all four pollutants. As these plants begin to retire per current Federal legislation (first at the end of 2019, then primarily between 2025 and 2029) emission and emission intensity forecasts drop off through natural attrition.

In the case of mercury, large drops are observed during the 2011-2013 time period when regulations required all coal-fired generation, except HR Milner, achieve a 70% reduction, then later an 80% reduction, in their mercury output.

Large drops in SOx and NOx result when certain units are forecast to be incented to install mitigation devices to lower emission intensities and earn credits for sale on the open market, as well as to ensure their continued operation once they pass their design life. The model proposes and quantifies a method to calculate the most cost-effective way to convert a small number of units, which would provide ample credits for the unconverted units. From this calculation, each unconverted unit is charged an implied cost to buy credits, which is added to its marginal costs and would be expected to raise its offer by some fraction of that amount. That may cause some changes in merit order, and therefore which units are dispatched, affecting pool price, production, emissions and ultimately the choice and amount of new generation additions.

EDCA's 2014 model forecasts that, across the study period (2014-2030), emission and emission intensities should fall between 50% and 90%, depending on the pollutant (see Figure 1 for typical reduction). The shape of the 2014 forecasts is quite different from the 2009 forecasts for two reasons. First, in the 2009 report, coal was forecast to be the primary source of future additions. The 2014 model sees combined-cycle take its place, with no future coal-fired additions in the supply stack, aside from small potential uprates towards the end of the decade. Second, emission intensity assumptions in the 2014 model are derived from actual data, whereas the 2003 and 2009 report had to rely on estimates with varying success.

Figure 1 - Sulphur Dioxide Emissions (kg)



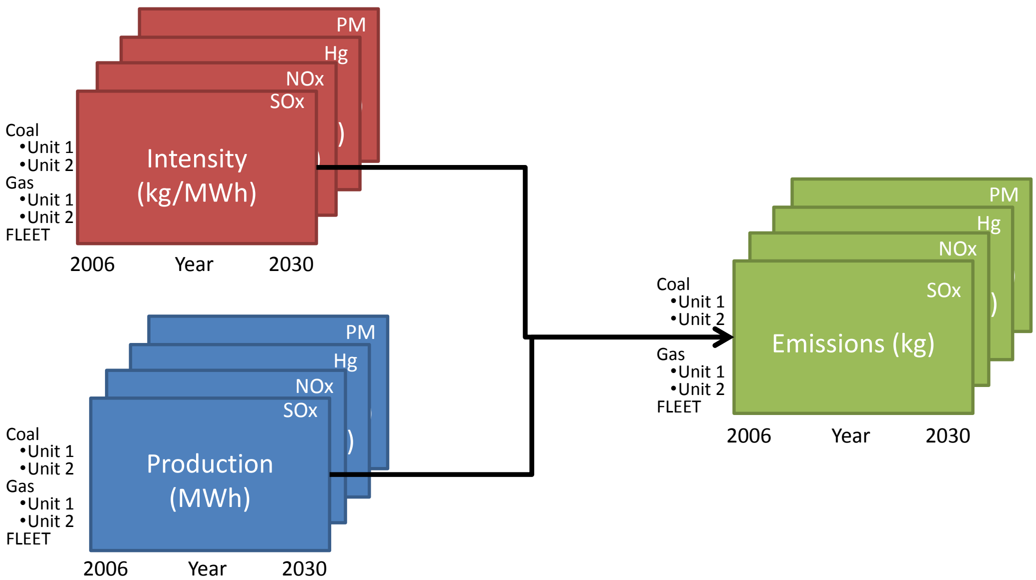
Methodology

This section outlines the methodology EDCA uses in this 2014 version of the CASA emissions study for calculating the level of emissions of each pollutant and then for determining the required amount of emission credits and the cost to purchase them.

Emissions Calculation

Computation of emissions and emission intensities follows two main streams. The first calculates the level of annual emissions by simply multiplying, at the unit level, the MWh of production in a year times that unit's unique emissions intensity (mg (or kg)/MWh). The results in terms of either emissions or emissions intensity can be summarized by unit, plant, generator type or total fleet for each of the 4 pollutants.

Figure 2 - Simple Emissions Calculation



Production by Unit

This all presumes that the production by unit is known. However, in the real world, the production by unit is determined by the hourly interaction of demand against the supply stack. Each unit offers its generation at different prices, depending partly on its individual marginal costs in the hour. One of the costs a generator wants to recover in the hour is the emissions compliance cost it incurs when it runs.

The second computational stream provides a compliance cost estimate to be input into EDCA's proprietary Hourly Electricity Load, Production and Price ("HELP") model. This stream is much more complicated. The analysis begins by determining how many credits of each type have been earned and accumulated. This is facilitated by the excellent records in a provincial registry of credits. Only NOx and SOx earn tradable credits. NOx is measured and controlled for both coal and gas-fired units. SOx credits are only collected for coal plants, since gas plants produce minimal amounts of SOx.

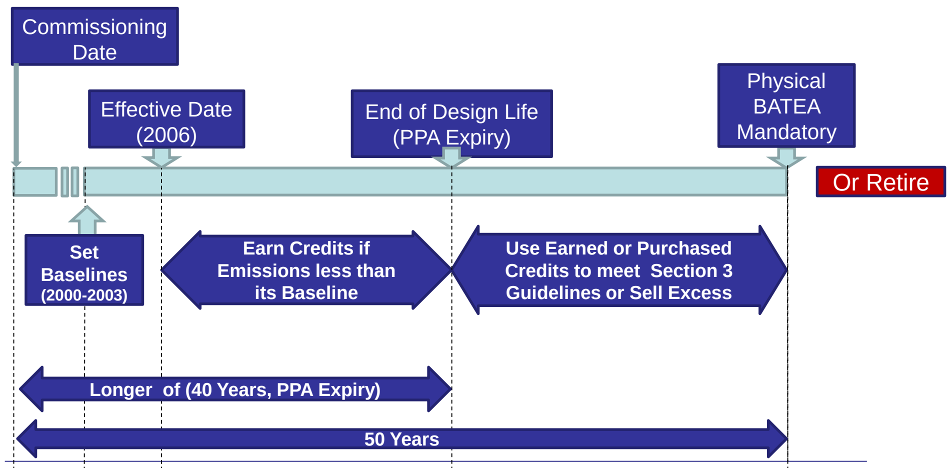
Credits have been accumulating since 2006, with only a handful used in 2013. The first units that will need to either physically meet BATEA or use earned/bought credits to make up the deficit are HR Milner and Battle River #3 and #4. Others join these units in succession as they each pass their respective design life (commissioning date plus 40 years for coal, or plus 30 years for gas-fired generators). The 2014 analysis forecasts that there are enough accumulated credits to meet the expanding need for SOx credits until about the end of 2018, and NOx credits until the mid-2020s, after which non-compliant plants will either not be able to run or will have to find an additional source of credits.

This analysis makes the presumption that some unit(s) would step up to the task of providing credits for the right price, and that the proper unit to do so should be the unit with the cheapest levelized cost at that moment. The following sections will outline how that cheapest unit is determined, but before explaining the process, a bit of background is presented.

Pre-Design Life

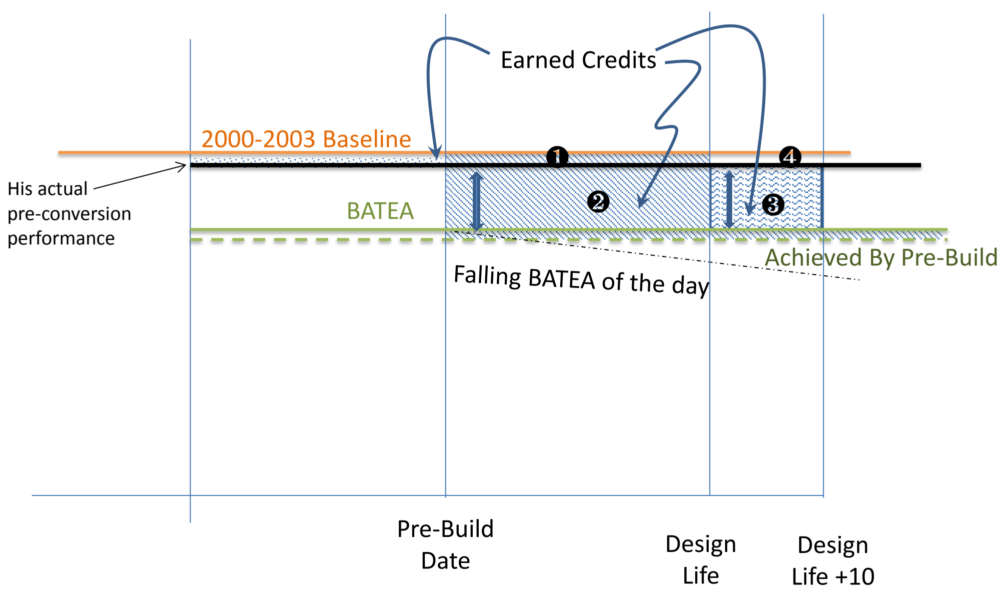
Each unit has a unique baseline intensity. Before a unit passes its own design life, if it can beat that baseline, it can earn tradable, storable credits which it can either hold for its own future use or sell to some emitter which is past its own design life but is not able to, or does not want to, fully mitigate its own emissions.

Figure 3 - CASA Coal Timelines



If a unit does not meet the baseline, there is no penalty or requirement to use previously accumulated credits in its pre-design life, but neither does it earn credits. Any credits not used within two years are subject to a one-time 10% discount (although several gas-fired units are exempt from this discounting).

Figure 4 - Generic Pre-Build Credit Calculation



A unit could possibly beat its baseline simply by improving its emissions without adding mitigation devices (area ❶, or by installing some type of mitigation device (area ❷ that partially or fully allowed it to beat its baseline.

Post-Design Life

From the time a unit passes its design life until 10 years thence, it must either physically meet its BATEA emission target or buy enough credits each year to make up the shortfall. Thousands of credits for both NOx and SOx have already been accumulated. Anyone who pre-installs a mitigation device can earn credits in its pre-design period It appears that enough credits could be earned over time to meet the needs of all units without having everyone install the devices.

Once the unit passes its "design life plus 10" threshold, it must either meet the BATEA of the day or retire. It cannot, after that point, buy its way out of compliance with credits. But at that point the credits begin to have real value since the economic penalty for not buying credits then becomes the full loss of any margin which that unit would have generated if it was permitted to run. Once it passes its post "design life plus 10" year, assuming it is not forced to retire pre-emptively by federal GHG rules, a unit would have to physically meet BATEA or retire. If it had been converted, it could continue to run, but if it was not, it would have to retire. For this exercise, it was assumed that the federal GHG legislation would likely trump the NOx /SOx constraints, so no unit would survive after its "design life +10" year mark, regardless of its NOx and SOx performance or equipment. At that point, credits would create no value for that unit in particular, although they could be sold for profit.

When faced with an investment decision as to whether or not to spend capital and operating costs on a mitigation device, the developer would consider all the likely future cash-flow changes he will see "with" versus "without" the device. If he does <u>not</u> build, to the extent that changes other that installation of an actual mitigation device by themselves lower his intensity (black line), as has been observed in some units, he will earn credits until the end of his design life, designated in area ➊. After his design life, until he is forced to, or decides to, retire, he will have to use up those credits which he accumulated in his pre-design life and/or buy additional credits from another unit with an excess as shown by area ➌

If he does pre-build a mitigation device ahead of his design life date, his unit will earn additional credits until the end of his design life because of his now hopefully lower level of intensity, as designated by area ➋ In his post-design life, a unit will still have to meet BATEA, but to the extent that his mitigation device physically achieves that, he will not have to buy any or as many credits. If the device allows him to just meet BATEA, he will require no new credits and is free to sell his prior accumulated credits at whatever the market will bear. EDCA reasons that this revenue will not be added into the unit's offer, since the generator earned the credit in another period and can sell them at any future time regardless if he runs in that hour or not. If he beats BATEA in his post design life, he will earn additional credits for reuse or resale against another unit. EDCA recommends that, by definition, the study methodology should not consider the possibility that the conversion project will be able to beat BATEA.

So a developer's decision to build or not would depend on the net change in costs and revenues of building the device or not. The costs of building (cash outflows) are the one-time front-end capital costs and the recurring operating costs. The only revenue (in-flow) changes that should be attributed to the capital investment are area ➋and ➌, since area ➊and ➍would be achievable without the capital expenditure. Those achievable amounts would be estimated by his 5-year actual emission level. Normally, but not always, his 5-year actuals would be lower than his baseline,

Allocation Amount

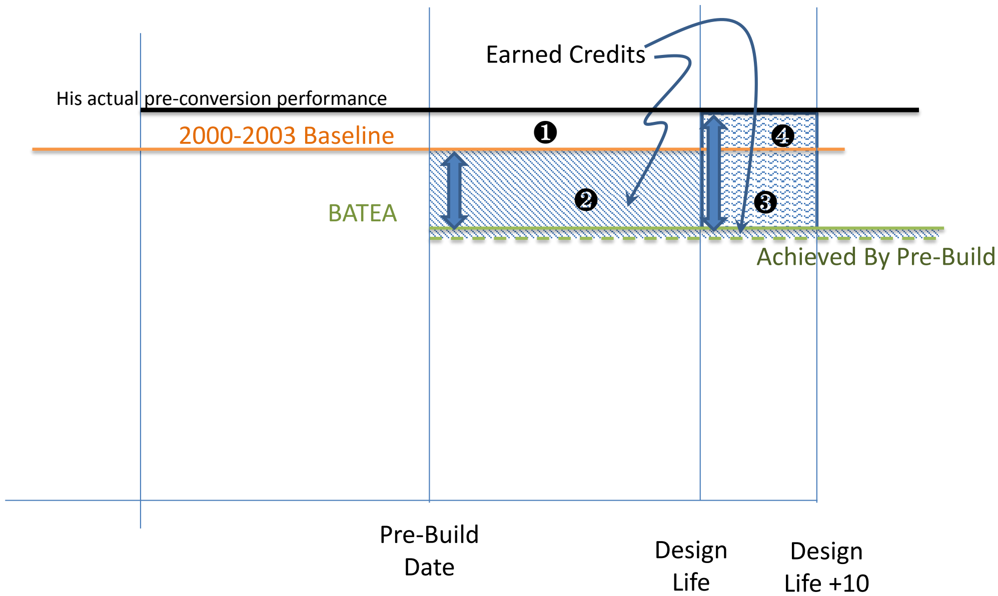
If a developer built a device early, until he exceeded his design life, he would be able to sell the earned credits in area ➋and ➌to someone in need, although the capital expenditure should only take credit for area ➋, since area ➊would have been earned even if he did not make the capital investment in the mitigation device. After his design life, the developer would be able to use the credits required in area ➌ to get down to his BATEA level instead of buying them in the market.

The annual amount of sales or avoided purchases would be the same in area ➋and area ➌. So it would be appropriate to spread the upfront costs over the entire period from the date of installation to the unit's retirement, even though the second area was an avoided cost, not actual revenue. Technically, as time advanced, the market value would likely rise, as progressively more expensive units were required to clear the market's demand for credits, and so the allocation of capital to the various years should be slightly back-weighted. EDCA chose to ignore this non-linearity in calculating the unit cost calculation.

Special Case: Pre-Conversion Intensity is Worse than Baseline

In the special circumstance where a unit's pre-conversion actual observed intensity has worsened from its baseline intensity, the calculation of the cost/t of converting a particular unit requires special treatment (see Figure 5). In that case, the earnings from the conversion will have two different amounts, depending on if we are calculating effects in a pre- or post-design life year:

Figure 5 - Pre-Build Credit Calculation when Actual Intensities Exceed Baseline



1) Pre-design life: The model would credit the conversion project only with the difference (left blue arrow) between the baseline and the post-conversion intensity (presumed to be BATEA), since in that time period, even though the pre-conversion actuals are above the baseline, it does not cost the project credits to be over baseline, albeit no additional credits are being earned (area ❺). Once converted, credits in the pre-design life period are earned by beating the baseline, not the actuals.
2) Post-design-life: The model would credit the conversion project with the difference between the 5 year average actual intensities and the post-conversion intensity (right blue arrow), which is the amount of credits that would need to be bought to meet BATEA if the conversion had not been done.

In this special case where the actuals exceed the baseline, the amount of value earned by converting (i.e. the "with" vs "without conversion" differential) is different pre- and post-design life (compare arrows). For this special case, the EDCA model takes all the annual credit earnings (in tonnes) back to a present worth. That "total PW of tonnes available across the remaining life" is divided into the capital costs to yield a "levelized cost of credits" ($/t). It is calculated in such a way that if that cost per tonne was charged to each tonne across the life, in the year it was consumed, then exactly the total capital costs (including interest on outstanding capital) would be collected by the end of the project life. In other words, that project will earn its proponent exactly his hurdle rate of return, so he would be motivated, at that price, to spend capital on that project (see sample calculation in Appendix 1.a).

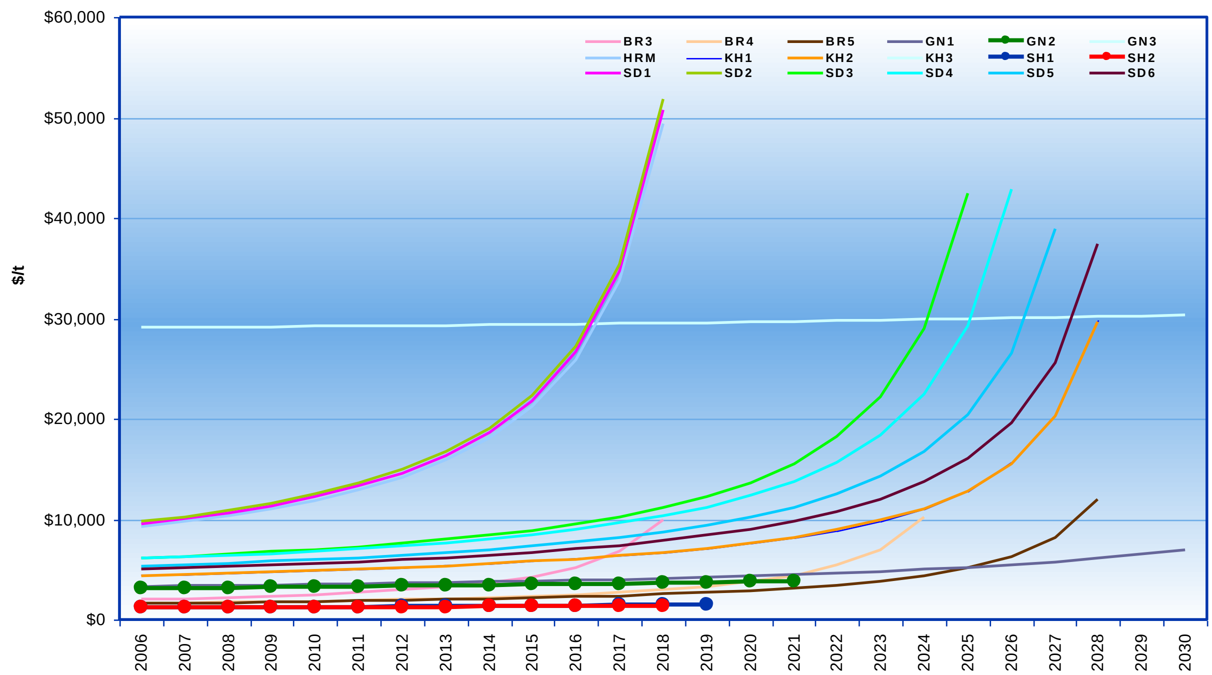
When a shortfall of credits first emerges, that calculation is done for each of the several as yet unconverted but potential conversion candidate projects for that year. Because different projects will generate more or fewer credits (one has a higher baseline than the other) for different lengths of time (i.e., one unit retires earlier than another), they will all have different levelized costs and all will have a strong upturn at the end of their life.

The conversion project with the lowest levelized cost in the year is chosen to be the next provider of credits. Those credits and all other credits already accumulated will earn at least that new levelized cost from then on until some subsequent year when additional credits are again needed to meet rising demand. From Figure 6, Sheerness #2 is clearly the cheapest, having the fortuitous combination of a high baseline and a very long service life. Sheerness #1 is very slightly higher and, as the second most suitable candidate, is chosen when the need arises a year later.

The race for third place between Battle River #5 and Genesee #2 illustrates how this process becomes more complicated when viewed out to the endgame. Rather than simply choosing the cheapest current next provider, one must anticipate how the balance of credits will build up, then collapse across the study period. If too much is collected upfront, the fund may be left with a large balance of unusable credits. Of the remaining units, post design life, Battle River #5 is forecast to consume the most credits by a wide margin. If the unit does not convert, it uses up credits quickly in the initial years. If it does convert in the early 2020s when it is marginally less expensive than Genesee #2, it drastically reduces the fleet's total need for credits such that by the end of the forecast, a significant amount of unused credits would be built up. If it were converted several years later, it would have fewer years left to spread its cost over and so would become more expensive than the Genesee units, and would also cause a shortfall in the credit balance at the tail-end of the forecast, requiring yet another unit to convert. Instead, if Genesee #2 were converted "out-of-order" in the early 2020s, because it does not yet have the lowest levelized cost, it minimizes both the number of units that would need to convert and the number of unused credits at the end of the forecast.

Genesee #3 is the long, shallow sloped line in the middle of the graph. It is long-lived, but it has been granted such a low baseline that it does not earn many credits in a year, even though it is a very low emissivity unit.

Figure 6 - Levelized Cost ($/t) of each Candidate SOx Credit Provider in Different Years



When a new, more expensive credit provider must be built, it sets the price even higher thereafter. EDCA made an additional enhancement. Since the next most expensive unit would theoretically not be built until it could charge its levelized costs, the first unit could, and EDCA assumes would, shadow price that second unit's price. So the first unit would collect additional rent above his pure cost. When the second unit was needed, it would be able to shadow price the third, and so on. As it turns out, only three units for SOx and NOx would need to be converted to earn enough credits for the total credit needs of the remaining coal fleet.

Appendix 1.b summarizes the credit and offer calculation rules.

Allocation Period

The 2003/9 Studies assumed a simple, equal allocation of the upfront capital costs to each year of a unit's remaining life, that is, dividing those capital costs by the remaining life from the date of the installation to the end of life. However, it was not applied consistently across pollutants or across studies (2003 and 2009). For the allocation period for capital in the 2014 Study, EDCA used the full time period (date of conversion until the earlier of "design life +10" or as per GHG rules. Although the developer would not put the allocated costs of the mitigation device into their offers, they would derive benefit from avoiding having to pay someone else for the credits, so their hourly margin will be higher by that avoided cost. Also, some other non-complying unit(s) will likely have to buy credits, raising the pool price when they are on the margin and therefore increasing the margin of the developing unit by something like that amount.

Table 1 - Summary of Assumed Life for allocating Capital Costs of Mitigation

Forecast	SOx	NOx
2003	From Installation to end of Design Life **plus 10**	From Installation to end of Design Life **plus 10**
2009	From Installation to end of Design Life	From Installation to end of Design Life **plus 10**
2014	From Installation to end of Design Life **plus 10**	From Installation to end of Design Life **plus 10**

Time Value of Money

In the 2003/9 studies, no allowance was made for the carrying costs (interest) on outstanding capital. In the investment world, a person will not spend upfront money unless he can recover his capital cost PLUS earn a rate of return on the money still outstanding. The interest on the outstanding money must also be recovered over the life of the asset. Assuming the yearly unit cost of a credit remained the same, it would be appropriate to calculate the amount that would have to be collected per unit of credit by amortizing the capital cost at an agreed to interest rate, over the life. EDCA used a conservative 5% internet rate in its calculations.

Capital and Operating Cost

The CASA team instructed EDCA to use the same mercury capital and operating costs as in the past reports. Regulations do not allow the trading of mercury credits and required a 70% reduction in 2011-2012, followed by an 80% reduction from 2013 onwards. Given the steep drop in Mercury emissions, it is assumed all units have been converted (except for HR Milner which is deemed a low final emitter). No costs have ever been assigned to particulate matter.

Coal-fired SOx and NOx capital costs were revised based on guidance from public reference sources provided by the CASA team[1] while operating costs were left unchanged. Gas-fired NOx costs remained the same. Table 2 summarizes this information.

Table 2 - Summary of Capital and Operating Cost Assumptions

		Capital ($/kW)			Operating		
		2003	2009	2014	2003	2009	2014
Hg		$52	$52	$52	$1.20/MWh	$1.20/MWh	$1.20/MWh
PM							
SOx		$225	$225	$635	$900/t	$900/t	$900/t
NOx	**Coal**	$125	$125	$300	$1,500/t	$1,500/t	$1,500/t
	Gas	$40	$40	$40	$2.00/MWh	$2.00/MWh	$2.00/MWh

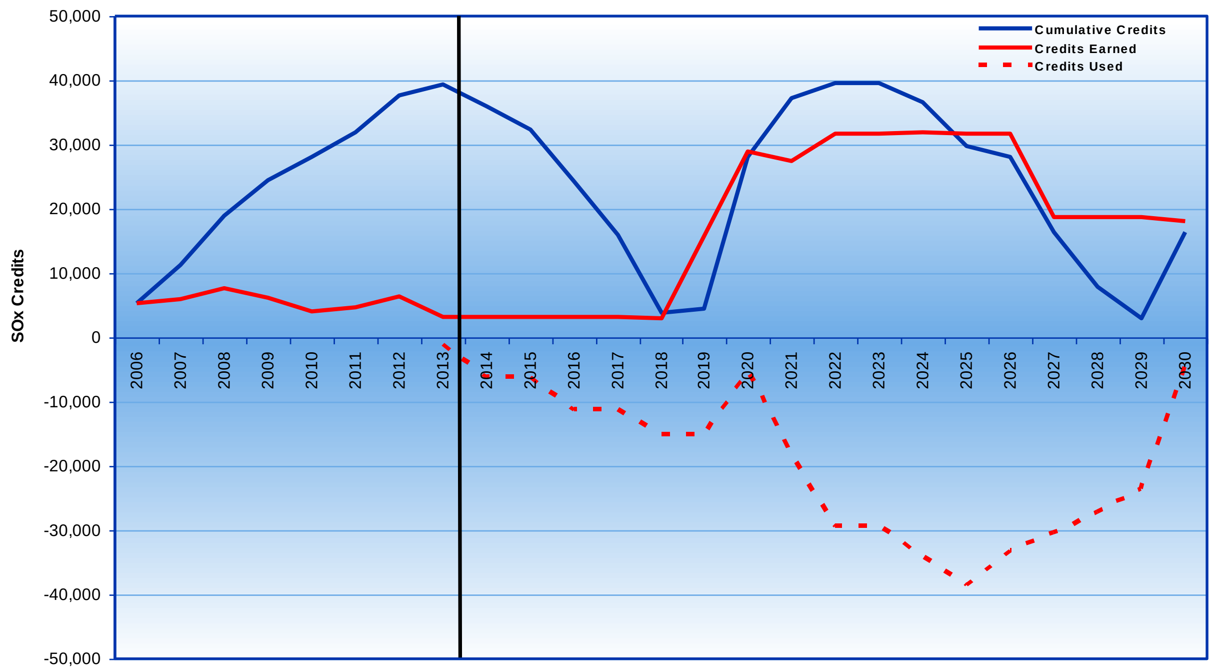
Timing of Conversions vs End-Game

The next viable developer of credits could wait until just before the need for new credits arose to build his credit producing mitigation device. The accumulated stock of credits (blue line in Figure 7) and the ongoing credits expected to be earned (solid red line), will adequately cover the need for credits (dashed orange line) for several years (about 2018 for SOx).

[1]*Current Capital Cost and Cost-Effectiveness of Power Plant Emissions Control Technologies,* prepared for the Utility Air Regulatory Group (January 2010) presented views on the costs of Dry FGD for SOx removal and SCR for NOx removal, which are consistent with the technologies considered by the CASA team. The Brattle Group's February 2014 *Coal Plant Retirements and Market Impacts* presentation contained information on the capital cost of major control equipment, including Dry FGD and SCR. These two studies were used to form a conservative estimate of capital costs.

But closer to the end of the study period, as coal units progressively retire, progressively more units will be converted, and thus create more credits in each of those later years, just as progressively fewer "credit-needy" unconverted units still remain in existence. The solid red line shows actual credits as they had already been earned in each year, or as expected to be earned in each year in the future. The dashed red negative line is a prediction of how credits will be used, starting in 2013, as HR Milner, then successive other units pass their respective design-life thresholds. The usage curve increases until about 2025, when, as various units retire pursuant to GHG rules, the amount needed in each year falls off rapidly. The blue line is the cumulative total, factoring in annual accumulation and usage.

Figure 7 - Illustrative Feasible Pattern of SOx Credit Generation and Application



The EDCA model allows credit development to significantly precede the precise scheduled yearly need for demand for credit. This way, a unit would have more years to accumulate a larger store of credits. Also, fewer units would actually have to convert. A much earlier pattern of pre-built units will therefore generate a stream of new credits that will accumulate earlier, then fall faster (as those converted units themselves retire and stop producing credits) than if a larger number of them were to convert "just-in-time" for the emerging demand. By trial and error, EDCA concocted this illustrative pattern of credit generation/application timing that would support the fleet until about 2040. Most other patterns tested either ended up with a stockpile of unused credits or a shortfall in some years.

All the credits/charges are accumulated by generator, by year. These are added to each generator's offer in different ways, depending on if the unit is buying or producing credits and if the subject year is before or after the unit's design life. If a unit is creating credits before its design life, it is assumed he will sell those credits at his first opportunity. If no one is buying yet, the price he receives will be the present worth equivalent of what he could charge in the first year he can sell credits. If a unit is buying credits, he will pay the levelized cost of the second cheapest provider of credits. If the unit has passed his design life, he will not be charged for his own credits. Appendix 3 shows the unique yearly charge or credit that each unit will put in his supply offer.

Results – Forecasts of Fundementals (2003, 2009 and 2014)

The 2014 HELP model, used to calculate dispatched production by each individual unit, was populated with the most current economic and generation assumptions from EDCA's published Q3-2014 Forecast Update, including overall load growth, existing fleet characteristics, new generation timing and size and an interpretation of how federal and provincial emission policies will affect generator costs, offers and service lives within the study period. From this point, two changes were made to the Q3 model to create a CASA specific model.

First, the Q3's CASA-related assumptions, which were derived from the initial 2014 draft report, were modified. The CASA team requested changes to several key model parameters (more stringent BATEA targets for SOx and NOx, as well as higher capital costs for conversions). EDCA incorporated these changes into its final 2014 CASA modeling, which resulted in different marginal cost adders.

Second, probabilities for units that are virtually certain to commission in the near-term (Oldman 2 Wind Farm, Shepard, Nabiye and Kearl) were raised to 100% (100% is normally reserved for when a unit actually begins sending power) in order to provide the most accurate near/mid-term generation forecast.

Energy Sales & Generation Forecasts

The emission forecasts depend on several input assumptions introduced in Phase 1, including changes in energy sales forecasts and coal and gas-fired generation forecasts. Figure 8 presents the energy sales forecasts from the 2003, 2009 and 2014 models. The 2009 model assumed very robust demand growth, driven by the optimistic view of the oil and gas sector. However, the unexpected economic downturn eroded demand to such a degree that it did not return to 2008 levels until 2011. Oil and gas prices discouraged the expansion plans of the oil patch and all downstream beneficiaries, so much so that in-migration turned negative for a year. These factors justified a much weaker demand forecast in the 2014 model.

Figure 8 - Energy Sales Forecast

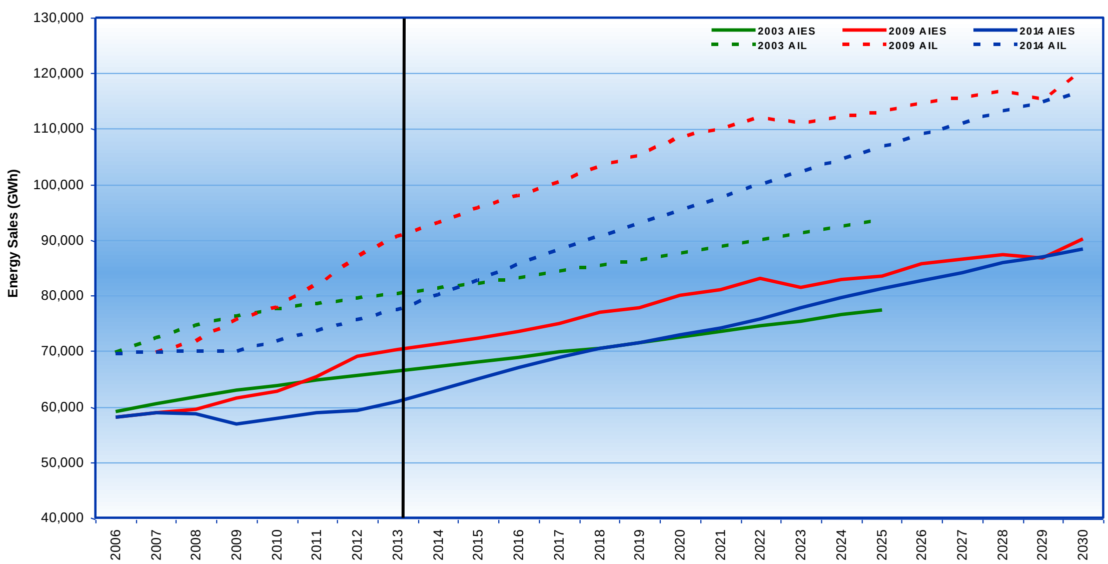


Figure 9 presents the coal-fired generation forecast from the three models. In the 2009 model, the robust demand forecast led to the need for more generation. From that time perspective, coal was forecast to be the cheapest source of base-load power to meet load-growth and retirements (as compared to the 2003 and 2014 models, which assumed it to be gas-fired generation).

In actuality, coal-fired generation tapered off drastically, exacerbated in 2011-2013 by the unexpected shutdown of Sundance #1 and #2 from December 2010 to fall 2013, and a winding failure at Keephills #1, which kept it offline throughout much of 2013.

Coal-fired generation is assumed to remain roughly flat until the end of the decade, at which point the first tranche of retirements (Battle River #3, Sundance #1, Sundance #2 and HR Milner) will cause a sharp dip in generation. Output should stabilize through the early 2020s, but eventually decline as additional units retire, starting in 2025, with a very sharp drop at the end of the forecast when 4 large units (Sundance #6, Battle River #5, Keephills #1 and Keephills #2) wind down by the end of 2029.

Unlike past forecasts, other than small potential uprates at Genesee #1 and #2 towards the end of the decade, there are no future coal-fired capacity additions in the forecast. Federal environmental policy requires any coal plant built after July 1, 2015 to meet a stringent performance standard of 0.42 t/MWh. With large market participants (TransAlta/Mid-American, Capital Power, ENMAX, TransCanada and Maxim Power) focused on combined-cycle generation, future growth in the coal fleet is likely limited to minor uprates and enhancements at existing facilities.

Figure 9 - Coal-Fired Generation Forecast

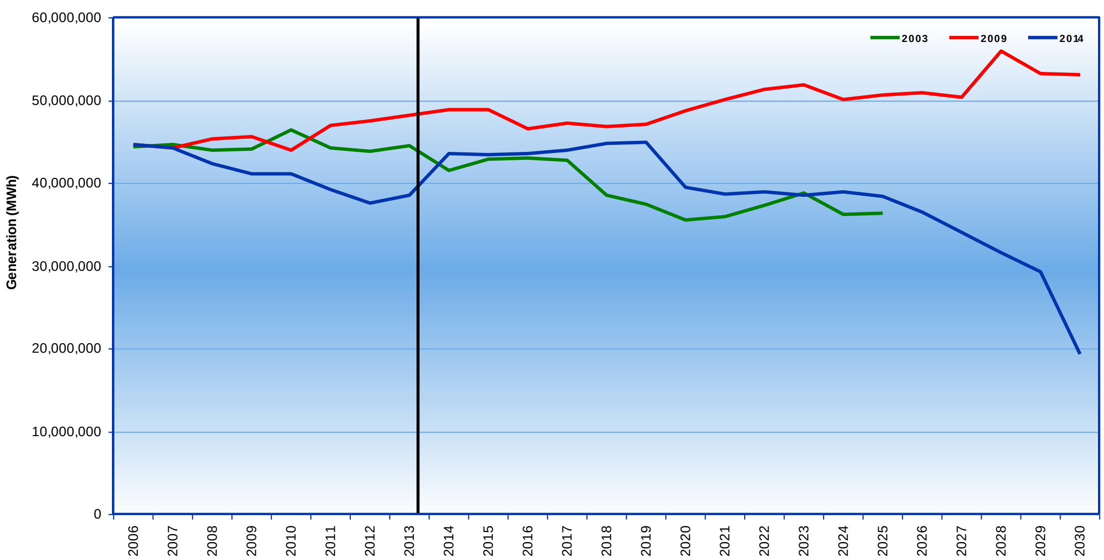
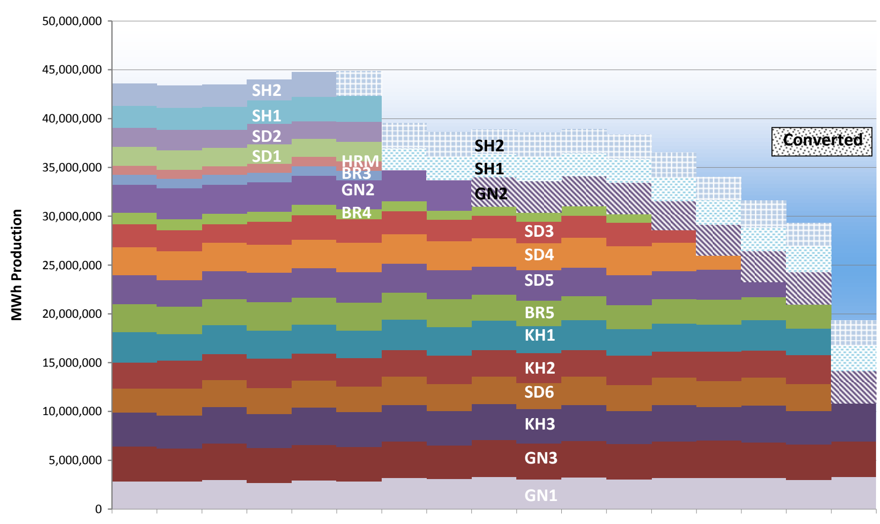


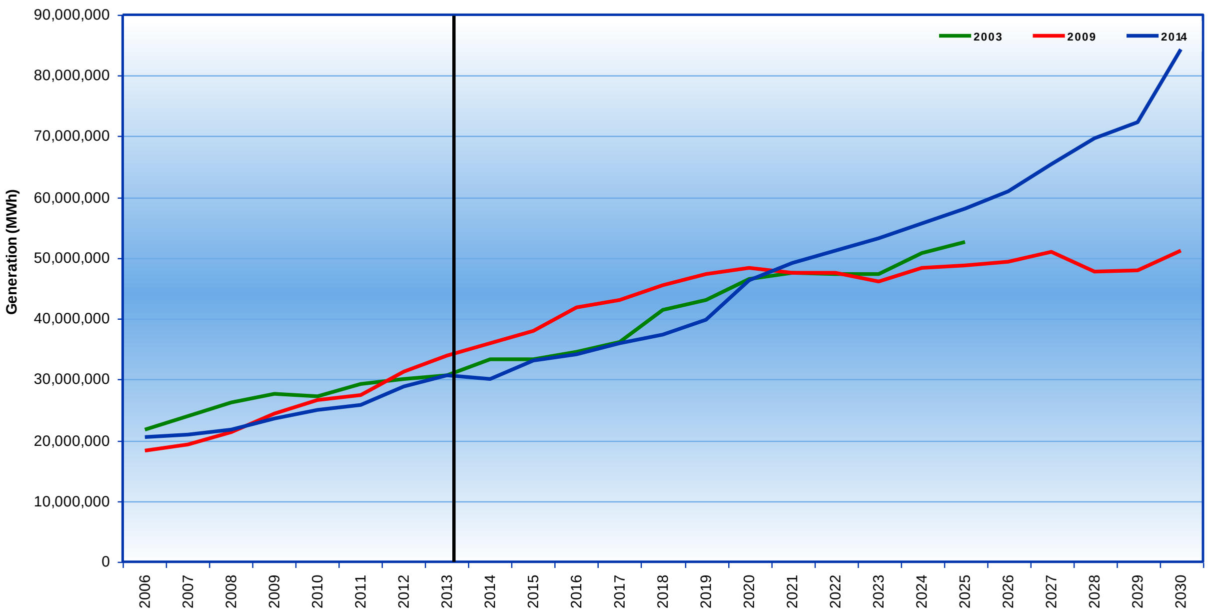
Figure 10 shows the deteriorating contribution to total production by unit (patterned area shows years in which respective units that have installed SOx control technology) from the 2014 modeling.

Figure 10 - Contribution to MWh of Production by Coal Unit



The gas-fired generation forecast (Figure 11) reflects 2009's robust domestic AIES demand forecast, which led to greater forecast near/mid-term net-to-grid sales, as well as the stronger oil sands growth expectations, which prompted greater behind-the-fence generation. By the early-2020s, however, the 2014 model crosses over the 2009 line, ending the forecast significantly above it as gas-fired generation is now forecast to be the cheapest source of base-load power, meeting coal retirements and load growth. The strong uptick towards the end of the forecast reflects greater reliance on gas generation as several large coal-fired facilities retire at the end of 2029.

Figure 11 - Gas-Fired (Behind-the-fence and Net-to-Grid) Forecast



Results - Emission Forecasts (2003, 2009 and 2014)

The following sections present forecast results for the 4 pollutants - Mercury (Hg), Particulate Matter (PM), Sulphur Dioxide (SOx) and Nitrogen Oxide (NOx) - in terms of emission and emission intensity for the 2014 Study, as well as the 2003 and 2009 Studies. The 2003 and 2009 forecasts represent the values exactly as previously reported. The 2014 line illustrates actuals from 2006 to 2013, then forecasts from 2014 to 2030. Note that in the case of mercury 2006 and 2007 data was unavailable, so it was estimated from actual generation but average 2008-2010 emission intensities. A mercury estimate was also required in 2013 due to emission data being unavailable.

Each of the sections begins with a discussion on the individual unit emission intensity assumptions, then presents the total fleet emissions and fleet emission intensity forecasts for that pollutant. Aggregate emission intensity levels are calculated by dividing the absolute emission levels by the total energy production for all generation units. The forecasts includes behind-the-fence electricity generation) which also produces NOx emissions[2]. Because cogen is predominately gas-fired and because it receives a credit for emissions associated with the thermal energy it co-produces, it has lower than fleet average emissions. Excluding it would not give a complete picture of the emissions associated with total electricity production in Alberta and would understate emission intensity.

Mercury (Hg) Emissions

Table 3 summarizes the mercury emission intensity assumptions used in the 2014 forecast.

Table 3 - Mercury Emission Intensity Assumptions (mg/MWh)

Mercury Emission Intensity (mg/MWh)										
ID		Baseline	2006	2007	2008	2009	2010	2011	2012	2013+
Battle River #3	BR3	12.90	*16.25*	*16.25*	13.68	15.49	19.56	9.47	7.23	*5.57*
Battle River #4	BR4	12.90	*16.12*	*16.12*	13.68	15.11	19.56	9.47	7.23	*5.57*
Battle River #5	BR5	12.90	*15.66*	*15.66*	13.68	13.73	19.56	9.47	7.23	*5.57*
Genesee #1	GN1	13.80	*16.70*	*16.70*	12.68	16.95	20.47	6.43	5.26	*3.90*
Genesee #2	GN2	13.80	*16.70*	*16.70*	12.68	16.95	20.47	6.43	5.26	*3.90*
Genesee #3	GN3		*13.44*	*13.44*	9.93	13.62	16.76	4.43	5.68	*3.37*
HR Milner	HRM	5.80	*4.87*	*4.87*	5.70	3.53	5.39	5.39	1.36	*1.36*
Keephills #1	KH1	29.70	*5.35*	*5.35*	3.89	5.38	6.77	2.93	3.94	*2.29*
Keephills #2	KH2	29.70	*5.35*	*5.35*	3.89	5.38	6.77	2.93	3.94	*2.29*
Keephills #3	KH3							0.94	2.29	*1.61*
Sheerness #1	SH1	20.60	*19.26*	*19.26*	15.26	22.75	19.77	6.11	7.90	*4.67*
Sheerness #2	SH2	20.60	*19.26*	*19.26*	15.26	22.75	19.77	6.11	7.90	*4.67*
Sundance #1	SD1	29.70	*13.14*	*13.14*	10.93	12.83	15.67			*3.55*
Sundance #2	SD2	29.70	*13.14*	*13.14*	10.93	12.83	15.67			*3.55*
Sundance #3	SD3	29.70	*13.14*	*13.14*	10.93	12.83	15.67	5.40	5.25	*3.55*
Sundance #4	SD4	29.70	*13.14*	*13.14*	10.93	12.83	15.67	5.40	5.25	*3.55*
Sundance #5	SD5	29.70	*13.14*	*13.14*	10.93	12.83	15.67	5.40	5.25	*3.55*
Sundance #6	SD6	29.70	*13.14*	*13.14*	10.93	12.83	15.67	5.40	5.25	*3.55*

**Actuals are in black, assumptions are in purple*

The Canadian Council of Ministers of the Environment (CCME) provides 2008-2012 progress reports detailing mercury emissions from coal-fired generation in Alberta. Some of the data is presented on a per-unit basis, some on a plant basis. For the latter, a plant's total emissions are allocated on a pro rata basis, proportionate to the percent of total energy each unit produced in that year (e.g., if Sheerness #1 produced 40% of Sheerness' total generation, it would be allocated for 40% of Sheerness' total emissions).

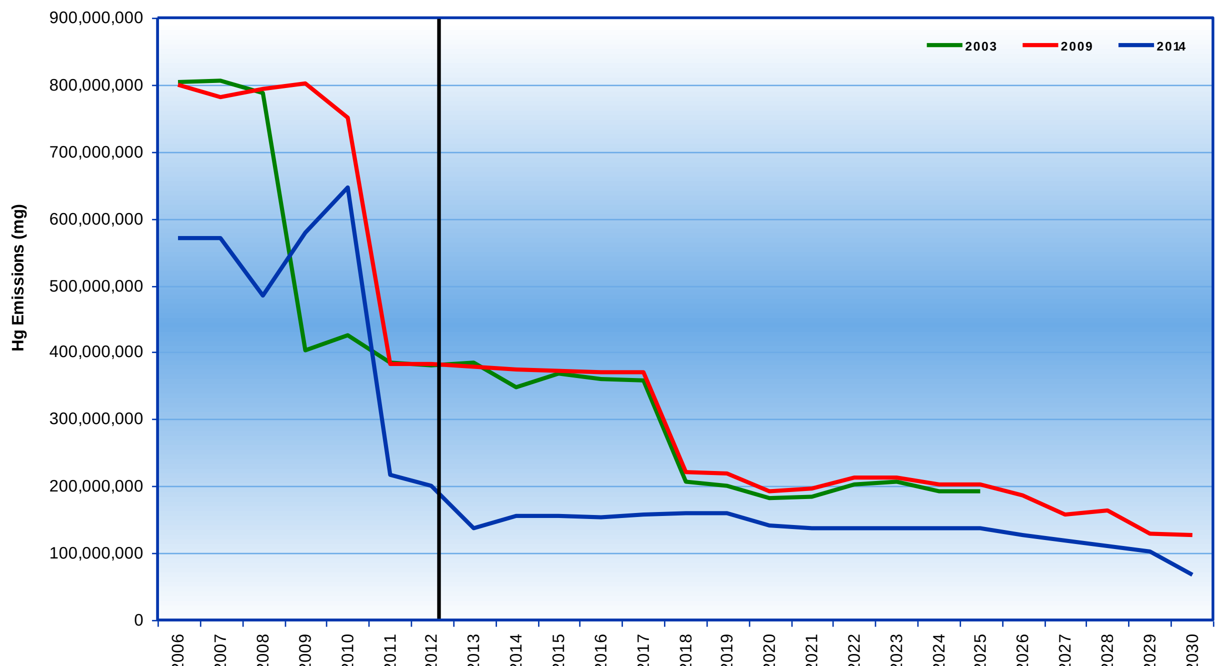
[2] EDCA's NOx emissions forecast for cogens includes only emissions attributable to the electricity component of total energy produced, i.e. not emissions attributable to steam production.

This apportionment method was used to populate 2008 through 2012 assumptions. 2006 and 2007 were assigned the average value of 2008 through 2010. 2013 onwards was assumed to be two-thirds of the average of 2011-2012. The logic behind this assumption was that the 2011-2012 period represents a mandatory 70% reduction from a baseline. 2013 onwards requires an 80% reduction from this baseline. Given the steep drop in emissions in 2011, it was assumed that all units met the 70% target and would meet the 80% target (2/3rds of the 70% target) from 2013 onwards. The exceptions to this were Keephills #3 (assumed that 2013 onwards would reflect the straight average of 2011 and 2012), Sundance #1 and #2 (which were made equal to the other Sundance units due to lack of recent data) and HR Milner (which is a low final emitter and only has to ensure its emissions stay constant). Interestingly, HR Milner's emission intensity dropped sharply in 2012; however, this was because the unit opted to burn gas, resulting in fewer emissions. Given Maxim has indicated they may continue to do so depending on the cost of natural gas and current market conditions (e.g., the value of SOx and NOx credits), EDCA assumed that HR Milner's mercury performance over the forecast would be best reflected by 2012.

Figure 12 presents the actual and forecast mercury emissions based on the above intensity assumptions. A sharp decline occurs after 2010, the result of noticeably less coal-fired generation during the 2011-2013 period and the assumed implementation of environmental regulations that require a 70% reduction in intensity for two years, followed by an 80% reduction. Emissions are forecast to rebound slightly in 2014 following the full year return of Sundance #1, Sundance #2 and Keephills #1, then remain roughly flat, experiencing declines in 2020 after the first tranche of coal-fired retirements, then again towards the tail-end of the forecast when additional units begin to retire. These retirement-based declines are not as noticeable as the compliance-based one in 2010 because emission intensities changed substantially post-compliance. For example, Sheerness #1 dropped from 22.75 mg/MWh in 2008 to an assumed 4.67 mg/MWh from 2013 onwards.

For the 2014 forecast, mercury emissions in Alberta are forecast to fall from 155,043,371 mg in 2014 to 68,497,117 mg in 2030, a 55.8% reduction. Although the number seems quite large, recall that the unit of measurement is milligrams, which is roughly 0.07 metric tonnes.

Figure 12 - Mercury Emissions (mg)



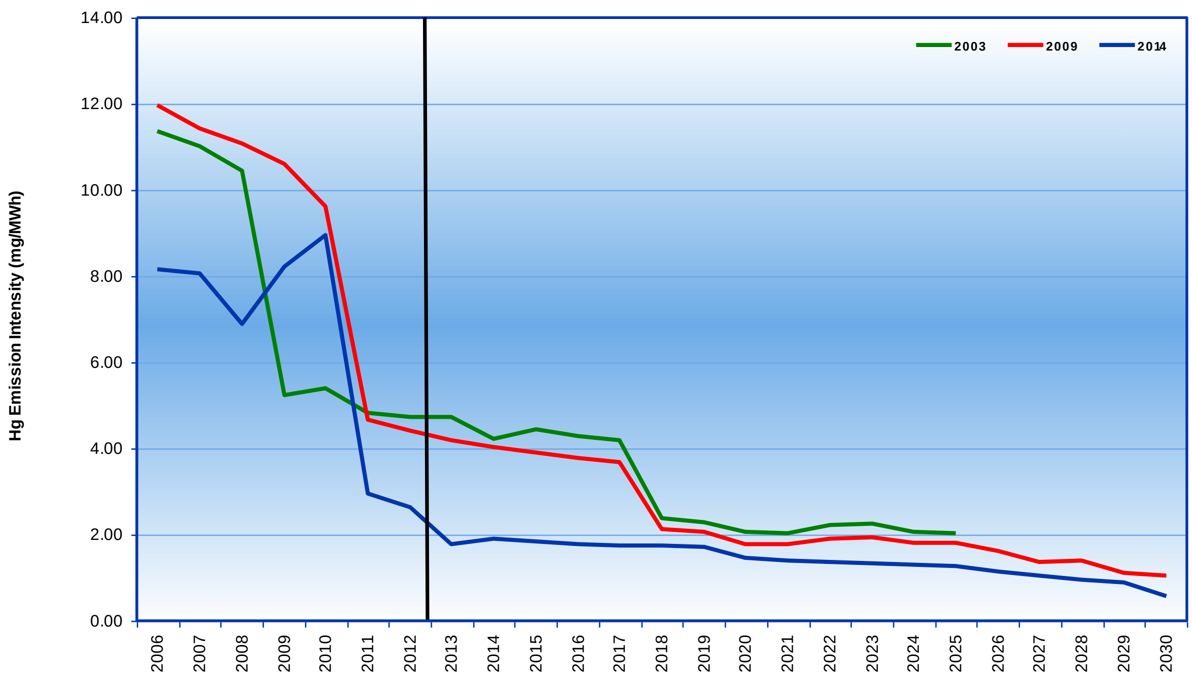
Compared to the 2009 model, the 2014 model forecasts fewer emissions across the board due to less coal-fired generation and significantly different intensity assumptions. The 2009 forecast appears to use virtually the same intensity assumptions as from 2003, some of which are abnormally high. For example, Sundance #1 and #2 were assigned intensities of 34.0 mg/MWh and 39.0 mg/MWh from January 2006 to January 2018 (retirement). The assumed retirement of these units at the beginning of 2018 is the primary reason the 2009 mercury forecast plummets from 369,778,707 mg in 2017 to 220,993,650 in 2018. As another example, Genesee #2, which retires outside the forecast period, was previously assigned a post-conversion value of 8.07 mg/MWh, as compared to the 2014 forecast's value of 2.29 mg/MWh, thus applying more upwards pressure to past emissions forecasts. Future coal-fired units were assigned a generic intensity value of 0.23 mg/MWh, so although future coal was forecast to act as base-load, it did not weigh too heavily on the back-end of past mercury forecasts.

The largest difference between the 2003 forecast and others is that conversions were assumed to happen one year earlier (2010 instead of 2011). Although the 2003 and 2009 forecast shared intensity assumptions, the 2009 forecast was marginally higher post-conversion because it forecast more generation from coal.

Mercury emission intensity, as illustrated in Figure 13, drastically decreases after 2010. A slight rise is seen in 2014 as Sundance #1, Sundance #2 and Keephills #1 return to service, then it gradually tapers downwards, accelerated by unit retirements (e.g., the first tranche at the end of 2019).

Although the 2009 Study's emissions were marginally on top of the 2003 forecast, its emission intensity remained below the 2003 forecast because the denominator of the equation – MWh of total fleet generation – was significantly higher due to a more robust energy sales forecast.

Figure 13 - Mercury Emission Intensity (mg/MWh)



For the 2014 model, it is EDCA's view that the fleet's mercury emission intensity will fall from 1.91 mg/MWh in 2014 to 0.58 mg/MWh in 2030, a 69.5% reduction.

Particulate Matter (PM) Emissions

CASA provided EDCA with particulate matter emissions from 2006 to 2013 on a per stack basis (e.g., Battle River #3 and #4 represented by Stack B, and Battle River #5 by Stack C). Each generator was allocated a portion of the emissions equal to its portion of the stack's generation. In other words, if Battle River #3 produced 40% of Stack B's generation, it would take 40% of the emissions. For 2014 onwards, a 3 year average (2011-2013) was used to capture any natural reduction in PM that occurred as a result of mercury abatements.

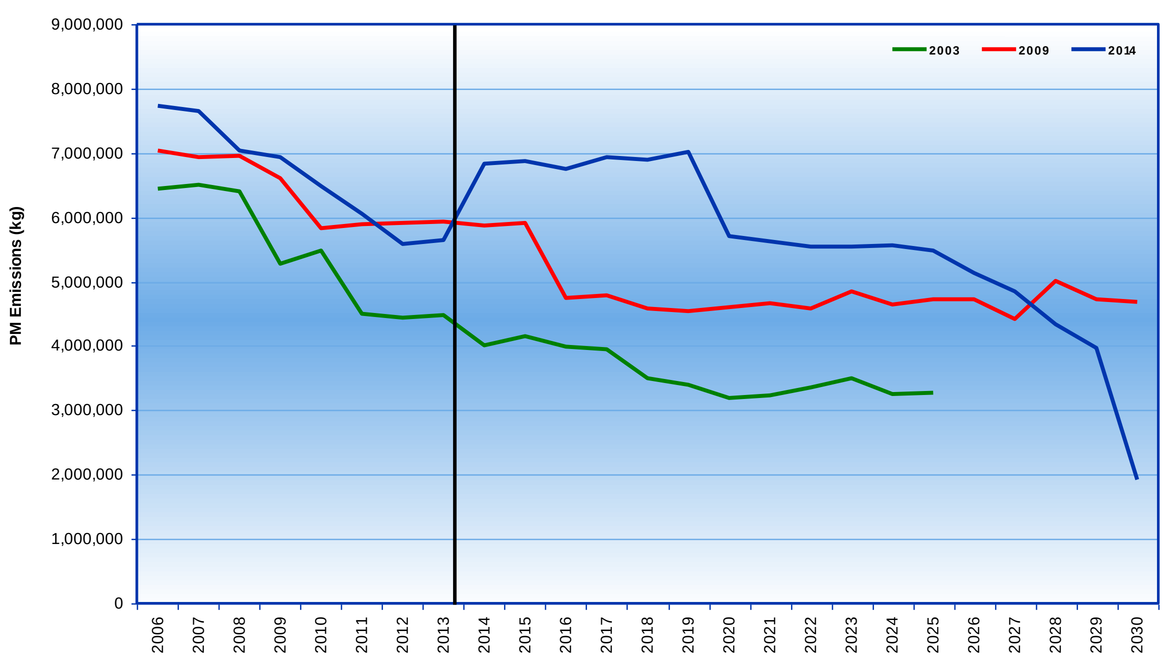
These assumptions are outlined in Table 4.

Table 4 - Particulate Matter Intensity (kg/MWh)

Particulate Matter Intensity (kg/MWh)										
ID		2006	2007	2008	2009	2010	2011	2012	2013	2014+
Battle River #3	BR3	0.16	0.13	0.12	0.12	0.12	0.19	0.23	0.23	*0.22*
Battle River #4	BR4	0.16	0.13	0.12	0.12	0.12	0.19	0.23	0.23	*0.22*
Battle River #5	BR5	0.33	0.36	0.35	0.35	0.37	0.34	0.39	0.42	*0.38*
Genesee #1	GN1	0.19	0.14	0.13	0.13	0.13	0.19	0.21	0.20	*0.20*
Genesee #2	GN2	0.19	0.14	0.13	0.13	0.13	0.19	0.21	0.20	*0.20*
Genesee #3	GN3	0.07	0.15	0.15	0.15	0.03	0.03	0.05	0.06	*0.05*
HR Milner	HRM	0.42	0.37	0.33	0.29	0.20	0.19	0.21	0.20	*0.20*
Keephills #1	KH1	0.13	0.13	0.12	0.13	0.13	0.11	0.11	0.09	*0.10*
Keephills #2	KH2	0.13	0.13	0.12	0.13	0.13	0.11	0.11	0.09	*0.10*
Keephills #3	KH3						0.02	0.02	0.04	*0.03*
Sheerness #1	SH1	0.08	0.07	0.03	0.03	0.04	0.06	0.06	0.06	*0.06*
Sheerness #2	SH2	0.08	0.07	0.03	0.03	0.04	0.06	0.06	0.06	*0.06*
Sundance #1	SD1	0.21	0.27	0.27	0.21	0.25			0.24	*0.24*
Sundance #2	SD2	0.21	0.27	0.27	0.21	0.25			0.24	*0.24*
Sundance #3	SD3	0.17	0.20	0.22	0.22	0.16	0.15	0.13	0.12	*0.13*
Sundance #4	SD4	0.17	0.20	0.22	0.22	0.16	0.15	0.13	0.12	*0.13*
Sundance #5	SD5	0.20	0.16	0.16	0.23	0.26	0.27	0.21	0.18	*0.22*
Sundance #6	SD6	0.20	0.16	0.16	0.23	0.26	0.27	0.21	0.18	*0.22*

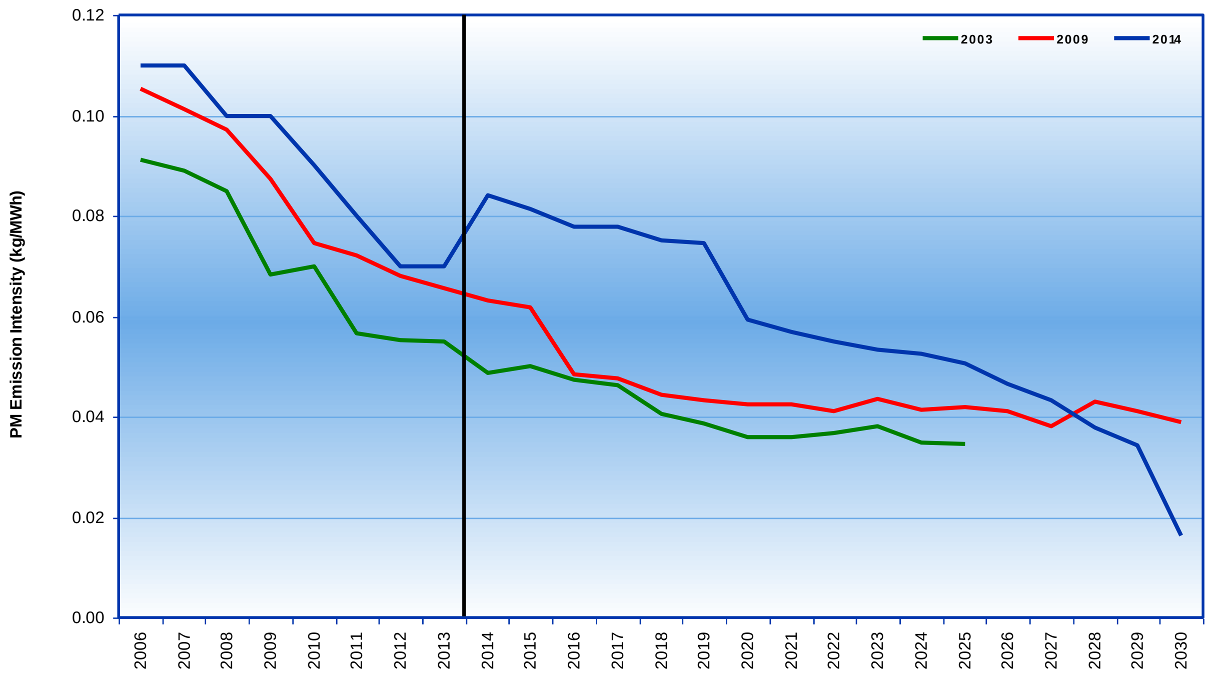
Figure 14 and Figure 15 present forecasts for Particulate Matter. In the near-term, emissions are forecast to rise due to the return of Sundance #1, Sundance #2 and Keephills #1, then remain roughly flat until the first tranche of retirements at the end of 2019. Particulate matter should remain flat through the early 2020s, then decline as additional coal-fired units retire. Intensity assumptions follow a similar pattern, but in years without retirements, exhibit downwards momentum since intensity is calculated by dividing total emissions (flat) by total fleet generation (growing).

Figure 14 - Particulate Matter Emissions (kg)



Past forecasts used a generic set of intensity assumptions that tended to be lower than actuals – 0.095 kg/MWh for existing coal and 0.066 kg/MWh for future coal (with the exceptions of the 3 Battle River units at 0.230 kg/MWh, Sheerness at 0.13 kg/MWh, Sundance #1/#2 at 0.11kg/MWh and HR Milner at 0.81 kg/MWh). In the 2009 forecast, 2016 sees a steep drop due to the assumed retirement of several high intensity units - Battle River #3 and #4, as well as HR Milner – without any replacement coal-fired capacity taking their place. This drop is not as steep in the 2003 forecast because the Battle River retirements were staggered and HR Milner was assumed to have retired in 2005. This is also the reason the 2003 forecast is noticeably below the 2009 forecast. Had HR Milner not been retired in 2005, the 2003 forecast would have started, and stayed, higher, albeit remaining below the 2009 forecast because of less forecast coal-fired generation.

Figure 15 - Particulate Matter Emission Intensity (kg/MWh)



For the 2014 model, EDCA forecasts that emissions from particulate matter will fall from 6,831,719 kg in 2014 to 1,927,007 kg in 2030, a 71.8% reduction. Emission intensities should drop from 0.08 kg/MWh in 2014 to 0.02 kg/MWh in 2030, an 80.5% reduction.

Sulphur Dioxide (SOx) Emissions

Alberta Environment and Sustainable Resource Development maintains very thorough records on SOx emissions, emission intensities and credits related to SOx activities. Table 5 presents the baseline data for each coal-fired unit, as well as their historical intensities, from 2006 to 2013. In order to create the forecast, it was assumed that taking an average of the last 5 years would suffice. The exception to this was HR Milner, which used an average of 2012 and 2013 since the unit is able to switch fuels (resulting in less SOx and NOx emissions), and does so depending on market conditions.

Unlike mercury, which has mandatory compliance, SOx offers the opportunity to either physically meet a certain intensity at a given point in time (the greater of the PPA expiration or 40 years after commissioning) or "pay" using credits. As discussed in greater detail above, EDCA's emission models suggest that at some point in time certain units will have to convert (i.e., lower their emissions to a BATEA target) so the coal fleet has enough credits available to run until the end of life. Thorough modeling of the SOx scenario, based on the most recently available data, suggests that the most economical situation would be for Sheerness #1 and Sheerness #2 to convert before the end of the decade, followed by Genesee #2 in the early-2020s. If these units converted and sold their credits on the open market, there would be enough credits to support the entire fleet. The below table lists the conversion year assumptions, as well as what the intensities are forecast to be post-conversion (0.65 kg/MWh).

Table 5 - Sulphur Dioxide Emission Intensity (kg/MWh)

Sulphur Dioxide Emission Intensity (kg/MWh)													
ID		Baseline	2006	2007	2008	2009	2010	2011	2012	2013	2014+ (No Conversion)	Conversion Year	Intensity if Converted
Battle River #3	BR3	5.10	4.94	5.03	5.07	5.14	5.65	5.61	5.33	6.05	*5.56*		
Battle River #4	BR4	5.10	4.94	4.89	4.98	5.13	5.64	5.54	5.33	5.77	*5.48*		
Battle River #5	BR5	5.04	4.67	4.39	4.52	4.77	5.03	4.82	4.69	4.86	*4.84*		
Genesee #1	GN1	2.33	2.07	2.08	1.94	1.99	2.09	2.17	2.07	2.47	*2.16*		
Genesee #2	GN2	2.33	2.07	2.08	1.94	1.99	2.09	2.17	2.07	2.47	*2.16*	*2021*	*0.65*
Genesee #3	GN3	0.80	0.99	1.05	1.10	0.90	0.99	0.94	1.02	1.10	*0.99*		
HR Milner	HRM	5.32	2.43	3.03	2.71	2.70	2.92	3.11	1.99	1.96	*1.97*		
Keephills #1	KH1	2.03	2.12	2.08	2.04	2.22	2.42	2.19	2.06	2.15	*2.21*		
Keephills #2	KH2	2.03	2.10	2.08	2.04	2.17	2.41	2.20	2.02	2.23	*2.21*		
Keephills #3	KH3	0.72						0.65	0.67	0.73	*0.69*		
Sheerness #1	SH1	5.93	7.30	7.54	6.60	6.02	6.26	6.43	6.98	6.66	*6.47*	*2019*	*0.65*
Sheerness #2	SH2	5.93	7.30	7.46	6.74	6.04	6.26	6.38	7.07	6.69	*6.49*	*2018*	*0.65*
Sundance #1	SD1	1.68	1.42	1.62	1.75	1.80	1.91			1.27	*1.66*		
Sundance #2	SD2	1.67	1.41	1.64	1.69	1.79	1.93			1.14	*1.62*		
Sundance #3	SD3	2.10	1.98	2.05	1.96	1.99	2.03	1.83	1.95	1.96	*1.95*		
Sundance #4	SD4	2.10	1.99	1.96	1.97	1.94	2.00	1.82	1.95	1.93	*1.93*		
Sundance #5	SD5	2.09	1.85	1.76	1.87	2.06	2.04	2.04	1.87	1.98	*2.00*		
Sundance #6	SD6	2.09	1.85	1.80	1.85	2.04	2.04	2.00	1.92	1.97	*2.00*		

As Figure 16 demonstrates, SOx emissions have been falling over time. Emissions are forecast to rise from 2013 following the return of the three coal-fired generators, jog up briefly towards the end of the decade, then fall as units being to convert and retire. Sheerness #2 is assumed to convert before the end of 2018, followed by Sheerness #1 during 2019 and Genesee #2 during 2021. In spite of greater forecast coal-fired generation, the 2009 forecast remains below the 2014 forecast until 2020 because its intensity assumptions, which were not based on actual data, tended to be lower. For example, the Sheerness units were assumed to be 5 kg/MWh, as compared to the 5 year average of approximately 6.5 kg/MWh. After 2020 its emissions forecast was higher because of a calculation error – units were assumed to convert to the lower BATEA, but the math incorrectly applied the pre-BATEA intensities to every year. For example, note the sharp drop between 2018 and 2019 in the 2014 forecast (Sheerness #2 conversion). A similar drop can be seen in the 2003 forecast between 2021 and 2022 (the year it assumed the first units – Sheerness – would convert). The latter drop should have been observed in the 2009 forecast, but it was not, thus the 2009 line only reflects unit retirements (e.g., the dip between 2015 and 2016 is due to the assumed retirement of Battle River #3, Battle River #4 and HR Milner).

Figure 16 - Sulphur Dioxide Emissions (kg)

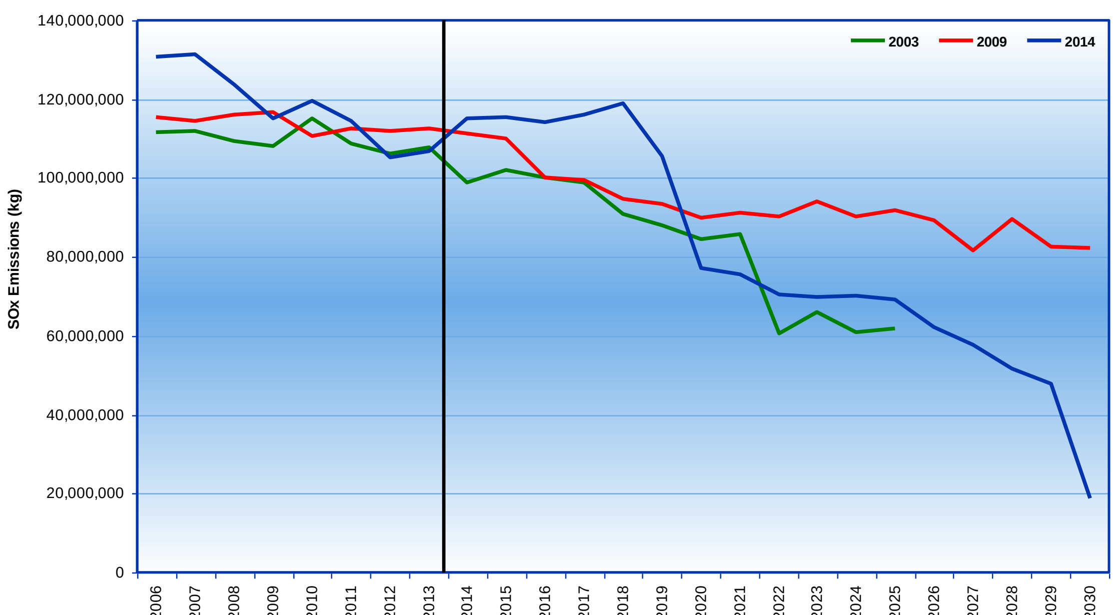
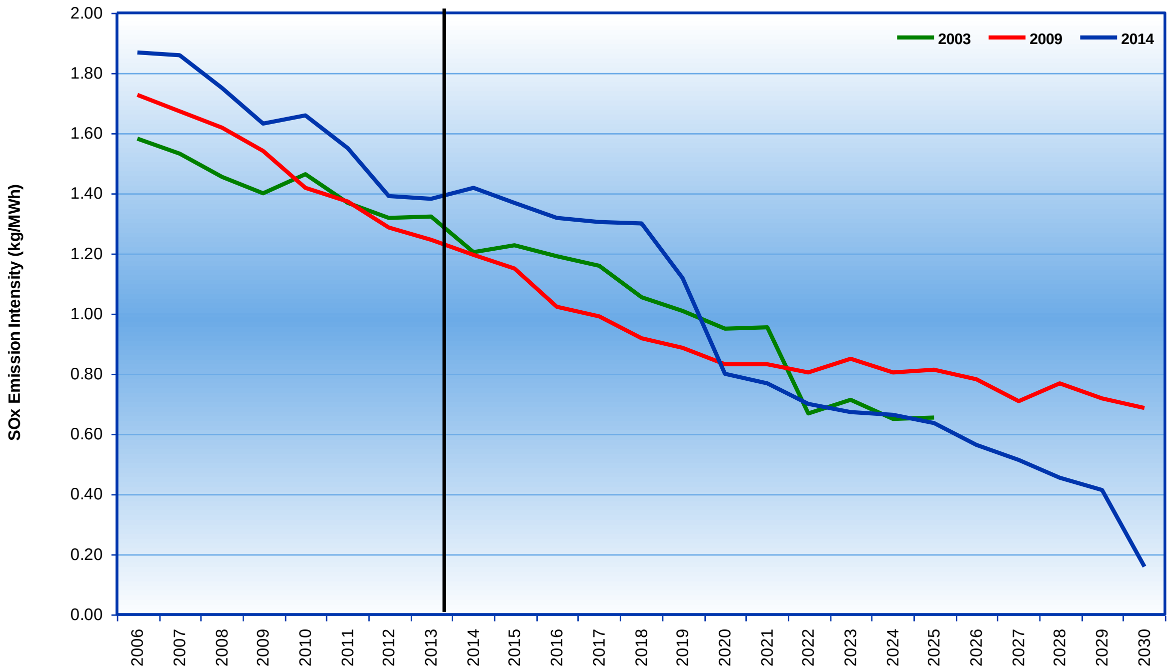


Figure 17 displays the SOx emission intensity for the entire Albertan generation fleet. Intensities should jog upwards briefly in 2014 in response to the return of Sundance #1, Sundance #2 and Keephills #1, then steadily decline, with the denominator in the intensity equation (total fleet generation) growing at the same time the numerator (emissions) is shrinking from retirements and conversions.

Figure 17 - Sulphur Dioxide Emission Intensity (kg/MWh)



For its 2014 modeling, EDCA forecasts that SOx emissions will fall from 115,091,765 kg in 2014 to 18,876,295 kg in 2030, a reduction of 83.6%. The fleet's emission intensity will fall from 1.42 kg/MWh in 2014 to 0.16 kg/MWh in 2030, a reduction of 88.7%.

Nitrogen Oxide (NOx) Emissions

NO_X is emitted from both coal and gas-fired generation technologies, with Alberta Environment keeping detailed records of emission, emission intensities and NOx credits. Table 6 details the model's underlying NOx assumptions.

NOx credits can be earned and traded, the same as SOx credits. A thorough analysis of the credit forecast, as discussed above, suggests several points. First, in order to generate enough credits to support the fleet at least three coal-fired units would have to convert and sell credits to the open market. It was determined that the most likely candidates would be Genesee #1 and Genesee #2 towards the end of the decade, followed by Sheerness #2 in the mid-2020s. Second, coal-fired units have the strongest impact on the credit scene (both in the usage of credits and the earning of them) so the majority of the modeling was focused on them. Gas units already have a low baseline, some below BATEA, some with no generation, and most with not as much room to improve emissions and earn credits. Even if a large group of them converted, they would not significantly delay the need for some coal to convert, and therefore would not likely affect the price of credits. As such, for gas-fired units, the modeling uses this simplifying conversion assumption - if a unit has to convert to meet a BATEA target of 0.30 kg/MWh it will convert at the same time as the first coal-fired conversion if it has earned credits in the past. If the unit did not earn any credits in the past, then it will only convert at the end of its design life (the maximum of a PPA, if applicable, or 30 years after commissioning).

A simple 5 year average (2009-2013) of past intensities was used to determine the units' pre-conversion emission intensities. The exception to this was HR Milner, which used an average of the last two years (2012-2013) in order to reflect the fact it can, and has, burned natural gas, based on market conditions.

Table 6 - Nitrogen Oxide Emission Intensity (kg/MWh)

Nitrogen Oxide Emission Intensity (kg/MWh)													
ID		Baseline	2006	2007	2008	2009	2010	2011	2012	2013	2014+ (No Conversion)	Conversion Year	Intensity if Converted
Battle River #3	BR3	2.28	1.88	1.84	1.91	1.85	1.87	1.92	2.12	2.40	*2.03*		
Battle River #4	BR4	2.28	1.88	1.78	1.84	1.84	1.87	1.88	2.13	2.23	*1.99*		
Battle River #5	BR5	2.39	2.01	1.94	1.87	1.96	1.53	2.35	2.31	2.39	*2.11*		
Genesee #1	GN1	2.13	1.95	1.76	1.83	1.90	1.87	2.01	1.87	2.37	*2.00*	*2019*	*0.47*
Genesee #2	GN2	2.13	1.95	1.76	1.83	1.90	1.87	2.01	1.87	2.37	*2.00*	*2018*	*0.47*
Genesee #3	GN3	1.18*	0.57	0.54	0.59	0.57	0.60	0.58	0.60	0.59	*0.59*		
HR Milner	HRM	2.88	2.59	2.73	2.94	2.27	2.15	2.15	1.77	1.46	*1.61*		
Keephills #1	KH1	2.19	1.95	1.84	1.85	2.21	2.19	2.12	1.89	1.91	*2.07*		
Keephills #2	KH2	2.17	1.99	1.84	1.86	2.16	2.20	2.15	1.85	1.91	*2.05*		
Keephills #3	KH3	0.62						0.55	0.56	0.53	*0.55*		
Sheerness #1	SH1	1.93	2.07	2.26	2.02	2.01	2.05	2.13	2.20	2.02	*2.08*		
Sheerness #2	SH2	1.93	2.07	2.25	2.01	2.03	2.03	2.12	2.23	2.03	*2.09*	*2025*	*0.47*
Sundance #1	SD1	1.52	1.54	1.98	2.32	2.67	2.57			1.90	*2.38*		
Sundance #2	SD2	1.55	1.53	1.98	2.31	2.66	2.67			1.79	*2.38*		
Sundance #3	SD3	1.63	1.64	1.80	1.86	1.88	2.00	1.95	2.20	1.93	*1.99*		
Sundance #4	SD4	1.64	1.66	1.77	1.86	1.87	1.98	1.93	2.17	1.91	*1.97*		
Sundance #5	SD5	1.50	1.43	1.55	1.75	1.78	1.64	1.69	1.75	1.72	*1.72*		
Sundance #6	SD6	1.50	1.39	1.54	1.65	1.67	1.63	1.65	1.80	1.74	*1.70*		
Cavalier	EC01	0.57	0.44	0.50	0.62	0.64	0.57	0.56	0.47	0.49	*0.54*	*2018*	*0.30*
Calgary Energy Centre	CAL1	0.20	0.15	0.15	0.15	0.05	0.07	0.06	0.05	0.07	*0.06*		
Air Liquide	ALS1	0.20	0.11	0.11	0.12	0.12	0.13	0.12	0.13	0.16	*0.13*		
Rainbow Lake 4	RL1	1.22	0.33	0.56	0.39	0.35	0.30	0.43	0.43	0.41	*0.38*	*2018*	*0.30*
CMH 11 (New)	CMH_11DLE	0.30	0.19	0.26	0.25	0.23	0.22	0.21	0.21	0.20	*0.21*		
Muskeg River 1	MKR1	0.20	0.07	0.08	0.09	0.10	0.09	0.09	0.09	0.11	*0.09*		
Muskeg River 2	MKR1_2	0.20	0.07	0.08	0.09	0.10	0.10	0.09	0.10	0.11	*0.10*		
CMH 10	CMH_10	2.54	1.91										
CMH 8	CMH_8	2.05	3.79	3.65	3.19	2.91					*2.91*		
CMH 11	CMH_11	2.02	2.37										
Scotford	APS1	0.31	0.09	0.21	0.17	0.17	0.18	0.07	0.29	0.35	*0.21*		
Poplar Hill	PH1	0.22	0.60	0.55	0.49	0.51	0.43	0.77	0.90	0.94	*0.71*	*2028*	*0.30*
Valleyview 1	VVW1	0.50	0.91	0.90	0.82	0.80	0.88	0.98	1.30	0.87	*0.97*	*2031*	*0.30*
Valleyview 2	VVW2	1.89			1.00	1.02	1.55	2.35	1.99	1.63	*1.71*		
Rainbow 1	RB1	5.12	7.40	0.00	0.00	0.00	0.00	0.00	0.00	0.00	*0.00*		
Rainbow 2	RB2	5.33	8.13	7.83	7.51	7.89	8.75	8.64	7.08	0.00	*6.47*		
Rainbow 3	RB3	5.43	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	*0.00*		
Rainbow 5	RB5	0.63	0.68	0.79	0.73	0.88	1.15	0.73	0.50	0.46	*0.74*	*2031*	*0.30*
Cloverbar 1	ENC1	0.30				0.49	0.33	0.39	0.38	0.37	*0.39*		
Cloverbar 2	ENC2	0.20				0.25	0.22	0.22	0.27	0.27	*0.25*		
Cloverbar 3	ENC3	0.20				0.25	0.22	0.22	0.24	0.22	*0.23*		
Crossfield 1	CRS1	0.30				0.27	0.22	0.24	0.28	0.31	*0.26*		
Crossfield 2	CRS2	0.30				0.19	0.18	0.17	0.16	0.15	*0.17*		
Crossfield 3	CRS3	0.30				0.22	0.19	0.24	0.26	0.28	*0.24*		
Northern Prairie	NPP1	0.20				0.16	0.36	0.27	0.27	0.28	*0.27*		
Balzac	NX01	0.54	0.62	0.60	0.63	0.56	0.46	0.45	0.41	0.40	*0.45*	*2031*	*0.30*
Bear Creek	BCRK	0.28	0.31	0.26	0.28	0.30	0.43	0.50	0.52	0.51	*0.45*	*2030*	*0.30*
Carseland	TC01	0.20	0.16	0.19	0.16	0.13	0.13	0.13	0.11	0.15	*0.13*		
MacKay	MKRC	0.20	0.12	0.15	0.11	0.10	0.13	0.14	0.12	0.11	*0.12*		
Redwater	TC02	0.20	0.14	0.10	0.10	0.14	0.10	0.14	0.19	0.24	*0.16*		
CMH 10 (New)	CMH_10DLE	0.30	0.30	0.24	0.26	0.25	0.25	0.25	0.27	0.26	*0.26*		
CMH 15	CMH_15	0.30				0.36	0.18	0.23	0.22	0.19	*0.24*		
CMH 14	CMH_14	0.24	0.22	0.24	0.26	0.29	0.35	0.34	0.34	0.31	*0.33*	*2030*	*0.30*

**On January 2016 Genesee #3's baseline resets to 0.62kg/MWh.*

Gas-fired units not in Alberta Environment's database are assumed to have an emissions intensity of 0.30 kg/MWh.

As depicted in Figure 18, NOx emissions should increase in the near-term as Sundance #1 and #2 return to full service, several oil sands projects commission and ENMAX/Capital Power's 873 MW Shepard begins operations. Emissions are forecast to drop at the end of the decade following several coal-fired retirements and the likely conversion of two units. Post 2020 emissions remain relatively flat with a slight upwards bias as multiple combined-cycle facilities are constructed in order to meet load growth, followed by a decline when vintage coal-fired units begin to wind down and a third coal unit (Sheerness #2) is converted by the end of 2025.

Similar to the SOx forecast, although the 2009 report suggests that several coal-fired units were modeled with lower intensities in order to earn enough credits, the actual calculation math assumed constant intensities from all units from 2006 to 2030. As such, the red line only reflects unit retirements.

Figure 18 - Nitrogen Oxide Emissions (kg)

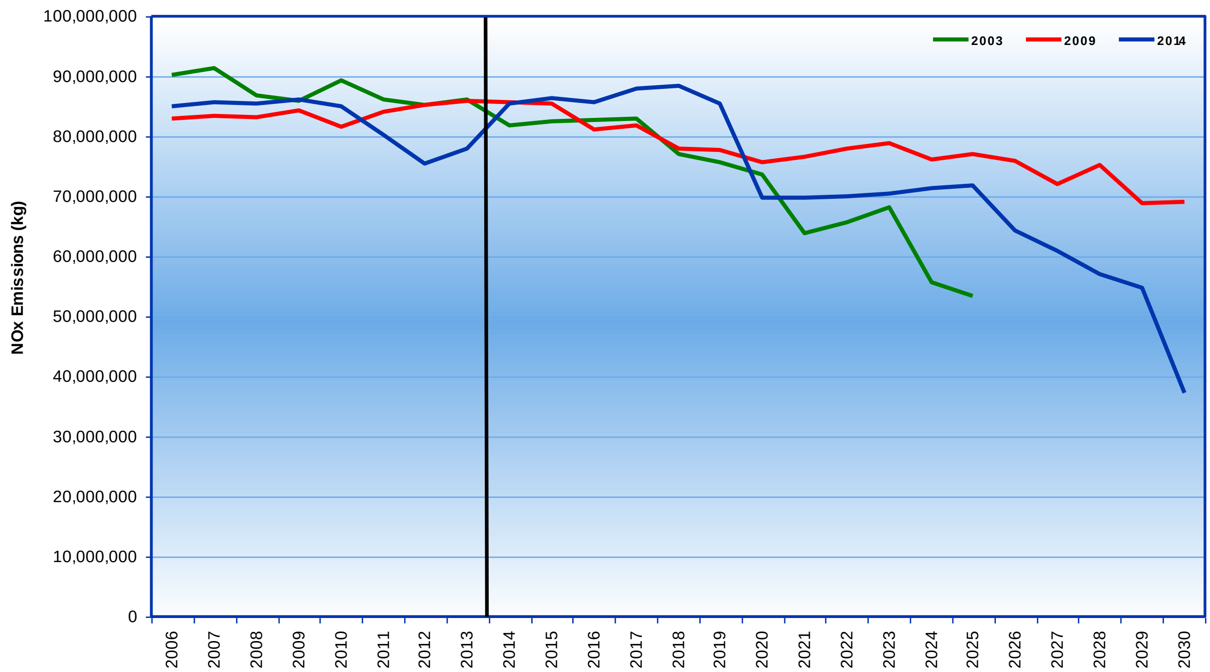
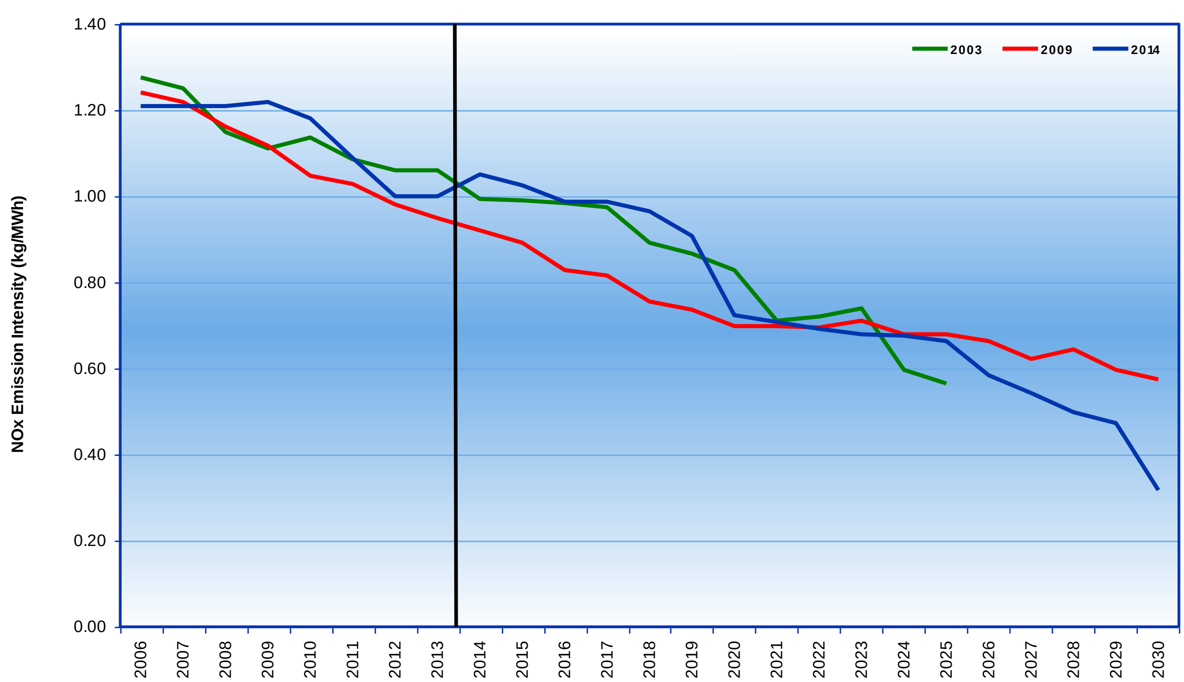


Figure 19 illustrates the downwards pressure on emission intensities, with the 2014 model ending the forecast (2030) significantly below the 2009 model due to the large number of coal-fired retirements by the end of 2029.

NOx emissions are forecast to fall from 85,480,313 kg in 2014 to 37,276,510 kg in 2030, a reduction of 56.4%. Emission intensities should fall from 1.05 kg/MWh in 2014 to 0.32 kg/MWh in 2030, a reduction of 69.9%.

Figure 19 - Nitrogen Oxide Emission Intensity (kg/MWh)



Current (2014) vs Prior (2009) Emission Forecast Differences

This final section illustrates the percent change between the current (2014) and prior (2009) forecast. Figure 20 presents this information in a bar chart.

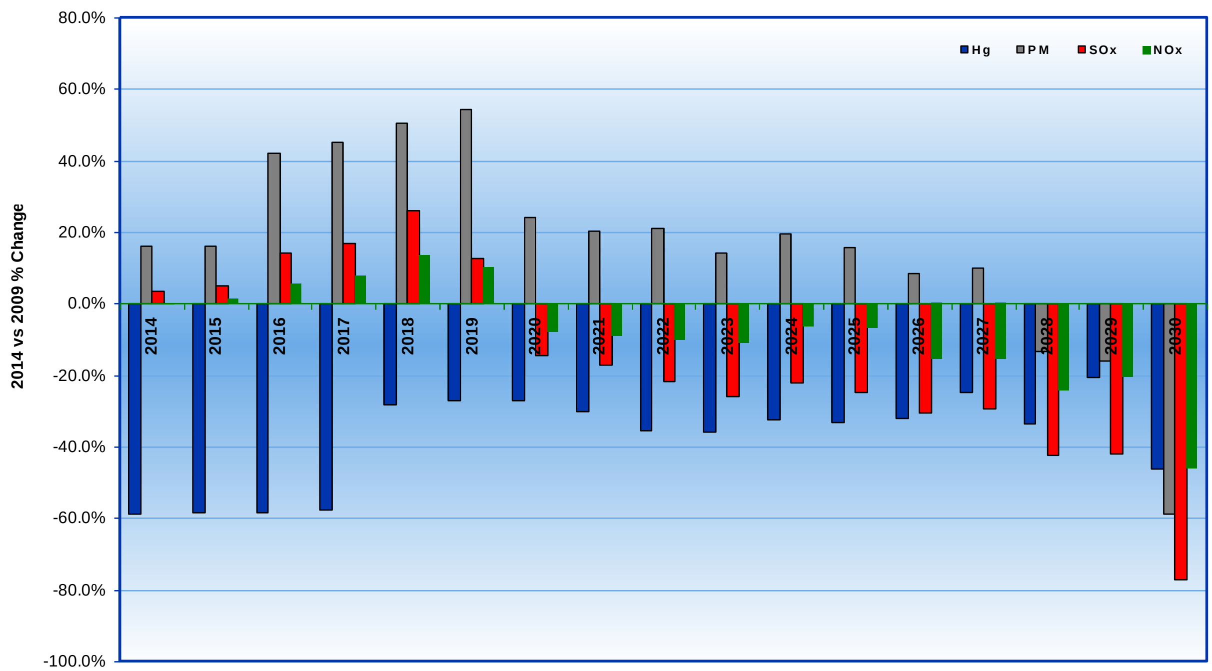
Mercury performance has improved across the board, with the widest difference being almost 60% less, over the next several years, and 46.3% lower at the end of the forecast (2030).

The Particulate Matter forecast has worsened between 2014 and 2027, but is 58.9% lower by the end of the study period. The higher forecast does not, and should not, suggest that units are expected to worsen their performance, just that the past particulate matter intensity estimates were understated.

Sulphur Dioxide is marginally higher until 2020, at which point the forecast shows steady improvement, with 2030 77.1% lower than in the previous report. It can be noted that in the front-end when the forecast has risen, the average of any forward-looking 5 year period never exceeds 15.0%.

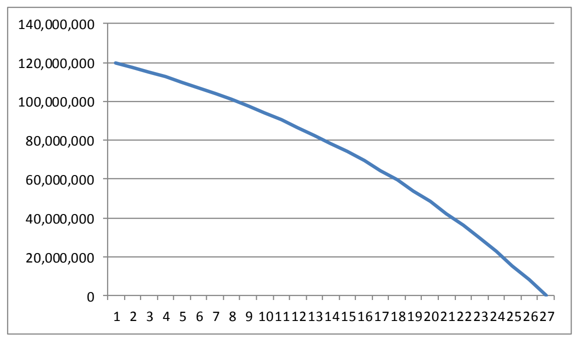
Nitrogen Oxides are also forecast to be marginally higher until 2020 (aside from being down 0.4% in 2014), with the end of the forecast 46.1% lower than previously reported. In the front-end, when the forecast has risen, the average of any forward-looking 5 year period never exceeds 15.0%.

Figure 20 - % Change Between the 2014 and 2009 Emissions Forecasts



Appendix 1.a – Sample Levelized Cost of Credit Calculation

NOx		MW Nameplate	400												
Genesee #2		Capital Cost $/kW	300												
		$ Capital/ Unit	120,000,000												
	Pre-Conversion (Actual)	Post (BATEA)	Baseline												
Intensity (kg/MWh)	2.005	0.470	2.125	Minimum of (Actual or Baseline) minus BATEA											
Capacity Factor	90.05%	90.05%	90.05%	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
MWh	3,155,250	3,155,250	3,155,250	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
Emissions (t/a)	6,325	1,483	6,705	4,842	4,842	4,842	4,842	4,842	4,842	4,842	4,842	4,842	4,842	4,842	4,842
Interest Rate	0.0500	PW Factor	0.0500	1.0500	1.1025	1.1576	1.2155	1.2763	1.3401	1.4071	1.4775	1.5513	1.6289	1.7103	1.7959
Years	26	PW of Credits	69,608	4,612	4,392	4,183	3,984	3,794	3,613	3,441	3,277	3,121	2,973	2,831	2,696
		Amortized Capital in this year	$ 1,723.95	8,347,718	8,347,718	8,347,718	8,347,718	8,347,718	8,347,718	8,347,718	8,347,718	8,347,718	8,347,718	8,347,718	8,347,718
		PW of all Collections	120,000,000	7,950,208	7,571,627	7,211,073	6,867,689	6,540,656	6,229,196	5,932,568	5,650,064	5,381,014	5,124,775	4,880,738	4,648,322
		Interest On O/S Balance		6,000,000	5,882,614	5,759,359	5,629,941	5,494,052	5,351,369	5,201,551	5,044,243	4,879,069	4,705,637	4,523,532	4,332,323
		Closing Balance	120,000,000	117,652,282	115,187,177	112,598,817	109,881,040	107,027,373	104,031,024	100,884,856	97,581,381	94,112,731	90,470,649	86,646,463	82,631,068



Appendix 1.b - Summary of Credit and Offer Calculation Rules

			Pre-Design Life					Post-Design Life				
			Value of Credits ($/t)	Run			Don't Run	Value of Credits	Run			Don't Run
		Capital Cost		Credits Earned	O&M Costs	Offer Includes			Credits Earned/(Spent)	O&M Costs	Offer	
Not Converted	Beats Baseline	$ Zero	PW of 2^{nd} best unit LC from first year new fleet credits required	(BL-A)* V	$ Zero	-Credits earned	$ Zero	LC of 2^{nd} best unit	-(A-BT)*V*P	$ Zero	2^{nd} best LC	$ Zero
	Worse than Baseline	$ Zero	PW of 2^{nd} best unit LC from first year new fleet credits required	$ Zero	$ Zero	-Credits earned i.e. $ Zero	$ Zero	LC of 2^{nd} best unit	-(A-BT)*V*P	$ Zero	2^{nd} best LC	$ Zero
Converted		Sunk	2^{nd} best unit LC	(Min(A,BL)-BT) *V	A*V*OM	O&M - Credits earned	$ Zero	$ Zero	Earned =Spent i.e. Net $ Zero	A*V*O M	O&M Costs	$ Zero

A=5 year average Actual Intensity (mg(kg) /MWh)	BL=Baseline Intensity	BT=BATEA Intensity	
V=MWh produced by this unit	OM=O&M ($/MWh)	P=Price ($/t) of Credit	LC=Levelized Cost of converted unit

Appendix 2 - Total Credits/Charges Included in Offers by Unit/Year

Hg, SOx and NOx Final Marginal Cost Adders																		
Unit	ID	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Battle River #3	BR3	$14.46	$15.29	$16.16	$17.16	$18.21	$24.42											
Battle River #4	BR4	$1.20	$1.20	$16.00	$16.98	$18.03	$24.12	$25.14	$33.19	$28.12	$30.20	$32.88	$37.43					
Battle River #5	BR5	$1.20	$1.20	$1.20	$1.20	$1.20	$1.20	$1.20	$1.20	$26.19	$28.01	$30.36	$34.47	$33.59	$35.19	$37.07	$39.53	
Genesee #1	GN1	$1.20	$1.20	$1.20	$1.20	$1.20	$1.20	-$3.07	-$3.19	-$3.31	-$3.44	-$3.57	-$4.47	-$4.79	-$5.16	-$5.69	-$6.38	$15.40
Genesee #2	GN2	$1.20	$1.20	$1.20	$1.20	$1.20	-$2.98	-$3.07	-$3.19	-$11.53	-$12.34	-$13.36	-$15.56	-$13.95	-$14.82	-$15.89	-$17.30	-$19.00
Genesee #3	GN3	$1.20	$1.20	$1.20	$1.20	$1.20	$1.20	$1.20	$1.20	$1.20	$1.20	$1.20	$1.20	$1.20	$1.20	$1.20	$1.20	$1.20
HR Milner	HRM	$8.88	$9.39	$9.92	$10.52	$11.14	$12.56											
Keephills #1	KH1	$1.20	$1.20	$1.20	$1.20	$1.20	$1.20	$1.20	$1.20	$1.20	$1.20	$18.72	$20.79	$19.13	$19.95	$20.96	$22.29	
Keephills #2	KH2	$1.20	$1.20	$1.20	$1.20	$1.20	$1.20	$1.20	$1.20	$1.20	$1.20	$1.20	$20.72	$19.07	$19.88	$20.89	$22.21	
Keephills #3	KH3																	
Sheerness #1	SH1	$1.20	$1.20	$1.20	$1.20	$1.20	$1.20	-$14.12	-$23.56	-$17.44	-$19.80	-$22.87	-$27.36	-$26.64	$14.95	$15.46	$16.13	$16.98
Sheerness #2	SH2	$1.20	$1.20	$1.20	$1.20	$1.20	-$13.01	-$14.15	-$23.62	-$17.49	-$19.85	-$22.93	-$27.43	-$32.44	-$34.52	-$36.94	-$40.09	-$43.82
Sundance #1	SD1	$1.20	$1.20	$1.20	$1.20	$13.28	$14.80											
Sundance #2	SD2	$1.20	$1.20	$1.20	$1.20	$13.22	$14.68											
Sundance #3	SD3	$1.20	$1.20	$1.20	$1.20	$1.20	$1.20	$1.20	$17.64	$15.93	$16.58	$17.39	$19.23	$17.49				
Sundance #4	SD4	$1.20	$1.20	$1.20	$1.20	$1.20	$1.20	$1.20	$17.49	$15.80	$16.43	$17.23	$19.04	$17.29	$18.00			
Sundance #5	SD5	$1.20	$1.20	$1.20	$1.20	$1.20	$1.20	$1.20	$17.12	$15.34	$15.99	$16.80	$18.51	$16.73	$17.41	$18.24		
Sundance #6	SD6	$1.20	$1.20	$1.20	$1.20	$1.20	$1.20	$1.20	$17.07	$15.29	$15.93	$16.74	$18.45	$16.66	$17.34	$18.16	$19.25	
Wabamun #4	WB4																	
Cavalier	EC01						-1.08	-$1.09	-$1.11	-$1.13	-$1.15	-$1.18	-$1.32	-$1.37	-$1.43	-$1.51	-$1.62	-$1.76
Calgary Energy Centre	CAL1																	
Scotford	ALS1																	
Rainbow Lake 4	RL1						-2.67	-$2.72	-$2.79	-$2.85	-$2.92	-$3.00	-$3.50	-$3.67	-$3.88	-$4.17	-$4.55	$2.00
Medicine Hat - 011610 (new 10 and 11) - 11	CMH_11DLE																	
ATCO - 073899 Muskeg - 1	MKR1																	
ATCO - 073899 Muskeg - 2	MKR1_2																	
Medicine Hat - 011610 (original 10 and 11) - 10	CMH_10																	
Medicine Hat - 011610 (original 10 and 11) - 8	CMH_8																	
Medicine Hat - 011610 (original 10 and 11) - 11	CMH_11																	
Shell Canada Limited - 077375 Shell Scotford - 1	APS1																	
Poplar Hill	PH1																$2.00	$2.00
Valleyview 1	VVW1																	
Valleyview 2	VVW2																	
Rainbow 1	RB1																	
Rainbow 2	RB2																	
Rainbow 3	RB3																	
Rainbow 5	RB5																	
Cloverbar 1	ENC1																	
Cloverbar 2	ENC2																	
Cloverbar 3	ENC3																	
Crossfield 1	CRS1																	
Crossfield 2	CRS2																	
Crossfield 3	CRS3																	
Northern Prairie	NPP1																	
Balzac	NX01																	
Bear Creek	BCRK																	
Carseland	TC01																	
MacKay	MKRC																	
Redwater	TC02																	
CMH 10 NEW	CMH_10DLE																	
CMH 15	CMH_15																	
CMH 14	CMH_14																	

Appendix 3 - Energy Production, Emission Forecasts and Emission Intensities

Table 7 - Generation by Fuel Type (MWh)

Generation Summaries (MWh)												
	Coal			Gas			Wind			Hydro/Imports/Other		
	2003	2009	2014	2003	2009	2014	2003	2009	2014	2003	2009	2014
2006	44,381,836	44,575,891	44,575,887	21,827,588	18,296,037	20,431,438	1,343,268	918,425	919,720	3,037,649	2,975,430	3,994,096
2007	44,598,835	44,167,618	44,167,616	23,973,281	19,309,862	20,938,369	1,713,880	1,479,272	1,483,872	2,817,611	3,469,401	4,095,398
2008	43,967,804	45,255,627	42,298,762	26,193,286	21,276,061	21,818,720	2,110,639	1,675,000	1,607,222	3,105,973	3,524,030	4,870,166
2009	44,037,885	45,522,846	41,117,886	27,631,178	24,287,869	23,497,625	2,359,794	1,976,696	1,573,328	3,191,115	3,786,565	4,284,492
2010	46,418,399	43,885,490	41,037,709	27,129,462	26,620,039	25,020,161	2,297,389	3,136,439	1,631,452	2,741,783	4,418,732	4,535,381
2011	44,283,394	46,878,726	39,250,198	29,295,088	27,469,874	25,719,836	2,348,468	3,914,166	2,429,527	3,578,134	3,602,828	6,344,038
2012	43,788,439	47,493,569	37,597,547	30,140,742	31,199,179	28,772,580	2,364,198	4,444,208	2,654,474	4,109,108	3,792,126	6,645,023
2013	44,472,098	48,210,095	38,517,513	30,691,781	34,018,734	30,655,524	2,435,212	4,515,269	3,110,909	3,788,492	3,747,594	5,430,363
2014	41,443,385	48,823,740	43,566,412	33,358,881	35,877,458	30,114,311	2,409,406	4,716,501	3,363,796	5,060,999	3,706,059	4,210,946
2015	42,888,578	48,827,024	43,412,573	33,290,311	37,954,408	33,149,464	2,448,802	5,126,007	4,037,957	4,537,602	3,692,729	3,848,303
2016	42,928,542	46,512,404	43,476,530	34,630,162	41,772,863	34,059,793	2,475,471	5,393,366	4,990,070	4,133,153	4,211,458	4,171,063
2017	42,706,961	47,248,126	43,988,809	36,228,817	43,054,035	35,952,614	2,436,826	5,560,085	4,622,190	3,936,396	4,422,354	4,583,163
2018	38,446,272	46,831,749	44,760,728	41,367,085	45,578,346	37,324,818	2,482,944	6,394,723	4,851,971	4,016,699	4,342,780	4,666,605
2019	37,464,145	47,014,468	44,855,764	43,031,279	47,392,909	39,756,489	2,451,888	6,296,507	4,366,008	4,471,688	4,572,415	5,127,247
2020	35,450,287	48,738,643	39,516,312	46,424,398	48,336,405	46,384,478	2,370,583	6,499,409	5,339,900	4,428,732	4,844,231	5,191,075
2021	35,918,595	50,087,078	38,583,868	47,562,266	47,609,283	49,240,909	2,411,628	6,737,807	5,419,923	3,964,975	5,367,006	5,540,135
2022	37,211,543	51,311,384	38,877,955	47,406,566	47,458,660	51,147,757	2,429,154	7,170,638	5,681,439	4,009,837	5,974,754	5,333,587
2023	38,778,097	51,871,646	38,540,203	47,339,998	46,174,929	53,242,911	2,452,711	7,254,627	6,360,943	3,657,119	5,562,714	5,549,608
2024	36,187,157	50,069,360	38,900,611	50,791,757	48,258,973	55,584,747	2,245,700	7,252,989	5,582,817	4,234,924	6,623,217	5,627,318
2025	36,385,612	50,653,710	38,359,906	52,649,438	48,805,689	58,025,632	2,278,555	7,178,375	6,367,211	3,394,159	6,385,939	5,711,534
2026		50,918,208	36,518,339		49,282,744	60,976,079		7,255,336	6,727,756		7,033,070	5,944,224
2027		50,331,525	34,027,940		51,009,091	65,358,060		7,164,779	6,422,693		7,131,394	6,577,003
2028		55,909,877	31,591,722		47,814,149	69,621,803		7,283,031	6,530,426		5,807,572	6,695,428
2029		53,215,623	29,279,896		47,895,397	72,240,685		7,315,995	7,699,643		6,786,818	6,871,859
2030		53,080,802	19,312,239		51,150,845	84,254,504		7,164,499	7,265,350		8,710,465	6,929,032

Table 8 - Emission (mg/kg) Summaries

Fleet Emission Summaries	Mercury (mg)			Particulate Matter (kg)			Sulphur Dioxide (kg)			Nitrogen Oxide (kg)		
	2003	2009	2014	2003	2009	2014	2003	2009	2014	2003	2009	2014
2006	803,174,582	799,168,364	570,136,667	6,443,350	7,032,352	7,726,850	111,510,299	115,319,905	130,661,000	90,186,066	82,856,305	84,922,587
2007	806,442,398	781,796,442	570,136,667	6,514,023	6,929,432	7,642,050	111,947,247	114,450,858	131,293,000	91,471,496	83,329,183	85,770,357
2008	787,228,477	794,341,851	485,660,000	6,398,262	6,962,143	7,041,250	109,490,582	115,939,512	123,711,810	86,705,952	83,260,751	85,567,162
2009	403,801,456	800,994,419	578,840,000	5,282,748	6,597,254	6,931,640	108,152,722	116,567,280	115,159,668	85,893,355	84,425,442	86,166,437
2010	425,248,636	751,640,370	645,910,000	5,485,194	5,819,396	6,483,180	115,187,194	110,712,518	119,672,662	89,230,362	81,668,446	85,036,911
2011	384,603,120	382,105,804	216,723,937	4,503,356	5,892,119	6,053,340	108,681,291	112,540,986	114,510,592	86,226,541	84,106,058	80,332,724
2012	380,322,144	383,182,634	200,700,000	4,435,454	5,905,421	5,583,480	106,077,869	111,976,433	105,390,658	85,195,401	85,180,497	75,551,026
2013	384,003,372	377,806,765	137,778,719	4,483,650	5,928,641	5,641,070	107,794,567	112,651,409	106,882,115	86,227,272	85,864,791	77,895,504
2014	347,062,872	374,121,845	155,043,371	4,007,903	5,877,049	6,831,719	98,993,356	111,278,663	115,091,765	81,774,490	85,784,161	85,480,313
2015	368,717,329	372,796,956	155,140,556	4,158,627	5,911,090	6,872,575	102,057,885	109,912,530	115,388,097	82,428,705	85,408,171	86,471,529
2016	359,696,028	369,500,753	154,190,485	3,980,143	4,743,906	6,740,779	100,162,573	99,981,299	114,183,524	82,826,567	81,140,437	85,693,391
2017	358,541,549	369,778,707	156,557,091	3,953,660	4,776,734	6,932,477	98,905,892	99,423,518	116,097,254	83,013,598	81,725,115	88,009,353
2018	206,328,880	220,993,650	159,058,682	3,488,363	4,578,979	6,890,893	91,010,785	94,560,566	119,093,547	77,118,010	78,016,207	88,475,760
2019	200,609,630	218,817,985	160,083,203	3,387,699	4,542,417	7,007,968	88,157,812	93,442,285	105,403,580	75,659,586	77,699,840	85,436,624
2020	181,571,838	192,198,752	140,159,037	3,194,262	4,595,362	5,710,574	84,434,894	89,998,380	77,177,358	73,543,552	75,613,881	69,703,709
2021	183,386,253	196,685,659	137,386,855	3,232,432	4,670,489	5,618,270	85,820,805	91,239,636	75,696,550	63,774,772	76,690,509	69,784,116
2022	203,121,358	212,716,072	137,764,479	3,353,514	4,586,416	5,550,826	60,656,439	90,293,307	70,617,310	65,749,052	77,901,003	70,059,537
2023	207,231,148	213,322,657	136,727,192	3,504,931	4,839,699	5,533,308	65,963,690	94,165,335	69,787,291	68,160,863	78,930,108	70,392,123
2024	192,363,376	203,133,455	137,418,770	3,258,405	4,642,360	5,556,568	60,779,899	90,176,070	70,253,791	55,766,413	76,084,987	71,355,289
2025	192,007,182	203,019,352	136,120,191	3,277,863	4,726,203	5,479,089	61,794,441	91,808,071	69,068,198	53,386,243	76,942,298	71,794,543
2026		187,059,761	127,480,997		4,719,437	5,130,481		89,409,033	62,101,678		75,987,221	64,315,894
2027		158,328,653	118,989,185		4,409,031	4,857,661		81,735,764	57,657,933		72,080,022	60,974,799
2028		164,528,220	109,606,124		5,008,819	4,342,542		89,743,371	51,786,221		75,336,179	57,091,489
2029		128,449,208	102,346,579		4,722,707	3,965,460		82,515,324	47,927,698		68,787,358	54,785,454
2030		127,544,114	68,497,117		4,687,811	1,927,007		82,379,175	18,876,295		69,175,572	37,276,510

*In the 2014 forecast, 2006 and 2007 mercury emissions are from actual generation multiplied by estimated intensities.

Table 9 - Emission Intensity Summaries (mg (kg)/MWh)

Fleet Emission Intensity Summaries												
	Mercury (mg/MWh)			Particulate Matter (kg/MWh)			Sulphur Dioxide (kg/MWh)			Nitrogen Oxide (kg/MWh)		
	2003	2009	2014	2003	2009	2014	2003	2009	2014	2003	2009	2014
2006	11.38	11.97	8.15	0.09	0.11	0.11	1.58	1.73	1.87	1.28	1.24	1.21
2007	11.03	11.43	8.07	0.09	0.10	0.11	1.53	1.67	1.86	1.25	1.22	1.21
2008	10.44	11.07	6.88	0.08	0.10	0.10	1.45	1.62	1.75	1.15	1.16	1.21
2009	5.23	10.60	8.21	0.07	0.09	0.10	1.40	1.54	1.63	1.11	1.12	1.22
2010	5.41	9.63	8.94	0.07	0.07	0.09	1.47	1.42	1.66	1.14	1.05	1.18
2011	4.84	4.67	2.94	0.06	0.07	0.08	1.37	1.37	1.55	1.08	1.03	1.09
2012	4.73	4.41	2.65	0.06	0.07	0.07	1.32	1.29	1.39	1.06	0.98	1.00
2013	4.72	4.18	1.77	0.06	0.07	0.07	1.32	1.24	1.38	1.06	0.95	1.00
2014	4.22	4.02	1.91	0.05	0.06	0.08	1.20	1.19	1.42	0.99	0.92	1.05
2015	4.43	3.90	1.84	0.05	0.06	0.08	1.23	1.15	1.37	0.99	0.89	1.02
2016	4.27	3.77	1.78	0.05	0.05	0.08	1.19	1.02	1.32	0.98	0.83	0.99
2017	4.20	3.69	1.76	0.05	0.05	0.08	1.16	0.99	1.30	0.97	0.81	0.99
2018	2.39	2.14	1.74	0.04	0.04	0.08	1.05	0.92	1.30	0.89	0.76	0.97
2019	2.29	2.08	1.70	0.04	0.04	0.07	1.01	0.89	1.12	0.87	0.74	0.91
2020	2.05	1.77	1.45	0.04	0.04	0.06	0.95	0.83	0.80	0.83	0.70	0.72
2021	2.04	1.79	1.39	0.04	0.04	0.06	0.96	0.83	0.77	0.71	0.70	0.71
2022	2.23	1.90	1.36	0.04	0.04	0.05	0.67	0.81	0.70	0.72	0.70	0.69
2023	2.25	1.92	1.32	0.04	0.04	0.05	0.72	0.85	0.67	0.74	0.71	0.68
2024	2.06	1.81	1.30	0.03	0.04	0.05	0.65	0.80	0.66	0.60	0.68	0.68
2025	2.03	1.80	1.25	0.03	0.04	0.05	0.65	0.81	0.64	0.56	0.68	0.66
2026		1.63	1.16		0.04	0.05		0.78	0.56		0.66	0.58
2027		1.37	1.06		0.04	0.04		0.71	0.51		0.62	0.54
2028		1.41	0.96		0.04	0.04		0.77	0.45		0.64	0.50
2029		1.11	0.88		0.04	0.03		0.72	0.41		0.60	0.47
2030		1.06	0.58		0.04	0.02		0.69	0.16		0.58	0.32

**In the 2014 forecast, 2006 and 2007 mercury emission intensities are from estimates.*

Appendix 4 – Qualifications and Study Team c.v., EDC Associates Ltd.

Incorporated in 1992, EDC Associates Ltd. (EDCA) is an independent energy-consulting firm based in Calgary, Alberta, Canada that provides consulting services with respect to electric energy pricing, generation economic development, energy procurement, regulatory and legal issues, and electric industry training.

EDCA's Experience and Qualifications

EDCA has designed, developed and continually updates and maintains an integrated suite of computer models that are used to provide very detailed quantitative analysis in support of its consulting services. These models are based on robust forecast methodologies designed to assess intricate market fundamentals and have been recognized as being leading edge, comprehensive and the "barometer" of electricity pricing used by industry and market participants in Alberta. These models use engineering end-use and econometric techniques to analyze electric energy market fundamentals with respect to supply, demand and price to produce both short and long-term hourly forecasts, typically from 1 to 30-years. Monte-Carlo techniques are utilized to quantify the risk associated with any key assumption. EDCA has a deep understanding of the Alberta market.

Electricity demand is modelled from the ground up starting with population, economics, through to hourly electricity demand by sector where large industrial facilities are tracked and added to the forecast independently, including any onsite generation. All electric energy supply resources are modeled discretely by unit (or import/export border point), using a levelized cost calculation and discrete offer behaviours to add generation as the supply/demand balance would incent knowledgeable investors to develop them. EDCA's detailed Alberta fundamental modeling is further enhanced by explicit modeling of electricity supply, demand and price fundamentals in adjacent markets from which inter-tie capacity exists. Most notably, the PacNW is modeled exogenously to derive Mid-C pricing that ultimately influences import and export volumes between Alberta, BC and the PacNW. Correspondingly, EDCA has been the premier supplier of independent pool price forecasts and generation energy production simulations in Alberta since the start of the electric energy industry re-structuring in 1996.

As part of the energy pricing consulting services provided by EDCA, the company has been retained to prepare case by case client specific market analysis and forecasts for a wide range of electricity industry participants including marketers, retailers, generation developers, industrial customers, regulators and governmental departments and also publishes several multi-client studies, newsletters and reports on its own volition that are widely circulated to industry clients on a fee for service basis. EDCA has conducted many surveys and regularly canvasses a broad spectrum of participants to gain more detailed insights into fundamentals.

As part of the generation economic development services provided by EDCA, the company has been retained by its clients to provide independent and rigorous analysis with respect to generation feasibility and economic modeling used by those considering generation development, value optimization, acquisition or divestiture. EDCA incorporates Monte-Carlo analysis with respect to quantifying volume, price and other key risk components related particularly to asset valuation, energy production and risk/hedging analysis as part of any generation economic or technology configuration options study. EDCA has designed and developed its own cumulative and discounted cash flow model that is used to quantify and assess the relative economics and financial position of the various electric energy producing technologies. This model conforms to GAAP accounting principles to calculate EBITDA, net income (before or after tax), and IRR, cumulative discounted cash flow, simple and discounted payback under any number of capital costs and structures with respect to debt or equity. The model is also used to derive relative generation technology "levelized" unit production costs given a consistent set of capital structure, cost and other financing assumptions.

As part of the energy procurement consulting services provided by EDCA, the company has been retained by electricity suppliers and consumers to facilitate energy procurement or sale processes. EDCA provides services in regards to: requests for quote and proposal development, purchase/sale recommendations, purchase/sale strategies and portfolio monitoring services, budget assistance and reporting. EDCA has made recommendations and negotiated vendor contract terms in respect of electricity and natural gas over-the-counter agreements up to 20 years in length.

As part of its regulatory and legal consulting services provided by EDCA, the company has on many occasions prepared and filed evidence in both legal and regulatory proceedings in Alberta and other provincial jurisdictions. EDCA staff has been prepared as an expert witness on many occasions on behalf of several clients and proceedings with several appearances in front of the AEUB.

Relevant Corporate Experience

Pertinent to this study, EDCA has significant experience with respect to the deregulation of Alberta's generation sector where the companies electric energy dispatch and price models are robust and use state of the art numeric methodologies to quantify electric energy demand, inter-market imports and exports, domestic generation energy production, fuel use, emissions etc. as well as the wholesale electric energy price.

Subsequently, EDCA has been retained by many companies in respect of completing generation energy production simulations and economic modeling to provide market pricing for revenue to both thermal and renewable electric energy technologies (including ancillary services) in addition to load for cost budgeting. This work has incorporated both deterministic and stochastic methodologies (using Monte-Carlo analysis) that have tested many assumptions such as bidding strategies, supply demand balance, fuel prices, hedge arrangements, emissions policy, transmission congestion, inter-regional import / export trade, proposed and adopted changes in market design, etc. EDCA has more recently enhanced the nature of its wind energy production modeling to account for the geographical diversity of wind development that allows for varied levels of cross-correlation between wind farms over time. As part of its generation dispatch and economics work, EDCA has developed generation economic models, verified various modeling assumptions, and completed numerous financial economic studies for prospective or exiting generation assets on behalf of client requests.

More specifically related to the scope of work noted in this proposal, EDCA has been retained on many occasions in respect of Alberta's electric system airborne emissions and emissions intensity calculations. EDCA was the lead consultant retained by the Alberta Department of Environment and the Clean Air Strategic Alliance (CASA) in 2003 as part of the stakeholder recommendations on all five priority emission substances (Particulate Matter, Mercury, NOx, SOx and GHG) that were submitted to government as part of its current emissions management frame work and policy. EDCA also prepared the 5-year update generation and emissions forecasts in 2009 for CASA.

In addition EDCA has also worked on behalf of many market participants, including CanWEA and the Department of Environment on GHG emissions and emissions intensity measures and analytics to validate the level of GHG offset emission credits eligible to Alberta's wind energy producers under the Specified Gas Emitters Regulation (SGER). As part of these engagements, EDCA has developed and continues to maintain a database of emissions intensity measures by unit and power plant that was developed in conjunction with the CASA stakeholder process and as such is accurate and robust. Finally, EDCA maintains historical energy production data, as compiled by the AESO, for all generating units in the province of Alberta.

EDCA's Independence and Objective Professionalism

EDCA maintains strict neutrality between commodity suppliers, generation developers, marketers and equipment suppliers. EDCA owns no generation assets or capacity rights and has no preferred commodity suppliers. This neutrality ensures our actions and advice are always independent and unbiased.

EDCA's client list (see www.edcassociates.com) further exemplifies the fact that our services are industry neutral with services being provided to all segments of the market from consumers to suppliers, marketers, retailers, utilities, governments and other implementing and regulatory agencies.

Project Team & Bios

EDCA has a team of well qualified and experienced analysts that have been engaged in consulting activities with respect to the electric energy industry that cover a wide spectrum of issues. Fundamental market analysis, asset valuation, risk management, procurement, environmental and emissions issues, policy, financial and economic impact have been a significant part of analytical work completed by staff at EDCA over the last 10 years.

The following members of EDCA's staff will contribute to the proposed scope of work as outlined above.

- Duane Reid-Carlson, P.Eng., Present and CEO
  - General project management support, overall market insights and historical context
- Allen Crowley, B.A., MBA, Vice President, Studies and Regulatory
  - Lead contact, direct project management, specify and audit analytics, and presentation of report material
- Alex Markowski, B.Sc., Senior Energy Market Analyst
  - Research, quantitative and analytical skills, and development of report material

Duane Reid-Carlson, P. Eng.
President and CEO

Duane Reid-Carlson has 25 years' experience working in the oil and gas, petrochemical and electric industries. He is currently the President of EDC Associates Ltd—a company that he founded in 1992. Since that time Mr. Reid-Carlson has led a team of energy economic analysts that have been responsible for providing electric energy supply, demand and price forecast information, energy procurement, risk management, generation economic and regulatory analytical services. These services and information is generally used by participants in the electric industry to help support short and long-term energy procurement and investment decisions.

Mr. Reid-Carlson holds a B.Sc. degree in Electrical Engineering from the University of Alberta, Canada.

Following graduation he gained direct oil, gas, pipeline and petrochemical experience working on projects in the Middle East and later in the UK. Working in Alberta, he has led numerous electric utility planning forecast studies used to assess the need and timing of generation, transmission and distribution facilities. In electricity price forecast matters, he has been instrumental in the development of software used internally, as well as commercially by clients, to assess future marginal and imbedded electricity pricing in Alberta and other jurisdictions in the US.

Mr. Reid-Carlson has authored a series of studies concerning the fundamentals of several electricity jurisdictions, most notably for the Alberta market, that have been utilized by government agencies, industry participants, utilities, generation developers and marketers/retailers to aid in their energy procurement and capital project decision making processes. He has presented the findings of these studies at many industry conferences and regularly facilitates an introductory course on electric industry operation and restructuring.

Mr. Reid-Carlson has developed evidence and provided expert witness testimony in the electric industry with respect to several legal and regulatory proceedings and is currently a Director on the Board of the Independent Power Producers Society of Alberta (IPPSA).

Allen Crowley, BA, MBA
Vice President, Market and Regulatory Studies

Allen Crowley has over 40 years of experience in the electricity, telecommunication and water industries. He has held widely varied, senior corporate positions and consulted in electricity, telecommunications, water, sewage and solid waste utilities in the areas of: Electricity market design, PPA analysis, utility rate making, regulation; Retail and wholesale marketing and sales of energy and derivative hedging products; Strategic marketing and strategic planning; Complex financial modeling and engineering economic studies; Process re-engineering, performance measurement and benchmarking; Customer service improvement and surveying, Delphi Nominal Group Technique; Evaluation of Potential Alberta Direct Load Control (Demand Side Management).

Mr. Crowley holds a BA Economics and Philosophy and an MBA both from the University of Alberta, Canada.

Mr. Crowley has participated in hearings before rate tribunals and consultative sessions in several utilities and jurisdictions (on behalf of Edmonton Telephones, Edmonton Water & Sanitation, West Kootenay Power, Aquila Energy Canada, IPPCAA, Bow City). He has an in-depth knowledge of the proposed FERC SMD NOPR and the Alberta Energy Transmission Policy. He has developed numerous complex financial models including valuation for the sale of a retail electrical distribution company, evaluation and bidding strategy for Alberta PPA's, numerous co-gens and hedging strategies, including weather products, and various rate designs. He prepared several successful comprehensive applications for BC Hydro's "Power for Jobs" and "Real Time Pricing" programs for major mining, chemical and lumber companies. He developed a unique operating lease financing process for Customer-Owned Substations, installing several in BC at a 20% and built the first customer owned substation in Alberta.

Mr. Crowley has had several papers and articles published in industry periodicals and made many presentations to industry conferences across Canada.

Alex Markowski
Senior Energy Market Analyst

Mr. Markowski holds a B.Sc. in statistics (actuarial science minor) from the University of Calgary and brings over 10 years of high-frequency quantitative market trading experience.

His present role at EDCA focuses on the creation of short and long-term price forecasts for the Alberta power market, in addition to generation economic development, energy procurement, cash flow analysis, PPA valuations and GHG scenario modeling for a variety of industry clientele. Mr. Markowski developed and maintains EDCA's data architecture that warehouses, disseminates and analyzes key electricity and natural gas data. He is responsible for the coding of proprietary in-house models and toolsets in a variety of object-oriented and database-centric programming languages, in addition to mentoring junior and senior analysts in technical skillsets, such as programming and critical thinking.

Mr. Markowski authors several industry-leading publications, including the Alberta kWh Newsletter, the Electricity SMP Predictions (ESP) Forecast Report, the Alberta Wind Energy Report and the Alberta Electricity Industry Statistics Report. He co-authors the Alberta Electricity Update, the Alberta Market Forecast Update and the annual Alberta Electric Industry Study.

Previous roles have seen him successfully negotiate the sale of a private investment management corporation, serve as investment counsel for a hedge fund trading US closed-end funds and consult within the bio-fuel industry.