Electricity Framework Review

Generation and Emissions Forecast:
Recommendations to the Electricity Framework Review Project Team for their consideration

Prepared by the Base Case Working Group of the CASA Electricity Framework Review Project Team

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1 Introduction

Recommendation 29 of the 2003 Emissions Management Framework for Alberta recommends that Alberta Environment lead, in consultation with Alberta Energy and other regulatory authorities, the establishment of a formal process, to be undertaken every five years, to review certain elements of the emissions management framework.

As part of the five year review initiated in 2013, a multi-stakeholder Base Case Working Group (BCWG) was established to:

- Develop a base case for the emissions profile expected under the Alberta Framework, and
- Update the emissions forecast for NOx, SO2, PM and Mercury and determine if the emissions are 15% higher for a five-year period than projected in the previous Five-Year Review.

The BCWG retained a consultant to assist with its work. The consultant undertook the work in two phases; the first to provide a detailed comparison of the key assumptions of previous forecasts and a second phase to provide a 2014 Emissions Forecast.

For the first phase of the work the consultant provided the key underlying assumptions for the 2003 NS-1 scenario, the 2008-2009 Base Case and the report entitled *Alberta's Annual Electricity Study 2013: Power Struggle*. Assumptions used in the various forecasts are appropriate for the time the models were developed however, they are different for the three time periods and have resulted in substantial differences in the models. In addition to the differences in assumptions there were also errors discovered in past models that impact the outcome of those models. It is important that users of the forecasts are aware of these aspects of the report. Details of these aspects are discussed in section 2.2 of this report.

2 Summary of Generation and Emission Forecasts

The Emissions Forecast was an important tool in the development of the 2003 Framework, as it allowed the project team to project the impact of the framework on emission reductions over time (for Nitrogen Oxides, Sulphur Dioxide, Particulate Matter and Mercury). To determine if there have been significant changes since 2008, an update of the forecast was completed in 2014, as part of the 5-year review.

The emission forecast encompasses the next 20 + years, until 2030.

2.1. 2014 Generation and Emissions Forecast

2.1.1. Mercury Emissions

Table 1: Mercury Emission Intensity Assumptions (mg/MWh) (EDC Associates, 2014)

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*

Figure 1: Mercury Emissions (mg) (EDC Associates, 2014)

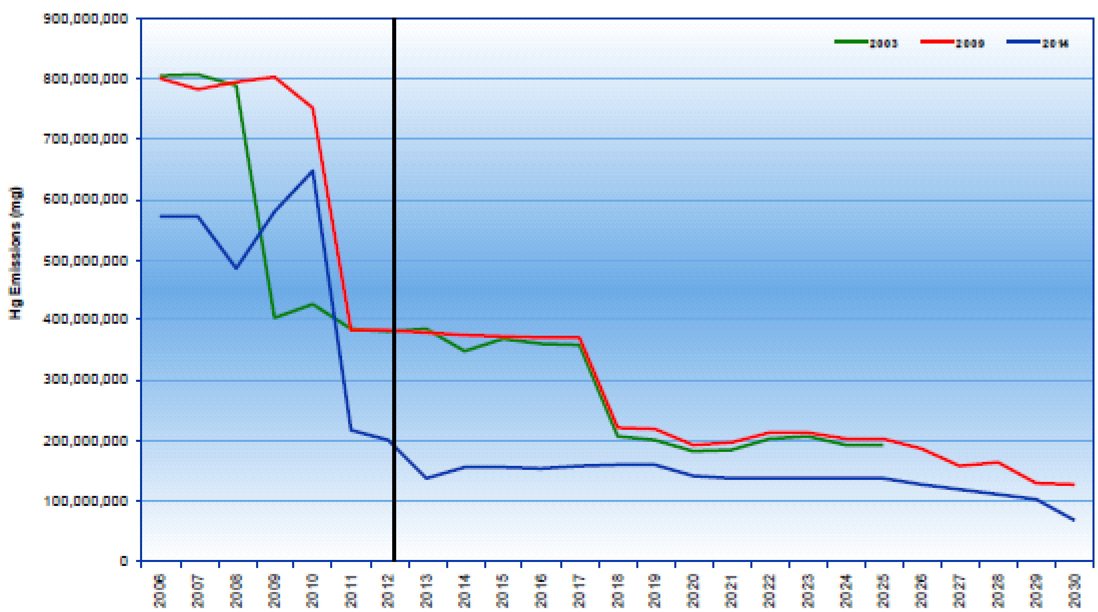
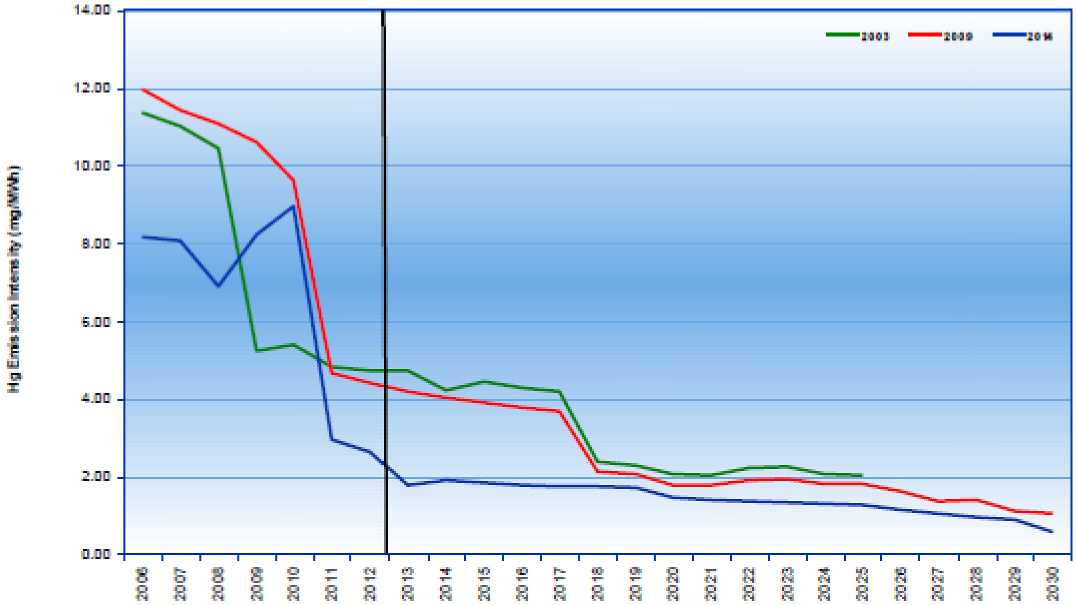


Figure 2: Mercury Emission Intensity (mg/MWh) (EDC Associates, 2014)



The Canadian Council of Ministers of the Environment (CCME) provides 2008-2012 progress reports detailing mercury emissions from coal-fired generation in Alberta.

Using an apportionment method to populate mercury emissions historically and then accounting for the capture rates required by regulation, a steep drop in emissions is noted in 2011 as it was assumed that all units met the 70% target and would meet the 80% target from 2013 onwards. Interestingly, HR Milner's emission intensity dropped sharply in 2012; however, this was because the unit opted to burn gas, resulting in fewer emissions.

A sharp decline occurs after 2010, the result of noticeably less coal-fired generation during the 2011-2013 period and the implementation of environmental regulations that required an initial 70% reduction in intensity for two years, followed by an 80% reduction moving forward. 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 assumed coal-fired unit retirements, then again towards the tail-end of the forecast when additional units begin to retire. These unit retirement-based declines are not as noticeable as the compliance-based one in 2010 because emission intensities changed substantially post-2011. 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.

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. 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 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 assumed unit retirements.

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. 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.

2.1.2. Particulate Matter Emissions

Figures 14 and 15 and Table 4 (below) present forecasts for Particulate Matter. In the near-term, emissions volume and intensity are forecast to rise due to the return of Sundance #1, Sundance#2 and Keephills#1(note that the 2014 forecast intensity for Sundance 1 and 2 is more than double of previous forecasts). Emission will then remain relatively flat (with intensity declining) until the next set of coal retirements at the end of 2019. From 2020 to the end of 2025 the emissions remain relatively flat with intensity declining as gas-fired generation increases while coal-fired generation remains flat. Beyond 2025, the emissions and intensity decreases significantly as a significant amount of coal-fired generation is forecast to retire.

Figure 3: Particulate Matter Emissions (kg) (EDC Associates, 2014)

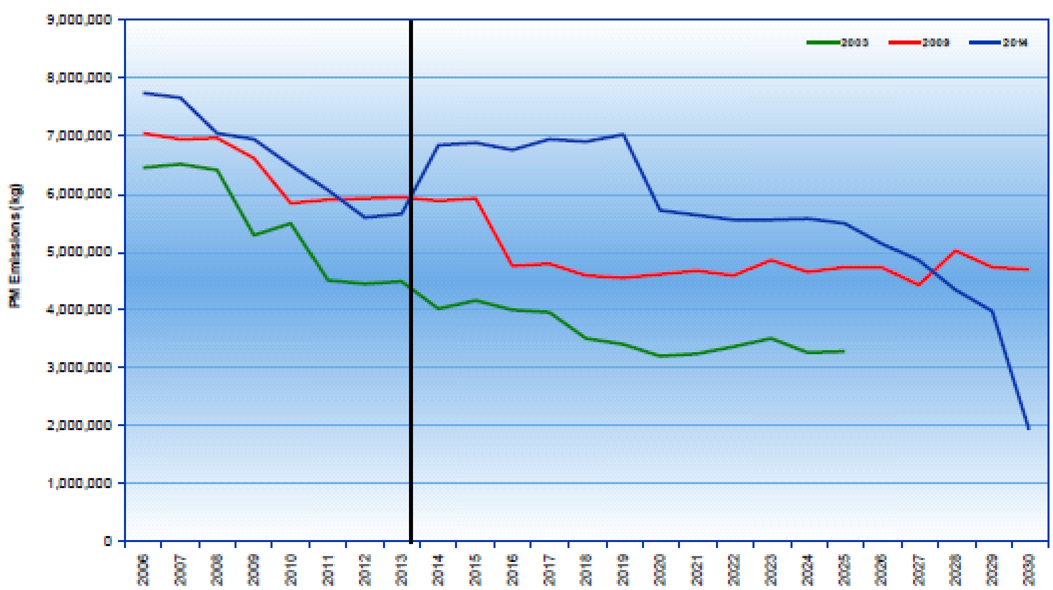


Figure 4: Particulate Matter Emission Intensity (kg/MWh) (EDC Associates, 2014)

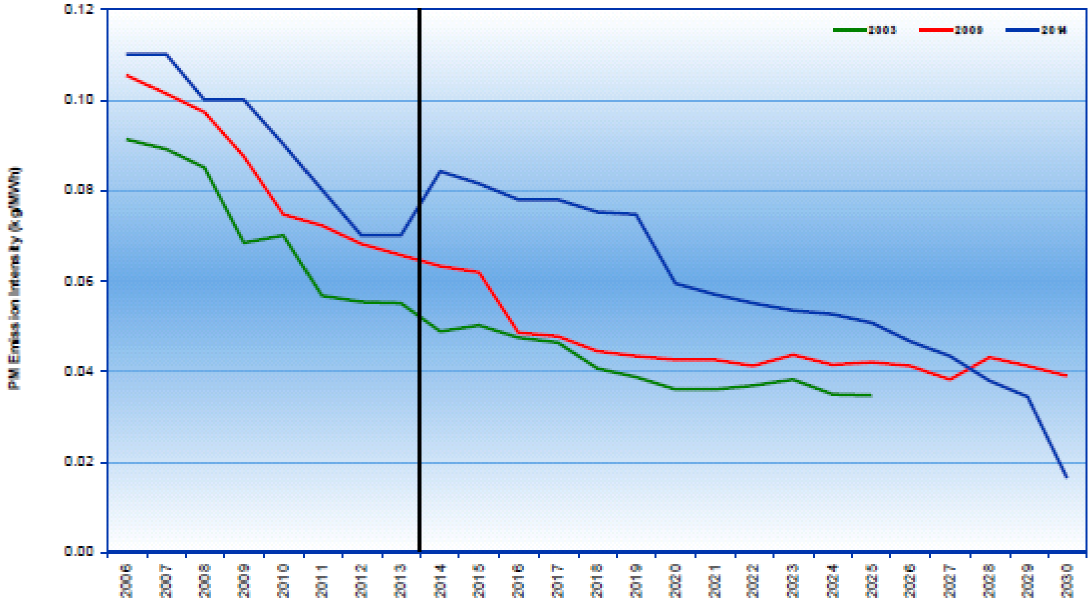


Table 2: Particulate Matter Intensity (kg/MWh) (EDC Associates, 2014)

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*

The actual PM emissions (2006 to 2013) have been above that forecasted by the 2003 and 2009 projections. For the 2003 forecast, this is due primarily to the PM BATEA standard not being implemented in 2009 as a co-benefit of Mercury capture and HR Milner not retiring in 2005. It was also assumed that Battle River 3&4 and Sundance 1&2 would retire at the end of their design life. The 2009 forecast assumed some units installed PM reduction as a co-benefit of mercury capture in 2009 and other units continued at current PM levels until the unit retires. - thus PM emissions are higher than the 2003 Forecast until 2017 when HR Milner (2015) and

Battle River units 3 & 4 (2016) and Sundance 1&2 (2017) were forecast to retire at the end of their 40-year or PPA design life. The 2014 forecast used actual PM intensities for 2006 to 2013 and to forecast future emissions an average of 2011 to 2013 values were used for the 2014+ intensities (see Table 2). Unit retirement dates in the 2014 forecast were set to match those set by the Federal GHG regulations.

For the coming period (2014 to 2025+), the significant gap between the 2014 forecast and that of 2003 and 2009 forecasts continues due to the PM BATEA standard not being implemented as a co-benefit of Mercury capture, changes in unit retirement dates and to changes in PM intensity assumptions for some units.

These results indicate that actual PM emissions since 2005 have exceeded the 15% emissions growth review trigger, whether compared to the 2003 or 2009 forecasts, and that the mass emissions indicates growth above the 15% threshold going forward – at least until several units are retired under the Federal GHG regulations near the end of the next decade. As per Recommendation 34, the Emissions Growth Trigger is more than 15% higher for a five year period thus the management framework elements addressing PM should be reviewed. It is proposed by the BCWG that this matter be referred to the EFR's PM Management subgroup.

2.1.3. Sulphur Dioxide Emissions

Table 3: Sulphur Dioxide Emission Intensity (kg/MWh) (EDC Associates, 2014)

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	4.89	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	1.98	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	1.98	1.99	2.03	1.83	1.95	1.98	1.95		
Sundance #4	SD4	2.10	1.99	1.98	1.97	1.94	2.00	1.82	1.95	1.93	1.93		
Sundance #5	SD5	2.09	1.85	1.78	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		

Figure 5: Sulphur Dioxide Emissions (kg) (EDC Associates, 2014)

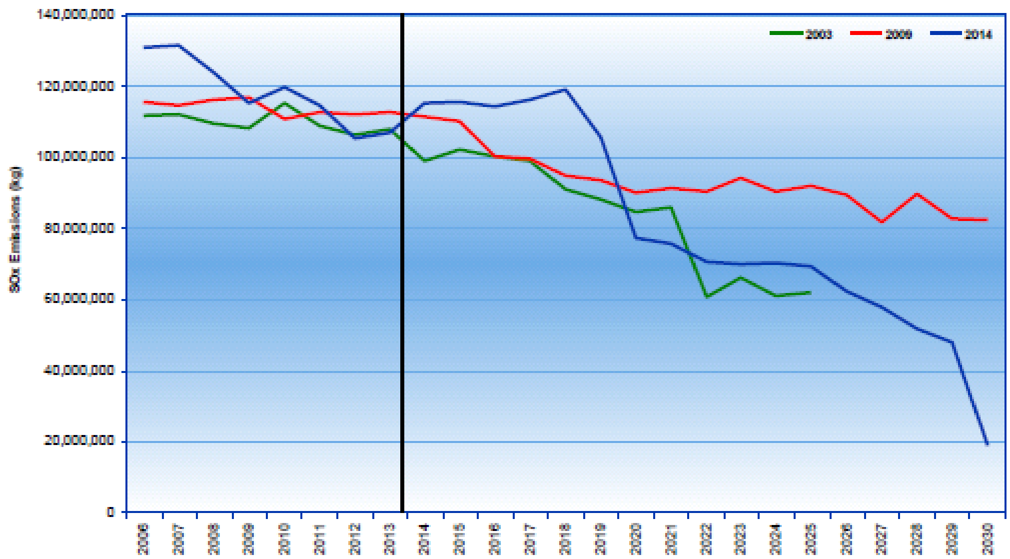
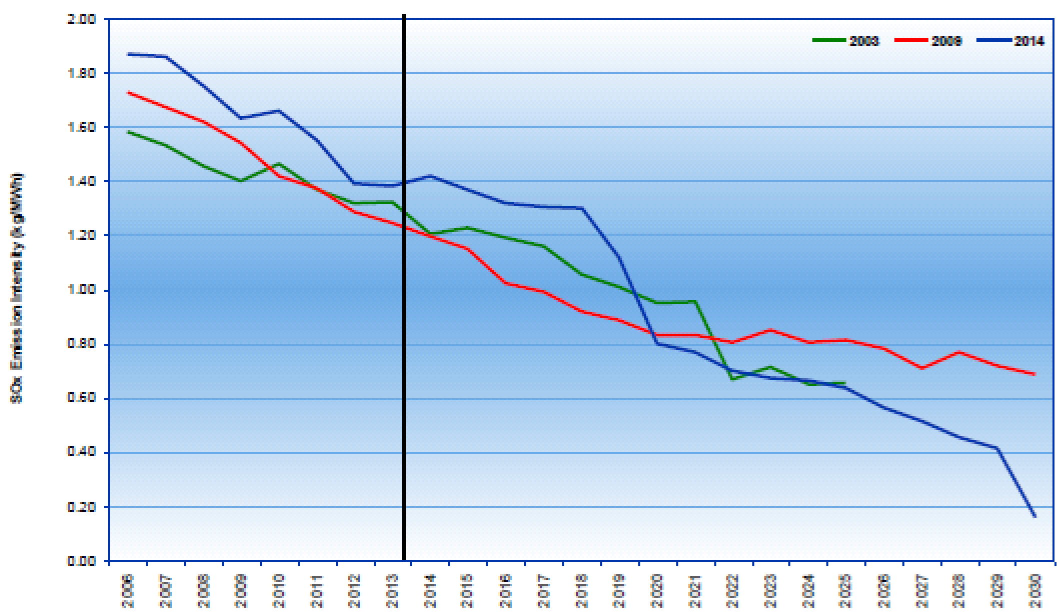


Figure 6: Sulphur Dioxide Emission Intensity (kg/MWh) (EDC Associates, 2014)



Modelling projections indicate that SO2 emissions will continue to fall over time as units meet their SO2 obligations in accordance with their BATEA end of design life timelines. Emissions are forecast to rise from 2013 in response to the return of Sundance 1&2 and Keephills 2 and then begin to fall as units convert and retire. 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. A similar drop can be seen in the 2003 forecast between 2021 and 2022. 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).

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%. Taking the impact of these different assumptions between the forecasts into consideration, it appears that the 2014 forecast for any given period is reasonably within 15% of that first projected in 2003.

The 2014 modelling conducted by EDC for CASA assumes early conversion of Sheerness 1 & 2 and Genesee 2 in order to generate sufficient SO2 credits to meet the emissions credit needs to operate end of design life units in the electricity sector. The consultant used a simplified method of typical capital cost of air quality control equipment divided by the remaining operating life of a unit after retrofit to pay off the investment. The units that resulted in the lowest cost per tonne of emission reductions using this method were assumed to be retrofit first. The method does not account for the commercial complexities of the Power Purchase Arrangements, the Alberta Electricity market, extra costs associated with retrofits or whether the addition of air control equipment is physically possible. The method also assumes that there is a viable market to buy and sell emissions credits that will attract private investors to make large capital investments in emission control equipment. The method is simply intended to illustrate emissions credit availability for continued operation of end of design life units and should not be considered as an assessment of technical and economic viability of emission control equipment options. Whether industry achieves compliance with the Alberta Framework in this manner, or through shutdowns, retrofits to other units or through other actions will be dependent on the assessment and decisions made by electricity sector participants on the viability of the various options.

This modelling assumes that the SO2 emission standards remain unchanged from that recommended by CASA in 2009.

2.1.4. Nitrogen Oxides Emissions

Table 4: Nitrogen Oxide Emission Intensity (kg/MWh) (EDC Associates, 2014)

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	1.48	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	ECD1	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.

Figure 7: Nitrogen Oxide Emissions (kg) (EDC Associates, 2014)

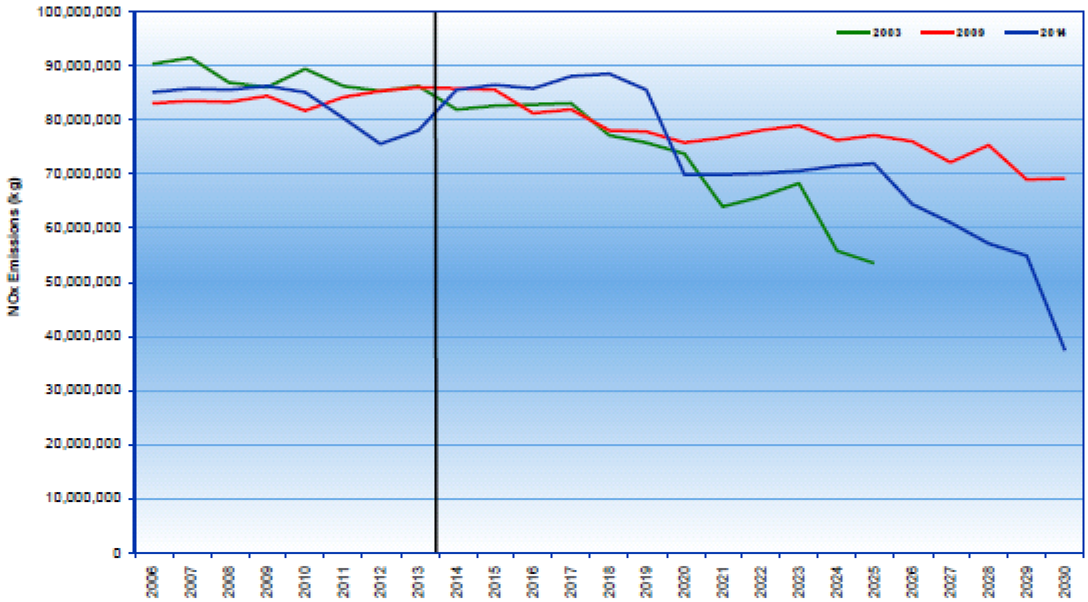
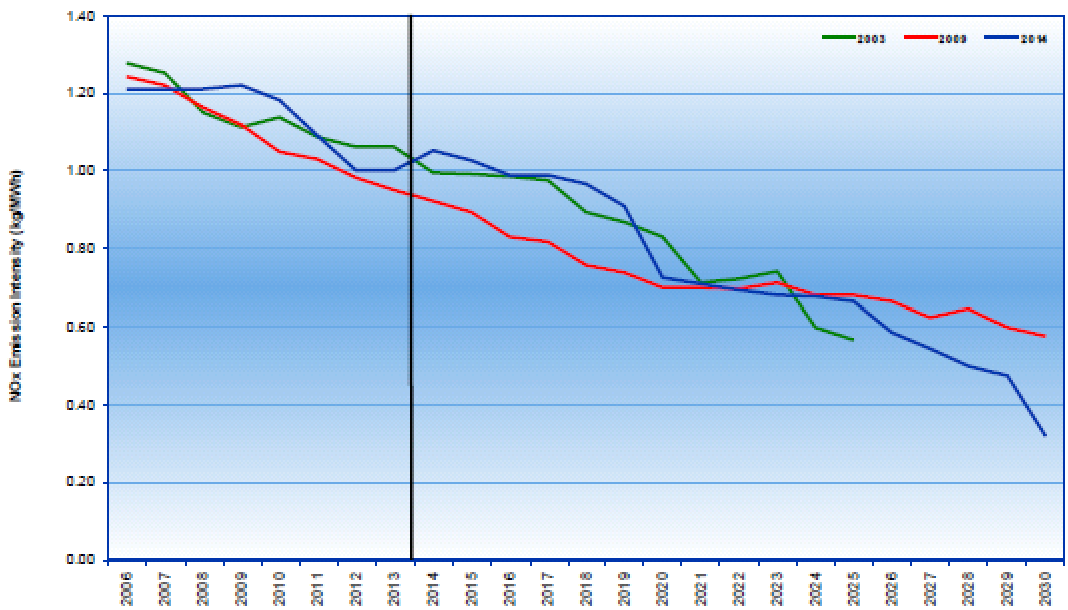


Figure 8: Nitrogen Oxide Emission Intensity (kg/MWh) (EDC Associates, 2014)



Modelling projections indicate a continued trend of modestly declining NOx emissions as new gas-fired units partially offset coal-fired units that retire or convert to meet their NOx obligations in accordance with their BATEA end of design life timelines. Emissions are forecast to rise in the near term as Sundance 1&2 and Keephills 2 return to service, along with commisssioning of several oil sands projects and the Shepard facility begins operations, and then begin to drop at the end of the decade. Similar to the SO2 modelling, key differences between the 2014 forecast and prior ones are attributable to:

a) Prior to 2020: the 2014 forecast is higher as it uses actual intensity values instead of the assumed values used in prior forecasts.
b) After 2010: the 2009 forecast is higher due to a mathematical error (it should have dropped in a manner similar to 2014 and 2003.

Taking the impact of these different assumptions between the forecasts into consideration, it appears that the 2014 forecast for any given period is reasonably within 15% of that first projected in 2003 at least until 2025. After 2025, NOx emissions are projected to remain higher than originally projected.

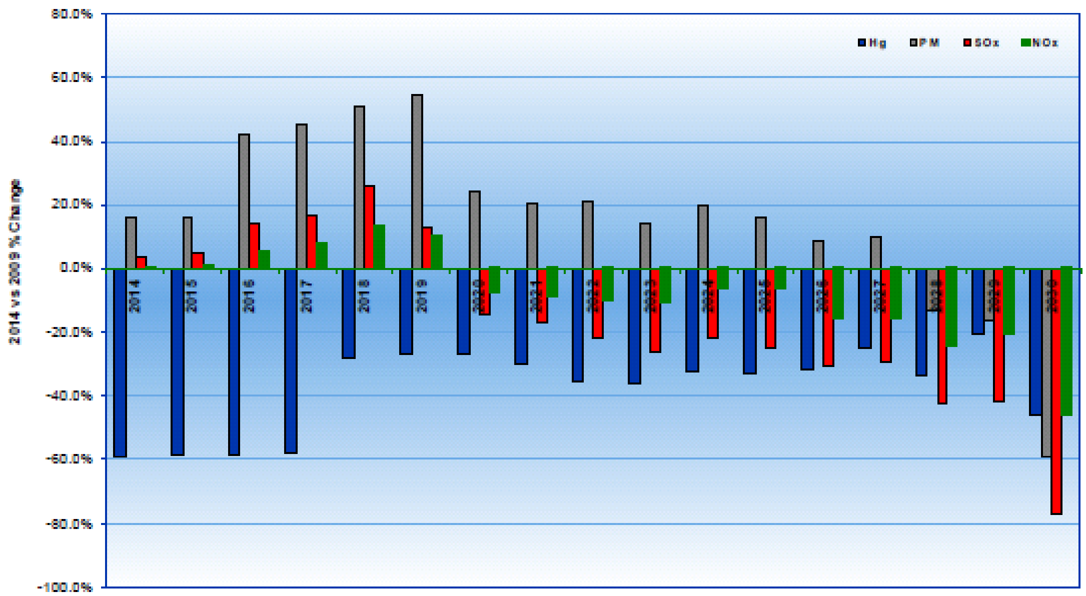
The 2014 modelling conducted by EDC for CASA assumes early conversion of Sheerness 1 & 2 and Genesee 2 in order to generate sufficient NOx credits to meet the emissions credit needs to operate end of design life units in the electricity sector. The consultant used a simplified method of typical capital cost of air quality control equipment divided by the remaining operating life of a unit after retrofit to pay off the investment. The units that resulted in the lowest cost per tonne of emission reductions using this method were assumed to be retrofit first. The method does not account for the commercial complexities of the Power Purchase Arrangements, the Alberta Electricity market, extra costs associated with retrofits or whether the addition of air control equipment is physically possible. The method also assumes that there is a viable market to buy and sell emissions credits that will attract private investors to make large capital investments in emission control equipment. The method is simply intended to illustrate emissions credit availability for continued operation of end of design life units and should not be considered as an assessment of technical and economic viability of emission control equipment options. Whether industry achieves compliance with the Alberta Framework in this manner, or through shutdowns, retrofits to other units or through other actions will be dependent on the assessment and decisions made by electricity sector participants on the viability of the various options.

This modelling assumes that the NOx emission standards remain unchanged from that recommended by CASA in 2009.

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

In the 2003 Framework, Recommendation 34 directs each five-year review team to assess whether emissions from the previous five-year forecast have increased more than 15%. This section illustrates the percent change between the current (2014) and prior (2009) forecast. Figure 20 presents this information in a bar chart.

Figure 9: % Change Between the 2014 and 2009 Emissions Forecasts (EDC Associates, 2014)



Based on the above information, the Base Case Working Group agreed that the emissions growth for Mercury, SO2 and NOx are less than the 15% trigger value for a five year period. The PM emissions modelling indicates growth is above the 15% trigger and as such the management framework elements addressing PM should be reviewed. The Base Case Working Group proposed that this matter be referred to the PM Management subgroup.

One of the challenges encountered by the team is that between 5-year reviews, many of the economic factors and environmental policy decisions that were used to develop emission forecasts changed quite dramatically. The working group spent some time early on in their discussions asking the consultant to identify these changes and look to see if they were material.

The three models used assumptions that were appropriate at the time the model was developed but this has resulted in differences between the models on supply/demand relationships, pool price expectations and emissions forecasts. For example the 2003 model assumed the Alberta economy would be strong with GDP growth averaging 2.4% between 2004 and 2008. The GDP for this period actually averaged 5.4% driven primarily by a substantial increase in the price of crude oil and natural gas. Table 1 summarizes the different thinking in the assumptions of the three models. Most assumptions will affect the overall electricity production and the fleet fuel mix. Different assumptions were also made on unit retirements. For example in the 2003 forecast the HR Milner unit was assumed to retire in 2005, 2015 in the 2008 forecast and 2019 in the 2014 forecast.

The Table below shows the assumptions that were used in the three forecasts.

Table 5: Summary of Model Changes

Assumption	2003	2008-09	2014
Oil Price / Economy	Low $30 Oil, $5 Gas $CDN - $0.75	High $100 Oil, $10 Gas,	Strong $95 Oil, $6 Gas, Slump in 2009-10, strong in 2014
Load Growth	Steady, good growth	Optimistic growth	Subdued growth
Coal Retirements	Typically 10 years after End of Design Life, Some early retirements See appendix D	Typically 10 years after End of Design Life, Some early retirements, See appendix D	Typically 10 years after End of Design Life, Coal retires due to Federal GHG Regulation See appendix D
Generation Additions	gas (cogen), coal, wind	coal, wind, gas, hydro	gas (combined cycle), wind
Pool Price	Low '04-'14	High Throughout	High '06-'08, low '14-'20
NOx, SO2, Hg, PM	Low intensities for SO2 and NOx See appendix D	Low intensities for SO2 and NOx See appendix D	NOx and SO2 use 5 year actual average, PM uses 3 year average, See appendix D
Emissions Reductions Assumptions	Units assumed to meet BATEA at End of Design Life	2008 – Units assumed to meet BATEA at End of Design Life 2009 – No reductions at End of Design Life due to error in model.	Some units assumed to retrofit early to allow other units to not meet BATEA at End of Design Life

Through the analysis of the assumptions, some mistakes and inappropriate assumptions were discovered in the 2003 and 2008 reports. The SO2 and NOx emissions intensities for the majority of coal-fired generating units were low; some units as much as 30% lower than the baseline values. Since the forecast is very sensitive to the choice of intensities, both the 2003 and 2008 emissions forecasts were understated for SO2 and NOx emissions. It should also be noted that the 2009 forecast intended to apply the BATEA levels at End of Design Life however, this did not occur as units continued to operate at 2009 intensities until the unit was assumed to retire. This resulted in the 2009 emissions forecast reductions occurring slower than intended.

The PM forecasts in 2003 and 2009 used PM intensity values based on the expectation that the PM BATEA standard would be implemented as a co-benefit of Mercury capture for a number of units and assumed retirement of certain units which subsequently did not occur. Further, the 2014 forecast applies different PM intensity assumptions for some units.

Please see Appendix B and C for the Terms of Reference for the consultant.

2.3. Lessons Learned and Recommendations for Future Five-Year Reviews

Advice:
For the foreseeable future, given environmental considerations and commodity prices, NOx emissions will likely be a growth area. This should be considered in taking action on “new unit” gas-fired standards for the 2018 Electricity Framework Review.

Lessons Learned and Recommendations for Future Five-Year Reviews

The Framework's recommendation #34: Emissions Growth Review Trigger reads as follows:

"During the Five-Year Review, if the updated emissions forecast for any of NOx, SO2, PM and Mercury is 15% higher for a five-year period than projected in the previous Five-Year Review, the management framework elements addressing that substance should be reviewed.”

Forecasts for any given period (2003, 2009, 2014, etc.) are based upon educated guesses about future trends (macroeconomics, unit retirements, environmental policies, etc.). Such assumptions will naturally change over time as circumstances evolve. “Forecast creep” is a potential concern, whereby emissions grow by less than 15% in each 5-year update, but the aggregate change across two or more updates exceeds 15%. Further, as demonstrated with this report, subsequent analysis can uncover errors in prior forecasts. In considering these issues, the BCWG has found that a strict and literal application of recommendation #34 is problematic.

The BCWG recommends that interpretation of recommendation #34 should be viewed in a “directional” sense, based on the following:

- At the time of the development of the Framework, there was a public perception expressed in regulatory hearings that many of the air-related issues were coming not only from new plants but existing plants. Furthermore, much of the existing generation was considered middle-aged and would soon hit a point defined as a designated end-of-design-life when decisions would be made about either repowering a unit or shutting it down. It was at that time that major improvements in environmental performance could be made. Given that, emission forecasts necessarily show these meaningful emission reductions over time from the existing fleet at those points.
- New generation build is expected to be far less emission intensive than Alberta’s coal units. A catch-all numerical value was put in place to show that in fact action had occurred on existing units and that new units were markedly better in emission performance and that this could be demonstrated.
- Forecasts are a directional indication of whether or not things are working as agreed to. This is why a forecast has value, not only to evaluate success but also to see impact of actions taken during the five-year reviews.

- In this context, the original 2003 forecasts form an integral part of the Framework "consensus" as to the general timing and quantum of emissions reductions expected to be achieved by the Framework.

- Where subsequent forecast analysis demonstrates material errors (e.g. such as intensity assumptions), the impact of these errors should be considered.

Advice for future groups

- Basis of comparison should consider the original emissions forecast (2003), as that reflects the intent of the framework and the directional basis for emissions reductions over time, and also assess how trends have evolved in subsequent forecasts.
- New, "go-forward" forecasts should always start the year after the most complete actual emission data is available. As was found with the 2014 review, recreating a prior forecast using updated assumptions from what was thought to be the best assumptions at that time is of limited value. If the common understanding is that the Framework was meant to be a de-grandfathering exercise, the blended forecast (using actual emission data coupled with some type of projections looking forward) becomes a way to evaluate success or whether further action would be required.
- While "forecast creep" has been identified as a potential issue by the BCWG, it may be immaterial to the overall intent of the Framework.

2.4. Impact of the proposed new BATEA standards on projected future emissions

Concurrent to the work of the BCWG, the Control Technologies and Reduction Strategies (CTRS) Task Group was having discussions to set new emission limit standards based on the Best Available Technology Economically Achievable (BATEA). Once new emission limit standards have been agreed upon, the task group would arrange for the emission forecast to be updated accordingly.

The group has agreed that this work is unwarranted for the following reasons:

- The CTRS task group agreed to retain the standards for conventional coal that were agreed to in May 2010. Since there is no change, this will not impact the forecast.
- The CTRS group has not been able to reach agreement on standards for gas-fired generation.
- There is agreement on standards for new reciprocating engines, but reciprocating engines are currently not included in the forecast.

It should be noted that the EFR team did not reach a consensus on the need to review and/or adjust the Alberta Framework given fundamentally divergent views regarding what is required to allow changes to be made to the Framework. The Government of Alberta has been asked to consider if adjustments to the Framework are warranted. A final decision from the Government of Alberta on a full review of the Framework is still pending and that decision may require a review of any foregoing provisional agreements.

Appendix A: Unit Retirement Assumptions

Unit	ISD Year	End of Design Life or PPA expiry	50th year or GHG EOL
Milner	1972	2012	2019
Battle River 3	1969	2013	2019
Battle River 4	1975	2015	2025
Sundance 1	1970	2017	2019
Sundance 2	1973	2017	2019
Sundance 3	1976	2020	2026
Sundance 4	1977	2020	2027
Sundance 5	1978	2020	2028
Sundance 6	1980	2020	2029
Battle River 5	1981	2021	2029
Keephills 1	1983	2023	2029
Keephills 2	1984	2024	2029
Sheerness 1	1986	2026	2036
Genesee 1	1989	2029	2039
Sheerness 2	1990	2030	2040
Genesee 2	1994	2034	2044
Genesee 3	2004	2044	2054
Keephills 3	2011	2051	2061

Table 6: Unit Retirement Assumptions

Coal-Fired Retirement Assumptions					
Unit	ISD Year	2003 Model	2008 Model	2013 Model	Reason
Battle River #3	1969	2014	2016	2019	50th Year
Sundance #1	1970	2018	2018	2019	2019 is before 50th Year
Sundance #2	1973	2018	2018	2019	2019 is before 50th Year
HR Milner	1972	2005	2015	2019	2019 is before 50th Year
Battle River #4	1975	2016	2016	2025	50th Year
Sundance #3	1976	2026	2026	2026	50th Year
Sundance #4	1977	2027	2027	2027	50th Year
Sundance #5	1978	2028	2028	2028	50th Year
Sundance #6	1980	2030	2030	2029	2029 is before 50th Year
Battle River #5	1981	2031	2031	2029	2029 is before 50th Year
Keephills #1	1983	2033	2033	2029	2029 is before 50th Year
Keephills #2	1984	2034	2034	2029	2029 is before 50th Year
Sheerness #1	1986	2036	2036	2036	50th Year
Genesee #1	1989	2039	2039	2039	50th Year
Sheerness #2	1990	2040	2040	2040	50th Year
Genesee #2	1994	2044	2044	2044	50th Year
Genesee #3	2004	2040	2034	2054	50th Year
Keephills #3	2011	2043	2041	2061	50th Year

Table 7: Coal-Fired Retirement Assumptions (EDC Associates, 2014)

Appendix B: Terms of Reference for “Electricity Framework 5 Year Review 2013 Phase I Report

Objective and Scope

EDC Associates Ltd. will provide the CASA task group with a detailed comparison of the key assumptions for the following:

- 2003 Generation and Emissions Forecast prepared by EDC for CASA
- 2009 Generation and Emissions Forecast prepared by EDC for CASA
- Alberta’s Annual Electricity Study 2013: Power Struggle – How wind and co-gen volatility interact.

In addition to the macro economic assumptions previously provided by EDC, the key assumptions provided for each of the model runs above should include the following:

1) How is compliance with the Alberta Framework and the Federal GHG Regulation assumed to be achieved?
    a. What is the assumed environmental legislation compliance cost (capital and operating) for each pollutant?
    b. How does the model allocate these costs to affected units (i.e. one time cost, vs. adding to levelized costs; and over what time period are the costs assumed to be amortized)?
    c. How are emissions credits accounted for in the projections?
2) What are the assumed future emission / BATEA standards?
3) What are the primary triggers for unit shut downs in the various scenarios?
4) How does the model deem investment decisions to be made (i.e. does it consider a rate of return, reserve margin, etc)?

Where assumptions were made in historical forecasts that didn’t reflect actual values seen, the comparison should also comment on whether this meant material differences in the forecast.

Proposed Time Line and Schedule

Based on the time necessary to complete the work plan tasks identified above, the project would be completed over the following time line.

Task	*Timeline*	*Payment Schedule*
Contract award and project start.	November 21, 2013	-
Prepare detailed review & comparison of assumptions	December 27, 2013	-
Prepare & present report on phase 1 to working group	January 13, 2014	-
Submit final report	**January 13, 2014**	**Max. $25,000**

Costs will be billed on a time and charges basis, as incurred on a monthly progress billing basis. Invoices are to include the assignment of billable hours to specific tasks. The maximum amount to be paid to the consultant under this agreement shall not exceed $25,000 plus GST.

All Consultant reports and any appended studies will be submitted provided electronically to Robyn Jacobsen at RJacobsen@casahome.org.

Appendix C: Terms of Reference for "Electricity Framework 5 Year Review 2013 Phase II Report

Objective and Scope

EDC Associates Ltd. will update the 2008/09 emission and generation forecast. This work should be based on the assumptions detailed in the Phase 1 report. Source standards to be used in the modelling will be those agreed to in the "Report on the First Five-Year Review of the Emissions Management Framework for the Alberta Electricity Sector", May 13, 2010.

Part 1

- The consultant will provide the task group with a list of proposed assumptions and methodologies, and possible alternates, for a 2013 Generation and Emissions Forecast, including comments on the anticipated impacts to the emissions profile. Source standards will be those agreed to in the First Five Year Review of the Emissions Management Framework for the Alberta Electricity Sector, May 13, 2010, or in CASA's sole discretion, as renegotiated early in the process.
- The task group will review and discuss the proposed assumptions before the consultant proceeds with the actual work. In particular, the consultant should list any assumptions used for emissions credits under the Alberta Framework and.

Part 2

This work will focus on updating the 2008/09 emission and generation forecast to reflect 2013/14 information and any methodological improvements proposed by the consultant and/or approved or modified by the Task Group.

a) **Parameters**: the 2013 emission and generation forecast should include the four parameters listed below:
   - NOx
   - SO2
   - PM
   - Hg

b) **Timeframe**: The primary focus is the emission forecast for the 5 year period from 2013-2018, however we are also very interested in a forecast for the next 25 years (or at least until 2040).

c) **Updated 2003 and 2008/09 Forecasts:** The modelling for the 2003 and 2008/09 forecasts should be recreated using:
   - Actual emissions intensities (numbers can be retrieved from the Emissions Trading Registry, and confirmed by Alberta Environment and Sustainable Resource Development)
   - All other assumptions developed for the original forecasts should remain the same.

d) **Year-Over-Year Comparison:** To ease the comparison of the updated forecast with the 2003 and 2008 forecasts, the consultant's final report should include data tables and associated figures (for both annual and cumulative emissions) from the:
   - 2003 Generation and Emissions Forecast prepared by EDC for CASA
   - 2008/09 Generation and Emissions Forecast prepared by EDC for CASA

e) **Presentations**: The consultant should prepare for one in-person presentation to the project team of the final report.

f) **Other Considerations**
   - All applicable figures and data tables should include annual actual emission values and intensities from 2003 to present. Emissions from coal-fired generation, gas-fired generation, and the sector as a whole should be presented in all figures and data tables.
   - All materials used to prepare the forecast (ie technical reports) should be identified and either listed or included in appropriate appendices, including all data tables
   - Input data (mass emission) will be supplied by Alberta Environment and Sustainable Resource Development. Please identify any additional data requirements.

Proposed Time Line and Schedule

Based on the time necessary to complete the work plan tasks identified above, the project would be completed over the following time line.

Task	*Timeline*	*Payment Schedule*
Contract award and project start.	April 15, 2014	-
Prepare & present report on phase 2 to working group	May 15, 2014	-
Submit final report	**May 30, 2014**	**$40,000**

Costs will be billed on a time and charges basis, as incurred on a monthly progress billing basis. Invoices are to include the assignment of billable hours to specific tasks. The maximum amount to be paid to the consultant under this agreement shall not exceed $40,000 plus GST.

All Consultant reports and any appended studies will be submitted provided electronically to Robyn Jacobsen at RJacobsen@casahome.org.

Appendix D: Emissions Intensities used in 2003, 2009 and 2014 Forecasts

Historical SOx Assumptions (kg.MWh)					
ID	Name	Baseline	2003 Forecast Intensity	2009 Forecast Intensity	2014* Forecast Intensity
BR3	Battle River #3	5.10	3.60	3.60	5.56
BR4	Battle River #4	5.10	3.60	3.60	5.48
BR5	Battle River #5	5.04	3.60	3.60	4.84
HRM	H.R. Milner	5.32	4.00	4.00	1.97
SH1	Sheerness #1	5.93	5.00	5.00	6.47
SH2	Sheerness #2	5.93	5.00	5.00	6.49
GN1	Genesee #1	2.33	2.10	2.33	2.16
GN2	Genesee #2	2.33	2.10	2.33	2.16
KH1	Keephills #1	2.03	1.80	1.80	2.21
KH2	Keephills #2	2.03	1.80	1.80	2.21
SD1	Sundance #1	1.68	2.00	2.00	1.66
SD2	Sundance #2	1.67	2.00	2.00	1.62
SD3	Sundance #3	2.10	2.00	2.00	1.95
SD4	Sundance #4	2.10	2.00	2.00	1.93
SD5	Sundance #5	2.09	2.00	2.00	2.00
SD6	Sundance #6	2.09	2.00	2.00	2.00
WB1	Wabamun #1		2.90	2.90	
WB2	Wabamun #2		2.90	2.90	
WB3	Wabamun #3		2.90	2.90	
WB4	Wabamun #4	3.12	2.90	2.90	
GN3	Genesee #3	0.80	0.80	1.03	0.99
KH3	Keephills #3	0.72	0.80	0.65	0.69
Past/Current Coal Uprates			0.00	0.00	
All Future Coal Units			0.00	0.65	

* Actual intensites used for 2006 to 2013 and forecast intensity used for 2014+, see Table 4

NOx Intensities by Unit and Year					
ID	Name	Baseline	2003 Forecast Intensity	2009 Forecast Intensity	2014* Forecast Intensity
BR3	Battle River #3	2.28	1.60	1.60	2.03
BR4	Battle River #4	2.28	1.60	1.60	1.99
BR5	Battle River #5	2.39	1.60	1.60	2.11
HRM	H.R. Milner	2.88	1.40	1.40	1.61
SH1	Sheerness #1	1.93	1.80	1.80	2.08
SH2	Sheerness #2	1.93	1.80	1.80	2.09
GN1	Genesee #1	2.13	2.10	2.10	2.00
GN2	Genesee #2	2.13	2.10	2.10	2.00
KH1	Keephills #1	2.19	1.90	1.90	2.07
KH2	Keephills #2	2.17	1.90	1.90	2.05
SD1	Sundance #1	1.52	1.60	1.60	2.38
SD2	Sundance #2	1.55	1.60	1.60	2.38
SD3	Sundance #3	1.63	1.60	1.60	1.99
SD4	Sundance #4	1.64	1.60	1.60	1.97
SD5	Sundance #5	1.50	1.60	1.60	1.72
SD6	Sundance #6	1.50	1.60	1.60	1.70
WB1	Wabamun #1		1.80	1.80	
WB2	Wabamun #2		1.80	1.80	
WB3	Wabamun #3		1.80	1.80	
WB4	Wabamun #4	2.17	1.80	1.80	
GN3	Genesee #3	1.18	1.20	1.20	0.59
KH3	Keephills #3	0.62	0.69	0.69	0.55
Past/Current Coal Uprates			0.00	0.00	
All Future Coal Units			0.00	0.47	
ALS1	Air Liquide (Sheel Scotford Refinery)	0.20	0.50	0.50	0.13
MKR1	ATCO/Shell Lease 13 Muskeg River	0.20	0.30	0.30	0.09
PR1	Primrose #1		0.30	0.30	
JOF1	Joffre		0.30	0.30	
PH1	Poplar Hill #1	0.22	0.30	0.30	0.71
RB5	Rainbow #5	0.63	0.53	0.53	0.74
RL1	Rainbow Lake #4	1.22	0.50	0.50	0.38
GOC1	Maxim Gold Creek (Ormat)		0.50	0.50	
DOW1	Dow Chemicals		0.50	0.50	
DOWG	Dow Chemicals		0.50	0.50	

EC01	Encana Cavalier Phase II (IBOC)	0.57	0.30	0.30	0.54
NX01	Encana/Nexen Balzac (IBOC)	0.54	0.30	0.30	0.45
IOR1	IOL (Mahkeses - Phase 11 to 13)		0.30	0.30	
ME01-05	Maxim Power		0.30	0.30	
FNG1	Fort Neilson (new combined cycle)		0.50	0.50	
SCR1	Suncor Tar Island		1.32	1.32	
SCR6	Suncor Stage 3 Utilities (Firebag S)		1.32	1.32	
SCR7	Suncor Firebag Stage 4		1.32	1.32	
SCL1	Syncrude Mildred Lake		0.50	1.32	
BCRK	Bear Creek #1 & #2	0.28	0.30	0.30	0.45
TC01	TCP Carsland/Agrium (IBOC)	0.20	0.30	0.30	0.13
TC02	TCP Redwater	0.20	0.30	0.30	0.16
ST1	Sturgeon #1		11.00	0.30	
ST2	Sturgeon #2		11.00	0.30	
CG1	Cloverbar (Old) #1		2.50	2.50	
CG2	Cloverbar (Old) #2		2.50	2.50	
CG3	Cloverbar (Old) #3		2.50	2.50	
CG4	Cloverbar (Old) #4		2.50	2.50	
RB1	Rainbow #1	5.12	2.50	2.50	0.00
RB2	Rainbow #2	5.33	2.50	0.30	6.47
RB3	Rainbow #3	5.43	2.50	2.50	0.00
RG10	Rossdale #10		2.50	2.50	
RG9	Rossdale #9		2.50	2.50	
RG8	Rossdale #8		2.50	2.50	
APS1	ATCO/Shell Scotford (Upgrader)	0.31	0.30	0.30	
CAL1	ENMAX Calgary Energy Centre	0.20	0.11	0.11	0.06
EC04	ENCANA Foster Ck		0.30	0.30	
MKRC	MacKay River	0.20	0.30	0.30	0.12
NPC1	Northstone		0.30	0.30	
ENC1	Cloverbar (New) #1	0.30		0.30	0.39
ENC2	Cloverbar (New) #2	0.20		0.30	0.25
ENC3	Cloverbar (New) #3	0.20		0.30	0.23
CRS1	Crossfield #1	n/a			0.26
CRS2	Crossfield #2	n/a			0.17
CRS3	Crossfield #3	n/a			0.24
NPP1	Northern Prairie Power	n/a			0.27

CMH_11DLE	CMH 11 (New)	0.30			0.21
MKR2	Muskeg River 2	0.20			0.10
CMH_10	CMH 10	2.54			
CMH_8	CMH 8	2.05			2.91
CMH_11DLE	CMH 11 (New)	2.02			
APS1	Scotford	0.31			0.21
VVW1	Valleyview 1	0.50			0.97
VVW2	Valleyview 2	1.89			1.71
CMH_10DLE	CMH 10 (New)	0.30			0.26
CMH_15	CMH 15	0.30			0.24
CMH_14	CMH 14	0.24			0.33
Historical Unnamed Gas Units			0.30	(*)	
Future Gas Units			0.30	(*)	
* Actual intensites used for 2006 to 2013 and forecast intensity used for 2014+, see Table 4					

Particulate Matter Intensities by Unit and Year										
		2003 Particulate Matter (kg/MWh)			2009 Particulate Matter (kg/MWh)			2014 Particulate Matter (kg/MWh)		
ID	Name	PM Installed	Pre-Installaion Intensity	Post-Installation Intensity	PM Installed	Pre-Installaion Intensity	Post-Installation Intensity	PM Installed	Pre-2014	2014+
BR3	Battle River #3	2009	0.23	0.095		0.23	0.23		Actual Value	0.22
BR4	Battle River #4	2009	0.23	0.095		0.23	0.23		Actual Value	0.22
BR5	Battle River #5	2009	0.23	0.095		0.23	0.23		Actual Value	0.38
HRM	H.R. Milner	2009	0.81	0.095		0.81	0.81		Actual Value	0.20
SH1	Sheerness #1	2009	0.13	0.095		0.13	0.13		Actual Value	0.06
SH2	Sheerness #2	2009	0.13	0.095		0.13	0.13		Actual Value	0.06
GN1	Genesee #1	2009	0.14	0.095	2009	0.14	0.095		Actual Value	0.20
GN2	Genesee #2	2009	0.14	0.095	2009	0.14	0.095		Actual Value	0.20
KH1	Keephills #1	2009	0.11	0.095	2009	0.11	0.095		Actual Value	0.10
KH2	Keephills #2	2009	0.11	0.095	2009	0.11	0.095		Actual Value	0.10
SD1	Sundance #1	2009	0.11	0.095		0.11	0.11		Actual Value	0.24
SD2	Sundance #2	2009	0.11	0.095		0.11	0.11		Actual Value	0.24
SD3	Sundance #3	2009	0.11	0.095	2009	0.11	0.095		Actual Value	0.13
SD4	Sundance #4	2009	0.11	0.095	2009	0.11	0.095		Actual Value	0.13
SD5	Sundance #5	2009	0.11	0.095	2009	0.11	0.095		Actual Value	0.22
SD6	Sundance #6	2009	0.11	0.095	2009	0.11	0.095		Actual Value	0.22
WB1	Wabamun #1		0.45			0.45			Actual Value	
WB2	Wabamun #2		0.45			0.45			Actual Value	
WB3	Wabamun #3		0.45			0.45			Actual Value	
WB4	Wabamun #4		0.45			0.45			Actual Value	
GN3	Genesee #3	2009	0.095	0.095	2009	0.095	0.095		Actual Value	0.05
KH3	Keephills #3	2009	0.095	0.095	2009	0.066	0.095		Actual Value	0.03
SD4/5/6U	SD4/5/6 Uprates	2009	(various)	(various)	2009	(various)	(various)		Actual Value	

Hg Intensities by Unit and Year											
			2003 Mercury (mg/MWh)			2008 Mercury (mg/MWh)			2014 Mercury (mg/MWh)		
ID	Name	Baseline	Mercury Installed	Pre-Installaion Intensity	Post-Installation Intensity	Mercury Installed	Pre-Installaion Intensity	Post-Installation Intensity	PM Installed	Pre-2013	2013+
BR3	Battle River #3	12.9	2010	12.00	12.00	2011	10.92	3.30		Actual Value	5.57
BR4	Battle River #4	12.9	2010	12.00	12.00	2011	10.92	3.41		Actual Value	5.57
BR5	Battle River #5	12.9	2010	10.92	3.24	2011	10.92	4.07		Actual Value	5.57
HRM	H.R. Milner	5.8	2010	0.00	0.00	2011	0.00	0.00		Actual Value	1.36
SH1	Sheerness #1	20.6	2010	21.51	3.16	2011	21.51	6.65		Actual Value	4.67
SH2	Sheerness #2	20.6	2010	21.51	3.18	2011	21.51	6.49		Actual Value	4.67
GN1	Genesee #1	13.8	2010	13.40	3.69	2009	13.40	3.52		Actual Value	3.90
GN2	Genesee #2	13.8	2010	13.40	3.69	2009	13.40	3.75		Actual Value	3.90
KH1	Keephills #1	29.7	2010	16.55	5.91	2011	16.55	6.48		Actual Value	2.29
KH2	Keephills #2	29.7	2010	16.55	6.47	2011	16.55	8.07		Actual Value	2.29
SD1	Sundance #1	29.7	2010	34.00	34.00	2011	34.00	34.00		Actual Value	3.55
SD2	Sundance #2	29.7	2010	39.00	39.00	2011	39.00	39.00		Actual Value	3.55
SD3	Sundance #3	29.7	2010	18.63	8.44	2011	18.63	9.73		Actual Value	3.55
SD4	Sundance #4	29.7	2010	18.63	8.32	2011	18.63	9.73		Actual Value	3.55
SD5	Sundance #5	29.7	2010	18.66	8.89	2011	18.66	9.93		Actual Value	3.55
SD6	Sundance #6	29.7	2010	18.66	7.66	2011	18.66	8.79		Actual Value	3.55
WB1	Wabamun #1		2010	19.29		2011	19.29			Actual Value	
WB2	Wabamun #2		2010	19.29		2011	19.29			Actual Value	
WB3	Wabamun #3		2010	19.29		2011	19.29			Actual Value	
WB4	Wabamun #4		2010	19.29		2011	19.29			Actual Value	
GN3	Genesee #3		2010	11.01	7.64	2011	11.01	0.23		Actual Value	3.37
KH3	Keephills #3					2011	0.23	0.23		Actual Value	1.61
SD4/5/6U	SD4/5/6 Uprates		2010	(various)	(various)	2011	(various)	(various)		Actual Value	